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

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Fourth Quarterly Technical Progress Report

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1. SUMMARY

In the fourth quarter of calendar year 1992, most of the effort was on Task 2. "Preliminary Systems Tests" and Task 4 "Economics and Commercialization Plan". Work also continued on several remaining items in Task 1."Design, Installation, and Shakedown of the Modifications to the 20 MMBtu/hr Air Cooled Combustor and Boiler Components"

In task 1 the only remaining planned work was the fabrication and installation of the automatic slag breaker. This device was installed and used successfully in the task 2 tests. In addition, unanticipated problems with the ultraviolet flame safety system required led to the replacement of one of the two UV detectors, and the design of an integrated UV-IR flame safety system that will be installed in the next quarter.

The only other remaining mechanical work is the installation of an air cooled, combustor exit nozzle system. This work has been deferred to the latter part of task 2.

In the analytical part of task 1, the specifications required for 2 dimensional combustor modeling with the Brigham Young combustion code were prepared and the results are anticipated in the next quarter. Additional work was performed to resolve the discrepancy in the combustion chemistry results obtained with the 3 dimensional FLUENT combustion code.

A major part of the work in this quarter was on the combustor tests in task 2. Three of the six planned tests in this task were completed. The first two were parametric tests of nominal one shift, (8 hour) duration on coal. Due to failure of the UV detector in the first test, only several hours of coal fired operation were completed. In the second test, coal fired operation continued for the planned one shift until the 4 ton coal bin was empty. After reviewing this work with DOE, it was decided to focus the remaining test on longer duration operation with each test at one optimum condition. The third test was planned for two shift coal fired operation. Due to a problem with the pilot gas ignitor, combustion was delayed by 5 hours from 7 AM to Noon. As a result coal fired operation was limited to one shift between 3 PM and 11 PM. Throughout this period the combustor remained at one fixed condition with the use of computer control. Results for these three tests are presented in this report.

Most of the work on the task 4 design and cost of a 20 MW combined gas-steam turbine power plant using the air cooled combustor was completed in the previous quarter. The results obtained by the A/E subcontractor on the installation design and cost were evaluated in the present quarter and they are summarized in this report. In addition, DOE-PETC's systems analyses group performed detailed cycle analysis of the Coal Tech 20 MW combined cycle using the Aspen computer code, and these results are also presented here. The overall cycle efficiency obtained with the Aspen code agreed with that obtained with a simpler analysis. The efficiency is in the low 30% range because 75% of the power output is derived from the steam bottoming cycle. The capital cost estimate was $1200 to $1400/kW. This compares with $1400 to $1750/kW for a natural gas fired, Cheng combined gas-steam turbine cycle, and $2000-$2300/kW for a fluid bed fired steam cycle.

Part of the task 4 effort is devoted to commercialization. A consulting firm was retained to identify potential sites for commercial application of the combustor technology in retried or standby utility power plants in the 20 to 50 MW range. Three possible sites in the East and Midwest were identified from a group of two dozen utilities. The choice was limited due to the specification of a small plant size. A similar effort was implemented on identifying candidate sites for independent power and industrial power plants in the same size range. However, currently almost all projects are gas fired, gas turbine power systems. Finally, questionnaires on the requirements for commercial acceptance of the combustor technology were prepared and submitted to companies in the boiler manufacturing, industrial power use, and power plant fabrication area. Highlights from this survey are included in this report. The results of the survey are being used to plan future commercialization activities.

A paper on the combustor effort was presented at the ASME Joint Power Conference in Atlanta in October. Also a paper was accepted for presentation at the Coal Technology Conference in Clearwater, FL in May 1993.

2. PROJECT DESCRIPTION

2.1. Objectives

The primary objective of the present Phase 3 effort is 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 will be 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 is to achieve 0.4 lb/ MMBtu of SO2 emissions, 0.2 lb/MMBtu of NOx emissions, and 0.02 lb particulates/MMBtu. Meeting the particulate goal will require the use of a baghouse or electrostatic precipitator to augment the nominal 80% ash retention in the combustor. The NOx emission goal will require a modest improvement over reductions achieved to date in the combustor of 0.26 lb/MMBtu. To reach the SO2 emissions goal inside the combustor may require a combination of reduction inside the combustor and inside the boiler by injection of suitable sorbents. To date, SO2 levels as low as 0.6 lb/MMBtu, equal to 81% reduction in 2% sulfur coals, have been measured with boiler injection of sorbents.

The project objectives will be met by a series of tests of increasingly longer duration, and totaling about 800 hours of total testing.

The final objective is 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 objective both simple steam generation and combined gas turbine-steam generation systems will be considered.

2.2. Technical Approach

2.2.1. Overview

The work of this Phase 3 project will be implemented on Coal Tech's patented, 20 MMBtu/hr, air cooled cyclone coal combustor that is installed on an oil designed, package boiler at the Tampella plant in Williamsport, PA. This combustor was installed in 1987. It has undergone development and demonstration testing since that time. The primary fuel has been coal. Other tests, including combustion of refuse derived fuels and vitrification of fly ash, have been successfully performed.

The combustor's novel features are air cooling and internal control of SO2, NOx, 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. SO2 is controlled by injecting calcium oxide based sorbents into the combustor to react with sulfur emitted during combustion. The spent sorbent is dissolved in the slag and removed with it, thereby encapsulating the sulfur in slag. NOx is controlled by staged, fuel rich combustion inside the combustor.

As described in Section 2.1. excellent progress has been made in the past several years in meeting these combustor performance objectives. One of the most important objectives of this technology development effort is to demonstrate very high SO2 reduc-tion in the combustor. Prior to the start of the present Phase 3 project, the peak SO2 reduction achieved with sorbent injection in the combustor had 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% SO2 reduction has been measured with sorbent injection in the boiler immediately downstream of the combustor. Tests in the past several years have revealed the critical role played by optimum operating conditions in the SO2 reduction process. Specifically, combustor operation must be automatically controlled, and solids feed and air-solids mixing in the combustor must be optimized. Progress in both areas has been accomplished in the past 2 years by using a microcomputer to control the combustion process and by testing various methods of feeding and mixing the coal and sorbents. In the summer of 1992, tests performed in a prior project indicated that in excess of 90% SO2 reduction could be achieved by sorbent injection in the combustor. Major emphasis in the initial tests to be performed in the present project will be to confirm these results.

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 3000F 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 is being solved. Since introduction of computer control two years ago, the need for frequent refractory liner patching inside the combustor has been sharply reduced. The project objective of combustor durability will be implemented by operating the combustor for increasingly longer continuous periods on coal. To date, the longest continuous operation on coal has been 8 to 10 hours. It is planned by the end of the present project to achieve continuous round-the-clock coal fired operation for up to 100 hours. The combustor internals and auxiliary components will be modified, and the automated computer control will be extended to accomplish the durability objective.

The final project objective of placing the combustor in a viable industrial steam or power generating system will be accomplished by detailed engineering analysis on the use of the combustor in one or more steam generating cycles. This effort will also include an assessment of the requirements for commercializing the combustor for an industrial application.

2.2.2. Task Description

Task 1: Design, Fabricate, and Integrate Components

This task consists of three sub-tasks. Components design, component fabrications, and components integration, and shakedown tests. The 20 MMBtu/hr combustor will be modified to allow safe and environmentally compliant operation for periods of up to 100 hours.

Task 2: Preliminary Systems Tests

The modified combustor system will undergo a series of one day parametric tests of total duration of 100 hours to validate the design changes introduced in task 1, and to accomplish the project objectives and goals.

Task 3. Proof of Concept Tests

The durability of the combustor will be determined in a series of tests of between 50 and 100 hours of continuous operation. The total test period will be 200 hours.

Task 4. Economic Evaluation & Commercialization Plan

The economics of one or at most two different industrial scale steam based cycles using the combustor will be evaluated. A commercialization plan will be developed for marketing the combustor in an industrial environment both in the US and overseas.

Task 5. Conduct Site Demonstration

This task will be the final test activity in the project. Its objective will be to demonstrate the durability and hence the commercial readiness of the combustor for its intended industrial application(s). The effort will consist of two sub-tasks. In the first one any changes required as a result of prior tests will be made to the combustor. In the second one, a series of tests, each of up to 100 hours of continuous coal fired operation will be performed, with a total test time of 500 hours.

Task 6. Decommissioning Test Facility

The test facility will be removed from the boiler installation and disposed in accordance with required regulations.

3. PROJECT STATUS.

3.1. Task 1."Design, Installation, and Shakedown of the Modifications to the 20 MMBtu/hr Air Cooled Combustor and Boiler Components"

Almost all the planned work in task 1 was completed in the previous quarter. In the present quarter work on this task was limited to the following items:

A key component in continuous long duration coal fired operation is the mechani-cal slag tap breaker. Without this component the slag tap will generally plug within about 1 hour of operation and this requires termination of coal firing. A manually operated slag breaker was first installed in early 1990, and it has been used successfully since that time. Its main shortcoming is the need for continuous operator attention. On a few occasions during the past 3 years, failure of the operator to regularly clear the slag tap caused blockages which required combustor shutdown. Therefore a key objective in task 1 was to design and install an automatic breaker system. In its absence round the clock coal fired operation would be impossible.

Work on the breaker automation began in May 1992. The two major technical problems were the design of a sensor that could detect the position of the breaker, and the design of a mechanism that would take up the slag in the breaker control wire. Several electrical motor designs were tested and rejected due to excessive friction in its mechanical components. It was finally decided to simply increase the tension in the breaker control wire to overcome friction. With regard to the breaker position indicator, both photo-electric and acoustic sensors were tested. After a number of iterations, a suitable photo-electric detector was developed.

The complete automatic breaker system was first tested in the second of the task 2 tests in November, and it operated well. At present the system operates by manually pushing two switches which actives the entire breaker cycle. The system has been used successfully in the second and third task 2 test. It was also in a test of fly ash vtrification using oil heat that was performed under another project. In that case, the slag was not friable. When the slag tap became flooded with slag and it plugged, it was not possible to reopen the tap with the breaker. This latter result shows that the physical characteristics of the slag and the nature of the slag flow also impact the effectiveness of the slag breaker. This slag behavior is less likely to occur under the conditions used on coal fired operation.

The second component item addressed in this quarter was the flame safety system. During the first test in task 2, the flame safety system repeatedly shutdown the combustor. After several shutdowns all effort to restart the combustor failed. The flame safety system consists of two ultraviolet detectors. In the tests, the flame safety system was shutdown due to blinding of the detectors by the solids injection streams. However, this problem had been eliminated by locating one of the detectors at a point where solids blinding was not possible. In the present case, it was found after much effort that the problem was caused by a failed detector tube in one of the two UV detectors. The flame safety system was designed to allow continued operation is one of the detectors was blinded, but not if one of them failed internally. To prevent this problem from recurring, a new control circuit was designed which integrates the two UV detectors with a newly acquired infrared flame detector. This will allow continued operation in the even of a tube failure or blinding of one of the detectors.

The only other component items performed in this task were minor. One was to replace a defective water flow meter, and install a total water flow meter suitable for computer use. As noted in the prior report, the exit nozzle cooling tubes will not be installed until late in task 2 or prior to task 3 tests. Also, isolating the cause of water pressures loss in the new water supply system will be deferred until next spring. Finally, other components modifications and maintenance will be performed as part of the test tasks 2, 3, and 5.

3.2. Task 1.1. Analytical Modeling Results

As part of Task 1, it was planned to use the 3D FLUENT code and BYU's 2D Mixing code to scope the effects of various injection geometries on performance, including fuel/air/sorbent 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 is to verify, wherever possible, the model predictions against experimental data. Once this is done and a reasonable confidence level is established, the model predictions, based on combustor design or operation changes outside the realm of direct experimental verification, would be somewhat believable. The following sections detail the modeling work to date.

3.2.1. Fluent Codes

Four cases were modeled using the commercially available 2D version of the FLUENT code. Owing to input complexity and resource limitations the FLUENT 2D code was used instead of the originally planned 3D version. 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.

As noted, 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	CO2	H2O	H2	O2			
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 O2 when all H2 and CO are converted to final products.
(b) C/H Mole Ratio = (CO + CO2)/[2 * (H2 + H2O)].
(c) Balance assumed to be N2.

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 given to Dr. Marston, who ran FLUENT, 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 fuel-lean 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 H2 in the presence of excess O2 in all cases, and high CO in the presence of O2 in the nominally fuel-rich cases. In any case, by converting all H2 and CO to H2O and CO2, the remaining O2 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 and 4030 F while for the fuel-rich cases the values are 3902 and 4130. 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 and 3900 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

$$H2O + CO = CO2 + H2$$

with

$$Kp = (PCO2*PH2)/(PH2O*PCO)$$

where PX = partial pressure of species X.

Based on the derived species concentrations in the product gas the calculated equilibrium constants were: 14.0 (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 (Kp) 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 high predicted 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 has devoted some time to address the situation, suggesting that the problem may be due to a lack of convergence, possibly related to grid size selection. However, the source of the problem has not been established. Based on information at hand, 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 in the university and other technical communities, it appears 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 have been sent to them for evaluation. It is hoped that they will uncover the source of our difficulties and rectify the situation. At present, however, the modeling results are of limited usefulness. If some deficiency in the code is responsible for skewing the output, then we would hope that FLUENT will correct the problem and run our cases at no additional cost. If no resolution of this difficulty is forthcoming then we must conclude that the FLUENT model is unsuitable for our application.

3.2.2. BYU CODE

Owing to the discovery and correction of an error in the code, dealing with solid carbon and the water-gas shift reaction, there has been some delay in implementation of the BYU modeling. However, upgraded input conditions for both fuel-lean and fuel-rich cases have been submitted and results are expected in the next several weeks. These will be subjected to the same rigorous scrutiny as the FLUENT results.

Although previous BYU 2D simulations of the Coal Tech combustor were useful, recent evaluation of operating data as well as improvements in the model itself now allow a more rigorous modeling effort. For example, one deficiency in the earlier modeling was the use of 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. Now, however, NG can be included as a premixed part of the primary air stream.

A second shortcoming was the incorrect specification of swirl air tangential velocity, resulting in ultra-high swirl numbers. Velocity probe measurements have shown that swirl velocity decays rapidly in the swirl cage and is considerably reduced at the entrance to the combustor. Thus both of the above problems were corrected for the next series of model simulations.

Globally, the present effort aims at modeling two base cases: one fuel-lean (FL) and one fuel-rich (FR). If these simulations are satisfactory, in terms of reasonable agreement with measured test data, two additional cases will be performed: 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 2D model is to allow the reaction chamber to have an axial wall temperature profile. It is now 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 recirculation 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. This is illustrated in figure 1.

As per figure 1, the combustor wall temperature rises from 250 F (394 K) at 0" (0.00 m) to 2500 F (1644 K) at 15" (0.38 m). This rise is not linear but takes the polynomial form:

$$Tw = ((0.113571*X) - (0.003571*X^2) + 0.1) * Tf$$

where Tw = wall temperature in F, X = axial combustor length in inches, and Tf = final wall temperature in F, namely 2500 F for both the FR and FL cases. Figure 2 shows the wall heatup curve in detail, with the wall temperature given as a fraction of the final combustor wall temperature value.

From 15" (0.38 m) to 48" (1.2195 m) the combustor wall is isothermal at 2500 F (1644 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 F (1700 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 will be represented as a function of axial wall temperature. Namely, if the wall temperature is below 2200 F (1477 K) the particles will rebound back into the gas stream or recirculation zone and continue to react. If the wall temperature is equal to or greater than 2200 F (1477 K) then the particles will stick and undergo 100 % burnout. The reason for this approach is to try to accommodate experimental evidence indicating that about the first foot of the combustor wall has essentially no slag covering. The 2200 F (1477 K) threshold value is related to experimental slag T250's as well as reported slag softening and melting data.

Another one of the model's recent improvements is 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. These parameters will be made available as part of the output.

3.3. Task 2. Preliminary Systems Tests

3.3.1. Task 2 Tests: Operation and Maintenance Results:

Three of the 6 planned tests in task 2 were perform during the present quarter. The present sub-section describes the operational results observed during the tests and the combustor maintenance activities that were performed as a result of these tests. The test results and analysis is given in the next sub-section. The first test was performed on October 8, the second one on November 11, and the third one on December 29.

Test No.1 October 8. As noted above, 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 8 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 was necessary to eliminate 8 point injection from future tests and to return to 4 point coal injection for the balance of the project. However, with a new combustior design, 8 point injection could be used.

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 calcium hydrate sorbent. This yielded poor slag flow on the combustor wall, which in turn reduced the char burnout under the fuel rich conditions used in this test.

The pneumatic feed line from the small sorbent storage bin was found to be inadequate to process the desired calcium hydrate flow. In subsequent tests, the large sorbent storage bin was used.

Test No.2. November 11: As stated in the task 1 discussion, the UV flame detector was repaired after the first test. Also, post test No.1 inspection revealed that a 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. If the leak increases again to unacceptable levels, it is planned to use air cooling of this section. A heat transfer analysis of the required air cooling rate showed that air cooling will be adequate.

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 been used in the first three two 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, calcium hydrate was used as a sorbent. It has a finer particle size distribution compared to limestone. Therefore, with hydrate 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 No2 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 the mechanical breaker. 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 as initiated in 1990. The reason the liner was refurbishment 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.

Test No. 3. December 29: 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 ignitor insulator tip was coated with oil, which shorted out the ignition spark. This occurred during 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 ignitor rod was removed from the combustor and the ceramic insulator sleeves were cleaned. It was not possible to re-insert the ignitor 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 ignitor rod was reinstalled. However, it was not possible to align the ignitor 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 gun 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 hydrate 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 effective in 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 next tests will be performed with a lower viscosity coal. 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, we will be in position to perform multi-day continuous coal tests.

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 repiping the water drainage pipes. Since few tests have been performed during very cold weather since that time, this blockage problem has not recurred. As a result of the experience in this test, the water drainage pipes were rerouted to eliminate all remaining horizontal sections.

In conclusion, the key results of these tests are that once steady state conditions under coal fired operation are established, the computer control system maintains the combustor at a steady operating condition. A major new result is that the viscosity of the coal has a major impact on both 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 sorbent fluxing this problem could be controlled. Therefore, the present result was unexpected, and it could limit the coal flexibility of the combustor. To resolve this matter further tests should be implemented.

3.3.2. Task 2 Tests: Summary of Performance Results:

This section contains a summary description of the combustor's performance in the three tests discussed in the previous sub-section. For continuity of presentation there is some duplication of information between this and the previous sub-section. A considerable body of performance data was collected during these three runs. However, as three more runs are scheduled for this tasks, the presentation of this material will be deferred until the next quarterly report. The data not included in this report consist of the combustion and thermal performance of the combustor, as collected both by computer and manually, the properties of the fuel and sorbent, and the post test analyses of the slag and scrubber samples.

The global objective of the three task 2 tests was to optimize the performance of the combustor with the modifications installed in Task 1. Specific objectives were to test multi-point injection and to optimize wall cooling, SO_2 reduction, and slag flow; a slag desulfurization test was also tentatively planned.

The test plan was prepared to allow maximum flexibility in order to address key commercial/technical issues, such as durability, in a timely manner. The exact sequence of test goal implementation is of minor importance so long as major goals are eventually met. Thus, based on discussions with PETC after the project review meeting of 11/17/92, it was decided that the third Group 1 test should focus primarily on a longer duration coal run at fixed operating conditions, instead of being a shorter duration parametric test as originally scheduled.

The following sections discuss in detail the tests conducted during this reporting period.

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. Eight-port injection was to be used with and without steam and/or water spray injection for wall cooling and as an additional parametric. This test was the first with the new high ash coal as well as the newly reinstalled high capacity coal feed auger.

Additional goals included: performance assessment of the 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 IR 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 NG. Combustor air averaged 78 % of theoretical air (SR1 = 0.78), while second stage air (SR2) averaged 1.40. Consumables: @ 2100 lbs coal & 100 lbs hydrate.

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.

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 mv 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 IR 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 while the coal auger ran with no problems.

iii) Technical Results: Owing to wall cooling requirements, initial direct and indirect combustor steam injection was high (@ 700 PPH), 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 SO2 at Ca/S = 1.0 was about 29 % at SR1 = 0.73; at Ca/S = 1.9, the reduction in stack SO2 was around 37 % at SR1 = 0.89.

Requirements prior to the next test included repairing or replacing the UV flame safety equipment as needed; initiate work to incorporate the IR detector into the flame safety system; upgrade sorbent feed system to handle hydrate; clean and refurbish slag tap chamber and burners as required (this work is somewhat extensive and was therefore delayed until convenient since acceptable slag tap operation can often be achieved without the burners).

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 sorbent injection. Depending on performance, it was hoped that a slag desulfurization test might be performed with gypsum injection, or that the effects of alumina/hydrate injection on combustor wall replenishment could be evaluated.

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. Eight-port solids injection was again implemented. However, in order to achieve improved hydrate injection, a larger eductor was employed. This test also used the high ash coal of test DP3. The slag tap burners were not employed during this test, however, the slag tap plunger was utilized in an almost fully automatic mode for the first time. In addition, the UV flame sensor system was repaired while incorporation of the IR flame sensor into the safety control system was deferred until later.

i) <u>General Results</u>: 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 hydrate feed system partially plugged owing to residual flyash agglomerates blocking the four small original sorbent ports. With the sorbent injection flow cross section considerably reduced, the larger eductor was oversized and the system could not transport any material, even at minimum sorbent and/or air flow. This required a quick reconversion back to the old feed system with the smaller eductor. With this arrangement, the four used annular sorbent ports, being larger than the blocked ports, performed with no problem.

Due to the lack of sorbent 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 sorbent injection, the exit nozzle opened. The plunger worked well in a semi-automatic mode, i.e. with manual initiation of the plunger operating sequence. In order to make the system fully automatic, a different plunger height location sensor is believed to be required. However, the present configuration was deemed adequate for the near future.

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) <u>Combustor Slagging:</u> Although higher than in test DP3, measured combustor slag rejection averaged only 28 %. However, 41 % of the operating time was with no hydrate 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 flyash 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 flyash during oil firing. Based on an evaluation of experimental slagging performance, it was believed that flyash 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 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.

In spite of combustor slag buildup in test OIL1, post test inspection of the combustor interior indicated that two small tube sections were exposed and that the slag layer was porous or pulled away in some places. Thus, refurbishment of the liner was required. This tube exposure and general erosion of the walls almost certainly took place during the coal fired tests, particularly DP4.

Another major result of the OIL1 coal ash replenishment test was that although the flyash slag melted easily, having a relatively low T250 of around 2200 to 2300 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.

Based on previous operating experience, it is now clear that the CaO must be injected separately from the ash in order to achieve not only a good slag T250 but also a breakable slag. In our view, separate injection results in non homogeneous layers of molten coal ash and CaO, with the boundaries serving as weak points easily fractured. In ashes where the CaO, though appropriately high in terms of T250, is part of the original structure it is too widely and uniformly dispersed to provide these fracture planes.

Returning to test DP4, it is felt that the ultimate source of poor slagging is the high T250 of the new high ash coal, namely 2649 F. Ordinarily, the addition of a calcium-bearing sorbent aids in fluxing such refractory ashes. However, as noted in previous reports, fine hydrate particles are not readily incorporated into the slag but are preferentially carried out of the combustor. This was borne out by chemical analysis of slag samples from test DP4 which showed some reduction in T250 with hydrate injection but also showed poor hydrate retention in the slag. From this, the conclusion is that although hydrate improved slagging and combustion efficiency with the new refractory ash coal, vs no sorbent injection, its performance was still below acceptable limits.

Thus, it was planned to test the high ash coal one more time with injection of coarse limestone, which is retained more efficiently in the slag. If this course of action does not work, we plan to return to a lower ash coal having a lower T250.

iii) <u>Technical Results:</u> 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 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 %).

At hydrate Ca/S @ 2, the reduction in stack SO2 averaged 18 (+/-) 7 % at average SR1 = 0.74 (+/-) 0.10. With no sorbent, up to 89 % of the coal sulfur was measured as SO2 in the stack. Statistical analysis of project test results to date suggests 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 hydrate sulfur capture efficiency at higher SR1, in contrast to limestone.

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

As noted above, based on discussions with PETC, it was decided that the this Group 1 test should focus primarily on a longer duration coal run at fixed operating conditions, instead of being a shorter duration parametric test as originally scheduled.

As also discussed with PETC, key process performance variables were identified in order of importance. Namely: (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 recent results with hydrate, as well as the historical data base, key variables (1), (2), and (3) are optimized under near-stoichiometric or fuel-lean conditions while variable (4) is 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 sorbent 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 involved the first test of dual sorbent injection; limestone primarily for ash fluxing and hydrate 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 NG 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 sorbent injectors used. Fuel heat input was steady at @ 14 MMBtu/hr, 94 % due to coal, balance NG. Combustor air averaged 88 (+/-) 3 % of theoretical air (SR1 = 0.88), while second stage air (SR2) averaged 1.25 (+/-) 0.03. Consumables: @ 4 tons of coal, @ 550 lbs of limestone, and @ 350 lbs hydrate. In addition, combustor wall cooling was maintained mostly by the cooling air with some cooling tube 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 are being prepared for an evaluation of mass balance. However, the present conclusion is 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 it is therefore planned to return to a coal having a lower ash T250.

At hydrate Ca/S @ 2, of which about half was due to hydrate and half due to limestone, the reduction in stack SO2 averaged 37 (+/-) 4 % at average SR1 = 0.88 (+/-) 0.03. With cooling tube water injection toward the end of the test, the measured SO2 reduction increased to 45 %, probably reflecting the previously noted enhancement of sulfur capture by limestone with combustor steam injection.

As noted at the beginning of this sub-section, considerable data has been collected manually and by computer on these three tests. It is planned to present this material in a comprehensive manner as soon as the remaining three tests in task 2 are completed.

3.4. Task 4. Economics/Commercialization

3.4.1. Cycle Analysis and Economics:

As discussed in the previous Quarterly Report, an architect/engineering firm was retained in June 1992 to perform the layout and costing of a 20 MWe combined steam-gas turbine power cycle. This work was completed its work in September, and a detailed final report was submitted by the firm to Coal Tech The results were not analyzed by Coal Tech in time to include in the prior quarterly report. They will be summarized here.

The cycle proposed by Coal Tech consists of a 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. These results were used by the A/E firm to prepare a detailed process flow diagram and plant layout for the combined cycle. Separately, the systems analysis group of DOE/PETC's Office of Project Management performed several detailed analyses of this cycle using the Aspen computer code. The results of these efforts are as yet not finalized. 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 are as yet not reflected in the overall analysis. For this reason, only overall results will be presented at this time.

A schematic of the combined cycle is shown in figure 3. The base case assumes a commercial natural gas fired turbine operating at a nominal 1800F turbine inlet temperature. Its rated output is 5,940 kW with steam injection. The gas turbine exhaust steam 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 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 3) 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 air flow 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 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 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 No1

If the steam continued to expand in a steam turbine to 2.5 in Hg, (instead of gas turbine injection), the power output for case B would be 2,082 kW, and for case C, 1537 kW. Here a 78% steam turbine efficiency was used.

The steam flow of 19,800 lb/hr in the gas turbine exhaust is at 960F. When expanded to the stack temperature of 260F, 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 59F and 260 psia and it reaches 860F, i.e. the temperature difference between the gas turbine exhaust temperature and the peak boiler steam temperature is 100F. 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, 900F expanding to 2.5 in Hg. ~~In other words~~,

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..

Calculation Set No2

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 960F and 59F. 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 2913F in the boiler and 260F in the stack should be applied to the present pre-heat energy. The overall boiler efficiency is based on the 260F 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 59F feedwater and 950 psi,900F. This in turn yield 731 kW of power. Applying the same calculation as in the first set above, one finds the efficiency of the added gas turbine fuel is 48.3% for the 900F case B, and 44% for the 400F case C.

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 for use the boiler to be used for gas turbine steam injection.

20 MW Combined Cycle Analysis: The cycle shown in figure 3 was used by the A/E firm to prepare a detailed process flow diagram, shown in figure 4, and a plot plan of the plant, figure 5, and an elevation view, figure 6. DOE/PETC's Systems Analysis group also performed a cycle analysis using the Aspen code. The process flow diagram used in that analysis is shown in figure

7. There are minor differences between the cycles shown figure 4 and 7. For example, the latter has one additional steam extraction point. Also the steam turbine ratings differ slightly.

The discussion will focus on the latter analysis as it was more detailed. Referring to figure 7. Two base cases were considered. In both cases the same gas turbine with steam injection was used. The turbine inlet temperature was 1800F. The compressor outlet pressure was 171 psia. The net gas turbine power output was 5374 kW. The gas turbine exhaust at 1080F was used for combustion air in the air cooled combustor. The latter was attached to the boiler which generated steam at 900F and 950psig. The stack outlet gas temperature was specified at 260F. To maintain this stack temperature two approaches were used.

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 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 260F, 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 2300F, 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 repower 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, the steam turbine-generator. As will be shown in the next section, 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 assumes 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 is under study in another DOE/PETC program, it was not addressed.

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: The A/E firm perform a plant layout and cost estimation analysis of the 20 MW power plant cycle shown in figures 3 to 7. With the exception of the air cooled coal combustor, all other major components are commercially

available. The A/E firm obtained budgetary vendor quotations for all major components and sub-systems. These components were arranged according to the layout shown in figures 5 and 6. 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 2. 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.

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 presently in use at the Williamsport, PA test site. Since this cost is negligible small compared to the total plant cost, it is not included in the total cost given above.

The A/E firm 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. This compares with a cost of $1400 to $1750/kW for a natural gas fired, steam injected combined 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.

In conclusion, the efficiency and economics of the present cycle are very attractive for industrial and small utility power plant applications using coal as the primary fuel.

3.4.2. Commercialization

A consulting firm was retained to assist Coal Tech in obtaining customer require-ments 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, a survey of small utility boiler plants that could be used was made. To identify these plants, a DOE data base 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 identi-fied in the Middle Atlantic States and in the Midwest. Of these, three were selected for detailed evaluation. The owners of two of these plants have agreed to participate in a site specific evaluation on retrofit with the present power cycle. This work will be performed in the next quarter.

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 2 dozen ques-tions. 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 are highlights of these interviews. The responses are composites for those cases where several companies responded to the question.

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.

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.

3. *In the 20 to 50 MWe range what type of combustors are used?*

Stokers in the bottom end, pulverized coal and fluid beds in upper range. Cyclones are not used

Comment: The cyclones referred to are crushed coal units.

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.NOx/MMBtu and 0.5lbs.SO2/MMBtu. Therefore, 50% reduction of NOx 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.

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) O . deterrent to other combustors is contractual liability.

(3) To recommend other combustors need performance data, confidence in company, and acceptable business relationship.

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

10. *What specification would you require to sell outside combustor as part of boiler package?*
(1) Combustion efficiency
(2) Low emissions
(3) Appropriate dimensions
(4) Firm price
(5) Performance guaranties

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, one large company has never 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 dont 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 SO2 and NOx ate 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.

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 project 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

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) Industrial companies do not want to be first.

<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 cofiring for environmental control of industrial air, water, or solid waste emissions.
(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 has decided to focus on special applications where there is an urgent need to control environmental emissions, and where the coal-waste fuel cofiring capability of the combustor offers performance and economic advantages. Work in that direction began near the end of this reporting period.

Independent Power Production/Cogeneration Company Survey.

In November, 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. While the results are incomplete, it was learned that currently almost all projects use natural gas fired turbines with heat recovery boilers. It appears that as long as the price of natural gas remains low, gas will be the fuel of choice. However, several companies that are 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.

4. Effort of the Next Quarter.

The global objective of the tests performed during this quarter was to optimize the performance of the combustor with the modifications installed in Task 1. This objective has been largely met. Additional specific objectives were to test multi-point injection and to optimize wall cooling, SO2 reduction, and slag flow. A slag desulfurization test was also tentatively planned but not performed.

Multi-point solids injection can enhance operation provided that flow passages can be kept clear. Improved coal flow screening was a key accomplishment in this regard. However, there appears to be a minimum flow passage size below which periodic plugging cannot be avoided.

Wall cooling can be easily and efficiently obtained by water injection into the cooling tubes. In addition, combustor steam injection also reduces wall temperature by flame temperature reduction. However, excessive water and/or steam injection can quench combustion processes and lead to poor combustion efficiency and slagging.

SO2 reduction with hydrate has not been fully optimized. This is partly due to test goal redirection from parametric evaluation to longer duration operation. However, many of the key process conditions have been identified and future work will attempt to further optimize the results.

Combustor slag rejection was discovered to strongly depend on the slagging characteristics of the coal ash, with the high T250 ash used in this test quarter yielding poor results over a wide range of operating conditions. The conclusion here is that fluxing agents can enhance the slagging properties of ashes which have marginally high T250's but cannot salvage the performance of ashes with ultra-high T250's. It is for this reason that the concept of combustor wall replenishment by alumina/hydrate mixes was abandoned in favor of flyash replenishment.

Although considerable progress was made in this quarter, the near-term goal of a longer duration run of about 16 hrs to 24 hours with coal and sorbent bin refill during the test, has not been achieved. The work of the next quarter will focus on completing the three remaining task 2 tests, with the emphasis on continuous coal fired operation ranging from 16 to 20 hours.

The task 4 effort will be expanded with the retrofit study of two retired 20 MW utility power plants that were identified in the present quarter. In addition, a market assessment effort will be performed with the paper industry which fits the requirements for cofiring of waste fuels with coal.

TABLE 2. COST ESTIMATE FOR 20 MW COMBINED CYCLE PLANT

CLIENT: COAL TECH
LOCATION:
DESCRIPTION: WASTE TO ENERGY

ESTIMATE/JOB NO.: J111
ESTIMATED BY:
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.
	TOTAL OTHER COSTS						$3,294,000
	ESCALATION						NOT INCL.
	SUB-TOTAL						$21,593,000
	CONTINGENCY						2,568,000
	FEE						NOT INCL.
	GRAND TOTAL						$24,161,000

NOTES:
{1} ALL COSTS ARE 3Q92.
{2} LABOR COST DEVELOPED FROM CLRC AT $41/MANHOUR.

APPROVED BY PROJECT MANAGER:

HR-G-1-1291

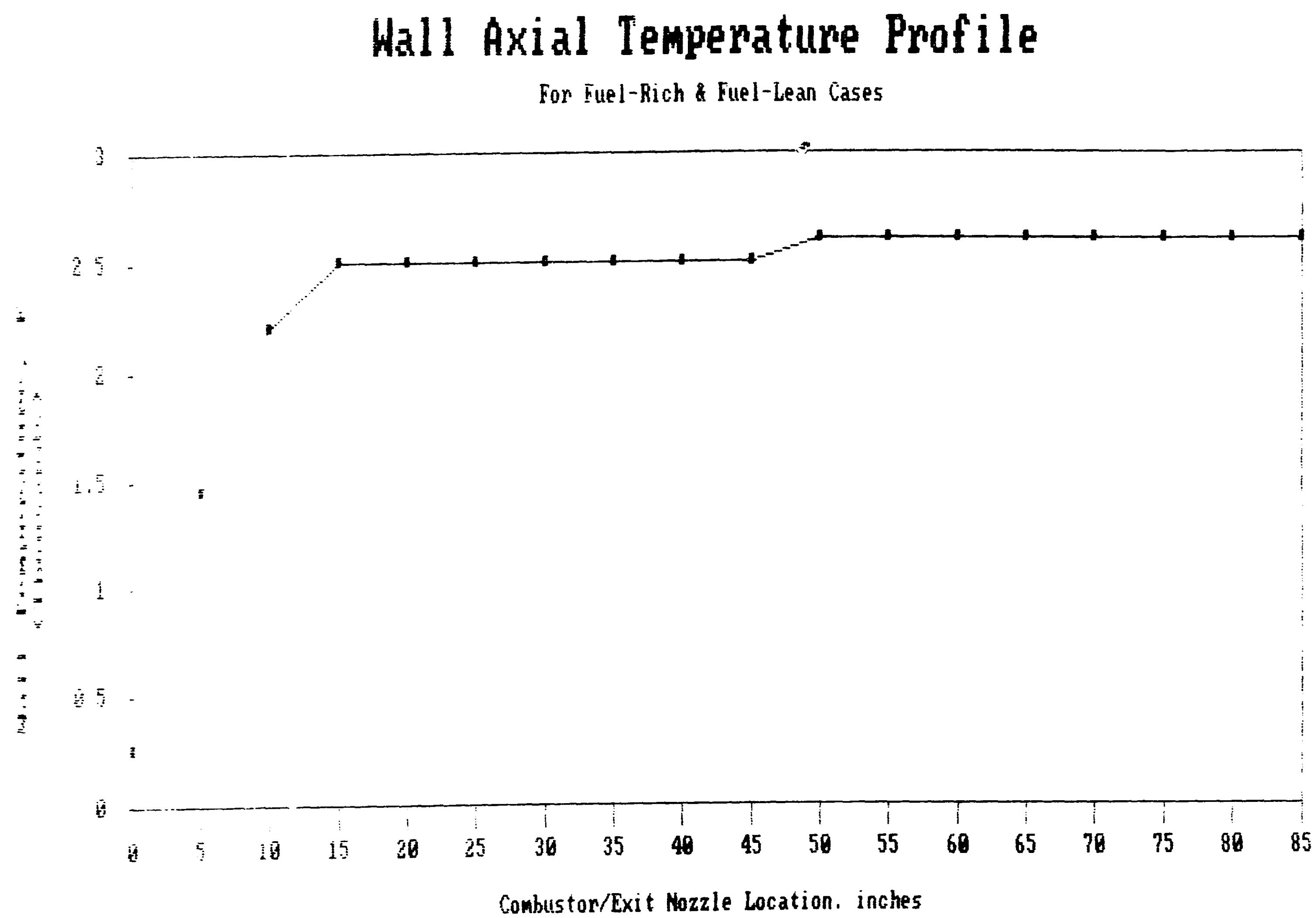


FIGURE 1. COMBUSTOR WALL TEMPERATURE AXIAL PROFILE

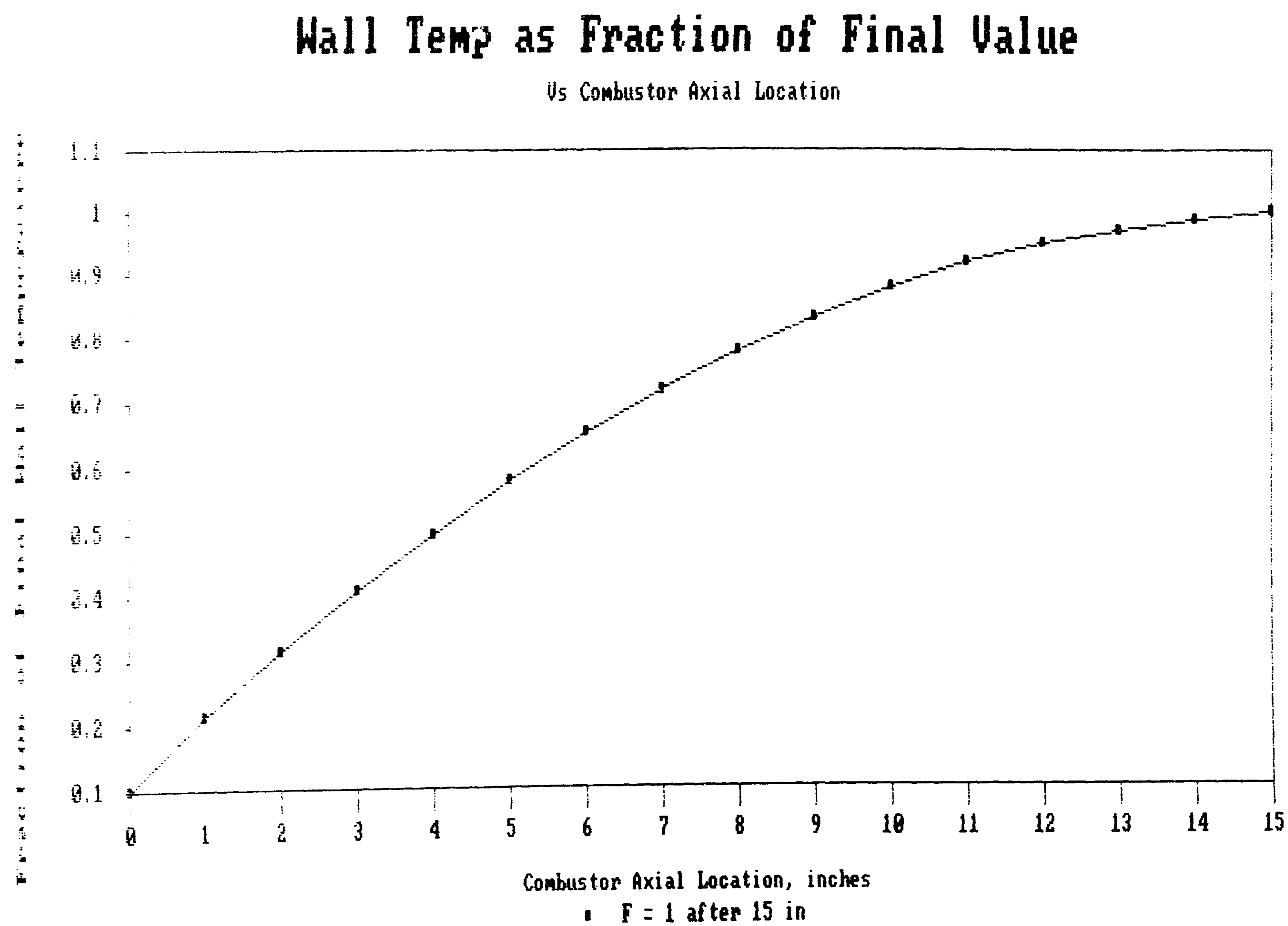


FIGURE 2. FRONT END COMBUSTOR WALL HEATUP

COAL TECH'S AIR COOLED COMBUSTOR COMBINED CYCLE PLANT

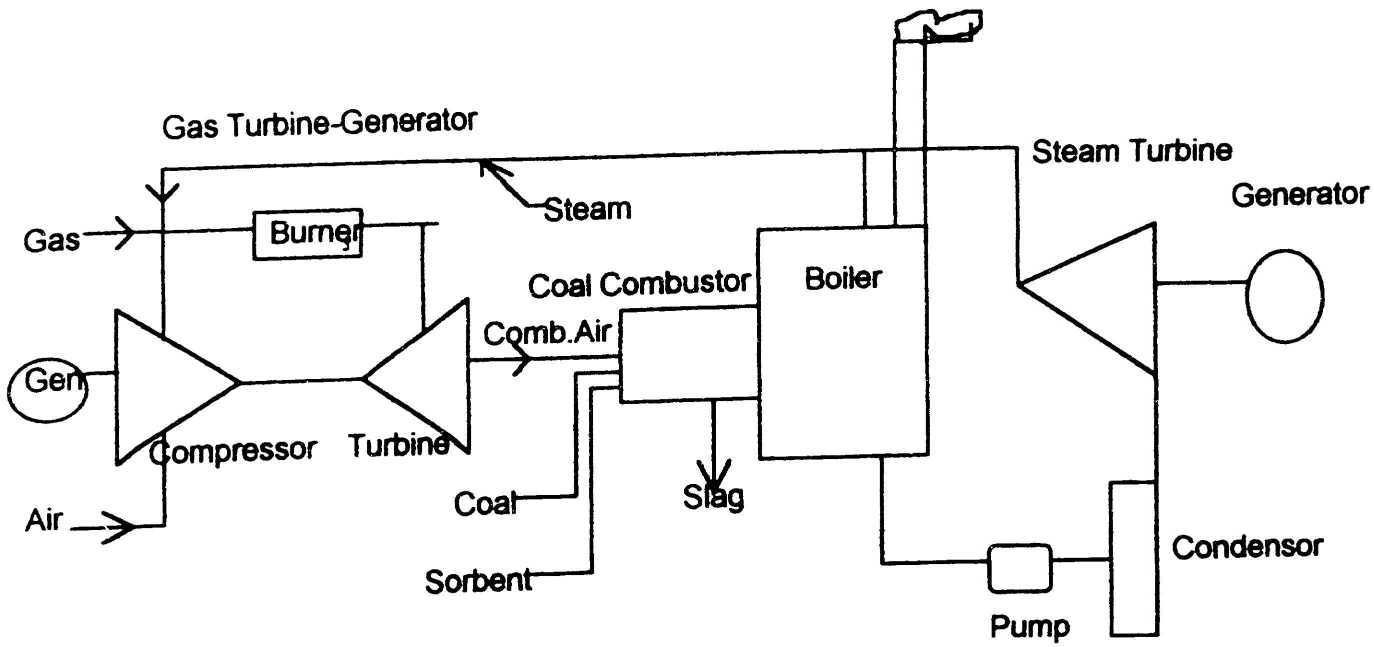
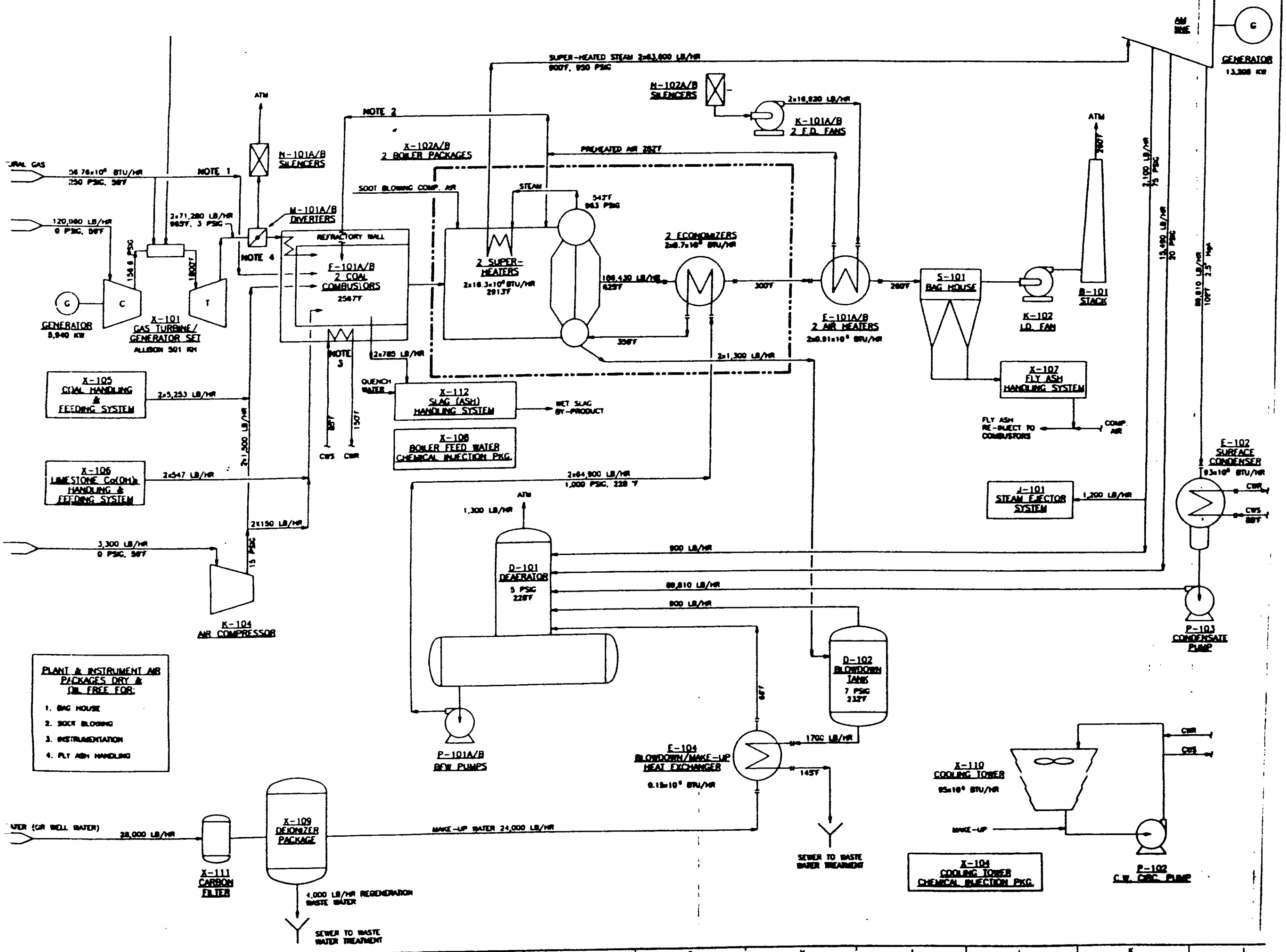


FIGURE 3: SCHEMATIC OF COAL TECH'S COMBINED CYCLE PLANT

FIGURE 4. 20 MW COMBINED CYCLE PLANT WITH AIR COOLED COMBUSTOR PROCESS FLOW DIAGRA



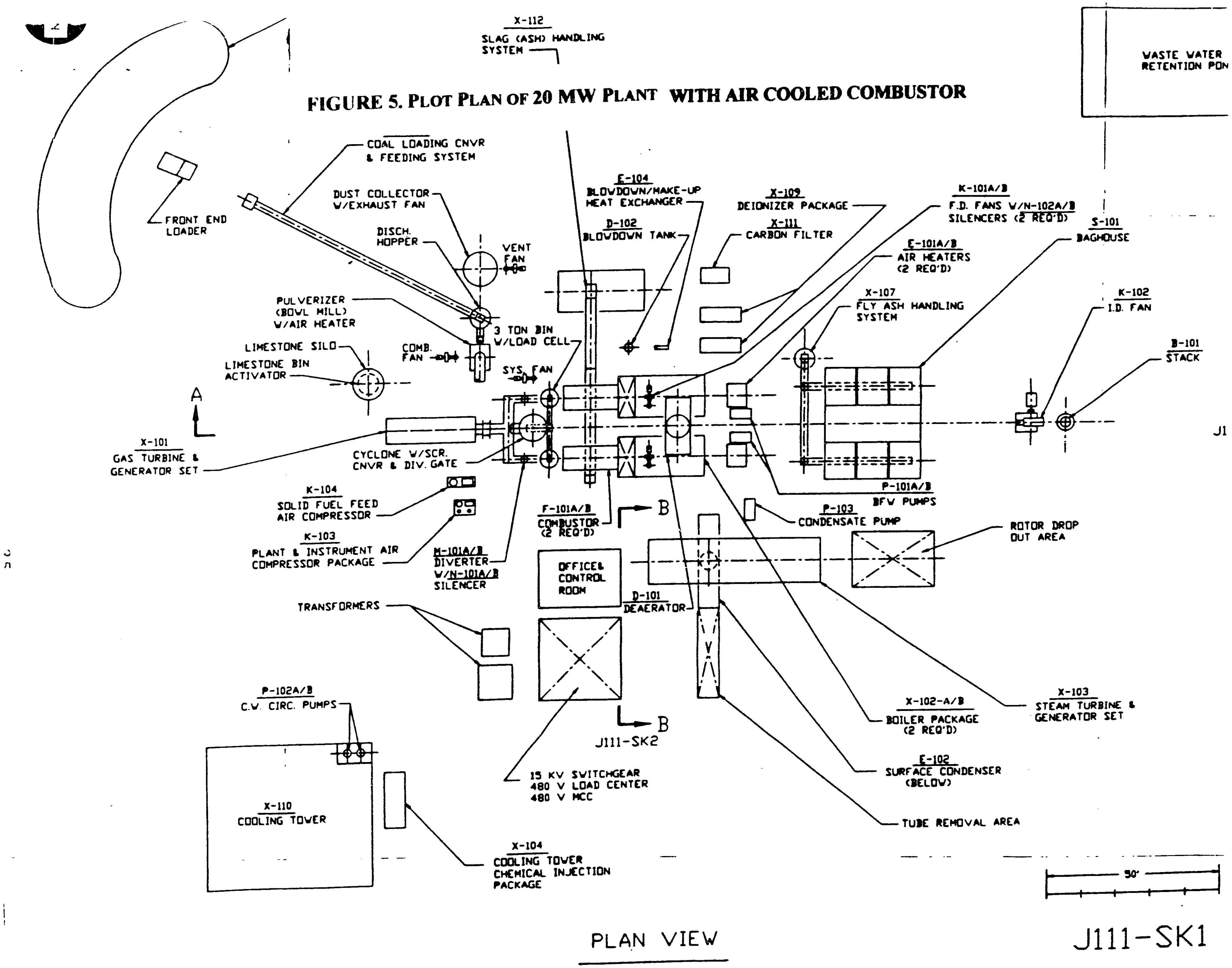


FIGURE 5. PLOT PLAN OF 20 MW PLANT WITH AIR COOLED COMBUSTOR

FIGURE 6. 20 MW PLANT EQUIPMENT ARRANGEMENT-SIDE VIEW

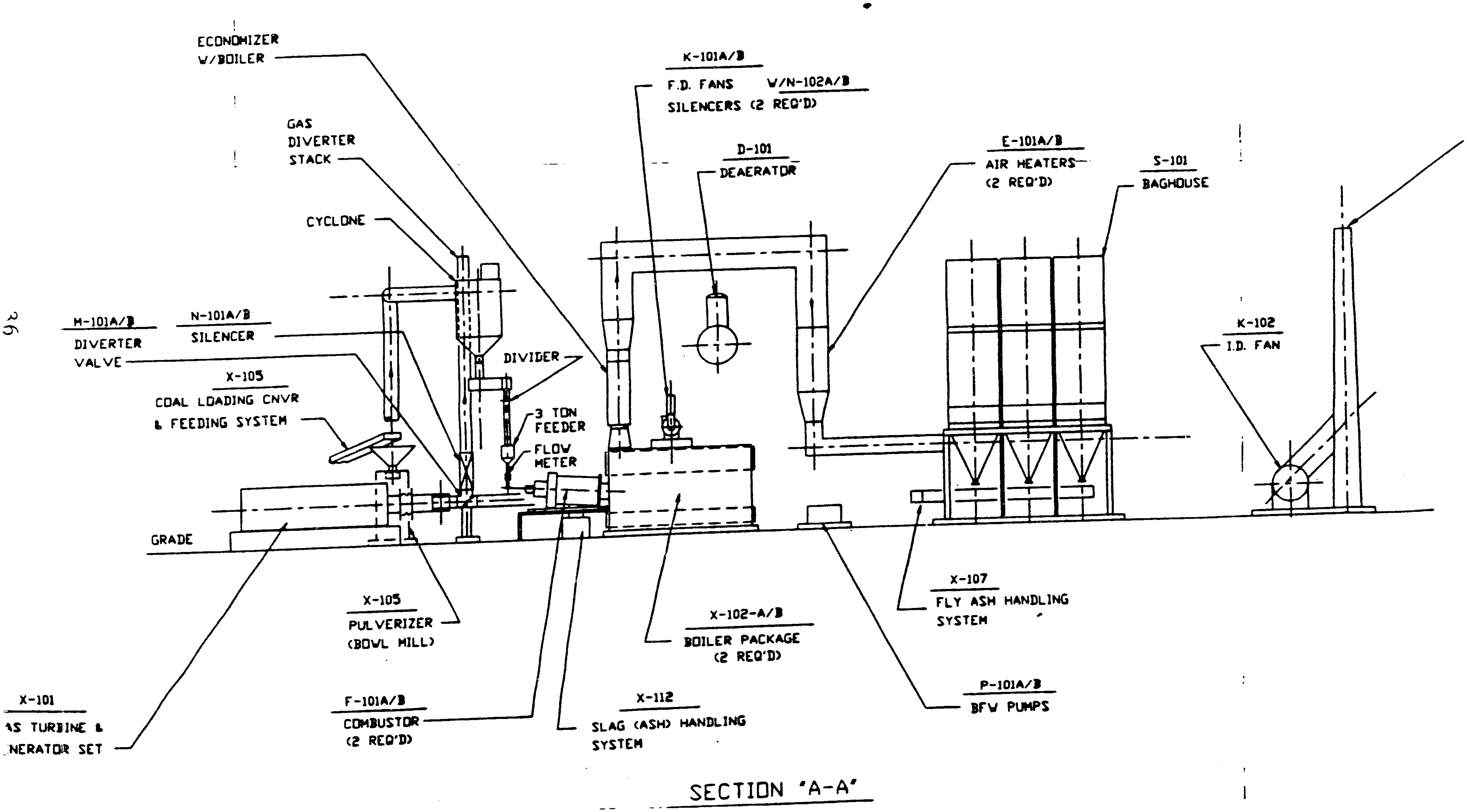
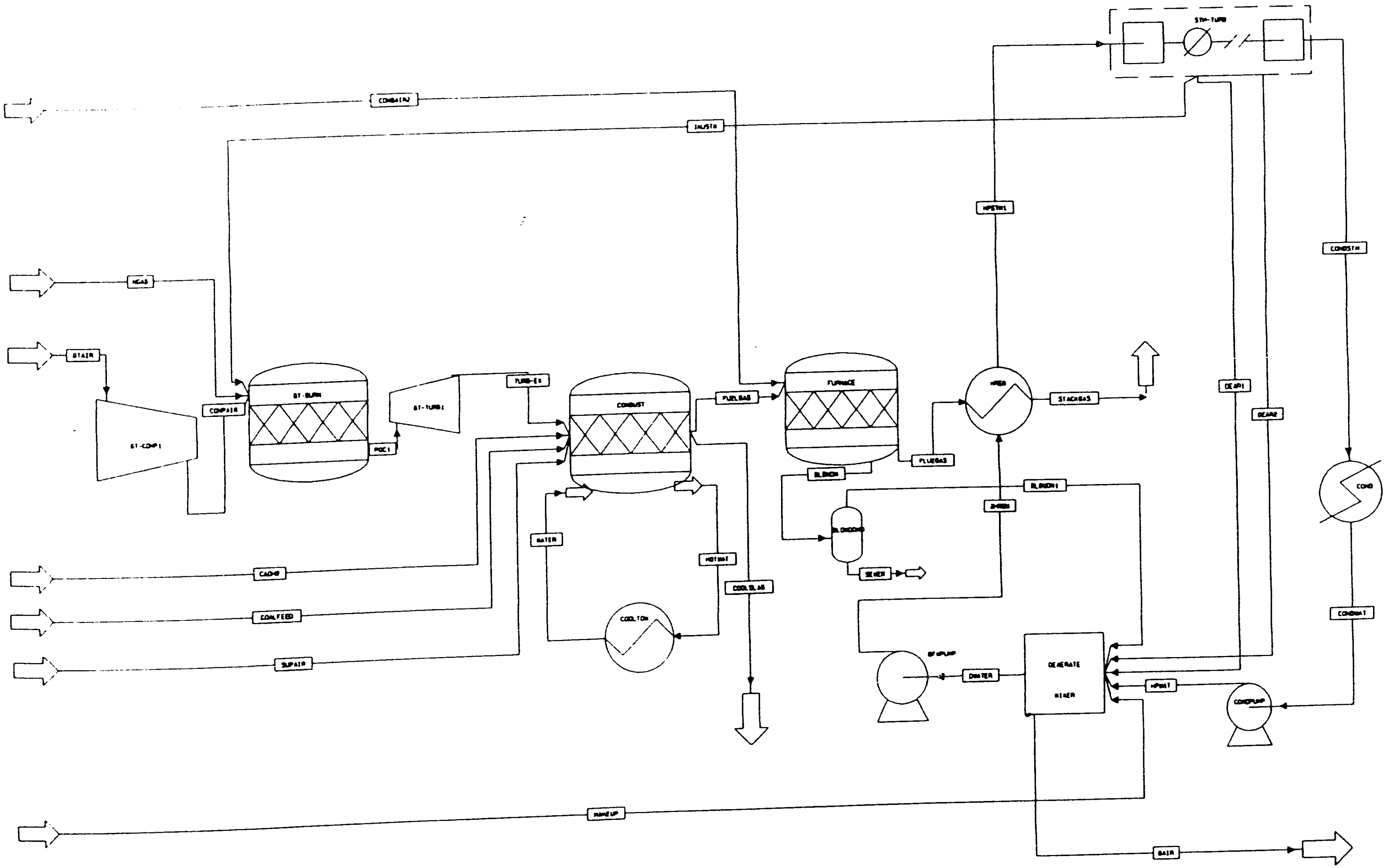


FIGURE 7. 20 MW COMBINED CYCLE PLANT WITH AIR COOLED COMBUSTOR -PROCESS FLOW DIAGRAM USED WITH ASPEN CODE



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