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CONCEPTUAL STUDIES AND
PRELIMINARY DESIGN OF A
FLUID BED FIRED BOILER FOR
SERVICE IN AN ELECTRIC UTILITY

Prepared by:
The Babcock & Wilcox Company
Fossil Power Generation Division
W. A. Hansen - Project Manager

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Contract Research Division
Alliance, Ohio

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I. INTRODUCTION

In recent years the fluidized bed combustion process has attracted a great deal of interest because of its ability to reduce undesirable sulfur emissions resulting from the burning of sulfur bearing fuels. The development of atmospheric fluidized bed boilers is viewed as a potential alternative to conventional boilers with stack gas scrubbers for control of sulfur dioxide control. At present, atmospheric fluidized bed utility boilers are still in the early stages of development and considerable additional work is required to more fully explore this concept.

Considerable effort has been expended in recent years to develop fundamental fluidized bed combustion data, but little effort was made to apply the data to engineering developments and studies. To overcome this deficiency, TVA together with ERDA, now DOE, commissioned B&W to perform the engineering studies required to develop the preliminary design of a 200 MW atmospheric pressure fluidized bed utility boiler. More specifically, B&W investigated different boiler cycle arrangements and various bed operating velocities to establish a single design which would be pursued in greater detail. Further, as a result of the engineering studies, estimates of capital and operating costs were made, predictions of system operability were prepared and areas requiring additional research and development were identified. In addition, it was shown how the resulting demonstration unit could be extrapolated to a commercial utility size (800 MW) and an assessment was made of the environmental impact of large fluid bed fired utility boiler systems. This report summarizes the results of thirteen months of engineering development studies.

When reviewing the information contained in this report it must be remembered that time did not permit a large number of optimization studies to be performed. Therefore, care should be exercised when comparing the costs and results presented in this study with conventional boilers equipped with scrubbers as these mature products have undergone considerably more development than fluidized bed utility boilers.

II. OBJECTIVE

Evaluate and develop the preliminary design of a small scale (150 MW to 250 MW) utility fluid bed boiler system, prepare capital and operating cost estimates, define areas where additional development is required, and evaluate the potential of this type of steam generator as applied to large (600 MW to 1000 MW) commercial power systems.

III DEVELOPMENT OF DESIGN PARAMETERS

As a part of this study, B&W was to develop fluid bed system design bases and parameters using any and all sources available. The design parameters used for the fluid bed boiler designs in this study were actually developed by B&W as part of their in-house AFB development program and also as a part of the subject design study.

This section of the report covers the design methods and limitations which were used in the study of candidate fluid bed systems and for the preliminary design of the 200 MW demonstration system. To properly carry out the assessment portion of the work it was essential to develop an understanding of the basic interrelationship of variables in order that the final comparisons would be as consistent and realistic as possible. Inputs to meet this goal were largely based on available literature, B&W experience, and engineering judgment. In some cases we also had to venture into some theoretical development work if published results appeared incomplete. The key subject areas to be covered in subsequent pages are listed below:

- A. General
- B. Fluidizing Velocity Requirements
- C. FBC Feed Particle Size Requirements
- D. Calculated Slip Velocities as a Function of Particle Size and Dispersed Density
- E. Heat Transfer Equations
- F. Heat Transfer to Horizontal Tubes in Shallow Fluidized Beds
- G. Combustion Efficiencies
- H. Sulfur Capture
- I. Freeboard Performance
- J. Distributor Plate Design
- K. Economic Considerations

A. General

The design conditions selected for a number of critical operating parameters are given in Table 3-1. The values for bed temperature and excess air were chosen on the basis of the information presented in Section 14-B entitled "Process Overview" on page 14-2. The main difference between the alternate schemes which were studied was the superficial gas velocity in the fluid bed combustors. Three different operating levels were selected for this design parameter: 4, 8 and 12 ft./sec.

B. Fluidizing Velocity Requirements

One of the important tasks of a designer is to estimate the interrelationship of gas velocity, particle size, and dispersed solids density. This knowledge is not only important in sizing the fluid bed boiler but it is needed to provide information in many subject areas such as pressure drop, heat and mass transfer, kinetics, turndown capabilities, etc.

A recommended approach to this problem area is one developed by Lapple (1) who studied the mechanics of fluid flow through beds of particulates. This approach is based on a diagram of a vertical multiphase system which involves a plot of "slip velocity" ($V_D/e = V_O/e - V_S$) versus pressure drop gradient ($\Delta P/L$) for a given particle size where

V_D = rate of slip between fluid and particles
defined as an effective approach velocity
uncorrected for voidage (ft/sec)

V_S = average solids velocity (ft/sec)

V_O = superficial fluid velocity, (ft/sec.)

e = volume fraction of voids in a bed of
particles (dimensionless)

$\Delta P/L$ = pressure gradient (lb/ft³)

For a transport system, V_S may be calculated by means of the following rigorous relation:

$$V_S = \frac{R}{\rho_f} = \frac{R}{\rho_s(1-e)}$$

TABLE 3-1
BED CONDITIONS SELECTED

	<u>FBC</u>	<u>CBB</u>
Bed Temperature (°F)	1550	2000
Excess air (%)	15	50
Feed particle size		
Coal	98%-1/4x0"	—
Limestone	Variable	—
% Elutriation		
Char	100	100
Spent Lime	35	100
Superficial gas velocities (ft/sec)	4, 8, 12	4, 8, 12

TABLE 3-2
TYPICAL SCREEN ANALYSES

<u>Coal</u>		<u>Limestone</u>	
<u>Mesh</u>	<u>% Passing</u>	<u>Mesh</u>	<u>% Passing</u>
1/4 (inch)	98.0	1/4 (inch)	98.0
4	95.5	4	92.7
8	83.5	6	82.0
16	64.6	14	44.2
30	45.3	16	37.5
50	29.5	30	16.7
100	18.0	50	5.9
200	10.4		

where

R = solids feed rate ($\text{lb/ft}^2\text{-sec}$)

ρ_f = dispersed density of solids (lb/ft^3)

ρ_s = true particle density (lb/ft^3)

However, for a stationary fluidized bed, $V_s = 0$; therefore, $V_D = V_o$. The general nature of a slip velocity diagram is shown in Figure 3-1 where

$\overline{OQ}$ = the relationship between slip velocity and pressure gradient in a consolidated bed

Q = point of quiescence

F = point of incipient fluidization

V_∞ = settling velocity in an infinite fluid

$\overline{QV}_\infty$ = dotted operating line normally encountered in the case of water fluidization

$\overline{FV}_\infty$ = general type of curve obtained for gas fluidization.

Means for predicting curve $\overline{FV}_\infty$ in Figure 3-1, the portion of the multiphase upflow diagram which is of interest in fluid-bed boiler operation, are provided by the following relationships (1) and (2):

$C = f(\text{Re})$, a relationship between a modified drag coefficient and a modified Reynolds number which coincides with the well-known resistance curve for spheres settling in an infinite fluid (see Figure 3-2). (1)

$V_D = V_c \left(1 + \frac{\text{KNV}_c \times 10^6}{135e} \right)$, an empirical relationship representing data on gas fluidization (see Figure 3-3). (2)

where $C = C_o \times \frac{Y}{K_w}$

$$C_o = \frac{4}{3} \frac{g \phi_s D_p (\Delta P/L)}{\rho V_c^2 (1-e)} \times \left[\frac{2}{K_v(K_v+1)} \right]$$

FIGURE 3-1

GENERAL GRAPHICAL PRESENTATION OF A MULTIPHASE
FLOW SYSTEM

SLIP VELOCITY DIAGRAM

FIGURE 3-2

GENERALIZED CORRELATION OF DATA ON FLOW OF FLUIDS THROUGH
BEDS OF GRANULAR SOLIDS (EXCLUSIVE OF DATA ON GAS FLUIDIZATION)

FIGURE 3-3

GENERALIZED CORRELATION OF DATA ON GAS FLUIDIZATION

$$Y = Y'' + (Y' - Y'') \sin \frac{24}{CRe} \frac{\pi}{2}$$

$$Y'' = \frac{1}{1 + \frac{9.65}{k} (1-e)}$$

$$Y' = \frac{1}{1 + \frac{9.65}{k} (1-e) - \frac{14.83}{k} (1-e)^2}$$

$$K_w = \frac{1}{\left[1 - \frac{D_p}{D_t} \right]^{2.25}}$$

$$Re = \frac{Re_p}{K_v}$$

$$Re_p = \frac{\phi_s D_p V_c \rho}{\mu}$$

$$K_v = \frac{1}{1 - 1.107 (1-e)^{2/3}}$$

$$K = \frac{\rho \mu^3}{\left[g \rho (\rho_s - \rho) \mu \right]^{4/3}}$$

$$N = \frac{1-e}{\frac{\pi}{6} D_p^3}$$

Y = generalized dispersion factor as defined above (dimensionless)

k = ratio of specific heats, C_p/C_v (dimensionless)

K_w = wall effect correction as defined above (dimensionless)

g = local acceleration due to gravity (ft/sec^2)

ϕ_s = Carman's shape factor for securing the specific surface of non-spherical particles

D_p = diameter of sphere of the same volume as that of the particle (ft)

V_D = observed slip velocity

V_c = calculated fluid velocity relative to a particle for gas fluidized bed assuming the validity of Figure 3-2 (ft/sec)

D_t = diameter of tube (ft)

ρ = density of fluid (lb/ft³)

μ = viscosity of fluid (lb/ft-sec)

K = a dimensional factor (ft²-sec)

N = particle concentration (number/ft³)

Trial and error solution is involved in the solution of Equation (1). This effort can be greatly minimized by using an alternate plot of CRe^2 versus Re where

$$CRe^2 = \frac{4}{3} \frac{g \phi_s^3 D_p^3 (\Delta P/L) \rho}{\mu^2 (1-e)} \times \left[\frac{2}{K_V^3 (K_V+1)} \right] \times \frac{Y}{K_w} \quad (3)$$

Another desirable plot suggested by Zenz (2) involves the relationship between $(Re/C)^{1/3}$ and $(CRe^2)^{1/3}$, in which velocity only is contained in one term and particle diameter only in the other. Values for $C-Re$ functions can be found in nearly every edition of Perry's Handbook.

The analytical approach described above shows promise in terms of generalized correlations to predict the performance of unrestricted fluidized bed systems and should provide a basis for extrapolation to FBC operation by making additional allowance for the volume occupied by the immersed heat transfer surface. As predicted by this technique, Section 3-D shows calculated slip velocities for FBC materials as a function of particle size and dispersed density for two temperatures (70°F and 1550°F). These values were used in establishing the fluidizing velocity requirements for the various candidate systems studied.

C. FBC Feed Particle Size Requirements

The particle size of the coal fed to the FBC in all cases was assumed to be 98% -1/4" x 0. A typical screen analysis for this feed is given in Table 3-2 (p. 3-3).

The size of the limestone feed, on the other hand, was varied with the gas velocity under consideration. This was necessary because of our decision to limit the amount of limestone elutriated from the bed to 35% and thereby keep the dust loading in subsequent convection tube banks controlled at a reasonable level. The screen analysis of limestone given in Table 3-2 was assumed to be typical for a 98%-1/4"x0 grind. It should be noted however, that the required limestone size was a variable, and the screen analysis shown in Table 3-2 for limestone was used only to provide the shape of the particle size distribution curve. It is also a well known fact that limestone is subject to thermal decrepitation during calcination. Based on a single set of data points obtained during the operation of the EPRI/B&W 3'x3' unit, a 20% reduction in particle size was estimated to occur during calcination. This degree of reduction is equivalent to splitting particles in half. While this may appear to be a reasonable estimate, decrepitation is expected to vary significantly with limestone source.

By establishing a quantitative limit for the degree of particle size reduction (decrepitation), it is possible to calculate the size distribution of the limestone feed which will result in 35% of the feed material being elutriated from the bed for each of the chosen design velocities. Table 3-3 (p. 3-10) shows the limestone feed size distribution for superficial bed velocities of 4, 8 and 12 ft/sec.

During our studies of candidate systems, 100% of the coal char or ash was assumed to be elutriatable from the FBC. While not true in practice, this was assumed to simplify heat and mass balances. However, this approximation should not significantly affect the end results on a relative basis. It was assumed that all the material which was carried over from the FBC and subsequently treated in the CBB was also 100% elutriatable from the CBB. This resulted from the fact that the CBB was to be operated at the same velocity as the FBC. This mode of operation is within the realm of experience and was assumed in order to maintain the unit capacity of the CBB at a reasonably high level.

Based on our coal gasification experience, the char particles from the FBC were assumed to have the following composition:

	<u>% By Weight</u>
Ash	Twice the ash in dry coal
S	67% of sulfur in coal
C ₈ H	Balance

TABLE 3-3

SIZE DISTRIBUTION OF LIMESTONE FEED

<u>V_o (ft/sec)</u>	<u>98% thru Mesh</u>
4	10-12
8	7-8
12	5

Limitations:

20% reduction in particle size
due to thermal decrepitation

35% elutriation

D. Calculated Slip Velocities As a Function
of Particle Size and Dispersed Density

Coordinate Values for Slip Velocity Curves

CONDITIONS: Material: Spent lime $\phi_s = 0.73$
 Temperature: 1550°F $\rho_s = 171.7 \text{ lbs/ft}^3$
 Pressure: 15 psia $\mu = 0.046 \text{ cp}$

1-e	ρ_f	V_D (ft/sec)				
		6 mesh	14 mesh	30 mesh	60 mesh	140 mesh
0.60						
0.55						
0.524	89.92	7.284	2.749	0.8024	0.2404	0.08318
0.50	85.83	7.896	3.120	0.9541	0.2887	0.1006
0.45	77.25	9.661	3.972	1.3732	0.4292	0.1519
0.40	68.66	11.64	5.127	1.876	0.6277	0.2252
0.35	60.08	13.75	6.365	2.669	0.9063	0.3286
0.30	51.50	16.62	7.990	3.627	1.299	0.4750
0.25	42.92	20.41	9.937	4.695	1.847	0.6795
0.20	34.33	24.69	12.36	6.245	2.634	0.9728
0.15	25.75	29.91	15.36	8.043	3.730	1.378
0.10	17.17	37.85	19.14	10.10	5.222	1.914
0.07	12.02	44.56	22.06	11.48	5.970	2.237
0.05	8.58	49.65	24.13	12.30	6.192	2.376
0.03	5.15	55.82	26.57	12.48	5.969	2.287
0.01	1.72	64.25	29.14	12.06	4.740	1.570
0	0	69.96	31.35	11.47	3.115	0.6174

Coordinate Values for Slip Velocity Curves

CONDITIONS: Material: Spent lime $\phi_s = 0.73$
 Temperature: 70°F $\rho_s = 171.6 \text{ lbs/ft}^3$
 Pressure: 15 psia $\mu = 0.0181 \text{ cp}$

1-e	ρ_f	V_D (ft/sec)				
		6 mesh	14 mesh	30 mesh	60 mesh	140 mesh
0.60	102.96	4.174	1.939	0.6687	0.1767	0.04779
0.55	94.38	4.936	2.380	0.9013	0.2665	0.07436
0.524	89.92	5.436	2.626	1.035	0.3231	0.09264
0.50	85.83	5.818	2.845	1.152	0.3769	0.1110
0.45	77.25	6.934	3.431	1.468	0.5293	0.1641
0.40	68.66	8.238	4.107	1.849	0.7440	0.2392
0.35	60.08	9.880	4.871	2.301	0.9931	0.3441
0.30	51.50	11.92	5.895	2.808	1.287	0.4917
0.25	42.92	14.36	7.061	3.503	1.695	0.6977
0.20	34.33	17.29	8.584	4.251	2.175	0.9934
0.15	25.75	20.88	10.58	5.255	2.798	1.334
0.10	17.17	25.81	13.45	6.569	3.489	1.797
0.07	12.02	29.92	15.58	7.578	3.953	2.072
0.05	8.58	32.36	17.47	8.370	4.230	2.186
0.03	5.15	36.00	19.52	9.334	4.461	2.115
0.01	1.72	39.92	22.42	10.48	4.471	1.754
0	0	43.11	24.43	11.30	4.442	1.298

Coordinate Values for Slip Velocity Curves

CONDITIONS: Material: Coal $\phi_s = 0.73$
 Temperature: 1550°F $\rho_s = 87$
 Pressure: 15 psia $\mu = 0.046$ cp

1-e	ρ_f	V_D (ft/sec)				
		6 mesh	14 mesh	30 mesh	60 mesh	140 mesh
0.60						
0.55						
0.524	45.80	4.581	1.639	0.4589	0.1442	0.05142
0.50						
0.45	39.33	6.188	2.508	0.7998	0.2591	0.09431
0.40						
0.35						
0.30						
0.25						
0.20						
0.15						
0.10						
0.07						
0.05						
0.03						
0.01						
0	0	46.44	19.84	6.713	1.706	0.3144

Coordinate Values for Slip Velocity Curves

CONDITIONS: Material: Coal $\phi_s = 0.73$
 Temperature: 70°F $\rho_s = 87$
 Pressure: 15 psia $\mu = 0.0181$ cp

1-e	ρ_f	V_D (ft/sec)				
		6 mesh	14 mesh	30 mesh	60 mesh	140 mesh
0.60						
0.55						
0.524	45.80	3.619	1.690	0.6257	0.1853	0.05505
0.50						
0.45	39.33	4.610	2.241	0.9184	0.3164	0.09828
0.40						
0.35						
0.30						
0.25						
0.20						
0.15						
0.10						
0.07						
0.05						
0.03						
0.01						
0	0	30.40	16.40	7.257	2.676	0.7099

Coordinate Values for Slip Velocity Curves

CONDITIONS: Material: Char $\phi_s = 0.73$
 Temperature: 1550°F $\rho_s = 62.4$
 Pressure: 15 psia $\mu = 0.046$ cp

1-e	ρ_f	V_D (ft/sec)				
		6 mesh	14 mesh	30 mesh	60 mesh	140 mesh
0.60						
0.55						
0.524	32.71	3.631	1.249	0.3494	0.1121	0.04055
0.50						
0.45	28.09	4.971	1.973	0.6117	0.2021	0.07494
0.40						
0.35						
0.30						
0.25						
0.20						
0.15						
0.10						
0.07						
0.05						
0.03						
0.01						
0	0	37.15	15.65	5.105	1.240	0.2245

Coordinate Values for Slip Velocity Curves

CONDITIONS: Material: Char $\phi_s = 0.73$
 Temperature: 70°F $\rho_s = 62.4$
 Pressure: 15 psia $\mu = 0.0181 \text{ cp}$

1-e	ρ_f	V_D (ft/sec)				
		6 mesh	14 mesh	30 mesh	60 mesh	140 mesh
0.60						
0.55						
0.524	32.71	2.904	1.339	0.4859	0.1402	0.04262
0.50						
0.45	28.09	3.785	1.787	0.7342	0.2455	0.07636
0.40						
0.35						
0.30						
0.25						
0.20						
0.15						
0.10						
0.07						
0.05						
0.03						
0.01						
0	0	25.53	13.28	5.787	2.020	0.5257

E. Heat Transfer Equations

Heat transfer to horizontal tube surface immersed in the fluid bed was handled by the procedure summarized below:

1. The single horizontal tube outside convection heat transfer coefficient was calculated by means of a MIT modified version of the Vreedenberg Equation (see appended copy of a paper in Section F by Andeen and Glicksman as presented at the ASME-AIChE Heat Transfer Conference, August, 1976):

$$\frac{h_c d_t / K_g}{Pr^{0.3}} = 900 (1-e) \left[\frac{G d_t \rho_p}{\rho_g \mu} \frac{\mu^2}{d_p^3 \rho_p^2 g} \right]^{0.326}$$

where $1 - e$ is calculated from Leva's relationship for voidage:

$$\frac{e^3}{1 - e} = \frac{200 V_g \mu}{d_p^2 (\rho_p - \rho_g) g}$$

h_c = single tube convection coefficient (Btu/hr-ft²-°F)

d_t = tube O.D. (ft)

K_g = gas thermal conductivity (Btu/hr-ft²-°F/ft)

Pr = Prandtl number = $\frac{C_g \mu}{K_g}$

C_g = specific heat of gas (Btu/lb-°F)

μ = viscosity of gas (lb/ft-hr)

e = void fraction in bed (dimensionless)

G = mass flow rate (lb/hr-ft²)

ρ_p = true density of bed material (lb/ft³)

ρ_g = gas density (lb/ft³)

d_p = average particle size in bed (ft)

g = constant = 4.173×10^8 (ft/hr²)

V_g = superficial bed velocity (ft/hr)

2. The application of the modified Vreedenberg equation was further altered by using fluid properties at the average temperature between the bed and the tube, as opposed to using bed temperature which was the basis for the original correlation of low bed temperature data.
3. The single tube convection coefficient was converted to a bundle coefficient by means of the equation developed by Gel'perin (3) (see Figure 3-4).
4. The radiant portion of the outside transfer surface coefficient was determined in a conventional manner:

$$h_r = \frac{0.173 \epsilon \left[\left(\frac{T_B}{100} \right)^4 - \left(\frac{T_w}{100} \right)^4 \right]}{T_B - T_w}$$

where h_r = radiant heat transfer coefficient
(Btu/hr-ft²-°F)

ϵ = overall effective emissivity ≈ 0.80

T_B = bed temperature (°R)

T_w = external tube wall temperature (°R)

$$5. \quad U = h_c F_A + h_r$$

where U = outside of bundle heat transfer coefficient (Btu/hr-ft²-°F)

In combining the calculation procedures discussed above, an outside of tube heat transfer coefficient can be calculated that seems to agree well with rates that have been determined by test work. Refer to Table 3-4 for a summary of this comparison.

For vertical heat transfer surface, the following relationship developed by Bartholomew and Katz (4) was used to calculate heat transfer coefficients:

$$h_c = C_g G \left[\frac{1.560 + \ln \left(\text{Re}_{dm}^{-2/3} - 0.0120 \right)}{-0.227 \text{Pr}^{2/3} f_{dm}^{0.42}} \right]$$

FIGURE 3-4
BANK ARRANGEMENT FACTOR
(STAGGERED ARRANGEMENTS ONLY)

TABLE 3-4
COMPARISON OF CALCULATED WITH OBSERVED
OUTSIDE OF BUNDLE HEAT TRANSFER COEFFICIENT

	Pope, Evans & Robbins Alexandria, Va.		B&W Alliance Research Center	BCURA
Superficial Bed Velocity (ft/sec)	10.9	13.3	9.6	2.3
Ave. Particle Size (in)	.032	.054	.066	.020
Bed Temperature (°F)	1390	1519	1610	1740
Bed Pressure (Atmos.)	1	1	1	6
Tube Wall Temp. (Approx. (°F)	270	270	200	100
Outside Coefficient (Btu/hr-ft ² -°F)				
Calculated	41.9	42.6	41.1	78.4
Observed	44.5	42.3	47.0	70.7
% Dev. from Observed Value	-5.8	+0.8	-12.6	+10.9

Note: Original value of 47 for the heat transfer coefficient from ARC data was determined by estimating it for a partially immersed bundle. Later data obtained for completely covered tubes yielded observed values of about 40, which are in closer agreement with the calculated value of 41.1.

$$\text{where } f_{dm} = \frac{D_p^3 g \rho (\rho_s - \rho)}{\mu^2}$$

$$\text{Pr} = \text{Prandtl number} = \frac{C_g \mu}{k_g}$$

Re = particle Reynolds number

$$= \frac{D_p V_o \rho}{\mu}$$

D_p = particle diameter

ρ_s = true density of solids

ρ = fluid density

μ = viscosity of gas

g = acceleration of gravity

h_c = convective heat transfer coefficient between wall and bed

C_g = specific heat of gas

k_g = thermal conductivity of gas

V_o = superficial gas velocity

In using the above equation again the arithmetic average temperature is used between the bed and the wall to evaluate fluid properties. The overall coefficient was finally determined by allowing for radiation as follows:

$$h_r = 0.1713 E \frac{\left[\left(\frac{T_B}{100} \right)^4 - \left(\frac{T_w}{100} \right)^4 \right]}{T_B - T_w}$$

$$h = h_c + h_r$$

where T_B = bed temperature ($^{\circ}\text{R}$)

T_w = wall temperature ($^{\circ}\text{R}$)

h_r = radiation coefficient ($\text{Btu/hr-ft}^2\text{-}^{\circ}\text{F}$)

E = effective emissivity

In this case one new consideration was to determine the degree of blackness of the extremely dilute dispersion of solids (volume fraction of solids ≈ 0.03) existing above the dense phase fluidized bed in the freeboard. To estimate this, the validity of the following expression presented by Zabrodsky (4) was assumed:

$$E_s = 1 - e^{-\frac{6n(1-f)(V/S)}{D_p}}$$

where E_s = degree of blackness caused by the solids

$$n \approx 0.9$$

f = voidage fraction

D_p = particle size

V = bed volume

S = radiant surface area bounding the bed volume

Since passage through a particle assemblage is repetitious after two layers of thickness ($2t$), it was assumed that V/S ratio in the above formula could be approximated by this characteristic dimension which is estimated as follows for a rhombohedral arrangement:

$$D_c = 2t = 1.478 \frac{D_p}{(1-f)^{1/3}}$$

$$\therefore E_s = 1 - e^{-8.0(1-f)^{2/3}}$$

The effective emissivity was then calculated by means of the following relationship:

$$E = \frac{1}{\frac{1}{E_s} + \frac{1}{E_w} - 1}$$

where $E_w \approx 0.8$ = emissivity of the wall.

Accordingly typical values of emissivity were calculated as tabulated below:

<u>1-f</u>	<u>E</u>
0.200	0.76
0.028	0.46

In utilizing the Bartholomew equation, its reliability for high voidages ($f > 0.9$) and very low values near the point of minimum fluidization ($e = 0.50-0.55$) appears to be questionable. For high voidages as encountered in the freeboard, we therefore estimated coefficients for somewhat lower values and interpolated between these values and those that would be predicted for normal boiler practice in the absence of high particle concentrations.

For the selected operating conditions in the various candidate systems investigated, calculated outside heat transfer coefficients were in the range of about 55-75 Btu/hr-ft²-°F for horizontal tubes immersed in the dense phase beds. Corresponding overall coefficients were around 40-55 Btu/hr-ft²-°F. Coefficients in the dilute phase regions in the freeboard ranged between above 25-35% of these values.

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F. Heat Transfer to Horizontal Tubes in Shallow Fluidized Beds

B. R. ANDEEN

Assoc. Mem. ASME

L. R. GLICKSMAN

Mem. ASME

Department of Mechanical Engineering,
Massachusetts Institute of Technology,
Cambridge, Mass.

Heat transfer measurements were made for horizontal tubes in shallow fluidized beds. Various methods to enhance the particle recirculation and the heat transfer were investigated. These included distributor design changes, internal vanes, and flattened tubes. Only flattening the tubes improved the heat transfer. The most satisfactory correlation of the data were made using a modified form of Vreedenberg's correlation. Existing heat transfer correlations gave erroneous results at high superficial velocities. A new correlation, modification of Vreedenberg's, gave good agreement for all available data on horizontal tubes.

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G. Combustion Efficiencies

The following discussion will involve the area of combustion efficiency.

A B&W analysis (6) of fluidized bed combustion allowed us to draw some significant conclusions relative to this area of concern:

- (a) Complete burnout of the very fine coal particles (~270 mesh) is feasible in a fluid bed combustor.
- (b) The problem of incomplete burnout may not be associated with the coarse fractions but is more likely the result of inadequate retention time of the elutriatable fraction of intermediate sizes.

Because of the high degree of vertical mixing in a fluid bed, it is also reasonable to assume that much of the oxygen is rapidly consumed in a relatively short distance above the air distribution plate. It is very likely that the volatile matter in the coal is thus rapidly consumed. Since complete combustion of the residual char contained in the very coarse and fine fractions is expected, one can then postulate a simplistic combustion model by assuming that the prime problem is one of burning the residual char in the intermediate size fraction with the remaining combustion air. It will also be assumed that the gases pass through the bed in plug flow.

As the air passes up through the bed, the oxygen concentration and its rate of consumption is expected to decrease with bed height until finally the rate of change would approach zero at infinite exposure time, at which point the oxygen concentration becomes equal to the excess air level. This can be written in a form as:

$$\frac{dC}{dt} = - K_1 \left(C - C_o \frac{x}{1+x} \right) \quad (1)$$

where

C = oxygen concentration at a given bed level

C_o = oxygen concentration in entering air

x = fraction of stoichiometric air in excess

$C - C_o \frac{x}{1+x}$ = consumable oxygen concentration remaining

K_1 = a proportionality factor for a given set of operating conditions

t = time (sec)

To translate equation (1) in terms of combustion efficiency (CE), the latter expressed as a fraction can be approximated as a function of the other variables as follows:

$$CE \approx \frac{C_o - C}{C_o / (1 + x)} \quad (2)$$

$$\text{or } C = C_o \left(1 - \frac{CE}{1 + x} \right) \quad (3)$$

$$\text{and } dC = - \frac{C_o}{1 + x} dCE \quad (4)$$

Substituting Equations (3) and (4) into Equation (1) yields the following relationship:

$$d \ln (1 - CE) = - K_1 dt \quad (5)$$

Based on general theories for the combustion of coal particles, a particle can be assumed to be surrounded by a boundary layer of stagnant gas. Oxygen diffuses through this layer from the free stream and reacts at the particle surface to form products which diffuse back out. In the combustion of carbon, the products may be either CO or CO₂, or a mixture of both, depending on the particle size, temperature, etc. The presence of significant quantities of CO in chilled exit gases from a fluid bed suggests that the former may be part of the prevalent combustion reaction:

It may be assumed that the proportionality factor, K_1 , in Equation (5) may vary with the concentrations of the reactants in the flame front as follows:

$$K_1 = k_1 (P_{CO})^2 (P_{O_2}) \quad (7)$$

To assess the CO concentration it was assumed that the CO concentration would be proportional to the concentration of the unburned char resulting from the intermediate size coal fraction (Δf). Since vertical mixing is rapid in a fluid bed, this concentration may be a

constant for a given set of operating conditions, but information is unavailable to predict its absolute value. For now, it may be reasonable to just assume that it is proportional to the average heating value of this unburned char between initial and outlet conditions. Thus,

$$P_{CO} = k_2 \left[\frac{(1 - \overline{VM}) \Delta f + (1 - \overline{CE})}{2} \right] \quad (8)$$

where $\overline{VM}$ = fraction of volatile matter in coal on ash-moisture-free basis

$\overline{CE}$ = fractional overall combustion efficiency

Δf = fraction of coal between elutriatable cut size and 270 mesh

As another reasonable approximation, it will be assumed that the oxygen concentration varies linearly with bed height:

$$P_{O_2} \approx k_3 C_o \left[\left(1 - \frac{1 - (1 - \overline{VM}) \Delta f}{1 + x} \right) \left(1 - \frac{h}{H} \right) + \left(1 - \frac{\overline{CE}}{1 + x} \right) \left(\frac{h}{H} \right) \right] \quad (9)$$

where: h = bed level under consideration (ft)

H = overall effective bed height (ft)

$$\text{Also since gas residence time} = \frac{h}{V_o/e}, \text{ then } dt = \frac{dh}{V_o/e} \quad (10)$$

where: V_o = superficial gas velocity (ft/sec)

e = bed voidage

Substituting equations (7), (8), and (9) into equation (5) and letting $y = \frac{(1 - \overline{VM}) \Delta f}{2}$ yields the following relationship:

$$d \ln (1 - CE) = - \frac{K_2 e}{V_o} \left[y + \frac{1 - \overline{CE}}{2} \right]^2 \left[\left(1 - \frac{1 - 2y}{1 + x} \right) \left(1 - \frac{h}{H} \right) + \left(1 - \frac{\overline{CE}}{1 + x} \right) \left(\frac{h}{H} \right) \right] dh \quad (11)$$

where K_2 = an isothermal combustion rate constant.

Integrating between appropriate limits results in the following:

$$\ln (1 - CE) \left|_{1 - [1 - (1 - \overline{VM}) \Delta f]}^{1 - \overline{CE}} \right. = - \frac{K_2 e}{V_o} \left[y + \frac{1 - \overline{CE}}{2} \right]^2 \left[\left(1 - \frac{1 - 2y}{1 + x} \right) \right. \\ \left. \left(h - \frac{h^2}{2H} \right) + \left(1 - \frac{\overline{CE}}{1 + x} \right) \frac{h^2}{2H} \right] \left|_0^H \right. \quad (12)$$

$$\text{or } \ln \frac{1 - \overline{CE}}{2y} = - \frac{K_2 H}{V_o / e} \left[y + \frac{1 - \overline{CE}}{2} \right]^2 \left[1 - \frac{\frac{1 + \overline{CE}}{2} - y}{1 + x} \right] \quad (13)$$

In transport of oxygen in coal oxidation (7), activation energy increases with rank:

- 16 kcal/mole for high volatile coal ($\overline{VM} = 39\%$),
- 25 kcal/mole for coking coal ($\overline{VM} = 23\%$), and about
- 26 kcal/mole for anthracite.

Using the lower value, one may then modify the value of K_2 in equation (13) to account for the effect of temperature.

$$K_2 = K_3 e^{-\frac{16,000}{1.986 (T/1.8)}} = K_3 e^{-\frac{14,502}{T}} \quad (14)$$

where T = temperature ($^{\circ}R$)

The combustion rate constant may furthermore vary with the reactivity, R , of the coal. (If it is considered to have a value of unity for coal, there are indications in the literature that it may be an order-of-magnitude lower for char.) Equation (13) can also be further simplified by letting $\overline{CE}$ in the terms on the right side of the expression approach 1, which is the ball-park end of the spectrum of main concern. These modifications, together with some other transformations, yield the desired result below:

$$\overline{CE} = 1 - ye^{0.693 - \frac{RaH}{V_o/e_1} [y]^2 \left[1 - \frac{1-y}{1+x}\right] e^{K \left(1 - \frac{14,502}{T}\right)}} \quad (15)$$

$$\text{or } \overline{CE} = 1 - ye^z \quad (15a)$$

where $a = \frac{h_o}{H} + b \left(1 - \frac{h_o}{H}\right)$, a variable for modification of gas residence time due to the presence of solids and heat transfer surface in various zones.

$$b = \frac{e_2 e_t}{e_1}$$

h_o = unrestricted bed height (ft)

e_1 = voidage in unrestricted zone, i.e. in zone containing no immersed heat transfer surface

e_2 = voidage within tube bank

e_t = fraction of volume not occupied by heat transfer tubes in tube bank zone

K = a constant

$$z = 0.693 - \frac{RaH}{V_o/e_1} [y]^2 \left[1 - \frac{1-y}{1+x}\right] e^{K \left(1 - \frac{14,502}{T}\right)}$$

Solving equation (15) for K yields the following relationship:

$$K = \frac{14,502}{T} + \ln \frac{\ln \frac{2y}{1 - \overline{CE}}}{\frac{RaH}{V_o/e_1} [y]^2 \left[1 - \frac{1-y}{1+x}\right]} \quad (16)$$

$$\text{where } y = \frac{(1 - \overline{VM}) \Delta f}{2}$$

Equation (16) will be useful in determining the value of the constant K from experimental data.

Figure 3-5 is a plot of all available combustion efficiencies versus superficial velocity reported in Reference 1, Section XIV. Although it shows a great deal of scatter, there is a statistical trend as represented by the solid line. As the superficial velocity is increased, the combustion efficiency is decreased. A fairly simple correlation which we developed earlier and which appeared to quantitatively reproduce this trend was as follows:

$$\overline{CE} = 1 - \left[1 - \frac{(1 + \overline{VM})}{2} \right] \Delta f = 1 - \left[\frac{(1 - \overline{VM})\Delta f}{2} \right] \quad (17)$$

$$\text{or } \overline{CE} = 1 - y \quad (18)$$

This was predicated on the assumption that the combustion efficiency of the intermediate size fraction of coal, Δf , would average between $\overline{VM}$ and unity which can be noted in equation (17). Equation (18) is represented by the dashed line in Figure 3-5 based on a coal size distribution of 98% - 1/4" x 0 (see Table 3-5), a specific gravity of the resulting char of 1.0, and a proximate analysis of coal given in our initial monthly report for January, 1977. Based on the proximate analysis of coal (Table 3-6) provided by TVA at a later date, the values of overall combustion efficiencies calculated by equation (18) for a few different velocities are given in Table 3-7. These values showed similar trends and were actually quite close to the original points used to establish the dashed curve in Figure 3-5. Since the solid and dashed lines were in close agreement, use of equation (18) was felt justified in predicting overall combustion efficiencies for the design studies. For the initial studies, the values thus determined as a function of velocity were as follows:

V_o	Overall $\overline{CE}$	In-Bed* $\overline{CE}$
4	0.91	0.85
8	0.88	0.80
12	0.85	0.75

*Based on judgment and some literature data indicating that 5-10% of the combustion occurs in the freeboard.

Note that there is a great deal of similarity between equations (15a) and (18), but the latter does not include the effects of bed height and/or other variables such as excess air and temperature. Equation (15a) was selected to provide future R&D guidance. Equation (16) was employed to establish a value of K of about 13.3

FIGURE 3-5

COMBUSTION EFFICIENCY AS A FUNCTION OF GAS VELOCITY

TABLE 3-5
SCREEN ANALYSIS OF COAL

<u>Mesh</u>	<u>% C⁻</u>
1/4"	98.0
4	95.5
8	83.5
16	64.6
30	45.3
50	29.5
100	18.0
200	10.4
Pan	--

TABLE 3-6
PROXIMATE ANALYSIS OF COAL

	<u>Wgt. %</u>
Moisture	8.9
Volatile Matter ($\overline{VM}$)	32.8
Fixed Carbon	42.4
Ash	<u>15.9</u>
	100.0

TABLE 3-7
COMBUSTION EFFICIENCIES CALCULATED BY EQUATION (18)

<u>Vo</u>	<u>Dpc*</u>		<u>Δf</u>	<u>$\overline{CE}$</u>
	<u>Ins.</u>	<u>Mesh</u>		
5.1	0.0234	30	.372	.8951
12.0	0.0450	~16	.560	.8421

*Maximum particle size of char elutriatable from fluid bed.

assuming the validity of the dashed curve in Figure 3-5 for a coal having the proximate analysis given in Table 3-6 and assuming normal conditions encountered in the AFB ($a = 0.9$, $H = 4$, $e_1 = 0.8$, $T = 2010$, $x = 0.15$). This resulted in the final form of equation (15a):

$$\overline{CE} = 1 - ye^z$$

$$\text{where } z = 0.693 - \frac{RaH}{V_o/e_1} \left[y \right]^2 \left[1 - \frac{1-y}{1+x} \right] e^{13.3 \left(1 - \frac{1087}{T} \right)} \quad (19)$$

The combustion efficiencies calculated via equation (19) for the above operating conditions are compared below to those determined from equation (18):

<u>V_o</u>	<u>CE</u>	
	<u>Eqn. 18</u>	<u>Eqn. 19</u>
5.1	.8951	.8870
12.0	.8421	.8462

These results are almost identical and thus provide some confidence for the use of equation (19).

While the approach used in arriving at equation (19) entailed assumptions on a mechanistic model and was only partially verified with experimental data, it does provide some insight on the effect of some of the pertinent variables. Additional calculations using equation (19) were then made, and the results of these calculations are shown in Figure 3-6 illustrating predicted changes with bed temperature, bed height and excess air. In Figure 3-6 the lower curve is identical to the dashed curve in Figure 3-5. Figure 3-6 shows that significant effects can be expected by increasing bed height and/or temperature. An increase in temperature is feasible as long as lime utilization is not adversely affected. In all cases, the use of low velocities are more favorable but within the expected operating range of velocities (4-12 ft/sec) has only a moderate effect as higher bed heights and temperatures are employed. As in the case of sulfur capture, it appears therefore, that from a technical standpoint, future R&D on fuel combustion should include data acquisition at low velocities and higher bed depths.

By assuming a solid fuel reactivity of $R = 0.1$, a bed temperature of 1950°F, excess air of 50%, and a bed height of 4 ft., a probable curve was predicted via equation (19) for the combustion of elutriated char

FIGURE 3-6

COMBUSTION EFFICIENCY VS. SUPERFICIAL VELOCITY SHOWING
EFFECTS OF BED TEMPERATURE, BED HEIGHT, AND EXCESS AIR

NOTE: SOLID CURVES FOR $\frac{1}{4}$ " x 0 COAL

* PREDICTED CURVE FOR ELUTRIATED CHAR RESIDUE.

LOWER CURVE - SAME AS DASHED CURVE IN FIGURE 3-5.

H = 3 - 4 FT.

residue which must be treated in the CBB. These results are comparable to those that might be expected from PER experience, i.e., under the assumed conditions, that the same combustion efficiencies are achieved in the CBB as in the FBC. This finding further increased our level of confidence in the use of equation (19).

H. Sulfur Capture

This section of the report furnishes the background with regard to the development of our design parameters for prediction of sulfur capture in fluid-bed combustors.

Since the first part of the TVA design study entailed an evaluation of alternative schemes, it was deemed essential to develop an understanding of the basic inter-relationship of variables in order that the comparisons would be consistent and realistic as possible. Three of the concepts we investigated involved variations in velocity: 4 ft/sec, 8 ft/sec and 12 ft/sec. Furthermore, the percentage carryover of lime was fixed at 35% in each case. This limitation basically fixed the particle size distribution of the bed material which was, incidentally, different for each concept. In making this estimate an attempt to account for thermal decrepitation was also made. In any case, it was necessary to account for the effects of changes in gas velocity (V_0), particle size (D_p) and elutriation in addition to limestone stoichiometry ($C=Ca/S$ mole ratio). Most of the available data base consisted only of plots of % SO_2 removal versus the Ca/S ratio and did not account for the variety of operating conditions. Also, no simplistic model was available for correlating this data. To make an objective comparison it was necessary to venture in some theoretical development work since the published results were inadequate for our purposes.

To initiate thinking along these lines, the first efforts directed attention to the basic reaction involved:

The following conditions and assumptions were made to formulate a model:

- (1) The gas passes through the bed in plug flow.
- (2) Solid mixing is near perfect so that the spent lime discharge composition is the same as that at any point within the bed, and this is the steady state composition that the gas sees at all times during its passage up through the bed.

- (3) As CaSO_4 is formed by the sulfation reaction, the pore volume of limestone consumed is greater than the pore volume developed by the calcination reaction. Therefore at some point zero porosity is achieved, and the reaction stops for all practical purposes. The indications are that the fractional saturation value (m) is attained when about 60-70% of the lime particle is reacted. This value may differ depending on the characteristics of the particular limestone being used.
- (4) For the given range of excess air normally employed, the rate of reaction (1) may thus be considered to be proportional to the available moles of CaO present in the spent discharge per mole of sulfur treated and also the concentration of the SO_2 (p) in the gas phase at any level in the bed under consideration.

The following rate equation can then be written:

$$\begin{aligned}\frac{dp}{dt} &= -k (mC - E) (p) \\ &= -kC \left(m - \frac{E}{C} \right) (p)\end{aligned}\quad (2)$$

where E = the fractional amount of sulfur captured.

k = empirical isothermal rate constant

t = gas residence time in the bed.

To further account for inefficiencies due to lime lost as carryover, a correlation factor, F , may be applied as follows and, from a conservative standpoint, may be assumed to be equal to the fraction elutriated:

$$\frac{dp}{dt} = -kC \left(m - \frac{E}{C} \right) (1-F) (p) \quad (3)$$

$$\text{or } \frac{dp}{p} = -kC \left(m - \frac{E}{C} \right) (1-F) dt \quad (4)$$

Integrating Equation (4) between limits results in the following relationship:

$$\ln \frac{p_2}{p_1} = -kC \left(m - \frac{E}{C} \right) (1-F) (t) \quad (5)$$

$$\text{or, } \ln \frac{P_2}{P_1} = \ln (1-E) = -kC \left(m - \frac{E}{C}\right) (1-F)(t) \quad (6)$$

$$\ln \frac{1}{1-E} = kC \left(m - \frac{E}{C}\right) (1-F)(t) \quad (7)$$

Solving Equation (7) for C yields the desired result below:

$$C = \frac{E + \frac{\ln \frac{1}{1-E}}{kt(1-F)}}{m} \quad (8)$$

Let e_1 = bed voidage in zone with no immersed tubes.

e_2 = bed voidage in zone with immersed tubes.

e_t = fraction of volume not occupied by tubes.

h = bed height of zone with no immersed tubes, i.e. unrestricted bed height (ft)

H = overall bed height (ft)

V_o = superficial gas velocity (ft/sec)

Then, gas residence time (sec), allowing for the volume occupied by the solids and tube bank, equals

$$t = \frac{h}{V_o/e_1} + \frac{H-h}{V_o/e_t e_2} \quad (9)$$

$$= \frac{H}{V_o/e_1} \left[\frac{h}{H} + b \left(1 - \frac{h}{H}\right) \right] \quad (10)$$

$$= \frac{aH}{V_o/e_1} \quad (11)$$

where $a = \frac{h}{H} + b \left(1 - \frac{h}{H}\right)$, a variable for modification of gas residence time due to the presence of solids and heat transfer surface in various zones. (12)

$$b = \frac{e_2 e_t}{e_1} \quad (13)$$

Recognizing that Equation (7) takes the form of a linear equation ($y=kx$) passing through the origin, $\ln \frac{1}{1-E}$

against $C \left(m - \frac{E}{C} \right) (1-F) \left(\frac{aH}{V_o/e_1} \right)$ can be plotted and the empirical constant, k , is evaluated by obtaining the slope of the resulting line. The data used for this correlation are given in Table 3-8. In order to establish the coordinates of points, assumptions had to be made regarding the values of certain parameters that were not defined in the data source:

1. It was assumed that the limestones used were all relatively active with the exception of Germany Valley. A value of $m = 0.6$ was thus used for the latter stone; $m = 0.7$, for all others.
2. The value of "F" was assumed to be close to zero since all the ARC and PER data was obtained on double screened material, thereby minimizing the amount of elutriatable fines.
3. The value of "a" was assumed close to unity. This appeared justified for the majority of data based on ARC test work because it was obtained for shallow beds with only a small amount of tube immersion.
4. The values of voidage for given values of particle size and gas velocity were estimated based on the results of calculations presented in Section 3-D.

Based on the above assumptions Figure 3-7 was finally prepared by plotting $\ln \frac{1}{1-E}$ vs. $C \left(m - \frac{E}{C} \right) \left(\frac{H}{V_o/e_1} \right)$.

From this graph the value of constant k was determined to be equal to about 2π . This led to the final form of the design equation:

$$C = \frac{E + \frac{\ln \frac{1}{1-E}}{2\pi (1-F)t}}{m} \quad (14)$$

In Figure 3-8 the limestone requirements predicted by this equation are compared to the observed values. The average deviation is about ± 0.25 in the stoichiometric ratio of Ca/S.

Equation (14) was used in predicting the stoichiometric requirements for the design studies utilizing a 4.5% sulfur coal (dry basis) at 4 ft/sec. Various input conditions and results including those for other velocities are given in Table 3-9.

TEST NO.	LIMESTONE	E	$\ln \frac{1}{1-E}$	$D_p^{(1)}$	V_o	e_1 (Calculated)	H	C	$C \left(\frac{m-E}{C} \right) \left(\frac{H}{V_o/e_1} \right)$
ARC*19	Lowellville, Ohio	0.679	1.136	0.0675	8.33	0.67	1.548	2.70	0.1508
20	"	0.240	0.2746	0.0700	8.35	0.66	1.638	0.58	0.02150
21	"	0.330	0.4008	0.0635	8.22	0.68	1.428	1.53	0.08759
22	"	0.370	0.4618	0.0720	8.28	0.65	1.685	1.48	0.08811
23	"	0.392	0.4977	0.0765	7.93	0.62	1.929	1.57	0.1066
24	"	0.467	0.6291	0.0700	11.90	0.74	2.047	1.81	0.1018
26	"	0.619	0.9651	0.0388	8.00	0.77	1.373	2.15	0.1171
27	"	0.583	0.8746	0.0415	8.11	0.76	1.375	2.27	0.1297
28	"	0.836	1.808	0.0440	8.30	0.75	1.374	3.50	0.2048
29	"	0.388	0.4910	0.0479	8.18	0.73	1.422	1.11	0.04936
30	"	0.416	0.5377	0.0513	8.19	0.72	1.412	1.11	0.04480
31	"	0.623	0.9757	0.0278	7.97	0.82	1.320	2.46	0.1492
32	"	0.778	1.470	0.0283	7.98	0.82	1.370	3.48	0.2334
33	"	0.333	0.4048	0.0292	8.06	0.81	1.364	0.87	0.03784
PER**636	Germany Valley	0.780	1.514	0.0736	14.0	0.78	2.825	4.4	0.2928
637-1	Greer	0.770	1.470	0.0736	12.4	0.74	3.375	2.9	0.2538
637-2	"	0.830	1.772	0.0736	12.5	0.75	3.325	3.2	0.2813
639	"	0.860	1.966	0.0736	15.5	0.80	3.175	3.5	0.2606
ANL***	British Limestone	0.470	0.6350	0.01732	3.0	0.73	2.000	1.0	0.1119
	"	0.800	1.609	0.01732	3.0	0.73	2.000	2.0	0.2920
	"	0.600	0.9163	0.01732	2.0	0.66	2.000	1.0	0.0660
	"	0.860	1.966	0.01732	2.0	0.66	2.000	2.0	0.3564

References:

- * - Babcock & Wilcox, Alliance Research Center, EPRI Project No. RP 719-1, Task 2, "SO₂ Absorption in Fluidized Bed Combustion of Coal - Effect of Limestone Particle Size", March 31, 1977.
 - ** - Pope, Evans & Robbins, Quarterly Report, Oct.-Dec., 1975.
 - *** - A. A. Janke, et al., Argonne National Laboratory, "Reduction of Atmospheric Pollution by the Application of Fluidized-Bed Combustion", Annual Report, July, 1970 - June, 1971 (Fig. 7).
- (1) - Average 50% C⁻ particle size of fluidized bed (inches).

SULFUR CAPTURE DATA USED FOR CORRELATION PURPOSES

TABLE 3-8

FIGURE 3-7
CORRELATION OF SULFUR CAPTURE DATA
 [Determination of Rate Constant (k) in Equation (7)]

FIGURE 3-8

LIMESTONE REQUIREMENTS

(OBSERVED VS. PREDICTED VALUES OF Ca/S RATIO)

Note: Predicted values were calculated by means of Equation (14).

TABLE 3-9
PREDICTED Ca/S RATIOS FOR DESIGN STUDIES

<u>V_O</u>	<u>E*</u>	<u>F</u>	<u>M</u>	<u>e₁</u>	<u>e₂</u>	<u>e_t</u>	<u>h</u>	<u>H</u>	<u>C</u>
4	0.84	0.35	0.65	0.73	0.77	0.80	1.5	4	2.34
8	"	"	"	0.78	0.83	"	"	"	3.24
12	"	"	"	0.81	0.86	"	"	"	4.11

* - Fractional sulfur capture efficiency needed to meet EPA emission standards making due allowance for the SO₂ (200 ppm) not absorbed in the CBB. Otherwise the required sulfur capture efficiency would be about one percent lower.

To develop a broader perspective relative to the effect of operating variables on sulfur capture, the chart shown in Figure 3-9 was prepared assuming the validity of equation (14). The graph shows the relationship between % SO₂ removal and Ca/S ratio for various values of H/V₀, where H is the overall bed height in feet and V₀ is the superficial gas velocity in ft/sec. In preparing this graph, a bed voidage of 0.8 and a 35% lime elutriation was assumed. The horizontal lines are approximate levels of SO₂ removal required to meet federal EPA emission standards for various sulfur contents of the coal.

For reasonable values of H/V₀ < 2, this chart shows that for most coals (% S > 3), there is little chance of meeting current EPA standards by operating at Ca/S ratios of less than 1.5 unless a technical breakthrough is achieved. For an average coal (% S $\approx$ 4-5%), it may be possible at a Ca/S ratio between 1.5 to 2.0 provided the unit is operated at an H/V₀ value of about two. Therefore, if the superficial gas velocity is 4 ft/sec, a bed height of 8 ft. would be required. On the other hand, for a normal bed depth of 4 ft. and a gas velocity in excess of 8 ft/sec, the chart would indicate that the limestone requirements would then be increased by a factor of two or more.

While the above procedure gives results which are in reasonable agreement with the reported data, this gas-solid contacting problem can also be potentially affected by limestone characteristics and localized bed conditions. To elaborate on the latter point, it would be informative to examine the nature of the Ca-S-O equilibrium diagram (8) shown in Figure 3-10 and the calculated equilibrium results given in Table 3-10. In the temperature range under consideration in the FBC, this diagram shows that reaction of sulfur values with lime can potentially and effectively be accomplished under both oxidizing and reducing conditions. However, near neutral or slightly reducing conditions, the percent sulfur retention is expected to be low. In a fluidized bed reactor, it is therefore important to control fluid bed behavior, minimize concentration gradients or provide adequate number of fuel guns and sufficient bed height to assure near uniform gas composition near the top of the bed. Otherwise incomplete mixing could result in incomplete combustion which implies that alternate reducing and oxidizing zones could exist. This is one reason why freeboard burning may occur and in turn maximum SO₂ retention may not be achieved.

For the oxidizing conditions expected in the CBB, one can also conclude from Table 3-10 that the equilibrium SO₂ concentration in the temperature range of

FIGURE 3-9
EFFECTS OF Ca/S RATIO AND GAS RESIDENCE TIME ON SO₂ REMOVAL
[Predictions by Means of Equation (14)]

FIGURE 3-10
Ca-S-O EQUILIBRIUM DIAGRAM

TABLE 3-10

EQUILIBRIUM CALCULATION RESULTS FOR $\text{CaCO}_3\text{-SO}_2$ REACTION ($\text{Ca/S}=1$)

CACO ₃ -SO ₂ REACTION 110% AIR		PRESSURE 1.00 ATMOS.		DATE= 71127					
TEMPERATURE		1000 K	1100 K	1200 K	1300 K	1400 K	1500 K	1600 K	1700 K
		1341 F	1521 F	1701 F	1881 F	2061 F	2241 F	2421 F	2601 F
GASEOUS SPECIES		VOLUME PERCENT							
CO		0.000	0.000	0.000	0.000	0.000	0.001	0.002	0.008
CO ₂		15.526	15.527	15.527	15.526	15.521	15.504	15.468	15.441
H ₂		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001
H ₂ O		7.460	7.460	7.460	7.460	7.458	7.450	7.433	7.432
N ₂		75.317	75.317	75.315	75.311	75.283	75.193	75.013	74.997
NO		0.001	0.003	0.006	0.012	0.022	0.037	0.059	0.088
O ₂		1.694	1.693	1.691	1.689	1.694	1.721	1.781	1.770
SO ₂		0.000	0.000	0.000	0.001	0.021	0.094	0.242	0.243
SO ₃		0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.001
TOTAL		99.999	100.000	100.000	100.000	100.000	100.000	100.000	100.000
CONDENSED PHASE		LBS / 100 LBS FEED							
CaO	S	0.0	0.0	0.000	0.002	0.040	0.176	0.454	0.454
CAS		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CASO ₄	S	1.103	1.103	1.103	1.099	1.006	0.675	0.0	0.0
TOTAL		1.103	1.103	1.103	1.100	1.046	0.851	0.454	0.454

CACO ₃ -SO ₂ REACTION-100% AIR		PRESSURE 1.00 ATMOS.		DATE= 71125					
TEMPERATURE		1000 K	1100 K	1200 K	1300 K	1400 K	1500 K	1600 K	1700 K
		1341 F	1521 F	1701 F	1881 F	2061 F	2241 F	2421 F	2601 F
GASEOUS SPECIES		VOLUME PERCENT							
CO		0.068	0.079	0.021	0.005	0.004	0.011	0.028	0.065
CO ₂		16.904	16.871	16.912	16.925	16.925	16.917	16.898	16.858
H ₂		0.047	0.037	0.008	0.001	0.001	0.002	0.005	0.009
H ₂ O		8.105	8.105	8.129	8.134	8.133	8.132	8.129	8.127
H ₂ S		0.003	0.001	0.000	0.000	0.000	0.000	0.000	0.000
N ₂		74.860	74.763	74.693	74.676	74.669	74.666	74.657	74.636
NO		0.000	0.000	0.000	0.000	0.001	0.002	0.005	0.012
O ₂		0.000	0.000	0.000	0.000	0.002	0.005	0.014	0.031
SO ₂		0.013	0.143	0.236	0.259	0.265	0.265	0.265	0.265
TOTAL		100.000	100.000	100.000	100.000	100.000	100.000	100.000	100.000
CONDENSED PHASE		LBS / 100 LBS FEED							
CaO	S	0.031	0.269	0.440	0.481	0.494	0.494	0.494	0.494
CAS	S	0.074	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CASO ₄	S	0.983	0.546	0.130	0.030	0.0	0.0	0.0	0.0
TOTAL		1.088	0.814	0.570	0.511	0.494	0.494	0.494	0.494

CACO ₃ -SO ₂ REACTION 90% AIR		PRESSURE 1.00 ATMOS.		DATE= 71125					
TEMPERATURE		1000 K	1100 K	1200 K	1300 K	1400 K	1500 K	1600 K	1700 K
		1341 F	1521 F	1701 F	1881 F	2061 F	2241 F	2421 F	2601 F
GASEOUS SPECIES		VOLUME PERCENT							
CO		2.071	2.327	2.519	2.681	2.958	3.448	3.594	3.675
CO ₂		0.000	0.000	0.001	0.002	0.004	0.004	0.001	0.000
CO ₂		16.276	16.019	15.826	15.662	15.370	14.849	14.700	14.619
H ₂		1.367	1.110	0.920	0.784	0.720	0.727	0.666	0.607
H ₂ O		7.445	7.699	7.885	8.013	8.060	8.042	8.118	8.191
H ₂ S		0.003	0.006	0.011	0.018	0.028	0.024	0.007	0.002
N ₂		72.838	72.838	72.838	72.831	72.778	72.655	72.636	72.631
SO ₂		0.000	0.000	0.001	0.009	0.078	0.243	0.276	0.284
S ₂		0.000	0.000	0.000	0.000	0.004	0.008	0.002	0.000
TOTAL		100.000	100.000	100.000	100.000	100.000	100.000	100.000	100.000
CONDENSED PHASE		LBS / 100 LBS FEED							
CaO	S	0.006	0.012	0.024	0.056	0.223	0.544	0.544	0.544
CAS	S	0.693	0.684	0.670	0.627	0.413	0.0	0.0	0.0
TOTAL		0.698	0.696	0.693	0.684	0.636	0.544	0.544	0.544

1900-2000°F may be on the order of 100 ppm. There are indications from data reported by PER that this level of concentration may be approached as the excess air is increased to the proposed level (~50%). Decomposition of CaSO_4 is not expected, and it was assumed that sulfur emission would be limited by twice the equilibrium concentration in the stack gas. However, more performance data is needed to verify this assumption.

I. Freeboard Performance

In attempting to assess freeboard performance, no direct information was found in the literature regarding disengagement height and the expected particle concentration gradient under operating conditions in the FBC. Therefore it was necessary to resort to reasonable theoretical estimates which are discussed below.

It may be assumed that particles are ejected from the surface of the bed in the wake of gas bubbles. The maximum vertical rise is said to be equivalent to the energy loss during particle deceleration given by the following relationship plus an additional but arbitrary allowance of 25%:

$$h_{\max} = 1.25 \frac{V_s^2}{g}$$

The initial particle velocity was assumed to be equal to the velocity of the bursting bubbles. Therefore,

$$h_{\max} = 1.25 \frac{V_B^2}{g}$$

$$\text{where } V_B = V_{mf} + \frac{V_o - V_{mf}}{\delta}$$

$$\delta = 1 - \frac{\rho_f}{\rho_{mf}}$$

$h_{\max}$ = disengagement height (ft)

V_B = bubble rise velocity (ft/sec)

V_o = superficial gas velocity (ft/sec)

V_s = solid particle velocity (ft/sec)

V_{mf} = superficial gas velocity at minimum fluidizing conditions (ft/sec)

ρ_{mf} = dispersed solid density at minimum fluidizing conditions (lb/ft³)

ρ_f = average dispersed density of solid phase under consideration (lb/ft³)

δ = volume fraction of bed occupied by gas bubbles (dimensionless).

Based on the above, values for disengagement height were calculated as a function of design velocity:

<u>V_o, ft/sec</u>	<u>h_{max}, ft</u>
4	4*
8	7
12	12

*Minimum Value: freeboard height = standard bed height of 4 ft.

Private communication with OSU (Oregon State University), who has obtained some data along these lines in their cold testing facility, provided some verification of the above calculation in that the pressure gradient approached zero at about 11 feet above the surface of the bed when operated at 12 ft/sec.

According to Rowe and Partridge (9), solids are carried in the wake of a rising bubble, which represents about 30% of the bubble volume. As the bubble bursts at the surface, one might then assume uniform redispersion of solids which consists of two distinct parts: (1) ρ_{f2} , which results from the elutriatable fraction that is carried out of the combustor, and (2) ρ_{f1} , which relates to a coarse fraction that is incapable of being supported in dilute phase and drops back into the bed, where ρ_{f2} and ρ_{f1} are spatial densities (lb/ft³) of the solids under consideration, respectively. The latter phenomenon results in a decreasing solids concentration with disengaging height. The nature of this relationship was deduced from data presented by Zenz (10) and together with the other assumptions above, we were able to derive the following expression to predict the particle concentration gradient:

$$\rho_f = \rho_{f2} + \rho_{f1} \left(1 - \frac{x}{TDH}\right)^2$$

$$\rho_{fl} = 0.3 \delta \rho_{mf}$$

where TDH = total disengagement height

X = distance above the fluid-bed level

J. Distributor Plate Design

Perforated plates or bubble caps have generally been considered for use in fluidized bed boiler applications. In the past, the design of such distributors has usually been predicted on providing enough pressure drop to achieve equal flow through the openings:

1. General range: 4 - 20 ins. of H₂O.
2. Percentage of bed ΔP : 10 - 30% with the lower criterion being indicated for down-pointed grid orifices.

Based on experience, a ΔP of less than 2 - 3 inches of water can result in considerable instability, i.e., a cyclic bed activity, whereas a ΔP greater than 15 - 20 inches of water is seldom justified. In fact for large utility application, greater pressure drops would result in severe economic penalties in horsepower requirements.

In accordance with a previous analysis of grid plate design (11) based on jet penetration theory, the need for high differential pressures appears unlikely in the probable design range of fluidizing velocity (>4 ft/sec). In this design range it thus appears that a ΔP of 5 inches of H₂O may be adequate. This preliminary conclusion may be reached from Figure 3-11, which summarizes the results of those calculations and shows the desirable grid plate ΔP as a function of the fluidized gas velocity, V_G , above the plate.

From the above discussion, it is concluded that a reasonable pressure drop across the plate is not only desirable but can probably be achieved provided a large turndown capability is not required. For design purposes a turndown capability of 1:0.75 was assumed without resorting to "bed slumping". Since ΔP is approximately proportional to gas flow squared, the design ΔP at full load was therefore taken as 9" of H₂O ($5/0.75^2 \cong 9$) so that the ΔP would not drop below 5" of H₂O at partial load.

The design of the air distributor was based on a correlation of data obtained by PER (12) for a bubble-cap plate. The approach that was taken to correlate this data was to assume that its performance was predictable through the use of the sharp-edge orifice equation.

FIGURE 3-11
DESIRABLE GRID PLATE ΔP PREDICTED ON BASIS OF
JET PENETRATION THEORY

BASIS: PERFORATED PLATE OR BUBBLE
 CAP DISTRIBUTOR WITH 8 HOLES/CAP
 BED TEMP. = 1550°F
 WINDBOX TEMP. = 600°F

However, the orifice coefficient was found to vary slightly with ΔP as shown in Figure 3-12. In order to obtain consistent results, it was necessary to make an empirical adjustment for the temperature rise across the constriction plate. With these limitations the following modifications of the orifice equation were derived for estimating the hole size in the bubble caps and the number of bubble caps required:

$$D = \frac{(\rho \sin \theta)^{1/2} S \sqrt{V_o}}{1.981 \left[n C \sqrt{\Delta P \left(\frac{530}{T} \right) \left(\frac{P_A + P}{760} \right)} \right]^{1/2}}$$

$$N = \frac{W}{98.15 n C D^2 \sqrt{\Delta P \left(\frac{530}{T} \right) \left(\frac{P_A + P}{760} \right)}}$$

where

W = air rate (lb/hr)

N = Σ number of bubble caps required

D = diameter of holes in caps (in)

n = number of holes/cap = 8

C = coefficient

ΔP = pressure drop (in. H_2O)

T = absolute temperature in windbox ($^{\circ}R$) corrected for 15% Δ effective rise across constriction plate

P_A = atmospheric pressure (mm Hg)

P = static pressure in windbox (mm Hg)

V_o = superficial air velocity at above plate conditions (ft/sec)

S = center-to-center cap spacing (in)

ρ = density of air at above plate conditions (lb/ft³)

θ = angle between caps in adjacent rows (degrees) - 90° for square spacing; 60° for triangular spacing.

FIGURE 3-12
ORIFICE COEFFICIENT FOR BUBBLE CAP AIR DISTRIBUTOR
AS A FUNCTION OF PRESSURE DROP

While the above equations are predicated on data obtained for a bubble-cap distributor, it is felt that the expressions are also applicable to the performance of a perforated plate. For design purposes, the latter situation may be handled by letting n in the equations be equal to unity. To fix the design, one usually makes a decision on a desirable hole size to make the plate non-draining. In this study the use of a perforated plate was finally assumed in view of overall considerations of costs and simplicity. A suitable hole size was taken as one tenth of an inch.

The usual concern in designing air distributors is to provide enough pressure drop to achieve equal flow through all the openings with uniform spacing. However, when coal is supplied to some finite area, radial concentration gradients of solids could develop and adversely affect combustion efficiency because of oxygen starvation in the vicinity of the fuel injection points. Thermodynamic effects on limestone utilization may also be anticipated as a result of these concentration gradients. Under these conditions it is conceivable that a maldistribution of air at the bottom of the bed may be beneficial in countering the potential effects of concentration gradients. This can possibly be accomplished by a plate design whose perforations are largest near the point of feed introduction and decrease in size with distance from that point. The largest air flow will therefore be admitted in the zone where the coal concentration is also the greatest. In this way, the stoichiometric relationship between gas-solid reactants could potentially be improved with an overall increase in reaction efficiencies. Once a better understanding of fluid-bed mixing properties is developed through such ongoing efforts by B&W - OSU (Oregon State University) under contract to EPRI, experimentation with this type of plate should be reconsidered if warranted and studied to determine the effects of velocity gradients.

K. Economic Considerations

Based on the previous discussion on combustion efficiency and sulfur capture, the following theoretical conclusions can be reached:

1. Potential improvements in reaction efficiencies are directly possible by resorting to low velocities or deep beds.
2. Data acquisition at high H/V_0 ratios or gas residence time is technically justified.

However, there is one question remaining at this point: "Is there economic justification to proceed in this direction?" We believe the answer is yes as illustrated in Figure 3-13. This graph gives relative operating costs as a function of bed height for various values of superficial gas velocity. The costs included incremental expenses over those for a conventional PC fired unit:

- (1) Limestone @ \$6/ton
- (2) Power consumption (bed ΔP) @ 3¢/kw-hr
- (3) Heat losses @ \$20/ton coal
 - a. Sensible heat in bed discharge
 - b. Reaction heat losses
 - c. Combustion inefficiency

Again this figure shows that the low velocity candidate is the most economical and that increasing the bed height to about 8 ft. can potentially effect further cost reduction. However, this will increase structural costs, but the economic implications of this must be evaluated.

FIGURE 3-13
RELATIVE OPERATING COST AS A FUNCTION OF BED
HEIGHT AND SUPERFICIAL VELOCITY

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IV. ASSESSMENT OF CANDIDATE SYSTEMS

A. Introduction

Five (5) fluidized bed boiler systems were proposed as candidates from which to select a small scale (150 MW to 250 MW) utility unit for detailed study. These systems may be categorized as follows:

1. Bed velocity of 4 ft/sec with a carbon burn-up unit
2. Bed velocity of 8 ft/sec with a carbon burn-up unit
3. Bed velocity of 8 ft/sec with char recycle to complete combustion (no separate carbon burn-up unit)
4. Bed velocity of 12 ft/sec with a carbon burn-up unit
5. Bed operated with less than theoretical air and with overfire air injection (Two stage combustion)

Initially, the two stage fluid bed combustion system appeared to have promise. The concept involves a limestone fluid bed gasification system for partial combustion and sulfur capture in the bed, with final combustion accomplished in a second stage suspension type furnace. Evidence exists in the literature (Reference 1 and 2) that indicates significantly better sulfur retention in a reducing bed with a correspondingly lower Ca/S ratio. Other possible advantages of such an approach (in addition to improved sulfur capture and reduced limestone requirements) were considered to be:

- .Reduction of CO in the flue gas with efficient second stage combustion.
- .Reduced bed size and number of feed points required.
- .Higher heat recovery (because of reduced limestone requirements).

Some possible disadvantages:

- .Increased corrosion problems in a reducing bed.
- .Disposal and/or regeneration of CaS.

.Release of SO_2 from elutriated CaS particles in the secondary combustor.

Figure 4-1 displays an equilibrium plot of pounds of sulfur in the gas per million BTU heat input versus temperature. In a fluid bed combustor, complete uniformity of combustion cannot be achieved because some of the gas passes through the bed in bubble form resulting in some inefficiency of solid-gas contact. Therefore, some adjustment of operation logic must be applied to equilibrium conditions. For highly oxidizing and highly reducing conditions, at normal bed temperature (about 1550°F) sulfur capture should be high. When a bed is operated at a reasonable average excess air (about 15%) much of the bed may actually be near neutral. Using this reasoning and comparing the curves on Figure 4-1 that represent 100 and 60% total air, equilibrium calculations seems to confirm that more efficient sulfur capture will be achieved under substoichiometric conditions.

Reference should also be made to Figure 4-2, which is a phase diagram, for the solid system of CaCO_3 -CaO-CaS- CaSO_4 in equilibrium with flue gas for various total air values versus temperature. The equilibrium data in Figure 4-1 and 4-2 indicate that a secondary combustor operating at 2200°F and 15 percent excess air would re-release a significant amount of sulfur to the gas stream. In the absence of actual test data for these conditions it appears necessary to effect particulate removal (to remove CaS) between the two stages of combustion. This would require a large, and expensive, hot cyclone solids removal system.

Investigation of the foregoing design and its problems resulted in the establishment of three main problem areas that required extensive development.

.We were unable to find data to establish carbon utilization in a fluid bed gasifier. This is a particularly vital part of fluid bed gasifier design work.

.We believe that the carbon content of the bed material will be high under substoichiometric conditions. This will necessitate an additional system (possibly an oxidizing bed) to achieve acceptable overall combustion efficiencies.

.A system must be developed for regeneration of the CaS produced, or to chemically alter it for disposal.

FIGURE 4-1
EQUILIBRIUM SULFUR IN GAS

FIGURE 4-2
EQUILIBRIUM SOLID PHASE DIAGRAM

$\text{CaCO}_3 - \text{CaO} - \text{CaS} - \text{CaSO}_4$

LIMESTONE - COAL - AIR

LEGEND

Ca/S = 1 ——— 115% STOICH. AIR
 — x — 100% STOICH. AIR
 - - - 60% STOICH. AIR
 Ca/S = 2 — · — 100% STOICH. AIR

Based on the extensive developmental work needed to cope with the problems listed above, it was concluded that such a system was beyond the scope of this contract. The two stage combustion approach may yet prove to be a viable alternate, but not before time and money are spent on development programs to solve the foregoing vital problems.

For the remaining four (4) systems, enough work had been done to prepare preliminary designs and costs. An existing 2400 psi 250 MW conventional coal fired boiler was used as a source of steam side conditions. For simplification and speed, the four (4) designs were only checked at full load conditions. No comparison was made at low loads and no comparison was made of turndown requirements at low load operation. An outline of the boiler design conditions used lists some of the basic bed operation and combustion parameters used in this study.

TABLE 4-1

OUTLINE OF BASIC BOILER DESIGN CONDITIONS

AIR TEMPERATURE TO BOILER	(°F)	600
FBC BED TEMPERATURE	(°F)	1,550
CBB BED TEMPERATURE	(°F)	2,000
GAS TEMPERATURE TO AIR HEATER	(°F)	700
GAS TEMPERATURE TO STACK	(°F)	285
SH STEAM FLOW RATE	(Lb/Hr)	1,837,500
RH STEAM FLOW RATE	(Lb/Hr)	1,646,000
SH STEAM OUTLET TEMPERATURE	(°F)	1,005
FEEDWATER INLET TEMPERATURE	(°F)	485
RH STEAM OUTLET TEMPERATURE	(°F)	1,005
RH STEAM INLET TEMPERATURE	(°F)	630

TABLE 4-2

BED OPERATION AND COMBUSTION PARAMETERS

MEANS OF CARBON BURNOUT	CBB	CBB	RECYCLE	CBB
NOMINAL BED VELOCITY (Ft/Sec)	4	8	8	12
COMBUSTION EFFICIENCY (%)	91	88	88 (1)	85
FRACTION OF BURNING IN BED(2)	0.94	0.91	0.91	0.88
AVG. PARTICLE SIZE IN BED(IN)	0.022	0.035	0.035 (3)	0.050
EXCESS AIR IN FBC (%)	15	15	15	15
EXCESS AIR IN CBB (%)	50	50	---	50

- (1) Combustion efficiency refers to fresh input coal. It is assumed that 50% of recycled combustibles burn in each cycle.
- (2) This is the fraction of overall predicted combustion that occurs in the bed. The remainder takes place in the freeboard zone above the bed. These were assumptions based primarily on judgement.
- (3) For the recycle unit the average particle size does not take into account the recycle material.

B. General Description of the Systems

Refer to Figure 4-3 for an outline of the system arrangement used for the three (3) designs employing a carbon burn-up bed for completion of combustion.

In the systems employing carbon burn-up beds, heated air is divided into two (2) streams. Most of it is used to fluidize the bed solids while the remaining portion is used to convey the limestone and crushed coal to the main unit beds, as well as to vaporize some of the water in these feed materials. The fluidizing air stream is further divided; the bulk being sent to the main beds, and the smaller stream being sent to the carbon burn-up bed. The limestone average particle size and size distribution was assumed to be that which would result in 35% of the solids being elutriated from the main beds.

The coal and limestone used for the design are shown in Table 4-3 and 4-4. In the main unit beds, the limestone was considered to be completely calcined. Most of the burning is estimated to take place in the beds, however some burning also takes place in the zone just above the bed, referred to herein as the freeboard zone. It is also in this zone where large particles carried out of the bed by local high bubble velocities drop back into the bed.

The heat produced by the burning coal is absorbed by steam and/or water in the containment walls as well as tube banks located in the main unit beds and convection pass. The solid material, carried out of the main unit in the gas, is removed in a cyclone separator and sent to the carbon burn-up bed. Here combustion of most of the unburned carbon particles leaving the main unit is completed. The heat produced in the carbon burn-up bed is absorbed by steam and/or water in the containment walls and tube banks in the convection pass. There are no tube banks in the beds of the carbon burn-up unit.

A cyclone separator removes most of the solids entrained in the gas stream leaving the carbon burn-up bed unit. The gas stream is joined with that leaving the main unit cyclone separator before final particulate removal in a hot precipitator, and final heat removal in an air heater.

Hot spent lime is purged from the main unit and carbon burn-up beds. Further solids purging takes place at the carbon burn-up unit's cyclone separator and from the hot precipitator.

FIGURE 4-3

Schematic Arrangement of Systems

Utilizing A Carbon Burn-up Bed

TABLE 4-3

COAL ANALYSIS FOR ASSESSMENT OF CANDIDATE SYSTEMS

PROXIMATE ANALYSIS		ULTIMATE ANALYSIS	
CONSTITUENTS	% BY WEIGHT	CONSTITUENTS	% BY WEIGHT
MOISTURE	15.0	ASH	27.5
VOLATILE MATTER	25.0	SULFUR	6.5
FIXED CARBON	36.7	HYDROGEN	4.0
ASH	23.3	CARBON	56.0
TOTAL	100.0	NITROGEN	1.0
		OXYGEN	5.0
SULFUR	5.5	TOTAL	100.0

INITIAL DEFORMATION TEMPERATURE	(°F)	1900
SOFTENING TEMPERATURE	(°F)	2050
FLUID TEMPERATURE	(°F)	2200
HHV (AS RECEIVED)	(BTU/LB)	9000

TABLE 4-4

LIMESTONE ANALYSIS FOR ASSESSMENT OF CANDIDATE SYSTEMS

	% BY WEIGHT
CALCIUM CARBONATE (CaCO_3)	90.25
INERTS (AS SiO_2)	4.75
MOISTURE (H_2O)	5.00
TOTAL	100.00

Sulfur removal takes place in the main unit beds and freeboard zones. Based on equilibrium considerations, some sulfur is also assumed to be removed in the carbon burn-up bed. The SO_2 content of the gas leaving the carbon burn-up bed is assumed to be 200 ppm/v, or about twice the equilibrium amount.

Figure 4-4 shows the arrangement used for the system employing carbon recycle to complete combustion. This is similar to the units utilizing the carbon burn-up beds in regard to coal and limestone crushing, conveying and feeding. The combustion equipment is significantly different, however. Following the freeboard zone the hot (1633°F), solids laden gases are sent to a battery of hot cyclones, where most of the unburned combustibles are removed and sent back to the beds to complete combustion. Prior to feeding the recycle material to the beds, a portion is purged to keep the system solids input and output in balance.

The gases from the hot cyclone separators (still containing small solids particles) are sent to a unit that is the equivalent of an upper boiler furnace and convection pass. Here heat is absorbed from the hot gases by steam and/or water in the containment walls and tube banks. The solid material carried through this unit is collected in a hot precipitator. Final heat removal from the gas stream is then effected by a conventional air heater.

Spent lime and solids purging takes place from the fluid beds, the hot cyclone underflow line and the hot precipitator. A small amount of solids may have to be removed intermittently from the convection pass unit.

All SO_2 removal takes place in the beds and freeboard zones.

It was assumed that half the recirculated combustibles were burned in each cycle and that the overall combustion efficiency equalled that in the 8 ft/sec unit with a carbon burn-up bed. With 90% cyclone separator collection efficiency (based only on combustibles), the gas leaving the freeboard zone contained about 673 lbs of solids per 1000 lbs of gas.

FIGURE 4-4

Schematic Arrangement of System
Utilizing Carbon Recycle to Main Bed

C. Results

1. Surface and Duty

Tables 4-5 and 4-6 outline the design and performance data of the first four (4) systems. Figures 4-5, 4-6, 4-7, 4-8, 4-9, 4-10 and 4-11 display a pictorial idea of the combustor portions of these systems.

At the time the candidate assessment study was carried out, the calculation of molar Ca/S ratio was done on the basis of an equation (based on some test data analysis) that showed strong responsiveness to bed velocity. Later test data analysis effectively altered the responsiveness, but the design work for the determination of equipment costs was based on the early calculation method. Note in Table 4-5 where the Ca/S ratio is 2, 4, and 6 for 4 ft/sec, 8 ft/sec and 12 ft/sec bed velocities, respectively. While this factor showed an important effect on thermal efficiency, coal usage and limestone usage, its effect on equipment size and cost turned out to be modest.

Examination of the physical aspects of the four (4) designs shown in Table 4-5 seem to indicate that the 4 ft/sec design with carbon burn-up bed is generally superior to the 12 ft/sec and 8 ft/sec designs utilizing carbon burn-up beds. The main exception is that of bed area, which is comparatively larger. This also results in a large number of coal feed points and a larger more complicated feed system. The 8 ft/sec unit with recycle is superior from the standpoint of requiring the least amount of total transfer surface. It was, however, found to have a number of serious drawbacks. Very high solids recycle rates were required to achieve a combustion efficiency comparable to the systems using carbon burn-up beds, resulting in dust loadings of 15 to 20 times that normally encountered in a conventional PC fired boiler. This is far beyond commercial boiler experience and so it was concluded that hot cyclone solids separation would be required ahead of the boiler convection pass banks. At the freeboard outlet temperature (about 1630°F), many massive, refractory lined cyclone separators are required, and these cyclones, together with a complicated refractory flue system, add considerable cost to this concept, and also required considerably more building volume. This is apparent in Figures 4-4 and 4-5 which shows side and plan views of such an arrangement.

A comparison of the two (2) 8 ft/sec systems (with carbon burn-up bed and with char recycle) shows that the recycle case has a 1.6% lower thermal efficiency.

TABLE 4-5

COMPARISON OF FOUR DESIGNS

NOMINAL SUPERFICIAL BED VELOCITY (FT/SEC)		4	8	8	12
MEANS OF CARBON BURN-UP		CBB	CBB	RECYCLE	CBB
PERFORMANCE	COAL FLOW (LB/HR)	237,900	251,560	254,480	269,150
	LIMESTONE FLOW (LB/HR)	101,600	214,900	224,100	351,800
	AIR FLOW (LB/HR)	2,267,500	2,389,600	2,337,100	2,542,400
	GAS LVG. SYSTEM (LB/HR)	2,482,200	2,672,200	2,623,500	2,898,200
	THERMAL EFFICIENCY (%)	85.6	81.1	79.5	75.8
	Ca/S RATIO (MOLAR)	2	4	4	6
	FBC BED VELOCITY (FT/SEC)	4	8	8	12
	CBB BED VELOCITY (FT/SEC)	4	8	-	12
DIMENSIONS	FBC HEIGHT (FT)	90	90	100	80.5
	CBB HEIGHT (FT)	39	39	-	61.8
	FBC BED PLAN AREA (SQ.FT)	7,776	4,032	4,590	2,880
	CBB BED PLAN AREA (SQ.FT)	1,080	729	-	648
	NO. OF COAL FEED POINTS	864	448	510	320
TRANSFER SURFACE	ECONOMIZER SURFACE (SQ.FT)	73,190	94,657	68,634	95,999
	SUPERHEATER SURFACE (SQ.FT)	20,112	20,851	21,520	22,195
	REHEATER SURFACE (SQ.FT)	92,945	74,949	74,755	59,005
	BOILING SURFACE (SQ.FT)				
	1) WALL	32,284	30,372	30,991	36,418
	2) BANKS:				
	FBC BED	8,366	6,352	10,646	1,484
	FBC CONVECTION PASS	-	-	2,352	29,864
	CBB CONVECTION PASS	-	9,732	-	20,204
TOTAL SURFACE (SQ. FT)		227,277	236,913	208,898	265,169

TABLE 4-6

SUMMARY OF CBB DESIGN

		SUPERFICIAL BED VELOCITY (FT/SEC)		
		4	8	12
TOTAL HEAT ABSORBED	(BTU/HR)	154,560,000	246,725,000	316,000,000
BOILING HEAT	"	95,120,000	189,580,000	269,520,000
ECONOMIZER HEAT	"	59,440,000	57,145,000	46,480,000
BOILING IN BED	"	59,260,000	83,494,000	109,000,000
BOILING CONVECTION PASS BANKS	"	--	77,580,000	106,400,000
BOILING IN WALLS (NOT BED)	"	35,860,000	28,506,000	54,120,000
BED WALL SURFACE	(SQ. FT)	744	1060	1386
OTHER BOILING SURFACE	"	5,687	13,767	28,611
ECONOMIZER SURFACE	"	17,055	13,764	15,080
TOTAL SURFACE	"	23,486	28,591	45,077
BED AREA	(SQ. FT)	1,080	729	648
NO. OF BED PARTITIONS		1	2	2
NO. OF ECONOMIZER BANKS		2	2	2
NO. OF BOILING BANKS		0	2	3

91-7

THE BABCOCK & WILCOX COMPANY
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REVISIONS			MICROFILM	
DASH NO.	DATE	DESCRIPTION	ORIGINAL

PLAN VIEW

SIDE VIEW

FIGURE 4-6

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DWN. BY EEP
DATE 2-6-78
CHK'D
APP'D

ARRGT OF FLUID BED BOILER
(4 FT/SEC BED VELOCITY)

SCALE $\frac{1}{4}$ INCHES = 1 FOOT
SK-172 B-O

K&E NO. 19-1283

THE BABCOCK & WILCOX COMPANY
POWER GENERATION GROUP

REVISIONS			MICROFILM	
DASH NO.	DATE	DESCRIPTION	ORIGINAL

PLAN VIEW

SIDE VIEW

FIGURE 4-7

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DWN. BY G.W.D. CHK'D
DATE 2-6-78 APP'D

ARRGT OF FLUID BED BOILER
(8 FT/SEC. BED VELOCITY)

SCALE 1/4" = 1 FOOT
SK-180 B-0

FORM BDM 1067 B-4

K&E NO. 19-1253

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POWER GENERATION GROUP

REVISIONS			MICROFILM	
DASH NO.	DATE	DESCRIPTION	ORIGINAL

PLAN VIEW

SIDE VIEW

FIGURE 4-8

K&E NO. 19-1253

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DWN. BY	E P	CHK'D
DATE	7-6-78	APP'D

ARRGT FLUID BED BOILER
(12 FT/SEC BED VELOCITY)

SCALE	1" = 1 FOOT
SK-170	B-0

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POWER GENERATION DIVISION

FIGURE 4-9

ARRANGEMENT OF CARBON BURN-UP BED (4 FT/SEC)

REVISIONS			MICRO-FILM
DASH NO.	DATE	DESCRIPTION	ORIG.

PLAN VIEW

ELEV VIEW

(4 FT/SEC BED VELOCITY)

DWN. BY EP	CHK'D	ARRGT CARBON BURNUP BED	SCALE $\frac{1}{4}$	DATE 2-6-78
PASSED BY	APP'D		DRWG. NO. SK-171	A-O

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FIGURE 4-10

ARRANGEMENT OF CARBON BURN-UP BED (8 FT/SEC)

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DASH NO.	DATE	DESCRIPTION	ORIG.

PLAN VIEW

ELEV. VIEW

(8 FT/SEC BED VELOCITY)

DWN. BY G.W.D.	CHK'D
PASSED BY	APP'D

ARRG'T
 CARBON BURNUP BED

SCALE	DATE 2-6-78
DRWG. NO.	SK-179 A-0

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FIGURE 4-11

ARRANGEMENT OF CARBON BURN-UP BED (12 FT/SEC)

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BRUNING 15

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ARRGT
 CARBON BURNUP BED

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This is caused by:

- .Increased radiation losses due to the many large cyclones and associated flues.
- .Increased heat loss associated with purged bed solids. With a carbon burn-up bed design, more of the stone passes through the boiler and eventually is purged at 700°F instead of 1550°F.

Recycling of unburned combustibles to the main beds results in increased heat release within the beds (as opposed to the comparable units with carbon burn-up bed) and therefore more steam generation from in-bed surface. Since this is a very efficient heat transfer zone, the overall result is a somewhat lower total boiler heating surface required, as indicated in Table 4-5. As will be discussed later, however, the cost of the hot cyclone system and the reduction in thermal efficiency over-balanced the savings in heating surface.

When comparing the three (3) systems having carbon burn-up beds, it should be noted that the primary factor in establishing the results is the strong influence of superficial bed velocity in setting the Ca/S ratio (which translates to the amount of limestone needed per unit of coal) and combustion efficiency. High velocities result in lower combustion efficiencies and poorer limestone utilization. This, in turn, results in lower thermal efficiency (because of the added calcining loss and the added loss from increased quantities of hot solids purged).

A comparison of the transfer surface in each of the three (3) designs with carbon burn-up beds is of interest. Though the potential heat input to the 12 ft/sec bed is highest because of the greater amount of coal input, the heat released to the bed transfer surface is least. This is caused by two factors:

- .Lower bed combustion efficiency in the high velocity bed.
- .Greater amount of heat lost due to limestone calcining in the high velocity bed.

For the four (4) developed designs, it was decided that all bed cooling was to be accomplished by superheat surface and boiling surface, and that all superheating would be accomplished in the beds. This results in less boiling taking place in the high velocity beds than the low velocity beds. The 4 ft/sec design does such a large

fraction of total boiling within the beds that it was found necessary to cut back on economizer duty.

Table 4-7 summarizes the bed boiling heat transfer requirements for the three (3) units with carbon burn-up beds.

Because increased heat release and boiling take place in the low velocity main beds, a corresponding adverse effect is noticed in regard to the reheater surface. In this case, the gases leaving the disengaging zone (free-board, or open zone above the bed where main bed combustion is completed) are at a lower temperature than in the high velocity units, because of less above-bed burning, resulting in a lower gas temperature entering the reheater and thus requiring an increased amount of reheater surface.

In the high velocity units, where only a limited amount of boiling can be accomplished in the beds, a large amount of convection pass boiling must be done. As convection pass boiling heat transfer rates are much lower than bed boiling heat transfer rates (by a factor of about 1/5), the convection boiling surface requirements for high velocity designs are significantly increased.

The tabulated data in Table 4-5 shows the result of the differences described above. The slight differences in superheater surface are due only to the effect of differences in average bed particle size and bed velocity on overall heat transfer rates.

The carbon burn-up beds for the three (3) design velocities are similar in that they:

- .Contain only boiling and economizer surface.
- .Have no bank surface in the beds.
- .Are designed for a bed superficial velocity equal to that of the corresponding main beds.

The last item, above, means that 100% of the solids fed to the carbon burn-up beds from the main bed solids separation systems will be elutriated. In order to maintain bed stability, spent limestone from the main bed's underflow material storage tank will be transferred to the carbon burn-up unit.

Refer to Table 4-6 for a comparison of the three (3) carbon burn-up bed units.

		SUPERFICIAL BED VELOCITY (FT/SEC)		
		4	8	12
TOTAL HEAT FROM COAL	(BTU/HR)	2,519,100,000	2,663,560,000	2,849,820,000
FBC COMBUSTION EFFICIENCY	(OVERALL)	0.91	0.88	0.85
FRACTION OF TOTAL COMBUSTION IN BEDS		0.94	0.91	0.88
BED COMBUSTION EFFICIENCY		0.855	0.801	0.748
HEAT RELEASED IN BEDS	(BTU/HR)	2,153,800,000	2,133,500,000	2,131,700,000
HEAT UNAVAILABLE FOR BED HEAT TRANSFER	(BTU/HR)	869,800,000	1,027,500,000	1,262,700,000
TOTAL HEAT TO BED SURFACE	(BTU/HR)	1,284,000,000	1,106,000,000	869,000,000
HEAT TO SH SURFACE	(BTU/HR)	748,000,000	748,000,000	748,000,000
HEAT TO BED BOILING SURFACE	(BTU/HR)	536,000,000	358,000,000	121,000,000
BOILING MEAN TEMPERATURE DIFFERENCE		(°F)	864	864
BOILING OVERALL U	(BTU/HR-°F-SQ.FT)	51.6	48.3	46.9
BOILING SURFACE:	(SQ.FT)			
BANKS		8,366	6,352	1,484
WALLS		3,600	2,208	1,505
TOTAL		11,966	8,560	2,989
BOILING HEAT FLUX	[BTU/(HR-SQ FT)]	44,790	41,820	40,480

SUMMARIZATION OF BOILING DUTY IN FBC BEDS

TABLE 4-7

2. Cost Estimates for the Candidate Systems

As part of the evaluation of the candidate systems, capital costs were prepared for four (4) of the original five (5) designs. The fifth system, utilizing two stage combustion, was eliminated early for lack of the necessary data to create a valid design. Since the objective of this task was to develop the relative merits of each system, it was not necessary to prepare a detailed capital cost estimate for the complete system. Instead costs were prepared for the following major items; boiler pressure parts, boiler structural steel, BRIL, feeders and seals, hot cyclones (for the recycle case only), cold multicyclones, air heaters, precipitators and fans (without motors). Table 4-8 summarizes the results of the cost estimates. These are preliminary cost estimates and should only be considered valid on a relative basis.

TABLE 4-8
SUMMARY OF CAPITAL COST OF
MAJOR BOILER COMPONENTS

	4 ft/sec with CBB	8 ft/sec with CBB	8 ft/sec with Recycle	12 ft/sec with CBB
TOTAL COST (1000'S \$)	14,820	14,430	18,240	15,960
UNIT COST* (\$/KW)	59.30	57.70	73.00	63.80

*Based on 250 MW Plant

The main thing revealed by this preliminary capital cost comparison is that the unit utilizing recycle has significantly higher costs than the other three, due entirely to the expensive hot cyclone system. The three (3) units with carbon burn-up beds are within $\pm 5\%$ of one another, and well within the estimating accuracy for these preliminary designs.

The most significant differences between the candidate system designs became apparent when the thermal efficiencies and limestone costs were factored into the comparison.

As stated above, additional sulfur capture data was obtained after the assessment of the candidate systems was initiated. In addition the sulfur content of the design coal was reduced from 6.5% by weight to 4.5% by weight (dry basis). Incorporating these two important changes into the design basis, Table 4-9 was prepared and lists the differential capitalized costs for coal and limestone for the four (4) schemes, with the 4 ft/sec unit as a base. Table 4-9 is based on the following assumptions:

Capitalization Factor	0.18
Load Factor	0.70
Cost of Coal (\$/10 ⁶ BTU)	1.00
Cost of Limestone (\$/Ton)	6.00
Plant Heat Rate (BTU/KW-HR) (Based on 89% boiler thermal efficiency)	4500
Coal HHV BTU/Lb (Dry)	12,026
Coal Sulfur Content (%)	4.5
Limestone Analysis	As in Section VI

TABLE 4-9

DIFFERENTIAL CAPITALIZED COST OF COAL AND LIMESTONE (\$/KW)BASED ON FINAL FORM OF EQUATION FOR Ca/S RATIO PREDICTION

DESIGN CONCEPT	THERMAL EFFICIENCY (%)	Ca/S RATIO	COAL COST (\$/KW)	LIMESTONE COST (\$/KW)	TOTAL COST (\$/KW)
4 ft/sec with CBB	87.9	2.34	Base	Base	Base
8 ft/sec with CBB	86.3	3.27	6.30	10.90	17.20
12 ft/sec with CBB	84.3	4.19	14.10	23.00	37.10
8 ft/sec with Recycle	84.9	3.27	11.60	11.50	23.10

FIGURE 4-12

COST COMPARISON OF 4 CANDIDATE SYSTEMS
USING FINAL (IMPROVED) EQUATION FOR Ca/S RATIO

KEY:

E = ABSOLUTE EQUIPMENT COSTS

L = DIFFERENTIAL CAPITALIZED LIMESTONE COST

C = DIFFERENTIAL CAPITALIZED COAL COST

On the basis of the information shown in Table 4-9 it is clear that the successful candidate system is the 4 ft/sec unit with a carbon burn-up bed. The results are heavily influenced by design correlations developed for this project in that both combustion efficiency and calcium utilization efficiency are strongly affected by bed superficial velocity (or possibly bed residence time). Even though the accuracy of the absolute numbers may be open to question we believe that the trends shown in Table 4-9 to be correct and the selection of the design type to be used in the demonstration plant was made on this basis. Figure 4-12 was also prepared and is a pictorial presentation of the capital cost and differential capitalized coal and limestone costs described in the foregoing.

Following the development of the differential coal and limestone costs described above, it was determined that the use of an electrostatic precipitator would be a feasible way of improving combustible collection leaving the FBC, thus increasing boiler thermal efficiency. An examination of the effect of this design improvement on differential coal and limestone costs showed that the total differential capitalized costs would be reduced by less than 10%. Therefore, the final results in the comparative costs were not materially altered and the final decision remained unchanged.

3. Conclusions

The 4 ft/sec unit with a carbon burn-up bed appears to be the best overall design of the group examined. A summary of its advantages as well as its disadvantages are as follows:

Advantages

- .Equal or lower capital equipment cost compared to the other units studied.
- .Lowest coal and limestone costs.
- .The highest bed combustion efficiency.
- .The highest boiler thermal efficiency.
- .The highest limestone usage efficiency.

Disadvantages

- .Requires more main bed area and carbon burn-up bed area than any other units.
- .Limestone and coal feeding will be complicated because the number of feeder lines is directly proportional to bed area.

References

1. A. A. Jonke, et al., "Reduction of Atmospheric Pollution by the Application of Fluidized Bed Combustion". EPA-IAG-0020, Annual Report, July 1970 - June 1971.
2. W. T. Abel, E. P. Fisher, "Limestone to Remove Hydrogen Sulfide from Hot Producer Gas", ERDA (MERC/RI-7513), January 1976.

V. DESIGN PHILOSOPHY

A. General

The steam generating portion of the fluid bed system consists of two major units, the main fluid bed boiler and a separate carbon burn-up bed unit. The overall design arrangements of these units are shown on pages A-2 and A-6.

The main bed unit is made up of four (4) beds, each 50 feet wide and 28 feet deep. All of the coal and limestone and a major portion of the combustion air are fed to this unit. The boiler is arranged with three (3) elevations of beds on the front wall and one at the base of the central furnace. As detailed in Section IV, our study of various conceptual designs indicated overall cost savings at lower bed gas velocities; and accordingly, this 200 MW demonstration unit is designed for a full load superficial bed velocity of 4 ft/sec. Because of the low bed velocity and the choice of four (4) boiler beds for the main boiler unit, it was necessary to neck down the main furnace shaft so that its depth is one half ($1/2$) of the bed depth (14 ft. versus 28 ft.). This was done to increase gas velocities through the high temperature reheater banks at the top of the furnace and thereby realize more efficient heat transfer in this area. For larger units (such as the 800 MW commercial design described in Section XIII) which will require more beds, this design approach will not be necessary.

An inspection of the arrangement drawings will reveal that the windbox areas located between the vertically disposed beds are rather large. This arrangement was dictated by the significant structural requirements within the windbox, due to high gas pressure differentials, distributor plate support systems, and thermal expansion requirements. In addition, routing of the many coal and stone feed pipes added to the congestion problem in these areas.

The main boiler design was predicated on the philosophy of not placing any reheater surface within the beds. This eliminated the need for a sophisticated by-pass system for protection of the reheater during start-up and unit trip conditions. The downflow convection pass, which resembles a conventional boiler arrangement, consists of a primary superheater section and a primary reheater section in parallel, with gas flow biasing for reheat steam temperature control. The major portion of the superheater surface is submerged in the beds. The superheater surface is located in two and one-half ($2-1/2$) of the four (4) beds. The remaining one and one-half ($1-1/2$) beds contain boiling heat transfer surface.

A pump assisted circulation boiler design was selected rather than a once through design. The AFB system with its many enclosure walls for both main unit and the CBB, as well as the horizontal boiler surface in the main beds, presents a large number of tubes to be cooled. The use of a once through design would require several sequential passes through the enclosure in order to achieve sufficiently high mass flow in the tubes to assure that departure from nucleate boiling would not occur. Considering the design problems that are known on conventional 2400 psi once through boilers, if multiple passes must be used, it seemed prudent not to utilize the once through design philosophy. In addition, the avoidance of a once through design permits the use of large (2-1/2 inch OD) diameter enclosure tubes. This size, as opposed to the 1-1/4 inch or 1-1/2 inch OD tubes usually used in once through designs, provides greater enclosure wall rigidity and hence reduces structural design requirements.

A pump assisted circulation design was selected over natural circulation for two primary reasons. First, the horizontal boiler tubes submerged in the beds require relatively high fluid mass flows to assure that there will be no departure from nucleate boiling. Second, the heat absorbed by the vertical wall enclosure tubes is significantly lower than for a conventional coal fired unit, resulting in insufficient natural pumping head.

The carbon burn-up bed unit is designed as a physically separate enclosure, although it is fed by the common circulating pumps and its water circuitry is integral with the main boiler. The alternative of physically integrating the CBB into the main boiler setting was not pursued for structural reasons. Under certain operating conditions, significant gas pressure differentials could exist between the main unit and the CBB, and if a common tubular wall was used to separate the two units, there appeared to be no reasonable means to buckstay this wall to accommodate the resulting forces.

The CBB consists of two (2) beds with vertical water cooled tubular enclosure walls. Unlike the FBC, there is no horizontal heat transfer surface within the beds. The CBB has been oversized by 20% for flexibility reasons. For example, in the event that the main bed combustion efficiency is poorer than anticipated, additional heat would be liberated in the CBB. Bed temperature can be controlled by slumping of bed compartments, varying bed depth, or a combination of both. Coal and limestone can be fed to the CBB beds for start-up for supplementary feed if required.

The design parameters used for this study were developed by B&W as part of an in-house AFB development program, and also during the early stages of this contract. This development work and pertinent results are discussed in detail in Section III of this report. The primary design factors used for the demonstration unit are as follows:

Main bed and CBB superficial velocity (ft/sec)	4
Main bed and CBB bed depth (ft)	4
Main bed operating temperature (°F)	1550
Main bed excess air (%)	15
CBB operating temperature (°F)	2000
CBB excess air (%)	50

B. Operating Characteristics and Philosophy

Based on B&W's studies of fluid bed combustion as applied to utility power plants and cycles, one of the major concerns that has surfaced is the probability of reduced operating flexibility as compared to conventional coal fired boilers. For a standard 2400 psi, 1000°F cycle, a considerable portion of the heat absorbed to satisfy the turbine cycle must be in superheat. Since a large portion of the heat released in an AFB boiler is within the bed, the major portion of the superheater must be immersed in the bed for this cycle. This requirement merely adds to the operating restrictions that have been experienced and reported on several laboratory scale apparatus. Within a fluid bed, and within our present knowledge of the process, the following operating restrictions would appear to apply (for this discussion the possibility of serious in-bed corrosion is ignored).

1. For optimum sulfur capture, the bed temperature should be maintained reasonably close to 1550°F (1550°F-1600°F might be a practical range).
2. Coal flow must be regulated to meet load demand, and air flow must be kept within reasonable excess air limits as with any boiler.
3. In-bed superheater input must be regulated sufficiently so that reasonable external means (attemperators) can be used for accurate control of steam temperature to the turbine.
4. In-bed heat transfer does not diminish greatly as fuel and air are decreased (assuming the bed temperature is maintained within required limits). Steam flow quantities decrease, however, with diminishing load, resulting in superheater metal design problems

at reduced loads. This phenomenon also requires that surface must be removed from service, as load is decreased, to control superheat temperature.

5. For a commercially sized fluid bed utility boiler, the bed area must be large. This, in B&W's opinion, eliminates the option of using vertical surface and mandates the use of horizontal surface within the bed. In turn, this makes it difficult to anticipate the use of bed height as a primary tool for significant bed turndown ability.
6. The above anticipated operating restrictions have led B&W to conclude that it is not practical to obtain load turndown by keeping all beds in service and modulating fuel and air to them, except for a quite limited control range. Instead, we have elected to proceed with a design that splits the main operating beds into a number of separate compartments, with individual coal, limestone and air controls. This philosophy anticipates that slumping of individual bed compartments will be a practical operating mode and will overcome many of the above listed operating problems.

C. Coal and Limestone Feed System

In developing the philosophy of design for the coal and limestone feed and transport system, B&W endeavored to meet the following design goals:

1. Utilize a feed system from under the bed to minimize the length of coal nozzle subjected to bed temperature conditions. The purpose of this approach was to minimize the possibility of coal nozzle coking.
2. Each coal and limestone feed nozzle was to service approximately nine (9) square feet of bed area, suggested by existing technology for reasonable bed distribution.
3. The design should eliminate the need for predrying coal or limestone.
4. Existing conventional boiler coal feeding and transport technology should be utilized as much as possible.

The resulting coal and limestone system is shown in Figure 5-1.

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FIGURE 5-1

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APP'D

FLUID BED COAL & LIMESTONE
FEEDING & DISTRIBUTION SYSTEM

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The coal and limestone injection system receives the crushed coal and limestone from their respective silos, mixes the coal and the limestone in the proper ratio for sulfur removal, dries, transports, distributes and injects the mixture into the fluid bed boiler and when required, into the carbon burn-up beds. The design of the coal and limestone injection system is based on an almost identical system supplied by B&W for injecting crushed coal into B&W Cyclone Furnaces.

Twenty (20) identical transport systems are used in parallel. Each starts at the outlet of the coal and limestone silos and ends at the injection point just above the distributor plate in the fluid bed boiler. As shown on the figure, crushed coal and limestone are fed by gravity through forty (40) gravimetric belt feeders to a discharge hopper. The mixture then passes through a rotary seal and to a mixing bustle. Here, the material is mixed and partially dried. Hot air, to dry the mixture of coal and limestone and to convey it from the bustle, is supplied by the primary air fan. A tempering air fan is used to provide ambient air to control the temperature into the mixing bustle. This air temperature will be dependent on the outlet temperature of the two-phase mixture transported from the mixing bustle. The solids-air mixture is split into thirty-two (32) streams before injection into each operating compartment of the fluid bed boiler.

In addition to the above, a similar system to convey limestone and coal was provided for CBB start-up, or for supplementary feed if it is found necessary.

The described system has been used and proven on commercial conventional coal fired units, with the exception of two areas that require further development:

1. Some concern has been voiced with regard to the possibility of bunker hang ups with wet limestone. If wet limestone feed to the belt feeder is not a problem, B&W is satisfied that the pneumatic transport system will adequately dry the limestone to prevent further pluggage problems. This system is equipped with live bottom silos for both coal and limestone to overcome this possible problem area. We do not believe that predrying of the feed material will be required with this arrangement.
2. We have demonstrated at our Alliance Research Center that a coal-limestone-air stream can be satisfactorily split from one (1) to four (4) feed pipes. The required split for this design, one (1) to thirty-two (32), has not been done and needs to be demonstrated. This is discussed in more detail in Section XIV.

D. Char Collection and Reinjection

One of the problem areas in AFB design that has become apparent is the poor combustion efficiency and unburned losses even when utilizing a carbon burn-up bed. Ways and means of significantly reducing these losses must be developed if the AFB is to be of practical use for utility boilers.

The base system arrangement shown in Figure 5-2 is the one that was originally considered, utilizing a mechanical solids collector following the main boiler for removal of char which in turn is burned in the CBB. We believe that, practically, only about 90% of the char can be recovered in this manner, contributing to a combustion inefficiency.

A study was made of a modified arrangement, shown on Figure 5-3, eliminating the main boiler mechanical collector and using a separate hot precipitator for collection of the char.

Although some questions have been raised with regard to the ability of hot electrostatic precipitators to remove carbon efficiently, this question has been reviewed with Rothemuhle in Germany and they have given assurance of 99% removal of carbon with proper precipitator design. Due to the chemical analysis of the solids entering the precipitator, the migration velocity required to remove these solids in a cold precipitator is approximately 60% of that for a hot precipitator, thus offsetting the increase in the hot precipitator due to the greater volume. In addition, a hot precipitator sized for the design conditions in this report has a lower particulate resistivity and less surface for the same efficiency than a cold precipitator. The arrangement shown in Figure 5-3 has been used for both the demonstration and the commercial designs, resulting in an overall system thermal efficiency gain of about 1% over the original scheme. The modified system will require an additional hot precipitator (for the CBB) but the fuel savings gain overshadows the higher equipment costs.

Another question which has been raised is the possibility of fires in a hot precipitator caused by sparking. According to Rothemuhle, carbon will not ignite in the precipitator due to arcking as long as there are no volatiles because of the low energy which the precipitator requires. Rothemuhle's stoker fired units, as shown on Table 5-1, running at temperatures in the range of 490°F and 540°F, have operated satisfactorily with up to 60% carbon. A recommendation made by Rothemuhle to prevent fires is to

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FIGURE 5-2

USING TWO CYCLONE SYSTEMS AND ONE
PRECIPITATOR FOR OVERHEAD SOLIDS
COLLECTION

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FIGURE 5-3

USING ONE CYCLONE SYSTEM AND TWO
PRECIPITATORS FOR OVERHEAD SOLIDS
COLLECTION

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MODIFICATION

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empty the precipitator hoppers on a continuous basis. In addition, if the boiler fuel master trips then the precipitator rectifier control units also trips, and the precipitator is prevented from energizing until the boiler master fuel trip is reset.

A mechanical solids collector is utilized following the CBB and prior to the CBB electrostatic precipitator. The reason for this is economics. The gas solids loading leaving the CBB is much higher than that leaving the FBC, and use of a mechanical collection device at this point significantly reduces the CBB precipitator size (and cost).

E. Boiler Sootblower Design

The number and spacing of sootblowers for this boiler arrangement were set in accordance with B&W standards for conventional P.C. fired units using the contract fuel. Some authorities predict that fluid bed fired boilers (with lower combustion temperatures and high stone carryover rates) will need fewer or no sootblowers and there may be some justification for this speculation. However, this point is presently unknown and therefore we have adopted a conservative position.

TABLE 5-1

ROTHERMUEHLE ELECTROSTATIC PRECIPITATORSOPERATING SATISFACTORILY ON HIGHCARBON CONTENT FLY ASH

<u>Name of Plant</u>	<u>Location</u>	<u>Fuel</u>	<u>Firing Type</u>	<u>Unburned Carbon %</u>
1. Feldmuehle AG	Feldmuehle Arnsberg, Germany	Bituminous	Wet Bottom	16.2
2. Steag Kraftwerks- betriebsgesellschaft MBH	Luenen Germany	Bituminous	Wet Bottom	9.5-17.7
3. Lansirannikon Voima Oy	Tahcoluoto Finland	Bituminous	Dry Bottom	11.7-62.2
4. Rheinische Braunkohlenwerke AG	Fortuna Nord, Niederaussem Germany	Lignite	Stoker	21.5-50
5. EVS/DKW ULM	ULM, Germany	Bituminous	Stoker	23.5
6. Universitaet Muenster	Muenster Germany	Bituminous		48.3-60.9

VI. SYSTEM DESCRIPTION

A. Process Description (See page A-1)

The 200 MW atmospheric pressure fluid bed boiler is designed to burn Paradise Seam No. 9 high sulfur coal and meet the Federal EPA Sulfur Dioxide Emission Standard of 1.2 pounds maximum per million Btu heat input without recourse to flue gas desulfurization (the use of wet scrubbing). The Nitrous Oxide Emission Standard of 0.7 pound maximum is also met.

1. Feed Crushing and Conveying System (See pages A-14, A-15 and A-16)

Two (2) identical crushing and conveying systems are supplied for the coal and limestone. From their yard sizes, minus 1-1/2 inch and minus 3 inch respectively, the coal and limestone are crushed to 1/4 x 0 inch and 12 US mesh. The crushed material discharges from the crusher outlet onto a vibrating screen. Oversize material is fed back to the crusher via a bucket elevator. The product passes through the vibrating screen to each of the two (2) belt conveyors. The belt conveyors transport the material to flight conveyors, located on top of the storage silos. The flight conveyors transport the material to the respective silos.

2. Coal-Limestone Feed System (See page A-2)

There are twenty (20) coal and twenty (20) limestone silos. One coal silo and one limestone silo constitute an FBC feed unit. Four (4) of the twenty (20) feed units also provide feed to the CBB for start-up and if supplemental heat input (firing) is required. The coal and limestone feed rates to the units are controlled by gravimetric feeders. Twenty (20) coal and twenty (20) limestone feeders are provided. A coal feeder and a limestone feeder operate together to provide the proper coal to limestone ratio. Both feeders discharge into a fuel feed hopper. The mixture passes through a rotary seal and into a mix bustle where it mixes with hot air for drying and conveying. The air-coal-limestone mixture is conveyed through a single coal pipe to a distributor bottle. At the distributor bottle, the flow is split into thirty-two (32) streams for feeding each main bed compartment and into eighteen (18) streams for feeding each start-up compartment. The individual injector feed lines pass through the air distributor plate and into the bed on approximately three (3) feet centers.

3. Boiler Arrangement (See pages A-2 and A-6)

The steam generator consists of two physically separate but functionally integral units. The main unit (FBC) is equipped with four (4) fluidized beds, each 50 feet wide and 28 feet deep. Each of the main beds is divided into five (5) compartments, each with separate fuel and air controls. This arrangement was devised to provide for operational flexibility. Four (4) of the compartments in each bed are 11 feet wide and 28 feet deep. The fifth compartment (the start-up compartment), located at the center of each bed, is 6 feet wide by 28 feet deep.

Horizontal heating surface is located in the FBC fluidized beds. One and one-half (1-1/2) of the beds contain boiling surface and two and one-half (2-1/2) of the beds contain superheat surface. The surface was designed to maintain a bed temperature of 1550°F with maximum continuous rating heat input to the bed. There is no submerged heating surface in the start-up compartments.

Horizontal reheater surface is located in the upper furnace section of the main unit. This is the high temperature portion, or outlet bank of the reheater. The downflow convection section is divided into two (2) flow paths for reheat control. Horizontal reheat surface is located in the lefthand section with primary superheater surface in the righthand section. Economizer surface is located at the bottom of the superheater section only.

Gas flow across the divided reheater and primary superheater is controlled by dampers at the boiler outlet.

The unburned char, ash and calcium compounds elutriated from the main unit are collected in a hot precipitator. This material is then stored and injected into the carbon burn-up bed (CBB). (See page A-6) The CBB is made up of two (2) fluid beds 15 feet wide and 36 feet deep, separated by a water cooled wall. Each bed is divided into two (2) compartments, each with separate fuel and air controls. Each compartment is 15 feet wide and 18 feet deep. A bed temperature of 2000°F, at full load input, is maintained by the cooling provided by the bed wall surface. There is no in-bed heating surface.

Only boiling surface is used in the CBB. Horizontal boiling surface is located in a convection pass located above the bed freeboard zone to recover the heat from the combustion gas.

4. Water Flow (See pages A-2 and A-3)

Feedwater to the unit enters an upflow economizer located in the FBC. From the economizer outlet header the water flows through a single outlet to the steam drum. Water from the drum flows down two (2) downcomers to two (2) circulation assist pumps. From the assist pumps the water is routed to the FBC and the CBB to supply the required flow to each of the boiler circuits. In the FBC, these circuits are made up of all the enclosure walls plus the horizontal water cooled tube banks located in one and one-half (1-1/2) of the beds. In the CBB, the enclosure and convection banks are supplied from this source. The steam-water mixture from the boiler circuits exists the outlet headers via risers which run directly to the steam drum. The steam-water mixture is separated in the steam drum by cyclone separators.

5. Steam Flow (See pages A-2 and A-8)

The saturated steam leaving the cyclone separators passes through a secondary scrubber and exits the steam drum through multiple connections running to a collecting header. The steam exists the collecting header through a single connection leading to the primary superheater inlet header. The steam flows upward through the primary superheater located on the righthand side of the main boiler downflow convection pass. The steam then flows to the secondary superheater which is located in two and one-half (2-1/2) of the beds and flows through these banks in series. More specifically, the steam exists the primary superheater via a single outlet connection on the header vertical centerline and enters a similar header on the superheater located in the upper fluidized bed at the righthand side. The steam passes through the superheater and exists via an outlet header on the lefthand side of the upper bed through a single nozzle located on the header vertical centerline. From here it enters a spray attemperator which reduces the steam enthalpy as required before it enters the second superheater bed, located below the upper bed. As in the first superheater bed, single centerpoint nozzles are located on the inlet and outlet headers. The steam enters the header at the lefthand side of the bed and exits at the righthand side header. The steam

is conveyed to the bed directly below which is split to hold both the final superheating bank and a boiling bank. The superheater inlet and outlet headers in this bottom bed are both located on the righthand side of the bed. Steam enters the lower header by a nozzle located on the header's vertical centerline, passes through the banks and leaves by a single center located nozzle in the upper header. This is the final stage of superheating. Steam exists the B&W terminal at 2581 psig and 1003°F.

6. Reheat Steam Flow (See page A-2)

Cold reheat steam enters the reheat inlet header via a single center located nozzle. The steam passes through the counterflow reheater, located in the left-hand side of the downflow convection section, flows to an intermediate header in the boiler penthouse, and then into full width counterflow reheater sections in the gas upflow section of the FBC. The steam finally exits through a single centerpoint outlet in the outlet header located at the front wall of the unit. Reheat steam temperature is controlled by biasing the gas flow in the FBC parallel back end. An attemperator is provided in the cold reheat line to control temporary temperature excursions.

7. Char Feed System (See page A-7)

The unburned char, ash and calcium compounds elutriated from the FBC are collected by two (2) Rothemuhle hot electrostatic precipitators operating in parallel. The precipitators operate at 700°F and remove 99.7% of the solids entrained in the flue gas. The precipitated solids are pneumatically conveyed from the precipitator hoppers to a compartmented CBB feed tank for injection into the CBB. The char is dispensed from the four (4) CBB feed tank compartments by rotary seal feeders to mix bustles, where it mixes with air for conveying. The air-char mixture travels through a single coal pipe to a distributor bottle where it is split into thirty (30) streams for feeding the CBB compartments. The individual injector feed lines pass through the air distributor plate and into the bed.

8. Spent Bed Material Removal System

Bed level is controlled and spent material is removed from the FBC and CBB beds by a bed let-down system. The bed material flows by gravity to screw-type water cooled ash coolers where it is cooled to

700°F. The ash coolers also act as a feeder thus regulating spent material flow from the bed. From the ash coolers, the cooled bed material travels through rotary seals and then is pneumatically conveyed to an ash storage bin. The bed material in the ash storage bin is either sent to the ash disposal area, stored for reuse during boiler start-up, or recycled to the CBB to make up for bed material losses due to particle attrition.

9. CBB Flue Gas Particulate Removal (See page A-7)

CBB flue gas particulate removal is obtained with a mechanical cyclone dust collector and a Rothemuhle hot electrostatic precipitator operating in series. 99.9% of the solids in the flue gas elutriated from the CBB are removed. Flue gas from the CBB precipitator and flue gas from the FBC precipitators are mixed prior to entering the air heater.

10. Air Heaters (See pages A-9 through A-13)

Two (2) alternative air heater designs are presented in this report, a tubular design and a regenerative design. Flue gas leaves the air heater at 285°F (with a regenerative air heater the air leakage lowers the flue gas temperature to 269°F), passes through the induced draft fan and then exists to the stack. To protect the air heater during low load cold operation, a steam coil air heater is installed prior to the secondary air heater.

11. Air Flow

Combustion air enters the system through a forced draft fan. Prior to the air entering the steam coil air heater and the secondary air heater a tempering air stream branches off. This stream flows through a tempering air fan and then is used as part of the conveying air for the coal and limestone that is transported to the FBC beds. The tempering air's function in the coal-limestone conveying system is to control the mixture temperature to 150°F. Combustion air leaves the secondary air heater at 636°F and is split into two streams, primary air and secondary air. Primary air after traveling through a primary air fan is used to supply the heat required for drying the coal and limestone, and to transport the mixture to the FBC. The secondary air stream provides the fluidizing air and the combustion air for bed fluidization and fuel combustion in both the FBC and CBB. A dampered wind-box is located under perforated air distributor plates in each bed.

B. Predicted Performance

The boiler is designed to perform as shown on the two (2) Predicted Performance Summary Sheets (See pages 6-8 and 6-9). One sheet covers the unit when using a tubular air heater, while the other sheet covers the unit when using a regenerative air heater. These sheets cover two load levels, maximum continuous rating and 75% of maximum continuous rating. The 75% load level was used as control load and also to set metals. Loads of 50% and 25% of maximum continuous rating were also examined and Figure 6-1 was prepared to show how steam temperature varies with load.

The technique of bed slumping was used to permit load reduction. This involves taking complete bed tube banks or parts of bed tube banks out of service by shutting down fuel, limestone and air flow to the zones in which the transfer surface is installed. With the unit as designed (for 75% load conditions), the beds were selectively slumped at the lower load conditions to maintain the bed metals. These calculations were used to develop the curves on Figure 6-1. The curves predict temperature differentials for reheat steam at lower loads that are slightly greater than specified by the turbine manufacturers. With more time to study the design this problem can probably be alleviated by such simple changes as:

- .rearranging bed superheater surface so the outlet bank is located higher on the boiler to get higher gas temperatures to the reheater.
- .increasing the proportion of primary superheater surface to reheater surface in the split convection pass to get greater control over reheat temperatures at low loads.

FIGURE 6-1

PREDICTED SUPERHEATER AND REHEATER

PERFORMANCE OVER THE USABLE LOAD

RANGE

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A	FUEL AS FIRED			B	PREDICTED PERFORMANCE			C	EQUIPMENT PER UNIT																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																					
SAMPLES	ANALYSES			KIND	CLASS	GROUP	MINE	SEAM	DISTRICT	COUNTY	STATE	SIZE	GRINDABILITY	SURFACE MOISTURE, %	ASH SOFT. TEMP., F (REDUCING)	MOISTURE, TOTAL	VOLATILE MATTER	FIXED CARBON	ASH	TOTAL	FUEL	% BY	ASH	S	H ₂	C	CH ₄	C ₂ H ₄	C ₂ H ₆	C ₃ H ₈	C ₄ H ₁₀	C ₅ H ₁₂	C ₆ H ₁₄	CO	CO ₂	SO ₂	H ₂ O	N ₂	O ₂	TOTAL	BTU/LB	BTU/CU FT AT 60F 30 IN.HG	STONE ANALYSIS	% BY WEIGHT	CaCO ₃	MgCO ₃	SiO ₂	H ₂ O	STONE SIZE = 98% THRU 10-12 MESH	BYH. DOSS	APPD.	DATE	THE BABCOCK & WILCOX COMPANY	NO. IN USE PER BOILER	TOTAL POWER, KW HR/TON MOTOR OUTPUT	% THRU 200 U.S.S. SIEVE	PREDICTED PERFORMANCE IS BASED ON COMBUSTION AIR ENTERING UNIT WITH 0.013 LB MOISTURE/LB DRY AIR, ON IN. HG. BAROMETRIC PRESSURE, ON CONDITIONS & EQUIPMENT GIVEN ON THIS SUMMARY SHEET & ON ARRANGEMENT SHOWN ON DRAWING	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60	61	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	100	101	102	103	104	105	106	107	108	109	110	111	112	113	114	115	116	117	118	119	120	121	122	123	124	125	126	127	128	129	130	131	132	133	134	135	136	137	138	139	140	141	142	143	144	145	146	147	148	149	150	151	152	153	154	155	156	157	158	159	160	161	162	163	164	165	166	167	168	169	170	171	172	173	174	175	176	177	178	179	180	181	182	183	184	185	186	187	188	189	190	191	192	193	194	195	196	197	198	199	200	201	202	203	204	205	206	207	208	209	210	211	212	213	214	215	216	217	218	219	220	221	222	223	224	225	226	227	228	229	230	231	232	233	234	235	236	237	238	239	240	241	242	243	244	245	246	247	248	249	250	251	252	253	254	255	256	257	258	259	260	261	262	263	264	265	266	267	268	269	270	271	272	273	274	275	276	277	278	279	280	281	282	283	284	285	286	287	288	289	290	291	292	293	294	295	296	297	298	299	300	301	302	303	304	305	306	307	308	309	310	311	312	313	314	315	316	317	318	319	320	321	322	323	324	325	326	327	328	329	330	331	332	333	334	335	336	337	338	339	340	341	342	343	344	345	346	347	348	349	350	351	352	353	354	355	356	357	358	359	360	361	362	363	364	365	366	367	368	369	370	371	372	373	374	375	376	377	378	379	380	381	382	383	384	385	386	387	388	389	390	391	392	393	394	395	396	397	398	399	400	401	402	403	404	405	406	407	408	409	410	411	412	413	414	415	416	417	418	419	420	421	422	423	424	425	426	427	428	429	430	431	432	433	434	435	436	437	438	439	440	441	442	443	444	445	446	447	448	449	450	451	452	453	454	455	456	457	458	459	460	461	462	463	464	465	466	467	468	469	470	471	472	473	474	475	476	477	478	479	480	481	482	483	484	485	486	487	488	489	490	491	492	493	494	495	496	497	498	499	500	501	502	503	504	505	506	507	508	509	510	511	512	513	514	515	516	517	518	519	520	521	522	523	524	525	526	527	528	529	530	531	532	533	534	535	536	537	538	539	540	541	542	543	544	545	546	547	548	549	550	551	552	553	554	555	556	557	558	559	560	561	562	563	564	565	566	567	568	569	570	571	572	573	574	575	576	577	578	579	580	581	582	583	584	585	586	587	588	589	590	591	592	593	594	595	596	597	598	599	600	601	602	603	604	605	606	607	608	609	610	611	612	613	614	615	616	617	618	619	620	621	622	623	624	625	626	627	628	629	630	631	632	633	634	635	636	637	638	639	640	641	642	643	644	645	646	647	648	649	650	651	652	653	654	655	656	657	658	659	660	661	662	663	664	665	666	667	668	669	670	671	672	673	674	675	676	677	678	679	680	681	682	683	684	685	686	687	688	689	690	691	692	693	694	695	696	697	698	699	700	701	702	703	704	705	706	707	708	709	710	711	712	713	714	715	716	717	718	719	720	721	722	723	724	725	726	727	728	729	730	731	732	733	734	735	736	737	738	739	740	741	742	743	744	745	746	747	748	749	750	751	752	753	754	755	756	

C. Design Basis

Plant Capacity

The information listed below is the basis for the preliminary design of a conceptualized 200 MW atmospheric fluidized bed boiler capable of burning high sulfur coal in an environmentally acceptable manner without recourse to flue gas desulfurization.

1. Coal, Limestone and Ash

Coal Analysis:

The coal analysis is based on Paradise coal, seam No. 9

<u>Constituent</u>	<u>% in Coal</u>
Carbon	60.69
Hydrogen	4.10
Oxygen	6.64
Nitrogen	1.37
Sulfur	4.10
Moisture*	9.00
Ash	14.10

*7.00% Surface moisture assumed

Limestone Analysis:

<u>Constituent</u>	<u>% in Limestone</u>
CaCO ₃	90.25
SiO ₂	2.75
Moisture**	5.00
MgCO ₃	2.00

**4.00% Surface moisture assumed

Ash Analysis:

<u>Constituent</u>	<u>% in Ash</u>	<u>Constituent</u>	<u>% in Ash</u>
SiO ₂	49.7	K ₂ O	2.5
Al ₂ O ₃	18.2	MgO	0.9
Fe ₂ O ₃	25.3	Na ₂ O	0.2
CaO	0.7	SO ₃	1.0
		TiO ₂	1.0

Both the Coal and Limestone will be Crushed to the Following Specifications:

Coal	1/4" x 0 Top Size
Limestone	12 Mesh (US Std.) Top Size

Heating Value

The coal heating value is 12,026 Btu/lb dry basis

2. Densities

Crushed Coal (lb/ft ³)	50
Crushed Limestone (lb/ft ³)	90
Spent Bed Solids (lb/ft ³)	70
CBB Char Feed (lb/ft ³)	25

3. Storage

All storage silos except the coal silo are designed for a ten (10) hour storage capacity. The coal silo has an eight (8) hour storage capacity.

4. Inlet Streams

Coal, limestone, air and water inlet streams are based on 80°F and atmospheric pressure.

5. Main Fluidized Bed (FBC)

Size	4-28 x 50 Ft. Fluidized Beds with 1-6 x 28 Ft. Start- up Compartment/Bed
Operating Temperature (°F)	1550
Superficial Gas Velocity (ft/sec)	4
Ca/S Ratio	2.37
Combustion Efficiency (%)	91
Excess Air (%) (1)	15
Air Leakage (%)	2
% Stone in Bed Elutriated	35
% Coal Ash in Bed Elutriated	75

6. Carbon Burn-up Bed (CBB)

Size	1-30 x 36 Ft. Fluidized Bed
Operating Temperature (°F)	2000
Superficial Gas Velocity (ft/sec)	4
Combustion Efficiency (%)	91
Excess Air (%)	50
Air Leakage (%)	1
% Bed Material Elutriated	100

7. Emission Limits

Maximum SO ₂ Level (lb/MM Btu heat input)	1.2
Maximum NO _x Level (lb/MM Btu heat input)	0.7
Maximum Particulate Level (lb/MM Btu heat input)	0.1

8. Feed Water and Steam

	<u>100%</u>	<u>Valves Wide Open</u>	<u>Valves Wide Open 5% Overpressure(2)</u>
Steam Flow (lb/hr)	1,325,218	1,391,479	1,461,053
Superheater Outlet Pressure (psig)	2450	2455	2581
Superheater Outlet Temperature (°F)	1003	1003	1003
Reheat Steam Flow (lb/hr)	1,127,402	1,183,772	1,242,961
Cold Reheat Pressure (psia)	552	580	609
Hot Reheat Pressure (psia)	524	551	578
Hot Reheat Temperature (°F)	1003	1003	1003
Feedwater Flow (lb/hr)	1,325,218	1,391,479	1,461,053
Feedwater Tempera- ture (°F)	477	482	487

9. Dust Collection

FBC Precipitator Overall Collection Efficiency (%)	99.70
CBB Precipitator Overall Collection Efficiency (%)	99.25
CBB Mechanical Dust Collector:	
For Char and Ash (%)	80.0
For Stone (%)	99.0

10. Steam Coil Air Heater

Steam Input Pressure (psia)	200
Steam Input Temperature (°F)	382

- (1) Excess air is based on the theoretical air required to complete predicted combustion and sulfur compound absorption. ~~This differs from normal combustion equip-~~
ment usage in which theoretical air is based on complete (or 100%) combustion of the fuel and involves no extra need for oxygen in accompanying chemical reactions.
- (2) The boiler maximum continuous rating (MCR) is based on operation at 5% overpressure with valves wide open.

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THE BABCOCK & WILCOX COMPANY
D. HEAT AND MATERIAL BALANCE

PROCESS 200 MW FLUID BED BOILER
CUSTOMER TVA/ERDA
PLANT PARADISE, KENTUCKY

CONTRACT NO. 591-0241
PROPOSAL NO.
DATE

OPERATING CONDITIONS
WITH TUBULAR AIR
HEATER

STREAM NUMBER	1	2	3	4	5	6	7	8	9	10	11	12
STREAM DESCRIPTION	COAL FEED	LIMESTONE FEED	CHAR, STONE & GAS FROM	FBC UNDERFLOW	FBC PRECI- PITATOR	CBB UNDERFLOW	CHAR, STONE & GAS FROM	CBB MECHANICAL PRECIPITATOR	CBB UNDERFLOW	FLUE GAS FROM CBB	FLUE GAS FROM FBC	TOTAL FLUE GAS
PROCESS CONDITIONS												
TEMPERATURE (°F)	80	80	720	1,550	700	2,000	787	762	762	762	700	710
PRESSURE (IN.WG) ①	-	-	- 6.8	-	-	-	- 3.4	-	-	- 8.6	- 8.0	- 8.8
PRESSURE (PSIG)	-	-	-	-	-	-	-	-	-	-	-	-
FLOW RATE (GAS OR LIQUID ONLY)	-	-	-	-	-	-	-	-	-	-	-	-
LB MOLE/HR	-	-	58,684	-	-	-	7,323	-	-	7,371	59,141	66,519
LB/HR	-	-	1,729,993	-	-	-	220,116	-	-	221,503	1,743,477	1,964,980
SCFM (OR GPM) @ 60°F, 1 ATM.	-	-	371,109	-	-	-	46,310	-	-	46,613	373,999	420,656
ACFM (OR GPM) @ CONDITIONS	-	-	856,441	-	-	-	111,990	-	-	111,905	851,033	967,393
PHYSICAL PROPERTIES	-	-	-	-	-	-	-	-	-	-	-	-
MOLE WT (GAS OR LIQUID ONLY)	-	-	29.48	-	-	-	30.06	-	-	30.05	29.48	29.54
STATE (S, L, G)	S	S	S & G	S	S	S	S & G	S	S	S & G	S & G	S & G
DENSITY (LB/FT³) (GAS OR LIQUID)	-	-	0.034	-	-	-	0.033	-	-	0.033	0.034	0.034
ENTHALPY (MMB/HR), BASE 77°F	0.16	0.041	296.90	12.72	5.41	-	45.42	5.04	0.66	38.80	283.86	322.66
COMPOSITION (LBS/HR) (GAS OR LIQUID)	-	-	-	-	-	-	-	-	-	-	-	-
O₂	-	-	52,286	-	-	-	16,133	-	-	16,449	55,362	71,811
N₂	-	-	1,199,686	-	-	-	158,922	-	-	159,975	1,209,918	1,369,893
H₂O	15,946	2,978	103,223	-	-	-	3,782	-	-	3,800	103,399	107,199
CO₂	-	-	372,563	-	-	-	41,186	-	-	41,186	372,563	413,749
SO₂	-	-	2,235	-	-	-	93	-	-	93	2,235	2,328
(GAS OR LIQUID) SUBTOTAL	15,946	2,978	1,729,993	-	-	-	220,116	-	-	221,503	1,743,477	1,964,980
SOLIDS (LBS/HR)	-	-	-	-	-	-	-	-	-	-	-	-
COAL	161,228	-	-	-	-	-	-	-	-	-	-	-
CaCO₃	-	53,747	-	-	-	-	-	-	-	-	-	-
MgCO₃	-	1,191	-	-	-	-	-	-	-	-	-	-
SiO₂ + INERTS	-	1,638	573	1,065	573	-	573	568	5	-	-	-
CaO	-	-	6,733	13,635	6,733	-	5,911	5,851	60	-	-	-
CaSO₄	-	-	9,242	14,419	9,242	-	11,238	11,124	114	-	-	-
C₈H₈	-	-	12,607	-	12,481	-	1,123	898	213	11	126	137
MgO	-	-	199	370	199	-	199	197	2	-	-	-
S	-	-	574	-	568	-	51	50	1	-	6	6
ASH	-	-	18,736	6,245	18,717	-	18,717	14,974	3,725	19	19	38
(SOLIDS) SUBTOTAL	161,228	56,576	48,664	35,734	48,513	-	37,812	33,662	4,120	30	151	181
(SOLIDS + GAS OR LIQUID) TOTAL	177,174	59,554	1,778,657	35,734	48,513	- 0 -	257,928	33,662	4,120	221,533	1,743,628	1,965,161

NOTES: ① ATMOSPHERIC PRESSURE = 14.696

HEAT AND MATERIAL BALANCE

PROCESS 200 MW FLUID BED BOILER

CUSTOMER TVA/ERDA

PLANT PARADISE, KENTUCKY

CONTRACT NO. 591-0241

PROPOSAL NO.

DATE _____

OPERATING CONDITIONS

WITH TUBULAR AIR
HEATER

	STREAM NUMBER	13	14	15*	16*	17*	18*	19*	20*	21	22	23	24
2	STREAM DESCRIPTION	FLUE GAS	GAS TO STACK	CIRCULATING	ATTEMP-	MAIN STEAM	COLD REHEAT	HOT REHEAT	FEED WATER	FBC	INLET AIR	TEMPERING	PRIMARY
3		FROM AIR		WATER TO	ERATOR					UNDERFLOW		AIR	CONVEYING
4		HEATER		RECIRCULAT-	SPRAY								AIR
5				ING PUMPS									
6													
	PROCESS CONDITIONS												
7	TEMPERATURE (°F)	285	290	686	487	1,003	642	1,003	487	700	100	103	648
8	PRESSURE (IN.WG) ①	- 13.5	- 2.3	-	-	-	-	-	-	-	53.2	61.0	61.0
9	PRESSURE (PSIG)	-	-	2,816	2,716	2,581	594	578	2,836	-	-	-	-
	FLOW RATE (GAS OR LIQUID ONLY)	-	-	-	-	-	-	-	-	-	-	-	-
10	LB MOLE/HR	66,519	66,519	486,477	7,378	81,080	68,977	68,977	81,080	-	61,429	3,211	7,009
11	LB/HR	1,964,980	1,964,980	8,766,318	132,950	1,461,053	1,242,961	1,242,961	1,461,053	-	1,758,725	91,937	200,681
12	SCFM (OR GPM) @ 60°F, 1 ATM.	420,656	420,656	(17,514)	(267)	-	-	-	(2,919)	-	388,468	20,306	44,324
13	ACFM (OR GPM) @ CONDITIONS	623,347	610,163	(34,259)	(328)	7,142	20,942	29,195	(3,667)	-	369,988	19,120	82,134
14		-	-	-	-	-	-	-	-	-	-	-	-
	PHYSICAL PROPERTIES	-	-	-	-	-	-	-	-	-	-	-	-
15	MOLE WT (GAS OR LIQUID ONLY)	29.54	29.54	18.02	18.02	18.02	18.02	18.02	18.02	-	28.63	28.63	28.63
16	STATE (S, L, G)	S & G	S & G	L	L	G	G	G	L	S	G	G	G
17	DENSITY (LB/FT³) (GAS OR LIQUID)	0.053	0.054	31.90	50.6	3.41	0.990	0.710	49.68	-	0.079	0.080	0.041
18		-	-	-	-	-	-	-	-	-	-	-	-
19	ENTHALPY (MMB/HR), BASE 77°F	102.28	104.74	6,747	62.99	2,126	1,656	1,890	690	4.64	11.06	12.50	28.77
20		-	-	-	-	-	-	-	-	-	-	-	-
21		-	-	-	-	-	-	-	-	-	-	-	-
	COMPOSITION (LBS/HR) (GAS OR LIQUID)	-	-	-	-	-	-	-	-	-	-	-	-
22	O ₂	71,811	71,811	-	-	-	-	-	-	-	401,149	20,970	45,773
23	N ₂	1,369,893	1,369,893	-	-	-	-	-	-	-	1,334,663	69,769	152,293
24	H ₂ O	107,199	107,199	8,766,318	132,950	1,461,053	1,242,961	1,242,961	1,461,053	-	22,913	1,198	2,615
25	CO ₂	413,749	413,749	-	-	-	-	-	-	-	-	-	-
26	SO ₂	2,328	2,328	-	-	-	-	-	-	-	-	-	-
27		-	-	-	-	-	-	-	-	-	-	-	-
28	(GAS OR LIQUID) SUBTOTAL	1,964,980	1,964,980	8,766,318	132,950	1,461,053	1,242,961	1,242,961	1,461,053	-	1,758,725	91,937	200,681
29	SOLIDS (LBS/HR)	-	-	-	-	-	-	-	-	-	-	-	-
30	COAL	-	-	-	-	-	-	-	-	-	-	-	-
31	CaCO ₃	-	-	-	-	-	-	-	-	-	-	-	-
32	MgCO ₃	-	-	-	-	-	-	-	-	-	-	-	-
33	SiO ₂ + INERTS	-	-	-	-	-	-	-	-	1,065	-	-	-
34	CaO	-	-	-	-	-	-	-	-	13,635	-	-	-
35	CaSO ₄	-	-	-	-	-	-	-	-	14,419	-	-	-
36	C ₈ H ₈	137	137	-	-	-	-	-	-	-	-	-	-
37	MgO	-	-	-	-	-	-	-	-	370	-	-	-
38	S	6	6	-	-	-	-	-	-	-	-	-	-
39	ASH	38	38	-	-	-	-	-	-	6,245	-	-	-
40	(SOLIDS) SUBTOTAL	181	181	-	-	-	-	-	-	35,734	-	-	-
41	(SOLIDS + GAS OR LIQUID) TOTAL	1,965,161	1,965,161	8,766,318	132,950	1,461,053	1,242,961	1,242,961	1,461,053	35,734	1,758,725	91,937	200,681

NOTES: ① ATMOSPHERIC PRESSURE = 14.696

* ALL FLOWS ARE FOR VALVES WIDE OPEN AND 5 % OVER PRESSURE
STEAM & WATER BASE IS 32° F.

THE BABCOCK & WILCOX COMPANY

PROCESS 200 MW FLUID BED BOILER

CONTRACT NO. 591-0241

OPERATING CONDITIONS

HEAT AND MATERIAL BALANCE

CUSTOMER TVA/ERDA

PROPOSAL NO.

WITH TUBULAR AIR

PLANT PARADISE, KENTUCKY

DATE

HEATER

1	2	3	4	5	6	7	8	9	10	11	12	13	
1	25	26	27	28	29	30	31*	32*	33*	34	35	36	
2	STREAM DESCRIPTION	CBB FEED	AIR TO CBB	AIR TO FBC	FBC FEED	FBC	FBC	CBB	CBB	CBB	AIR IN-	AIR IN-	AIR IN-
3		CONVEYING			CONVEYING	UNDERFLOW	UNDERFLOW	UNDERFLOW	UNDERFLOW	UNDERFLOW	FILTRATION	FILTRATION	FILTRATION
4		AIR			AIR	COOLING	COOLING	COOLING	COOLING		TO FBC	TO CBB	TO FBC
5						WATER INLET	WATER OUTLET	WATER	WATER OUTLET				PRECIP.
6								INLET					
7	PROCESS CONDITIONS												
8	TEMPERATURE (°F)	501	636	636	475	80	110	80	110	700	80	80	80
9	PRESSURE (IN.WG) ①	61.0	45.2	45.2	61.0	-	-	-	-	-	-	-	-
10	PRESSURE (PSIG)	-	-	-	-	-	-	-	-	-	-	-	-
11	FLOW RATE (GAS OR LIQUID ONLY)	-	-	-	-	-	-	-	-	-	-	-	-
12	LB MOLE/HR	1,108	6,158	45,051	9,112	14,946	14,946	851	851	-	942	48	471
13	LB/HR	31,729	176,301	1,289,806	260,889	269,334	269,334	15,333	15,333	-	26,968	1,385	13,484
14	SCFM (OR GPM) @ 60°F, 1 ATM.	7,007	38,942	284,896	57,623	(538)	(538)	(31)	(31)	-	5,957	304	2,979
15	ACFM (OR GPM) @ CONDITIONS	11,262	73,874	540,452	90,105	(538)	(538)	(31)	(31)	-	6,186	316	3,094
16		-	-	-	-	-	-	-	-	-	-	-	-
17	PHYSICAL PROPERTIES	-	-	-	-	-	-	-	-	-	-	-	-
18	MOLE WT (GAS OR LIQUID ONLY)	28.63	28.63	28.63	28.63	18.02	18.02	18.02	18.02	-	28.63	28.63	28.63
19	STATE (S, L, G)	G	G	G	G	L	L	L	L	S	G	G	G
20	DENSITY (LB/FT³) (GAS OR LIQUID)	0.047	0.040	0.040	0.048	62.4	62.4	62.4	62.4	-	0.073	0.073	0.073
21		-	-	-	-	-	-	-	-	-	-	-	-
22	ENTHALPY (MMB/HR), BASE 77°F	3.25	24.39	178.40	25.41	0.810	8.90	0.046	0.510	0.200	0.020	0.001	0.010
23		-	-	-	-	-	-	-	-	-	-	-	-
24		-	-	-	-	-	-	-	-	-	-	-	-
25	COMPOSITION (LBS/HR) (GAS OR LIQUID)	-	-	-	-	-	-	-	-	-	-	-	-
26	O ₂	7,237	40,213	294,193	59,506	-	-	-	-	-	6,151	316	3,076
27	N ₂	24,079	133,791	978,809	197,984	-	-	-	-	-	20,465	1,052	10,233
28	H ₂ O	413	2,297	16,804	3,399	269,334	269,334	15,333	15,333	-	352	17	175
29	CO ₂	-	-	-	-	-	-	-	-	-	-	-	-
30	SO ₂	-	-	-	-	-	-	-	-	-	-	-	-
31		-	-	-	-	-	-	-	-	-	-	-	-
32	(GAS OR LIQUID) SUBTOTAL	31,729	176,301	1,289,806	260,889	269,334	269,334	15,333	15,333	-	26,968	1,385	13,484
33	SOLIDS (LBS/HR)	-	-	-	-	-	-	-	-	-	-	-	-
34	COAL	-	-	-	-	-	-	-	-	-	-	-	-
35	CaCO ₃	-	-	-	-	-	-	-	-	-	-	-	-
36	MgCO ₃	-	-	-	-	-	-	-	-	-	-	-	-
37	SiO ₂ + INERTS	-	-	-	-	-	-	-	-	41	-	-	-
38	CaO	-	-	-	-	-	-	-	-	526	-	-	-
39	CaSO ₄	-	-	-	-	-	-	-	-	556	-	-	-
40	C ₈ H	-	-	-	-	-	-	-	-	-	-	-	-
41	MgO	-	-	-	-	-	-	-	-	14	-	-	-
42	S	-	-	-	-	-	-	-	-	-	-	-	-
43	ASH	-	-	-	-	-	-	-	-	241	-	-	-
44	(SOLIDS) SUBTOTAL	-	-	-	-	-	-	-	-	1,378	-	-	-
45	(SOLIDS + GAS OR LIQUID) TOTAL	31,729	176,301	1,289,806	260,889	269,334	269,334	15,333	15,333	1,378	26,968	1,385	13,484

NOTES: ① ATMOSPHERIC PRESSURE = 14.696

* ONLY IF COAL AND LIMESTONE ARE FIRED IN CBB.

THE BABCOCK & WILCOX COMPANY

HEAT AND MATERIAL BALANCE

PROCESS 200 MW FLUID BED BOILER

CUSTOMER TVA/ERDA

PLANT PARADISE, KENTUCKY

CONTRACT NO. 591-0241

PROPOSAL NO.

DATE

OPERATING CONDITIONS

WITH TUBULAR AIR

HEATER

1	STREAM NUMBER	37											
2	STREAM DESCRIPTION	AIR IN-											
3		FILTRATION											
4		TO CBB											
5		PRECIP.											
6													
	PROCESS CONDITIONS												
7	TEMPERATURE (°F)	80											
8	PRESSURE (IN.WG) ①	-											
9	PRESSURE (PSIG)	-											
	FLOW RATE (GAS OR LIQUID ONLY)	-											
10	LB MOLE/HR	48											
11	LB/HR	1,387											
12	SCFM (OR GPM) @ 60°F, 1 ATM.	304											
13	ACFM (OR GPM) @ CONDITIONS	316											
14		-											
	PHYSICAL PROPERTIES	-											
15	MOLE WT (GAS OR LIQUID ONLY)	28.63											
16	STATE (S, L, G)	G											
17	DENSITY (LB/FT³) (GAS OR LIQUID)	0.073											
18		-											
19	ENTHALPY (MMB/HR), BASE 77°F	0.001											
20		-											
21		-											
	COMPOSITION (LBS/HR) (GAS OR LIQUID)	-											
22	O₂	316											
23	N₂	1,053											
24	H₂O	18											
25	CO₂	-											
26	SO₂	-											
27		-											
28	(GAS OR LIQUID) SUBTOTAL	1,387											
29	SOLIDS (LBS/HR)	-											
30	COAL	-											
31	CaCO₃	-											
32	MgCO₃	-											
33	SiO₂ + INERTS	-											
34	CaO	-											
35	CaSO₄	-											
36	C₈H	-											
37	MgO	-											
38	S	-											
39	ASH	-											
40	(SOLIDS) SUBTOTAL	-											
41	(SOLIDS + GAS OR LIQUID) TOTAL	1,387											

NOTES: ① ATMOSPHERIC PRESSURE = 14.696

THE BABCOCK & WILCOX COMPANY

HEAT AND MATERIAL BALANCE

PROCESS 200 MW FLUID BED BOILER

CUSTOMER TVA/ERDA

PLANT PARADISE, KENTUCKY

CONTRACT NO. 591-0241

PROPOSAL NO.

DATE

OPERATING CONDITIONS

WITH REGENERATIVE

AIR HEATER

1	STREAM NUMBER	13	14	22								
2	STREAM DESCRIPTION	FLUE GAS	GAS TO	INLET AIR								
3		FROM AIR	STACK									
4		HEATER										
5												
6												
7	PROCESS CONDITIONS											
8	TEMPERATURE (°F)	269	274	100								
9	PRESSURE (IN.WG) ①	- 13.5	- 2.3	53.2								
10	PRESSURE (PSIG)	-	-	-								
11	FLOW RATE (GAS OR LIQUID ONLY)	-	-	-								
12	LB MOLE/HR	72,391	72,391	67,311								
13	LB/HR	2,133,372	2,133,372	1,927,117								
14	SCFM (OR GPM) @ 60°F, 1 ATM.	457,790	457,790	425,665								
15	ACFM (OR GPM) @ CONDITIONS	663,805	649,860	405,416								
16		-	-	-								
17	PHYSICAL PROPERTIES	-	-	-								
18	MOLE WT (GAS OR LIQUID ONLY)	29.47	29.47	28.63								
19	STATE (S, L, G)	G	G	G								
20	DENSITY (LB/FT ³) (GAS OR LIQUID)	0.054	0.055	0.079								
21		-	-	-								
22	ENTHALPY (MMB/HR), BASE 77°F	104.24	106.93	12.12								
23		-	-	-								
24		-	-	-								
25	COMPOSITION (LBS/HR) (GAS OR LIQUID)	-	-	-								
26	O ₂	110,219	110,219	439,558								
27	N ₂	1,497,683	1,497,683	1,462,453								
28	H ₂ O	109,393	109,393	25,106								
29	CO ₂	413,749	413,749	-								
30	SO ₂	2,328	2,328	-								
31		-	-	-								
32	(GAS OR LIQUID) SUBTOTAL	2,133,372	2,133,372	1,927,117								
33	SOLIDS (LBS/HR)	-	-	-								
34	COAL	-	-	-								
35	CaCO ₃	-	-	-								
36	MgCO ₃	-	-	-								
37	SiO ₂ + INERTS	-	-	-								
38	CaO	-	-	-								
39	CaSO ₄	-	-	-								
40	C ₈ H	137	137	-								
41	MgO	-	-	-								
42	S	6	6	-								
43	ASH	38	38	-								
44	(SOLIDS) SUBTOTAL	181	181	-								
45	(SOLIDS + GAS OR LIQUID) TOTAL	2,133,553	2,133,553	1,927,117								

NOTES: ① ATMOSPHERIC PRESSURE = 14.696

AIR LEAKAGE FROM AIR SIDE TO GAS SIDE IS 168,392 Lbs/Hr

VII. EQUIPMENT LIST

The fluidized bed boiler system included in B&W's scope of supply is divided into several systems with respect to classification of the equipment by either type or purpose. These systems are:

- A. Coal and Limestone Feed
- B. Fluid Bed Boiler
- C. Solids Collection and Removal
- D. Air Heater
- E. Steel
- F. Controls

The following summary is a synopsis of the major components and assemblies by system:

A. Coal and Limestone Feed System

- 2 Coal and Limestone Crushers and Drives
- 2 Classifying Screens and Drives
- 2 Bucket Elevators and Drives
- 2 Belt Conveyors
- 6 Flight Conveyors
- 40 Rack and Pinion Motorized Gates
- 20 Coal Silos
- 20 Limestone Silos
- 20 Coal Silo Vibrating Bin Bottoms
- 20 Limestone Silo Vibrating Bin Bottoms
- 20 Coal Feeders
- 20 Limestone Feeders
- 20 Feed Hoppers
- 20 Feed Hopper Rotary Seals
- Lot Piping, Valves, and Expansion Joints
- Lot BRIL (Brickwork, Refractory, Insulation and Lagging)

B. Fluid Bed Boiler System

- 1 Fluid Bed Boiler (FBC)
- 1 Steam Drum
- 1 Carbon Burn-Up Bed Boiler (CBB)
- 2 Recirculation Water Pumps and Drives
- 19 Sootblowers
- 1 Oil Pump and Drive
- Lot Oil Burners, Piping, and Valves
- 16 Main Compartment Distributor Bottles (32:1)
- 4 Start-Up Compartment Distributor Bottles (18:1)

- 4 CBB Supplemental Firing Distributor Bottles (6:1)
- 20 FBC Mixing Bustles
- 4 CBB Mixing Bustles
- Lot Flues, Ducts, Piping, Valves, Expansion Joints, and Dampers
- Lot BRIL

C. Solids Collection and Removal

- 2 FBC Hot Precipitators
- 1 CBB Hot Precipitator
- 1 CBB Mechanical Dust Collector
- 1 CBB Feed Tank
- 4 Char Rotary Feeders
- 2 Char Conveying Systems From FBC Precipitators To CBB Feed Tank
- 1 Bed Material Storage Silo
- 16 FBC Main Compartment Ash Coolers
- 4 FBC Start-Up Compartment Ash Coolers
- 4 CBB Compartment Ash Coolers
- 20 FBC Underflow Rotary Seals
- 4 CBB Underflow Rotary Seals
- 1 FBC Bed Material Distributor Bottle (4:1)
- 1 CBB Bed Material Distributor Bottle (2:1)
- Lot Piping, Valves, Ducts, Dampers, and Expansion Joints
- Lot BRIL

D. Air System

- 1 FD Fan and Drive
- 1 Tempering Air Fan and Drive
- 1 Hot Primary Air Fan and Drive
- 1 ID Fan and Drive
- 1 Steam Coil Air Heater
- 1 Air Heater (Regenerative Or Tubular)
- 10 Sootblowers (Tubular Air Heater)
- Lot Flues, Ducts, Dampers, Piping, Valves and Expansion Joints
- Lot BRIL

E. Steel

Lot Steel Integral To Boiler (Including Flues,
Ducts And Coal Piping Supports); Not To
Include Top Support Steel, Structural
Steel, Platform Steel, Etc.

F. Controls

Lot Controls And Instrumentation

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7-4

VIII. DESCRIPTION OF MAJOR EQUIPMENT AND SPECIFICATIONS

A. Main Fluidized Bed Boiler (FBC) (See pages A-2,A-3,A-4, and A-5)

The main fluidized bed boiler has four (4) fluidized beds. Each bed is 50 feet wide and 28 feet deep. The bed enclosures are formed by water wall membrane panels made of 2-1/2 inch O.D. tubes on 3 inch centers. The four (4) beds are attached to a common furnace 50 feet wide and 14 feet deep.

A counterflow reheater is located in the upper portion of the common furnace and in one side of the downflow convection pass. The downflow convection pass is 50 feet wide and 14 feet deep. A division wall formed by water wall membraned panels of 2-1/2 inch O.D. tubes on 3 inch centers separates the gas passes. Counterflow primary superheat surface is located in the top part of the righthand downflow gas pass. Economizer surface is located at the bottom of the superheater gas pass only. Sootblowers are provided above, below, and in the cavities between the convective heating banks.

Horizontal heating surface is submerged in each of the four (4) beds of the FBC. Each bed rests on an air plenum divided into five (5) compartments. The center compartment supplies air to a start-up zone in the bed above it that is devoid of bank transfer surface. The start-up compartment is 6 feet wide and 28 feet deep. Each of the remaining four (4) compartments is 11 feet wide and 28 feet deep.

Of the sixteen (16) compartments with heating surface submerged in the fluidized beds, ten (10) have superheat surface and six (6) have boiling surface. The tubes comprising the in-bed heating surface have a staggered arrangement. The air compartments are separated from the fluidized beds by a perforated plate which distributes air evenly throughout the beds.

Two (2) circulation assist pumps are provided in the downcomer system and are located in rear of the FBC. The circulation system is described in Section VI.

Access doors and observation ports are installed over the walls of the FBC to provide for maximum observation and sampling.

Sections and panels are designed to be shop assembled complete with header attached, wherever possible. For section tube penetration through the membraned panels, wall tubes would be shipped loose and field welded and refractory seals installed.

The FBC is top supported. Loads are transferred to the boiler top steel by hanger rods attached to the water wall headers, steam drum, superheater and reheater headers, downcomers, and risers.

Four (4) load conditions were examined. Maximum continuous load (MCR) and 75% of MCR were examined in detail. Metals were set at 75% of MCR. Both 50% of MCR and 25% of MCR were also examined in order to prepare Figure 6-1, Load Versus Superheater and Reheat Steam Outlet Temperatures. It can be seen from Figure 6-1 that reheater steam temperature can be maintained between 75% load and full load, but drops off after the 75% load level to differentials that are slightly lower than recommended by turbine manufacturers. Given more time to study the problem it is expected these reheater temperature differentials could be improved by such things as:

- relocating the outlet superheater bed to a higher position in the FBC to establish higher part load gas temperatures to the reheater banks.
- increasing the proportion of superheater surface to reheater surface in the FBC convection pass to establish control over the reheater heat absorption over a wide load range.

B. Carbon Burn-up Bed Boiler (CBB) (See pages A-6 and A-7)

Two (2) fluidized beds, each 15 feet wide by 36 feet deep are formed by water wall membraned panels made of 2-1/2 inch O.D. tubes on 3 inch centers. Boiling surface is located in the reduced cross-sectional area convection pass formed by the wall tubes. Sootblowers are located under and above the convective surface and in the three cavities formed by the convective surface.

The (2) air compartments are located under each bed. Each compartment is 15 feet wide by 18 feet deep. A perforated plate separates the air compartment from the fluidized bed and provides for air distribution to the bed. The sections and panels are designed to be

shop assembled complete with headers attached, wherever possible. For section tube penetration through the membraned panels, wall tubes would be shipped loose and field welded and refractory seals installed.

The CBB is top supported. Loads are transferred to the top steel by hanger rods attached to the water wall headers and risers.

Access doors and observation ports are provided in the walls of the CBB to provide for maximum observation and sampling.

C. Bed Surface Setting and Heat Transfer

1. Main Beds (See page A-8)

To maintain a bed temperature of 1550°F in the main fluidized beds, heating surface is immersed within the beds. The B&W modified Vreendenburg equation was used for the convective component of heat transfer. The radiation component was calculated using an emissivity of 0.8. No heating surface was located in the start-up compartments of the beds.

The heating surface required to maintain bed temperatures of 1550°F is as follows:

Bed Identification		Tube O.D. (In)	Transfer Surface (Sq. Ft.)		
No.	Location		SH	Boiling	Total
1	Top	1.75	5,927*	-	5,927
2	Center	1.875	6,350*	-	6,350
3	Bottom, Front	2.0	4,792	-	4,792
		2.25	-	2,540	2,540
4	Bottom, Back	2.25	-	5,598	5,598

Totals		17,069	8,138	25,207
--------	--	--------	-------	--------

*Does not include transfer surface that interconnects the banks in each half of beds 1 and 2. This surface is relatively ineffective as it is not submerged in the beds but is located above the start-up zones.

The materials selected for the tubes submerged in the fluidized beds are identical to materials used in conventional coal fired boilers. Selection was based on pressure-stress calculations per the A.S.M.E. Code and the oxidation limits of the materials. No allowance was made to account for the possible corrosion that may take place in the beds.

The tube metals were selected by applying upset absorption rates to account for bed temperature variations and variations in the heat transfer coefficient; and accounting for reduction of steam flow through the tubes due to possible tube to tube flow unbalances. Table 8-1 lists the materials used in the design of the fluidized bed boiler.

The horizontal boiling tubes in the fluidized beds are cold finished, multiple lead ribbed tubes. All other heating surface is cold finished smooth tubes.

Provision has been made for heating surface adjustment in all beds, if required.

TABLE 8-1

METALS USED IN THE DESIGN OF THE
FLUIDIZED BED BOILER

Material Type	Material Spec. ASME	Location						
		FBC						CBB
		Walls	Bed		C.P. Banks			Walls & C.P. Banks
		Boil	SH	Boil	RH	SH	Econ.	Boil
CS	SA-178A				X			
CS	SA-178C				X			
CS	SA-192				X			
CS	SA-210A1	X		X		X	X	X
C-Mo	SA-209T1a		X		X			
2-1/4Cr	SA-213T22		X		X			
304SS	SA-213TP304H		X		X			

2. Carbon Burn-up Bed (See pages A-6 and A-7)

The bed temperature of the carbon burn-up unit is maintained at 2000°F by balancing heat input from the burning char against heat removal through the walls. Vertical walls provide the only heat transfer surface in the bed. The CBB was designed for 120% of full load expected char flow to allow for variations in the combustion efficiency in the FBC. Additional flexibility is provided by the ability to feed coal and limestone to the CBB, if required.

The CBB is split into two (2) beds with two (2) compartments per bed. Each bed compartment has separate air and char feed systems. Auxiliary coal firing is provided to one compartment of each bed. The coal and limestone feeders that supply the CBB also supply the start-up compartments of the FBC. The system is designed to feed either the CBB or the FBC start-up compartment, but not both simultaneously.

D. Spray Attemperators

1. Superheater Attemperator (See Figure 8-1)

One main steam spray attemperator will be furnished. It is located between the first (top) and second (center) all superheater beds. It will include the following parts:

Attemperator body; internals
consisting of spray nozzle,
thermal sleeve and venturi.

Valves; spray water control
valve, block valves

2. Reheater Attemperator (See Figure 8-2)

One set of spray attemperator internals is furnished consisting of a thermal sleeve plus spray water connection and nozzle. It is to be installed in the steam piping at the inlet to the reheater.

FIGURE 8-1

SUPERHEATER SPRAY ATTEMPERATOR

Superheater spray attemperator

FIGURE 8-2

SPRAY ATTEMPERATOR

Spray attemperator

E. Reheater

The entire reheater is located in the common furnace enclosure above the fluidized beds and the lefthand side of the parallel downflow convection pass. The design philosophy evidenced by such an arrangement avoids placing reheat surface in the beds and consequently eliminates the need for a protection system during start-ups, shut-downs and unit trips; and also facilitates matching of main and reheat steam temperatures to the turbine over the load range.

Reheat steam temperature control is obtained by biasing the gas flow over the reheater surface located in the downflow section. The surface was designed to obtain a reheat steam temperature of 1003°F, with no gas biasing, at the boiler's maximum continuous rating.

F. Precipitators (See Figures 8-3 and 8-4)

Hot Rothemuhle electrostatic precipitators have been designed and sized to meet the particulate requirements of 0.1 lb. per million Btu. The Rothemuhle precipitator is conservatively designed based on extensive knowledge and many years of experience and evaluation of test results

Rothemuhle precipitators are arranged to pass flue gases horizontally through a series of fields containing alternating parallel lanes of discharge frames and collecting plates. An electrical field develops between the negative discharge frames and the grounded collecting plates. A portion of the flue gas is ionized and the ions adhere to the dust particles carried by the gases. The dust particles, thus charged are attracted to the positive collecting surfaces. Rapping devices periodically strike the base of each collecting plate curtain and dislodge the dust particles which are then collected in hoppers.

Each Rothemuhle precipitator consists of a shell casing reinforced to withstand positive and negative gas pressures and to maintain a gas tight enclosure. Inlet and outlet flanges are provided for attachment of dampers or flue transition sections. Proper gas distribution is accomplished by means of a test model which establishes the number of perforated plates to be placed in series at the inlet.

FIGURE 8-3

ROTHEMUHLE PRECIPITATOR

FIGURE 8-4

ROTHERMUHLE PRECIPITATOR

The self-supporting shell casing, consists of plates reinforced by stiffeners of standard rolled sections welded together. Roof support beams are designed as hollow box girders and carry the loads of all internal equipment as well as house the high voltage insulators. The precipitator structure rests on special sliding bearings which allow movement due to thermal expansion. Sufficient number of access doors are provided for maintenance and inspection purposes. Hoppers are provided under the precipitators for collection and disposal of entrapped dust.

Collecting plates are roll formed from cold rolled strip incorporating a number of parallel grooves and recesses. These recesses are designed to form flow shadows which enhance collecting properties and minimize dust re-entrainment. The plates feature high frequency vibration characteristics which aid in adequate cleaning performance. Each plate is rigidly connected at top and bottom to assure maximum transmission of rapping forces.

Rapping devices are of the hammer and anvil type. Rappers are mounted on slowly rotating shafts across the width of the unit, and staggered so that each surface row is rapped independently.

Each precipitator field is equipped with its own high voltage transformer and silicon rectifier set which steps line voltage up to 60 KV and provides pulsating direct current to the electrodes.

The control system components are housed in a separate control cabinet. The system seeks to maintain optimum voltage under varying load and operating conditions. The voltage and current fluctuations at a flash-over are instantly monitored and adjustments made to the operating voltage to automatically extinguish possible arcs.

G. Steam Coil Air Heater (See page 8-56)

A steam coil air heater is furnished prior to the secondary air heater for low load cold-end protection and to assure a uniform inlet air temperature of 105°F into the secondary air heater. Steam for the air heater will be supplied by the intermediate pressure turbine first draw-off.

H. Secondary Air Heater

Both regenerative and tubular type air heaters were selected as alternates to one another. Aside from capital cost and maintenance cost differences there are physical and operational differences in the two basic designs that will contribute to a final selection. While a tubular air heater takes up much more space than a regenerative air heater it has the advantage of virtually no air-to-gas leakage, and no gas entrainment in the heated air. Its major operational drawback of cold-end corrosion and fouling may prove to be only a minor factor when handling the relatively clean gas that will be sent to it.

1. Rothemuhle Regenerative Air Heater (See pages 8-57 A-9, A-10)

The Rothemuhle regenerative air heater is of the rotary regenerative type which employs static heating surface contained within a fixed housing (stator). Alternating gas and air flow is obtained by the rotation of a distributing duct (hood) on each face of the stator. Both hoods are keyed to a common main shaft.

The heating surface elements are arranged in the stator in baskets. An access door permits removal and maintenance of elements.

A geared electric drive unit rotates the hoods. An auxiliary air motor drive is provided for emergency operation should electric power to the main drive be interrupted.

The following items are included with the air heater assembly:

- Driving mechanism including speed reducer and motor.
- Auxiliary air motor drive.
- Cold-end layer of heating elements of corrosion resistant low alloy steel mounted in baskets for removal.
- Hot-end and intermediate layers of baskets are of mild carbon steel.
- Lubricating oil system including piping, valves and fittings.
- Access doors as required for maintenance.
- Terminal frame flanges integral to the air heater assembly at cold air inlet and spent gas outlet.

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FIGURE 8-5

ROTHEMUHLE REGENERATIVE AIR HEATER

Rothemuhle regenerative air heater

The air heater is equipped with a sootblowing device at the cold side of the stator. The sootblower is installed at the air hoods between the two wings and rotate with the hoods. Permanent water washing nozzles are also provided.

2. Tubular Air Heater (See pages A-11, A-12, and A-13)

The heating surface is made up of vertical 2 inch O.D. tubes arranged so that the cold-end surface (lower part of unit) is separate from the hot-end tubes (upper part of the unit). Such an arrangement facilitates replacement of cold end tubes should corrosion and fouling make it necessary. The heater has one gas pass (inside the tubes) and three air passes (outside the tubes). Gas passing down through the tubes gives up heat to the air outside the tubes. The inlet air crosses the cold-end tubes at the bottom of the unit and then makes two (2) passes across the hot-end tubes. This arrangement is an attempt to come as close to counterflow as possible in a crossflow heat exchanger.

The tubes are as follows:

Hot End	2" O.D.	#18 BWG	40 ft. long
		Carbon Steel	
Cold End	(Zones numbered in direction of air flow)		
Zone 1	2" O.D.	#14 BWG	18 ft. long
		Corten Steel	
Zone 2	2" O.D.	#14 BWG	18 ft. long
		Carbon Steel	
Zone 3	2" O.D.	#18 BWG	18 ft. long
		Carbon Steel	

I. CBB Mechanical Dust Collector (See page 8-41)

A high particulate loading in the flue gas from the CBB is expected. A mechanical cyclone dust collector of the multiclone type is employed prior to the CBB hot precipitator. This arrangement was adopted to reduce the hot precipitator size and consequently the cost.

J. Fans (See pages 8-50 through 8-55)

Four (4) fans are supplied: A forced draft intake air fan, a hot primary air fan, a tempering air fan, and an induced draft fan. The forced draft intake air fan supplies all of the combustion and conveying air. The tempering air and primary air fans provide air to all the system mixing bustles at sufficient pressure for pneumatic conveying of the solids to the FBC and CBB. The induced draft fan creates sufficient draft to exhaust the gaseous products from the boiler to the stack.

K. Crushing, Classifying and Conveying System (See pages A-14, A-15, and A-16)

The purpose of this system is to crush, classify and transport to the storage silos the coal and limestone. The coal and limestone systems are duplicates. Each system consists of a crusher, a classifying vibrating screen, a bucket elevator to recycle oversize back to the crusher from the screens, a belt conveyor which runs to flight conveyors located on top of the storage silos, and motorized rack and pinion slide gates that empty the material into the silos through connecting chutes.

Reversible impact crushers are employed to crush coal and limestone from their yard sizing (89% through 1-1/2" mesh) for coal and 3 inch top size for limestone) to the sizes needed by the boiler (1/4 inch top size for coal and 12 US mesh top size for limestone).

To utilize the full effectiveness of this impactor and to obtain the longest wear life of the crushing parts, a spreading feeder should be employed in order to distribute material across the entire rotor width. A vertical free fall drop of material into the impactor of 3 to 4 feet should be employed.

The impactor is an all steel unit having rolled plates and structurals strongly welded into one integral unit. The frame is lined with abrasion resistant, carbon manganese side liners. The impact block is a heavy duty manganese steel casting which is reversible, end for end, and side for side.

Each crusher is sized to handle 300 tons/hr of coal or 190 tons/hr of limestone. Each is located at ground level and the inlet chute terminal to the crusher is approximately 9 feet above ground. See pages 8-25 and 8-26 for crusher specifications.

The crushers are operated in closed circuit with external screening equipment. A vibrating screen located under each crusher collects and classifies the coal and limestone before it falls onto the belt conveyors. The screens are single stage and enclosed.

The product (1/4" x 0 coal, 12 US mesh limestone) is dropped through a collection hopper onto the belt conveyors. Oversize discharges off the vibrating screens down a chute to bucket elevators which carry it back to the crusher inlets.

The size of the bucket for the bucket elevator is 10' L x 5' W x 7-3/4" deep, and requires a 3 HP motor. The distance between the sprocket centerlines is 41 feet. There is an access platform with railings for maintenance of the bucket elevator at an elevation of approximately 23'-0" with a ladder and cage for access.

The belt conveyor lower end is located in a pit for a better equipment arrangement. The pit is 24' x 50' x 16' deep with a sump. The belt conveyor consists of a 24 inch belt using 20° troughed idlers running at 225-250 fpm. The limestone belt conveyor is 347'-11-7/8" between the centerline of the pulleys and requires a 10 HP drive. The coal belt conveyor is 359'-4" between the centerline of the pulleys and requires a 15 HP drive. The lower work point of both belt conveyors is at a depth of 13 feet. The discharge work point of the limestone conveyor is at an elevation of 98'-0-7/8". Both conveyors are covered and have a common walkway between. The idlers are furnished with lubrication from one side thus making maintenance easy. The conveyor truss is 42 inches in depth and has an unsupported span of 60'-0". Both conveyors slope at an 18° angle. The gravity take-ups have been located at the lower end of the conveyor at grade level for easy access. At the discharge of both conveyors there is a two-way chute with a flop gate for directing the flow to the flight conveyors.

The silo arrangement is in a U-type configuration and both of the belt conveyors discharge at one corner. The longer two (2) flight conveyors which run across the front of the boiler require 15 HP drives and run at a speed of 100 fpm. The flights are on 24 inch centers and are 24 inches wide. The shorter flight conveyors which feed the silos on the side of the FBC are all sized the same for simplicity and easy access. These flights are also on 24 inch centers and are 24 inches wide running at 100 fpm. Each requires a 7-1/2 HP drive.

The discharge of all the flight conveyors to the silos is made through a motorized rack and pinion slide gate. These can be manual or automated. The system of flight conveyors is fully enclosed and sealed. The conveying system stops at the inlet to the storage silos.

Flight conveyors were recommended over belt trippers for several reasons:

- Belt trippers would be a maintenance item because of short discharge centers between silos (13'-10") causing high usage on a short belt.
- Trippers add more height than the flight conveyors above silos.
- It was felt that with trippers a gallery would be required for dust problems associated with them.
- The control of the tripper discharge would deteriorate with usage. The alignment of the tripper chutes and the silo inlets would be progressively more difficult with wear of the tripper.
- The conveyor vendor estimated that the trippers would cost approximately 2-1/2 to 3 times the cost of flight conveyors.

Therefore, flight conveyors were suggested by the conveyor vendor because of the arrangement of the silos and the easy discharge to the storage silos from the conveyor through a motorized slide gate. The flight conveyors are completely enclosed so there is no dust problems.

L. Storage Tanks and Silos

1. Coal and Limestone Silos (See pages A-17 and A-18)

Coal and limestone silos provide on-line storage of coal and limestone prior to feeding the boiler. The storage capacities of coal and limestone silos are respectively eight (8) and ten (10) hours of the full load requirements. The silo bin and the hoppers are fabricated from carbon steel and stainless steel respectively. Stainless steel is utilized on the hopper portion for better flow of the discharging material. Circular cross sections represent the most economic design.

2. CBB Feed Tank (See page A-19)

Underflow from the FBC precipitator is stored in the CBB feed tank prior to burning in the CBB. A rectangular tank with four (4) discharge hoppers represents the lowest cost functional design. The hoppers are stainless steel and have a cone angle of 30° to the vertical. The tank storage capacity is ten (10) hours of full load underflow from the precipitators.

3. Bed Material Storage Silo (See page A-20)

Spent bed material from the FBC and CBB is cooled and conveyed to the bed material storage silo for storage. The tank is circular in cross section and is sized to hold the entire capacity of the FBC and CBB beds. The bin and hopper are fabricated from carbon steel and stainless steel respectively. The discharge hopper has a cone angle of 30° to the vertical.

M. Vibrating Bin Bottoms (See pages 8-29 and 8-30)

The coal and limestone silos are provided with gyratory vibrating bin bottoms. Due to the sizing and moisture content of the coal and limestone, the particles may have a tendency to stick to the storage silo walls. Vibrating bin bottoms assure material flow by inducing shear to the bound particles.

N. Feeders (See pages 8-31 and 8-32)

Forty (40) gravimetric weighbelt feeders are employed to meter coal and limestone from their storage silos to the fuel feed hoppers. Weighing is controlled by a closed loop digital control system. Feeder accuracy is $\pm 0.5\%$ of the set rate.

O. FBC and CBB Underflow Coolers (See pages 8-45, 8-46 and 8-47)

Ash, unreacted stone and sulfur compounds are continually purged from each of the four (4) FBC beds to maintain the bed height. The bed material exits the FBC at 1550°F and is cooled to 700°F by water cooled screw type ash coolers. Sixteen (16) ash coolers, one per compartment, are provided for this function. Four (4) ash coolers are also provided for the start-up compartments.

If additional coal and limestone is fired in the CBB along with the char, bed material will require purging. Four (4) ash coolers, one per compartment, are provided to cool this bed material from 2000°F to 700°F .

The coolers are equipped with variable speed drives wherein, control of the purged material flow can be achieved.

P. FBC Precipitator Char Conveying System

Two (2) precipitators are used to remove the particulate matter from the flue gas leaving the FBC. Each precipitator is fitted with sixteen (16) hoppers. Periodically, the accumulated ash is removed from the hoppers and transported to the CBB feed tank by the FBC precipitator char conveying system.

The FBC precipitator char conveying system is made up of two (2) independent vacuum transport systems with one system servicing each of the two (2) precipitators. Furthermore, the main transport line of each system is split into four branch lines with each branch line serving four (4) precipitator hoppers. Thus the two (2) main transport lines serve all thirty-two (32) hoppers.

During operation only four (4) of the sixteen (16) hoppers per precipitator are emptied at one time. These hoppers discharge into a single branch line which in turn discharges to the main transport line. The remaining twelve (12) hoppers are isolated from their respective branch lines by air operated valves. In addition, the three (3) inactive branch lines are isolated from the main transport line to minimize vacuum requirements.

Each of the main transport lines feeds a separation system which feeds two (2) of the four (4) CBB feed tank compartments. Vacuum is produced by 125 HP mechanical exhausters. Three (3) mechanical exhausters will be furnished, one for each conveying system and the third one as a standby.

Each system is complete with the necessary conveyor piping, valves and automatic controls.

Q. Sootblowers (See pages 8-35, 8-36, 8-37 and 8-38)

A complete automatic sequential air blowing, electronically driven and operated sootblowing system is provided for cleaning the primary superheater, reheater, economizer, horizontal convective boiling surface and tubular air heater (if used). Plant compressed air at 300 psig is required for the sootblowers. Steam from the primary superheater outlet is used as a back-up blowing medium. Three (3) types of sootblowers are used depending on the particular functions and the temperature zone at which they have to operate:

- Long retractable sootblowers are used at temperature zones above 1100°F.
- Extended lance sootblowers are used at temperature zones below 1100°F.
- Straight line single arm retractable sootblowers are used on the tubular air heater (if used).

The sootblowers are equipped with:

- a. Mechanically operated poppet type valve with adjustable pressure control.
- b. Totally enclosed drive carriage assembly and motor.
- c. Negative pressure wallbox.
- d. Solid-state sootblower control panel.
- e. Individual reversing starters.
- f. Pressure reducing valves.

The FBC is provided with fourteen (14) sootblowers, six (6) being the long retractable type, and eight (8) being the extended lance type. The CBB is furnished with five (5) long retractable sootblowers. The tubular air heater, if used, will be provided with ten (10), straight line single arm retractable sootblowers. The Rothemuhle regenerative air heater uses one (1) crank gear (radially shifting) type sootblower with eight (8) nozzles.

R. Structural Steel (See page A-21, A-22, A-23 and A-27)

The design arrangement of the FBC and CBB were reviewed with the intent of identifying and solving unique structural problems and to determine preliminary sizes for structural systems such as fluid bed supports and buckstays.

The following design conditions and codes were used:

	<u>Gas Side of Bed</u>	<u>Air Side of Bed</u>
Condition I	+35 IN WG	+80 IN WG
Condition II	-20 IN WG transient 1600°F	-20 IN WG transient 650°F

- Wind loading was not considered because the unit was assumed to be enclosed.
- Zone 2 earthquake was considered.
- ASME Section I, AISC (Modified for temperature) and ANSI 58.1 codes were used.

1. Support Systems and Load Analysis

The unit was reviewed to determine the most feasible support arrangement. Suspension of the boiler, as on standard B&W boilers, is accomplished by a system of header and tube lugs and hanger rods from top structural steel. The unit is also tied to the framing steel by a system of structural ties, buckstays and buckstay attachments for horizontal loading conditions. The membrane walls are used as shear planes for resistance to seismic loading and provide the vertical support for the internal heating surfaces as well as for other appurtenances attached to them.

Water cooled furnace tubes are utilized to support the overhanging fluid bed enclosures at the front of the unit. Variable springs are used to limit load redistribution due to the possibility of a temperature difference between the unheated support tubes and the heated furnace walls. The rear of the bottom bed is spring supported between headers at the top of the bed and headers at the bottom of the horizontal convection pass.

The fluid bed support structure consists of a stiffened 1/4" perforated plate (SA 240 TP 304) supported by rolled structural wide flange shapes utilizing rocker type end connections to accommodate differential expansions. The following design temperature were used for preliminary support sizing:

1/4" perforated plate - 1100°F
Plate stiffeners - 1050°F
Floor support beams - Start-up bed - 1000°F
 Remaining beds - 650°F

Design loading for the fluid bed structure included the weight of limestone, distribution plate, heating surface, coal piping and weight of the supporting structure itself.

The windbox is supported off the bottom of the boiler walls. The windbox division plates have to be seal welded and appropriate expansion joints have to be designed.

2. Buckstay System

A typical boiler buckstay system is used to keep wall tube bending and axial stresses within allowable design levels at saturation temperature. The system is also designed to prevent excessive wall deflections, and to resist forces from unbalanced pressure effects, earthquake loads and to control boiler expansion by anchoring the unit to building steel.

The exterior wall buckstays consist of rolled structural beams positioned with their strong axis parallel to the wall to which they are attached. They are completely outside of the enclosure insulation and are therefore near ambient temperature. The buckstays within the air side of the bed enclosures are also rolled structural beams but are designed at elevated temperatures. The buckstay system is attached to the membraned walls by a system of tie bars, wall lugs, pins, standoffs and buckstay lugs in order to provide for differential expansions.

Buckstay sizing and spacing is based on the following design parameters:

<u>Buckstay Location</u>	<u>Design Pressure</u>	<u>Design Temperature</u>
Outer Furnace Walls	+80 IN WG or +35 IN WG (Depending on Buckstay Elev.)	100°F
	-20 IN WG Transient	100°F
Horizontal Convection Pass	+29 IN WG Stay or	100°F
	-20 IN WG Transient	
Roof over top bed	+35 IN WG Stay or	100°F
	-20 IN WG Transient	
Inner wall & Roof over remaining beds	45 IN WG	650°F

The members were sized based on allowable stresses at design temperature using overturning posts, compartment division plates, or bracing between pairs of buckstays for compression flange stabilization. The end connections for the interior wall buckstays follow B&W standards for utility boiler. The sidewall buckstays were designed to span between exterior front and rear walls with no attachment to interior walls. To prevent compression load transfer from the sidewalls to the interior membraned walls, a flexible or sliding seal is used at their junction with the sidewalls. In addition, the fluid bed supporting wall deflections must be taken into consideration when the details of the support structure are finalized.

S. SPECIFICATIONS

CRUSHER DATA SHEET

File No. ES-241 By J. S. Bloss

Duty	<u>Coal</u>
Number of Units	<u>1</u>
Inlet Material Size	<u>89% thru 1½" U.S. Mesh</u>
Crushed Material Size	<u>¾" Top</u>
Grindability (Hardgrove)	<u>60</u>
Capacity (lb/hr)	<u>600,000</u>
Motor Size (HP)	<u>500</u>
Power Requirements	<u>460 Volt 3 pH 60 Hz</u>
Materials of Construction	<u>Steel w/carbon manganese wear liners</u>
Unit Weight (Lbs)	<u>27,000</u>

CRUSHER DATA SHEET

File No. ES-241 By J. S. Bloss

Duty	<u>Limestone</u>
Number of Units	<u>1</u>
Inlet Material Size	<u>3" top</u>
Crushed Material Size	<u>12 mesh top</u>
Grindability	<u>-</u>
Capacity (lb/hr)	<u>380,000</u>
Motor Size (HP)	<u>500</u>
Power Requirements	<u>460 Volt 3 pH 60 Hz</u>
Materials of Construction	<u>Steel w/carbon manganese</u> <u>wear liners</u>
Unit Weight (Lbs)	<u>27,000</u>

STORAGE TANK DATA SHEET

File No. ES-241 By J.S. Bloss

Name	<u>Coal Silo</u>
Number of Units	<u>20</u>
Storage Capacity (Hours)	<u>8</u>
Capacity (lb)	<u>73,000</u>
Volume (Ft ³)	<u>2,307</u>
Design Temperature, (°F)	<u>130</u>
Design Pressure (in. WG)	<u>0</u>
Wind Zone (UBC) (lb/Ft ²)	<u>25</u>
Seismic Zone (UBC)	<u>2</u>

Material of Construction

Bin	<u>Carbon Steel</u>
Hopper	<u>Stainless Steel</u>

General Dimensions

Diameter (Ft)	<u>13</u>
Length (Ft)	<u>-</u>
Width (Ft)	<u>-</u>
Total Height (Ft)	<u>20.1</u>
Cone Angle with Vertical	<u>30°</u>
Unit Weight (lbs)	<u>19,800</u>

Note:

For one unit

STORAGE TANK DATA SHEET

File No. ES-241 By J.S. Bloss

Name	<u>Limestone Silo</u>
Number of Units	<u>20</u>
Storage Capacity (Hours)	<u>10</u>
Capacity (lb)	<u>28,600</u>
Volume (Ft ³)	<u>439</u>
Design Temperature, (°F)	<u>130</u>
Design Pressure (in. WG)	<u>0</u>
Wind Zone (UBC) (lb/Ft ²)	<u>25</u>
Seismic Zone (UBC)	<u>2</u>

Material of Construction

Bin	<u>Carbon Steel</u>
Hopper	<u>Stainless Steel</u>

General Dimensions

Diameter (Ft)	<u>6</u>
Length (Ft)	<u>-</u>
Width (Ft)	<u>-</u>
Height (Ft)	<u>16.6</u>
Cone Angle with Vertical	<u>30°</u>
Unit Weight (lbs)	<u>8,900</u>

Note:

For one unit

VIBRATING BIN BOTTOM

FILE NO. ES-241

BY J. S. BLOSS

DUTY:	COAL
NO. OF UNITS:	20
Storage Capacity (Ft ³)	35
Density (Lb/Ft ³)	50
Temperature	Ambient
Surface Moisture (%)	7
Particle Size (In)	$\frac{1}{4}$ " x 0
Type Bottom	Gyrated
Model	6GH
Slope (Degrees)	30
Inlet Dia. (In)	72
Outlet Dia. (In)	12
Shell Thickness (In)	$\frac{1}{4}$
Shell Material	Carbon Steel
Type of Liner Material	N/R (Not Required)
Thickness	—
Drive	Shaker Motor
Horsepower	1.5
Enclosure	TENV
Frequency (Hz)	1,800
Stroke (design) (In)	1/16
Force output (max.) (Lbs)	4,700 lbs.
Power requirements	230/460v, 3 ph, 60 hz.
Isolation System	Rubber Bushed Hanger Arms
Method of Support	From Static Storage Bin
Hanger Bracket	N/R
Adaptor Ring	Welded Type Included
Flexible Connections	Reinforced Nordel
Inlet sock	Included
Outlet sock	N/R
Inlet skirt	N/R
Weight. (Lbs)	1,500

NOTE: FOR ONE UNIT

VIBRATING BIN BOTTOM

FILE NO. ES-241

BY J. S. BLOSS

DUTY:	<u>LIMESTONE</u>
NO. OF UNITS:	<u>20</u>
Storage Capacity (Ft ³)	<u>8</u>
Density (Lbs/Ft ³)	<u>90</u>
Temperature	<u>Ambient</u>
Surface Moisture (%)	<u>4</u>
Particle Size (In)	<u>12 Mesh Top</u>
Type Bottom	<u>Gyrated</u>
Model	<u>3GH</u>
Slope (Degrees)	<u>30</u>
Inlet Dia. (In)	<u>36</u>
Outlet Dia. (In)	<u>8</u>
Shell Thickness (In)	<u>1/8</u>
Shell Material	<u>Carbon Steel</u>
Type of Liner Material	<u>N/R (Not Required)</u>
Thickness	<u>—</u>
Drive	<u>Shaker Motor</u>
Horsepower	<u>0.75</u>
Enclosure	<u>TENV</u>
Frequency (Hz)	<u>1,800</u>
Stroke (design) (In)	<u>1/16</u>
Force output (max.) (Lbs)	<u>2,000</u>
Power requirements	<u>230/460v. 3 ph. 60 hz.</u>
Isolation System	<u>Rubber Bushed Hanger Arms</u>
Method of Support	<u>From Static Storage Bin</u>
Hanger Bracket	<u>Not Required</u>
Adaptor Ring	<u>Welded Type Included</u>
Flexible Connections	<u>Reinforced Nordel</u>
Inlet sock	<u>Included</u>
Outlet sock	<u>N/R</u>
Inlet skirt	<u>N/R</u>
Weight (Lbs)	<u>350</u>

NOTE: FOR ONE UNIT

FEEDER DATA SHEET

File No. ES-241 By J.S. Bloss

Duty	<u>Coal</u>
Number of Units	<u>20</u>
Type	<u>Gravimetric</u>
Capacity (Lb/Hr)	<u>10,750</u>
Material Size	<u>1/4" x 0</u>
Bulk Density (lb/Ft ³)	<u>50</u>
Materials of Construction	<u>Steel wear plates/rubber belt</u>
Inlet Size (In)	<u>24 x 30</u>
Outlet Size (In)	<u>24 x 25</u>
Feeder Length (Ft)	<u>11</u>
Motor Type	<u>AC Explosion Proof</u>
Motor Size (HP)	<u>1</u>
Power Requirements	
Drive	<u>230/460</u> Volt <u>3</u> pH <u>60</u> Hz
Instruments	<u>110/230</u> Volt <u>1</u> pH <u>60</u> Hz
Weight (Lbs)	<u>2,400</u>

Note:

For one unit

FEEDER DATA SHEET

File No. ES-241 By J.S. Bloss

Duty	<u>Limestone</u>
Number of Units	<u>20</u>
Type	<u>Gravimetric</u>
Capacity (Lb/Hr)	<u>3,375</u>
Material Size	<u>12 Mesh (USS) Top</u>
Bulk Density (lb/Ft ³)	<u>90</u>
Materials of Construction	<u>Steel wear plates/rubber belt</u>
Inlet Size (In)	<u>24 x 30</u>
Outlet Size (In)	<u>24 x 25</u>
Feeder Length (Ft)	<u>11</u>
Motor Type	<u>DC w/SRC Drive</u>
Motor Size (HP)	<u>1/2</u>
Power Requirements	
Drive	<u>110/230</u> Volt <u>1</u> pH <u>60</u> Hz
Instruments	<u>110/230</u> Volt <u>1</u> pH <u>60</u> Hz
Weight (Lbs)	<u>2,400</u>

Note:

For One Unit

ROTARY FEEDER/SEAL DATA

1 NAME Fuel Feed Hopper Rotary Seal FILE NO. ES-241
2 NUMBER - DATE 12/6/77 BY J.S. Bloss
3 SERVICE OF UNIT SEAL X FEEDER REVERSIBLE X
4 DUTY OF UNIT CONTINUOUS X INTERMITTENT
5 NO. OF UNITS 20

PERFORMANCE

6 MATERIAL HANDLED Coal and Limestone
7 SCREEN OR MICRON SIZE Max: 1/4"
8 INLET TEMPERATURE, °F 80 MOISTURE CONTENT 6%
9 CAPACITY, LB/HR MIN 0 MAX 14250 lb/hr
10 MATERIAL WEIGHT, LB/FT³ BULK MIN 60 MAX 90
11 DESIGN CAPACITY, FT³/HR 238
12 HOURS PER 24 HR. DAY EQUIPMENT WILL OPERATE 24 hours
13 INLET PRESSURE, PSIG ATM OUTLET PRESSURE, PSIG 2
14 PRESSURE DIFFERENTIAL, PSI 2
15 DESIGN PRESSURE, PSIG 3
16 DESIGN TEMPERATURES, °F 600
17 EXPECTED GAS LEAKAGE, ACFM @ INLET CONDITIONS -
18 OPERATING SPEED, RPM 16.9 CONSTANT VARIABLE X
19 MATERIALS OF CONSTRUCTION Cast Iron Body; Ni-Hard Rotors

DRIVER 230
20 ELECTRICAL CHARACTERISTICS 1/3 VOLTS 460 PHASE 3 CYCLE 60
21 MOTOR HP REQUIRED
22 TOTALLY ENCLOSED FAN COOLED EXPLOSION PROOF X
23 VARIABLE SPEED X CONSTANT SPEED MIN. RPM 0
24 MAX. RPM 25

25 NOTES

For One Unit

PUMP DATA SHEET

BY J.S. Bloss

DATE 12/12/77

FILE NO. ES-241

1			
2	NAME	Boiler Water Recirculation	
3		Pump	
4	GENERAL TYPE	Centrifugal	
	PROCESS REQUIREMENTS	For each pump	
5	FLUID HANDLED	Boiler Water	
6	SUCTION TEMP., °F	686	
7	MOLECULAR WEIGHT	18.02	
8	DENSITY, LB/FT ³	31.9	
9	SP. GRAVITY @ T	0.51	
10	SOLIDS, %	0	
11	VISCOSITY @ T, CP	0.062	
12	VAPOR PRESS., PSIA		
13	AVAIL. NPSH @ CENTERLINE, FT.		
14	SUCTION PRESS., PSIG	2,816	
15	DISCHARGE PRESS., PSIG	2,837	
16	DIFFERENTIAL PRESS., PSIG	21	
17	CAPACITY, MLB/HR	6,574.8	
18	CAPACITY, LB MOLE/HR	364,857	
19	CAPACITY, SGPM @ 60°F	13,135	
20	CAPACITY, GPM @ T	25,695	
21			
22			
23			
	DESIGN AND CONSTRUCTION		
24	DRIVER TYPE	Motor	
25	BRAKE HORSEPOWER	400	
26	RPM OF PUMP	594	
27	MATERIALS		
28	CASING DESIGN TEMP., °F		
29	CASING DESIGN PRESS., PSIG		
30			
31			

32 NOTES

For Each of the Two Pumps

SOOTBLOWER DATA

Name Sootblower File No. ES-241
Number - By H. S. Doss
Where Used FBC
Valve Mechanical Poppet Type Motor HP 1-1/2
Electrical Characteristics 460V, 3PH, 60HZ
Blowing Medium Plant air at 300 PSIG as primary blowing medium.
Steam from outlet of primary superheater reduced
to 600 PSIG as backup medium.
Type of System Automatic Sequential - Electric Motor Drive

Type	No. of Units	Cycle Time/Unit (Min.)	Air Flow SCFM	Total Coverage (Ft)
Long Retractable	6	4.1	4,600	25
Extended Lance	4	5.1	2,300	30
Extended Lance	4	3.4	2,300	20

TOTAL 7,200

SOOTBLOWER DATA

Name Sootblower File No. ES-241
Number - By H. S. Doss
Where Used CBB
Valve Mechanical Poppet Type Motor HP 1-1/2
Electrical Characteristics 460V, 3PH, 60HZ
Blowing Medium Plant air at 300 PSIG as primary blowing medium.
Steam from outlet of primary superheater reduced
to 600 PSIG as backup medium.
Type of System Automatic Sequential - Electrical Motor Drive

Type	No. of Units	Cycle Time/Unit (Min.)	Air Flow SCFM	Total Coverage (Ft)
Long Retractable	4	1.6	2,200	7 1/2
Long Retractable	1	1.1	1,150	7 1/2

TOTAL 3,350

SOOTBLOWER DATA

Name Sootblower File No. ES-241
Number - By H. S. Doss
Where Used Tubular Air Heater
Valve Mechanical Poppet Type Motor HP 1-1/2
Electrical Characteristics 460V, 3PH, 60HZ
Blowing Medium Plant air at 300 PSIG as primary blowing medium.
Steam from outlet of primary superheater reduced
to 600 PSIG as backup medium.
Type of System Automatic Sequential - Electric Motor Drive

Type	No. of Units	Cycle Time/Unit (Min.)	Air Flow SCFM	Total Coverage (Ft)
Straight Line Single Arm Retractable	3*	2.7	5,697	4
Straight Line Single Arm Retractable	1**	2.7	4,782	4
Straight Line Single Arm Retractable	5*	5.8	5,664	8 1/2
Straight Line Single Arm Retractable	1***	5.8	5,471	8 1/2

TOTAL 21,614

* each with 42 nozzle elements

** each with 30 nozzle elements

*** each with 46 nozzle elements

SOOTBLOWER DATA

Name Sootblower File No. ES-241

Number - By H. S. Doss

Where Used Regenerative Air Heater

Blowing Medium Plant air at 300 PSIG as primary blowing medium.

Steam from outlet of primary superheater reduced

to 600 PSIG as backup medium.

Type	No. of Units	Cycle Time/Unit (Min.)	Air Flow SCFM
Crank Gear	1	25	2,708

TOTAL 2,708

PRECIPITATOR DATA SHEET

File No. ES-241 By J.S. Bloss

Name	<u>FBC Boiler Precipitator</u>
Number of Units/Boiler	<u>2</u>
Gas Volume/Boiler (ACFM)	<u>860,000</u>
Gas Temperature ($^{\circ}$ F)	<u>720</u>
Design Inlet Loading (Grains/ACF)	<u>6.60</u>
Predicted Outlet Loading (Grains/ACF)	<u>0.02</u>
Effective Migration Velocity (Cm/Sec)	<u>5.45</u>
Gas Velocity (Ft/Sec)	<u>3.23</u>
Number of Precipitator Casings/Boiler	<u>2</u>
Surface Area (Ft ² /Casing)	<u>222,956</u>
No. of Lanes/Casing	<u>54</u>
Effective Plate Height (Ft)	<u>39.38</u>
Number X Depth of Field (Ft)	<u>4 x 13.10</u>
Overall Collection Efficiency(%)	<u>99.7</u>

PRECIPITATOR DATA SHEET

File No. ES-241 By J.S. Bloss

Name	<u>CBB Precipitator</u>
Number of Units/Boiler	<u>1</u>
Gas Volume/Boiler (ACFM)	<u>112,000</u>
Gas Temperature (°F)	<u>787</u>
Design Inlet Loading (Grains/ACF)	<u>4.32</u>
Predicted Outlet Loading (Grains/ACF)	<u>0.031</u>
Effective Migration Velocity (Cm/Sec)	<u>5.23</u>
Gas Velocity (Ft/Sec)	<u>3.21</u>
Number of Precipitator Casings/Boiler	<u>1</u>
Surface Area (Ft ² /Casing)	<u>51,468</u>
No. of Lanes/Casing	<u>19</u>
Effective Plate Height (Ft)	<u>29.55</u>
Number X Depth of Field (Ft)	<u>4 x 11.46</u>
Overall Collection Efficiency(%)	<u>99.3</u>

MECHANICAL DUST COLLECTOR EQUIPMENT

1. Name CBB Mechanical Dust Collector File No. ES-241
2. Number - Date 12/21/77 By J.S. Bloss
3. Type of Unit Multiclone
4. Number of Units 1

Performance

5. Inlet Gas Flow, (ACFM) 112,000
6. Inlet Gas Flow, (Lb-Mole/Hr) 7,323
7. Inlet Gas Density, (Lb/ACF) 0.033
8. Inlet Temperature, ($^{\circ}$ F) 787
9. Inlet Pressure, (IN WG) -3.4
10. Gas Molecular Wt. (Lb/Lb-Mole) 30.06
11. Inlet Dust Load, (Lb/ 10^3 Lb Wet Gas) 172
12. Outlet Dust Load, (Lb/ 10^3 Lb Wet Gas) 18.85
13. Collection Efficiency, (%) 89
14. Pressure Drop, (IN WG) 3.1

Construction

15. Design Pressure, (In. WG) 10 Design Temp. ($^{\circ}$ F) 825
16. ASME Code Stamped - Yes No X
17. Corrosion Allowance, (In) -
18. Shell Thickness (In) - Shell Material Corten
19. Lining Material -

Notes

STORAGE TANK DATA SHEET

File No. ES-241 By J.S. Bloss

Name	<u>CBB Feed</u>
Number of Units	<u>1</u>
Storage Capacity (Hours)	<u>10</u>
Capacity (lb)	<u>476,000</u>
Volume (Ft ³)	<u>22,816</u>
Design Temperature, (°F)	<u>725</u>
Design Pressure (in. WG)	<u>0</u>
Wind Zone (UBC) (lb/Ft ²)	<u>25</u>
Seismic Zone (UBC)	<u>2</u>

Material of Construction

Bin	<u>Carbon Steel</u>
Hopper	<u>Stainless Steel</u>

General Dimensions

Diameter (Ft)	<u>-</u>
Length (Ft)	<u>52</u>
Width (Ft)	<u>13</u>
Total Height (Ft)	<u>40.5</u>
Cone Angle with Vertical	<u>30°</u>
Unit Weight (Lbs)	<u>115,000</u>

Note:

Tank has four (4) compartments

ROTARY FEEDER/SEAL DATA
THE BABCOCK & WILCOX COMPANY

1 NAME CBB Feed Tank Rotary Seal FILE NO. ES-241
2 NUMBER - DATE 12/16/77 BY J.S. Bloss
3 SERVICE OF UNIT SEAL X FEEDER X REVERSIBLE X
4 DUTY OF UNIT CONTINUOUS X INTERMITTENT
5 NO. OF UNITS 4

PERFORMANCE

6 MATERIAL HANDLED Coal Char and Ash
7 SCREEN OR MICRON SIZE Max: 1000 microns Min: 1 micron
8 INLET TEMPERATURE, °F 700 MOISTURE CONTENT -
9 CAPACITY, LB/HR MIN 0 MAX 14,750
10 MATERIAL WEIGHT, LB/FT³ BULK MIN 20 MAX 70
11 DESIGN CAPACITY, FT³/HR 739
12 HOURS PER 24 HR. DAY EQUIPMENT WILL OPERATE 24
13 INLET PRESSURE, PSIG ATM OUTLET PRESSURE, PSIG 3
14 PRESSURE DIFFERENTIAL, PSI 3
15 DESIGN PRESSURE, PSIG 3
16 DESIGN TEMPERATURES, °F 725
17 EXPECTED GAS LEAKAGE, ACFM @ INLET CONDITIONS -
18 OPERATING SPEED, RPM 20 CONSTANT VARIABLE X
19 MATERIALS OF CONSTRUCTION Cast Iron Body; Ni-Hard Rotors

DRIVER 230
20 ELECTRICAL CHARACTERISTICS VOLTS 460 PHASE 3 CYCLE 60
21 MOTOR HP REQUIRED 1/2
22 TOTALLY ENCLOSED FAN COOLED EXPLOSION PROOF X
23 VARIABLE SPEED X CONSTANT SPEED MIN. RPM 0
24 MAX. RPM 25

25 NOTES

For One Unit

STORAGE TANK DATA SHEET

File No. ES-241 By J.S. Bloss

Name	<u>Bed Material Storage</u>
Number of Units	<u>1</u>
Storage Capacity	<u>To Hold Entire Bed Volume</u>
Capacity (lb)	<u>1,306,000</u>
Volume (Ft ³)	<u>32,270</u>
Design Temperature, (°F)	<u>725</u>
Design Pressure (in. WG)	<u>0</u>
Wind Zone (UBC) (lb/Ft ²)	<u>25</u>
Seismic Zone (UBC)	<u>2</u>

Material of Construction

Bin	<u>Carbon Steel</u>
Hopper	<u>Stainless Steel</u>
General Dimensions	
Diameter (Ft)	<u>30</u>
Length (Ft)	<u>-</u>
Width (Ft)	<u>-</u>
Total Height (Ft)	<u>61.25</u>
Cone Angle with Vertical	<u>30°</u>
Unit Weight (Lbs)	<u>112,000</u>

Note:

CHAR COOLER DATA SHEET

File No. ES-241

By J.S. Bloss

Name	<u>FBC Main Compartment Underflow</u>			
Number of Units	<u>16</u>			
Duty	<u>Spent Stone</u>			
Capacity (lb/Hr)	<u>3,460 (max)</u>			
Bulk Density (lb/ft ³)	<u>70</u>			
Volume Capacity (ft ³ /Hr)	<u>50</u>			
Inlet Temperature (°F)	<u>1,550</u>			
Outlet Temperature (°F)	<u>700</u>			
LMTD (°F)	<u>975</u>			
Specific Heat (Btu/Lb)	<u>0.3</u>			
Heat Load (Btu/Hr)	<u>882,300</u>			
Water Inlet Temperature (°F)	<u>80</u>			
Water Outlet Temperature (°F)	<u>110</u>			
Water Flow Rate (lb/hr)	<u>29,410 (max)</u>			
Materials of Construction	<u>Carbon Steel</u>			
Motor Type	<u>TEFC</u>			
Motor Size (HP)	<u>2</u>			
Power Requirements	<u>230/460</u>	Volt	<u>3</u>	pH <u>60</u> Hz
Speed	<u>X</u>	Variable	<u></u>	Constant
Minimum RPM	<u>1.8</u>	Maximum RPM	<u>3.6</u>	

Note: For One Unit

CHAR COOLER DATA SHEET

File No. ES-241

By J.S. Bloss

Name	<u>FBC Start-up Compartment Underflow</u>			
Number of Units	<u>4</u>			
Duty	<u>Spent Stone</u>			
Capacity (lb/Hr)	<u>3,460 (max)</u>			
Bulk Density (lb/ft ³)	<u>70</u>			
Volume Capacity (ft ³ /Hr)	<u>50</u>			
Inlet Temperature (°F)	<u>1,550</u>			
Outlet Temperature (°F)	<u>700</u>			
LMTD (°F)	<u>975</u>			
Specific Heat (Btu/Lb)	<u>0.3</u>			
Heat Load (Btu/Hr)	<u>882,300</u>			
Water Inlet Temperature (°F)	<u>80</u>			
Water Outlet Temperature (°F)	<u>110</u>			
Water Flow Rate (lb/hr)	<u>29,410 (max)</u>			
Materials of Construction	<u>Carbon Steel</u>			
Motor Type	<u>TEFC</u>			
Motor Size (HP)	<u>2</u>			
Power Requirements	<u>230/460</u>	Volt	<u>3</u>	pH <u>60</u> Hz
Speed	<u>x</u>	Variable	<u> </u>	Constant
Minimum RPM	<u>1.8</u>	Maximum RPM	<u>3.6</u>	

Note: For One Unit

CHAR COOLER DATA SHEET

File No. ES-241

By J.S. Bloss

Name	<u>CBB Underflow</u>
Number of Units	<u>4</u>
Duty	<u>Spent Stone</u>
Capacity (lb/Hr)	<u>500</u>
Bulk Density (lb/ft ³)	<u>70</u>
Volume Capacity (ft ³ /Hr)	<u>7</u>
Inlet Temperature (°F)	<u>2,000</u>
Outlet Temperature (°F)	<u>700</u>
LMTD (°F)	<u>1127</u>
Specific Heat (Btu/Lb)	<u>0.3</u>
Heat Load (Btu/Hr)	<u>195,000</u>
Water Inlet Temperature (°F)	<u>80</u>
Water Outlet Temperature (°F)	<u>110</u>
Water Flow Rate (lb/hr)	<u>6,500</u>
Materials of Construction	<u>316L Stainless</u>
Motor Type	<u>TEFC</u>
Motor Size (HP)	<u>1/2</u>
Power Requirements	<u>230/460</u> Volt <u>3</u> pH <u>60</u> Hz
Speed	<u>X</u> Variable <u>Constant</u>
Minimum RPM	<u>2.2</u> Maximum RPM <u>4.4</u>

Note: For One Unit

ROTARY FEEDER/SEAL DATA

1 NAME FBC Underflow Rotary Seal FILE NO. ES-241
2 NUMBER - DATE 12/7/77 BY J.S. Bloss
3 SERVICE OF UNIT SEAL ☒ FEEDER REVERSIBLE ☒
4 DUTY OF UNIT CONTINUOUS ☒ INTERMITTENT
5 NO. OF UNITS 20

PERFORMANCE

6 MATERIAL HANDLED Spent Stone
7 SCREEN OR MICRON SIZE Max: 1/4"
8 INLET TEMPERATURE, °F 700 MOISTURE CONTENT -
9 CAPACITY, LB/HR MIN 0 MAX 3,500
10 MATERIAL WEIGHT, LB/FT³ BULK MIN 50 MAX 90
11 DESIGN CAPACITY, FT³/HR 70
12 HOURS PER 24 HR. DAY EQUIPMENT WILL OPERATE 24
13 INLET PRESSURE, PSIG 2 OUTLET PRESSURE, PSIG 0
14 PRESSURE DIFFERENTIAL, PSI 2
15 DESIGN PRESSURE, PSIG 3
16 DESIGN TEMPERATURES, °F 700
17 EXPECTED GAS LEAKAGE, ACFM @ INLET CONDITIONS
18 OPERATING SPEED, RPM 14.4 CONSTANT VARIABLE ☒
19 MATERIALS OF CONSTRUCTION Cast Steel Body; Hardened Rotors

DRIVER

20 ELECTRICAL CHARACTERISTICS VOLTS 230
21 MOTOR HP REQUIRED 1/3
22 TOTALLY ENCLOSED ☒ FAN COOLED ☒ EXPLOSION PROOF
23 VARIABLE SPEED ☒ CONSTANT SPEED MIN. RPM 0
24 MAX. RPM 25

25 NOTES

For One Unit

ROTARY FEEDER/SEAL DATA

1 NAME CBB Underflow Rotary Seal FILE NO. ES-241
2 NUMBER - DATE 12/16/77 BY J.S. Bloss
3 SERVICE OF UNIT SEAL X FEEDER REVERSIBLE X
4 DUTY OF UNIT CONTINUOUS X INTERMITTENT
5 NO. OF UNITS 4

PERFORMANCE

6 MATERIAL HANDLED Spent Stone
7 SCREEN OR MICRON SIZE Max: 1/4"
8 INLET TEMPERATURE, °F 700 MOISTURE CONTENT -
9 CAPACITY, LB/HR MIN 0 MAX 500
10 MATERIAL WEIGHT, LB/FT³ BULK MIN 50 MAX 90
11 DESIGN CAPACITY, FT³/HR 10
12 HOURS PER 24 HR. DAY EQUIPMENT WILL OPERATE 24
13 INLET PRESSURE, PSIG 2 OUTLET PRESSURE, PSIG 0
14 PRESSURE DIFFERENTIAL, PSI 2
15 DESIGN PRESSURE, PSIG 3
16 DESIGN TEMPERATURES, °F 725
17 EXPECTED GAS LEAKAGE, ACFM @ INLET CONDITIONS -
18 OPERATING SPEED, RPM 2.9 CONSTANT VARIABLE X
19 MATERIALS OF CONSTRUCTION Cast Iron Body; Ni-Hard Rotors

DRIVER
20 ELECTRICAL CHARACTERISTICS VOLTS 230
21 MOTOR HP REQUIRED 1/3
22 TOTALLY ENCLOSED X FAN COOLED X EXPLOSION PROOF
23 VARIABLE SPEED X CONSTANT SPEED MIN. RPM 0
24 MAX. RPM 25

25 NOTES

For One Unit

FAN OR BLOWER DATA SHEET

BY J.S. Bloss

DATE 12/19/77

FILE NO. ES-241

1		Net	Test Block
2	NAME	F.D. Inlet Air Fan	F.D. Inlet Air Fan
3			
4	GENERAL TYPE	Airfoil	Airfoil
5	FLUID HANDLED	Air	Air
6	SUCTION TEMP., °F	80°F	105
7	DENSITY @ T, LB/FT ³	0.073	0.069
8	MOLECULAR WEIGHT	28.63	28.63
9	% WATER (WEIGHT)	1.3	1.3
10	VISCOSITY @ T, CP	-	-
11	BARO. PRESS., IN HG	29.92	29.92
12	SUCTION PRESS.,	ATM	ATM
13	DISCHARGE PRESS., IN WG	53.2	66.5
14	DIFFERENTIAL PRESS., IN WG	53.2	66.5
15	CAPACITY, MLB/HR	1,759	2,058
16	CAPACITY, LB MOLE/HR	61,439	71,914
17	CAPACITY, MSCFM @ 60°F, 1 ATM.	382.5	454.8
18	CAPACITY, MACFM @ INLET	403.5	494.1
19	Cp/Cv	1.4	1.4
20	TEMP. RISE, °F	19	25
21			
22			
23			
	DESIGN AND CONSTRUCTION		
24	DRIVER TYPE	Motor	Motor
25	BRAKE HORSEPOWER @ % EFF.	4,702	5,839 @ 88.7
26	RPM OF FAN OR BLOWER	1,180	1,180
27	MATERIALS		
28	CASING DESIGN TEMP., °F		
29	CASING DESIGN PRESS.,		
30			
31			

32 NOTES

For Use With Tubular Air Heater

FAN OR BLOWER DATA SHEET

BY J.S. Bloss

DATE 12/7/77

FILE NO. ES-241

	Net	Test Block
1 NAME	F.D. Inlet Air Fan	F.D. Inlet Air Fan
2		
3		
4 GENERAL TYPE	Airfoil	Airfoil
5 FLUID HANDLED	Air	Air
6 SUCTION TEMP., °F	80°F	105
7 DENSITY @ T, LB/FT ³	0.073	0.069
8 MOLECULAR WEIGHT	28.63	28.63
9 % WATER (WEIGHT)	1.3	1.3
10 VISCOSITY @ T, CP	-	-
11 BARO. PRESS., IN HG	29.92	29.92
12 SUCTION PRESS., ATM	ATM	ATM
13 DISCHARGE PRESS., IN WG	53.2	66.5
14 DIFFERENTIAL PRESS., IN WG	53.2	66.5
15 CAPACITY, MLB/HR	1,927	2,271
16 CAPACITY, LB MOLE/HR	67,307	79,318
17 CAPACITY, MSCFM @ 60°F, 1 ATM.	425.6	501.6
18 CAPACITY, MACFM @ INLET	442.0	545.0
19 Cp/Cv	1.4	1.4
20 TEMP. RISE, °F	19	25
21		
22		
23		
DESIGN AND CONSTRUCTION		
24 DRIVER TYPE	Motor	Motor
25 BRAKE HORSEPOWER @ % EFF.	5,160	6,410 @ 89.2
26 RPM OF FAN OR BLOWER	1,180	1,180
27 MATERIALS	Steel	Steel
28 CASING DESIGN TEMP., °F	-	-
29 CASING DESIGN PRESS.,	-	-
30		
31		

32 NOTES

For Use With Regenerative Air Heater

FAN OR BLOWER DATA SHEET

BY J. S. Bloss

DATE 12/7/77

FILE NO. ES-241

1		Net	Test Block
2	NAME	Primary Air Fan	Primary Air Fan
3			
4	GENERAL TYPE	Radial Tip.	Radial Tip.
5	FLUID HANDLED	Air	Air
6	SUCTION TEMP., °F	600°F	625°F
7	DENSITY @ T, LB/FT ³	0.041	0.040
8	MOLECULAR WEIGHT	28.63	28.63
9	% WATER (WEIGHT)	1.3	1.3
10	VISCOSITY @ T, CP	-	-
11	BARO. PRESS., IN HG	29.92	29.92
12	SUCTION PRESS., IN WG	43.0	43.0
13	DISCHARGE PRESS., IN WG	61.0	66.0
14	DIFFERENTIAL PRESS., IN WG	18.4	23.0
15	CAPACITY, MLB/HR	301.9	362.3
16	CAPACITY, LB MOLE/HR	10546	12655
17	CAPACITY, MSCFM @ 60°F, 1 ATM.	66.7	80.0
18	CAPACITY, MACFM @ INLET	122.9	151.0
19	Cp/Cv	1.4	1.4
20	TEMP. RISE, °F	12	15
21			
22			
23			
	DESIGN AND CONSTRUCTION		
24	DRIVER TYPE	Motor	Motor
25	BRAKE HORSEPOWER	555	750
26	RPM OF FAN OR BLOWER	1,180	1,180
27	MATERIALS		
28	CASING DESIGN TEMP., °F	-	-
29	CASING DESIGN PRESS.,	-	-
30			
31			

32 NOTES

FAN OR BLOWER DATA SHEET

BY J. S. Bloss

DATE 12/7/77

FILE NO. ES-241

1	NUMBER	Net	Test Block
2	NAME	Tempering Air Fan	Temp Air Fan
3			
4	GENERAL TYPE	Airfoil	Airfoil
5	FLUID HANDLED	Air	Air
6	SUCTION TEMP., °F	100	131
7	DENSITY @ T, LB/FT ³	0.079	0.075
8	MOLECULAR WEIGHT	28.63	28.63
9	% WATER (WEIGHT)	1.3	1.3
10	VISCOSITY @ T, CP	-	-
11	BARO. PRESS., IN HG	29.92	29.92
12	SUCTION PRESS., IN WG	53.2	53.2
13	DISCHARGE PRESS., IN WG	61.0	63.6
14	DIFFERENTIAL PRESS., IN WG	8.7	10.4
15	CAPACITY, MLB/HR	266.9	320.3
16	CAPACITY, LB MOLE/HR	9,322	11,187
17	CAPACITY, MSCFM @ 60°F, 1 ATM.	58.9	70.7
18	CAPACITY, MACFM @ INLET	56.2	71.2
19	Cp/Cv	1.4	1.4
20	TEMP. RISE, °F	3	4
21			
22			
23			
	DESIGN AND CONSTRUCTION		
24	DRIVER TYPE	Motor	Motor
25	BRAKE HORSEPOWER	127	165
26	RPM OF FAN OR BLOWER	1,180	1,180
27	MATERIALS	-	-
28	CASING DESIGN TEMP., °F	-	-
29	CASING DESIGN PRESS.,		
30			
31			

32 NOTES

FAN OR BLOWER DATA SHEET

BY J. S. Bloss

DATE 12/19/77

FILE NO. ES-241

1	NUMBER	Net	Test Block
2	NAME	I.D. Fan	I.D. Fan
3			
4	GENERAL TYPE	Radial Tip	Radial Tip
5	FLUID HANDLED	Flue Gas	Flue Gas
6	SUCTION TEMP., °F	285	298
7	DENSITY @ T, LB/FT ³	0.053	0.053
8	MOLECULAR WEIGHT	29.55	29.55
9	% WATER (WEIGHT)	5.5	5.5
10	VISCOSITY @ T, CP	-	-
11	BARO. PRESS., IN HG	29.92	29.92
12	SUCTION PRESS., IN WG	-13.75	-13.75
13	DISCHARGE PRESS., IN WG	-2.3	0.6
14	DIFFERENTIAL PRESS., IN WG	11.45	14.35
15	CAPACITY, MLB/HR	1,965	2,209
16	CAPACITY, LB MOLE/HR	66,497	74,774
17	CAPACITY, MSCFM @ 60°F, 1 ATM.	420.5	472.8
18	CAPACITY, MACFM @ INLET	623.1	688.3
19	Cp/Cv	1.35	1.35
20	TEMP. RISE, °F	6	7
21			
22			
23			
	DESIGN AND CONSTRUCTION		
24	DRIVER TYPE	Motor	Motor
25	BRAKE HORSEPOWER @ % EFF.	1,793	2,411 @ 64.8
26	RPM OF FAN OR BLOWER	590	590
27	MATERIALS		
28	CASING DESIGN TEMP., °F		
29	CASING DESIGN PRESS.,		
30			
31			

32 NOTES

For Use With Tubular Air Heater

FAN OR BLOWER DATA SHEET

BY J. S. Bloss

DATE 12/7/77

FILE NO. ES-241

1	NUMBER	Net	Test Block
2	NAME	I.D. Fan	I.D. Fan
3			
4	GENERAL TYPE	Radial Tip	Radial Tip
5	FLUID HANDLED	Flue Gas	Flue Gas
6	SUCTION TEMP., °F	269	269
7	DENSITY @ T, LB/FT ³	0.053	0.053
8	MOLECULAR WEIGHT	29.55	29.55
9	% WATER (WEIGHT)	5.5	5.5
10	VISCOSITY @ T, CP	-	-
11	BARO. PRESS., IN HG	29.92	29.92
12	SUCTION PRESS., IN WG	-13.00	-13.75
13	DISCHARGE PRESS., IN WG	-2.3	0.6
14	DIFFERENTIAL PRESS., IN WG	10.70	14.31
15	CAPACITY, MLB/HR	2,133	2,418
16	CAPACITY, LB MOLE/HR	72,183	81,829
17	CAPACITY, MSCFM @ 60°F, 1 ATM.	456.5	517.0
18	CAPACITY, MACFM @ INLET	661.9	753.3
19	Cp/Cv	1.35	1.35
20	TEMP. RISE, °F	5	7
21			
22			
23			
	DESIGN AND CONSTRUCTION		
24	DRIVER TYPE	Motor	Motor
25	BRAKE HORSEPOWER @ % EFF.	1,997 @ 63.6	2,685 @ 63.6
26	RPM OF FAN OR BLOWER	590	590
27	MATERIALS	-	-
28	CASING DESIGN TEMP., °F	-	-
29	CASING DESIGN PRESS.,		
30			
31			

32 NOTES

For Use With Regenerative Air Heater

STEAM COIL AIR HEATER DATA SHEET

File No. ES-241

By J.S. Bloss

Air Side

Capacity

Lb/Hr	<u>1,900,000 (max)</u>
SCFM	<u>419,700</u>
ACFM	<u>404,200</u>
Inlet Temperature (°F)	<u>-20 (min)</u>
Outlet Temperature (°F)	<u>105</u>
Heat Duty (MM Btu/Hr)	<u>57.0 (max)</u>
Pressure Drop (in. WG)	<u>0.83</u>

Steam Side

Steam Supply Pressure (PSIA)	<u>200</u>
Inlet Temperature (°F)	<u>382</u>
Degrees Superheat	<u>0</u>
Flow Rate (Lb/Hr)	<u>54,500</u>
Pressure Drop (psi)	<u>1.9</u>
Heat Transfer Surface (Ft ²)	<u>20,554</u>
Face Dimensions (Ft)	<u>14.34 W x 28.0 L x 0.83 H</u>
Number of Faces	<u>2</u>
Number of Coils/Face	<u>2</u>
Tube Size (Inches)	<u>1 x 0.065 thick</u>
Fins/Inch	<u>11</u>
Materials of Construction -	
Tubes	<u>Carbon Steel</u>
Fins	<u>Aluminum</u>
Frame	<u>Steel</u>
Gaskets	<u>Soft Iron</u>
Weight (lbs)	<u>8,434</u>

ROTHEMULE AIR HEATER DATA

1.	NAME <u>Secondary Air Heater</u>	FILE NO. <u>ES-241</u>
2.	NUMBER <u>-</u>	BY <u>J.S. Bloss</u>
3.	NO. OF UNITS <u>1</u>	

PERFORMANCE

4.	TEMPERATURE OF AIR IN ($^{\circ}\text{F}$)-----	<u>105</u>
5.	TEMPERATURE OF AIR OUT ($^{\circ}\text{F}$)-----	<u>636</u>
6.	TEMPERATURE OF GAS IN ($^{\circ}\text{F}$)-----	<u>710</u>
7.	TEMPERATURE OF GAS OUT (UNCORRECTED) $^{\circ}\text{F}$ -----	<u>285</u>
8.	TEMPERATURE OF GAS OUT (CORRECTED) $^{\circ}\text{F}$ -----	<u>269</u>
9.	TOTAL WEIGHT OF AIR LEAVING AIR HEATER (Lbs/HR)	<u>1,675,379</u>
10.	TOTAL WEIGHT OF GAS LEAVING AIR HEATER (Lbs/HR)	<u>2,133,372</u>
11.	TOTAL EXPECTED AIR LEAKAGE (Lbs/HR)-----	<u>168,393</u>
12.	AIR SIDE PRESSURE DROP ("W.G.)-----	<u>4.27</u>
13.	GAS SIDE PRESSURE DROP ("W.G.)-----	<u>3.57</u>

AIR HEATER DESIGN

14.	STATOR SIZE-----	<u>11.2</u>
15.	COLD END DEPTH (INCHES)-----	<u>12</u>
16.	INTERMEDIATE DEPTH (INCHES)-----	<u>38</u>
17.	HOT END DEPTH (INCHES)-----	<u>26</u>
18.	TOTAL DEPTH (INCHES)-----	<u>76</u>
19.	STATOR DEPTH (INCHES)-----	<u>89</u>
20.	TOTAL HEATING SURFACE AREA/AIR HEATER(FT^2)-----	<u>378,597</u>

NOTES

Regenerative Air Heater

MOTOR DATA

1. Name Coal Crusher Date 1/2/78 File No. ES-241
2. Number - By J.S. Bloss
3. No. of Units 1 Installation (Indoor or Outdoor) I.D.
4. Driven Equipment Coal Crusher
5. Motor Horsepower 500
6. Motor RPM 1,200
7. Electrical Characteristics 460 Volt 3PH 60HZ
8. WR^2 of Driven Equipment (lb-Ft²) 5237
9. Type of Enclosure Open Drip-Proof
10. Class of Insulation B
11. Temperature Rise ($^{\circ}F$) 194
12. Maximum Ambient Temperature -
13. Direct Connected O/V-Belt Direct
14. How Mounted -
15. Driving thru Fluid Drive? No

Extras

16. Mounting Half Coupling X
17. Export Boxing -
18. Dual Shaft Extension -
19. Sole Plates X
20. Tropical Protection -
21. Space Heaters -
22. Pot Head -
23. Tachometer -
24. Temperature Detectors X
25. Type of Bearings Ball Bearing
26. Non-Standard Service Factor Required 1.15

Notes

MOTOR DATA

1. Name Limestone Crusher Date 1/2/78 File No. ES-241
2. Number - By J.S. Bloss
3. No. of Units 1 Installation (Indoor or Outdoor) I.D.
4. Driven Equipment Limestone Crusher
5. Motor Horsepower 500
6. Motor RPM 1,200
7. Electrical Characteristics 460 Volt 3PH 60HZ
8. WR^2 of Driven Equipment (1b-Ft²) 5237
9. Type of Enclosure Open Drip-Proof
10. Class of Insulation B
11. Temperature Rise ($^{\circ}F$) 194
12. Maximum Ambient Temperature -
13. Direct Connected O/V-Belt Direct
14. How Mounted -
15. Driving thru Fluid Drive? No

Extras

16. Mounting Half Coupling X
17. Export Boxing -
18. Dual Shaft Extension -
19. Sole Plates X
20. Tropical Protection -
21. Space Heaters -
22. Pot Head -
23. Tachometer -
24. Temperature Detectors X
25. Type of Bearings Ball Bearing
26. Non-Standard Service Factor Required 1.15

Notes

MOTOR DATA

The Babcock and Wilcox Company

1. Name Boiler Water Recirc. Pump Date 2-2-78 File No. ES-241
2. Number _____ By H.S. Doss
3. No. of Units 2 Installation (Indoor or Outdoor) I.D.
4. Driven Equipment Centrifugal Pump
5. Motor Horsepower 400
6. Motor RPM 600
7. Electrical Characteristics 460V 3PH 60HZ
8. WR^2 of Driven Equipment 22,870
9. Type of Enclosure Open Drip-Proof
10. Class of Insulation B
11. Temperature Rise 176
12. Maximum Ambient Temperature -
13. Direct Connected O/V-Belt Direct
14. How Mounted _____
15. Driving thru Fluid Drive? No

Extras

16. Mounting Half Coupling X
17. Export Boxing -
18. Dual Shaft Extension -
19. Sole Plates X
20. Tropical Protection -
21. Space Heaters -
22. Pot Head -
23. Tachometer -
24. Temperature Detectors X
25. Type of Bearings Split Sleeve-Ring Oil
26. Non-Standard Service Factor Required 1

Notes

MOTOR DATA

1. Name F.D. Inlet Air Date 1/5/78 File No. ES-241
2. Number - By J.S. Bloss
3. No. of Units 1 Installation (Indoor or Outdoor) I.D.
4. Driven Equipment Fan
5. Motor Horsepower 6,000
6. Motor RPM 1,200
7. Electrical Characteristics 4,160 Volt 3PH 60HZ
8. WR^2 of Driven Equipment (1b-Ft²) 105,769
9. Type of Enclosure Open Drip-Proof
10. Class of Insulation B
11. Temperature Rise (°F) 176
12. Maximum Ambient Temperature -
13. Direct Connected O/V-Belt Direct
14. How Mounted -
15. Driving thru Fluid Drive? No

Extras

16. Mounting Half Coupling X
17. Export Boxing -
18. Dual Shaft Extension -
19. Sole Plates X
20. Tropical Protection -
21. Space Heaters -
22. Pot Head -
23. Tachometer -
24. Temperature Detectors X
25. Type of Bearings Split Sleeve - Oil Ring
26. Non-Standard Service Factor Required 1.15

Notes

Sized For Tubular Air Heater Duty

MOTOR DATA

1. Name F.D. Inlet Air Date 1/2/78 File No. ES-241
2. Number - By J.S. Bloss
3. No. of Units 1 Installation (Indoor or Outdoor) I.D.
4. Driven Equipment Fan
5. Motor Horsepower 7,000
6. Motor RPM 1,200
7. Electrical Characteristics 4160 Volt 3PH 60HZ
8. WR^2 of Driven Equipment (lb-Ft²) 122,661
9. Type of Enclosure Open Drip-Proof
10. Class of Insulation B
11. Temperature Rise ($^{\circ}F$) 176
12. Maximum Ambient Temperature -
13. Direct Connected O/V-Belt Direct
14. How Mounted -
15. Driving thru Fluid Drive? No

Extras

16. Mounting Half Coupling X
17. Export Boxing -
18. Dual Shaft Extension -
19. Sole Plates X
20. Tropical Protection -
21. Space Heaters -
22. Pot Head -
23. Tachometer -
24. Temperature Detectors X
25. Type of Bearings Split Sleeve - Oil Ring
26. Non-Standard Service Factor Required 1.0

Notes

Sized for Regenerative Air Heater Duty

MOTOR DATA

1. Name Primary Air Fan Date 1/2/78 File No. ES-241
2. Number - By J.S. Bloss
3. No. of Units 1 Installation (Indoor or Outdoor) I.D.
4. Driven Equipment Fan
5. Motor Horsepower 800
6. Motor RPM 1,200
7. Electrical Characteristics 4,160 Volt 3PH 60HZ
8. WR^2 of Driven Equipment ($lb-Ft^2$) 24,821
9. Type of Enclosure Open Drip-Proof
10. Class of Insulation B
11. Temperature Rise ($^{\circ}F$) 176
12. Maximum Ambient Temperature -
13. Direct Connected O/V-Belt Direct
14. How Mounted -
15. Driving thru Fluid Drive? No

Extras

16. Mounting Half Coupling X
17. Export Boxing -
18. Dual Shaft Extension -
19. Sole Plates X
20. Tropical Protection -
21. Space Heaters -
22. Pot Head -
23. Tachometer -
24. Temperature Detectors X
25. Type of Bearings Split Sleeve - Oil Ring
26. Non-Standard Service Factor Required 1.0

Notes

MOTOR DATA

1. Name Tempering Air Fan Date 1/2/78 File No. ES-241
2. Number - By J.S. Bloss
3. No. of Units 1 Installation (Indoor or Outdoor) I.D.
4. Driven Equipment Fan
5. Motor Horsepower 200
6. Motor RPM 1,200
7. Electrical Characteristics 460 Volt 3PH 60HZ
8. WR^2 of Driven Equipment (1b-Ft²) 507
9. Type of Enclosure Open Drip-Proof
10. Class of Insulation B
11. Temperature Rise (°F) 176
12. Maximum Ambient Temperature -
13. Direct Connected O/V-Belt Direct
14. How Mounted -
15. Driving thru Fluid Drive? No

Extras

16. Mounting Half Coupling X
17. Export Boxing -
18. Dual Shaft Extension -
19. Sole Plates X
20. Tropical Protection -
21. Space Heaters -
22. Pot Head -
23. Tachometer -
24. Temperature Detectors X
25. Type of Bearings Split Sleeve - Ring Oil
26. Non-Standard Service Factor Required 1.15

Notes

MOTOR DATA

1. Name I.D. Fan Date 1/5/78 File No. ES-241
2. Number - By J.S. Bloss
3. No. of Units 1 Installation (Indoor or Outdoor) I.D.
4. Driven Equipment Fan
5. Motor Horsepower 2,500
6. Motor RPM 600
7. Electrical Characteristics 4,160 Volt 3PH 60HZ
8. WR^2 of Driven Equipment (lb-Ft²) 83,549
9. Type of Enclosure Open Drip-Proof
10. Class of Insulation B
11. Temperature Rise (°F) 176
12. Maximum Ambient Temperature -
13. Direct Connected O/V-Belt Direct
14. How Mounted -
15. Driving thru Fluid Drive? No

Extras

16. Mounting Half Coupling X
17. Export Boxing -
18. Dual Shaft Extension -
19. Sole Plates X
20. Tropical Protection -
21. Space Heaters -
22. Pot Head -
23. Tachometer -
24. Temperature Detectors X
25. Type of Bearings Split Sleeve - Oil Ring
26. Non-Standard Service Factor Required 1.0

Notes

Sized For Tubular Air Heater Duty

MOTOR DATA

1. Name I.D. Fan Date 1/2/78 File No. ES-241
2. Number - By J.S. Bloss
3. No. of Units 1 Installation (Indoor or Outdoor) I.D.
4. Driven Equipment Fan
5. Motor Horsepower 3,000
6. Motor RPM 600
7. Electrical Characteristics 4,160 Volt 3PH 60HZ
8. WR^2 of Driven Equipment (1b-Ft²) 90,080
9. Type of Enclosure Open Drip-Proof
10. Class of Insulation B
11. Temperature Rise ($^{\circ}F$) 176
12. Maximum Ambient Temperature -
13. Direct Connected O/V-Belt Direct
14. How Mounted -
15. Driving thru Fluid Drive? No

Extras

16. Mounting Half Coupling X
17. Export Boxing -
18. Dual Shaft Extension -
19. Sole Plates X
20. Tropical Protection -
21. Space Heaters -
22. Pot Head -
23. Tachometer -
24. Temperature Detectors X
25. Type of Bearings Split Sleeve - Oil Ring
26. Non-Standard Service Factor Required 1.0

Notes

Sized for Regenerative Air Heater Duty

IX. B&W SYSTEM TERMINALS

A. Water Connections

1. Inlet to feedwater stopcheck at economizer inlet header.
2. Inlet to chemical feed valve on steam drum.
3. Inlet and outlet connections of all B&W furnished equipment requiring water cooling such as ash coolers.
4. Inlet to water cleaning device on regenerative air heater.
5. Inlet to spray water nozzle on spray attemperator.
6. Water level recorder valves at steam drum.
7. Feedwater regulator connections at steam drum.
8. Inlet to valve at all acid cleaning inlet connections.
9. Outlet of valve at all acid cleaning outlet connections.
10. Outlet of drain valves for water column and gage located at operating floor level.
11. Outlet of drain valves.
12. Outlet of continuous blowdown valve on steam drum.
13. Outlet of water sampling valve on economizer inlet header.

B. Fuel Connections

1. Inlet to coal crusher.
2. Inlet to limestone crusher.
3. Inlet to oil pump.

C. Steam Connections

1. Inlet of reheater piping at reheat inlet header on boiler lefthand side.
2. Inlet of steam coil air heater.
3. Inlet of sootblowers.
4. Outlet of steam coil air heater.
5. Outlet of superheater piping at boiler front wall on boiler righthand side.
6. Outlet of reheater piping at reheat outlet header on boiler front wall.
7. Outlet of each safety valve.
8. Outlet of electromatic relief valve.
9. Outlet of each vent valve.
10. Outlet of pressure gage test valve.
11. Outlet of steam sampling valve.
12. Outlet of auxiliary steam valve on steam drum.
13. Outlet of drain valve in sootblower piping.

D. Air Inlets

1. Forced draft fan.
2. Air piping at air atomized oil lighters at lighter control package.
3. Air piping manifold for air blowing sootblowers located at side of boiler at operating floor level.

E. Miscellaneous Terminal Points

1. Blank connections at wall boxes for future sootblowers.
2. Outlet flange of mechanical dust collector hoppers.
3. Outlet flange of CBB hot precipitator hoppers.
4. Thermometer well connections as required.
5. Draft connections as required.
6. Air measurement connections as required.
7. Blanked test connections for air and gas traverses.

F. Gas Outlets

1. Gas outlet at stack breeching.

G. Piping

TVA/ERDA will furnish all piping external to the boiler. As an exception to the above, B&W will furnish the following:

1. Coal piping from bunker outlet to fluidized beds.
2. All piping from FBC hot precipitator to CBB fluidized beds.
3. Water gage and column drain piping terminating at valve located at operating floor level.
4. Drum pressure gage to operating floor level.
5. Piping between air blowing sootblowers and manifold at side of boiler.
6. Drain piping for primary and secondary superheater and reheat headers to include second valve at operating floor level.
7. Seal air piping.
8. Oil piping to air heaters from lubrication sets.
9. Electromatic relief valve piping to controller.
10. Continuous blowdown piping to operating floor level.

H. Wiring

TVA will furnish all electrical wiring from power sources to the terminals located on the equipment furnished by B&W. In addition, TVA will furnish all control and interlock wiring.

As an exception to the preceding, the following wiring will be furnished by B&W.

1. Permanent thermocouples with leads to terminal box located at side of boiler.

I. Tubing

TVA will furnish all power and control tubing to connect the equipment furnished by B&W except the pressure control line for the electromatic relief valve.

J. The following equipment is included in B&W's scope of supply

1. Sootblower control panel for mounting on TVA's control panel.
2. Reheat attemperator sleeve and spray nozzle to be installed in cold reheat piping.
3. Controller for electromatic relief valve.
4. Bailey Meter Company's switches and indicators.

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X. CONTROLS AND INSTRUMENTATION

A. Conceptualized Control Philosophy and Unit Operation

The control philosophy incorporated for most of the systems for the AFB is very similar to that used in conventional coal fired units. The major new area that was addressed is the start-up, shut-down (slumping) and control of the fluidized beds.

Operation of the fluidized bed boiler is quite different from a conventional drum type unit. A large portion of the heat transfer in the AFB occurs in the fluidized beds of the FBC and CBB. The heat transfer, however, must be properly split between the boiling surface and the superheat surface. The steam flow rate and pressure are established by the amount of heat absorbed by the boiling surface while the main steam temperature is a function of the heat absorbed by the superheat surface. The superheater surface was designed to absorb more heat than is required to superheat the steam with the spray attemperators controlling the main steam temperature to its desired value (1003°F).

The primary method utilized to change load is either removing bed compartments from service (slumping) or placing them into service (fluidizing) depending on if the load is to be increased or decreased. The total number of compartments in service is a function of boiler load, also the ratio of superheat compartments to boiling surface compartments must be such that steam generation as well as superheat temperature are satisfied. This is pre-programmed into the boiler controls.

To start the unit up, a turbine by-pass valve is required to establish flow through the superheat tubes for protection of the superheat surface. A steam flow of approximately 25% is required prior to the start-up of any superheat compartments. This flow is dumped to the condenser via the turbine by-pass valve. Superheat compartments are then placed into service to superheat the steam for turbine warming, rolling and synchronization. Turbine load is then increased while the turbine by-pass valve is closing until the entire steam flow passes through the turbine. Load is then increased by placing additional compartments in service.

To remove the unit from service, the load is reduced by removing compartments from service until the steam flow is reduced to approximately 25% of full load steam flow. The turbine by-pass valve is then opened to accept the excess steam flow as load on the turbine is reduced. When the turbine is no longer taking steam flow, the superheater compartments are removed from service. After the superheat compartments have cooled, the boiling compartments are slumped and the unit bottled up.

In the event of a unit trip while any superheat bed is in service, the turbine by-pass valve will open to assure steam flow through the superheat tubes for protection.

The conceptualized control system for the AFB is attached in Sections: B, C and D. Items shown with an underlined blank are areas that require additional study or testing before a value can be assigned.

B. Analog Control System

Index

<u>Section</u>	<u>Subject</u>
1	Boiler Demand
2	Fuel Demand Master Subsystems
3	Compartment Group Control
4	Air Flow Calibration
5	Primary Air Control
6	Secondary Air Flow Control
7	Forced Draft Fan Control
8	Induced Draft Fan Control
9	FBC/CBB Draft Control
10	Superheat Temperature Control
11	Reheat Temperature Control
12	Feedwater Flow Control
13	Air Heater Control
14	Steam Turbine Bypass Control

1 Boiler Demand (Target Load)

A. Purpose

The purpose of the boiler demand subsystem is to develop the firing rate demand for combustion control, to develop a signal for Btu correction related to variations in the Btu input of the fuel, and to initiate boiler runbacks for boiler safety.

B. Firing Rate Demand Development

As the turbine valves are positioned to vary the generated megawatts, energy demand and throttle pressure will vary. At a constant throttle pressure (and temperature), megawatts are proportional to the energy delivered by the boiler to the turbine. The product of megawatts and throttle pressure error is a direct indication of the energy demanded by the turbine. This energy flow gained by the throttle pressure error, is referred to as target load since it represents the actual energy required by the unit at zero throttle pressure error. The target load (required energy output) sets the demand for fuel flow (required energy input) to the unit. The throttle pressure error is an indication of the overfiring or underfiring requirements, during load changes, which compensate for changing energy storage levels in the boiler at various load ratings.

C. Btu Correction

Under ideal conditions, the firing rate demand will accurately determine the fuel flow into the boiler. However, because of variations in the Btu content of the fuel, it is necessary to provide a correction to the actual fuel flow into the boiler. The basis for this correction is the integrated throttle pressure error at steady state conditions. This correction is applied through the Btu correction station to the feeder speed control to reduce the throttle pressure error to zero. It should be noted that under a fast rate of load change, the integral on the throttle pressure error is blocked.

Fuel Demand Master Subsystem

A. Purpose

The purpose of the fuel demand master subsystem is to develop a demand for fuel and to distribute this demand to the FBC and CBB compartments.

B. Furnace Fuel (Coal) Demand Development

In order to maintain proper distribution of heat input within the FBC, it is necessary to turndown compartments containing boiler surface at a different rate than the compartments containing superheater surface. The furnace firing rate demand is split between boiler surface compartment demand and superheater surface compartment demand. The split can be biased by the operator. In addition, to assure that proper absorption is maintained in the superheater surface, the split is modified based on superheater absorption i.e. superheater spray flow. The firing rate demands are compared to the total fuel flow into the compartments. Both error signals are scaled in "sensitivity" multipliers by the number of compartments in service. The furnace generator provides a reciprocal function so that when a large number of compartments are in service the output of the multiplier will be reduced, and when only a few compartments are in service the output of the multiplier will be increased. Proportional plus integral control action on this modified error signal then provides an output signal representative of fuel demand for each of the compartments under the influence of the control system. The output signal is low limited to a per compartment minimum.

C. CBB Fuel (Char) Demand Development

During normal operation, char is consumed in the CBB at the rate that it is produced in the FBC. That is, char inventory remains constant. The CBB firing rate demand, as modified by any change in char inventory, is compared to the total fuel flow into the CBB. This error signal is then scaled in the "sensitivity" multiplier by the number of compartments in service. The function generator provides a reciprocal function so that when a large number of compartments are in service, the output of the multiplier will be reduced, and when only a few compartments are in service, the output of the multiplier will be increased. Proportional plus integral control action on this modified error signal

FIRING RATE DEMAND
FROM BOILER DEMAND

FIRING RATE
DEMAND FROM
FUEL MASTER

CBB
FEED TANK

then provides an output signal representative of fuel demand for each of the bed sections under the influence of the control system. The output signal is low limited to a per compartment minimum.

3 Compartment Group Control

A. Purpose

The purpose of the compartment control logic is to control feeder and rotary seal speed and to generate the demand for secondary air flow.

B. FBC Compartment

The fuel demand from the fuel master through the compartment fuel master selector stations becomes the demand for compartment Btu input. This demand determines the set point for compartment bed level and secondary air. The compartment bed temperature is used as a feedforward index signal for both the Btu demand and bed level demand whenever the bed temperature exceeds its upper or lower operating limit. After being scaled by the Btu correction, the demand is proportioned, biased, and modified by a feedforward index signal to establish the limestone feeder speed demand. SO_2 , as measured leaving the unit, cannot be used as a trim on limestone flow because of the overall sluggishness of the fluid bed. This measurement rather should be used as an indication to the operator of the need to make changes in a predetermined sorbent flow ratio.

C. Feeder Speed Control

The feeder speed demand will be the output of the Btu corrected fuel demand, provided the feeder speed station is on auto and that secondary air is not cross-limiting the fuel flow through the low auctioneer. The secondary air flow crosslimit uses compartment secondary air flow plus the feeder speed correction for Btu correction.

D. Feeder Speed Totalizing

If the feeder has been in service for _____ seconds (start-up timer), the feeder speed is selected for totalizing in the fuel master subsystem. When the feeder stops, the current feeder speed is stored for _____ seconds (shutdown time). After this, or when the close primary air flow signal is received from the fuel equipment digital control system, the zero feeder speed is selected for the fuel totalizing circuit. This allows the control system to have representative values of fuel flow into the FBC during the transient shutdown conditions so as to minimize upsets in the process.

E. CBB Compartment

The fuel demand from the fuel master through the CBB fuel master selector station becomes the demand for compartment fuel. This demand determines the set point, compartment bed level and secondary air. The compartment bed temperature is used as a feed-forward index signal for both the fuel demand and bed level demand whenever the bed temperature exceeds its upper or lower operating limit.

Air Flow Calibration

A. Purpose

This subsystem works in conjunction with the individual compartment air flow controls to maintain the proper total boiler air flow for the existing combustion conditions. The air flow calibration subsystem prevents the oxygen content of the main bed or carbon burn-up bed exit flue gas from dropping below a minimum allowable value.

B. Analog Logic Description Minimum O₂ Limit

The minimum oxygen limit is determined by considering the increased efficiency gained by reducing the excess air and the possibility of incomplete combustion and boiler tube corrosion which will result from very low excess air operation.

C. Air Flow Correction

This subsystem compares the measured O₂ content to the minimum limit and raises the air flow demand to the compartments if the O₂ content ever drops below the minimum. A proportional plus integral controller operates to keep the oxygen content from dropping below the minimum limit. The output of the controller is limited so that it can only raise the air flow.

An air flow trim station is provided for manual control of excess air. The output of the controller is limited to allow only reasonable adjustments to the air flow.

The air flow correction goes to the secondary air flow demands in all active bed compartments.

FIRING RATE DEMAND
FROM BOILER DEMAND

FURNACE OR CBB
EXIT O₂ CONTENT

COMBUSTION AIR FLOW CORRECTION
TO FURNACE OR CBB
SECONDARY AIR FLOW CONTROL

PRIMARY AIR
DUCT PRESSURE

PRIMARY AIR
FAN
DAMPER CONTROL

PRIMARY AIR
FAN
DISCHARGE DAMPER

5 Primary Air Control

A. Primary and Tempering Air Fan Control

The maximum fuel demand provides the set point for air duct pressure. An operator adjusted bias is also provided. The error signal is brought directly to a proportional plus integral controller which, through the primary air fan selector station, positions the inlet damper to provide the proper air duct pressure. A bias may be applied to the individual fans if necessary. An interlock downstream of the station allows closing the dampers regardless of station mode of operation.

B. Primary Air Flow Control

The air flow is compared to the set point demand, and the error signal is modified by a proportional plus integral control which, through the primary air flow control station, provides positioning of the primary air control damper. When a compartment is not in service, as indicated by the logic developed in the fuel equipment digital control system, the primary air flow will be reduced to zero through the transfer below the control station.

C. Primary Air Temperature Control

The temperature of the air is measured at the outlet of the mixing bustle. This temperature is compared to an operator adjustable fuel-air temperature set point and the resultant error signal is brought to a proportional plus integral controller which, through the air temperature selector station, controls the hot air damper and tempering air damper. These two dampers are controlled in a reciprocal fashion so that when one opens, the other closes, thereby controlling the outlet temperature.

TEMPERING AIR
DUCT PRESSURE

TEMPERING AIR
FAN
DAMPER CONTROL

TEMPERING AIR
FAN
DISCHARGE DAMPER

PRIMARY
AIR FLOW

PRIMARY AIR
CONTROL DAMPER

MIXING BUSTLE
OUTLET TEMPERATURE

PRIMARY AIR TEMPERATURE
CONTROL DAMPERS

6 Secondary Air Flow Control

A. Purpose

This logic regulates total compartment air flow for all operating conditions by modulating the secondary air flow control damper.

B. Secondary Air Flow Description

The secondary air flow control subsystem programs total secondary air flow using the combustion air flow demand plus the excess air demand (operator adjustable bias). The excess air demand is trimmed by a correction from the air flow and the compartment secondary air dampers are positioned through proportional plus integral control action. During purge or light-off, the fuel equipment digital control system will demand light-off flow through a transfer module. When the compartment is shutdown, a minimum air flow will be maintained through the compartment for cooling purposes. The secondary air flow is measured by use of an airfoil at the entrance of the compartment. This measurement is temperature corrected to compensate for changes in the secondary air density.

COMPARTMENT SEC
AIR FLOW DEMAND
FROM COMPARTMENT GROUP CONTROL

COMPARTMENT SEC
AIR FLOW

COMBUSTION AIR FLOW CORRECTION
FROM AIR FLOW CALIBRATION

COOLING
AIR
FLOW

A

T

A

LIGHTOFF
AIR
FLOW

A

>

<

A

Δ

T

+

5%

X G

A 0%

KIS

A T

T

PURGE
INTERLOCK

f(x)

COMPARTMENT
SECONDARY AIR
CONTROL DAMPER

Forced Draft Fan Control

A. General Description

The forced draft (FD) fan provides the total air required by the boiler. The FD fan inlet damper is modulated to maintain a programmed secondary air duct pressure. This control logic also incorporates safety features to protect the boiler and fan during both manual and automatic startup operation.

B. FD Fan Inlet Damper Control

The FD fan inlet damper is modulated to control the secondary air duct pressure. By varying the secondary air duct pressure, it is possible to reduce the modulation required by the secondary air dampers on each fluidized bed section. Ideally, the secondary air dampers will remain fixed for all loads. A program based on firing rate demand is used to develop the set point for the secondary air duct pressure. This program can be biased by the operator to effect a program change without requiring recalibration of the associated function generator. This set point will respond instantly to load increase, while responding slowly to load decreases. This assures that the air flow will increase faster than fuel on load increases and will decrease at the same rate as fuel on load reductions.

Secondary air duct pressure is compared to the developed set point. Control action applied to any deviation develops the base control signal for FD fan inlet damper position.

C. FD Fan Inlet Damper Control Stations

The FD fan inlet damper control station permits the operator to select either auto or manual control of the inlet damper.

D. FD Fan Inlet Damper Interlocks and Discharge Damper Controls

The FD fan inlet and discharge digital logic interlocks the inlet damper and positions the discharge damper to maintain safe operation of the unit.

8 Induced Draft Fan Control

A. General Description

The induced draft (ID) fan provides the exhausting force for gas flow through the boiler. When the FD fan and ID fan are properly balanced, the FBC and CBB pressure will be at the proper value. The ID fan's function is to control the ID fan inlet plenum pressure. A feedforward from firing rate demand allows rapid response to load changes. Provisions to protect the FBC and CBB from exceeding low pressure limits are included.

B. Draft Control

Pressure is measured by pressure transmitters. The operator selects a draft set point. Since the draft control is inherently a low gain high integral control, a nonlinear function generator is added between the error and the proportional plus integral controller. This configuration provides a control stability by using a high gain proportional correction on large pressure errors but low gain control when near set point.

C. Feedforward Program

Under normal conditions, the firing rate demand will provide the feedforward signal for the ID fan. This feedforward signal is corrected by the draft control (described above) to maintain the FBC and CBB pressure at set point. The feedforward signal is low limited to a value which will keep the ID fan dampers open the required amount to exhaust the no-load boiler air flow.

D. ID Fan Gas Flow Control

The pressure drop between the unit and the ID inlet plenum can be used as an indication of the gas flow rate through the ID fan. Since the FBC and CBB pressure is always close to atmospheric, the ID fan inlet pressure is a direct indication of gas flow rate. Therefore, the ID inlet plenum pressure signal is converted to flow rate by a function generator.

The actual gas flow signal is compared to the demand for gas flow. Any error has proportional plus integral action applied to develop the ID fan inlet damper position control signal.

E. ID Fan Damper Control

The developed inlet damper control signal is sent to the inlet damper of the ID fan. A hand-auto station allows the operator to select the developed inlet damper control signal or manually control the inlet damper of the fan. The output of the inlet damper selector station can be overridden by interlocks which ensure safe operation during fan start-ups and shutdowns and, finally, interlocks which maintain furnace protection.

F. Furnace Implosion Protection

If FBC or CBB pressure drops below a nominal set point, a special control circuit downstream of the selector stations will be activated. This circuit will override the normal control signal and close the ID fan dampers (as required) to keep the pressure from dropping below set point. This circuit is implemented in such a way that no failure of the pressure transmitters or control circuitry will cause the ID fan dampers to open beyond their desired position.

This control system recognizes when a main fuel trip has occurred and takes action to reduce the resulting negative pressure excursion. When a main fuel trip occurs, a large negative bias, based on load, is added to the control signal to the ID fan inlet dampers. This immediately starts the dampers running closed. This "kicker" signal decays to 0% in a short time.

G. ID Fan Inlet and Discharge Damper Interlocks

The ID fan dampers are interlocked to ensure safe unit operation during fan start-ups and shutdowns.

9 FBC/CBB Draft Control

A. Purpose

 This logic regulates FBC and CBB pressure by modulating the economizer and CBB outlet dampers.

B. Draft Control Description

 The draft control system maintains FBC and CBB operating pressure through the modulation of outlet dampers. Pressure is compared to a set point. Control action applied to any deviation develops the base control signal. Firing rate demand is used as a feedforward signal for damper position.

10 Superheat Temperature Control

A. Single Stage Attenuation

The superheat temperature control system provides control over the normal temperature range of the boiler. It is designed for use with a single stage attenuator and a full mix (or single) secondary superheater. The system recognizes the need for extra spray when overfiring on load increase and spray reduction on load decreases. All integral controllers are provided with a means to prevent "windup" when the steam temperature is out of control range.

B. Set Point Generation

The set point is manually adjusted by the operator. However, the throttle pressure error, as an indication of over and underfiring, temporarily biases the set point to more rapidly increase or decrease the spray on load changes.

C. Secondary Superheater Inlet Temperature Program

The secondary inlet temperature set point is programmed from load. As the program will vary from changing boiler conditions, the set point is trimmed from final steam temperature error through a proportional plus integral control. The proportional and integral controllers are separated to permit the high gain and low integral rates required for final steam temperature control.

D. Secondary Superheater Inlet Control

The secondary inlet temperature is compared to the set point generated above and, through a proportional plus integral controller, sets the spray valve demand. This signal is limited to 0% to prevent the integral from winding down below zero when the boiler is below temperature rating.

E. Indexing System (Anti-Integral Wind-up)

Whenever the sprays are on manual or the boiler is in the load range below where temperature is made, the main steam temperature integral is forced to make the set point error equal (within 1%) to zero. This prevents the integral from winding up to either extreme.

10 Superheat Temperature Control

F. Block Valves Control

These valves are opened wide when the control valves are opened greater than zero. They are closed whenever the control valve is closed. Whenever the boiler or turbine is tripped, both the control and block valves are closed. They may also be closed manually. Once the block valves have been closed by a boiler, turbine or manual trip, they must be reset by the operator before they will open in response to the automatic control.

11 Reheat Temperature Control

Reheat steam temperature is basically controlled by biasing the gas flow in the parallel back end of the unit. The system also provides for spray attemperation to control temporary temperature excursions.

A. Spray Control

The spray control is normally not required. Whenever the damper control is not limited, the set point for the spray is biased +10°F. Thus, the spray acts as a safety override coming into service when reheat temperature reaches 10°F above set point. As the damper control is limited, the bias is removed and spray will control to set point.

B. Reheat Spray Block Valves

The reheat spray block valves open whenever the spray control valve is not required closed, and close when the control valve is required closed. On a boiler or turbine trip or operator initiated spray trip, both control and block valves are closed. The valves will not respond to automatic control after a trip until the operator has energized the reset pushbutton.

FIRING DEMAND
RATE FROM
BOILER DEMAND

REHEAT OUTLET
TEMPERATURE

12 Feedwater Flow Control

A. Purpose

An adequate feedwater flow is required at all loads to replace the water which has been converted to steam and sent to the turbine. The feedwater flow control subloop uses a cascaded feedforward type of control to regulate the feedwater pumps. Drum level set point is selected by the operator. Shrink and swell effects are minimized by using a feedforward load index based on steam flow.

B. Feedwater Flow Demand Development

Steam flow is used as the feedforward signal to generate the basic demand for feedwater flow. This feedforward signal is modified by proportional action applied to drum level error. The operator selects the drum level set point which is compared to the actual drum level. Any error, such as errors due to the blowdown, meter error, etc., is used to correct the feedforward program. Since the basic demand for feedforward is developed based on load, shrink and swell have only minimal effect on the control system.

C. Feedwater Flow Control

The feedwater flow from each feedwater pump is measured by a differential pressure transmitter. The ΔP is converted, through square root action, to a flow signal. The feedwater flow signal is also temperature compensated.

The demand for feedwater flow is compared to the actual temperature compensated feedwater flow. Any error is operated on by a proportional plus integral controller through a control station to correct the feedwater pump speed.

13 Air Heater Controls

A. Purpose

During low load operation and/or low ambient temperatures, there exists the possibility that the metal temperatures in the heater will be below the dewpoint of the flue gas. This condition could result in condensation forming on the surfaces of the heater which leads to rapid corrosion and plugging. To prevent this condition from occurring, the air entering the air heater is heated. The corrective action will increase the temperature of the surfaces of the heater.

B. Air Heater Fluid Flow Control

The temperature of the air entering the air heater and the temperature of the flue gas leaving the air heater are averaged to provide average air heater metal temperature. The average metal temperature is compared to an operator adjustable set point to provide the average metal temperature error. This error has proportional plus integral action applied to develop the fluid flow control valve position demand. Limits on the integral prevent the signal from exceeding either 0% or 100%. A hand/auto control station is provided to permit direct operator control of the fluid valve.

14 Steam Turbine Bypass Control System

A. Purpose

 The purpose of the steam turbine bypass control system is to dump superheater outlet steam to the condenser.

B. Description

 During start-up of the unit, superheater steam will be diverted to the condenser until steam temperature is achieved. During normal shutdown, steam flow is maintained through the unit by diverting steam to the condenser. Following unit or appropriate equipment trips, the control system will demand the bypass valve to open through a transfer module.

C. Fuel Equipment Digital Controls

Index

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2	Operating Modes
3	Operator Interface
4	Unit Purge and Monitor
5	Start-Stop Sequences
6	Oil Lighter Control
7	Primary Air Flow Control
8	Secondary Air Flow Control
9	Feeder Control
10	Flame Monitoring
11	Interface With Analog Control System

1. General Requirements

The fuel equipment digital control system shall incorporate a continuous purge of the unit to insure that the boiler is free of any accumulation of combustibles for light-off, and that the boiler will remain so during operation. The fuel equipment digital control system shall also supervise the operation of the fuel-air equipment associated with each compartment. It shall accept operator commands and, if the required permissives are met, perform the required operation. Equipment shall be continuously monitored and any deviation shall be alarmed while the system either corrects the deviation or shuts down equipment as necessary to avoid hazardous conditions or equipment damage.

The system shall monitor the operation of the fuel equipment and, if the equipment fails to respond to commands from the fuel equipment digital control system, the equipment tripped status shall be set. Indications shall be provided to allow the operator to determine the equipment level which initiated a trip of fuel equipment. Tripped equipment shall be successfully shutdown before reset of the trip is permitted. The status of the fuel-air equipment shall be displayed to the operator at all times.

The fuel equipment digital control system shall interface with a master fuel trip system. It also shall interface with the analog fuel control system to position and monitor devices for start-up and shutdown which are normally modulated during on-line operation. The fuel equipment digital control system shall be designed to operate reliably and to minimize the number of false trips which occur in order to establish operator confidence in this system, such that the system will be maintained in service and available to respond if hazardous conditions develop.

The term compartment group, as used in this guide specification, refers to the coal feeder, limestone feeder, rotary seals and primary and secondary air systems associated with an individual bed section.

2. Operating Modes

In the manual sequence control mode, the operator has the responsibility for initiating each step in the start and stop sequences at the proper time and for positioning the modulating devices controlled by the analog fuel and air control system. This system shall monitor the operator's progress and inhibit him from departing from the proper operating sequences. The manual control mode does not include sequence timing functions other than for lighter and boiler purge functions. The manual mode of control includes the basic supervisory interlocks, trips and monitoring functions including proper positioning of functions controlled by the analog system.

In the automatic sequence control mode, the fuel equipment digital control system shall automatically place the compartment group in service, or remove it from service on operator initiation to start or stop that compartment group. In the automatic mode, start/stop sequences, including timing between the steps, are superimposed over the manual mode. As such, all of the interlocking and tripping functions that are part of the manual mode shall be an integral part of the automatic mode.

3. Operator Interface

To provide for operator interaction with the fuel equipment digital control system, inserts for boiler purge control and feeder group control (one for each compartment group) which are suitable for mounting on the plant's main control board from which system operations can be monitored and directed, shall be provided.

Means shall be provided for the operator to initiate a compartment group emergency trip which will shutdown all compartment group equipment.

4. Unit Purge and Monitor

The unit purge control shall incorporate a continuous purge of the FBC and CBB to insure that the boiler is free of any accumulation of combustibles for light-off and that the boiler will remain so during operation.

Prior to light-off, the air and gas passages of the unit shall be purged of any combustibles that may have accumulated. This purging shall be accomplished by maintaining a minimum of 30% air flow through all compartments with all sources of fuel to the unit shut-off for at least _____ minutes. Purge permissives shall include:

- a. All rotary seals stopped.
- b. All feeders stopped.
- c. All primary air control dampers closed.
- d. All lighter oil valves closed.
- e. Lighter oil header trip valve closed.
- f. Air heater running. (Regenerative only).
- g. FD and ID fans running.
- h. No primary or tempering air fan running.
- i. Purge air flow established through all compartments.
- j. FBC and CBB air flow greater than 30%.

Accumulation of purge credit shall start automatically when the purge permissives are established. Once the purge is complete, a continuous purge with greater than 30% boiler air flow must be maintained. The boiler shall not be tripped on low air flow, but the start of any additional fuel equipment shall be blocked until air flow has been restored for at least _____ minutes. A continuous purge of one minute with greater than 30% air flow shall occur after the start or trip of any feeder, or rotary seal, or the occurrence of a compartment group emergency trip, before any additional fuel equipment may be started.

Completion of the FBC and CBB purge shall allow reset of the master fuel trip. A purge shall be required on a master fuel trip, FD fan not operating, or when all lighters and compartment groups are stopped or tripped after main fuel firing has been initiated. Purge required shall trip the master fuel trip, the lighter oil header trip valve and all fuel equipment in the compartment groups.

The unit monitor shall prevent starting any fuel equipment if the firing permissives are not met. The firing permissives shall include:

- a. Master fuel trip not present.
- b. Continuous purge requirements met.
- c. All compartment group equipment trips reset.
- d. Lighter oil header valve open.
- e. Lighter oil header pressure above minimum.

The purge control insert shall provide indications to the operator of the status of the purge and firing permissives and the progress of the purge. These shall include:

- a. Purge required.
- b. Purge in progress.
- c. Purge complete.
- d. Status of each individual purge permissive.
- e. Status of each individual firing permissive.

A first-out annunciator shall be included to indicate to the operator the initiating cause of a unit trip. Points in the first-out display shall include:

- a. Master fuel trip.
- b. Turbine trip.
- c. FD fan trip.
- d. ID fan trip.
- e. FBC pressure high trip.
- f. FBC pressure low trip.
- g. CBB pressure high trip.
- h. CBB pressure low trip.
- i. PA fan trip.
- j. Tempering fan trip.
- k. All fuel off trip.
- l. Drum level trip.
- m. Secondary air duct pressure high.
- n. Primary air duct pressure high.
- o. Tempering air duct pressure high.

5. Start-Stop Sequences

The fuel equipment digital control system shall start and stop the compartment group following fixed sequences. The system shall be capable of transferring between the start-up and shutdown sequences at any time.

The recommended start-up sequence for compartments with lighters is:

- a. Establish compartment secondary air flow at light-off through the manipulation of the analog air flow control subloop.
- b. Start lighters.
- c. Hold for bed temperature to reach light-off value (minimum 1000°F).
- d. Start primary air flow.
- e. Hold to allow primary air flow to stabilize (approximately _____ seconds).
- f. Start rotary seals.
- g. Start feeders.
- h. Release mixing bustle outlet fuel-air temperature control to automatic.
- i. Hold for initial stabilization period (approximately _____ minutes).
- j. Release compartment secondary air flow control to automatic.
- k. Release compartment group demand to automatic control.
- l. Hold for final stabilization period (approximately _____ minutes).
- m. Stop lighters after stable combustion has been established (approximately _____ minutes).

The recommended start-up sequence for main bed compartments without lighters is:

- a. Establish compartment secondary air flow at light-off through the manipulation of the analog air flow control subloop.
- b. Hold for bed temperature to reach light-off value (minimum 1000°F).
- c. Start primary air flow.
- d. Hold to allow primary air flow to stabilize (approximately _____ seconds).
- e. Start rotary seals.
- f. Start feeders.
- g. Release mixing bustle outlet fuel-air temperature control to automatic.
- h. Hold for stabilization period (approximately _____ minutes).
- i. Release compartment secondary air flow control to automatic.
- j. Release compartment group demand to automatic control.

The recommended start-up sequence for CBB compartments is:

- a. Establish compartment secondary air flow at light-off through the manipulation of the analog air flow control subloop.
- b. Start lighters.
- c. Hold for bed temperature to reach light-off value (minimum 1000°F).
- d. Start primary air flow.
- e. Hold to allow primary air flow to stabilize (approximately _____ seconds).
- f. Start rotary seals.
- g. Start feeders.
- h. Release mixing bustle outlet fuel-air temperature control to automatic.
- i. Hold for initial stabilization period (approximately _____ minutes).
- j. Release compartment secondary air flow control to automatic.
- k. Hold for final stabilization period (approximately _____ minutes).
- l. Stop lighters after stable combustion has been established (approximately _____ minutes).
- m. Release compartment group demand to manual.
- n. Reduce coal-limestone demand to minimum.
- o. Close hot air damper and open cold air damper to reduce primary air temperature to minimum.
- p. Hold for mixing bustle cooling (approximately _____ minutes).
- q. Stop feeders.
- r. Stop rotary seals.
- s. Establish compartment air flow at light-off.
- t. Stop coal-limestone primary air flow.
- u. Start char primary air flow.
- v. Hold to allow primary air flow to stabilize (approximately _____ seconds).
- w. Start rotary seals.
- x. Release char mixing bustle outlet fuel-air temperature control to automatic.
- y. Hold for initial stabilization period (approximately _____ minutes).
- z. Release compartment secondary air flow control to automatic.
- aa. Release fuel demand to automatic control.

The recommended shutdown sequence for all compartments is:

- a. Reduce fuel demand to minimum.
- b. Close hot air damper and open cold air damper to reduce primary air temperature to minimum.
- c. Stop fuel flow.
- d. Stop rotary seals.
- e. Establish compartment secondary air flow at light-off.
- f. Stop primary air flow.
- g. Hold for compartment burn out (approximately 15 minutes).
- h. Release compartment secondary air flow to cooling value.

Start-up and shutdown sequence indications shall be provided to allow the operator to follow the progress of compartment start-up or shutdown sequences when in the automatic sequence mode and to guide the operator through the sequences in the manual sequence mode. These indications shall show the next step to be performed as well as the progress through the sequence.

6. Oil Lighter Control

Each lighter equipped compartment has either one secondary air duct lighter or one secondary air duct lighter and one bed lighter. Each lighter or lighter set will be controlled by a separate electro-pneumatic lighter control package. All of the lighters associated with a compartment shall be started or stopped at the same time. Each lighter or lighter set shall be independently monitored and tripped.

The fuel equipment digital control system shall provide a start lighter command upon which the electro-pneumatic control package will:

- a. Insert lighter (s) (as required).
- b. Insert high energy spark (s).
- c. Admit atomizing medium to the lighter (s).
- d. Purge condensate from atomizing line (s) (steam atomized lighters only) for approximately 30 seconds.
- e. Energize the high energy spark (s).
- f. Open oil valve.
- g. After a delay de-energize and retract the high energy spark (s).

The fuel equipment digital control system shall provide a stop/clean lighter command upon which the electro-pneumatic control package will:

- a. Insert and energize high energy spark (s).
- b. Close oil valve (s).
- c. Open purge valve.
- d. Clean lighter (s) for approximately one minute.
- e. Close purge valve.
- f. Close atomizing medium valve.
- g. De-energize and retract high energy spark (s).
- h. Retract lighter (s) (as required).

The fuel equipment digital control system shall provide an emergency stop lighter command when a Master Fuel Trip or an operator initiated compartment group emergency trip occurs, upon which the electro-pneumatic control package will:

- a. Close oil valve (s).
- b. Close purge valve.
- c. Close atomizing medium valve.
- d. De-energize high energy spark (s).
- e. Retract high energy spark (s).
- f. Retract lighter (s) (as required).

The following outputs from the electropneumatic control package are available for use by the fuel equipment digital control system:

- a. Lighter (s) inserted.
- b. Purge pressure to atomizer (s) greater than minimum (purge valve open).
- c. Oil pressure to atomizer (s) greater than minimum (oil valve (s) open).

A lighter group shall be tripped if:

- a. Boiler tripped.
- b. Compartment group emergency trip initiated by operator.
- c. Lighter fails to start when commanded.
- d. Lighter oil valve not open after trial for ignition.
- e. Lighter flame not detected after trial for ignition.

Maintained lighter selection on a compartment group basis shall be provided for any system which includes automatic sequence control. This capability shall allow the operator to start or stop the lighter (s) any time firing is permitted in the boiler, provided the automatic sequence does not require the lighter (s) in service at that time. If the lighter is in service, selection of maintained lighter (s) shall prevent shutdown of the lighter (s) by the automatic sequence control.

Indications shall be provided to the operator on the status of the lighter (s). These shall include:

- a. Lighter (s) ready to start.
- b. Lighter (s) maintained.
- c. Lighter group successfully lit.
- d. Lighter group successfully shutdown.
- e. Lighter group tripped.
- f. Lighter group cleaning.
- g. Lighter group trouble due to unsuccessful shutdown or shutdown without cleaning.

7. Primary Air Flow Control

With a common primary air fan, the fuel equipment digital control system shall provide commands to open or close the compartment group primary air flow control damper. This damper is normally controlled by the analog control system.

Permissives to start the primary air flow on a compartment group shall include the following:

- a. Boiler firing permissives met.
- b. Primary air fan running.
- c. Tempering air fan running.
- d. Cold air damper open and hot air damper closed.
- e. Bed temperature above light-off value (minimum 1000°F).

The primary air flow shall be tripped if the boiler is tripped, primary air flow is less than _____%, or the compartment group is tripped.

The hot and cold primary air control dampers are normally controlled by the analog control system to maintain mixing bustle outlet fuel-air temperature. The fuel equipment digital control system shall provide commands to open and close the hot and cold air damper. The hot air damper shall be closed and the cold air damper opened whenever the rotary seals are not operating.

Indications provided to the operator on the status of the primary air flow control shall include:

- a. Primary air flow started.
- b. Primary air flow stopped.
- c. Primary air flow tripped.
- d. Primary air flow low.
- e. Hot air damper closed and cold air damper open.
- f. Mixing bustle temperature control released to automatic.

8. Secondary Air Flow Control

Secondary air flow control shall normally be the responsibility of the analog control system. The fuel equipment digital control system shall provide outputs to the analog control system to establish the air flows required for boiler purge and compartment start-up and shutdown. During operation at lower loads, the digital control system shall avoid calling for individual compartment air flows which could reduce total boiler air flow below its minimum value. On a master fuel trip, the digital control system shall avoid any conflict with the normal analog control of secondary air flow.

Indications provided to the operator on the status of the secondary air flow control shall include:

- a. Secondary air flow control released to automatic.
- b. Secondary air flow at light-off.
- c. Secondary air flow released to cooling.

9. Feeder Control

The feeder may be started if the feeder inlet gate is open, the coal and limestone rotary seal is running, the ash cooler and the rotary seal of the bed material level control system are running, firing permissives are met, coal or limestone is detected at the feeder inlet and the feeder outlet is not plugged. The feeder shall be stopped if the boiler is tripped or either rotary seal is stopped. The feeder shall be

tripped if the feeder outlet is plugged, primary air flow is below minimum for 20 seconds or no coal or limestone is detected at the feeder inlet or on the feeder belt for 20 seconds.

Indications provided to the operator on the status of the feeder control shall include:

- a. Feeder running.
- b. Feeder stopped.
- c. Feeder tripped.
- d. Feeder inlet gate closed.
- e. No coal or limestone detected at feeder inlet.

10. Flame Monitoring

The fuel equipment digital control system minimizes the possibility of developing hazardous conditions by shutting down lighter equipment on loss of ignition. It shall also minimize the number of false trips which occur.

Indications of the status of each flame detector shall be provided to the operator.

11. Interface with Analog Control System

The digital control system shall interface with the analog control system to position devices for start-up and shutdown which are normally modulated during on-line operation. This interface shall be designed such that the loss of power in one system does not interfere with the proper operation of the other system.

Signals from the digital control system to the analog control system shall include, but are not limited to:

- a. Close primary air control damper.
- b. Allow secondary air flow to cooling value.
- c. Set secondary air flow to light-off value.
- d. Close hot air damper and open cold air damper.
- e. Set compartment fuel demand to light-off value.

Signals from the analog control system to the digital control system shall include:

- a. FBC and CBB air flow greater than ____%.
- b. PA fan running.
- c. Tempering air fan running.
- d. Unit load greater than 35%.
- e. Unit load less than 30%.
- f. Unit load greater than 60%.
- g. Compartment fuel demand at light-off.
- h. Primary air control damper closed.
- i. Secondary air flow at light-off.
- j. Secondary air flow at cooling.

D. Guide Specifications
Metering and Control Equipment
Control Systems
Recommended Interlocks

INDEX

<u>Section</u>	<u>Subject</u>
1	Total Unit Trip
2	Fan Trips
3	Turbine Low Load
4	Initial Pressure Regulator, Throttle Pressure Regulator or Throttle Pressure Limit (IPR,TPR, or TPL)
5	Recommended Boiler Interlocks and Alarms

All of the following alarm and interlocks are to be considered as recommended.

Notations have been specified to indicate types of interlock or alarm operation with the following term definition.

I. Interlocks

Automatic	Interlock designed to operate automatically without operator intervention to take the required action for safe operation.
Recommended	Operation of this action is required for safe operation but the action may be initiated by the operator or it may be automated if the customer desires.
Optional	May be placed under direct supervision and manual control of the operator.

II. Alarms

Required	Alarm is required for safe operation of the boiler.
Recommended	Alarm is recommended but not required.

Whenever a fault develops on a system, or the safety of the equipment is in jeopardy due to a malfunction, a trip will be initiated to protect that equipment. Depending upon the magnitude of the problem and the equipment involved, the following trip sequence will occur:

1. Total Unit Trip will initiate;

A. Boiler Trip (All actions to occur simultaneously)

1. Master Fuel Trip

- a. Trip primary and tempering air fans, feeders, rotary seals
- b. Close lighter fuel supply shut-off valves
- c. After master fuel trip, open register post purge of boiler and purge required before reset of master fuel trip

2. Close reheater, attemperator water spray control and block valves
3. Close superheater attemperator wash spray control and block valves
4. Slowly decrease air flow to minimum purge air flow (forced draft fan may be shutdown manually by operator following a post-purge)
5. Maintain ID fan on automatic to control furnace draft (ID fan may be shutdown manually by operator following a post-purge)
6. Trip automatic sootblowers
7. Open steam turbine by-pass valve

B. Turbine Trip

Turbine Relay

Boiler will normally trip through action of interlocks on turbine throttle and reheat stop valves. Close all attemperator block valves. Open steam turbine by-pass valve.

C. Generator Circuit Breaker Trip (Loss of all load)

1. Trip Generator Breakers
2. Trip Turbine
3. Trip Boiler

2. Fan Trips

A. FD Fan (Loss of FD Fan)

1. Initiate Master Fuel Trip
2. ID fan shutdown manually or continue to operate

B. ID Fan (Loss of ID Fan)

1. Initiate Master Fuel Trip
2. Trip FD fan

3. Turbine Low Load Switch

Refer to Turbine Manufacturer for recommendation

4. Initial Pressure Regulator, Throttle Pressure Regulator or Throttle Pressure Limit (IPR, TPR, or TPL)

Refer to Turbine Manufacturer for recommendation

5. Recommended Boiler Interlocks and Alarms

A. Steam Cycle

1. Operator Action- Manual Switch	
a. TRIP Boiler	Required
2. Turbine Trip - Originated by Turbine	
a. TRIP Boiler (See 1-a)	Automatic
3. Generator Breaker Trip - Loss of All Load	
a. TRIP Turbine (See 1-b)	Automatic
b. TRIP Boiler (See 1-a)	Automatic
4. Loss of Control Power	
a. ALARM loss of power to analog controls	Required

b.	TRIP boiler on loss of analog control system logic power after 0-5 second time delay	Automatic
c.	ALARM loss of power to all control drives and valves	Required
d.	TRIP boiler on loss of power to all control drives and valves after 0-5 second time delay	Optional
e.	ALARM loss of power to fuel equipment digital control system.	Required
f.	TRIP boiler on loss of burner control system logic power after 0-5 second time delay	Automatic
5. Reheat Water Spray Control and Block Valves		
a.	ALARM the condition where the block and control valves are demanded closed and the by-pass valve is not closed. (Applicable when a by-pass valve around the control valve is provided).	Required
b.	CLOSE control and block valves whenever unit load is less than 25 % or the demand for control valve position is requiring the control valve closed.	Recommended
c.	TRIP control and block valves closed on a Master Fuel Trip or a Turbine Trip. Prevent reset of control and block valve trip until Master Fuel Trip and Turbine Trip are reset, the demand for control valve position is zero, unit load is greater than 25%, and reset is initiated by the operator.	Automatic

6. Superheater Water Spray Control
and Block Valves

a.	ALARM the condition where the by-pass valve is not closed under a Master Fuel Trip condition. (Applicable when a by-pass valve around the control valve is provided).	Required
b.	TRIP control and block valves closed on a Master Fuel Trip. Prevent reset of control and block valve trip until Master Fuel Trip is reset, the demand for control valve position is zero, and block valve reset is initiated by the operator.	Automatic

7. Steam Turbine By-Pass Valve

a.	OPEN by-pass valve on a Master Fuel Trip or a Turbine Trip. Prevent closing of by-pass valve until Master Fuel Trip and Turbine Trip are reset.	Automatic

B. Internal, Water & Steam

1. Secondary Superheater Outlet Temperature

a.	ALARM high steam temperature	Required
b.	BOILER TRIP - high steam	Optional
c.	ALARM low steam temperature	Recommended
d.	TURBINE TRIP - low steam temperature	Turb. Manuf.

2. Steam Pressure - at turbine stop valves

a.	ALARM low steam pressure (load cutback by turbine initial or throttle pressure regulator).	Turb. Manuf.

3. Reheater Outlet Temperature
 - a. ALARM high steam temperature Required
4. Circulating Water Pumps
 - a. ALARM - circulating pump manifold differential pressure switch imbalance Required
 - b. ALARM - 2 pumps in service and pump manifold differential pressure _____ psi. Required
 - c. ALARM - less than 2 pumps in service or pump manifold differential pressure less than _____ psi. Required
 - d. ALARM - less than 2 pumps in service and throttle pressure less than _____ psi. Required
 - e. ALARM - motor cavity temperature greater than _____ °F Required
 - f. ALARM - cooling water flow less than _____ gpm. Required
 - g. TRIP boiler - no pumps in service Automatic
 - h. TRIP boiler - less than 2 pumps in service and throttle pressure greater than _____ psi (this condition must exist for _____ minutes). Automatic
 - i. TRIP pump - motor cavity temperature greater than _____ °F. Automatic
 - j. TRIP pump - motor amps greater than _____ amps (motor overload). Automatic

C. Boiler Feedwater

1. DRUM WATER LEVEL - Water level recorder or manometric water level with taps located 15 inches above and below normal water level (NWL).
 - a. LOW WATER LEVEL-ALARM when water level is 4 inch below NWL. Required
 - b. BOILER TRIP when water level drops 7 inch below NWL Automatic (after 20 sec. time delay)
 - c. HIGH WATER LEVEL-ALARM when water level is 4 inch above NWL Required
 - d. BOILER TRIP when high water level is 7 inch above NWL Optional
 - e. TURBINE TRIP when high water level exceeds the point at which the cyclones may be flooded (High Boiler Trip) and result in carryover. Optional
 - f. BOILER FEEDPUMP TRIP - when water level exceeds the level at which the cyclones may be flooded (High Boiler Trip) and result in carryover after the fuel and turbine have been tripped. Optional
2. Economizer Recirculation Valve - (Automatic Operation) - the feedwater flow started should be developed by the feed pumps started and the feedwater flow path to the boiler open (i.e., feedwater shut-off valves open and feedwater control valves not closed).
 - a. CLOSE - economizer recirculation valves when feedwater is flowing to the boiler or when firing is stopped. Automatic

b.	OPEN - economizer recirculation valves when feedwater flow to the boiler is stopped and firing is in progress.	Automatic
c.	ALARM - economizer recirculation valves malfunction if action in a. or b. above fails to take place.	Recommended

D. Boiler Air and Gas

1. Interlocks required for start of Induced Draft (ID) Fan:		
a.	Shut-off dampers and control dampers closed.	Automatic
b.	Shut-off and control dampers open on FD fan.	Recommended
c.	At least one of each kind of shut-off damper (air heater, etc.) between the FD fan inlet and the stack open.	Recommended
d.	For the hot precipitators, at least one set of shut-off dampers open on a per module basis.	Recommended
e.	Open shut-off damper on operating ID fan after FD fan has been started.	Automatic
(Simultaneous with 2d.)
2. Interlocks required for start of forced-draft (FD) fan:		
a.	Shut-off dampers and control dampers closed.	Automatic
b.	ID fan running with its shut-off damper closed and its control damper on automatic or not closed.	Automatic
c.	At least one of each kind of shut-off damper (air heater, etc.) between the FD fan inlet and the stack open.	Recommended

d.	Open shut-off dampers on FD fan when ID fan is started with its shutoff damper open and its control damper on automatic, or not closed.	Automatic
(Refer 1e) |
|----|---|-------------------------|
3. High Boiler Pressure
a.	ALARM if FBC or CBB pressure exceeds +2 in. H ₂ O (for nominal operating range of +0.5 to -1.0 in. H ₂ O)	Required
b.	TRIP master fuel trip if FBC or CBB pressure exceeds continuous design pressure or exceeds by more than 5 in. H ₂ O the normal operating pressure whichever is less, for 2 seconds.	Automatic
c.	Before main fuel firing and following a five minute period after a master fuel trip (FBC post purge), trip FD fan if the FBC or CBB pressure exceeds continuous design pressure or exceeds by more than 5 in. H ₂ O the normal operating pressure, whichever is less, for 2 seconds.	Automatic
d.	TRIP FD fan and master fuel trip if FBC or CBB pressure exceeds continuous design pressure by more than 3 in. H ₂ O for 5 seconds.	Automatic
4. High Secondary, Primary or Tempering Air Duct Pressure. Applicable when maximum fan static discharge pressure capability exceeds the duct design pressure plus 20% or the specified transient design pressure, whichever is greater.
a.	ALARM if duct pressure exceeds a value midway between maximum operating pressure and design pressure.	Required

b.	TRIP master fuel trip if duct pressure exceeds continuous design pressure for 2 seconds.	Automatic
c.	Before main fuel firing and following a five minute period following a master fuel trip (unit post purge), trip FD fan if secondary duct pressure exceeds continuous design pressure for 2 seconds.	Automatic
d.	TRIP fans and master fuel trip if duct pressure exceeds continuous design pressure by 10%, or 3 in. H ₂ O, or the specified transient design pressure, whichever is greatest for 5 seconds.	Automatic
5. High Boiler Draft (balanced-draft units with nominal operating range of +.5 to -1.0 in. H₂O)
a.	ALARM if FBC or CBB pressure exceeds -3.0 in H ₂ O.	Required
b.	TRIP master fuel trip if negative FBC or CBB pressure exceeds 7 in. H ₂ O for 2 seconds.	Required
c.	Before main fuel firing and following a five minute period after a master fuel trip (unit post purge), trip FD and ID fan if FBC or CBB pressure exceeds 7 in H ₂ O for 2 seconds.	Automatic
d.	An emergency control system to close the ID fan dampers in the event of high draft should be considered. This control would act even if the fans were on manual control. For units with high negative head capabilities such as those with gas clean-up systems, the emergency control should preferably also be applied to a separate set of dampers. See Figure 10-1.	Optional

FIGURE 10-1
FURNACE DRAFT CONTROL

6. Loss of Forced-Draft Fan -- pressure switch or electrical interlock. Include a limit switch on FD fan shut-off damper to prove open.
- a. ALARM loss of individual fan and close dampers on tripped fan. Required
 - b. TRIP master fuel trip on loss of FD fan. Open FD fan dampers which are not already open, after a time delay to avoid high duct pressure during fan coast down. Dampers to remain open. ID fan may continue to operate or be shutdown manually. Automatic
7. Loss of Induced Draft Fan -- pressure switch or electrical interlock. Include a limit switch on ID fan shut-off damper to prove open.
- a. ALARM loss of individual fan and close dampers on tripped fan. Required
 - b. TRIP master fuel trip on loss of ID fan -- Trip FD fan. Open all ID fan dampers after a time delay (0-1 minute should be adequate to avoid high draft during fan coast down.) Automatic
8. Multiple, Variable Speed Fans -- on start of fan, whether FD, PA, ID or tempering, it is required that the fan be delivering air flow prior to opening of its dampers. Proof of air flow can be established with a differential pressure switch and time delay. Automatic

9. Air Heater - Regenerative Only
 - a. ALARM if air heater stops - Required
On single heater installations,
or on multiple air heaters with-
out provisions for isolation,
the fuel and air may have to be
tripped to prevent the temperature
differential between the incoming
air to the compartments and that
of the fluid in the wall tubes
from exceeding 250°F. This will
be a customer decision.
 - b. ALARM - low lube oil level. Required
 - c. ALARM - loss of lube oil flow. Required
 - d. ALARM - high lube oil temperature. Required
10. Low Air Flow
 - a. ALARM - when air flow below 30%. Required
 - b. For air temperature below 350°F, it is recommended that
temperature compensation be
held at the value corresponding
to 350°F. Recommended
11. Penthouse Sealing Air
 - a. ALARM high (2.5 in. H₂O) and
low (0.2 in. H₂O) penthouse
differential pressure (differ-
ential across roof). Required
 - b. ALARM on high pressure equal to
design pressure. Required
12. Precipitators
 - a. Trip - Precipitator rectifier
control units on master fuel
trip and prevent energizing
precipitator until boiler master
fuel trip is reset. Recommended

E. Fuel

1. Loss of Fuel Flow

a.	ALARM when fuel detectors signal no flow, feeders tripped or rotary seal stopped.	Required
b.	TRIP rotary seals when fuel detector signal no flow after _____ second time delay.	Automatic
c.	TRIP feeder if fuel or limestone is not present on belt after _____ second time delay.	Automatic

2. Loss of Flame on Individual Lighter

a.	ALARM - Loss of flame	Required
b.	TRIP - Individual lighter	Automatic

3. Low Lighter Header Pressure - Ahead of control valve.

a.	ALARM high or low lighter pressure after the pressure regulator.	Required
b.	TRIP individual lighter	Automatic
c.	TRIP individual compartment if no main flame detector installed.	Recommended

4. Low Lighter Atomizing Steam or Air-Oil Pressure Differential

a.	ALARM low lighter atomizing steam or air-oil differential	Required
b.	TRIP lighters	Automatic

5. Hardware Trouble
 - a. TRIP individual compartment on secondary air shut-off damper NOT open, feeder off, or rotary seal stopped. Automatic
 - b. TRIP feeder or prevent start if rotary seal is stopped. Automatic
6. Low Coal Level in Coal Line to Feeder - Nuclear or Capacitance Level Detector
 - a. ALARM when fuel or limestone level is below bunker outlet valve. (live bin bottoms, may be automatically started at this point). Required
7. Loss of Primary or Tempering Air Fan
 - a. ALARM and close dampers on tripped fan. Required
 - b. TRIP FIRING on loss of PA fan or loss of tempering air fan. Automatic
8. Primary or Tempering Air Fan Start
 - a. Establish lube oil pressure on all force lubricated fans prior to start-up. Recommended
 - b. Shut-off damper and control dampers closed on fan to be started. Automatic
9. High Mixing Bustle Outlet Temperature
 - a. ALARM mixing bustle outlet temperature greater than 210°F. This could indicate possible fire or malfunction of tempering air damper. Required

10. High Bed Temperature

a.	ALARM high bed temperature	Required
b.	TRIP compartment on high bed temperature after _____ second time delay.	Automatic

11. Low Bed Temperature

a.	ALARM low bed temperature	Required
b.	TRIP compartment on low bed temperature after _____ second time delay.	Optional

E. Tabulation Of Instrument Connections

ABBREVIATIONS

CN - CAPPED NIPPLE
COND - CONDUCTIVITY
ERV - ELECTROMATIC RELIEF VALVE
EW - ELEMENT IN WELL
GSA - GRAB SAMPLE ANALYSIS
G/T - GAUGE OR TRANSMITTER
HP - HOT JUNCTION PAD
HYD - HYDRAZINE
PC - PLUGGED PIPE CP. LG.
SWN - SOCKET WELD NIPPLE
TC - THERMOCOUPLE
TE - TEMPERATURE ELEMENT
TI - TEMPORARY INSTRUMENT
XMTR - TRANSMITTER

a - ALARM
bc - BURNER CONTROL
c - COMBUSTION CONTROL
cr - CONTINUOUS RECORD
fw - FEEDWATER CONTROL
i - INDICATE
mc - MISCELLANEOUS CONTROL
pm - PERIODIC MONITOR
qt - QUALITY TEST
rt - REHEAT STEAM TEMPERATURE CONTROL
st - SUPERHEATER TEMPERATURE CONTROL
t - TEST
tr - TREND RECORD ON DEMAND

WATER-STEAM CONDITIONS

LINE	MEASURED VARIABLE				CONNECTION		PRIMARY SENSOR			
	MEASUREMENT LOCATION	IDENT NO.	VARIABLE CONDITION	PURPOSE	QTY/ UNIT	TYPE	QTY/ UNIT	SIG/ UNIT	DESCRIPTION	REMARKS
1	FURN ECON INLET	T1/1	TEMP	pm-tr	1		1	1	EW	
2	FURN ECON INLET	T1/2	TEMP	test only	1		- - -	- - -	T1	
3	FURN ECON OUTLET	T1/3	TEMP	pm-tr	1		1	1	EW	
4	FURN ECON OUTLET	T1/4	TEMP	test only	1		- - -	- - -	T1	
5										
6	CBB ECON INLET	T1/6	TEMP	pm-tr	1		1	1	EW	
7	CBB ECON INLET	T1/7	TEMP	test only	1		- - -	- - -	T1	
8	CBB ECON OUTLET	T1/8	TEMP	pm-tr	1		1	1	EW	
9	CBB ECON OUTLET	T1/9	TEMP	test only	1		- - -	- - -	T1	
10										
11	FURN WALL RISERS	T1/11	TEMP	pm-tr		HP			PERM TC	
12	CBB RISERS	T1/12	TEMP	pm-tr		HP			PERM TC	
13	STEAM DRUM	T1/13	TEMP	pm-tr	6	HP	6	6	PERM TC	
14	SAT CONN TUBE	T1/14	TEMP	pm-tr	1	HP	1	1	PERM TC	
15	PRI SH OUTLET LEGS	T1/15	TEMP	pm-a						
16	PRI SH OUTLET LEGS	T1/16	TEMP	test only		HP			PERM TC	
17	PRI SH OUTLET	T1/17	TEMP	pm-tr		HP			PERM TC	
18	PRI SH OUTLET	T1/18	TEMP	test only		HP			PERM TC	
19										
20	SH BED #1 OUTLET LEGS	T1/20	TEMP	pm-a		HP			PERM TC	
21	SH BED #1 OUTLET LEGS	T1/21	TEMP	test only		HP			PERM TC	
22										
23	SH BED #1 OUTLET BEFORE ATTEMP.	T1/23	TEMP	pm-tr	1		1	1	EW-TC	
24	SH BED #1 OUTLET BEFORE ATTEMP.	T1/24	TEMP	test only	1		- - -	- - -	T1	
25	SH BED #1 OUTLET AFTER ATTEMP.	T1/25	TEMP	st-i-cr-a	1		1	1	EW-TC	
26	SH BED #1 OUTLET AFTER ATTEMP.	T1/26	TEMP	pm-tr	1		1	1	EW-TC	
27	SH BED #1 OUTLET AFTER ATTEMP.	T1/27	TEMP	test only	1		- - -	- - -	T1	
28										
29	SH BED #2 OUTLET LEGS	T1/29	TEMP	pm-a		HP			PERM TC	
30	SH BED #2 OUTLET LEGS	T1/30	TEMP	test only		HP			PERM TC	
31	SH BED #2 OUTLET	T1/31	TEMP	pm-tr	1		1	1	EW-TC	
32	SH BED #2 OUTLET	T1/32	TEMP	test only	1		- - -	- - -	T1	
33										
34	SH BED #3 OUTLET LEGS	T1/34	TEMP	pm-a		HP			PERM TC	
35	SH BED #3 OUTLET LEGS	T1/35	TEMP	test only		HP			PERM TC	
36	SH BED #3 OUTLET	T1/36	TEMP	a-i-cr-st					EW-TC	
37	SH BED #3 OUTLET	T1/37	TEMP	test only			- - -	- - -	T1	
38										
39	RH ATTEMP INLET	T1/39	TEMP	pm-tr	1		1	1	EW-TC	
40	RH ATTEMP INLET	T1/40	TEMP	test only	1		- - -	- - -	T1	
41	RH ATTEMP OUTLET	T1/41	TEMP	pm-tr	1		1	1	EW-TC	
42	RH ATTEMP OUTLET	T1/42	TEMP	i-cr	1		1	1	EW-TC	
43	RH ATTEMP OUTLET	T1/43	TEMP	test only	1		- - -	- - -	T1	
44										

WATER-STEAM CONDITIONS

LINE	MEASURED VARIABLE				CONNECTION		PRIMARY SENSOR			
	MEASUREMENT LOCATION	IDENT NO.	VARIABLE CONDITION	PURPOSE	QTY/UNIT	TYPE	QTY/UNIT	SIG/UNIT	DESCRIPTION	REMARKS
1	RH OUTLET LEGS	T2/1	TEMP	pm-a		HP			PERM TC	
2	RH OUTLET LEGS	T2/2	TEMP	test only		HP			PERM TC	
3	RH OUTLET	T2/3	TEMP	a-i-cr-rt	1				EW-TC	
4	RH OUTLET	T2/4	TEMP	test only	1		- - -	- - -	T1	
5										
6	FW LINE NEAR FLOWMETER	T2/6	TEMP	FW	1		1	1	EW	
7										
8	FURN ECON INLET	P2/8	PRESS	i	1		1	1	G/T	
9	CBB ECON INLET	P2/9	PRESS	i	1		1	1	G/T	
10										
11	STEAM DRUM	P2/11	PRESS	CR		1"SWN			G/T	
12	STEAM DRUM	P2/12	PRESS	i	TEE OFF	LINE ABOVE			PRESS GAGE	
13										
14	SH BED #3 OUTLET	P2/14	PRESS	i	1		1	1	G/T	
15	SH BED #3 OUTLET	P2/15	PRESS	mc					ERV CONTROL	
16	SH BED #3 OUTLET	P2/16	PRESS	test only	TEE OFF	LINE 14	- - -	- - -	T1	MC = PRESS RELIEF
17										
18	TURBINE FIRST STAGE	P2/18	PRESS	i	1	BY TURB MFR	1	1	G/T	
19	TURBINE FIRST STAGE	P2/19	PRESS	fw-c	1	BY TURB MFR	1	1	PRESS XMTR	
20										
21	RH INLET	P2/21	PRESS	i	1		1	1	G/T	
22	RH INLET	P2/22	PRESS	test only	TEE OFF	LINE ABOVE	- - -	- - -	T1	
23	RH OUTLET	P2/23	PRESS	i	1		1	1	G/T	
24	RH OUTLET	P2/24	PRESS	test only	TEE OFF	LINE ABOVE	- - -	- - -	T1	
25										
26	DEAERATOR	P2/26	PRESS	i	1		1	1	G/T	
27	HIGH PRESS HEATER	P2/27	PRESS	i	1		1	1	G/T	
28	FEEDWATER MAKEUP	F2/28	FLOW	a-i	2		1	1	FLOW XMTR	
29	FW LINE TO ECON	F2/29	FLOW	a-fw-i-cr	2		1	1	FLOW XMTR	
30										
31	SH ATTEMP SPRAY	F2/31	FLOW	i-cr	2		1	1	FLOW XMTR	
32	RH ATTEMP SPRAY	F2/32	FLOW	i-cr	2		1	1	FLOW XMTR	
33										
34	STEAM DRUM	L2/34	LEVEL	i		1-1/2"SWN		- - -	GAGE GLASS	
35	STEAM DRUM	L2/35	LEVEL	fw-a-cr	2	1" SWN	1	1	LEVEL XMTR	
36	STEAM DRUM	L2/36	LEVEL	i-mc	2	1" SWN	1	1	INDICATOR	MC = INTERLOCKS
37	STEAM DRUM	L2/37	LEVEL	i	2	1" SWN	1	1	INDICATOR	
38	STEAM DRUM	L2/38	HIGH LEVEL	i	2	1" SWN	1	- - -	GAGE GLASS	
39										
40	DEAERATOR	L2/40	LEVEL	i	2		1		G/T	
41										
42										
43										
44										

WATER-STEAM ANALYSIS

LINE	MEASURED VARIABLE				CONNECTION		PRIMARY SENSOR			
	MEASUREMENT LOCATION	IDENT NO.	VARIABLE CONDITION	PURPOSE	QTY/ UNIT	TYPE	QTY/ UNIT	SIG/ UNIT	DESCRIPTION	REMARKS
1	FURN ECON INLET	S3/1	CATION COND	a-cr	1		1	1	COND METER	FROM DRY PAN
2	FURN ECON INLET	S3/2	SPECIF COND	cr	1		1	1	COND METER	
3	FURN ECON INLET	S3/3	HYD CONT	cr	1		1	1	HYD METER	
4	FURN ECON INLET	S3/4	pH INDEX	cr	1		1	1	pH METER	
5	FURN ECON INLET	S3/5	QUALITY	qt	1		- - -	- - -	GSA	
6	STEAM DRUM (WATER)	S3/6	SPECIF COND	cr	1	1" SWN	1	1	COND METER	
7	STEAM DRUM (WATER)	S3/7	pH INDEX	cr	FROM ABOVE CONN		1	1	pH METER	
8	STEAM DRUM (WATER)	S3/8	QUALITY	qt	FROM ABOVE CONN		- - -	- - -	GSA	
9	STEAM DRUM (SAT STM)	S3/9	SPECIF COND	cr	1	1" SWN	1	1	COND METER	
10	STEAM DRUM (SAT STM)	S3/10	CATION COND	a-cr	FROM ABOVE CONN		1	1	COND METER	
11	HOTWELL PUMP DISCHARGE	S3/11	SPECIF COND	cr	1		1	1	COND METER	
12	HOTWELL PUMP DISCHARGE	S3/12	CATION COND	cr	1		1	1	COND METER	
13	HOTWELL PUMP DISCHARGE	S3/13	O2 CONT	cr	1		1	1	HYD METER	
14	HOTWELL PUMP DISCHARGE	S3/14	QUALITY	qt	1		- - -	- - -	GSA	
15	DEAERATOR INFLUENT	S3/15	O2 CONT	cr	1		1	1	O2 METER	
16	DEAERATOR INFLUENT	S3/16	HYD CONT	cr	1		1	1	HYD METER	
17	DEAERATOR INFLUENT	S3/17	QUALITY	qt	1		- - -	- - -	GSA	
18	DEAERATOR INFLUENT	S3/18	O2 CONT	cr	1		1	1	O2 METER	
19	DEAERATOR INFLUENT	S3/19	QUALITY	qt	1		- - -	- - -	GSA	
20	HP HTR SHELL BEFORE DRAIN TO DA	S3/20	QUALITY	qt	1		- - -	- - -	GSA	
21	HP HTR SHELL BEFORE DRAIN TO DA	S3/21	SPECIF COND	cr	1		1	1	COND METER	
22										
23										
24										
25										
26										
27										
28										
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AIR-GAS CONDITIONS

LINE	MEASURED VARIABLE				CONNECTION		PRIMARY SENSOR			
	MEASUREMENT LOCATION	IDENT NO.	VARIABLE CONDITION	PURPOSE	QTY/ UNIT	TYPE	QTY/ UNIT	SIG/ UNIT	DESCRIPTION	REMARKS
1	AIR LEAVING FD FAN	T4/1	TEMP	pm	1		1	1	TE	
2	AIR LVG COIL PREHEATER	T4/2	TEMP	pm	1		1	1	TE	
3										
4	AIR ENTERING AH	T4/4	TEMP	mc					TE	MC = COLD END CONTROL
5	AIR ENTERING AH	T4/5	TEMP	test only		2" CN	- - -	- - -	T1	
6	AIR LEAVING AH	T4/6	TEMP	pm		1-1/2" PC			TE	
7	AIR LEAVING AH	T4/7	TEMP	i-pm-c		1-1/2" PC			TE	AIR FLOW TEMP COMP
8										
9	PRI AIR DUCT	T4/9	TEMP	i-c		1-1/2" PC			TE	AIR FLOW TEMP COMP
10	MIXING BUSTLE OUTLET	T4/10	TEMP	a-cr-c		2" NPT			TE IN WELL	
11										
12	GAS ENTERING RH (PROBE)	T4/12	TEMP	a-i-c		5 1/2" SB OPNG			TC	
13	GAS LEAVING FBC	S4/13	NO _x	i-cr					NO _x ANALYZER	
14	GAS LEAVING CBB	S4/14	NO _x	i-cr					NO _x ANALYZER	
15	GAS ENTERING STACK	S4/15	NO _x	i-cr					NO _x ANALYZER	
16										
17	GAS LEAVING FBC	S4/17	O ₂ CONTENT	i-cr-c		3" CN			O ₂ ANALYZER	
18	GAS LEAVING FBC	T4/18	TEMP	pm		1-1/2" PC			TE	
19	GAS LEAVING CBB	S4/19	O ₂ CONTENT	i-cr-c		3" CN			O ₂ ANALYZER	
20	GAS LEAVING CBB	T4/20	TEMP	pm		1-1/2" PC			TE	
21										
22	GAS ENTERING AH	T4/22	TEMP + O ₂	test		4" CN	- - -	- - -	T1	
23	GAS LEAVING AH	T4/23	TEMP + O ₂	test		4" CN	- - -	- - -	T1	
24	GAS LEAVING AH	T4/24	TEMP	pm					TE	
25	GAS LEAVING AH	T4/25	TEMP	mc					TE	MC = COLD END CONTROL
26										
27	FD FAN OUT BEFORE DAMPER	P4/27	PRESS	i					G/T	
28										
29	AIR ENTERING AH	P4/29	PRESS	i		2" CN			G/T	
30	AIR LEAVING AH	P4/30	PRESS	i		2" CN			G/T	
31										
32	PRI AIR FAN DISCHARGE	P4/32	PRESS	c		2" CN			G/T	PA FAN CONTROL
33	TEMP AIR FAN DISCHARGE	P4/33	PRESS	c		2" CN			G/T	TEMP FAN CONTROL
34										
35	SEC AIR DUCT	P4/35	PRESS	pm-a-mc		2" CN			PRESS XMTR/SWITCH	MC = INTERLOCKS
36	SEC AIR DUCT	P4/36	PRESS	c		2" CN			PRESS XMTR	
37										
38										
39										
40										
41										
42										
43										
44										

AIR-GAS CONDITIONS

LINE	MEASURED VARIABLE				CONNECTION		PRIMARY SENSOR			
	MEASUREMENT LOCATION	IDENT NO.	VARIABLE CONDITION	PURPOSE	QTY/ UNIT	TYPE	QTY/ UNIT	SIG/ UNIT	DESCRIPTION	REMARKS
1	FURN GAS	P5/1	PRESS	pm		2" CN			PRESS XMTR	DRAFT CONTROL PENTHOUSE - FURN DP MC = INTERLOCKS
2	FURN GAS	P5/2	PRESS	c		2" CN			PRESS XMTR	
3	FURN GAS	P5/3	PRESS	a-mc	FROM CONN ABOVE				SEE SH 6 L1 & 2	
4	FURN GAS	P5/4	PRESS	a-mc		2" CN			PRESS SWITCH	
5										
6	FURN GAS	P5/6	PRESS	a-mc	FROM CONN LINE 4				SEE SH 6 L22 & 23	RH VEST - FURN DP
7	FURN GAS	P5/7	PRESS	a-mc		2" CN			SEE SH 6 L25 & 26	PRI VEST - FURN DP
8	FURN GAS	P5/8	PRESS	a-mc	FROM CONN ABOVE				SEE SH 6 L28 & 29	FURN ECON VEST - FURN DP
9	FURN GAS	P5/9	PRESS	test only	FROM CONN LINE 1		- - -	- - -	T1	
10										
11	CBB GAS	P5/11	PRESS	pm		2" CN			PRESS XMTR	DRAFT CONTROL MC = INTERLOCKS
12	CBB GAS	P5/12	PRESS	c		2" CN			PRESS XMTR	
13	CBB GAS	P5/13	PRESS	a-mc		2" CN			PRESS SWITCH	
14	CBB GAS	P5/14	PRESS	test only	FROM CONN LINE 11		- - -	- - -	T1	
15										
16	CONVECTION PASS GAS	P5/16	PRESS	a-mc	1	2" CN			SEE SH 6 L19 & 20	PENTHOUSE - CONNECTION PASS DP
17	PENTHOUSE AIR	P5/17	PRESS	a-mc	1	2" CN			SEE SH 6 L17 & 18	PENTHOUSE - FURN DP
18	PENTHOUSE AIR	P5/18	PRESS	a-mc	1	2" CN			SEE SH 6 L19 & 20	CONVECTION PASS - PENTHOUSE DP
19	PENTHOUSE AIR	P5/19	PRESS	test only.	2	3/4" CN	- - -	- - -	T1	1 EACH SIDE
20										
21	RH VESTIBULE AIR	P5/21	PRESS	i	1	2" CN	1	1	G/T	FURN - RH VEST DP
22	RH VESTIBULE AIR	P5/22	PRESS	a-mc	1	2" CN			SEE SH 6 L22 & 23	
23	RH VESTIBULE AIR	P5/23	PRESS	a	1	2" CN	1	1	PRESS SWITCH	
24	RH VESTIBULE AIR	P5/24	PRESS	test only	2	3/4" CN	- - -	- - -	T1	
25										
26	PRI VESTIBULE AIR	P5/26	PRESS	i	1	2" CN	1	1	G/T	FURN - PRI VEST DP
27	PRI VESTIBULE AIR	P5/27	PRESS	a-mc	1	2" CN			SEE SH 6 L25 & 26	
28	PRI VESTIBULE AIR	P5/28	PRESS	a	1	2" CN	1	1	PRESS SWITCH	
29	PRI VESTIBULE AIR	P5/29	PRESS	test only	2	3/4" CN	- - -	- - -	T1	
30										
31	FURN ECON VESTIBULE AIR	P5/31	PRESS	i	1	2" CN	1	1	G/T	FURN - ECON VEST DP
32	FURN ECON VESTIBULE AIR	P5/32	PRESS	a-mc	1	2" CN			SEE SH 6 L28 & 29	
33	FURN ECON VESTIBULE AIR	P5/33	PRESS	a	1	2" CN	1	1	PRESS SWITCH	
34	FURN ECON VESTIBULE AIR	P5/34	PRESS	test only	2	3/4" CN	- - -	- - -	T1	
35										
36										
37										
38										
39										
40										
41										
42										
43										
44										

AIR-GAS CONDITIONS

LINE	MEASURED VARIABLE				CONNECTION		PRIMARY SENSOR			
	MEASUREMENT LOCATION	IDENT NO.	VARIABLE CONDITION	PURPOSE	QTY/UNIT	TYPE	QTY/UNIT	SIG/UNIT	DESCRIPTION	REMARKS
1	(N) TO UTILIZE PRESSURE LOSSES THROUGH VARIOUS SURFACES AS INDICATION OF FOULING									
2										
3	FURN GAS ENT DOWN FLOW PATH (N)	P6/3	PRESS	i	1	2" CN	1	1	G/T	
4										
5	FURN GAS LV RH (N)	P6/5	PRESS	i	1	2" CN	1	1	G/T	
6										
7	FURN GAS LV PRI (N)	P6/7	PRESS	i	1	2" CN	1	1	G/T	
8										
9	FURN GAS LV ECON (N)	P6/9	PRESS	i	1	2" CN	1	1	G/T	
10										
11	CBB GAS LV BOILER SURFACE (N)	P6/11	PRESS	i	1	2" CN	1	1	G/T	
12										
13										
14										
15	ID FAN OUT BEFORE DAMPER	P6/15	PRESS	i	1		1	1	G/T	
16										
17	PENTHOUSE AIR - FURN GAS		DIFF PRESS	mc	SEE SH5	L3 & 17	1	1	DP XMTR	MC = DP CONTROL
18	PENTHOUSE AIR - FURN GAS		DIFF PRESS	a	SEE SH5	L3 & 17	1	2	DP SWITCH	DUAL SWITCH
19	PENTHOUSE AIR - CONV PASS GAS		DIFF PRESS	mc	SEE SH5	L16 & 18	1	1	DP XMTR	MC = DP CONTROL
20	PENTHOUSE AIR - CONV PASS GAS		DIFF PRESS	a	SEE SH5	L16 & 18	1	2	DP SWITCH	DUAL SWITCH
21										
22	RH VEST AIR - FURN GAS		DIFF PRESS	mc	SEE SH5	L6 & 22	1	1	DP XMTR	MC = DP CONTROL
23	RH VEST AIR - FURN GAS		DIFF PRESS	a	SEE SH5	L6 & 22	1	2	DP SWITCH	DUAL SWITCH
24										
25	PRI VEST AIR - FURN GAS		DIFF PRESS	mc	SEE SH5	L7 & 27	1	1	DP XMTR	MC = DP CONTROL
26	PRI VEST AIR - FURN GAS		DIFF PRESS	a	SEE SH5	L7 & 27	1	2	DP SWITCH	DUAL SWITCH
27										
28	ECON VEST AIR - FURN GAS		DIFF PRESS	mc	SEE SH5	L8 & 32	1	1	DP XMTR	MC = DP CONTROL
29	ECON VEST AIR - FURN GAS		DIFF PRESS	a	SEE SH5	L8 & 32	1	2	DP SWITCH	DUAL SWITCH
30										
31	AIR THROUGH AH	F6/31	FLOW	i-pm-c-bc-cr	2	2" CN	1	1	FLOW XMTR	TUBULAR AH ONLY
32										
33	FURN COMPARTMENT GROUP SEC AIR	F6/33	FLOW	i-pm-c-bc-cr		2" CN			FLOW XMTR	3 PER FOIL
34	CBB COMPARTMENT GROUP SEC AIR	F6/34	FLOW	i-pm-c-bc-cr		2" CN			FLOW XMTR	3 PER FOIL
35	AIR THRU PRI AIR DUCTS	F6/35	FLOW	i-pm-c-bc-cr		2" CN			FLOW XMTR	
36	AIR THRU TEMP DUCTS	F6/36	FLOW	i-pm-c-bc-cr		2" CN			FLOW XMTR	
37										
38	AIR ENT FURN MIXING BUSTLES	F6/38	FLOW	i					FLOW XMTR	
39	AIR ENT CBB MIXING BUSTLES	F6/39	FLOW	i					FLOW XMTR	
40	AIR ENT DISTRIBUTOR	F6/40	FLOW	i					FLOW XMTR	
41										
42	TOTAL AIR ENT FURN		FLOW	i-pm-c-bc-cr		COMBINED FLOWS		- - -	L 33 & 38	
43	TOTAL AIR ENT CBB		FLOW	i-pm-c-bc-cr		COMBINED FLOWS		- - -	L 34 & 39	
44	TOTAL AIR ENT UNIT		FLOW	i-pm-c-bc-cr		COMBINED FLOWS		- - -	L 42 & 43	

FUEL AND MISC CONDITIONS

LINE	MEASURED VARIABLE				CONNECTION		PRIMARY SENSOR			
	MEASUREMENT LOCATION	IDENT NO.	VARIABLE CONDITION	PURPOSE	QTY/UNIT	TYPE	QTY/UNIT	SIG/UNIT	DESCRIPTION	REMARKS
1	COAL FEEDER DISCHARGE	T7/1	TEMP	a-cr	20		20	20	TEMP SWITCH	
2	COAL FEEDER SPEED	f7/2	FUEL INPUT	i-bc-c	20		20	20	TACHOMETER	
3	COAL SUPPLY DETECTOR	f7/3	FUEL INPUT	a-bc	20		20	20	COAL DETECTOR	
4	COAL ON FDR BELT	f7/4	FUEL INPUT	a-bc	20		20	20	PADDLE SWITCH	
5	COAL FDR PLUGGAGE	f7/5	FUEL INPUT	a-bc	20		20	20	PADDLE SWITCH	
6										
7	LIME FEEDER DISCHARGE	T7/7	TEMP	a-cr	20		20	20	TEMP SWITCH	
8	LIME FEEDER SPEED	17/8	LIME INPUT	i-bc-c	20		20	20	TACHOMETER	
9	LIME SUPPLY DETECTOR	17/9	LIME INPUT	a-bc	20		20	20	DETECTOR	
10	LIME ON FDR BELT	17/10	LIME INPUT	a-bc	20		20	20	PADDLE SWITCH	
11	LIME FDR PLUGGAGE	17/11	LIME INPUT	a-bc	20		20	20	PADDLE SWITCH	
12										
13	COAL/LIMESTONE ROTARY SEAL	E7/13	ROTATION	a-bc	20		20	20	FREQ	
14	CBB FEED TANK ROTARY SEAL	E7/14	ROTATION	a-bc	4		4	4	FREQ	
15	ASH ROTARY SEAL	E7/15	ROTATION	a-bc	24		24	24	FREQ	
16	LIGHTER OIL SUPPLY LINE	P7/16	PRESS	i	1		1	1	G/T	
17	LIGHTER OIL SUPPLY LINE	P7/17	PRESS	a-bc-mc					PRESS SWITCH	MC = INTERLOCKS
18	LIGHTER ATOMIZING STEAM/AIR	P7/18	PRESS	i	1		1	1	G/T	
19	LIGHTER ATOMIZING STEAM/AIR	P7/19	PRESS	a-bc					PRESS SWITCH	
20										
21	SCANNER COOLING AIR	P7/21	PRESS	a-bc					PRESS SWITCH	
22	SCANNER COOLING AIR BLOWER	P7/22	PRESS	a-mc					PRESS SWITCH	MC = BLOWER CONTROL
23										
24										
25										
26										
27										
28										
29										
30										
31										
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MISCELLANEOUS CONDITIONS

LINE	MEASURED VARIABLE				CONNECTION		PRIMARY SENSOR			
	MEASUREMENT LOCATION	IDENT NO.	VARIABLE CONDITION	PURPOSE	QTY/UNIT	TYPE	QTY/UNIT	SIG/UNIT	DESCRIPTION	REMARKS
1	SEAL AIR BLOWER DISCHARGE	P8/1	PRESS	a-mc					PRESS SWITCH	MC = BLOWER CONTROL
2	SEAL AIR BLOWER DISCHARGE - SUCTION	P8/2	DIFF PRESS	a-mc					DP SWITCH	MC = BLOWER CONTROL
3	SEAL AIR BLOWER SUCTION	P8/3	PRESS	mc					PRESS SWITCH	MC = BLOWER CONTROL
4										
5	TV COOLING AIR BLOWER DISCHARGE	P8/4	PRESS	a-mc					PRESS SWITCH	MC = BLOWER CONTROL
6										
7	CIRCULATION PUMP MOTOR	T8/7	TEMP	a-mc	2		2	2	TEMP SWITCH	)
8	CIRCULATION PUMP MOTOR	T8/8	TEMP	a-mc	2		2	2	PERM TC	)
9	CIRCULATION PUMP CASING	T8/9	TEMP	a-mc	2		2	2	TEMP SWITCH	)
10										)
11	CIRCULATION PUMP	P8/11	DIFF PRESS	a-mc	2		2	2	PRESS SWITCH	) MC = CIRCULATION
12	CIRCULATION PUMP	P8/12	DIFF PRESS	a-i-mc	2		2	2	PRESS XMTR	) PUMP CONTROL
13										)
14	CIRCULATION PUMP COOLING WATER	F8/14	FLOW	a-mc	2		2	2	FLOW METER	)
15	CIRC PUMP GLAND SEAL	T8/15	TEMP	a-i-mc	2		2	2	TEMP SWITCH	)
16	CIRC PUMP GLAND SEAL	T8/16	TEMP	i	2		2	2	GAUGE	)
17										)
18	UPPER & LOWER THRUST BEARINGS	T8/18	TEMP	a-i-mc					PERM TC	)
19	UPPER & LOWER RADIAL BEARINGS	T8/19	TEMP	a-i-mc					PERM TC	)
20										)
21	SMOTHERING GLAND JACKET COOLING WTR	T8/21	TEMP	i					GAUGE	
22	CIRC PUMP GLAND SEAL	P8/22	PRESS	i					GAUGE	
23	CIRC PUMP DISCHARGE	P8/23	PRESS	i	2		2		GAUGE	
24										
25										
26	CIRC PUMP GLAND SEAL	P8/26	DIFF PRESS	a-i-mc					PRESS XMTR	MC = CIRC PUMP CONTROL
27	LUBE SYS COOLING WATER	F8/27	FLOW	i					GAUGE	
28	SMOTHERING GLAND JACKET COOLING WTR	F8/28	FLOW	i					GAUGE	
29	COIL PREHEATER OUTLET FLUID	T8/29	TEMP	mc					TE	MC = COIL AH CONTROL
30										
31										
32										
33										
34										
35										
36										
37										
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39										
40										
41										
42										
43										
44										

REGENERATIVE AH INSTRUMENTATION

LINE	MEASURED VARIABLE				CONNECTION		PRIMARY SENSOR			
	MEASUREMENT LOCATION	IDENT NO.	VARIABLE CONDITION	PURPOSE	QTY/UNIT	TYPE	QTY/UNIT	SIG/UNIT	DESCRIPTION	REMARKS
1	AIR ENTERING AH	T9/1	TEMP/PRESS	test	1	2" CN	- - -	- - -	TI	
2	AIR LEAVING AH	T9/2	TEMP/PRESS	test	2	2" CN	- - -	- - -	TI	
3										
4	GAS ENTERING AH	T9/4	TEMP	a	4	1½" PC	4	4	TC	
5	GAS LEAVING AH	T9/5	TEMP	a	4	1½" PC	4	4	TC	
6										
7	AIR ENTERING AH	T9/7	TEMP	a	2	1½" PC	2	2	TC	
8	AIR LEAVING AH	T9/8	TEMP	a	2	1½" PC	2	2	TC	
9										
10	AH DRIVE UNIT ROTATION STOP	E9/10	ROTATION	a	1		1	1	FREQ SWITCH	
11										
12	AH DRIVE UNIT - LUBE OIL	T9/12	TEMP	a	1		1	1	TEMP SWITCH	
13	AH DRIVE UNIT - LUBE OIL	F9/13	FLOW	a	1		1	1	FLOW SWITCH	
14	AH DRIVE UNIT - LUBE OIL	T9/14	TEMP	mc	1		1	1	THERMOSTAT	
15	AH DRIVE UNIT - LUBE OIL	L9/15	LEVEL	i	1		1	- - -	SIGHT SWITCH	
16										
17	AH BEARING LUBE UNIT - LUBE OIL	L9/17	LEVEL	a	1		1	1	LEVEL SWITCH	
18	AH BEARING LUBE UNIT - LUBE OIL	L9/18	LEVEL/TEMP	i	2		2	- - -	SIGHT LEVEL/THERMOMETER	
19	AH BEARING LUBE UNIT - LUBE OIL	P9/19	PRESS	i	1		1	- - -	GAUGE	PUMP DISCHARGE
20	AH BEARING LUBE UNIT - LUBE OIL	T9/20	TEMP	i	1		1	- - -	THERMOMETER	DOWNSTREAM COOLER
21										
22	AH BEARING LUBE UNIT - LUBE OIL	T9/22	TEMP	mc	1		1	1	TEMP SWITCH	MC = OIL COOLER CONTROL
23	AH BEARING LUBE UNIT - LUBE OIL	T9/23	TEMP	mc	1		1	1	TEMP SWITCH	MC = OIL HEATER CONTROL
24	AH BEARING LUBE UNIT - LUBE OIL	T9/24	TEMP	mc	1		1	1	TEMP SWITCH	MC = OIL PUMP INT'L
25										
26	AH BEARING OIL SUPPLY LINE	F9/26	FLOW	a-i			1	1	FLOW SWITCH/GAUGE	
27	AH BEARING OIL RETURN LINE	T9/27	TEMP	i				- - -	THERMOMETER	
28	AH BEARING OIL RETURN LINE	T9/28	TEMP	a-i					TC	
29										
30	AH SOOT BLOWER INLET	P9/30	PRESS	i	1		1	- - -	GAUGE	
31										
32										
33										
34										
35										
36										
37										
38										
39										
40										
41										
42										
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- NOTE 1. — TABULATION SHEET NO
TABULATION LINE NO
2. INSTRUMENT CONNECTIONS NOT SHOWN
3. SEE DWG. 40032A FOR REGENERATIVE AH INSTRUMENTATION

DESIGNED BY **DLC**

CHECKED BY

DRAWN BY

DATE **2-7-78**

SCALE

TVA.

CONCEPTUAL DESIGN
INSTRUMENTATION
DWG. FOR
ATMOSPHERIC FLUIDIZED
BED BOILER
(200 MW)

THE BARCOCK & WILCOX CO.
POWER ENGINEERING GROUP

REV. **254227E**

THE BABCOCK & WILCOX COMPANY
POWER GENERATION GROUP

FIGURE 10-3

INSTRUMENT CONNECTIONS SCHEMATIC DIAGRAM
OF ROTHEMUHLE AIR HEATER

REVISIONS			MICRO-FILM
DASH NO.	DATE	DESCRIPTION	ORIG.

NOTES:

- A. T 9/4 AND T 9/5 SHOULD BE LOCATED 180° APART.
- B. T 9/1, T 9/2 AND T 9/8 SHOULD BE LOCATED 90° APART.
- C. IF RECTANGULAR FLUES OR DUCTS ARE USED, THERMOCOUPLES SHOULD BE LOCATED AT EQUAL SPACING ON ONE SIDE.

ES-241

TVA

DWN. BY DLC	CHK'D	INSTRUMENT CONNECTIONS SCHEMATIC DIAG. ROTHEMUHLE A.H.	SCALE X	DATE 2-7-78
PASSED BY	APP'D		DRWG. NO. 140032	A-0

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10-81

XI. UTILITIES

A. Boiler Feed Water

Flowrate (lb/hr)	Temperature (°F)
1,461,053	487

B. Boiler Make Up Water

Flowrate (lb/hr)
14,650

C. Service Water

Location	Flowrate (GPM)	Temperature (°F)
FBC Underflow Cooling Water	506	80
CBB Underflow Cooling Water	31	80

D. Fuel

Fuel	Feedrate (lb/hr)
Coal	177,174
Limestone	59,554
#2 Oil	16,820*

E. Steam

Location	Supply Pressure (PSIA)	Temperature °F	Quantity (lb/hr)
Inlet to Steam Coil Air Heater	200	382°F	13,235

*Based on a maximum of twenty-two (22) lighters used during start-up.

DRIVERS

EQUIPMENT NAME	NO. OF UNITS	GROSS HP	TOTAL GROSS HP	NET HP	TOTAL NET HP	ELECTRICAL CHARACTERISTIC
LIMESTONE CRUSHER	1	525	525	500	500	460V/3PH/60HZ
COAL CRUSHER	1	525	525	500	500	460V/3PH/60HZ
COAL SCREENS	1	7	7	6	6	460V/3PH/60HZ
LIMESTONE SCREENS	1	7	7	6	6	460V/3PH/60HZ
COAL BELT CONVEYOR	1	15	15	14	14	460V/3PH/60HZ
LIMESTONE BELT CONVEYOR	1	10	10	9	9	460V/3PH/60HZ
COAL BUCKET ELEVATOR	1	3	3	2.5	2.5	460V/3PH/60HZ
LIMESTONE BUCKET ELEVATOR	1	3	3	2.5	2.5	460V/3PH/60HZ
COAL FLIGHT CONVEYOR	1	15	15	13	13	460V/3PH/60HZ
COAL FLIGHT CONVEYOR	2	7.5	15	7	14	460V/3PH/60HZ
LIMESTONE FLIGHT CONVEYOR	1	15	15	13	13	460V/3PH/60HZ
LIMESTONE FLIGHT CONVEYOR	2	7.5	15	7	14	460V/3PH/60HZ
COAL LIVE BIN BOTTOM	20	1.5	30	1.25	25	460V/3PH/60HZ
LIMESTONE LIVE BIN BOTTOM	20	3/4	15	5/8	12.5	460V/3PH/60HZ
COAL FEEDER	20	1	20	3/4	15	460V/3PH/60HZ
LIMESTONE FEEDER	20	1/2	10	1/3	3.33	230V/1PH/60HZ

TOTAL 1230 TOTAL 1149.8

DRIVERS

EQUIPMENT NAME	NO. OF UNITS	GROSS HP	TOTAL GROSS HP	NET HP	TOTAL NET HP	ELECTRICAL CHARACTERISTIC
FUEL FEED HOPPER ROTARY SEAL	20	1/3	6.67	1/4	5	230V/3PH/60HZ
CHAR CONVEYING SYSTEM BLOWERS	2	125	250	100	200	460V/3PH/60HZ
CHAR FEED TANK ROTARY SEALS	4	1/2	2	1/3	1.33	230V/3PH/60HZ
BOILER WATER RECIRCULATION PUMPS	2	800	1600	775	1550	460V/3PH/60HZ
FBC ASH COOLERS	16	2	32	1.75	28	460V/3PH/60HZ
FBC START-UP ASH COOLERS	4	2	8	1.75	7	460V/3PH/60HZ
CBB ASH COOLERS	4	1/2	2	1/3	1.33	230V/3PH/60HZ
FBC UNDERFLOW ROTARY SEALS	20	1/3	6.67	1/4	5	230V/3PH/60HZ
CBB UNDERFLOW ROTARY SEALS	4	1/3	1.33	1/4	1	230V/3PH/60HZ
ASH CONVEYING SYSTEM UNLOADER AND PUMP	1	55	55	40	40	460V/3PH/60HZ
PRIMARY AIR FAN	1	800	800	750	750	460V/3PH/60HZ
TEMPERING AIR FAN	1	200	200	165	165	460V/3PH/60HZ
SOOTBLOWERS (FBC + CBB)	19	1.5	28.5	1.25	23.75	460V/3PH/60HZ

TOTAL 2992.2 TOTAL 2777.4

DRIVES FOR REGENERATIVE AIR HEATER

EQUIPMENT NAME	NO. OF UNITS	GROSS. HP	TOTAL GROSS HP	NET HP	TOTAL NET HP	ELECTRICAL CHARACTERISTIC
FD FAN (REGENERATIVE)	1	7,000	7,000	6,410	6,410	4160V/3PH/60HZ
AIR HEATER	1	20	20	18	18	460V/3PH/60HZ
ID FAN (REGENERATIVE)	1	3,000	3,000	2,685	2,685	4160V/3PH/60HZ

TOTAL 10,020 9,113

FOR TUBULAR AIR HEATER

EQUIPMENT NAME	NO. OF UNITS	GROSS HP	TOTAL GROSS HP	NET HP	TOTAL NET HP	ELECTRICAL CHARACTERISTIC
FD FAN	1	6,000	6,000	5,839	5,839	4160V/3PH/60HZ
ID FAN	1	2,500	2,500	2,411	2,411	4160V/3PH/60HZ
SOOTBLOWERS	10	1.5	15	1.25	12.5	460V/3PH/60HZ

TOTAL 8,515 8,262.5

PRECIPITATORS

NAME	NO. OF UNITS	POWER REQUIRED	ELECTRICALS CHARACTERISTICS
FBC	2	1654 KW	460V/3PH/60HZ
CBB	1	264 KW	460V/3PH/60HZ

TOTAL 1918 KW

E. Power Requirements

Total Power Requirements*

Case	Gross HP	Net HP
Regenerative Air Heater	16,814	14,686
Tubular Air Heater	15,309	13,835

*Includes precipitators

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11-6

XII. BASIS OF SYSTEM COSTS AND SCHEDULE

The costs developed for the system (See Table 12-1) were based on B&W's base estimating data for those items normally supplied by B&W and on vendor quotations for items normally purchased. The costs include B&W's G&A expense and profit as normally used by B&W in a proposal for a commercial boiler. Development costs, for first of a kind unit, have been included in the controls and engineering but no other contingencies were included in the estimate. All costs are present day dollars as of February 1, 1978.

As stated above, no contingency has been included in the costs except for the developmental costs mentioned above. However, it must be remembered that certain assumptions were made to establish the design of the AFB system. If these assumptions are borne out by future developments, we believe that the costs presented here represent a reasonable appraisal of what an AFB system would cost. Developing technology may identify areas and conditions which could significantly affect system costs.

Table 12-2 is a graphical representation of the design and construction schedule for the 200 MW fluid bed boiler demonstration unit, scheduled to start-up approximately 47 months after the engineering begins.

TABLE 12-1

200 MW CAPITAL COST ESTIMATE

	<u>Material, \$</u>	<u>Erection, \$</u>
I. Coal and Limestone Feed System	2,100,000	1,227,000
II. Fluid Bed Boiler System	13,300,000	8,425,000
III. Solids Collection & Removal System	6,700,000	3,890,000
IV. Air Heater System (Regenerative)	2,100,000	943,000
V. Controls	<u>2,800,000</u>	<u>875,000</u>
Total	27,000,000	15,360,000

For the particular arrangement of the air heater systems which we have developed, the tubular air heater arrangement is more expensive than the regenerative case by \$80,000 on Materials and \$470,000 on Erection cost. These arrangements have not been optimized and the above comparison is not necessarily true for all cases. Also, there is a greater power penalty for the regenerative system due to the inherent air leakage which must be balanced against the indicated higher capital cost of the tubular system. The regenerative case requires 1500 HP more for the ID and FD fans, than the tubular case. This amounts to 1.5×10^6 , assuming \$1000/HP, which is greater than the capital cost differential.

The scope of equipment included in the above categories is listed in Section VII.

PRODUCTION CONTROL SCHEDULED SHOP LOAD

Start
ShipmentFabrication
Span

FOR THE MONTH OF _____

19 ____

TABLE 12-2

200 MW FLUID BED BOILER

ERECTION SCHEDULE

XIII. COMMERCIAL PLANT DESIGN

A. 800 MW Main Fluidized Bed Boiler (FBC) (See page A-28)

The FBC is made up of eight (8) fluidized beds, each 93 feet by 30 feet. The eight (8) beds are attached to a "common furnace", 93 feet wide and 30 feet deep, and are enclosed by water walls formed by membraned panels consisting of 2-1/2 inch O.D. tubes on 3 inch centers.

A counterflow reheater is located in the upper portion of the common furnace and in the front portion of the downflow convection pass. The downflow convection pass is 93 ft. wide with a total depth of 30 feet. A division wall formed by water cooled membraned panels of 2-1/2 inch O.D. tubes on 4-1/2 inch centers separates the downflow convection pass into two (2) parallel gas passes. Horizontal reheat surface is located in the front pass which is 14 feet deep, with primary superheat and economizer surface in the rear pass which is 16 feet deep. Sootblowers are located above, below and in the cavities formed by the convective heating surfaces.

Each of the eight (8) fluidized beds is divided into five (5) compartments with the air to each compartment supplied by a separate windbox located below the bed. The five (5) compartments of each bed are arranged such that horizontal heating surface is submerged in four (4) bed compartments, with two (2) on each side of the start-up compartment which does not contain submerged heating surface. The start-up compartment is 7 feet wide and 30 feet deep. The remaining four (4) compartments are each 21 feet-6 inches wide and 30 feet deep. Of the thirty-two (32) compartments with heating surface submerged in the fluidized beds, twelve (12) contain boiling surface and twenty (20) contain superheat surface. Tubes comprising the in-bed heating surface are arranged in a staggered pattern. The windboxes are separated from the beds by a perforated plate which distributes the air flow throughout each bed.

Four (4) circulation assist pumps are provided in the downcomer system and are located in front of the FBC. The circulating system is similar in design to the 200 MW demonstration design.

Access doors, sampling and observation ports are provided on the FBC walls of the FBC to provide for maximum observation, sampling, and access.

Superheater, reheater and economizer sections, in addition to the furnace wall panels, are designed to be shop assembled complete with headers attached where possible. The FBC is top supported with loads transferred to the boiler top steel by hanger rods attached to the water wall headers, steam drum, superheat and reheat headers, downcomers and risers.

B. Carbon Burn-up Bed Boiler (CBB) (See page A-29)

The CBB is made up of six (6) fluidized beds, each 12 feet wide and 60 feet deep. The enclosure is formed by water cooled membraned wall panels made of 2-1/2 inch O.D. tubes on 3 inch centers. Boiling surface is located in the downflow convection pass of the CBB to obtain the desired exit gas temperature. No horizontal heating surface is used for the 800 MW CBB design because of geometrical considerations. As the required bed area of the carbon burn-up beds increase with plant size, the wall area for heat transfer to maintain a bed temperature of 2000F, requires longer and narrower beds. It was decided to partially stack the beds because it appears to provide the minimum overall unit height at little sacrifice in plant area. It also provided efficient integration of the bed enclosure into the overall enclosure.

Two (2) air compartments are located under each bed providing a total of twelve (12) separate fluid bed compartments. Each compartment is 12 feet wide and 30 feet deep. A perforated plate separates the air compartment from the fluidized bed and provides the air distribution to the beds.

Boiler sections and the water wall panels are designed to be shop assembled complete, with headers attached, wherever possible. The CBB is top supported with loads transferred to the top steel by hanger rods attached to the water wall headers and risers.

Sootblowers are located above the horizontal convective surface and in the two (2) cavities formed by the convective surface. Access doors, sampling and observation ports are provided in the walls to allow for maximum observation, sampling, and access.

C. Design Philosophy

The design philosophy for the FBC, CBB and the auxiliary systems for the 800 MW power plant are similar to the 200 MW AFB demonstration plant. Design features such as pump assisted circulation, multiple bed compartments (for turndown

control), pneumatic under bed feeding of coal and limestone, bed operating temperatures, bed velocity and excess air requirements are equivalent to the 200 MW demonstration design.

The only major difference, other than the bed arrangement of the CBB, is the layout of the reheater surface in the FBC. Convection pass depths for smaller (under 300 MW) fluidized bed boilers are not deep enough to permit a front to rear split to obtain the two gas paths required for reheat temperature control. The smaller size of the 200 MW demonstration unit required the split to be side to side with an intermediate transition header to change the half width reheater tube arrangement to full width in the upflow gas section. Splitting the downflow convection pass front to rear on the 800 MW design, eliminates the transition header and simplifies the construction.

The physical design of the main furnace of the 800 MW FBC is more straight forward than for the demonstration unit. The 200 MW unit, as explained in Section V, has only four (4) main boiler beds. With a bed velocity of 4 ft/sec., it was necessary to reduce the depth of the main furnace shaft to increase the gas velocities through the high temperature reheater banks at the top of the furnace. By increasing the gas mass flow past the tubes, more efficient heat transfer rates are obtained resulting in a considerable reduction in the required heat transfer surface. With eight (8) main beds on the 800 MW design, optimum velocities are obtained without reducing the depth of the furnace.

Under bed feeding of coal and limestone to the FBC, with pneumatic transport and drying, is similar to the demonstration design. However, the bed compartments are larger, requiring 70 feed points per compartment (30 feed points for the start-up compartments). This will probably require an initial and a secondary split of feed lines in order to allow a single pair of gravimetric feeders to supply each operating compartment.

D. Cost Estimate

The 800 MW fluid bed boiler (FBC and CBB) was estimated to cost approximately $\$33 \times 10^6$. The equipment included in the price base follows:

- .FBC - including boiler envelope, buckstays, furnace wall tubes, hanger rods, steam drum, boiler piping (sootblower piping, etc.), supplies, risers, downcomers, etc.

.CBB - similar to above.

.Convection banks - economizer, primary superheater, reheater

.Boiler bed surface

.Boiler firing equipment - piping from mixing bustles to boiler beds, distribution bottles, piping supports, perforated plate, and structural supports.

.Sootblowers, thermoprobes and thermocouples

.Lighter Controls

.Circulation Pumps and Motors

.Circulation Valves

The estimated price for the 800 MW boiler is only approximate and was prorated based on the estimates that B&W has already done for fluid bed boilers of the following capacities: 200 MW, 470 MW, 570 MW.

THE BABCOCK & WILCOX COMPANY
E. HEAT AND MATERIAL BALANCE

PROCESS 800 MW Fluid Bed Boiler
CUSTOMER TVA/ERDA
PLANT Paradise, Kentucky

CONTRACT NO. 591-0241
PROPOSAL NO.
DATE

OPERATING CONDITIONS
With Tubular
Air Heater

STREAM NUMBER	1	2	3	4	5	6	7	8	9	10	11	12
STREAM DESCRIPTION	COAL FEED	LIMESTONE FEED	CHAR, STONE & GAS FROM FBC	FBC UNDERFLOW	FBC PRECI-PITATOR UNDERFLOW	CBB UNDERFLOW	CHAR, STONE & GAS FROM CBB	CBB MECHANICAL DUST COLLECTOR UNDERFLOW	CBB PRECIPITATOR UNDERFLOW	FLUE GAS FROM CBB	FLUE GAS FROM FBC	TOTAL FLUE GAS
PROCESS CONDITIONS												
TEMPERATURE (°F)	80	80	720	1,550	700	2,000	787	762	762	762	700	710
PRESSURE (IN.WG) ①	-	-	-6.8	-	-	-	-3.4	-	-	-8.6	-8.0	-8.8
PRESSURE (PSIG)	-	-	-	-	-	-	-	-	-	-	-	-
FLOW RATE (GAS OR LIQUID ONLY)	-	-	-	-	-	-	-	-	-	-	-	-
LB MOLE/HR	-	-	234,736	-	-	-	29,292	-	-	29,484	236,564	266,076
LB/HR	-	-	6,919,972	-	-	-	880,464	-	-	886,012	6,973,908	7,859,920
SCFM (OR GPM) @ 60°F, 1 ATM.	-	-	1,484,436	-	-	-	185,240	-	-	186,452	1,495,996	1,682,624
ACFM (OR GPM) @ CONDITIONS	-	-	3,425,764	-	-	-	447,960	0	0	447,620	3,404,132	3,869,572
PHYSICAL PROPERTIES	-	-	-	-	-	-	-	-	-	-	-	-
MOLE WT (GAS OR LIQUID ONLY)	-	-	29.48	-	-	-	30.06	-	-	30.05	29.48	29.54
STATE (S, L, G)	S	S	S&G	S	S	S	S&G	S	S	S&G	S&G	S&G
DENSITY (LB/FT ³) (GAS OR LIQUID)	-	-	0.034	-	-	-	0.033	-	-	0.033	0.034	0.034
ENTHALPY (MMB/HR), BASE 77°F	0.64	0.164	1187.60	50.88	21.64	-	181.68	20.16	2.64	155.20	1135.44	1290.64
COMPOSITION (LBS/HR) (GAS OR LIQUID)	-	-	-	-	-	-	-	-	-	-	-	-
O ₂	-	-	209,114	-	-	-	64,532	-	-	65,796	221,448	287,244
N ₂	-	-	4,798,744	-	-	-	635,688	-	-	639,900	4,839,672	5,479,572
H ₂ O	63,784	11,912	412,892	-	-	-	15,128	-	-	15,200	413,596	428,796
CO ₂	-	-	1,490,252	-	-	-	164,744	-	-	164,744	1,490,252	1,654,996
SO ₂	-	-	8,940	-	-	-	372	-	-	372	8,940	9,312
(GAS OR LIQUID) SUBTOTAL	63,784	11,912	6,919,972	-	-	-	880,464	-	-	886,012	6,973,908	7,859,920
SOLIDS (LBS/HR)	-	-	-	-	-	-	-	-	-	-	-	-
COAL	644,912	-	-	-	-	-	-	-	-	-	-	-
CaCO ₃	-	214,988	-	-	-	-	-	-	-	-	-	-
MgCO ₃	-	4,764	-	-	-	-	-	-	-	-	-	-
SiO ₂ + INERTS	-	6,552	2,292	4,260	2,292	-	2,292	2,272	20	-	-	-
CaO	-	-	26,932	54,540	26,932	-	23,644	23,404	240	-	-	-
CaSO ₄	-	-	36,968	57,676	36,968	-	44,952	44,496	456	-	-	-
C ₈ H ₈	-	-	50,428	-	49,924	-	4,492	3,592	852	44	-	-
MgO	-	-	796	1,480	796	-	796	788	8	-	504	548
S	-	-	2,296	-	2,272	-	204	200	4	-	-	-
ASH	-	-	74,944	24,980	74,868	-	74,868	59,896	14,900	76	24	24
(SOLIDS) SUBTOTAL	644,912	226,304	194,656	142,936	194,052	-	151,248	134,648	16,480	120	604	724
(SOLIDS + GAS OR LIQUID) TOTAL	708,696	238,216	7,114,628	142,936	194,052	-0-	1,031,712	134,648	16,480	886,132	6,974,512	7,860,644

NOTES: ① ATMOSPHERIC PRESSURE = 14.696

THE BABCOCK & WILCOX COMPANY

HEAT AND MATERIAL BALANCE

PROCESS 800 MW Fluid Bed Boiler

CUSTOMER TVA/ERDA

PLANT Paradise, Kentucky

CONTRACT NO. 591-0241

PROPOSAL NO.

DATE

OPERATING CONDITIONS

With Tubular

Air Heater

STREAM NUMBER	13	14	15*	16*	17*	18*	19*	20*	21	22	23	24
STREAM DESCRIPTION	FLUE GAS	GAS TO	CIRCULATING	ATTEMPER-	MAIN	COLD REHEAT	HOT REHEAT	FEED WATER	FBC	INLET AIR	TEMPERING	PRIMARY
	FROM AIR	STACK	WATER TO RE-	ATOR SPRAY	STEAM				UNDERFLOW		AIR	CONVEYING
	HEATER		CIRCULATING									AIR TO FBC
			PUMPS									
PROCESS CONDITIONS												
TEMPERATURE (°F)	285	290	686	487	1,003	642	1,003	487	700	100	103	648
PRESSURE (IN.WG) ①	-13.5	-2.3	-	-	-	-	-	-	-	53.2	61	61
PRESSURE (PSIG)	-	-	2,816	2,716	2,581	594	578	2,836	-	-	-	-
FLOW RATE (GAS OR LIQUID ONLY)	-	-	-	-	-	-	-	-	-	-	-	-
LB MOLE/HR	266,076	266,076	1,945,908	29,512	324,320	275,908	275,908	324,320	-	245,716	12,844	28,036
LB/HR	7,859,920	7,859,920	35,065,272	531,800	5,844,212	4,971,844	4,971,844	5,844,212	-	7,034,900	367,748	802,724
SCFM (OR GPM) @ 60°F, 1 ATM.	1,682,624	1,682,624	(70,056)	(1,068)	-	-	-	(11,676)	-	1,553,872	81,224	177,296
ACFM (OR GPM) @ CONDITIONS	2,493,388	2,440,652	(137,036)	(1,312)	28,568	83,768	116,780	(14,668)	-	1,479,952	76,480	328,536
PHYSICAL PROPERTIES												
MOLE WT (GAS OR LIQUID ONLY)	29.54	29.54	18.02	18.02	18.02	18.02	18.02	18.02	-	28.63	28.63	28.63
STATE (S, L, G)	S&G	S&G	L	L	G	G	G	L	S	G	G	G
DENSITY (LB/FT ³) (GAS OR LIQUID)	0.053	0.054	31.90	50.6	3.41	0.990	0.710	49.68	-	0.079	0.080	0.041
ENTHALPY (MMB/HR), BASE 77°F	409.12	418.96	26,988	251.96	8,504	6,624	7,560	2,760	18.56	44.24	50.00	115.08
COMPOSITION (LBS/HR) (GAS OR LIQUID)												
O ₂	287,244	287,244	-	-	-	-	-	-	-	1,604,596	83,880	183,092
N ₂	5,479,572	5,479,572	-	-	-	-	-	-	-	5,338,652	279,076	609,172
H ₂ O	428,796	428,796	35,065,272	531,800	5,844,212	4,971,844	4,971,844	5,844,212	-	91,652	4,792	10,460
CO ₂	1,654,996	1,654,996	-	-	-	-	-	-	-	-	-	-
SO ₂	9,312	9,312	-	-	-	-	-	-	-	-	-	-
(GAS OR LIQUID) SUBTOTAL	7,859,920	7,859,920	35,065,272	531,800	5,844,212	4,971,844	4,971,844	5,844,212	-	7,034,900	367,748	802,724
SOLIDS (LBS/HR)	-	-	-	-	-	-	-	-	-	-	-	-
COAL	-	-	-	-	-	-	-	-	-	-	-	-
CaCO ₃	-	-	-	-	-	-	-	-	-	-	-	-
MgCO ₃	-	-	-	-	-	-	-	-	-	-	-	-
SiO ₂ + INERTS	-	-	-	-	-	-	-	-	4,260	-	-	-
CaO	-	-	-	-	-	-	-	-	54,540	-	-	-
CaSO ₄	-	-	-	-	-	-	-	-	57,676	-	-	-
C ₈ H ₈	548	548	-	-	-	-	-	-	-	-	-	-
MgO	-	-	-	-	-	-	-	-	1,480	-	-	-
S	24	24	-	-	-	-	-	-	-	-	-	-
ASH	152	152	-	-	-	-	-	-	24,980	-	-	-
(SOLIDS) SUBTOTAL	724	181	-	-	-	-	-	-	142,936	-	-	-
(SOLIDS + GAS OR LIQUID) TOTAL	7,860,644	1,965,161	35,065,272	531,800	5,844,212	4,971,844	4,971,844	5,844,212	142,936	7,034,900	367,748	802,724

NOTES: ① ATMOSPHERIC PRESSURE = 14.696

* All Flows are for valves wide open, and 5% overpressure
Steam and boiler water base is 32°F.

THE BABCOCK & WILCOX COMPANY

HEAT AND MATERIAL BALANCE

PROCESS

800 MW FLUID BED BOILER

CUSTOMER

TVA/ERDA

PLANT

Paradise, Kentucky

CONTRACT NO:

591-0241

PROPOSAL NO.

DATE

OPERATING CONDITIONS

With Tubular

Air Heater

1	STREAM NUMBER	25	26	27	28	29	30	31 *	32 *	33 *	34	35	36
2	STREAM DESCRIPTION	CBB FEED	AIR TO CBB	AIR TO FBC	FBC FEED	FBC	FBC	CBB	CBB	CBB	AIR	AIR	AIR INFIL-
3		CONVEYING			CONVEYING	UNDERFLOW	UNDERFLOW	UNDERFLOW	UNDERFLOW	UNDERFLOW	INFILTRA -	INFILTRA-	TRATION TO
4		AIR			AIR	COOLING	COOLING	COOLING	COOLING		TION TO FBC	TION TO CBB	FBC PRECIP.
5						WATER	WATER	WATER	WATER				
6						INLET	OUTLET	INLET	OUTLET				
7	PROCESS CONDITIONS												
8	TEMPERATURE (°F)	501	636	636	475	80	110	80	110	700	80	80	80
9	PRESSURE (IN.WG) ①	61	45.2	61	-	-	-	-	-	-	-	-	-
10	PRESSURE (PSIG)	-	-	-	-	-	-	-	-	-	-	-	-
11	FLOW RATE (GAS OR LIQUID ONLY)	-	-	-	-	-	-	-	-	-	-	-	-
12	LB MOLE/HR	4,432	24,632	180,204	36,448	59,784	59,794	3,404	3,404	-	3,768	192	1,884
13	LB/HR	126,916	705,204	5,159,224	1,043,556	1,077,336	1,077,336	61,332	61,332	-	107,872	5,540	53,936
14	SCFM (OR GPM) @ 60°F, 1 ATM.	28,028	155,768	1,139,584	230,492	(2,152)	(2,152)	(124)	(124)	-	23,828	1,216	11,916
15	ACFM (OR GPM) @ CONDITIONS	45,048	295,496	2,161,808	360,420	(2,152)	(2,152)	(124)	(124)	-	24,744	1,264	12,376
16		-	-	-	-	-	-	-	-	-	-	-	-
17	PHYSICAL PROPERTIES	-	-	-	-	-	-	-	-	-	-	-	-
18	MOLE WT (GAS OR LIQUID ONLY)	-	-	-	-	18.02	18.02	18.02	18.02	-	28.63	28.63	28.63
19	STATE (S, L, G)	G	G	G	G	L	L	L	L	S	G	G	G
20	DENSITY (LB/FT ³) (GAS OR LIQUID)	0.047	0.040	0.040	0.048	62.4	62.4	62.4	62.4	-	0.073	0.073	0.073
21		-	-	-	-	-	-	-	-	-	-	-	-
22	ENTHALPY (MMB/HR), BASE 77°F	13	97.56	713.60	101.64	3.24	35.6	0.184	2.04	0.80	0.08	0.004	0.040
23		-	-	-	-	-	-	-	-	-	-	-	-
24		-	-	-	-	-	-	-	-	-	-	-	-
25	COMPOSITION (LBS/HR) (GAS OR LIQUID)	-	-	-	-	-	-	-	-	-	-	-	-
26	O ₂	28,948	160,852	1,176,772	238,024	-	-	-	-	-	24,604	1,264	12,304
27	N ₂	96,316	535,164	3,915,236	791,936	-	-	-	-	-	81,860	4,208	40,932
28	H ₂ O	1,652	9,188	67,216	13,596	1,077,334	1,077,334	61,332	61,332	-	1,408	68	700
29	CO ₂	-	-	-	-	-	-	-	-	-	-	-	-
30	SO ₂	-	-	-	-	-	-	-	-	-	-	-	-
31		-	-	-	-	-	-	-	-	-	-	-	-
32	(GAS OR LIQUID) SUBTOTAL	126,916	705,204	5,159,224	1,043,556	1,077,334	1,077,334	61,332	61,332	-	107,872	5,540	53,936
33	SOLIDS (LBS/HR)	-	-	-	-	-	-	-	-	-	-	-	-
34	COAL	-	-	-	-	-	-	-	-	-	-	-	-
35	CaCO ₃	-	-	-	-	-	-	-	-	-	-	-	-
36	MgCO ₃	-	-	-	-	-	-	-	-	-	-	-	-
37	SiO ₂ + INERTS	-	-	-	-	-	-	-	-	164	-	-	-
38	CaO	-	-	-	-	-	-	-	-	2,104	-	-	-
39	CaSO ₄	-	-	-	-	-	-	-	-	2,224	-	-	-
40	C ₈ H ₈	-	-	-	-	-	-	-	-	-	-	-	-
41	MgO	-	-	-	-	-	-	-	-	56	-	-	-
42	S	-	-	-	-	-	-	-	-	-	-	-	-
43	ASH	-	-	-	-	-	-	-	-	964	-	-	-
44	(SOLIDS) SUBTOTAL	-	-	-	-	-	-	-	-	5,512	-	-	-
45	(SOLIDS + GAS OR LIQUID) TOTAL	126,916	705,204	5,159,224	1,043,556	1,077,334	1,077,334	61,332	61,332	5,512	107,872	5,540	53,936

NOTES: ① ATMOSPHERIC PRESSURE = 14.696

* Only if coal and limestone are fired in CBB.

THE BABCOCK & WILCOX COMPANY

HEAT AND MATERIAL BALANCE

PROCESS 800 MW Fluid Bed Boiler

CUSTOMER TVA/ERDA

PLANT Paradise, Kentucky

CONTRACT NO. 591-0241

PROPOSAL NO.

DATE

OPERATING CONDITIONS

With Regenerative

Air Heater

1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41
	STREAM NUMBER	13	14	22																																				
	STREAM DESCRIPTION	FLUE GAS	GAS TO	INLET AIR																																				
		FROM AIR	STACK																																					
		HEATER																																						
	PROCESS CONDITIONS																																							
	TEMPERATURE (°F)	269	274	100																																				
	PRESSURE (IN.WG) ①	-13.5	-2.3	53.2																																				
	PRESSURE (PSIG)	-	-	-																																				
	FLOW RATE (GAS OR LIQUID ONLY)	-	-	-																																				
	LB MOLE/HR	289,564	289,564	269,244																																				
	LB/HR	8,533,488	8,533,488	7,708,468																																				
	SCFM (OR GPM) @ 60°F, 1 ATM.	1,831,160	1,831,160	1,702,660																																				
	ACFM (OR GPM) @ CONDITIONS	2,655,220	2,599,440	1,621,664																																				
	PHYSICAL PROPERTIES	-	-	-																																				
	MOLE WT (GAS OR LIQUID ONLY)	29.47	29.47	28.63																																				
	STATE (S, L, G)	G	G	G																																				
	DENSITY (LB/FT ³) (GAS OR LIQUID)	0.054	0.055	0.079																																				
	ENTHALPY (MMB/HR), BASE 77°F	416.96	427.72	48.48																																				
	COMPOSITION (LBS/HR) (GAS OR LIQUID)	-	-	-																																				
	O ₂	440,876	440,876	1,758,232																																				
	N ₂	5,990,732	5,990,732	5,849,812																																				
	H ₂ O	437,572	437,572	100,424																																				
	CO ₂	1,654,996	1,654,996	-																																				
	SO ₂	9,312	9,312	-																																				
	(GAS OR LIQUID) SUBTOTAL	8,533,488	8,533,488	7,708,468																																				
	SOLIDS (LBS/HR)	-	-	-																																				
	COAL	-	-	-																																				
	CaCO ₃	-	-	-																																				
	MgCO ₃	-	-	-																																				
	SiO ₂ + INERTS	-	-	-																																				
	CaO	-	-	-																																				
	CaSO ₄	-	-	-																																				
	C ₈ H ₈	548	548	-																																				
	MgO	-	-	-																																				
	S	24	24	-																																				
	ASH	152	152	-																																				
	(SOLIDS) SUBTOTAL	724	724	-																																				
	(SOLIDS + GAS OR LIQUID) TOTAL	8,534,212	8,534,212	7,708,468																																				

NOTES: ① ATMOSPHERIC PRESSURE = 14.696

Air Leakage FROM AIR SIDE TO GAS SIDE IS 673568 Lbs/Hr

XIV. AFB BOILER STATE OF THE ART

A. Introduction

Recent interest in fluidized bed combustion for utility application has been stimulated by the in-process pollution control capability of the Atmospheric Fluid Bed Combustor (AFB):

.Low NO_x Formation

SO₂ removal is accomplished by reaction of limestone or lime with SO₂ released during coal combustion to produce a dry CaSO₄ waste product. Low NO_x formation is experienced as well because of the low operating temperature (1500-1600°F). However, the viability of this approach must still be established relative to that of wet scrubbing:

This alternate approach also involves the reaction of limestone with SO₂ in the stack gas but produces a wet slurry of CaSO₃. Relatively speaking, wet scrubbing is fairly well developed and accepted as a commercial system.

The above consideration is primary in nature and worth emphasizing because one of the key problems currently facing the AFB is the high limestone requirements to meet the EPA sulfur dioxide emission standard (1.2 lbs SO₂/million Btu input). This situation could be further aggravated if EPA proceeds to enact more restrictive standards for sulfur emission. This is a likelihood based on recent reports in the literature (Energy Research Digest, November 7, 1977). In wet scrubbing systems the required Ca/S mole ratio is on the order of 1.1, while in the AFB system ratios of up to four (4) or five (5) may be needed depending on the sulfur content of the coal. The latter represents an economically unacceptable amount of limestone, and a major R&D thrust is needed to minimize these requirements. NO_x formation, on the other hand, can be comfortably maintained below current EPA emission standards (0.7 pounds per million Btu or about 525 ppm) but not as low as expected from an equilibrium standpoint because of fixation of fuel nitrogen. Values of 250 to 500 ppm of NO_x in the off-gases have been observed when burning coal containing about 1.0 to 1.4% fixed nitrogen in fluidized beds.

Nevertheless, while the economics of the fluid bed combustion process are not firmly established, some investigators feel that capital and operating costs could be lower than conventional plants using wet scrubbing for sulfur control and that further improvement is potentially possible. To achieve an acceptable status, large scale demonstration of the concepts is needed. However, before this can be accomplished, it is the general feeling that the level of confidence in design knowledge must be increased as the desirable configurations of the system become more clearly defined through pilot activities.

Background history and documentation is thoroughly treated in References 1-5. It is the purpose of this section to analyze some of the existing problem areas in the light of this literature and/or in-house knowledge and to identify areas requiring additional development work. In order to develop this overall picture, a simple schematic flowsheet (Figure 14-1) for an AFB system is presented. Problem areas are highlighted in the following pages.

B. Process Overview

Starting at the front end of the process shown in Figure 14-1, the first objective is to combine coal and limestone and convey them to the FBC. To date the preferred method of doing this has been pneumatic transport and introduction of the feed materials near the bottom of the FBC just above the air distributor plate. Based on prior B&W experience with cyclone furnace firing, it may be possible to avoid predrying by employing preheated air as the conveying medium. This practice requires about 20% of the combustion air which is several fold greater than the amount needed from the standpoint of conveying alone. The effect of this additional amount of air on FBC performance is unknown.

The next step is a problem of major concern and relates to the means of splitting the feed stream into a large number of smaller ones for distribution into the FBC. This is required to assure reasonably good combustion in the FBC. As the coal enters at or near the bottom of the bed, it must be further distributed in a radial direction by means of injection nozzles. Overhead feeding and spreading in the freeboard of the FBC is an alternate approach under consideration by some investigators.

The design of the AFB involves the selection of a number of critical operating parameters. Those of greatest significance are:

- .Bed temperature

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FIGURE 14-1

SCHEMATIC FLOWSHEET OF FBC SYSTEM

DWN. BY JB	CHK'D
PASSED BY	APP'D

SCHEMATIC FLOWSHEET

SCALE $\frac{1}{4}$	DATE 5/1/78
DRWG. NO. 140031	A-C

- .Excess air
- .Superficial gas velocity
- .Feed particle size and/or elutriation of bed solids

With regard to bed temperature the efforts of many investigators have reasonably well defined the desirable operating range. In order to promote rapid combustion and reaction rates of SO_2 with lime, temperatures above 1400°F are preferred. However, above 1600°F sorbent activity appears to drop and at higher temperatures volatilization of corrosive alkali metals can potentially commence to become a problem, in addition, bed agglomeration may occur. Therefore, an operating temperature of about 1550°F is considered optimum for the FBC. Operation of the FBC at 15% excess air seems to be an acceptable design condition. However, in the case of the CBB a higher temperature of 2000°F and also a greater amount of excess air (50%) are desirable to assure adequate carbon burnout.

Wide ranges of gas velocity from 3 to 15 ft/sec have been studied, but no specific guidelines have been found in the open literature to establish design recommendations. However, general preference has developed for the use of coarse feed materials. Pope, Evans and Robbins appears to be the prime proponent of coarse grinds ($-1/4" \times 0$) requiring a high superficial gas velocity of 10-15 ft/sec., whereas others such as Westinghouse, the British consortiums, etc. prefer to operate under conditions permitting the use of lower velocities in the range of 3-8 ft/sec.

It should be noted that particle size, gas velocity and bed voidage are all interrelated by laws of fluid flow through particle assemblages. These conditions can therefore not be independently selected. Predictive relationships for this purpose are suggested in Reference (4). In Reference (5) the values of voidage for given values of particle size and gas velocity were estimated based on these relationships for conditions normally encountered in the FBC. Relationships such as these are predicted on data for unrestricted beds and must still be verified or modified for use in the case where heat transfer tubes are immersed in the bed. This knowledge is needed for estimating the pressure drop across the fluid bed and is also useful in the design of an AFB to establish an appropriate gas velocity and/or particle size distribution. For example, once an average particle size of the bed is chosen, a superficial gas velocity corresponding to a suitable bed voidage can be determined via relationships mentioned above to permit the desired turndown capability, or the particle size distribution may be selected to limit the amount of elutriation for a given velocity, etc.

The heat released in the bed is absorbed by tubes immersed in the bed. Because the temperature and the amount of heat transfer surface is "fixed", flexible response to wide load changes is not easy to attain. Such variations in load also present a problem of maintaining good air distribution through the distribution plate without undue pressure drop at full load.

As previously mentioned, the amount of limestone required for sulfur capture in the AFB has been found to be excessive. Most of the available data base consists only of plots of % SO_2 removal versus the Ca/S ratio with or without additives as shown by Figure 14-2. Combustion efficiency has also been found to be a problem area in FBC units in that it is generally in the range of 85-95% or less as shown by Figure 14-3. This graph is a plot of the available combustion efficiencies versus superficial velocity reported in Reference 4. Although this graph shows a great deal of scatter, there is a statistical trend. As the velocity is increased, the combustion efficiency is decreased. This serves as a preliminary basis for predicting the velocity dependency of combustion efficiency, but more information is needed relative to the effects of bed height and/or other variables such as excess air, bed voidage and temperature.

Most of the unburned char, together with a fair amount of spent lime, are elutriated and must be subsequently collected and reprocessed in order to achieve an acceptable level of thermal efficiency for the overall system. This calls for the possible use of a number of different dust collection devices such as a mechanical cyclone collector, a baghouse and a hot or cold electrostatic precipitator. The nature and performance of an appropriate dust collection system is still to be defined.

One approach for retreating the dust collected is to recycle it back to the FBC. This practice would result in high dust loadings and potential economic penalties. Another approach is to inject the dust to a carbon burnup bed which is another fluid bed but is operated at a much higher temperature and excess air so that acceptable single pass combustion efficiencies can be achieved. In accordance with PER experience, no decomposition of CaSO_4 should occur in this step. The degree of sulfur capture is said to vary between zero and that corresponding to equilibrium concentrations in the exit gases. The sources of this sulfur may be two fold: (1) sulfur contained in the unburned char from the FBC and (2) additional coal that may be fired in the CBB to maintain temperature control.

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FIGURE 14-2
SULFUR CAPTURE AS A FUNCTION OF
STOICHIOMETRY AND EFFECTS OF
SALT ADDITION

BRUNING 16635

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OWN. BY JB	CHK'D
PASSED BY	APP'D

SO₂ REDUCTION VS Ca/S

SCALE 7/8	DATE 5/1/78
DRWG. NO. 40030	A-0

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FIGURE 14-3
COMBUSTION EFFICIENCY AS A FUNCTION
OF GAS VELOCITY

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DWN. BY JB	CHK'D	COMBUSTION EFFICIENCY VS SUPERFICIAL VELOCITY FT/SEC	SCALE <i>H</i>	DATE 5/1/78
PASSED BY	APP'D		DRWG. NO. 140029	A-0

In commercial practice it would be anticipated that spent bed material from the FBC would provide the material comprising the fluid bed in the CBB. In any case the sensible heat lost in this material and that discharged from the CBB is significant and means for recovering this heat must be developed.

C. Process Developments and Assessments

Many problem areas still exist relative to the operation of a fluid bed combustor for steam generation. Broadly speaking, questionable areas can be classified as being mechanical or technical in nature. The former are largely associated with start-up procedures, response to load changes and controls, operating compatibility of system components, and turndown. The latter relate to process conditions affecting operating performance such as heat transfer, pressure drop, reaction efficiencies, etc. Appropriate data in both of these areas still need to be developed in order to establish feasibility of an AFB system versus a conventional PC boiler provided with a wet scrubbing system.

There are many existing R&D programs that are aimed at these broad objectives and associated subtasks. These are summarized on pages 14-17 through 14-31, "Current Projects Influencing AFBC of Coal" compiled by the Radian Corporation. In review of these efforts and prior discussions, it is apparent that most of the significant problem areas involve the new fluid bed technology and auxiliaries that are being employed in the FBC and CBB. For the purpose of subsequent discussions, those areas of major concern beyond normal efforts of obtaining or deriving design information will be covered under the following categories:

1. Feed distribution
2. Combustion efficiency
3. Turndown control
4. Sulfur capture
5. Disposal of spent bed material
6. Corrosion and erosion
7. Dust collection

1. Feed Distribution

In the area of feed distribution, the main problem relates to the large number of coal injection points that are required to assure reasonably good combustion. Previous experience indicates the need for one fuel injector per nine (9) square feet when feeding crushed coal to beds approximately 3-4 feet in depth. For

operation at 8 ft/sec., this criteria requires more than 1,000 feed points in a 600 MW plant. To supply all the multiple feed points, prior splitting would therefore be desirable.

One solution to this problem is pneumatic splitting into the bottom portion of the bed. This problem will be partially addressed during the operation of the EPRI/B&W 6' x 6' unit at Alliance, Ohio, which will be equipped to split feed to four (4) 3' x 3' quadrants. However, more scale-up information will be needed for supplying the larger number of feed points required in a demonstration plant, particularly in the presence of a pulsating back pressure of a fluidized bed. Similar problems will exist in re-distributing entrained char from the FBC unit into the CBB unit.

Another approach is overhead feeding in the freeboard. This alternative is being investigated by others. It is possible that this practice may result in some sacrifice in combustion efficiency and sulfur capture unless special attention is given to coal sizing, but this remains to be proven.

Firm recommendations are also needed for the design of injection nozzles. It is probable that such information will arise through efforts under EPRI contracts at B&W and Oregon State University (OSU) or various government sponsored activities at PER, etc.

2. Combustion Efficiency

The basic problem here results from the low single-pass combustion efficiency which is in the range of only 85-95% for either the FBC or CBB. In this area, we continue to need more information which will permit us to predict the effects of bed operating conditions and the amount of in-bed burning versus freeboard performance so that the heat transfer surface can be accurately designed for the heat release expected in each zone. This information is equally as important as the capability of predicting heat transfer coefficients.

Since coal oxidation is basically a chemical reaction involving oxygen transport, it is our feeling that gas residence time is an important parameter to be studied. This infers that improved efficiency should be achieved by resorting to the use of lower velocities and higher bed heights. Also expected is significant sensitivity with temperature, excess air and coal

properties. A B&W analysis (3) of fluidized bed combustion allowed some conclusions to be drawn on the significance of coal sizing:

- .Complete burnout of the very fine coal particles (-270 mesh) is feasible in a fluid bed combustor.

- .The problem of incomplete burnout may not be associated with the coarse fractions but is more likely the result of inadequate retention time of the elutriatable fraction of intermediate sizes.

It is very likely that the volatile matter in the coal is rapidly consumed. Since complete combustion of the residual char contained in the very coarse and fine fractions is also expected, then one can postulate that the prime problem is one of burning the residual char in the intermediate size fraction with the remaining combustion air.

While some of the discussion above is within the realm of speculation, it illustrates the need for a better understanding of the basic combustion process. One of the main objectives of the EPRI/B&W 6' x 6' fluid bed at Alliance, Ohio, will be to provide valuable inputs on possibilities of improving carbon utilization and to further delineate the significance of the above mentioned variables. In addition OSU (Oregon State University) under contract to EPRI/B&W is also obtaining basic data on the flow characteristics of coarse char and concentration gradients of elutriatable fines. Hopefully this effort will increase our ability to understand the combustion process and suggest possibilities for improving it.

The use of coarse coal as overhead feed has been logically suggested as a means for improving combustion and alleviating the problem of feed distribution. At this point in time, however, there is insufficient experience to confirm its feasibility and/or justify its application as a basis for design. If feasible, other benefits can be anticipated as well: possible elimination of the CBB by restricting most of the combustion to the FBC, reduction of char content in the carryover material, reduction in CO formation which is probably promoted in the freeboard due to the presence of the char particles and also reducing NO_x formation because of the lower time averaged temperature during the combustion of larger coal particles. The disadvantage would be the need for coal preclass-

ification and a separate disposal of fines, but in lesser amounts.

3. Turndown Control

In this area of concern, the problem is inflexibility of heat transfer versus load changes resulting from the fact that the immersed surface and temperatures are "fixed", so to speak.

The preferred solution to this problem appears to be the technique of "bed slumping" although there is little background experience in its application on a large scale. The approach is to compartmentalize the boiler windbox and provide separate air flow to each section, so that each section can in turn be shut off. This capability is provided in the EPRI/B&W 6' x 6' unit. Also OSU, under contract to EPRI/B&W, has built and will test a cold test unit to study the phenomenon of slumping.

There is, however, an urgent need for an alternate backup method, should bed slumping fail to provide the desired results. An engineering study should be undertaken to investigate the feasibility of alternate methods. One such approach might involve an unexplored concept employing graduated vertical spacing of heat transfer tubes so that just the proper amount of surface is exposed as bed height is varied with air flow. This, of course, would also call for a near constant differential pressure air distribution plate so that uniformity of fluidization is always maintained.

4. Sulfur Capture

This is a very significant problem area because, based on available data, the limestone requirements may be unduly high as explained earlier. The high cost of limestone, resulting thermal inefficiencies and requirements for spent lime disposal would give rise to severe economic penalties.

Again, more information is needed to permit the designer to predict the effects of bed conditions and increased gas-solid contact time. The generation of appropriate data will be within the scope of the B&W program sponsored by EPRI at Alliance, Ohio. Supporting information should also be available through the operation of the fluidized bed combustion unit at Rivesville, West Virginia.

In addition, there are also some advanced concepts that can be conceived or are under development:

- .Precalcination of limestone under selected conditions (EPRI-Westinghouse),
- .The use of additives such as sodium chloride (EPRI, ERDA-PER, University of Maryland),
- .Recycle system with external regeneration (ANL),
- .Fine grinding of spent sorbent and recycle, etc.

Some of these concepts warrant preliminary engineering studies to establish their economic potential and future R&D priorities. Associated efforts should be closely monitored to assess future impacts as early as possible.

5. Heat Recovery from Spent Bed Material

Another problem area is the disposal of hot spent bed material. This represents a thermal inefficiency due to the sensible heat loss and the unburned carbon contained in the bed material. Solutions to counteract these inefficiencies must be found eventually. Although it is not considered critical, engineering studies should be initiated to assess potential alternatives so that the best prospect(s) can be piloted at a later date.

6. Corrosion and Erosion

Because of the long term nature of corrosion and related studies, they should proceed as quickly as possible so that required inputs become available before designing a demonstration plant. There are indications that high corrosion rates may exist for submerged surface in a fluidized bed of spent lime, and firm design information is lacking. Furthermore, the degree of upset conditions in an AFB and related effects on corrosion are unknown. EPRI has recently contracted work in this area to BCURA including an effort to prepare a three-dimensional corrosion map emanating around a feed point where upset conditions may be the most severe. Information is also needed on the effect of high dust loadings in convection passes, particularly from the standpoint of erosion. Certainly the fate of some recycle concepts for improving combustion efficiency and sulfur capture are dependent on such knowledge.

7. Dust Collection

The prediction and characterization of dust carry-over is essential in specifying subsequent dust collection facilities, but subject information is quite sparse in the literature. Rothemuhle feels that hot electrostatic precipitators can be designed to handle final gas cleanup. Others have expressed some doubt relative to the operability of an electrostatic precipitator due to the presence of carbon particles and the reduced concentration of the SO₂ in the gas. In any case, operating data for an electrostatic precipitator under hot (700°F) and cold (300°F) conditions is needed to verify feasibility and determine the appropriate mode of operation.

Recent reports indicate that the EPA is expected to propose a substantial reduction of particulate emissions to a fraction of the current standard (0.1 pounds per million Btu). This is noteworthy because of its potential impact on R&D. Some utility sources believe that if the level of emissions were reduced by an order of magnitude this would all but mandate the use of baghouses. Rothemuhle, however, generally anticipates no problems in achieving emission levels down to at least 0.03 pounds per million Btu with a hot precipitator.

D. Summary, Conclusions, and Recommendations

Based on our assessment pertaining to the degree of development of AFB boiler technology and the areas requiring more extensive R&D work, our final conclusions and recommendations can be summarized under two categories:

- .General R&D needs.
- .Additional R&D efforts that deserve more attention.

1. General R&D Needs

The mechanical feasibility and compatibility of a total system on a pilot scale must be demonstrated. Such a demonstration is needed at an early date. In addition, more data is needed which will describe the operation of the FBC and CBB boilers. The effect on operation of gas velocity, bed temperature, bed material size distribution, etc. must be established before scale-up to commercial size utility can be accomplished with a reasonable level of confidence.

There are still many problems to solve such as combustion efficiency and sulfur capture. The former is a problem because of single-pass efficiency of only about 85-95% (depending on operating conditions) is typical of AFB operation. Sulfur capture is a problem because limestone requirements equivalent to a Ca/S ratio of three (3) or more are needed to achieve acceptable sulfur capture and this appears to be economically unacceptable. Hopefully, however, much of this type of information will be obtainable through ongoing or extended efforts by DOE, EPRI, B&W and others.

2. Additional R&D Efforts That Deserve More Attention

- a. Data acquisition for higher gas residence time (increased bed heights and/or lower velocities) is recommended because it appears to be technically justified to proceed in this direction as a means for further improving combustion efficiency and sulfur capture.
- b. A second item is the solid feeding system. Alternate pressurizing and feed distribution concepts need to be tested. The question of feed distribution will be partially addressed during the operation of the B&W 6' x 6' unit under contract to EPRI, but more scale-up information is needed on pneumatic splitting to the large number of feed points required for a commercial unit.
- c. A backup method for turndown control is needed if the proposed approach of bed slumping fails to provide the desired results. One alternate approach might involve the variation of bed height with air flow to expose the required amount of heat transfer surface. This requires design information on the required gradation in vertical spacing of heat transfer tubes and probably also the development of a constant ΔP air distribution plate to maintain good fluidization at all loads.
- d. The erosion effect of high dust loading in convection passes needs to be evaluated. Certainly the fate of proposed recycle systems for improving combustion efficiency and sulfur capture will be dependent on this knowledge.

- e. There is a need for developing methods capable of recovering heat from spent bed material. The problem here is twofold:
 - .to complete the combustion of residual carbon and
 - .to recover the sensible heat.
- f. Engineering studies of advanced concepts (pre-calcination, use of additives, recycle system with external regeneration, etc.) should be initiated to establish their economic potential and thereby establish R&D priorities.

We feel that the first two items are of paramount significance while the balance are of lower priority or require preliminary engineering studies before proceeding. There is a good possibility that Item (a) relative to gas residence time may be addressed as a future activity under EPRI/B&W AFB programs. Item (b) however, could probably be best handled as part of a larger pilot facility assuming the availability of tankage and feeding systems.

References

1. D. H. Archer, Westinghouse Research Laboratories, "Evaluation of the Fluidized Bed Combustion Process", Volume I - Summary Report, Office of Air Programs (EPA), Contract No. CPA 70-9, November 15, 1969 - November 15, 1971.
2. D. H. Archer, Westinghouse Research Laboratories, "Evaluation of the Fluidized Bed Combustion Process", Volume II - Technical Evaluation, Office of Air Programs (EPA), Contract No. CPA 70-9, November 15, 1969 - November 15, 1971.
3. Babcock & Wilcox Company, "Summary Evaluation of Atmospheric Pressure Fluidized Bed Combustion Applied to Electric Utility Large Steam Generators", Volume I - Final Report, EPRI FP-308, Project 412-1 - October, 1976.
4. Babcock & Wilcox Company, "Summary Evaluation of Atmospheric Pressure Fluidized Bed Combustion Applied to Electric Utility Large Steam Generators", Volume II - Appendices, EPRI FP-308, Project 412-1 - October, 1976.
5. Babcock & Wilcox Company, EPRI No. RP 718 - 1, Progress Report No. 2, "Fluidized Bed Development Facility", November 15, 1976, Appendix A.

RADIAN CORPORATION

Radian No. 200-151-09

ERDA Contract No. EX-76-C-01-2314

PROJECTS INFLUENCING AFBC OF COAL

9 September 1977

To:

R. R. Fleischbein

U.S. Energy Research & Development Administration
Division of Major Facilities Program Management
20 Massachusetts Ave., N. W.
Washington, D.C. 20545

Prepared by:
William C. Howe
Radian Corporation

(14-17)

Radian Corporation is currently providing technical support services to ERDA Major Facilities Program Management on the ERDA sponsored program to develop conceptual designs for a 600 MWe Commercial Size and a 200 MWe Demonstration Size AFBC Utility Plant. As part of this technical support service, Radian was asked to compile a "scorecard" of current projects pertaining to fluidized bed combustion of coal. Although directed toward assisting the AFBC conceptual design effort, the ultimate purpose of the scorecard is to provide individuals working on FBC projects a quick reference guide to related studies.

To serve this purpose, the information listed for each project includes the program title, sponsor, brief project description, address and telephone number of a contact for further information, and project status (progress/date of expected results). Projects are grouped under main subject areas of investigation as shown in the Table of Contents on the following page.

Sources for the information listed in this document are as follows:

- Personal Telephone Conversations with Individuals Involved with Programs.
- EPRI Publication "Research and Development Projects".
- ERDA Publication "Direct Combustion Research and Development Program Plan".
- Proceedings of the Fluidized Bed Combustion Technology Exchange Workshop" at Reston, Virginia, April 13-15, 1977.

Radian would like to thank all of those who cooperated in the process of compiling this information.

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PROJECTS INFLUENCING AFBC OF COAL

TOPIC: AFBC DEVELOPMENT

Program Title	Sponsor	Program Description	Name/Add./Tel. of Person in Charge	Progress/Date Of Expected Results
Multi-cell Fluidized Bed Boiler; (MFBB). Pope, Evans & Robbins Inc.	ERDA	Initiated in 1972, the project is to design, construct and operate a 30 MWe size fluidized-bed boiler under practical utility conditions. The boiler, built by Foster Wheeler Energy Corp., was erected in one end of the existing power plant at the Monongahela Power Company at Rivesville, West Virginia, and consists of 4 side by side cells. Steam conditions are to match the requirements of the existing plants' turbo-generators. This is a four-phase program as follows: I. Engineering and Design Verification. II. Design and Fabrication of MFB Boiler and Auxiliaries III. Operational Testing IV. Design Manual and Test Reports	G. T. Claypoole Manager, Rivesville Operations Pope, Evans & Robbins, Inc. c/o Monongahela Power Company Rivesville, W. VA 26505 304-278-5315	Phases I and II complete. Light-off and continuous firing of one cell during December, 1977, and now in operation at testing phase. Currently de-bugging systems and controls to effect continuous runs and material balances. Monthly/Quarterly/Interim progress reports submitted to ERDA.
Alexandria, Virginia .5 MWe Fluidized Bed Combustor. Pope, Evans & Robbins, Inc.	ERDA	A laboratory research program in support of 30 MWe Multi-cell FBC project at Rivesville, West Virginia, the instrumentation, control system, and auxiliaries closely resemble those associated with the Rivesville unit. The facility is used for process testing and optimization, as well as operational planning/testing to aid the Rivesville facility.	R. R. Reed (Mgr. Alexandria Operation) Pope, Evans & Robbins, Inc. 320 King Street Alexandria, VA 22314 703-549-2884	Currently a new combustor is being purchased and will be installed in the fall of 1977. The facility has been a operating since 1965, and has over 8,000 hours of coal burning test operation. Monthly/Quarterly/Interim progress reports are submitted to ERDA. (Note: these are contained in the same reports as the MFBB progress reports.)
Fluidized Bed Development Facility	EPRI RP 718	This project is aimed at building a test facility on a scale that will allow exploration of various bed designs, solids and air supply systems, and the mixing patterns and chemical reactions of the resulting solids. The primary contractor is Babcock & Wilcox.	Mr. Steve Strom Babcock & Wilcox Research & Development Division Alliance, Ohio 44601 216-821-9110	The unit has been constructed and instrumented and is currently in the shakedown phase. The unit is 6' x 6'.

PROJECTS INFLUENCING AFBC OF COAL

TOPIC: AFBC DEVELOPMENT (CONT.)

Program Title	Sponsor	Program Description	Name/Add./Tel. of Person in Charge	Progress/Date Of Expected Results
Atmospheric Fluidized Bed Combustion/Component Test and Integration Unit (AFBC/CTIU). Morgantown Energy Research Center. (MERC)	ERDA	The unit has a mission to address and resolve a number of key fluidized bed combustor/boiler development technical issues which will arise in the Rivesville 30 MWe system, and to provide solid design data for stacked-bed applications and steam generator scale-up to the AFBC Demonstration Plant. The CTIU will consist of 4 stacked cells, each approximately 6' x 6'. The proposed test plan will consist of the following: <ul style="list-style-type: none"> • Materials Handling of Large Multi-cell Stacked Bed Systems • Evaluation of Performance Features • Test Bed to Evaluate Systems/Component Integrity/Reliability 	Morgantown Energy Research Center P.O. Box 880 Morgantown, West Virginia 26505 304-599-7147	Construction is expected to be complete at the end of 1979. Currently Reynolds, Smith, & Hill is under contract and is proceeding with the plant drawings and specifications. MERC has primary project responsibility. Bid packages are currently "on the road" for the boiler, the building structure, etc.
6' x 6' Cold Model Test System Morgantown Energy Research Center Morgantown, West VA	ERDA	This is the same cold-model that was used during the initial design verification and system testing of the 30 MWe Rivesville, West Virginia MFBB facility. The system will be used for cold component testing for the Morgantown Component Test and Integration Unit (CTIU) design and also for the 30 MWe Rivesville Unit support, if needed.	Morgantown Energy Research Center P.O. Box 880 Morgantown, West Virginia 26505 Dr. John Wilson 304-599-7147	Unit should be delivered by October. Tests will include coal feeding and mixing, segmental fluidization, and other activities in support of CTIU.
Experimental and Engineering Investigations for the Development of FBC Processes	EPA	Develop an understanding of process performance for environmental assessment and to develop control technology for FBC processes. Areas of investigation include: 1) develop SO _x control system using calcium based sorbents and alternate sorbents, 2) study NO _x formation and control, 3) project particulate emissions and control of trace materials, 4) spent sorbent and fly ash disposal, 5) systems evaluation. This is applicable to both atmospheric and pressurized applications.	Dr. Dale Keairns Westinghouse Electric Corp. R&D Center Beulah Road Pittsburgh, PA 15235 412-256-7000	Further information available thru D. Keairns or EPA.

PROJECTS INFLUENCING AFBC OF COAL

TOPIC: AFBC INDUSTRIAL APPLICATIONS

Program Title	Sponsor	Program Description	Name/Add./Tel. of Person in Charge	Progress/Date Of Expected Results
Fluidized Bed Combustion (FBC) for Cement Kiln; Aerojet Energy Conversion Co.	In Proposal stages with ERDA.	The ultimate objective of this program is to produce a fluidized-bed reactor that will produce 2500SCFM of low Btu gas for the cement making process.	Aerojet Energy Conversion Company Process Development Unit Sacramento, CA Mr. Alan H. Kreeger	Currently in the proposal stages. Bench scale work is currently being done by Aerojet.
Institutional Size Industrial Fluidized-Bed Boiler. Georgetown University Washington, D.C.	ERDA/Industry Cost Share	This will be a 100,000 lbs/hr. coal fired boiler plant producing 250 psig saturated steam which is to prove that AFBC industrial boilers in the capacity range of 15,000 to 150,000 lbs/hr. can be used to supply energy for the nation's colleges, hospitals, and related institutions.	Georgetown University 37th & O Streets Washington, D.C. 20545 202-625-4932	Building permits have just been secured from the city of Washington, D.C.
Fluidized Bed Combustion Process Heater Development. Exxon Research & Engineering	ERDA/Industry Cost Shared	Phase I: All technological unknown factors presently limiting direct application of FBC to fired process heaters will be investigated. Phase II: The heaters to which the technology proves applicable will be identified, and design specs. for a 10-15 M Btu/hr. fluid-bed process development heater will be prepared. Phase III: The process development unit will be designed, constructed and operated. The operation will provide the data necessary to design a commercial fluid-bed heater.	Dean Cherrington Exxon Research & Engineering Co. P.O. Box 101 Florham Park, N.J. 07932	Currently in Phase I; cold-model, 2-dimensional flow visualization tests to determine optimum tube geometric configurations are currently being carried out. Also tests are being planned to determine the effect of high heat flux rates in FBC on the coking rate of hydrocarbon streams.
Heating Air to 900°F for Manufacturing Process and Space Heating. Fluidyne Engineering Corp.	ERDA/Industry Cost Shared	This is a demonstration unit which will consist of three beds, and will heat clean low pressure air (1 Atm) indirectly with a capacity of 28.5×10^6 Btu/hr. The air will be directed through submerged tubes in the bed, with continuous variation of output achieved by use of a thermal storage system in conjunction with the shut-down and start-up of individual beds. No turndown capacity of individual beds will be effected. The facility will be located in Owatonna, Minnesota at the Owatonna Tool Plant.	Fluidyne Engineering Corp. Minneapolis, MN Dr. Henry Hansen David DeCourfin 612-544-2721	Test program has been completed using an 18-inch combustor. (This is currently being used for corrosion tests with Oak Ridge.) A 17 ft ² bed is currently being tested. A 500 hour run simulating actual load changes is currently being planned. Preliminary designs for the demonstration unit have been completed and are awaiting ERDA approval.
Industrial Steam Generator Combustion Engineering, Inc. Great Lakes Naval Training Center Chicago, Ill.	ERDA/Industry Cost Shared	This project is to demonstrate the potential of an atmospheric pressure, natural circulation, fluidized bed unit. Phase I will develop the necessary data (by hot and cold subscale units) to design the full scale demonstration plant. The demonstration unit will be designed and constructed in Phase II. The unit will be installed at the Great Lakes Naval Training Center and will provide maximum availability for testing and evaluation purposes for observers and participants. The unit will be capable of generating 50,000 lbs./hr. of steam at 500 psig and 600°F.	William Norcross Combustion Engineering, Inc. 1000 Prospect Hill Rd. Windsor, CN 06905 203-688-1911	Cold flow subscale testing is essentially complete. Report will be issued later in fall. More cold flow work is currently being done involving segmental fluidization and bed mixing. The hot subscale unit is currently being built and is expected to be completed by November 1977. Preliminary designs have begun on the demonstration unit Phase II.

PROJECTS INFLUENCING AFBC OF COAL

TOPIC: COMBUSTION & HEAT TRANSFER STUDIES

Program Title	Sponsor	Program Description	Name/Add./Tel. of Person in Charge	Progress/Date Of Expected Results
Methods for Improving Heat Transfer Film Coefficients in a Fluidized Bed Packed with Heat Exchangers	ERDA	Investigate the interrelationship between temperature distribution fluid flow, and heat exchanger design and performance in a coal fired fluidized-bed combustor. This is mostly pressurized work.	Dept. of Applied Sciences New York University 26-36 Stuyvesant Street Westbury, L.I., N.Y. 10003	Data has been obtained on a one foot diameter bed. A three foot diameter bed is presently under construction and further tests will be performed. Monthly reports sent to ERDA under Contract No. EF-76-C-01-22 Dist. Category UC-90E.
Bed Dynamics and Heat Transfer at Surfaces of Immersed Tubes in Fluidized Beds.	EPRI Corporate Research and Development, General Electric Company	Experimentally determine the dynamics of fluidized bed emulsion and bubbles at the surface of immersed tubes for various particle sizes and air flow rates, and measure local heat transfer coefficients around the circumference of horizontal tubes.	John C. Chen Lehigh University Dept. of Mechanical Engineering Bethlehem, PA 18015	Contact sponsor for available data.
Modeling of Heat Transfer Characteristics in a Fluidized Bed	ERDA	Investigate and model heat transfer from a fluidized bed to horizontal tubes as a function of gas velocity, particle size, particle shape, particle and gas thermal properties, tube size, shape, and pitch with different bed materials. The test unit is 12" by 12".	University of Illinois Dept. of Energy Engineering Box 4348 Chicago Circle Chicago, IL 60680	Monthly reports sent to ERDA under contract No. E (49-18)-1787.
Behavior of Fine Particles in a Fluidized Bed of Coarse Material.	EPRI RP 839	This project is intended to provide quantitative data on the behavior of fine particles in fluidized bed of coarse material, specifically on the relevant conditions near the distributor plate that bear on practical questions relating to reactant feed systems. The information could lead to substantial improvements in the efficiencies of combustion and sulfur capture upon which the economics of fluid bed boilers heavily depend.	Dr. Derek Geldart Department of Chemical Engineering Bradford University Bradford BD7 1DP West Yorkshire, England 9-011-44-274-33466	

PROJECTS INFLUENCING AFBC OF COAL

TOPIC: COMBUSTION & HEAT TRANSFER STUDIES (CONT.)

Program Title	Sponsor	Program Description	Name/Add./Tel. of Person in Charge	Progress/Date Of Expected Results
Evaluation of Combustion of Various Solid Fuels and Waste Materials in AFBC. Morgantown Energy Research Center (MERC)	ERDA/Industry Cost Shared Program	This is a program which is examining the combustibility characteristics of such potential fuels as the waste material resulting from the mining and cleaning of anthracite coal, oil shale, Texas lignite and bituminous refuse. The two 18 inch diameter AFBC combustors at the MERC facility are being used for these tests. Also planned are corrosion/erosion studies with different coals.	Morgantown Energy Research Center P.O. Box 880 Morgantown, West Virginia 26505 Dr. John Wilson 304-599-7147	Work has been completed on burning anthracite, Western sub-bituminous coal, Texas Lignite. Contact MERC directly for more information.
Fluidized Bed Combustion of Lignite and Western sub-bituminous coals. Grand Forks Energy Research Center Grand Forks, North Dakota	ERDA	The program is based on the premise that the alkaline ash in some lignites and Western sub-bituminous coals retain sulfur during combustion in a similar way that the injected limestone does in burning high sulfur Eastern coals. The tests being conducted are to survey the sulfur retention capabilities of the ash of various low rank coals as a function of particle size, location of the coal feed, bed depth, air/fuel ratio, temperature, and residence time in the bed. A 6 inch I.D. AFB combustor is being used.	Grand Forks Energy Research Center Grand Forks, North Dakota Mr. Goblirsch Everett A. Sondreal 701-775-4207	18" combustor to be built in 9-12 months. Currently testing lignite, recycling ash and obtaining approximately 60% sulfur retention.
Fluidized Beds with Immersed Heat Exchange Tubes. Oregon State University	EPRI RP 315	The objective of this program is to study the effects of the size, configuration, spacing, and inclination of immersed heat transfer tubes on the behavior (bubble formation, solids mixing, circulation, heat transfer rate, elutriation, tube erosion, and tube stresses) of fluidized beds. Will use a 3' x 3' cold model.	Dr. Tom Fitzgerald Associate Professor Chemical Engineering Department Oregon State University Corvallis, Oregon 97331 503-754-2091	Model has been built and instrumented. Experiments have just commenced. Reports will be sent to EPRI. Also work being done for ERDA by the Mechanical Engineering Department at OSU.
Two-phase Flow and Heat Transfer in Fluidized Beds for Application to Power	EPRI RP 525	In this 3 year project the design correlations will be developed for the heat transfer and fluid-solid flow characteristics of atmospheric and pressurized fluidized beds with immersed tubes. The effect of the equipment scale, gas, and particle properties on the flow characteristics and heat transfer to immersed tubes in atmospheric fluidized beds and simulated high pressure beds will be determined. The effect of gas pressure, bed height, and particle properties will also be studied.	Mr. Fred Staub Thermal Branch Research & Development Center General Electric P.O. Box 43 Schenectady, N.Y. 12301 518-385-4483	Quarterly reports are being sent to EPRI. Currently are using three test units (cold); a 1' x 1' and a 2' x 2' at atmospheric pressure, and a 1' x 1' operating @ 10 atmospheres. A 2' x 2' atmospheric pressure hot model is expected to be completed by the Spring of 1978.

PROJECTS INFLUENCING AFBC OF COAL

TOPIC: SULFUR CAPTURE & REGENERATION OF SORBENT

Program Title	Sponsor	Program Description	Name/Add./Tel. of Person in Charge	Progress/Date Of Expected Results
Improvements in Sulfur Dioxide Sorbent Utilization in Fluidized Bed Coal Combustion. Task 1: Effect of Sorbent Particle Size	EPRI RP 7	This one year project is an investigation of the effect of limestone particle size on sulfur capture in a fluidized bed boiler. The objective is to find out if very fine particles, such as those produced in a hydrator, can reduce the quality of limestone required to meet sulfur dioxide emission standards. Ultimately, the viability of the fluidized bed combustion system, which allows in situ removal of sulfur compounds, will depend on how its economic compare with those of conventional boilers with stack gas clean-up systems. Used Pittsburgh No. 3 coal with three types of limestone.	Dr. Howard Lange Chemical Engineering Section Alliance Research Center Babcock & Wilcox P.O. Box 835 Alliance, Ohio 44601 216-821-9110	Program is complete. Final Report should be available in November, 1977, thru EPRI.
Effect of Chemical Additives on the Removal of SO ₂ by Limestone in Fluid Bed Boilers	EPRI RP 837	The purpose of this project is to determine the mechanism of action of chemical additives on sulfur capture by limestone in order to develop techniques and recommend additives to promote sulfation reaction. Measurement of kinetic parameters will be made by thermal analysis of specific reactions in existing equipment. The project will provide information on the effect of additives on sulfur removal in an attempt to reduce the quantity of limestone required during the process.	Dr. Larry Gasner Chemical Engineering Department University of Maryland College Park, MD 20742 301-454-4593	Detailed analysis of the sulfur capture process using thermogravimetric analysis of lime particles of different sizes with and without salt. Computer programs available for predicting sulfur capture capabilities of any random sample of limestone. Preliminary reports have been sent to EPRI.
Improvements in Sulfur Dioxide Sorbent Utilization in Fluidized Bed Coal Combustion; Task 2: Effect of Limestone Calcination.	EPRI RP 720	The kinetics of limestone calcination and its effect on the sulfation reaction in fluidized bed coal combustion will be investigated in a laboratory apparatus. Experimental studies will be carried out concerning the effect of calcination parameters on sorbent utilization and on the overall fluidized-bed combustion system. Should these studies indicate that pre-calcination is favored in achieving maximum limestone utilization, then optimum calcination procedures and conditions will be specified.	Dr. E. P. O'Neill Westinghouse Electric Corp. Research & Development Center Beulah Road Pittsburgh, PA 15235 412-256-7687	Program is essentially complete and results have been sent to EPRI. Results were obtained using bench scale apparatuses.
Criteria for the Selection of Sulfur Dioxide Sorbents	EPRI RP 721	The objective of this one year project is to establish criteria for predicting the ability of a given limestone to efficiently capture sulfur dioxide in a fluidized-bed coal combustor. A complete search and evaluation will be made of available data on the desulfurization capability of different limestone and dolomites.	Dr. E. P. O'Neill Westinghouse Electric Corp. Research & Development Center Beulah Road Pittsburgh, PA 15235 412-256-7687	This will be in effect a continuation of the previous work done on EPRI-RP-720 starting September, 1977. Closer definition of factors influencing sulfur capture will be addressed.

PROJECTS INFLUENCING AFBC OF COAL

TOPIC: WASTE HANDLING, UTILIZATION, & DISPOSAL

Program Title	Sponsor	Program Description	Name/Add./Tel. of Person in Charge	Progress/Date Of Expected Results
Agronomic Evaluation of Fluidized Bed Boiler Waste Material TVA Muscle Shoals, AL	ERDA	This project continues studies that have been done at TVA expense for the past year on the use of a part of AFBC waste bed-material as a nutrient and as a source of lime for the neutralizing of acid solids in soil. Also it expands its previous scope to determine whether the utilization of the waste on peanut crops in Alabama will give similar benefits to those obtained by VPI in Virginia where different soil and climatic conditions exist.	William T. Harvey Jr., Program Man. U.S. ERDA 20 Massachusetts Avenue N. W., Washington, D.C. 20545 202-376-9352	Contact Mr. Harvey (ERDA) for more information.
Utilization of Fluidized Bed Combustion Bed Material Remedial Treatment of Soils. U.S. Department of Transportation Federal Highway Admin.	ERDA	The Federal Highway Administration is investigating the feasibility of using the sulphate and active lime from the AFBC bed material for stabilizing fine grain soils when they are used as a sub-base for highways. This could potentially substitute/supplement the use of Portland cement as a stabilizer.	William T. Harvey Jr., Program Man. U.S. ERDA 20 Massachusetts Ave. N. W., Washington, D.C. 20545 202-376-9352	Contact Mr. Harvey (ERDA) for more information.
Utilization of Fluidized Bed Combustion Bed Material Soil-Plant Nutrient Relationship in Peanuts Virginia Polytechnic Institute	ERDA	The project continues studies that have been done for the past two years on the use of a part of the AFBC waste bed material as a source of calcium for peanut crops. The previous studies have shown that the application of this waste material in increasing the crop yield was almost as effective as the application of a commercial procured calcium source.	William T. Harvey Jr., Program Man. U.S. ERDA 20 Massachusetts Ave. N. W., Washington, D.C. 20545 202-376-9352	Program completed. Results available through ERDA-Fossil Energy.
Agricultural Utilization Studies Fluidized-Bed Combustion Waste Materials U.S. Department of Agriculture	ERDA	This project will be worked through the Agricultural Research Service (ARS), U.S. Department of Agriculture. ARS and selected state agricultural experiment stations will perform the greenhouse and growth chamber testing, and where indicated, field testing of FBC waste material to determine its effects on land reclamation, forage, plant growth response and soil conditioning.	USDA/ARS West Virginia University Morgantown, West Virginia 26505	Contact Mr. William Harvey (ERDA) for detailed information. 202-376-9352

PROJECTS INFLUENCING AFBC OF COAL

TOPIC: CORROSION/EROSION & ENVIRONMENTAL STUDIES

Program Title	Sponsor	Program Description	Name/Add./Tel. of Person in Charge	Progress/Date Of Expected Results
High Temperature Dust Control Department of the Army Alexandria, VA Construction Engineering Research Laboratory (CERL)	ERDA	The project concentrated on verifying the performance of the Particle Precipitating Heat Transfer Surface (PPHTS). The device was placed in the exhaust duct of the Pope, Evans & Robbins FBC laboratory in Alexandria, Virginia where the existing dust collectors collect about 75% of the particulates larger than 20 microns. The device was tested to evaluate its capability of collecting particles smaller than 20 microns.	CERL Champagne, IL 217-352-6511	Work is complete, reports have been sent to ERDA. Results were inconclusive. SYSTECH Corp. may carry on work. Contact John Geffken, ERDA Fossil Energy for more information. 202-376-9350
Modeling of Fluidized Bed Combustion of Coal, MIT Cambridge, MA	ERDA	This is a 3 phase program consisting of: I. MIT review of all existing FBC literature and data, then construct a phenomenological mathematical model of the process. II. Present to ERDA a future planning document which will address both data required and possible programs for generation of those data. III. Write a training manual so that interested parties may use the computer model and its supporting data base through remote computer terminals.	Mass. Institute of Technology Room 26-147 Cambridge, MA 02139	Contact ERDA - Fossil Energy for more information. Attn. William Harvey 202-376-9352.
Corrosion/Erosion, in Fluidized-Bed Combustion	EPRI RP 388	The objective of this 16 month project is to test a number of selected bed tube and turbine blade materials in an existing fluidized-bed FBC pilot plant under controlled conditions to determine their corrosion/erosion characteristics for extended periods of time. Primary contract is to Combustion Systems, Ltd., and subcontracted to C-E and Foster Wheeler (U.S.).	Dr. John Stringer EPRI 3412 Hillview Ave. P.O. Box 10412 Palo Alto, CA. 94303 415-493-4800	A series of 250 hr. tests were run. Results were significant enough to re-plan this program and initiate other EPRI programs investigating corrosion/erosion in FBC.
Fluidized Bed Combustion Corrosion/Erosion Tests	EPRI	A selected set of superheater alloys will be exposed to 2000 hours of FBC operation in order to resolve a major technical question regarding the life of boiler tubes in a fluidized bed combustor. The objectives are to: (1) by metrology, determine metal loss as a function of alloy, metal surface temperature, position of specimen in relation to the injector outlet and radial position; (2) by metallographic examination, determine whether intergranular sulfidation occurs and how it relates to alloy, metal surface temperature and specimen position; (3) predict the life of the tubes and (4) establish whether metal corrosion is accelerated when the superheater is situated close to a feed point.	Dr. John Stringer Mr. Shelton Ehrlich EPRI P.O. Box 10412 Palo Alto, CA 94303 415-493-4800	These test are being run by Central Research Establishment of the National Coal Board in Great Britain. (Mr. Paul Thurlow) 3 out of 4 tests have been run, and more tests are being planned.
Heat Exchanger Tube Materials for AFBC	ERDA	The project will evaluate the corrosion/erosion characteristics of horizontal tubes of different materials in a fluidized bed atmosphere. The bed is 24 inch diameter and will operate at approximately 9 ft/sec fluidizing velocity.	Albert Hall Metallurgical Department Battelle Memorial Institute Columbus, OH 514-424-7564	The unit has operated for 1500 hours continuously. The sample tubes have been removed and are currently being evaluated.

PROJECTS INFLUENCING AFBC OF COAL

TOPIC: AFBC ADVANCED TECHNOLOGY

Program Title	Sponsor	Program Description	Name/Add./Tel. of Person in Charge	Progress/Date Of Expected Results
Fluidized Bed Combustion Industrial Application Demonstration Projects. Battelle Memorial Institute, Columbus, Ohio	ERDA/Industry Cost Shared	<p>This is considered a Multisolid Fluidized-Bed Combustion Process which utilizes a high specific gravity bed material in a dense fluidized phase coupled with an entrained or "fast" phase of similar or different bed material. It has been shown on a bench scale that this type of fluidization process enhances gas solid contact, therefore, enhances gas sorbent reactions. Battelle is teaming in the development, demonstration and subsequent commercialization of the process. The program will be 3-phases as follows:</p> <p>Phase I: R&D utilizing a sub-scale experimental unit in support of demonstration plant design using 400 lbs/hr. of coal producing 4000 lbs/hr. of steam.</p> <p>Phase II: Construction and start-up of demonstration plant which will produce 25,000 lbs/hr. of steam @ 100 psig. The plant will be built @ Battelle Institute.</p> <p>Phase III: Three year operational period for the collection of data to be used for future industrial application design.</p>	Battelle Memorial Institute Columbus, Ohio Mr. Herman Nack 614-424-4998	Currently in Phase I; the subscale experimental unit has just been built and is now in the pre-operational shakedown phase. Light-off is expected by Sept. 1. The unit will run at 30-40 ft/sec and the bed is approximately 1 ft x 2 ft ² . Five months of concentrated operation is planned before proceeding to Phase II.
AFBC Closed Cycle Gas Turbine Technology Test Unit. Oak Ridge National Laboratory Oak Ridge, TN	ERDA	<p>The program consists of developing a Technology Test Unit (TTU) which will be a coal burning AFBC system coupled ultimately to a closed cycle hot air gas turbine-generator. The unit capacity will be 300 to 500 KW plus approximately 2.5×10^6 Btu/hr. of recoverable waste heat. The size test unit will provide credible scale-up data to the 5 to 50 MWe range for commercial application in the industrial/institutional sector.</p> <p>Phase I: Technology studies and preliminary engineering and economic analysis (complete).</p> <p>Phase II: Complete a conceptual design for the TTU.</p> <p>Phase III: Detailed design and construction of TTU.</p> <p>Phase IV: Operation, test, analysis and evaluation of results.</p>	Mr. R. S. Holcomb Oak Ridge National Laboratory P.O. Box Y Oak Ridge, Tennessee 37830 615-483-8611 Ext. 37416	Design has been completed, current construction and performance specifications are being written in preparation for bids.

PROJECTS INFLUENCING AFBC OF COAL

TOPIC: INSTRUMENTATION & CONTROL

Program Title	Sponsor	Program Description	Name/Add./Tel. of Person in Charge	Progress/Date Of Expected Results
Particulate Analysis Instrumentation for Fluidized Bed Combustion Systems Leeds & Northrop Co.	ERDA	The project is directed to development and delivery of one particulate monitoring instrument to ERDA to measure particulate loadings of micron-size particles in the gas streams of FBC reactors. The first phase will be the design and construction of an instrument to be used on the Argonne National Laboratory 6 inch AFBC reactor. This will be followed by the installation and testing in conjunction with Curtiss Wright's 3' x 3' PFBC reactor for their 13 MWe pilot plant project..	Leeds & Northrup Company Dickerson Road North Wales, PA 215-643-2000	The instrument is currently being tested at Argonne National Laboratory. Some preliminary reports are available thru ERDA. (John Geffken, ERDA, 202-376-9350)
In-situ Laser Measurements in FBC Systems	ERDA	A laser interferometer was developed to measure particles at the Argonne National Laboratory FBC facility. The unit simultaneously measures particle size and velocity.	Spectron Development Laboratory, Inc. 3303 Harbor Blvd. Suite G-3 Costa Mesa, CA 92626	Work has been completed. Reports were sent to ERDA Contract No. EX-76-C-01-2413 (John Geffken, ERDA, 202-376-9350)
Mathematical Modeling of FBC Process for Control Analysis	ERDA	Develop mathematical models for FBC process control, acquire data to "fit" into model to check its accuracy, then analyze and optimize the control modes.	Dr. David Berkowitz The MITRE Corp. P.O. Box 208 Bedford, MA 01730	Mathematical models have been formulated. A data acquisition system was installed at Pope, Evans & Robbins FBC Lab in Alexandria, Virginia. The data has been gathered and is currently being "fit" into the models.

PROJECTS INFLUENCING AFBC OF COAL

TOPIC: MATERIAL FEEDER DEVELOPMENT

Program Title	Sponsor	Program Description	Name/Add./Tel. of Person in Charge	Progress/Date Of Expected Results
Coal Feed Testing & Development (Pressurized) Lockheed	ERDA	This program is to generate analytical and test data to permit confident design and fabrication of equipment into pressurized environments. A 3-phase program is in progress: Phase 1: Concepts Selection Phase 2: Lab-Scale Development Phase 3: Pilot Plant Development	Lockheed Missiles & Space Co., Inc. Sunnyvale, CA	Monthly reports issued to ERDA. (Attn. R. R. Fleischbein MFPM)
Coal Feeder Development Ingersoll-Rand (Primarily for PFBC)	ERDA	This is a dry coal screw feeder program for feeding coal in a reactor operating up to 1500 psig.	Ingersoll-Rand Research Inc. Princeton, NJ	Monthly reports issued to ERDA. (Attn. R. R. Fleischbein MFPM)
Dry Coal Feed System Development (Foster-Miller)	ERDA	This is a program to develop alternative methods of feeding coal into pressurized conversion processes. Four methods have been tested. 1. Centrifugal Solids Feeder 2. Fluidized Piston Feeder 3. Linear Pocket Feeder 4. Compacted Coal Plug Feeder	Foster-Miller Associates Waltham, MA	Monthly reports issued to ERDA. (Attn. R. R. Fleischbein MFPM).

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PROJECTS INFLUENCING AFBC OF COAL

TOPIC: FEASIBILITY/ECONOMIC/CONCEPTUAL & GENERAL STUDIES

Program Title	Sponsor	Program Description	Name/Add./Tel. of Person in Charge	Progress/Date Of Expected Results
Engineering Evaluation of Atmospheric Fluidized-Bed Combustion (AFBC) Applied to Electric Utility Large Steam Generators	EPRI RP 412	The objective of this 16 month program is to evaluate the adequacy of available information for commercialization of the AFBC process. The program includes a study of existing designs of utility boilers using FBC.	Mr. Steve Strom Babcock & Wilcox Company Research & Development Division Alliance, Ohio 44601 216-821-9110	Project complete - report should be available thru EPRI.
Fluidized Bed Combustion (FBC) Retrofit Study for Conversion of Oil Fired Boilers to Coal.	EPRI RP 717	Because of legislative action or a curtailment of available fuel, some utilities may be forced to consider conversion of units from oil to coal firing retrofit so that a reasonable evaluation of alternatives can be made. Two retrofit concepts are available: (1) an external system that involves high sulfur oil and (2) the approach, to be evaluated in this study, that involves putting several fluidized bed combustors inside an existing furnace. The New York State Energy Research & Development Authority is the major funder. The study is being carried out by Combustion Engineering with support from Combustion Processes, Inc.	Shelton Ehrlich EPRI 3412 Hillview Ave. P.O. Box 10412 Pal Alto, CA 94303	Preliminary drafts complete, currently being reviewed by EPRI. Publications will be available in December or January from EPRI.
Preliminary Design and Cost Estimate for a Commercial Scale Atmospheric Fluidized Bed Combustion (AFBC) Steam Generator	EPRI RP 722	This project calls for preparation of a site-oriented preliminary design and estimate in order to evaluate the cost of a 200 MWe demonstration plant. The design contemplated would be at an existing utility site using as much mechanical and electrical equipment as possible so as to minimize costs.	Shelton Ehrlich EPRI P.O. Box 3412 Hillview Ave. Palo Alto, CA 94303 415-493-4800	No progress noted at this date.
Conceptual Design of an Atmospheric Fluidized Bed Combustion Steam Generating Plant.	ERDA	The objective is to prepare a conceptual design for an electric power generating plant of an approximately 600 MW commercial size AFB Boiler and a 150-200 MW demonstration size unit that is a scaled down version of the 600 MW unit. The work will be of sufficient detail such that firm bids could be made for actual construction of the plant. Two types of coal will be used: Burns & Roe - Western sub-Bituminous; Stone & Webster - Eastern Coal	William Bradley Project Engineer Burns & Roe, Inc. 185 Crossways Park Dr., Woodbury, NY 11797 516-677-4000 T. G. Wells Power Engineer Stone & Webster P.O. Box 2325 Boston, MA 02107	Burns & Roe has contracted Combustion Engineering, Inc., and Stone & Webster has contracted Foster Wheeler and Babcock & Wilcox for the boiler designs. Final Reports are due by January 1, 1978. Pope, Evans, & Robbins, Inc. is working with Stone & Webster.

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XV. ENVIRONMENTAL ASSESSMENT

A. Summary

The objective of this section is to discuss the environmental factors involved with atmospheric pressure fluidized bed combustion boilers (AFB). The major areas discussed are the flue gas emissions and the solid waste products from the beds and precipitators. From the data so far compiled, no problems are expected from pollutant concentrations in the stack gas emissions. However, solid waste disposal may present some difficulties, depending upon which method of disposal is considered.

From the environmental viewpoint, the fluidized bed boiler has a high potential for success. Of importance in today's power industry, are stack gas SO_2 and NO_x emissions which are regulated by both Federal and State laws. The fluidized bed boiler's low pollutant emissions have placed it in direct competition with conventional coal-fired boilers equipped with scrubbers. A comparison of the two types of boilers show them to be similar in air quality control.

The spent sorbent of the AFB boiler has revealed some interesting properties which may open new fields of general uses for it. Some of the ideas include: use in landfill projects, highway road bases, farmland treatment, building materials, and sewage sludge stabilization. The high CaO content of the sorbent may make it suitable for farmland purposes while its compressibility and strength properties make it a potential substitute in sludge stabilization and building projects. Research is proceeding in all these areas but no final recommendations have yet been announced.

The study of the proposed AFB boiler is based upon the need to investigate all probable forms of power generation which burn coal in an environmentally acceptable fashion. The AFB boiler uses a technique of adding limestone and coal in the same bed such that the limestone will react with the sulfur to form a non-polluting material, CaSO_4 , thus decreasing the amount of SO_2 emission which will be discharged from the stack. By utilizing the proper limestone versus sulfur ratio, the SO_2 emission can be limited to within the Federal regulations.

B. General

The Federal regulations of most concern are the New Source Performance Standards (NSPS) for SO₂, NO_x, and particulate matter as passed in the Clean Air Act of 1970:

<u>Pollutant</u>	<u>Federal Limit (#/10⁶ BTU)</u>
SO ₂	1.2
NO _x	0.7
Particulate Matter	0.1

Regulations for the disposal of solid waste have not been established on a national basis but are set up by the individual states. The states of Tennessee and Kentucky have no specific legal guidelines for landfills or ground water contamination. Both do have limits for trace metal leachings in surface supplies. It is in this manner these states regulate waste disposal sites. Land-fill projects are required to contain all run off water for treatment before it is discharged into a stream or river. The allowable pollutant levels and monitoring of the discharges are determined on a case by case basis by the individual state's EPA. This year in Tennessee, a new law was passed changing existing water regulations to conform more closely with Federal water standards. (See Section E). Kentucky is also in the process of drawing up new legislation. (1,2).

The operating conditions and stack emissions for an AFB boiler are dependent upon the feed coal available. The percentage sulfur in the coal determines the amount of limestone which must be fed to the boiler. A Ca/S ratio minimum of one and one half (1-1/2) and a maximum of five (5) or six (6) seems to form a typical range. When the molar ratio is less than one, the sulfur retention efficiency of the limestone is too low (less than 50%) to be technically feasible. As the molar ratio increases, the system becomes less economical.

For design purposes, the Ca/S ratio for this study has been established at 2.37 so that the SO₂ stack concentration will be 1.2 lb per million BTU. A conventional PC boiler, burning the same high sulfur coal, cannot match this low SO₂ level without a desulfurization unit.

When operating with a Ca/S ratio of 2.37 considerable amounts of unreacted calcium compounds are discharged from the bed. This high ratio is detrimental, as compared to wet scrubbers, from two standpoints: a) the high cost of supplying the limestone, and b) the increased burden for disposing of the spent material.

Experiments are now being conducted in an effort to find an "additive" for improving sulfur capture, thereby reducing the Ca/S ratio. Results from tests utilizing salt as an additive to bed combustion showed some success in improving the efficiency of the SO₂ retention of the limestone. In the Pope, Evans, and Robbins Alexandria test unit, salt (as NaCl) was added in many trials over a period of eleven years. No corrosive effects were observed in the boiler. However, the operating conditions and materials tested were not representative of those which exist in a high pressure utility boiler. Also, the effects of the soluble sodium compounds introduced into the system by this additive will complicate the ultimate disposal of the bed material.

Considerable additional testing is required before positive conclusions can be drawn concerning the effect of additives on calcium requirements, AFB boiler operations, and boiler emissions.

C. Stack Emission

1. Major Gaseous Constituents

Table 15-1 lists the results of a test conducted by Battelle Columbus Laboratories on the fluid bed combustor located at their Columbus, Ohio laboratories. Comparison of these results with similar data from a typical PC fired unit shows that this AFB generates significantly more CO than conventional boilers whose CO concentrations are generally less than 100 ppm. Bed temperature is a decisive factor affecting CO formation. As bed temperatures decrease, CO levels increase due to inefficient carbon burning. The 1550°F temperature of the 200 MW FBC bed is expected to produce more CO than the greater than 3000°F flame temperature of a PC boiler. In the Battelle test, CO in excess of 2000 ppm was generated when the temperature of the bed was 1650°F (3).

TABLE 15-1

BATTELLE FLUIDIZED BED TESTS

<u>Gases</u>	<u>FBC</u> <u>Run 2</u>
O ₂ , %	3.6
CO ₂ , %	17.3
CO, ppm	2090
SO ₂ , ppm	730
NO _x , ppm as carbon	350
HC, ppm(C)	360

The CBB operates at 2000°F which is a better temperature to burn out carbon and thus decrease CO formation. Tests completed by Pope, Evans and Robbins indicate low level CO emissions can be expected from the CBB.

The cause of the high concentration of CO in the flue gas has not been fully identified. During 1978, tests will be conducted on the 6' x 6' AFB located at Alliance in an effort to explain and minimize the presence of CO in the flue gas from fluidized bed combustors.

The SO₂ concentrations in the gas is obviously lower than would be expected from a PC unit without SO₂ control means. As discussed above the concentration of SO₂ in the stack gas is a function of the sulfur content of the fuel and the ratio of calcium oxide to sulfur in the bed, and is within reason, controllable to desired maximum levels.

The 350 ppm NO_x concentration shown in Table 15-1 is typical of the values measured from other AFB's. Table 15-2 lists additional NO_x emission data (4). These concentrations are within the range of values measured for PC boilers and in general less than present Federal EPA limits.

The hydrocarbon emissions are greater than those of conventional unit which emits negligible hydrocarbons (less than 5 ppm for C₁ through C₆ compounds).

While some of these concentrations are greater than desired it is still too early to draw any final conclusions, as considerable additional R&D is required.

2. Trace Elements

Table 15-3 lists data from tests conducted by Battelle (5). This table compares the concentration of trace elements found in coal and the corresponding values found in the bed material of various fluid bed test units and in the fly ash of a conventional boilers. It must be noted that the conventional boiler results listed under Power Plant Sample are not as extensive as the data taken for the AFB boiler. Therefore, conclusions about which boiler has better results must be postponed until further testing is completed.

51	52	53	54	55	56	57	58	59	60
B&W NO.	CARD NO.	FINES RECIRCULATION LB/HR	STARTING BED	NOX OUTLET PPM	NOX REDUCTION PCT	SO PPM	X10 ⁻¹ CO2 PPM	CH4 HYDROCARBONS PPM	CARBON LOSS LB/HR
1	6	0.0	ALUMINA	*	*	*	*	*	*
2	6	0.0	ALUMINA	*	*	*	*	*	*
3	6	0.0	ALUMINA	*	*	*	*	*	*
4	6	0.0	ALUMINA	*	*	*	*	*	*
5	6	0.0	ALUMINA	*	*	*	*	*	*
6	6	0.0	ALUMINA	*	*	*	*	*	*
7	6	0.0	ALUMINA	*	*	*	*	*	*
8	6	0.0	ALUMINA	*	*	*	*	*	*
9	6	0.0	ALUMINA	*	*	*	*	*	*
10	6	0.0	ALUMINA	*	*	*	*	*	*
11	6	0.0	ALUMINA	*	*	*	*	*	*
12	6	0.0	ALUMINA	*	*	*	*	*	*
13	6	0.0	ALUMINA	*	*	*	*	*	*
14	6	0.0	ALUMINA	*	*	*	*	*	*
15	6	0.0	ALUMINA	*	*	*	*	*	*
16	6	0.0	ALUMINA	*	*	*	*	*	*
17	6	0.0	COAL-CA	*	*	*	*	*	*
18	6	0.0	ALUMINA	440.	38.0	400.	*	2.2	0.0009
19	6	0.0	ALUMINA	400.	33.0	*	*	*	*
20	6	0.0	ALUMINA	400.	28.5	310.	*	20.0	0.0007
21	6	0.0	ALUMINA	360.	34.5	75.0	*	5.0	0.0002
22	6	0.0	ALUMINA	720.0	0.0	1700.	14300.	*	*
23	6	0.0	ALUMINA	600.0	17.0	1700.	14300.	*	*
24	6	0.0	COAL-CA	600.0	17.0	1700.	14300.	*	*
25	6	0.0	COAL-CA	600.0	17.0	1700.	14300.	*	*
26	6	0.0	COAL-CA	650.0	20.0	1700.	14300.	*	*
27	6	0.0	ALUMINA	420.0	29.0	*	*	*	*
28	6	1.0	COAL-CA	420.0	29.0	*	*	*	*
29	6	0.0	ALUMINA	500.0	29.0	2000.	15500.	*	*
30	6	0.0	COAL-CA	400.0	43.0	2000.	15500.	*	*
31	6	0.0	COAL-CA	460.0	35.0	2000.	15500.	*	*
32	6	0.0	COAL-CA	500.0	29.0	2000.	15500.	*	*
33	6	0.0	ALUMINA	420.0	24.0	*	*	*	*
34	6	0.0	COAL-CA	400.0	27.0	*	*	*	*
35	6	0.0	ALUMINA	550.0	19.0	*	*	*	*
36	6	0.0	ALUMINA	520.0	15.0	*	*	*	*
37	6	1.0	COAL-CA	510.0	16.0	*	*	*	*
38	6	1.0	COAL-CA	510.0	16.0	*	*	*	*
39	6	0.0	COAL-CA	470.0	17.0	*	*	*	*
40	6	1.0	COAL-CA	420.0	26.0	*	*	*	*
41	6	0.0	ALUMINA	800.0	0.0	1500.	10500.	*	*
42	6	0.0	COAL-CA	560.0	31.0	1500.	10500.	*	*
43	6	0.0	COAL-CA	600.	28.0	1500.	10500.	*	*
44	6	0.0	COAL-CA	600.	28.0	1500.	10500.	*	*
45	6	0.0	COAL-CA	600.	28.0	1500.	10500.	*	*
46	6	0.0	ALUMINA	*	*	2800.	15200.	*	*
47	6	0.0	COAL-CA	*	*	2800.	15200.	*	*
48	6	0.0	COAL-CA	*	*	2800.	15200.	*	*
49	6	0.0	COAL-CA	*	*	2800.	15200.	*	*
50	6	0.0	COAL-CA	*	*	2800.	15200.	*	*
51	6	0.0	ALUMINA	760.	0.0	2800.	16100.	*	*
52	6	0.0	COAL-CA	550.	30.0	2800.	16100.	*	*
53	6	0.0	COAL-CA	570.	25.0	2800.	16100.	*	*

TABLE 15-2a

51	52	53	54	55	56	57	58	59	60
B&W NO.	CARD NO.	FINES RECIRCULATION LB/HR	STARTING BED	NOX OUTLET PPM	NOX REDUCTION PCT	CO PPM	X10 ⁻¹ CO2 PPM	CH4 HYDROCARBONS PPM	CARBON LOSS LB/HR
54	6	0.0	COAL-CA	600.	9.0	2800.	16100.	*	*
55	6	0.0	COAL-CA	530.	30.0	2800.	16100.	*	*
56	6	0.0	ALUMINA	*	22.0	*	*	*	*
57	6	0.0	ALUMINA	*	22.0	*	*	*	*
58	6	0.0	ALUMINA	500.	6.0	*	*	*	*
59	6	0.0	ALUMINA	550.	24.0	*	*	*	*
60	6	0.0	ALUMINA	350.	42.0	*	*	*	*
61	6	0.0	COAL-CA	395.	34.0	*	*	*	*
62	6	0.0	COAL-CA	365.	28.0	*	*	*	*
63	6	0.0	COAL-CA	400.	22.0	*	*	*	*
64	6	0.0	BCR1359	600.	*	*	25000.	*	*
65	6	0.0	COAL-CA	400.	*	*	16000.	*	*
66	6	0.0	COAL-CA	380.	*	*	16000.	*	*
67	6	0.0	ASH-CA-C	340.	*	*	*	*	*
68	6	0.0	ASH-CA-C	220.	*	*	*	*	*
69	6	0.0	ASH-CA-C	310.	*	*	*	*	*
70	6	0.0	ASH-CA-C	320.	*	*	*	*	*
71	6	0.0	ASH-1359	400.	*	0.4	*	0.4	*
72	6	0.0	ASH-1360	440.	*	0.4	*	0.4	*
73	6	0.0	ASH-COAL	340.	*	0.4	*	0.4	*
74	6	0.0	ASH-COAL	460.	*	0.4	*	0.4	*
75	6	0.0	ASH-COAL	250.	*	4570.	*	210.	*
76	6	0.0	ASH-COAL	280.	*	3750.	*	200.	*
77	6	0.0	ASH-1359	360.	*	1440.	*	46.	*
78	6	0.0	ASH-1359	430.	*	700.	*	52.	*
79	6	0.0	ASH-1359	430.	*	900.	*	56.	*
80	6	0.0	ASH-1359	270.	*	3930.	*	200.	*
81	6	0.0	SINASH	360.	*	0.0	13800.	60.	*
82	6	0.0	ASH	340.	*	0.0	14200.	60.	*
83	6	0.0	ASH	340.	*	0.0	14500.	60.	*
84	6	1.0	ASH	300.	*	0.0	14500.	60.	*
85	6	0.0	SIN. ASH	280.	*	0.0	14300.	120.	*
86	6	0.0	ASH	280.	*	0.0	14700.	80.0	*
87	6	0.0	ASH	280.	*	0.0	14200.	50.0	*
88	6	0.0	ASH	280.	*	0.0	14500.	100.	*
89	6	0.0	ASH	280.	*	*	*	180.	*
90	6	0.0	ASH	260.	*	0.0	15000.	180.	*
91	6	0.0	ASH	220.	*	0.0	15300.	180.	*
92	6	0.0	ASH	160.	*	0.0	15500.	180.	*
93	6	0.0	ASH	380.	*	0.0	12600.	50.0	*
94	6	0.0	ASH	360.	*	0.0	13200.	50.0	*
95	6	0.0	ASH	340.	*	0.0	15000.	180.	*
96	6	0.0	ASH	260.	*	0.0	14900.	180.	*
97	6	0.0	ASH	230.	*	0.0	14900.	180.	*
98	6	0.0	ASH	230.	*	0.0	15000.	180.	*
99	6	0.0	ASH	280.	*	0.0	14900.	260.	*
100	6	0.0	ASH	280.	*	0.0	15200.	260.	*
101	6	0.0	ASH	*	*	0.0	15200.	*	*
102	6	0.0	ASH	280.	*	0.0	15200.	250.	*
103	6	0.0	ASH	280.	*	0.0	14800.	250.	*
104	6	0.0	ASH	300.	*	0.0	14900.	240.	*
105	6	0.0	ASH	300.0	*	0.0	16200.0	240.0	*
105A	6	0.0	ASH	260.0	*	0.0	15200.0	210.0	71.3

TABLE 15-2b

51	52	53	54	55	56	57	58	59	60
B&W NO.	CARD NO.	FINES RECIRCULATION LB/HR	STARTING BED	NOX OUTLET PPM	NOX REDUCTION PCT	CO PPM	X10 ⁻¹ CO2 PPM	CH4 HYDROCARBONS PPM	CARBON LOSS LB/HR
106	6	0.0	ASH	260.	*	0.0	16500.	210.	*
107	6	0.0	ASH	260.	*	0.0	16000.	210.	*
108	6	1.0	ASH	260.	*	0.0	15800.	210.	*
109	6	0.0	ASH	240.	*	0.0	15500.	230.	66.06
110	6	0.0	ASH	240.	*	0.0	16900.	230.	78.33
111	6	0.0	ASH	240.	*	0.0	16500.	230.	*
112	6	0.0	ASH	220.	*	0.0	14900.	285.	108.0
113	6	0.0	ASH	220.	*	0.0	15800.	285.	102.0
114	6	0.0	ASH	220.	*	0.0	16000.	285.	*
115	6	0.0	ASH	320.	*	0.0	14800.	260.	92.2
116	6	0.0	ASH	320.	*	0.0	16100.	260.	152.6
117	6	0.0	ASH	260.0	*	0.0	15500.0	260.0	56.89
118	6	0.0	ASH	260.0	*	*	*	260.0	99.14
119	6	0.0	ASH	260.0	*	*	*	260.0	*
120	6	0.0	ASH	240.0	*	0.0	14900.0	250.0	76.49
121	6	0.0	ASH	240.0	*	*	*	250.0	139.36
122	6	117.7	ASH	240.0	*	*	*	250.0	*
123	6	246.2	ASH	240.0	*	*	*	250.0	*
124	6	0.0	ASH	250.0	*	0.0	15200.0	260.0	68.9
125	6	0.0	ASH	250.0	*	*	*	260.0	85.1
126	6	0.0	ASH	250.0	*	*	*	260.0	*
127	6	0.0	ASH	270.0	*	0.0	15300.0	350.0	71.29
128	6	0.0	ASH	270.0	*	*	*	350.0	112.46
129	6	0.0	ASH	270.0	*	*	*	320.0	*
130	6	0.0	ASH	290.0	*	0.0	14800.0	250.0	64.08
131	6	0.0	ASH	290.0	*	*	*	250.0	90.95
132	6	1.0	ASH	290.0	*	*	*	250.0	*
133	6	1.0	ASH	290.0	*	*	*	250.0	*
134	6	0.0	ASH	350.0	*	0.0	16100.0	500.0	*
135	6	0.0	ASH	330.0	*	0.0	17200.0	500.0	*
136	6	1.0	ASH	380.0	*	0.0	17500.0	490.0	*
137	6	1.0	ASH	460.0	*	0.0	15500.0	50.0	*
138	6	0.0	ASH	220.0	*	0.0	16000.0	1000.0	*
139	6	0.0	ASH	220.0	*	200.0	17000.0	500.0	*
140	6	0.0	ASH	320.0	*	*	*	50.0	*
141	6	0.0	ASH	225.0	*	0.0	13700.0	80.0	*
142	6	0.0	ASH	240.0	*	0.0	15200.0	40.0	*
143	6	0.0	ASH	210.0	*	0.0	15900.0	40.0	*
144	6	0.0	ASH	200.0	*	*	*	60.0	*
145	6	1.0	ASH	200.0	*	*	*	60.0	*
146	6	0.0	ASH	320.0	*	0.0	15600.0	127.0	*
147	6	0.0	ASH	320.0	*	0.0	16200.0	85.0	*
148	6	0.0	ASH	310.0	*	0.0	16200.0	94.0	*
149	6	0.0	ASH	200.0	*	*	*	*	*
150	6	0.0	ASH	360.0	*	0.0	14800.0	100.0	*
151	6	0.0	ASH	360.0	*	0.0	15200.0	100.0	*
152	6	0.0	ASH	360.0	*	0.0	15200.0	100.0	*
153	6	0.0	ASH	360.0	*	0.0	15100.0	100.0	*
154	6	0.0	ASH	380.0	*	0.0	13500.0	100.0	*
155	6	0.0	ASH	380.0	*	0.0	14600.0	100.0	*
156	6	0.0	ASH	380.0	*	0.0	14500.0	100.0	*
157	6	0.0	ASH	380.0	*	0.0	*	100.0	*
158	6	0.0	ASH	375.0	*	0.0	15500.0	50.0	*

TABLE 15-2c

51	52	53	54	55	56	57	58	59	60
B&W NO.	CARD NO.	FINES RECIRCULATION LB/HR	STARTING BED	NOX OUTLET PPM	NOX REDUCTION PCT	CO PPM	X10 ⁻¹ CO2 PPM	CH4 HYDROCARBONS PPM	CARRON LOSS LB/HR
159	6	0.0	ASH	370.0	*	*	*	50.0	*
160	6	0.0	ASH	370.0	*	*	*	50.0	*
161	6	0.0	ASH	*	*	*	*	*	*
162	6	0.0	ASH	160.0	*	0.0	14200.0	50.0	*
163	6	0.0	ASH	50.0	*	0.0	15400.0	50.0	*
164	6	0.0	ASH	370.0	*	0.0	15700.0	50.0	*
165	6	0.0	ASH	360.0	*	0.0	14200.0	50.0	*
166	6	0.0	ASH	360.0	*	*	*	50.0	*
167	6	1.0	ASH	360.0	*	*	*	50.0	*
168	6	0.0	ASH	360.0	*	*	*	50.0	*
169	6	0.0	ASH-SH	*	*	20.0	14900.0	0.0	8.2
170	6	0.0	ASH-SH	*	*	0.0	13900.0	0.0	6.0
171	6	0.0	ASH-SH	*	*	0.0	14600.0	0.0	6.95
172	6	0.0	ASH-SH	*	*	0.0	15300.0	0.0	4.96
173	6	0.0	ASH-SH	*	*	0.0	14400.0	0.0	5.99
174	6	0.0	ASH-SH	*	*	0.0	15200.0	0.0	6.47
175	6	0.0	ASH-SH	*	*	0.0	15100.0	0.0	6.49
176	6	0.0	ASH-SH	*	*	0.0	14600.0	0.0	6.81
177	6	0.0	ASH-SH	*	*	0.0	15400.0	0.0	5.40
178	6	0.0	ASH-SH	*	*	0.0	13500.0	0.0	4.52
179	6	0.0	ASH-SH	470	*	0.0	15200.0	0.0	24.02
180	6	0.0	ASH-SH	515.0	*	0.0	14700.0	0.0	21.09
181	6	0.0	ASH-SH	650.0	*	0.0	16100.0	0.0	22.46
182	6	0.0	ASH-SH	*	*	0.0	15000.0	0.0	6.96
183	6	0.0	ASH-SH	*	*	0.0	16400.0	0.0	*
184	6	0.0	ASH-SH	*	*	0.0	15200.0	0.0	18.43
185	6	0.0	ASH-SH	*	*	0.0	15500.0	0.0	16.65
186	6	0.0	ASH-SH	*	*	0.0	15000.0	0.0	15.24
187	6	0.0	ASH-SH	*	*	0.0	15000.0	0.0	20.21
188	6	0.0	ASH-SH	*	*	0.0	15200.0	0.0	21.39
189	6	0.0	ASH-SH	*	*	0.0	16000.0	0.0	5.42
190	6	0.0	ASH	*	*	*	*	*	*
191	6	0.0	ASH	*	*	*	*	*	*
192	6	0.0	ASH	*	*	*	*	*	*
193	6	0.0	ASH	*	*	*	*	*	*
194	6	0.0	ASH	*	*	*	*	*	*
195	6	0.0	ASH	*	*	*	*	*	*
196	6	0.0	ASH	*	*	*	*	*	*
197	6	0.0	ASH	*	*	*	*	*	*
198	6	0.0	ASH	*	*	*	*	*	*
199	6	0.0	ASH	*	*	*	*	*	*
200	6	0.0	ASH	*	*	*	*	*	*
201	6	*	ASH	340.0	*	*	*	50.0	*
202	6	*	ASH	340.0	*	*	*	50.0	*
203	6	*	ASH	340.0	*	*	*	50.0	*
204	6	*	ASH	340.0	*	*	*	50.0	*
205	6	*	ASH	400.0	*	*	*	50.0	*
206	6	*	ASH	400.0	*	*	*	50.0	*
207	6	*	ASH	400.0	*	*	*	50.0	*
208	6	*	ASH	400.0	*	*	*	50.0	*
209	6	*	ASH	340.0	*	*	*	50.0	*
210	6	*	ASH	380.0	*	*	*	50.0	*
211	6	*	ASH	380.0	*	*	*	50.0	*

TABLE 15-2d

51	52	53	54	55	56	57	58	59	60
B&W NO.	CARD NO.	FINES RECIRCULATION LB/HR	STARTING BED	NOX OUTLET PPM	NOX REDUCTION PCT	CO PPM	X10 ⁻¹ CO ₂ PPM	CH ₄ HYDROCARBONS PPM	CARBON LOSS LB/HR
212	6	*	ASH	380.0	*	*	*	50.0	*
213	6	*	ASH	480.0	*	*	*	50.0	*
214	6	*	ASH	480.0	*	*	*	50.0	*
215	6	*	ASH	*	*	*	*	50.0	*
216	6	*	ASH	420.0	*	*	*	50.0	*
217	6	*	ASH	400.0	*	*	*	50.0	*
218	6	*	ASH	370.0	*	*	*	50.0	*
219	6	*	ASH	380.0	*	*	*	50.0	*
220	6	*	ASH	380.0	*	*	*	50.0	*
221	6	*	ASH	340.0	*	*	*	50.0	*
222	6	0.0	ASH	*	*	*	*	*	*
223	6	0.0	ASH	*	*	*	*	*	*
224	6	0.0	ASH	*	*	*	*	*	*
225	6	0.0	ASH	*	*	*	*	*	*
226	6	0.0	ASH	*	*	*	*	*	*
227	6	0.0	ASH	234.0	*	0.0	16500.0	0.0	8.1
228	6	0.0	ASH	*	*	0.0	15700.0	0.0	7.31
229	6	0.0	ASH	244.0	*	0.0	15800.0	0.0	8.33
230	6	0.0	ASH	*	*	0.0	15200.0	0.0	7.38
231	6	0.0	ASH	360.0	*	0.0	16700.0	0.0	3.92
232	6	320.0	ASH	392.0	*	0.0	16300.0	0.0	0.31
233	6	0.0	ASH	*	*	0.0	15200.0	0.0	7.06
234	6	0.0	ASH	445.0	*	0.0	15300.0	0.0	19.78
235	6	0.0	ASH	*	*	0.0	16200.0	0.0	27.59
236	6	0.0	ASH	560.0	*	0.0	16200.0	0.0	37.09
237	6	0.0	ASH	*	*	0.0	16900.0	0.0	*
238	6	0.0	ASH	*	*	0.0	16200.0	0.0	22.91
239	6	0.0	ASH	390.0	*	0.0	16500.0	0.0	22.14
240	6	0.0	ASH	360.0	*	0.0	16700.0	0.0	26.54
241	6	0.0	ASH	400.0	*	0.0	16500.0	0.0	28.01
242	6	0.0	ASH	425.0	*	0.0	16600.0	0.0	27.43
243	6	0.0	ASH	370.0	*	*	*	50.0	*
244	6	0.0	ASH	*	*	*	*	*	*
245	6	0.0	ASH	*	*	*	*	*	*
246	6	0.0	ASH	*	*	*	*	*	*
247	6	0.0	ASH	*	*	*	*	*	*
248	6	0.0	ASH	*	*	*	*	*	*
249	6	0.0	ASH	*	*	*	*	*	*
250	6	0.0	ASH	*	*	*	*	*	*
251	6	0.0	ASH	*	*	*	*	*	*
252	6	0.0	ASH	*	*	*	*	*	*
253	6	0.0	ASH	*	*	*	*	*	*
254	6	0.0	ASH	*	*	*	*	*	*
255	6	0.0	ASH	*	*	*	*	*	*
256	6	0.0	ASH	*	*	*	*	*	*
257	6	77.0	ASH	430.0	*	660.0	14300.0	*	*
258	6	71.0	ASH	*	*	680.0	14100.0	*	*
259	6	75.0	ASH	*	*	690.0	14300.0	*	*
260	6	73.0	ASH	*	*	660.0	14600.0	*	*
261	6	71.0	ASH	380.0	*	650.0	14800.0	*	*
262	6	73.0	ASH	490.0	*	720.0	14100.0	*	12.7
263	6	75.0	ASH	500.0	*	690.0	14700.0	*	15.0
264	6	73.0	ASH	390.0	*	710.0	13900.0	*	*

TABLE 15-2e

51	52	53	54	55	56	57	58	59	60
B&W NO.	CARD NO.	FINES RECIRCULATION LB/HR	STARTING BFO	NOX OUTLET PPM	NOX REDUCTION PCT	CO PPM	X10 ⁻¹ CO2 PPM	CH4 HYDROCARBONS PPM	CARBON LOSS LB/HR
265	6	0.0	ASH	*	*	540.0	14300.0	*	*
266	6	0.0	ASH	*	*	570.0	11900.0	*	15.2
267	6	75.0	ASH	*	*	700.0	14900.0	*	*
268	6	75.0	ASH	*	*	680.0	16200.0	*	*
269	6	73.0	ASH	490.0	*	710.0	15200.0	*	*
270	6	86.0	ASH	200.0	*	670.0	16900.0	*	*
271	6	86.0	ASH	500.0	*	750.0	14800.0	*	*
272	6	82.0	ASH	*	*	710.0	15400.0	*	*
273	6	0.0	ASH	*	*	640.0	13700.0	*	*
274	6	0.0	ASH	*	*	480.0	10700.0	*	*
275	6	84.0	ASH	*	*	690.0	13200.0	*	*
276	6	82.0	ASH	330.0	*	650.0	14900.0	*	*
277	6	0.0	ASH	470.0	*	630.0	14900.0	*	*
278	6	0.0	ASH	410.0	*	570.0	13500.0	*	*
279	6	84.0	ASH	500.0	*	640.0	14000.0	*	*
280	6	86.0	ASH	470.0	*	720.0	14500.0	*	18.16
281	6	82.0	ASH	530.0	*	630.0	14300.0	*	24.66
282	6	97.0	ASH	410.0	*	640.0	12300.0	*	*
283	6	95.0	ASH	*	*	600.0	14500.0	*	*
284	6	97.0	ASH	480.0	*	720.0	13700.0	*	*
285	6	99.0	ASH	*	*	740.0	12300.0	*	*
286	6	0.0	ASH	380.0	*	0.0	14.9	24.0	*
287	6	0.0	ASH	380.0	*	*	*	24.0	*
288	6	0.0	ASH	380.0	*	*	*	24.0	*
289	6	0.0	ASH	380.0	*	*	*	24.0	*
290	6	0.0	ASH	380.0	*	*	*	24.0	*
291	6	0.0	ALUMNA	*	*	40.0	14500.0	0.0	*
292	6	0.0	AL-ASH	*	*	50.0	14800.0	0.0	*
293	6	0.0	AL-ASH	*	*	30.0	15300.0	0.0	*
294	6	0.0	AL-ASH	*	*	30.0	15400.0	0.0	*
295	6	0.0	ALUMNA	*	*	60.0	15200.0	0.0	*
296	6	0.0	AL-ASH	*	*	50.0	15800.0	0.0	*
297	6	0.0	AL-ASH	*	*	50.0	16000.0	0.0	*
298	6	0.0	ALUMNA	*	*	80.0	15400.0	0.0	*
299	6	0.0	ALUMNA	*	*	200.0	14600.0	0.0	*
300	6	0.0	AL-ASH	*	*	200.0	14600.0	0.0	*
301	6	0.0	AL-ASH	*	*	100.0	14200.0	0.0	*
302	6	0.0	AL-ASH	*	*	200.0	14400.0	0.0	*
303	6	0.0	AL-ASH	*	*	120.0	15200.0	0.0	*
304	6	0.0	AL-ASH	*	*	100.0	15700.0	0.0	*
305	6	0.0	AL-ASH	*	*	400.0	16700.0	0.0	*
306	6	0.0	ALUMNA	*	*	100.0	15000.0	0.0	*
307	6	0.0	ALUMNA	*	*	120.0	15500.0	0.0	*
308	6	0.0	AL-ASH	*	*	110.0	15500.0	0.0	*
309	6	0.0	AL-ASH	*	*	60.0	15600.0	0.0	*
310	6	0.0	ALUMNA	*	*	80.0	15400.0	0.0	*
311	6	0.0	AL-ASH	*	*	100.0	15700.0	0.0	*
312	6	0.0	AL-ASH	*	*	90.0	15600.0	0.0	*
313	6	1.0	ALUMNA	*	*	160.0	15400.0	0.0	*
314	6	0.0	ALUMNA	*	*	1100.0	15300.0	0.0	*
315	6	0.0	AL-ASH	*	*	1200.0	15200.0	0.0	*
316	6	0.0	ALUMNA	*	*	300.0	15400.0	0.0	*
317	6	0.0	AL-ASH	*	*	500.0	15600.0	0.0	*

TABLE 15-2f

51	52	53	54	55	56	57	58	59	60
B&W NO.	CARD NO.	FINES RECIRCULATION LB/HR	STARTING BED	NOX OUTLET PPM	NOX REDUCTION PCT	CO PPM	X10 ⁻¹ CO2 PPM	CH4 HYDROCARBONS PPM	CARRON LOSS LB/HR
318	6	0.0	ALUMNA	*	*	700.0	15500.0	0.0	*
319	6	0.0	AL-ASH	*	*	500.0	16000.0	0.0	*
320	6	0.0	ALUMNA	*	*	800.0	14900.0	0.0	*
321	6	0.0	AL-ASH	*	*	600.0	15000.0	0.0	*
322	6	0.0	AL-ASH	*	*	600.0	15200.0	0.0	*
323	6	0.0	AL-ASH	*	*	600.0	15500.0	0.0	*
324	6	0.0	ALUMNA	*	*	800.0	14500.0	0.0	*
325	6	0.0	AL-ASH	*	*	600.0	15300.0	0.0	*
326	6	0.0	AL-ASH	*	*	600.0	15300.0	0.0	*
327	6	99.0	ASH	*	*	750.0	12900.0	*	*
328	6	99.0	ASH	*	*	690.0	14100.0	*	*
329	6	97.0	ASH	*	*	630.0	13100.0	*	*
330	6	99.0	ASH	480.0	*	750.0	17500.0	*	*
331	6	99.0	ASH	*	*	640.0	14800.0	*	*
332	6	0.0	ASH	350.0	*	4200.0	16000.0	*	*
333	6	0.0	ASH	310.0	*	*	16300.0	200.0	*
334	6	0.0	ASH	265.0	*	5500.0	16200.0	*	*
335	6	0.0	CA-CASO4	240.0	*	4050.0	16000.0	*	*
336	6	0.0	CA-CASO4	260.0	*	3700.0	16500.0	*	*
337	6	0.0	CA-CASO4	215.0	*	3000.0	16200.0	*	*
338	6	0.0	CA-CASO4	240.0	*	3600.0	16800.0	*	*
339	6	0.0	*	250.0	*	2400.0	16200.0	*	*
340	6	0.0	*	265.0	*	4800.0	16400.0	*	*
341	6	0.0	ASH	200.0	*	0.0	14800.0	40.0	*
342	6	0.0	ASH	*	*	0.0	15100.0	40.0	*
343	6	0.0	ASH	20.0	*	0.0	*	40.0	*
344	6	0.0	ASH	370.0	*	0.0	13900.0	40.0	*
345	6	0.0	ASH	330.0	*	0.0	15000.0	40.0	*
346	6	0.0	ASH	330.0	*	0.0	14800.0	40.0	*
347	6	0.0	ASH	280.0	*	0.0	14800.0	40.0	*
348	6	0.0	AL-ASH	*	*	600.0	14600.0	0.0	*
349	6	0.0	AL-ASH	*	*	800.0	14800.0	0.0	*
350	6	0.0	AL-ASH	*	*	200.0	14800.0	0.0	*
351	6	0.0	AL-ASH	*	*	180.0	15400.0	0.0	*
352	6	0.0	ASH	250.0	*	0.0	15800.0	*	*
353	6	0.0	ASH	210.0	*	1500.0	16800.0	*	*
354	6	0.0	ASH	240.0	*	0.0	16000.0	430.0	*
355	6	0.0	ASH	290.0	*	2250.0	16400.0	430.0	*
356	6	0.0	ASH	360.0	*	3220.0	16800.0	390.0	*
357	6	0.0	ASH	280.0	*	0.0	17000.0	230.0	*
358	6	0.0	ASH	280.0	*	4100.0	*	250.0	*
359	6	0.0	ASH	285.0	*	0.0	*	90.0	*
360	6	0.0	ASH	285.0	*	3100.0	14600.0	100.0	*
361	6	0.0	ASH	285.0	*	5400.0	15300.0	90.0	*
362	6	0.0	ASH-S	260.0	*	0.0	16200.0	*	*
363	6	0.0	ASH-S	260.0	*	1070.0	*	*	*
364	6	0.0	ASH-S	235.0	*	2100.0	*	*	*
365	6	0.0	ASH-S	330.0	*	2860.0	*	*	*
366	6	0.0	ASH-S	360.0	*	0.0	15800.0	200.0	*
367	6	0.0	ASH-S	310.0	*	1780.0	16200.0	250.0	*
368	6	0.0	ASH-S	290.0	*	3100.0	16300.0	180.0	*

TABLE 15-2g

61	62	63	64	65	66	67	68	69	70
B&W NO.	CARD NO.	COMBUSTION EFFICIENCY PCT	OUTLET DLST LOADING LB/HR	CARBON IN FLY ASH PCT	ELUTRIATED FINES PRCLC SIZE, MICRONS	MEAN (WT) PARTICLE SIZE MICRON IN BED	FRACTION CAN IN RED	FRACTION S IN RED	BULK DENSITY OF BED LB/FT**3
1	7			*	*				
2	7			*	*				
3	7			*	*				
4	7			*	*				
5	7			*	*				
6	7			*	*				
7	7			*	*				
8	7			*	*				
9	7			*	*				
10	7			*	*				
11	7			*	*				
12	7			*	*				
13	7			*	*				
14	7			*	*				
15	7		0.496	*	*				
16	7		0.991	*	*				
17	7			*	*				
18	7	99.9	1.10	*	100.0				
19	7			*	*				
20	7	99.9	0.661	*	*				
21	7	99.9		*	*				
22	7	94.6	*	*	*				
23	7	94.6	*	*	*				
24	7	94.6	*	*	*				
25	7	94.6	*	*	*				
26	7	94.6	*	*	*				
27	7	*	*	*	*				
28	7	*	*	*	*				
29	7	93.4	*	*	*				
30	7	93.4	*	*	*				
31	7	93.4	*	*	*				
32	7	93.4	*	*	*				
33	7	*	*	*	*				
34	7	*	*	*	*				
35	7	*	*	*	*				
36	7	*	*	*	*				
37	7	*	*	*	*				
38	7	*	*	*	*				
39	7	*	*	*	*				
40	7	*	*	*	*				
41	7	94.4	*	*	*				
42	7	94.4	*	*	*				
43	7	94.4	*	*	*				
44	7	94.4	*	*	*				
45	7	94.4	*	*	*				
46	7	95.6	*	*	*				
47	7	95.6	*	*	*				
48	7	95.6	*	*	*				
49	7	95.6	*	*	*				
50	7	95.6	*	*	*				
51	7	94.7	*	*	*				
52	7	94.7	*	*	*				
53	7	94.7	*	*	*				

TABLE 15-2h

TABLE 15-3a

COMPARISON OF TRACE ELEMENTS IN COALS AND COAL PRODUCTS ($\mu\text{g/g}$)

Element	Coal				Final Bed			
	ANL	BCL (b)		Power Plant	ANL	BCL		Power Plant Sample BA
	Run TR 3 (a)	Run No. 1	Run No. 2		Run TR 3	Run No. 1	Run No. 2	
As	5	2.7	<3		3.5	0.67	1.0	15
Ba		35	200			180	200	
B		93	<0.03			33	5	
Bc	0.7	0.17	2		0.8	<0.18	<0.005	
Br	13	4.7	10			4.5	1.0	
Ce		9.8	50			15	5.0	
Cd		0.10	<30			0.14	<10	
Co	1.8	4.0	10			0.14	0.3	
Cr	100	13	100		12	1.3	10	
Cu		9.0	30	9.6		78	3	82
Dy	0.2	0.70	<1			0.49	<0.2	
Eu			<0.5			0.25	<0.3	
F	25	110	<3			170	<3	
Fe($\times 10^4$) (d)	1	>1	-5	0.37	55	0.46	-0.10	6.6
Hf		0.18	<2		96	1.1	<0.5	
Hg	0.15	0.16	<2	0.070	<0.005	<0.01	<0.3	0.140
K($\times 10^3$)	5.8	1.2	-6		0.66	-1.6	-2.0	
La	4.2	5.0	20		3.7	6.4	2	
Li		0.13	20			5.7	1	
Mn	26	80	100		39	26	20	
Mo		2.9	30	0.99		1.2	<3	3.5
Na($\times 10^2$)	6.9	8.9	200		13	3.2	2	
Ni		33	<10			2.3	<2	
Pb	29	0.47	<1		51	1.9	1	
Sb	0.3	0.56	<0.5		0.7		<0.2	
Sc	1.7	1.6	3		1.8	0.16	1.0	
Se		0.29	<5	1.9			<2	7.7
Sm	0.8	0.71	<1		0.1	0.83	<0.5	
Tb			<0.2				<0.1	
V		20	500			7.0	10	
Yb	<1	0.23	<0.5		5.2	<0.49	<0.2	
Zn		37	<10	7.3		17	<3	58
Zr		10	300	13	390	28	20	220

TABLE 15-3b

Element	Primary Cyclone			Power Plant Sample MA	Secondary Cyclone			Power Plant Sample PA
	ANL	BCL			ANL	BCL		
	Run TR 3	Run No.1	Run No.2		Run TR 3	Run No.1	Run No.2	
As	25	4.1	1.0	44		6.1	3	120
Ba	350	180	500		860	320	300	
B		500	50			2000	300	
Be	2.6	2.6	0.20		6.0	6.0	2	
Br		6.0	0.50		3	60	1	
Ce	19	15	50		13	44	20	
Cd		0.67	<3			1.0	<3	
Co	11	2.1	10		19	14	10	
Cr	180	15	100		300	87	100	
Cu		66	50	150		120	50	230
Dy	1.8	1.4	3		2.9	2.0	2	
Eu		0.50	1			0.94	1	
F	20	290	<5		10	450	<20	
Fe(x10 ⁴)(d)	5.9	>1	-2	7.0	3.6	>1	-2	6.9
Hf	2.9	1.8	2		6	1.8	<0.5	
Hg	0.46	<0.01	<0.3	0.026	0.46	14	<0.3	0.310
K(x10 ³)	3.7	>5	-10		5	>10	-20	
La	31	6.4	50		52	30	30	
Li			10			57	20	
Mn	110	60	200		140	60	500	
Mo		3.3	20	12		14	10	41
Na(x10 ²)	41	-14	30		72	>50	50	
Ni		23	200			99	100	
Pb	95	4.3	20		260	43	100	
Sb	3	0.67	0.2		6.2	1.4	1	
Sc	9	1.6	30		19	7.3	30	
Se		0.94	<5	4.1		9.4	<5	27
Sm		1.7	5			3.6	3	
Tb		0.19	0.5			0.48	0.3	
V		25	500			140	1000	
Yb	4	1.6	1		7.5	2.5	1	
Zn		67	<3	100		140	<3	250
Zr		35	200	260		120	200	210

(a) Run TR 3 bed temperature 1560 F; Arkwright coal used.

(b) Run No. 1 bed temperature 1560 F; Run No. 2 bed temperature 1655 F; Illinois No. 6 coal used.

(c) Mean analytical values for constituents in 101 different coals.

(d) Recorded values to be multiplied by 10^4 , e.g., reported value of 1 is really 10,000 ppmw.

To better understand the fate of trace elements in a fluid bed combustor, it is convenient to classify these elements into four classifications. (See Table 15-4) (6). Within each classification the elements behave in a similar manner with the elements either: leaving the system essentially unreacted, condensed on other particles, or leaving as a gas in the stack effluent.

"Trace elements listed in Class I are lithophiles and are associated with aluminosilicate minerals in coal. As such, they are high boiling compounds and do not decompose on combustion. They usually melt and coalesce to form fly ash and slag. Elements in this class are not enriched during combustion.

Class II elements are generally present in coal as sulfides. These sulfides themselves may be fairly volatile or, upon combustion, decompose, and the elements themselves are produced in the vapor phase. These volatile sulfides or elements can then condense on the extensive surface area presented by particulates thus leading to a surface enrichment. This enrichment is usually most prevalent in the fine particle fraction ($i \leq 3 \mu m$) of the total particulate loading." Generally, elements could be placed in Class II if:

$$\frac{\text{Wt \% of constituent in fly ash}}{\text{Wt \% of constituent in coal}} > 3$$

"Class III elements boil below the furnace and flue gas temperatures and can exist from the stack as vapors.

The elements listed under Class IV exhibit the characteristics of Class I and Class II elements." (7).

Upon study of the factors affecting trace element emissions, it may be postulated that the AFB boiler can be expected to emit lower concentrations of these elements than a conventional boiler. The potential reduction of trace element emissions is related to the bed temperature, coal size and the fact that limestone is used. The low AFB temperature should oxidize or volatilize fewer trace elements than a PC boiler while the larger size of the AFB feed coal should reduce the amount of fine particulate matter which is released. With the use of limestone,

TABLE 15-4

THE SEPARATION OF ELEMENTS IN THE GEOCHEMICAL
CLASSIFICATION SCHEME

Class I		Class II	Class III	Class IV
Al	Mn	As	Hg	Cr
Ba	Rb	Cd	Cl	Cs
Ce	Sc	Cu	Br	Na
Co	Si	Ga	F	Ni
Eu	Sm	Pb		U
Fe	Sr	Sb		V
Hf	Tu	Se		
K	Th	Zn		
La	Ti			
Mg				

the AFB boiler has the advantage of a sorbent that acts like a sink for certain trace metals, such as lead.

Argonne National Laboratories has conducted a study in an effort to determine which trace elements could present an environmental problem. Tables 15-5 and 15-6 present the results of these studies. The basis for their studies, the models used and assumptions made can be found in Reference (8).

There are high predicted levels of calcium and silicon but neither element is listed by the EPA as a hazardous element. Many more elements in Table 15-6 have the potential to be of concern. Some of these, Be, As, Pb, U, Na, and the halogens, may form toxic compounds harmful to human health. However, should the combustion reaction of the fluidized bed occur as predicted, these compounds should not create an environmental problem.

The actual amount of trace elements that escape the AFB system is unknown at this time. Until the performance of electrostatic precipitators and other collection devices is established little can be done except to speculate what elements will leave in the stack gas.

Again it must be emphasized that the information contained in Tables 15-5 and 15-6 is based on theoretical relationships. Definitive field measurements must be made before any conclusions can be drawn concerning the emission of trace elements.

D. Bed Solids

The solid wastes from the AFB system come from the FBC beds, and the CBB cyclone and precipitator. There may also be some solid waste from the CBB but very little, if any, is expected. The material discharged from the bed is unique in that it is dry as contrasted with scrubber sludge. This characteristic lends itself to the primary disposal idea of a landfill. Unlike the sludge obtained from limestone scrubbers, this waste is ready to be used almost immediately where dry CaO and CaSO₄ are the desired materials. Scrubber sludge and fly ash from a PC boiler can be very costly to dispose, approximately \$7.00-\$11.00 per ton (treated, dry basis). A limestone scrubber at a 184 MW plant burning 4% sulfur coal would generate about

TABLE 15-5

COMPARISON OF ESTIMATED TRACE ELEMENT

CONCENTRATIONS (CLASS I ELEMENTS) WITH AN

ENVIRONMENTAL INDEX BASED ON THRESHOLD

LIMITING VALUES

Element	<u>A</u> Emission factor after control device (assuming 99% control of particulates)		<u>B</u> Estimated ambient concentration: (A/1000)		<u>C</u> Environmental index (TLV/1000)	<u>D</u> Ambient concentration/ index (D ≥ 1.0 indicates a potential environmental problem)	
	Bituminous ^a	Lignite ^a	Bituminous	Lignite		Bituminous	Lignite
Al	72.4	48.31	0.075	0.048	—	—	—
Ba	0.25	0.70	2.5×10^{-4}	7.0×10^{-4}	5×10^3	0.05	0.14
Ca	89	129	0.089	0.129	0.05	1.8	2.6
Ce	0.04	0.02	4×10^{-5}	2×10^{-5}	—	—	—
Co	0.01	0.01	1×10^{-5}	1×10^{-5}	1×10^{-3}	0.01	0.01
Eu	1.4×10^{-3}	2.8×10^{-4}	1.4×10^{-5}	2.8×10^{-6}	—	—	—
Fe	108	84	0.108	0.084	0.15	0.72	0.56
Hf	5.6×10^{-3}	5×10^{-4}	5.6×10^{-5}	5×10^{-6}	0.005	0.01	0.001
K	11.6	3.8	11.6×10^{-3}	3.8×10^{-3}	—	—	—
La	0.052	0.004	5.2×10^{-5}	4×10^{-6}	—	—	—
Mg	8.4	29.5	0.008	0.03	0.10	0.08	0.3
Mn	0.1	0.1	0.001	0.001	0.05	0.02	0.02
Rb	0.21	0.002	2.1×10^{-4}	2×10^{-6}	—	—	—
Sc	0.03	0.01	3×10^{-5}	1×10^{-5}	—	—	—
Si	112	66	0.11	0.06	0.1	1.0	1.6
Sn	0.003	0.01	3×10^{-6}	1×10^{-5}	0.02	0.0002	0.0005
Sr	0.03	0.66	3×10^{-5}	6.6×10^{-4}	—	—	—
Ta	0.0003	—	3×10^{-7}	—	0.05	6×10^{-6}	—
Th	0.0001	0.0002	1×10^{-7}	2×10^{-7}	1×10^{-3}	1×10^{-4}	2×10^{-4}
Ti	10.3	1.6	0.01	0.001	0.1	0.1	0.01

^aBased on References 4 through 11.

TABLE 15-6

COMPARISON OF ESTIMATED TRACE ELEMENT CONCENTRATIONS (CLASS II ELEMENTS) WITH AN ENVIRONMENTAL INDEX BASED ON THRESHOLD LIMITING VALUES

Element	<u>A</u> Emission factor without controls (mg/m ³) ^a (combined vapor and particulate)		<u>B</u> Ambient concentration: (A/1000)		<u>C</u> Environmental index (mg/m ³) (TLV/100)	<u>D</u> Ambient concentration/ environmental index D ≥ 1 indicates potential problem		<u>E</u> Degree of control required to make D ≤ 1.0	
	Bituminous	Lignite	Bituminous	Lignite		Bituminous	Lignite	Bituminous	Lignite
Class II									
As	8.42	1.70	8.42 × 10 ⁻³	1.70 × 10 ⁻³	0.005	1.7	0.3	60%	0
Cd	0.04	0.04	0.04 × 10 ⁻³	0.04 × 10 ⁻³	0.0005	0.08	0.08	0	0
Cu	5.61	3.74	5.6 × 10 ⁻³	3.8 × 10 ⁻³	0.01	0.6	0.4	0	0
Pb	2.0	1.5	2 × 10 ⁻³	1.5 × 10 ⁻³	0.0015	1.3	1.0	20%	0
Sb	0.06	0.02	6 × 10 ⁻⁵	2 × 10 ⁻⁵	0.005	0.01	0.004	0	0
Se	0.4	0.3	0.4 × 10 ⁻³	0.3 × 10 ⁻³	0.2	0.2	0.2	0	0
Zn	7.0	5.4	7.0 × 10 ⁻³	5.4 × 10 ⁻³	0.05	0.1	0.1	0	0
Be	1.1	1.0	1 × 10 ⁻³	1 × 10 ⁻³	2 × 10 ⁻⁵	50	50	98%	98%
Class III									
Hg	0.07	0.02	0.07 × 10 ⁻³	0.02 × 10 ⁻³	5 × 10 ⁻⁴	0.04	0.04	0	0
Cl	184	476	0.18	0.48	0.03	16	16	85%	94%
Br	1.8	—	1.8 × 10 ⁻³	—	0.007	0.2	—	0	—
F	27	13	0.027	0.013	0.02	1.35	0.65	26%	0
Cr	7.0	4.7	7.0 × 10 ⁻³	4.7 × 10 ⁻³	0.01	0.7	0.5	0	0
Ni	5.6	3.5	5.6 × 10 ⁻³	3.5 × 10 ⁻³	0.01	0.6	0.4	0	0
U	11.2	56.1	0.01	0.06	0.002	5	30	80%	97%
V	9.8	7.0	9 × 10 ⁻³	7 × 10 ⁻³	0.005	2	1.4	50%	29%

^aFor comparison, 1 m³ of air equals approximately 10⁶ mg.

128 tons per hour of sludge (8% solids). The ponding cost for untreated sludge is \$3.00 per ton. If the sludge is dewatered and stabilized, its disposal costs would be \$7.00 or more per ton. (9). The 200 MW AFB boiler will generate 36 tons of waste per hour. This is a smaller amount than a scrubber output, so costs for disposal are expected to be lower.

Several studies are progressing on the use of AFB waste as landfill. The testing has included leachate and shake tests by Westinghouse, Lysimeter and field cells tests by Ralph Stone and Company. Results reviewed to date have indicated trace metal concentrations in the leachate are within acceptable limits for discharge purposes. Problem areas, which may prevent direct discharge, are the high total dissolved solids (calcium) and the high pH (10.5-11.6) of water passing through the spent bed material. A future problem may arise with the concentrations of Ni, Pb, As, Hg, and Cd when large quantities of material are placed in disposal sites.

Although no actual set of standards exists for leachate, threshold limits will be established by the Federal EPA as soon as the data is compiled. It is thought, with this set of standards for comparison, the trace elements concentrations of actual landfills will exceed the allowable limits. One point should be mentioned here. The trace metal's solubility is related to pH and the high pH of the AFB bed material will cause trace metals to precipitate in the limestone mixture. This may prevent most of the trace metals from leaving the landfill in the leachate. Monitoring of a test landfill area would provide the information needed to evaluate this problem.

A number of other disposal choices are being tested, some of which may help pay disposal costs. Agricultural possibilities are being explored for use of the spent bed material as a source of sulfur and calcium for crops. The waste material, when mixed with compost form a nutrient fertilizer. A program now in progress in Alabama has corn growing in a soil mixture containing the AFB waste. Results, however, will not be known until the full growing season ends in March, 1978. Peanuts have already been successfully grown in an agricultural mix of the AFB waste material.

Crop yields for the peanuts were similar to the yields obtained when a commercial calcium source was applied. A series of feeding tests will be conducted in which crops grown with the waste material will be fed to animals to see if trace metals are passed through the food cycle via the plants. These tests will be carried out in the fourth and fifth year of the agricultural program. (10, 11).

Although the future outlook is positive concerning farm usage of AFB material, there remains two main drawbacks. The first is limited scope of the agricultural area. The cost of transporting the material restricts its use to the farms surrounding the AFB boiler plant. To attempt to ship the material over long distances would raise the cost beyond that of a commercial fertilizer. Secondly, the amount of bed waste which can be disposed of in this manner is small compared to the huge amounts generated. Other uses must be developed which will consume large amounts of the waste.

As more samples of the waste material become available, they will be shipped to Pennsylvania, New York, and Ohio. It is hoped that sewage waste can be stabilized and neutralized by the AFB bed material additive. The Philadelphia Sewage Authority of Pennsylvania will attempt to treat sewage wastes with the bed material. Compressibility and load factor results have been encouraging enough to interest officials of New York and Ohio. New York City is interested in building blocks of the bed material. The blocks will be applied in the building of jetties in the harbor area. In Ohio, the bed material will be tested in place of the usual limestone in road bases. (12).

An experimental study was done by Babcock & Wilcox Company with AFB ash. Different amounts of AFB ash were mixed with wet scrubber sludge to form a cementitious type of landfill material. By varying the AFB ash fraction, B&W was able to obtain a satisfactory percentage range for a good landfill product. Results show a 20%-25% AFB bed material concentration could withstand pressures necessary to support light construction equipment. Additional tests revealed no problems with leachate contamination other than high pH levels. (13).

There has been speculation that AFB bed material could be used as a limestone replacement in a scrubber due to the high percentage of unreacted CaO. Naturally, this idea has fair economic potential but then the problem of sludge disposal does not disappear. It is merely displaced from one plant to another.

Another question to consider is whether active CaO in the solid waste will cause any problems in a landfill without first being treated or slaked. When water is added to active CaO, an exothermic reaction occurs to form Ca(OH)_2 . This hydration reaction can be very violent if too little water is added to the CaO particles. In such a case, the CaO could become "burned". The temperature of the reaction can reach as high as 400 to 500°F causing dehydration of nearby hydrated particles which can make them very unstable.

Should large amounts of water be added too quickly to the CaO particles, another unstable condition will occur. The CaO particles become "drowned". In this instance, the outer layer of the particle reacts to form an impervious layer which prevents water from reaching the interior. Thus the reaction does not go to completion, forming an unstable product that is liable to hydrate later causing heat generation.

The hydration reaction equation is:

Figures 15-1 and 15-2 illustrate the rise in temperature when the hydration reaction occurs. These temperatures were recorded when 3.8 liters of water were added to 13.6 kg of sample. In Figure 15-1, the samples were bed material and in Figure 15-2, the samples were fly ash. (14).

Until it is certain no adverse environmental effects will occur, the AFB boiler will be unable to use the landfill method of disposal. The high pH of the leachate samples implies the need to use an impervious liner before the dry effluent is placed in a landfill. It will also be necessary to cover the material because the dry bed material has a tendency to air slake, forming very fine dust particles which could add to the fugitive emissions of the area. An alternative to the landfill method is ponding. Again, an impervious liner will be required to prevent the formation of an unacceptable

TEMPERATURE CHANGE FROM WATER ADDITION TO BED MATERIAL

FIGURE 15.1

FIGURE 15.2
TEMPERATURE CHANGE FROM WATER ADDITION TO FLYASH

leachate of high pH. The AFB waste would have to be slaked with water, then pumped to the pond in a manner similar to disposal of limestone scrubber sludge. In both disposal methods, the containment of the leachate is important as the pH levels of 10-13 are above the new limits developed by Tennessee (6-9 pH). The treatment of the leachate water should not cause any special problems.

E. 1200-4-5-.03 EFFLUENT LIMITATIONS FOR EFFLUENT LIMITED SEGMENTS

The U. S. Environmental Protection Agency has adopted effluent limitations and guidelines for existing sources and standards of performance for new sources pursuant to Section 301, 304, and 306 of the Federal Water Pollution Control Act as amended, PL92-500. Permits for discharges to effluent limited segments will contain limitations and standards in accordance with these guidelines, when such are in effect. The Commissioner has authority, pursuant to Section 70-330, Tennessee Code Annotated, and Rule 1200-4-3, to require wastewater treatment, independent of Federal guidelines. A set of effluent limitations will be required in each permit which will indicate adequate operation or performance of treatment units used and which will appropriately limit those harmful parameters present in the wastewater. In the absence of Federal guidelines, treatment units will be required to achieve as a minimum the following as maximum effluent limitations when such parameters are present as a result of processes causing the contamination or discharges:

(1) Municipal and domestic wastewater treatment plants

<u>Parameter</u>	<u>Monthly Avg. (mg/l)</u>	<u>Weekly Avg. (mg/l)</u>	<u>Daily Max. (mg/l)</u>
BOD ₅	30	40	45
TSS	30	40	45

The concentration of settleable solids shall not exceed 1.0 ml/l as measured by the standard one-hour Imhoff cone test.

(2) Industrial wastewater treatment plants

<u>Parameter</u>	<u>Daily Maximum Concentrations (mg/l)</u>
Aluminum	250
Antimony	1.0
Arsenic	1.0
Barium	5.0
Boron	500
Cadmium	0.01
Chlorine (total)	2.0
Chromium (total)	3.0
Cobalt	10
Copper	1.0
Cyanide	0.05
Fluoride (soluble)	20.0
Iron (total)	10.0
Lead	0.1
Manganese	10.0
Mercury	0.05
Nickel	3.0
Oil and Grease	(a) 30

(b) No visible or floating oil or grease

pH (6.0 to 9.0)	
Phenols	1.0
Selenium	0.01
Silver	0.05
*Suspended Solids	40
Settleable solids	0.5 ml/l
Zinc	2.0

*In the case of biological treatment units, the daily maximum TSS may be 120 mg/l.

(3) Domestic waste stabilization lagoons (existing)

<u>Parameter</u>	<u>Monthly Avg. (mg/l)</u>	<u>Weekly Avg. (mg/l)</u>	<u>Daily Max. (mg/l)</u>
BOD ₅	30	40	45
TSS ₅	100	110	120

Where it can be demonstrated that higher concentration values have resulted from utilization of water conservation practices, allowances may be made in determination of effluent limitations. Parameters other than those listed may be limited in accordance with current treatment technology.

Where it can be demonstrated that treatment by practical conventional unit treatment processes cannot provide compliance with the concentration limitations listed in paragraph 1, 2, and 3 of this section, other reasonable effluent limitations may be established.

It is not the intent or purpose of these regulations that all Permits require limitation of or monitoring of all parameters listed in paragraph (2) of this Section. Rather, it is the intent of this Section that each permit include limitations of those parameters listed that are directly attributable to the processes causing the discharge for which the permit is granted.

EFFLUENT LIMITATIONS FOR EXISTING AND PROPOSED
WATER QUALITY LIMITED SEGMENTS

Permits for all existing or proposed discharges to water quality limited or proposed water quality limited segments of the State's waters may include, when necessary to maintain assigned classifications, individually calculated effluent limitations on any parameter more stringent than BPTCA, BATEA, or results of treatment by practical conventional unit treatment processes.

- (1) Effluent limitations on toxic substances will be required in accordance with the General Water Quality Criteria, Rule 1200-4-3, using the 96-hour LC₅₀ criterion and appropriate application factor for each toxic parameter.
- (2) Appropriate limitations on organic related and other oxygen demanding parameters will be required in any Permit to insure adequate dissolved oxygen in the State's waters in accordance with the General Water Quality Criteria, Rule 1200-4-3.
- (3) When a treatment process greater than BPTCA, BATEA, or conventional unit treatment processes is required by application of these Rules, a set of effluent limitations will be required in any Permit which will completely describe expected results of such treatment process.

1200-4-5-.05

EFFLUENT LIMITATIONS NECESSARY TO PREVENT
DEGRADATION

Regardless of whether or not a segment of the State's waters is designated as a water quality limited segment, effluent limitations may be required in any Permits to insure compliance with the Antidegradation Statement, Rule 1200-4-3-.01(6).

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XVI. APPENDIX

DWN. BY H. JOHNSON		CONCEPTUAL DESIGN FLOW SCHEMATIC FOR ATMOSPHERIC FLUIDIZED BED BOILER 200MW UNIT	<small>THIS SCHEMATIC IS THE PROPERTY OF THE BARCOCK & WELCOX CO. POWER SIMULATION GROUP. IT IS TO BE USED FOR THE PURPOSES OF THE PROJECT ONLY. IT IS NOT TO BE REPRODUCED OR TRANSMITTED IN ANY FORM OR BY ANY MEANS, ELECTRONIC OR MECHANICAL, WITHOUT THE WRITTEN PERMISSION OF THE BARCOCK & WELCOX CO. POWER SIMULATION GROUP.</small>
CHKD. BY			
PASSED BY			
APPROV. BY			
ES-241		DATE 1-13-73	REV. 0
TVA		SCALE	254214 E 10

PLAN SECTION "A-A"

3699 J

T.V.A. The Babcock & Wilcox Company Power Generation Group	
DESIGNED BY: M. BLAIR CHECKED BY: APPROVED BY:	This drawing is the property of Babcock & Wilcox and is loaned upon condition that it is not to be reproduced or copied in whole or in part, or used for furnishing information to others, or for any other purpose without the written consent of Babcock & Wilcox and will be returned upon request. CONCEPTUAL DESIGN BOILER PLAN SECTION "A-A" FOR ATMOSPHERIC FLUIDIZED BED BOILER
ES-241 CONTRACT AFFILIATE	SCALE: 1" = 10'-0" DO NOT SCALE - USE DIMENSIONS ONLY SHEET NO. 3699 J OF 10

REVISIONS			
NO.	DESCRIPTION	DATE	APPROVAL
1

PLAN SECTION 'B-B'

T. V. A.

DESIGNED BY	B. THAYER
CHECKED BY	
APPROVED BY	
DATE	3-8-78
REV.	ES-241

CONCEPTUAL DESIGN
BOILER PLAN SECT. 'B-B'
FOR ATMOSPHERIC
FLUIDIZED BED BOILER
200MW UNIT

THE SARGENT & Lundy CO. POWER ENGINEERING GROUP 1000 NEW YORK AVENUE NEW YORK, N.Y. 10022 TELEPHONE (212) 512-2000 FACSIMILE (212) 512-2001 CABLE SARGENT LUNDY NEW YORK 25-1100	250391E 0
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REVISIONS			
REVISION NO.	DESCRIPTION	DATE	APPROVAL

PLAN SECTION A-A

SIDE VIEW

FRONT VIEW

DESIGNED BY
E.E. PINSKE

CHECKED BY

APPROVED BY
S.B. 78

DATE
ES-241

CONCEPTUAL DESIGN
CBB ARRGT
FOR ATMOSPHERIC
FLUIDIZED BED
BOILER 200 MW

SCALE 1/8" = 1'-0"

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THE BARCOCK & WILCOX CO.
POWER GENERATION GROUP
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ANY OTHER PURPOSES WITHOUT THE
WRITTEN PERMISSION OF THE BARCOCK
& WILCOX CO. OR ITS SUCCESSORS.
REV. 0

250400E

T.V.A.

A-6

T. V. A.	
The Babcock & Wilcox Company	
Project: Carbon Burnup Bed Plant Side View	
Drawing: CONCEPTUAL DESIGN	
Title: CARBON BURNUP BED PLANT SIDE VIEW FOR ATMOSPHERIC FLUIDIZED BED BOILER	
ES-241	3698 J

DESIGNED BY R. SZITAL		T.V.A. The Babcock & Wilcox Company Power Generation Group	
CHECKED BY _____		This drawing is the property of Babcock & Wilcox and is loaned upon condition that it is not to be reproduced or copied in whole or in part, or used for furnishing information to others, or for any other purpose without the written consent of Babcock & Wilcox and will be returned upon request.	
DRAWN BY _____		CONCEPTUAL DESIGN REGENERATIVE AIRHEATER SIDE VIEW FOR ATMOSPHERIC FLUIDIZED BED BOILER	
PROJECT NO. ES-241		SCALE 1" = 1'-0"	SHEET NO. 3701 J
DATE 1/27/79		DRAWING NO.

T.V.A.

The Babcock & Wilcox Company

Power Generation Group

Drawn: R SZITAL

Checked: J. J. J.

Approved: J. J. J.

Scale: 1" = 1'-0"

Project: 3702 J

Sheet: 1 of 1

CONCEPTUAL DESIGN
REGENERATIVE AIRHEATER PLAN VIEW
FOR
ATMOSPHERIC FLUIDIZED
BED BOILER

T.V.A.	
The Babcock & Wilcox Company	
Power Generation Group	
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CONCEPTUAL DESIGN OF TUBULAR AIRHEATER PLANT SIDE VIEW FOR ATMOSPHERIC FLUIDIZED BED BOILER	
ES - 241	3703 J
SCALE: 1/8" = 1'-0"	DO NOT SCALE - SEE DIMENSIONS ON DRAWING
CONTRACT AFFILIABLE	SHEET NO. 3703 J

T.V.A.
The Babcock & Wilcox Company
Power Generation Group

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CONCEPTUAL DESIGN OF
TUBULAR AIRHEATER PLANT
PLAN VIEW FOR
ATMOSPHERIC FLUIDIZED
BED BOILER

ES-241

SCALE: 1/8" = 1'-0"

DO NOT SCALE
USE DIMENSIONS ONLY

SHEET NO. 3704 J

DATE

VIEW "A-A"

VIEW "E-E"

VIEW "CC"

VIEW "F-F"

TVA			
The Tennessee Valley Authority			
Power Generation Group			
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CONCEPTUAL DESIGN			
COAL & LIMESTONE CONVEYOR SYSTEM			
AUX. VIEWS FOR			
ATMOSPHERIC FLUIDIZED			
BED BOILER			
ES-241	3707J	0	0

THE BABCOCK & WILCOX COMPANY
POWER GENERATION DIVISION

REVISIONS				MICRO-FILM
CASH NO.	DATE	DESCRIPTION	ORIG.

NOTES:

1. BIN & LID MAT'L. $\frac{3}{8}$ " THK. R. CARBON STL. (A 36 MIN)
2. HOPPER MAT'L. $\frac{3}{8}$ " THK. R. STAINLESS STL.
3. STIFFENERS & CONNECTIONS CARBON STL.

CAPACITY = 2,307 CU. FT.

20 REQ'D.

ES-241

TVA

DWN. BY H. J.	CHK'D
PASSED BY	APP'D

COAL SILO

SCALE $\frac{1}{4}" = 1'-0"$	DATE 1-31-78
DRWG. NO. 140026	A-0

THE BABCOCK & WILCOX COMPANY
POWER GENERATION DIVISION

REVISIONS			MICRO-FILM
DASH NO.	DATE	DESCRIPTION	ORIG.

NOTES:

1. BIN & LID MAT'L. $\frac{3}{8}$ " THK. R. CARBON STL. (A 36 MIN)
2. HOPPER MAT'L. $\frac{3}{8}$ " THK R. STAINLESS STL.
3. STIFFENERS & CONNECTIONS CARBON STL.

CAPACITY=439 CU. FT.

20 REQ'D.

TVA

ES-241

OWN. BY H. J.	CHK'D
PASSED BY	APP'D

LIMESTONE SILO

SCALE $\frac{3}{8}" = 1'-0"$	DATE 1-31-78
DRWG. NO. 140027	A. 0

145530 B

NOTES:

1. BIN & LID MAT'L. $\frac{3}{8}$ " THK. R. CARBON STL (A 36 MIN.)
2. HOPPER MAT'L. $\frac{1}{2}$ " THK. R. STAINLESS STL.
3. STIFFENER & CONNECTIONS CARBON STL.

THE BABCOCK & WILCOX COMPANY
POWER GENERATION GROUP

REVISIONS			MICROFILM	
DASH NO.	DATE	DESCRIPTION	ORIGINAL

CAPACITY=22,816 CU. FT.
1 REQ'D.

TVA

ES-241

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DWN. BY H.J. CHK'D
DATE 1-31-78 APP'D

CBB FEED TANK

SCALE $\frac{1}{8}$ " INCHES = 1 FOOT
145530 B-0

THE BABCOCK & WILCOX COMPANY
POWER GENERATION DIVISION

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REVISIONS				MICRO-FILM
DASH NO.	DATE	DESCRIPTION	ORIG.	

NOTES:

1. BIN & LID MAT'L. $\frac{3}{8}$ " THK. R. CARBON STL. (A 36 MIN.)
2. HOPPER MAT'L. $\frac{3}{8}$ " THK. R. STAINLESS STL.
3. STIFFENERS & CONNECTIONS CARBON STL.

CAPACITY = 32,270 CU. FT.

1 REQ'D.

ES-241

TVA

DWN. BY	H. J.	CHK'D
PASSED BY		APP'D

BED MATERIAL
STORAGE SILO

SCALE	$\frac{1}{8}" = 1'-0"$	DATE	1-31-72
DRWG. NO.	140025	A	0

REVISIONS			
NO.	DESCRIPTION	DATE	APPROVAL
1			

TVA

OWN. BY H. JOHNSON

CHKD. BY

DESIGNED BY

APPROV. BY

STD. APP. DATE

ES-241

DO NOT SCALE - USE DIMENSIONS ONLY

CONCEPTUAL DESIGN
FBC START-UP BED
DISTRIBUTION PL. SUPPT.
FOR ATMOSPHERIC
FLUIDIZED BED SUPPORT
200MW UNIT

SCALE AS NOTED

THIS DESIGN IS THE PROPERTY OF
THE SARGENT & LUNDY CO.
POWER RESEARCH GROUP
AND IS LOANED TO YOU CONDITIONED
UPON YOUR ASSUREMENT THAT IT
WILL BE KEPT CONFIDENTIAL AND NOT
BE REPRODUCED OR TRANSMITTED IN
ANY MANNER WITHOUT THE WRITTEN
CONSENT OF SARGENT & LUNDY CO.

254219 E

REV.

REVISIONS			
NO.	DESCRIPTION	DATE	APPROVAL
1			
2			
3			
4			
5			

DESIGNED BY E. PINSKE CHECKED BY PASSED BY APPROVED BY DATE 1-31-78 STD. NO. ES-241	CONCEPTUAL DESIGN CBB DISTRIBUTION PLATE SUPPT. FOR ATMOSPHERIC FLUIDIZED BED BOILER 200MW UNIT	THIS DRAWING IS THE PROPERTY OF THE BABCOCK & WILCOX CO. POWER GENERATION GROUP IT IS LOANED TO YOUR COMPANY FOR YOUR INFORMATION AND USE ONLY IT IS NOT TO BE REPRODUCED OR COPIED IN ANY MANNER WITHOUT THE WRITTEN PERMISSION OF THE BABCOCK & WILCOX CO. IF YOU HAVE ANY QUESTIONS CONCERNING THIS DRAWING, PLEASE CONTACT THE DESIGN ENGINEER OR THE PROJECT MANAGER.
DO NOT SCALE - USE DIMENSIONS SCALE 1/4" = 1'-0"	A-23	REV. 0 254217 E

REVISIONS

REVISION NO.	DESCRIPTION	DATE	APPROVAL

DWN. BY J. PALUR CHKD. BY PASSED BY APPVD. BY STD. DATE 4-24-78 ES-241	PLANT ARRANGEMENT FLUID BED BOILER 200 MW PERSPECTIVE	THIS DRAWING IS THE PROPERTY OF THE BABCOCK & WILCOX CO. POWER GENERATION GROUP AND IS LOANED UPON CONDITION THAT IT IS NOT TO BE REPRODUCED OR COPIED IN WHOLE OR IN PART, OR USED FOR PURSUING INFORMATION TO OTHERS, OR FOR ANY OTHER PURPOSES WITH- OUT THE WRITTEN PERMISSION OF THE BABCOCK & WILCOX COMPANY AND WILL BE RETURNED UPON REQUEST. DWG. NO. 146499 D REV. 0
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REVISIONS	
NO.	DESCRIPTION
1	DATE APPROVAL

DESIGN BY: J. PALUR	
CHECKED BY:	
DESIGNED BY:	
DATE: 5-27-72	
BY: J. PALUR	
ES-241	
FLUID BED BOILER 200 MW PERSPECTIVE	
THE SAATCHI & SAATCHI CO. NEW YORK, N.Y. 10017	
REV. 254266 E O	

REVISIONS			
REVISION NO.	DESCRIPTION	DATE	APPROVAL

OWN. BY E PINSKE	ARRANGEMENT SINGLE BED FLUID BED BOILER 200 MW PERSPECTIVE	THIS DRAWING IS THE PROPERTY OF THE BARCOCCI & WILCOX CO. POWER GENERATION GROUP AND IS LOANED TO YOU ON THE CONDITION THAT IT IS NOT TO BE REPRODUCED OR COPIED IN WHOLE OR IN PART, OR USED FOR PROMOTION, INFORMATION, TO OTHERS, OR FOR ANY OTHER PURPOSES WITHOUT THE WRITTEN PERMISSION OF THE BARCOCCI & WILCOX COMPANY AND WILL BE RETURNED UPON REQUEST.	
CHKD. BY			REV.
PASSED BY			
APPVD. BY			
STD. DATE 8-24-78			
ES-241	146500 D	C	
DO NOT SCALE - USE DIMENSIONS ONLY.	SCALE 1/2"		

REVISIONS			
REVISION NO.	DESCRIPTION	DATE	APPROVAL

ESTIMATED PIER LOADS ONLY
 NOT TO BE USED FOR DESIGN OR CONSTRUCTION OF FOUNDATIONS

DWN. BY C. B. CHKD. BY PASSED BY APPVD. BY STD. DATE 2-23-78 591-0241	PIER LOADING DIAGRAM	THIS DRAWING IS THE PROPERTY OF THE BABCOCK & WILCOX CO. POWER GENERATION GROUP AND IS LOANED UNDER CONDITION THAT IT IS NOT TO BE REPRODUCED OR COPIED IN WHOLE OR IN PART, OR USED FOR FURNISHING INFORMATION TO OTHERS. OR FOR ANY OTHER PURPOSES WITHOUT THE WRITTEN PERMISSION OF THE BABCOCK & WILCOX COMPANY, AND WILL BE RE- TURNED UPON REQUEST.
R.W. (146501D) 151202 D 0	SCALE X	REV.

254218E

REVISIONS			
NO.	DESCRIPTION	DATE	APPROVAL

DESIGNED BY <i>E.D.</i>	CONCEPTUAL DESIGN FBC SECTIONAL SIDE VIEW FOR ATMOSPHERIC FLUIDIZED BED BOILER (800 MW)	254218 E
DRAWN BY		
CHECKED BY		
APPROVED BY		
DATE 11/11/79	SCALE 1/4" = 1'-0"	254218 E

T. V. A.

REVISIONS			
NO.	DESCRIPTION	DATE	APPROVAL

T. V. A.

OWN. BY E.E. PINSKE	CONCEPTUAL DESIGN CB8 SECTIONAL SIDE VIEW FOR ATMOSPHERIC FLUIDIZED BED BOILER 800MW UNIT		
CHG. BY			
PAID BY			
APPROV. BY			
STD. 1-31-78	DATE	REV.	254220 E 0
ES-241	SCALE 1/8" = 1'-0"	REV.	