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**Assessment of the State of the Art
of Pressurized Fluidized Bed
Combustion Systems**

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OAK RIDGE NATIONAL LABORATORY
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ASSESSMENT OF THE STATE OF THE ART OF PRESSURIZED
FLUIDIZED BED COMBUSTION SYSTEMS

Interim Report

A. P. Fraas
R. L. Graves
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ASSESSMENT OF THE STATE OF THE ART OF PRESSURIZED FLUIDIZED BED COMBUSTION SYSTEMS

Interim Report

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ABSTRACT

This report was prepared at the request of the Tennessee Valley Authority (TVA) to clarify the development status of the pressurized fluidized bed combustor (PFBC) and to place in perspective the problems which are yet to be solved before commercialization of the concept is practical. The report is viewed as preliminary to a more complete and comprehensive work to be carried out during FY 1979.

An evaluation of the PFBC concept is included citing potential advantages over atmospheric pressure fluidized bed combustors (AFBC) in the areas of combustion efficiency, sulfur retention, furnace design, power plant efficiency, and others. The key disadvantage of unproven hot gas cleanup and associated gas turbine technology is discussed in considerable detail.

A survey of existing and developing PFBC experimental facilities is presented plus some results from the experimental programs. Recent design studies for full-sized PFBC power plants are reviewed with emphasis on key design parameters. Results for similar AFBC design studies are presented in contrast.

The general conclusion is drawn from this preliminary survey that the potential advantages of the PRBC used in conjunction with a high-temperature [850°C (1560°F)] gas turbine will be difficult to realize due primarily to the formidable task of developing adequate hot gas cleanup and turbine systems, and due to the anticipated high cost of these systems.

INTRODUCTION

The problems of both atmospheric and pressurized fluidized beds are complex, and conflicting claims are prevalent. To help clarify the situation and give perspective to the concept, TVA has requested that Oak Ridge National Laboratory (ORNL) survey the status of the design and development of pressurized systems including the merits and developmental problems of these systems. As a first step in the program, it was requested that a preliminary scoping report be prepared surveying the work that has been

done on pressurized fluidized beds, what can be expected from the more complete survey planned, and the degree of difficulty of the major problems.

Following the brief summary, the main body of this report begins with a general review of the PFBC, emphasizing its often cited advantages and disadvantages. This evaluation is followed by a survey of the development status of major components and of the concept itself. This survey covers experimental facilities and the results of experimental programs plus design studies of full-scale PFBC power plants. It is the purpose of this survey section to delineate the progress which has been and is being made toward realization of the predicted advantages of the PFBC and toward overcoming its apparent problems. The last section delineates the key problem areas requiring further developmental effort.

SUMMARY AND CONCLUSIONS

It has been generally assumed that there is a major advantage to pressurizing a fluidized bed coal combustion system because the furnace plan area and hence the number of coal feed points is essentially inversely proportional to the furnace pressure. Thus, to a first approximation, the size and cost of the furnace can be reduced markedly by pressurizing the unit. However, the power required for compressing the air is so large that this can be accomplished economically only if the high-temperature, high-pressure combustion gases are used to drive a gas turbine which, in turn, drives the compressor that supplies the pressurized air to the furnace. The incorporation of the gas turbine provides an opportunity to increase the cycle efficiency by using a furnace pressure of ~ 1.0 MPa (~ 10 atm) with a combined gas turbine-steam cycle similar to that of over 200 such units in operation in the U.S. employing oil or gas as fuel. However, the problems presented by turbine erosion and deposits if coal is used as fuel have made the development of such a system appear at least much more difficult than an atmospheric fluidized bed. The situation is quite complex with numerous other factors involved which have bearing on the attractiveness of the concept and the time and effort necessary for its development.

Experimental programs have verified improvements in sulfur retention and combustion efficiency by increasing the fluidized bed combustor pressure. It is likely that a carbon burnup cell would not be necessary with the PFBC due to the higher combustion efficiency which is greatly attributable to the deeper bed of the PFBC.

In addition, the deeper bed permissible in the PFBC permits mounting the boiler tubes vertically. This allows the elimination from the bed of uncooled structure for supporting the boiler tubes and is a more compatible configuration in a cylindrical furnace shell. The deep bed and vertical tube arrangement have further advantages for start-up and control.

Despite its advantages, the PFBC is faced with several formidable obstacles to its development. Forty years of experience with removing particulate matter from hot gas streams flowing into gas turbines indicates that the best that has been achieved with an economically viable system is to reduce the particulate content to around 100 ppm. However, for an acceptable turbine life, the particulate content must be kept below 1 ppm if the turbine inlet temperature is to be in the 816 to 871°C (1500 to 1600°F) range as conceived in most of the recent design studies which propose bed pressures of 0.7–1.0 MPa (7–10 atm). Both turbine bucket erosion and deposit problems become less serious as the turbine inlet temperature is reduced, and it appears that if the turbine inlet temperature is kept to ~538°C (1000°F) a tolerable turbine life can be obtained with an inlet gas particulate content of 100 ppm. This is an indication that the development time and requirements for capital intensive equipment associated with hot gas cleanup may be lower for a PFBC of intermediate pressure, 0.3–0.5 MPa (3–5 atm).

An additional serious obstacle to the development of the PFBC is that of feeding coal into a pressurized vessel. Solids feeding in general has not received sufficient attention in fluidized bed development programs and is often a source of trouble in experimental rigs. There is, of course, even less experience with PFBC coal feeders than with the AFBC feeders which are in a development stage themselves. Design studies have also indicated a high cost for PFBC solids feeding systems as currently envisioned.

The four recent design studies with cost estimates reviewed in this report, in general, do not bear out all of the advantages of the PFBC which appear upon first inspection. Even with no monetary value placed on the development process and uncertainty in the performance of critical components, the PFBC, as conceived in these particular studies, is not universally seen as providing lower cost electricity. An advantage in fuel economy for the PFBC over conventional systems and the AFBC is concluded in all of the design studies but the incremental cost (mostly associated with gas cleanup equipment) is marginally justifiable. It should be noted that, at this time, a power system utilizing an intermediate pressure combustor has not been subjected to a rigorous analysis, design study, and cost estimate. Such an effort is recommended before any final conclusions are drawn on the PFBC system.

EVALUATIONS OF PFBC SYSTEMS FROM THE STANDPOINT OF DESIGN ADVANTAGES AND DISADVANTAGES, RELATIVE COSTS, AND HEAT RATES

It has been recognized for about 15 years that there is a major advantage to pressurizing a fluidized bed coal combustion system because the furnace size and hence the number of coal feed points is essentially inversely proportional to the furnace pressure. Thus, to a first approximation, the size and cost of the furnace can be reduced markedly by pressurizing the unit. However, the power required for compressing the air is so large that this can be accomplished economically only if the high temperature, high pressure combustion gases are used to drive a gas turbine which, in turn, drives the compressor that supplies the pressurized air to the furnace. The incorporation of the gas turbine provides an opportunity to increase the cycle efficiency by using a furnace pressure of ~ 1.0 MPa (~ 10 atm) with a combined gas turbine-steam cycle similar to that of over 200 such units in operation in the U.S. employing oil or gas as fuel. However, the problems presented by turbine erosion and deposits if coal is used as fuel have made such a system appear at least much more difficult to develop than an atmospheric fluidized bed. The situation is quite complex with numerous other

factors being involved. This section presents a fairly comprehensive survey of the situation from the design and development standpoint to indicate the major boundary conditions and something of the quantitative value of the various advantages and disadvantages of the pressurized fluidized bed system as compared to the atmospheric fluidized bed.

Principal Advantages of the PFBC

The principal advantage of the pressurized fluidized bed stems from the fact that the maximum permissible combustion air velocity through the bed is determined by elutriation rates, which depend mainly on the superficial velocity of the combustion gas leaving the bed, essentially independent of the pressure. As a consequence, the maximum practicable mass flow of combustion air through the bed is directly proportional to pressure. Thus, both the furnace size and the number of feed points are essentially inversely proportional to the furnace pressure. Further, the depth of the bed that can be employed without experiencing excessive pumping power losses can be increased in direct proportion to the furnace pressure. A deep bed has the advantage that it gives a greater transit time for the fine coal particles passing through the bed if a bottom coal feed location is employed, and this in turn increases both the combustion efficiency and the sulfur retention. Note that in the Rivesville atmospheric fluidized bed, the bed depth is limited to about 1.2 m (4 ft). To increase the output per unit area of the bed, a high superficial gas velocity [3.7 m/s (12 ft/sec)] is employed, and, as a consequence, about 25% of the carbon in the coal fed to the bed is blown out with the fines even with doubly screened coal. To avoid a serious loss in the energy available from the coal, it is necessary to return the fines from the first-stage cyclone to a carbon burnup cell, and this must be operated at a temperature around 1093°C (2000°F) in order to burn the carbon in the high ash material. The high temperature leads to the formation of NO_x to a much more serious degree than is the case for the main portion of the fluidized bed.

An important advantage of the deep beds in pressurized furnaces is that the boiler tubes in the bed can be mounted vertically instead of

horizontally. This not only makes it possible to eliminate all uncooled structure for supporting the boiler tubes in the bed, which is advantageous from the corrosion standpoint, but it also makes it possible to employ a cylindrical furnace with a minimum of awkwardness in tube bundle configuration. Both of these factors tend to reduce the cost of the furnace shell and the tube matrix in the bed. Note, too, that the use of vertical tubes makes it possible to effect good water recirculation in the boiler tubes by natural thermal convection so that a boiler recirculating pump is not required.

The greater bed depth permissible if the furnace is pressurized has a number of subtle but important advantages from the standpoint of control. The greater bed depth, for example, makes possible a larger space between the air tuyeres and the bottom of the boiler tube matrix, this gap being only a small fraction of the total bed depth at full power. The pumping power associated with such an increment in bed depth is small, while the gap improves mixing of the fuel and air before it reaches the heat transfer matrix so that it reduces the possibility for boiler tube corrosion arising from local regions in which a reducing atmosphere might prevail. Further, the use of a fairly generous plenum between the air tuyeres and coal feed points on the one hand and the bottom of the tube matrix on the other, makes it possible to start-up the fluidized bed with its level a little below the boiler tube matrix so that there would be no boiler tubes immersed in the bed under start-up conditions, and hence, no large heat losses to these tubes. Further, with a fluidized bed depth of the order of 3.7 m (12 ft) at full power, the problems of sensing and controlling bed depth are eased because a few-inch change in bed depth represents a much smaller fraction of the total depth than for a typical atmospheric bed. Also, by using bed depth as the prime mechanism for controlling the boiler furnace output, one has a reasonably linear relationship between bed depth and furnace output because the amount of heat transfer surface area immersed in the bed is directly proportional to the bed depth above the bottom of the heat transfer matrix. The exposed tube matrix above the bed will remove some heat from the flue gas which in turn will reduce the flue

gas turbine output. The combination of reduced bed heat transfer surface and reduced turbine output can be utilized as a plant load control mechanism.

PFBC Disadvantages

In addition to the principal difficulty of turbine erosion, corrosion, and deposits (discussed in a later section), pressurizing a fluidized bed poses some very serious problems in feeding the coal into the bed against a relatively high furnace pressure. If an atmospheric bed is employed, the coal feed system needs to operate against a pressure of perhaps 0.014 MPa (2 psig), but if the furnace is pressurized, the coal feed system must deliver the crushed coal against a pressure of 0.3 to 1.0 MPa (3 to 10 atm). This can be accomplished with lockhoppers, but these have proved to be a major source of mechanical troubles in every type of chemical process system in which they have been employed. Other methods of introducing granular solids through some sort of a pressure lock have all given substantial difficulties so that a major set of development problems must be overcome in the development of the coal feed system for pressurized fluidized beds.

Another important disadvantage of pressurized fluidized beds stems from the fact that there is considerably less operating experience with units of this type than with atmospheric fluidized bed coal combustion systems. It is not clear just how serious this disadvantage will prove to be, but it certainly is a factor in the thinking of many people involved.

The various advantages and disadvantages of pressurized fluidized beds cited above are summarized in Table 1. Some of these factors involve considerations that merit further discussion.

Furnace Design

There are many subtle considerations in the design of the boiler furnace that are difficult to quantify. These include the problems of making a furnace shell sufficiently leak-tight so that combustion gas and fine ash do not percolate out into the surrounding area, the

Table 1. Comparison of relative advantages and disadvantages of atmospheric and pressurized fluidized bed coal combustion systems

Furnace pressure	Atmospheric 0.10 MPa (1 atm)	Pressurized 0.3-0.5 MPa (3-5 atm)	Pressurized 1.0 MPa (10 atm)
Advantages	<p>Fewest feasibility problems</p> <p>Greatest amount of test experience</p> <p>Coal feed against only 0.014 MPa (~2 psi)</p> <p>Solid waste disposal much less difficult than for wet scrubbers</p> <p>Plant efficiency higher than for wet scrubbers by ~1 point</p> <p>Capital cost modestly improved over conventional plant with scrubbers</p>	<p>Capital cost of furnace and steam generation appears lower than for conventional pulverized coal unit</p> <p>Coal feed points reduced by a factor of 3-5 over AFB</p> <p>Large bed depth improves combined efficiency and SO₂ removal and permits vertical boiler tubes with simpler furnace structure</p> <p>Plant thermal efficiency about 1 point higher than for AFB</p> <p>Control characteristics appear to be excellent</p>	<p>Potential cycle thermal efficiency is about 3.5 points higher than AFB</p> <p>Capital cost of furnace and steam generator appears lower than for conventional pulverized coal unit</p> <p>Coal feed points reduced by about a factor of 10 relative to AFB</p> <p>Large bed depth gives better coal utilization and SO₂ removal as well as permitting vertical tube array and simpler furnace structure</p>
Disadvantages	<p>Large number of coal feed points gives complex coal feed system</p> <p>Shallow beds require horizontal tubes with support structure at bed temperature</p> <p>Startup and control problems appear to be complex</p>	<p>Feasibility of acceptable turbine erosion and deposits with 538°C (1000°F) turbine inlet temperature seems likely but has not yet been proven</p> <p>Coal feed against 0.3-0.5 MPa (3-5 atm) poses difficult reliability problems</p> <p>Test experience much less than for AFB</p>	<p>Feasibility of acceptable turbine erosion and deposit rates is highly doubtful</p> <p>Coal feed against 1.0 MPa (10 atm) poses difficult reliability problems</p> <p>Test experience much less than for AFB</p> <p>Large heat capacity of granular bed filters for hot gas cleanup gives very slow response times</p> <p>Particulate removal equipment may entail excessive capital cost</p>

problems of retrofitting a new type of furnace to an existing plant, and floor space requirements.

Although not obvious, the pressure drop across an atmospheric fluidized bed is of the order of 0.015 MPa (60 in.) of water. Thus, a potential problem exists in leakage of combustion gas and fly ash into the furnace room with conventional rectangular furnaces in which the joints between elements of the structure might be difficult to gasket. As a consequence, there is a major advantage to the use of a cylindrical shell that could be welded to give a simple leak-tight structure. It would be particularly desirable to make this shell so that the bulk of the gasketed flanged joints for access are located on the fresh combustion air side so that any leaks into the furnace room will be of clean air rather than combustion gas plus fine ash. Unfortunately, if an atmospheric fluidized bed is used, it is difficult to arrange the horizontal serpentine tubes required in a good cylindrical array; hence, one is almost required to employ a rectangular furnace shell. If a pressurized fluidized bed is employed, the tubes can be mounted vertically which facilitates making the heat transfer matrix cylindrical with the boiler tubes suspended from support structure up in the freeboard over the bed. It is difficult to quantify this advantage, but a comparison of various designs for both pressurized and fluidized beds indicates that the cylindrical shell weighs substantially less and is substantially less complex to fabricate than a rectangular shell which requires extensive external bracing to carry the bending loads from the internal pressure on the large flat surfaces.

Furnace floor space requirements are an important factor in determining building size in a new plant and in the feasibility of retrofitting a fluidized bed boiler to an existing plant. Such retrofit projects may be quite important during the coming decades. The difficulties presented by the large cross-sectional area of atmospheric fluidized beds can be mitigated by stacking the beds one above the other. However, around 2.3 m (8 ft) of freeboard is required above each bed so that the overall height of the stacked beds for a given output is much greater than for a pressurized bed. Further, the cross-sectional area of the fluidized bed in such a

stacked array is increased by the cross-sectional area required for the flow passages for flue gas and combustion air required by beds at higher or lower levels.

A major problem in the design of the fluidized bed furnaces is that the weight of material in the bed makes the structural design of the bed support grid progressively more difficult for bed diameters greater than about 4.6 m (15 ft) and for deeper beds. The structural weight tends to go up quite rapidly with bed diameter and depth because differential thermal expansion problems in the bed support grid structure make it necessary to employ a relatively small number of support points. The bending loads in the unsupported span between these support points build up so that the weight of structure required tends to become excessive for bed diameters of more than about 10.7 m (35 ft).

Comparison of Pulverized Coal-Fired and FBC Systems

Table 2 has been structured to facilitate a comparison of key parameters for the various conceptual designs for fluidized bed combustion systems with conventional pulverized coal plants that have been built and operated. Unfortunately, some of the data were not readily available and, hence, will have to be obtained at a later date. However, it is clear that the technology for fluidized bed combustor design is not yet sufficiently well in hand to provide a good basis for furnace designs. Differences in the number of coal feed points per unit of output are so large that the technological basis for choosing the number of coal feed points is clearly inadequate. Many other parameters reveal equal uncertainty.

SURVEY OF FACILITIES, PROGRAMS, AND EXPERIMENTAL RESULTS TO DATE FOR PFBC SYSTEMS

The combustion of coal in a pressurized fluidized bed has been investigated in small experimental units since the late 1960's. The earlier investigations were performed by the British Coal Utilization Research Association (BCURA) and the Argonne National Laboratories (ANL).

Table 2. Major design parameters for both typical pulverized coal-fired power plants and conceptual designs for fluidized bed combustion systems

Plant	Conventional pulverized coal			Atmospheric fluidized bed				Supercharged fluid bed	Pressurized fluid bed		
	Bull Run	Colbert #5	Kingston #9	Rivesville	Foster-Wheeler	Combustion Engineering	Babcock & Wilcox	ORNL	GE - ECAS	Westinghouse ECAS	Curtiss-Wright
Design steam pressure and temperature, MPa/°C/°C (psig/°F/°F)	24/538/538 (3500/1000/ 1300)	17/566/538 (2400/1050/ 1000)	12/566/566 (1800/1050/ 1050)	9/496/538 (1350/925/ 1000)	26/540/540 (3800/1005/ 1005)	18/540/540 (2600/1005/ 1005)	18/539/539 (2581/1003/ 1003)	12/566/566 (1800/1050/ 1050)	24/538 (3515/1000)	24/538 (3515/1000)	6/440 (800/825)
Design output, MW(e)	850	550	200	30	150	200	200	200	904	679	500
Overall plant thermal efficiency, %	40	38.6	26.7						39.2	39.0	38.8
Furnace arrangement	Conventional	Conventional	Conventional	Single bed 4 compart- ments	Stacked 4 main 1 CBC	Ranch 7 main 1 CBC	Stacked 4 main 2 CBC	Single bed vertical tubes	Stacked 7 bed	Stacked 4 bed	
Furnace pressure, MPa (atm)	0.10 (1)	0.10 (1)	0.10 (1)	0.10 (1)	0.10 (1)	0.10 (1)	0.10 (1)	0.30 (3)	1.0 (10)	1.0 (10)	0.7 (7)
Surface area, m ² (ft ²)	70,000 (753,000)		20,500 (221,000)			22,000 (237,000)		8,000 (86,700)	8,300 (89,400)	5,900 (62,980)	
Surface area, m ² /MW(e) [ft ² /MW(e)]	82 (836)		103 (1,105)			110 (1,185)		40 (434)	9 (59)	9 (93)	
Furnace plan area, m ² /MW(e) [ft ² /MW(e)]	0.051 (5.5)		0.052 (5.6)	0.14 (1.52)	0.97 (10.4)	1.24 (13.4)	1.80 (19.4)	0.632 (6.8)	0.055 (0.59)	0.17 (1.85)	
Heat transfer surface weight, kg (lb)		2,270,000 (5,000,000)	1,000,000 (2,200,000)					404,500 (890,000)			
Total furnace weight, kg (lb)	10,900,000 (24,000,000)		3,800,000 (8,400,000)						1,825,000 (4,016,000)		
Heat transfer surface weight, kg/MW(e) [lb/MW(e)]		4,140 (9,100)	5,000 (11,000)					2,000 (4,450)			
Total furnace weight, kg/MW(e) [lb/MW(e)]	12,800 (28,230)		19,000 (42,000)						2,000 (4,400)	1,872 (4,120)	
Number of burners or fuel feed points	175		56	44	16	118	640	144	335	64	
Number of burners or fuel feed points/100 MW(e)	21		28	147	11	59	320	72	37	9.4	

These experimenters were later joined by groups at Combustion Power Company, Exxon Research and Engineering Company, NASA-Lewis Research Center, and Curtiss-Wright Corporation (Power Systems Division).

British Coal Utilization Research Association

The British Coal Utilization Research Association, Ltd. (BCURA), began a series of pressurized fluidized bed coal combustion experiments in 1969.¹⁻³ The experiments have proceeded in essentially three phases. The initial work was performed to obtain data on the emission of sulfur and nitrogen oxides and the effects of the fluidized bed environment upon boiler metal and turbine blade specimens when operating at absolute pressures of 0.35–0.6 MPa (3.5–6 atm) and temperatures in the range of 800°C (1470°F). The second phase involved an investigation of the bed operating characteristics at temperatures of 900 to 950°C (1650 to 1740°F) at an absolute pressure of approximately 0.6 MPa (6 atm). This phase of the work was completed in 1973.

A bed depth of approximately 1.2 m (4 ft) was employed during the first two series of experiments. For the third experimental series, the bed depth was increased to 2.4 m (7.9 ft). The system was operated at an absolute pressure of approximately 0.6 MPa (6 atm) and a temperature of 870°C (1600°F).

The fluidizing velocity was maintained at approximately 0.6 m/s (2 ft/sec) during the experimental series. The influence on the performance of the fluidized bed of the bed temperature, the Ca/S ratio, and the bed depth were the major parameters investigated during the experimental series. Future experimental work is planned to investigate the effects of superficial velocity on the bed operation.

Figure 1 shows the effects of varying the Ca/S ratio upon the sulfur retention by the bed for both dolomite and limestone. Shown in Figure 2 are effects of bed temperature on the sulfur retention at a constant Ca/S ratio of 2. The combustion efficiency of the pressurized combustion at a fluidizing velocity of 0.75 m/s (2.5 ft/sec) is in the 97.5 to 99.5% range as shown in Figure 3. Preliminary experiments at a fluidizing velocity of 2.1 m/s (6.9 ft/sec) at a temperature of 986°C (1645°F)

Fig. 1. Retention of sulfur in the BCURA 0.6 x 0.9-m pressurized fluidized bed combustor.

Fig. 2. Effect of combustor temperature on sulfur retention with Ca/S mole ratio = 2. Fluidizing velocity 0.6 to 0.75 m/s, bed depth 1.14 to 2.44 m and freeboard pressure 0.35 to 0.60 MPa.

Fig. 3. Effects of combustor temperature on combustion efficiency with 17% excess combustion air.

indicate a combustion efficiency of 98% which can be compared to 99.3% shown in Figure 3.

As of August 1978, the BCURA facility is being used in connection with the Stal-Laval-American Electric Power program to develop a PFBC system. Turbine blade cascade tests are being run with 100% excess air and a combustion gas inlet temperature of 788°C (1450°F) into the cascade and gas velocities 527 m/s (1730 ft/sec) leaving the simulated stator and 390 m/s (1280 ft/sec) leaving the simulated rotor. The first test of 200 hr was terminated because of plugging of the drain from a cyclone separator. A 1000-hr test is to be run next.

Argonne National Laboratory

The Argonne National Laboratory (ANL) has been conducting a basic research and development program since early 1969 to demonstrate the feasibility of the combustion of coal in a pressurized fluidized bed combustor. A 15-cm (6.0-in.) diam, pressurized, fluidized bed combustor capable of operating to 0.10 MPa (10 atm) pressure and temperatures in the range of 775 to 975°C (1427 to 1787°F) was used to investigate sulfur retention, combustion efficiency, additive utilization, and heat transfer coefficients.

A series of eleven experiments were performed in 1974 to demonstrate the effects of the bed temperature, fluidizing velocity, and the Ca/S mole ratio upon the sulfur retention, nitrogen oxide levels in the flue gas, and the combustion efficiency. The operating conditions for these experiments are given in Table 3, and some results are given in Table 4. These data indicate the Ca/S mole ratio is the most significant source of variation in the sulfur retention. For Ca/S ratios above 2.0, the sulfur retention is generally above 90%, which agrees well with the findings of BCURA as shown in Figures 1 and 2.

Since 1974, the 15-cm (6-in.) diam combustor has been operated in conjunction with a lime regeneration system.

Combustion Power Company

The Combustion Power Company began work on coupling a gas turbine to a fluidized bed burning solid waste in 1969 and subsequently shifted

Table 3. Design operating conditions and matrix representation for the eleven experiments in the Latin-square experimental designs (Ref. 4)

Equipment:	15-cm (6-in.) diam pressurized fluidized bed combustor
Coal:	Arkwright (Consolidation Coal Company)
Additive:	Tymochtee dolomite (C. E. Duff and Sons)
Pressure:	0.8 MPa (8 atm abs)
Fluidized bed height:	0.91 m (3 ft)
Excess air:	~15% (3% O ₂ in the dry flue gas)

	Levels of independent variables		
	Level 1	Level 2	Level 3
(T) Temperature, °C (°F)	788 (1450)	843 (1550)	899 (1650)
(R) Ca/S mole ratio	1.0	2.0	3.0
(V) Gas velocity, m/s (ft/sec)	0.61 (2.0)	1.07 (3.5)	1.52 (5.0)

in 1974 to operation with coal.⁵⁻⁸ By 1976, the unit operated at 0.4 MPa (4 atm) pressure had accumulated approximately 600 hr of turbine operation at an inlet temperature of 760°F (1400°F). The hot gas cleanup system for these tests was operated at temperatures of 815 to 860°C (1500 to 1580°F) with cooling downstream of the last stage of particle separation so as to not exceed the design turbine inlet temperature of 788°C (1450°F). The hot gas cleanup devices used in this series of tests consisted of tangential entry cyclones and 15.2- and 1.6-cm (6- and 0.6-in.) multicyclones. In each test, the multicyclones became ineffective after a few hours of operation owing to ash plugging which resulted in heavy fouling and erosion in the turbine. Subsequent work has been directed toward the development of granular bed filters.⁸

NASA-Lewis

The NASA-Lewis pressurized fluidized bed test system is primarily for determining the effects of exhaust gases from the combustion of

Table 4. Operating conditions and flue-gas analyses for the eleven experiments investigating the effects of independent operating variables (Ref. 4)

Coal: Arkwright (2.82% sulfur)
 Additive: Tymochtee Dolomite
 Fluidized bed height: 0.91 m (3 ft)
 System pressure: 0.8 MPa (8 atm abs)

Experiment	Combustion temperature °C(°F)	Ca/S mole ratio	Gas velocity, m/s (ft/sec)	Flue-gas analysis ^a				
				O ₂ ,%	CO ₂ ,%	SO ₂ ,ppm	NO,ppm	CO,ppm
VAR-1	785 (1445)	2.9	0.64 (2.1)	2.7	17	120	190	100
VAR-2	852 (1565)	2.9	1.46 (4.8)	3.0	17	130	210	30
VAR-3	857 (1575)	1.1	0.64 (2.1)	3.0	15	350	140	30
VAR-4	899 (1650)	1.9	0.69 (2.3)	3.0	16	120	180	50
VAR-5	793 (1460)	1.0	1.02 (3.4)	3.0	15	680	150	760
VAR-6	852 (1565)	2.0	1.10 (3.6)	3.0	16	170	190	30
VAR-6-R	849 (1560)	2.1	1.10 (3.6)	2.9	15	210	180	30
VAR-6-2R	843 (1550)	2.0	1.07 (3.5)	3.0	16	190	160	30
VAR-7	793 (1460)	2.2	1.28 (4.2)	2.7	16	260	150	90
VAR-8	888 (1630)	3.2	1.10 (3.6)	3.0	17	130	270	40
VAR-9	907 (1665)	1.0	1.49 (4.9)	2.9	16	850	120	40

^aDry basis.

coal upon turbine blade material. The fluidized bed is a combination of a cylindrical and a conical bed.⁹ The cylindrical bed is 22.6 cm (8.90 in.) in diameter. The conical bed expands to a diameter of 50.6 cm (20 in.) The system is designed to operate over a pressure range of 0.17 to 1.36 MPa (1.7 to 13.6 atm) and a temperature range of 760 to 1090°C (1400 to 1994°F).

The fuel is burned in the lower cylindrical section, while the upper conical bed serves as a fixed bed filter for the hot flue gases supplied to a turbine test section. The system became operable in 1977. The first test program was to involve the use of a turbine section, high-temperature cyclones, and a high-temperature ceramic filter.

Westinghouse Research and Development Center

A high-temperature, high-pressure test facility is being constructed by the Westinghouse R&D Center to test particulate control equipment. The facility is designed to investigate the effects of temperature, pressure, flow rate, particle type, loading, and size distribution on the performance of various types of particulate removal devices.¹⁰ Shakedown runs were expected to begin in 1978. The test unit is designed for a gas flow rate of 0.24 m³/s (8.5 ft³/sec) at 1.0 MPa (10 atm) and 875°C (1607°F).

Curtiss-Wright Corporation

The Curtiss-Wright program to develop a pressurized fluidized bed combustion system coupled to a gas turbine has entailed, as a first major step, the design and construction of a facility called the Small Gas Turbine-Pressurized Fluidized Bed (SGT/PFB) rig.¹¹ This unit employs an 0.8-m (2.5-ft) diam fluidized bed furnace designed to operate at 0.65 MPa (6.5 atm). A portion of the combustion products passes through a series of cyclone separators and a granular bed filter en route to a small gas turbine. The effectiveness of various designs for the particle removal equipment will be determined as a function of the principal variables. Concurrently, the effects of the particulate content of the combustion gas entering the gas turbine on turbine bucket erosion and deposits will

be investigated. The test rig has been undergoing shakedown tests as of January 1978.

Grimethorpe Experimental Facility

A pressurized fluidized bed combustor experimental facility under construction at Grimethorpe, England (jointly financed by the U.K., U.S.A., and West Germany, in equal shares), is designed to investigate combustion efficiency, heat transfer, gas cleanup, corrosion, and energy recovery.¹²

The basic design characteristics of the facility are:

Bed temperature	850°C (1560°F)
Superficial velocity	2.5 m/s (8.2 ft/sec)
Operating pressure	1.0 MPa (10 atm abs)
Internal cross section	2 m x 2 m (6.6 ft x 6.6 ft)
Bed depth (approximately)	4 m (13 ft)
Hot gas flow (approximately)	36 kg/s (79 lb/sec)

The initial system will be supercharged by a steam turbine-driven centrifugal compressor to obviate potential problems that may arise from a flue gas turbine drive. The initial cascade tests, scheduled for the 1979-1980 period, will include two cascades in series to simulate the erosion of the blade pressure surface near the trailing edge. Provisions may be incorporated in the facility to allow the testing of a flue gas turbine with a much lower inlet gas temperature than the combustion gas temperature leaving the bed.

Tentatively, a major objective of the flue gas turbine experimental program is to determine the feasibility of running a bed supercharged by a turbine-compressor unit that does not produce electricity. Tests will also be made to investigate the feasibility of operation at higher temperatures that would make it possible to get a substantial electrical output from the gas turbine.¹³

SURVEY OF TURBINE EROSION, CORROSION, AND DEPOSIT PROBLEMS

The most important feasibility question associated with pressurized fluidized bed coal combustion systems is the feasibility of employing a gas turbine-compressor to provide the high pressure air to the fluidized bed. Unless this can be done with a gas turbine, the power requirements for the air compressors are exorbitant. This section reviews the extensive test and operating experience with turbines in which the gas entering the turbine contained particulate matter. The experience with particulate removal equipment is also reviewed to give an indication of the levels of particle concentration that can be obtained with the equipment that has been tested to date. (A study¹⁴ of this problem was completed recently at ORNL as a part of an overall survey of advanced energy systems.)

Experience with Erosion in Wet Steam Turbines

One's first thought is to consider the experience that has been gained with turbine bucket erosion in steam power plants. It has been found that the erosion phenomena with wet steam are substantially different from those found in gas turbines handling solid particulates; as one might expect, the solid particles give a much more severe erosion problem. Further, the solid particles also give difficulty with deposits.

Locomotive Development Committee (LDC) Experience

By 1945, the successful operation of a gas turbine for supercharging Velox boilers, diesel engines, and aircraft engines together with Swiss experience with commercial gas turbines led to the launching of a project to develop a coal-burning gas turbine for locomotive service. This project was launched with great enthusiasm and staffed with some outstanding engineers. Twelve years later the effort was terminated because in spite of some fine engineering work and some very clever innovations it was not possible to obtain an operational power plant. The program began with some highly encouraging initial runs in which the turbine inlet temperature was kept to less than 538°C (1000°F); little difficulty with corrosion or deposits was experienced. However, at these

lower temperatures it was not possible to produce a significant useful output, and, when higher temperatures [the goal was 676°C (1250°F)] were employed, severe erosion and fouling of the turbine were experienced. A wide variety of particulate removal equipment was designed, built, and tested, but none proved sufficiently effective to permit a long operating life. The longest period of operation obtained was about 1400 hr, involving turbine inlet temperatures of 593 to 676°C (1100 to 1250°F). The run was terminated due to a loss of power from the turbine.

After the program was dropped, both the Bureau of Mines and the Union Pacific Railroad proceeded with efforts to solve the erosion and deposit problems, but little further improvement was effected in spite of the fact that a redesigned turbine was built to take advantage of the experience gained in the LDC program.

Australian Program

In the 1950's, the Australian government initiated a program to try to develop a gas turbine that would operate on Australian coal. The program took advantage of the experience gained in the LDC, Bureau of Mines, and Union Pacific programs and succeeded in getting what appeared to be lower erosion and deposit rates. However, the longest successful run of a turbine was 125 hr. On the basis of the relatively low erosion and deposit rates experienced in this run, the Australian final report concluded that a 50,000-hr life could be obtained. In view of the non-linear characteristics of deposition in particular, it is an open question whether this large extrapolation was valid. In any event, the program was discontinued.

Catalytic Cracking Unit Experience

There has been extensive experience with gas turbines used to provide air at pressures of 0.3 to 0.5 MPa (3 to 5 atm) for regenerating the catalyst in catalytic cracking units. Up until the 1950s, the turbine inlet temperature for these units had been limited to less than 538°C (1000°F) because of erosion problems. Efforts were made to capitalize on the LDC experience with improved particulate removal equipment, notably the

multiclone particle separator, which is a large number of small cyclones operated in parallel. The small cyclones are more effective in removing small particles than large cyclones because of the fact that the radial acceleration is larger for the small radii of the multiclones. Extensive development work made it possible to obtain particle concentrations (following two stages of conventional cyclones and a third stage of a multiclone unit) of around 100 ppm with the bulk of the material being in the particle size range below 1 micron. This particle removal equipment, in turn, made it possible to operate the turbine with inlet temperatures as high as 621°C (1150°F), which is sufficient to produce substantial amounts of useful electrical power. Several important additional developments were required to make this possible. These included the use of tungsten carbide-coated stellite blades in the turbine, the use of a single-stage turbine with a very clean inflow condition so that the particles would not be segregated in any limited portion of the flow-stream, and the use of blades substantially thicker than would be favored if the prime objective was a high aerodynamic efficiency in the turbine. With these developments, a turbine life of the order of 15,000 hr has proved possible with turbine inlet temperatures as high as 621°C (1150°F). Note that the experience in this development program showed clearly that the erosion rate is a quite steep function of the operating temperature.

Blast Furnace Gas Turbines

The energy available from the carbon monoxide present in blast furnace gas has been utilized in gas turbines for the past 40 years. However, the particulate matter in the blast furnace gas has made it necessary to employ a particulate removal system to keep turbine bucket erosion and deposits to a tolerable level. Extensive tests, both in Europe and the U.S., have led to the use of cyclone separators followed by coolers and two stages of water scrubbers in order to get the particulate content to an acceptable level. This work has shown that particulate contents in the turbine working fluid must be kept to about 1 ppm for turbine inlet temperatures of 730°C (1346°F).

Air Filter Requirements for Commercial Gas Turbines

Specifications on the particulate content in the airstream entering commercial gas turbines call for particulate contents of no more than 1 ppm. This ordinarily entails the use of filters which are placed in the inlet airstream ahead of the compressor.

Permissible Ash Content of Fuel Oils for Gas Turbines

Difficulties with deposits in gas turbines have been experienced with conventional No. 2 fuel oil. As a consequence, the fuel oil for use in gas turbines is required to have an ash content less than 1 part in 10,000. This is equivalent to a particulate content in the hot gas stream of ~1 ppm.

Gas Turbines Used with Coal Gasification Plants

The Lünen Plant of Steinkohlen Elektrizität AG in Germany is a combined cycle, gas turbine-steam plant coupled to a low Btu coal gasification plant employing Lurgi gasifiers. This plant included cyclone separators for removing particulates in the gas stream coming from the Lurgis together with provisions for cooling and cleaning the gas in two stages of water scrubbers.

Deposits in High Temperature Gas Turbines

Difficulties with turbine deposits apparently become much more serious as the turbine inlet temperature is increased above 1093°C (2000°F). One of the first indications of this was experienced at the Philadelphia Navy Yard in 1973 when serious deposits were noted after 150 hr of testing in which about half was at turbine inlet temperatures of 1204°C (2200°F). The deposits were formed of Fe_2O_3 that apparently entered in the inlet air which had a total particulate content of only 0.06 ppm. Subsequent investigations disclosed that this particulate content is common in the cleanest air to be expected in an industrial environment, and similar difficulty with deposits of this sort has been experienced at General Electric, United Technologies, and NASA-Lewis Laboratory. Deposits formed appear to be a very adherent coating of

iron-oxide which appears on both the pressure and suction surfaces of the blade and cannot be cleaned off by motoring the turbine while injecting crushed nutshells and hot water. Note that the sintering point of iron-oxide is approximately 1121°C (2050°F), and there are probably somewhat lower melting point materials present which aid in the sintering process.

Summary

A review of the experience gained in the past 40 years with removal of particulates from hot gases supplied to gas turbines indicates that by special handling of the gas, it is possible to operate gas turbines with inlet temperatures up to about 621°C (1150°F) with particulate contents of the order of 100 ppm with tolerable rates of turbine bucket erosion. However, where material having a low sintering temperature is present, as is the case with coal ash, the maximum permissible turbine inlet temperature from the standpoint of deposits appears to be of the order of 538°C (1000°F) if the particulate content of the hot gas is of the order of 100 ppm. For operation in the 816°C (1500°F) to 871°C (1600°F) range, it appears from extensive experience with commercial gas turbines that the particulate content must be kept below 1 ppm to avoid difficulties with either erosion or deposits. If the gas temperature is increased to over 1093°C (2000°F), it appears that the particulate content must be kept to a still lower level. Figure 4 summarizes this experience in graphical form.

The weight of the evidence cited above may lead to a change in objectives in the joint U.K./U.S./West Germany program for the PFB facility at Grimethorpe, England; consideration is now being given to placing early emphasis on determining the feasibility of supercharging a fluidized bed with a gas turbine using an inlet temperature of no more than 538°C (1000°F). An effort to achieve higher turbine inlet temperatures would follow in a second phase of the program if this approach is adopted.

Fig. 4. Summary of experience with particulate removal equipment and gas turbines operating with particulates in the gas.

SURVEY OF HOT GAS FILTER TESTS

The Locomotive Development Committee work was concerned primarily with the development of cyclone filters including the multiclone units mentioned above. A little work was done on electrostatic precipitators but it was found that deposits of ash on the insulators had sufficient conductivity at high temperature to cause high-tension shorts, hence the electrostatic precipitators were not effective in the temperature region of interest.

The catalytic cracking unit gas turbine experience paralleled that of the LDC but was extended to obtain a long life in the multiclone filters through the use of ceramic inserts to resist the erosive effects of the particulate matter being separated in the tiny cyclone elements.

Combustion Power, Inc., in Menlo Park, initially under an EPA contract and subsequently under DOE contracts, is attempting to run a fluidized bed coal combustion system using granular bed filters between the fluidized bed coal combustion system and the turbine. This work has been under way for about four years; a successful filter has not yet been demonstrated.

Work at BCURA in England on fluidized beds had included some tests of blade cascades with two or three stages of cyclones between the fluidized bed and the blade cascades. The two initial tests appeared to be favorable but the most recent test did not turn out well, apparently because of a malfunction in the lower stage cyclone separator. However, it should be noted that the velocity of the gas approaching the cascade was relatively low in the early tests so that erosion should not have been expected. Further, the tests were only of the order of 500 hr so that they were not definitive from the standpoint of the accumulation of deposits.

Work at Exxon Research Laboratory under EPA contract has entailed the operation of a pressurized fluidized bed in conjunction with a variety of cyclone and granular bed filters. After two years of test work, the best gas cleanup that has been accomplished has been to achieve particulate contents of the order of 1 ppm, but this level of gas cleanup can be sustained only by frequent backflows of gas to clear the bed, and

even then cannot be sustained for more than a day before excessive pressure drops are experienced.

Work on electrostatic precipitators for use with fluidized bed combustion systems has been initiated in Germany, but no experimental data have been obtained up to the time of writing. A survey of hot gas filtering equipment capabilities has been completed recently at ORNL.¹⁵

SURVEY OF DESIGN STUDIES FOR FULL-SCALE PFBC's

This section includes a review of the recent design studies on PFBC systems that were carried out by the following organizations.

1. Westinghouse, Energy Conversion Alternatives Study (ECAS)¹⁶
2. General Electric (GE), Energy Conversion Alternatives Study (ECAS)^{17,18}
3. Burns & Roe et al.¹⁹
4. Curtiss-Wright²⁰
5. ORNL²¹

In the first two designs, the PFBC serves as a steam generator, whereas in the next two, the PFBC is actually a gas generator and gas heater coupled to a gas turbine with heat recovered from the turbine exhaust for a steam bottoming cycle. The fifth system is similar to the first two except that the hot gases leaving the fluidized bed are cooled to $\sim 538^{\circ}\text{C}$ (1000°F) before entering the gas turbine so that its output is only sufficient to drive the compressor. A short, general description of each system is presented below followed by a more detailed discussion of the major design parameters and assumptions as incorporated by the respective designers. These assumptions may be compared to the state of the art of development presented elsewhere in this report. Also, where possible, contrasts between these designs and recent AFBC system designs are noted.

General Description of Power Plants

Each designer's system is described briefly with a simplified schematic diagram included. Major system parameters are tabulated in Table 5, following, for comparison.

Table 5. Comparison of recent PFBC conceptual designs

	GE-ECAS 1976	Westinghouse-ECAS 1976	Burns & Roe 1977	Curtiss-Wright 1977
Overall plant efficiency % fuel HHV	39.2	39.0	38.0	38.8
Fluidized bed temperature °C (°F)	899 (1650)	1010 (1850)	899 (1650)	899 (1650)
Gas turbine inlet temperature °C (°F)	871 (1600)	960 (1760)	871 (1600)	871 (1600)
Steam conditions MPa, °C (psia, °F)	24.4, 538 (3513, 1000)	24.2, 538 (3515, 1000)	16.6, 538 (2400, 1000)	5.5, 441 (800, 825)
Fluidized bed pressure MPa (atm)	1.0 (10)	1.0 (10)	1.0 (10)	0.71 (7)
Hot gas cleanup	cyclone/GBF ^a	cyclone/GBF	cyclone/GBF	cyclone/cyclone
Calcium/sulfur mole ratio	2.0	1.5	1.0	-
Fuel feeding m ² (ft ²) per injector	0.56 (6.0)	2.14 (23.0)	-	-

^a Granular bed filter.

General Electric system

The steam cycle selected by GE for the ECAS study was a conventional supercritical cycle with one reheat.^{17,18} Two low pressure feed-water heaters were utilized plus one more which served as an economizer by cooling the exhaust gases from the gas turbine. The thermodynamic cycle efficiency was 41.3% and the net power output of the system is listed as 904 MW(e) with about 23% of the output attributable to the gas turbines. The condenser pressure was set at 0.0078 MPa (2.3 in. Hg) absolute. A simplified schematic of the GE configuration is depicted in Figure 5.

Westinghouse system

The Westinghouse design also incorporated a supercritical steam cycle with one reheat.¹⁶ Seven stages of feed heating were used in addition to the turbine exhaust cooler/economizer. The gas turbine in this study was described as utilizing air cooling on the first two blade rows. The thermodynamic cycle efficiency was reported as being 42.3% and the net power of the system as 679 MW(e) with the gas turbines contributing about 20%. A condenser pressure of 0.0085 MPa (2.5 in. Hg) was selected. A simplified diagram of the Westinghouse conceptual power plant is presented in Figure 6.

Burns & Roe, United Technologies, and Babcock & Wilcox

The system conceived by these organizations comprised a PFBC for firing a topping gas turbine and a supplementally-fired AFBC steam generator for a steam bottoming cycle.¹⁹ The gas turbine exhaust, which is composed of the PFBC combustion products and a large quantity of air heated in the PFBC, is used as combustion air in the AFBC steam generator. The net output for this conceptual design was 574 MW(e), about 21% of which was generated by the gas turbine.

The most prominent feature in this PFBC design is the use of the furnace as an air heater rather than as a steam generator. By mixing this clean heated air with the combustion gases, the working fluid for the gas turbine presents a hot gas cleanup problem less difficult

Fig. 5. Simplified schematic diagram for General Electric PFBC steam power plant, Ref. 17, 18.

Fig. 6. Simplified schematic diagram for Westinghouse PFBC steam power plant, Ref. 16.

than for the systems of Figures 5 and 6. The power plant cycle is shown schematically in Figure 7.

Curtiss-Wright

The design under development by Curtiss-Wright^{11, 20} is similar to that of Burns & Roe et al. Curtiss-Wright, however, has elected to use a more conventional unfired heat recovery steam generator and a lower pressure steam bottoming cycle. The gas turbine working fluid is, again, a mixture of clean, hot air and combustion gases. In this system, the gas turbine is responsible for about 66% of the plant power output. The turbine blades are to be protected from erosion and corrosion by transpiration air. Few design details were given in the reports on this system available to the writers. The proposed system is diagrammed in Fig. 8.

The significant design and performance parameters of the respective designs are compared in Table 5. These parameters are discussed individually in greater detail in the following subsections.

Oak Ridge National Laboratory

In an effort to exploit the advantages of a pressurized fluidized bed while avoiding the severe problems of erosion, corrosion, and deposits caused by coal combustion products in a high-temperature gas turbine, a design for a turbo-supercharged steam generator was evolved at ORNL.²¹ This system is essentially an 0.3 to 0.5 MPa (3 to 5 atm) Velox boiler (of which over 100 oil-fired units have been built in Europe). Combustion gas cooled to 427 to 538°C (800 to 1000°F) would serve to power a gas turbine giving sufficient output to drive the compressor. (No significant electrical output would be obtained from the gas turbine.) As indicated in the previous section, this should make it possible to get an acceptable turbine system life with good reliability.

In addition to reducing the furnace size and cost relative to an AFBC, the system is believed to have the further advantage of giving much improved control characteristics over either an AFBC or the other

Fig. 7. Burns & Roe PFB/AFB combined cycle power plant, Ref. 19.

Fig. 8. Diagram of Curtiss-Wright PFBC power system, Ref. 11.

PFBC's previously described. Good startup characteristics would be obtained by starting at atmospheric pressure with a bed only about 0.3-m (1-ft) deep with no steam generator tubes in the bed to impose a large heat load. The bed depth, combustion air velocity, and furnace pressure would then be increased linearly with power. Increasing both the superficial gas velocity through the bed and the furnace pressure by a factor of ~ 3 each should make possible a turn-down ratio of ~ 10 . Note that by using a free turbine rather than one coupled to a generator, the turbine speed and compressor discharge pressure can be varied to give a relatively simple control system.

Comparison of Selected Design and Performance Parameters

Furnace size, weight, and materials

Representative furnace data from several design studies indicate an advantage in both size and weight for PFBC systems over AFBC systems (see Table 6). The extent of this advantage is a strong function of the detail designs. For example, Babcock & Wilcox selected a relatively low air velocity through the bed, resulting in a perhaps larger than typical plan area requirement.

None of the steam cycle design studies indicated that any materials more exotic than stainless steel would be required for the boiler tubes. However, the PFBC air heaters may require a more expensive tube material than austenitic stainless steel because the tube temperature will run closer to that of the fluidized bed than is the case for a steam generator.¹⁹

The deep PFBC beds permit the use of vertical boiler tubes and natural circulation boiling which is thought to be a simplifying design configuration. Both ECAS designs, however, utilized horizontal serpentine tubes in the bed. The Burns & Roe and Curtiss-Wright air heater designs specify the vertical arrangement.

Sorbent requirements

Conceptual designs for PFBC systems have taken advantage of the favorable sulfur retention potential of the PFBC by incorporating higher

Table 6. Comparison of PFBC, AFBC furnace configurations

	General Electric PFBC (ECAS)	Westinghouse PFBC (ECAS)	Babcock & Wilcox AFBC (TVA)
Furnace arrangement, typical module	Vertical tower 7 stacked beds	Vertical tower 4 stacked beds	Vertical tower - 3 plus one unstacked
Plan area per MW(e) m ² (ft ²)	0.054 (0.59)	0.17 (1.85)	1.80 (19.4)
Weight per MW(e) kg (tons)	2019 (2.22)	1875 (2.06)	-
Installed cost-boiler system only, \$/kW(e)	24.1 ^a	24.8 ^a	105 ^b
Primary heat transfer surface material	carbon steel chrome alloy steel stainless steel	carbon steel chrome alloy steel stainless steel	same as conventional coal- fired boiler

^aMid-1975 dollars

^b1978 dollars

combustion temperatures and lower Ca/S ratios than considered practical for the AFBC. The longer gas residence time in the deeper PFBC beds, in addition to a more favorable chemical equilibrium for sulfur capture with dolomite in pressurized beds, is responsible for this design advantage.

An additional recent study sponsored by DOE found that the limestone consumption cost was a very small part of the plant's cost of electricity.²² On this basis, the effort expended in optimizing the Ca/S ratio would not seem justifiable. However, the capital investment associated with the solids handling is rather significant (to be discussed in a later section) warranting that the limestone or dolomite feed not be oversized.

In summary, it is reasonable to assume that a PFBC can operate with a somewhat lower Ca/S ratio than an AFBC to achieve the same sulfur capture. This advantage is somewhat offset by the lower active sorbent content of dolomite.

Hot gas cleanup

Pertinent information on the hot gas cleanup systems envisioned in the PFBC designs is provided in Table 7. Each designer stated that the performance of the systems was yet to be verified. The reasons for the different cost estimates in ECAS are mostly the result of different filter areas per unit volume of gas flow and different assumptions for the flue gas particulate loading. Note that the cost of these systems exceeds that of the furnace modules.

Coal and sorbent metering

The solids transport method and number of solid injectors per bed are the two most significant design features of the fluidized bed coal and sorbent feed systems since they, to a great extent, determine its cost. Design data for several conceptual systems are summarized in Table 8. Combustion Engineering²³ specifically discarded the GE AFBC solids feeding choice which introduces the solids into the bed through needles protruding through the walls of the bed. The needles, being

Table 7. Comparison of PFBC hot gas cleanup systems

	GE-ECAS	Westinghouse-ECAS	Burns & Roe	Curtiss-Wright
Number of cyclone stages	2	2	2	2
Granular bed filter	Yes	Yes	Uncertain	Uncertain
Gas velocity through filter m/s (ft/sec)	11.9 (39)	22.9 (75)	-	-
Anticipated particulate load in dirty gas - kg/kg gas (gr/SCF)	.0287 (15.5)	0.0245 (13.3)	0.0165 (8.9)	-
Anticipated particulate load in filtered gas kg/kg gas (gr/SCF)	unknown	0.000014 (.00742)	0.000043 (0.023)	0.000024 (0.013)
System installed cost \$/kW(e)	76.3	32.6	-	-

Table 8. Summary of PFBC and AFBC solids feeding designs

	GE-ECAS PFBC	Westinghouse-ECAS PFBC	GE-ECAS AFBC	Combustion Engr. AFBC
Method of transport	Pressurized injector	Pressurized injector	Vibrating table with air assist at injector	Screw feeder with air assist
Bed area per injector m ² (ft ²)	0.56 (6.0)	2.14 (23.0)	0.79 (8.5)	1.67 (18.0)
Over/under bed feed	under, through grid plate	under, through grid plate	under, through injection needles	under, through grid plate
System cost \$/kW(e)	55.2	37.8	35.1	-

exposed to the burning materials, are subject to coking and plugging. Note that the pressurized injector systems are substantially more expensive.

Fluidized Combustion Company²⁴ is proposing an overbed spreader for coal and overbed limestone injection. It is claimed that this system is reliable, simple, and reduces the solids crushing requirements. However, introducing the coal at the top of the bed means that some sulfur will be released near the top of the bed and have essentially no opportunity to react with the lime.

The Babcock & Wilcox design is similar to the Combustion Engineering design except that an injector serves only 0.84 m^2 (9.0 ft^2) of bed area.

The coal metering system proposed in the ECAS PFBC design studies is based on the Petrocarb solids injecting system which has been utilized in the industrial sector for some time. This system consists of a storage bin which receives solids from a larger storage vessel, a lockhopper where the solids are pressurized in batches, and pneumatic, dense phase transport lines. Such a system is currently in use at the National Coal Board PFBC experimental facility in Leatherhead, England. The feed ports enter the bed through the air tuyere plate in most conceptual designs but enter through the sides of the bed in the National Coal Board test unit. The nozzles in this test unit are water-cooled since they are exposed to the hot bed material.

Combustion efficiency

Combustion efficiency and freeboard burning are fluidized bed parameters which must be considered in the design of the furnace system. PFBC's are envisioned as having higher combustion efficiencies and less freeboard combustion since the beds are deeper. However, both GE and Westinghouse (even with its high temperature bed) considered it necessary to add a carbon burnup cell to their respective PFBC furnace designs to minimize the unburned carbon loss. The Burns & Roe air-cooled PFBC, on the other hand, is proposed to operate at a lower air velocity for which there is evidence of nearly complete combustion in the bed.¹⁸ Hence, the carbon burnup cell is absent from their PFBC unit.

The AFBC design of Combustion Engineering, Inc.,²³ also includes a carbon burnup cell needed especially for their high superficial velocity [3.7 m/s (12 ft/sec)] design. Babcock & Wilcox²⁵ also incorporated the carbon burnup cell in their AFBC design. Final carbon loss is generally anticipated as about 1% of the fuel heating value.

Overall power plant efficiency

The predicted efficiencies of the PFBC plants have been included in Table 5 at the beginning of the section. It is apparent that there is some advantage in utilizing the high thermodynamic availability of the energy in hot combustion gas for power generation. The variation between the designs is small, being generally attributable to differences in the assumed losses, different stack gas temperatures, etc.

Brown-Boveri (developer of the Velox boiler) has investigated the effect of the gas turbine inlet temperature on the efficiency of conceptual systems utilizing pressurized oil-fired furnaces.²⁶ They found no difference in the efficiency of plants utilizing a 430°C (806°F) inlet temperature and plants utilizing a turbine inlet temperature of 880°C (1616°F). The reason for this result is that, in the latter case, the gas leaving the turbine at about 430°C (806°F) was necessarily utilized for feed heating in the steam bottoming cycle in lieu of conventional feed heating. This degraded the steam cycle efficiency enough to nullify the advantage gained in obtaining power from the gas turbine (18% of plant total) in surplus of that needed for the combustion air compressor.

Whether the capital cost associated with the incremental efficiency gain is justifiable is unclear according to the estimates currently available. However, the components required for the PFBC system will require a substantially greater technology advancement relative to the AFBC units currently envisioned.

Estimates for plant cost and cost of electricity

The cost estimates from several design studies for the PFBC plants are provided in Table 9, including the major cost estimating assumptions.

Table 9. PFBC cost estimates and assumptions

	GE-ECAS PFBC 1976 ^a	Westinghouse-ECAS PFBC 1976 ^a	Burns & Roe PFBC 1977 ^b	Curtiss-Wright PFBC 1976 ^c
Escalation during construction %	6.5	6.5	0.0	-
Interest during construction %	10.0	10.0	8.0	-
Contingency %	20.0	10.0	10.0	-
Fixed charge rate %	18.0	18.0	18.0	13.5
Capacity factor	0.65	0.65	0.65	0.65
Plant capital cost \$/kW(e)	722.9	548.6	583.0	640.0
Cost of electricity mills/kW-hr	34.1	28.1	28.9	35.0
Fuel cost, \$/MW(t) (¢/10 ⁶ Btu)	2.90 (85)	2.90 (85)	3.07 (≈ 90)	2.90 (85)
Sorbent cost, \$/Mg (\$/ton)	5.51 (5.0)	5.51 (5.0)	7.71 (7.0)	-

^aMid-1975 dollars

^bMid-1977 dollars

^cLate 1976 dollars

Differing design assumptions concerning gas cleanup and solids handling are primarily responsible for the cost disagreement in the ECAS systems, and it is difficult to estimate which one, if either, is correct. Addition of charges for escalation during construction would bring the Burns & Roe estimate for their PFBC to probably over 650 \$/kW(e), considerably higher than the Westinghouse system.

These cost estimates are generally lower than those calculated in recent AFBC design studies and evaluations. It should be noted, however, that the AFBC studies are generally more detailed and, therefore, perhaps more reliable.

Summary of design study survey

In general, the current design studies with cost estimates do not bear out the hoped for advantages of the PFBC. Even with no monetary value placed on the development required and the uncertainty in performance of critical components, the PFBC is not universally seen as providing lower cost electricity. An advantage in fuel economy for the PFBC is concluded in all of the design studies, but capital charges are much more pronounced in their contribution to the cost of electricity than fuel charges. The combined cycle systems utilizing the PFBC to heat most or all of the air supplied to a gas turbine offer some relief in gas cleanup costs but are likely to be penalized by higher costs for the heat transfer surface.

It should be noted that the design study participants for the PFBC units expressed the belief that further development work was needed, especially in turbine technology and gas cleanup. Otherwise, the PFBC must be viewed as having development needs similar to those of the AFBC. Such development needs cited by AFBC design teams include:

1. System control and response
2. Combustion efficiency
3. Sulfur capture
4. Tube corrosion/erosion
5. Fuel feeding for large units.

DELINEATION OF KEY PROBLEMS

Hot Gas Cleanup

Forty years of experience with removing particulate matter from hot gas streams flowing into gas turbines indicates that the best that has been achieved with an economically viable system is to reduce the particulate content to around 100 ppm, whereas for an acceptable turbine life, the particulate content must be kept below 1 ppm if the turbine inlet temperature is to be in the 816 to 871°C (1500 to 1600°F) range. However, both turbine bucket erosion and deposit problems become less serious as the turbine inlet temperature is reduced, and it appears that if the turbine inlet temperature is kept to ~538°C (1000°F), a tolerable turbine life can be obtained with an inlet gas particulate content of 100 ppm. Thus, the first order of business in establishing the feasibility of a pressurized fluidized bed would be to determine whether the particulate matter emerging from the hot gas cleanup system in the 100-ppm range gives a tolerable turbine erosion and deposit problem.

Coal Feed System

Feeding crushed coal into a furnace operating at 0.3 to 1.0 MPa (3 to 10 atm) poses formidable problems that can be investigated in bench tests at a relatively modest cost. Thus, bench tests of various types of equipment suitable for metering and feeding the coal into a pressurized furnace ought to be initiated and pursued vigorously. The imperativeness of adequate development for these systems is typified by operating problems experienced during tests at the Rivesville AFBC system and the Babcock & Wilcox AFBC.

Lateral Rate of Coal Dispersion from Feed Points

It is important to know for both atmospheric and pressurized fluidized beds the rate at which coal is dispersed laterally by turbulence in the bed from feed points so that locally rich regions where reducing conditions might prevail can be avoided. These tests are badly needed to establish the appropriate spacing for coal feed points and the depth of bed required between coal feed points and the bottom of

the boiler tube matrix in order to avoid difficulty with serious corrosion of the tubes. These tests must include the effects of the amount of excess air on combustion rates and the development of reducing zones in a fluidized bed. These test should also include the effects of variations in feed port and air tuyere design because details in the geometry of these parts is likely to have a strong influence on the mixing rate.

Effects of Pressure Level on Plant Heat Rate

The advantage from the standpoint of thermal efficiency of a 1.0-MPa (10-atm) bed as opposed to a supercharged bed at 0.3 to 0.5 MPa (3 to 5 atm) or an atmospheric bed needs to be clarified. Information on oil-fired combined cycles indicates that even if the turbine erosion and deposit problems can be solved, the heat rate advantage may not offset the extra pressure drop and capital costs requirements of the hot gas cleanup equipment required for the 1.0-MPa (10-atm) combined cycle plant with a 816 to 871°C (1500 to 1600°F) turbine inlet temperature.

Effects of Bed Depth on the Performance of Pressurized Fluidized Beds

There has been no systematic investigation of the effects of bed depth on the performance of pressurized fluidized beds with respect to combustion efficiency and sulfur retention with good control of the amount of excess air, the fuel and limestone compositions, bed temperature and pressure, Ca/S ratio, etc. Thus, a set of tests ought to be run to investigate the effects of bed depth on the combustion efficiency and sulfur retention for the full range of variables.

Further, an evaluation of the potential benefits of greater bed depth particularly in terms of use of vertical tubes in the bed should be carried out.

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