

APPENDIX B: SITE VISIT REPORTS

ASSESSMENT OF RESEARCH NEEDS FOR
COAL UTILIZATION

DOE COAL COMBUSTION AND APPLICATIONS WORKING GROUP
(CCAWG)

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APPENDIX B

SELECTED REPORTS OF SITE VISITS, CONFERENCES AND DISCUSSIONS

This section contains edited copies of site-visit and other reports prepared by CCAWG members. Some of the hand-out materials prepared by DOE contractors and others are included (without explication) to permit readers the construction of a coherent picture of work in progress.

AB-1

CCAWG SITE VISIT AND DISCUSSIONS
AT PETC (March 19, 1982)

CCAWG members J. Beér, A. K. Oppenheim, S. S. Penner, D. Smoot, and I. Wender attended a review meeting dealing with 1982 and 1983 programmatic activities on coal utilization supported by the Department of Energy. J. Birkeland, G. Jordy, R. Roberts, and S. Freedman of DOE Washington also attended the presentations. The topics discussed and the agenda are shown in Attachment I.

Following brief inspections of experimental facilities, the tentative work plan shown in Attachment II was defined for CCAWG.

Attachment I

CCAWG

PETC COMBUSTION PROGRAM REVIEW
FRIDAY, MARCH 19, 1982

PROGRAM CONTROL ROOM

8:00 a.m. - Introductory Remarks - Jorgen W. Birkeland, Combustion & Heat Systems, Division, Office of Coal Utilization and Extraction

8:15 a.m. - PETC Overview - Sun W. Chun, Director

8:30 a.m. - Combustion Project Management Overview - Daniel Bienstock, Manager, Combustion Project Management Division

8:45 a.m. - Advanced Research and Technology Development - James D. Hickerson, Chief, Combustion Phenomena Branch

9:30 a.m. - Alternative Fuels, Roy C. Kurtzrock, Chief, Coal-Oil Mixture Branch

9:50 a.m. - Magnetohydrodynamics - Ralph A. Carabetta, Assistant Manager, Combustion Project Management Division

10:00 a.m. - Break

10:15 a.m. - Introduction to Characterization of Coals - Joseph Cavallaro, Chief, Coal Characterization Branch

10:30 a.m. - Benefits of Clean Coal for Combustion - Richard E. Hucko, Assistant Manager, Coal Preparation Division

10:45 a.m. - Combustion Technology Division Overview - James I. Joubert, Manager, Combustion Technology Division

11:00 a.m. - Combustion Test Facilities - George Bellas, Chief, Liquid Fuel Combustion Branch

11:15 a.m. - Coal Slurry Combustion Tests: Coal-Oil Mixtures, Coal-Water Mixtures, Coal-Alcohol Mixtures - Yuan-Siang Pan, Liquid Fuel Combustion Branch

11:45 a.m. - Lunch

12:15 p.m. - Fuel Rheology and Flow Characteristics - James M. Ekmann, Chief, Engineering and Technical Support Branch

12:45 p.m. - Pneumatic Transport of Coal - Mahendra P. Mathur, Engineering and Technical Support Branch

1:00 p.m. - Flue Gas Clean-up Technology - James I. Joubert, Manager, Combustion Technology Division

1:15 p.m. - Discussions

2:30 p.m. - Tour/Departure

CCAWG
PETC Combustion Program Review
Friday, March 19, 1982

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ATTACHMENT II: CCAWG WORK PLAN

A. Meetings for the Entire Working Group

1. May 27 and 28 in La Jolla, California, on "Preparation, Distribution and Utilization of Coal Slurries."

Preparatory work will be done by one or two members who will participate at the symposia on "Industrial Coal Utilization" (Cincinnati, April 1 and 2) and "Coal Slurries" (Orlando, May 10-12) and prepare status reports for discussions at the La Jolla meeting. The emphasis in this work will be on identification of technical and economic problems that are impeding commercial applications of coal-oil, coal-water, and coal-alcohol mixtures.

2. June 24 and 25 in Princeton, New Jersey on "Utilization of Pulverized Coals."

3. July 8 and 9 at the Morgantown Energy Technology Center on "Fluidized Bed Combustion, Modeling and Environmental Issues." Participants will be invited as appropriate from PETC and TVA.

4. October in the Eastern United States on "Stokers and Fixed Bed Combustors" at an industrial contractor.

5. December in La Jolla on "Long-Range Basic Research and MHD."

Additional work will be scheduled as needed.

B. Industry Members of CCAWG

Six members of CCAWG will be identified from industry as follows: one from EPRI, two from electric utilities, two from equipment manufacturers, and one from a service-type industrial organization. Alternate members from a given organization will be invited as appropriate. The names of nominees will be submitted by the Chairman of CCAWG to DOE for approval. The industry members are expected to become regular participants beginning with the May meeting in La Jolla.

Tentative rosters of names were discussed by the university members of CCAWG at Pittsburgh.

CCAWG DISCUSSIONS AT LA JOLLA,
(May 27 and 28, 1982)

1. Meeting Summary

CCAWG members S. B. Alpert, J. M. Beér, G. R. Bozzuto, I. Glassman, A. K. Oppenheim, S. S. Penner, L. D. Smoot, R. E. Sommerlad, C. L. Wagoner, I. Wender, and K. Yeager participated at parts or all of the meeting. DOE Headquarters was represented by ex officio CCAWG member J. Birkeland.

The meeting began with a review and evaluation of information derived from the "Fourth International Symposium on Coal Slurries." R. Kurtzrock of PETC presented a report on the "Status of Coal-Liquid Mixture Fuel Development" (see Appendix I), which was followed by a presentation of EPRI programs and plans introduced by K. Yeager and presented by R. Manfred of EPRI (see Appendix II). Next, L. D. Smoot reviewed past and current work on coal-water mixtures (CWM), with emphasis on studies performed at Brigham Young University (for details, see the paper in the Fourth Symposium). J. M. Beér discussed combustion studies at MIT on coal-oil mixtures (COM) and amplified the contribution made by his group at the Fourth Symposium (see Appendix III for details). The formal presentations were concluded with a paper by V. S. Engleman (Science Applications, Inc., La Jolla), which had been presented at the Fourth Symposium and dealt with a "conceptual design and economic analysis for coal/water mixture utilization in an oil-designed utility boiler."

The discussion on the following day involved in-depth program planning for future CCAWG meetings and evaluations of R&D requirements for the commercialization of COM and CWM, as well as assessments of the likely long-term commercial merits of these activities. These topics are discussed in Section 3.

2. Meeting Plans

CCAWG will meet on June 23 and 24 at Combustion Engineering in Windsor, Connecticut, with C. R. Bozzuto serving as host. This meeting will emphasize direct combustion of comminuted coal and will be followed by inspections of experimental facilities located at the host organization. A tentative meeting agenda will include the following presentations: a discussion of critical problems in utility operations using coal by a utility executive, R. Bryers (Foster-Wheeler Development Corp.) on ash formation and fouling, M. Jones (DOE, Grand Forks) on utilization of low-rank coals, K. Yeager et al (EPRI) on coal cleanup and beneficiation and on environmental controls, R. van Dolah (formerly of PETC and LETC and now a private consultant) on explosions and fires.

The subsequent CCAWG meeting will be held at METC on July 15 and 16. The agenda will be arranged by J. Birkeland and will include discussions of fluidized bed combustion, modeling, environmental issues, and other DOE-sponsored activities.

In view of the anticipated participation at the International Combustion Symposium (Haifa, Israel) during August by a number of CCAWG members, no formal meeting has been scheduled for CCAWG during August or September.

A meeting is tentatively scheduled for October 14 and 15 on industrial, non-utility applications of coal. The agenda will be defined by C. L. Wagoner, J. M. Beér, L. D. Smoot, and S. S. Penner and this meeting will be held in Columbus, Ohio, at Battelle or at Babcock and Wilcox in Alliance, Ohio, with C. L. Wagoner serving as host.

Subsequent meetings are tentatively scheduled for Houston, Texas, in conjunction with a conference on coal-handling and utilization equipment (December 9-10) and for La Jolla (January 1983).

3. CCAWG Discussions on the Utilization of Coal-Liquid Mixtures

Assuming that COM or CWM will enter the commercial markets, it is a relatively straightforward task to define R&D requirements for slurries of these types. These recommendations are summarized in Sections 3.1 and 3.2, respectively. Of equal concern are the crucial issues of costs and likely market penetration assuming that technological issues have been well defined and that application strategies are well in hand and allow reasonably reliable cost estimations. These topics are discussed in Section 3.3.

3.1 COAL-OIL MIXTURE COMBUSTION: R&D STATUS AND RESEARCH NEEDS*

Introduction

Sporadic use of coal-oil mixtures in marine boilers (tankers) and in blast furnaces has a history of several decades. In the mid-1960s, the Bethlehem Steel Co. and the National Coal Board-Esso carried out systematic experiments on the rheological properties of COM and demonstrated the technical feasibility of burning coal in the raceways of blast furnaces to replace expensive metallurgical coke partially by COM. The main objective was to use pulverized coal, the oil serving as a transport medium to permit the more convenient hydraulic feed-transportation system to be used in place of a pneumatic system. Combustion studies at the Canadian Bureau of Mines were the first to highlight the necessity of matching coal and oil combustion properties and showed wide ranging variations in carbon combustion efficiency when different types of coal were used. More recently, results of systematic combustion studies carried out at the DOE Pittsburgh Energy Technology Center have been reported in the four international symposia on COM combustion organized annually since 1978. These symposia are the main source of technical information on fuel preparation, rheological properties (stability, viscosity), atomization, and combustion of COM. Following an earlier demonstration experiment in a boiler at a General Motors Company Plant, which showed encouraging results for the use of COM in an industrial steam-raising plant, two major demonstration trials were carried out in utility plants by NEPSCO (80 MW_e) and by FPL (400 MW_e). These showed that long-term operation of utility boilers with COM is feasible after relatively small alterations to plants and requires little derating. These last conclusions are, however,

* Prepared by J. M. Beér.

site-specific and depend on the original design of the retro-fitted boiler.

COM Preparation and Handling

Successful introduction of COM into industrial use requires that the mixture be stable (i.e., the coal particles do not settle out over a period of weeks) and that the rheological properties be favorable (the mixture can be pumped and atomized). It is also desirable to increase the coal content as much as possible and to use particle sizes which do not require excessive grinding energy for their preparation.

The relationships between these variables show that good stability and favorable rheological properties have conflicting requirements. Thus, the stability improves but the viscosity of the mixture increases with increasing coal concentration, finer particle sizes and increasing oil viscosity. Additions of small amounts (up to 5%) of water and about 1% of surfactant can produce an acceptable solution, e.g., 50 wt% coal ground to a fineness usual in power station practice (80% <76 μm).

The mechanism of COM stabilization is poorly understood. The action of the chemical additives is explained by their effects on electrostatic, steric and flocculated networks in the fluid but the relationships between additive properties and COM stability are, at best, semi-empirical. Improved understanding in these areas is desirable.

COM with less than 40% coal concentration and without water behaves as a Newtonian fluid; COM is pseudoplastic for higher coal concentrations. For these latter conditions, the shear stress τ can be expressed as $\tau = k\dot{\gamma}^n$, where $\dot{\gamma}$ is the shear rate (sec^{-1}) and $n < 1$.

Water and additives influence the k and n values; higher k values are associated with improved stability. The smaller the value of n , the lower the viscosity under flow conditions.

Additive selection and optimization of concentrations of water and additives are determined from optimizations involving k and n .

Storage, Pumping, Flow Metering

Stirred storage tanks and special positive displacement pumps and flow-metering devices for handling COM are commercially available. R&D is needed in this area for design optimization of stirred tanks, for increasing availability of pumps, and for further development of the presently available mass-flow metering devices.

Atomization

High atomization quality (i.e., sufficiently fine atomization with a minimum of droplets in excess of $300 \mu\text{m}$) is a prime requisite of good COM combustion and reduced slagging tendency in the combustion chamber. In liquid-fuel atomizers, the fluid is forced by high pressure through orifices and thin liquid sheets are formed which, as the result of development of Rayleigh-type instabilities, break down into ligaments that disintegrate into droplets due to surface-tension forces. An exception to this mechanism of liquid break-up occurs in some mechanical atomizers (rotary cups) in which the liquid sheet is formed on the surface of a fast-spinning disk or cup and its break-up is assisted by impinging high-velocity air.

An important engineering problem in COM atomization lies in the high viscosity and abrasive nature of the fuel. High-velocity flows through nozzles are required to produce fine atomization and may cause unacceptable rates of erosion. The use of special materials in atomizing nozzles has been shown to lead to reduced metal wastage and hence increased atomizer life. The alternative solution, i.e., relaxation of atomization quality, is unacceptable since it leads to high solid carbon carry-over. Studies of atomization in COM require a significant R&D effort.

Improved atomizers should be developed through a better understanding of the physical processes involved and through use of special materials for the structural parts exposed to erosion. Parallel with these fundamental studies, a semiempirical approach to design, coupled with experimental testing of nozzles, will be necessary for early development of improved and acceptable atomizer nozzles. Atomizers should be developed which maintain high atomization quality over a period approaching 1000 hours, before the changing of atomizer tips will become economically and operationally acceptable.

Combustion and Pollutant Emissions

The combustion of COM in an industrial type turbulent diffusion flame is dominated in the near field (i.e., close to the burner) by characteristics of the oil flame and by the burn-out of the residual coal char towards to end of the flame (far field). Single COM droplet studies have shown that COM droplets ignite more readily than oil drops, perhaps because of increased absorptivity to thermal radiation caused by the presence of the solid particles. If a bituminous coal is used, its thermal decomposition commences while the particles are still surrounded by the liquid phase. The high molecular weight tars which evolve from the coal are partially extracted by the oil, and the coal particles swell and produce an

agglomerate. On the termination of oil combustion, a solid or carbonaceous residue is left, which encloses the partially devolatilized coal char particles. As oxygen reaches the surface, the temperature of the char agglomerate is raised, causing further evolution of coal volatiles and an increase of pressure; the carbon surface becomes spherical and, eventually, this cenosphere ruptures to permit the volatiles to escape through a blow-hole. The char cenosphere burns out in the tail end of the flame where the temperature is high but the oxygen concentration is low due to the prior combustion of oil and the coal volatiles.

Flame stability obtainable with COM fuel is so good that the recirculation of hot combustion products to the burner could be reduced. Some reduction of recirculation is highly desirable. Otherwise, the combination of resulting high temperature close to the burner and the possibility of carbon (from unburned fuel) becoming embedded in the wall deposit can cause serious slagging problems.

The atomization quality has to be high because the sizes of the char cenospheres are close to those of their parent droplets and their burning time follows Nusselt's square law, i.e., the burning time is proportional to the square of the initial particle diameter.

It is expected that the NO_x emission from COM will be somewhat higher than from oil alone, mainly because of the increased fuel nitrogen content of the COM. However, the staged combustion nature of COM, which involves coal-nitrogen evolution in an atmosphere in which the O₂ has been strongly depleted, tends to reduce the NO_x emission. NO_x emission has been shown to respond sensitively to the variation of the overall excess air.

The emission of sulfur will depend on the compounded sulfur contents of coal and oil in the mixture. Sulfur reduction is an important consideration in coal preparation, because sufficiently

low sulfur content of the fuel may lead to arrangements with the EPA for permission to operate without flue-gas desulfurization.

The particulate emission from COM combustion will be higher than from oil burners. It is most likely that the EPA will require compliance with present emission standards for retrofitted oil-fired boilers.

The flame emissivity is increased by coal particles and enhanced radiative heat transfer from the flame is expected. This process, however, does not produce increased heat transfer in the combustion chamber because of the insulating effect of the ash-slag deposit on heat-exchanger surfaces. In FPL demonstration experiments, the flue gas volume had to be increased because of higher excess air requirements for complete combustion and this, together with reduced heat transfer in the combustion chamber, resulted in a higher proportion of the enthalpy of the flue gas being carried into the convective superheater section of the boiler. More research is needed on radiative heat transfer in a partially slagged-up combustion chamber to determine the full implications of these factors upon the distribution of the thermal load over the radiative-convective parts of the boiler.

Transformations of Coal Ash

Perhaps the most sensitive area of COM combustion technology is the slagging of the combustion chamber due to the deposits of partially molten ash and the carry-over of molten fly ash particles into the convective heat exchange section of the boiler. Due to the rapid temperature rise after ignition, slagging can be heavy near the burner unless special care is taken to reduce the recirculation of hot combustion products. Large droplets and coal particles may reach the walls and become embedded in the ash deposit, thus causing the fluxing of the molten slag and attack

of the slag on the protective oxide film on the heat-exchanger tube surface.

Research is needed to improve our understanding of the transformations that the mineral matter in the coal undergoes in the combustion process and in the wall deposit and also to predict the physico-chemical properties of the fly ash from knowledge of the coal ash composition and of the concentration-temperature history of the ash. Such information would serve not only the designers and operators of boilers and furnaces but could guide the industrial development of coal beneficiation as well.

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6. G. D. Botsaris, Y. M. Glasman and M. Adams-Viola, "Characterization and Structure Studies of Various Types of COM," Proc. Second International Symposium on COM Combustion, Danvers, MA, April 1980; J. M. Eckman and D. Bienstock, "The Role of Coal and Oil Characteristics on the Stability of COM," *ibid*.

3.2 STATUS AND NEEDS FOR COMBUSTION-RELATED RESEARCH ON COAL-WATER MIXTURES (CWM)*

Introduction

Coal-water mixtures (CWM) represent a relatively new area of combustion application. The major interest in CWM is for replacement of oil in existing utility and industrial boilers. With declining interest in coal-oil mixtures, resulting principally from low economic incentive, interest in CWM has increased, particularly in the U.S., Sweden, Canada, and Japan.

The 4th International Symposium on Coal Slurry Combustion¹ has afforded a good review of the status of CWM technology. Of the 93 papers presented, approximately one-quarter dealt with CWM; of these, about 13 were on slurry formation and handling, 1 on atomization, 6 on combustion, and 3 on systems evaluations. Not all of the authors reported experimental results. For example, only three of the combustion papers (from PETC, ARC and B&W) showed combustion data for pulverized coal-water mixtures.

To date, no major technical problems have been encountered in the use of CWM. However, work in this area is new and it will require about 3 years to establish a sufficient data base to evaluate the potential of CWM critically. This technical area is related to coal-slurry transport, slurry-fed gasification, and combustion of high-moisture coals.

CWM Preparation/Handling

About 11 industrial organizations are developing CWM for possible commercial use. Six have developed methods and equipment (pilot plants) for the production of CWMs in the 75-120 tpd capacity range. The presently available technology suggests that optimal mixtures contain about 70% coal and 30% water. The blended

* Prepared by L. D. Smoot.

coal particles generally cover a range from small to large sizes. It is customary to use small percentages (1-2%) of additives for the control of viscosity and settling. Claims are made that mixtures are stable for significant periods of time (e.g., one month). Independent research (e.g., Eckmann³) is being conducted on rheological properties of CWM.

Identified research needs in this area include the following:

1. Optimization of CWM, including definitions of particle-size distributions for particulate coal loadings, the use of additives, and the resulting mixture stabilities.
2. Incorporation of beneficiated coal through fine grinding (micronization) for reductions in ash level. This procedure is being applied to reduce ash levels to 3%. Work is continuing in the private sector and with EPRI and DOE support.

Atomization and Dispersion

Extensive research has not been performed on atomization rates of water in dispersions of coal in CWM. Only one paper on this subject (from BNL) was presented at the 4th International Symposium and this discussion referred to coal-loading levels well below practically achievable levels. Workers at DOE/PETC have recently initiated sponsored research in this area (Carnegie-Mellon University). The efficiency of coal burnout, fouling, and NO_x pollutant formation are all related to droplet atomization, particle dispersion, and the combustion processes. Atomization studies and the associated CWM nozzle designs have been considered in CWM combustion by workers at PETC and ARC. Commercially available nozzles were frequently used in these early combustion studies.

Key research needs on atomization and dispersion include the following:

1. Determinations of variables such as mass flowrates, pressure levels, and nozzle configurations that control the droplet-size distributions and the droplet and dust-particle dispersions. Relationships must be established between particle-size distributions and droplets formed on injection. The CWMs should cover the ranges of solids loadings, coal sizes and distributions, and additives that are of practical interest.
2. Determination of the relations between nozzle designs, secondary air-flow patterns, and mixing rates in CWM for the purpose of optimizing burner designs.

These studies will have to be closely linked with the combustion studies defined in the next section. Work on optimum nozzle design is in progress at CE and other laboratories, with and without external support.

CWM Combustion

Early investigations of the combustion characteristics of pulverized CWMs were performed at ARC,² PETC,⁴ and EPRI/B&W.⁵ It is apparent from this work that pulverized coal can be burned with high percentages of water. Coal burnout levels up to 98% have been reported and CWMs containing up to 70% of coal have been tested. PETC tests were conducted in 100 hp and 700 hp water tube boilers with up to 63% coal in the CWM. In the smaller unit, carbon conversion up to 85% was achieved while, in the larger unit, carbon conversion up to 96% was obtained with the use of surplus secondary air.

The ARC² investigations on CWM involved coal percentages up to 65% in a small laboratory furnace (10^6 BTU/hr). Carbon conversion levels up to 90% were reported. More recent tests⁶ have shown combustion efficiencies up to 95% with 70% CWM in the small-scale furnace.

Investigations of CWM combustion are also underway at MIT and BYU. These latter studies will provide details concerning the flame structure. Plans for larger scale testing of CWM in a utility boiler have been outlined by workers at EPRI and at DOE/PETC/CE.

While early results are encouraging, much work remains to be done to provide a suitable data base for quantitative modeling. Important research needs include the following:

1. Measurements of combustion rates, fouling, and pollutant-formation characteristics of practically usable CWMs, including higher coal solids levels, use of beneficiated coals with low ash contents, and effects of additives. Of particular importance are adequate flame stability, control of nozzle erosion, much higher carbon conversions (>99%), and post-combustion controls of ash and NO_x levels.
2. Determination of the optimum burner configurations for CWMs remains to be accomplished.
3. Demonstration of successful, long-term operation of CWMs in large-scale, oil-designed utility boilers, with emphasis on slurry mixture stability, flame stability, fouling and ash control, nozzle erosion, high carbon conversion, boiler derating, and moderation of NO_x levels. This applied task must be performed successfully before commercial applications of CWMs can be considered.

There are many unresolved fundamental research questions that relate to implementation of CWM technology. These include the behavior of dispersions of condensed phases in turbulent

media, droplet formation and evaporation in three-phase flows, devolatilization processes of wet coals, turbulence in swirling multiphase flows, and others.

References

1. 4th International Symposium on Coal Slurry Combustion, sponsored by PETC, May 10-12, 1982, Orlando, Florida.
2. E. T. McHale, R. S. Scheffee, and N. P. Rossmeissel, Combustion & Flame 45, 121 (1982).
3. J. H. Eckmann, "Transport and Handling Characteristics of Coal Water Mixtures," in Ref. 1.
4. Y. S. Pan et al., "Exploratory Coal-Water and Coal-Methanol Mixture Tests in Oil-Designed Boilers," in Ref. 1.
5. G. A. Farthing, Jr., S. A. Johnson, and S. J. Vecci, "Combustion Tests of Coal-Water Slurry," CS-2286, EPRI Final Report, Palo Alto, CA, March 1982.
6. R. S. Scheffee et al., "Further Development and Evaluation of Coal-Water Mixture Technology," in Ref. 1.

3.3 GENERAL REMARKS ON THE ECONOMICS OF INTRODUCING NEW TECHNOLOGIES INTO UTILITY OPERATIONS*

A plot plan of a typical, large, coal-fired power plant is shown in Fig. 1. Space has been allowed for a second unit (right hand side of the page). If this space is subtracted from the total, we can approximate the space requirements for one unit. Rail lines surround the plant and parking lots; security fences, guard shacks, administration buildings, and the like are not shown.

The space required for boiler unit one with precipitators and scrubbers is about 14% of the total space. The waste-treatment facilities shown at this site assume that major ash and sludge disposal is made off-site. If a 20-year ash/sludge disposal area were on-site, it would be at least double the area of the coal pile. In general, when we consider alternative, coal-fired, power generation, we are considering changing the equipment within this 14% enclosure.

The Federal Energy Regulatory Commission (FERC) uses a code of accounts to tally direct costs. These account numbers can be further broken down to provide the level of detail needed by an A/E company to carry out a major project. For government projects (TVA, DOE, DOD, etc.), the FERC code of accounts is generally used. However, each A/E firm may have its own internal account system. This fact causes considerable confusion when discussing costs. For example, the feedwater system can be allocated to the turbine or to the boiler. Boiler manufacturers prefer to allocate the feedwater system to the turbine because it is not in their scope of supply. However, the FERC code of accounts allocates the feedwater system to the boiler plant. Hence, the cost of the boiler plant may mean different things to different people.

* Prepared by C. R. Bozzuto.

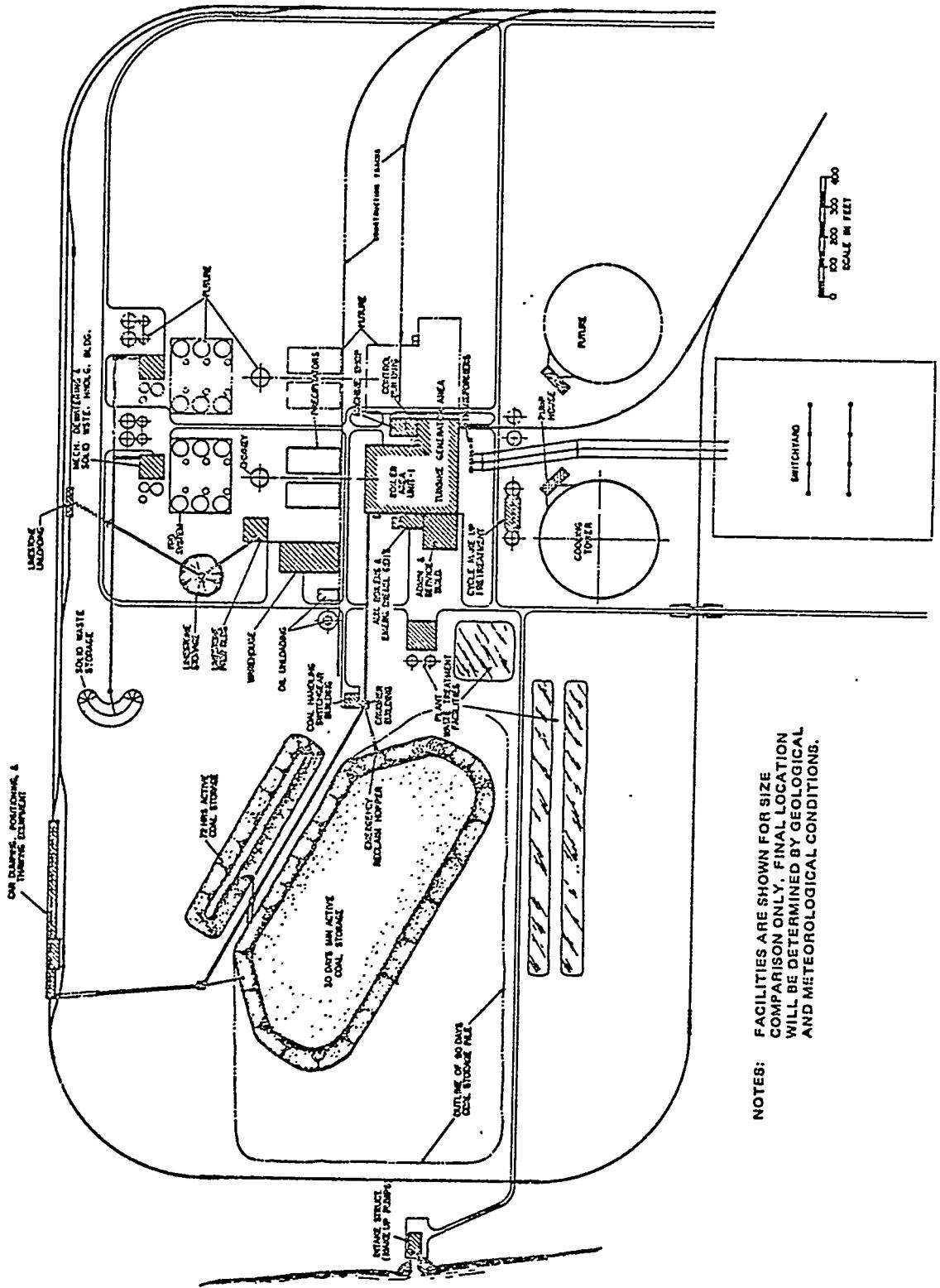


Fig. 1 Plot showing a large, coal-fired power plant.

Using the FERC system, the capital costs are broken down in \$/kW as follows:

<u>Account No.</u>	<u>Item</u>	<u>Cost (mid-81, \$/kW)</u>
310	Land and Land Rights	3
311	Structures and Improvements	73
312	Boiler Island, including Cleanup and Coal Handling:	430
	- Boiler	100
	- Gas Cleanup	100
	- Coal Handling	100
	- Piping & Steam System	65
	- Mech. Equip., Auxiliaries, Feedwater System, Ash System, Draft System	65
314	Turbogenerator Set	170
315	Electrical and Switchgear	40
316	Misc. Station Plant & Equip.	14
A/E fees, interest, contingency, etc.		<u>730</u>
		<u>230</u>
		960
Working capital		<u>40</u>
	TOTAL	1000

These figures are approximate only and final estimates are site-specific. Nonetheless, a review of these figures shows that the majority of the power plant costs will be fixed, as long as coal firing is employed. In going from pulverized coal to fluidized beds to gasified coal to MHD, basically only the boiler and gas-cleanup system are changed. The remaining items are largely fixed and dependent upon the amount of coal fired. Typically, these fixed costs amount to some \$800/kW. Clearly, some money must be spent on equipment that replaces the boiler and gas cleanup. Within reason, this figure should be \$200/kW ($\pm 30\%$). Thus, all coal-fired plants cost \$1000/kW ($\pm 6\%$) in mid-1981 dollars. It is easy to see why utilities are reluctant to build

plants with new technology. Capital cost savings are at best very small. Therefore, only operating cost reductions can be hoped for. However, how can one expect to get real operating savings with unproven equipment? Any reduction in capacity factor will basically result in an operating loss. Therefore, it is much more prudent to stick with known technology than risk chasing elusive operating gains based on unproven assumptions.

Nuclear plants cost \$1500/kW within 10%. About \$100/kW is the cost of the initial fuel load, within 10% accuracy. Assuming that the cost of the first load is included (approximately 2 operating years of fuel), then about \$87/kW could be subtracted from the nuclear plant to put it on a 90-day fuel basis. However, since the core is normally maintained with a full load of fuel, it is proper to treat the fuel load as required working capital (just like the 90-day coal pile) and, hence, no subtraction is necessary.

The overall plant economics are then dependent upon a number of assumptions such as the fixed charge rate, fuel cost, capacity factor, heat rate, etc. Some typical assumptions follow:

Fixed Charge Rate - 18.2 - 25.6%, depending on interest rates and tax laws

Fuel Costs
(levelized for 30 yrs) - \$3.00 - 4.00/MM Btu for coal,
\$1.70/MM Btu for nuclear energy,
\$10.00/MM Btu for oil & gas;

Capacity Factor
(levelized) - 70%

Heat Rate - 9,500 Btu/kW-hr for coal,
10,500 Btu/kW-hr for nuclear energy,
9,000 Btu/kW-hr for oil & gas.

On the basis of these figures, the following capital and fuel charges are derived in mills/kW-hr:

	<u>Coal</u>	<u>Nuclear</u>	<u>Oil</u>
Capital Charges	41.75	62.62	25.05
Fuel Costs	28.5 (38.0)	17.85	90.00
O&M	<u>8.0</u>	<u>5.00</u>	<u>5.00</u>
COE	78.25(87.25)	85.47	120.05

It is instructive to examine the preceding costs. They show that, on the average, coal is cheaper than nuclear energy except where coal costs are high (e.g., New England). Oil prices would have to drop by about a factor of two for new oil-fired units to be competitive. Capital represents about half the cost of electricity (COE) in the case of coal. For oil, fuel is about 75% of the COE, which accounts for the high fuel adjustment charges in New England (especially in Massachusetts). It is significant to note that no nuclear units and no large oil- or gas-fired units have been ordered in the U.S. since 1975.

Referring to Fig. 1, coal is delivered by rail to the site where it is dumped, thawed (if necessary), and transported to the coal pile. About 6000 T/day must be delivered for each 500 MW(e) unit; this corresponds to about 60-100 cars per day. Coal from the pile is conveyed to a crushing station to reduce the size to 1-1/2" x 0 so that the coal can enter a pulverizer. The coal is then transported to the pulverizers, where it is ground to 70% through 200 mesh and dried. The pulverized coal is conveyed pneumatically by using a mixture of 1 lb of air per lb of coal to the boiler. The mixture is injected through fuel nozzles and mixed with secondary air, which is at a higher pre-heat temperature. The majority of the coal is burned out in the radiant portion of the boiler. The flue gases then pass over a convective surface, hopefully at a temperature low enough to avoid fouling or corrosion. When the gas is cooled to about 750°F, it is used to preheat air. The flue gas is next cooled to about 300°F. It is finally subjected to particulate removal,

which is followed by SO_2 removal. The cleaned flue gas is then routed to the stack. Some flue gas reheat may be necessary to protect fan and stack equipment. Typically, a 175°F stack temperature is sufficient. Ash is collected from ash hoppers at several boiler locations and from the particulate removal system. It can be mixed with sludge from the web scrubber system for stabilization or may be disposed of separately.

Water is taken from the condenser and pumped through various feedwater heaters and a deaerator to the economizer section of the boiler. This procedure preheats the water to a temperature near to but less than the boiling point. The water is then transported to a steam drum, where it is mixed with the water-steam mixture that is circulating within the waterwalls of the boiler. In the steam drum, steam is separated from the water and sent on to the superheater. The water is recirculated to the lower headers of the waterwalls. Because this water absorbs heat, steam is formed, thus creating a steam-water mixture that rises to the steam drum. The superheated steam is sent to the steam turbine, where a part of its enthalpy is recovered. The steam is now at a lower temperature and pressure and is returned to the boiler to be reheated. The reheated steam is returned to the turbine for final conversion to shaft work. Exhaust steam is condensed by cooling water in the condenser. Steam may be extracted from the turbine at various points to heat feedwater. This practice serves to improve cycle efficiency by routing a portion of the working fluid around the condenser. The cooling water is sent to a cooling tower to reject its heat to the atmosphere.

The maximum Carnot efficiency for such a plant, using 1000°F steam and 120°F cooling water, is about 60%. In actual practice, about 38% efficiency is achieved because of stack losses (10-12%), mechanical efficiency of the turbine (88%), electric generator efficiency (97%), auxiliary power requirements (10-12%), and environmental cleanup and other losses (4-8%).

The principal areas of interest to utilities today center on reducing operating costs by improving reliability and availability, reducing auxiliary power requirements, and reducing environmental costs. A significant period of time is required to demonstrate effects on reliability or availability.

A. Comments on Market Penetration*

The preceding discussion represents a good summary of the problems involved with market penetration of improved technologies. Utilities cannot afford to pioneer innovations. New technologies will enter the utility market only after (a) favorable economic assessments have been completed and (b) a large-scale, commercial prototype has been adequately tested, either with federal support or through a joint venture involving an industry consortium (e.g., EPRI). While step (a) has been achieved for CWM but appears doubtful for COM, step (b) remains to be implemented for CWM.

It should be noted that other views and procedures determine market policy in other countries. Thus, in Japan, rates of return are determined from a 25-year perspective for the benefit of the country (not for the benefit of a single industry) and private companies, in cooperation with MITI, pioneer technological assessments (step b). The logical implementation of the indicated U.S. procedures for market penetration has led to non-competitive U.S. steel and automobile production facilities, among others.

* Prepared by S. S. Penner.

3.4 COAL-AIR MIXTURES*

In the retrofitting of oil-burning utility power plants for the use of coal, COM and CWM have found the greatest interest due to what many consider a primary advantage of tank-car delivery of the coal fuel. Such tank-car delivery eliminates the requirement for extensive land use for the storage of raw coal. COM and CWM impose combustion problems and/or loss in plant efficiency that may override the advantage of coal displacement of the oil used. It would appear that the best fluid for transmitting pulverized coal, the same as that used in COM and CWM, would be air and I term this mixture CAM. The finely divided (pulverized) coal could be shipped in the same type of tank cars as those proposed for COM and CWM. A system could easily be developed to transfer the tank-car coal to a simple hopper, which could feed an airstream at a regulated rate. This CAM would then pass through injection nozzles much the same as those used for oil alone. Fundamentally, one would believe CAM should burn extremely well and require practically no modification, other than perhaps injection nozzle design, to an oil-fired power plant. The system poses one major difficulty and that is one of safely transporting and handling finely-divided coal. Great amounts of grain and flour are transported and handled in this country, far more than would be anticipated for CAM. Indeed, grain and flour explosions are known; however, these materials are far more prone to spontaneous or accidental ignition than coal. Nevertheless, the safety aspects of transporting and handling very finely divided coal must be considered. This type of possible coal explosion should be the object of research and reasonable solutions could undoubtedly be found. In fact, such solutions may be simpler to find than the combustion and other problems that COM and CWM pose.

*Prepared by I. Glassman.

A. Comments on the Proposal for Coal-Air Mixtures (CAM) *

The following comments refer to CAM. First of all, it must be understood that CAM will not solve the problems of retrofitting oil and gas fired units to coal. These units are inherently not suited to handling solids of any kind. The furnace volumes are too small, the tube spacings too close, and the ash handling equipment non-existent. Therefore, all the problems of downrating and substantial boiler modifications would still be present with CAM. In addition to these problems, there are safety problems which, while solvable, add to the cost of this fuel.

For new plant applications, the suggestion of CAM is workable. Coal has been distributed in the past in containers and continues to be distributed this way in the UK for small applications. However, large powerplants use conventional pulverized coal firing. In order for delivered fuel to be practical for a new utility plant, it must have the following attributes: (1) it must be low in sulfur (i.e., sufficient to meet all regulations), (2) it must be low in ash and moisture, (3) it must have guaranteed delivery so that on-site storage is not required, (4) it must be accompanied with guaranteed ash disposal from the site so that no ash ponds or other disposal facilities are required, and (5) it must be safe. A fuel with these attributes would save the utility the cost of the scrubbers, coal pile, coal handling, ash disposal, and limestone. These savings would allow for a price differential of up to \$1.00/MM Btu on fuel costs. Present day coal prices are in the neighborhood of \$1.50/MM Btu. Thus, a clean fuel costing \$2.50/MM could be competitive. This amounts to producing a clean fuel (such as oil) for about half the price of oil. By way of example, SRC-I would have the above five attributes but costs about

* Prepared by Carl R. Bozzuto.

twice as much as oil. Indeed, oil itself is uneconomical today for new powerplant applications.

As each of the restrictions imposed by the five attributes is eased, the utility plant costs go up and the full cost differential becomes less. If we were to assume that pulverized coal is delivered without treatment or guarantees, the system would be uneconomical because the utility still must buy 90-day storage, SO_2 scrubbers, handling equipment, ash-disposal ponds, limestone, sludge disposal, and safety equipment. In addition, the distributor must buy equipment and make a profit. Therefore, such a system would not be economical and I would see no point in recommending any research on it.

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Appendix I

STATUS OF COAL-LIQUID MIXTURE FUEL DEVELOPMENT

by R. Kurtzrock (PETC)

GENERAL

- CANADIAN GOVERNMENT HAS IDENTIFIED COAL-LIQUID MIXTURE TECHNOLOGY DEVELOPMENT AS A PRIORITY FOR FUNDING UNDER THEIR NATIONAL ENERGY PROGRAM (NEP).
- JAPAN AND SWEDEN HAVE TAKEN A SIMILAR POSITION WITHOUT SPECIFIC STATEMENTS.
- U.S. POSITION IS SOMEWHAT NEBULOUS BASED ON BUDGET REQUESTS FOR FY 1983.

STATUS OF COAL-LIQUID MIXTURE FUEL DEVELOPMENTCOAL-OIL MIXTURES (COM)

- COM IS AN ALMOST COMMERCIAL FUEL (SWEDEN). DEMONSTRATIONS IN A NUMBER OF COUNTRIES.
- LONG TERM EFFECTS ON BOILERS ARE STILL UNKNOWN.
- COUNTRIES IMPORTING BOTH OIL AND COAL (JAPAN) CAN REDUCE THEIR OIL DEPENDENCE BY USING COM.
- COM WILL PROBABLY NOT SEE ANY SIGNIFICANT APPLICATION IN THE U.S. UTILITY INDUSTRY.
 - BREAK EVEN POINT FOR COM WITH FLORIDA POWER & LIGHT CO. IS \$31/BBL; CURRENT PRICE OF FUEL OIL IS \$26/BBL.
- INDUSTRIAL APPLICATION OF COM IS NOT PREDICTABLE; BLAST FURNACES WILL BE ONE OF THE FIRST USERS.
- CANADA WILL NOT USE A FUEL MIXTURE CONTAINING FUEL-OIL IN UTILITY BOILERS, HOWEVER IT APPEARS LIKELY COM WILL BE USED IN INDUSTRIAL BOILERS.
- MOST COST ESTIMATES BY SUPPLIERS OF COM INDICATE A FUEL COST SAVING OF APPROXIMATELY 10% OVER THAT OF NO. 6 FUEL OIL.

STATUS OF COAL-LIQUID MIXTURE FUEL DEVELOPMENT
(continued)

COAL-WATER MIXTURES (CWM)

- "COAL OUTLOOK" (MAY 17TH) SAYS A MID-COURSE SHIFT FROM COM TO CWM IS TAKING PLACE.
- AN ADEQUATE DATA BASE SHOULD BE AVAILABLE IN 3 YEARS OR LESS.
- SIX SLURRY DEVELOPERS HAVE PILOT PRODUCTION FACILITIES OPERATING OR WILL BE OPERATING SOON. PRODUCTION CAPACITIES RANGE FROM 25 TONS/DAY TO 120 TONS/DAY.
- ASH EFFECTS ARE THE KEY TO SUCCESSFUL APPLICATION OF CWM.
 - SLAGGED DEPOSITS IN COMBUSTION ZONE.
 - EXTENSION OF COMBUSTION ZONE BY BURN-OUT TIME.
 - CONVECTION PASS EROSION AND/OR FOULING.
- BENEFICIATED COAL.
- ULTRA FINE GRINDING OF COAL.

CURRENT DOE ACTIVITIES IN CWM DEVELOPMENT

● ENGINEERING ASPECTS

— COMBUSTION & FUEL CHARACTERIZATION
(COMBUSTION ENGINEERING)

— EQUIPMENT SELECTION & PERFORMANCE
(TRW, INC.)

● FUNDAMENTAL R&D

COMBUSTION AND FUEL CHARACTERIZATIONScope of Work

- Selection of Candidate Fuels
 - Selection of Candidate Coals
 - Acquisition of Beneficiated Coals
 - Selection of Candidate CWM's
- Bench Scale Characterization and Screening Tests
 - Bench Scale Properties
 - Secondary Fracturing of CWM Particles
- CWM Preparation and Test Slurry Supply
 - Coal Acquisition
 - Beneficiation of Test Coals
 - CWM Preparation
 - Storage
- Combustion Evaluation/Atomization and Burner Testing
 - Commercial Burner Selection
 - Initial Burner Evaluation
 - Secondary Burner Evaluation
 - CWM Combustion Characterization
- Ash Deposition/Performance Testing
 - Facility Requirements
 - Facility Shakedown and Baseline Oil Testing
 - CWM Performance Testing

(Continued)

COMBUSTION AND FUEL CHARACTERIZATION

- Commercial Application and Performance Prediction
 - Selection of Typical Oil-Designed Units for Evaluation
 - Boiler Performance Evaluation Firing Oil
 - Performance Evaluation Firing Several CWM's
 - Identify Required Modifications
 - Economic Trade-Off Studies

PLANT EQUIPMENT SELECTION AND PERFORMANCE

Scope of Work

- Facility Modifications
 - Preliminary Design
 - Final Design
 - Equipment Selection
 - Instrumentation
 - Equipment Installation and Test Loop Checkout
- Slurry Selection and Supply
 - Selection of Slurry for Hydraulics/Screening Tests
 - Slurry Selection for Long-Term Testing
 - Slurry Supply
- Test Operations and Data Collection
 - Screening Test Plan
 - Screening Test Operations
 - Long-Duration Test Operations
 - Equipment, Component, and Piping Evaluation
 - Slurry Degradation Evaluation
 - Erosion/Corrosion Evaluation
 - Hydraulic System Tests
 - Data Collection and Reduction
- Data Analysis and Reporting
 - Slurry Degradation Analysis
 - Hydraulics Analysis
 - System/Component Evaluation
 - Corrosion/Erosion Evaluation
 - Full-Scale, CWM-Fired Boiler Applications Assessment

FUNDAMENTAL R&DSLURRY RHEOLOGY

CARNEGIE-MELLON
UNIVERSITY

RHEOLOGY OF COAL-WATER MIXTURES

- MEASURE RHEOLOGY, STABILITY, ELECTRO KINETIC BEHAVIOR
- "PURE" SLURRIES, INORGANIC AND ORGANIC ADDITIVES

SLURRY HANDLING

PETC

TRANSPORT CHARACTERISTICS OF COAL-LIQUID MIXTURES

- PRESSURE DROP MEASUREMENT AND CORRELATION
- LABORATORY MEASUREMENTS
- INSTRUMENT EVALUATION

ATOMIZATION

CARNEGIE-MELLON
UNIVERSITY

ATOMIZATION OF COAL-WATER MIXTURES

- PRESSURE, TWO-FLUID, ROTATING CUP ATOMIZER
- MECHANISMS OF DROPLET FORMATION
- DROPLET SIZE AND VELOCITY MEASUREMENTS

COMBUSTION/CHAR BURNOUT

JOHNS HOPKINS
APPLIED PHYSICS
LABORATORY

COMBUSTION OF COAL-WATER MIXTURE DROPLETS

- MONODISPERSE DROPLET ARRAY
- EFFECTS OF PARTICLE SIZE, DROPLET SIZE,
TEMPERATURE, HEAT FLUX
- PHOTOGRAPHIC OBSERVATIONS

BRIGHAM YOUNG
UNIVERSITY

COMBUSTION CHARACTERISTICS OF COAL-BASED FUELS

- PYROLYSIS CHARS AND COAL-WATER MIXTURES
- DETAILED COMBUSTOR MAPPING
- RESULTS EMPLOYED FOR MODEL IMPROVEMENT

JET PROPULSION
LABORATORY

"CATALYTIC" COAL COMBUSTION

- EXTENSION OF GRAPHITE COMBUSTION TECHNOLOGY
- CALCIUM, POTASSIUM, LITHIUM, ACETATES
- TREATMENT METHODS
- COMBUSTION TESTS FOR BURNING RATES AND
EMISSIONS

PYROLYSIS/DEVOLATILIZATION

ADVANCED FUEL
RESEARCH

DEVOLATILIZATION AND PYROLYSIS OF COAL BASED
FUELS

- COAL-WATER MIXTURES AND HIGHLY CLEANED COALS
- FLOW REACTOR
- IN-SITU APPLICATION OF FTIR
- EMPHASIS ON PYROLYSIS CHEMISTRY
- APPLY DATA TO UPGRADE EXISTING MODEL

POLLUTANT FORMATION/REDUCTION

ENERGY &
ENVIRONMENTAL
ENGINEERING

SULFUR CAPTURE IN COAL-WATER MIXTURES

- Ca FIXATION TECHNIQUES
- COMBUSTION EXPERIMENTS
- MODEL SULFUR CAPTURE

AB-2

Appendix II

by R. Manfred (EPRI)

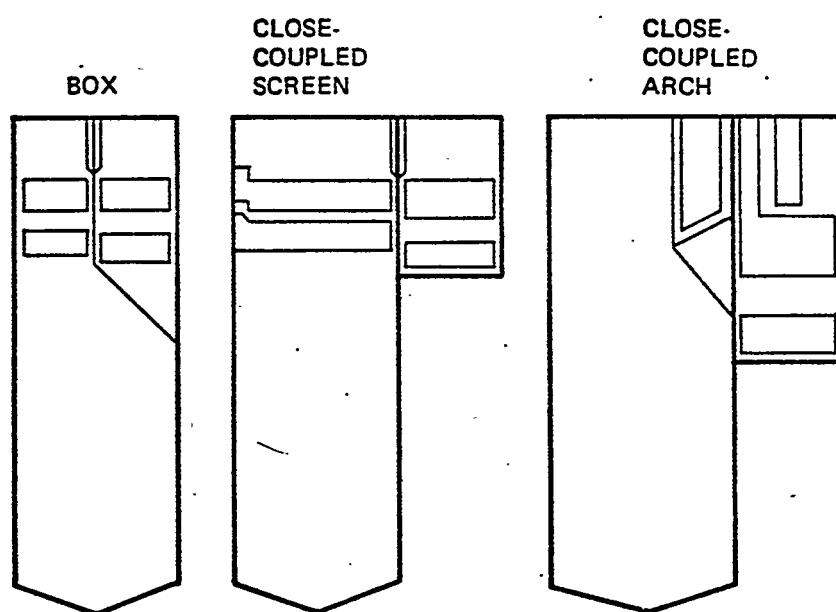


Figure 2-1 STUDY BOILER CONFIGURATIONS

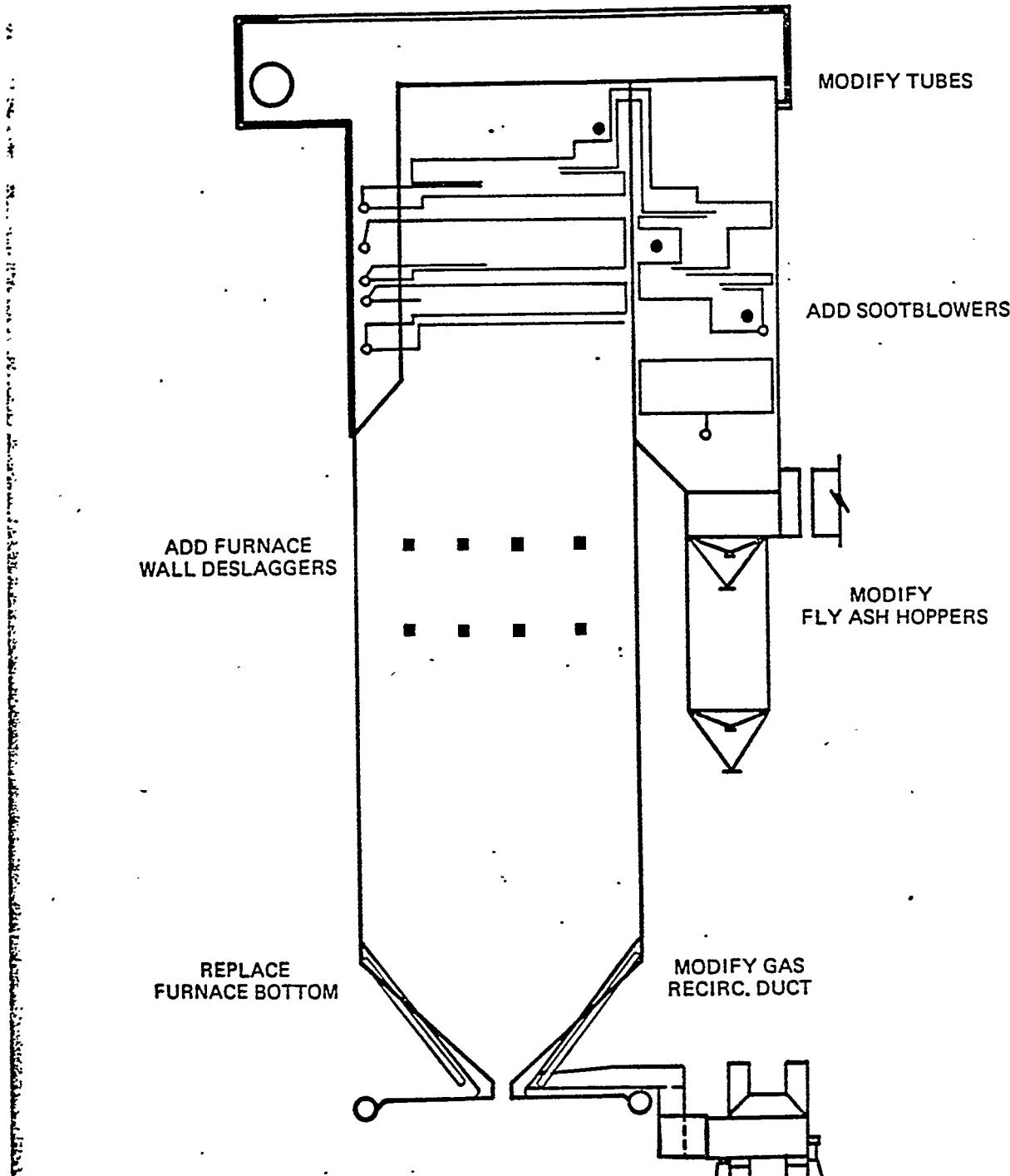
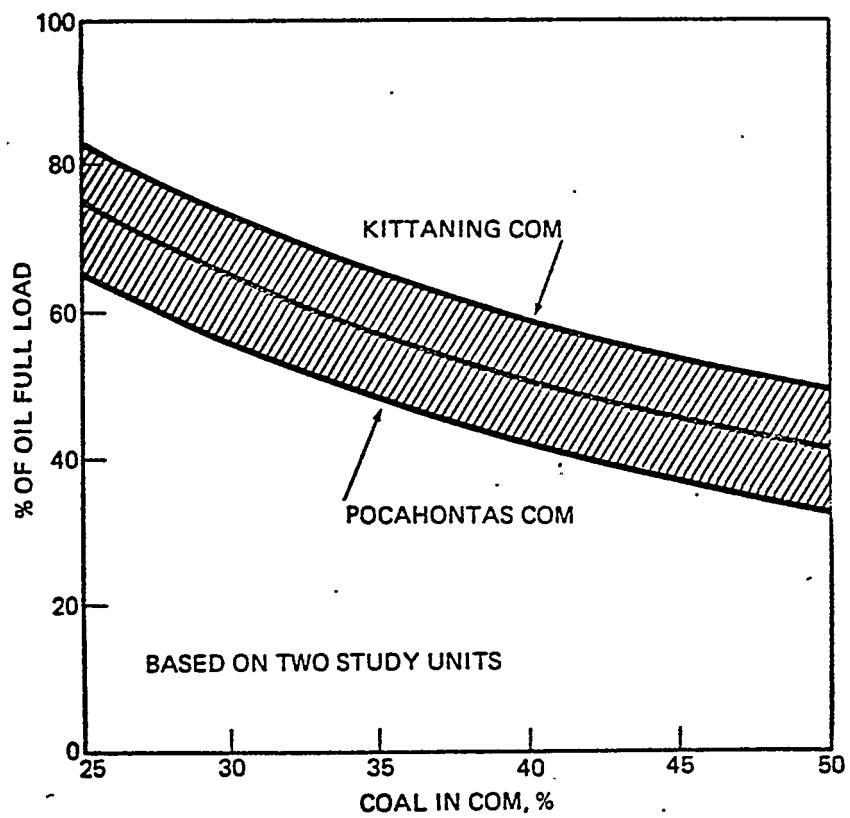


Figure 2-5 SCHEMATIC OF MODIFIED OIL-DESIGNED CCS BOILER UNIT

Table 2-1
BOILER LOAD DERATING FIRING 50/50 COM

Study Boiler Configuration	Nameplate Capacity on Fuel Oil, MWe	Percent Load Derating ⁽¹⁾	
		Kittanning COM	Pocahontas COM
Close-Coupled Arch (CCA-1)	850	27	50
Close-Coupled Arch (CCA-2)	820	20	51
Close-Coupled Screen (CCS)	565	36	56
Box (Box-1)	410	56	66
Box (Box-2)	382	58	64
Conventional Pul- verized Coal Capable (C/PCC)	392	0	0

(1) Based on the predicted reduction in the maximum rate of steam generation when firing fuel oil.



**Figure 2-4 BOILER LOAD CAPABILITY FOR FIRING COM
(Box Boilers Designed for Oil)**

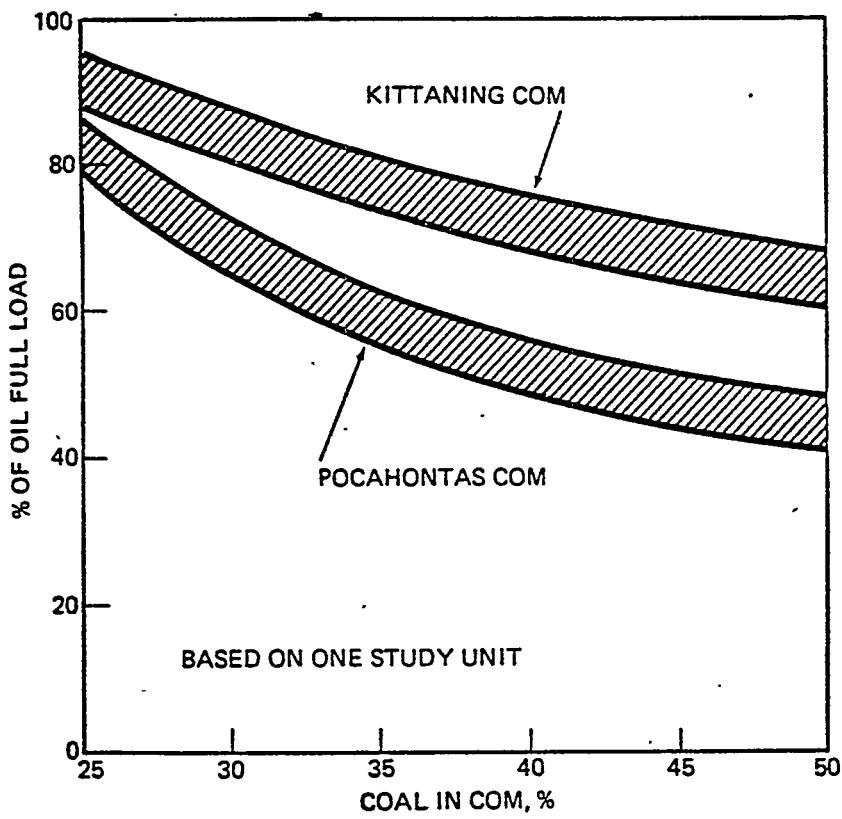
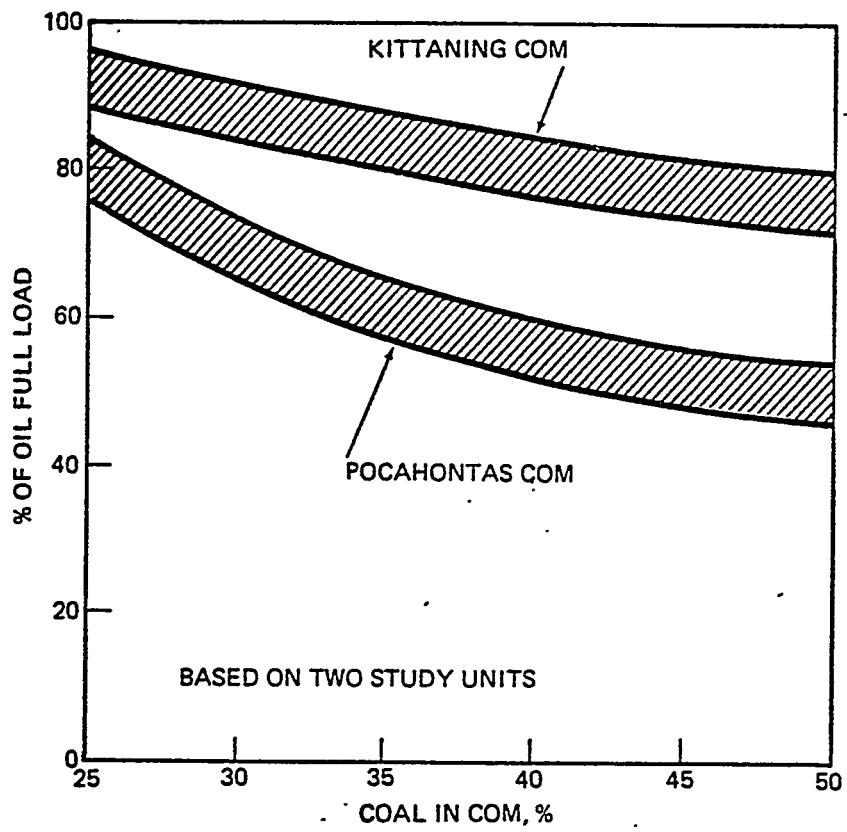


Figure 2-3 BOILER LOAD CAPABILITY FOR FIRING COM
(Close-coupled Screen Boilers Designed for Oil)



**Figure 2-2 BOILER LOAD CAPABILITY FOR FIRING COM
(Close-coupled Arch Boilers Designed for Oil)**

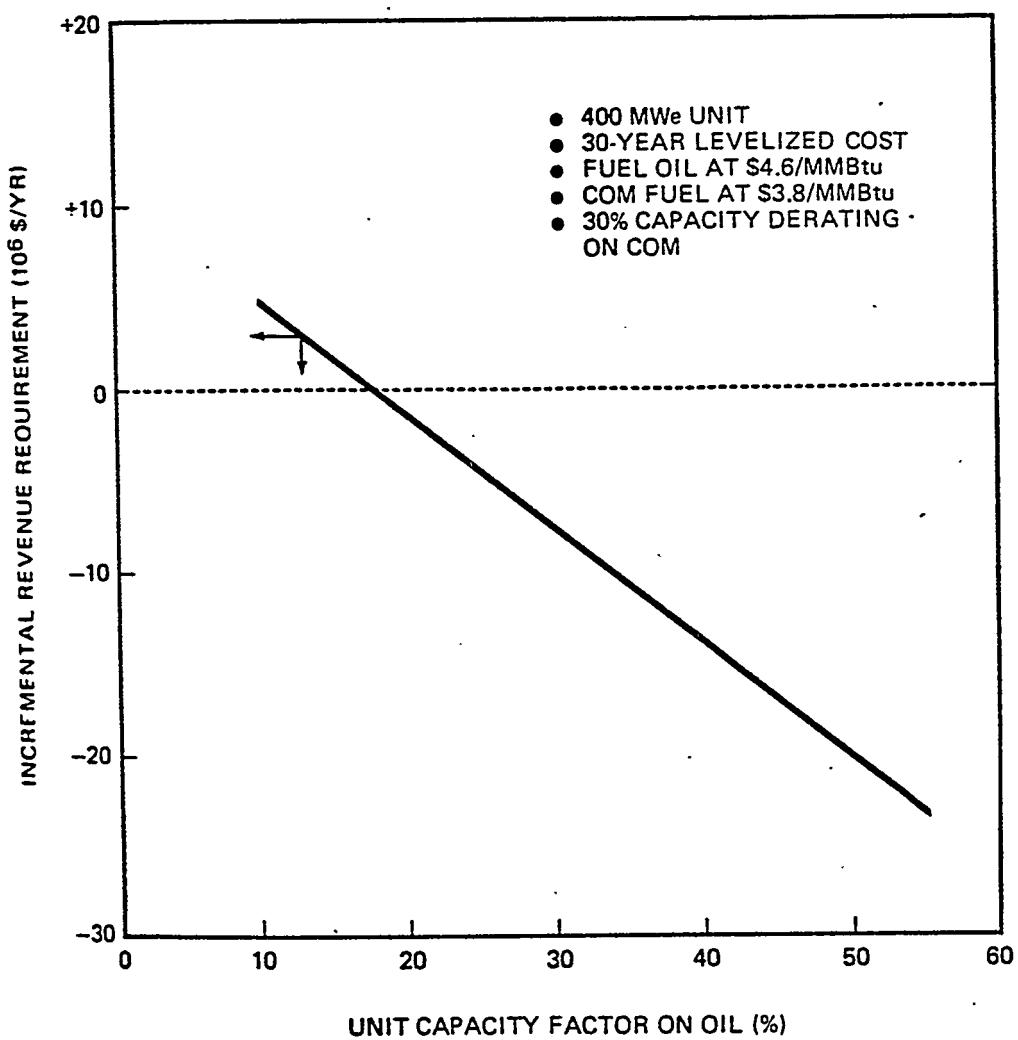


Figure 2-12 SENSITIVITY TO CAPACITY FACTOR

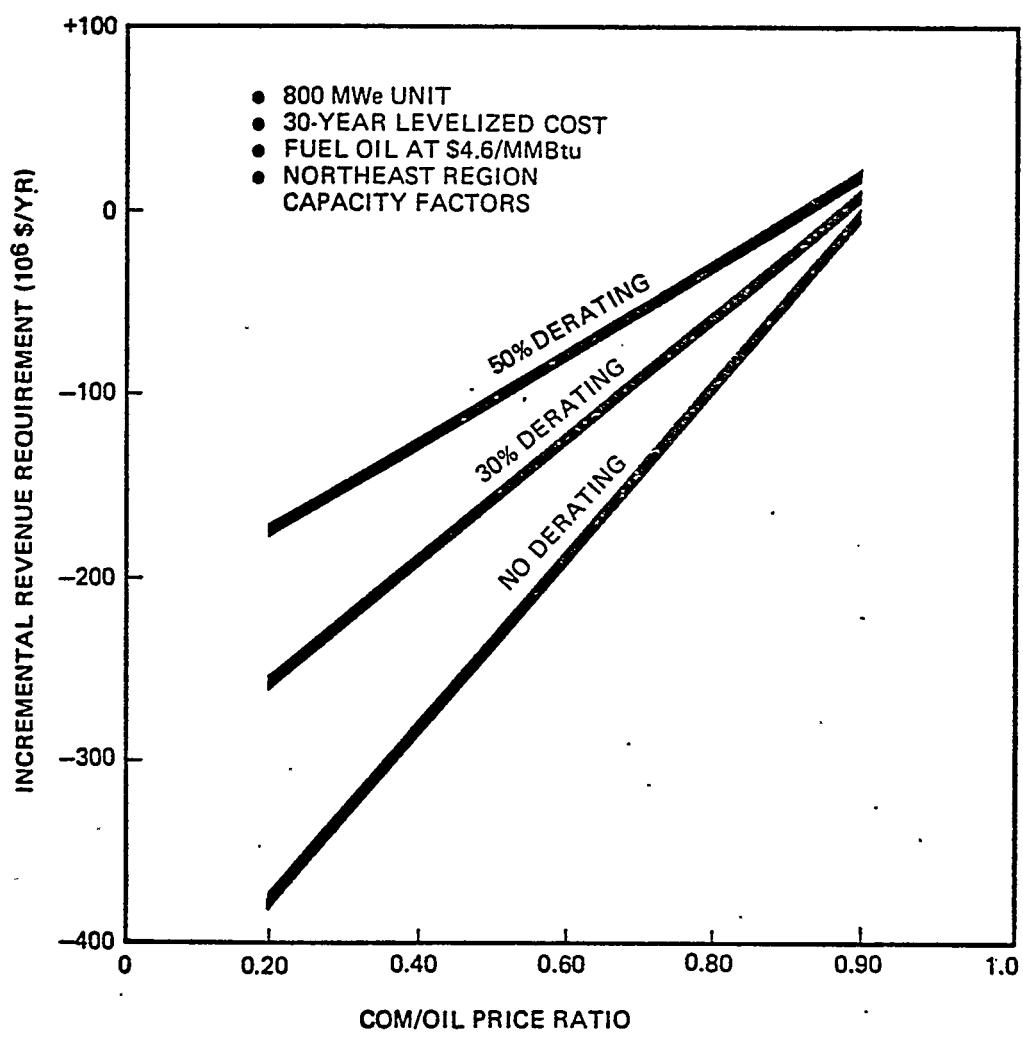


Figure 2-13 SENSITIVITY TO COM/OIL PRICE RATIO

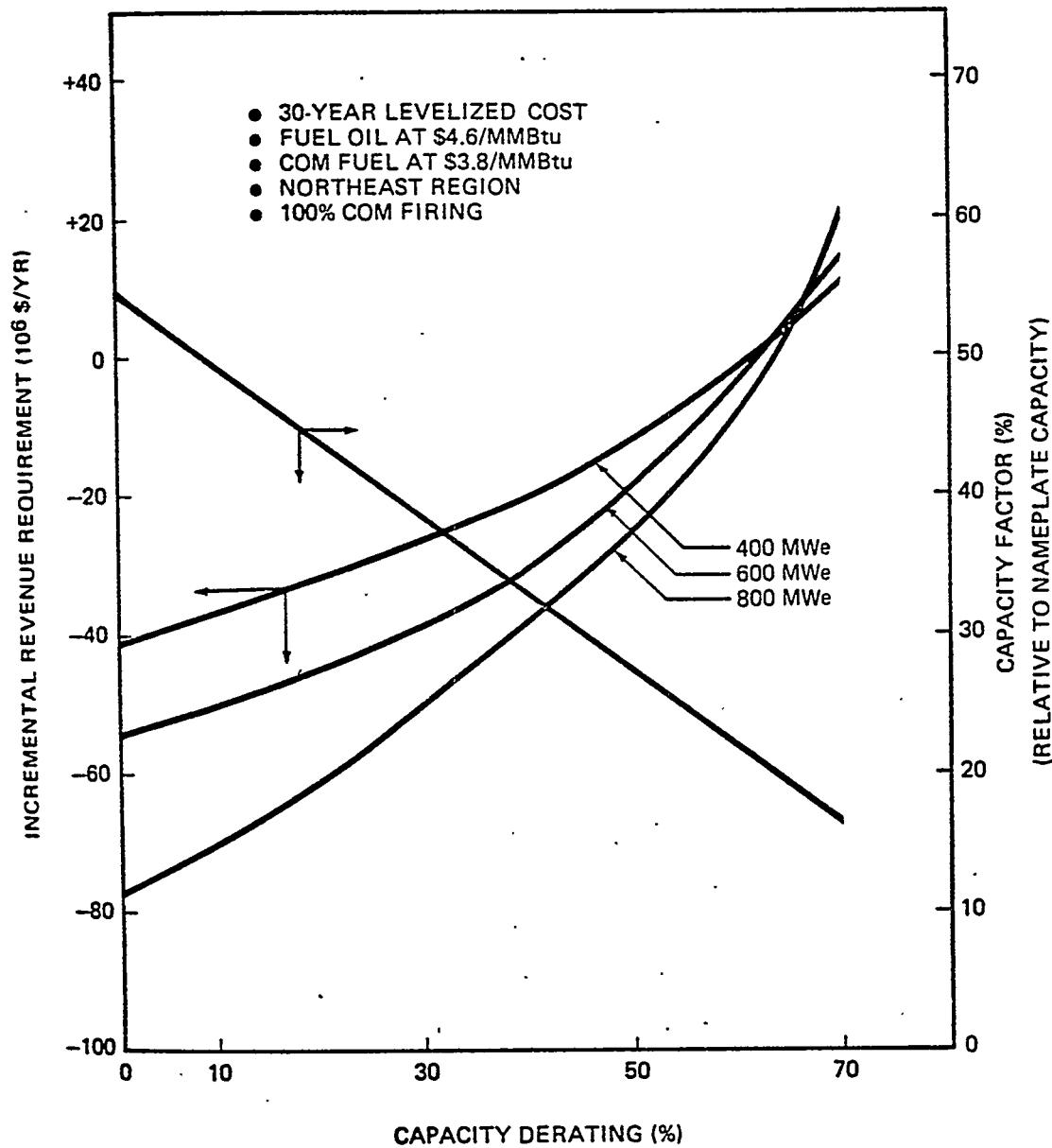


Figure 2-11 SENSITIVITY TO DERATING

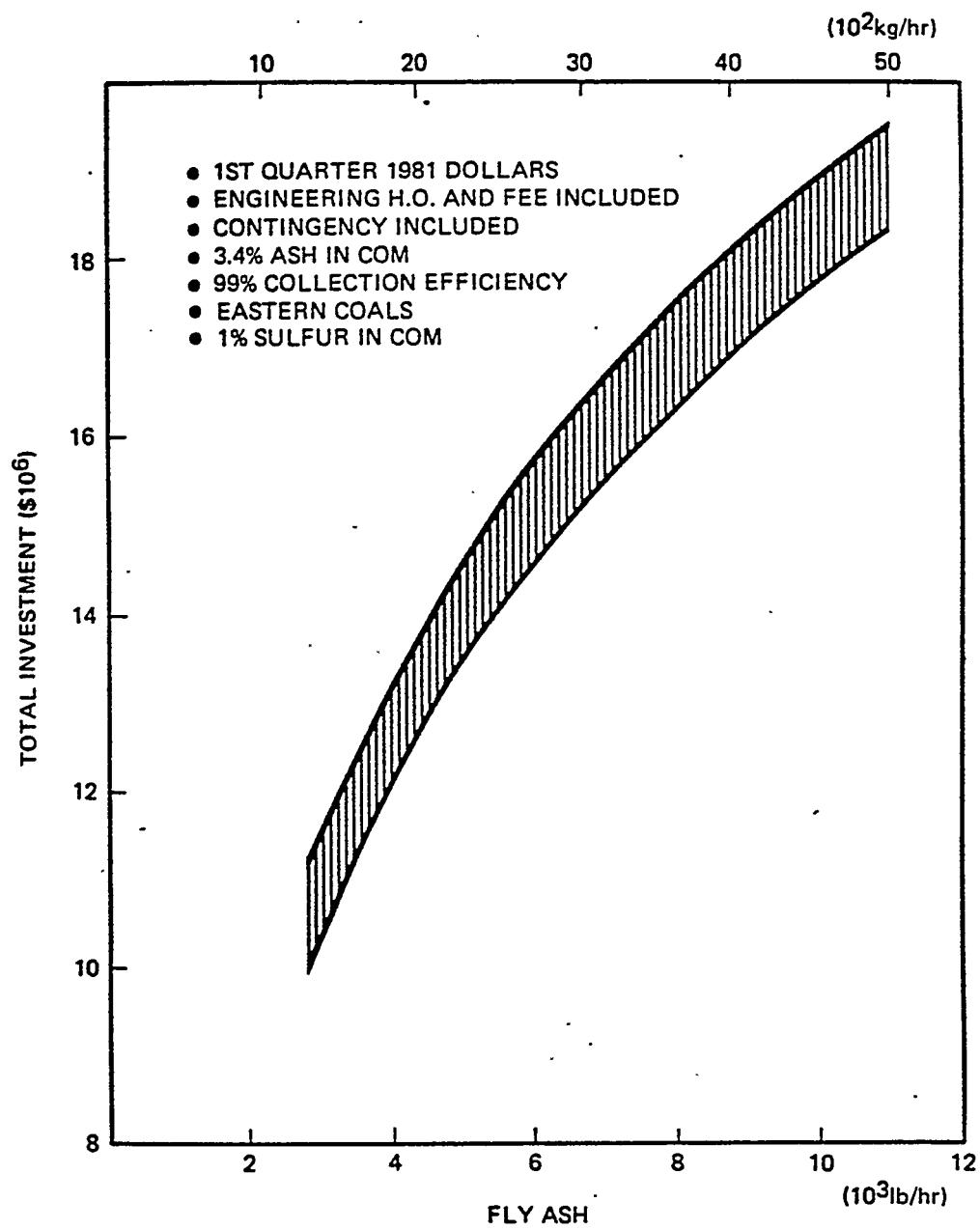


Figure 2-8 GENERALIZED ELECTROSTATIC PRECIPITATOR COSTS

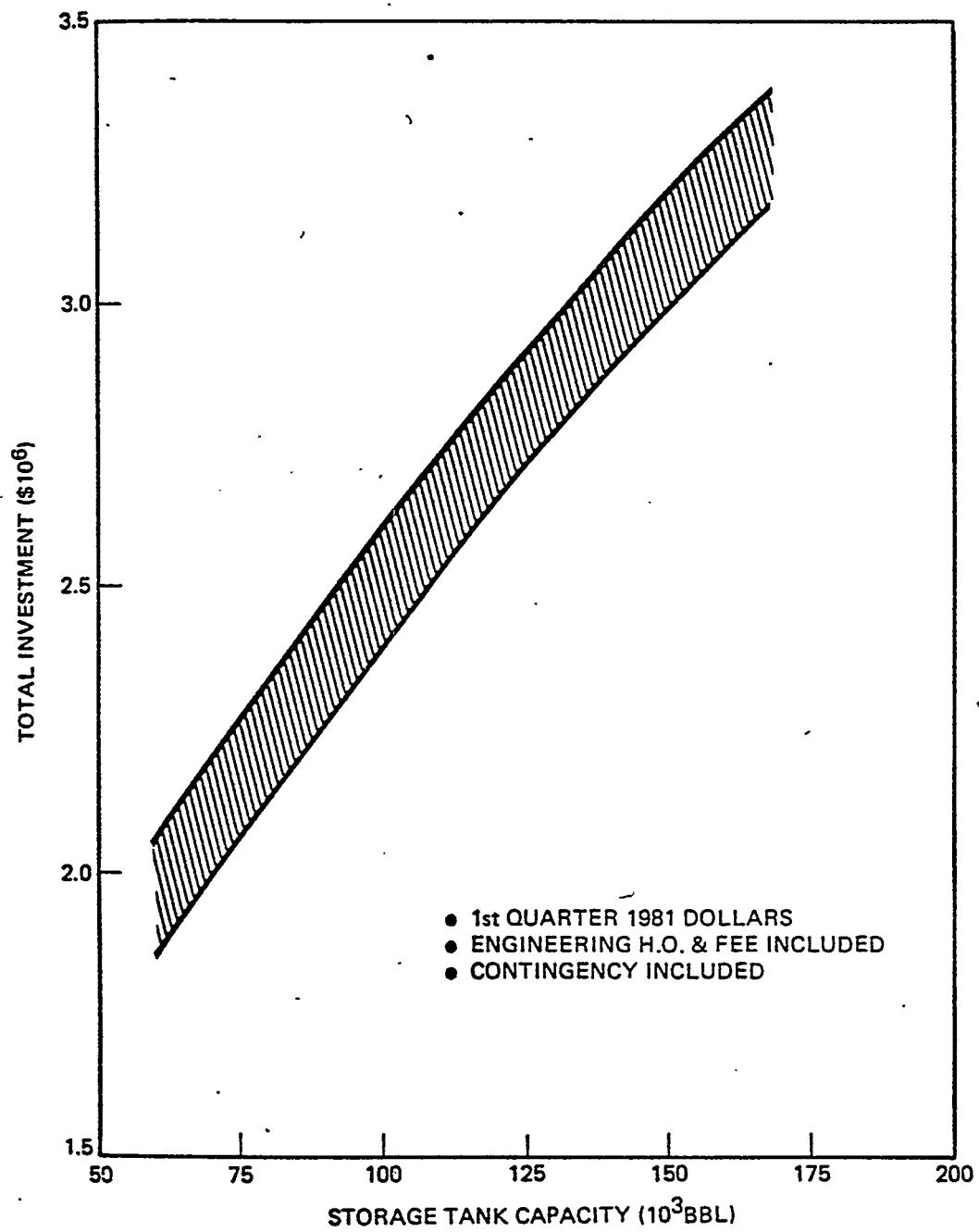


Figure 2-9 GENERALIZED COM STORAGE COSTS

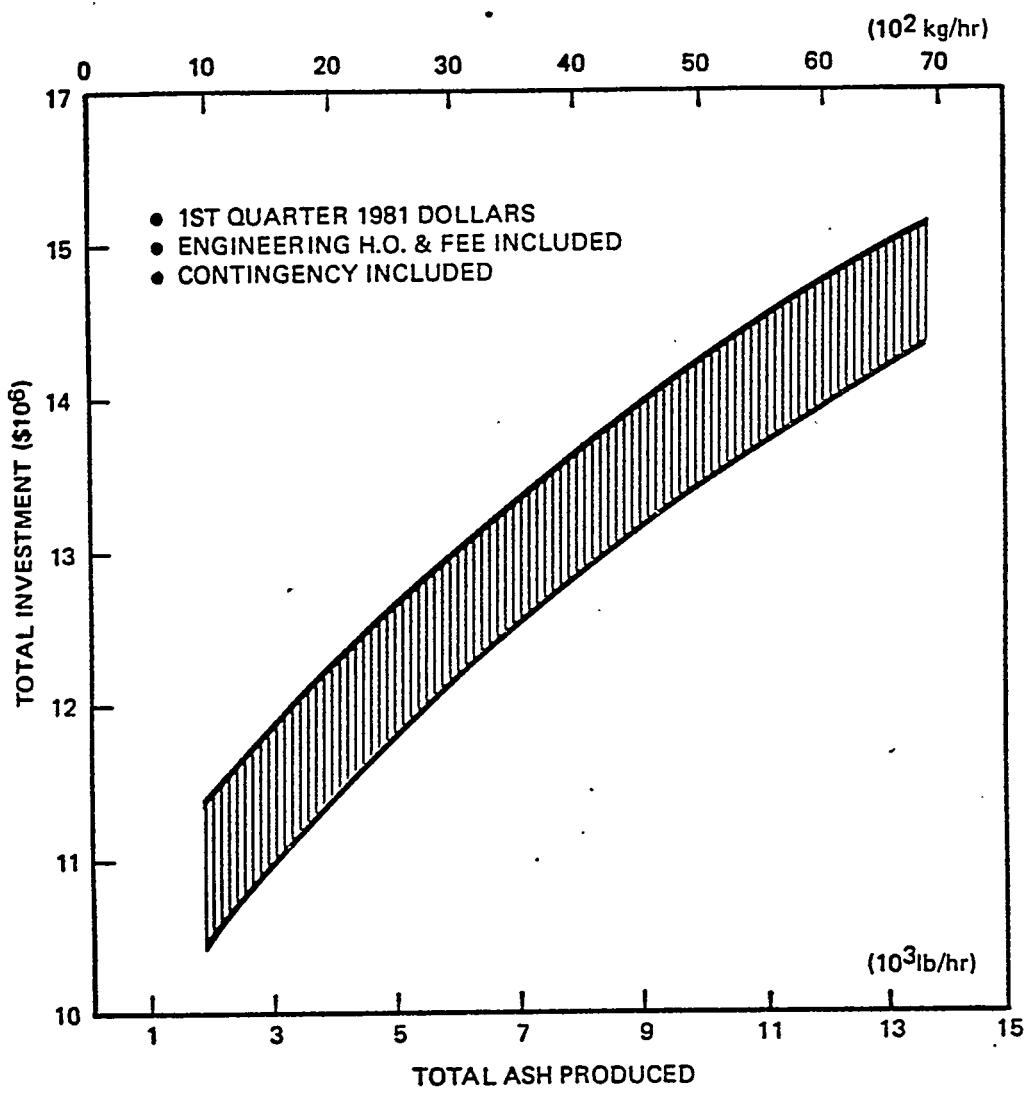


Figure 2-7 GENERALIZED ASH HANDLING COSTS

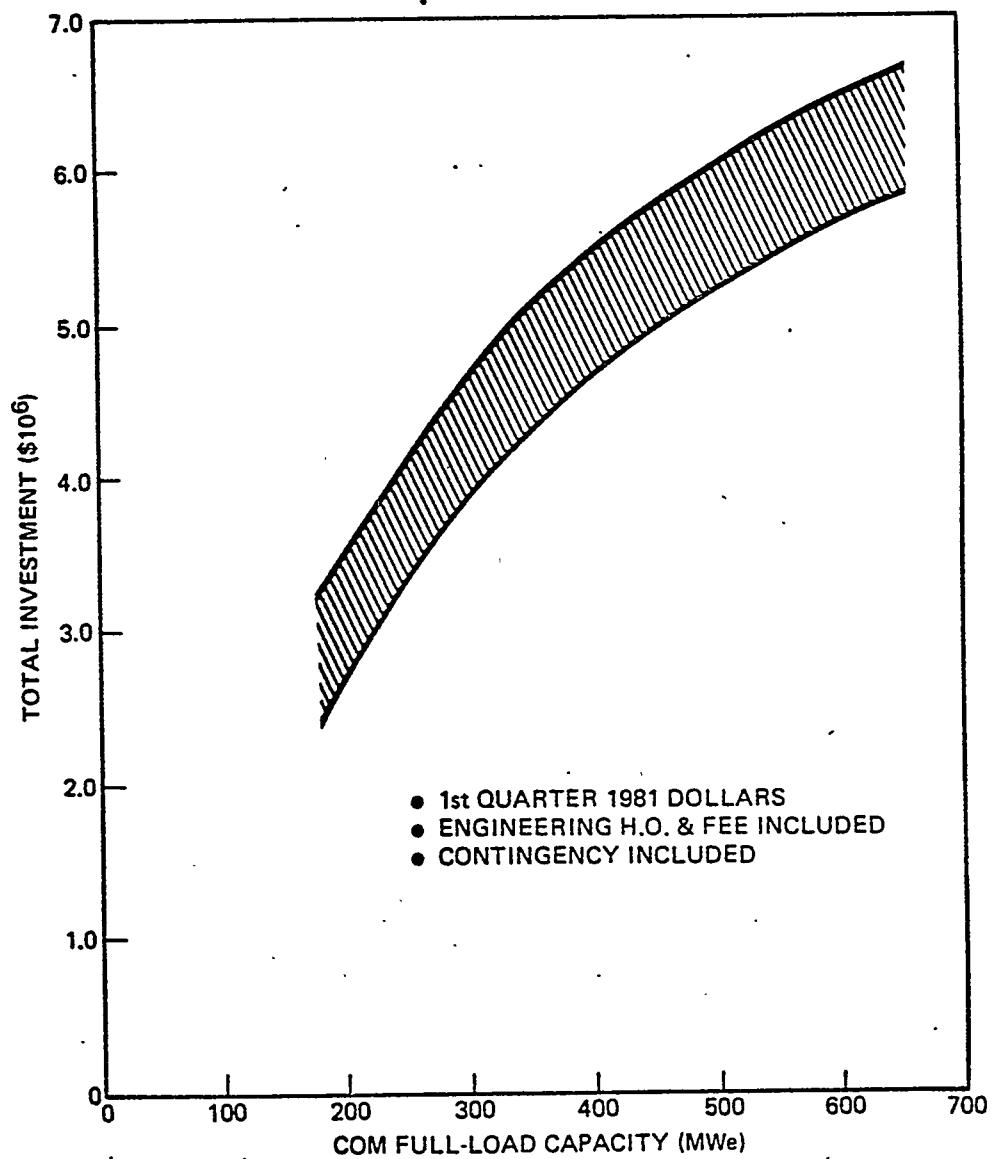


Figure 2-10 GENERALIZED COM HANDLING COSTS

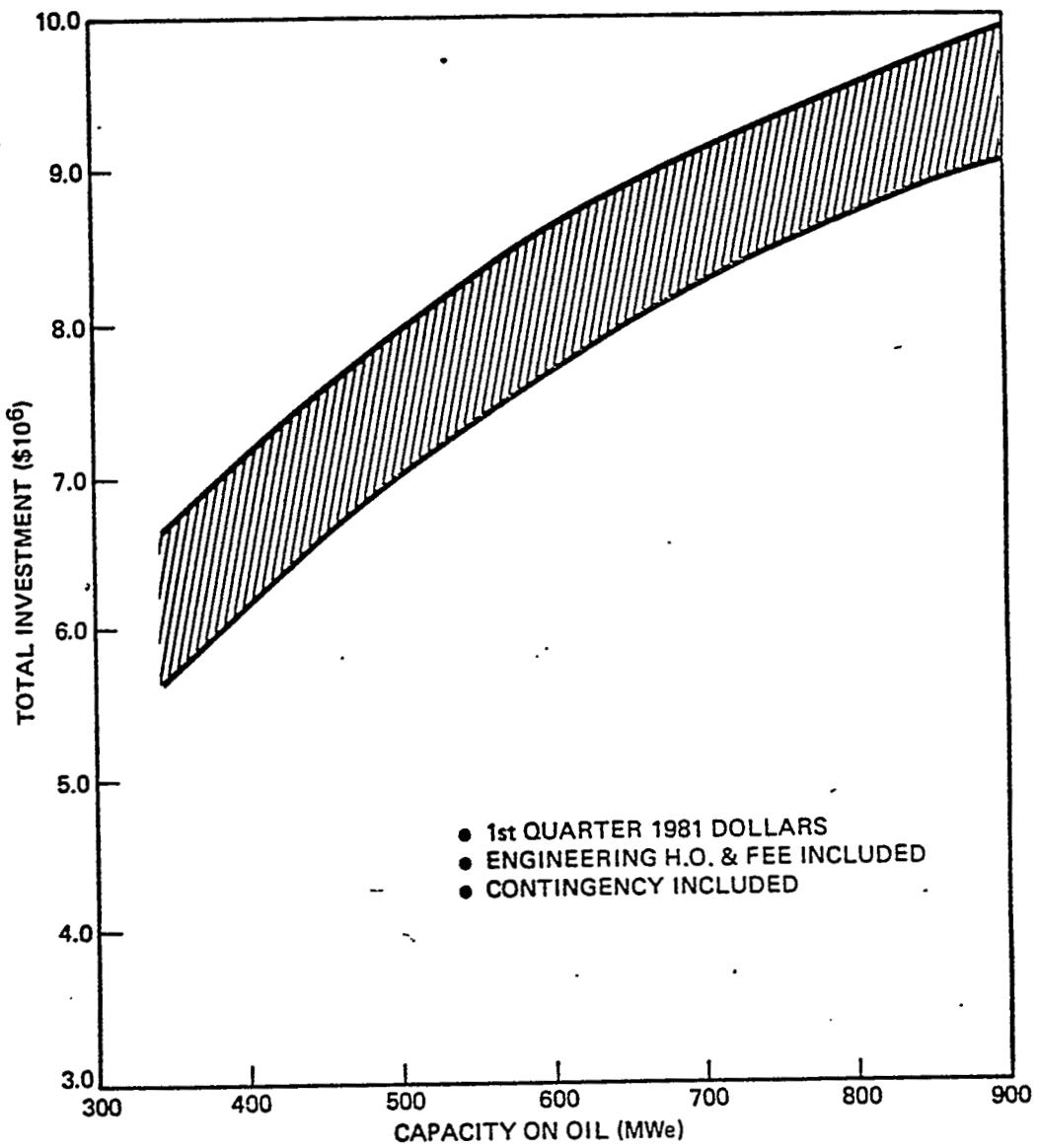
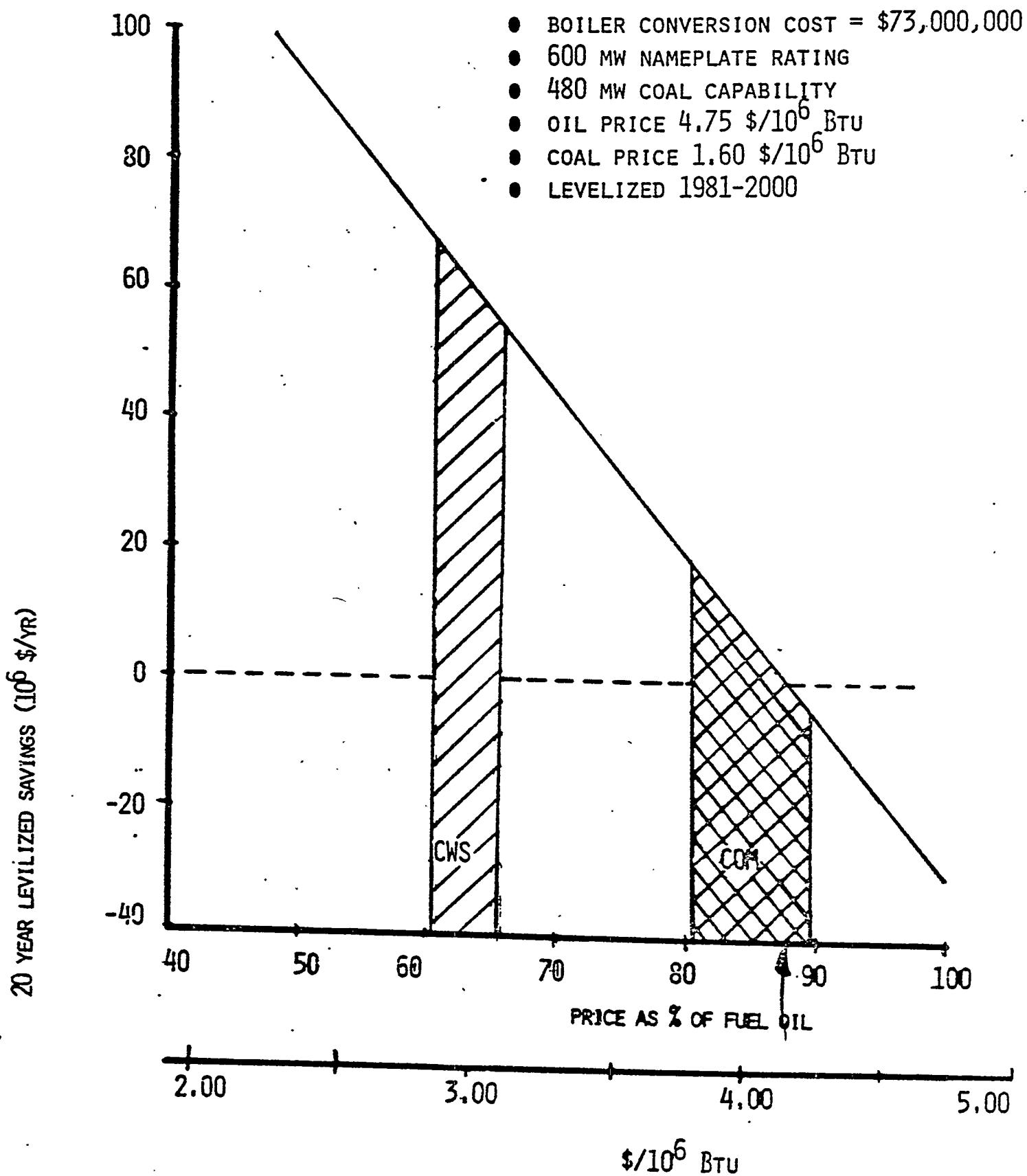


Figure 2-6 GENERALIZED BOILER MODIFICATION COSTS

COM/ALTERNATE FUEL COST INCENTIVES



BENEFITS

- LOWER COST THAN OIL

ESTIMATED DELIVERED COSTS (\$/MBTU)

OIL	4.7
COAL-OIL MIXTURE	4.0
COAL-WATER SLURRY	~ 3.0
COAL	1.6

- USES EXISTING OIL HANDLING/STORAGE SYSTEMS
(PLANT MODIFICATIONS ESTIMATED TO BE IN
RANGE FROM \$80 TO \$150/KW)

- DOMESTIC FUEL SUPPLY

- USES EXISTING RAIL TRANSPORTATION AND UNLOADING FACILITIES
FOR BRINGING COAL TO CENTRAL PRODUCTION PLANT. LESS EXPENSIVE
BARGES THEN TRANSPORT CWS TO UTILITY.
- TECHNOLOGY HAS INTERFACE POTENTIAL (PIPELINING, GASIFICATION,
COAL CLEANING).

WHERE IS THE UTILITY APPLICATION FOR CWS?

MARKET # 1

OIL-DESIGN BOILERS

- ATLANTIC SEABORD, GULF COAST, MISSISSIPPI RIVER REGIONS
- AT LEAST 60% OF 55 GW ARE CANDIDATES
 - 10⁺ YEARS OF SERVICE LIFE LEFT
 - CONFIGURATIONS OR LOCATIONS WHERE CONVERSION TO COAL IS IMPRACTICAL

SECOND MARKET

A FEW COAL-DESIGN BOILERS

- PLANTS WITH SPACE OR HANDLING PROBLEMS
- ESTIMATED 30% OF 15 GW ARE CANDIDATES

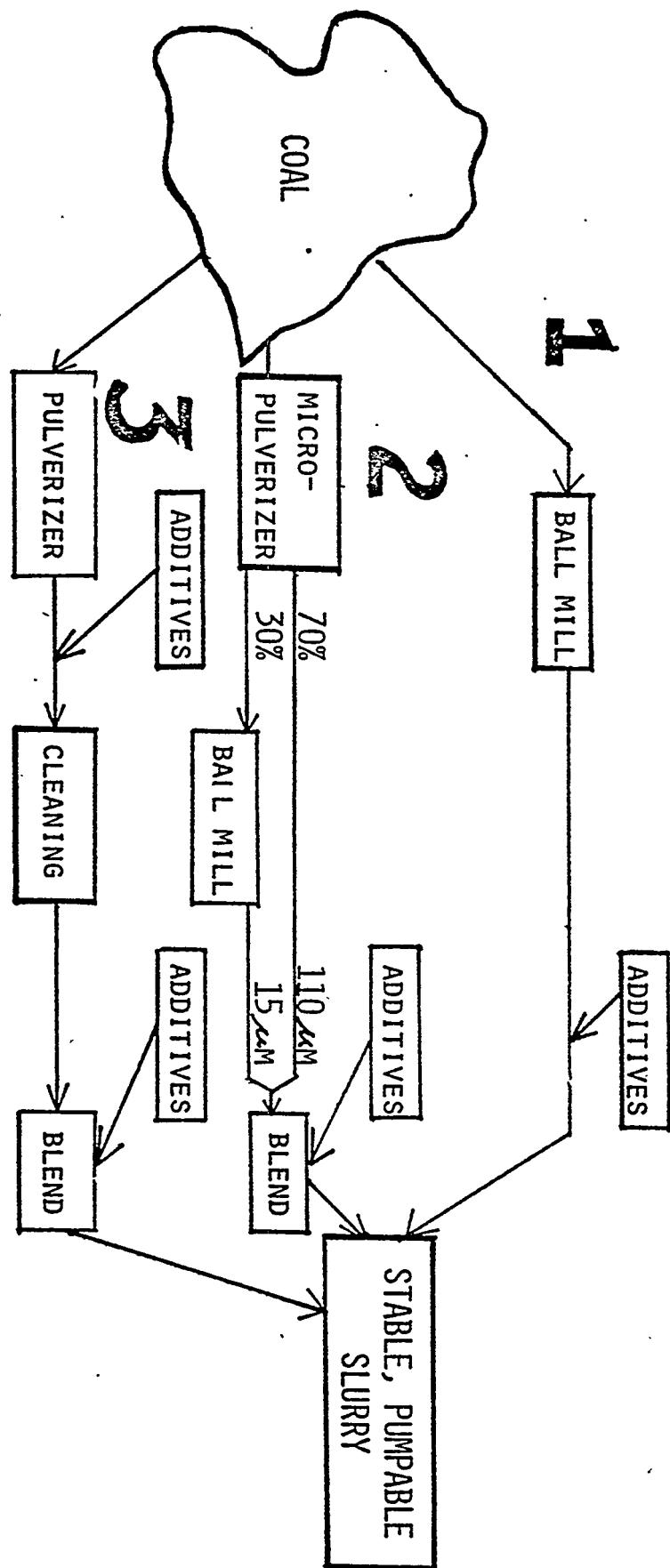
UNLIKELY MARKET

NEW PLANTS

PROBLEMS

- COMBUSTION STABILITY IN LARGE-SCALE TO BE DEMONSTRATED
- EROSION-RESISTANT BURNERS/NEED DEVELOPMENT AND DEMONSTRATION
- SUB-SYSTEMS STATE-OF-ART MUST BE DEMONSTRATED
- 4% BOILER EFFICIENCY LOSS DUE TO WATER
- DERATING
- INSTALLATION OF EMISSION CONTROL SYSTEM
- SLURRY PRODUCT MUST BE DEFINED AND VENDORS MUST BUILD PLANT (\$200 MILLION)

THREE WAYS TO MAKE CWS

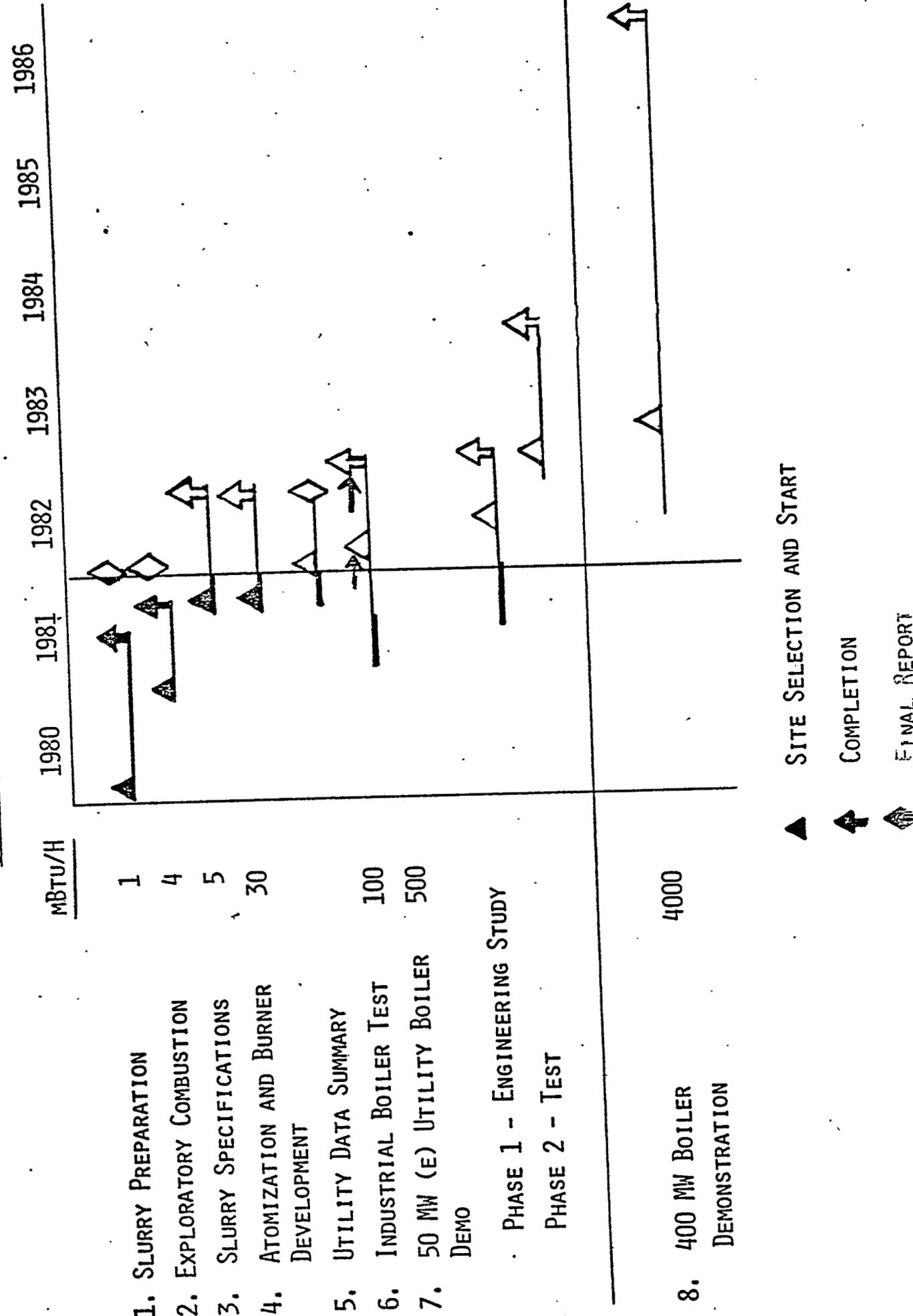


STATUS OF SLURRY SUPPLIERS (JAN. '82)

	LAB	PILOT PLANT (1-10 TPH)	PRODUCTION PLANT
GULF + WESTERN *	X	ON STREAM	1.0 MT/YR ('83) SWEDEN
Occidental Research *	X	JUNE '82	-
SLURRYTECH (AND OTHERS)	X	ON STREAM	0.5 MT/YR ('83) ANNOUNCED
ATLANTIC RESEARCH CORP.	X	ON STREAM	0.03 MT/YR ('82) ANNOUNCED
AB CARBOGEL *	X	(1 TPH AND 10 TPH) ON STREAM	0.01 MT/YR ('82) NOVA SCOTIA 0.3 - 0.6 MT/YR ('82-'83) SWEDEN
ASHLAND OIL	X	EARLY '82	-
GULF OIL *	X		
ARCO *	X		
SHELL *	X		
BRITISH PETROLEUM	X		
COALIQUID	X		
ERGON	X		

* PROCESS INCLUDES COAL CLEANING

COAL-WATER SLURRY PROJECT PLAN



Appendix III

COMBUSTION, HEAT TRANSFER, ASH DEPOSITION AND
POLLUTANT EMISSION CHARACTERISTICS OF COAL-OIL MIXTURES

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Abstract

A detailed combustion characterization study is under way at the MIT Combustion Research Facility (CRF) on industrial type turbulent diffusion flames. The objectives of the study are to characterize COM flames with respect to gaseous and particulates emissions, heat transfer, COM and slagging/solids deposition, and to determine flame input and operating conditions which favorably influence these flame characteristics. Results from the first experiments carried out in this ongoing research program are reported.

The CRF is a 1.2 x 1.2m cross section, 10m long variable heat sink combustion tunnel equipped with a variable swirl burner of up to 3 MW thermal, multi-fuel firing capability, and is used for detailed study of industrial type turbulent diffusion flames.

The major flame input and operating variables investigated to date consist of atomizer type: an International Combustion Ltd. design for COM fuels and a modified Y-jet; fuel type: 40% and 50% COM fuels of differing coal and oil constituents; excess air level: $\sim 15\%$ and $\sim 5\%$ in the flue; and without or with swirl in the combustion air flow. The thermal input in these experiments was maintained at 1 MW.

Measurements carried out include gas temperatures, velocities, gaseous and solids species concentrations, at several points in the flame and also incident radiation from the flame to the furnace wall along its length. Scanning electron micrographs were taken of char and ash cenospheres for a number of the in-flame solids.

Taking place concurrent with the CRF experiments are modeling efforts on COM flame radiative heat transfer and fuel burnout. Some preliminary results from the radiation modeling are reported.

Introduction and Research Objectives

Coal-oil mixtures (COM) are seen as an attractive alternative fuel for the power industry from the point of view of decreasing dependence upon foreign oil, of stretching existing domestic petroleum supplies,

of taking advantage of the nations immense coal reserves, of abating rising fuel costs, and of potentially requiring a minimum expenditure in time and capital for implementation in existing facilities. Potential problems that can accompany the retrofit of oil-fired utility boilers to utilize COM include: (1) an increased slagging tendency brought about by the relatively large ash content of the coal, by possible synergistic effects of oil ash constituents and those of coal ash, and by differences in the heterogeneous combustion process in COM flames; (2) increased emissions of combustibles and NO_x due primarily to the coal in the fuel; and (3) possible changes in the heat flux distribution caused by differences in flame temperature profiles and emissivities.

A research effort is under way at the 3 MW thermal MIT Combustion Research Facility (CRF) under the sponsorship of a number of utility and oil companies, aimed towards obtaining information on the effects of flame input and operating parameters upon the combustion, heat transfer, pollutant emission and ash deposition characteristics of COM flames. It is considered that these important flame characteristics can be favorably affected or controlled by suitable choice of flame input conditions, with the result of making the use of COM in existing utility boilers practical. Major input parameters that can be used to favorably influence COM flame characteristics include atomizer design, air-fuel mixing (degree of swirl of the combustion air, axial momentum of the jet flame) excess air level, and combustion air preheat. This paper presents results from some of the first COM combustion trials carried out in this ongoing research program.

Parallel with the experimental research being carried out at MIT, modeling efforts are being made in the areas of COM fuel burnout and radiative heat transfer. The overall objectives of these efforts is to develop a predictive capability for COM flames as well as for those of other fuels so as to facilitate the retrofit and new design of combustion devices, particularly utility boilers, with a minimum amount or need of experimentation. Preliminary results of radiative heat transfer modeling for the MIT-CRF are reported within.

Experimental Apparatus

The experimental program involved the use of the MIT Combustion Research Facility (Figure 1) which was designed especially to permit detailed experimental investigations of large turbulent diffusion flames. The CRF is a 1.2 x 1.2 m cross-section, 10 m long combustion tunnel equipped with a single burner of up to 3 MW thermal multi-fuel firing capability. The combustion tunnel comprises a number of individual 30 cm wide sections all of which are water cooled with some sections having a refractory lining on the fireside while the rest have bare-metal fireside walls. The sections are interchangeable, an arrangement which permits a variable heat sink for control of heat extraction along the length of the flame (Figure 1).

The burner used in these experiments is equipped with a variable swirl generator (moveable block type International Flame Research Foundation burner); the combustion air enters in the form of a swirling annular jet, the annulus being formed around the 60 mm diameter fuel spray

gun. At the burner exit a 35° half angle water cooled quarl assists in the formation of a toroidal recirculation zone in the central region of the jet.

Combustion of the fuel is completed in the portion of the furnace labeled 'experimental section' in Figure 1. In the present COM combustion studies, the experimental section is approximately 4.5 m long and is composed of refractory lined sections only. It is considered that the use of refractory lined walls is necessary for the reduction of the heat loss from the flame so as to simulate the thermal environment characteristics of large boiler combustion chambers. The firing rate in these experiments is approximately 1 MW, giving a total average residence time in the experimental section of ~ 3.8 seconds.

The COM fuel delivery system (Figure 2) consists of a 275 gallon, heated (120F) and stirred 'day' tank for holding the COM test fuel, a Moyno pump designed for handling of highly viscous materials, and a fuel line capable of heating the COM in two steps to maximum firing temperature of 140-150C (280-300F). The day tank allows operation for about 10 hours before requiring refilling from 55 gallon COM storage drums.

Measurements

Measurements were carried out within the flame along the axial centerline, in the flue and along the furnace walls. They consist of time average determinations of gas temperatures, gas velocities, and gaseous and solids species concentrations (O_2 , CO_2 , CO, NO_x , soot, coke, fly-ash). Incident radiation at the furnace walls, furnace wall temperatures, and furnace wall heat absorption were also measured. Additional measurements are planned; these include flame emissivity profiles by the modified Schmidt method, ash deposition rates, and ash deposit collection and analysis along the furnace walls and within the flames.

Water cooled probes are used in the measurements; some of these were developed by the International Flame Research Foundation^{1,2} (IFRF) at Ijmuiden, Holland, and others at MIT³. They include gas and solids sampling probes, suction pyrometer for temperature measurement, multi-directional impact tube for velocity, ellipsoidal-cavity radiation probe for radiative heat flux, narrow-angle radiometer for flame emissivity, conductivity plug type heat flux meter for ash deposition rates, and in-flame and furnace-wall steam, air or water-cooled ash deposit collection probes.

Experimental Run Conditions, Input Variables

Flame input and operating conditions for the experimental runs reported here are given in Table 1.

Experiments were carried out without and with swirl in the combustion air. When swirl was used, the degree of rotation was moderate ($S=0.53$)*, the fuel nozzles consisted of a scaled down version similar *The swirl number, S , is a nondimensional ratio of the angular to linear momentum of the flow and is an indicator of mixing and recirculation in the flame. At $S=0.53$ an internal recirculation pattern is just beginning to form within the flame.

to one tested by the Florida Power and Light Company, manufactured by International Combustion, Ltd. (Figure 3), and a modified Y-jet originally intended for oil in which the number of exit holes was reduced from 6 to 3, and their size enlarged from 0.053 inches in diameter to 0.084 inches (Figure 4). Excess air level was held at 15% and ~ 5% in these first experiments.

Three fuels have been employed in the tests. These come from two sources, the first being the Florida Power and Light Company (a 50% COM) and the second the Columbia Chase Corporation (40% COM). The fuels are somewhat different in composition as shown by the analyses in Table 2.

The water and asphaltenes content of these fuels may have a strong effect upon their burnout characteristics. The coal ash initial deformation and fluid temperatures are an indication of the slagging tendency.

Experimental Results

Visual Inspection of the COM Flames

All of the COM flames investigated to date were visibly longer than No. 6 fuel oil and SRC-II* flames of earlier studies having similar input conditions. Typically, flame of the No. 6 and SRC-II fuels at a 1 MW firing rate and low swirl ($S=0.53$) were 2 to 3 meters long, whereas the COM flames ($S=0.53$) were seen to extend the entire length (4.5 m) of the furnace experimental section. This increase in visible flame length can be attributed to the longer burnout time of the coal in the COM fuel and to the presence of relatively large amounts of fly ash which continue to radiate even after the combustion of the fuel is essentially complete.

Visual comparison of COM flames of the International Combustion, Ltd. (ICL) and Y-jet nozzles show that the ICL nozzle produces a superior flame from the point of view of stability and cleanliness of combustion. The ICL nozzle gave better atomization. When viewed from the back end of the furnace (facing the burner) flames of the Y-jet nozzle showed distinct areas of brightness corresponding to the lobes of fuel issuing from the 3 holes of the nozzle. Flamelets and puffs of soot and smoke were minimal in flames of the ICL nozzle when compared to those of the Y-jet. Also, the higher operating pressure of the ICL nozzle (see Table 1) made the flames less susceptible to instabilities caused by slight fluctuations in the fuel pressure (on the order of 1/2 psi).

A visual comparison of weakly swirling flames ($S=0.53$) and flames of essentially zero swirl ($S=0$) shows that as would be expected, the introduction of swirl improves the combustion of the fuel and the stability of the flame. Large frequency fluctuations, fluctuations in flame brightness, of flamelets and of puffs of soot and smoke observed

*A liquid distillate fuel oil produced by the Solvent Refined Coal II process developed by a subsidiary of the Gulf Oil Corporation under contract to the U. S. Department of Energy.

in the zero swirl flame were reduced by swirling air flow.

Axial particulates concentration profiles presented later confirm these visual comparisons drawn between flames of the two nozzle types and of the two swirl degrees.

Visual inspection of the furnace walls following experimental runs on the Florida Power and Light fuel (FPL) and that of the Columbia Chase Corporation (CCC) indicate an increased slagging tendency on the part of the latter. Examination of the initial deformation temperature of the coals of these two fuels (Table 2) explains this result; that of the CCC fuel is considerably lower than of the FPL COM.

Axial Temperature Profiles

Axial temperature profiles of various COM flames, and of No. 6 fuel oil and SRC-II heavy distillate flames are shown in Figure 5. Axial centerline temperatures for most of the 15% excess air COM flames peak in the range of 1350C - 1400C and decrease to a value of \sim 1200C at the furnace exit. The low excess air COM flame represented in Figure 5 exhibits temperatures that are approximately 100°C higher than those of the 15% excess air COM flames. The temperature profiles of the COM, No. 6 fuel oil and SRC-II distillate flames of comparable swirl ($S=0.53$) and excess air level (10-15%) are quite similar, the differences in temperature values at a particular axial position being attributable to scatter in the temperature measurement or slight variations in fuel input, as easily as to differences in fuel type.

The temperature peaks of the zero swirl COM flames shown in Figure 5 are seen to be shifted further downstream of the burner nozzle when compared with those of the weakly swirling flames ($S=0.53$). This behavior is expected; introduction of swirl alters the pressure distribution within the flame, thus causing the flame to become shorter and moving the area of most intense combustion in towards the nozzle.

The axial temperature profile of the zero swirl, modified Y-jet COM flame shown in Figure 5 displays a temperature peak that is shifted further downstream of the fuel nozzle than that of the zero swirl, ICL nozzle COM flame. The temperatures of the Y-jet flame are also somewhat higher than those of the ICL flame. At present there are insufficient data to determine with certainty whether these differences in the two profiles are attributable to the atomizer, fuel types, or to errors in the measurement. It should be noted that the two profiles were taken with different suction pyrometers. These probes can yield temperatures under identical flame conditions that vary as much as 5% from one another.

Axial Velocity Profiles

Axial velocity profiles as measured with the multi-directional impact tube are presented in Figure 6 for various COM flames. The gas velocity distributions within the flames are of particular interest from the point of view of COM combustion modeling studies, which are presently being undertaken at MIT.

The profiles shown in Figure 6 are similar to those of No. 6 fuel oil and SRC-II distillate flames of comparable input conditions. Note that the peak axial velocity of the weakly swirling COM flame ($S=.53$) represented in Figure 6 is somewhat lower than those of the zero swirl COM flames shown in the figure. This is to be expected: swirling flames tend to exhibit lower velocities along the axial centerline than non-swirling due to the adverse pressure gradient that is set up within the flame. Towards the tail end of the flames the pressure differentials across the pressure taps in the head of pitot probe become so small in value that they begin to approach the lower detectable limits of the pressure transducers installed at the facility. When the gas velocities fall below 3 meters per second the accuracy of the measurement begins to fall off and data points begin exhibit more scatter.

Combustion Chamber Heat Balance

As mentioned earlier, the experimental furnace is composed of a number of individually water-cooled refractory lined and/or bare metal sections. The cooling water flow rate and temperature rise is measured for each section; this allows the determination of the distribution of the furnace wall heat loss along the furnace length. The exit gas heat loss (chimney loss) can be calculated based upon knowledge of the exit gas temperature, and the fuel and air flow rates, the assumption being made that the combustion of the fuel is complete.

A typical heat balance for the experimental combustion chamber is given in Table 3. Since 94% of inside surfaces are refractory lined the (wall temperatures at a 1 MW firing rate typically reaching 1050-1300°C), a major proportion of the heat released by the flames is re-radiated to the combustion gases leaving combustion number. Heat absorption through the furnace surfaces accounts for approximately a third of the thermal input which is somewhat lower than that in boiler furnaces.

Radiative Heat Flux

Radiation measurements were carried out on COM and No. 6 fuel oil flames to determine the axial distribution of radiative flux incident to the furnace wall. Incident radiative flux was measured along the length of the furnace with an ellipsoidal radiometer having a solid view angle of 2π steradians positioned flush with the inside surface of the furnace wall. The probe was calibrated in two blackbody furnaces, and is subject to a calibration error of about 5%.

Figure 7 is a comparison of the axial distribution of radiative flux of a No. 6 fuel oil flame and three 50% Florida Power and Light COM flames. The relevant input conditions of these flames are given in the figure. Note that the radiative heat fluxes at a particular axial position of the various flames differ from one another by no more than 15%, and that the No. 6 fuel oil radiative profile is bracketed by those of the COM flames. The most important conclusion that can be drawn from this figure is that the change in fuel type from a No. 6 fuel oil to a 50% COM does not greatly affect the radiative flux from the flame in this furnace.

It may be that expected increases in flame emissivity caused by

high particulate concentrations in COM flames are compensated for by lower peak flame temperatures that tend to be characteristic of the heterogeneous combustion processes taking place in this type of flame. The resulting radiative flux emanating from the COM flame, thus in this fashion may turn out to be comparable to that of a No. 6 fuel oil.

A comparison of the axial positions at which the maximum radiative heat flux occurs for the different flames represented in Figure 7 is also of interest. The exact shape of the radiative flux profile of the weakly swirling ($S=0.53$) ICL nozzle COM flame in Figure 7 is uncertain at distances from the nozzle falling between 0.2 and 1.0 meters because the ellipsoidal cavity of the probe was being fouled by ash from flame during the measurements, despite nitrogen purging. Keeping this uncertainty in mind the peak in radiation from this weakly swirling COM flame occurs at about the same position as, or a little further from the burner than that of the No. 6 fuel oil flame which is of comparable swirl. Because COM combustion is delayed somewhat by the presence of the coal particles, a shift in position of the peak away from the burner is expected.

As would be expected, the radiation peak in the case of the zero swirl ICL nozzle COM flame occurs at a position further downstream of the burner than that of the weakly swirling ($S=0.53$) ICL nozzle COM flame. A lack of swirl results in a longer, more slowly burning flame. This longer flame leads to the radiation plateau in the profile shown in Figure 7. The radiative heat flux measurements for the zero swirl, ICL nozzle, 15% excess air FPL COM flame were compared with preliminary results of radiative heat transfer computer modeling. As shown in Figure 8, radiative fluxes predicted by the computer model are within 11% of the measured values throughout the furnace.

The computer model being used is based on the zone method of furnace analysis originally proposed by Hottel and Cohen⁴ in which the furnace is divided into many volume and surface zones. The properties of each zone are considered uniform and constant, and the radiative exchange areas between the zones are determined based on measured concentrations of absorbing species in each zone. Given fluid flow and combustion patterns, a system of nonlinear energy balance equations can be set up and solved for the unknown temperature of each zone, allowing the radiative heat flux distribution to be predicted.

Johnson was successful in developing a computer program that employed this zone method to predict radiative flux from a fuel oil flame⁵. Wall and co-workers extensively modified this program, primarily by incorporating the Monte Carlo method to determine direct exchange areas⁶. This probabilistic method, in which a zone's energy emission is divided into several thousand "particles" that are tracked as they are reflected and absorbed throughout the furnace, allows considerable flexibility in choosing zone size and shape. The zone shapes can be made physically more realistic, thus allowing a smaller number of zones to be used in the model while retaining the same degree of accuracy. For example, the zones containing the flame itself can be shaped as truncated cones which more accurately represent the flame's shape.

This program has been modified for use at the MIT-CRF, and has been used successfully to model synthetic fuel flames. Further modifications are being made to allow COM and other ash-bearing flames to be modeled. The current zoning system consists of 11 volume zones and 10 surface zones in a parallelepiped as shown in Figure 8. Because the zone method requires the absorbing gas and soot concentrations of each volume zone as inputs, measurements are required in any flame being modeled. Although only the axial distributions of these concentrations are known for COM flames in the MIT-CRF, radial distributions can be approximated to allow preliminary computer modeling. Figure 9 is a comparison of the axial radiative heat flux distributions of the zero swirl, ICL nozzle, FPL COM flame and as predicted for those conditions by the Monte Carlo zone method computer program. The predicted and average measured values are less than 11% apart in each of the 5 axial surface zones. Johnson was able to predict radiative fluxes within 10% of measured fluxes; it is believed that these numbers may be further improved as refinements in the input data and radiation model are made.

The major improvement required for COM radiative flux modeling is in the treatment of radiation from fly ash. At present, all particulates in the COM flame are combined and assigned the absorption coefficients that Johnson determined for soot alone. The validity of treating ash as soot has not been demonstrated, so further work is needed to determine suitable absorption coefficients for ash. For high fly ash concentrations, scattering of radiation by the particles will become important, so its effect-must also be investigated and modeled.

Other improvements being made include re-evaluating the gas absorption coefficients used by Johnson, since the partial pressure of water to that of carbon dioxide in the combustion products of this COM flame is 0.7 compared to 1.0 for the fuel oil flames Johnson investigated. Also, further detailed experiments on COM flames will remove the uncertainty in predictions due to some approximated input data used in the present calculations. Finally, the possibility of improving the accuracy of radiative flux prediction by doubling the number of zones is also being investigated.

Implementing the improvements mentioned above will determine the accuracy of applying the zone method to COM flames, but the results obtained thus far show that the feasibility of extending the method to ash-bearing flames is quite good.

Axial Gas Composition Profiles

Measurements of O_2 , CO_2 , CO and NO_x concentrations along the flame axis were carried out for a number of COM flames and are shown in Figures 10 to 14. Similar profiles for an SRC-II flame are presented in Figure 15.

A comparison of the O_2 and CO_2 profiles of the COM flames with the SRC-II distillate clearly demonstrates the delayed nature of the combustion process for COM. In the case of the SRC-II all-liquid fuel

the O_2 and CO_2 profiles are relatively flat indicating that combustion is completed very near the burner. In the case of COM, the O_2 and CO_2 concentrations begin to reach equilibrium only very close to the exit of the combustion chamber, this being indicative of slower fuel burnout rates, particularly of the coal in the fuel.

A comparison of the CO profiles of long ($S=0$) and short ($S=0.53$) flames of the 50% FPL COM using the ICL nozzle (Figures 10 and 11) shows the effect of swirl, an indicator of the degree of turbulent mixing of air and fuel, upon the rate of combustion of the fuel. The CO is seen to burn out in the case of the shorter ($S=.53$) flame 1 meter from the nozzle and in the case of the longer ($S=0$) at 2 meters. It is interesting to note that the concentration of CO for both flames is essentially the same at the furnace exit, being on the order of 0 to 50 ppm. Axial total particulates concentration profiles discussed in the next section exhibit similar behavior.

The axial NO_x concentration profile for the weakly swirling ($S=0.53$), 50% FPL COM flame shown in Figure 13 is flatter than those of the zero swirl flames represented this figure and in Figure 14, indicating that the NO_x is formed a little more rapidly at this swirl condition. These profiles, like those of the CO, are illustrative of the more rapid fuel/air mixing and subsequent reaction processes that accompany the introduction and increase of swirl in a flame.

The gas composition profiles of the flames of the 50% FPL fuel and of the 40% CCC Figures 10 and 12, respectively, at a zero swirl condition exhibit trends that are fairly similar. The CO is seen to burn out at approximately the same position along the furnace axis.

Decreasing the excess air level from 15% to 5% resulted in modest increases in CO emissions. COM flames at 15% excess air exhibited CO emissions usually close to 0 ppm with occasional rises to 50 ppm. The 5% excess air flame studied in detail (Flame 5, in Table 1) yielded CO emission levels that were within 100 ppm. At near stoichiometric conditions ($< 0.2\% O_2$ in the flue) the CO concentration usually remained within 500 ppm. The relatively modest increase in CO emission, particularly in changing from a 15% excess air level to a 5% level, may be attributed in part to the relatively high temperatures in the combustion chamber at this excess air condition, even towards the exit, which were in the neighborhood of 1300C, and also to the excellent fuel/air mixing that can be achieved within this experimental combustor.

Axial Particulates Concentration Profiles

Axial total particulates concentration profiles for several COM flames are shown in Figure 16. The input conditions for each flame are also indicated in the figure.

The effect of swirl is seen in Figure 16 to be most noticeable in the early portions of the flames, at distances of less than 2 meters from the burner. At these distances, solids concentrations in the weakly swirling ($S=0.53$), ICL nozzle, 50% Florida Power and Light (FPL) COM flame are considerably lower than the zero swirl ($S=0$) flame

of the same nozzle and fuel type. This can be probably attributed to the improved fuel/air mixing that accompanies the swirl. It is interesting to note that from the point of view of solids emissions these two flames are practically identical; the solids concentrations are seen in Figure 16 to decay to nearly the same value.

The effect of nozzle type upon COM flame solids concentration profiles may also be seen in Figure 16. Early in the zero swirl ($S=0.0$), 50% Florida Power and Light COM flames (at distances less than 1.5 meters from the nozzle) the Y-jet gives slightly lower particulate levels than the ICL nozzle. Considering that the 3-hole Y-jet gives a very distinct hollow cone, 3-lobed spray pattern this result is quite understandable. Upon examining the particulates concentrations towards the end of the flames represented in Figure 16, it appears that the ICL nozzle gives a slightly lower emission than the Y-jet. This is in keeping with the visual observations on these flames discussed earlier, and is supportive of the conclusion that the ICL nozzle gives better atomization than the modified Y-jet, which in turn results in improved fuel burnout.

The solids emission levels of the COM flames of the two fuel types but which are otherwise similar, are quite close in value. At positions near the nozzle (< 2 m) solids concentrations in the 40% CCC flame are slightly lower than the 50% FPL flame, this presumably being attributable to the lower coal content of the fuel.

An example of the effect of excess air level upon COM flame particulates emission is given in Table 4. In the case of this zero swirl, Y-jet nozzle, 40% CCC COM flame, solids concentrations are seen to increase by 25% when going from a 15% excess air to a near stoichiometric condition. This is probably due to the increase in combustibles emission.

At the time of the preparation of this paper all of the solid samples that are represented in Figure 16 and Table 4 are being analyzed for their combustibles content.

Ash Deposition Studies

A number of samples have been collected of ash and slag that have accumulated on the furnace walls and upon the $\sim 3/4$ inch diameter stainless steel flue gas sampling tube which extends into the center of the exit of the furnace experimental section. Tables 5 and 6 present mineral and fusion temperature analyses carried out by a commercial laboratory on a few of the deposits from flames of the 50% Florida Power and Light COM. The deposits were accumulated over more than one set of flame conditions.

Mineral analyses using atomic absorption techniques were carried out upon the inside and outside layer of an ash deposit formed on the flue gas sampling tube. A thickness of approximately $1/8 - 1/4$ inches was scraped off for each layer. This deposit was lightly packed in nature and could be broken up into fine particles in the hand. The deposit was collected over a period of about 10 hours over flame con-

ditions varying in swirl ($S=0.0-0.053$) and in excess air level (1-4% O_2) and was approximately 3-4 inches thick. The temperature of the gases passing by and being drawn into the sampling tube was approximately 1000 C (± 100 C).

As evident from Table 5 the mineral analyses of the deposits are similar to that of the coal ash. The relative concentrations of sulfur and alkalies in the inner and outer layer are noted with interest since they appear to follow a trend contrary to that typically reported in the literature⁷. It should be mentioned, that the period of time over which the deposit was exposed to the flame was probably of insufficient duration for the diffusion processes of the alkali metal and sulfur species through the porous deposit to be manifested. Relative concentrations of various species in deposit layers formed from COM flames can be followed more closely in later experiments using deposition probes, which will allow the conditions under which the deposits are formed to be monitored and controlled more closely.

Fusion temperature analyses were carried out upon slag chipped off of the furnace wall at a distance of approximately 2 meters from the burner and upon an ash deposit on the flue gas sampling tube. The results are reported in Table 6. The initial deformation temperature (~ 1340 C) and fluid temperature (~ 1440 C) of these samples is slightly lower than that of the coal ash (~ 1430 C and ~ 1540 C, respectively). Peak flame temperatures measured along the axis were typically $\sim 1400-1500$ C as shown in the profiles in Figure 5.

Detailed Particulates Characterization Studies

The history of coal particles within COM flames, their burnout and accompanying transformation of inherent mineral matter, are of particular interest, since such information may bring to light factors and/or conditions in the flames which enhance and/or retard their propensity towards combustibles emission and ash deposition. In the current studies diagnostic tools for characterization of particulates and deposits are being explored and developed.

A number of in-flame solids samples of one of the COM flames investigated to date were examined under a scanning election microscope at MIT (Materials Science Laboratory) and some of the photographs that were taken are shown in Figures 17 through 23. The major input conditions for this flame are as follows: thermal input: 1 MW, swirl No.: 0.53, excess air level: 15%, fuel type: 50% Florida Power and Light COM, and air preheat: nil. A general history of coal particle transformations within a COM flame as believed to be represented by Figures 17-23, may be described briefly as follows.

In the first stage coal particles or agglomerations thereof, are heated and undergo plastic deformations. The trapped coal volatiles, gases and water vapor blow the particle into a 'ballon' (Figure 17). As a result of further pyrolysis and cracking the particle surface carbonizes; a hollow coke particle or cenosphere is formed, and blow holes develop through which gases escape (Figures 18 and 19). As the coal char burns away some of the finer particles of mineral residues

are separated at the burning surface and disperse as carbon is converted to CO (Figures 20 and 21. Others if touching tend to coalesce, this process being aided by the negative contact angle between silicate glass and the carbon surface. The non-wetting of the carbon by the molten silicates results in the production of a large number of glassy spheres and cenospheres from each coal particle (Figure 22 and 23).

Summary of Experimental Observations

1. The axial temperature profiles of COM, No. 6 fuel oil and SRC-II distillate flames of comparable swirl ($S=0.53$), and excess air level (10-15%) are similar in shape and close in value, peaks occurring at $\sim 1400\text{C}$ and exit temperatures being $\sim 1200\text{C}$.

2. The axial centerline temperature peaks of the zero swirl COM flames are shifted downstream of those of the weakly swirling ($S=0.53$) flames. This is an effect that would be expected to accompany the introduction of swirl.

3. Axial velocity profiles of COM, No. 6 fuel oil and SRC-II distillate flames of comparable swirl and excess air level are similar in form and value. Swirling flames ($S=0.53$) exhibited peak velocities on the centerline ($\sim 7.5 \text{ m/s}$) that were lower than those of zero swirl flames ($\sim 12 \text{ m/s}$), as was expected.

4. Axial radiative heat flux profiles of No. 6 fuel oil and COM flames of comparable input conditions are similar in form and value, exhibiting a relative insensitivity towards fuel type. The radiative heat flux in these flames peak in the neighborhood of $350-370 \text{ kW/m}^2$ and towards the tail end are on the order of $250-275 \text{ kW/m}^2$.

5. The radiative heat flux peak of zero swirl COM flames appears to be slightly shifted downstream of that of flames having swirl. This is an expected trend; as swirl is increased the flame is shortened and the region of most intense combustion moves in towards the nozzle.

6. A comparison of the axial O_2 and CO_2 concentration profiles of COM flames with those of a flame of an all-liquid fuel, in this case SRC-II, demonstrates the somewhat delayed nature of the COM combustion process. The concentrations of O_2 and CO_2 reach their equilibrium values earlier along the SRC-II flame axis than along that of the COM flames.

7. The sharp decay in CO concentration that accompanies its burnout, along the axis of zero swirl COM flames takes place at a position further downstream of that of swirling COM ($S=0.53$ flames). However the CO concentration decays to nearly identical values of 0-50 ppm for both flame types at the combustor exit.

8. Axial total particulate concentration profiles of COM flames investigated to date decay to values on the order of 0.8 g/Nm^3 at the combustor exit. Exit particulate concentrations of No. 6 fuel oil and SRC-II flames are on the order of 0.01 to 0.05 g/Nm^3 .

9. The introduction of swirl (from S=0 to S=0.53) in COM flames noticeably affects the solids concentration along the flame axis at positions close to the nozzle (< 1.5 m). However the total solids concentration decays to nearly identical values at the combustor exit.

10. The solids emission levels of a zero swirl COM flame were observed to increase by approximately 25% when changing from 15 excess air to near stoichiometric combustion conditions.

11. COM flames at a 15% excess air level exhibited CO emissions on the order of 50 ppm. Decreasing the excess air level to 5% resulted in modest increases in CO emissions, which ranged up to 100 ppm. COM flames at or very near to stoichiometric combustion conditions (< 0.1 - 0.2 O₂ in the flue) yielded CO emissions that were usually less than 500 ppm, except for occasional puffs in excess of this value.

12. Ash deposits collected over varying input and operating conditions of the Florida Power Light COM yielded mineral analyses that were similar to that of the coal ash.

13. The relative concentrations of alkalies and sulfur on the inside and outside layer of an ash deposit from flames of the 50% Florida Power and Light COM exhibited a trend contrary to that typically reported in the literature. However, the deposit was collected over a time that may have been too short for migration of these species to be evidenced.

14. Fusion temperature analyses of ash and slag from flames of the Florida Power and Light COM show initial deformation and fluid temperatures under reducing conditions that are 80-100C lower than that of the coal ash. This is possibly indicative of the formation of eutectics resulting from the interaction of mineral constituents in the ash of the coal and the oil.

15. Photographs taken with a scanning electron microscope of axial centerline solids samples of a Florida Power and Light COM flame show the presence of cenospheres of diameters typically 50-100 μm which are believed to be formed from the coal in the fuel. Glassy spheres and cenospheres of pure mineral matter typically of diameters of 2-10 μm are also observed.

Acknowledgements

We wish to express our thanks and appreciation to CRF Operations Engineer Rolf Steendal, and to the CRF support crew, who made the experiments reported within possible.

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TABLE I
RUN CONDITIONS FOR COM FLAMES INVESTIGATED
AT THE MIT CRF

FLAME NO. (DATE)	1 (10/15/81)	2 (11/4/81)	3 (11/4/81)
Thermal Input MW (lb/min)	~ 1	~ 1	~ 1
Fuel Type	50% FPL	50% FPL	50% FPL
Nozzle Type	ICL	ICL	Y-Jet
Swirl No., S	0.53	0.0	0.0
Velocity of Jet at Burner Exit ft/s (m/s)	115 (35)	115 (35)	115 (35)
% O ₂ in Flue (Excess Air)	2.82 ± .2 (~ 15)	2.82 ± .2 (~ 15)	2.82 ± .2 (~ 15)
Comb. Air Inlet Temp. F (C)	80±20(27)	80±20(27)	80±20(27)
Air Flow Rate lb/min (SCFM @ 60°F, 1 atm)	52±2(680)	52±2(680)	52±2(680)
COM 'Day' Tank Temp. F (C)	160(71)	140(60)	125(52)
Com Firing Temp. F (C)	245(119)	245(119)	180(83)
COM Firing Press., psig	200	195	46
Atomizing Fluid Pressure, psig	110	110	60
Measurements Taken:	Axial Pro- files: CO ₂ , O ₂ , CO, NO _x , Temp., Parti- culates, Radi- ative Flux, and Flue Gas Analy- sis	Axial Profiles: CO ₂ , O ₂ , CO, NO _x , Temp., Par- ticulates, Radi- ative Flux, and Flue Gas Analy- sis	Axial Profiles: Particulates only, and Flue Gas Analysis

TABLE I
(Continued)

FLAME NO. (DATE)	4	4a	4b	5
Thermal Input MW (lb/min)	~1	~1	~1	~1
Fuel Type	40% CCC(A)	40% CCC(A)	40% CCC(A)	40% CCC(A)
Nozzle Type	Y-Jet	Y-Jet	Y-Jet	ICL
Swirl No., S	0.0	0.0	0.0	0.53
Velocity of Jet at Burner Exit ft/s (m/s)	~110(34)	91(27.7)	100(30.4)	96(29.2)
% O ₂ in Flue (Excess Air)	2.8±.3	0.5±.1(~2%)	1.1±.2(~5%)	0.9±.2(~5%)
Comb. Air Inlet Temp., F (C)	60±20(16)	60±20(16)	60±20(16)	50±20(10)
Air Flow Rate, lb/min (SCFM @ 60°F, 1 atm)	52±2(680)	43±1(560)	47±1(615)	46±1(600)
COM 'Day' Tank Temp., F(C)	118(48)	118(48)	118(48)	130(55)
COM Firing Temp., F (C)	210(99)	210(99)	210(99)	250(120)
COM Firing Press, psig	~50	~50	~50	~175
Atomizing Fluid Pressure, psig	100	100	100	100
Measurements Taken	Axial Pro- files of CO ₂ , O ₂ , CO, NO _x , Temp., Particulates, and Flue Gas Analysis	Flue Gas/ Solids Sampling and Analysis	Flue Gas/ Solids Sampling and Analysis	Axial Pro- files of CO ₂ , O ₂ , CO, NO _x , Temp., Particu- lates, Radi- ative Flux and Flue Gas Analysis

TABLE 2
ANALYSES OF COM FUELS AND OF THEIR
COAL AND OIL COMPONENTS

FUEL SOURCE: FLORIDA POWER AND LIGHT CO. (FPL)

	OIL	COAL	MIXTURE 10/2/81	MIXTURE 10/15/81	MIXTURE 11/4/81
% Coal in Mixture			49.3	51.4	47.4
Coal Particle Size			~80% through 200 mesh		
<u>Ultimate Analysis</u>					
Carbon		82.21	85.16	84.99	83.44
Hydrogen		3.82	9.23	9.03	9.20
Nitrogen		1.15	0.75	0.69	0.64
Sulfur	1.8-2.3	0.71	1.94	1.78	1.81
Oxygen		2.32	1.73	3.76	3.85
Ash	0.04	6.87	1.48	1.72	1.67
Water		2.75	0.36	0.44	0.48
Asphaltenes	5.0				
Vanadium (PPM)	200				
Sp. grav. 60F			0.996		1.05
API grav, 60F	13				
HHV BTU/lb	18,410		16,706	16,356	16,610

FUEL SOURCE: COLUMBIA CHASE CORPORATION (CCC)

	CCC (A)			CCC(B)		
	OIL	COAL	MIXTURE	OIL	COAL	MIXTURE
% Coal in Mixture			40			40
% Water in Mixture			3			3
% Oil in Mixture			57			57
Coal Particle Size	~80% through 200 mesh			100% through 100 mesh		
<u>Ultimate Analysis</u>						
Carbon	85.15	75.3		84.41		
Hydrogen	10.72	5.1		11.15		
Nitrogen	0.37	1.50		0.39		
Sulfur	1.98	2.10		2.00		
Oxygen	1.71	6.8		1.98		
Ash	0.07	7.2		0.07		
Water	0.07	2.0		0.8		
Asphaltenes	8.0			9.0		
Vanadium (PPM)	252			340		
Sodium (PPM)	68			59		
API grav. (60F)	12.4			14.8		
HHV Btu/lb	18417	12887		18563	13688	
<u>Proximate Analysis</u>						
Volatile Matter		39.21			40.11	
Fixed Carbon		47.77			52.34	
Ash		13.02			7.55	

TABLE 2
(Continued)

FUEL	FPL	CCC(A)	CCC(B)
<u>COAL ASH FUSION TEMPERATURES (F)</u>			
Initial Deformation			
Fluid Temperature	2600	2230	2200
2800			
<u>COAL ASH ANALYSES</u>			
Silica	50.72	49.3	
Alumina	30.78	23.20	
Titanium Oxide	1.40	1.20	
Ferric Oxide	8.58	20.3	
Calcium Oxide	1.29	2.10	
Sodium Oxide	0.45	0.70	
Potassium Oxide	2.96	1.10	
Sulfur Trioxide	1.10	0.90	

(1) Analytical data on these fuels are still being collected at the time of writing of this paper.

(2) The data presented above has come from Florida Power and Light Company, New England Power Service Company and Galbraith Laboratories, Inc.

TABLE 3
CRF HEAT BALANCE (KW)

THERMAL INPUT	REFRACTORY LINED SURFACES (23.56 m ²)	WATER-COOLED BURNER (0.76 m ²)	STEEL SURFACES VIEWING DOORS (0.19 m ²)	AIR-COOLED ACCESS DOORS (0.27 m ²)
996	240	70	25	27
FURNACE EXIT RADIATIVE LOSS (0.21 m ²)	CHIMNEY LOSS	UNDETERMINED		
63	580	9		

TABLE 4
SOLIDS EMISSIONS AT DIFFERENT EXCESS AIR LEVELS
(S=0.0, Y-jet, 40% CCC (A) COM)

<u>Excess Air</u>	<u>Solids Emission g/Nm³</u>
0-2%	1.15
5%	1.06
15%	0.923

TABLE 5

MINERAL ANALYSES OF ASH DEPOSITS
OF 50% FLORIDA POWER
AND LIGHT COM FLAMES

<u>Mineral Analysis</u>	<u>Ash in Coal</u>	COM ASH ² Deposit Inside Layer (1/8-1/4")	COM ASH ² Deposit Outside Layer (1/8-1/4")
Silica	50.72	49.39	49.00
Ferric Oxide	8.58	7.48	7.11
Alumina	30.78	29.02	28.46
Titania.	1.4	1.49	1.48
Lime	1.29	3.03	3.26
Magnesia	1.12	1.47	1.63
Sulfur Trioxide	1.10	0.10	0.67
Potassium Oxide	2.96	1.52	1.53
Potassium Pentoxide	0.45	---	---
Sodium Oxide	0.45	0.49	1.09
Phos. Pentoxide	---	0.02	0.01
 <u>Sulfur Forms</u>			
<u>Percent</u>			
Pyritic		0.02	0.01
Sulfate		<0.01	0.03
Organic		0.03	0.14
Total		0.05	0.18

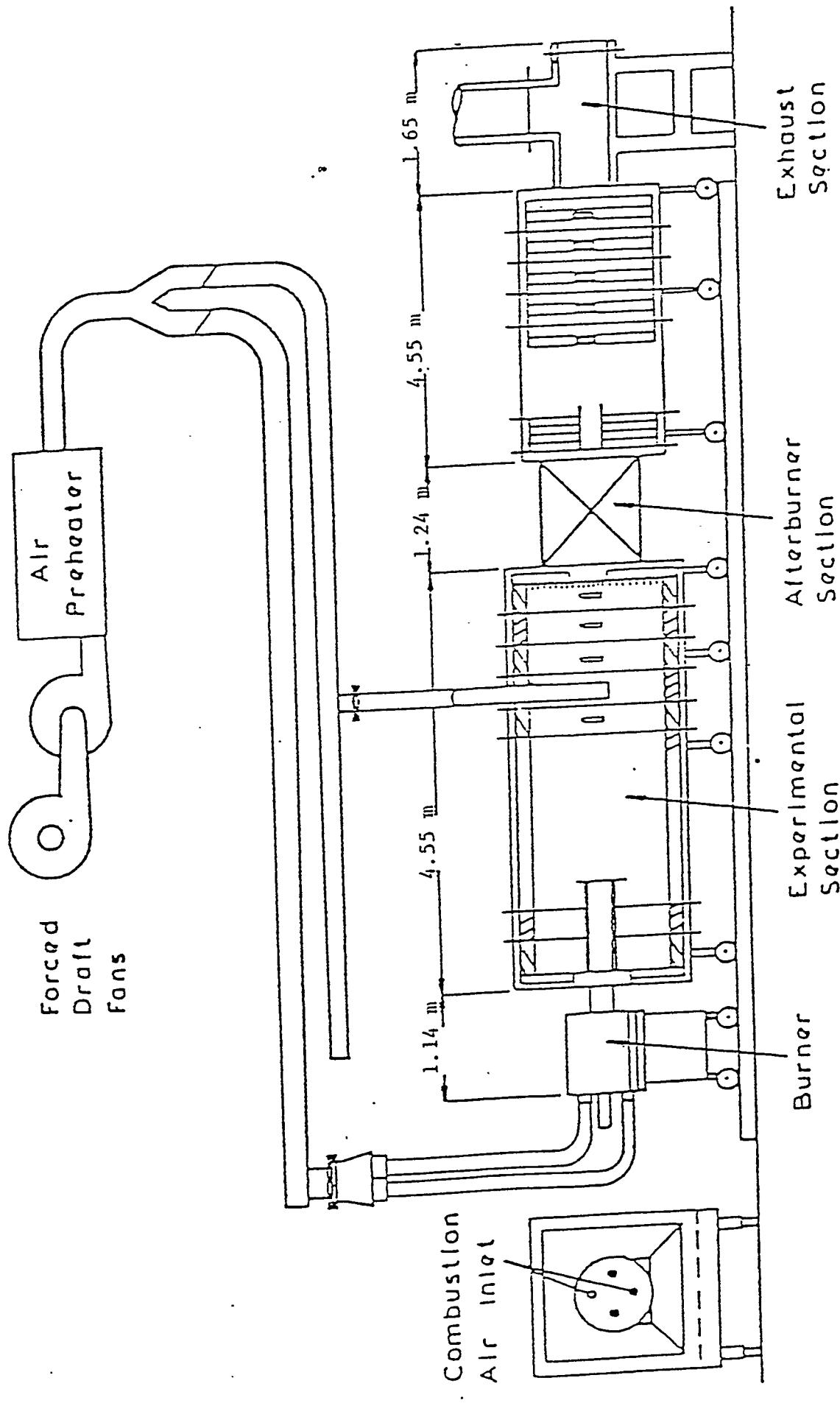
1. Data provided by Florida Power and Light.
2. Analyses carried out by Galbraith Laboratories.

TABLE 6
FUSION TEMPERATURE ANALYSES OF SLAG AND ASH DEPOSITS
(Fuel Type: 50% Florida Power and Light COM)

	<u>Reducing Atmosphere</u>		
	Ash in ¹ Coal	Slag Deposit ² 2m from burner	Ash Deposit ² 4.5m from burner
Initial Deformation	2600F(1427C)	2480F(1360C)	2440F(1338C)
Fusion (Softening) H/W		2540F(1393C)	2520F(1382C)
Fusion (Softening) 1/2 H/W		2560F(1405C)	2550F(1399C)
Fluid Temperature	2800F(1538C)	2620 (1438C)	2620F(1436C)

1. Data provided by Florida Power and Light Co.

2. Analyses carried out by Galbraith Laboratories Inc.



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FIGURE 1. DIAGRAM OF THE MIT COMBUSTION RESEARCH FACILITY

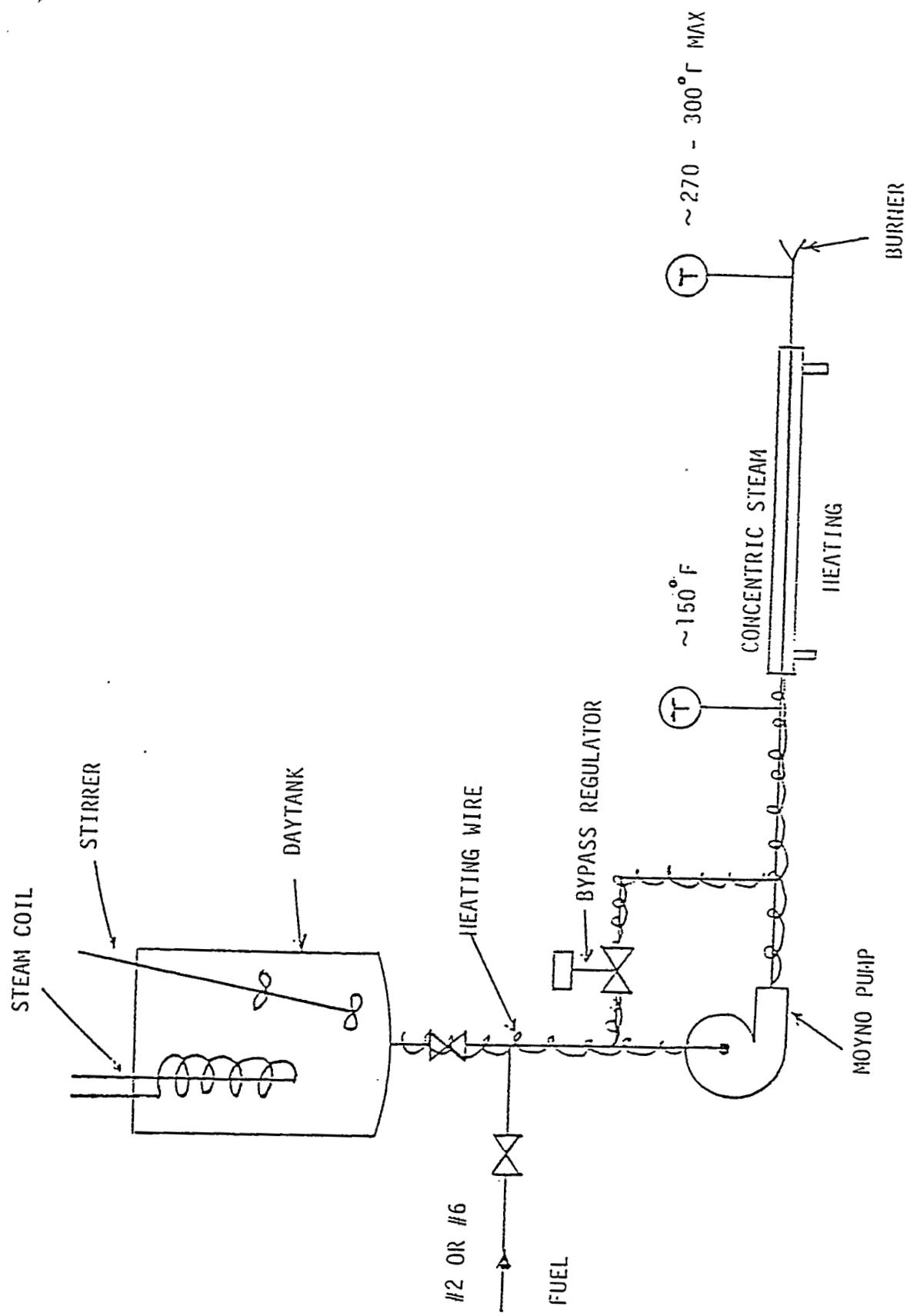
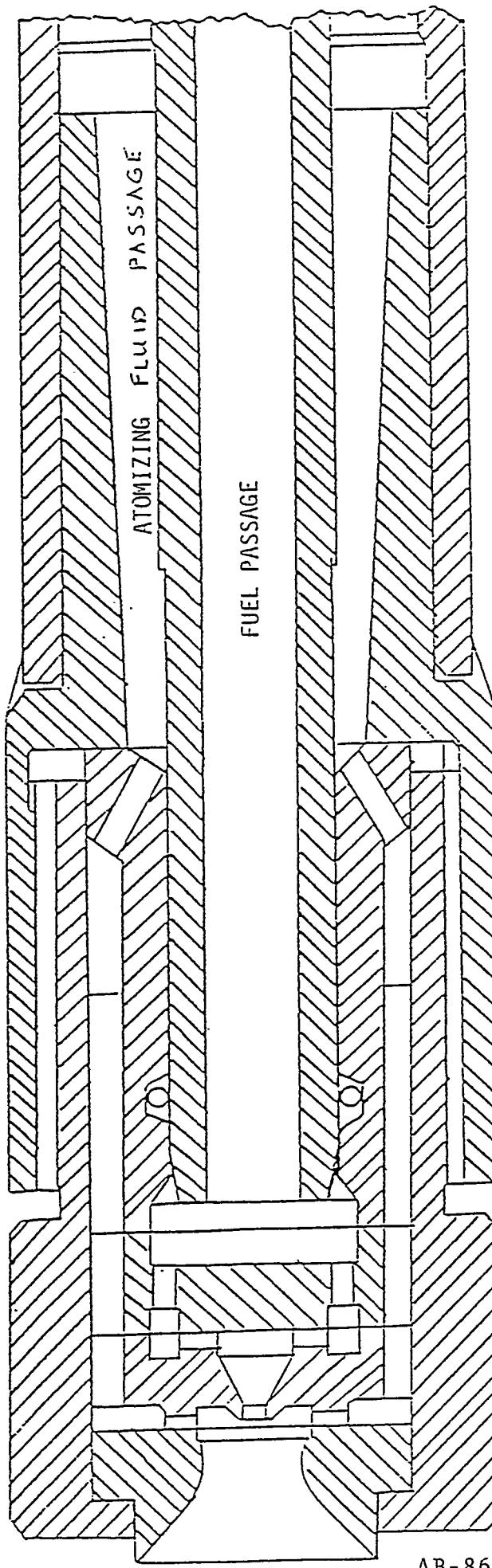


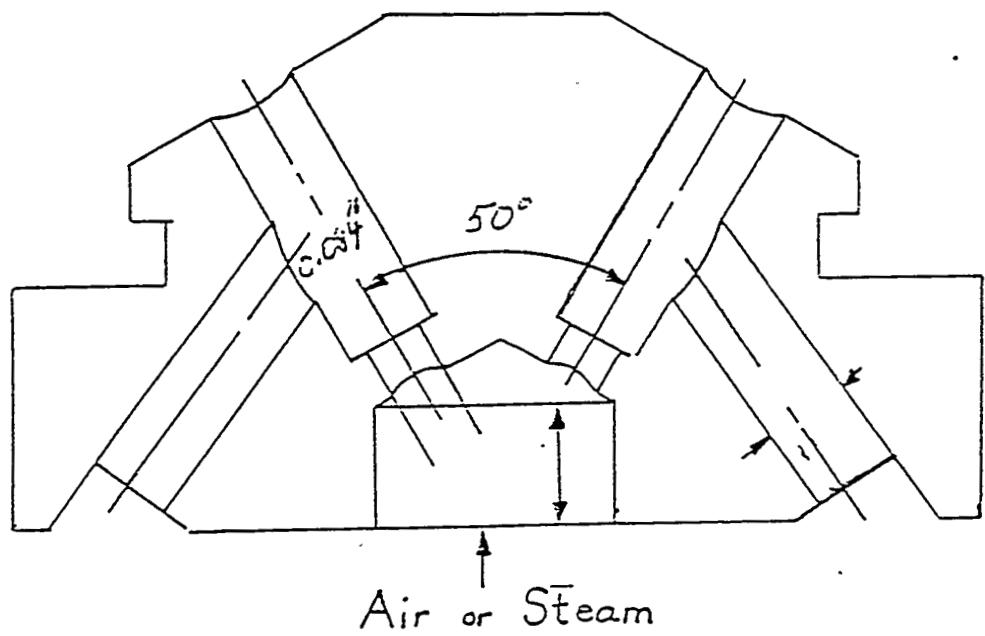
FIGURE 2. THE MIT - CRF COM FUEL DELIVERY SYSTEM



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FIGURE 3. ATOMIZER FOR COAL OIL MIXTURES, ~ 1 MW
(HEI ICL COMBUSTION SYSTEMS)

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MODIFIED Y-JET TYPE ATOMIZER

FIGURE 4. MODIFIED Y-JET TYPE ATOMIZER

TEMPERATURE °C

1600
1500
1400
1300
1200
1100
1000

0.5 1.0 1.5 2.0 2.5 3.0 3.5 4.0

AXIAL DISTANCE FROM THE BURNER IN METERS

XS = 0.53, 40% COLUMBIA CHASE COM (3), ICI NOZZLE, EXCESS AIR ~ 6%

□ S = 0.53, NO. 5 FUEL OIL, SONICORE NOZZLES, EXCESS AIR ~ 10%

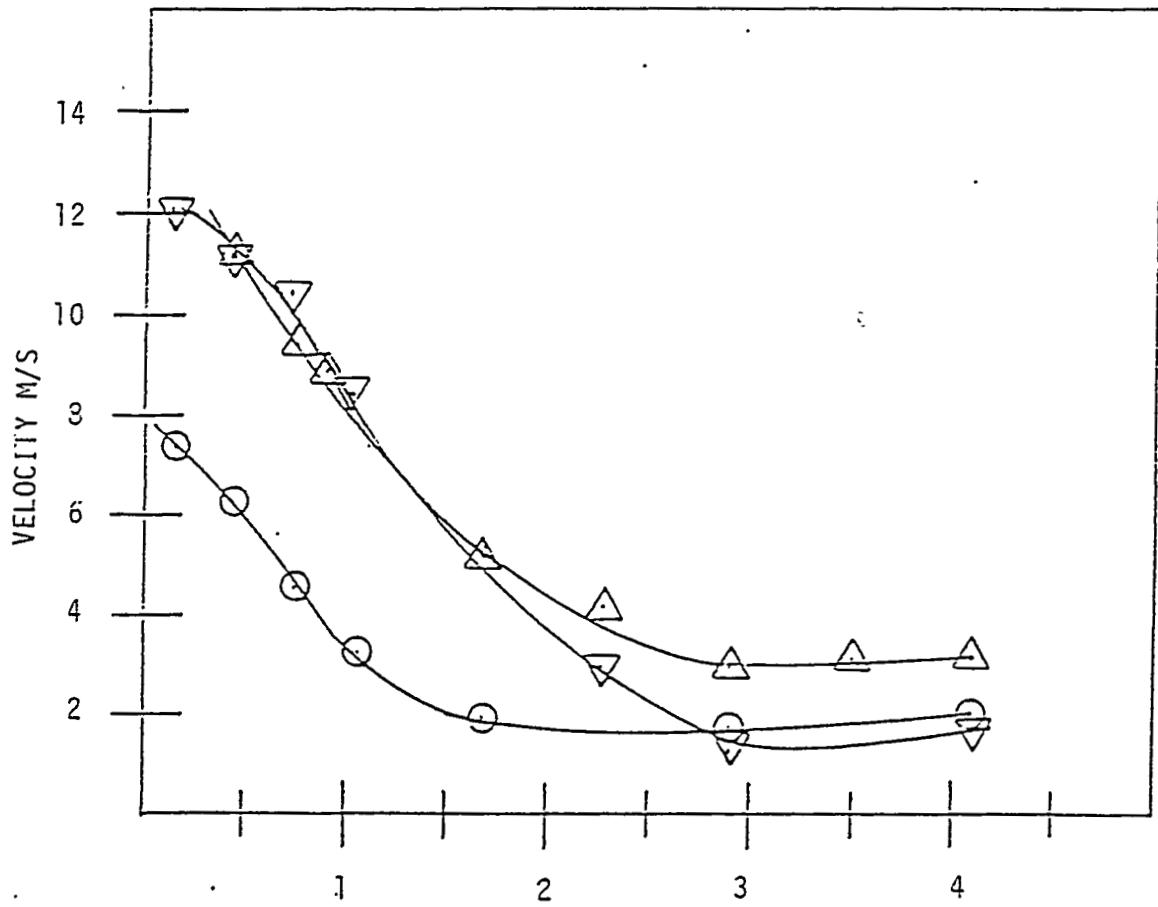
XS = 0.53, SRC II HEAVY DISTILLATE SONICORE NOZZLES, EXCESS AIR ~ 10%

○ S = 0.00, 50% FLORIDA POWER AND LIGHT COM, ICI NOZZLES, EXCESS AIR ~ 10%

△ S = 0.53, 50% FLORIDA POWER AND LIGHT COM, ICI NOZZLES, EXCESS AIR ~ 15%

▽ S = 0.0, 40% COLUMBIA CHASE CORE COM (A), JET NOZZLES, EXCESS AIR ~ 15%

FIGURE 5. AXIAL TEMPERATURE PROFILES (1 MWth INPUT, INLET COMBUSTION AIR TEMP. ~80°F).



AXIAL DISTANCE FROM THE BURNER IN METERS (ALONG THE CENTERLINE)

FIGURE 6. AXIAL VELOCITY PROFILES (1 MWth INPUT, INLET - COMBUSTION AIR TEMP. $\sim 80^{\circ}\text{F}$, EXCESS AIR 15%)

○ $S=0.53$, 50% FLORIDA POWER AND LIGHT COM
ICL NOZZLE

△ $S=0.0$, 50% FLORIDA POWER AND LIGHT COM
ICL NOZZLE

▽ $S=0.0$, 40% COLUMBIA CHASE CQRP. COM (A)
Y - JET NOZZLE

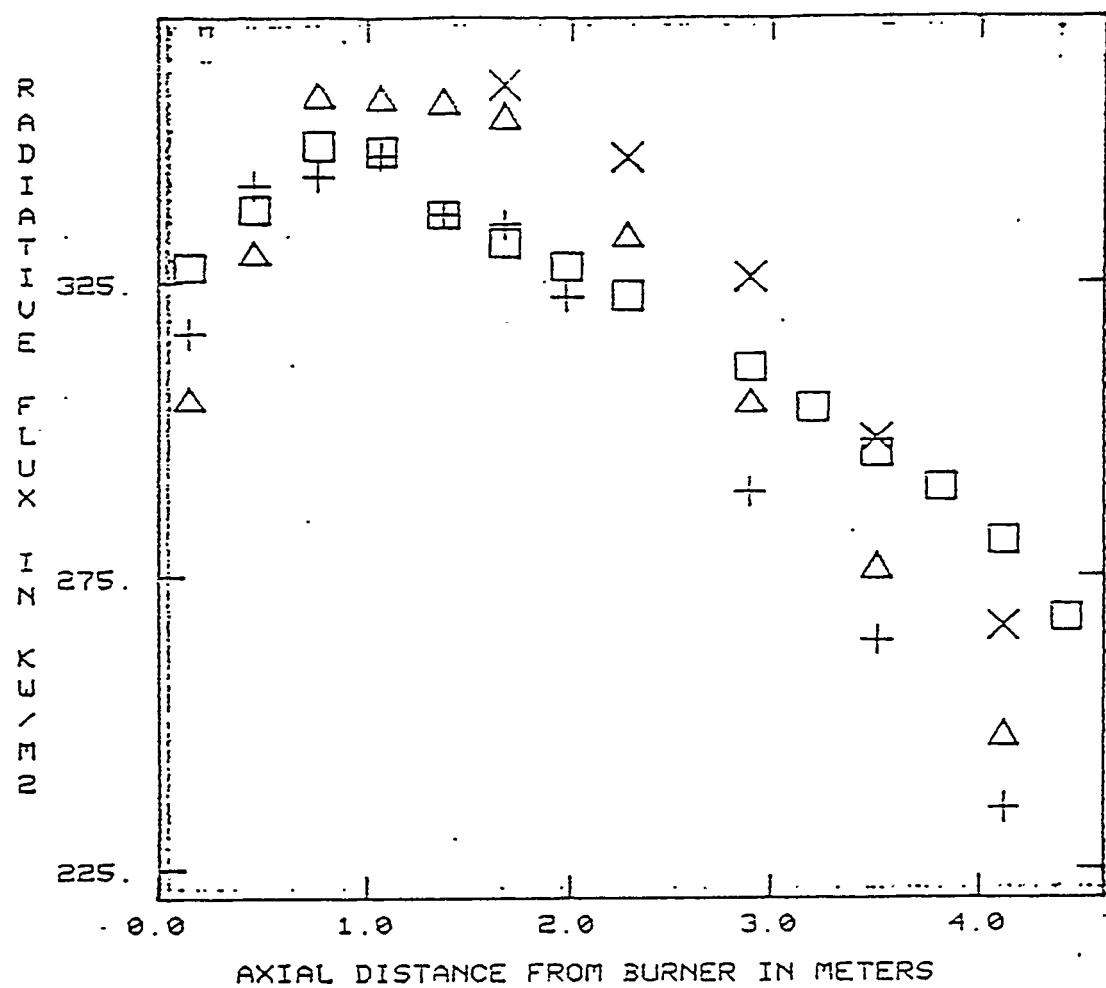


FIGURE 7. AXIAL PROFILES OF RADIATIVE HEAT FLUX TO THE FURNACE WALL

- NO 6 FUEL OIL, 1 MW, $S = 0.53$, $T_{AIR} = 100F$
EXCESS AIR ~10%, SONICORE NOZZLE
- + 50% FPL COM, 1 MW, $S = 0.53$, $T_{AIR} = 80F$
EXCESS AIR ~15%, ICL NOZZLE
- △ 50% FPL COM, 1 MW, $S = 0.0$, $T_{AIR} = 80F$
EXCESS AIR ~15%, ICL NOZZLE
- × 50% FPL COM, 1 MW, $S = 0.0$, $T_{AIR} = 80F$
EXCESS AIR ~15%, Y-JET

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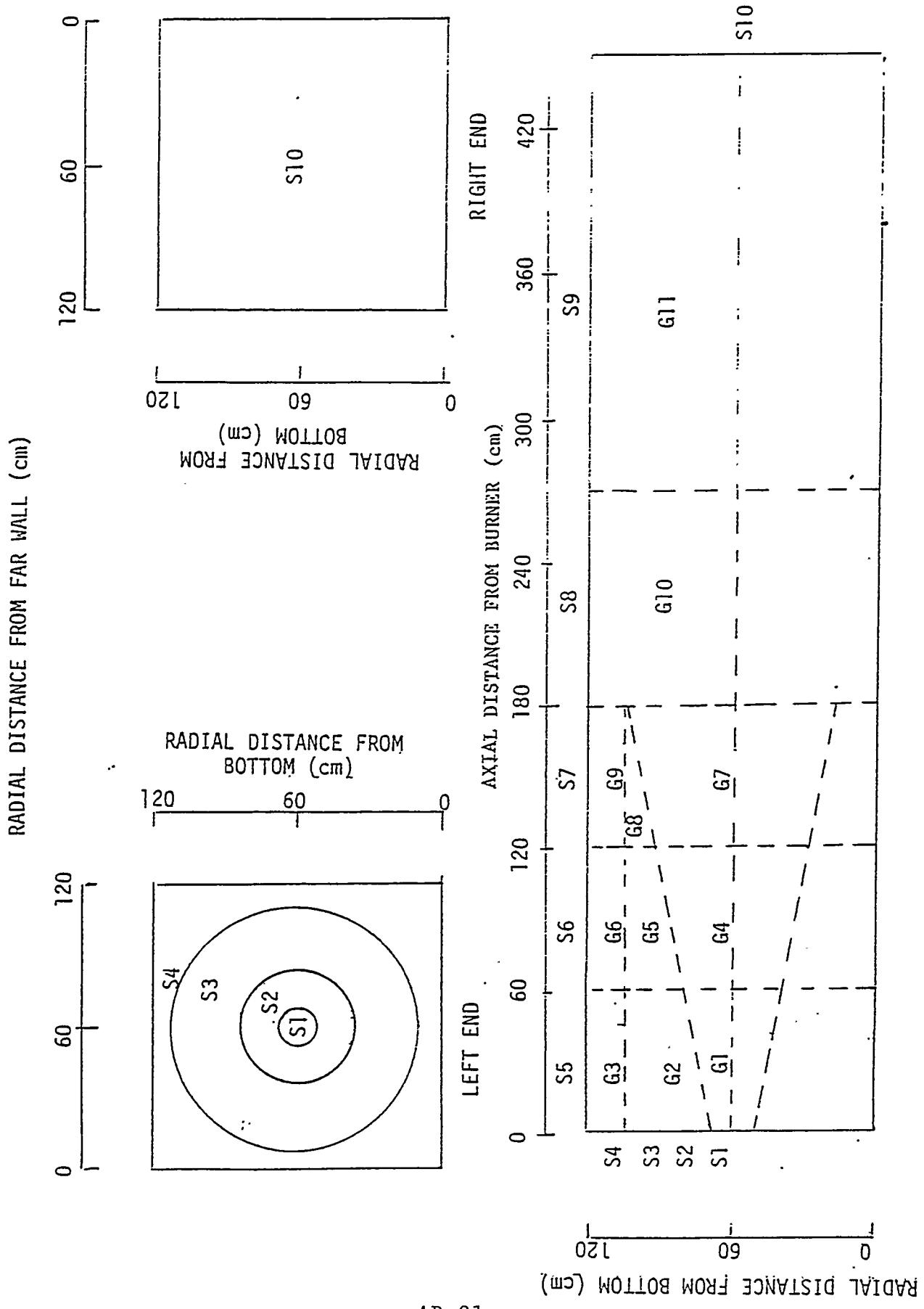
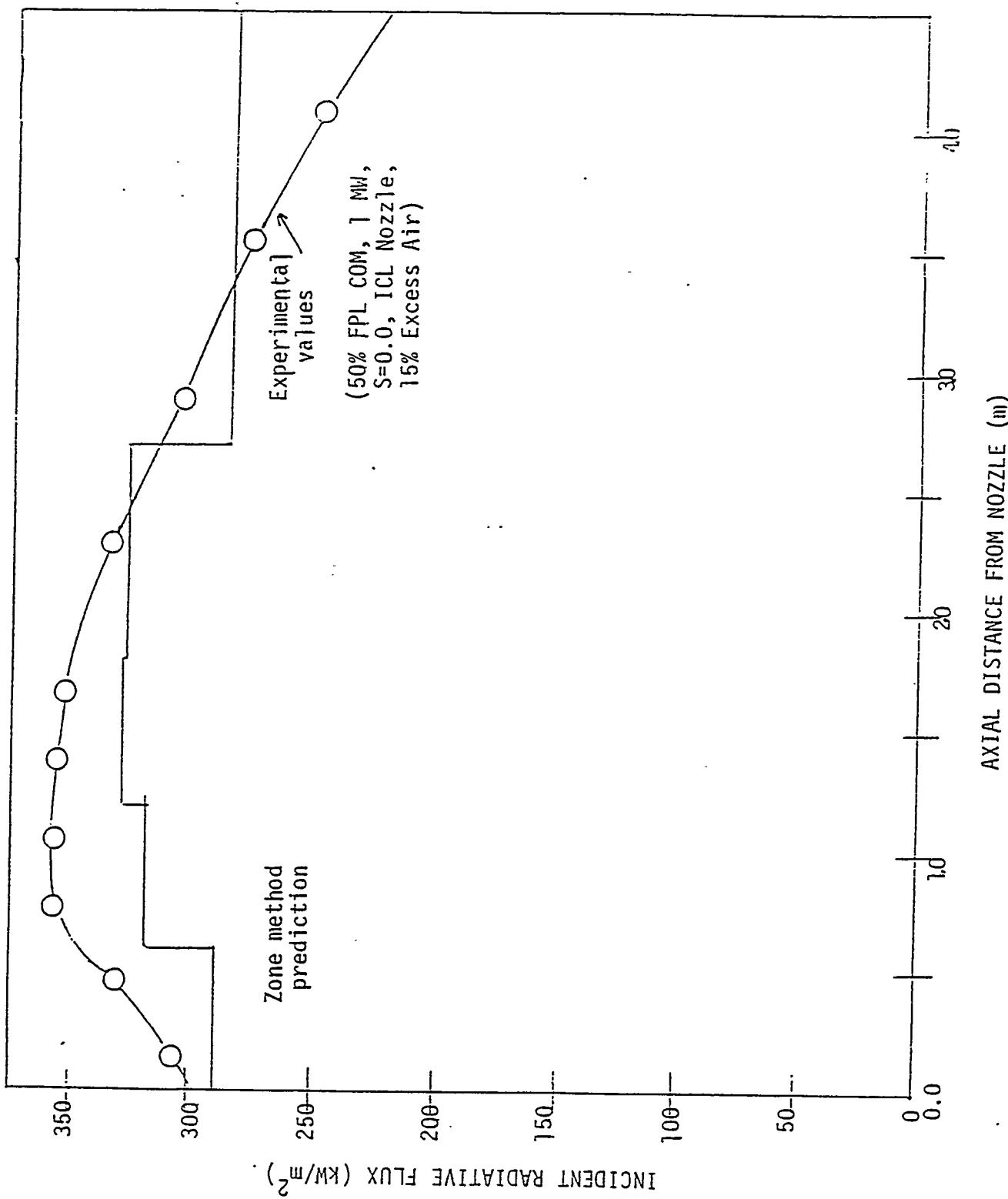


FIGURE 8. ZONING SYSTEM FOR CRF DESIGN USED IN THE MONTE CARLO ZONE METHOD PROGRAM (10 SURFACE ZONES, 11 GAS OR VOLUME ZONES).



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FIGURE 9. MEASURED AND PREDICTED RADIATIVE FLUX DISTRIBUTIONS.

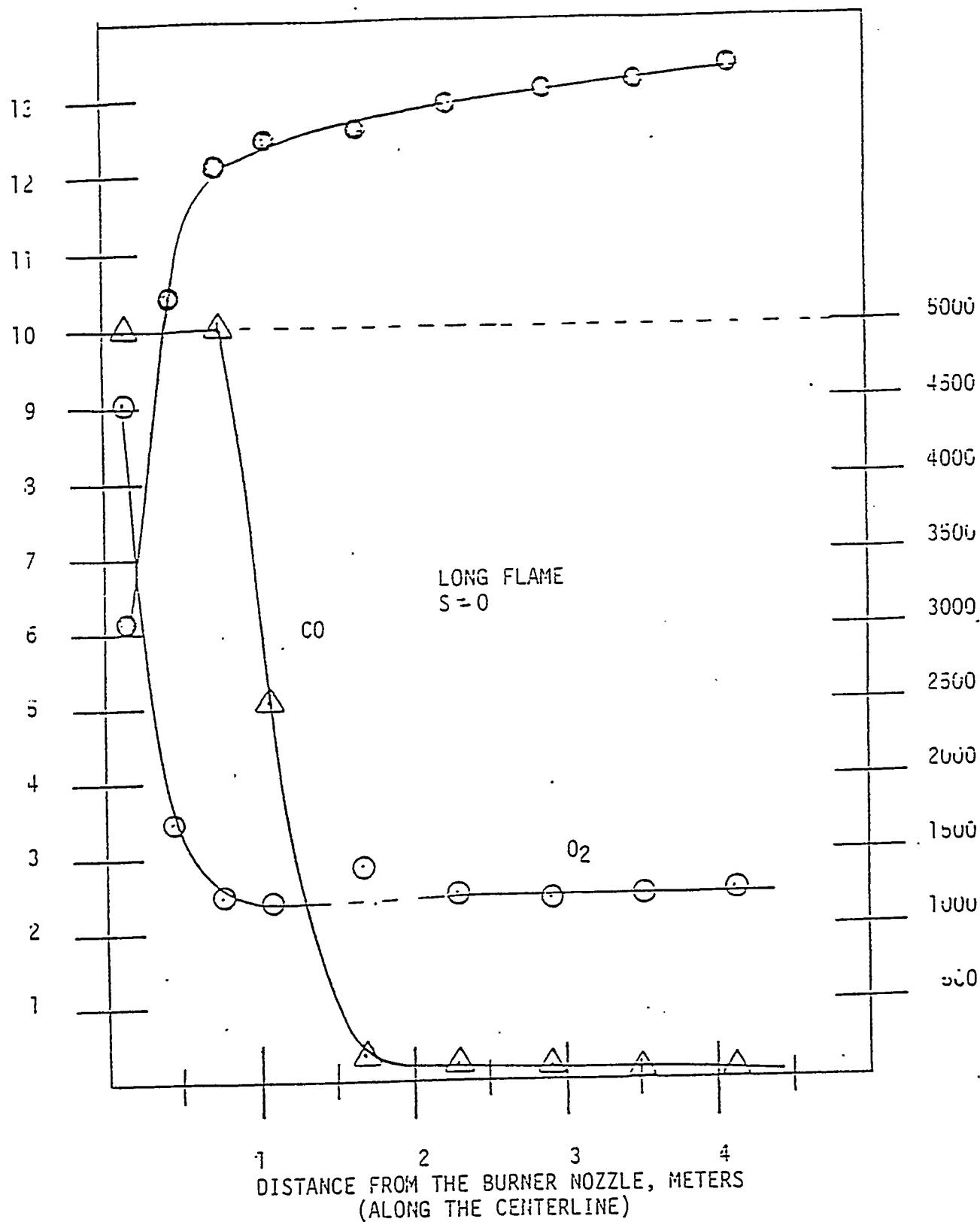


FIGURE 10. AXIAL O_2 , CO_2 AND CO CONCENTRATION PROFILES (50% FLORIDA POWER AND LIGHT CO., 1 MW INPUT, INLET COMBUSTION AIR TEMP $\sim 80^\circ F$)

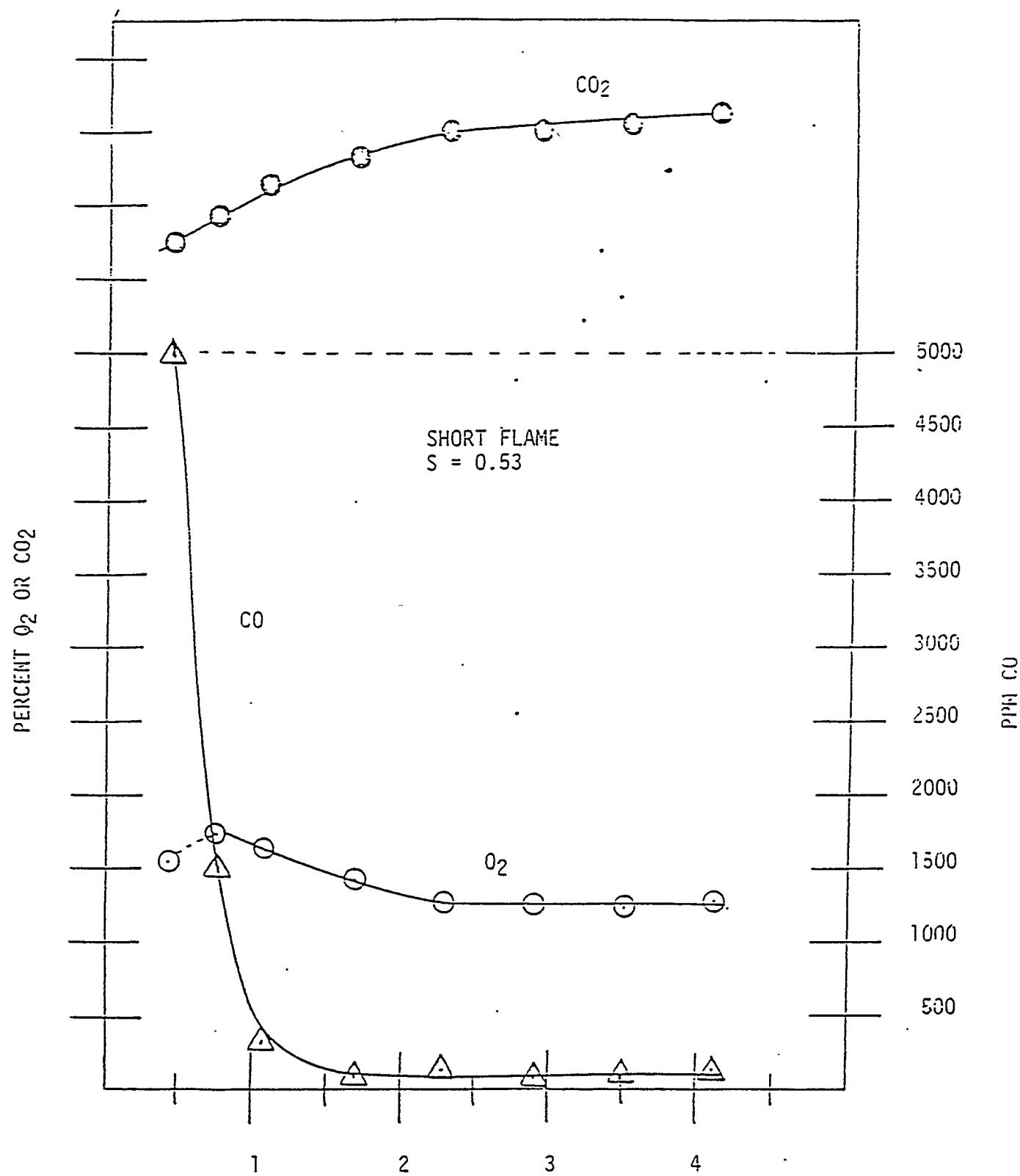


FIGURE 11. AXIAL O₂, CO₂, AND CO CONCENTRATION PROFILES
(50% FLORIDA POWER AND LIGHT CO., 1 MW, ICL NOZZLE,
INLET COMBUSTION AIR TEMP ~80° F)

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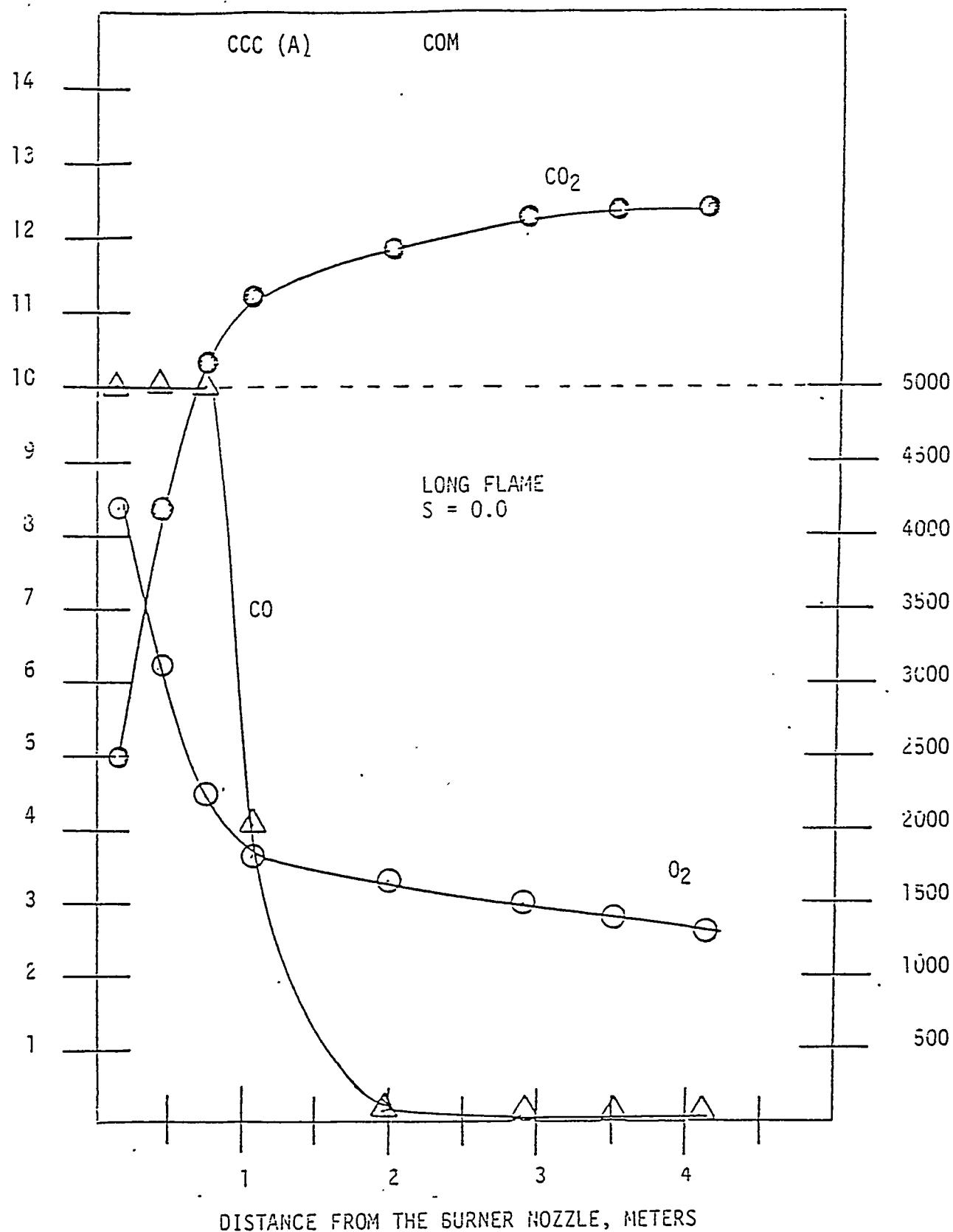


FIGURE 12. AXIAL O_2 , CO_2 AND CO CONCENTRATION PROFILES
(40% COLUMBIA CHASE CORP. COM, Y - JET NOZZLE,
TNI FT COMBUSTION AIR TEMP $\approx 60^{\circ}\text{F}$)

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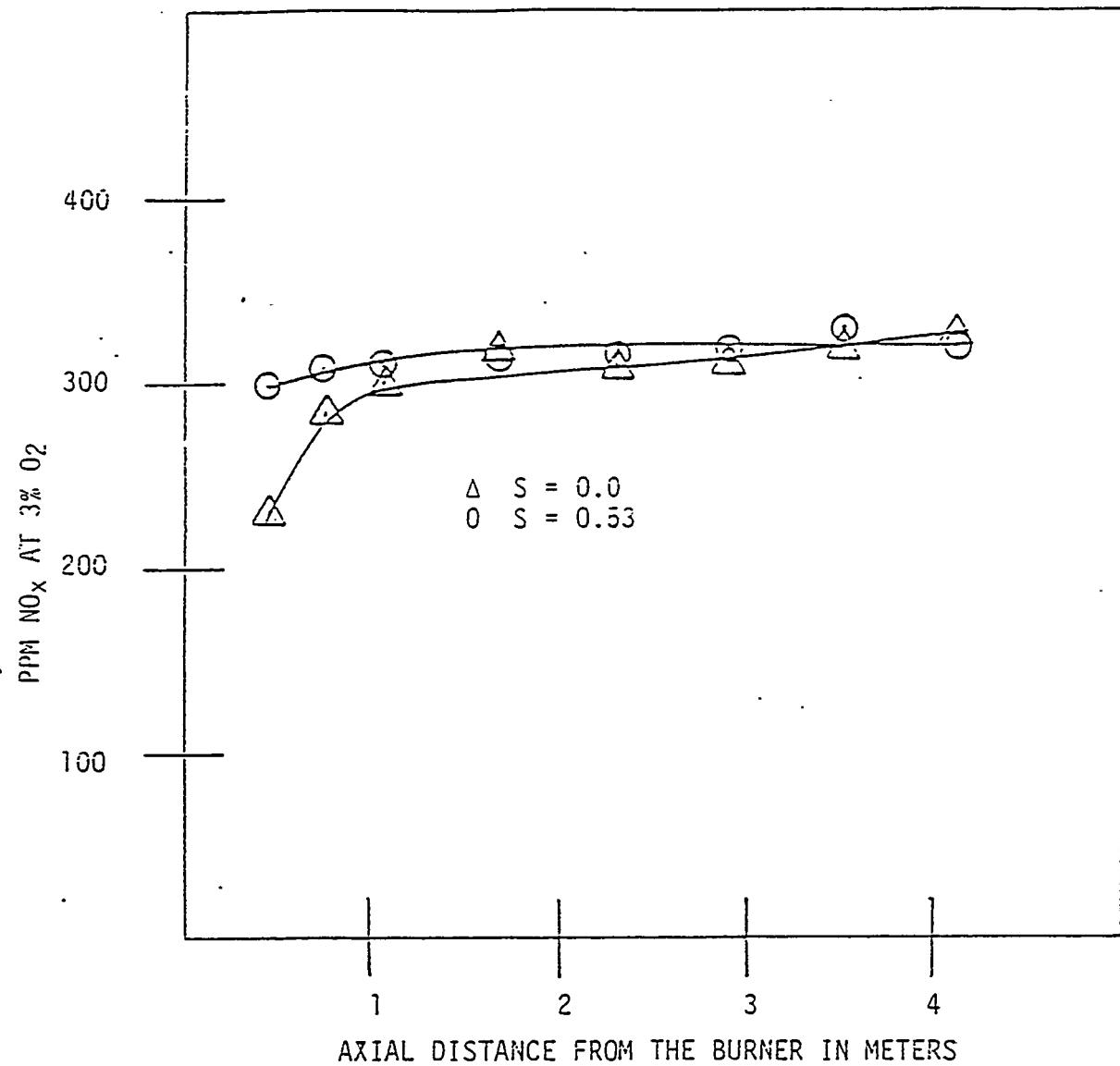


FIGURE 13. AXIAL NO_x CONCENTRATION PROFILES
(50% FLORIDA POWER AND LIGHT COM,
1 MW INPUT, ICL NOZZLE, INLET COM-
BUSTION AIR TEMP. ~80°F, EXCESS
AIR ~15%)

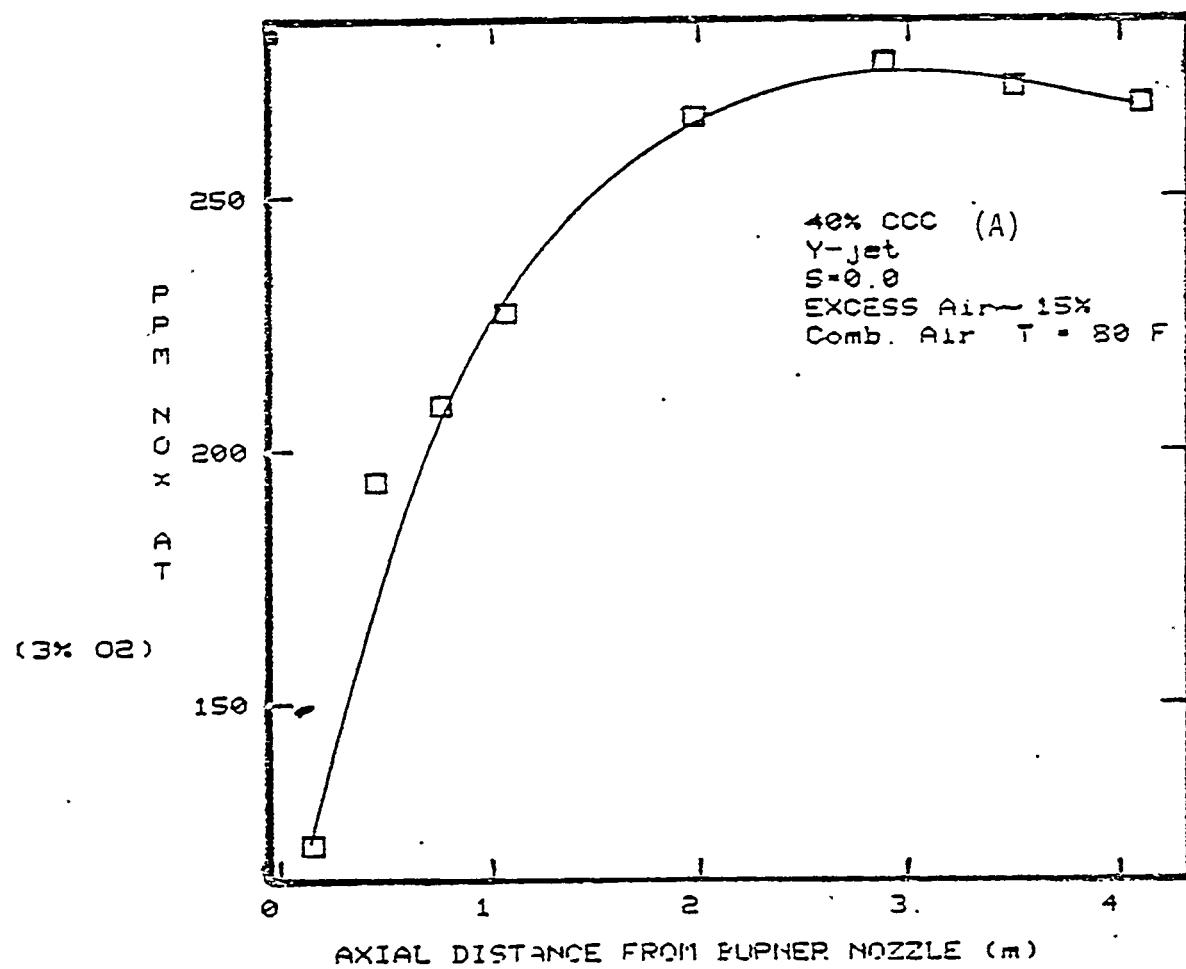


FIGURE 14. AXIAL NO_x CONCENTRATION PROFILE.

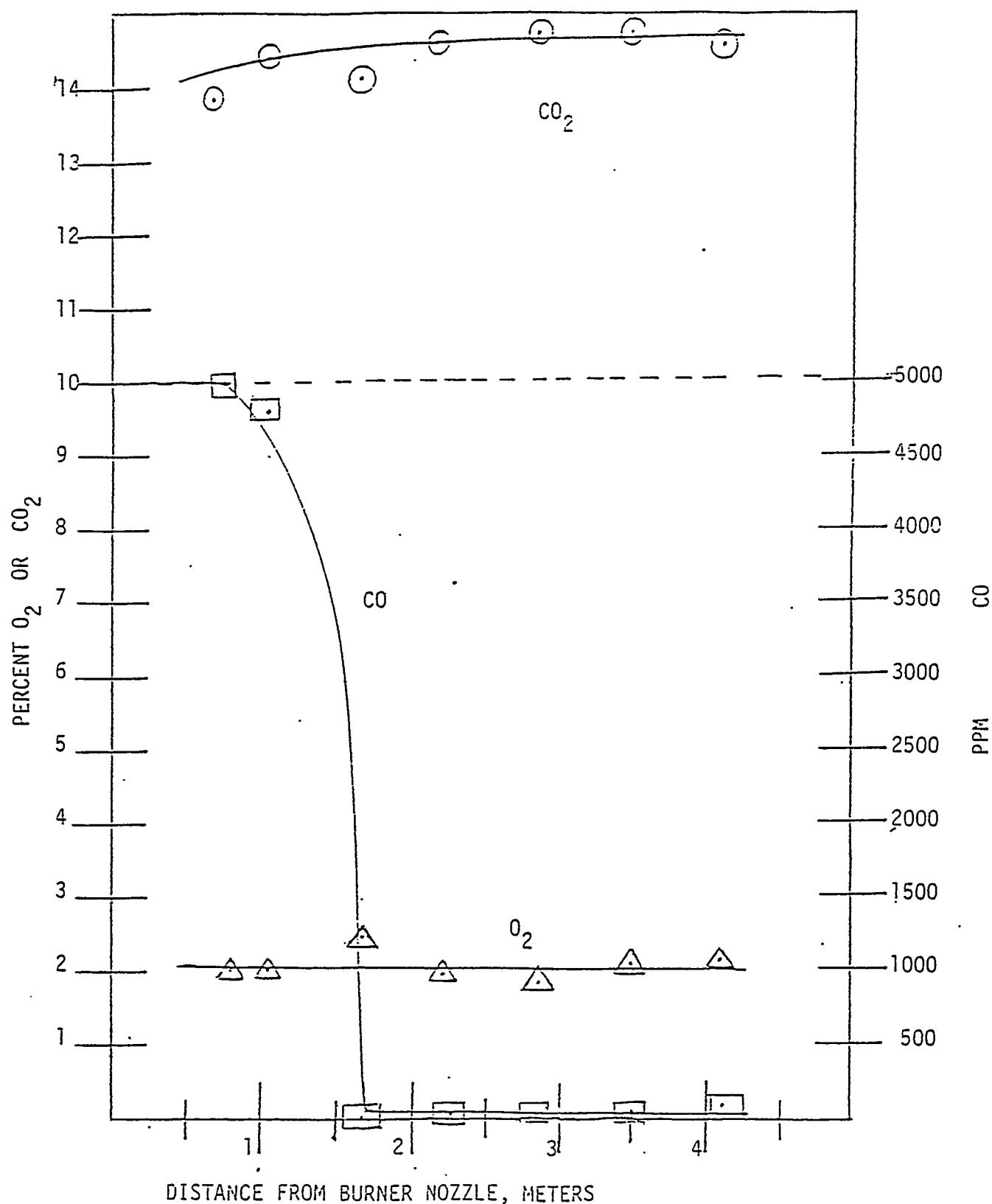


FIGURE 15. AXIAL O_2 , CO_2 and CO CONCENTRATED PROFILES (SRC-II
HEAVY DISTILLATE, 1 MW INPUT, EXCESS AIR ~10%,
SONICORE NOZZLE, INLET COMBUSTION AIR TEMP, 100°F)

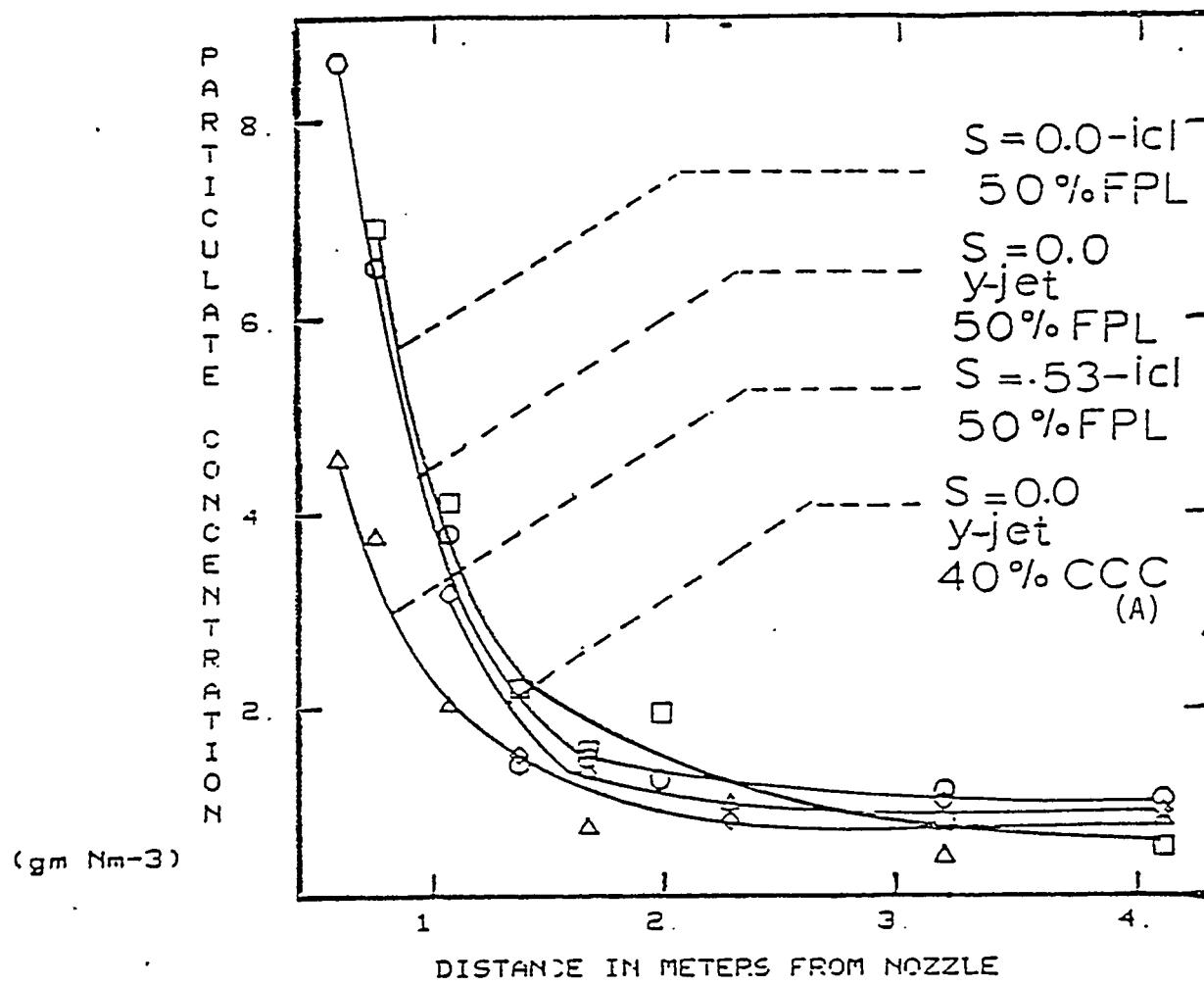


FIGURE 16.

TOTAL PARTICULATES CONCENTRATION
PROFILES ALONG THE FLAME AXIS

(1 MW INPUT, INLET COMBUSTION AIR
TEMP. ~80F, EXCESS AIR ~15%)

CCC = COLUMBIA CHASE CORP. COM

FPL = FLORIDA POWER AND LIGHT CO. COM

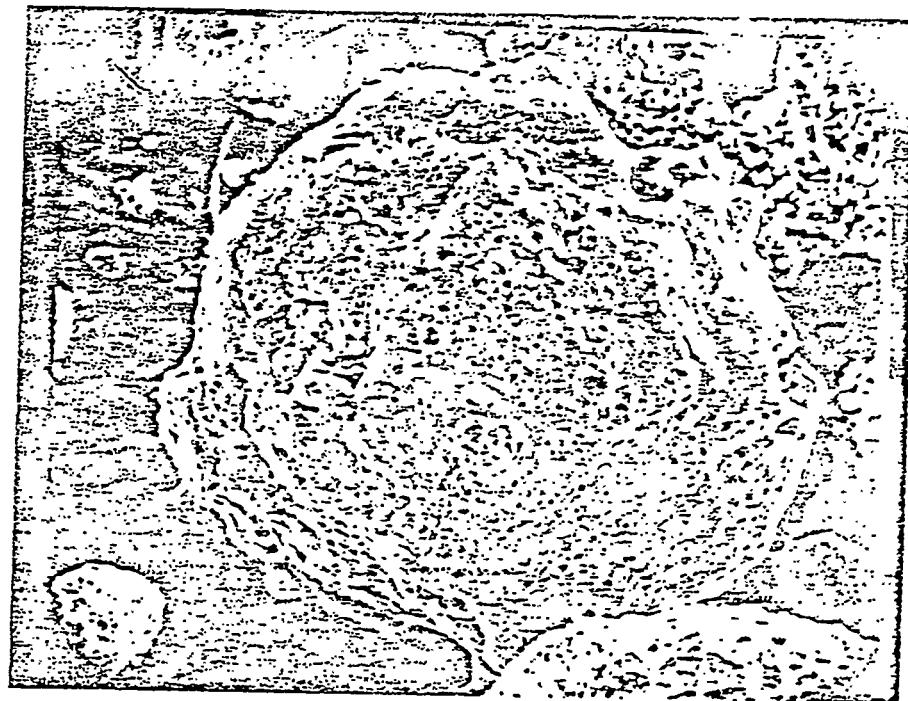


FIGURE 17 CENOSPHERE IN A COM FLAME SOLIDS SAMPLE AS VIEWED WITH A SCANNING ELECTRON MICROSCOPE, BELIEVED TO HAVE ORIGINATED FROM A COAL PARTICLE. APPROXIMATE DIAMETER: 100 μm , DISTANCE FROM BURNER AT WHICH SAMPLE WAS TAKEN: 1.07m, MAGNIFICATION: x400. (50% FLORIDA POWER AND LIGHT COM, $S = 0.53$, ICL NOZZLE, EXCESS AIR ~15%, 1 MW INPUT)



FIGURE 18

CENOSPHERES IN A COM FLAME SOLIDS SAMPLE AS VIEWED WITH A SCANNING ELECTRON MICROSCOPE, BELIEVED TO HAVE ORIGINATED FROM COAL PARTICLES. APPROXIMATE DIAMETER: 50-100 μm , DISTANCE FROM BURNER: 0.76 m, MAGNIFICATION: . x 200)



(a)

FIGURE 19 CENOSPHERES IN A COM FLAME SOLIDS SAMPLE AS
VIEWED WITH A SCANNING ELECTRON MICROSCOPE,
BELIEVED TO HAVE ORIGINATED FROM COAL PARTICLES.
APPROXIMATE DIAMETER: 50-100 μm , DISTANCE FROM
BURNER 1.07m, MAGNIFICATION x 200)

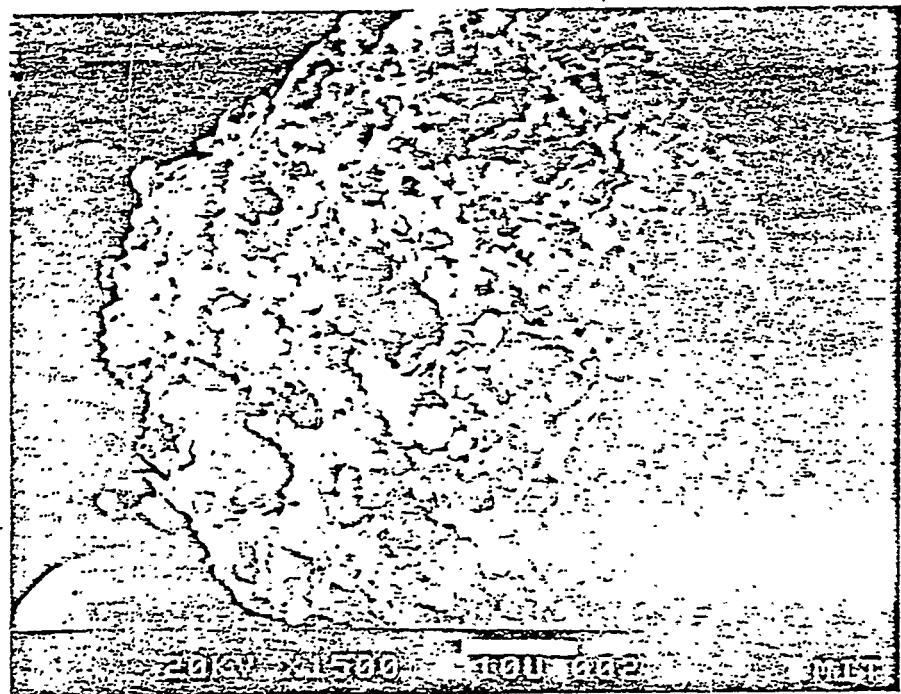


FIGURE 20 CENOSPHERE IN A COM FLAME SOLIDS SAMPLE AS
VIEWED WITH A SCANNING ELECTRON MICROSCOPE,
BELIEVED TO HAVE ORIGINATED FROM A COAL
PARTICLE. DISTANCE FROM BURNER: 1.67m,
DIAMETER AND MAGNIFICATION GIVEN IN PHOTOGRAPH

AB-103

Beer

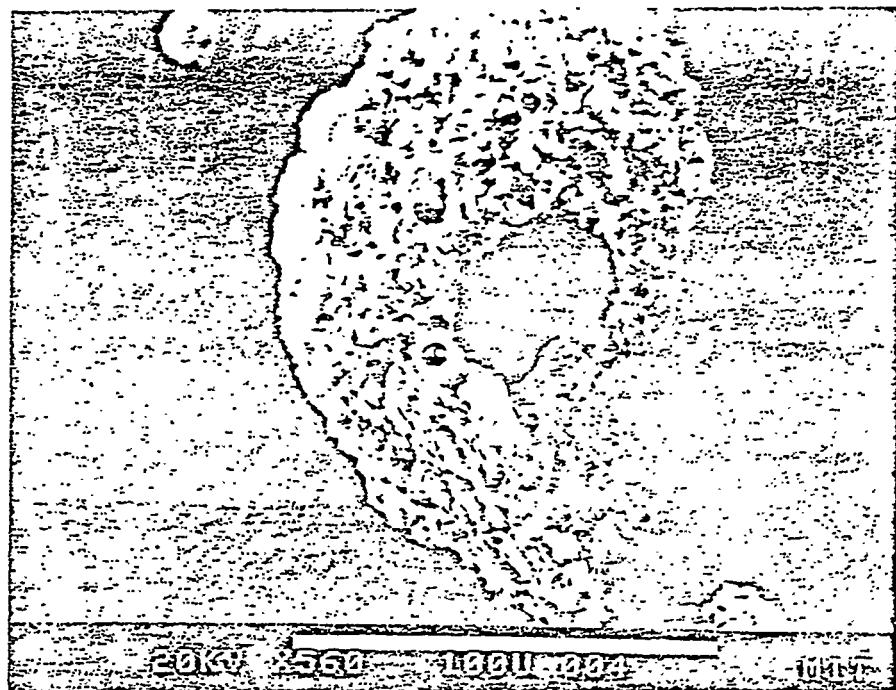


FIGURE 21

CENOSPHERE IN A COM FLAME SOLIDS SAMPLE AS
VIEWED WITH A SCANNING ELECTRON MICROSCOPE,
BELIEVED TO HAVE ORIGINATED FROM A COAL
PARTICLE. DISTANCE FROM BURNER 1.67m.

AB-104

Beer



FIGURE 22

ASH CENOSPHERES IN A COM FLAME SOLIDS SAMPLE
(SCANNING ELECTRON MICROSCOPE). DISTANCE FROM
BURNER AT WHICH SAMPLE WAS TAKEN: 4.11 m.
(50% FLORIDA POWER AND LIGHT COM, $S = 0.53$, ICL
NOZZLE, EXCESS AIR $\sim 15\%$, 1 MW INPUT)

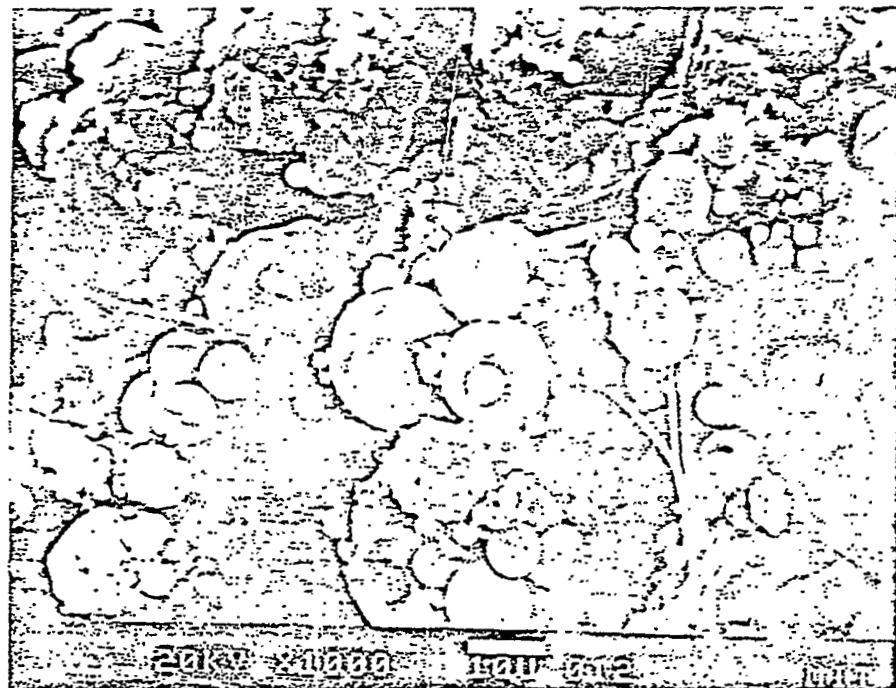


FIGURE 23

ASH CENOSPHERES IN A COM FLAME SOLIDS SAMPLE
(SCANNING ELECTRON MICROSCOPE). DISTANCE FROM
BURNER AT WHICH SAMPLE WAS TAKEN: 4.11 m. (50%
FLORIDA POWER AND LIGHT COM, $S = 0.53$, ICL
NOZZLE, EXCESS AIR ~15%, 1 MW INPUT)

CCAWG MEETING AT COMBUSTION ENGINEERING (CE),
WINDSOR, CONNECTICUT
(June 23, 1982)

The following members of CCAWG participated: J. M. Beér, C. R. Bozzuto, A. K. Oppenheim, S. S. Penner, L. D. Smoot, R. E. Sommerlad, C. L. Wagoner, and I. Wender; DOE/Washington was represented by J. F. Kaufmann. The agenda is shown in Table 1. Following an overview of work at CE and inspection of CE facilities (C. R. Bozzuto), the following topics were emphasized: ash formation and fouling in the direct utilization of low-rank (M. Jones, GFERC) and of bituminous (R. Bryers, Foster-Wheeler Corp.) coals and explosions and fires in coal handling (M. Hertzberg, Bureau of Mines, Pittsburgh). L. D. Smoot presented an introduction to environmental studies and concerns, which will be discussed in greater detail during the July meeting of CCAWG at METC.

The presentation by C. R. Bozzuto (CE) included brief mention of (now terminated) studies on coal gasification (5 tons of coal per hour), work on a sub-scale fluidized bed boiler producing 2000 lbs of steam per hour and on a prototype boiler (Great Lakes Station) producing 50,000 lbs of steam per hour, various SO₂ removal systems, flow-model facilities for scrubbers, and an EPRI-funded program on atomization and utilization of coal-water mixtures. The utility of experimental, cold-flow modeling in preference to numerical studies for multi-phase flows was emphasized.

A. Fouling and Slagging

M. L. Jones (GFERC) discussed direct, low-rank, pulverized coal combustion and emphasized the serious problems encountered with slagging and fouling. Depending on the coal used, highly alkaline ash adhering to walls (e.g., with North Dakota lignites

Table 1. Coal combustion and application working group meeting agenda (June 23, 1982).

9:00 - 9:15	Getting Organized	
9:15 - 9:30	Introduction	C. R. Bozzuto (Combustion Engineering, CE)
9:30 - 11:00	Tour of Facilities	
11:00 - 12:00	Utilization of Low-Rank Coals	M. Jones (Grand Forks Energy Technology Center, GFERC)
12:00 - 1:00	Lunch	
1:00 - 2:00	Ash Formation and Fouling	R. W. Bryers (Foster-Wheeler Corp., FW)
2:00 - 2:45	Environmental Concerns	D. Smoot (Brigham Young University, BYU)
2:45 - 5:30	Explosions and Fires	M. Hertzberg (U.S. Bureau of Mines, Pittsburgh, BMI)

or subbituminous coals) or ash with high SiO_2 contents (e.g., with Gulf lignites) are produced. Low-rank coals contain substantial amounts of moisture (30 to 45% in lignites and 10 to 25% in subbituminous coals), are non-caking, have relatively low heating values ($\sim 6,500 \text{ Btu/lb}$) and sulfur contents ($\sim 0.6\%$ for subbituminous coals, $\sim 1.0\%$ for lignites), produce highly variable alkaline ash, and have relatively high organic oxygen contents. The benefits of chemical additives (e.g. limestones or dolomites) and of physical control agents (e.g., vermiculite) in reducing ash fouling are under investigation; about 1 to 1.5% of the total fuel flow rate is typically added as limestone. Representative performance studies on a 220 MW_e , wall-fired, utility boiler with low-rank coals showing 6-8% of Na in the ash allowed full-load operation for only about two weeks, whereas about one year of operation is anticipated with the use of limestone at full load. It is known that substantial boiler derating and the use of low peak temperatures ($\gtrsim 1000^\circ\text{C}$) will reduce slagging. Experimental studies are in progress (e.g., at Foster-Wheeler) to determine temperature levels below which fouling and slagging are substantially reduced. Critical issues relate to ash-deposition rates and deposit-tenacity correlations, which have been investigated for low-ash Montana subbituminous coal and high-Na lignite from Australia. A major data collection and consolidation effort has been initiated and will include data from laboratory, pilot and field studies. The cost to utilities from fouling and slagging has been estimated to be $\sim \$8 \times 10^6/\text{yr}$ in the operation of a 500 MW_e facility. For low-rank coals, fundamental data are needed on (a) reactions of inorganic species in flames, (b) coal dust-air combustion in laminar and turbulent flames, (c) determinations of alkali metals in samples of particulates, (d) chemical analyses of fouling deposits. Research recommendations derived from a recent workshop have been classified as "highest priority" (see Table 2) and "lower priority" (see Table 3).

Table 2. GFERC research recommendations on low-rank coals (LRC) of "highest priority."

A. Basic Research

From LRC Studies	From Workshop on Basic Coal Science
Classification of standard low-rank coal samples; reactions between alkali materials and sulfur; compositions and characteristics of ashes and slags from low-rank coals and peats.	Methods for the determination of macerals (petrographic characterization); standard low-rank coal samples; organic structure of low rank coals; distribution of inorganics; devolatilization reactions; moisture determinations.

B. Combustion Research

Ash fouling and slagging mechanisms; control of fouling and slagging with additives; direct ignition of pulverized coal without oil; determination of the thermal properties (emissivities and absorptivities) of ash at high temperatures; determination of the form and distribution of inorganic constituents; sulfur retention on ash as a function of ash composition and operating parameters, including combustion modifications for low NO_x; on-line measurements of fouling and slagging (full-scale and pilot units) and correlation with fuel characteristics and operating parameters; mechanisms of ash fouling; evaluation and use of additives to reduce fouling and slagging; corrosion rates for low-rank coals as a function of ash composition, metal temperature, and metal type.

Table 3. GFERC research recommendations on LRC of "lower priority."

A. Basic Research

From LRC Studies	From Workshop on Basic Coal Sciences
Surface characteristics of low-rank coals and peat fines; kinetics and reaction mechanics of LRC and their chars with H_2O , H_2 , CO , and CO_2 .	Within-seam variability of mineral distribution; surface characteristics and properties; high-temperature oxidation.

B. Combustion Research

Improved boiler cleaning procedures; temperature limitations vs. boiler corrosion; improved stoker furnace for small-scale applications; devolatilization and carbon burnout characteristics and the effect of burner/furnace modifications for NO_x control; probe testing of burners on full-scale boilers to provide input data for furnaces; assessment of fouling and slagging leading to improved guidelines for preparing boiler specifications; a 1-5 TPH, PC-fired test facility to study fouling and slagging at larger scale than in the present pilot units; effects on boiler tubes of using water blowers to clean low-rank coal boilers and determine factors controlling blower effectiveness; fluidized-bed combustion; low-rank coal/water slurry combustion and low-rank coal/oil slurry combustion; improvements in cyclone firing of LRC; effective SO_x/NO_x and particulate controls for smaller industrial stokers operating on LRC; development of more reliable flame scanners, more reliable instruments to measure furnace flue gas temperatures, and cheaper and more reliable, continuous SO_2 analyzers.

R. Bryers (FW) presented a comprehensive overview of information derived on fouling and slagging from pilot and full-scale units and correlations with predictive indices in conventionally-fired steam generators. This presentation is reproduced in full in Table 4. Particularly noteworthy are the interesting observed differences between elementary compositions of coals and corresponding slag samples. While a wealth of empirical information has been collected and control measures are necessarily implemented when slagging and fouling require remedial measures in operating boilers, fundamental understanding is limited with regard to each of the following basic problems: (a) the relation between measures taken for coal beneficiation and slagging and fouling, (b) the extent to which deleterious depositions can be controlled by aerodynamic measures, (c) the quantitative relations between coal mineral contents and the physicochemical processes that lead to slagging and fouling, (d) the roles of ash loadings and particle-size distributions in deposit formations, (e) the mechanisms involved in selective depositions of minerals, (f) predictions and verifications of deposit compositions and their spacial variations, (g) the nature of the aging processes of the deposited materials, (h) the phase behavior and phase changes of deposits with temperature variations, (i) the strengths and durabilities of deposits and their stabilities to soot blowing and removal attempts.

While the costs and penalties associated with the production of fireside deposits are being evaluated, an adequate and well integrated fundamental research program remains to be developed. Fundamental studies on ash deposits and corrosion should be performed, even though the demonstrable connection between these studies and control in large boilers remains to be made. The members of CCAWG judge the currently funded efforts on fundamental studies in these fields to be inadequate in view of the economic importance of reliable performance of (large) boilers to utilities and industrial users all over the world.

Table 4. The viewgraphs shown by R.W. Bryers (Foster Wheeler Corp.) in his discussion of slagging and fouling.

All the prediction indices are based on composite coal ash. None of the indices take into account:

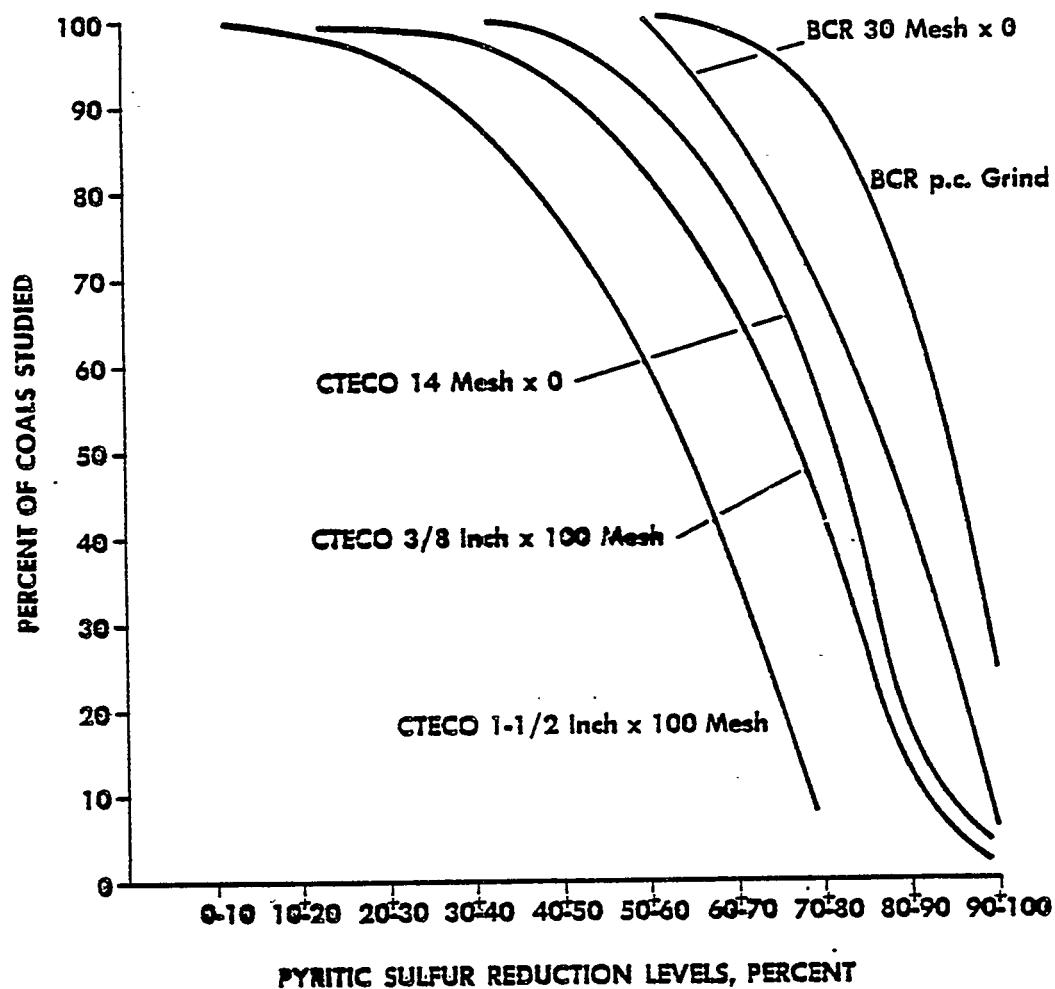
- The heterogeneity of the coal ash by size and gravity
- The relationship of mineral forms to each other and the variation in mineral composition with coals
- The effects of ash loading on deposit formation
- The relationship of mass transport mechanism on deposit formation
- Selective deposition within the steam generator
- Variation in composition of the deposit as it is laid down on the tube surface and aged with time
- The impact of the chemistry on operating variables and design variables other than the furnace exit temperature
- Only a modest effort has been directed at identifying minor melts formed below the detectable limits associated with ash fusion cones. Such minor melts can be responsible for initial sticking of ash which precludes the massive build-up
- Sintering strength on deposit removal by soot blowing.

Pitfalls still remain in analyzing the true concentration levels of certain elements. The reliability of predicting quantitatively the minerals present is uncertain. Real time measurement of ash composition permitting better diagnosing of problems and better quality control of the fuel are just beginning to receive attention.

Modeling the behavior of ash in the furnace in terms of its fusibility and time/temperature history has received little attention.

Little attention has been paid to the economics of fireside deposits or the impact of beneficiation and its cost on fireside deposits.

Table 4, continued



Bituminous Coal Research, Inc. 6070G12

**Pyritic Sulfur Reduction at 1.60 Specific Gravity as
Related to Nominal Topsize of Coal**

Table 4, continued

Comparison of Coal Ash and Slag Deposit Formed
From a South African Coal

<u>Elemental Analysis</u>	<u>Coal</u>	<u>Slag</u>
SiO ₂	48.4	46.4
Al ₂ O ₃	25.2	27.8
TiO ₂	1.5	1.7
Fe ₂ O ₃	1.8	4.1
CaO	14.2	12.2
MgO	2.1	2.4
Na ₂ O	3.2	1.9
K ₂ O	0.5	0.5
SO ₃	4.6	<0.1
P ₂ O ₅	0.7	0.8

Table 4, continued

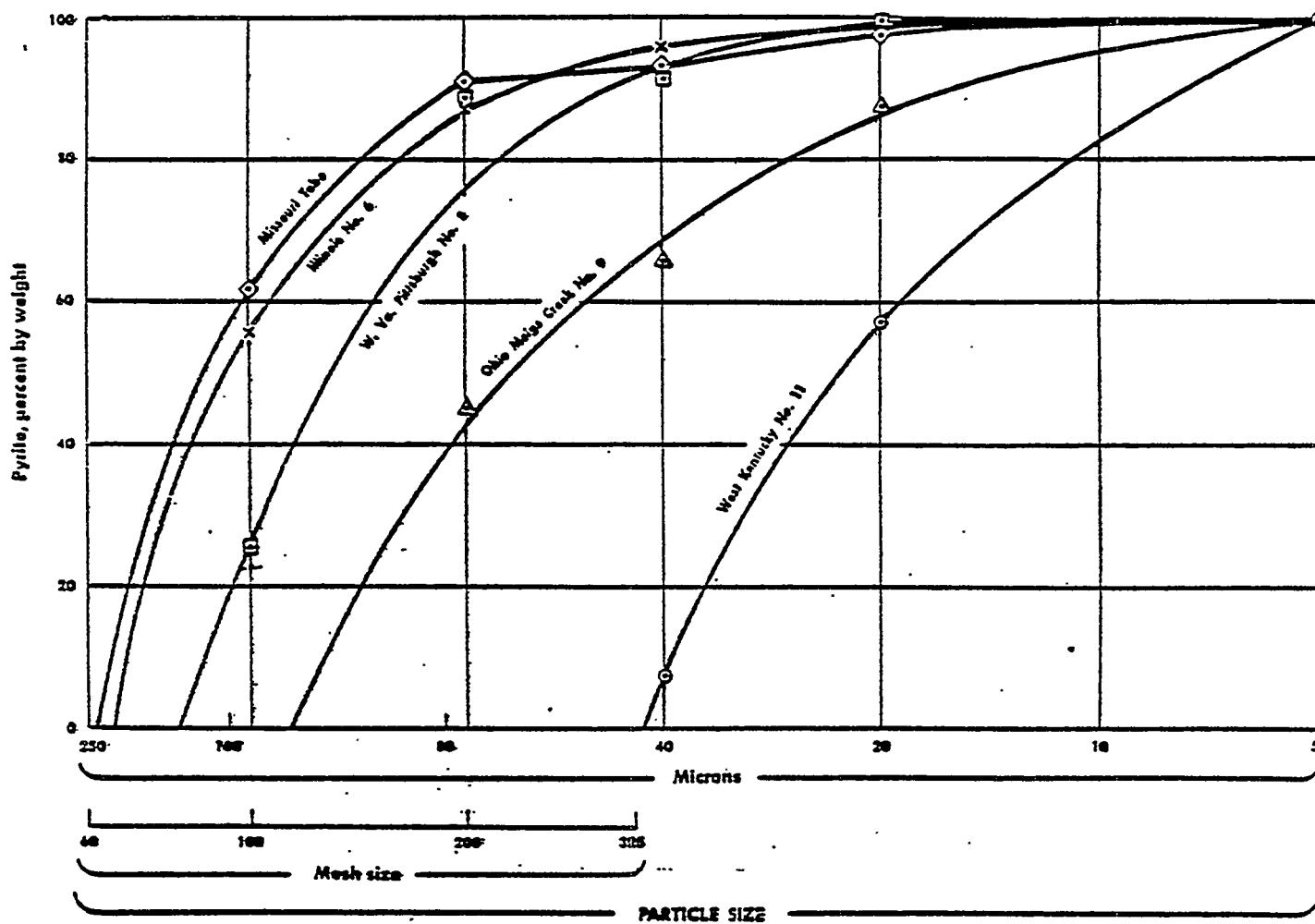


Table 4, continued

ASH SOFTENING TEMPERATURE ($H=1/2W$)
REDUCING ATM. °F

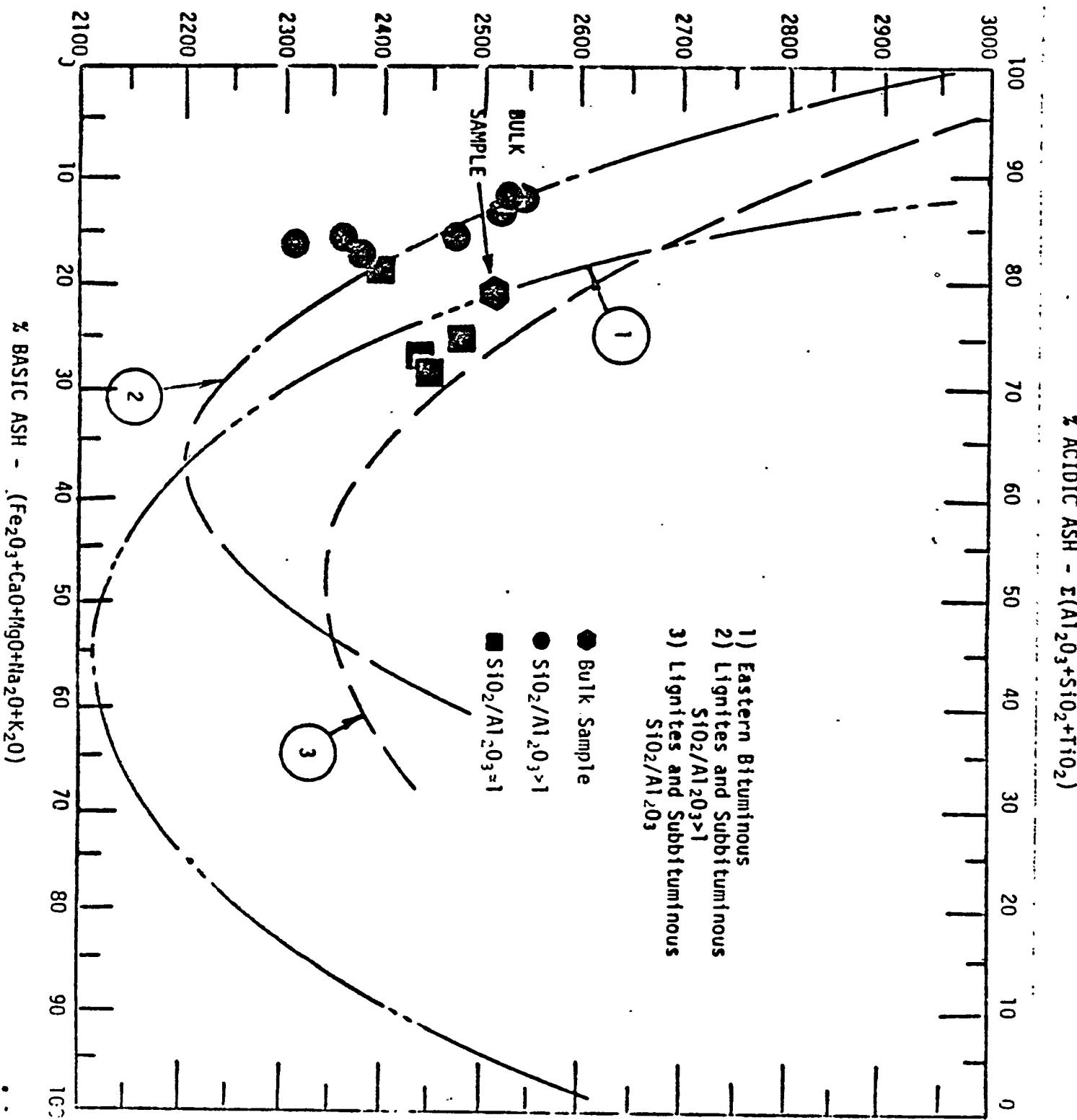


Table 4, continued

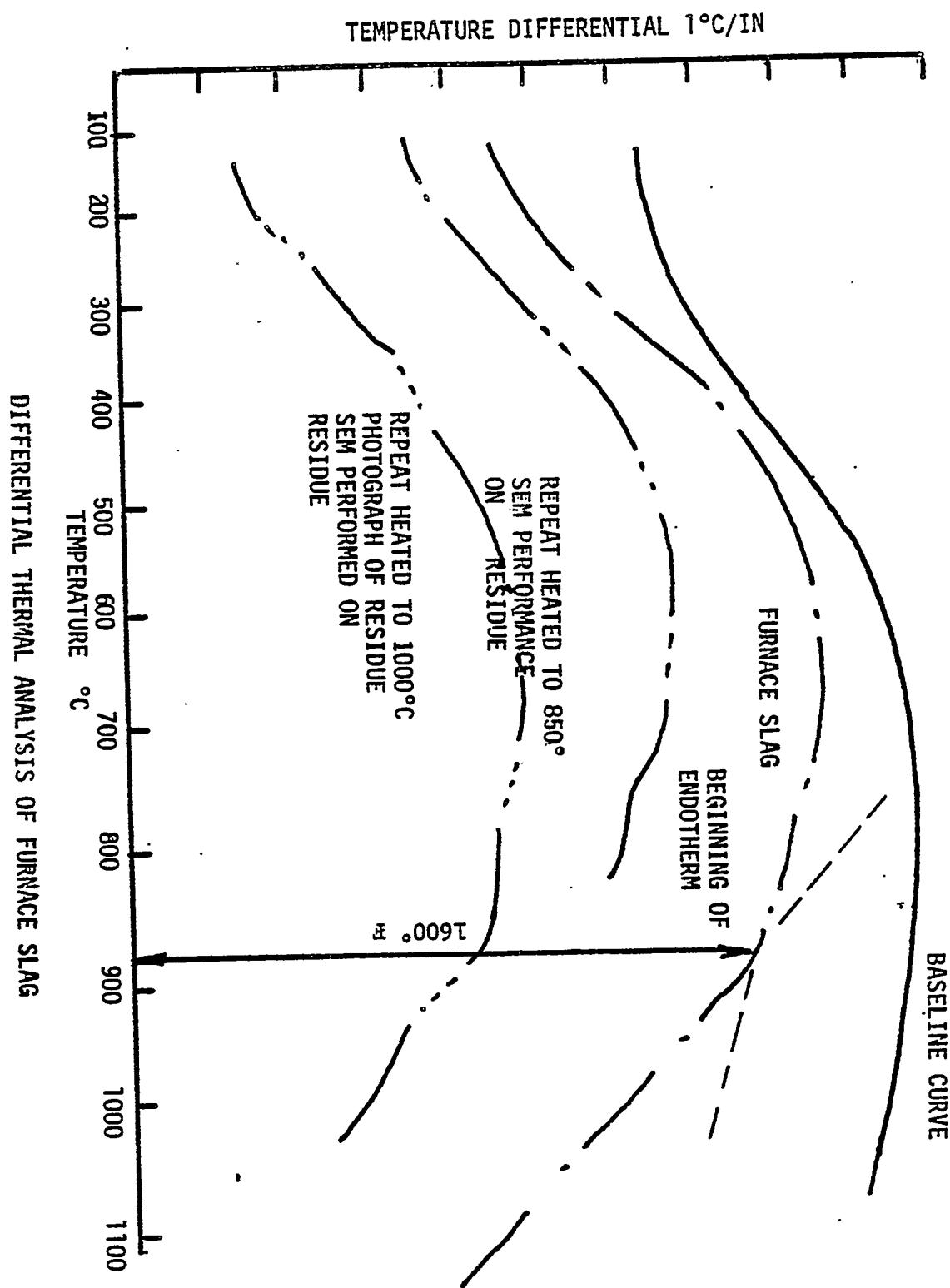


Table 4, continued

Comparison of Ash Chemistry of Coal and Slag

<u>Element as an Oxide</u>	<u>Coal</u>	<u>Slag</u>
SiO ₂	31.8	66.0
Al ₂ O ₃	13.8	10.3
TiO ₂	0.5	0.3
Fe ₂ O ₃	8.8	4.5
CaO	20.0	16.8
MgO	3.5	1.9
Na ₂ O	0.6	0.3
K ₂ O	1.0	1.1
SO ₃	13.3	0.1
P ₂ O ₅	0.5	0.1

Ash Fusion:

Reducing/Oxidizing

Initial Deformation	2075/2160	2010/2060
Softening (Sph.)	2131/2236	2020/2070
Softening (Hem.)	2172/2360	2035/2090
Fluid	2768/2395	2180/2250

Table 4, continued

**Compositions of the Slag Sample From a Wall Tube of the Furnace
After Firing Polish Coal**

Elementary Composition (Wt%):

	<u>1</u>	<u>2</u>	<u>3</u>	<u>Coal</u>
SiO ₂	24.59	63.01	64.29	45-55
Al ₂ O ₃	10.13	13.70	14.11	20-30
Fe ₂ O ₃	56.30	8.46	8.57	7-12
CaO	2.87	3.15	2.96	5-8
MgO	2.57	2.44	2.45	3-5
K ₂ O	1.98	1.94	2.20	1.5-2.5
Na ₂ O	1.21	0.61	0.66	0.3-1.0
SO ₃	<u>3.12</u>	<u>0.23</u>	<u>0.29</u>	1-5
	102.77	93.54	95.53	

Main Compounds:

<u>1</u>	<u>2 and 3</u>
Hematite, Fe ₂ O ₃	Silicate Glass Quartz, SiO ₂
Anhydrite, CaSO ₄	Anorthite, CaO·Al ₂ O ₃ ·2SiO ₂
Silicate Glass	Magnetite, Fe ₃ O ₄
	Hematite (traces), Fe ₂ O ₃

Table 4, continued

Compositions of the Slag Sample From the Noncooled Brickwork Wall
in the Lowest Part of the Furnace After Firing Polish Coal

Elementary Composition (Wt%):

	<u>1</u>	<u>2</u>	<u>3</u>	<u>Coal</u>
SiO ₂	52.17	54.55	53.78	45-55
Al ₂ O ₃	18.73	16.05	17.88	20-30
Fe ₂ O ₃	12.54	11.24	12.34	7-12
CaO	6.16	5.36	6.01	5-8
MgO	3.93	3.35	3.70	3-5
K ₂ O	1.74	1.61	1.72	1.5-2.5
Na ₂ O	0.54	0.36	0.42	0.3-1.0
SO ₃	<u>0.43</u>	<u>0.20</u>	<u>0.25</u>	1-5
	96.24	92.72	96.10	

Main Compounds:

Silicate Glass
Quartz, SiO₂
Anorthite, CaO•Al₂O₃•2SiO₂
Magnetite, Fe₃O₄
Hematite, Fe₂O₃ (traces)

Comparison of Coal Ash and Slag Deposit Formed From a North Dakota Lignite

Table 4, continued

Elemental Analysis	Coal	Furnace Deposit					
		Bottom Ash	Inside Layer	Middle Layer	Outside Layer	Superheater	Economizer
SiO ₂	32.0	28.75	15.5	15.5	25.0	25.0	33.50
Al ₂ O ₃	12.5	14.25	18.0	17.5	15.0	15.0	13.0
TiO ₂	0.6	0.48	0.30	0.30	0.50	0.50	0.55
Fe ₂ O ₃	7.5	13.0	54.0	26.0	25.5	8.5	17.0
CaO	24.60	28.0	12.0	20.0	21.4	28.5	31.8
MgO	0.70	8.33	0.50	1.90	3.50	7.4	2.68
Na ₂ O	3.48	0.27	0.40	1.46	1.71	3.6	2.70
K ₂ O	0.48	0.36	0.38	0.36	0.24	0.48	0.30
P ₂ O ₅	2.98	0.68	0.80	2.07	2.29	3.45	0.46
SO ₃	16.40	3.58	5.90	11.90	3.60	10.0	2.05

Ash Fusion (Reducing):

In. Def.	2250	---	2450	2330	2220	2240	2280
Softening	2310	---	2640	2400	2280	2350	2320
Fluid	2350	---	2800	2580	2420	2600	2340

SAMPLES FROM IGT GASIFIER

CYCLONE DISCHARGE:

Al_2SiO_5 (KYANITE), Fe_2SiO_4 (FAYALITE),
 $FeAl_2O_4$ (HERCYNITE) S (BY LECO): 0.6%

CYCLONE INLET DEPOSIT:

Fe_2SiO_4 , $Fe_{1-x}S$ (PYRRHOTITE),
 Fe_3O_4 (MAGNETITE)
S (BY LECO): 6%

INTERNAL CYCLONE DEPOSIT: $Fe_{1-x}S$, Fe_3O_4

S (BY LECO): 34%

CYCLONE DEPOSIT: POORLY CRYSTALLIZED. DETECTED PRESENCE
OF Fe_3O_4 AND Fe_2SiO_4

Table 4, continued

Table 4, continued

COMPARISON OF GASIFIER DEPOSIT WITH RAW COAL

<u>ELEMENT</u>	<u>RAW COAL</u>	<u>DEPOSIT</u>
SiO ₂	38.0	10.77
Al ₂ O ₃	32.5	3.74
TiO ₂	1.0	---
Fe ₂ O ₃	17.7	73.75
CaO	5.5	5.21
MgO	0.5	0.30
Na ₂ O	<0.1	---
K ₂ O	2.1	---
SO ₃	2.0	6.20

Table 4, continued

Comparison of Ash Chemistry of Slag from a Steam Generator and Gasifier with Ash Chemistry of -40 Mesh/+100 Mesh, -2.85 Gravity Fraction

Chemical Constituents	Slag (Inside Layer)	Slag (Outside Layer)	Ash Chemistry -40 +100	Ash Chemistry (Bulk Coal Sample)	Gasifier Deposit
SiO ₂	6.9	12.5	4.9	47.9	10.77
Al ₂ O ₃	8.9	8.5	2.8	30.6	3.74
TiO ₂	0.2	0.3	0.1	1.0	—
Fe ₂ O ₃	79.2	73.7	86.3	8.3	73.75
CaO	1.3	2.5	0.1	3.4	5.21
MgO	1.0	1.3	0.8	1.5	0.30
Na ₂ O	1.8	2.6	1.4	0.2	—
K ₂ O	0.2	0.4	0.2	1.4	—
SO ₃	N.D.	N.D.	N.D.	3.5	6.20
P ₂ O ₅	N.D.	N.D.	N.D.	N.D.	—
<u>Ash Fusion Temperatures (°F)</u>					
<u>Reducing Atmosphere</u>					
Initial Deformation	2400	2100	2288	1960	—*
Softening (Sph.)	2560	2180	2330	2340	—
Softening (Hem.)	2800	2250	2320	2920	—
Fusion	2800	2340	2400	2800	—
<u>Oxidizing Atmosphere</u>					
Initial Deformation	2680	2680	2800	2020	—
Softening (Sph.)	2800+	2800+	2800	2800	—
Softening (Hem.)	2800+	2800+	2800	2800	—
Fusion	2800+	2800+	2800	2800	—

*Sample fused in crucible during ashing.

Table 4, continued

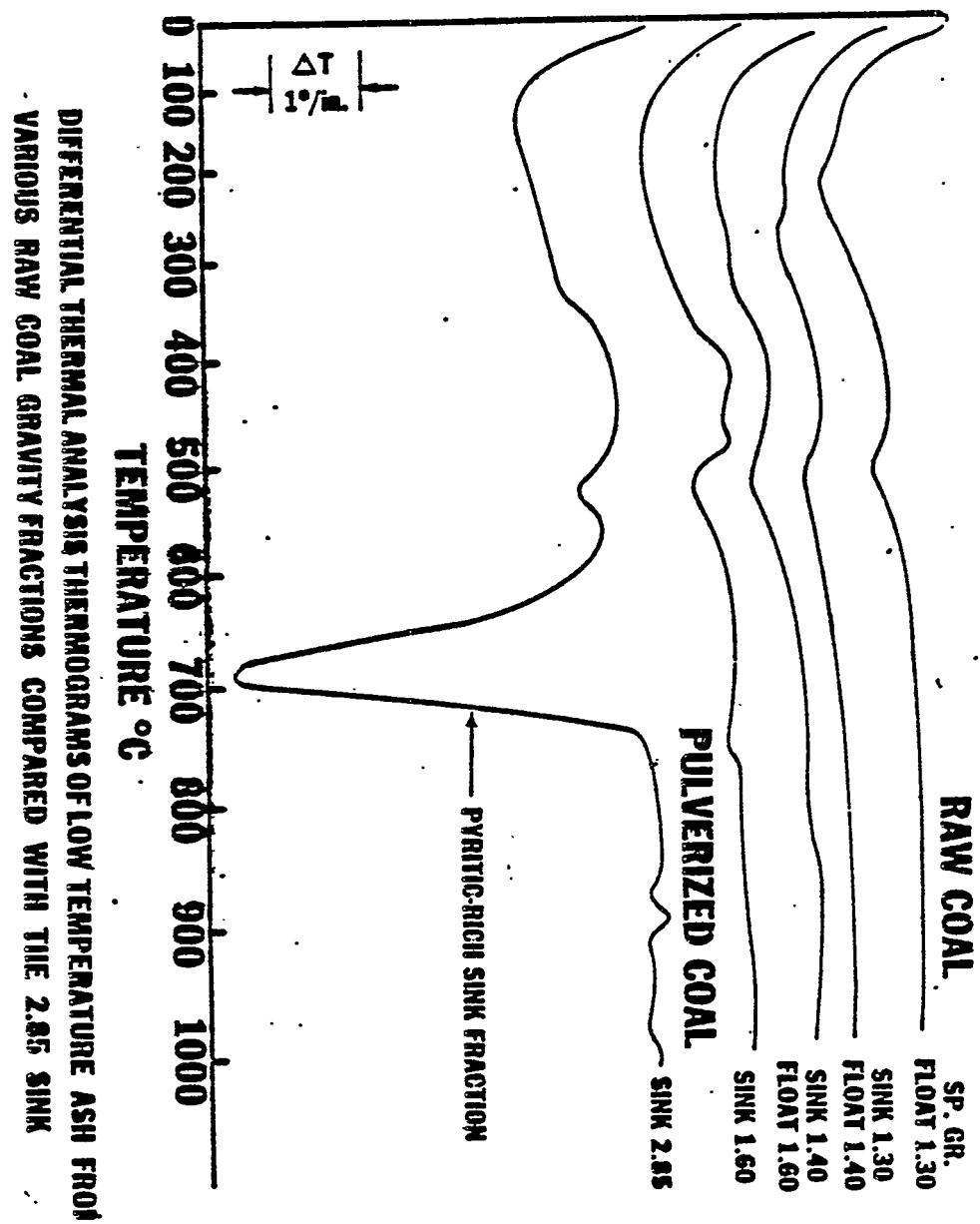


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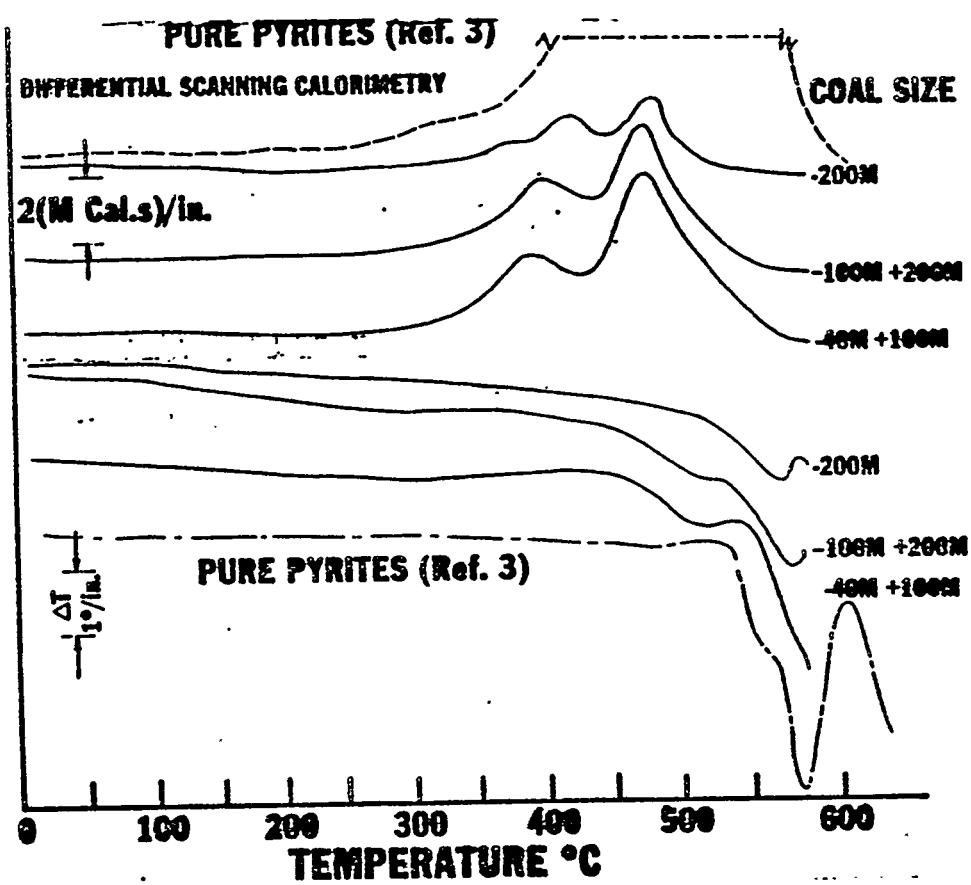


Table 4, continued

ASH FUSIBILITY DIAGRAM FOR PULVERIZED COAL 100% -40 MESH

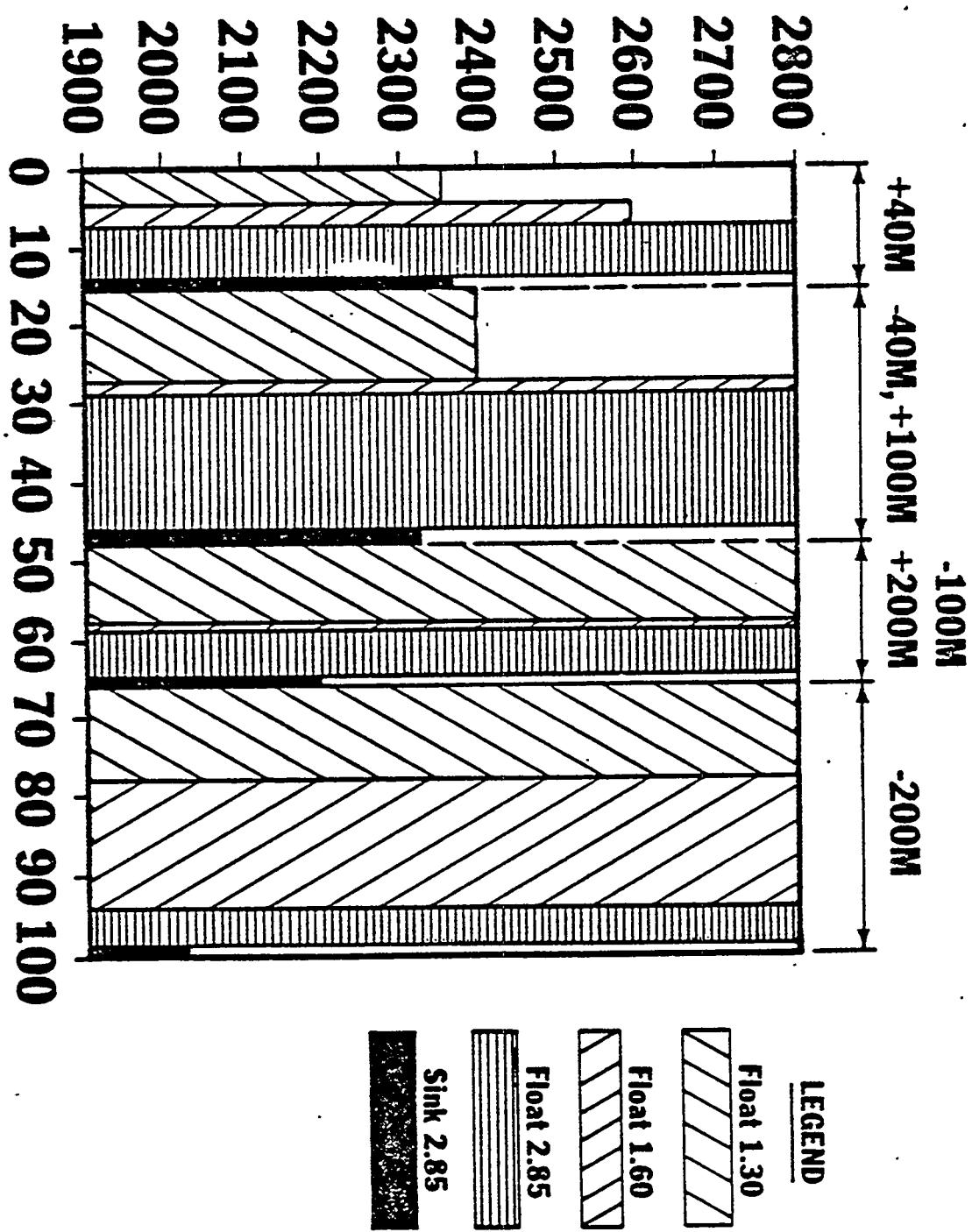


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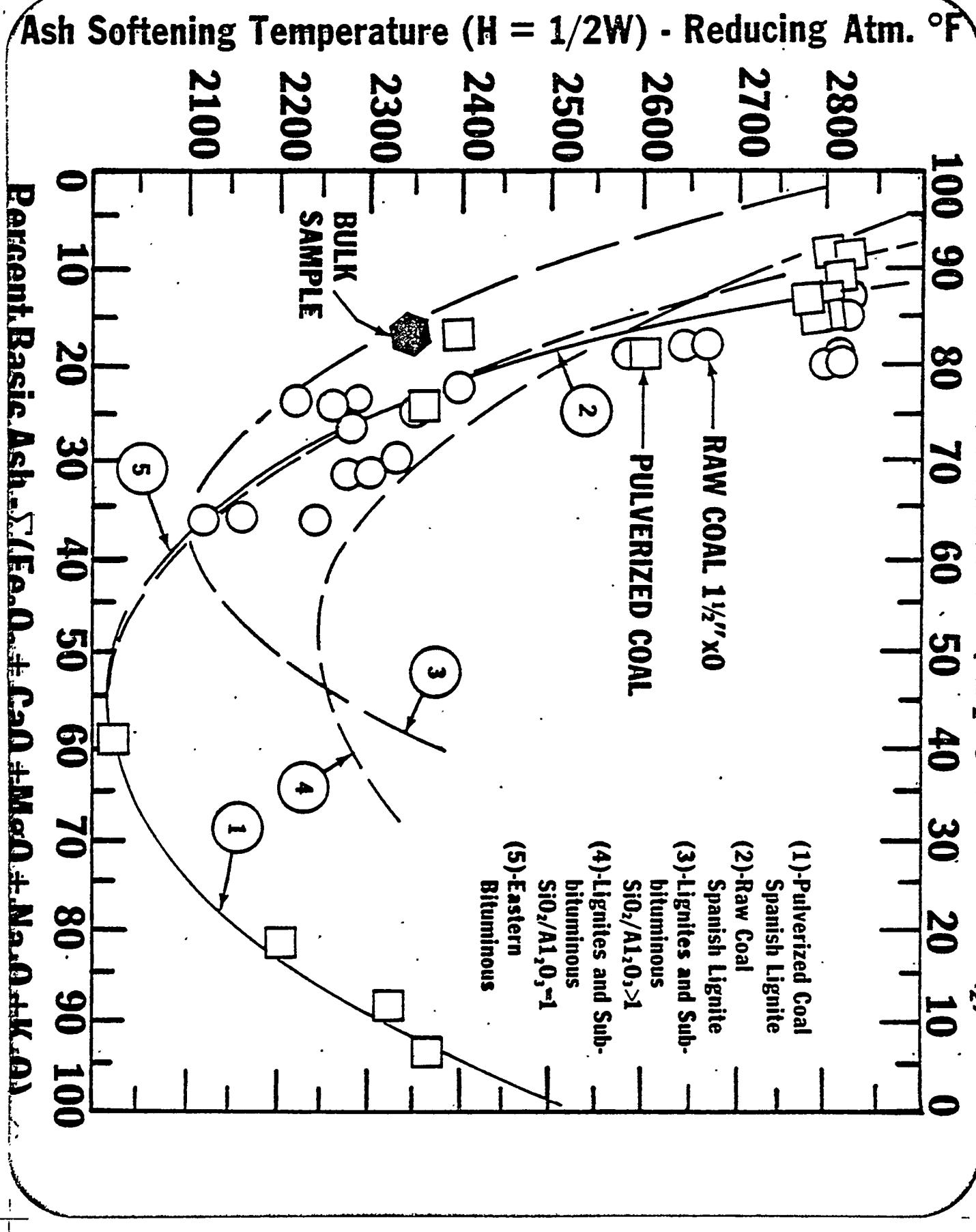


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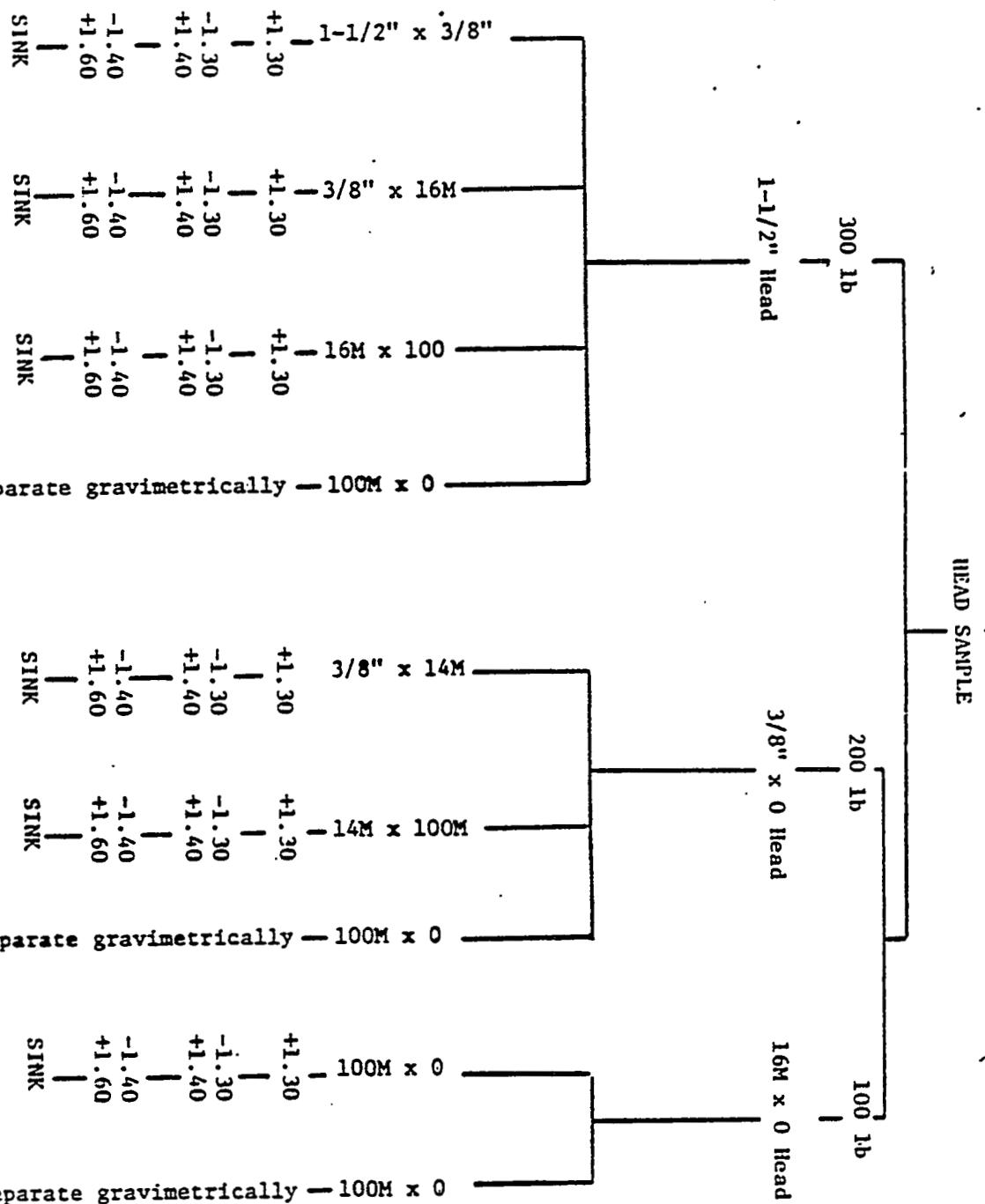


Table 4, continued

SCHEMATIC OF THE MINERAL
OCCURRENCE IN ONE SIZE OF PULVERIZED COAL

	RAW COAL	NON-PYRITIC ASH	PYRITIC ASH	ASH BLEND
SPECIFIC GRAVITY	1.3 - 1.60	2.50	5.00	5.00 - 5.8
MELTING TEMPERA- TURE	2200 - 2800+	2800	1000°F (RED. ATM.)	2200 - 2800

Table 4, continued

Test	Index	Values	Fuels
1. Ash Fusion Temperature	Initial Deformation Temperature	1.D.	Function of Ash Chemistry
	Softening Temperature (Sph.)	S.I.	S.I. Used to Select Furnace Exit
	Softening Temperature (Temp.)	H.T.	Temperature
	Fusion Temperature	F.T.	Dry Bottom Furnace < Slagging Furnace >
2. T_{cv}	Temp. at Which Viscosity Changes From Newtonian to Bingham Plastic	None	All
3. T_{250}	Temperature at 250 Poise	Ratings (Dry Bottom)	Ratings (Wet Bottom)
		Low	Low
		Medium	250 <2600°F
		High	250 to 2100
		Severe	2275 to 2050.
4. % Basic Constituent	$\frac{\%(\text{Fe}_2\text{O}_3 + \text{CaO} + \text{MgO} + \text{Na}_2\text{O} + \text{K}_2\text{O})}{\%(\text{Al}_2\text{O}_3 + \text{SiO}_2 + \text{TiO}_2)}$	None	All
5. Base-to-Acid Ratio (B/A)	$\frac{\%(\text{Fe}_2\text{O}_3 + \text{CaO} + \text{MgO} + \text{Na}_2\text{O} + \text{K}_2\text{O})}{\%(\text{Al}_2\text{O}_3 + \text{SiO}_2 + \text{TiO}_2)}$	0.5 Maximum for Dry Bottom Units 0.27 for Wet Bottom Units	All
6. R_s - Slagging Factor	B/A \times % S on Dry Coal	R_s	Slagging Type
		<0.6	Low
		0.6-2.0	Medium
		2.0-2.6	High
		>2.6	Severe
7. R_f, R_f' - Fouling Factor	$R_f = B/A \times \% \text{ Na}_2\text{O}$ (ASTM Ash)	R_s	Eastern Coals
	$R_f' = B/A \times \% \text{ Water Soluble Na}_2\text{O}$ From LIA (Low Temperature Ash)	R_f'	Fouling Type
		<0.1	Low
		0.1-0.5	Medium
		0.5-1.0	High
		>1.0	Severe

Table 4, continued

Test	Index	Values	Fuels
8. Sodium Content of Coal Ash	% Na ₂ O in ASTM Ash		
		% Na ₂ O	Lignite
		2.0	Fouling
		2.6	Low
		6-8	Medium
		8	High
			Severe
9. Alkali Content of Coal Ash	$\gamma(\% \text{Na}_2\text{O} + 0.6589 \times \% \text{K}_2\text{O})$	Same as 8.	All
10. Alkali Content of Coal	$\gamma(\% \text{Na}_2\text{O} + 0.6589 \times \% \text{K}_2\text{O}) \times \% \text{Ash}$ 100	Alkali, %	Eastern Coals Only
		0.3	Fouling Low
		0.3-0.45	Medium
		0.45-0.6	High
		>0.60	Severe
11. Ash Sintering Strength	Compression Strength of Specially Prepared Fly Ash Pellets	Fouling Type	All
		Fouling Type	Strength of Sintered Fly Ash (1700°F)
		Low	1000
		Medium	1000-5000
		High	5000-16000
		Severe	>16000
12. Chlorine	% on Coal	Fouling Type	All
			% on Coal
		Low	<0.2
		Medium	0.2-0.3
		High	0.3-0.5
		Severe	>0.5

Table 4, continued

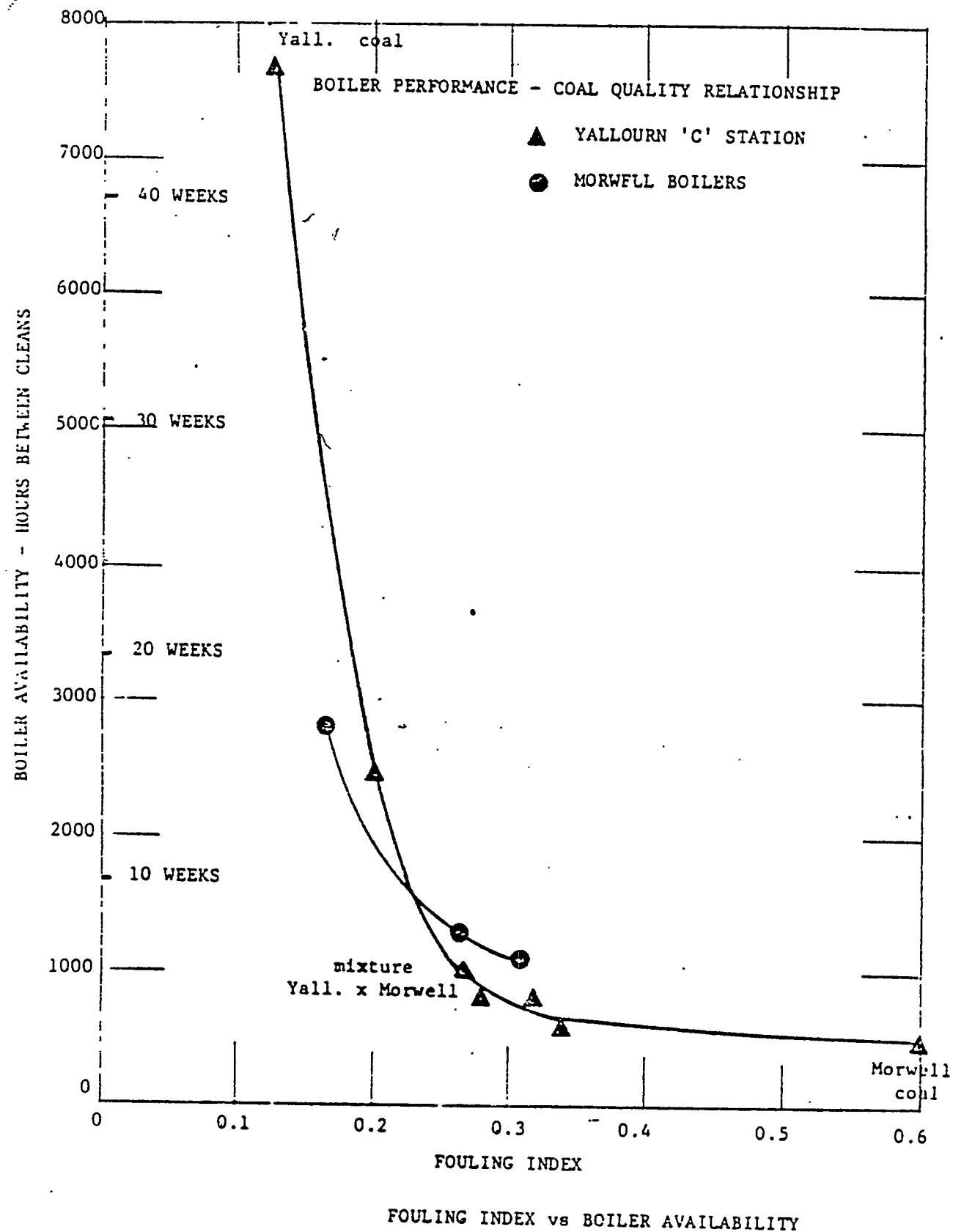


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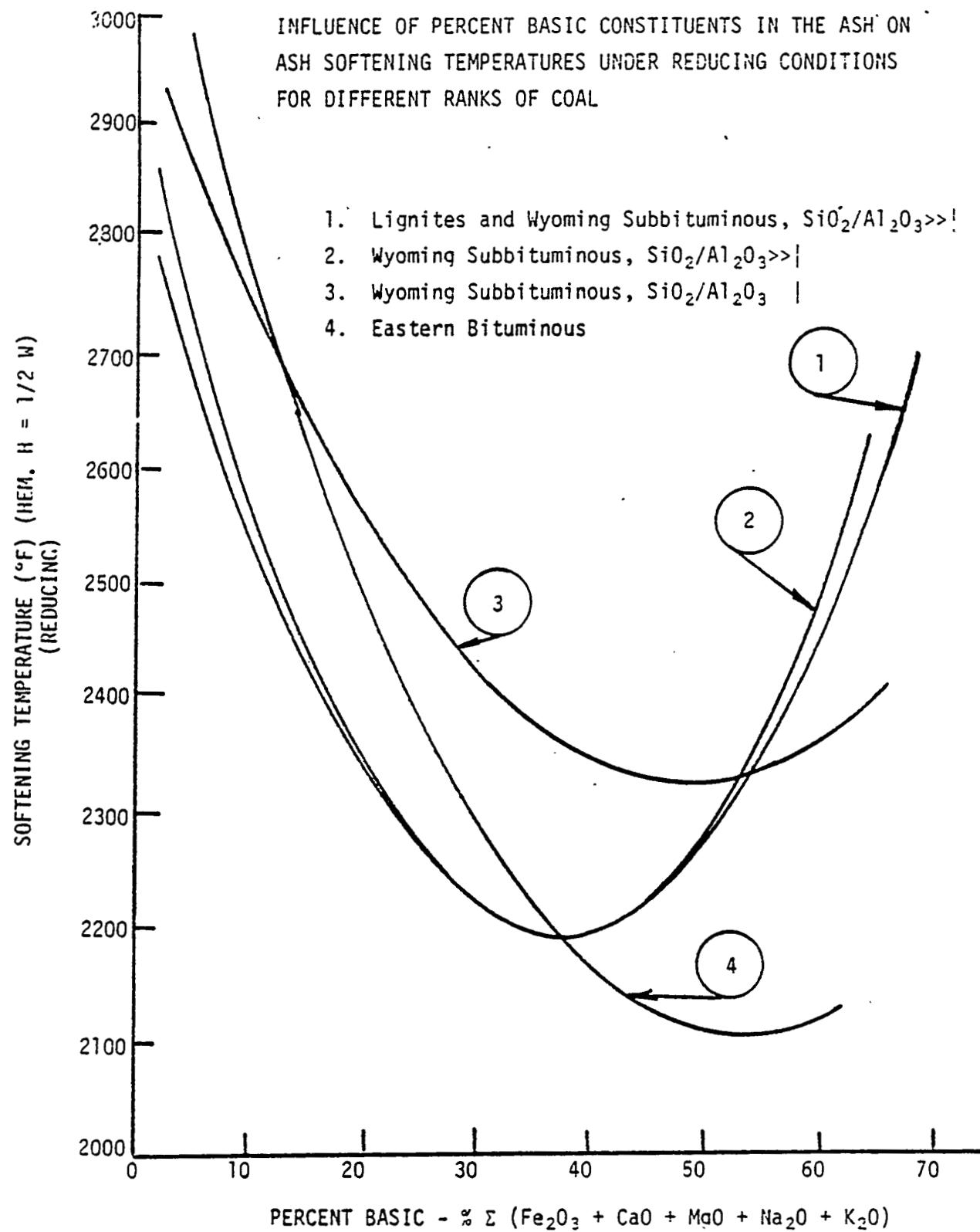
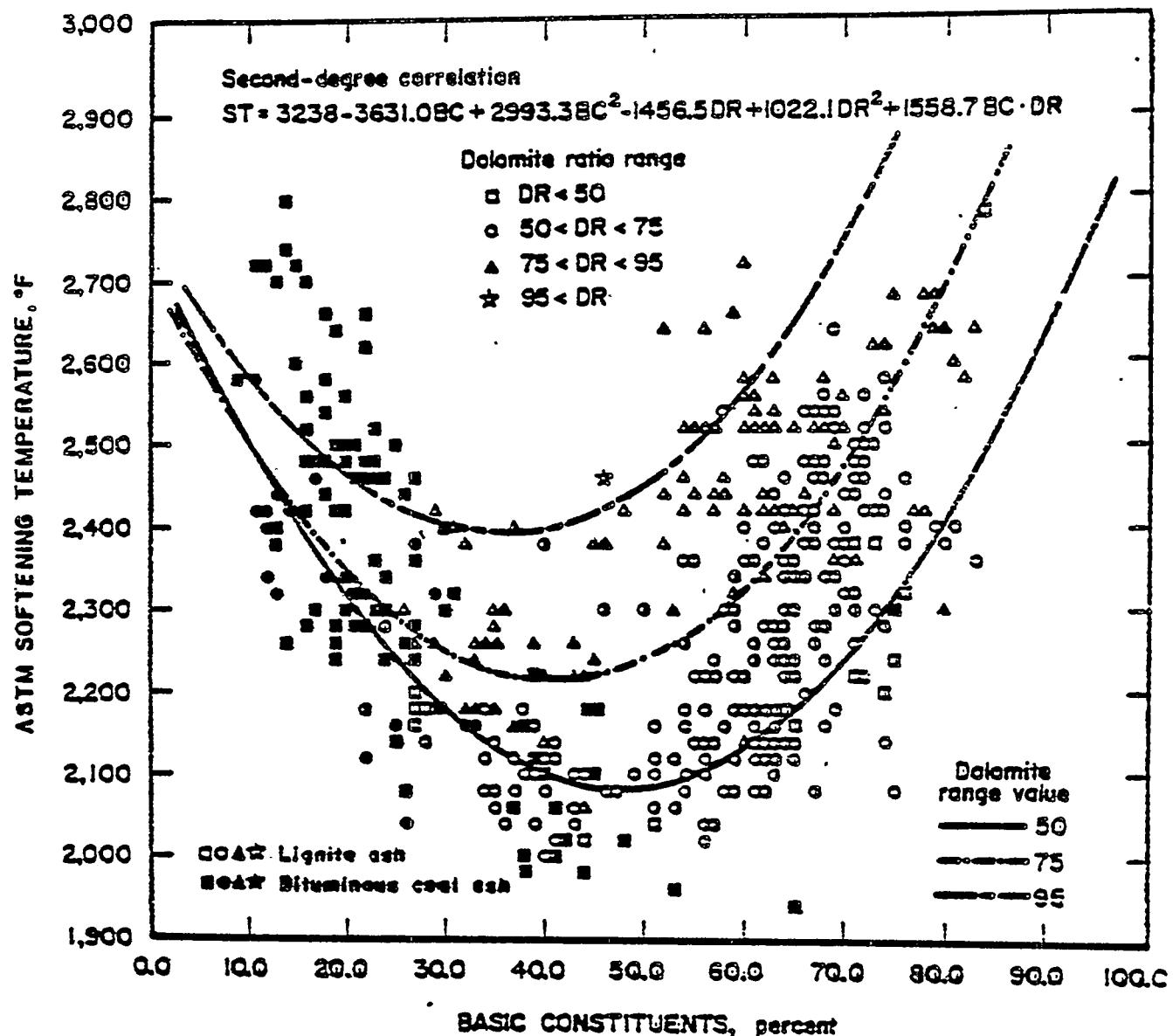


Table 4, continued



Prediction of softening temperature for ash from lignite and bituminous coals using the percentage of basic constituents (BC) and the dolomite ratio (DR) as parameters

Figure 7

Table 4, continued

Table 3 Summary of Fusibility Correlations

Investigator	Correlation	Coal Type	Coal No.	Standard Deviation	Correlation Coefficient	Remarks
Nicholls, Selvig, Ricketts - 1932	$(SiO_2 + Al_2O_3)/(Fe_2O_3 + CaO + MgO + Na_2O + K_2O)$	Bituminous U.S.	135	150.6 154.8	0.674 0.409	When applied to bituminous When applied to lignite by Sondreal
Schaefer - 1933	$RS = (Al_2O_3/SiO_2)/(SiO_2 + Al_2O_3/FeO + 0.6 [CaO + MgO + Na_2O + K_2O])$	Bituminous U.S.	135	135.5 165.1	0.748 -0.233	When applied to bituminous When applied to lignite by Sondreal
Mahmudar - 1958	$RH = [3.3 SiO_2 + 1.96 Al_2O_3]/[2.5 Fe_2O_3 + 3.37 CaO - 15.0 MgO + 3.22 (Na_2O + K_2O)]$	Bituminous Indian	135	-	0.702	When applied to lignite by Sondreal
Nicholls, Reid - 1940	$SiO_2/[SiO_2 + Equiv. Fe_2O_3 + CaO + MgO]$	Bituminous U.S.	135	-	-0.450	When applied to lignite by Sondreal
Dunay - 1965	$Fe_2O_3 + CaO + MgO + Na_2O + K_2O$	Lignite U.S.	-	-	-0.514 -0.590	When applied to bituminous When applied to lignite
Sondreal - 1975	$LR = [CaO + MgO]/[Fe_2O_3 + CaO + MgO + Na_2O + K_2O]$ as a parameter	Lignite U.S.	135	72.4	0.923	
Bryers and Taylor - 1976	$ST_{RED} = 2063 - 37.1K + 0.15K^2$ $ST_{RED} = 2942 - 27.1K + 0.27K^2$ $ST_{OND} = 2814 - 35K + 0.50K^2$ $ST_{RED} = 3114 - 38.6K + 0.37K^2$	Western U.S. SiO ₂ /Al ₂ O ₃ 3 ± 20%	151	100.4	0.772	Data includes composite ash fusion temperatures as well as size and gravity fractionate coal ash fusion temperatures
	Where $X = [Fe_2O_3 + CaO + MgO + Na_2O + K_2O]$	Western U.S. SiO ₂ /Al ₂ O ₃ 1 ± 20%	30	113.1	0.63	
	Calculated:	Western U.S.	79	99.5	0.773	
	1) $SiO_2/(Al_2O_3 + TiO_2)$ 2) $[CaO + MgO]$ from $[SiO_2 + Al_2O_3 + TiO_2 + CaO + MgO]$	Eastern	-	-	-	Used British H.T. Three empirical curves required
Butta Kal and Chakravorty - 1960, 1962	Estimate hemispherical temperature (H.T.) Subtract 25° for each percentage $[Na_2O + K_2O]$ Correct for Fe_2O_3 using empirical curve	Indian	-	-	-	1) H.T. vs $CaO + MgO$ 2) H.T. vs Fe_2O_3 3) H.T. vs Fe_2O_3 (RED/OND)
	With $SiO_2/(Al_2O_3 + TiO_2)$ as a parameter					

Table 4, continued

Inventor	Correlation	Coal Type	Coal No.	Standard Deviation	Correlation Coefficient	ASTM ash fusion	Remarks
Grainger - 1951	Calculate: $S = SiO_2 + TiO_2 + P_2O_5$ $A = Al_2O_3$ $T = CaO + 0.7MgO + 2.25 Na_2O + 1.5K$ Obtain: $z_S = (S/S + A + T)100$ $z_A = (A/S + A + T)100$ $z_T = (T/S + A + T)100$	Bituminous U.S.	-	-	-	-	
Estep, Seitz and Oahm - 1937	From ternary diagram S, A, T, (Z) obtain softening temperature Determine: $Z \pm (Fe_2O_3/S + A + T + Fe_2O_3)100$ From empirical curves obtain ΔFe_2O_3 , and subtract from softening temperature	U.S.	-	±100°	17.6		
Kovitukki, Karngedilina, and Martyanova - 1975	Obtain: Z_{CaO} from $SiO_2 + Al_2O_3 + Fe_2O_3 + CaO = 100\%$ Determine hemispherical temperature from $SiO_2 - Al_2O_3 - Fe_2O_3$ ternary diagram modified by CaO for specific CaO conc. MgO compensation for by combining with CaO; MgO compensated for by subtracting 50 / percent MgO	U.S.	-	-	-	-	
Kovitukki, Karngedilina, and Martyanova - 1975	$K_{fu} = (SiO_2 + Al_2O_3/Fe_2O_3 + CaO + MgO)$ $t_2 = 1094 + 42.3K_{fu}$ (softening temperature) $I_9 = 1139 + 48.6K_{fu}$ (fluid state)	Soviet	-	-	-	-	
Kovitukki, Karngedilina, and Martyanova - 1975	$K_u = (SiO_2 + P_2O_5/Al_2O_3 + Fe_2O_3 + CaO + MgO)$ $T_{200}^{\circ}C = 1085 + 318K_u$ Valid $0.42 \leq K_u \leq 2.03$	Soviet	-	-	-	-	
Densigmeur - 1963	$(R_B = SiO_2 + Al_2O_3 + MgO/CaO + Fe_2O_3 + K_2O)$ Plotted against $(DB + FB)_2$ DB - Deformation Temperature FB - Fusion Temperature	French	94	-	-	-	
Wingartner, Rhodes - 1974	$(P.T., S.T., I.O.) = f (51$ independent variables including Al_2O_3 , SiO_2 , Fe_2O_3 , CaO , MgO , MnO_2 , K_2O , and various groups of the same	U.S. Eastern Western	2	-	-	-	
I. Garner - 1964	Deposit Weight = X Where: $X_1 = 0.030 [TiO_2] + 0.09 [Fe_2O_3] + 0.061 [CaO] +$ and $0.264 [MgO] + 0.423 [Na_2O] - 10.6$ $X_2 = 0.044 [TiO_2]^{0.22} \cdot [Na_2O]^{0.72} \cdot [CaO]^{0.005}$	Australian	-	-	-	-	Applicable only to Australian coals. However, most practical correlation as chemistry directly relate to full-scale outage based on pilot plant tests.

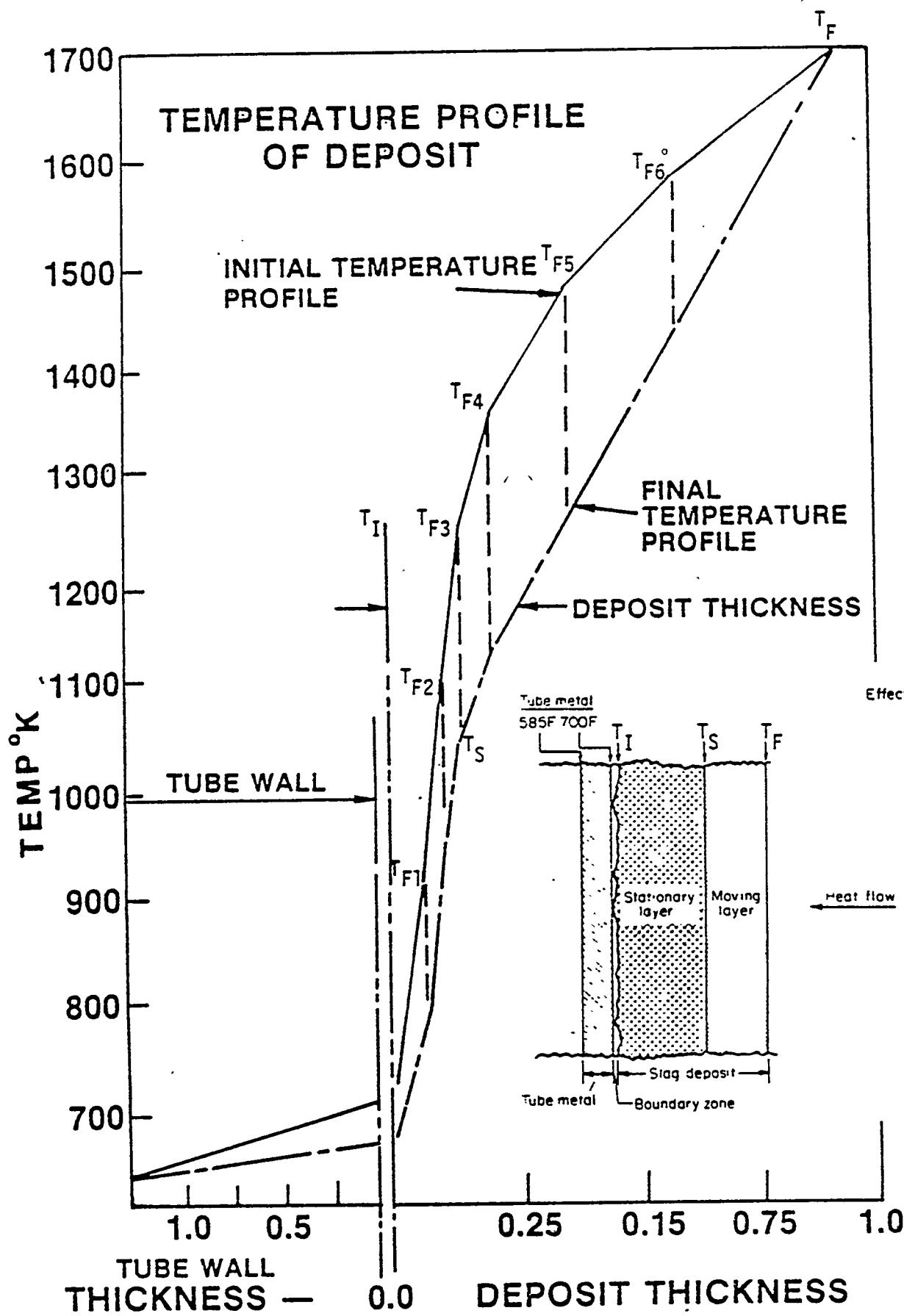


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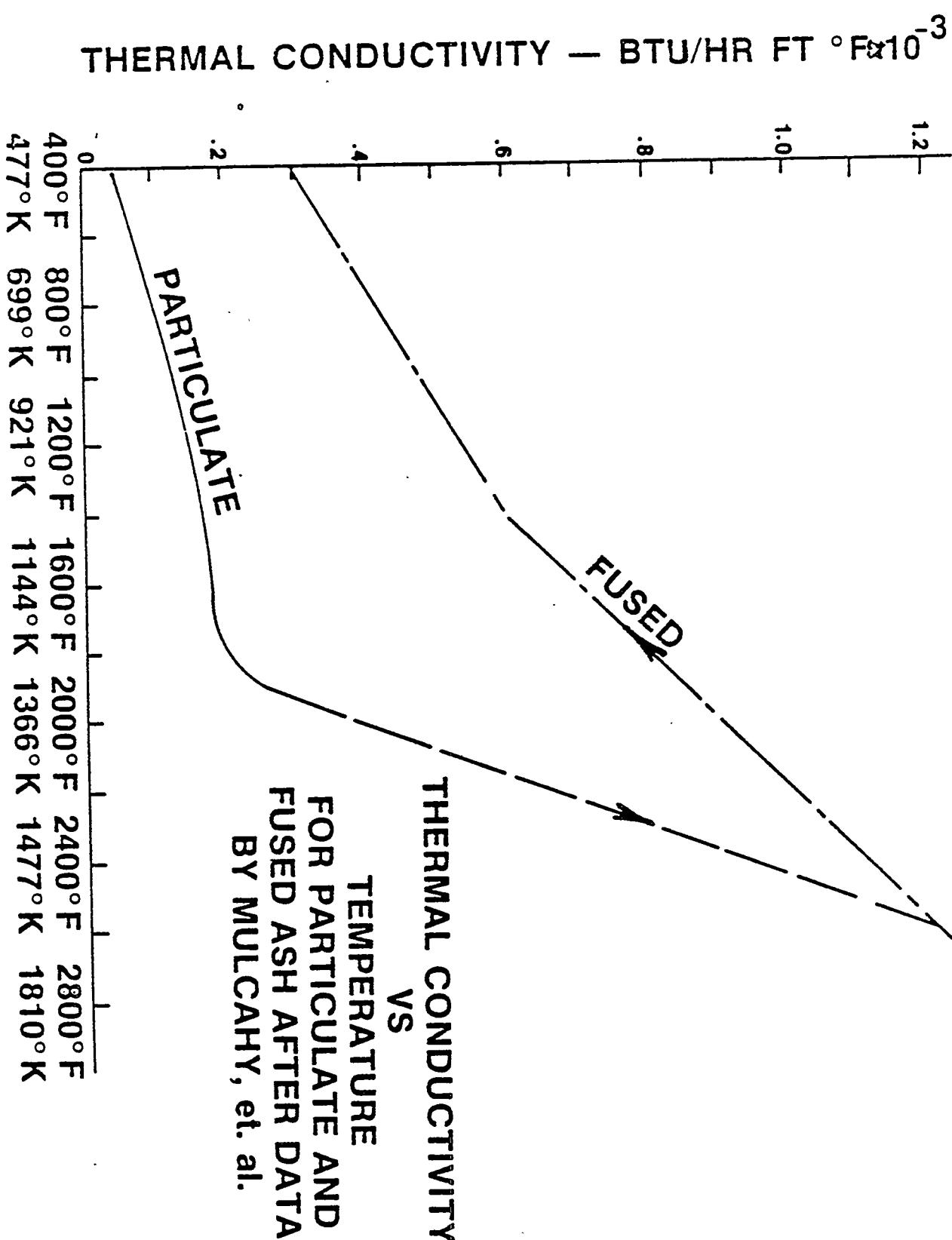
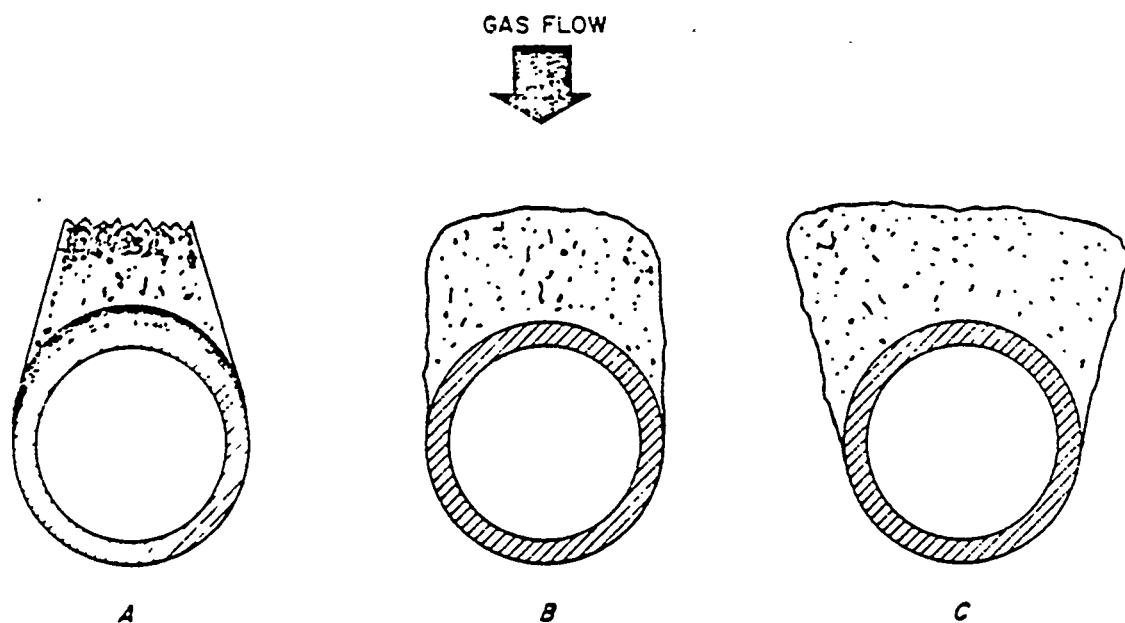


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DEPOSIT BUILDUP CHARACTERISTIC OF STAGES:

1, 2, and 3

1 and 3

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— INCREASING-LOW-MELTING-POINT CONSTITUENTS —→

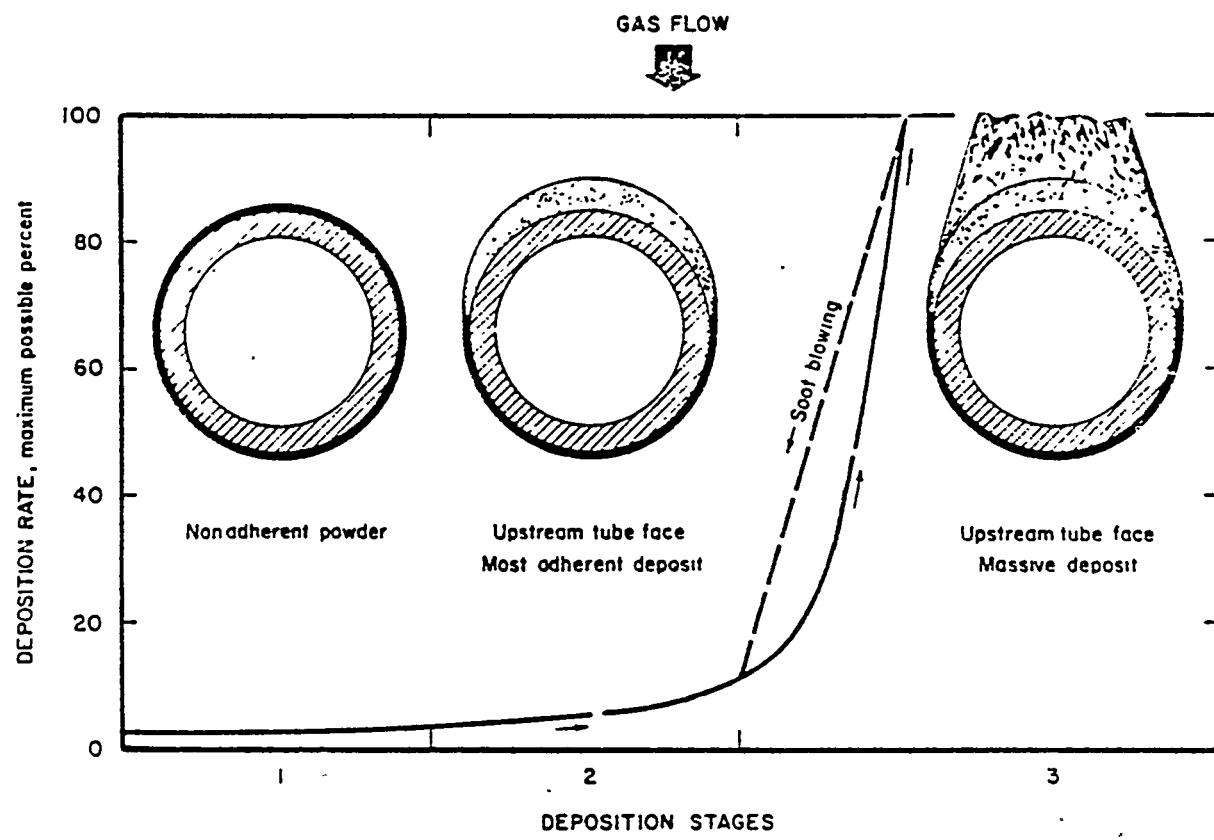


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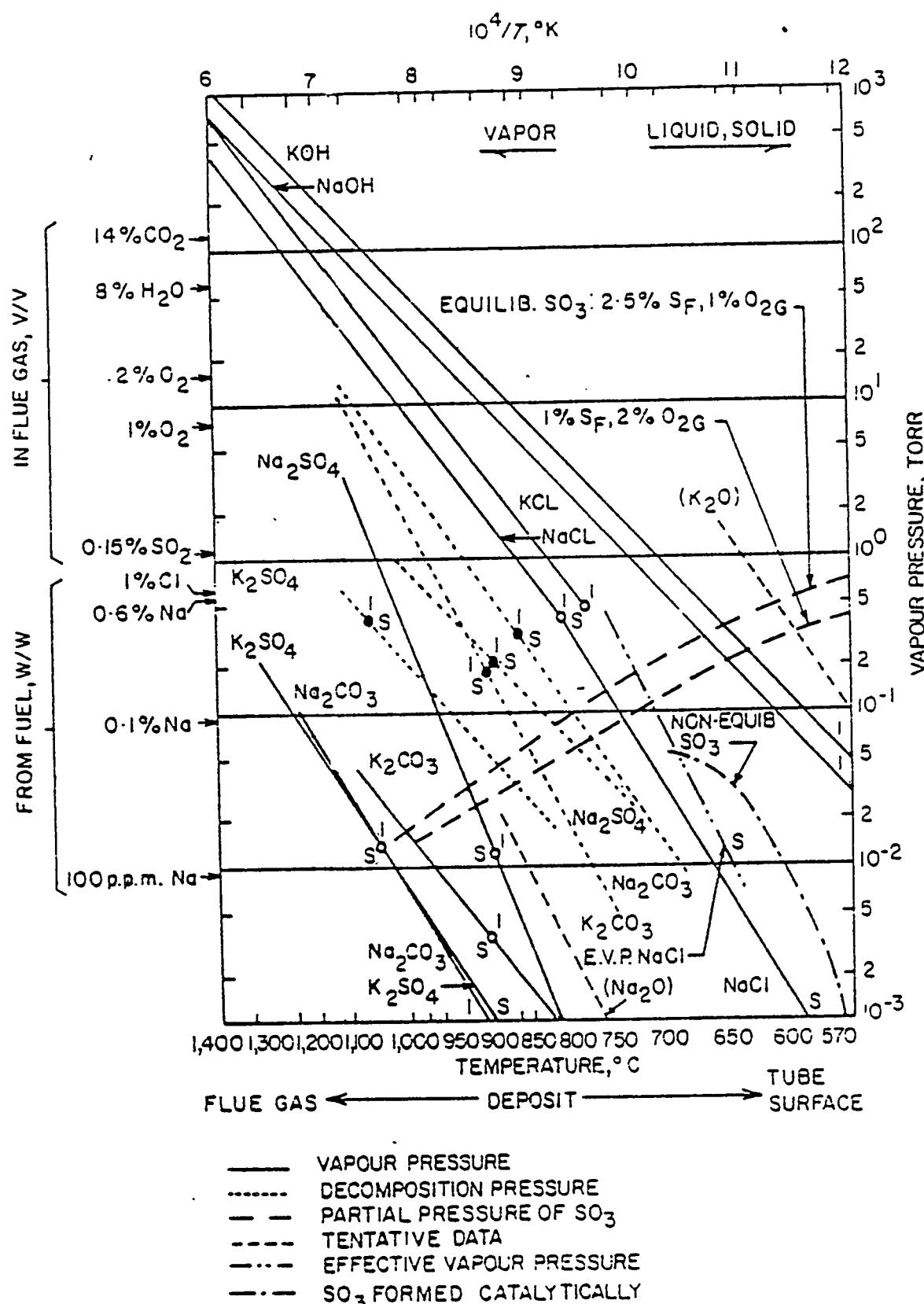


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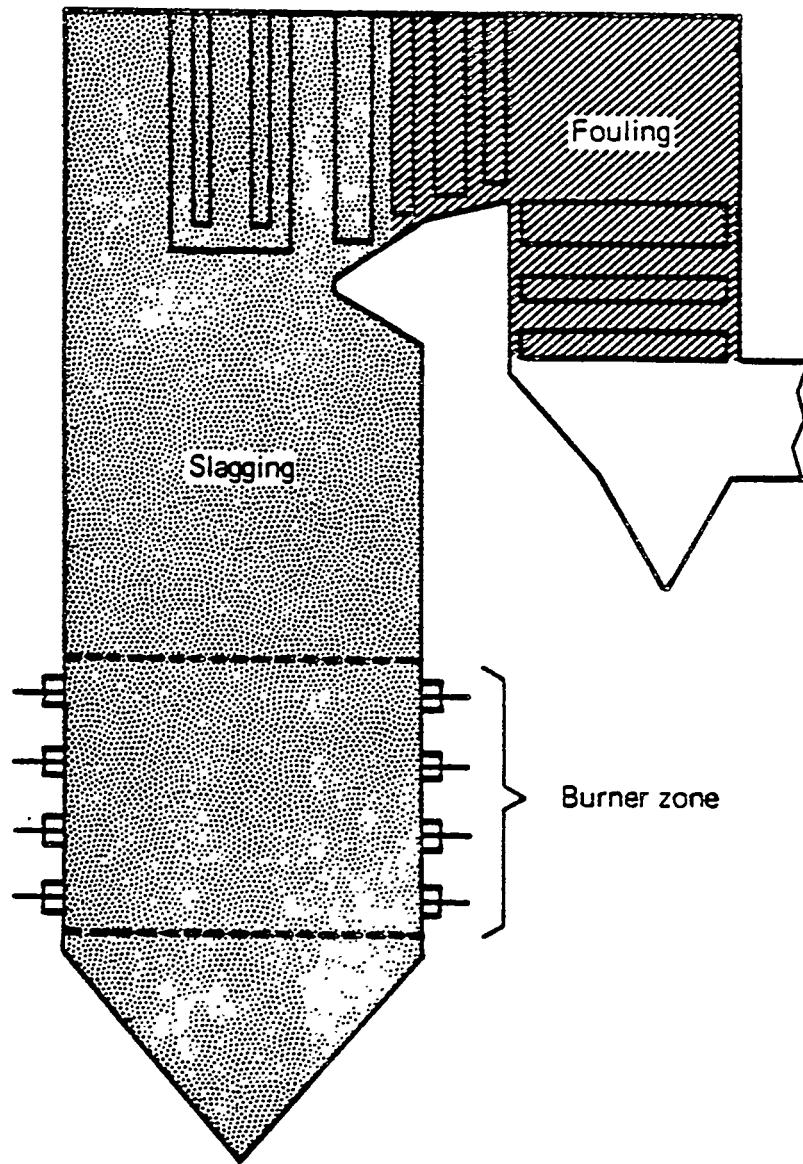
**Deposition zones in a coal fired boiler**

Table 1 Fuel Types (Coal) (References 13 and 14)

	Anthracite ¹³	Bituminous ¹³	Subbituminous ¹³	Lignite ¹⁴
% by Weight				
Proximate Analysis				
Moisture	11.0	2.0 - 3.5	12.0 - 20.8	35.0 - 43.0
Volatile Matter	5.5	19.9 - 35.7	38.4 - 30.0	24.3 - 26.8
Fixed Carbon	70.5	70.4 - 51.8	43.6 - 43.8	24.4 - 32.5
Ash	13.0	7.7 - 9.0	6.0 - 5.5	4.2 - 8.9
% by Weight				
Ultimate Analysis				
Ash	13.0	7.7 - 9.0	6.0 - 5.4	4.20 - 8.9
S	0.5	0.7 - 2.2	0.7 - 0.6	0.23 - 0.90
H ₂	1.9	4.3 - 4.8	4.5 - 3.2	6.90 - 7.4
C	70.6	80.9 - 72.8	67.6 - 57.6	35.40 - 41.5
N ₂	0.8	2.0 - 3.5	1.12 - 1.2	0.50 - 0.7
O ₂	2.2	1.5 - 1.5	13.0 - 11.2	42.20 - 48.2
Moisture	11.0	2.0 - 3.5	12.0 - 20.8	35.00 - 43.0
Ash Chemistry				
SiO ₂	48.0 - 68.0	7.0 - 68.0	17.0 - 58.0	6.0 - 45.0
Al ₂ O ₃	25.0 - 44.0	4.0 - 37.0	4.0 - 35.0	6.0 - 22.0
TiO ₂	1.0 - 2.0	0.5 - 4.0	0.6 - 2.0	0.0 - 0.8
Fe ₂ O ₃	2.0 - 10.0	2.0 - 44.0	3.0 - 19.0	1.0 - 18.0
CaO	0.2 - 4.0	0.7 - 36.0	2.2 - 45.1	15.0 - 44.0
MgO	0.2 - 1.0	0.1 - 4.0	0.5 - 8.0	3.0 - 12.0
Na ₂ O	---	0.2 - 3.0	---	0.2 - 12.0
K ₂ O	---	0.2 - 4.0	---	0.1 - 1.3
SO ₃	0.1 - 1.0	0.1 - 32.0	3.0 - 16.0	6.0 - 30.0
P ₂ O ₅	0.1 - 4.0	0.0 - 3.0	0.0 - 3.0	0.0 - 1.0

B. Environmental Concerns

CCAWG member L. D. Smoot prepared, on very short notice, an overview of pollutant issues as an introduction to more detailed considerations of this important topic at later CCAWG meetings. He discussed existing federal standards and current understanding of the processes involved in the productions of NO_x, flyash, sulfur compounds, CO, hydrocarbons, soot, and emissions of trace metals. While current federal standards for boilers producing steam to generate more than 73 MW_e are 0.6 lb of NO_x per 10⁶ Btu for bituminous coals and 0.5 lb of NO_x/10⁵ Btu for subbituminous coals, it is viewed as likely that more rigid control measures will be imposed in the future. Current limits are 1.2 lbs/10⁶ Btu for SO_x with the supplementary requirement of 90% removal whenever SO_x emissions exceed 0.6 lb/10⁶ Btu. Particulates are limited to 0.03 lb/10⁶ Btu and are not currently qualified with regard to chemical composition, although a number of investigators have expressed apprehension about the possible presence of carcinogenic hydrocarbons and other carcinogenic compounds on particulate emissions and flyash.

A great deal needs to be learned about the control of NO_x emissions through combustion modifications that emphasize desirable competitions between NO_x formation and depletion processes. Studies are in progress on NO_x control using staging and combustion modifications. Removal of NO_x by reduction with NH₃ is a well developed procedure for some gas mixtures, provided the SO_x concentrations are not excessively high. The oxides of sulfur are removed by wet scrubbing and by limestone scavenging; their initial concentration levels are reduced by the use of low-sulfur coals, by coal cleaning, etc. The formations of particulates and flyash may be minimized by coal beneficiation and they may be removed from the flue gases by using electrostatic precipitation and other means.

The following is a listing of some identified problem areas: (a) technological implementation to meet future reductions in allowable NO_x emissions; (b) integrated management of boiler feed, boiler operations, and boiler emissions; (c) coal beneficiation to reduce pollutant outputs; (d) SO_x removal within the boilers and from the flue gases; (e) improved understanding of chemical processes that couple NO_x , SO_x , HC, and flyash productions; (f) chemical nature and possible toxicological implications of hydrocarbon and trace-metal emissions; (g) modifications of fluidized bed combustors to reduce NO_x emissions and carbon carryover; (h) the special problems involved in the control of emissions from very small combustors.

C. Coal-Dust Fires and Explosion Hazards

M. Hertzberg (U.S. Bureau of Mines/PETC) presented a comprehensive overview of work at the Bureau of Mines dealing with coal-dust fire and explosion hazards. This presentation included the results of deliberations at a workshop on "Coal Dust Fire and Explosion Hazards in Cement Plants, Power Plants, and other Surface Facilities," sponsored by the U.S. Bureau of Mines/PETC and held in Denver, Colorado, April 1982. We refer to published articles¹⁻⁴ for a description of these important and continuing investigations.

Data are available for particular coals on the lean flammability limit (in mg/l) as a function of the mean particle size. The energy required for ignition has been mapped as a function of the lean-limit concentration for various hydrocarbons and also for coal-dust dispersions in air. Maps are available showing flammable and thermally ignitable, flammable but not thermally ignitable, and nonflammable regions as functions of temperature and particle concentrations for selected coals. In general, the probability of explosion is the product of the probability of finding a flammable volume and the probability of encountering

an ignition source of adequate strength. Flammable mixtures are usually encountered in coal pulverizers. Hence, explosion avoidance means avoidance of ignition. Nonflammable coal-dust dispersions may be created by reducing oxygen concentrations below 11% or by the introduction of sufficiently large concentrations of steam, flue gases or other "inerting" materials (e.g., concentrations of $\text{NH}_4 \cdot \text{H}_2\text{PO}_4$ exceeding about 20-30% of the coal-dust concentrations).

CCAWG discussions concerning the need for basic studies to supplement the work at the Bureau of Mines/PETC did not lead to definitive conclusions. It is generally apparent that operational difficulties can be resolved by intelligent applications of knowledge accumulated by M. Hertzberg and his associates. On the other hand, coal-dust explosions do occur and represent a hazard not only in coal-mining operations but also in the type of coal handling involved in the use of pulverized coal in utility and other boilers. For this reason, improved quantitative understanding of fundamental processes may well deserve augmented effort, especially with regard to the possible importance of equipment specifications in defining both flammability limits and ignition requirements.

References

1. J. L. Elder, L. D. Schmidt, W. A. Steiner, and J. D. Davis, "Relative Spontaneous Heating Tendencies of Coals," Technical Paper 681, U.S. Department of Interior, Bureau of Mines, 1945.
2. F. L. Shea, Jr., and H. L. Hsu, "Self-Heating of Carbonaceous Materials," Industrial & Engineering Chemistry Product Research and Development 11, 184-187 (1972).
3. M. Hertzberg, K. L. Cashdollar, and J. J. Opferman, "The Flammability of Coal Dust-Air Mixtures," RI 8360, U. S. Department of Interior, Bureau of Mines, PETC, 1979.
4. M. Hertzberg, K. L. Cashdollar, and C. P. Lazzara, "The Limits of Flammability of Pulverized Coals and Other Dusts," Eighteenth Symposium (International) on Combustion, pp. 717-729, The Combustion Institute, Pittsburgh, PA, 1981.

CCAWG MEETING AT THE
MORGANTOWN ENERGY TECHNOLOGY CENTER (METC),
MORGANTOWN, WEST VIRGINIA[†]
(July 15, 1982)

1. Introduction

The following CCAWG and ex officio members attended the METC meeting: J. M. Beér, J. Birkeland, C. R. Bozzuto, I. Glassman, A. K. Oppenheim, S. S. Penner, R. Roberts, L. D. Smoot, C. Wagoner, and W. Wolowodiuk. The EPRI representative was S. Drenker. Host institution participants included A. Pitrolo, J. S. Wilson, K. Castleton, F. Crouse, W. French, L. Graham, J. Halow, A. Hall, J. Hall, L. Headley, K. Markel, J. Notestein, J. Y. Shang, D. Waltermire, and J. Williams. The meeting agenda is reproduced in Table 1. The morning session was devoted to a review and discussion of atmospheric (AFBC) and pressurized (PFBC) fluidized combustion of coals and other fuels. Most of the afternoon session dealt with environmental control and research programs. Also included in the afternoon presentations was a discussion of METC studies dealing with coal-water mixtures. The meeting was concluded with a brief tour of METC facilities.

2. Fluidized Bed Combustion^{*}

Complete sets of viewgraphs for all of the presentations were furnished by the speakers and are available on request. Here, we present a tutorial overview of these presentations.

[†]Prepared by S. S. Penner.

^{*}The proposed FY83 METC budget is $\$6.3 \times 10^6$ for advanced concepts relating to AFBC ($\$1 \times 10^6$ for advanced low-rank coal studies, $\$1.48 \times 10^6$ for an advanced PDU and components, $\$2.3 \times 10^6$ for advanced technical projects chosen in response to RFPs, and $\$1.02 \times 10^6$ for in-house projects); a total of $\$1.5 \times 10^6$ has been proposed in support of industrial applications ($\$0.25 \times 10^6$ each for work at Gilbert, E. Stroudsburg, U.S. Navy/Great Lakes, Shamokin, Wilkes-Barre, and in-house projects).

Table 1. Agenda for CCAWG meeting at METC (July 15, 1982).

METC AFB & PFB Overview of Activities	8:00
- Introduction - J. S. Wilson	
- AFB Overview - Art Hall	
- PFB Overview - Floyd Crouse	
- PFB Modeling - Tom O'Brien	
- Needs in FBC Research - Jerry Shang	
EPRI Overview - S. Drenker	9:30
MIT FBC Overview - J. Beér	10:15
Foster Wheeler Overview - W. Wolowodiuk	11:30
Lunch in Conference Room	12:00
METC Environmental Control Technology Review	12:30
- Introduction - Jack Halow	
- Flue Gas Cleanup Overview - John Williams	
- Hot Gas Cleanup Overview - Ken Markel	
- Needs in Cleanup Research	
- Fundamental Needs - Kent Castleton	
- Modeling Needs - Larry Headley	
METC Review of Gas Turbine Applications of Coal Water Mixtures	3:15
- Overview - Floyd Crouse	
- METC Activities - Debbie Waltermire	
Tour of METC Facilities - Emphasis on FBC, Coal/Water, Cleanup	4:00
Leave for Pittsburgh Airport	5:00

A. Why Fluidized-Bed Combustion?

Fluidized-bed combustion offers the following potential advantages: fuel flexibility, lower costs for meeting environmental regulations (by using SO₂ clean-up with limestone and reducing NO_x production), simplicity of operation (because of the absence of sootblowers and slagging) and low maintenance costs, reduced size and busbar costs in utility operations, and reduced cost sensitivity to the unit size.

B. AFBC Developments

Fluidized beds represent a logical evolution in coal-fired power plants from the stoker and pulverized coal burner (see Fig. 1 for a schematic diagram). Details of representative industrial fluidized bed steam generators are shown in Figs. 2 to 5 and have been reproduced from a paper by R. L. Gamble.^{2,3} Industrial fluidized-bed combustors represent developed technology. On the other hand, the larger units needed for utility applications remain to be designed, built, and tested on substantial scales.

Current programs on AFBC and PFBC encompass process and engineering developments and commercial demonstrations.

¹S. Drenker (EPRI), CCAWG meeting at METC, July 15, 1982.

²R. L. Gamble, "Industrial Fluidized Bed Steam Generation," ASME Paper 81-IPC-FU-2, The American Society of Mechanical Engineers, 345 E 47th Street, New York, NY 10017.

³W. Wolowodiuk (CCAWG), CCAWG meeting at METC, July 15, 1982.

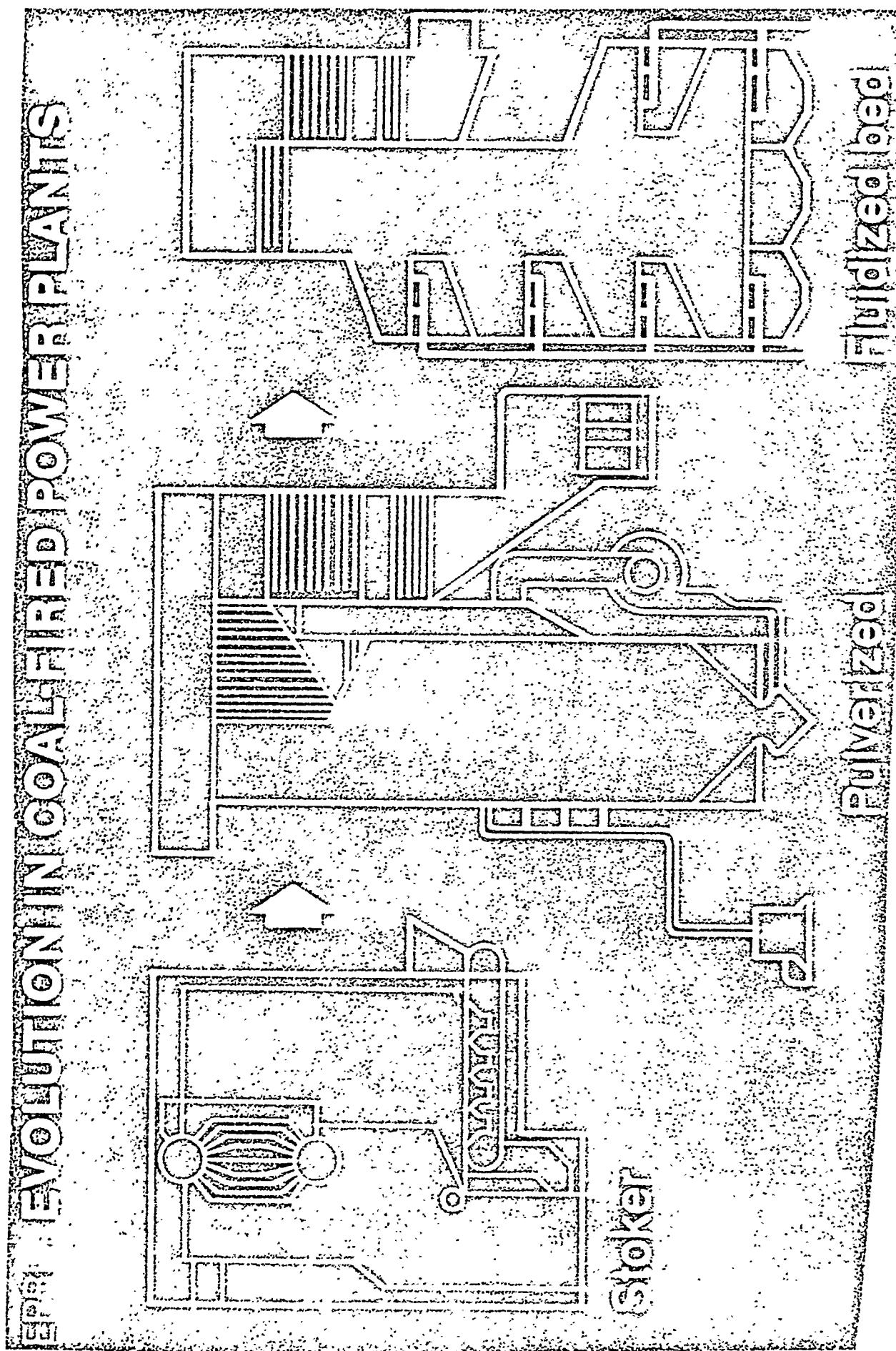


Fig. 1 Schematic diagram showing changes in the geometrical designs of coal-fired power plants from stoker to pulverized coal burner to fluidized-bed combustor; reproduced from S. Drenker.

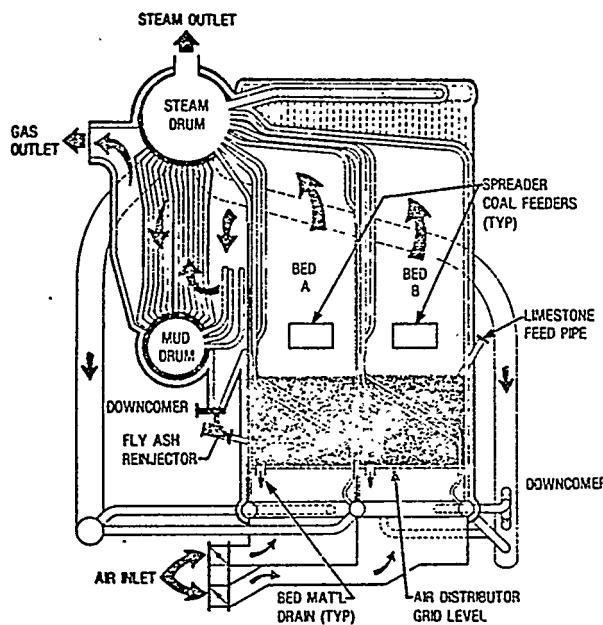


Fig. 2 Georgetown University steam generator ($12.6 \text{ kg/s} = 100,000 \text{ lb/h}$) using AFBC; this unit was put into service in 1979 and has operated successfully with full automatic control. An over-bed coal-feed system [with standard spreader feeder as in stokers using coal smaller than 32 mm (1.25 in.)] and a natural circulation steam flow with balanced draft are used. Reproduced from Gamble.²

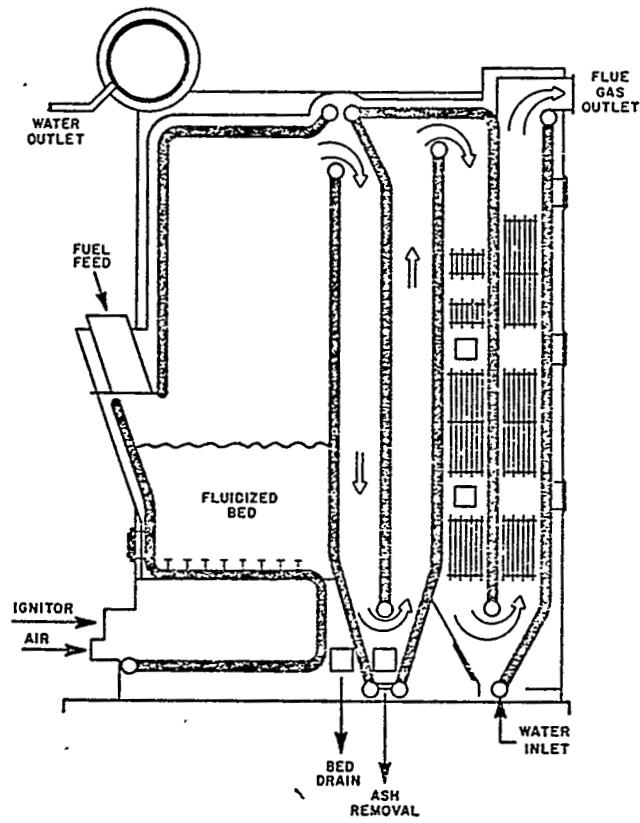


Fig. 3 City of Eksjo (Sweden) hot-water generator which normally burns municipal refuse and wood chips in a fluidized bed of sand at an output of 5 MW_t; with oil firing, the output level is raised to 10 MW_t. Forced circulation is used for the water flows. Reproduced from Gamble.²

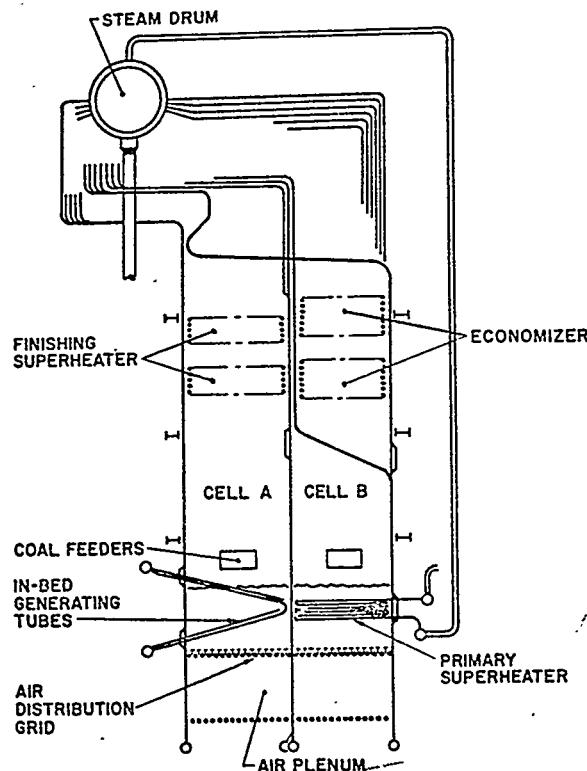


Fig. 4 Royal Dutch Shell (Netherlands) steam generator built by the Foster Wheeler Corporation with start-up in 1982. This unit operates on bituminous coal to produce superheated steam for a backpressure turbine generating up to 6 MW_e while providing steam for heating an oil-tank farm and associated piping. The over-bed feed system is similar to that used in the Georgetown facility (Fig. 2). Reproduced from Gamble.²

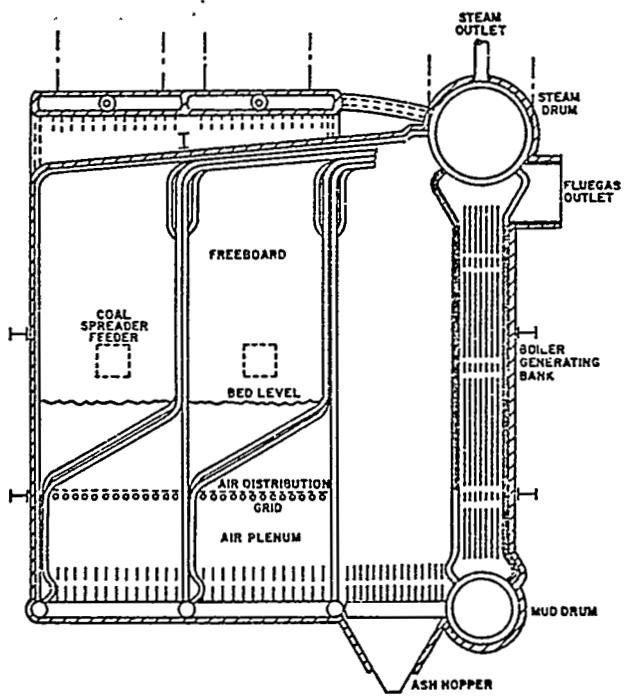


Fig. 5 Idaho National Energy Laboratory saturated steam generator [Idaho Falls, Idaho ($8.5 \text{ kg/s} = 67,500 \text{ lb/h}$)] for heating a nuclear fuel-processing facility (start-up is planned for 1984). This unit is similar to the Georgetown AFBC unit, except that space has been provided between the fluidized bed and the boiler intake for the addition of a superheater for cogeneration. Reproduced from Gamble.²

Significant improvements in process efficiency have been achieved by increasing the freeboard length above the fluidized bed.¹ For example, the Rivesville plant (1972) had a 2-ft freeboard length and a combustion efficiency of 88%; a 6-ft x 6ft section with an 18-ft freeboard showed 94% combustion efficiency; when recycle was added to this unit, the combustion efficiency exceeded 99%.¹ The EPRI AFBC development program on a 6ft x 6ft bed included tests with bituminous coal containing 4% of sulfur and lignite with 0.5% of sulfur. Limestone was added to effect 90% SO_2 removal. Required Ca/S ratios were 2.0 for the bituminous coal and 1.5 for the lignite at maximum temperatures of 1550 and 1450°F, respectively; NO_x emissions were controlled in both cases at 0.2-0.3 lb per 10^6 Btu while successful operation was achieved with bed load reductions of 2:1, implemented at a rate of 10%/minute.¹ These operational characteristics, together with a reduced number of coal-feed points, are scheduled to be implemented by EPRI in a 20 MW_e pilot at the TVA in Paducah, Kentucky (with demonstration testing beginning in 1988).¹ Support studies include the definition of materials suitable for use in the superheater and modeling with predictions of heat transfer and bed dynamics.¹ A schematic diagram of the 20 MW_e facility is shown in Fig. 6. Load turn-down methods in utility applications include both reductions and redistributions of coal and limestone feed rates. Recycle options include pneumatic injection with solids cooling, forced under-bed injection without cooling, and gravity injection.¹ A long-range program may involve shop fabrication of 100 MW_e boiler units with barge transport to users, a procedure that could provide access to 200 GW_e of installation capacity representing 93% of U.S. electrical power demand. The 100 MW_e units may provide turbocharged steam generation (from a boiler-cyclone-filter-turbocharger sequence) with the advantage of reduced gas-turbine firing temperature, thereby reducing metallurgical demands, simplifying structural design, and allowing reliable

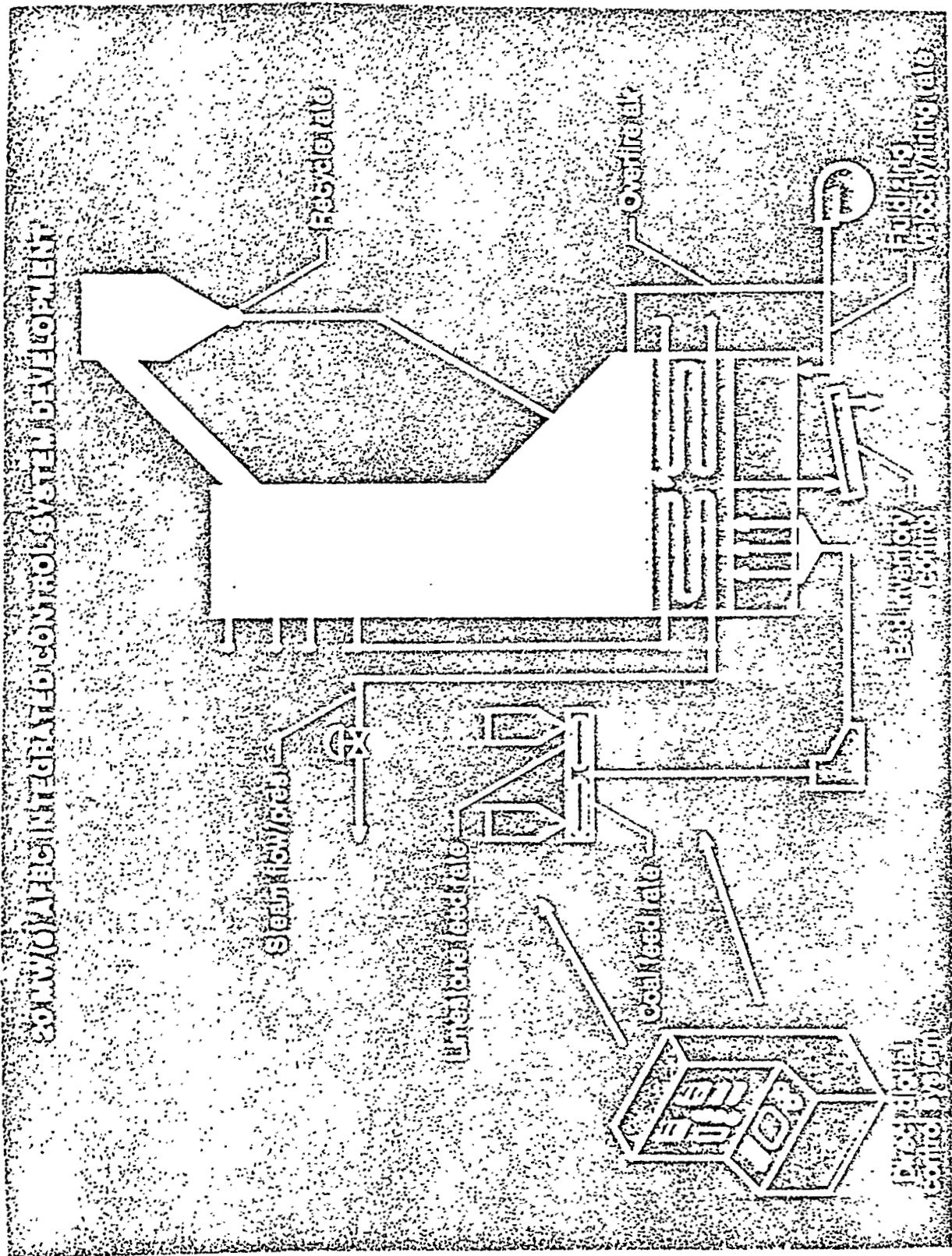


Fig. 6 Schematic diagram of the proposed 20 MWe EPRI AFBC; reproduced from S. Drenker.¹

filtration at reduced turbine-generator speed.¹ Remaining development problems on AFBC deal primarily with combustor performance and reliability.

The Foster Wheeler development program³ has involved performance and reliability evaluations on an 18-in. diameter AFBC and (see Fig. 7) on a 20-in. x 20-in. unit (operated for 4.5 y).^{*} Both in-bed and over-bed feed systems have been tested with fly-ash recycle and NO_x control (through injection and cleanup with NH₃ and staged combustion, which showed that NO_x emissions were smaller for smaller residual O₂ levels).³ The influence of fuel pelletization has been studied, especially in efforts to achieve improved limestone utilization.³ Cold-model and subcomponent testing, as well as work on PFBC, have been performed.³ Cyclone recycle has typically been used.

With in-bed feed, control of surface moisture was required and an excessively large number of feed points was needed (one per 16-25 ft²).³ Fuel distribution to the feed points was difficult to control and small fuel sizes (0.5" x 0) were required.³

With over-bed feed (see Fig. 2 for an operating unit), larger particles (1.25" x 0) could be handled, the surface moisture problem was absent, addition of water improved combustion efficiency, the required number of feed points was smaller (one per 110 ft²).³ There is, however, a tendency for the fluidized bed to malfunction with improper fuel distribution.³ Using a spreader-type stoker feeder, the coal throw distance is 6.70 m in the 20" x 20" unit.³ The use of fly-ash recycle eliminates

*The following are performance figures for the 20-in. x 20-in. unit: feed rates of 100-500 lb/h, bed temperatures of 1300-2100°F, superficial velocities of 4-12 ft/s, 1-100% of excess air, Ca/S ratios of 0-20, in-bed and over-bed feeds, fly-ash recycle, and staged combustion. Fuels used include North Dakota lignite, petroleum coke, Irish Arigna coal, anthracite culm, coal and wood waste mixtures, pelletized coal fines, pelletized sludge, and process gas. Combustion efficiencies ranged from 82 to 98+%.

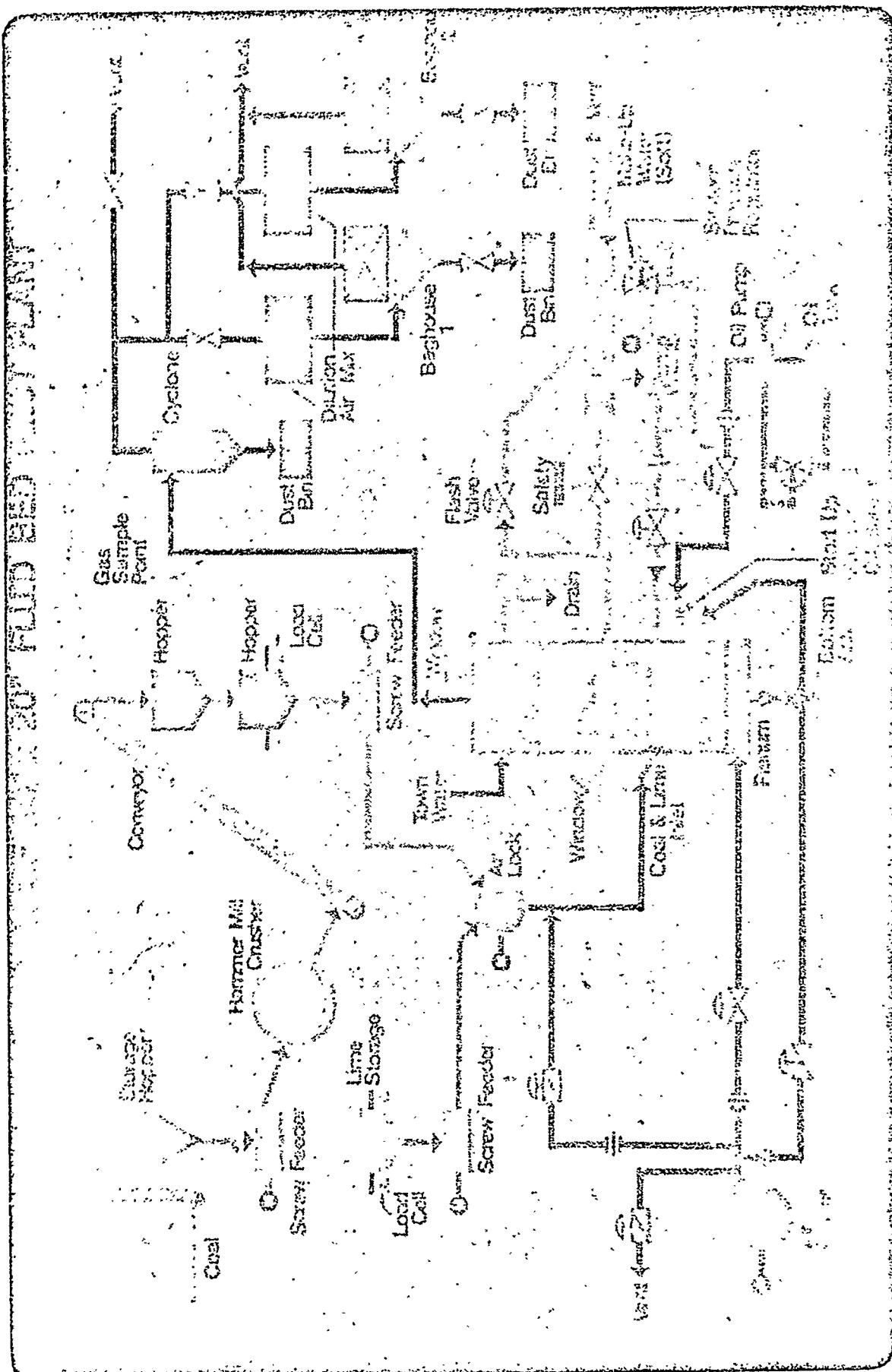


Fig. 7 Flow diagram for the 20" x 20" ₃ Foster Wheeler fluidized bed pilot plant; reproduced from W. Wolowodiuk.

the necessity for achieving carbon burn-up in the cell, improves both combustion efficiency and sulfur burn-up, and reduces NO_x emission.³ Subcomponent testing included work on distribution plates, feeders, fuel splitting, pneumatic transport, hot-gas transfer ducts, and the pneumatic classifier.³ The air-distribution arrangement was found to be of critical importance.³ Two-dimensional, cold-flow models were used to study the effects of tubes in the bed.³ Extensive operational tests have been performed relating to the influence of the Ca/S mole ratio on the percentage of sulfur retained and mole ratios greater than about 3 were found to be necessary in order to effect 90% sulfur removal. Limestone sulfation is believed to be enhanced by hydration (see Fig. 8 for a model of this hydration process).

C. PFBC Developments

The EPRI studies have shown that FeCrAlY prevents erosion and corrosion by the PFBC dust (in a test at 1600°F, 1170 ft/s flow speed, 100 ppm of dust with 5% of the particles $>10\mu\text{m}$, and added $\text{Na}_2\text{SO}_4 \cdot \text{K}_2\text{SO}_4$).¹ Program development cited by Drenker¹ involved a 0.8 ft² bed area test facility, 1.0 ft diameter, at Exxon using a coal-feed rate of 0.14 t/h. This work has been followed by tests performed at the U.K. National Coal Board with 6 ft² bed area, 2 ft x 3 ft bed lengths, 0.5 t/h coal feed rate, 5 atm pressure. Current IEA-sponsored work at Grimethorpe (25 MW_t, P = 10 atm, 1000 h of operation) in the UK involves a 42.9 ft² bed area, 6.5 ft x 6.5 ft dimensions, and ≈ 10 t/h of coal feed. A 100 MW_e prototype will have two sections with 196 ft² bed area, each with 14 ft x 14 ft dimensions, and will use 21 t/h of coal feed in each.¹ Net heat rates (in Btu/kWh_e) have been estimated to be 8470 for PFBC, 9640 for AFBC, and 9860 for a conventional pulverized coal burner; corresponding capital cost estimates (in \$/kW_e) are 875, 820, and 995, while the estimated

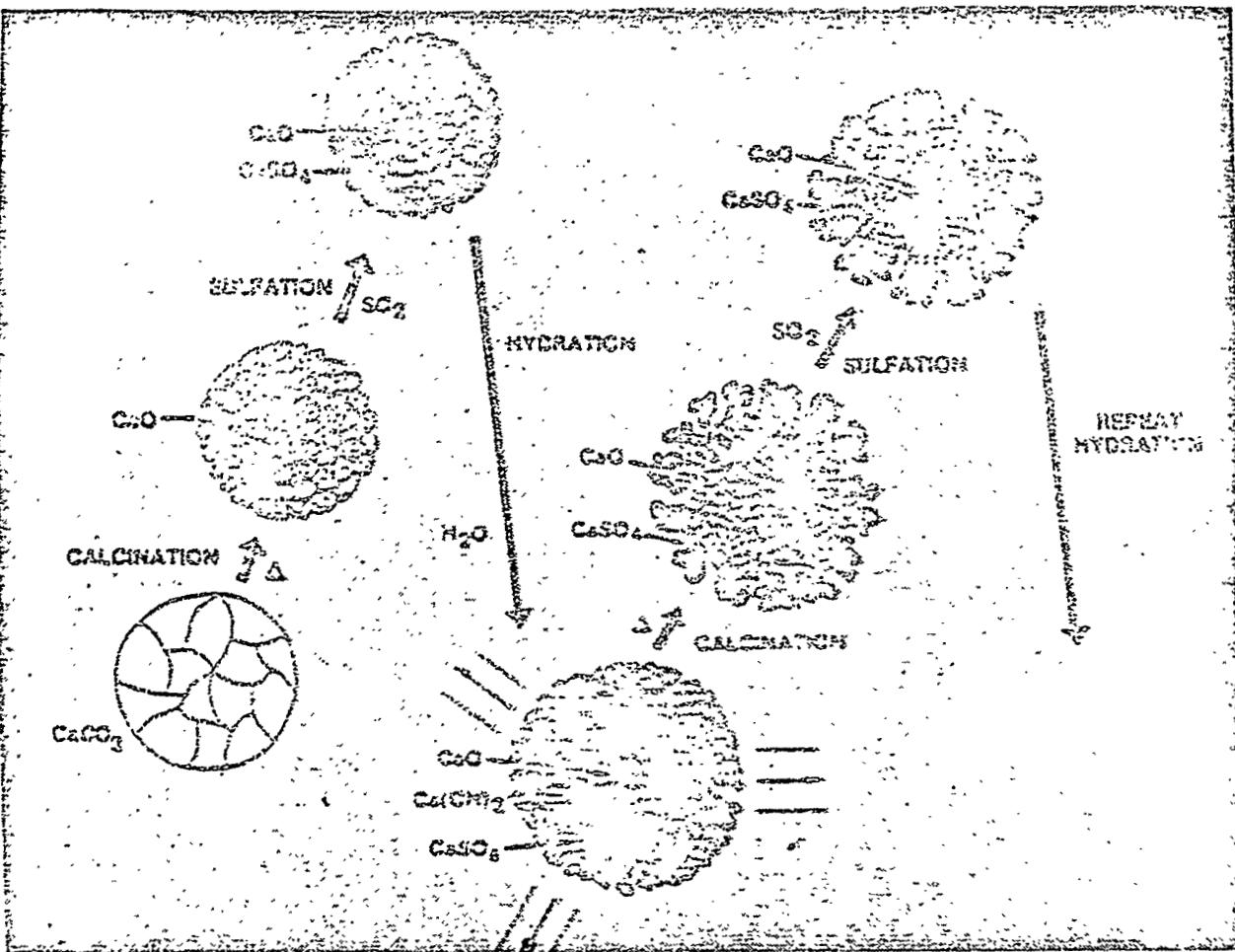


Fig. 8 Enhancement of limestone sulfation by hydration;
reproduced from W. Wolowodiuk.³

electricity costs (levelized for 1981-2000 in mills/kWh_e) are 74, 77, and 86, respectively.¹ The conceptual design of a combined cycle PFBC is shown in Fig. 9.

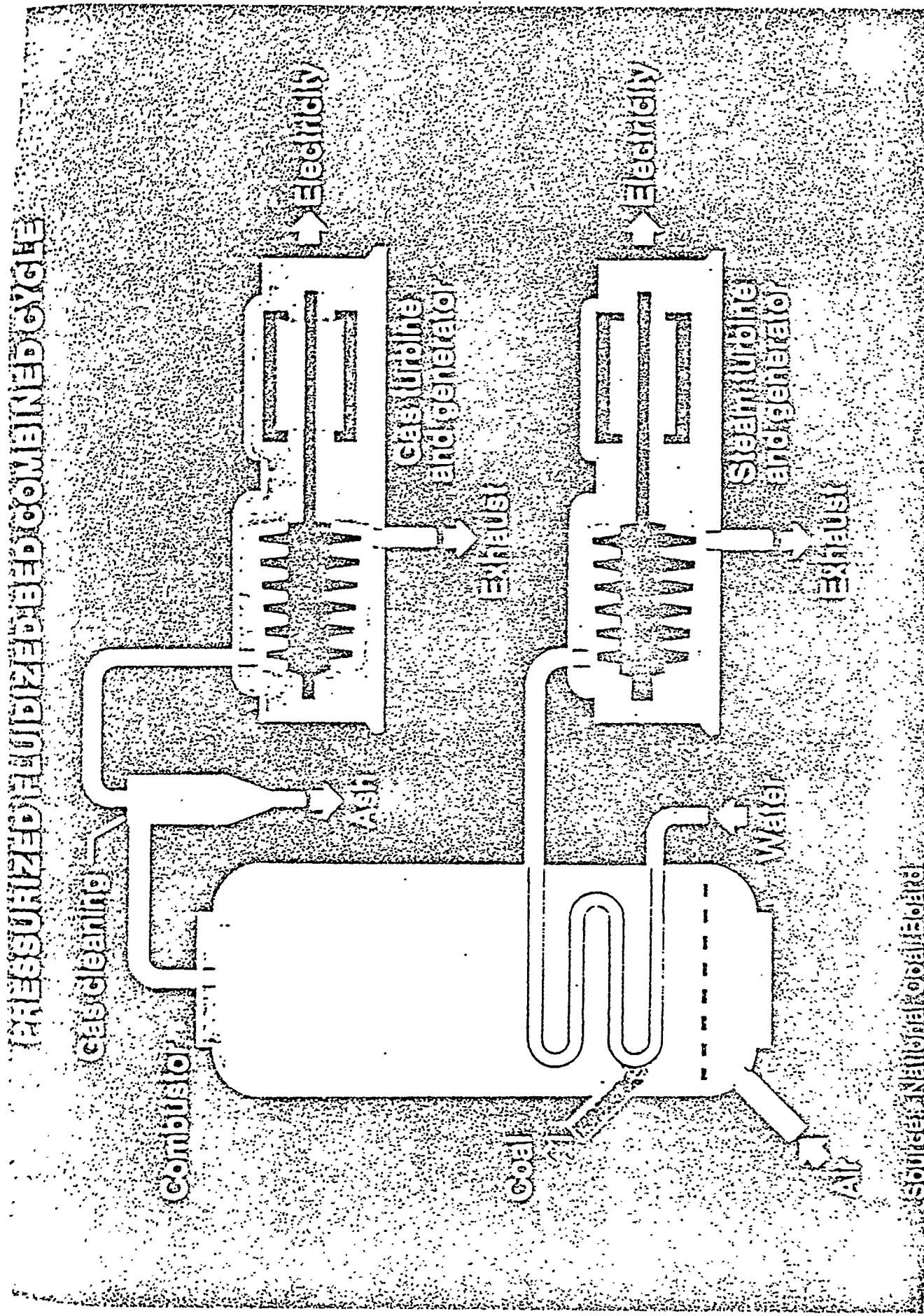
A great deal of fundamental and development work needs to be done on the PFBC.⁴ A 13 MW_t pilot plant operating at 7 atm pressure is being constructed by Curtiss Wright for start-up in 1983.⁴ Other studies are in progress at NYU, GE, ANL, ORNL, and METC.⁴

D. R&D Needs on AFBC and PFBC

Research needs in AFBC were discussed by J. M. Beér and J. Shang (METC), while T. O'Brien (METC) emphasized model design and development.⁵ R&D needs in PFBC were discussed by F. Crouse (METC).⁵ The identified R&D needs reflect the operational problems encountered in fluidized bed combustors and include solids handling (including fines), design of the feeding system, heat and mass transfer phenomena, fluidized bed stability and dynamics, reaction kinetics in multiphase flow processes, pollutant controls through in-bed removal techniques, combustion efficiency determinants, modeling, control strategies, etc.⁵ Knowledge gained from catcrackers cannot be applied directly because the particulate sizes involved are generally much (i.e., about a factor of 10) larger.⁵ The importance of the freebroad design on performance has been clearly demonstrated and it is therefore appropriate to consider the sequential and interactive phenomena that couple the fluidized bed to the freeboard. Retrofitting of existing stoker-fired boilers represents a special challenge. The use of cold-flow models as a predictive performance tool requires quantification.

⁴F. Crouse (METC), CCAWG meeting at METC, July 15, 1982.

⁵CCAWG meeting at METC, July 15, 1982.



AB-163

Fig. 9 Schematic diagram of a combined cycle PFBC.

J. M. Beér has identified the following topical areas as representing research needs relating to the freeboard in AFBC: (1) entrainment of solid particles from the bed and their elutriation from the freeboard, as affected by bed operating conditions and freeboard design parameters; (2) burn-out of CO, hydrocarbons and of solid carbon particles as affected by freeboard temperature, height and the mode of particle feed; (3) sulfur capture by sorbent particles entrained from the bed; (4) reduction of NO_x by CO and solid carbon along the freeboard height. For the fluidized bed itself, the following research areas were emphasized by Beér:⁵ (1) movement of particles after injection into the bed or for over-bed feeding; (2) evolution and combustion of coal volatiles to estimate locally reducing zones and hot spots; (3) carbon burning as affected by particle swelling, fragmentation, the build-up of ash layers and changing pore structures of the coal char; (4) the flow near the distributor, bubble size, gas-emulsion exchange coefficients along the bed height; (5) the respective roles of mixing and chemical kinetics in the burn-out of CO in the bed; (6) the transient operation of the fluidized bed, including stability limits; (7) the evolution of fuel-nitrogen from the coal and the formation of NO_x from volatiles- and char-nitrogen; (8) the reduction of high NO_x concentrations found experimentally near the coal injection point by reactions between NO_x and volatile nitrogenous compounds and NO_x or carbon; (9) the kinetics of sulfation of CaO, the effects of combustion, and the pore structure of the calcined stone upon sorbent utilization.

Research needs in PFBC are analogous to those listed for AFBC at elevated pressure levels.

3. Environmental Control Technologies

CCAWG continued discussions relating to environmental control technologies.* An overview of the advanced environmental control technology program at METC was presented by J. Halow⁶ and included considerations of flue-gas cleanup (using lime and limestone scrubbers, other flue gas desulfurization techniques, and combined NO_x/SO_x/particulate flue-gas cleanup), gas-stream cleanup (for turbine systems, fuel cells and other technologies), and studies of cleanup base technologies (including waste management, instrumentation, and systems economic comparisons). Also noted was METC phase-out of lime and limestone R&D relating to advanced flue-gas desulfurization (FGD) and continuing studies on combined (NO_x/SO_x/particulates) flue-gas cleanup (including such novel ideas as E-beam utilization to facilitate reactions for conversions of NO_x and SO_x);⁷ gas-stream cleanup at elevated temperatures (>10³°F) and pressures (>6.5 atm) in PFBC, turbines (with emphasis of the effect of Na on turbine life and the utilization of absorbents such as activated bauxite, diatomaceous earths, and other aluminosilicates), and particulate removal (by using an electrocyclone, electrostatic precipitation, electrostatic granular bed filters, barries such as ceramic bag and granular bed filters, moving panel beds, cross-flow membranes, augmentation agglomeration, etc.);⁸ identification of the principal deleterious constituents in coals and reaction mechanisms involving mineral inclusions and entrained particles;⁹ modeling of complete cleanup systems.¹⁰

* See AB-3, CCAWG meeting at Combustion Engineering (June 24, 1982) for previous discussions of this important topic.

⁶ J. Halow (METC), CCAWG meeting at METC, July 15, 1982.

⁷ J. Williams (METC), CCAWG meeting at METC, July 15, 1982.

⁸ K. E. Markel, Jr. (METC), *ibid.*

⁹ K. Castleton (METC), *ibid.*

¹⁰ L. Hadley (METC), *ibid.*

4. METC Studies of Coal-Water Mixtures (CWM)

The potentially important topic of combustion of CWM in a gas turbine was also addressed.^{11,12}

¹¹F. Crouse (METC), CCAWG meeting at METC, July 15, 1982.

¹²D. Waltermire (METC), *ibid.*

5. Cost Analysis of the Application of Coal-Water Mixtures (CWM) to Gas-Turbine Firing*

This analysis relates to the magnitude of the price differential that may be tolerated when using clean fuel combined cycle (CFCC) plants in gas-turbine applications in place of coal. Very high numbers, such as \$5-7/MM Btu price differential, have been given as the basis for pursuing coal-water mixtures (CWM) for turbine applications. It is easy to show that these figures cannot be right. Clean fuel combined cycles are available today by firing oil or gas. Very few have been sold because the prices of oil and gas cannot compete with coal. The following calculations bear out this conclusion.

Using realistic figures of \$600/kW_e for a CFCC plant and \$1000/kW_e for a conventional coal-fired plant, 7000 hrs/yr operation, 30 years leveled fuel costs, 20% capital charges, 10,000 Btu/kWh_e heat rate for conventional plants, and 8,000 Btu/kWh_e heat rate for CFCC plants, the first year fuel-cost differential is \$1.38/MM Btu. This statement will now be verified.

We list in Table 1 the costs for conventional and CFCC plants.

The fuel costs are a function of heat rate, leveling factor, and first year fuel price. Based on the EPRI leveling procedures, the leveling factor is about 2. The first year coal price is about \$1.50/MM Btu. Thus, the leveled coal price is \$3.00/MM Btu. The leveled fuel cost is then

$$C_{\text{leveled}} = (\$1.50/\text{MM Btu}) \times 2 \times (10,000 \text{ Btu/kWh}_e) \\ \times (1000 \text{ mills/\$}) = .30 \text{ mills/kWh}_e .$$

*Prepared by C. R. Bozzuto.

Table 1. Cost comparisons between conventional and CFCC plants.

Costs and Charges	Conventional Plant	CFCC Plant
Capital cost	\$1000/kw _e	\$600/kw _e
Capital charges	\$200/kw _e -yr	\$120/kw _e -yr
Annualized electricity cost	28.6 mills/kWh _e	17.1 mills/kWh _e
Levelized fuel cost	30 mills/kWh _e	Y mills/kWh _e
O&M (including limestone)	8.4 mills/kWh _e	3.9 mills/kWh _e
Total energy costs:	67 mills/kWh _e	21 + Y mills/kWh _e

The leveledized clean fuel price differential is (compare Table 1)

$$\frac{[(67 - 21) \text{ mills/kWh}_e] \times (10^6 \text{ Btu/MM Btu})}{(8000 \text{ Btu/kWh}_e) \times (1000 \text{ mills/\$})} = \$5.75/\text{MM Btu} .$$

The first year clean fuel price is thus seen to be \$2.88/MM Btu. Therefore, the differential first year fuel price between coal and coal-water mixture must be less than \$2.88-\$1.50/MM Btu or \$1.38/MM Btu. The coal-water mixture fuel must, of course, meet all gas-turbine and environmental regulations and specifications. This would include at least 90% sulfur removal, 99% particulate removal, and sufficient nitrogen removal to meet NO_x specifications. This degree of beneficiation has not been demonstrated for any reasonable cost. Coal liquefaction or coal gasification will deliver this clean fuel at a price of roughly double that of oil or gas. Since neither oil nor gas are currently available at less than \$1.38/MM Btu fuel price differential, it seems unlikely that the goals of the CWM program for turbine applications will be met.

REPORT OF SITE VISIT TO THE GENERAL ELECTRIC COMPANY,
CORPORATE RESEARCH AND DEVELOPMENT -
STUDIES ON COAL COMBUSTION AND UTILIZATION*
(August 5, 1982)

S. S. Penner visited the General Electric Research Laboratory, primarily for the purpose of assuring a detailed presentation to CCAWG at a later date on the potential merits of utilizing CWM and other low-grade fuels in gas turbines. Discussions were held with N. J. Lipstein (Manager, Fluid Mechanics and Combustion Branch), M. Lapp (Combustion Diagnostics), D. P. Smith (Manager, Process Operations Unit), J. C. Blanton (Mechanical Systems and Technology Laboratory), P. G. Kosky (catalytic coal gasification), and D. H. Maylotte (tomography of heated coals during pyrolysis). D. P. Smith agreed to attend the October 18 CCAWG meeting at Babcock and Wilcox and to discuss the potentials and problem areas relating to coal utilization in gas turbines.

Brief summaries of the research programs discussed are given in the following paragraphs.

1. Combustion Diagnostics

M. Lapp has been one of the pioneers in the application of laser-Raman spectroscopy to combustion systems. Current research deals with instantaneous species concentration and temperature measurements (using laser-Raman scattering) on turbulent jets. The program will include determinations of correlation functions involving species and temperatures and is closely related to recently published modeling studies by R. Bilger (Sidney, Australia).

* Prepared by S. S. Penner.

2. Use of Low-Grade (Residual) Fuels in Gas Turbines

Extensive studies have been performed on the use of high-ash fuels (residuals) in gas turbines. Erosion, corrosion, and depositions (ash fouling) were observed primarily in the turbine nozzles. With heavy resids, the primary operational problems result from the presence of vanadium. This element is not readily removed from residual oils but is generally not an important constituent of coals. Experimental studies have been performed with Mg-addition (at a weight ratio about 3 times that required for a stoichiometric mixture) to remove the V. An ash deposit is observed on the nozzles and blades after prolonged operation (i.e., several hundred hours), which can be removed by "nutshelling" (i.e., temporary injection of crushed walnut shells at a mass ratio of about 0.5 of that of fuel). A substantial data base has been accumulated on the operation of high-ash residual fuels in gas turbines. The principal design features and problem areas are sketched in Fig. AB-5.1.

Destructive compressor surges result from plugging of the first-stage nozzle. The use of higher temperatures to eliminate plugging of the first-stage nozzle tends to move the operational problems to the first-stage rotor and further downstream.

The extent of wall deposition is primarily determined by the wall temperature. Extensive simulation experiments on wall deposition have been performed by inserting an air-cooled, flat plate in a 3-in.² test section and measuring deposit formation from a number 2 fuel oil to which dopants had been added to simulate high-ash resids. The data in Table AB-5.1 indicate the importance of local temperature. Experimental studies were performed on carefully modeled nozzles with four vanes. The flow speed was sonic at the throat while operating with pressure ratios of 2 to 1. An effective nozzle area was obtained as a function of time by determining the percentage of nozzle blockage per 100

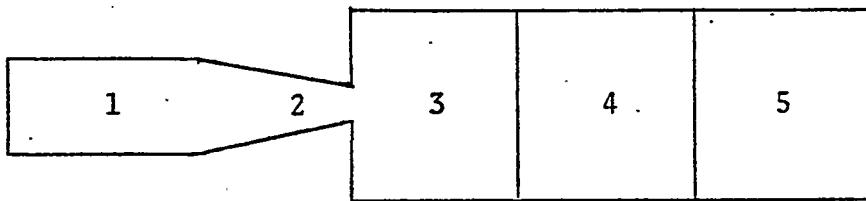


Fig. AB-5.1 Schematic diagram showing operation of a gas turbine with high-ash resids; 1, combustor operating at about 4000°F with the formation of particulates; 2, transition piece which yields exit temperatures of about 2000°F and allows particle growths by condensation and agglomeration; 3, first-stage nozzle where deposition occurs by impaction and condensation; 4, first-stage rotor; 5, subsequent turbine stages.

Table AB-5.1 Deposit formation ratios observed in simulation tests with number 2 fuel oil containing dopants.

Atomic weight ratios	Mg \div V	Na \div V
Measured atomic weight ratios	10.6	3.2
Calculated equilibrium atomic weight ratios at the equilibrium gas temperature	7.14	2.3
Calculated atomic weight ratios at equilibrium for the measured local wall temperature, after prior equilibration at the equilibrium gas temperature	11.4	3.4

hours of operation. Tolerable blockage in industrial applications is up to about 5% of area (corresponding to a 10% power loss). The observed deposit thickness was not simply related to an effective throat restriction. Instead, an effective area parameter has been used to characterize nozzle plugging.

3. Applications to CWM

The METC program at GE deals with the use of CWM. A prior, EPRI-funded program was pursued during 1979-80 on a water-cooled turbine. This engine will probably be used with CWM. Engine cleanability has been found to be better with water-cooled than with air-cooled engines.

4. Publications Dealing with Turbines Using Resids

The following publications deal with turbine-engine performance while using fuels with high-ash and minerals contents:

i. R. S. Rose, A. Caruvana, A. Cohn, H. von E. Doering, and D. P. Smith, "Application of Water Cooling for Improved Gas Turbine Flexibility and Availability," ASME Paper 81-GT-68, presented March 1981.

ii. J. C. Blanton and W. F. O'Brien, Jr., "An Empirically-Based Simulation Model for Heavy-Duty Gas Turbine Engines Using Treated Residual Fuel," ASME Paper 82-GT-139.

iii. C. T. Sims, H. von E. Doering, and D. P. Smith, "Effects of the Combustion Products of Coal-Derived Fuels on Gas Turbine Hot-Stage Hardware," ASME paper 79-GT-160, presented March 1979.

5. Integrated Coal Gasification Gas Turbine Combined Cycle (IGCC) System

IGCC systems were considered by FERWG-I. While a reevaluation of these systems for utility applications may be appropriate, this study has not been specifically assigned to CCAWG. A useful 1981 evaluation of this concept is the following: J. C. Corman, "Integrated Gasification Combined Cycle Experimental Simulation," paper presented at the Eight Energy Technology Conference and Exposition, Sheraton Park, Washington, D.C., March 9-11, 1981.

DISCUSSIONS AT THE AVCO-EVERETT RESEARCH LABORATORY
OF (a) THE E-BEAM SCRUBBER AND
(b) SLAGGING COMBUSTORS*
(August 6, 1982)

The purpose of this visit was two-fold. First, to obtain first-hand information on the E-beam scrubber and, second, to commence the CCAWG assessment of the potential of slagging combustors for retrofits in industrial and utility boilers. The second topic will be discussed briefly by D. B. Stickler of Avco at the October 18 CCAWG meeting at Alliance, Ohio.

The following Avco-Everett personnel were involved in the discussions (R. Gannon, R. Kessler, R. Patrick, V. Shui, D. B. Stickler, ** D. Swallom, C. von Rosenberg, and V. Shui***). The agenda is shown in Table AB-6.1.

1. The E-Beam Scrubber

Management for the DOE-funded work on the E-beam scrubber has been transferred from METC to PETC.

The E-beam scrubber was developed by Ebara in Japan (since 1969-70) and is currently being pursued jointly by Avco and Ebara, who have cross-licensing agreements, with Ebara holding most of the patents and Avco contributing expertise in the areas of electron-beam technology developed in connection with excimer and other laser programs. According to its proponents, the E-beam scrubber will allow cost-effective SO_x and NO_x removals not only at currently mandated effluent levels but also if substantially more rigorous clean-up standards are implemented in the

* Prepared by S. S. Penner.

** D. B. Stickler supplied the information on slagging combustors.

*** V. Shui furnished all of the material dealing with the E-beam scrubber.

Table AB-6.1: AGENDA
Friday, 6 August 1982

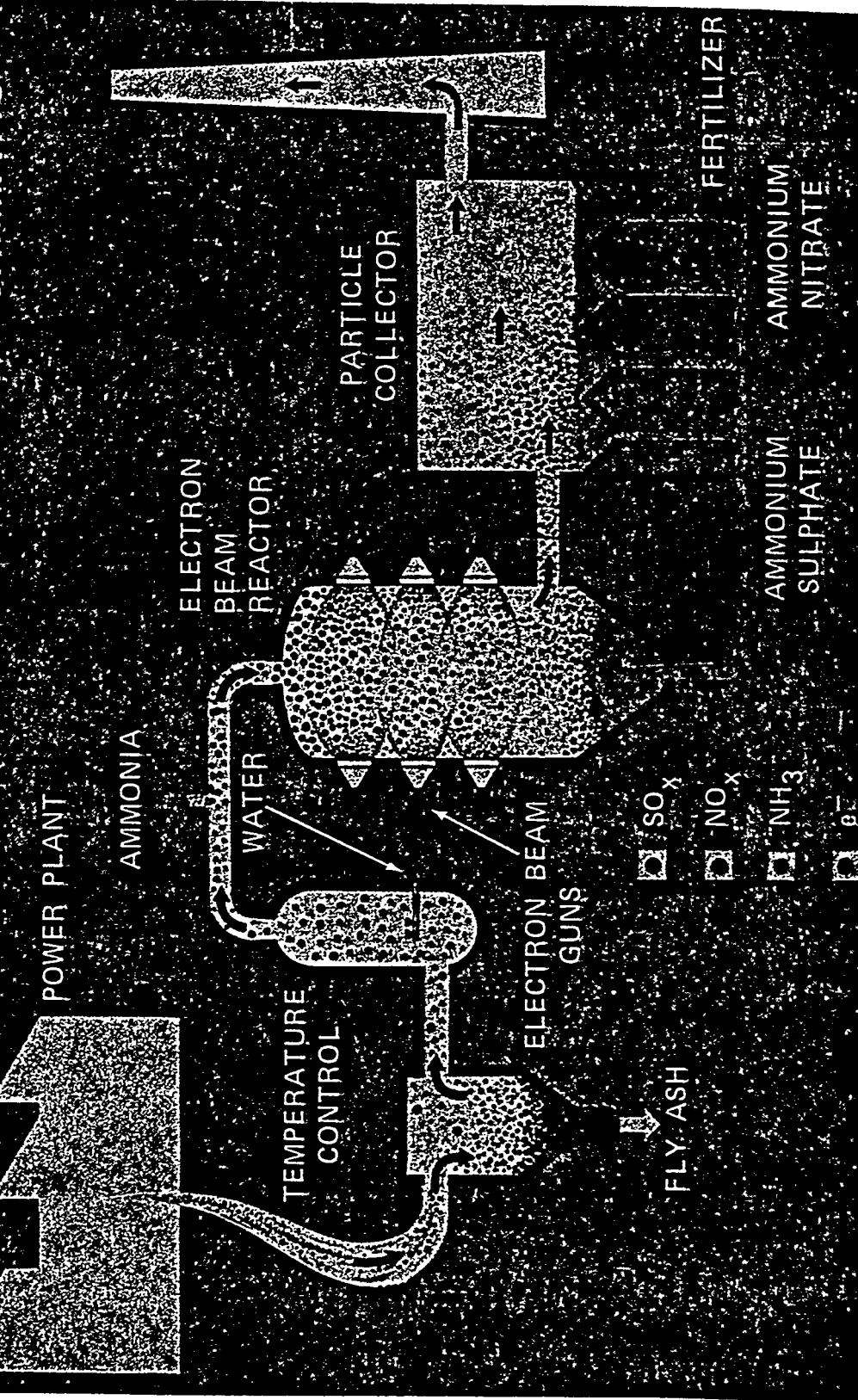
10:00 a.m.	Introduction
10:15 a.m.	E-Beam Scrubber V. Shui
11:15 a.m.	Slagging Combustor D. B. Stickler
12:15 p.m.	Lunch
1:15 p.m.	Tour of Experimental Facilities. . R. Gannon
2:15 p.m.	General Discussions

future. While a great deal of useful empirical information has been obtained in Japan, the fundamental processes involved in effluent gas clean-up on exposure to electron beams are mostly not understood and, therefore, theoretical design-optimization techniques are not yet available. DOE funding of \$600,000 is to be used for studies on a PDU (gas flow rate of 20,000 ft³/min). In Japan, effluent control technologies are so widely implemented that there remains only very limited market potential without the legislation of new performance standards. This is said to be one of the reasons for Ebara's interest in a joint venture with Avco.

A schematic diagram of the removal system is shown in Slide AB-6.1. The novel feature involves low-temperature chemical reactions with NH₃ during bombardment by electrons. For the conditions shown in Slide AB-6.1, the SO_x and NO_x are converted to the fertilizers (NH₄)₂SO₄ and NH₄NO₃, respectively, albeit at the expense of NH₃ and energy; without NH₃ injection, sulfuric and nitric acids are formed, which may also be readily collected. As is shown in Slide AB-6.2, SO_x and NO_x removals are achievable at levels substantially lower than are currently mandated.

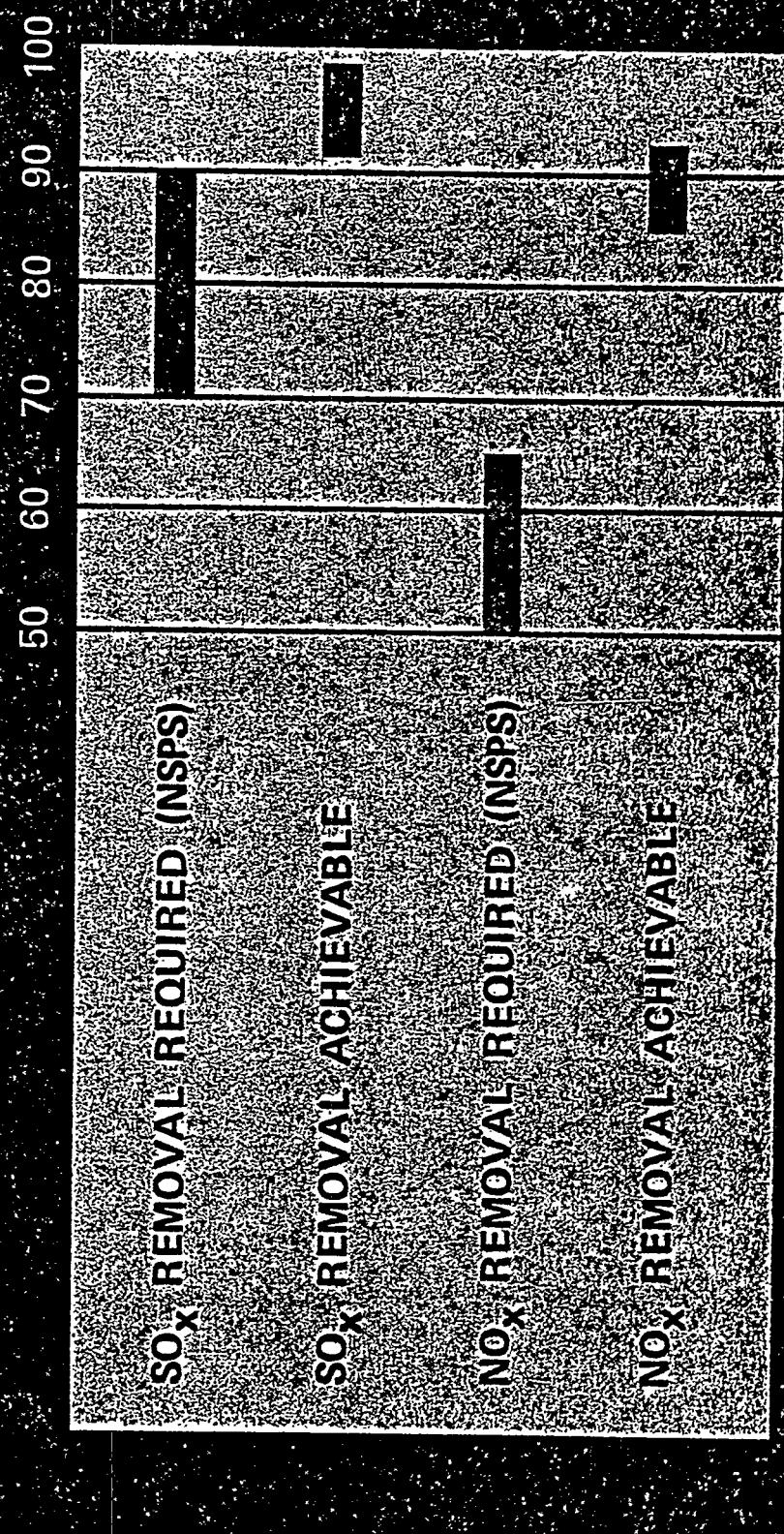
AVCO/EBARA COMBINED SO₂/NO_x PARTICULATE REMOVAL SYSTEM

E-BEAM DRY SCRUBBER SCHEMATIC



AVCO/EBARA COMBINED SO₂/NO_x PARTICULATE REMOVAL PROU

E-BEAM DRY SCRUBBER SO₂/NO_x PERCENT REMOVAL



A 1980 costing study was performed by Gibbs and Hill. The results of this study are summarized in Slide AB-6.3 and include credits for the fertilizers formed (~\$15/ton of fertilizer, as compared with current costs of \$90/ton of fertilizer).* The E-beam scrubber is seen to have substantially lower estimated cost than lime scrubbers.

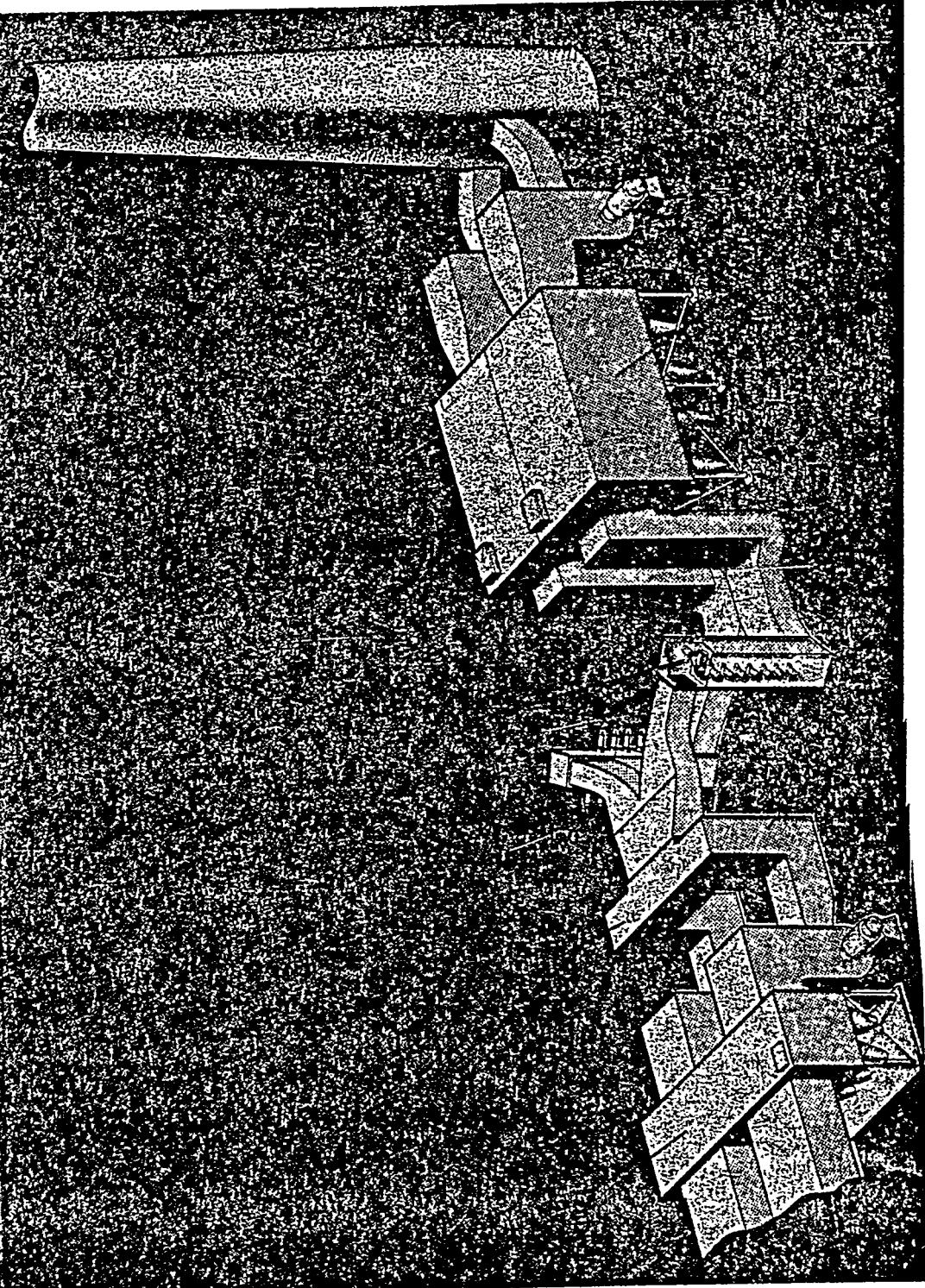
An artist's conception of a plant design is shown in Slide AB-6.4. The claimed advantages for the system are summarized in Slide AB-6.5 and include relatively low capital and operating costs, as well as cost savings because stack-gas reheat is not required. The E-beam reactor cross section is shown in Slide AB-6.6; the foil thickness is 1 to 2 mm. Test conditions used by Ebara during the development phase are summarized in Slide AB-6.7; it should be noted that up to 10,000 m³/hr (at normal conditions) were handled for up to 3000 hours. The experimental data shown in Slide AB-6.8 show that saturation of SO_x removal was achieved above about 1 megarad (= 10 joules per gram) while about 1.5 Mrad were required for NO_x removal. The E-beam system is a commercial unit (obtainable, for example, from High Voltage Engineering). It uses 800,000 volt electrons, which have about an 8-ft range and can be swept over a 50-60° divergence angle at scanning rates of 60 to 400 cycles per sec. With two oppositely located E-beams, fairly uniform exposure is achieved throughout the test section. Scaling represents no problems and substantial cost reductions should be achievable for large-scale devices as the result of more efficient use of power-conditioning equipment.

* An EPRI-funded design and costing study is said to be in progress at Bechtel.

AVCO/EBARA E-BEAM DRY SCRUBBER
CUTS COST 43% FOR 500 MW UTILITY

	AVCO/EBARA	LIME SCRUBBER	
TOTAL CAPITAL COST	\$M 43	\$M 60	
	\$/kW 86	\$/kW 120	
		(mils/kwh)	
FIXED CHARGE	3.3	4.7	
OPERATING/MAINTENANCE COST	2.5	2.9	
REHEAT COST	0	0.9	
BYPRODUCT CHARGE/(CREDIT)	(0.6)	0.4	
TOTAL		5.2	8.9
			COSTS BASED ON EPRI GUIDELINES

SIMPLE PROCESS USES ELECTRONS AND AMMONIA

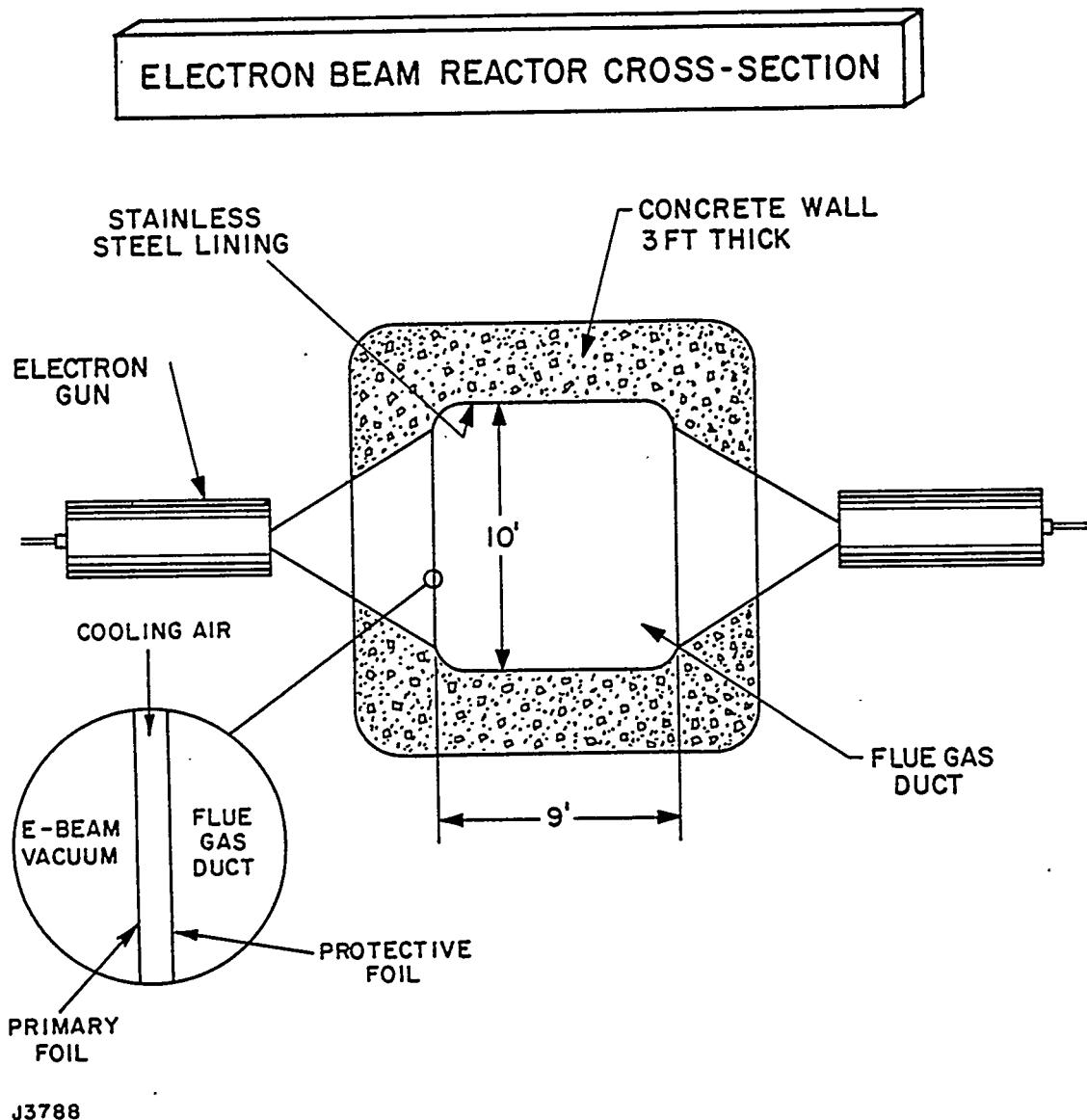


AVCO/EBARA COMBINED SO_x, NO_x PARTICULATE REMOVAL PDU

E-BEAM DRY SCRUBBER FEATURES

- ELECTRON BEAM WITH AMMONIA CONVERTS SO_x + NO_x TO FERTILIZER
- NO SLUDGE DISPOSAL PROBLEMS
- NO SLURRY RECYCLING PROBLEMS
- NO STACK GAS REHEAT
- LOW CAPITAL COST
- LOW OPERATING COST

Slide AB-6.6



TEST CONDITIONS

GAS SOURCE: LABORATORY SIMULATED
HEAVY-OIL BOILER FLUE GAS
IRON-ORE SIMTERING FLUE GAS
SPIKING

FLOW RATE: BATCH
FLOWS UP TO 10,000 NM³/HR

GAS COMPOSITION:

SO ₂	-	UP TO 2,000 PPM
NO _x	-	UP TO 1,000 PPM
H ₂ O	-	UP TO 20%
O ₂	-	UP TO 20%
CO ₂	-	UP TO 15%
PARTICULATES	-	UP TO 2 GR/FT ³

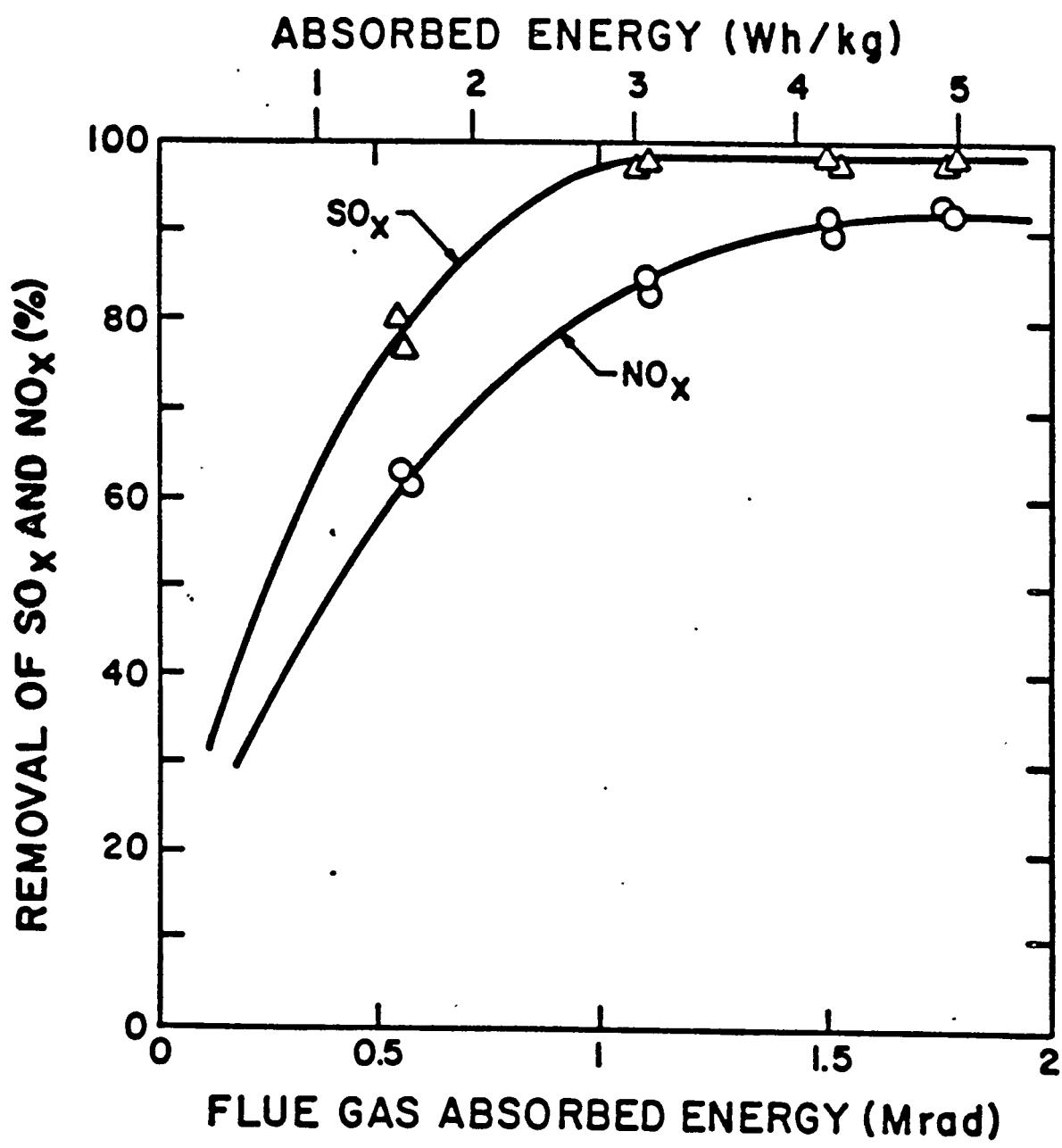
GAS TEMPERATURE: 60 TO 130°C

AMMONIA ADDED: 0 TO 2 TIMES STOICHIOMETRIC

ELECTRON DOSE: 0 TO 10 MRAD

RESIDENCE TIME: 0.05 TO 15 SEC.

DURATION OF TESTS: UP TO 3,000 HOURS



Operational problems include durability of the foil wall (1 to 1.5 mills) in the presence of flyash. Water is an essential component in the conversions. About 12 papers have been published by workers at the University of Tokyo on the chemical processes involved in E-beam scrubbing. Modeling is in progress. The device efficiency depends critically on the number of reactions that occur per ion pair produced. This number is said to be upward of 10.

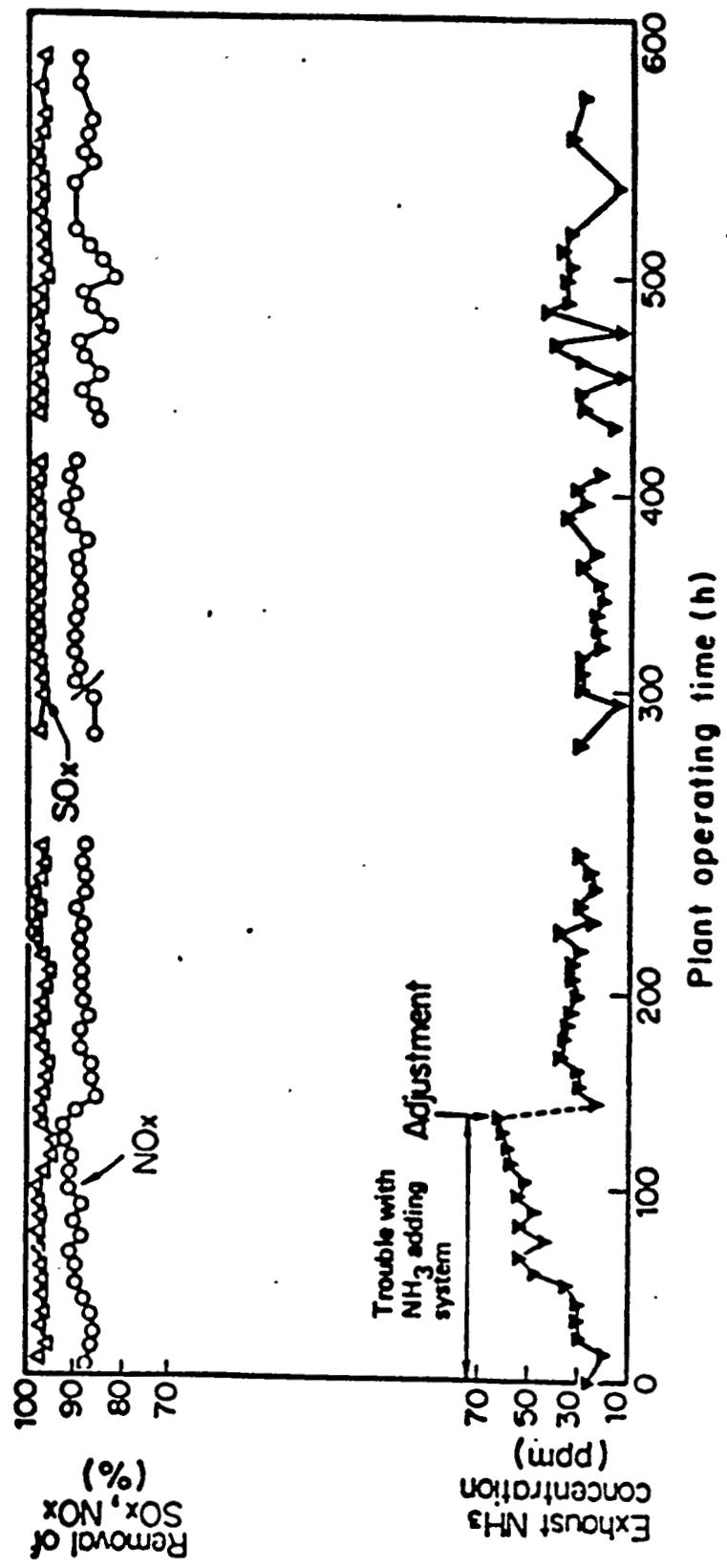
Slide AB-6.9 shows the excellent operational stability for SO_x and NO_x removals that has been achieved in long-term tests. The handling of fines is summarized in Slide AB-6.10. The E-beam induces particle condensation and an electrostatic precipitator (ESP) could then be used to reduce particulate levels to 5 mg/m³ in a pilot plant. It has been shown experimentally that the presence of flyash does not interfere with gas scrubbing (see Slide AB-6.11). A schematic diagram of the incompletely understood reaction processes is shown in Slide AB-6.12. The market potential for the product fertilizers is substantial (Slide AB-6.13). Important areas for future research relate to trace metal concentrations and clean-up (Slides AB-6.14 to AB-6.16).

The PDU flow diagram for the DOE-sponsored study is shown in Slide AB-6.17, while the proposed operating conditions are indicated in Slide AB-6.18.

2. Slagging Combustors

Little, if any, experimental work has been done on retrofitting slagging combustors for utility applications. D. B. Stickler considered the following five principal topics, with information derived from Avco's MHD programs: coal-combustion behavior, transport and flow behavior of coal slag, MHD coal-fired combustors, high-throughput coal gasifiers, and issues relating to retrofits of slagging combustors.

Slide AB-6.9



Slide AB-6.10

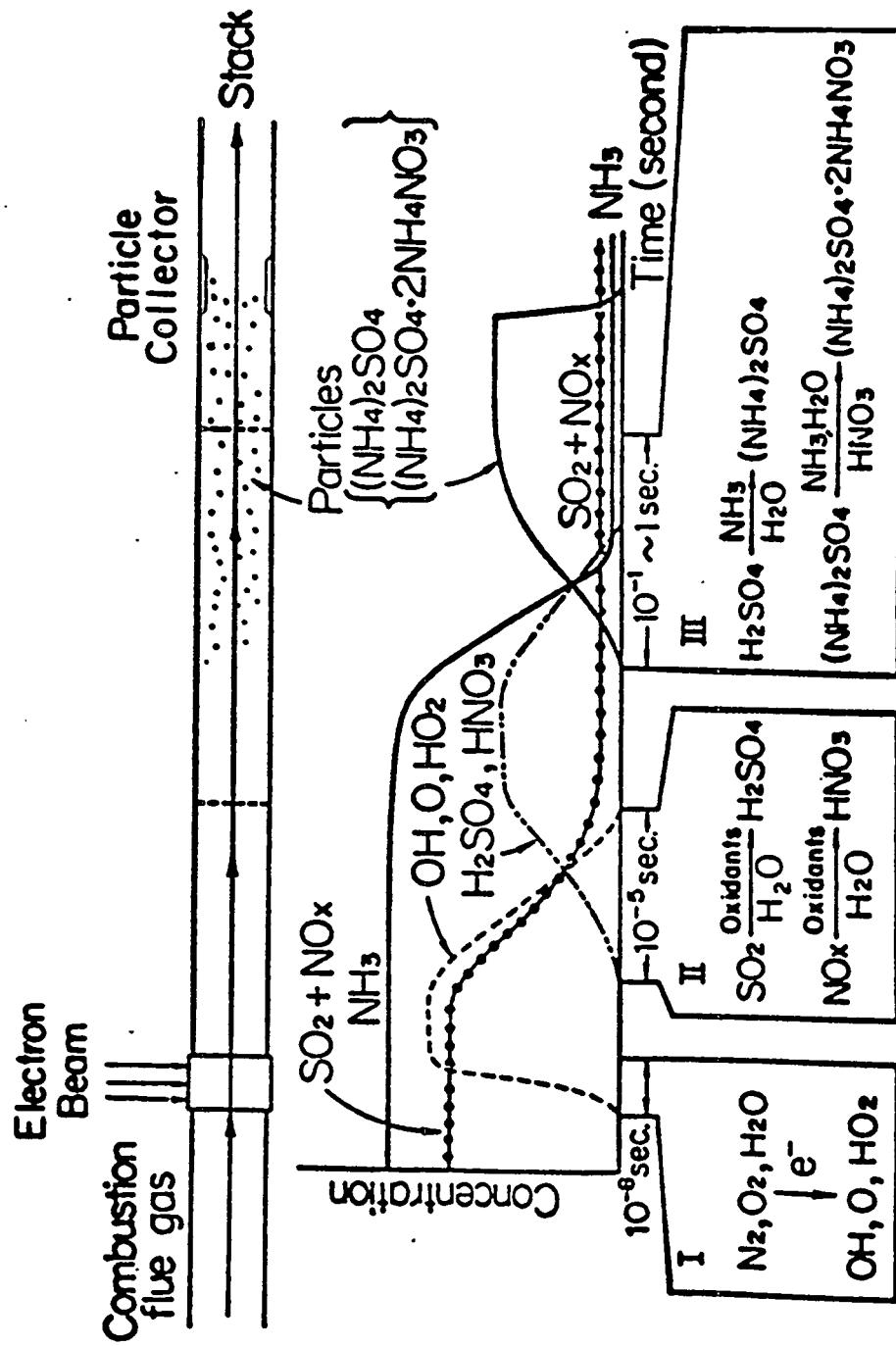
AVCO/EBARA SCRUBBER HELPS REMOVAL OF FINE PARTICLES

- CONDENSATION MAKES FINE PARTICLES LARGER
- ESP ACHIEVED 5 mg/m^3 IN PILOT PLANT

FLY ASH DOES NOT AFFECT REMOVAL EFFICIENCY

- ADDED FLY ASH FROM MONTANA AND NEW HAMPSHIRE POWER PLANTS
- MAXIMUM AMOUNT ADDED WAS 2 G/M³
- CALCULATION SHOWS INSIGNIFICANT ENERGY ABSORPTION BY FLY ASH

**MODEL OF REACTION MECHANISM
FOR PRECIPITATION OF SO_x AND NO_x**



MARKET POTENTIAL FOR BY-PRODUCT FERTILIZER

- 500 MW POWER PLANT BURNING 2.5% S COAL PRODUCES:
147 KTONS/YR OF BY-PRODUCT (24%N ; 20%S)
- CURRENT DEMAND BASED ON AMMONIUM SULFATE / AMMONIUM NITRATE SALES:
2,500 KTONS/YR 80% SULFATE: 20% NITRATE • \$65/TON
- S-DEFICIENCY REQUIREMENTS:

<u>CROP - TYPE</u>	<u>GEOGRAPHIC</u>
FIELD CROPS	1900 KTONS/YR
FORAGE CROPS	13,100
	<u>15,000</u>

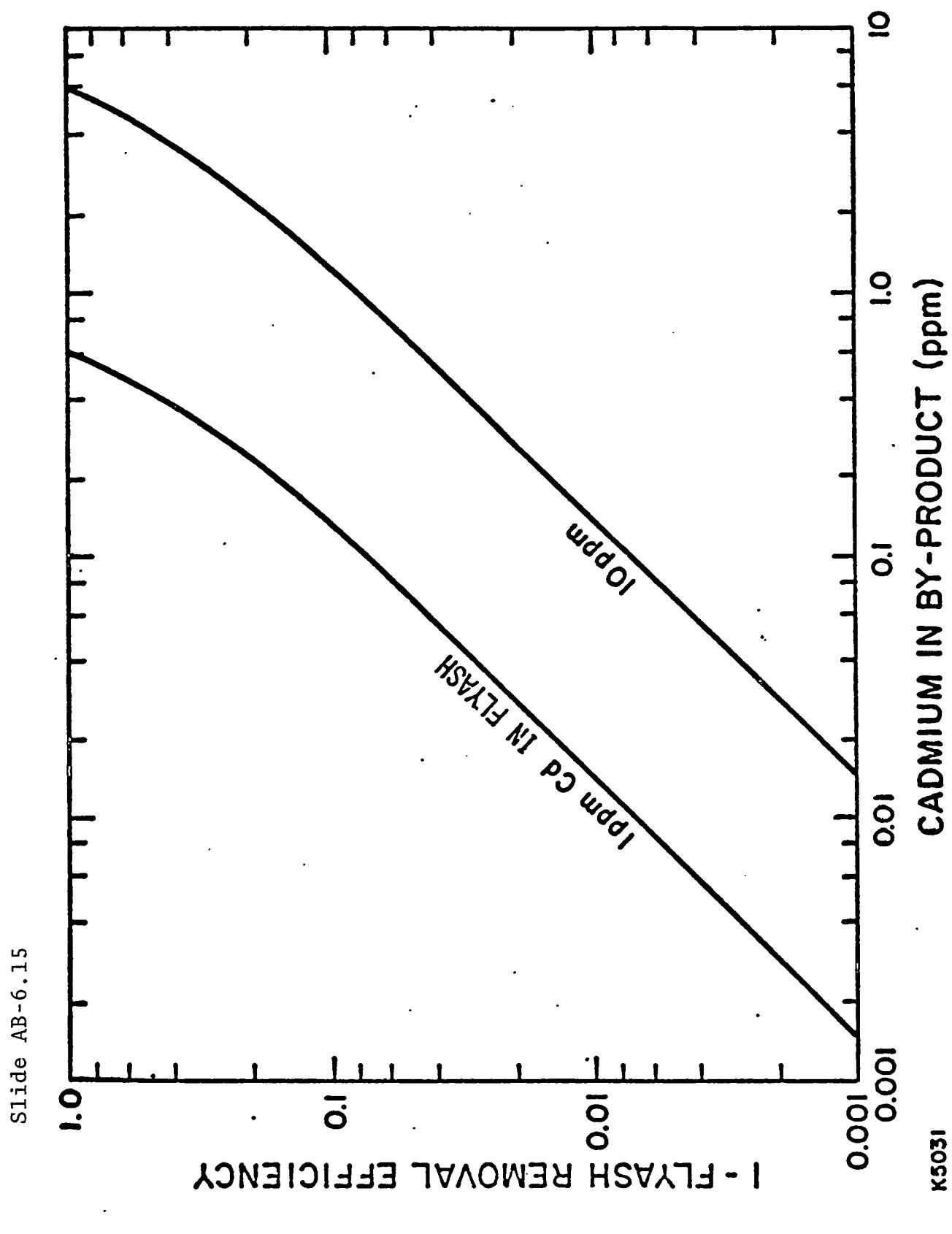
<u>CROP - TYPE</u>	<u>GEOGRAPHIC</u>
FIELD CROPS	1900 KTONS/YR
FORAGE CROPS	13,100
	<u>15,000</u>

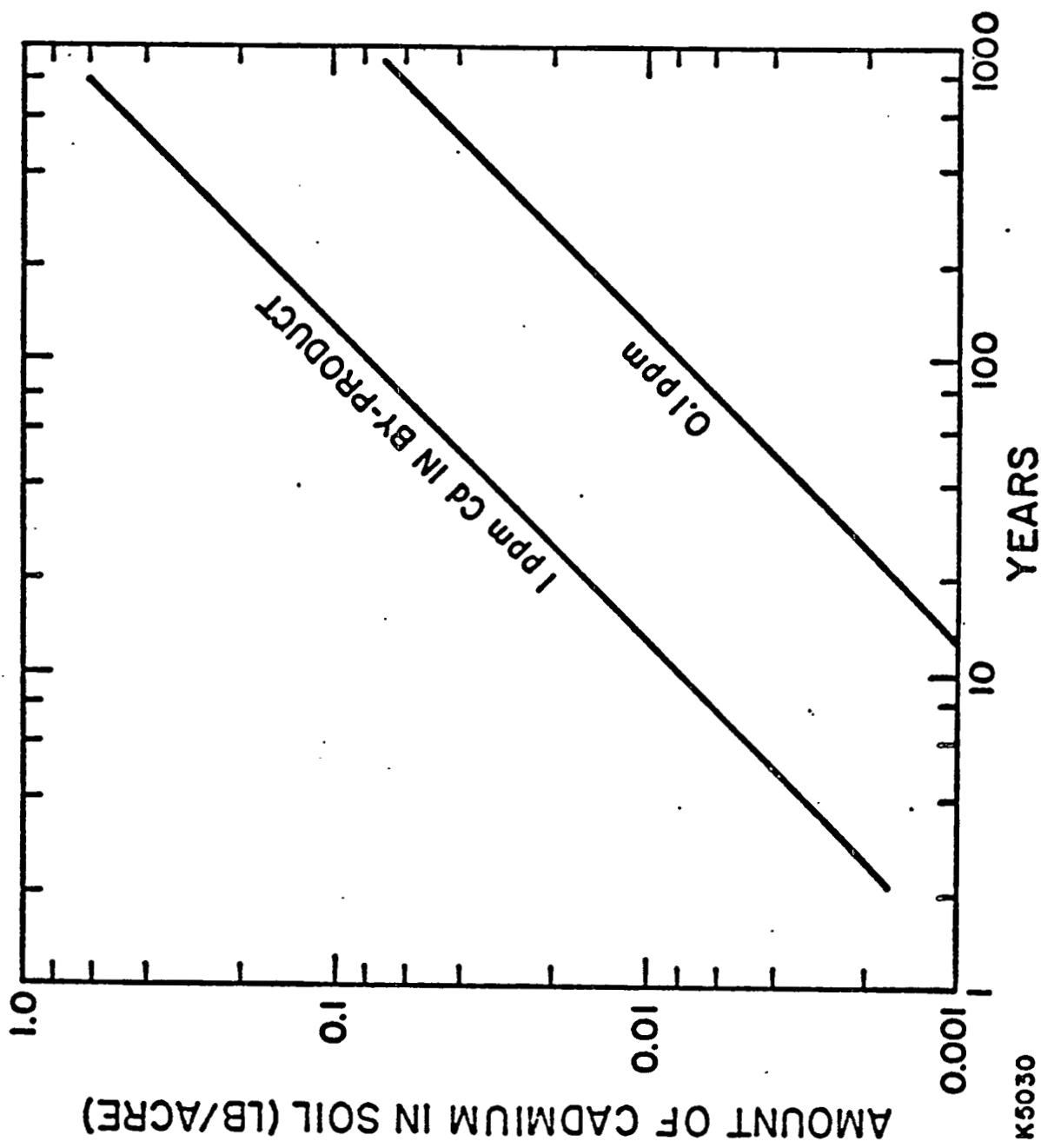
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Slide AB-6.14

TABLE I. Range of Trace Metal Concentrations
in Flyash Collected from Different
Plants in the U.S.A.

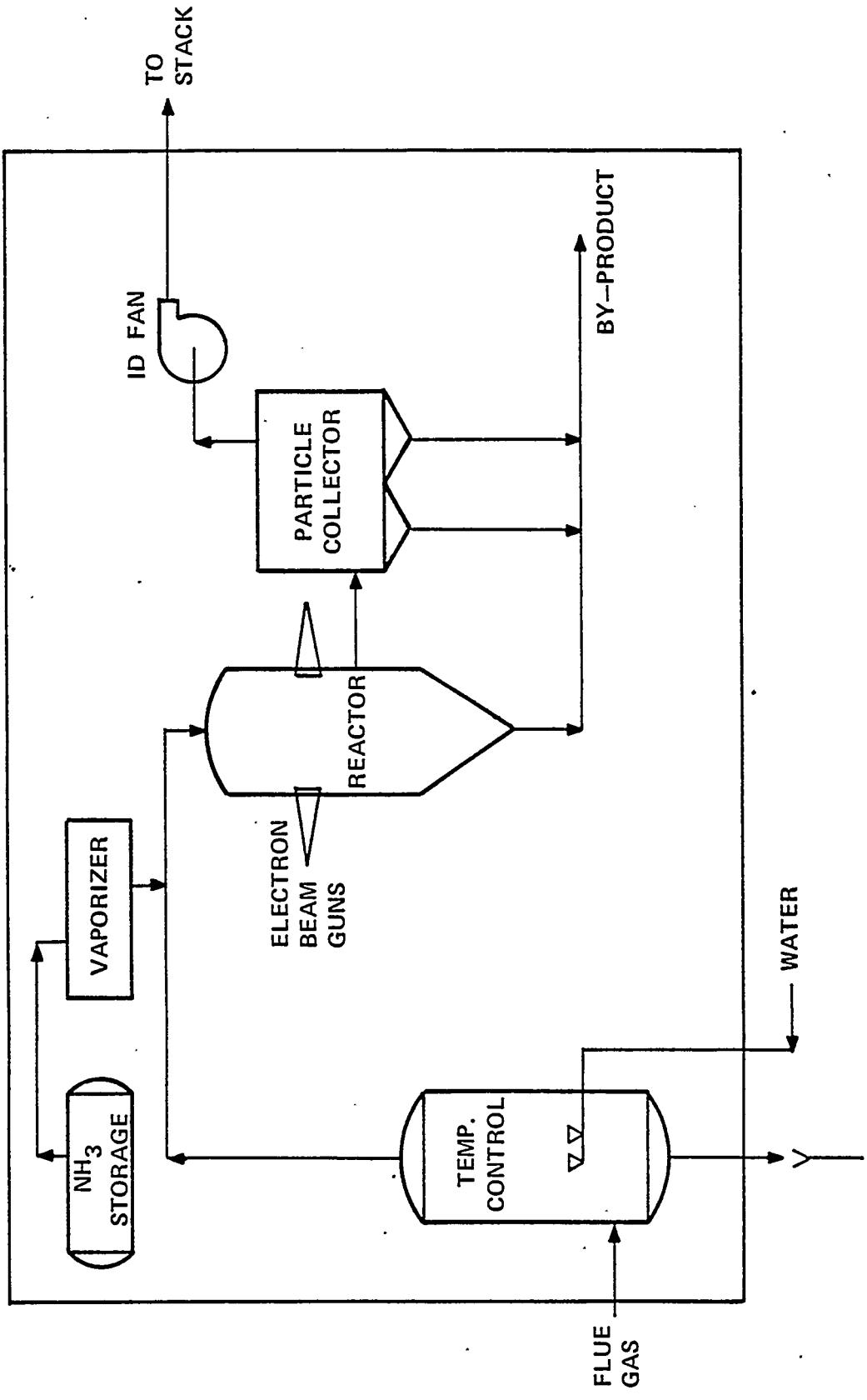
ELEMENT	RANGE OF CONCENTRATION (ppm)
Arsenic	9.7 - 161.
Beryllium	5.1 - 17.4
Cadmium	<0.5 - 8
Mercury	0.04 - 0.31
Nickel	19.3 - 207
Selenium	6.75 - 27
Lead	43 - 80
Thallium	1.1 - 4.1
Uranium	9.4 - 30.1
Vanadium	133 - 440





PRELIMINARY PDU PROCESS FLOW DIAGRAM

AERI



Slide AB-6.18

FLUE GAS SLIP-STREAM

- COAL-FIRED FLUE GAS
- FLOW RATE: ABOUT 20,000 CFM
- INITIAL CONCENTRATIONS:

SO_x = UP TO 4000 PPM

NO_x = UP TO 1000 PPM

- REMOVAL EFFICIENCIES: MEET OR EXCEED EPA REQUIREMENTS

In MHD applications, the pulverized coal is exposed to air at about 2000°F, which leads to hypergolic ignition. A combustion model has been developed for these operating conditions and involves a two-step pyrolysis reaction that is followed by oxygen attack on char. Successful predictions have been achieved of flame stability and flame extinction. The combustor developed for MHD applications produced slag layers. The development and time histories of these slag layers could be approximated by utilizing analytical procedures analogous to those employed for reentry heat shields.

A conceptual design for a slagging industrial combustor was discussed and will be further considered at the next CCAWG meeting. In response to the DOE proposal requests, a joint program was developed in collaboration with Riley-Stoker of Worcester, Massachusetts.

COMMENTS ON PRESSURIZED (PFBC) AND
ATMOSPHERIC (AFBC) FLUIDIZED-BED COMBUSTORS*
(August 1982)

1. New York University, Antonio Ferri Laboratories, Merrick
and Stewart Avenues, Westbury, N.Y. 11590

Victor Zakkay and his colleagues have successfully run a PFBC since 1975. A new facility was constructed at a cost of ~\$700,000 and has been operational since early July 1982. It consists of a 30-inch i.d. burner operating at 1 to 10 atm, 1300-1400°F, with coal throughputs of 0.5 to 1.5 TPH. Shake-down tests have been run with bituminous coals (supplied as ground coals at -1/8" in barrels by Curtiss-Wright at a cost of ~\$500/T), although the primary studies will be concerned with North Dakota lignites. Combustion efficiencies generally exceed 99% and less than 100 ppm of NO_x are emitted. The primary emphasis has been on combustor design and control and on effluent clean-up.

Current activities deal especially with a response to an RFP from METC, which is being developed jointly with Burns and Roe. The basic design involves a three-stage fluidized bed reactor with the first stage carrying relatively large coal particles confined by grids in a circulating combustor, heat exchangers are located in the second stage, and an elutriator for particulate removal serves as the third stage. The design appears to be especially well suited for studies of the elementary sequential processes that occur in all fluidized bed combustors.

An interesting feature of the current DOE-sponsored program at NYU is a full-day visit once per week by a DOE representative from Gilbert and Associates.

*Prepared by S. S. Penner.

2. Curtiss-Wright Corporation, One Passaic St., Woodridge, N.J. 07075

Following extensive (i.e., over 10,000 hrs of operation with one-third of allowable NO_x and SO_2 production, as well as excellent durability for the in-bed heat exchanger and turbine-blade materials) experience with a small-scale model, a pilot plant is currently under construction and is expected to be operational by the fall of 1983. The equivalent electric power output of the plant should be somewhat more than 13 MW_e . The plant will have an industrial gas turbine with an air-flow capacity of 120 lb/sec and a 7:1 compressor pressure ratio. The power turbine will be gas-coupled to a gas generator and will be mechanically coupled to a gearbox and generator producing 7 MW_e . The gas will leave the power turbine through a bifurcated duct and enter a waste-recovery boiler producing a steam-flow rate of 58,000 lb/hr. This pilot plant is viewed as about a one-sixth scale version of a commercial module to be used in a 500 MW_e combined cycle plant.

The emphasis in this work is on the production of electric power and steam using high-sulfur coal under environmentally acceptable conditions. Observation of the construction phase of the pilot plant is an especially informative experience. A good description of these developments has been given by S. Moskowitz (Curtiss-Wright) and J. F. Geffken (DOE) in AIAA-81-0392, "Pressurized Fluidized Bed - A Technology for Coal-Fired Combined Cycle Power Generation," Aerospace Sciences Meeting, January 12-15, 1981, St. Louis, MO.

Like Victor Zakkay, Sy Moskowitz is currently heavily occupied responding to the RFP from METC on advanced concepts for PFBC.

3. AFBC at Georgetown University in Washington, D.C.

On Wednesday mornings at 10:00 a.m., a public tour is generally held of the AFBC commercial steam generator designed by Foster-Wheeler and others and operational on the Georgetown campus for about 3 years. The unit costs $\$12 \times 10^6$ and generates 100,000 lbs of steam per hour using a once-through fluidized bed combustor burning stoker coal.

Although this AFBC is supposed to operate as a commercial device without undue down-time, persistent operational problems have been caused by erosion of steam tubes as the result of particle-laden flows. Extensive modifications have been made in the baghouse to improve particulate removal efficiencies. The levels of SO_x are controlled by limestone absorption while NO_x control is achieved through controls of air-flow rates.

4. Conclusions

There is important work of diverse character in progress on AFBC and PFBC. The question of commercial acceptability for these units merits discussion by CCAWG, as do novel design concepts and potential problem areas in large-scale operations. Clearly identified problems deal with heat-exchanger tube erosion in particle-laden flows, with improved designs for coal feed, and with environmental clean-up.

Tentative plans have been made for a detailed review by CCAWG of PFBC during February of 1983. It may be useful to discuss both funded and unfunded concepts by talking especially to the large number of people who are currently responding to the RFP from METC.

CCAWG MEETING AT THE BABOCK AND
WILCOX RESEARCH CENTER,
1562 BEESON STREET, ALLIANCE, OHIO 44601
(October 18, 1982)

CCAWG members C. R. Bozzuto, A. K. Oppenheim, S. S. Penner, L. D. Smoot, C. L. Wagoner, I. Wender, W. Wolowodiuk, and J. Birkeland (DOE) attended the meeting. Also present were G. Jordy (DOE), D. Stickler (AVCO-Everett), D. Anson (Battelle), D. Smith (General Electric), and E. Michaud (Babcock and Wilcox).

The topics discussed and the agenda are summarized in Table AB-8-1.

1. Summary of Discussions

J. Birkeland's review of the DOE Design Study of Advanced Fossil-Fuel Systems (DAFFS) was of particular interest to CCAWG members. There was considerable discussion of the preliminary report, especially of the February 1980 cost estimates for 3 PC, 2 PFBC, and 3 IGCC plants. It was noted that atmospheric fluidized bed combustors had not been included and might well have been shown to be the most favorable and lowest cost electricity-generation plants. While sensitivity analyses had been included in DAFF, several CCAWG members noted the importance of showing cost estimates as functions of allowable NO_x and SO₂ production levels well below those that are deemed to be acceptable today. Dr. Birkeland emphasized the possible importance of plant size in making comparisons of results obtained in the 500-MW_e DAFF studies with the 1000-MW_e ECAS (= energy conversion alternative systems) data released a few years ago. Several CCAWG members concurred with Dr. Birkeland's remarks that he was dealing with a highly

sensitive subject that could not be summarized without extensive qualifications.

D. Stickler presented a good overview of potential developments of slagging combustors utilizing information and knowledge derived from extensive investigations of MHD combustors. Most of this work has been summarized previously in AB-6.

D. Anson presented an overview of coal-combustion studies at Battelle. His lecture presentation is outlined in Appendix AB- 8-1.

D. Smith reviewed studies performed at the General Electric Company on the utilization of low-grade fuels in gas turbines. This work has been referred to previously in AB-5. Most of the turbine tests were conducted with synthetic fuels, including resids with ash contents up to 1000 ppm. The concentrations of sodium and potassium are of critical importance in defining the levels of hot corrosion. At a weight ratio of 3:1, Mg (usually added as an aqueous solution of epsom salts) is a useful inhibitor in reducing corrosion by V. Nut sheels have been used to remove some of the deposits. However, complete removal of solid deposits requires a water wash and soaking. Without cleanup, allowable peak turbine temperatures may be quickly derated by about 100°F. Quantitative studies of blockage in stationary, first-stage blading were described in which a nozzle-area inlet number was employed as measure in an equation for the reduced rate of nozzle plugging (e.g., in % per 100 hrs of operation). Turbine studies with fuels containing the high ash levels that are characteristic of coals (i.e., at least 10 times higher concentrations than have been tested) remain to be performed. Ways should be sought to modify ash contents in order to eliminate sticking of the solid phase. The relations between beneficiation procedures and possible IGCC systems require quantification.

Coal-related studies at B&W were summarized by C. Wagoner and E. Michaud (see Appendix AB-8-2 for details). Also of interest are the development of a second generation laboratory furnace for

ashing studies (Appendix AB-8-3) and observations on fireside deposition of ion-exchangeable calcium in coal (Appendix AB-8-4).

Table AB-8-1. Agenda for CCAWG Meeting

Babcock & Wilcox Research Center
1562 Beeson Street
Alliance, Ohio 44601
(216) 821-9110

Conference Room A
Monday, October 18, 1982

8:00 am	Introduction	C. Wagoner (B&W) S. Penner (CCAWG)
8:15 am	Review of the DOE Design Study of Advanced Fossil Fuel Systems, DAFFS	J. Birkeland (DOE)
9:25 am	Slagging, High-Intensity Combustors	D. Stickler (AVCO-Everett)
10:05 am	Coal-Related Studies at Battelle, Columbus	D. Anson (Battelle)
11:15 am	Discussion of Future Meetings and Agendas	S. Penner (CCAWG)
11:35 am	Lunch: Cold Buffet in Conference Room B	
12:15 pm	Utilization of High-Ash Fuels in Turbines	D. Smith (General Electric)
1:00 pm	Coal-Related Studies at Babcock & Wilcox	C. Wagoner (B&W) E. Michaud (B&W)
2:45 pm	Tour of B&W Facilities	E. Michaud (B&W)
4:00 pm	Adjourn	

COAL COMBUSTION AT BATTELLEIntroduction and Background

The Battelle Memorial Institute dates from 1929, and work in coal combustion was one of its first activities. Soon afterwards, Ralph Sherman, using a cylindrical combustor some 2 ft. in diameter and 8 ft. long, carried out experiments on the combustion of pulverized coal that yielded classical data on radiant heat transfer from p.c. flames. In 1932 Bituminous Coal Research, Inc., was established by the coal producers, with Battelle staff and facilities. This was a very early example of a group funded industrial program, and served the interests of both industrial and domestic coal users, although it was not heavily involved in utility related work.

Highlights in coal combustion work during the 1940's and 1950's included the development of an efficient inverted (or downdraft) underfeed domestic coal stoker that overcame the smoke emission problems of conventional systems; the development of stable and efficient pulverized coal combustors for a gas turbine intended for locomotive applications; and the collection of data on slagging and corrosion by fuel ash which are assembled in W. T. Reid's authoritative book on the subject, which was produced in 1971.

In the early 1970's Battelle had extensive in-house funds, of which a substantial portion was invested in the Battelle Energy Program, aimed at providing solutions to the emerging energy crisis. The most important product of this program was a novel circulating fluidized bed combustion process, the Battelle Multi Solids Fluidized Bed (MSFB). The early development of this system was supported by federal funding, and it is now licensed for commercial use.

In the mid 1970's a large part of the combustion at Battelle related to the control of emissions to the atmosphere, with direct relevance to the use of coal in large utility boilers. Much of this work was,

and still is, supported by coal burning utilities and by the Electric Power Research Institute (EPRI). Research related to coal combustion broadened in the late 1970's to include a substantial effort aimed at improving the reliability and performance of coal fired utility plant, which had been found to be deteriorating as mine mechanization increased. The electric utilities are anxious to reduce the impact of coal quality on plant availability, and to this end research is continuing into the relative overall economics of coal cleaning, use of chemical additives, and increased plant investment levels.

As fuel prices increase other industrial fuel users are finding that their production costs are significantly affected by fuel costs, and are turning, amongst other things, to wider use of coal and improvements in coal use efficiency.

Battelle's combustion related work has always reflected a substantial proportion of industrially supported effort, and this facilitates the transfer of the results of government supported basic work to the private sector. Currently, more than half of our work relevant to coal combustion is industry funded, compared with about 40 percent of Battelle research in all departments.

Recent and Current Work

Work recently completed and in progress at Battelle reflects the general picture given in the introduction. Most of the industrial sponsorship comes from the utility industry, directly or through EPRI. However, coal producers, additive vendors, and equipment manufacturers are responding to the users' requirements for more definitive data on their products, and are sponsoring independent research to provide those data. Listed below are some of the more important topics in the category of recent and current work for industry.

Recent and Current Projects
for Industrial Sponsors

- Effect of coal properties on boiler deposits and plant performance (3 projects)
- Developments in fluidized bed combustion (conventional and MSFBC)
- Use of fuel additives to modify the properties of fly ash and coal ash deposits (3 projects)
- Design of a pilot scale pulverized coal combustion facility for fuels evaluation
- Combustion assessments of coal/oil and coal/water slurries (including ash deposition behavior).

Government sponsored work, as would be expected, is generally more concerned with advanced, high risk, or basic concepts. The following list is a sample of the more important recent and current projects.

Recent and Current Projects
for Government Sponsors

- The potential for use of Peat Blends with Coal for Electric Power Generation DOE/GFETC/0231
- Calcium Oxide Interaction in the Staged Combustion of Coal - DOE DE-AC22-80PC-30301
- Utilization of Battelle Treated Coal in Gasification and Combustion Processes to Control Sulfur Emissions- DOE Contract W-7405-Eng-92-111
- Advanced Development of a Coal/Limestone Fuel Pellet for Industrial Boilers - EPA 68-02-3189
- Advanced Atmospheric Fluidized Bed Combustion Design - Spouted Bed - DOE Contract DE-AC21-82MS-19328
- Advanced Atmospheric Fluidized Bed Combustion Design - Ultra High Velocity Multisolid Fluidized Bed - DOE Contract DE-AC21-82M19331

- The Spouted Bed Combustor - A Novel Approach to burn low calorific value fuels in an environmentally acceptable manner - EPA Grant 8095840
- Coal Fired Closed Cycle Gas Turbine Research and Development (Subcontract to Rocketdyne) DOE Contract DE-AC01-80-ET15020

Several of these projects are referred to in more detail in the section on Current Research Interests, in which their importance in the context of ongoing work is made apparent.

Coal Burning Facilities

Battelle employs 3000 people at Columbus, and some 5000 elsewhere. Facilities that are available in-house cover all aspects of coal use from exploration to the toxicology of wastes and emissions. Facilities that are used for direct coal combustion research cover a range of types and scales. They are generally of rather simple basic design, and are capable of rapid low cost adaptation to specific sponsor requirements. The largest, having a thermal capability of 5 million Btu/hr, is presently nearing completion, and can handle a variety of fuels, although it is designed primarily for pulverized coal. This unit incorporates the main features of a pulverized coal fired boiler system - a vertical spindle 5 ball pulverizer, air pre-heat, dry ash removal, and variable swirl burner - and includes test sections simulating furnace wall and superheater tube conditions. At the other end of the scale is a flat flame methane burner into which pulverized coal can be fed in order to study reaction kinetics using classical optical and sampling techniques.

Fluidized bed combustion facilities include both a conventional bubbling bed with immersed heat transfer surface and pilot scale combustors using the MSFB technology. The range of coal burning facilities is summarized in the list which follows.

Coal Burning Experimental Facilities

- 5 Million Btu/hr Pulverized Coal Combustion Facility for research into combustion processes, deposits formation and characterization, emissions control, and other aspects of the evaluation of fuels and combustion systems
- 0.5 Million Btu/hr Multifuel Research Facility, used for fuels and additive evaluations and as a screening unit for larger scale work
- 25,000 Btu/hr Combustor, this unit fires vertically downwards into an externally heated reactor tube. This allows use of a simple aerodynamic flow field, and simplifies collection of time based data related to kinetics of single- and multi-staged combustion processes.
- Flat Flame Combustor, basically a "flat" methane flame with facilities for introducing pulverized coal particles into a controlled temperature and composition environment. Used for studies of in-flame chemical reactions in combustion and sulfur capture processes.
- 1 Million Btu/hr MSFB combustion pilot plant. This has been the most important vehicle for development of this process, to improve combustion and sulfur capture, and to provide a basis for commercial units.
- 0.4 Million Btu/hr MSFB combustion development unit. This was used for much of the early development work and has been especially useful in characterizing the combustion behavior of different fuels.
- 2 Milltion Btu/hr Fluidized Bed Combustor. This is a "conventional" bubbling bed with considerable flexibility as to base design and heat removal rates. It has been used as a vehicle for the development of in-bed diagnostics and for studies of the materials problems associated with high temperature heat transfer surfaces.

Current Research Interests

Because Battelle's work is almost entirely dependent on sponsor's needs at any one time, there are many diverse projects in progress. This presentation therefore concentrates on topics in which Battelle workers have a strong interest and in which we see a reasonable continuity through both government and industrial contracts. These topics fall under the broad headings given below. All are discussed in the context of combustion only, although there are associated programs in materials technology, coal treatment, and fuels conversion technology such as gasification.

- Coal quality
- Mineral impurities in coal
- Modification of impurity content
- Slurry fuels
- Advanced combustion technology
- Diagnostics
- Chemistry.

Coal Quality. Coal purchases frequently are made on the basis of heating value, sulfur content, and proximate analysis. More discriminating buyers may also specify ultimate analysis, ash fusion temperatures, ash analysis, grindability, and swelling index. For power generation boilers operating at the upper end of the steam temperature range (1000 F or more), the really critical factor is very often the behavior of the ash in regard to deposit formation and slagging. None of the listed parameters gives an adequate guide to this behavior, although there is broad acceptance that ash behavior is sensitive to sulfur, iron, and alkali contents and that the ASTM ash fusion test provides a guide to slagging propensity.

Past work on coal slags provides consistent methods of correlating the behavior of fully molten and homogenized slag with ash composition. Boiler deposits are far from homogeneous, so that empirical relationships, based purely on elemental analyses, do not present the full picture. A

typical example of such an empirical relationship is that published by Babcock & Wilcox which combines the amount of sodium in the ash with the base/acid ratio of the ash constituents.

In the past few years Battelle has had projects which have attempted to correlate coal quality records with utility plant performance and reliability. The success of the effort has been constrained by the limited extent of the records, both in regard to coal data and the causes of plant outages or load reductions. To complicate matters, coal sulfur and ash content, and obviously plant age itself, changed systematically over the time period studied. We are presently engaged in a very comprehensive collection and analysis of data from which better results should emerge. The willingness of utilities in the U.S. and abroad to complete and return exhaustive questionnaires on this subject attests to the importance attached to understanding why coals behave as they do, and ultimately knowing how to select them. With this broad support the exercise should at least lead to better empirically based guidelines.

At this time pilot scale combustion testing provides the best guide to coal selection but very small scale combustion tests still leave open many questions of similarity and considerable judgement is needed to apply test results to full scale plant behavior. An alternative approach, in which we have a keen interest, is in developing laboratory procedures based on parameters that relate more directly to the complex combination of chemical and physical factors affecting coal deposit behavior in a boiler environment.

Mineral Impurities in Coal. Closely related to the behavior of coal ash deposits is the nature of minerals in coal and the transformations which they undergo during coal combustion. The range of clay minerals, silicates, carbonates, sulfides, phosphates, and other rocks that are found with coal are greatly modified by thermal treatment and the changing chemical environment, and even after combustion they do not correspond to a laboratory ash. Now that analytical methods are available that greatly widen the scope of coal minerals identification and characterization, it seems reasonable to build up a better understanding of the ways in which specific minerals

contribute to deposit and emissions behavior. Battelle has a strong ceramics group and we have recently involved some of their people in examination of coal, fly ash, and ash deposits. This is a very promising and interesting area for future work.

Modification of Impurity Content. Modification of the impurity content of coal can be affected by selective cleaning or by addition. All practical cleaning processes are selective, usually in terms of specific gravity, but the basis of selection relates only indirectly to coal ash properties. Discussion of coal cleaning is not relevant here, but the effects of coal cleaning on combustion are. Density separation removes heavy rocks such as pyrite, calcite, and quartz minerals, but is ineffective on some of the alkali metal compounds. The questions facing a potential user are, to what extent will density separation improve a fuel? And what is the economically optimum treatment for a given coal and application? Several coal beneficiation processes are available, and Battelle has patented procedures that can reduce ash contents to less than 1 percent and remove 90 percent of the sulfur in coal, if such a level of cleaning can be justified. We feel that the utilization (combustion) aspects of coal cleaning have been severely underestimated and advocate more attention to coal combustion behavior, particularly as it affects impurities, in the specification and evaluation of cleaning procedures.

Once the total impurity level in a coal has been reduced, it becomes more feasible to modify the residual ash by making additions to the coal. Unlike cleaning procedures, additives are quite specific and may be chosen to retain sulfur, inhibit formation of bonded deposits, or induce self shedding properties in the deposits. The cost of using an additive would have to be less than that of further cleaning or use of a better grade of coal in order to achieve the same result.

Battelle has carried out work in the area of additives for both EPRI and a number of industrial sponsors and this work is expected to continue. A particular technique, which was developed by Battelle and which will be referred to later, involves hydrothermal impregnation of coal with

calcium. Work has also been carried out on the effects of small additions of materials such as limestone, quartz, and dolomite on the strength of sinters made from fly ash. The experimental techniques were adapted from earlier work by Barnhart and Williams at Alliance. This work has, quite incidentally, provided data on the transport of certain elements between particles within deposits, and may have implications on both minerals behavior and the use of vapor phase additives.

Two additives that are dispersed as vapors and have been reported to change the properties of coal ash deposits are copper oxychloride and manganese (incorporated in an organic liquid). Both have been said to weaken deposits even when used at parts per million rates. Their actions are not understood but it is presumed that they modify the surfaces of fly ash particles (possibly selectively) so as to reduce interparticle bonding. Of the two, there is more experience with copper oxychloride, and it has been suggested that it affects deposit properties by promoting crystallization from glassy phases, and by influencing the development of voids in slags. We hope to receive support for investigation of additives of this kind - that is surface acting substances - for the purpose of inhibiting boiler fouling.

Slurry fuels. Coal/water slurries are among the more interesting fuels now being produced and tested. Battelle has carried out a number of industry sponsored combustion/deposit evaluations on slurries and we see considerable potential for their use. The ability to use them as oil replacements in existing plants depends on being able to achieve comparably rapid combustion, and (for boilers) comparably low ash deposition rates.

Combustion of slurries involves first the dryout of slurry droplets, then ignition and combustion of the solid residue. There is no doubt that these steps can be achieved without extensive modification to techniques used for oil firing, but there are few data on the burnout rate or methods of enhancing it to match that of oil.

The amount, nature, and behavior of ash forming impurities in slurries is of special interest and fits into Battelle's related activities in coal cleaning and additives. Deep cleaning of coal, and incorporation of additives by such methods as hydrothermal treatment, require size reduction to liberate impurities and expose surface. When applied to slurries, the elimination of the need for separation and drying significantly simplifies the beneficiation process. On this basis we see scope for the development of a range of "advanced" coal slurries having inherently low sulfur, low ash, and low deposition potential. While the cleaning processes are already developed, treatment of the slurries to produce the desired emission and deposition free properties requires further experimentation, particularly in the form of combustion testing.

Advanced Combustion Technology. Battelle has a number of projects involving the evaluation and/or development of advanced coal combustion technologies. Most of these have received or are receiving government financial support. They are described very briefly here, but all involve quite extensive efforts.

Battelle Multi Solids Fluidized Bed

Although the MSFB has entered the commercialization phase, development and research continue, with emphasis in further improvements in combustion sulfur capture, and NO_x control. Proposals have been made for pressurization of this type of unit. Pressurization would lead to a very compact unit, but would also be expected to change the fluidization behavior, two phase mixing in the entrained region, and spatial concentration of the carbon phase. This represents a significant extension of FBC technology, supported by math modeling to provide a sound basis for extrapolation to larger scales and higher pressures.

Flue Gas Dilution of Pulverized Coal Combustion. As part of a major experimental program on coal fired closed cycle gas turbines we have been studying air heater designs which incorporate both novel geometric layouts and extensive flue gas recirculation in a pulverized coal fired system. The objectives were to produce more uniform heating and less aggressive deposits than would be expected in a normal boiler combustion situation. This work has involved cold flow modeling, reduced scale combustion testing, and materials testing in p.c. fired environments.

Staged Combustion

Much of the staged combustion work at Battelle has been related to fluidized bed technology, using both the MSFB principle and conventional FBC. The MSFB is particularly amenable to staging. There has also been considerable bench scale and small lab scale work related to staged combustion of pulverized coal, some of which is described in a later section.

Spouted Bed Combustion

Spouted bed combustion is distinguished from fluidized bed combustion by the existence of vertically upward spouts in which air and reacting fuel penetrate the bed surface, the solids raining back onto the bed surface to be recycled. The recycled solids form an effective heat carrier, and in a gas fired system the recycled heat permits stable combustion of very dilute mixtures. Battelle currently has two projects in which the spouted bed principle is being examined in the context of coal firing, as well as for firing other gaseous, liquid, and solid fuels. The spouted bed may also be regarded as an extreme example of a directionally fluidized bed with controlled bed movement, and we consider that other alternatives of this sort warrant serious study.

Diagnostics

Diagnostics form an essential part of Battelle's coal combustion research effort, and in particular we have developed a strong capability in in-bed diagnostics for FBC systems. Fluidized beds constitute a very severe environment in which to make scientific measurements. We have been especially pleased with the results of in-bed measurements of oxygen partial pressure which have given valuable data on both temporal and spatial variations of oxygen partial pressure. These data relate to the corrosion of heat exchanger tubes immersed in a coal fired bed and are potentially important in relation to combustion and pollutant control. Other diagnostics techniques that have been developed deal with particle size distribution, temperature and velocity measurement. Extensive use has been made of laser and fiber optics technology.

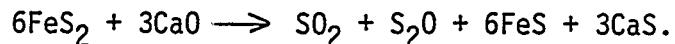
The use of advanced diagnostics in investigation of physical and chemical conditions in fluidized bed combustors is very much needed. Present understanding of these conditions is very deficient, and for this reason considerable uncertainty remains as to the durability of advanced large scale fluidized bed combustor devices, and the potential for further improvement of in-bed reactions.

Chemistry

In the area of coal combustion chemistry, Battelle has been active for some time in work related to the formation and control of gaseous pollutants. The precursors of current programs were initiated to explain the production of corrosive salts (the alkali iron trisulfates) in boiler furnace deposits. In a series of small scale experiments the oxidation of H_2S to SO_2 and SO_3 in the absence of catalysts was demonstrated. Catalysts present in fly ash are judged important, however, in accelerating the production of SO_3 to form complex sulfates at or near tube surface temperatures. In more recent work related to staged combustion enhanced production of SO_3 has been demonstrated in the secondary combustion stage and has been attri-

buted to the production of atomic oxygen as a by product of the $\text{CO} \rightarrow \text{CO}_2$ reaction.

In work aimed at controlling SO_2 emission levels we have studied, in a small scale one dimensional flame system, the effects of limestone additions to powdered coal, with particular reference to coal treated by hydrothermal impregnation with CaO slurries solutions. Lime added in this way is far more effective than lime physically mixed with the coal, virtually complete SO_2 capture being observed at $\text{Ca/S} = 2.5$. Current work is concerned with the interaction between CaO and iron pyrite, FeS_2 , in flames. In the absence of oxygen, SO_2 and S_2O are produced as well as CaS , according to the reaction scheme

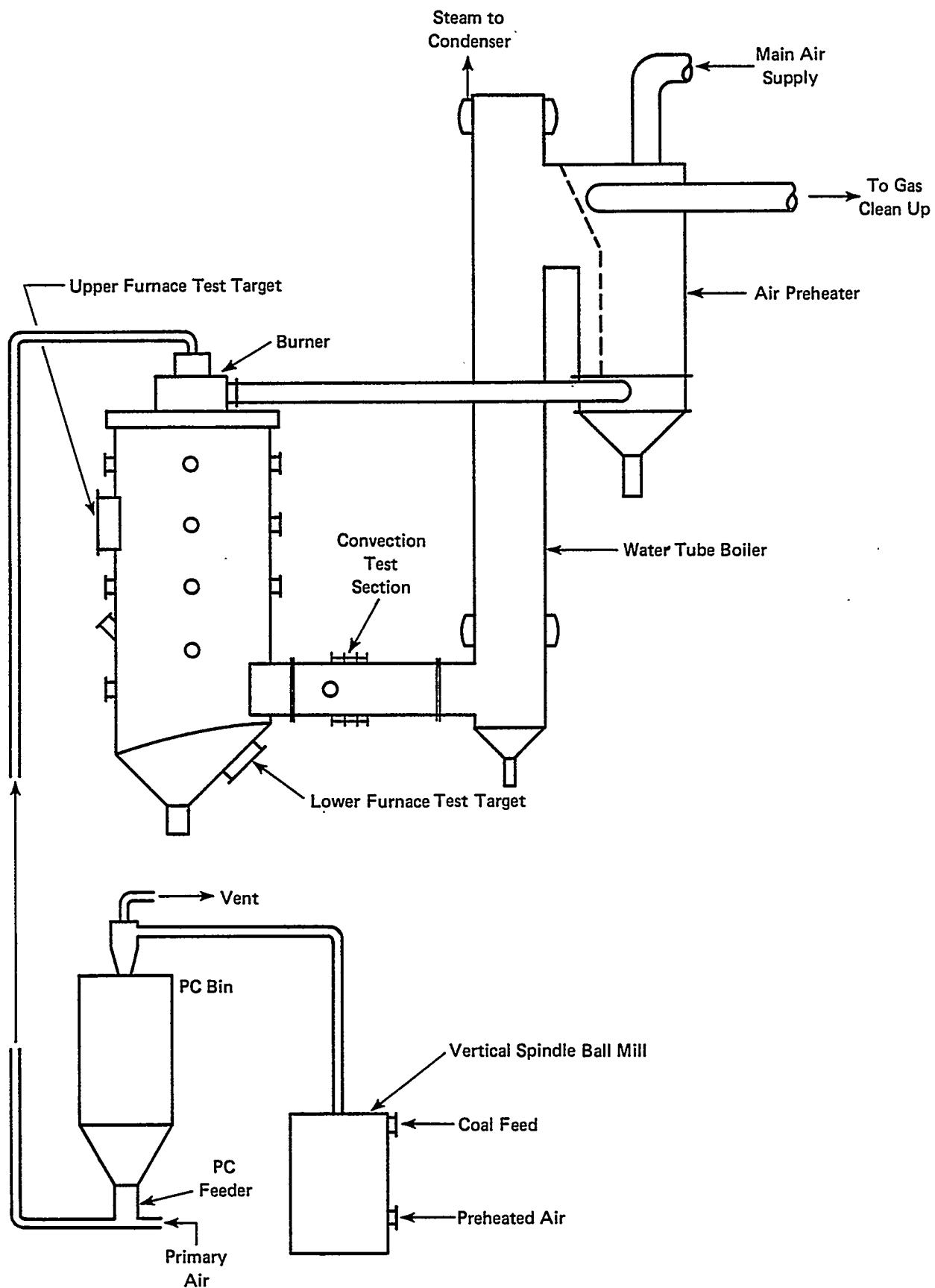


The capture of sulfur as CaS is an important issue in relation to several combustion techniques. Where sulfur is intimately associated with the coal, it reacts in a low oxygen environment, and hence will tend to form sulfides rather than sulfates. CaS , if formed, is more stable than CaSO_4 and hence affords the possibility of sulfur capture at temperature higher than 1600 F. This is applicable to stoker fired units and gasifiers as well as in staged combustion and FBC systems.

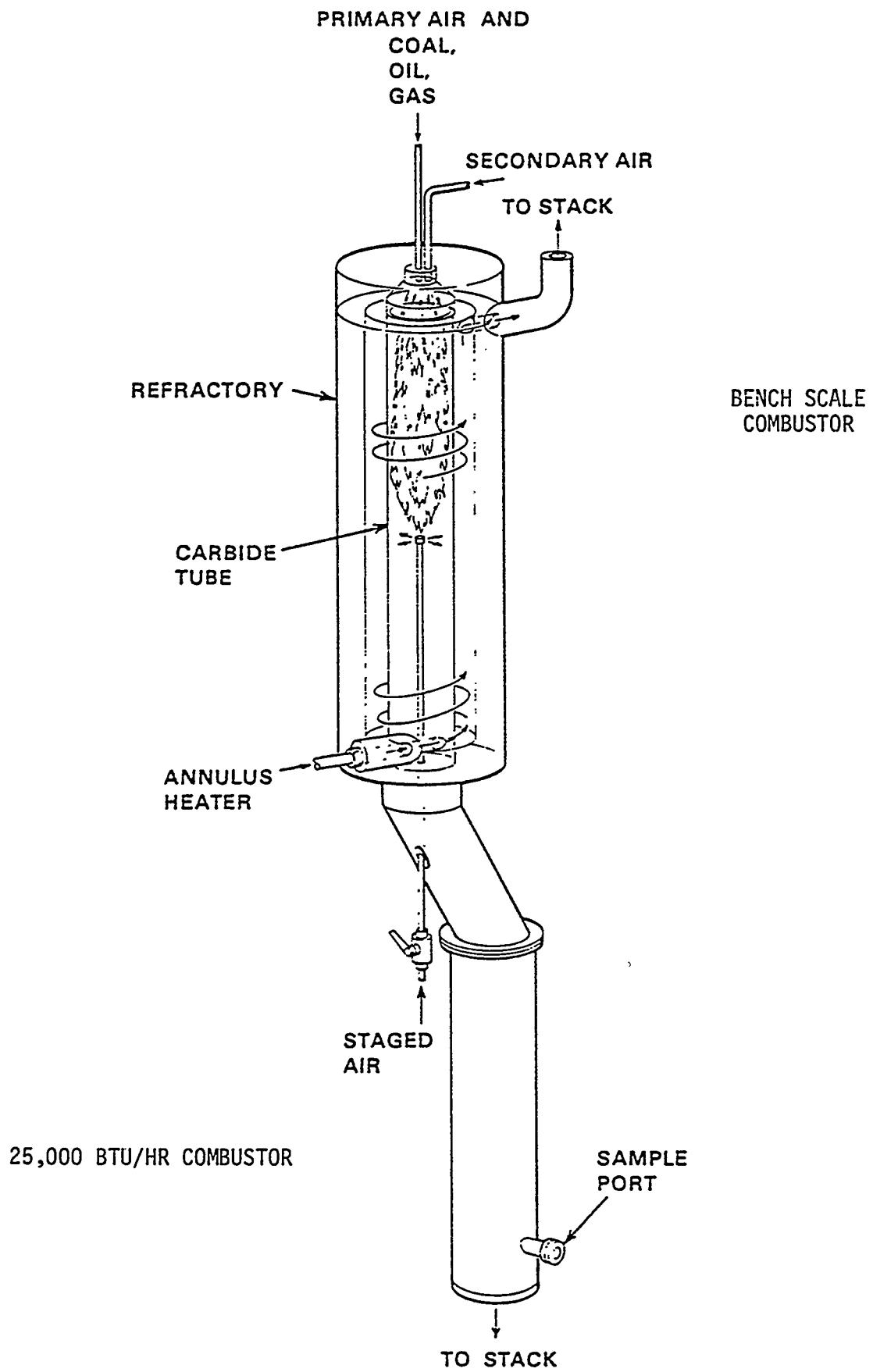
Future Work

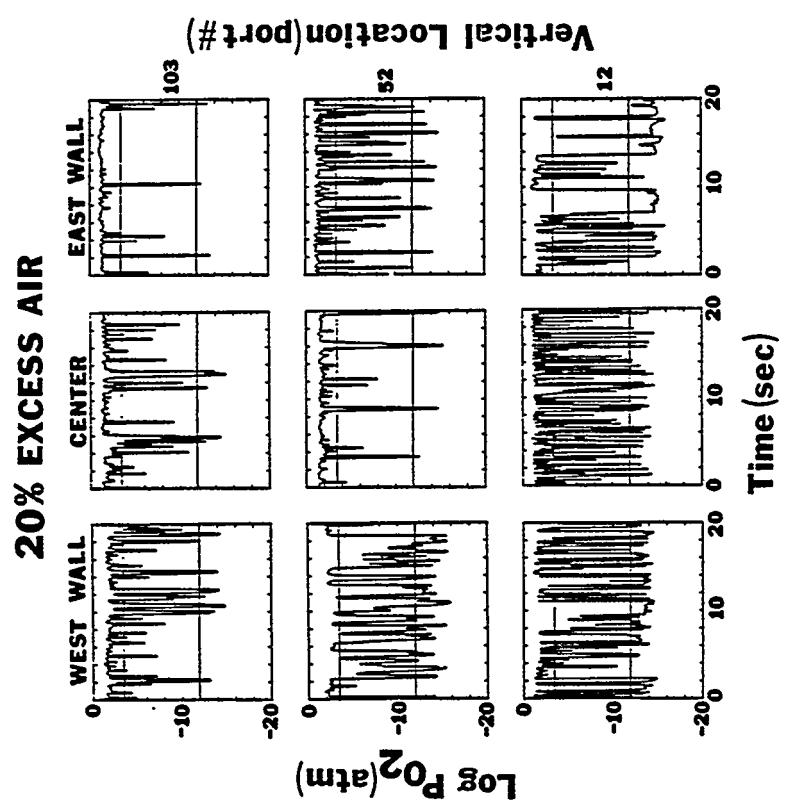
The topics in which we see a need for more work in the immediate future are:

- Mechanism of coal ash deposit formation and bonding
- Beneficiated coals and optimization of beneficiation treatments
- High purity coal slurry fuels
- FBC in-bed physical and chemical mechanisms
- Chemistry of emission control in coal combustion processes
- Advanced combustion processes.



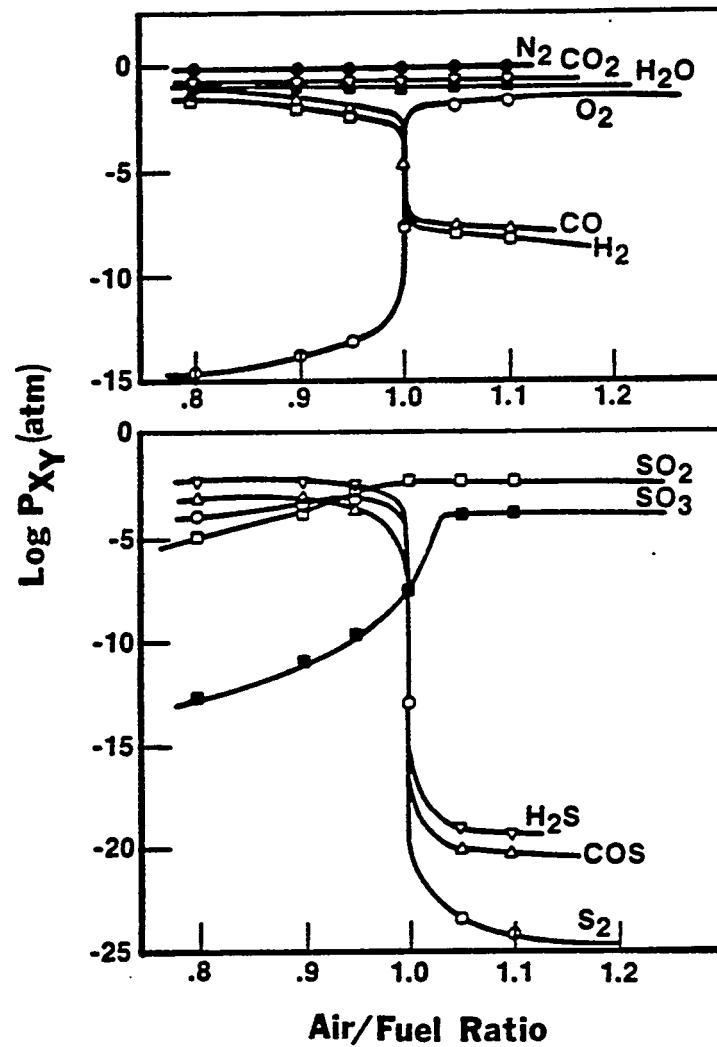
5M Btu/hr PC COMBUSTION RESEARCH FACILITY



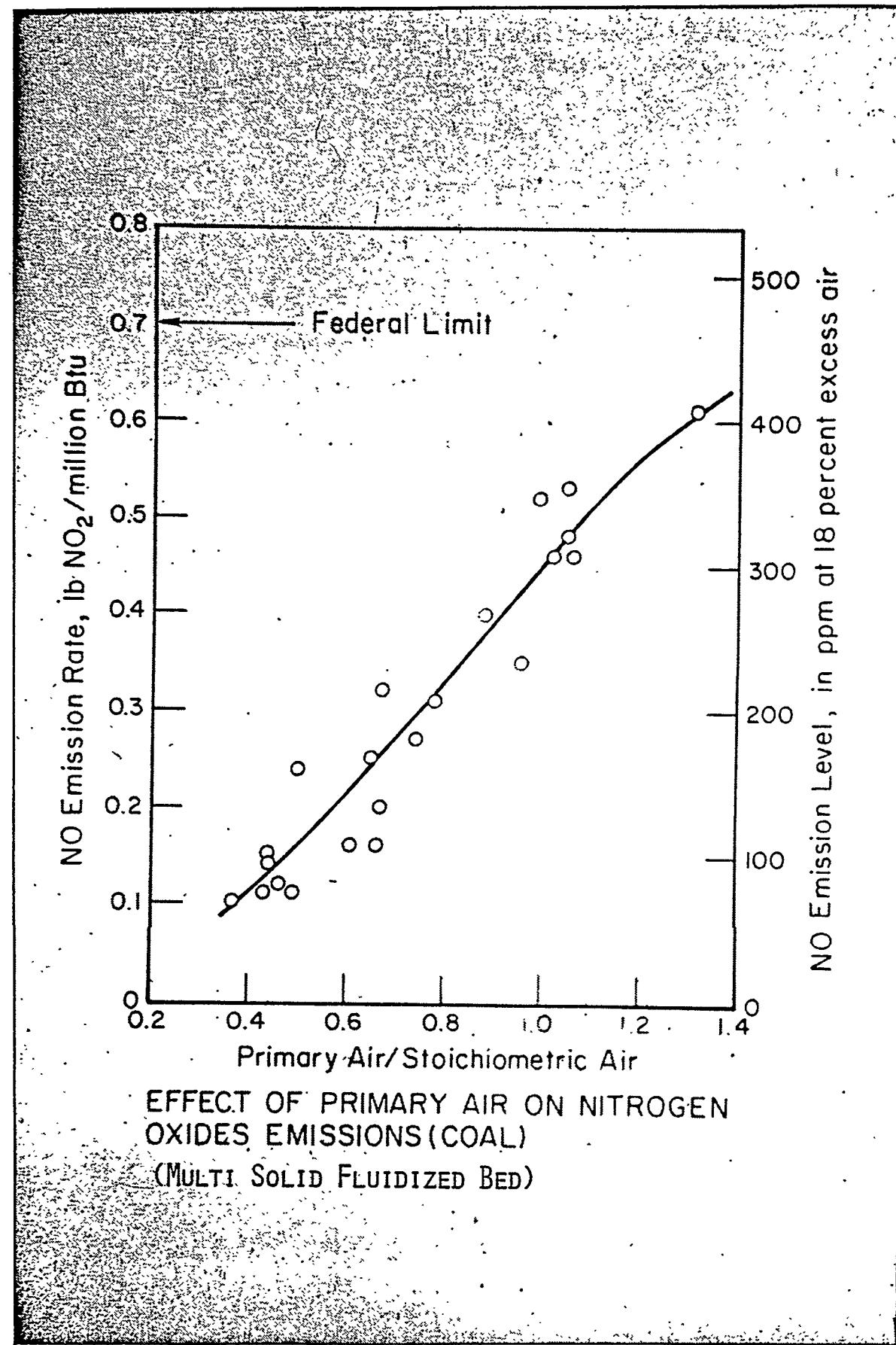


PARTIAL PRESSURE OF OXYGEN WITHIN
A BUBBLING FLUIDIZED BED

Level 12 - Below tube bank
52 - Lower tube bank
103 - Upper tube bank



EQUILIBRIUM COMPOSITION FOR
COMBUSTION PRODUCTS AT 1150K



EFFECT OF PRIMARY AIR ON NITROGEN
OXIDES EMISSIONS (COAL)
(MULTI SOLID FLUIDIZED BED)

APPENDIX AB-8-2

COAL-RELATED
STUDIES AT B&W

CHUCK WAGONER

GENE MICHAUD

QUANTITATIVE MEASUREMENT OF SLAGGING AND FOULING EFFECTS

EXPERIMENTAL TECHNIQUES

- TRADITIONAL
DEPOSITION
ASTM ANALYSES
- ENGINEERING ORIENTED
DEPOSIT REMOVAL
HEAT TRANSFER BETWEEN
CLEANING CYCLES

CORRELATIONS AND CREDIBILITY

FUEL / ASH CHARACTERISTICS

- LAB, FREQUENTLY ASTM ASH
- SMALL PILOT-SCALE
- LARGER PILOT-SCALE
- FULL SCALE

STEAM GENERATOR PERFORMANCE

- AVAILABILITY
- CAPACITY
- HEAT RELEASE RATES
- EFFICIENCY
- DEPOSITION

TRADITIONAL CORRELATION

SEQUENCE

- LABORATORY CHARACTERIZATION OF FUEL, ASTM ASH, AND SIMULATED FLY ASH
- CALCULATION OF INDICES (HARDWARE DESIGN EXPERIENCE, EMPIRICISM)
- STEAM GENERATOR DESIGN DETAILS

EASTERN COAL

TABLE 10-1. DESIGN VALUES OF PLAN AREA HEAT RELEASE RATES

HAZARD *EPRI CS-1418*

Boiler Manufacturer	References	Period	Fuel Type	$10^6 \text{ Btu}/\text{ft}^2 \text{ Hr}$ Plan Area
Combustion Engineering	Lyons ⁽¹⁾	1977	Eastern bituminous	2.07
			Midwest bituminous	1.79
			Texas lignite	1.65
			North plains lignite	1.47
CE	Harris ⁽²⁾	1972	Eastern bituminous	1.8 - 2.5
			Midwest bituminous	1.7 - 2.0
			Subbituminous	1.7 - 2.0
			Oil	2.3 - 2.7
CE	Tuppeny ⁽⁶⁾		All - 60's vs 70's	
Babcock & Wilcox	Gray ⁽³⁾ or Heil ⁽⁴⁾	1970's 1960's	All coals	1.45 - 1.90 1.90 - 2.15
Foster Wheeler	Frederick ⁽⁵⁾	1970's	All coals	1.70 - 2.00

Plan Area Heat Release Rates for Test Boilers

			Design	Actual	
2	Labadie		Midwest bituminous	2.06	1.84 89%
1	Mill Creek		Midwest bituminous	1.90	1.59 84
5	Cliffside		Eastern bituminous	2.06	1.89* 92
3	Morgantown		Eastern bituminous	2.57	2.28* 89
4	Montour		Eastern bituminous	2.15	2.28 106

* Not slagging-limited.

GENERATION LOSS UP TO 16%

References:

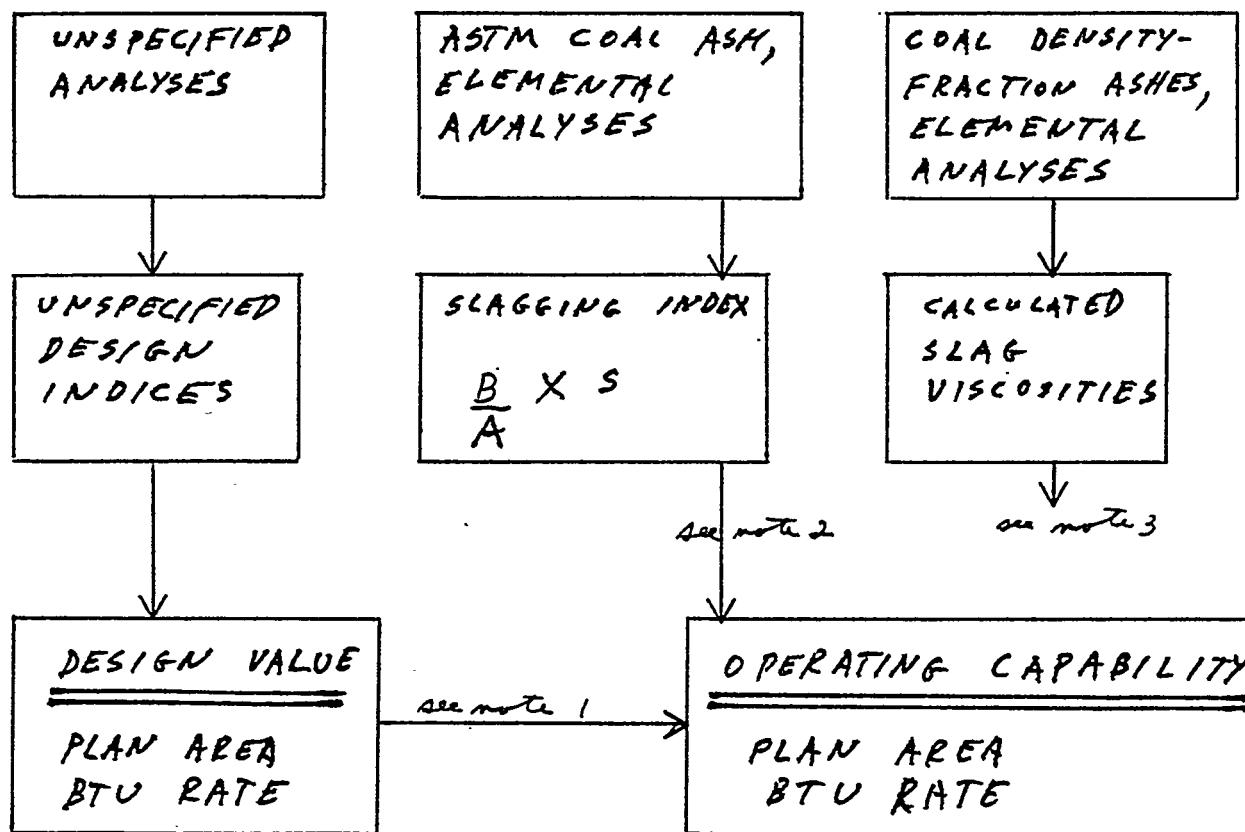
1. Lyons, D. E. and Blackburn, S. S., "Design for availability - An Update", Proc. American Power Conf., Vol. 39, 1977, pp 349-368.
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6. Tuppeny, W. H., Jr. "Effects of Changing Coal Supply on Steam Generator Design", Proc American Power Conference, Vol 40, 1978, pp 367-380

*"BETTER PREDICTIVE TOOLS ARE REQUIRED"
in a dimmer*

EASTERN COAL

40-MONTH EXPLORATORY STUDY, RESULTS

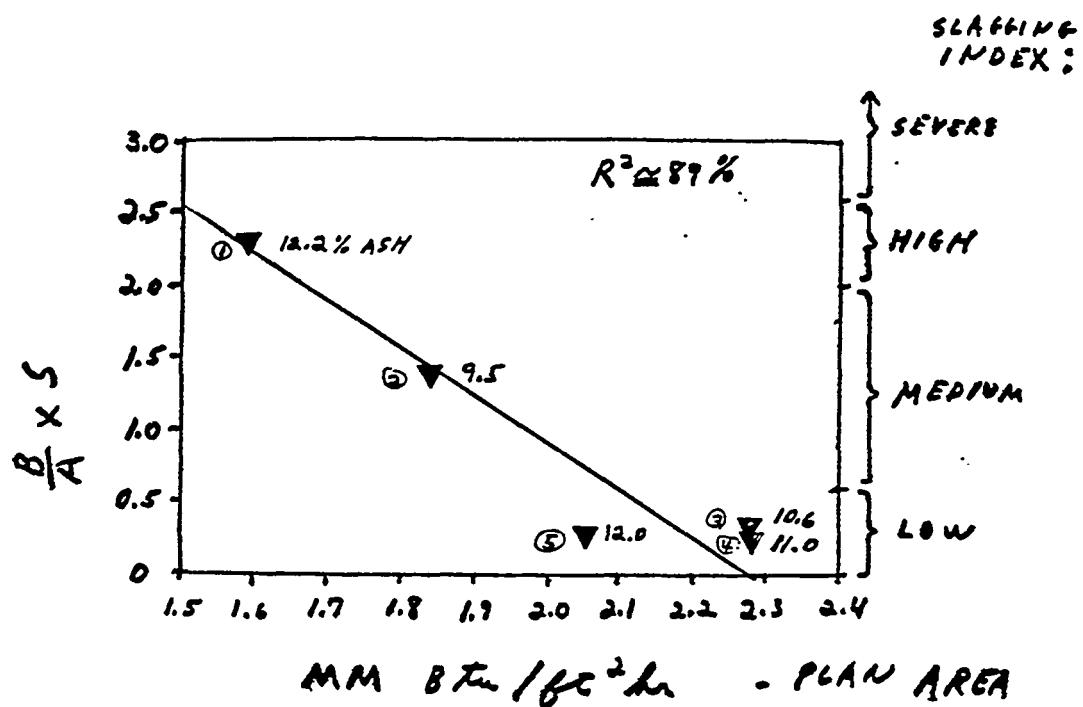
EPRI CS-1418



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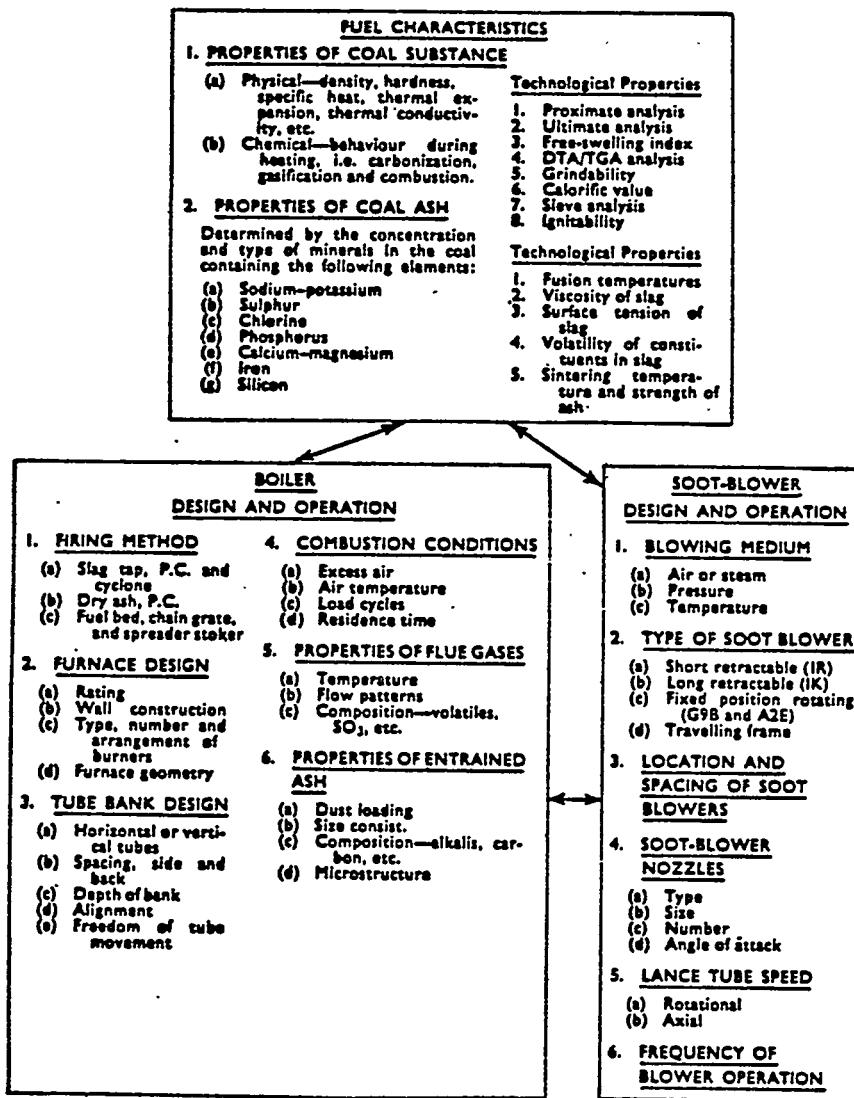
1. generation loss up to 16 %
2. "a realistic design basis for the coals fired"
 $\times 10^{-3}$
3. "the relation of furnace ash characteristics to iron and calcium segregation in coal density fractions appears to be a fruitful subject for research"
 $\times 10^{-14}$

EASTERN COAL:
DEMONSTRATED OPERATING CAPABILITY
CORRELATION



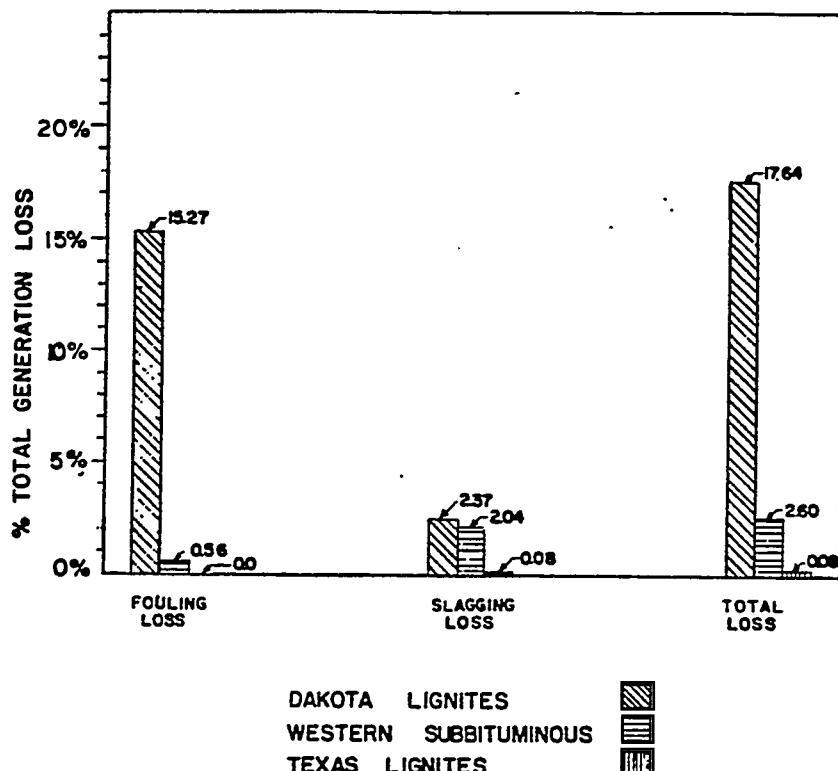
FROM DATA BY
 HAZARD
 EPRI CS-1418

FACTORS AFFECTING ASH DEPOSITION



ATTIG, BARNHART
MARCHWOOD CONFERENCE
MAY 1963

WESTERN COAL

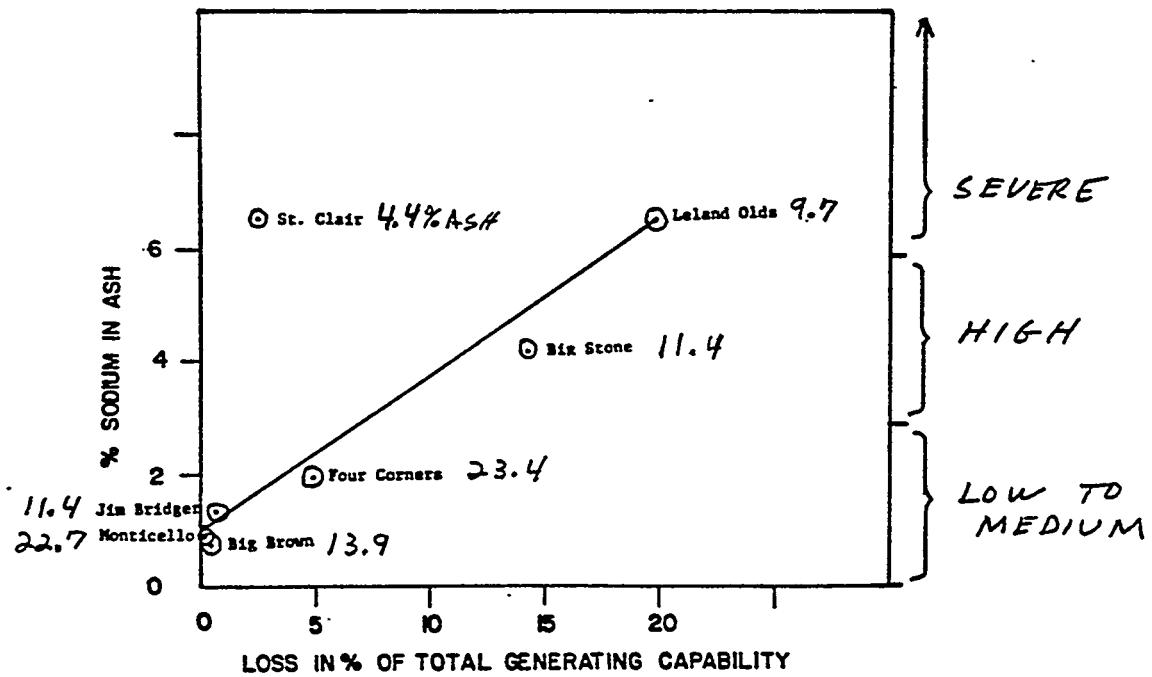


Percentage of Potential Generation Lost Due to Slagging and Fouling

BURKHARDT
DOE/GFETC/0059-1

WESTERN COAL

FOULING INDEX



% Sodium vs. Loss of Generating Capacity

FROM DATA BY BURKHARDT
DOE/GFETC/0059-1

WESTERN COAL ASH DEPOSITION,

COSTS AND RECOMMENDATIONS

BURKHARDT DOE /GFETC /00 59-1
DECEMBER 1980

- \$ 1,794,600 FTS COSTS PER STEAM-
GENERATOR YEAR (415 Mw AVG. SIZE
FOR 23 UNITS STUDIED)
- "TESTING SHOULD BE PERFORMED
WHICH EVALUATES SOOT BLOWER
EFFECTIVENESS" (#1)
- "UTMOST IMPORTANCE SHOULD BE
PLACED ON CONTROLLING
FURNACE GAS EXIT TEMPERATURES"
(#2)

CREDIBILITY OF TRADITIONAL CORRELATIONS

EXPERIENCE FACTOR -

WORST WHEN MOST NEEDED!

COAL SOURCE

- EXISTING MINE
- CORE DRILLING
- CLEANING PLANT (WASHED, SRC)

COAL FORM

- PULVERIZED
- BLENDED PC
- MICRONIZED
- COM, CWM

ENGINEERING ORIENTED MEASUREMENTS

QUANTITATIVE BOILER DIAGNOSTICS

- IN LARGE STEAM GENERATORS
- IN SMALL PILOT-SCALE

DIRECT DATA COMPARISON GOALS

- MINIMIZE SCALING CORRECTIONS
AND INDEX / CORRELATION COSTS
- OBTAIN QUANTITATIVE DATA
WITH SAME TECHNIQUE
 - AT DIFFERENT POWER PLANTS
 - WITH SMALL AND LARGE SCALE
- IMPROVE ABILITY TO EVALUATE
NEW OR MODIFIED FUELS

ENGINEERING ORIENTED
MEASUREMENTS

ADDITIONAL GOALS

- ESTABLISH A STANDARD BOILER DIAGNOSTIC PROCEDURE
- IMPROVE COMMUNICATIONS AMONG UTILITIES
BOILER MANUFACTURERS
ENGINEERING SOCIETIES
TECHNICAL STANDARDS SOCIETIES
COMPUTER MODELERS
SPONSORING ORGANIZATIONS

APPENDIX AB-8-3

THE SECOND-GENERATION LABORATORY ASHING FURNACE

by

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Alliance, Ohio 44601

Prepared for

The Engineering Foundation Publication:

Experimental Research Into Fouling and Slagging Resulting From
Impurities in Combustion Gases

Proceedings of the July 1981 Conference

Session 3 — Pilot Plant Experience in North America

THE SECOND-GENERATION LABORATORY ASHING FURNACE

ABSTRACT

In 1963, Attig and Barnhart described a Babcock & Wilcox laboratory ashing furnace at an international conference in Marchwood, England [1]. The small, pulverized fuel-fired furnace was designed to produce fly ash with properties similar to ash from a utility steam generator.

A second-generation furnace was completed early in 1981. This new unit has one added capability -- the combustion of solid-liquid mixtures. It is designed to provide improved understanding of formation and characteristics of deposits formed on sootblown heat-transfer surfaces.

INTRODUCTION

Accurate prediction of the effectiveness of sootblowing and the quality of heat transfer in a steam generator is a necessity for the boiler designer. The required accuracy is difficult to obtain for a fuel that has not been burned previously in a boiler and is available only in a small quantity. Further complications arise because of wide potential variations in ash quality and quantity.

The design objective of the second-generation laboratory ashing furnace (LAF II) is to obtain useful engineering information directly from combustion tests using a limited amount of fuel. This permits using core drillings or material from restricted small-scale production runs.

Improvements include a new coal feeder and combustion chamber/guard heater design. A complete system was added for storing, pumping and burning coal-oil mixtures (COMs), or other solid-liquid mixtures. Also, we are developing a deposition test section as part of a current Department of Energy (DOE) contract.

LABORATORY ASHING FURNACE (LAF II)

Description of Pulverized Fuel Unit

An isometric drawing of the pulverized fuel-fired unit is shown in Figure 1. The LAF II is comprised of five major components:

1. A system for feeding pulverized fuel
2. A laminar flow coal burner to minimize impingement of ash on the furnace wall
3. A refractory combustion chamber with a three-zone, electrically-powered guard heater to control outward heat flux through the furnace walls
4. A water-cooled pressurized boiler to cool the hot flue gas
5. A system for collecting fly ash

Pulverized fuel is prepared using a small impact mill to achieve a product with about 70 to 75 weight percent passing a No. 200 sieve (75μ). Any material not passing a No. 60 sieve (250μ) is removed by sieving. The sample of pulverized fuel is air-dried at 105°F and loaded into the hopper of a twin-screw feeder. Higher levels of moisture are simulated by adding steam to the combustion air.

The coal feeder is mounted on load cells and weighed continuously. Additional fuel can be added at any time because the feeder is not pressurized.

Fuel passes from the feeder into an eductor where it is mixed with primary air and transported to the burner. Typically, primary air is 20 percent of total combustion air. Secondary air passes through an electrically-powered preheater, is heated to about 400°F, and then is delivered to the burner.

The burner is comprised of three concentric tubes. Preheated secondary air flows through the inner and outer tubes; primary air/pulverized fuel flows through the middle tube. No swirl is imparted by the burner. This keeps furnace wall slagging at a minimum.

Typical firing rates for pulverized fuel are in the range of 50,000 to 150,000 Btu/hr.

The furnace wall is a silicon carbide tube that is four feet long with a one foot inside diameter. The wall is enclosed by a three-zone guard heater with Globar elements. This heater is used to control the rate of cooling of the flame. Typical wall temperature is between 2500° and 2600°F. Furnace residence times are on the order of one to two seconds. The furnace wall can be cooled to permit extinction measurements as described in a recent publication by Winegartner and Lin [2].

An uncooled refractory slagging probe can be inserted above the furnace outlet to simulate flame impingement on the high temperature surface of a thick wall slag. The furnace exit gas temperature at this convergent location usually is near 2450°F.

A deposition test section (Figure 2) will be designed and constructed as part of a current contract sponsored by DOE [3]. This will adapt the existing LAF II for fundamental deposition studies. The refractory-walled section will be located below the exit of the combustion chamber. Ports will be included for insertion of deposition tubes and sootblower nozzles, and will permit application of optical diagnostic instruments. The air-cooled tubes will be designed to have the capability for slowly rotating the deposition surface in a harmonic oscillation to provide a uniform thickness of deposit. The deposition section/tube

combination will be designed to simultaneously simulate furnace wall slagging and superheater fouling conditions, including metal and gas temperature combinations, tube alloys, and sootblowing.

Deposition tube metal temperatures will be determined from thermocouples embedded in the tube. Deposit surface temperature will be measured using two-color pyrometry. Deposit thickness will be determined from analysis of time-lapse photography. Heat flux from the hot gas through the deposit and tube wall will be determined from calorimetric measurements of the cooling fluid. These measurements will allow calculation of the thermal conductivity of the deposit. Spectral emissivity of the deposit, from visible to mid-infrared wavelengths, will be determined from measurements of spectral irradiance in spectral regions where the combustion product gases are essentially transparent. In wavelength regions where the combustion gases are absorbing, the emissivity will be estimated by interpolation.

The deposition section will be two feet long with an inside diameter of five inches. Flue gas velocity will be nearly 10 feet per second at the superheater tube. The deposition tubes will have one inch outside diameters.

A pressurized water heat exchanger cools the flue gas before fly ash is collected in a cyclone separator followed by a bag filter. The sample of fly ash is used for a variety of laboratory analyses, including measured sintering strength [4,5].

Description of Coal-Oil Mixture (COM) System

The system for handling solid-liquid mixtures is shown in Figure 3. The main components include a heated, 55-gallon storage tank with an air-powered mixer, a Moyno pump with a variable speed drive, heated connecting lines, and a burner with either an internal or external mixing sprayer plate that can use either air or steam for atomization.

The slurry burner is installed in place of the pulverized fuel burner.

The storage tank is mounted on load cells and weighed continuously.

RESULTS AND DISCUSSION

Six coal-oil mixtures, one No. 6 oil, and three parent pulverized coals have been tested using LAF II this year under contract to the U. S. Maritime Administration (MARAD)[6]. As a result, we have measured relative values and ranked the fuels using the following parameters:

- Atomizer Wear
- Flame Quality and Length
- Slagging Potential from Deposition on Refractory Probe
- Fly Ash Sintering Potential from Measured Sintering Strength
- Carbon Conversion Efficiency

Although details cannot be released at this time, significant differences were found among the fuels.

CONCLUSIONS

The choice of COM fuel for a shipboard demonstration on the Great Lakes for MARAD was greatly aided by testing using LAF II. The results complemented other laboratory analyses and greatly improved our ability to predict engineering properties from fuel analyses.

The LAF II is expected to continue to produce useful engineering information in future studies.

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Babcock & Wilcox LAB ASHING FACILITY

1. ELECTRIC FURNACE
2. ELECTRIC FURNACE CONTROL CABINET
3. STEAM DRUM
4. PULVERIZED FUEL TWIN-SCREW FEEDER
5. NATURAL GAS
6. COAL TRANSPORT LINE
7. EXHAUST FAN
8. SECONDARY AIR HEATER
9. FLY ASH BAG
10. SLAG-COLLECTOR
11. CYCLONE ASH COLLECTOR
12. MAIN CONTROL PANEL
13. COMBUSTION PRODUCTS
14. HEAT EXCHANGER
15. SECONDARY AIR
16. HIGH PRESSURE TREATED WATER PUMP
17. BLOW DOWN DRAIN
18. PLANT STEAM
19. FEED RATE MONITOR
20. RELIEF VALVE
21. MANUAL STEAM VENT
22. EXHAUST TO ATMOSPHERE (FLUE GASES)
23. HEATED SECONDARY AIR

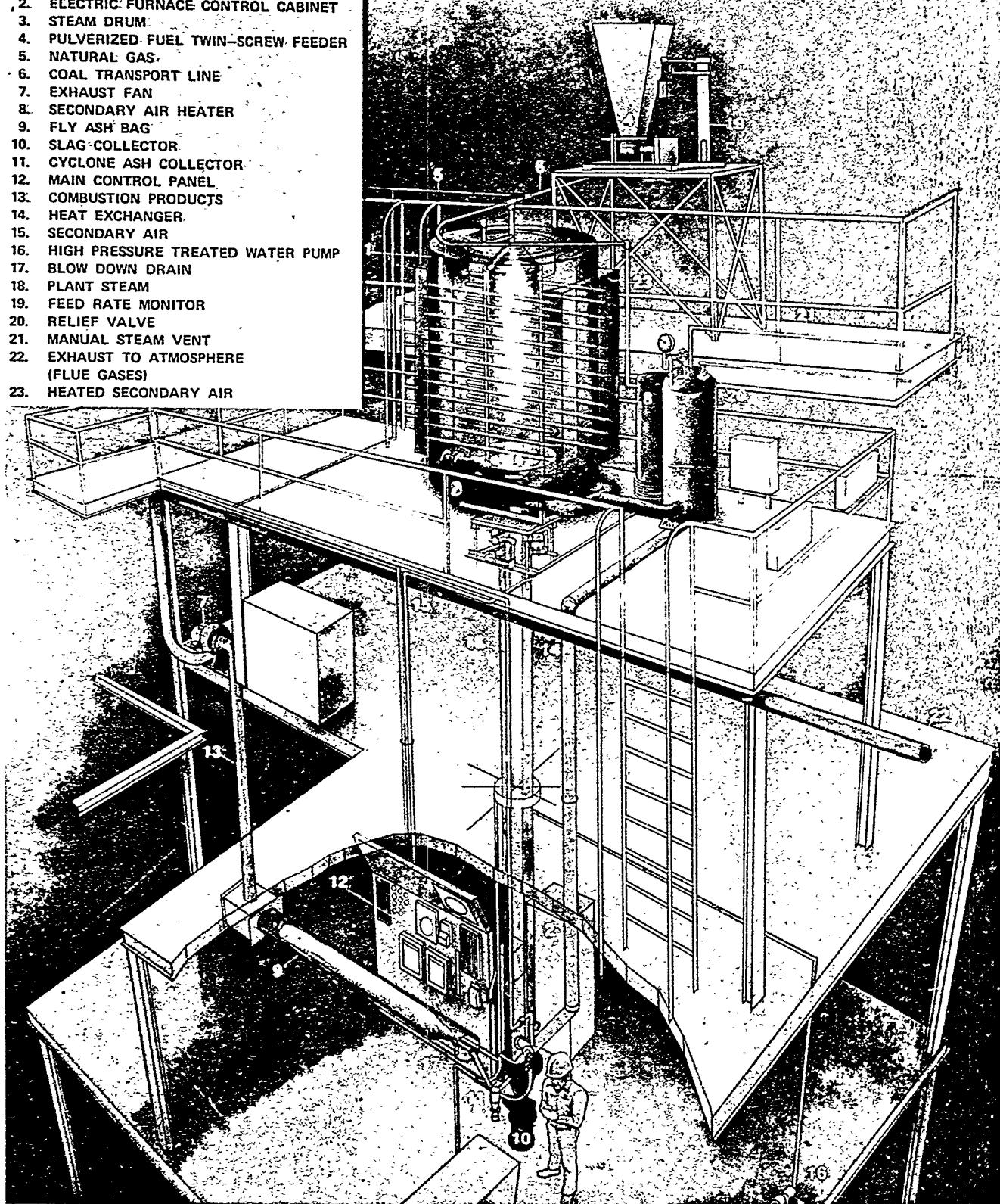


FIGURE 1

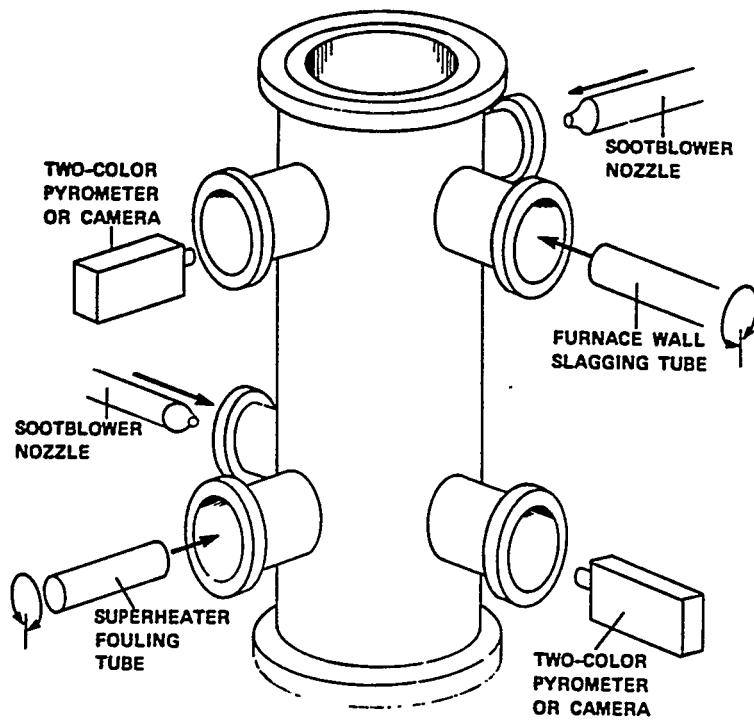


FIGURE 2 CONCEPTUAL DRAWING OF DEPOSITON TEST SECTION

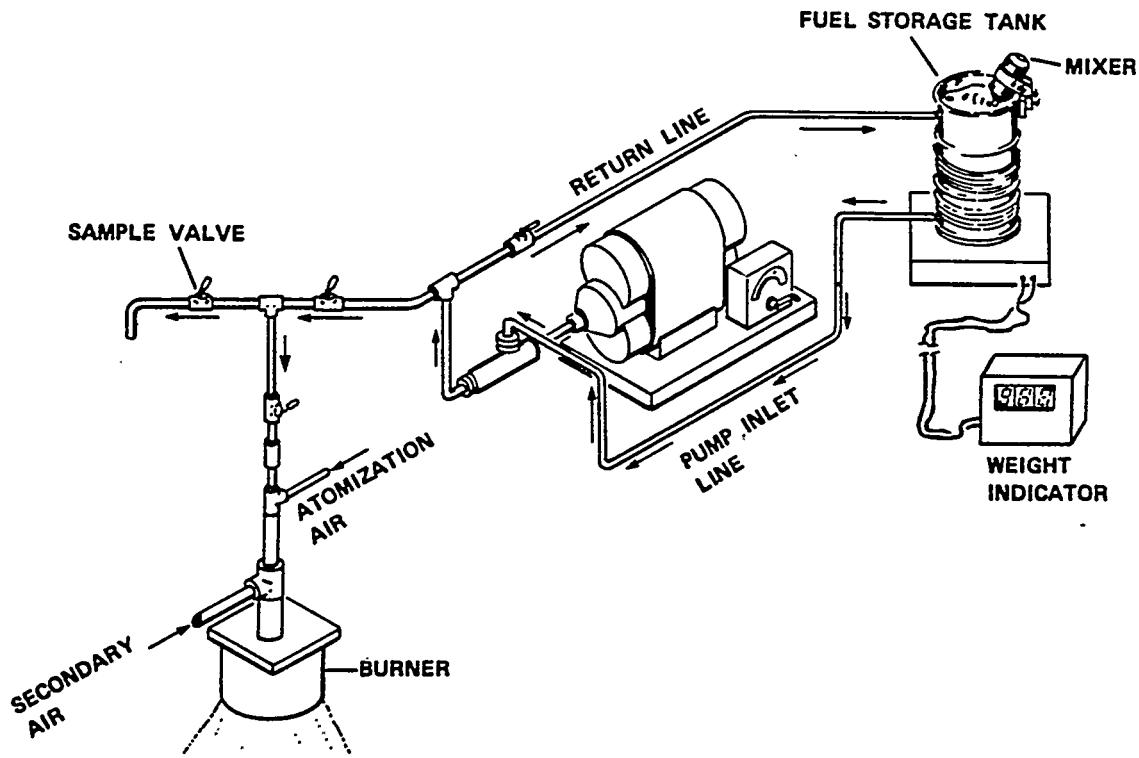


FIGURE 3 SYSTEM FOR SOLID-LIQUID MIXTURES

APPENDIX AB-8-4

Preliminary Observations of the Influence on Fireside Deposition
of Ion-Exchangeable Calcium in Coal*

by

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The Engineering Foundation

International Conference on Fouling of Heat Exchange Surface

Session on Chemical Reaction Fouling
White Haven, Pennsylvania

October 31 - November 5, 1982

*This Document is an Extended Abstract Prepared for Inclusion in
Conference Preprints

ABSTRACT

Recent work indicates the role of ion-exchangeable calcium in low-rank coal can be more important than previously thought. A sample of subbituminous coal was modified by removing about one-half of the ion-exchangeable calcium. Contrary to most published correlations, ash fouling and slagging characteristics associated with combustion of pulverized fuel were changed significantly. Heat transfer rates and sootblower cleaning capabilities were reduced when the calcium was lowered. This investigation was sponsored by the U.S. Department of Energy (DOE), Pittsburgh Energy Technology Center under its program for Advanced Research and Technology Development.

INTRODUCTION

A project is underway with the goal of measuring the fundamental properties characterizing coal minerals and fireside deposits.

In an early phase of the activity at Pennsylvania State University, samples of a Montana subbituminous coal (Decker coal) were prepared in which a significant amount of the ion-exchangeable sodium or calcium was replaced with hydrogen ion. These samples are being burned as pulverized fuels in small-scale tests by Babcock & Wilcox (B&W); the resulting deposits are analyzed and compared with those of the unmodified parent coal.

To date, combustion tests have been concluded for the parent coal and a low-calcium sample. Although analyses are not yet complete, preliminary observations indicate that when burning low-rank coals, the role of ion-exchangeable calcium in fireside deposition may be more important than previously reported by many investigators. This conclusion is based on measurement of significant differences for deposition rates, heat transfer properties, and ease of removal by sootblowing.

LABORATORY ASHING FURNACE

The second-generation laboratory ashing furnace (LAF II) was described in detail^[1] at a recent conference sponsored by the Engineering Foundation.

Figure 1 is a drawing of the pulverized-fuel-fired unit. Firing rates of approximately 100,000 Btu/hr are being used during the current investigation for DOE.

The concept of the deposition test section is shown in Figure 2. This design permits direct measurement of deposition rate, deposit thermal conductivity and emissivity, heat flux, and sootblowing effectiveness during a 40-hour test period. Simultaneous data are obtained for separate radiant and convective heat exchange surfaces.

RESULTS AND DISCUSSION

Figure 3 shows the influence of time and sootblowing on heat flux (heat absorption rate) for a typical sootblowing cycle during a test with unmodified (parent) Decker coal. Heat flux decreased with time for the furnace wall tube, and sootblowing did not restore the flux to earlier levels. Thin layers (up to about 0.040 inch) of dry, granular and reflective ash mainly were responsible for the changes in heat flux. Visually, both the furnace wall and superheater tubes appeared relatively clean, and the sootblowing seemed effective.

Figure 4 illustrates the appearance of the superheater tube about 20 hours after sootblowing. The parent Decker coal produced this deposit. Sootblowing appeared to remove virtually all of the deposit. In contrast, Figure 5 shows a much greater amount of deposition produced under similar test conditions with a modified Decker coal sample. The modification reduced the amount of ion-exchangeable calcium by about 50 percent. Sootblowing was relatively ineffective in removing this deposit, as seen in Figure 6, which is a photograph taken immediately after sootblowing.

This behavior was not predicted using well established correlations, including those developed in the United States by the Grand Forks Energy Technology Center(GFETC)^[2] or Babcock & Wilcox^[3], or in Australia by L. J. Garner^[4].

Recent investigations by C. J. Lin and E. C. Winegartner^[5] involved limestone additions to coals from North Dakota and Montana. The addition of

calcium in an inorganic form (CaCO_3) reduced fouling rates for the North Dakota lignite. However with the Montana coal (Decker), limestone added at 25 lb/ton coal caused the fouling rate to double. This could indicate that the role of inorganic calcium may be vastly different than that of ion-exchangeable calcium.

Haller and Moore^[6] identified mixtures of Na_2SO_4 - CaSO_4 with low melting points ranging between 1623 - 1700 F as the glue that bonds flyash particles together to form superheater deposits when low-rank Western U. S. coals are burned. In Figure 7, data are shown as triangles that were reported in Table 1^[6] for the amount of immiscible Na_2SO_4 - CaSO_4 phase that formed in slag-viscometer samples produced by melting ash from four lignitic coals, each containing different levels of Na_2O ; calcium concentrations in the lignitic ashes were reported between 19 - 24% as CaO . Fouling classifications as proposed by Gray and Moore^[7] for lignites as a function of Na_2O in ash also are shown in Figure 7.

Haller and Moore^[6] emphasized the dominant role of sodium in fouling. They also pointed out that increased calcium concentration can lead to increased melting temperatures for the Na_2SO_4 - CaSO_4 system. Although the results obtained with the low-calcium-modified Decker coal (no change in sodium level compared with parent Decker) cannot be explained on the basis of a variation in sodium content via Figure 7, a closer look at the Na_2SO_4 - CaSO_4 system is warranted.

A phase diagram for the Na_2SO_4 - CaSO_4 system^[8] was examined to determine what relationships would result if calculations were made using specific values for the elemental composition of ASTM ash prepared from parent and low-calcium-modified Decker coals, normalized to a system containing only sodium and calcium sulfates. The liquidus temperature calculated for the low-calcium-modified coal is about 2030 F, a value 100 degrees lower than calculated for parent Decker. The amount of low melting material that would be present as the mixture initially melts was calculated to be 1.4 times greater for the low-calcium coal. Although these data predict increasing potential for deposition with lower calcium, they appear to underestimate the magnitude of increase observed in Figure 5.

Work at the Grand Forks Energy Technology Center^[2] with Beulah and Velva lignites shows increased depositon rates with lower total calcium contents when sodium levels are high. This seems to be in general agreement with the B&W results, except the magnitude of change was less for the GFETC results.

CONCLUSION

Initial results show that ion-exchangeable calcium can have a significant influence on fireside deposition. As knowledge of the role of calcium in depositon improves, it may be possible to increase boiler efficiency and availability when burning low-rank coals.

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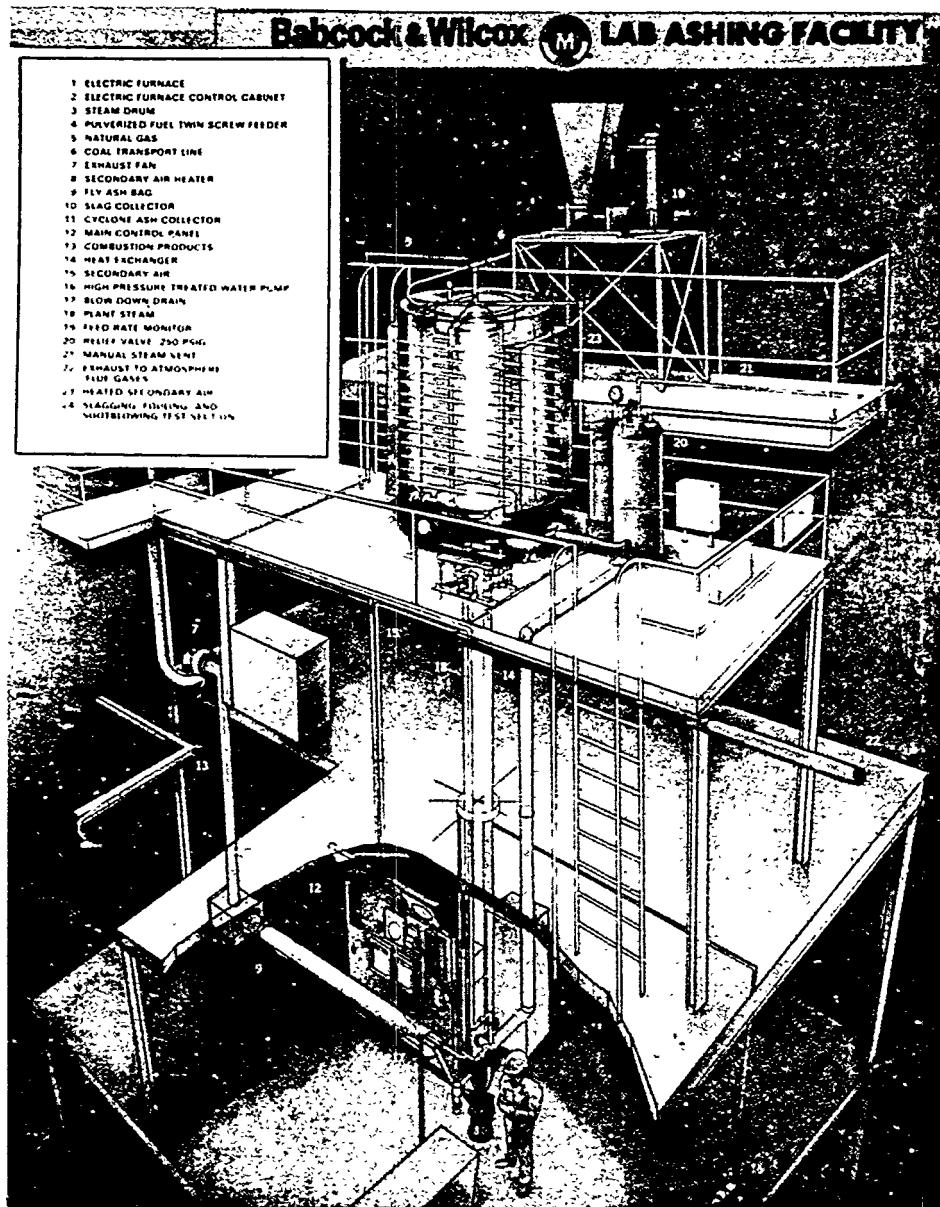


FIGURE 1 Laboratory ashing furnace

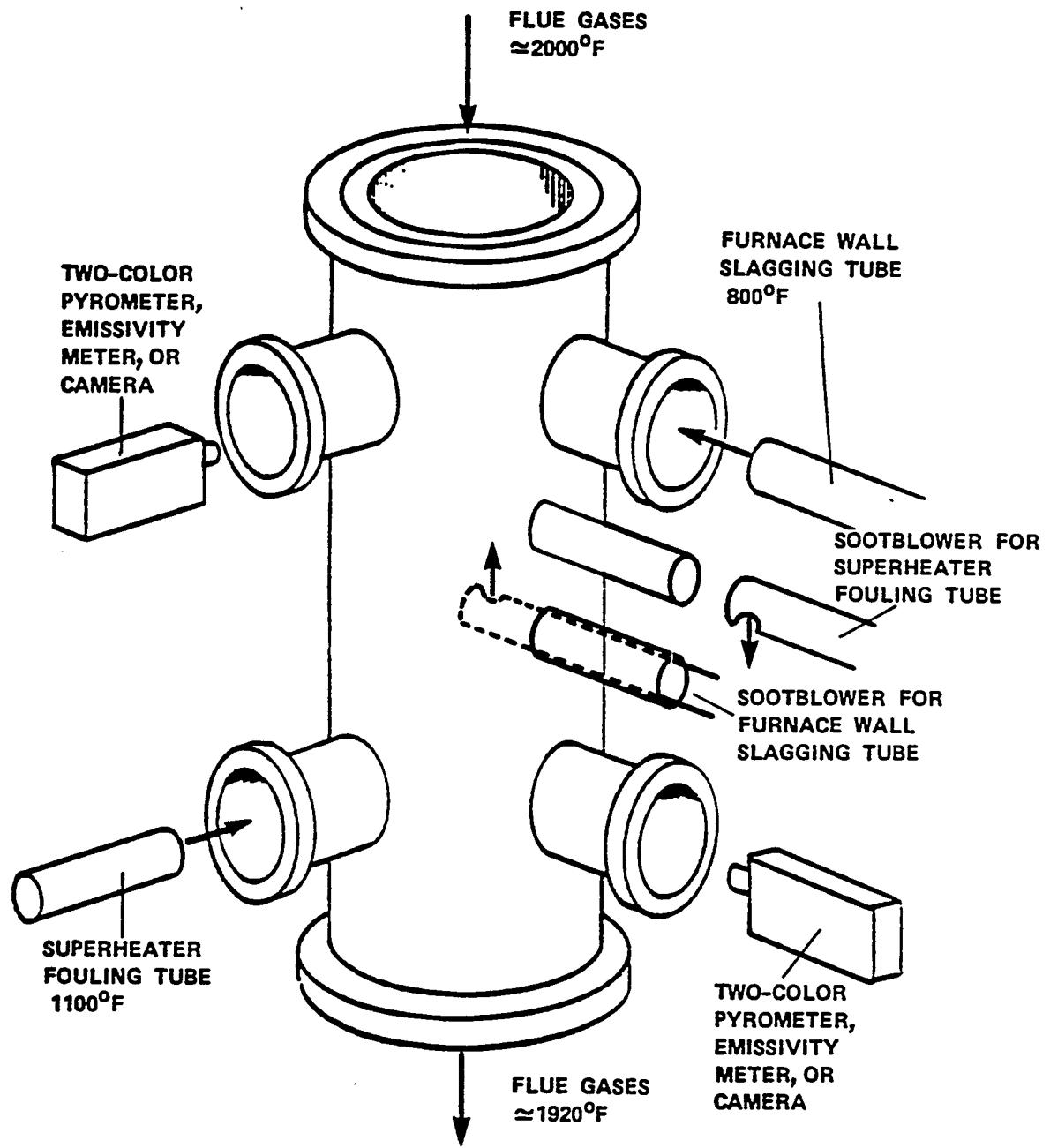


FIGURE 2 Schematic diagram of slagging, fouling and sootblowing test section

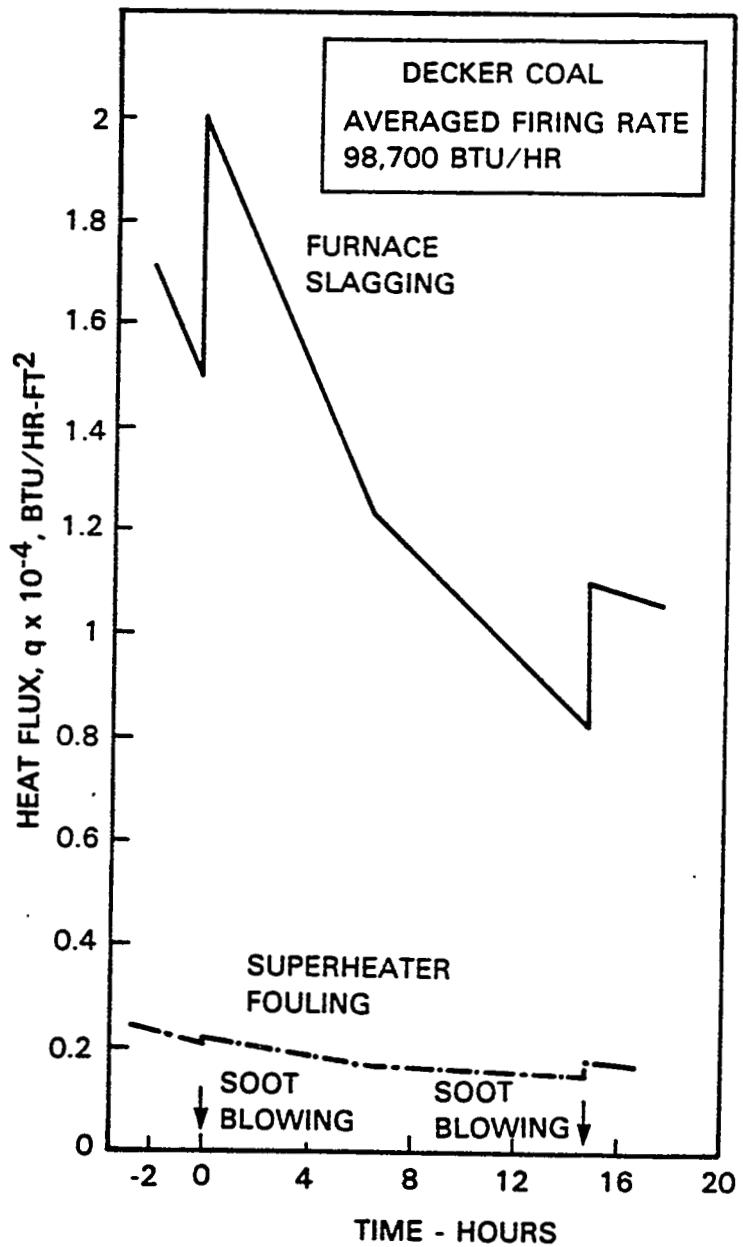


FIGURE 3 Effect of time and sootblowing on heat flux for a typical sootblowing cycle during test with parent Decker coal

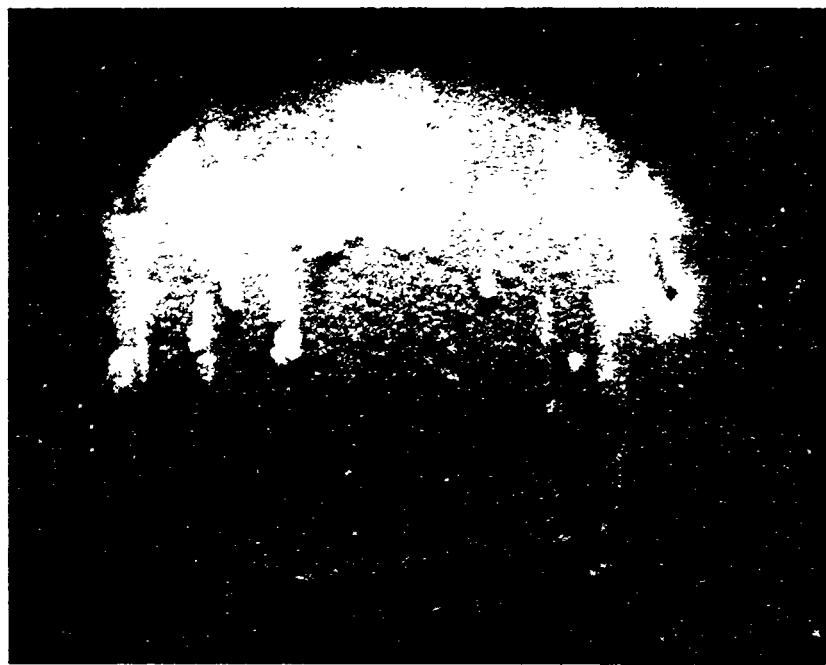


FIGURE 4 Superheater tube deposit about 20 hours after sootblowing during test with parent Decker coal

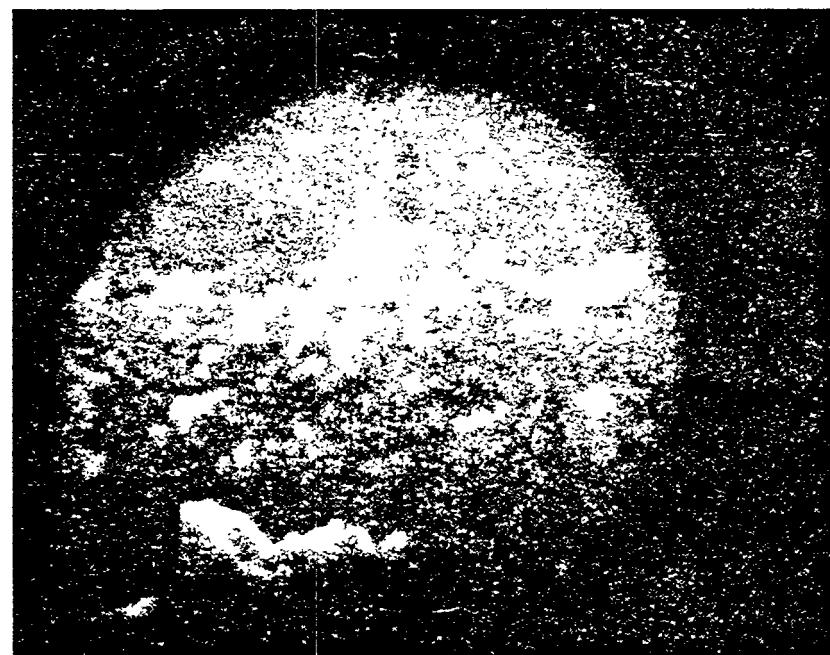


FIGURE 5 Superheater tube deposit about 20 hours after sootblowing during test with modified Decker coal for lower ion-exchangeable calcium

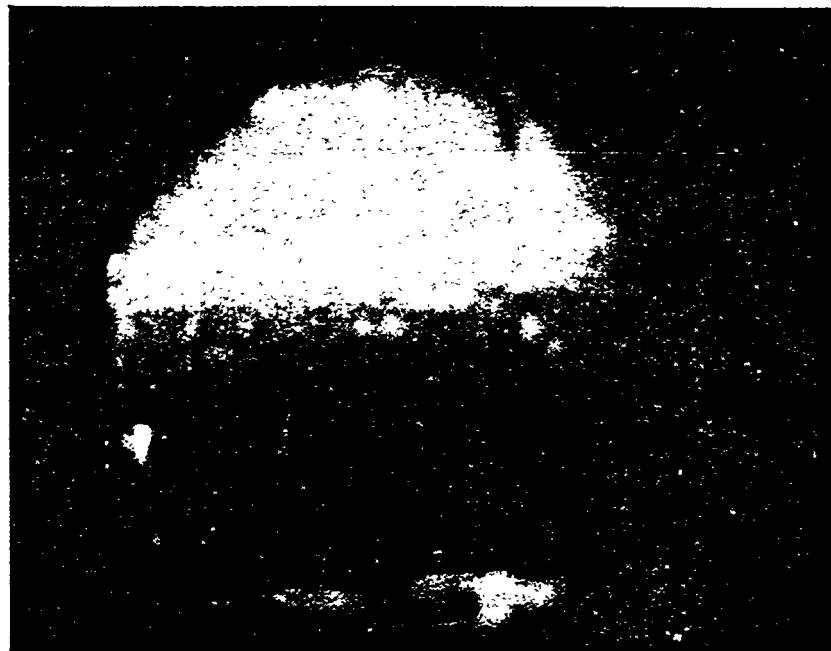


FIGURE 6 Effect of sootblowing on superheater tube deposit from modified Decker coal for lower ion-exchangeable calcium

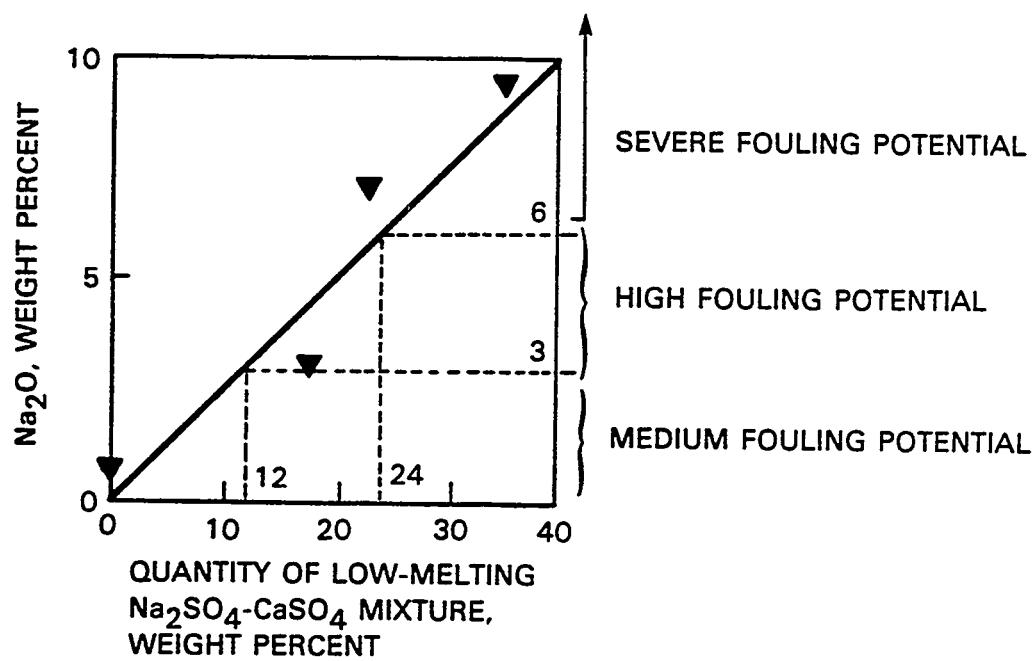


FIGURE 7 Relationships among total Na_2O in lignitic coal ash (ASTM analysis), quantity of low-melting immiscible liquid phase formed when lignitic ash is melted (slag viscometer melt), and superheater fouling classification (B&W index)

CCAWG MEETING AT FOSTER WHEELER CORPORATION,
JOHN BLIZARD RESEARCH CENTER,
12 PEACH TREE HILL ROAD, LIVINGSTON, NEW JERSEY 07039*
(December 9, 1982)

CCAWG members J. M. Beér, C. R. Bozzuto, I. Glassman, A. K. Oppenheim, S. S. Penner, R. E. Sommerlad, C. L. Wagoner, I. Wender, W. Wolowodiuk, J. Birkeland (DOE), and G. Jordy (DOE) attended this meeting. Also present were D. Bienstock (PETC), H. Fruh (FWDC), C. Harrison (EPRI), S. Moskowitz (Curtiss-Wright), I. Lutes (FWDC), H. Nack (Battelle-Columbus), A. Robertson (FWDC), F. Rourke (FWDC), S. P. N. Singh (Oak Ridge National Lab.), and V. Zakkay (NYU).

The topics discussed and the agenda are summarized in Table AB-9-1.

1. Summary of Discussions

A. Robertson (FWDC) presented an excellent overview of the development of pressurized fluidized bed combustors. His view graphs are self-explanatory and are enclosed in Appendix AB-9-1. These view graphs cover the following topics: advantages of PFB operations over conventional PC combustors, PFB combined cycles (air-cooled PFB and water/steam cooled PFB), overall plant efficiency vs. compressor pressure ratio for various turbine-inlet temperatures, the CURL/Leatherhead PFB and 1972-73 test results, the Exxon PFB miniplant cooling coil after 1200 hours of operation, SO_2 retention vs. Ca/S mole ratio in miniplant dolomite tests for contact times between 0.5 and 3.0 sec, NO_x emission (in g/Mj or 1b/MMBTU) vs. % of excess air, combustion efficiency vs. average temperature in Exxon tests, CFCC tube bundle configuration at NCB-CURL for 16.8% packing density, heat-transfer coefficients vs. height above the distributor for immersed tubes in a 9-ft bed at 1420 and 1620-1640°F, freeboard heat-transfer coefficients vs. height above the bed surface, factors

* Prepared by S. S. Penner.

affecting turbine expander life, Sta-Laval and GE cascades used in turbine tests, cyclone configurations and test data for particulate removal in PFBC at Exxon and CURL, viewgraph of a 170 MW PFB demonstration plant, catcracker and PFB comparisons, low-risk PFB cycles, schematic diagrams of a contained 250 MW PFB steam generator and a superheater reheater, PFB barge shipments of shop-assembled 125 MW units, test results obtained with the Grimethorpe PFB and at CURL/Leatherhead, notes on hot-gas cleanup.

S. Moskowitz presented a comprehensive overview of the Curtiss-Wright pilot plant development (see Appendix AB-9-2 and also AB-7-2) status and program. The PFB coal combustion program at NYU was ably summarized by V. Zakkay (Appendix AB-9-3).

These presentations were followed by discussions of critical areas in PFB development that require further R&D. The technical uncertainties listed by V. Zakkay (see Appendix AB-9-3, p. 7) were generally accepted, except that S. Moskowitz considered turbine deposition to be of relatively low priority. Furthermore, all participants concurred that further work needed to be done to improve our understanding of the fluid mechanics and combustion properties of PFB, including fuel dispersion from feed points, combustion chemistry, calcination and sulfur retention, and freeboard processes.

The Battelle-Columbus multisolid FB (MSFB) combustor was next reviewed by H. Nack (see Appendix AB-9-4). The operational concept of this idea is well illustrated in the second and third viewgraphs (see Appendix AB-9-4). A 0.4×10^6 Btu/hr pilot and performance data are shown in Appendix AB-9-4, as are the following data: solids residence times tests, sulfur capture, NO_x emission, influence of fuel reactivity, a summary of technical features, and selected applications. There was general agreement that the MSFB combustor presented a potentially useful concept but that a good deal of fundamental and development work needed to be done in order to gain needed understanding for optimal designs and practical exploitation of this configuration.

Operational experiences with commercially available (from FW) AFBs were next described by I. Lutes, H. Fruh, and F. Rourke of FWDC. The Shell, Netherlands, program is summarized in Appendix AB-9-6. While operational difficulties were encountered, equipment modifications to assure successful operations have been implemented without undue difficulties.

S. P. N. Singh (ORNL) provided a comprehensive overview of coal-beneficiation techniques, including both commercially practiced and developing procedures (see Appendix AB-9-6). A cost summary is included in Table 3 of Appendix AB-9-6. Discussions ensued on the commercial viability of these techniques (with C. R. Bozzuto noting that the economic value of removing the necessity for post-combustion SO_x removal was about \$6/ton and increased reliability in utility operation was equivalent to savings of about \$1/ton), which was viewed by several participants as unconvincing in view of required cleaning costs. There was, however, general agreement that research on improved beneficiation techniques was needed and that coal beneficiation represented an integral component of programs leading to possible commercialization of coal-water slurries.

The discussions were concluded with a summary of completed work on coal-methanol slurries by D. Bienstock of PETC (see Appendix AB-9-7 for details). Dr. Bienstock made a convincing case for the following statement: When slurry preparation, pipelining, and combustion are considered in an integrated system, an optimal mixture may well consist of coal in water containing small amounts of methanol. Additional research in this field is clearly justified.

TABLE AB-9-1

CCAWG AGENDA FOR THE MEETING ON
DECEMBER 9, 1982

8:30-8:45	INTRODUCTION	R. E. Sommerlad (FWDC) S. S. Penner (UCSD)
8:45-9:40	OVERVIEW OF PFB DEVELOPMENTS	A. Robertson (FWDC)
9:40-10:30	CURTISS-WRIGHT'S ACTIVITIES IN PFB	S. Moskowitz (C-W)
10:30-11:30	PFB ACTIVITIES AT NYU	V. Zakkay (NYU)
11:30-12:15	MULTISOLID FB	H. Nack (Battelle)
12:15-12:30	BREAK	
12:30-1:15	OPERATION OF GEORGETOWN & SHELL AFB	I. Lutes (FWDC), H. Fruh (FWDC), and F. Rourke (FWDC)
1:15-2:00	PHYSICAL CLEANING OF COAL	S. P. N. Singh (ORNL)
2:00-2:30	COAL/METHANOL SLURRIES	D. Bienstock (PETC)
2:30-3:00	DISCUSSION OF FUTURE MEETINGS	S. S. Penner (UCSD)
3:00-4:00	TOUR OF FWDC R&D FACILITIES	W. Wolowodiuk (FWDC)
4:00	ADJOURN	

APPENDIX AB-9-1

OVERVIEW OF PFB DEVELOPMENTS

A. ROBERTSON
FWDC
DECEMBER 9, 1982

PFB COMBUSTION CYCLES

OPERATE AT \approx 1650°F AND 5 TO 15 ATM WITH FLUIDIZED DOLOMITE BEDS.

COMBUSTS HIGH SULFUR COAL EFFICIENTLY - ENVIRONMENTALLY ACCEPTABLE EMISSIONS.

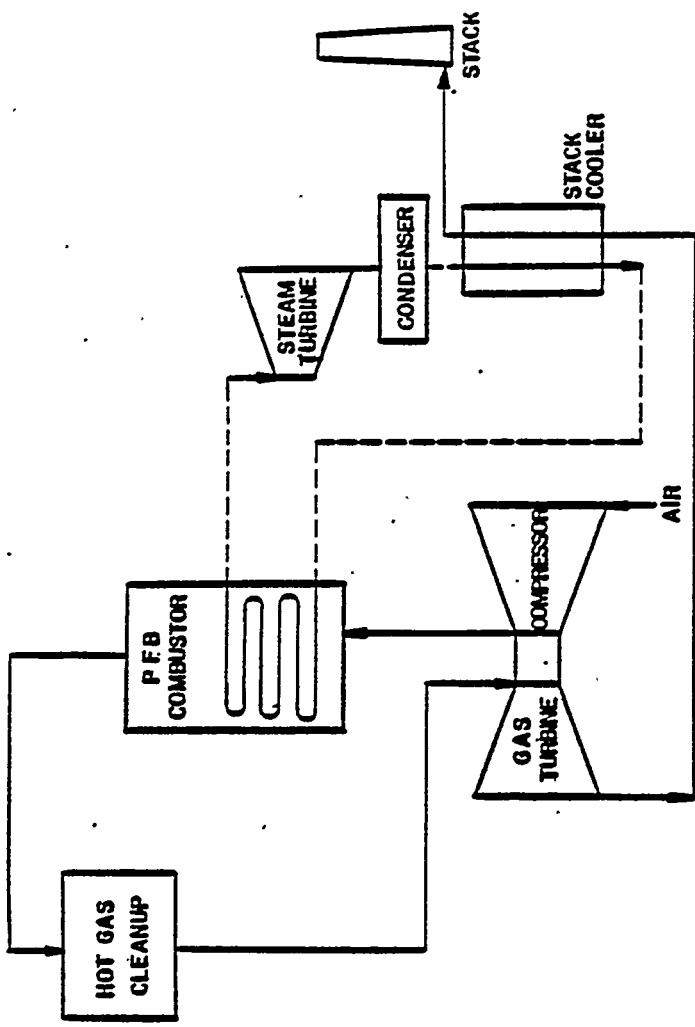
BEDS CONTAIN AIR OR WATER COOLED TUBES.

GAS TURBINES/EXPANDERS PROVIDED FOR POWER RECOVERY.

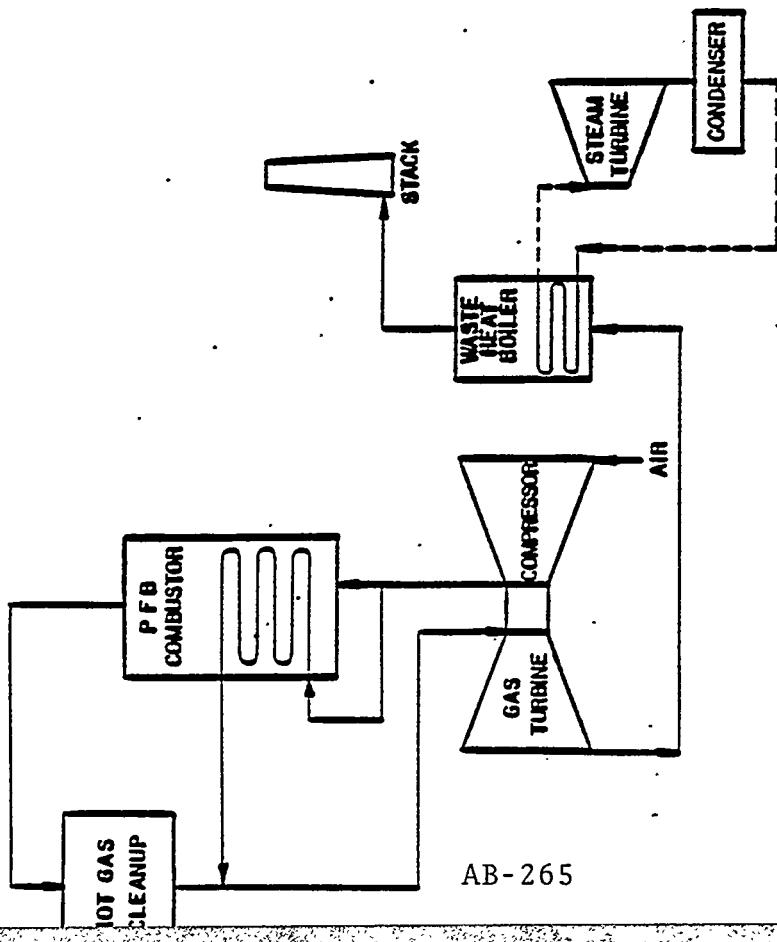
PROVIDES HIGH EFFICIENCY (\approx 40%) COMBINED STEAM TURBINE GAS TURBINE CYCLES.

ALTERNATE PFB COMBINED CYCLES

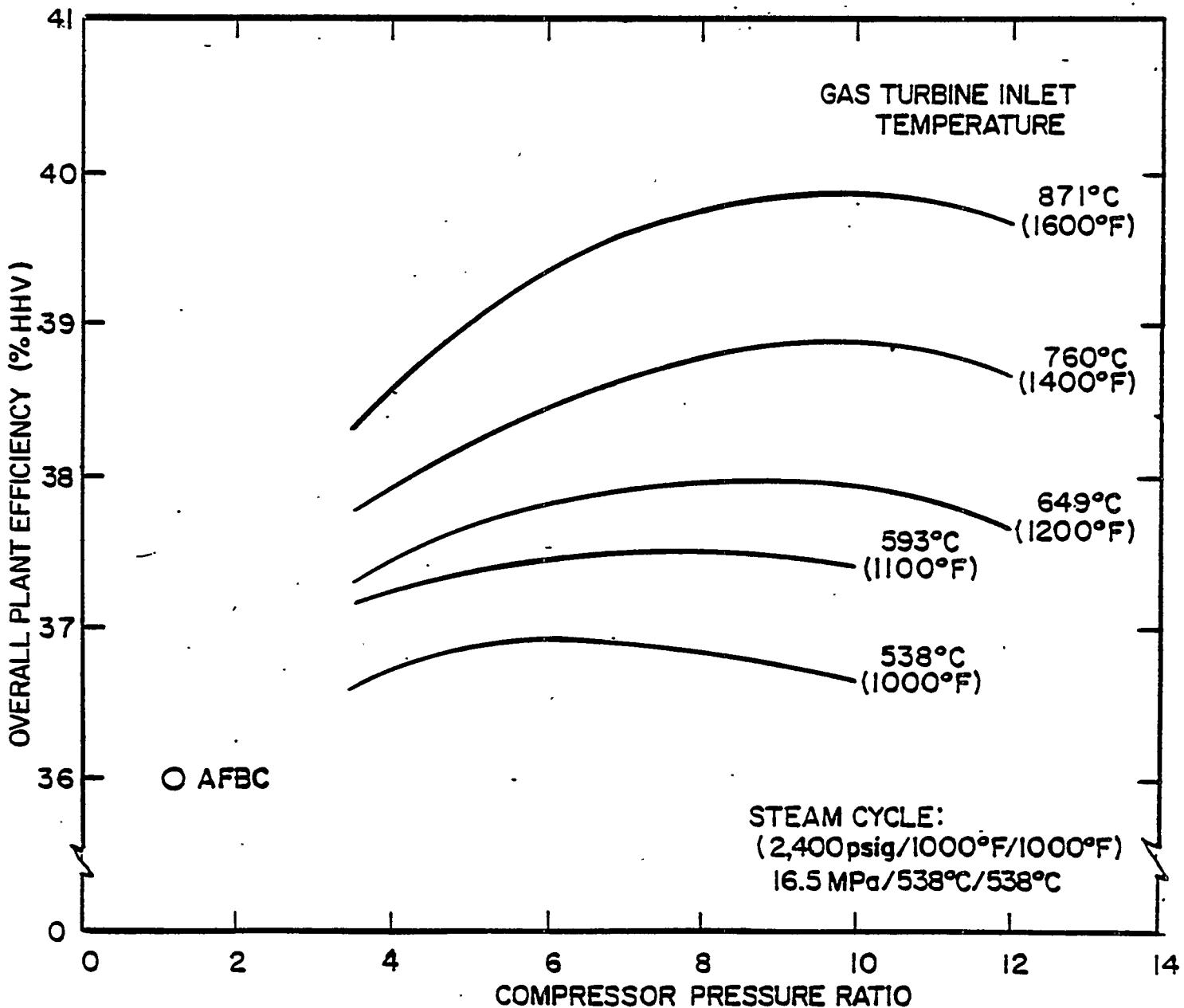
WATER/STEAM COOLED PFB



AIR COOLED PFB



EFFECTS OF TURBINE INLET TEMPERATURE
AND PRESSURE RATIO ON PFBC OVERALL EFFICIENCY.



EXTENSIVE TESTS HAVE BEEN CONDUCTED AT SEVERAL PFB
FACILITIES TO IDENTIFY:

SULFUR CAPTURE EFFICIENCIES

NO_X EMISSIONS

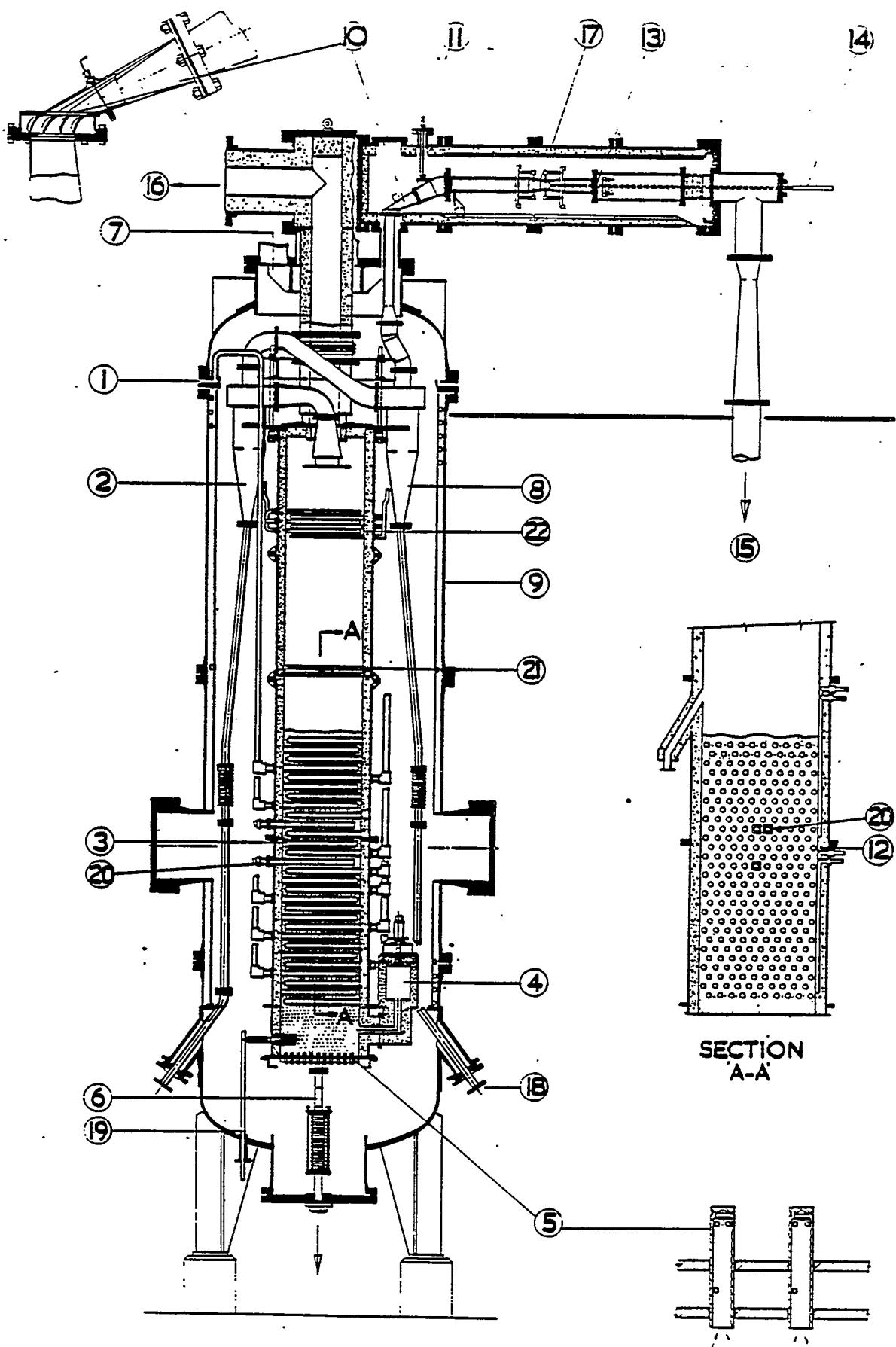
COMBUSTION EFFICIENCIES

HEAT TRANSFER COEFFICIENTS

BED ELUTRIATION RATES

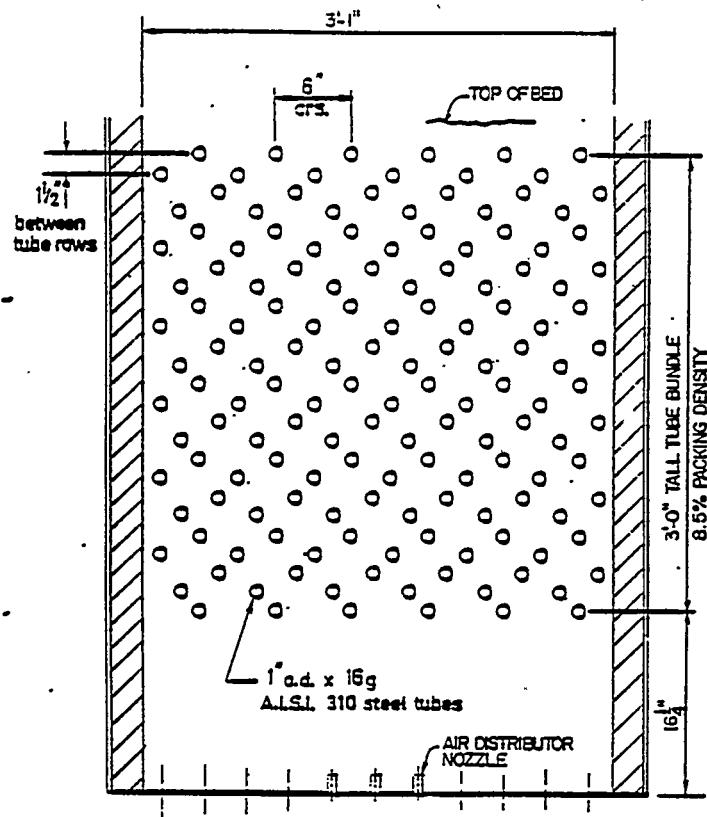
HOT GAS CLEANUP EQUIPMENT

TURBINE MATERIAL EROSION & HOT CORROSION



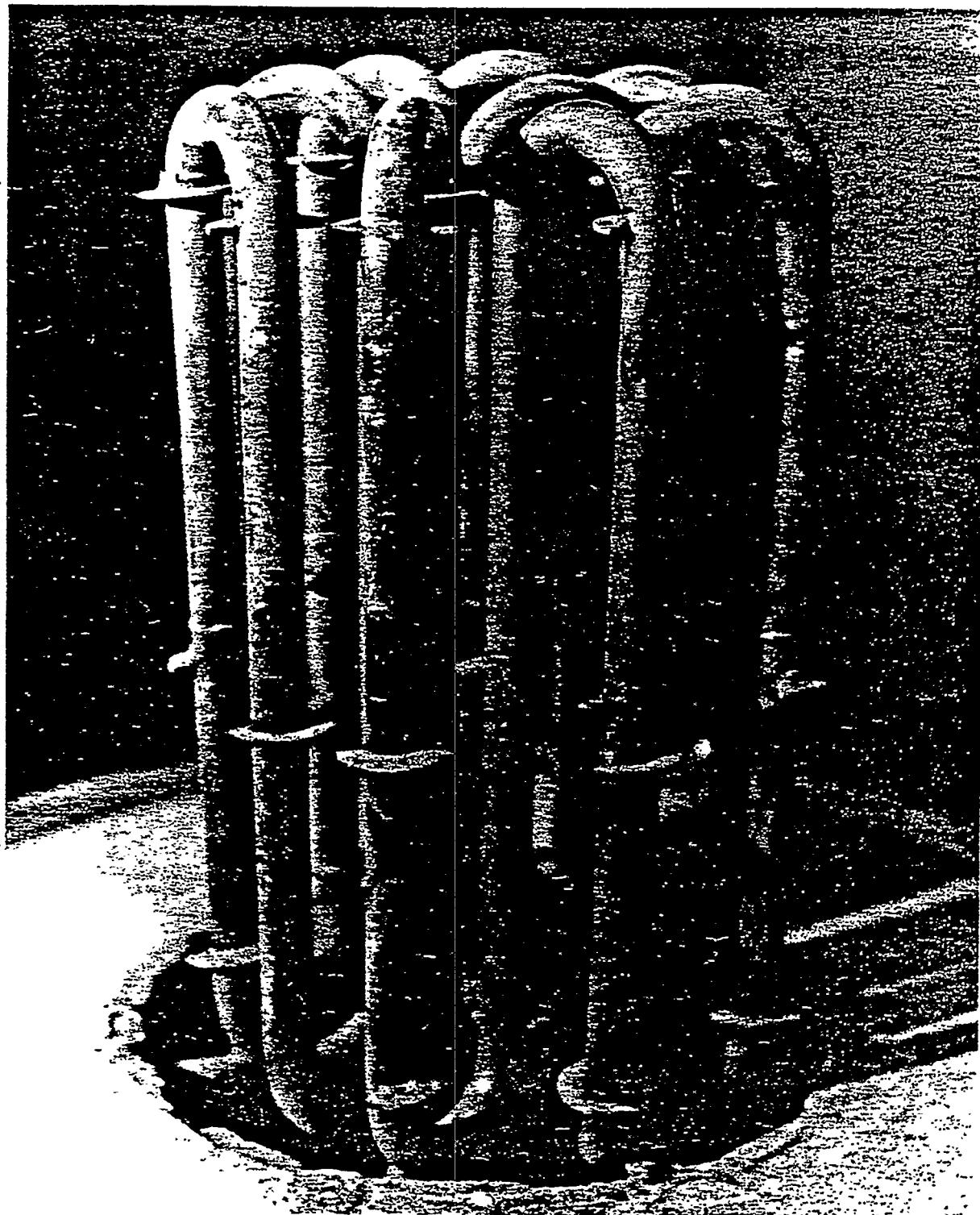
ARRANGEMENT OF CURL/LEATHERHEAD PFB

LEATHERHEAD 1972-73 TESTS

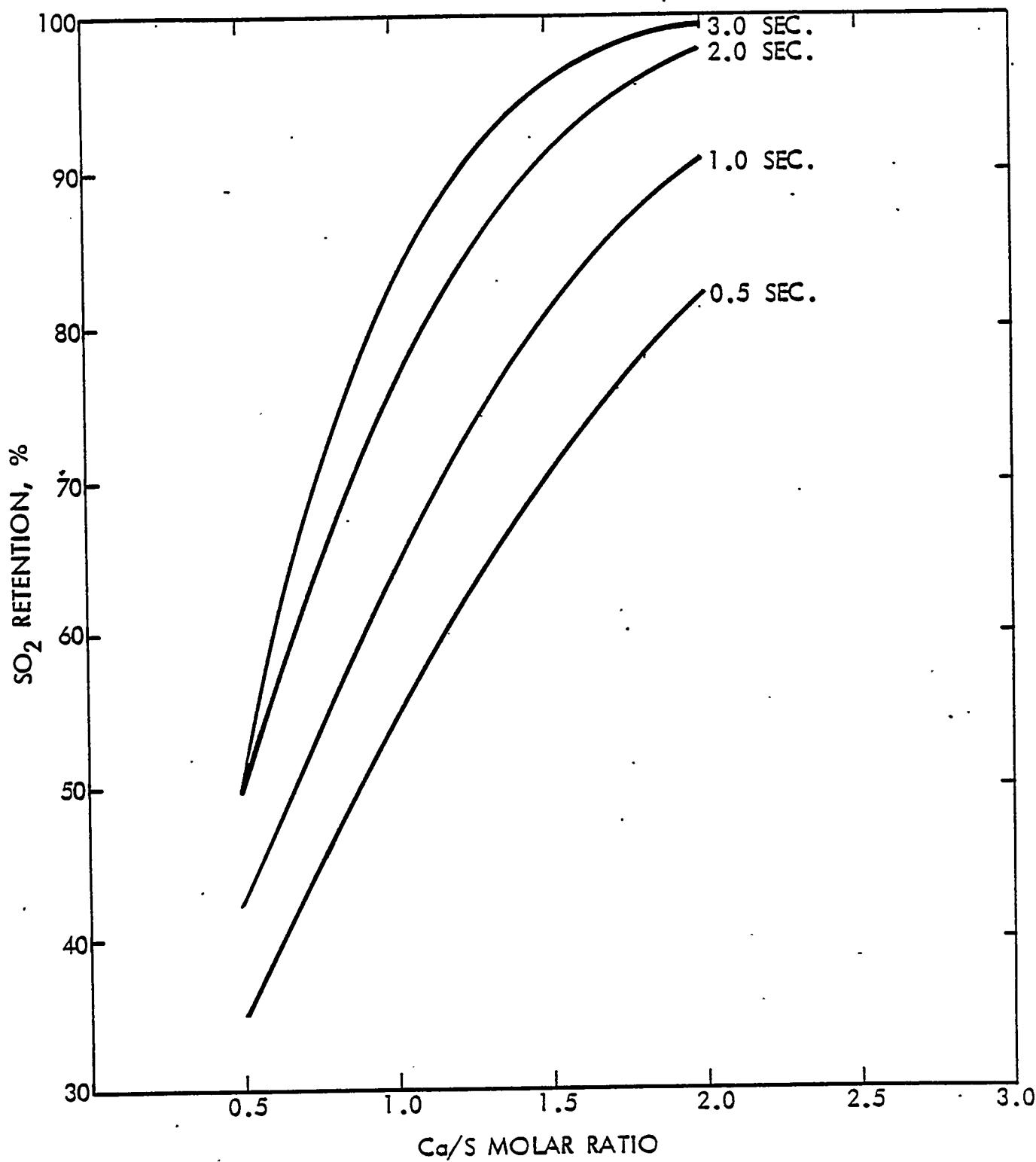


Test No.		1	2	3.1	3.2	4.1	4.2
Fluidising velocity	ft/s	2.3	2.5	2.3	2.3	2.2	2.3
Bed depth	ft	4.4	4.6	4.4	4.7	4.0	4.1
Combustor pressure	psig	66	72	71	68	73	72
Excess air	%	14	19	16	20	16	16
Bed temperature	°F	1630	1745	1670	1655	1645	1740
Cascade inlet temperature	°F	1600	1675	1620	1590	1575	1565
Coal		Pittsburgh		Illinois			
Combustion efficiency	%	99	99 1/2	n.d.	99	n.d.	99 1/2
SO ₂ Acceptor		U.S. Dolomite 1337				U.K. Limestone	
Ca/S mole ratio		2.0	2.2	1.4	1.7	2.1	2.0
Sulphur retention	%	97	99	85	98	75	74
SO ₂ emission	lb/10 ⁶ Btu	0.11	0.05	0.54	0.10	1.3	1.4
NO _x emission	lb/10 ⁶ Btu	0.36	0.22	0.21	0.21	0.11	0.13

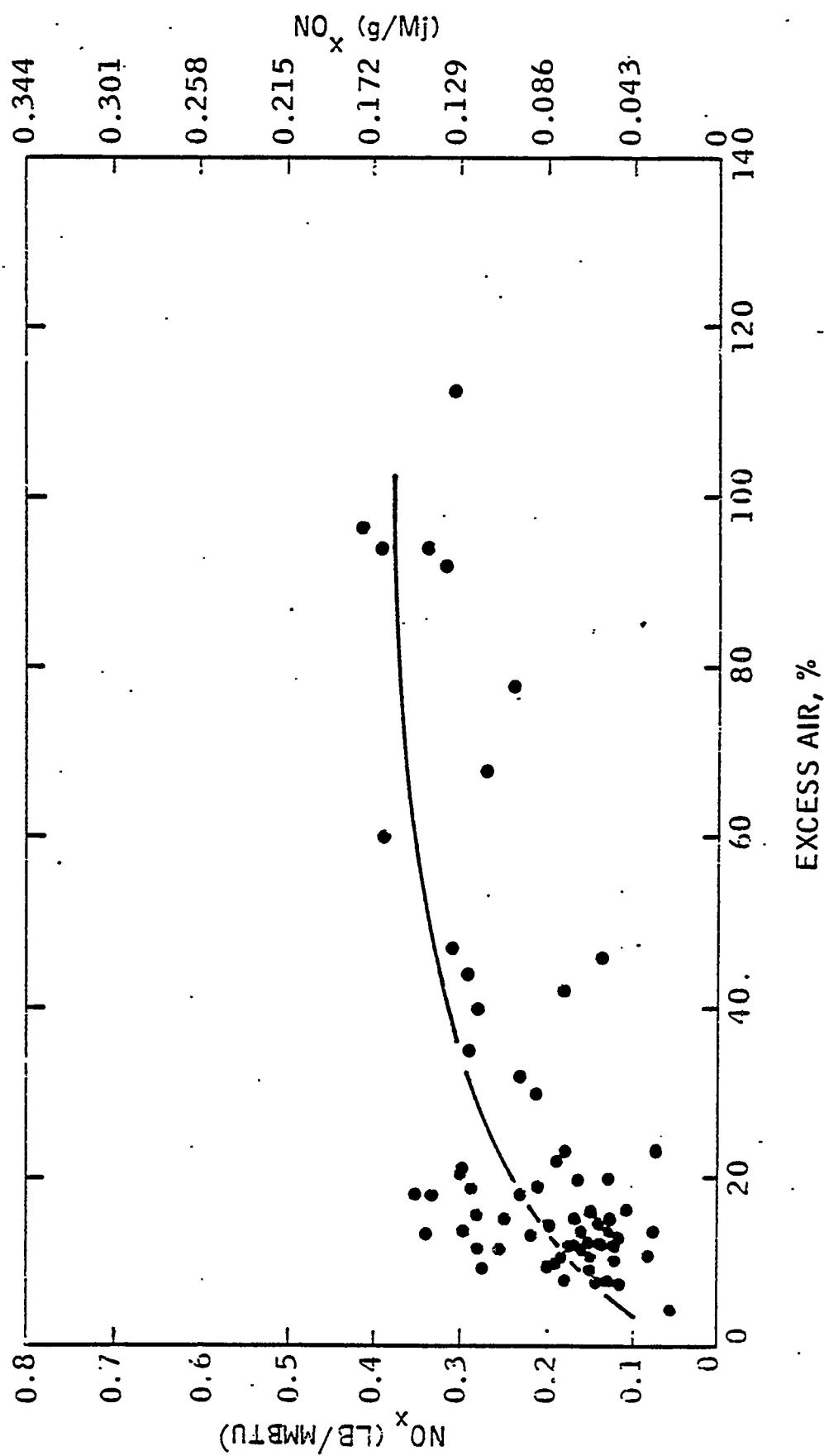
EXXON
MINIPLANT COMBUSTOR COOLING COIL 1A AFTER
1200 HOURS OPERATION



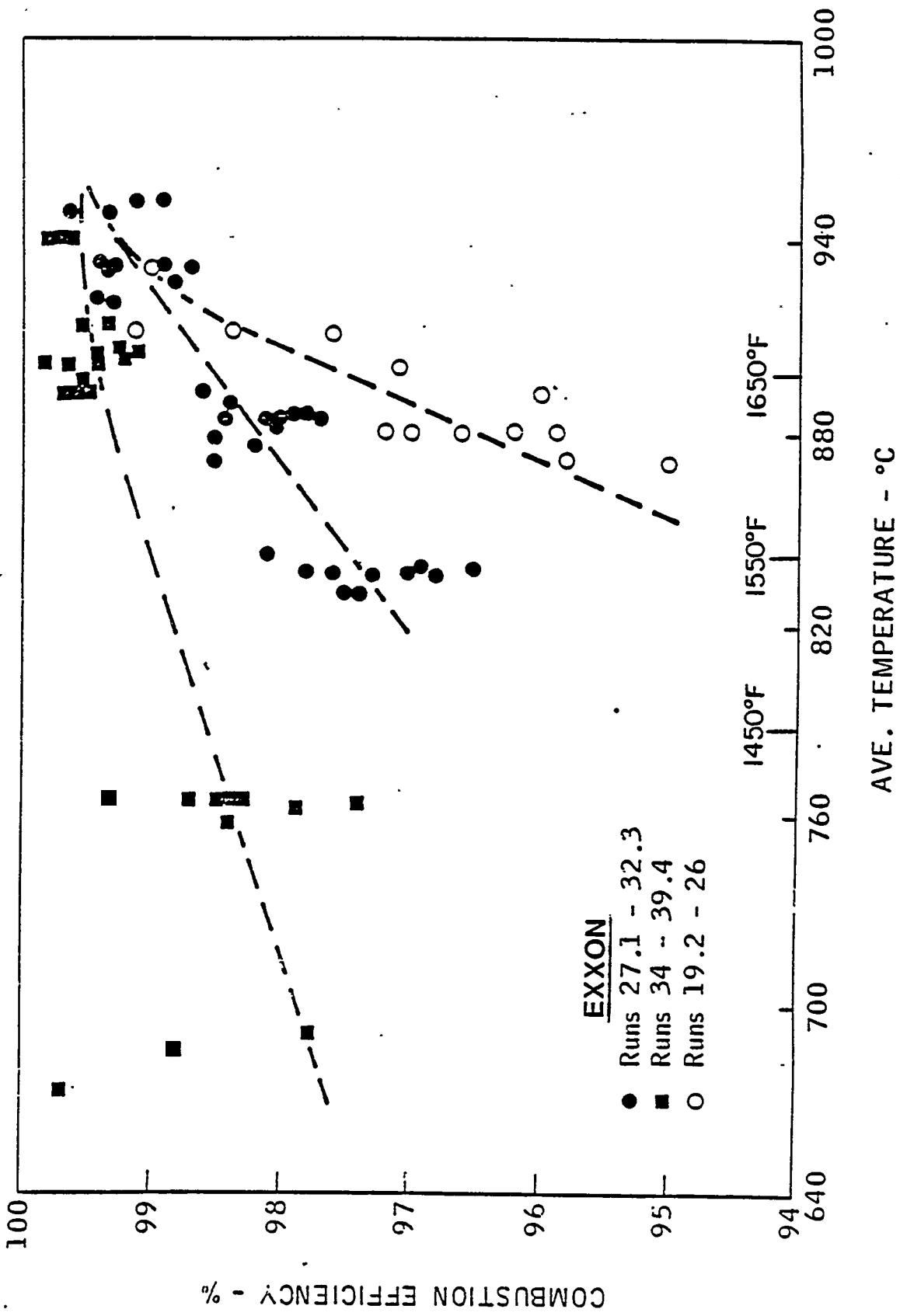
CALCULATED SO_2 RETENTION VS. Ca/S
MINIPLANT DOLOMITE RUNS

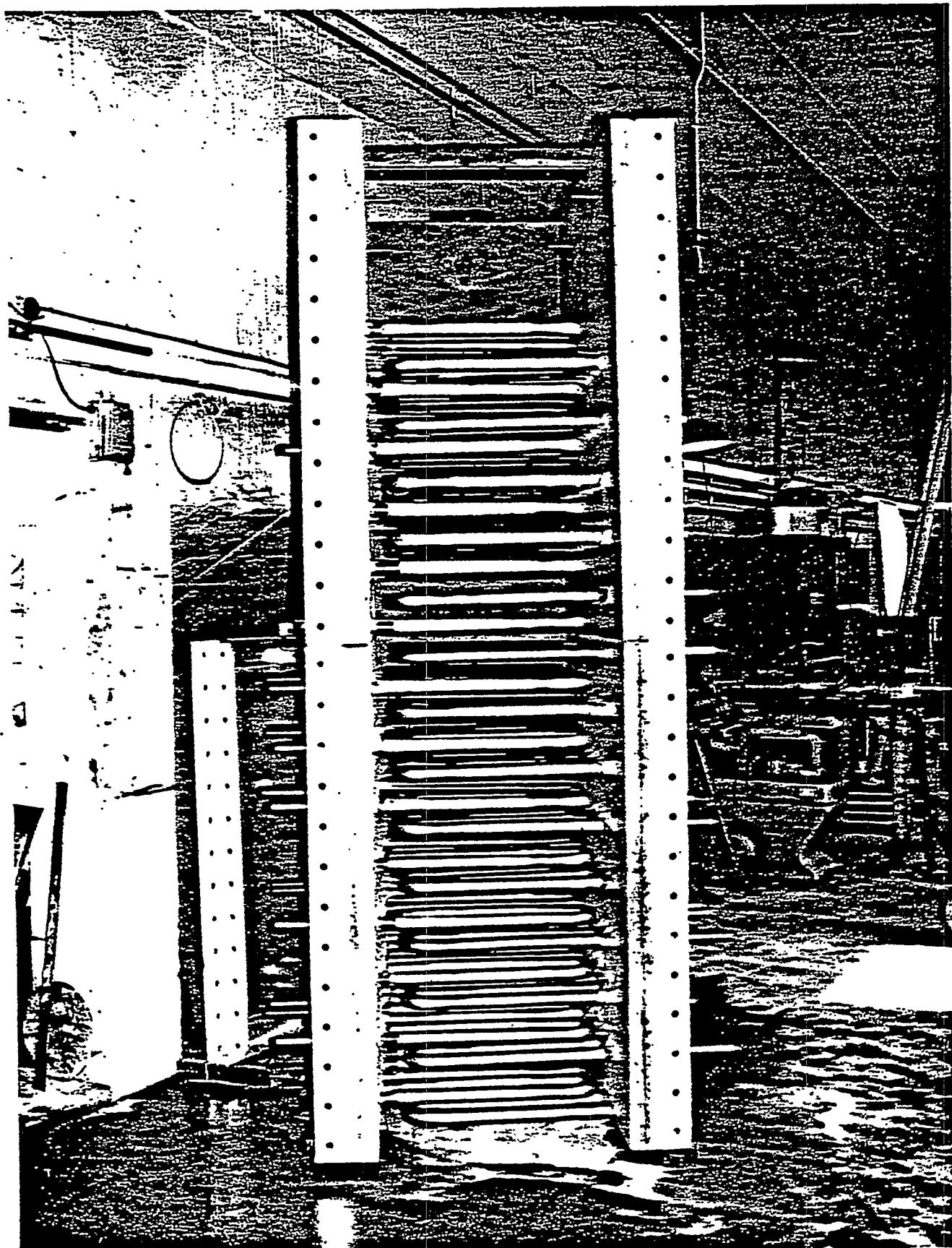


NO_x EMISSIONS VS. EXCESS AIR

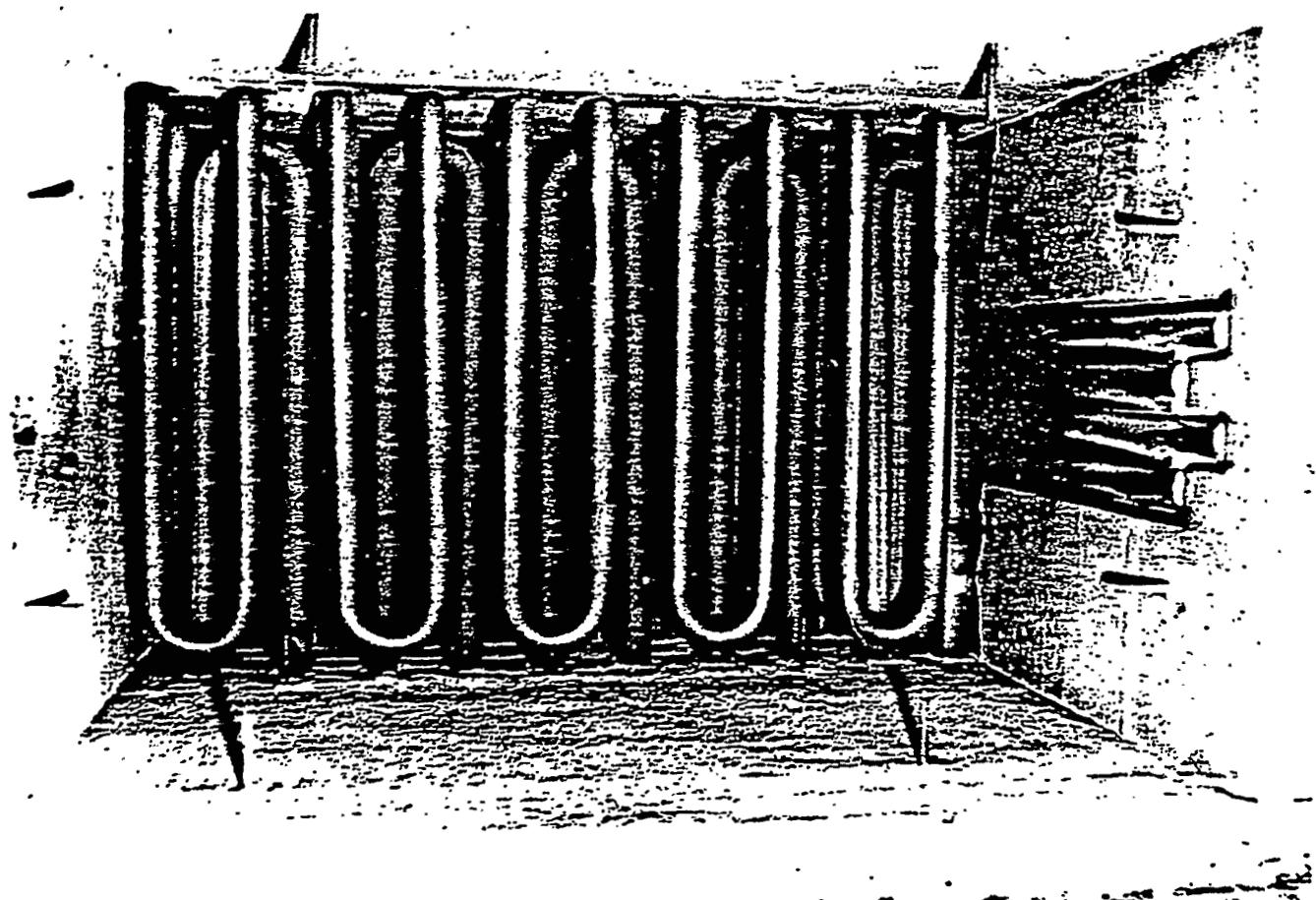


COMBUSTION EFFICIENCY VS. TEMPERATURE





CFCC Prototype Tube Bundle Configuration as Tested at NCB-CURL.
TUBE BUNDLE PACKING DENSITY 16.8%
AB-274



Plan View of CFCC Prototype Tube Bundle Configuration as Tested at NCB-CURL.

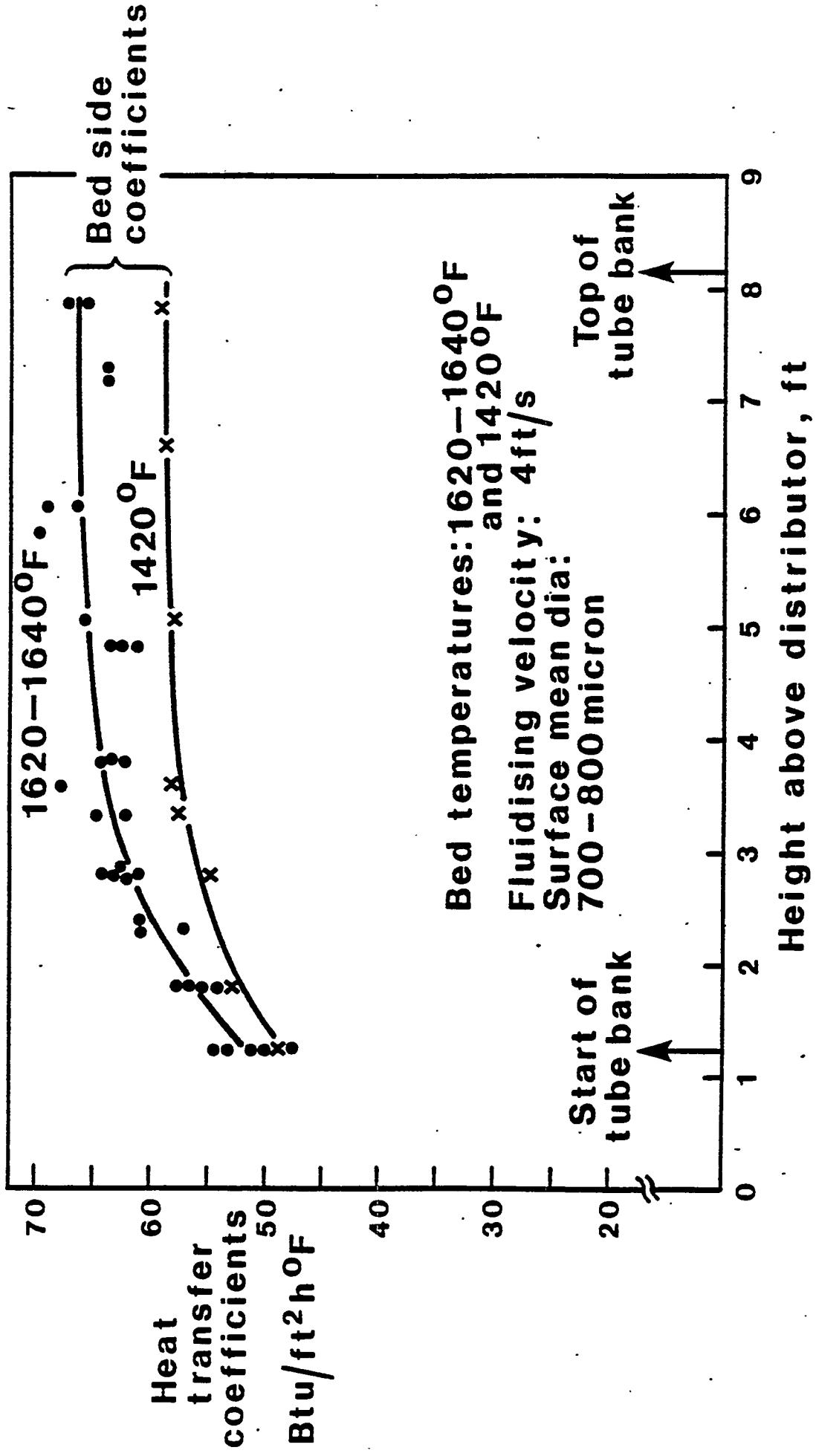


Fig.40 Heat transfer to immersed tubes: Bed depth 9ft.

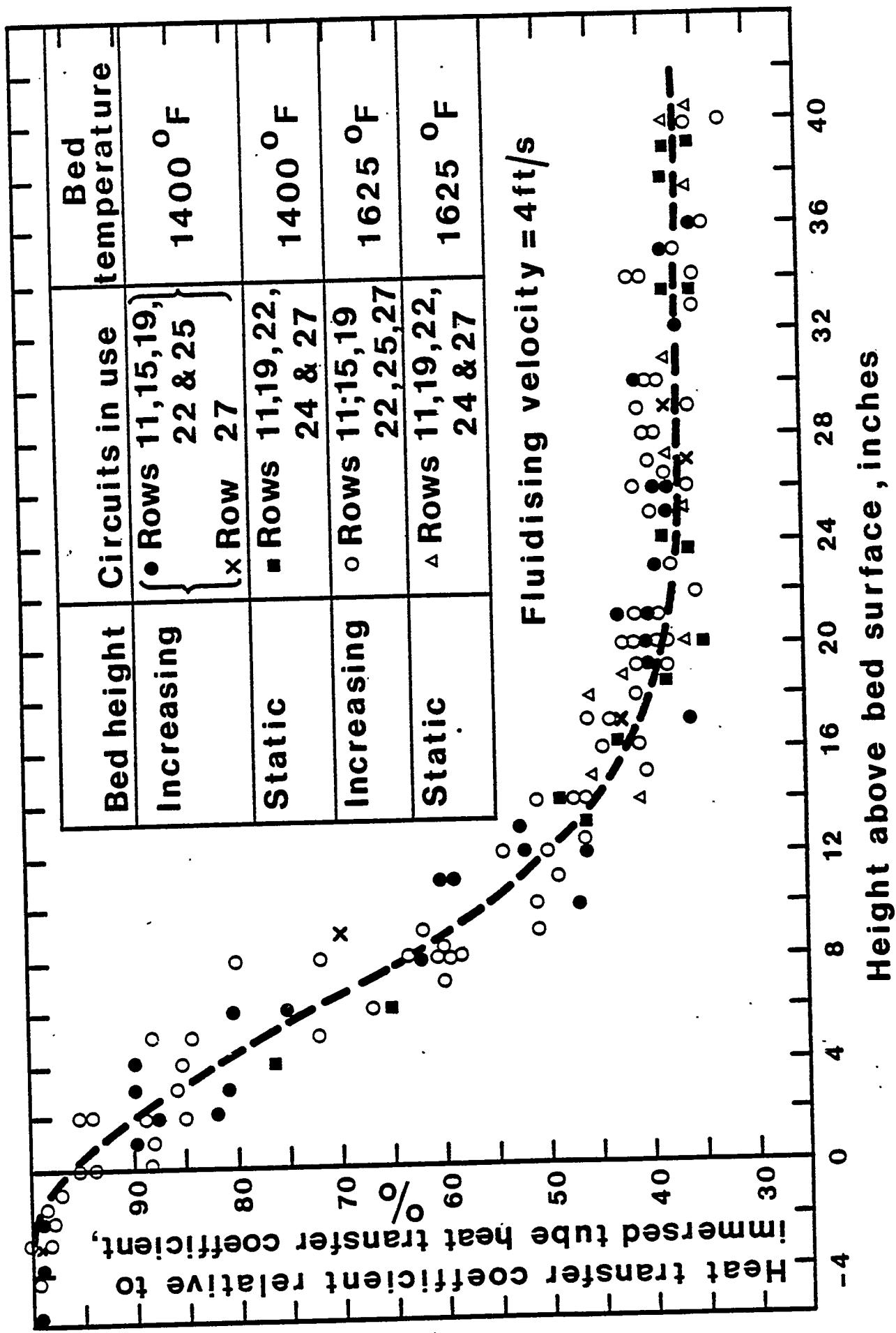


Fig.4.3 Freeboard heat transfer coefficients

HIGH TEMPERATURE EXPANDER LIFE, HAS BEEN MAJOR UNCERTAINTY.

TURBINE EXPANDER LIFE AFFECTED BY:

QUANTITY OF BED EFFLUX

SIZE DISTRIBUTION

CHEMICAL COMPOSITION

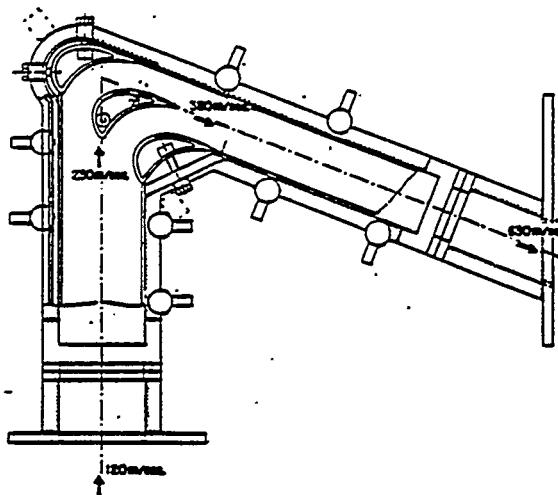
PARTICLE HARDNESS & STICKINESS

HOT-GAS CLEANUP EFFICIENCY

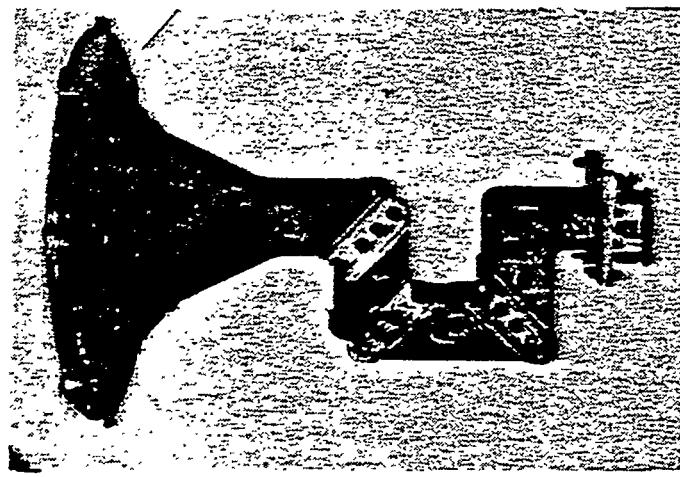
MATERIALS OF CONSTRUCTION & TEMPERATURE

1000 HR PFB TURBINE CASCADE TESTS CONDUCTED ~1979

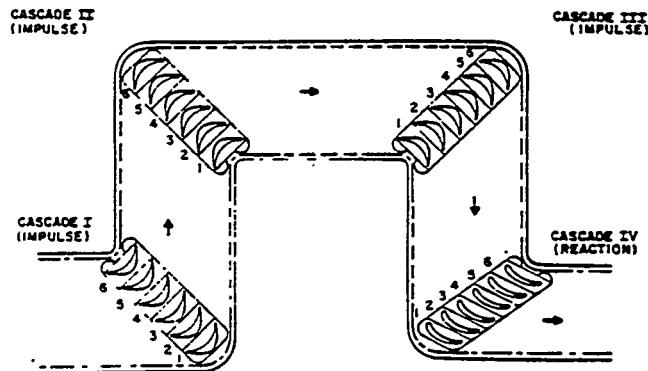
<u>FACILITY</u>	<u>CASCADES</u>
EXXON	GE
CURL	GE & STA Laval



STA-LAVAL CASCADE



(a)



(b)

GE CASCADE

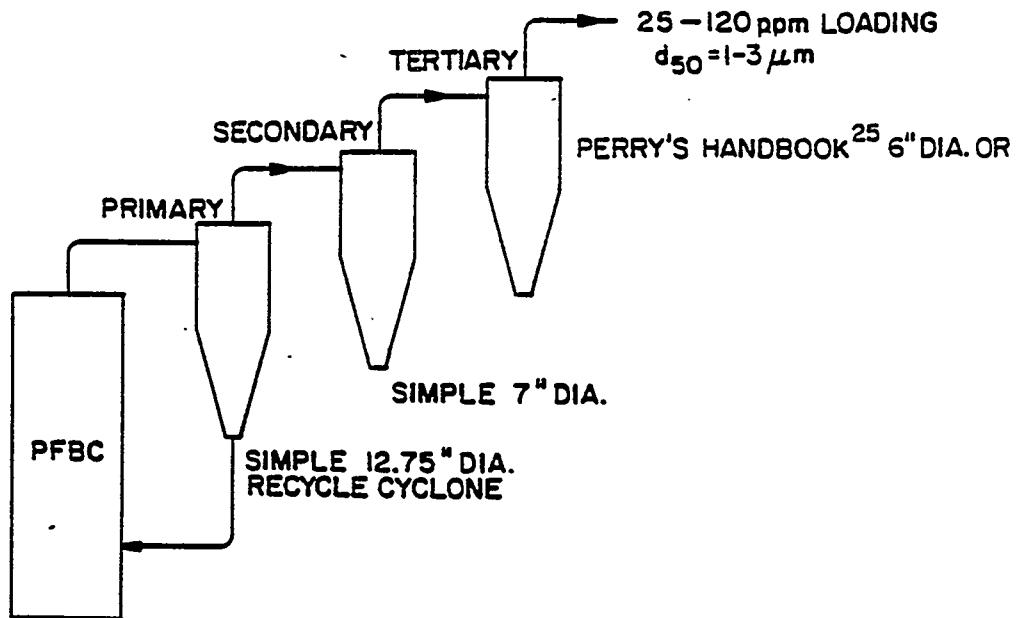


Fig. 4. Exxon PFBC System Schematic.
 1 lb/s, 9000 ppm loading,
 $d_{50} = 20-25 \mu\text{m}$

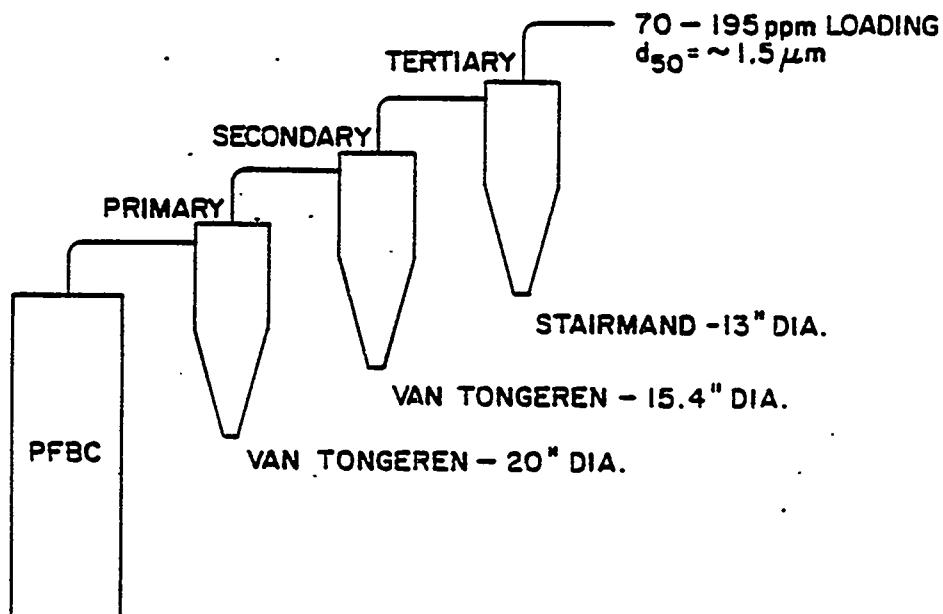


Fig. 5. CURL PFBC System Schematic for Stream 1.
 2 lb/s, 11000 ppm loading, $d_{50} = 25-40 \mu\text{m}$

NOMINAL PFB CONDITIONS FOR 1000 HR CASCADE TESTS

<u>EXXON</u>	<u>CONDITION</u>	<u>CURL (GE)</u>
ILL#6	COAL	OHIO GLEN BROOK
PFIZER #1337	DOLomite	OHIO PLUM RUN
1700°-1770°F	BED TEMPERATURE	1560°-1585°F
10 ATMS	PRESSURE	5 ATMS
6 FT./SEC.	SUPERFICIAL FLUIDIZING VELOCITY	3 FT./SEC.
~1.8 SEC.	BED RESIDENCE TIME	~2.8 SEC.
3 CYCLONES	PARTICLE SEPARATORS	3 CYCLONES + SKIMMER
35-860 PPM	PARTICLE LOADING	~250 PPM
95% < 10 μ m	PARTICLE SIZE	99.2% < 10 μ m
1500°-1590°F	SPECIMEN TEMPERATURE	1350°-1475°F
900 FT./SEC.	MAXIMUM SPECIMEN INLET VELOCITY	1400 FT./SEC.

CASCADE TEST IMPACT

GE FINDINGS

EXXON CORROSION AND EROSION SIGNIFICANTLY HIGHER
DIFFERENCES DUE TO GAS/METAL TEMPERATURES
DEPOSITION NOT A PROBLEM
LONG TURBINE LIFE APPEARS POSSIBLE

STA-LAVAL FINDINGS

NO MEASURABLE EROSION OF BLADE MATERIAL
NO MEASURABLE SIGNIFICANT CORROSION ATTACK
MINIMAL DEPOSITION
ECONOMICAL TURBINE LIFE APPEARS POSSIBLE

AEP/STA-LAVAL BELIEVE PFB READY FOR DEMONSTRATION

170 MW TIDD PLANT PRELIMINARY DESIGN

15 MW_T CTF MALMO SWEDEN

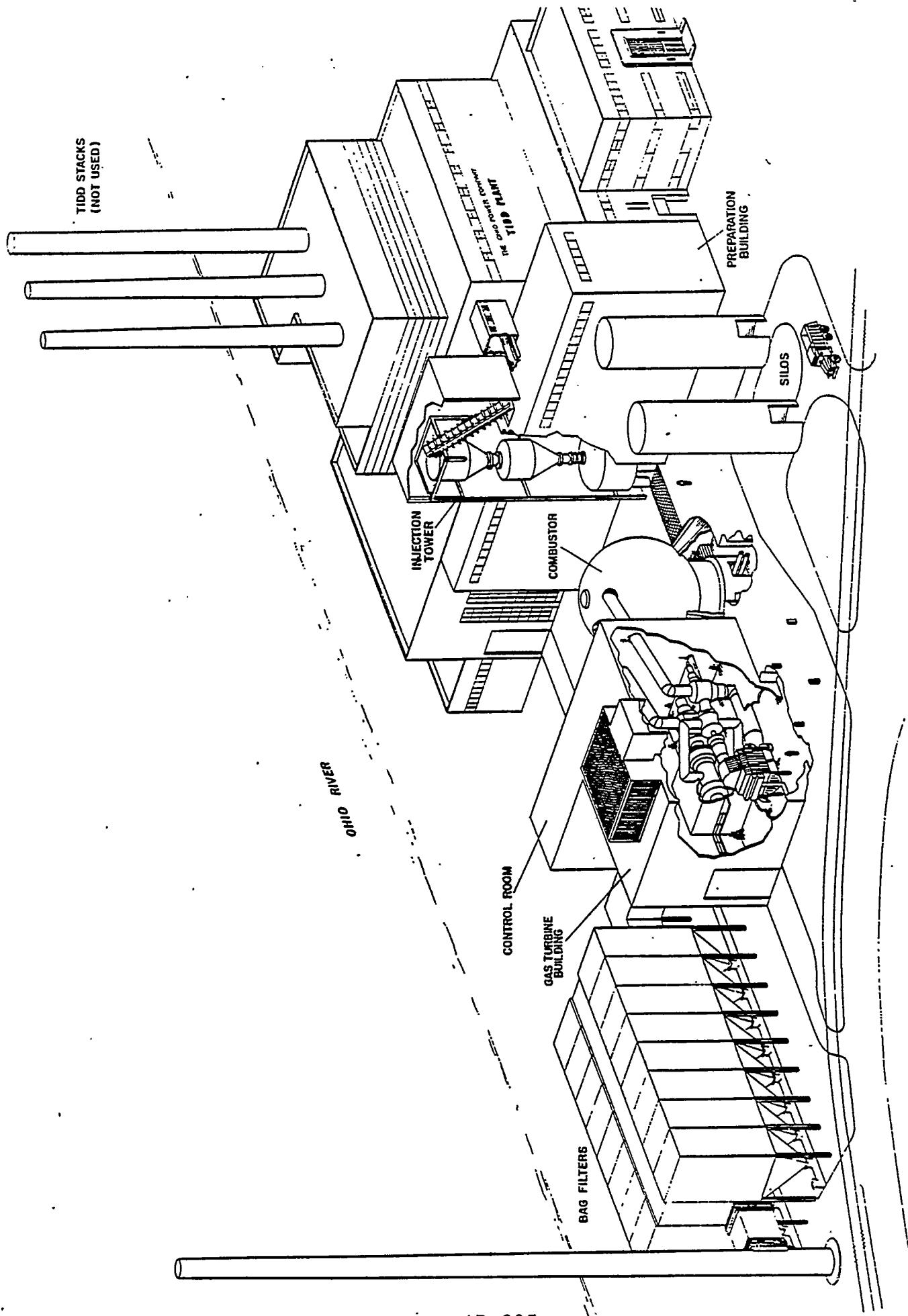
FULL SCALE 1/36TH SLICE OF TIDD

3 STAGES OF PROPOSED CYCLONES

GAS TURBINE-NO LOAD UNIT

STEAM TO PLANT TURBINE

SHAKEDOWN STARTED FALL 82

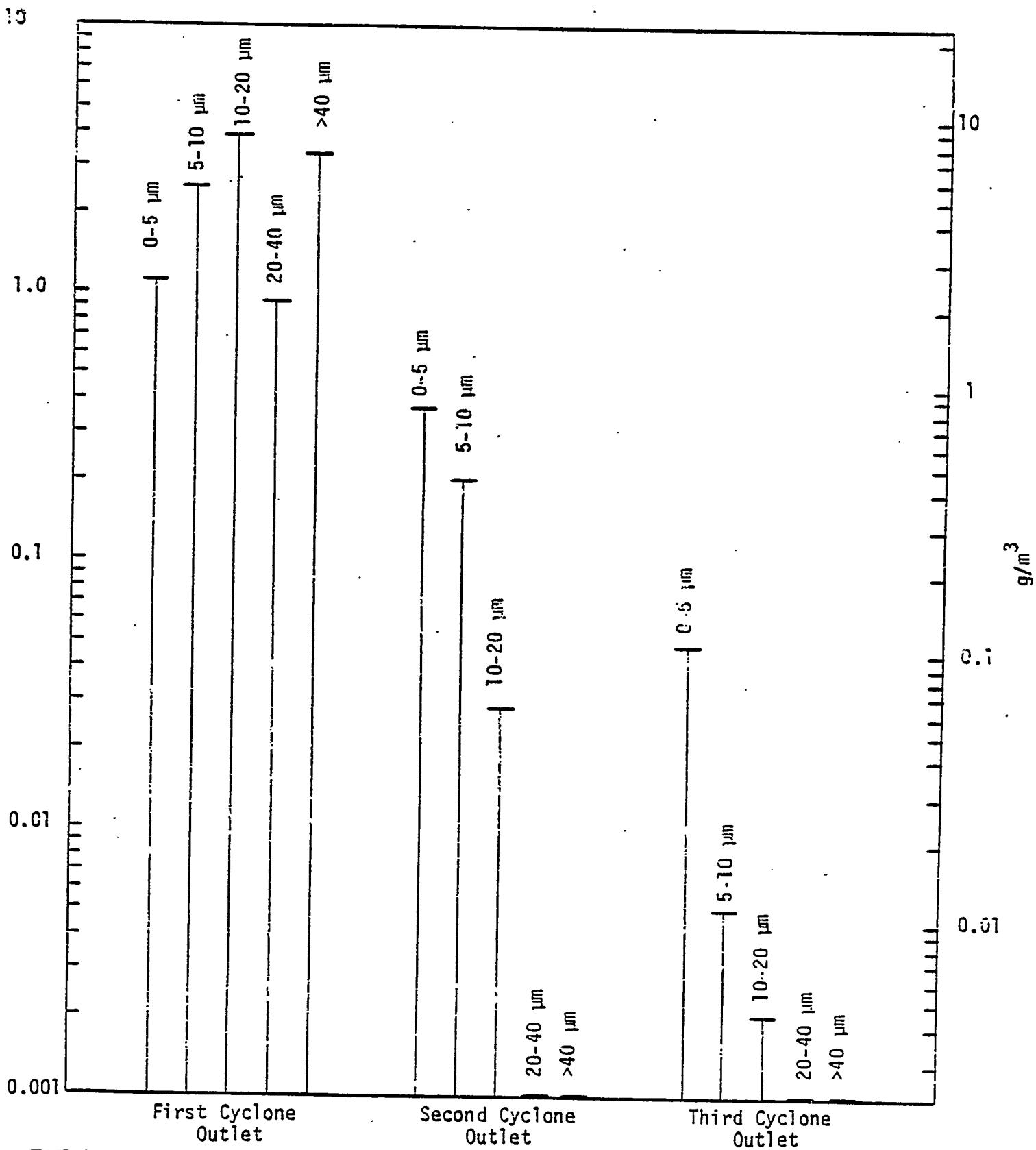


AEP 170MW PFB DEMOPLANT (TIDD)

EXXON MINIPLANT

Particulate Concentration in Cyclone Gas Outlet

Particulate Concentration (gr/SCF)



TOTAL
GR./SCF

11.6

.600

AB-284

.057

CATCRACKER-PFB CYCLE COMPARISON

CATCRACKER POWER RECOVERY EXPANDERS-4 ATM/1350°F

CATCRACKER ELUTRIATION RATES MUCH HIGHER

CATALYST HARDER AND MORE EROSION

3 STAGES OF CYCLONES PROTECT EXPANDER

EXPANDERS COMMERCIALLY GUARANTEED-120 PPM/.06 GR/SCF

AVERAGE TIME BETWEEN BLADING 35000 HRS (IR)

EXPANDER MATERIALS RESISTANT TO ALKALI ATTACK @ 1350-1400°F

LOW RISK PFB CYCLE

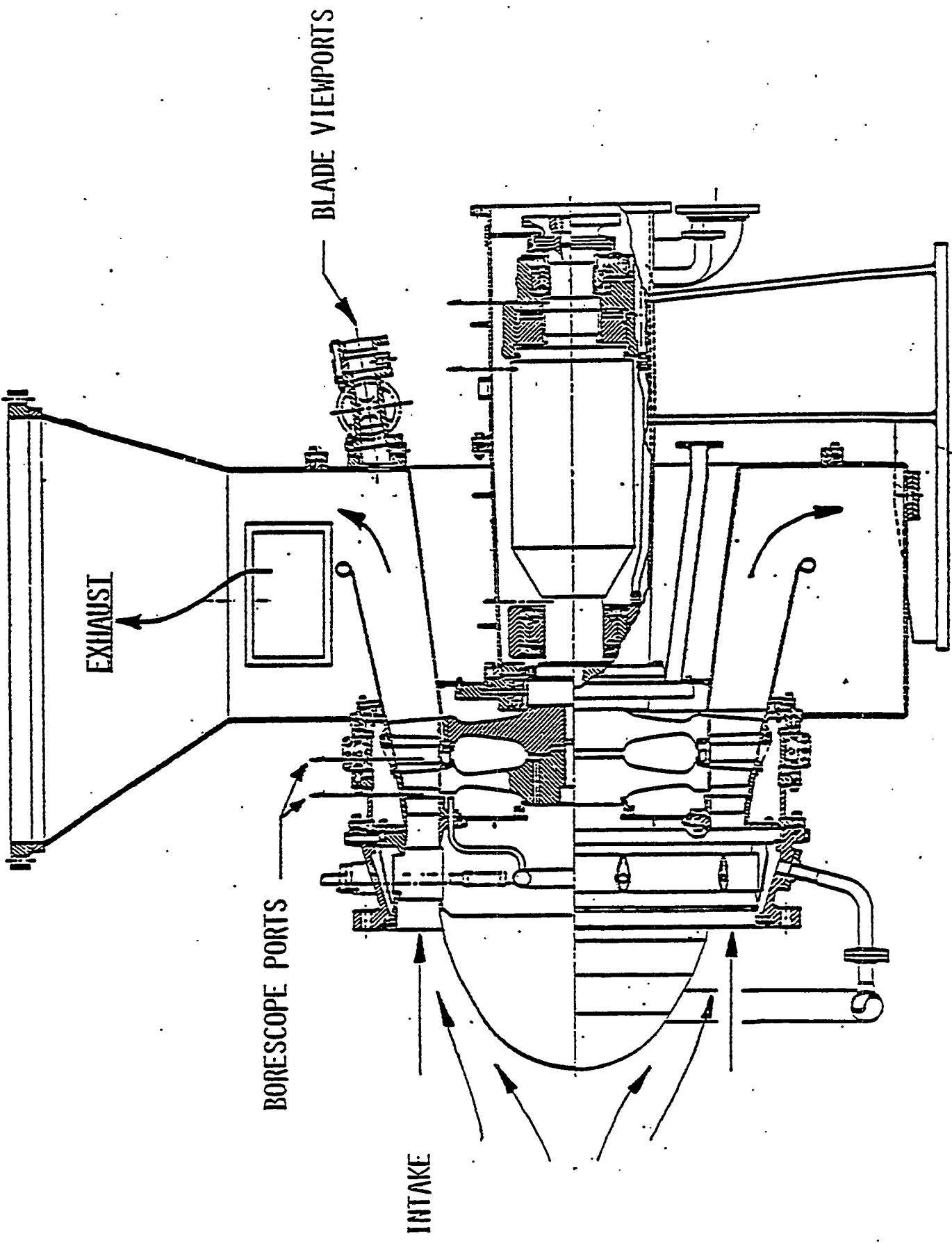
1650°F PFB

FREEBOARD COOLING TUBES

1400°F EXPANDER INLET

INGERSOL-RAND EXPANDER

CROSSECTIONAL VIEW OF
INGERSOLL-RAND 2-STAGE EXPANDER



GILBERT/COMMONWEALTH ANALYSIS OF LOW RISK PFB CYCLES

TABLE II
CYCLE PERFORMANCE SUMMARY

	Conventional Coal Fired Power Plant	Steam Cooled PFBC Gas Turbine	Air Cooled PFBC Gas Turbine
Gross Power, MWe	533.8	446.7	506.6
Auxiliary Power, MWe	36.2	7.1	9.5
Net Power, MWe	497.6	439.6	497.1
Heat Rate, Btu/kWh	9665	8446	8979
Plant Efficiency, %	35.3	40.4	38.0
			501.9
			9.9
			492.0
			8929
			38.2

TABLE III
CAPITAL COST SUMMARY
(Costs in millions of 1980 Dollars)

Description	Conventional Coal Fired Power Plant 498 MWe	Steam Cooled PFBC Gas Turbine 439 MWe	Air Cooled PFBC Gas Turbine 492 MWe	
Land & Land Rights	1.0	1.0	1.0	
Structures & Improvements	28.5	21.6	25.5	
Boiler Plant Equipment	161.3	111.0	133.8	
Gas Turbine/Expander Gen.	-	22.0	31.3	
Steam Turbine Generator Unit	56.7	42.6	50.4	
Accessory Electrical Equipment	16.5	21.0	22.6	
Misc. Power Plant Equipment	3.2	4.0	4.0	
Station Equip./Transmission	6.0	6.0	6.0	
	—	—	—	
Total Direct Cost	273.2	229.2	274.8	
Indirect Costs	297.7	242.1	287.5	
	—	—	—	
Total Capital Cost \$/kW	570.9 1146	471.3 1074	562.3 1131	725.4 1474

TABLE IV
COST OF ELECTRICITY COMPARISON
(Costs in mills/kWh, 1980 Dollars)

Levelized Busbar Costs	Conventional Coal Fired Power Plant 498 MWe	Steam Cooled PFBC Gas Turbine 439 MWe	Air Cooled PFBC Gas Turbine 492 MWe
Capital Cost	33.6	31.5	33.2
Fuel Cost	42.8	37.3	39.7
Fixed O&M	6.7	6.1	6.4
Variable O&M	5.3	8.0	8.3
Reliability Penalty	5.4	4.6	4.6
	—	—	—
Total COE	93.7	87.5	92.2
			101.1

BROWN BOVERI-EPRI STUDY

CYCLE	BED COOLANT	PRESSURE (ATM)	GAS TURBINE TEMP. (°F)	EFFICIENCY %	COMMENTS
A	WATER/ STEAM	10	1560	40.0	
B	WATER/ STEAM	5	1300	38.6	CAT CRACKER TYPE EXPANDER
C	AIR	7	1600	33.6	
E	WATER/ STEAM	10	770	38.0	SELF SUSTAINING

SELF SUSTAINING/TURBO CHARGED PFB HAS LOWEST CAPITAL COSTS AND
LOWEST RISK

MINIMUM HOT GAS VOLUMETRIC FLOW

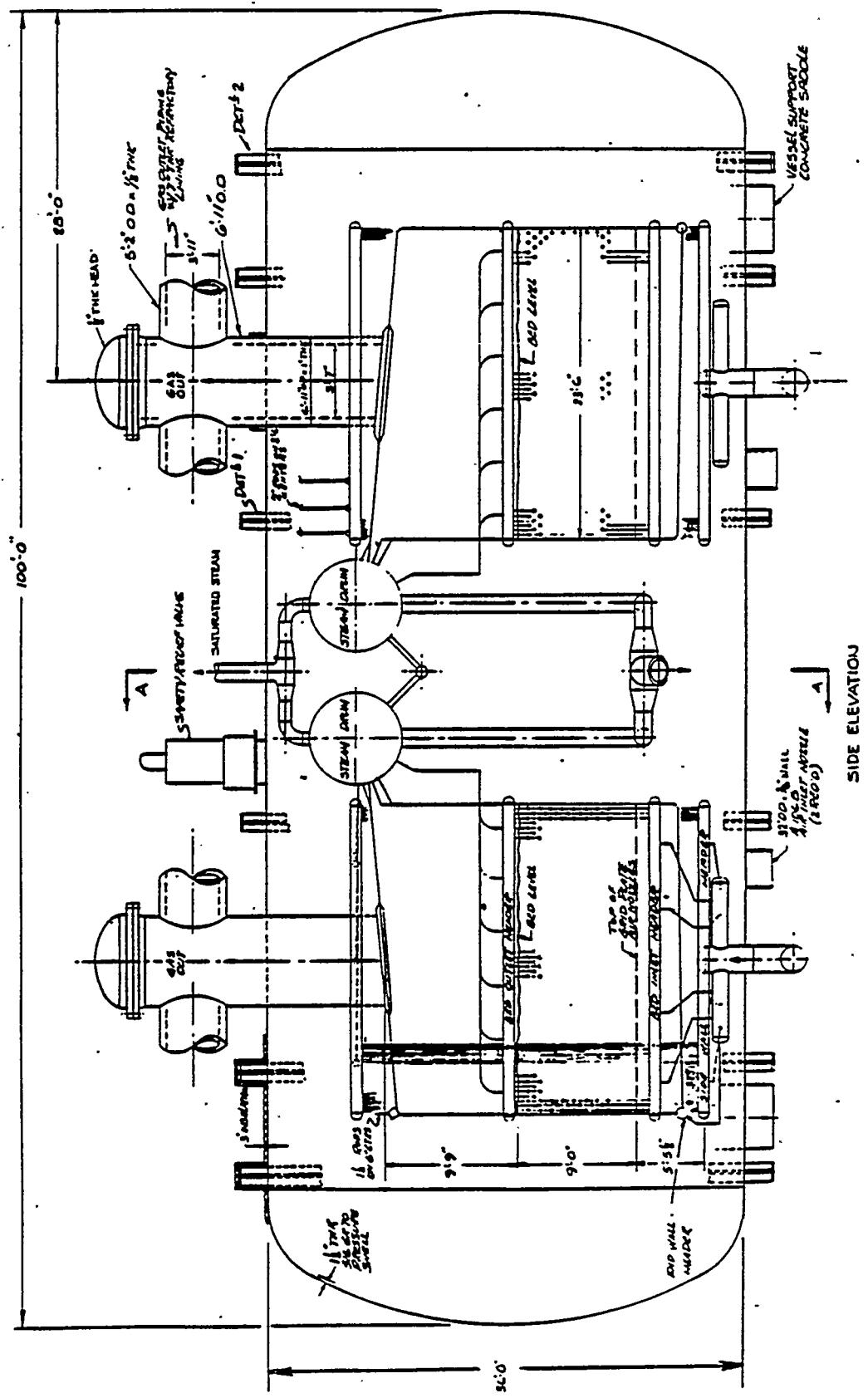
HOT GAS PIPING AND CLEAN UP CONVENTIONAL

MINIMUM GAS TURBINE OVER SPEED PROTECTION

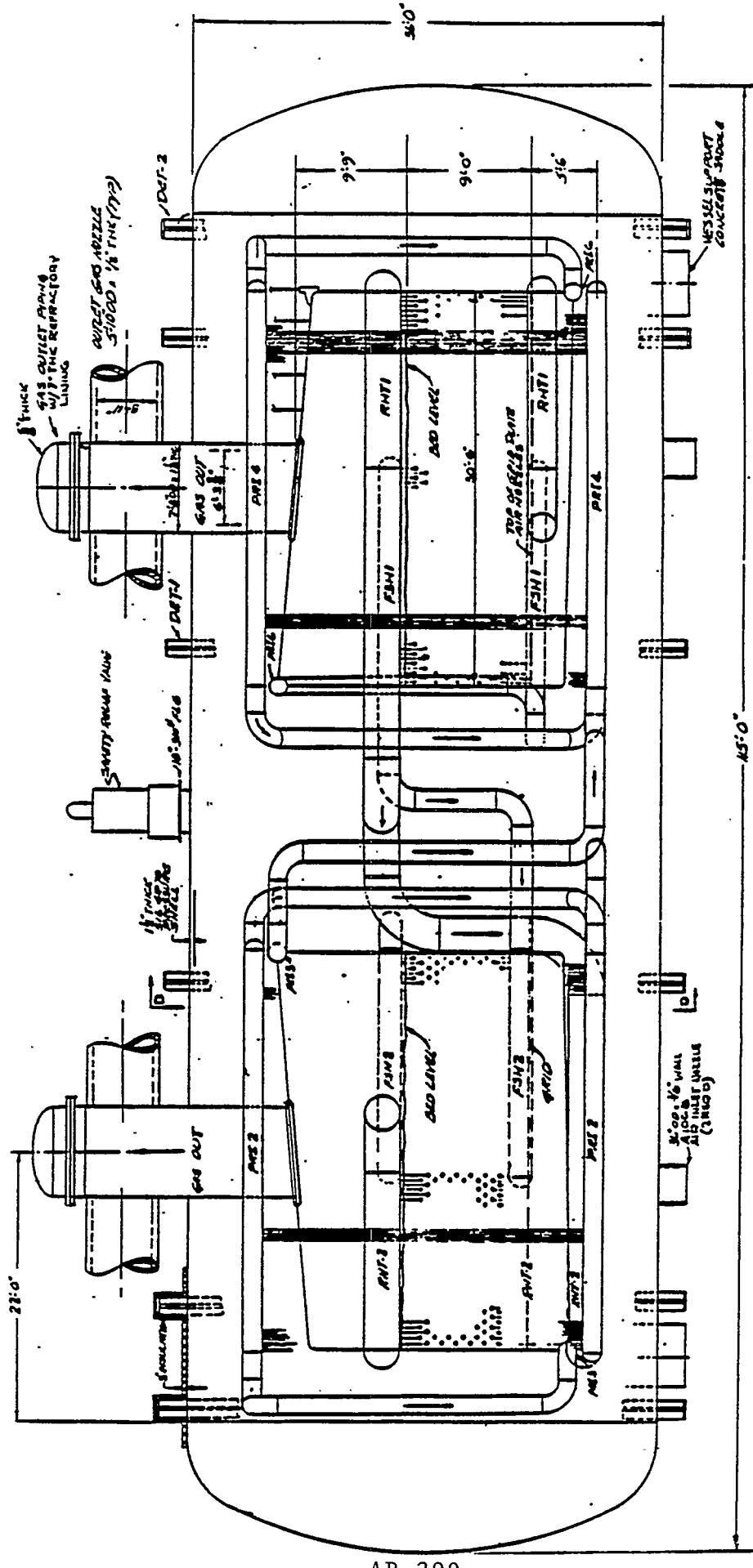
No HRSG

TURBO CHARGED PFB COE 10% LOWER THAN HIGH TEMPERATURE CYCLES

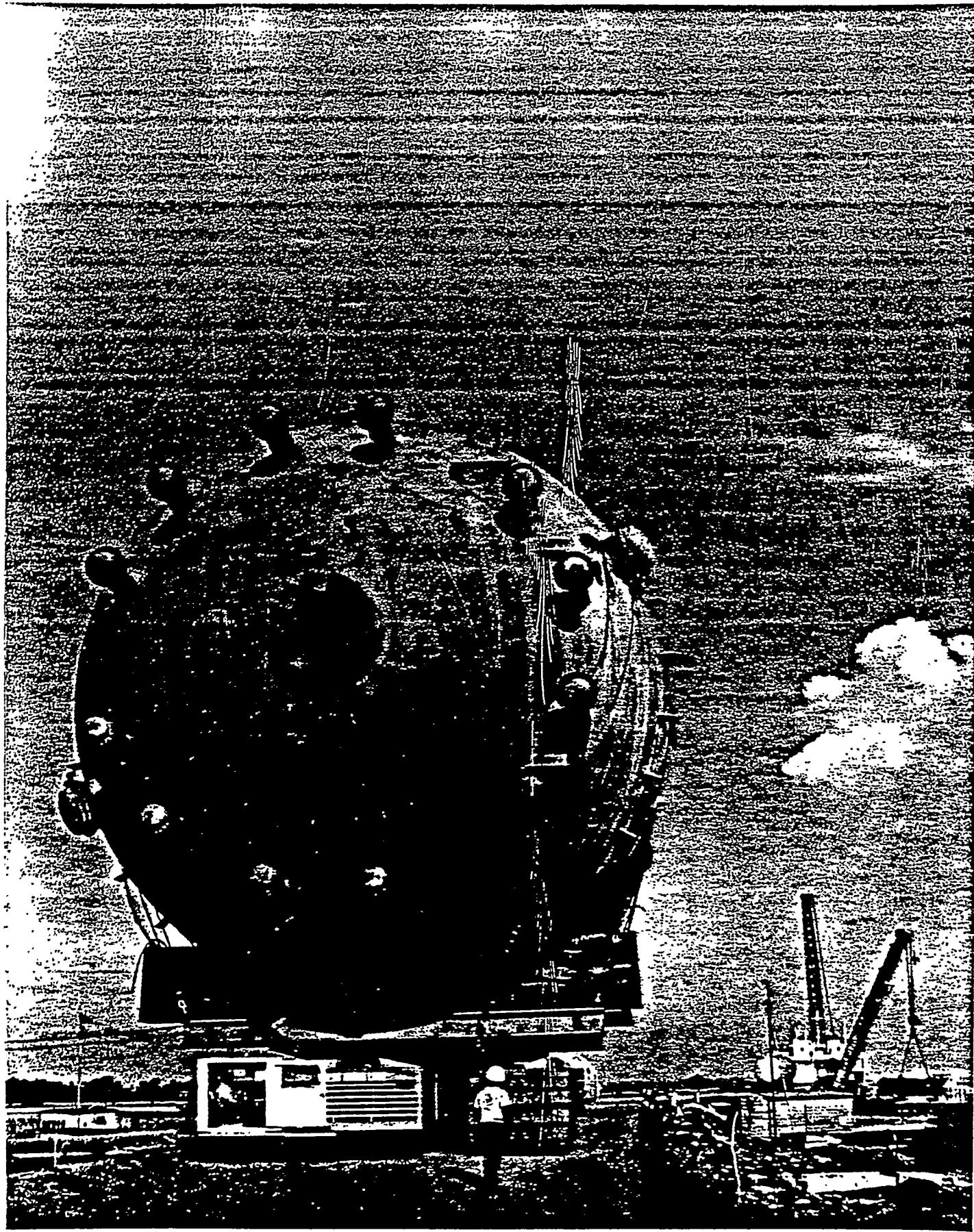
EPRI TO AWARD CONTRACT FOR MORE DETAILED STUDY



250 MW PFB STEAM GENERATOR



250 MW PFB SUPERHEATER-REHEATER



36' OD-400 TON CATCRACKER REGENERATOR AB-291



125MW SHOP ASSEMBLED PFB BARGE SHIPMENT

GRIMETHORPE PFB

75 MW_T EXPERIMENTAL FACILITY-COMPLETED 1980

BED CONDITIONS

6'-7" SQUARE

6-12 ATM

1470-1750°F

8. FT/SEC. NOMINAL

TUBE BANK "A" - 858 HRS OPERATION OCT.-DEC. 81

1-1/4" OD ON 3-1/8" TP

11'-6" TALL (14 1/2% PACKING DENSITY)

6.7 FT/SEC.

240°F ΔT - BED HEIGHT 12.8 FT

ERATIC COAL FEED - ROTARY VALVES ± 27°F

TUBE BANK "C" - 469 HRS OPERATION JUNE-SEPT. 82

1-5/16" OD ON 3-1/8" Vx7" H

10'-6" TALL (6.3% PACKING DENSITY)

4.9-6.6 FT/SEC.

No ΔT PROBLEM (15.4' BED DEPTH)

SEVERE EROSION BOTTOMMOST TUBES

CURL/LEATHERHEAD

COAL-WATER SLURRY TESTS SUCCESSFUL

25-35% WATER

99% COMBUSTION EFFICIENCY

87% SRE @ 1.8 CA/S AND 1 SEC.

30% WATER .7% CYCLE EFFICIENCY REDUCTION

20 ATM PFB TESTS

SLIGHT INCREASE IN COMBUSTION EFFICIENCY

SRE NOT SENSITIVE

NO_X EMISSION NOT SENSITIVE

RUN OF MINE COAL

98 TO 99-1/2% COMBUSTION EFFICIENCY

85% SRE @ 1.5 CA/S AND 1 SEC.

4% BED CARBON CONTENT

LARGE STONE ACCUMULATION

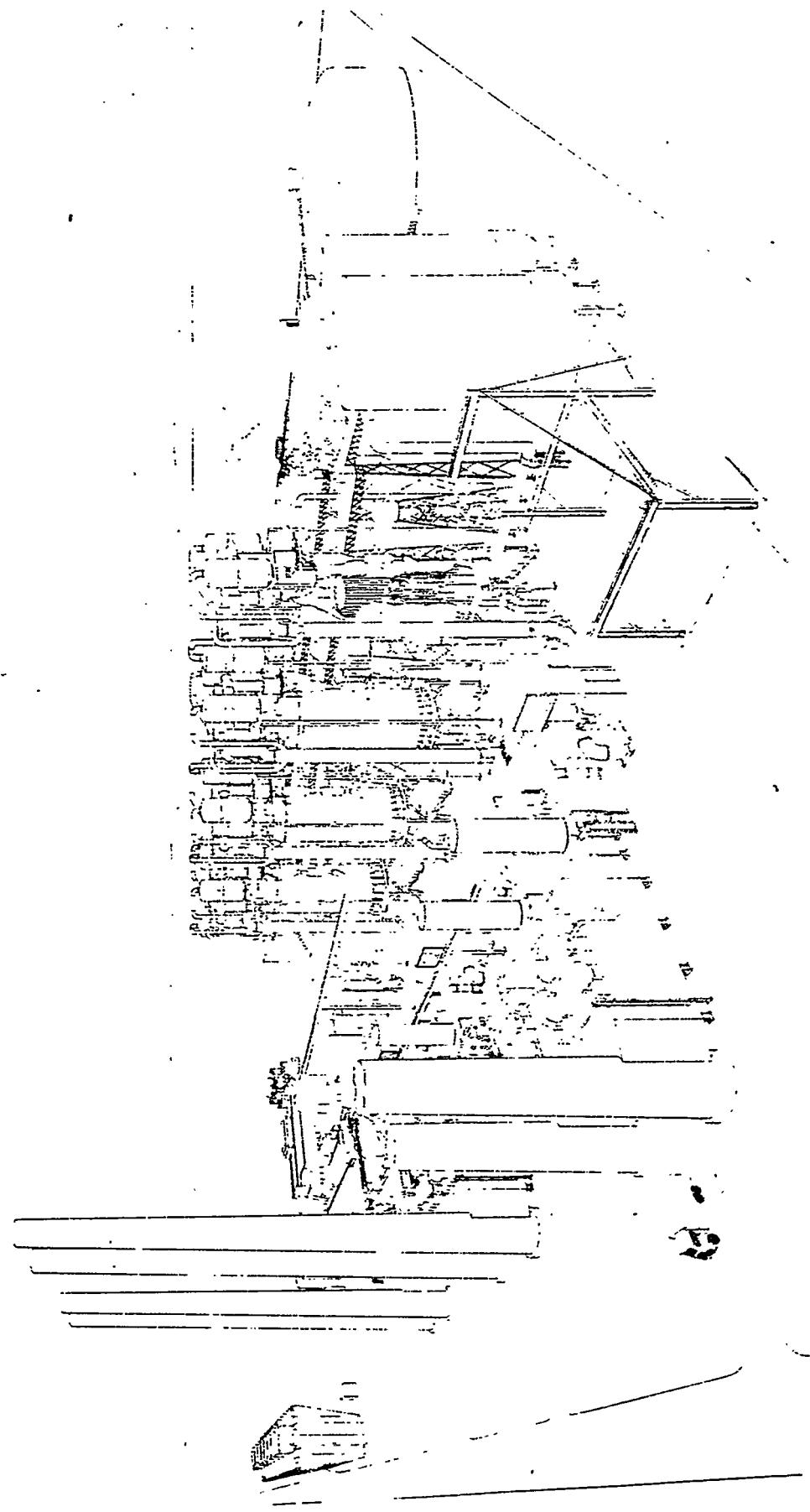
HOT GAS CLEANUP

AT THE PRESENT, CYCLONE SEPARATORS REPRESENT THE ONLY COMMERCIAL TECHNOLOGY FOR REMOVING PFB PARTICULATES.

ADVANCED DEVICES ARE UNDER DEVELOPMENT:

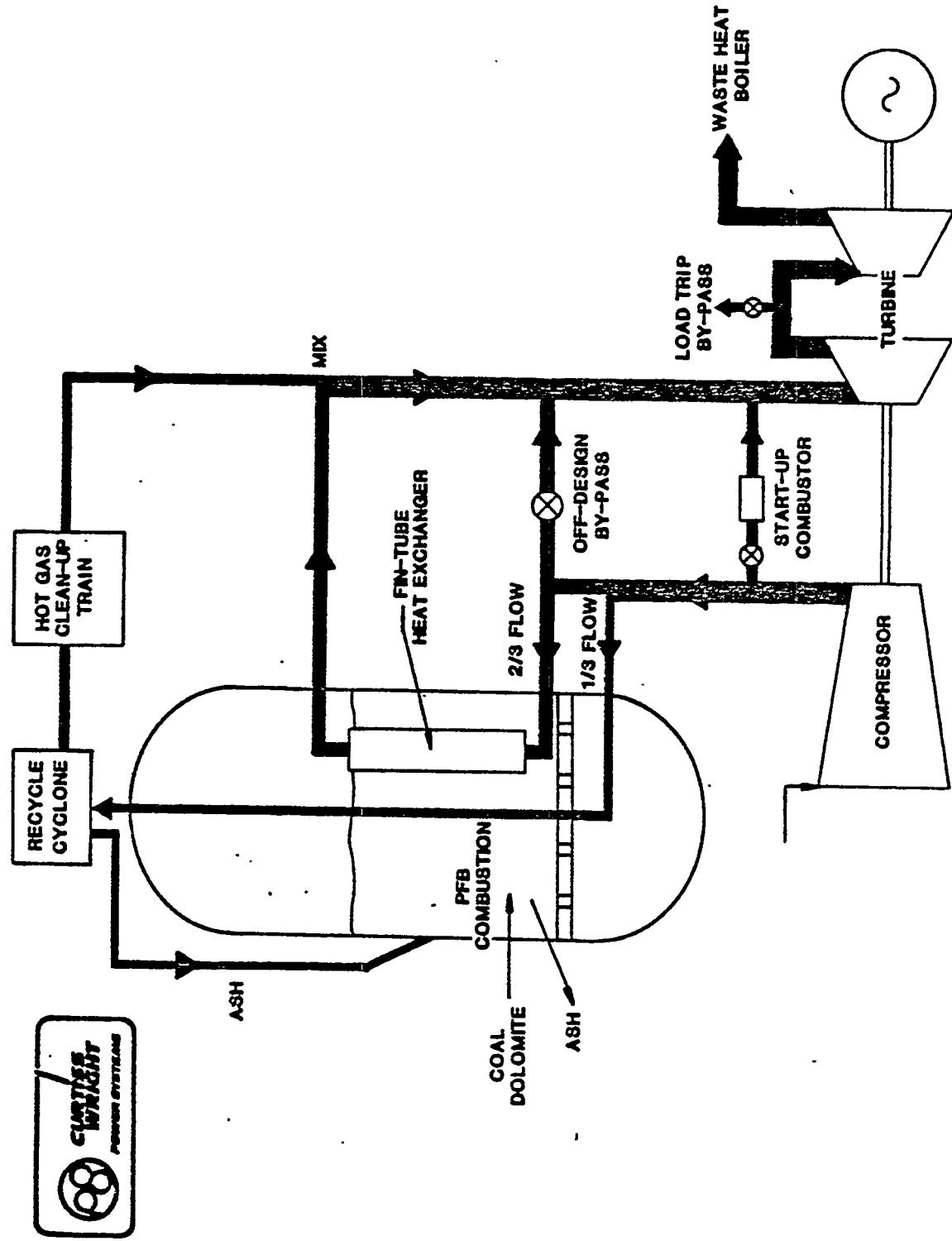
- CERAMIC BAGHOUSE FILTERS
- CERAMIC BLOCK FILTERS
- ELECTROSTATIC PRECIPITATORS
- ELECTRO CYCLONES
- GRANULAR BED FILTERS

PRESENTATION ON
CURTISS-WRIGHT
PRESSURIZED FLUIDIZED BED PILOT PLANT

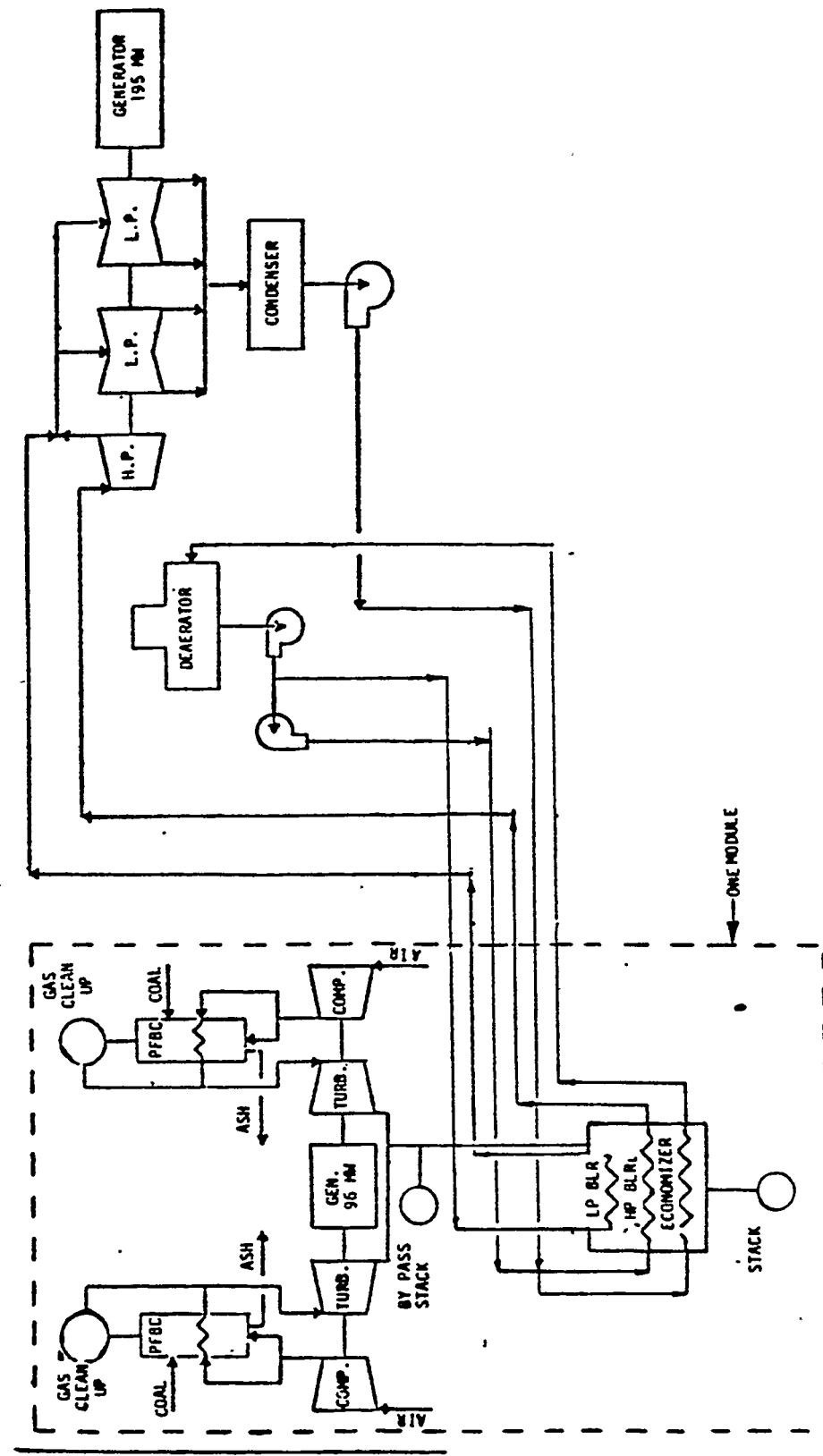


PFB OVERVIEW

PFB AIR HEATER SYSTEM DESIGN



**500 MW PFB - COMBINED CYCLE PLANT
MODULAR ARRANGEMENT**



AB-299

PFB-III-68A

COMMERCIAL PLANT

NOMINAL PERFORMANCE

Heat Rate 8600 BTU/KW HR
Coal Pile to Busbar Efficiency 40%

Modular Plant Design

- 3 Gas Turbine Modules 3 x 110 MW
Each Containing, 2 PFB, 2 GT,
1 Alternator
- 1 Steam Turbine $\frac{180 \text{ MW}}{510 \text{ MW}}$

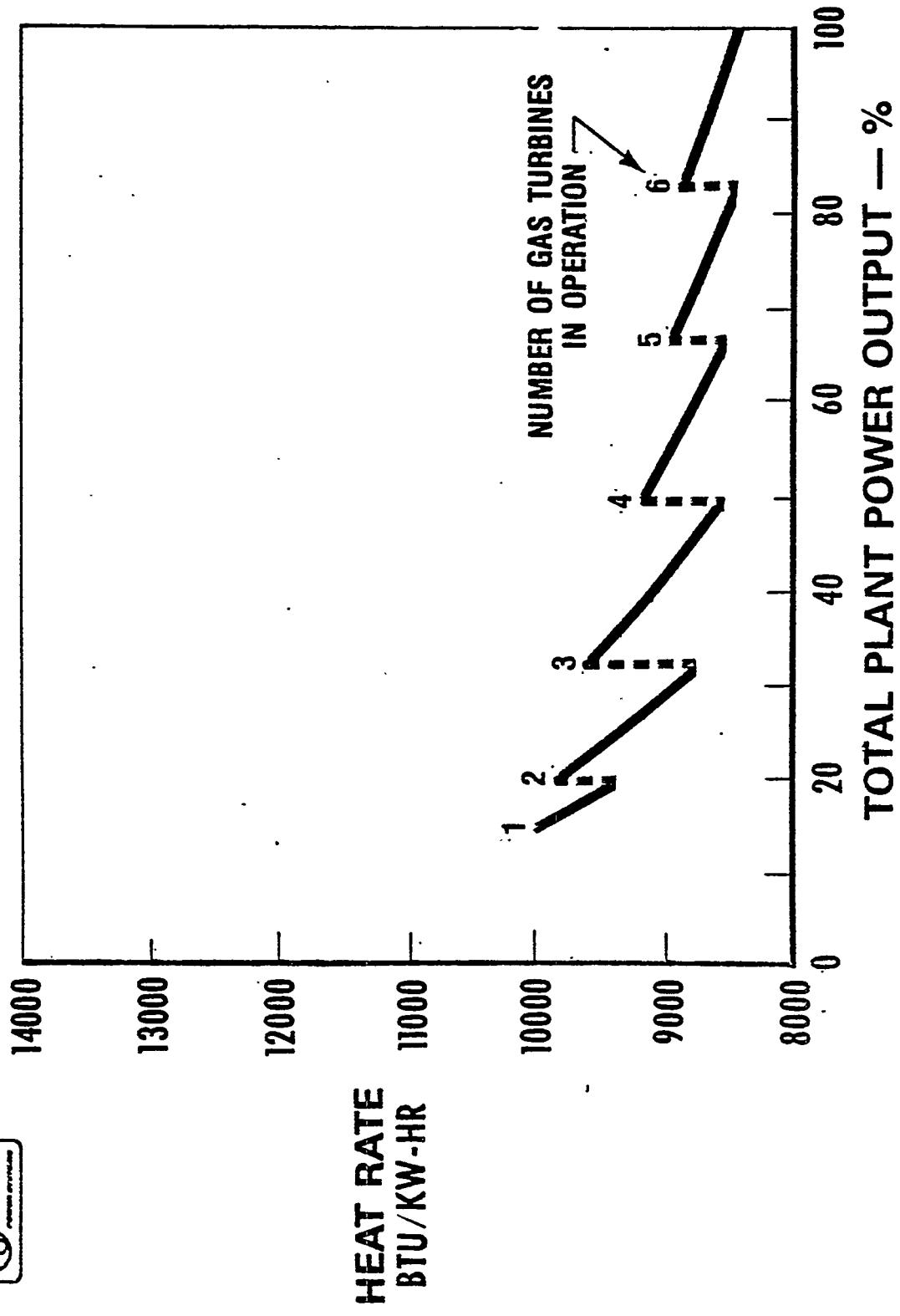
BENEFITS OF AIR HEATER FBC SYSTEMS

- FUEL FLEXIBILITY
- HIGHER PLANT EFFICIENCY
- REDUCED WATER REQUIREMENTS
- LOWER SO₂ AND NO_X EMISSIONS
- EASIER TO DISPOSE ASH
- LOWER CAPITAL COST
- LOWER COST OF ELECTRICITY
- MODULAR SYSTEM
- SHORTER CONSTRUCTION CYCLE
- HIGHER AVAILABILITY
- OPERATING FLEXIBILITY
- WIDER APPLICATIONS
- BASE AND INTERMEDIATE
- PEAKING
- COGENERATION

PFB-III-639A

500 MW PFB MODULAR COMMERCIAL PLANT

TURN DOWN CAPABILITY



500 MW MODULAR COMMERCIAL PLANT

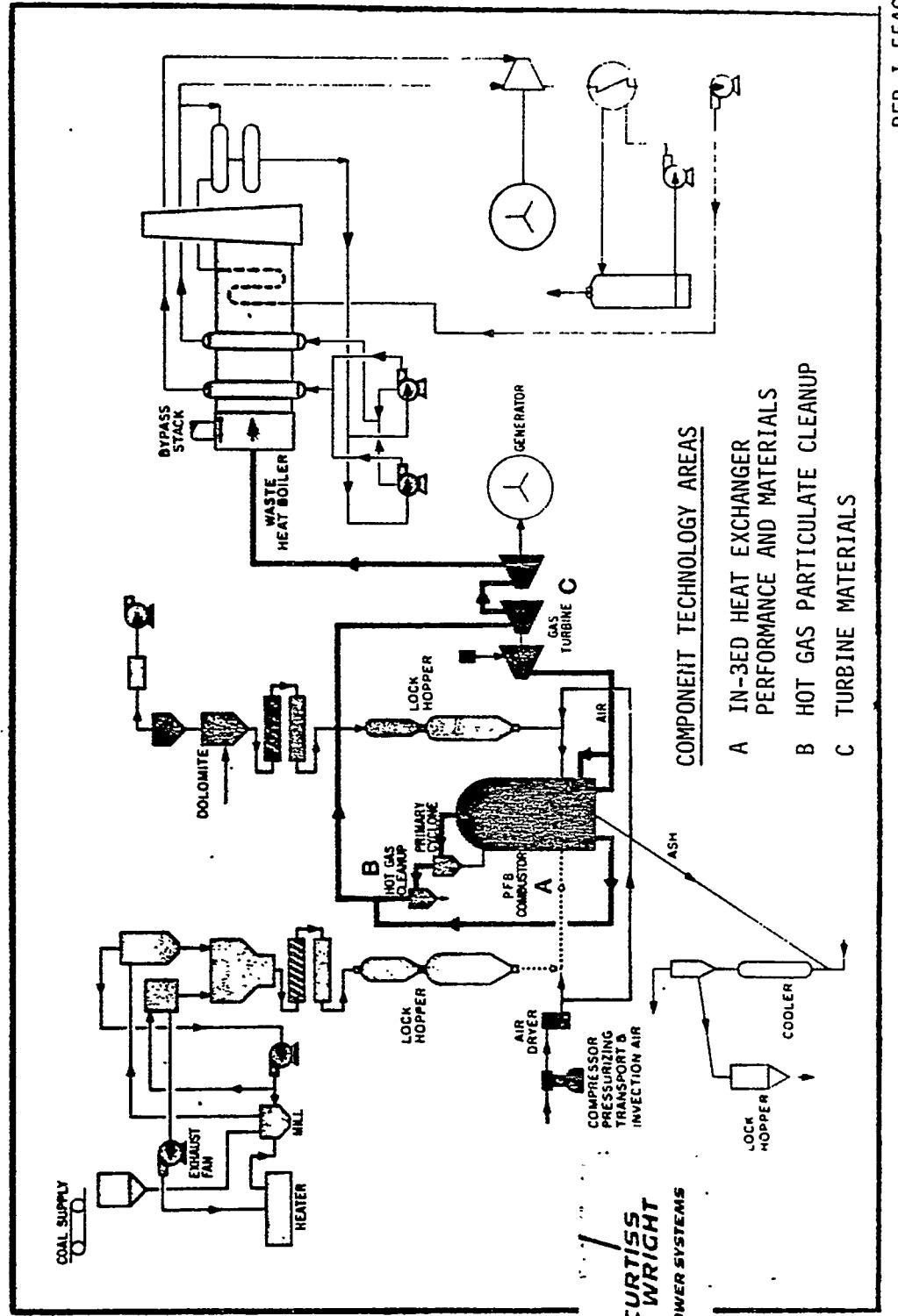
POWER AVAILABILITY DURING MAINTENANCE

<u>UNAVAILABLE ITEMS</u>	<u>POWER AVAILABILITY PERCENT</u>	<u>HEAT RATE BTU/KW HR</u>
GAS TURBINE	83	8600
PFB/HOT GAS CLEANUP	83	8600
WASTE HEAT BOILER	83-93*	8600-9140*
STEAM TURBINE	60	14,240
ST ALTERNATOR	60	14,240
GT ALTERNATOR	66	8,620

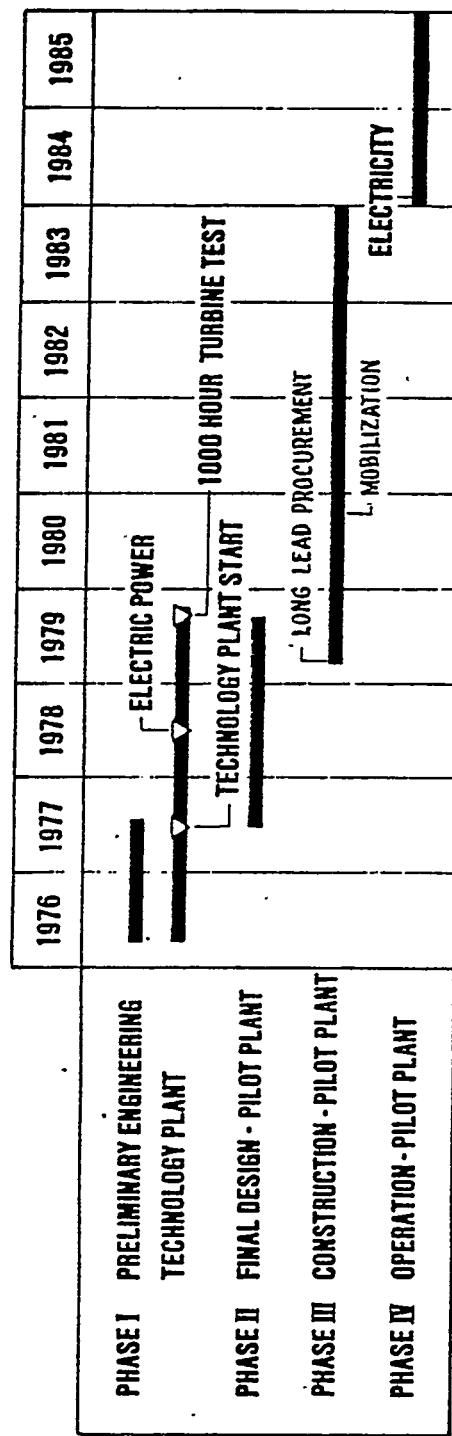
* INCLUDES ONE GAS TURBINE IN SIMPLE CYCLE MODE

PFB-1-567C

COMBINED CYCLE POWER PLANT SIMPLIFIED FLOW DIAGRAM



PFB PROGRAM PLAN



TECHNOLOGY SUPPORT TESTS

AB-306

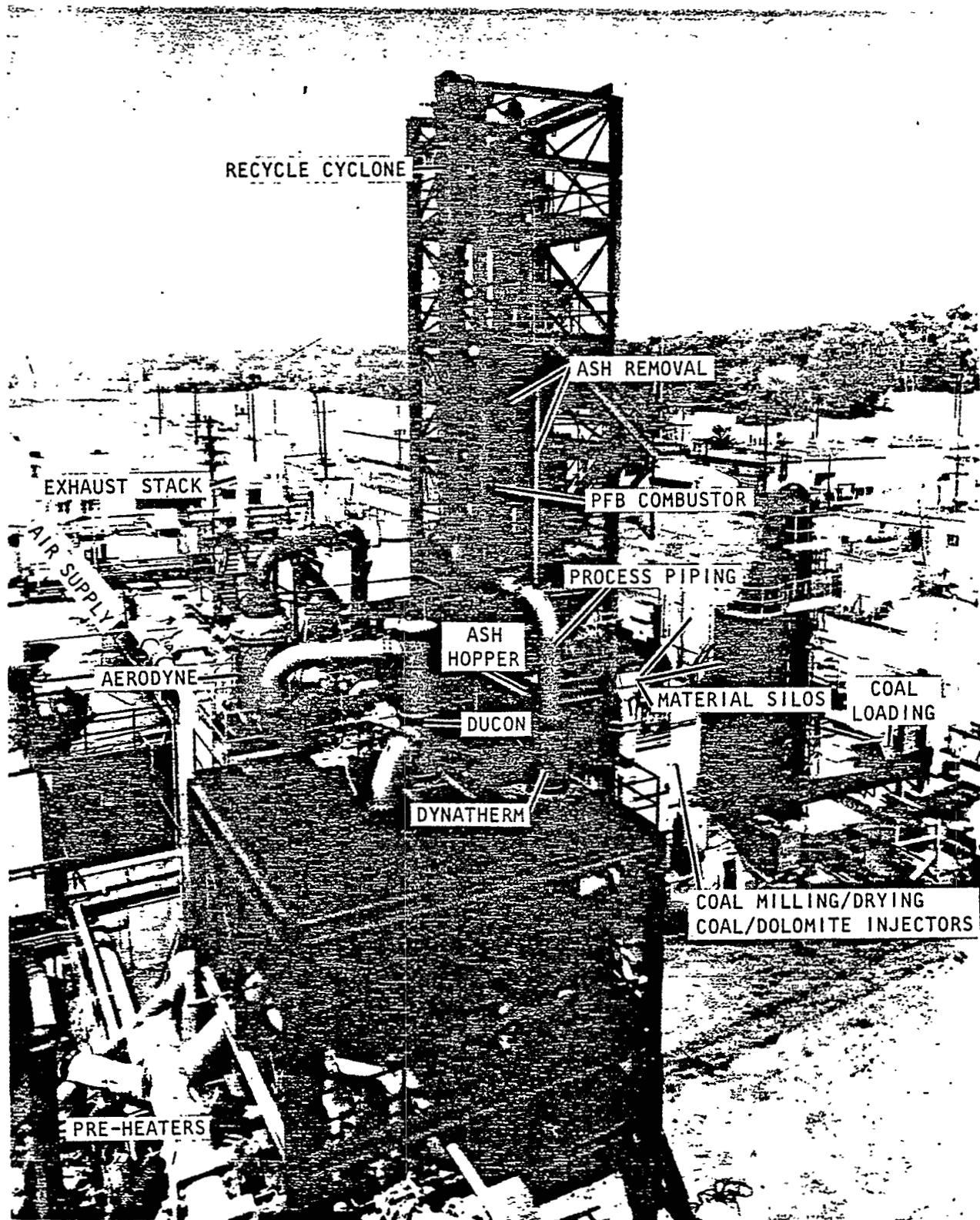
SUMMARY OF TECHNOLOGY SUPPORT TESTS

- HEAT TRANSFER CHARACTERISTICS OF IN-BED HEAT EXCHANGER TUBES 600 HOURS
FBC LABORATORY RIG
- HEAT EXCHANGER TUBE MATERIALS DURABILITY 8000 HOURS
COMMERCIAL FLUID BED CALCINER
FBC LABORATORY RIG
- TURBINE AND TUBE MATERIALS DURABILITY AND PFB OPERATING
PARAMETERS FOR COMBUSTION/EMISSIONS 3500 HOURS
LARGE SCALE PFB TECHNOLOGY PLANT

TOTAL 12,100 HOURS

PFB-III-808

TECHNOLOGY UNIT

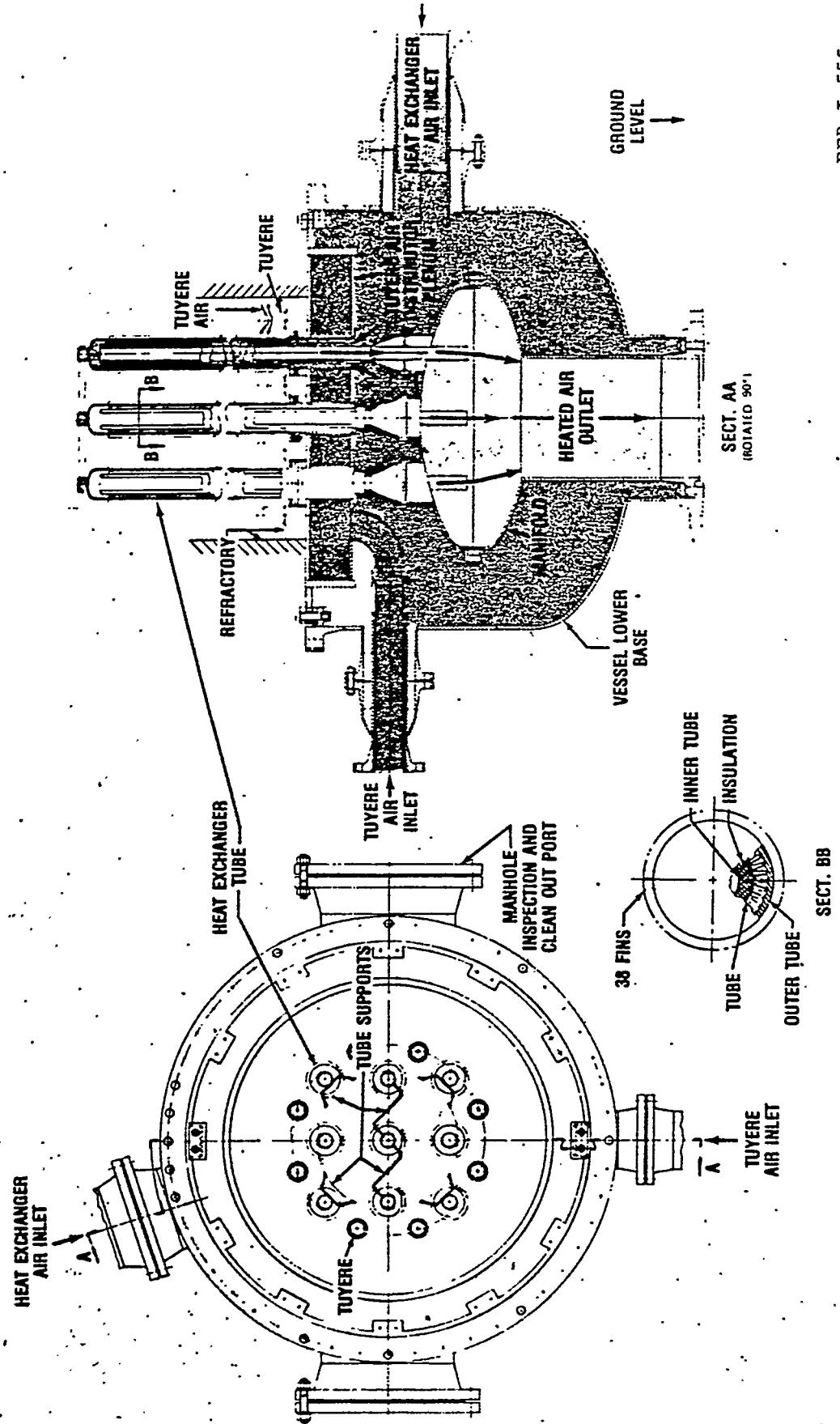


AB-308

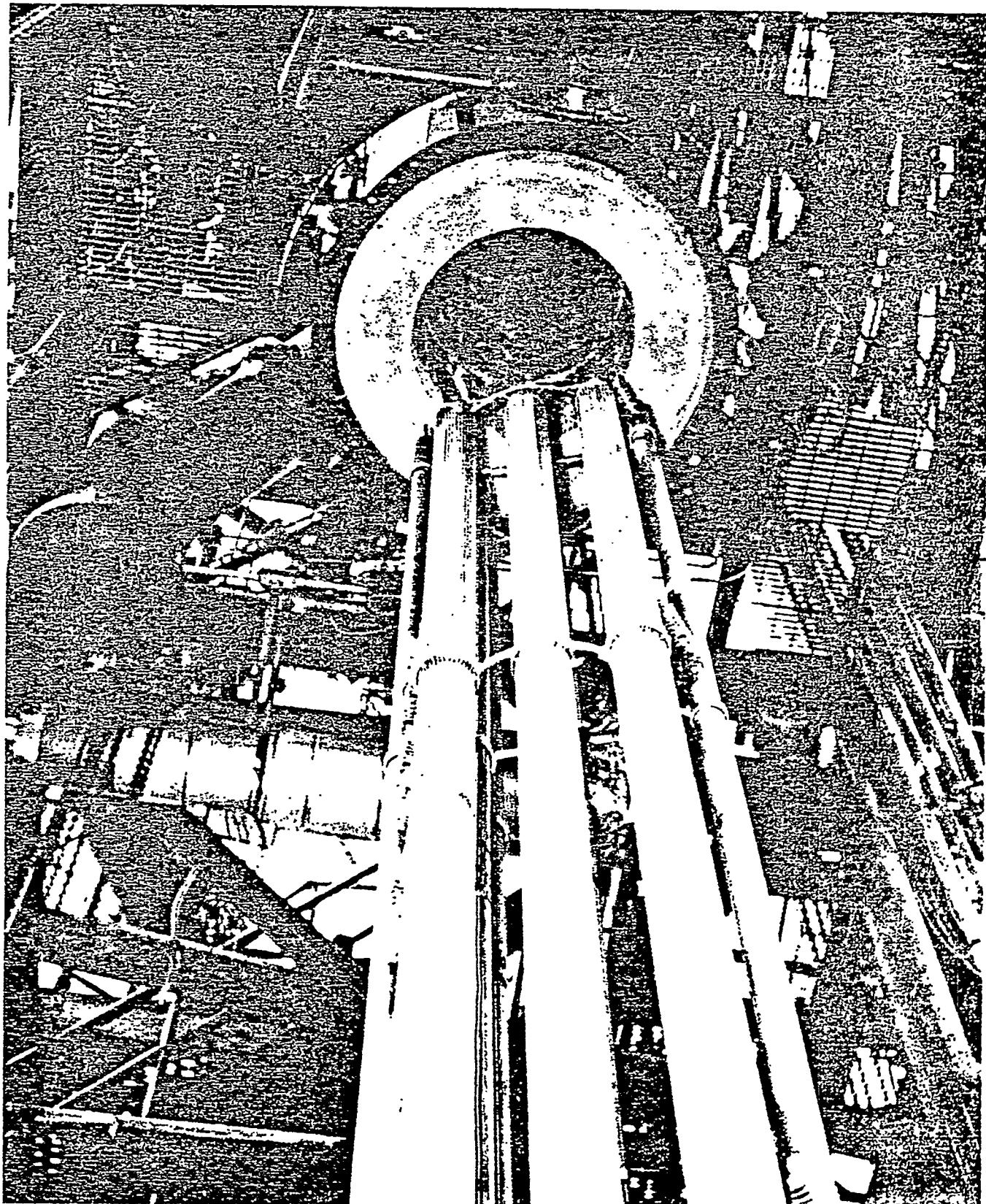
PFB-III-474C

SMALL GAS TURBINE RIG

DISTRIBUTOR AND HEAT EXCHANGER ASSEMBLY



HEAT EXCHANGER TUBES
BEING INSERTED IN PFB COMBUSTOR



AB-310

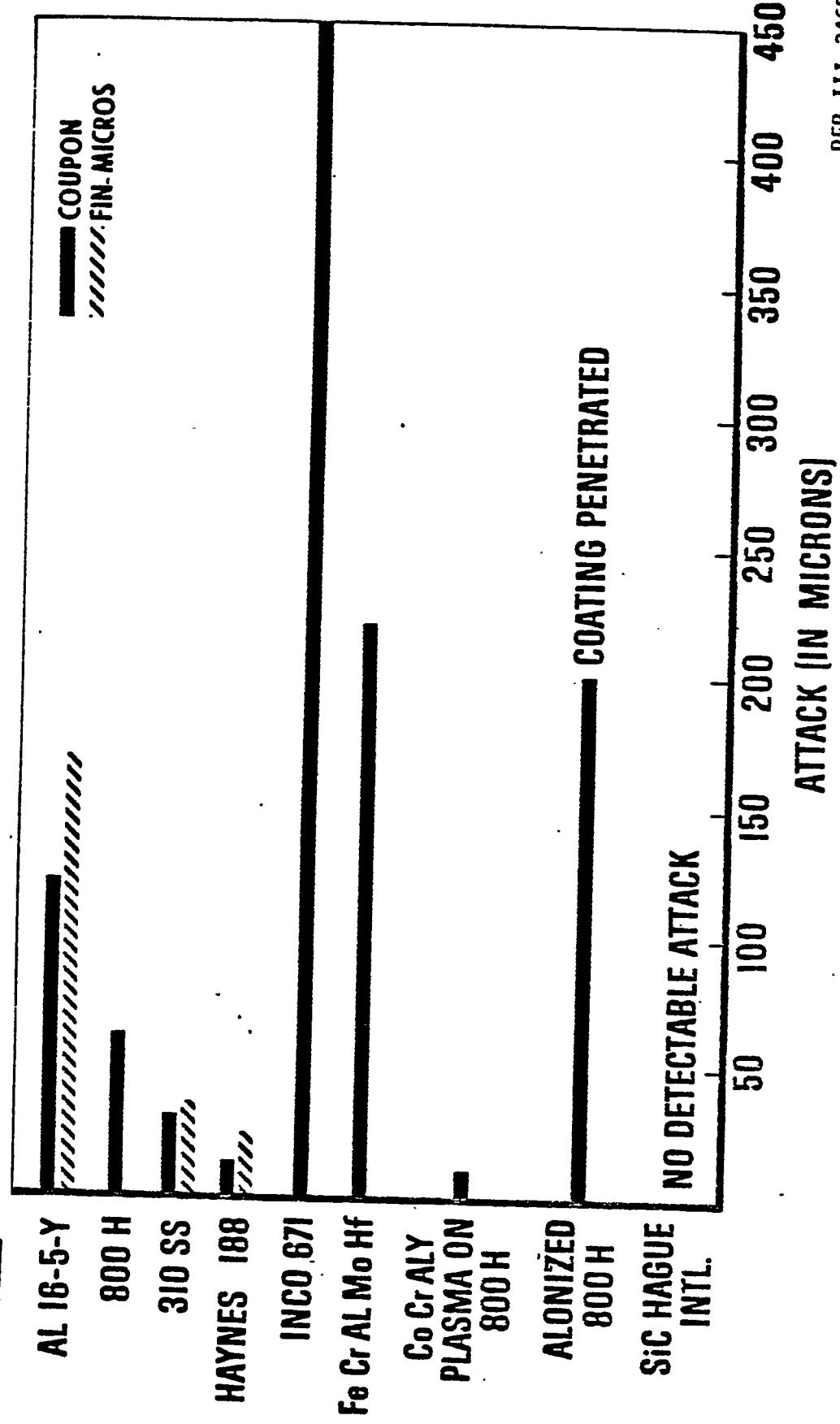
PFB-III-640

PFB HEAT EXCHANGER TUBE MATERIALS

SUMMARY OF RESULTS

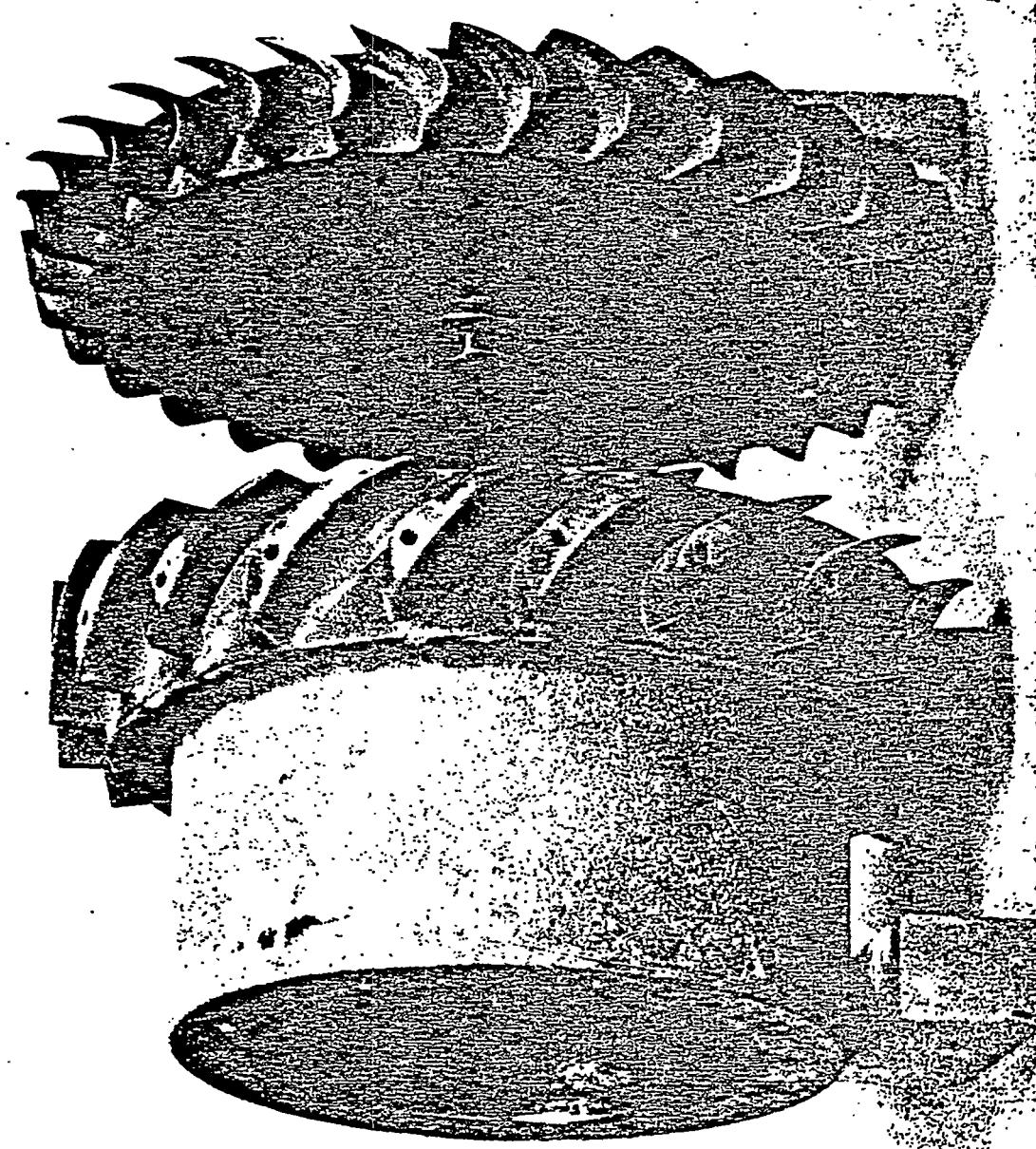
2000 HOUR EXPOSURE OF COUPONS IN SGT/PFB COMBUSTOR

ALLOY



PFB-III-3460

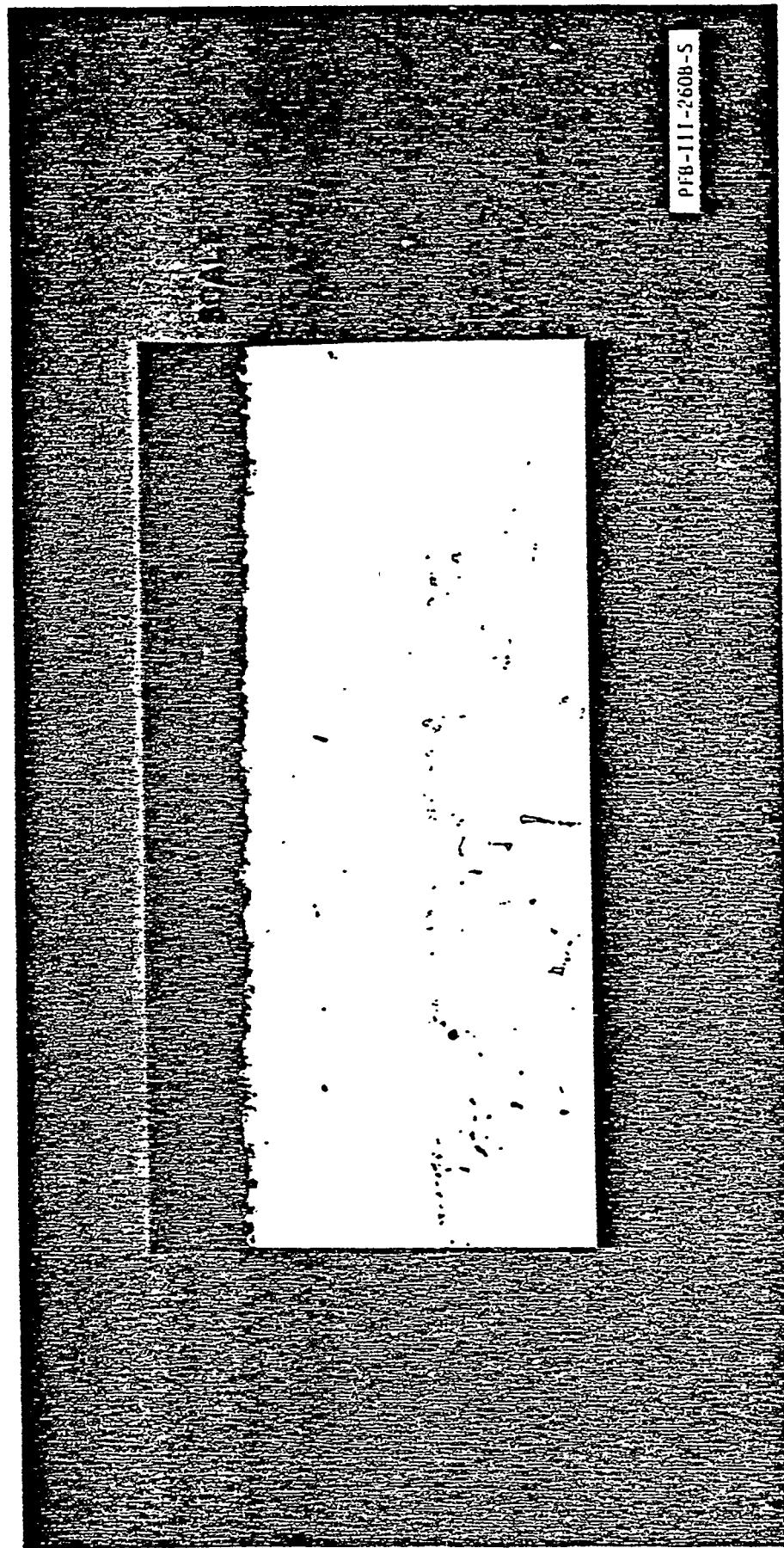
ROVER STATOR AND ROTOR AFTER COMPLETION
OF THE 1000 HOUR TEST



AB-312

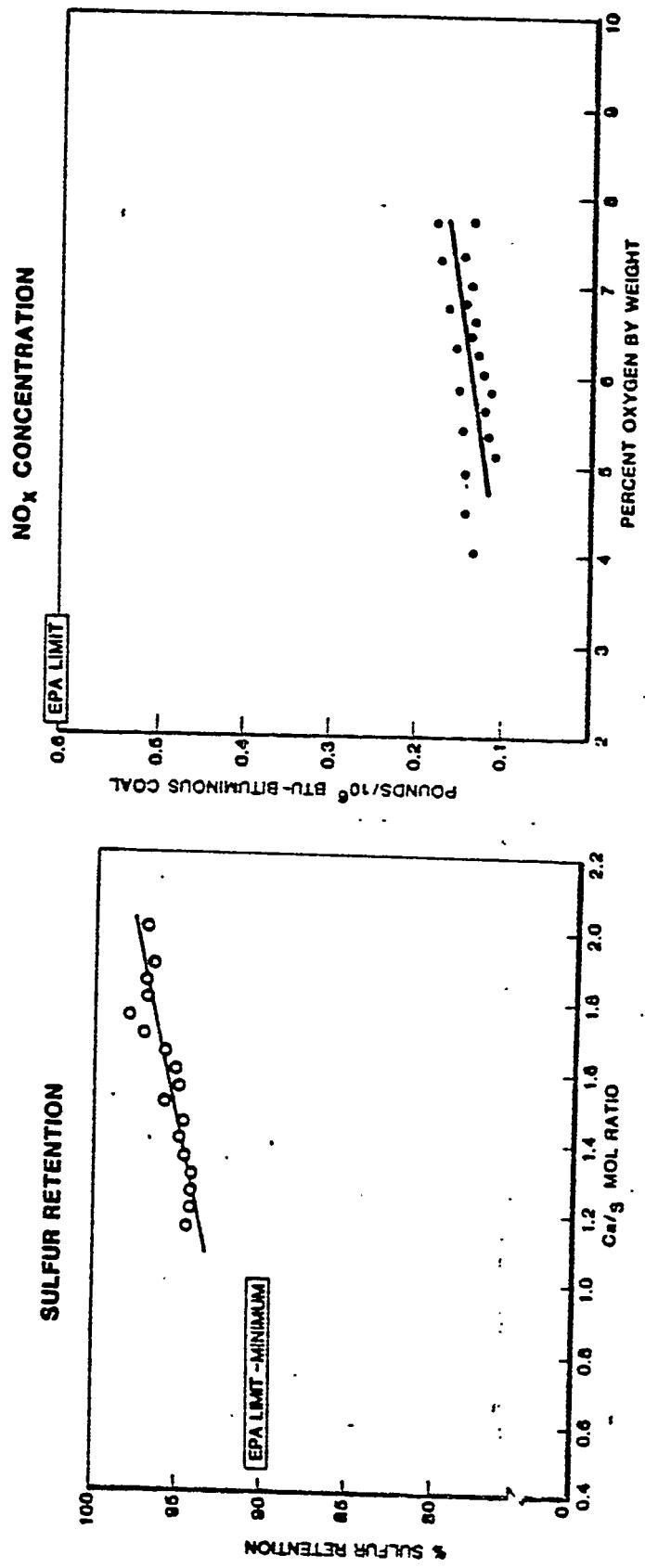
PFB-111-265-S

**PHOTOMICROGRAPH OF Fe Cr Al-Y COATING ON ROVER VANE
After 1000 Hour Test**



AB-313

PFB COMBINED CYCLE EMISSION SUMMARY

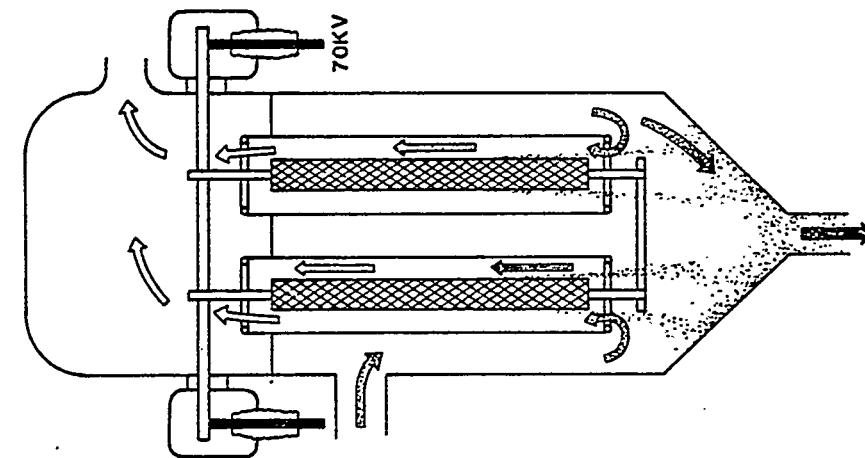


PfB-III-646

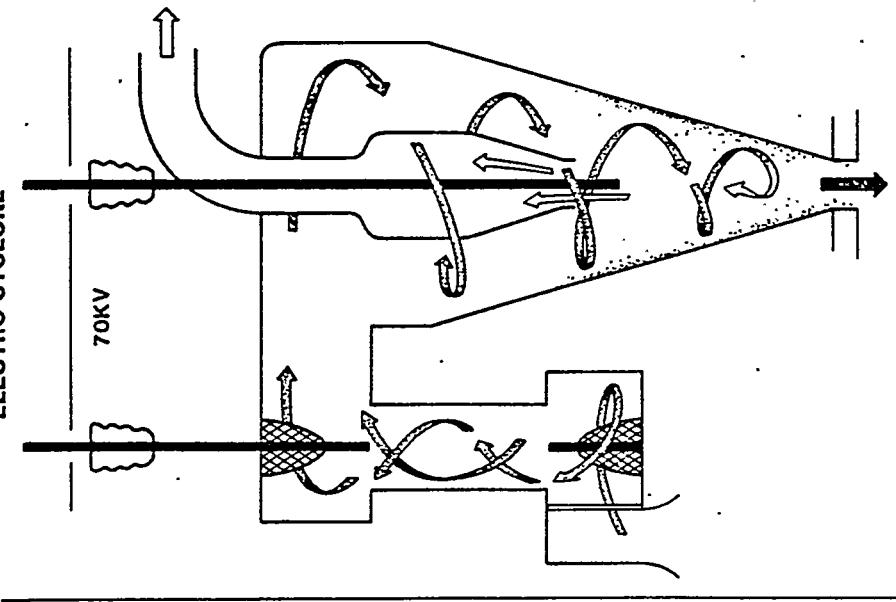
AB-314

HOT GAS CLEANUP SYSTEMS

ELECTROSTATIC PRECIPITATOR

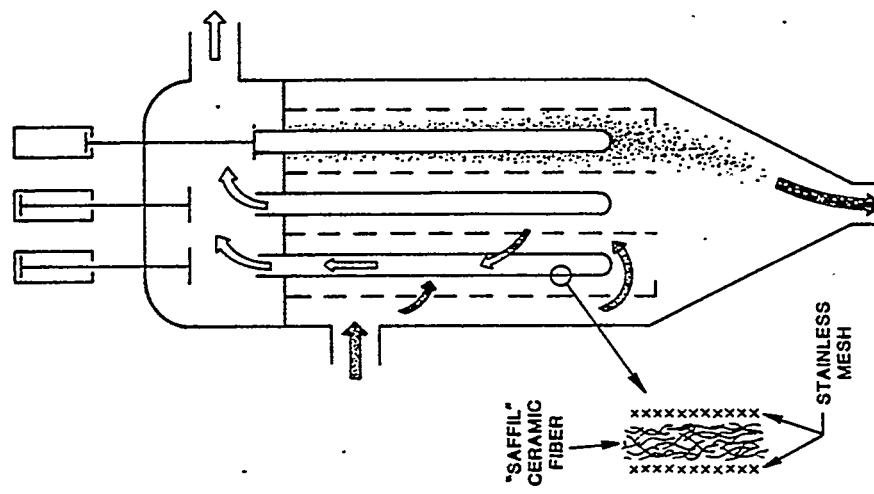


ELECTRO CYCLONE



RESEARCH COTTRELL

CERAMIC FELT BAG



ACUREX

GENERAL ELECTRIC

PFB-P-57

TEST PLANT ACCOMPLISHMENTS

- Over 3500 Hours of Coal Fired PFB Operation
- Over 1300 Hours of PFB / Gas Turbine Operation
- Verified Design Parameters / Material Selections
- Demonstrated High Combustion Efficiency (> 99%)
- Demonstrated High Sulfur Capture (> 95%, < 0.3 lb/mm Btu)
- Demonstrated Low NO_x Production (< 0.2 lb/mm Btu)
- Demonstrated Acceptability of Heat Exchanger Materials
- Developed Reliable Coal / Dolomite Feed Systems
- Developed Adequate Hot Gas Cleanup System for Turbine Protection

PFB-III-603

PFB PILOT PLANT

AB-317

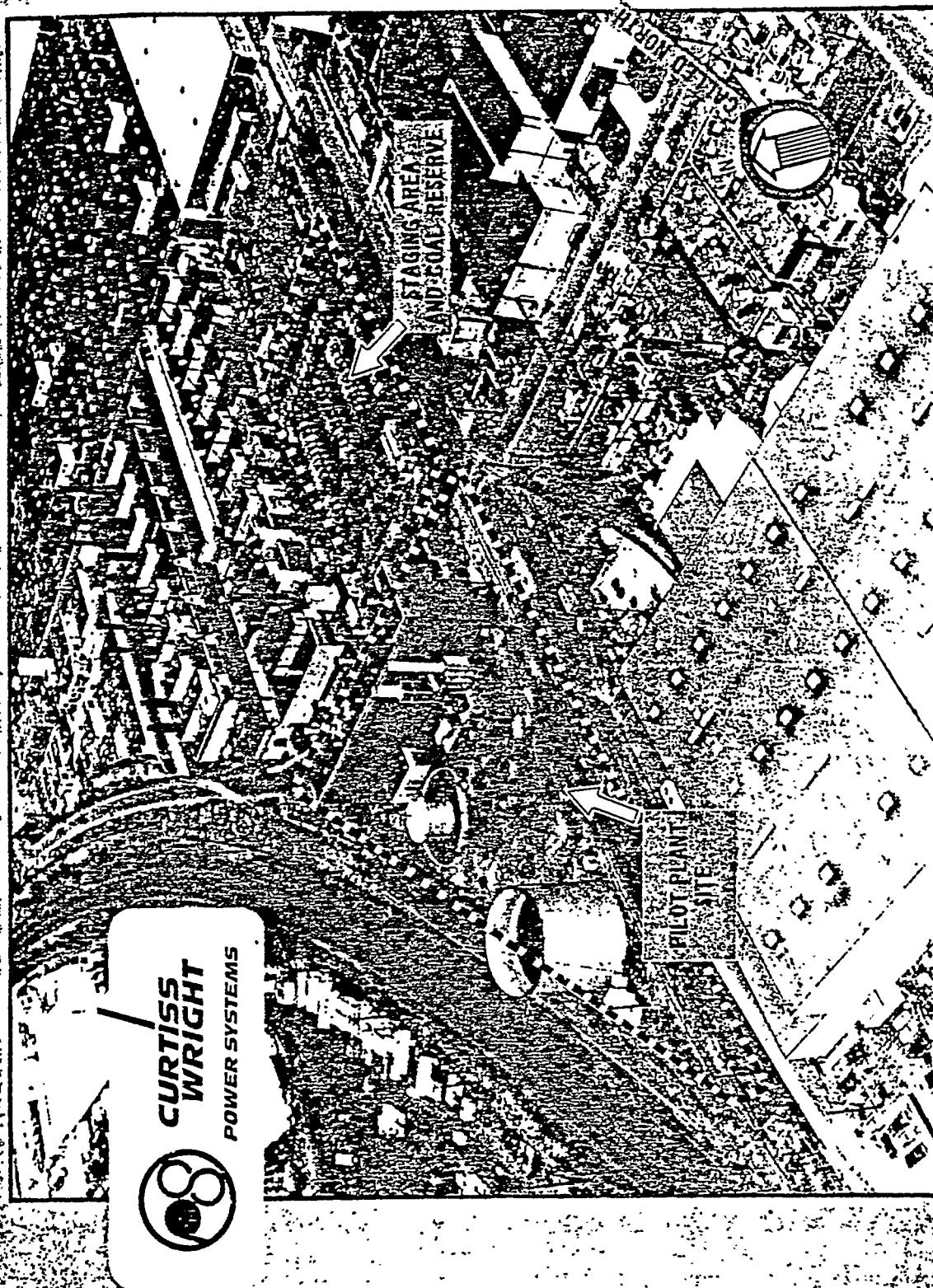
PFB PILOT PLANT DESIGN POINT



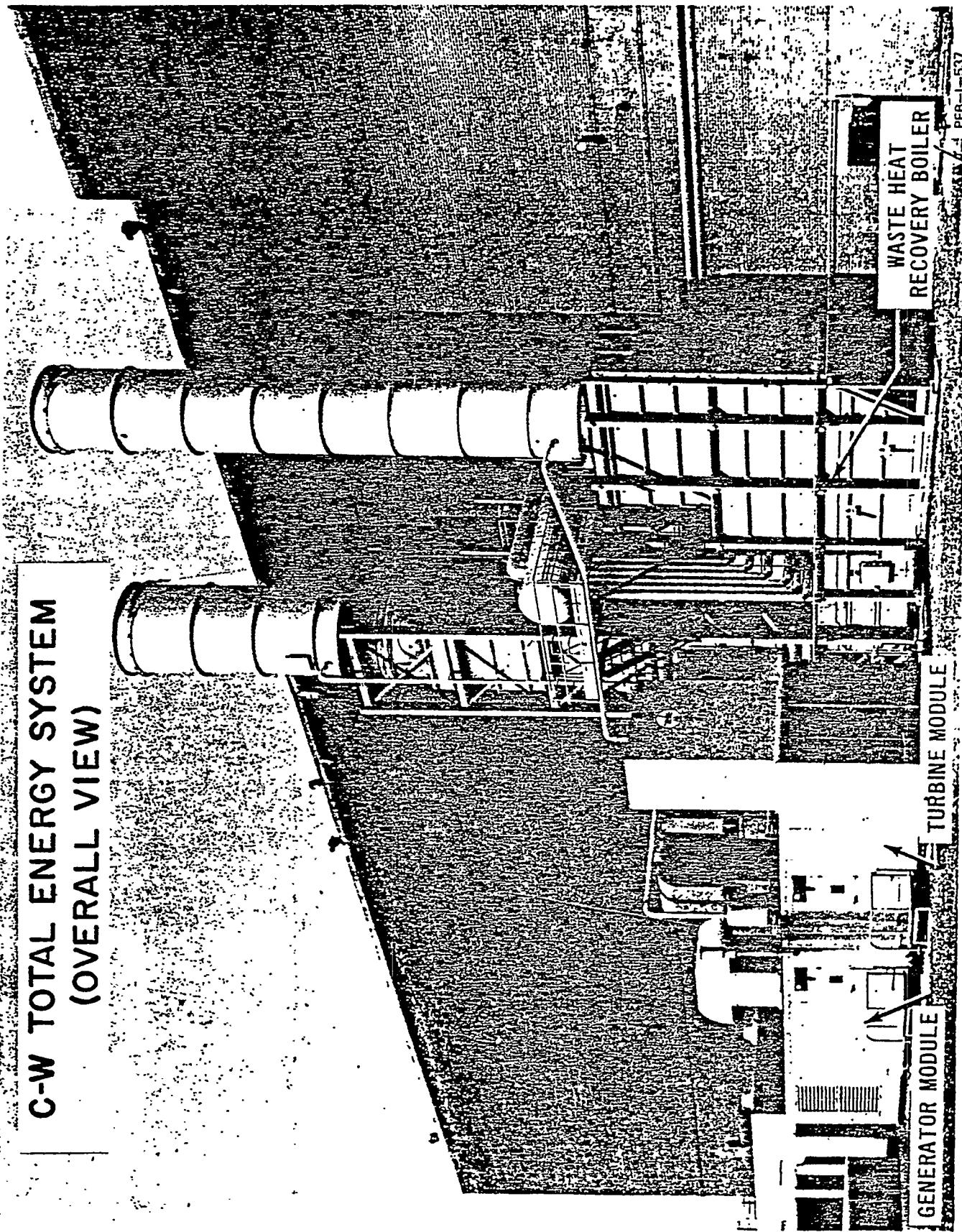
EQUIVALENT ELECTRIC POWER FROM G.T. 7150 KW
EQUIVALENT ELECTRIC POWER FROM STEAM 6470 KW
EQUIVALENT HEAT RATE..... 8725 BTU/KW/HR
COAL FLOW..... 10,240 PPH
AIRFLOW..... 120 PPS
STEAM GENERATED AT 175 PSIG 58,000 PPH

PFB-II-384B

WOOD-RIDGE FACILITY
CURTISS-WRIGHT CORPORATION

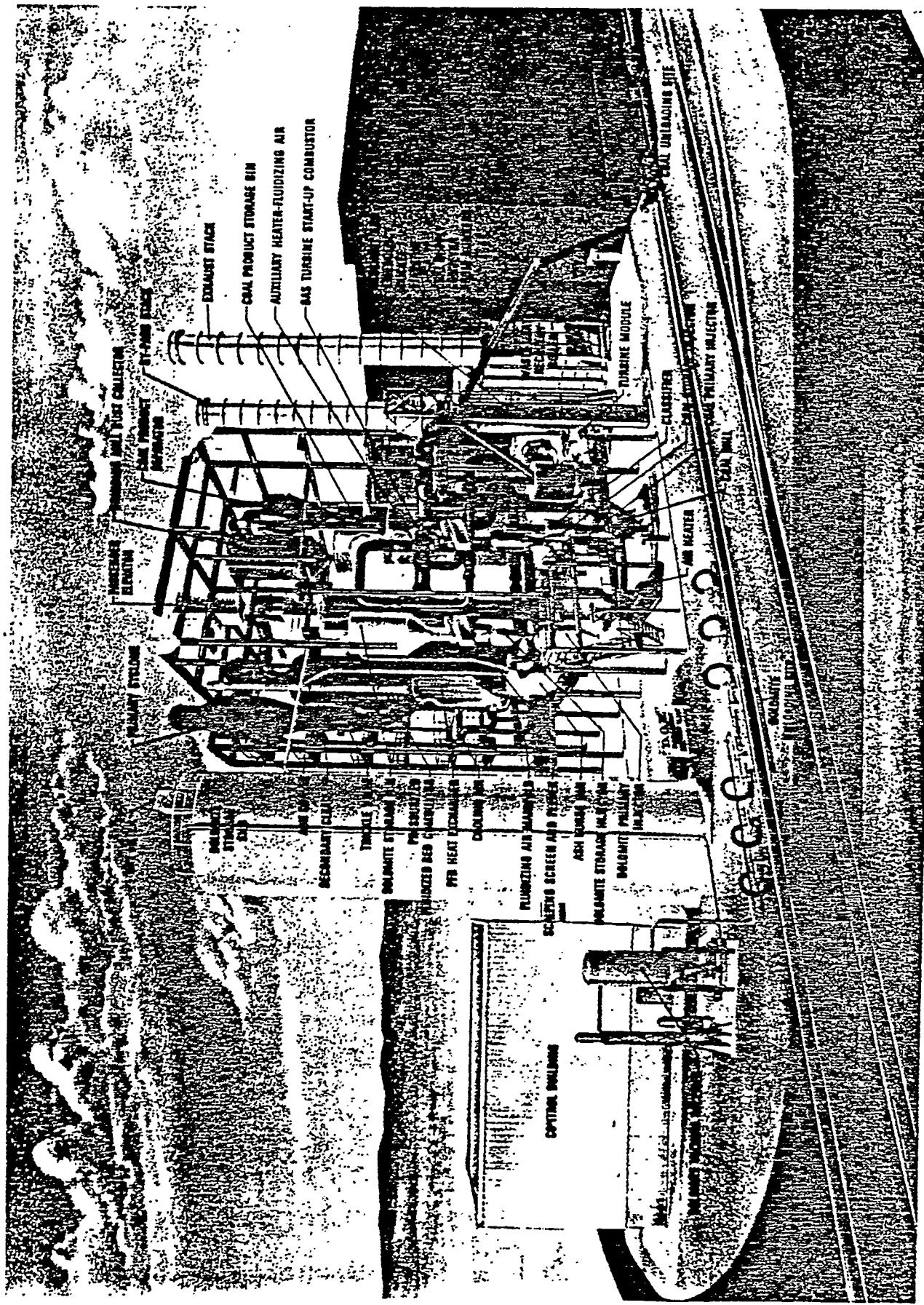


C-W TOTAL ENERGY SYSTEM (OVERALL VIEW)

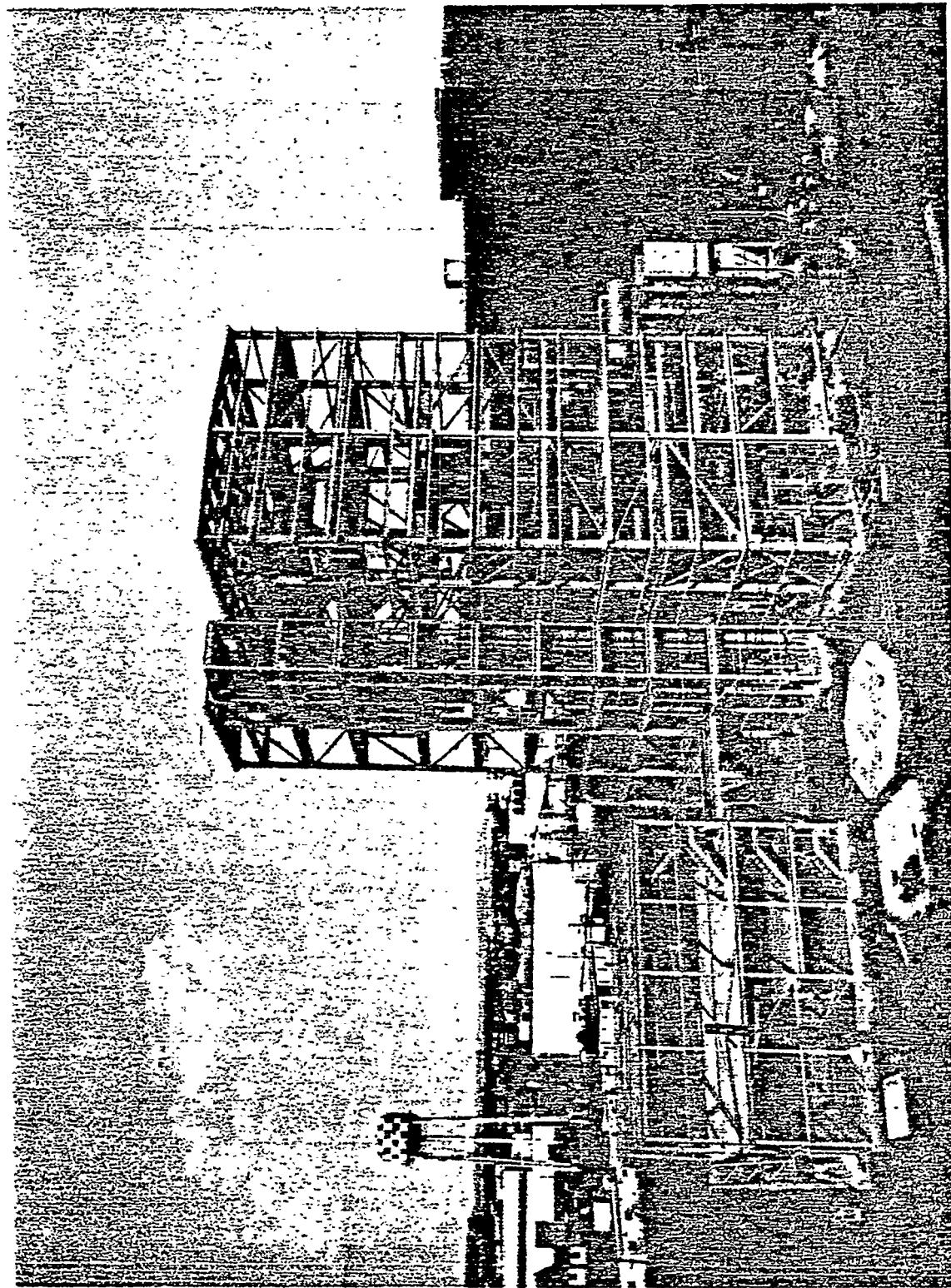


AB-320

PFB PILOT PLANT - Wood-Ridge Site



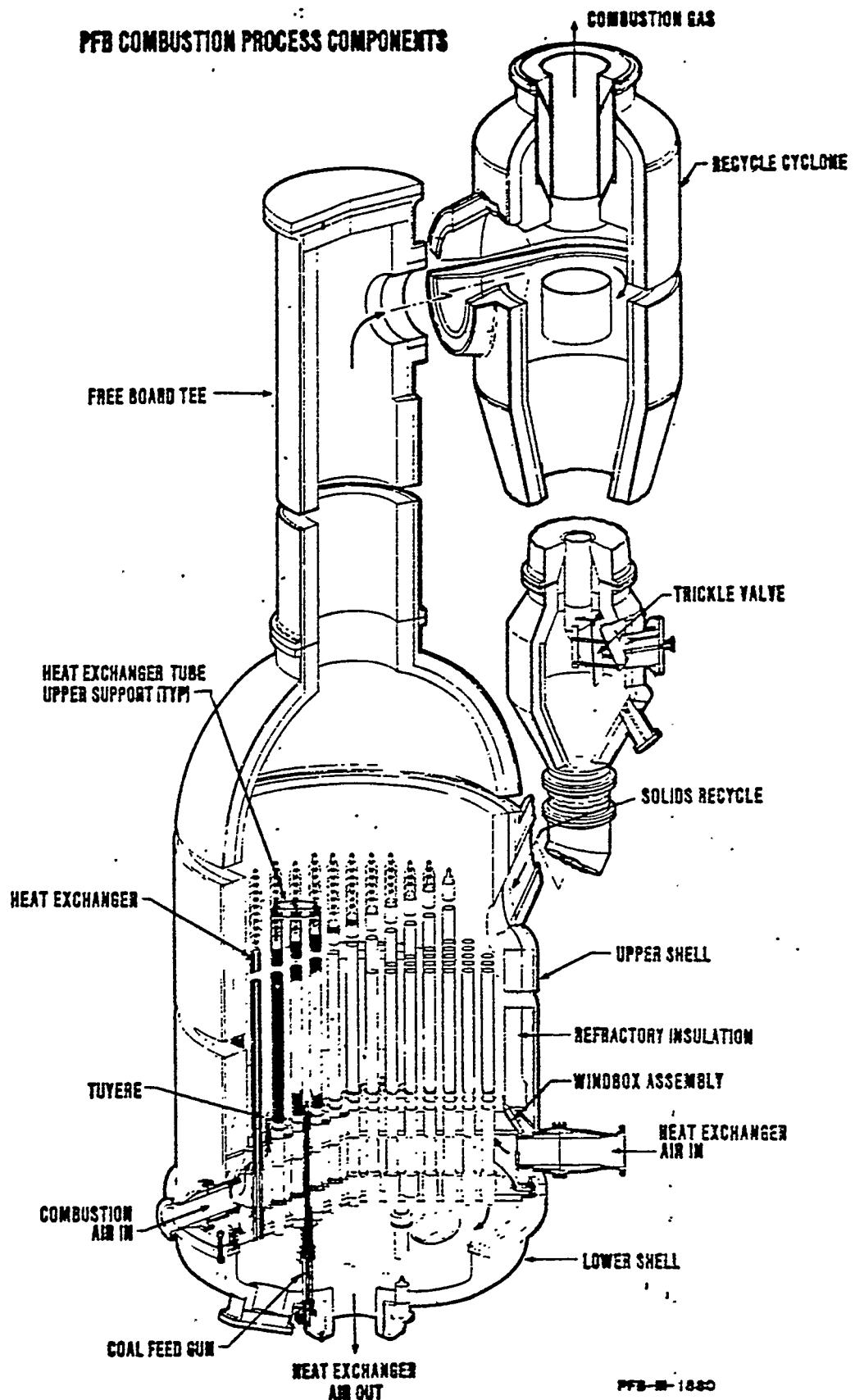
PFB AND CONTROL BUILDING STEEL STRUCTURE - LOOKING WEST



AB-322

PFB-III-821

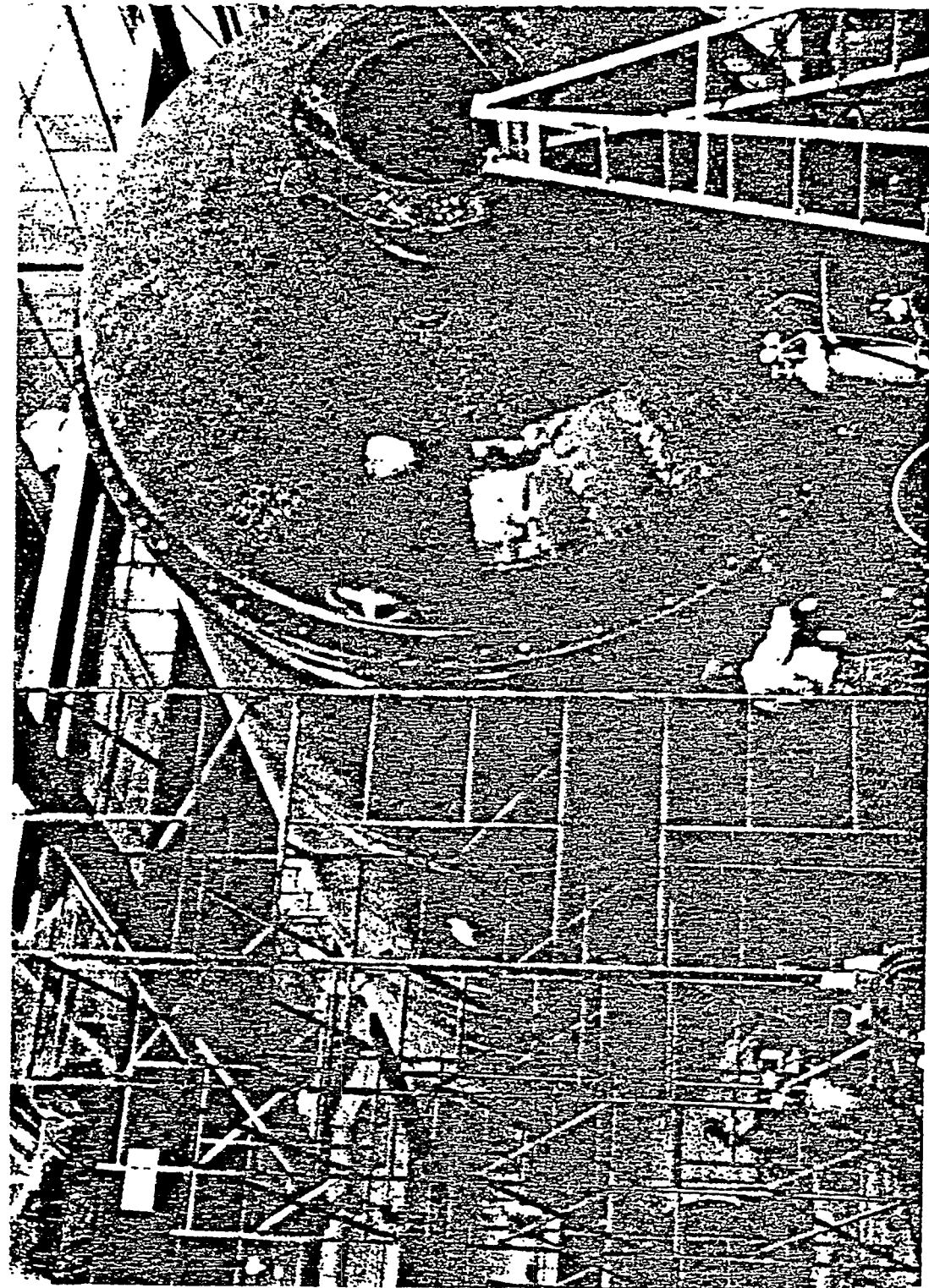
PFB COMBUSTION PROCESS COMPONENTS



PFB-III-1880

Figure 2.34

PFB COMBUSTOR VESSEL AND LOWER HEAD

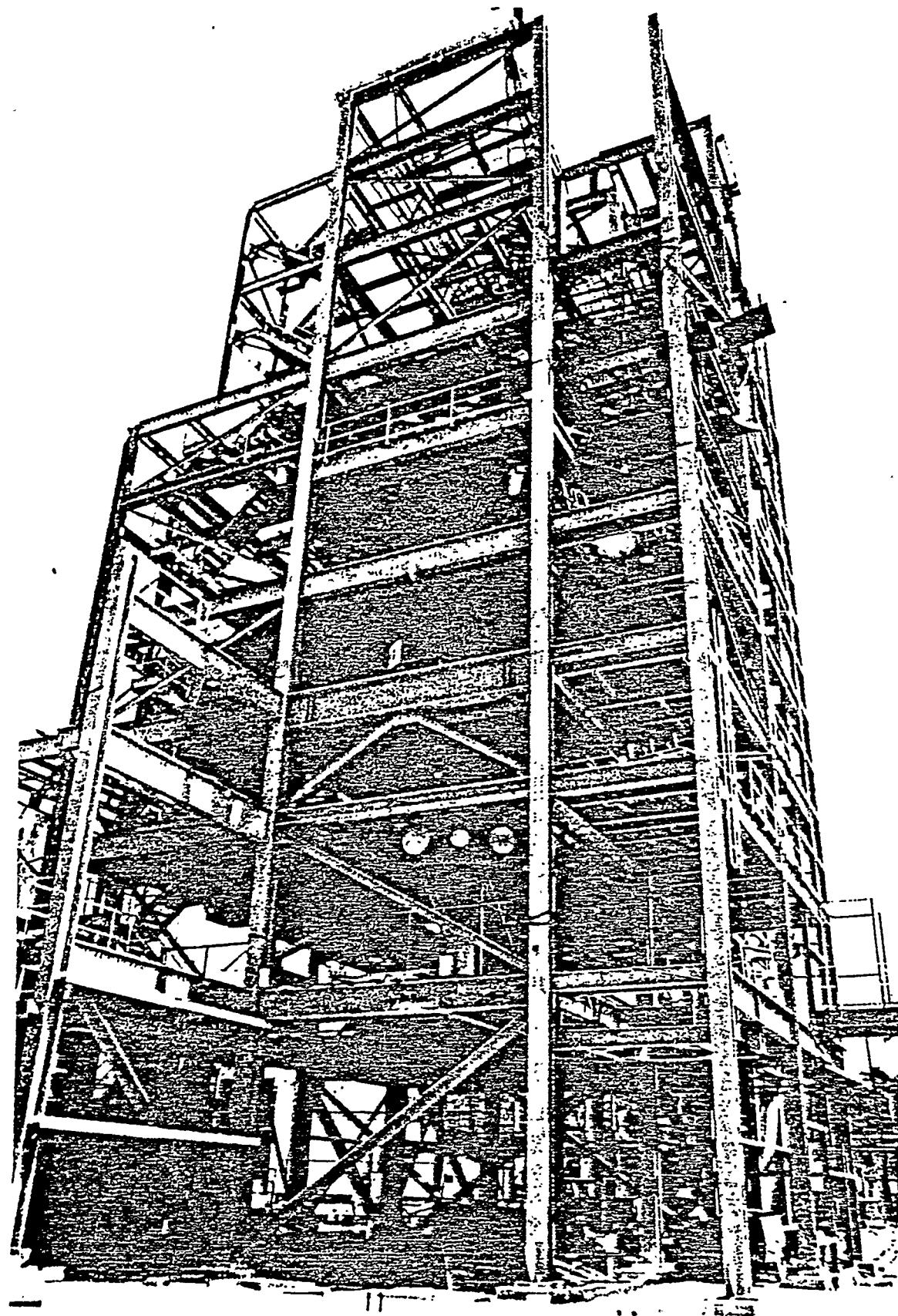


AB-324

CIRCUMFERENTIAL SEAM WELDING

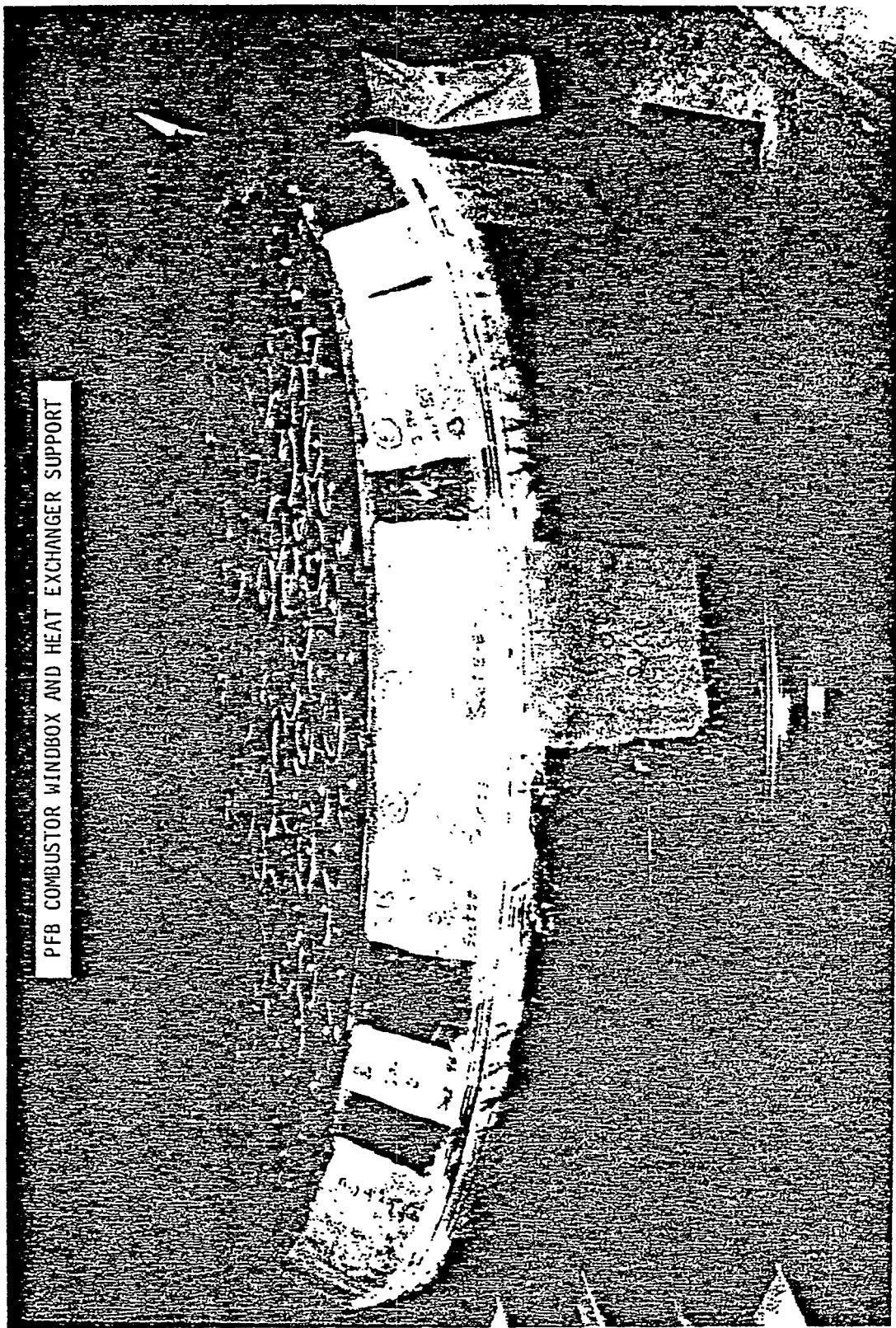
PFB-III-56A

PFB PILOT PLANT COMBUSTOR



PFB-III-822

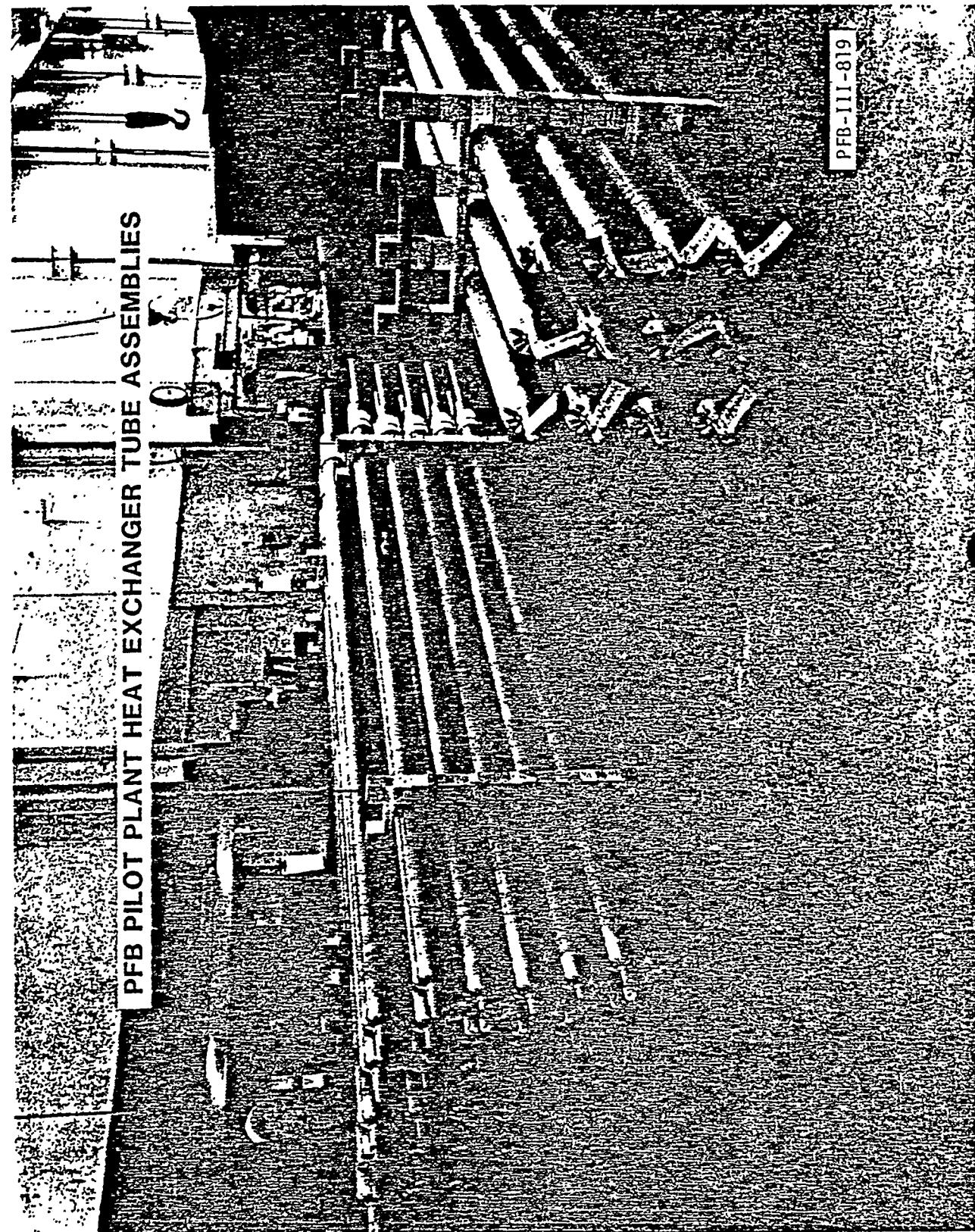
AB-325



PFB COMBUSTOR WINDBOX AND HEAT EXCHANGER SUPPORT

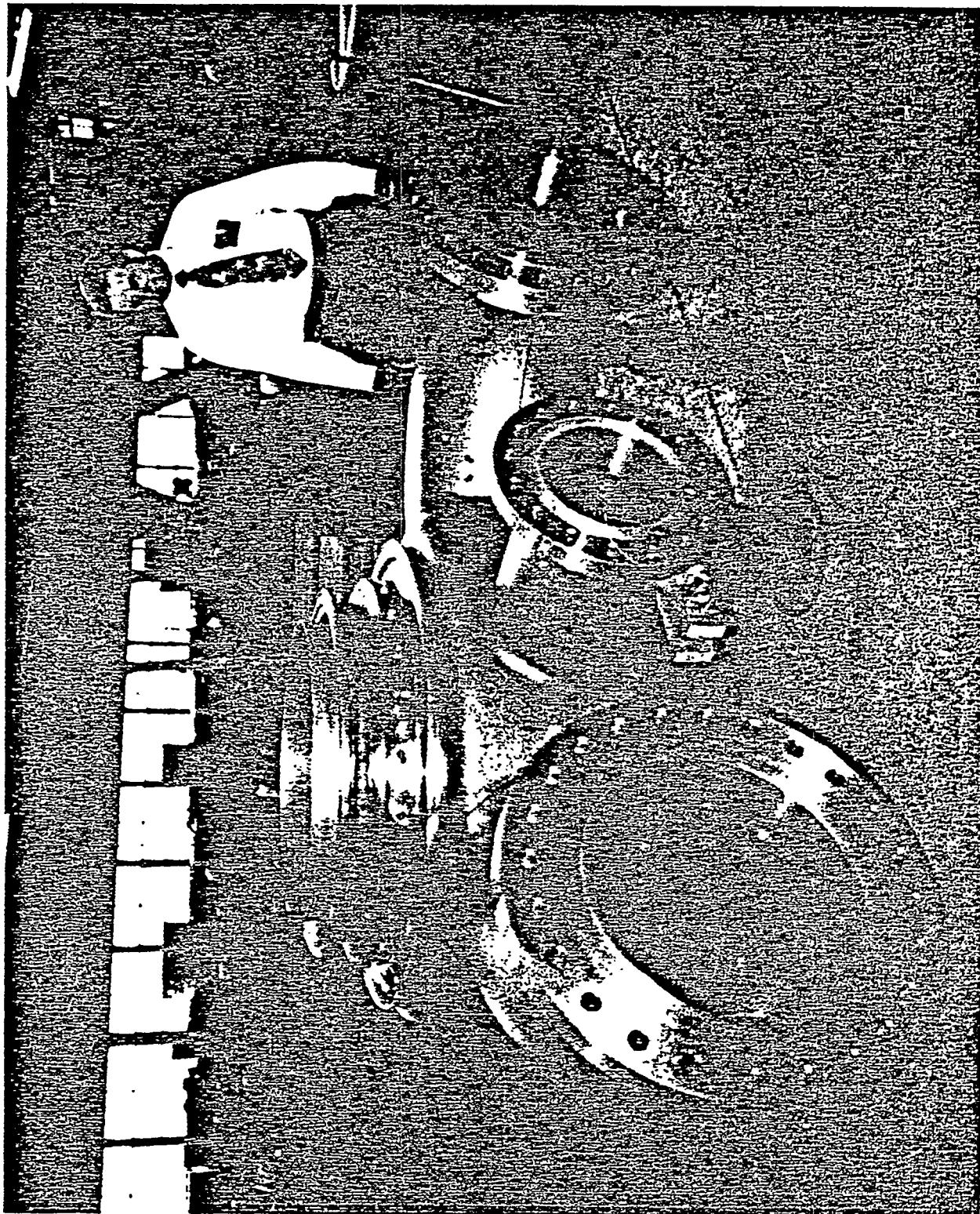
PFB-III-823

AB-326



AB-327

PFB PILOT PLANT COMBUSTOR AIR EXCHANGE HOUSING



AB-328

PFB-III-826

PRESSURIZED FLUIDIZED BED PILOT PLANT

R&D OBJECTIVES

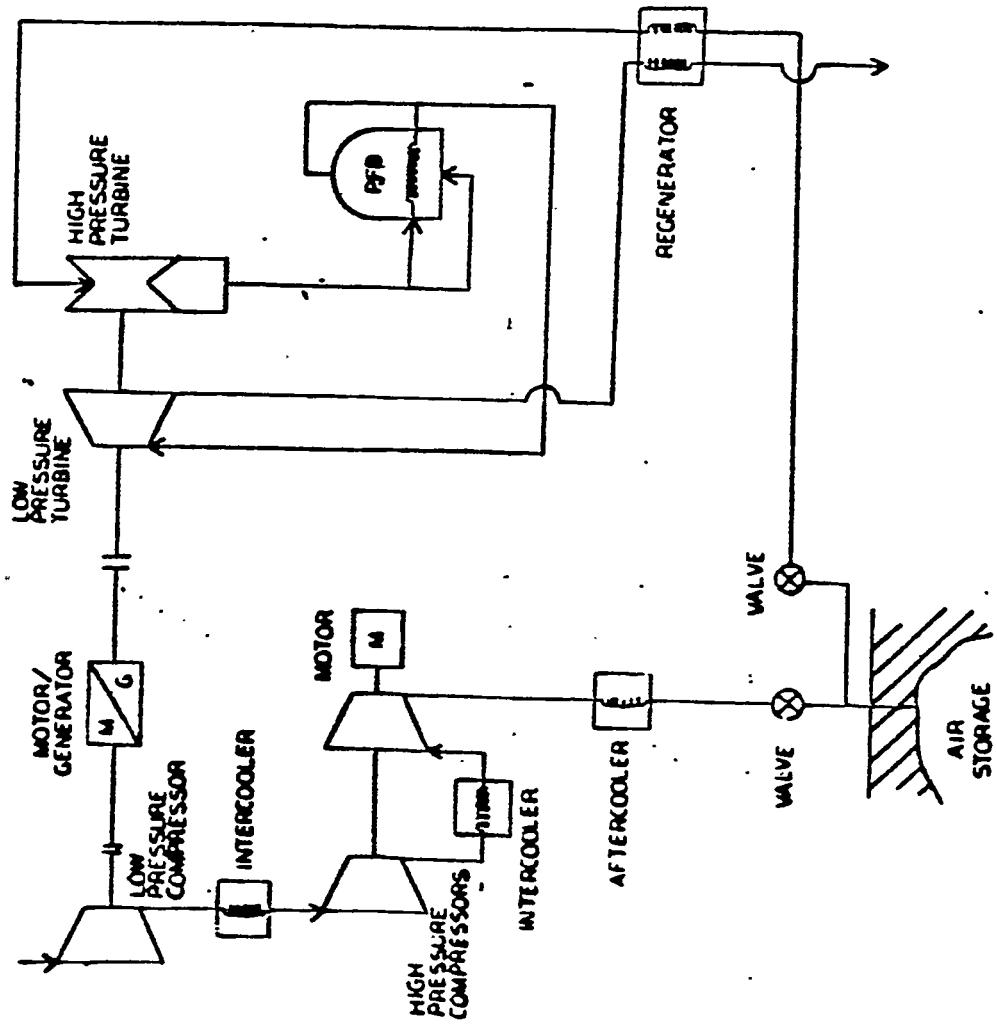
- LONG TERM MATERIAL CONFIRMATION
 - TURBINE BLADING
 - IN-BED HEAT EXCHANGER
- MULTI-STAGE TURBINE EROSION/CORROSION/DEPOSITION
- MULTIPLE COAL FEED - EFFECT ON COMBUSTION EFFICIENCY, EMISSIONS, GAS CONDITION AND BED TEMPERATURE UNIFORMITY
- SCALE-UP EFFECT ON HOT GAS CLEAN-UP PERFORMANCE
- INTEGRATED CONTROL SYSTEM
 - PFB/GAS TURBINE/WASTE HEAT BOILER

PFB- III-774

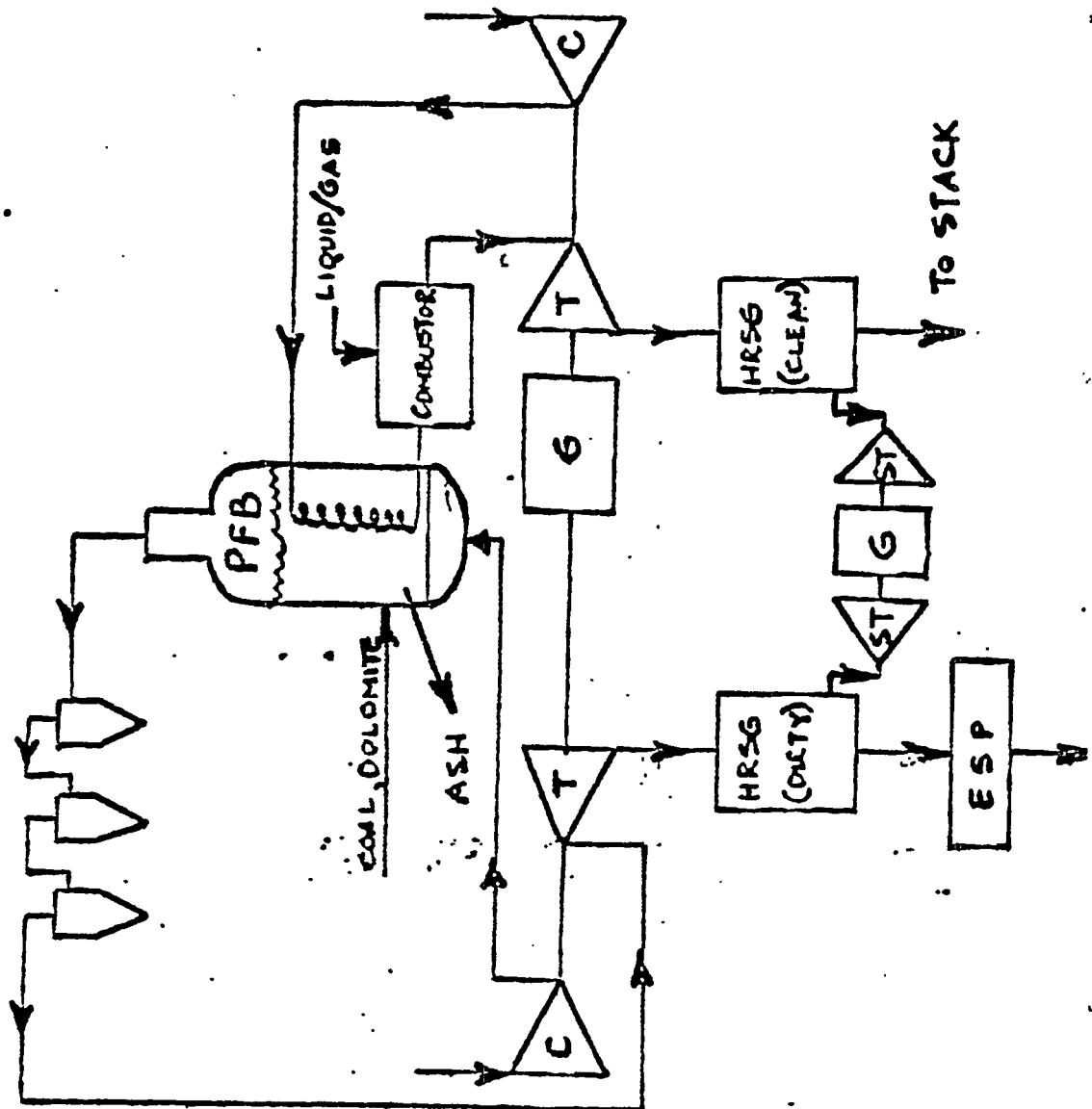
ALTERNATIVE CONCEPTS FOR AIR COOLED PFB

AB-330

FLOW DIAGRAM OF COMPRESSED AIR ENERGY STORAGE (CAES)
WITH COAL FIRED PFB



PFB AIR HEATER DESIGN WITH SUPPLEMENTARY FIRING



CURTIS WRIGHT CORP.

SUPPLEMENTARY FIRED AIR CYCLE PFB

Turbine Inlet °F	1594 (mixed)	Supplementary Firing		Combined Cycle Repowering
		Commercial PFB Plant	Current Turbine Cooling	
Clean Turbine	2200		2750	2066
Dirty Turbine	1450		1650	1450
Mw/Module	85.1	213.9	236.7	181
Airflow/Module lb/sec	696	1074	1023	1061
Thermal η (HHV)	39.1	44.3	48.0	39.5
Heat Rate (HHV)	8728	7703	7110	8640
MM BTU Fuel/Hr				
Coal	743	1147	724	984
Oil	-	495	957	530
*Fuel Cost Mills/Kwhr	17.81	20.51	22.94	23.18
Bed Dia/Bed Height Ft	30.75/16	38.2/16	28/24	34.4/18.5

*Coal @ \$2.04/MM Btu; Oil @ \$4.13/MM Btu

APPENDIX AB-9-3

PRESSURIZED FLUIDIZED COAL COMBUSTION PROGRAM

AT NEW YORK UNIVERSITY

Presented At

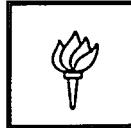
Coal Combustion and Applications Working Group

December 9, 1982

Livingston, New Jersey

by

DR. VICTOR ZAKKAY



THE WORK REPORTED HEREIN WAS SUPPORTED BY
THE DEPARTMENT OF ENERGY UNDER CONTRACT
NO. DE-AS21-80MC-14322

NEW YORK UNIVERSITY
FACULTY OF ARTS AND SCIENCE
DEPARTMENT OF APPLIED SCIENCE

A D V A N T A G E S O F P. F. B. C.

- 1) SUPERIOR ENVIRONMENTAL PERFORMANCE - REMOVE SO₂ AS A DRY SOLID
- 2) ELIMINATING THE NECESSITY FOR ADD-ON SULFUR REMOVAL UNITS
- 3) REDUCED EMISSIONS OF OXIDES OF NITROGEN (NO_X) - LOWER OPERATING TEMPERATURES
- 4) SUBSTANTIAL IMPROVEMENT IN THE HEAT TRANSFER FILM COEFFICIENT (AS MUCH AS 20 TIMES THAT OF EXISTING COAL COMBUSTIONS)
- 5) INCREASED SYSTEM EFFICIENCIES BY INCORPORATING A GAS TURBINE TO RECOVER ENERGY FROM THE PRESSURIZED PRODUCTS OF COMBUSTION
 - A) WATER/STEAM - COOLED TUBES IN BED
 - B) AIR-COOLED TUBES IN BED
 - C) NO IN-BED TUBES, WITH ALL HEAT REMOVAL BY AIR BLOWER THROUGH THE BED
- 6) WIDE RANGE OF FUELS POSSIBLE, COAL OF ALL RANKS

MAJOR P. F. B. C. FACILITIES

POWER GENERATING UNITS

<u>BED CROSS SECTION</u>	<u>CURTISS-WRIGHT CORPORATION</u>	<u>AEP STAL Laval</u>	<u>GRIMETHORPE</u>
BED HEIGHT, FT	12' DIA	3' x 6.5' TOP 3' x 3' BOTTOM	6' x 6' SQUARE
BED TEMPERATURE, °F	1650	1560	1560
BED PRESSURE, ATA	6.8	16	10
FLUIDIZATION VELOCITY, FT/S	2.7	3	8.2
POWER OUTPUT	13 MW _E	15 MW _{TH}	80 MW _{TH}
<u>R & D UNITS</u>	<u>CURTISS-WRIGHT CORPORATION</u>	<u>GENERAL ELECTRIC</u>	<u>LEATHERHEAD</u>
BED CROSS SECTION	3' DIA	3' DIA	1' DIA
BED HEIGHT, FT	10'	16	5.2
BED TEMPERATURE, °F	1600	1650	1400-1750
BED PRESSURE, ATA	7-10	6.8	10
FLUIDIZATION VELOCITY, FT/S	4	2.7	20
POWER INPUT, MW _{TH}	3.2	2.2	3
		0.5	1.0

SULFUR RETENTION AND CALCINATION

- A) CALCINATION PROCESS IN P, F, B, C.
- B) EFFECT OF PRESSURE ON CALCINATION PROCESS, WITH REGARD TO:
 - 1) LIMESTONE ($CaCO_3$)
 - 2) DOLOMITE ($CaCO_3$ $MgCO_3$)
- C) EFFECT OF TEMPERATURE
- D) EFFECT OF PARTICLE DIAMETER
- E) EFFECT OF EXCESS AIR

COAL ANALYSIS

<u>ULTIMATE ANALYSIS</u>	BITUMINGUS COAL		LIGNITE	
	<u>DRY BASIS %</u>	<u>WET BASIS %</u>	<u>DRY BASIS %</u>	<u>WET BASIS %</u>
Carbon	75.72	73.44	63.51	41.05
Hydrogen	5.50	5.34	3.26	6.03
Nitrogen	1.50	1.46	3.85	0.55
Sulphur	3.22	3.12	1.49	0.97
Oxygen	6.29	6.10	18.60	8.00
Chlorine	0.09	0.087	--	--
Ash	7.68	7.45	12.30	8.00
Moisture	--	3.00	---	35.40
Heating Value	13,800 Btu/lb		10,417 Btu/lb	

SORBENT ANALYSIS

	DOLOMITE	LIMESTONE
Calcium Carbonate	54.60%	94.04%
Magnesium Carbonate	44.70%	1.46%
Silicon Dioxide	0.40%	1.16%
Aluminum Oxide	0.35%	0.24%
Iron Oxide	0.05%	--
Moisture	--	3.00%

FUTURE PROGRAMS AT NYU IN PRESSURIZED FLUIDIZED BED COMBUSTION

- 1) TESTS WITH LIGNITE AND LIGNITE WATER SLURRY
- 2) TESTS WITH EROSION IN EROSION OF HEAT EXCHANGER TUBES
IN SUPPORT OF THE GRIMETHORPE PROJECT
- 3) ELECTROSTATIC GRANULAR BED TESTS - JOINT PROJECT
WITH GENERAL ELECTRIC
- 4) ADVANCED MODULAR CELLS PFBC CONCEPT
- 5) GAS TURBINE STUDIES TO PROVIDE ADDITIONAL SUPPORT
FOR NYU FACILITY

TECHNICAL UNCERTAINTIES

- 1) HOT GAS CLEANUP/TURBINE PERFORMANCE
 - A) TURBINE EROSION
 - B) TURBINE DEPOSITION
 - C) PRESENCE OF ALKALI METALS, AND SULFUR OXIDES
- 2) MATERIAL PROBLEM FOR RELIABILITY IN BED TUBE EROSION
- 3) SULFUR RETENTION AT HIGH PRESSURE
- 4) FEED WITH RUN OF THE MINE COAL

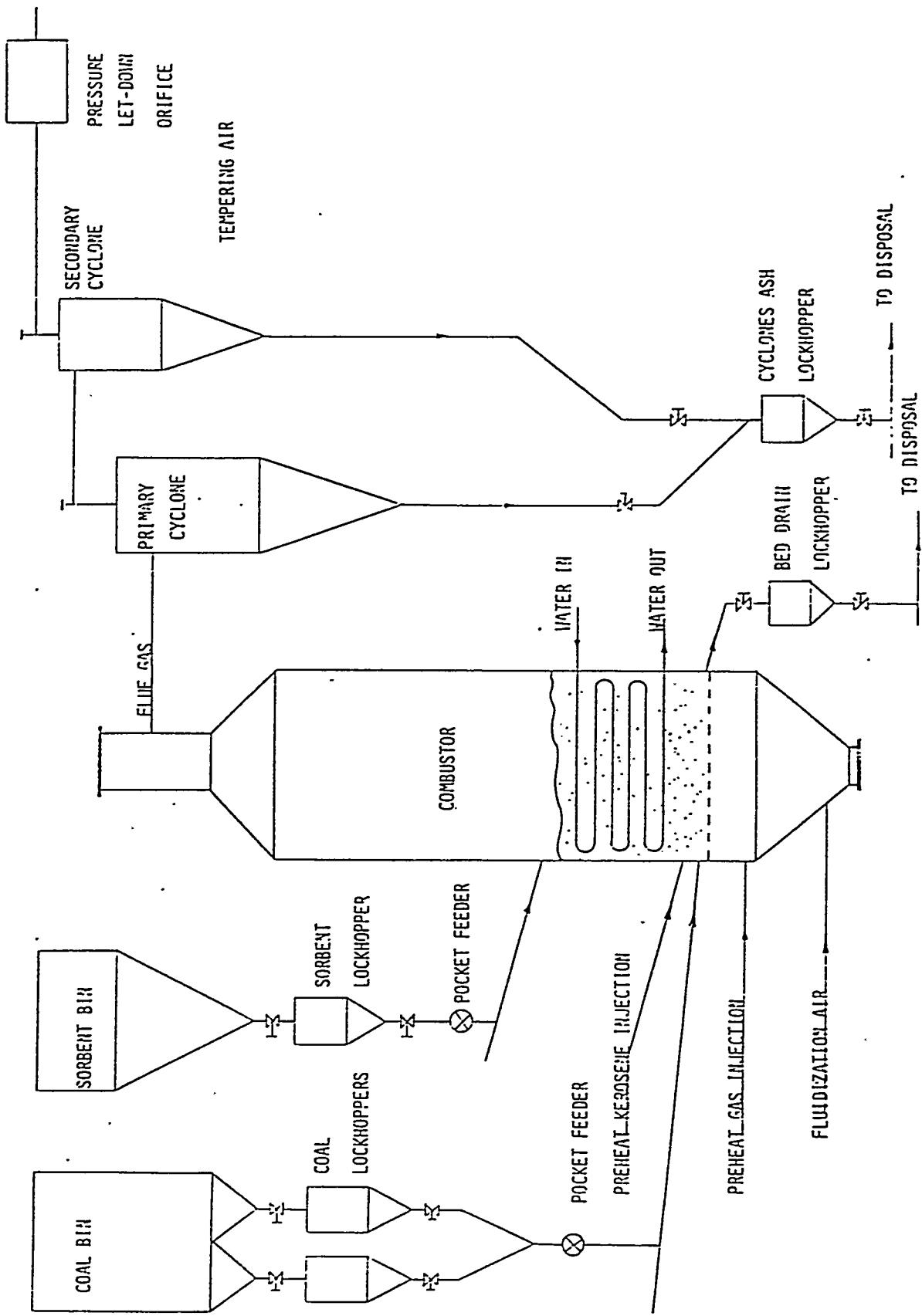
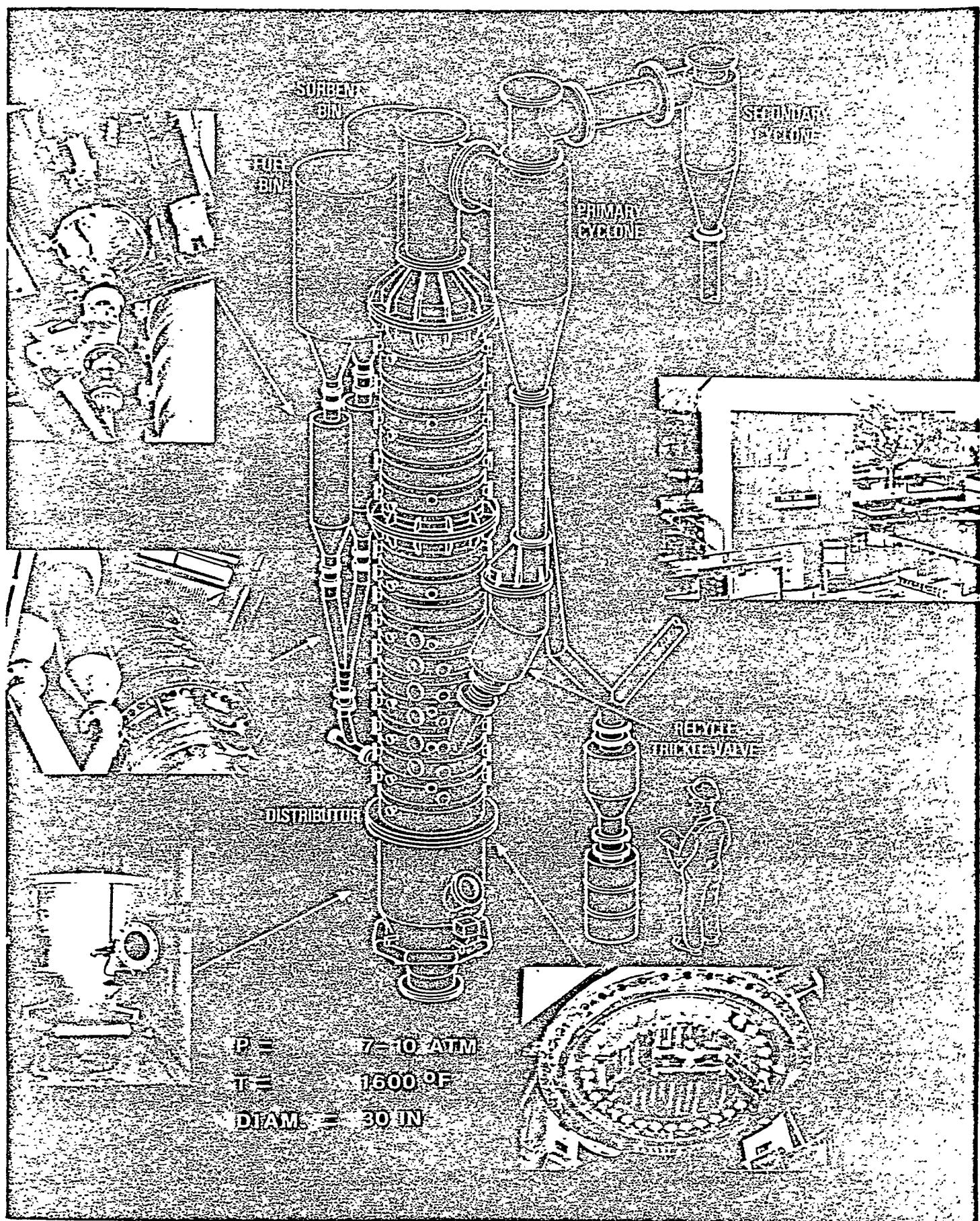
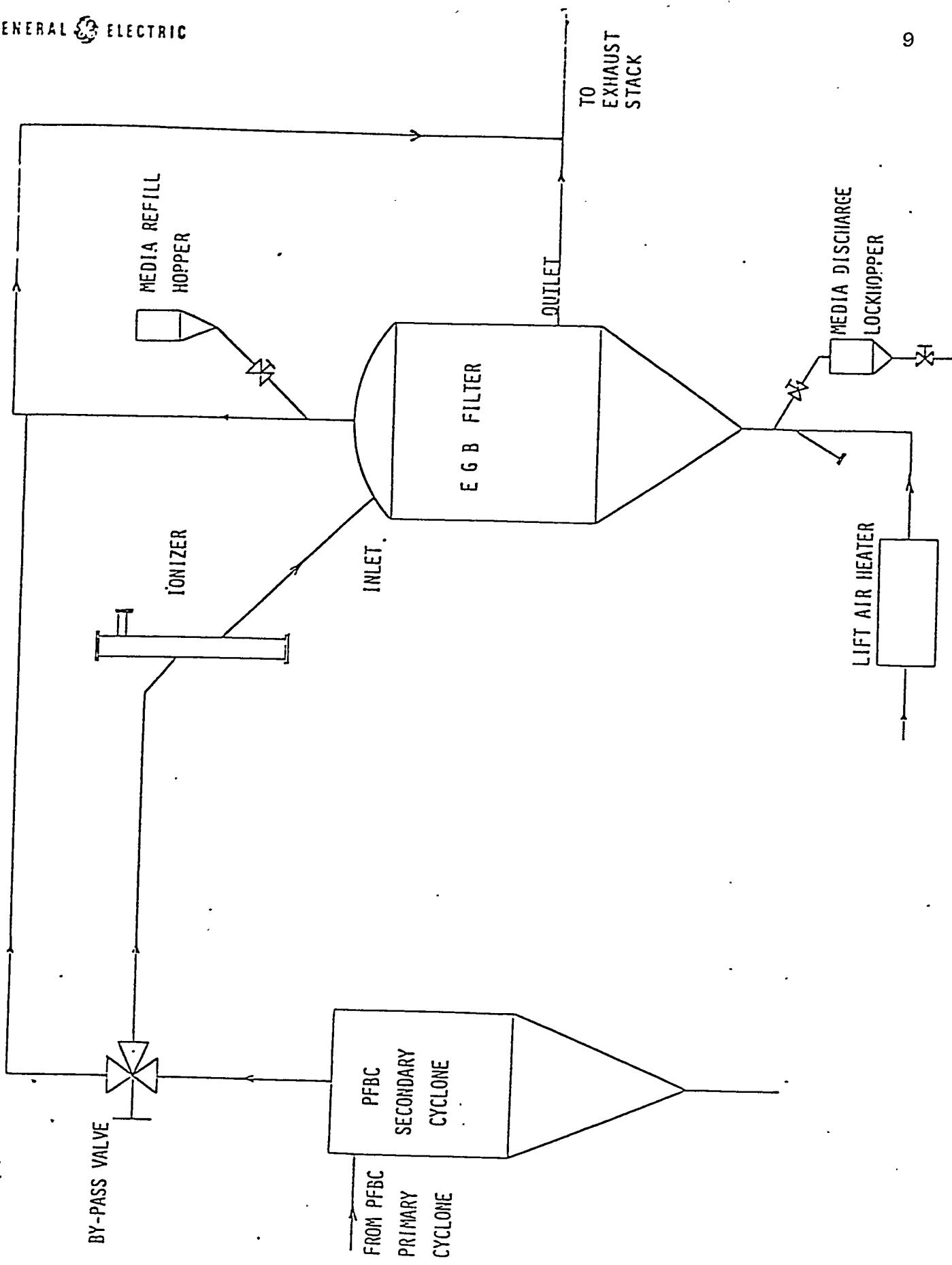


FIGURE III.1 NYU-DOE PRESSURIZED FLUIDIZED BED COMBUSTOR FACILITY





AB-343

FIGURE 5-2. EGB-PFB FILTER INTEGRATION

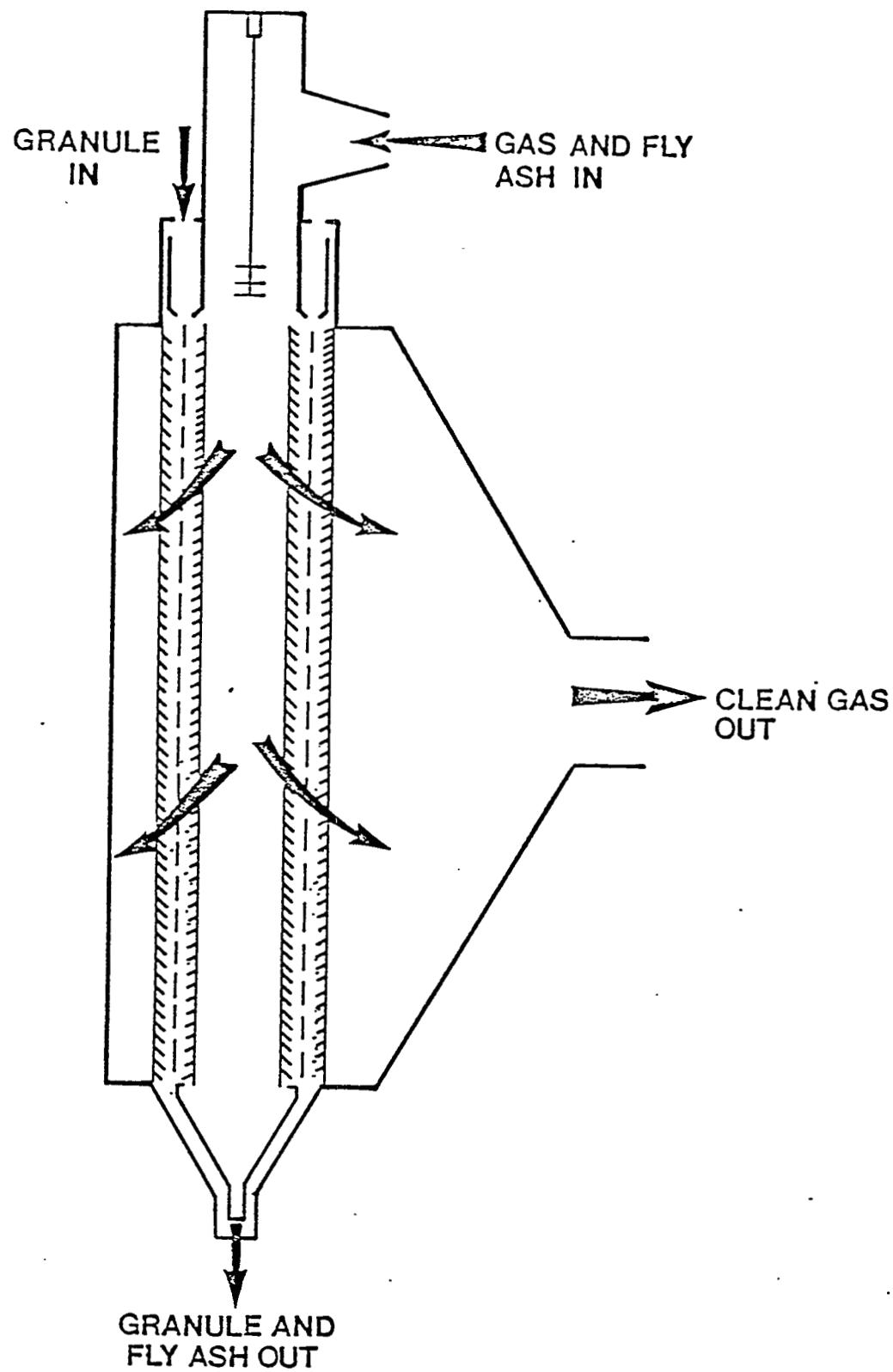


Figure 2-3. Schematic of EGB Filter Element

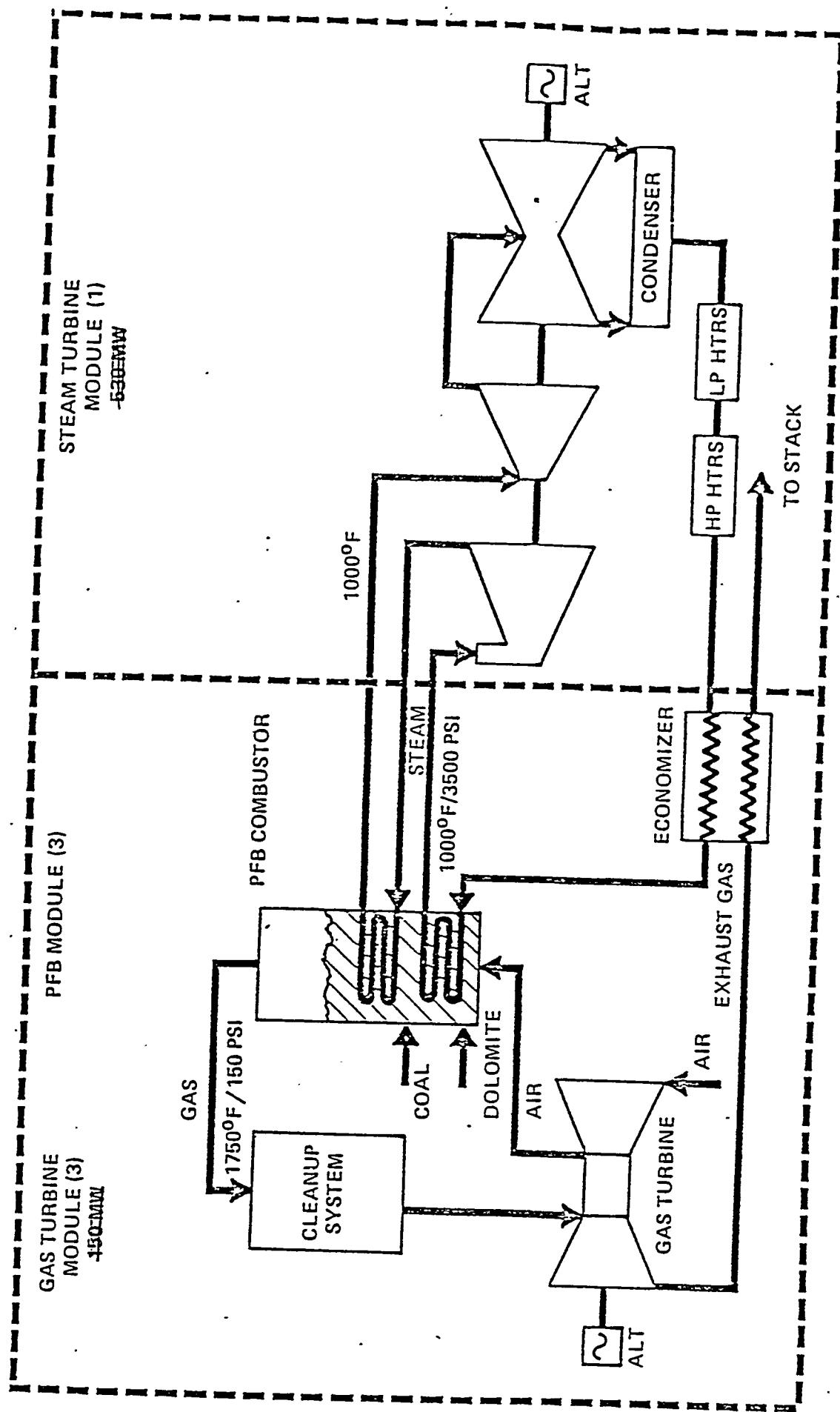


Figure 2-1. Pressurized Fluidized Bed Powerplant Schematic

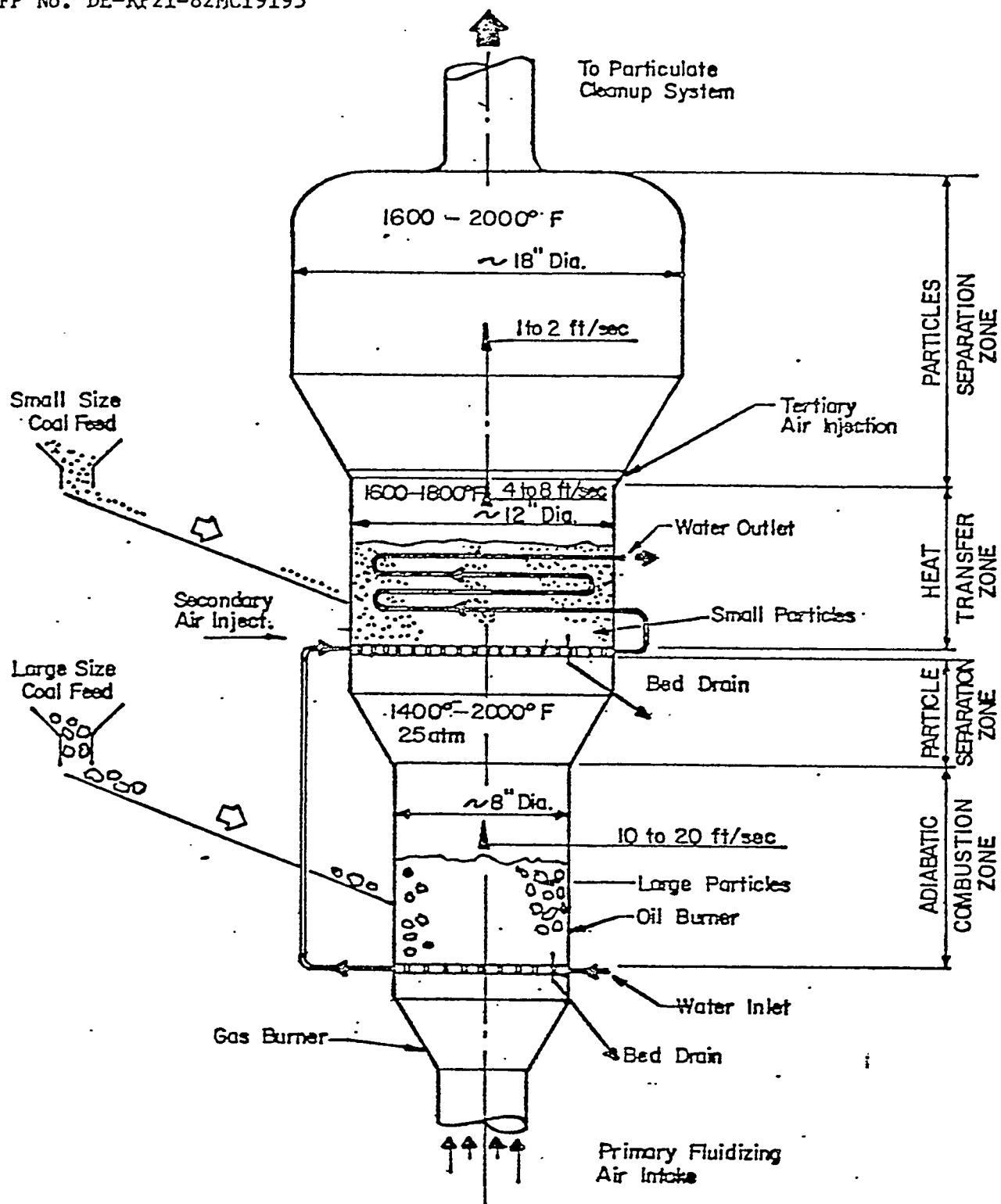


EXHIBIT II-1

NYU's ADVANCED MODULAR-CELL PFBC CONCEPT

GAS PREHEAT SYSTEM - (Scheme)

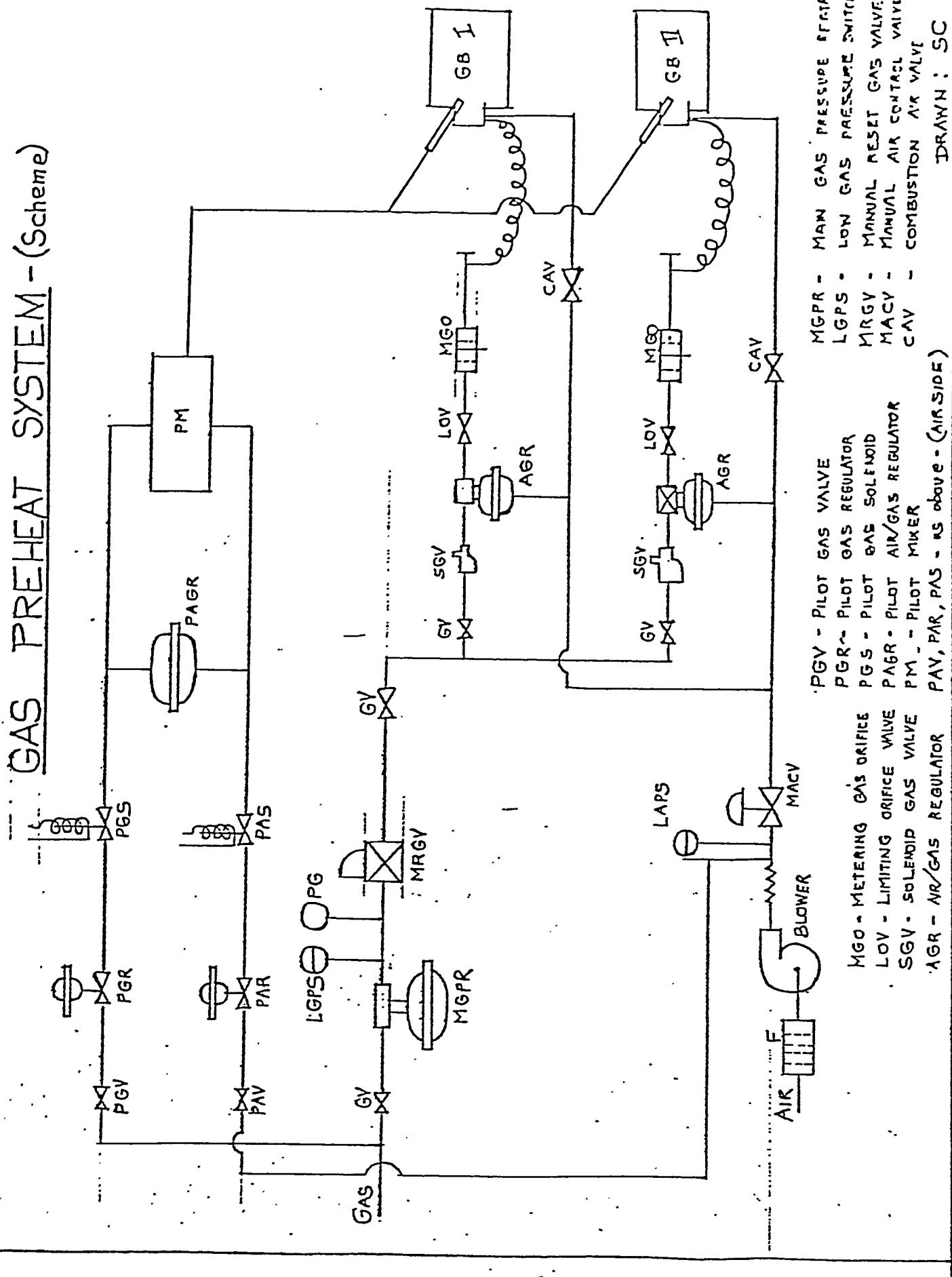


FIGURE 111.4 GAS PREHEAT SYSTEM

KEROSENE INJECTION SYSTEM - (Scheme)

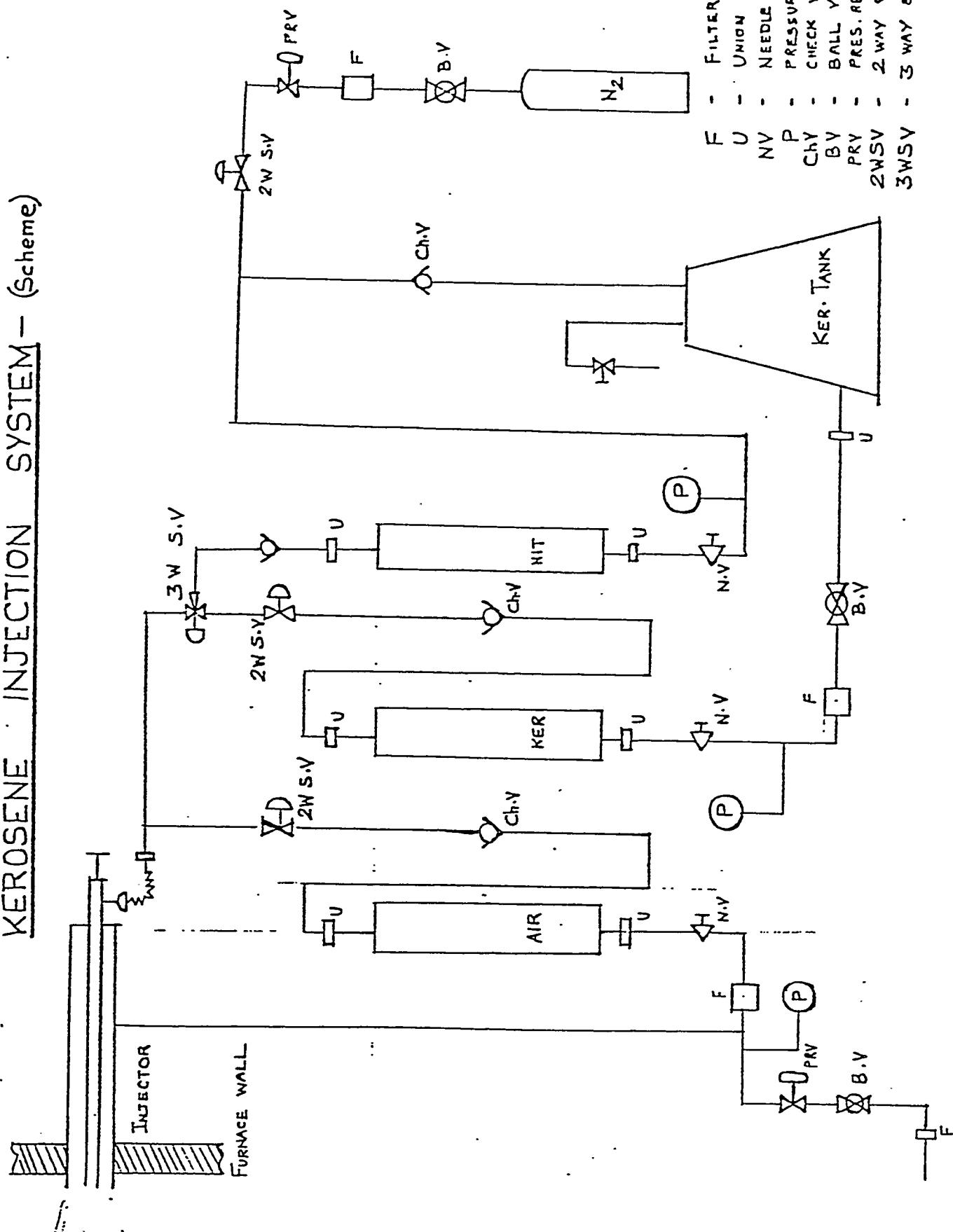


FIGURE III.5 KEROSENE PREHEAT SYSTEM

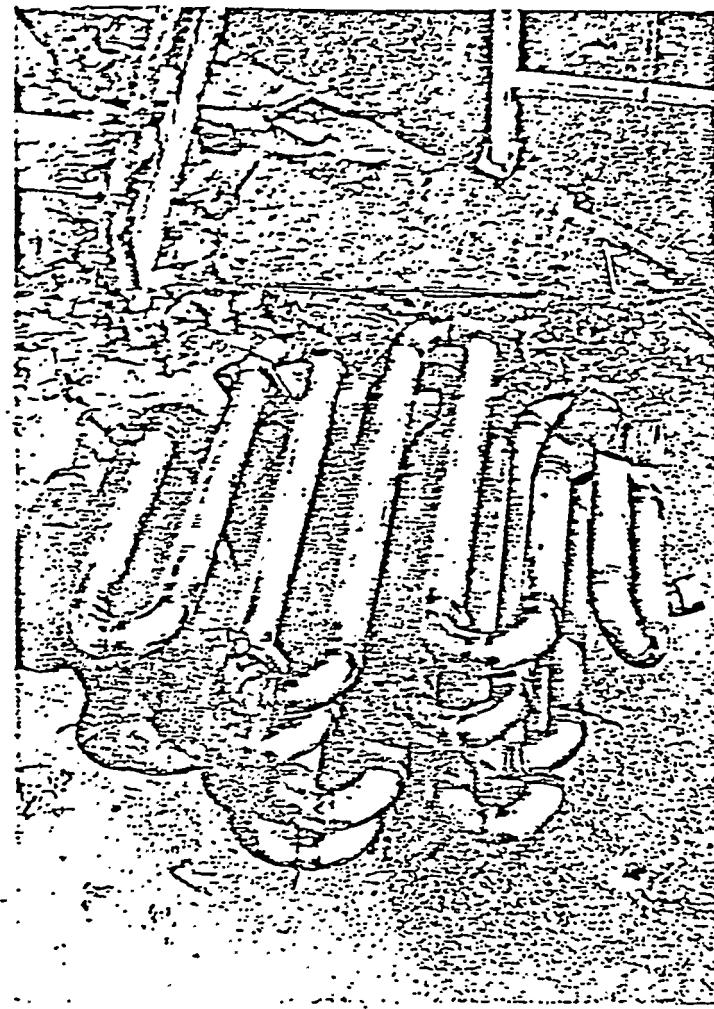
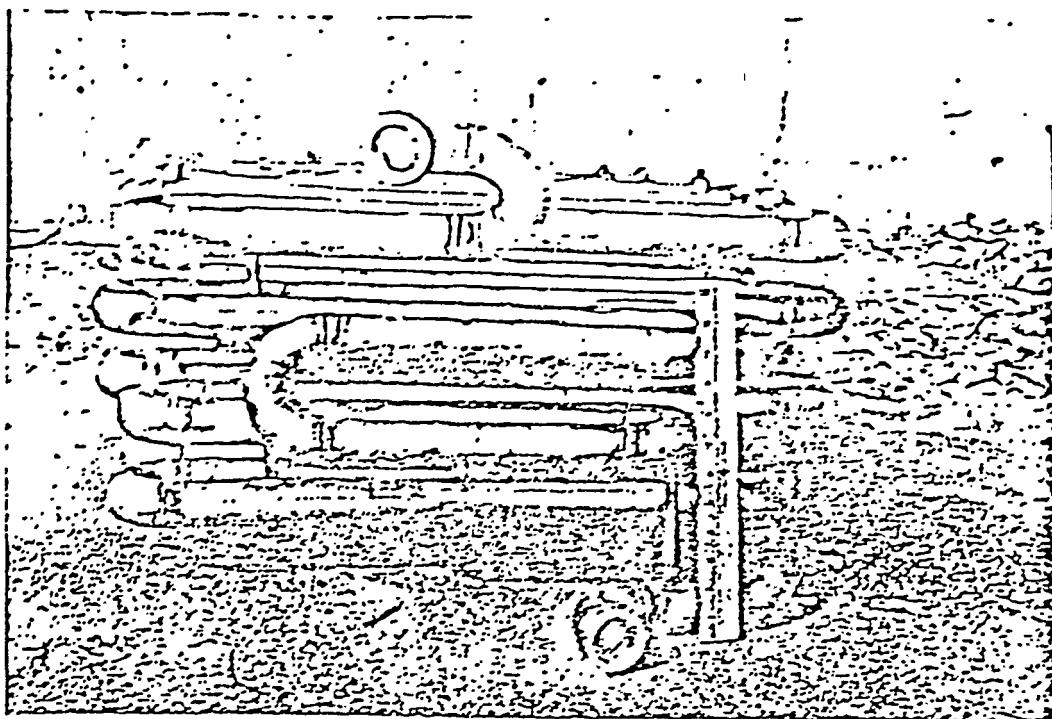


FIGURE 111.6 HEAT EXCHANGER BUNDLE

AB-349

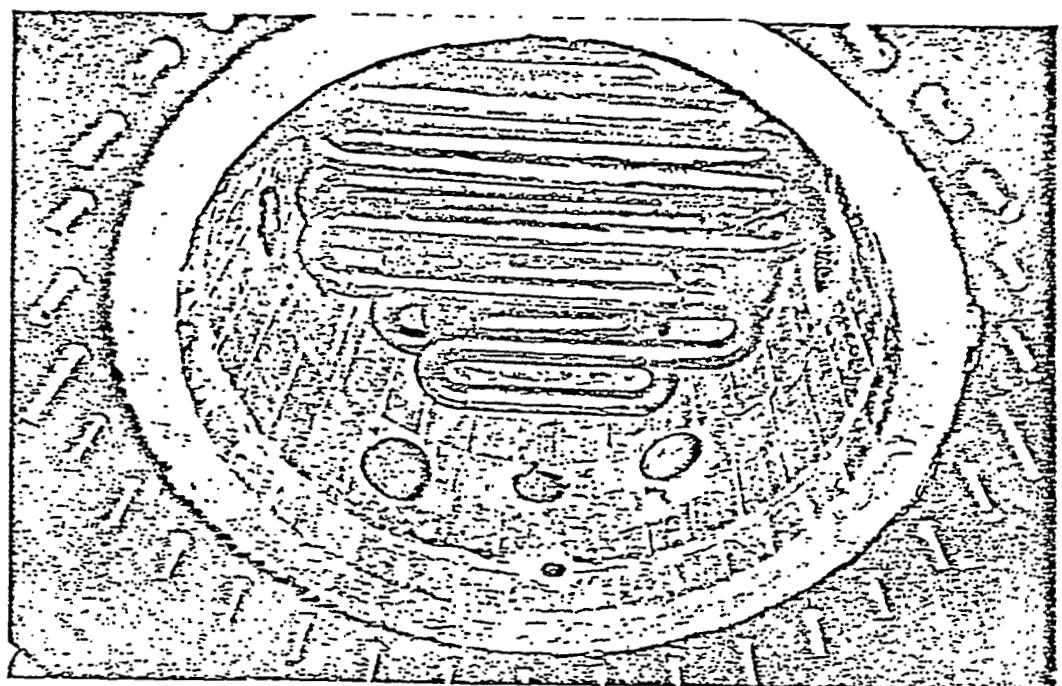
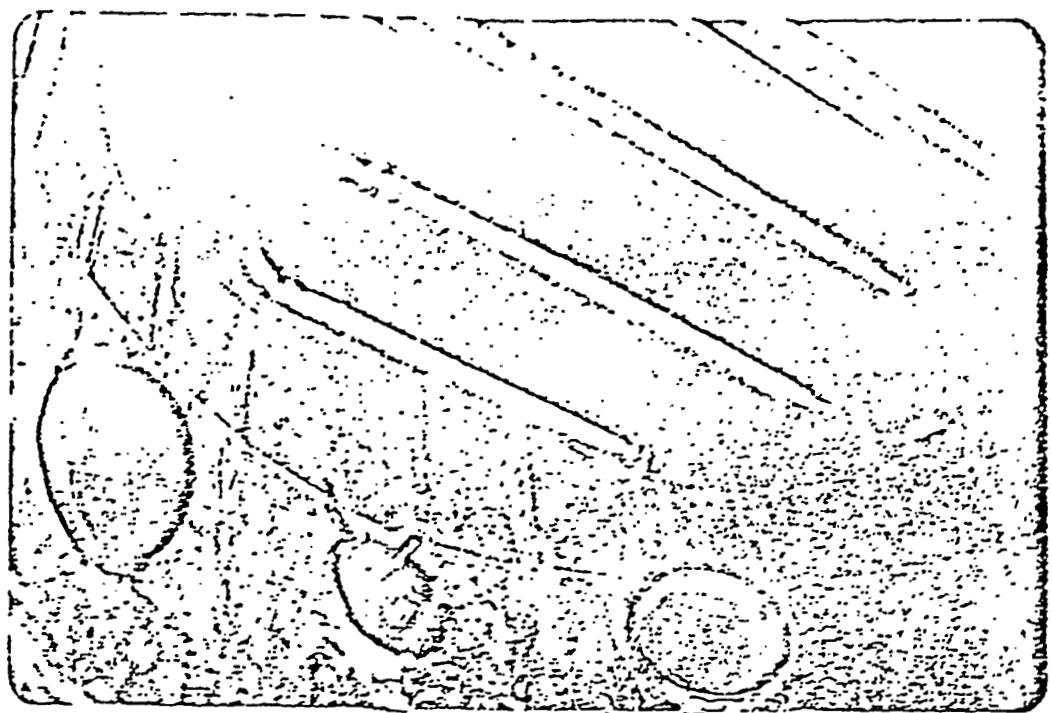


FIGURE III.7 HEAT EXCHANGER LOCATION
AB-350

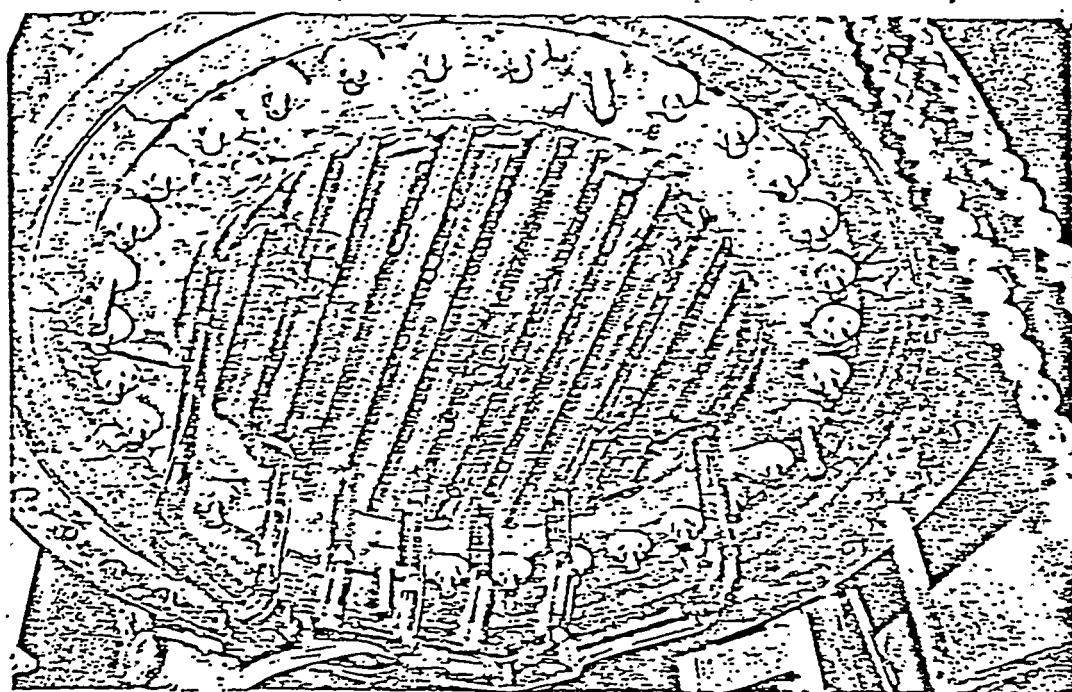
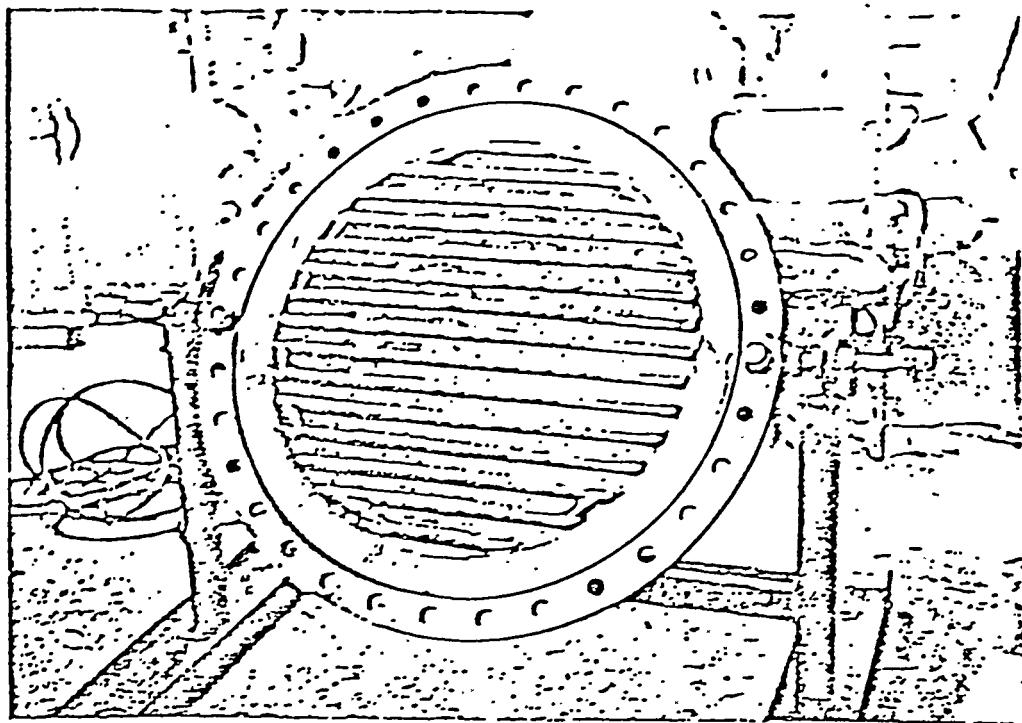


FIGURE III.10 DISTRIBUTOR PLATE, TOP AND BOTTOM VIEWS

AB-351

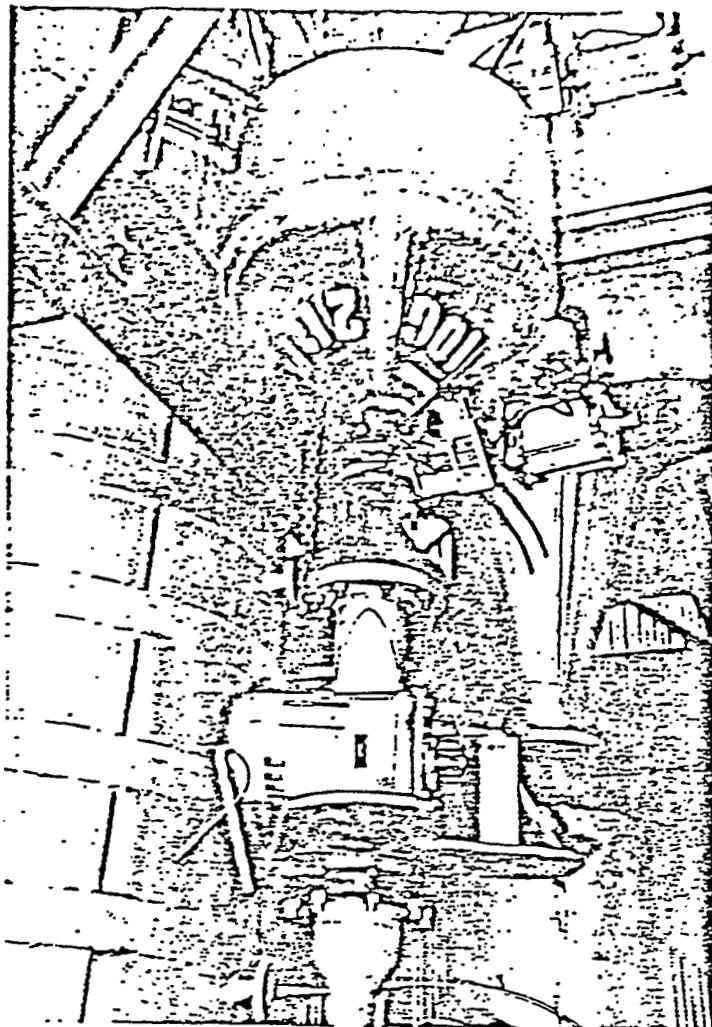
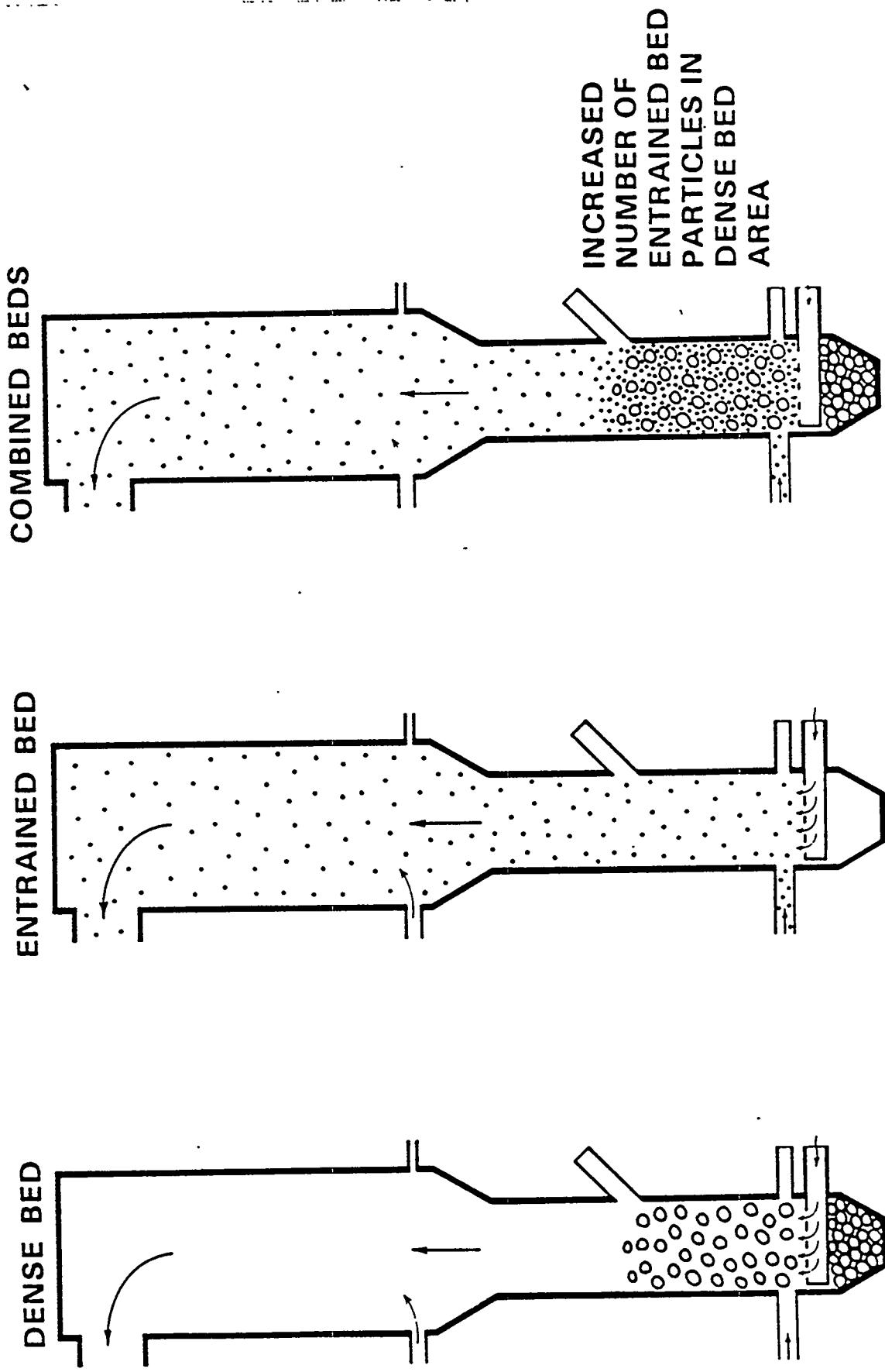


FIGURE III.12 SORBENT FEED SYSTEM

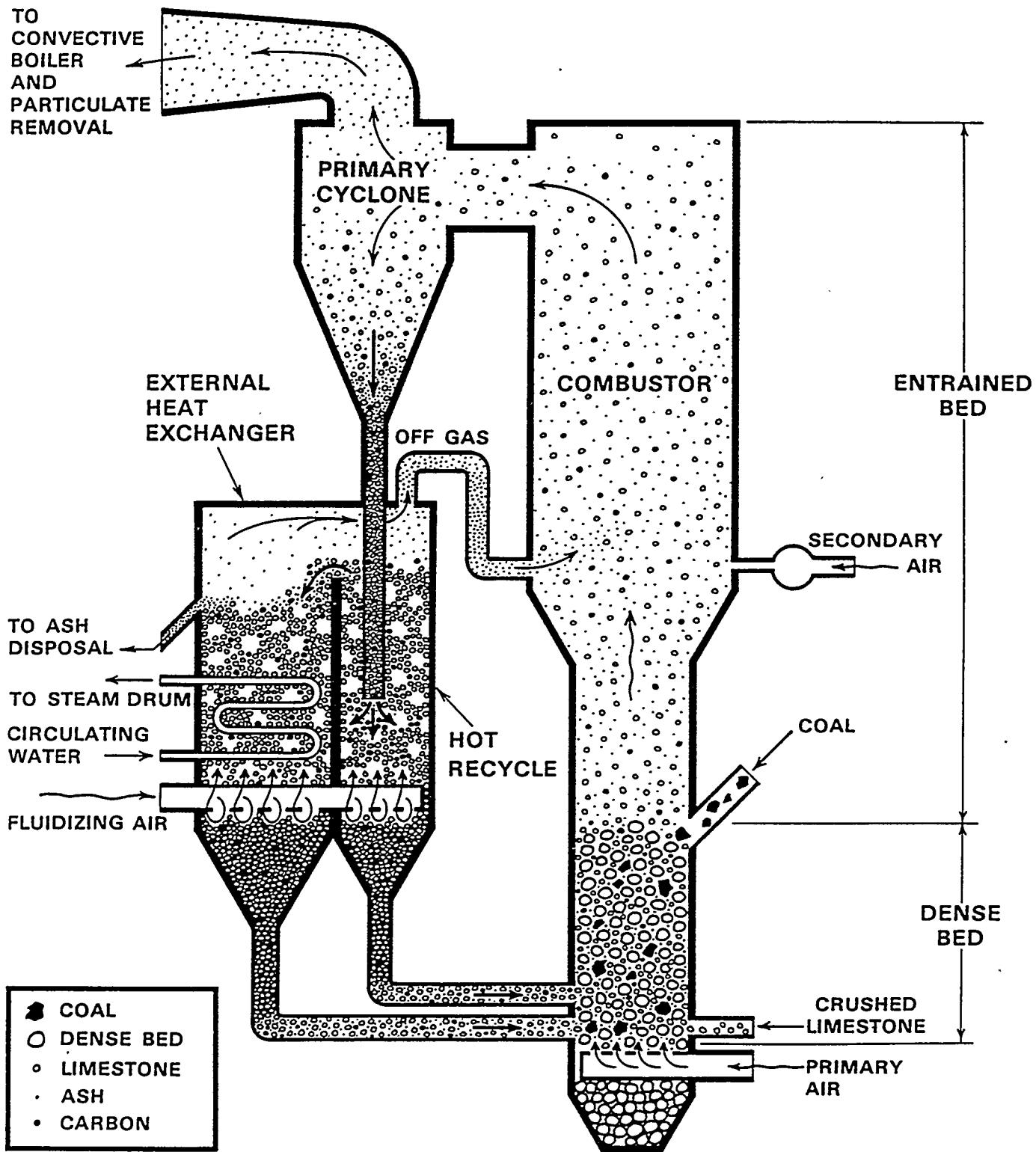
GOALS OF THE BATTELLE MSFB PROGRAM

- ENABLE EXPANDED USE OF SOLID FUELS OF ALL TYPES
- DEVELOP HIGH PERFORMANCE COMBUSTION SYSTEM TO MEET CURRENT AND PROJECTED EMISSION STANDARDS
- PROVIDE A TECHNICAL BASIS FOR SYSTEM DESIGN
- COMMERCIALIZE THROUGH LICENSES

BATTELLE MULTISOLID FLUIDIZED BED COMBUSTOR

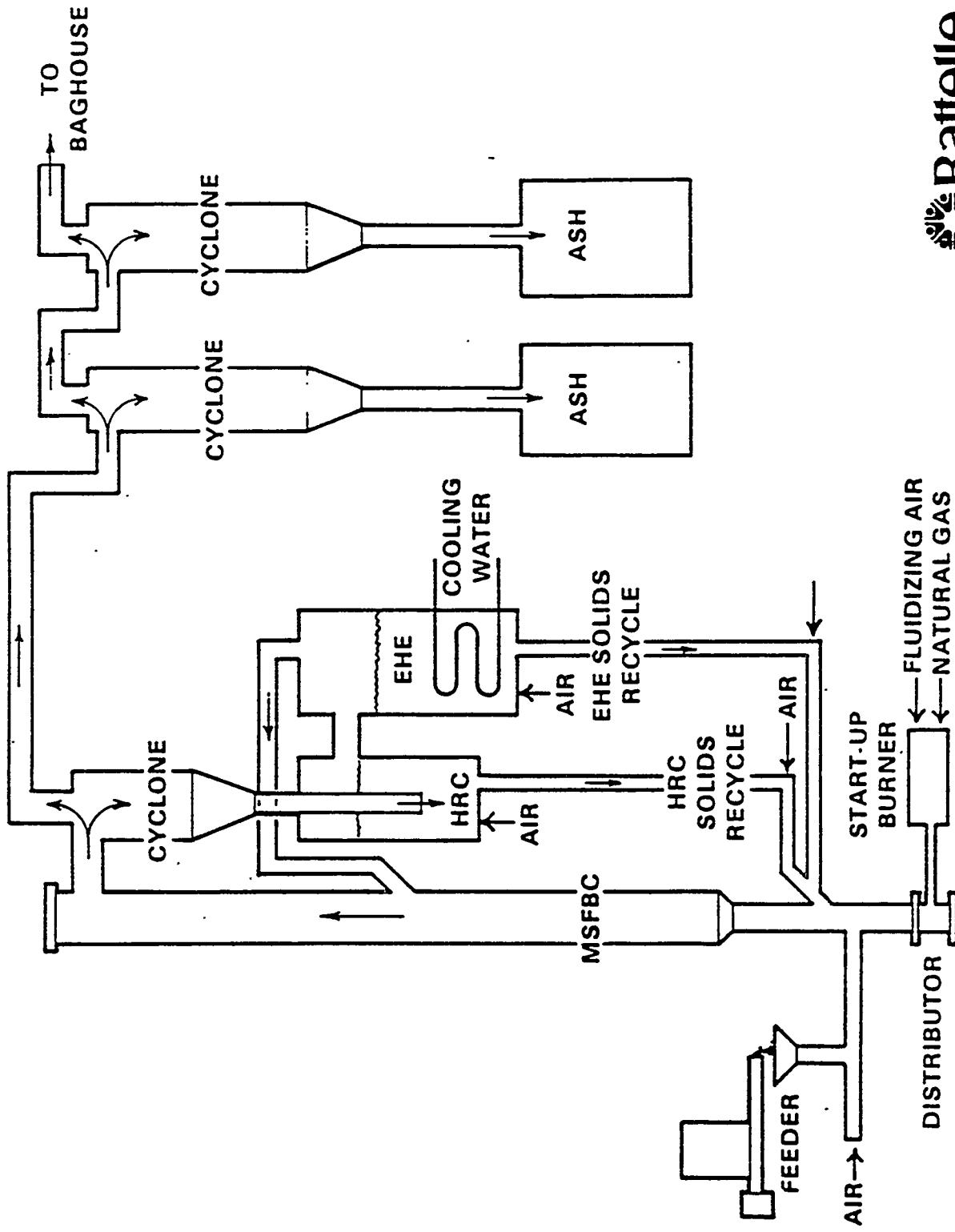


BATTELLE MULTISOLID FLUIDIZED BED COMBUSTOR



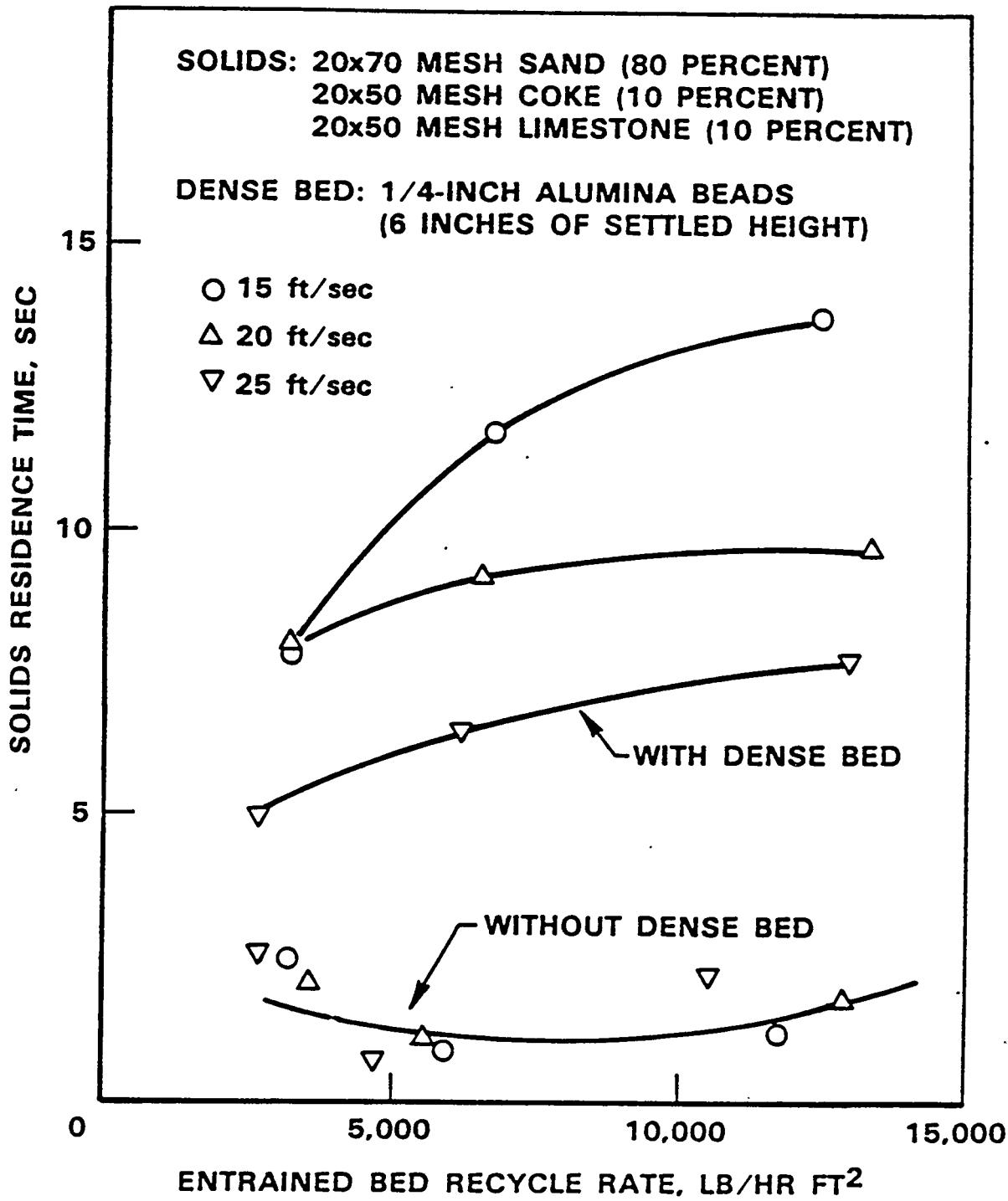
MSFB-0.4 PILOT PLANT

(0.4 x 10⁶BTU/HR)



AB-356

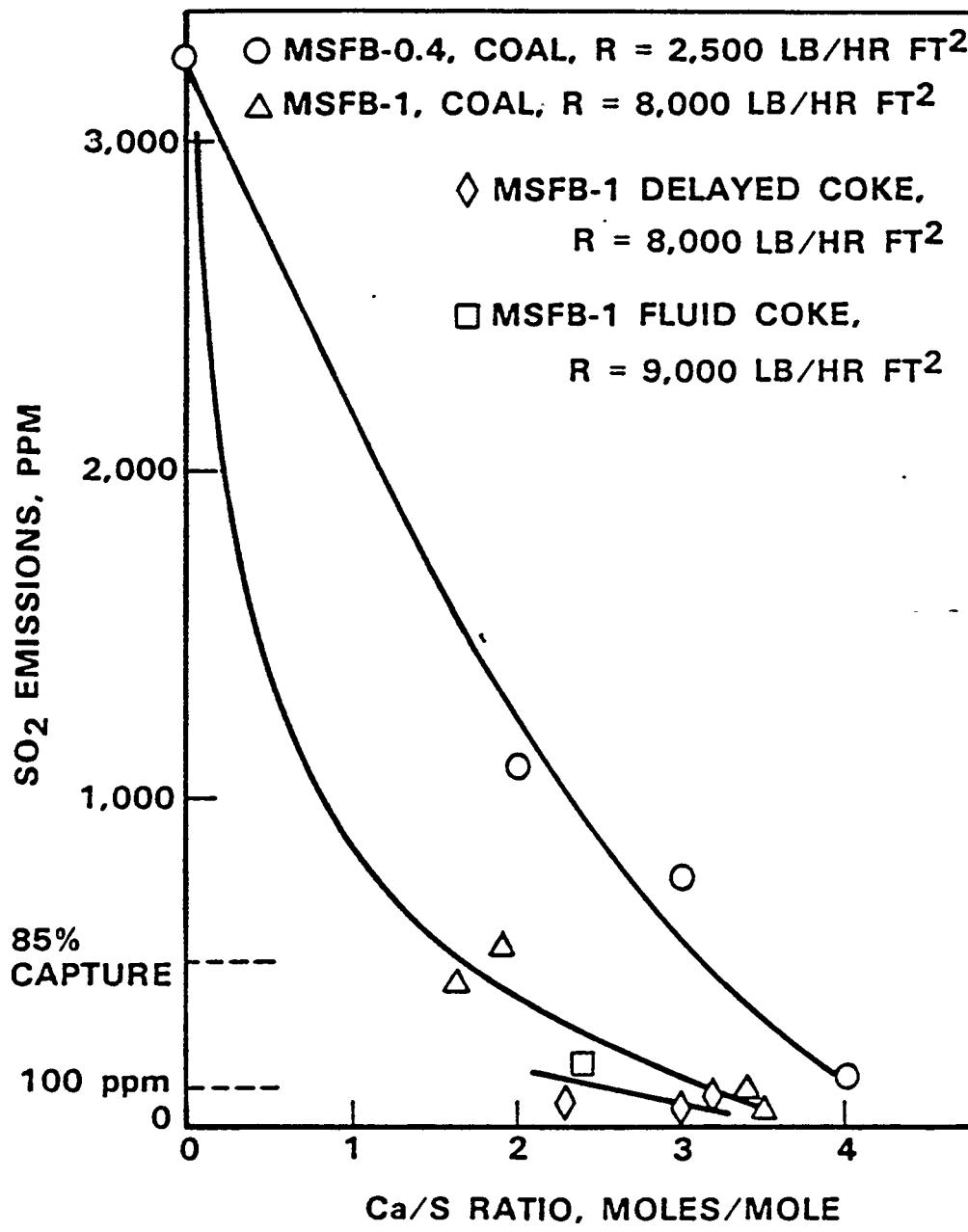
SOLIDS RESIDENCE TIME TESTS



FUELS TESTED IN MSFBC

- COAL
- KRAFT LIQUOR
- WOOD WASTE
- MUNICIPAL WASTE
- SEWAGE SLUDGE
- DELAYED COKE
- FLUID COKE
- CHAR
- ROCK CONTAINING BITUMEN

SULFUR CAPTURE IN MSFBC—EFFECT OF ENTRAINED BED RECYCLE (R)



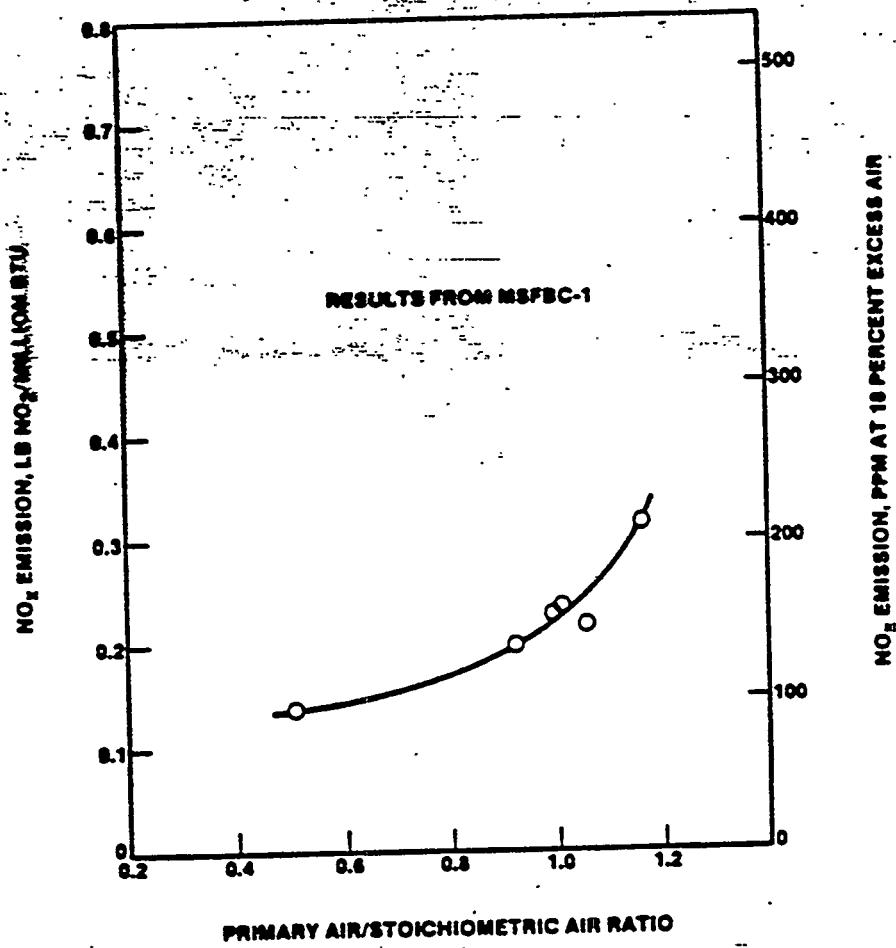


FIGURE 7. EFFECT OF PRIMARY AIR ON
NITROGEN OXIDES EMISSION (COAL)

EFFECT OF STAGED COMBUSTION ON NO_x AND SO₂ EMISSIONS (DELAYED COKE)

	MSFB-0.4	MSFB-1
Total Air/Stoichiometric Air	1.14	1.28
Primary Air / Stoichiometric Air	0.51	0.76
NO _x , ppm*	100	76
Ca/S Ratio	2.9	3.2
SO ₂ , ppm*	91	82
CO, ppm*	412	162

*Corrected to 18% excess air.

COMBUSTION EFFICIENCY IN MSFBC: EFFECT OF FUEL REACTIVITY

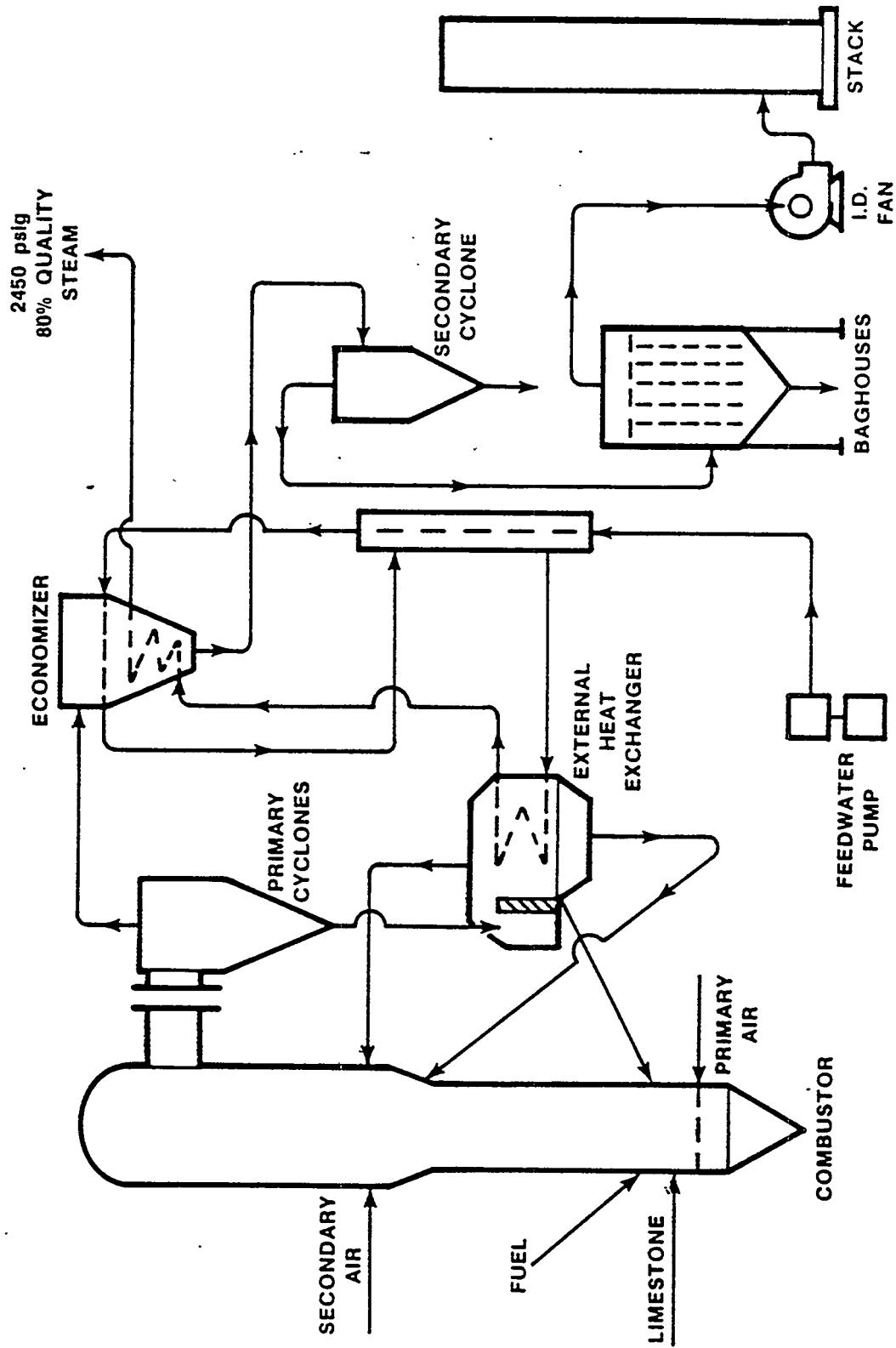
Fuel	Carbon Utilization*	
	MSFB-1	MSFB-0.4
Coal	99	97
Delayed Coke	97	96
Fluid Coke	95	91

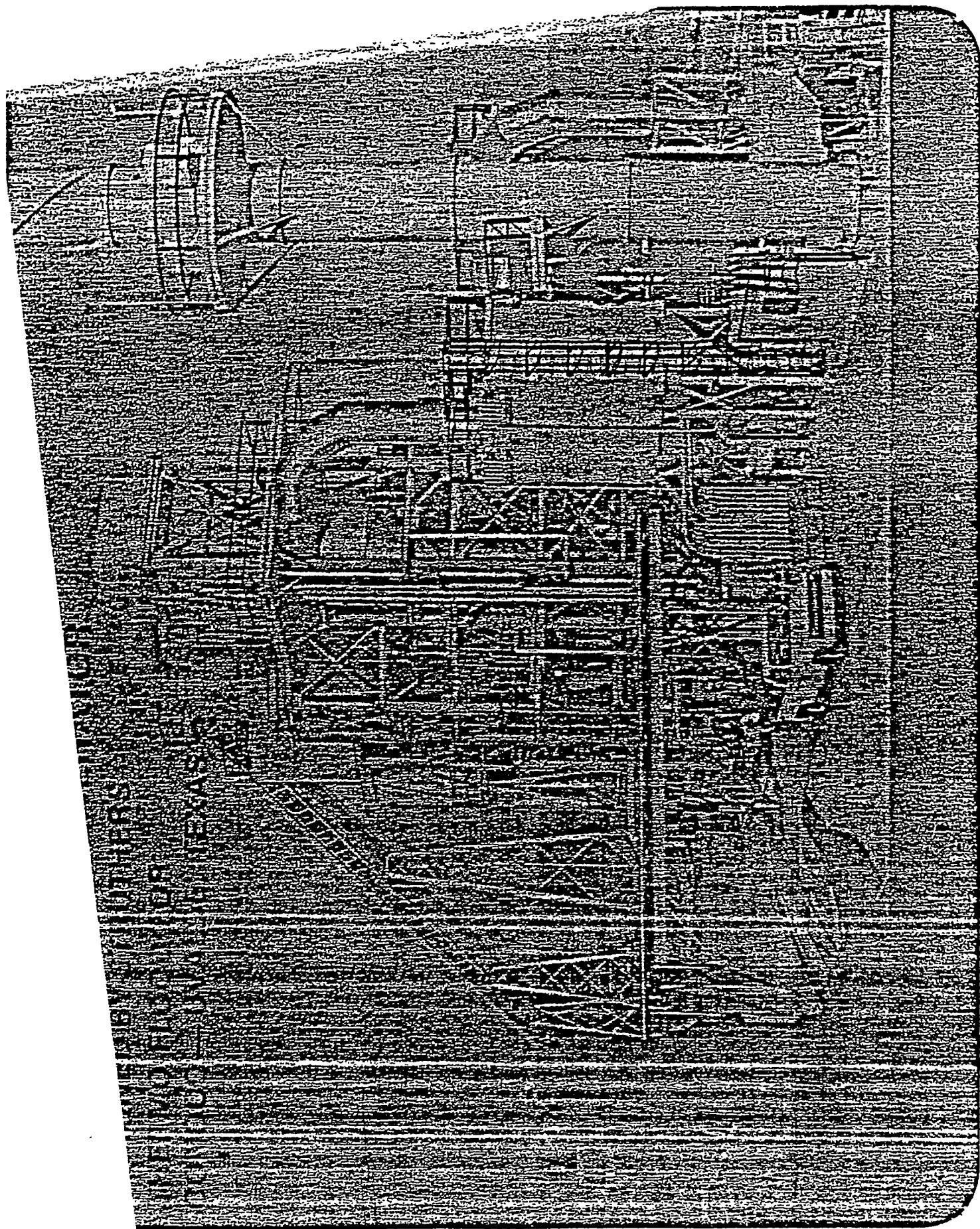
*Without ash recycle.

SUMMARY OF KEY TECHNICAL FEATURES

FEATURE	BENEFIT
INCREASED SOLIDS RESIDENCE TIME	HIGH UTILIZATION OF FUEL AND SORBENT
TURBULENT MIXING	FEWER FEED POINTS; SCALE-UP CONFIDENCE
MINIMUM TREATMENT OF LARGE SIZE FUEL	USE AVAILABLE/LOW COST FUELS
FUEL FLEXIBILITY	USE AVAILABLE/LOW COST FUELS
LIMESTONE FLEXIBILITY	MINIMIZE SUPPLY AND DISPOSAL COSTS
ENVIRONMENTAL CAPABILITY	COMPLY WITH STRINGENT EMISSIONS REGULATIONS
DESIGN FLEXIBILITY	OPTIMIZE COMBUSTION, SORPTION AND HEAT EXCHANGE; GOOD LOAD RESPONSE

**MSFBC SIMPLIFIED PROCESS FLOW DIAGRAM
FOR STEAM FLOOD GENERATOR**





AB-365

PERFORMANCE HIGHLIGHTS OF CONOCO MSEB STEAM GENERATOR

- STARTUP, JANUARY, 1982
- BURN AS-RECEIVED 2" X 0 COAL AND PETROLEUM COKE
LIMESTONE 1/8" X 0
- OVERBED FUEL FEEDING THROUGH DROP PIPE
- 96 PERCENT SULFUR RETENTION AT Ca/S = 3.0
(SULFUR CONTENT OF COAL = 1.50%, COKE = 7.08%)
- CARBON BURNUP > 97%
- BOILER EFFICIENCY, 84.4%
- NO_x AND CO EMISSIONS < 100 PPMV
- 55 DAYS OF CONTINUOUS OPERATION IN LAST TEST RUN

MSFB LICENSES, AND NEGOTIATIONS UNDER WAY

STRUTHERS WELLS

- ENHANCED OIL RECOVERY—EXCLUSIVE WORLDWIDE
- PROCESS HEATERS (NONSTEAM)—NONEXCLUSIVE WORLDWIDE
- INDUSTRIAL AND PROCESS STEAM BOILERS—NONEXCLUSIVE FOR
EUROPE, AFRICA, USSR, INDIA, AND NORTH/SOUTH/CENTRAL
AMERICA [FOR PETROLEUM FUELS ONLY]
- AIR HEATING FOR GAS TURBINE POWER GENERATION—
EXCLUSIVE WORLDWIDE

FOSTER WHEELER POWER PRODUCTS (41K)

- INDUSTRIAL AND PROCESS STEAM BOILERS—EXCLUSIVE FOR
EUROPE, AFRICA, INDIA, AND USSR WITH STRUTHERS WELLS
EXCEPTION

RILEY STOKER

- INDUSTRIAL AND PROCESS STEAM BOILERS—EXCLUSIVE FOR
NORTH/SOUTH/CENTRAL AMERICA WITH STRUTHERS WELLS
EXCEPTION
- UTILITY STEAM BOILERS—EXCLUSIVE FOR NORTH/SOUTH/CEN-
TRAL AMERICA

FOSTER WHEELER

Industrial Fluidized Bed Cogeneration System at the Shell Nederland Raffinaderij Europoort Tank Farm

W. R. Kelly

Manager

Contract Operations

J. M. Rourke

Project Manager

Contract Operations

S. R. Moore

Manager

Start-Up Operation

Foster Wheeler Boiler Corporation

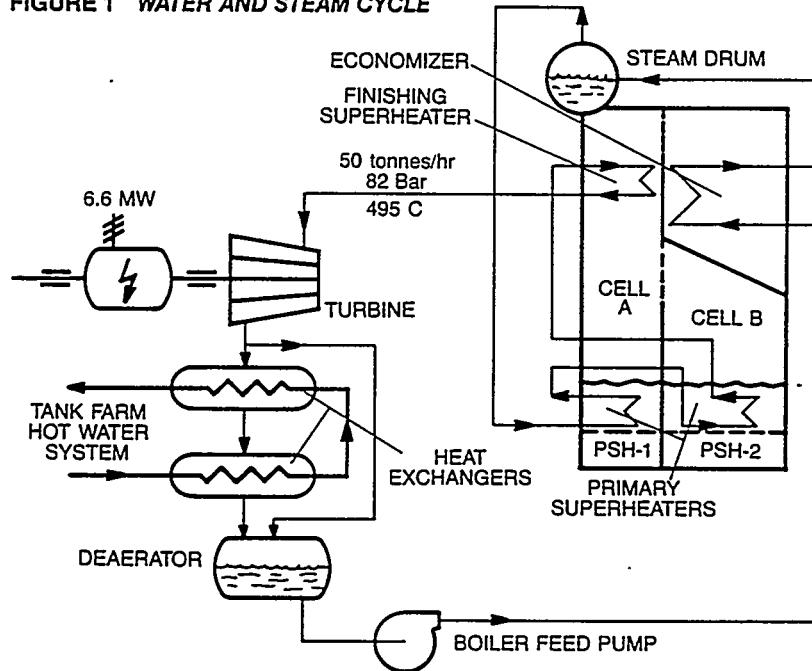
In recent years development work and pilot plant studies into the concept of fluidized bed combustion have given way to ever larger and more ambitious commercial projects. The rapid movement of this technology from the laboratory into industrial application has been fueled by the two primary advantages of fluidized bed combustion: (a) the ability to burn low grade inexpensive fuel and (b) burn it in an environmentally acceptable manner.

In a major contribution to the commercialization of fluidized bed technology, Shell Nederland Raffinaderij (SNR) awarded a contract to Foster Wheeler (FW) for the design, fabrication and erection management of the world's first commercial cogeneration, coal-fired atmospheric fluidized bed boiler ca-

pable of generating superheated steam. The fluidized bed steam generator facility is located at the SNR's Europoort Tank Farm near Rotterdam in the Netherlands. It is designed as a cogeneration facility in which high pressure steam passes to a back-pressure turbine which generates 6.6 MW of electricity (refer to Figure 1). The 7 bar (103 psig) back-pressure steam is then fed to twin heat exchangers, which provide 37 MW of thermal heat energy via medium-pressure hot water to satisfy the heat demand of the tank farm.

This paper will describe the design of the steam generator and subsystems, as well as indicate where specific design features have been modified from previous units' designs to improve performance and reliability.

FIGURE 1 WATER AND STEAM CYCLE



Fluidized Bed Description

A fluidized bed is a mixture of granular limestone or other material supported by a nonsifting grid through which an upward flow of air passes that lifts and fluidizes the bed material. This results in a turbulent mixture of the bed particles, which assume the free flowing property of a liquid and provide an environment for stable combustion. When coal is introduced into this turbulent mixture and burned, the sulfur dioxide released by the burning coal is chemically captured by the limestone. This eliminates the need for an external flue-gas desulfurization system as used on conventional steam generators.

Since the fluidized bed operates at low combustion temperatures (about 850°C, 1560°F) the formation of nitrogen oxides (NO_x) is also held to a minimum. Another advantage of fluidized bed combustion is that boilers can be designed to tolerate and effectively burn a very broad range of fuel qualities, including low grade, high ash coals and solid or liquid waste materials.

Slagging, fouling and corrosion of steam generator surfaces is essentially eliminated because the fluidized bed operates at temperatures which are below the ash softening temperatures of coal fuels. Residue from the system is a dry, granular material suited for easy handling.

The SNR unit represents a considerable refinement of the basic concepts just described. In order to evaluate those refinements, a system-by-system review of the SNR unit is provided in the sequence listed below:

- 1) Steam Generator
- 2) Air and Gas System (including Gridplate Design)
- 3) Material Handling Systems
 - a) Coal Feed
 - b) Limestone Feed
 - c) Spent Bed and Inert Material Handling
 - d) Flyash Capture and Re-injection
- 4) Controls and Load Change Capability
- 5) Start-Up

The steam generator designed for the FBC Europort project is a natural circulation, single drum, balanced draft design. At its maximum continuous firing rate the boiler is capable of producing 50 metric tons per hour (110,250 lb/hr) of superheated steam at 495°C (923°F) and 82 bar gage (1174 psig)

pressure. Steam generator efficiency of approximately 85% is predicted while maintaining a 90% sulfur dioxide capture rate. Additional information concerning design parameters is given in Table 1. Power consumption for the operation of accessory equipment is estimated at 1850 KW. The unit is top supported and consists of two adjacent fluidized bed combustion cells (refer to Figure 2).

Boiler feedwater enters at 145°C (293°F) through a bare tube economizer located within the boiler waterwalls as convection surface above Cell B. Water flows upward in two passes through horizontal tube runs in a counterflow arrangement with downflowing flue gas. This maximizes surface effectiveness and insures stable waterside flow. Water exiting the econ-

TABLE 1

STEAM FLOW	110,250 lb/hr (50 tonnes/hr)
STEAM PRESSURE	1174 psig (82 Bar)
STEAM TEMPERATURE	923°F (495°C)
FEEDWATER	293°F (145°C)
BED DIMENSIONS CELL A	8' x 16'4" (2.44m x 4.99m)
BED DIMENSIONS CELL B	7'6" x 16'4" (2.29m x 4.99m)
BED HEIGHT (EXPANDED)	4' (1.22m)
BED TEMPERATURE	1650°F (899°C)
FLUIDIZING VELOCITY	9 ft/s (2.74 m/s)
FREEBOARD HEIGHT	15' (4.57m)
CALCIUM/SULFUR (MOLAR RATIO)	3
COAL FLOW	14,071 lb/hr (6381 Kg/hr)
DESIGN COAL	BITUMINOUS
HEATING VALUE	11,138 Btu/lb (25,810 KJ/Kg)
ASH	14.0% by wt.
MOISTURE	7.7% by wt.
VOLATILE MATTER	23.0% by wt.
FIXED CARBON	55.3% by wt. } Proximate
SULFUR	0.50% } Analysis
EFFICIENCY	84.9%

FIGURE 2 BOILER PLANT GENERAL ARRANGEMENT

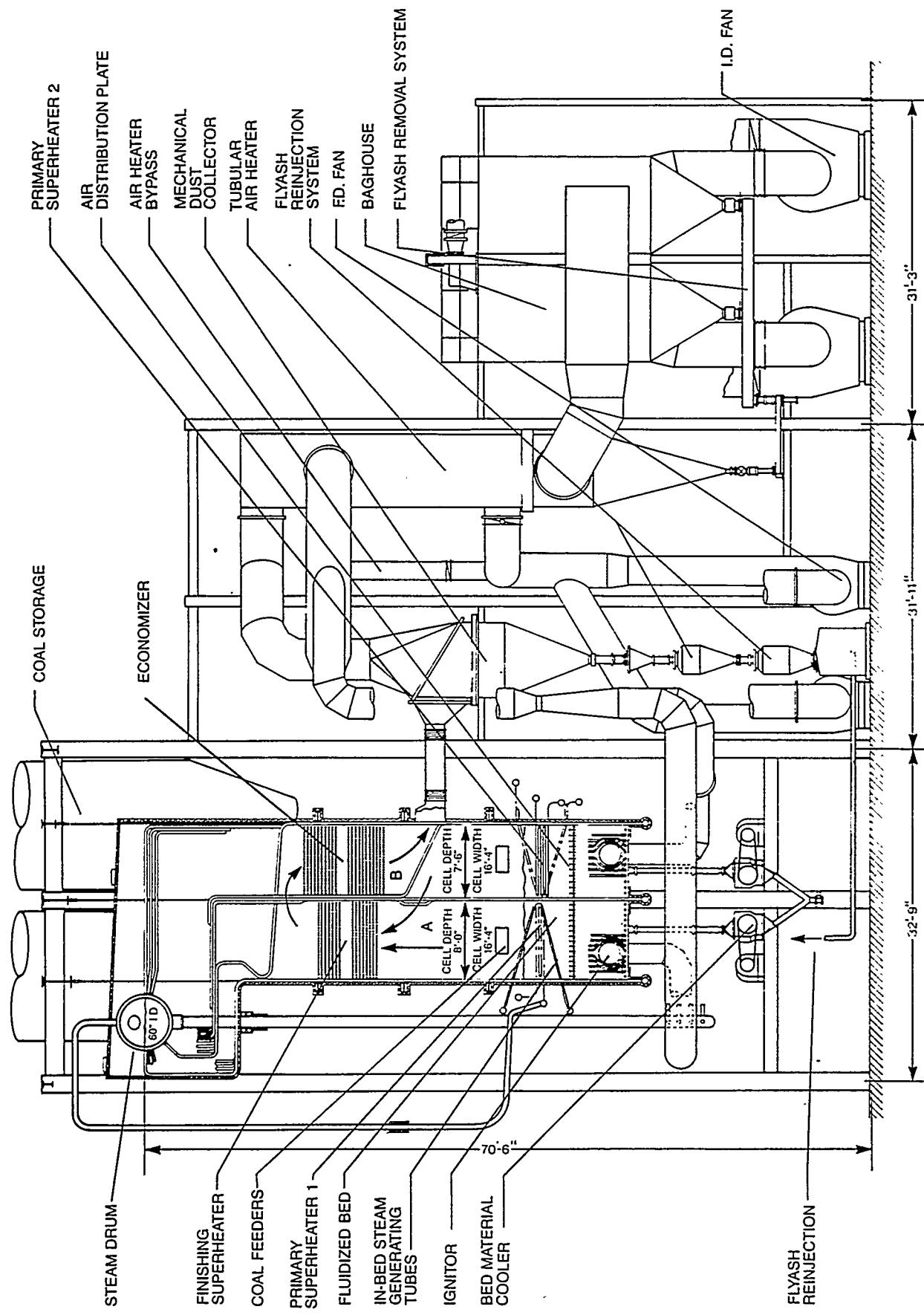
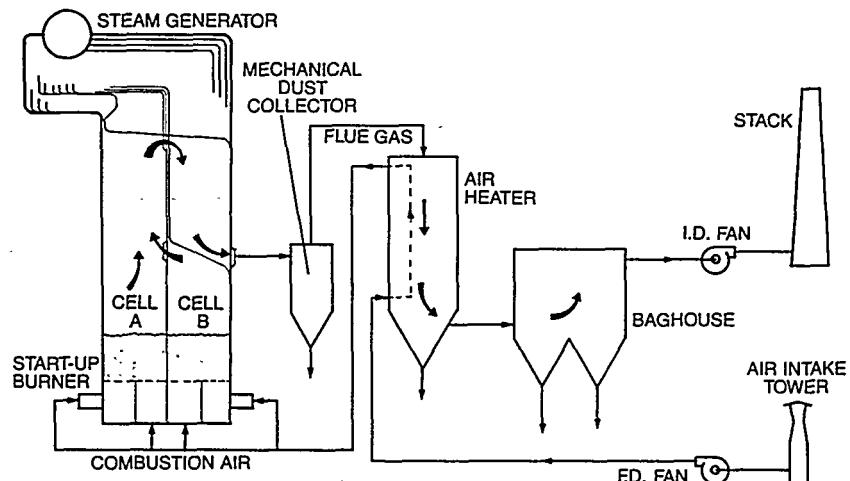


FIGURE 3 AIR AND FLUE GAS SYSTEM



omizer is transported to the steam drum to mix with water circulating through the steam generating circuitry.

Steam generating circuitry consists of vertical finned tube waterwalls (MONO-WALL[®]) construction which enclose the steam generator, a finned tube partition wall which separates Cell A from Cell B, a finned tube partition wall which separates Cell B from the convection pass above it, and sloped in-bed tubes in each cell. Water from the steam drum is supplied to inlet headers for each circuit using two downcomers and multiple feeders. The steam/water mixture leaving each heated circuit is returned to the steam drum through unheated risers. Flow is by natural circulation due to the difference in density between steam-free saturated water in the downcomers and feeders and the steam/water mixture in the heated tubes and unheated risers.

The steam collected in the drum is directed to the first stage primary superheater (PSH 1) located in bed A. Steam enters the lower header and passes upward through horizontal coils to the outlet header. Upflow circuitry permits the hottest tubes to be exposed above the fluidized bed during turndown conditions, thereby subjecting them to lower heat transfer rates and correspondingly lower metal temperatures. A high mass flow rate is maintained at full load to insure adequate cooling of the tubes during low load and start-up conditions. Steam leaving PSH 1 is transferred to the second stage primary superheater (PSH 2) located in bed B.

An emergency spray is located in the transfer line between the first and second stage primary superheaters. This spray station is normally not used, but is provided to protect the second stage primary superheater if required during upset operating transients.

Final superheat is obtained in the convection finishing superheater located above the freeboard in Cell A. Steam enters the upper header and flows downward through horizontal coils counterflow to the upflowing flue gas. The finishing superheater (and economizer) are divided into two banks to provide space for sootblowers (not installed) in the event they are required for some future alternate fuel.

Steam temperature at the finishing superheater outlet is controlled by spray attemperation in the transfer line between the second stage primary superheater and finishing super-

heater. Water for spray attemperation is taken from the discharge of the boiler feed pump.

Superheater sizing and location in the boiler represents an optimization for achieving a relatively flat temperature profile over the predicted operating range of 30% to 100% load while minimizing superheater spray requirements. Steam leaving the finishing superheater at 1174 psig enters a backpressure turbine/generator and is exhausted at about 100 psig. It then flows through heat exchangers to heat the circulating water used for oil tank heating. Condensate from the heat exchangers flows to the deaerator and back to the economizer and boiler via the boiler feedpumps. This arrangement provides an energy-efficient, closed-loop system.

Air & Gas System and Gridplate Design

Air enters this system through an inlet screen and venturi and feeds the forced draft fans which are equipped with inlet vane control and discharge isolation dampers (refer to Figure 3). Air from the FD fans is routed to a tubular air heater. An air heater air bypass is provided to control the average cold end temperature of the tubular air heater and to protect the baghouse from low gas temperatures during part-load operation. During start-up, all air is bypassed around the air heater to facilitate rapid warming of the baghouse.

Air leaving the tubular air heater and air heater air bypass recombines and then passes through parallel paths to Cell A and Cell B. Each path contains an air flow measurement device and air flow control damper. After leaving the control damper the air flow is again split to provide combustion air to each segment of each cell. The path leading to the first segment to be started in each cell contains an in-duct burner which is used during start-up to warm the unit and ignite the coal. The path leading to the other segment in each cell contains a shut-off damper. This arrangement of air inlet ducts provides a mechanically simple design requiring no high temperature dampers or special start-up ducts and dampers. It is designed to provide easy transfer from start-up to segmental fluidization and from segmental fluidization to full cell operation while maintaining air flow measurement to each cell during all operating modes.

After entering the cell plenums, air passes through an air distribution grid to enter the fluidized bed. This grid consists of tee nozzles installed in the fin section of a water tube cooled grid plate. This design allows the grid to operate at a controlled temperature thereby eliminating sealing problems caused by thermal expansion.

The tee nozzles provide uniform air distribution throughout both cells and allow the formation of a layer of unfluidized bed material which acts as an insulating layer to protect the grid plate.

Protection of the grid is further insured by providing insulation on the plenum side of the tubes and fins in the start-up sections. During start-up, the use of a water-cooled gridplate permits warming up each cell with 815°C (1500°F) air without elaborate special design considerations to account for thermal expansion. The floor and walls of the air plenum in the start-up segments are insulated to minimize cooling of the air in the plenum. A steel plate located in each plenum separates the two segments. Because of the small dimensions of this plate (1500 x 2400mm) thermal expansion can be accommodated. This steel plate is insulated on the face exposed to the start-up zone (refer to Figure 4).

Within the fluidized bed, air mixes with the coal and lime to effect coal combustion and sulfur capture. Flue gases and elutriated fines leave each fluidized bed and are combined in an extended freeboard in Cell A. Sufficient freeboard height is provided to permit burnout of elutriated coal fines and combustible gases.

After leaving the freeboard, flue gases pass over the finishing superheater surface located above Bed A, through a water-wall screen separating Cell A and Cell B, down through a bare tube economizer located above Cell B, and through a water-wall screen in the rear wall to mechanical dust collecting cyclones. The cyclones remove approximately 85% of the flyash for reinjection into Cell A. The flue gases and remaining fines pass through a tubular air heater and then to a baghouse for final particulate control. Flue gases exiting the baghouse are routed to the ID fans which discharge into an existing stack. The ID fans have inlet vanes to control furnace draft and discharge isolation dampers.

The coal, and inert refractory bed materials for the boiler enter the plant by totally enclosed conveyor trucks (refer to Figure 5).

These materials are conveyed by bucket elevator to a diverter valve located above all the storage silos. They are then distributed by gravity to their respective storage silos. Limestone may also be delivered to the storage silo in this manner. However, the preferred method is to have it pneumatically conveyed from the delivery truck directly to the limestone storage silo. Coal and limestone leave their silos on a common belt conveyor which connects the silos to a bucket elevator and a conveyor which discharges through a diverter valve directly to the coal day bin or, if limestone, by a conveyor to the day bin. The inert material is transported to the boiler pneumatically.

The coal feed system delivers coal from day bins to the boiler. One day bin for each cell supplies coal to a mass flow extraction screw conveyor and through a stream spreader to a rotor flipper. Coal is distributed across the fluidized bed by the rotor flipper. Foster Wheeler has successfully pioneered the use of overbed feed for fluidized bed combustion as a means of avoiding the problems often encountered with underbed feed systems using injection nozzles.

The rate of coal feed is controlled by the speed of the mass flow extraction screw conveyor. The rotor flipper operates at a low speed when distributing coal across half the bed during segmental fluidization and at a higher speed for full cell operation. Weigh cells on the coal day bin provide a means for totalizing coal usage. Identical coal feed systems are provided for both A cell and B cell.

To take advantage of the fluidized bed's ability to burn a variety of fuels, the SNR unit has also been designed with provision for feeding alternate fuels, both liquid and solid.

The limestone feed system takes limestone from the limestone day bin and delivers it to the boiler cells at the required flow rate.

One limestone day bin is located along the side of Cell B opposite the coal rotor flipper and supplies limestone through two discharge hoppers. Each hopper feeds one cell through an isolation slidegate valve and a single rotary feeder which regulates the flow. For Cell A, the limestone falls by gravity through a pipe to an injection point located in the side wall just above the fully expanded fluidized bed level. For Cell B, the

FIGURE 4 ARRANGEMENT OF START-UP ZONE

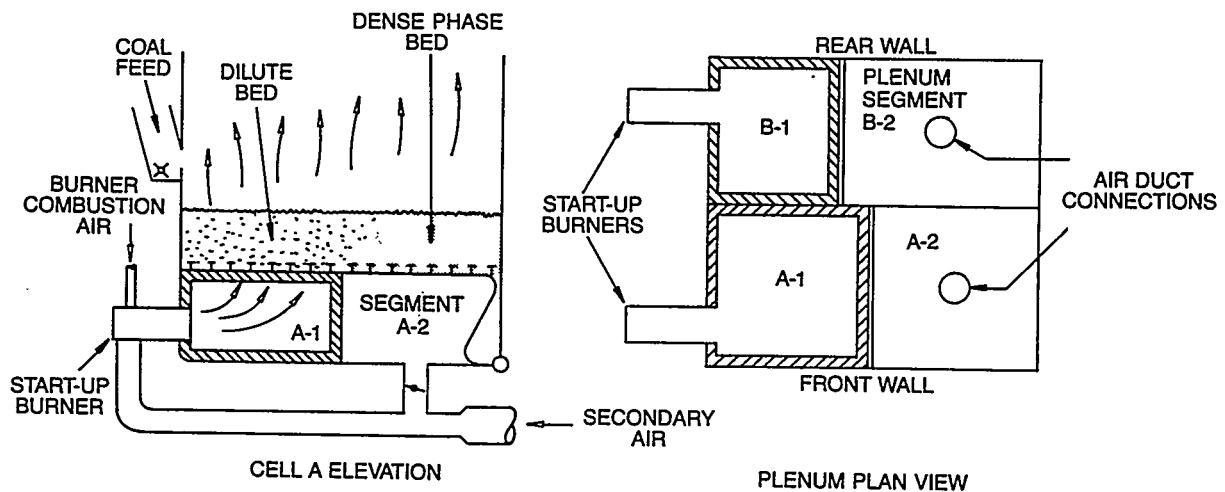


FIGURE 5 MATERIAL RECEIVING AND HANDLING SYSTEM

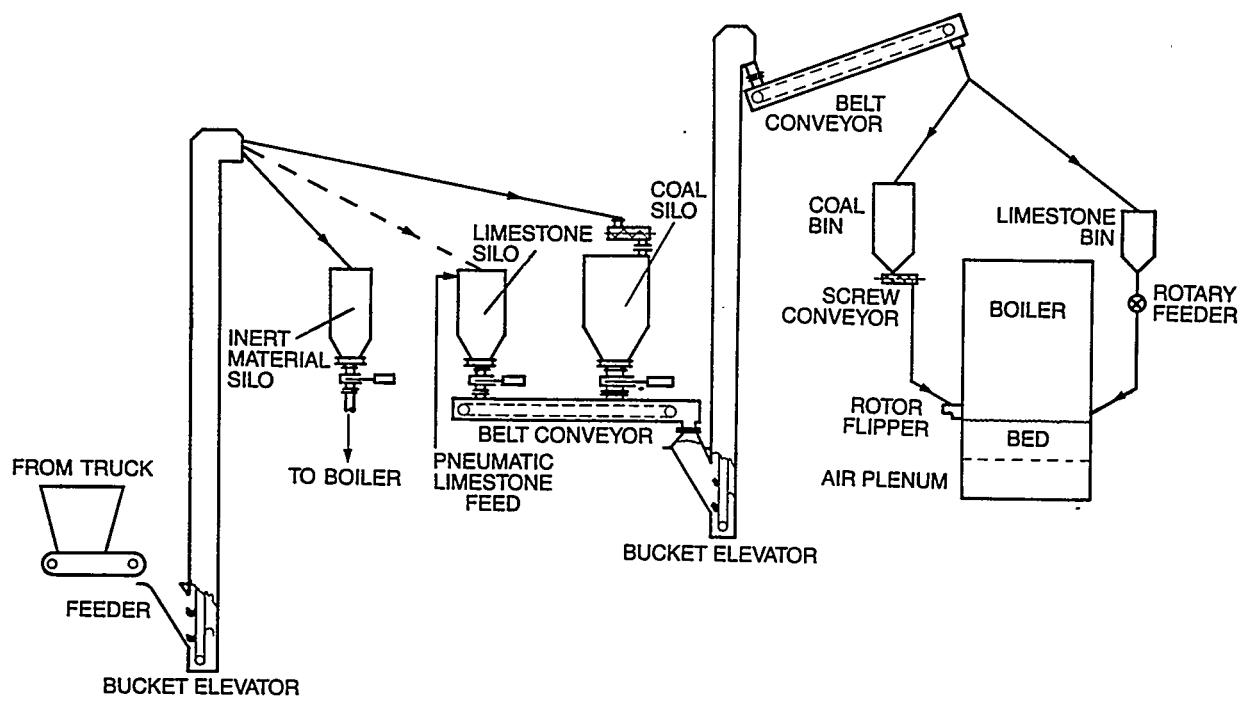


FIGURE 6 BED REMOVAL AND RECYCLE SYSTEM

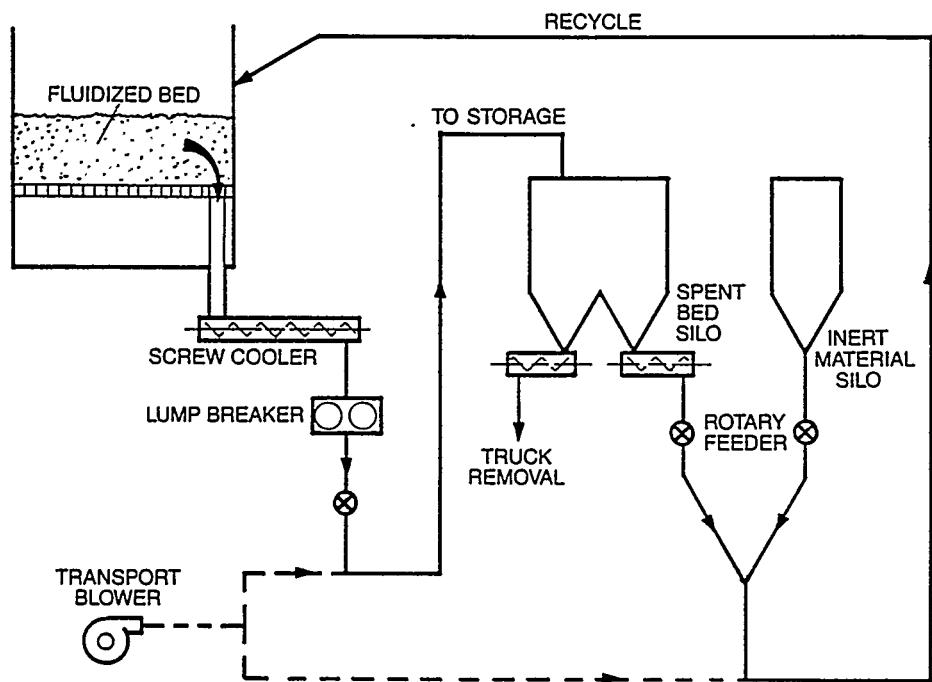
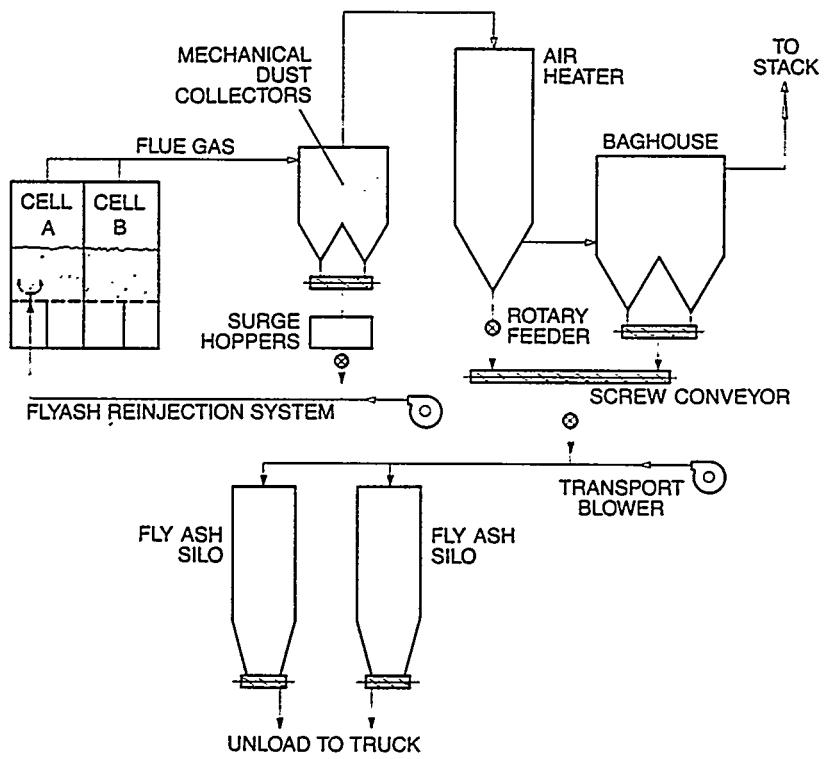


FIGURE 7 FLY ASH SYSTEM



limestone enters the unit through one of two paths. When the entire cell is fluidized, the path is identical to that described for Cell A. During segmental fluidization, limestone is diverted to a transport screw conveyor for injection into the bed through a pipe located on the coal rotor flipper wall of the cell which discharges the limestone just above the fully expanded fluidized bed level. To safeguard working mechanisms in the rotary feeder, each injection chute is provided with a seal air system. In addition, the limestone feed system from the day bin outlet to the boiler penetration is completely sealed.

Due to the good mixing characteristics in the bed only one feed point is required per cell. This simplification eliminates the need for limestone driers, pneumatic injection systems, and flow splitters to multiple injection points, thereby reducing possible hangup problems associated with small diameter lines.

The spent bed material removal system extracts and cools bed material from each of the cells independently at a rate required to maintain a constant bed material inventory regardless of coal ash content or reinjection rate (refer to Figure 6).

Flexibility of this system has been maximized by providing two slidegates in the partition wall between Cell A and Cell B so that all material can be extracted through one cooler. Operating experience may prove this to be the preferred mode of operation when firing low sulfur coal.

As the spent bed material passes through the screw cooler, its temperature is reduced to approximately 60°C (140°F). Material leaving the screw cooler is fed through a lump breaker and a rotary air lock prior to pneumatic transport to the spent bed material storage silo. Once in the storage silo, spent bed material can be either unloaded for truck removal or reinjected into the bed as needed to maintain or build bed inventory.

Pilot plant testing has indicated that under certain circumstances, depending on the coal and limestone being used, bed material may elutriate at a faster rate than fresh limestone would be added to control SO₂ emissions. If this situation develops, there would be a gradual reduction in bed level and consequent reduction in the rate of steam generation. In order to provide for this eventuality, a spent bed/inert material reinjection system capability has been included in the overall system design. By using that system, bed level can be controlled independent of the limestone feed rate, or spent bed cooler withdrawal rate, thereby providing additional operating flexibility and conserving limestone.

Separate storage silos are provided for spent bed material, flyash and inert material. In this way, stored spent bed material can be removed periodically since extended storage of that material is not recommended.

In operation, when material needs to be added to a cell to either maintain or increase bed inventory, the material can be taken from either the spent bed storage silo or the inert material storage silo. A variable speed feeder controls the rate of material withdrawal and a rotary valve acts as an air lock to the pneumatic transport line. A pneumatic transport line is used for spent bed and inert material injection. Near the steam generator a diverter valve in the pneumatic transport line directs material to either Cell A or Cell B. The injection point in each cell is located in the side wall above the fully expanded bed.

Previous experience has verified that some of the coal and limestone fed into the bed elutriates without taking part in the combustion or SO₂ capture processes. To recover and use this elutriated material, the SNR unit has been fitted with a flyash reinjection system which is shown schematically on Figure 7.

Flyash is collected in two 50% capacity multicyclone mechanical dust collectors. The gas inlet of one multicyclone has a damper which is closed below 50% gas flow to maintain collector efficiency and the material outlet has an actuated slidegate to prevent gas bypass during single collector operation.

A common collecting screw under both mechanical dust collectors has a single discharge into an upper weigh hopper which batch feeds a lower surge hopper. A variable speed rotary feeder on the outlet of the lower surge hopper continuously feeds material into a pneumatic transport line. Valves and piping are arranged to permit the lower surge hopper to operate continuously at a pressure equal to the pneumatic transport line pressure while the upper weighing hopper cycles between the transport line pressure and the pressure in the mechanical dust collectors. The rate of material collection in the upper surge hopper is used to control the speed of the rotary feeder. One blower supplies the required transport air. Splitter tees, located in the transport piping are used to generate eight individual streams of flyash. The flyash reinjection nozzles penetrate through the gridplate of Cell A in segment A-1. This configuration has been selected because this seg-

ment of Cell A is the first to go into operation.

By reinjecting the captured flyash, carbon burnup efficiency is expected to increase by approximately 5% to a total of 98%.

A baghouse downstream of the mechanical dust collector provides final cleaning of the flue gases before they are discharged through the stack into the atmosphere.

This unit has been designed with a two-part control system. The first part automatically controls sequential and modulating operations for the entire plant by using a microprocessor based distributed control system (DCS) employing cathode-ray tube (CRT) displays. It has the capability to automatically light-off and shutdown Cell B, without operator assistance, as the steam load demand changes.

The second part of the control system is a hard wired fail-safe system which operates independent of the DCS. Its purpose is to interlock critical components thereby ensuring a safe sequence of operation during startup, normal operation and shutdown.

TABLE 2

Steaming Rate	No. of Cells in Service
30%— 50% MCR	1
42%— 70% MCR	1½
60%—100% MCR	2

The normal bed operating temperature range is 771°C to 899°C (1420°F to 1650°F).

During normal operation, a change in steam generating rate can be accomplished by varying bed temperature and by the slumping or fluidizing cells or cell segments as indicated in Table 2. By using this method, bed inventory may be held constant.

Each boiler cell is provided with an in-plenum start-up section and an oil fired start-up burner as shown in Figure 4. The burner is fired to warm the unit and preheat the bed material to the coal ignition temperature. Since the plenum and gridplate are watercooled, they can withstand the burner exhaust gas temperatures that occur in the start-up zone.

As an alternate start-up method, if one cell is on line, it is possible to allow the hot bed material from that cell to flow into the adjoining cell by opening the slidegate valves in the partition wall that separates the two boiler cells.

If the present trend continues, the price of premium fuel will rise while emission limits become increasingly restrictive. The Shell plant at Europoort is demonstrating that fluidized bed combustion is a viable option when addressing those trends. It is providing a means of burning high sulfur coal in an environmentally acceptable manner. In addition, by the application of cogeneration techniques, overall cycle efficiencies as high as 80% can be achieved. Based on these advantages, it is expected that fluidized bed combustion will become an increasingly important contributor in meeting future steam generation needs throughout the world.

APPENDIX AB-9-6

COAL BENEFICIATION — THE CINDERELLA TECHNOLOGY *

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Paper to be presented at DOE's Coal Combustion and Applications Working Group (CCAWG) meeting to be held at Foster Wheeler Development Corporation, Livingston, New Jersey, December 9, 1982.

*Research sponsored by the Fossil Energy Office, U.S. Department of Energy under contract W-7405-eng-26 with the Union Carbide Corporation.

#Chemical Technology Division.

##Engineering Technology Division.

**Instrumentation and Control Division.

COAL BENEFICIATION — THE CINDERELLA TECHNOLOGY *

S. P. N. Singh,‡ J. C. Moyers,‡‡ and K. R. Carr**
Oak Ridge National Laboratory
Oak Ridge, Tennessee 37830

ABSTRACT

A brief introduction to coal beneficiation processes is given. The paper includes brief summaries of current commercial practices and several developmental coal cleaning methods. Coal beneficiation economics and research needs are also discussed.

It is felt that coal beneficiation can play a significant role in the increased usage of coal to meet the nation's future energy needs. Fertile areas for coal beneficiation research and development are suggested, such as increased automation of coal cleaning circuits and novel coal cleaning methods to increase the recovery of higher quality coal from the mine product.

*Research sponsored by the Fossil Energy Office, U.S. Department of Energy under contract W-7405-eng-26 with the Union Carbide Corporation.

‡Chemical Technology Division.

‡‡Engineering Technology Division.

**Instrumentation and Control Division.

INTRODUCTION

Raw coal as it comes from the mine ranges in size from large rocks (often 24 in.) to dust. In addition to the organic coal matter, the mine product contains shale from mine partings, stray machine parts, pieces of lumber, water, ash, and other mineral impurities such as pyrites. The raw mine product is often referred to as run-of-mine (ROM) or as-mined coal. ROM coal is seldom used as is; it is beneficiated to make it more suitable for the end-use application.

Coal beneficiation is a generic term that is used to designate the various operations performed on the coal to make it more suitable for its end-use application (e.g., feed to a coal-fired boiler or a coke oven, or a coal conversion process such as gasification or liquefaction). Coal beneficiation is also referred to as coal preparation, coal cleaning, or coal washing. In the past, when the need arose for lump coal, coal beneficiation consisted of operations such as hand-picking of coal lumps from the mine product. In recent years, however, coal beneficiation has come to encompass the entire spectrum of operations, ranging from the relatively simple crushing and size classification operations (that are almost routinely performed on all coals used today) to rather elaborate chemical and microbiological processes that are used or are being developed to render the ROM coal more suitable for the end-use process. Coal beneficiation processes prepare the ROM coal for its end use by removing the undesirable constituents associated with the coal without destroying the physical identity of the coal. However,

liquefaction-type processes (such as the solvent-refined coal process) that upgrade the coal to yield a clean fuel product are generally not regarded as coal beneficiation processes primarily because they alter the physical identity of the coal; that is, the coal is liquefied, upgraded, and then resolidified to yield a coal-like product called solid SRC (solvent refined coal).

Beneficiating the coal has several advantages, including the following:

1. The cleaned coal is more uniform in size, composition, calorific value, and moisture content. When the cleaned coal is burned, it results in more uniform and steady combustion.

2. By reducing the ash and sulfur impurities in the coal, beneficiation contributes to reduced slagging and fouling in the furnace.

This leads to increased boiler on-stream availability, decreased maintenance, and lower overall operating costs.

3. Removal of the associated mineral matter from the ROM coal results in lower transportation costs, higher combustion efficiency, and reduced ash disposal and flue-gas desulfurization (FGD) requirements for obtaining the same calorific value at the furnace.

4. The moisture content of the cleaned coal can be controlled (generally, the coal moisture content is reduced), which can result in improved coal handling and burning characteristics. This procedure leads to more efficient fuel use because less energy is wasted in drying the coal.

5. Beneficiation can be used to "tailor" the coal to more closely meet customer specifications, thereby resulting in a higher value for

the product. This takes on greater significance when one considers the potentially lucrative export market for U.S. coals.

6. Beneficiation can make it possible to use many of the high-sulfur and high-ash coals which could not otherwise be used, thereby increasing the usable resource base.

As with any technology, coal beneficiation has its disadvantages too, especially from the viewpoint of the beneficiation plant owner/operator. These disadvantages are the following:

1. Beneficiating the coal results in reduced marketable coal output from the mine product because some of the coal is discarded with the refuse. Current cleaning processes result in a significant fraction of the coal calorific value being lost to the plant refuse stream.

2. Capital must be invested to beneficiate the coal, thereby necessitating a higher price for the product coal because the invested capital must be recovered.

3. The beneficiation plant operator is confronted with the problems and the cost of disposal of the plant refuse in an environmentally acceptable manner. This cost (and concern) is absent (or, at least significantly reduced) if as-mined coal is shipped to the consumer.

As can be seen from the above, the advantages of beneficiating coal appear to far outweigh the disadvantages. A study by Hoffman et al.¹ indicated that coal beneficiation combined with FGD appeared to offer the most economical means of achieving sulfur oxides emission control for coal burning facilities. The study further stated that for some

coals, beneficiation could even eliminate the need for FGD systems in order to economically achieve acceptable sulfur oxides emission control.

If, as projected:

1. coal is to provide an increasing share of the national energy needs,
2. future coal utilization plants will be required to meet increasingly stringent environmental constraints, and
3. the supply of acceptable coal is limited,

then coal beneficiation will be called upon to play an increasingly important role in meeting the nation's future energy needs.

The remainder of this paper will cover briefly the following topics related to coal beneficiation: current commercial practices, novel coal beneficiation processes, coal beneficiation economics, and coal beneficiation research activities. Large portions of the material to follow have been extracted from previous publications by Singh et al.^{2,3} These publications may be consulted for additional information.

COAL BENEFICIATION PROCESSES

Coal beneficiation at present is more an art than a science. The beneficiation processes may be broadly classified into one of three areas:

1. physical or mechanical,
2. chemical, or
3. microbial.

Physical beneficiation processes rely on physical principles such as gravity separation, centrifugal action, surface tension, magnetic separation, etc. to separate the coal from the refuse. These processes will be discussed in somewhat greater detail later in the paper under current commercial practices.

Chemical beneficiation processes rely on the action of certain chemical reagents such as acids, alkalis, etc. to separate the ROM coal into clean coal and refuse. The chemical reagents used essentially affect only the sulfur and the ash impurities present in the coal, not the basic coal matrix.

Microbial beneficiation processes, as the name implies, rely primarily on the use of bacterial strains such as Thiobacillus ferrooxidans (also known as Ferrobacillus ferrooxidans) and Thiobacillus thiooxidans to remove some of the impurities from the coal. Microbial processes are known to occur in nature during the weathering of coal and mine wastes and are responsible for acid mine drainage. While earlier studies were directed at devising methods to minimize acid mine drainage (primarily because of environmental concern), it is only recently that the same bacterial process has been investigated as a potential beneficiation process.

Up to the present, commercial practice has relied primarily on physical coal-cleaning processes to beneficiate coals. Chemical, microbial, and other novel coal beneficiation processes are of recent origin and are still at various levels of process development. The microbial beneficiation processes are still in their infancy, for example. The chemical beneficiation processes (though generally capable of producing a higher yield of a cleaner coal product from the ROM coal) have not been used on a commercial scale, primarily because they have not yet proven to be economical.

CURRENT COMMERCIAL PRACTICES

Currently in the United States and other coal-producing countries, the ROM coal is prepared by a physical beneficiation process. The degree of preparation can vary from no beneficiation to a very thorough treatment of the raw coal. The process(es) used and the degree of cleaning employed are very dependent on the type of coal and the product coal specifications desired. However, in general, commercial beneficiation processes rely on the use of gravitational and/or centrifugal forces to effect the separation of the clean coal from the accompanying impurities. Physical coal cleaning generally consists of dry or wet beneficiation methods. In 1975, only 2.5% of the coals cleaned in the United States were beneficiated using dry separation methods; the other 97.5% were cleaned by using wet beneficiation methods.⁴

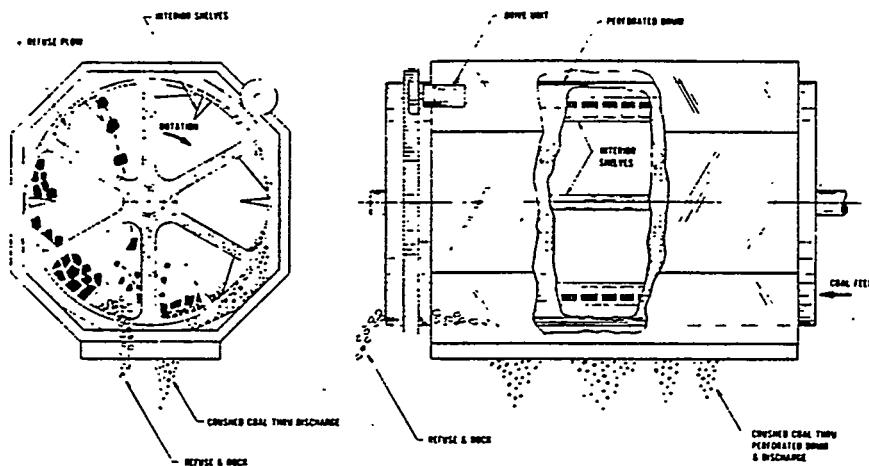
In general, physical beneficiation processes consist of various combinations of some or all of the following unit operations.

1. Size reduction. This operation consists of reducing the size of the coal received from the mine (often 24 in. x 0) to more manageable sizes. Size reduction is usually accomplished by using equipment such as rotary breakers, impact mills, and single and double roll crushers. Sketches of some typical size reduction equipment are given in Figure 1.

2. Size classification. This operation consists of segregating the coal into various size fractions to facilitate downstream processing. Both the ROM coal and the crushed product may be classified into different size fractions. Equipment for size classification includes stationary, vibrating, and cross-flow screens and classifying cyclones.

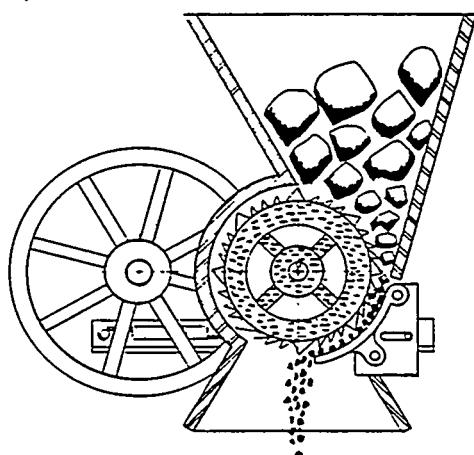
Figure 2 shows some sketches of typical size classification equipment.

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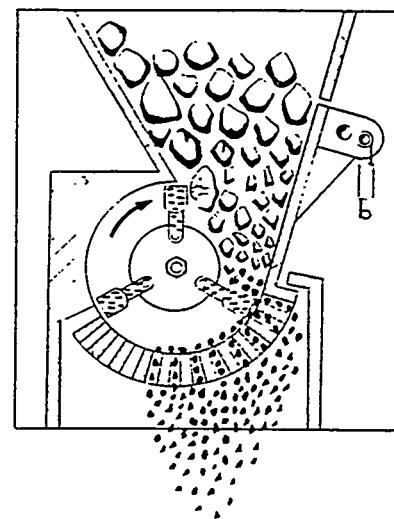
(a) Rotary breaker

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(b) Single roll crusher

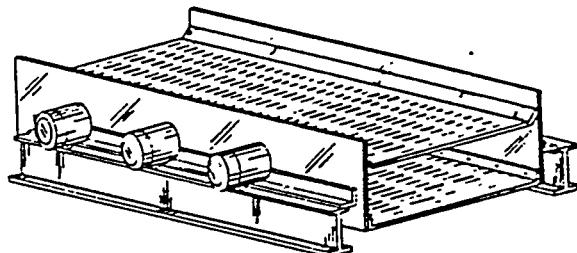
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(c) Hammer impact mill

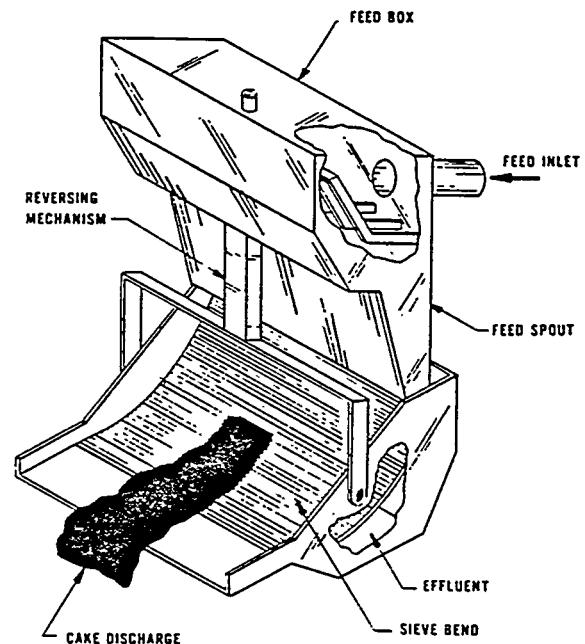
Figure 1. Sketches of typical size reduction equipment used in coal preparation plants.

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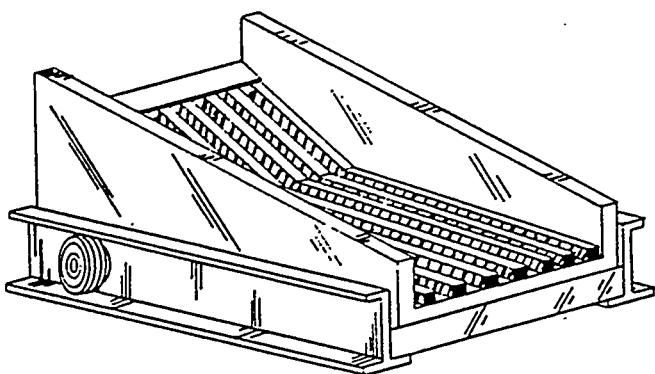


(a) Double deck mechanically vibrated screen

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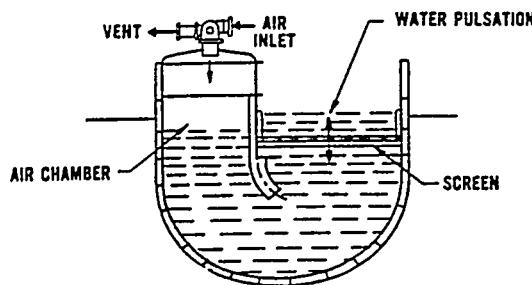
(b) Mechanically vibrated bar grizzly

(c) Sieve bend

Figure 2. Sketches of typical size classification equipment used in coal preparation plants.

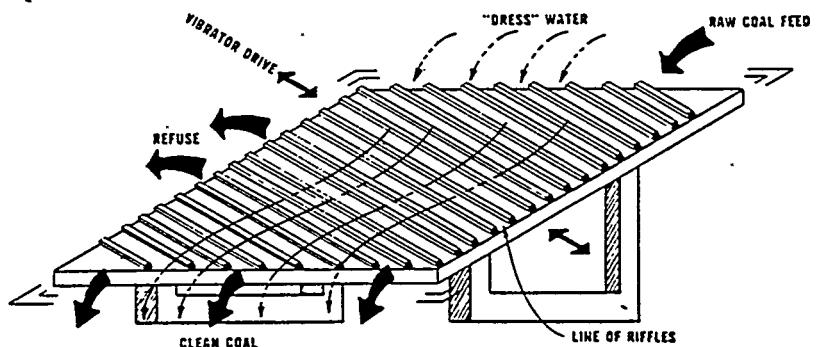
3. Cleaning. This operation is the heart of many coal beneficiation (preparation) plants. It involves mainly the separation of the physically attached sulfur and/or mineral impurities of higher specific gravities from the coal of lower specific gravity. This step is often accomplished by using jigs, cyclones, and concentration tables, which utilize a combination of frictional and/or gravity or centrifugal forces to effect an apparent density differential separation between the coal and its sulfur and mineral impurities. Schematics of typical equipment used in coal preparation plants are given in Figure 3. Another commonly used cleaning method is the heavy-medium separation, which employs an intermediate specific gravity suspension of fine heavy minerals (such as magnetite or sand) in water to effect the desired separation. In general, heavy-medium separation results in a fairly high recovery of the clean coal, although the clean coal has to be separated from the heavy medium before it can be either used or processed further. Because of this additional processing step required, heavy-medium separation incurs higher operating costs than similar beneficiation processes using only clear water. Finally, froth flotation processes are generally used to beneficiate very fine-size (28 mesh x 0) fractions. In froth flotation, the coal is beneficiated in a liquid medium (usually water) by air bubbles (injected into the coal bath) that float the very fine clean coal particles to the liquid surface, where the coal particles are mechanically skimmed. A surfactant is generally added to the coal bath to render the coal more hydrophobic and thereby facilitate the flotation of the coal. The impurities associated with the coal sink to the bottom of the vessel from where they are removed for eventual disposal.

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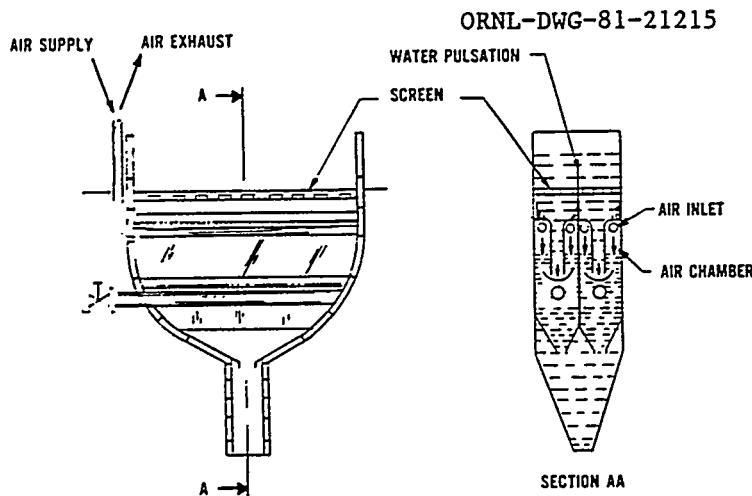
(a) Baum jig

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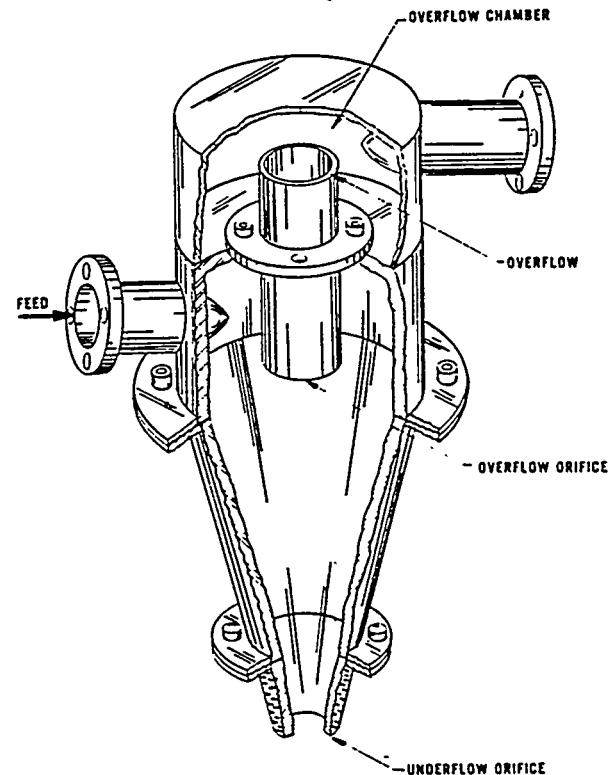


(b) Concentrating table

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(c) Batac jig



(d) Hydrocyclone

Figure 3. Sketches of typical cleaning equipment used in coal preparation plants.

4. Drying. This unit operation involves the reduction of the moisture content in the coal to the desired value. Various types of equipment such as screens, filters, centrifuges, and thermal dryers are used to dry the coal, depending upon the desired moisture content in the product coal. Figure 4 is a sketch of a fluidized-bed coal dryer installation.

In general, coal beneficiation plants use various combinations of all or some of the above unit operations to beneficiate different size fractions of the raw coal, depending upon the level of beneficiation desired. The latter is greatly dependent on the desired specifications of the coal to be produced. The various levels of coal beneficiation are discussed below.

LEVELS OF COAL BENEFICIATION

ROM coal may be beneficiated at various levels ranging from level 1, which involves essentially no beneficiation, up to level 4, which implies a very thorough beneficiation of the coal. Of course, the cost of beneficiation also increases correspondingly from level 1 to level 4. Level 4 cleaning is generally intended for coals to be used in metallurgical operations (coke production, for example), although some Eastern and Interior Basin coals (intended for steam production) may also require this thorough level of beneficiation in order to meet environmental restrictions. The four levels of coal beneficiation are described briefly below.

Level 1. This level is a very basic stage of beneficiation, consisting of size reduction and classification with some attendant removal

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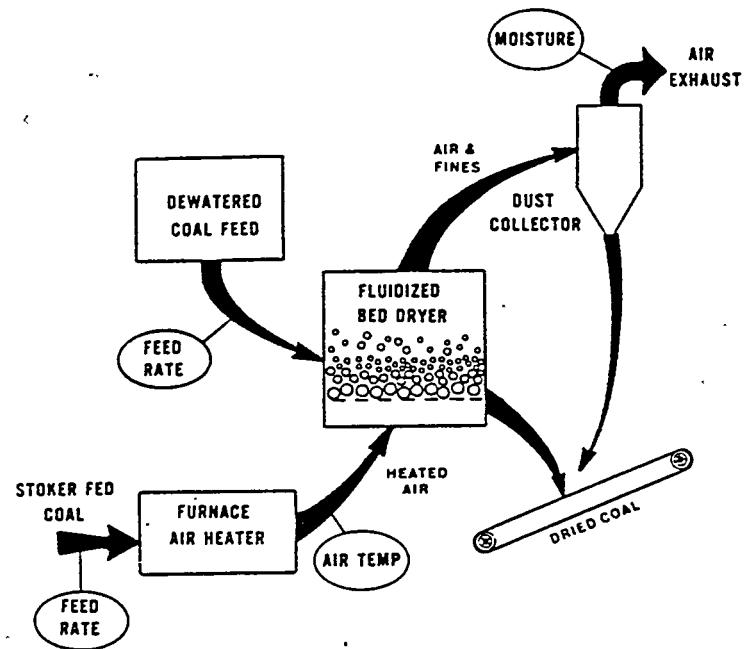


Figure 4. Sketch of a fluidized-bed coal dryer installation.

of refuse and mine dilutions such as pieces of timber, stray machine parts, etc., which can cause problems with downstream processing equipment. Level 1 beneficiation is practiced essentially on all coal burned. Calorific recovery or recovery of the ROM coal heating value is about 100%. However, there is essentially no reduction in the mineral impurities present in the coal.

Level 2. This level involves level 1 preparation plus wet beneficiation of the coarse coal (generally larger than 3/8 in. in size) fraction only. The fines fraction generated in the process is usually collected and shipped as part of the product coal. Calorific recovery at this level of treatment is generally high (>90%), but there is relatively little to no reduction in the mineral impurities in the coal.

Figure 5 is a sketch of a conceptual level 2 coal beneficiation plant.

Level 3. This level involves level 2 preparation plus further beneficiation of all coal down to +28-mesh size fraction. The -28-mesh coal is either dewatered and shipped with the plant product or disposed of as refuse, provided environmental regulations permit such disposal. Calorific recovery is generally good (>80%), and there is a significant reduction in the sulfur and mineral impurities in the product coal.

Level 4. This level involves a full-scale or thorough beneficiation of the coal. Figure 6 is a sketch of one version of a conceptual level 4 coal beneficiation plant. In the version shown, only one product stream is shown for simplicity. However, level 4 cleaning can usually yield several coal product streams that contain varying levels of sulfur and mineral matter. The ultraclean fraction with the lowest level of sulfur and ash may be routed to metallurgical operations. This

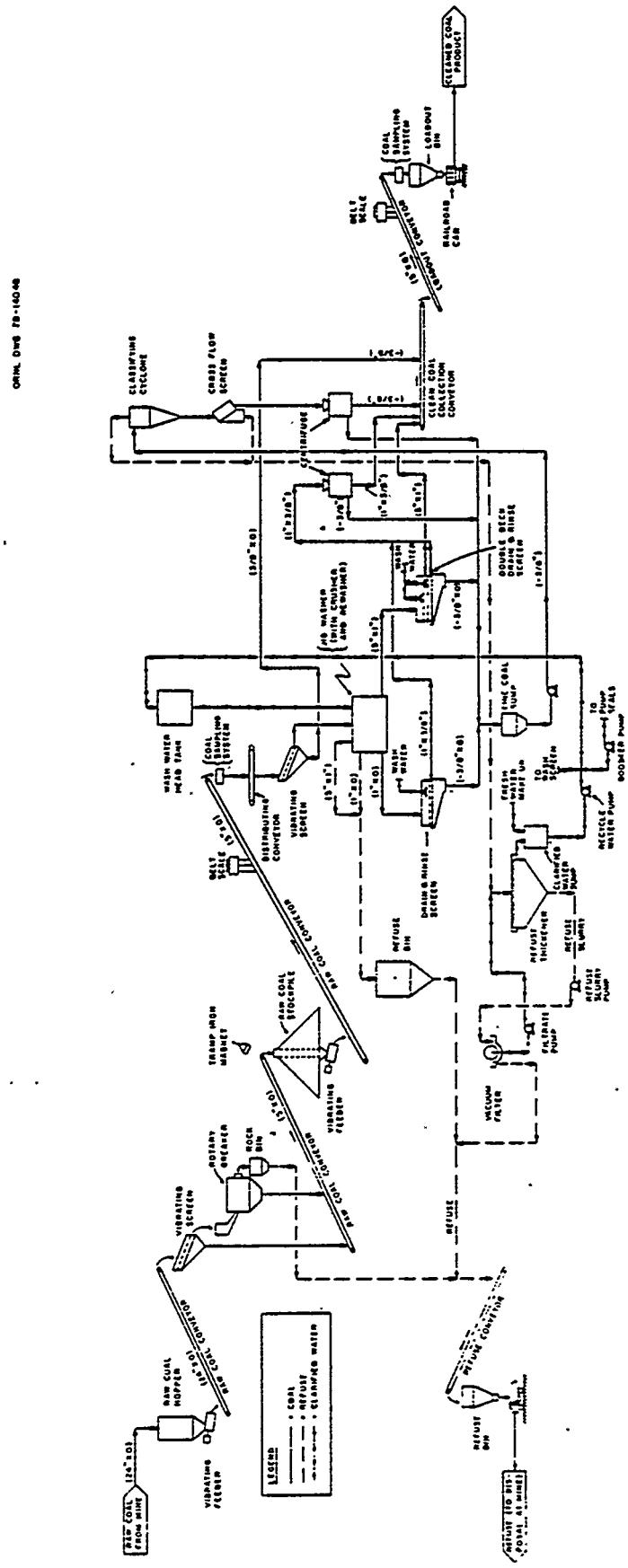


Figure 5. Process flow diagram of one version of a conceptual level 2 wt mechanical coal beneficiation plant.

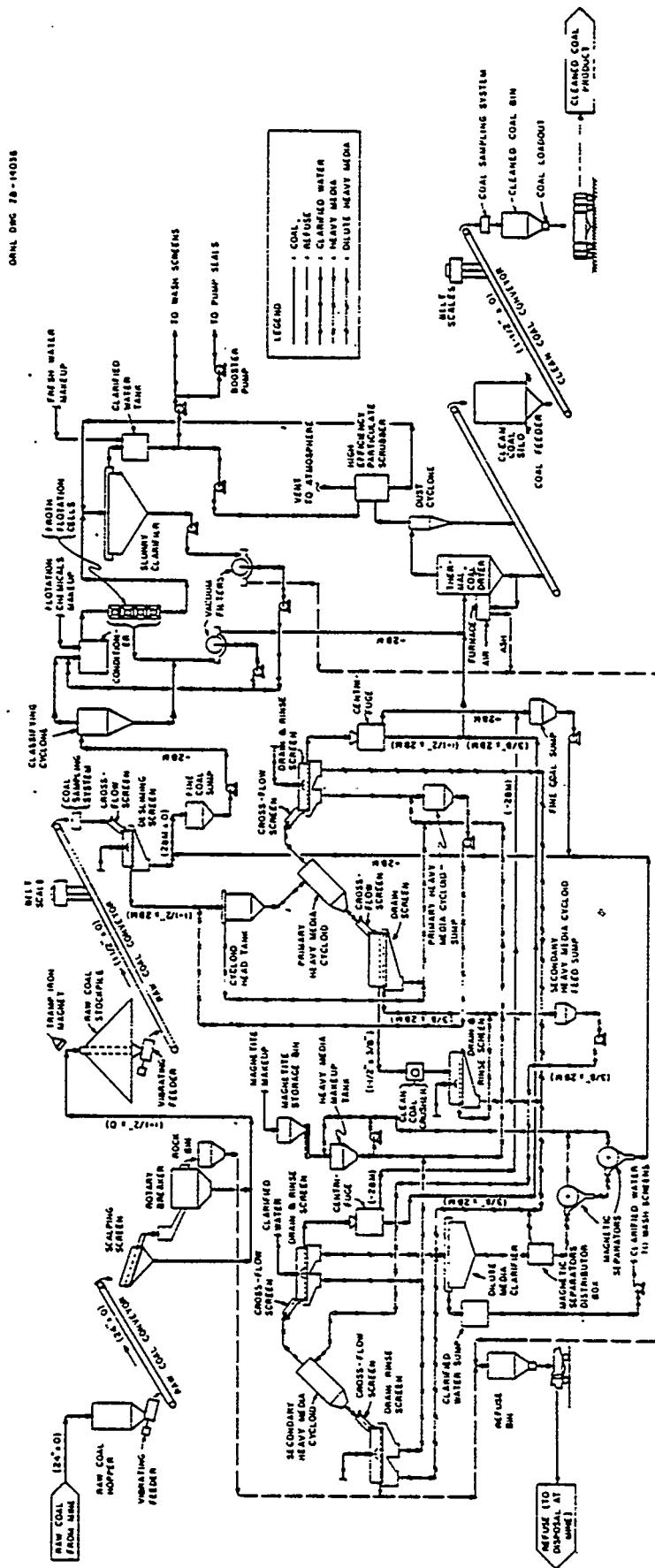


Figure 6. Process flow diagram of one version of a conceptual level 4 wt mechanical coal beneficiation plant.

stream may amount to as little as 25% of the raw coal feed to the plant.⁵ Several intermediate fractions are also produced which contain coal with significantly reduced sulfur and ash levels but not low enough to meet metallurgical coal specifications. These intermediate streams are often referred to as "middlings" and are usually suitable for steam generation purposes. Material yields at this level of beneficiation typically range between 60 to 80%, while calorific recovery is generally between 85 and 95% of the incoming coal.⁵

Regardless of the levels of cleaning achieved, physical coal beneficiation processes have limitations in that they can remove only the inorganic sulfur (mainly the pyritic sulfur) and the extraneous mineral impurities from the ROM coal. These processes are unable to reduce the organic sulfur content of the coal. Inorganic sulfur reductions by conventional physical beneficiation processes can range between 0 and 60 wt %. This generally corresponds to a 0 to 50 wt % reduction of the total sulfur content of the coal. Material recoveries or clean coal yields for the currently used beneficiation processes generally vary between 60 to 80 wt % of the feed coal.

NOVEL COAL BENEFICIATION PROCESSES

Historically, coals (other than those intended for metallurgical operations) were given perfunctory beneficiation, with the objective of recovering as much lump coal as possible. The fines generated during the upgrading operations were often discarded as plant refuse. However, during the past few years, the needs of the coal markets have greatly changed because of the following factors:

1. the increased emphasis to use coal instead of oil or natural gas to generate electric power;
2. The increasingly stringent environmental controls being promulgated for the burning of coal and for the disposal of refuse from coal processing plants;
3. increased mechanization in the coal mines, which results in higher volumes of fines in the ROM coal; and
4. current coal economics, which almost mandates that as much clean and marketable coal be recovered from every ton of raw product mined.

As a result, more and more emphasis is being placed on processing the fine-size (generally -1/4-in.) coal to recover usable coal and minimize the amount discarded as refuse. In particular, considerable research effort is currently being expended on developing new processes that either minimize the production of fines during the cleaning operations (such as the chemical comminution process) or clean the fine coal to yield a marketable product and thereby concurrently reduce the refuse to be processed from the beneficiation plant.

To overcome the limitations of the physical beneficiation processes and to better serve the changing needs of the coal markets, several novel beneficiation processes have recently been (and are being) developed. These include several novel physical beneficiation processes, as well as new chemical and microbial beneficiation processes.

Table 1 is a listing of novel physical beneficiation processes that have been developed. Brief descriptions of the processes and references for additional information regarding these processes are also given.

Table 1. Novel physical coal beneficiation processes

Process name	Process developer	References	Temp. (°F)	Pressure (psig)	Typical operating conditions			Impurities reduction potential, χ	Comments
					Particle size	U.S.S. ^a mesh size	Pyritic sulfur		
Dry Beneficiation Processes									
1. MagneX Process	Ilagen Research, Inc.	6, 7	338	Ambient	-14	~85	67	85	Magnetic separation process; uses iron carbonyl [Fe(CO) ₅] vapors to render the pyrites and the ash impurities magnetic; an 8- to 12-kilogauss magnetic field is used to separate the clean coal from the impurities; process has been tested in a 200-lb/h pilot plant.
2. High-gradient Magnetic Separation (HGS) Process	Auburn University / Oak Ridge National Laboratory	8-10	Ambient	Ambient	-28 + 325	87	52	~80	Magnetic separation process; impurities separated from the clean coal by subjecting a fluidized bed of finely pulverized coal to a high-intensity (20 kilo-oersted) magnetic field; process has been developed up to one ton/h pilot scale.
3. Dry table separator	FHC Corp.	11	Ambient	Ambient	1/8 in. to 1/8 in.	~50	~74	72	Clean coal is separated from the impurities by the action of vibratory and gravity forces; pyrite and ash reduction is very dependent on the type of coal processed and the extent of pyrite liberation in the feed coal; best used as a "rougher;" equipment has been field-tested; preferred top size to bottom size ratio of feed coal per pass = 4:1.
4. Microwave coal cleaning process	G.E. Laboratories	12	392-572	Ambient	-30 + 100	40-50 ^b	N.A. ^c	N.A.	Process uses microwave heating to remove sulfur from coal; process can remove pyritic and organic sulfur (for organic sulfur removal), the feed coal is mixed with NaOH; process has negligible effect on coal volatiles; process has been developed up to a laboratory bench-scale unit.

Table 1. (continued)

Process name	Process developer	References	Temp. (°F)	Pressure (psig)	U.S.S. ^a mesh size	Particle size	Typical operating conditions		Impurities reduction potential, %		Clean coal yield (%)	Comments
							Pyritic sulfur	Ash	N.A.	N.A.		
Wet Beneficiation Processes												
5. Two-stage froth flotation	U.S. Bureau of Mines	13	Ambient	Ambient	-28	<90	N.A.	N.A.	Similar to conventional froth flotation except that the clean coal from the first stage is subjected to reverse froth flotation in the second stage (i.e., in the second stage, the clean coal is permitted to sink while the impurities are floated and collected); process development has proceeded up to laboratory bench-scale unit.			
6. Wet HIGHS process	Auburn University, Indiana University, Sata Magnetics, Inc., Oak Ridge National Laboratory	14-16	Ambient	Ambient	-200	80-90	35-45	95	Pyritic sulfur and ash impurities are removed from finely pulverized coal slurried in water by subjecting the coal slurry to a high-intensity (20 kilo-oersted) magnetic field in a specially designed separator; process is based upon proven technology used in the kaolin industry; process has been developed up to a small pilot-plant-scale unit.			
7. Otisca process	Otisca Industries Ltd.	17	60-68	1 to 2 in. of H ₂ O	1/2 in. x 0	~44	~50	>73	Process is a heavy-media separation process that uses a halogenated hydrocarbon fluid as the heavy media. No water (other than that associated with the coal) is used in the process; hence, dewatering costs are reduced substantially. Process operates at a high vacuum. Process has been developed up to a 20-ton/h pilot plant.			
8. OII agglomeration	National Research Council of Canada (NRCC)	18, 19	Ambient	Ambient	-28	56	76	90d	Process beneficiates coal by forming micro-agglomerates or flocs of the coal particles; process uses light hydrocarbon liquids (such as kerosene or fuel oil) to preferentially wet the coal particles to form flocs; the flocs are separated from the impurities and then pelletized to form large balls to improve their mechanical handling properties; process is especially suited to beneficiating fine sized coal particles; it has been developed up to pilot-plant-scale level by NRCC.			

Table 1. (continued)

Process name	Process developer	Typical operating conditions			Impurities reduction potential, %			Comments
		Temp. (°F)	Pressure (psig)	Particle size U.S.S. ^a mesh size	Pyritic sulfur	Ash	Clean coal yield (%)	
<u>Wet Beneficiation Processes</u>								
9. Chemical comminution process	Syracuse University Research Center (SIRC)	20, 21	-30 to 75	15-120 x 0	3 in. ~73	~55	>95	The process uses anhydrous liquid or gaseous ammonia instead of mechanical grinding to reduce the size of the ROM coal and to liberate the pyrites; the comminuted coal is then separated by conventional sink-float methods into clean coal and reject fractions; the process has been developed up to a small pilot-plant-scale level.

^aU.S.S. = U.S. Sieve Series.^bTotal sulfur reduction potential reported.^cN.A. = not available.

Yield reported is the calorific value recovery potential of the process. This value is generally higher than the material yield from the process.

Table 2 is a similar listing for the novel chemical beneficiation processes. Several of the chemical beneficiation processes under development claim to be able not only to reduce the pyritic (and inorganic) sulfur, but also to remove a fraction of the organically bound sulfur without incurring a significant loss in the heating value of the coal.

The microbial beneficiation processes, as mentioned earlier, are still at the bench-scale level of development.

Additional details on the novel beneficiation processes may be obtained from the references indicated in Tables 1 and 2 and from refs. 34-35. Some general characteristics primarily related to the commercial potential of these processes in coal beneficiation operations are summarized below.

1. All of the novel processes are developmental in nature. The processes are at various levels of process development ranging from bench-scale to pilot-plant stages. None of the novel processes have been used in a commercial plant yet, though some efforts are being made to commercialize some of the processes such as the HGMS process, for example.

2. All of the processes exhibit high recoveries, ranging up to 90 to 95% of the incoming coal. These recoveries, if achieved in commercial practice, indicate significant improvements over current coal beneficiation processes.

3. The new processes offer significantly higher sulfur and/or ash reductions than can be achieved even by the highest level of the conventional wet beneficiation processes practiced today. Inorganic sulfur

Table 2. Novel chemical coal beneficiation process

Process name	Process developer	References	Temp. (°F)	Pressure (psig)	U.S.S. ^a mesh size	Particle size	Chemical reagent used	Pyritic sulfur	Ash	Impurities reduction potential, %	
										Clean coal yield (%)	Comments
1. TRW-Haynes Coal Desulfurization Process	TRW, Inc.	22, 23	194-266	<120	-14	Ferric sulfate ^b	495	10-30	82-92	Process only removes the pyritic sulfur from the coal; it does not affect the organic sulfur present in the coal; ferric sulfate used in the process is generated from the pyrites liberated from the coal; free sulfur is formed in the process; process requires oxygen and lime as chemicals; process has been developed up to an 8-ton/day process design unit.	
2. Battelle Hydrothermal Coal Process	Battelle Columbus Laboratories	24, 25	430-650	350-2500	-200	Sodium hydroxide	90-98 plus 24-70% of the organic sulfur present in the coal	c	97-100 for battery-limits plant; 49-60 for grassroots plant	Process has the capability of reducing the pyritic, organic sulfur, and the free swelling index of the coals tested; increase in the ash content of the coal is due to NaOH impregnation of the product coal; product coal may be de-rashed by acid treatment; yield is lower for the grassroots plant because a significant fraction of the clean coal is used to provide the plant energy requirement.	
3. Ledgemont Oxygen Leaching (LOL) Process	Ledgemont Laboratory Kennecott Copper Corp.	26, 27	212-266	<300	-100	Oxygen, water	>90	N.A. ^d	N.A.	Process removes only pyritic sulfur formed in the process; process has been developed up to a laboratory bench-scale unit.	
4. Ledgemont Ammonia Oxygen-Water Process	Ledgemont Laboratory Kennecott Copper Corp.	28	212-266	<300	-100	Ammonia, oxygen	>90 plus up to 25% organic sulfur removal	N.A.	N.A.	Process is similar to the LOL process except that organic sulfur is also removed from the coal; however, process can result in an 8-13% loss in the coal heating value. Process has been developed up to a laboratory bench-scale unit.	

Table 2. (continued)

Process name	Process developer	References	Typical operating conditions				Impurities reduction potential, %			
			Temp. (°F)	Pressure (psig)	Particle size U.S.S. ^a mesh size	Chemical reagent used	Pyritic sulfur	Ash	Clean coal yield (%)	Comments
5. KVB Coal Desulfurization	KVB Engineering, Inc.	29, 30	100-500	15-300	~14 + 28	Gaseous NO ₂	<90 ^e	N.A.	N.A.	Process claims to be able to remove pyritic and organic sulfur from coal; reaction is performed in a fluidized-bed reactor; no free sulfur is formed in the process; process at bench-scale level of development.
6. PERC Oxidative	Pittsburgh Energy Technology Center	31, 32	~300-430	220-1500	-200	H ₂ SO ₄ ^b	>95 plus <40% of the organic sulfur in the coal	N.A.	90 ^f	Process claims to be able to reduce the pyritic and the organic sulfur present in the coal; process requires air and water as reagent chemicals; process has been developed up to a laboratory bench-scale unit.
7. Low-Temperature Chlorinolysis	Jet Propulsion Laboratory, California Institute of Technology	33	165	15	-200	Chlorine	<90 plus <70 organic sulfur removal	N.A.	98 ^f	The finely pulverized coal is slurried in methylchloroform; the coal slurry is then treated with chlorine gas for 1-4 hr; the treated coal is then dechlorinated by heating to 644°F; process has been developed up to a laboratory bench-scale unit.

^aU.S.S. = U.S. Sieve Series.^bThe chemical reagent is generated in the process from the pyrites present in the coal.^cThe ash content of the product coal increases due to NaOH impregnation in the coal.^dN.A. = not available.^eTotal sulfur reduction potential reported.^fYield reported is the calorific value recovery potential of the process. This value is generally higher than the material yield from the process.

reductions >90 wt % and significant organic sulfur reductions have been reported for some coals when using some of the chemical beneficiation processes (see Table 2).

4. Most of the new physical coal cleaning methods achieve the high sulfur reductions mentioned above by beneficiating the fine and ultra-fine-sized coal (-28 mesh and smaller). This procedure appears to be acceptable commercially since most of the coal used in utility boilers today is fired in pulverized coal-fired boilers. However, this trend may necessitate that these beneficiation processes be located near the end-use facility to avoid either the excessive losses of coal in fine-coal transportation or the increased costs associated with briquetting operations.

5. The application of the novel beneficiation processes, though potentially yielding higher recoveries of cleaner coal, will undoubtedly raise the price of the cleaned coal. However, the increase may well be less than the additional costs of providing FGD processes to meet statutory gaseous emission regulations.

6. Most of the novel processes can be considered to be add-on-type processes which could be added to conventional coal beneficiation plants to clean, for example, the fine coal fraction. However, many of the novel processes can also be designed to clean the entire raw coal feed to the preparation plant.

COAL BENEFICIATION ECONOMICS

The economics of coal beneficiation are equivocal in nature primarily because they are very project and coal specific. Coal preparation

plants today are by and large customized for each application. The costs developed for one situation may not be directly applicable to another. However, bearing in mind the above caveat, Roman³⁶ (quoting Phillips⁵) indicates that the cost estimates for physically cleaning coal (in 1977 dollars) can range from ~\$0.80 per ton of cleaned coal for rudimentary beneficiation to ~\$15 per ton for full-scale coal beneficiation.

Also, especially for power plant applications, beneficiation economics need to be examined in concert with FGD economics. Ehrlich³⁷ speculated that it may cost ten times as much money to remove a pound of sulfur with FGD as it does with coal cleaning. Hoffman and Holt³⁸ report that assessments conducted on new power plants using cleaned coal indicate savings of 2 to 112% as compared to meeting the emission limitations by using FGD alone. They further report that the above type of savings are even more impressive for existing power plants (ranging between 13 and 140%) when they used cleaned or beneficiated coal.

Of course, the application of the novel beneficiation processes will tend to increase coal cleaning costs. However, using the novel technologies should produce increased yields of a higher quality product which may well lower the overall cost to power plants of meeting increasingly stringent emission regulations. To illustrate the likely costs of using some of the novel coal beneficiation processes, the results of an assessment conducted at ORNL are reported in Table 3. The potential costs for level 2 and level 4 conventional wet beneficiation plants are included in Table 3 for comparative purposes. The above

Table 3. Comparison of the material recoveries and beneficiation costs for the five conceptual coal beneficiation processes (second-quarter 1978 costs)

Process	Material recovery ^a (%)	Beneficiation cost per ton coal processed, b, c (\$/ton)	Incremental cost over wet mechanical beneficiation	
			Level 2 (\$/ton)	Level 4 (\$/ton)
Wet magnetic	85	20.42	13.17	10.12
Chemical comminution	89	14.46	7.21	4.16
Meyers process	86	28.23	20.98	17.93
Level 2 wet mechanical	72	7.25	-	-3.05
Level 4 wet mechanical	74	10.30	3.05	

^aDerived as tons of cleaned product coal per ton of ROM coal feed.

^bDerived as (product price per ton - feed coal cost per ton of product coal) x material recovery, %/100.

^cThe values reported are for \$20/ton ROM coal, 100% equity financing, and 15% annual after-tax rate of return (AARR) on equity.

assessments were performed for conceptual battery-limits facilities processing 200 tons per h of feed coal and operating 14 h/d for 329 d/year. Further details of the assessment may be obtained from ref. 2.

As can be seen from Table 3, use of some of the novel processes may tend to double and even triple the beneficiation cost. However, these costs have to be examined against the likely larger decrease in power plant and FGD costs associated with burning a higher quality coal to appreciate their true significance.

No conclusions regarding the potential benefits of using the newer technologies can be derived based on the above assessments. A much more detailed analysis (preferably for an actual plant situation) will have to be performed to determine the merit of using some of the newer technologies. However, it seems fairly certain that any improvements in coal preparation technology will likely translate into sizable benefits, especially for the utility industry.

COAL BENEFICIATION RESEARCH ACTIVITIES

Most coal cleaning plants (including some of the newer facilities) today still use rather simple cleaning techniques and manual control methods. This leads to considerable loss of otherwise usable coal. Until recently, there was little incentive to improve coal cleaning efficiencies because (1) supplies of high-quality coals were plentiful, (2) environmental constraints were minimal to nonexistent, and (3) economics did not warrant anything beyond perfunctory beneficiation except for metallurgical coals. However, the energy crises and the increased environmental activism of the seventies together changed all that. Coal

was looked upon as the near-term energy savior of the industrial nations, yet it was a "dirty" fuel. Because of the above, several initiatives were undertaken in the seventies to improve and develop environmentally acceptable coal conversion technologies including coal beneficiation.

Coal beneficiation research activities proposed were to be conducted along these three broad fronts:

1. Improve existing technologies — seeking improvements in recovery and separation efficiencies of coal cleaning unit operations such as coal comminution, coal washing, and froth flotation.

2. Improve preparation plant operations — the development and incorporation of advanced instrumentation and process controls to operate the plants so as to produce more cleaned coal of a consistent quality at a lower cost.

3. Develop newer cleaning technologies — the development of processes with the potential of recovering more clean coal containing less ash and sulfur impurities than current practices. Some of the novel beneficiation processes are summarized in Tables 1 and 2.

An off-shoot of this category is the development of novel technologies to ultra-clean fine coal for use in coal-water mixtures. These coal-water mixtures could hopefully be burned like oil in existing oil-fired units.

Although the economic downturn of the early eighties has taken the bloom off coal usage, coal beneficiation research still flourishes (albeit with reduced vigor) at several locations. Two examples of ongoing research activities are given below:

1. EPRI in 1981 completed their \$15.2 million Coal Cleaning Test Facility near Homer City, Pennsylvania. The objectives of the facility³⁹ are (1) to characterize coal cleanability on a national basis, (2) to develop and test new equipment and processes, (3) to train coal-preparation engineers and operators, and (4) to be one of the major sources of near-term R&D in coal beneficiation.

2. ORNL and TVA are building a 1-ton/h HGMS pilot plant at TVA's newest 2000-tons/h Coal Preparation Plant (feeding TVA's adjacent power plant) at Paradise, Kentucky, to compare the performances of the HGMS and froth flotation processes. The pilot plant is expected to be in operation by the summer of 1983. The 2000-tons/h plant is a conventional wet beneficiation plant using heavy-media processing and froth flotation to clean an ~5.5 wt % sulfur and ~15 wt % ash Kentucky No. 9 coal to produce a 3.5 wt % sulfur and an ~8.5 wt % ash cleaned coal. The design calorific recovery and mass yield are ~90% and ~84%, respectively.

CONCLUSIONS

A very brief introduction to coal beneficiation has been presented in this paper. References have been given for further details. Some conclusions that can be drawn regarding coal beneficiation are summarized below:

1. It is evident that coal preparation can play a significant role in increasing coal use to meet future energy needs in an environmentally acceptable manner. However, beneficiation is not a panacea for the use of the nation's high-sulfur and/or high-ash coals. It has limitations.

Present technology can at best remove only a fraction of the pyritic sulfur and mineral matter from coal, and much usable coal is often discarded with the refuse. Nonetheless, coal beneficiation can certainly mitigate the problems associated with using the high-sulfur and high-ash coals, and (for some coals) it can even obviate the need for downstream FGD processes.

2. Present commercial beneficiation technologies can often be economically superior compared to FGD processes, when burning certain high-sulfur coals in a utility boiler.

3. Current preparation plants rely too heavily on manual process control methods, resulting in a significant loss of saleable coal in the refuse. Improved instrumentation and process controls are needed in these plants to provide higher yields of a more consistent quality product.

Several foreign coal-producing countries (especially England) have recognized this deficiency and have begun to incorporate advanced process controls in their newer preparation plants. In the United States, however, many coal preparation plant operators are too small to be able to support an extensive R&D program, with the result that automation and process controls have not been widely used in the industry. This is an area where a Federal (or state-supported) R&D program can yield significant benefits.

4. Novel coal beneficiation technologies are required that will increase the yield of cleaned coal containing much less sulfur and ash than currently practiced. These technologies are being developed, and some of them show considerable promise of achieving the above goals.

The further development of these technologies should be encouraged.

The new technologies will very likely cost more than current methods, with the costs appearing to increase with the degree of processing. However, the new technologies also promise higher yields of better quality (coal with less impurities) product which could translate into larger benefits with downstream processes, such as greater boiler availability and lower (to nonexistent) FGD costs.

5. R&D should be encouraged in novel coal cleaning technologies that go even beyond the capabilities of current novel processes and can produce a very low-sulfur and low-ash coal (the so-called "ultra-clean" coal) with the goal of developing coal-water mixtures that can be used directly (with minor modifications) as a replacement fuel in present day oil-fired units.

6. In spite of the current oil-glut, many forecasters still feel that coal will be the near-term energy savior of the industrial nations. Any increased coal use will greatly benefit from improved coal beneficiation.

7. Coal beneficiation is truly a Cinderella technology because its potential significance has been overshadowed by the attention given to other emission control technologies such as flue-gas desulfurization, yet it is a technology that is basic to all coal conversion processes.

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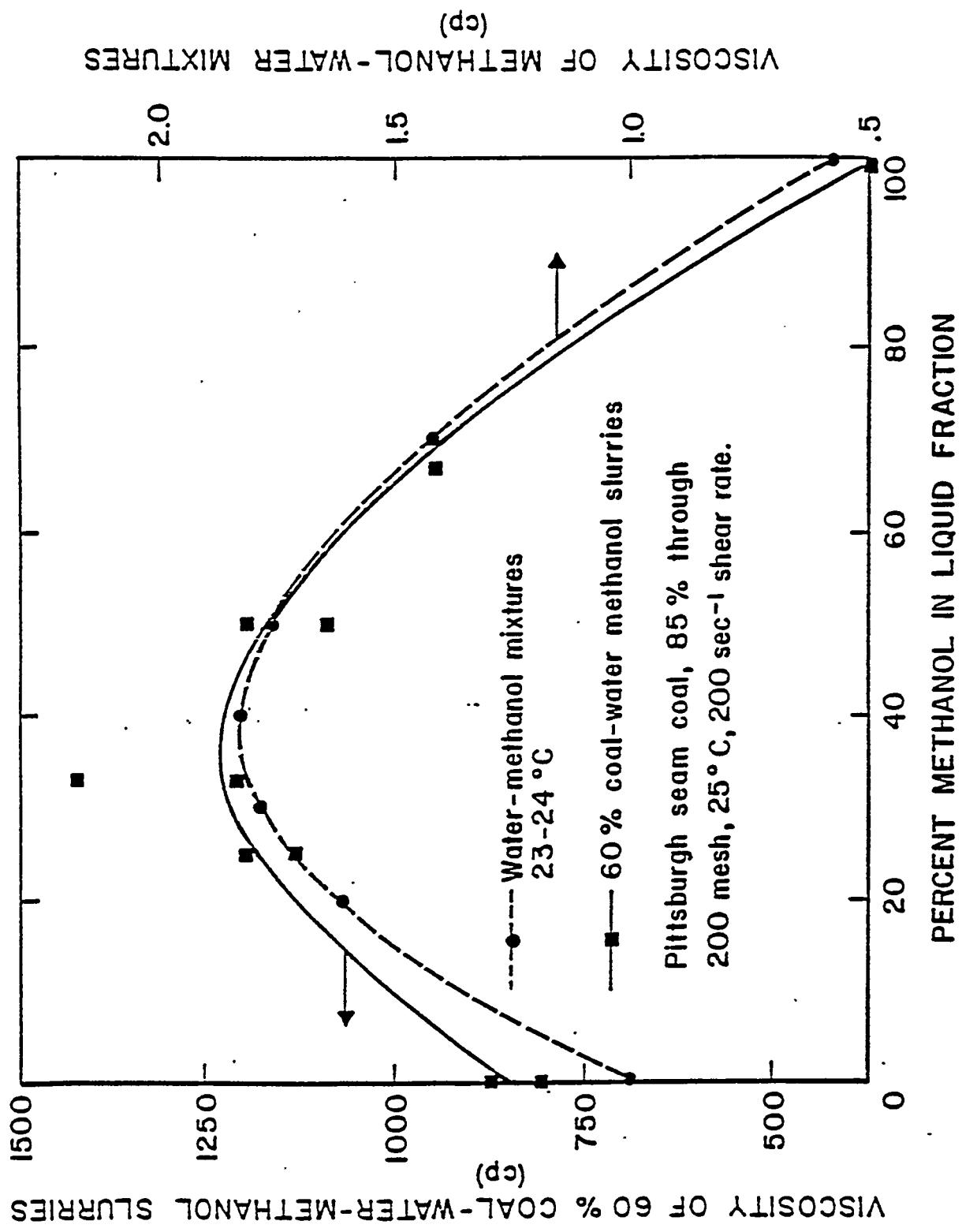
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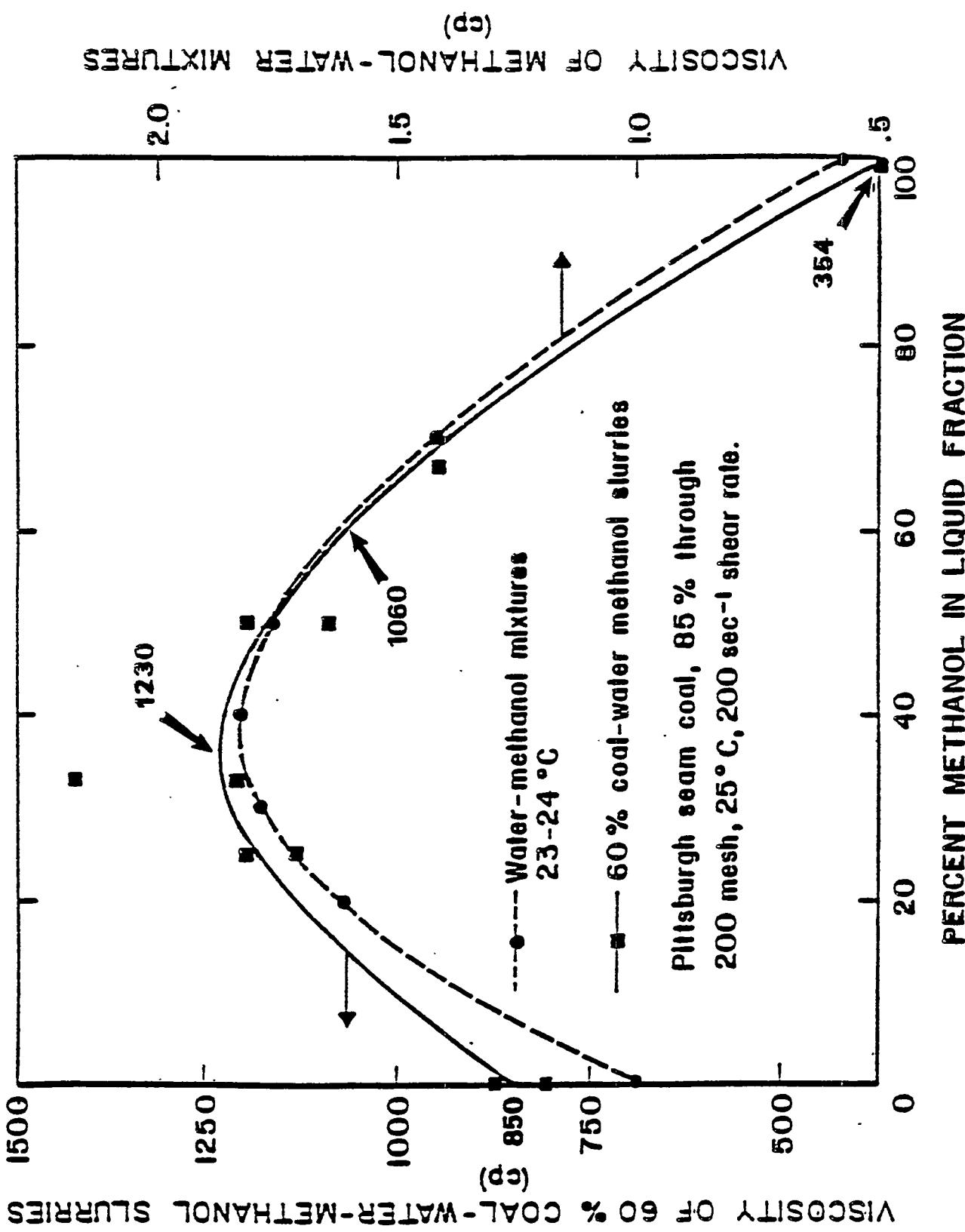
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COAL-METHANOL SLURRY

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U.S. Department of Energy
Pittsburgh Energy Technology Center





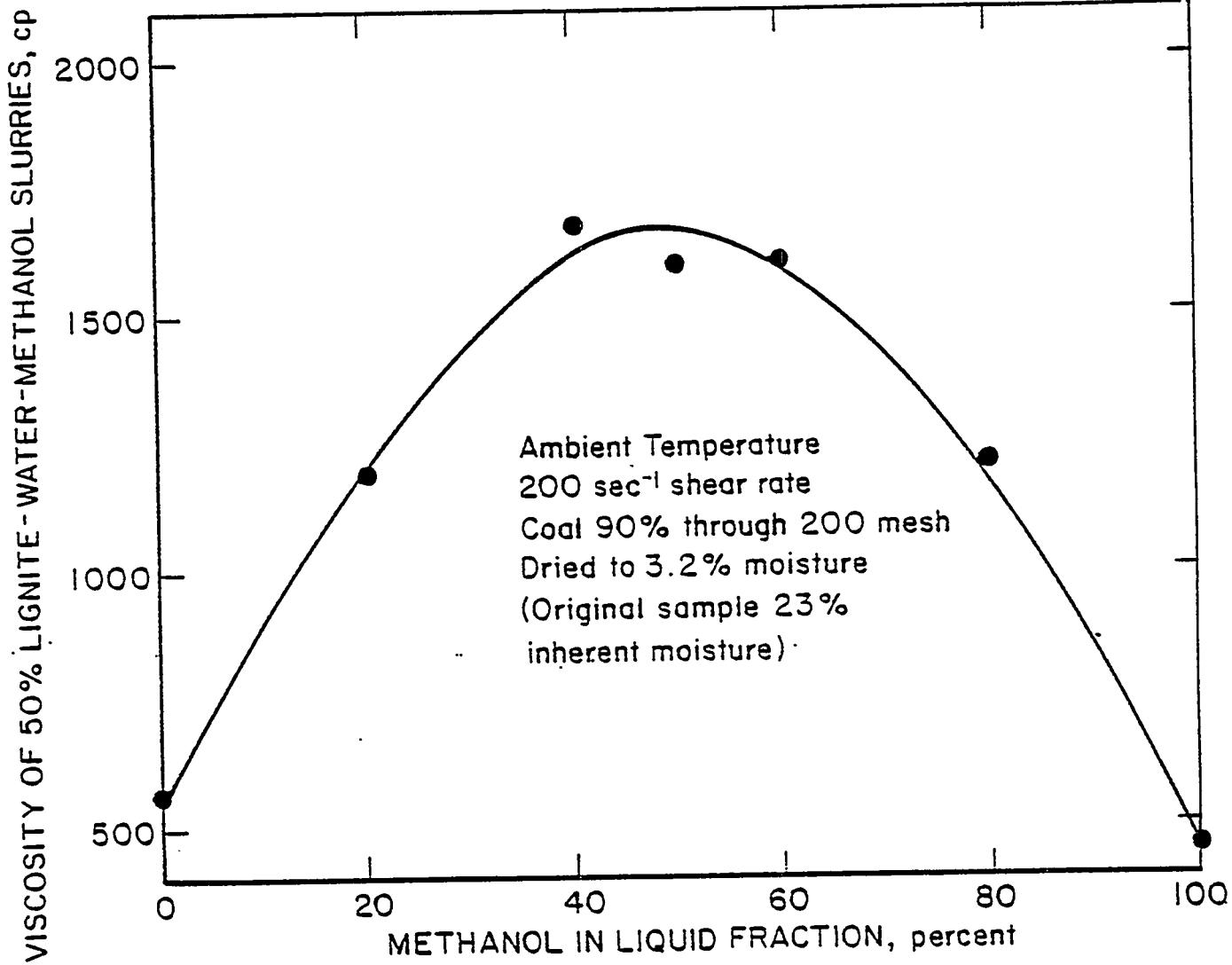
VISCOSITY vs DEPENDENT METHANOL

VISCOSITY OF DRIED MONTANA ROSEBUD IN METHANOL^{1/}

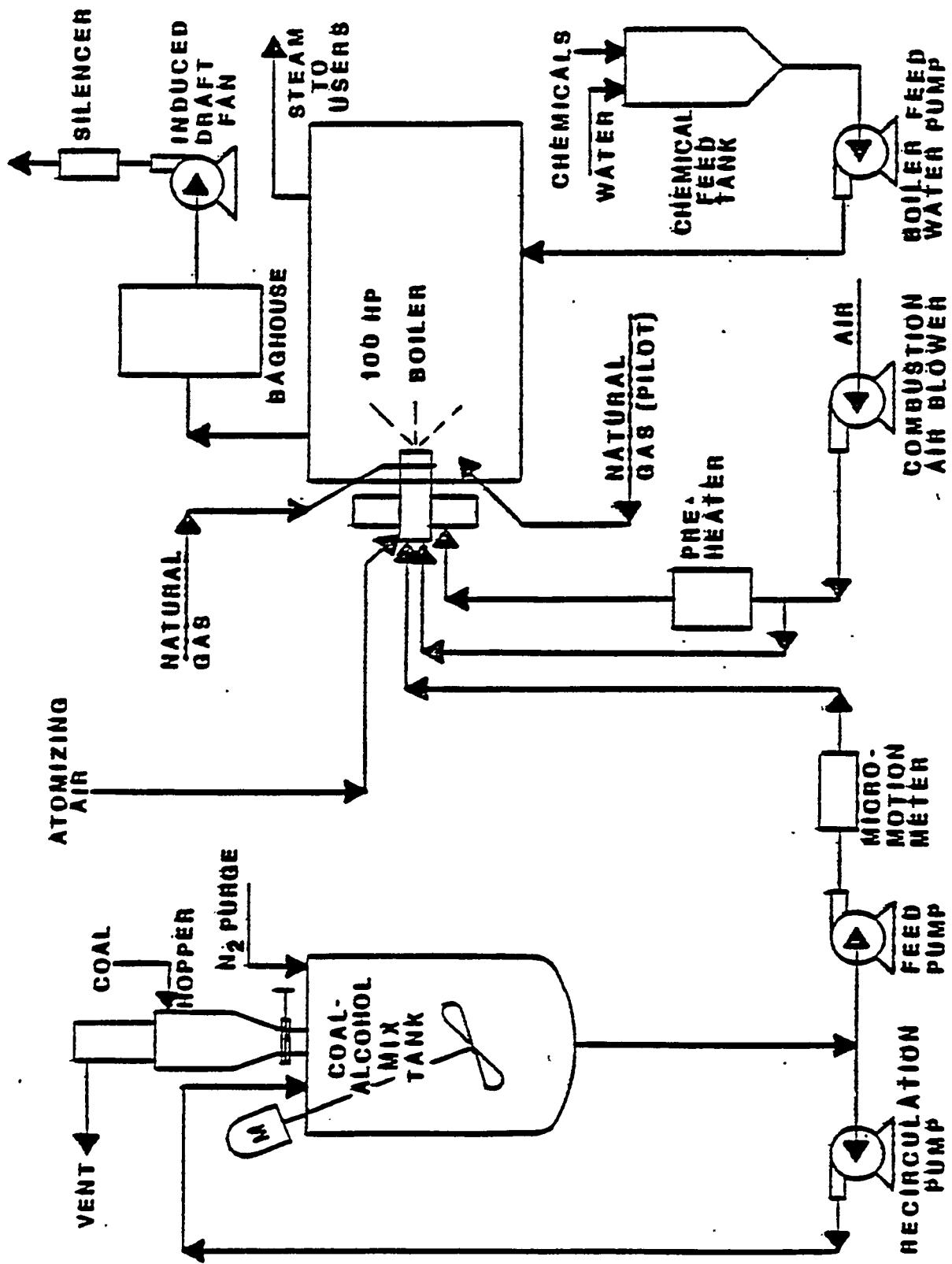
<u>COAL CONC., wgt %</u>	<u>VISCOSITY, Cp*</u>
45.0	46
47.5	251
50.0	652
52.5	2360
(60% PGH SEAM COAL	354)

*AFTER 50 SEC AT SHEAR RATE OF 200⁻¹ sec

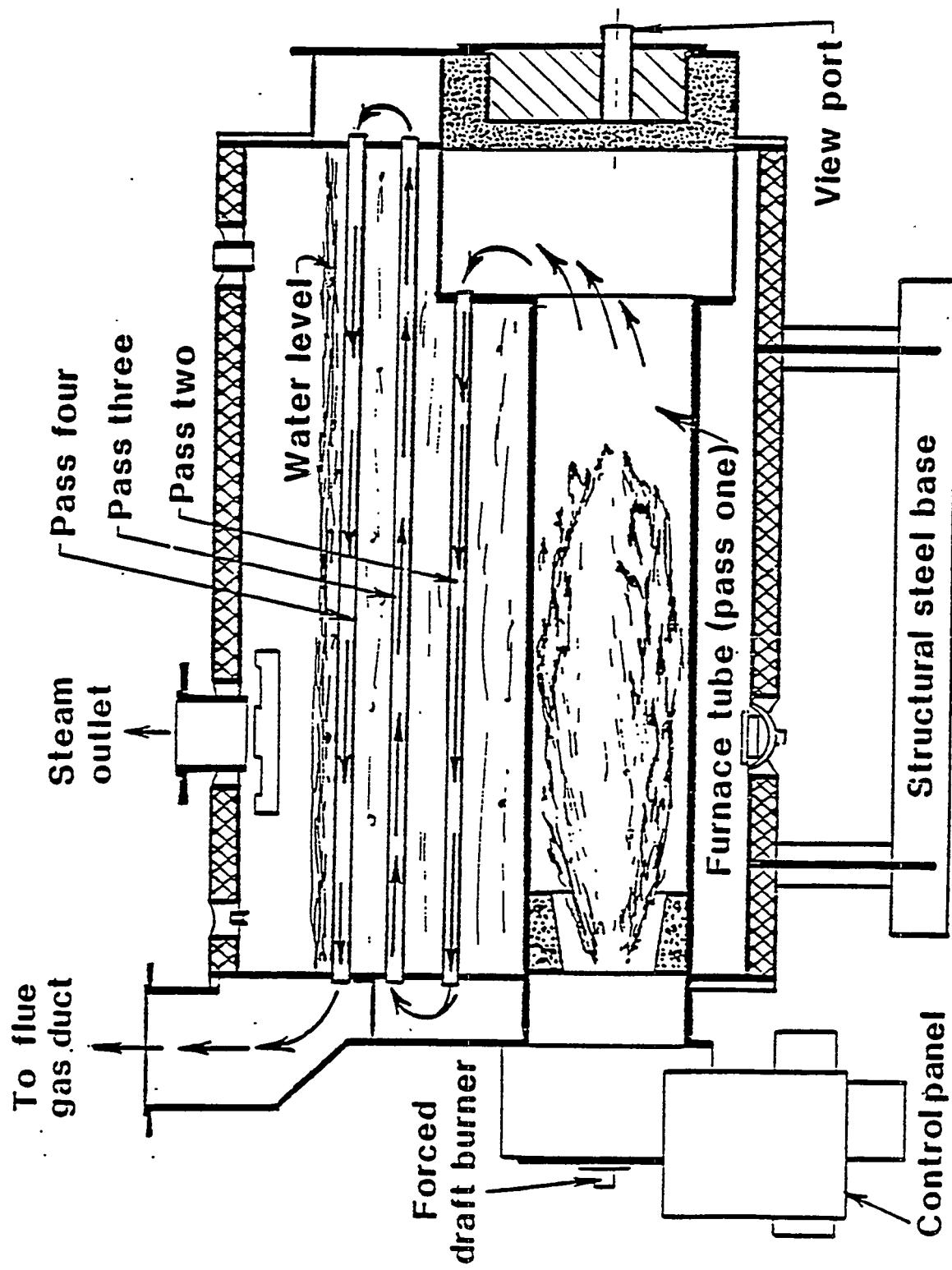
^{1/}J. M. Ekmann, Pittsburgh Energy Technology Center



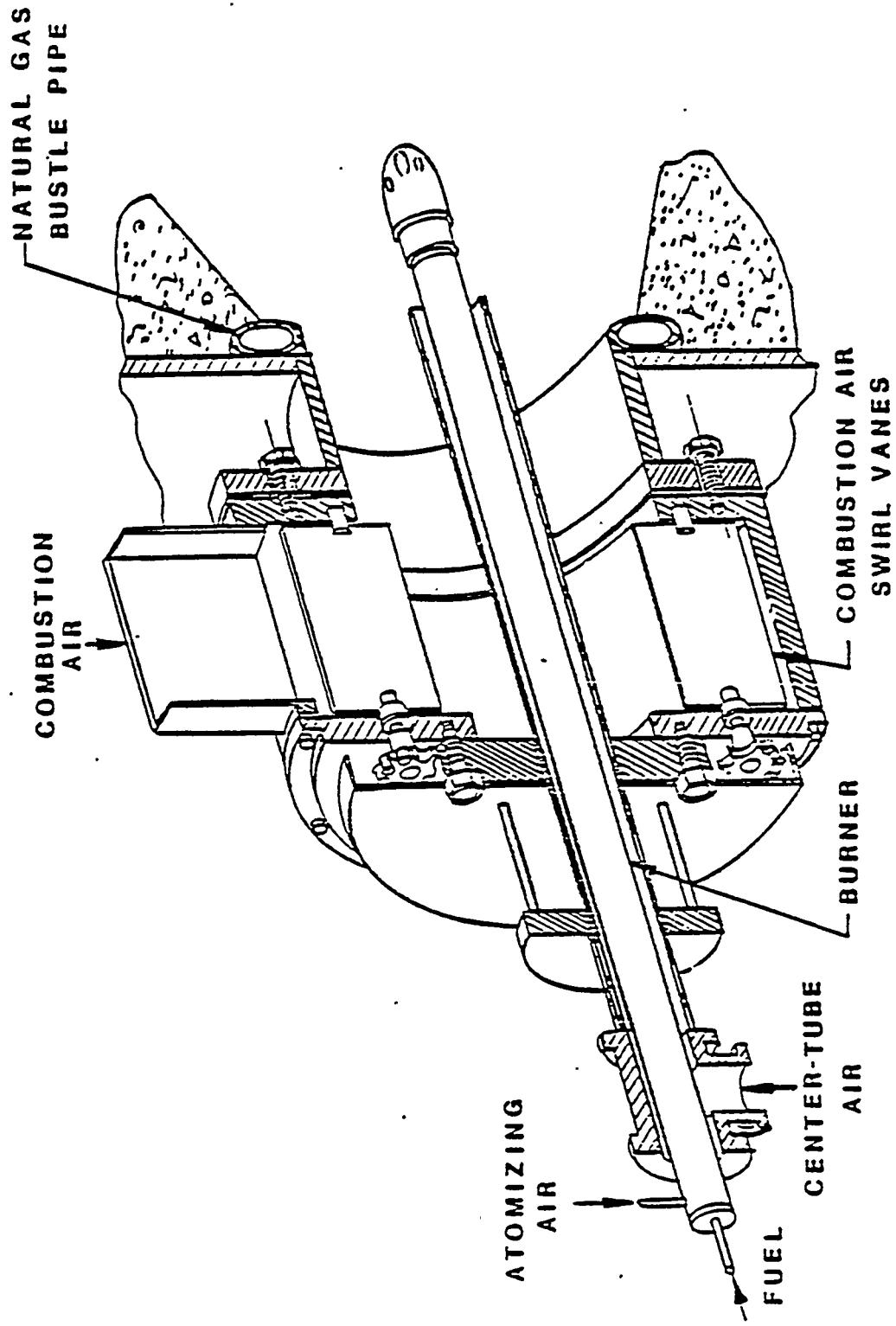
VISCOSITY vs PERCENT METHANOL IN LIGNITE-WATER-METHANOL MIXTURES



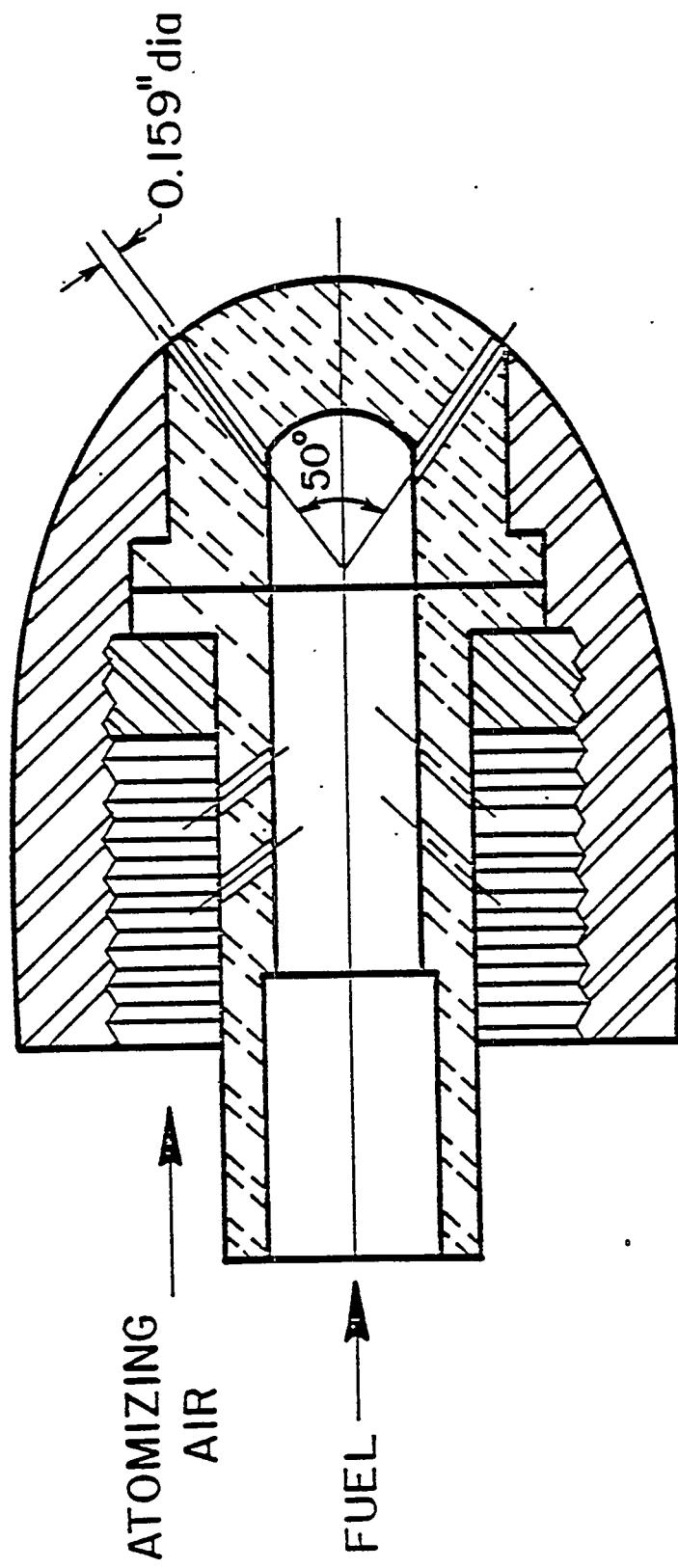
Flow Diagram of the 100-hp Combustion Test Facility as Arranged for
COAL-METHANOL Combustion Tests



Vertical Cross-Section View of the 100-hp Firetube Boiler



Air Register and Burner Nozzle Arrangement in the 100-hp Boiler



BURNER NOZZLE USED FOR CMM AND CMM TESTS IN THE 100-HP BOILER

COAL SLURRY TESTS IN 100-HP BOILER(1)

NO. 6 OIL	CWM	CMM	CMM	CMM	CMM	CMM
FUEL COMPOSITION, %						
COAL (MOISTURE FREE)	60.0	61.0	55.9	54.9	56.0	
METHANOL	----	39.0	26.0	17.8	8.7	
WATER	40.0	0	18.1	60/40	40/60	20/80
HEATING VALUE (BTU/LB)	18530	7810	11649	9639	8710	7960
FLUE GAS O ₂ , %	2.3	3.3	3.0	5.0	4.2	3.6
EXCESS AIR, %	11.6	2.5	8.3	20.0	14.8	5.4
COMBUSTION AIR TEMP., °F	75	528	79	79	66	428
CARBON CONVERSION						
EFF., %	99.8	85.2	92.2	85.9	90.2	88.8
BOILER EFFICIENCY, %	82.9	69.3	77.2	69.9	72.0	72.4
HEAT LOSS, %						
H ₂ O IN FUEL	0	5.72	0.11	2.24	3.75	5.02
HYDROGEN IN FUEL	6.04	3.79	7.17	6.59	6.00	4.80
CO IN FLUE GAS, PPM	98	106	53	124	105	50
NOX IN FLUE GAS, PPM	255	712	564	407	429	684
LB/MBTU	0.32	0.85	0.67	0.53	0.55	0.81
FLY ASH EMISSIONS, #/HR	0.9	81.9	34.0	75.8	63.7	62.8
LB/MBTU	0.19	15.67	7.94	14.41	12.82	12.64

FUEL COSTS

	<u>\$/MBTU</u>
NO. 6 OIL	4.90
60 COAL, 40 MeOH	4.84*
55 COAL, 18 MeOH, 27 H ₂ O	3.64*
45 COAL, 55 OIL	3.60
56 COAL, 9 MeOH, 35 H ₂ O	2.63*
60 COAL, 39.5 H ₂ O/0.5% ADDITIVE	2.08*

*CORRECTED FOR LOWER BOILER EFFICIENCY

	<u>\$/MBTU</u>
COAL \$30/ton	1.20
NO. 6 OIL \$30/BBL	4.90
MeOH \$0.70/GAL	10.90
ADDITIVE \$0.80/LB	—

FUEL COST COMPARISON OF METHACOAL AND COAL-WATER MIXTURES

70 COAL, 30 H₂O

ADDITIVE RANGE 0.5-1.0 wgt% (80¢/lb)

\$1.96-2.49/MBTU

56 COAL, 9 MeOH, 35 H₂O

METHANOL RANGE 50-70¢/GAL.

\$2.23-2.63/MBTU

CANADA-JAPAN COAL METHANOL SLURRY PROJECT*

o FINANCED:

1/3 - PROVINCE OF ALBERTA

1/3 - WEST COAST TRANSMISSION CO.

1/3 - CHIEFTAIN DEVELOPMENT LTD.

o AGREEMENT SIGNED WITH 15 MITSUI COMPANIES

o SLURRY TO BE MADE IN ALBERTA WHERE COAL FIELDS AND NATURAL GAS ARE PLENTIFUL. SHIPMENT BY PIPELINE OF 55 COAL-45 MeOH, 750 MILES TO COAST, THEN BARGED TO JAPAN. FUEL CAN BE DELIVERED TO JAPAN AT 65% OF FUEL OIL COST. IN JAPAN, PART OF METHANOL WILL BE REPLACED BY WATER.

o PREPARATION COST OF METHANOL U.S. \$165/METRIC TON = \$0.50/GAL.

POSTED PRICE OF METHANOL \$0.76/GAL.

***INFORMATION OBTAINED 11/16/82 FROM R. M. RUTHERFORD, PROJECT MANAGER, CHIEFTAIN CONSORTIUM, AND N. A. LAWRENCE, DIRECTOR, CHIEFTAIN DEVELOPMENT**

KBNW

METHANOL FROM COAL:

	<u>EASTERN PLANT</u>	<u>WESTERN PLANT</u>
TECHNOLOGY EMPLOYED	INDIRECT LIQUEFACTION	INDIRECT LIQUEFACTION
METHANOL PRODUCTION CAPACITY	22,000 BBL/DAY	46,000 BBL/DAY
COAL CONSUMPTION	6,000 TONS/DAY	16,000 TONS/DAY
COAL COST	\$35/TON (\$1.60/MILLION BTU)	\$9/TON (\$0.60/MILLION BTU)
LOCATION	TENNESSEE	WYOMING
ANNUAL OPERATING COSTS 1982 DOLLARS	\$130 MILLION (43¢/GALLON)	\$170 MILLION (27¢/GALLON)
PLANT INVESTMENT 1982 DOLLARS	\$1.1 BILLION	\$2.0 BILLION
PLANT GATE METHANOL COST, 1982 DOLLARS	75-85¢/GALLON	60-70¢/GALLON

COAL-WATER-METHANOL

A COAL-WATER SLURRY CONTAINING SOME METHANOL MAY PROVIDE THE BEST COMPROMISE OF PERFORMANCE AND ECONOMICS.

1. LOWER COST OF PIPELINE TRANSPORT. A 50/50 MIXTURE OF COAL/MEOH HAS 60% MORE ENERGY THAN AN EQUAL VOLUME OF 50/50 COAL/H₂O.
2. COAL/MEOH PIPELINE AND COAL/H₂O/MEOH PROCESS FEED LINES NEED NOT BE HEATED OR PLACED UNDERGROUND. 6.4% MEOH PROTECTS TO 0°F, 11% PROTECTS TO -40°F.
3. CARBON CONVERSION AND BOILER EFFICIENCY HIGHER.
4. COMBUSTION AIR PREHEAT PROBABLY NOT NECESSARY.
5. FUEL COSTS ARE APPROXIMATELY 10% HIGHER.

DISCUSSIONS ON COAL RESEARCH AT TRW*
(December 13, 1982)

S. S. Penner visited TRW on December 13, 1982. Discussions related to coal beneficiation and the TRW entrained slagging coal combustor.

A. Coal Beneficiation

The TRW work on the Gravimelt Process by R. A. Meyers and his associates is summarized in Appendix AB-10-1, which is reproduced from a paper presented at the 17th Intersociety Energy-Conversion and Engineering Conference, August 1982. In the Gravimelt Process, fused caustics are used for sulfur removal. Bench-scale tests (5 lbs of coal/hr) have been performed, although not for sufficiently long periods of time to reach steady-state conditions. The beneficiated coal has not yet been used in combustion tests. Caustic regeneration represents about one half of the total cost, with sodium sulfide dissolved in NaOH representing the main products.

Performance data and capital cost estimates are summarized, respectively, in Tables 1 and 2 of Appendix AB-10-1. Ash removal for a single pass is seen to fall in the range 95-99% for mine-cleaned coals containing up to ~23% of ash; SO_2 removals fall in the range 83-92%. Total costs are estimated to amount to about \$25 per ton of coal cleaned, with additional savings possible when larger scale tests are performed.

B. The TRW Entrained, Slagging Combustor

The TRW entrained, slagging combustor was described by Albert Solbes. A readable description of this development is reproduced

*Prepared by S. S. Penner.

in Appendix AB-10-2. This combustor has applications in MHD power conversion [6 atm. pressure, $T_{\text{oxidizer}} > 2500^{\circ}\text{F}$, the oxidizer is oxygen-enriched air, and the equivalence ratio (ϕ) ranges from 0.5 to 0.7], in low-Btu gasifiers (4 to 25 atm., pure O_2 , $\phi = 0.4$), and in retrofits for industrial and utility boilers (1 atm, $T_{\text{oxidizer}} = 750^{\circ}\text{F}$, air is used as oxidizer).

For the third application, tests have been conducted in a 17 in. combustor at about the 3-MW_t level. About 350 hrs. of operation were completed. In general, the TRW combustor will be interposed between the coal-inlet section and the existing (oil-firing) boiler in retrofits for conversion to the use of PC or CWM. The slagging operation will remove about 90% of the coal ash.

Scale-up to a 34 in. i.d. unit (50×10^6 Btu/hr) is being proposed. A 10×10^6 Btu/hr burner is currently in operation at TRW's Capistrano Beach facility.

The modeling program developed by A. Solbes appears to provide an excellent example of current work in this field and may be reviewed at the March meeting of CCAWG in La Jolla.

APPENDIX AB-10-1

PRECOMBUSTION EXTRACTION OF 90% OF THE SULFUR AND 95% OF THE MINERAL MATTER FROM COAL

R. A. Meyers, W. D. Hart and L. C. McClanahan

TRW Electronics and Defense - Energy Development Group

The Gravimelt Process, which results in near complete removal of sulfur and mineral matter from coal consists of treatment with fused caustic to remove the sulfur and a subsequent series of water and dilute sulfuric acid washes to remove the remaining mineral matter. Preliminary engineering design and economic studies indicate that the process will add approximately \$30 per ton to the cost of coal. This is significantly lower than the cost of scrubbing exhaust from existing burners in order to meet air pollution regulations and is consistent with the currently paid premium for coal which can contain as much as 1% sulfur and 10% ash. Major applications for Gravimelt coal can include coal water and coal oil slurries for retrofit boiler and furnace systems, coking coal for steel, aluminum and silicon carbide industries and transportation fuel for automotive turbine engines.

The near complete desulfurization and demineralization of coal has been demonstrated in the laboratory via the TRW proprietary Gravimelt Process (1). Subsequently, the process was further laboratory-tested at TRW under the sponsorship of the U.S. Department of Energy (Contract No. DE-AC22-80PC30141) and TRW is supporting testing and assessing a proprietary regeneration method and scale up to large batch reactor size to provide samples for potential Gravimelt coal users. The process is currently being tested under D.O.E. sponsorship in a 5-10 lb/hr continuous bench scale unit at our San Juan Capistrano California Chemical Test Facility (Contract No. DE-AC-81PC42295).

The TRW Gravimelt Process (Figure 1) involves the treatment of mine-cleaned coal with molten potassium and or sodium hydroxide to chemically extract both organic and pyritic sulfur into the molten alkali. The coal mineral content is broken down to forms mainly insoluble in water but highly soluble in dilute acids such as sulfuric acid. The high density of the melt causes the desulfurized coal to float to the surface, where it is skimmed off. The coal is then washed with water to recover the alkali metals and product sulfur compounds. The coal is next washed with a dilute sulfuric acid where the mineral matter is extracted

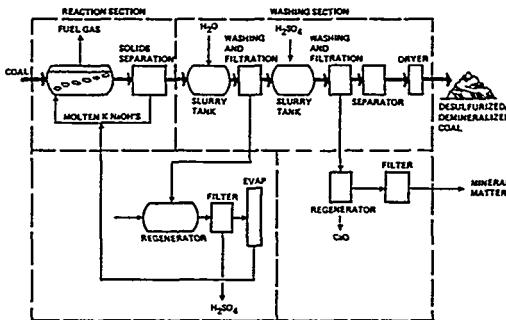


Figure 1. Gravimelt Conceptual Process Flow Diagram

into the solution.

The caustic wash water is treated to recover the extracted coal sulfur as sulfuric acid and the caustic solution is reconcentrated in an evaporator system for recycle to the reactor. The acidic wash water is neutralized with lime to produce a clay, silica and gypsum material.

TEST RESULTS

A summary of typical results, obtained under standardized conditions, for a range of U.S. coals is presented in Table 1. All of the samples were reduced to well below 1 lb of $\text{SO}_2/10^6$ Btu and less than 0.4 lbs of ash/ 10^6 Btu which corresponds to 83-93% removal of sulfur and 95-99% removal of ash. When sulfur and ash reduction due to cleaning at the mine is added to these results, sulfur reduction approaches an average of 90-95% and ash removal approaches 99% for all of the samples. The standardized removal results shown above can be improved by the use of longer reaction times and by multiple pass extractions to give residual sulfur and ash at 0.1% concentrations.

ENGINEERING

Preliminary engineering design and cost studies indicate that the total installed capital cost of a 10×10^9 Btu/hr (approximately 400 ton/hr input coal) Gravimelt plant can be estimated at about \$80,000,000 which corresponds to a total invested capital cost of \$115,000,000. Table 2 indicates the percentages of these costs associated with each process section.

TABLE 1. TRW GRAVIMELT PROCESS RESULTS* FOR U.S. COALS

Coal	Feed Product	Analysis, dry basis		Heat content, Btu	lbs SO ₂ 10 ⁶ Btu	lbs Ash 10 ⁶ Btu	SO ₂ removal %	Ash removal %
		S, %	Ash, %					
W. Ky. No. 9	Feed Product	3.93 0.37	22.85 0.27	10795 13359	7.28 0.55	21.2 0.20	92	99
W. Ky. No. 11	Feed Product	3.51 0.52	7.26 0.21	13182 13530	5.33 0.77	5.50 0.16	86	97
Ill. No. 6	Feed Product	3.45 0.28	11.92 0.14	12342 13518	5.60 0.40	9.66 0.10	93	99
Lucas No. 5	Feed Product	2.17 0.25	8.29 0.41	13116 13334	3.30 0.38	6.32 0.31	88	95
Pittsburgh No. 8	Feed Product	3.12 0.55	10.68 0.40	12907 13801	4.83 0.80	8.28 0.32	83	96
Lower Kittanning	Feed Product	5.24 0.64	13.60 0.39	12931 14420	8.11 0.89	10.52 0.27	89	97

*coal treated for 30 mins at 370°C with a 1:1 wt mixture of fused NaOH/KOH, washed with water, then with aqueous sulfuric acid, then with water and dried.

TABLE 2. GRAVIMELT PROCESS CAPITAL COSTS

Reaction Section	
Solids handling and storage, fused caustic reactor, filtration, pumps, etc.	25%
Coal Recovery and Mineral Rejection	
Slurry tanks, filtration neutralization, storage, etc.	25%
Caustic Regeneration	
Regenerators, evaporator system, centrifuges, sulfuric acid plant, etc.	50%
Total Installed Capital Cost	\$ 80,000,000
Total Invested Capital	\$115,000,000

Total non-capitalized operating costs are estimated to be approximately \$46,000,000 (includes coal for process heat, caustic loss, power, process and cooling water, labor, supervision, general overhead, maintenance, taxes and insurance and operating supplies, etc.). Annual capital charges of 20% of the total plant investment or \$23,000,000 brings the total amortized operating costs to near \$70,000,000 which corresponds to \$25 per ton of coal product as a cost to be added to the price of coal. Since the process is in an early stage of development, it is believed that this processing cost has an upside potential of about 25%. Thus, it is recommended that a potential price (in 1980 dollars) of \$30 per ton should be utilized when assessing the Gravimelt Process for various applications.

APPLICATIONS

The Gravimelt coal could offer major advantages for use as a boiler fuel either in its solid form or as a coal water or coal oil slurry. These advantages are as follows:

- 1) low sulfur and ash content will comply with the majority of governmental regulations for pollution control,
- 2) the low sulfur and ash content will reduce boiler downtime due to corrosion and erosion and would allow production of smaller boilers due to the elimination of slag and ash handling,
- 3) as a coal water or coal oil slurry ingredient, the Gravimelt coal will have the previous two advantages and will not erode or corrode in plant boiler equipment or furnace nozzles,
- 4) the Gravimelt coal may have use as a transportation fuel for turbine and diesel engines where engine component erosion due to coal ash is presently a limiting factor, and
- 5) coke made from Gravimelt coal could have premium qualities due to low ash and sulfur.

REFERENCE

- 1) Meyers, R. A. and W. D. Hart, Patents Pending.

TRW'S ENTRAINED SLAGGING COAL COMBUSTOR

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1.0 Abstract

For the past seven years TRW has been engaged in the development of an advanced coal combustor which can be used to retrofit coal-, oil- and gas-fired boilers, furnaces and process heaters. We have conducted over 700 tests on four entrained slagging coal combustors ranging in power level from 1 MBTU/hr to 70 MBTU/hr. The extensive data base generated in these tests has been combined with an engineering computer program specifically developed to predict combustor scaling, design parameters, and performance. The design is based upon technology developed through company-sponsored programs using as a baseline TRW's experience in rocket propulsion, low NO_x burners, and Magnetohydrodynamic (MHD) coal combustors. A demonstration is planned in 1983-84 to obtain life, reliability and maintenance information.

2.0 Introduction

TRW is developing three related coal conversion systems:

1. A combustor for retrofit/replacement of existing coal-, oil- and gas-fired burners on kilns, process heaters and industrial and utility boilers.
2. A compact gasifier for producing fuel gas and higher grade chemical feedstock gas from coal.
3. A high temperature combustor for Magnetohydrodynamic (MHD) power generation when coupled to fluid flow/electrical conversion equipment.

This paper overviews the chronological development of TRW's coal conversion systems while rapidly focusing on the retrofit combustor device which the company plans to commercially manufacture, sell and service beginning in 1985. Combustor hardware and test results are described followed by our plans for a field demonstration program in 1983-84.

3.0 Coal Combustion Technology Evolution

TRW's entry into coal combustion was a natural continuation of years of successful work in combustion research, rocket propulsion, and low NO_x burner development. In 1975, we initiated coal combustor design activities. Continuing into 1976, we fabricated a small scale test unit (1 MBTU/hr) and conducted both atmospheric and pressurized combustion tests. We demonstrated that powdered coal could be fluidized at 10/1 mass ratio of coal to transport fluid and successfully injected into the combustion chamber using an injector concept derived from our Lunar Module Descent

Engine. A 10/1 throttling ratio was required in this engine to maintain high performance across the entire range of thrust levels. The rocket propulsion concepts of aeroballistically controlling combustion ratio and fuel particle trajectories were incorporated into the small scale coal combustor design. Good ignition and stable combustion were achieved with slag being centrifugally driven to the wall by the aerodynamic swirling flows.

We next scaled the combustor design to 10-30 MBTU/hr. The specific power level achieved for the fixed design depended upon the mass throughput at an operating pressure in the range of one to six atmospheres. A feasibility test unit was constructed and an extensive combustion test series was performed in 1977-78 using preheated air and coal flow rates in the range of one half to two tons/hr. Good combustion and acceptable slag removal conditions were achieved during this company sponsored test series in each of the three regimes of interest for retrofit combustors, low BTU gasifiers, and MHD combustors.

DOE sponsored further testing of the feasibility unit in 1978 in the MHD application regime; i.e., high air preheat and/or oxygen enrichment, three to six atmosphere combustor pressures, potassium carbonate seeding to enhance gas electrical conductivity and exit gas temperatures in excess of 4000°F. After these tests, the combustor was loaned to Argonne National Laboratory for heat recovery/seed recovery experiments. Based on the feasibility unit test results, the combustor was scaled to 70 MBTU/hr. A test unit at this scale was designed and fabricated. Over 100 tests were conducted on this unit at TRW's Fossil Energy Test Site during 1979-80. These tests were performed with air preheat conditions of 1100°F to 3700°F, combustor pressures of 3 to 6 atms and coal flow rates of 2 to 3.5 T/hr. A final demonstration series was successfully conducted at 6 atms and 2900°F air preheat conditions, after which TRW was selected as DOE's MHD combustor developer. Since the demonstration, we have conducted a 140 cumulative hour MHD combustor life test and performed integrated combustor/channel testing using the 70 MBTU/hr hardware. We have also completed the preliminary design of a 170 MBTU/hr MHD field test unit and expect to build and test this unit within the next year.

More recently, we have concentrated on testing a second 10 MBTU/hr combustor at the one atmosphere, 400-750°F air preheat conditions characteristic of existing industrial, commercial and utility plants. During 1981-82, over 200 tests were conducted under company sponsorship with good combustion, low NO_x emission and acceptable slagging results. We expect to complete the design of a 40 MBTU/hr combustor by year end. This unit will be fabricated and tested in our facility during 1983 to provide the design of a 40 MBTU/hr combustor by year end. This unit will be fabricated and tested in our facility during 1983 to provide the design basis for a commercial type 40 MBTU/hr combustor which will be used in an industrial boiler plant demonstration program planned to begin in late 1983.

4.0 Coal Combustor Description

The TRW Entrained Slagging Combustor is shown in Figure 1. The design is based upon the extensive development effort described in the previous section. The configuration consists of a water-cooled right circular cylinder with a simple baffle located in the aft region to promote the appropriate mixing/combustion reactions and slag flow patterns. Powdered coal (70% through 200 mesh) is transported to the pintle in a dense-phase fluidized condition, conically injected into the combustor and then burned in flight in the cylindrical volume with slag impinging on the wall and being driven to the slag tap by a combination of aerodynamic and gravity forces. The slag is removed from the combustor by flowing into a water-filled slag tank where slag fracture and size reduction are accomplished. Coal water mixtures (70% powdered coal, 30% water) have also been burned in the combustor by substituting an air atomized injector for the powdered coal pintle previously discussed.

Generally the combustor is operated at an equivalence ratio in the range of 0.7-0.9. The resulting hot product gas which is rich in CO and H₂ is ducted to the heat utilization equipment interface where secondary air is added. Combustion of the product gas is completed within the furnace volume of the heat utilization equipment resulting in a staged combustion process which minimizes NO_x formation. Sufficient temperature and heat flux must be generated within the coal combustor volume to achieve liquid slag flow conditions but the classical high NO_x formation regime can be avoided by the combination of temperature and gas composition control. The product gas can be delivered to the heat utilization equipment either via a deswirl section aft of the baffle as shown in Figure 1 or by allowing the swirling flows to continue axially into the secondary furnace volume. The approach to be used depends upon the specific application.

The combustor offers significant advantages when compared to competitive retrofit technologies including simplicity and compactness of design, refractory free construction, highly efficient combustion, and high ash removal. These characteristics, combined with low NO_x operation, small particulate carryover and high turndown ratio, allow operational flexibility with low maintenance and high reliability. A more definitive listing of the principle characteristics of the combustor is given in Table 1.

The combination of simplicity and compactness make the device ideal for retrofitting existing oil- and gas-fired kilns, furnaces and boilers within the available space. Note that a combustor 2'D X 4'L produces up to 20 MBTU/hr and when scaled by a factor of over twelve to 250 MBTU/hr grows to only 7'D X 11'L.

TABLE 1
CHARACTERISTICS OF TRW COMBUSTOR

• SIMPLE CONFIGURATION	CYLINDER WATER COOLED	LOW MAINTENANCE
• SMALL SIZE	2'D x 4' - 7'D x 11' (20-250 MBtu/HR) 1 MBtu/HR-FT ³	FITS AVAILABLE SPACE
• NO REFRACTORY LINER	~ 1" SLAG ON WALL	AVOIDS FAILURE, DOWNTIME
• HIGH SLAG REMOVAL	80 - 90%	MINIMIZES CARRYOVER
• HIGH CARBON BURNOUT	>99.5%	EFFICIENT COMBUSTION
• LOW NO _x	250 - 450 ppm	STAGED COMBUSTION
• LOW HEAT REJECTION	5 - 8%	EFFICIENT SYSTEM OPERATION
• FLEXIBLE DEVICE	ADJUSTABLE AIR AND COAL FEED	ACCOMMODATES RANGE OF COALS
• TEST PROGRAM	SHORT DURATION	MANY CYCLES
• STATE OF DEVELOPMENT	FEASIBILITY SHOWN	SPECIFIC RUN CONDITIONS, SCALING AND LONG DURATION DEMO REQUIRED

Since no refractory materials are used within the slagging combustor, refractory erosion, failure and replacement downtime are avoided. The continually generated slag on the walls of the combustor acts as an effective thermal and hot gas barrier allowing the water-cooled walls to operate at a conservative temperature of approximately 600°F. Heat transferred to the cooling water is calculated to be only 5-8% of the total heat released in commercial combustor designs. This heat can be effectively utilized in boiler feedwater circuits or for air preheating, thus contributing to the overall thermodynamic efficiency of the heat utilization system.

The high slag removal characteristic minimizes particulate carryover into heat utilization equipment; e.g., for a 10% ash coal only about 1%-2% particulates would carryover. Additionally, the carryover material typically consists of slag particles less than 10-15 μ which tend to follow the flue gas streamlines rather than eroding or depositing out on any internal

structures within the heat utilization equipment; e.g., convective pass tube bundles. The major advantage sought from the current and proposed test program is the ability to convert existing heat utilization equipment designed for oil-/gas-firing to coal firing without any significant derating of the equipment.

Stable, well-anchored flames are produced in the combustor with gas residence times on the order of 100 milliseconds. This leads to efficient combustion with carbon burnout values in excess of 99.5% as measured by the amount of carbon remaining in the slag waste material. The staged combustion feature of the TRW retrofit system leads to low NO_x production, in the range of 250 to 450 ppm. We are attempting to demonstrate NO_x values at the stack outlet consistent with present oil fired standards (approximately 250 ppm) while simultaneously obtaining high slag removal and carbon conversion values. Since both coal and air flow rates are adjustable and the air inlet momentum can be varied by use of a movable damper valve, combustor turndown values in the range of two to four are possible. Three western and two eastern coals have been successfully burned in the feasibility unit.

To date, our combustor test program has yielded data over a wide range of operating conditions. The hardware has experienced numerous thermal cycles without failure. Test durations have typically been 1 to 2 hours in length with some runs up to eight hours. We have also subjected the pintle to hundreds of hours of simulated erosion tests in our laboratories. This approach has provided data on the combustor geometry/run conditions which are applicable to retrofit applications in general. The basic feasibility of the combustor has been shown at 10 MBTU/hr. We are now focusing on specific run conditions for kilns, furnaces and boilers while at the same time scaling a test unit to 40 MBTU/hr. After confirming tests at our Fossil Energy Test Site (FETS) with the larger scale hardware, we will be ready to implement a long duration field demonstration with a commercial 40 MBTU/hr combustor integrated with an existing industrial boiler located in our Cleveland Aircraft Parts Plant. The field demonstration will provide essential data on combustor performance, life and reliability as well as the combustor's exhaust interaction with the boiler.

5.0 Combustion Research Activities

A continuing combustion research program undergirds TRW's hardware development efforts. For example, coal devolatilization rate information is acquired in a special inert gas chamber where an infrared laser is used to simulate combustion heat fluxes to the coal particles. Turbulent mixing information is obtained using the laboratory flow visualization equipment shown on left side of Figure 2. During operation, different density gases, some of which are seeded with fine particulates, are injected into the volume and visible low power lasers are used to produce images to study the mixing effects as shown on the right of Figure 2.

Prior to final hardware fabrication, a full scale plastic model of a proposed combustor test unit is constructed for detailed aerodynamic flow visualization as shown in Figure 3. Heated air enters the model through

the horizontal wrapped duct on the left side of the figure. Entrance Reynolds numbers are thus simulated. Fine particulates are injected through the pintle at the right end of the combustor model and high speed photographs are taken to establish particle trajectories and distribution, as well as the nature of the internal swirling flows and their sensitivities to model geometry changes. Key model pressures are measured and recorded via pressure transducers and the Manometer bank, shown in the background. Using this approach, much insight into combustor geometry optimization can be obtained before actual combustors are built and hot firing tests conducted.

In parallel with the above laboratory and engineering studies, an analytical model has been developed and computerized. It utilizes five subroutines to analytically model thermochemistry, aerodynamics, combustion, heat transfer and slag flow phenomenon. The model functions in much the same way as a test is conducted; i.e., combustor geometry, orientation, pressure, coal type and flow rate and oxidizer type and flow rate are input. The model then computes expected gas compositions, temperatures, carbon burnout, pressure drop, heat transfer to coolant and slag removal/losses. The model is anchored with test data from actual combustor firings and used in combustor scaling and test prediction/analysis efforts. It is very useful as a means of improving our understanding of the internal workings of the entrained slagging combustor.

6.0 Combustor Scaling

The first small scale combustor hardware fabricated and tested in 1975-76 is shown in Figure 4. Coal injection experiments were first conducted to establish fluidization, flow and injection parameters. Combustion chamber components were fabricated and initial coal-fired combustion tests using both swirling and tangential preheated air injection were performed at atmospheric and pressurized conditions. We achieved acceptable mixing and combustion conditions with slag being centrifuged to the chamber wall.

The next hardware designed and fabricated was the feasibility unit shown in Figure 5. This unit employed a 17" internal diameter chamber scaled from the analysis and test data previously obtained from the small scale experiment. The hardware was designed so that the chamber geometry could be varied in length by the addition or deletion of spool sections. The positions of the coal pintle, tangential air inlet, internal baffle and slag tap with its accompanying slag tank could also be varied from run to run as appropriate. Each major section was individually flanged to accommodate repositioning and water cooled so that axial calorimetry information could be obtained. The feasibility unit was designed to produce 10 MBTU/hr at a combustor pressure of one atmosphere and slightly over 30 MBTU/hr when operated at about six atmospheres. The hardware was horizontally mounted with the slag tank vertical as shown in Figure 5. The hot, swirling combustor gases exited the unit axially into a chamber where more air was added to complete combustion. After testing at TRW, the unit was loaned to Argonne National Laboratory for MHD heat recovery/seed recovery experiments. The combustor is still in use at their facility.

To accommodate larger sized combustors, TRW constructed a major new capital facility in 1978, the Fossil Energy Test Site (FETS), at our Capistrano Test location as shown in Figure 6. Two test bays separated by a coal storage/feed area were built. Each bay can accommodate two combustors. Cooling water is pumped in a closed loop through the combustor flow channels and then to the cooling tower shown at the right of the figure. Liquid oxygen and liquid nitrogen storage vessels are also visible. Test control and instrumentation functions are performed within the control center building located in front of the test bays as shown in Figure 6. The automated control panel and instrumentation setups are shown in Figure 7.

The next combustor designed and fabricated by TRW is shown in Figure 8. This unit is 24" in diameter and operates at 70 MBTU/hr in the 3 to 6 atmospheres pressure regime associated with the MHD application. The second stage air injector and slag tank are also shown in the figure. Primary air is preheated to very high temperatures and tangentially injected into the combustor. Powdered coal is introduced via the pintle located on the combustor axis and potassium carbonate seed material is injected to enhance the electrical conductivity properties of the high temperature exit gas.

A photograph of the internal slag layer adhering to the combustor walls after a test is shown in Figure 9. Note the pintle injector located on axis and the tangential air inlet in the upper left of the picture. The slag layer uniformly covers the combustor wall to a depth of 3/8" to 3/4" and has the appearance of a black glassy material. It acts as an efficient thermal and hot gas barrier as previously discussed.

The MHD combustor is currently undergoing additional tests to obtain the design and scaling information necessary to finalize the 170 MBTU/hr combustor configuration.

In parallel with the 70 MBTU/hr hardware development program discussed above, a second feasibility unit was constructed so TRW could concentrate on the commercial retrofit combustor operating regime. The combustor hardware was installed in the Fossil Energy Test Facility as shown in Figure 10. The combustor was elevated at 30° to the horizontal thus adding a gravity vector to aid slag flow. A deswirl section was used in the aft region of the combustor. Hot combustion gas laden with some fine particulates exits the combustor at right angles to its axis entering a circular duct in which secondary air is added to complete combustion of the CO and H₂ rich gas. A water deluge and cyclone scrubber, shown outside the open test cell, is used to provide the required pollution control in the test facility. A closeup of the feasibility test unit is shown in Figure 11. As in the first feasibility unit, this combustor is assembled from flanged sections providing flexibility in combustor length and specific geometry. Each section is individually water-cooled allowing axial calorimetry data to be taken during testing. A vitiator shown in the figure near the test technician is used to preheat the incoming air stream. This system is being used to explore the low preheat, low pressure operating regime characteristic of retrofit applications.

7.0 Test Results

Test results from the first feasibility test unit and the 70 MBTU/hr combustor are summarized in Table 2. Note the wide range of operating conditions explored with the first feasibility test unit as indicated by the values listed for operating pressure, air preheat temperature and equivalence ratio range. Up to 86% of the total ash contained in mine-mouth coals has been captured as slag. Coal ash contents have varied from 5% to 24%. Carbon burnout has consistently exceeded 99.5% as measured by quantitative analyses of carbon contained in the slag. Outlet temperatures vary with the type of coal used and the operating equivalence ratio. Very high values are desired for the MHD operating conditions. Heat rejection to the cooling water in these experimental devices is generally higher than expected in commercial design hardware due to the large number of joints, flanges, etc. The total number of tests on the first feasibility unit have exceeded 300, leading to extensive thermal cycling of the hardware. However, individual tests have been of relatively short duration; i.e., long enough to obtain equilibrium conditions.

Similar data for the 70 MBTU/hr unit is also shown in Table 2. Note that slag recoveries up to 91% were obtained with the larger hardware while at the same time achieving the high carbon burnout values accomplished with the smaller feasibility hardware. In general, both air preheat and exhaust gas temperatures are higher in this unit due to the MHD operating requirements. Test durations were similar to those used in the feasibility test series, except a life test was accomplished on the 70 MBTU/hr unit where continuous operating periods of 22 hours were obtained with accompanying exit gas temperatures in excess of 4400°F.

A summary of the tests performed on the second feasibility test unit operating at approximately 10 MBTU/hr using powdered coal is given in Table 3. These tests were designed to provide information primarily in the retrofit regime. Combustor L/D ratios varied from 1.5 to 4; the combustor orientation was inclined 30° to the horizontal. Operating pressures were consistent with commercially available fans and the air preheat temperature was maintained in the range achievable with conventional waste heat recovery systems, except for some excursions designed to provide complete parametric data. The maximum slag capture and carbon burnout values achieved were consistent with the first feasibility unit. The outlet temperature was generally in the range of 2300 to 2900°F with some parametric excursions to higher values.

TABLE 2
TRW COAL COMBUSTOR TEST SUMMARY

COMBUSTOR TYPE	FIRST FEASIBILITY	MHD
POWER LEVEL (MBTU/HR)	10 - 30	70
INSIDE DIAMETER (INCH)	17	24
OPERATING PRESSURE (ATM.)	1.0 - 6.0	3.2 - 6.0
AIR PREHEAT TEMPERATURE (°F)	800 - 2900	1100 - 2950
EQUIVALENCE RATIO RANGE	0.4 - 1.3	0.5 - 1.2
MAXIMUM SLAG CAPTURE (%)	86	91
CARBON BURNOUT (%)	>99.5	>99.5
OUTLET TEMPERATURE (°F)	2300 - 4070	3600 - 4430
HEAT REJECTION TO COOLING WATER (%)	8 - 15	>10
TOTAL NUMBER FIRINGS	314	173
TOTAL RUN DURATION ON COAL (HRS)	128	191
INDIVIDUAL RUN (HRS)	1 - 2	1 - 22

TABLE 3
TRW COAL COMBUSTOR TEST SUMMARY
Second Feasibility Unit (10 MBTU/hr)

DIAMETER (INCH)	17
LENGTH (INCH)	26 - 62
ORIENTATION	INCLINED AT 30°
OPERATING PRESSURE (ATMS)	1.05 - 1.2
AIR PREHEAT TEMPERATURE (°F)	500 - 1500
EQUIVALENCE RATIO RANGE	0.4 - 1.2
MAXIMUM SLAG CAPTURE (%)	86
CARBON BURNOUT (%)	>99.5
OUTLET TEMPERATURE (°F)	2300 - 3700
HEAT REJECTION TO COOLING WATER (%)	8 - 15
TOTAL NUMBER OF FIRINGS TO DATE	184
TOTAL RUN DURATION ON COAL (HRS)	323
INDIVIDUAL RUN (HRS)	1 - 8

Because of growing interest in making logistical improvements in coal delivery systems, a brief test series using coal water mixtures (CWM) was recently accomplished. Four tons of ARC 70% coal, 30% water CWM was used. The results are summarized in Table 4. The operating conditions were similar to those used with powdered coal. A specially designed atomizing slurry injector replaced the powdered coal pintle previously used. Atomization air mass flow was about 2% of the incoming primary air as indicated by atomization ratios in the range of .01 to .03. Somewhat higher equivalence ratios and a stronger ignition source were required in the CWM tests, but once ignited, the flame was well-anchored and stable. Good combustion was achieved as evidenced by high carbon burnout and stable flame conditions. Maximum slag capture of 75% was accomplished in the limited test series. It appears that comparable slag capture values to those achieved using powdered coal are obtainable. In general, the CWM test results were very encouraging and more testing is planned in the near future.

TABLE 4
TRW CWM COMBUSTOR TEST SUMMARY
Second Feasibility Unit (10 MBTU/hr)

DIAMETER (INCH)	17
LENGTH (INCH)	26
ORIENTATION	30°
OPERATING PRESSURE (ATMS)	1.05 - 1.2
AIR PREHEAT TEMPERATURE (°F)	700 - 1900
EQUIVALENCE RATIO RANGE	0.7 - 1.2
ATOMIZATION RATIO RANGE	0.01 - 0.03
<hr/>	
MAXIMUM SLAG CAPTURE (%)	75
CARBON BURNOUT (%)	>99.5
OUTLET TEMPERATURE (°F)	2800 - 3700
HEAT REJECTION TO COOLING WATER (%)	8 - 10
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TOTAL NUMBER OF FIRINGS TO DATE	6
TOTAL RUN DURATION ON COAL (HRS)	9
INDIVIDUAL RUN (HRS)	1 - 2

The basic feasibility of burning powdered and water slurried mine-mouth coal has been established by TRW at 10 MBTU/hr. Efficient combustion and high ash removal as molten slag have been demonstrated. We are now focusing on specific run conditions for kilns, furnaces and boilers. In parallel, we are designing a 40 MBTU/hr engineering test unit which will be fabricated and tested in 1983 to verify scaling and provide the basic data for final design and construction of a commercial type combustor to be used in a field demonstration program.

8.0 Field Demonstration

TRW believes that the final step prior to commercialization involves a field demonstration program using a representative commercial combustor integrated with typical heat utilization equipment. We have structured such a program and are now seeking interested sponsors to assist in funding this effort. The participants will probably include utilities, potential industrial users and other organizations interested in seeing advanced coal combustion technology commercialized.

TRW's demonstration program will provide combustor life, reliability and maintenance data through the conduct of a 4000-hour long-term test under continuous plant operating conditions. It will also provide quantitative data on the performance of heat utilization equipment under the influence of combustor exhaust products. The program has been designed to take full advantage of TRW's prior development work; the engineering services of Stone & Webster, a company with 90 years experience in engineering design and construction; and the operating steam plant in TRW's TAPCO (Thompson Aircraft Parts Company) facility shown in Figure 12.

The industrial boiler selected for this test series was originally designed for stoker coal firing and converted to oil and gas firing in 1969. Much of the required coal receiving and handling capability is still in place as shown in Figure 13 and will be used in the demonstration.

The demonstration will involve the following sequence of activities:

- Modifications to the existing boiler plant which are necessary to accommodate the combustor equipment including the addition of coal crushing/grinding, cooling water, air preheating, stack gas particulate removal, and slag disposal systems.
- Design and fabrication of a 40 MBTU/hr commercial type coal combustor system consisting of an entrained slagging combustor, dense phase coal feed system, slag removal equipment, a secondary burner which interfaces with the boiler, and appropriate instrumentation.
- Brief hot-fired acceptance test of the combustor system at FETS.
- Integration of the combustor system with the 30,000 lb/hr Keeler boiler and necessary support systems at the TAPCO boiler plant as shown in the artist's rendering of Figure 14.
- Short duration test series to check out integrated combustor system-boiler performance.
- 4000-hour test conducted during a six-month period using a selected low sulfur coal to obtain key information on durability, maintenance and long-duration operation of the combustor system and boiler when exposed to combustor exhaust products. The latter data will be used to evaluate the expected performance of various types of oil-fired heat utilization equipment when coupled to the TRW combustor.
- Three-month test series using coals of particular interest to our sponsors.

This demonstration will be followed by specific field applications in customer facilities and the sale of commercial coal combustion retrofit systems by 1985. We will also further scale the device to larger sizes after the technology is demonstrated.

9.0 Conclusion

The retrofit of oil- and gas-fired commercial heat utilization equipment with TRW combustors will result in a substantial fuel savings and provide a much more secure fuel supply. Also since the combustor hardware costs will be modest and most of the existing heat utilization equipment already in place could be used, the capital investment required will be much smaller than for replacement of competing coal-fired equipment.

TRW is firmly committed to the development and commercialization of the coal combustor system as evidenced by the continuing expenditure of millions of dollars of its own funds. We are now seeking interested organizations who will directly benefit from the application of the developed unit to assist in sponsoring the TAPCO Demonstration Program as a final step prior to commercialization.

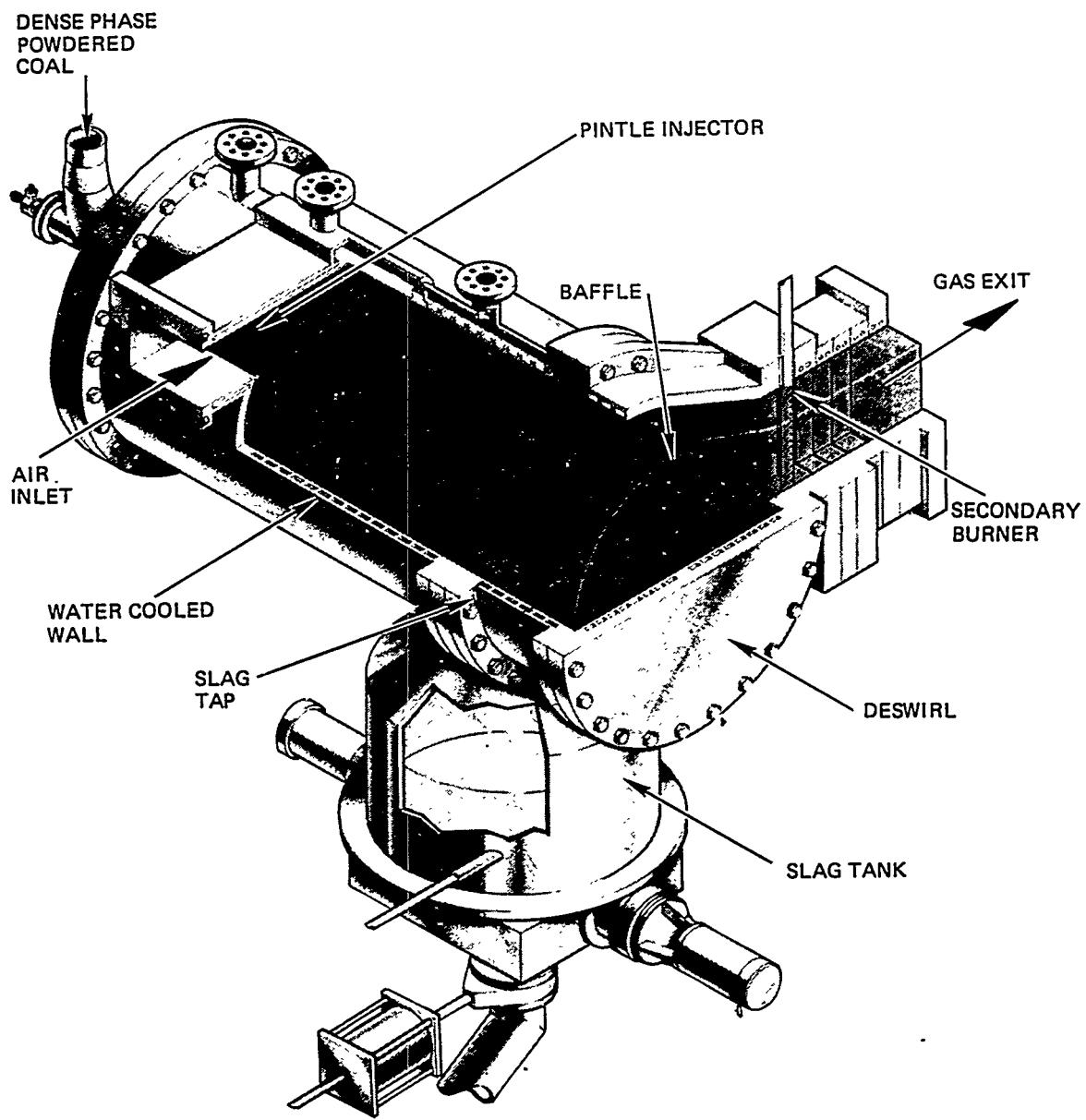


FIGURE 1. TRW COAL COMBUSTOR

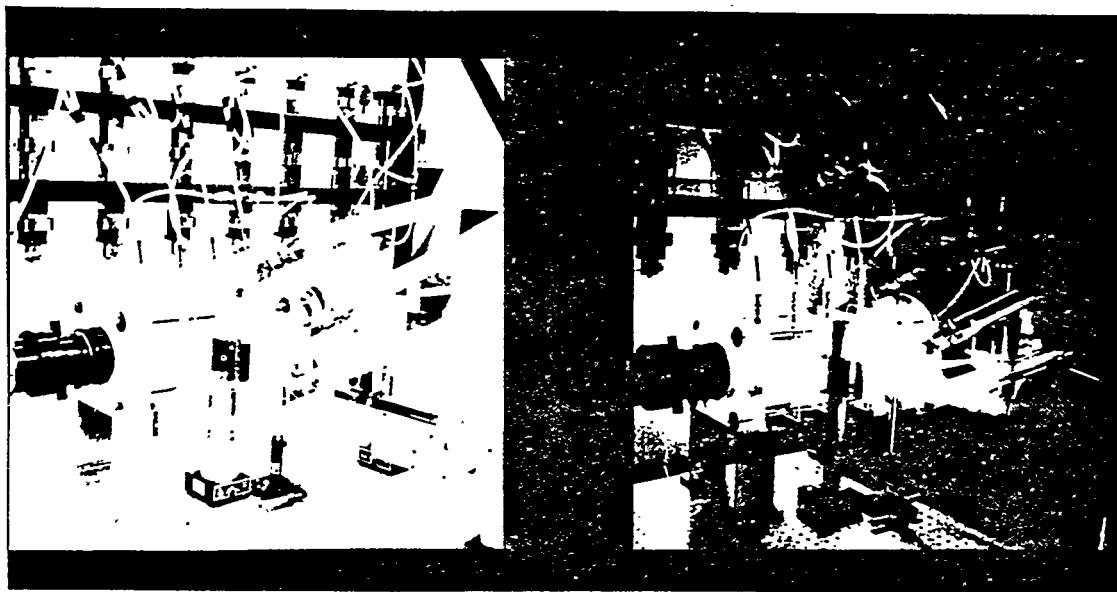


FIGURE 2. COMBUSTION RESEARCH

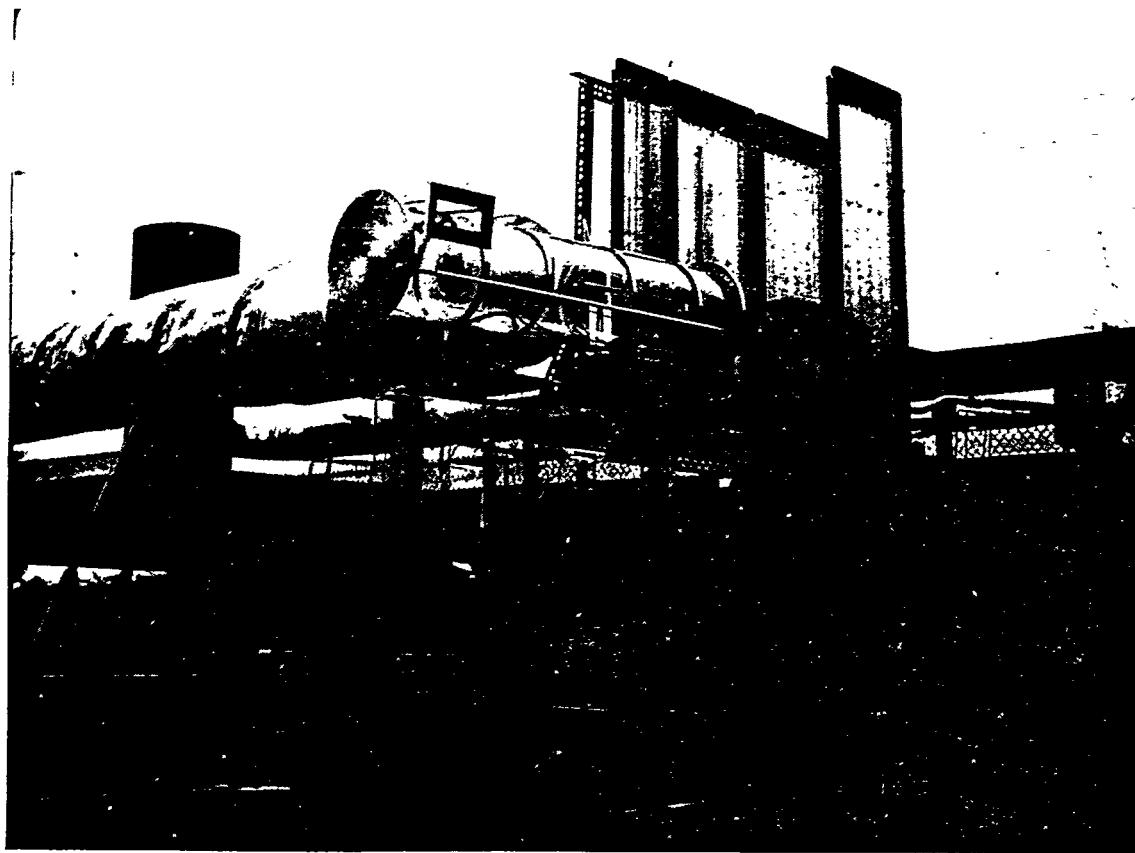


FIGURE 3. COMBUSTOR AIR FLOW MODEL

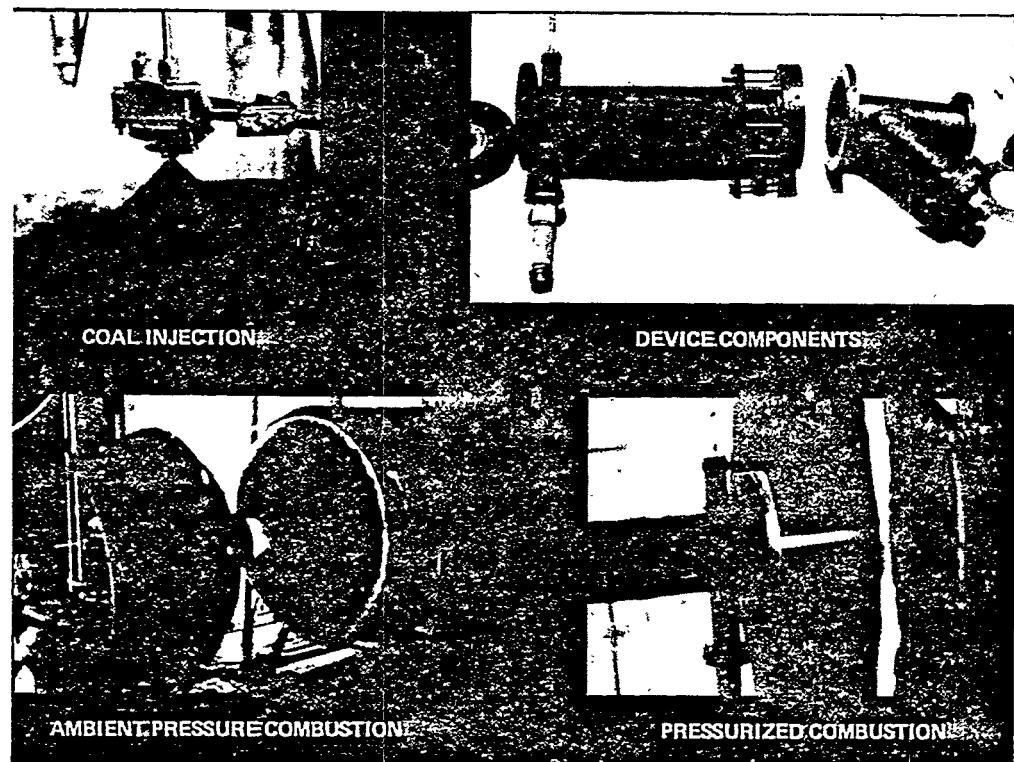


FIGURE 4. SMALL SCALE DEVICE (1 MBTU/HR)



FIGURE 5. FEASIBILITY UNIT (10-30 MBTU/HR)

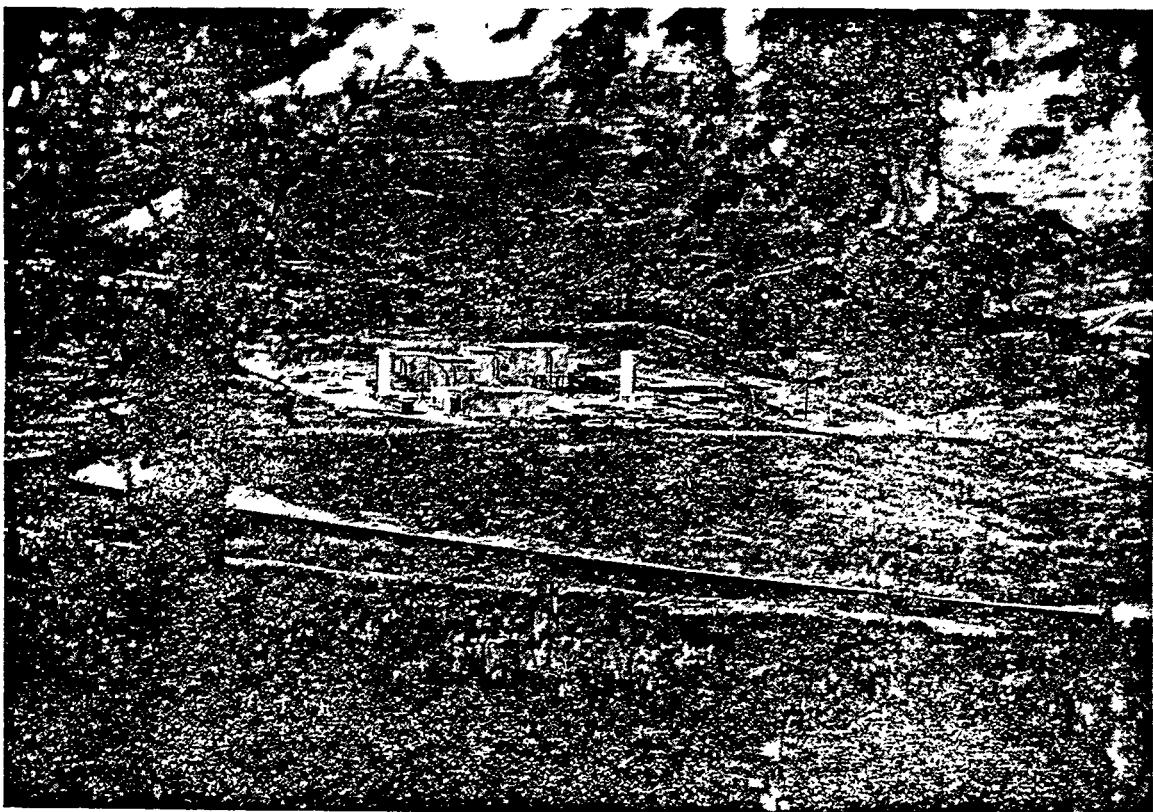


FIGURE 6. FOSSIL ENERGY TEST SITE (FETS)

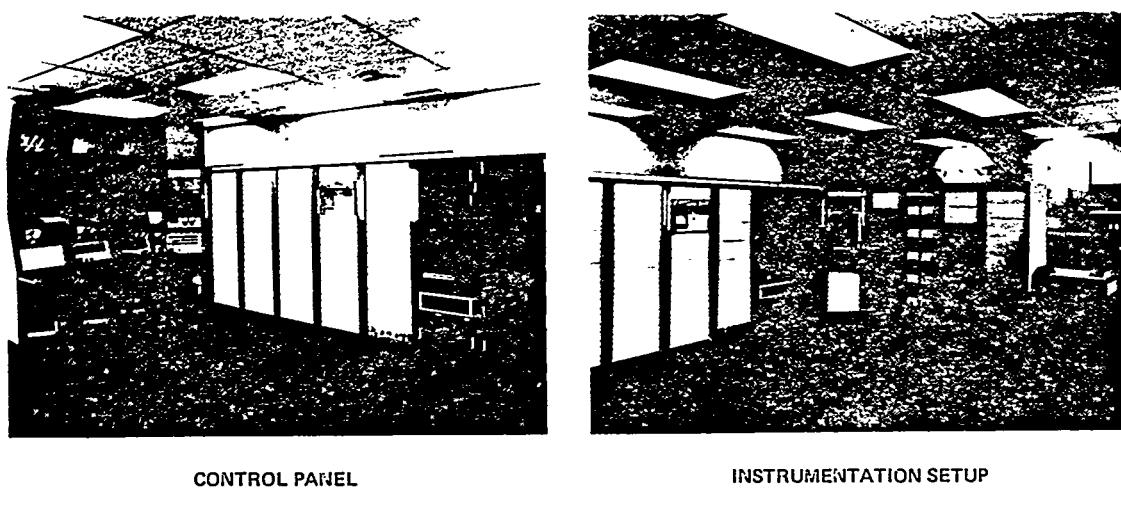


FIGURE 7. FETS CONTROL/INSTRUMENTATION CENTER

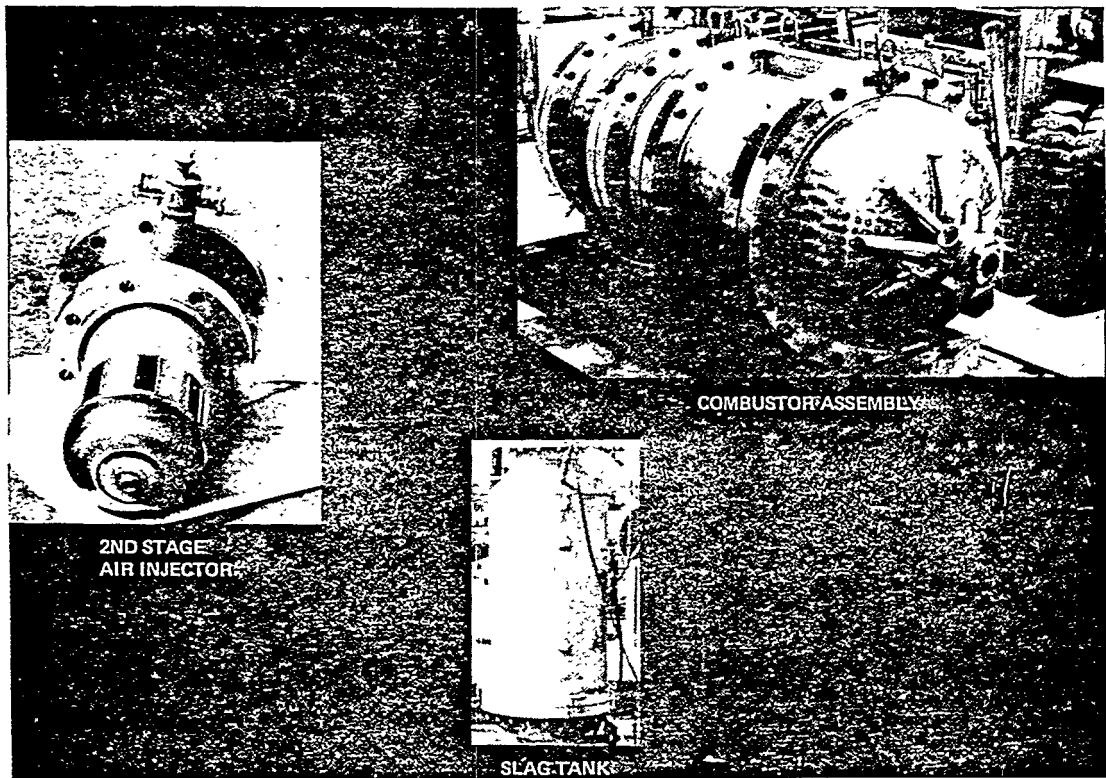


FIGURE 8. 70 MBTU/HR COAL COMBUSTOR HARDWARE

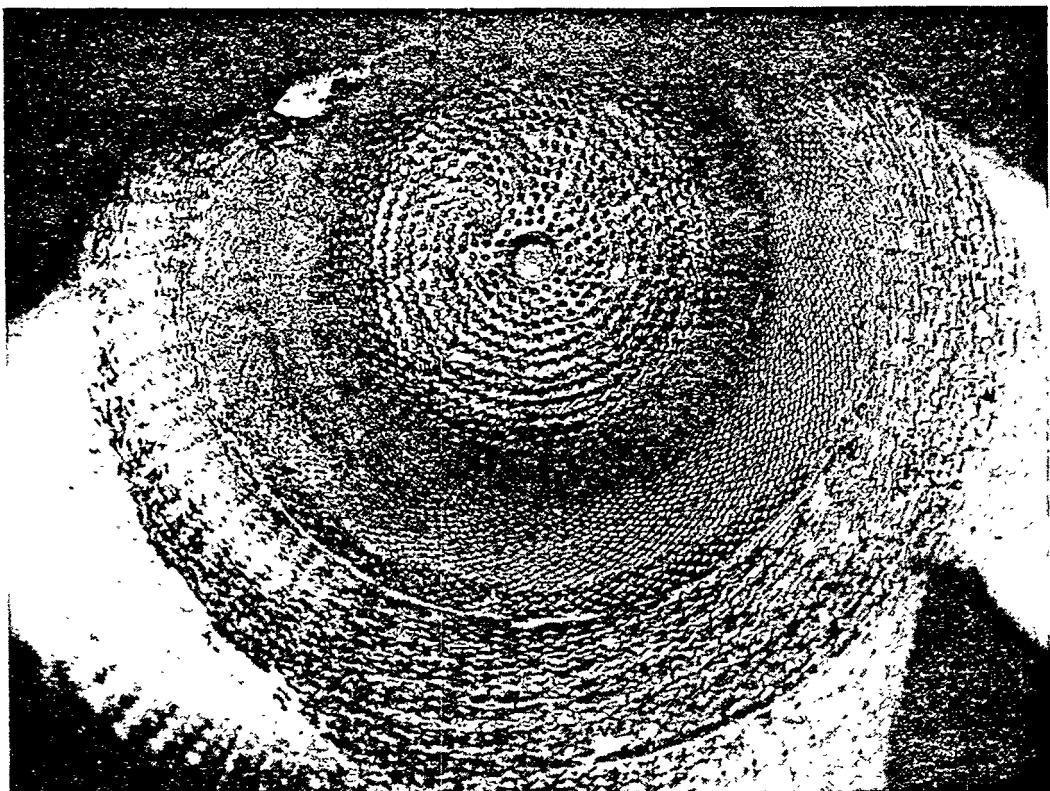


FIGURE 9. EQUILIBRIUM SLAG LAYER.



FIGURE 10. SECOND FEASIBILITY UNIT ON TEST STAND AT FETS
(10 MBTU/HR)

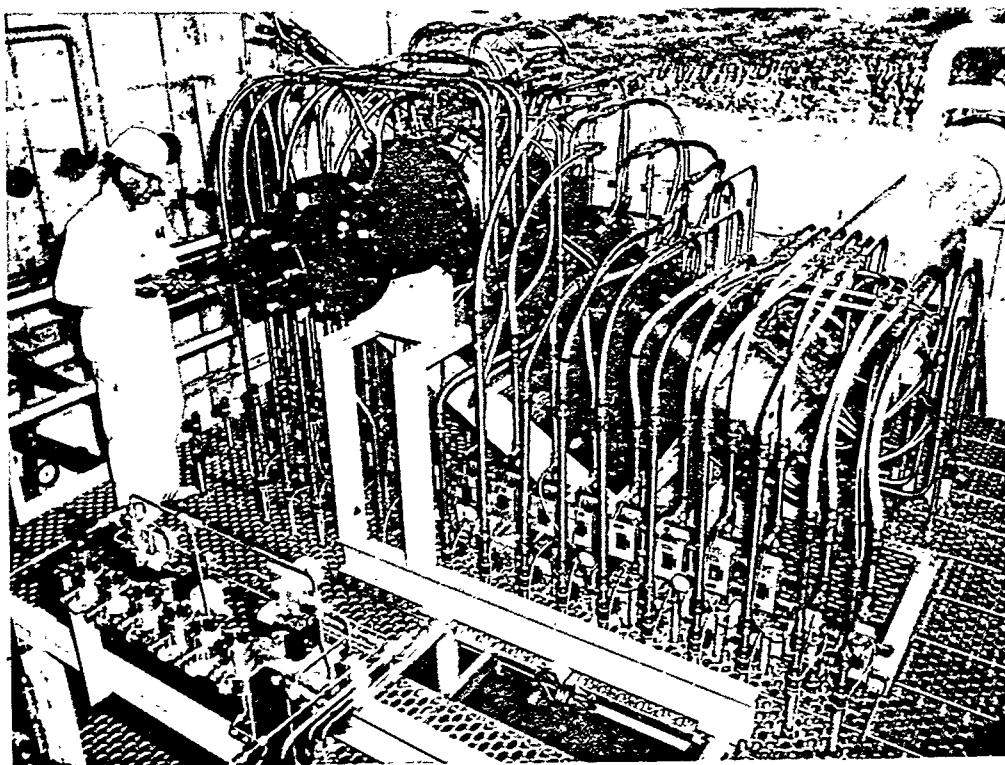


FIGURE 11. 10 MBTU/HR FEASIBILITY TEST UNIT

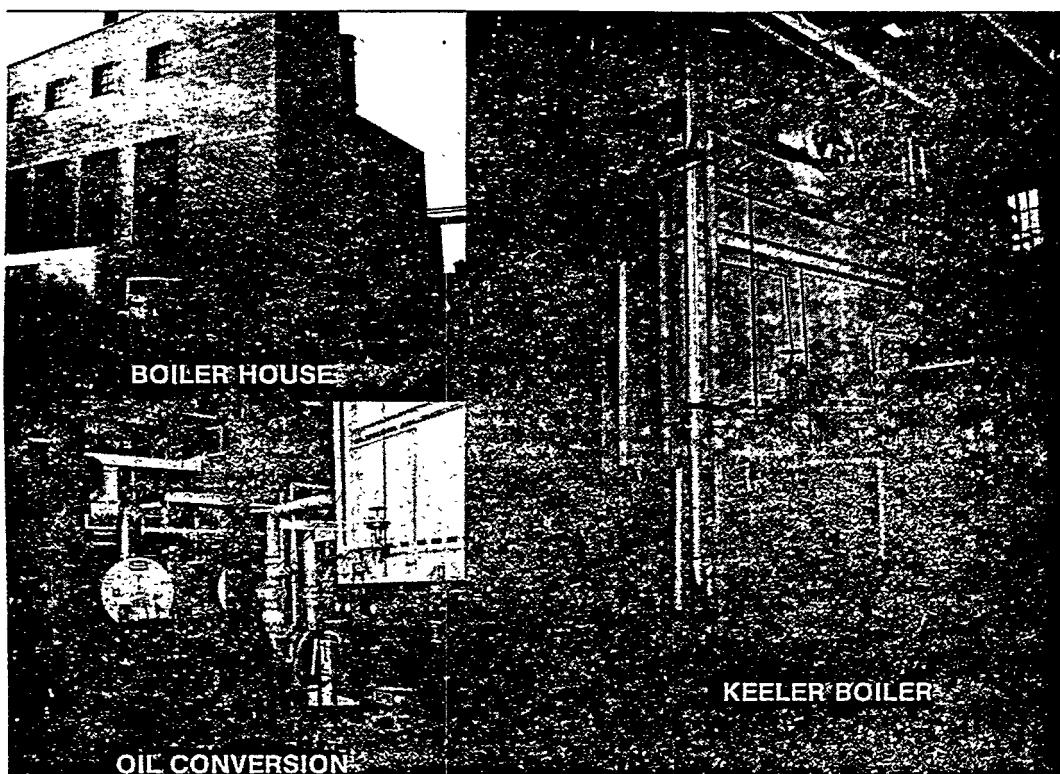


FIGURE 12. TAPCO BOILER FACILITY

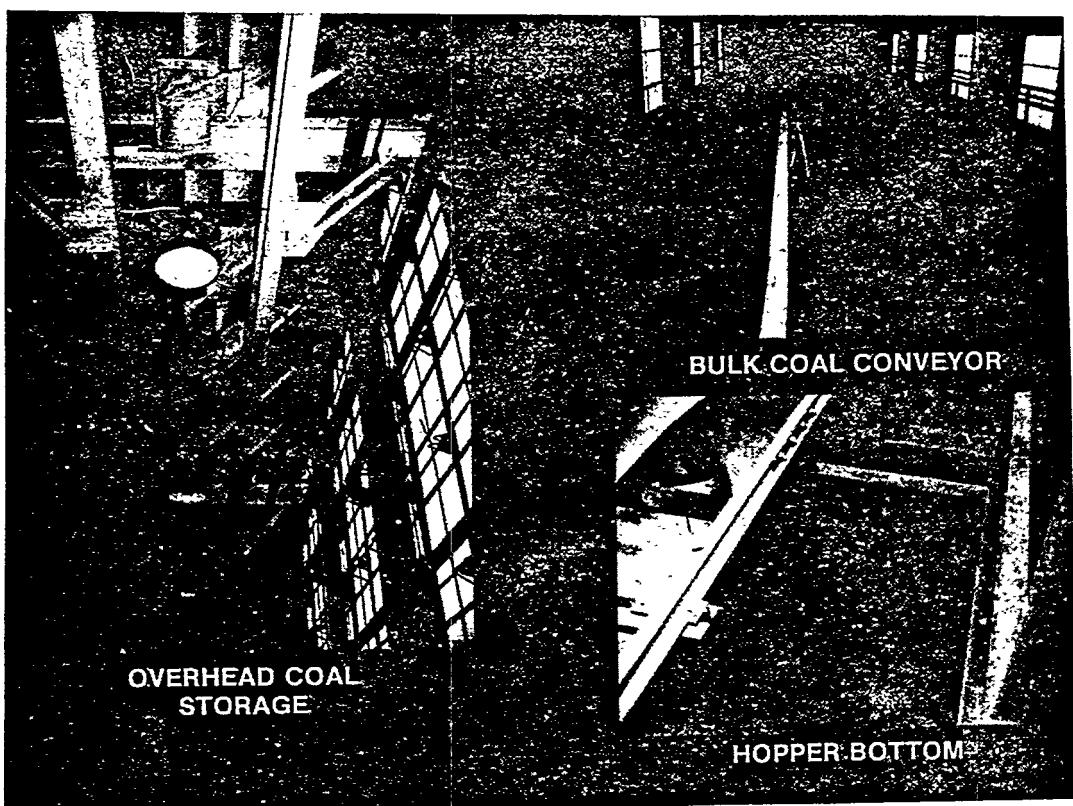


FIGURE 13. TAPCO COAL HANDLING/STORAGE



FIGURE 14. ARTIST'S RENDERING OF TRW COMBUSTOR
INTEGRATED WITH KEELER BOILER

STUDIES ON COAL UTILIZATION AT THE
ENERGY AND ENVIRONMENTAL RESEARCH CORPORATION (EER),
18 MASON, IRVINE, CALIFORNIA 92714
(January 1983)*

EER has been involved in a broad program on coal utilization for some years. Funding for the current year runs at a level of about $\$6 \times 10^6$, with support from EPA, EPRI, DOE, and private companies. The EER co-founders are M. A. Heap and T. Tyson, who serve as principal officers. The larger experimental facilities are located in Irvine, California, at a test site developed during the fifties by Philco-Ford for rocket and cannon testing.

A. Current Programs

EER has served as primary consultants to the EPA on a fundamental combustion research program, for which support levels have recently been reduced from about $\$4 \times 10^6$ /year to $\$1 \times 10^6$ /year. These studies have included work on kinetic models for reaction processes involving fuel-derived nitrogen in flames, dry additives for SO_2 control, characterization of sorbents for SO_2 removal under conditions of high heating rates, and downstream reburning with fuel injection to achieve NO_x and SO_2 control. Successful correlations have been derived for the volatile materials and nitrogen contents of fuels with total NO_x concentrations remaining in the exhaust flows.

Bartlesville/DOE is supporting experimental studies on coal utilization in a diesel engine. A high-intensity cyclone combustor is under development, with primary burning occurring in the suspension phase. A fundamental program on coal-particle ignition and combustion of particles in jets is supported by NSF. The EPRI program on coal-quality control and its effects on utility-boiler

*Prepared by S. S. Penner

performance has recently included funding for EER. A DOE program is in progress on retrofitting gas-fired burners for the use of pulverized coals. There are also current studies on fuels evaluations, programs with boiler manufactures on second generation NO_x control (to about 0.3 lb/ 10^6 Btu), and the design (for Bechtel Corp.) of a dry-scrubber bag house with sorbent injection for SO_2 control.

Studies on slagging and fouling are viewed as representing an especially challenging area. While qualitative performance predictions can be made on the basis of small-scale tests, quantitative predictions for new coal types are not yet feasible and development of the needed understanding represents a special challenge. Fundamental work to characterize the chemical compositions and size distributions of particles reaching and then adhering to the boiler walls are needed in order to obtain insights into the governing processes.

B. Publications

The following is a listing of some recent publications by EER personnel, which are available at UCSD:

1. M. P. Heap and W. Richter, "Einfluß der Brennstoffart auf die Wärmeübertragung in Feuerungen," VDI-Berichte 423, 225-234 (1981).
2. W. Richter and M. P. Heap, "The Impact of Heat Release Pattern and Fuel Properties on Heat Transfer in Boilers," The American Society of Mechanical Engineers Paper No. 81-WA/HT-27 (1981).
3. W. Richter, "Anwendung von Berechnungsmodellen für Feuerräume," VGB Kraftwerkstechnik 62, Heft 10, 845-852 (1982).
4. Energy and Environmental Research Corporation, "Evaluation of Time/Temperature History of Gases and Particles in the Radiant Furnace Zone of Pulverized Coal-Fired Steam Generators," November 1982.
5. Energy and Environmental Research Corporation, "Evaluation of In-Furnace NO_x Reduction and Sorbent Injection on NO_x/SO_x Emissions of U.S.-Designed Pulverized-Coal-Fired Boilers," November 1982.

6. Energy and Environmental Research Corporation, "Development of Limestone-Injected, Internally Staged Low-NO_x/SO_x Retrofit Coal Burners," November 1982.
7. Energy and Environmental Research Corporation, "Prototype Evaluation of Second-Generation Low NO_x Burner Performance and Sulfur Capture Performance," December 1982.
8. J. E. Broadwell, P. E. Dimotakis, T. J. Tyson, C. J. Kau, and W. R. Seeker, "The Structure of Turbulent Diffusion Flames and Nitric Oxide Formation," Energy and Environmental Research Corporation, 1982.
9. S. L. Chen, W. C. Clark, M. P. Heap, D. W. Pershing, and W. R. Seeker, "NO_x Reduction by Reburning with Gas and Coal—Bench Scale Studies," Energy and Environmental Research Corporation, 1982.
10. W. R. Seeker, W. D. Clark and G. S. Samuelson, "The Influence of Scale and Fuel Properties on Fuel-Oil Atomizer Performance," Energy and Environmental Research Corporation, 1982.
11. S. L. Chen, M. P. Heap, and D. W. Pershing, "Bench-Scale Emissions Testings of Non-U.S. Coals: Influence of Particle Size and Thermal Environment," Energy and Environmental Research Corporation, 1982.
12. G. England, M. Heap, Y. Kwan, R. Payne, and D. Pershing, "Development of a Low NO_x Burner for Enhanced Oil Recovery," paper presented at the Joint Symposium on Stationary Combustion NO_x Control (1982).
13. J. H. Pohl, S. L. Chen, M. P. Heap, and D. W. Pershing, "Correlation of NO_x Emissions with Basic Physical and Chemical Characteristics of Coal," Energy and Environmental Research Corporation, 1982.
14. P. L. Case, M. P. Heap, R. Payne, and D. W. Pershing, "Limb Testing: The Use of Dry Sorbents to Reduce Sulfur Oxide Emissions from Pulverized-Coal Flames Under Low-NO_x Conditions," Energy and Environmental Research Corporation, 1982.
15. B. Folsom, A. Abele, J. Reese, and J. Vatsky, "NO_x Emissions Control with the Distributed Mixing Burner - Part I. Field Evaluation of an Industrial Size Boiler"; B. Folsom, R. Payne, A. Abele, and P. Nelson, "Part II. Thermal Environment and Heat Release Capacity Scaling," Energy and Environmental Research Corporation, 1982.
16. S. L. Chen, D. W. Pershing, and M. P. Heap, "Bench-Scale Evaluation of Non-U.S. Coals for NO_x Formation Under Excess Air and Staged Combustion Conditions," Energy and Environmental Research Corporation, Report No. IERL-RTP-1367, December 1981.
17. M. P. Heap, B. A. Folsom, and R. Payne, "Effects of Coal Quality on Power Plant Performance and Costs," Energy and Environmental Research Corporation Monthly Progress Report No. 1, November 1982.

C. Research and Facility Descriptions

We have available at UCSD the 1982 EER report on "Research, Development, Applications." Also, it is expected that M. A. Heap will describe the EER programs at a future meeting of CCAWG.

CCAWG MEETING AT EPRI*
(Tuesday, February 1, 1983)

The following CCAWG members participated in an excellent overview of EPRI programs arranged by K. Yeager: S. B. Alpert, J. M. Bee , C. R. Bozzuto, I. Glassman, A. K. Oppenheim, S. S. Penner, L. D. Smoot, R. E. Sommerlad, C. L. Wagoner, I. Wender, and K. Yeager. The meeting was also attended by ex officio members J. F. Kaufmann and R. E. Roberts and by EPRI speakers (see Table AB-12-1) and others (J. Maulbetch, S. Dalton, et al). A copy of the meeting agenda is attached (see Table AB-12-1).

1. Overview

Appendix AB-12-1 contains three papers that provide overviews of EPRI's work on coal combustion and applications. K. Yeager's paper is reprinted from the Public Utilities fortnightly and summarizes R&D priorities for EPRI. Related policy issues and studies are presented in the mid-1982 summary of EPRI programs on advanced pulverized coal power plants. A brief summary of an EPRI study mission to Japan is contained in the third paper.

The EPRI work on coal combustion systems has projected funding of $\$361 \times 10^6$ for the period 1983-87 (i.e., an average funding level of about $\$72 \times 10^6/\text{yr}$).

T. Armor emphasized the importance of powerplant availability and performance for which 1983 EPRI expenditures are $\$13 \times 10^6$. Important availability problem areas involve blade failures and solid-particle erosion in the steam turbine, failure of waterwall tubes and fouling and slagging in the boilers. Improved powerplant performance can be achieved through monitoring and utilization of

* Prepared by S. S. Penner.

Table AB-12-1 CCAWG Meeting at EPRI, Palo Alto, CA (February 1, 1983)

9:00	Welcome and Introduction	K. Yeager
9:30	Availability and Performance Program - Advanced Coal Plant - Plant Diagnostics - Japanese Technical Transfer	T. Armor
10:30	Retrofitting Utility Power Plants for Coal	R. Manfred
11:15	Environmental Control Systems - EPRI Program Overview	G. Preston
12:00	Lunch	
12:30	Impact of Environmental Issues on Coal-Fired Power Generation	K. Yeager
1:30	Utility Particulate Emission Control	M. McElroy
2:15	Combustion Control of NO _x - Retrofit Low NO _x Burners - Furnace Limestone Injection SO ₂ /Low NO _x	M. McElroy
3:00	Coal Gasification/Combined Cycle - Coolwater Project Status	S. B. Alpert
4:00	Adjourn	

appropriate plant diagnostics. An advanced PC design shows a 3% increase in efficiency, corresponding to about a 10% decrease in heat rate (i.e., heat rates reduced from about 9100 Btu/kW-hr to 8200 Btu/kW-hr). The next generation of powerplants is being designed to operate under supercritical conditions. Supercritical plants have been found to have the same availability as subcritical plants. The Japanese are planning to construct 40,000 MW_e of supercritical capacity by the year 2000. These advanced PC units are expected to be economically competitive with IGCC and PFBC plants.

R. Manfred discussed retrofitting of existing boilers for coal use. He noted that no one has as yet constructed a PC plant adjacent to an existing oil-fired unit and used the existing balance of plant. Boilers originally designed for coal use have been reconverted to coal use. Retrofitting of two 200-MW_e oil burners in Australia required derating to 60% capacity, i.e., to 120 MW_e. Actual derating of oil-fired burners depends on the boiler design. COM appears to be uneconomical; CWM production in the U.S. is growing and is expected to reach 1×10^6 TPY by 1984, which should be sufficient for one large utility demonstration plant. The required differential between oil and CWM costs must be greater than about \$1.5/10⁶ Btu at derating of less than 30% for CWM to represent an economically attractive option. Modeling of CWM tests has not been supported by EPRI in the past but may now constitute an appropriate activity.

G. Preston described environmental control systems and performance, including the use of bag houses, regenerable FGD, combustion and post-combustion control of NO_x, zero-discharge cooling towers, wet and dry cooling. EPRI does not develop improved control technologies for the purpose of producing tighter regulatory measures. Major problem areas include scrubber corrosion, materials specifications, waste disposal. It appears that all of the environmental control technologies could profit from research and improved understanding of the fundamental processes involved.

K. Yeager gave an excellent overview of problem areas involved in acid precipitation. He noted that, whereas total NO_x levels are expected to grow to the year 2000, SO_2 levels are expected to remain level. Rapid restoration of acidified lakes can only be achieved through implementation of active remedial measures such as direct lime additions.

M. McElroy discussed particulate emission controls using filter bag houses or ESP and NO_x control using combustor modifications and post-combustion clean-up. A low- NO_x , staged-combustion burner now marketed by Mitsubishi is based on principles clearly defined by U.S. researchers during the sixties. NO_x control to 0.2 lb/ 10^6 Btu is achievable at moderate costs (~0.13 to 0.34 mills/kW-hr with capital costs of \$5 to 12/kW). It was noted that EPRI has not supported a significant level of fundamental combustion research.

Limestone injection into or above the burner region may be a preferred SO_2 -removal technology in accord with the fact that chemical conversions are generally implemented more quickly and efficiently at elevated than at low temperatures, as has been repeatedly emphasized especially by A. K. Oppenheim. Unresolved clean-up issues relate to the interplay between systems design and SO_2 removal, ESP performance, ash disposal and utilization, slagging and fouling, soot blowing, tube erosion, and the formation of backpass deposits.

The EPRI presentations were concluded by S. B. Alpert with an overview of the Coolwater IGCC demonstration plant. This important facility (100 MW_e net output) represents a milestone in advanced engineering applications on coal utilization. It could not have come to fruition without Alpert's dedication, knowledge and skill. Coolwater is being built by EPRI, Texaco, SCE, JCDC, and others (without DOE support). Many if not all of the participants concurred with Alpert's view that the U.S. will become a third-rate power unless we take the high risks represented by advanced technological implementations of the type represented by Coolwater.

Along the Technical Front in Coal Utilization

By KURT E. YEAGER

How the electric utility industry and its suppliers respond in this decade to declining demand growth rates, uncertainty over petroleum availability and pricing, stringent environmental controls, lessened capital investment capability, loss of momentum for the nuclear option, decreased governmental funding of technology development, and increased emphasis by domestic coal suppliers on their international market will have important consequences for the industry's power generation capability and structure in the next century. The following article describes technological advances in direct coal utilization which effectively address those challenges.

THE past decade brought new constraints that are reshaping the technical approach of the U. S. utility industry to coal utilization. In the 1970s, increasing electrical rates, restrictive environmental controls, uncertainty over petroleum availability, and skyrocketing fuel costs caused the industry to consider a variety of new coal-based generating options.

Now, in the 1980s, these constraints are compounded by declining demand growth rates, restricted capital investment capability, loss of public confidence in the nuclear initiative, withdrawal of government funding in technology development, and increased emphasis by domestic suppliers on the international market.

Coal now provides over 50 per cent of the electricity generated in the United States. Its importance will continue to grow over the remainder of this century, pro-

viding about two-thirds of the nation's energy growth. How the U. S. utility industry and its suppliers respond in this decade to those constraints will have important consequences for the nation's power generation capability and structure into the next century. Certain trends seem clear. For example:

Generation capacity will depend increasingly on direct coal combustion. Private sector responsibility for technology improvements will encourage lower-risk, nearer-term options. Priority will be placed on improving the reliability and longevity of existing generating coal capacity to minimize investment.

Technological advances in direct coal utilization which effectively address these challenges are (1) coal quality improvement, (2) improved pulverized coal technology, and (3) fluidized bed combustion (FBC).

Coal Quality

Traditionally, the U. S. utility industry has not given high priority to quality control of its coal feedstock. The general decline in plant reliability and efficiency has, however, led to a reexamination of the entire power generating system from coal supply to ash disposal. The sensitivity of pulverized coal-fired power plant performance and reliability to coal quality has particularly emerged as a major industry concern. As a result utilities are learning that the cheapest coal does not necessarily produce the lowest cost electricity.

A principal facility for assessing the effects of coal quality on power plants is the new Electric Power Research Institute-sponsored coal cleaning test facility



Kurt E. Yeager is director of the coal combustion division of the Electric Power Research Institute and responsible for its principal research and development program on near-term environmental, performance, and reliability issues. Earlier he was director of energy R&D planning for the Environmental Protection Agency's Office of Research. His professional experience has included the development of advanced upper atmospheric sampling systems. **Mr. Yeager** received an MS degree in physics from the University of California and a BS degree in chemistry from Kenyon College.

(CCTF) located at the Homer City power station of Pennsylvania Electric Company and New York State Electric and Gas Corporation. Based on commercial scale equipment, the CCTF has a coal handling rate of 20 tons per hour. Unlike other test facilities, it is not dedicated to a single cleaning process but can simulate more than 50 commercial cleaning plant designs. Participating utilities and suppliers deliver 1,000 ton coal samples to the CCTF for cleaning characterization. The results provide a reliable estimate of the commercial cleanability potential of the coal, the effect of cleaning on fouling and slagging, as well as verification of cleaning plant design and cost meeting the company's specific needs.

Coal Quality Assessment

New apparatus to determine coal quality has been developed with the support of the Electric Power Research Institute and is being applied in full-scale utility tests. Called CONAC (for "continuous nuclear analysis of coal"), the method blends the principles of nuclear physics with the practicalities of coal technology. CONAC instrumentation is based on a technique called prompt neutron activation analysis. The technique is already accepted in a wide variety of industrial applications.

CONAC uses a small specimen of radioactive californium (Cf-252) to bombard a coal stream with neutrons. When a neutron is captured by an atomic nucleus, gamma rays are emitted that have a frequency characteristic of the elements involved. CONAC uses radiation detectors to count the number of gamma rays at each characteristic frequency. The number of each is proportional to the abundance of the element associated with that frequency.

CONAC's application range includes determining coal quality at the mine, coal blending, control of coal washing and beneficiation, prediction and avoidance of slagging and fouling, heat management around a boiler, real time heat rate determination, optimal load dispatch, and compliance with flue gas emission limits.

Coal Slurries

Continued oil and gas cost escalation, as well as potential supply interruption, are strong incentives for the conversion of oil-fired power plants to coal. EPRI has conducted studies examining the technical and economic considerations in the several options for achieving this conversion. Based on the results, EPRI is conducting research to develop, demonstrate, and commercialize coal-water slurries (CWS) as a cost-effective, oil replacement fuel for oil-fired utility boilers.

Coal slurries may substantially lower the cost of conversion. The advantage of these slurries over pulverized coal is that they can be transported, stored, and handled with less extensive changes to existing oil-firing facilities.

EPRI, therefore, is focusing its future projects on the rapid development and demonstration of CWS. Various coal feedstocks, coal treatment processes, grinding methods, and stabilizing processes are being studied so that selection and use guidelines can be prepared for the broad range of utility conditions. Combustion tests have

been performed in small furnaces and development projects are under way to demonstrate stable and reliable combustion in larger boilers. Utility scale demonstration of CWS combustion is planned by EPRI for 1984-85.

Improved Pulverized Coal Technology

In the next twenty years, the utility industry will be faced with maintaining the integrity of power generation and supply with only a limited number of new plant additions. The difficulty of financing new plants, the cancellation and deferment of many nuclear orders, and the uncertain rate of growth of the industry place increasing emphasis on the availability of existing generation. In particular, many fossil units are approaching the limit of their design lives (typically thirty to forty years) and present a challenge to utilities in extending life without impacting availability.

It is in this current climate that the techniques of incipient failure detection are beginning to flourish. Early warning of component deterioration is seen as an essential part of any predictive maintenance program for fossil plants. Conversely, the absence of such techniques leads to sudden, and often catastrophic, equipment failure causing extended outages for repair and replacement. Even when faced with only one day of additional downtime on a large unit, it is apparent that the capital cost of monitoring equipment is quickly justified.

Diagnostic monitoring is advancing for all areas of the power plant: boilers, turbines, generators, fans, pumps, heat exchangers, but the degree of sophistication of the techniques is not uniform. Some monitoring techniques — vibration signature analysis for example — are well developed and can be implemented into utility maintenance procedures. Others, such as boiler stress and condition analyzers, will require further development and field qualification before across-the-board application to aging fossil plants.

The average station heat rate decreased continuously until the early 1960s. Subsequently, there was little incentive to continue the effort because of the expected increase in nuclear power generation for base-load application and the availability of relatively inexpensive fossil fuels; also additional environmental restrictions required flue gas treatment which had a significant adverse effect on heat rate. A further negative impact resulted from the need to cycle many large fossil plants and run the units at other than base load. This mode of operation typically results in lower component efficiencies and increased heat rate of the units.

EPRI believes that it is important to reverse this trend and has recently carried out a study on the design of fossil plants. As a result, a substantial improvement in heat rate appears possible in new fossil plants. For existing units, EPRI is pursuing a program of on-line performance monitoring and improved instrumentation and testing. The cumulative effect of this effort on the close to 1,000 fossil units currently in service can be a significant reduction in fuel usage as well as immediate economic benefits to the operating utilities.

The trend in unit availability and capacity factor suggests that reserve margins will continue to be of concern in the future. Improved heat rate will be one factor which will assist in improving system reserve margins.

The evaluation of the benefits of higher steam conditions and innovative design concepts must include critical consideration of their impact on unit reliability. Traditional opinion has suggested that supercritical steam-electric plants cannot be expected to produce reliability levels equivalent to those of subcritical plants. Further, the fuel cost savings from high efficiency plants may be more than offset by their increased capital cost and reduced reliability. The EPRI studies concluded that this is unlikely.

U. S. utility experience indicates there is now no statistically significant difference between once through (supercritical) and drum-type (subcritical) unit reliability. Furthermore, we find nothing inherent in the design of supercritical plants which should contribute to lower reliability. The total forced outage hours are about the same for once through and drum units. While, on average, the first large, supercritical power plants achieved poorer availability during the 1960s, the plants built in the 1970s demonstrated results superior to those of drum units. In fact, for plants in the 600- to 825-megawatt-electric range with supercritical pressure and double reheat average availabilities over 80 per cent have been maintained in recent years.

Integrated Environmental Control

Today, environmental regulatory requirements on coal-fired plants involve continuous control of air, water, solid waste, and thermal discharges. This has become a major cost factor in construction and operation, typically 30 to 40 per cent of a coal plant's investment cost. The high-cost, poor reliability, and reduced operational flexibility resulting from the add-on, piecemeal response to these rapidly changing environmental control requirements are changing the historical approach of user, designer, and supplier.

Environmental control in the 1980s has become as much an integral part of the coal-fired power plant system as the boiler or turbine. A design strategy which pursues a more systematic approach to control of all effluent streams may offer capital savings of \$100 per kilowatt, increase plant availability by 5 per cent, and improve heat rate by up to 500 kilojoules per kilowatt-hour. These savings occur less from new technology than from assigning single point responsibility for environmental control system design and elevating its engineering priority to a level equivalent with its economic importance.

EPRI's integrated emission control pilot plant (IECPP) at the Arapahoe power station of Public Service Company of Colorado in Denver has the flexibility to test a very wide range of possible equipment configurations. Initially focusing on air, water, and solid waste control technologies, the pilot scale program represents a cost-effective means to obtain critical design and operation

information. The overall goal is to produce engineering design guidelines for the selection, configuration, and operation of integrated environmental control equipment under the operating conditions a typical utility might encounter. Emphasis is on the emissions control capability and on the interface among the various components and the power plant to minimize operating, maintenance, and cost requirements.

The IECPP is the first coal-fired pilot system in the United States for investigating different integrated emission control systems and for providing environmental management services to the utility industry. The equipment options provide the unique advantage of sophisticated research flexibility at a size representative of large, commercial installations.

Fluidized Bed Combustion

The electric utility industry also is aggressively evaluating and developing technologies which may ultimately provide less costly and more reliable operation than current pulverized coal systems. These options are intended to carry utility coal utilization beyond the limits inherent in pulverized coal technology. The most important factor in commercial acceptance will be their *demonstrated* capability to be at least as reliable as pulverized coal-fired power plants. Accordingly, priority must be placed on reliability. This requires the construction and operation of large-scale, engineering prototype or pioneer plants over a range of designs and fuels at operating conditions which are representative of the using utility industry.

EPRI and the utility industry are accelerating the development and application of fluidized bed combustion as a further *evolutionary* improvement in coal utilization to meet the expanding needs for coal-fired power generation. The improvements which excite this utility interest include reduced sensitivity to fuel quality, thus permitting the use of a much broader fuel supply, from anthracite to municipal refuse, without suffering large losses in efficiency and reliability in a single boiler design. Less cost sensitivity to unit size in a period of load growth and siting restrictions may favor smaller FBC boilers rather than larger pulverized coal furnaces.

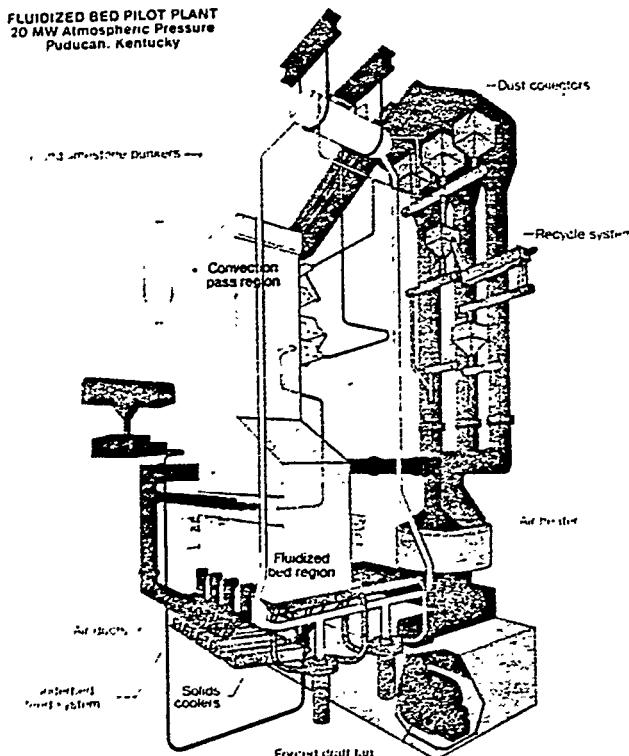
A third primary advantage of FBC that may lead to the displacement of pulverized coal boilers is environmental performance. Our experiments with fluidized combustion of coal confirm that it is possible to control sulfur and nitrogen oxides economically without parasitic postcombustion cleanup devices.

Atmospheric Fluidized Bed Combustion

The atmospheric fluidized bed combustion (AFBC) option shows its greatest initial advantage under low-grade or highly variable fuel conditions such as lignite, high-sulfur and high-ash content coal, mine and cleaning plant wastes, and municipal refuse. Since both private and federal projections indicate that a large portion of U. S. coal production growth over the rest of the century and beyond will occur in these low-grade fuels,

the AFBC market potential appears substantial. For example, 40 per cent of new utility generating additions during the 1980s will use low-rank coal.

A cost-effective utility scale AFBC design is achievable, and the important hardware questions and alternatives are being resolved. To this end the Tennessee Valley Authority has implemented a 20-megawatt-electric engineering prototype at the Shawnee power station near Paducah, Kentucky. The prototype was built by Babcock and Wilcox. Operation began in May of this year and the EPRI-cosponsored test program will continue through at least 1986. This will provide the basis for 100- to 200-megawatt commercial utility AFBC demonstrations, operational this decade.



The Tennessee Valley Authority's new 20-megawatt atmospheric fluidized bed combustion pilot plant located at Paducah, Kentucky, features a boiler that burns coal and limestone mixed together.

Pressurized Fluid Bed Combustion

The new and dynamic utility climate also influences pressurized fluid bed combustion (PFBC) development goals. The influence arises from the trend toward smaller new unit size and growing utility interest in uprating the capacity of existing units to bring capacity on line at the lowest investment cost. As a result, development emphasis is being placed on turbocharged boilers which can provide shop-fabricated, barge transportable, steam generation modules. These can be rapidly field-erected to provide the desired uprating in unit sizes of 150 to 250 megawatts-electric. This approach will also use coal to replace and increase the capacity of existing oil- or gas-fired plants while minimizing space and environmental control requirements.

The primary physical difference between the turbocharged boiler and the PFBC-combined cycle that has been previously emphasized is the reduction in gas turbine operating temperature. This substantially reduces the development risk and cost, and improves the reliability of the boiler system.

Efforts are now being initiated by EPRI to design engineering prototypes of the turbocharged boiler based on results from operational pilot plants. This approach should permit commercial prototypes to be operational this decade, thus yielding important financial advantages to utilities during the current period of low-load growth and high-construction costs.

Summary

The emphasis in utility coal technology development is on near-term resolution of the reliability, cost, and environmental issues limiting domestic coal utilization. The focus is, therefore, on improvements in conventional pulverized coal power plants and fluidized bed combustion of coal. New apparatus for rapid analysis of coal composition and heat content is being applied to commercial utility installations. Coal quality control has become increasingly important as one element in improving power plant performance and reliability, reducing investment in new capacity, and complying with emission regulations.

EDITOR'S NOTE: The foregoing article was adapted from a paper presented by the author at the 12th general meeting of the International Electric Research Exchange held earlier this year in San Francisco.

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1982

EPRI Program on Advanced Pulverized Coal Power Plants

1. Background

Coal-fired, steam-electric power plants currently produce over 50% of the electric power in the United States. Due to the cost and scarcity of oil and the slowdown in growth of nuclear power generation capacity, attention is still being focused on pulverized coal-fired power plants as a major energy resource for the nation's future. The development of conventional coal-fired power plants has been an evolutionary process, and from 1900 until the early 1960s there was a continuous trend toward lower heat rates. For the past twenty years, however, because there was little economic incentive to continue the effort, research and development to increase thermal efficiency has been relatively stagnant. The rapid escalation in fossil fuel costs during the 1970s has changed this view and warranted a re-examination of the potential for improving thermal efficiency.

During recent years, the U. S. utility companies have retreated from purchasing large power plants with high efficiency, supercritical pressure thermal cycles (once-through), and instead have chosen smaller, subcritical pressure plants (drum). In general, the rationale for this trend was based on the perception that drum units are more reliable and cost effective than supercritical units which were introduced in the early 1960s. Since that time, as a result of the natural design maturation process and increased operator experience, once-through units have proved as reliable as drum units. Furthermore, because of their inherent efficiency advantage, they are an economic choice for the industry.

EPRI Engineering Studies

In light of these considerations, EPRI sponsored two independent engineering studies to evaluate the potential for improving the thermal efficiency of coal-fired, steam-electric power plants. The specific objectives of the two teams, each of which comprised a turbine-generator manufacturer, boiler manufacturer, architect-engineer and utility, were to"

- o Assess the technical and economic feasibility of concept to increase thermal efficiency.
- o Identify critical research necessary to commercialize these concepts and maintain or improve plant availability.
- o Develop conceptual designs for "base" (reference case) and "advanced" plants.

- o Evaluate the development, construction, and operating costs for the advanced plants as compared to the base plant.
- o Assess the reliability of the advanced plant.

These studies have now been completed and have concluded that advanced pulverized coal power plants offer significant economic advantages to the utility industry for new capacity additions. It is also apparent that much of the technology outlined for the advanced plant has application, on a retrofit basis, to existing coal plants.

EPRI Advanced Plant Development, Phase I

It is the intention of EPRI to pursue the development efforts related to advanced plants through a series of tasks designed to bring new innovations into the utility industry. Phase I of this work will cover a detailed planning effort related to the development of advanced steam cycles and equipment improvements and will last 18 months. This Phase will also plan the orderly introduction of retrofittable features into existing fossil plants, so as to capitalize on the advanced plant development work. Phase II represents the development, qualification and testing efforts related to the next generation of supercritical steam plants, particularly covering material considerations at high temperatures. The output from Phase II will include a detailed specification for an advanced coal plant, designed to improve heat rate approximately 10% beyond what is currently available.

The objective of Phase I is to carry out the planning necessary for a major development effort on advanced pulverized coal power plants. It is an additional goal to plan the orderly introduction of advanced features into existing coal-fired plants so as to enhance existing plant heat rate. The R&D necessary to qualify these retrofit features is included in this effort.

The important aspects of the approach to the planned work are:

- A. A review and consolidation of past studies in the U. S., Japan, and Europe.
- B. A study on the state-of-the-art in high temperature materials.
- C. A survey and assessment of existing test facilities, domestic and foreign.
- D. An assessment and recommendation of retrofittable features to improve existing plant heat rate, including cost/benefit studies.
- E. The development of an implementation plan for existing plant enhancement, including utilities, costs, milestones.
- F. Development work related to retrofit application.

G.. The development of a detailed R&D plan for the development of the advanced plant covering costs, facilities, timetable, contractors, milestones.

EPRI Advanced Plant Development, Phase II

Phase II involves the development, qualification and testing work for the advanced plant, defined during Phase I. It is anticipated to be a 5-7 year effort. The major objectives of this phase are:

- o Qualify any new materials and components of the advanced plant,
- o Produce a detailed specification for the advanced plant, as jointly determined with cooperating utilities,
- o Implement the retrofit features of Phase I,
- o Produce utility guidelines for a cross-the-board implementation of retrofit features.

The result of this program is expected to be a 10% improvement in new plant heat rate and a 3% improvement in existing plant heat rate, with no adverse impact on availability.

EPRI STUDY MISSION TO JAPAN

Evaluation of Japanese Design, Operating and Maintenance Practices for Coal Fired Power Plants.

Background

The successful design, operation and maintenance of conventional coal-fired plants in the U.S. is the cornerstone of the nation's power generation plans over the next 20-30 years. The availability and efficiency of the more than 1000 large fossil units currently in operation will largely determine the future need for new plants or new forms of power generation. Utilities are, therefore, dedicating increased effort to maximize the potential of these existing fossil plants. Recent reviews of fossil plant performance to Japan suggest that Japanese innovations in plant design and operation may have significant benefits. To assess the implications of this, an EPRI-led study team from U.S. utilities will perform detailed analyses of Japanese power plant practice, in cooperation with the Japanese utility industry.

Japan has recently made a major commitment to coal for their future supply of electric power. Current Japanese plans call for 20,000-40,000 MW of installed coal plant capacity by the year 2000.

Over the past few years, EPRI has become increasingly aware that the Japanese are successfully implementing coal-fired electric power generation technologies without heavy reliance upon the United States. Engineering, fabrication, installation, startup, operation and maintenance are being performed by Japanese firms. In particular, the Matsushima Power Station of the Electric Power Development Company (EPDC), a pure Japanese enterprise (commercial in 1981), is viewed by many as the most technologically advanced coal-fired power station in the world. Although the equipment at Matsushima is similar to that pioneered in the United States, closer inspection reveals improvements to equipment design and fabrication processes, and several new innovations in overall plant design. Differences are also apparent between fundamental Japanese and American design philosophies, methods of procurement, and division of responsibilities. The result at Matsushima is an environmentally acceptable power plant with very high availability and thermal efficiency while burning a broad range of imported coals.

Study Mission Procedure

The specific objectives of the mission are to: (1) evaluate the Japanese design/construction/procurement practices and compare them to the U.S. experience; (2) assess the Japanese technology innovations and their applicability to the U.S. utility industry; (3) verify the reported costs, performance, and reliability of Japanese coal-fired power plants; (4) evaluate Japanese operating and maintenance (O&M) practices and their applicability to the U.S. plants; and (5) confirm Japanese (utilities and manufacturers) plans for adding new coal-fired generating capacity.

To accomplish these objectives a three phase program will be implemented:

- I Technical and Administration Preparation
- II Visit to Japan
- III Data Interpretation and Report Preparation

A delegation comprised of utility company representatives and EPRI staff members will visit Japan in October of 1983. A most important element to help assure success for the mission will be the quality of and degree of involvement by the U.S. utility company delegates. Approximately 17 utility delegates (Supervisory and Vice-Presidential level) have agreed to participate in the mission. They will generate portions of and review the written inquiry; join the visit to Japan; provide data analysis, recommendations and conclusions; and write portions of and review the final report. Each delegate has committed approximately 30 man days of effort, including travel time to Japan.

An independent contractor will be principally responsible for the coordination of activities. Specifically, the contractor will be responsible for the technical content and editing of the written inquiry, for travel and meeting arrangements of the delegation in the United States and Japan, for language interpretation; for data analysis and documentation; and for preparation of the final report.

The Study Mission will be organized into five technical study groups:

- (1) Turbine/Generator
- (2) Boiler
- (3) Air Quality
- (4) Water Quality and Solid Waste
- (5) System Engineering including plant layout, instrumentation and controls, maintenance and inspection.

Each study group will be comprised of nominally three delegates.

Utility Delegates

The following utility personnel have indicated their willingness to participate:

J. W. Arlidge	Dayton Power & Light
D. L. Aswell	Louisiana Power & Light
R. H. Bielecki	Pennsylvania Power & Light
G. Burris	American Electric Power
J. Credit	Colorado Ute Electric Association
F. Davis	Utah Power & Light
H. Fox	Tennessee Valley Authority
G. P. Green	Public Service of Colorado
E. E. Haddad	Boston Edison
R. D. McRanie	Southern Company Services
C. R. Morey	Dayton Power & Light
J. E. Rasmussen	Potomac Electric Power
J. O. Rich	Salt River Project
W. R. Rogers	Florida Power & Light
P. G. Sikes	Wisconsin Electric Power
T. P. Wolff	Pennsylvania Electric
C. J. Wylie	Duke Power