EPA U.S. Environmental Protection Agency
Office of Research and Development

Industrial Environmental Research Laboratory
Research Triangle Park, North Carolina 27711

EPA-600/7-77-071
July 1977

HIGH-TEMPERATURE AND HIGH-PRESSURE PARTICULATE CONTROL REQUIREMENTS

Interagency
Energy-Environment
Research and Development
Program Report

RESEARCH REPORTING SERIES

Research reports of the Office of Research and Development, U.S. Environmental Protection Agency, have been grouped into seven series. These seven broad categories were established to facilitate further development and application of environmental technology. Elimination of traditional grouping was consciously planned to foster technology transfer and a maximum interface in related fields. The seven series are:

1. Environmental Health Effects Research
2. Environmental Protection Technology
3. Ecological Research
4. Environmental Monitoring
5. Socioeconomic Environmental Studies
6. Scientific and Technical Assessment Reports (STAR)
7. Interagency Energy-Environment Research and Development

This report has been assigned to the INTERAGENCY ENERGY-ENVIRONMENT RESEARCH AND DEVELOPMENT series. Reports in this series result from the effort funded under the 17-agency Federal Energy/Environment Research and Development Program. These studies relate to EPA's mission to protect the public health and welfare from adverse effects of pollutants associated with energy systems. The goal of the Program is to assure the rapid development of domestic energy supplies in an environmentally--compatible manner by providing the necessary environmental data and control technology. Investigations include analyses of the transport of energy-related pollutants and their health and ecological effects; assessments of, and development of, control technologies for energy systems; and integrated assessments of a wide range of energy-related environmental issues.

REVIEW NOTICE

This report has been reviewed by the participating Federal Agencies, and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Government, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

This document is available to the public through the National Technical Information Service, Springfield, Virginia 22161.

EPA-600/7-77-071
July 1977

HIGH-TEMPERATURE AND HIGH-PRESSURE PARTICULATE CONTROL REQUIREMENTS

by

Richard Parker and Seymour Calvert

Air Pollution Technology, Inc.
4901 Morena Boulevard, Suite 402
San Diego, California 92117

Contract No. 68-02-2137
Program Element No. EHE623A

EPA Project Officer: Dennis C. Drehmel

Industrial Enironmental Research Laboratory
Office of Energy, Minerals, and Industry
Research Triangle Park, N.C. 27711

Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Research and Development
Washington, D.C. 20460

ABSTRACT

High temperature and high pressure particulate cleanup requirements of existing and proposed energy processes are reviewed and evaluated. The intention of this study has been to define specific high temperature and pressure particle removal problems, indicate potential solutions, and identify areas where current knowledge and data are inadequate.

Primary emphasis has been placed on the requirements of processes now being proposed as clean methods for obtaining energy from coal; that is, fluidized bed coal combustion, coal gasification, and direct coal-fired gas turbines.

In addition, the cleanup requirements and experiences of other high temperature and/or high pressure processes such as fluid bed catalytic cracking units, metallurgical furnaces, geothermal power plants, high pressure pipelines, and magneto-hydrodynamic power generation have been considered.

A review of current knowledge concerning turbine erosion, corrosion, and deposition problems is also presented.

This report was submitted in partial fulfillment of Contract No. 68-02-2137 by A.P.T., Inc. under the sponsorship of the U.S. Environmental Protection Agency.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

ACKNOWLEDGEMENT

A.P.T., Inc. wishes to express its appreciation for excellent technical coordination and for very helpful assistance in support of our technical effort to Dr. Leslie Sparks of the EPA, and Dr. Dennis Drehmel, EPA Project Officer.

SUMMARY AND CONCLUSIONS

High temperature and high pressure (HTP) particulate cleanup requirements of existing and proposed energy processes have been reviewed and evaluated. The results are presented in this final report. The intention of this study has been to:

1. define specific HTP particle removal problems,
2. indicate potential solutions, and
3. identify areas where current knowledge and data are inadequate.

Primary emphasis has been placed on the requirements of processes now being proposed as clean methods for obtaining energy from coal. That is:

Fluidized Bed Coal Combustion
Coal Gasification
Direct Coal-Fired Gas Turbines

In addition, the cleanup requirements and experience of other high temperature and/or high pressure processes, such as:

fluid bed catalytic cracking units,
metallurgical furnaces,
geothermal power plants,
high pressure pipelines, and
magnetohydrodynamic power generation

have been considered.

Fluidized bed coal combustion, coal gasification, and direct coal-fired gas turbine processes all have been proposed for use with industrial gas turbines. Particulate collection is required at HTP to protect the turbine blades from excessive wear. Temperature and pressure losses through the particle collection equipment must be minimized to maintain a high turbine efficiency. In all cases the particulate emissions from the turbine must satisfy the applicable emissions standards.

CONDITIONS FOR PARTICULATE CLEANUP

The conditions for HTP particle collection are summarized in Table 1. Temperatures range up to 1,100°C (2,000°F) and could go higher as industrial gas turbine inlet temperatures increase. Current maximum turbine inlet temperatures are near 1,200°C.

Fluidized bed coal combustion temperatures are typically about 850°C. This temperature optimizes the removal of sulfur in the fluidized bed and reduces the formation of nitrogen oxides. Because this combustion temperature is relatively low and because gas turbine efficiencies increase in proportion to the turbine inlet temperature, temperature losses in the particulate collection equipment are very costly.

This problem is less important in coal gasification processes because the gas releases heat when it is burnt prior to entering the turbine. In this case, air injection is often required to reduce the gas temperature to the required turbine inlet temperature.

Table 1 indicates that particle collection may be required at pressures anywhere from near atmospheric to about 70 atm. The most extreme pressures are encountered when pipeline quality gas is produced. It is generally more economical to operate the gasification process at or above pipeline pressure (50 - 70 atm) than to compress the gas after it has been produced. When pipeline pressures are not required, the processes normally are not pressurized above about 20 atm; a pressure of 10 atm is common. Particle collection is required at system pressure. High pressure systems have the advantage that they are not as sensitive to pressure drop across the collection equipment as low pressure systems.

Gas and particle compositions are also shown in Table 1. The gases are generally the products of combustion (N_2, CO_2) or of gasification (H_2, CO, CO_2). Moisture may be present from a few percent up to as much as 20% (by volume). In the coal gasification process, the product gas may be predominantly

Table 1. CONDITIONS FOR HIGH TEMPERATURE AND PRESSURE PARTICULATE COLLECTION

PROCESS	TEMPERATURE °C	PRESSURE atm	TYPICAL GAS COMPOSITION mol %	EXPECTED PARTICULATE COMPOSITION
Open cycle coal-fired gas turbine	650-1,000	4-10	83% N_2, 15% CO_2, 2% O_2, H_2O, SO_x, NO_x, CO, and gaseous hydrocarbons	coal ash, unburnt carbon
Fluidized bed coal combustion	800-900	~1-20	80% N_2, 10% CO_2, 6% O_2, 4% H_2O, + SO_2, NO, CO	60 wt % ash, 30% unburnt carbon, 10% sorbent
Coal gasification	150-1,100	~1-70		ash, unburnt carbon, sorbent, possibly tar
O_2 blown			30% H_2, 25% CO, 15% CO_2, 20% H_2O, 3% CH_4, H_2S, N_2	
Air blown			50% N_2, 12% H_2, 20% CO, 10% H_2O, 6% CO_2, + CH_4, H_2S	
FCC regenerator	300-800	~1-3	68% N_2, 5% CO, 3% O_2, 8% CO_2, 16% H_2O, + NO_x, SO_x, NH_3, HCN, aldehydes, hydrocarbons	catalyst dust depends on catalyst type, commonly silica and alumina
Metallurgical furnaces	250-1,000	~1	N_2, CO_2, O_2	very fine metal fume
MHD power generation	300-800	~1	---	K_2CO_3 seed particles

methane (after shift conversion and methanation), however particle removal would occur downstream of the gasifier and before shifting. The gases at this stage of the process are the gasification products listed in Table 1.

Particulate composition depends on the process. For coal processes, ash (principally silica, alumina, and iron oxide), and unburnt carbon are usually present. Sorbent material (such as limestone) used for sulfur removal during combustion or gasification may also be present. Some of the lower temperature gasification processes may also produce tar particles. Tar particles are difficult to handle and can cause plugging problems in cyclone collectors. Wet scrubbers have been used successfully for controlling tar emissions.

PARTICULATE CLEANUP REQUIREMENTS

The degree to which particles must be removed from HTP processes depends on the application. Typical HTP particulate cleanup requirements are presented in Table 2. In any case, the final emissions to the atmosphere must satisfy all applicable emissions standards. If necessary, this could be accomplished using conventional control equipment downstream from the HTP process.

A potentially more stringent requirement is imposed on the particle collection equipment when the cleaned gas is to be passed through a gas turbine. A gas containing dust particles can severely erode and corrode turbine blades and other internal components. Also, deposition of dust particles on the turbine blades can impair the aerodynamic performance of the turbine.

A large number of research investigations have been reported which deal with turbine blade erosion and deposition problems. Much of this work was done in connection with military gas turbines for helicopter and ground tracked-vehicle engines. Similar research has also been conducted with industrial gas turbines. It is generally believed that large particles (over 2-5 μm diameter) cause severe erosion damage and

Table 2. HIGH TEMPERATURE AND PRESSURE PARTICULATE CLEANUP REQUIREMENTS

PROCESS	ALLOWABLE PARTICULATE LOADING		DETERMINING FACTOR	CONTROL DEVICE USED OR PROPOSED
	S.I. UNITS	ENGLISH UNITS		
Open cycle coal-fired gas turbine, Pressurized fluidized bed coal combustion, and Combined cycle low-BTU coal gasification	2.3 mg/m^3 >2 μm 43 mg/MJ <2 μm	0.001 gr/SCF >2 μm 0.1 lb/10^{6}BTU* <2 μm	Turbine wear Emissions	Cyclones, followed by filters; hot electrostatic precipitators, or granular bed filters
High BTU coal gasification	4.6 mg/m^3	0.002 gr/SCF	Pipeline quality	Cyclones followed by high efficiency scrubbers
FCC catalyst regenerator	0.001 gram of particulate per gram of coke burnt off	0.001 lb particulate per lb coke burnt off	Emissions	Electrostatic precipitators, baghouses, scrubbers, granular bed filters
Metallurgical furnaces (in general) Steel electric arc furnaces	50.4 mg/m^3 11.9 mg/m^3	0.022 gr/SCF 0.0052 gr/SCF	Emissions Emissions	Electrostatic precipitators, high efficiency scrubbers, and baghouses

*Current new source performance standards are 0.1 lb/10^{6}BTU, however a stricter standard of 0.05 lb/10^{6}BTU has been proposed.

must be removed. Particles under 1 - 2 μm diameter cause much less erosion damage. However, there is a scarcity of data concerning the tolerance of turbines for fine particles.

From the available data on turbine tolerances for particulate matter, it appears that effectively all particles larger than about 2 μm must be removed from the gas. Fine particles (<2 μm) must be removed sufficiently to satisfy the emissions regulations.

When pipeline quality gas is the product the particulate matter must be removed at high pressure and moderate temperature to provide a clean fuel for burning and to protect the compressors used during pipeline transport.

The principal control devices used or proposed for HTP particle cleanup are listed in Table 2. If the gas is not intended for gas turbine use, high efficiency scrubbers are commonly used. They can serve the dual function of cooling the gas, and removing the particulate matter. They also can condense out pollutants which existed in the vapor state at high temperature.

Usually all fine particle control equipment (scrubbers, baghouses, electrostatic precipitators, and others) are preceded by a series of cyclone collectors. The principal purpose of the cyclones is to reduce the particulate loading on subsequent collection equipment. The cyclones efficiently remove large particles (greater than about 10 or 20 μm), and often recycle them through the combustor or gasifier. This makes more efficient use of the carbon contained in the feed coal, but increases the loading of fine particles emitted from the process.

Conventional scrubbers are not suitable for HTP particle collection when the gas is to be expanded through a turbine because they cool the gas being cleaned. High temperature granular bed filters, baghouses, and electrostatic precipitators have been proposed for the final cleaning stage, but none have been proven to have a sufficient collection efficiency to meet the turbine requirements. Development work is under way with these devices.

Particle collection at HTP is much more difficult than at standard conditions and the turbine may impose more stringent requirements than normally encountered. Therefore it is possible that two stages of fine particle collection will be required. Demonstration of fine particle collection equipment operating at HTP is lacking and is needed.

CONCLUSIONS

Particulate cleanup requirements for HTP processes vary depending on the intended use of the gas. If it is to be vented (as with the effluent from a secondary metals recovery furnace) then the gas can be cooled and must be cleaned sufficiently to meet the emissions standards. This can be done satisfactorily with high efficiency scrubbers at the penalty of high energy consumption.

If the gas is to be converted to a pipeline quality gas, very efficient particle collection is required. However, final temperatures are relatively low and scrubbers may be used.

The most difficult situation is where the hot gas is to be expanded through a gas turbine. Very efficient collection is required by the turbine, and it is desirable to do this at system temperature and pressure.

The particle collection requirements for pressurized, fluidized coal combustion and for low-BTU coal gasification processes are very similar. They are primarily determined by the gas turbine requirements and the emissions standards. The conditions for particle collection, however, have some important differences.

Gasifier exit temperatures can range from 150°C to over 1,100°C depending on the specific process. The low temperature presents problems with tar emissions, but allows the use of conventional control equipment (operating at system pressure). The high temperatures present severe materials problems, as well as making particle collection more difficult (because the gas is more viscous at high temperature). Temperature losses in the collection equipment are not critical because the gas is to be burnt (generating heat) before it passes into the turbine. Hot gas cleanup, however, could be more economical. Corrosion may be more of a problem with gasification than with combustion because of the reducing atmosphere in the gasifier.

Pressurized fluidized bed coal combustion temperatures are typically about 850°C. This is less severe than the maximum gasifier temperature, however temperature losses during particle collection are critical and therefore scrubbers are not suitable.

HTP particle collection devices need to be tested to determine their collection efficiency and the cost to achieve a given degree of particle removal.

Particle size distributions and mass loadings at HTP conditions need to be measured for all processes for which HTP particle collection is being considered. This information is necessary in order to define the HTP cleanup requirements (i.e., the required collection efficiencies) and is essential in developing and evaluating collection equipment for specific processes.

INTRODUCTION

The commercial development of advanced energy processes, such as pressurized fluidized bed coal combustion, and low-BTU coal gasification, is hindered by the problem of removing dust from hot, pressurized gases. In many cases the gas is to be expanded from high temperature and pressure through a gas turbine. Any temperature or pressure losses during the dust collection stage will reduce the overall thermodynamic efficiency of the process. Therefore it is desirable to clean the gas at system pressure and at a temperature no lower than the desired turbine inlet temperature.

Many industrial process effluent gas streams are at high temperature and atmospheric pressure. Ordinarily it is economical to recover the sensible heat of the gas in a waste heat boiler which can generate process heat, power, or steam. The waste heat boiler cools the gas to a temperature just above the dew point of any condensible vapors in the gas.

In some situations there is not sufficient need for process heat or power to justify the expense of a waste heat boiler. However, conventional dust cleaning equipment is limited to relatively low temperatures and therefore the hot effluent gas must be quenched before it is cleaned. If suitable high temperature particle collection equipment were available, it would be possible to clean the gas at high temperature and exhaust it to the atmosphere, thereby saving the expense of gas cooling.

There are also processes where high pressure and low temperature particle collection is desirable. One example is the production of pipeline quality gas from the gasification of coal and subsequent methanation of the resulting coal gas. In many proposed processes the gas is cooled and cleaned at low temperature before being methanated and added to the supply of pipeline gas. The whole process, including gas cleaning, is carried out at pipeline pressure. High pressure particle collection has also been a problem in removing entrained particles from natural gas pipelines.

High temperature and high pressure (HTP) particle collection is much more difficult than the collection of the same particles would be at relatively low temperatures and pressures (see Calvert and Parker, 1976). There is not only a severe materials problem, but also the gas properties (especially viscosity) at high temperature and pressure make the separation of suspended solids from gases much more difficult.

Equipment for HTP particle collection has been under development for more than thirty years but no generally satisfactory solution to the problem has yet been proven. Some of the earliest efforts were in connection with the development of a coal-fired gas turbine for locomotive use. Work was conducted in the U.S.A. by the Locomotive Development Committee of Bituminous Coal Research, Inc., between about 1945 and 1955, and by the U.S. Bureau of Mines in the 1960s. Parallel development programs were going on in Australia, Canada, and Great Britain. Particle collection at HTP was needed to prevent excessive erosion of the turbine blades. High efficiency cyclones, electrostatic precipitators, and filtration systems were tried without success. Some variations in turbine blading reduced erosion, but efficiency fell off so badly as to make the approach impractical.

Most current interest in HTP particle collection is in relation to pressurized fluidized bed coal combustion and low-BTU coal gasification. It has been proposed that these processes be used in a combined cycle gas turbine/steam turbine power generation system (Robson and Giramonti, 1972), where HTP particle cleanup is required to protect the gas turbine components. Also it is necessary that the processes meet all federal and local standards that are imposed for particulate emissions.

This report contains the results of a literature survey summarizing the HTP particle removal requirements of past, present, and future energy processes. The information presented here was obtained from published literature, government reports, and personal communications with current researchers. Some information was not available because it is proprietary, and some information concerning the particulate emissions from the processes is as yet unknown.

The particulate removal requirements for each process are discussed in detail. Because the requirements are strongly dependent on the particulate tolerance of gas turbines, a separate section is presented which discusses current knowledge of turbine erosion, corrosion, and deposition problems.

FLUIDIZED BED COAL COMBUSTION PROCESSES

The fluidized bed combustion (FBC) of coal is a relatively new combustion technique being developed in the U.S. to burn sulfur-containing coals with an acceptably small emission of sulfur oxides. Sulfur oxides are controlled by using limestone or dolomite as a bed component. High heat transfer coefficients between the fluidized bed and immersed steam generation surfaces reduce the surface area requirements and also permit operation at lower and more uniform bed temperatures (800-900°C). The lower temperatures help to reduce nitrogen oxide emissions and decrease steam tube corrosion. Lower grade coals can also be burned because the bed temperatures are lower than their ash slagging temperatures. Particulate emissions from the fluidized bed must be controlled before the effluent gas is vented or used in a power recovery turbine.

Fluidized bed combustors have been operated at atmospheric pressure and at pressures as high as 10 atm. The pressurized FBC processes are being designed for use in combined cycle power plants, where high temperature and pressure particle removal will be required to protect the turbine components. The atmospheric FBC process has been developed to compete with conventional boilers. High temperature particle removal is not necessarily required for atmospheric systems.

Combustion temperatures in fluidized beds are much lower than in conventional boilers because of the larger heat transfer coefficients that may be obtained. Combustion temperatures can range anywhere from 400°C to over 1,000°C. However, most FBC processes operate near 850 - 900°C, in order to optimize sulfur oxide removal in the fluidized bed.

Table 3 gives a summary of conditions after the secondary cyclone for the major FBC systems under development. Each of these systems will be discussed in more detail below.

Table 3. SUMMARY OF FBC PARTICULATE CLEANUP REQUIREMENTS

	EXXON	ARGONNE	CPA*	NCB	PER
Temperature, °C	820-950	790-900	760-980	750-950	300-400
Pressure, atm	5-10	to 8	3-7	1-5	1
Mass loading, g/Nm^3	1.8-2.8	0.5-4.8	0.09	3.0	.2-1.7
Mass loading, gr/SCF	0.8-1.2	0.2-2.1	0.04	1.4	.5-4
Mass median diameter, μm	4-8	---	1.2	---	4.6
Geometric standard deviation	2.7	---	1.9	---	2

*waste-fired combustor

PROCESS EVALUATION

Westinghouse Research Laboratories

The fluidized bed combustion process has been evaluated by Westinghouse Research Laboratories and reported by Archer et al. (1971) and Keairns et al. (1973, 1975) in a number of reports for the EPA. Of all the systems studied, the pressurized FBC boiler operating in a combined cycle (gas turbine/steam turbine) power plant appeared to be the most effective process for satisfying projected standards for sulfur oxide, nitrogen oxide, and particulate emissions. It also appears to be the most economical process for electric power generation.

The pressurized fluidized bed boiler system is illustrated in Figure 1. Compressed air is supplied at from 10% to 100% excess air. Steam is generated in the fluidized bed. The hot gas leaves the bed at high pressure and is expanded through a gas turbine, passed through a heat recovery unit (boiler feedwater preheat), and exhausted out the stack. Approximately 82% of the power is generated in the steam cycle, before any collection equipment, and only 18% is generated in the gas turbine. Keairns et al. (1975) report that cooling the gas and scrubbing it at high pressure before the gas turbine might be economical in this system under certain conditions, however it would not be as economical as hot gas cleanup.

One alternative pressurized FBC system is the adiabatic FBC system. This system is illustrated in Figure 2. The hot, high pressure gases from the combustor are cleaned and passed through a gas turbine where they are expanded to atmospheric pressure. The hot gas leaving the gas turbine is passed through a heat recovery boiler to generate steam for one steam turbine. High temperature and pressure particle removal is required to clean the gas prior to passing it through the gas turbine. As with the pressurized fluidized bed boiler system, it is economically desirable to clean the gas with a minimum loss of temperature and pressure. However the adiabatic system is

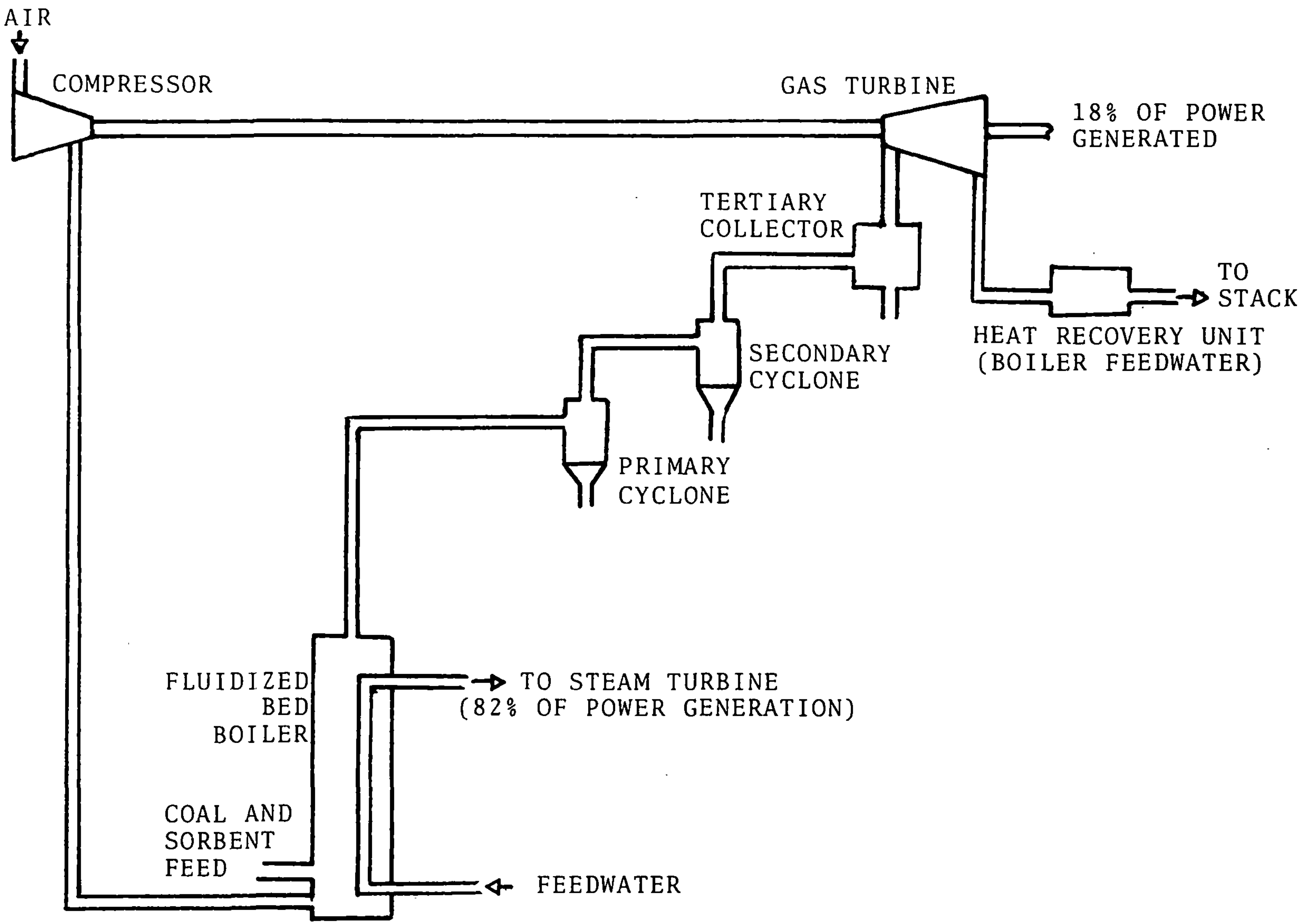

Figure 1. Pressurized fluidized bed boiler power plant.

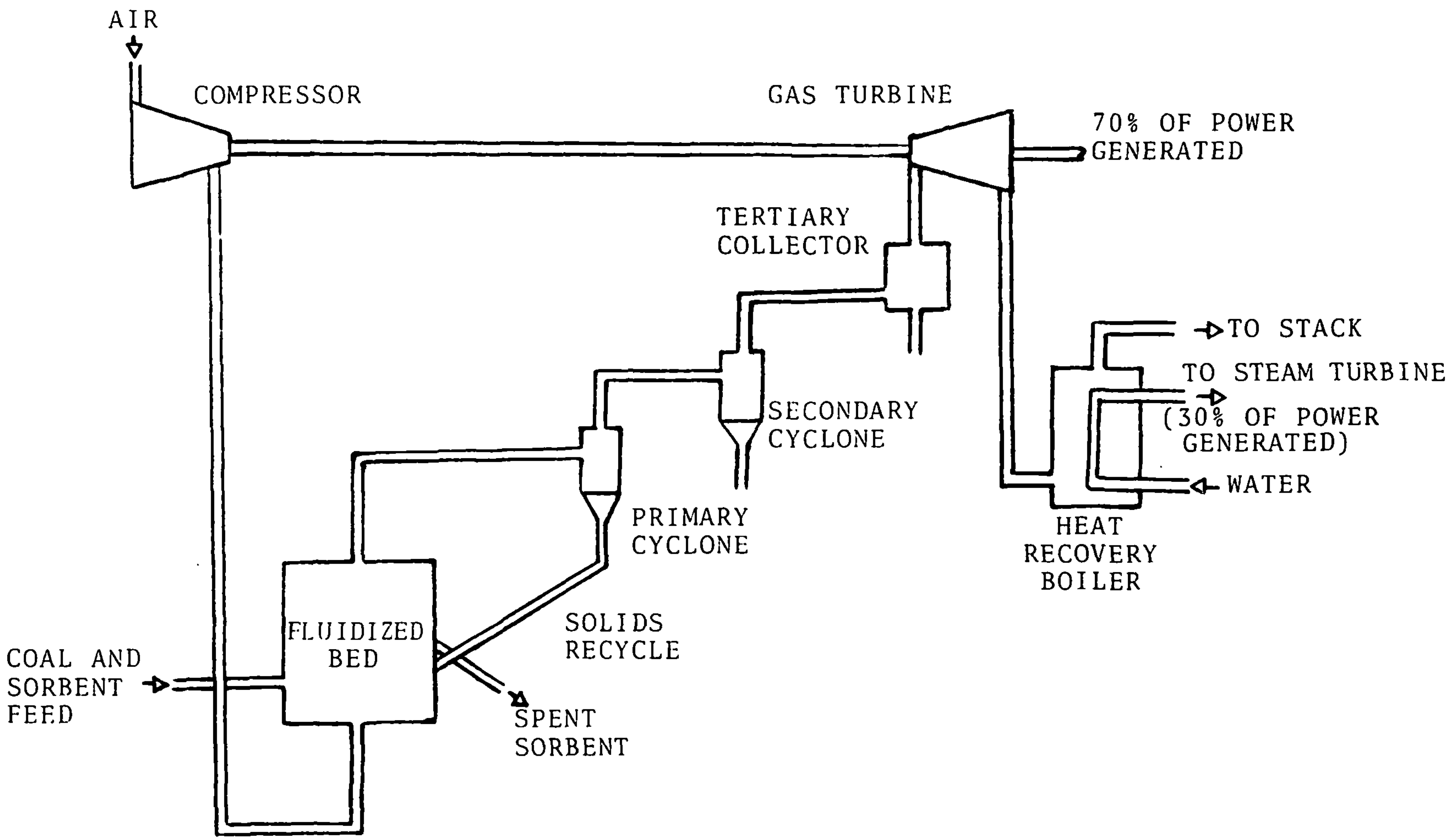

Figure 2. Adiabatic pressurized fluidized bed combustor in combined-cycle power plant. From Keairns et al. (1975)

more sensitive to temperature and pressure losses during particle removal because all power generation occurs downstream of the particulate control equipment. High excess air (300 - 360%) is required with the adiabatic system to prevent overheating.

A third system reported by Westinghouse is the indirect air cooled FBC system. This system maintains the bed temperature by passing excess air under pressure through an air cooled heat exchanger in the bed. Approximately 70% of the air is used in this manner and is later combined with the cleaned combustion gas. The cycle performance will be somewhat lower than the adiabatic system (depending on the efficiency of heat transfer). The advantage is that a smaller volume of gas needs to be cleaned.

The Westinghouse design for the HTP particle collection system in these cases consists of two stages of cyclones followed by a tertiary collector. The primary cyclone would collect large particles (including much of the unburnt carbon) and recycle them to the fluidized bed. The secondary cyclone would remove finer particles to reduce the dust loading to the tertiary collector.

The tertiary collector would be an HTP granular bed filter, ceramic fiber filter, or other high efficiency collection device. It should be capable of collecting substantially all particles greater than 2 μm, and should reduce the total mass loading to within the anticipated EPA emissions regulations. This would be roughly equivalent to a mass loading of 0.12 g/Nm^3 (0.05 gr/SCF) based on current regulations.

The flue gas composition at the high temperature and pressure cleanup location would be predominantly nitrogen (80+%), carbon dioxide (10-15%), and oxygen. Westinghouse (Keairns et al., 1975) has made an evaluation of an oxygen-blown atmospheric pressure fluidized bed boiler and concluded that the high cost of oxygen makes the process uneconomical for steam or power generation.

The particulate loading leaving the pressurized fluidized bed boiler is expected to be on the order of 16 g/Nm^3 (7 gr/SCF) The particulate matter should consist of about 60% ash, 30% unburnt carbon, and 10% sorbent, such as dolomite ($CaCO_3 \cdot MgCO_3$) or limestone ($CaCO_3$). The ash composition depends on the specific coal being burnt. A typical coal ash would contain mostly silica, alumina, and ferric oxide, possibly with smaller amounts of calcium oxide, magnesium oxide, titanium oxide, alkalies (Na_2O, K_2O), and phosphorus pentoxide.

The particulate removal requirements will depend on the concentration of particulate at the collection device, and on the amount of excess air added to the system. Because of the high excess air, the adiabatic system will have a significantly lower concentration of particulate in the combustion gas. The air cooled system will have a relatively large mass loading to the collection equipment, but subsequent dilution with the excess air will reduce the loading to the turbine and environment. Thus the required particle removal efficiency will be less stringent than with the pressurized FBC boiler system.

The particulate removal requirement for all FBC systems will depend on the requirements of the gas turbine and the source emissions standards. The turbine requirements are not well established, but it is anticipated that dust loadings of particles larger than 2 μm must be reduced below 2.7 mg/Nm^3 (0.0012 gr/SCF) for satisfactory turbine life (Robson, 1976). Larger dust loadings of fine particles (<2 μm) of the order of 0.34 g/Nm^3 (0.15 gr/SCF) may be acceptable for the turbine (Westinghouse, 1974). The turbine requirements also depend on gas and particle composition and on whether the concern is for erosion or corrosion.

Particulate emissions from fluidized bed boilers also will have to satisfy the Federal New Source Performance Standards for coal-fired boilers. This standard is currently at 43 mg/MJ (0.1 $lb/10^6 BTU$). In the future, however, it will probably be necessary to have more stringent standards in order to meet and maintain Ambient Air Quality Standards while not severely restraining economic growth capacity. Therefore new FBC systems should be developed with the capability of satisfying more stringent standards than currently are required. A standard of 21 mg/MJ (0.05 lb/10^6BTU) has been suggested as an anticipated future emissions standard.

The Westinghouse studies are primarily theoretical predictions based on anticipated emissions and design criteria. There are not many data available to quantify the particulate emissions from fluidized bed combustion processes. One reason for this lack of data is that the FBC process is still in the development stage. What data are available are for specific test situations and are not necessarily representative of FBC processes optimized for commercial applications. Also, HTP sampling for particulate emissions is very difficult and expensive.

EXPERIMENTAL STUDIES

Exxon Research and Engineering Company

Fluidized bed combustion research is being conducted by Exxon Research and Engineering Company. This work has been reported by Nutkis (1975), Hoke (1975), Hoke et al. (1974, 1976), and in many previous reports to the U.S. EPA. Exxon is working with a small, batch-fluidized bed pilot unit and a larger, continuous pilot unit (miniplant) which operates at flows up to about 25 Nm^3/min (900 SCFM).

The miniplant is being used to study a regenerative limestone process for the combustion and desulfurization of coal. They also have taken a leading role in obtaining data to characterize the particulate emissions from pressurized FBC processes.

Representative size distributions of the particulate matter emitted from the batch plant and miniplant are presented in Figure 3. Particulate leaving the secondary cyclone

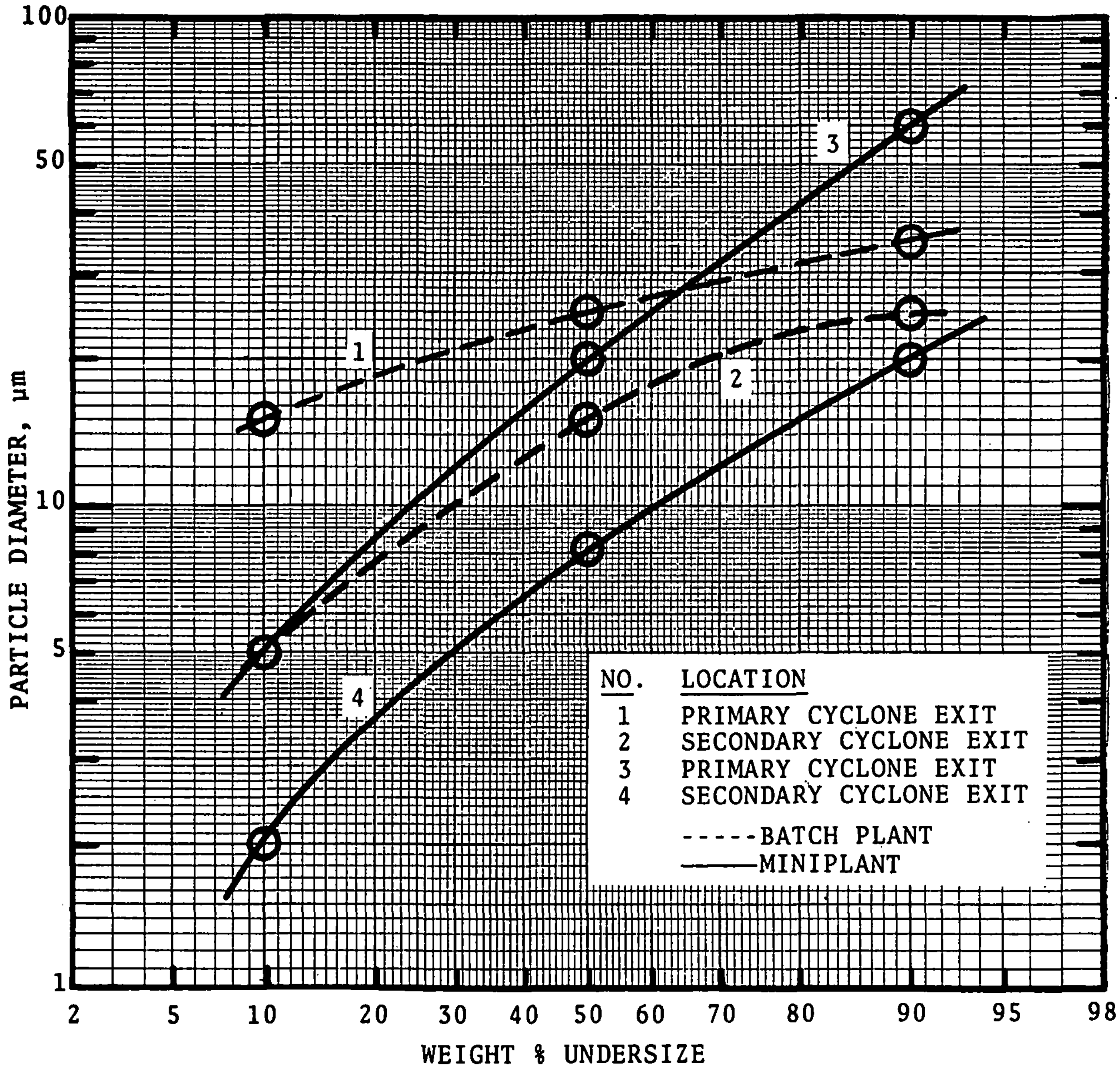

Figure 3. Particle size distributions from Exxon batch and miniplant fluidized bed coal combustors. From Monthly Report #77, July 1976.

at the miniplant has a mass median diameter (MMD) of 8 μm and a geometric standard deviation (σ_g) of 2.7. Data for the batch plant were obtained by microscopy, while data for the miniplant were obtained by sieve and Coulter Counter analyses. Gas conditions and particulate loading data are presented in Table 4. The miniplant loading is much larger because the solids collected in the primary cyclone are recycled to the combustor.

In the Exxon miniplant the current and proposed standards for particulate emissions (0.1 and 0.05 lb/10^6BTU) correspond to dust loadings of approximately 0.1 and 0.05 g/Nm^3 (0.05 and 0.025 gr/SCF). Recent particulate emissions from the second cyclone have been consistently in the range 1.8 to 2.8 g/Nm^3 (0.8 - 1.2 gr/SCF) with mass median diameters from 4 to 7 μm (Hoke, 1977). Therefore it can be seen that the cyclones will not reduce the particle concentration sufficiently, and a third stage, or tertiary cleanup, device is required.

Exxon is currently testing a Ducon granular bed filter for this application. Preliminary experience indicates that cleaning of the bed will be a very difficult problem. The granular bed filter system has been redesigned to avoid the problem of plugging the gas inlet screens. The particulate matter appears to be very sticky (although dry) and agglomerates easily. Because of the relatively low combustion temperatures, the particulate is most likely not formed by condensation (fume). Exxon has estimated that the effective density is 1.5 g/cm^3 and has observed that the particles are not porous but are irregular in shape.

Low temperature tests with the Ducon filter are currently under way and high temperature and pressure tests are planned for the near future. Exxon will also be testing a ceramic bag filter and a high temperature and pressure electrostatic precipitator as possible tertiary collection devices.

Table 4. SUMMARY OF CONDITIONS FOR PARTICLE REMOVAL FROM THE EXXON BATCH PLANT AND MINIPLANT FLUIDIZED BED COAL COMBUSTORS[1]

Temperature Range: 820 to 950°C

Pressure Range: 5 to 10 atm

Dust Loading: Batch Plant

Leaving Combustor[2]; 14 to 18 g/Nm^3 (6 to 8 gr/SCF)
Leaving Primary Cyclone[2]; 0.9 to 2.3 g/Nm^3 (0.4 to 1.0 gr/SCF)
Leaving Secondary Cyclone[2]; 0.2 to 1.4 g/Nm^3 (0.1 to 0.6 gr/SCF)

Dust Loading: Miniplant (with solids recycle)

Leaving Combustor[3]; 70 to 700 g/Nm^3 (30 to 300 gr/SCF)
Leaving Primary Cyclone[3]; 9 to 23 g/Nm^3 (4 to 10 gr/SCF)
Leaving Secondary Cyclone[2]; 0.9 to 4.6 g/Nm^3 (0.4 to 2 gr/SCF)

Composition of Effluent Gas Stream (typical):

Component	Vol.%
CO_2	8-10
O_2	8-12
H_2O	3-4
N_2	77-78

[1]From Exxon monthly report to the EPA, July 1976.

[2]Data from measured samples.

[3]Estimated loading.

Argonne National Laboratories

Fluidized bed combustion studies also are being conducted at Argonne National Laboratories. This work has been reported by Vogel et al. (1974, 1975). They use a 15 cm (six-inch) diameter fluidized bed bench-scale unit. Particulate loadings and gas conditions are presented in Table 5. The particulate loadings are for various test conditions and may not be representative of what could be achieved under optimized conditions. The test variables include temperature, fluidizing velocity, and the calcium/sulfur ratio.

The particulate emissions were observed to increase with the fluidizing velocity and the calcium/sulfur ratio. No general trends in the effect of temperature on particulate emissions were reported.

Size distributions of the particulate matter collected in the primary and secondary cyclones are shown in Figure 4 to have an MMD=1.6 μm and σ_g=2. The data were taken by Coulter Counter. The cyclones were not optimized for particle collection and thus their efficiencies are not necessarily representative of the best attainable.

The gas leaving the cyclones was passed through one or two stages of filters. Size analysis of the particulate on the filter was not available, however subsequent tests showed that from 0.12 to 0.20 g/Nm^3 (0.051 to 0.089 gr/SCF) was penetrating the first filter stage. Approximately 60 to 80% of this particulate was smaller than 2 μm (by Brink impactor analysis). Therefore, emissions of fine particles (<2 μm) can at least be the order of 0.1 g/Nm^3 (0.05 gr/SCF).

Once again, it should be emphasized that the data reported here (from Vogel et al., 1974) are not necessarily representative of the loadings and particle size distributions that would be obtained in a commercial unit with an optimally designed system for the high-temperature removal of fine particulate matter from the flue gas.

Table 5. SUMMARY OF CONDITIONS FOR PARTICLE REMOVAL FROM THE ARGONNE BENCH-SCALE FLUIDIZED BED COAL COMBUSTOR[1]

Temperature Range: 790 to 900°C

Pressure Range: up to ~8 atm

Dust Loading:

Leaving Combustor[2]; 9 to 55 g/Nm^3 (4 to 24 gr/SCF)
Leaving Primary Cyclone[2]; 1.1 to 10.8 g/Nm^3 (0.5 to 4.7 gr/SCF)
Leaving Secondary Cyclone[2]; 0.5 to 4.8 g/Nm^3 (0.2 to 2.1 gr/SCF)

Dust Emissions:

Leaving Combustor[2]; 3 to 17 g/MJ (7 to 39 lb/10^{6}Btu)
Leaving Primary Cyclone[2]; 0.3 to 3.2 g/MJ (0.8 to 7.4 lb/10^{6}Btu)
Leaving Secondary Cyclone[2]; 0.2 to 1.4 g/MJ (0.5 to 3.3 lb/10^{6}Btu)

Composition of Effluent Gas Stream:

Component	Vol.%
CO_2	15-17
O_2	~3
N_2	80-82
SO_2	120-850 ppm
NO	140-270 ppm
CO	30-760 ppm

[1]From Vogel et al. (Sept, 1974)

[2]Data from measured sample. Estimated accuracy is ±10%.

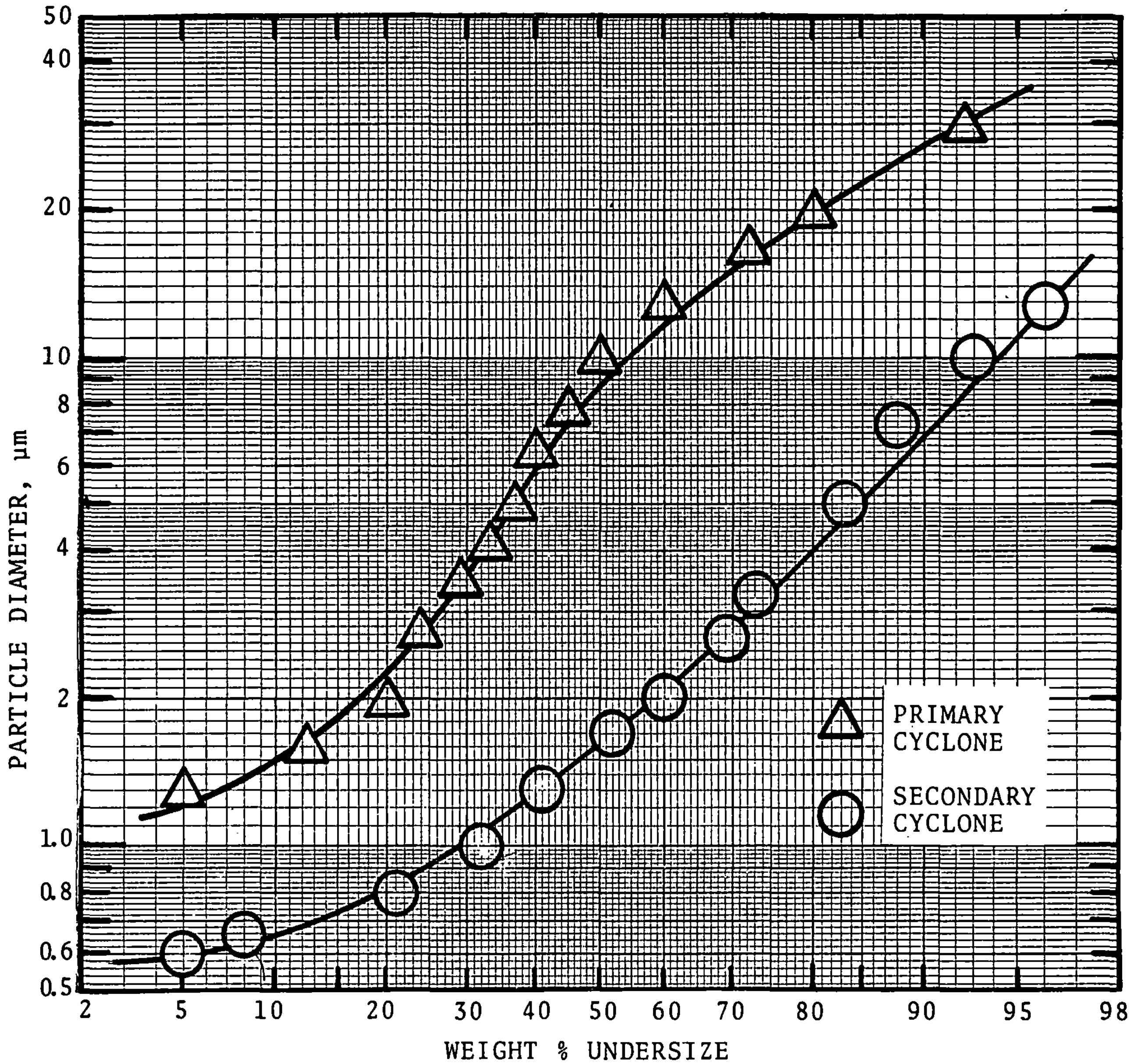

Figure 4. Size distributions of particulate matter collected in primary and secondary cyclones at the Argonne bench-scale fluidized bed combustion project. Data were replotted from data presented by Vogel et al. (Sept. 1974).

Argonne National Laboratories is constructing a larger (0.8 to 3.1 equivalent MWe) fluidized bed combustion component test and integration unit (CTIU) under E.R.D.A. sponsorship. This facility will have the capability of testing alternative hot gas cleanup systems. The conceptual design for this facility was reported by Carls and Podolski (1975). This facility will be a pressurized CTIU as opposed to the Morgantown CTIU which operates at atmospheric pressure.

Combustion Power Company

The Combustion Power Company has developed the CPU-400 fluidized bed combustor and gas turbine system. It was originally designed to generate electric power from the combustion of municipal waste (Combustion Power Company, 1969-1974). More recently it has been used with dolomite additive to burn high sulfur coal.

The solid waste or coal is burnt at temperatures ranging from about 760°C to 980°C, and at pressures from atmospheric to about 7 atm. These data are summarized with the gas composition and particulate emissions in Table 6. The size distribution for the particulate leaving the secondary cyclone from the combustion of municipal waste is also given in Table 6. Approximately 0.07 g/Nm^3 (0.03 gr/SCF) were smaller than 2 μm.

As a tertiary cleanup device, Combustion Power has developed a moving bed granular bed filter (dry scrubber), reported by Wade (1975). A high temperature and high pressure model of the granular bed filter was built but the unit had materials problems which resulted in mechanical failure. Current development work is being conducted at low temperature under ERDA sponsorship.

The burning of municipal waste may be a more difficult problem than burning coal because of the variety of gases and particulate pollutants that are emitted. For example, aluminum condensation particles are difficult to collect and may increase the potential for turbine blade corrosion from particulate de-

Table 6. SUMMARY OF CHARACTERISTICS OF PARTICLE REMOVAL FROM THE COMBUSTION POWER COMPANY FLUIDIZED BED COMBUSTION PROCESS[1]

Bed Temperature: 760 to 980°C

Turbine Inlet Temperature: 690 to 750°C

Pressure: 3 to 7 atm

Dust Loading: Waste-fired combustor:

Leaving Secondary Cyclone; 0.09 g/Nm^3 (0.04 gr/SCF)

Smaller than 2 μm; 0.07 g/Nm^3 (0.03 gr/SCF)

Composition of Effluent Gas Stream:

Component	Waste-Fired Vol.% low pressure	Waste-Fired Vol.% high pressure	Coal-Fired Vol.%
CO_2	5.8	5.2	3.5-6.7
O_2	13.4	16.1	13-16
CO	<30 ppm	<30 ppm	---
CH_x	---	2 ppm	---
SO_2	<20 ppm	35 ppm	---
NO_x	139 ppm	100 ppm	---
HCl	161 ppm	63 ppm	---
N_2 + Other	~81	~81	80.5

Particle Size Distribution: Waste-fired combustor:

Particle diameter, μm	Wt % undersize
5.0	99.5
4.0	98.5
3.0	95.1
2.5	90.1
2.0	82.7
1.2[2]	50[2]

[1]From C.P.C. Report to the EPA, Sept. 1974.

[2]Extrapolated from log-normal distribution.

posits. Combustion Power also has had trouble with cyclones plugging up with large, sticky particles.

National Coal Board

The National Coal Board of London, England has conducted experimental pilot plant tests of atmospheric and pressurized fluidized bed coal combustors. This work has been reported by Hoy (1970), Williams (1970), the National Coal Board (1970, 1972), Wright (1973), Locke et al. (1975), and Highley (1975).

Their combustion temperatures ranged from about 750°C to 950°C. Atmospheric pressure was used for most of the earlier tests, with some pressurized tests conducted at 5 atm. Operating pressures up to 10 or 15 atm are being considered. A typical effluent gas composition is: 15% CO_2, 3% O_2, and 82% N_2, with trace amounts of SO_2.

Particulate emissions downstream of the secondary cyclone ranged from about 0.2 to 1.4 g/Nm^3 (0.1 to 0.6 gr/SCF). This is equivalent to about 1 to 5% of the noncombustible material in the feed. In the pressurized combustor, a third cyclone was used which reduced the dust loading to about 0.1 to 0.2 g/Nm^3 (0.05 to 0.1 gr/SCF). When the fumes from the primary cyclone were recycled to the combustor, the particulate emissions from the secondary cyclone increased to more than 3 g/Nm^3 (1.4 gr/SCF).

The particulate emissions consisted of unburnt carbon, ash, and sorbent additives. When the fines collected in the primary cyclone were recycled, 5 to 15% of the feed coal, and 80 to 100% of the ash and additives were elutriated from the bed.

Particulate emissions increased approximately in proportion to the feed rate of ash plus additive. The increased elutriation at faster fluidizing velocities was found to be balanced by an increased cyclone collection efficiency at the higher inlet velocity. No size distribution data for the particulate emissions were reported.

Pope, Evans, and Robbins

Pope, Evans, and Robbins, Inc. (PER) has studied an atmospheric pressure fluidized bed boiler. Their work has been reported by Ehrlich (1970), Robison et al. (1970, 1972), and Pope (1975) as well as many other reports.

The PER development work involved pilot scale (50 kg coal/hour) and full scale module (363 kg coal/hour) tests at combustion temperatures ranging from 800°C to 1,000°C. The combustors operate at near atmospheric pressure and the flue gas leaves the boiler at about 300°C to 400°C. Particulate emissions are removed by cyclones and possibly an electrostatic precipitator. Particle removal must be sufficient to meet the new source performance standards for coal-fired boilers. It is not necessary that the particulate matter be removed at high temperature.

Unburnt carbon is oxidized in a carbon burnup cell operating near 1,100°C. The carbon burnup cell is a section of the fluidized bed boiler. Particle carryover is recycled via the cyclones to the burnup cell which is at a higher temperature than the primary boiler bed. The lower temperature in the primary bed is necessary to optimize sulfur removal by the sorbent.

Particulate emissions penetrating the cyclones are on the order of 0.4 to 3.4 g/MJ (1 to 8 $lb/10^6BTU$). Therefore, to satisfy an emissions standard of 21 mg/MJ (0.05 $lb/10^6BTU$), approximately 95 to 99+% collection efficiency will be required. The size distribution of the effluent dust, as reported by Robison et al. (1970), is shown in Figure 5. The MMD was 4.6 μm and σ_g was approximately 2.

The PER atmospheric FBC process has been used as a basis for the design of an 800 MWe, multicell utility steam generating system by PER and Foster Wheeler. This design was reported by Gamble (1975).

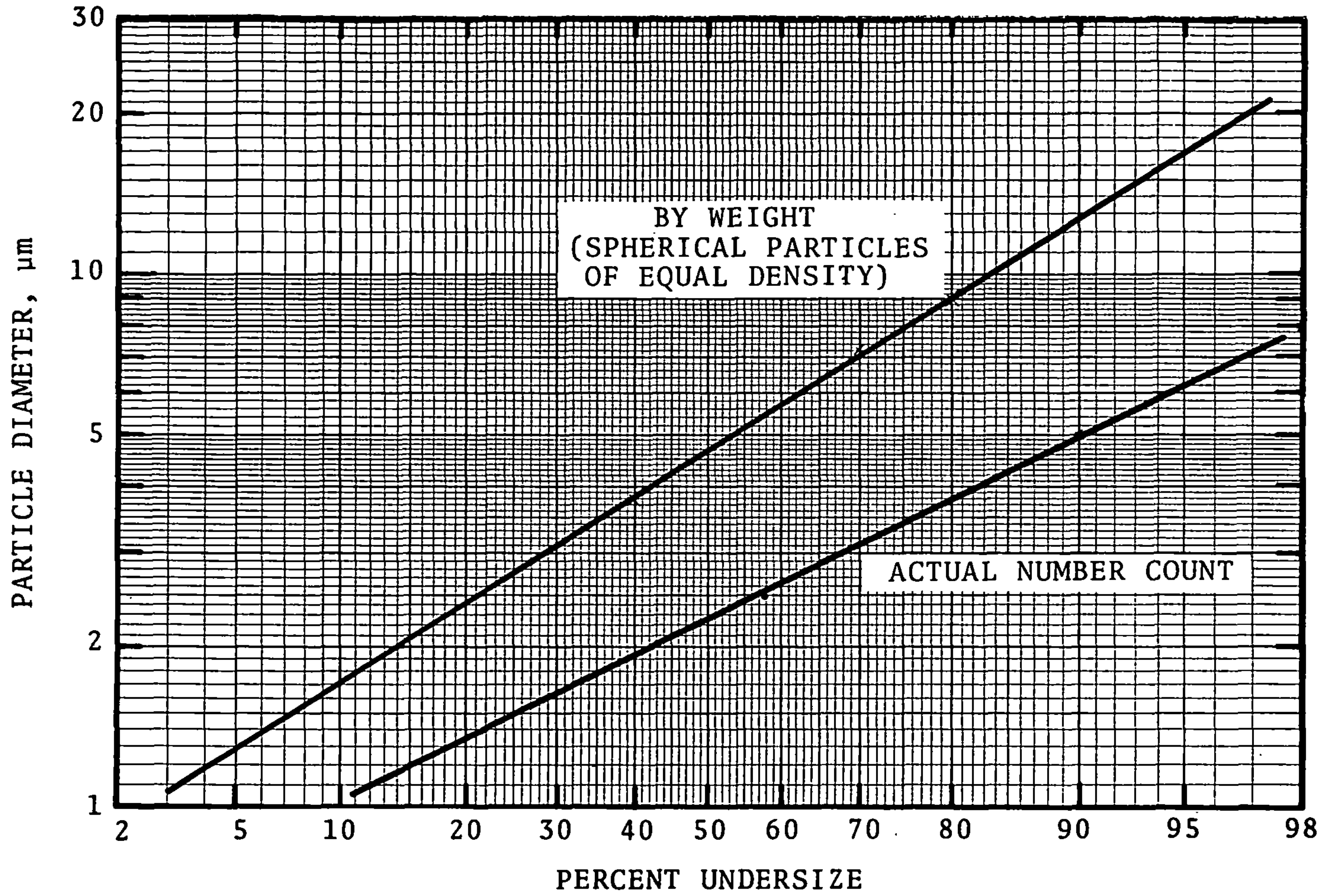

Figure 5. Particle size distribution penetrating the cyclone in the PER fluidized bed combustor. Data from Robison et al. (1970)

MERC Atmospheric FBC

Another atmospheric pressure fluidized bed combustion component test and integration unit (CTIU) with a capacity of 6 MWe is to be built at the E.R.D.A. Morgantown Energy Research Center. This facility will have the capability of testing alternative hot gas cleanup systems. The conceptual design has been described by Wilson and Gillmore (1975).

COAL GASIFICATION PROCESSES

Coal gasification processes are being developed as potential methods for obtaining clean energy from coal. They can be classified as either low-BTU or high-BTU processes. The low-BTU process produces a gas with a low energy content (principally carbon monoxide and hydrogen) which can be used as a fuel for a gas turbine. It can also be burnt directly in a boiler or can be used as a synthesis gas for the production of pipeline gas, ammonia, or methanol. However, it is not economical to transport low-BTU gas in a pipeline. High-BTU processes convert the synthesis gas into methane to produce a pipeline quality gas.

The basic gasification process converts solid coal into a combustible gaseous fuel by reacting it with air, oxygen, steam, carbon monoxide, hydrogen or mixtures of these gases in a reducing environment. The product gas leaves the gasifier at high temperature (up to 1,500°C) and often at high pressure (up to 70 atm). The gas generally contains a large concentration of entrained particulate matter (mostly ash and unburnt carbon). In some of the lower temperature processes (below about 500°C), the gas may also contain a large amount of tar. Also, corrosive contaminants such as alkali metals, mercury, and chlorides may be present in the ash. The particulate matter and tar must be removed from the gas before the gas can be used as a fuel for a gas turbine, or can be upgraded to a pipeline quality gas.

There is no current New Source Performance Standard (NSPS) for advanced fossil-fuel conversion processes, although the EPA plans to use the NSPS approach for controlling these emerging industries (Durham, 1975). In order to allow for industry growth while maintaining regional air quality standards, it will probably be necessary to control particulate emissions from new sources more stringently than current standards. The NSPS for particulate emissions from advanced fossil fuel conversion processes will most likely be at least as stringent as the anticipated new standards for boilers, that is, <0.05 lb/10^6BTU (21.5 mg/MJ), or at least be based on BACT (best available control technology).

In many situations it would be advantageous for economic reasons to clean the gas as it leaves the gasifier, at high temperature and pressure. If the gas is to be used as a fuel, it is desirable to use it at or near the temperature at which it is produced. When the gas is to be used as a synthesis gas, shift conversion of the gas is required to increase the ratio of H_2 to CO. Particle removal at a temperature suitable for the shift reaction (400 to 500°C) is desired.

High temperature particle collection is much more difficult than low temperature collection not only because of materials problems, but also because conventional collection equipment is significantly less efficient at high temperatures (Calvert and Parker, 1977). No high temperature and pressure particle removal equipment except cyclones has yet been proven satisfactory for commercial operation, and cyclones are not efficient enough to meet the cleanup requirements. Therefore many of the designs currently proposed for coal gasification processes include a waste heat boiler for cooling the gas before it is cleaned. The gas is then cleaned at high pressure and relatively low temperature. When pipeline gas is being produced, it is convenient to operate the gasifier (and hence the particle collection equipment) at pipeline pressures (50 to 70 atm). This increases the production of methane in the gasifier, and eliminates the need for compression of the gas after production. Gasifier pressures used for the production of low-BTU gas for industrial or utility use normally are much lower (20 atm or less).

There are many different processes for gasifying coal, and the gaseous and particulate emissions vary from one process to another. The most common classification of gasification processes is classification according to the flow of the gas relative to the coal. The four basic types of gasifiers, classified in this manner, are:

1. fixed or slowly moving beds of solids
2. entrained solids
3. fluidized beds
4. molten baths.

Gasifiers also may be classified with regard to the ash removal method. At temperatures below ~1,000°C the mineral matter in the ash remains dry. At temperatures somewhat higher the ash becomes tacky and tends to agglomerate. At even higher temperatures the ash melts. Molten ash usually becomes free-flowing at temperatures of about 1,500°C to 1,600°C. Therefore, coal gasifiers can be classified as dry bottom, ash agglomerating, or slagging gasifiers with respect to ash removal. Gasifiers can also be classified as to pressure level, number of reaction stages, and the source of oxygen (either air blown or oxygen blown).

In general, particulate emissions are greater for entrained bed and fluidized bed dry bottom type gasifiers. Particulate emissions are fewer for ash agglomerating and molten bath gasifiers. Table 7 summarizes the important types of coal gasifiers and the developers of each process.

A review and evaluation of coal gasification processes has been conducted by the National Academy of Engineering (1973, 1974). A review of coal conversion processes for potential use by the electric utilities industry was reported by Katz et al. (1974). A number of gasification processes have been evaluated with respect to their pollution control needs by Exxon Research and Engineering Company. These reports will be cited with the individual processes discussed below. An assessment of the environmental impact of coal gasification has been reported by Robson et al. (1976), and the status of high temperature particle cleanup has been reviewed by Zabolotny et al. (1974) and by Fulton and Youngblood (1975).

Table 8 summarizes the particulate removal requirements for the coal gasification processes considered in this review.

Table 7. CLASSIFICATION OF COAL GASIFIERS

GASIFIER TYPE	DEVELOPER
Fixed or Slowly Moving Bed	Lurgi U.S. Bureau of Mines
Fluidized Bed (Dry)	Winkler E.R.D.A. (HYDRANE) E.R.D.A. (SYNTHANE) Institute of Gas Tech. (HYGAS) Consolidation Coal Company (CO_2 ACCEPTOR) Bituminous Coal Research
Ash Agglomerating Fluidized Bed	Battelle Memorial Institute Institute of Gas Tech. (U-GAS) Westinghouse Electric Company
Slagging - Entrained Flow	Koppers-Totzek Bituminous Coal Research (BIGAS) Combustion Engineering Foster Wheeler Brigham Young University Texaco
Molten Bath	Atomics International M.W. Kellogg Applied Technology, Inc.
In-Situ Gasification	E.R.D.A.

Table 8. SUMMARY OF PARTICULATE CLEANUP REQUIREMENTS FOR COAL GASIFICATION PROCESSES

Process	Gasifier Exit Temperature °C	Gas Cleanup Temperature °C	Pressure atm	Mass Loading g/Nm^3	Mass Loading gr/SCF	Control Devices Used or Anticipated	Remarks
I Fixed Beds							
Lurgi	400-600	200	20-30	24	10	scrubbers	tars present
USBM Stirred Bed	500-650	--	7	24	10	scrubbers	tars present
II Dry Fluidized Beds							
Winkler	800-1,000	150-200	1	--	--	cyclones, scrubbers, electrostatic precipitators	
USBM Hydrane	900	500	70	--	--	cyclones	pulverized coal in fuel
USBM Synthane	400-750	250	20-70	--	--	scrubber	tars and heavy hydrocarbons present
IGT Hygas	300	--	70-100	--	--	series cyclones	
CO_2 Acceptor - Gasifier	800-850	200	10	20	8.8	venturi scrubber	
CO_2 Acceptor - Regenerator	1,000	1,000	10	18	7.8	cyclones, sand bed filters	
BCR Fluidized Bed	1,000-1,150	650	20-50	--	--	--	
III Ash Agglomerating Fluidized Bed							
Battelle-Union Carbide	1,100	--	7	--	--	cyclones	
IGT U-Gas	1,000	400	20-70	--	--	proprietary process	
Westinghouse	750-900	--	10-15	--	--	rotary flow cyclones, granular bed filters	

Table 8. Continued

Process	Gasifier Exit Temperature °C	Gas Cleanup Temperature °C	Pressure atm	Mass Loading		Control Devices Used or Anticipated	Remarks
				g/Nm^3	gr/SCF		
IV Slagging-Entrained Flow							
Koppers-Totzek	1,200-1,300	200	1	40	17.5	two disintegrator or venturi scrubbers in series	MMD~1,000 μm σ_g~15
BCR Bi-Gas	900	600 350	80-100 80-100	230 10	100 5	cyclone scrubber sand bed filters	MMD~300 μm σ_g~5
Combustion Engineering	900	150	10	--	--	scrubber	
Foster Wheeler	1,000	100	30	--	--	scrubber	
BYU	650-1,300	--	1	--	--	--	bench scale development
Texaco	1,400	300	15	--	--	--	
V Molten Bath							
M.W. Kellogg	900	--	80	--	--	--	
ATC Molten Iron	1,100	--	1-70	--	--	--	
Atomics International	950	--	5	--	--	--	alkali metal fumes present
VI In-Situ							
LERC	--	250-350	2-7	--	--	scrubbers	tars present

The information presented was obtained from available literature and personal correspondence with researchers.

The individual processes are discussed in more detail in the remainder of this section. Some information concerning particulate emissions and control devices was not reported because data were not available, or because the information is proprietary. In general it may be concluded that more data concerning particulate mass emissions and size distributions are needed before the specific cleanup requirements can be determined with good accuracy.

FIXED OR SLOWLY MOVING BED GASIFIERS

Lurgi Process

The Lurgi gasification process has been described by Krieb (1973), Katz et al. (1974), and in numerous other publications and reviews. The pollution control needs of the Lurgi process have been reviewed and evaluated by Shaw and Magee (1974). The Lurgi process uses either a fixed or a slowly moving counter-current bed on non-caking coal. Gasification may be either air blown or oxygen blown. The gasification pressure is about 20 atm for the production of low-BTU process fuel gas (air blown), and about 30 atm or more for the production of intermediate-BTU (oxygen blown) synthesis gas. Pipeline gas is produced from the synthesis gas by shift conversion and methanation.

The exit temperature of the gas leaving the gasifier ranges from about 400°C to 600°C. The gas contains coal dust, oil, naphtha, phenol, ammonia, tar, ash, and char. Approximately 5% of the ash is char. The hot gas generally goes through a scrubbing and cooling tower, and then through a waste heat boiler. It leaves the waste heat boiler at about 200°C and is used directly as a process fuel, or is converted to methane for use as a pipeline gas. Typical raw gas compositions for oxygen blown and air blown Lurgi gasifiers are listed in Table 9.

The composition of the particulate matter emitted from the gasifier is expected to be similar to that emitted from stoker-

Table 9. RAW GAS COMPOSITION FOR LURGI GASIFIER

COMPONENT	MOL % OXYGEN BLOWN	AIR BLOWN
H_2	38.8	24.7
CO_2	28.9	5.0
CO	19.6	18.8
CH_4	11.1	6.4
C_2H_4	0.4	0.3
H_2S	0.3	---
C_2H_6	0.3	0.4
N_2 + Other	0.6	44.4
TOTAL	100	100
Higher Heating Value	~11 MJ/Nm^3 (300 BTU/SCF)	~7 MJ/Nm^3 (180 BTU/SCF)

type boilers; that is, approximately 40% silica, 30% alumina, and 10% iron oxide. The mass emissions of particulate matter are expected to be on the order of 2 g/MJ (5 lb/10^6BTU) which would be equivalent to about 24 g/Nm^3 (10 gr/SCF) based on a heating value of 300 BTU/SCF. No quantitative data have been reported to verify these predictions.

To meet the current emissions regulations for coal-fired boilers (43 mg/MJ or 0.1 lb/10^6BTU), approximately 98% collection efficiency would be required. To meet the more stringent standards being proposed (21.5 mg/MJ or 0.05 lb/10^6BTU), approximately 99% collection efficiency would be necessary. Particle collection occurs at high pressures (20 to 30 atm) and relatively low temperatures (~200°C). Wet scrubbers are typically used to remove the tar and oils as well as the ash and coal dust.

The most unique problem associated with the Lurgi process is that the gasification temperature is too low to eliminate tars from the effluent gas. Therefore it is necessary to remove the tar by quenching and scrubbing the gas as it leaves the gasifier. The condensed tar is then returned to the gasifier. This severely limits the ability to make use of the sensible heat of the gas stream. The cleaned gas must be reheated to about 400°C or 500°C for the shift conversion process when synthesis gas is being produced.

The Lurgi process has been proposed and used primarily for the production of synthesis gas, and low-BTU gas for the generation of process heat in conventional boilers. It would be possible to use the product gas as the principal fuel in a combined-cycle gas turbine-steam turbine power generation plant. In this case, the gas turbine would require more efficient particle removal (>99.9%) for particles larger than a couple of micrometers in diameter. The turbine inlet requirements are discussed in more detail in a later section of this report.

U.S. Bureau of Mines Stirred-Bed Process

The U.S. Bureau of Mines in Morgantown, West Virginia (now the Morgantown Energy Research Center of the E.R.D.A.), has developed a stirred-bed gasifier. The stirring device agitates the coal bed to prevent agglomeration and caking. This work has been reported by McGee (1966), and reviewed by Lewis et al. (1973) and Katz et al. (1974).

The gasifier operates at a pressure of about 7 atm, and temperatures from about 500°C to 650°C. Essentially, the stirred-bed gasifier is a modification of the Lurgi gasifier allowing for the use of strongly caking coals. The major problem, as with the Lurgi process, is that the gasifier temperature is relatively low and therefore large quantities of oil and tar are present in the gas. The oils and tars may be removed by quenching and scrubbing, however this limits the ability to recover sensible heat for the process.

The gas and particulate emissions and cleanup requirements should be similar to the Lurgi process as discussed above.

DRY FLUIDIZED BED GASIFIERS

Winkler Process

The Winkler gasification process has been described by Banchik (1973), Katz et al. (1974), and by the National Academy of Engineering (1974). The pollution control aspects of the Winkler process have been reviewed and evaluated by Jahnig (1974).

The Winkler gasifier is a dry bottom, single stage fluidized bed gas generator which operates at atmospheric pressure with either air or oxygen. The gasification temperature is kept between about 800°C and 1,000°C, which is hot enough to cause the cracking of tars and heavy hydrocarbons. The dust laden gases are cooled in heat exchangers to produce process steam. Then they are partially cleaned in a cyclone at about 150°C to 200°C, and further cleaned in a scrubber followed by an electrostatic precipitator.

Typical gas compositions from the air blown and oxygen blown Winkler process are shown in Table 10. The particle emis-

Table 10. PRODUCT GAS COMPOSITION FOR THE WINKLER PROCESS

COMPONENT	MOL % OXYGEN BLOWN	MOL % AIR BLOWN
H_2	32.2	11.7
CO_2	15.8	6.2
CO	25.7	19.0
CH_4	2.4	0.5
H_2O	23.1	11.5
N_2	0.5	51.0
H_2S	0.3	0.1
TOTAL	100	100
Higher Heating Value	~10 MJ/Nm^3 (275 BTU/SCF)	~4 MJ/Nm^3 (120 BTU/SCF)

sions have not been quantified. High temperature and pressure particle removal is not required for this process. However, if high temperature cleanup equipment were available, it might be beneficial to clean the gas before it passes through the heat exchangers.

HYDRANE Process

The HYDRANE process is a dry, fluidized bed coal gasification process originally developed by the U.S. Bureau of Mines and now under development by E.R.D.A. It is based on the reaction of raw coal with hydrogen to form methane directly. This process has been described by Feldmann et al. (1972), Yavorsky (1973), and by Katz et al. (1974).

A two-stage reactor is used and operates at approximately 70 atm and 900°C. The products are a methane-rich gas and char. The char is used in a fluidized bed synthesis gasifier to produce hydrogen. Typical gas and char compositions are shown in Table 11.

Some information concerning particle collection requirements was obtained from Chambers (1976). Particle removal would be required before the product gas could be used as a pipeline gas, or used as a fuel for a gas turbine. Particle removal is expected to occur at about 500°C and 70 atm. Pulverized coal is the fuel for the process, and entrained particulates are expected to be fairly small (15 μm or smaller). A cyclone filter device is being considered for particle collection. There are not yet any data describing particulate mass emissions per product gas volume, nor are there any size distribution data.

SYNTHANE Process

The SYNTHANE process is a fluidized bed, coal gasification system developed by the U.S. Bureau of Mines for the production of pipeline quality gas. It has been described by Forney et al. (1973), the National Academy of Engineering (1974), and Katz et al. (1974). The pollution control aspects of the SYNTHANE pro-

Table 11. TYPICAL GAS AND CHAR COMPOSITIONS FOR HYDRANE PROCESS

PRODUCT GAS		CHAR	
COMPONENT	WT. %	COMPONENT	WT. %
H_2	27.9	C	66.0
CH_4	68.6	H	1.6
C_2H_6	0.1	O	7.0
CO	1.4	N	0.9
CO_2	0.6	S	0.7
N_2	1.4	Ash	23.8
TOTAL	100	TOTAL	100

cess have been reviewed and evaluated by Kalfadelis and Magee (1974).

In the SYNTHANE process, the gas leaving the gasifier undergoes cleaning, shift conversion, and methanation to obtain a pipeline gas. To increase the production of methane in the gasifier, and to avoid the need to compress the gas to pipeline pressure, the gasifier is operated at high pressure (about 70 atm). The temperature at the gasifier exit is between 400°C and 750°C. At this temperature it passes through cyclone collectors. Then it passes through a cold-water scrubber (probably a venturi scrubber) at approximately 250°C, and near 70 atm.

The gasifier output contains tars, heavy hydrocarbons, coal dust and ash. The gas composition leaving the gasifier is shown in Table 12. Particle mass emissions and size distribution data have not been quantified.

The HTP particle collection is required to clean the gas so that it is suitable for pipeline use, and also to prevent plugging and contamination in the shift conversion and methanation steps.

Although the SYNTHANE process was developed for the production of pipeline gas, the process could be modified to produce low-BTU synthesis gas for a combined cycle power system. In this case, particle cleanup would be required to meet the gas turbine inlet loading requirements as well as the applicable mass emissions regulations. The gasification pressure (and hence the pressure during particle cleanup) would probably be much lower (maybe 20-30 atm).

IGT Process

The Institute of Gas Technology (IGT) has developed a four-stage, fluidized bed coal gasification process trade-named the "HYGAS Process." It has been described by Schora et al. (1973), and by Katz et al. (1974). The pollution control aspects of the IGT HYGAS process were reviewed and evaluated by Jahnig (1974).

The HYGAS process was designed to produce pipeline quality

Table 12. GAS COMPOSITION FROM THE GASIFIER OF THE SYNTHANE PROCESS

COMPONENT	MOL %
CO	10.5
CO_2	18.2
H_2	17.5
CH_4	15.4
H_2O	37.1
H_2S	0.3
N_2	0.5
Other	0.5
TOTAL	100
Higher Heating Value	~15 MJ/Nm^3 (400 BTU/SCF)

gas through direct hydrogenation of coal at high pressures (70 to 100 atm).

The synthesis gas leaves the gasifier at about 300°C. Char is formed in the second stage of the gasifier and reacted with oxygen and steam in the fourth stage to produce hydrogen for the process. The hydrogen-rich synthesis gas goes directly into the gasifier and therefore does not need to be cleaned. Two air-based processes for hydrogen production have also been developed: the electrothermal process, and the iron-steam process.

Representative gas compositions leaving the gasifier are shown in Table 13. The gas leaving the gasifier is purified and methanated. Purification removes most of the CO_2 and H_2S. In addition, any coal dust, oils, or ash must be removed before the gas can be conveyed through a pipeline. Series cyclones have been proposed for particulate removal.

It has been proposed that agglomeration of the ash in the fluidized bed will reduce fly ash carryover. However, no quantitative data describing the particle mass emissions or size distributions have been obtained.

The CO_2 Acceptor Process

The CO_2 Acceptor Process is a fluidized bed coal gasification process developed by Consolidation Coal Company to produce pipeline gas from lignite or sub-bituminous coal. This process has been described by Fink (1973) and Katz et al. (1974). The pollution control aspects of the process were reviewed and evaluated by Jahnig and Magee (1974). Additional particle removal requirements have been obtained from McCoy (1976).

The gasifier operates at about 10 atm pressure and at temperatures from about 800°C to 850°C. Limestone or dolomite is used as the "acceptor" to remove CO_2 from the gas prior to methanation. Particle removal is required from the effluents of both the gasifier and the dolomite (or limestone) regenerator.

The process gas leaves the gasifier, passes through a series of cyclones at about 800°C and 10 atm, and then is cooled

Table 13. GAS COMPOSITION LEAVING THE HYDROGASIFICATION REACTOR (OIL FREE) FOR IGT HYGAS PROCESS

COMPONENT	MOL %		
	ELECTROTHERMAL	OXYGEN	STEAM-IRON
CO	21.3	18.0	7.4
CO_2	14.4	18.5	7.1
H_2	24.2	22.8	22.5
H_2O	17.1	24.4	32.9
CH_4	19.9	14.1	26.2
C_2H_6	0.8	0.5	1.0
H_2S	1.3	0.9	1.5
Other	1.0	0.8	1.4
TOTAL	100	100	100

in a waste heat boiler. Final cleaning of the gas is done in a venturi scrubber operating at 10 atm and about 200°C. Particulate emissions are expected to be about 20 g/Nm^3 (8.8 gr/SCF). No size distribution data have been reported. The gas compositions for the gas leaving the gasifier and the regenerator are shown in Table 14.

The dolomite regenerator operates at about 1,000°C. The effluent gas is expected to be cleaned by a series of cyclones, or other hot gas cleaning equipment which may be developed, at 10 atm and 1,000°C. Energy recovery could be obtained by expanding the clean, HTP gas through a gas turbine. The particulate mass emissions from the regenerator are expected to be about 18 g/Nm^3 (7.8 gr/SCF). In order to meet the current federal New Source Performance Standards for coal-fired boilers (0.1 lb/10^6BTU), the particulate emissions must be reduced to about 180 kg/hr (400 lb/hr). This is equivalent to approximately 99.7% collection efficiency.

Several stages of cyclones, and sand bed filters, are being considered for hot gas cleanup. A reliable and efficient system for removing dust from the regenerator flue gas has yet to be demonstrated.

In a typical commercial operation, the regenerator flue gas cleanup could be done at lower temperature if the gas were not to be passed through a gas turbine. In this case, high temperature and pressure gas cleanup (550°C to 650°C, 10 atm) would still be required to allow operation of an expander which would be used to drive the regenerator air compressor (McCoy, 1976).

BCR Fluidized Bed Gasifier

Bituminous Coal Research, Inc. (BCR) is developing a multiple stage fluidized bed coal gasification process for the production of low-BTU gas. This process has been described briefly by Katz et al. (1974).

High temperature cyclones (1,000°C to 1,150°C) will be used to recycle unburnt coal and large ash particles after each stage

Table 14. EFFLUENT GAS COMPOSITIONS FROM THE CO_2 ACCEPTOR PROCESS

COMPONENT	MOL % GASIFIER	MOL % REGENERATOR
H_2	70.9	0.1
CO	15.2	2.5
CO_2	6.9	32.1
CH_4	6.1	--
NH_3	0.7	--
N_2	0.2	64.1
Other	--	1.2
TOTAL	100	100

of the gasifier. The synthesis gas will leave the final stage at about 650°C. The gasifier pressure will depend on the final use of the synthesis gas (20 to 50 atm).

Particle collection probably will be necessary before the synthesis gas is used. The collection requirements will depend on the use. Gasification can be with air and steam, oxygen and steam, or carbon dioxide. Gasification with carbon dioxide will yield a carbon monoxide rich gas which could be suitable for MHD power generation.

ASH AGGLOMERATING FLUIDIZED BED

Battelle-Union Carbide Gasifier

Battelle Memorial Institute, Columbus, under sponsorship of Union Carbide, has developed an agglomerated-ash fluidized bed coal gasification process. This process has been described by Corder et al. (1973, 1974), and by Katz et al. (1974).

Pulverized coal is fed to the gasifier which will operate at pressures up to about 7 atm, and temperatures to about 1,000°C. Future applications may require operation at higher pressures. The gas goes from the gasifier to an agglomerating ash, char burner at about 1,100°C.

The high temperature bed promotes agglomeration of the ash (especially as the ash fusion temperature is approached), and presumably this will significantly reduce the particulate emissions from the gasifier. It is believed that the ash agglomerating fluidized bed is capable of reducing emissions to about 0.1 g/Nm^3 (0.05 gr/SCF). Ultrafine particles may not be captured in the agglomerating bed.

Exit gases from the burner pass through a high temperature and pressure cyclone which captures the coarse particles and agglomerated ash that may be blown from the bed. Other more efficient collection equipment may be required if the fine particle emissions are in excess of the emissions regulations. It is expected that the particles will be small enough not to erode gas turbine blades. Data to support this have not been reported yet.

U-GAS Process

The Institute of Gas Technology (IGT) has developed the "U-GAS" fluidized bed, ash agglomerating gasification process. This process has been described by Loeding and Tsaros (1973), and by Katz et al. (1974). The pollution control aspects of this process have been reviewed and evaluated by Jahnig (1974).

The U-GAS process operates at a gasification temperature of about 1,000°C and a pressure of about 20 atm when producing low-BTU gas for combined cycle power generation, and a pressure of about 70 atm for the production of a pipeline gas. The gasifier is air blown. Typical gas compositions for gasification pressures of 20 atm and 70 atm are shown in Table 15.

Particle removal occurs in two stages of cyclones. The first cyclone is in the gasifier exit and operates at near the gasification temperature and pressure. The secondary cyclone operates at a slightly cooler temperature (about 850°C). The particulate emissions are expected to be minimized by the ash agglomerating characteristics of the fluidized bed.

The IGT Meissner Process is a proprietary process being developed to remove sulfur and fine particles from the fuel gas at high temperature and pressure. It operates at about 400°C, and near the gasification pressure.

Westinghouse Advanced Gasifier

Westinghouse Electric Corporation, under E.R.D.A. sponsorship, is developing an advanced coal gasification system for electric power generation. Early stages of the development of this process were reported by Archer et al. (1973), Katz et al. (1974), and in numerous Westinghouse reports to the Office of Coal Research and the E.R.D.A. (1972-1976). More recent information concerning the particulate removal problems of this process has been obtained from Lancaster (1976) and Ciliberti (1976).

The Westinghouse process uses a multi-stage fluidized bed operating at 10 to 15 atm pressure. The bottom stage operates at 1,000°C to 1,100°C to agglomerate the ash and thereby reduce

Table 15. TYPICAL GAS COMPOSITION FOR THE U-GAS PROCESS

COMPONENT	MOL % 20 ATM	70 ATM
CO	17.8	12.5
CO_2	9.2	12.6
H_2	12.1	11.6
H_2O	8.5	8.5
CH_4	4.3	7.1
N_2	48.1	46.7
TOTAL	100	100
Higher Heating Value	~5.5 MJ/Nm^3 (153 BTU/SCF)	~6 MJ/Nm^3 (164 BTU/SCF)

particulate emissions. The upper stages will operate at lower temperatures (750°C to 900°C). No tars or condensable hydrocarbons are expected to be present in the effluent gas.

Particle removal from the effluent gases is achieved using two stages of cyclone separators. High efficiency rotary flow cyclones (Aerodyne, Tanjet) have been tried and their performance in high temperature and pressure conditions was found to be unsatisfactory. Granular bed filtration is currently being considered as a tertiary cleanup device.

The degree of particle removal required is determined by balancing the turbine inlet requirements against the emissions regulations. It is anticipated that effectively all particles larger than 1-2 μm in diameter will have to be removed to protect the turbine blades. Some particles smaller than 1-2 μm may have to be removed in order to satisfy the emissions (or opacity) regulations.

Westinghouse is running a process development unit at Waltz Mill, Pennsylvania. No particulate emissions data are available yet.

SLAGGING—ENTRAINED FLOW GASIFIERS

Koppers-Totzek Process

The Koppers-Totzek gasification process uses a single stage entrained flow, ash slagging gasifier operating slightly above atmospheric pressure. This process was developed by Koppers Co., Inc., and has been described by Farnsworth et al. (1973) and Katz et al. (1974). The pollution control aspects of the Koppers-Totzek process have been reviewed and evaluated by Magee et al. (1974). Recent information concerning the particulate emissions and removal requirements has been obtained from McGurl (1976).

The Koppers-Totzek Process operates near atmospheric pressure and at temperatures up to over 1,500°C. Water sprays at the gasifier exit reduce the temperature of the gas to about 1,200°C-1,300°C. Pulverized coal is fed into the side of the slag. The gas leaving the gasifier is cooled to about 200°C in a waste heat boiler, before it is cleaned by a high efficiency scrubber (either a disintegrator or a high efficiency venturi scrubber).

A typical gas composition is shown in Table 16. The gas generally contains most of the unburnt carbon and about half the ash in the coal. The composition of the ash depends on the coal, but usually will contain mostly silica, alumina, and ferric oxide, with possibly some calcium oxide, magnesium oxide, titanium oxide, alkalis (Na_2O, K_2O), sulfur trioxide, and phosphorus pentoxide. The particulate matter will contain varying amounts of ash and carbon depending on the feedstock. If lignite is used, the particulate matter will be mostly ash, while if petroleum coke is used the particulate could be almost pure carbon. In the latter case the particulate may be recycled to the gasifier.

Particulate concentrations prior to cleanup will depend on the ash content of the coal, and on the degree of carbon conversion. For a 12% ash coal with 95% carbon conversion, about 40 g/Nm^3 (17.5 gr/SCF) wet is the particulate loading before cleanup (McGurl, 1976). The size distribution is as shown in Figure 6, with approximately one percent by weight smaller than one micron, a MMD of about 1,000 μm and a σ_g of 15. Therefore the loading of submicron particles would be approximately 0.4 g/Nm^3 (0.175 gr/SCF). Submicron particles are thought to be too small to damage turbine blades, but in these concentrations there are enough of them to exceed the emissions regulations, even if all particles larger than 1 μm were removed. That is, if the proposed new source performance standard for coal-fired boilers (0.05 lb/10^{6}BTU) and an average higher heating value of 11 MJ/Nm^3 (300 BTU/SCF) are used, the emissions regulation would be equivalent to about 0.2 g/Nm^3 (0.04 gr/SCF). If the heating value of the coal feedstock were used, the emissions regulations would be even more stringent.

The current particulate removal system used by Koppers

Table 16. TYPICAL PRODUCT GAS COMPOSITION FROM THE KOPPERS-TOTZEK PROCESS

COMPONENT	MOL %
CO	46.2
CO_2	8.8
H_2	30.8
H_2O	12.3
N_2 + Ar	1.0
H_2S	0.85
COS	0.05
TOTAL	100

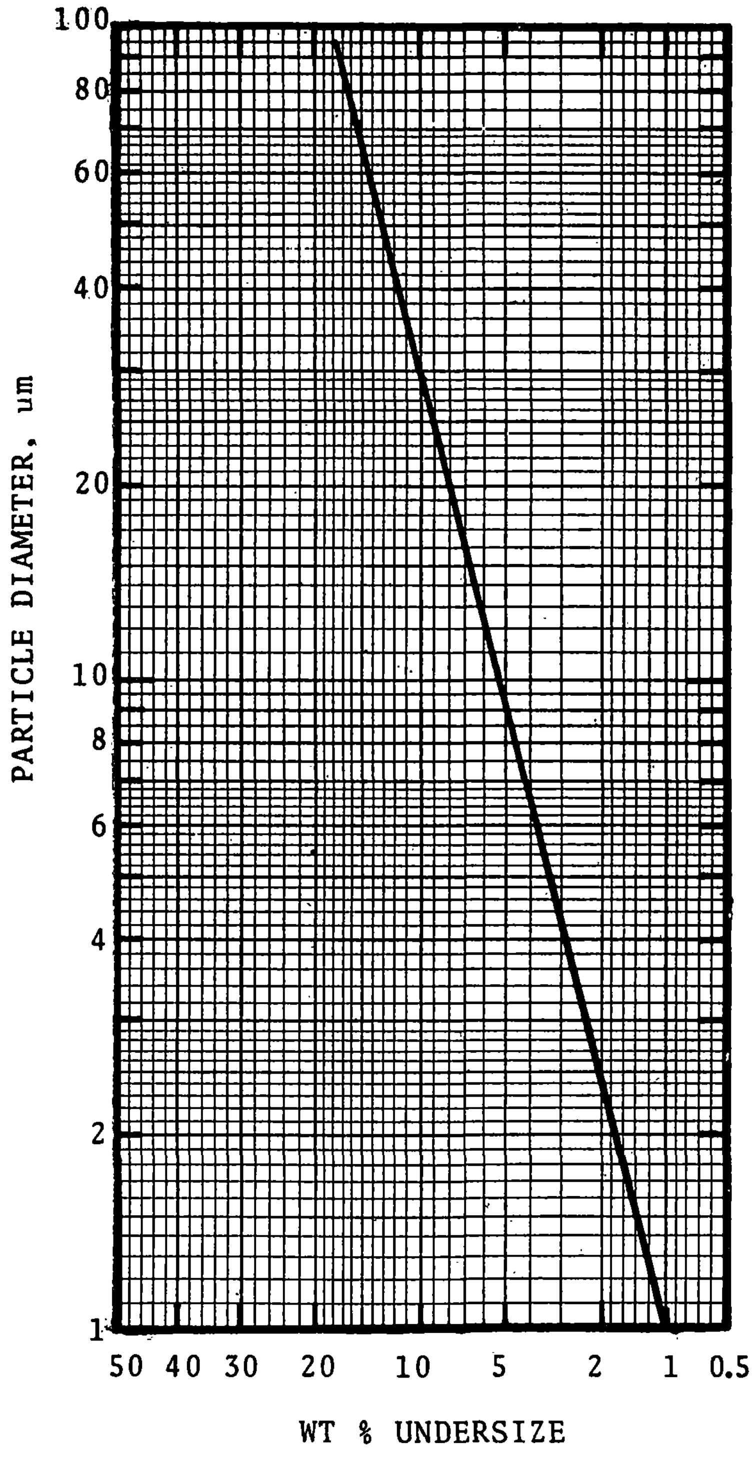

Figure 6. Particle size distribution expected from the Koppers-Totzek coal gasifier, before any particle removal.

Company consists of a direct spray type washer-cooler followed by two rotary, squirrel cage type disintegrators in series. High energy venturi scrubbers have been proposed for application at pressures above atmospheric. Two venturi scrubbers in series would be required to decrease the loading below 0.004 g/Nm^3 (0.002 gr/SCF), which has been found by Koppers to be adequate for most uses.

The critical components requiring particle removal are the turbine blades when the gas is to be used to fuel a gas turbine and the compressor blades if the gas is to be compressed for pipeline transport. If the gas is to be compressed to greater than about 30 atm pressure, the particulate loading may need to be reduced even lower than the required loadings mentioned above

BI-GAS Process

Bituminous Coal Research, Inc. has developed the BI-GAS process for producing pipeline quality gas. This process has been described by Grace (1973), and by Katz et al. (1974). The pollution control aspects of the BI-GAS process were reviewed and evaluated by Jahnig (1975). Recent information concerning the particulate emissions and control requirements was obtained from Grace (1976).

The BI-GAS process uses a two-stage, high pressure (80 to 100 atm) entrained flow gasifier. The bottom stage operates at about 1,500°C, to allow much of the ash to be removed as molten slag, and to provide devolatilization of the coal and thermal cracking of oils and tars. The second stage completes the gasification process at about 900°C. The synthesis gas and entrained char leave the gasifier at 80 to 100 atm pressure and about 900°C. A typical synthesis gas composition for this process is shown in Table 17.

The raw gas is cleaned in a cyclone-scrubber to remove the char and recycle it to the gasifier. The gas leaves the cyclone at 600°C and process pressure. A typical char size distribution is shown in Figure 7 with a MMD of 300 μm and a σ_g of 5. The

Table 17. TYPICAL GAS COMPOSITIONS FROM THE BI-GAS PROCESS BEFORE AND AFTER QUENCHING

COMPONENT	MOL % BEFORE QUENCH	MOL % AFTER QUENCH
CO_2	15.7	12.0
CO	22.9	17.5
H_2	30.4	23.3
CH_4	6.8	5.2
N_2	0.5	0.4
H_2S	0.5	0.4
H_2O	23.2	41.2
TOTAL	100	100

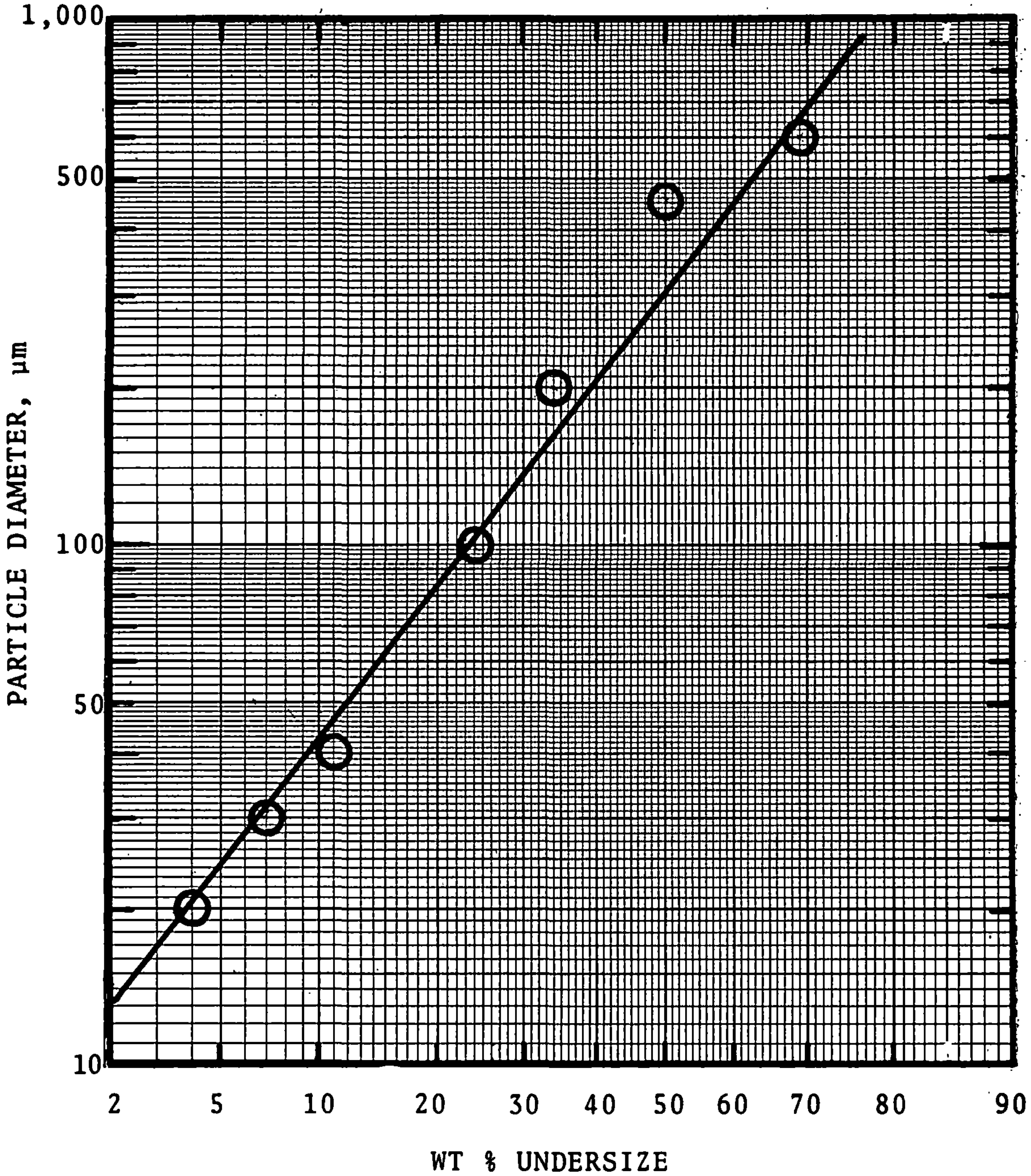

Figure 7. Size distribution of char and ash from the BI-GAS process effluent. Data from Grace (1976).

char is 86-89% fixed carbon, 2-1% volatile matter, and 12-10% ash. The amount of char entrained in the gas is about 4,400 kg/hour. The inlet loading to the cyclone is about 230 g/Nm^3 (100 gr/SCF). The cyclone is approximately 95% efficient so the cyclone exit loading should be about 10 g/Nm^3 (5 gr/SCF) If Figure 7 is extrapolated, about 0.01% of the particulate matter appears to be smaller than 1 μm.

After leaving the cyclone, the gas is quenched to about 350°C in a gas washer, and then passed through two sand bed filters in parallel. The sand filters are used to remove fine particles that can plug the fixed bed of the shift conversion catalyst. The sand filters are cleaned alternately by a reverse flow of gas, which returns the reentrained dust to the gasifier. The ash eventually leaves the system as molten slag.

The gas composition entering the sand filters is shown in Table 17. The principal advantage to using sand filters instead of a high efficiency scrubber is that it is possible to clean the gas at a high enough temperature to prevent water condensation, so that the steam present in the gas will be available for the shift conversion process.

Combustion Engineering Gasifier

Combustion Engineering, Inc. has designed an atmospheric pressure, entrained-flow type coal gasification system suitable for generating low-BTU gas for electric power generation. The gasification temperature is about 900°C, with a 1,600°C stage for ash slagging and removal. This process has been described by Katz et al. (1974).

The gas leaving the gasifier is cooled to about 150°C by a series of waste heat boilers before the gas is cleaned by cyclone separators and a water scrubber. Condensing tars may present a problem in plugging the particle removal equipment. Long range plans are being considered for operating this process at 10 atm pressure, for use in a combined cycle power generation system.

Foster Wheeler Gasifier

Foster Wheeler Corporation has designed a demonstration plant to gasify coal at 30 atm pressure in an air-blown, entrainment-type gasifier. The gas is to be used to fuel a gas turbine and a gas-fired steam boiler. This gasification system is described by Katz et al. (1974).

The gasification process is similar to the BI-GAS process, with gasification at 1,000°C in the upper stage. The bottom, ash slagging stage operates at 1,500°C. Char is removed from the gas at near gasifier temperature and pressure by a series of cyclones and is recycled to the gasifier. Waste heat boilers are used to recover sensible heat downstream of the cyclones. The final particulate removal stage is a water scrubber operating at about 100°C and system pressure.

B.Y.U. Gasifier

Brigham Young University is developing an entrained flow type gasification process which uses the flow of gas and solids in a downwards direction. This research has been described by Katz et al. (1974).

Their bench scale tests operated at atmospheric pressure and at temperatures from 650°C to over 1,300°C. The gasifier is oxygen blown. A typical gas composition from this process is shown in Table 18.

Texaco - Partial Oxidation Process

Texaco, Inc. has developed a partial oxidation gasifier which has been used commercially for the production of hydrogen for the synthesis of ammonia. This process has been described by Katz et al. (1974).

The gasifier operates at 15 atm pressure and about 1,400°C. A pebble-bed heat exchanger is used to cool the effluent gas and to preheat the air used for gasification. Most of the ash is removed from the bottom of the gasifier. Some may also be collected in the pebble-bed. The gas entering the pebble-bed

Table 18. TYPICAL GAS COMPOSITION FROM THE B.Y.U. ENTRAINED-FLOW GASIFIER

COMPONENT	MOL %
CO	37.5
CO_2	5.0
H_2	39.0
CH_4	2.0
C_2H_4	1.5
H_2O	15.0
TOTAL	100
Higher Heating Value	~12.5 MJ/Nm^3 (340 BTU/SCF)

is at about 1,300°C and leaves at about 300°C. The gas pressure is at 15 atm.

MOLTEN BATH GASIFIERS

M.W. Kellogg Gasifier

The M.W. Kellogg Company has developed a molten salt gasification process which was described by Cover and Skaperdas (1973) and by Katz et al. (1974).

The process uses a bath of molten sodium carbonate with injection of steam and oxygen. Gasification occurs at about 900°C and 80 atm pressure. Ash is retained in the bath, and there are no tars present. No particle emissions problem is expected. A typical gas composition is shown in Table 19.

Molten Iron Process

The Applied Technology Corporation is developing a molten bath process which uses crushed coal and limestone dissolved in a bath of molten iron to generate a low-BTU synthesis gas. The bath retains both the sulfur and the ash from the coal. Air or oxygen is injected into the bath to gasify dissolved carbon to carbon monoxide. This process has been described by LaRosa (1973).

If air is used for the gasification process, the process is called the "2-stage" process and generates a hot, low-BTU gas for combustion in boilers or gas turbines. If oxygen is used, the process is called the "PATGAS" process and the gas is used as a synthesis gas. If the synthesis gas is upgraded to pipeline quality, the process is called the "ATGAS" process. Typical gas compositions for the three processes are shown in Table 20.

The applicability of these processes for electric utility and industrial boiler facilities has been studied by Jain and Hixson (1972). They noted that the amount of particulate emissions had not been definitely established. LaRosa (1973) noted that a 95 to 97% efficient electrostatic precipitator would be

Table 19. TYPICAL GAS COMPOSITION FOR KELLOGG MOLTEN SALT GASIFIER

COMPONENT	MOL %
CO	26.0
CO_2	10.3
H_2	34.8
CH_4	5.8
H_2O	22.6
H_2S	0.2
N_2	0.3
TOTAL	100
Higher Heating Value	~12 MJ/Nm^3 (330 BTU/SCF)

Table 20. TYPICAL GAS COMPOSITION FOR THE MOLTEN IRON GASIFICATION PROCESSES

COMPONENT	MOL % 2-STAGE	PATGAS
CO	30	63.5
H_2	15	36.0
N_2	55	0.5
TOTAL	100	100

necessary to reduce particulate emissions to a level that would satisfy EPA performance standards.

The product gas temperature in the 2-stage process is about 1,100°C, and the pressure is slightly above atmospheric. In some applications (ATGAS, synthesis PATGAS) the product gas may be cooled in a waste heat boiler and then cleaned by water scrubbing. When the gas is to be used to produce pipeline gas (ATGAS), the process is pressurized to about 70 atm.

Atomics International Gasifier

Atomics International is developing a molten salt gasification process. This process has been described by Katz et al. (1974). The process consists of the oxidation of carbon to CO and partial pyrolysis and distillation of volatile matter in a bed of molten sodium carbonate, sulfide, and sulfate.

The gasification takes place at 950°C and 5 atm pressure. No tars are produced, and all the ash is retained in the bed. The gas is expected to be clean enough for direct use in a gas turbine.

One problem is the presence of alkali metal fumes in the gas which may cause serious corrosion damage in the turbine.

IN-SITU GASIFICATION

The in-situ, underground gasification of coal is being studied by the E.R.D.A. Laramie Energy Research Center. This work has been reported by Nadkarni et al. (1973), Campbell et al. (1974), Fischer et al. (1975), Schrider et al. (1975), and Brandenburg et al. (1975). Recent information concerning the particle emissions and control requirements has been obtained from Schrider (1976).

In underground coal gasification, air is injected into the well and the coal is ignited (usually by firing with a gas fuel such as propane). The gasification process produces hydrogen, carbon monoxide, and various hydrocarbons. The gas may be used as a low-BTU fuel gas for electric power generation, or upgraded to a pipeline quality fuel gas. A typical gas composition is shown in Table 21. The gas also contains 1 to 3% coal tar vapors.

The gas temperature at the surface can range from 250°C to 350°C, at a pressure of about 2 atm. Pressures up to 7 atm are possible in a large scale plant, but this would depend on the depth of the coal seam.

Tests are under way to determine particulate mass emissions, size distributions, and trace metal concentrations. No data are available yet.

Scrubbing units are proposed for gas cleanup and no unique problems are anticipated. At the relatively low surface temperatures and pressures, particle removal is expected to be much easier than in low-BTU gas surface plants. Condensation of tars may be a problem.

necessary to reduce particulate emissions to a level that would satisfy EPA performance standards.

The product gas temperature in the 2-stage process is about 1,100°C, and the pressure is slightly above atmospheric. In some applications (ATGAS, synthesis PATGAS) the product gas may be cooled in a waste heat boiler and then cleaned by water scrubbing. When the gas is to be used to produce pipeline gas (ATGAS), the process is pressurized to about 70 atm.

Atomics International Gasifier

Atomics International is developing a molten salt gasification process. This process has been described by Katz et al. (1974). The process consists of the oxidation of carbon to CO and partial pyrolysis and distillation of volatile matter in a bed of molten sodium carbonate, sulfide, and sulfate.

The gasification takes place at 950°C and 5 atm pressure. No tars are produced, and all the ash is retained in the bed. The gas is expected to be clean enough for direct use in a gas turbine.

One problem is the presence of alkali metal fumes in the gas which may cause serious corrosion damage in the turbine.

IN-SITU GASIFICATION

The in-situ, underground gasification of coal is being studied by the E.R.D.A. Laramie Energy Research Center. This work has been reported by Nadkarni et al. (1973), Campbell et al. (1974), Fischer et al. (1975), Schrider et al. (1975), and Brandenburg et al. (1975). Recent information concerning the particle emissions and control requirements has been obtained from Schrider (1976).

In underground coal gasification, air is injected into the well and the coal is ignited (usually by firing with a gas fuel such as propane). The gasification process produces hydrogen, carbon monoxide, and various hydrocarbons. The gas may be used as a low-BTU fuel gas for electric power generation, or upgraded to a pipeline quality fuel gas. A typical gas composition is shown in Table 21. The gas also contains 1 to 3% coal tar vapors.

The gas temperature at the surface can range from 250°C to 350°C, at a pressure of about 2 atm. Pressures up to 7 atm are possible in a large scale plant, but this would depend on the depth of the coal seam.

Tests are under way to determine particulate mass emissions, size distributions, and trace metal concentrations. No data are available yet.

Scrubbing units are proposed for gas cleanup and no unique problems are anticipated. At the relatively low surface temperatures and pressures, particle removal is expected to be much easier than in low-BTU gas surface plants. Condensation of tars may be a problem.

Table 21. TYPICAL GAS COMPOSITION FROM IN-SITU COAL GASIFICATION

COMPONENT	MOL %
CO	13.4
CO_2	11.3
H_2	15.7
CH_4	3.0
N_2	46.4
Ar	0.5
H_2S	0.1
H_2O	9.1
Other Hydrocarbons	0.5
TOTAL	100
Higher Heating Value	~4 MJ/Nm^3 (~120 BTU/SCF)

DIRECT COAL-FIRED GAS TURBINE PROCESSES

The removal of particulate matter from high temperature and pressure gas streams has been a problem since the 1940s, when a great deal of effort was expended in an attempt to develop a direct coal-fired gas turbine for locomotives, and for power generation. Removal of fine fly ash from the combustion products to the extent needed to avoid turbine-blade erosion proved to be very difficult. No fully satisfactory solution to this problem has yet been reported in the more than thirty years of worldwide development.

Much of the early work was sponsored by the Australian government, and has been reported by Wisdom (1958), Morley and Wisdom (1964), Atkin (1969), and other reports from the Australian Aeronautical Research Laboratory. They used a 900 kW (1,200 horsepower) Ruston and Hornsby gas turbine fired with pulverized coal. Fly ash was collected at temperatures from 650°C to over 750°C and at pressures up to a few atmospheres. Two stages of multiple cyclones were used and turbine life appeared to be acceptable when firing brown coal (lignite) but was unacceptably short when firing bituminous coal. Even with brown coal, however, turbine blade erosion and ash deposition problems were severe. It was necessary to reduce the turbine inlet temperature to about 650°C in an attempt to prevent the formation of hard ash deposits.

In the U.S.A., the Locomotive Development Committee (LDC) of Bituminous Coal Research, Inc. directed a program to develop a coal-fired gas turbine locomotive. This work was conducted during the period 1945 to 1958, and was reported in numerous publications authored by Yellott and Broadley. Turbine blade erosion remained a major obstacle to their coal-burning turbine development when they terminated their experimental work in 1959.

In the 1960s, the U.S. Bureau of Mines continued tests on the LDC coal-fired turbine. They investigated new blade designs and high temperature and pressure particle removal techniques. Their interest was in developing a coal-fired gas turbine for power generation. No satisfactory solution to the turbine blade erosion problem was achieved. The turbine blade life was limited to less than 20,000 hours for rotating blades and 5,000 hours for the stator blades. This was not sufficient to justify commercial development. The work done at the Bureau of Mines has been reported by Smith et al. (1966, 1967). Their coal-fired gas turbine development program was terminated around 1970.

Coal-fired gas turbines were also developed in Great Britain and Canada. British development was reported by Fitton and Voysey (1955). They developed open- and closed-cycle gas turbines burning pulverized coal. The open- and closed-cycle systems are illustrated in Figures 8 and 9. In the open-cycle the combustion products pass directly through the turbine. In the closed-cycle only the cycle air, which flows in an entirely closed circuit, passes through the turbine.

In the open-cycle turbine erosion of turbine blades was severe. High temperature and pressure ash separators (cyclones) were found to be unsatisfactory. Although the turbine is a poor collector of ash, a very small amount of ash adhering to the blades was found to significantly upset their aerodynamic form and reduce their efficiency. Corrosion resulting from ash deposition was not very noticeable. More discussion of the turbine tolerance for particles is presented in a later section of this report.

Canadian development concentrated on a semi-closed-cycle railroad locomotive gas turbine. This did not require elaborate high temperature and pressure ash separators. This work has been reported by Mordell (1957).

PROCESS EMISSIONS AND CLEANUP REQUIREMENTS

There are four basic methods by which coal might be fired to an open-cycle gas turbine: pulverized coal, the gas producer, the cyclone burner, and the spreader stoker. These methods have been described, and their dust emissions have been characterized

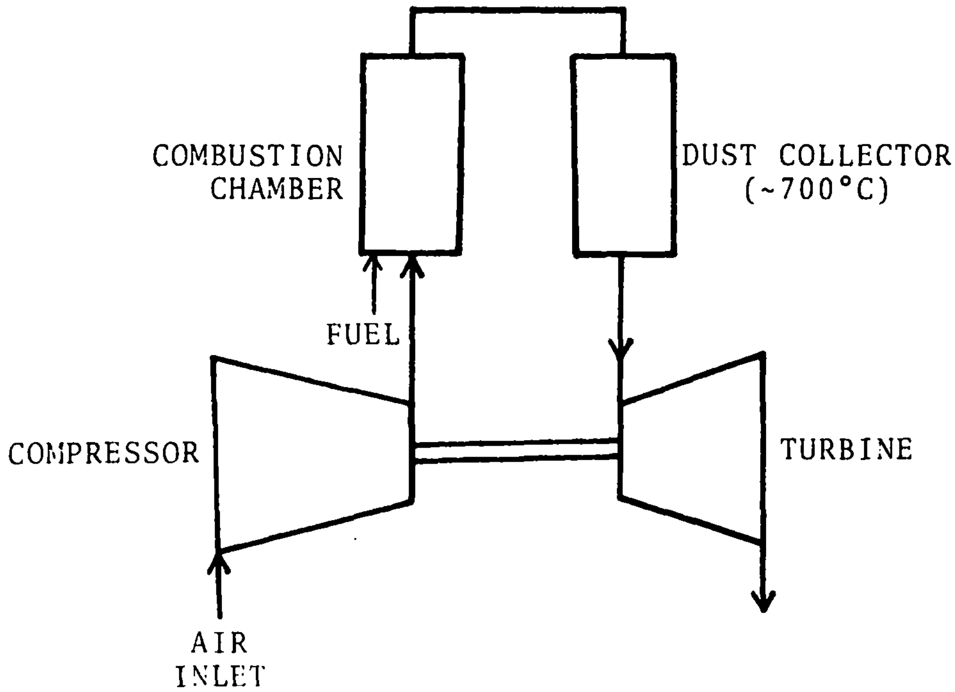

Figure 8. Open cycle gas turbine.

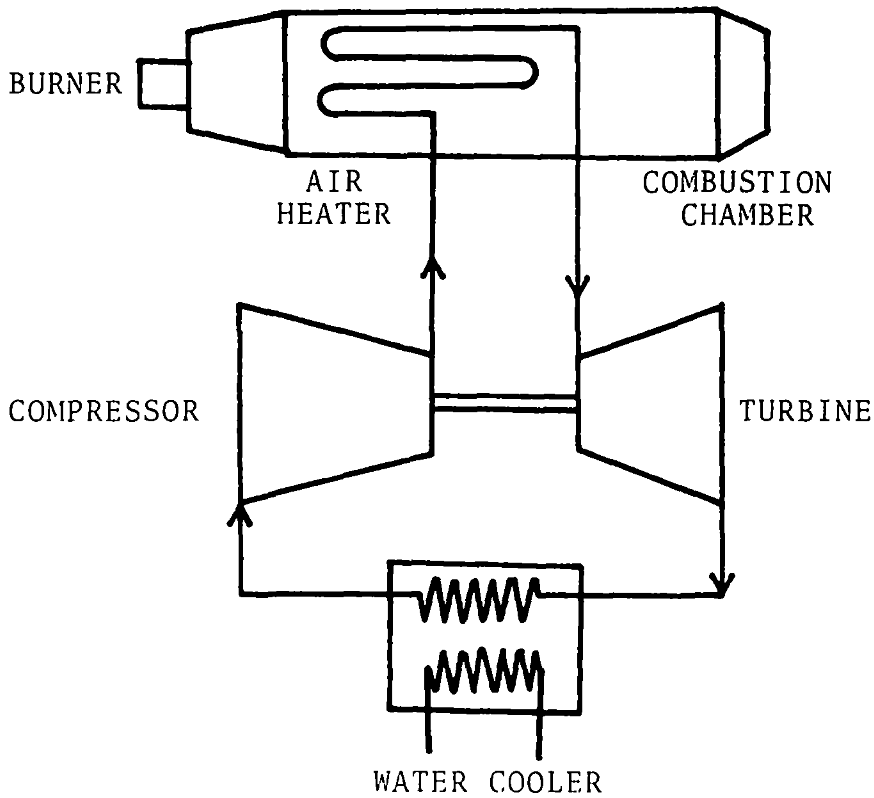

Figure 9. Closed cycle gas turbine.

by Hazard (1955). His results are summarized in Table 22. In all cases, the dust loading was too large to allow satisfactory turbine life. Only the gas producer would have satisfied current emissions standards for coal-fired boilers (43 mg/MJ or 0.1 lb/10^6BTU), and no method would satisfy the proposed future standards (21 mg/MJ or 0.05 lb/10^6BTU). The particle size distributions for these emissions are shown in Figure 10.

Dust removal for coal-fired gas turbines would be at the maximum allowable turbine inlet temperature. At the time much of the work was done (1950s) industrial turbine inlet temperatures were on the order of 600 to 700°C. Current industrial turbines can operate with inlet temperatures in excess of 1,000°C. Pressures for coal-fired gas turbines are on the order of 4 to 10 atm (60 to 150 lb/in^2).

The particulate emissions are predominantly ash and unburnt carbon. The unburnt carbon may be recycled from the dust collector to the combustor to increase efficiency. A reducing atmosphere should be maintained in the cyclones to prevent the unburnt carbon from igniting and burning in the dust collectors. Common coal, coal ash, and turbine ash composition analyses are presented in Table 23 (from Smith et al., 1966).

The gaseous emissions from an open-cycle coal-fired gas turbine should be the same as for similar coal combustion in a boiler. That is usually 83% nitrogen, 15% carbon dioxide, 2% oxygen, and trace amounts of sulfur oxides, nitrogen oxides, unburnt gaseous hydrocarbons, and carbon monoxide.

Many ash removal devices were tried during the thirty years of coal-fired gas turbine development. Parent (1946) and Yellott and Broadley (1955) reported tests of cyclone and multiclone separators at 5 atm pressure and 700°C. Overall efficiency decreased from about 95% to 86% as the temperature was raised from room temperature to 700°C. At 540°C (1,000°F) and atmospheric pressure the collection efficiency was only about 50% for particles smaller than 10 μm. The mass loadings had no significant influence on the collection efficiency for both high and low

Table 22. DUST EMISSIONS FROM COAL-FIRED GAS TURBINES (From Hazard,1955)

FIRING METHOD	ASSUMED COMBUSTION EFFICIENCY	COAL-FIRED		TOTAL SOLIDS DISCHARGED WITH GAS		DUST COLLECTOR EFFICIENCY	DUST TO TURBINE	
	%	g/s	lb/hr	g/10^6J	lb/10^6BTU	%	g/10^6J	lb/10^6BTU
Pulverized Coal:								
Non-slagging,fine pulverization	95	570	4,520	4.8	11.2	70	1.5	0.7
Non-slagging,coarse pulverization	95	570	4,520	4.8	11.2	85	0.7	1.7
Non-slagging,coarse pulverization	90	603	4,780	6.6	15.4	85	1.0	2.3
Slagging	98	555	4,400	2.2	5.2	70	0.7	1.6
Spreader Stoker:								
With ash reinjection	98	555	4,400	1.3	3.1	0	1.0	2.4
Without ash reinjection	94	578	4,580	3.4	7.9	96	0.1	0.3
Cyclone Furnace	100	542	4,300	0.6	1.4	82[1]	0.4	0.9
Cyclone Furnace:								
With dust collector	100	542	4,300	0.6	1.4	95.5[2]	0.1	0.3
Gas Producer, fixed bed	100	542	4,300	0.3	0.7	90	0.03	0.07
Gas Producer, Pulverized:								
Coal-fired vortex	100	542	4,300	1.7	4.0	80	0.3	0.8

1. Cyclone alone.
2. Cyclone + secondary multiple cyclone.

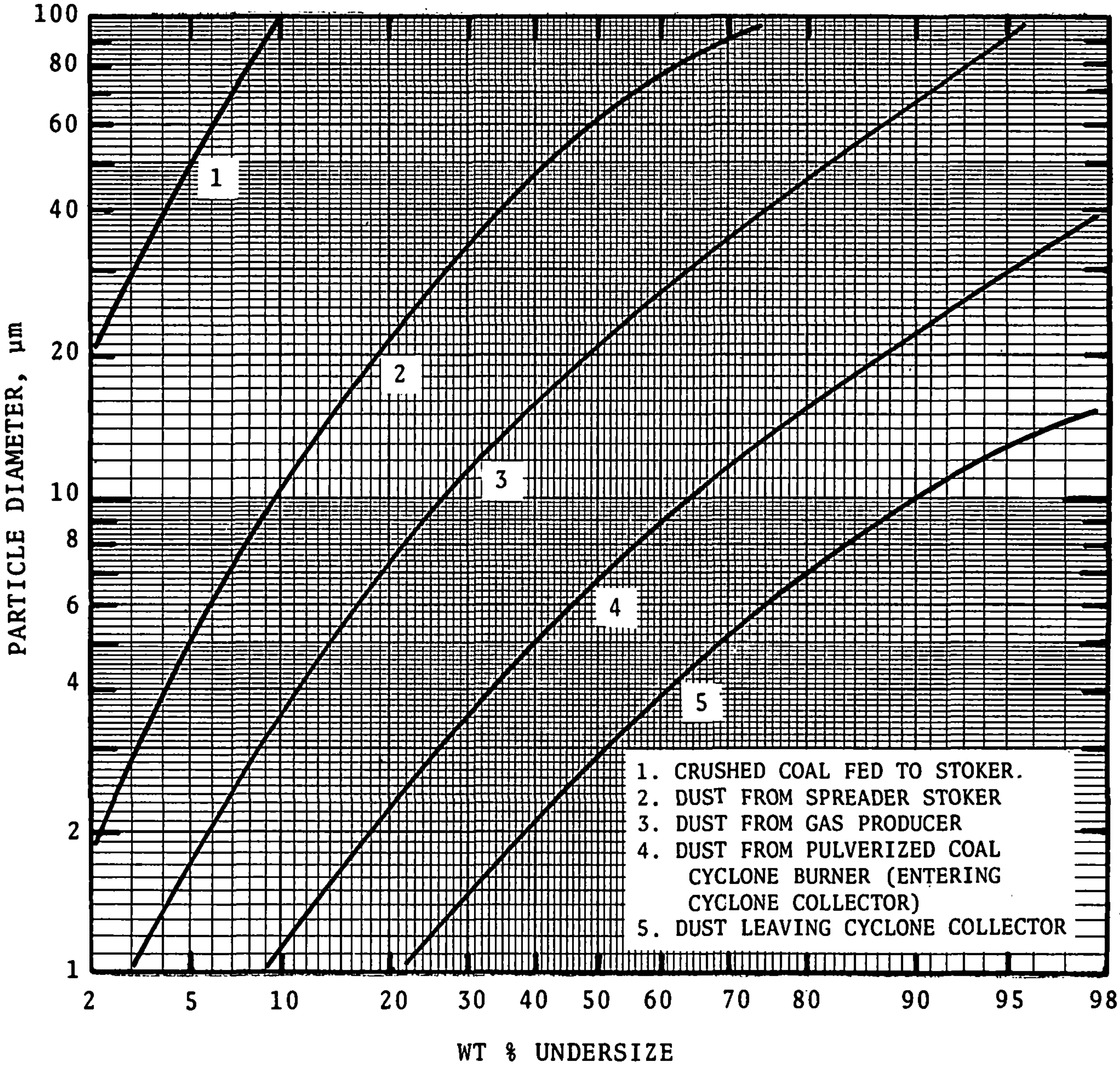

Figure 10. Particle size distributions from coal-fired gas turbines. From Hazard (1955).

Table 23. COAL, COAL ASH, AND TURBINE ASH ANALYSES (from Smith et al., 1966)

COAL CONSTITUENT	H_2O	Ash	S	H_2	N_2	Total C	O_2	HEATING VALUE, BTU/lb
WEIGHT PERCENT	1.1	6.4	2.3	5.2	1.3	77.8	5.9	14,143

ASH ANALYSES							
			Ash in Turbine				
CONSTITUENT	COAL ASH	ASH FROM SEPARATOR[a]	INLET GAS[a]	EXHAUST GAS[a]	ON BLADES[b]	FIRST STAGE STATORS	LOOSE ASH[c]
SiO_2	39.2	30.1	44.8	40.3	27.3	28.3	41.0
Al_2O_3	23.1	19.5	31.6	29.5	21.9	23.1	27.1
Fe_2O_3	17.8	34.0	5.2	7.7	6.2	5.9	7.5
TiO_2	1.7	0.7	1.3	1.3	1.6	1.9	2.1
P_2O_5	0.8	0.7	0.8	1.4	3.7	3.6	1.0
CaO	5.9	7.9	6.2	6.3	5.6	6.7	5.5
MgO	1.8	1.4	1.9	1.3	1.9	1.8	0.9
Na_2O	1.6	2.3	2.0	2.2	3.3	2.6	2.3
K_2O	1.2	0.8	1.7	1.8	4.6	4.3	1.6
SO_3	6.9	2.4	4.5	8.2	19.8	19.6	6.8

[a] Contained 12 to 25 percent unburned carbon, depending on the condition of the combustors. Does not include analyses for constituents other than those shown.

[b] Average analysis of ash deposits on the first and fifth-stage stator and rotor blades.

[c] Loose ash in turbine, not hard deposits on blades.

temperature tests. To maintain an overall efficiency of about 95%, the pressure drop had to be increased from about 3 inches to 10 inches of water column. At best, cyclone efficiencies are not high enough to adequately protect the critical turbine components.

High temperature and pressure electrostatic precipitators were developed for coal-fired gas turbines during the 1950s and 1960s. This work has been reported by Koller and Fremont (1950), Thomas and Wong (1958), Shale et al. (1963, 1964, 1965, 1967, 1969), Robinson (1967, 1969), and Brown and Walker (1971). These studies dealt primarily with the problems of corona generation and the current voltage characteristics of electrostatic precipitators at high temperature and pressure. Although Brown and Walker demonstrated the feasibility of electrostatic precipitation up to 900°C and 7 atm the collection efficiency was significantly reduced at high temperature (for the same precipitator field strength).

It is not clear how far above 900°C it is possible to operate electrostatic precipitators. At higher temperatures, thermal ionization will play an important role in limiting the precipitator operating temperature. Strength of materials, thermal expansion, thermal ionization, and the prevention of explosion are all potential problem areas that need to be resolved before high temperature and pressure electrostatic precipitation can be commercially feasible. Also, further investigation is required to understand the interrelationship between gas pressure and gas temperature at temperatures above 700 or 800°C.

The Bureau of Mines coal-burning turbine research also involved studies of high temperature filtration. First et al. (1956) and Kane et al. (1960) demonstrated the use of aluminum silicate filters operating at 980°C. Filter efficiencies greater than 99% were obtained with a composite filter of 20 μm, 8 μm, and 4 μm fibers, operating at 760°C and about 13 cm W.C. pressure drop. Designing a large flow rate, high temperature and pressure baghouse, and developing means for cleaning the bags at high temperature and pressure are problem areas still requiring further development.

Direct coal-fired gas turbine research was terminated largely because of the turbine erosion problem. If effective high temperature and pressure particle collection equipment is developed and proven, then coal-fired turbines may become attractive again. However current standards would require sulfur dioxide control to be incorporated into the process, unless only very low sulfur coals are used.

MISCELLANEOUS HIGH TEMPERATURE AND/OR HIGH PRESSURE PARTICULATE REMOVAL APPLICATIONS

The removal of particulate matter from hot gases at near atmospheric pressure is a common problem among many industries. Effluent gas from incinerators, fossil fuel fired boilers, metallurgical furnaces, cement and lime kilns, glass furnaces, and many chemical processes can reach 700°C - 800°C or more if they are uncontrolled.

As mentioned in earlier sections, it is often useful to recover this heat in a waste heat boiler, and then clean the effluent gas at much lower temperatures. High temperature particle collection, however, would protect the waste heat boiler from fouling of the heat exchanger surfaces and reduce corrosion and erosion problems. In some cases there is no need for waste heat recovery, and the waste heat boiler is needed only to cool the gas for particle cleanup. Therefore high temperature particle removal would be advantageous.

Another major requirement for high temperature and pressure particle collection is the control of emissions from catalyst regenerators in fluid catalytic cracking units used in the petroleum industry.

There are also some particulate control applications where high pressure particle removal is required at relatively low temperatures. Many of the high-BTU gasification processes discussed above propose venturi scrubbers operating at high pressure and low temperature downstream of the waste heat boiler. The removal of lube fume from natural gas pipelines also involves high pressure and low temperature particle collection.

In this section, some of the above applications of high temperature and high pressure particle collection will be discussed There is not sufficient space to thoroughly discuss the clean-up requirements of all processes with potentially hot effluent gases In general, however, the requirements will depend on the applicable emissions regulations, the effluent gas temperature, and the particle size, concentration, and composition.

If high temperature particle collection equipment could be developed to operate at an efficiency and cost competitive with that for low temperature collection, it is likely that high temperature cleanup would be advantageous in many other applications.

FCC REGENERATOR

The fluid bed catalytic cracking (FCC) process is commonly used in the petroleum industry to convert selected heavy fractions of crude oil into gasoline. The conversion takes place over a powdered catalyst at fairly high temperature (~500°C) and moderately high pressure (2 to 4 atm).

The catalyst activity is reduced by the formation of a carbonaceous deposit on the catalyst. The catalyst is regenerated by combustion in the regenerator. The regenerator discharges gases and entrained dust to a flue gas line at temperatures ranging from 600 to 700°C and at 2 to 4 atm pressure.

A schematic of an FCC unit is shown in Figure 11. The particulate cleanup equipment is shown downstream of the waste heat boiler where the temperature has been reduced to about 300°C. Some installations have proposed using a power recovery gas turbine before the waste heat boiler. In this case, particulate cleanup is necessary before the turbine at a temperature of 700 - 800°C.

Particulate emissions from FCC units have been reported by many investigators including Wilson (1967), Vandegrift et al. (1970), and Kalen and Zenz (1973). Generally two stages of cyclones are used before the final cleanup device. Typical mass loadings leaving the second stage cyclones range from 0.23 to 2.3 g/Nm^3 (0.1 to 1.0 gr/SCF). Typical size distribution ranges are given in Table 24.

Particulate removal in the cyclones reduces the mass loading to the third stage collector as well as limits the catalyst losses from the system. Final stage collection must be suffi-

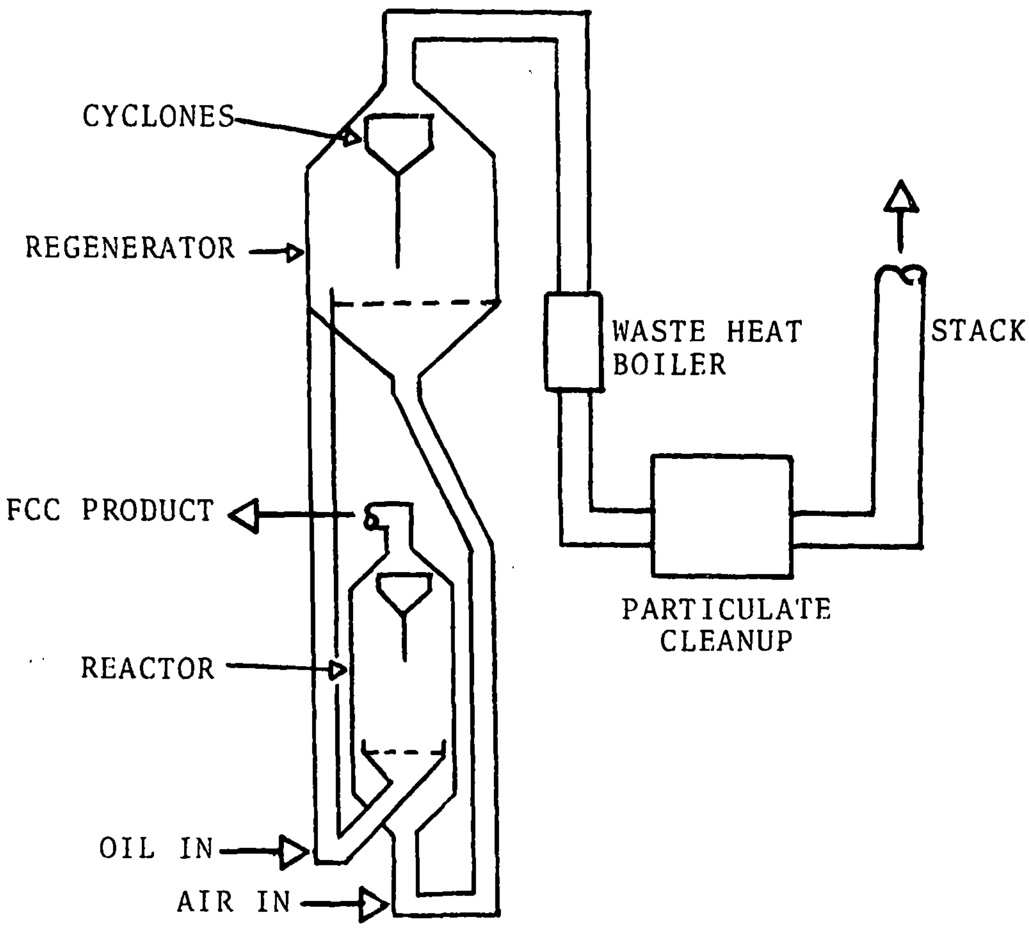

Figure 11. Fluid bed catalytic cracking unit.

Table 24. SIZE DISTRIBUTION FOR PARTICULATE EMITTED FROM FCC REGENERATOR UNIT
From Wilson (1967)

PARTICLE DIAMETER, μm	WT % IN SIZE RANGE
+40	3 - 16
20 - 40	23 - 54
10 - 20	22 - 34
4 - 10	7 - 28
2 - 4	1 - 8
0 - 2	.4 - 4

cient to meet the emissions regulations (currently ~0.03 grain/SCF). Thus the final collector must have an efficiency up to approximately 97%. More stringent requirements would be necessary if a power recovery turbine were being used.

The most common cleanup devices for FCC regenerators are electrostatic precipitators and baghouses. Wet scrubbers and granular bed filters have also been used successfully.

METALLURGICAL FURNACES

The open hearth furnace is a major heat source for steel production. High temperature, atmospheric pressure particle cleanup for open hearth furnaces has been discussed by Silverman (1955) and Spaite et al. (1961). The particulate emissions consist primarily of very fine iron oxide particles. The particles range from 0.001 μm to over 1 μm in diameter, with the mass median diameter less than 0.5 μm. Mass loadings generally can range from 0.23 to 4.6 g/Nm^3 (0.1 to 2.0 gr/SCF).

Particle removal may occur either before or after the waste heat boiler. In the waste heat boiler the gas temperature is cooled from about 700°C to 250°C. If process steam is not needed, the waste heat boiler may be just an additional cost to the particulate control equipment. In this case high temperature particulate control would save the cost of the waste heat boiler. Another advantage to cleaning directly at high temperature is that it minimizes fume deposition on heat recovery surfaces and thus allows improved heat transfer and reduced maintenance and cleaning problems.

The effluent gas must be cleaned sufficiently to satisfy emissions and opacity regulations. The average mass loadings are approximately 1.1 to 2.3 g/Nm^3 (0.5 to 1 gr/SCF). The allowable emission is of the order of 2.3 g/Nm^3 (0.05 gr/SCF). Thus at least 90-95% collection efficiency will be required.

Similar high temperature, atmospheric pressure particulate cleanup problems exist in other metallurgical furnaces. Gray iron cupolas emit submicron fumes at temperatures ranging from 500 - 1,100°C. The fume is mostly iron oxide, with 20 to 30% by weight smaller than 5 μm. Mass loadings are often about 2.3 g/Nm^3 (1.0 gr/SCF).

Brass furnaces emit lead oxide and zinc oxide fumes at temperatures up to about 1,000°C. The size of the particles ranges from 0.03 to 0.3 μm, with a representative mass loading of about 3.2 to 10.3 g/Nm^3 (1.4 to 4.5 gr/SCF).

Secondary metals recovery furnaces emit high temperature effluent gases which generally must be cooled before cleaning. Stack temperatures can range from 500 - 800°C, with mass loadings of 2.3 to 23 g/Nm^3 (1 to 10 gr/SCF). Mass median diameters are often smaller than 0.5 μm.

The fumes emitted from metallurgical furnaces are very difficult to control because the particle size is so small, with MMDs often smaller than 1 μm. Collection efficiencies of 90 to 99% may be required to meet the emissions regulations. At low temperature, this is usually accomplished using high efficiency venturi scrubbers, electrostatic precipitators, or baghouses.

MHD POWER GENERATION

Magnetohydrodynamic (MHD) generation of electricity from coal is being studied for possible use in large coal-burning power plants. A simplified sketch of an MHD system fueled with coal is shown in Figure 12. Powdered coal mixed with seed (a reaction-promoting material) is burned in the combustor producing highly ionized gases in excess of 2,760°C (5,000°F).

An electric current is induced as the ionized gases from the combustor pass through the magnetic field at high speed. The electric current can then be tapped from the generator. The hot gases leaving the generator are used to preheat the combustion air, and then go to a conventional steam power plant.

Because the seed (K_2CO_3) is relatively expensive, it is removed from the product gases and reused. Approximately 90% recovery is desired at temperatures from 300 - 800°C. Cyclones

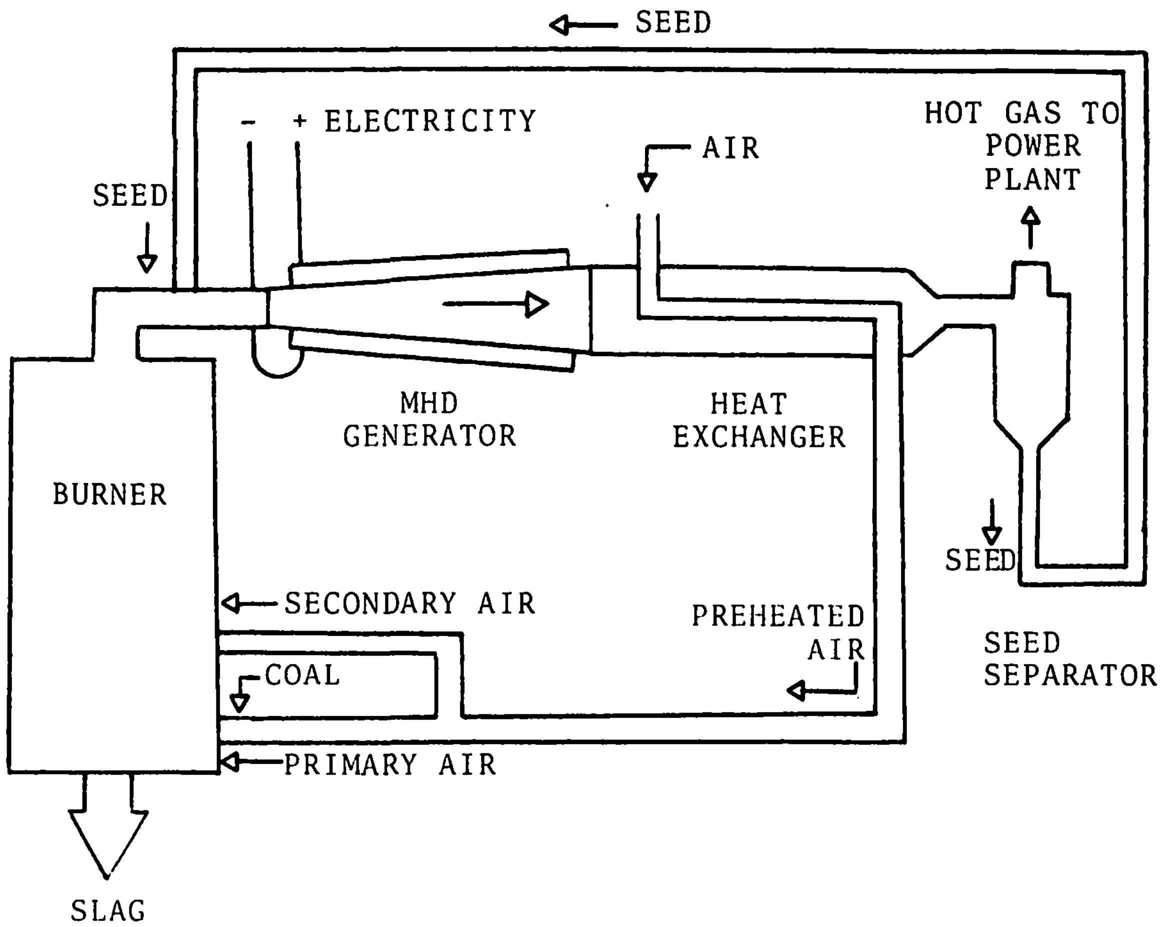

Figure 12. MHD power generation.

may be sufficient for seed recovery, although this has not been demonstrated yet. Conventional flue gas cleanup downstream of the steam power plant still will be required.

PARTICLE REMOVAL FROM HIGH PRESSURE PIPELINES

Coal-Natural Gas Pipeline

Spencer et al. (1965) reported the particulate removal needs of pipelines proposed for the simultaneous transport of pulverized coal and natural gas. The basic objective was to lower the cost of transporting energy and to expand markets for coal and gas.

Separation of solids is required at the line terminal or market delivery points and at compressor stations along the way. The gas is at high pressure and low temperature and contains 2 - 5 kg coal/kg gas. They anticipated solids removal to 0.0009 g/Nm^3 (0.002 gr/SCF) for suitable use by consumers. Thus effectively 100% separation of the coal and gas was required. The cleanup conditions and requirements are summarized in Table 25. The proposed separation system consisted of a first stage of cyclones followed by a bag filter or possibly an electrostatic precipitator.

Removal of Oil Fume from Natural Gas Pipeline

The removal of submicron lube fume from natural gas pipelines has been shown to raise the line efficiency (Hall et al., 1968 and Eaton, 1969). The pipeline pressure is about 50 atm, and the temperature is about 40°C.

Lubricating oil fume appeared to act as condensing and concentrating nuclei for dissolving lighter hydrocarbons. The hydrocarbons drop out and cause a deterioration in line efficiency.

The particle mass concentration is very low ($\sim 10^{-4}$ gr/SCF) and the particles range from 0.1 to 1 μm in diameter. Gas flow rates are on the order of 7,000 Nm^3/min (250,000 SCFM).

Design specifications for the electrostatic precipitator

Table 25. PARTICLE COLLECTION REQUIREMENTS FOR COAL - NATURAL GAS PIPELINES

FACTOR	TYPICAL SPECIFICATION
Gas Composition:	94% methane, negligible moisture
Gas Temperature:	16 - 38°C
Gas Pressure:	40 - 55 atm
Particulate:	Pulverized bituminous coal
Particle Size Distribution:	70 - 80% <74 μm 50 - 60% <40 μm 20 - 30% <10 μm
Particle Density:	1.3 - 1.5 g/cm^3
Electrical Resistivity:	Low
Gas Flow Rate:	300 m^3/min (~10,000 ACFM)
Solids Concentration:	2 - 8 kg coal/kg gas
Required Concentration of Delivered Gas:	0.0046 g/Nm^3 (~0.002 gr/SCF)
Overall Efficiency:	>99.9999%

reported by Hall et al. (1968) are given in Table 26. The precipitator was found to be suitable, however development was discontinued because recent reductions in required throughput in pipelines have eliminated the economic advantage of removing the oil fume.

GEOTHERMAL POWER PLANT

A geothermal power plant, producing steam at 350°C and 50 - 80 atm was reported by Krikorian (1972). Silica particles entrained in the steam can erode and/or scale the turbine blades. The maximum permissible silica concentration in steam with 80 atm of steam pressure at the turbine inlet is about 0.05 ppm (2.6×10^{-5} gr/SCF).

If geothermal steam is to be used directly in turbine operations at high pressures, it is likely that it will need purification to prevent inefficient turbine operation. One method is to scrub the steam with high-purity water before passing it through the turbine. Unfortunately such a process cools the steam, degrades its energy, and lowers the efficiency. Also, after scrubbing, the steam is saturated and, if used in the turbine, could lead to erosion of the turbine blades by impinging drops of water.

Solid phase scrubbers (for example, limestone) have been considered.

Table 26. PRECIPITATOR DESIGN SPECIFICATIONS FOR NATURAL GAS PIPELINES
From Hall et al. (1968)

FACTOR	DESIGN SPECIFICATION
Gas Composition:	Natural Gas - 94% methane
Gas Temperature:	30 - 50°C
Gas Pressure:	55 atm
Gas Viscosity (basis of CH_4):	~1.2×10^{-4} poise
Gas Flow Rate at Standard Conditions:	~7,000 Nm^3/min (208,000 - 278,000 SCFM)
Collection Efficiency:	~99% (by weight)
Particle Size of Oil Fume:	Est. 0.1 to 1.0 micron diameter
Particle Concentration:	0.03 g/Nm^3 (0.07 gr/SCF)

GAS TURBINE PARTICLE TOLERANCES

In many high temperature and pressure energy processes the effluent gas is used to drive a gas turbine and thereby generate electric power. The useful life of the gas turbine depends on the extent of erosion and corrosion damage to the internal components of the turbine. The extent of damage depends upon the concentration and size of particulate matter suspended in the gas, and upon the chemical composition of the gas and particulates.

Erosion damage results from the inertial bombardment of particles onto the stator and rotor blades of the gas turbine. The erosion damage is proportional to the kinetic energy of the particulate matter striking the turbine blades. Therefore the damage is more severe when larger, more massive particles are present in the gas stream. Large concentrations of very small particles may be even less harmful than their total mass would imply because their trajectories would tend to follow the gas streamlines and thus would be less likely to impact the turbine blades.

Corrosion damage depends on the amount of particulate that adheres to the turbine surfaces as well as the chemical composition of the gas and particulate. In general, the most corrosive compounds are those containing sodium and potassium. Liquid deposits of such compounds can form inside the turbine at temperatures between about 500°C and 1,000°C. These molten films attack the protective oxide scale on the blade material, and thus initiate accelerated oxidation of the turbine components.

The buildup of particulate deposits on the turbine blades also can significantly impair the aerodynamic performance of the blades. Furthermore, large agglomerates can break off from such deposits and cause additional erosion damage.

SMALL TURBINES FOR MILITARY USE

Turbine blade erosion by entrained dust has been a problem with turbine engines used in military helicopters and tracked ground vehicles (tanks). An extensive study of sand and dust erosion in gas turbine engines was performed for the U.S. Army (reported by Smeltzer et al., 1970a,b). Their principal results are summarized below.

- Erosion per particle is directly proportional to particle kinetic energy.
- Erosion ceases for fine particles (≤20 μm) below about 30 - 60 m/s. This suggests that a certain minimum particle energy is necessary to cause erosion.
- Corner-oriented particle impacts cause the preponderance of erosion damage.
- The energy absorbed by the target is translated into both metal deformation and metal removal. The metal deformed is typically 300 - 400 times greater in volume than that eroded.

These tests were conducted using Arizona road dust (70% SiO_2) with a size distribution as shown in Table 27.

Table 27. SIZE DISTRIBUTION OF ARIZONA ROAD DUST

Diameter, μm	Weight %
0-5	39±2
5-10	18±3
10-20	16±3
20-40	18±3
40-80	9±3

Tests on an air cleaner for the U.S. Army Overland Train Mark II were reported by the Donaldson Company (1964). They obtained an overall efficiency of 85% with their cyclone-type dust collector. A concentration of 0.02 g/Nm^3 (0.01 gr/SCF) was found to be satisfactory to extend the turbine life from 200 hours to well over 460 hours (no significant damage after 460 hours).

Thomas (1968) reported tests of a cyclone air cleaner on a small, general-purpose military gas turbine. The unprotected turbine failed after 6 hours and 50 minutes. The turbine life was extended to 132 hours with the cyclone air cleaner (0.01 g/m^3 dust loading).

The requirements for air cleaners for Army uses were expressed by Barnett (1976). Military helicopter turbine engines have limited duty cycles and therefore can survive with 80 - 90% overall particle removal. Tracked ground vehicles using gas turbine engines require 99 - 99.5% removal of the standard Arizona road dust (Table 27). Reciprocating engines require a similar degree of particle removal.

Other work performed for the Army was reported by Wood and Hafer (1966). They studied the mechanisms of dust erosion and the sintering of dust at high temperatures. They found that the erosion rate is proportional to the impact velocity squared. Using a 90% SiO_2 dust, they found that fusion and adherence to the target began at about 950°C and increased as the temperature approached 1,100°C.

Erosion of turbine blades in steam and metal vapor turbines has been investigated under NASA sponsorship (Spies et al., 1968, and Pouchot et al., 1971). They were concerned with turbine erosion resulting from the impingement of condensed drops of potassium or mercury in metal vapor turbines used for space power systems. The erosion damage was found to be proportional to the kinetic energy of the impinging drops. The condensate particles were so small that less than 5% impinged on the turbine blades.

GAS TURBINES FOR UTILITY USE

Corrosion

To successfully operate a gas turbine on the exit gases of a high temperature and pressure energy process, it is necessary to limit the concentration of alkali-metal compounds. Particulates must be limited to levels low enough that excessive deposition, hot corrosion, and erosion of turbine components do not occur. Westinghouse Electric Corporation has studied these problems in connection with their fluidized bed combustion process evaluation (Keairns et al., 1975), and their coal gasification process development (Chamberlin et al., 1976).

The concentration of alkali-metal compounds must be sufficiently low to prevent the formation of liquid films of sulfates and chlorides which can initiate the hot corrosion of turbine components. The turbine tolerance for sodium is shown in Figure 13 (from Keairns et al., 1975), assuming sodium is the only alkali metal present.

The tolerance for sodium is reduced by a factor of about four when potassium is present. The reason is that the sodium sulfate-potassium sulfate (Na_2SO_4-K_2SO_4) eutectic melt has a lower melting point (832°C) than the Na_2SO_4 alone (884°C). The presence of potassium and sodium chlorides permits a four-component eutectic of even lower melting point (514°C).

Deposition

If the alkali-metal compound tolerances are met, liquid films should not be present on either the turbine hardware or on the surface of the particles. Deposits resulting from the impaction and dry sintering of fine particles can occur, especially at high temperature. These deposits can break off and cause erosion damage or can build up and impair the aerodynamic performance of the turbine blades. At temperatures below 667°C (1,250°F) erosion rather than deposition is the factor expected to limit turbine life. At higher temperatures deposition should become more important.

Figure 14 shows the capture efficiency of a gas turbine rotor blade as a function of particle diameter. Approximately 10% of the submicron particles are captured by the turbine blades. Experimental work by MacFarlane and Foster (1972) indicates that the capture efficiency reaches zero for about 0.5 μm diameter particles and then increases very slowly be-

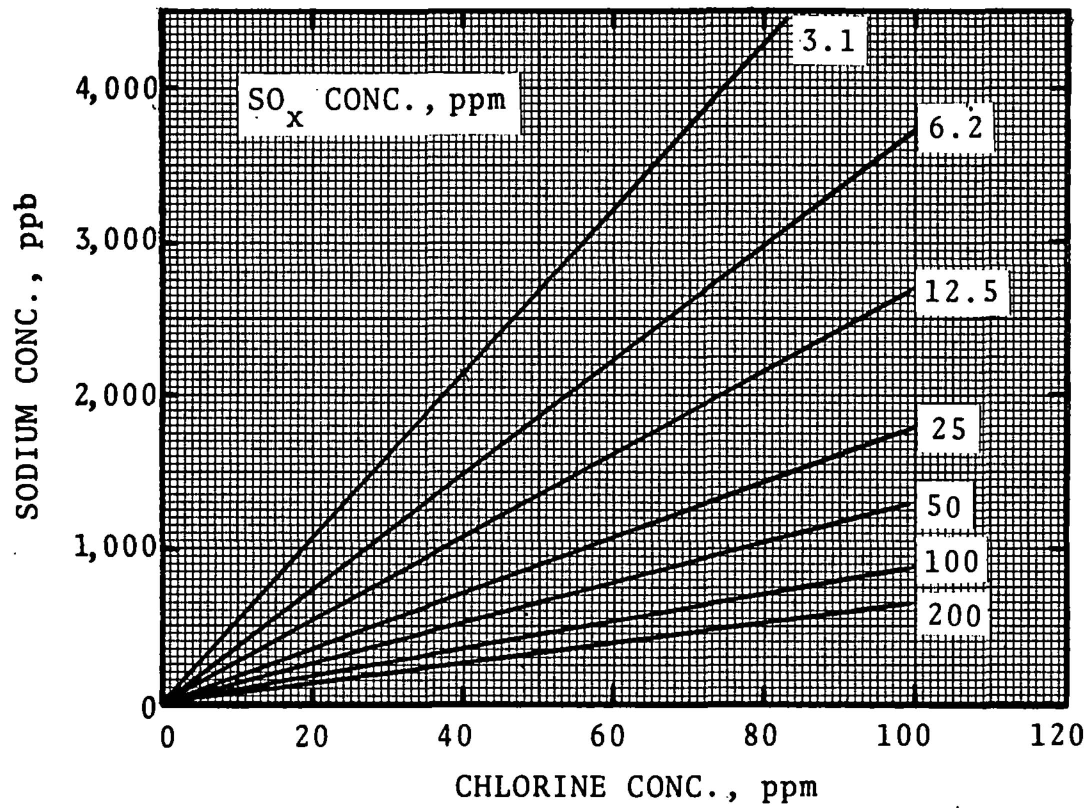

Figure 13. Turbine tolerance for sodium as a function of the concentration of chlorine and oxides of sulfur, for fluid bed combustor. From Keairns et al. (1975)

System pressure: 10 atm
Oxygen: 1.7%
Water vapor: 8.5%

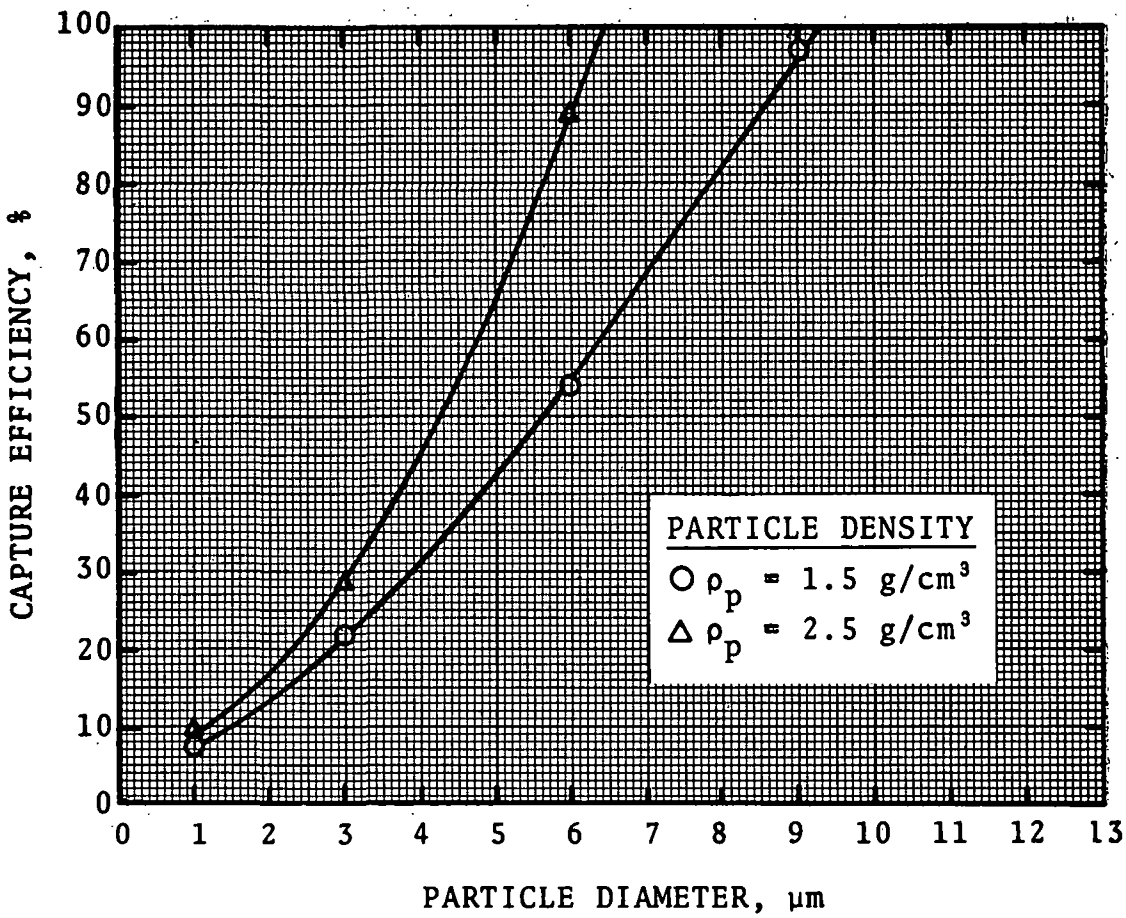

Figure 14. Particle capture efficiency for rotor blades of a gas turbine. From Chamberlin et al. (1976)

cause of diffusion. The capture efficiency rises to about 1% for 0.01 μm particles and 25% for 0.001 μm particles.

MacFarlane also noted that significant deposition on the trailing edge of the blade upset the boundary layer and caused separation of flow to occur earlier on the blade surface. This caused a decrease in turbine efficiency.

The above discussion indicates that particle deposition can be a substantial problem. However, more quantitative work must be done in order to specify realistic tolerances for particle deposition in utility size gas turbines.

Erosion

Large gas turbines for utility use show less erosion damage than small gas turbines. This is partly because the larger turbines have larger blade chords and thicker edges. Also, as the passage through the turbine shrinks relative to the dust size, the number of impacts increases, the impact velocity decreases slightly, and the impact occurs at more damaging impact angles. Taking these into account, Keairns et al. (1975) predict that a full-scale turbine would erode about 80% of the rate of a half-linear-scale turbine.

The Australian gas turbine experience has been reported by Morley and Wisdom (1964), Duke (1968), and Brasinikas (1970). They found no erosion for particles smaller than 5 or 6 μm in diameter. They found that the erosion rate is proportional to the "n" power of the velocity. The exponent "n" ranged from 2 to 5 depending on the ash and blade material. Black coal ash appeared to be about 10% as erosive as silica dust. Erosion damage was noted on the turbine shroud as well as the blades.

Morley and Wisdom (1964) noticed a serious deposition problem in addition to erosion. They found that at high temperatures (700°C) about 25% of the ash deposits in the turbine.

U.S. Coal-fired gas turbine experience was reported by McGee et al. (1969). They used a fly ash test dust with a size distribution as shown in Table 28. They found a dust loading of 0.023 g/Nm³ (0.01 gr/SCF) to be excessive for allowing commerically acceptable blade wear (at 650°C). They anticipated that the dust loading will need to be as low as 0.002 g/Nm³ (0.001 gr/SCF).

Table 28. FLY ASH TEST DUST
(From McGee et al., 1969)

Diameter, μm	Weight %
30-35	2
20-30	5
15-20	22
10-15	19
7-10	31
5-7	15
5	6

Robson et al. (1975) have reported that a total dust loading of 4 ppm (0.0012 gr/SCF) would allow a suitable turbine life. In a typical application, this would require that effectively all particles larger than 2 μm would have to be collected. Also 90% collection of particles smaller than 2 μm would be required.

There is still some disagreement as to the potential harm to turbines ingesting fine particles. Some authors have suggested that turbine requirements should be specified in two size ranges. Westinghouse (1974) suggested an allowable concentration of 0.34 g/Nm³ (0.15 gr/SCF) with no more than 0.023 g/Nm³ (0.01 gr/SCF) larger than 2 μm. A recent Program Opportunity Notice from the E.R.D.A. Fossil Energy Program (PON FE-7, July 26, 1976) requests potential developers of high temperature and pressure electrostatic precipitators. They suggest that reducing the dust loading to below about 1.7 g/Nm³ (0.75 gr/SCF) for particles in the 0 - 2 μm range, and to below 0.002 g/Nm³ (0.001 gr/SCF) for particles in the 2 - 6 μm range would be sufficient to protect the turbine.

Much of the literature is in agreement that at some diameter (1 to 5 μm) particles no longer cause significant erosion damage. The reason is that the particles are smaller, are slowed down in the boundary layer, and impact with insufficient kinetic energy to erode the blade material. Also the capture efficiency is much lower for small particles (at least down to 0.01 μm). However, as discussed above, particle deposition may still be a problem even when direct erosion is insignificant.

The problems of particle deposition, corrosion, and erosion of turbine components are far from settled. There is some uncertainty as to the minimum allowable particle diameter and the maximum tolerable concentration of fine particles. Data are lacking, and theory is inadequate to determine this information. Therefore it would be prudent to design high temperature and pressure particle collection equipment to meet the required mass concentration reduction for all particle sizes.

Emissions Requirements

In any case, the particulate emissions from the gas turbine must satisfy the requirements of the Federal New Source Performance Standards. If the particle size distribution is sufficiently small, it is possible to exceed the mass emissions standards (or possibly the opacity standards) while still allowing satisfactory turbine life. In this case, additional particulate removal equipment might be needed downstream of the turbine before the effluent gas could be exhausted to the atmosphere.

As an example, Figure 15 illustrates the relative importance of the turbine inlet requirements and emissions standards for emissions from a fluidized bed combustion process. The solid lines represent emissions standards while the dashed line represents the turbine requirements.

The curves were obtained using the size distribution reported by Exxon Research and Engineering Co. (1976) as leaving the second cyclone. Curve 2 is for the current new source performance standard for particulate emissions from a coal-fired

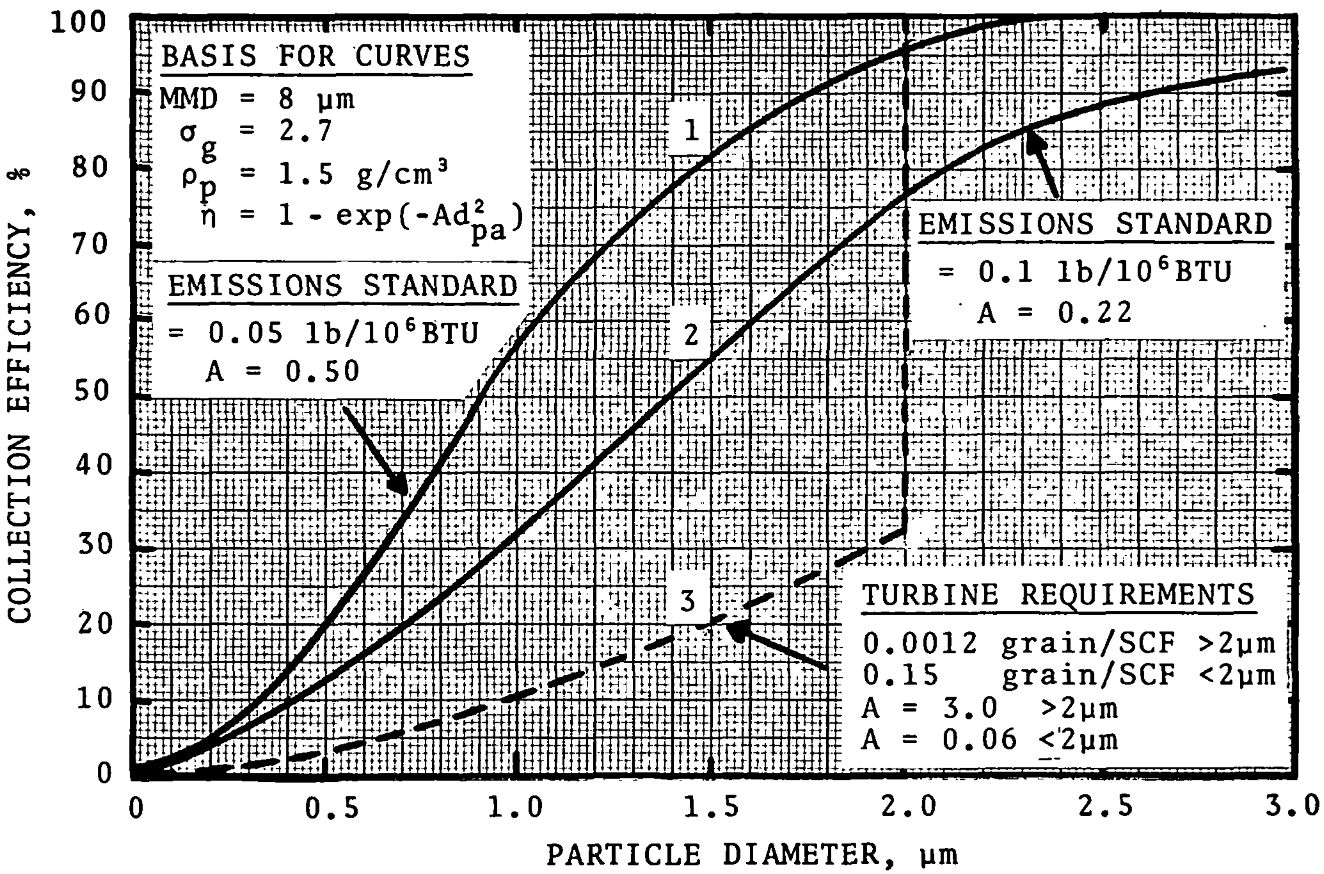

Figure 15. Particle emissions standards versus turbine requirements for the fluidized bed combustion of coal.

boiler (<0.1 lb/10^6BTU). Curve 1 shows what the effect would be if the standard were reduced by half (to 0.05 lb/10^6BTU). In both cases, the turbine requirements (curve 3) are less stringent for particles smaller than 2 μm, and more stringent for particles larger than 2 μm.

Figure 15 was obtained using the "cut diameter" approximation for performance of particulate control equipment presented by Calvert et al. (1974). Figure 15 should not be taken as an accurate design criterion, but rather as an illustration of the relative importance of the emissions standards and turbine requirements as a function of particle size.

TURBINE INLET TEMPERATURE

The efficiency of a gas turbine is directly related to the turbine inlet temperature. As inlet temperatures for industrial gas turbines increase, it is likely that particle collection will be required at higher temperatures than at present.

Figure 16 shows a projection of industrial turbine inlet temperatures taken from Hedley (1974). This prediction is based on trends in commercial and military aircraft engines and assumes that sufficient R&D money is available to maintain steady progress.

Gas turbine inlet temperatures may be increased by improving the cooling techniques for the turbine blades, or by finding materials which maintain satisfactory strength at extreme temperatures. It has been suggested that ceramics can be used for much of the internals of the turbine (burners, seals, nozzles), and may eventually be suitable as turbine blades. Ceramic lined turbines would enable inlet temperatures approaching 1,400°C to 1,500°C.

Therefore it is conceivable that future high temperature particle collection equipment could be needed at significantly higher temperatures than currently required.

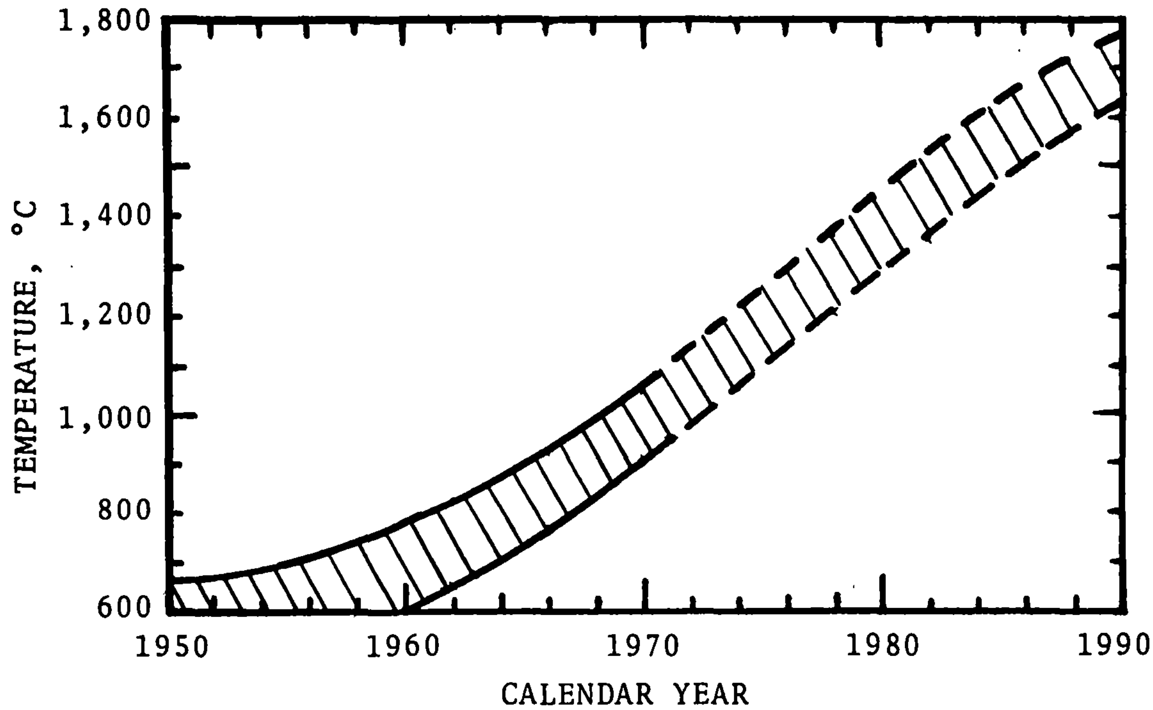

Figure 16. Estimated industrial gas turbine inlet temperatures. From Hedley (1974).

REFERENCES

Archer, D.H., D.L. Keairns, et al. Evaluation of the Fluidized Bed Combustion Process. Volumes I-IV. Report APTD-1165. November 1971.

Atkin, M.L. Australian Coal-Burning Unit. Gas Turbine International. September - October, 1969.

Banchik, I.N. The Winkler Process for the Production of Low BTU Gas from Coal. In: Clean Fuels from Coal; Symposium Papers, IGT, Chicago, September 10-14, 1973.

Barnett, L.H. Department of the Army, Tank-Automotive Development Center. Personal Communications. March 1976.

Brandenburg, C.F., R.D. Reed, R.M. Boyd, D.A. Northrop, and J.W. Jennings. Interpretation of Chemical and Physical Measurements from an In-Situ Coal Gasification Experiment. Presented at the 50th annual meeting of the Society of Petroleum Engineers, AIME, Dallas, Texas, September 28 - October 1, 1975.

Brown, R.F., and A.B. Walker. Feasibility Demonstration of Electrostatic Precipitation at 1,700°F. A.P.C.A. Journal, 21 (10): 617, 1971.

Calvert, S., J. Goldshmid, and D. Leith. Scrubber Performance for Particle Collection. Recent Advances in Air Pollution Control, AIChE Symposium Series No. 137, Vol. 70, 1974.

Calvert, S., and R.D. Parker. The Effects of High Temperature and Pressure on Particle Collection Mechanisms: Theoretical Review. EPA 600/7-77-002. January 1977.

Campbell, G.G., C.F. Brandenberg, and R.M. Boyd. Preliminary Evaluation of Underground Coal Gasification at Hanna, Wyoming. Bureau of Mines Coal Gasification Program, T.P.R. 82, October 1974.

Carls, E.L., and W.F. Podolski. Conceptual Design of a Pressurized Component Test and Integration Facility. Proceedings of the 4th International Conference on Fluidized-Bed Combustion, McLean, Virginia, December 1975.

Chamberlin, R.M., et al. Advanced Coal Gasification System for Electric Power Generation. Quarterly reports for the E.R.D.A. under contract no. E(49-18)-1514, fiscal year 1976.

Chambers, H. Jr., E.R.D.A. Pittsburgh Energy Research Center, Personal Communication, May 12, 1976.

Ciliberti, D.F. Westinghouse Research Laboratory, Pittsburgh, Pennsylvania. Personal Communication, 1976.

Combustion Power Company. Energy Conversion from Coal Utilizing CPU-400 Technology. Report to the Office of Coal Research, U.S. Dept. of the Interior. OCR/R&D 94, November 1974.

Combustion Power Company. Summary of the CPU-400 Development. Report to the EPA, contract no. 68-02-0054, September 1974.

Corder, W.C., and W.M. Goldberger. Design, Installation and Operation of a 25-Ton-A-Day Coal-Gasification Process Development Unit for the Agglomerating Burner-Gasification Process, OCR/R&D 97/Int. 1, November 1974.

Corder, W.C., H.R. Batehelder, and W.M. Goldberger. The Union Carbide/Battelle Coal Gasification Process Development Unit Design. Proceedings of the 5th Synthetic Pipeline Gas Symposium, October 29-31, 1973.

Cover, A.E., and G.T. Skaperdas. The Kellogg Coal Gasification Process, Single Vessel Operation. In: Clean Fuels from Coal, Symposium Papers, IGT, Chicago, Sept. 10-14, 1973.

Donaldson Company, Dust Concentration Measurement on the U.S. Army Overland Train Mark II. TRECOM Technical Report 64-16, April 1964.

Duke, G.A. Erosion Tests on an Modified Rover Gas Turbine. Australian Aeronautical Research Laboratory, M.E. Note 297, June 1968.

Durham, J.F. Federal Regulation of Atmospheric Emissions from Coal Gasification Plants. Presented at: Environmental Aspects of Fuel Conversion Technology II, EPA Symposium, Dec. 15, 1975.

Eaton, J.B. Maintaining Clean Pipelines by Electrostatic Precipitation. Presented at the American Gas Association Operating Section Transmission Conference, New Orleans, Louisiana, May 1969.

Ehrlich, S. Combustion of Carbon-Burning Fly Ash in a Carbon-Burn-up Cell. In: Proceedings of the 2nd International Conference on Fluidized-Bed Combustion, Hueston Woods, Ohio, October 1970.

Exxon Research and Engineering Company. A Regenerative Limestone Process for Fluidized Bed Coal Combustion and Desulferization. Monthly Reports to the EPA, contract no. 68-02-1451, 68-02-1312 (1976).

Farnsworth, J.F., H.F. Leonard, D.M. Mitsak, and R. Wintrell. Production of Gas from Coal by the Koppers-Totzek Process. In: Clean Fuels from Coal, Symposium Papers, IGT, Chicago, September 10-14, 1973.

Feldmann, H.F., et al. Supplemental Pipeline Gas from Coal by the Hydrane Process. Presented at the 71st National Meeting, AIChE, Dallas, Texas, Feb. 20-23, 1972.

Fink, C.E. The CO_2 Acceptor Process in Clean Fuels from Coal, Symposium Papers, I.G.T., Chicago, September 1973.

First, M.W., J.B. Graham, G.M. Butler, C.B. Walworth, and R.P. Warren. High Temperature Dust Filtration. Ind. Eng. Chem. 48 (4): 696, 1956.

Fischer, D.D., C.F. Brandenburg, and L.A. Schrider. Energy Recovery from In-Situ Coal Gasification. Energy Sources: 2 (3): 281, 1975.

Fitton, A., and R.G. Voysey. Solid-Fuel - Fired Gas Turbines in Great Britain. Engineering: p. 239, Aug. 19, 1955.

Forney, A.J., et al. The Synthane Coal-to-Gas Process. In: Clean Fuels from Coal, Symposium Papers, IGT, Chicago, Sept. 1973.

Fulton, R.W. and S. Youngblood. Survey of High Temperature Cleanup Technology for Low BTU Fuel Gas Processes. Report for EPA contract no. 68-02-1318, Accurex Corp., Jan. 1975.

Gamble, R.L. Design of the Rivesville Multicell Fluidized-Bed Steam Generator. In: Proceedings of the 4th International Conference on Fluidized-Bed Combustion, McLean, Virginia, December 1975.

Grace, R.J. Process Engineering Manager. Bituminous Coal Research, Inc., Monroeville, PA. Personal Communication, May 1976.

Grace, R.J. Development of the Bi-Gas Process. In: Clean Fuels from Coal, Symposium Papers, IGT, Chicago, Sept. 10-14, 1973.

Hall, H.J., R.F. Brown, J.B. Eaton, and C.W. Brown. Removal of Lube Fume Raises Line Efficiency. The Oil and Gas Journal, p. 109, Sept. 9, 1968.

Hazard, H.R. Battelle Columbus Laboratories, Columbus, Ohio. Personal Communication, January 1976.

Hazard, H.R. Coal Firing for the Open-Cycle Gas Turbine: A Comparison of Methods. Proceedings of the Joint Conference on Combustion, 1955, ASME and IME.

Hedley, W.H. Effect of Gas Turbine Efficiency and Fuel Cost on Cost of Producing Electric Power. Monsanto Research Corp. Final Report, EPA 650/2-74-041, May 1974.

Highley, J. Report on Progress at the NCB Coal Research Establishment (CRE). In: Proceedings of Fourth International Conference on Fluidized-Bed Combustion, McLean, Virginia, December 1975.

Hoke, R.C. Exxon Research and Engineering Company, Linden, New Jersey. Personal Communication, June 1977.

Hoke, R.C., R.R. Bertrand, M.S. Nutkis, D.D. Kinzler, L.A. Ruth, and M.W. Gregory. Studies of the Pressurized Fluidized-Bed Coal Combustion Process. EPA 600/7-76-011. September 1976.

Hoke, R.C. Emissions from Pressurized Fluidized-Bed Coal Combustion. In: Fourth International Conference on Fluidized-Bed Combustion, McLean, Virginia, December 1975.

Hoke, R.C., M.S. Nutkis, L.A. Ruth, and H. Shaw. A Regenerative Limestone Process for Fluidized-Bed Coal Combustion and Desulfurization. EPA 650/2-74-001, January 1974.

Hoy, H.R. Pilot-Plant Experiments at BCURA. In: Proceedings of the 2nd International Conference on Fluidized-Bed Combustion. EPA report no. AP-109, October 1970.

Jahnig, C.E. and E.M. Magee. Evaluation of Pollution Control in Fossil Fuel Conversion Processes. Gasification: Section 1. CO_2 Acceptor Process. EPA 650/2-74-009-d, December 1974.

Jahnig, C.E. Evaluation of Pollution Control in Fossil Fuel Conversion Processes. Gasification: Section 5. BI-GAS Process. EPA 650/2-74-009-g, May 1975.

Jahnig, C.E. Evaluation of Pollution Control in Fossil Fuel Conversion Processes. Gasification: Section 6. HYGAS Process. EPA 650/2-74-009-h, August 1975.

Jahnig, C.E. Evaluation of Pollution Control in Fossil Fuel Conversion Processes. Gasification: Section 7. U-Gas Process. EPA 650/2-74-009-i, September 1975.

Jahnig, C.E. Evaluation of Pollution Control in Fossil Fuel Conversion Processes. Gasification: Section 8. Winkler Process. EPA 650/2-74-009-j, September 1975.

Jain, L.K. and T.J. Hixson. Applicability Study - Coal Gasification Process. APTD-1103, March 1972.

Kalen, B. and F.A. Zenz. Filtering Effluent from a Cat Cracker. Chem. Eng. Prog., 69(5):67, June 1973.

Kalfadelis, C.D. and E.M. Magee. Evaluation of Pollution Control in Fossil Fuel Conversion Processes. Gasification: Section 1. Synthane Process. EPA 650/2 74-009-b, June 1974.

Kane, L.J., G.E., Chidester, and C.C. Shale. Ceramic Fibers for Filtering Dust from Hot Gases. Bureau of Mines, Report of Investigations 5672, 1960.

Katz, D.L., D.E. Briggs, E.R. Lady, J.E. Powers, M.R. Tek, B. Williams, and W.E. Lobo. Evaluation of Coal Conversion Processes to Provide Clean Fuels. Parts I, II. E.P.R.I. 206-0-0-2, February 1974.

Keairns, D.L., et al. Fluidized-Bed Combustion Process Evaluation Phase II - Pressurized Fluidized-Bed Coal Combustion Development. EPA 650/2-74-027-c, September 1975.

Keairns, D.L., D.H. Archer, et al. Evaluation of the Fluidized-Bed Combustion Process, Volumes I-IV. EPA 650/2-73-048a,b, c,d, December 1973.

Koller, L.R., and H.A. Fremont. Negative Wire Corona at High Temperature and Pressure. J. Applied Phys. 21:741, 1950.

Krieb, K.H. Combined Gas and Steam Turbine Process with Lurgi Coal Pressure Gasification. In: Clean Fuels from Coal, Symposium Papers, IGT, Chicago, Illinois, September 1973.

Krikorian, O.H. Corrosion and Scaling by Steam in Nuclear Geothermal Power Plants. Presented at the American Nuclear Society Annual Meeting, Las Vegas, Nevada, June 1972.

Lancaster. B.W. Westinghouse Research Laboratory, Pittsburgh, Pennsylvania. Personal Communication, January 1976.

LaRosa, P. Fuel Gas from Molten Iron Coal Gasification. In: Clean Fuels from Coal, Symposium Papers, IGT, Chicago, Illinois, September 10-14, 1973.

Lewis, P.S., A.J. Liberatore, and J.P. McGee. Strongly Caking Coal Gasified in a Stirred-Bed Producer. Bureau of Mines, Report of Investigation 7644, 1973.

Locke, H.B., H.G. Lunn, H.R. Hoy, and A.G. Roberts. Fluidized Combustion in Great Britain - Environmentally Clean Steam and Power Generation from Coal, Heavy Oil and Dirty Fuels. In: Proceedings of the Fourth International Conference on Fluidized-Bed Combustion, McLean, Virginia, December 1975.

Loeding, J.W., and C.L. Tsaros. IGT U-Gas (Clean Utility Gas) Process. In: Clean Fuels from Coal, Symposium Papers, IGT, Chicago, Illinois, Sept. 10-14, 1973.

MacFarlane, J.J., and D.H. Foster. Nozzle Guide Vane Models for Studying Deposition in Gas Turbines. In: Deposition and Corrosion in Gas Turbines, pg. 58. John Wiley and Sons, New York, 1972.

Magee, E.M., C.E. Jahnig, and H. Shaw. Evaluation of Pollution Control in Fossil Fuel Conversion Processes. Gasification: Section 1. Koppers-Totzek Process. EPA 650/2-74-009-a, January 1974.

McCoy, D.C., Conoco Coal Development Company, Library, PA. Personnel Communication, May 19, 1976.

McGee, J.P., A.J. Liberatore, D.C. Strimbeck, and G.B. Goff. Turbine Blade Wear by Coal Ash in Working Fluid at 1,200°F. U.S. Bur. of Mines, Report of Investigation 7255, April 1969.

McGurl, G.V. Koppers Company, Inc., Engineering and Construction Division, Pittsburgh, PA. Personal Communication, June 1976.

Mordell, D.L. Indirect-Fired Gas Turbines. The Engineer, Feb. 8, 1957, pg. 210.

Nadkarni, R.M., C. Bliss, and W.I. Watson. Underground Gasification of Coal. In: Clean Fuels from Coal, Symposium Papers, IGT, Chicago, Illinois, Sept. 10-14, 1973.

National Academy of Engineering. Evaluation of Coal Gasification Technology. Part II. Low and Intermediate BTU Fuel Gas. O.C.R. Report No. OCR-74, Int. 2, March 1974.

National Coal Board, London, England. Reduction of Atmospheric Pollution. Vol. 1-3, EPA report nos. APTD-1082, 1083, 1084, Sept. 1971, 1972.

Nutkis, M.S. Operation and Performance of the Pressurized FBC Miniplant. In: Proceedings of the 4th International Conference on Fluidized-Bed Combustion. McLean, Virginia, Dec. 1975.

Parent, J.D. Efficiency of Small Cyclones as a Function of Loading, Temperature and Pressure Drop. Trans. A.S. Ch.E. 42: 989, 1946.

Pope, M. Pilot and Research Plants: A Progress Report. In: Proceedings of 4th International Conference on Fluidized Bed Combustion. McLean, Virginia, Dec. 1975.

Pouchot, W.D., et al. Basic Investigation of Turbine Erosion Phenomena. NASA report no. CR-1830, Nov. 1971.

Robinson, M. Critical Pressures of the Positive Corona Discharge Between Concentric Cylinders in Air. J. Appl. Phys. 40 (13): 5107, 1969.

Robinson, M. The Corona Threshold for Coaxial Cylinders in Air at High Pressures. I.E.E.E. Trans. on Power Apparatus and Systems, PAS-86 (2): 185, 1967.

Robison, E.B., R.D. Glenn, S. Ehrlich, J.W. Bishop, and J.S. Gordon. Study of Characterization and Control of Air Pollutants from a Fluidized-Bed Combustion Unit. The Carbon-Burn-up Cell. EPA report no. APTD-1170, February 1972.

Robison, E.B., A.H. Bagnulo, J.W. Bishop, and S. Ehrlich. Characterization and Control of Gaseous Emissions from Coal-Fired Fluidized-Bed Boilers. EPA report no. APTD-0655, Oct. 1970.

Robson, F.L., W.A. Blecker, and C.B. Colton. Fuel Gas Environmental Impact. EPA 600/2-76-153, June 1976.

Robson, F.L., W.A. Blecker, and A.J. Giramonti. Combined Cycle Power Systems. Presented at the Symposium on Environmental Aspects of Fuel Conversion Technology II, Holywood, Florida, December 1975.

Robson, F.L. and A.J. Giramonti. The Use of Combined Cycle Power Systems in Non-Polluting Central Station. APCA Journal, 22 (3): 177, March 1972.

Schora, F., Jr., B.S. Lee, and J. Huebler. The HYGAS Process. In: Clean Fuels from Coal, Symposium Papers. IGT, Chicago, Illinois, Sept. 10-14, 1973.

Schrider, L.A. Laramie Energy Research Center, ERDA, Laramie, Wyoming. Personal Communication, 1976.

Schrider, L.A., C.F. Brandenburg, D.D. Fischer, R.M. Boyd, and G.G. Campbell. The Outlook for Underground Coal Gasification. Presented at the 1975 Lignite Symposium, Grand Forks, N.D., May 1975.

Shale, C.C. Operating Characteristics of a High Temperature Electrostatic Precipitator. Bur. of Mines Report of Investigation 7276, 1969.

Shale, C.C. Progress in High Temperature Electrostatic Precipitation. APCA Journal, 17 (3): 159, 1967.

Shale, C.C. The Physical Phenomena Underlying the Negative and Positive Coronas in Air at High Temperature and Pressures. I.E.E.E. Int. Conv. Record, 1965.

Shale, C.C., W.S. Bowie, J.H. Holden, and G.R. Strimbeck. Characteristics of Positive Corona for Electrical Precipitation at High Temperature and Pressures. Bur. of Mines Report of Investigation 6397, 1964.

Shale, C.C., W.S. Bowie, J.H. Holden, and G.R. Strimbeck. Feasibility of Electrical Precipitation at High Temperatures and Pressures. Bur. of Mines Report of Investigation 6325, 1963.

Shaw, H., and E.M. Magee. Evaluation of Pollution Control in Fossil Fuel Conversion Processes. Gasification: Section 1. Lurgi Process. EPA 650/2-74-009-c, July 1974.

Silverman, L. Technical Aspects of High Temperature Gas Cleaning for Steel Making Processes. Air Repair, 4 (4): 189, 1955.

Smeltzer, C.E., M.E. Gulden, and W.A. Compton. Mechanisms of Metal Removal by Impacting Dust Particles. Transactions of the ASEM: Journal of Basic Engineering, pg. 639, Sept. 1970a.

Smeltzer, C.E., M.E. Gulden, S.S. McElmurry, W.A. Compton. Mechanisms of Sand and Dust Erosion in Gas Turbine Engines. USA-AVLABS Technical Report No. 70-36, August 1970b.

Smith, J., R.W. Cargill, D.C. Strimbeck, W.M. Nabors, and J.P. McGee. Bur. of Mines Coal Fired Gas Turbine Research Project U.S. Bur. of Mines Report of Investigations 6920, 1967.

Smith J., D.C. Strimbeck, N.H. Coates and J.P. Mcgee. Bur. of Mines Progress in Developing Open and Closed-Cycle Coal-Burning Gas Turbine Power Plants. Journal of Engineering for Power, 88 (4), October 1966.

Spaite, P.W., D.G. Stephen, and A.H. Rose. High Temperature Fabric Filtration of Industrial Gases. APCA Journal, 11, 243, 1961.

Spencer, J.D., T.J. Joyce and J.H. Faber. Pneumatic Transportation of Solids. U.S. Bur. of Mines Information Circular no. 8314, October, 1965.

Spies, R., J.R. Baughman, and J.E.T. Blake. Investigation of Variables in Turbine Erosion, Influence of Aerodynamic and Geometric Parameters. Rocketdyne Report for NASA, contract NAS 7-391, Dec. 1968.

Thomas, G.E. Effectiveness of an Inertial Air Cleaner in Extending Gas Turbine Life in a Dusty Environment. U.S. Army Report no. AR-643, March 1968.

Thomas, J.B., and E. Wong. Experimental Study of DC Corona at High Temperatures and Pressures. J. Appl. Phys. 29 (8): 1226, 1958.

Vandegrift, G., et al. Handbook of Emissions, Effluents, and Control Practices for Stationary Particulate Pollution Sources. Midwest Research Institute report to the EPA for contract no. CPA 22-69-104, 1970.

Vogel, G.J., M. Haas, W. Swift, J. Riha, C.B. Schoffstoll, J. Hepperly, and A.A. Jonke. Reduction of Atmos. Pollution by the Application of Fluidized-Bed Combustion. EPA 650/2-74-057, June 1974.

Vogel, G.J., W.M. Swift, J.F. Lenc, P.T. Cunningham, W.I. Wilson, A.F. Panek, F.G. Teats, and A.A. Jonke. Reduction of Atmos. Pollution by the Application of Fluidized-Bed Combustion and Regeneration of Sulfur-Containing Additives. EPA 650/2-74-104, Sept. 1974.

Vogel, G.J., W.M. Swift, J.C. Montegue, J.F. Lenc, and A.A. Jonke. Recent ANC Bench Scale, Pressurized Fluidized-Bed Studies. In: Proceedings of the 4th International Conference on Fluidized-Bed Combustion, McLean, Virginia, Dec. 9-11, 1975.

Wade, G.L. Particulate Removal from Hot Combustion Gases. In: Proceedings of the 4th International Conference on Fluidized-Bed Combustion, McLean, Virginia, Dec. 1975.

Westinghouse Electric Corporation. Advanced Coal Gasification System for Electric Power Generation. O.C.R. contract no. 14-32-0001-1514, 1972-1975. E.R.D.A. contract no. E(49-18)-1514, 1975 to present.

Westinghouse Electric Corporation, Research and Development Center. Clean Power Generation from Coal, O.C.R. 84, April 1974, NTIS # PB 234-188.

Westinghouse Electric Corporation. Low BTU Gasification of Coal for Electric Power Generation. O.C.R. contract no. 14-32-0001-1512, 1972 - 1973.

Wigton, H.F. Corrosion and Erosion of Gas Turbine Blades. In: Proceedings of the 4th International Conference on Fluidized Bed Combustion, McLean, Virginia, Dec. 1975.

Williams, D.F. Pilot Plant Experiments at the Coal Research Establishment. In: Proceedings of the 2nd International Conference on Fluidized-Bed Combustion, EPA report no. AP-109, October 1970.

Wilson, J.G. The Removal of Particulate Matter from Fluid Bed Catalytic Cracking Unit Stack Gases. APCA Journal, 17, October, 1967.

Wilson, J.S., and D.W. Gillmore. Preliminary Report on Fluid-Bed Combustion of Anthracite Wastes. In: Proceedings of the 4th International Conference on Fluidized-Bed Combustion, McLean, Virginia, Dec. 1975.

Wisdom, J.C. Brown Coal Burning Gas Turbines. The Engineer, p. 328, August, 1958.

Wood, C.D., and C.A. Hafer. Dust Research Studies-Part 1: Mechanisms of Dust Erosion, Part 2: The Study of Sintering of Dust at High Temperatures. U.S. Army Material Command, Report No. AR-572, NTIS # AD 603-798, February 1966.

Wright, S.J. The Reduction of Emissions of Sulfur Oxides and Nitrogen Oxides by Additions of Limestone or Dolomite During the Combustion of Coal in Fluidized Beds. In: Proceedings of the 3rd International Conference on Fluidized-Bed Combustion, EPA 650/2-73-053, Dec. 1973.

Yavorsky, P.M. The Hydrane Process. In: Clean Fuels from Coal. Symposium Papers, IGT, Chicago, Sept. 10-14, 1973.

Yellott, J.I., and P.R. Broadley. Fly Ash Separators for High Pressures and Temperatures. Ind. Eng. Chem. 47 (5): 944, 1955.

Yellott, J.I., P.R. Broadley, and W.M. Meyer. The Progress of the L.D.C.-Alco Coal-Burning Gas Turbine Project, Annual Reports Bituminous Coal Research, Inc., 1945-1958.

Yellott, J.I. and A.D. Singh. Coal as the Fuel for the Gas Turbine. National Engineer, 50, p. 448, 1946.

Zabolotny, E.R., et al. Purification of Hot Fuel Gases from Coal on Heavy Oil. Stone and Webster Corporation Report to the E.P.R.I., November 1974.

TECHNICAL REPORT DATA *(Please read Instructions on the reverse before completing)*		
1. REPORT NO. EPA-600/7-77-071	2.	3. RECIPIENT'S ACCESSION NO.
4. TITLE AND SUBTITLE High-temperature and High-pressure Particulate Control Requirements		5. REPORT DATE July 1977 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) Richard Parker and Seymour Calvert		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Air Pollution Technology, Inc. 4901 Morena Boulevard, Suite 402 San Diego, California 92117		10. PROGRAM ELEMENT NO. EHE623A 11. CONTRACT/GRANT NO. 68-02-2137
12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development Industrial Environmental Research Laboratory Research Triangle Park, NC 27711		13. TYPE OF REPORT AND PERIOD COVERED Final; 5/76-5/77 14. SPONSORING AGENCY CODE EPA/600/13
15. SUPPLEMENTARY NOTES IERL-RTP project officer for this report is Dennis C. Drehmel, Mail Drop 61, 919/541-2925.		

16. ABSTRACT

The report reviews and evaluates high-temperature and high-pressure particulate cleanup requirements of existing and proposed energy processes. The study's aims are to define specific high-temperature and high-pressure particle removal problems, to indicate potential solutions, and to identify areas where current knowledge and data are inadequate. Primary emphasis is on the requirements of processes now being proposed as clean methods for obtaining energy from coal; that is, fluidized-bed coal combustion, coal gasification, and direct coal-fired gas turbines. Also considered are the cleanup requirements and experience of other high-temperature and/or high-pressure processes such as fluid-bed catalytic cracking units, metallurgical furnaces, geothermal power plants, high-pressure pipelines, and magnetohydrodynamic power generation. Current knowledge concerning turbine erosion, corrosion, and deposition problems is also presented.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Air Pollution	Coal	Air Pollution Control	13B	21D
Dust	Fluidized Bed	Stationary Sources	11G	
High Pressure Tests	Processing	Particulate	14B	13H,07A
High Temperature Tests				
Energy Conversion Techniques	Coal Gasification			
	Gas Turbines		10A	13G

18. DISTRIBUTION STATEMENT	19. SECURITY CLASS *(This Report)*	21. NO. OF PAGES
Unlimited	Unclassified	119
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE

EPA Form 2220-1 (9-73)