United States
Environmental Protection
Agency

Office of Air Quality
Planning and Standards
Research Triangle Park NC 27711

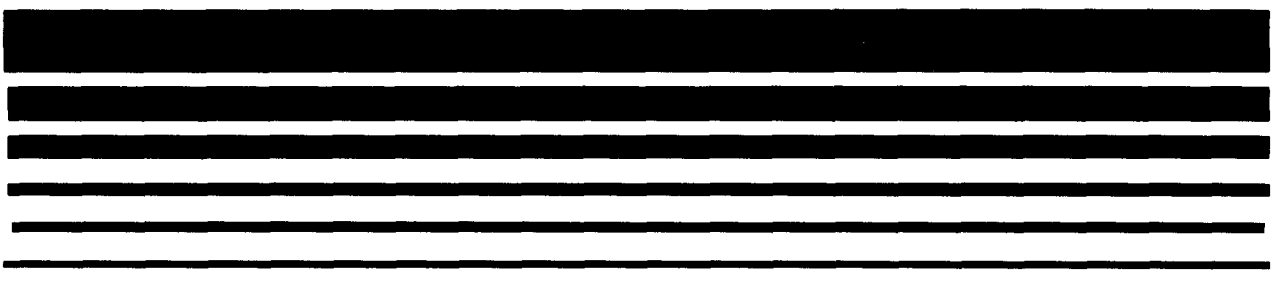
EPA-453/B-94-056
September 1994

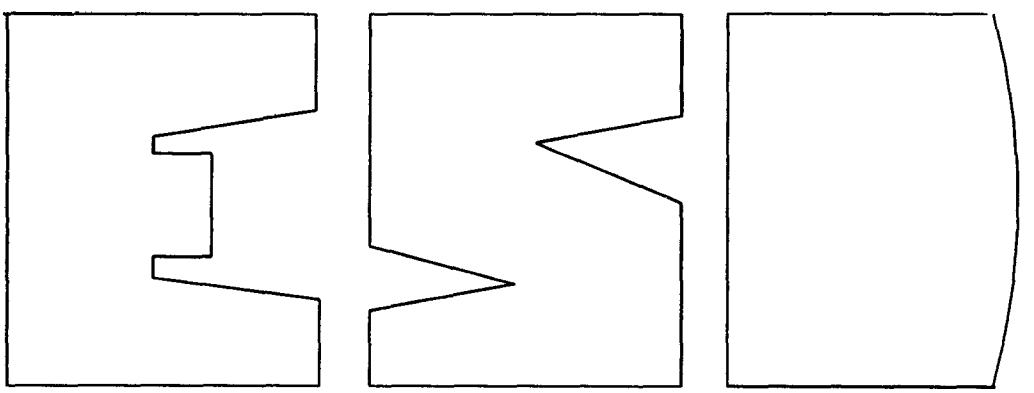
Air

EPA

High Capacity Fossil Fuel Fired Plant Operator Training Program

Student Handbook





EPA-453/B-94-056

HIGH CAPACITY FOSSIL FUEL-FIRED PLANT OPERATOR TRAINING PROGRAM

STUDENT HANDBOOK

U.S. Environmental Protection Agency
Region 5, Library (PL-12J)
77 West Jackson Boulevard, 12th Floor
Chicago, IL 60604-3590

U. S. Environmental Protection Agency
Industrial Studies Branch/ESD
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

September 30, 1994

NOTICE

This Student Handbook is part of a model state training program which addresses the training needs of high capacity fossil fuel-fired plant (boiler) operators. Included are generic equipment design features, combustion control relationships, and operating and maintenance procedures which are designed to be consistent with the purposes of the Clean Air Act Amendments of 1990.

This training program is not designed to replace the site-specific, on-the-job training programs which are crucial to proper operation and maintenance of boilers.

Proper operation of combustion equipment is the responsibility of the owner and operating organization. Therefore, owners of boilers and organizations operating such facilities will continue to be responsible for employee training in the operation and maintenance of their specific equipment.

DISCLAIMER

This Student Handbook was prepared by the Industrial Studies Branch, Emission Standards Division, U. S. Environmental Protection Agency (USEPA). It was prepared in accordance with USEPA Contract Number 68-D1-0117, Work Assignment Number 68.

Any mention of product names does not constitute an endorsement by the U. S. Environmental Protection Agency.

The U. S. Environmental Protection Agency expressly disclaim any liability for any personal injuries, death, property damage, or economic loss arising from any actions taken in reliance upon this Handbook or any training program, seminar, short course, or other presentation based on this Student Handbook.

AVAILABILITY

This Student Handbook and the accompanying Instructor's Guide are issued by the Office of Air Quality Planning and Standards of the U.S. Environmental Protection Agency. These training materials were developed, as required by the Clean Air Act Amendments of 1990, to assist operators of high capacity fossil fuel-fired plants in becoming certified as may be required by state regulatory agencies.

Individual copies of this publication are available to state regulatory agencies and other organizations providing training of operators of high capacity fossil fuel-fired plants. Copies may be obtained from the Air Pollution Training Institute (APTI), U.S. EPA, MD-17, Research Triangle Park, NC 27711. Others may obtain copies, for a fee, from the National Technical Information Service, 5825 Port Royal Road, Springfield, VA 22161.

Although this government publication is not copyrighted, it does contain some copyrighted materials. Permission has been received by the authors to use the copyrighted material for the original intended purpose as described in the section titled Handbook Introduction. Any duplication of this material, in whole or in part, may constitute a violation of the copyright laws, and unauthorized use could result in criminal prosecution and/or civil liabilities.

The recommended procedure for mass duplication of the Student Handbook is as follows:

Permission to use this material in total may be obtained from the APTI, provided the cover sheet is retained in its present form. Permission to use part of this material may also be obtained from the APTI, provided that the APTI and the authors are properly acknowledged.

COURSE HANDBOOK INTRODUCTION

This Student Handbook was developed by the U. S. Environmental Protection Agency (USEPA) in support of improving the air pollution control practices at high capacity fossil fuel-fired plants (boilers). The USEPA was required to develop a model state training and certification program for boiler operators under Title III, Section 129 of the Clean Air Act of 1990.

The training materials are composed of this Student Handbook and an Instructor's Guide which includes the masters for the projection transparencies. State and regional air pollution control agencies are encouraged to use these training materials in their training and certification programs. The materials will also be useful in private entity training programs.

TRAINING PROGRAM GOAL

The primary goal of the training program is to provide an adequate level of understanding to boiler operators to successfully complete the Operator Certification Examination of the ASME Standard for Qualifications and Certification of High Capacity Fossil Fuel-Fired Plant Operators (under development).

The training program focuses on the knowledge required by operators for understanding the basis for proper operation and maintenance of boilers in minimizing air pollutant emissions. Particular emphasis is placed on the various aspects of combustion which are important for environmental control. Fundamental information is related to applications and to the operator's own work experiences.

Participants are encouraged to make comments and ask questions throughout the program, as such discussion will help establish a creative environment for the course.

The program is designed to augment the normal site-specific, on-the-job, and supervised self-study training programs which are typically provided by the vendor, owner, or operating company. The program is not a substitute for such hands-on operator training programs.

TABLE OF CONTENTS

Section	Title	Page
1.	INTRODUCTION	
	1.1 Purpose of Course	1-1
	1.2 Steam Generators	1-2
	1.3 Regulatory Requirements	1-4
	1.4 Course Overview	1-9
2.	WATER AND STEAM CIRCUIT	
	2.1 Steam Fundamentals	2-1
	2.2 Boiler Fundamentals	2-3
	2.3 Water - Steam Circuit	2-6
	2.4 Water Treatment	2-11
3.	COMBUSTION GAS CIRCUIT	
	3.1 Introduction	3-1
	3.2 Combustion Process	3-1
	3.3 Heat Transfer	3-6
	3.4 Combustion Gas Flow Path	3-7
	3.5 Flue Gas Treatment	3-9
4.	FOSSIL FUELS	
	4.1 Introduction	4-1
	4.2 Natural Gas	4-1
	4.3 Fuel Oil	4-6
	4.4 Coal	4-13
5.	COMBUSTION PRINCIPLES	
	5.1 Basic Combustion Concepts	5-1
	5.2 Air-Fuel Mixture	5-2
	5.3 Combustion Equations	5-3
	5.4 Combustion Calculations	5-8
	5.5 Heat Transfer Fundamentals	5-14
6.	AIR POLLUTION FUNDAMENTALS	
	6.1 Introduction	6-1
	6.2 Fuel Dependent Air Pollutants	6-1
	6.3 Combustion Dependent Air Pollutants	6-3
	6.4 Smoke and Particulates	6-3
	6.5 Gas Concentrations	6-5
	6.6 Emission Factors	6-7
	6.7 Correcting Concentrations	6-8
	6.8 Excess Air Calculations	6-15
	6.9 Combustion Efficiency Calculation	6-16
	6.10 Boiler Efficiency Calculations	6-17

TABLE OF CONTENTS (Continued)

Section	Title		Page
7.	NATURAL GAS FIRED BOILERS		
	7.1	Introduction	7-1
	7.2	Fuel Supply System	7-1
	7.3	Burner Arrangements	7-4
	7.4	Boiler Design Parameters	7-12
	7.5	Emissions	7-14
8.	OIL FIRED BOILERS		
	8.1	Introduction	8-1
	8.2	Fuel Supply System	8-1
	8.3	Burner Arrangements	8-7
	8.4	Boiler Design Parameters	8-8
	8.5	Emissions	8-8
9.	PULVERIZED COAL FIRED BOILERS		
	9.1	Introduction	9-1
	9.2	Pulverizing Properties of Coal	9-1
	9.3	Coal Preparation	9-3
	9.4	Methods of Pulverizing and Conveying Coal	9-7
	9.5	Pulverizing Air Systems	9-10
	9.6	Types of Pulverizers	9-12
	9.7	Pulverized Coal Boilers	9-18
	9.8	Emissions	9-24
10.	STOKERS		
	10.1	Introduction	10-1
	10.2	Types of Stokers	10-2
	10.3	Underfeed Stokers	10-2
	10.4	Mass Feed Stokers	10-6
	10.5	Spreader Stokers	10-10
	10.6	Emissions	10-20
11.	FLUIDIZED BED BOILERS		
	11.1	Introduction	11-1
	11.2	Typical Fluidized-Bed Conditions	11-2
	11.3	Fluidized-Bed Combustion Advantages	11-3
	11.4	Atmospheric Pressure Fluidized-Bed Boilers	11-5
	11.5	Fluidized-Bed Boiler Furnace Design	11-7
	11.6	Fluidized-Bed Boiler Arrangements	11-8
	11.7	Operation	11-10
	11.8	Emissions	11-12

TABLE OF CONTENTS (Continued)

Section	Title	Page
12.	GAS TURBINE WITH A HEAT RECOVERY STEAM GENERATOR	
	12.1 Introduction	12-1
	12.2 Gas Turbine Description	12-1
	12.3 Design Classifications	12-4
	12.4 Operating Cycles and Efficiency	12-10
	12.5 NO_x Formation Mechanisms	12-15
	12.6 Control Options	12-19
13.	PACKAGE BOILERS	
	13.1 Introduction	13-1
	13.2 Package Boiler Types	13-1
	13.3 Emissions	13-9
14.	NORMAL OPERATION	
	14.1 Introduction	14-1
	14.2 Maintaining Suitable Combustion Conditions	14-1
	14.3 Monitoring Combustion	14-7
	14.4 Maintaining Steam Temperature and Pressure	14-11
	14.5 Maintaining Suitable Feedwater Conditions	14-12
	14.6 Monitoring the Steam/Water Circuit	14-14
	14.7 Controlling the Steam Temperature	14-15
	14.8 Startup Procedures	14-17
	14.9 Shutdown Procedures	14-20
15.	AUTOMATIC CONTROL SYSTEMS	
	15.1 Introduction	15-1
	15.2 Types of Analog Control Systems	15-1
	15.3 Types of Digital Control Systems	15-3
	15.4 Automatic Control System Elements	15-4
	15.5 Gas-side and Water-side Control Parameters	15-6
	15.6 Single, Two, & Three Element Controllers	15-7
	15.7 Microprocessor Based Control Systems	15-12
	15.8 Control System Applications	15-13

TABLE OF CONTENTS (Continued)

Section	Title	Page
16.	INSTRUMENTATION: GENERAL MEASUREMENTS	
	16.1 Introduction	16-1
	16.2 Pressure Measurement	16-1
	16.3 Temperature Measurement and Equivalence	16-2
	16.4 Level Measurement	16-4
	16.5 Flow Measurement	16-4
	16.6 Weigh Scales	16-5
17.	ELECTRICAL THEORY	
	17.1 Introduction	17-1
	17.2 Fundamental Parameters	17-1
	17.3 Electrical Power Equipment	17-9
	17.4 Instruments and Meters	17-13
18.	TURBINE GENERATOR	
	18.1 Introduction	18-1
	18.2 Steam Turbine Generator Description	18-1
	18.3 Steam Turbine Designs	18-5
	18.4 Steam Turbine Generator Operation	18-8
	18.5 Generator Synchronization Utility Grid	18-10
	18.6 Turbine Generator Off-Nominal Conditions	18-11
19.	PREVENTATIVE MAINTENANCE	
	19.1 Potential Economic Losses	19-1
	19.2 Features of Preventative Maintenance	19-2
	19.3 Periodic Inspections	19-4
	19.4 In-Service Maintenance	19-5
	19.5 Outage Maintenance Planning	19-5
20.	SAFETY	
	20.1 System Safety Hazards	20-2
	20.2 Consequences of Exposure to Hazards	20-5
	20.3 Standard Safety Considerations	20-6
	20.4 Personnel Protection Equipment	20-8
21.	AIR POLLUTANTS OF CONCERN	
	21.1 Introduction	21-1
	21.2 Air Quality Overview	21-2
	21.3 National Ambient Air Quality Standards	21-3
	21.4 Primary Pollutants	21-7
	21.5 Secondary Pollutants	21-12
	21.6 Hazardous Pollutants	21-15

TABLE OF CONTENTS (Continued)

Section	Title	Page
22.	ENVIRONMENTAL REGULATIONS	
	22.1 Regulatory Overview	22-1
	22.2 Provisions of the Clean Air Act Relative to Boiler Operations	22-7
	22.3 New Source Performance Standards	22-9
	22.4 Additional Standards	22-19
	22.5 Permits	22-23
23.	CONTINUOUS EMISSION MONITORING	
	23.1 Statement of Purpose	23-1
	23.2 General Classifications of CEMS	23-1
	23.3 Components of CEMS	23-5
	23.4 Usage of CEMS in Utility/Industrial Boilers	23-7
	23.5 Analytical Methods	23-8
	23.6 Flow Monitors	23-18
	23.7 Opacity Monitors	23-22
	23.8 Maintenance and Continuing Operations	23-24
24.	PARTICULATE CONTROL	
	24.1 Control Methods and Typical Arrangement	24-1
	24.2 Cyclones	24-2
	24.3 Electrostatic Precipitators	24-6
	24.4 Fabric Filters	24-12
25.	NITROGEN OXIDES CONTROL	
	25.1 Nitrogen Oxides Control Overview	25-1
	25.2 NO_x Formation	25-3
	25.3 Control of NO_x Emissions	25-5
26.	SO_x CONTROL	
	26.1 Introduction	26.1
	26.2 Wet Scrubbers	26-2
	26.3 Dry Scrubbers	26-13
	26.4 Furnace Injection	26-19
27.	WATER POLLUTION	27-1
28.	WASTEWATER TREATMENT	
	28.1 Removal of Suspended Solids	28-1
	28.2 Neutralization	28-6
	28.3 Dechlorination	28-8

TABLE OF CONTENTS (Continued)

Section	Title	Page
29.	SOLID WASTES	
	29.1 Introduction	29-1
	29.2 Bottom Ash and Fly Ash	29-1
	29.3 Ash Removal and Handling Techniques	29-3
	29.4 Ash Characterization and Testing	29-8
	29.5 Flue Gas Desulfurization Wastes	29-11
	29.6 Handling of FGD Wastes	29-12
	29.7 Groundwater Contamination from Ponds and Landfills	29-12
30.	SOLID POLLUTION CONTROL	
	30.1 Introduction	30-1
	30.2 Disposal Methods	30-1
	30.3 Wet Disposal – Ponds	30-2
	30.4 Dry Disposal – Landfills	30-3
	30.5 Treatment Methods	30-4
	30.6 Dewatering	30-5
	30.7 Stabilization	30-11
	30.8 Fixation	30-11
	30.9 Utilization	30-12
31.	GLOSSARY	

CHAPTER 1. INTRODUCTION

1.1 Purpose of Course

1.2 Steam Generators

1.3 Regulatory Requirements
- **A. NAAQS**
- **B. NSPS**
- **C. SIPs**
- **D. NESHAPS**
- **E. Clean Air Act Amendments**

1.4 Course Overview

Slide 1–1

1. INTRODUCTION

1.1 Purpose of Course

The operator of fossil fuel-fired boilers has a significant responsibility in assuring that the unit is continuously operated in a manner which complies with the various state and federal regulations. The Clean Air Act Amendments (CAAA) of 1990 require the Environmental Protection Agency (EPA) to "...develop and promote a model State program for the training and certification of ... high-capacity fossil fuel-fired plant operators." The primary purpose of this course is to fulfill the training portion of this requirement.

The course will emphasize the operating principles for all types of boilers and for all types of control equipment used for controlling air emissions from boilers. The course will emphasize the significant operating parameters that directly influence air emissions. The specific objectives of this training course are to:

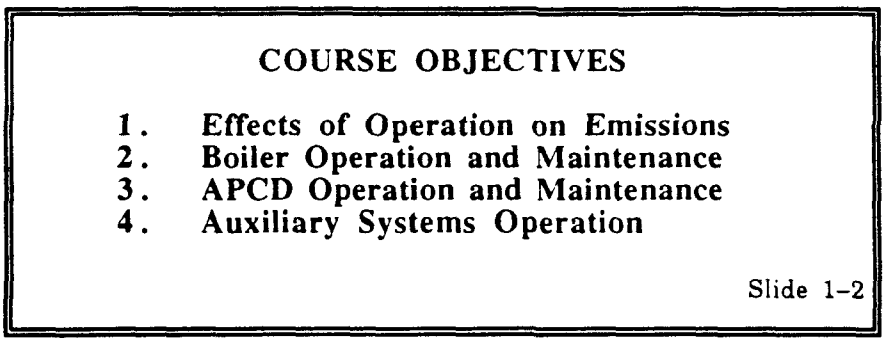
1. Provide boiler operators with an adequate level of understanding on the effects of their actions on the air pollution emitted from the boiler.

2. Provide information for the proper operation and maintenance of the boiler.

3. Provide a knowledge base necessary for the proper operation and maintenance of the associated air pollution control devices (APCD).

4. Provide an understanding to operators in the proper operation of coal, ash, and other auxiliary systems.

This course is intended to be a **supplement** to site specific "hands-on" operator training.



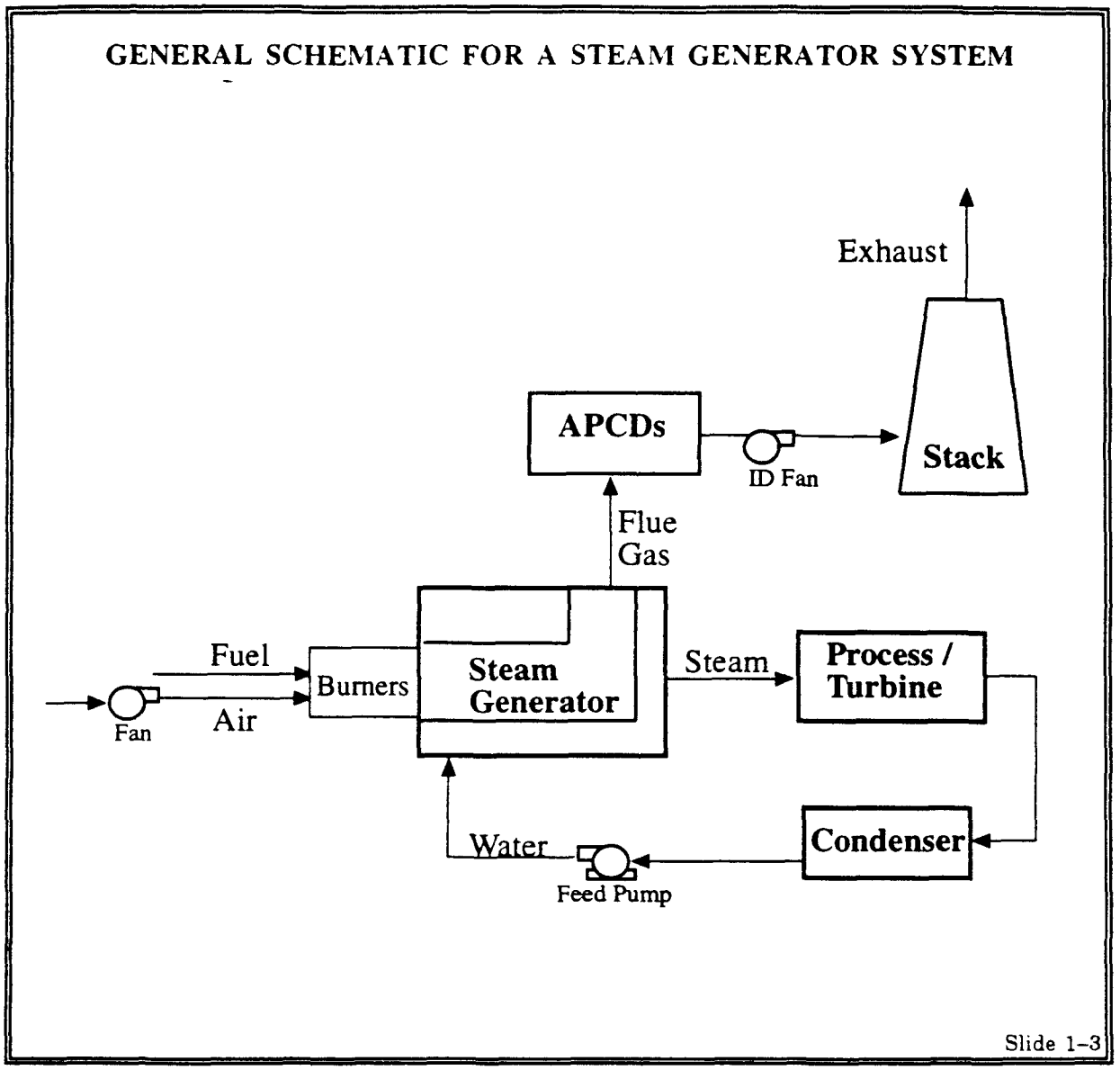
The group of high-capacity fossil fuel-fired plants which will be covered during this course are those boilers defined in the federal regulations as electric utility steam generating units, and industrial, commercial, and institutional steam generating units. This group covers boilers ranging in size from 10 million Btu per hour to the large utility boilers.

1.2 Steam Generators

Steam generators, or boilers, convert chemical energy bound in the fuel to heat water to produce steam. Fuels burned in today's steam plants include coal, oil or natural gas as well as nuclear fuel, and solid and liquid wastes among others. The steam which is generated may be used for electric power generation and industrial process heating, such as food preparation and paper and wood products manufacturing as well as other applications.

There are many types of boiler designs which range in size from those needed to heat a small building to large utility power generating stations. The design of the boiler is dependent on the fuel used. The types of boilers which will be discussed in more detailed throughout this course include natural gas fired, oil fired, pulverized coal, stoker fired, fluidized bed and package boilers.

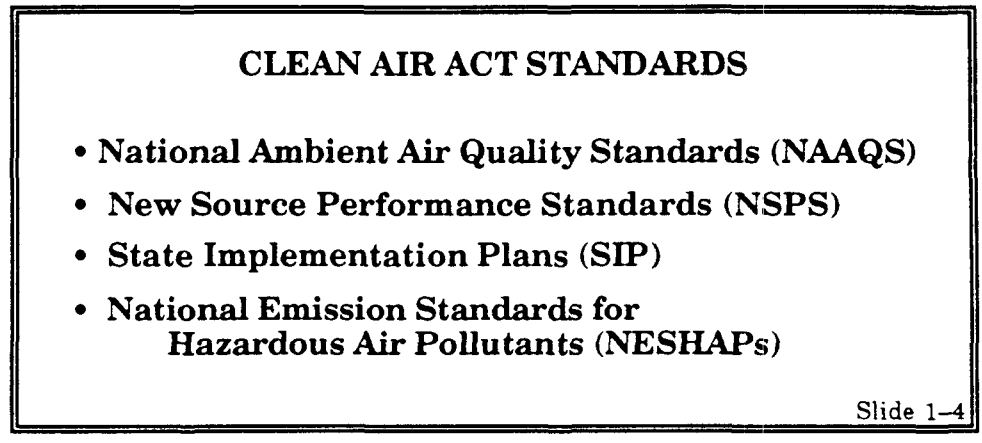
Generally, as shown in slide 1-3, a steam generating system includes a fuel delivery system, burner/combustion system, air/gas handling, steam-water flow system, and flue gas treatment system prior to discharge through the stack. The fuel delivery system prepares the fuel for combustion and transports it to the steam generator. The associated air system supplies air to the burners through a forced draft fan. Within the steam generator, the fuel-air mixture burns. This heat release is captured by the water which flows through tubes exposed to the hot combustion gases and generates the high pressure and high temperature steam. The steam is then supplied to the process or steam turbine generator equipment depending on the application. After the steam has provided the required heat to the process/turbine, the steam is cooled and condensed back to water for return to the steam generator to start the cycle once again. The flue gas leaves the steam generator and passes through air pollution control devices (APCDs). The type of APCDs employed depends on the fuel and boiler design and applicable environmental regulations. The cleaned flue gas is pulled by an induced draft (ID) fan and discharged to the stack.



There are many variations of the schematic shown above and these will be discussed in detail in the following Learning Units on different boiler designs. Today's designs are sophisticated to achieve the maximum level of efficiency. Efficiency is typically measured by the amount of energy produced (i.e. electricity, steam) divided by the amount of energy provided (i.e. fuel). The specific efficiency improvements for each type of boiler design will be discussed in Learning Units 7 through 13.

1.3 Regulatory Requirements

The process of burning fossil fuels creates products of combustion that are released to the atmosphere as flue gas. The air pollutants which are generated by burning fossil fuels include sulfur oxides, particulate matter, nitrogen oxides, hydrocarbons, and carbon monoxide. The impact of each of these pollutants will be discussed in more detail in Learning Unit 21. In the late 1960s, no effective mechanism existed for controlling air pollution so, legislation was developed resulting in the 1970 Clean Air Act which passed as amendments to the 1963 Clean Air Act. The Clean Air Act amendments of 1970 required the Environmental Protection Agency (EPA) to establish ambient standards for certain pollutants to protect and enhance the nation's air resources. The following areas of the Clean Air Act may apply to boiler operation.



National Ambient Air Quality Standards (NAAQS)

The most fundamental of the Clean Air Act regulations are the National Ambient Air Quality Standard (NAAQS) which are directly related to human health. These standards are developed and monitored by the federal EPA and set upper limits on the allowable concentration of various chemical compounds in the local atmosphere. The pollutants regulated are those that have an adverse impact on human health or the environment (i.e., visibility). The ambient concentration limits are established to assure protection of the general population. Pollutants covered by NAAQSs are referred to as "Criteria Pollutants." Of particular significance to fossil fuel-fired boiler operations are the NAAQS limits for the pollutants listed in slide 1-5. NAAQS apply to general geographic areas or basins. The local regulations maybe more strict than the federal regulations depending on the compliance status of the air shed with the federal standards.

NATIONAL AMBIENT AIR QUALITY STANDARDS

Limit ambient concentration of air pollutants

Concentration limits based on health risk data

Covered Pollutants called "Criteria Pollutants"
- **Sulfur Oxides (SO_x)**
- **Nitrogen Oxides (NO_x)**
- **Carbon Monoxide (CO), and**
- **Particulate Matter**

Standards apply to geographical areas or basins

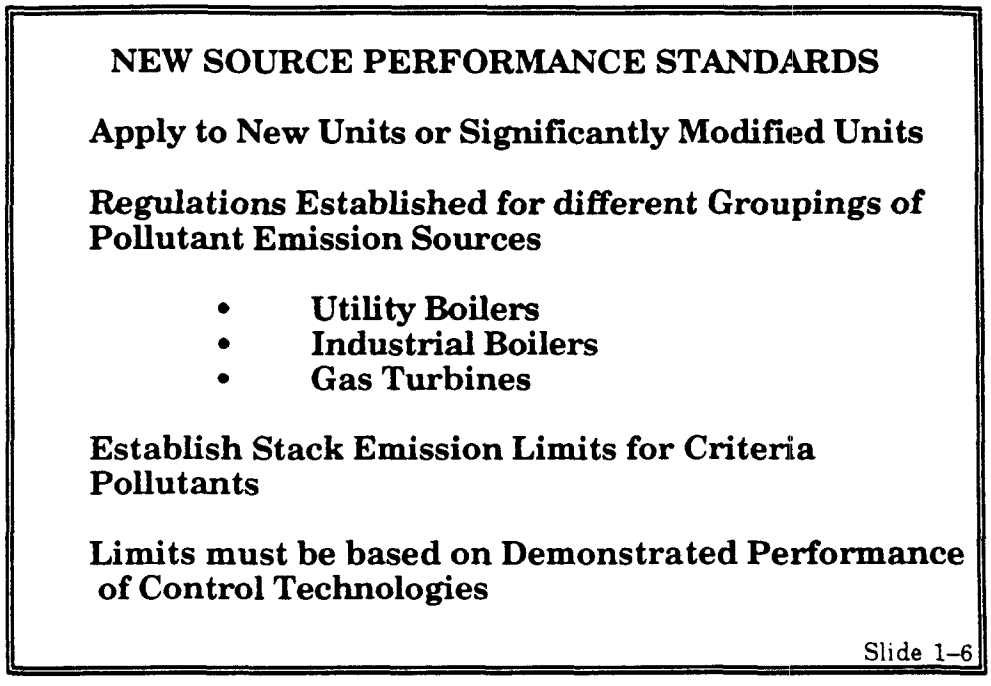
Slide 1-5

New Source Performance Standards (NSPS)

The second type of pollutant regulation of importance to boiler operations are New Source Performance Standards or NSPS. These standards are also developed and administered by the Federal EPA. As the name implies, they apply to "new sources" and establish unit "performance standards" limiting the rate at which pollutants may be emitted from the stack. NSPSs are developed for different groupings of pollutant emission sources including:

- Electric Utility Boilers
- Industrial-Commercial-Institutional Boilers - This grouping includes all non-utility boilers with heat input ratings greater than 100 million Btu per hour.

- Small Industrial-Commercial-Institutional Boilers - This grouping includes all units with heat input rates between 10 million and 100 million Btu per hour.
- Gas Turbines.



For each of these major groupings, the NSPS's establish limits on the stack emission rates or stack concentrations for various NAAQS "criteria pollutants." Thus, there is a direct link between the ambient air quality standards and the new source performance standards. There are, however, important differences in the applicability and the basis for the two types of standards. The NAAQS limits are based on consideration of health effects while the NSPS limits are established based on the best *demonstrated performance* of control technologies on actual units in full-scale operation. As will be discussed in this course, significant differences in pollutant emissions is expected for different types of boilers burning different types of fuels. For this reason, the utility and industrial boiler NSPS set different emission limits for units firing gas, oil, and coal. These regulations are discussed further in Learning Unit 22 on "Environmental Regulations."

The NSPS only apply to newly constructed units (i.e., units constructed after the date of proposal of the NSPS) or to existing units undergoing significant modification. The logic behind this applicability is that boilers have a lifetime of approximately 30 to 40 years. Boilers constructed prior to passage of the original Clean Air Act were exempted from the original NSPS but they were expected to be retired by shortly after the turn of the century. The significant modification provision was included to help assure that old boilers would be retired in an orderly fashion and replaced by new units, subject to the NSPS.

State Implementation Plans (SIPs)

Each state is required to develop a series of State Implementation Plans (SIPs). In broad terms, SIPs are the detailed procedures that a state will use to assure that NAAQS requirements are maintained or the detailed corrective actions that a state will use to bring local areas into compliance. If areas are in compliance, the state has broad flexibility in establishing emission criteria for all source categories. Most states rely on the NSPS for stationary sources and mobile source standards to limit emissions from automobiles. The states may elect to impose more strenuous emission limits than suggested by the federal government. If an area is out of compliance with the NAAQS, a completely different set of emission criteria are imposed. Clearly, any new source represents an additional burden to an ambient air situation that is already considered unacceptable. Accordingly, to add a new source, that source must (1) meet extremely stringent emission control requirements, and (2) the owners must find a way to reduce emissions from an existing source that more than off set emissions from the proposed new unit. Further, to remedy the non-compliance situation in the area, states may require the existing sources to make plant modifications to reduce the emission rate for a particular pollutant.

STATE IMPLEMENTATION PLANS (SIPs)

- **Plans for Implementing the Requirements of the Clean Air Act at the State level.**
- **SIPs provide the road map for States to meet NAAQS**
- **Regulations may apply to New and Existing sources**
- **Regulations may be More Stringent than NSPS**
- **SIPs must be reviewed and approved by Federal EPA**

Slide 1-7

National Emission Standards for Hazardous Air Pollutants (NESHAPs)

The NSPS address the group of criteria pollutants and are only applicable to new sources. There are a variety of pollutants that have been determined to pose immediate health risks to the exposed public. To address this situation, the EPA has authority to develop National Emission Standards for Hazardous Air Pollutants (NESHAPs). The major factors associated with NESHAPs are that these standards are based on acute health risk determinations and they apply equally to all sources covered by the regulations. That is, a NESHAP emission release rate requirement is the same for existing sources and new sources. The 1990 Amendments to the Clean Air Act required the EPA to conduct wide ranging research relative to a group of 189

compounds that are classified as hazardous air pollutants (HAPs). Many of those pollutants are emitted from fossil fuel fired boilers. Those regulations have not yet been enacted but it is likely that in the near future, control of HAP emissions will be a major consideration for fossil fuel fired boiler operations.

Clean Air Act Amendments of 1990

Since the 1970 Clean Air Act gave States unrealistic deadlines for bringing the areas unable to attain the NAAQS into attainment, Congress enacted a nonattainment program in 1977 with strict new requirements for existing and new sources and provided a revised deadline for achieving the NAAQS for those areas not in compliance by the end of 1987. However, by the end of 1987, numerous areas of the country still were not in compliance with the NAAQS. In November of 1990, the Clean Air Act Amendments of 1990 were signed into law as a set of amendments substantially more comprehensive and more complex than the prior Clean Air Act. The amendments include eleven titles. The titles of importance to boiler operation include the following:

Clean Air Act Amendments of 1990
Titles with Impact on Boiler Operation

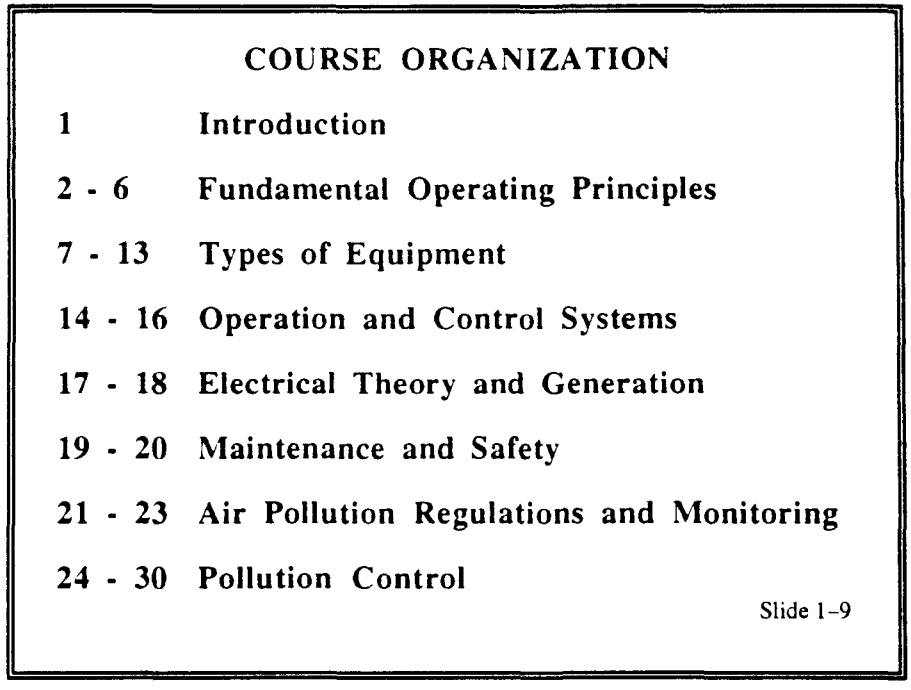
Title I:	**Attainment and Maintenance of NAAQS**
Title III:	**Hazardous Air Pollutants**
Title IV:	**Acid Deposition Control**

Slide 1-8

Under Title I, each state has primary responsibility for assuring attainment of the NAAQS through a state implementation plan (SIP). The SIP can have significant impact on how a boiler is operated. Title III focuses on the identification and control of hazardous air emissions. Thus, the EPA was directed to perform studies on electric steam generating unit emissions to determine the hazards to public health reasonably anticipated to occur as a result of emissions of listed hazardous air pollutants. The results from this study and others may provide the basis for EPA to formulate additional regulations to control power plant emissions. Title IV addresses acid deposition which occurs when sulfur dioxide and nitrogen oxide emissions are transformed in the atmosphere to acids and return to earth as rain, fog or snow. Most of the sulfur dioxide emitted in the U.S. is the result of burning fossil fuels by electric utilities. Therefore, this title contains sulfur dioxide emissions reduction requirements for power plants in a two phase program.

1.4 Course Overview

This course is divided into thirty individual learning units each designed to present the given topic within a 45 to 90 minute class. After the course introduction, the course content includes a review of the boiler characteristics, fuel properties, combustion principles and air pollution fundamentals. The next group of topics addresses typical boiler designs. Next, a discussion of normal operation and process control systems is included with an emphasis on the effects of operation on air pollutant emissions. Learning units are presented on electrical theory and generation since most of the larger boilers are in service to generate electricity. The maintenance and safety in operating all components of the power plant are discussed in the next two units. The remaining units address the pollution regulations, monitoring and emission control.



REFERENCES

1. Moyer, C. and Francis, M., *Clean Air Act Handbook: A Practical Guide to Compliance*, Clark Boardman Company, 1991.

2. *Steam, Its Generation and Use*, 40th Edition, Babcock and Wilcox Company, 1992.

3. Elliott, Thomas C., *Standard Handbook of Powerplant Engineering*, McGraw-Hill Publishing, 1989.

CHAPTER 2. WATER AND STEAM CIRCUIT

2.1. Steam Fundamentals

2.2. Boiler Fundamentals

2.3. Water - Steam Circuit
- A. Circulation
- B. Water-Side Components
- C. Steam-Side Components

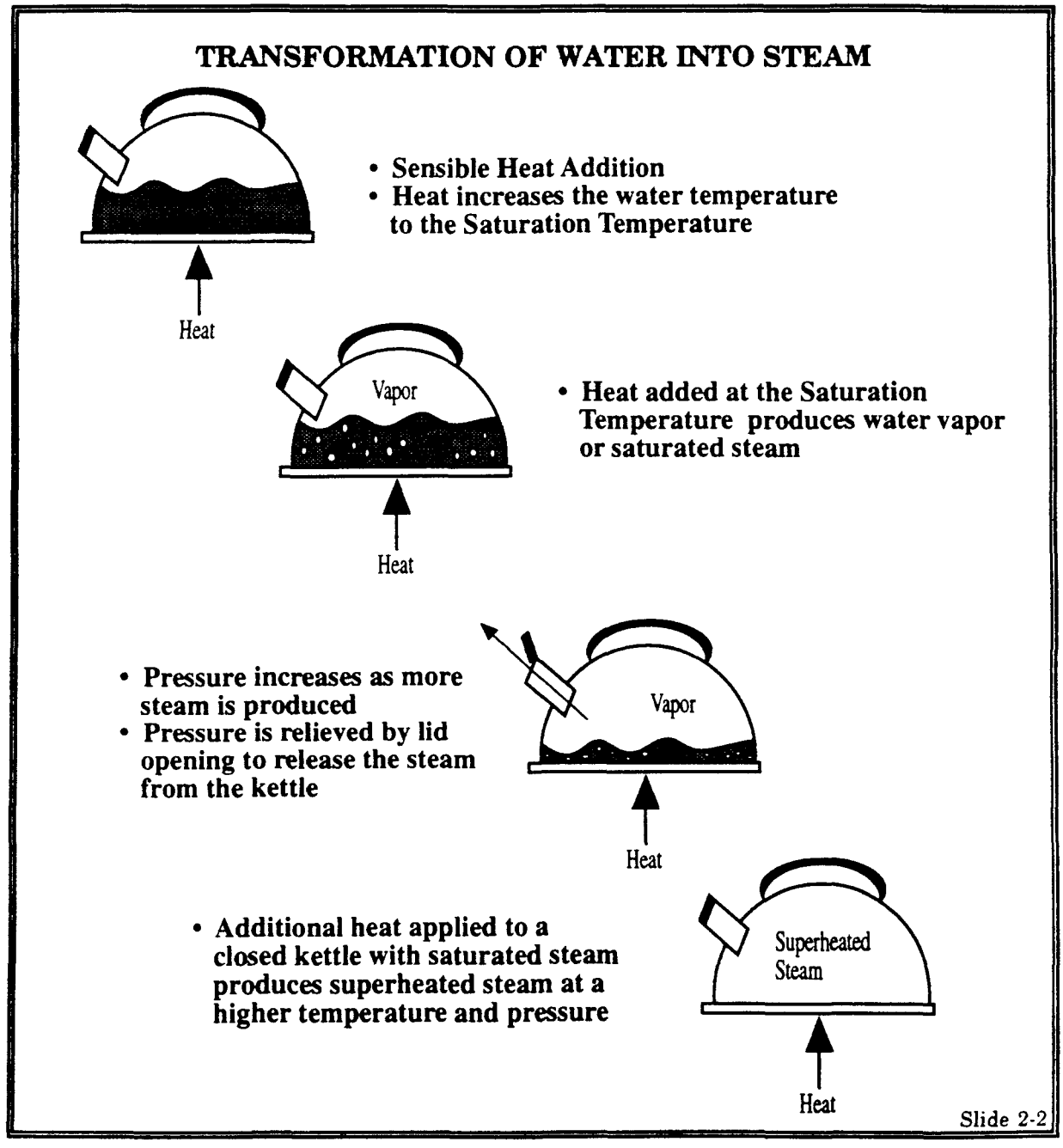
2.4. Water Treatment
- A. Mechanical Treatments
- B. Chemical Treatments

Slide 2–1

2. WATER AND STEAM CIRCUIT

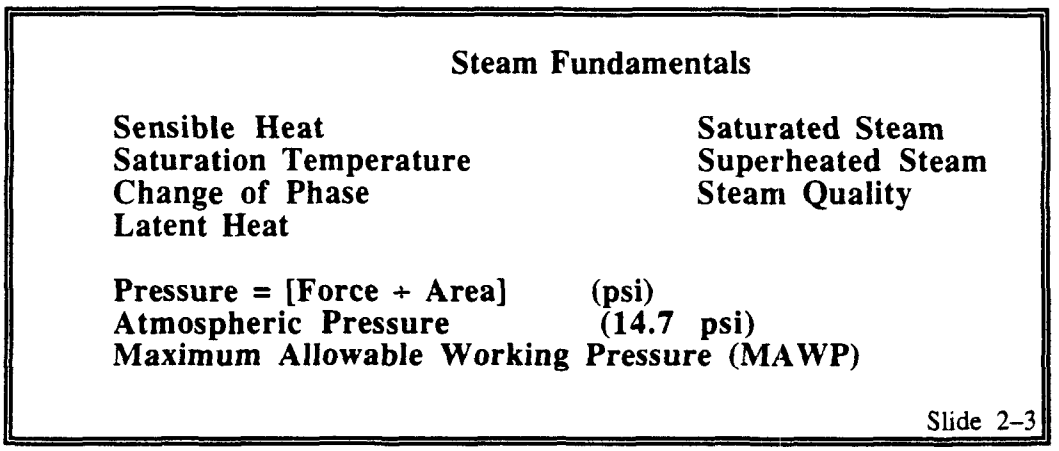
2.1 Steam Fundamentals

Steam is created when enough heat is added to water to bring it to a boil and thus vaporize the water. A good example to illustrate the properties of steam is the boiling of water in a tea kettle.



As heat is applied to the tea kettle, the water temperature increases. Heat applied which results in a change in temperature is known as **sensible heat**. When the temperature approaches the boiling point or **saturation temperature** (212°F at one atmosphere of pressure), the addition of more heat results in a **change of phase**. That is, some of the liquid becomes water vapor. This amount of heat added to change a liquid at saturation temperature into a gas is known as **latent heat**. The temperature at which water boils depends on the surrounding pressure. For example, at high altitudes, the pressure of the surround air is less than at sea level, therefore water boils at a lower temperature that 212°F at higher elevations. During boiling, the temperature remains constant and there is a mixture of water and steam. The steam produced under these conditions is defined as **saturated steam**.

As steam is produced, the steam expands into the empty space above the water in the kettle. As more steam is produced the space above the water becomes filled and the pressure inside the kettle rises due to the force produced by the steam continuing to try expand against the kettle walls. (**Pressure** is defined as force exerted on an area and is measured in pounds per square inch or psi; one atmosphere is 14.7 psi) This pressure is relieved when the lid of the kettle opens and provides a path for the steam to exit the confined space inside the kettle.



If the kettle was not able to vent the steam, the pressure inside the kettle would continue to rise as more steam is generated. The tea kettle would then be considered a pressure vessel. As the pressure increases, the saturation pressure also increases. When the last drop of liquid has vaporized, the continued addition of heat would result in an increase in both temperature and pressure within the kettle. At this point the contents of the kettle would be defined as **superheated steam**.

At very high pressures, a point is reached where water no longer exhibits boiling behavior, this pressure is known as the **critical point** (3208 psi, 705°F). Heat addition no longer results in the typical boiling process where there is an exact division between steam and water. Rather, as the fluid is heated at this high pressure it passes through a point at which the properties of the water change from those of a liquid to those of a gas (steam). Boilers which operate at or above the critical

pressure are known as supercritical boilers; all others are known as subcritical.

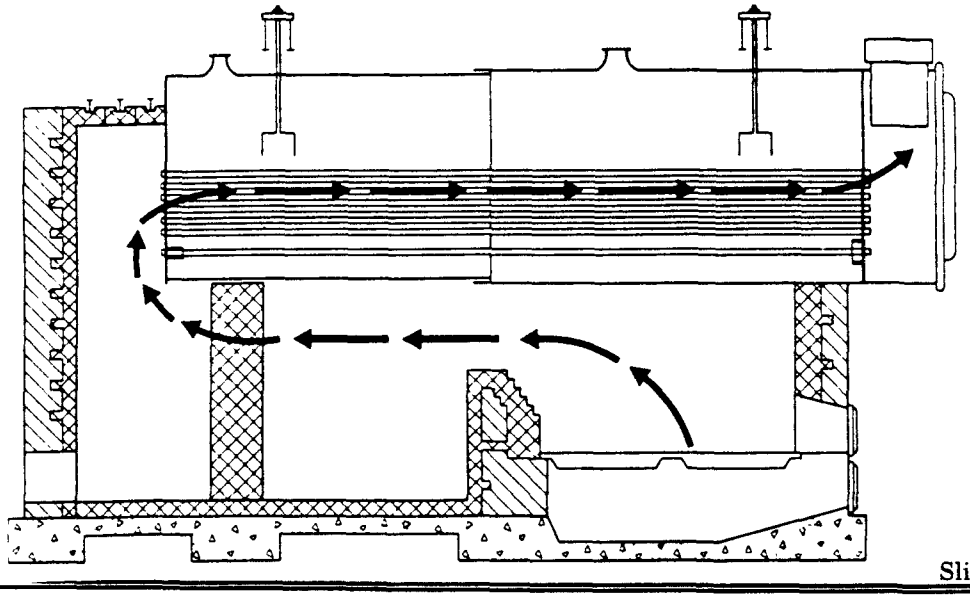
In reality, the tea kettle construction would probably not be able to withstand the higher pressure and would result in a failure of the tea kettle (i.e. bursting apart). To prevent this type of failure with boilers, boilers are rated to a **Maximum Allowable Working Pressure** (MAWP) which is the highest pressure at which the boiler may be operated. According to ASME code, boilers are typically design to withstand four times the rated pressure. Similar to the tea kettle lid, boilers are fitted with safety valves which keep the boiler from exceeding its MAWP in order to maintain a safe operating environment.

The steam produced by a boiler is measured in terms of **quality** which refers to the dryness of the steam. As steam flows, moisture may be carried along or entrained by the steam flow. Pure steam, 100% quality, contains no moisture. So, if the quality of steam is 92%, it contains 8% moisture. Steam that contains any moisture is called wet steam. Superheated steam has a quality of 100% (dry steam) which is a valuable characteristic to help eliminate condensation in the steam lines which results in delivering less steam to the end user.

2.2 Boiler Fundamentals

By definition, a boiler is a closed vessel in which water under pressure is transformed into steam by the application of heat. Boilers come in a variety of sizes, configurations, and designs. The steam temperature and pressure for different boiler applications can have a significant impact on design as will be discussed later in Learning Units 7 through 13. As a brief overview of boiler design, the two common boiler design categories are the watertube boiler and firetube boiler.

FIRETUBE BOILER[1]

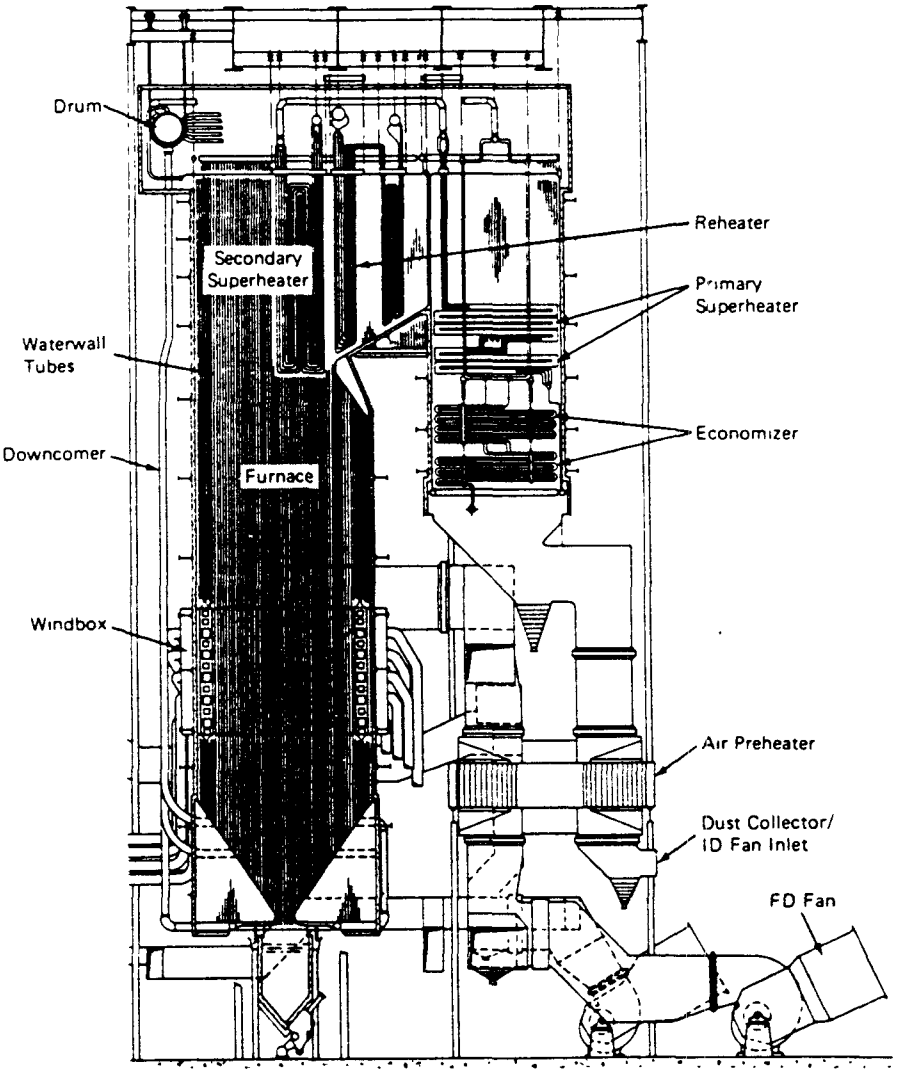


Slide 2–4

The firetube boiler can be simply described as a water-filled cylinder with tubes running though it which provide the escape path for the combustion gases or flue gas. As the flue gas passes through the tubes, the hot gases heat the tubes which in turn heat the water to produce steam. The firetube boiler is primarily used in industrial applications and will be discussed in more detail in Learning Unit 13.

The more complicated watertube boiler is used in large industrial applications and utility powerplants and therefore will be the focus of this discussion and Learning Units 7 through 11.

WATERTUBE BOILER[3]



Slide 2–5

Generally, the boiler can be physically divided into two sections, the furnace and the convection pass. Furnaces (fireboxes, combustion chambers) will vary in configuration and size, but their function is to contain the flaming combustion gases and transfer the heat energy to the water-cooled walls. The convection pass contains the *superheaters, reheater, economizer* and *air preheater* heat exchangers where the heat of the combustion flue gases is used to increase the temperature of the steam, water, and combustion air.

CONVECTION PASS COMPONENTS

Superheaters
Reheater
Economizer
Air Heater

Slide 2–6

The *superheaters* and *reheaters* are designed to increase the temperature of the steam generated within the tubes of the furnace walls. Steam flows inside the tubes and flue gas passes along the outside surface of the tubes.

The *economizer* is a counterflow heat exchanger designed to recover energy from the flue gas after the superheater and the reheater. The boiler economizer is a tube bank type, hot-gas-to-water heat exchanger. It increases the temperature of the water entering the steam drum. The tube bundle is typically an arrangement of parallel horizontal serpentine tubes with the water flowing inside but in opposite direction to the flue gas. Tube spacing is as small as possible to promote heat transfer while still permitting adequate tube surface cleaning and limiting flue gas side pressure loss. By design, steam is usually not generated inside these tubes.

The *air heater* is not a portion of the steam-water circuit, but serves a key role in the steam generator system heat transfer and efficiency. In many cases, especially in a high pressure boiler, the temperature of the flue gas leaving the economizer is still quite high. The air heater recovers much of this energy and adds it to the combustion air. Heating the combustion air prior to its entrance to the furnace reduces fuel usage.

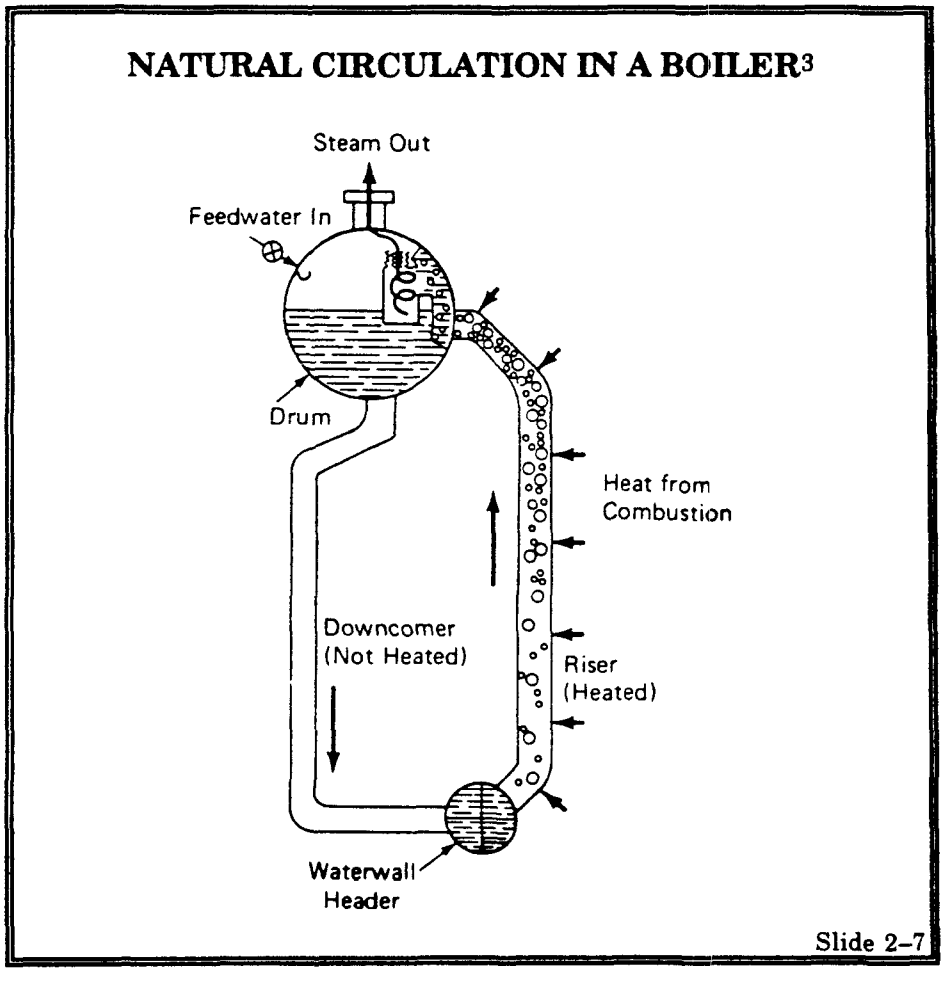
Functionally, a boiler has two separate but interactive circulation circuits - the water-steam circuit and the combustion gas circuit. The combustion gas circuit will be discussed in detail in the next Learning Unit (#3). The water-steam circuit usually includes the furnace enclosure walls, steam drum and steam-water separation, and associated connecting piping (downcomers, supplies and risers). The next section provides a more detailed discussion on the operation of the steam-water circuit.

2.3 Steam- Water Circuit

The discussion of the steam-water circuit will first cover the overall circulation followed by a description of the components on the water and steam side of the circuit.

Circulation

For the boiler to generate steam continuously, water must be circulated through the tubes. Two different approaches are commonly used, natural or thermal circulation, and forced or pumped circulation. Natural circulation consists of half of the circulation loop being heated, a steam-water separation device or steam drum, and a non-heated second half of the circulation loop as shown in Slide 2 - 7.



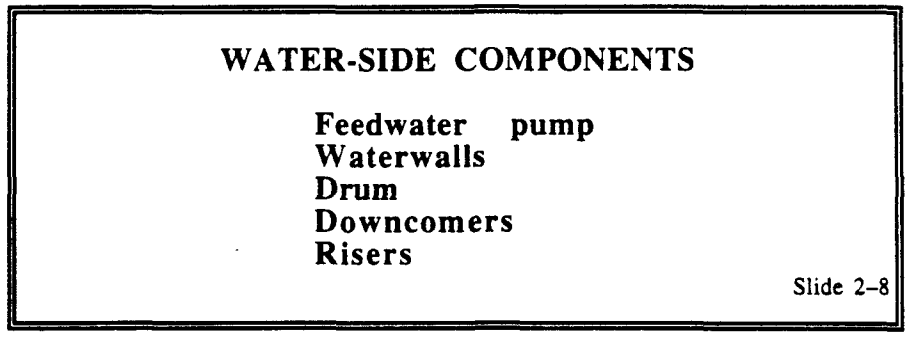
As the water in the waterwalls is heated, it rises due to the difference in density between water at different temperatures. Hot water is lower in density than cool water. Therefore, the hotter water in a boiler will rise toward the surface of the water while the cooler water will descend toward the bottom of the boiler. As the water changes phase into steam, the steam naturally expands and rises in the tubes. When

the steam flows up the tubes some of the hotter water is entrained in the steam. This steam-water mixture rises to the steam drum where the steam and water are separated. From the steam drum, gravity will cause the water to flow downward through the downcomer section. The rate of water flow depends on the difference in average density between the water in the downcomer and the steam-water mixture in the waterwall tubes. The density difference is a function of boiler height and boiler operating pressure. The greater the height of the boiler, the greater the difference in pressure between the bottom and top of the boiler. In some applications, the pressure difference is not adequate to produce the water flow rate required. In these cases, forced circulation is required. Forced circulation adds a mechanical pump to the flow loop to control the water flow rate.

In addition to natural and forced circulation, there are two other common boiler circulation configurations. The once-through system provides continuous evaporation of water to 100% steam without the need for water separation. This design uses forced circulation for the necessary water flow. This is a common configuration for supercritical boilers. The other circulation configuration is a combination of the once-through and recirculation. At low loads, recirculation maintains the necessary water flow to cool the tube walls while at high loads, high pressure once-through operation enhances cycle efficiency.

Water-Side Components

The water-side components of the steam-water circuit include the feedwater pump, waterwall tubes, drum, downcomers, and risers. Boiler feedwater is the water added to a boiler to replace evaporation and other losses. In many cases, steam is condensed and returned to the boiler as part of the feedwater. The water needed to supplement the returned condensate is known as "make-up" water. The feedwater is composed of this make-up water and returned condensate for recirculating systems.



In forced circulation systems, the boiler **feedwater pump**, as the name implies, pumps water to the boiler. It maintains the water level and flow required in the boiler and therefore the pressure of the steam. The water flow is controlled by different methods: A constant speed driver (A.C. motor) with a flow regulating valve or a variable speed driver (turbine and/or variable speed coupling) with or without a flow regulating valve. The water is generally pumped through feedwater heaters to the boiler economizer and then on to the boiler steam drum through **risers**.

Furnace walls or **waterwalls** are typically constructed of tubes arranged side-by-side. Some waterwalls may be coated with refractory to protect the tube metal from corrosion and/or overheating. Generally, over half of the heat generated in the combustion process is absorbed by the water in the waterwall tubes.

The steam **drum** is a large cylindrical vessel at the top of the boiler in which saturated steam is separated from the steam-water mixture leaving the boiler tubes. Drums can be quite large with diameters of 3 to 6 ft and lengths approaching 100 ft. The functions of the steam drum include housing the steam-water separation equipment, purifying the steam, mixing the replacement feedwater and chemicals, and returning the near saturated water back to the inlet of the boiler tubes.

Boiler water carryover is the contamination of steam with boiler water solids. There are several common causes of boiler water carryover include foaming, priming and leakage. Foaming results from very high concentrations of solids in boiler water such as oils, greases, and suspended solids. Priming is a sudden surge of boiler water caused by a rapid change in load, similar to the effects produced by uncapping a bottle of charged water. Steam contamination may also occur from leakage of water through improperly designed or installed steam-separating equipment in the boiler drum. The best prevention against carryover is to maintain the concentration of solids in the boiler water at the recommended levels.

Water supply to the waterwall is from the steam drum through large diameter pipes which are unheated and are referred to as **downcomers**. The downcomers bring water which is close to saturation temperature to the lower waterwall headers. Headers are the main lines to which the bottom of each watertube is connected.

It is not possible to describe the many various configurations of furnaces or boilers since each manufacturer or designer has preferences and/or design variations because of economics, fuel, desired efficiency, controllability, and a multitude of other reasons. However, all furnace and boiler manufacturers follow the same basic principles.

While discussing circulation, it should be pointed out that flow through a tube located in a high temperature area is what prevents the tube from failure due to overheating of the tube metal. It is difficult to visualize 1,000 °F steam cooling the tube in which it is flowing, but that is what happens in a superheater with an upper metal temperature limit of approximately 1,070 °F located in a hot gas stream of 1,200 ° to 1,500 °F. The flow rate and the allowable temperature increase must be high enough to remove the heat absorbed by the tube external surface. This condition exists in the furnace probably to a higher degree as temperature in the combustor zone can easily exceed 2,000 °F and the tube material is carbon steel with an upper temperature limit far below this temperature.

Overheated tube metal is a major cause of forced boiler outages. The primary reason for overheated tubes is firing with no water or low water levels in the boiler, inadequate flow for the firing rate, or a scale build-up inside the tubes which prevents heat transfer from the tube metal to the water or steam flowing through the tube.

The first two reasons can be eliminated by following established operating procedures. Scale build-up on the inside surface of tubes can be controlled by the use of proper water treatment techniques for the boiler water. Periodic inspections and cleaning of internal tube surfaces is a necessary maintenance practice for all boilers.

Steam-Side Components

The primary components of the steam-side of the steam-water circuit may include the steam drum, superheaters, reheaters, desuperheaters, and safety valves.

STEAM-SIDE COMPONENTS

Steam Drum
Superheater
Desuperheater
Reheater
Safety Valves

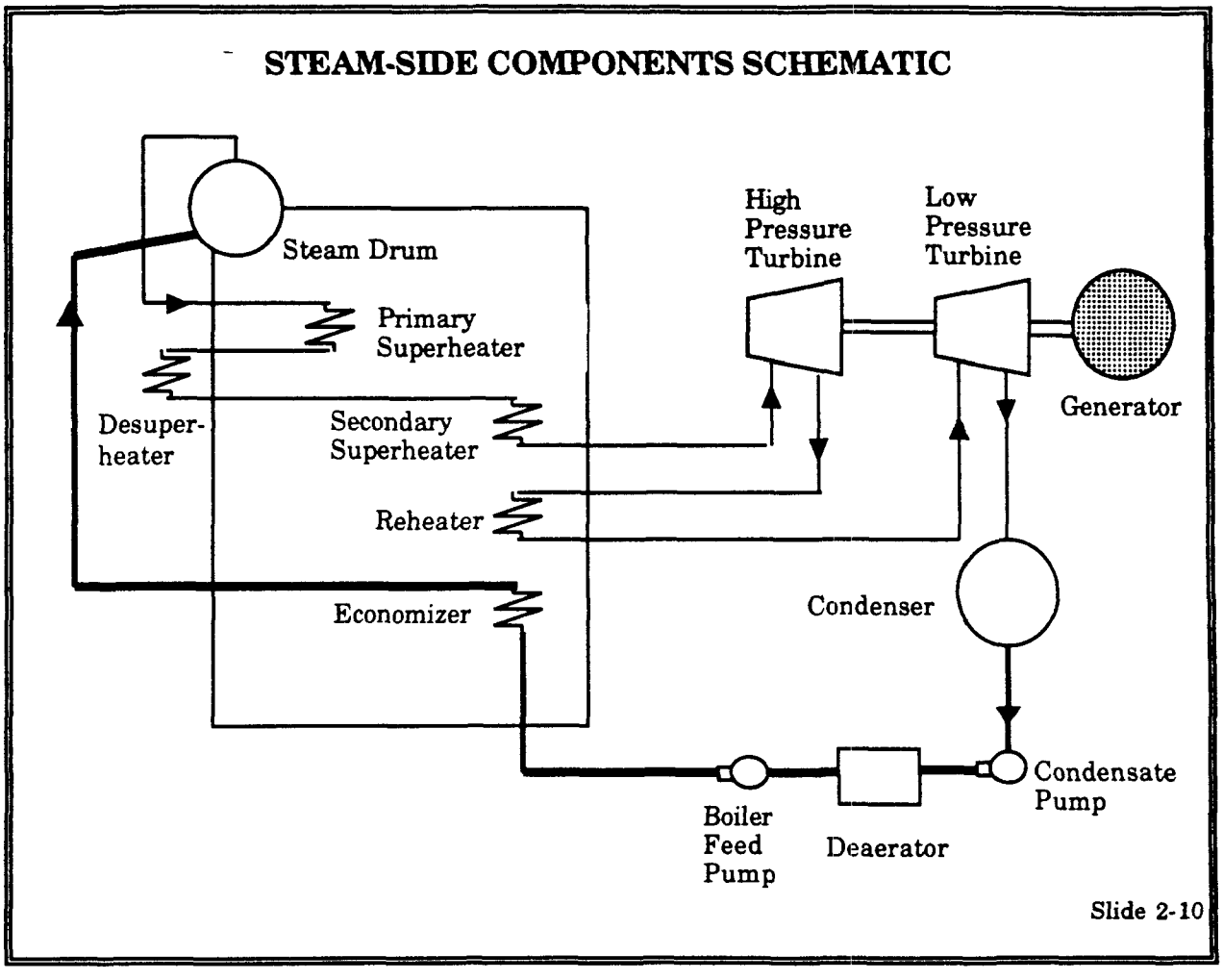
Slide 2–9

The **steam drum** serves three functions. The primary function of the drum is to separate steam from the boiler water. Secondly, the apparatus used to purify the steam is housed in the drum, and to a lesser degree the drum serves as a small water storage area for water level in the boiler.

The drum contains various arrangements of baffles and different configurations and types of moisture separators. The purpose of this equipment is to remove as much as possible of the solid impurities and water droplets from the steam before it leaves the drum. Any liquid carried over in the steam will contain impurities which become solids when the moisture is evaporated in the superheater. The solids in the steam flow are undesirable because of damage that they can cause to turbines or other steam-driven equipment.

Some plants use the steam in the state that it leaves the drum for their process; these are referred to as saturated steam plants. Most plants will dry or superheat the stream to some degree before use by passing it through one or more stages of the tube bank type heat exchangers in the boiler.

Steam to be superheated is routed from the drum through various tube arrangements to the primary **superheater** located in the hot gas passage upstream of the economizer. Depending on the boiler design and the end use of the steam, the steam may go to a secondary superheater located in a higher temperature zone of the furnace. A typical arrangement of the steam circuit with a primary and secondary superheater is shown in Slide 2-10. The final stage of superheat is the high temperature, which is referred to as "Radiant" or secondary superheater, as shown in Slide 2-5, since it is exposed to the radiant heat of the furnace as well as the conductive heat from the hot gases.



The final steam outlet temperature may be controlled by several methods involving firing and gas flow control, however, in many boilers a **desuperheater** is employed. Desuperheating is the reduction of temperature in superheated steam by spaying water into the flue gas either ahead of or behind a superheater or reheater section. Another method of reducing or controlling the steam temperature is by diverting the steam through a bank of tubes submerged in boiling water which absorb part of the energy from the steam.

The steam produced by the boiler is used for many purposes. Typically, the large high capacity boilers are used to supply steam for turbine driven electric power generators. The steam is expanded through the turbine, which converts the heat energy to rotational energy and then electrical energy. The steam, then at a low temperature and pressure, enters the condenser where it is condensed by cooling water from a river, lake, or cooling tower. The condensate is then pumped by condensate pumps through a train of feedwater heaters to the boiler feedwater pumps. Some plants use a reheat cycle in which the high temperature superheater

outlet steam goes through the High Pressure (HP) section of the turbine and returns to the boiler reheater to be reheated before going through the Intermediate Pressure (IP) and/or Low Pressure (LP) turbines. The steam generator reheaters are located and function in basically the same manner as the superheater.

The boiler water/steam circuit is a large capacity pressure vessel that has a vast amount of stored energy which must be and generally is very well controlled. To limit the internal pressure in the boiler one or more **safety relief valves** are installed on a boiler. In the strictest definition a safety valve is used for gas or vapor service, a relief valve is used primarily for liquid service, and a safety relief valve may be suitable for use as either a safety or a relief valve.[6] These valves open at a preset pressure and then close when the pressure drops below this pressure. These valves are generally located on the drum, superheater outlet and reheater inlet.

2.4 Water Treatment

Boiler feed water quality directly affects the life of the boiler tubes. The accumulation of deposits carried in by the feed water onto pipes and equipment surfaces can (1) impair heat transfer and fluid flow, and (2) contribute to the corrosion of metal surfaces which degrades system and equipment reliability. These deposits form an insulating layer on the metal heat-transfer surfaces, reducing the efficiency of heat transfer. At points of inefficient heat transfer, tube temperatures can rise above design limits creating a point of metal stress. As deposits continue to accumulate, fluid flow may become restricted and can lead to plugging of water tubes. Underneath the deposits, highly corrosive conditions can exist.

Treatment of water for steam generation is necessary to preserve the boiler components as well as steam purity. The purpose of this section is to introduce the typical impurities in the boiler water and the water treatment techniques. The pressure and design of a boiler determine the quality of water it requires for steam generation. The water quality of the boiler feed water and the boiler discharge water will depend upon the original source of the water as well as the nature of any preceding treatment process steps. Described below are the various sources of contamination for these water streams.

WATER IMPURITIES AND MEASUREMENTS

Dissolved Solids
Dissolved Gases
Suspended Solids
Hardness
pH

Slide 2-11

There are three basic classifications of impurities found in natural water; dissolved solids, dissolved gases, and suspended solids. **Dissolved solids** are impurities that have passed into solution. Dissolved solids exist in natural water even though they are not visible. Examples of solids that dissolve in natural water include calcium, silica, and iron. **Dissolved gases** may be released through processes like deaeration. Examples of gases that may be dissolved in natural water include oxygen, carbon dioxide, and hydrogen sulfide. **Suspended solids** are impurities that do not pass into solution. Suspended solids are visible in natural water and may include algae, other organic substances and silt.

The most detrimental natural elements in the formation of scale deposits in the boiler are calcium and magnesium. The **hardness** of water is the measurement of these minerals in parts per million (ppm). A level of 0 ppm of calcium and magnesium is desirable, but typical boiler water hardness ranges from 0.005 ppm to 1 ppm.

Another measure of the quality of the feedwater is the **pH**, which represents how acidic or alkaline (basic) water is. The pH scale ranges from 0 to 14 with 0 being the most acidic and 14 the most alkaline. Corrosion will attack the boiler metal below a pH of 7.0. Since boiler metal plate thickness is reduced by corrosion, the pH specifications for most steam boilers is set between 8.0 and 10.0. However, alkaline conditions which do exist at this level are conducive to scale formation, but this can be counteracted with chemicals. Therefore, as a safety buffer against corrosion, slightly alkaline water is recommended by boiler manufacturers. The use of boiler chemicals and boiler blowdown helps control pH. Boiler blowdown is the discharge of water containing concentrated dissolved and suspended solids. As blowdown water is replaced with feedwater, the boiler water is diluted. By regulating the amount of blowdown, the amount of solids in the boiler water can be controlled.

Mechanical (Physical) Treatments

Mechanical treatments include very commonly known devices such as filters and sedimentation tanks. Various types of pollutants including floating debris, suspended solids and dissolved solids and gases can be removed by physical means. Slide 2-12 lists some of the mechanical water quality treatments typically employed at an industrial or utility boiler.

Debris, usually found in water from a natural supply, must be removed before the stream can be used. Foliage (leaves, twigs, etc.), animal debris, and other organic matter can be quite abundant in water from lakes or river. Such contaminants must be removed to avoid clogging of water flow lines. This is effectively accomplished by crude devices such as rakes and flow diversion gates.

Suspended solids are removed through clarification and filtration. Both processes are commonly used as a **pretreatment** of boiler feed water, and, if required, the same techniques can be used to treat waste water discharge. **Clarification** is the removal of large suspended solids and sediments. Large suspended particles settle out of the water stream, leaving the remaining water clear. Sedimentation is the specific use of gravity to settle out particles, thereby clarifying

MECHANICAL WATER TREATMENTS

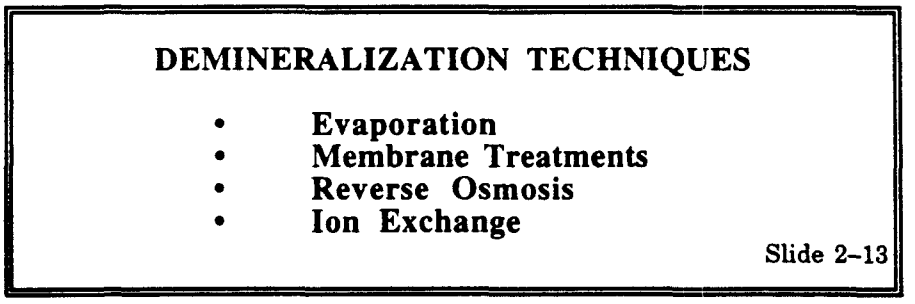
Technology	Primary Application	Devices
Pretreatment	Removal of debris	Rakes, gates
Cooling	Regulation of water temperature	Cooling tower, canals
Clarification	Removal of large suspended matter	Sedimentation tanks, horizontal clarifier tanks, vertical clarifiers
Filtration	Removal of remaining suspended matter	Screens, beds of rigid or granular material
Aeration	Removal of dissolved iron & manganese	Rotor brush aerators, aerator towers
	Stripping of dissolved gases (CO_2, H_2S)	Rotor brush aerators, aerator towers
Demineral-ization	Removal of remaining dissolved matter	Flash distillation units, semipermeable membranes, reverse osmosis unit, ion exchange resins

Slide 2-12

the water. Typical devices include sedimentation tanks, horizontal tank clarifiers, and vertical clarifiers. **Filtration** is the removal of fine residual suspended solids. A filtration system consists of two parts; filtration and backwashing. Filtration is the passing of water through a filter medium. After the media has been saturated with the contaminants, the filter is backwashed to remove the material. Screens, beds composed of granular material, and cloth can all be used as filtration devices.

Dissolved gases are removed from water streams by oxidation. Oxidation is a chemical reaction that increases the oxygen content of a compound (usually changing a compound to its oxide form). This treatment makes use of the addition of oxygen (O_2) to convert soluble gases (and some dissolved solids) to their insoluble oxide form. The addition of O_2 is accomplished by a process called **aeration**. Aeration has two primary applications. One is the oxidation of dissolved iron and manganese to form insoluble hydroxides. Precipitated at proper pH levels, these can be settled or filtered out. The second use is for the stripping of dissolved gases like hydrogen sulfide and CO_2 from solution. Aeration devices include degasifiers and decarbonators. In these devices, aeration is performed by allowing air bubbles to diffuse upward through water in a holding tank. Air flows countercurrent to the downflowing water allowing O_2 in the air to come in contact with the soluble gases in the water. The dissolved gases are stripped from the water and both the air and the stripped gases are vented out the top of the tank.

Demineralization is the removal of soluble solids such as manganese and calcium from the water stream. For boiler feed water, demineralization has become an industry standard. Most other boiler feed water treatments are merely steps applied to remove the bulk of troublesome solids, ions, gases that can interfere with demineralization operations, reducing its effectiveness and throughput of high quality water. Demineralization is accomplished by the use of evaporation, membrane treatments, reverse osmosis and ion exchange.



Evaporation is the application of heat to cause a change of phase, producing a vapor free of dissolved and suspended solids in the feed water; condensation of the vapor produces a considerably purified product. There are numerous devices which utilize evaporation.

Membrane treatment is the separation of pollutants from a pressurized fluid by semipermeable membranes. Membrane treatments can be one of two approaches; cross flow filtration or electrodialysis. Cross flow filtration differs from

filtration in that the direction of flow need not be head on to the filter. A membrane material, usually a polymeric material, applied to a surface is able to hold on to particles as the fluid stream moves along parallel to the surface. In electrodialysis pollutants are moved away from the water through the application of an electric filed to the fluid. Here, an electric current applied perpendicular to the flow cause positively charge impurities to move towards a cathode while negatively charged impurities move to the anode. The impurities travel through selectively permeable membranes (i.e.; a cation membrane allows the passage of positive ion but rejects negative) thereby trapping impurities.

Reverse osmosis is a widely applied demineralization technique which utilizes pressure applied to the surface of a fluid. Osmotic pressure exist when two fluids with different concentrations are separated by a semipermeable membrane. Under osmotic pressure, fluid moves from the more dilute to the more concentrated side. When an opposing pressure is applied, the fluid will move in the reverse direction leaving behind its impurities which cannot travel back through the membrane.

Ion exchange is a process whereby one type of impurity within a fluid is exchanged for another that is less objectionable. An ion exchange resin is a synthetic resin capable of supplying ions (impurities with an electrical charge) to a fluid in which it comes in contact with. These ions chemically react and are exchanged for like charged impurities already existing in the fluid. A well known example is the replacement of calcium and magnesium ions with sodium to decrease the hardness of water. Demineralization of condensate return is almost exclusively accomplished through ion exchange.

Softening is a form of demineralization. Although the term commonly designates only the removal of calcium and magnesium (hardness), silica, alkalinity and other constituents are also removed in softening. Makeup water is softened to prevent dissolved solids from settling on component surfaces and producing a hard scale. Softening techniques make use of precipitation, ion exchange, or semi-permeable membranes. The first is precipitation and settling out of calcium and magnesium by chemical addition to the water. Chemical treatments are discussed in the next section.

Chemical Treatments

The amount of chemicals available for treatment, either solely for water purification or as additives to protect cooling water tubes, flow pipes and equipment are numerous. Slide 2-14 lists a variety of chemical treatments commonly applied to boiler cooling water systems.

Like physical treatments, chemicals can be used to remove suspended and dissolved solids within a water stream. Clarification is the mechanical removal of large suspended matter. To apply this technology effectively to a wider range of fluid streams, coagulation chemicals are often added to the water. Addition of these chemicals causes finer particles to come together into a larger suspended mass, much easier for the clarifier to remove. Dissolved solids, also, can be removed

CHEMICAL WATER TREATMENTS

Chemical	Application
Sodium hydroxide (caustic soda)	Increases pH, precipitates magnesium
Sodium carbonate	Increases pH, precipitates calcium
Sodium phosphate	Precipitates calcium
Sodium aluminate	Precipitates calcium and magnesium
Chelants	Controls scale by forming heat stable soluble compounds
Tanins, starches, lignin	Prevents water deposits by coating scale to produce a sludge that does not adhere as readily to pipe surfaces
Polymers, copolymers	Disperses sludge, prevents scale, prevents fouling by corrosion products
Sodium sulfite	Prevent O_2 corrosion
Hydrazine	Prevent O_2 corrosion
Ammonia	Adjusts pH
Filming amines	Control return line corrosion by forming protective film on metal surfaces
Neutralizing	Controls return line corrosion by amines adjusting condensate pH
Sodium nitrate	Inhibits caustic embrittlement
Antifoams	Reduces foaming tendency of high solids boiler water
Chlorine	Removal of dissolved gases by chemical oxidation, control of slime and algae
Potassium permanganate	Control of slime and algae
Coagulants	Causes suspended matter to coagulate, used in conjunction with clarification
Calcium hydroxide (lime)	Adjusts pH

Slide 2-14

through the addition of chemicals to the water stream. Soda ash, lime, sodium phosphate and sodium aluminate all chemically react with calcium or magnesium, to precipitate out these two minerals from the fluid flow. Dissolved solids and gases can be removed by oxidation whereby chemicals instead of oxygen (as with aerators) are introduced into the fluid stream. Chlorine has been the customary oxidizing chemical with hydrogen peroxide seeing some use. Typical applications include the conversion of dissolved iron to ferric chloride; removal of the insoluble ferric chloride is then by clarification or filtration.

Chemicals are used extensively for protection of the boiler system (water side) against scale, corrosion and other deposits. Chemicals called polymers and copolymers are added to makeup water to condition sludge deposits whereby impurities are precipitated out and held in a suspended non-adherent form. Final removal of the nonsticky sludge is then accomplished by boiler blowdown. Chemicals known as chelants are used to reduce scale formation. Ethylenediamine-tetraacetic acid (EDTA) and nitrilotriacetic acid (NTA) are the two most common boiler water chelating agents.

Corrosion within the boiler water tubes, flow pipes, cooling tower equipment or any other associated components is inhibited in one of two ways. By either the removal of O_2 and other gases which contribute to corrosion from the boiler feed water before they enter boiler, or by the control of boiler feed water pH. Soluble oxygen may be removed from a water supply by the use of a scavenger agent. Injection of a chemical such as sodium sulfite can result in a reaction with O_2. Removal of the solid product is by blowdown. Corrosion in steam and return lines can occur because of carbonic acid resulting from the reaction of water with CO_2 gas coming from the boiler. Chemicals called amines are traditionally added to adjust the pH of the condensate. Fed into the boiler water, these neutralizing amines volatilize and carry over with the steam. This type of corrosion can also be prevented by the addition of a different type of amine which provides a protective film over the metal surfaces of the condensate return system The metals surface is thereby immune to any corrosive effects of the carbonic acid.

REFERENCES

1. Wilson, Dean R., *Boiler Operator's Workbook*,American Technical Publishers, Inc., 1991.

2. *Steam, Its Generation and Use*, 40th Edition, Babcock and Wilcox Company, 1992.

3. Elliott, Thomas C., *Standard Handbook of Powerplant Engineering*, McGraw-Hill Publishing, 1989.

4. Strauss, S.D., *Water Treatment - Special Report*, Power, June, 1993 Vol 137; pp. 17 - 107

5. ASME Boiler Operation Code, 1986, Subsection C2.

6. ASME Boiler and Preesure Vessel Code, Section I.

3. COMBUSTION GAS CIRCUIT

3.1 Introduction

3.2 Combustion Process
- A. Process Components
- B. Furnace Draft

3.3 Heat Transfer
- A. Radiation
- B. Conduction
- C. Convection

3.4 Combustion Gas Flow Path
- A. Furnace
- B. Convection Pass

3.5 Flue Gas Treatment

3. COMBUSTION GAS CIRCUIT

3.1 Introduction

In the previous Learning Unit, the production of steam was discussed based on an available heat source. The combustion gas circuit, which consists of the fuel, air, and products of combustion flowpath, provides the heat to generate the steam. This Learning Unit will discuss the release of heat from the combustion process, the heat transfer from the combustion of fossil fuels, the flowpath of the products of combustion, and the flue gas treatment.

COMBUSTION GAS CIRCUIT FUNCTIONS

1. **Release of heat from the Combustion Process**
2. **Heat Transfer to Steam-Water Circuit**
3. **Flue Gas Treatment for Pollution Control**

Slide 3–2

3.2 Combustion Process

Combustion is defined as the rapid combination (burning) of oxygen with fuel which results in releasing heat. The oxygen for combustion is supplied by air, which is about 21% oxygen and 78% nitrogen by volume. Therefore, the combustion gas circuit begins with the supply of fuel and air. The ratio of air-to-fuel required for complete combustion of the fuel is dependent on the type of fuel. A more in-depth discussion of combustion principles is contained in Learning Unit 5.

COMBUSTION PROCESS COMPONENTS

- **Fuel**
- **Primary Air**
- **Secondary Air**
- **Combustion Chamber**
- **Burners**
- **Fans**

Slide 3–3

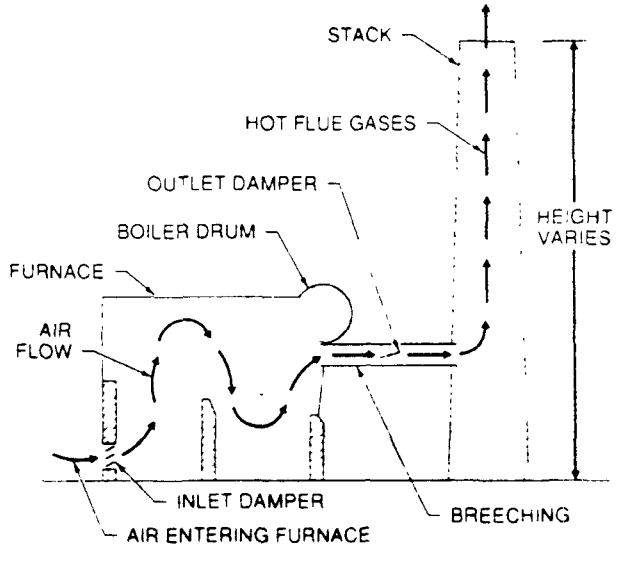
In general, air is supplied as primary and secondary air. The primary air serves as the initial source of combustion for the fuel and sometimes acts as the carrier gas which transports the fuel to the burner. Secondary air is provided for ensuring complete combustion of the fuel. The mixing of the fuel and air takes place

in the burners and the combustion chamber of the boiler furnace. The mixing characteristics determined by the burner design and the type of fuel dictate the shape of the flame created during the combustion process. Good mixing of the fuel and air is important so that the mixture will be uniform throughout; that is every particle of fuel comes in contact with a particle of air. Most fuels actually turn into a gas before they burn. The chemical reaction of the elements in the fuel, such as carbon, hydrogen, and sulfur, combining with oxygen produce chemical compounds and heat. These chemical reactions are defined as exothermic reactions because heat is released during the process.

The designs of the burner, combustion chamber and furnace are dependent on the type of fuel and the application of the steam generated. For small boilers, a single burner may be employed while for utility boilers, multiple burners are arranged on a single wall of the boiler or in multiple locations. The specifics of the burner arrangements and design will be discussed in Learning Units 7, 8, 9, 10, 11 and 13.

The combustion chamber is the area of a boiler where the burning of fuel begins. The efficient combustion of fuel and transfer of heat in the boiler require that adequate combustion air be provided and that the products of combustion or flue gas be removed from the area of combustion. In some boilers, removal is accomplished solely by natural convection, commonly called natural draft.

NATURAL DRAFT FURNACE[1]



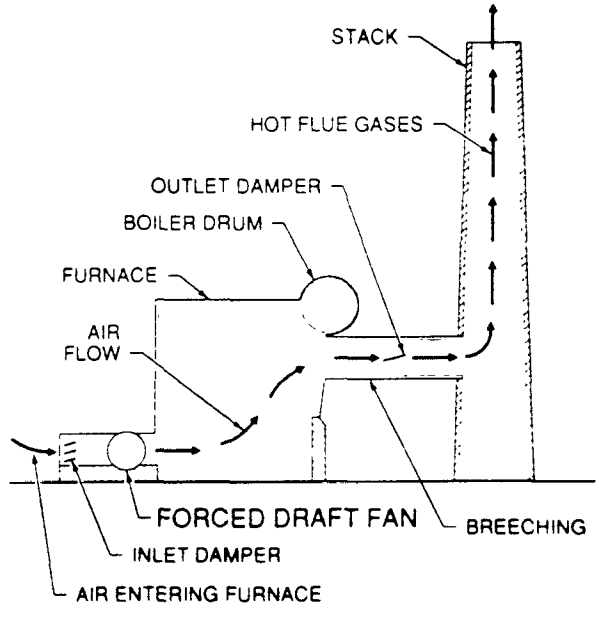
Slide 3–4

Natural draft occurs as the hot flue gas rises through the stack and cool air is drawn to the burners to replace the volume of gases leaving. Draft is controlled by using a damper. The amount of draft, or movement of air, is determined by the height of the stack, the difference between the inside temperature and outside temperature, and the draft losses. Draft losses are caused by the use of high flue-gas velocities, tube banks of small diameter, economizers, mechanical dust collectors, and air preheaters. While these items increase the heat transfer efficiency of a boiler, for larger boilers, the draft losses they create preclude the use of natural draft.

Mechanical draft is draft created by one or more fans. Forced draft is the introduction of the combustion air into a furnace to combine with the fuel from combustion. A forced draft (FD) fan provides the primary air to the burner windbox. Induced draft is the use of a fan to lower the pressure in the furnace. An induced draft (ID) fan draws the flue gas to the stack.

Boilers with FD fans and no induced-draft (ID) fans are called pressurized-furnace boilers because the boiler furnace is above atmospheric pressure. This situation can be troublesome because flue gas, which is toxic and corrosive, and flyash leak out of the smallest openings in the furnace, causing maintenance and personnel safety problems.

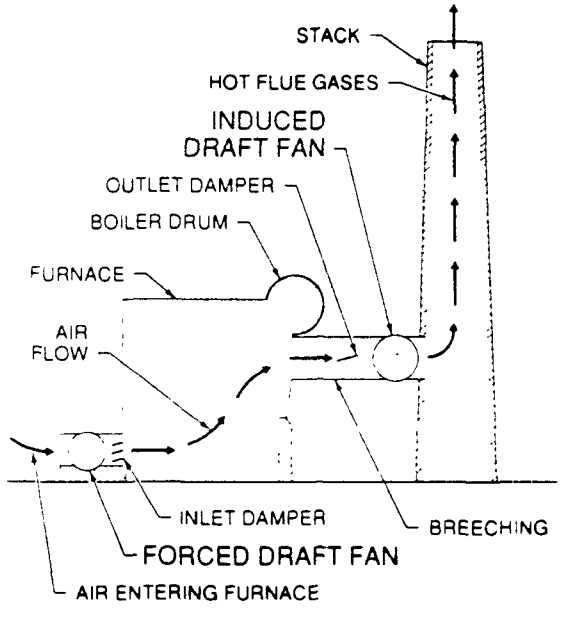
FORCED DRAFT FURNACE[1]



Slide 3-5

The solution to these problems is the addition of an ID fan that draws suction on the furnace and lowers the furnace pressure. Boilers having both FD and ID fans include dampers or inlet vanes on the fans to balance them and to operate the furnace at a pressure slightly less than atmospheric also known as negative furnace pressure. With this arrangement, the leakage of the flue gas and flyash is eliminated. This configuration is called a balance-draft boiler.

BALANCED DRAFT FURNACE[1]



Slide 3-6

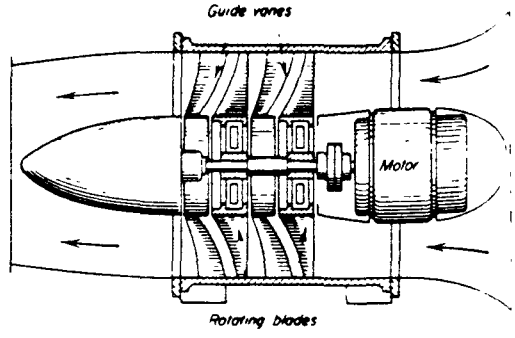
To complete the combustion process, secondary air is air added to the combustion process to ensure that sufficient oxygen is available to complete the combustion. Secondary air is often introduced through high-velocity air jets or ports. The high velocity of the secondary air creates turbulence of the burning gases which enhances the mixing of the oxygen and the combustible gases. The secondary air may be supplied by a separate secondary fan. The combustion process is completed in the furnace before the gases enter the convection section of the boiler.

The fans in the combustion gas circuit move a quantity of air or gas by adding sufficient energy to the stream to initiate motion and overcome all resistance to flow. The fan consists of a bladed rotor, or impeller, and usually a housing to collect and direct the air or gas discharged by the impeller. The power required depends upon the volume of air or gas moved over a given time period. Basically, there are two different kinds of fans; centrifugal and axial. The centrifugal fan accelerates the incoming air radially outward into a surrounding casing. The axial flow fan design accelerates the air parallel to the fan axis. The fan output can be achieved by controlling the flow into

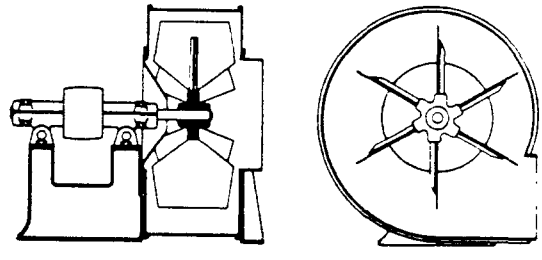
the fan or by controlling the fan speed. To control the flow into the fan, variable-inlet vanes and parallel-blade inlet box dampers are used. For the second control technique, any speed-changing device such as a multiple-speed motor could be used to control the fan speed.

TYPICAL FAN DESIGNS[3]

Two-stage Axial Fan



Straight-Blade Centrifugal Fan



Slide 3–7

3.3 Heat Transfer

Heat is released from the combustion of the fuel and then transferred to the steam generating side of the boiler by the three modes of heat transfer - radiation, conduction and convection.

HEAT TRANSFER MODES

Radiation **Conduction** **Convection**

Slide 3–8

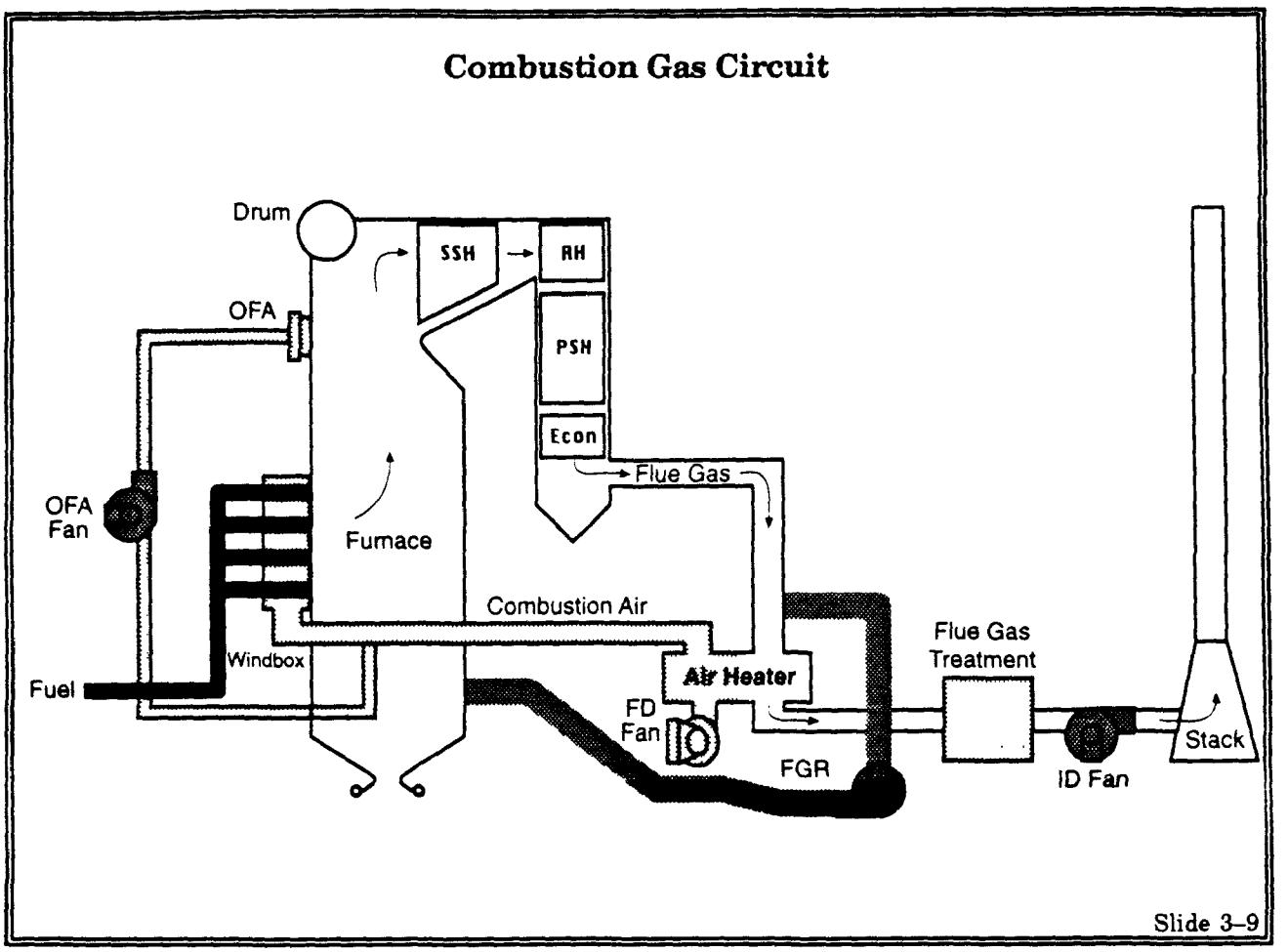
Radiation is the transfer of energy by electromagnetic waves from a hot body to a cold body without physical contact. Light is a form of radiation, but all heat radiation is not visible. The burning fuel is so hot that a tremendous amount of energy (infrared and other radiation) is generated. Radiant heat travels in straight lines and may pass through a vacuum, air, some gases, some liquids and a few solids such as glass and quartz. Some of the thermal radiation is absorbed by the receiving body, such as the waterwalls, and raises the temperature of the body and the remaining energy is reflected from or transmitted through the body. The intensity of thermal radiation is dependent on the temperature of the radiating matter. Almost all the heat transferred to the waterwalls of the boiler in the furnace section is by radiation due to the high temperature of combustion process.

Conduction is the transfer of heat between one molecule to the next within a substance. For instance, when one end of a steel rod is inserted into a furnace, the other end of the rod will become hot after a time due to conduction of the heat through the metal rod.

Convection heat transfer occurs in the convection section of the boiler between walls, superheater, reheater, and economizer and the flue gas by a combination of conduction and fluid motion. As an example, heat is transferred from the hot flue gas to the outside surface of the tube in a superheater and then moves downstream at a lower temperature. The heat is then transferred to the inside of the tube by conduction within the tube wall. At the same time, steam flowing on the inside of the tubes receives the heat by conduction between the steam the inner tube wall and moves on at a higher temperature. Note that increasing the velocity of the flue gas through the convection portion of the steam generator increases the convective heat transfer.

More details on the calculation of each of these modes of heat transfer are contained in Learning Unit 5.

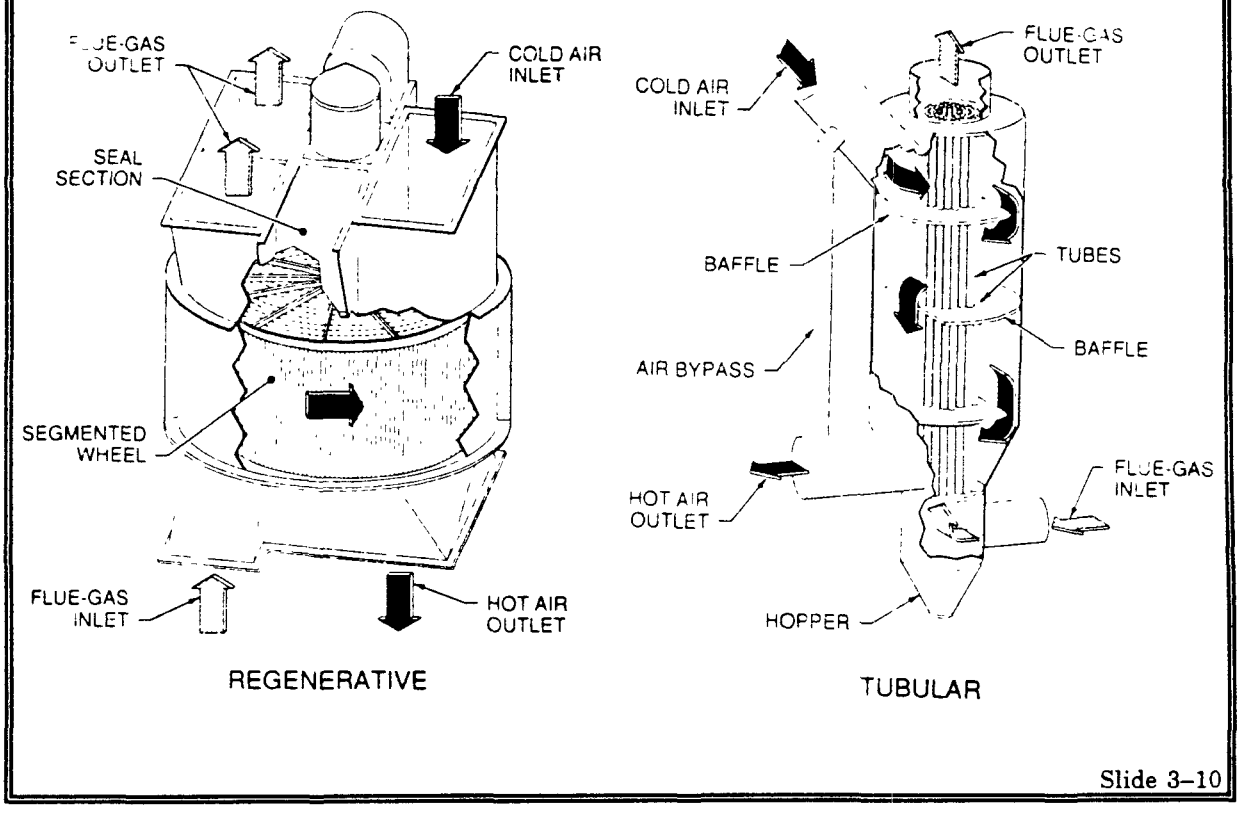
3.4 Combustion Gas Flow Path



The flow of combustion gases begins with the combustion air supply. The air from the FD fan discharge is routed through ducts to the air heater. This is an energy conserving device which transfers heat from the boiler exhaust gas to the combustion air. In coal-fired units where the moisture in the coal has to be evaporated in the coal preparation process prior to combustion, the preheated air is of special importance. The two principle types of air heaters are the tubular recuperative and the regenerative.

The tubular air heater is a stationary unit constructed of 2- to 3-inch tubes through which the hot gases flow. The air flows across the tube bank. The regenerative air heater transfers heat from the flue gas to the air by heating regenerative heat-transfer surfaces in a rotor that turns continuously through the gas and air stream. The air heater will typically reduce the hot combustion product gas from 600-800 °F to 250- 350 °F and increase the combustion air from 70-80 °F to 500-700 °F.

AIR PREHEATERS[1]



Slide 3–10

After being heated in the air heaters, the air is ducted to the furnace "windbox" which is basically an air supply chamber attached on the outside of the furnace walls in the burner or fuel supply zones. The air that is discharged through the windbox will supply the secondary air for the combustion process. In some furnace designs this secondary air will be divided between the windbox and the upper section of the furnace. The air that is routed to the upper furnace is known as overfire air (OFA). The OFA is supplied by a OFA fan that pulls the air from the combustion air supply header. By staging the combustion, the lower furnace temperature will be reduced which is helpful in reducing the formation of some pollutants.

On coal-fired units, hot air is ducted from downstream of the air heater to the coal pulverizers, which prepare the coal for combustion, to be used in the coal drying process as well as for transporting the pulverized coal to the furnace area.

Following the combustion process in the boiler furnace, the air flow is referred to as "combustion products," "flue gas," or "exit gas." Products of combustion is probably the most applicable name from an environmental viewpoint because these gases contain the components of air which remain following the combustion process as well as those components of the fuel that were not consumed.

These hot gases exit the furnace or radiant zone of the boiler and move through the convection zone or rear pass section. Then the gases cross the tube banks of the steam secondary superheater (**SSH**), reheater (**RH**), primary superheater (**PSH**) and the feedwater economizer (**Econ**) where heat is transferred to the steam/water cycle; as shown in Slide 3-9.

Some units have a flue gas recirculating (FGR) fan in the gas circuit. This fan will typically take hot gas downstream of the economizer and recirculate it into the lower furnace area. Flue gas recirculation is one method of steam temperature control that basically increases the total flow of gases through convection section and increases the heat transferred to the steam.

3.5 Flue Gas Treatment

The flue gas contains the products of the combustion process. Some of these products have been determined to be detrimental to the environment as "pollutants." Air quality or environmental regulations may require (depending on the fuel type and quantity) that these gases be treated to remove those undesirable elements before the gases are released to the atmosphere. These air pollution control devices (APCDs) will be located in the gas stream between the economizer outlet and the stack or chimney.

As will be discussed in Learning Units 21 through 30, there are many different types of pollution control devices depending on the air pollutant to be controlled. The more common devices control particulate matter, nitrogen oxides, and sulfur oxides. Depending on the local regulations, a continuous emissions monitoring system (CEMS) may also be required to measure the emissions levels of the air pollutants prior to being emitted to the atmosphere. Therefore, the CEMS is the last device in the stack.

REFERENCES

1. Wilson, R. Dean, *Boiler Operator's Workbook*, American Technical Publishers, Inc., 1991.

2. Elliott, Thomas C., *Standard Handbook of Powerplant Engineering*, McGraw-Hill Publishing Co., 1989.

3. Perry, Robert H. and Green, Don, *Perry's Chemical Engineers' Handbook*, Sixth Edition, McGraw-Hill Publishing Co., 1984, p. 6-22.

CHAPTER 4. FOSSIL FUELS

4.1 Introduction

4.2 Natural Gas
- A. Gaseous Fuel Characterization
- B. Natural Gas Properties

4.3 Fuel Oil
- A. Fuel Oil Grades
- B. Liquid Fuel Characterization
- C. Fuel Oil Properties

4.4 Coal
- A. Formation of Coal
- B. Classification of Coal
- C. Coal Characterization
- D. Items of Proximate Analysis
- E. Items of Ultimate Analysis
- F. Example Coal Analysis

4. FOSSIL FUELS

4.1 Introduction

FOSSIL FUELS

Natural Fuels
- Natural gas
- Fuel oils
- Coal

Byproduct Fuels
- Residual oils

Manufactured Fuels
- Coke
- Char, tar
- Chemical and industrial gases, etc...

Slide 4–2

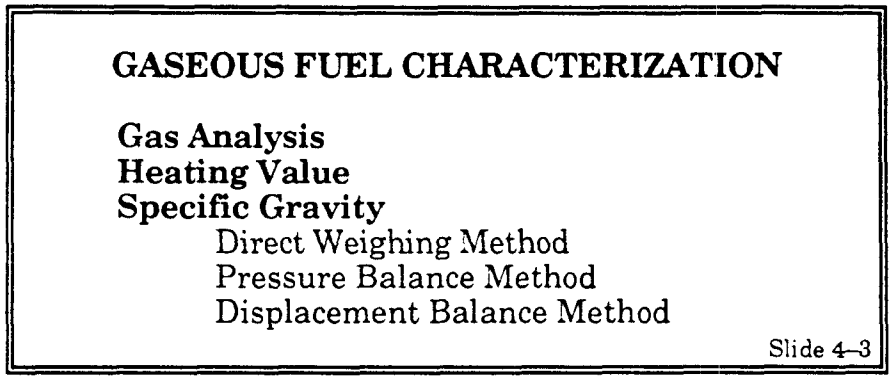
Fossil fuels used for steam generation in utility, industrial, commercial and institutional power plants may be classified into solid, liquid, and gaseous fuels. Each fuel is classified as natural, byproduct fuel, or manufactured. Obvious examples of natural fuels are coal, crude oil, and natural gas. Byproduct fuels include residual oils, which are byproducts of the refining of crude oils, gas, char, tars, and chemicals and industrial gases which are derived from coal. Among the fuels, natural fuels are typically used to generate steam in power plants. This section focuses on characteristics of natural gas, fuel oil, and coal.

4.2 Natural Gas

Natural gas is perhaps the closest approach to an ideal fuel because it is practically free of noncombustible gas or solid residue. It is found in porous rock and shale formations, or cavities, which are sealed between layers of closed–textured rocks under the earth's surface. When a natural–gas field is tapped by drilling wells, it is usually found to be under rock pressure, which can be high as 2000 psig. Natural–gas fields frequently exist in the neighborhood of oil deposits. Usually, natural gas occupies the space above the oil and the oil, in turn lies over salt water. Not all natural gas is associated with oil. Sometimes, it is found by itself, or indirect contact with salt water.

Although, whenever possible, natural gas is delivered at the required destination under well pressure, it is frequently transported over long distances by means of pipelines and compressors. The conditions of the pipelines may change the composition of natural gas going to the furnace. For instance, aside from the effect of compression, which liquefies the heavy members of the hydrocarbon family, water and oil are sometimes sprayed into the gas to keep it "moist." For this reason, any natural gas analysis, as fired, should be taken at the furnace rather than at the well.

Gaseous Fuel Characterization



Characterization of gaseous fuels (manufactured and natural gases) consists of determining the gas compositions, heating value and specific gravity.

Gas Analysis: The analysis of fuel gas is expressed in terms of volume percentages of the component gases. Several methods have been used for fuel gas analysis. These are absorption in chemical solution, distillation, spectrometry, and chromatography. Components of fuel gases consist of typical gases including oxygen, nitrogen, carbon dioxide, etc..., saturated hydrocarbons, and unsaturated hydrocarbons.

Heating Value: The heating values refers to the quantity of heat released during combustion of a unit amount of fuel gas. Constant pressure gas calorimeters are used for the heating value determination. A calorimeter in general is an apparatus used for measuring heat quantities generated in or emitted by materials in processes such as chemical reactions, change of state, or formation of solution. The heating value as determined by calorimeters is termed *higher heating value*, which is the quantity of heat evolved when the products of combustion are cooled to 60°F and the water vapor produced completely condensed to a liquid at that temperature. The *lower heating value* differs from the high heating value by the latent heat of evaporation of water formed in the combustion process. Latent heat is defined as the

amount of heat absorbed or evolved by one mol, or a unit mass, of a substance during a change of state at constant temperature and pressure.

The heating value of gaseous fuels, typically expressed in Btu per cubic foot (Btu/ft^3) measured at 60°F and 30 in. of mercury and saturated with water vapor, varies considerably, depending on the constituents present.

American Society for Testing and Materials (ASTM) Standards D 3588 gives a method for calculating calorific value and specific gravity of gaseous fuels and includes a method for determining the repeatability of the calculated values. ASTM, founded 1898, is a scientific organization formed for the development of standards on characteristics and performance of materials, products, systems, and services. Standard as used in ASTM is a document that has been developed and established within consensus principles of the Society and that meets the approval requirements of ASTM procedures and regulations.

Specific Gravity: Various methods for determining the specific gravity of a fuel gas are available but three methods have been adopted as ASTM Standards D 1070.

Direct Weighing Method: This method involves the determination of the weight differential between two equal volumes of gas and air, both at identical conditions of temperature and pressure.

Pressure Balance Method: In this method, a flask containing the gas is counterbalanced on a beam enclosed in a container. The beam is brought to balance by adjusting the air pressure within the container which varies the buoyancy of the flask. The procedure is repeated with air in the flask and the specific gravity determined from the ratio of the required absolute pressures

Displacement Balance Method: The instrument consists of a balance beam on each end of which two bells are suspended in a sealing liquid. One bell, containing air, is open to the atmosphere through holes on its top; the other

bell, containing the gas, is open to the atmosphere through a 59–in gas column connected to the space under the bell. An unbalanced force is produced which is equal to the pressure differential above and within the gas–filled bulb. The magnitude of this force is an indication of the specific gravity.

Natural Gas Properties

NATURAL GAS PROPERTIES

Composition of Natural Gas
Dry and Wet Natural Gas
Sweet and Sour Natural Gas
Heating Value
Specific Gravity

Slide 4–4

Composition of Natural Gas: The characteristics of natural gas, as it comes out of the earth's surface, depend to some extent on its underground conditions. Generally, it is odorless and colorless. It burns with a blue flame and is highly explosive when mixed with air in the correct proportions. Typical natural gas compositions are shown in Slide 4–5.

TYPICAL NATURAL GAS ANALYSES[1]

Constituents (% by volume)

CO_2	5.50	3.51	26.2	0.17
N_2	-----	32.00	0.70	87.69
H_2S	7.00	0.50	-----	-----
CH_4	77.73	52.54	59.20	10.50
C_2H_6	5.56	3.77	13.9	1.64
C_3H_8	2.40	2.22	-----	-----
C_4H_{10}	1.18	2.02	-----	-----
C_5H_{12}	0.63*	3.44*	-----	-----
Density (lb/ft^3)	0.0562	0.0661	0.0675	0.0712
High Heating Value				
$Btu/ft^{3\dagger}$	1,061	874	849	136
Btu/lb	18,880	13,220	12,580	1,907

* All hydrocarbons heavier than C_5H_{12} are assumed to be C_5H_{12}

† If gas is saturated with moisture at 60°F and 30.0 in. Hg, reduce by 1.74%.

Slide 4–5

Methane, CH_4, and ethane, C_2H_6, are its principal combustible components. When sulfur is present in the oil deposit, the analyses of natural gas associated with this oil often include hydrogen sulfide, H_2S. This hydrogen sulfide is removed in most instances before distributing the gas because it is a potential source of pipeline corrosion. In addition to its combustible constituents, natural gas may contain considerable amounts of carbon dioxide, CO_2, or nitrogen, N_2. Sometimes, the analysis of natural gas also shows the presence of oxygen.

Dry and Wet Natural Gas: If natural gas has been in contact with oil, it would absorb various amounts of heavy hydrocarbon vapors, such as pentane, C_5H_{12}, or hexane, C_6H_{14}, which are liquid at ordinary pressure and temperature. This is known as "wet" natural gas. In a complete analysis of natural gas, a certain fraction of a heavy hydrocarbon is sometimes preceded by the letter "n," such as "n–butane," which means "normal" butane, and the remainder uses the prefix "iso," meaning "equal," as "iso–butane." The chemical formula is the same in both cases; however, the physical and chemical properties of these so–called "isomers" are not usually the same.

"Dry" natural gas comes from wells away from oil deposits and is, therefore, comparatively devoid of heavy hydrocarbons.

Sweet and Sour Natural Gas: Natural gases are also classified as either "sweet" or "sour." The *sour* gas is one which contains some mercaptans and a high percentage of hydrogen sulfide while the *sweet* gas is one in which these objectionable constituents have been removed. Mercaptan is a group of compounds derived from hydrogen sulfide. It has a characteristically strong odor, and is often added to natural gas to give it a scent for easy detection.

Heating Value: The heating value refers to the quantity of heat released during combustion of a unit amount of natural gas. Determinations are made with a continuous flow (constant pressure) gas calorimeter. The heating value as determined in calorimeters is termed *higher heating value* and is the quantity of heat evolved when the products of combustion are cooled to 60°F and the vapor produced is completely condensed to a liquid at that temperature. The *lower heating value* differs from the higher heating value by the latent heat of evaporation of water formed in the combustion process. The higher heating values of natural gas are commonly reported at a pressure of 14.7 psia or 30 in. of Hg, at a temperature of 60°F, and generally on a dry basis.

The higher or gross heating value of natural gas is usually about 1,000 Btu per cubic foot (Btu/ft^3), and it can be computed by adding together the heat contributed

by volumetric percentages of the various component gases. The method will usually result in a lower value per cubic foot than that obtained by calorimetric determinations, because the unsaturated hydrocarbons are frequently grouped and reported with C_2H_6. For the same reason, the corresponding density, under standard conditions of 60°F and 30 in. Hg, will also be lower. The calculated Btu per pound, however, will be close to its actual value, because of the compensating effect of the lower calculated density.

4.3 Fuel Oil

Over millions of years, rivers carried mud and sand which deposited and ultimately became sedimentary rock formations. Along with this inorganic material, tiny marine organisms were buried with the silt. Over time, in an airless and high pressure environment, the organic material containing carbon and hydrogen was converted to the hydrocarbon molecules of petroleum. Because of the porosity of sedimentary rock formations, the oil flowed and collected in traps, or locations where crude oil is concentrated.

Fuel Oil Grades

FUEL OIL GRADES

Distillate Fuel Oils
- Fuel Oil No. 1
- Fuel Oil No. 2

Residual Oils
- Fuel Oil No. 4
- Fuel Oil No. 5
- Fuel Oil No. 6

Slide 4–6

Fuel oils include virtually all petroleum products that are less volatile than gasoline. They range from light oils, suitable for use in internal combustion or turbine engines, to heavy oils, suitable for steam generation boilers. To burn fuel oil, it is necessary to atomize the fuel before mixing with combustion air. Fuel oils can be divided into two classes: distillate and residual.

Distillate fuels: Distillate fuels are those that are vaporized in a petroleum process. They are typically clean, essentially free of sediment and ash, and relatively free of viscosity. These fuels fall into the No. 1 and No. 2 category in ASTM D 396. Although No. 2 oil is sometimes used as a premium steam generation fuel, it best

lends itself to applications where cleanliness and ease of handling outweigh its cost. Examples includes home heating and industrial applications where low ash and/or sulfur are important. Steam generating applications are primarily limited to use distillate fuels as a startup or support fuel.

Residual fuels: Residual fuel oils are those that are not vaporized by heating and contains virtually all the inorganic constituents present in the crude oil. Frequently, residual oils are black, high viscosity fluids that require heating for proper handling and combustion.

Grade No. 4 and 5 fuel oils are less viscous and therefore more easily handled and burned than No. 6 oil. Depending on crude oil used, a fuel meeting the No. 4 specification may be a blend of residual oil and lighter distillate fractions. This oil does not usually require heating for pumping and handling. Grade No. 5 oils may require heating, depending on the firing equipment and the ambient temperature. Grade No. 6 oils usually require heating for handling and burning.

Liquid Fuel Characterization

LIQUID FUEL CHARACTERIZATION

Ultimate Analysis
Specific Gravity
Heating Value
Viscosity
Pour Point
Flash Point, and
Water and Sediment

Slide 4–7

Characterization of liquid fuels consists of determining fuel compositions, and their properties including specific gravity, heating value, viscosity, pour point, flash point, and water and sediment.

Ultimate Analysis: The ultimate analysis of a liquid fuel is similar to that for a solid fuel, and uses the ASTM D 3176 Standard Method. The results indicate the quantities of sulfur, hydrogen, carbon, nitrogen, oxygen, and ash.

Sulfur is a very undesirable element in fuel oils because its products of combustion are acidic and cause corrosion in economizers, air heater and gas ducts. Because of the high hydrogen content in fuel oils, and the resulting high water vapor

content in the products, a given amount of sulfur in fuel oils has the potential of doing more damage than the same amount of sulfur in coal.

Fuel oils contain all of the solid impurities originally present in the crude oil. If these solids, contain a large proportion of salt, they are very fusible and can cause considerable trouble.

Specific Gravity: This is the ratio between the density of a liquid oil and the density of water at 60°F. Gravity determinations are conducted by immersing a hydrometer into the sample and reading the scale at the point to which the instrument sinks into the oil. The specific gravity is either read direct or the gravity is measured in degrees API (American Petroleum Institute). The relationship between the API gravity and the specific gravity is given by the following formula:

$$°\text{API} = \frac{141.5}{\text{Sp. Gr. } 60/60°\text{F}} - 131.5 \quad \text{(Equation 4–1)}$$

Heating Value: The heating value of a liquid fuel is expressed in Btu per pound or Btu per gallon at 60°F. Bomb calorimeters are used to determine the heating value of a liquid fuel.

Viscosity: Viscosity is defined as the measure of the resistance to flow. The greater this resistance, the longer it takes a given volume of liquid fuel to flow through a fixed orifice. Viscosity is expressed in Seconds Saybolt Universal (SSU), which is the time it takes to run 60 cubic centimeters (cc) through a standard size orifice at the desired temperature. Viscosity is commonly measured at 100, 150, and 210°F. The liquid fuel is at a held constant temperature within ±0.25°F during the test period.

Other scales, which are Seconds Saybolt Furol (SSF), Centipoise, and Centistokes, are also used to measure viscosity of a liquid fuel. Sixty–two SSF is equal to 600 SSU. Centipoise is used to measure absolute viscosity and centistoke is used to measure kinematic viscosity of a liquid fuel. Kinematic viscosity is a ratio of absolute viscosity divided by density of the liquid fuel.

Pour Point: Pour point is the lowest temperature at which a liquid fuel flows under standardized conditions. The viscosity of liquids decreases as temperature is increased and the pour point is the minimum temperature at which a liquid will flow.

Flash Point: Flash point of a liquid fuel is the lowest temperature at which sufficient vapor is given off to form a momentary flash when flame is brought near

the surface. This is measured by increasing the temperature of the liquid in air and in the presence of a flame or repeating spark.

Water and Sediment: The water and sediment is a measure of the contaminants in a liquid fuel. The sediment normally consists of calcium, sodium, magnesium, and iron compounds. For heavy fuels, the sediment may also contain carbon. Problems that can be caused by sediment during combustion include line plugging, and strainer, control–equipment, and burner–nozzle blockage. Water can lead to corrosion, erratic and inefficient combustion, and even flame failure.

Fuel Oil Properties

TYPICAL ANALYSES AND PROPERTIES OF FUEL OILS*

Grade	No. 1 Fuel Oil	No. 2 Fuel Oil	No. 4 Fuel Oil	No. 5 Fuel Oil	No. 6 Fuel Oil
Type	Distillate	Distillate	Very Light Residual	Light Residual	Residual
Color	Light	Amber	Black	Black	Black
API gravity, 60°F	40	32	21	17	12
Specific gravity, 60/60°F	0.8251	0.8654	0.9279	0.9529	0.9861
Density, lb/U.S gal, 60°F	6.870	7.206	7.727	7.935	8.212
Viscos., centistokes, 100°F	1.60	2.68	15.00	50.00	360.00
Viscos. SSU, 100°F	31	35	77	232	——
Viscos., SSF, 122°F	——	——	——	——	170
Pour point, °F	Below zero	Below zero	10	30	65
Temp. for pumping, °F	Atmospheric	Atmospheric	15 min.	35 min.	100
Temp. for atomizing, °F	Atmospheric	Atmospheric	25 min.	130	300
Carbon residue, %	Trace	Trace	2.5	5.0 max.	12.0 max.
Sulfur, %	0.1	0.4–0.7	0.4–1.5	2.0 max.	2.8 max.
Oxygen and nitrogen, %	0.2	0.2	0.48	0.70	0.92
Hydrogen, %	13.2	12.7	11.9	11.7	10.5
Carbon, %	86.5	86.4	86.1	85.55	85.7
Water and sediment, %	Trace	Trace	0.5 max.	1.0 max.	2.0 max.
Ash, %	Trace	Trace	0.02	0.05	0.08
Heating Value, Btu/gal	137,000	141,000	146,000	148,000	150,000

*Data from Exxon Corporation

Slide 4–8

Typical analyses and properties of fuel oils are shown in Slide 4–8.

Ultimate Analysis: The different grades of fuel oils have varying percentages of sulfur, ranging from about 0.3 to 3.0 percent. Distillate oils usually are at the lower end of the range, and heavy fuels are generally at the upper end. Depending on crude composition, however, it is possible for a distillate to contain more sulfur than some residual oils. Distillate oils have about 0 to 0.1 percent ash, and the heavier grades from 0.2 to 1.5 percent. Although the percentages are quite small, a considerable amount of ash can accumulate on the fireside of a boiler if firing rates are high.

Heating Value: The heating value per gallon increases with specific gravity, because there is more weight per gallon, and ranges from about 135,000 to 150,000 Btu per gallon. The heating value per pound varies inversely with the specific gravity, because the lighter oil contains more hydrogen; it ranges from 18,300 to 19,500 Btu/lb. There is an approximate relationship between specific gravity and higher heating value. For an uncracked (applied to those oils not produced by cracking process, which is used to reduce the molecular weight of hydrocarbons by breaking molecular bonds using thermal or catalytic methods) distillate or residue,

$$\text{HHV (Btu/lb)} = 17{,}660 + (69 \times \text{API gravity})$$

For a cracked distillate,

$$\text{HHV (Btu/lb)} = 17{,}780 + (54 \times \text{API gravity}).$$

Specific Gravity: As previously shown, the API degree has an inverse relationship with the specific gravity, according to Equation 4–1. Therefore, heavier liquid fuels are denoted by lower API gravity values. Slide 4–9 shows an example calculation to convert specific gravity to degrees API and density.

CALCULATING API GRAVITY FROM SPECIFIC GRAVITY

Given:

Sp. Gr. (60/60°F) = 1.000

°API = 141.5/(Sp. Gr. (60/60°F)) - 131.5
= 141.5/(1) - 131.5
= 10°

CALCULATING DENSITY FROM SPECIFIC GRAVITY

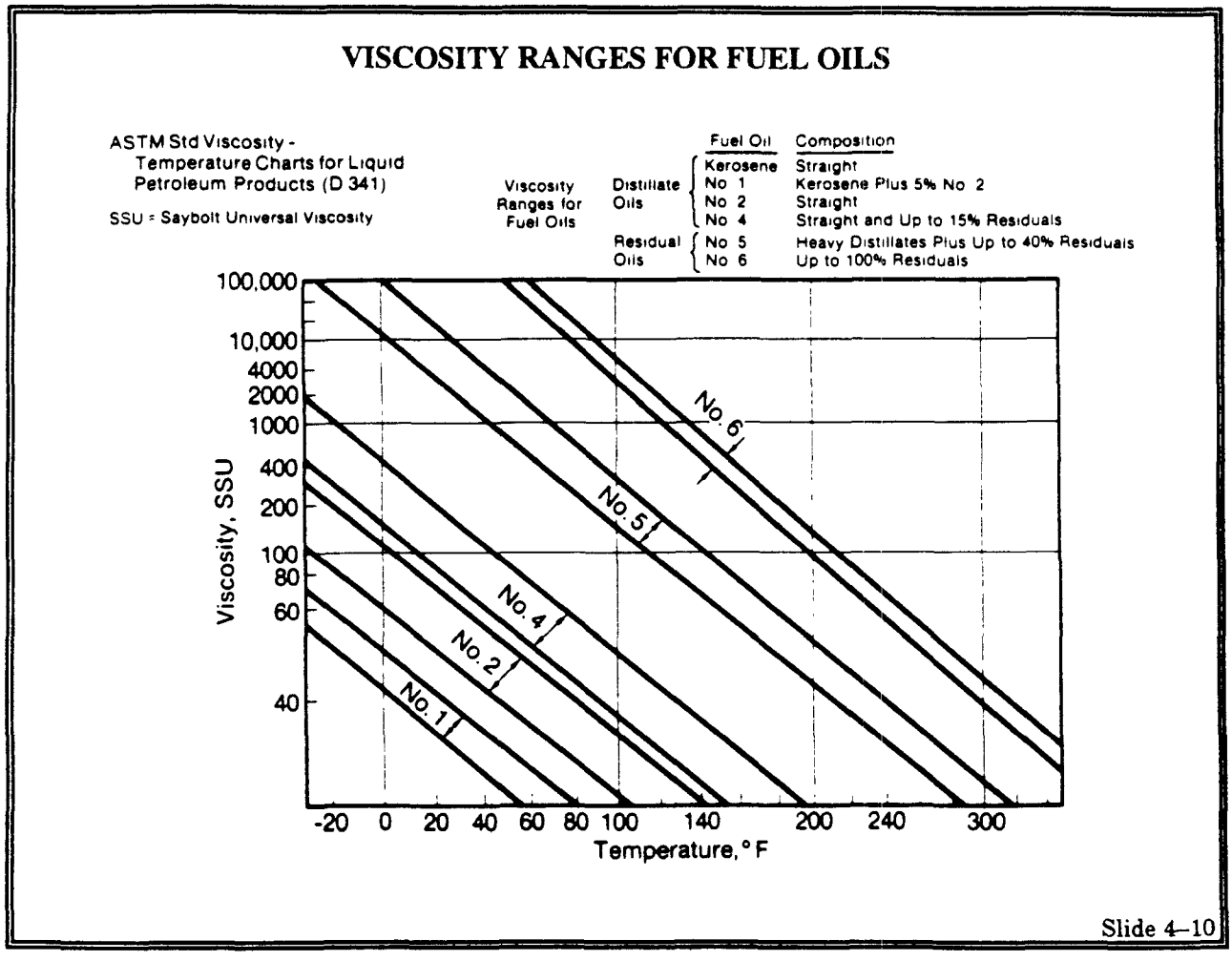
Given:

Sp. Gr. (60°F) of oil = 0.973
Water Density (60°F) = 8.328 lb/gal

Oil Density (60°F) = 0.973 x 8.328
= 8.099 lb/gal

Slide 4–9

Viscosity: Handling and burning equipment is usually designed for a maximum oil viscosity. If the viscosities of heavy oils are known at two temperatures, their viscosities at other temperatures can be closely predicted by a linear interpolation (a process to find a value of a function between two known values under the assumption that the three plotted points lie on a straight line) between these two values on the standard ASTM chart shown in Slide 4–10. Viscosity–temperature variations for certain light oils can also be found using the ASTM chart. In this case, however, the designer only needs to know the viscosity at one temperature. For example, the viscosity of a light oil at a given temperature within the No. 2 fuel oil range can be found by drawing a line parallel to the No. 2 boundary lines through the point of known temperature.



Pour point: Pour points for domestic heavy oils range from 25 to 65°F. But normal heating of storage tanks, pipelines, and pumping equipment above this range of temperatures reduces the resistance to flow.

Flash point: Distillate oils normally have flash points from 145 to 200°F, while the flash points for heavy oils can be as high as 250°F. Thus, fuels oils do not present a fire hazard at ambient temperatures unless they are contaminated with a volatile product.

Water and Sediment: Distillate oils have a trace to 0.2 percent of water and sediment; the heavier grades have from 0.1 to 2 percent.

4.4 Coal

Formation of Coal

Coal is formed from plants which have undergone chemical and geological processes over millions of years. Layers of plant debris are deposited in wet and swampy regions under conditions which prevent exposure to air and complete decay as the debris accumulate. Bacterial actions, pressure, and temperature act on the organic matter over time to form coal. The geological process that transforms debris to coal is called *coalification*. The first product of this process, peat, often contains partially decomposed stems, twigs, and bark and is not classified as coal. However, peat is progressively transformed to lignite which eventually can become anthracite given the proper progression of the geological changes.

Coal is very heterogeneous and can vary in chemical composition by location. In addition to the major organic ingredients—carbon, hydrogen, and oxygen—coal also contains impurities. The impurities that are of major concern are ash and sulfur. The ash results from mineral or inorganic material introduced during coalification. Ash sources include inorganic substances, such as silica, which are part of the chemical structure of the plants. Dissolved inorganic ions and mineral grains found in swampy water are also captured by the organic matter during early coalification. Mud, shale, and pyrite are deposited in pores and cracks of the coal seams. Sulfur occurs in coal in three forms: 1) organic sulfur, which is part of the coal's molecular structure, 2) pyritic sulfur, which occurs as the mineral pyrite, and 3) sulfate sulfur, primarily from iron sulfate. The principal source is sulfate ion, which is found in water. Fresh water has a low sulfate concentration while salt water has high sulfate content. Therefore, bituminous coal, deposited in the interior of the U.S. when seas covered this region, are high in sulfur. Some Iowa coals contain as much as 8% sulfur.

Classification of Coal

Coals are grouped according to rank, the degree of progressive alteration in the transformation from lignite to anthracite. The system used in the U.S. for classifying coal by rank was established by the American Society for Testing and Materials (ASTM). ASTM classification is a system which uses the volatile matter and fixed carbon (FC) results from the proximate analysis and the heating value of the coal as ranking by criteria. This system aids in identifying commercial uses of coals and provides basic information regarding combustion characteristics.

The classification system is given in Slide 4–11 and described in section D 388 of the ASTM standards. For older and higher rank coals, fixed carbon and volatile matter are used as the classifying criteria. These criteria are determined on a dry, mineral–matter–free basis using formulas developed by S.W. Parr in 1906 (Slide 4–12). The younger or lower rank coals are classified by Btu content on a moist, mineral–matter free basis. Agglomerating or weathering indices as described in the ASTM D 388, are used to differentiate adjacent groups.

CLASSIFICATION OF COAL BY RANK[a]

Class and Group	Fixed Carbon Limits, % (Dry, Mineral-Matter-Free Basis) Equal or Greater Than	Fixed Carbon Limits, % (Dry, Mineral-Matter-Free Basis) Less Than	Volatile Matter Limit,s, % (Dry, Mineral-Matter-Free Basis) Equal or Greater Than	Volatile Matter Limit,s, % (Dry, Mineral-Matter-Free Basis) Less Than	Calorific Value Limits, Btu/lb (Moist[b], Mineral-Matter-Free Basis) Equal or Greater Than	Calorific Value Limits, Btu/lb (Moist[b], Mineral-Matter-Free Basis) Less Than	Agglomerating Character
I. Anthracite							
1. Meta-Anthracite	98	—	—	2	—	—	Nonagglomerating
2. Anthracite	92	98	2	8	—	—	
3. Semi-Anthracite[c]	86	92	8	14	—	—	
II. Bituminous Coals							
1. Low-volatile	78	86	14	22	—	—	
2. Medium-volatile	69	78	22	31	—	—	
3. High-volatile A	—	69	31	—	14,000[d]	—	Agglomerating[e]
4. High-volatile B	—	—	—	—	13,000[d]	14,000	
5. High-volatile C	—	—	—	—	11,500	13,000	
					10,500	11,500	Agglomerating
III. Subbituminous Coals							
1. Subbituminous A	—	—	—	—	10,500	11,500	
2. Subbituminous B	—	—	—	—	9,500	10,500	Nonagglomerating
3. Subbituminous C	—	—	—	—	8,300	9,500	
IV Lignite							
1. Lignite A	—	—	—	—	6,300	8,300	
2. Lignite B	—	—	—	—	—	6,300	

[a] This classification does not include a few coals, principally nonbanded varieties, which have usual physical and chemical properties and which come within the limits of fixed carbons or calorific value of the high-volatile bituminous and subbituminous ranks. All of these coals either contain less than 48% dry, mineral-free-matter fixed carbon and have more than 15,500 moist, mineral-matter free Btu per pound.

[b] Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.

[c] If agglomerating, classify in low-volatile group of the bituminous class.

[d] Coals having 69% or more fixed carbon on the dry, mineral-matter-free basis shall be classified by fixed carbon, regardless of calorific value.

[e] It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class, and there are notable exceptions in high-volatile C bituminous group.

Data from ASTM Standards D 388, Classification of coals by Rank. Slide 4–11

PARR FORMULAS[2]

$$\text{Dry, mineral-free FC} = \frac{\text{FC} - 0.15\text{S}}{100 - (\text{M} + 1.08\text{A} + 0.55\text{S})} \times 100$$

$$\text{Dry, mineral-free VM} = 100 - \text{Dry, mineral-free FC}$$

$$\text{Moist, mineral-free Btu} = \frac{\text{Btu} - 50\text{S}}{100 - (1.08\text{A} + 0.55\text{S})} \times 100$$

APPROXIMATION FORMULAS[2]

$$\text{Dry, mineral-free FC} = \frac{\text{FC}}{100 - (\text{M} + 1.1\text{A} + 0.1\text{S})} \times 100$$

$$\text{Dry, mineral-free VM} = 100 - \text{Dry, mineral-free FC}$$

$$\text{Moist, mineral-free Btu} = \frac{\text{Btu}}{100 - (1.1\text{A} + 0.1\text{S})} \times 100$$

Where:
Btu = Heating value per lb,
FC = Fixed carbon, %
VM = Volatile matter, %
M = Bed moisture, %
A = ash, %
S = Sulfur, %

Slide 4–12

Anthracite: Anthracite, the highest rank of coal, is shiny, black, hard and brittle, with little appearance of layers. It has the highest content of fixed carbon, 86 to 98%. However, its low volatile content makes it a slow burning fuel. Most anthracite have a very low moisture content of about 3% and heating values of about 15,000 Btu/lb. Anthracite is low in sulfur and volatiles and burns with a hot clean flame. These qualities make it a premium fuel used mostly for domestic heating.

Bituminous: Bituminous coal is the rank most commonly burned in electric utility boilers. In general, it appears black with banded layers of glossy and dull black. Typical bituminous coals have heating values of 10,500 to 14,000 Btu/lb and a fixed carbon content of 69 to 86%. The heating value is higher but moisture and volatile matter content are lower than subbituminous and lignite coals. Bituminous coals rarely experience spontaneous combustion in storage. Furthermore, the high heating

value and fairly high volatile matter enable bituminous coals to burn easily when pulverized to a fine powder. Some types of bituminous coals, when heated in the absence of air, soften and release volatiles to form a porous, hard, black product known as *coke*.

Subbituminous: Subbituminous coals are black, having little of the plant like texture and none of the brown color, associated with the lower rank coals. Subbituminous coals are noncoking (undergo little swelling upon heating) and have relatively high moisture content which averages from 15 to 30%. They also display a tendency toward spontaneous combustion when drying.

Although they are high in volatile matter content and ignite easily, subbituminous coals generally have less ash and are cleaner burning than lignite coals. Subbituminous coals in the U.S. in general have a low sulfur content, often less than 1%, and reasonably high heating values, 8,300 to 11,500 Btu/lb.

Lignite: Lignite is the lowest rank coal. Lignite are relative soft and brown to black in color with heating value less than 8,300 Btu/lb. The deposits are geologically young and can contain recognizable remains of plant debris. The moisture content of lignites is as high as 30% but the volatile matter is also high; consequently, they ignite easily. Lignite coal dries when exposed to air and spontaneous combustion during storage is a concern. Long distance shipment is not economical because of their high moisture and low Btu contents.

Peat: The first product in the formation of coal, is a heterogeneous material consisting of partially decomposed plant and mineral matter. Its color ranges from yellow to brownish black, depending on its geologic age. Peat has a moisture content up to 70% and a heating value as low as 3,000 Btu/lb.

COAL CHARACTERIZATION

Proximate Analysis
Ultimate Analysis
Bases of Analyses
- As–received basis
- Dry basis
- Dry mineral–matter free basis

Slide 4–13

There are two types of fuel characterization methods: *proximate analysis* and *ultimate analysis*. Proximate analysis, typically conducted for solid fuels, gives information on the behavior of a solid fuel when it is heated; that is, how much of the fuel burns as gas or *volatile matter*, and how much remains as *fixed carbon*. Proximate analysis provides useful information to assist in the selection of a fuel for a boiler. In addition to the volatile matter and fixed carbon determination, proximate analysis provides *moisture* and *ash* contents as well as the *heating value* of the fuel. ANSI/ASTM Standards D 3172 is the basic method for proximate analysis of coal and coke.

The ultimate analysis gives the elemental analysis of the fuel. The elements include *carbon*, *hydrogen*, *nitrogen*, *oxygen*, and *sulfur*. *Ash* which consists of several compounds is usually determined as a whole, and whenever necessary, composition of the ash is given in a separate analysis. ASTM Standards D 3176 is the standard method for ultimate analysis of coal and coke.

Fuel analysis may be given in several bases. In combustion calculations, the *as–received* basis is applicable. Typically, the *dry* or *moist* and *mineral–matter–free* bases are used.

As–Received Basis: The as–received analysis of a fuel represents the actual proportions of the constituents in the fuel sample as received at the laboratory. The sample may be fuel as fired, as mined, or in any other given condition.

Dry Basis: Moisture content is variable, even in the same coal, under different conditions of handling and exposure. For example, coal as received at a plant may

contain an amount of moisture different from that received at the laboratory for analysis, and both may vary with weather conditions.

Dry Mineral–Matter–Free Basis: As mentioned previously, because the ash does not correspond in percentage to the mineral matter in the coal, errors are introduced which becomes significant in problems of classifying coals according to rank. Parr and other approximation formulas (Slide 4–12) are used for such calculations.

Items of Proximate Analysis

ITEMS OF PROXIMATE ANALYSIS

Moisture
Volatile Matter
Fixed Carbon
Ash
Heating Value
Ash Fusion Temperature
Free Swelling Index
Grindability

Slide 4–14

Moisture: Coal received at an electric power plant contains varying amounts of moisture in several forms. There is inherent and surface moisture in coal . Inherent moisture is that which is a naturally combined part of coal deposit. It is held tightly within the coal structure and can not be removed easily when the coal is dried in air. The surface moisture is not part of the coal deposit and has been added externally. Surface moisture is more easily removed from coal when exposed to air. It is not possible to distinguish, by analysis, inherent and surface moisture.

There are many other moistures which arise when characterizing coal including equilibrium, free and air dry moisture. Their definitions and use depend on the application. The ASTM standard procedure for moisture determination, D 121, defines the total coal moisture as the loss in weight of a sample under controlled conditions of temperature, time and air flow. Using ASTM 3302, the total moisture is calculated from the moisture lost or gained in air drying and the residual moisture. The residual moisture is determined by oven drying the air dried sample. Because subsequent ASTM analyses (such as proximate and ultimate) are performed on an air dried sample, the residual moisture value is required to convert these results to a

dry basis. In addition, the moisture lost on air drying provides an indication of the drying required in the handling and pulverization portions of the boiler coal feed system.

Volatile Matter: The volatile matter is that portion which, exclusive of water vapor, is driven off in gas or vapor form when the coal is subjected to a standardized temperature test. It consists of hydrocarbons and other gases resulting from distillation and decomposition. ASTM D 3175 is the standard method to determine volatile matter in coal and coke.

The main constituents of volatile matter in all ranks of coal are hydrogen, oxygen, carbon monoxide, methane and other hydrocarbons, and that portion of moisture that is formed by chemical combination during thermal decomposition of the coal substance. The composition of volatile matter varies greatly for different ranks of coals.

Fixed Carbon: The fixed carbon is the combustible residue left after driving off the volatile matter. It is not all carbon, and its form and hardness are an indication of the coking (dry distillation of coal to make coke) properties of a coal, and therefore, a guide in the choice of fuel–firing equipment. In general, the fixed carbon represents that portion of the fuel that must be burned in solid state, either in the fuel bed on a stoker, or as solid particles in the pulverized fuel furnace.

The fixed carbon in a proximate analysis is a calculated figure obtained by subtracting from 100 the sum of the percentages of moisture, volatile matter and ash.

Ash: Ash is the noncombustible residue after complete combustion of the coal. The weight of ash is usually slightly less than that of the mineral matter originally present before burning. The ASTM definition for coal ash is the organic residue remaining after ignition of combustible substances, determined by definite prescribed methods. This definition is followed by two notes, one of which states that ash may not be identical—in composition or quantity—to inorganic substances before ignition.

The second note specifies that, in the case of coal and coke, the methods shall be those prescribed by ASTM Standards D 3174. This method determines the ash content by weighing the residue remaining after the coal is burned under rigidly controlled conditions of sample weight, temperature, time and atmosphere, oxidizing or reducing.

Ash is usually considered the product of complete combustion of coal. It is composed of the oxides formed from the mineral constituent of coal. However, these minerals may be present in two forms in coal: (1) as visible impurities or (2) as minute impurities so finely divided and so intimately mixed that they may be considered a part of the coal structure.

The term *inherent* or *fixed ash content* is used to designate that portion of the ash content that is structurally part of the coal and cannot be separated from it by mechanical means. This is a relative term, however, and will have different values, since mechanical separation is accomplished at varying levels according to the size of the coal.

Heating Value: In the U.S., the calorific or heating value of a solid fuel is expressed in Btu per lb of fuel on as–received, dry, or moisture– and ash–free basis. It is the amount of heat recovered when the product of complete combustion of a unit quantity of a fuel are cooled to the initial temperature of the air and fuel. Heating values as determined in calorimeters are termed high or gross heating values, and include the latent heat of the water vapor in the products of combustion. The most common type of calorimeter in use today is the adiabatic bomb calorimeter, and ASTM Standards D 2015 covers this test. In actual operation of boilers, the water vapor in the combustion gas leaving is not cooled below its dew point, and this latent heat is not available for making steam. The latent heat can be substracted from the high, or gross, heating value to give the low, or net, heating value. Lower heating values are standard European practice and higher heating values are standard American practice.

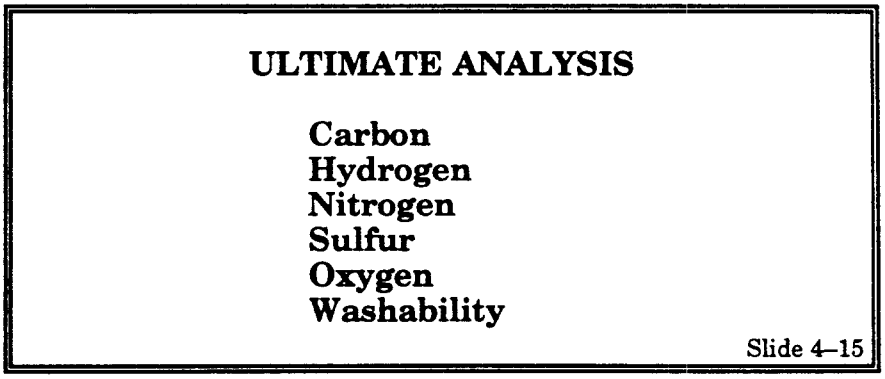
Ash–Fusion Temperature: Coal ash fusion temperatures are determined from cones of ash prepared and heated in accordance with ASTM Standards D 1857. The temperatures at which the cones deform to specific shapes are determined in oxidizing and reducing atmospheres (see Chapter 29). Fusion temperatures provide ash melting characteristics and are used for classifying slagging potentials of the ash. Slagging is the formation of molten, partially melt or resolidified deposits on furnace walls and other surfaces exposed predominantly to radiant heat or excessively high gas temperatures.

Free Swelling Index: The free swelling index is used to measure the caking (changing of a powder into a solid mass) characteristics of a coal. ASTM Standards D 720 is used for free swelling index tests. In these tests, one gram of of coal sample is burned in a covered crucible under specific conditions of temperature and time. The shape of the sample (button formed) is then compared to a set of standard buttons. The larger button formed indicates higher free swelling indices.

Grindability: This test determines the relative ease of pulverization of coal in comparison with coals chosen as standards. The Hardgrove method has been accepted as the standard, and ASTM Standards D 409 is the Grindability of Coal by the Hardgrove–Machine Method. Each Hardgrove machine is calibrated by use of standard reference samples of coal, having grindability indexes of approximately 40, 60, 80, and 100. The Hardgrove–index number reported by the laboratory is based on an original soft coal chosen as a standard coal whose grindability index was set at 100. Therefore, the harder the coal, the lower the index number.

Since the grindability index varies, not only from seam to seam but also within the same seam, grindability data are of utmost economic importance to the users of commercial grinding and pulverizing equipment.

Items of Ultimate Analysis



Ultimate analysis is needed for computation of air requirements, weight of products of combustion, and heat losses, on boiler tests. The air requirement and the weight of products of combustion determine fan sizes. The following are items of ultimate analysis as determined by ASTM standards D 3176.

Carbon: Total carbon includes both the carbon in the fixed carbon and in the volatile matter, and will be proportionately greater than the fixed carbon as the volatile content of the coal increases. All this carbon appears in the products of combustion as CO_2 when the fuel is completely burned.

Hydrogen: When coal is burned, all hydrogen in the fuel is transformed into water and, together with the moisture in the fuel, appears as water vapor in the waste gas. Ultimate analysis includes moisture in the hydrogen and oxygen items. The weight of the water vapor in the products of combustion is nine times the weight of the hydrogen in the coal.

Nitrogen: Nitrogen in most solid fuels is low and of no importance in combustion calculations.

Sulfur: Sulfur is separately determined, and its amount is useful in judging the corrosiveness of the products of combustion of a fuel. Combustion of sulfur forms an oxide, which combines with water to form acids that may be deposited when the combustion gas is cooled below its dew–point temperature.

Sulfur in coal occurs mainly in three forms. It can be present as the sulfide ion in pyrites and marcasite; or it can be present as the sulfate ion. Rarely, sulfur may occur as elemental sulfur in coal, but in amounts too insignificant to be appreciable. ASTM Standards D 2492 gives a standard test method to determine the form of sulfur in the coal.

Two methods are generally accepted for total sulfur determination. Eschka's method converts all the sulfur present in the coal to the sulfate ion, which is then precipitated as $BaSO_4$. The Eschka method requires a time period—including sample preparation—of up to 24 hours, so a more rapid method of high–temperature combustion has been adopted. Details and analytical procedures for both of these methods may be found in ASTM standards D 3177.

Oxygen: The oxygen content of fuels is a guide to the rank of the fuel. The amount of oxygen is high in low–rank fuels like lignite. Oxygen in fuels is in combination with carbon and hydrogen and, therefore, represents a reduction in the potential heat of a fuel. High–oxygen fuels have low heating values. As there is no direct ASTM method of determining oxygen, it is calculated by subtracting from 100 the sum of the other components in the ultimate analysis.

Washability: The washability characteristic of a coal is the most important tool available to determine the extent to which a coal may be cleaned. Examination of washability data for a particular coal of a particular size of coal will reveal the quality of coal which may be obtained by mechanical cleaning, as well as the quantity of coal of particular quality. Further examination of the data will indicate the ease or difficulty with which the coal may be cleaned or will give valuable information concerning the type of commercial cleaner most suitable for that particular coal.

The ash, sulfur, or Btu specifications of all of the final product generally dictate whether or not cleaning is necessary. After technical considerations are evaluated with the help of washability characteristics and if cleaning is technically sound, the

economic decisions are made. These considerations include the value of the final product and the cost of obtaining it.

Float–and–sink separation is quite effective for determining the washability characteristics of coarse coal, but the problems associated with cleaning of extremely fine sizes dictate other methods. Froth flotation process consists of passing air through a suspension of fine coal in water. The coal particles attach themselves to the air bubbles and are removed in the froth on top of the pulp. The refuse particles remain in the pulp. Chemical are added to the pulp to help produce the froth.

Example Coal Analyses

EXAMPLE COAL ANALYSES

Coal: Eastern Bituminous

Proximate Analysis (as rec'd)		**Ultimate Analysis** (as rec'd)	
Total Moisture	17.80	Moisture	17.80
Volatile Matter	34.04	Carbon	57.76
Fixed Carbon	39.38	Hydrogen	3.99
Ash	8.78	Oxygen	7.51
		Nitrogen	1.16
		Sulfur	3.00
		Ash	8,78

Higher Heating Value 10,406 Btu/lb

Ash Analysis (as rec'd)		**Ash Fusion Temperatures** (°F)		
			Reducing	Oxidizing
SiO_2	50.65			
Al_2O_3	13.91			
TiO_2	0.89	Initial Deform temp.	1,930	2,230
Fe_2O_3	18.88	Softening temp.	2,000	2,400
CaO	6.26	Hemispherical temp.	2,150	2,480
MgO	0.85	Fluid temp.	2,260	2,580
Na_2O	1.36			
K_2O	1.52	**Slagging Index**	Medium	
P_2O_5	0.18	**Fouling Index**	High	
SO_3	5.72			

Hardgrove Grindability Index 58

Slide 4–16

Slide 4–16 shows an example coal analysis of a bituminous coal. In this example, proximate, ultimate and ash analyses are on as received basis. Ash fusion temperatures are given in both reducing and oxidizing environments.

REFERENCES

1. Singer, J. G., *Combustion: Fossil Power Systems*, 3rd edition, Combustion Engineering, Inc., 1981.

2. *Steam, Its Generation and Use*, 40th Edition, Babcock and Wilcox Company, 1992.

3. Elliot, C.T., *Standard Handbook of Powerplant Engineering*, McGraw Hill Publishing Company, New York, 1989.

4. *Annual Book of ASTM Standards*, Section O, Index, American Society for Testing and Materials, 1987.

CHAPTER 5. COMBUSTION PRINCIPLES

5.1 Basic Combustion Concepts
- A. Combustion Processes
- B. Composition of Combustion Air

5.2 Air-Fuel Mixture

5.3 Combustion Equations
- A. Concept of the Mole
- B. Fundamental Laws
- C. Balancing Combustion Equations

5.4 Combustion Calculations
- A. Molar Evaluation of Combustion
- B. Calculating Theoretical Air
- C. Calculating Excess Air
- D. Calculating Percent Excess Air

5.5 Heat Transfer Fundamentals
- A. Basic Modes of Heat Transfer
- B. Heat Transfer Parameters

5. COMBUSTION PRINCIPLES

5.1 Basic Combustion Concepts

Combustion Processes

SIMPLIFIED COMBUSTION PROCESSES

Reactants				Products	
carbon	+	oxygen	--->	carbon dioxide	+ heat
hydrogen	+	oxygen	--->	water vapor	+ heat
sulfur	+	oxygen	--->	sulfur dioxide	+ heat

Slide 5-2

As a simplification, combustion processes can be described as shown Slide 5–2. Combustion, or burning, is a rapid combination of oxygen with a fuel, resulting in release of heat. The principal combustible constituents of a fuel are elemental carbon, hydrogen, and their compounds. In the combustion process, the elements and compounds are burned to release heat. Carbon dioxide and water vapor are formed in the process. In addition, small quantities of sulfur are present in most fuels. Although sulfur is a combustible and contributes slightly to the heating value of the fuel, its presence is generally detrimental because of the corrosive nature of its compounds.

The three products of combustion listed above are called *chemical compound*s, and they are made up of molecules in which elements are combined in certain fixed proportions. For example, a molecule of carbon dioxide, written as CO_2, contains one atom of carbon plus two atoms of oxygens; a molecule of water, written as H_2O, contains two atoms of hydrogen plus one atom of oxygen.

Composition of Combustion Air

The oxygen needed for the combustion process comes from the air, which is about 21 percent oxygen, 78 percent nitrogen, and 1 percent by volume of other elements or compounds, such as argon, carbon dioxide, moisture, etc... The composition of dry atmospheric air is given in Slide 5–3.

COMPOSITION OF COMBUSTION AIR

Dry Atmospheric Air

	Volume %	Mole. Wt.
Nitrogen	78.09	28.02
Oxygen	20.95	32.00
Argon	0.93	39.94
Carbon dioxide	0.03	41.01

Slide 5–3

5.2 Air–Fuel Mixture

COMBUSTION TERMS

Excess Oxygen
Excess Air
Stoichiometric
Lean Mixture, Oxidizing Flame
Rich Mixture, Reducing Flame
Oxygen Supply
Time, Turbulent, Temperature

Slide 5–4

Perfect combustion is obtained by mixing and burning just exactly the right proportions of fuel and oxygen so that nothing is left over (no *excess* oxygen). These proportions are called, in theory, *stoichiometric* quantities. In practice, however, it is not possible to operate a boiler at the theoretical level of zero percent excess oxygen. This condition is approached by providing an excess amount of oxygen in the form of *excess air* from the atmosphere. The amount of excess air varies with fuel, boiler load, and the type of firing equipment.

In practice, excess air levels are kept at a minimum for the reasons as follows:

- minimize heat loss due to heating up the extra air (see Chapter 6),
- reduce chances of tube erosion in the upper furnace,
- reduce air pollution emissions (see Chapter 6), and
- this minimum needs to be sufficient to minimize combustible losses in the flue gas and CO and hydrocarbon emissions (See Chapter 6).

If more than the stoichiometric amount of oxygen is supplied, the mixture is

called *lean* and the fire is called *oxidizing*. This results in a flame that tends to be shorter and clearer. If more than the stoichiometric amount of fuel is supplied, the mixture is called *rich* and the fire is called *reducing*. This results in a flame that tends to be longer and sometimes smoky. This situation is usually called incomplete combustion; that is, all of the fuel particles combine with *some* oxygen, but they cannot get enough oxygen to burn completely.

The *oxygen supply* for combustion usually comes from the air. Because air contains a large proportion of nitrogen, the required volume of air is much larger than the required volume of pure oxygen. Most of the nitrogen in the air does not take part in the combustion reaction. It does, however, absorbs some of the heat. This means that a much lower flame temperature results from using air instead of pure oxygen. The same phenomenon occurs when large amounts of excess air are supplied.

In addition to absorbing heat, a small amount of nitrogen combines with oxygen at high temperatures (greater than 2500°F) to form nitrogen oxides, which become air pollutants once emitted to the atmosphere. Air pollutants from combustion processes will be discussed in Chapter 6.

The rate and degree of completion of a combustion process are greatly influenced by three general factors: *time, turbulence* and *temperature.* The more **time** a fuel and air mixture have at the proper combustion conditions, the more likely complete combustion will occur. Mixing of the fuel and air is important for a uniform mixture where every particle of fuel contacts oxygen. **Turbulent** mixing of the fuel and air results in a more uniform mixture, the combustion reaction will go to completion better—turbulent. At higher a **temperature**, the rate of the combustion reaction will go faster since fuel and air will be in contact more frequent due to increases in molecular movement.

5.3 Combustion Equations

Concept of the Mole

CONCEPT OF THE MOLE

- **A mole always contains the same number of particles.**
- **Pound mole (mole) is molecular weight expressed in pounds.**

Example:
1 mole of CO_2 weighs 44 lbs
1 mole of H_2O weighs 18 lbs

Slide 5-5

The key to understanding the concept of the mole is that it always contains the same number of particles, no matter what the substance. Many, many experiments over the years have established that number as:

$$1 \text{ mole} = 6.022045 \times 10^{23} \text{ particles}$$
$$= 602{,}204{,}500{,}000{,}000{,}000{,}000{,}000 \text{ particles}$$

This number, usually rounded off to 6.022×10^{23}, is known as Avogadro's number in honor of Amadeo Avogradro, an Italian lawyer and physicist (1766–1856) who conceived the basic idea.

A molecular weight expressed in pounds is called a *pound mole*, or simply a *mole*. The molecular weight is the sum of the atomic masses of a substance's constituent atoms. For example pure elemental carbon (C) has an atomic mass and molecular weight of 12 and therefore a mole of C is equal to 12 lbs. In the case of carbon dioxide (CO_2), carbon still has an atomic mass of 12 and oxygen has an atomic mass of 16 giving CO_2 a molecular weight and a mole equal to (1 x 12) + (2 x 16) or 44 lbs.

In the case of a gas, the volume occupied by one mole is called the molar volume. The volume of one mole of an ideal gas is constant regardless of its composition for a given temperature and pressure. Therefore, one mole or a mole of oxygen (O_2) at 32 lb and one mole of CO_2 at 44 lb will occupy the same volume equal to 394 ft^3 (cubic feet) at 80°F and 14.7 psi (pounds per squared inch). The volume occupied by one mole of a gas can be corrected to other pressures and temperatures by the ideal gas law.

Fundamental Laws

FUNDAMENTAL LAWS

Conservation of Matter
Conservation of Energy
Law of Combining Weight
Avogadro's Law
Ideal Gas Law

Slide 5-6

Combustion calculations are based on several fundamental physical laws.

Conservation of Matter: This law states that matter can not be destroyed or created. There must be a mass balance between the sum of the components entering a process and the sum of those leaving: X pounds of fuel combined with Y pounds of air always results in X + Y pounds of products.

Conservation of Energy: This law states that energy can not be created or destroyed. The sum of the energies (potential, kinetic, thermal, chemical and electrical) entering a process must equal to the sum of those leaving, although the proportions of each may change.

Law of Combining Weight: This law states that all substances combine in accordance with simple, definite weight relationships. These relationships are exactly proportional to the molecular weights of the constituents. For example, carbon (molecular weight = 12) combines with oxygen (molecular weight = 32) to form carbon dioxide (molecular weight = 44) so that 12 lb of C and 32 lb of O_2 combine to form 44 lb of CO_2.

Avogadro's Law: Avogadro determined that equal volumes of different gases at the same pressure and temperature contain the same number of molecules. From the concept of the mole, a pound mole of any substance contains a mass equal to the molecular weight of the substance. Therefore, the ratio of mole weight to molecular weight is a constant and a mole of any chemically pure substance contains the same number of molecules. Because a mole of any ideal gas occupies the same volume at a given pressure and temperature (ideal gas law), equal volumes of different gases at the same pressure and temperature contain the same number of molecules.

IDEAL GAS LAW

This law state that the volume of an ideal gas is directly proportional to its absolute temperature and inversely proportional to its absolute pressure. The proportionality constant is the same for one mole of any ideal gas, so this law may be expressed as:

$$\mathbf{R} = \frac{P_1V_1}{T_1} = \frac{P_2V_2}{T_2}$$

Where:

R = universal gas constant, 1545 ft lb/mole R.
V = molar volume, ft^3/mole
P = absolute pressure, lb/ft^2
T = absolute temperature, R = °F + 460

Most gases involved in combustion calculations can be approximated as ideal gases.

Slide 5-7

Balancing Combustion Equations

The law of conservation of matter requires that the mass of the substances must be the same on each side of the reaction equation. In another word, balancing a chemical equation ensures that the same number of atoms of each element involved appears on each side of the equation. A partial list of the combustion equations are given in Slide 5–8.

COMBUSTION EQUATIONS

Combustibles	Reaction	
Carbon	$C + O_2$	---> CO_2
Hydrogen	$H_2 + {}^1/_2O_2$	---> H_2O
Sulfur	$S + O_2$	---> SO_2
Methane	$CH_4 + 2O_2$	---> $CO_2 + H_2O$
Ethane	$C_2H_6 + {}^7/_2O_2$	---> $2CO_2 + 3H_2O$
Propane	$C_3H_8 + 5O_2$	---> $3CO_2 + 4H_2O$

Slide 5–8

Taking the combustion equation of carbon as an example and applying these concepts, now this equation can be written in several ways:

FORMS OF COMBUSTION EQUATIONS

$C + O_2 = CO_2$

1 molecule C	+	1 molecule O_2	=	1 molecule CO_2
1 mole C	+	1 mole O_2	=	1 mole CO_2
12 lb C	+	32 lb O_2	=	44 lb CO_2
1 ft^3 C(1)	+	1 ft^3 O_2	=	1 ft^3 CO_2

(1) If C were an ideal gas instead of solid, 1 ft^3 of C combines with 1 ft^3 of O_2 to form 1 ft^3 of CO_2.

Slide 5–9

Each equation balances; there are the same number of atoms of each element and the same weight of reacting substances on each side of the equal sign but *not necessarily the same number of molecules, or moles or volumes.* Thus, one atom of carbon combines with one molecule of oxygen to give *only* one molecule of carbon dioxide.

BALANCING COMBUSTION EQUATIONS

(unbalanced equation)

$C_3H_8 + O_2 \dashrightarrow CO_2 + H_2O$

$\mathbf{C_3H_8} + O_2 \dashrightarrow \mathbf{3}CO_2 + H_2O$

$C_3\mathbf{H_8} + O_2 \dashrightarrow 3CO_2 + \mathbf{4}H_2O$

(balanced equation)

$C_3H_8 + \mathbf{5}O_2 \dashrightarrow 3CO_2 + 4H_2O$

Slide 5–10

Let's take the combustion equation of propane as another example and balance this equation step by step, see slide 5-10.

Although there are several systematic ways to balance such an equation, it is advisable to leave the oxygen balance to the last step. Generally, it is best to balance the C atom first, followed by H, and then O.

Step 1. *Balance the C atoms.* There are 3 carbon atoms in the reactants, so there must be 3 carbon atoms in the products. Therefore, we need 3 CO_2 molecules on the right side.

Step 2. *Balance the H atoms.* There are 8 H atoms in the reactants. Each molecule of water gas has 2 H atoms, so 4 molecules of water will have the required 8 H atoms.

Step 3. *Balance the O atoms.* There are 10 O atoms on the right side (3 x 2 = 6 in CO_2 and 4 x 1 = 4 in H_2O). Therefore, 5 O_2 molecules are needed to supply the required 10 O atoms.

Step 4. *Verify that each element is balanced.* The reaction involves 3 C atoms, 8 H atoms, and 10 O atoms on each side.

It should be noted again that the total mass of the reactants is the same as that of the products, but not the total number of moles.

Mass of reactants:	(3 x 12 + 8 x 1) + (5 x 32)	= 204 lbs
Mass of products:	(3 x 44) + (4 x 18)	= 204 lbs

(Note that one atom of H weighs 1 lb and one mole of water weighs 18 lbs)

Moles of reactants:	1 moles + 5 moles	= 6 moles
Moles of products:	3 moles + 4 moles	= 7 moles

5.4 Combustion Calculations

Molar Evaluation of Combustion

MOLE-VOLUME RELATIONSHIP

Because a mole of every ideal gas occupies the same volume, by Avogadro's law, the mole fraction of a component in a mixture of ideal gases equals the volume fraction of that component.

$$\frac{\text{Moles of component}}{\text{Total moles}} = \frac{\text{Volume of component}}{\text{Volume of mixture}}$$

This is a valuable concept because the volumetric analysis of a gaseous mixture automatically gives the mole fractions of the components.

Slide 5–11

Molar calculations have a simple and direct application to gaseous fuels, where the analyses usually reported on a volume percent basis. The mole fraction of a component in a mixture is the number of moles of that component divided by the total number of moles of all components in the mixture.

Consider the following fuel analysis:

(1) Constituents	(2) Vol. %	(3) Moles
CH_4	85.0	85.0
C_2H_6	12.5	12.5
CO_2	0.2	0.2
N_2	1.8	1.8
O_2	0.5	0.5
Total	100.0	100.0

The fuel analysis may be expressed as 85.0 moles of CH_4 per 100 moles of fuel, 12.5 moles of C_2H_6 per 100 moles of fuel, etc... as shown in Column 3.

The elemental breakdown of each constituent may also be expressed in moles per 100 moles of fuel as follows:

C in CH_4	=	85.0 x 1	=	85.0 moles
C in C_2H_6	=	12.5 x 2	=	25.0 moles
C in CO_2	=	0.2 x 1	=	0.2 moles
Total C per 100 moles of fuel			=	110.2 moles
H_2 in CH_4	=	85.0 x 2	=	170.0 moles
H_2 in C_2H_6	=	12.5 x 3	=	37.5 moles
Total H_2 per 100 moles of fuel			=	207.5 moles
O_2 in CO_2	=	0.2 x 1	=	0.2 moles
O_2 as O_2	=	0.5 x 1	=	0.5 moles
Total O_2 per 100 moles of fuel				0.7 moles
Total N_2 per 100 moles of fuel			=	1.8 moles

Therefore, the above fuel analysis may be written in term of *elemental basis* as follows:

Element	moles/100 moles fuel
C	110.2
H_2	207.5
O_2	0.7
N_2	1.8

The oxygen/air requirements and products of combustion can be calculated for each constituent on an elemental analysis. Converting the gaseous constituents to an elemental basis has two advantages. It provides a better understanding of the combustion process and provides a means for determining the elemental fuel analysis on a *mass basis*. This is boiler industry standard practice and is convenient for determining a composite analysis when gaseous and solid/liquid fuels are fired in combination.

CONVERTING FUEL ANALYSIS FROM VOLUME BASIS TO MASS BASIS

(1) Element	(2) Moles / 100 Moles fuel	(3) lb / Mole	(4) lb / 100 Moles fuel	(5) lb / lb fuel	(6) lb / 100 lb fuel
C	110.2	12.01	1323.5	0.73	72.9
H_2	207.5	2.02	419.2	0.23	23.1
O_2	0.7	32.00	22.4	0.12	1.2
N_2	1.8	28.01	50.4	0.28	2.8
Total			1815.5		100.0

Slide 5–12

Column 3 is the molecular weight of the elements.

Column 4 is determined by multiplying Column 2 by Column 3 to convert moles to mass (lb).

Column 5 is determined by dividing lb of each element by the total lb of fuel in Column 4. For example for carbon C, 1323.5/1815.5 = 0.729, etc...

Column 6 is determined by simply multiplying the mass of each element in column 5 by 100.

Calculating Theoretical Air

The molar evaluation method is a useful tool in calculating air flows in combustion processes. Assume a coal of the following analysis, calculate the *theoretical air* (stoichiometric air) required to burn 100 lbs of the coal.

THEORETICAL OXYGEN CALCULATIONS

(1) Coal Constit.	(2) % by wt.	(3) Mole. wt.	(4) Moles	(5) Comb. Product	(6) Moles theo. O_2 req.
C	63.5	12	5.30	CO_2	5.30
H	4.1	2	2.04	H_2O	1.02
S	1.5	32	0.05	SO_2	0.05
O_2	7.4	32	0.23		-0.23
N_2	1.3	28	0.05	N_2	0.00
H_2O	15.0	18	0.83	H_2O	0.00
Ash	7.2				
Total	100.0				6.12

Slide 5-13

Number of moles of each element in Column 4 is determined by dividing each mass by its respective molecular weight (Column 4 = Column 2/ Column 3).

Number of moles of theoretical O_2 in Column 6 required to burn 100 lb of fuel is determined based on combustion equation of each element (see Slide 5–8).

The composition of dry air presented in Slide 5–3 shows that 100 moles of air contains 20.95 moles of oxygen. Therefore, 6.12 moles of O_2 correspond to 29.2 moles of dry air (6.12*100/20.95).

Multiply the moles of air by its molecular weight to obtain mass of air required to burn 100 lb of fuel.

29.2 x 28.97 = 846.8 lb dry air/100 lb fuel.

(Note: 28.97 lb/mole is the molecular weight of air).

Calculating Excess Air

Use the above example, determine the actual air when the coal is burned with 23 percent excess air.

The *actual air* flow is determined by adding the *excess air* flow with the theoretical air flow.

Excess air flow:	846.8 x 0.23	=	194.8 lb dry air/100 lb fuel
Actual air flow:	846.8 + 194.8	=	1041.6 lb dry air/100 lb fuel.

Calculating Percent Excess Air

In practice, the excess oxygen concentration in the flue gas is generally monitored. The following method is applied to determine percent excess air from the measured flue gas oxygen concentration and the elemental composition of the fuel.

CALCULATING PERCENT EXCESS AIR

$$\text{Excess Air, \%} = K \times \frac{O_2}{21 - O_2}$$

Where:

O_2 = Volume percent, dry oxygen in the flue gas

$$K = \frac{100C + 237H + 37.5S + 9N - 29.6O'}{C + 3H + {}^3/_8S - {}^3/_8O'}$$

C = Mass fraction of carbon in the fuel
H = Mass fraction of hydrogen in the fuel
S = Mass fraction of sulfur in the fuel
O' = Mass fraction of oxygen in the fuel
N = Mass fraction of nitrogen in the fuel

(Note that these mass fractions should be given on a dry weight percent basis; lb/lb dry fuel.)

Slide 5-14

Using the fuel composition of Slide 5–13, and given flue gas oxygen concentration of 3.25%, dry and applying the calculation procedure summarized in Slide 5–14, the percent excess air can be determined as follows.

Step 1: Converting fuel composition to dry basis.

(1) Coal Constit.	(2) % by wt.	(3) % by Wt. dry	(4) lb/lb dry coal
C	63.5	74.7	0.747
H	4.1	4.8	0.048
S	1.5	1.8	0.018
O_2	7.5	8.8	0.088
N_2	1.3	1.5	0.015
H_2O	15.0	0.00	
Ash	7.2	8.4	0.084
Total	100.00	100.00	1.000

Column 3 is determined by each constituent composition to the total subtracting moisture. For example, for carbon: 63.5/(100 – 15) = 74.7

Column 4 is determined by converting to 1 lb total basis (Column 3 divided by 100).

Step 2: Calculating K

$$K = \frac{100(0.747) + 237(0.048) + 37.5(0.018) + 9(0.015) - 29.6(0.088)}{0.747 + 3(0.048) + {}^{3}/_{8}(0.018) - {}^{3}/_{8}(0.088)}$$

$$= 97.5$$

Step 3: Calculating percent excess air

$$\text{Excess air, \%} = 97.5 \frac{3.25}{(21 - 3.25)}$$

$$= 17.9\%$$

Basic Modes of Heat Transfer

BASIC MODES OF HEAT TRANSFER

Conduction
Convection
Radiation

Slide 5-15

There are three basic modes of heat transfer: conduction, convection and radiation. One or more of these modes controls the amount of heat transfer in all applications.

Conduction: Conduction of heat is simply the heat transfer of energy due to a temperature difference between adjacent molecules in a solid, liquid or gas. If one end of a steel rod is inserted into a furnace, after a while the other end will become hot due to heat conduction through the rod.

Convection: Heat is transferred between solids and fluids (gas or liquid) by a process known as convection. This is really a combination of conduction and fluid motion. For example, heat moves from the outside surface of a hot oven wall to the adjacent air molecules by conduction, and then the air moves away carrying the heat with it. The motion of the fluid (air in this case) may be due to the natural buoyancy of the heated molecules (hot air rises) in which case the process is termed *free* or *natural convection*, or the motion of the fluid may be mechanically produced (as by a fan) in which case it is termed *forced convection*.

Radiation: Radiation is entirely different from the other two modes of heat transfer. Light is a form of heat radiation, but all heat radiation is not necessarily visible (light). for example, a person can feel the heat radiation from a furnace wall and a hot piece of metal even though neither may be red hot; that is, neither is radiating light. Radiant heat travels in straight lines and may passes through a vacuum air, some gases, some liquids, and a few solids such as glass or quartz.

HEAT TRANSFER PARAMETERS

Heat Transfer Area
Temperature Difference
Conductivity
Diffusivity
Velocity and Turbulence
Relative Positions

Slide 5-16

Heat Transfer Area: The rate of heat flow from a heat source to a heat absorber is proportional to the amount of area through which the heat may flow. For example, the heat loss from a 20 ft^2 furnace wall is twice as great as that from a 10 ft^2 wall if all other factors are the same. The rate of heat transfer through a single square foot of surface area, Btu/ ft^2 hr, is called the *heat flux*.

Temperature Difference: In conduction and forced convection, the heat flow rate is directly proportional to the temperature difference between the heat source and the heat absorber. For example, the heat transfer from a bank of 150°F finned heating coils to a 50°F air stream is only half as much as the heat transferred from 250°F coils to a 50°F air stream, if all other conditions are the same.

In cases involving radiation, temperature difference has a much greater effect because heat flow is proportional to $(T_s^4 - T_a^4)$ where T_s is the absolute temperature of the source in degrees Rankine or Kelvin, and T_a is the absolute temperature of the absorber, in the same units. Radiation heat transfer is intense at high temperatures, usually overwhelming convection in the range where source or receiving object is visibly radiant.

Conductivity: In conduction heat transfer, a property known as "thermal conductivity" is used as a measure of a material's ability to conduct heat. Conductivity is the rate of heat flow through a unit thickness when the temperature difference across that thickness is one degree.

Diffusivity: The rate at which heat diffuses through a solid is called diffusivity, which is conductivity divided by volume specific heat. Diffusivity is expressed as $\eta = k/c\rho$, where k is thermal conductivity, c is *specific heat* and ρ is density. Volume specific heat is defined as the quantity of heat required to raise a unit mass of a material one degree in temperature at constant volume.

Velocity and Turbulence: In convection heat transfer, velocity and turbulence have a significant effect upon the rate of heat transfer. A high velocity and a high

degree of turbulence tend to scrub the heated molecules from a hot surface and replace them with colder molecules, thus hastening the heat transfer process. The fluid molecules closest to the solid surface are either stationary or moving very slowly because of viscous friction; so they form a stagnant "film" or "boundary layer" across which the heat must pass by conduction. Most fluids, especially gases and vapors have very low conductivity; so the film constitutes the major resistance to heat flow. The reciprocal of this resistance, called film coefficient, h_c, is a measure of convection capability in convection heat flow:

$$Q_c = h_c \times A \times \Delta T$$

Where Q_c is convective heat transfer rate and A is area of the heat flow path. Conductivity of the fluid film is a major factor—film coefficients for gases usually range from 2 to 50 Btu/ft^2 hr °F, whereas the range for liquids is often greater than 100. The next most important factor is film thickness, which is reduced by velocity and turbulence. In turbulent flows, the film coefficient, and therefore the heat transfer rate, varies depending on the geometry of the solid surface.

Nature of the surface affects convection heat transfer to a small degree depending on its roughness. Radiation heat transfer; however, depends to a large extent upon the *emissivity* (ability to radiate) and *absorptivity* (ability to absorb radiation) of the surfaces. Smooth shiny surfaces are poor emitters and absorbers of radiation.; rough, corroded, dirty, and dark surfaces are good emitters and absorbers. The best possible emitter and absorber of radiation is termed a *black body* (not necessary black in color). Both the emissivity and absorptivity of black bodies are 1.0, and the emissivity and absorptivity of all other surface are less than this.

Relative Position: In radiation heat transfer, the relative positions of the radiating and receiving surfaces affect the heat transfer rate, determining how well one surface can "see" the other. The quantity measure of this ability is termed the arrangement factor, F_a, which is the fraction of radiation from one of the surfaces that falls upon the other. Thus, radiative heat flux can be expressed as:

$$q_r = 0.1713 \times 10^{-8} \times (T_s^4 - T_a^4) \times F_e \times F_a$$

Where F_e is the emissivity and F_a is the arrangement, and T in degrees Rankine.

In natural convection heat transfer, the position of the surface also affects the heat transfer rate. Generally speaking, positions which enhance the fluid motion resulting from natural buoyancy have high heat transfer rates, whereas those positions which tend to impair the natural fluid motion have low heat transfer rates.

UNITS OF HEAT TRANSFER PARAMETERS

Parameter	Symbol	English	SI
Conduction heat flux rate	Q_k	Btu/hr	Watts
Conduction heat flux	q_k	Btu/ft^2 hr	W/m^2
Thermal Conductivity	k	Btu/ft hr °F	W/m K
Length of heat flow path	L	ft	m
Area of heat flow path	A	ft^2	m^2
Temperature difference	ΔT	°F	K
Diffusivity	η	ft^2/hr	m^2/s
Specific heat	c	Btu/lb °F	J/kg K
Density	ρ	lb/ft^3	kg/m^3
Film Coefficient	h_c	Btu/ft^2 hr °F	W/m^2 K

Slide 5–17

Slide 5–17 shows units of these heat transfer parameters in English and SI units.

REFERENCES

1. *North American Combustion Handbook*, Vol. 1, 3rd Edition, North American Manufacturing Company, 1986.

2. Koltz, J. C., Purcell, K. F., *Chemistry and Chemical Reactivity*, Saunders College Publishing, New York, 1987.

3. *Steam, Its Generation and Use*, 40th Edition, Babcock and Wilcox Company, 1992.

4. Singer, J. G., *Combustion: Fossil Power Systems*, 3rd Edition, Combustion Engineering, Inc., 1981.

CHAPTER 6. AIR POLLUTION FUNDAMENTALS

6.1 Introduction

6.2 Fuel Dependent Air Pollutants

6.3 Combustion Dependent Air Pollutants

6.4 Smoke and Particulate

6.5 Gas Concentrations
- A. Mole Fractions
- B. Parts Per Million (ppm)

6.6 Emission Factors
- A. Converting ppm to lb/MMBtu

6.7 Correcting Concentrations
- A. Correcting to 3% Oxygen
- B. Correcting to 0% Oxygen
- C. Correcting to 12% Carbon Dioxide
- D. Converting [gr/dscf] to [mg/dscm]

6.8 Excess Air Calculation

6.9 Combustion Efficiency Calculation

6.10 Boiler Efficiency Calculations
- A. Methods to Calculate Boiler Efficiency
- B. Heat Loss Efficiency
- C. Heat Input-Output Efficiency
- D. Heat Rates
- E. Heat Release Rates

6. AIR POLLUTION FUNDAMENTALS

6.1 Introduction

Air pollution may be defined as any atmospheric condition in which substances are present at concentrations which produce a measurable adverse effect on man, animals, vegetation, or materials.[7] The focus of this course is on those types of substances which fossil-fuel fired boilers emit into the atmosphere which cause air pollution. In this chapter, the types of pollutants emitted, and the related measurement and performance calculations are discussed.

6.2 Fuel Dependent Air Pollutants

There are a number of different types of air pollutants which are emitted from combustion sources. In general, their formation is dependent upon the composition of the fuel, combustion quality, and temperature of the combustion mixture.

Fuel dependent air pollutants can be divided into three categories; acid gases, toxics and hazardous materials, and carbon dioxide.

FUEL DEPENDENT AIR POLLUTANTS

Acid Gases
- Sulfur Oxides
- Nitrogen Oxides (Fuel NO_x)

Toxics and Hazardous Materials
- Lead
- Mercury
- Arsenic
- Beryllium
- Benzene
- Radionuclides
- Vinyl Chlorides

Carbon Dioxide

Slide 6–2

Fuel dependent air pollutant emissions generally can be controlled by either changing the fuel property before combustion or by removing the pollutant from the flue gas after combustion. For example, coal and oil typically contain sulfur in varying amounts depending on the region of origin. During combustion, the elemental sulfur in these fuels will form undesirable emissions of sulfur oxides (SO_x). The emission of SO_x may be reduced by switching to a lower sulfur fuel or by stack gas

cleaning through SO_x control equipment, both of which are described in detail in Chapter 26.

In addition, fossil fuels typically contain some nitrogenous compounds which produce "fuel" nitrogen oxides (*fuel* NO_x). Nitrogen oxides are also acid gases. Acid gases create emission problems and tend to cause fire-side corrosion of the metal heat exchanger surfaces.

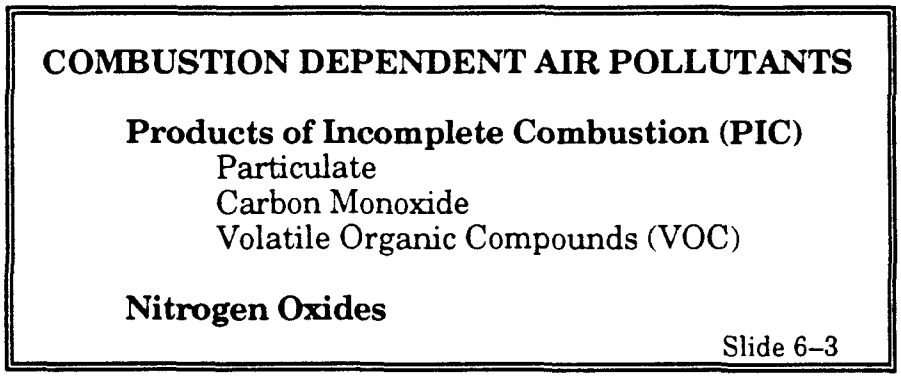
Ash produced from the combustion of fossil fuels contains trace concentrations of toxics and hazardous materials. These pollutants include arsenic, mercury, benzene, beryllium, radionucleides and vinyl chlorides. Upon being heated during combustion, mercury will tend to vaporize and react to form oxides or chlorides. Other metals will vaporize, react or remain unchanged in the solid residue. By lowering the temperature of the flue gas upstream of the APCD, many of the metal vapors and compounds will condense on the fly ash and be removed by the APCD.

Carbon dioxide is not generally considered to be an air pollutant. It is a naturally occurring compound which participates in the carbon cycle of organic growth and decay. There is general agreement that carbon dioxide concentrations have increased as a result of the combustion of fossil fuels. The global warming theory suggests that this excess atmospheric carbon dioxide acts to decrease the amount of heat energy radiated by the earth back to space. Therefore, it may effectively trap radiant energy in the earth's atmosphere and potentially create global warming.

6.3 Combustion Dependent Air Pollutants

As discussed previously in Chapter 5, complete combustion is achieved by mixing and burning the exact proportions of fuel and oxygen so that neither is left over. If too much oxygen or excess air is supplied, the mixture is lean and the fire is oxidizing. If too much fuel is supplied, the mixture is rich and the fire is reducing. This condition is also called incomplete combustion since all of the fuel particles do not get enough oxygen to burn completely.

A number of air pollutants, such as particulates, carbon monoxide, volatile organic compounds, and nitrogen oxides, can be formed from incomplete combustion of organic materials. The measurement of carbon monoxide is generally an indicator of incomplete combustion since carbon monoxide will burn to carbon dioxide if adequate oxygen is available. Correcting incomplete combustion may be accomplished through providing more combustion air or by altering the mixing characteristics between the fuel and the air.



6.4 Smoke and Particulate

Air pollution is "visible" when smoke is emitted from a boiler. Smoke is a mixture of gases, particles and droplets of liquid which have the effect of obscuring the transmission of light (increasing opacity). The particles, which include solid and condensed liquid materials, actually cause the opacity by scattering light. Opacity meters are used to measure the emission of smoke. In most cases, the color of the smoke may be an indication of the cause of the smoke.

Black smoke is flue gas which contains unburned carbon particles. Although the major constituents of the particulate are inorganic materials, the unburned carbon and carbonaceous materials are responsible for the black color. Improving the combustion conditions will generally reduce the smoke emissions.

SMOKE & PARTICULATE

Black Smoke
Carbon in Particulate
Particulate
Removed by APCDs
White Smoke
Condensed Hydrocarbon Gases
Ammonium Chloride
Water Droplets (Not Smoke)
Blue Smoke
Ammonium Sulfate
Brown Smoke
Nitrogen Oxides

Slide 6–4

White smoke can be formed by the condensation of unburned hydrocarbon gases. It can also result from the reaction of ammonia with HCl in the flue gas, which forms ammonium chloride. Vapors often are condensed when cooled by the air, forming small droplets which scatter light very well. Such smoke is visually detached from the stack because a period of cooling is required for droplet formation. Condensed water vapor, such as the emission from a scrubber stack, has the appearance of white smoke. Such droplets will tend to re-vaporize after a fairly short period of time in the atmosphere, unless the ambient relative humidity is very high.

Blue smoke can result from reactions of sulfur oxides with the ammonia or urea used for NO_x control. The reaction produces gaseous ammonium sulfate which will condense in the atmosphere, so this smoke will appear as a detached plume.

Brown smoke can be caused by NO_x emissions and/or particulate. Formation and control of NO_x emissions will be discussed in Chapters 21 and 25.

Particulate emissions are controlled by Air Pollution Control Devices (APCDs), as will be discussed in Chapter 21. The very small particulates are the most difficult to collect and are of most concern because they are able to pass into the lungs of humans and become trapped there.

6.5 Gas Concentrations

Gas concentrations may be expressed in terms of mole fractions or parts per million.

GAS CONCENTRATIONS

Mole Fractions

Parts Per Million (ppm)

Slide 6–5

Mole Fractions

In Chapter 5, we considered complete combustion under stoichiometric and excess air conditions. We now wish to consider gas concentrations, which may be fractions of total molecules or *mole fractions*. The balanced chemical reaction equation can be used to obtain ideal gas concentrations. A mole fraction for a gas can be obtained by dividing the moles of the gas by the total moles in the mixture.

STOICHIOMETRIC COMBUSTION

$C_{1.85}H_{5.4}O_{2.08}N_{.02}S_{.006} + 1.22\ H_2O + 2.165\ O_2 + 8.14\ N_2 \rightarrow$
$1.85\ CO_2 + 3.92\ H_2O + 8.15\ N_2 + 0.006\ SO_2$

Product Gas	Wet Gas Moles	Dry Gas Moles	Dry Gas Mole Frac.	Dry Gas Mole %
CO_2	1.85	1.85	0.185	18.5
H_2O	3.92			
N_2	8.15	8.15	0.814	81.4
SO_2	0.01	0.01	0.001	0.1
Total	13.93	10.01	1.000	100.0

Slide 6–6

A complete combustion reaction equation for burning fossil fuels under stoichiometric air conditions is presented in Slide 6–6. The product gases for this

idealized condition are composed of 1.85 moles of CO_2, 3.92 moles of water vapor, 8.15 moles of N_2, and 0.006 moles of SO_2. If the water vapor is neglected, the product gas analysis can be performed on a dry basis. Therefore, there will be 10.012 moles of dry gas.

Parts Per Millions (ppm)

EQUIVALENCE OF GAS CONCENTRATIONS

Mole Fraction x 100 --> Percentage

Mole Fraction x 1,000,000 --> ppm

Percentage x 10,000 --> ppm

Slide 6–7

Mole fractions are volume fractions. Such concentrations can be converted to either mole percentages or *parts-per-million* (ppm or ppmv) by the simple mathematics of moving the decimal point.

Literally, a percentage is a part-per-hundred, whereas a ppm is defined with one million in the denominator instead of one hundred. A mole fraction can be converted to a ppm basis by moving the decimal six places to the right. Conversions from a percentage to a ppm basis involve four orders of magnitude or moving the decimal four places to the right. Correspondingly, the 1 ppm is equivalent to 0.0001 percent, with the decimal going four places to the left.

Using the example of stoichiometric combustion shown in Slide 6–6, the dry gas mole fraction of CO_2 is 1.85/10.012 = 0.185, which can be expressed as 18.5 percent. The mole fraction of SO_2 in the dry product gases is 0.006/10.012 = 0.0006, which can also be expressed as 0.06 percent or 600 ppm.

6.6 Emission Factors

An *emission factor* is defined as the emission rate of pollutant per unit heat input of fuel. NO_x emission factor, NO_x lb/MMBtu, is the mass of NO_x as NO_2 in pounds divided by million gross Btu input of fuel. The NO_x emission factor has been used in the EPA's New Source Performance Standard (NSPS) (see Chapter 22) since 1971. It was selected by the EPA because it directly relates to the amount of fuel fired, which is easier to monitor. Likewise, SO_2 emission factor is defined as the mass of SO_2 in pounds divided by million gross Btu input of fuel.

EMISSION FACTORS

$$\text{lbs } NO_x/\text{MMbtu} = \frac{\text{lbs of } NO_2 \text{ emitted}}{\text{Millions Gross Btu Fuel Input}}$$

$$\text{lbs } SO_2/\text{MMBtu} = \frac{\text{lbs of } SO_2 \text{ emitted}}{\text{Millions Gross Btu Fuel Input}}$$

Slide 6–8

Converting ppm to lb / MMBtu

Since gas concentrations may be expressed in parts-per-million (ppm), a necessary calculation to determine compliance with some regulations is to convert ppm to lb/MMBtu.

CONVERSION OF PPM TO LB/MMBTU

$$\text{lb } NO_x/\text{MMBtu} = 1.19 \times 10^{-7} \times F_d \times NO_x \text{ (ppm @ 3\% } O_2\text{, dry)} \times (21/(21-3))$$

$$\text{lb } SO_2/\text{MMbtu} = 1.69 \times 10^{-7} \times F_d \times SO_2 \text{ (ppm @ 3\% } O_2\text{, dry)} \times (21/(21-3))$$

Where: F_d is the dry F factor of fuel

Slide 6–9

- The constants 1.194×10^{-7} and 1.69×10^{-7} are the conversion factors from ppmv to lb/scf (pounds per standard cubic foot) for NO_x and SO_2, respectively.

- NO_x and SO_2 concentrations are in ppm at 3% O_2, dry.
- The factor (21/(21-3)) is the conversion factor to correct concentration to 0% O_2 from 3% O_2.
- F_d is the dry F factor of fuel and varies depending on fuel types. Slide 6–10 shows average F_d value for various fuels.

AVERAGE F_d FACTOR FOR VARIOUS FUELS[4]

Coal:		
	Anthracite	10,100
	Bituminous	9,780
	Lignite	9,860
Oil:		
	(Crude, residual or distillate)	9,190
Gas:		
	Natural gas	8,710
	Propane	8,710
	Butane	8,710
Wood:		9,240
Wood Bark:		9,600

Slide 6–10

6.7 Correcting Concentrations

Gas concentration limits are expressed at standard dilutions in order to prevent dilution from being a method for meeting the concentration requirements. Emission standards used over the years have been referenced to different dilution bases. The nitrogen oxide data for coal, gas and oil combustion are often presented dry basis with 3% O_2. In addition, both 0% O_2 and 12% CO_2 are sometimes required.

GAS CONCENTRATIONS AT STANDARD DILUTION

3% O_2, dry
or 0% O_2, dry
or 12% CO_2, dry

Slide 6–11

Correcting to 3% Oxygen

As indicated in the slide below, gas concentrations can be corrected to 3% oxygen by multiplying the measured concentration by (21 – 3) and dividing by (21 – O_{2m}). The variables with a subscript "m" are the measured dry gas concentrations. If the available data is obtained from in–situ instruments, the values will be on a wet basis. Corrections to a dry basis are made by dividing by (1.0 - moisture fraction).

EQUATION FOR CORRECTING TO 3% OXYGEN[2]

Assume: CO_m is the measured dry gas CO
Expressed as a ppm or %
O_{2m} is the measured dry gas O_2
Expressed as a percentage

Converting:

$$CO\ (@\ 3\%\ O_2) = CO_m \times (21 - 3)/(21 - O_{2m})$$
$$= CO_m \times (18)/(21 - O_{2m})$$

Slide 6–12

The derivation of the above gas concentration conversion equation is based on theoretical gas mixture considerations, including the assumption that air is 21% oxygen on a volumetric basis.

Correcting to 0% Oxygen

Similarly, gas concentrations can be corrected to 0% O_2 by multiplying the measured concentrations by 21 and dividing by 21-O_{2m}.

EQUATION FOR CORRECTING TO 0% OXYGEN[1]

Assume: CO_m is the measured dry gas CO
Expressed as a ppm or %
O_{2m} is the measured dry gas O_2
Expressed as a percentage

Converting:

$$CO\ (@\ 0\%\ O_2) = CO_m \times (21 - 0)/(21 - O_{2m})$$
$$= CO_m \times (21)/(21 - O_{2m})$$

Slide 6–13

To illustrate corrections of concentrations from the measured values to a standard basis, let us consider the combustion of methane gas at 20% excess air as presented in Slide 6–14. Note that for illustrative purposes, 0.001 moles of CO have been arbitrarily added to the product gases.

PRODUCT GAS ANALYSIS, METHANE @ 20% EXCESS AIR

Gas	Wet Gas Moles	Dry Gas Moles	Dry Gas Mole %
CO_2	1.0	1.0	9.59
H_2O	2.0		
O_2	0.4	0.4	3.84
N_2	9.024	9.024	86.56
CO	0.001	0.001	0.01
Total	12.425	10.425	100.00

Slide 6–14

The flue gas analysis is illustrated above, with the oxygen content in the dry gases being 0.4/10.425, 0.0384 or 3.84 percent on a dry gas basis. This is fairly typical of operating numbers for commercial and industrial gas-fired equipment.

Let us now consider the incomplete combustion indicated in the above gas analysis, with 100 ppm CO measured on a dry flue gas basis. Note that 100 ppm corresponds to a mole fraction of 0.0001 or 0.01 percent. Therefore, the mole fraction of CO is so small that it will not significantly change either the moles of oxygen or the total moles in the mixture.

The correction of the CO concentration to the standard dilution rate of 3% O_2 is a straightforward calculation. As shown below, the measured 100 ppm of carbon monoxide became 104.9 ppm when corrected to 3% oxygen.

EXAMPLE FOR CONVERSION OF GAS CONCENTRATIONS TO 3% OXYGEN

Let: CO_m = 100 ppm
O_{2m} = 3.84% (dry gas)

$CO\ (@\ 3\%\ O_2) = CO_m \times (21 - 3)/(21 - O_{2m})$
$= 100 \times (18)/(21 - 3.84)$
$= 104.9$ ppm

Slide 6–15

Particulate concentrations which are presented on a mass per unit volume basis can be corrected by the same equation as before. Particulate loadings are a case in point, regardless of whether they are measured in [gr/dscf] or [mg/dscm].

EXAMPLES FOR CONVERSION OF PARTICULATE TO 3% OXYGEN

Let: PM_m = 0.035 gr/dscf (Particulate Matter)
O_{2m} = 3.84% (Measured Dry Gas O_2)

$PM\ (@\ 3\%\ O_2) = PM_m \times (21 - 3)/(21 - O_{2m})$
$= 0.035 \times (18)/(21 - 3.84)$
$= 0.037$ gr/dscf @ 3% O_2

Slide 6–16

Correcting to 12% Carbon Dioxide

EQUATION FOR CORRECTING TO 12% CO_2[1]

Assume: CO_m is the Measured Dry Gas CO
Expressed as a ppm or %
CO_{2m} is the Measured Dry Gas CO_2
Expressed as a Percentage

Converting:

$$CO\ (@\ 12\%\ CO_2) = CO_m \times (12/CO_{2m})$$

Slide 6–17

Gas concentrations (e.g., CO in the above slide) can also be corrected to 12% CO_2 by multiplying the measured concentration by the ratio of 12% divided by the measured percentage of CO_2. As before, the variables with a subscript "m" are the measured dry gas concentrations. If the gas concentration data were to be obtained using in situ instruments, the values will be on a wet basis, so that corrections to a dry basis would require dividing original concentrations by (1.0 - moisture fraction).

The derivation of the above conversion equation is based on theoretical mixture considerations, including the assumption that the percentage of CO is much less than the percentage of CO_2, which is valid for most combustion product gas samples.

The logic of the equation is consistent with the fact that if the measured CO_2 were less than 12%, the actual volume of mixture would be larger than that corresponding to 12% CO_2, so that the actual gas concentration would be less than the standard concentration. Therefore, the gas concentration is adjusted by multiplying by 12 divided by the measured percent of CO_2.

Consider the previous example of incomplete combustion with 100 ppm CO (or 0.01 percent) measured on a dry flue gas basis. The correction of the CO concentration to the standard dilution of 12% CO_2 yields 125 ppm of carbon monoxide when corrected to 12% carbon dioxide.

EXAMPLE CORRECTION TO 12% CO_2

Let: CO_m = 100 ppm
CO_{2m} = 9.59% (dry gas)

CO (@ 12% CO_2) = $CO_m \times (12/CO_{2m})$
= 100 x (12/9.59)
= 125 ppm

Slide 6–18

Converting [gr/dscf] to [mg/dscm]

Many of the current regulations are in System International (SI) Units. For example, the NSPS standard for metals is given in terms of particulate matter measured in [mg/dscm]. Other particulate standards are expressed in [gr/dscf] units, where there are 7,000 grains in a pound. The abbreviation, dscf, refers to dry standard cubic foot, and dscm refers to dry standard cubic meter. The term "dry" refers to the flue gas without water vapor while the term "standard" refers to a defined temperature and pressure (usually 60°F and 14.7 psi).

CONVERSION OF [gr/dscf] TO [mg/dscm]

Basic Identities:
1 pound [lb] = 454 grams [g]
1 gram [g] = 1,000 milligrams [mg]
1 foot [ft] = 0.3048 meters [m]
1 pound = 7,000 grains [gr]
For Dry Gases at Standard Conditions:
1 dry standard cubic foot [dscf]
1 dry standard cubic meter [dscm]
1 dscf = 0.0283 dscm
So That:
1 [gr/dscf] =
1 [gr/dscf] x (1 lb/7000 gr) x (454 g/lb)
x (1000 mg/g) x (1 dscf/0.0283 dscm)
Therefore:
1 [gr/dscf] = 2,290 [mg/dscm]

Slide 6–19

The factor for converting expressions in units of [gr/dscf] to units of [mg/dscm] is presented above. Conversion factors are developed using various identities and simple multiplication and division. The theoretical basis for conversion factors relates to the fact that the quantity obtained by dividing one side of an identity by the other can be treated as unity. For example, an expression can be multiplied by (1 lb/7000 gr) without changing its value.

EXAMPLE APPLICATION OF THE CONVERSION FACTOR

Factor: 1 [gr/dscf] = 2,290 [mg/dscm]

Given: 34 [mg/dscm]

Therefore:

34 [mg/dscm] x (1 [gr/dscf]/2,290 [mg/dscm])

= 0.015 [gr/dscf]

Slide 6–20

The application of the conversion factor, 1 [gr/dscf] = 2,290 [mg/dscm], is demonstrated in the above slide. The given particulate concentration of 34 [mg/dscm] is shown to be equivalent to a concentration of 0.015 [gr/dscf].

Note also, if it were desired to convert a given quantity expressed in [gr/dscf] units into [mg/dscm] units, the quantity would need to be multiplied by (2,290 [mg/dscm]/1 [gr/dscf]).

6.8 Excess Air Calculation

The average amount of excess air (EA) can be determined from a set of dry gas measurements for carbon dioxide, carbon monoxide, and oxygen. The procedure includes the assumption that the gas concentrations are expressed as a percentage and that sulfur oxides, nitrogen oxides, and hydrogen chlorine are small enough to be neglected. Therefore, the nitrogen in the dry product gas can be determined by subtracting the measured percentages for carbon dioxide, carbon monoxide, and oxygen from 100 percent.

DETERMINATION OF EXCESS AIR FROM DRY GAS ANALYSIS[1]

Assume:
CO_{2m} = Percent Dry Gas CO_2
CO_m = Percent Dry Gas CO
O_{2m} = Percent Dry Gas O_2

Therefore:
$N_{2m} = 100 - (CO_{2m} + CO_m + O_{2m})$

And:
$EA = (O_{2m} - 0.5\ CO_m)/(.264\ N_{2m} - O_{2m} + 0.5\ CO_m)$

Slide 6–21

Next, the excess air (EA) expressed as a percentage can be found using the equation in Slide 6-21, which is derived using theoretical considerations.[1] Note that CO_m is included in the above equations. However, when CO is expressed on a percentage basis, it generally has a trivial influence on the excess air calculation.

EXAMPLE DETERMINING EXCESS AIR

Let:
$CO_{2m} = 9.59\%$
$CO_m = 0.01\%$
$O_{2m} = 3.84\%$

Therefore:
$N_{2m} = 100 - (CO_{2m} + CO_m + O_{2m})$
$= 100 - (9.59 + 0.01 + 3.84)$
$= 86.56$

And:
$EA = (O_{2m} - 0.5\ CO_m)/(.264\ N_{2m} - O_{2m} + 0.5\ CO_m)$
$EA = (3.84 - 0.005)/(.264 \times 86.56 - 3.84 + 0.005)$
$EA = 0.20 \rightarrow 20\%$

Slide 6–22

The basic excess air calculation process is illustrated in Slide 6-22 using the previous example of methane gas combustion. This calculation for excess air gives the value of 20%. We know that this calculation is correct, since our original numbers were based on 20% excess air.

6.9 Combustion Efficiency Calculation

EQUATION FOR COMBUSTION EFFICIENCY (BASED ON CARBON COMBUSTION TO CO_2)

$$C.E.(\%) = (100\% \times CO_{2m}) / (CO_{2m} + CO_m)$$

or

$$C.E.(\%) = 100\% \times (1 - (CO_m / (CO_{2m} + CO_m))$$

Slide 6–23

Many state regulations require a minimum combustion efficiency to avoid a fine and mandatory shutdown. There are two equivalent forms of the combustion efficiency equation, both of which are illustrated in the above slide. The equations are often referred to as a carbon combustion efficiency, but they actually measure the carbon monoxide combustion efficiency.

EXAMPLE COMBUSTION EFFICIENCY CALCULATION

Let: CO_{2m} = 9.59 Percent
CO_m = 0.01 Percent (100 ppm)

$C.E.(\%) = (100\% \times CO_{2m})/(CO_{2m} + CO_m)$
$= (100\% \times 9.59)/(9.59 + 0.01)$
$= 99.9\%$

Slide 6–24

The above slide provides an example calculation of combustion efficiency. Note that carbon monoxide is generally measured as ppm and will require conversion to a percentage basis.

6.10 Boiler Efficiency Calculations

Boiler efficiency (η) is defined as the ratio of energy output to input expressed as a percentage. There are two methods to determine boiler efficiency: *Heat Loss* method and *Heat Input–Output* method. Heat loss efficiency is determined by subtracting all heat losses during combustion from the sum of heat in fuel and heat credits. Heat input–output method is based upon the ratio of heat output, heat absorbed by the working fluid or fluids, to the sum of heat in fuel and heat credits

METHODS TO DETERMINE BOILER EFFICIENCY

Heat Loss Method:

$$\eta(\%) = 100 - \text{Net Heat Losses } (\%)$$

Heat Input–Output Method:

$$\eta(\%) = \frac{\text{Output}}{\text{Input}}$$

$$= \frac{\text{Heat absorbed by working fluid(s)}}{\text{Heat in fuel + Heat credits}} \times 100$$

Slide 6–25

Heat Loss Efficiency

HEAT LOSS EFFICIENCY

Net losses = Loss due to dry gases +
Loss due to moisture in the fuel +
Loss due to hydrogen in fuel +
Loss due to CO in flue gas +
Loss due to unburnt carbon +
Loss due to radiation +
Unaccounted losses

Efficiency = 100 - Net losses

Slide 6-26

Net heat losses during fossils fuel combustion include *loss due to dry gases, loss due to moisture in the air, loss due moisture in the fuel, loss due to hydrogen in fuel, loss*

due to unburnt carbon, loss due to radiation, and *accounted losses*. Boiler efficiency is then determined by subtracting the net losses from 100%.

HEAT LOSS DUE TO DRY GASES

$$\text{HL due to dry gases} = \frac{\text{lb dry gas}}{\text{lb fuel fired}} \times 0.24\,(t_g - t_a)$$

Where:

0.24 = Specific heat of gas, Btu/lb °F

t_g = Temperature of gas leaving unit, °F

t_a = Temperature of air entering unit, °F

$$\frac{\text{lb dry gas}}{\text{lb fuel fired}} = \frac{11\,CO_2 + 8\,O_2 + 7\,(N_2 + CO)}{3(CO_2 + CO)} \times \frac{\text{lb C burned}}{\text{lb fuel fired}} + 3/8\,S$$

CO_2, O_2, N_2 and CO are in % by volume of flue gas

S is % by weight of sulfur in fuel

Slide 6–27

Heat loss due to dry gases represents the difference between the heat content of the dry exhaust gases and the heat content that these gases would have at the temperature of the ambient air. This loss usually is the largest loss of all.

LOSS DUE TO MOISTURE IN FUEL

$$\text{HL due moisture in fuel} = \frac{H_2O}{100} \times (h_g - h_l)$$

Where:

H_2O = % moisture in fuel

h_g = Enthalpy of vapor at 1 psia and t_g

h_l = Enthalpy of liquid at t_a

Slide 6–28

Heat loss due to moisture in the fuel represents the difference in the heat content of moisture in the exit gases and that at the ambient air.

HEAT LOSS DUE TO HYDROGEN IN FUEL

$$\text{HL due to } H_2 \text{ in fuel} = \frac{9\,H_2}{100} \times (h_g - h_a)$$

Where:

H_2	=	% of hydrogen in fuel
h_g	=	Enthalpy of vapor at 1psia and t_g
h_a	=	Enthalpy of liquid at t_a

Slide 6–29

Heat loss due to hydrogen in fuel represents the latent heat of moisture from combustion of the hydrogen in the fuel.

HEAT LOSS DUE TO CO IN FLUE GAS

$$\text{HL due to CO in flue gas} = \frac{CO}{CO + CO_2} \times 10{,}160 \times \frac{\text{lb C}}{\text{lb fuel}}$$

Where:

CO and CO_2 are % by volume in flue gas

10,160 is Btu generated burning 1 lb of CO to CO_2

Slide 6–30

Heat loss due to CO in flue gas represents the loss due to incomplete combustion of CO. This loss is usually small and dependent on the combustion conditions in the unit.

HEAT LOSS DUE TO UNBURNED CARBON

$$\text{HL due to unburned C} = \frac{\text{lb C in ash}}{\text{lb of fuel}} \times \text{Btu per lb of ash}$$

Slide 6–31

Heat loss due to unburned carbon represents the thermal energy unliberated due to the failure to completely oxidize the carbon content in the fuel. This carbon is contained in the bottom ash and the fly ash.

Calculations of each of the previously mentioned heat losses will give the energy loss for each type of loss per pound of fuel. To determine the percent loss in efficiency, divide each loss by the heating value of the fuel (Btu/lb).

$$\% \text{ loss} = \frac{\text{Heat loss sum}}{\text{Heating value of fuel}}$$

Heat loss due to radiation represents the heat loss to the air due to radiation. This loss is very difficult to measure, and may be determined by using the American Boiler Manufacturer Association's (ABMA) Standard Radiation Loss Chart, shown in Figure 6–1.

Unaccounted losses include relatively minor losses such as sensible heat in ash or slag, radiation to ash pit, moisture in air, heat pickup in cooling water, etc... generally not measured because the effort is not justifiable. Typically a value of about 1.5% is used for unaccounted losses.

Boiler efficiency is then equal to the sum of these losses subtracted from 100%. Typical heat loss efficiency for coal-fired boilers ranges from 86 to 89%.

Heat Input–Output Efficiency

This method for calculating the boiler efficiency is based on the water-steam side of the boiler. By using the energy content or enthalpy of the water entering the boiler and the steam enthalpies and dividing by the total heat input from the fuel, the efficiency is calculated as shown in Slide 6-32.

HEAT INPUT–OUTPUT EFFICIENCY

$$\text{Heat I-O Efficiency} = \frac{W_1(H_1-h_1) + W_2(H_2-h_2)}{C} \times 100\%$$

Where:

W_1	=	Main steam flow, lb/hr
W_2	=	Reheat steam flow, lb/hr
H_1	=	Enthalpy of main steam, Btu/lb
H_2	=	Enthalpy of reheat steam, Btu/lb
h_1	=	Enthalpy of feed water, Btu/lb
h_2	=	Enthalpy of steam entering reheater, Btu/lb
C	=	Total heat input from fuel, Btu/hr

Slide 6–32

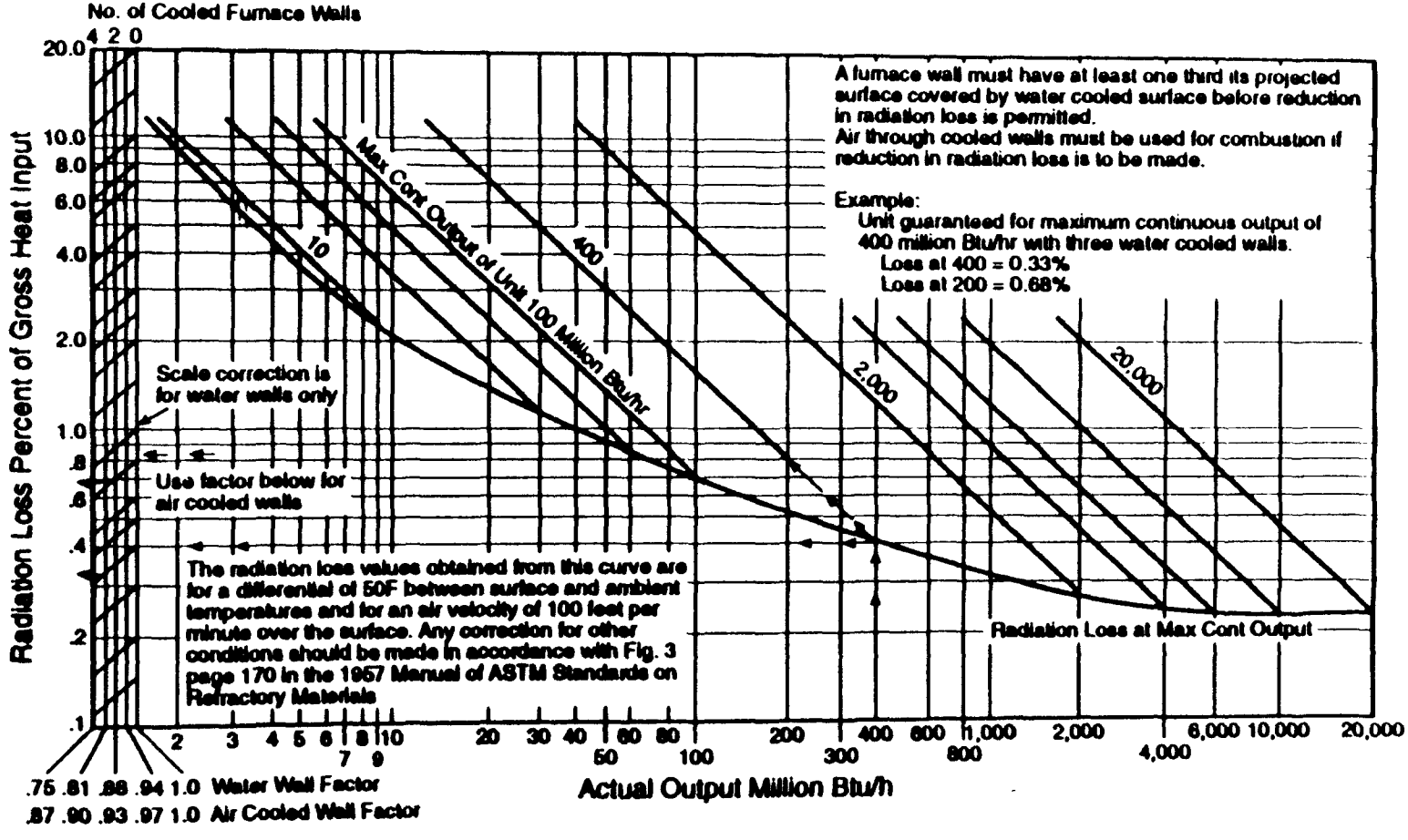


Figure 6-1. Radiation loss in percent of gross heat input (American Boiler Manufacturers Association).

Heat Rates

Heat rate of a utility boiler is defined as the ratio of boiler heat input from the higher heating value of the fuel to electrical output, and is a measure of overall generating unit efficiency including boiler combustion and steam turbine cycle. Heat rate is an important measure of performance due to its direct relationship to the cost of generating electricity.

HEAT RATES

Gross Heat Rate
Net Heat Rate

Slide 6–33

There are two types of heat rate: gross heat rate and net heat rate. Gross heat rate is based on the total electrical power generated by the utility boiler. Net heat rate is based on the total electrical power generated by the boiler subtracting the power coming into the station and the auxiliary power used by the station.

HEAT RATE CALCULATIONS

$$\text{Gross Heat Rate} = \frac{\text{Heat input from fuel}}{\text{Electrical output}}$$

$$= \frac{\text{Fuel flow x HHV}}{\text{MW generated}} = \text{Btu/kWh}$$

Slide 6–34

Gross heat rate is determined by multiplying fuel flow rate with the higher heating value of the fuel and dividing by the MW generated. Heat rate is expressed as Btu per kilowatt-hour (Btu/kWh).

EXAMPLE OF HEAT RATE CALCULATIONS

Let: Coal flow = 60,000 lbs/hr
Coal HHV = 10,540 Btu/lb
Gross MW = 55 MW

$$\text{GHR} = \frac{60{,}000 \times 10{,}500}{55\ \text{MW}} \times \frac{1\ \text{MW}}{1000\ \text{kW}}$$

$$= 11{,}454\ \text{Btu/kWh}$$

Slide 6–35

Gross heat rate is calculated using the example shown in Slide 6–35. Net heat rate can be calculated by the same method using net MW, which is equal to gross MW subtracting power coming into the plant and auxiliary power used by the station.

Heat Release Rates

HEAT RELEASE RATES

Volumetric Heat Release rate

Burner Zone Heat Release Rate

Slide 6-36

Volumetric heat release rate is another important parameter related to boiler calculations. It is defined as the total amount of heat introduced into the furnace by the fuel divided by the total furnace volume. The total heat input is calculated based upon the higher heating value of the fuel. The furnace volume is typically defined as the furnace volume extending from the top of the hopper to the top of the furnace section. Volumetric heat release rate is expressed as Btu/hr-ft^3. Boiler manufacturers use volumetric heat release rate in specifying boiler furnace sizes, heat absorbing surfaces, flue gas temperatures, and selecting the fuels.

Burner zone heat release rate is another important boiler parameter. It is defined as the total heat released by the fuel divided by surface area of the burner zone, and is expressed as Btu/hr-ft^2. This parameter has been used by boiler manufacturers to relate to the formation and control of NO_x. Figure 6-2 shows a relationship between burner heat release rate and NO_x emissions. Different boiler manufacturers use different burner zone definitions. Some manufacturers define it as the surface area extending from top burner row to the bottom burner row; some extend the burner zone area four feet above and below the top and bottom burner rows.

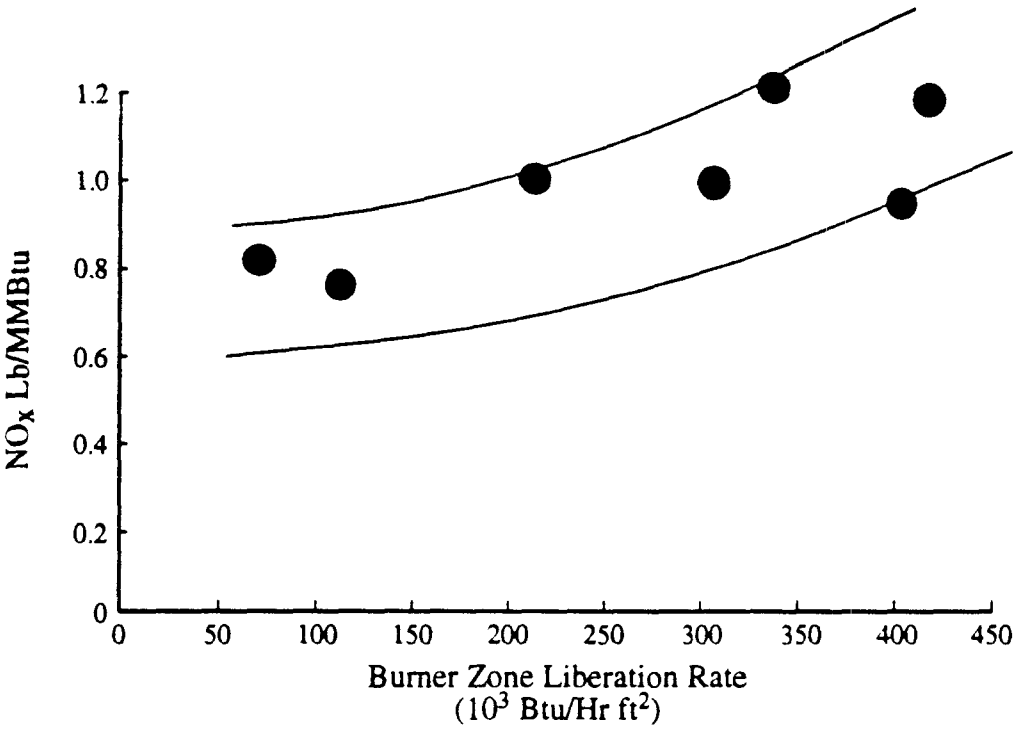


Figure 6-2. Foster Wheeler boiler NO_x correlation.

REFERENCES

1. J. T. Beard, F. A. Iachetta, and L. U. Lilleleht, *APTI Course 427, Combustion Evaluation, Student Manual,* U.S. Environmental Protection Agency, EPA-450/2-80-063, February 1980, pp. 5-4 to 5-21.

2. Babcock and Wilcox Company, *Steam, Its Generation and Use*, 40th Edition, 1992.

3 Singer, J. G., *Combustion: Fossil Power Systems*, 3rd edition, Combustion Engineering, Inc., 1981.

4. *Codes of Federal Regulations*, Protection of Environment 40, Parts 53 to 60, Office of the Federal Register National Archives and Records Administration, July 1991, p. 1014.

5. *Performance Test Codes Steam Generating Units*, PTC 4.1, The American Society of Mechanical Engineers, 1965.

6. Godish, Thad, *Air Quality*, Lewis Publishers, Inc., Chelsea, Michigan, 1991, p. 123.

7. Seinfeld, John H., *Air Pollution Physical and Chemical Fundamentals*, McGraw-Hill Book Company, 1975, p. 1.

7. NATURAL GAS FIRED BOILERS

7.1 Introduction

7.2 Fuel Supply System

7.3 Burner Arrangements
- **A. Burner Design**
- **B. Burner Configuration**

7.4 Boiler Design Parameters

7.5 Emissions

Slide 7-1

7. NATURAL GAS FIRED BOILERS

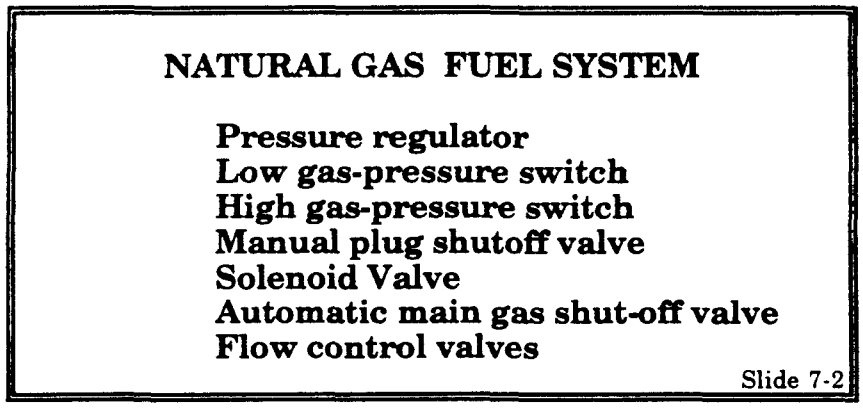
7.1 Introduction

In steam generating equipment, the design of the equipment is dependent on the type of fuel being fired in the unit. This Learning Unit is the first of seven which address the design characteristics of steam generating units. The following discussion will provide the fundamentals of natural gas supply systems and natural gas firing equipment. In addition, a discussion of how the characteristics of burning natural gas affect the boiler design and the environmental concerns during operation.

7.2 Fuel Supply System

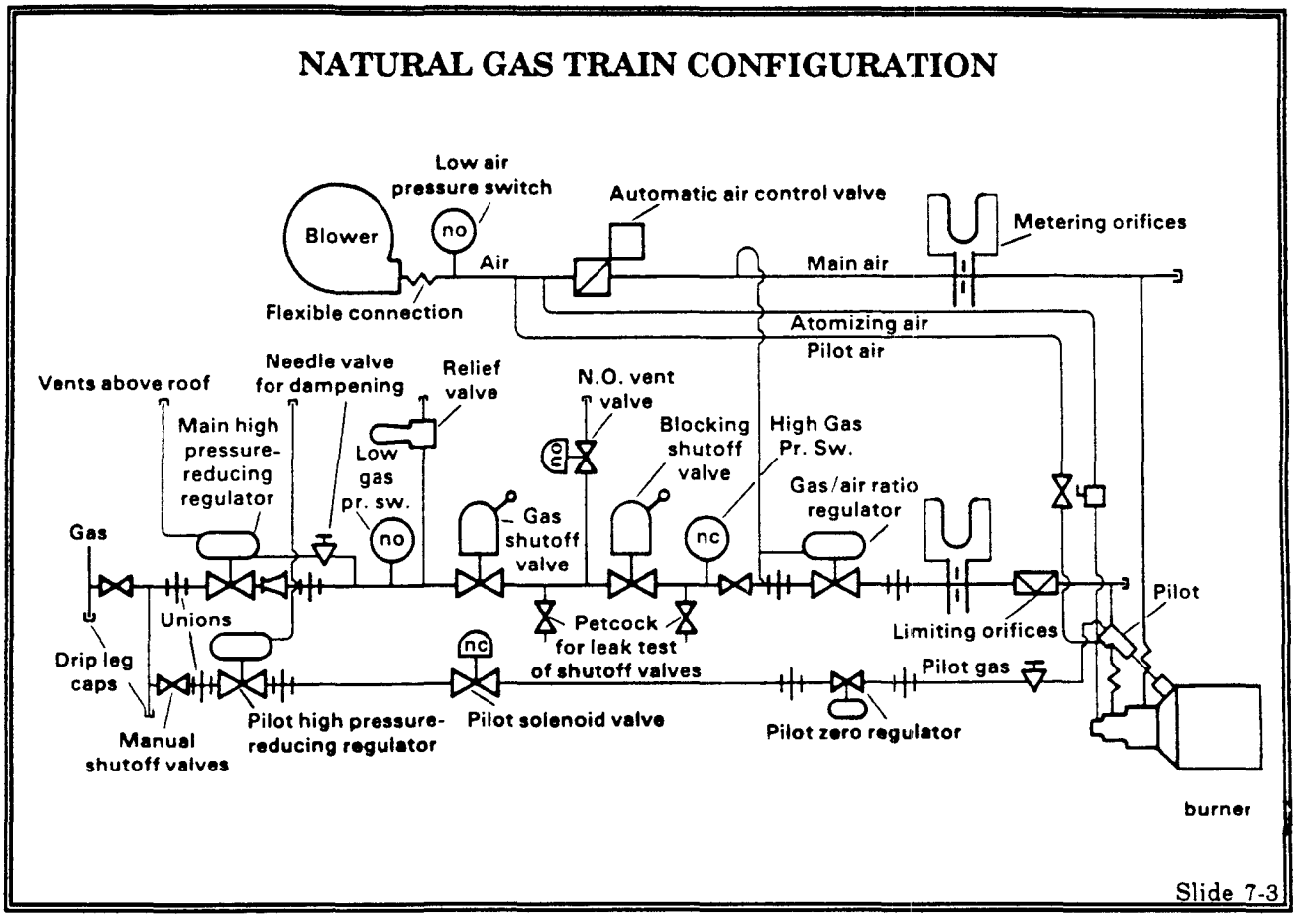
Burning gaseous fuels is perhaps the most straightforward of all combustion processes. No fuel preparation is necessary because gases are easily mixed with air and the combustion reaction proceeds rapidly, once the ignition temperature is reached. Of the many gaseous fuels, natural gas is the most important one for large-scale stationary combustion installations. Pipeline natural gas is perhaps the closest approach to an ideal fuel. It is virtually free of sulfur and solid residues, and it is the cleanest burning of all fossil fuels.

For a natural gas fired boiler, the fuel system consists of supply line piping and safety valves to provide the control and regulation of the gas supply to a boiler.



A pressure regulator controls the gas pressure that is delivered to the burner. The actuator senses the pressure on the down-stream side of the regulator and throttles the gas flow in order to maintain the downstream pressure at the desired setting.

A low gas-pressure switch is installed on the main gas line located downstream of the main regulator. As long as the gas pressure from the main supply is satisfactory, the switch remains closed. If the supply pressure drops, the low pressure switch sends a signal to the actuator which closes the main fuel valve to the burner or the burner row. The main fuel valve arrangement is a double block and bleed valve arrangement whereby two block valves are in series and with a bleed valve in-between which opens when the block valves are closed. This approach provides two fuel block points and a pressure release between the two block points. Each burner can be equipped with a double block and bleed valve arrangement, or each row of burners. The low gas-pressure switch is also known as a vaporstat. The location of this component is illustrated in Figure 7-3.



A high gas-pressure switch is installed in the main gas line after the pressure regulator. If the pressure regulator should fail, which would result in high gas pressure, the same sequence of events would occur as when the low pressure switch actuates closure of the main fuel flow. In this case, the high gas-pressure switch would send a signal to the actuator to close the main fuel valve. The main gas valve is typically a manual plug shutoff cock, which is a ball valve or plug valve that may be opened or closed by a 90° turn of a lever.

In the event of closure of the main gas line, which is usually called "high or low fuel gas header pressure trip", there are a number of conditions that must be met before a fire can be reintroduced into the furnace to prevent the possibility of an explosion due to a fuel rich condition in the furnace. The main condition is that a specified air flow is passed through the furnace to purge the furnace before attempting light-off of the pilots and burners. The length of purge is boiler design dependent.

Solenoid valves are used in the gas line to the pilot and are energized by a electrical current. The automatic main gas shutoff valve is most commonly solenoid actuated. When energized the main gas valve opens and as long as the control circuit is energized the valve will be held open. If the circuit is opened by an interlock, such as low water in the boiler, the power will be disconnected and the valve will shut.

The pilot ignites the main flame. A separate pressure control valve and an automatic solenoid shutoff valve are provided for the pilot. A typical pilot is mounted to shoot a long flame across the path of the incoming main fuel and air mixture. Once the pilot flame has been established and the air flow through the burner has been established, the main fuel valve is opened.

Flow control of natural gas may be based on measuring a pressure differential across a valve or simply by the position of a butterfly valve. In many control schemes, the fuel and air are controlled by a gas/air ratio regulator which maintains the proper air flow based on the fuel flow. A schematic of this type of control system is shown in Slide 7-3.

A flame scanner is used to monitor the burner flame for safety control. During start-up, fuel explosion is a potential hazard. Thus, detection of the presence of flame to verify ignition is a requirement for continued operation in burner safety systems. Flame is an electromagnetic phenomenon. It contains ionized particles, components of infrared radiation caused by heat, visible radiation, and ultraviolet radiation. By applying these characteristics, four types of devices have been developed to detect the presence of flame: flame rods, photoelectric sensors, infrared radiation sensors, and ultraviolet sensors.

7.3 Burner Arrangements

The function of a gas burner is to deliver fuel and air in a desired ratio to the combustion chamber and to provide mixing and ignition of the combustible mixture. The performance of a given boiler depends on the burner design and the number and configuration of the burners.

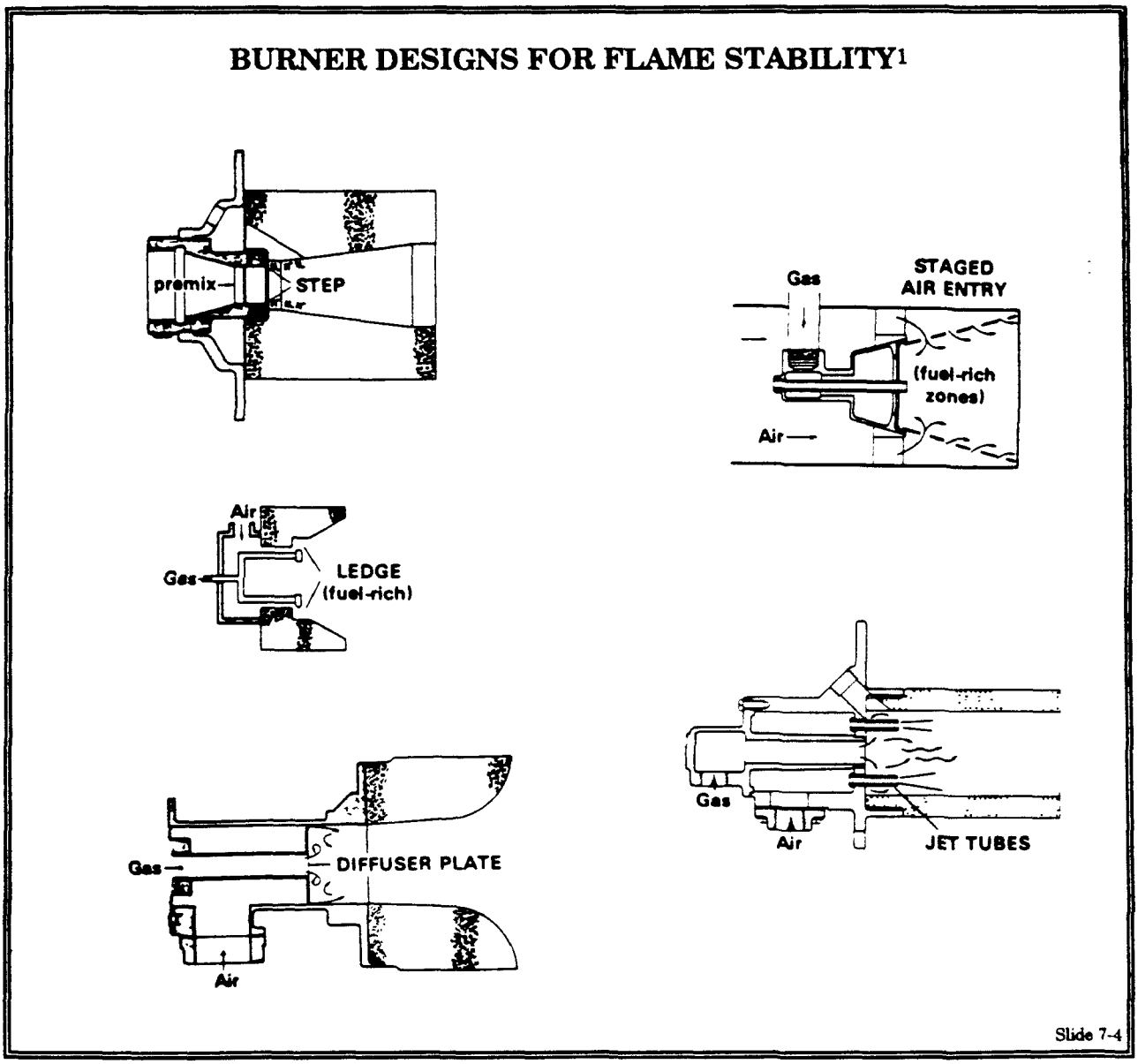
Burner Design

The burner design, which determines the relative velocities of the fuel and air streams, impacts the flame shape, flame stability, and combustion zone required. In regards to the latter, rapid mixing, with a high degree of turbulence, is likely to create a short "bushy" flame, while delayed mixing and low velocities result in long and more slender flames. The shape of the flame will depend on the mixture pressure and the amount of primary air. For a given burner, increasing mixture pressure will broaden the flame, increased primary air will shorten it. The flame characteristics vary among the various burner designs and are dependent primarily on gas orifice size, design and orientation.

There are two principal mechanisms of flame combustion producing flames of quite different appearance: blue flame and yellow flame. Blue flame results when gaseous fuel is mixed with air prior to ignition. In this instance, hydrocarbon molecules are oxidized gradually in stages passing through to the end products of carbon dioxide and water. Incomplete combustion results in the emission of the intermediate partially oxidized compounds. However, no soot is developed.

Yellow flame results when the fuel and air enter the combustion zone separately - without having been intimately mixed prior to ignition. The hydrocarbon molecules decompose to form solid carbon particles and hydrogen when exposed to the high furnace temperatures before they have had an opportunity to combine with oxygen. The carbon particles are incandescent at the elevated temperatures and give the flame a yellowish appearance. Eventually sufficient oxygen will diffuse into the flame to form carbon dioxide and water. Insufficient oxygen or incomplete combustion due to flame quenching will result in soot and black smoke.

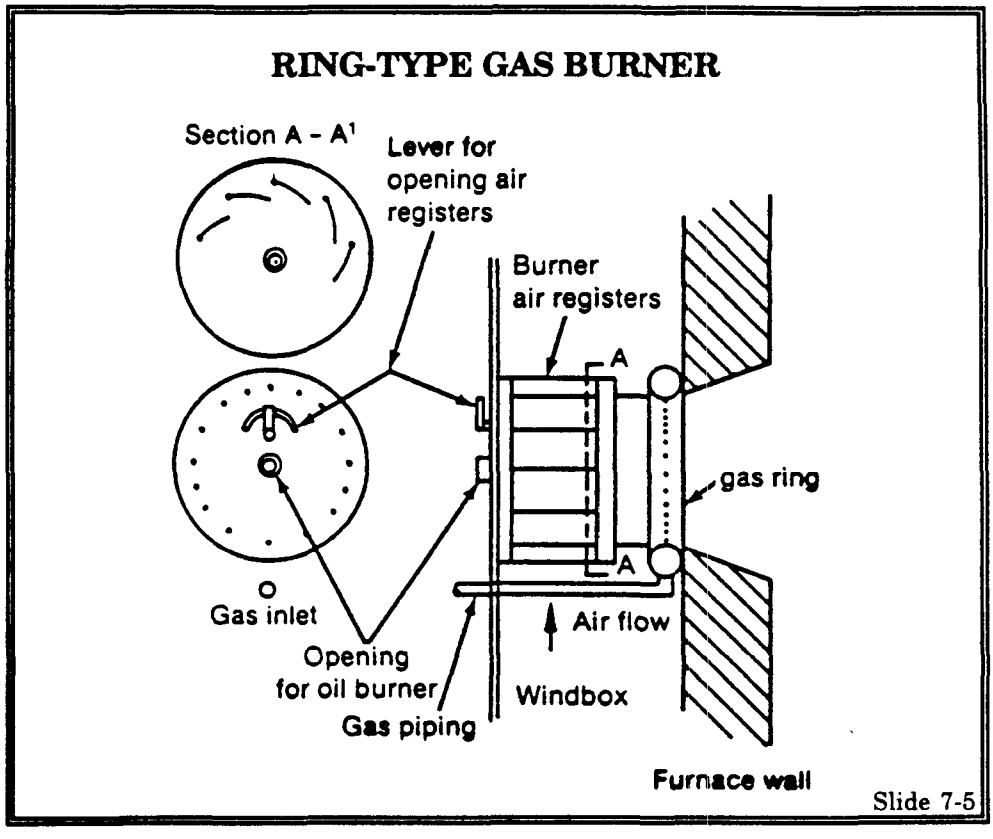
Flame stability is very important for safe, reliable operation. A stable burner maintains ignition throughout the range of pressures, input rates, and fuel/air ratios encountered during operating conditions. Stability is achieved by maintaining minimum ignition temperature for the given mixture of fuel and air, and holding the flame in close proximity to the burner nose. Stability may be enhanced by the bluff bodies (step, diffuser plate or ledge), jet tubes, or stage air entry, as illustrated in Slide 7-4. All of these create interfaces between streams of different velocities, producing small scale turbulence. Another mechanism for improving flame stability is swirl, which recirculates the products of combustion into the base of the flame and therefore broadens the range of velocities in which flame stabilization is possible.



The range of input rates within which a burner will operate is specified by the burner turndown ratio. This is the ratio of the maximum to minimum heat input rates with which the burner will operate satisfactorily.

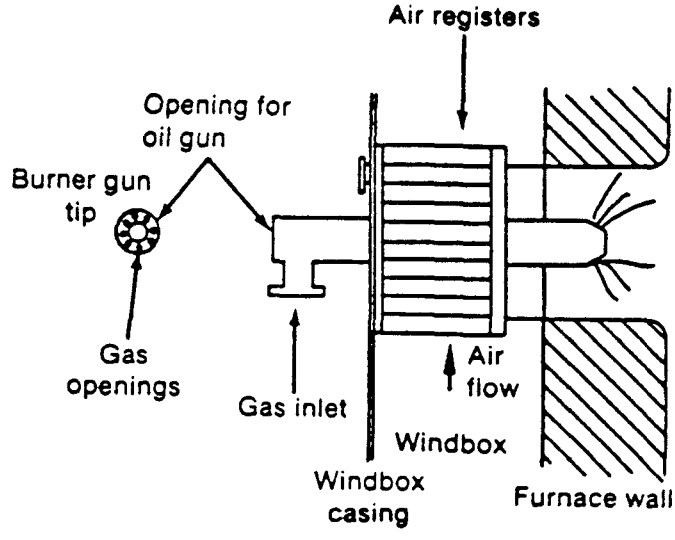
The burner design is critical in determining the mixing between the fuel and air. Three common gas burner designs include the ring-type, gun-type, and spud type burners.

The ring-type burner, illustrated in Slide 7-5, is common for high-pressure gas burner applications. The normal gas pressure operating range is from approximately 1 to 10 psig. As the air passes through the air registers the velocity is increased and a swirl is imparted to the air, which then is forced toward the burner centerline or throat. The gas enters from the small holes shown on the inside of the hollow gas ring and is injected perpendicular to the air stream. Although this burner can maintain a stable flame at low pressures, the relatively small gas orifices tend to become plugged with dirt or other substances. When this happens the boiler must be shut down and the burners cleaned.



A gun-type gas burner is shown in Slide 7-6. In this burner the air register is similar to that of the ring burner, and functions to impart a swirl to the flow of combustion air. The gas, however, is injected into the air stream from the center instead of the outer periphery. Because space is more limited on the tip of the smaller diameter gun, the gas orifices are large and fewer in number than on the ring burner. An advantage of this burner over the ring burner is that the gas orifices are large and need less cleaning. When properly adjusted, gun-type burners can be operated at pressures in excess of 20 psig and with a minimum pressure stable flame at approximately 1 psig.

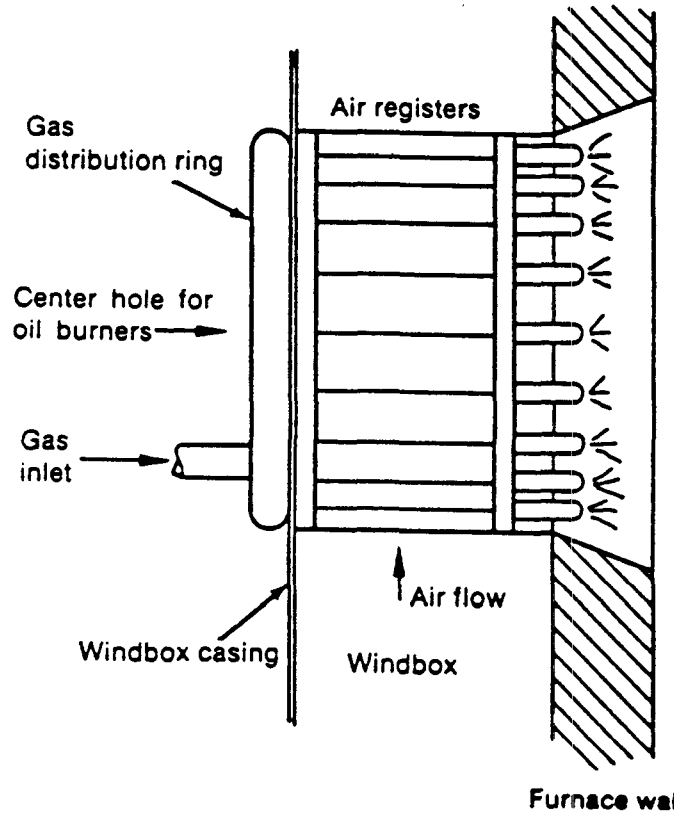
GUN-TYPE GAS BURNER



Slide 7-6

The third type of burner, the spud-type burner, has an external gas ring with a number of smaller gas guns or spuds connected to the ring. This burner is a design that obtains the benefits of both the ring and the gun type burners. The gas orifices are greater in number and smaller for better dispersal of the gas into the gas stream.

SPUD-TYPE GAS BURNER



Slide 7-7

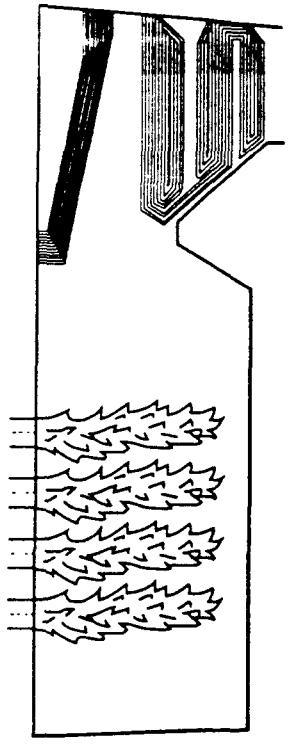
The gas burners which have been discussed to this point are categorized as nozzle-mix or delayed mix burners in which the fuel and air do not mix until they reach the burner chamber. Another type of gas burner, the premix burner, mixes the primary air and fuel at some point upstream from the burner ports. The most common premix burners are manifold burners used in low temperature processes which require heat spread uniformly over a wide area. Processes such as drying ovens, baking ovens use premix manifold burners.

Burner Configurations

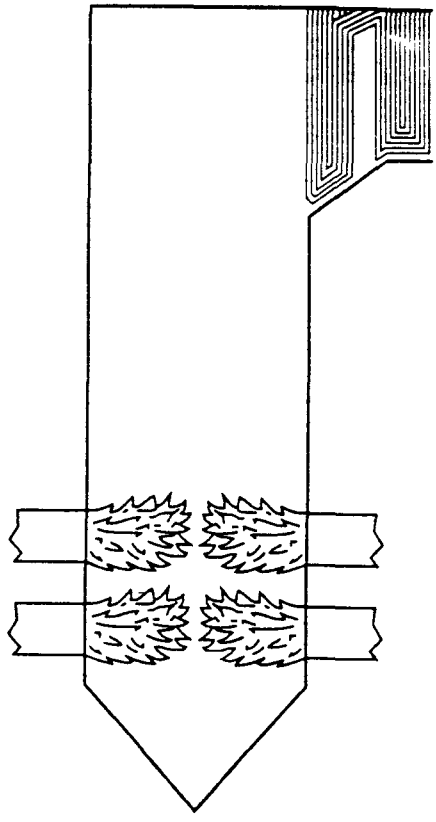
In addition to the different burner designs, the number and configuration of the burners in the furnace will determine the overall performance of the boiler. For gas fired boilers, there are basically three different burner locations. The first and most straight forward is the front wall location. The second is the opposed wall firing configuration.

WALL MOUNTED BURNER CONFIGURATIONS

Front Wall Firing

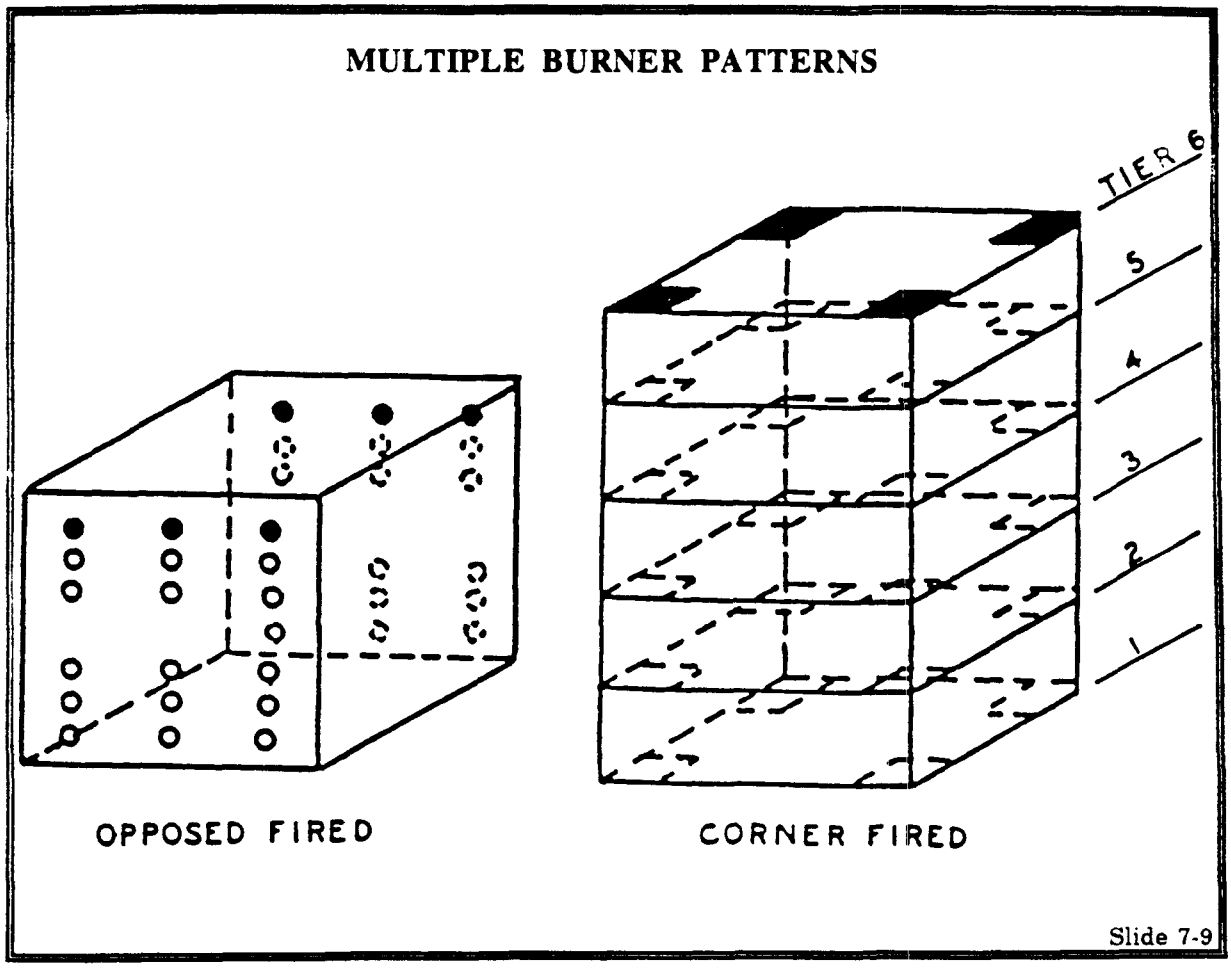


Opposed Wall Firing

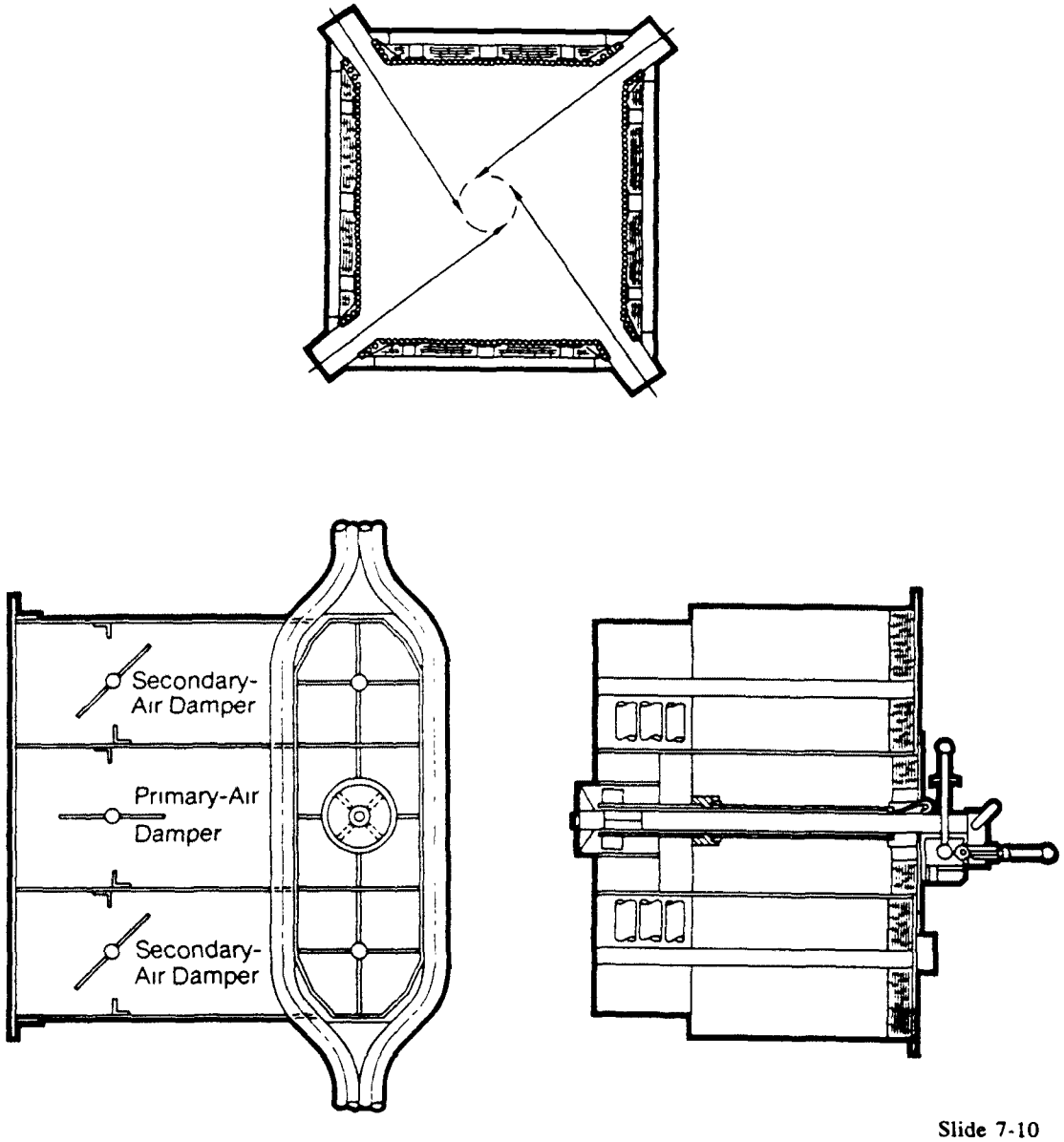


Slide 7- 8

For both configurations, there are multiple patterns in which the burner spacing and location may vary based on each boiler and burner manufacturer's requirements.



TANGENTIAL FIRING BURNER LOCATIONS[4]



Slide 7-10

The third gas burner configuration that is in use today is corner firing or tangentially firing. Although this configuration is more commonly used in coal and oil firing boilers, the conversion to cleaner burning fuels has forced some utilities to modify the boilers to gas burning only or in combination with the coal and/or oil.

7.4 Boiler Design Parameters

There are numerous boiler design parameters which contribute combustion control and efficiency. The predominant parameters include burner zone heat release area, burner spacing, and windbox configurations.

The burner zone heat release area determines how rapidly the fuel-rich combustion gases radiate heat to the furnace walls and the degree of combustion product recirculation into the primary combustion zone. Data collected on numerous utility boilers have indicated that the heat release rate per furnace volume is an important factor in determining minimum NO_x emission levels from a given boiler.

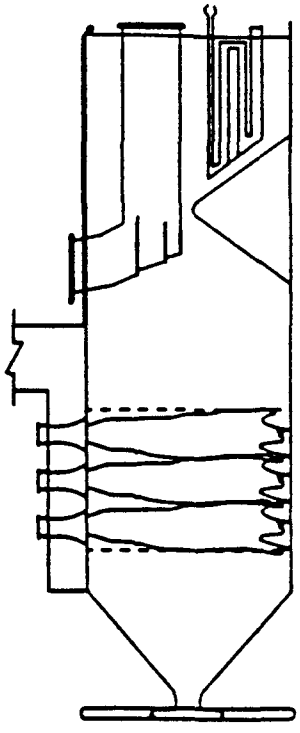
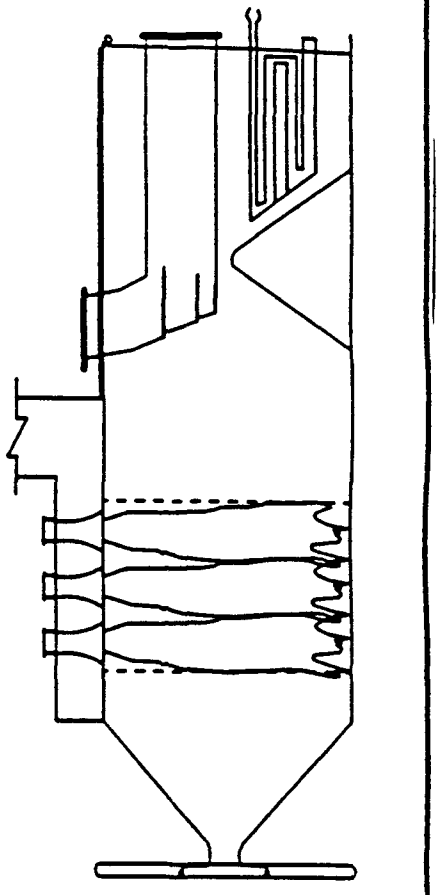
Burner spacing determines the location of combustion within the furnace, as well as the degree of quenching of the combustion gases by cooler gases at the wall of the boiler. If sufficient heat is lost before air from the burners mixes with the fuel-rich combustion gases, the production of NO_x, the primary pollutant of concern when burning natural gas, will be significantly reduced due to the strong temperature dependence of the NO_x formation. With extremely close spacing the secondary combustion takes place before the fuel-rich gases have lost sufficient heat to be near the NO_x formation threshold. The quenching effect with close spacing is also minimized due to flame interaction. At the other extreme, with large spacing, the NO_x level may be limited by excessive CO in the combustion gases. The excessive CO is due to poor mixing with the secondary air. More details on NO_x formation and control techniques is provided in Chapter 25.

Redistribution of combustion due to burner spacing produces variations in the heat transfer occurring in the furnace. If there is increased heat transfer in the convective pass, this condition can usually be controlled by existing superheat/reheat proportioning dampers, or by spray attemperation. If the increases in temperatures are not compatible with metal temperatures or steam turbine operation, the situation may necessitate removal of convective heat transfer surface, or result in an increase of the water or steam attemperation (desuperheater) capacity.

The windbox design controls the air distribution. Inadequate windbox design may create restrictions in the air flow to one or more burners, thus limiting the extent of overall fuel-rich burner operation because of non-uniform air distribution. To help promote uniform air distribution, existing windbox designs may be modified by incorporating vanes or minimizing restrictions. In some cases, air register adjustments may drastically affect the individual burner flame holding characteristics and consequently cannot be varied without awareness of the overall impact on the boiler operation.

The furnace volume is an important parameter since it determines the space available for mixing and secondary combustion as shown in Slide 7-11.

FURNACE VOLUME EFFECTS[3]

PARAMETER \ UNIT DESIGN	HIGH HEAT RELEASE RATE	LOW/MEDIUM HEAT RELEASE RATE
FURNACE ELEVATION (SAME MW SIZE UNIT)		
BURNER ZONE VOLUME	(3 X Burner Spacing) X Width X Depth	1.66 X (High HRR Volume)
BURNER ZONE HEAT RELEASE RATE	88,000 BTU/Hr/Ft3	53,000 BTU/Hr/Ft3
NOx @ MCR GAS FIRING*		
- LOW EXCESS AIR BURNER	0.55 Lb/Million BTU	0.22 Lb/Million BTU

Slide 7- 11

7.5 Emissions

Natural gas is the cleanest burning fossil fuel. The criteria pollutants of concern which are emitted from natural gas fired boilers include NO_x, CO, and hydrocarbons. Sulfur oxides are not a primary concern due to the lack of sulfur content in the natural gas. Since natural gas is usually provided via a pipeline, no environmental concerns result from the storage of this fuel.

In a recent study completed by the EPA, the following range of emissions were measured and documented for industrial boilers.

UNCONTROLLED EMISSION DATA FROM NATURAL GAS-FIRED BOILERS[5]

Boiler Type and Capacity	NO_x, lb/MMBtu[a]	CO, lb/MMBtu[a]	THC, lb/MMBtu[a]
≤ 100 MMBtu/hr	0.03 to 0.31	0.0 to 1.45	0.0 to 0.02
> 100 MMBtu/hr	0.04 to 0.45	0.0 to 0.23	0.0 to 0.05

[a] To convert to ppm @ 3% O_2, multiply by the following: NO_x, 835; CO, 1,370; THC, 2,400

Slide 7-12

REFERENCES

1. *North American Combustion Handbook*, Second Edition, North American Manufacturing Company, 1978.

2. Wilson, R. Dean, *Boiler Operator's Workbook*, American Technical Publishers, Inc., 1991.

3. Price, Joyce V., et al., "Low NO_x Oil/Gas Burner Retrofits and Their Effects on Overall Emissions and Boiler Performance," May, 1993 EPA/EPRI Joint Symposium on Stationary Combustion NO_x Control.

4. Singer, J. G., *Combustion: Fossil Power Systems*, 3rd Edition, Combustion Engineering, Inc., 1981.

5. "Alternative Control Techniques Document -- NO_x Emissions from Industrial/ Commercial/Institutional (ICI) Boilers", U.S. EPA, EPA-453 / R-94-022, March, 1994.

6. Elliot, C.T., *Standard Handbook of Powerplant Engineering*, McGraw–Hill Publishing Company, New York, 1989.

CHAPTER 8. OIL FIRED BOILERS

8.1 Introduction

8.2 Fuel Supply System
- A. Atomization
- B. Operation

8.3 Burner Arrangements

8.4 Boiler Design Parameters

8.5 Emissions

Slide 8-1

8. OIL FIRED BOILERS

8.1 Introduction

As with the discussion on natural gas fired boilers presented in the previous learning unit, the oil fired boiler system operation depends on a consistent fuel supply system, burner design which provides flame stability over a wide range of operating conditions, and the boiler chamber design to deliver the desired steam to the end user. The properties of fuel oil dictate that the design of each of these subsystems vary considerably from the simple designs used for natural gas fired boilers. The following sections present the specific design and operating parameters for each of these subsystems.

8.2 Fuel Supply System

In comparison to gas fired boilers, oil fired boilers have a more complicated fuel delivery system. For efficient combustion, the fuel system needs to supply clean oil at the required volume, pressure, and viscosity. A fuel oil system therefore conditions the fuel oil prior to delivery to the boiler burners. The conditioning starts at the fuel oil tank which provides storage and heating if required.

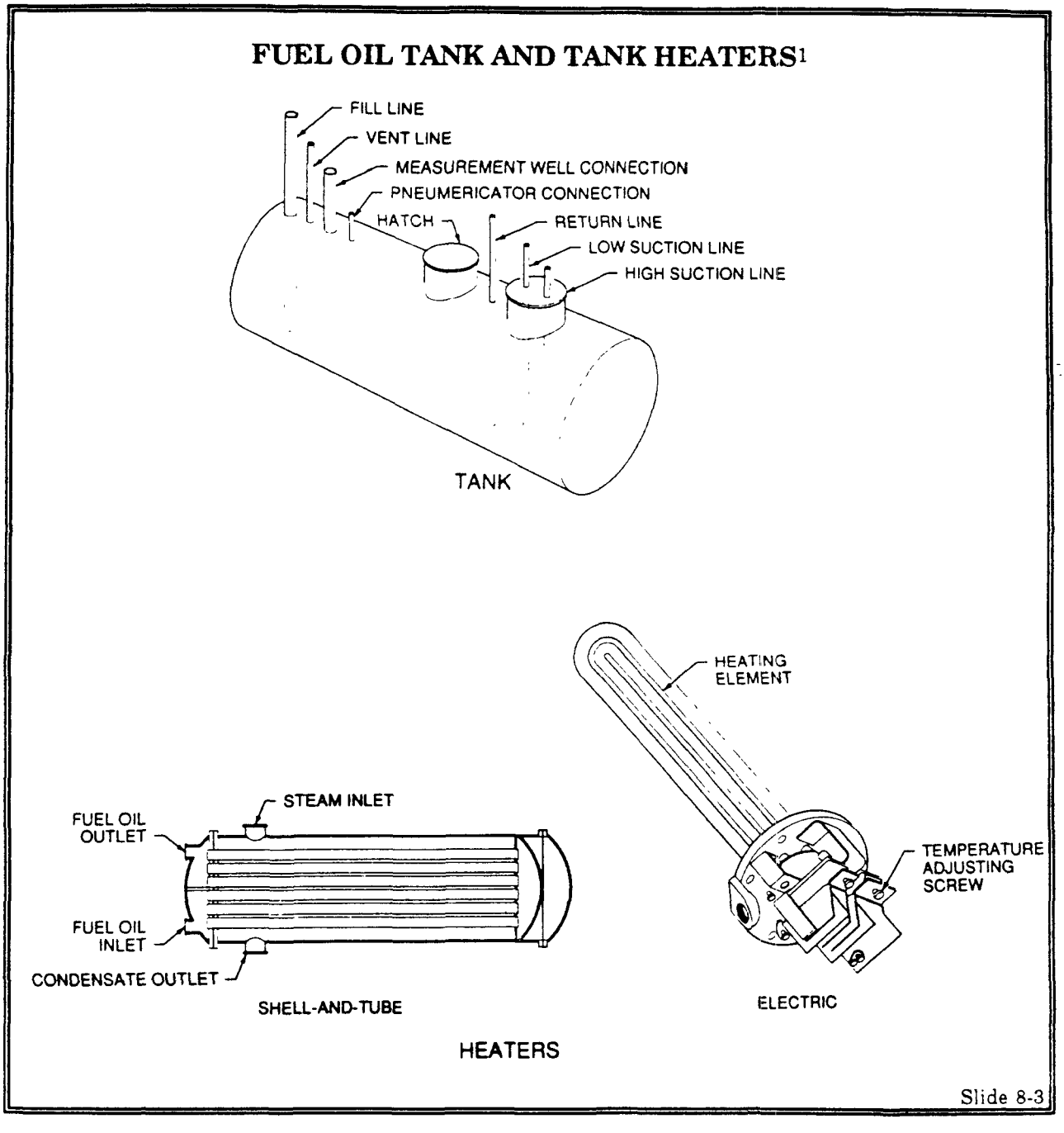
FUEL OIL SUPPLY SYSTEM COMPONENTS

Fuel Oil Tank
Oil Pressure Regulator with bypass
Oil Heater
Oil Heater Relief Valve
Fuel Oil Strainers
Pump
Pump Discharge Relief Valve
Atomizing Gun

Slide 8-2

The fuel oil tank stores fuel oil. The storage tank needs to be sized based on method of oil delivery, rate of fuel consumption, and the frequency of oil deliveries and contingency for delivery delays and fuel shortages. Depending on the size of the plant, multiple tanks may be used. Fuel oil tanks are often buried to minimize space requirements, avoid freezing, and increase safety. However, corrosion and deterioration of buried fuel oil tanks must be monitored by using sample wells located around the tank. For tanks installed above ground, concrete containment areas must be constructed to prevent environmental or safety hazards in the event of a spill. A vent line is provided to vent the tank while filling.

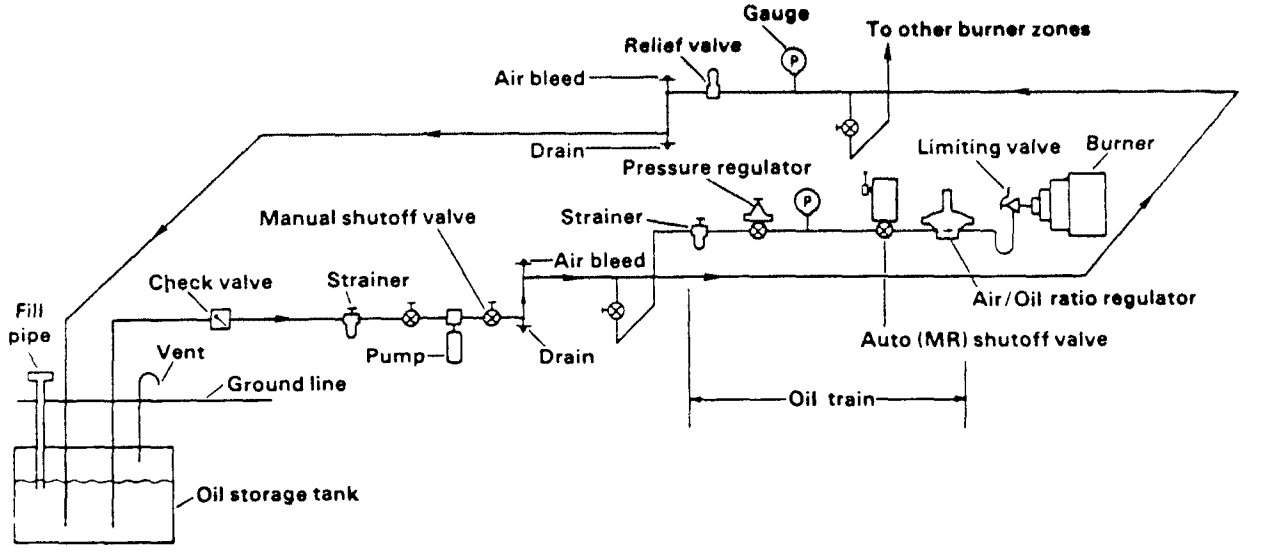
Fuel oil heaters are required to reduce the resistance of the oil to flowing when heavier grades of fuel oil are used. Fuel oil heaters supply heat to the oil by steam or by electricity. A steam heater may consist of a steam chamber or shell with tubes through which the oil flows. An electric heater consists of a chamber for the fuel oil with one or more heating elements inserted into the chamber. Both of these types of heating systems are shown in Slide 8-3.



The National Fire Protection Association (NFPA) has prepared a standard set of rules for the storage and handling of oils. These rules serve as a basis for many local ordinances and form a practival guide for the safe transportation and handling of fuel products. In some states, regulations require that a storage tank can only hold oil to a certain tank capacity to avoid overflows. Oil tanks must be inspected regularly to ensure no leakages.

From the fuel oil tank, the fuel oil is circulated to the burner via the fuel oil pump. The fuel oil pumps used for supplying fuel oil to boiler burners are usually positive displacement pumps. The fuel pump supplies more fuel oil than is used by the burners. The excess fuel oil is returned either to the suction side of the pump or to the storage tank by a pressure relief valve installed in the discharge piping. This valve maintains a constant fuel oil supply pressure to the burners and prevents excessive pressure buildup in the piping. Fuel oil strainers remove impurities such as sand, dirt, and rust. Strainers are usually located on the suction and discharge side of the pump.

FUEL OIL SYSTEM PIPING[2]



Slide 8-4

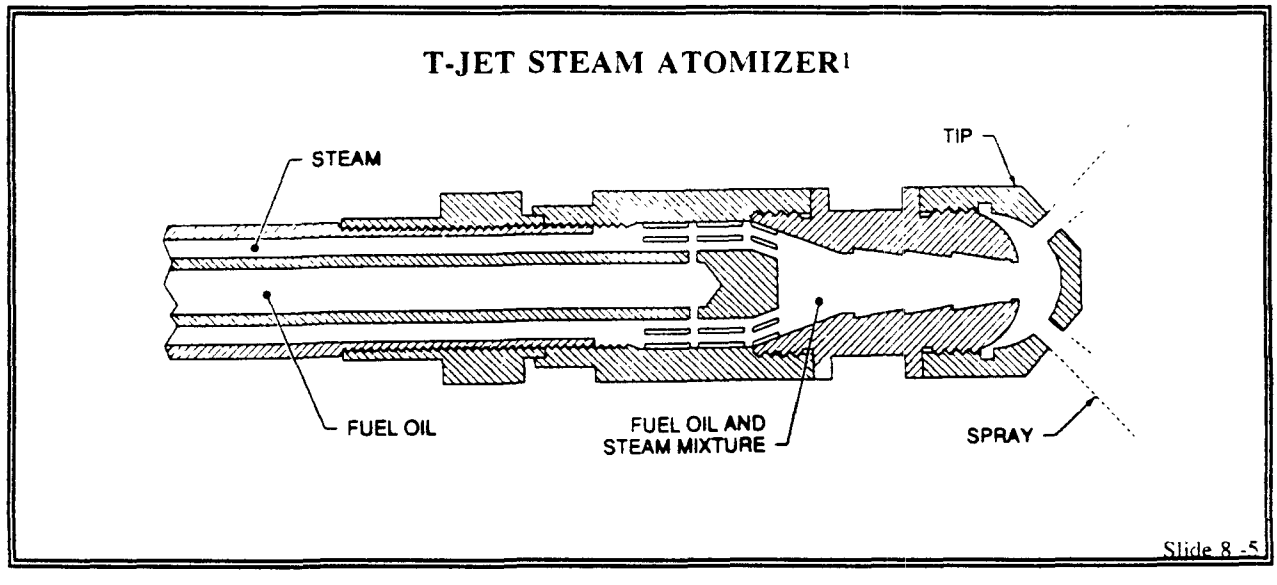
Atomization

Once the oil is supplied to the burner, the fuel oil is dispersed into a mist of droplets by atomization. The purpose of atomizing the fuel is to increase the fuel oil surface area and therefore increase the exposure of the fuel to the oxygen in the combustion air. By quickly and efficiently mixing the oxygen and fuel, complete combustion of the fuel oil is promoted. The atomization of oil is accomplished by the oil gun. An oil gun atomizes, or breaks up, the oil into small droplets and then disperses the droplets. The atomization process can be achieved by three common methods: steam, air, and mechanical atomization.

Steam and air atomization are closely related, the same gun often being adaptable to both uses. For these types, oil droplet sizes are controlled by the pressure differential between the atomizing fluid (steam or air) pressure and the oil pressure. Higher pressure differential would result in smaller oil droplet sizes. Therefore, desired droplet sizes, and hence the burner combustion characteristics, can be controlled by controlling this pressure differential.

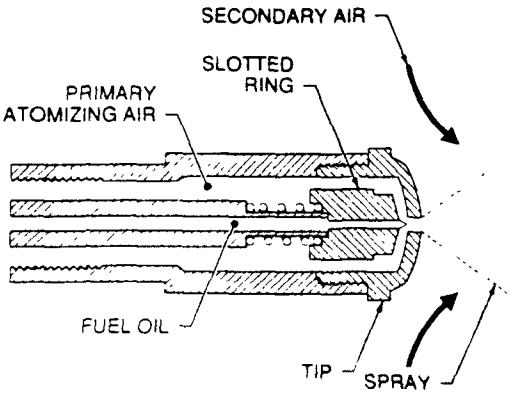
For large boilers, air atomization is seldom used because of the high operating cost of pumping large quantities of air. In package boilers, however, air atomization is popular. Air atomization of light oils produces good results. Turndown is somewhat more limited than with steam atomization due to the relatively low compressed air pressures usually available. There are three basic types of steam/air atomizers: T-Jet, Y-Jet, and Rotary.

For a T- Jet design, oil flows down the central tube and turns radially outward to impinge on the axially flowing steam through the outer tube. Steam pressure is maintained 20 psi above oil pressure up to a maximum steam pressure of about 100 psig. The density of the oil is roughly two hundred times that of the steam. At the "T" junction where the two streams mix the steam is moving at several hundreds of feet per second, with the oil velocity is several tens of feet per second.



The Y- Jet type of steam atomizer, with the oil entering the high velocity steam passage at an acute angle is illustrated in Slide 8- 6. Steam pressure is held constant and the variation of oil flow is adjusted by the oil pressure. This same design may be adapted to air atomization. The quality of atomization is consistently good over the range of oil flow for this design.

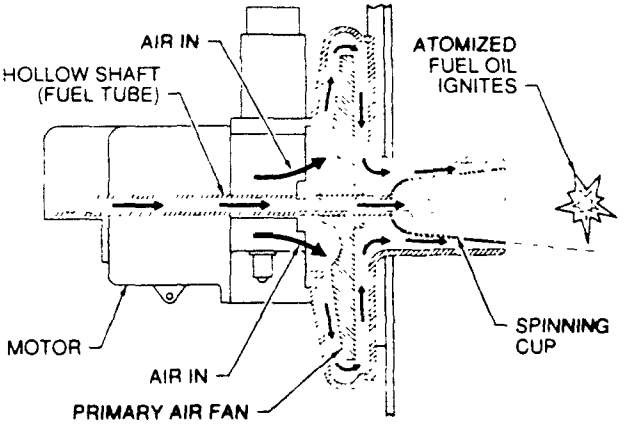
Y-JET STEAM/AIR ATOMIZER[1]



Slide 8-6

A rotary cup burner has a cone-shaped cup that mixes fuel oil with air, as shown below. The rotating cup is mounted on the end of the hollow blower shaft. Fuel oil is delivered to the inside of the rotary cup burner through the hollow shaft. Fuel oil is thrown to the wall of the rotating cup by centrifugal force and air from the blower mixes with the fuel oil as it sprays off the end of the rotary cup burner. The burning rate is determined by the fuel feed rate.

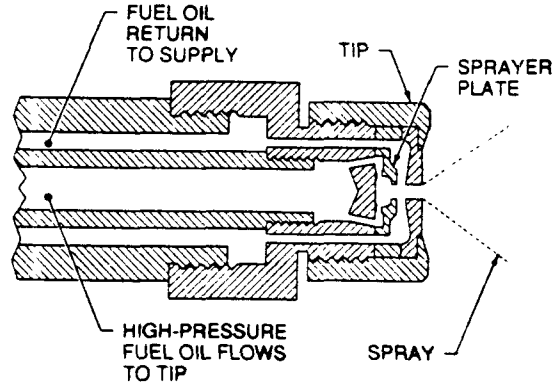
ROTARY CUP ATOMIZER[1]



Slide 8-7

Mechanical atomization of both light and heavy oils is available, but fuel pressure requirements are much higher than for steam or air atomization. Mechanical atomization is generally not recommended for single-burner applications because of the limited turndown. Straight mechanical atomization is the simplest oil firing system. It requires only a fuel supply line to each burner and the firing rate is altered by adjusting the oil supply pressure. Wide-range mechanical atomization requires both fuel supply and return lines at each burner. For the constant differential pressure system, a separate pump maintains a constant pressure differential between supply and return. Firing rate is adjusted using a fuel supply valve upstream of the constant-differential pump. For the constant supply pressure system, the supply pressure is constant over the complete operating range of the burner and the firing rate is adjusted by throttling the return line.

MECHANICAL ATOMIZER[1]



Slide 8-8

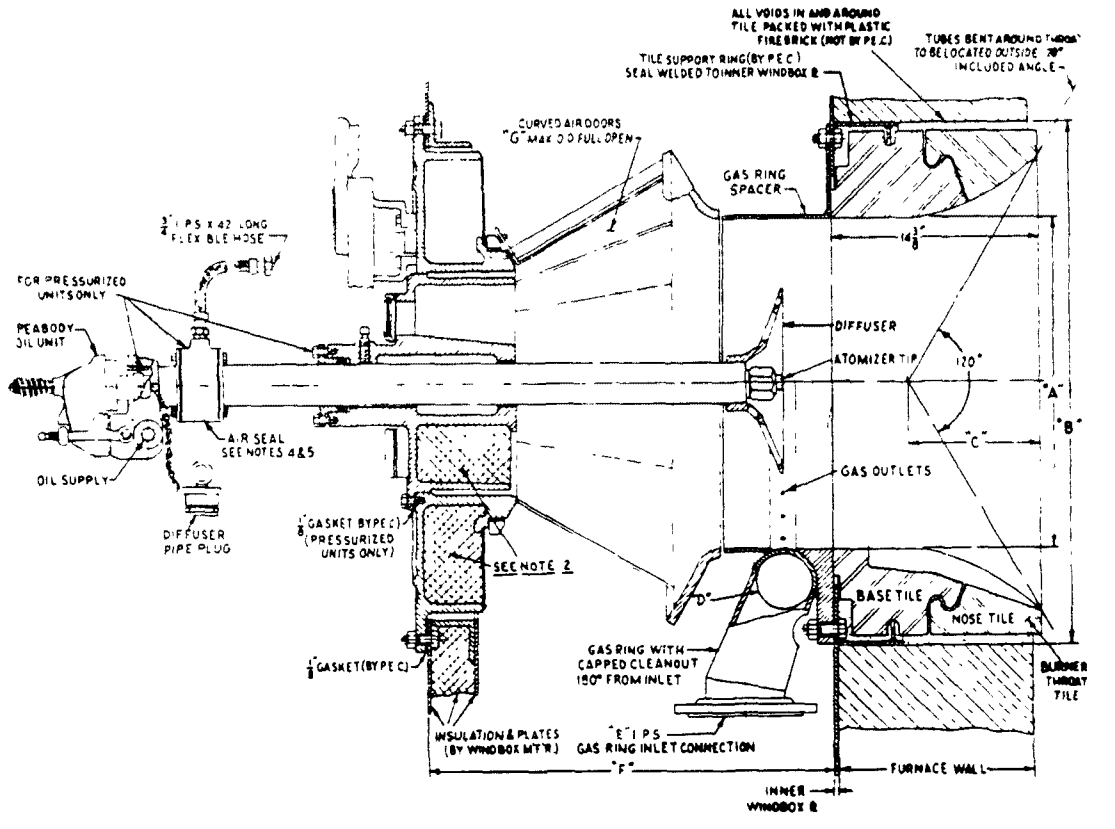
Operation

A few common problems to oil handling systems include air in oil lines, dripping of oil, oil expansion, and clinker. The effect of air in the oil lines may result in poor control, irregular burning, and limited capacity. Removal of air from a system is best accomplished in a recirculating system where both the air and fuel return to the fuel tank. In other systems, manual air bleed valves should be installed at high points and opened when a problem is determined. Fuel oil dripping through the burners may cause an accumulation of carbon sooting the burner nozzles or on the surrounding burner surfaces. To prevent buildup, the holes in the burner tip should be cleaned out on a regular basis. Oil expansion may cause damage to gauges, regulators and other apparatus. After a burner is shut off, heat from the furnace causes the remaining oil in the pipes to expand against the pipe wall. Accumulators should be installed to take up the oil expansion and checked periodically for normal operation. In some cases, the carbon buildup at the fuel nozzles becomes so severe that some clinkers are formed and plug up a portion of the tips. This may result in inadequate oil atomization and hence affecting the flame characteristics.

8.3 Burner Arrangements

Burners for gas and oil firing function very much the same. In many cases, the capability to burn both fuels is incorporated into one burner assembly. These burners are known as dual fuel burners which introduce either fuel and the required air into the furnace for the combustion process. The figure in Slide 8-9 shows a cross sectional view of a typical gas and oil firing circular burner assembly manufactured by Peabody Engineering Corporation (PEC). This particular burner has a gas ring burner with an oil atomizing gun located in the center of the ring. The atomizing gun is fitted with a diffuser to stabilize the oil flame. The air is supplied to the burners via a forced draft fan. The air is metered to the burner by the air register doors. The air register also provides the turbulence necessary to mix the fuel and air and produce short, compact flames.

DUAL FUEL BURNER CROSS SECTION



Peabody Engineering Corporation (Type H Forced Draft Ring Gas &/or Oil Fired)

Slide 8-9

The fuel oil is introduced to the burner via the oil atomizer (oil gun), in a fairly dense mixture in the center. The direction and velocity of the air, plus dispersion of the fuel, provides the mixing of air and fuel required for combustion. The oil atomizer disperses the oil fuel into the furnace as a fine mist. This exposes a large amount of oil particle surface in contact with the combustion air to assure rapid oil vaporization, prompt ignition and rapid combustion. If the atomizer is located too far forward in the furnace, the flame may whip around the diffuser. If the atomizer is withdrawn too far, spray will strike the burner throat and buildup carbon and the flame will tend to flutter. Once the oil gun position and the air registers are set properly no further adjustments are normally required during operation.

Similar to the gas burners, the common oil burner configurations are front wall fired, opposed fired, and tangential or cornered fired. Likewise, multiple and singular burner arrangements are commonly used.

8.4 Boiler Design Parameters

Oil firing requires a larger furnace area than for natural gas firing primarily due to higher heat absorption. The rapid burning and high radiation heat transfer rate from oil firing results in high heat absorption rates in the active burning zone of the furnace. The furnace size must therefore be increased for complete combustion and to avoid excessive furnace-wall metal temperatures. However, oil does not require as large a furnace as coal to achieve complete combustion.

The operation of a boiler on oil continuously for several weeks results in a build up of a very thin deposit on the waterwalls. This deposit is thermally insulating. The insulation is usually too insignificant to cause any deterioration in performance.

8.5 Emissions

The emissions of interest from fuel oil fired boilers include sulfur oxides, nitrogen oxides, carbon monoxide, and opacity. Sulfur oxide emissions are dependent on the sulfur content of the fuel. For most cases, almost all the sulfur in the fuel is converted to SO_2 with a small fraction converted to SO_3. Until recently, limits in maximum sulfur content in fuel oils were set by ASTM and customer specifications. But, the maximum limit now is dictated by regulations, which vary considerably in different localities.

Likewise, NO_x emission from oil fired boilers are related to fuel nitrogen content. Other fuel properties, such as oil atomization, carbon burnout, and excess oxygen minimization affect NO_x emissions.

Carbon monoxide (CO) is measured to provide a measurement of the combustion process. If CO increases, the amount of combustion air usually needs to be increased.

The opacity when burning fuel oil is usually greater than when the same unit is operated on natural gas. The visible smoke coming from the stack indicates the efficiency of the combustion process. If the smoke from the stack is a light brown, the oxygen level is too low. A heavy white smoke leaving the stack indicates the too much air is available in the combustion process while black smoke indicate incomplete combustion. Under complete combustion conditions, there will be no visible smoke.

A survey of a wide range of oil-fired boilers burning distilled and residual fuel oils was conducted by the EPA. A summary of the emission ranges for NO_x, CO and total hydrocarbon (THC) is given in Slide 8-10.

UNCONTROLLED EMISSIONS DATA FOR OIL-FIRED BOILERS[5]

Oil Type and Boiler Capacity	NO_x, lb/MMBTU[a]	CO, lb/MMBtu[a]	THC, lb/MMBtu[a]
Residual Oil:			
Watertube Units:			
10 to 100 MMBtu/hr	0.20 to 0.79	0.0 to 0.11	0.0 to 0.03
> 100 MMBtu/hr	0.31 to 0.60	0.0 to 0.07	0.002 to 0.02
Distillate Oil:			
Watertube Units:			
10 to 100 MMBtu/hr	0.08 to 0.16	0.0 to 1.18	0.0 to 0.003
>100 MMBtu/hr	0.18 to 0.23	0.0 to 0.84	0.001 to 0.009

[a]To convert to ppm @ 3% O_2, multiply by the following: NO_x, 790; CO, 1,300; THC, 2,270

Slide 8-10

REFERENCES

1. Wilson, R. Dean, *Boiler Operator's Workbook*, American Technical Publishers, Inc., 1991.

2. *North American Combustion Handbook*, Second Edition, North American Manufacturing Company, 1978.

3. Singer, J. G., *Combustion: Fossil Power Systems*, 3rd Edition, Combustion Engineering, Inc., 1981.

4. Price, Joyce V., et al., "Low NO_x Oil/Gas Burner Retrofits and Their Effects on Overall Emissions and Boiler Performance," May, 1993 EPA/EPRI Joint Symposium on Stationary Combustion NO_x Control.

5. "Alternative Control Techniques Document -- NOx Emissions from Industrial/Commercial/Institutional (ICI) Boilers", U.S. EPA, EPA-453 / R-94-022, March, 1994.

CHAPTER 9. PULVERIZED COAL BOILERS

9.1 Introduction

9.2 Pulverizing Properties of Coal
- A. Grindability
- B. Moisture
- C. Wear Properties

9.3 Coal Preparation
- A. Coal Crushers
- B. Coal Feeders

9.4 Methods of Pulverizing and Conveying Coal
- A. Storage System
- B. Direct-Fired System
- C. Semidirect System
- D. Source of Heated Air

9.5 Pulverizing Air Systems
- A. Indirect Coal-Storage Pulverizing Systems
- B. Direct Firing Arrangements

9.6 Types of Pulverizers
- A. Ball-Tube Mills
- B. Impact Mills
- C. Attrition Mills
- D. Ring-Roll and Ball-Race Mills
- E. Types of Pulverizers for Various Materials

9.7 Pulverized Coal Boilers
- A. Wall Fired Boilers
- B. Tangentially Fired Boilers
- C. Vertically Fired Boilers
- D. Cyclone Fired Boilers

9.8 Emissions

9. PULVERIZED COAL BOILERS

9.1 Introduction

PULVERIZED COAL SYSTEMS

Pulverizing Properties of Coal
Coal Preparation
Methods of Pulverizing and Conveying Coal
Pulverizing Air Systems
Types of Pulverizers
Pulverized Coal Boilers

Slide 9-2

In a pulverized coal firing system, coal is grinded into very fine powder, called *pulverized coal*, using a mechanical device called a *pulverizer* and fed into a boiler furnace through a burner specially designed to burn the coal. Since pulverized coal is so fine, it burns like a gas and its flame is easily lighted and controlled. Pulverized coal firing systems have the ability to adapt operating conditions to all coal ranks from anthracite to lignite. This chapter describes pulverizing properties of coal, coal preparation, methods of pulverizing and conveying coal, pulverizing air systems, types of pulverizers, and types of pulverized coal boilers. It also presents typical emissions from these coal fired boilers.

9.2 Pulverizing Properties of Coal

PULVERIZING PROPERTIES OF COAL

Grindability
Moisture
Wear Properties

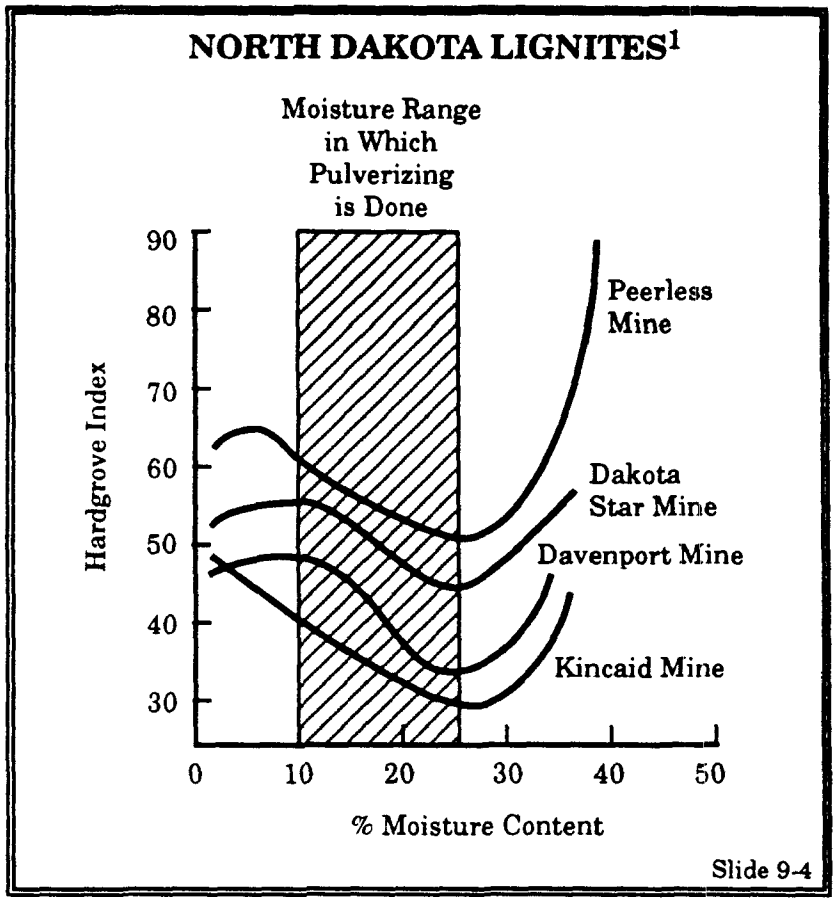
Slide 9-3

Grindability

The ease of pulverization of a coal is measured by its grindability index. This index, unlike moisture, ash or heating value, is not an inherent property of coal. Rather, it represents the relative ease of grinding coal when tested in a particular type of apparatus.

Grindability is not the same as the hardness of coal. The same coal may have a range of grindabilities depending on other constituents in the coal. For example,

Slide 9–4 shows typical relationships between Hardgrove grindability and moisture content for North Dakota lignites. Typically, anthracites and some lignites have at least one point where their grindabilities are very close. Anthracite, however, is a very hard coal whereas lignite is soft, yet they both are difficult to grind.

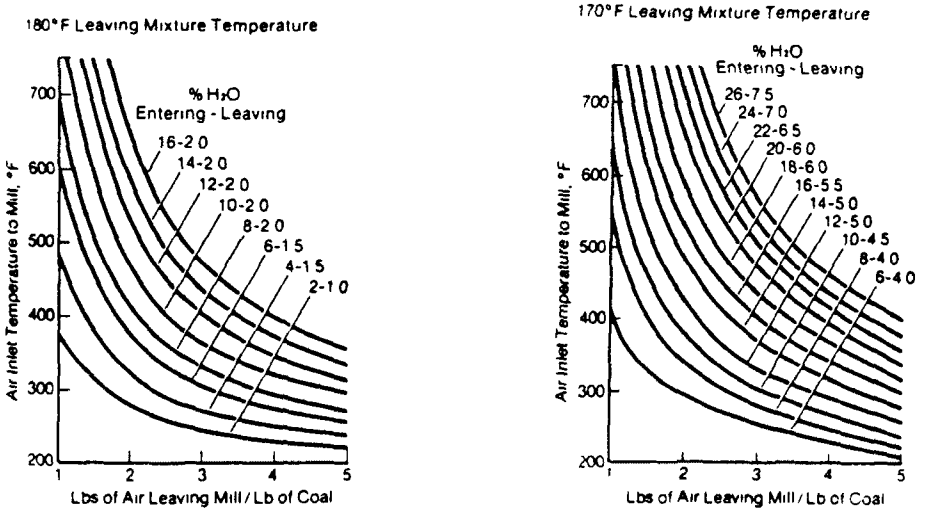


Moisture

As mentioned in Chapter 4, moisture of a coal is usually referred as the total moisture, which consists of inherent moisture and surface moisture. Surface moisture has negative effects on both the pulverization performance and combustion process. The surface moisture produces agglomeration of fines in the pulverizing zone, and reduces pulverizer drying capacity. Agglomeration of fines has the same effect as coarse coal during combustion since particle surface available for reaction is reduced.

Hot air is used to dry coal in the pulverizing system. Slide 9–5 shows curves which indicate the air temperature required to dry coal of varied total moisture and coal air mixture. If there is a deficiency of hot air, the mill output will be limited to the drying capacity and not the grinding capacity. Therefore, it may be possible to obtain more capacity with low moisture coal of lower grindability than with high moisture coal of higher grindability.

TEMPERATURE OF AIR TO MILL[1]



Slide 9-5

Wear

Pulverizing typically wears down the grinding element material. Balls, rollers, rings, races, and liners gradually erode and wear out as a result of abrasion and metal displacement in the grinding process. Thus, the maintenance of the grinding elements is one of the major costs of the pulverizing operation. "Pure coal" is relatively nonabrasive; however, such foreign material as slate, sand, and pyrites, commonly found in coal as mined, are quite abrasive. These are undesirable constituents that produce rapid and sometimes excessive wear in pulverizing apparatus. The economics of coal cleaning to remove such abrasive foreign materials depends on many variables and must be determined for each individual application.

9.3 Coal Preparation

COAL PREPARATION

Coal Crushers
- Swing-Hammer Crushers
- Roll Crushers

Coal Feeders
- Belt Feeders
- Overshot Feeders

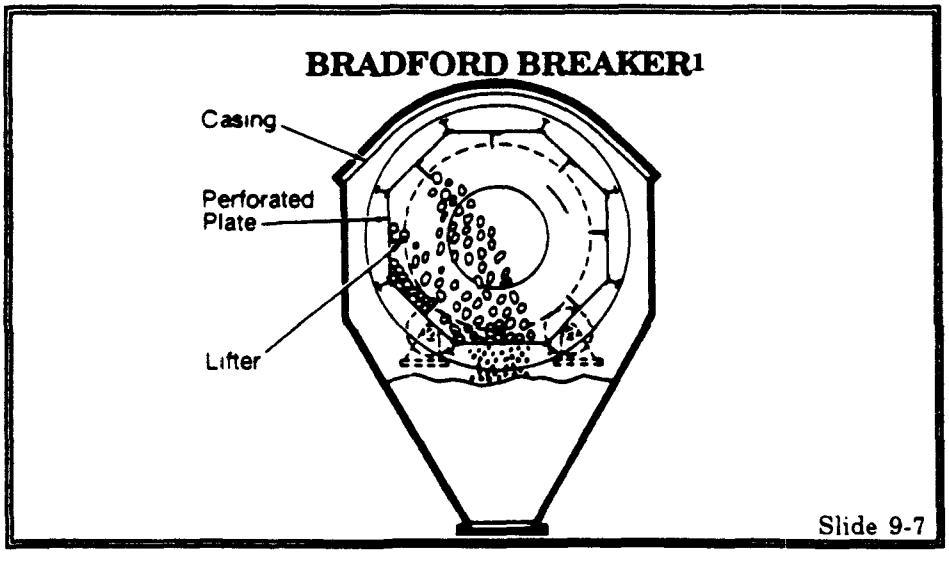
Slide 9-6

Coal should be prepared properly to insure its safe, economical, and efficient use in a pulverizing system. Coal must be crushed before it can be fed to the pulverizers. The issues associated with coal preparation are as follows:

- Controllable continuity of flow to the pulverizer must be maintained.
- Organic foreign materials such as wood, cloth, or straw should be removed. These materials may collect in the milling system and obstruct the flow patterns in the mill. They may also become a fire hazard.
- The raw coal must be crushed to a size that will promote a uniform flow rate to the mill by the feeder. Favorable coal particle sizing minimizes segregation of coarse and fine fractions in the bunker, and result in a more uniform rate of feed to different pulverizers supplied from a given bunker.
- An ideal feed is the one that is closely sized and double–screened ($^3/_4$ in. x $^1/_4$ in.). Coal of this size will permit excess water to drain off; it will flow freely and uniformly from bunkers.

Coal Crushers

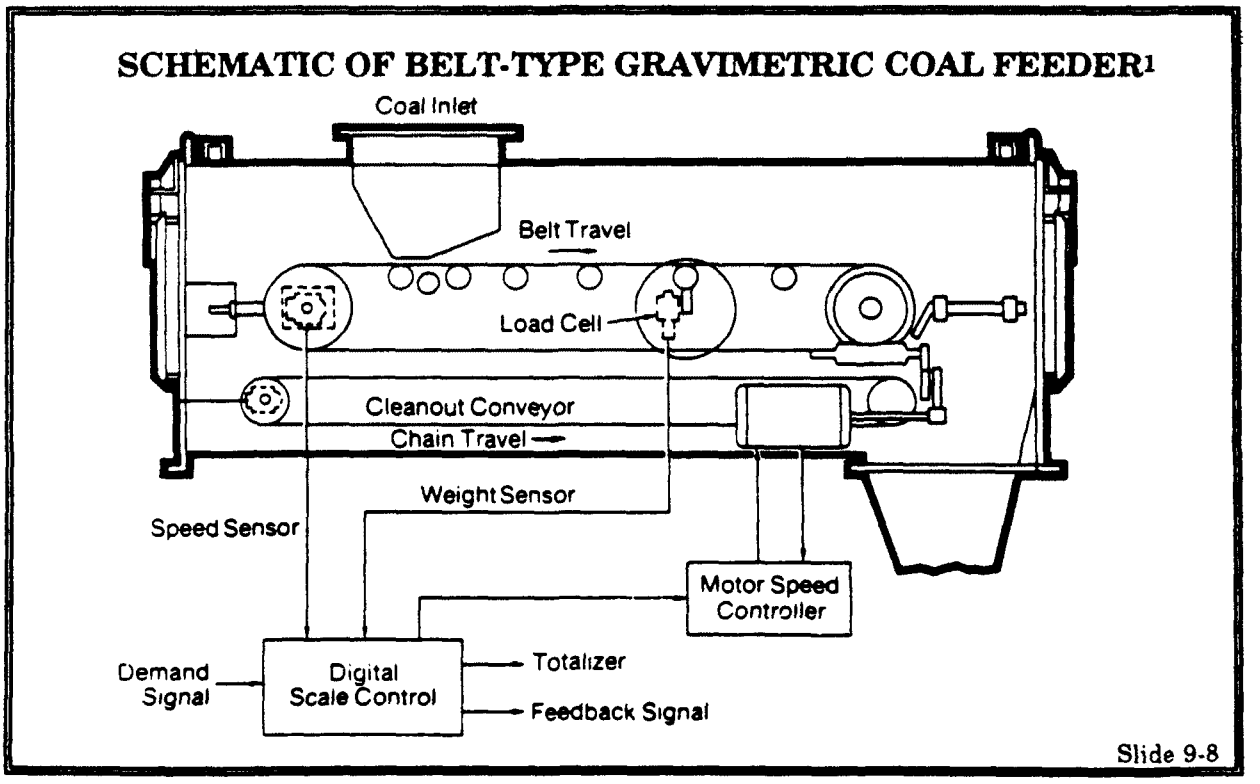
Swing–Hammer Crushers: Swing–hammer crushers are typically used for smaller capacities. These crushers have proven satisfactory for overall use and have demonstrated reliability and economy. A swing–hammer crusher consists of a casing enclosing a rotor to which pivoted hammers or rings are attached. Coal is fed through an opening in the top of the casing and crushing is affected by impact of the revolving hammers or rings directly on the liners or spaced grate bars in the bottom of the casing. The degree of size reduction depends on hammer type, speed, wear, and bar spacing. These crushers produce uniform coal sizing and break up pieces of wood and nonmetallic foreign material.



Roll Crushers: Roll crushers have been used but are not always satisfactory because of their inability to deliver a uniform sized product. The Bradford breaker, shown in Slide 9–7, is probably the most satisfactory crusher for large capacities. The design consists of a large diameter, slowly revolving cylinder of perforated steel plates. The size of the perforation determines the final coal sizing. These openings are $1\frac{1}{4}$ to $1\frac{1}{2}$ inches in diameter. The breaking action of coal is accomplished as follows: the coal is fed in at one end of the cylinder and carried upward on projecting vanes and shelves. As the cylinder rotates, the coal cascades of the vanes and break upon striking the perforated plate. Since the coal drops a relatively short distance, coal crushing occurs with the production of very few fines. Broken coal passes through the perforations in the plates to a hopper below. Rocks, wood, slate, tramp iron, and other foreign materials are rejected. This breaker produces a relatively uniform product and uses very little power.

Coal Feeders

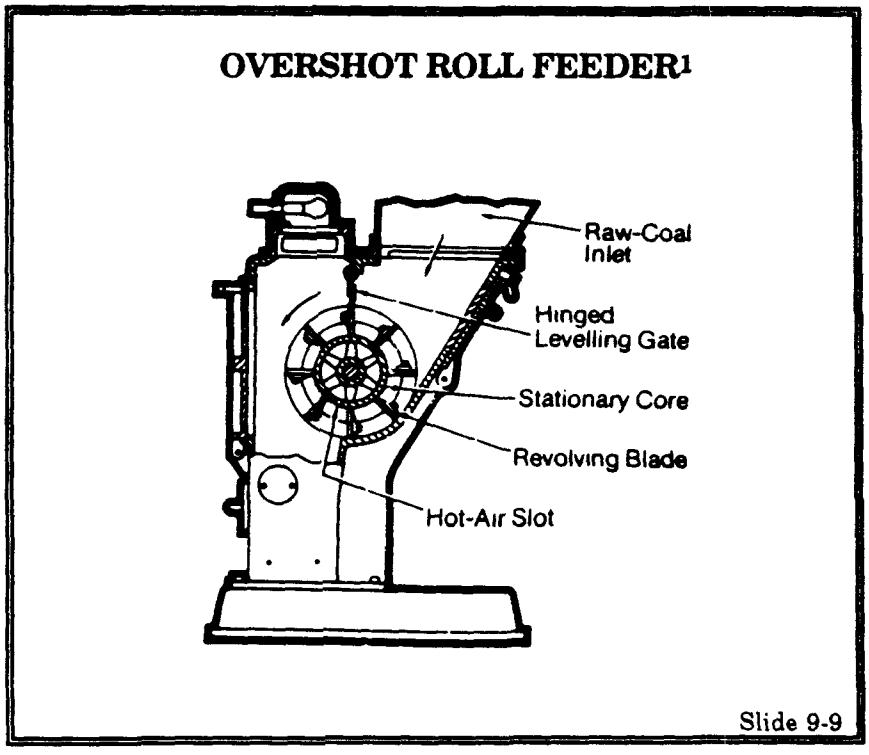
A coal feeder is a device that supplies the pulverizer with an uninterrupted flow of raw coal to meet system requirements. This is especially important in a direct fired system.



Belt Feeders: The belt feeder uses an endless belt running on two separated rollers receiving coal from above at one end and discharging it at the other end. The feed rate is controlled by varying the speed of the driving belt. A leveling plate fixes the depth of the coal on the belt. The belt feeder can be used in either a volumetric type and gravimetric type of application (Slide 9-8). The gravimetric type is more

popular due to its ability to deliver accurate quantities of coal to each individual pulverizer.

There are two methods of continuously weighing the coal on the feeder belt. One method uses a series of levers or balance weights; the other uses a load cell across a weigh span on the belt. Both are very accurate mechanisms and both are well accepted by utilities. This same belt feeder design can also be used for volumetric measurement.



Overshot Feeders: Slide 9–9 shows a schematic of an overshot roll feeder. The feeder has a multiblade rotor which turns about a fixed, hollow, cylindrical core. The core has an opening to the feeder discharge and is provided with heated air to minimize wet coal accumulation on surfaces and to aid in coal drying. A hinged, spring loaded leveling gate mounted over the rotor limits the discharge from the rotor pockets. This gate permits the passage of oversize foreign material. Feeders of this type may be attached to the side of a pulverizer or mounted separately.

9.4 Methods of Pulverizing and Conveying Coal

METHODS OF PULVERIZING AND CONVEYING COAL

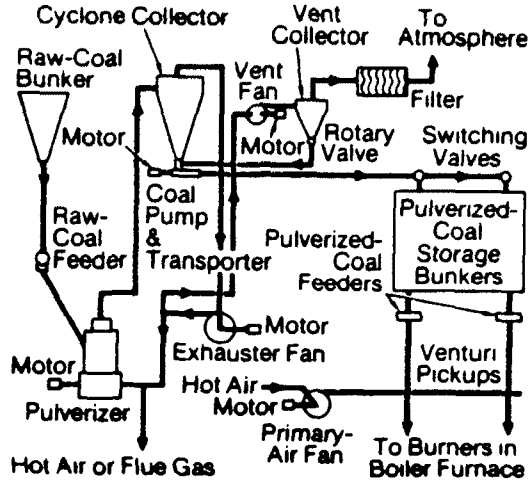
Storage System
Direct Fired System
Semidirect System

Slide 9-10

Three methods of supplying and firing pulverized coal have been developed: the storage system, the direct fired system and the semidirect system. These methods differ on the basis of their drying, feeding, and transport characteristics.

The Storage System

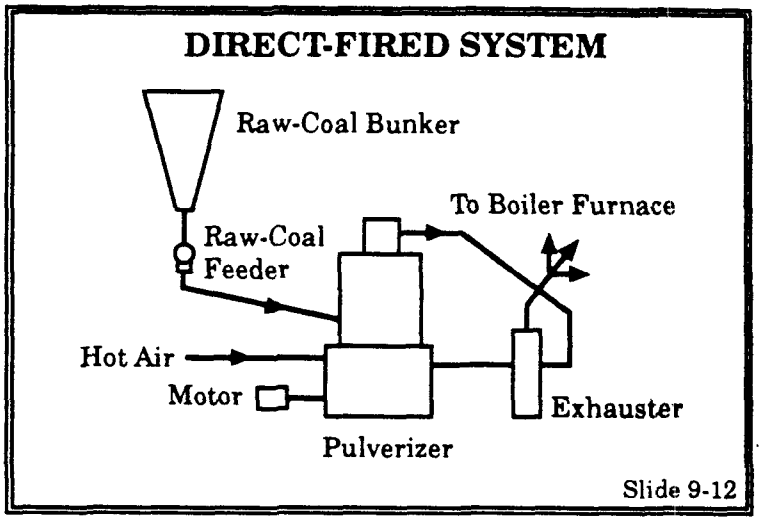
STORAGE SYSTEM[1]



Slide 9-11

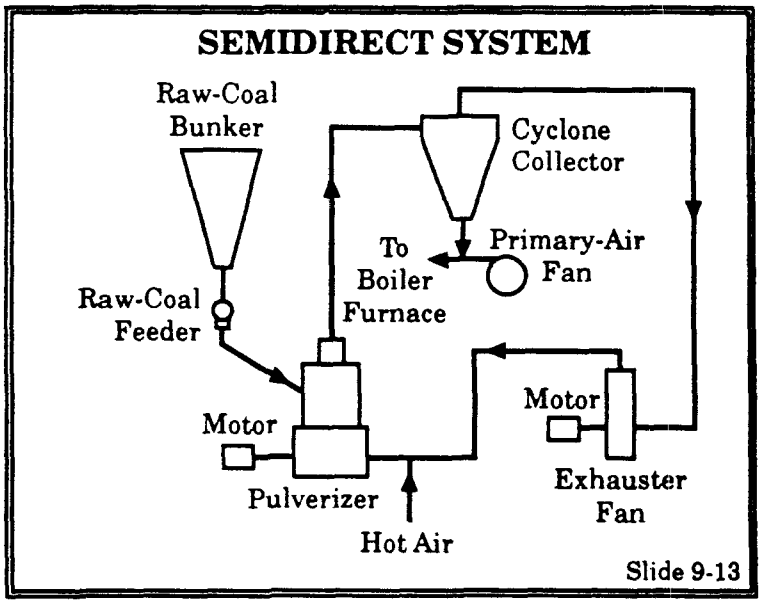
In a storage system, coal is pulverized and conveyed by air or gas to a suitable collector from which the coal is transferred to a storage bin. The hot air or gas introduced into the mill provides for system drying requirements and is vented from the system with the moisture evaporated from the fuel. The pulverized coal is fed from the bin into the furnace as required.

The Direct Fired System



In a direct fired system, coal is pulverized and transported directly to the furnace where it is burned. The hot air supplied to the mill provides the heat for drying the coal or transporting the fuel to the furnace. This air is known as primary air and is a portion of total combustion air.

The Semidirect System



In a semidirect system, a cyclone collector located between the pulverizer and the furnace separates the conveying medium (hot air) from the coal. The coal is fed directly from the cyclone to the furnace in a primary air stream which is different from the air supplied to the mill. The drying medium, therefore, is the same as in a storage system.

Source of Heated Air

The hot air from either a regenerative or recuperative air heater (see Chapter 3) is the best source of heated air for mill drying. Large boiler installations usually provide sufficient temperatures for almost any moisture condition. On small installations, where the moisture content in the coal is not high, steam air heaters are used to dry the fuel.

All the moisture in the coal must be removed before the fuel can be ignited. Therefore, for rapid ignition, surface moisture must be removed before the coal is injected into the furnace. The type of fuel and its surface moisture govern mill drying requirements.

The drying capability of a given pulverizer depends on the following factors: (1) the extent of circulating load within the mill, (2) the ability to mix the dry return coal with the incoming wet coal feed, and (3) the air quantity and air temperature design limits. Some pulverizers are designed to operate with inlet air temperatures as high as 825°F, while others limit maximum air temperature to 600°F.

The type of fuel and the kind of system being used will determine the mill outlet temperature. As shown in Slide 9–14, outlet temperatures for storage system mills are lower than those of direct fired or semidirect systems. This is because most coals will not store safely at temperatures used in direct firing. Inadequate outlet temperature control may cause fires resulting from spontaneous combustion of coal in the storage bins.

ALLOWABLE MILL OUTLET TEMPERATURES, °F[1]

System	Storage	Direct	Semidirect
High-rank, high volatile bituminous	130 *	170	170
Low-rank, high volatile bituminous	130 *	160	160
High-rank, low-volatile bituminous	135 *	180	180
Lignite	110	110–140	120–140
Anthracite	200	...	...
Petroleum coke (delayed)	135	180–200	180–200
Petroleum coke (fluid)	200	200	200

* 160°F permissible with inert atmosphere blanketing of storage bin and low oxygen concentration conveying medium.

Slide 9-14

9.5 Pulverizing Air Systems

PULVERIZING AIR SYSTEMS

Indirect Coal-Storage Pulverizing Systems
- Primary Air
- Vented Air

Direct-Firing Arrangements
- Suction System
- Pressure Exhauster System
- Cold Primary Air System

Slide 9-15

Two methods are used to supply air for drying and transporting purposes: indirect coal storage pulverizing system and direct firing arrangements.

Indirect Coal Storage Pulverizing Systems

In an indirect pulverizing system, a cyclone collector separates the coal from the air. The pulverized coal is conveyed either mechanically or pneumatically to storage hoppers or bunkers. Fuel feeders at the bunker outlets deliver the required quantity of coal to the fuel lines where the coal is mixed with air, called primary air, in proper proportions for transport to the burners. In some installations, the primary air is taken from the room or a preheated air duct, or both. In other installations, the air vented from the pulverizer system is used for all or part of the primary air supply.

Primary Air: Primary air is used to carry the coal to the furnace and to provides the required velocity of the coal air mixture in the burners. The primary air quantity therefore depends on the type of firing system, on the type of piping system selected (vertical, horizontal or sloped), and on the burner and furnace arrangement.

Pulverized–coal feeder and fuel piping arrangements determine the primary air temperature, which may be as high as 600°F. A minimum amount of *tempering air* (admitted to the system to achieve proper coal air mixture condition) should be used in the primary air system since it reduces the quantity of air passing through the air heater, reducing the overall unit efficiency.

If *vented air* is to be used for tempering, the temperature of delivered air will depend on the temperature of the vent air, the position of the vent in the return air line, and on whether preheated coal air is added to the primary air at the fan inlet. The vented air will usually have a relative humidity of 70 to 90 percent, a temperature of 110 to 160°F and will contain coal fines from the collectors.

Vented Air: In a storage system, some or all of the drying air is discharged from the system by venting. This removes the moisture which has been evaporated from the fuel. The amount of air vented will depend on the pulverizer output, the moisture removed from the fuel, the initial temperature of the drying air, the temperature of

the vented material and the efficiency of the drying system.

The vented mixture may be disposed in one of two ways: (1) by venting directly to the atmosphere through the boiler stack, or (2) by using it as part of the air supplied to the furnace. Since the vented air contains some extremely fine coal (up to 2 percent of the amount being pulverized), it cannot be vented directly to the atmosphere economically. This is because of the need to collect the coal dust in cyclones, bag filters, air washers, or a combination of these. In the second case, the air does not need cleaning.

Direct Firing Arrangements

There are three basic air conveying systems used for direct firing arrangement. The first is a suction system in which a fan induces air flow through the pulverizer and discharges the coal air mixture under pressure to the furnace. The second is a pressurized exhauster system, in which the pulverizer is pressurized by a forced draft fan with both hot and ambient air and discharges the coal air mixture through the exhauster to the furnace, acting as a booster fan. Lastly a cold primary air system uses a primary air fan that forces air through an air heater and the pulverizer and then forces the coal air mixture to the furnace.

Suction System: The suction system has a number of advantages. It is easy to keep the area around the pulverizer clean. It is easy to control the air flow through the pulverizer. Control of the coal air mixture temperature is by a single hot air damper and a barometric damper through which room temperature air is induced by the suction in the pulverizer. With this control, the fan is designed for a constant, low temperature mixture and has low power consumption, even though such material handling fans have a relative low efficiency of 55 to 60 percent.

The main disadvantage of the suction system is the maintenance required on the exhauster. However, by using proper design techniques and wear resistant materials the maintenance on an exhauster can be minimized. Exhaust maintenance costs are more than offset by the power and capital savings of the system; this justifies the continued use of the suction system on smaller units.

Pressurized Exhauster System: To obtain sufficient pressure for firing a pressurized furnace, the pressurized exhauster system was developed. This system retains the advantages of the suction system, such as maintaining a constant low temperature mixture and ease of airflow control. This flow varies with the amount of fuel being fed to the pulverizer.

One advantage of the pressurized exhauster system is that the low pressure in the pulverizers does not pose a serious problem to sealing the head of coal over the raw fuel feeder as compared with pulverizers under direct blower pressure. The disadvantage of the system is the high maintenance of the exhauster.

Cold Primary Air System: In this system the primary air fan handles only ambient air. The chief advantage of this system over the other two systems is in fan power and maintenance. Since the fans only handle cold air, they can be smaller, run at higher speed. They also can use highly efficient airfoil blade shapes. Inlet vanes can control air flow and add to fan efficiency.

Some other advantages of this system are that higher pressure differentials are possible and larger mills with longer fuel pipes become more practical. Thus, pulverizers can be located a further from the boiler furnace. Space requirements can be reduced since an individual fan for each pulverizer is not necessary. Moreover, with the high fan pressure head available, the inlet airflow can be measured by installing a venturi other metering device.

Controlling air flow to various pulverizers is still relatively simple even with fewer pulverizer fans. The total primary air required is a function of the number of pulverizers in operation. This permits a simple control for the air flow requirements. Because load and coal moisture content can vary among pulverizers, it is not only necessary to control the total air flow but also the temperature of the air to individual pulverizers. This is accomplished with a system which uses a hot primary air duct and a cold primary air duct with a damper in each duct to the mills. The air flow requirement for a pulverizer is met by adjusting both dampers, while controlling temperature by properly proportioning the flow between the hot and cold air ducts.

The cold primary air system offers savings through the elimination of exhauster maintenance and reduction in fan power. These saving are partially offset by the capital investment for additional ductwork, dampers, and controls. With large units and pulverizers, the use of a cold primary air system becomes economically favorable.

9.6 Types of Pulverizers

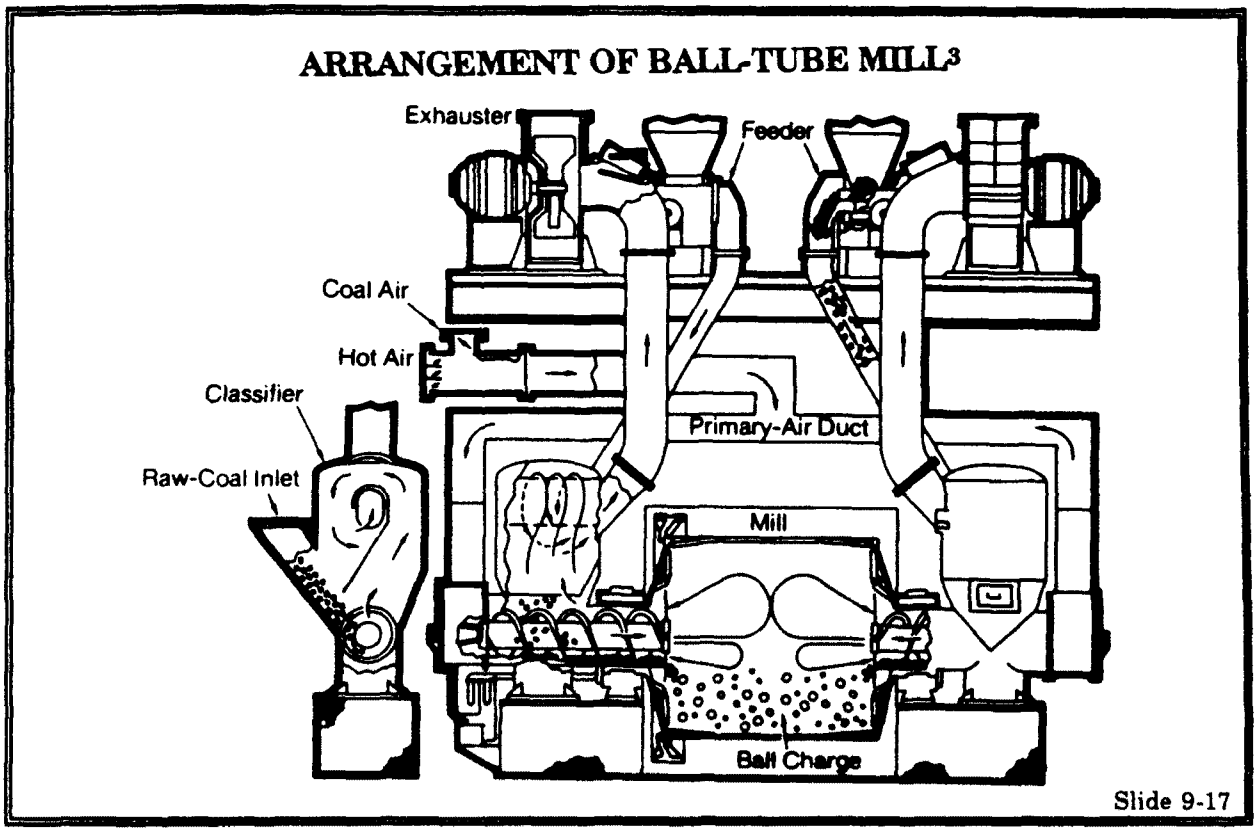
PULVERIZER TYPES[1]

Speed	Low	Medium	High
Type	Ball-Tube Mill	Ring Roll or Ball-Race Mill	Impact or Hammer Mill Attrition Mill

Slide 9-16

Grinding uses either one, two, or all three of the basic principles of particle size reduction; namely, impact, attrition, and crushing. The four most commonly used pulverizers are the ball tube, the ring–roll or ball–race, the impact or hammer mill, and the attrition type.

Ball–Tube Mills



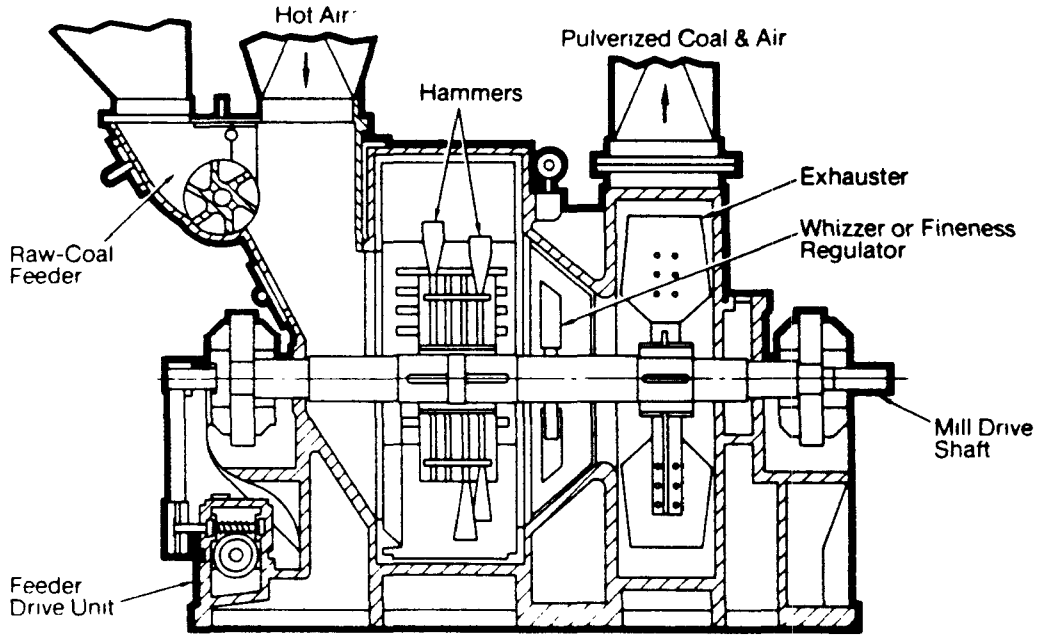
A ball–tube mill is basically a hollow horizontal cylinder, rotated on its axis, whose length is slightly less than its diameter. Heavy wear resistant liners fit the inside of the cylindrical shell, which is filled to a little less than one half with forged steel or cast alloy balls varying from 1 to 4 inches in diameter. Rotating slowly at 18 to 35 rpm, the balls are carried about two thirds of the way up the periphery and continually cascaded toward the center of the cylinder.

Mill Operation: Coal is fed to the cylinder of the ball tube mill. Pulverization, which is accomplished through the continual cascading of the mixtures, results from (1) impact of the falling balls on the coal, (2) attrition as the coal slides over each other as well as over the liners, and (3) crushing as balls roll over each other and over the liners with coal particles between them. Large pieces of coal are broken by impact, and the fine grinding is done by attrition and crushing as the balls roll and slide within the charge.

Hot air is passed through the mill to dry the coal and remove the fines from the pulverizing zone. In most designs, an external classifier regulates the size of the finished product. The oversize rejects from the classifier are returned to the grinding zone with the raw coal.

Impact Mills

DIAGRAM OF AN IMPACT MILL[1]



Slide 9-18

An impact mill consists primarily of a series of hinged or fixed hammers revolving in an enclosed chamber lined with wear resistant plates. Grinding results from the combination of hammer impact on the larger particles and attrition of the smaller particles on each other and across the grinding surfaces. An air system with fan mounted either internally or externally on the shaft induces a flow through the mill. An internal or external type of classifier can be used.

This type of mill is simple and compact and may be built in very small sizes. Its ability to handle high inlet air temperatures, plus the return of dried classified rejects to the raw feed, makes it an excellent dryer. However, the high speed design results in high maintenance and high power consumption for grinding fines.

Progressive wear on the grinding elements reduces the product fineness. It is very difficult to maintain fineness over the life of the wearing parts.

Attrition Mills

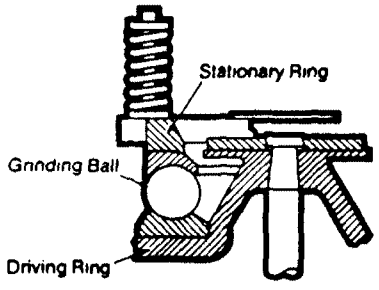
Because of the high rate of wear on parts, attrition mills are not used for coal

pulverizing. A high speed mill that relies on considerable attrition grinding along with impact grinding is, however, used for direct firing of pulverized coal. In this type of mill, the grinding elements consist of pegs and lugs mounted on a disk rotating in a chamber. The periphery of the chamber is lined with wear resistant plates, and its walls contain fixed rows of lugs within which the rotating lugs mesh. The fan rotor is mounted on the pulverizer shaft. A simple rejector which is mounted on the shaft is used instead of an external classifier. This mill type exhibits all the characteristics of the impact mills.

Ring–Roll and Ball–Race Mills

Ring–roll and ball–race mills are medium speed mills. They use primarily crushing and attrition of particles, plus a small amount of impact to obtain size reduction of the coal. The grinding action takes place between two surfaces, one rolling over the other. The rolling element may be either a ball or a roller, while the other member may be either a race or a ring.

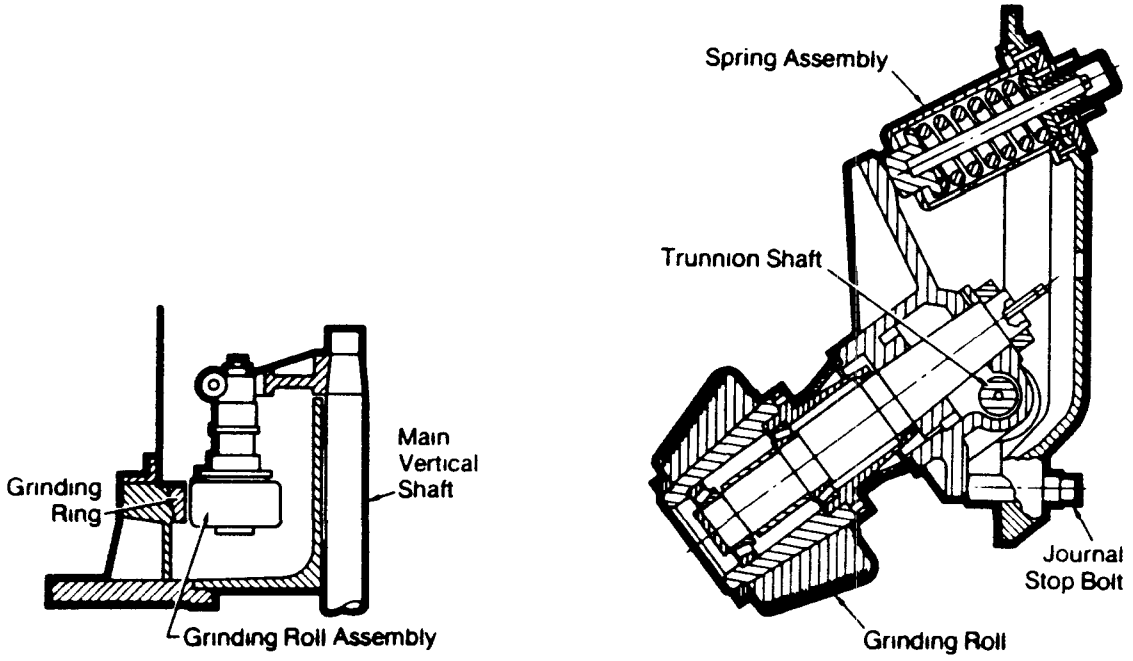
DIAGRAM OF BALL-RACE MILL[3]



Slide 9-19

Ball–Race Mill: When the rolling elements are balls, they are confined between races. In the majority of designs, the lower race is the rotary member while the upper race is stationary. Some other designs also use a rotating upper race.

DIAGRAM OF RING-ROLL MILL JOURNAL ASSEMBLY[3]



Slide 9-20

Ring–Roll Mills: Two general classes of mills use rollers as the rolling elements. In one class, the roller assemblies are driven and the ring is stationary; in the other class, the roller assembly is fixed and the ring rotates.

Types of Pulverizers for Various Materials

TYPES OF PULVERIZERS FOR VARIOUS MATERIALS[1]

Type of Material	Ball-Tube	Impact and Attrition	Ball Race	Ring Roll
Low-volatile anthracite	x	...	...	...
High-volatile anthracite	x	...	x	x
Coke breeze	x	...	...	...
Petroleum coke (fluid)	x	...	x	x
Petroleum coke (delayed)	x	x	x	x
Low-volatile bituminous coal	x	x	x	x
Med-volatile bituminous coal	x	x	x	x
High-volatile A bituminous coal	x	x	x	x
High-volatile B bituminous coal	x	x	x	x
High-volatile C bituminous coal	x	...	x	x
Subbituminous A coal	x	...	x	x
Subbituminous B coal	x	...	x	x
Subbituminous C coal	...	...	x	x
Lignite	...	...	x	x
Lignite and coal char	...	...	x	x
Brown coal	...	x	...	...

Slide 9-21

Different types of mills are used for different types of coals, depending on the grinding requirements and cost considerations. Slide 9–21 shows the types of pulverizer used for various coals.

9.7 Pulverized Coal Boilers

PULVERIZED-COAL BOILERS

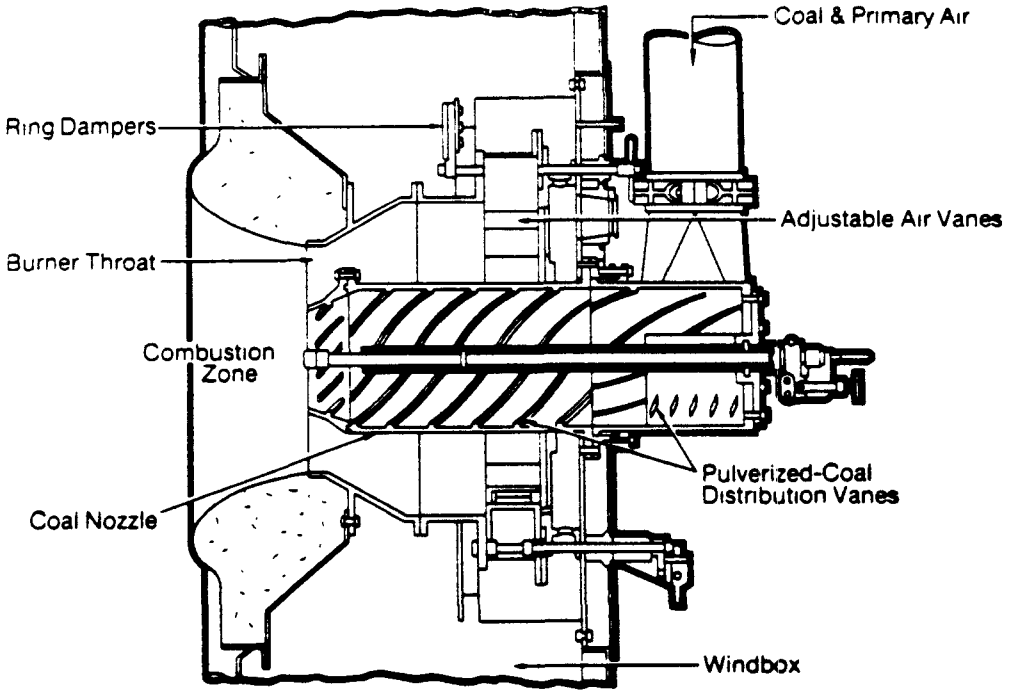
Wall-Fired Boilers
Tangentially-Fired Boilers
Vertically-Fired Boilers
Cyclone-fired Boilers

Slide 9-22

Two representative systems of boilers to burn pulverized coal are the wall fired systems (characterized by individual flames) and tangentially fired systems (which have a single flame envelope). There are other types and combinations; one such is the vertically fired system, which uses characteristics of both aforementioned systems.

Wall-Fired Boilers

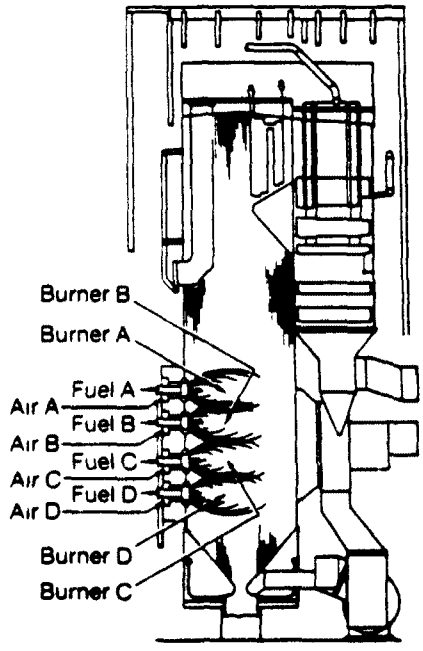
BURNER FOR HORIZONTAL FIRING OF COAL[1]



Slide 9-23

In wall fired boiler systems, the fuel is mixed with combustion air in individual burner registers. Coal and primary air are introduced tangentially to the *coal nozzle,* thus creating a strong rotational flow within the nozzle. An ignitor assembly is located at the centerline of the coal nozzle and is cooled with a bleed of *windbox* air. Surrounding the coal nozzle is the *secondary air passage*, which has adjustable vanes to impart swirling flow of the preheated secondary air from the windbox for flame stabilization. The degree of air swirl, coupled with the flow shaped contour of the *burner throat*, establishes a recirculation pattern in front of the burner exit extending several burner diameters into the furnace. Once the coal is ignited, the hot products of combustion recirculate in front of the nozzle providing stable combustion.

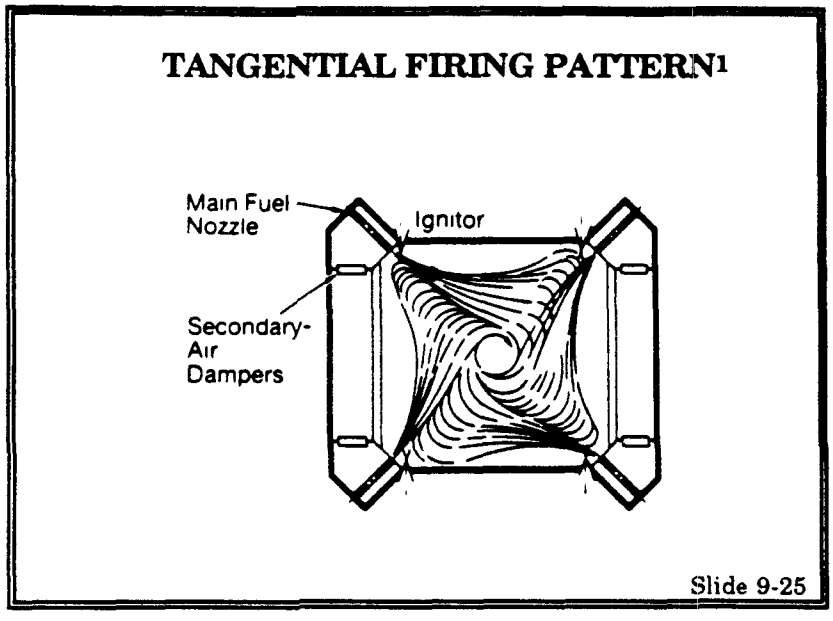
FLOW PATTERN OF HORIZONTAL (WALL) FIRING[1]



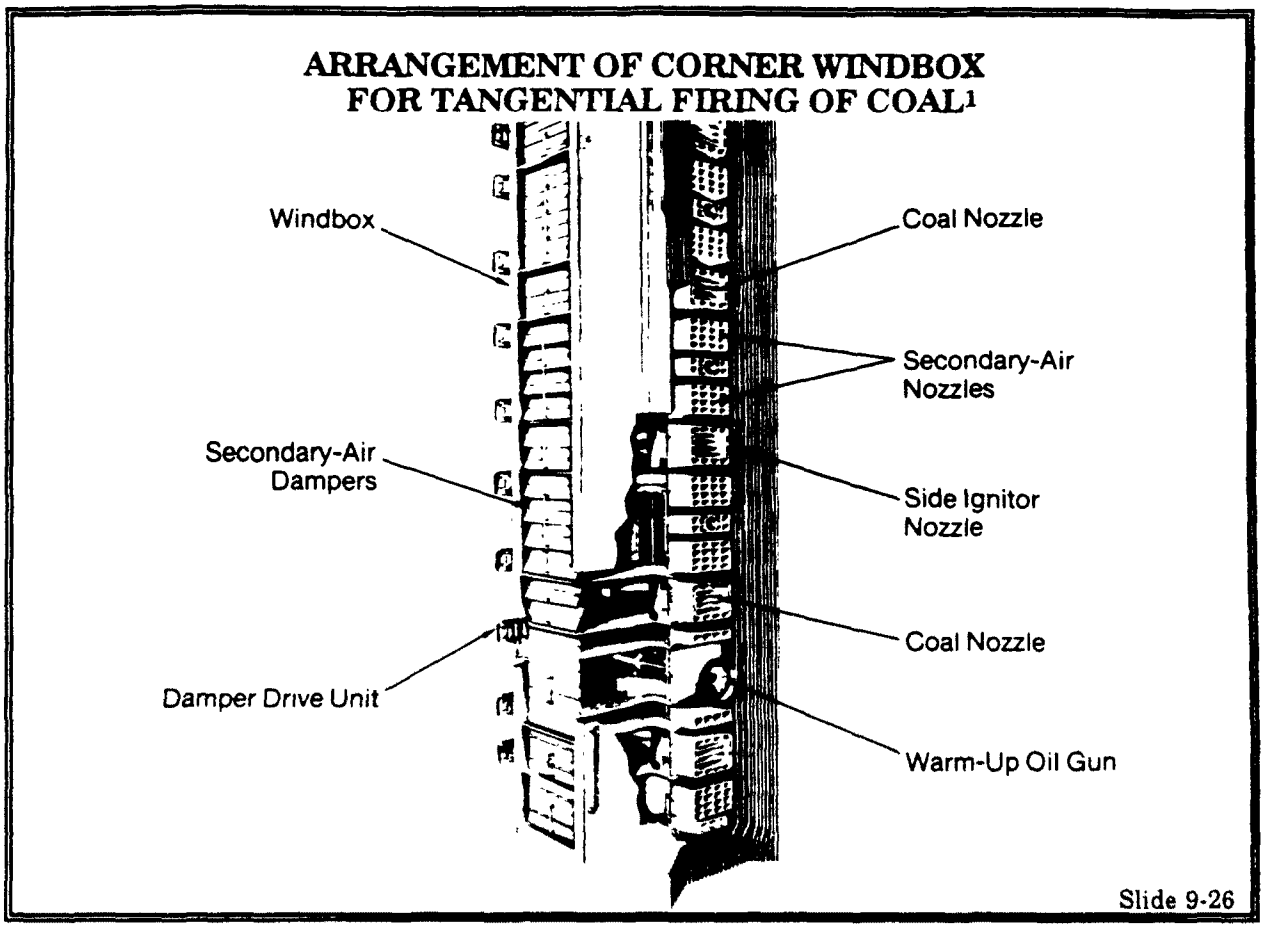
Slide 9-24

Burners are typically arranged on the boiler front wall only (Slide 9–24) or on both the front and rear walls. The latter is called *opposed fired.*

Tangentially Fired Boilers



In the tangentially fired boiler systems, both fuel and combustion air are injected from burners in each corner of the furnace (Slide 9–25). When the streams from the four corners meet, they create a large rotating flame, called a fireball, rather than creating individual flames at each burner. In some units, the fuel and air exiting the corner ignite almost immediately before passing into the swirling fireball. In others, the ignition point is extended and occurs when the fuel/air mixture reaches the fireball.

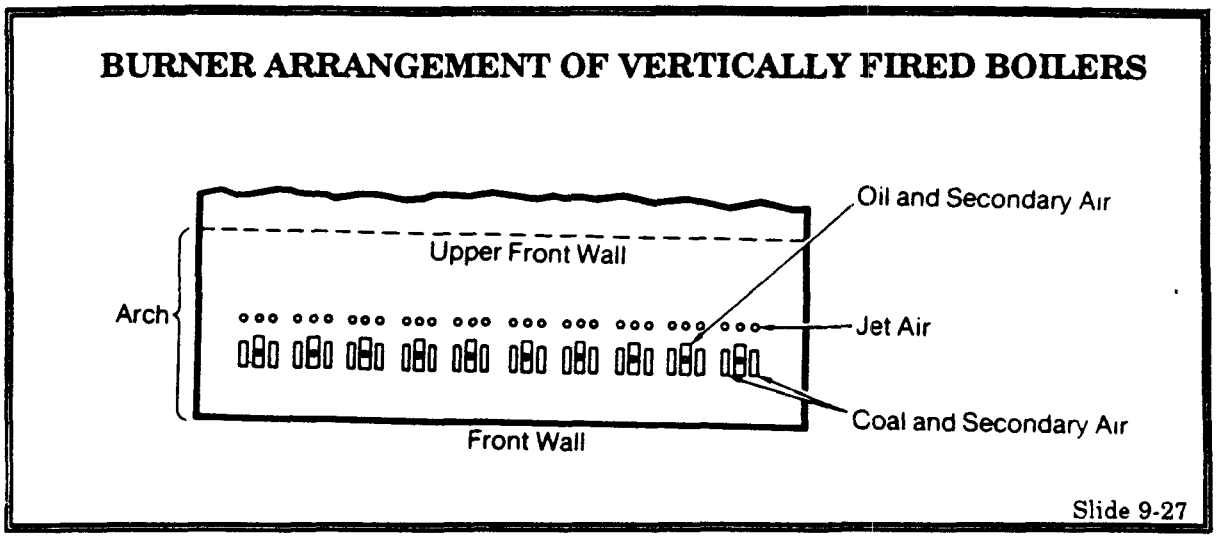


Fuel and air are injected from the furnace corners in vertical compartments. Slide 9–26 shows a schematic of a *burner pack* used in tangentially fired boilers. Dampers control the air quantity to each compartment, making it possible to vary air distribution over the height of the burner pack. It is also possible to vary the air velocity, change the mixing rate of air and fuel , and control the ignition point of the fuel/air mixture.

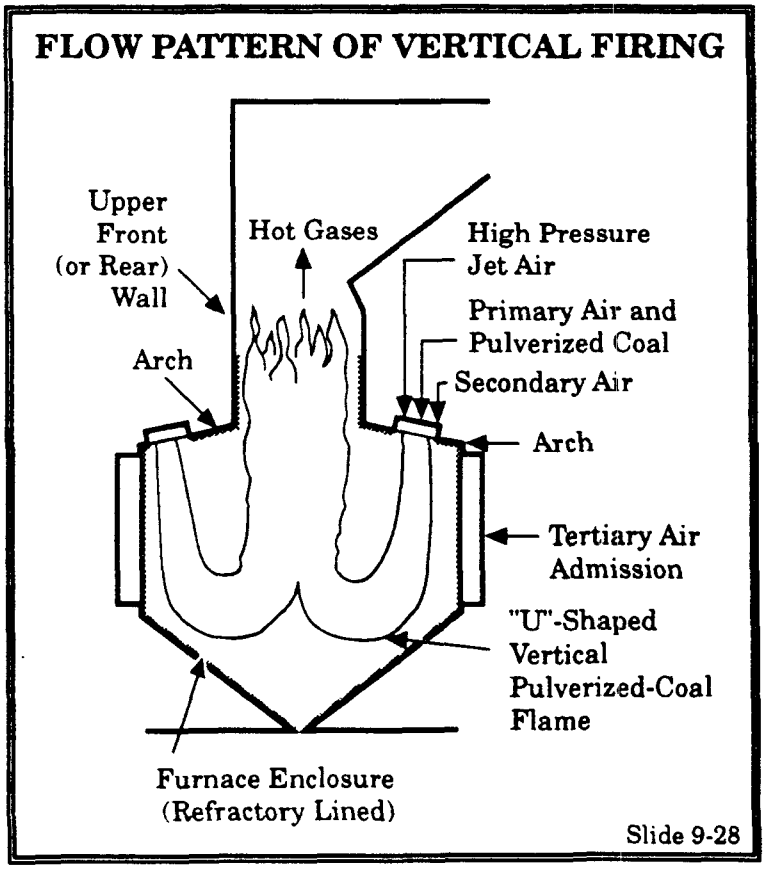
The vertical arrangement of the burner pack allows flexibility in multiple fuel firing. Gas or oil nozzles are typically located in the secondary air compartments adjacent to the coal nozzles.

Some tangentially fired boilers have tilting burners. Tilting the burners allows the relative heat absorption between the furnace and convective pass to be varied to control steam temperature. When the furnace is clean, the burners are tilted upward to increase the heat transfer to the high temperature superheat and reheat surfaces in the upper furnace. As ash deposits build on the furnace walls, furnace heat absorption drops resulting in an increase in heat transfer to the superheat and reheat sections. Then, the burners are tilted downward to compensate.

Vertically Fired Boilers

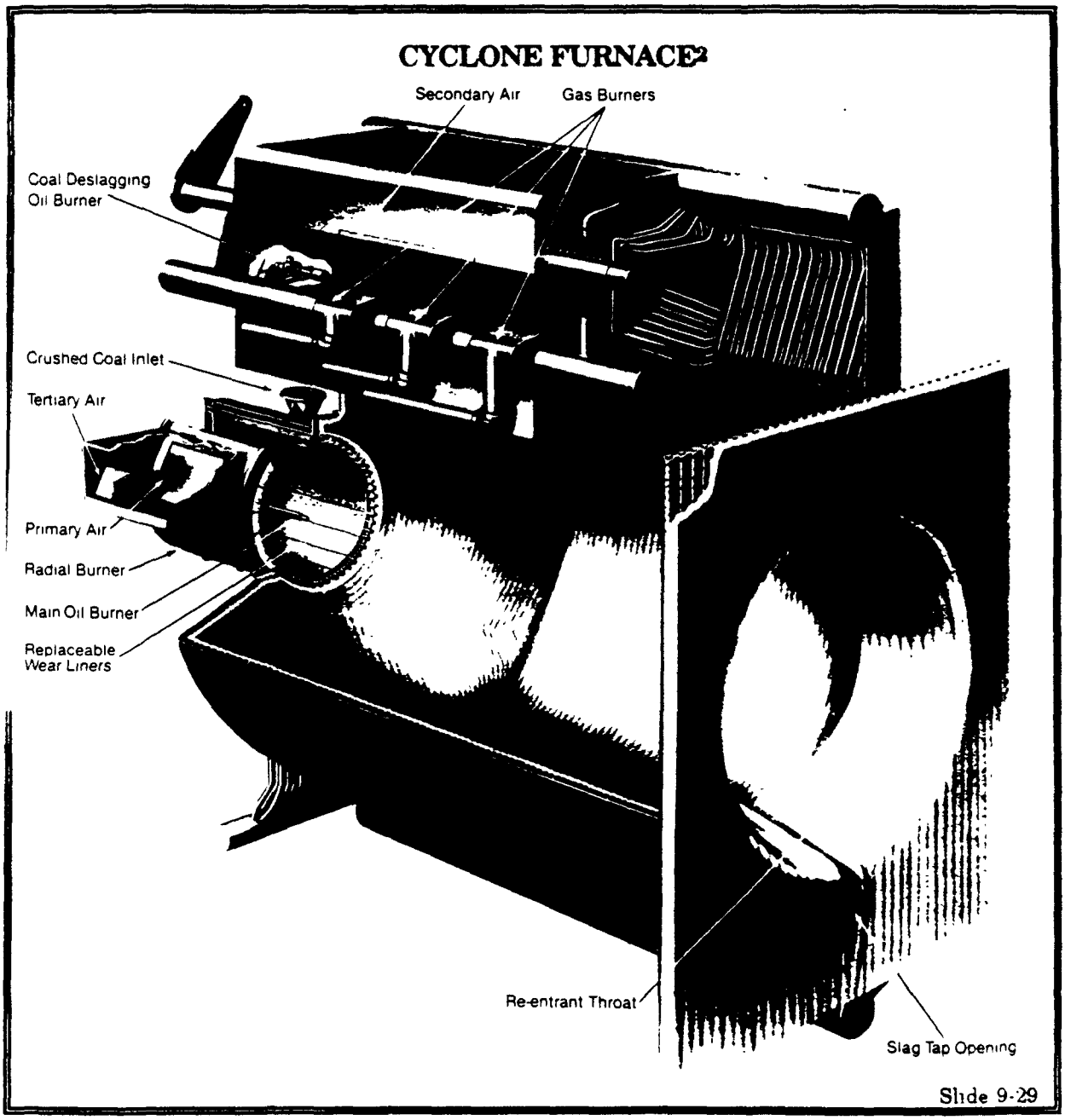


A schematic of a burner used in vertically fired boilers is shown Slide 9–27. Pulverized coal is discharged through the fuel nozzles. Combustion air is introduced through ports located around the fuel nozzles and through auxiliary ports. Tertiary air ports are located on the front and rear walls in the lower furnace.

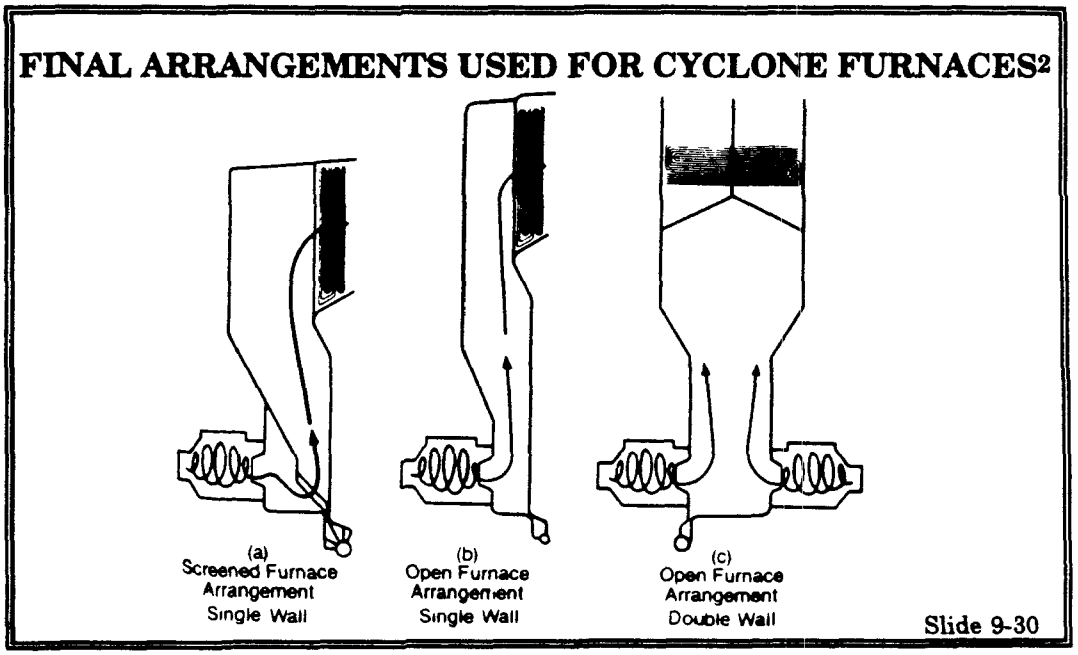


The firing system produces a long looping flame in the lower furnace, with the combustion products discharging up the center (Slide 9–28). A portion of the combustion air (tertiary air) is injected well downstream of the burners. This provides needed turbulence in the flame. The flow patterns passes the hot flue gases in front of the fuel nozzles, thus contributing energy necessary to ignite the fuel. The flow pattern also promotes entrainment of large solid fuel particles, thus allowing long residence times in the combustion chamber.

Cyclone Fired Boilers



Cyclone fired boilers are designed to burn relatively large coal particle sizes (95% passing through a 4 mesh screen) than the other boiler systems. In a cyclone furnace (Slide 9–29, crushed coal and primary air enter the front of the cyclone through a specially designed burner. Secondary air is added tangentially to the main cyclone, creating a swirl motion. A unique circulating combustion pattern results. The products of combustion eventually leave the cyclone through a *re–entrant throat.* A molten slag layer develops and coats the inside surface of the cyclone barrel. The slag drains to the bottom of the cyclone and is discharged through a slag tap.



Several cyclone firing arrangements have been utilized. These are single wall fired with screen, single wall fired without screen, and double wall fired. The main furnace is relatively small and maintains high furnace temperatures over the furnace floor slag taps and to promote slag flow on the furnace walls. The lower furnace walls have a protective refractory lining.

9.8 Emissions

As previously discussed in Chapter 6, sulfur oxides (SO_x), nitrogen oxides (NO_x), CO, CO_2, particulate flyash, volatile organic compounds (VOC) and some trace quantities of other materials are exhausted from the stack. These are primarily byproducts of the combustion process. Fugitive dust arises from fuel handling. Solid wastes include ash collected at boiler bottom, economizer and air heater hoppers as well as from the ESP and fabric filters. Solid wastes also include byproducts of flue gas desulfurization scrubbing process. Typical emissions from a 500 MW pulverized coal fired boiler is shown in Slide 9–31.

COAL FIRED BOILER EMISSIONS
(500 MW Boiler, 2.5 % sulfur, 16% ash)[2]

Emissions	Discharge Rate (t/h) Uncontrolled	Controlled	Control Equipment
SO_x as SO_2	9.3	0.9	Wet Limestone Scrubber
NO_x as NO_2	2.9	0.7	Low-NO_x Burners
CO_2	485	485	Not Applicable
Flyash to Air*	22.9	0.05	ESP or Baghouse
Ash to Landfill*	9.1	32	Controlled Landfill
Scrubber Sludge (Gypsum plus Water)	0	25	Controlled Landfill or Wallboard Quality Gypsum

* As flyash emissions to the air decline, ash shipped to landfills increases.

Slide 9-31

REFERENCES

1. Singer, J.G., *Combustion: Fossil Power Systems*, 3rd edition, Combustion Engineering, Inc., 1981.

2. *Steam, Its Generation and Use*, 40th Edition, Babcock and Wilcox Company, 1992.

3. Elliot, C.T., *Standard Handbook of Powerplant Engineering*, McGraw–Hill Publishing Company, New York, 1989.

4. Folsom, B.A., *Coal Boiler Basics*, Energy and Environmental Research Corporation, Irvine, CA.

CHAPTER 10. STOKERS

10.1 Introduction

10.2 Types of Stoker

10.3 Underfeed Stokers
- A. Side ash Discharge Type
- B. Rear Ash Discharge Type
- C. Coal Specifications
- D. Boiler Furnaces
- E. Overfire Air and Combustion Air

10.4 Mass Feed Stokers
- A. Chain Grate
- B. Traveling Grate
- C. Water-Cooled Vibrating Grate
- D. Fuel Specifications
- E. Furnace Design
- F. Overfire Air

10.5 Spreader Stokers
- A. Fuel
- B. Fuel Burning
- C. Fuel Feeders
- D. Types of Grates
- E. Overfire Air
- F. Fly Carbon Reinjection

10.6 Emissions

10. STOKERS

1.0 Introduction

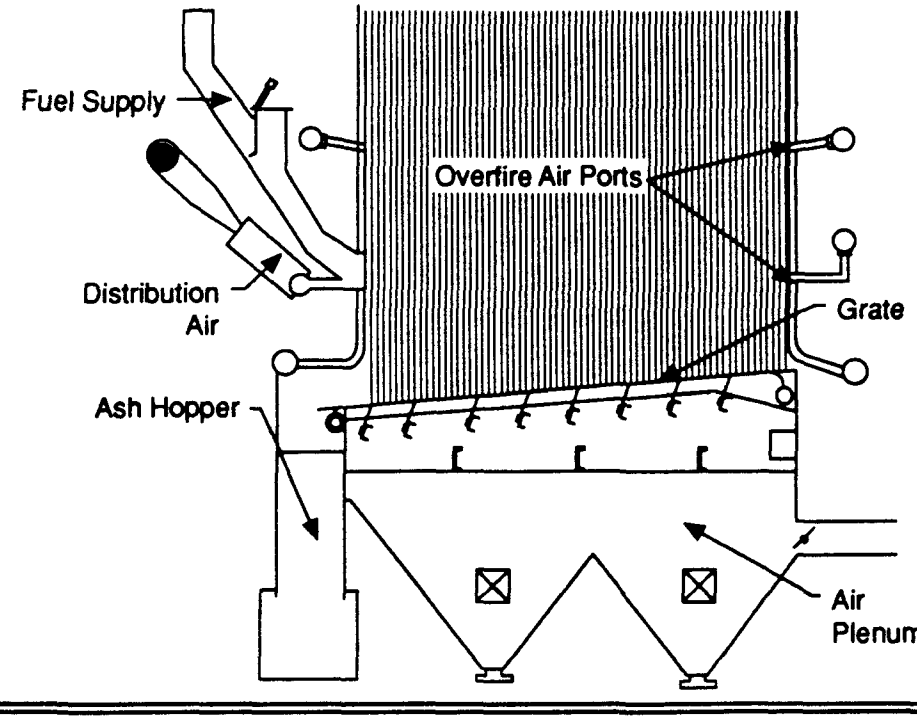
COMPONENTS OF A STOKER

Fuel Supply System
Burning Grate
Overfire Air System
Ash Discharge System

Slide 10-2

Stokers are mechanical devices that feed solid fuels, including coal, wood wastes, bagasses as well as residential and commercial refuse, onto a grate at the bottom of the furnace and remove the ash residue. Stokers are designed to permit continuous or intermittent fuel feed, fuel ignition, air supply for combustion, free passages for the resulting gaseous products, and disposal of non-combustible materials. A stoker firing system typically consists of a fuel supply system, a stationary or moving grate assembly which supports the burning mass of fuel and admits most of the combustion air to the fuel, an overfire air system to complete combustion, and an ash or residual discharge system.

VIBRATING GRATE STOKER



Slide 10-3

10.2 Types of Stoker

TYPES OF STOKER

Underfeed System
Overfeed System
Mass Feed System
Spreader System

Slide 10-4

There are two general types of stoker: *underfeed* and *overfeed.*

Underfeed Stoker: In an underfeed stoker, the fuel and air are supplied from underneath the surface of the grate. Underfeed stokers use both stationary– and moving–grate *tuyeres* (openings in a shell through which air is forced).

Overfeed Stokers: In an overfeed stoker, the fuel is fed from a hopper above the moving grate, and combustion air is supplied from below the grate.

The overfeed stokers are divided into mass feed and spreader categories based on the method of introducing the fuel into the furnace. A discussion of each stoker type follows.

10.3 Underfeed Stokers

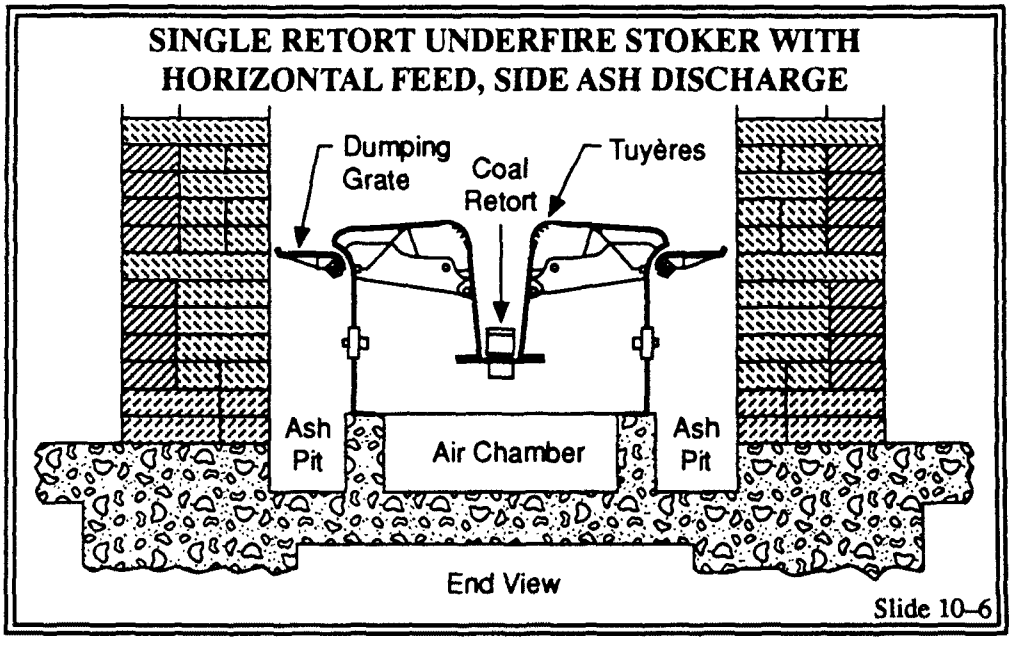
UNDERFEED STOKERS

Side Ash Discharge Type
Rear Ash Discharge Type
Coal Specifications
Boiler Furnaces
Overfire air and Combustion Air

Slide 10-5

There are two general types of underfeed stokers, the *horizontal feed side ash discharge type* and the *gravity feed rear ash discharge type.*

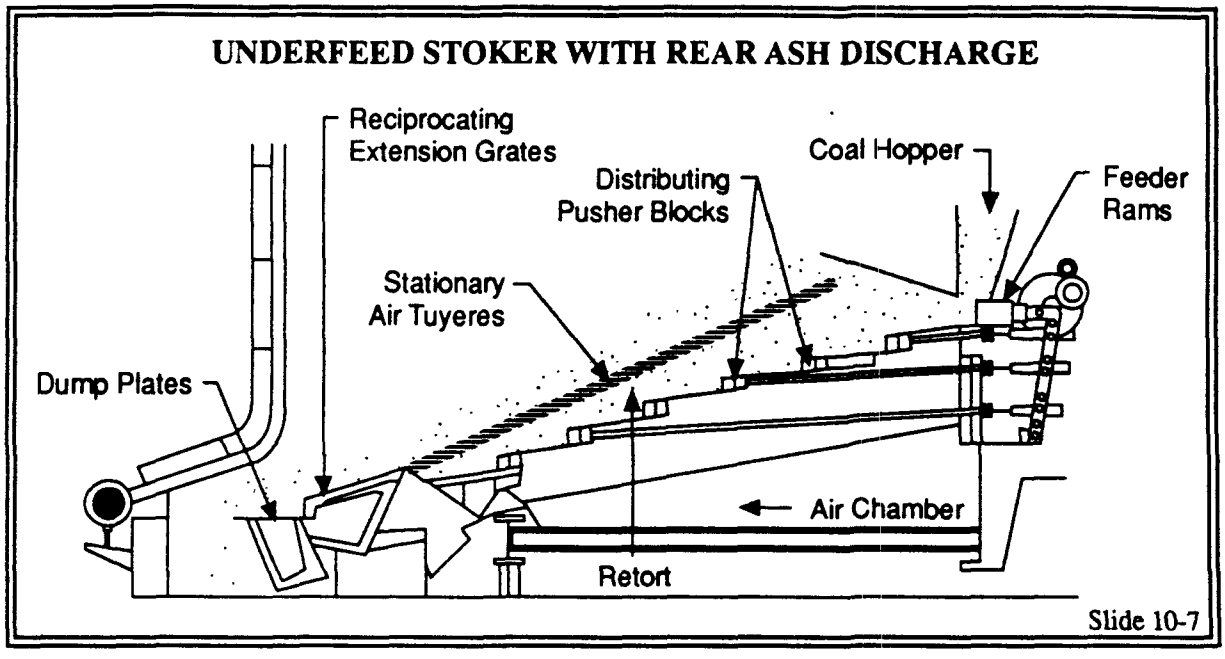
Side Ash Discharge Type



In the side ash discharge type, shown in Slide 10–6, coal is fed from a hopper to a central trough or retort, by a screw or a ram pusher. In larger units, a ram assisted by pusher blocks or a sliding retort bottom (fuel distributors) moves the coal upward and into the retort. As the retort is filled from the bottom coal moves upward and out of the retort onto the grate area where it is exposed to air and radiant heat from the furnace. As the coal moves along the grate to the sides and/or rear, the distillation of the volatiles in the coal occurs leaving the coke which is burned out near the edges or end of the grate. High pressure overfire air is added to produce high turbulence to enhance mixing and reduce smoke.

Burning coal in side ash discharge underfeed stokers increases the chance of producing large agglomerates of ash slags (clinkering) and layers of ash slag (matting). To reduce this tendency alternate fixed and moving grate sections are applied to the underfeed stoker design to break-up and distribute the fuel.

Rear Ash Discharge Type



The grate of this type is inclined at an angle of 20 to 25° above the horizontal, so that gravity assists in distributing the coal over the length of the retorts. This type of stokers uses a series of retorts installed side by side and normally extending from front to rear of a boiler, with tuyere sections between the retorts and along the side walls of the boiler.

Round or square rams are installed to move the coal from the coal hopper into the upper or front end of the retorts below the point of combustion air supply. Secondary rams or pusher plates move the coal along the retort and upward into the burning zone immediately above the retorts, where combustion air is supplied to the fuel bed through tuyeres located between and above the retorts. An adjustable dump grate section is used at the rear end of the retorts to retain the ash and prevent an avalanching of unburned coal into the ash pit.

TYPICAL UNDERFEED STOKER COAL CHARACTERISTICS [2]

		Stationary Grate	Moving Grate
Moisture	% vol.	0 to 10	0 to 10
Volatile Matter	% vol.	10 to 40	30 to 40
Fixed Carbon	% vol.	40 to 50	40 to 50
Ash	% vol.	5 to 10	5 to 10
Higher Heating Value	Btu/lb	12,500	12,500
Free Swelling Index		5 max	7 max
Ash Softening Temp.*	°F	2,500**	2,500**
Coal Size	in	1 x 0.25 max 20% through 0.25 with round screen.	Equal portions: 0.25, 0.25 to 0.5, 0.5 to 1.0.

* The ash softening temperature is the temperature at which the height of a molten globule is equal to half its width under reducing atmosphere conditions.

** Below 2500°F the moving grate is derated linearly to 70% of its rated capacity at 2300°F ash fusion temperature. Stationary grates are derated linearly to 70% at 2100°F ash fusion temperature and use steam for temperatures below about 2400°F fusion temperature.

Slide 10-8

A relatively wide range of coals can be burned on underfeed stokers; however, the largest size is limited to a range of $^3/_4$ to $1^1/_2$ in, and typical specifications call for $1^1/_4$–in particles. The amounts of fines should be limited to 50 percent passing through a $^1/_4$–in round–hole screen.

The *free swelling index* (see Chapter 4 for definition) of the coal should be limited to 5 with side discharge stokers having stationary tuyeres. A coal having free swelling index up to 7 percent can be on side discharge stokers with moving tuyeres and on rear discharge stokers. Underfeed stokers can burn coals at rated capacity with an ash fusion temperature above 2,400°F. Coals having an ash fusion temperature as low as 2,100°F can be burned at reduced burning rates.

It is normally recommended that the iron content in the ash be no more than 20 percent as Fe_2O_3 with an ash fusion temperature above 2,400°F and below 15 percent with coals having a lower ash fusion temperature.

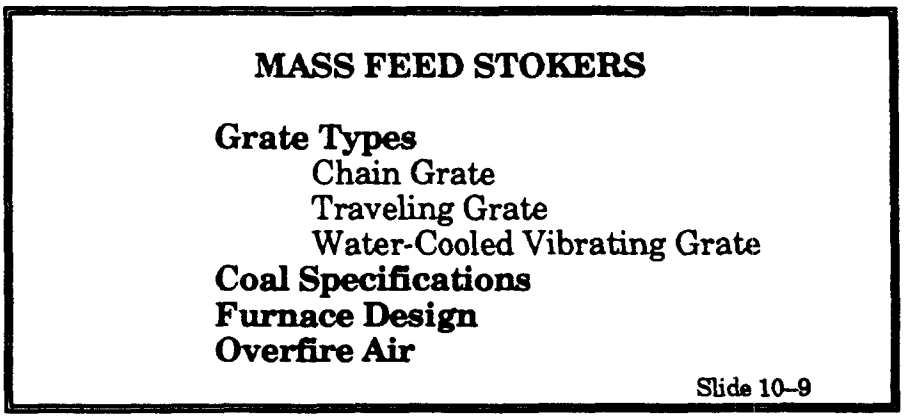
Boiler Furnace

Water–cooled furnaces are preferred with underfeed stokers. On the smaller sizes of side charge stokers, however, satisfactory performance can be obtained with refractory walls. Adequate furnace volume must be provided in accordance with the recommendations of the manufacturer.

Overfire Air and Combustion Air

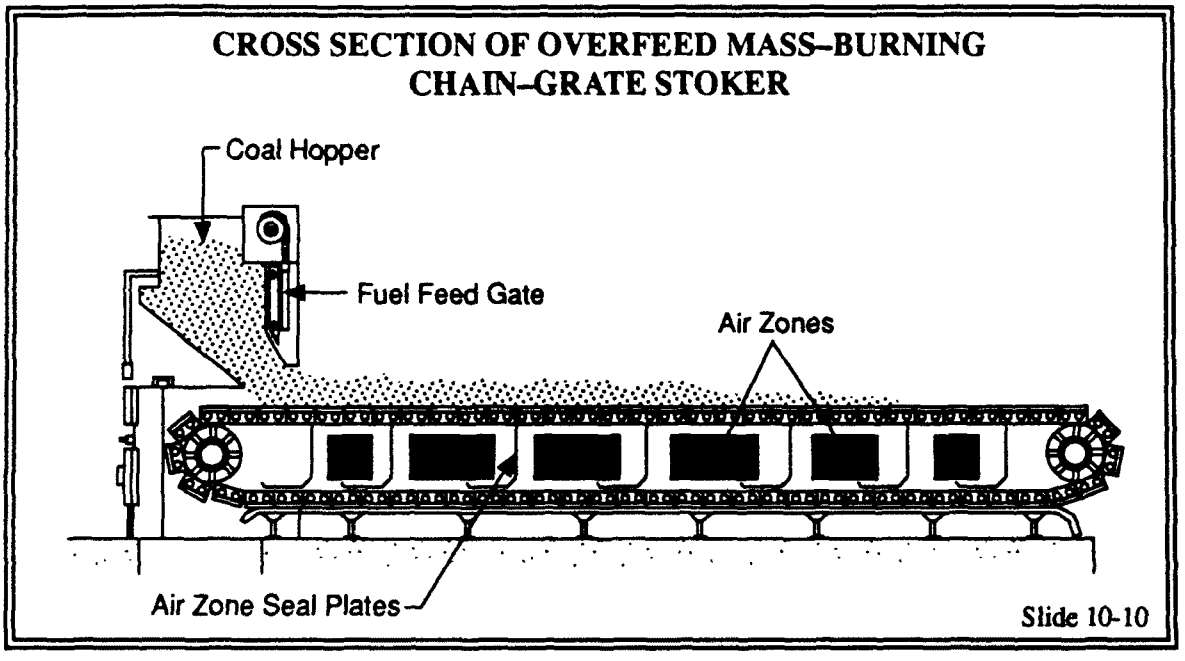
All underfeed stokers should be provided with an overfire air system designed to provide adequate furnace turbulence to complete burnout of the hydrocarbons. Depending on the width of the stoker, load conditions, and coal–burning characteristics, overfire air will represent 7.5 to 12 percent of the total combustion air (theoretical air plus excess air).

10.4 Mass Feed Stokers



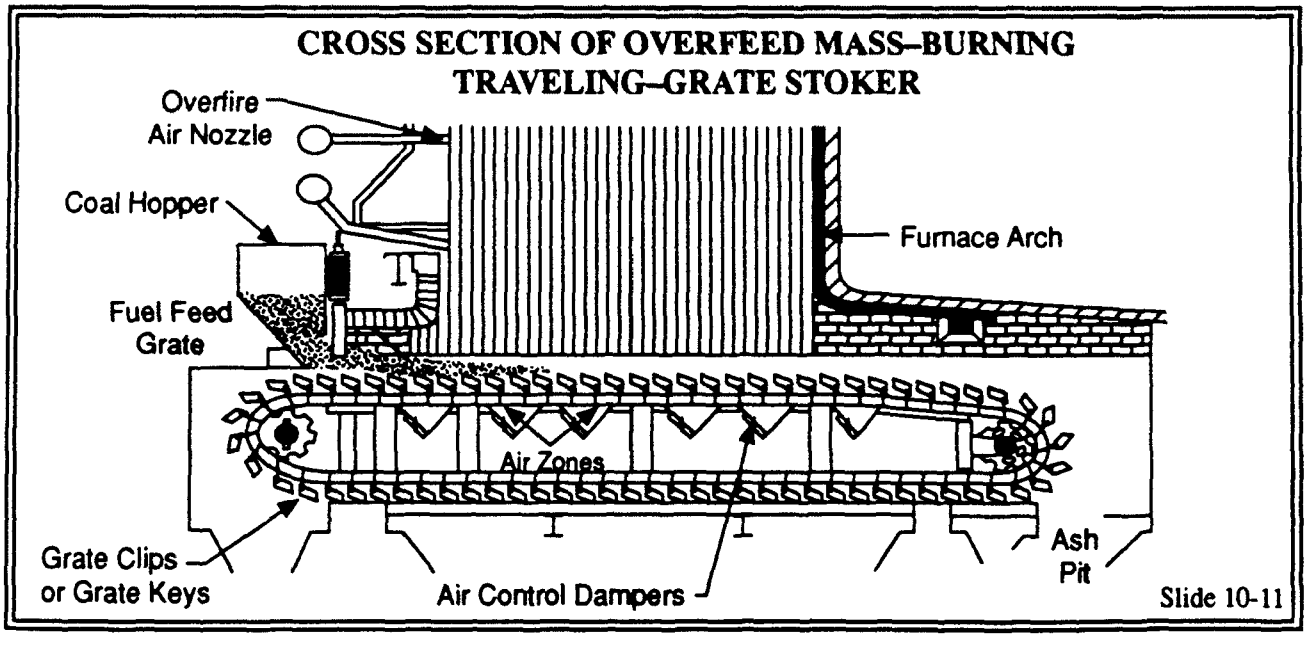
Mass feed stokers are the first of two categories of overfeed stokers discussed in this chapter. Three basic types of grates utilized with overfeed stokers are *chain grate*, *traveling grate*, and *water–cooled vibrating grate*.

Chain Grate



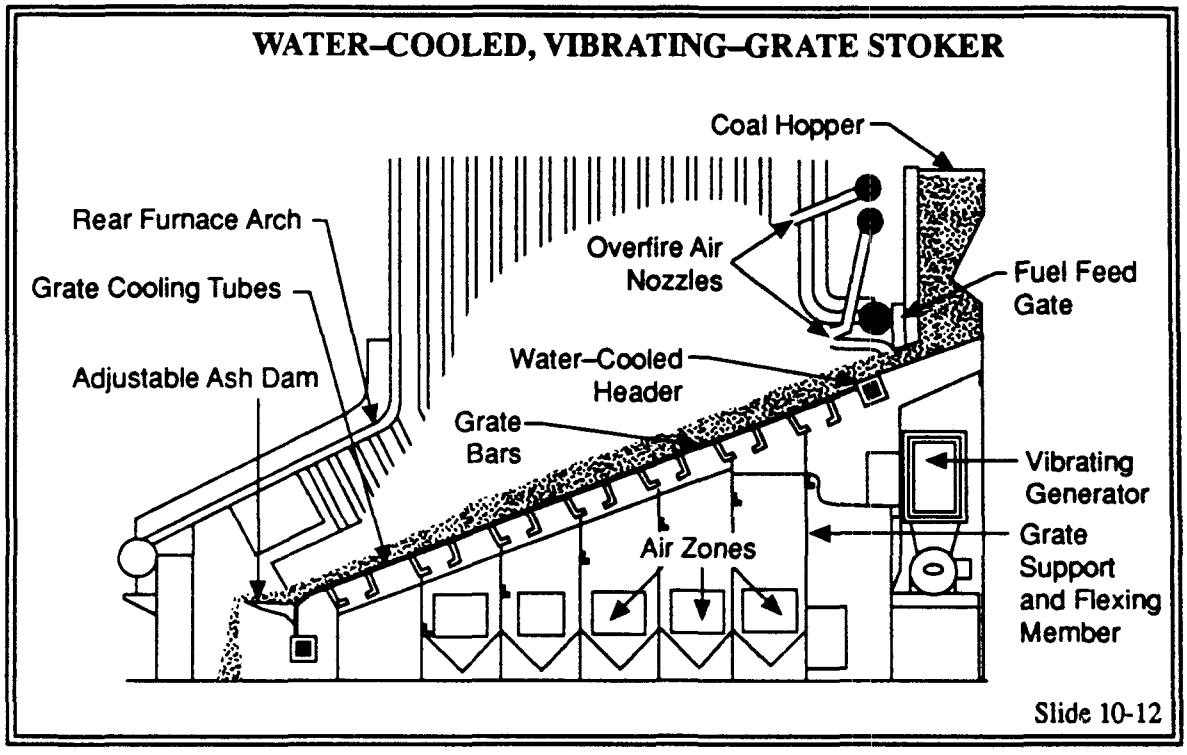
The grate surface of the chain–grate stoker consists of narrow grates which form links. The links are staggered and connected by rods extending across the stoker width to form a wide–continuous–chain assembly, which is pulled or pushed through the furnace by an electric or a hydraulic drive.

Traveling Grate



The grate surface of the traveling grate consists of narrow grate clips mounted on lateral carrier bars that are attached to the grate chains, which pull or push the grate through the furnace, using an electric or a hydraulic drive.

Water–Cooled Vibrating Grate



The grate surface of the water–cooled vibrating–grate stoker consists of tuyere–type grates mounted on and in close–fitting contact with a grid of water–cooled tubes, which are connected to the boiler circulation system for positive cooling. The entire structure is supported on steel flexing plates, permitting the entire water–cooled grid and grate surface to vibrate with a preset amplitude that moves the fuel bed through the furnace. Vibration of the grate is intermittent, and the vibration period and delay between vibrations are regulated by a timing device synchronizing the fuel feeding rate with steam demand.

TYPICAL MASS STOKER COAL CHARACTERISTICS [2]

		Chain/Traveling Grate	Water-Cooled Grate
Moisture	% vol.	0 to 10	0 to 10
Volatile Matter	% vol.	10 to 40	30 to 40
Fixed Carbon	% vol.	40 to 50	40 to 50
Ash	% vol.	5 to 10	5 to 10
Higher Heating Value	Btu/lb	12,500	12,500
Free Swelling Index		5 max	7 max
Ash Softening Temp.*	°F	2,500	2,500
Coal Size	in	1 x 0.25 max 20% through 0.25 with round screen.	Equal portions: 0.25, 0.25 to 0.5, 0.5 to 1.0.

* See Slide 10-8 for definition.

Slide 10-13

A relatively wide range of coals can be burned on mass feed stokers; however, the top size is limited to a range of $^3/_4$ to $1^1/_2$ in, and typical specifications call for $1^1/_4$–in particles. The amounts of fines should be typically limited to 50 percent passing through a $^1/_4$–in round–hole screen.

Fuel Types: Almost all fuels of suitable size can be burned, including peat, lignite, subbituminous, bituminous, anthracite, or coke. However, bituminous coals may have a tendency to clog and prevent proper passage of air through the fuel bed, thus causing high carbon loss to the ash hopper. The fuel bed can be made more porous by water or steam tempering (to reduce clogging tendency) of the fuel. This is done in the stoker coal hopper on chain– and traveling–grate units. Tempering is not required on water–cooled vibrating–grate stokers, since the vibrating action of the grate tends to keep the fuel bed uniform and porous.

Grate Sizing: Overfeed stokers are best suited for industrial and institutional powerplants having steady load demands. Since all the fuel is consumed on the grate, the stoker grate surface must be conservatively sized. The grate heat release rate (quantity of heat released per hour divided by grate area) should be limited to a maximum of 425 Btu/hr–ft^2 of active grate area. These stokers are normally designed for capacities up to 150,000 lb/hr of steam.

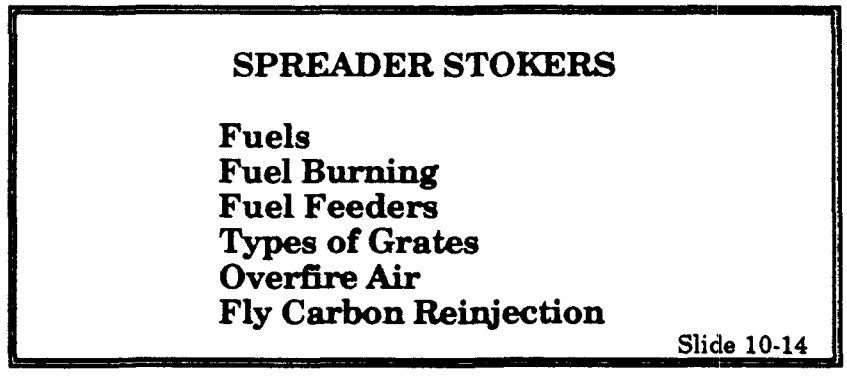
Furnace Design

Water–cooled furnaces are preferred with all moving–grate stokers to prevent slag formation on the furnace walls. The tube spacing of the furnace walls should not exceed twice the tube diameter. Adequate furnace volume must be provided as recommended by the boiler and stoker manufacturers.

Overfire Air

Overfeed stokers are provided with high–pressure overfire–air system consisting of one or two rows of closely spaced air jets located above the fuel bed in the front wall of the furnace. The jets provide adequate furnace turbulence to complete the burnout of the hydrocarbons. The high–pressure–air fans will be sized to provide approximately 10 percent of total air. The static pressure of the fan is selected to provide proper penetration of the air into the furnace.

10.5 Spreader Stokers



The second category of overfeed stokers are spreader stokers. In spreader stokers, the fuel is spread into the furnace over the grates from feeders located across the front of the unit. The purpose is to feed the fuel evenly over the grate surface in order to release an equal amount of energy from each square foot of active grate surface. The air for combustion should then be admitted evenly through the grate to provide the oxygen for burning. Above the grates, an overfire–air system is provided for additional oxygen and turbulence in the lower–furnace zone temperature to ensure efficient performance. Since spreader stokers can burn a wide range of solid fuels, and cover a wide range of boiler sizes, the arrangement and design of each of the three basic components—fuel feeders, type of grate, and overfire–air system—depend on the specific project.

Fuels

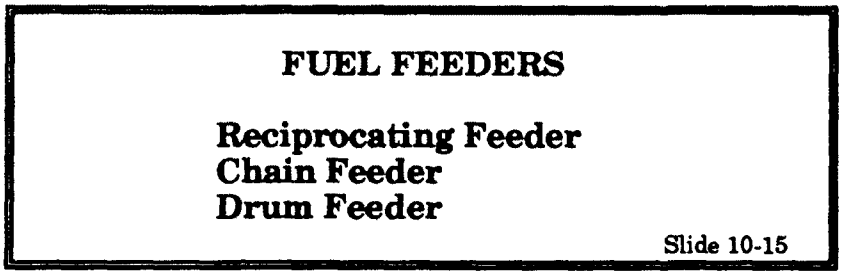
The fossil fuels burned on spreader stokers include bituminous, subbituminous, and lignite coals. It is necessary to size the fuel properly for spreader stokers. The coals should have 95 percent less than $1^1/_4$ inch in maximum size.

Fuel Burning

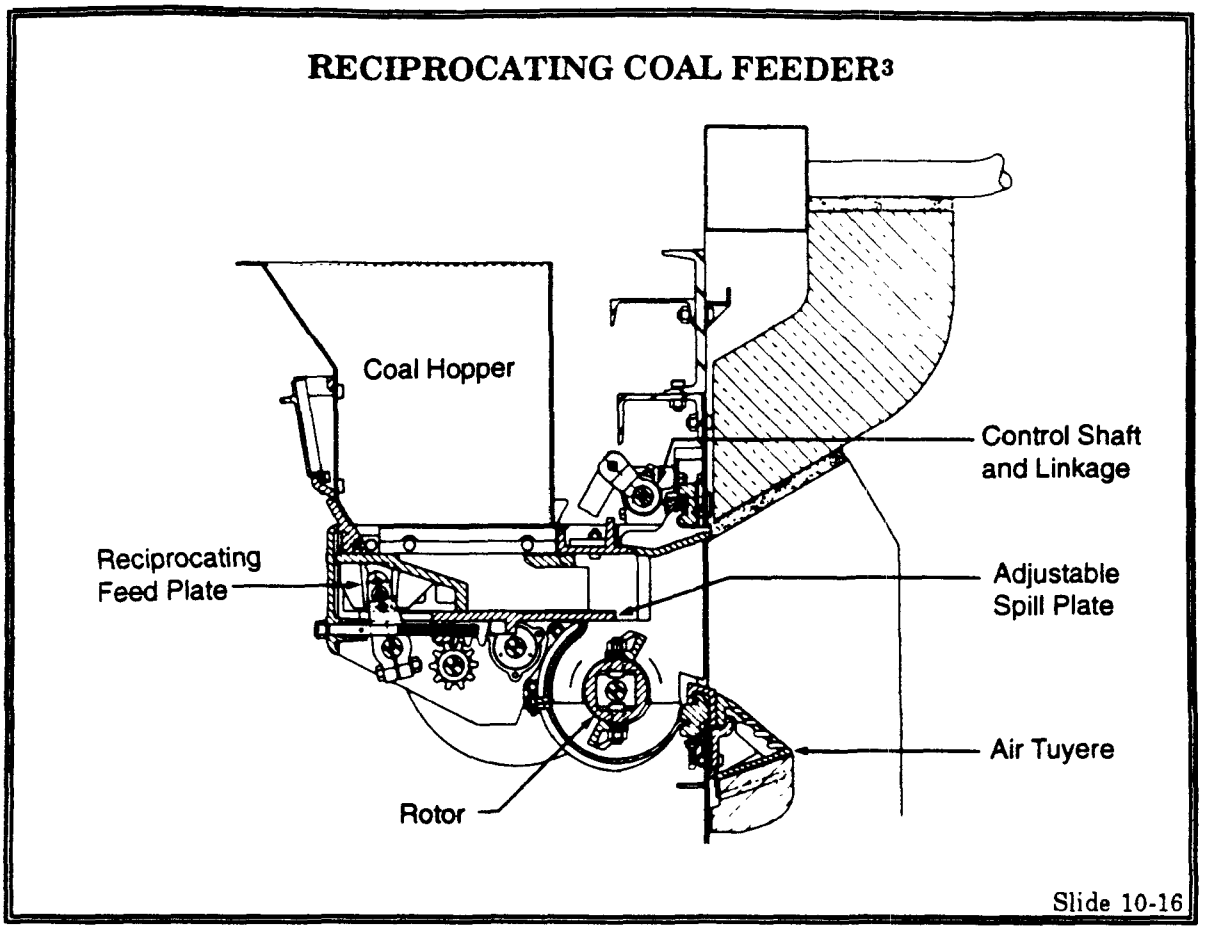
As the fuel is fed to the furnace in a manner to spread it evenly over the complete grate surface, it burns both in suspension and on the grate. The amount burned in suspension depends on a number of factors. Fine fuel burns more in suspension; that is, with coal the size 16 mesh is significant. High–volatile fuels release more energy in suspension. High moisture can increase the energy release on the grate. The burning fuel bed on the grate may be only about 1 in thick. This depth depends on fuel characteristics and firing rate. Under the burning fuel, an ash bed is formed, which should be about 3–in thick.

The ash–bed thickness also depends on fuel characteristics, but not on the firing rate since the rate of ash discharge is regulated to the firing rate. The ash bed provides an insulating barrier between the burning fuel and the metal–grate surface additionally cooled by the combustion airflow across the grate.

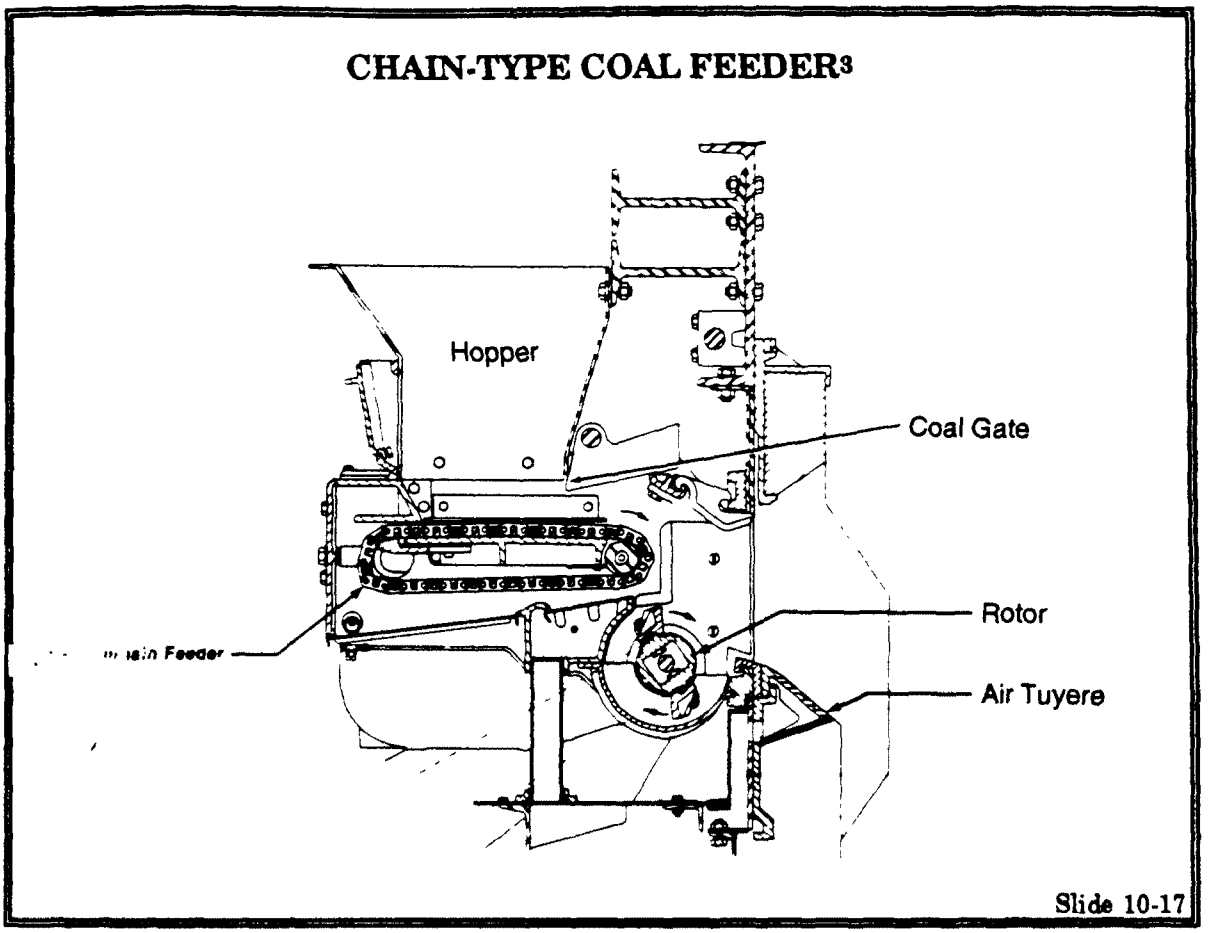
Fuel Feeders



There are many types of fuel feeders utilized in spreader stokers: *reciprocating feeder, chain feeder, and drum feeder.*



Reciprocating Feeder: Coal feeders have a device which meters the coal from the coal feeder and delivers it to the built–in rotor. This device should have a bias means built in so that coal feed can be varied from one to another. This allows adjustment for segregation in fuel sizing from one feeder to another. A schematic of a reciprocating feeder is shown in Slide 10–16. The reciprocating feeder has one or more feed plates which travel back and forth on a spill plate. On the back stroke, coal drops from the hopper in front of the plate. On forward stroke, coal is pushed off from the spill plate onto the rotor. The amount of coal per stroke is adjusted by (1) the length of stroke of the feed plate through mechanical devices, (2) the number of strokes per minute through mechanical variable–speed devices, or (3) electronic devices such as variable–frequency power units to alternating–current (ac) motors, or silicon controller rectifier control units to direct–current (dc) motors.



Chain Feeder: A schematic of a chain feeder is shown in Slide 10–17. A chain feeder has a drag conveyor deliver the coal out of a hopper, off the end of the chain, onto the rotor. The amount of coal is a function of the speed of the chain and the depth of the coal. the depth of the coal is adjusted by the position of a gate above the chain. The speed can be regulated by an internal mechanical variable–speed device, or electronically, as described previously.

Drum Feeder: The drum feeder utilizes a revolving drum with semipockets to deliver the coal out of a hopper onto the rotor. As with the chain feeder, the amount of coal is regulated by the speed of the drum and the depth of coal coming out of the hopper on the drum. The vibrating feeder delivers the coal to the rotor out of the coal hopper on a vibrating conveyor. The amount of coal is adjusted by the frequency of vibration and the depth of coal on the conveyor.

Types of Grates

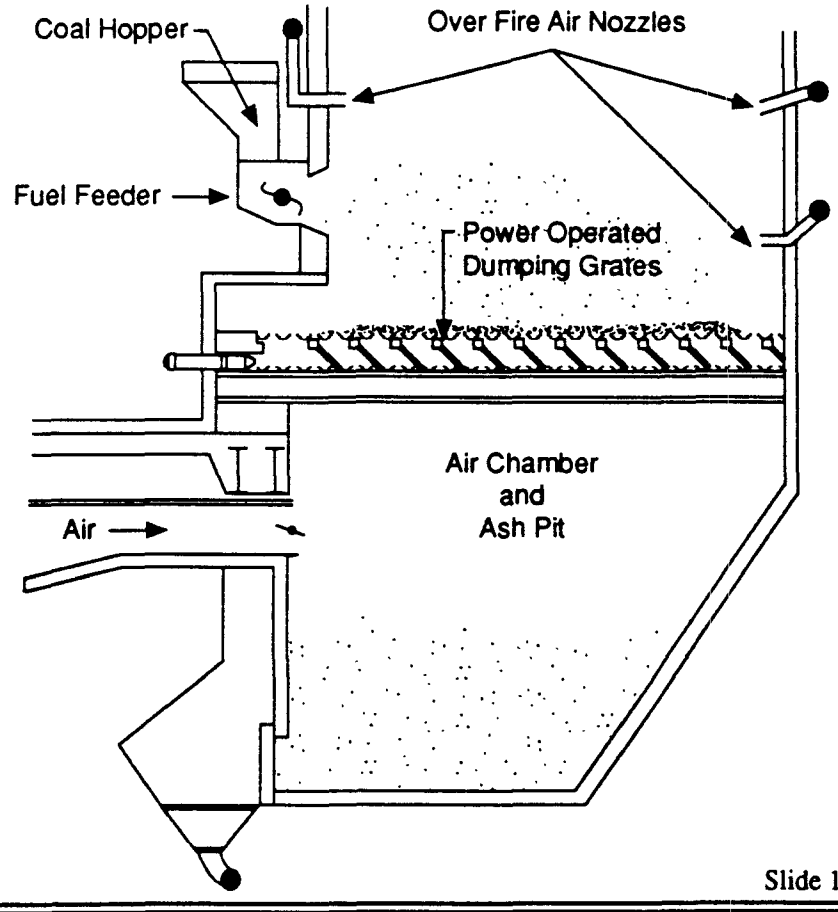
TYPES OF GRATES

Stationary and Dumping
Reciprocating
Vibrating
Traveling
Vibrating, Water-Cooled

Slide 10-18

A number of grate types are utilized for spreader–stoker firing. They are stationary and dumping grate, reciprocating grate, vibrating grate, traveling grate, and vibrating, water–cooled grate. They all serve the same purpose: they provide a floor on which the fuel can burn, a means of distributing air evenly through the grates, and a method of discharging the ashes that accumulate on the grate from the consumed fuel. A description of each of these grate types is given below.

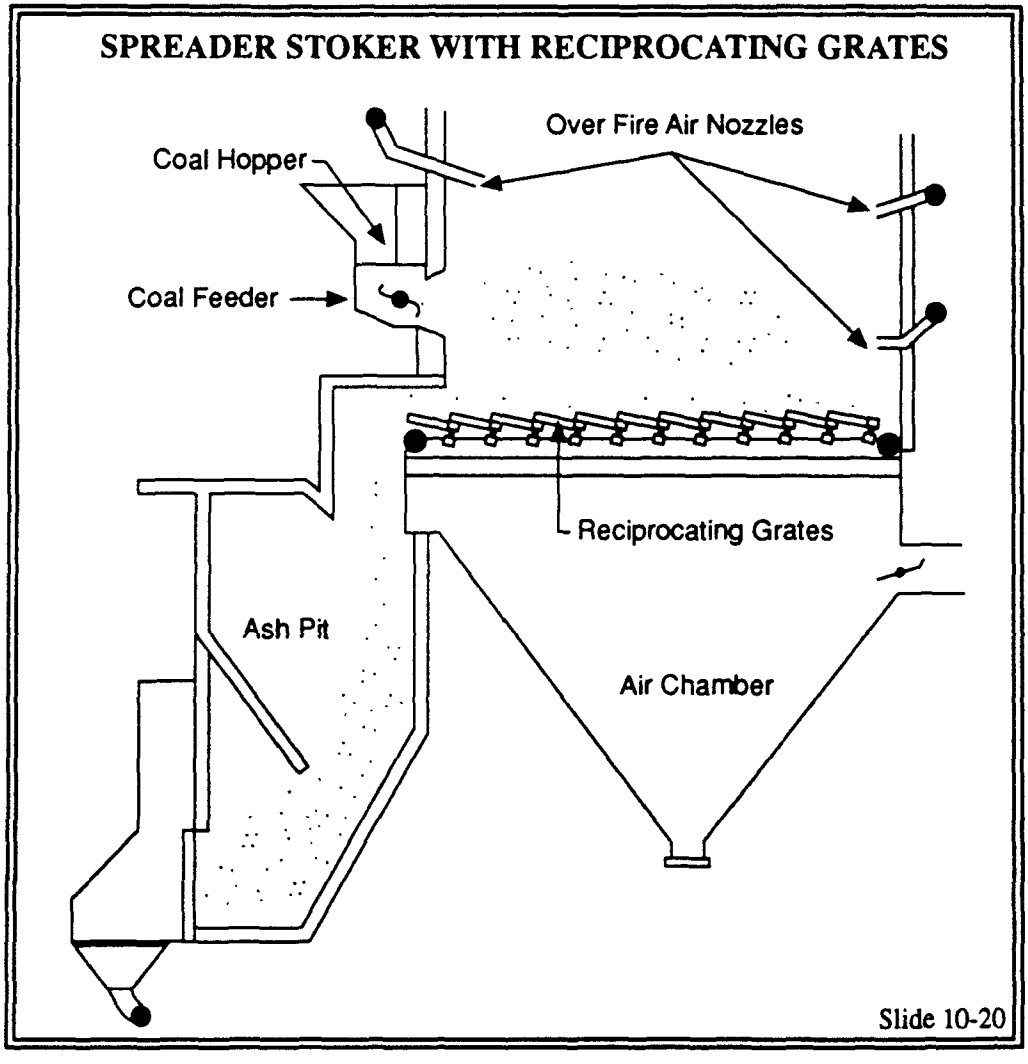
SPREADER STOKER WITH DUMPING GRATES



Slide 10-19

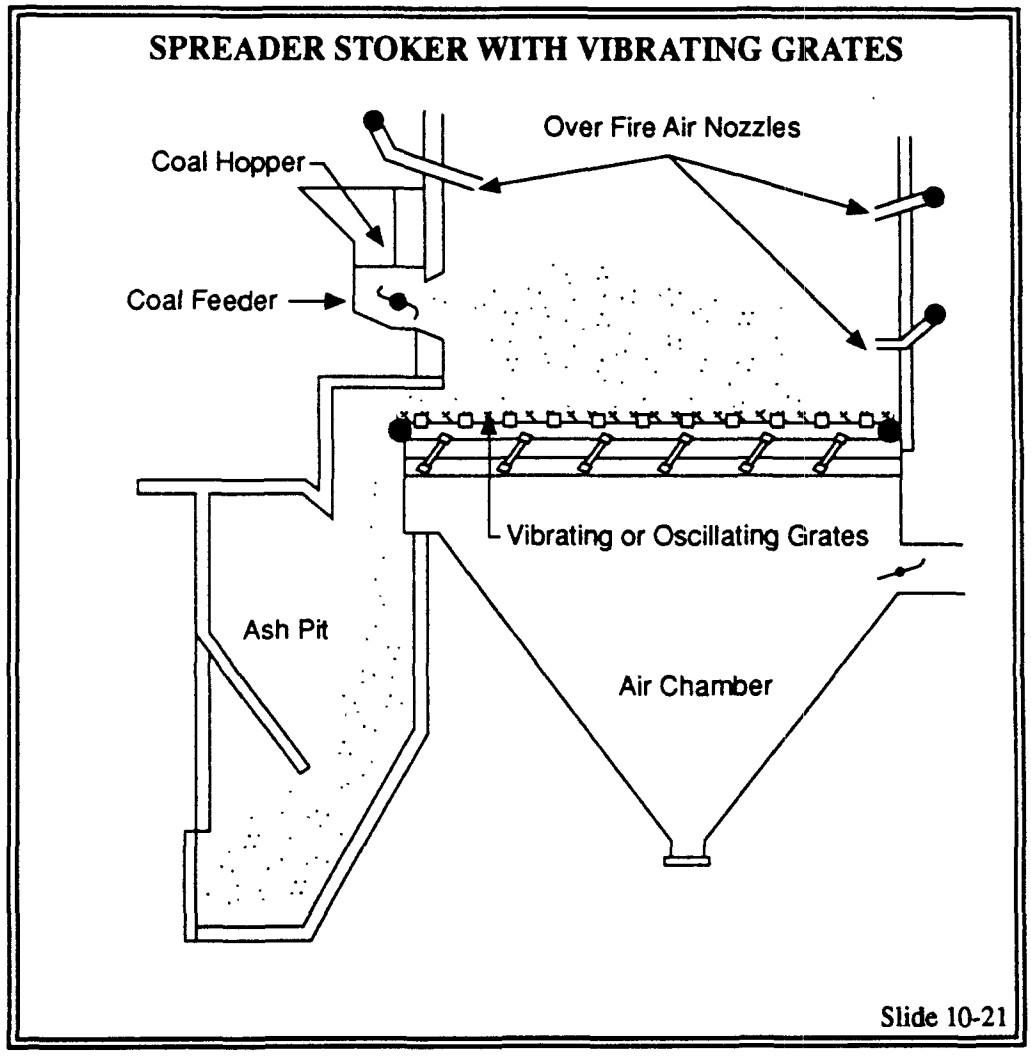
Stationary and Dumping: The intermittent cleaning types of grates are stationary and dumping. The stationary grate is rarely used because of hazards to the operator when removing ashes through the open fire door and the resultant exposure directly to the furnace. It is extremely difficult to clean fires without creating a smoky fire condition of high opacity.

The manual dumping type of grate (Slide 10–19) has one section for each fuel feeder. To remove ashes, the fuel feed is stopped in front of one of the grate sections, to allow complete burnout of combustible products. The air supply to that section is then cut off with appropriate dampers, and the ashes can be dumped into a pit below. While this cleaning is done it is necessary for the remaining sections to burn additional fuel to maintain the boiler rating. After the ashes are dumped, the fuel feeder is started again. When the fuel ignites, the undergrate damper to that section is reopened to resume normal combustion. It is very difficult to accomplish this cleaning process without high opacity. Consequently, the dumping grate is seldom used for burning coal having a high percentage of volatiles and low ash content.



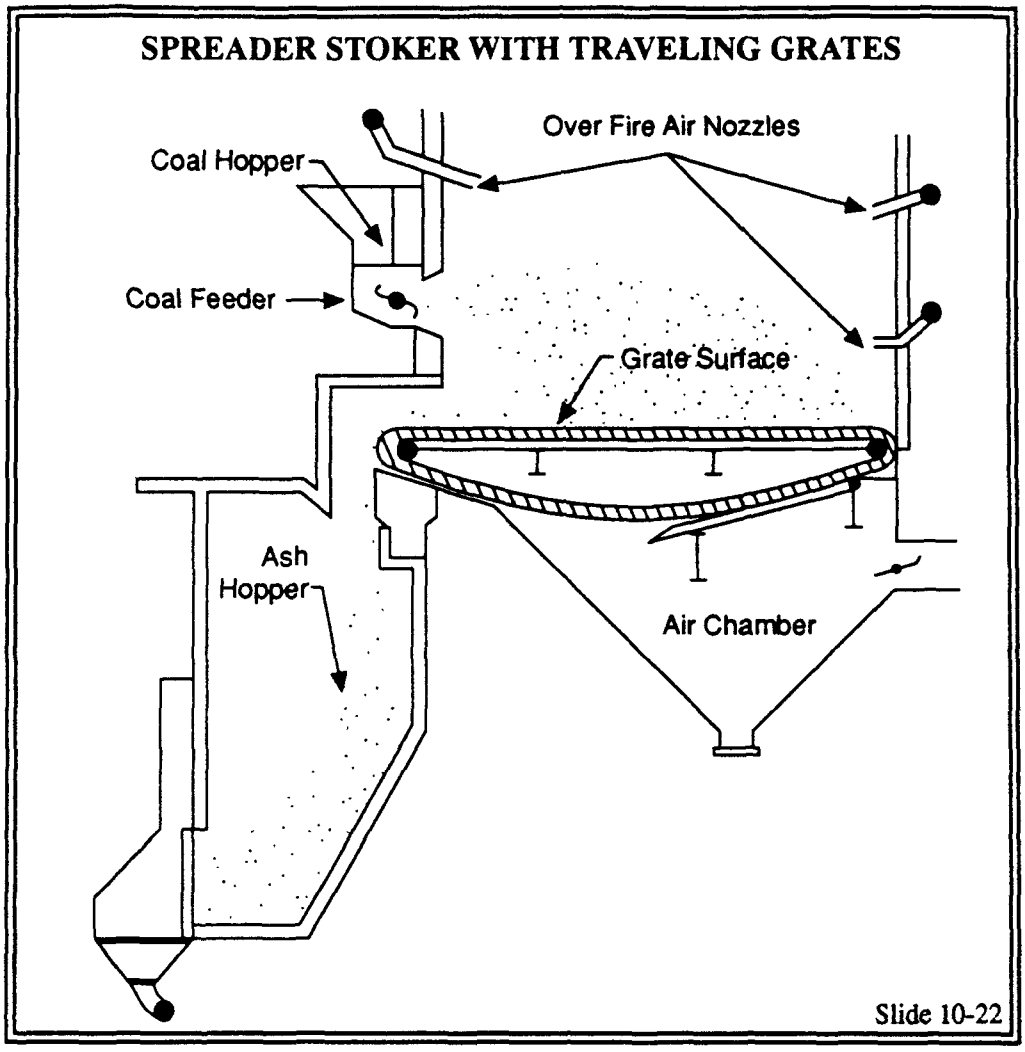
Reciprocating: The reciprocating grate (Slide 10–20) discharges ashes by a slow back–and–forth motion of moving grates alternating with stationary grates. Each row of grates rests on the row in front and has a raised nose which pushes the ashes toward and off the end of the grate into an ash hopper. It is preferable to discharge the ashes at the front under the feeders. Since the fuel is thrown toward the rear, best control of ash discharge with minimum combustibles in the ashes can be achieved with front ash discharge from any type of conveying grate.

Because of the stepped nature of the reciprocating grate, it is used only for fuels with sufficient ash quantity to provide an adequate ash depth insulation on top of the grate. Undergrate air temperatures are ambient.



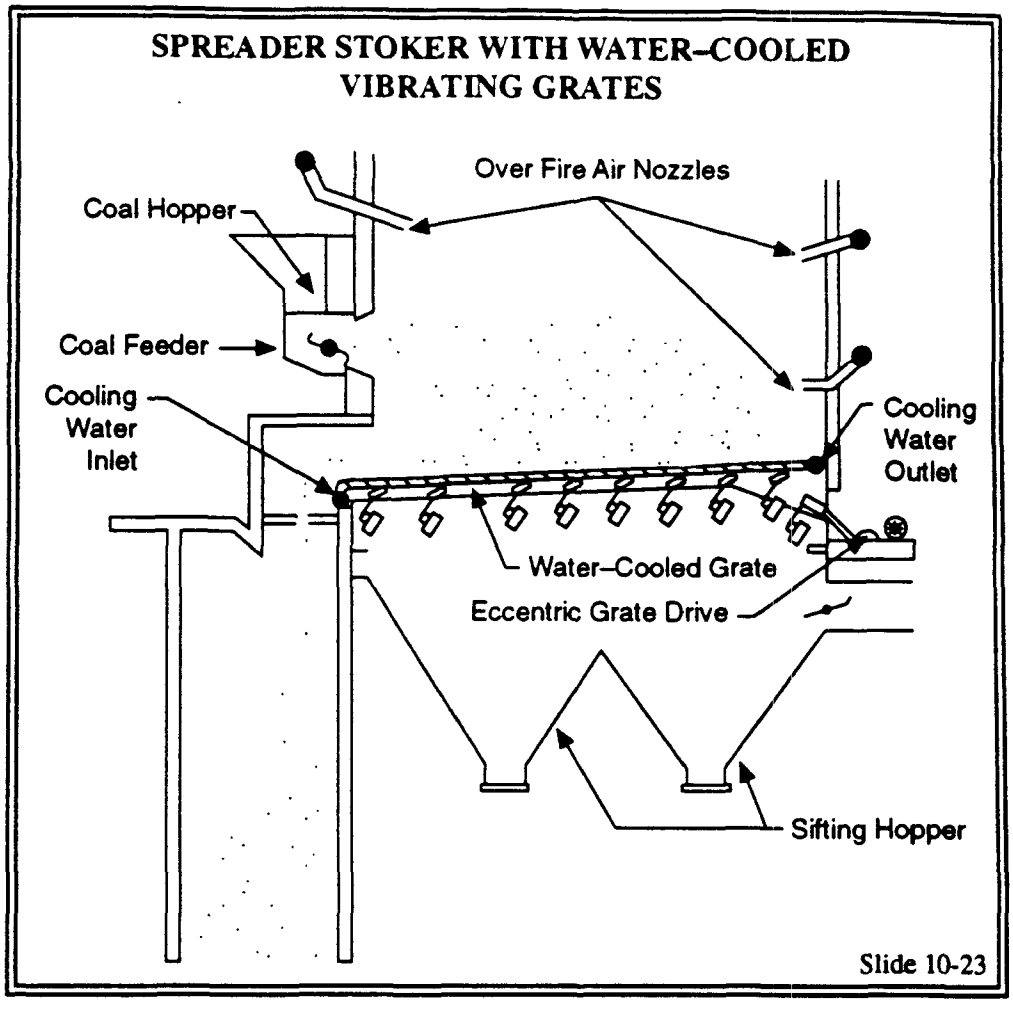
Vibrating: The vibrating or oscillating grate (Slide 10–21) is suspended on flexing plates. Either an eccentric drive or rotating weights impart a vibrating action to the grate surface, which conveys ashes to the front and discharges them into an ash pit. The frequency of vibration is kept well below the natural frequency, to minimize the forces on the support structure. The rate of ash discharge is regulated by a timer system that controls the off time between vibrating cycles and the length

of vibrating time. Since the vibrating grate is flat, it is well suited for coal.



Traveling: The traveling–grate spreader stoker (Slide 10–22) is by far the most popular type, and there are numerous types of construction. The most important consideration is that the design of the grate surface should provide a high resistance to airflow through the grate to ensure even distribution of air through the grate. The traveling grate moves forward to discharge the ashes at the front end under the fuel feeders. The return grate then passes underneath in the air chamber. The traveling grate is driven either mechanically or hydraulically through appropriate mechanical devices, electronic devices, or hydraulic flow–control valves.

When the ash content in the fuel is consistent, the speed of the grates can be regulated by the combustion controls to maintain an even ash–bed thickness. The grate bars can be made from cast iron with small amount of alloy for heat and wear resistance, or from ductile iron for increased heat resistance and impact resistance.



Vibrating, Water-Cooled: The water-cooled vibrating grate spreader stoker (Slide 10-23) is used for refuse burning, but could conceivably be used for coal firing too. A water-cooled grid on which a grate surface is fastened is mounted on a frame. The whole assembly is supported on flexing plates on an angle of 6° down toward the ash discharge end. An eccentric drive vibrates the grate assembly through a timing circuit that controls the amount of off and on time. The vibrating action moves the ash to the front of the grate and into the ash pit. The vibration frequency is kept well below the natural frequency.

The water-cooled grid is cooled by tying into the boiler water-circulation circuit or a separate forced-cooling system. Which method selected is dictated by the needs of the individual projects.

Overfire Air

The overfire air system on spreader-stokers has three functions: (1) to provide oxygen and turbulence to mix the fuel and oxygen in the lower high-temperature zone of the furnace for complete burnout, (2) to distribute fuel and assist in distribution

when the design dictates the use of air for this purpose, and (3) to provide cooling air for mechanical fuel feeders. The air can come from a common fan that would have static pressure capabilities of 25 to 30 in H_2O to provide the necessary energy for turbulence or fuel distribution.

Overfire air nozzles are placed in rows in the front and rear walls of the furnace. The design should place the air nozzles at elevations which will ensure mixing of the furnace gases in the high–temperature zones, so that the combustion processes can be completed in the furnace. Air–nozzle spacing in each row should be on centers 10 to 12 inches for complete coverage of the furnace.

The size of the air nozzles in the various rows is a function of the depth of the penetration desired and the amount of overfire air required. Bituminous–coal–fired boilers are designed with 15 to 25 percent overfire air. Lignite–fired boilers are designed with 20 to 25 percent overfire air. The overfire air temperature may be either ambient or the temperature of the undergrate air. The choice of temperature is generally a function of air heater and boiler system design.

Fly Carbon Reinjection

The particulate leaving the furnace of a spreader stoker can contain considerable combustible material and thus is termed *fly carbon*. It is beneficial to return some percentage of this fly carbon to the furnace for burning to improve the boiler efficiency. This is accomplished by the conveying system, which transfers the fly carbon from hoppers through a pipeline to the furnace using air as the conveying medium. By using a nozzle and venturi arrangement, air at up to 25 in H_2O can create a suction to draw the fly carbon into the pipeline and pressure–convey it to the furnace.

The air supplied is generally from the overfire air fan; however, a separate fan can be used. The fly carbon can be collected in hoppers under the boiler's steam generating section, economizer, air heater, or mechanical dust collector, although continuous evacuation of the hopper is required. The amount of reinjection sets the increase in boiler efficiency.

The particulate collected in an electrostatic precipitator or fabric filter should not be returned to the furnace. Since the particulate collected in an electrostatic precipitator or fabric filter (located downstream of the mechanical dust colletor) usually contains more ash than fly carbon, it should not be returned to the furnace. Reinjection of significant ash is undersirable because it can contribute to boiler surface erosion and grate clinkering.

TYPICAL UNCONTROLLED EMISSIONS FOR SPREADER-STOKER FIRING [4]

	NO_x (as NO_2) lb/10^6 Btu	CO lb/10^6 Btu	Unburned Carbon Loss* with Reinjection	Unburned Carbon Loss* without Reinjection
Bituminous	0.35 to 0.50	0.05 to 0.30	0.5 to 2.0	3 to 6
Subbituminous	0.30 to 0.50	0.05 to 0.30	0.5 to 1.5	3 to 5
Lignite	0.30 to 0.50	0.10 to 0.30	0.5 to 1.5	3 to 5

* % of Heat Input

Slide 10-24

Slide 10–24 lists typical uncontrolled emission values for spreader–stokers firing various coals. These values will vary with fuel composition and equipment selection.

NO_x is formed from the oxidation of the nitrogen compounds in the combustion air and in the fuel (see Chapter 4). With stoker firing it is believed that most of the NO_x is derived from fuel–bound nitrogen. NO_x emissions can be effectively controlled by staging combustion, inherent in spreader–stoker firing, and by controlling excess air levels. For coal stoker firing, the excess air level in low NO_x stoker systems is about 25%. To control NO_x to the lower end of the range shown in Slide 10–24, deeper staging is employed, i.e., lower undergrate and higher overfire air flows. For spreader firing, feeder are also designed to improve fuel distribution and combustion on the grates. Other factors that reduce NO_x formation include minimizing the quantity of fines in the fuel and using ambient temperature combustion air.

For most stoker–fired units burning coals which contain sulfur, sulfur dioxide (SO_2) will be present in the flue gas (see Chapter 4). For prediction purposes and sizing of SO_2 control equipment it is assumed that all the fuel sulfur becomes SO_2.

Carbon monoxide (CO) and volatile organic compound emissions are generally a function of the efficiency of the combustion process and the quantity and control of fines and excess air. CO will tend to increase as NO_x is reduced.

REFERENCES

1. Singer, J. G., *Combustion: Fossil Power Systems*, 3rd edition, Combustion Engineering, Inc., 1981.

2. *Steam, Its Generation and Use*, 40th Edition, Babcock and Wilcox Company, 1992.

3. Elliot, C.T., *Standard Handbook of Powerplant Engineering*, McGraw–Hill Publishing Company, New York, 1989.

4. "Alternative Control Techniques Document -- NO_x Emission from Industrial/Commercial/Institutional (ICI) Boilers," US EPA, EPA-453/R-94-022, March, 1994.

CHAPTER 11. FLUIDIZED-BED BOILERS

11.1 Introduction

11.2 Typical Fluidized-Bed Conditions

11.3 Fluidized-Bed Combustion Advantages
- A. Reduced Emissions
- B. Fuel Flexibility

11.4 Atmospheric Pressure Fluidized-Bed Boilers
- A Bubbling Bed
- B. Circulating Bed

11.5 Fluidized-Bed Boiler Furnace Design
- A. Design Information
- B. Bed Material
- C. Pressure Drop
- D. Heat Transfer

11.6 Fluidized-Bed Boiler Arrangements
- A. Boiler Subsystems
- B Auxiliary Equipment

11.7 Operation
- A. System Control
- B. Bed Temperature Control
- C. Bed Material Inventory Control
- D. Overfire Air Control

11.8 Emissions
- A. Sulfur Dioxide
- B. Nitrogen Oxides
- C. Carbon Monoxide and Hydrocarbons
- D. Particulates

11. FLUIDIZED-BED BOILERS

11.1 Introduction

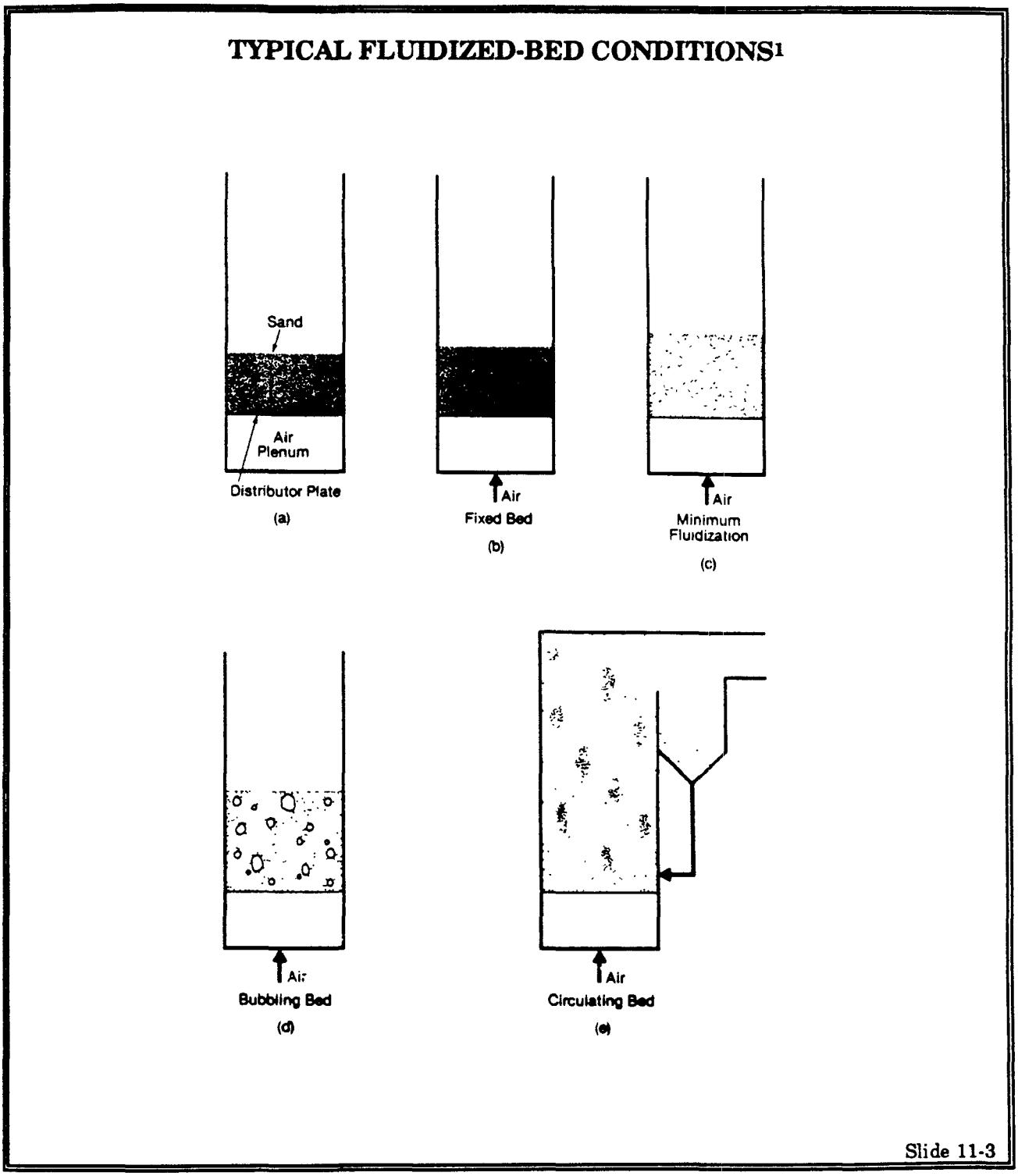
FLUIDIZED-BED BOILERS

Typical Fluidized–Bed Conditions
Fluidized–Bed Combustion Advantages
Atmospheric Pressure Fluidized–Bed Boilers
Fluidized–Bed Boiler Furnace Design
Fluidized–Bed Boiler Arrangements

Slide 11–2

In fluidized–bed boilers, combustion of solid fuels take place in a *bed* containing inert materials (typically sands). This combustion process produces high heat transfer rates and low combustion temperatures. Key benefits of this process are fuel flexibility and reduced emissions. This chapter provides detailed discussions of the fluidized–bed combustion technology and its applications in electric power generation industries. It first provides a description of typical fluidized–bed conditions. The chapter then discusses advantages of fluidized–bed combustion. Atmospheric pressure fluidized–bed boilers and their design and arrangements are next described. Boiler operation and their emissions are subsequently presented.

11.2 Typical Fluidized–Bed Conditions



Slide 11–3 shows typical fluidized–bed conditions. The upper chamber of a fluidized–bed container is filled with sand or other granular materials. Air is supplied

from a plenum located at the bottom chamber. A distributor plate provides even air flow through the bed.

If a small amount of air flows through the distributor plate, it passes through the immovable mass of the bed materials. If the air velocity is weak, it does not exert much force into the sand particles and they remain in place. This condition is called a *fixed bed* (Slide 11–3b).

As the air flow increases, it exerts greater force on the sand to a point where the sand particles become suspended in the upward flowing air stream. At this point, the bed starts to behave like a fluid. This condition is called *minimum fluidization* (Slide 12–3c).

As the air flow increases further, bubbles of air start to form and the bed becomes violent. This condition is called *bubbling bed* (Slide 11–3d). The volume occupied by the air–solid mixture now increases substantially. By increasing the air flow further, the bubbles becomes larger and begins to form large voids in the bed. This condition is called *turbulent* fluidized bed.

If the solids are caught, separated from the air and returned to the bed they will circulate around a loop. This condition is defined as a *circulating* fluidized bed (CFB) (Slide 11–3e). Unlike the bubbling bed, there is no distinct transition between the dense bed in the bottom of the container and the dilute zone above.

11.3 Fluidized–Bed Combustion Advantages

FLUIDIZED–BED COMBUSTION ADVANTAGES

Reduced Emissions
- SO_2
- NO_x

Fuel Flexibility
- Fuel Ash Properties
- Low Btu Fuels
- Fuel Preparation

Slide 11–4

One distinct advantage of fluidized–bed combustion is that the system can be operated at low combustion temperatures. Most fluidized–bed boilers are designed to have the bed operating temperature of about 1,500 to 1,600°F (pulverized–coal boilers typically operate at about 2500 to 2600°F). The ability to operate at this low temperature results in several operating advantages. Another advantage of fluidized-bed combustion is that it achieves higher heat transfer rates from the fuel to the water tubes.

Reduced Emissions

Sulfur Dioxide: Inexpensive sorbents such as limestone or dolomite are used to reduce SO_2 emissions from fluidized–bed boilers. Because of the low bed operating temperatures, these sorbents can be added directly to the bed to obtain good mixing and long residence times necessary for the *sulfation* reaction (see Chapter 21). Ninety percent (90%) or more SO_2 reduction is achieved depending on fuel sulfur content and the amount of sorbent added.

Nitrogen Oxides: With an operating bed temperature between 1,500 to 1,600°F, the amount of NO_x formed in the fluidized bed is less than in conventional systems which operate at much higher temperatures. This is because the rate of NO_x formation drops off substantially as the gas temperature decreases. Further NO_x reduction can be achieved in fluidized–bed boilers by air staging since they can be operated with less impacts on combustion efficiency than the conventional units.

Fuel Flexibility

Fuel Ash Properties: Due to the low combustion temperatures, fluidized–bed boilers allow the use of high slagging fouling fuels at temperatures below their ash fusion temperature. As a result, many of the boiler operating problems associated with these fuels are greatly reduced.

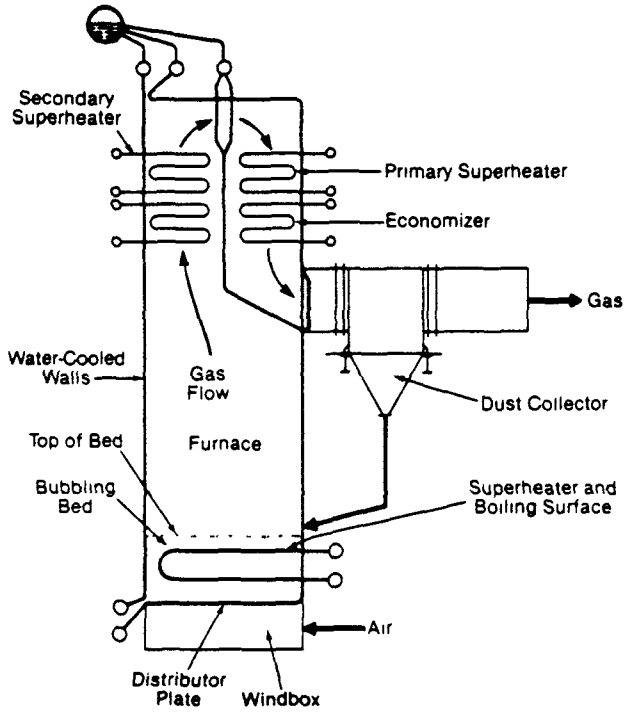
Low Btu Fuels: The fluidized–bed combustion process can also burn fuels with very low heating values. This capacity results from the rapid heating of the fuel particles by the hot bed materials and from the long residence time the fuel particles spend in the boiler, both of which offset the effects of low combustion temperatures.

Fuel Preparation: Fluidized–bed boilers can burn crushed coals with particle size up to 0.25 in. These coals are easier and less costly to prepare than pulverized coals.

11.4 Atmospheric Pressure Fluidized–Bed Boilers

Bubbling Bed

TYPICAL BUBBLING FLUIDIZED-BED BOILER SCHEMATIC[1]

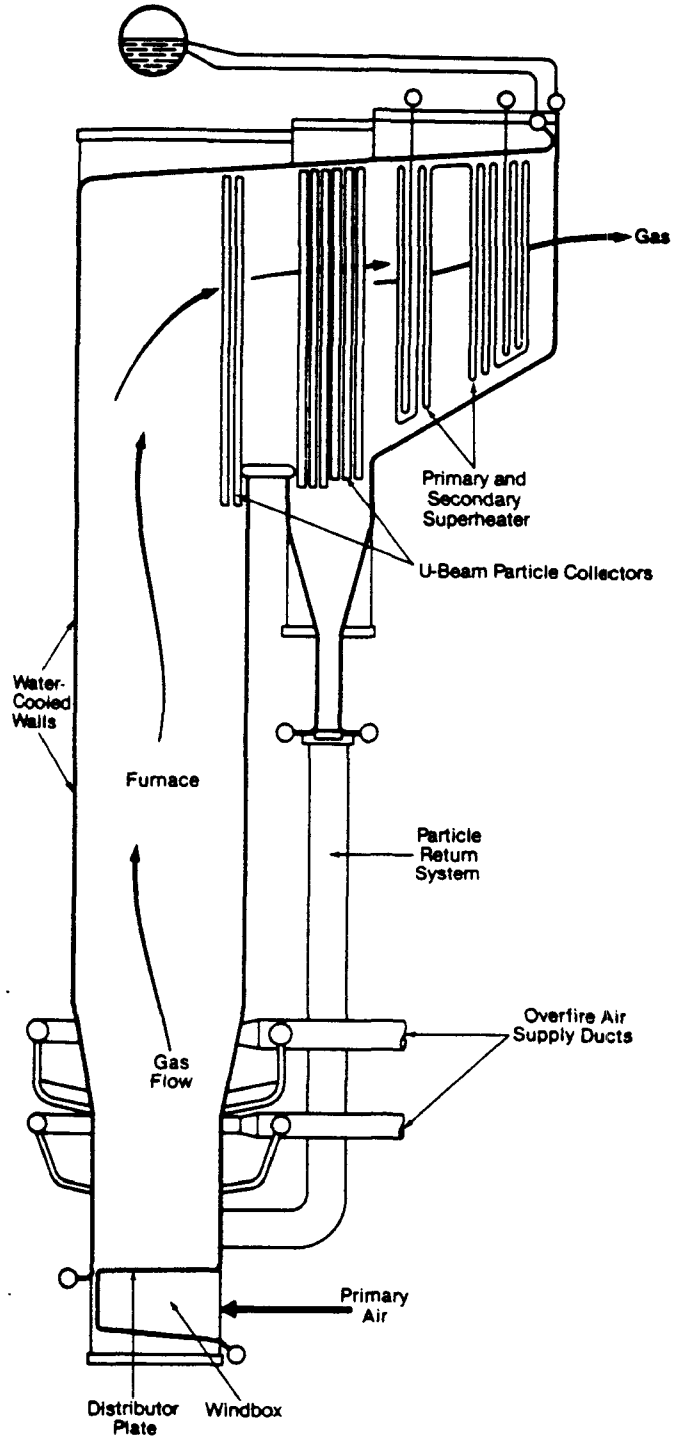


Slide 11-5

Slide 11–5 shows the main features of a bubbling fluidized–bed boiler. Normally, heat transfer surfaces are placed in the bed to achieve the desired heat balance and bed operating temperature. Because of the vigorous mixing of gas and solids, the bed temperature is very uniform (± 25°F).

Coal–fired bubbling–bed boilers normally use a recycle system after the economizer to recycle the solids. This maximizes combustion efficiency and sulfur capture. Furnace flue gas velocity is about 8 to 10 ft/s at maximum load.

TYPICAL CIRCULATING-BED BOILER SCHEMATIC[1]



Slide 11-6

Slide 11–6 shows the main features of a circulating fluidized–bed boiler. The bed does not contain any heat transfer surfaces. This type of boiler typically uses division walls to provide the required heat removal. Furnace temperature remain uniform since the mass of solids is many times the mass flow rate of the combustion gases. Furnace walls typically provides sufficient heat absorption required to maintain bed temperature around 1,500 to 1,600°F. Furnace flue gas velocity is about 20 ft/s at full load.

11.5 Fluidized–Bed Boiler Furnace Design

FLUIDIZED–BED BOILER FURNACE DESIGN

Design Information
Bed Material
Pressure Loss
Heat Transfer

Slide 11–7

Design Information

Typical information used to establish design requirements for a fluidized–bed boiler is as follows:

- Unit capacity — steam flow requirements,
- Fuel — type, ash and moisture content, pulverizing characteristics, reactivity, and fouling characteristics,
- Limestone — type, reactivity, size and attrition characteristics,
- Sulfur removal requirements,
- NO_x emission limits, and
- Load turndown range.

Bed Material

A sufficient amount of bed material with proper size distribution must be maintained for a fluidized–bed boiler to operate properly. If the particles are too coarse, the bed will defluidize and become fixed. If the particles are too fine, the bed material will get blown out of the furnace, making it impossible to maintain an adequate amount of bed material.

Pressure Drop

Pressure loss in a fluidized–bed boiler furnace is of great importance since it defines the amount of solids in the furnace, which is a major variable that influences heat transfer. Because the concentration of solids and the pressure profile are closely

related, the determination of pressure drop is a primary task when establishing furnace performance.

Heat Transfer

Due to the high solid content in the gas flow, heat transfer coefficients in a fluidized–bed boiler furnace are considerably higher than those of a conventional unit. However, due to the lower gas temperatures in fluidized–bed furnace, the overall heat fluxes in the two systems are similar. Solid and gas convection and solid and gas radiation are the predominant heat transfer modes in a fluidized–bed boiler.

11.6 Fluidized–Bed Boiler Arrangements

FLUIDIZED-BED BOILER ARRANGEMENTS

Boiler Subsystem
- Distributor Plate
- Overfire Air System
- Boiler Furnace

Auxiliary Equipment
- Fuel Feed System
- Sorbent Feed System
- Ash Removal System
- Sootblowers

Slide 11-8

Boiler Subsystem

Distributor Plate: The distributor plate is located at the bottom of the furnace and separate the windbox from the furnace. The plate typically has flow distributors such as bubble caps to provide uniform flow distribution of combustion over the cross–section of the furnace. Typically, 50 to 70% of the combustion air flow through the distributor plate at full load in a circulating bed boiler. In a bubbling bed, 85 to 100% combustion air flows through the plate if staged combustion is not used.

Overfire Air: The overfire air system is used to enhance combustion and control NO_x emissions. With overfire air, a portion of combustion air that does not flow through the distributor plate is injected into the combustion gases shortly after the coal ignition to complete combustion. The overfire air must provide good mixing to complete combustion and minimize CO emissions. Overfire air mixing depends on the size of the overfire air nozzles and the air and gas velocities and densities.

Boiler Furnace: Boiler furnace is constructed of water–cooled membraned tubes welded together to form a gas–tight furnace.

Auxiliary Equipment

Fuel Feed Systems: There are three types of fuel feed system used for fluidized–bed boilers. These are *underfeed*, *overfeed* and *in–bed feed* systems.

An underfeed system is usually a pneumatic transport system that moves the fuel from the storage silo to the bed. For good fuel–air mixing, the fuel feed pipes under the bed should be closely spaced. Typical fuel pipe spacing for a underfeed system is about 4 feet. Underfeed systems are used in bubbling fluidized–bed boilers burning bituminous coal. The coal used in an underfeed system should be crushed to less than 0.25 in and fuel moisture should be less than 6% to avoid pluggage in the transport pipes.

The overfeed system is located above the bed where the gas pressure is slightly below atmospheric. Therefore, the fuel stream does not have to be pressurized. Overfeed systems are also typically used in bubbling fluidized–bed boilers. The coal should be crushed to a top size of 1.25 in, and the amount of fine coal (less than 30 mesh) is limited to prevent excessive burning in the furnace zone immediately above the bed (called *freeboard*).

An in–bed system typically uses a feed screw or air assisted chute system. In the in–bed feed system, the fuel is injected through an enclosure wall just above the distribution plate. The fuel stream must be sealed against the bed pressure, which is substantially higher than atmospheric. In–bed feed systems are used in CFB boilers.

Sorbent Injection System: Sorbent can be mixed and fed with the fuel into the furnace using an underfeed or in–bed feed system. Sorbent can not be fed properly with an overfeed system due to its fineness. Sorbent is blown into the furnace through separate pneumatic feed points and by gravity from a silo.

Ash Removal Systems: Solids including bed ash, bed material and sorbent or inerts can be removal from a fluidized–bed boiler at two places: a bed drain and a baghouse or an ESP. The bed drain normally removes from 0 to 50% of total solids.

Sootblowers: Because fluidized–bed boilers are operated at temperatures below the ash softening points, fouling and slagging on the boiler furnace are usually not a problem. Some boilers do not need to have sootblowers. However, sootblowers are necessary when firing fuels containing high sodium and/or potassium ash.

11.7 Operation

OPERATION

System Control
Bed Temperature Control
Bed Material Inventory Control
Overfire Air Control

Slide 11–9

System Control

Most of the operating and control features of fluidized–bed boilers and conventional boilers are the same, except two main areas. One is the ability to transport and control large quantities of solids; the other is to control primary and secondary air splits to maximize combustion efficiency and minimize emissions. By controlling solid quantities and air flows, important parameters of fluidized–bed boilers such as bed temperature and bed inventory can be controlled.

Bed Temperature Control

Bubbling Bed: Since the heat absorbing surfaces are located within the bed itself, heat balance around the bed controls the bed temperature. As load varies, heat balance around the bed must be varied to achieve the desired bed operating temperature. The heat balance can be altered by either increasing or decreasing the bed depth. Decreasing the bed depth will decrease the amount of heat transfer since less heat removing surface is submerged in the bed, or vice versa.

Bed temperature can also be controlled by increasing or decreasing excess air and air temperature. Increasing excess air will decrease the bed temperature since more heat is required to heat up the extra air. Bed temperature increases as air temperature increases.

Circulating Bed: Due to the more uniform distribution of the bed material throughout the furnace, gas temperature is more uniform in CFB boilers than in bubbling bed boilers. As mentioned previously, heat transfer is a function of solid inventory in the furnace. Therefore, furnace temperature in CFB boilers can be controlled by controlling bed inventory.

Bed Material Inventory Control

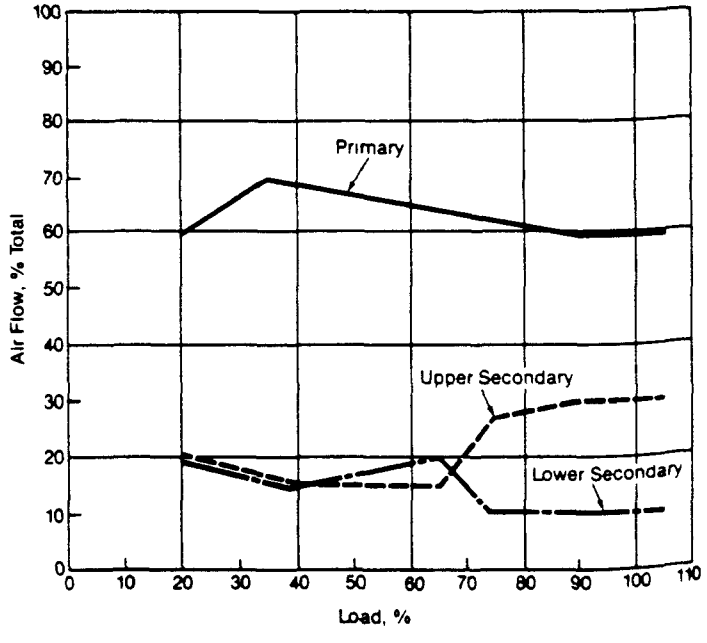
Bubbling Bed: Bed inventory is dependent on the balance between feed solids and bed drain flows, plus the solids that escape the furnace to back–end collectors. In practice, the minimum solids feed flow rate must provide enough material to maintain the bed drain flow required to remove oversized particles plus make up the back–end

loss. Bed inventory is controlled by measuring pressure drop across the bed and maintaining it at a value corresponding to the desired inventory.

Circulating Bed: In CFB boilers, the amount of solids leaving the furnace and bed inventory are interdependent. Solids leaving the furnace must be collected and returned to the furnace to maintain bed inventory. Overall inventory is controlled in the same way with a bubbling bed boiler.

Overfire Air Control

AIR FLOW DISTRIBUTION[1]



Slide 11-10

Slide 11–10 shows a typical split between primary and secondary (overfire) air for a bituminous coal–fired boiler. The split is established to maximize combustion efficiency and minimize CO and NO_x emissions.

11.8 Emissions

FLUIDIZED–BED BOILER EMISSIONS

Sulfur Dioxide
Nitrogen Oxides
Carbon Monoxide and Hydrocarbon
Particulates

Slide 11–11

Sulfur Dioxide

Sulfur dioxide emissions from a fluidized–bed boiler depends on the sulfur content of the fuel. A limestone injection system is usually installed on a fluidized–bed boiler to reduce SO_2 emissions. Due to the solids circulation, sulfur capture is better in a CFB boiler than in a bubbling bed boiler. Sulfur reductions of about 90% are typically achieved in a CFB with calcium–to–sulfur ratio (molar) of 2.0 to 2.5, depending on the fuel sulfur content and the reactivity of the sorbent.

Nitrogen Oxides

Due to low furnace operating temperatures, NO_x emissions from fluidized–bed boilers are typically much less than conventional boilers. Typical values for NO_x emissions are within the 100 to 200 ppm (0.15 to 0.30 lb/MMBtu of heat input) range for a CFB boiler burning coal. Overfire air systems are typically installed on a fluidized–bed boiler to reduce NO_x emissions.

Carbon Monoxide and Hydrocarbon

Carbon monoxide (CO) and hydrocarbon (HC) are the products of incomplete combustion of the fuel. Typical values for CO and HC emissions from a CFB boiler are 200 and 20 ppm (by volume), respectively. CO and HC emissions can be minimized by choosing the proper number of feed points, by properly designing the overfire air system, and by providing sufficient furnace residence time for mixing and complete combustion.

Particulates

Ash particles larger than 140 mesh (105 microns) are typically removed by the bed drain system. Particles smaller than 325 mesh (44 microns) are removed by back–end particulate collectors. A fabric filter is typically used for fluidized–bed boilers because it is less sensitive to the ash properties, such as size, concentration, and resistivity, than an ESP.

REFERENCES

1. *Steam, Its Generation and Use*, 40th Edition, Babcock and Wilcox Company, 1992.

CHAPTER 12. GAS TURBINE WITH A HEAT RECOVERY STEAM GENERATOR

12.1 Introduction

12.2 Gas Turbine Description
- A. Compressor
- B. Combustor
- C. Turbine

12.3 Design Classifications

12.4 Operating Cycles and Efficiency
- A. Simple Cycle
- B. Regenerative Cycle
- C. Cogeneration Cycle
- D. Combined Cycle

12.5 NO_x Formation Mechanisms

12.6 Control Options
- A. Fuel switching
- B. Water/Steam Injection
- C. Fuel Emulsion
- D. Combustion Modifications
- E. Selective Catalytic Reaction
- F. Oxidation Catalyst

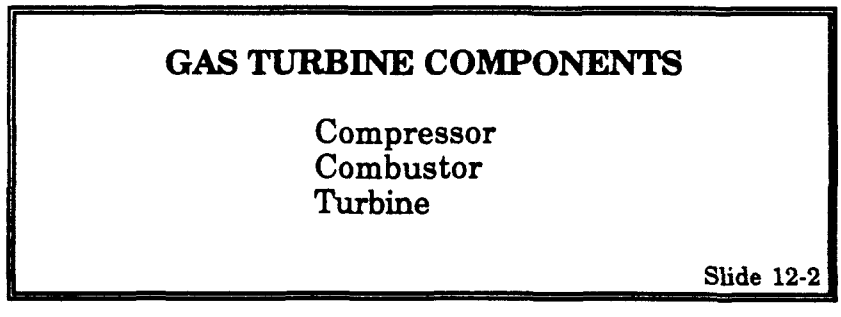
12. GAS TURBINE WITH A HEAT RECOVERY STEAM GENERATOR

12.1 Introduction

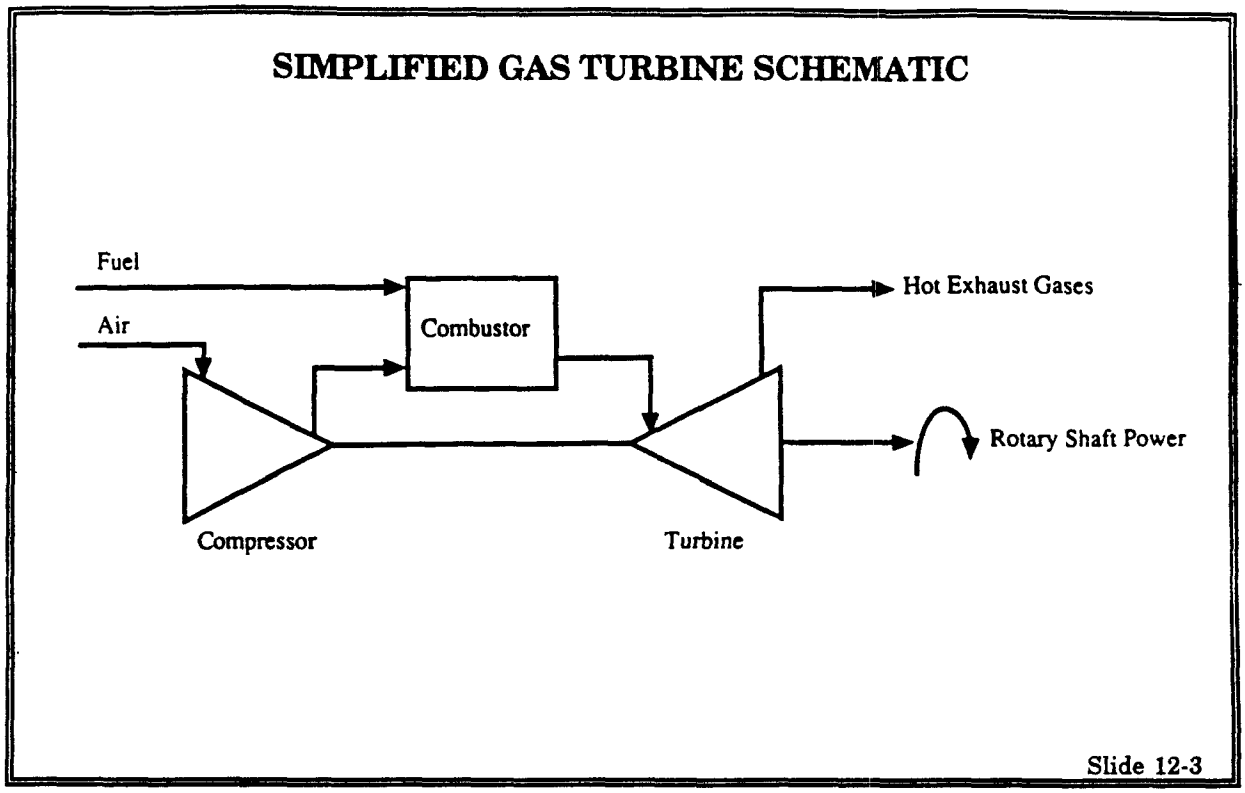
The Federal Energy Regulatory Commission (FERC) defines the term cogeneration as the simultaneous production and use of thermal and shaft power. Historically, utility and industrial boiler operators have long used this term to describe a boiler which creates electricity or mechanical energy via a steam turbine. However, FERC cogeneration is not limited to boilers or to units for electrical power generation. More recently, the term cogeneration is used to describe an industrial power plant consisting of a gas turbine (GT) in conjunction with a heat recovery steam generator (HRSG). This type of unit is consistent with the FERC's definition of cogeneration in that the gas turbine produces the shaft work and the HRSG produces the usable thermal energy in the form of steam. This chapter will discuss the general description of both the gas turbine and the HRSG. A description of the emissions and viable NO_x control technologies is also offered in this chapter.

12.2 Gas Turbine Description

A gas turbine is a rotary combustion engine which provides power to either stationary or mobile applications. For stationary applications, the exit gases from the combustor are directed to a turbine which extracts energy from the hot gases to produce net shaft horsepower similar to a steam turbine. This shaft horsepower is primarily used to either drive an electric generator or to transport a fluid by driving a pump or compressor. In some applications, the hot exhaust gases from the turbine are used for steam production or process heating. A gas turbine's power output is based on mass throughput. To increase the output of a GT, one only needs to increase mass throughput by increasing the overall size or increasing the density of the inlet gas.



Gas turbines are comprised of three major components: the compressor, the combustor, and the turbine. Ambient air is drawn into the compressor, where the pressure of the air is increased by as many as 30 atmospheres for some turbine models. This compressed air is passed to the combustor where fuel (gaseous or liquid) is introduced, mixed with a portion of the air, ignited, and burned. The combustion gases can reach temperatures of 3630°F, which are too high for the present-day turbine metals technology. To reduce this temperature to a safe



operating level below 2300°F, the combustion gases are dilution cooled with additional air from the compressor section. Energy from the gas stream is extracted by the axial flow turbine in the form of shaft horsepower. Typically, 50 percent of the energy extracted by the turbine is required to drive the compressor with the remainder of the energy available to drive either a mechanical load or an electric generator. Exit gas temperatures from the turbine are normally around 960°F.

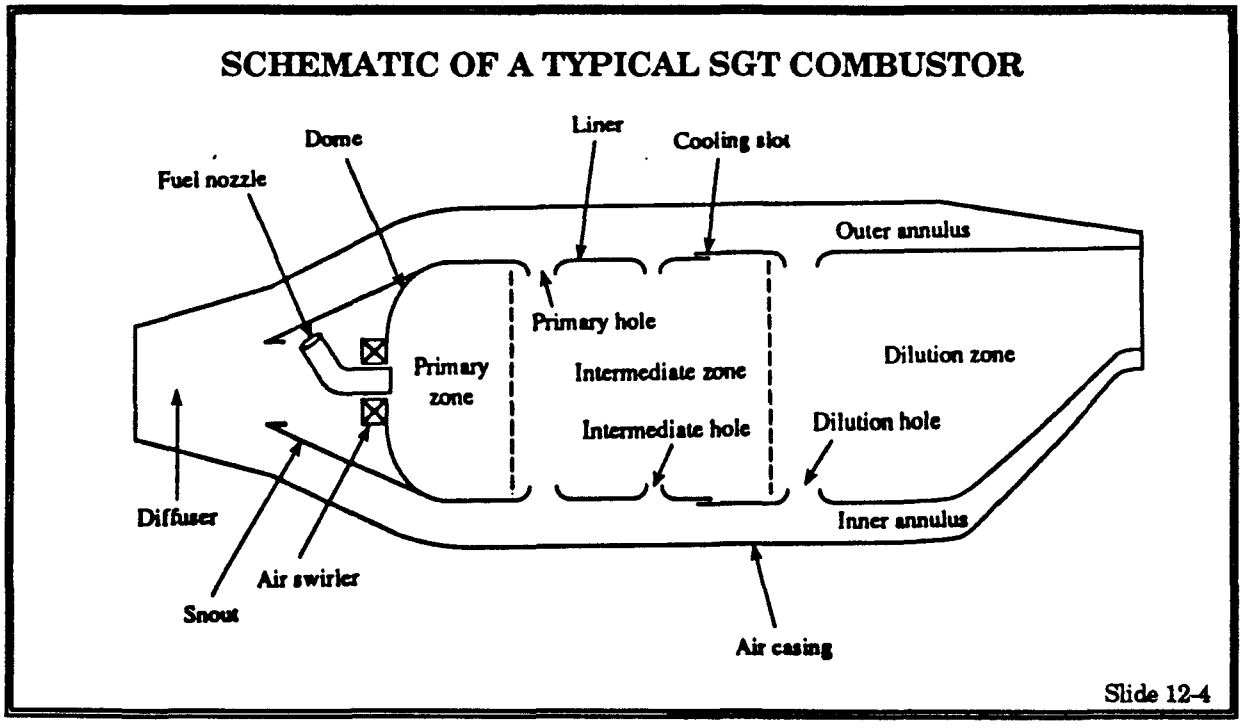
Compressor

The first of the three major components of the gas turbine is the compressor. Two main types of compressor designs exist in the market today: axial and centrifugal. Axial flow compressors have both higher pressure ratios and higher efficiencies than centrifugal compressors. Centrifugal compressors are now only used in small gas turbines (< 500 kW) where the air flow is too small to be handled efficiently by axial blading. Axial compressors consist of several rows of blades attached to the main shaft of the gas turbine. As the shaft rotates, the compressor blades increase the velocity of the air by forcing the air along the length of each compressor blade. Following each row of compressor blades is a row of stationary stator blades. These stator blades decelerate the air, causing the kinetic energy produced by the velocity increase to be converted to a static pressure rise. Velocity and pressure increases in the compressor are caused by decreasing the cross-sectional area down the length of the compressor.

Compressors are generally described in terms of pressure ratio. The term pressure ratio describes the increase in air pressure attributed to the compressor. Pressure ratio is simply the compressor exit pressure divided by the compressor inlet pressure (ambient pressure). Increases in pressure ratio can be obtained by either changing the blade geometry or by adding rows of compressor and stator blades.

Combustor

Combustor designs have developed into three basic configurations: annular, can-annular, and silo. Although these designs are physically different, each combustor has four basic zones: the inlet transition zone, the primary combustion zone, the secondary combustion zone, and the outlet transition zone.



The inlet transition zone reduces the incoming gas velocity in order to establish and maintain combustion. If the flow velocity is not reduced sufficiently, residence time in the combustor will be too short, which may result in incomplete combustion. Ignition of the fuel and air mixture occurs in the primary combustion zone. The fuel is injected into the combustion chamber. Air first flows through the area between the liner and the combustor casing. This area serves the dual purpose of preheating the air and cooling the combustor liner. Holes in the liner regulate the amount of air entering the combustor and allow for mixing of the air and fuel while minimizing pressure drop. Swirl vanes and/or radial jets direct the combustion air in order to create a turbulent section in front of the fuel nozzle. This turbulent flow allows for thorough mixing of the air and fuel so that the fuel burns evenly and completely.

The materials used to construct the combustor and turbine cannot withstand the high temperatures of combustion. As a result, the secondary combustion zone provides air for dilution cooling and completion of combustion. The cooling air is provided between the flame and the combustor liner to maintain a tolerable temperature on the combustor walls.

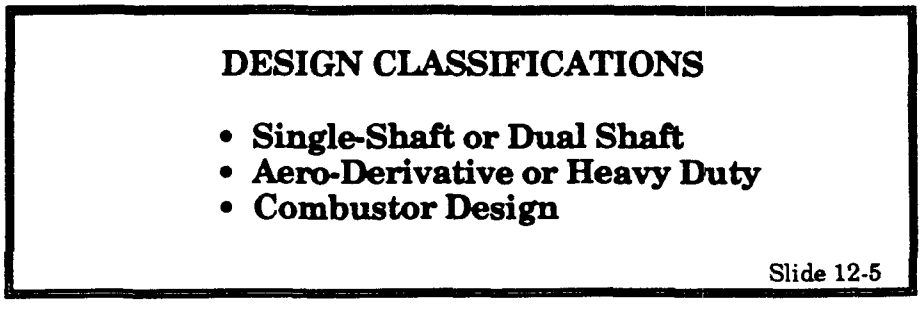
The final zone in the combustor is the outlet transition zone. In this zone, the combustion gases pass through an accelerator which raises the velocity of the gases before entering the turbine. This acceleration process is accomplished primarily by throttling the flow. Although the combustor's overall fuel to air ratio is normally around 0.02 at full load and the combustors are small in comparison with utility boilers, for instance, the residence time is relatively high due to the pressures to which the combustors are subject. Gas turbine combustion process efficiency is usually in excess of 99 percent.

Turbine

The turbine section of a gas turbine is composed of several rows of blades attached around the circumference of the turbine shaft. Energy in the hot combustion gases is converted to shaft work as it is expanded across the rows of turbine blades. Similar to the compressor, there are two basic types of turbines: radial flow and axial flow. Radial flow turbines expand the gas along the radius of the gas turbine. Axial turbines expand the gases along the turbine axis. Radial turbines are primarily confined to applications which require compact size such as auxiliary power units for aircraft. In stationary mechanical and electric power generation industries, axial flow turbines are almost exclusively used due to their more efficient conversion of thermal energy in the combustor exhaust gases and their ability to handle large mass flows.

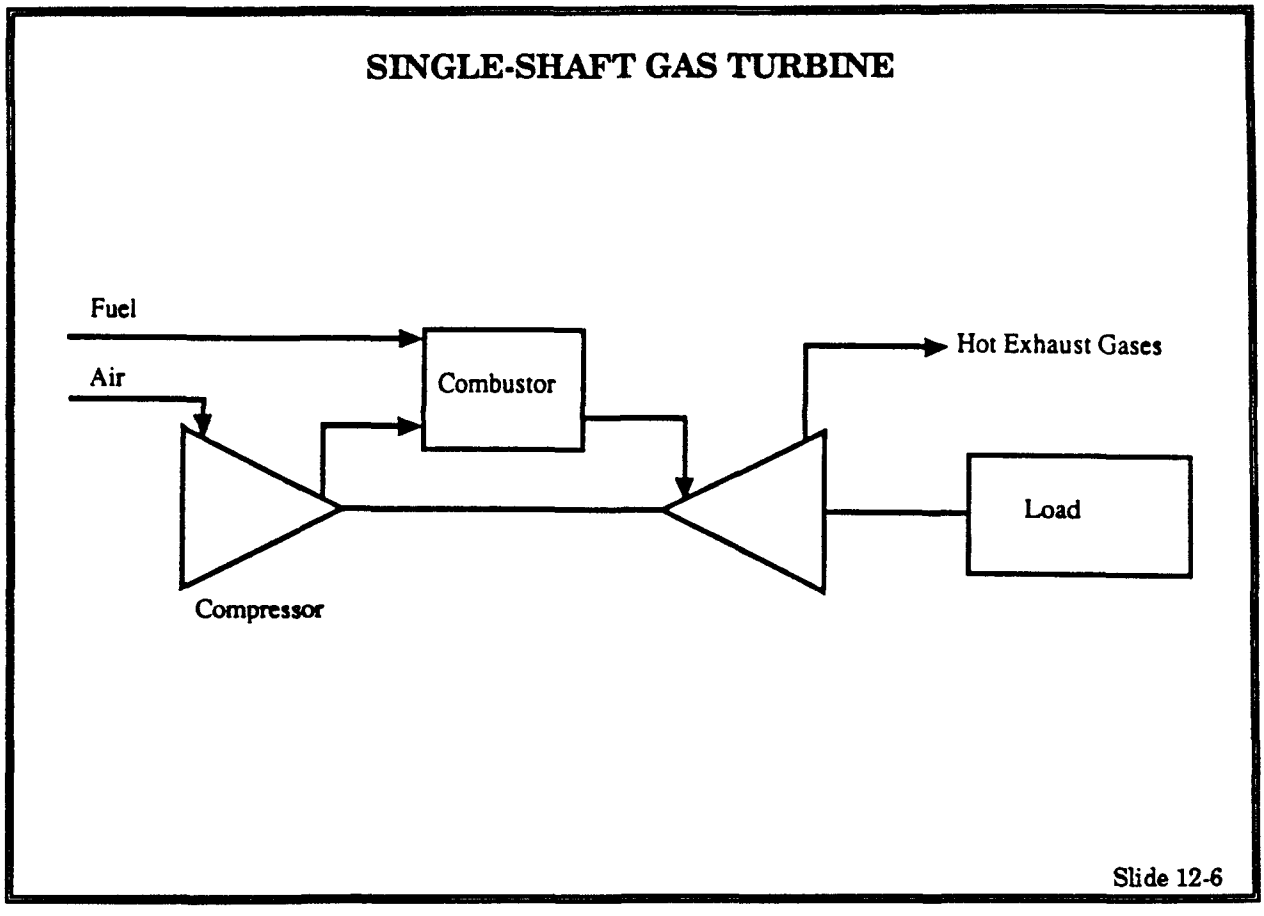
12.3 Design Classifications

For the most part, the fundamental design of a gas turbine is nearly identical over the entire spectrum of sizes and manufacturers. Each has the three major components: a compressor, a combustor, and a turbine. Even with these basic similarities, there are specific design criteria which can further classify stationary gas turbines. These design criteria are the following: single shaft or multi-shaft, aero-derivative or heavy duty, and combustor design.



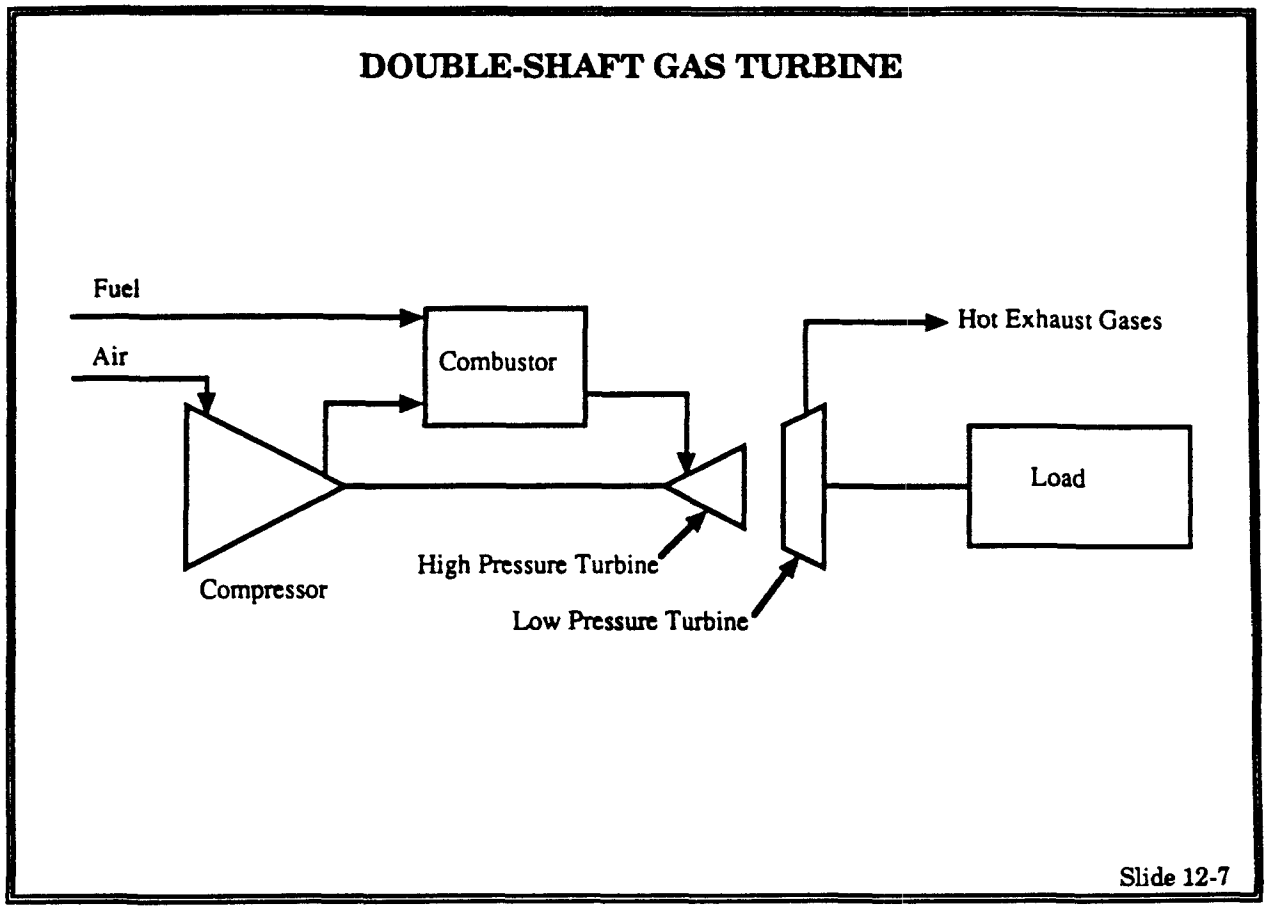
In gas turbine technology, the intended application of a turbine quite often determines the characteristics of the final design. This certainly is the case with single- and dual-shaft turbine designs. Other multi-shaft designs do exist, however, discussion will be limited to single- and dual-shaft arrangements as shown in Figure 3. This exclusion results from the relative scarcity of multi-shaft units in the domestic gas turbine market.

A single-shaft gas turbine is designed precisely as the name suggests. The compressor and turbine stages are fixed to the same continuous shaft and operate at the same speed. Applications that do not require variable speed operation, such as electric power generation, are ideal for single-shaft machines. The design is straightforward and power can be increased simply by increasing the fuel input to the combustor.



Dual-shaft machines divide the turbine into low- and high-pressure turbines. The high-pressure (HP) turbine is connected directly to the compressor by a single shaft. The low-pressure (LP) turbine, also known as the "free" or "power" turbine, has its own shaft which is connected directly to an external load. The primary advantage of this design is the wide range of speeds at which the power turbine can operate making it ideal for variable load applications. Part of the load efficiency of

the dual-shaft unit is higher due to less flow required to drive that turbine at low power turbine speeds. One disadvantage of the dual-shaft machine is that in order to restore power to the power turbine at low load, the compressor must be accelerated to maximum speed.

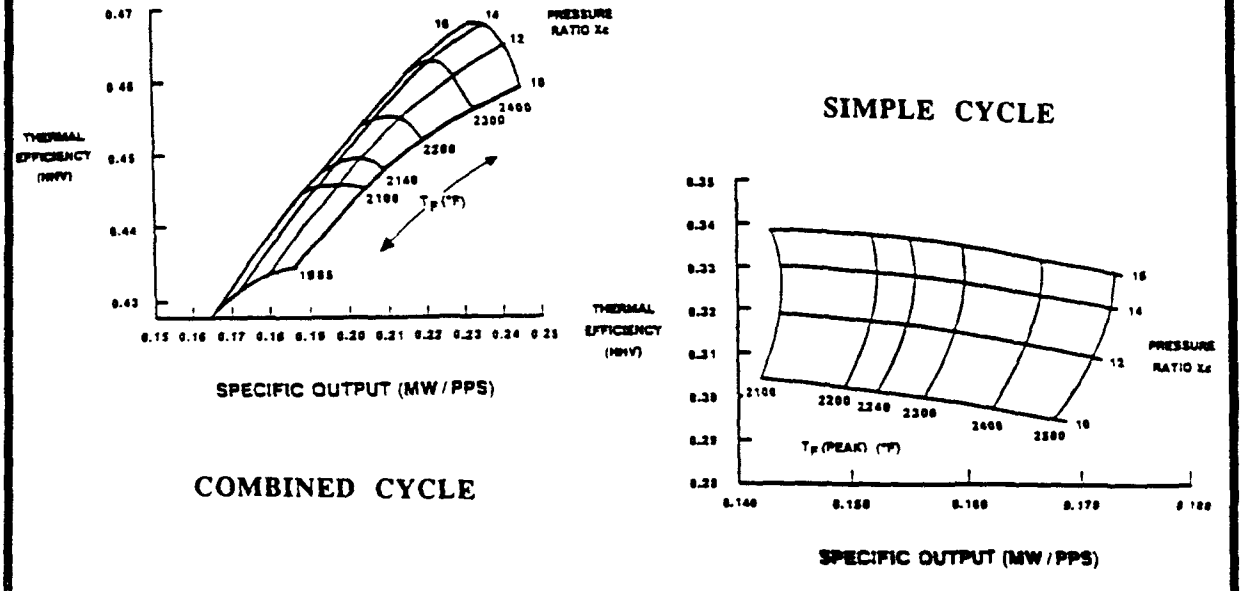


Gas turbine design has evolved from two basic user industries: the airline industry and electric power generating facilities. Gas turbines which are designed with the basic characteristics of aircraft engines (higher temperature ratios, increased pressure ratios) are classified as "aero-derivative" (AD) machines. Those units which are refinements of earlier power generating machines (constant operating speeds, extended component life) are classified as "heavy duty" (HD) machines. However, both AD and HD engines are used as power generating sources.

Higher efficiency, smaller size, and alloys that can withstand higher temperatures are advances made in the aircraft engine industry that have been incorporated into the design of the AD engines. The higher efficiency is due to the increased pressure ratios and temperature ratios across the compressor and are indicative of AD engines in comparison to HD engines. The temperature and pressure ratios of a gas turbine are major contributors to the engine's efficiency (MW/PPS is megawatt/lbs exhaust flow per second and is used as a normalizing unit because gas

turbine power is directly related to mass throughput). Increases in either of these ratios produces an increase in the efficiency of the engine. As one may expect, an AD engine looks nearly identical to its aircraft jet engine counterpart with a power turbine attached.

EFFECT OF TEMPERATURE AND PRESSURE ON THERMAL EFFICIENCY



Slide 12-8

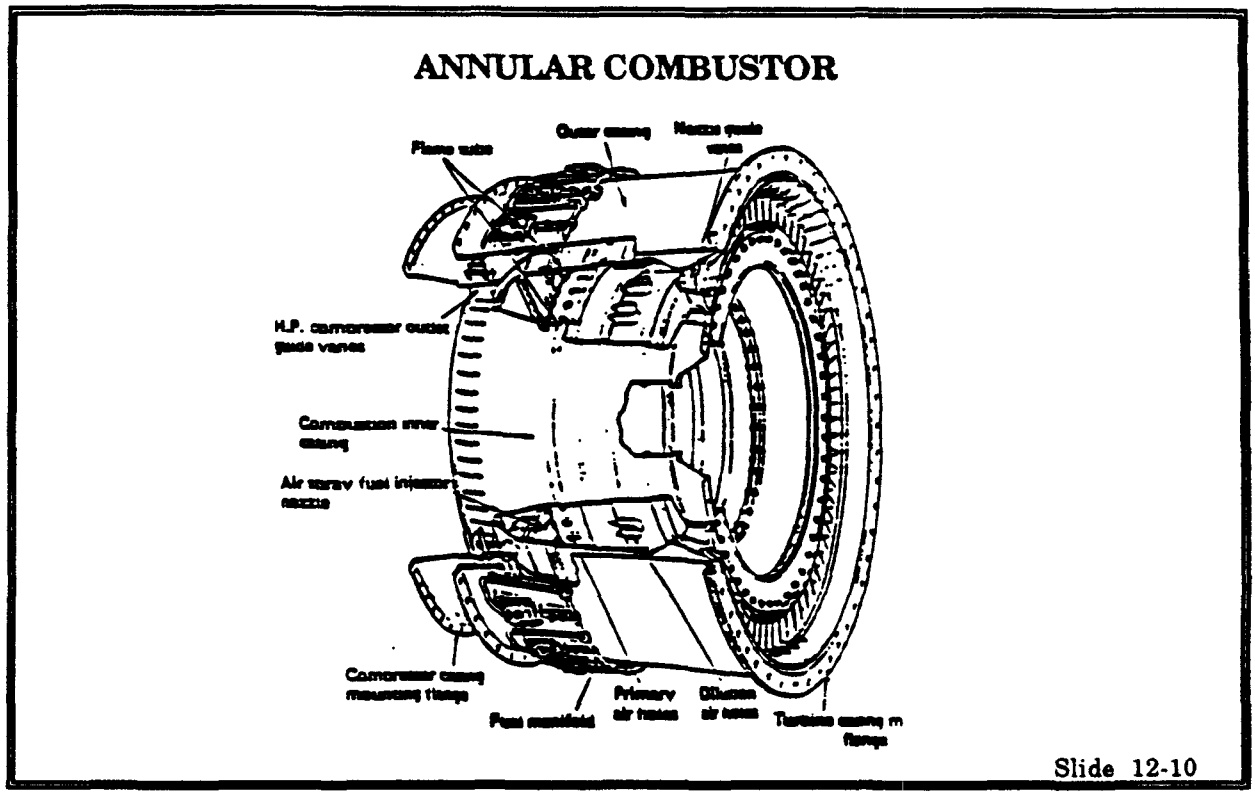
The combustor design is the last criteria used to describe a specific engine. Gas turbine engine manufacturers usually produce one combustor design, and the engine can be readily identified to its manufacturer by its combustor. The combustor size increases from small to large turbines, but the basic design and burner arrangements are the same. Similarity in design allows refinements made for one machine's combustor to be easily incorporated into the design of another unit. Current combustors have three basic designs: annular, can-annular, and silo.

COMBUSTOR DESIGN

Annular
Can-Annular
Silo

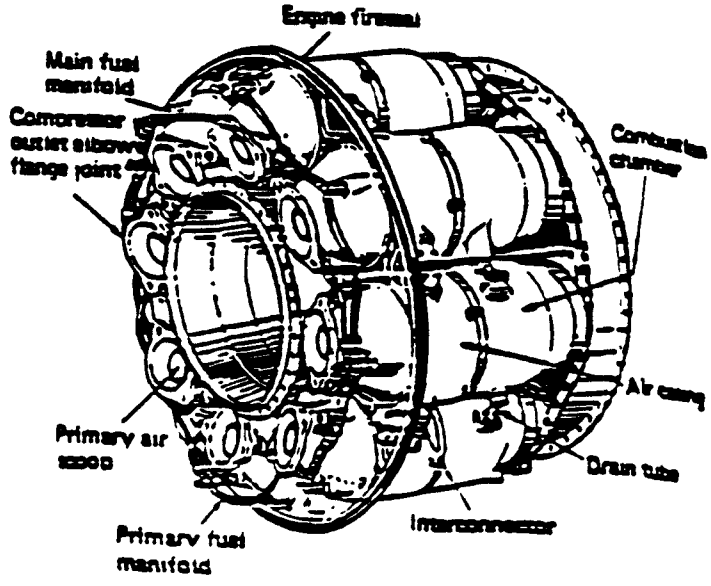
Slide 12-9

The annular design is most often found in aero-derivative machines. This combustor is a carryover from the earlier aircraft engine designs. Annular combustors are composed of a single continuous combustion chamber that "rings" the turbine shaft in the area between the compressor and turbine sections. Simplicity is the primary advantage to this combustor configuration. A single combustor allows for greater fuel flexibility, simplified fuel supply system, and ease in monitoring fuel injection.



The can-annular designs have a series of individual can shaped combustors arranged in an annular configuration that rings the turbine between the compressor and turbine. All basic combustor components found in the large annular combustor are found in each of these cans. The major advantage of this design is that it allows for easy removal of cans for maintenance and repair.

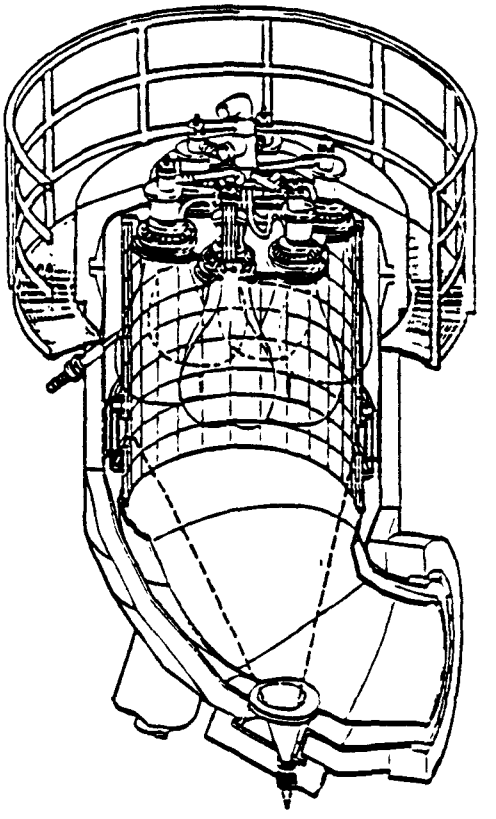
CAN-ANNULAR COMBUSTOR



Slide 12-11

Silo combustors are the only one of the three combustors that are found outside the body of the gas turbine. Depending on the manufacturer and model, one or two silo combustors can be found on a particular unit. Orientation of the combustors can be either vertical or horizontal with the vertical arrangement gaining the greatest acceptance in the gas turbine industry. Advantages of this combustor design include ease of maintenance and emission reduction. These advantages result from the fact that the size constraints affecting modifications to can-annular and annular designs do not exist for external pieces of equipment such as the silo combustor.

SILO COMBUSTOR



Slide 12-12

12.4 Operating Cycles and Efficiency

Gas turbines are very versatile machines. They are capable of burning a wide variety of fuels and can be used to produce shaft horsepower for applications ranging from pipeline fluid compression, to electric power generation, to aircraft and marine propulsion. This versatility extends to operation in a variety of thermal cycle arrangements. Thermal operating cycles compatible with the characteristics of gas turbines are simple, regenerative, cogeneration, and combined cycle.

OPERATING CYCLE

Efficiency
Simple Cycle
Regeneration
Cogeneration
Combined Cycle

Slide 12-13

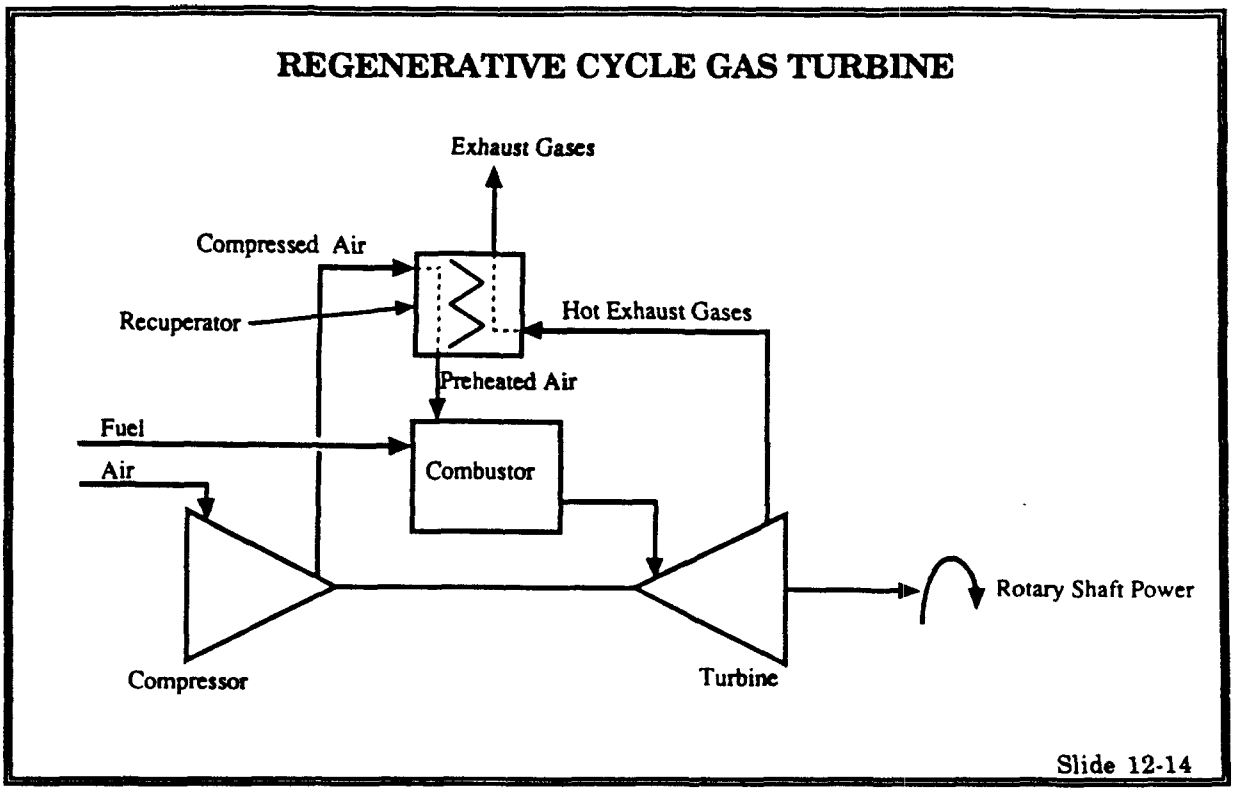
As mentioned previously, gas turbine efficiency is affected by the temperature and pressure prior to the combustor and the temperature at the turbine inlet. The thermal efficiency of the gas turbine alone is simply the percentage of useful energy contained in the fuel that is converted to shaft horsepower that can be used to drive an external load. This useful horsepower is calculated by subtracting the power required to drive the compressor from the gross power generated by the turbine itself. If a turbine is used in the regenerative, cogeneration, or combined cycles, the determination of cycle efficiency is not as straightforward.

Simple-cycle

The simple-cycle is the most basic operating cycle of a gas turbine. In a simple-cycle application, the components used are the compressor, the combustor, and the turbine. No heat recovery or inlet air preheating is performed at any point in the cycle. Due to the lack of heat recovery, the simple-cycle exhibits the lowest thermal efficiency of the four gas turbine operating cycles. Typical efficiencies for simple cycle gas turbines are in the range of 28 to 38 percent, with values as high as 42 percent for a machine recently marketed by one manufacturer. From an energy input standpoint, roughly 1 to 2 percent of the thermal energy input of the fuel can be attributed to mechanical losses, with the remaining energy being lost in the high temperature exhaust gases. This cycle is typically used when shaft horsepower production is important with little need for exhaust heat recovery. Of all four cycles, the simple-cycle offers the lowest capital investment, but provides the least efficient use of fuel, which increases operating costs.

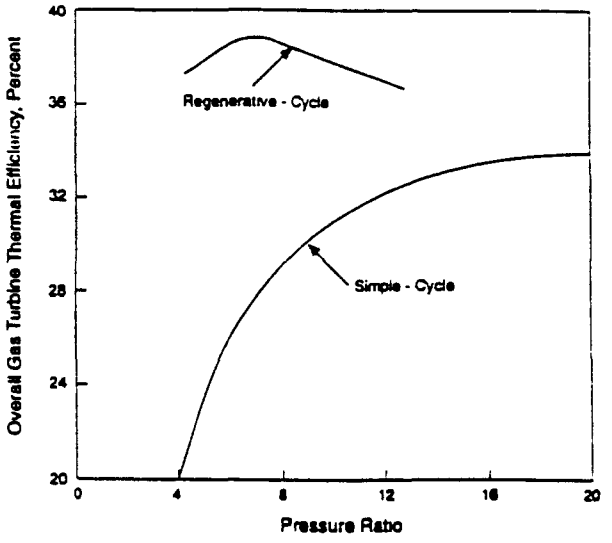
Regenerative Cycle

Regenerative-cycle gas turbines differ from simple-cycle gas turbines in that the inlet air to the combustor is heated by indirect contact with the exhaust gases. The heat exchanger that allows this to happen is called a regenerator or recuperator. This regenerator becomes an additional component of the gas turbine cycle and alters various cycle parameters including thermal efficiency, air and gas temperatures, and emissions.



The process of using the waste heat in the turbine exhaust to preheat the combustion air reduces the amount of fuel necessary to reach the desired temperature level. Reducing the amount of fuel consumed directly causes a reduction in the total mass emissions of the turbine while increasing the thermal efficiency. This increase in efficiency is directly proportional to the temperature rise between the compressor discharge and the combustor exit. At high pressure ratios, regenerators are not as effective in increasing cycle efficiency. As pressure ratios rise in the compressor, the compressor exit temperature approaches the turbine exhaust temperature. The closer these two temperatures come to each other, the lower the amount of energy (heat) that can be transferred to the compressor exit air. This continues to occur until a point at which the marginal gain in efficiency (reduction in fuel consumption) does not outweigh the increased capital and maintenance costs attributed to the regenerator.

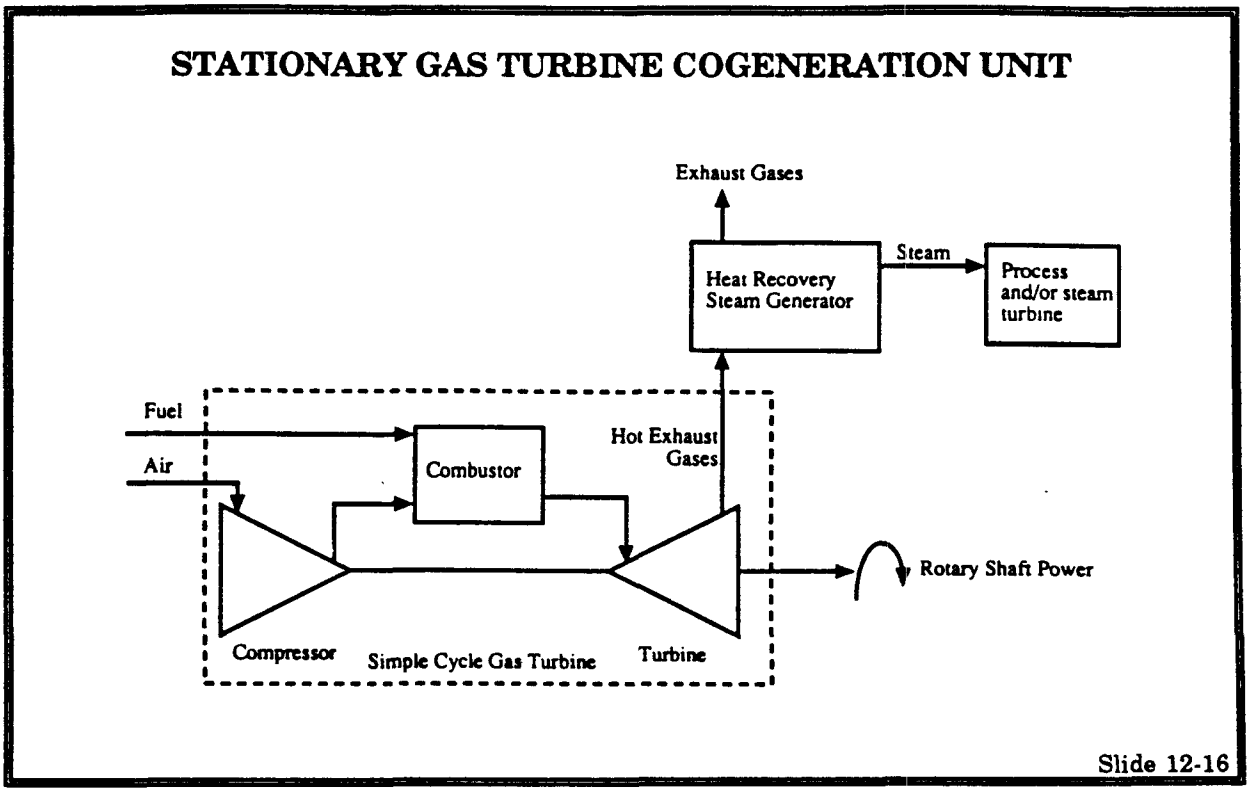
EFFECT OF REGENERATIVE CYCLE ON GT THERMAL EFFICIENCY



Slide 12-15

Cogeneration Cycle

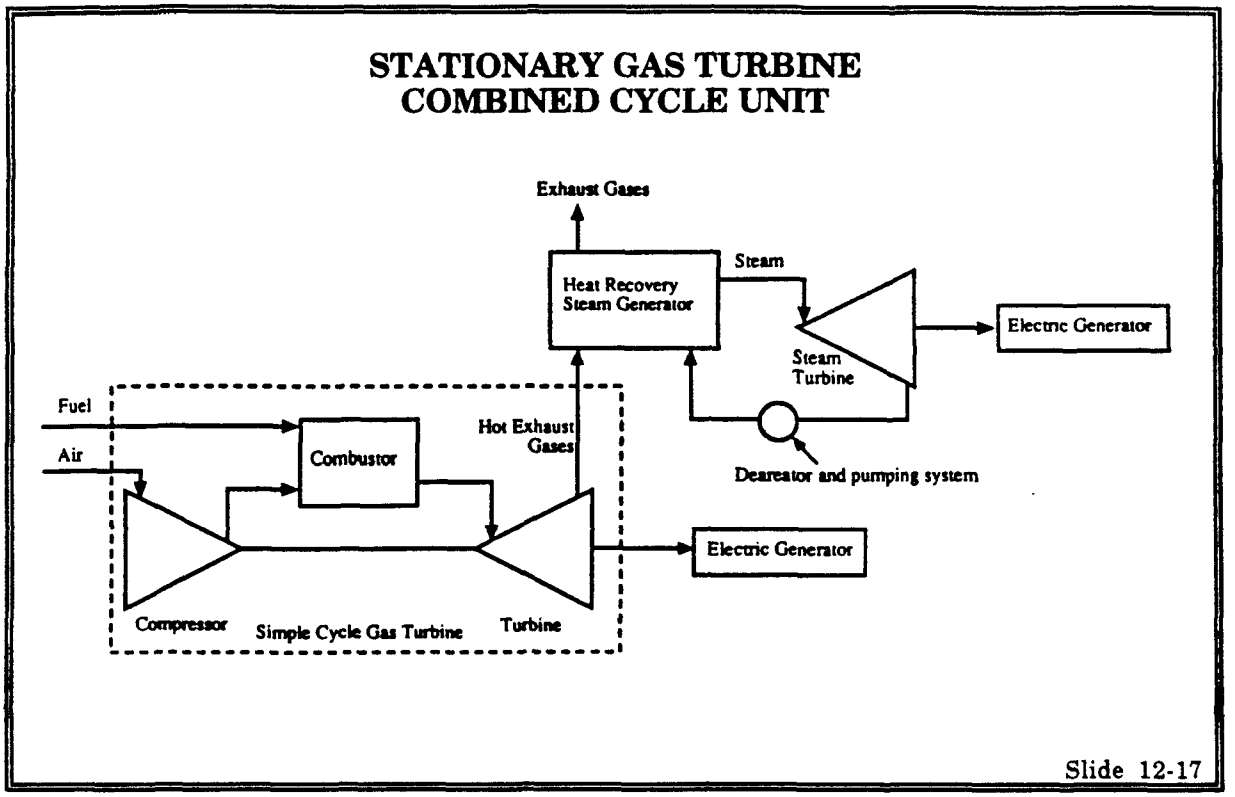
The cogeneration cycle is basically a simple-cycle configuration with a waste heat boiler attached to the system which uses the turbine exhaust gases to produce steam. The waste heat boiler is usually referred to as a heat recovery steam generator (HRSG). As is the case with a fired boiler, an HRSG is capable of producing steam at various temperatures and pressures in order to meet the needs of the customer. Typical exhaust temperatures for gas turbines are on the order of 950°F, thus having limited steam production capabilities. When the exhaust heat energy is not sufficient to meet the steam requirements of the customer, a supplementary burner, or duct burner, can be placed in the exhaust duct upstream of the HRSG to increase the exhaust heat energy. Duct burners can increase the exhaust gas on the order of 500°F and, since the HRSG heat transfer works solely by convection, the driving force is the temperature difference between the exhaust gas and evaporator tubes. Cogeneration can reach thermal efficiencies around 80 percent, however, the efficiency in regards to the conversion of fuel energy input to mechanical power conversion (hp or MW output) still remains around the level of a simple cycle at 30-40 percent.



As mentioned above, the HRSG is similar to a fired boiler. The steam can be used in a process on- or off-site, power a steam turbine used in a mechanical operation, or create electrical power by a generator, or a combination of these. Often, cogeneration units produce a low temperature and pressure steam for process units and use the high temperature, high pressure steam to power a turbine. Due to the variety of steam use, the efficiency in regards to the conversion of fuel energy input to mechanical power conversion can reach as high as 45 percent for some combinations. The highest efficiency is found when all the steam is used for electric power generation in the combined cycle.

Combined Cycle

The combined cycle is the most complex of the gas turbine operational cycles and is a specific form of cogeneration. This cycle consists of a simple-cycle gas turbine to which an HRSG is added to produce steam that is then used to drive a steam turbine to produce additional electric power. As can be expected, the primary users of this cycle are the electric power utilities and independent power producers. The HRSG or boiler used to produce the steam may be supplementary fired to increase steam production and power generation capacity. Due to the imperfect conversion of the thermal energy in steam to electrical energy produced by the generator, typical efficiencies for the combined cycle are around 50 percent.



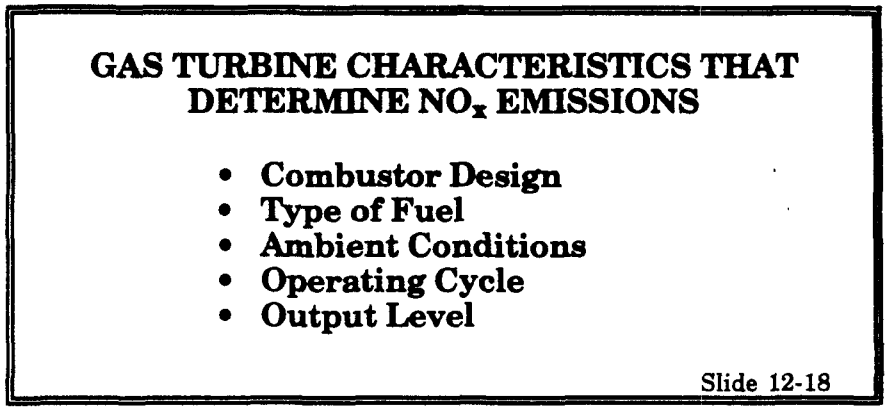
12.5 NO_x Formation Mechanisms

Nitrogen oxides (NO_x) are products of all conventional combustion processes. NO_x is a collective term for nitric oxide (NO) and nitrogen dioxide (NO_2). NO is the predominate form of NO_x produced by GT's, with lesser amounts of NO_2; however, once emitted to the atmosphere, NO converts to NO_2.

NO_x emissions from gas turbines are generated in the primary combustion zone of the combustor. Within the combustor, localized regions of stoichiometric and near stoichiometric fuel/air mixtures exist at high engine power conditions, resulting in high flame temperatures. These high flame temperatures are responsible for most of the NO_x emissions from gas turbines.

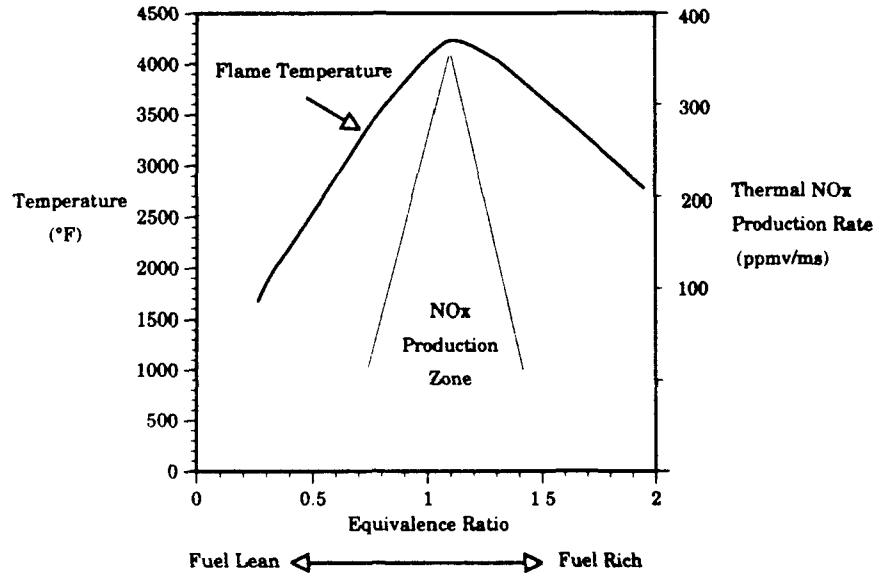
The amount of NO_x formed by a gas turbine is unique to each engine model and its operating characteristics. Gas turbines have a wide range of uncontrolled emissions due to varying designs and operating requirements. Emission factors are based on uncontrolled emission levels provided by manufacturers in ppmv, dry, and corrected to 15 percent O_2, corresponding to 100 percent output load and International Standards Organization (ISO) conditions of 15°C (59°F) and one atmosphere (14.7 psia) ambient pressure and the heat rate of the gas turbine. The uncontrolled full load emission actors range from 0.397 to 1.72 lb/MMBtu (99 to 430 ppmv) for natural gas fired engines and 0.551 to 2.50 lb/MMBtu (150 to 680 ppmv)

for DF-2. CO and UHC emissions, at full load, are usually nominal due to the combustion efficiency and high firing temperatures. SO_2 and particulate emissions are also nominal due to the fact that GT fuels contain very little sulfur or materials that will cause particulate formation. The primary characteristics that determine the engine's NO_x emissions are the combustor design, the type of fuel, ambient conditions, operating cycles, and the output level as a percent of the full power output of the gas turbine.



The combustor design has the greatest effect on the formation of NO_x. One of the functions of the combustor is to mix the fuel and air prior to and during combustion. This mixing will have a direct effect on the local equivalence ratio of combustion where the equivalence ratio is ratio of fuel to air based on the stoichiometric air. An equivalence ratio of 1 indicates a stoichiometric fuel to air ratio. If insufficient mixing occurs there can exist localized near stoichiometric pockets of fuel and air which will burn hotter and create more NO_x. Currently, combustor design is undertaking a trend to lower the amount of NO_x created in the combustor. This technology is called low-NO_x combustion and will be discussed in the Control Option part of this section.

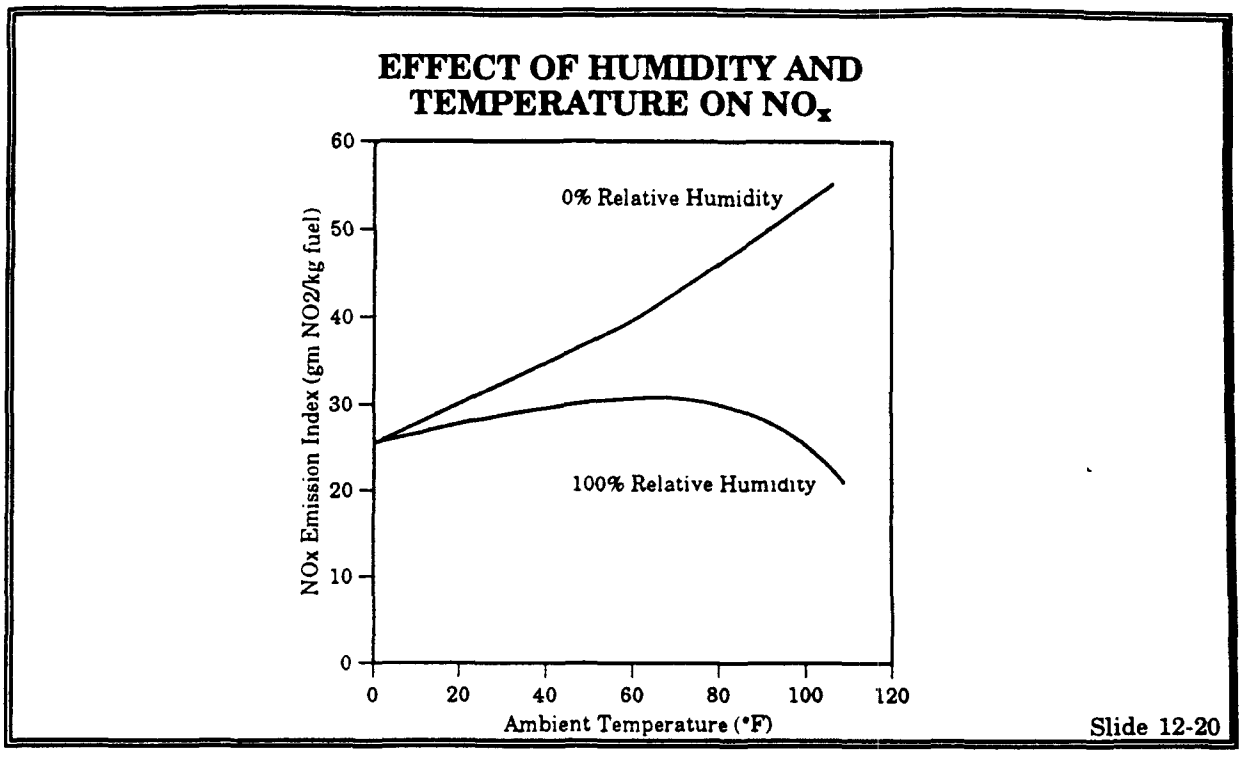
THERMAL NO_x PRODUCTION AS A FUNCTION OF FLAME TEMPERATURE AND EQUIVALENCE RATIO



Slide 12-19

The type of fuel can affect the formation of NO_x. Liquid fuels fired in GT's tend to yield higher emission factors because of the burning properties of the fuel. Gas fuels can be mixed completely with air and can burn in lean conditions, while liquid fuels burn as droplets that burn at near stoichiometric air, and therefore produce more thermal NO_x.

Ambient conditions affect the emissions of gas turbines in several ways. The temperature and pressure can affect the compressor inlet temperature, which will affect the thermal NO_x production by changing the firing temperature of the combustor. Humidity also affects the emissions of GT's by lowering the flame temperature. The water in the air acts as a heat sink and lowers the flame temperature in the combustor lowering the thermal NO_x formation rate, this effect operates on the same principal as water/steam injection for NO_x control.



Operating cycles affect NO_x emissions from a gas turbine at full power. Regenerative cycle gas turbines typically have higher NO_x, typically by a factor of 2 at full power, than a similar simple cycle gas turbine. This is due to the higher combustor inlet temperatures associated with this cycle. In addition, cogeneration cycles and combined cycles which use duct burners to add energy to the exhaust gas have an increased NO_x emission rate on a mass basis. The operation and control of duct burners is driven by measuring the flue gas temperature and comparing it to the optimum temperature. The firing rate would be expected to vary with the load on the turbine. Currently, duct burners are available which will emit approximately 0.1 pound of NO_x per million Btu (lb NO_x/MMBtu) of natural gas burned.

The gas turbine power level also affects the emissions from the engine. As power increases, firing temperature and flame temperature also increase. When the engine is at full load, the flame temperature is hotter and therefore can support nearly complete combustion with very low CO emissions. At the same time, the higher temperatures increase the rate of thermal NO_x production.

12.6 Control Options

CONTROL OPTIONS

Fuel Switching
Water/Steam Injection
Fuel Emulsion
Combustion Modifications
Selective Catalytic Reduction
Oxidation Catalyst

Slide 12-21

Fuel Switching

Fuel switching is predominately conducted to lower the sulfur and particulate content of the fuel, and therefore the sulfur dioxide and particulate emissions from the gas turbine. Most distillate fuels and natural gases have negligible sulfur and particulate contents, and therefore have virtually no sulfur dioxide and particulate emissions. However, some gas turbines may use a lower distillate fuel or a residual oil to fire the gas turbine for short period of time such as when there is a shortage of the preferred grade of fuel.

Water/Steam Injection

Steam or water injected into the primary combustion zone of a gas turbine engine provides a heat sink which lowers the flame temperature and thereby reduces thermal NO_x formation. This injection is described by the water-to-fuel ratio (WFR) evaluated on a mass basis (lb water or steam injected per lb fuel consumed). For water injection, the control system would require a water purification system, pump(s), water metering valves and instrumentation, turbine-mounted injection nozzles, and any necessary interconnecting piping. A steam injection system would require the same items except a steam generator would replace the pump(s).

The WFR is the most important factor affecting the performance of steam or water injection. The injection rate is directly related to the NO_x abatement potential. The higher the WFR, the higher the possible NO_x abatement. For gas-fired units, WFR's for water and steam range from 0.33 to 2.48 to achieve controlled NO_x emission levels ranging from 25 to 75 ppmv, corrected to 15 percent O_2. For oil-fired units, WFR's for water and steam range from 0.46 to 2.28 to achieve controlled NO_x emission levels ranging from 42 to 110 ppmv, corrected to 15 percent O_2. Water-based WFR's are usually lower than the steam WFR for the same NO_x abatement. The latent heat associated with water injection increases the heat sink capability of water injection and therefore lowers the required WFR for a given NO_x reduction level.

From available gas turbine data, steam/water injection is used to achieve NO_x removal efficiencies of 70 to over 85 percent from uncontrolled levels.

The type of fuel burned in the turbine affects the performance of steam or water injection. In general, lower controlled NO_x emission levels may be achieved with gaseous fuels than with oil fuels. For turbines firing distillate oil fuels, steam/water injection has the effect of increasing the conversion of fuel bound nitrogen to NO_x. This would not be anticipated to affect the emissions from gas turbines (GTs) which burn fuels with fuel bound nitrogen levels of typically less than 0.015 weight percent.

Water and steam injection do affect the performance and maintenance of the gas turbine. Since gas turbine power is based on mass through-put, the power output of the engine will increase from the use of water or steam injection. Also, the percent overall efficiency will decrease. For water injection, the fuel energy required to vaporize the water in the turbine combustor results in a larger loss than for steam injection. The change in output and efficiency will change depending on the WFR and the whether the injection fluid is steam or water. In general, a WFR of 1.0 with water causes a 5 percent increase in power output and less than 3 percent loss of overall efficiency. Water or steam injection can increase erosion and wear in the hot section of the turbine, thereby increasing maintenance requirements. The impact depends on the WFR and the model of gas turbine. Some manufactures do not recommend a short time between inspections for water or steam, and others recommend decreased inspection intervals for water injection only.

Maintaining the water/steam injection system is critical to GT operation and emission control. If a WFR is too high, this can decrease flame stability. If a WFR is too low, this can hamper NO_x reduction. Also, water purity is extremely important to combustor and turbine maintenance. If the water is not clean enough, the contaminants can erode the combustor or turbine more quickly than normal operation. The water purification is usually a separate on-site plant with its own operators and support staff. Steam injection usually does not require the same level of purification due to the distillation that occurs during steam production.

Fuel Emulsion

The use of a water-in-fuel emulsion is a more recent NO_x control technique developed for the gas turbine industry. The process reduces NO_x by lowering the peak flame temperature in precisely the same manner as steam/water injection discussed above. The water-in-fuel suspension allows a more ideal heat absorption to occur due to both the homogeneous nature of the emulsion and the ideal location of the water in close vicinity to the burning fuel droplet. Additionally, the process creates the emulsion prior to injection and combustion. In contrast, the steam/water injection fluid forms a heterogeneous post-combustion mixture where fuel predominates in some areas of the flame and the steam/water predominates in others.

The fuel emulsion homogeneous mixture allows for a lower WFR than in traditional steam/water injection. The emulsion WFR ranges from 20 to 50 percent and is stabilized with chemical additives to maintain the emulsion at the high temperature and pressure associated with injection. The process uses similar hardware as in water injection, with additional equipment for the emulsification, chemical stabilizer, storage, and injection systems (including metering valves and instrumentation). This system can be retrofitted onto existing fuel delivery systems.

Similarly to water/steam injection, the emulsion process is more operator intensive due to chemical addition and storage. Precise measurements of water, fuel and chemical stabilizers are necessary to ensure proper GT operation and NO_x reduction. Again, a fuel-emulsion system would likely be a separate on-site facility which prepares the emulsion just prior to combustion.

Combustion Modifications

The formation of NO_x depends on the operating conditions of the combustor, so it follows that altering the combustor to minimize the conditions which cause NO_x formation will lower the NO_x emissions from the combustor. Several designs have been developed to minimize the NO_x formation mechanisms within the combustor: Lean combustion and reduced residence time; lean premixed combustion; and dual staged rich/lean combustion.

COMBUSTION MODIFICATIONS TO LOWER NO_x EMISSION RATE

Lean Combustion and Reduced Residence Time
Lean Premixed Combustion
Dual-Staged Rich/Lean Combustion

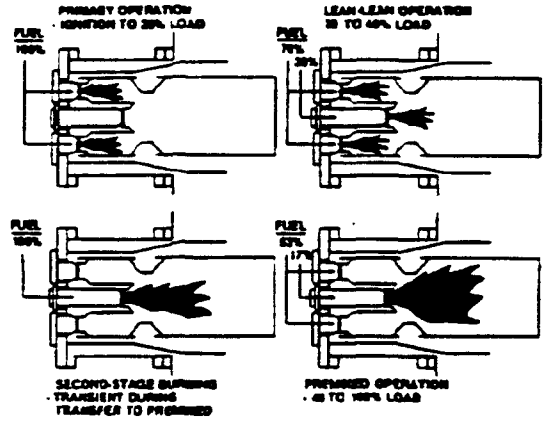
Slide 12-22

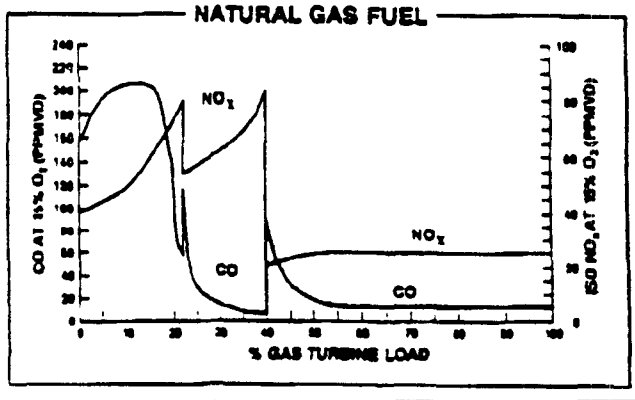
Lean combustion, coupled with reduced residence time of the fuel in the primary combustion zone, operates with a low equivalence ratio. In conventional combustors, the primary zone operates near equivalence ratios of 1 (near stoichiometric fuel to air ratios) and near the maximum NO_x formation rate. Lean combustion operates with excess air, which acts similarly to water/steam injection in that it provides a heat sink to cool the flame and reduce the NO_x formation rate.

In a conventional gas turbine combustor, the fuel and air are mixed in the combustion zone and fuel/air mixing and combustion take place simultaneously. In a

lean premixed combustor, the fuel and air are premixed prior to combustion to ensure complete mixing and the creation of a homogeneous mixture. This reduces the NO_x producing stoichiometric fuel sections. Also, the additional air acts as a heat sink to maintain a cooler flame temperature, which limits the formation rate of NO_x. The implementation of pre-mixing a fuel lean mixture can greatly reduce the NO_x formation rates.

LOW NO_x STAGING AND NO_x CONCENTRATION PROFILE





Slide 12-23

The level of NO_x emissions reduction achieved by using lean premixed combustion varies depending on the manufacturer and the type of combustor. However, emissions at full power range from 25 ppmv, at 15 percent O_2, to as low as 9 ppmv, at 15 percent O_2. Most of the combustors designed to date are used on GT's of 10 MW or larger. Only one of the manufacturers offers lean premixed combustors on units smaller than 10 MW. Unfortunately, these emission reductions are capable when firing natural gas fuel, and the reductions when firing oil fuels is not as successful. Currently water/steam injection and water-in-fuel emulsion are the only technologies to reduce NO_x when firing oil fuels.

The dual-staged rich/lean combustor configuration is a more complex system, with the potential for a more stable flame. One configuration indicative of the basic approach is a combustor developed for use on aircraft engines. This design incorporates a rich burn area which incompletely burns the fuel, promoting flame stability. The flame is then quenched and diluted with the pressurized air from the compressor section of the engine. The combustion is then completed in the lean burn section of the combustor. These three sections of the combustor employ variable geometry to maintain the local stoichiometry within the design operating limits and allow for optimization of airflow splits to each combustion zone. Currently, it is estimated that this combustor can lower NO_x emissions to one-tenth the present level and is effective in limiting both fuel NO_x and thermal NO_x. However, this technology has not been applied to gas turbines but has been designed for turbine-based aircraft engines and is applicable to the gas turbine industry.

A GT incorporating combustion modifications would not need the vast support of operators that the water/steam injection or fuel emulsion would require. Most combustion modifications would operate on the same computer system with additional software to monitor the staging operations.

Selective Catalytic Reduction

SCR is a post-combustion NO_x control technology which employs a highly reaction-specific process which reacts NO and NO_2 with ammonia over a catalyst, enabling the following reaction to occur.

SCR REACTION

$$NO + NH_3 + 1/2\ O_2 \longrightarrow N_2 + 3/2\ H_2O$$
$$NO_2 + 2\ NH_3 + 1/2\ O_2 \longrightarrow 3/2\ N_2 + 3/2\ H_2O$$

Slide 12-24

The products of the reactions under idealized conditions are nitrogen and water. However, under practical conditions, the reaction is not complete and results in some unreacted ammonia (NH_3 slip) and NO in the exiting flue gas.

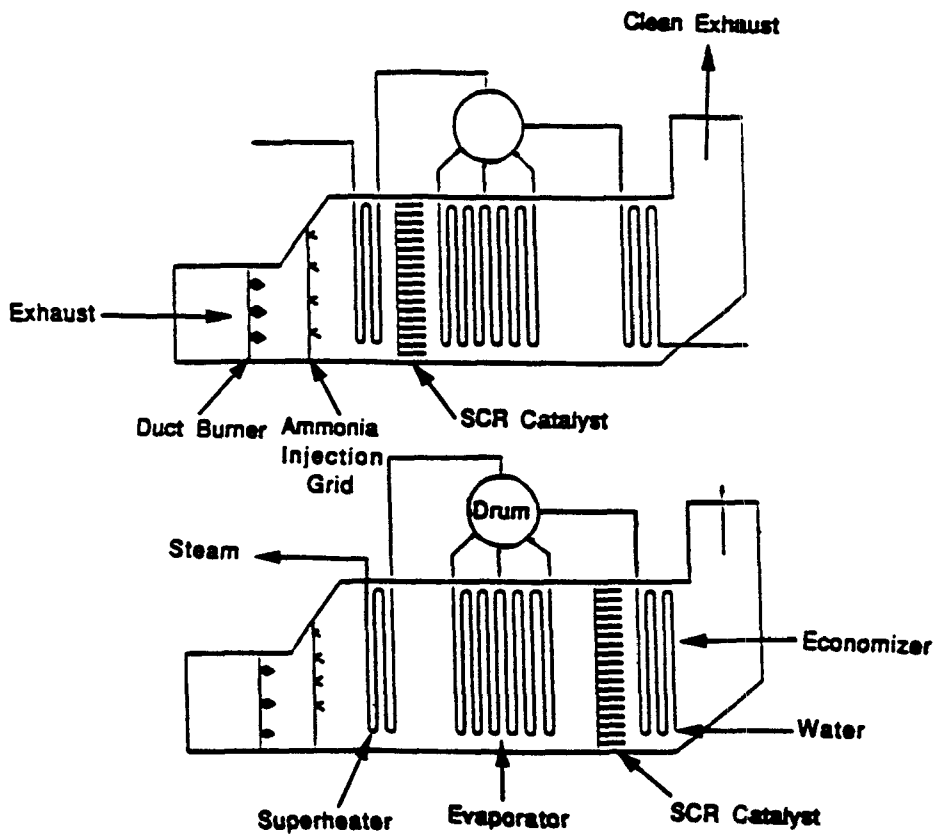
The purpose of the catalyst is to lower the temperature in which these reactions occur. Typically these reactions will occur at 1800°F. Gas turbine exhaust is on the order of 1000°F and would require a considerable amount of reheat fuel to obtain the necessary temperatures for the reactions to occur. Although the catalyst does lower the temperature at which the reactions will occur, the temperature window is usually quite narrow, around 100 to 150 °F. There are several types of catalysts available for use. Platinum, base metal oxides, such as titanium dioxide

and vanadium pentoxide, and zeolite are all present day catalysts and each has a specific and different temperature operating window.

The cycle and purpose of the gas turbine will determine which catalyst will be the best for the systems. The zeolite catalyst can operate at temperatures on the order of 1000°F and is effective for simple-cycle gas turbines because of the exhaust temperatures of a gas turbine and the lack of an HRSG. Both the platinum and base metal oxide catalysts have operating temperatures from about 300°F to 550°F and would require the exhaust gas to be cooled. These catalysts are usually used when an HRSG is present and are located in the HRSG boiler tube section at the appropriate temperature.

The catalyst structure is placed with the exhaust structure or HRSG at the appropriate location to ensure proper operating temperature across the catalyst. The catalyst structure has several different designs, but each is designed to maximize catalyst surface area and flue gas residence time over the catalyst as well as to minimize the back pressure caused by the catalyst. Most catalysts sold today can limit the back pressure to less than 2 inches water gauge.

POSSIBLE LOCATIONS FOR SCR UNIT IN HRSG



Slide 12-25

In addition to the catalyst, an SCR system has an ammonia injection grid. The injection grid is placed upstream so that the ammonia will be thoroughly mixed with the exhaust and a minimum amount of ammonia will escape into the atmosphere. Ammonia is injected at a NH_3/NO_x molar ratio of about 1. Ammonia is stored in one of two forms, an anhydrous gas under pressure or an aqueous solution of typically 27 percent ammonia by weight. The ammonia is vaporized and diluted, usually with air, and added to the exhaust.

Due to the operating nature of SCR, it requires tight controls so that reduction efficiency is maximized and ammonia slip is minimized. Most SCR systems use CEMs to monitor outlet emissions such as NO_x before and after the catalyst and NH_3 after the catalyst to maintain proper operation. Due to the tightly controlled nature of SCR, it is only applicable to steady stream operation (meaning a gas turbine that operates at a constant load). An SCR system would also require additional operators for the maintenance of the CEMs and the ammonia storage and injection system.

Although the NO_x reduction potential of SCR is on the order of 90 percent, there are considerations which need to be mentioned. Some of the catalyst materials are considered hazardous. Because the catalysts have a finite life, up to 10 years with natural gas-fired units and as high as 6 years with oil fired units, disposal considerations are of concern. Some catalyst manufacturers do recycle spent catalyst, and others dispose of it. Usually, SCR is not used when firing the gas turbine with high sulfur and high soot bearing fuels. Sulfur can react with the NH_3 to form a salt which can coat the catalyst or the HRSG, decreasing the efficiency of both. Soot can also coat the catalyst and decrease its reduction potential.

As mentioned above, SCR can reach NO_x reductions of 90 percent. However, only one facility in the U.S. uses SCR alone. All other SCR systems applied to GT's use SCR mostly in combination with water or steam injection. Water and steam injection can lower the NO_x level to the 25 to 42 ppmv, at 15 percent O_2 range, then SCR can lower the NO_x to levels as low as 1 and 2 ppmv, at 15 percent O_2, but can maintain NO_x levels around 4 to 9 ppmv, at 15 percent O_2.

Oxidation Catalyst

An oxidation catalyst can be used to lower the CO and UHC emissions. Most oxidation catalysts are used in conjunction with water/steam injection and SCR and are necessary due to high WFR which inhibits complete combustion. The oxidation catalyst operates at high temperatures, on the order of 900 to 1000 °F, and is usually located prior to duct burners, ammonia injection grid, boiler tubes, and the SCR system. Oxidation catalysts do not use an additive and lower both CO and UHC emissions to the 1 ppm level, at 15 percent O_2, and usually do not require additional operators.

REFERENCES

1. U.S. Environmental Protection Agency. Alternative Controls, Techniques Document — NO_x Emissions from Stationary Gas Turbines. Research Triangle Park, NC. Publication No. EPA-453/12-93-007, January 1993.

2. Report to U.S. Environmental Protection Agency. Data Analysis Report. Prepared by Energy and Environmental Research Corporation, Durham, NC. Contract No. 68-D1-0117. December 23, 1992.

3. U.S. Environmental Protection Agency. Standards Support and Environmental Impact Statement, Volume 1: Proposed Standards of Performance for Stationary Gas Turbines. Research Triangle Park, NC. Publication No. EPA-450/2-77-017a, September, 1977.

4. Draft Report to U.S. Environmental Protection Agency. Methods to Reduce NO_x Emissions from EUAETC's. Prepared by Energy and Environmental Research Corporation, Durham, NC. Contract No. 68-D1-0117, July 1993.

CHAPTER 13. PACKAGE BOILERS

13.1 Introduction

13.2 Package Boiler Types
- A. Firetube
- B. Watertube
- C. Cast Iron Sectional

13.3 Emissions

Slide 13-1

13. PACKAGE BOILERS

13.1 Introduction

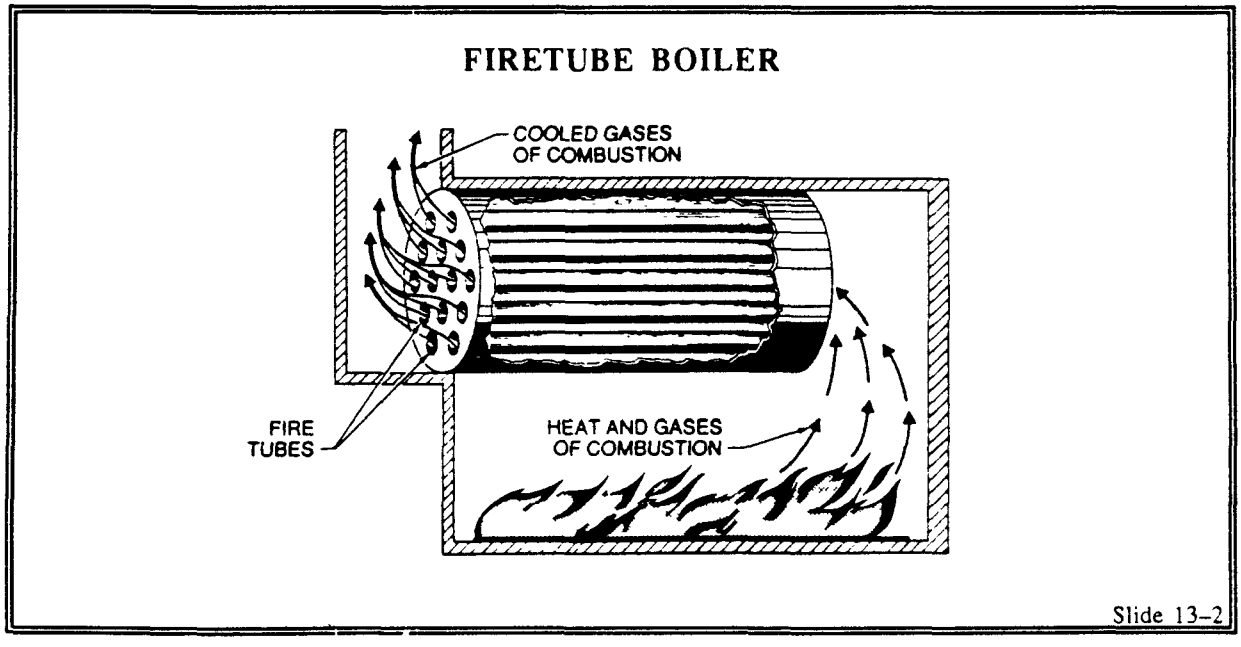
In the late 1940's, the demand for industrial boilers combined with increasing costs of field assembled equipment led to the development of the shop-assembled package boiler.[2] These boilers are used in manufacturing, refining, and mining industries to provide steam, hot water, and electricity. Package boilers range in size up to 600,000 lb/hr of steam at conditions ranging from 2 psig and 215°F to 1800 psig and 1000°F.[4] In many applications, multiple package boilers are used to provide the required steam to the process. This chapter will present the common package boiler designs, and their pollutant emission characteristics. Normal operation and maintenance are addressed in Chapters 14 and 19, respectively.

13.2 Package Boiler Types

There are three major package boiler designs: firetube, watertube and cast iron. Each of these boiler types are described in the following sections.

Firetube

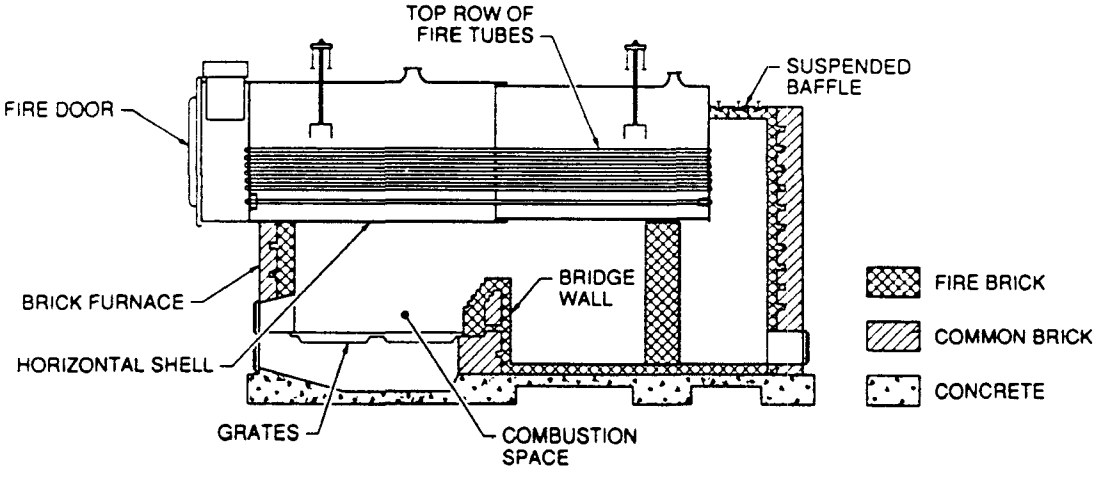
In a firetube boiler, the hot gases of combustion pass through tubes whose outside surfaces contact the boiler water. An internally-fired firetube boiler is a boiler with a furnace area surrounded by the water/steam filled pressure vessel.



The advantages of firetube boilers are that they are compact, low in initial cost, and easy to modularize based on plant requirements. The disadvantages are that they are slow to respond to changes in demand for steam (load) compared to watertube boilers, and circulation is slower. Also, stresses are greater in firetube boilers because of their rigid design and subsequent inability to expand and contract easily. Firetube boilers usually range in size from less than 2 to 50 million Btu per hour. Most industrial firetube boilers are either horizontal return tube (HRT), scotch marine, or firebox.

A horizontal return tube (HRT) boiler has a separate furnace area that is built of refractory brick. In a HRT boiler, the firetubes are horizontal. Typically, these boilers were originally designed to burn solid fuels. The fuel firing burner assembly is at one end, and the products of combustion are recirculated or "returned" to make two, three, or four passes through the tubes surrounded by the boiler water. A HRT is classified as an externally-fired firetube boiler since the furnace area is separated from the heat transfer area. The boiler is encased with brick, and the furnace is set on rollers or suspended on hangers to allow for expansion and contraction which occurs when the boiler increases and decreases in temperature. These types of boilers are found in older installation with some retrofitted to burn oil and/or gas, but generally these boilers have been replaced with the scotch marine boiler design.

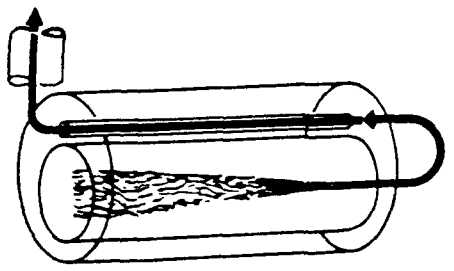
HORIZONTAL RETURN TUBE BOILER[1]



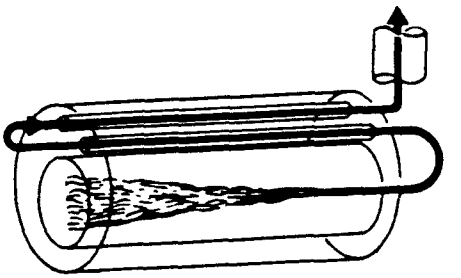
Slide 13-3

Scotch marine boilers are an example of internally-fired firetube boilers. The original scotch marine boilers were used on ships and typically fire natural gas or fuel oil to maximize the convenience of automatic operation. A scotch marine boiler has a water cooled flue furnace within a horizontal shell. The flue furnace is composed of a large tube or pipe, usually corrugated, that passes through the length of the shell. The fuel burner is located at the front end of the flue so that the combustion flame extends across most of the length of the flue. The combustion gases first pass through the furnace tube, heating the bottom of the water basin, and then pass through the fire tubes, heating the water in the basin. Scotch marine boilers may be designed in two-, three-, and four pass units, as shown in Slide 13-4.

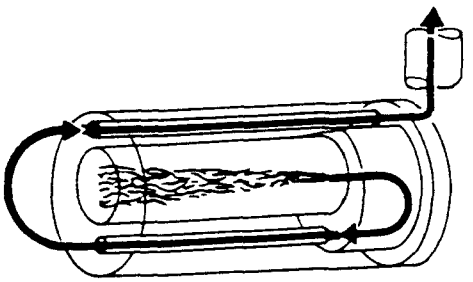
MULTIPLE PASS FIRETUBE BOILER ARRANGEMENTS[1]



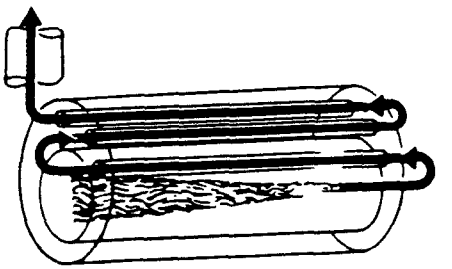
2-pass Dryback



3-pass Dryback



3-pass Wetback



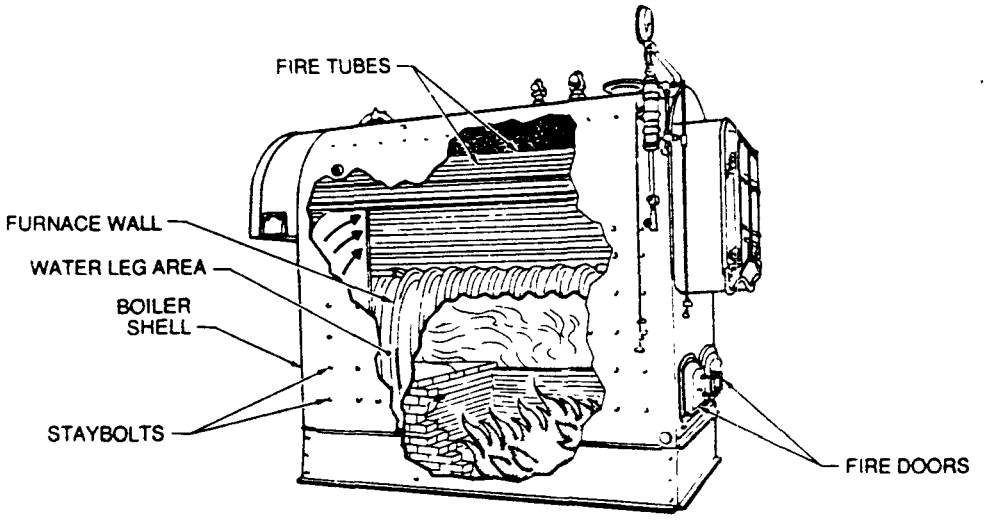
4-pass Dryback

Slide 13–4

Typically, the scotch marine boiler is a forced draft configuration. Package boilers typically have fully automated burner control tied to a single element of the process (i.e. steam temperature). The burners described in Chapters 7 and 8 can be applied in firetube boilers as well as watertube. For any application, the flame pattern needs to be designed so that flame impingement on the internal boiler surfaces is avoided.

A firebox boiler is a firetube boiler in which the furnace is surrounded on the sides by water leg area. The water space is extended downward so that the furnace walls are surrounded by water. These flat, side water leg areas are supported by staybolts to prevent them from bulging. These types of boilers are no longer built due to the design integrity of the staybolts. Coal or other fuels (for example, wood waste and paper waste) may also be burned depending upon the design of the furnace. Early firebox boilers burned coal, but most firebox boilers still in operation have been converted to burn natural gas or fuel oil for convenience.

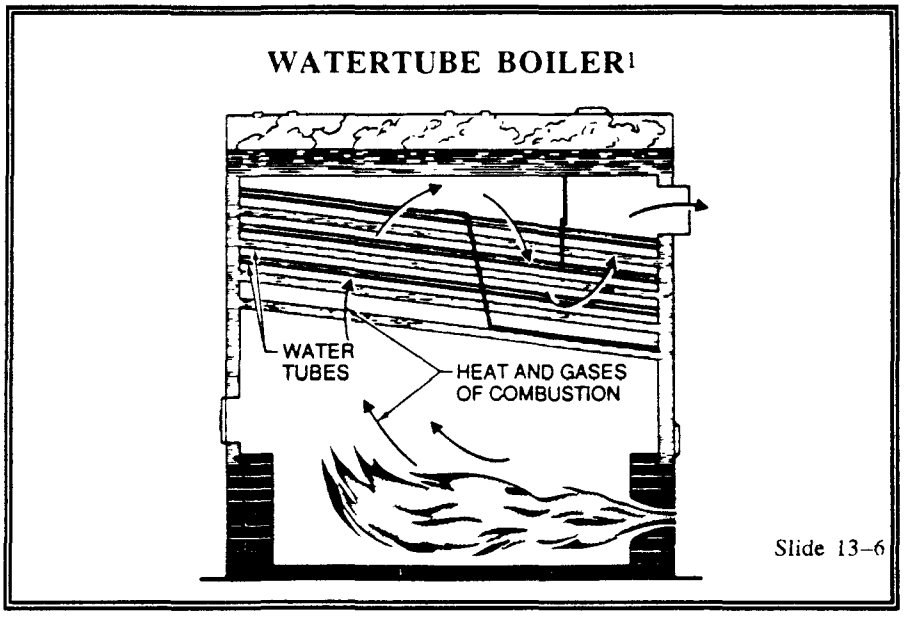
FIREBOX BOILER[1]



Slide 13-5

Watertube

The original design of a water tube boiler circulates the water through tubes with the hot combustion gases passing over the outside surfaces of the tubes, as shown in Slide 13-6. The advantages of watertube boilers are that they are rapid steamers and respond quickly to changes in demand for steam due to improved water circulation. They can withstand much higher operating pressures and temperatures than firetube boilers. Their design is safer, since failure of one tube will not result in an explosion, as is possible with firetube boilers. Additionally, they can burn a wide variety of fuels. Also, watertube boilers expand and contract more easily than firetube boilers. The disadvantage are that they are more expensive to install. They also require more complicated furnaces and repair techniques.

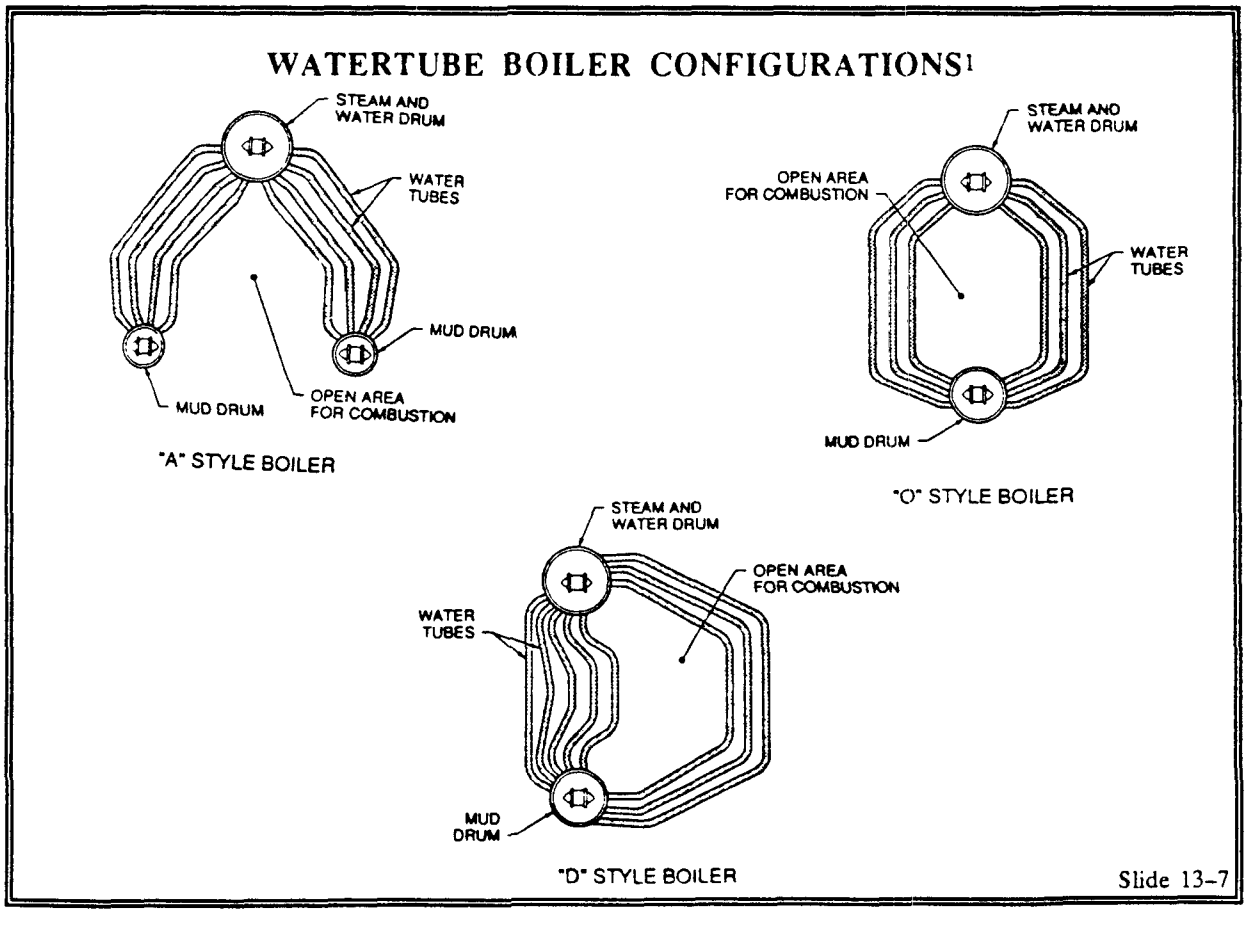


There are several common designs for watertube boilers. All of these recirculating type of designs incorporate, risers, downcomers, a steam and water drum and a mud drum as discussed in Chapter 2. The purpose of the steam and water drum is to allow separation of the steam from the water. The purpose of the mud drum is to collect the sediments found in the boiler water for removal during the boiler blowdown.

An "O" style boiler is a watertube boiler with a top steam and water drum and a bottom mud drum. These are interconnected by banks of symmetrical tubes in an "O" shape. The burner is in the center of the "O", as shown in Slide 13-7. This boiler can be made with a waterwall furnace, which is a popular configurations for package type boilers. An "O" style boiler commonly burns natural gas and fuel oil.

An "A" style boiler is a watertube boiler with a top steam and water drum and two bottom mud drum. The steam and water drum is connected to the mud drums by banks of symmetrical tubes in a "A" shape. This is a popular configuration for package types.

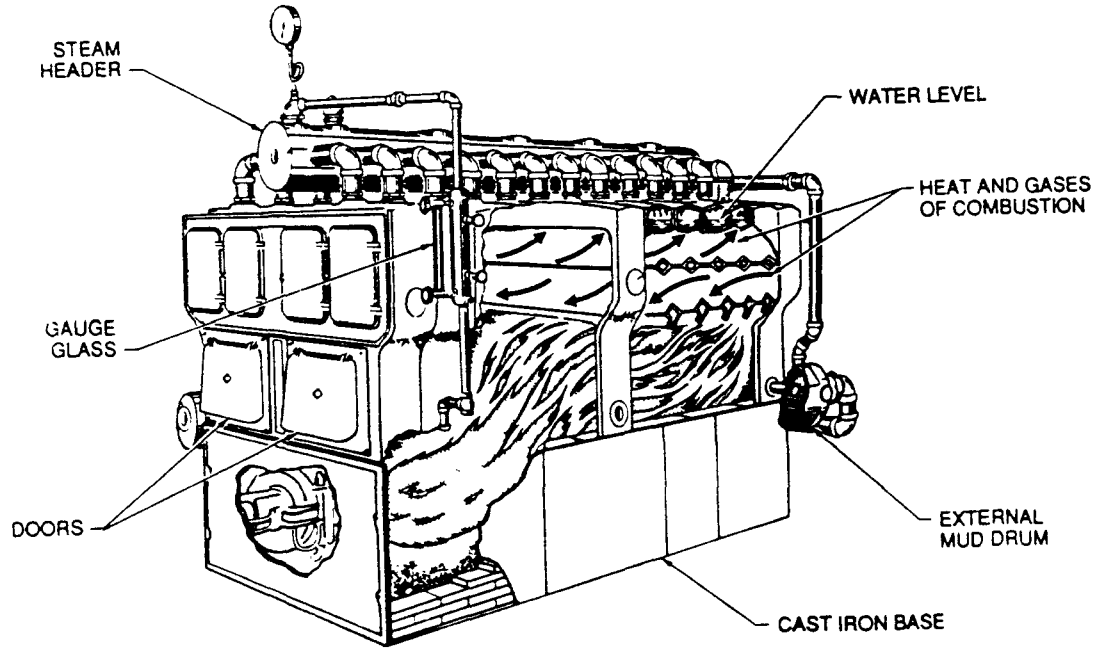
A "D" style boiler is a watertube boiler similar to the "O" style except that the steam-generating tubes on one side are extended to leave an open area close to the center. This area is for the combustion of the fuel. The two sides are separated by a baffle so that the gases pass to the rear on the combustion side and then turn back toward the front for the convection side. There is either a top or side outlet for the gases to leave the unit.



Cast Iron Sectional Boilers

In cast iron boilers, the hot gases pass through tube sections surrounded by water circulating outside the tubes. These individual sections are interconnected to form one unit. The primary advantage to sectional boilers is the ability to assemble the boiler in locations where access is limited (i.e. building basements). The units are constructed of cast iron rather than steel. The leading cause of failure in cast iron boilers is the corrosion and failure of the connection of these sections. Cast iron boilers are used to produced either low-pressure steam (15 psig) or hot water, and range in size from 30,000 to 10 million Btu per hour. Thus, cast iron boilers are most commonly used in domestic heating or small commercial applications.[3]

CAST IRON SECTIONAL BOILER[1]

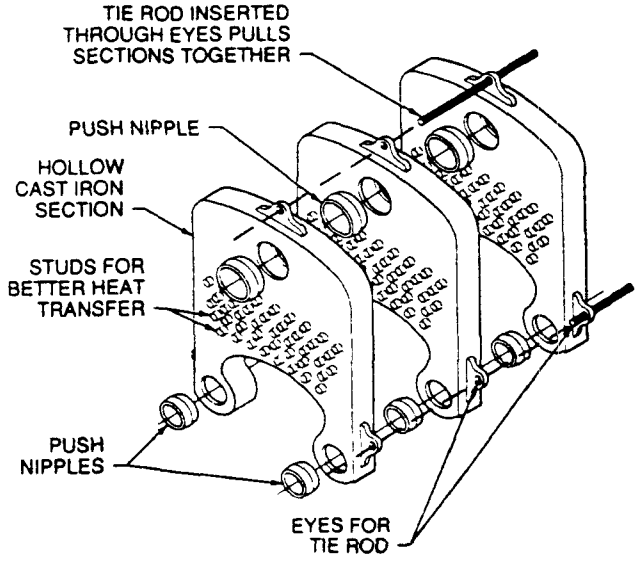


Slide 13-8

A push-nipple cast iron section boiler contains a hollow cast iron section joined with tapered nipples and pulled together with tie rods or bolts, as shown in Slide 13-9. These cast iron sections are individually connected to the manifold; if a section develops a leak, the boiler must be dismantled to replace the individual section.

An external header cast iron sectional boiler contains cast iron sections individually connected to external headers with screwed nipples. If a section in the boiler develops a leak, individual section can be replaced without disturbing the other sections.

PUSH-NIPPLE CAST IRON SECTION[1]



Slide 13-9

13.3 Emissions

The emissions from a package boiler depend on the fuel being burned and the design of the boiler. The emissions from package boilers include NO_x, SO_x, CO, total hydrocarbons (THC), particulate matter, and trace elements. The emissions from watertube boilers has been given in the previous chapters dedicated exclusively to natural gas-fired, oil-fired, and coal-fired boilers. In slide 13-10, a summary of the emissions measured from firetube boilers during an EPA study is presented. The results have been normalized on a pound of emission of the pollutant per million Btu per hour thermal input (lb/MMBtu).

FIRETUBE BOILER EMISSIONS[5]

Fuel	NO_x (lb/MMBtu)[a]	CO (lb/MMBtu)	THC (lb/MMBtu)
Natural Gas	0.07 to 0.13	0.0 to 0.784	0.004 to 0.117
Distillate Fuel Oil	0.11 to 0.39	0.0 to 0.014	0.012[b]
Residual Fuel Oil	0.21 to 0.39	0.0 to 0.023	0.002 to 0.014

[a] To convert to ppm @ 3% O_2, multiply by the following: NOx, 790; CO 1300; THC, 2270

[b] Single data point

Slide 13-10

REFERENCES

1. Wilson, R. Dean, *Boiler Operator's Workbook*, American Technical Publishers, Inc., 1991.

2. Elliott, Thomas C., *Standard Handbook of Powerplant Engineering*, McGraw-Hill, Inc., 1989.

3. "Fossil Fuel Fired Industrial Boilers - Background Information", Volume 1: Chapter 3, EPA-450/3-82-006a, March, 1982.

4. *Steam, Its Generation and Use*, 40th Edition, Babcock & Wilcox, 1992.

5. "Alternative Control Techniques Document -- NO_x Emission from Industrial/Commercial/Institutional (ICI) Boilers," US EPA, EPA-453/R-94-022, March, 1994.

CHAPTER 14. NORMAL OPERATION

14.1 Introduction

14.2 Maintaining Suitable Combustion Conditions
- A. Fuel Supply
- B. Combustion Air Supply
- C. Flame Appearance

14.3 Monitoring Combustion
- A. Combustion Air Flow
- B. Combustion Air Temperature
- C. Combustion Air Pressure
- D. Combustion Fuel
- E. Combustion Flue Gas Monitoring

14.4 Maintaining Steam Temperature and Pressure

14.5 Maintaining Suitable Feedwater Conditions

14.6 Monitoring the Steam/Water Circuit
- A. Regular Operation/Maintenance
- B. Low Water Level Concerns
- C. High Water Level Concerns

14.7 Controlling the Steam Temperature
- A. Desuperheater
- B. Burner Tilt
- C. Flue Gas Recirculation
- D. Soot Blowing

14.8 Startup Procedures

14.9 Shutdown Procedures

14. NORMAL OPERATION

14.1 Introduction

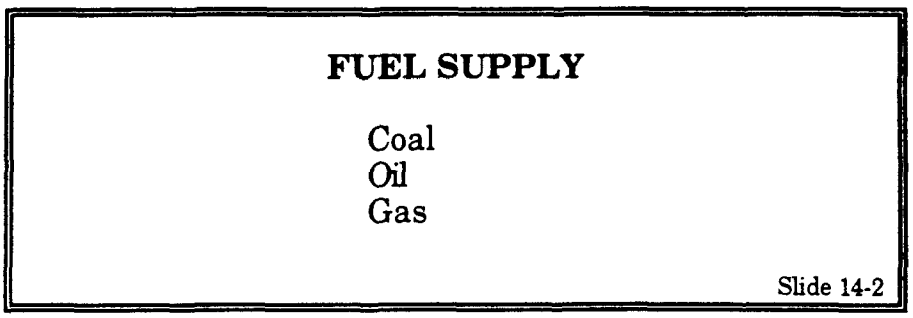
The boiler operator's primary duties when operating a boiler furnace are safety, fuel efficiency, and meeting emissions standards. Safety is the boiler operator's first consideration. The boiler operator prevents fires and explosions by keeping the flame safety system in good working order. Secondly the boiler operator optimizes furnace efficiency by adjusting equipment to maintain the proper ratio of air and fuel to the furnace as needed to satisfy steam demand. Finally, the boiler operator monitors flue-gas conditions at the stack to insure compliance with the allowable stack emissions standards. The following discussion will address the operating parameters an operator needs to monitor for normal operating conditions, as well as start-up and shut-down conditions.

Since there are many types of boilers and they vary in size, capacity, design, operating procedures, etc., this course will provide a general description of boiler operation. The specific onsite training and manufacturer/vendor recommendations should take precedence. The purpose of this chapter is to highlight the most important operating parameters to monitor and control.

14.2 Maintaining Suitable Combustion Conditions

As discussed in earlier chapters, combustion is accomplished by mixing fuel and air at elevated temperatures. The air supplies oxygen which unites chemically with the carbon and hydrogen in the fuel to produce heat. Though most boilers today control the combustion process automatically, it is important for the operator to know what conditions are required for proper combustion and how to use the equipment available to maintain these conditions. Suitable combustion conditions result from monitoring the fuel supply, combustion air supply and flame appearance.

The supply of fuel to the boiler is as important as the supply of water for steam generation. It is the responsibility of the operator to ensure a good quality fuel is supplied to the boiler at all times.



Coal

If it is a coal burning plant, the level of the coal bunkers should be checked at the beginning and end of the shift. The conveying equipment should be checked for proper transport of coal and wear as coal is very abrasive. If the boiler is a stoker type (retort, traveling grate, or vibrating grate) then the level of coal in the hopper must be sufficient to feed the grate evenly during the combustion period. When burning coal the ash is usually discharged into an ashpit located below the boiler. The ashpit is usually big enough to hold the ash that is produced during one eight hour shift, however, it must be emptied frequently as an excessive amount of ash or refuse in the furnace ashpit will blank off the air and cause the grates to overheat.

When burning pulverized coal, the coal is supplied to the burners through pulverizing mills. On units using pulverizer mills, the feed to the mills is controlled automatically in response to steam demand. Most mills require very little maintenance. However, if the mill becomes excessively noisy or the fuel supply to the burners becomes erratic, then the mill must be taken out of service and inspected.

Oil

If burning oil, the level in the supply tanks should also be checked at the beginning and end of a shift. If it is necessary to switch fuel oil tanks during a shift, a sample must be taken from the tank that is to be used *(prior to switching)* to check for water or other contaminants. Fuel oil comes in six grades numbered 1 to 6. No.1 is the lowest viscosity and No.6 is the highest. When fuel oils 1,2, or 3 are used no preheating is required. When using fuel oils 4, 5, or 6 steam or electric heating coils are usually placed in the storage tanks to heat the fuel so the viscosity is low enough to be atomized properly at the burner tip. Most fuel oil supply systems have duplex strainers installed between the storage tanks and the suction side of the supply pumps. These strainers should be switched and cleaned by the operator at least once a shift or more often if required. The burner tips should be cleaned and inspected at least once a day when firing 24 hours a day.

Gas

Gas fuels are available as natural, manufactured, oil gas and by-product gases such as coke-oven, blast-furnace, and refinery gas. Gas is supplied to the boiler house via pipelines and the pressure in these lines is either above or below that which is required by the burner. If the pressure is above, then the gas to the burners must go through a reducing station. If it is below, then the gas must go through a booster compressor. The operator must ensure the supply pressure is constant and sufficient to promote good combustion. The maintenance of gas burning equipment is less than that for coal or oil but there are still areas which require the operators' attention. The air-register operating mechanisms and gas regulators must be kept in good operating condition. The burners must be kept clean and the boiler casing must be checked to reduce air leakage to a minimum.

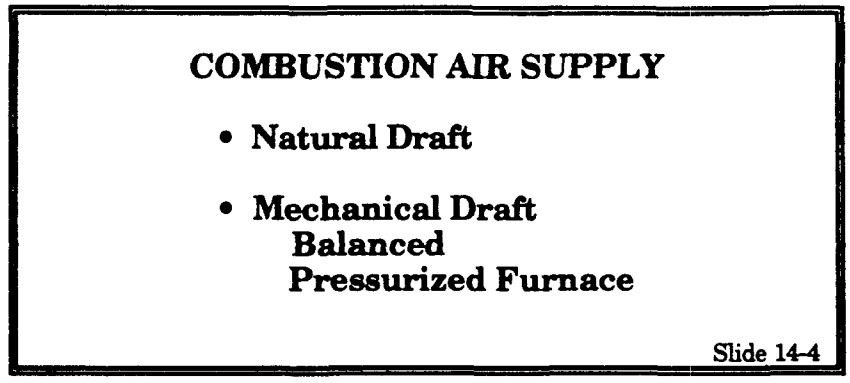
Slide 14-3 is a checklist summarizing the actions required to maintain fuel supply systems.

FUEL SUPPLY CHECKLIST

FUEL	EQUIPMENT	ACTION	FREQUENCY
Coal	Coal Bunkers	Check level	Start and end of shift
	Conveying Equipment	Check for wear	Once a shift
	Coal Hopper	Check level	Once an hour
	Ash Pit	Check level and empty	Once a shift / as required
	Pulverizer Mills	Visually inspect and ensure constant supply of fuel to burners.	Once an hour
Fuel Oil	Storage/Supply Tanks	Check level	Start and end of shift
	Duplex Strainers	Switch and clean	Once a shift / as required
	Burner Tips	Clean and inspect	Once a day
Gas	Reducing Station or Booster Compressor	Ensure proper inlet and outlet pressure	Once an hour
	Burner Air Register	Inspect and check for proper operation	Once a shift
	Burner Tip	Clean and inspect	Once a day
	Boiler Casing	Inspect for air leaks	Once a shift

Slide 14–3

Combustion air is supplied to the furnace through natural draft or mechanical draft. It is the operators responsibility to ensure an unrestricted flow of air through the furnace and flue gas out of the stack.



Natural draft is produced by a properly sized stack which pulls air into the furnace and discharges the products of combustion into the atmosphere. The draft is caused because the hot gases inside the stack are lighter than the surrounding air causing the gases to rise and exit. As the hot gases exit, air is pulled in, through the furnace, to replace it.

There is usually a stack damper located between the base of the stack and the outlet of the furnace. It is the operators responsibility to make sure the damper is positioned properly to balance the flow of air with the fuel so good combustion can take place. If the damper is fully open and draft is still low then the following conditions could exist:

1. Boiler passes covered with soot, slag, or fly-ash,

2. Defective or shifted baffles restricting the flow of gases.

3. Air leaks.

4. The stack damper out of adjustment even though the outside arm indicates it is full open.

5. The flowmeter is out of adjustment and the boiler is operating at higher rates than indicated.

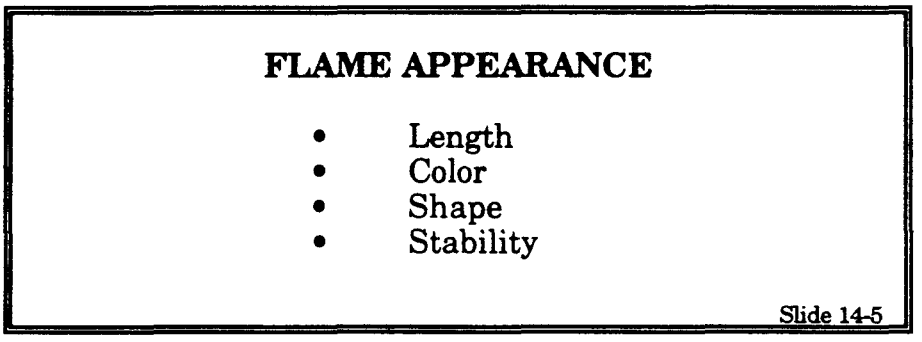
Boilers may operate with a furnace pressure that is positive (higher than atmospheric) or negative (less than atmospheric). Natural draft furnaces are negative pressure furnaces while mechanical draft furnaces may be either positive or negative. Mechanical draft is produced by two methods. The first method is known as *Balanced draft*, in which a forced draft fan delivers air to the furnace and an induced draft fan produces the draft to remove the gases from the unit. These types of boilers commonly operated at a negative pressure ranging form -0.1 in to -0.5 in of

water. In very large boilers, furnace implosions can occur if the boiler I.D. fan is providing excess suction when the boiler is at low load.

The second method is known as a *Pressurized furnace*, in which a forced draft fan is used to force air into the furnace, producing a positive pressure, and cause the hot gases to flow through the unit and out the stack. The operating pressure in a positive pressure furnace may vary from 5 in. to 25 in of water.[5] Pressurized furnaces are associated with smaller package firetube boilers and small to medium package water tube boilers. These package boilers can be sealed with gaskets to prevent loss of pressurized gases.

Centrifugal fans are generally used for these purposes and are driven by either electric motors or steam turbines. The operator must ensure that the inlet and outlet dampers to these fans are in good operating condition.

Bearings are the most important part of any fan. It is the operators responsibility to make sure the bearings are properly lubricated. Some fans are fitted with water cooled bearings. The temperature of these bearings must be checked at least four times a shift and sometimes as often as once an hour. If a rise in temperature is noticed, check the cooling water supply to the bearing. If the temperature exceeds recommended limits, then the fan must be taken out of service and inspected. Induced draft fans which are located in the gas stream are subject to fan blade erosion due to the fly ash in the gas. The blades should be periodically inspected and repaired or replaced when necessary.



An operator must be aware of proper flame appearance during periods of normal operation with good combustion. The following is a brief description of what to look for when burning coal, oil, or gas fuel.

On a traveling grate or retort fed furnace, it is important to maintain an even distribution of coal over the grates. The fire, then, should appear bright and even with no dark "holes" which could indicate poor distribution or areas of wet coal. A hole in the fire is an area on the grates where the fuel bed is very thin or an area where bare grates are exposed. Grates which may not have adequate protection from the radiant heat in the furnace may be damaged by overheating. In addition, holes in the fire are the path of least resistance for the combustion air and thus other areas on the grate become oxygen starved and may create clinker.

When operating a pulverized coal furnace the flame length is important. It must be long enough to allow for complete combustion of the fuel but must not be long enough to strike the furnace walls as this will cause overheating of the area it is striking as well as cause slag deposits. If the mixture of coal and primary air becomes too lean, the flame will leave the burner tip and then return. This is a dangerous condition as it could lead to loss of ignition. To correct the condition, decrease the flow of primary air.

Fuel oil is usually atomized with air or steam and, when properly mixed with the primary air, burns a bright lemon yellow. The flame should appear even around the tip of the burner. If not, it could indicate a plugged orifice in the atomizer. As with pulverized coal, fuel oil burners should be adjusted so the flame does not contact any of the boiler heating surfaces or the furnace walls.

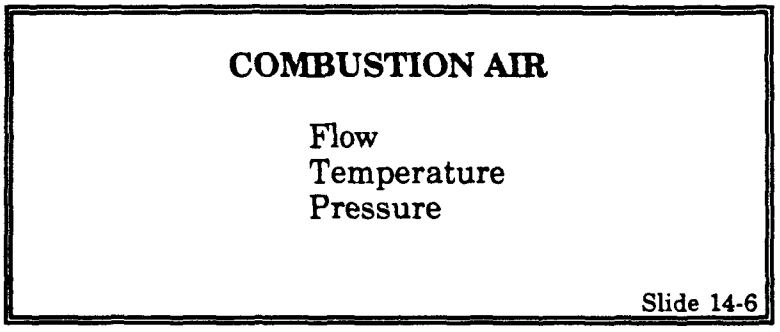
Gas burners require proper mixing of gas and air to work efficiently. Flame appearance is a poor way to adjust the air to the furnace. It is best to analyze the flue gases for oxygen and carbon monoxide and regulate the air accordingly. Improper mixing of air and gas could result in long flame travel causing the flame to hit the heating surfaces. This can cause soot deposits and a smoking condition. If the flame appears to pulsate, then the furnace draft may need to be adjusted.

Loss of ignition in the furnace is a dangerous situation as the continued feeding of fuel into a hot furnace can lead to an explosion. For this reason flame scanners are usually installed to monitor the fire. A flame scanner is a photo-electric eye connected to the fuel supply trip. If no fire is detected, the supply of fuel to the boiler is automatically shut off. If there is no flame scanner then it is the operators duty to continually monitor the fire and shut off the fuel supply if there is a loss of ignition.

Draft differential, appearance of the fire, smoke emission, and furnace slag accumulation are all indications of proper air supply. The draft gauge readings, wind box pressure, furnace temperature, boiler outlet pressure, etc., should be noted during times of normal operation with good combustion. These values can be used to establish normal conditions so the operator can quickly detect trouble and make the necessary adjustments.

14.3 Monitoring Combustion

Efficient combustion is dependent on monitoring combustion air, fuel, and flue gas analysis.



Combustion air supplies the oxygen necessary for combustion. This air is transported to the combustion zone through ducts. These ducts are usually referred to as air ducts. On some boilers this combustion air has additional uses. For those fuels which are pulverized (such as pulverized coal) a part of the combustion air may be used to transport the fuel to the burners. The transport air is usually referred to as "primary air". The remaining air required for combustion is usually called "secondary air" and is transported separately to the burners.

There are many other boiler applications which also split the combustion air. These applications may have primary, secondary, and tertiary air. The operator must know the process application and the approximate required percentages of each combustion air stream.

Combustion Air Flow

The operator's main operating concern with combustion air is to maintain a proper amount for adequate combustion. On some boiler applications, the controls will indicate a combustion air flow as well as fuel flow. However, unless the operator knows the air flow required for the applicable fuel flow, an air flow indication will be of little use. Therefore, operational data should be recorded and saved for future reference. Some boilers have meters that match the steam flow with the air flow. With this arrangement steam flow is considered an indication of fuel flow. With these boilers, the operator can adjust the air flow (by hand for manual controls or adjust a bias for automatic controls). The air flow and steam flow meters are calibrated by boiler technicians. When the indication for air flow equals the indication for steam flow, the operator knows that they are matched for efficient combustion.

Combustion Air Temperature

Some boilers have air heaters which are used to preheat the air. This hotter air improves combustion. The air heater absorbs heat in addition to that absorbed by the water/steam absorbing surfaces (economizer, boiler, superheater, and reheater). If the air heater were not present, the flue gases leaving the stack would be higher in temperature and heat losses out the stack would be higher. However, care must be take not to lower the flue gas temperature below the dewpoint of the flue gas. Condensation of the acid gases onto the metal surfaces would cause corrosion. The temperature of the combustion air and the flue gas is sometimes controlled by using air bypass around the air heater. Thus, the operator must monitor the percentage of by-pass air, the combustion air temperature, and the flue gas exit temperature.

Combustion Air Pressure

The air flow (and gas flow) through a boiler is dependent upon the available differential pressure and pressure drops through the system. The available pressure differential is supplied either by natural draft of mechanical draft as discussed previously in this chapter. The pressure drops exist due to resistance to flow across the air heater, burner, furnace, heat traps, etc. The operators should be aware of approximate pressure levels and pressure drops of the air-flue gas system through the boiler. Changes to the pressure drops may indicate problems. If the burner pressure drop changes, burner combustion efficiency may be affected. Possibly the registers on one or more burners are in the wrong position. An increase of pressure across a convection heat trap (superheater or economizer) may be the result of heavy fouling from the ash in the fuel. The operator must evaluate using the soot blowers to clean the boiler surfaces. Cleaning the surfaces will also improve the heat transfer.

Combustion Fuel

Any material that releases heat during a combustion process can be defined as a fuel. Some fuels, however, are easier to burn than others. Depending upon the physical characteristics and requirements of the fuel, different attributes of the fuel may be measured. Some of these attributes are listed below in Slide 14-7.

FUEL MONITORING PARAMETERS

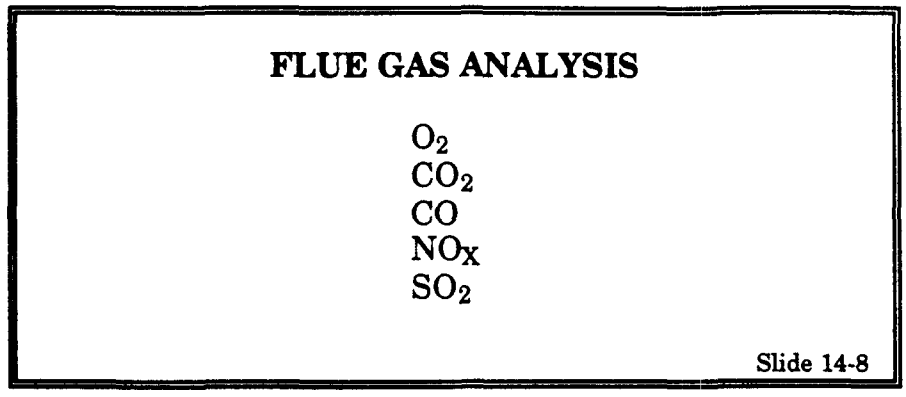
Fuel Type	Pressure	Temperature	Flow
Solid			
Pulverized Coal			X
Stoker Coal			X
Refuse (Garbage)			X
Liquid			
Oil	X	X	X
Chem By-Product	X	X	X
Gaseous			
Natural Gas	X	X	X
Gaseous By-Product	X	X	X

Slide 14-7

Pressures and temperatures are usually inputs to the instruments for metering flow. However, pressures are also inputs for the burner permissives of burner safety system. Pressures and temperatures are not normally monitored for solid fuels. There are, however, instruments that monitor the flow of solids in either weight or volumetric terms. Both liquids and gases can be monitored in pressure, temperature and flow. Piping for liquids and gases are designed for the maximum expected pressures and temperatures. Also, the burner(s) have maximum and minimum flow, temperature, and pressure limits. The burner safety system is set to trip the fuel if these limits are not maintained, for whatever reason. The operator, however, should be knowledgeable of these minimum and maximum temperature and pressure limits and be prepared to trip the boiler.

Combustion Flue Gas Monitoring

From the combustion of fuel and air is the creation of hot flue gases. These flue gases contain heat released from the combustion process. These hot flue gases give up heat as they pass through the different components of the boiler (furnace, superheaters, etc.). Flue gases exiting the stack contain heat that was not transferred to the boiler or superheater. The heat in these stack gases is referred to as "heat losses". The greater the temperature of the flue gases or the greater the quantity of flue gases exiting the stack, the greater the losses. Heat energy that is lost and not recovered are heat losses as previously discussed in the calculation of boiler efficiency presented in Chapter 6.

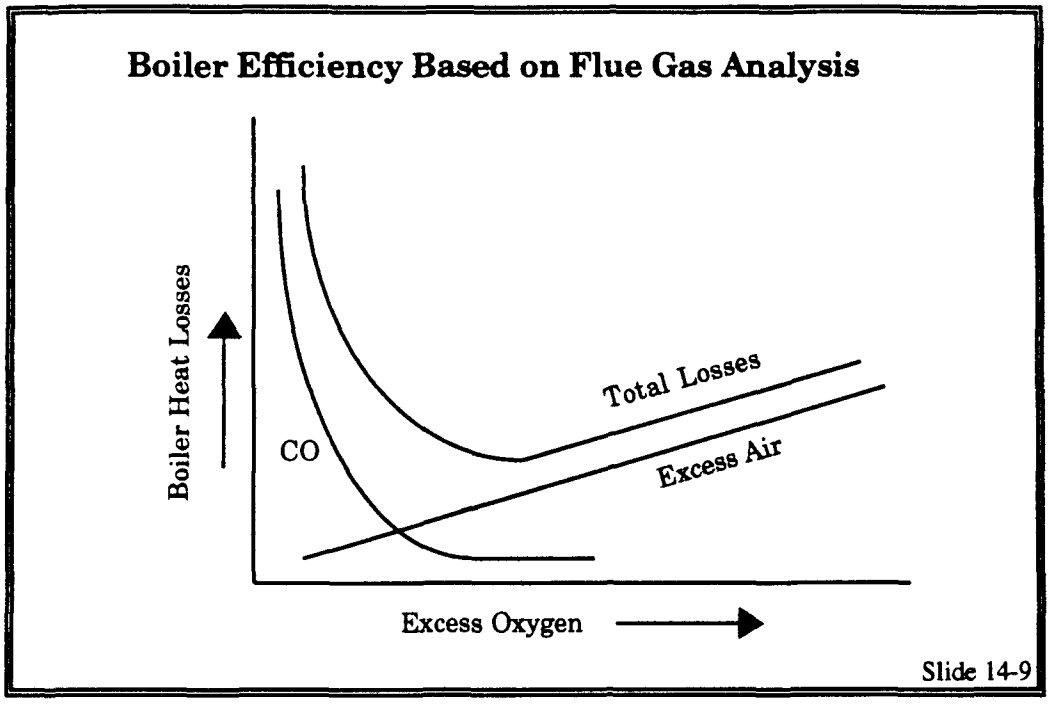


Flue gases are often monitored to evaluate the combustion process and the effectiveness of the heat transfer to the steam. Flue gases are analyzed for excess oxygen (O_2) and carbon dioxide (CO_2). Other constituents that require monitoring may include carbon monoxide (CO), sulfur dioxide (SO_2), and other pollutants.

O_2, CO_2, and CO are used to measure the efficiency of the combustion process and the thermal heat transfer between the hot flue gases and the steam. O_2 is an indication of the excess air in the flue gases. CO is an indication that there is a lack of oxygen for complete combustion. A boiler can not usually show an excess O_2 and a quantity of CO at the same time. Typically, the O_2 will range from 2.5 to 3.5 percent. A boiler operating with a large quantity of excess O_2 will have a large quantity of hot gases leaving the stack. The larger the quantity of excess O_2, the larger will be the losses of heat out of the stack, as shown in Slide 14-9.

CO_2 is the molecular compound resulting from the combustion of carbon (from a fossil fuel such as coal, oil, or gas). CO_2 can exist with either O_2 or CO but not with both.

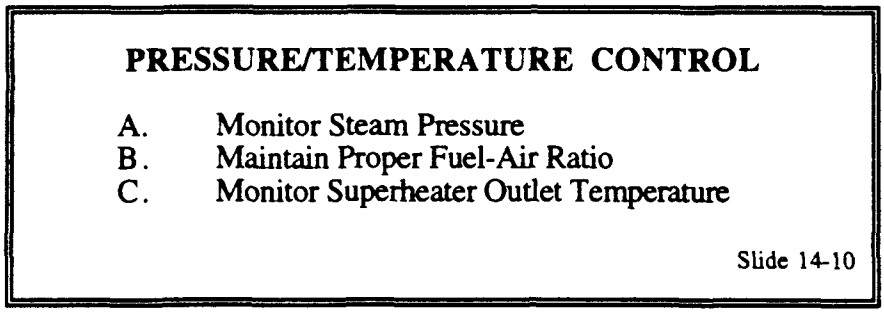
Flue gases may also be analyzed for pollutants in an effort to reduce emissions from the stack. An example may be oxides of nitrogen (NO_x) and SO_2.



14.4 Maintaining Steam Temperature and Pressure

An operating boiler producing steam is a continuous process. Fuel, air and water are supplied while steam and waste products (ash, flue–gases, water blow–down) are discharged. It is the responsibility of the operator to keep these materials flowing in the right proportions and as required to produce steam.

Many of these functions are performed automatically, but an operator is still required to oversee the equipment. Strict supervision is required since much depends on a continuous flow of steam from the boiler.



A drop in steam pressure, as indicated by a steam pressure gage, shows the operator that fuel must be increased to the boiler. Too much pressure indicates that fuel to the boiler must be decreased. If the boiler is equipped with automatic controls,

then the fuel flow is adjusted automatically in response to the change in steam pressure.

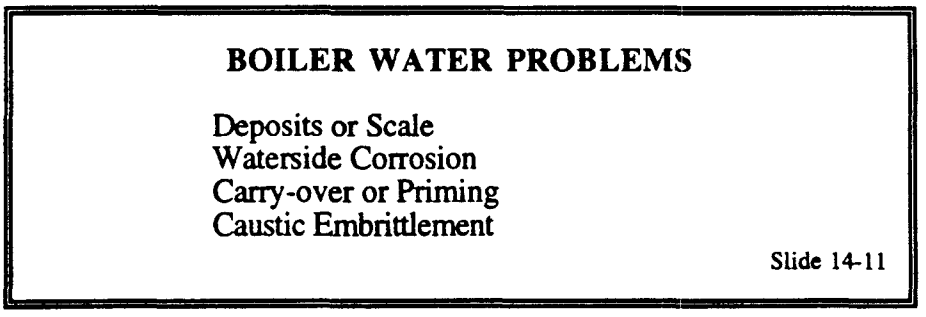
Each time the rate of fuel supply is changed, the air flow must be changed proportionally. Normally the automatic controls change the air flow to compensate for load changes and to maintain the proper fuel-air ratio.

When operating a boiler with no superheater, the temperature of the steam corresponds to the operating pressure. For example, a boiler operating at 600 psi with no superheater will have a steam temperature of 486°F. If, however, the boiler is equipped with a superheater then the superheater temperature must be monitored so that it does not exceed the recommended design temperature.

Operator control of final superheat steam temperature is limited. The operating pressure and corresponding saturated steam temperature along with the actual superheater surface have the greatest effect upon the temperature of the steam leaving the superheater. Some superheaters have an attemperator (also called desuperheater) to control the steam temperature over the upper load range. These attemperators, however, are designed during the boiler engineering phase and are operated automatically. Operators can bias the operation of the attemperators only slightly. If the "attemperation" of the superheater is done incorrectly, damage can be done to the superheater surface. Options available to the operator include burner tilt (if available), flue gas recirculation (if available) and soot blower operation. These options are discussed in section 14.7.

14.5 Maintaining Suitable Feedwater Conditions

The supply of water to the boiler is a very important part of proper boiler operation. The water supply must be heated and conditioned with chemicals to prevent operating difficulties. The four main problems caused from inadequate water treatment are (1) waterside deposits or scale, (2) waterside corrosion, (3) carry-over or priming, and (4) caustic embrittlement.



Scale is the deposit of solids on the heating surfaces. The formation of scale is caused by the dissolved solids in the feedwater. As the water enters the boiler and becomes hot and pressurized, these solids become insoluble and adhere to the heating surfaces. The scale deposits form an insulating layer which retards the heat flow to the water and can cause the metal to overheat, blister, and over an extended period of

time, fail. Feedwater containing a high level of dissolved solids is considered "hard" and must be controlled chemically. The addition of phosphate (PO_4) and caustic helps precipitate the dissolved solids and causes them to adhere less to the heating surfaces. These solids usually settle in the drums and headers as "sludge" or remain suspended in the water and are removed by blow-down (surface and bottom blow). Conductivity of boiler water helps determine when a blow-down is required. The higher the concentration of solids, the higher the conductivity.

Waterside corrosion is caused by low alkaline or acidic water, oxygen in the water, or both. The boiler metal is converted into red or black powder (iron oxide), which is washed away with the water. Over a period of time the metal thickness is reduced and the stress in those areas is increased leading to eventual failure. Low alkaline levels can be compensated for by the use of a lime-soda softener, addition of alkaline salts, or by treating the make-up water with acid. Oxygen can be reduced by heating and deaerating the feedwater and adding oxygen scavenging chemicals such as sodium sulfite or hydrazine.

Carry-over or priming is what occurs when water is carried over with the steam into the steam header or superheater. This is a hazardous condition as it could cause damage to both equipment and personnel. It is caused by too many impurities in the water, too high a firing rate, or foam. Foam is caused by solids or oil in the water which form a film on the surface of the water causing bubbles to pile up rather than bursting. As these bubbles pile up some are carried over into the steam line bringing with them moisture and impurities. Proper testing and chemical treating of the boiler water along with surface blowdown can help prevent this situation.

Caustic embrittlement is the weakening of boiler metal at joints, seams and cracks due to long-term exposure to highly alkaline water. The condition is worse on boilers with riveted joints but is still a concern on welded boilers especially where there may be small cracks or rolled tube ends.

Water Sampling

The operator is responsible for taking water samples from the feedwater and condensate systems and from the boiler. The sample should be taken just before or at the time of blowdown. Samples should be taken on a regular basis and recorded for comparison. As mentioned in Chapter 2, the samples should be tested for pH, hardness, suspended solids, and dissolved solids and gases. All containers for collecting samples should be kept clean and rinsed with the water to be sampled several times before final filling.

Water Treatment

As previously mention in Chapter 2, there are various water treatment techniques which may be used to maintain boiler water quality. Instructions for feedwater treatment prepared by a feedwater chemist should be followed. For chemically treated water systems, the operators are required to add the chemicals to the feedwater system, inject chemicals into the boiler feedwater and perform the required blow-downs. If water softeners and deaeraters are used then the operator

must maintain the proper level of salt in the softeners as well as perform or monitor the regeneration cycle. The water level in the deaerator is very critical and although it is usually maintained automatically the operator must check the level visually at least twice during a shift or as often as required. Since the deaerator holds the feedwater supply, a low level could result in no feedwater to the boiler.

14.6 Monitoring the Steam/Water Circuit

Boiler water tubes for generating steam from water are required to be filled with water at all times during boiler operation. Superheater tubes that add heat to the steam generated in the boiler circuits require dry steam to be supplied at all times during boiler operation. Operators must use a water level gauge to monitor the operation of these water and steam circuits.

MAINTAINING WATER LEVEL

Regular Maintenance/Operation
Low Level Problems
High Level Problems

Slide 14-12

All boilers will have a water level gauge attached to the boiler. Some boilers will have this water level signal transmitted to the operator location, such as a control room.

Operator maintenance is important for accuracy of the water level indication. Because there is no flow during normal operation of the water level gauge, the water connection of the gauge tends to plug with boiler water solids and or chemicals. The level gauge should be blown down regularly. The frequency of the water level gauge blowdown depends upon the boiler operation, boiler water solids, and feedwater chemicals. Some boiler operators blow down the water level gauges as much as once per shift. All boiler drum level gauges should be blown down once per day.

The water level of the boiler must be maintained between low level limits and high level limits. Most boilers have a drum level control which will automatically control the feed water flow to maintain the drum level between these two limits. This feedwater control will also maintain the correct flow of water to operate the boiler with the actual steam flow.

Low Water Level Concerns

Minimum drum levels are required to assure that the boiler has an adequate supply of water. Water is required not only for the generation of steam, but also for cooling protection of the boiler surfaces. If the actual water level decreases below this

minimum level, some or all boiler surfaces will not have water. The surfaces without water will be destroyed.

When the water level is found to be below the minimum water level limit, STOP the fuel and air supplies. If the drum level gauge does not register a water level, STOP the feedwater flow. Adding feedwater to a hot dry boiler will add additional thermal stresses to the drum material. Take the boiler out of service for a thorough internal check by experienced boiler engineers to determine the extent of damage and repairs necessary.

High Water Level Concerns

Maximum drum levels should not be exceeded. Higher than permitted drum levels may cause carry over of water droplets with the steam. Water carried over in the steam may reduce final steam temperature and be harmful to downstream equipment (turbines, heaters, etc.). Any slugs of water put in motion by the steam can cause water-hammer and rupture the pipeline.

For boilers with superheaters, this carryover of water droplets presents an additional problem. Each water droplet contains solids at the same concentration as the boiler water in the steam drum. When the steam passes through the superheater, these water droplets will evaporate, leaving the solids to form deposits on the inside of the superheater tubes. These solids reduce the transfer of heat from the combustion gases through the tube wall and into the steam. The solids act like a layer of insulation between the hot tube wall and the cooler steam. With this layer of "insulation", cooling of the tube wall will be reduced resulting in overheating.

Solids from carry-over may possibly pass completely through the superheater and into downstream equipment. Solids entering a steam turbine can damage the turbine blades. Turbine repairs are not only expensive, but can result in long outages.

High drum level conditions can usually be reduced by decreasing the firing rate. Steam bubbles below the water level will tend to collapse causing the water level to fall. However, if the high drum level trips the fuel, the non-return valve (steam stop check valve) closes to prevent back flow of higher pressure steam into the boiler (if the boiler is supplying steam to a common header), heat may not be able to readily escape water-steam enclosure. Keep fans operating and the pressurized vessel will slowly cool. DO NOT re-establish a fire in the furnace until proper water levels are re-established in the drum.

14.7 Controlling the Steam Temperature

Steam is superheated by adding heat to the saturated steam produced in the boiler circuits. The saturated steam leaves the drum (or other steam space) and travels through the "superheater" absorbing more heat. To control the final steam temperature leaving the boiler unit, one needs to control the input of heat to the saturated steam. The results of any adjustments to the steam temperature are typically delayed due to the thermal capacity of the boiler elements.

Superheaters are designed to absorb a certain amount of heat for each steaming rate. Many of the conditions that determine the heat absorbed include the type of fuel, the amount and temperature of flue gases flowing across the superheater, and the size and the arrangement of the superheater surface. Most superheaters are also designed to slightly modulate the temperature of the steam.

SUPERHEAT STEAM TEMPERATURE CONTROL

Desuperheater
Burner Tilt
Flue Gas Recirculation
Sootblower

Slide 14-13

Desuperheater

A desuperheater dilutes the temperature in superheated steam by spraying "cold" water into the steam circuit. The spray water absorbs heat from the superheated steam and is evaporated into steam. Conversely, the superheated steam loses temperature when it comes in contact with the spray water. This de-superheater can be located either at the end of the superheater or in between two superheater banks. The de-superheater located at the end of the superheater is called a "Terminal" desuperheater. Those located in between two banks are referred to as "Interstage" desuperheaters. Desuperheaters can be supplied by most boiler manufacturers. The de-superheater control can be set to "control" the steam temperature at a desired set point (with-in design limits). The operators can make small adjustments to this control.

Burner Tilt

Absorption of heat into steam can also be affected by temperature. If the flue gases can be increased in temperature, the transfer of heat to the superheater will be greater. Some Combustion Engineering boilers have "tilting" burners. These burners have the ability to move the fire-ball up or down in the furnace. Moving the fire ball to a lower position will decrease the temperature of the flue gases exiting the furnace and likewise, decrease the superheater absorption. Moving the fire-ball higher in the furnace will increase the temperature of the flue gases leaving the furnace and increase the absorption by the superheater. Operators of units with tilting burners have the ability to control superheater temperature with the tilting burners.

Flue Gas Recirculation

Superheater absorption can also be affected by the amount of gases flowing across the superheater surface. Some B&W units have flue gas recirculation (FGR). These FGR systems remove a certain amount of flue gases from the economizer gas-

out flues and inject it into the furnace. This effectively increases flue gas flow across the superheater surfaces without any increased firing. Increasing the flow rate across the superheater increases the superheater steam temperatures. Operators of B&W units with an FGR system have the ability to control superheat temperatures at low loads. FGR is used for several conditions. Superheater steam control is only one use.

Soot Blowing

One other important means of maintaining superheater temperature is to keep the superheater surfaces as clean as possible. Firing fuels that leave ash entrained in the flue gases may cause a build-up of an ash layer on the superheater tube surface. Any layer of ash on the tubes will probably reduce heat transfer, causing a decrease in superheater temperature. The operators will need to monitor the superheater temperature and develop a soot blowing schedule to minimize the layer of ash build-up on the superheater tube surfaces.

If an operator chooses to decrease superheat temperature, for whatever reason, he has the option to let the superheater surface foul or become dirty from the ash in the fuel. As the coating of ash builds, heat transfer will decrease and steam temperature will also decrease.

14.8 Startup Procedures

The start-up procedures may divided into four stages, pre-startup inspection, establishment of water level, light-off, and warm-up.

STARTUP PROCEDURES

- **Pre-startup Inspection**
- **Establishment of Water Level**
- **Light-off**
- **Warm-up**

Slide 14-14

Pre-startup Inspection

The pre-startup inspection will be specific to each boiler system, but at a minimum it should include the elements of the ASME Recommended Guidelines for the Care of Power Boilers. The following is a summary of the items included in the guidelines.

RECOMMENDED PRE-STARTUP INSPECTION CHECKLIST

- **Pressure Measurement Device Accuracy**
- **Blowoff Valves Closed and Functional**
- **Gauge Glass and shut-off valves**
- **Infrared Detection System**
- **Main Steam Valve Inspection**
- **Safety Valves Inspection**
- **Fans Operational Condition**
- **Pumps Operational Condition**
- **Water Conditioning System**

Slide 14-15

All instrumentation and protective devices that provide the required margins of safe operation should be checked and operable prior to starting the boiler. At least one recently calibrated steam pressure gage should be properly mounted on the boiler and ready for service. Pressure transmitters should also be calibrated for accurate transmittal of the pressure signal to the control center.

Blowoff valves, including continuous blowdown valves, water column drain valves, gage glass drain valves, gage cocks, feedwater supply valves, and feedwater control valve should be closed and in good working order. Valves, if any, between the steam drum and water column and gage glass shutoff valves should be locked or sealed open. Gage glass and furnace infrared detection gear, water level indicators, and recorders should be ready for use. The water level in the boiler should be lowered by draining water from the boiler to check the action of the water level in the gage glass.

Safety valves should be inspected externally to see that they are free to operate and that their discharge piping and drain piping are open to atmosphere and free to expand without imposing loads on the safety valve bodies.

Manual or motor operated main steam stop valve stems can be eased up just enough to reduce thermal expansion stresses which could result as they go from cold to hot. If the header system is not under steam pressure, the main steam stop valve can be actually unseated and reclosed gently.

Fans and boiler feed pumps should be checked to ensure they are ready for service. Chemical injection equipment should be check by actually pumping a small amount of the water into the boiler.[5]

Establishment of water level

In filling the boiler for startup, certain precautions should be taken to protect the pressure parts. First, high quality water should be used to minimize water side corrosion and deposits. Second, the temperature of the water should be regulated to match the temperature of the boiler metal to prevent thermal stresses. High

temperature differentials can cause thermal stresses in the pressure parts and if severe, will limit the life of the pressure parts. Differentials up to 100°F are generally considered acceptable. A third precaution is the use of vents to displace all air with water. This reduces oxygen corrosion and assures that all boiler tubes are filled with water. A final precaution is to establish the correct water level before firing begins.

Light-off

After the boiler operator has completed the pre-startup inspection, the next step is to begin the light-off or ignition of the burner. Most furnace explosions occur during startup and low load periods.[4] Therefore, the most critical step of the lighting the burner is to eliminate the combustible gas prior to introducing a spark into the furnace. As a minimum the boiler should be purged with a 25% of full load rated air flow for five minutes. After the purge, the flue gas emission control equipment should be place in service. Next, the fuel availability should be confirmed by opening the manual valves in the fuel train and checking the level of the fuel. Finally, the burner startup sequence should begin by activating the automatic controller. The controller will first ignite the pilot flame and once that is confirmed by the flame scanner, the main burner will be lit. Once the burner is lit, the burner controls should be left in the manual setting at low fire to allow the boiler to heat slowly.

Warm-up

During the period when steam pressure is initially being raised, the boiler should be checked carefully to see that it expands freely in the manner and direction intended in its design. As steam pressure is increased, the water level should be carefully controlled within normal limits. Prior to picking up load, it is desirable to keep the water level near the lowest safe level to allow for thermal expansion of the water as the steam generation rate increases. When raising the steam pressure on a boiler not connected to a header system, the steam line should be warmed up along with the boiler by the operation of drain valves to remove condensation and create the desired flow of warming steam.

In bringing a boiler on the line with other boilers on a header system, certain precautions are necessary to avoid water hammer and excessive temperature gradients in the piping. Adequate drainage and warming of the piping will eliminate the risk of water hammer. The judicious use of bypass valves around main header valves will avoid steep temperature gradients. Header drains should be operated. The steam line form the boiler to the header should be brought up to temperature by operating bypass and drain valves to create a backflow of steam from the header. When up to temperature and line pressure, the header valve may be opened wide and the bypass closed. The stem for the nonreturn valve should be back off to a position corresponding to about 25% open until the boiler begins to supply steam to the header, after which the stem should be backed off to the wide open positions. In the absence of a nonreturn valve, the boiler stop valve should be opened slowly when the pressure in the boiler and header are approximately equal.[5]

14.9 Shutdown Procedures

In general, boiler shutdown procedures are less complicated than startup procedures. Two shutdown situations may occur, a controlled shutdown or one required in an emergency. During both procedures, the emphasis is on safety and protection of the boiler materials.

During a controlled shutdown, the firing rate is gradually reduced. Once the combustion equipment is brought to its minimum capacity, the fuel is shutoff and the boiler is purged with fresh air. If furnace pressure is to be maintained, the fans are shut down and the dampers are closed. The water side pressure gradually lowers as heat is lost from the boiler. A minimal amount of air drifts out of the stack due to natural draft when fans are not in operation. If inspection and maintenance are required the draft fans remain on in order to cool the boiler more quickly. If a tubular air heater is present, the air is by-passed around the air heater in order to cool the boiler. The cool down rate should not exceed 100°F per hour of saturation temperature change to prevent damaged due to thermal stress.[5]

In an emergency shutdown, the fuel is immediately shut off and the boiler is purge of combustible gases. Additional procedures may apply to the fuel feed equipment to insure safe conditions. The boiler may be held at reduced pressure or may be completely cooled.

REFERENCES

1. Woodruft, Everett B., Lammers, Herbert B. and Lammers, Thomas F., *Steam Plant Operation*, Fifth Edition, McGraw-Hill Publishing Co., 1984.

2. *Boiler Technician, First and Chief*, Naval Training Command, United States Printing Office, 1972.

3. Elliott, Thomas C., *Power Plant Engineering*, McGraw-Hill Publishing Co., 1989.

4. *Steam, Its Generation and Use*, 38th Edition, Babcock & Wilcox, 1972.

5. ASME Boiler and Pressure Vessel Code, Section VII, "Recommended Guidelines for the Care of Power Boilers", ASME, New York, July, 1986.

CHAPTER 15. AUTOMATIC CONTROL SYSTEMS

15.1 Introduction

15.2 Types of Analog Control Systems
- A. Mechanical
- B. Hydraulics
- C. Pneumatics
- D. Discrete Electronic Components
- E. Microprocessor

15.3 Types of Digital Control Systems

15.4 Automatic Control System Elements

15.5 Gas-side and Water-side Control Parameters

15.6 Single, Two, & Three Element Controllers

15.7 Microprocessor Based Control Systems

15.8 Control System Applications

15. Automatic Control Systems

15.1 Introduction

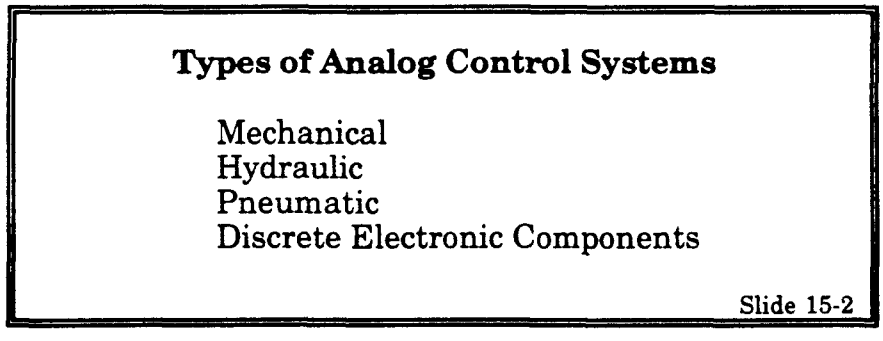
The objective of this chapter is to give the reader a brief overview of automatic control systems as applied to boilers. Examples are given to illustrate typical types of hardware and applications.

When discussing controls, two distinct categories of controls must be considered. The first is analog controls which can be described as modulating controls. This type of control system controls flow, temperature, pressure, etc. over the control range of the process. Examples in boiler control include feedwater control, combustion control, and steam temperature control.

The second category is digital control which can be described as on-off controls. This type of control system controls the starting and stopping sequence of various pieces of hardware such as the boiler fans of the power plant. Digital systems continuously monitor the status of the plant and can initiate actions (such as a boiler trip) if the system determines that such action is required for safety reasons.

15.2 Types of Analog Control Systems

There are many analog control technologies that can be used and many classifications of categories of analog control systems. Some types of hardware have or are becoming obsolete but many are in use today. In reality, most modern control systems utilize a mixture of available technology. Unfortunately, different manufacturers apply slightly different names to some systems but they can all be grouped into the following categories.



Mechanical

Straight mechanical control systems can be categorized as any controlled that does not use external power (electricity, air pressure, etc.) for process variable sensing or for motive power. Examples of straight mechanical control systems include the Bailey Thermohydraulic Feedwater (Drum Level Control) Regulator and the Copes Feedwater Regulator. The Bailey Thermohydraulic Regulator works on the

principle of boiling water in a diagonal tube that is positioned near the end of the steam drum. As the water level in the drum drops, the water in the diagonal tube is turned to steam increasing the pressure in the tube which exerts a force on a bellows that opens the feedwater control valve. As the water level increases, some of the steam in the diagonal tube condenses decreasing the pressure in the tube which allows the feedwater control valve to re-close. The Copes Feedwater regulator works on the principle of expanding a metal rod as drum level drops which creates a force on a linkage that opens the feedwater valve as drum level drops. The reverse happens when drum level increases. These types of devices have the advantage of not requiring external power for operation (continues to function on an electrical power outage and does not require compressed air) but are not normally found in use today except for small heating boilers.

Another example of a mechanical control system is the Fly Ball Governor used for regulating the speed of a turbine. A flyball governor consists of two metal balls mounted and attached on the sides of a shaft that rotates at a speed proportional to the speed of the turbine. As the shaft rotates faster and faster, the balls are forced away from the shaft by centrifugal force which actuates a linkage to close down on the steam control valve to the turbine. The reverse happens as the turbine slows down. Again, this type of speed controller operates without external power but has in most cases been replaced with more modern and accurate technologies.

Hydraulics

The use of hydraulics (water and/or oil) for control systems has been around for a long time. The primary benefit of hydraulics is that of being able to develop large forces with a cylinder and precisely control the position of the cylinder without overshoot. The use of hydraulic controls in modern power plants is primarily limited to turbine governor controls.

Pneumatics

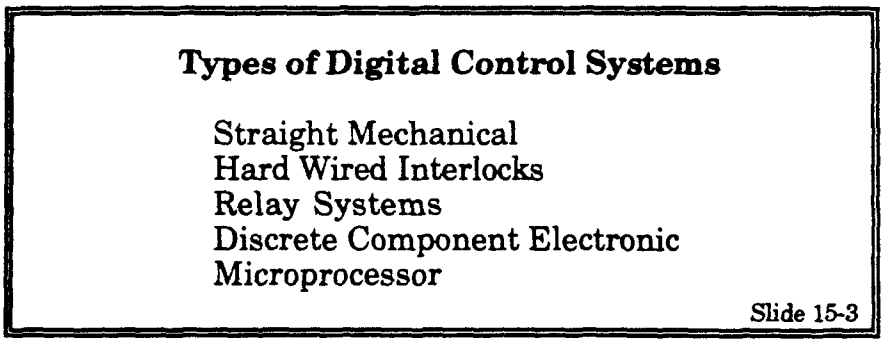
The use of pneumatics in controls enjoyed widespread use in the 1930's, 40's, 50's and into the 60's. Pneumatic controls can be categorized as any control system that uses air pressure (usually 3 to 15 or 3 to 27 psi) for transmitter outputs and control signals to drives and/or control valves. A pneumatic transmitter is a device that converts a process variable (pressure, temperature, flow, etc.) to an air pressure signal that is proportional to the process variable that is being measured. The primary benefit of pneumatic controls was its immunity to electrical noise which is interference from stray electrical currents from other control circuits and/or near-by electrical power lines (a real problem in electric devices of that era) and its reliability. Pneumatic devices (transmitters and controllers) are relatively immune to failures caused by high temperature when compared to electronic devices. Another inherent advantage is the ability to provide an emergency power back-up system in the form of an air storage tank. A disadvantage of pneumatic controls is the relatively high cost of clean dry compressed air and control component calibration drift and lack of flexibility when it comes to making changes.

Discrete Electronic Components

With the advent of relatively reliable and inexpensive diodes (a two terminal solid state semiconductor device that permits current flow in one direction only) and transistors (a three terminal solid state semiconductor device which may act as an amplifier or a switch) that discrete component electronic control systems (a control system made up from a large series of transistors and diodes) became prevalent. In this vintage of analog control systems, the transistors were used as analog devices (amplifiers). When used in this mode, they are subject to drift (calibration shift) due to ambient temperature changes and aging, and do fail (usually instantaneously and with no warning). The transistor control systems were subject to interference from electrical noise which is very difficult to control particularly in a power plant. The advantages of discrete component electronics is their rapid speed of response, ability to package relatively large control systems in a small volume, and the low cost of system power when compared to the cost of clean dry compressed air.

15.3 Types of Digital Control Systems

As is the case with analog controls, there are many types of digital controls.



An example of **straight mechanical** interlocks can be where the hand actuating levers of two valves are oriented (perhaps by linkage or cams) so that one valve must be opened before the hand lever on the second valve can be moved. In other words the second valve is interlocked to the first in such a fashion as to prevent the second valve from being manually actuated unless the first valve is open.

Hard wired interlocks are frequently used in motor control circuits. For example, it is undesirable to start or allow a forced draft fan to operate unless the corresponding induced draft fan is running. A contact from the I.D. fan starter or breaker is normally wired into the starting circuit for the corresponding F. D. fan in such a way as to not permit starting of the F. D. fan unless the starter or breaker for the I. D. fan is closed. The same contact will open if both fans are in operation and the I. D. fan is tripped thus causing the F. D. fan to trip.

Relay type interlocking systems have been in use for many years and are still common in the modern power plant. Electrical relays consist of an electrical coil that when energized, changes the state of one or many electrical contacts from open or closed to the opposite state when the coil is energized. The coil of the relay may be wired so that it energizes when a certain condition exists such as a pressure greater than a certain value or the limit switch of a certain valve indicates that the valve is closed. It is possible to design relay interlocking systems by the use of many relays to insure that equipment is started in a certain order and only after proper operating conditions are proven. By the same token, equipment tripping can be initiated if proper operating conditions are not maintained for normal operation.

The function of relay type systems can also be accomplished by the use of **discrete component electronic** technology (see discussion in previous section). Designs utilizing this technology whereby electrical relays are replaced by the use of diodes and transistors were very prevalent during the 1960's and 1970's. In some areas this technology is in use today.

The **microprocessor** is an equally powerful tool for interlocking and safety systems. The advancement of electronic technology has lead to the development of microprocessor based systems. A microprocessor system is basically a digital computer. This technology is based on digital signals which are processed as ones or zeros. One of the main advantages of using digital technology is the elimination of signal drift which affords greater accuracy. Modern microprocessor based systems also allow the control engineer to apply control strategies that were impractical to implement with earlier systems. Most modern power plants utilize microprocessors in combination with relays in boiler interlocking and safety systems.

15.4 Automatic Analog Control System Elements

The elements of an automatic control system can be placed in the following categories:

Automatic Analog Control System Elements

Process or Measured Variable
Controller
Hand/Auto Station
Operator Interface
Final Control Element

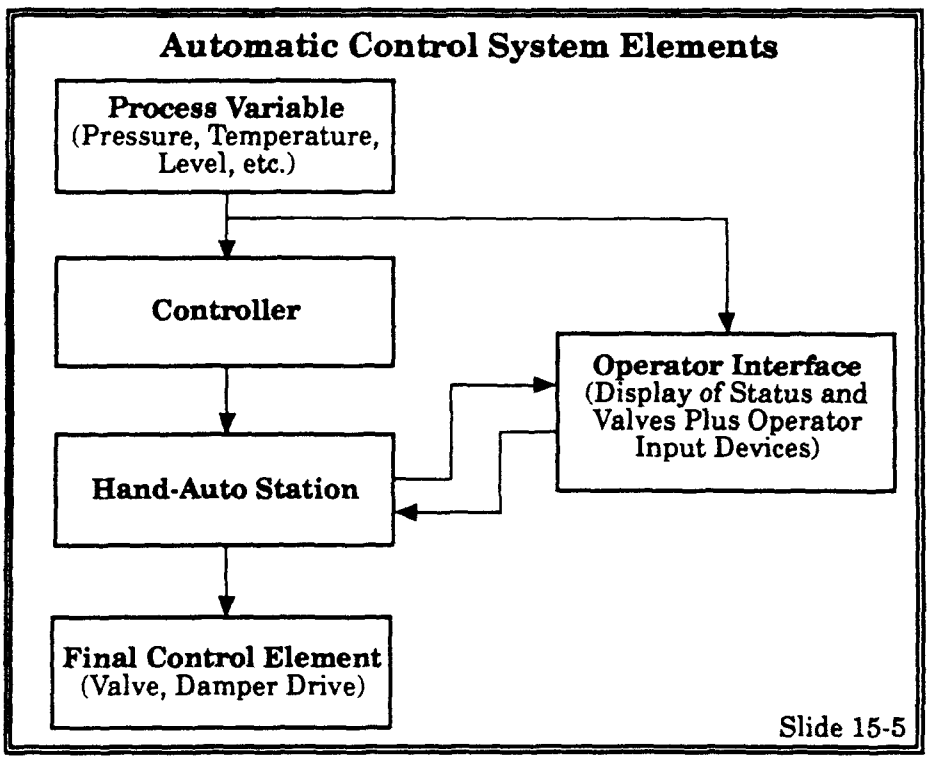
Slide 15-4

The first component is the **process variable or measured variable**. For example, drum level is the primary process variable for any feedwater control system on a drum type boiler. The drum level is measured by a transmitter (or transmitters) and a signal that is proportional to the drum level is sent to the drum level controller.

The second component is the **controller**. Depending on the type of control system, this may be in the form of a pneumatic "black box" or in the case of a microprocessor based system the controller may be "buried" within the processor itself. The function of the controller is to determine what needs to be done to keep the drum level as close to the desired level (set point) as possible. In this case this will involve the determination of what position to place the feedwater control valve or what speed to run the boiler feed pump.

The third component is the **Hand/Auto Control Station**. The purpose of this device is to allow the operator to interrupt the desired action of the controller and position the feedwater valve (or set the desired pump speed) where desired depending on the operator's observation of operation.

The fourth component is the **Operator Interface**. The Operator Interface can be any form of indication on the control panel that allows the operator to determine the status of the system. This indication may be a gauge (round, vertical, horizontal, etc.) or it may be a display on a CRT or TV Monitor. The second function of the Operator Interface is to allow the operator to make changes to the system. For example, set-points may be changed, the process variable may be controlled in the "hand" mode, or start and stop signals may be initiated. All or portions of the operator interface may be a part of the Hand/Auto Control Station.



The fifth component is the **Final Control Element**. This is the device that determines what action is taken by the system to restore the process variable to the desired value. In the case discussed above, it would be the feedwater control valve or the feedwater pump speed controller.

15.5 Gas-side and Water-side Control Parameters

In a typical boiler application, there are many parameters that have to be controlled to meet the desired unit output with maximum efficiency and safety.

Gas-Side and Water-Side Control Parameters

Steam Pressure
Drum Level (if applicable)
Main Steam Temperature
Reheat Steam Temperature (if applicable)
Furnace Draft (if applicable)
Desired Excess Air

Slide 15-6

Depending on the configuration of the boiler being controlled, main steam pressure is normally controlled by adjusting the firing rate of the boiler. Drum level is controlled by the adjustment of the feedwater flow rate to the boiler.

Main steam temperature may be controlled by means of adjusting the burner tilts, regulation of an attemperator (normally a station where water is sprayed into the main steam line to reduce steam temperature) or by varying the amount of flue gas recirculation within the boiler. In some boiler designs, more or less flue gas flow can be forced to pass over a portion of the superheater surface by modulating the position of control dampers in the flue gas stream. Reheat steam temperature may also be controlled by any of the above systems.

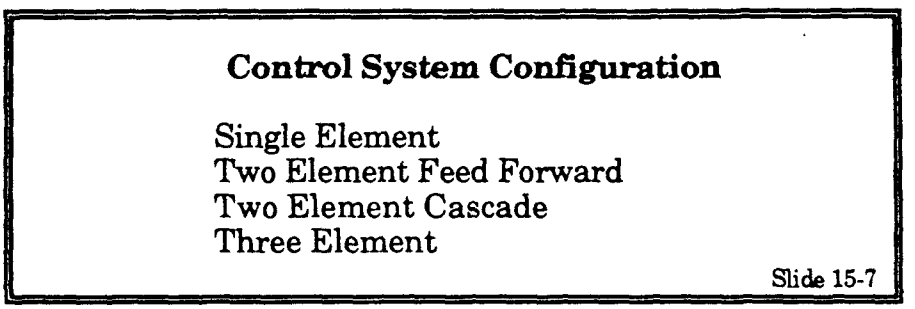
Furnace draft is normally controlled by operation of the F.D. fan and the I.D. fans. Some I.D. fans are equipped with variable speed drive motors or variable speed couplings between the fan motor and the fan shaft. If this is the case, the flue gas flow is modulated by varying the fan speed. Other I.D. fans are equipped with inlet dampers. In this case the position of the inlet damper is modulated to control the flue gas flow through the I.D. fan.

The desired excess air is normally controlled by varying the air flow to the boiler from the F.D. fans. The air flow is controlled in a predetermined proportion to the fuel flow and perhaps trimmed as required and determined by the excess O_2 that is measured in the backpass of the boiler. As with the I.D. fan, the flow of air delivered to the boiler by the F.D. fan is varied by either varying the speed of the fan or the position of the inlet damper on the fan.

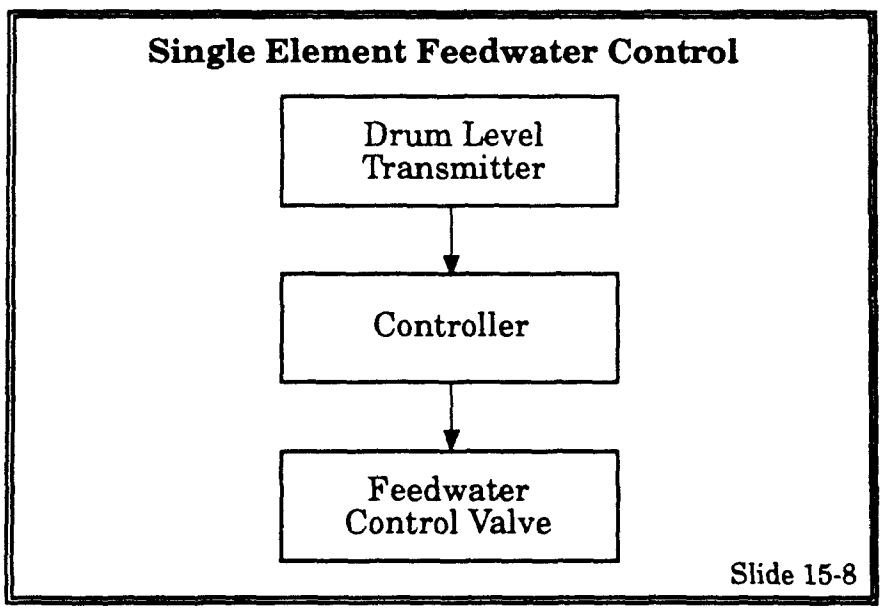
There are many subsystems associated with the combustion control system. For example, in a pulverized coal fired plant, there are several control loops such as primary air flow control, pulverizer outlet temperature control, coal feeder control, etc. required for each pulverizer. In addition, the controls for each pulverizer must be integrated into an overall system that controls the total fuel feed to the boiler.

15.6 Single, Two and Three Element Controllers

Control systems can be configured in many different ways to meet the requirements of any particular system.The most common controllers are the single element system, two element system, and three element system.



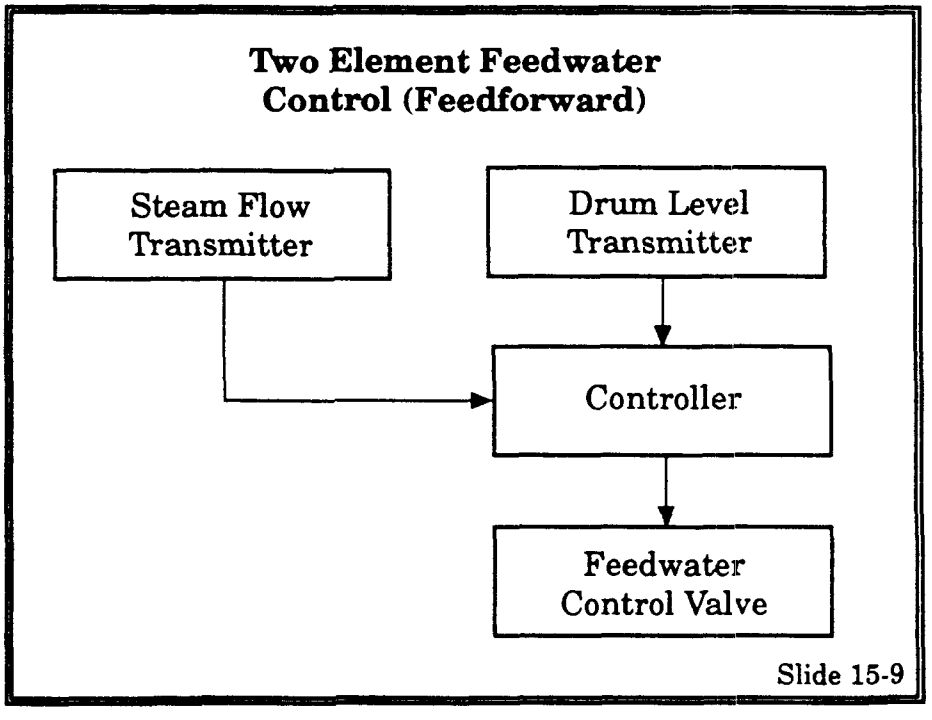
The **single element control system** is a system that has as an input one measured variable only and the system output controls a single process variable. An example of this is the single element drum level controller.



If the only measurement that can be made for a drum level control system is the drum level, then the desired position of the feedwater valve for any given load (or

for any status of load stability) would be determined from the drum level measurement. If the drum level is high, the feedwater valve will move towards the closed position. If the drum level is low, the feedwater valve will move towards the open position. When the drum level is at set point, the position of the feedwater valve will remain constant. Note that there are many times that the above may not be desirable such as during load changes.

The **two element control system** has inputs from two measured variables. In the case of a two element feedwater control system, this would normally be steam flow and drum level. Note that it is possible to establish a correlation between the feedwater valve position and steam flow for most "normal" operating conditions. A two element feedwater control system would be then configured to first drive the feedwater control valve to a particular position based on steam flow and then trim this position (open a little more or close a little) from the position required because the drum level is a little low or high at any given time.

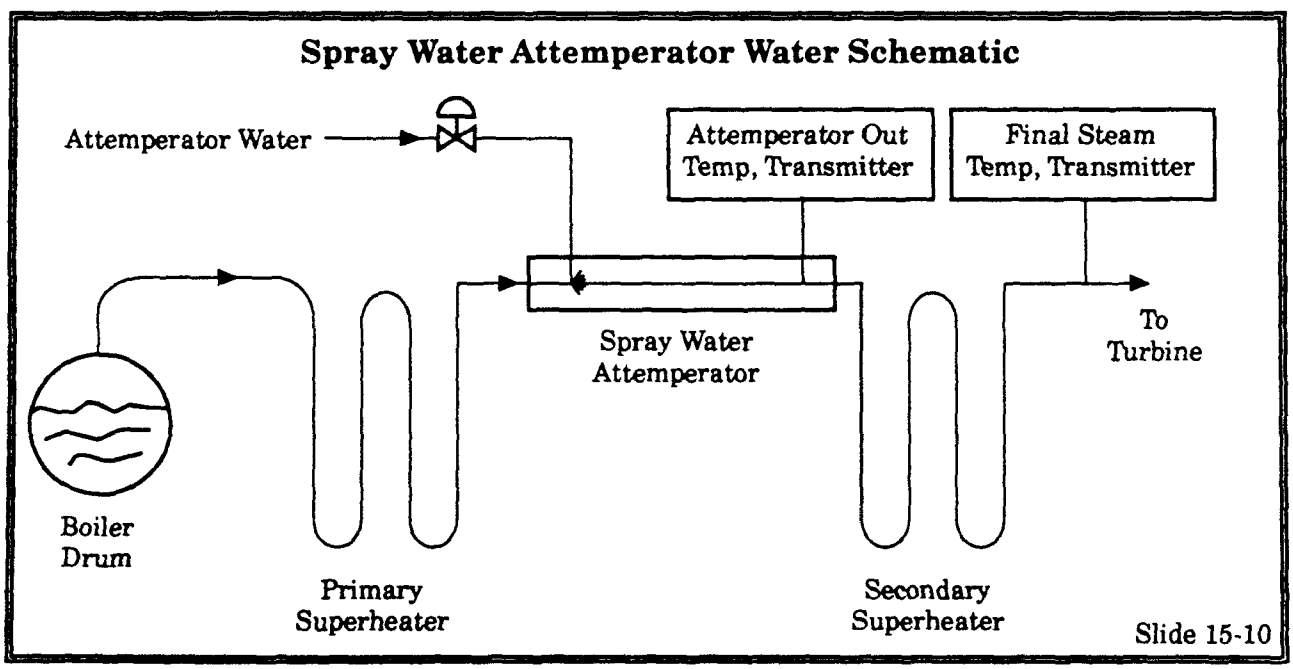


This system will operate in a superior manner over a single element system particularly during load changes. As load increases, the feedwater valve opens a proportional amount but the drum level transmitter may see a "swell" in drum level and call for the feedwater control valve to close a small amount. The two signals will cancel each other and the net effect will be to not change the feedwater valve position. This is more desirable than to close the feedwater valve on a load increase as would happen with the single element system. As the water level swell goes away, the feedwater valve will go to the new desired position as determined by steam flow. Therefore a two element feedwater control system will work in a far superior manner when compared to a single element control system on any boiler where load swings

are anticipated.

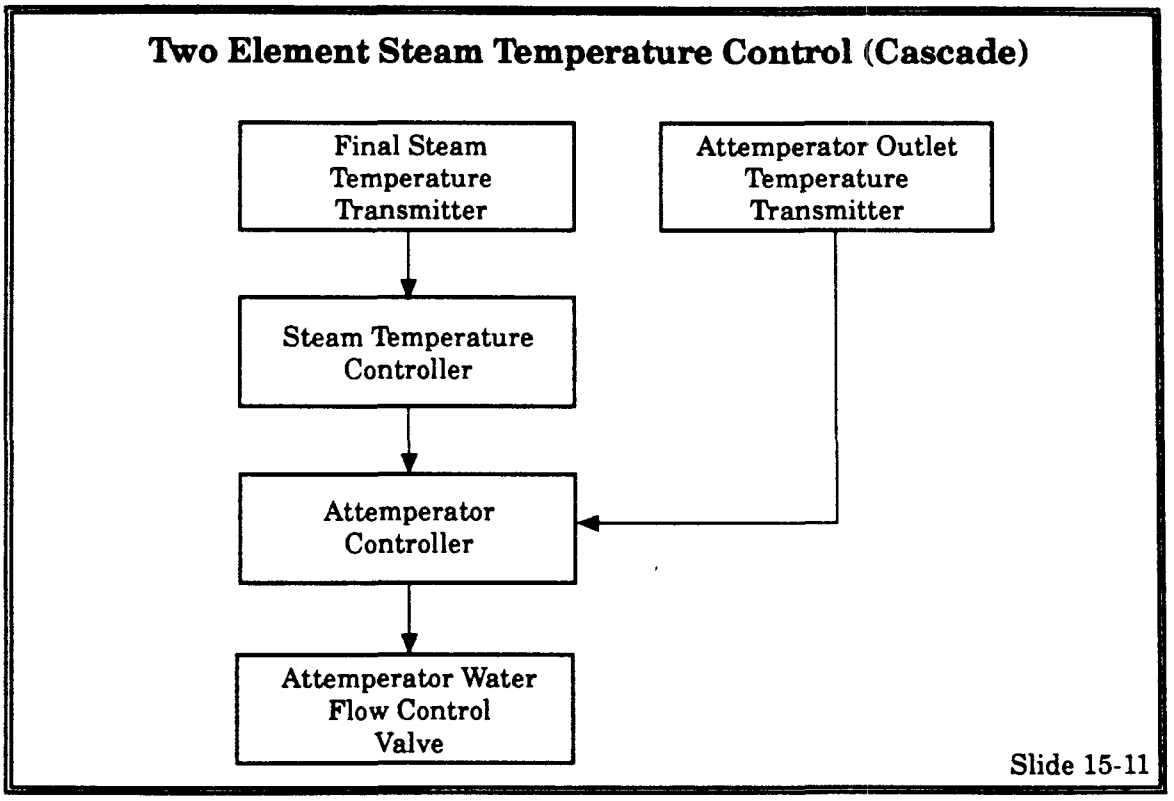
A second type of two element system is the cascade control system. In this case, the second element is not used to directly determine the position of the final control device but is used to determine the set point for a second controller.

An example of a **two element cascade system** is a steam temperature control system. It is next to impossible to control the position of a spray water attemperator valve by looking at final steam temperature only. The reason for this is that there is such a large mass of metal in the secondary superheater that the response time of the loop is extremely slow. That is to say, if the boiler is being operated in a steady state mode and the spray water control valve is further opened by some amount, it will be several minutes (perhaps as much as 10 minutes) before the final steam temperature starts to drop. If the control system can only detect final steam temperature and a high steam temperature is detected, the control action will be to increase the spray water flow. Since no drop in final steam temperature is observed within a short time period, the action of the controller will be to increase the spray water flow some more. This cycle will be repeated until too much water is being sprayed into the attemperator and the final steam temperature will start to drop excessively and a new cycle will be started. This is called overshoot.



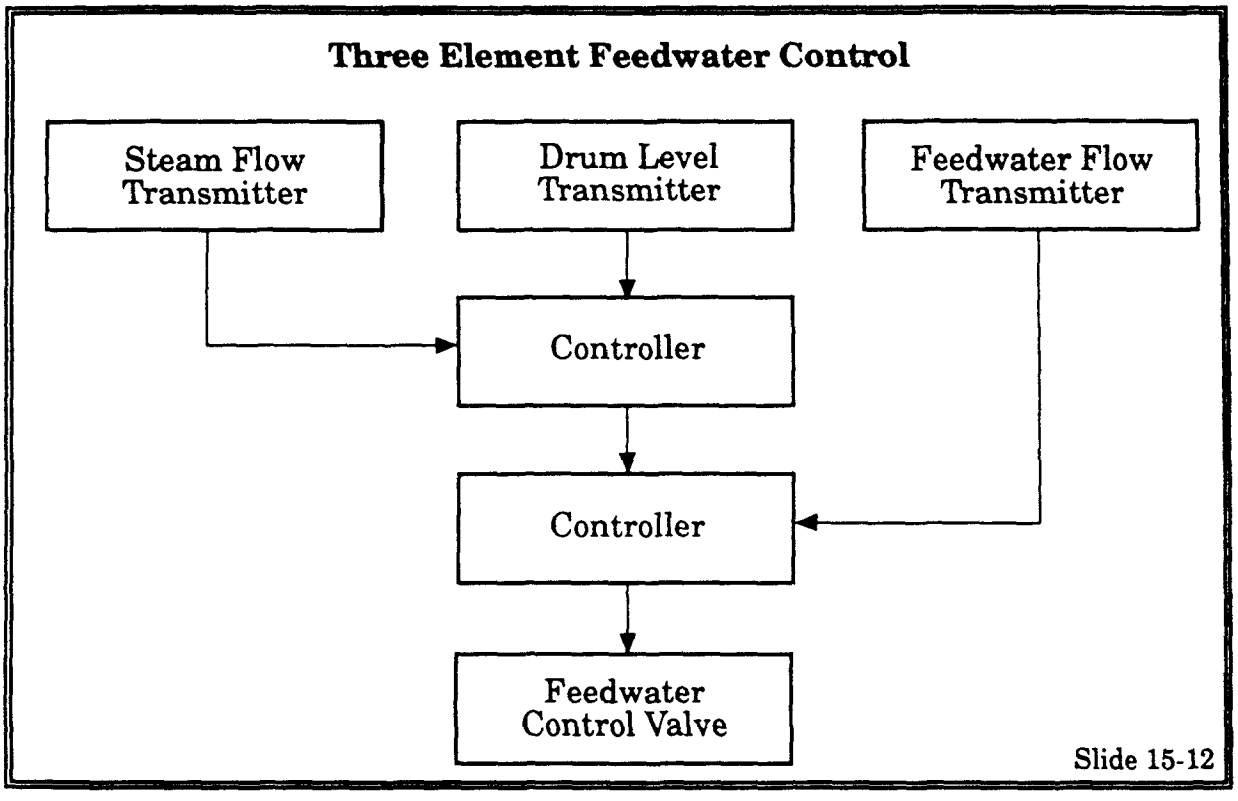
One method of overcoming the problem of overshoot is to measure the attemperator outlet temperature. Note that the attemperator outlet temperature will detect a temperature change in a very short time period if the amount of attemperator water flow is changed. This input can be used in the following manner by use of a cascade control system.

The two element cascade control system utilizing final steam temperature and attemperator outlet temperature as the two elements will be set up so that the controller for final steam temperature will generate a set point for attemperator outlet temperature. If final steam temperature increases, the controller will call for a lower attemperator outlet temperature. The second controller for attemperator outlet temperature will sense the change in set-point and open the attemperator outlet valve until the new lower attemperator outlet temperature is reached. The system is now essentially satisfied and eventually the final steam temperature will drop to it's desired set-point without the overshoot experienced with the single element system.



A **three element control system** utilizes three measured variables to determine the proper action for the final control element. A three element feedwater control system utilizes steam flow and drum level (as did the two element system) with the third variable being feedwater flow. The two element system essentially "assumed" that a certain feedwater flow would result from a particular feedwater valve position. This may not always be the case. For example, if a second feedwater pump is placed on the line at a given load, this will result in a higher pressure drop across the feedwater control valve than with the single pump. The higher pressure drop will result in a higher flow for the same position.

In a three element feedwater control system, the steam flow and drum level signals are combined as in the two element system, but now the output calls for a particular feedwater flow and is no longer dependent on the relationship of feedwater valve position and feedwater flow. The feedwater control valve will open or close as required until the actual desired flow is established. With this system, when the second feedwater pump is placed on the line, the system will immediately detect an increase in feedwater flow when none was called for by the steam flow and drum level signals, and the feedwater valve will close the proper amount to bring the feedwater flow back in line.



15.7 Microprocessor Based Control Systems

Microprocessor based control systems are applied to most new boiler control applications and are in many cases being retrofitted to older existing units. There are many advantages for using this technology in modern control systems.

Advantages of Microprocessor Systems

Flexibility
Improved Operator Interface
Reliability
Ability to Incorporate and Integrate Numerous Systems in a Single Package

Slide 15-13

With the advent and development of microprocessor based control technology, whole new vistas have been opened to control engineers. It is now possible to use control strategies that more specifically meet the needs of particular processes instead of a few "canned" strategies that were previously available (or at least economical to implement). The control engineer can now experiment with different control algorithms as a new system is brought on line and select the system that responds in the most optimum manner. All of the above can be accomplished with a few keystrokes instead of time consuming and costly wiring and/or pneumatic tubing changes along with changes in control hardware.

It is also possible to bring to the operator a more useful and understandable visual window to the process. Properly engineered screens on the CRT (Cathode Ray Tube) can provide the operator with new understanding and instantly recognizable status of the process at any given point in time. The screen displays are linked to an operator keyboard for the initiation of operator inputs to the system.

Alarm systems can now monitor more points and prioritize all alarms so that the operator can concentrate on the most important "problems" during an upset condition and clean-up less important problems when time permits.

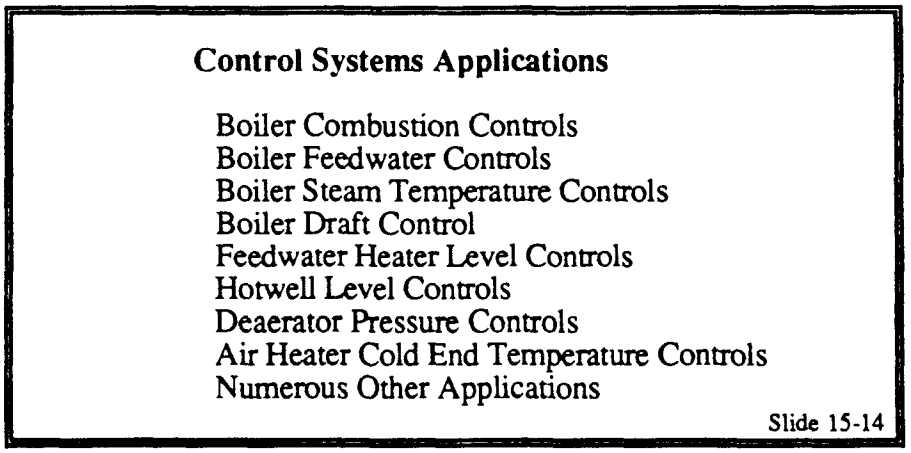
Data logging and event logging is another important capability of a microprocessor based system. Selected data points can be periodically recorded for future review of plant performance. Event logging records what happens and/or actions taken by the operator during routine and upset conditions. These logs are most useful to determine what happened during a plant upset.

As with any electronic component based system, instantaneous and sometimes catastrophic failures of a non redundant system are possible. This shortcoming has been overcome by the implementation of redundant components and subsystems that continually monitor themselves and will continue normal control by utilizing the back-up system prior to any process upset.

The shear capacity and power of a microprocessor permits the integration of the total process into a single control unit or at least what appears to be a single unit. It is common practice to tie several microprocessor control units together by means of data highways so that all controllers function as a single unit. In this manner it is possible to control the entire steam-water cycle of a power plant by means of a single system. This enables more precise control and programs can be implemented to prevent unwanted outages due to a non–critical problem in a portion of the cycle.

15.8 Control Systems Applications

There are numerous applications for control systems in a power plant from the most simple single element control loops to complex interrelated and integrated systems which utilizes numerous measured variables and control system outputs to achieve optimum operation.



The potential for control system applications in a power plant are numerous. Wherever a valve exists or a control damper exists that must be positioned to control a particular flow, temperature or level to maintain optimum operating conditions, the potential for a control system exists. The advantage of an automatic control system is that it is always alert (except in the case of a control system failure) and constantly adjusting its final control element to maintain optimum conditions. By integrating systems, it is possible to optimize overall plant operation in a manner that is not possible with manual control.

CHAPTER 16. INSTRUMENTATION: GENERAL MEASUREMENTS

16.1 Introduction

16.2 Pressure Measurement

16.3 Temperature Measurement and Equivalences

16.4 Level Measurement

16.5 Flow Measurement

16.6 Weigh Scales

Slide 16-1

16. INSTRUMENTATION: GENERAL MEASUREMENTS

16.1 Introduction

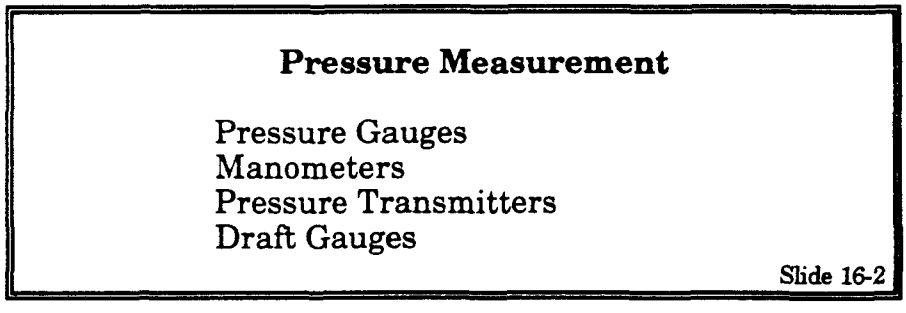
Instrumentation for measuring different properties of fluid and solid streams are essential to all steam generating installations to ensure safe, economic and reliable operation. Instruments can range from the simplest indicating devices to complex automatic measuring devices. The fundamental purpose of the instrument is to convert some physical property of the streams into useful information. The methods used to obtain the measurement depend on available technology, economics, and the purpose for which the information is being obtained.

There are many process variables that must be monitored in a power plant. Pressure, temperature, level, flow, weight, voltage, current and power consumption are a few. The degree of accuracy desired and the required readout location dictate what type of sensors are used.

Test instrumentation, often portable, may be used to determine conditions required to satisfy the boiler operator and to show that the design operating conditions have been achieved. Instruments used for continuous measurement may require compromises in accuracy for long term, dependable and reliable operation.

16.2 Pressure Measurement

Pressure and/or vacuum is a very important process variable in the power plant cycle. At times, safety can be affected if proper pressures are not maintained and plant efficiencies are dramatically impacted if the proper pressure levels are not maintained. There are several devices available for measuring pressure.



The pressure gauge is probably the most common device used to indicate process pressure. Pressure gauges come in a wide variety of sizes and accuracies. Most pressure gauges are of the bourdon tube type. Although improvements have been made in construction and accuracy, its basic principle of operation remains unchanged. A closed end oval tube in a semicircular shape straightens with internal pressure. The movement of the closed end is converted to an indication (needle movement). Pressure gauges can be liquid filled to aid in dampening of oscillations or furnished with a snubber on the pressure connection to dampen high frequency

pressure fluctuations. A disadvantage of the pressure gauge is that the operator must be close to the point of pressure measurement in order to observe the reading. It is possible to run a long pressure sensing line (say from the point of measurement to the control room) but this practice is not commonly used for most applications today because of the installation cost. Most modern control room designs do not allow the running of high pressure sensing lines into the control room space. Most pressure indications in the control room come from transmitted signals.

A manometer (normally a "U" tube filled with a liquid) is frequently utilized to measure relatively low pressures in the inches of water range. Inclined manometers can be used to accurately measure very low pressures in the 0 to 5 inch water pressure range. Manometers are normally used for test purposes or for the calibration of low range pressure transmitters.

A pressure transmitter is a device that senses pressure and develops an output signal (normally pneumatic or electronic) that is linear to the input pressure. Transmitter outputs are a relatively low level signal that can be safely brought into the control room where the signal is directed to an operator interface (gauge or display on the microprocessor CRT) and/or a controller.

Pressure measurement devices are most often used to indicate process pressure. However, another use is when two pressure measurements are taken on either side of a restricting device in a fluid stream (see section 16.5). The resulting difference in pressure can be used to calculate flow. This is probably the simplest and most economical method used to determine flow rates. This is an example of how one process variable can be used to determine another.

16.3 Temperature Measurement and Equivalences

Depending on the temperature range to be measured and accuracy required, there are a number of devices for sensing temperature and displaying the value to the operator. These devices sense heat affected properties, such as thermal expansion, radiation, and electrical effects, to determine the temperature of a substance.

Temperature Measurement

Human Hand
Liquid Filled Bulb & Tube
Liquid Filled Bulb & Gauge
Thermocouple with Readout Device
Resistance Temperature Detector with Readout Device
Optical Pyrometer

Slide 16-3

The human hand is probably one of the best known methods for detecting approximate temperature. If accuracy is not of prime concern, many operators "feel" to determine whether a bearing is overheating or whether the fluid in a pipe is more or less up to temperature. One advantage (or disadvantage) of using the hand for temperature is the instantly recognizable high temperature alarm.

The liquid filled bulb and tube (thermometer) has been one of the most common methods for displaying temperature providing that the temperature is somewhere between the freezing and boiling point of the fluid in the thermometer. An advantage of this device is its lack of requirement for external power, relative accuracy, freedom from calibration, and ease of operator observation. A disadvantage of the thermometer is that the operator must be close to the point of temperature measurement in order to observe the reading.

The liquid filled bulb and gauge operates very similar to the thermometer except the tube is replaced with a round dial (usually) gauge. This device may not hold its accuracy quite as well as a thermometer but in other ways is very similar in characteristics.

The thermocouple is the most common device to sense temperature in a power plant. Temperature measurements using thermocouples are based on the discovery that electrical current will flow in a continuous circuit of two different metallic wires if the wire junctions are at different temperatures. An electrical voltage is generated at the junction point of the two metals that varies according to the temperature of the junction point. The voltage generated therefore becomes a function of temperature and can be converted to a temperature readout. Thermocouples are available with suitable materials and packaging to meet most power plant applications. A thermocouple can be connected to a transmitter where it's milli-volt output is converted to a 4 to 20 milli–amp signal or the milli-volt output can be directly inputted to a microprocessor based system. In some applications, the thermocouple is connected to a digital readout meter. Portable units are available where a hand held unit is connected to a thermocouple for field checking of temperatures.

An RTD (Resistance Temperature Detector) functions similarly to the thermocouple for many applications except instead of generating a milli-volt output, the resistance of the RTD varies with temperature. The RTD can be connected to transmitters, direct connected to a microprocessor, direct readout digital meters and hand held units.

The optical pyrometer is a non-contact method for determining temperature - that is, temperature can be sensed without direct contact of the sensor with the process or device requiring monitoring. Optical pyrometers sense the properties of the radiated wavelengths generated by the surface that it is aimed at and directly correlates this to temperature. Most optical temperature sensing devices are hand held and temperature is determined by aiming the sensor at the point where a measurement is desired. This device is most useful for making spot checks of bearing temperatures, motor temperatures, boiler casing temperatures, etc.

16.4 Level Measurement

Level measurement has many applications in a power plant. Several different methods can be utilized for detecting level in open tanks or pressure vessels.

Level Measurement

Float Type
Sight or Gauge Glass
Level Transmitter

Slide 16-4

Level of a liquid is often determined by the position of a float that moves up and down with the level of the liquid. The motion of the float (mechanical position) can be determined and correlated to the liquid level.

Level of a liquid in an open tank or pressure vessel can be determined in several ways. One of the most simple is that of a sight glass or gauge glass. On open tanks, the sight glass may only be connected near the bottom of the tank whereas, for pressure vessels, it is necessary to connect the sight glass to both the top and bottom of the pressure vessel.

A differential pressure transmitter, connected to a tank or closed vessel similar to a sight glass, essentially measures the difference in pressure between the top and bottom of a tank or pressure vessel. If the tank is open to the atmosphere, then the transmitter need only be connected to the bottom of the vessel. This difference in pressure can be directly correlated to the level of liquid in the tank or pressure vessel. The transmitter measures the differential pressure and develops an output signal (normally pneumatic or electronic) that is linear to the level. Transmitter outputs are a relatively low level signal that can be safely brought into the control room where the signal is directed to an operator interface (gauge or display on the microprocessor CRT) and/or a controller.

16.5 Flow Measurement

The measurement of flow of liquids and gases is very important in a power plant. Some of the more common methods for determining flow are discussed.

The flow of water flowing through an open channel can be determined by measuring the height of the water in the channel. Since the water travels at a relatively constant velocity in a particular channel, the flow is proportional to the height of the water in the channel.

Flow Measurement

Open Channel
Variable Area Meters
Pitot Tube
Differential Pressure
Turbine Meters

Slide 16-5

A variable area meter or a rotometer is a device usually utilized to indicate the flow of liquids or gases. It consists of a gradually tapered tube mounted vertically with the larger end up. The fluid flows upward through the tapered tube and suspends a float which is submerged in the fluid. The float position is an indication of the flow rate, and the greater the flow rate, the higher the float rides in the tube. The entire fluid stream must flow through the annular space between the float and tube wall. The tube is marked off in divisions, and the reading of the meter is obtained from the divisions at the reading edge of the float which is taken at the largest cross-section of the float.

The pitot tube is a device that measures the "total head" (velocity head plus static head) at one port and the static head at the other port. Head is defined as pressure in this application. When the pitot tube is placed in a flow stream and aimed in the upstream direction, the differential pressure measured between the two ports can be correlated to the flow if the static pressure and temperature of the flowing media is known. This device is used frequently for testing work but is also used in some boiler combustion air flow measurements for on-line controls.

When a restriction such as an orifice, flow nozzle or venturi is placed in the flow stream in an enclosed duct or pipeline, the restriction will create a pressure drop in the line that is proportional to the square of the velocity. This principle is the most frequent method used for the determination of flows in a power plant.

A turbine meter is a small turbine that is placed in the flow stream. As flow increases the turbine will spin at increasing speeds. By measuring the speed of the turbine, the flow is determined.

16.6 Weigh Scales

The most common application for weigh scales in a power plant is for measuring coal flow although there are other applications. The coal feeder can consist of load cells that determine the weight of coal on a section of belt in the coal feeder. If the speed of the feeder belt is also measured, a calculation of coal flow can be calculated.

CHAPTER 17. ELECTRICAL THEORY

17.1 Introduction

17.2 Fundamental Parameters
- A. Current
- B. Voltage
- C. Other Parameters
- D. Ohm's Law
- E. DC Wattage or Power
- F. AC Wattage or Power

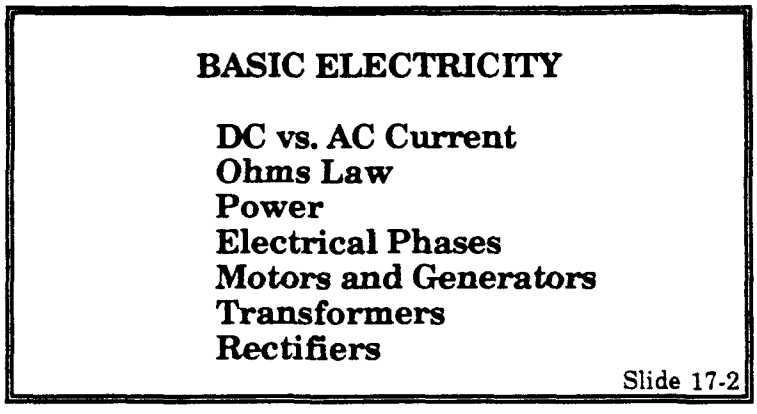
17.3 Electrical Power Equipment
- A. Motors
- B. Generators
- C. Transformers
- D. Other Equipment

17.4 Instruments and Meters

17. ELECTRICAL THEORY

17.1 Introduction

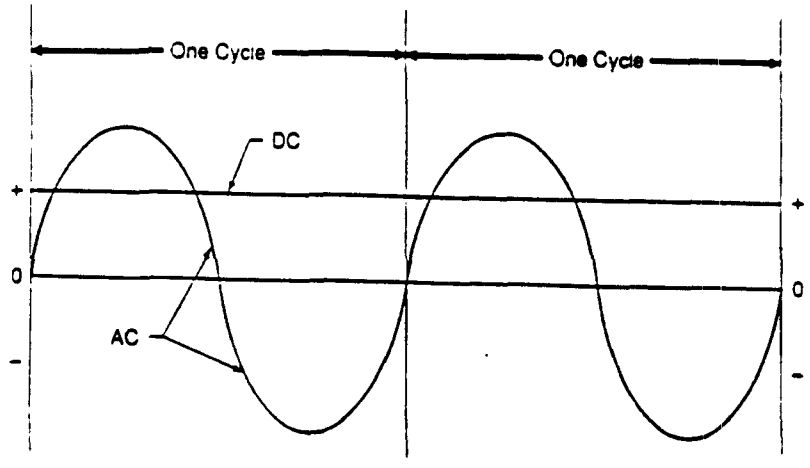
A basic understanding of electrical principles is necessary for informed operation, maintenance, and troubleshooting of boiler electrical systems and generator systems. This learning unit will present the basic principles of electricity. It will focus on the basic knowledge required for the understanding of transformers, rectifiers, and electric generators.



17.2 Fundamental Parameters

We will begin by defining electricity and some of its related properties. Initially, we will focus on steady "direct current" (DC), such as that associated with battery powered systems. By contrast, the other form of electricity is "alternating current" (AC). This is the form of electricity produced by steam turbine generators. Alternating current is the momentary flow of electrons in one direction and then in the reversed direction at regular intervals of time.[1]

STEADY DC AND OSCILLATING AC ELECTRON FLOW



Slide 17-3

Current

Current is the flow of electrons. When we say, "electric current or electricity can flow through a wire," we mean that electrons can flow through the wire. The electrons of steady DC current flow in one direction.

Current can be thought of as the rate of electron flow, where one ampere is a very large number of electrons per second. Current is measured in amperes or amps. We will use the fluid flow analogy to help our understanding of electricity.[2] Current is analogous to fluid flow rate, which can be expressed in gallons per minute (gpm).

ELECTRICITY - FLUID FLOW ANALOGY

Parameter	***Electricity***	***Fluids***
Flow Rate	Electron Flow/Current (amps)	Fluid Flow (gpm)
Driving Force	Electrical Potential Difference or Voltage (volts)	Pressure Difference (psi)

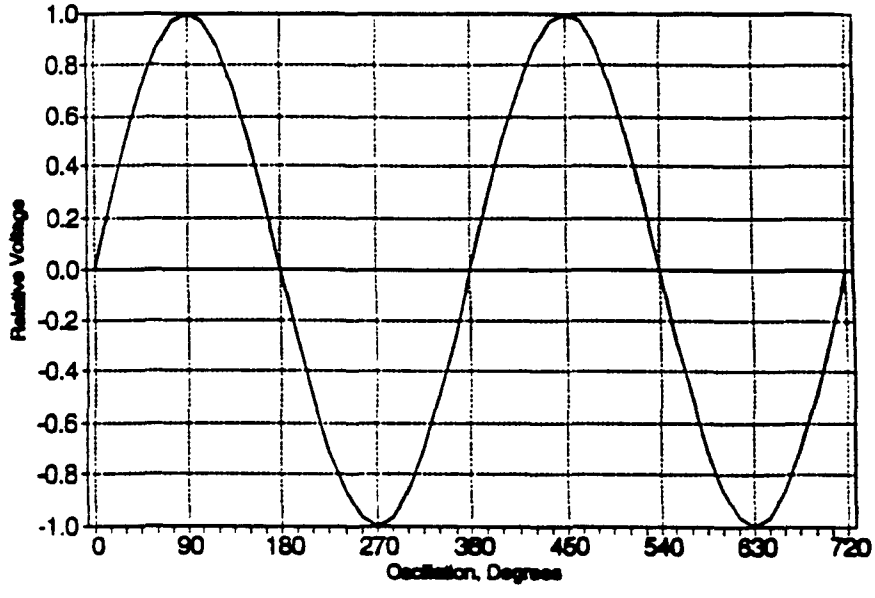
Slide 17-4

Voltage

We know that fluid flow is caused by a pressure difference, such as that developed by a pump. The electrical driving force is called the electrical potential or voltage difference. It causes current to flow through a conductor. Electrical potential is measured in volts and is analogous to pressure, which can be measured in pounds per square inch (psi).

The voltage of alternating current (AC) electricity periodically changes. AC is the traditional form of commercial electricity which is produced by most steam turbine generators and is delivered to customers through interconnecting electrical transmissions lines (the grid). The voltages for standard AC electricity in the United States oscillates at 60 cycles per second (60 Hz), where each cycle would correspond to an oscillation occurring over 360 degrees.

VOLTAGE OSCILLATIONS OF ALTERNATING CURRENT



Slide 17-5

Because of the oscillations, the actual time-average AC voltages and the corresponding AC currents have values of zero. However, conventional AC instruments measure representative voltages and currents. The instruments are designed to give "root-mean-square" values, which are the average of the square of the values over time. It may be interesting to note that the oscillating features of AC voltages and currents can be measured by oscilloscopes.

Other Parameters

Conductors are materials with properties that permit the flow of electrons. Materials are generally ranked according to their relative resistance to electrical flow. Electrical resistance is generally measured in units of ohms.

OTHER BASIC ELECTRICAL PARAMETERS

Conductor	Material Which Permits Electrons to Flow
Resistance	Measures Opposition to Flow
Ohm	Unit of Electrical Resistance
Insulator	Material with High Resistance
Circuit	The Path of Electrical Current From a Source Through Various Conductors and Devices

Slide 17-6

The resistances of conductors depend upon chemical composition, size (diameter), and length. Glass objects generally have enough electrical resistance to be called insulators, whereas metal wires are called conductors. Large diameter (small gauge) copper wires have much lower electrical resistance than thin copper wires. Electrical conductors must be properly selected so that they will not overheat and fail (melt) under high current conditions. The current carrying capacity of wire conductors is dependent upon size (gauge) and electrical insulation design.

An electrical circuit is composed of at least one electrical source, various conductors (or resistors) and/or other electrical devices (e.g., motors) which are connected together. A battery or some other electrical source is required to provide the voltage which will cause electricity to flow through a circuit.

Ohm's Law

Ohm's law establishes the basic relationship of steady electrical flow [Steingress and Frost, 1991]. The electrical potential (measured in volts) is equal to the current (measured in amps) times the resistance (measured in ohms). Ohm's law uses "V" as the standard symbol for the voltage or electrical potential. The symbol for current is "I", and the symbol for resistance is "R".

OHM'S LAW
VOLTAGE-CURRENT RELATIONSHIP

Voltage = Current x Resistance

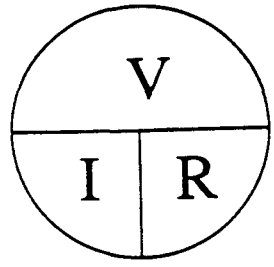
V= I x R

I = V / R

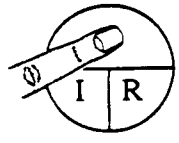
Slide 17-7

If any two of these variables are known, the third can be found from Ohms law by using simple algebra.

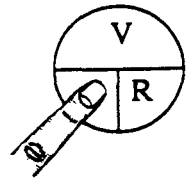
GRAPHICAL RELATIONSHIP OF VOLTAGE AND CURRENT BY OHM'S LAW



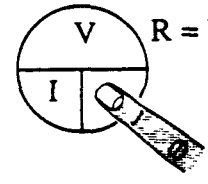
V = Voltage (volts)
I = Amperage (amps)
R = Resistance (ohms)



V = I x R



I = V / R



R = V / I

Slide 17-8

Ohm's law can be conveniently used in steady applications which involve both large and small electrical quantities. Many power applications involve high voltages, measured in kilovolts (thousand volts) or megavolts (million volts). By contrast, instruments often produce small voltage signals which are measured in millivolts (one-thousandth of a volt) or current signals which are measured in milliamperes (one-thousandth of an amp). It is recommended that conversions be made to the standard units of volts, amps, and ohms before Ohm's law is used for calculations.

DC Wattage or Power

The basic unit of electrical power is a watt. In power generation, we often are concerned with large quantities of power which can be measured in kilowatts (kW, thousand watts) or megawatts (MW, million watts). As described later, the alternative units often used in AC electric generation applications are volt-amps (VA), kilovolt-amps (kVA), and megavolt-amps (MVA).

Electrical power is generally defined as the product of the voltage times current. The electrical power unit is a "watt" which has dimensions equivalent to a volt-amp (VA). Other formulas are obtained using Ohm's law substitutions.

DC POWER RELATIONSHIPS

Power = Voltage x Current

$$P = V \times I$$

$$P = (I \times R) \times I$$

$$P = (I)^2 \times R$$

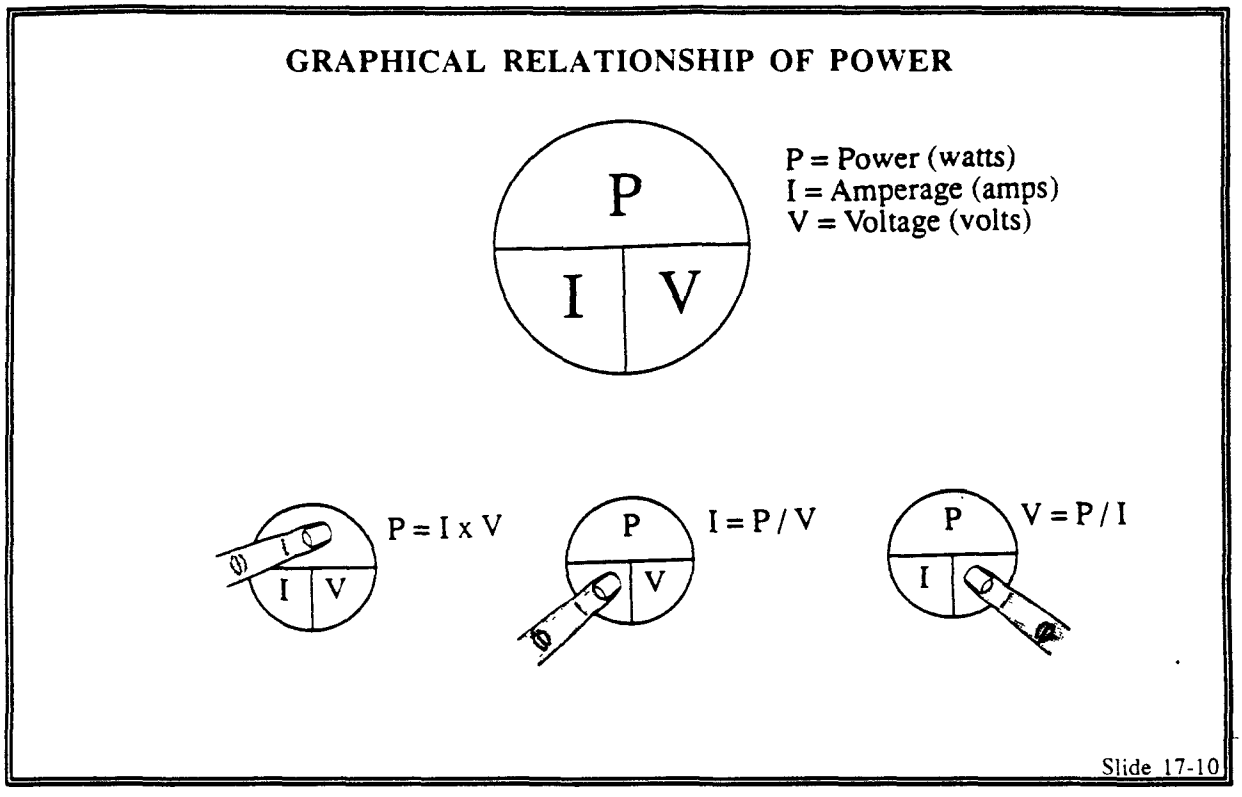
or

$$P = (V / R)^2 \times R$$

$$P = (V)^2 / R$$

Slide 17-9

The power relationships can be applied to the example of the resistance heating of a conductor. If the resistance of the conductor and the voltage across it can be calculated or measured, the rate of resistance heating can be determined.



AC Wattage or Power

Alternating current or AC power is commonly encountered whenever power must be conveyed over a distance. The previously developed DC power equations require modification for AC power, as indicated in Slide 17-11.

AC POWER RELATIONSHIPS

Power = Voltage x Current x Power Factor

$$P = V \times I \times \cos \emptyset$$

$$P = (I \times R) \times I \times \cos \emptyset$$

$$P = (I)^2 \times R \times \cos \emptyset$$

or

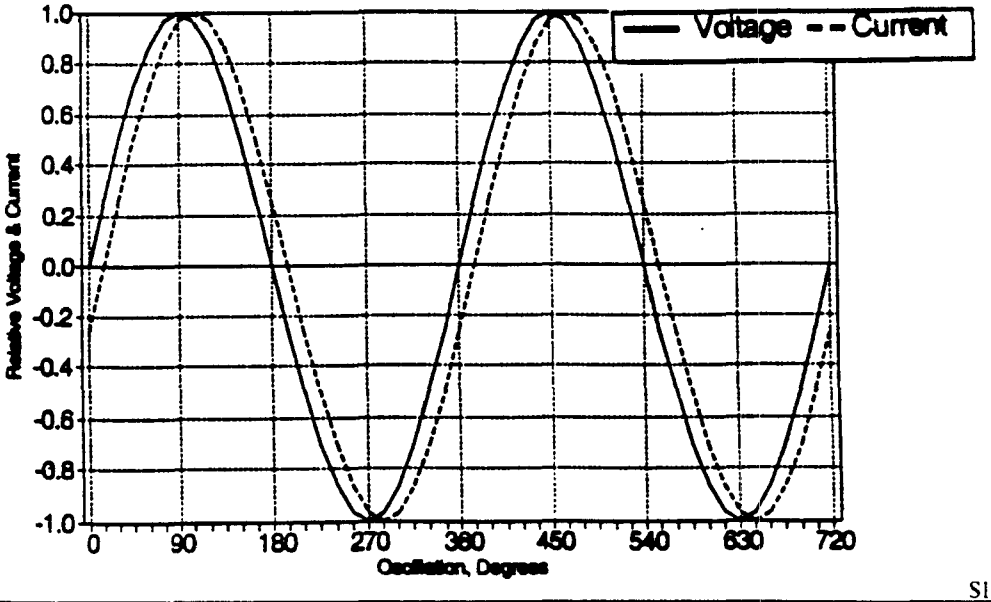
$$P = V \times (V / R) \times \cos \emptyset$$

$$P = (V)^2 / R \times \cos \emptyset$$

Slide 17-11

For AC, power is expressed as voltage times current times the power factor. The "power factor" is the correction factor required because the current and voltage generally are slightly out of phase with each other, as shown in Slide 17-12. If the current and voltage reach their maximum value at the same point in the cycle, they are said to be "in phase". Since the voltage reaches its peak at a point earlier in the cycle than the current in the figure below, the current is said to be lagging.

AC VOLTAGE AND CURRENT RELATIONSHIPS (EXAMPLE OF CURRENT LAGGING)



Slide 17-12

If steady current and voltage readings are obtained across a component of an AC circuit, they may be multiplied together to yield the "apparent power." This is the power which is available to "do work".[3] In electric power generation, the apparent power is often expressed in MVA units, as it represents an upper production limit. The power factor is defined as the ratio of the "real power" divided by the "apparent power." The conventional representation of a power factor is "cos ø" where " ø " represents the phase angle difference between the voltage and current. For the example where the phase angle difference was 15 degrees, the power factor would be 0.96 (cos 15°).

AC ELECTRICAL POWER

Apparent Power is Current times Voltage

$$P_{apparent} = I \times V, \text{ [KVA]}$$

Power Factor

$$\text{Power Factor} = \cos \emptyset = P/P_{apparent}$$

Slide 17-13

17.3 Electrical Power Equipment

Motors

Motors convert electrical energy into mechanical energy used to drive various types of machinery. The development of the electric motor has had a profound effect on modern industry. Low operating costs and ease of operation of electric motors has resulted in motors replacing steam engines and turbines to drive auxiliary equipment.

Motors commonly used in industrial applications are single-phase and multi-phase. Single phase consists of two wires (which power the motor). Multi-phase motors have either three or four wires with 3-phase (3 wires) being the most common. Single phase motors are induction motors. A magnetic field is induced by the flow of current through wiring arranged around a rotor. The wiring is referred to as the stator because it remains stationary. The magnetic field oscillates with the input AC current and voltage (usually at 60 cycles/second). The rotor spins as it attempts to magnetically align with the field which creates mechanical motion.

Single-phase motors are primarily used in fractional horsepower applications (1/4, 1/3, 1/2, 3/4 horsepower) and where three-phase power is not available. Single-phase motors differ slightly depending upon the method of starting: split-phase, capacitor-start, capacitor start-and-run, and shaded-pole.

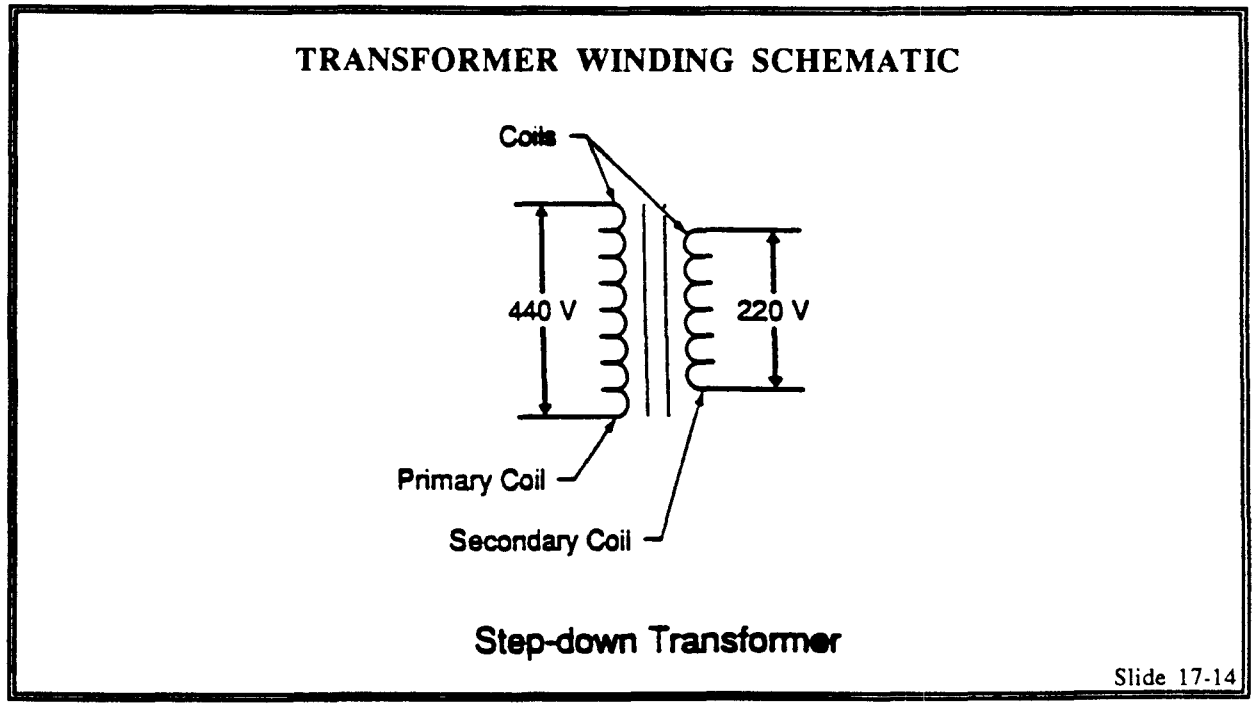
Multi-phase motors are typically used in large horsepower applications due to their higher torque capacity. The three most commonly used three-phase induction motors are squirrel-cage, wound-rotor, and synchronous motors. Squirrel-cage and wound-rotor motors have three separator stator windings. There is one stator winding for each phase distributed at 120° angles. This produces a rotating magnetic field which causes the rotor to turn. Synchronous motors uses two magnetic fields which are synchronized. The rotor is excited with AC power to create a rotating magnetic field while the stator is powered with DC to create a stationary field. The effect of the magnetic fields attempting to stay "in synch" causes the rotor to turn.[1]

Generators

Generators are essentially motors operated in reverse. They convert mechanical energy into electrical energy. Both DC and AC generators are commonly used. DC generators were first developed to produce electricity from steam engines. This creates low voltage with high amperage, which requires large wiring and results in significant line losses. AC generators are almost exclusively used presently to produce electricity at high voltage and low amperage. This makes it possible to transmit power over extended distances. Substations (with transformers) are used to "step-down" the power at the point of use.

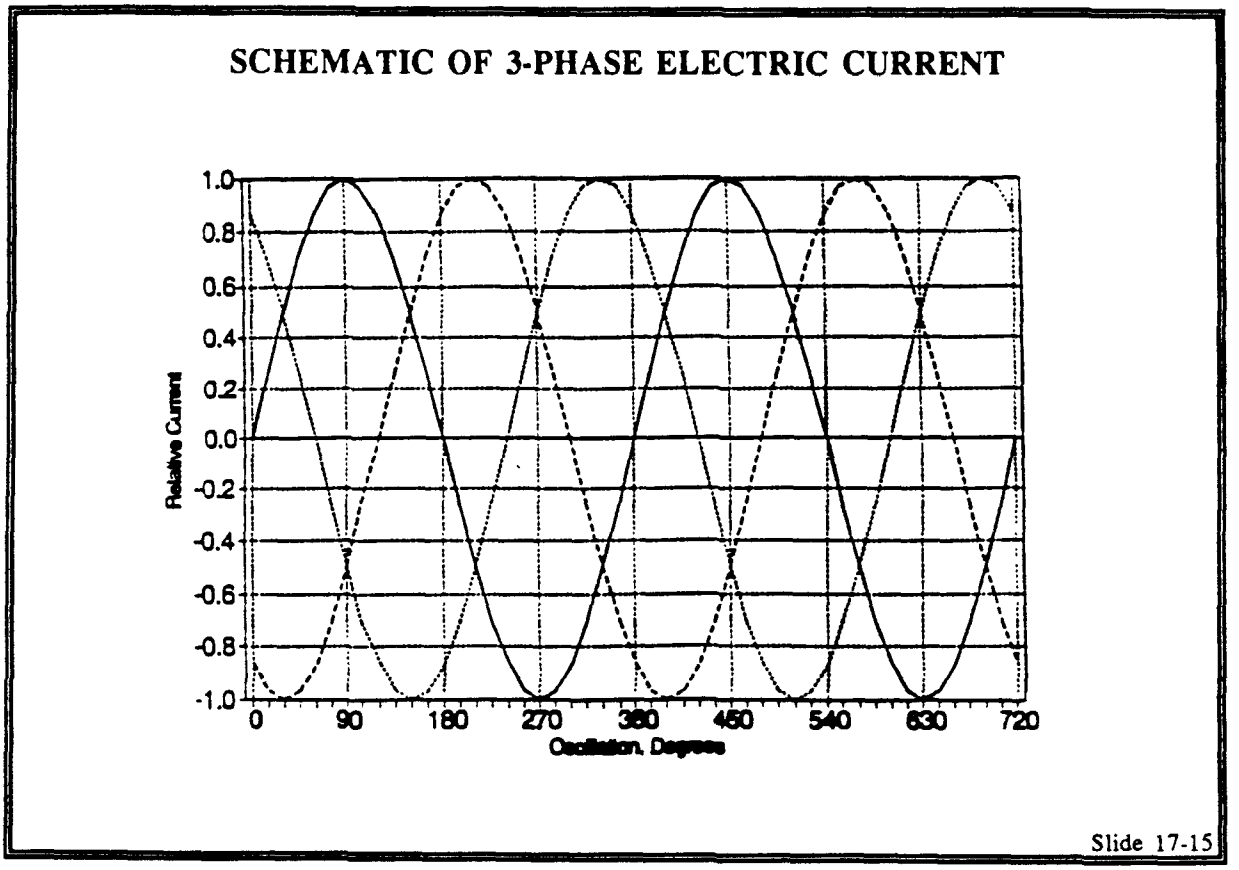
Transformers

Transformers are designed to increase or decrease voltage in AC circuits. A step-up transformer delivers a higher voltage from the secondary coil than is received by the primary coil, and a step-down transformer will deliver a reduced voltage.



The fractional increase or decrease in voltage of a transformer is proportional to the ratio of the windings of wire in the primary and secondary coils. If there are twice as many windings on the primary coil as on the secondary coil, the transformer will function as a step-down transformer with the resulting voltage at one-half that of the supply voltage. Transformers are essential elements in the connection between the utility grid, the electric generator, and in-plant distribution system.[5]

Operators should be aware that the utilities transport 3-phase, high voltage, AC power. Three-phase generation uses three primary conductors which carry AC currents whose cycles are timed in a regular offset pattern. Many circuit designs will use four conductors in order to accommodate a ground requirement.



Other Equipment

Special electrical power equipment such as circuit breakers, rectifiers, and inverters are commonly used in utility and industrial boiler units.[5]

ELECTRICAL POWER EQUIPMENT

COMPONENT	FUNCTION
Voltage Regulator	Maintains constant voltage from AC source
Circuit Breaker	Controls the flow of electricity
Rectifier	Converts AC electricity to DC
Inverter	Converts DC electricity to AC

Slide 17-16

Voltage regulators are used to maintain a constant voltage on an AC generator. Constant terminal voltage is maintained by increasing or decreasing the field current to the generator.

Circuit breakers are designed to provide the switching required in electrical generation and electrical service. Some circuit breakers are provided primarily to protect the utility grid, whereas others function as a local safety device. The utility can trip the main circuit breaker as part of the normal and correct functioning of the network protective system.

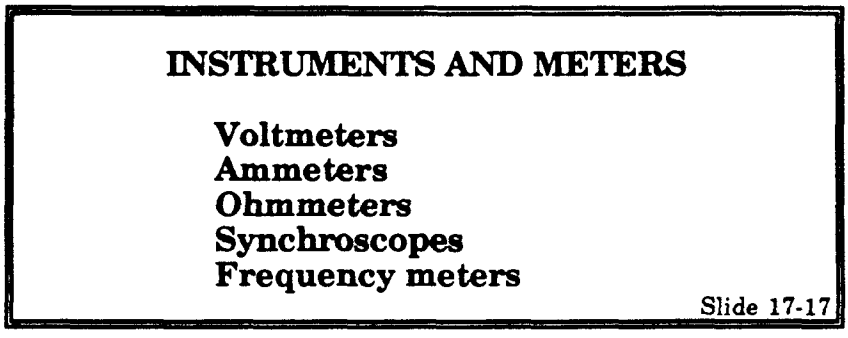
Circuit breakers are switches that are mechanically closed after a heavy spring is compressed and held in place by a latch. Circuit breakers are designed to open automatically when an external tripping signal is received. The signal may signify that the current flow on the circuit is too high, the voltage is too high or too low, or that some fault condition has occurred. The signals are often actuated by the action of a relay. For example, a directional relay is designed to prevent the reversed flow of electricity, such as the case when a generator receives grid power (which causes it to act as a motor).

A rectifier is an electronic device which receives an AC electrical supply and produces DC electricity. Rectifiers are used to produce the DC electricity which is used to produce the electrical fields required for particle collection in electrostatic precipitators. Rectifiers can also be used for charging the batteries which store energy for emergency power supply systems.

Inverters are used to convert the DC electricity into AC electricity. Emergency power supply systems are generally designed around storage batteries and inverters. These are required because AC power is generally required to drive almost all the electric motors and controls used in utility and industrial units.

17.4 Instruments and Meters

Instruments and meters are used to monitor and control electrical operations in a plant. Instruments and meters commonly used include voltmeters, ammeters, ohmmeters, synchroscopes, and frequency meters.[1]



Voltmeters measure the difference in voltage between two points in a circuit. Voltmeters are commonly used to check the voltage, fuses, and for breaks in circuits.

Ammeters measure the current in any part of a circuit. Ammeters are commonly used to check for excessively high current in a circuit. Ammeter reading must be carefully monitored as plant load is increased to ensure that the generator windings do not overheat.

Ohmmeters measure the amount of resistance in a part of a circuit or in a complete circuit. Continuity can also be checked using an ohmmeter.

Synchroscopes measure the phase relationship between two voltages. Synchroscopes are used when two AC generators are paralleled or synchronized.

Frequency meters indicate the frequency of oscillation in a system. Electrical equipment is designed to operate at a specific frequency. Any variation in frequency affects all electric motors, electric clocks, and other inductive electrical devices.

REFERENCES

1. Frederick M. Steingress and Harold J. Frost, Stationary Engineering, American Technical Publishers, Inc., Homewood, IL, 1991, pp. 301-328.

2. Basic Electricity, Field Manual, FM 55-506-1, Department of the Army, Washington, DC, 22 April 1977.

3. Electricity, Theory and Fundamentals, Student Workbook 52C10, US Army Engineer School, Fort Belvoir, VA, June 1979.

4. W. A. La Pierre and B. M. Jones, "Electrical and Electronics Engineering," Mark's Standard Handbook for Mechanical Engineers, Eighth Edition, Edited by T. Baumeister, et al., McGraw Hill Book Company, NY, 1978, pp. 15-1 to 15-6.

5. John Reason, "Electrical Interconnections," Standard Handbook of Power Plant Engineering, Thomas C. Elliott, editor, McGraw Hill Book Co., NY, 1989, pp. 5.3-5.24.

CHAPTER 18. TURBINE GENERATOR

18.1. Introduction

18.2. Steam Turbine Generator Description

18.3. Steam Turbine Designs

18.4. Steam Turbine Generator Operation

18.5. Generator Synchronization With Utility Grid

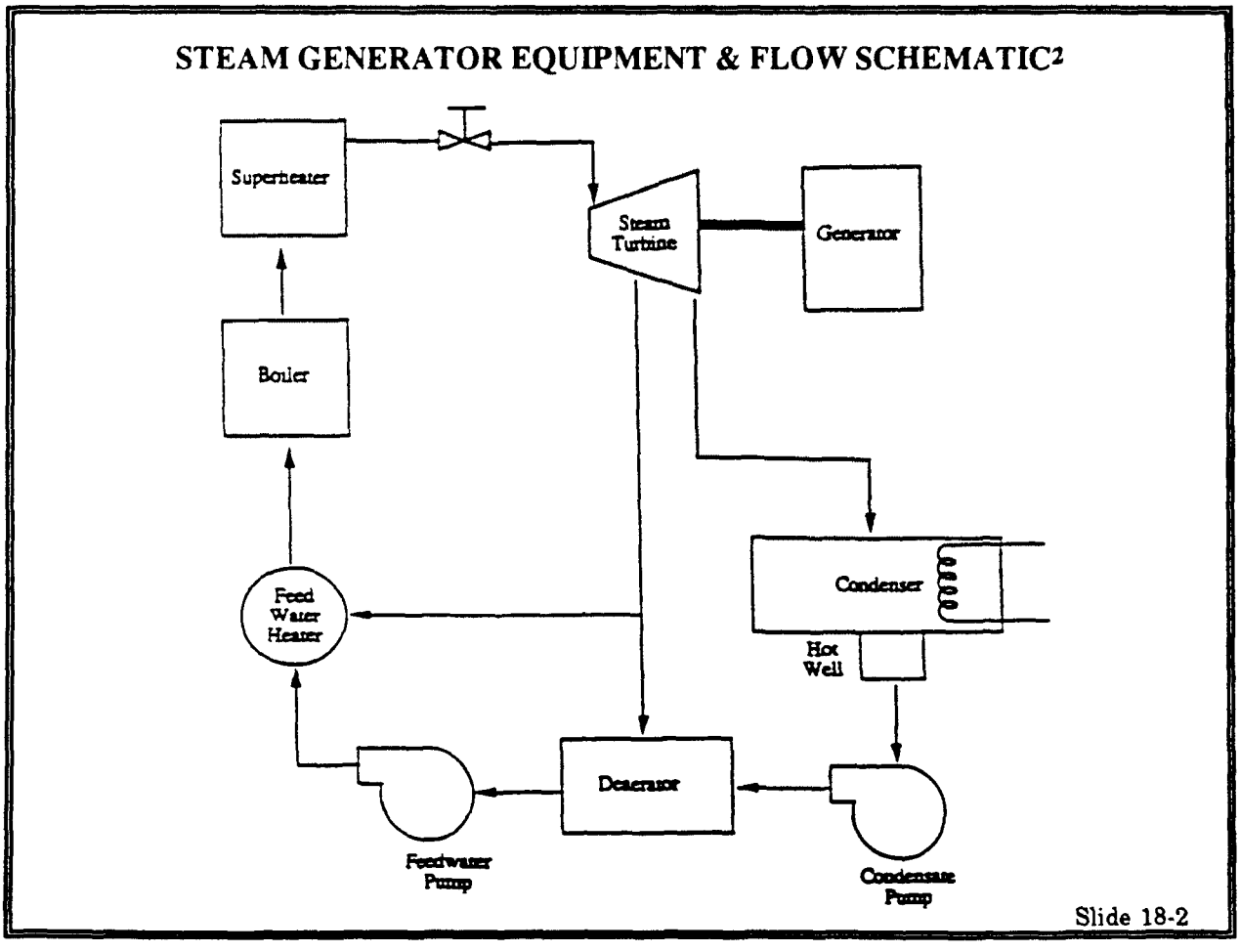
18.6. Turbine Generator Off-Nominal Conditions

18. TURBINE GENERATOR

18.1 Introduction

This unit addresses the design and operation of turbine generators. Most of the electric power produced in the U.S. is via fossil fuel burning steam plants in combination with turbines. Such systems allow either a portion or all of the thermal energy generated in the boiler to be converted to electrical power. Steam turbines are also used to drive many different types of mechanical devices such as electric generators, pumps, and compressors.

18.2 Steam Turbine Generator Description



A turbine generator set will consist of a variety of major components and system ancillary components. The above slide illustrates the typical arrangement for the steam side of a boiler and turbine generator set and its auxiliary components.

TURBINE GENERATOR SYSTEM COMPONENTS

Steam Turbine
Condenser, Hotwell, & Air Ejector
Condensate Pump & Heater
Deaerator
Feedwater Pumps & Heaters
Electrical Generator

Slide 18-3

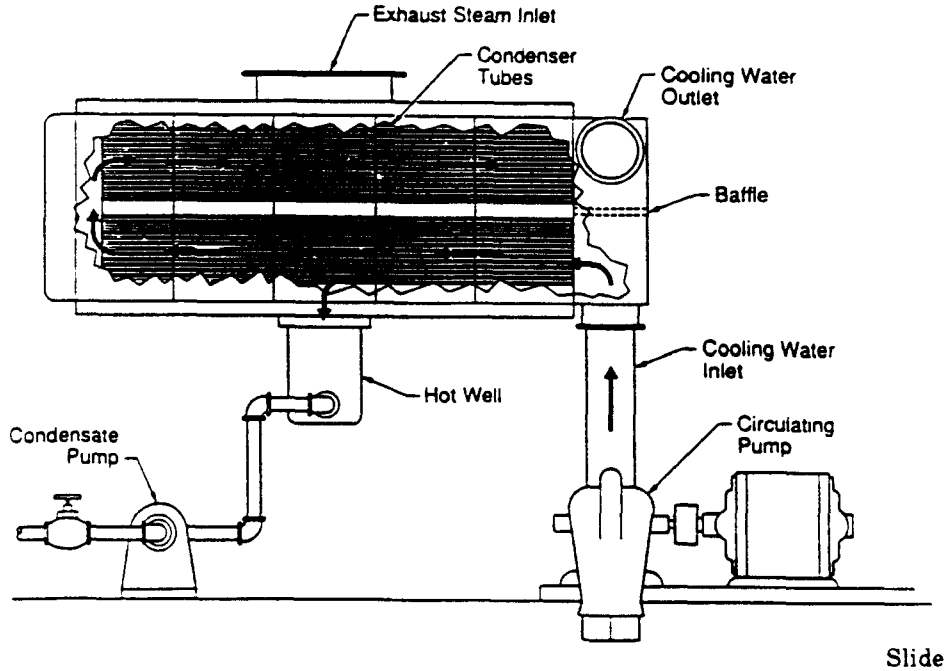
Steam turbines convert stored thermal energy to mechanical work by controlled expansion of steam through a series of stationary blades or nozzles, and rotating blades. The combination of a stationary vane and a rotating blade is called a turbine stage. Steam enters the turbine through the relatively small nozzles and as it expands it attains a high velocity and exerts a force against the rotating blade causing it to turn.

In the flow schematic shown in slide 18-2, the steam from the boiler first passes through a throttle valve which modulates the flow rate and pressure of steam being delivered into the steam turbine. The amount of power generated by the turbine is proportional to the flow rate of steam through the turbine and the steam pressure drop across the turbine. By modulating the main throttle valve, the total flow of steam and the steam pressure at the first stage nozzle can be adjusted to provide the required rotor speed at the desired power output level.

Outlet flow from the turbine is directed into a condenser, which is basically a series of water cooled tubes that cause the steam to condense. Water then drips from the condenser tubes into a lower chamber known as a hotwell. A minimum level of water must be maintained in the hotwell at all times to prevent cavitation in the condensate pump.

The condensate pump extracts the water from the hotwell and directs it to a device known as a deaerator. The purpose of the deaerator is to remove dissolved gases from the water before it is pumped to the boiler. To accomplish that objective, the condensate is heated to its saturation point where dissolved gases will boil off. Released gases are then vented to atmosphere. The deaerator operates at a pressure ranging from around 5 to 75 psig, depending on the particular design of the plant.

STEAM CONDENSER SCHEMATIC[1]



Slide 18-4

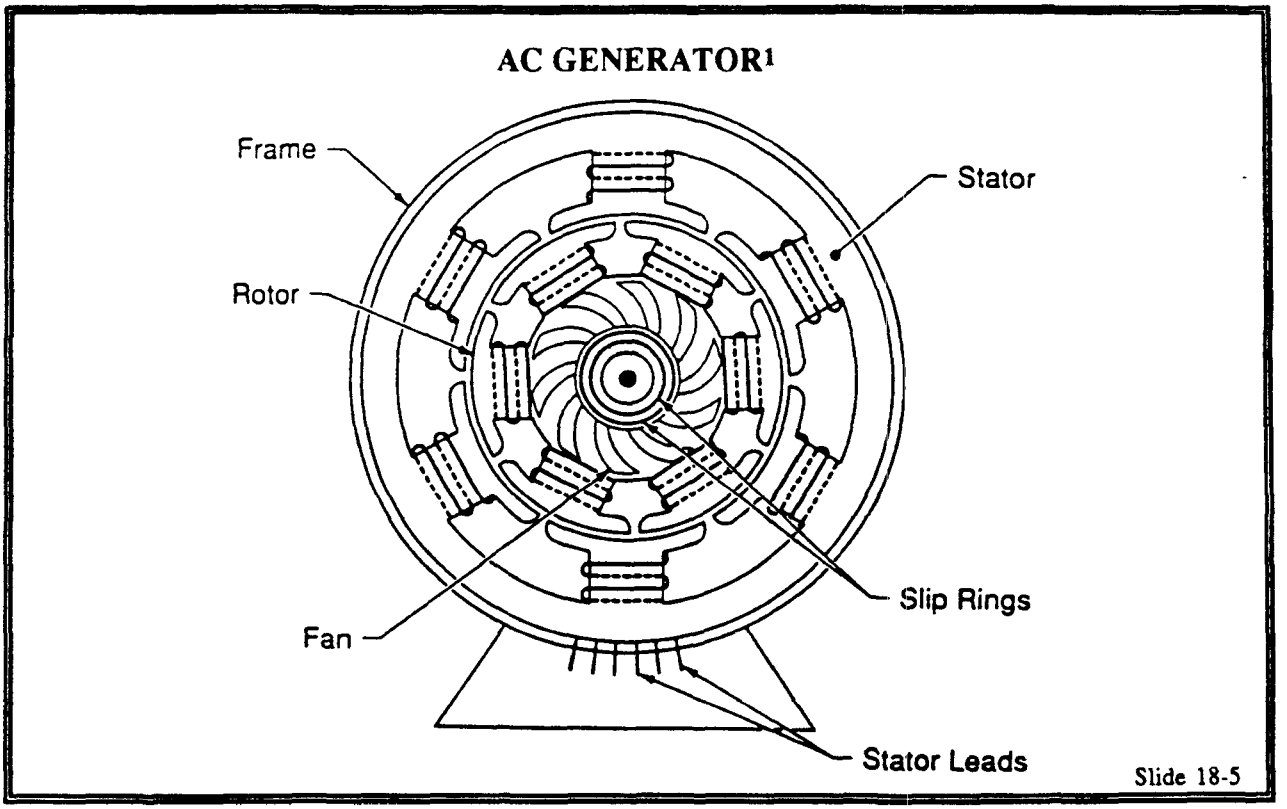
The boiler feedwater pump increases the pressure of deaerated water to the full boiler operating pressure. Also at this stage, the feedwater is preheated before it enters the boiler economizer. Heat for operation of the deaerator and the feedwater heaters is often supplied by extracting steam from various stages of the turbine.

Because the functions of the feedwater pump are so critical to boiler operations, a parallel set of pumps is generally installed. This allows switching between the pumps to provide for maintenance, without having to take the boiler off-line.

In addition to the steam cycle described above, other key ancillary components of the turbine/generator are the oil heating and cooling systems and the turning gear. The shaft in the turbine and generator rotates on bearings which are bathed in oil. The oil is provided at a pressure (by a lift pump) high enough to maintain an oil film which carries the load of the rotor. To avoid serious bearing friction, the oil must continually flow through the system at a proper viscosity. Under no load or cold start conditions, the viscosity considerations require oil heating. Under full load operation, oil coolers are used to maintain viscosity by rejecting heat. Because of the critical nature of the oil flow, turbine generators will be supplied with a redundant set of oil pumps and will generally have an emergency system operated by an alternate power supply, such as DC powered pumps with a battery pack.

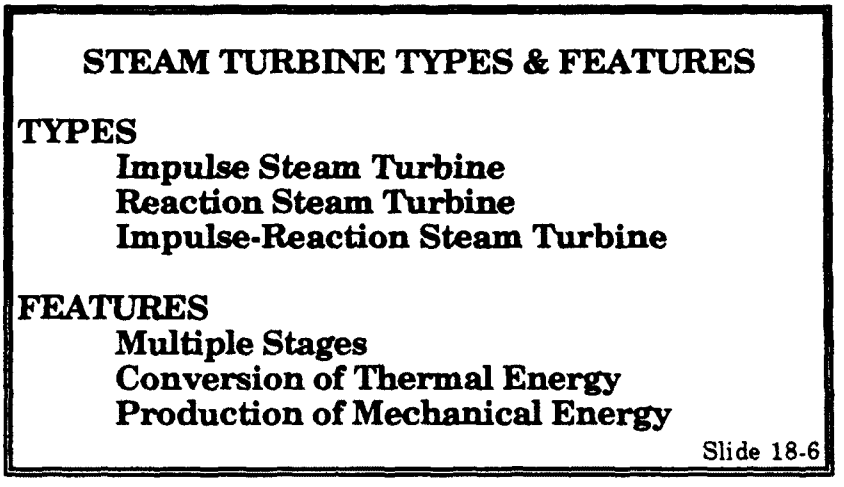
Once the turbine generator set is placed into operation, the shafts should be kept in continual rotation, even when the unit is down and no power is being generated, to maintain the turbine and generator shaft alignment and to minimize vibrations in the shaft. The turning gear is a motor driver which provides rotation of the main shaft, generally less than 10 rpm. Typically, a centrifugal clutch mechanism disengages the turning gear whenever steam flow through the turbine causes the rotor to turn at higher speeds.

The final component of the turbine generator system is the electrical generator. The primary purpose of the generator is to convert mechanical energy into electrical energy. The mechanical energy is supplied by the rotating shaft in the turbine. The purpose of the slip rings, shown in Slide 18-5, is to transmit DC electric energy as excitation current to the rotor. The stator leads are connected to switching devices which transmit the three-phase AC energy from the coils on the stator to the utility grid.



18.3 Steam Turbine Designs

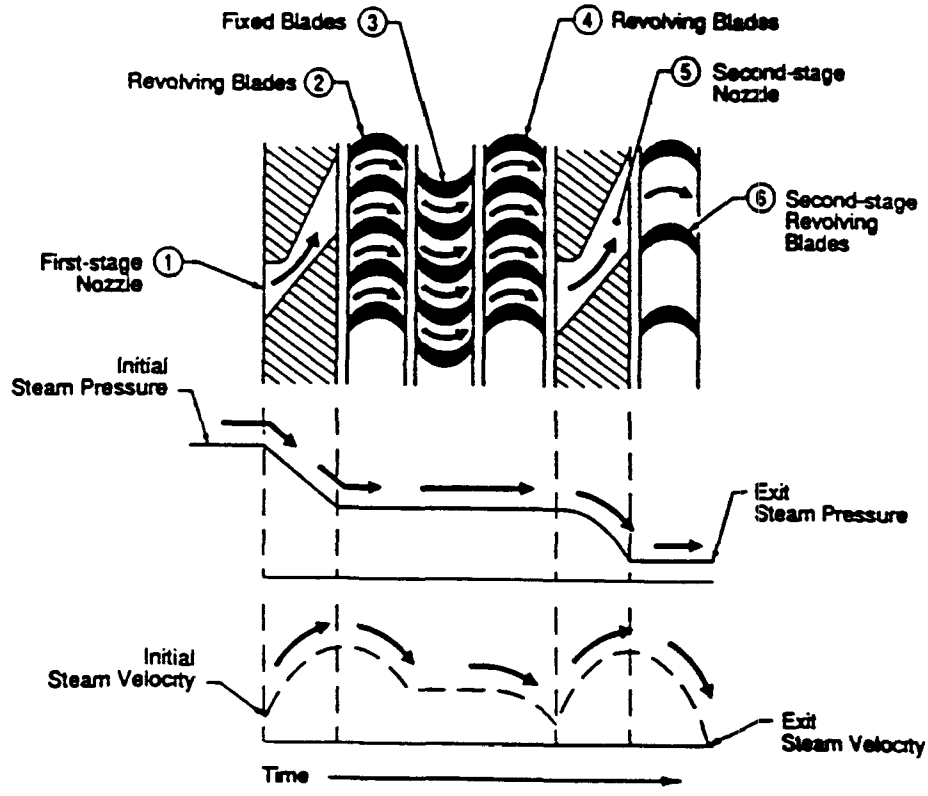
Three types of turbines are commonly used: the impulse, reaction and impulse-reaction turbines. Their designs have many similarities, as described below.



Steam turbines consist of many stages of airfoil blades which convert energy in the steam to rotating shaft power. Steam pressure and temperature decrease from stage to stage in a steam turbine.

As the pressure is decreased, the density drops which causes the steam to expand and occupy more volume. This results in the progressive increases in turbine wheel diameter and blade length as steam moves through each successive stage.

IMPULSE TURBINE BLADE CONFIGURATION & FLOW PARAMETERS[1]

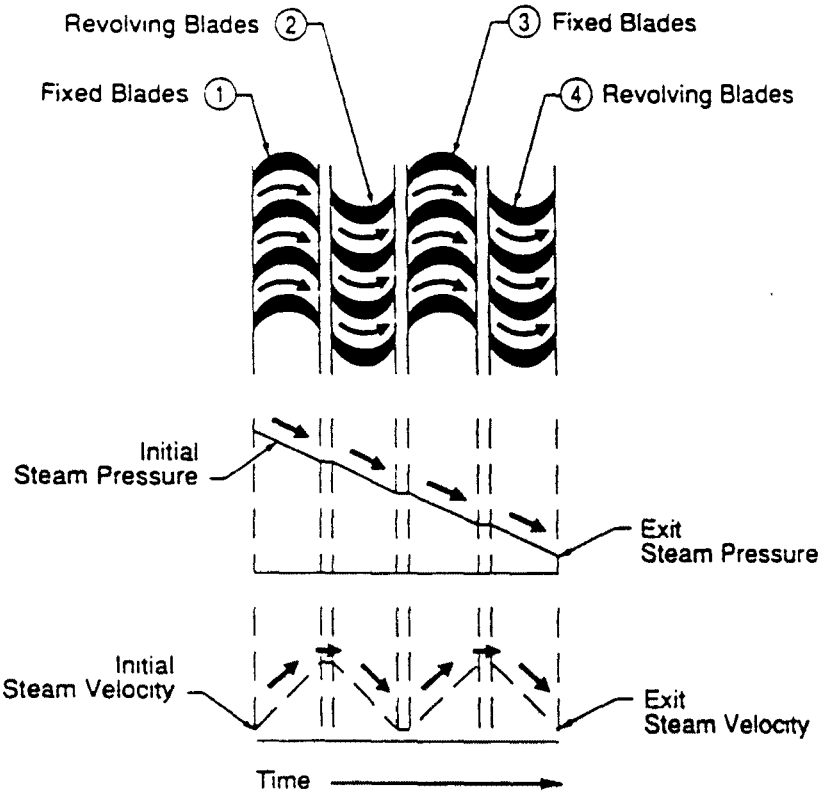


Slide 18-7

Impulse steam turbines use the impact of high velocity steam to create a force acting on a blade mounted on a wheel. As illustrated in the above slide, impulse turbines have multiple stages consisting of a nozzle, two rows of rotating airfoil blades and one row of stationary blades. The system is designed so that most of the pressure drops occur through the nozzles rather than the blades. Although the pressure within a blade section is nearly constant, the velocity drops-off considerably.

The rotating blades are attached to disk wheels which are mated to the rotor shaft while the fixed blades, or stators, are attached to the turbine casing. Expansion of the steam through the turbine causes the shaft to rotate and converts the high pressure thermal energy of steam into mechanical energy (shaft work). The stationary blades act mainly to change the direction of the steam flow, so the optimum angle of steam flow exists as the steam enters the second set of rotating blades.

REACTION TURBINE CONFIGURATION & FLOW PARAMETERS[1]



Slide 18-8

Reaction steam turbines make use of reaction forces produced by a flow of steam through the turbine blades. The difference in the momentum of the flow entering and leaving the rotating blades causes a mechanical force on the blades which is transferred to the shaft. The high velocity steam gives up its kinetic energy (velocity) as it flows through the revolving blades.

The reaction turbine uses fixed blades to act as nozzles. As illustrated above, steam enters the first set of fixed blades and has its velocity increased as its pressure drops. The fixed blades also change the direction of the steam flow so it enters the rotating blades at the optimum angle. The process then repeats itself at succeeding stages.

Impulse-reaction turbines combine impulse and reaction blading. There are several stages of impulse blades in the high pressure end of the steam turbine and reaction blades in the low pressure end of the turbine.

TURBINE GENERATOR OPERATION

Cold Start
Synchronization
Shut-Down

Slide 18-9

Each turbine generator set will be provided with a detailed set of operating instructions developed by the vendor.

In large installations, there will typically be an area operator at the turbine generator as well as remote control from the main control room. In the main control room, the operator will usually have a major panel devoted to instrumentation and control of the turbine generator set. Redundant measurements and controls may be provided for the area operator.

It is critically important that the control room and area operators remain in close contact especially during system start-up and shut-down.

During start-up, the generator will provide no load to the turbine and the turbine will be relatively cool (or cold). Bringing the system from that state to full operational status is a critical responsibility of the operator.

All system components such as condensate pumps, deaerator, feedwater pumps, feedwater heaters, control valves, recirculation valves, vent valves, and emergency systems must be sequentially brought to operational status or standby status. All liquid supply system components must also be at their proper level and automatic control systems operational.

A key responsibility of the operator is to bring the turbine generator to its operational state at a rate specified by the manufacturer. During the start-up cycle, the turbine metal temperature will rise to the temperature of the steam supplied by the boiler. That process can cause severe thermal stress to build within the turbine and will cause a differential expansion of the casing and internal components. From a cool start, manufacturers generally require that the casing be warmed at a rate of about 100 °F per hour and at all times the temperature difference across any metal wall should not exceed about 150 °F. Procedures associated with preheating of the steam supply lines and assuring proper operation of emergency and auxiliary systems may cause the time required for the start-up process to extend over more than a single operating shift.

In addition to metal temperature concerns, care must be exercised to prevent the turbine rotor from accelerating too rapidly. After coming off the turning gear, the rotor is often limited to an acceleration of about 100 rpm/minute until a mid-range

speed is reached. Then a hold period is often required to prewarm the rotor and casing. Typical mid-range rotor speed will be on the order of 1000 rpm, and a hold time on the order of a half hour or more is not unusual. The manufacturer will also specify the acceleration rate for the turbine rotor which will assure safe operation through the rotor's critical speed points. Critical speed points are speed at which the rotor shaft becomes dynamically unstable with large lateral amplitudes, due to resonance with the natural frequency of lateral vibration of the shaft. Operation at the critical speed can cause excessive vibration of the turbine shaft resulting in catostrophic damage. Compliance with the start-up cycle is vitally important.

The generator rotor will begin to turn as the turbine rotor begins to turn. Fine adjustments of the rotor speed and excitation will be required to match the generator electrical voltage and phase characteristics with those of the utility grid. The proper rotational speed will typically be 3600 rpm to provide 60 Hz, three phase power output, although some generators are designed to operate at 1800 and 1200 rpm.

Generation of electricity by the system requires that an array of electrical subsystems be in operation. Provisions will be made for an excitation system and for adjusting the generator side voltage. During start-up, careful adjustment of generator side voltage may be required to prevent possible feedback to the generator end when the generator is synchronized.[3]

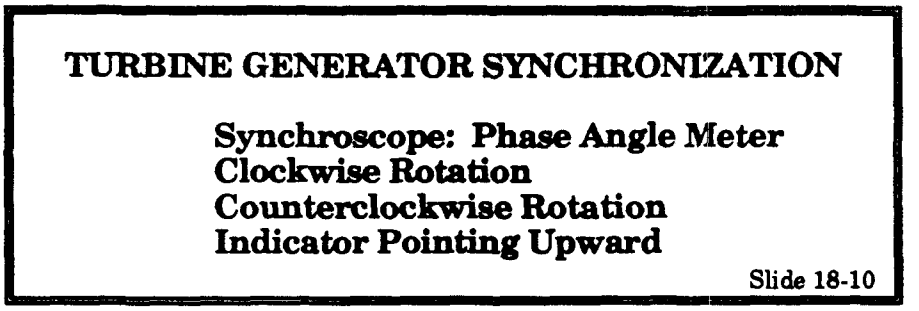
Picking up load on the generator must be accomplished in a gradual fashion and coordinated with adjustments on the steam flow side of the turbine generator. The rate at which load can be added will depend upon the turbine starting conditions. For colder starts, the load should be added at a very gradual rate (about 0.5% of rated capacity per minute). For hot starts, load can be added at a much faster rate (about 2 to 3 % of rated capacity per minute is typical).

Unit shut-down must rigorously follow a schedule of events which will basically be a reverse of the start-up procedures. The operator is responsible for assuring that the sequencing of events in the shut-down schedule are appropriately fulfilled.

The preceding material only addresses the broad general features of that operation. It is the responsibility of the operator to become familiar with the detailed instructions provided by the turbine generator manufacturer. These instructions should also be incorporated into a detailed operating procedures manual which is specific to the overall facility configuration and characteristics.

18.5 Generator Synchronization With Utility Grid

The synchronizing process requires that the three phases of electricity generated exactly match with the three phases of the AC buses of the utility grid before the breaker switch is closed.



A synchroscope is a phase angle meter which is provided to indicate any frequency mismatch and the difference in the phase angle between that of one leg of the generated power and the corresponding leg of the grid.[4] The operator uses information from the synchroscope to adjust turbine speed and excitation energy, thereby synchronizing the generator to the grid before closing the switch gear.

If the synchroscope indicator rotates counterclockwise, it is an indication that the frequency of the generated energy ("incoming" to the grid) is greater than that of the grid.[4] A clockwise rotation would indicate a lower generator frequency than that of the grid.

A stationary synchroscope pointer indicates that the frequencies are matched. The angular displacement of the pointer is an indication of the phase difference between the incoming and grid energy. The indicator is stationary and points directly upward when the phase of the incoming energy is matched to that of the grid.[4]

18.6 Turbine Generator Off-Nominal Conditions

TURBINE GENERATOR OFF-NOMINAL CONDITIONS

Water Induction
Excessive Vibration
High Bearing Temperatures
High Back-Pressure
Speed Control

Slide 18-11

A number of potential off-nominal turbine generator operating conditions are listed above.

Water induction can be caused by the flow of relatively cold vapor or liquid water from the feedwater heater through the steam extraction line and into the turbine casing. Water induction can cause severe thermal stress problems which can cause distortion of the casing and destruction of turbine blades. It can be controlled by installing automatic block valves and proper feedwater heater maintenance.

Excessive vibration of the turbine-generator may be an indication of potential problems, which can cause serious damage to the unit. Many modern turbine-generators are instrumented to "trip" if pre-set vibration limits are reached.

Likewise, high bearing temperatures can be caused by an inadequate cooling water flow rate, excessive cooling water temperature, or by the lack of lubrication. Most modern turbine-generator sets have bearing temperature controllers which will "trip" the unit if excessive temperatures occur. If this happens, the turbine manufacturer should be contacted for assistance.

It is possible for the generator to act as a synchronous motor and drive the turbine. This phenomena, which is called "motoring," may occur during low load operations, such as during the turbine generator start-up and shutdown. The turbine blades can become overheated and damaged due to the lack of steam flow, which normally controls the blade temperatures. Modern systems generally incorporate reverse power relays to automatically prevent this occurrence.

High steam turbine back-pressure or low vacuum in the condenser can be caused by inadequacies in the cooling water system. High back-pressure can result in overheating of the low pressure blading if the problem is not corrected. Temperature sensors or vacuum gages can be set to trip the turbine automatically.

Problems with speed control can be attributed to the turbine governor, voltage regulator or mechanical problems in the control system. Most units now incorporate mechanical or electrical over-speed limit controls.

REFERENCES

1. Frederick M. Steingress and Harold J. Frost, Stationary Engineering, American Technical Publishers, Inc., Homewood, IL, 1991, pp. 227-275, printed with permission.

2. Kenneth Wark, Jr., Thermodynamics, Fifth Edition, McGraw Hill Book Company, New York, 1988, p. 739.

3. Basic Electricity, Field Manual, FM 55-506-1, Department of The Army, Washington, DC, April 1977, pp. 299-304.

4 Joe Kaiser, Electrical Power, Motors, Controls, Generators, Transformers, Goodheart-Willcox Company, Inc., South Holland, Illinois, 1991, pp. 166-186.

CHAPTER 19. PREVENTIVE MAINTENANCE

19.1 Potential Economic Losses

19.2 Features of Preventative Maintenance

19.3 Periodic Inspections

19.4 In-Service Maintenance

19.5 Outage Maintenance Planning

Slide 19-1

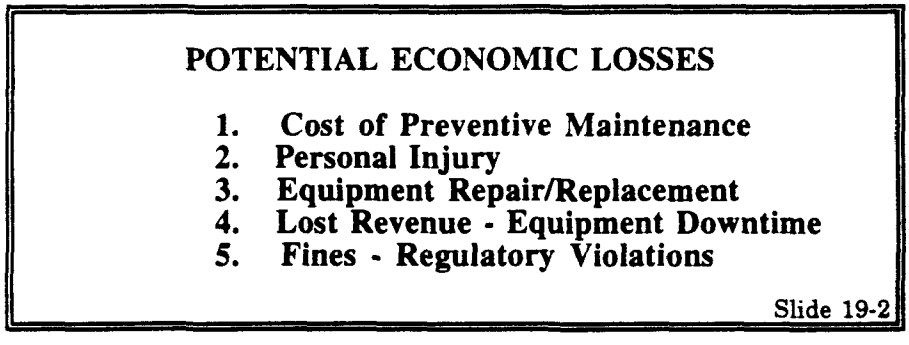
CHAPTER 19. PREVENTIVE MAINTENANCE

A well executed preventative maintenance program is essential to achieving high reliability and efficiency as well as maintaining safety. In addition, a sound maintenance program can reduce total operating expenses in the long term. This learning unit considers the general aspects of preventive maintenance. The safety aspects will be addressed in Chapter 20.

19.1 Potential Economic Losses

A preventative maintenance program can be thought of as an effective insurance program. In some industries, insurance policies are available to provide protection against revenue losses associated with unit outages, as well as casualty and liability losses. In general, losses will occur if equipment is not properly operated and maintained.

A broader view of preventative maintenance program includes the various economic aspects of production and loss. The economic aspects include: the costs of the preventive maintenance program; consideration of losses associated with injury and repair; lost revenue associated with equipment outages; and fines for regulatory violations.



Operators participate in preventative maintenance through their decision-making on issues of safety, operation, corrective maintenance and preventive maintenance. Operators have the responsibility for assuring that the equipment is both properly operated and maintained.

OPERATOR RESPONSIBILITIES

1. **Safety**
2. **Production (System Operations)**
3. **Preventive Maintenance**
4. **Corrective Maintenance**
5. **Record Keeping & Communications**

Slide 19-3

Preventive maintenance consists of planned maintenance actions (including inspection) to prevent equipment breakdown. In cases where the equipment has failed, corrective maintenance is performed. Operators also have responsibilities for record keeping and communications. Operators help address these issues in the development of policies and standard operating procedures.

19.2 Features of Preventative Maintenance

A steam generating unit and associated air pollution control equipment must be properly operated and maintained so that it can perform reliably, efficiently and safely over their expected life. Consequently, there are considerable economic risks associated with an improper maintenance program.

GOALS OF PREVENTIVE MAINTENANCE

1. **Maximize Unit Reliability**
2. **Minimize Total Operating Costs**
3. **Enhance Equipment Life**
4. **Restore Unit Performance**

Slide 19-4

An operating goal is to assure overall equipment reliability and to minimize unit down-time. This is a critical component for minimizing the total operating costs and preserving the plant's capital investment in the equipment. Maintenance can represent a significant part of the total cost. Priorities must be set in an attempt to balance the economic consequences associated with either acting now or deferring maintenance.

"A stitch in time saves nine" is still a valid expression. As maintenance is deferred, operational problems will generally worsen and unit down-time will be increased. The financial consequences include the direct losses associated with making the repairs, lost production, and potential costs associated with safety hazards.[1] Preventive maintenance is performed to assure that the unit can operate safely, efficiently, and reliably.

To some extent, the performance of all equipment tends to deteriorate with operating time. Therefore, a preventive maintenance program is designed to assure that productive equipment life is preserved. Obviously, good operating practices must include many routine activities, such as maintaining proper boiler water conditions to avoid tube failures and boiler problems and maintaining proper lubrication for rotational equipment like compressors, fans, and turbines.

Preventive maintenance is also designed to restore performance efficiencies. Routine operations, such as soot blowing, are important operations which restore system efficiency. On smaller boilers, it is necessary to periodically clean tube surfaces using manual methods such as rodding out the convective section.

Predictive maintenance is the part of preventive maintenance which tries to identify potential problems. Routine inspection of equipment and instrument readings, as well as a review of the performance and maintenance records, can lead to the identification of equipment problems. Predictive maintenance also includes the use of special instruments for vibrational analysis, lube oil sample analysis, ultrasonic testing, infrared imaging and meggering (e.g., measuring electrical resistance of insulation) of electric motors and wiring.[2]

FEATURES OF A MAINTENANCE PROGRAM

1. **Review Vendor Recommendations**
2. **Identification of Problems**
3. **Evaluation of Options**
4. **Communication & Planning**
5. **Implementation**

Slide 19-5

A maintenance program generally begins with the review of the equipment design features and an implementation of the manufacturers' recommended maintenance procedures. Special attention should be given to the specified lubrication requirements and operating limits (temperatures, pressures, loads, etc.).

An important aspect of unit operations is to identify problems and solve them before they become unmanageable. Problem evaluation begins with an analysis of the current status and an attempt to identify problems and evaluate the causes.

Repairing the symptom of a problem may be easier than solving the real problem. For instance, a bad bearing can be replaced as a short-term solution. However, determining and eliminating the cause of the failure, such as correcting an imbalanced rotor or preventing a corrosion condition, can lead to a long-term solution to the problem.

Communication with other individuals is also an important aspect of operators' duties. Discussions and group meetings with auxiliary operators, maintenance staff, vendor representatives, engineers and/or designers may be required for planning a proper solution to a special maintenance problem.

Cooperative discussions may be in order before deciding whether to take the equipment off-line for repair or to delay the maintenance until the next scheduled outage. Knowledge of both the equipment design features and maintenance records will be important in the decision. Nevertheless, operators are called upon to make timely judgments about taking a unit out of service because of various equipment upsets and safety considerations.

The implementation of maintenance must be scheduled with the operator. A proper lock-out/tag-out program should be used for equipment that poses an electrocution or mechanical injury hazard. Lock-out often refers to the use of padlocks to lock circuit breakers in the "off" position. It also refers to the use of mechanical means to secure equipment (e.g., prevent rotation) for personnel safety. Tags are used to identify who is in charge of the maintenance activity.

19.3 Periodic Inspections

Periodic inspection/maintenance of plant equipment may be on a weekly, monthly, 6-month, annual or 2-year basis. The inspection intervals are typically recommended by the equipment vendor manuals, just as with an auto owner's manual. Power plant operating conditions vary much more than an auto's would because of the large variables in fuel, water, and ambient conditions. Consequently, in 48 of the 50 states, annual internal and external inspections of boilers are required. These inspections must be made by authorized inspectors acceptable to the state. Auxiliary systems inspection requirements will vary based on the specific plant conditions. For instance, a pulverizer's grinding components may need to be replaced after 9,000 hours of operation on one coal, whereas a harder coal may wear the components out after 6,000 hours. Therefore, experience and good records are essential to establishing a good maintenance program.

Many components in the power plant can and should be inspected by regular visual observation. Poor flame patterns or a change in the appearance of the stack gases is an indication of fouled burner tips or improper fuel/air ratio. Equipment such as fans and pulverizers have inspection doors that can be removed to permit internal inspection. Some equipment such as pumps, heat exchangers and turbines will

require performance tests to determine the internal conditions. Calibration of plant instrumentation is one area that should receive high priority in the periodic maintenance program.

19.4 In-Service Maintenance

In-service maintenance consists of the day-to-day activities that are implemented while the boiler is in operation. These activities usually include lubrication, seal and packing adjustments, and repair of components that can be removed from service without affecting operation. These routine operations follow the manufacturer's recommended procedures. For equipment, the special design and operational features need to be reviewed prior to performing in-service maintenance. In addition, a clear understanding of its relationship to other elements of the unit and the possibility of switching to alternate equipment should also be reviewed as part of the maintenance procedure.

Examples of in-service maintenance may include pulverizer maintenance, CEMS instruments, and control sensors. Once again, communication is critical between the boiler operator and maintenance personnel to indicate which equipment is available for maintenance and which is critical for operation.

19.5 Outage Maintenance Planning

Whether specific maintenance can be performed while the unit is in service or during an outage will be determined by the severity of the conditions and the design of the equipment. The scheduling of major (annual) outages requires planning, setting priorities, and arranging for special inspectors and appropriate maintenance personnel, supplies, replacement parts and repair equipment.

OUTAGE MAINTENANCE

1. **Make & Update an Outage Plan**
2. **Arrange for Materials/Services**
3. **Make Detailed Inspections**
4. **Revise Plans as Necessary**
5. **Follow Proper Procedures**
6. **Inspect Upon Conclusion**

Slide 19-7

The annual boiler outage is a standard inspection requirement associated with operating a boiler. The inspection and repair must be performed in accordance with applicable requirements. The National Boiler Inspection Code (NBIC) is the recognized standard for inspections, alterations and repairs to boilers and auxiliary equipment.[4] In particular, the NBIC Code includes the proper welding procedures and welder qualifications for repair and alterations.

The annual outage is utilized for several purposes. The primary purpose is to conduct a thorough inspection of the fire and gas side of the boiler as well as the water side (steam drum, headers, waterwalls, etc). These are the areas with which the State or insurance company inspector is most concerned.[3]

The secondary purpose is to permit inspection and repair operations of ancillary equipment which cannot be conducted while the boiler is operating. This might include components such as fans or pumps which, if removed from service, would restrict boiler load. Example maintenance problems would be items such as leaking valves, air/gas leaks, or inoperable dampers. The operator should communicate these problems, preferably through written trouble tickets issued on a daily basis, for inclusion on an outage action item list. This will permit proper planning so that materials and manpower will be available to make the necessary repairs during the outage period.

REFERENCES

1. Riggs, James L. and West, Thomas M., *Essentials of Engineering Economics*, Second Edition, McGraw Hill Book Company, New York, 1986, pp. 438-464.

2. Singer, Joseph G., *Combustion, Fossil Power Systems*, Third Edition, Combustion Engineering, Inc., Windsor, CT, 1981, pp. 22-1 to 22-23.

3. *Steam, Its Generation and Use*, 39th Edition, Babcock and Wilcox, New York, 1978, pp. 36-1 to 36-20.

4. National Board Inspection Code, ANSI/NB-23 1992, The National Board of Boiler and Pressure Vessel Inspectors.

CHAPTER 20. SAFETY

20.1 System Safety Hazards

20.2 Consequences of Exposure to Hazards

20.3 Standard Safety Considerations

20.4 Personnel Protection Equipment

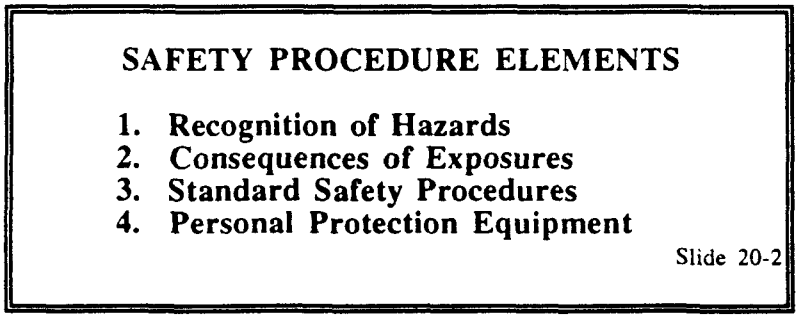
Slide 20-1

20. SAFETY

The responsibility for employee safety is broadly based in federal regulations, managers, and the employees themselves. The Occupational Safety and Health Administration (OSHA) has established mandatory job safety and health standards based on the specific operation and activity being performed. In addition, state and local codes have been established and must be followed as well. Managers have the responsibility to train and educate their employees about the health concerns and hazards they may encounter and how to comply with the safe working practices. The safe practices are specific to the equipment and plant design and comply with OSHA standards. Ultimately, the boiler operator and other employees are responsible for their own safety by following these safe practices.

The following is a discussion of the general steam generating system safety hazards, consequences of exposure, standard safety procedures, and personnel protection equipment. Once again, this manual is not intended to replace any existing on-site safety training program. Each steam generating system will have a safety program tailored to the specific plant design. All operators should be familiar with these safe practices and execute them diligently.

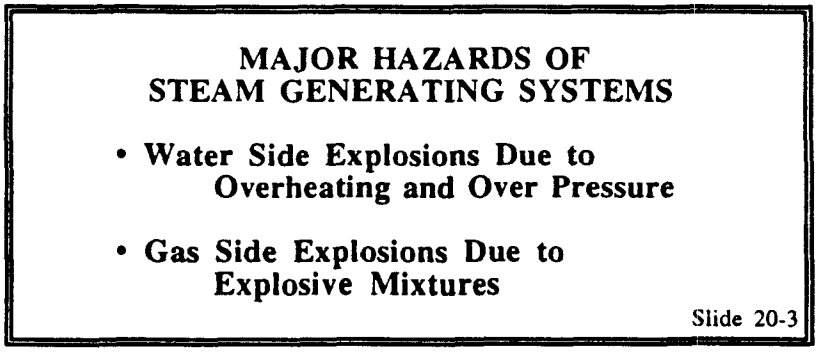
There are four main elements to a safety procedure:



Recognition of hazards answers the question : Does a hazard exist? Education and experience are required to answer this question. Once the hazard is identified the consequences of the exposure must be known to assess what to do to reduce the exposure. In some cases, personal protection equipment is required to reduce the exposure. A discussion of each of these four aspects of a safety procedure follows.

20.1 System Safety Hazards

The first step in a safety training program is to identify existing and potential problems and hazards in the work place.



The combustion process releases heat that passes through the boiler walls and is adsorbed by the water or steam flow. Any disruption in water or steam flow also disrupts removal of heat from the boiler with potentially catastrophic effects. A variety of factors can result in steam/water flow disruptions. Boiler operations and safety systems must be available to deal with those disruptions and prevent explosions. Two examples of water/steam flow disruptions are discussed to illustrate the types of safety systems installed on boilers and to indicate why those safety systems must be properly maintained.

First, situations such as a turbine trip cause the turbine stop valves to instantly slam shut, stopping all steam flow from the boiler. Without immediate action from the boiler control system and safety systems, the following situations would occur:

- The feedwater pump continues to pump into the closed steam systems.
- The burners would continue to heat the fixed mass of water/steam.
- Steam temperature and pressure rise rapidly.
- Boiler tubes or headers explode.

To keep this from happening, there is a series of critical safety features. First, whenever steam flow is terminated, safety interlocks should instantly trip all fuel flow to the boiler. This action helps, but often there is enough fuel already in the boiler (i.e., grate feed systems) or fuel in the supply lines that cause the heat release not to immediately be terminated. The residual fuel can release enough heat to rapidly raise the boiler pressure. To prevent catastrophic failure from over pressurizing, the

ASME boiler code requires installation of pressure relief valves. Specific code provisions define the number, type, installation, and testing features of the safety valves.

A second, equally dangerous situation occurs if there is a loss of water level in the boiler. This can occur through failure of feedwater pumps or mismatch of feedwater pump and steam flow. Similar to the turbine trip example, heat released by the flame is being adsorbed by a reduced mass of water and steam. The steam pressure does not rise, but the steam temperature does rise. The boiler tubes can then overheat, leading to structural failure of the tubes.

To prevent this type of failure, most boiler control systems monitor steam temperature and water level in the boiler. Typically, water level is automatically controlled by the combustion control system. Additionally, there should be alarms for both high and low water levels and a trip switch for Hi-Hi and Lo-Lo levels which initiate shut-off of fuel flow. The main fuel shut-off is referred to as an MFT, which stands for Master Fuel Trip.

Many safety features are also included in the boiler combustion control system. Before igniting the pilot flame of the boiler burner, no lingering combustible gases are permitted to be presented in the furnace. Modern combustion control systems are designed to prevent such hazards by adequately purging the furnace with air to dilute any combustible gases that may remain in the furnace and cause them to exit up the stack prior to starting the ignition sequence. Once operating, excess combustion air needs to be provided to prevent the formation of pockets of unmixed combustible gases within the furnace.

OTHER BOILER SYSTEM SAFETY HAZARDS

1. **Combustion Gases**
2. **Noise**
3. **Observation Hatches**
4. **Operations in Confined Spaces**
5. **Boiler Auxiliary Systems**

Slide 20-4

The products of combustion or combustion gases are of health and safety concern. Boiler operators may be exposed to carbon monoxide (CO) and sulfur oxides. The best understood biologic effect of CO is its combination with hemoglobin in the blood. Carbon monoxide enters the bloodstream through the lungs in the same manner as oxygen, but it displaces the oxygen in the blood and reduces the oxygen-carrying capacity of the blood. Therefore, exposure to CO prevents an adequate oxygen supply from reaching the tissues of the body. Sulfur dioxide in relatively large quantities causes irritation to the eyes and mucous membranes and over time may

result in bronchitis and decrease pulmonary function.[5] In addition, combustion gases may carry particulate matter as dust or fly ash. The boiler operator may be exposed to particulate matter in higher concentrations when operating or maintaining particulate collection devices, such as baghouses and ESPs. In addition, the SCR and SNCR techniques used to control NO_x emissions, as discussed in Chapter 25, require the injection of ammonia or another agent which releases ammonia. Operators should be aware that excess ammonia emissions could occur and ammonia monitors should be in use.

The boiler operation requires the operation of rotating equipment, such as fans and pumps, which create noise during operation. In addition, the turbulent mixing of the combustion air with the fuel also created noise. OSHA requires ear protection to be worn for noise levels exceeding 85 dB. With 25% of all industrial workers experiencing permanent noise-induced hearing losses, hearing protection should be worn in this boiler operating environment.[5]

Generally, observation hatches into the furnace should be opened only after taking precautions against exposure to furnace pressure pulsations. Materials can blow through an observation hatch as a result of sootblowing, tube failure or aerosol can explosions on the fuel bed.[4] Therefore, individuals should not stand directly in front of open furnace ports or doors. Design provisions for safety include delivering aspirating air to the observation hatch and providing a protective transparent cover. Open-ended pipes should not be used for removing slag from walls, as the hollow pipes can become very hot and can direct hot gases onto the handler.[1]

Operators should also be aware of the potential for eye damage associated with intense thermal radiation. Tinted goggles or other eye protection should be used when viewing the flame.

Serious burns can occur if individuals contact steam pipes, valves and other hot metal objects. The improper opening of high pressure steam vents and/or the rupture of steam pipes can cause severe scalding.

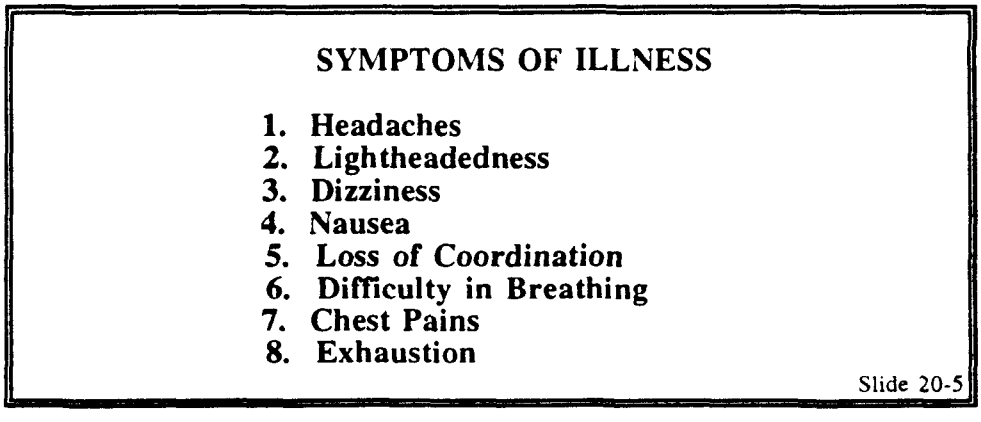
In addition, it is potentially hazardous to enter confined spaces such as the equipment cavities of the furnace, steam drum, and baghouse. Hazards here arise from poor ventilation, space being cramped, limited lighting and exposure to accumulated pollutants and/or dust. Specific OSHA requirements must be met. Explosion proof lights and properly grounded electrical extension cords should be used.[4] Confined spaces should be entered only after they have been properly cooled and ventilated. Appropriate doors and valves should be locked or tagged. The lockout and tagout procedures should call for notification of all employees that a lockout and/or tagout prior to the lockout/tagout. All stored energy must be dissipated or restrained by methods such as repositioning, blocking, bleeding down, etc. After applying the lockout/tagout and ensuring no personnel are exposed, a check on the disconnection of the energy sources should be made by operating the control to make certain the equipment will not operate. After the servicing is completed and the

equipment is ready for normal operation, check the area for remaining tools, replace protection guards, ensure that no one is exposed prior to restoring energy.

One of the primary requirements of the OSHA Hazard Communication Standard is that Material Safety Data Sheets (MSDSs) must be available to all employees potentially exposed to hazardous substances. A MSDS is a special form that conveys the hazardous physical characteristics and properties of a substance, known acute and chronic health effects, target organs, safe handling procedures, spill and leakage procedures, and waste disposal procedures. Important data sheets for boiler operators would include those for chemicals used in water treatment and scrubber systems, solvents, refractories, and paints. In older boiler installation, the operators should be aware that asbestos may be contained in insulation materials used on the boiler and the steam piping. any handling of these insulating materials should follow the asbestos handling procedures. The Hazard Communication Standard requires that employees exposed to hazardous substances receive at least annual training. New employees must be trained before they are placed in environments where hazardous substances are being used.

20.2 Consequences of Exposure to Hazards

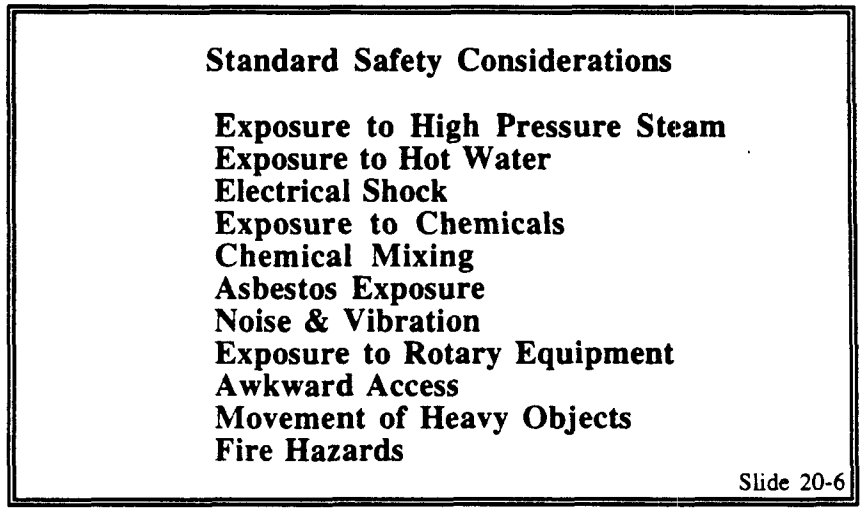
Although the reaction to the hazards encountered during boiler operation will vary with each operator, operators should be aware of the significant safety risks associated with operating staff who perform their duties while having certain symptoms of illness.



The above symptoms of illness may result from heat stress, inhalation problems and/or a variety of non-occupational related conditions. An impaired worker is a threat to the overall safety of the unit as well as to fellow personnel.

20.3 Standard Safety Procedures

The standard safety procedures at a boiler operating facility should include, but are not limited to, normal operation procedures, lockout/tagout, hearing conservation, asbestos notification and identification, compressed gas cylinder training, respiratory protection, contingency plan emergency response, hazardous materials training, fire prevention plan, emergency action plan, and equipment qualification requirements.[2] These procedures should account for the safety considerations, listed in Slide 20-6, which exist when working around a boiler.



Standard industrial safety considerations include those associated with electrical shocks, noise, vibrating equipment, exposure to hot metal surfaces, exposure to rotating equipment, awkward access to equipment, movement of heavy objects, welding, exposure to corrosives and fire hazards.

For example, the electrical and steam service to rotary equipment should be "locked out" and "tagged out" before servicing. In addition, it may be appropriate to have the shaft blocked to prevent rotation, which could otherwise cause injuries such as mashed, cut, or severed fingers.

To address these safety issues the following safety rules should be incorporated into the safety program and followed:

1. Use low-voltage droplights and ground fault interrupters when working inside boilers. The entire boiler is a conductor, so low-voltage droplights minimize the risk of electrical shock.

2. Know the locations of all emergency showers and eyewash fountains. Certain chemicals can cause serious skin and eye burns.

3. Wear ear and eye protection, safety shoes, and hard hats in all designated areas. When looking into furnace ports use tinted glass to protect the eyes from the infrared and ultraviolet rays.

4. Assume all piping is hot and wear protective gloves to prevent burns.

5. Do not wear loose-fitting clothing around rotating equipment such as pumps or fans to prevent clothing from becoming entangled in a rotating shaft.

6. Use proper ladders to gain access to equipment. Do not climb on equipment or building steel.

7. Eliminate clutter from the operating floor using good housekeeping standards. Clean all spills immediately.

8. Always use appropriate lockout procedures when removing equipment from service for cleaning or repairs.

9. Use proper lifting techniques and back support when moving heavy objects and do not lift more than can be handled comfortably.

10. Store all oily rags and other waste in approved containers to prevent fires and empty these containers regularly.

11. Inspect safety equipment, such as fire extinguishers, on a regular basis.

12. Repair of Tools/Devices should be completed by qualified personnel only.

Also, care should be exercised when walking to avoid bumps, slips and falls. Improper ladders and unsecured scaffolds should not be used. Care should be used to assure that objects are placed securely to avoid damage due to falling. All accidents should be reported immediately to facilitate the investigation of the causes of the accident and corrective actions as to how to prevent a recurrence.

20.4 Personal Protection Equipment

The first line of defense against exposure to hazards is good engineering and administrative practices.[3] However, there are times when personal protective equipment can provide and may be required to provide additional protection.

PERSONAL PROTECTION EQUIPMENT

1. **Ear Protection**
2. **Heavy Gloves**
3. **Hard Hat**
4. **Respirator**
5. **Goggles and Safety Glasses**
6. **Safety Shoes**
7. **Proper Clothing**
8. **Back Support**
9. **Gaseous Concentration Monitors**

Slide 20-7

Standard industrial safety procedures relate to the use of personal protective equipment, such as that listed above. However, respirators should not be used unless the operator has received the specific training. In addition to the above listed personal safety protection equipment, persons should wear proper clothing so that there are no loose fitting parts which could become tangled in rotating equipment. Natural fiber work clothes should also be worn because some synthetic fibers can melt when exposed to hot equipment. Exposure to harmful gases must be monitored. Depending on the fuel and emission control systems, monitors for H_2S, ammonia, CO, etc. may be used.

REFERENCES

1. *Steam, Its Generation and Use*, 39th Edition, Babcock and Wilcox, New York, 1978, pp. 34-8.

2. Steingress, Frederick M. and Frost, Harold J., *Stationary Engineering*, American Technical Publishers, Inc., Homewood, IL, 1991, pp. 71-82.

3. Woodruff, E. B., Lammers, H. B. and Lammers, Thomas F., *Steam Plant Operations*, Fifth Edition, McGraw-Hill Book Company, New York, 1984, pp. 223-230.

4. Singer, Joseph G., *Combustion, Fossil Power Systems*, 4th Edition, Combustion Engineering, Inc., Windsor, CT, 1991, pp. 21-1 to 21-34.

5. Hoover, Reynold L, et al., *Health, Safety, and Environmental Control*, Van Nostrand Reinhold, New York, 1989, pp. 187-189.

CHAPTER 21. AIR POLLUTANTS OF CONCERN

21.1 Introduction

21.2 Air Quality Overview

21.3 National Ambient Air Quality Standards

21.4 Primary Pollutants

- A. Particulate Matter
- B. Sulfur Oxides
- C. Nitrogen Oxides
- D. Hydrocarbons
- E. Carbon Monoxide

21.5 Secondary Pollutants

- A. Photochemical Oxidant
- B. Acid Deposition

21.6 Hazardous Pollutants

- A. Hazardous Metals
- B. Organics

21. AIR POLLUTANTS OF CONCERN

21.1 Introduction

CLASSIFICATION OF POLLUTANTS

Primary Pollutants
- Particulate Matter
- Sulfur Oxides (SO_2, SO_3)
- Nitrogen Oxides (NO_x, NO_2)
- Hydrocarbons
- Carbon Monoxide

Secondary Pollutants
- Photochemical Oxidant (ozone, etc...)
- Sulfates

Hazardous Pollutants
- Metals (Lead, Mercury, etc...)
- Organics (Benzene, Vinyl Chlorides, etc...)

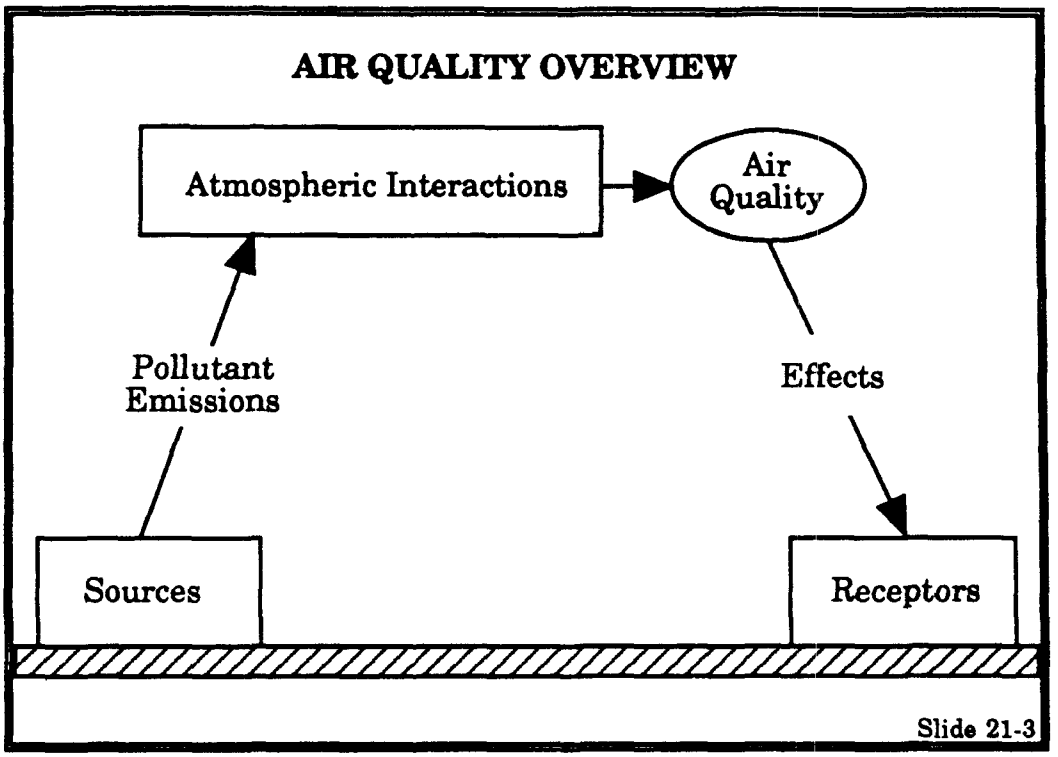
Slide 21-2

From an environmental perspective, air pollutants can be classified into three broad categories: primary pollutants, secondary pollutants and hazardous pollutants. Primary pollutants, such as particulate matter, sulfur dioxide, and hydrocarbon compounds, are those which are emitted directly from emission sources. These pollutants may directly have an adverse effect on human health or welfare and may also react in the atmosphere to form secondary pollutants such as photochemical oxidant or sulfates, which also have negative impacts on the environment. Hazardous pollutants, like primary pollutants, are also released from emission sources. These pollutants can be broken into two categories: inorganic compounds, which are primarily metals such as lead and mercury, and organic compounds, such as benzene and vinyl chloride. Pollutants are classified as hazardous if exposure to them can lead to death or serious illness.

In Learning Unit 6, we learned how pollutants are formed in combustion systems. Recall that sulfur dioxide and particulate emissions are largely dependant upon the fuel that is fired. Carbon monoxide and hydrocarbon emissions, both volatile and hazardous organics, are pollutants that are emitted due to incomplete combustion of the fuel. Nitrogen oxide emissions are dependant upon the fuel type and the design and operation of the combustion system. In the atmosphere, nitrogen oxides and reactive hydrocarbons can react to form other pollutants such as

photochemical oxidant, which is commonly referred to as "smog". In this learning unit, we will review the impacts that pollutants have on air quality and the environment in order to gain a better understanding of the basis of pollution control regulations.

21.2 Air Quality Overview



To better understand how pollutants affect our health and welfare, we must first understand how pollutants impact air quality. Pollutants emitted from sources enter the atmosphere, where they are diluted, transported, and capable of reacting to form secondary pollutants. The effects that the pollutants have on receptors determines the extent to which air quality is degraded. If there were no adverse effects on receptors, then pollutants would be of no concern[1].

Pollutants can come from manmade sources or from natural sources, both sources are important to air quality; however, manmade pollutants are the focus of this lesson. Manmade or *anthropogenic* sources are classified as stationary or mobile. Stationary sources include boilers and furnaces, while mobile sources include automobiles, trucks, buses, and airplanes. The type and quantity of pollutant emissions tend to vary by source. For example, nearly 75 percent of all sulfur dioxide emissions due to combustion are from electric power generating boilers, while nearly 65 percent of all VOC emissions are from the use of fossil fuels in transportation[2].

Once pollutants enter the atmosphere, they are mixed with air resulting in a decrease in their concentration. Local and regional wind patterns then transport the pollutants away from the source and promote additional mixing and dilution. During the transport process, some pollutants undergo chemical reaction to form other pollutants. Due to these different forms of atmospheric interactions—transport, dilution, and reaction—the quality of air arriving at a receptor is a function of both the type and quantity of the pollutant and the extent of mixing and chemical reaction which has occurred during transport of the pollutant to the receptor.

Receptors which are potentially affected by air quality include people, plants, animals, and materials. The effects of poor air quality range from respiratory irritation and damage in humans, to damage of ornamental plants and crops. Long term exposure to some pollutants can result in damage to exposed metals or other sensitive materials. Pollution control regulations are implemented to preserve the public health and welfare.

How is air quality defined? Generally, air quality is most often detected as a reduction in visibility due to smog, haze, or smoke in the atmosphere. However, many pollutants exist as gases or particles which are not visible. Special monitoring equipment is used to detect the presence of these pollutants. Along with the need to define air quality comes the need to establish standards for air quality.

21.3 National Ambient Air Quality Standards

To minimize the impacts of poor air quality on receptors, the federal government has established air quality standards for pollutant species that impact public health and welfare[3]. These air quality standards are maintained by regulating the emission of pollutants from combustion sources and by requiring that the pollutants which are emitted are effectively mixed or dispersed into the atmosphere.

National Ambient Air Quality Standards (NAAQS) for particulate matter, sulfur dioxide, nitrogen dioxide, hydrocarbons, carbon monoxide, were established in 1971 by the U.S. Environmental Protection Agency (EPA) as required by the 1970 Federal Clean Air Act Amendments. In 1978, the standard for photochemical oxidant was revised and converted to an ozone standard, which is the compound most commonly monitored as an indicator of photochemical oxidant. A standard for lead was added to the NAAQS in 1978. Recognizing that the primary hazard to human health due to particulate is from particles with a size below 10 microns, the suspended particulate standard was revised in 1987 and redesignated as a standard for particulate matter under 10 microns or PM_{10}.

The National Ambient Air Quality Standards represent the maximum levels of these pollutants that are permitted to exist in ambient air. Averaging times reflect the period of time over which the concentration of a pollutant is averaged for comparison to the standard. Standards, other than those based on the annual average, are not to be exceeded more than once per year.

NATIONAL AMBIENT AIR QUALITY STANDARDS

(Reference: Godish)

POLLUTANT	AVERAGING TIME	PRIMARY STANDARD	SECONDARY STANDARD
Particulate Matter (≤ 10μm)	annual mean	50 $\mu g/m^3$	50 $\mu g/m^3$
	24 hour	150 $\mu g/m^3$	150 $\mu g/m^3$
Sulfur Oxides	annual average	80 $\mu g/m^3$	
	24 hour	365 $\mu g/m^3$	
	3 hour		1300 $\mu g/m^3$
Nitrogen Dioxide	annual average	100 $\mu g/m^3$	Same
Hydrocarbons (corrected for methane)	3 hour	160 $\mu g/m^3$	160 $\mu g/m^3$
Carbon Monoxide	8 hour	10 mg/m^3	Same
	1 hour	40 mg/m^3	Same
Ozone	1 hour	235 $\mu g/m^3$	Same
Lead	3 month average	1.5 $\mu g/m^3$	Same

Slide 21-4

Primary standards are those which were established to protect the public health. Secondary standards, which are generally more stringent, are those which were established to protect the public welfare (e.g. property, plants, etc...). Implicit in the establishment of these standards is the assumption that there exist safe exposure levels to these pollutants. To assure the public health, the established air quality standards are based upon an assessment of the health risk associated with

exposure based upon available scientific evidence. To this risk is added a margin of safety to ensure that the health of sensitive individuals, such as those with asthma or other respiratory diseases, is not at risk.

It is important to note that the National Ambient Air Quality Standards establish a uniform nationwide standard for air quality, but do not define the limits on emissions from boilers and other combustion devices. Individual states are required to implement control measures for pollutants which allow the air standards to be met and maintained. Since air quality is influenced by the type and quantity of pollutants emitted and by local meteorological conditions, it is possible for allowable emissions levels of pollutants to vary from state to state.

NAAQS OBJECTIVES

Pollutant	Objective of the Standard
Particulate	To prevent health effects due to long term exposure
Sulfur Dioxide	To prevent pulmonary irritation (primary) and to prevent odor (secondary)
Nitrogen Dioxide	To prevent possible risk to public health and atmospheric discoloration
Hydrocarbons	To reduce photochemical oxidant formation
Carbon Monoxide	To prevent interference with the capacity to transport oxygen to the blood
Ozone	To prevent eye irritation and respiratory problems and to prevent damage to vegetation
Lead	To prevent lead poisoning

Slide 21-5

As stated previously, the NAAQS were established based upon available scientific evidence of the effects of these pollutants on human health and welfare. More detailed effects of these pollutants will be described in subsequent panels. The primary objectives of the NAAQS were to[1]:

- Prevent negative health effects due to long term continued exposure to small particulate suspended in the atmosphere.
- Prevent pulmonary irritation and unpleasant odor due to sulfur dioxide.
- Prevent possible risk to public health and atmospheric discoloration due to nitrogen dioxide.
- Reduce photochemical oxidant formation due to the presence of hydrocarbons.
- Prevent the interference of carbon monoxide with the capacity to transport oxygen to the blood.
- Prevent eye irritation and respiratory problems and to prevent damage to vegetation and materials due to ozone.
- Prevent overexposure of sensitive groups, such as children, to lead leading to acute or chronic lead poisoning.

21.4 Primary Pollutants

Given the preceding background, we will now examine the primary effects of air pollutants on human health and welfare. The following paragraphs address the emission of particulate matter, sulfur oxides, nitrogen oxides, hydrocarbons and carbon monoxide.

Particulate Matter

PARTICULATE MATTER

Typical Form:	Solid, Liquid, Aerosol
Critical Factors:	Particle Size Particle Type Aerosol Concentration
Health Effects:	Deposits in respiratory passages. Increases exposure to toxic substances
Welfare Effect:	Reduces visibility

Slide 21-6

Particulate matter is a general term used to describe small solid and liquid particles. As discussed in Chapter 6, particulate emissions from boilers may be in the form of smoke or soot (i.e. unburned carbon), or in the form of flyash. Particulate matter suspended in the atmosphere generally consists of these pollutants and particulate matter formed from other pollutants, such as the sulfates formed from sulfur dioxide. The term aerosol is used to describe a collection of suspended particles.

The three factors which most significantly influence the impact of particulate on air quality are the size and type of the particulate and the concentration of the particles. Small particles are most easily transported away from pollutant sources and also have the highest impact on human health and welfare. The size of particles in the atmosphere is measured in microns—one micron equals one millionth of a meter. One thousandth of an inch is approximately 25 microns. Flyash from combustion systems is generally in a size range of 0.5 to 100 microns. For comparison, pollen has a size range of 10 to 100 microns, and tobacco smoke is generally between 0.01 to 1.0 microns. The type of particulate is also important. For example, exposure to sulfate aerosols is more hazardous than exposure to dust.

There are two primary health effects associated with particles. First, small particles are easily inhaled into the respiratory system where they are deposited in bronchial passages and the pulmonary system. Buildup of these deposits can lead to constriction of the bronchial passages. Particle size is important since the human respiratory system can generally prevent particles above 10 microns in size from entering the lungs. Particles below this size are deposited in the tracheobronchial and pulmonary systems, which are the lung tissues responsible for supplying oxygen to the blood. The deposited particles can irritate lung tissue and constrict small passages. The second adverse health effect of particles is due to the tendency of toxic substances to absorb onto the particle surface where they are easily transported deep into the respiratory system and absorbed into the body through lung tissue. Substances of concern include sulfates, polycyclic aromatic hydrocarbons (PAH), and heavy metals such as lead and mercury.

Particulate matter influences human welfare by reducing visibility of the atmosphere. Visibility is difficult to quantify in substantial terms, but may be defined as the ability to see clearly over a distance. Visibility is influenced by a number of atmospheric and human factors. Particle size has a significant effect on visibility since it influences the ability of a particle to scatter light. Particles in the size range of 0.2 to 1.0 microns are the most effective at scattering light. This is one of the reasons cigarette smoke is so easily detectable.

Sulfur Oxides

SULFUR OXIDES	
Typical Form:	Sulfur dioxide – gaseous Sulfates (SO_3, H_2SO_4) – liquid
Critical Factor:	Conversion of SO_2 to sulfates in the atmosphere
Health Effect:	Causes broncho-constriction, especially in asthmatics
Welfare Effect:	Results in acid deposition

Slide 21-7

Sulfur emissions from combustion systems are typically in the form of sulfur dioxide, SO_2, with a small amount of sulfur trioxide, SO_3. In the atmosphere, sulfur dioxide is oxidized to SO_3 which can react with moisture in the air to form sulfuric acid, H_2SO_4. The various sulfur carrying species which can exist following oxidation of SO_2

are collectively called sulfates. Conversion of sulfur dioxide to sulfates in the atmosphere is the most significant influence of sulfur dioxide on air quality.

Exposure to high concentrations of sulfur dioxide can be fatal; however, the concentration levels that are toxic are significantly above typical ambient levels. Exposure to low levels of sulfur dioxide can lead to acute constriction in the bronchial passages to sensitive individuals, particularly those with asthmatic conditions. Scientists now believe that exposure to sulfate compounds, particularly acid aerosols, is the more significant health risk associated with emissions of sulfur dioxide.

Deposition of sulfates in the environment poses a significant threat to human welfare due to the potential consequences of acid deposition. Fossil fuels are the primary source of sulfur oxides in the atmosphere. The amount of sulfur dioxide emitted from a particular fossil fuel depends entirely on the amount of sulfur contained in the fuel. The amount of sulfur contained in coals and oil vary widely depending on where it comes from. Coal and fuel oils can contain very high amounts of fuel sulfur where as natural gas typically contains no sulfur at all.

Nitrogen Oxides

NITROGEN OXIDES

Typical Form:	Nitric oxide (NO) – gaseous Nitrogen dioxide (NO_2) – gaseous Nitric acid (HNO_3) – liquid
Critical Factor:	Conversion of NO to NO_2 and to nitrates in the atmosphere
Health Effects:	Damages respiratory tissues, causes respiratory symptoms
Welfare Effect:	Results in atmospheric discoloration, promotes formation of photochemical oxidant, and results in acid deposition

Slide 21-8

Nitrogen oxide emissions from combustion systems are typically in the form of nitric oxide, NO, with trace amounts of nitrogen dioxide, NO_2. Nitric oxide is a colorless, odorless, relatively nontoxic gas. Nitrogen dioxide is a light–brown, toxic gas with a pungent, irritating odor reminiscent of bleach. In the atmosphere, nitric oxide is

readily converted to NO_2 through oxidative and photochemical reactions. NO_2 can then be converted to nitric acid, HNO_3.

Nitric oxide is a pollutant of concern because it is readily converted to NO_2 in the atmosphere. Exposure to high concentrations of NO_2 results in severe damage of lung tissue. Some studies indicate that exposure to low concentrations of NO_2 leads to a higher occurrence of respiratory symptoms, such as chest pain, pneumonia, bronchitis and asthma, in sensitive population groups like children.

Atmospheric NO_2 can have several effects on human welfare. Since it is colored gas, NO_2 in small concentrations is visible in the atmosphere as a brown haze or discoloration which can reduce visibility. Formation of NO_2 in the exhaust from boiler stacks can lead to problems with brown plumes. Nitrogen dioxide also participates in the formation of photochemical oxidant. Nitrates formed from NO_2 result in acid deposition. The formation of photochemical oxidant and the problems associated with acid deposition will be described in more detail in Section 21.5.

Nitrogen oxides result from the combustion of all fossil fuels. As will be discussed in more detail in Chapter 25, NO_x results from fuel bound nitrogen and combustion dynamics. Natural gas, the cleanest burning of all fossil fuels, typically achieves the lowest level of nitrogen oxide formation. Typical nitrogen oxide emissions from natural gas fired boilers range from 0.03 to 0.45 lb/MMBtu depending on the type of boiler and the scale of combustion. Oil fired boilers have emissions in the range from 0.08 to 0.39 lb/MMBtu for distillate oils and 0.13 to 0.79 lb/MMBtu for residual oils. Coal fired boilers have a wide range of nitrogen oxide emissions depending on the coal nitrogen content and type of combustion system, however typical levels for new units fall into the range between 0.15 to 0.50 lb/MMBtu.

Hydrocarbons

HYDROCARBONS	
Typical Form:	A wide range of organic molecules are possible
Critical Factor:	Molecule type
Health Effects:	Not critical at typical concentrations
Welfare Effect:	Contributes to photochemical oxidant and ozone

Slide 21-9

Combustion systems can emit a wide range of different organic compounds. Substances that fall into this category contain only carbon and hydrogen molecules. Organic compounds may be present in the atmosphere in gaseous, liquid, or solid form. The smaller compounds which exist in gaseous or liquid form represent the critical compounds which most significantly impact air quality. Larger organic compounds are generally absorbed onto the surfaces of particles. In the atmosphere, organic compounds released from combustion systems may react with a wide variety of other compounds to form a wide range of hydrocarbon derivatives.

The variety of organic compounds which exist range from compounds that are harmless to those which can be hazardous in large quantities. However, ambient concentrations of these compounds are so low that they do not pose a significant risk. Typical non-methane hydrocarbon concentrations in urban areas range from 1 to 10 ppm.[3] Hydrocarbon emission standards are based upon the need to control photochemical oxidant.

Natural gas typically achieves Total Hydrocarbon (THC) emissions in the range from 0.00 to 0.117 lb/MMBtu depending on the type of boiler and the scale of combustion. Oil fired boilers have emissions in the range from 0.00 to 0.012 lb/MMBtu for distillate oils and 0.00 to 0.031 lb/MMBtu for residual oils. See the individual chapters on boiler types for more specific information of the levels of THC's found with different boilers and fuel types.

Carbon Monoxide

CARBON MONOXIDE	
Typical Form:	Gas
Critical Factor:	Concentration
Health Effects:	Impairs oxygen transport in blood. Impacts central nervous system.
Welfare Effect:	None

Slide 21-10

Carbon monoxide, CO, emissions occur from the incomplete combustion of fossil fuels and are generally low from properly operating boilers. Mobile sources emit the largest quantity of carbon monoxide emissions. Carbon monoxide is a colorless, odorless gas. In the atmosphere, carbon monoxide is slowly converted to carbon dioxide though the action of microorganisms in the soil.

Exposure to high levels of carbon monoxide concentrations causes asphyxiation and death. However, ambient concentrations of carbon monoxide are only a fraction of the level needed to cause asphyxiation. Exposure to low levels of carbon monoxide impacts the central nervous system to an extent in direct proportion to the concentration. No effects on human health or welfare have been detected for exposure to the limit established by the air quality standards.

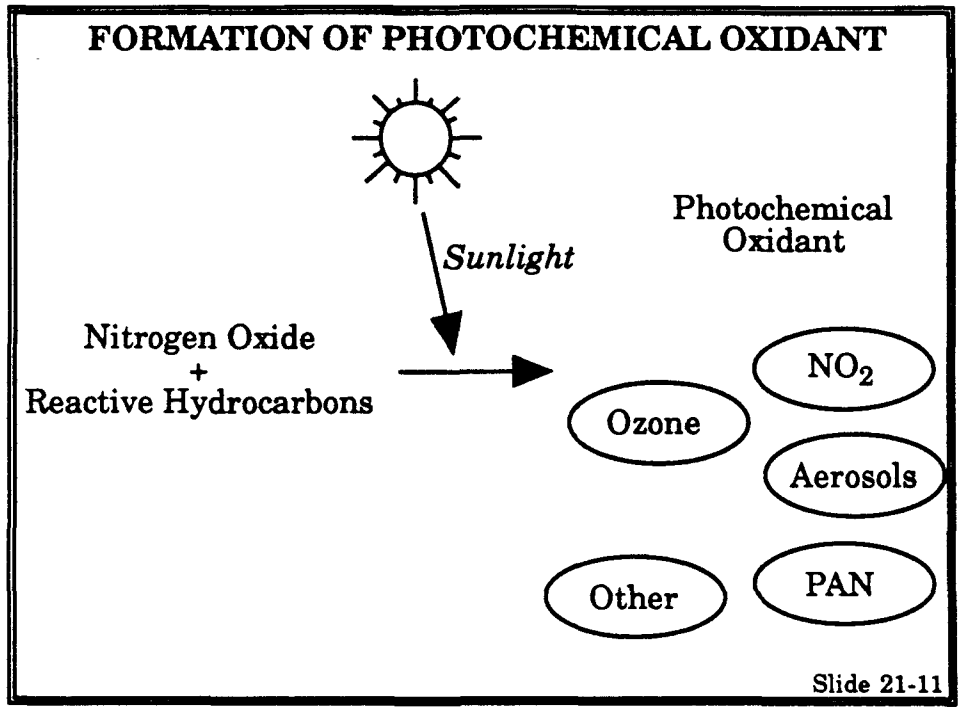
Carbon monoxide can result from combustion of all fossil fuels and is largely dependent on the air to fuel mixture. The presence of CO is and indication of incomplete combustion. Natural gas typically achieves the lowest level of carbon monoxide emissions which range from 0.00 to 0.223 lb/MMBtu depending on the type of boiler and the scale of combustion. Oil fired boilers have emissions in the range from 0.00 to 1.177 lb/MMBtu for distillate oils and 0.00 to 0.114 lb/MMBtu for residual oils. Coal fired boiler carbon monoxide emissions depend on the type and scale of combustion system, however typical levels fall into the range between 0.05 to 0.30 lb/MMBtu.

21.5 Secondary Pollutants

Sulfur dioxide, nitrogen oxide, and hydrocarbons are pollutants which are regulated primarily because they react in the atmosphere to form secondary pollutants which have adverse effects on air quality. Two of the most common secondary pollutants are photochemical oxidant and acid gases. These pollutants will be described in the following.

Photochemical Oxidant

Photochemical oxidant is the name given to a mixture of pollutants resulting from the reaction of nitrogen oxides and reactive hydrocarbons in the presence of ultraviolet rays in sunlight to form ozone and other pollutants. Here, the term *reactive* hydrocarbons is used to indicate that some types of hydrocarbons are able to participate more effectively in the process than other hydrocarbons.



The five types of components that make up photochemical oxidant are: ozone, nitrogen dioxide, aerosols, peroxyacyl nitrates (PAN), and other types of hydrocarbon derivatives. As mentioned earlier, the federal air quality standard is based upon ozone, O_3, since it is the most significant and most easily measured component of photochemical oxidant. Nitrogen dioxide and aerosols were introduced in previous panels. Peroxyacyl nitrates are a family of compounds that occur in trace amounts in photochemical oxidant.

OZONE

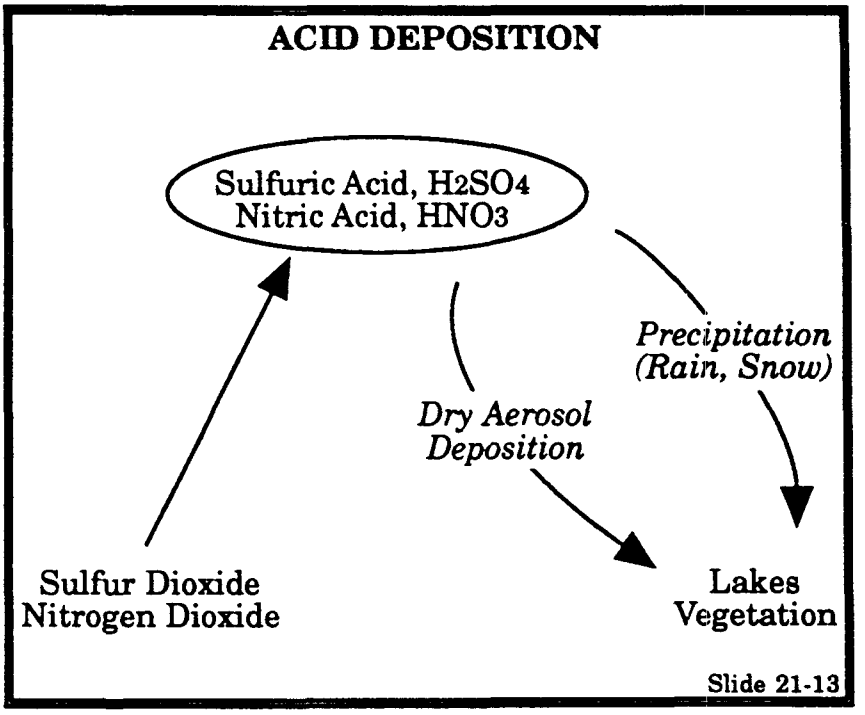
Typical Form:	Gas
Critical Factor:	Concentration
Health Effects:	Irritates eyes and mucous membranes. Causes respiratory symptoms and lung damage.
Welfare Effect:	Damages plants and materials.

Slide 21-12

Photochemical oxidant poses a significant risk to human health and welfare. Ozone, the primary constituent of photochemical oxidant, is one of the most toxic compounds for which ambient air quality standards have been established. Ozone concentrations slightly below the standard can irritate mucous membranes and temporarily impair lung functions. Ozone concentrations at or above the standard can cause respiratory symptoms in adults. Long term exposure can result in lung damage.

Three constituents of photochemical oxidant—ozone, nitrogen dioxide, and peroxyacyl nitrates— can retard plant growth and cause severe plant damage. Ozone can also cause metal corrosion and cracking in rubber.

Acid Deposition



In the atmosphere, sulfur dioxide and nitrogen dioxide undergo reaction to form sulfuric acid and nitric acid. Although these compounds can pose a hazard to human health, their hazard to human welfare is far greater. The deposit of these acidic compounds into lakes and on vegetation is called acid deposition. The term "acid rain" is frequently used to describe this process. Acid deposition can occur through two pathways: by dry deposition of the compounds onto surfaces and by incorporation of the compounds into rain and snow.

It should also be pointed out that rain can be acidic naturally without chemical mechanisms resulting from pollutant emissions. Carbon dioxide which occurs

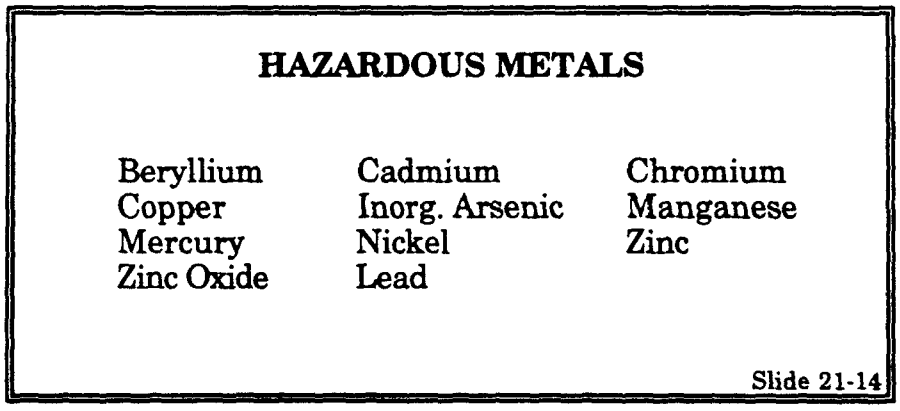
naturally in the atmosphere can become dissolved in rain and other forms of precipitation causing rain to be slightly acidic.

Acid deposition is believed to have harmful effects on environmental ecosystems. However, the effects of acid deposition on vegetation, lakes and streams are complex and difficult to understand. At present the effects of acidification of lakes and streams has not been proven conclusively but is believed to have a negative impact on these ecosystems of and can potentially destroy both plants and fish.

21.6 Hazardous Pollutants

Federal regulations recognize that it is necessary to safeguard the public health against exposure to extremely hazardous or toxic substances. Unlike the pollutants just described, exposure to hazardous pollutants is not widespread, but instead is confined to areas surrounding the emissions sources. For purposes of this discussion, hazardous pollutants can be classified as metal or organic compounds.

Hazardous Metals



Hazardous metals are emitted from combustion systems when they are present in the fuel being combusted. Hazardous metals can be emitted directly when present in ashes or particulates which escape control. In extreme instances hazardous metals may occur in the vapor phase and escape control in very high temperature thermal processes.[4]

Hazardous Organics

Sources of hazardous organic emissions fall into two different categories, which are direct emissions and indirect emissions to the atmosphere. Direct emissions typically occur from volatile organic pollutants and result from either spills, leaks or process venting. Indirect emissions are typically the result of emissions from

combustion systems where hazardous organics are partially destroyed as a result of incomplete combustion. For example, benzene is a product of incomplete combustion of toluene, a polycyclic aromatic hydrocarbon.

HAZARDOUS ORGANICS

Acrolein	Benzene	Benzo(a)pyrene
Carbon Tetrachloride	Chloroform	Ethylene Dibromide
Ethylene Dichloride	HCHO	Methyl Bromide
Methylene Chloride	Peroxyacyl Nitrate (PAN)	Perchloroethylene
Toluene	Trichloroethane	1,1,1-Trichloroethane
Vinyl Chloride	Xylenes	

Slide 21-15

Health effects from hazardous organics depend on the particular hazardous compound and its concentration during exposure. Slide 21-15 lists some hazardous organic substances of concern to regulatory agencies. Many of these substance target a particular organ in the body or are carcinogenic. Vinyl chloride appears to be a multipotent carcinogen in that it produces cancers in many different organ and in come cases it produces different kinds of tumors in the same organ. Hydrocarbon chemicals of their derivatives of health concern include carcinogenic polycyclic aromatic hydrocarbons (PAH), such as benzo(a)pyrene, and the eye irritants, including formaldehyde (HCHO), acrolein, and peroxyacyl nitrate (PAN). The PAHs are produced as a result of incomplete combustion of high-molecular-weight hydrocarbon species. Benzo(a)pyrene is the most abundant PAH in urban air.[3]

Eye irritation for HCHO occurs in the range of 0.1 to 1 ppm. Acrolein produces moderate eye irritation at levels of 0.25 ppm, and PAN causes irritation at 20 ppb. Eye irritation experienced in urban areas is most likely produced by the combined effects of these substances and other hydrocarbon derivatives.[3]

REFERENCES

1. G. S. Samuelsen. *Air Quality Impact Analysis.* Chapter 3 in: Environmental Impact Analysis Handbook. Rau, J. G. and D. C. Wooten, editors, McGraw–Hill, New York, New York, 1980.

2. Pahl, D. A., D. Zimmerman and R. Ryan. *An Overview of Combustion Emissions in the United States.* Chapter 1 in: Emissions from Combustion Processes: Origin, Measurement, Control. Clement, R. and R. Kagel, editors, Lewis Publishers, Incorporated, Chelsea, Michigan, 1990.

3. Godish, T. *Air Quality.* Lewis Publishers, Incorporated, Chelsea, Michigan, 1991.

4. Griffin, Roger D., *Principles of Hazardous Materials Management.* Lewis Publishers, Incorporated, Chelsea, Michigan, 1988.

CHAPTER 22. ENVIRONMENTAL REGULATIONS

22.1 Regulatory Overview
- A. Clean Air Act History
- B. Clean Air Terminology
- C. Clean Air Act Provisions

22.2 Provisions of the Clean Air Act Relative to Boiler Operations

22.3 New Source Performance Standards
- A. Performance Standards for Steam Generators (>250 MMBtu/hr)
- B. Performance Standards for Electric Utility Steam Generators (>250 MMBtu/hr)
- C. Performance Standards for Steam Generators (>100 MMBtu/hr)
- D. Performance Standards for Small Steam Generators (10–100 MMBtu/hr)

22.4 Additional Standards
- A. Acid Rain Program
- B. State Implementation Plans
- C. National Emission Standards for Hazardous Air Pollutants

22.5 Permits
- A. Title V Overview
- B. Permit Program Elements
- C. Information Requirements

22. ENVIRONMENTAL REGULATIONS

22.1 Regulatory Overview

The purpose of this chapter will be to review regulatory requirements that are applicable to industrial and utility boilers. From the outset, it must be recognized that federal regulations protecting the environment mandate that the states implement sufficient pollution control measures both to *attain* the federal air quality standards and to *maintain* air quality. Therefore, local limits on pollutant emissions can vary significantly from the limits established by the Clean Air Act, and from state to state. Boiler operators seeking a permit must consult with local and/or state regulatory agencies to determine what standards are applicable for their situation. The information contained in this learning unit is intended to provide boiler operators and owners with the ability to begin discussions with regulatory agencies on an informed basis.

Clean Air Act History

The process of burning fossil fuels creates air pollutants that are released to the atmosphere. As discussed in chapters 6 and 21, the air pollutants which are generated by burning fossil fuels include sulfur oxides, particulate matter, nitrogen oxides, hydrocarbons, carbon monoxide and carbon dioxide. Some of these pollutants represent a direct health hazard, while others are of concern because they react in the atmosphere to form secondary pollutants, which have detrimental impacts on public health and welfare (e.g. materials, vegetation, etc...). Therefore, regulations are needed to limit the release of these pollutants to the atmosphere.

Modern air pollution control regulations have their beginnings at the turn of the century. During this period, rapid industrialization lead to increased use of coal near urban centers. Smoke control ordinances were enacted in 1881 in Chicago and Cincinnati to abate smoke problems[1]. Local smoke control ordinances were enacted by most large cities in the first half of this century; however, these ordinances did little to control the detrimental impacts of modernization of the nation's air quality.

In 1955, federal air pollution legislation, commonly called the Air Pollution Control Act, was passed enabling the Public Health Service to conduct research on air pollution and to provide training and assistance to state and local governments in developing air pollution control programs. Modifications to this legislation in the early 1960s emphasized research into the health effects of automobile emissions. In 1963, the federal Clean Air Act was passed. This legislation provided for the award of grants to states to develop and improve air pollution control programs and gave federal agencies responsibility for establishment of non–mandatory air quality criteria, abatement of interstate air pollution problems, and performance of automobile and sulfur oxide pollution research. In 1965, amendments to the Clean Air Act required federal agencies to establish emissions standards for new motor vehicles.

Recognizing that improvements in air quality were slow under the 1963 Clean Air Act, Congress passed the Air Quality Act in 1967. This act was significant because it recognized that air quality was a regional problem and it called for the development and implementation of air quality standards. The federal government was given authority to establish standards and to require states to develop plans to achieve these standards. The federal government was also given the authority to review the plans and progress, and to take action if significant progress was not made.

HISTORY OF THE CLEAN AIR ACT

1881	**Smoke control ordinances passed in Chicago and Cincinnati.**
1955	**Federal Air Pollution Control Act enacted to evaluate and assist with air pollution control.**
1963	**Federal Clean Air Act passed to increase federal government role in protecting public health and welfare.**
1965	**Motor Vehicle Air Pollution Control Act passed to set emissions standards for new vehicles.**
1967	**Federal Air Quality Act enacted to increase air pollution control efforts.**
1970	**Clean Air Act Amendments passed to improve efforts for improving air quality.**
1977	**Additional Amendments to the Clean Air Act passed to extend deadline for achieving air quality standards.**
1990	**Clean Air Act Amendments passed to control acid rain, auto emissions, hazardous pollutants, and to meet the ozone standard nationwide.**

Slide 22-2

Unfortunately, progress under the 1967 Air Quality Act was slow. Therefore, Congress passed a series of amendments to the Clean Air Act in 1970. The 1970 Clean Air Act Amendments placed significant control and responsibility for air pollution with the federal government and established a rigorous timetable for implementing air pollution control measures. The basic premise of the Clean Air Act

Amendments was that air quality could be preserved through two actions: 1) establishment of national ambient clean air standards to limit pollutant levels to below those which would have adverse effects on public health and welfare, and 2) development of emissions standards for combustion equipment designed to maintain pollutant concentrations below the clean air standards. The Clean Air Act also passed responsibility for federal air pollution control programs to a new government agency, the Environmental Protection Agency.

Recognizing that many areas of the country had not achieved clean air standards for several pollutants by 1975 as mandated by the 1970 Clean Air Act Amendments, Congress passed additional amendments in 1977 extending the deadline for achieving the standards.

In 1982, the Clean Air Act was slated for revision. However, delays in Congress and lack of agreement between Congress and the President on the issue of acid rain delayed further amendments to the Clean Air Act for nearly a decade. Finally, on November 15, 1990, President Bush signed a series of amendments to the Clean Air Act. The primary objectives of these amendments were to address problems with acid rain (which is primarily linked to sulfur and nitrogen oxide emissions), emissions from automobiles, and hazardous pollutants. A primary goal of the act was also to permit the National Ambient Air Quality Standards for ozone and other pollutants to be achieved across the nation, particularly in affected urban areas. These amendments are referred to as the Clean Air Act Amendments (CAAA) of 1990.

Clean Air Terminology

Before reviewing the Clean Air Act Amendments of 1990, it is useful to review some of the terminology used in the regulations.

CLEAN AIR ACT TERMINOLOGY

NAAQS	**National Ambient Air Quality Standards**
PSD	**Prevention of Significant Deterioration**
NSPS	**New Source Performance Standards**
SIP	**State Implementation Plans**
NESHAP	**National Emission Standards for Hazardous Air Pollutants**

Slide 22-3

As discussed above, the Clean Air Act empowers the EPA to establish *National Ambient Air Quality Standards* (NAAQS) for pollutants which have the

potential to have an adverse effect on human health or welfare. Chapter 1 provides a brief introduction to the NAAQS, while Chapter 21 summarizes the current pollutants covered by the NAAQS and their known impacts. For the purposes of the regulation, specific areas across the United States that are not in compliance with the NAAQS are designated as *nonattainment areas*.

In order to protect air quality in regions of the country where the NAAQS are being met, the Clean Air Act establishes guidelines for the *Prevention of Significant Deterioration* (PSD) in air quality in these regions. These quidelines prevent areas of high air quality from being polluted to the levels allowable by the NAAQS.

To control emissions from new sources, the Clean Air Act empowers the EPA to establish *New Source Performance Standards* (NSPS) for various types of stationary emissions sources. These standards limit the rate at which criteria pollutants (e.g. sulfur oxides, nitrogen oxides, particulate, etc...) can be emitted from new sources. These standards also apply to existing equipment undergoing major modification resulting in increases in emissions of criteria pollutants.

The Clean Air Act also requires the EPA to develop *National Emissions Standards for Hazardous Air Pollutants* (NESHAP). These standards will set emissions limits on hazardous pollutants. The 1990 Clean Air Act Amendments contain a list of 189 chemicals for which the EPA will be required to develop standards requiring facilities to institute control of these pollutants.

CLEAN AIR ACT CONTROL STANDARDS

Criteria Pollutants

LAER	**Lowest Achievable Emissions Rate**
BACT	**Best Available Control Technology**
RACT	**Reasonably Available Control Technology**

Hazardous Air Pollutants

MACT	**Maximum Available Control Technology**
GACT	**Generally Available Control Technology**

Slide 22-4

Passage of the Clean Air Act has introduced a wide range of terms regarding the level of pollution control technology that needs to be applied to meet emissions standards established under the act. For criteria pollutants, *Best Available Control*

Technology (BACT) is the technology required for new sources or existing sources undergoing major modification in attainment areas. BACT is defined as the most effective emissions control in use, taking into account factors of availability and cost on a case–by–case basis[2]. In nonattainment areas, new sources may be expected to comply with the *Lowest Achievable Emissions Rate*, the most stringent emissions limit. All existing major emissions sources in nonattainment areas will be required to implement *Reasonably Available Control Technology* (RACT) control measures. The EPA is required to release Control Technology Guidance documents which advise states on technologies which will be classified as RACT for various sources.

Two levels of emissions control have been established for hazardous air pollutants. Major sources of hazardous pollutants will be required to implement *Maximum Available Control Technology* (MACT). This technology provides the maximum degree of emissions reduction achievable, taking into account several factors including availability and cost. Alternatively, the EPA may permit *Generally Available Control Technology* (GACT) to be implemented for certain area emissions sources.

Clean Air Act Provisions

The 1990 Clean Air Act Amendments were the most comprehensive piece of environmental legislation enacted by the federal government to date. The impacts of the Clean Air Act are expected to reach all businesses and consumers[2]. The Clean Air Act Amendments are divided into eleven titles, each of which covers specific topics:

Title I **Air Pollution Prevention and Control** establishes the framework for attaining and maintaining National Ambient Air Quality Standards. Areas which are specified as nonattainment areas are classified into different categories. Deadlines and measures required to achieve NAAQS are specified. State Implementation Plans are required for specific pollutants in nonattainment areas.

Title II **Emissions Standards for Moving Vehicles** regulates mobile sources by establishing stricter emissions limits for new vehicles and by requiring the use of fuels with lower emissions (e.g. reformulated gasoline).

Title III **Hazardous Air Pollutants** greatly expands the regulation of hazardous pollutants. The title requires the establishment of MACT standards for major sources emitting hazardous air pollutants identified in the act.

Title IV **Acid Deposition Control** governs the control of sulfur oxides and nitrogen oxides, primarily from utility boilers. Industrial sources may elect to participate in the emissions credits program.

Title V **Permits** establishes a new permit system for any source regulated under the Clean Air Act. The permit system will be implemented at the state level.

Title VI **Stratospheric Ozone Protection** is designed to implement controls on substances, primarily refrigerants such as chlorofluorcarbons and hydrochlorofluorocarbons, that are believed to impact the ozone layer.

Title VII **Enforcement** provides new requirements for enforcement and establishes criminal penalties for noncompliance.

Title VIII **Miscellaneous Provisions** contains several provisions regarding control of emissions from sources in the outer continental shelf, assessment of visibility in National Parks, and other topics.

Titles IX–XI **Clean Air Research, Disadvantaged Business Concerns, and Clean Air Employment Transition Assistance** contain provisions for research, allocation of research funds to disadvantaged businesses, and assistance for persons who lose their job as a result of the Clean Air Act.

1990 CLEAN AIR ACT TITLES

I.	**Air Pollution Prevention and Control**
II.	**Emissions Standards for Moving Vehicles**
III.	**General**
IV.	**Acid Deposition Control**
V.	**Permits**
VI.	**Stratospheric Ozone Protection**
VII.	**Enforcement**
VIII.	**Miscellaneous Provisions**
IX.	**Clean Air Research**
X.	**Disadvantaged Business Concerns**
XI.	**Clean Air Employment Transition Assistance**

Slide 22-5

CLEAN AIR ACT PROVISIONS RELATIVE TO BOILER OPERATIONS

Title I: **Air Pollution Prevention and Control**

Title III: **Hazardous Air Pollutants**

Title IV: **Acid Deposition Control**

Title V: **Permits**

Slide 22-6

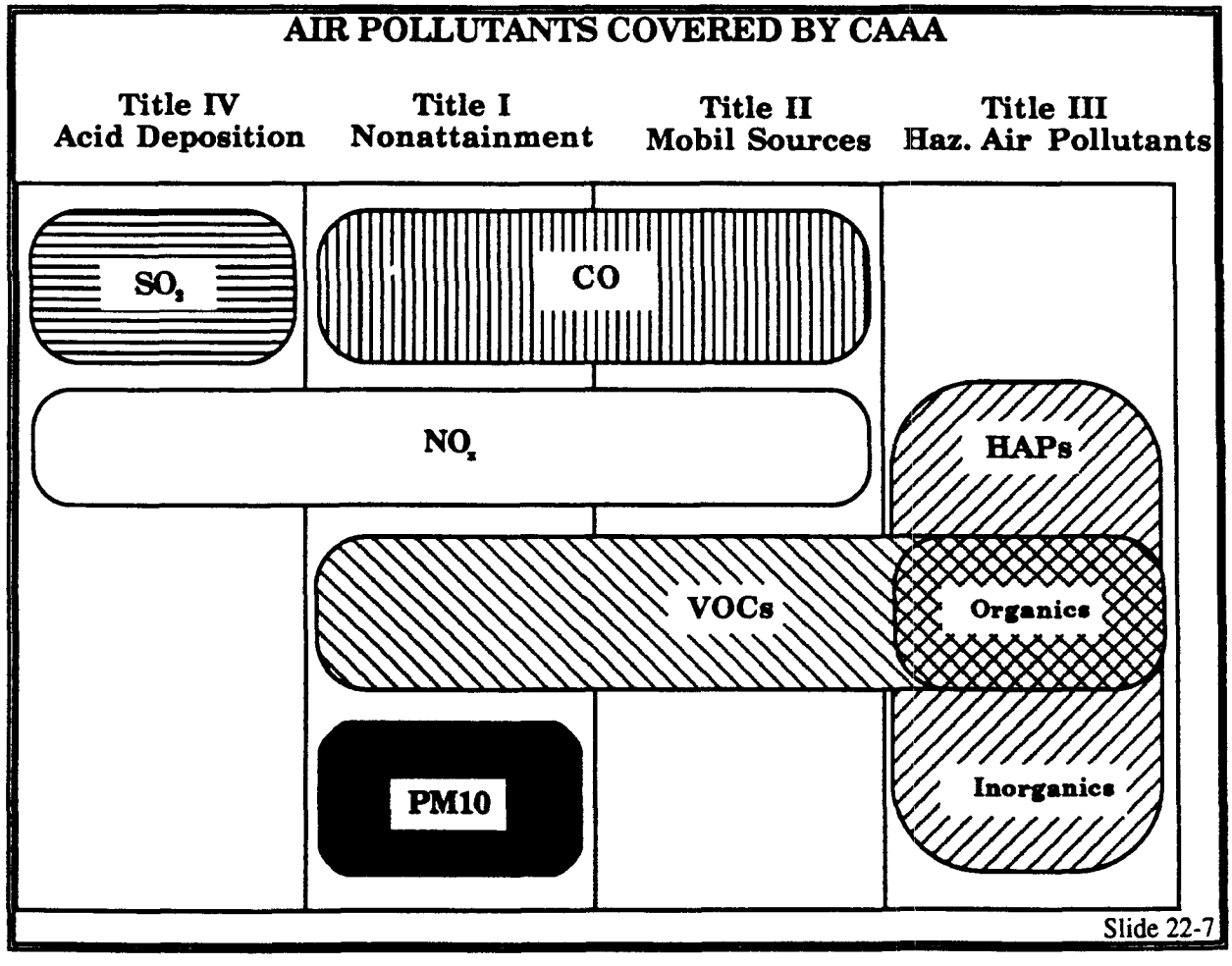
The four provisions of the Clean Air Act expected to have the strongest impact on owners and operators of industrial and utility boilers are Titles I, III, IV, and V. Under Title I, each state has primary responsibility for assuring attainment of the NAAQS through a state implementation plan (SIP). The SIP can have significant impact on how a boiler is operated. Boilers located in areas needing to come into attainment with the federal ozone standard will likely need to implement RACT to control NO_x emissions. Title I also requires the EPA to issue technical documents which identify alternative controls for NOx emissions from industrial and utility boilers. These documents will assist the states with developing and implementing the SIP programs.

As discussed earlier, Title III focuses on the identification and control of hazardous air emissions. Under the act, the EPA was directed to perform studies on electric steam generating unit emissions to determine the hazards to public health reasonably anticipated to occur as a result of emissions of listed hazardous air pollutants. The results from this study and others may provide the basis for EPA to formulate additional regulations to control emissions of hazardous pollutants from power plant emissions. This section of the act also requires the EPA to develop a model state program for the training and certification of high capacity fossil fuel fired plant operators. This manual was prepared to satisfy the training requirements. The American Society of Mechanical Engineers is developing a certification program for such operators.

Title IV addresses acid deposition which occurs when sulfur dioxide and nitrogen oxide emissions are transformed in the atmosphere to acids and return to earth as rain, fog or snow. Most of the sulfur dioxide emitted in the U.S. is the result of burning fossil fuels by electric utilities. Therefore, this title contains sulfur reduction requirements for all power plants. Nitrogen oxides contribute significantly to acid deposition. Therefore, Title IV also establishes limits on emissions of nitrogen oxides from power plants.

Title V contains a new permit system for sources controlled under the Clean Air Act Amendments. Boiler operators will need to establish whether they need an operating permit and then apply to obtain one if needed. Permits will be issued by the states following federal quidelines. Permits will establish detailed requirements governing emissions from the source and related activities such as monitoring, record–keeping, and reporting.

The following chart shows how various air pollutants are governed under the Clean Air Act Amendments. Title IV limits emissions of sulfur dioxide and nitrogen oxides from utility boilers. Non–utility sources may apply to fall under this regulation in order to generate emissions credits. Title I limits emissions of carbon monoxide, nitrogen oxides, volatile organic compounds and particulate from stationary combustion sources. Title II establishes limits for these pollutants from mobile sources. Hazardous Organic compounds and inorganic particulate materials, such as various metal compounds which may be present in fly ash will be regulated under Title III.



22.3 New Source Performance Standards

The Clean Air Act Amendments provide the EPA with the power to develop and administer New Source Performance Standards (NSPS). These standards apply to "new sources" and establish unit "performance standards" limiting the rate at which pollutants may be emitted from the stack. The NSPS also apply to sources undergoing modifications which would result in increases in regulated pollutants.[3]

NEW SOURCE PERFORMANCE STANDARDS

Apply to New Units or Significantly Modified Units

Regulations Established for different Groupings of Pollutant Emission Sources

- **Utility Boilers**
- **Industrial Boilers**
- **Gas Turbines**

Establish Stack Emission Limits for Criteria Pollutants

Limits must be based on Demonstrated Performance of Control Technologies

Establish Monitoring, Recordkeeping, and Reporting Requirements

Slide 22-8

From Chapter 1, you may recall that NSPSs have been developed for different groupings of pollutant emission sources including gas turbines and:

- Large Fossil Fuel Fired Boilers - This grouping is dominated by electric utility boilers, but includes all boilers with heat input ratings greater than 250 million Btu per hour.

- Industrial Boilers - This grouping includes all units with heat input rates between 10 million and 250 million Btu per hour.

For each of these major groupings, the NSPSs establish limits on the stack emission rates or stack concentrations for the NAAQS "criteria pollutants." Thus, there is link between the ambient air quality standards and the new source performance standards. There are, however, important differences in the applicability and the basis for the two types of standards. The NAAQS limits are based on consideration of health effects while the NSPS limits are established based on *demonstrated performance* of actual units in full-scale operation.

The utility boiler NSPS set different particulate, sulfur oxide, and nitrogen oxides emission limits for units firing gas, oil, and coal. The NSPS only apply to newly constructed units *or* to existing units undergoing significant modification. The logic behind this applicability is that boilers have a finite lifetime—on the order of 30 to 40 years. Boilers constructed prior to passage of the original Clean Air Act were exempted from the original NSPS but they were *expected* to be retired by shortly after the turn of the century. The significant modification provision was included to help assure that old boilers would be retired in an orderly fashion and replaced by new units, subject to the NSPS.

Performance Standards for Steam Generators (>250 MMBtu/hr)

NEW SOURCE PERFORMANCE STANDARDS
Steam Generators with Heat Input > 250 MMBtu/hr

Apply to Units Constructed After 8/17/71
or Significantly Modified Units

Fuel	Pollutant	Allowable Emissions Rate (lb/10^6 Btu)
Coal	SO_2	1.2
	NO_x	0.7
	Particulate	0.1
Oil	SO_2	0.8
	NO_x	0.3
	Particulate	0.1
Gas	NO_x	0.2
	Particulate	0.1

Slide 22-9

The initial performance standards for fossil–fuel–fired boilers with a heat input greater than 250 million Btu per hour are shown in the above table[4]. The standards apply to units constructed after 17 August 1971. These standards were later revised for utility boilers and for industrial boilers.

The performance standards also contain requirements for the installation of continuous emissions monitors for measuring stack concentrations of sulfur dioxide, nitrogen oxides, and either oxygen or carbon dioxide. Each boiler owner or operator is required to install continuous emissions monitors for SO_2, NO_x, and either O_2 or CO_2 with the noted exceptions in Slide 22-10.

CONTINUOUS EMISSIONS MONITORS

Each boiler operator is required to install continuous emissions monitors for SO_2, NO_x, and either O_2 or CO_2 with the following exceptions:

1) **Boilers burning gas do not need an SO_2 monitor.**

2) **Boilers burning coal and oil can opt to monitor SO_2 by fuel sampling and analysis, if they do not have a desulfurization unit.**

3) **Boilers with NO_x emissions which are less than 70 percent of the standards do not need to install a NO_x monitor.**

4) **Boilers not needing SO_2 or NO_x monitors do not need to install an O_2 or CO_2 monitor.**

Slide 22-10

To verify the compliance with the emission limits and the continuous emission monitoring system operation, the NSPS requires specific reports be submitted to the administrator of the regulation, which varies from region to region. These reports are typically submitted every three months and contain the average emission rates for each 30 day period, identification of boiler operating days which were not in compliance with the standard, reasons for the non-compliance, and description of corrective actions taken. For small steam generating units, the reporting requirements may be semiannual if no excess emissions occurred during the quarter.

For those sources which require continuous emission monitoring system (CEMS), similar information is required to be reported for the CEMS performance. A typical list of the information boiler operators need to record and log to support these reporting requirements is shown in Slide 22-11.

BOILER OPERATION LOG DATA FOR NSPS REPORTING

Calendar date

Emission rates (hourly) and /or opacity
Reasons for noncompliance with the emission standards
Description of corrective actions taken.

Operating days for which emission data have not been obtained by an approved method
Justification for not obtaining sufficient data
Description of corrective actions taken.

Type of fuel(s) combusted and reference to compostion (i.e. fuel supplier certification)

If a CEMS is used,

- **Identification of any times when the pollutant concentration exceeded the full span of the CEMS.**
- **Description of any modification to the CEMS that could affect the ability of the CEMS to comply with Performance Specifications**
- **Results of daily CEMS drift tests**

Slide 22-11

Performance Standards for Electric Utility Steam Generators (>250 MMBtu / hr)

Special emissions limits have been established for boilers used in electric utility operations. As discussed earlier, this provision was added to the NSPS to address the problems associated with acid rain—electric utility boilers are the greatest source of sulfur oxide emissions in the United States. The performance standards for fossil–fuel–fired boilers operated by electric utilities with a heat input greater than 250 million Btu per hour are shown in the following two tables.[5] The standards apply to units constructed after 9/18/78. Emissions of sulfur dioxide and particulate have been established based on the fuel type fired—coal, gas, or liquid. For NO_x emissions, the standards are based upon a wider definition of fuel types. A distinction is made between typical fuels and fuels derived from coal and coal refuse. Coal refuse if defined as waste products from coal mining, preparation or physical preparation. For coal, NO_x emissions standards are also based upon coal type. Note that boilers firing 25 percent by weight of North Dakota, South Dakota, or Montana lignite in a slag–tap furnace have the highest allowable emissions.

NSPS - SULFUR DIOXIDE & PARTICULATE
Electric Utility Steam Generators
with Heat Input > 250 MMBtu/hr

Apply to Units Constructed After 9/18/78
or Significantly Modified Units

Fuel	Pollutant	Allowable Emissions Rate (lb/10^6 Btu)	Emissions Reduction
Coal	SO_2	1.2	90%
		0.6	70%
	Particulate	0.03	99%
Oil	SO_2	0.8	90%
		0.2	0%
	Particulate	0.03	70%
Gas	SO_2	0.8	90%
		0.2	0%
	Particulate	0.03	—

Slide 22-12

The NSPS for electric utility boilers requires two standards to be met: 1) a maximum emission rate and 2) a percent reduction in potential emissions. The percent reduction is calculated based upon the amount of emissions which would be present in the absence of any controls.

NSPS - NITROGEN OXIDES
Electric Utility Steam Generators with Heat Input > 250 MMBtu/hr

Apply to Units Constructed After 9/18/78 or Significantly Modified Units

Fuel	Allowable Emissions Rate ($lb/10^6$ Btu)	Emissions Reduction
Gaseous Fuel:		
Coal-Derived	0.5	25%
All Other	0.2	25%
Liquid Fuels:		
Coal-Derived	0.5	30%
Shale Oil	0.5	30%
All Other	0.3	30%
Solid Fuels		
Coal-Derived	0.5	65%
Fuel (25% coal Refuse)	(1)	(1)
Fuel (25% lignite/slag)	0.8	65%
Fuel (25% lignite/other)	(2)	(2)
Subbituminous	0.5	65%
Bituminous	0.6	65%
Anthracite	0.6	65%
All Other	0.6	65%

(1) exempt from the NO_x standards and monitoring requirements.
(2) fuels in this category are not prorated.

Slide 22-13

Federal regulations define the following *potential combustion concentrations* (e.g. uncontrolled emissions) to be used in calculation of the potential emissions reduction:

- Particulate emissions:
  - 7.0 lb/million Btu heat input for solid fuels.
  - 0.17 lb/million Btu heat input for liquid fuels.

- Sulfur dioxide emissions to be calculate based upon the fuel analysis.

- Nitrogen oxides emissions:
  - 0.67 lb/million Btu heat input for gaseous fuels.
  - 0.72 lb/million Btu heat input for liquid fuels.
  - 2.3 lb/million Btu heat input for solid fuels.

POTENTIAL COMBUSTION CONCENTRATIONS

Pollutant	Fuel Type	Concentration (lb/MMBtu)
Particulate	**Solid**	**7.00**
	Liquid	**0.17**
SO_2	**All**	**Based Upon Fuel Content**
NO_x	**Solid**	**2.30**
	Liquids	**0.72**
	Gaseous	**0.67**

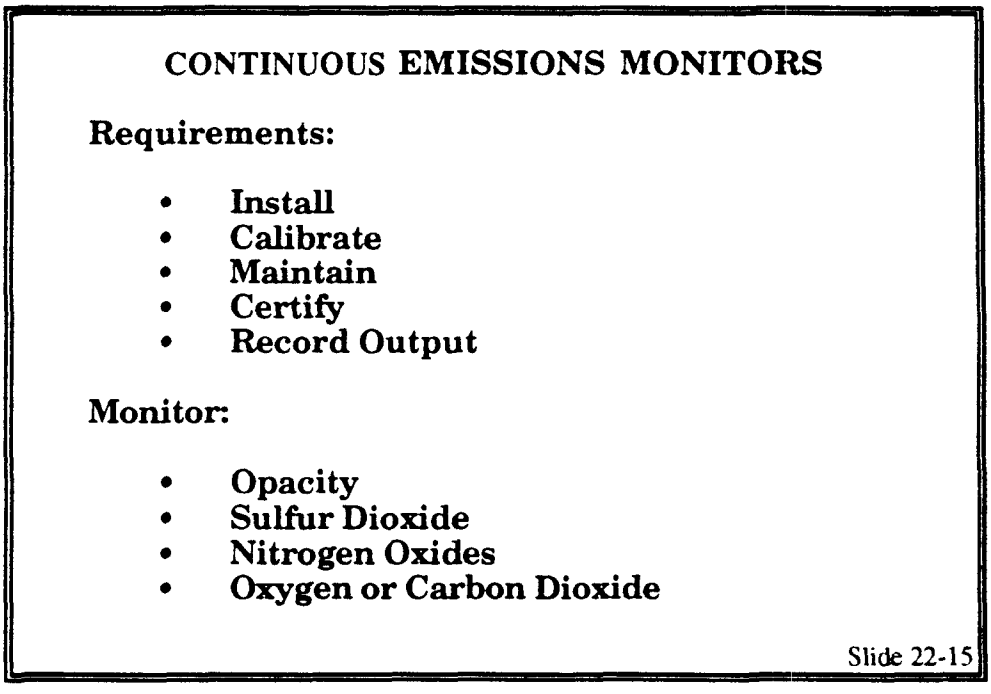
Slide 22-14

For utility boilers firing multiple fuels, the applicable NO_x standard (in pounds per million Btu of heat input) is calculated based upon a special formula:

$$E_n = [0.20\ w + 0.30\ x + 0.50\ y + 0.60\ z + 0.80\ v]/100$$

where: E_n is the emissions standard for firing combined fuels, w is the percent of heat input from the combustion of fuels subject to the 0.20 lb/MMBtu standard, x is the percent of heat input from the combustion of fuels subject to the 0.30 lb/MMBtu standard, y is the percent of heat input from the combustion of fuels subject to the 0.50 lb/MMBtu standard, z is the percent of heat input from the combustion of fuels subject to the 0.60 lb/MMBtu standard, and v is the percent of heat input from the combustion of fuels subject to the 0.80 lb/MMBtu standard. Consult 40CFR60.44a (c) for details.

Owners of electric utility boilers which are subject to these regulations are required to install, calibrate, maintain and certify continuous emissions monitors for opacity, sulfur dioxide, nitrogen oxides. Oxygen or carbon dioxide monitors must be installed at all points where sulfur dioxide and nitrogen oxides are measured. Sulfur dioxide emissions must be monitored at the inlet and outlet of any sulfur dioxide control device. Outlet emissions monitoring only is permitted for units classified as resource recovery facilities, units burning anthracite, and solid fuel burning units in noncontinental areas. Fuel monitoring may be substituted for an emissions monitor upstream of the control device.



Performance Standards for Steam Generators (>100 MMBtu/hr)

Performance standards have been established for steam generating units used in industrial, commercial, or institutional facilities[6]. These standards apply to each steam generating unit that commences construction, modification, or reconstruction after 29 June 1984 and that has a heat input greater than 100 million Btu per hour. The performance standards for these units are summarized in the following table[7].

Similar to the standards for sulfur dioxide emissions from electric utility boilers, the standards for industrial boilers are based upon a concept of maximum allowable emissions rate and percent emissions reduction from the uncontrolled level. As before, the uncontrolled level is defined as the emissions that would occur based upon firing the fuel in an uncleaned, uncontrolled state. The potential emissions are based upon the fuel analysis.

The standard for NO_x emissions varies with fuel type and, for coal, varies with the type of boiler: spreader stoker, mass–feed stoker, pulverized coal, and fluidized bed are the defined boiler types. For oil and gas fuels, the NO_x standard also varies with the *heat release rate* of the boiler. The heat release rate is defined as the design heat input of the boiler divided by the total furnace volume.

The particulate standard also contains an opacity limit of 20 percent.

SOURCE PERFORMANCE STANDARDS
Steam Generators with Heat Input > 100 MMBtu/hr

Apply to Units Constructed After 6/19/84 or Significantly Modified Units

Fuel	Pollutant	Allowable Emissions Rate (lb/10^6 Btu)	Emissions Reduction
Coal	SO_2	1.2	90%
	NOx:		
	Spreader Stoker	0.6	—
	Mass–Feed Stoker	0.5	—
	Pulverized Coal	0.7	—
	Fluidized Bed	0.6	—
	Particulate	0.05	—
Oil	SO_2:		
	Residual	0.5	0%
	Others	0.8	90%
	NOx:		
	HRR < 70,000	0.3	—
	HRR > 70,000	0.4	—
	Particulate	0.10	—
Gas	NOx:		
	HRR < 70,000	0.1	—
	HRR > 70,000	0.2	—

HRR = Heat Release Rate in Btu/hr–ft^3.

Slide 22-16

Operators of boilers which are subject to these standards must install continuous emissions monitors for sulfur dioxide, opacity, and nitrogen oxides. Continuous emissions monitors for oxygen and carbon dioxide must be installed at points where sulfur dioxide and nitrogen oxides emissions are measured.

Similar to the provisions for utility boilers, sulfur dioxide emissions must be monitored at the inlet and outlet of any sulfur dioxide control devices. Monitoring of fuel sulfur content can be substituted for a sulfur dioxide continuous emissions monitor at the inlet of the control device. Operators may also elect to use manual sampling methods to monitor outlet emissions rather than installing a continuous emissions monitor. Operators firing low sulfur fuel oil are exempt from the sulfur dioxide monitoring requirements.

Boilers firing residual oil with a nitrogen content below 0.3 percent can elect to develop and use a predictive methodology to estimate nitrogen oxide emissions based upon monitored boiler operating conditions. Duct burners used in combined cycle systems are exempt from the nitrogen oxide monitoring requirements.

Performance Standards for Small Steam Generators (10 to 100 MMBtu / hr)

Performance standards have been established for small steam generating units used in industrial, commercial, or institutional facilities[8]. These standards apply to each steam generating unit that commences construction, modification, or reconstruction after 9 June 1989 and that has a heat input greater than 10 million Btu per hour, but less than 100 million Btu per hour. The performance standards for these units are summarized in the following table.

SOURCE PERFORMANCE STANDARDS
Steam Generators with Heat Input 10–100 MMBtu/hr

Apply to Units Constructed After 6/9/89 or Significantly Modified Units

Fuel	Pollutant	Allowable Emissions Rate (lb/10^6 Btu)	Emissions Reduction
Coal	SO_2	1.2	90%
	Particulate	0.05	—
Oil	SO_2	0.5	-
Wood	Particulate	0.10	-

Slide 22-17

Similar to the standards for sulfur dioxide emissions large coal–fired industrial boilers, the standards for small coal–fired industrial boilers are based upon a concept of maximum allowable emissions rate and percent emissions reduction from the uncontrolled level. As before, the uncontrolled level is defined as the emissions that would occur based upon firing the fuel in an uncleaned, uncontrolled state. The potential emissions are based upon the fuel analysis.

Operators of boilers that used an emerging technology for sulfur dioxide emissions control must meet a standard of 0.60 lb SO_2 per million Btu and achieve 50 percent control. Operators of oil–fired boilers may choose to limit fuel sulfur content to below 0.5 percent by weight rather than complying with the emissions standard. Fuel pretreatment can be used to comply with the reduction requirements; however, it will not be credited to the reduction performance unless pretreatment results in a 50 percent reduction in potential emissions or reduces emissions to less than the standard.

The particulate standard also contains an opacity limit of 20 percent. For some boilers, this requirement may limit the permissible particulate emissions below the allowable emissions rate.

22.4 Additional Standards

In addition to the New Source Performance Standards, boilers may also be subject to additional emissions limits.

ADDITIONAL STANDARDS REQUIRING EMISSIONS CONTROLS

- **Acid Rain Program (Title IV)**
  - **SO_2**
  - **NO_x**
- **State Implementation Plans (SIP)**
  - **NO_x**
  - **Hydrocarbons**
  - **Particulate**
- **National Emission Standards for Hazardous Air Pollutants (NESHAP)**
  - **Hazardous Organics**
  - **Metals in flyash**

Slide 22-18

The three primary sources of controls will be due to requirements contained in the acid rain provisions of the Clean Air Act established in Title IV, to limits established in individual state implementation plans, and to standards established under Title III of the Clean Air Act, Hazardous Pollutants. The requirements of under Title IV will require significant reductions in emissions of both sulfur dioxide and nitrogen oxides from electric power utility boilers. Provisions in the state implementation plans may require additional control of nitrogen oxides and hydrocarbons, particularly in ozone nonattainment areas, or particulate. The NESHAP standards may require control of hazardous organic compounds resulting from incomplete combustion or control of metal compounds contained in flyash.

Acid Rain Program

The objective of the acid rain program established under Title IV of the Clean Air Act is to reduce emissions of acid rain precursors, both sulfur dioxide and nitrogen oxides, from boilers used to generate electric power. In all, the provisions of the program are designed to reduce annual sulfur dioxide emissions due to electric utility boilers by 10 million tons by the year 2000. Thereafter, the provisions establish a nationwide cap on annual sulfur dioxide emissions of 8.9 million tons. The initial provisions of Title IV are also expected to reduce annual NOx emissions from utility boilers by 2 million tons.

Reductions in sulfur dioxide emissions are to be achieved in two phases. In Phase I, fifty percent of the total reductions will be achieved by limiting emissions from power plants with a generating capacity above 100 MW. Total sulfur dioxide emissions for large plants will be limited to 2.5 lb/MMBtu multiplied by the average fuel use during 1985 to 1987. The regulation specifically identifies the 111 plants which will need to implement controls and their allowable emissions. These 111 plants are the highest sulfur dioxide emitters in the United States. In Phase II, almost all power plants rated at greater than 25 MW must limit emissions to below 1.2 lb/MMBtu.

Sulfur dioxide emissions will be reduced though a new market–based scheme under which power plants are allocated emissions allowances that will require plants to reduce their emissions or acquire allowances from others to achieve compliance. Under this scheme, one allowance is worth one ton of sulfur dioxide removed. Allowances can be earned, banked, leased or bought. The emissions trading scheme outlined in the Clean Air Act will permit utilities to emit more sulfur dioxide than allowed by acquiring emissions allowances or to control to levels below those allowed to generate emissions credits. This market–based scheme to emissions control is expected to provide utilities with the ability to achieve compliance using the most cost–effective control strategies.

ACID RAIN PROGRAM

Purpose

- Reduce annual SO_2 emissions from electric utility power plants by 10 million tons by the year 2000.
- Reduce NOx emissions from electric utility power plants by 2 million tons.

Sulfur Dioxide Control

- Phase I (1995)
  - Emissions limited to 2.5 lb/MM Btu for plants greater than 100 MW (111 affected plants).
  - SO_2 allowance/trading scheme.
- Phase II (2000)
  - Emissions limited to 1.2 lb/MM Btu for nearly all power plants greater than 25 MW.
  - Nationwide cap on utility SO_2 emissions at 8.9 million tons per year.

Nitrogen Oxides Control

- Emissions limits to be established by EPA.
- Preliminary limits:
  - Tangentially fired boilers = 0.45 lb/MMBtu.
  - Wall-fired boilers boilers = 0.50 lbs/MMBtu.
- EPA to establish limits for cyclone boilers, wet bottom boilers and boilers equipped with cell burners.
- EPA to revise NSPS.

Slide 22-19

Emissions of nitrogen oxides will also be reduced under the acid rain program. Preliminary limits for Phase I boilers were set at 0.45 lb/MMBtu for tangentially fired boilers and 0.50 lb/MMBtu for dry bottom wall-fired boilers. EPA is in the process of finalizing emissions limits for these boilers. Initial control limits are being established on the basis of low-NO_x burner technology. EPA will also be required to establish limits for cyclone boilers, wet bottom boilers and boilers equipped with cell burners. These boilers are not easily retrofitted with low-NO_x burner technology. EPA is also required to promulgate revised New Source Performance Standards for NOx emissions from fossil fuel fired steam generating units.

State Implementation Plans (SIPs)

Each state is required to develop a series of State Implementation Plans (SIPs). In broad terms, SIPs are the detailed procedures that a state will use to assure that NAAQS requirements are maintained or the detailed corrective actions that a state will use to bring local areas into compliance. If areas are in compliance, the state has broad flexibility in establishing emission criteria for all source categories. Most states rely on the NSPS for stationary sources and mobile source standards to limit emissions from automobiles. The states *may* elect to impose more strenuous emission limits than suggested by the federal government. If an area is out of compliance with the NAAQS, a completely different set of emission criteria are imposed. Clearly, any new source represents an additional burden to an ambient air situation that is already considered unacceptable. Accordingly, to add a new source, that source must (1) meet extremely stringent emission control requirements, and (2) the owners must find a way to reduce emissions from an existing source that more than off set emissions from the proposed new unit. Further, to remedy the non-compliance situation in the area, states may require the existing sources make plant modifications to reduce the emission rate for a particular pollutant.

STATE IMPLEMENTATION PLANS (SIPs)

- **Plans for Implementing the Requirements of the Clean Air Act at the State level.**
- **SIPs provide the road map for States to meet NAAQS**
- **Regulations may apply to New and Existing sources**
- **Regulations may be More Stringent than NSPS**
- **SIPs must be reviewed and approved by Federal EPA**
- **As SIPS are approved, boiler operators will need to contact state regulatory agencies to determine compliance requirements.**

Slide 22-20

Across the nation, the need to bring ozone non–attainment areas into compliance will likely require control of NO_x emissions from boilers. These controls may place stricter limits on NO_x emissions that those established by the NSPS, and may affect boilers not governed under the NSPS. In addition, further controls for hydrocarbons or particulate may be required by the states.

Boiler owners and operators will need to contact state regulatory agencies to determine compliance requirements as the SIPs are approved.

National Emission Standards for Hazardous Air Pollutants (NESHAPs)

The NSPS address the group of criteria pollutants and are only applicable to new sources. There are a variety of pollutants that have been determined to pose immediate health risks to the exposed public. To address this situation, the EPA has authority to develop National Emission Standards for Hazardous Air Pollutants (NESHAPs). The major factors associated with NESHAPs are that these standards are based on acute health risk determinations and they apply equally to *all* sources covered by the regulations. That is, a NESHAP emission release rate requirement is the same for existing sources and new sources. The 1990 Amendments to the Clean Air Act required the EPA to conduct wide ranging research relative to a group of 189 compounds that are classified as hazardous air pollutants (HAPs). Many of those pollutants are emitted from fossil fuel fired boilers. Those regulations have not yet been enacted but it is likely that in the near future, control of HAP emissions will be a major consideration for fossil fuel fired boiler operations.

22.5 Permits

Title V Overview

Title V of the Clean Air Act establishes a comprehensive federal permit operating program for sources regulated under the act. The primary objective of this provision is to include in one document all of the requirements concerning air emissions that apply to a specific plant.

TITLE V - PERMITS

- **Comprehensive Program for Federal Operating Permits**
- **Applies to significant sources of air pollution:**
  - **Major sources of criteria pollutants**
  - **Sources regulated by NSPS provisions**
  - **Sources subject to NESHAP rules**
- **States to develop operating permit program based upon EPA quidelines**
- **EPA to approve program plan**
- **Annual permit fees ~ $25/ton of pollutant, except CO**

Slide 22-21

The secondary objectives of Title V are to provide operators with the ability to have flexibility to respond to changing market conditions and to generate money for states to fund aspects of their emissions control programs.

Under the act, sources will be required to apply for and obtain an operating permit. Sources required to obtain a permit are those which are classified as major sources of criteria pollutants under the act, which are subject to the New Source Performance Standards, or which are subject to the NESHAP regulations on hazardous pollutants. Major sources of criteria pollutants include those which emit 100 tons per year and smaller sources in more extremely pollutant areas[9].

States are required to develop a plan for administering the *Operating Permit Program*. The program is to be based upon guidelines published in the Federal Register on July 21, 1992. Following EPA approval of the state plan, the original time line calls for the state operating permit program is to be established in late 1995.

States are allowed to charge annual permit fees of at least $25 per ton of each regulated pollutant emitted excluding carbon monoxide.

Permit Program Elements

STATE PERMIT PROGRAMS

- **Provisions for permit applications and their completeness**
- **Requirements for payment of fees**
- **Authority to issue permits**
- **Provisions for reopening and terminating permits**
- **Provisions to ensure operating flexibility**
- **Permits to contain requirements for:**
  - **Compliance certification**
  - **Monitoring requirements**
  - **Reporting Requirements**

Slide 22-22

The state operating permit program must contain specific elements dictated by the EPA. The plan must contain provisions for permit applications and determination of the completeness of the application. States are given authority both to issue permits and to levy fees. The permit program is also structured to permit reopening and terminating permits. The program also contains defining enforcement authorities including civil and criminal penalties for sources not in compliance. Civil penalties of up to $10,000 per day for individual permit violations may be levied.

Under the operating permit program, sources who determine that they need it will apply to the state to obtain an operating permit. The state will review the permit application and, if acceptable, will issue an operating permit. Each permit application and final permit will be transmitted to the EPA. To permit business to have some operating flexibility, the permit application can contain several different operating scenarios that a business anticipates operating over to meet future market demands. Once these scenarios are approved in the permit, businesses will be allowed to make operating changes that may result in emissions increases without being subject to an extensive and time consuming administrative review process.

When issued, an operating permit will contain all of the detailed information regarding emissions from the source and several other requirements, such as procedures for compliance certification, monitoring and reporting of emissions. Each permit will be issued on a three to five year term.

Information Requirements

PERMIT INFORMATION REQUIREMENTS

- **Location**
- **Type of source**
- **Owner/operator details**
- **Source and process description and an alternative operating scenario.**
- **Emissions inventory information**
- **Compliance plan (if needed)**
- **Compliance certification**

Slide 22-23

A significant amount of information will need to be assembled to submit a proper permit application[10]. The table above details some of the requirements. State and local authorities should be consulted to obtain the exact requirements for a

permit application. The permit application will need to summarize pertinent information regarding the source including: location, type of equipment, and names of the owner/operator. The permit application will also need to include a detailed description of the process, including fuels used, fuel firing rates, raw materials, production rates, and operating schedules. Where possible, alternative operating scenarios should be included.

A key element of the permit will be the development of a detailed emissions inventory for a source. The emissions inventory will include quantifying emission rates and emission points of all regulated pollutants. A description of air pollutant control equipment should also be included. All emissions calculations should be included in the application. Sources will need to determine whether they are in compliance with state and federal regulations. Those that are in compliance will need to submit a report certifying that the facility is in compliance. If a source is not in compliance, a compliance plan detailing level of pollution control required, and a schedule for achieving compliance will be needed.

REFERENCES

1. Godish, T. *Air Quality.* Lewis Publishers, Incorporated, Chelsea, Michigan, 1991.

2. Moyer, C. and M. Francis. *Clean Air Act Handbook: A Practical Guide to Compliance*, Clark Boardman Company, 1991.

3. Elliott, Thomas C., *Standard Handbook of Powerplant Engineering*, McGraw-Hill Publishing, 1989.

4. *Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971.* Title 40, Code of Federal Regulations, Part 60, Subpart D, U.S. Government Printing Office, July 1, 1991.

5. *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978.* Title 40, Code of Federal Regulations, Part 60, Subpart Da, U.S. Government Printing Office, July 1, 1991.

6. *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.* Title 40, Code of Federal Regulations, Part 60, Subpart Db, U.S. Government Printing Office, July 1, 1991.

7. *Steam, Its Generation and Use*, 40th Edition, Babcock and Wilcox Company, 1992.

8. *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.* Title 40, Code of Federal Regulations, Part 60, Subpart Dc, U.S. Government Printing Office, July 1, 1991.

9. Quarles, J. and W. H. Lewis, Jr. *The New Clean Air Act.* Morgon, Lewis & Bockius, Washington, D. C., 1990.

10. Beckham, B. J. *CAAA Title V Permit Regulations Vary from State to State.* Chemical Processing, pp. 29–38, March 1993.

CHAPTER 23. CONTINUOUS EMISSION MONITORING

23.1. Statement of Purpose

23.2. General Classifications of CEMS
- A. In-situ
- B. Extractive

23.3. Components of CEMS
- A. Probe
- B. Sample Transport Line
- C. Conditioning System
- D. Analyzer and/or Detector
- E. Data Acquisition System (DAS)

23.4. Usage of CEMS in Utility/Industrial Boilers

23.5 Analytical Methods
- A. Spectroscopic
- B. Luminescence
- C. Electrochemical
- D. Paramagnetism

23.6 Opacity Monitors
- A. Single-Pass Transmissometer
- B. Double-Pass Transmissometer

23.7 Flue-Gas Flow Monitors

23.8 Maintenance and Continuing Operations
- A. Calibrations
- B. Probe Blockage
- C. Condensation
- D. Leakage

CHAPTER 23. CONTINUOUS EMISSION MONITORING

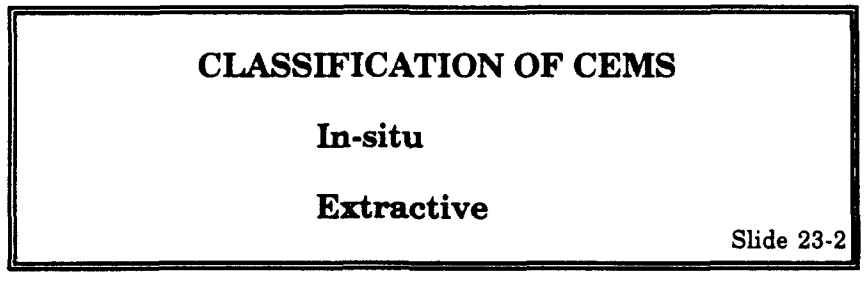
23.1 Statement of Purpose

This learning unit presents the design and operational features of instrumentation which is used to measure the concentrations of selected gaseous constituents and stack opacity. Instrumentation of this type is generally referred to as continuous emission monitoring systems (CEMS). The term "CEMS" denotes the entire system of instrumentation required to measure the gas constituents and should not be confused with "analyzers" which are the subcomponent which actually determines the concentration of selected constituents.

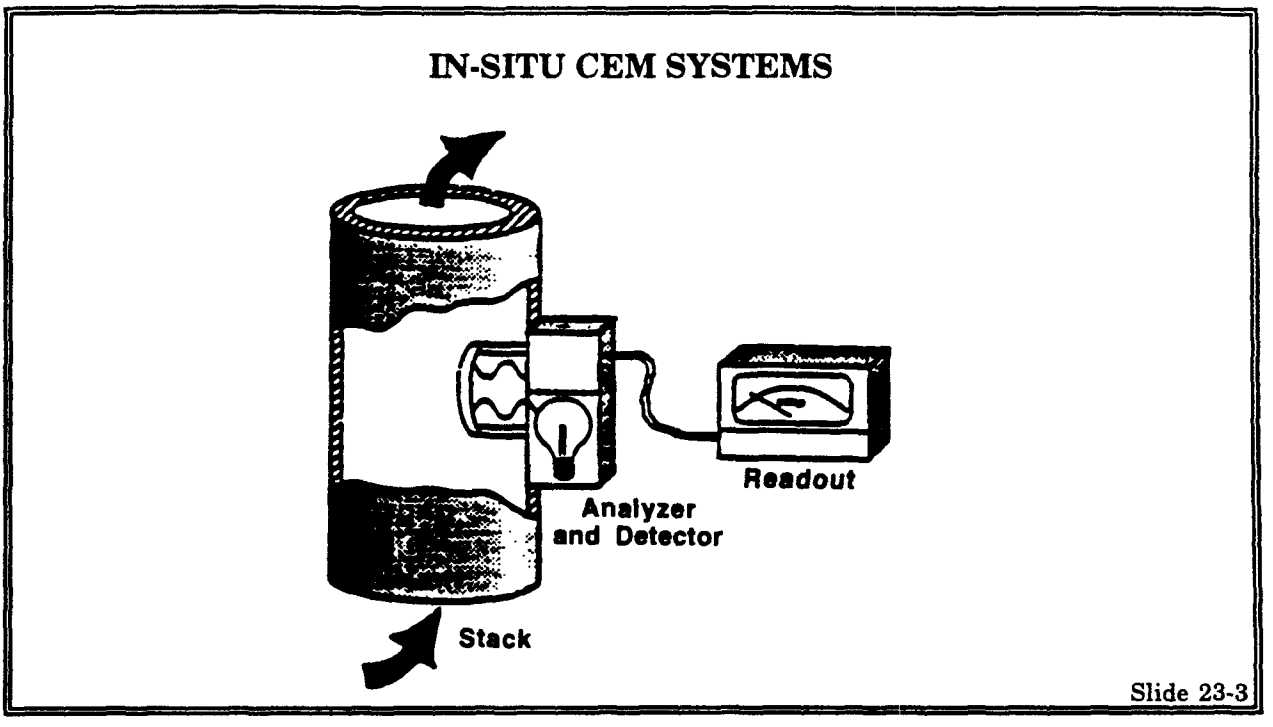
The following paragraphs contain the descriptions of CEMS classifications, CEM components, analytical methods employed by analyzers, and operating and maintenance procedures.

23.2 General Classifications of CEMS

Monitoring systems are categorized as either in-situ or extractive CEMS according to the location of the detection device used and the means by which sample gas is delivered to the analyzers.



The in-situ systems directly measure gas concentrations in the stack. In-situ systems utilize a sensor that is mounted either in the flow of the gases or adjacent to the gas stream. The term in-situ refers not to the placement of the sensor but rather to the monitoring of the gases without conditioning. The typical in-situ system utilizes electro-optical or acoustical techniques, where light or sound is transmitted through the flue gas. The effects of the flue gas on the transmission are used to provide a measurement of flue gas parameters.

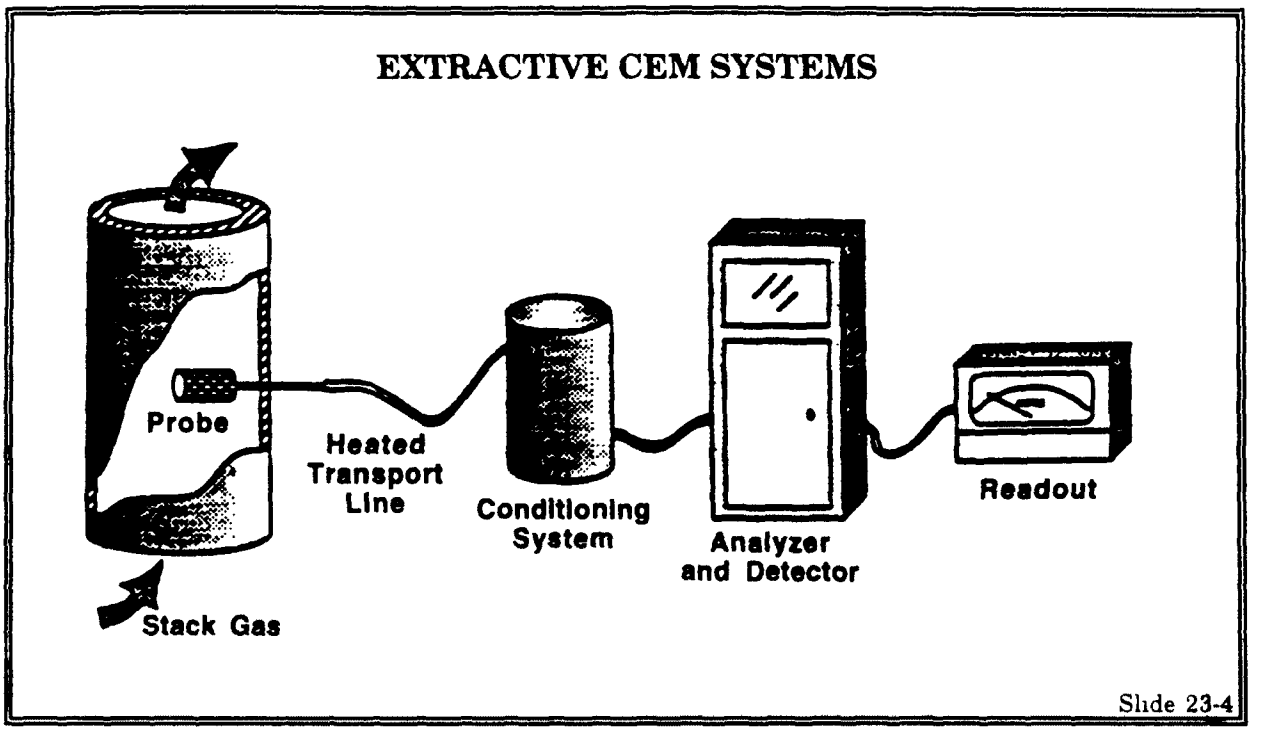


There are two categories of in-situ monitoring systems: in-stack monitors and cross-stack monitors.

The in-stack system, samples at a specific point in the stack. Typically, this type of in-situ sensor must be able to withstand high particulate loading and elevated temperatures (>250 °F) and must be rugged in construction. These monitors use both spectroscopic and electroanalytical techniques. The measurement of oxygen is commonly performed using an in-stack monitoring system. These analytical techniques are discussed in detail in Section 23.5.

Cross-stack monitoring systems measure the gas concentration along a path greater than 10 percent of the stack diameter. The cross-stack monitoring systems combine a light source shining across the stack with a receiver-analyzer. There are two types of path monitors: single-pass and double-pass. In the single-pass arrangement, the light source and receiver are located on opposite sides of the stack. Single-pass systems are used for the measurement of gas concentrations, flue gas velocity, and opacity. A double-pass monitor utilizes a reflector to redirect the light beam back to the source where the detector is located. Double-pass systems are used for measuring gas concentrations and opacity. Both of these are discussed in Section 23.7.

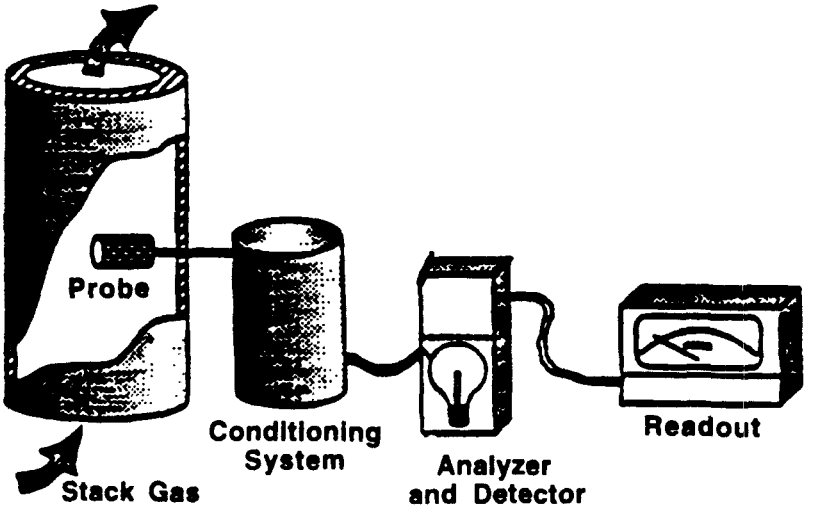
In-situ systems have the advantage of providing near "real-time" measurements. Some of these systems are typically mounted on the stack. These systems must be housed in weatherproof enclosures to minimize the effects of ambient conditions.



Extractive systems are by far the most common type of CEM system. These systems withdraw a sample of the gas stream by using a vacuum pump and then condition the sample by removing moisture, particulate, and reducing the temperature to ambient. The analyzers used in an extractive system generally operates on a dry basis. Therefore, the conditioning system must remove the moisture prior to sending the samples to the analyzers. Analyzers are typically at a convenient location within the plant and do not need weatherproof enclosures. A disadvantage of extractive systems is the "lag" in response to the process conditions which is a function of the internal volume of the extraction system (e.g. probe, sampling line, and conditioning system) since the sample must travel through all components of the sample extraction system. This lag time ranges from 5 to 10 minutes depending on the sample line length.

Another type of extractive system is the dilution-extraction system which uses a carrier/dilution gas mixed with the sampled air. The dilution gas is supplied to the extraction probe and creates a positive pressure in the sampling line. The dilution gas is supplied downstream of a critical orifice opening which creates a vacuum to pull the sample gas from the stack. The dilution of the sample gas by a ratio of 50 to 200 reduces the problems associated with dirty, wet and corrosive flue gases. The conditioning system is similar to the extractive conditioning system with the exception of the moisture control. Since the flow rate associated with these systems is relatively high compared to the extractive system, typically the conditioning does not remove the moisture from the sample. Like the in-stack monitors the readings obtained from these systems is on a wet basis.

CLOSE-COUPLED CEM SYSTEMS

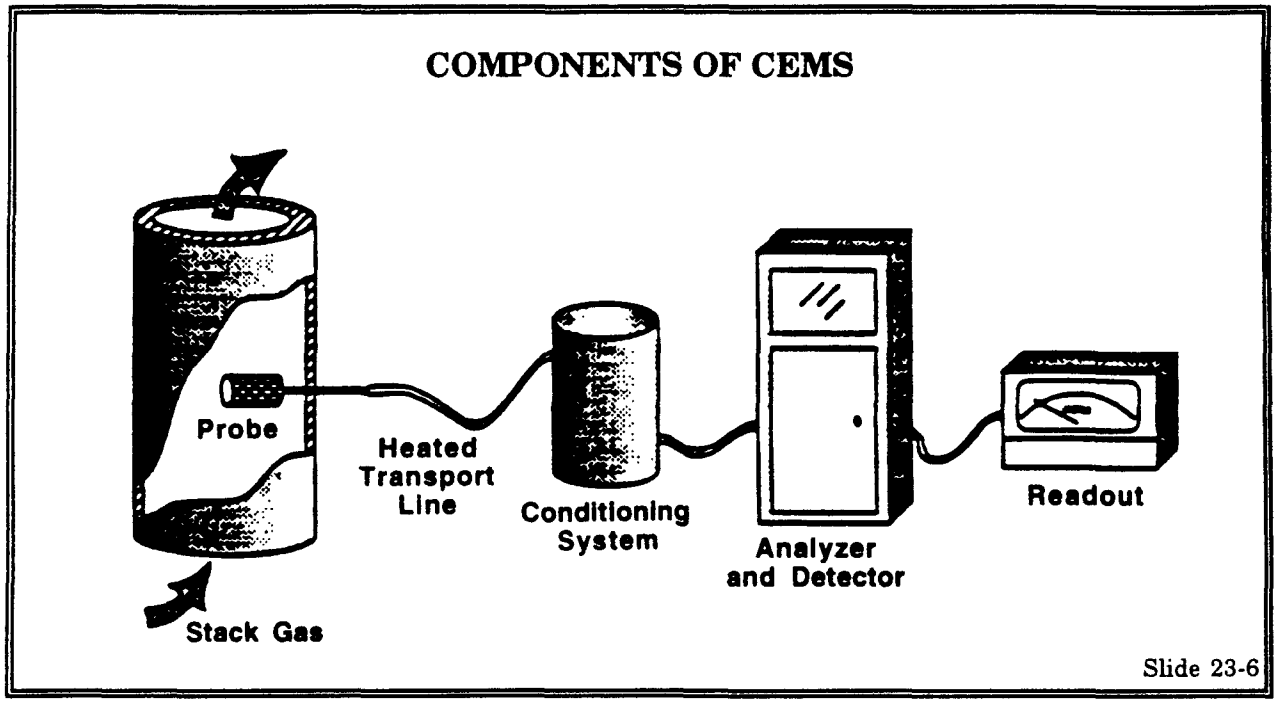


Slide 23-5

Another type of extractive system is the close-coupled system which reduces the "lag" time. Close-coupled systems refer to those systems which utilize a conditioning system and analyzer both placed directly on the stack. Typically, a sample is withdrawn from the gas stream and conditioned to remove particulate and/or moisture and to lower the temperature. The sample then passes through a detection chamber for measurement of the gas constituent of interest. The method of detection varies but often involves wavelength-specific energy absorption in either the ultraviolet (UV) or infrared (IR) range. This method has been successfully applied to the measurement of the common gas constituents. Close-coupled systems are often used in industrial settings where gas stream conditions prohibit the use of in-situ systems and the response time from a conventional extractive analyzer would be too long .

23.3 Components of CEMS

So far we have discussed the general classifications for CEMS. This subsection deals with the components which typically comprise a system. Although not every system will have every component, certain elements are present in all systems. The five components which typically make up a CEMS are: (1) probe; (2) sample transport line; (3) conditioning system; (4) analyzer and/or detector; and (5) data recorder or data acquisition system (DAS). Each of these is discussed below.



Probe

The basic purpose of the probe is to provide continuous access to a representative portion of the stack gas. For extractive systems, the probe should therefore be:

- located to obtain a representative gas sample;
- protected from the buildup of particulate matter;
- unaffected by moisture, temperature, and vibration;
- capable of accepting calibration gases; and
- constructed of a corrosion resistant material such as stainless steel, glass, quartz, or ceramic.

In the case of in-situ analyzers, the probe is typically not present or is a coarse ceramic filter used to shield the sensor from particulate matter.

Sample Line

Only extractive CEMS will have a sample line or conditioning system. Typically, the gas sample from the probe is transferred to the conditioning system via a heated sample line. The line is heated to prevent condensation of moisture since water vapor and acid gases can easily condense in a nonheated pump and corrode the interior. In addition, the condensing of the gas sample would result in an inaccurate measurement of the gas concentration. In extractive systems utilizing the dilution technique (discussed later in this subsection), heating of the sample line may not be necessary. The sampling line must also be chemically and corrosion resistant to minimize reactions and ensure long-life.

Conditioning System

The conditioning system typically provides a clean, dry sample to the analyzers, however, not all conditioning systems remove the moisture from the sample. Sample conditioning equipment usually includes primary and secondary particulate filters as well as some type of water removal apparatus. The primary filter is often located at the probe inlet. This filter serves to remove the coarse particulate. The secondary filter, located downstream of the primary filter, removes nearly all of the remaining particulate greater than 1 micrometer. Moisture removal is typically accomplished either by condensation, permeation, or dilution. Condensation of the moisture is accomplished by rapidly cooling the sample and trapping the condensed water in a collection vessel. The standard approach uses a compressor-type refrigeration unit. More recent systems have used thermoelectric plate coolers or a vortex chiller. Permeation dryers can be used with or in place of condensers. The operation of permeation dryers is based on the selective permeability of water through a membrane.

The third method employed by some units for moisture conditioning is the addition of dilution air to the sample stream. Moisture is not removed in this method but merely diluted to a level acceptable to the analyzers being used. This step may take place in the stack (probe) or at a remote location. Dilution requires the accurate metering of air so that the diluted sample concentrations measured can be corrected to the actual stack concentrations. Dilute ratios of 100:1 are typical, although higher ratios are used for hot, moist gas streams.

Analyzer

The overall purpose of the analyzer is to accurately measure the concentration value of the target gas. The components of the analyzers include detectors, convertors, and readouts. The variety of analytical techniques are discussed in Section 23.5. As these analyzers measure selected parameters, a signal will be received by the detector, converted to an electrical signal, and sent to a readout instrument as a concentration value.

DAS

The final subsystem of a CEMS is the data recorder or data acquisition system (DAS). Typically, this is separate from the analyzer and incorporates the signals from multiple analyzers on a single output. Often, the DAS is as simple as a pen chart recorder. More sophisticated systems developed recently take advantage of computer technology to develop systems which not only store the data on a permanent media but also provide such functions as averaging and data trending. On a daily basis, the CEM system operator or plant environmental engineer works more with the DAS than with any other CEMS components

23.4 Usage of CEMS in Utility/Industrial Boilers

CEMS typically used in utility and industrial boilers include analyzers for the measurement of opacity, oxygen, carbon dioxide, carbon monoxide as well as NO_x and SO_2. The specification for a CEMS applied to a given boiler depends mainly upon the various state and federal regulations. Case in point, Title IV of the Clean Air Act Amendments requires continuous monitoring of flue gas flow rate. State or local regulatory reporting requirements may necessitate the use of CEMS for oxygen or CO_2 to correct other pollutant concentration to a given standard. Under local regulatory agency requirements, some utility and industrial boilers are required to correct pollutant concentrations to 3 percent oxygen although 12 percent CO_2 may also be used by local regulatory agencies.

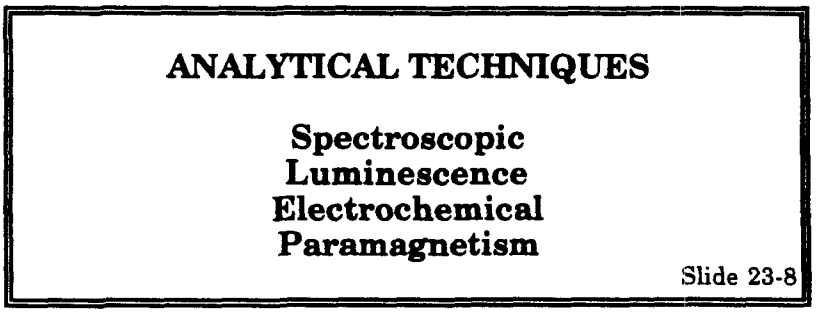
ANALYZERS TYPICALLY USED IN UTILITY AND INDUSTRIAL BOILERS

Oxygen (O_2)
Carbon Dioxide (CO_2)
Carbon Monoxide (CO)
Nitrogen Oxides (NO_x)
Sulfur Dioxide (SO_2)
Opacity
Flue-Gas Flow Rate

Slide 23-7

23.5 Analytical Methods

In general, measuring techniques are based both on the physical and chemical properties of gases. The method selected for gas analysis is primarily dependent upon characteristics of the gas, but it can also be due to regulatory or process requirements. Detection of individual gases is possible because of the unique characteristics gases exhibit when subjected to specific analytical methods. These characteristics determine the principles of design and operation of reliable CEMS.

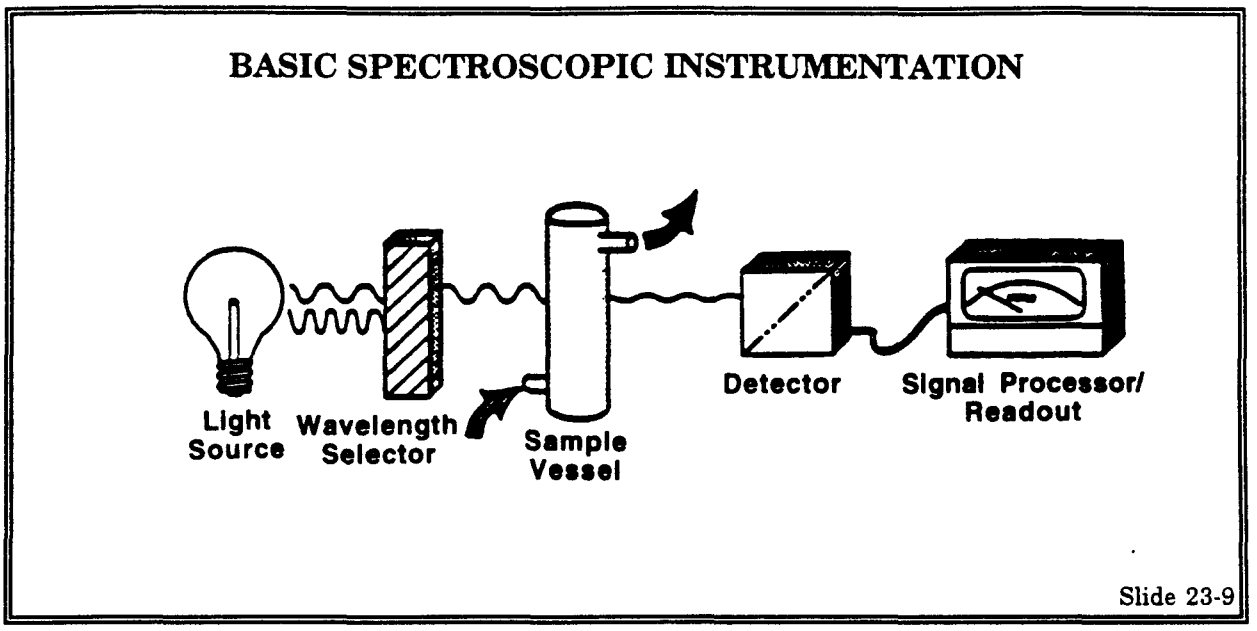


The four analytical techniques to be discussed herein are spectroscopic, luminescence, electrochemical, and paramagnetism.

Spectroscopic

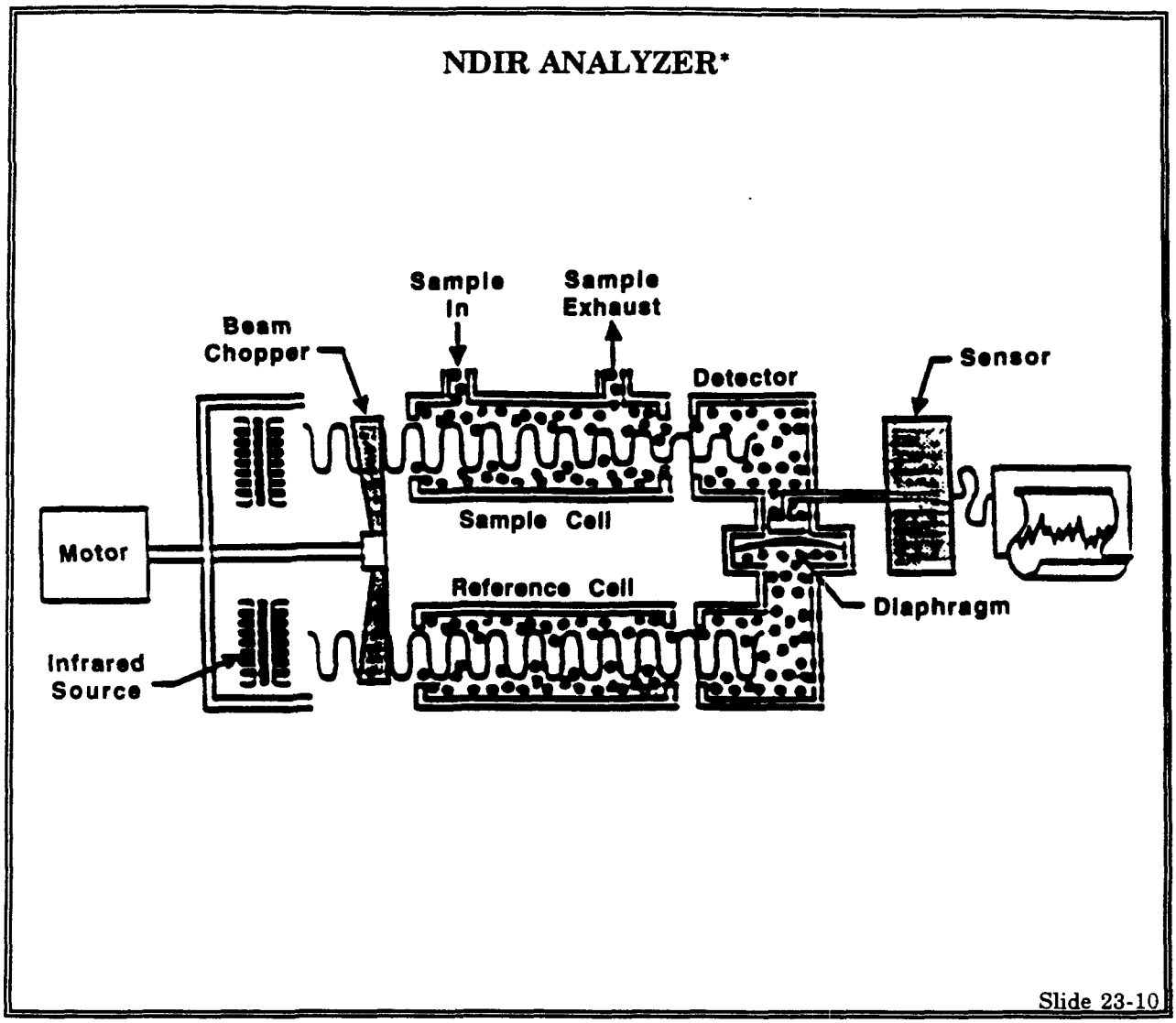
One of the most common analytical techniques used in CEMS are spectroscopic absorption techniques. Using these methods, CEMS are able to identify and to measure the amounts of selected gases via the attenuation (weakening) of a beam of electromagnetic radiation (EMR) at a specific wavelength. This can also be referred to as "light" although it may not be visible. Specific examples of electromagnetic radiation include ultraviolet, infrared, microwave, x-rays, television, and radio waves as well as visible light.

Identification of a gas is possible because different types of gaseous molecules are known to absorb specific, unique wavelengths of electromagnetic radiation. Determining the amount of a particular pollutant gas is accomplished by converting the percentage of absorbance (also called attenuation) to a concentration. This is generally accomplished by comparison with a reference absorption of a known gas.



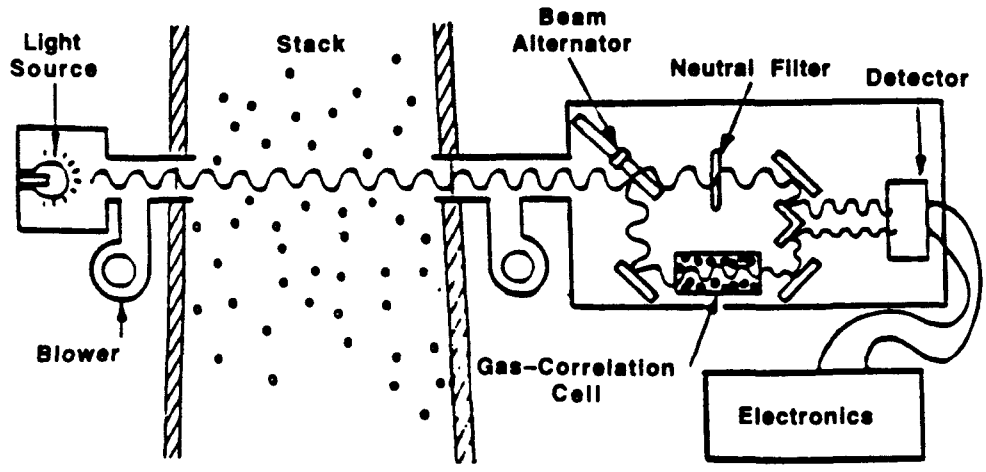
The five basic components of a spectroscopic instrument are:

- a stable source of EMR ("light"). This can be as simple as a standard household light bulb;
- a wavelength selector or filter to isolate the desired wavelength;
- a sample chamber;
- a radiation detector/transducer used to convert the radiation energy into an electrical signal; and
- a signal processor and readout.



Nondispersive infrared (NDIR) analyzers measure the amount of light absorbed by a pollutant molecule. NDIR spectroscopy uses infrared "light". The light is filtered to isolate the wavelengths which are selectively absorbed by gaseous molecules. These instruments differ from dispersive infrared instruments in that the light is not scanned or "dispersed." The filtered light passes through a cell that contains flue gas extracted from the stack. Another portion of the light passes through a cell which contains a reference gas which does not absorb any of the filtered light. A detector senses the amount of light absorption in the sample cell relative to the signal from the reference cell. This relative difference is output to a readout as a concentration reading. NDIR instruments have been developed for measurement of SO_2, NO, NO_2, HCl, CO, and CO_2.

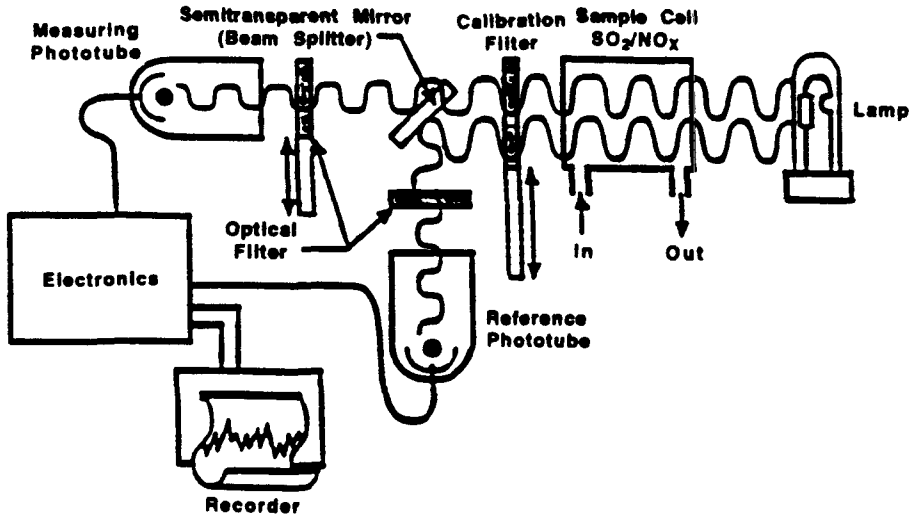
GAS FILTER CORRELATION ANALYZER



Slide 23-11

A variant of the NDIR technique, called gas filter correlation spectroscopy, requires light, usually in the IR or UV region, to pass through the sample cell and into a receiving unit. In this unit, the beam is divided into two beams which enter into two parallel cells called the gas filter and the neutral density filter cells. The gas filter cell contains a high concentration of the gas being analyzed, and therefore removes nearly all of the energy of the light source. Thereby, the reference (gas filter) cell has a zero transmittance (100 percent absorbance). The beam to the neutral density cell passes through unchanged. The difference at the detector between the two beams is related to the concentration of the gas of interest. This method has been successfully applied to both in-situ (e.g. the sample cell is in the stack or ducting) and extractive analyzer systems.

DIFFERENTIAL ABSORPTION ANALYZER



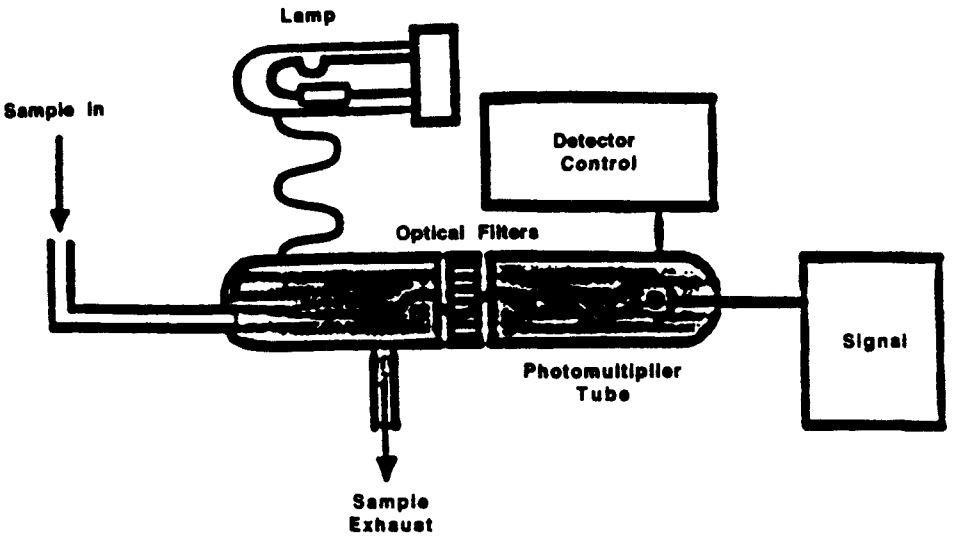
Slide 23-12

Differential absorption spectroscopy is also based on the principle that certain gas molecules absorb unique wavelengths of light. Unlike NDIR spectroscopy which uses a sample and a reference cell, differential absorption uses two distinct reference and measuring light wavelengths. The measuring wavelength corresponds to a wavelength where the gaseous molecules of interest absorb light energy while the reference wavelength corresponds to a wavelength in which the gaseous molecules of interest absorb no light. The concentration of the gas is determined by finding the difference in energy for the two wavelengths. Some differential absorption systems are single pass, in-situ monitors that use ultraviolet light. These can measure SO_2 or NO, although by changing the optical system it is possible to measure other gases. The differential absorption method can also be used in extractive CEMS.

Luminescence

Luminescence is the emission of light from an atom or molecule that has been excited in some manner. Excitation refers to the temporary placement of electrons into higher energy levels. As the electrons return to their normal levels, excitation energy in the form of light is emitted. Two luminescence methods are used in the field of source monitoring: UV fluorescence and chemiluminescence. The component requirements are the same as for spectroscopic techniques though their configuration is somewhat different.

ULTRAVIOLET FLUORESCENCE ANALYZER

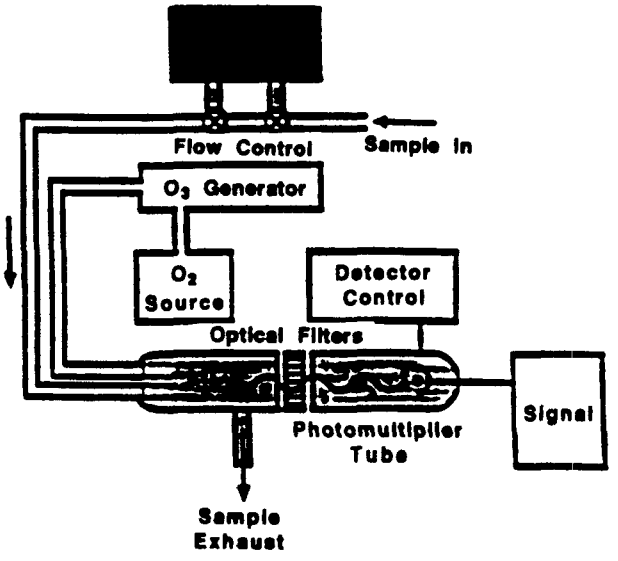


Slide 23-13

The UV fluorescence method of analysis is primarily used to measure SO_2 present in exhaust gas streams. SO_2 molecules are excited by the use of UV light of wavelength 210 nanometers. Excitation is the results of an atom's absorption of the beam of EMR. As the molecule returns to a relaxed state, light is emitted. The released light is detected and its intensity related to the gas concentration. A constant background (concentration of other gas constituents) must be maintained in order to account for quenching of the signal due to the emitted energy being absorbed by other gas molecules. Typically, UV fluorescence analyzers are used in conjunction with dilution extractive systems to account for background quenching.

Chemiluminescence is the most common method used for the measurement of NO and NO_2. A chemiluminescent analyzer senses the light emitted in a chemical reaction. In this application, excited NO_2 molecules are produced by reaction of NO in the presence of ozone. The light emitted as the NO_2 returns to its ground state is detected by a photomultiplier tube and related to the NO and NO_2 concentrations. Chemiluminescence methods have the advantage of high specificity and sensitivity.

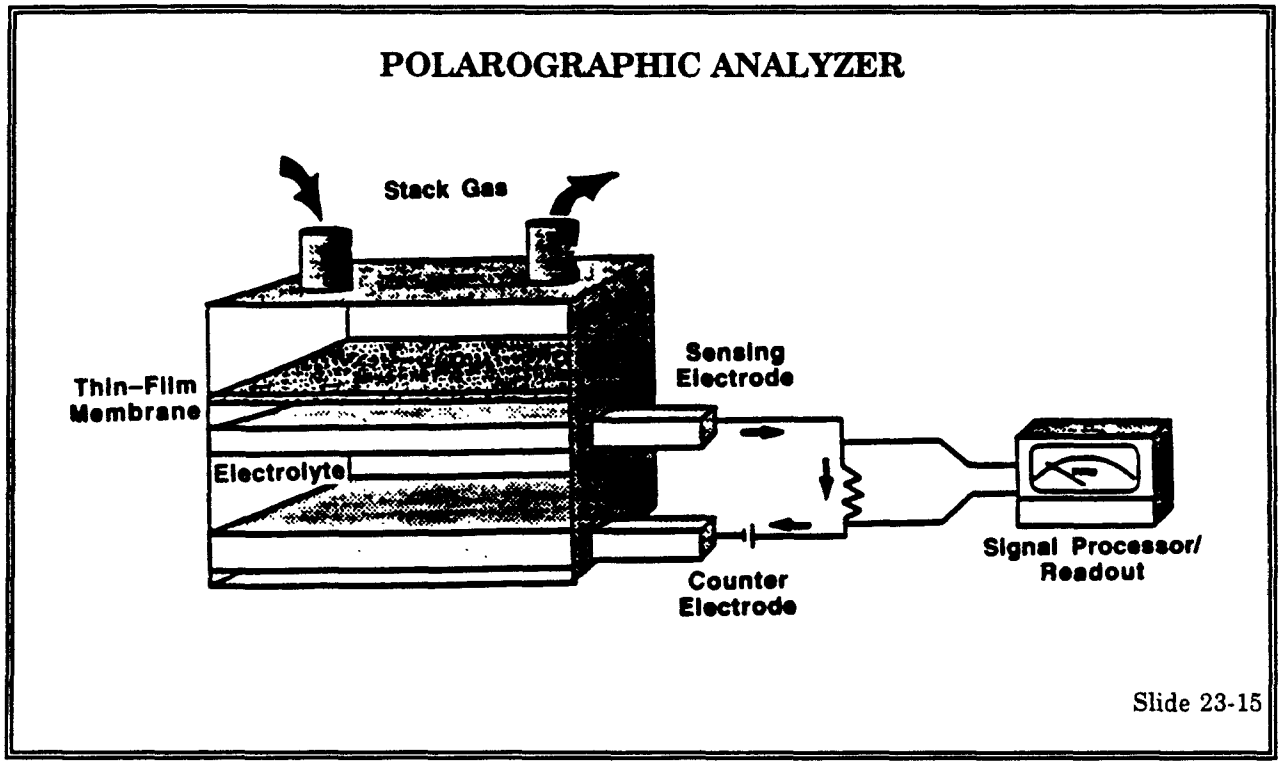
CHEMILUMINESCENCE ANALYZER



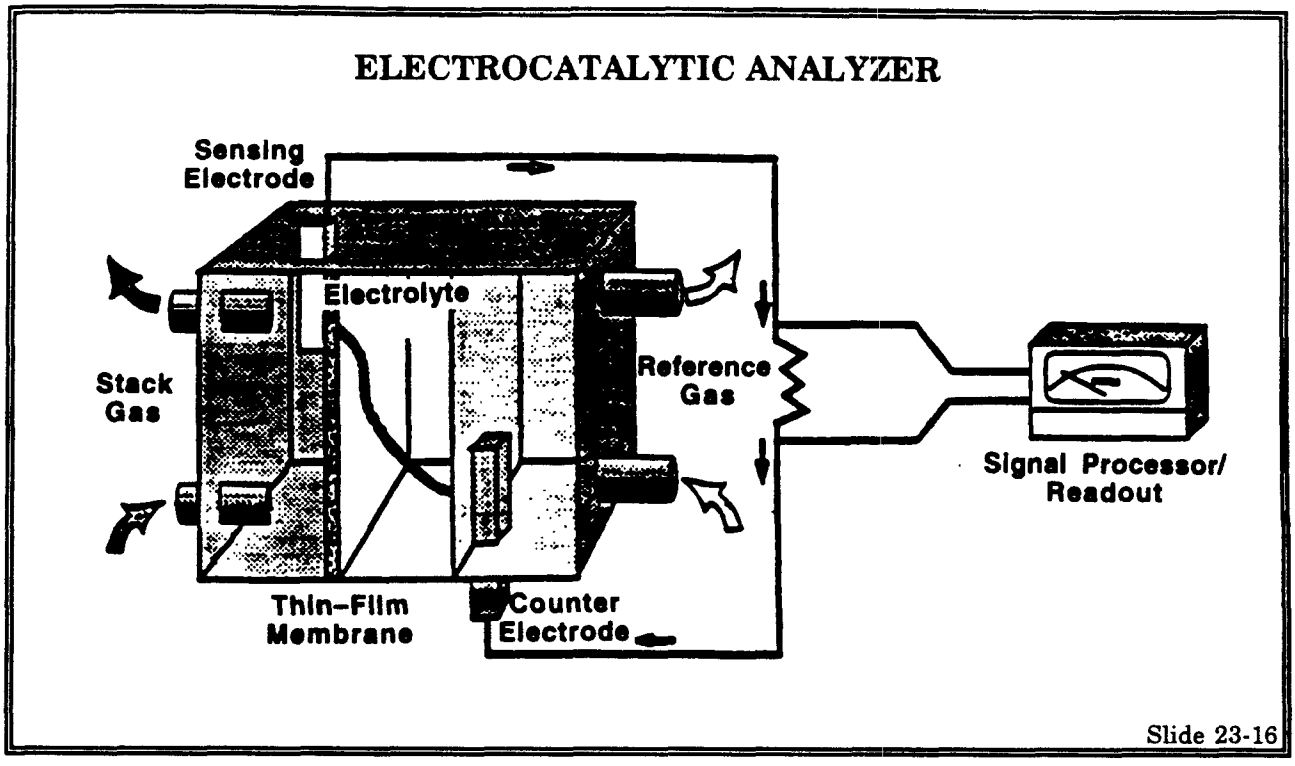
Slide 23-14

Electrochemical

Two principal electrochemical techniques have been developed for the measurement of gases in exhaust streams: polarography and electrocatalysis. These method can quantify flue gases by measuring the currents or voltages that are produced in the electrochemical cells.



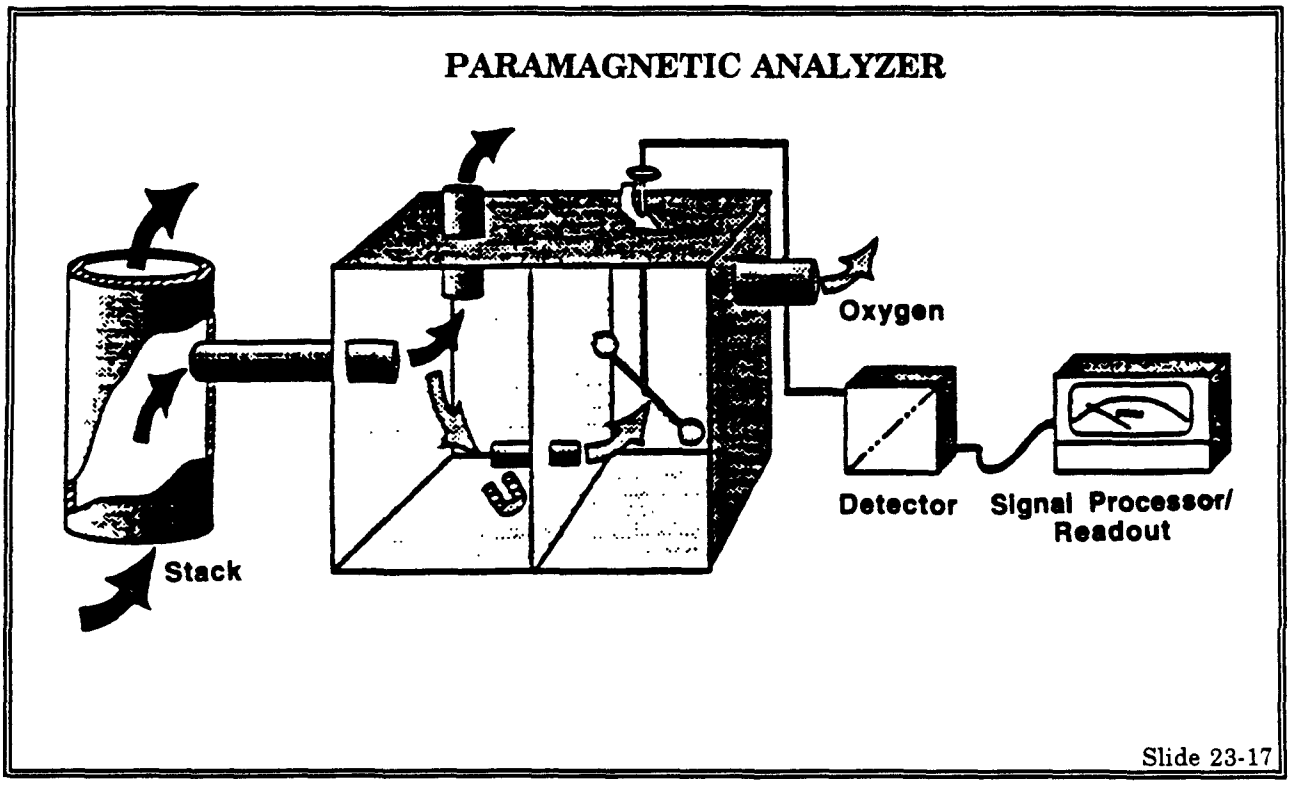
Polarography utilizes analyzers which are basically diffusion-controlled electrochemical cells. The current across the cell is proportional to the rate of diffusion of the pollutant into the cell and also proportional to the pollutant concentration. Being constructed much like batteries, the cells have a sensing electrode, an electrolyte, and a counter electrode. The main difference from a battery is that polarographic analyzers also possess a thin-film membrane through which the pollutant must diffuse in order to initiate the electrochemical reaction and current flow. Polarographic analyzers have been developed to measure gases such as O_2, SO_2, NO, NO_2, CO, and CO_2. Different types of electrodes and electrolytes are required depending upon which gas is selected. As with batteries, the electrolyte will eventually be consumed and must be replaced. Because these type of analyzers require clean, dry sample, they can only be used in conjunction with extractive systems.



Electrocatalysis employs analyzers that use a solid electrolyte instead of a liquid electrolyte. A thin film on the surface of the solid usually catalyzes the reaction which allows gas molecules to migrate through the solid and generate a current. A typical electrocatalytic analyzer uses a zirconium oxide (ZrO_2) disc which has been coated with a thin film of platinum. A reference gas (usually ambient air) at 21 percent oxygen is maintained on one side of the solid. The sample gas is on the other side. Oxygen ions are generated at the platinum surface and then migrate through the solid electrolyte. Electrons are released in the process as the system attempts to reach equilibrium (i.e. the same concentration) of oxygen on both sides of the solid. The electron flow is related to the concentration of oxygen in the sample. The ZrO_2 analyzer has the distinct advantage that it can withstand temperatures up to 1560 °F. This type of analyzer is commonly used as the oxygen sensor in the exhaust system of newer automobiles to measure and adjust the fuel/air mixture.

Paramagnetism

Oxygen is known to exhibit paramagnetic behavior. That is to say that oxygen is attracted by and interacts with a magnetic field. Although this property can be used in several different ways to measure oxygen concentrations, one extractive method is commonly used. The magnetodynamic technique is used in CEMS to relate the oxygen concentration in the gas to disturbances in a magnetic field about a torsion pendulum. Oxygen flows through the magnetic field and disrupts the alignment of the magnetic charges which consequently causes the torsion pendulum to turn. The degree of this movement can be related to the O_2 concentration. Paramagnetism can also be used to measure other diatomic molecules such as N_2.



23.6 Flow Monitors

Under the Clean Air Act Amendments—Title IV, emissions standards are expressed in terms of mass emission rates as in lb/MMbtu. This implies that flow monitors are required as part of the CEM system. There are a number of techniques currently available for monitoring flue gas flow rates. These techniques include: differential pressure sensing, thermal sensing, and acoustic velocimetry.

FLOW MONITORING TECHNIQUES

Techniques	Instrumentation or Sensor
Differential Pressure Sensing	Head Meters, Pitot Tube, Annubar Fluidic Sensor
Thermal Sensing	Heated Sensor
Acoustic Velocimetry	Ultrasonic Tranducers

Slide 23-18

Differential Pressure Sensing

Pitot Tubes: A pitot tube consists of two tubes, one facing the direction of the flow of the gas to measure an impact pressure and the other tube either perpendicular or opposite to the direction of the flow to measure static pressure. The pressure differential between the static pressure and the impact pressure is the velocity pressure (Δp) and is measured using a manometer, Magnehelic gauge, or pressure transducer.

VELOCITY AND VELOCITY PRESSURE RELATIONSHIPS

$$V_s = K_p C_p [(T_s \Delta p)/(P_s M_s)]^{1/2}$$

Where:
V_s = velocity of the gas
K_p = constant
C_p = pitot tube calibration coefficient
T_s = absolute temperature of the gas
P_s = absolute pressure of the gas
M_s = molecular weight of the gas

Slide 23-19

Type-S pitot tube, specified in EPA Reference Method 2, is the simplest pitot tube. The impact and static pressures can be monitored continuously using pressure transducers. A thermocouple is usually attached to the pitot tube to monitor the stack gas temperatures. A pitot tube is used to measure single point velocity only. Multiple tubes can be used to average a flow distribution across the stack or duct.

Annubar: The annubar is a modified form of pitot tube that has multiple ports in a pipe, located at the grid points of the stack cross section. These ports face the direction of flow and give an averaged stagnation pressure over the stack diameter. The static pressure is averaged using ports located behind the high-pressure ports. Annubars are usually made specific to each application since port locations are different from one installation to another, and the stack dimensions must be carefully specified before the annubar is constructed.

The annubar and pitot tube are less sensitive to low flow rates than to high flow rates because low pressure differentials are difficult to measure accurately. To clear the tubes from pluggage, high pressure blowing with air is usually employed.

Thermal Sensing System

Thermal sensing systems are based on the transfer of heat from a heated body to a flowing gas. This requires the use of two sensors; one heated and one unheated. Slide 23-20 shows typical thermal sensing systems. One configuration uses two platinum resistance wires wound on ceramic cylinders, which are then protected by a stainless steel tube. The longer sensor is heated ; the shorter one is not heated. These two resistance elements are connected to a bridge circuit that maintains the temperature of the heated sensor. As the flue gas passes and cools the sensor, the current through the element is increased to keep the temperature constant. This current is related to the heat loss from the sensor. The unheated sensor is used to compensate for the temperature changes in the gas.

The other configuration combines the heated and the unheated resistance elements into a single tip (also called hot-wire anemonmetry). The tip is glass coated and is typically applied to monitoring flow in noncorrosive atmospheres.

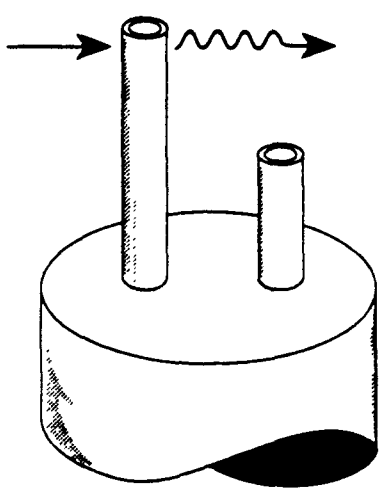
The thermal sensing systems measure mass flow rates directly, rather than volumetric flow rates as in the case of pressure sensing systems. the rate of cooling of the heated sensor is dependent upon the thermal conductivity of the gas, which is dependent upon the gas viscosity and specific heat. Gas viscosity in turn is dependent upon velocity over a given path and on the gas density. As a net results of these effects, thermal sensing instruments produce an output that is proportional to mass flow:

$$[\text{Signal}] \sim [\text{Heat Loss}] \sim \rho V_s A_s$$

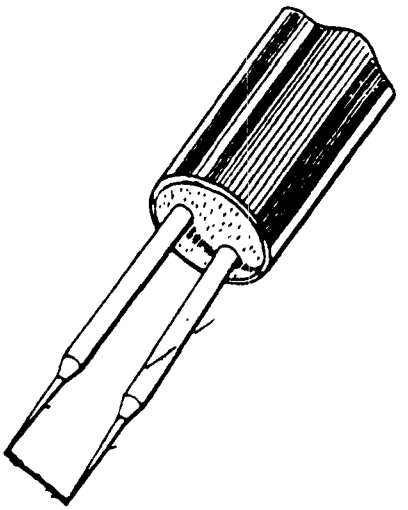
where ρ is the density of the gas

One advantage of the thermal sensing systems is that multiple sensors can be combined easily in arrays to measure the average flow rate over the cross-section of a duct or a stack. Because each sensor makes an independent measurement, it is possible to monitor the gas flow distribution over the cross-section.

THERMAL SENSING SYSTEMS



A thermal–sensing velocity probe

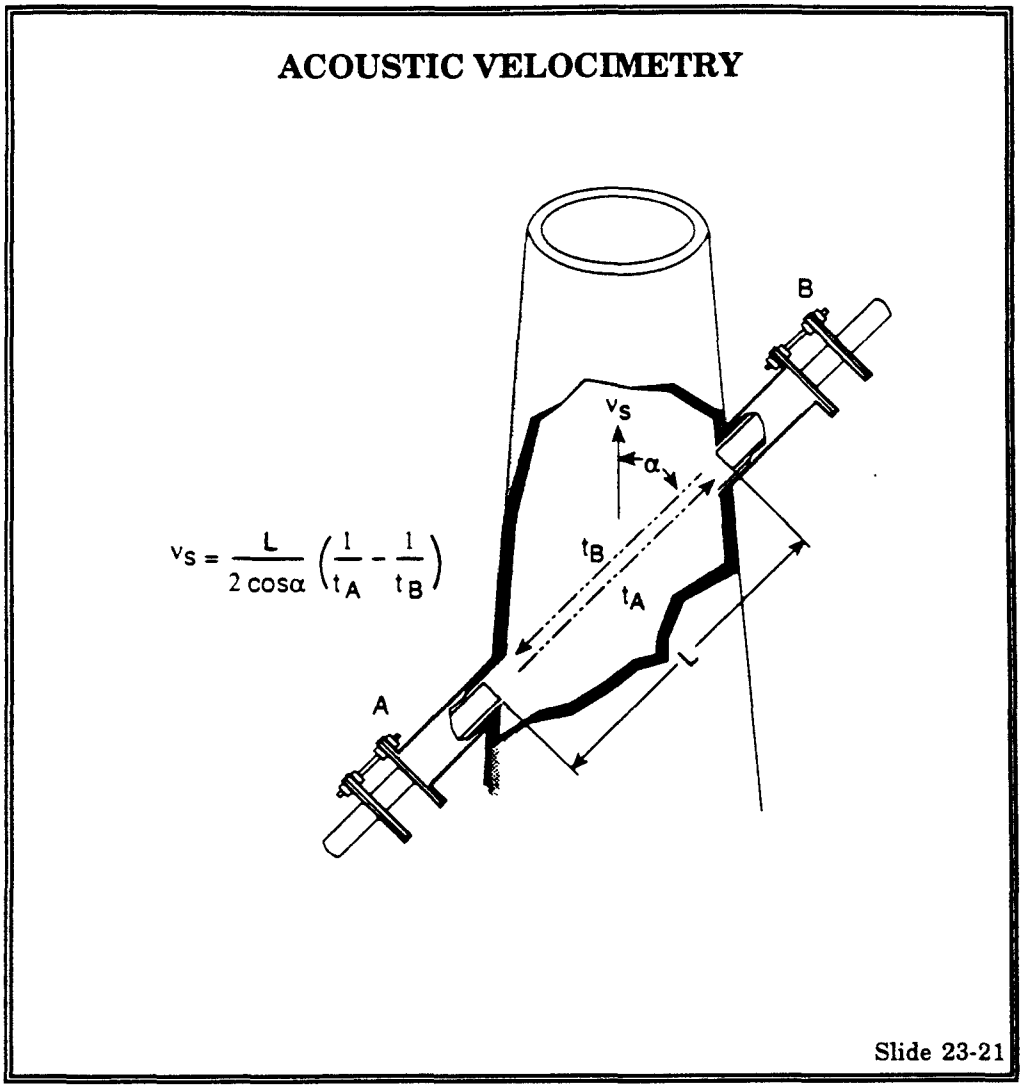


A hot-wire anemometry sensor

Slide 23-20

Acoustic Velocimetry

This method measures the time it takes sound pulses to travel with and against the direction of gas flow. Slide 23-21 shows a schematic of the acoustic velocimetry technique. In this method, ultrasonic pulses in the rage of 50 kHz are transmitted both upstream and downstream of the flow. Two transceivers are located opposite each other on the stack at an angle of typically 45°. In each transceiver, a piezoelectric transducer transmits ultrasonic pulses to the opposite transceiver. The transducers both convert electric signals to acoustic signals and acoustic signals to electric signals. The speed at which the pulses crosses the stack is dependent upon whether it is going with or against the flow.



The stack gas velocity can be expressed as:

$$V_s = \frac{l}{2\cos\alpha}\left[\frac{1}{t_A} - \frac{1}{t_B}\right]$$

Where: l = path between A and B
t_A = transmit time from A to B

t_B = transmit time from B to A
V_s = gas velocity
α = angle between stack and path l

This expression gives the volumetric flow rate in actual cubic feet per minute when used with stack cross-sectional area. Note that the expression is independent of other gas properties such as density, pressure, or temperature.

Because the acoustic instrument is a cross-stack path system, it is not subject to the corrosion and particulate fouling problems that may affect the in-stack insertion-type probes. However, the particulate matter can foul the transceivers, so purge air is blown directly through them.

23.7 Opacity Monitors

Many sources are required to monitor opacity. Opacity is defined as the amount of attenuation of a visible light beam as it passes through stack gases. The visible light attenuation by smoke is primarily due to the scattering of light by small particles. Opacity monitors measure the effects of light scattering and absorption.

In its most elementary form, opacity from a source can be determined by visual observation. Individual smoke readers observe the flue gas plume leaving the top of the stack and record the relative opacity. Legally binding visual opacity readings are allowed in most states if made by certified opacity (smoke) readers. However, opacity observations are limited in precision and are somewhat subjective based on atmospheric conditions.

Opacity analyzers are the simplest of the in-situ monitoring devices. Opacity monitoring systems or transmissometers are composed of a light source, detector, and associated electronic and optical components. Continuous opacity measurements are made on a fixed line across the flue gas stack.

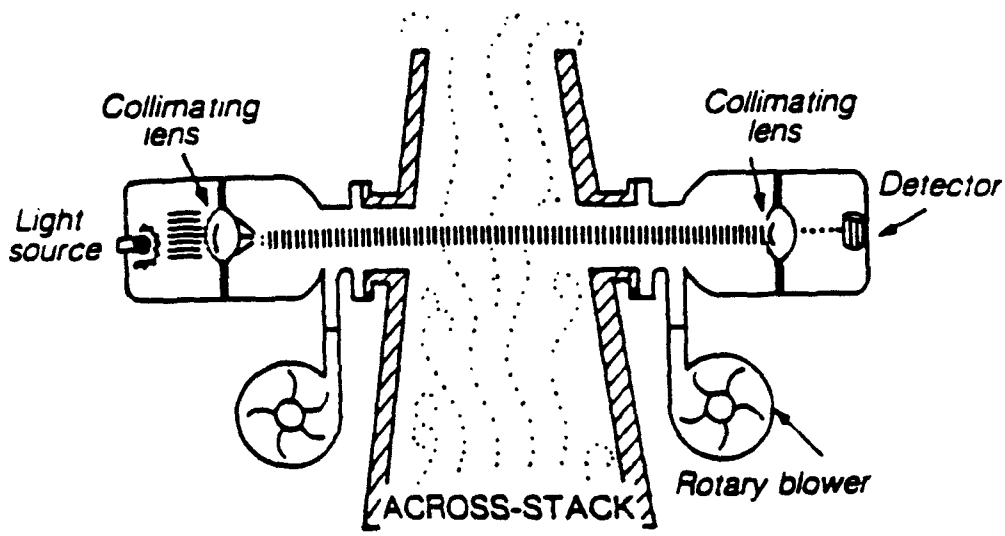
A transmissometer measures the transmittance of light passing through the flue gas. Transmittance and opacity are related by the following expression:

$$\% \text{ opacity} = 100 - \% \text{ transmittance}$$

So, if all the light is transmitted through the flue gas, the transmittance is 100% and opacity is 0%. A single pass transmissometer incorporates a light source, focusing and diffusing lenses, and a detector.

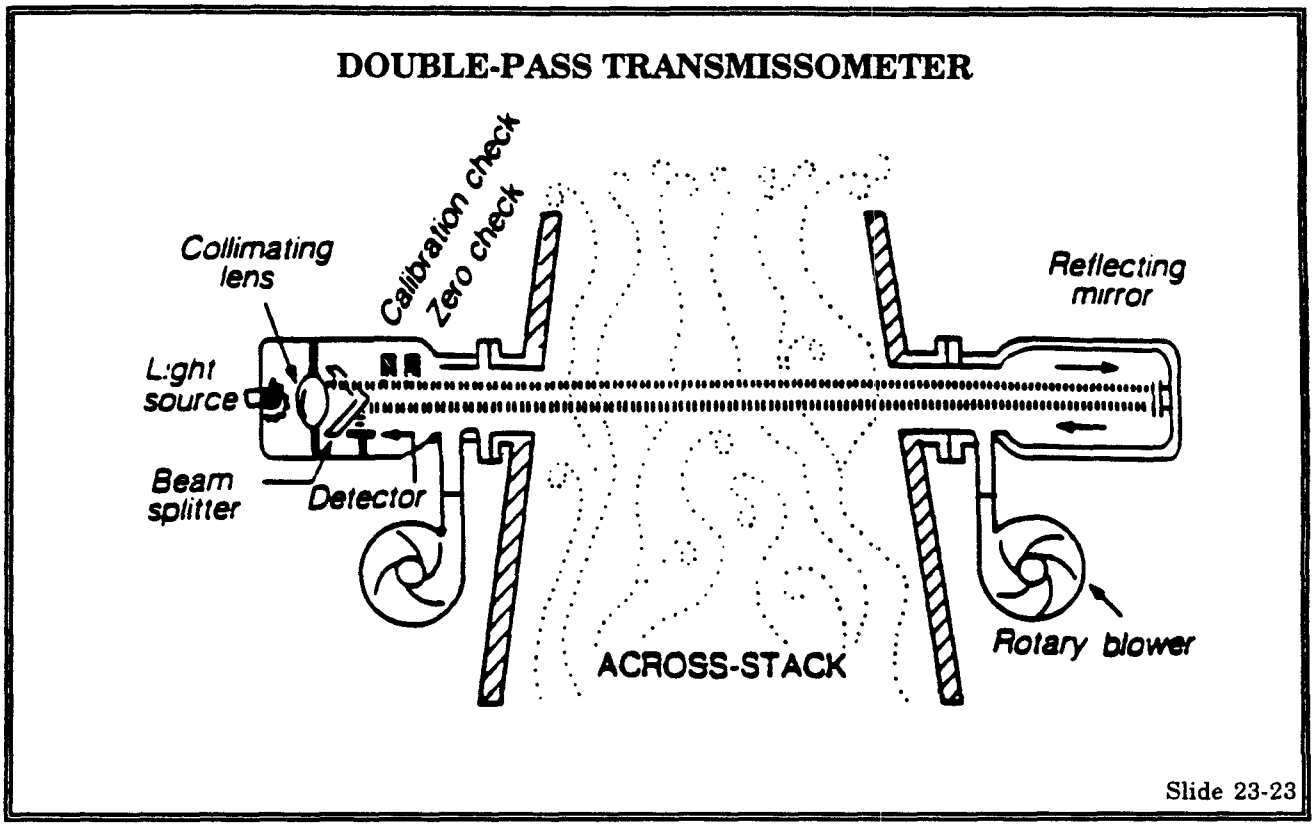
A single pass transmissometer incorporates a light source, focusing and diffusing lenses, and a detector.

SINGLE PASS TRANSMISSOMETER



Slide 23-22

A double pass transmissometer has the distinct advantage of providing an internal reference. The light beam is split to provide a reference and a measurement beam. The reference beam is directed onto the detector while the measurement beam crosses the stack and is reflected back to the detector. The transmittance is determined by comparison of the reference and measurement beams. Calibration at zero and span values is obtained through the use of standard filters which can be inserted into the path of the beam.



23.8 Maintenance and Continuing Operations

CEMS owners are responsible for implementing a written quality assurance plan to ensure the validity of the data recorded. The plan should include written procedures for CEMS calibration, calibration drift determination, preventative maintenance, data recording and reporting, accuracy audit procedures, and corrective action for CEMS malfunctions. This plan will be very specific to the type of analyzers incorporated into the CEMS. The following is a general discussion of the operating and maintenance procedures for CEMS.

Operation checks are procedures performed on a daily basis to determine whether the system is functioning properly. These procedures include daily zero and calibration checks and visual checks of system operating indicators, such vacuum and pressure gauges, rotometers, and control panel lights.

OPERATION CHECKS

Routine Calibration
Probe Blockage
Condensation
Leakage
Optical Surfaces

Slide 23-24

Routine calibration of the individual instruments can be achieved through the use of standard calibrated optical filters or through the use of zero and span gases, depending upon the design of the instrument. Span gases must be analyzed or replaced periodically to assure their validity. The calibration procedure for each instrument is dependent upon its design. Generally, an extractive CEMS must be zeroed and spanned using special bottled gases of known concentrations.

Nitrogen is normally selected as the zero gas. Span gases are selected to cover the concentration ranges for the instrument. If a single span calibration is to be completed, the span gas is generally selected at 80 percent of the full scale (FS) range of the instrument. A three point (zero and two span) calibration would also include a 20 percent FS calibration gas. CEMS are normally zeroed and spanned at least once per day, although some may require more frequent calibration to account for drift. Calibration drift is the difference in the CEMS output reading from a reference value after a period of operation during which no adjustments took place. The performance drift specifications found in the federal regulations are 2 to 5% of the instrument span value. In other words, if the reading from the calibration gases varies by more than 2 to 5% from the previous calibration, the system will need to be re-calibrated.

The blockage of the gas sampling probes and transport lines can be a serious problem, particularly if the flue gas contains significant flyash. Monitoring the system vacuum and rotometers provides an indication of possible problems. Filters which are used to remove particulate must be cleaned or replaced routinely. Most conditioning systems also include an arrangement for purging particulate matter from the filter, lines, and probe periodically. The condenser, if present, must be maintained at a constant temperature slightly higher than the freezing point to prevent blockage.

Other problems related to the condensation of moisture and acid gases can occur. These liquids can absorb gas constituents of interest and/or cause chemical reactions which lead to scale build-up and corrosion. All components of the system should be inspected for corrosion on a regular basis.

Leakage of gases into lines transporting collected samples to analyzers can occur if the connections are not properly sealed. Vibration and thermal expansion can cause leakage to occur. Because the sample line is generally below atmospheric

pressure, leakage will occur into the sampling line. Leakage will result in sample dilution and gas concentration readings which are lower than actual. The indication of leakage will occur when the reading from the calibration results in a lower than acceptable reading.

Although fans are provided to limit the accumulation of deposits on the optical surfaces in opacity monitors, routine maintenance includes cleaning of such surfaces and recalibration.

Closely related to the operations checks, a suggested maintenance checklist is shown below with a brief description of the maintenance procedures.

CEMS MAINTENANCE CHECKLIST

Filter Cleaning
Sample Line Leakage Check
Optical Surface Cleaning
Pump Maintenance
Data Recording Equipment Check

Slide 23-25

Filter Cleaning The performance of the filter should be monitored for increased pressure drop across the filter which would indicate pluggage. For the filters which flow from the outside in, a visual inspection can be made to determine the cleanliness. In most cases, a dirty filter is simply replaced.

Sample Line Leakage Check: The easiest method of determining leakage in the sample line is to plug the end of the sample probe. When this is done and there is no leakage, there will be no flow rate to the analyzers. When leakage is indicated, each connection in the line needs to be inspected and adjusted accordingly.

Optical Surface Cleaning: The optical surfaces in the NDIR and NO_x analyzer periodically require cleaning. However, these surfaces should only be cleaned in a clean laboratory environment equipped with the proper equipment to realign the surfaces after the cleaning.

Pump Maintenance: Pump maintenance includes oil replacement, seal inspection and replacement, diaphragm replacement, and motor bearing replacement. The need for maintenance may be indicated by reduced sample flow rate, reduced vacuum, and/or inability to perform the span check on the instruments.

Data Recording Equipment Check: To check the accuracy of the data recording equipment, a voltmeter should be used to compare the voltage at the recorder to the voltage output from the data acquisition system.

REFERENCES

1 Jahnke, J. A., "Continuous Emissions Monitoring" Van Nostrand Reinhold, New York, 1993.

CHAPTER 24. PARTICULATE CONTROL

24.1 Control Methods and Typical Arrangement

24.2 Cyclones
- **A. Design Principles**
- **B. Performance**
- **C. Operator Duties**

24.3 Electrostatic Precipitators
- **A. Design Principles**
- **B. Performance**
- **C. Operator Duties**

24.4 Fabric Filters
- **A. Design Principles**
- **B. Performance**
- **C. Operator Duties**

24. PARTICULATE CONTROL

24.1 Control Methods and Typical Arrangement

Particulate matter (PM) constitutes a major source of air pollution. Particles have a variety of shapes and sizes with a wide range of physical and chemical properties. Particles are emitted from many different natural and manmade sources including combustion sources, industrial processes, mining operations, motor vehicles, volcanoes, forest fires, and pollen. This section presents information on the design, performance, and operation of some typical particulate control devices used for the removal of particles from boilers.

PARTICULATE CONTROL

Particulate Pollution Sources:
Boilers, Industrial Processes, Mining, Motor Vehicles, Nature

Particulate Distribution in Boilers:
Bottom Ash, Convective Passes, Air Pollution Control Device, Stack

Slide 24-2

Fossil fuels can possess high levels of ash comprising over 20 percent of the fuel's mass. This ash consists of many elements including metals. Ash and unburnt carbon from the gas suspended particulate which can fall-out in furnace bottom ash, be removed in convective heat transfer passes, be captured by particulate control devices, or emitted to the atmosphere.

Boiler's are generally equipped with cyclones, electrostatic precipitators, fabric filters, wet scrubbers, or side stream separators depending on the particle capture requirements. Other types of particulate control devices include venturi scrubbers, sintered metal filters and ceramic filters. These particulate control technologies, are more extensively found in specific applications where high efficiency capture of fine particulate is required, or where extreme operating conditions exist.

PARTICULATE CONTROL DEVICES

- **Cyclone**
- **Electrostatic Precipitator**
- **Fabric Filter**
- **Wet Scrubber**
- **Side Stream Separator**

Slide 24-3

With the increasing need to reduce pollution, some boilers are equipped with combinations of particulate control devices while others integrate pollution control devices such as acid gas scrubbers with the more conventional particulate control devices such as fabric filters. Cyclones are often used as an initial step in particle removal since cyclone efficiency for fine particle removal is poor. This section will focus on the three common and conventional particulate control devices, namely; cyclones, electrostatic precipitators, and fabric filters. The wet scrubber operation is discussed in Chapter 26 on SO_x control since these devices reduce SO_x emissions as well as remove particulate. The side stream separator system is a recent development in particulate removal. Its application is currently limited to retrofitting existing mechanical collectors on spreader stokers firing a limited range of coal types.[3] The side stream separator system consists of a cyclone and a pulse-jet baghouse which will each be discussed in the following sections.

24.2 Cyclones

The cyclone separator is typically incorporated as a pre-filtering process for removing larger particles. Cyclones can operate at relatively high temperatures and function without moving parts making operation simple. The cyclone chamber provides angular (swirling) gas flow which causes the suspended particles to accelerate towards the chamber walls. Particles, being denser than gas, separate from the gas stream and impact the cyclone chamber walls. The cyclones are erected vertically and the particles fall under gravity to the collection hopper.

CYCLONE APPLICATION

- **Low Capture Efficiency**
- **Poor Fine Particle Capture**
- **Simple Operation and Maintenance**
- **High Temperature Application**

Slide 24-4

Design Principles

The cyclone device is typically positioned immediately downstream of the boiler. The cyclone's service environment is dependent on its material of construction. Cyclones can be constructed to withstand harsh environments such as extreme weather conditions and high temperatures since they have no moving parts.

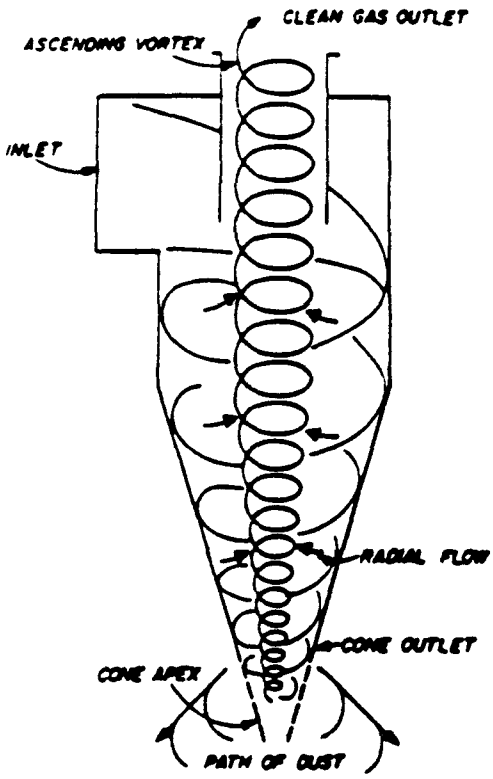
CYCLONE DESIGN

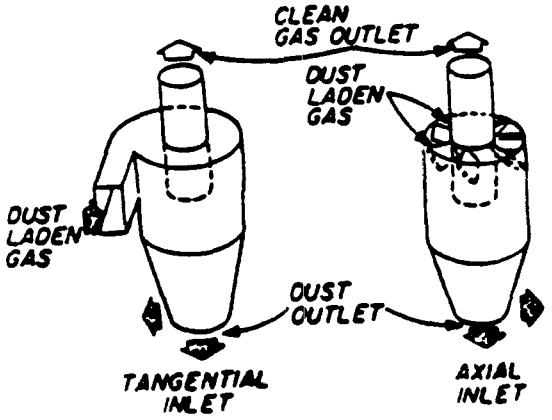
- **Vertical Gas Chamber**
- **Axial or Tangential Gas Entry**
- **Swirling Gas Flow**
- **No Moving Parts**

Slide 24-5

The cyclone is typically a vertically erected conical or cylindrical shaped chamber which receives particle laden gas in the upper chamber region. The gas enters either tangentially or axially in a downward spiral path around the chamber walls. The spiralling motion causes the particles in the gas flow to accelerate to the chamber walls where their momentum causes them to separate and fall-out of the gas stream. The particles drop to the bottom of the cyclone by gravity and downward motion of the gas. The particles fall into the collection hoppers and are removed by an ash removal system. The cleaned gas still carries significant levels of fine particulate which remain suspended in the flow due to their airborne characteristics. The treated gas reverses direction at the bottom of the chamber and returns up the center of the chamber and exits out the top.

CYCLONE





(Reprinted from "Pollution Engineering Guide to Fine Particulate Control in Air Pollution" by P. Cherminisoff with permission from Conner Publishing)

Slide 24-6

Performance

Cyclone removal efficiency is dependent on the gas velocity, rate of change of gas direction and the particle size distribution, density and composition. The main limitation of the cyclone is the inability to effectively remove small particles less than 5μm in diameter. For small particles, the inertial separating force (particle momentum) is low and the particles are more prone to remain suspended in the gas stream.

CYCLONE PERFORMANCE

Capture Efficiency is Dependent on:

- **Gas Velocity**
- **Chamber Diameter**
- **Particle Size, Density and Composition**

Slide 24-7

The removal efficiency of a cyclone can be increased by increasing the swirling velocity of the gas which increases the inertial separating force or particle momentum. This is effectively accomplished by reducing the diameter of the cyclone chamber or increasing the gas flow rate. Cyclone performance is effected by gas flow rate since this effects the swirling velocity in the cyclone. Cyclone efficiency is relatively insensitive to dust loading and in fact, the efficiency can increase with higher loading due to particle interactions.

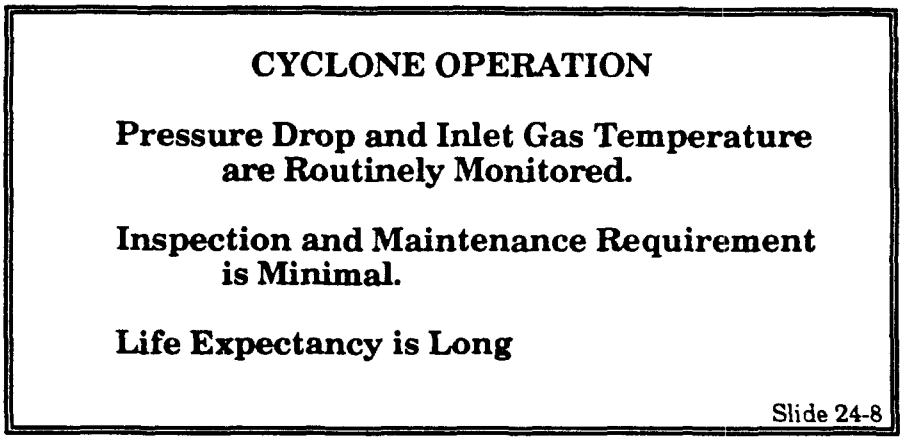
Cyclone efficiency is generally poor compared with the efficiency of electrostatic precipitators and fabric filters. Cyclone efficiency is less than 20 percent for sub-micron particulate. Efficiency varies linearly with particle size from 5 percent for 0.5 micron particles to 50 percent for 3 micron particles.

Operator Duties

Process Monitoring: The pressure drop and inlet gas temperature are monitored to assure proper operation. The pressure drop is monitored so that any tendency of the cyclone to plug can be signaled by high pressure drop. Also leaks and cracks in the cyclone can be detected by reduced pressure drop. Pressure drop is also a function of gas flow and may be used as an indicator of capture efficiency. Generally efficiency increases with higher pressure (i.e. higher gas flow). Monitoring the inlet gas temperature may be required depending on the cyclone's application and material of construction to operate above the acid dew point and avoid corrosive conditions.

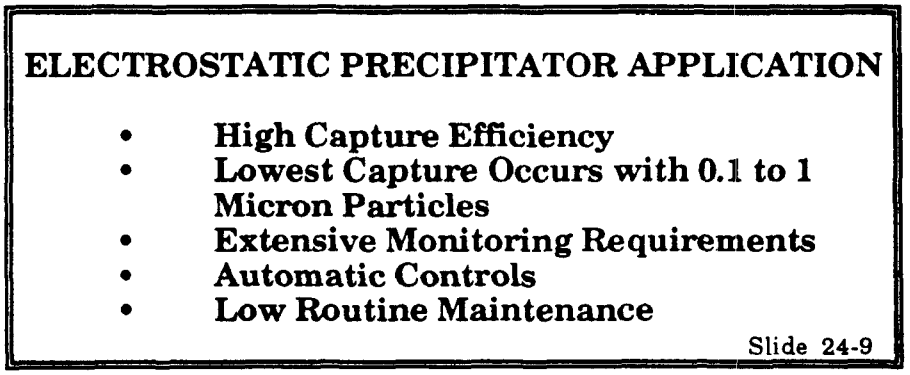
Inspection and Maintenance: Cyclones have minimal maintenance requirements due to lack of moving parts. Cyclone wall corrosion, leakage, particle deposits and plugging should be regularly checked. Life expectancy of cyclones is long

and is only limited by material corrosion, erosion and thermal stresses and cracking. Overall, the cyclone requires very little routine maintenance.



24.3 Electrostatic Precipitators

Electrostatic precipitators (ESPs) are more efficient at removing fine particles than are cyclones. The electrostatic precipitators are available in a variety of designs and can operate in dry or wet mode and in hot or cold gas conditions. Many ESPs are operated in dry cold-side applications. The "cold-side" categorization refers to the ESP located downstream of the air preheater. Dry cold-side ESPs operate



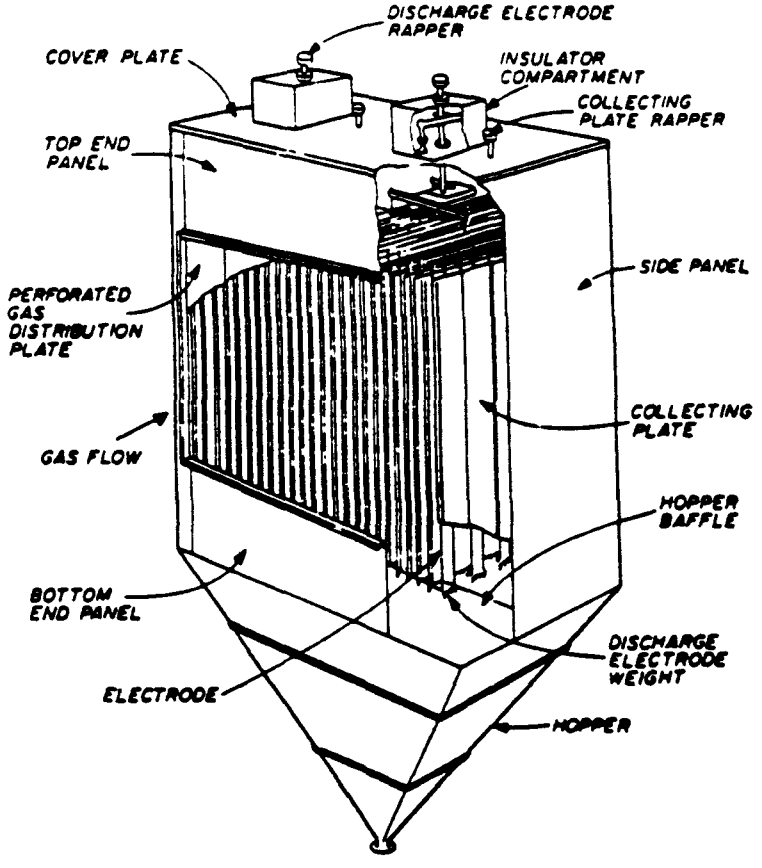
without water spray and at gas temperatures below 500°F. The principles of electrostatic precipitation are more complex than the principle of cyclone separation, however, the fundamental process is the same. The suspended particles are accelerated towards the electrostatic precipitator's chamber walls by electromotive forces rather than inertial forces. The particles collect on the walls and are periodically dislodged from the walls and fall into the collection hoppers. The typical cold-side electrostatic precipitator is erected downstream of the air heater and is configured with rod or wire discharge electrodes and flat collecting plates. Electrostatic precipitators consist of a series of chambers with vertical hanging

collecting plates, electrical power supplies and mechanical rapping devices to dislodge particle build-up from the plate.

Design Principles

Electrostatic precipitators are a well established particle removal technology for pollution control on utility boilers. Electrostatic precipitation is a process by which gas suspended particles are electrically charged and passed through an electric field which propels the charged particles towards the collecting plates. The charged particles stick to the plates and periodically a rapping (impact) mechanism dislodges the collected particles from the plates. The dislodged particles drop into the collection hopper for removal.

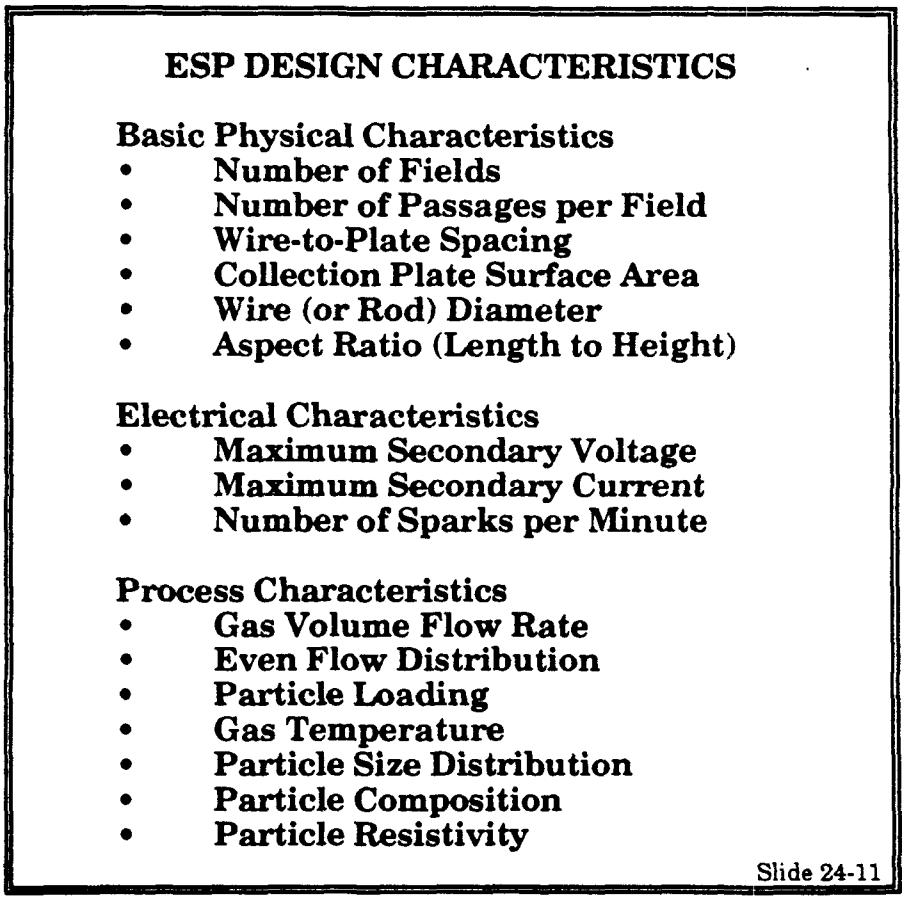
ELECTROSTATIC PRECIPITATOR



(Reprinted from "Pollution Engineering Guide to Fine Particulate Control in Air Pollution" by P. Cherminisoff with permission from Conner Publishing)

Slide 24-10

Electrostatic precipitators can be found in both low or high temperature applications up to material limits of 1300°F and down to the condensation point of flue gas constituents. Precipitators are commonly designed for either hot- or cold-side treatment. Hot-side precipitators, located upstream of the air preheater, have larger collecting plate areas and are constructed of suitable steels to handle continuous high temperature operation. The principle of electrostatic precipitation is carried out in three main steps, namely; particle charging, particle collection, and particle removal. The electrostatic precipitators can be classified in the following three types; tubular, wire-to-plate and flat plate. Some ESPs have precharge chambers which divide the precipitator into a charging stage and a collecting stage. These types of units are used for particles which are characteristically harder to charge.



The general configuration of an ESP is a wire (or rod) discharge electrode positioned an equal distance between two collecting plates. The electrostatic precipitator casing houses many passages of parallel collecting plates with wires (or rods) suspended at regular intervals through the passage. The plates are further compartmentalized into fields, with each field typically energized by its own set of power supplies. A negative high-voltage direct-current power is applied to the discharge electrodes and the collecting plates are grounded. The high-voltage, direct-current power source produces a corona in the wire-to-plate spacing by ionizing the gas. The corona creates an avalanche of negative ions traveling from the negative discharge electrode to the grounded collecting plates. Suspended particles passing

through the wire-to-plate spacing are bombarded by negative ions and become charged. The high voltage electricity produces an electric field between the wire and the plate which provides the electromotive force to attract the charged particles to the collecting plates.

The charged particles which accumulate on the collecting surfaces must be periodically dislodged. Dislodging the collected particle layer is accomplished in several ways using either mechanical rapping devices or water. Typically, dry electrostatic precipitators utilize mechanical rapping devices which strike the collecting plates and dislodge the particles. The particles fall into the collection hoppers and are removed for disposal. Wet electrostatic precipitators utilize water to rinse the collected particle layer of the collecting surface. The wet electrostatic precipitator is used effectively in the following conditions:

- after flue gas has been through a wet scrubber,
- low gas temperature and high moisture content,
- high sub-micron particle concentration,
- liquid particle collection,
- for handling wet dust.

Newly designed ESPs have larger wire-to-plate spacings and use rigid rod discharge electrodes instead of wire. The newer electrostatic precipitators are capable of operating at higher voltage which increase the electric field strength and the subsequent particle capture. Many electrostatic precipitators are equipped with advanced controlled power supplies which monitor electrical condition and maximize performance while minimizing power consumption. Advanced control units provide features such as intermittent energization and spark rate control. Intermittent energization switches off power repeatable for extremely short durations and maintains ESP performance while minimizing power consumption. Spark rate is important in the electrical operation. Sparking is a phenomenon which occurs due to an ionized discharge to the collecting surface resembling an electrical arc. Excessive sparking will reduce the applied voltage and waste power, insufficient sparking may indicate that the ESP is not operating near its full potential. With automatic controls, a desired spark rate can be specified and will be automatically monitored and maintained.

Performance

Operating efficiency of the ESP increases with increasing plate area, increasing voltage and decreasing gas flow rate. The precipitator's size is measured in terms of specific collection area (SCA) which is the ratio of collection surface area to gas volume flow rate. Electrostatic precipitators are least efficient at capturing particles in the 0.1 to 1 micron diameter size range; however, when designed and operated properly the ESP is still capable of excellent collection of particles in this size range. Electrostatic precipitators capture submicron particulate with approximately 90 to 95 percent efficiency. From the efficiency level for submicron particles, the efficiency increases linearly to 99.9 percent for particles of 5 microns. Operation is sensitive to fluctuations in gas flows, temperature, particulate and gas composition, and particle loadings.

ESP PERFORMANCE

Capture Efficiency is Dependent on:
- **Specific Collection Area (SCA)**
- **Operating Voltage**
- **Particle Characteristics**

Particle Size of 0.1 to 1 Micron is Hardest to Capture

Particle Resistivity in the Range of $2x10^8$ to $2x10^{11}$ ohm-cm is Best for Performance

Slide 24-12

In addition, the electrostatic precipitator's effectiveness is strongly influenced by the resistivity of the particles in the gas stream. Resistivity is a measure of the resistance of the particulate matter to being charged. Normal resistivity for ideal operation is between $2x10^8$ and $2x10^{11}$ ohm-cm.

Other factors which adversely effect electrostatic precipitator performance include; misaligned electrodes, excessive dust build-up on collecting and discharging electrodes, re-entrainment of collected particle especially during rapping, undersized equipment, flow distribution within the ESP and the presence of non-ideal electrical conditions.

Operator Duties

Process Monitoring: To assure proper operation, the inlet gas temperature, flue gas flow rate and electrical conditions are monitored. On-line electrostatic precipitator performance is typically monitored with a opacity meter, however, continuous and reliable monitoring of electrostatic precipitator performance is difficult. An electrostatic precipitator's performance is sensitive to flow rate, particle composition and temperature and the electrostatic precipitator's response to these parameters is relatively slow.

Temperature has a direct effect on particle resistivity and therefore electrostatic precipitators must be operated within the designed temperature range. Temperature changes due to changes in the boiler load may adversely affect the ESP effeciency. For cold-side ESPs, the temperature range is limited to temperatures above the condensation point and below the electrostatic precipitator's material limit usually specified by the manufacturer. For hot-side electrostatic precipitators, high temperature is preferred within the maximum operating range specified by the manufacturer. Particle resistivity peaks at about 400°F and is lower for temperatures greater than and lower than 400°F.

The electrical conditions do depend on the type of ESP. For the conventional cold-side wire-to-plate ESP, the voltage will range from 25 to 50 kV with even higher voltage for wider wire-to-plate designed electrostatic precipitators. Spark rate is often optimized on site but is generally between 50 and 150 sparks per minute. The higher the secondary current the better. Secondary current may be quenched by excessive particle loading. The secondary current density, which is the secondary current divided by the collecting plate surface area, is often less than 100 nA/cm^2. The secondary current density can be calculated for each field by dividing the field secondary current by the plate surface area in that field. Generally, the first fields have the lowest current density because a significant percentage of the current goes into charging the particles which are captured in fields downstream.

ESP MONITORING AND MAINTENANCE

Monitoring:
- **Inlet Gas Temperature**
- **Gas Flow Rate**
- **Electrical Conditions**
- **Rapper Intensity**
- **Hopper Ash Level**

Maintenance:
- **Requires Highly Trained Personnel**
- **Requires Low Routine Maintenance**
- **Inspect for Electrode Misalignment, Pitting, Ash Build-Up, Ash Hardening, Hopper Blockage, Electrode Insulation Cracks, and Rapper Performance.**

Slide 24-13

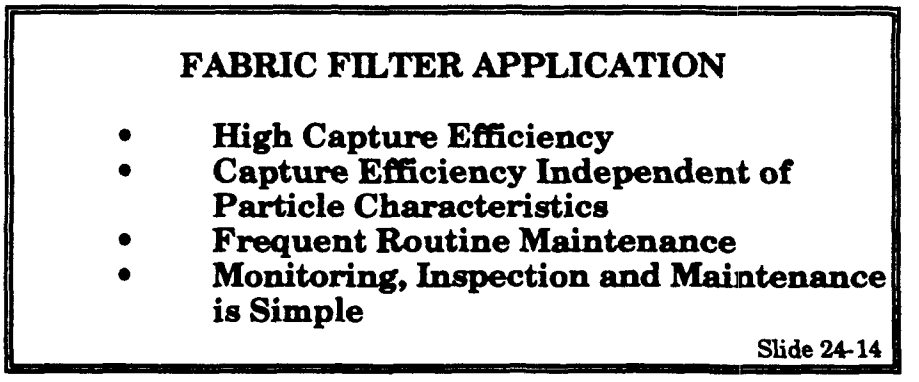
Inspection and Maintenance: Maintenance is required for cleaning carbon deposits on plates which can cause short circuits, corrosion of plates, and erosion of electrodes. Electrostatic precipitators are fairly sophisticated devices requiring automatic controls for rectifier equipment, measurements systems for rapper intensity, hopper dust level, and monitoring systems of gas process variables such as gas flow and temperature. Because of this complexity, highly trained maintenance personnel are required. The frequency of inspections and maintenance are typically monthly for external systems such as power supplies, monitors, etc. and annually for internal systems such as electrode conditions, electrical connections, etc. Internal inspections and maintenance are conducted in hostile environments due to the potential mechanical and electrical energy of the electrostatic precipitator. Annual inspections are necessary of electrode alignment, electrode pitting, ash build-ups, ash hardening, hopper performance, electrode insulation and rapper operations.

24.4 Fabric Filters

Fabric filters, also commonly known as baghouses, are used to remove gas suspended particles much like the filtration device on common household vacuum cleaner. The fabric filter is utilized in relatively low temperature environments around 350°F but always above the dew point of water and common acid gases. The particle laden gas stream enters the fabric filter chamber and passes through vertically suspended filter bags. Particles collect on the filters. Particle build-up is periodically removed from the filters by one of a variety of methods. The collected particles fall to the collection hopper situated below the filter bags.

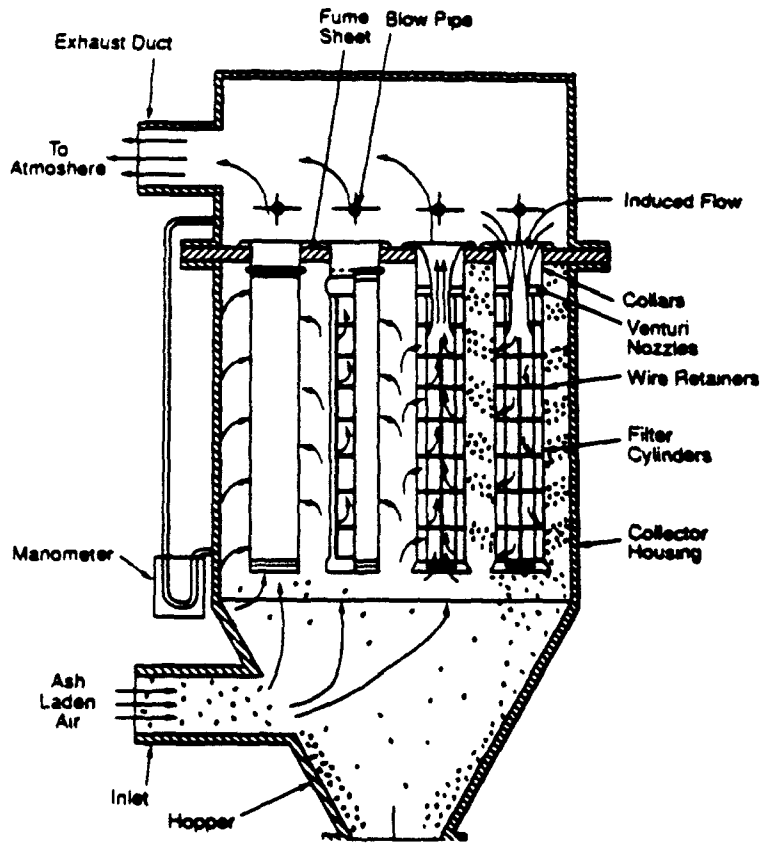
Design Principles

Fabric filters are used to remove suspended particles from flue gas by capturing the particles on the surface of a porous fabric. Particle laden gas enters the collection device and passes through an array of cylindrical filtering bags which retain the particles; and the clean gas exits through the outlet duct. The design of the fabric filter system slows the gas velocity and evenly distributes the gas to all the filter bags. Particle collect on the filters and form a dust cake on the surface of the filters. As the dust layer builds, it becomes more difficult for particles to penetrate. This increases both the pressure drop across the filters and the collection of the particles. It is actually the dust cake which achieves the high efficiency collection of particulate. For this reason, unless the filters are preconditioned (i.e. an artificial filter cake is built-up) prior to operation, filter efficiency is lowest at start-up and after the bags are cleaned.



Fabric filters are usually externally heated and/or insulated to ensure that the device remains above the minimum require operating temperature to prevent condensation which can plug and corrode the filter bags. This is especially important during start-up and shutdown operations when temperatures are likely to drop below the gas dew point. Fabric filters' maximum operating temperature is limited by the working temperature of the fabric. For many common filtering fabrics the maximum operating temperature is less than 500°F. Fabric filters are equipped with spark arresters upstream to prevent fugitive sparks and hot flyash from burning the filters.

FABRIC FILTER



Slide 24-15

Filters are most effective at collecting particles when coated with dust, however, too high a coating will create a high pressure drop across the filter. The filters need to be cleaned periodically. When removing the dust build-up, it is important not to remove too much dust cake since excessive dust leakage will occur while fresh cake develops. There are four principal types of cleaning systems; pulse jet, reverse gas, shaker, and sonic.

The pulse jet system utilizes high pressure air to clean the filters. The high pressure air inflates the bags, cracking the external dust cake. When the air is removed, the bags return to their original shape and the dust cakes drop into the collection hopper. Pulse jet systems can be cleaned while on-line which allows continuous operation of the unit. Filters can be maintained from outside the collector, which allows the maintenance to be performed in a clean, safe environment. This vigorous cleaning technique tends to limit filter bag life.

PULSE JET

- **High Pressure Air**
- **Inflates Bag to Dislodge Dust Cake**
- **On-Line Cleaning**
- **Vigorous Cleaning Limits Bag Life**

Slide 24-16

In reverse air systems the dirty gas enters the fabric filter and passes from the interior to the exterior of the bags. The fabric filter must be divided into modules which are taken off-line during cleaning. Air is introduced from the exterior of the bags, collapsing the bags and cracking the interior dust cake which fall to the collection hopper. The cleaning is accomplished at a relatively low air pressure which results in maximum bag life.

REVERSE AIR

- **Low Pressure Air**
- **Contracts Bag to Dislodge Dust Cake**
- **Off-Line Cleaning Requires Modular Fabric Filter System**
- **Low Pressure System Provides Maximum Bag Life**

Slide 24-17

Shaker systems move the tops of the bags in a circular path causing a wave motion through the bag length. This causes the dust to crack and fall to the hopper. Bags must have high abrasion resistance for this cleaning technique. In addition, individual bags must be taken off-line for the cleaning process.

SHAKER

- **Mechanical Sinusoidal Bag Shaker**
- **Off-Line Cleaning Requires Modular System**
- **High Abrasion to Fabric**

Slide 24-18

Sonic cleaning, if used, usually augments another cleaning method. Sonic energy is introduced into the filtering device. The sonic waves generate acceleration forces that tend to separate the dust from the fabric.

SONIC

- **Augments Other Cleaning Techniques**
- **Sonic Waves Generates Acceleration and Dislodges Dust Cake**

Slide 24-19

Performance

Fabric filters are very efficient at removal of particles of all sizes. Efficiency ranges between 99 and 99.9 percent for particle sizes as low as 0.1 microns. Particle capture is relatively insensitive to particle and dust physical characteristics such as particle resistivity and dust loading. Efficiency is decreased as the gas-to-cloth ratio increases, which increases as gas velocity increases. Gas-to-cloth ratio is a ratio of the gas volume flow rate to the filter surface area and is a measure of the superficial gas velocity through the filter. Particle capture efficiency is also dependent on the frequency of bag cleaning, cake build-up, fabric type and weave, and on the physical condition of the bags.

Operator Duties

Process Monitoring: Fabric filter operations are monitored by flue gas inlet temperature, gas flow rate and pressure drop across the system. The baghouse temperature must be maintained above the acid condensation point in order to reduce corrosion and fabric wear. This is most important during boiler start-up and shut-down conditions. If acid deposition occurs after shut-down, the acid moisture will

settle on the fabric and eventually leave behind a residue which may contribute to the brittleness of the bags and cause a failure when put into operation again.[3] An atypically high pressure drop can signify that bags are binding or plugging, gas flow is excessive or fabric cleaning is inadequate. Low pressure drop signifies possible filter holes and leakage, leakage between the bag and bag supports, or inadequate dust cake formation. The fabric filter performance can be monitored with an opacity meter.

FABRIC FILTER PROCESS MONITORING

Operation is Monitored by:
- **Flue Gas Temperature**
- **Gas Flow Rate**
- **Pressure Drop**
- **Opacity**
- **CEM**

High Pressure can Indicate:
- **Binding or Plugging of Filters**
- **Excessive Gas Flow**
- **Inadequate Filter Cleaning**

Low Pressure can Indicate that Leaks and Holes Exist Across the Filters.

Slide 24-20

Inspection and Maintenance: Fabric filters require relatively simple operation, maintenance and repair. However, they require frequent routine inspection and maintenance. Several fabric filter inspections and maintenance items are required on a daily and weekly basis. Filter bags require periodic inspection for correct tensioning and conditions such as tears, holes abrasion, and dust accumulation on the surface. The typical filter bag life is as much as 10 years using reverse air cleaning, but this can be reduced to 2 years for improperly operated systems. Filter bags are fragile and prone to hole formation if not handled carefully.

FABRIC FILTER MAINTENANCE

High Routine Maintenance is Required

Simple Operation, Maintenance and Repair Compared to ESP

Periodic Inspection of Filter Bags for Tears, Holes, Abrasion, Leaks and Dust Build-Up

Cleaning Cycle Timing, Effectiveness and Equipment

Typical Bag Life is 10 Years but can be Reduced to 2 Years for Poorly Operated Device

Slide 24-21

REFERENCES

1. Elliott, Thomas C., *Standard Handbook of Powerplant Engineering*, McGraw-Hill Publishing Co., 1989.

2. McDonald, Jack R. and Dean, Alan H., *Electrostatic Precipitator Manual*, Noyes Data Corporation, 1982.

3. "Fossil Fuel Fired Industrial Boilers - Background Information", Volume 1, Chapter 4, EPA-450/3-82-006a, March, 1982.

4. *Steam, Its Generation and Use*, 40th Edition, Babcock & Wilcox, 1992.

CHAPTER 25. NITROGEN OXIDES CONTROL

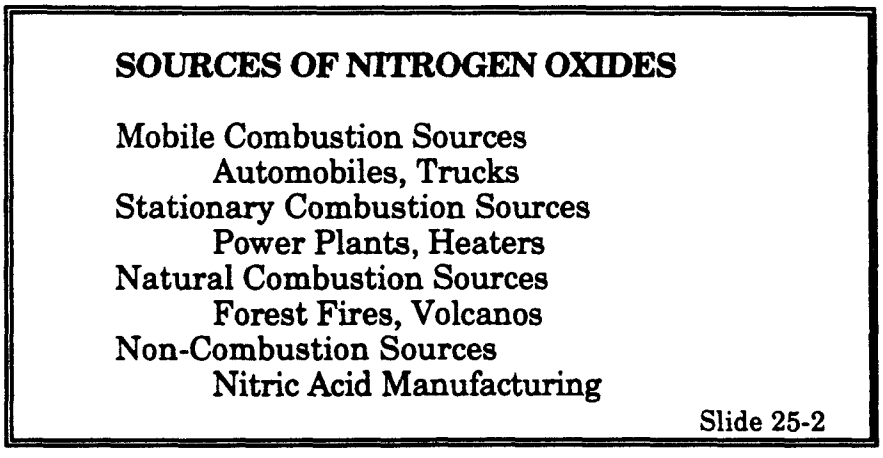
25.1 Overview
- A. Sources
- B. Species
- C. Environmental Concerns

25.2 NO_x Formation

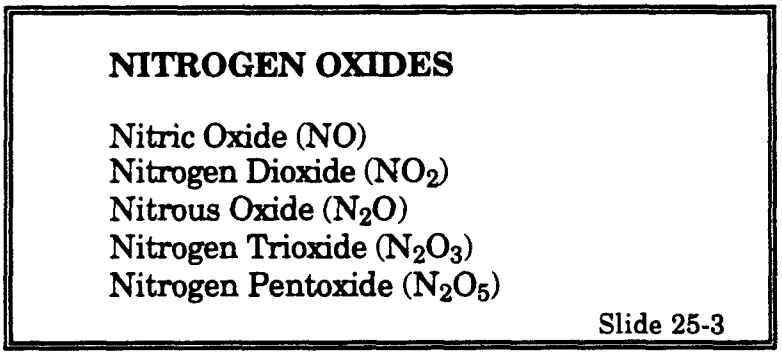
25.3 Control of NO_x Emissions
- A. Combustion Modifications
- B. Post-Combustion Control

Slide 25-1

25.1 Nitrogen Oxides Control Overview



Nitrogen oxides are emitted from almost all combustion sources, including stationary sources such as power plants, mobile sources such as automobiles, and natural sources such as forest fires. Non-combustion sources include those associated with the manufacture and use of nitric acid and ammonia.



There are a number of different oxides of nitrogen which are listed above. Nitrogen oxides are essential to the nitrogen cycle in nature. Nitrogen dioxide (NO_2) can be converted to nitric acid in the atmosphere, which under normal circumstances reacts to form nitrates which return to the earth as either dry deposition or precipitation (rain and snow). Nitrates are an important natural fertilizer for organic growth. However, the additional NO_x produced by man-made sources shift natures balance. NO_x has been associated with respiratory disorders, corrosion and degradation of materials, and damage to vegetation.

For regulatory purposes, nitrogen oxides (NO_x) are composed of nitric oxide (NO) and nitrogen dioxide (NO_2), the two major combustion related oxides of nitrogen. NO is the dominant molecular form produced during combustion. It undergoes slow oxidation to NO_2, with most of the conversion occurring in atmospheric air. Commonly, NO_x emission measuring instruments have provisions for measuring NO and NO_2.

Nitrous oxide is commonly known as laughing gas. It is a greenhouse gas which reacts in the upper atmosphere (stratosphere) to form nitric oxide which subsequently depletes ozone.[1] Nitrous oxide is generally not included as part of NO_x, because conventional NO_x instruments do not measure it. Likewise, nitrogen trioxide and nitrogen pentoxide are found in very small, trace quantities and are not commonly measured.

ENVIRONMENTAL CONCERNS ABOUT NO_x

Acid Rain
- Damage to Structures
- Damage to Water Quality & Fish Life
- Sudden Release of Acids

Photochemical Smog
- Impairs Human Health, Respiration
- Stunts Growth of Vegetation
- Oxidizes Materials

Slide 25-4

A significant fraction of the NO_x emitted from stationary combustion sources can result in either the formation of acid rain and/or photochemical smog.

Environmental concerns about acid rain can be related to the damage done to structures, plants and fish-life both near and far from the emission sources. The problems are worsened by the sudden release of acid materials, such as occurs during the melting of snow which contains accumulated amounts of the acid precipitation. Likewise, the first rain after a drought generally is much more acidic than normal due to the scrubbing action of rain water on the atmosphere.

Photochemical smog is the brownish colored air, first identified in the 1940s in the Los Angeles air basin. Sunlight causes the break down or disassociation of nitrogen dioxide, which leads to a series of chemical reactions with hydrocarbons and other gases. Photochemical smog formation is a transient process which varies with sunlight, atmospheric mixing conditions, and the emissions of NO_x, hydrocarbons and other products of combustion. Photochemical smog is often trapped by an atmospheric inversion, which prevents its dilution with fresh air.[2] Smog is particularly observable by looking through the horizontal layers of such stratified air.

The high oxidant levels associated with smog can impair human health, particularly for those individuals with respiratory diseases. Other measurable effects of smog are the stunting of growth of vegetation, the discoloration of fabrics, the cracking of rubber, the deterioration of concrete structures, and the corrosion of metals.

25.2 NO_x Formation

NO_x FORMATION - FOSSIL FUEL FIRED BOILERS

FUEL NO_x
Combustion of Chemically-Bound Nitrogen in the Fuel with Oxygen

THERMAL NO_x
High Temperature Reaction of Nitrogen with the Oxygen and Nitrogen from Air

PROMPT NO_x
Oxidation of Fuel Bound Nitrogen under Fuel Rich Conditions

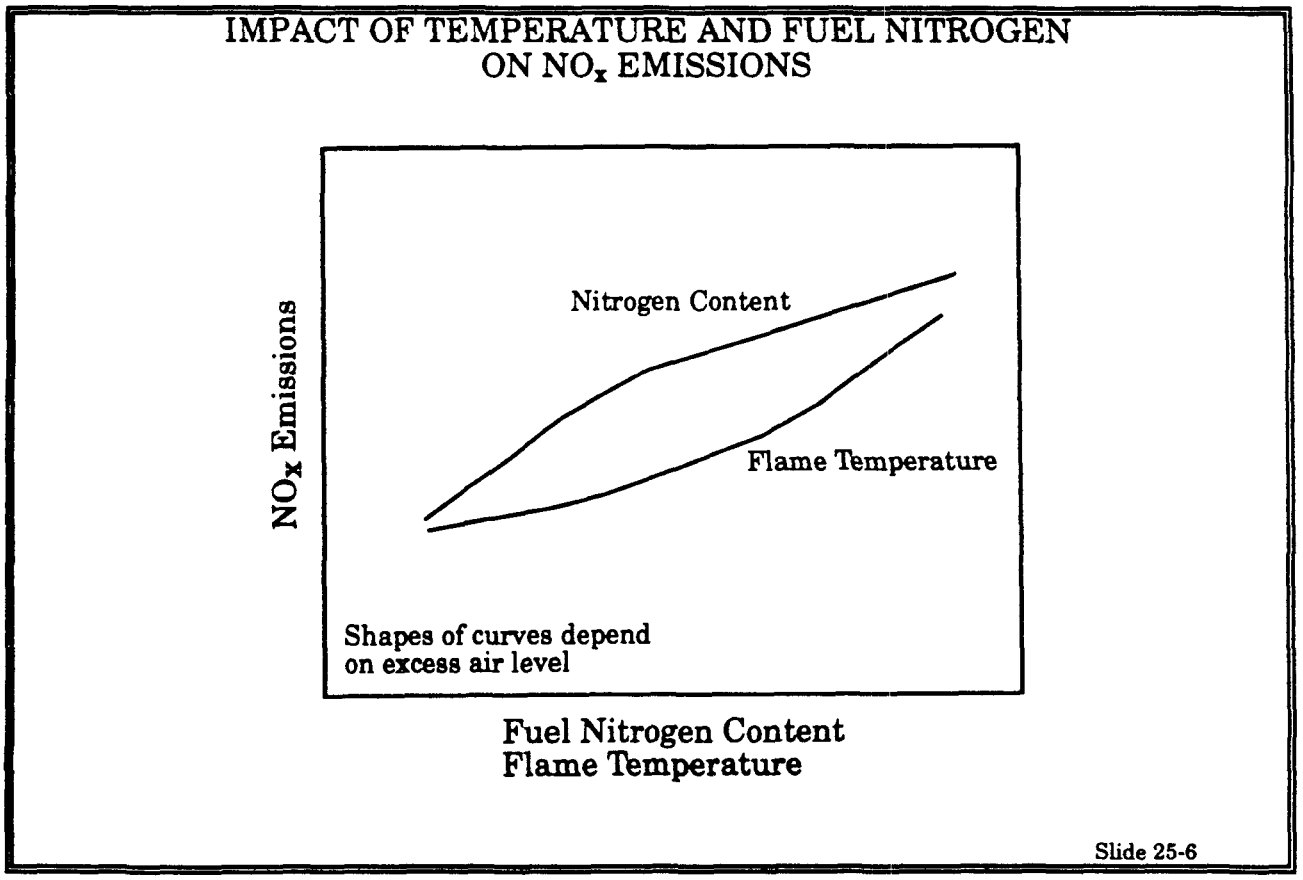
Slide 25-5

Oxides of nitrogen formed in combustion processes are due to either the conversion of chemically bound nitrogen in the fuel which produces "fuel NO_x" and "prompt NO_x" or thermal fixation of atmospheric nitrogen and oxygen in the combustion air which produces "thermal NO_x".

Fuel NO_x designates the NO formed by oxidation of the chemically-bounded nitrogen in the fuel. Fuel-bound nitrogen occurs in petroleum and coal fuels. During combustion, most of the fuel nitrogen will be released as molecular nitrogen (N_2), hydrogen cyanide (HCN), NO and ammonia (NH_3), with a modest fraction remaining with the char. Fuel nitrogen conversion to NO is highly dependent on the fuel/air ratio for the range existing in typical combustion equipment. The stoichiometric and mixing conditions will determine the fractions of the HCN and NH_3 which is oxidized to NO. Conversions of fuel nitrogen to NO range from around 5% at starved-air conditions to 50% under well-mixed conditions.

Thermal NO_x designates the NO formed through the mechanism of high temperature oxidation of nitrogen from the air. A fuel with a low fraction of chemically-bound nitrogen, such as natural gas, forms mainly thermal NO_x. The formation rate of thermal NO is dependent on the reaction temperature, the local fuel and air mixing, and the residence time. The thermal dependency of NO generated is linked to the high activation energy required to break the triple-bonded nitrogen molecules and to disassociate the O_2 molecules to supply O atoms needed to form NO.

NO formation decreases with increasingly fuel-rich mixtures due to the preferential reaction of available oxygen with carbon and hydrogen. Fuel-lean mixtures also suppress NO formation due to the fact that high excess air dilutes the reaction mixture, thus depressing the reaction temperature. The temperature depression effect of high excess air overrides the effect of the increased oxygen availability. The amount of thermal NO formed is lastly determined by the residence time in a high temperature region. Residence times in utility boilers at temperatures sufficiently high to form NO have been hypothesized to be on the order of 0.01 to 0.05 seconds. Although the mean residence time for gases in a utility boiler furnace is on the order of 1 to 2 seconds, the lower bulk gas temperature generally leads to significant NO formation for most of this period.



Prompt NO_x is formed during the early stages of the combustion process. Combustion is initiated under fuel rich conditions which produces intermediate hydrogen cyanide (HCN) species. After reacting with molecular nitrogen and hydrocarbon compounds in this environment, the HCN then forms NO by oxidation. Prompt NO_x is a small contributor to the total NO_x emissions. As a consequence, the control of Prompt NO_x is not as fully understood as the other two forms of NO_x production.

25.3 Control of NO_x Emissions

The control of NO_x emissions can be achieved by inhibiting the initial formation of the NO_x and/or reducing the NO_x species after they form. Therefore, this discussion is divided into two major categories: (1) Combustion modifications, and (2) Post-combustion control processes.

NO_x FORMATION REDUCTION TECHNIQUES

1. Decrease Primary Flame Zone Oxygen Level
   a. Decrease overall oxygen level
   b. Controlled mixing of fuel and air
   c. Use of fuel-rich primary flame zone

2. Decrease Time of Exposure at High Temperature
   a. Decreased peak temperature
   b. Decreased adiabatic flame temperature
   c. Decreased combustion intensity
      - Increased flame cooling
      - Controlled mixing of fuel and air
      - Fuel-rich primary flame zone
   d. Decreased primary flame zone residence time

Slide 25-7

Combustion Modifications

A variety of NO_x control methods use these NO_x formation reduction techniques singularly and in combination and are classified as combustion modifications.

Operational modifications, such as low excess air (LEA) and burner-out-of-service, are typically the simplest and least costly NO_x control techniques.

NO_x CONTROL TECHNIQUES

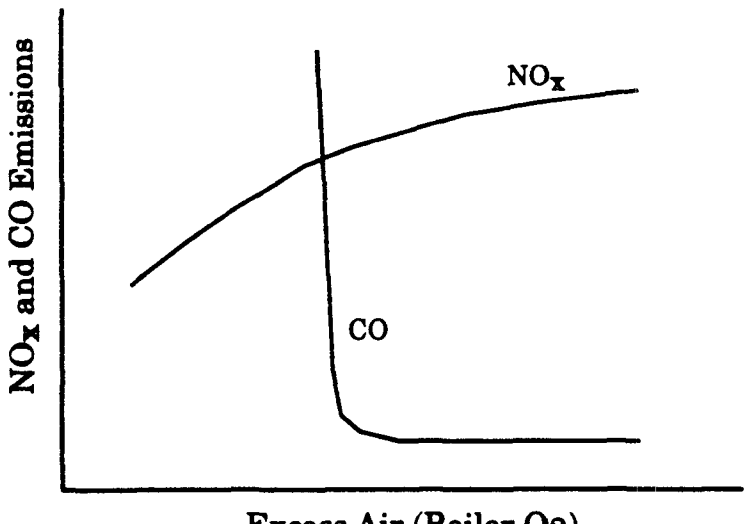
Combustion Modifications

- Low Excess Air Operation
- Burners-Out-of-Service (BOOS) Operation
- Overfire Air (OFA)
- Reduced Air Preheat
- Low NO_x Burners (LNB)
- Flue Gas Recirculation (FGR)
- Reburning

Slide 25-8

Low Excess Air Operation (LEA) - Boilers are always operated with an excess of combustion air to insure complete combustion. Since the formation of thermal and fuel NO_x are directly related to the concentration of available oxygen in the furnace, the level of excess air is one of the primary operating variables in the control of NO_x. The level of excess air also directly impacts boiler operating efficiency. The practical limit of minimum excess air will vary with furnace design, maintenance, control flexibility and fuel characteristics. Boilers designed to provide nearly equal air/fuel ratios at all operating conditions have the potential to operate at the lowest excess air levels. Windbox configuration, burner design, primary to secondary air flow ratios as well as combustion air damper and control settings can have a significant impact on minimum excess air requirements. Accurate monitoring of the level of excess oxygen is necessary to optimize this NO_x reduction technique. Likewise, monitoring any increase in carbon monoxide emissions will allow early detection of localized combustion problems.

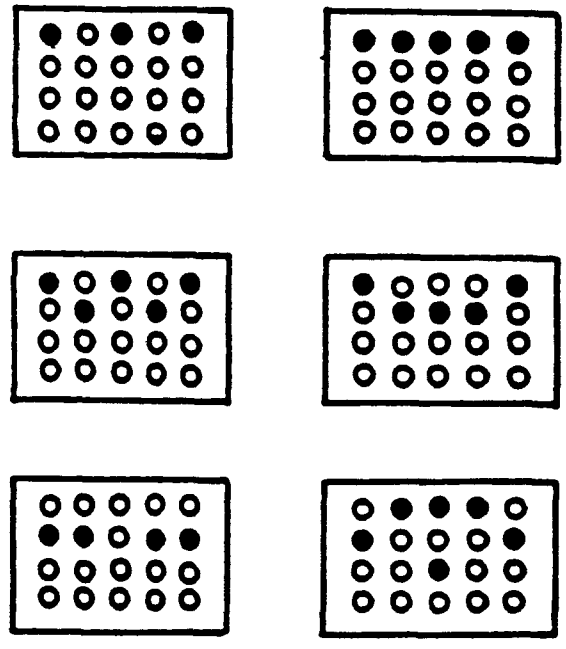
NO_x Emissions as a Function of Excess Air



Slide 25-9

Burners-Out-Of Service (BOOS) - Throttling of the fuel flow to selective burners while maintaining partial or full air flow through these same burners is an effective method of implementing staged combustion. Staged combustion involves generating a fuel-rich region near the burner with the remainder of the air added downstream in another section of the furnace. The limited availability of oxygen in the fuel-rich region results in a reduction in the conversion of fuel-bound nitrogen to NO_x. Although this is an excellent method of reducing NO_x emissions, extreme care must be taken when implementing combustion in this manner. Boiler design parameters which contribute to NO_x emission control include the burner type, burner zone heat release area, burner spacing, and windbox configurations. Redistribution of combustion (staged combustion) produces variations in the heat transfer occurring in the furnace. Therefore, monitoring of superheater temperature and reheater temperature, as well as the oxygen and carbon monoxide levels, are necessary to optimize BOOS.

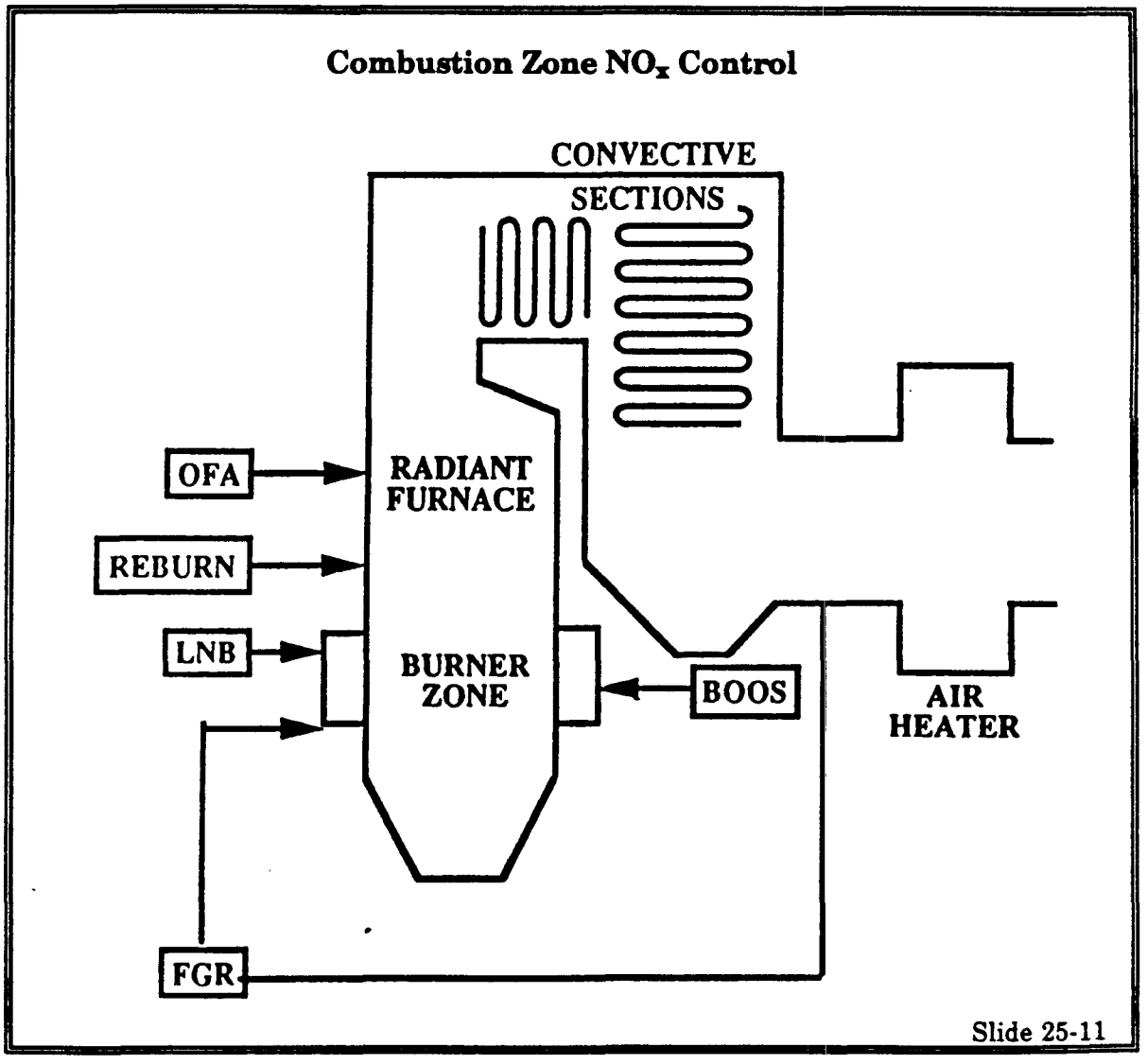
Typical-Burners-Out-of-Service Patterns for Face Fired Units



● Fuel Flow Terminated
○ Burner in Service

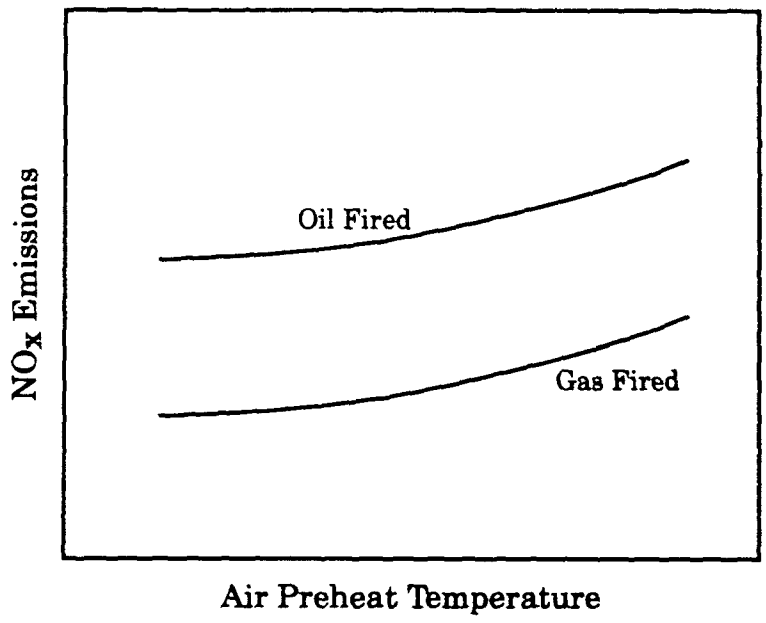
Slide 25-10

Overfire Air (OFA) - Another means of achieving staged combustion involves the use of OFA operation. A portion of the combustion air is diverted to air ports arranged above the burner elevation to generate an air blanket similar to that set up in BOOS operation. This technique requires that the furnace be fitted with overfire air ports as a retrofit or as part of the initial design. The location of these ports is dependent on the flue gas flow pattern characteristics. The primary advantage of using OFA is that it offers more flexibility for implementing the staged combustion with varying operating conditions, if required. The entire burner region serves as a first stage combustion region. A portion of the sensible heat of the flue gas is removed prior to the addition of the OFA, thus reducing the maximum temperature achieved. For pulverized coal-fired boilers, OFA has the added advantage of not involving the pulverizer feed supply system and therefore does not limit boiler capacity.



Reduced Air Preheat - Significant reduction in NO_x emission have been effected for certain fuels through the use of reduced combustion air preheat temperature. The implementation of such control involves minor hardware modification comprising either of the installation of air preheater bypass ducts or the removal of air preheater surface. The effect of reduced air preheat is to lower combustion temperatures, thus lowering the formation of thermal NO_x. Therefore, reduced air preheat is not an effective means of control for oil and coal-fired furnaces where the fuel NO_x component is significant. Also, the use of reduced air preheat results in substantial boiler efficiency losses since the heat, which is otherwise transferred to the combustion air, is exhausted in the flue gas.

NO_x Emissions as a Function of Air Preheat Temperature

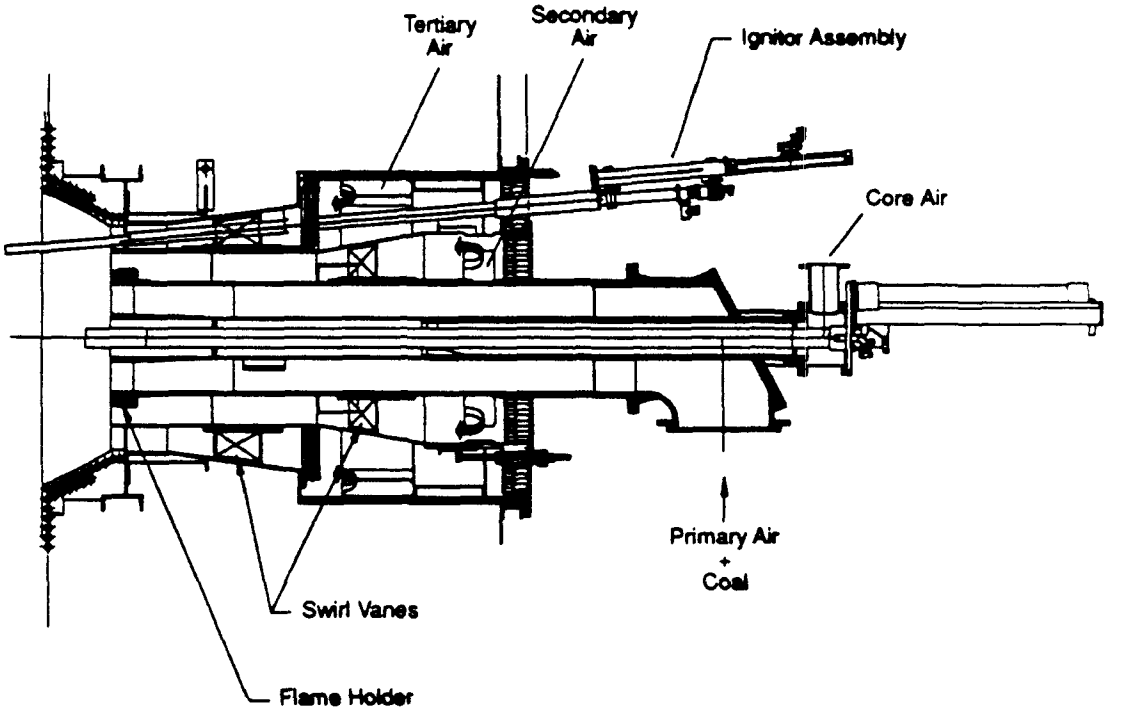


Slide 25-12

Low NO_x Burners (LNB) - A variety of LNB designs have been developed to reduce NO_x emissions from gas-,oil-, and coal-fired boilers. LNB designs control NO_x formation by (1) limiting the availability of oxygen in the primary combustion regions, (2) reducing flame temperatures, and (3) reducing the residence time at peak temperatures.

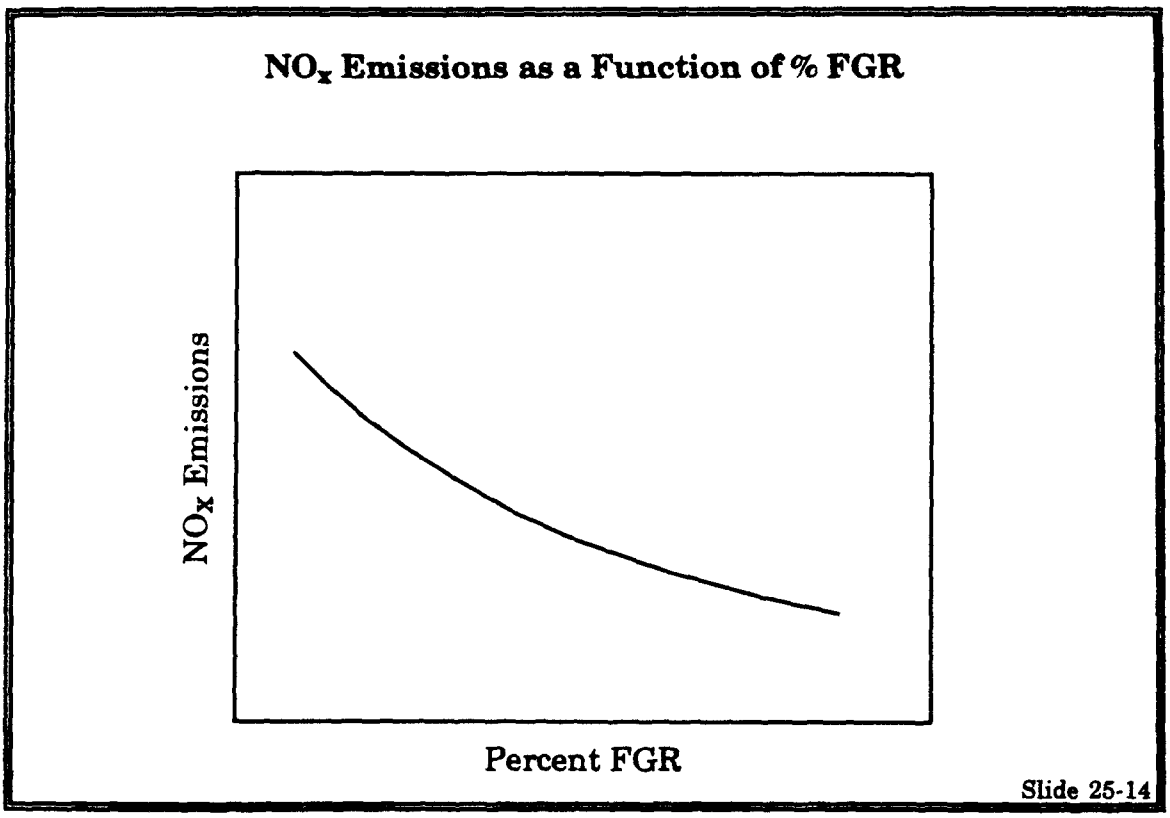
Each burner designer has a different approach toward achieving NO_x emission reduction while maintaining flame stability, complete combustion, and high turndown ratios. The LNB designs can be categorized into four general groups determined by the approach used to achieve reduced NO_x emissions. The first burner group includes designs that limit oxygen availability and reduce flame temperatures through two-stage combustion. Burners generating localized off-stoichiometric conditions, both fuel-rich and fuel-lean, form the second group. The third group uses self-recirculation of furnace gases from the near-burner region into the flame to reduce peak temperature and thereby NO_x formation rates. The fourth and final group includes the LEA burners primarily designed for high efficiency, low-NO_x, low excess air operation.

Burmeister & Wain Energi (BWE) Low NO_x Burner



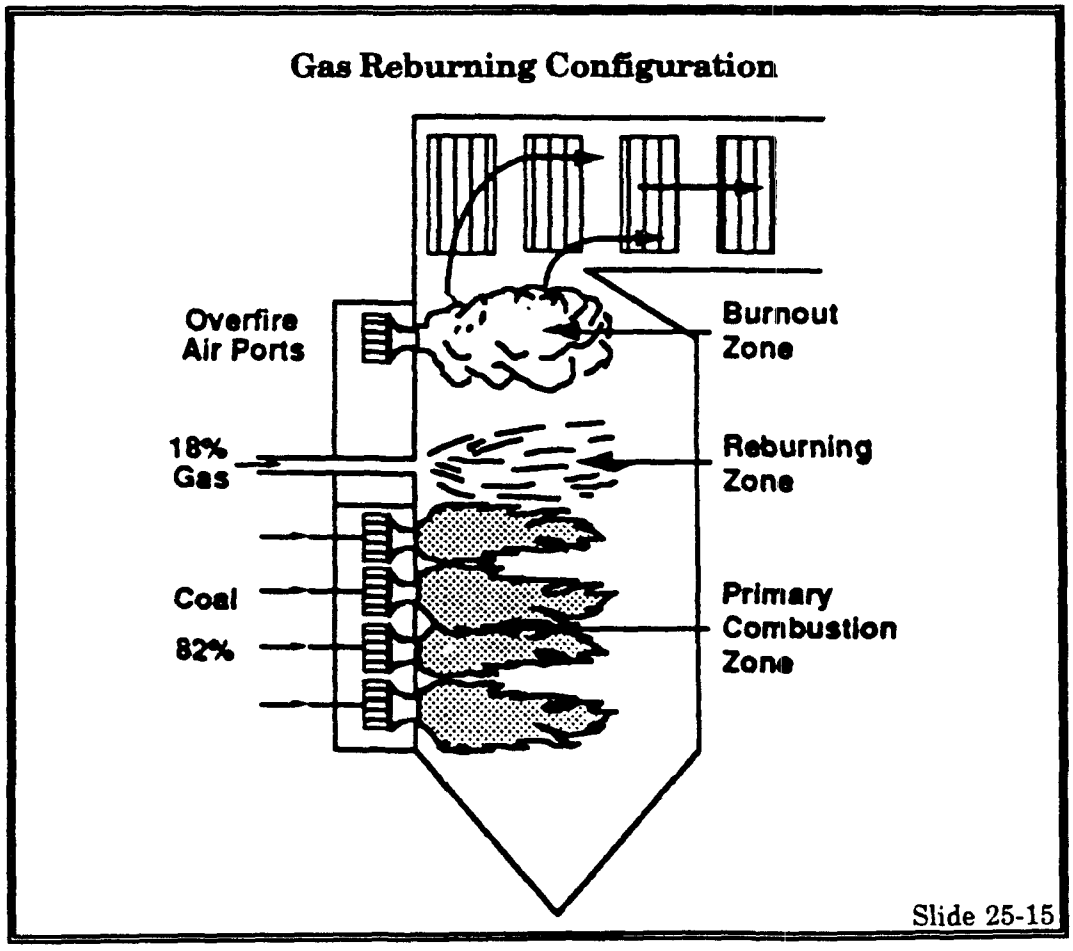
Slide 25-13

Flue Gas Recirculation (FGR) - The effect of FGR is a reduction in combustion temperature and thus, suppressed thermal NO_x formation. For the most part, inert flue gas and/or steam are mixed with the combustion air and act as heat sink materials to reduce combustion gas temperatures. Flue gas recirculation is often used to control thermal NO_x emissions from natural gas fired power plants. Steam injection is a traditional means of NO_x control in gas turbines. The flue gas injection header is normally located in the combustion air duct at the exit of the air preheater. The recirculation of the flue gas reduces the combustion product residence time in the furnace cavity and increases the mass flow which provides more heat transfer in the convective section. In some gas-fired boiler applications, the NO_x emissions have been reduce by 30 to 60% with the introduction of FGR flow rates of 10 to 30%. The application of FGR requires the boiler operator to monitor changes in heat distribution due to the increased total flue gas flow rate.



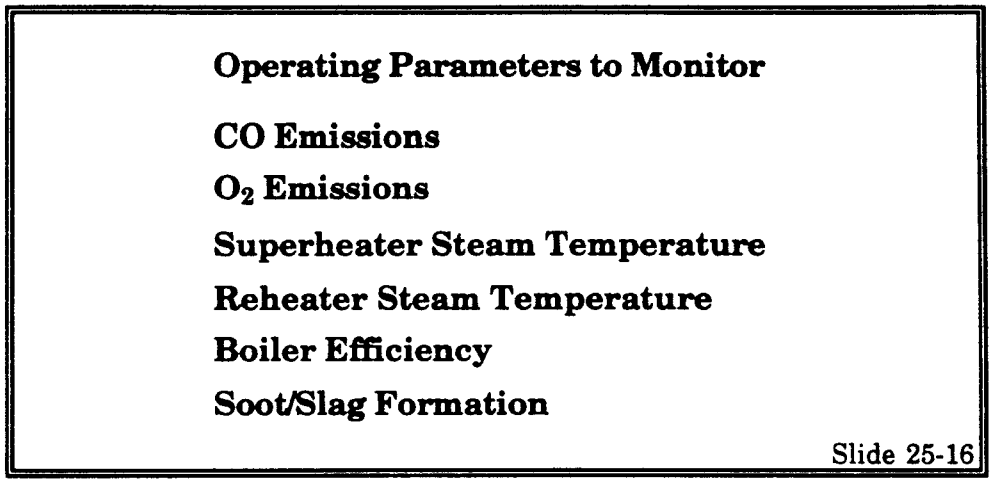
Reburning - Reburning is a three-stage NO_x control technique which has been applied in various fossil fuel power plants. In reburning, the first stage of combustion is under excess air conditions to complete the combustion. The second stage occurs downstream where an auxiliary fuel is injected into the combustion product gases. The auxiliary fuel is typically natural gas or some other low nitrogen content fuel although an emerging technology makes use of coal as the auxiliary fuel. Reburning is generally designed to occur in the radiant section of the furnace, so that auxiliary fuel is part of the overall energy input. Reburning creates a reducing atmosphere with about 90 percent of the theoretically required air. The reburn fuel and NO are primarily converted to CO, N_2, and H_2O. In the third combustion stage, burnout air is injected in order to convert the CO to CO_2.

It is possible for reburning to occur with the use of a conventional auxiliary fuel burner. However, auxiliary fuel burners typically operate under excess air conditions and are designed to increase combustion gas temperatures. Modifications would be required to produce the required reducing atmosphere and the subsequent downstream addition of air for complete combustion. Reburning has been demonstrated to reduce NO_x emissions by as much as 50-70%.



Operator Duties

In general, the combustion modifications for NO_x control require little additional effort from the boiler operator than monitoring of normal operation. The operating boundaries for each of the modifications are specific to the boiler design. For each combustion modification, extensive optimization testing of the boiler should be performed to determine the optimal setting for the control parameters as a function of boiler load. Once the combustion process has been modified for NO_x control, the following parameters should be monitored:



Post-Combustion Control

NO_x reduction techniques applied downstream of the combustion zone are categorized as post-combustion control technologies. These technologies, which include Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR), will be discussed in this section.

NO_x CONTROL TECHNIQUES

Post-Combustion

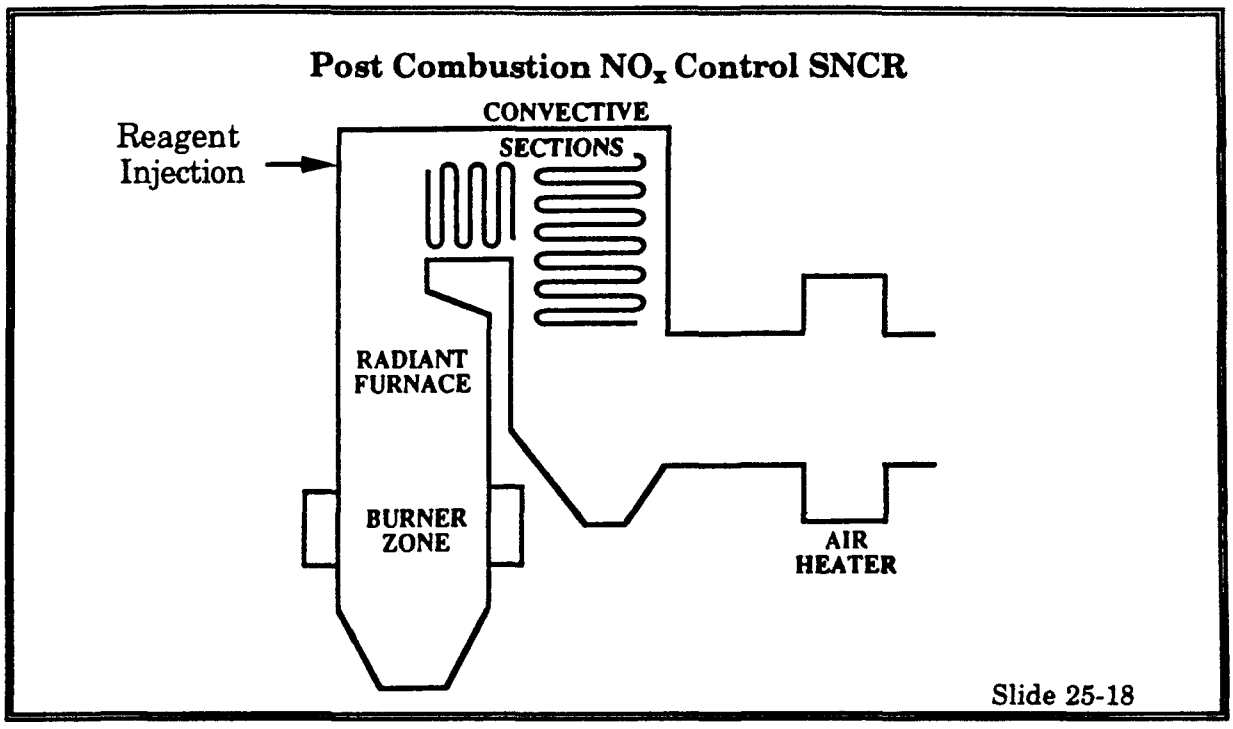
Selective Non-Catalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)

Slide 25-17

Both of these technologies control NO_x emission by injecting NO_x reduction reagents into the exhaust flue gas stream. The SNCR and SCR techniques have some similarities to gas reburning. The contrasting feature is that gas reburning provides an additional fuel input into the furnace combustion zone, whereas the SNCR and SCR reagents are generally injected after the combustion zone.

SNCR - The operation of SNCR systems requires the injection of a reagent material which can react with nitrogen oxide (NO) to produce nitrogen gas (N_2). A number of reagent materials can be used. Ammonia and urea are the most widely used reagents. The process using ammonia for SNCR is generally known as Thermal $DeNO_x$, which is patented by EXXON. The process using urea for SNCR was developed under sponsorship of the Electric Power Research Institute.

The SNCR process involves the injection of the reagent within the convective section of a boiler. The process is implemented by the installation of an injection grid at a location within the boiler where the optimum temperature occurs. The injection grid generally covers the entire boiler cross-section to ensure good mixing between the ammonia and the flue gas.



The major operational factors which influence the performance of SNCR are listed below. A properly designed SNCR system is required to have controls which take into consideration the influences of these factors. The most important constraint is the temperature of the flue gases into which the reagent is injected.[3,4] Although the process will often work in the design temperature window from 1,600° to 1,800°F, the temperature at which the process works best will vary depending upon which reagent is used and on the specific features of the application. For instance, a complicating factor is that as the concentration of CO increases, there is a shift of the effective range for the reduction reaction to lower temperatures. Because of the variability of the combustion conditions, the practical limit of NO reduction is considerably less than would occur under ideally controlled mixture conditions.

SNCR PERFORMANCE FACTORS

Reagent Selection
Temperature Region: 1,600°- 1,800°F
CO Concentration
Residence Time
Reagent Injection Rate Keyed to NO
Gas Mixing Efficiency

Slide 25-19

Under steady conditions, the relative rate of reagent injection must be set to obtain the amount of NO reduction desired. However, the fuel burning rates and combustion gas temperatures will vary as the boiler load changes. Corresponding variations will occur in residence times and NO concentrations. Therefore, the injection rate must be metered in response to demand. In addition, mixing of reagent and combustion gases must be appropriately controlled. The usual application includes a heater for the reagent and a carrier gas stream to enhance injection of the reagent into the furnace.

Either steam or compressed air can be used as the carrier gas. In some applications the reagent is mixed with recirculated flue gas before being injected into the flue gas stream. An air compressor or blower can be used to deliver the mixture to various damper controlled nozzles which will control the injection location and to regulate its delivery and mixing rate.

Operators should be aware that there are three possible reactions which can occur when reagents are injected into the flue gas. The reduction reaction, oxidation reaction, or neither type of reaction may dominate, depending upon the combustion gas temperature and local mixture conditions.

COMPETING REACTIONS OF AMMONIA

Reduction:

$$4\ NH_3 + 4\ NO + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

Oxidation (Flue Gas too Hot):

$$4\ NH_3 + 5\ O_2 \rightarrow 4\ NO + 6\ H_2O$$

No Reaction (Cool Flue Gas, Ammonia Slip):

$$NH_3 \rightarrow NH_3$$

Slide 25-20

Ammonia will be used to illustrate the three types of reactions because it undergoes a fairly simple set of chemical reactions. The first reaction in Slide 25-20 is the reduction reaction, in which the ammonia causes the NO to be reduced back to molecular nitrogen. This reduction process generally occurs if the gases are in the right temperature range.

However, if the gas temperatures are too high (e.g. above 2,000°F), the ammonia will undergo an oxidation process, forming additional NO. If the gas is too cool, the ammonia will simply flow out with the combustion gases, or "slip" through (or break through) without being reacted or influencing nitrogen oxide.[4] If excessive ammonia is injected, some of it may react with HCl or sulfur compounds, forming ammonium chloride or ammonium sulfate. These two products cause the formation of a white or blue smoke, respectively.

Urea offers an attractive alternative to the use of ammonia for the reduction of NO_x emissions. The urea compound dissociates to produce ammonia (NH_3). When injected into the boiler in an aqueous solution the urea remains in solution essentially until the liquid drop is totally evaporated. Therefore, the solution strength (urea/water ratio) and degree of atomization (drop size distribution) can be controlled to time the release of the NH_3 molecule in the boiler. Upon being injected into the furnace, urea decomposes to ammonia and iso-cyanuric acid (HNCO). The ammonia fraction performs in much the same way as in the thermal $DeNO_x$ process. The iso-cyanuric acid can also react with NO to cause its reduction. A potential product of reactions with the iso-cyanuric acid is nitrous oxide (N_2O). However, reagent additives are being developed to limit the formation of N_2O by iso-cyanuric acid.

CHEMICAL DECOMPOSITION OF UREA, $CO(NH_2)_2$

$CO(NH_2)_2$ ---> NH_3 + HNCO (Iso-cyanuric acid)

Slide 25-21

The urea process offers several process variables that may be modulated to optimize its performance in a practical application and provide the means to deal with potential variations in injection temperature. These include modulating the urea solution concentration and/or controlling the drop size distribution of the urea spray. If too much reagent is injected or if the mixing or temperature levels are inappropriate, some of the reagent can slip through unreacted.[4] This reagent can subsequently react into such compounds as ammonium chloride, ammonium sulfide, or ammonium bisulfide. These materials may cause plume opacity and/or corrosion problems.

Operator Duties

The SNCR system will typically consist of the following components:

- Reagent Storage Tanks
- Air Compressor
- Reagent and Air Control Loops
- Microprocessor or Programmable Controller

Generally, the operation of these components will be automatically controlled. However, potential operating problems may occur as listed below.

SNCR POTENTIAL OPERATIONAL PROBLEMS

Furnace Temperature Variations

Furnace Velocity Variations

NO Increases if T > 2,000 °F

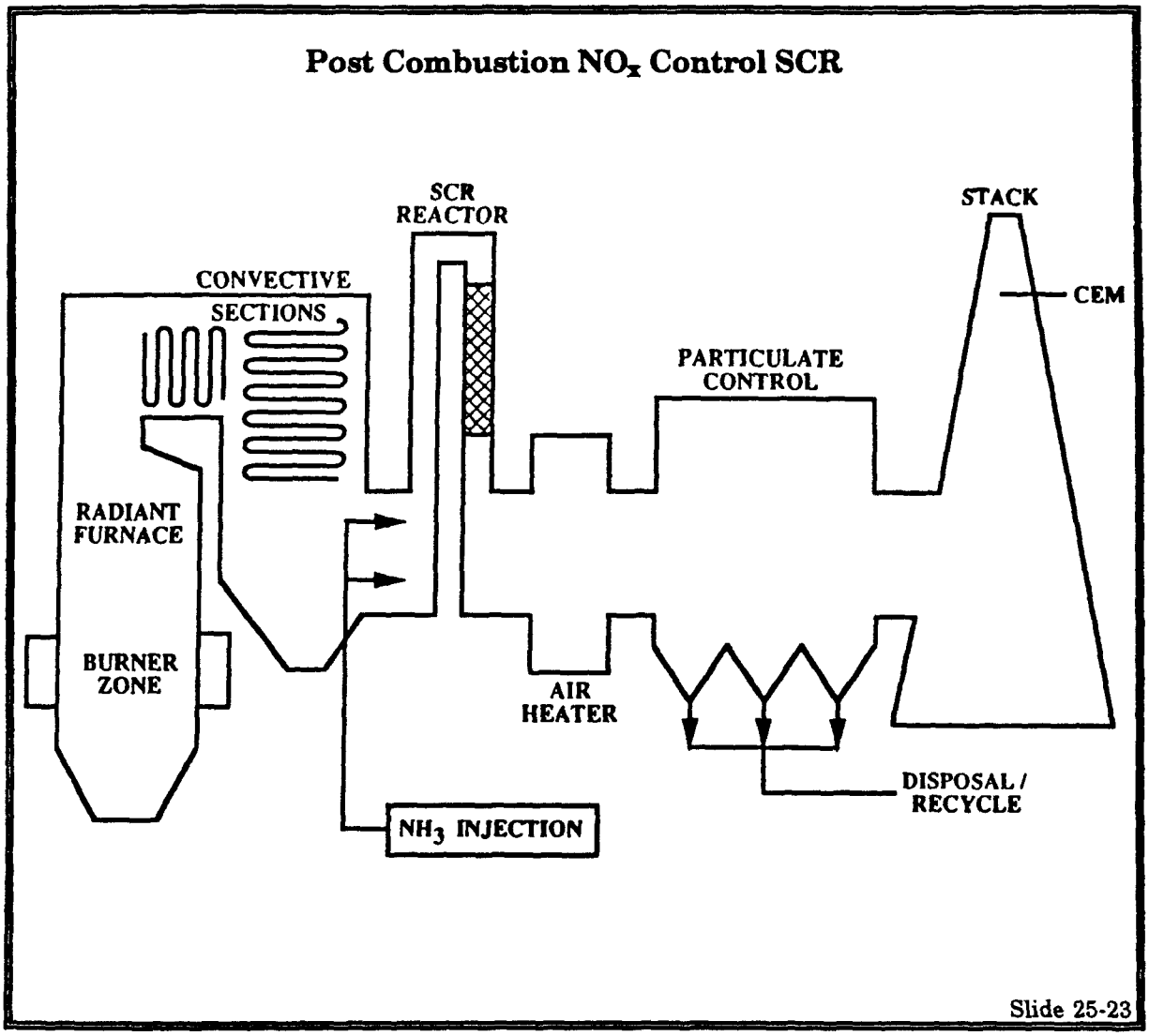
Ammonia Slip - Can React to Form Ammonium Chloride & White Smoke

Slide 25-22

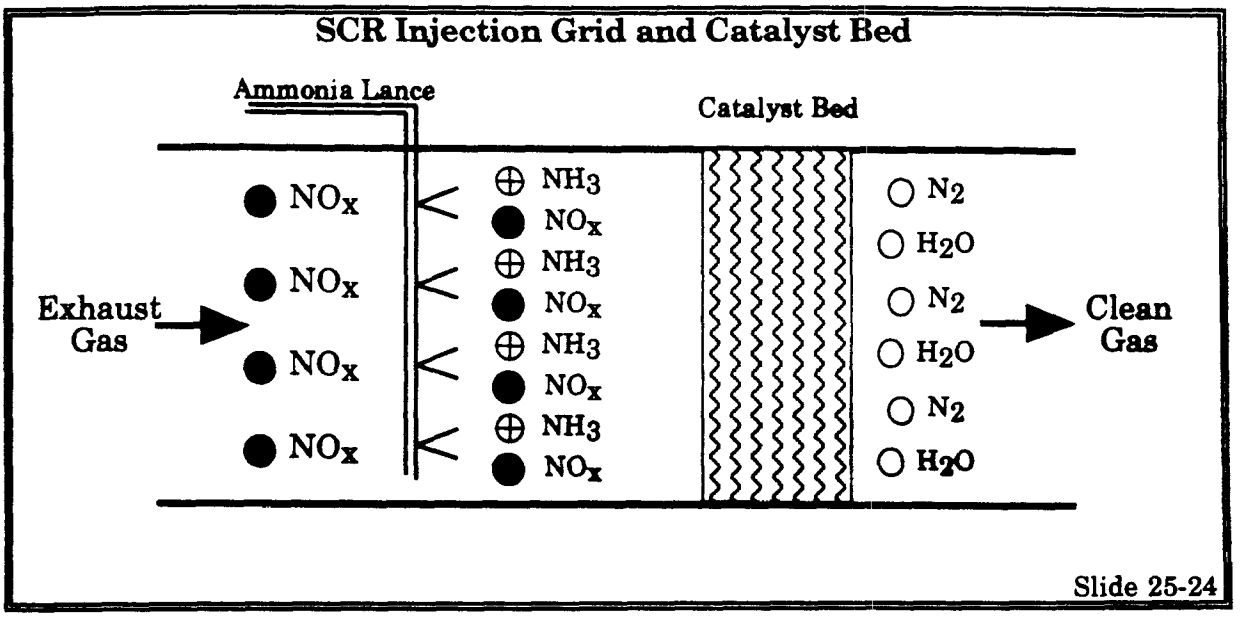
The furnace temperature and velocity will change with boiler load. The use of multiple injection ports will assist in maintaining NO_x reduction efficiency. In less sophisticated systems, the operator may be required to adjust the number of injectors in operation for a given operating condition.

Excessive injection of ammonia with respect to the NO_x in the flue gas will result in ammonia slip. Since reliable ammonia monitors are not readily available, a relationship between the boiler load and reagent injection rate needs to be maintained. Thus, monitoring the furnace temperatures and superheater temperatures are essential to proper operation.

SCR - Selective Catalytic Reduction systems reduce the NO_x in the flue gas to molecular nitrogen and water by using a ammonia injection and a catalyst material to increase the reaction rate. Depending on the application, NO_x emissions from 70% to 90% have been achieved, which is significantly higher than for SNCR systems.[5] In a SCR system, flue gas leaving the economizer at a temperature of about 750°F is first mixed with ammonia in approximately a 1:1 NO-to-ammonia molar ratio. The gas is then processed through the fixed bed catalytic reactor. The treated gas then resumes the flow through the normal boiler system; i.e., air preheater, particulate collection, etc.



The ammonia is injected through a grid system into the flue gas stream upstream of a catalyst bed as shown in Slide 25-24. On the catalyst surface, ammonia reacts with NO_x and forms molecular nitrogen and water.



Many different types of catalyst composition and configuration have been developed. Active metals used in catalyst include titanium and vanadium which are resistant to SO_x poisoning. Many other active metals are used but the exact combination and bonding techniques for most catalysts are proprietary.

Operator Duties

Two basic process controls are essential for optimum NO_x removal. One is maintaining proper reactor temperature and the other is controlling the feed of ammonia. Temperature control can be achieved by the processes previously discussed. Ammonia feed control is essentially achieved by measuring the gas throughput and the NO_x concentration.

The major problem with most catalyst systems is that the gas must be cleaned before the catalyst is used. Many metals such as copper, iron, chromium, nickel, molybdenum, vanadium and cobalt can be used as the catalyst material. If any dirty gas were to come in contact with the catalyst, its surface would become fouled by the particulate and/or condensable materials. The conversion performance would be considerably decreased by fouling of the catalysts.

Therefore, for a coal or oil fired boiler, a designer would have to provide for flue gas cleaning before the gases enter the SCR process. Assuming that a spray dry absorber and fabric filter system is used, the flue gas would be cooled to somewhere around 400°F. This temperature is below the optimum operating temperature range for the catalysts, which generally range from 530° to 800°F.[4] Therefore, the flue gas would have to be reheated, requiring either auxiliary fuel or the application of an air-to-air heat exchanger.

REFERENCES

1. H. Whalely et al., "Control of Acid Rain Precursors," Emissions from Combustion Processes: Origin, Measurement, Control, Raymond Clement and Ron Kagel, editors, Lewis Publishers, Chelsea, Michigan, 1990, pp. 315-316.

2. Philip A. Leighton, Photochemistry of Air Pollution, Academic Press, New York, 1961, pp. 1-5, 254-278.

3. "Nitrogen Oxide Control For Stationary Combustion Sources," EPA/625-5-86/020, U. S. Environmental Protection Agency, July 1986, pp. 1-3.

4. Michael Medock, "An Overview of Non-Catalytic NO_x Control," Solid Waste and Power, February 1990, pp. 46-51.

5. "Sourcebook: NOx Control Technology Data," EPA-600/2-91-029, U.S. Environmental Protection Agency, July 1991.

CHAPTER 26. SO_X CONTROL

26.1 Introduction

26.2 Wet Scrubbers

- A. Operating Fundamentals
- B. System Hardware
- C. Operation and Maintenance

26.3 Dry Scrubbers

- A. Semi-Dry Scrubbers
- B. Dry Injection

26.4 Furnace Injection

Slide 26-1

26. SO_x CONTROL

26.1 Introduction

In the United States, Title IV of the 1990 Clean Air Act Amendments specifies that annual emissions of SO_x from utilities must be reduced by 10 million tons. To achieve this, an Allowance system has been devised. Every year, each utility will be given an Allowance by EPA to emit a certain number of tons of SO_2 in that year. The utility then must decide whether to:

1. Buy additional SO_2 Allowances at the Chicago Board of Trade to cover their actual SO_2 emissions, or

2. Reduce their emissions of SO_2 and either sell or save their unused Allowances.

The choice will depend upon the cost of the SO_2 control equipment and the cost of SO_2 Allowances on the market.

There are several options available to reduce SO_2 emissions from utility and industrial boilers: reducing the sulfur content of the fuel fired, or purchasing SO_2 control equipment. The majority of the SO_2 controls in place today on utility and industrial boilers are the result of the NSPS regulations. To reduce the sulfur content of the fuel used, the boiler can switch to low sulfur coal, oil, or natural gas. Unfortunately, boilers are typically designed to fire a specific fuel, and switching can reduce boiler efficiency and shorten boiler life. Alternatively, many large boiler owners have already purchased flue gas desulfurization (FGD) equipment consisting mainly of wet and dry scrubbers, and furnace sorbent injection systems. Each of these systems are described in the following subsections.

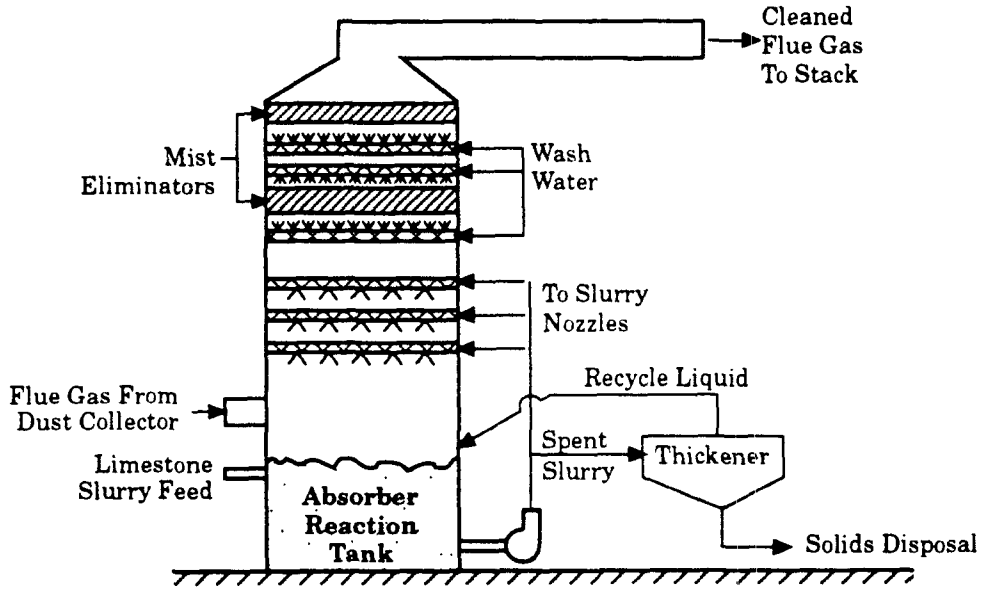
26.2 Wet Scrubbers

Of the approximately 180,000 MW of FGD systems installed worldwide, 85 percent are wet scrubbers. The advantages of wet scrubbers include high SO_x removal efficiencies coupled with efficient use of the scrubbing slurry. The following sections describe wet scrubber operating fundamentals, system hardware, and operation and maintenance requirements.

Operating Fundamentals

Wet scrubbers work by reacting the SO_2 in the flue gas with a scrubbing solution. This solution is also often referred to as scrubbing liquor or scrubbing slurry. The majority of operating scrubbers use lime or limestone as the scrubbing solution because of its wide availability and low cost. Sodium based scrubbing solutions are also used, but to a lesser extent. A popular wet limestone scrubber design is the spray tower shown schematically in Slide 26-2.

Schematic of wet scrubbing spray tower system



Slide 26–2

After the flue gas passes through the boiler's ESP or baghouse, it enters the scrubber horizontally just above the scrubber solution level. The flue gas travels up through the spray nozzles where it contacts the scrubbing slurry. The SO_2 in the flue gas is absorbed into the scrubbing solution and forms a disposable sludge. The cleaned gas passes through the mist eliminators, and travels to the stack.

The scrubber slurry side of the process starts with the fresh scrubber slurry being pumped into the scrubber. The portion of the scrubber that contains the slurry solution is often referred to as the reaction tank. Next, the scrubbing slurry is pumped from the bottom of the tank to the slurry nozzles located approximately two thirds of the way up the tower. The nozzles spray down against the flue gas flow. The scrubbing solution reacts with the flue gas and most of the particles fall back into the reaction tank, but some of the slurry (the smaller particles) can become entrained in the flue gas flow and travel up toward the mist eliminators. The mist eliminators serve to trap most of the particles entrained in the flue gas, and they are then washed down to the reaction tank by wash water spray.

Not all of the slurry pumped from the bottom of the reaction tank is sent to the slurry nozzles. A small percent is removed as waste, and is made up for by the fresh slurry feed. The spent slurry is diverted to a thickener or hydroclone which removes moisture. The dewatered slurry is disposed of, and the excess moisture is recycled back into the reaction tank and is also used as mist eliminator wash water.

The chemical reactions governing SO_2 reduction by lime or limestone scrubbing are shown in Slide 26-3. As the flue gas contacts moisture, the gaseous SO_2 dissolves to aqueous SO_2. Aqueous SO_2 in turn forms bisulfite ion (HSO_3^-). At the same time that the SO_2 is dissolving and ionizing, the limestone is also dissolving and forming calcium ion (Ca^{++}). The bisulfite ion formed from the SO_2 combines with the calcium ion, and forms calcium sulfite hemihydrate ($CaSO_3 \cdot 1/2H_2O$) and gypsum – solids that are ultimately removed from the scrubbing solution.

Wet limestone scrubber chemistry

Gaseous SO_2	Limestone ($CaCO_3$)
SO_2 (gas) —> SO_2 (aqueous)	$CaCO_3 + H^+$ —> $\mathbf{Ca^{++}} + HCO_3^-$
SO_2(aqueous) + H_2O —> $\mathbf{HSO_3^-}$	

$$\mathbf{HSO_3^-} + \mathbf{Ca^{++}} + 1/2H_2O \longrightarrow \mathbf{CaSO_3 \cdot 1/2H_2O} + H^+$$

or

$$\mathbf{HSO_3^-} + 1/2O_2 + \mathbf{Ca^{++}} + 2H_2O \longrightarrow \mathbf{Gypsum}$$

Slide 26-3

Limestone and lime based scrubbing slurries are by far the most commonly used scrubbing reagents. The main advantages of using lime or limestone include:

1. The process is simple and has few process steps.
2. Capital and operating costs are low and limestone is abundant.
3. SO_2 removal efficiency can be as high as 95 percent.

The main disadvantages of lime and limestone based scrubbing systems include:

1. Large quantities of waste must be disposed of in an acceptable manner.
2. Limestone systems have a tendency for scaling, plugging and erosion.
3. Large slurry flows are needed resulting in large pumps with high electrical consumption.

In addition to lime and limestone scrubbing slurries, dual alkali systems are also being used which use a mix of sodium carbonate ($NaCO_3$) and lime or limestone. The main advantage of the dual alkali process is that scaling (deposits of calcium solids on the scrubber surfaces) is minimized. The main disadvantage is that sodium may leak out of the system with the waste and potentially contaminate ground water. While many industrial boilers utilize some form of sodium scrubbing, the majority of the wet scrubber population are lime and limestone based systems. Therefore, the remainder of this discussion focusses on lime and limestone scrubbers.

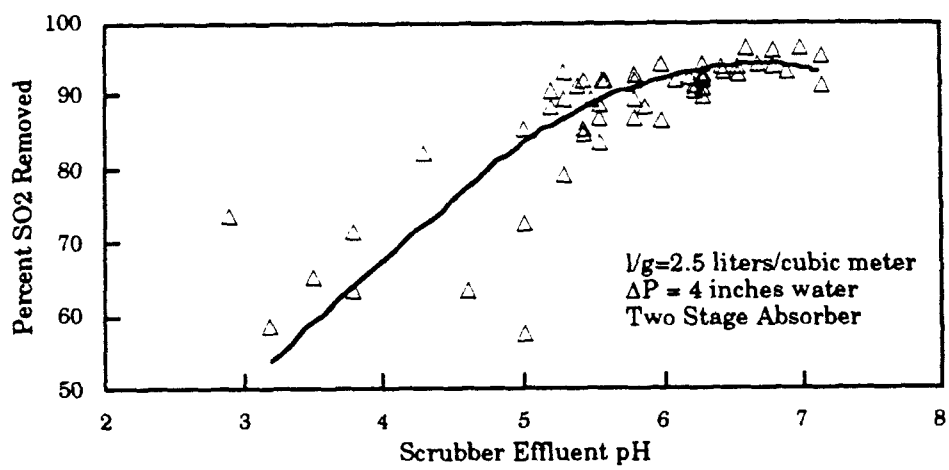
From the chemistry shown in Slide 26-3, it is clear that good removal of SO_2 depends primarily upon good contacting of the bisulfite ions (formed from SO_2 in the flue gas) with the calcium ions. To achieve this, several design and operating parameters must be considered including:

- Concentration and pH of limestone in scrubbing slurry,
- Scrubbing slurry flow rate compared to gas flow rate,
- Uniform distribution of the scrubbing slurry, and
- Uniform distribution of the flue gas.

The amount of limestone in the slurry controls the amount of calcium ion available to react with the bisulfite ion. The chemical equations show that theoretically one molecule of limestone is required to remove one SO_2 molecule. However, due to real world limitations on how well the limestone and flue gas can mix, up to 1.2 molecules of limestone are typically used for every molecule of SO_2.

One would think that to achieve very good contacting of limestone to SO_2, one should simply increase the concentration of limestone in the scrubber solution. However, if too much limestone is added, the pH of the solution will rise (the solution will become less acidic). The SO_2 removal reactions work most efficiently at pH levels below approximately 6.3. Therefore, the amount of limestone added must be high enough to allow contacting with SO_2, but not so high as to raise the pH above 6.3. Slide 26-4 shows the effect of scrubber solution pH on SO_2 removal.

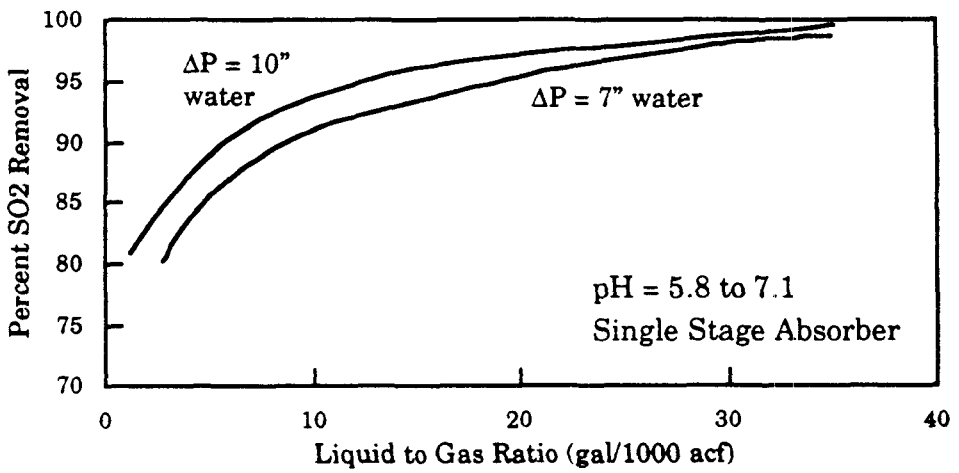
Impact of slurry pH (acidity) on SO_2 removal efficiency[1]



Slide 26–4

In addition to limestone concentration in the scrubbing solution and scrubbing solution pH, the slurry solution flow rate also determines what level of SO_2 reduction can be achieved. The slurry flow rate is related to the flue gas flow rate and is referred to as the liquid to gas ratio (l/g). In general, the higher the liquid to gas ratio, the better the SO_2 removal efficiency will be. Typical limestone scrubbers operate at liquid to gas ratios of approximately 30 gallons of slurry for every 1000 cubic feet of flue gas. Since the flue gas flow rate varies with load, so must the slurry flow rate if the design liquid to gas ratio is maintained. Slide 26-5 demonstrates how the liquid to gas ratio (at a constant pH) impacts the SO_2 removal efficiency. As may be seen, liquid to gas ratios above 30 gallons per 1000 cubic feet of flue gas does not significantly impact SO_2 reduction efficiency.

Impact of liquid to gas ratio on SO_2 removal efficiency[1]



Slide 26–5

Even if the concentration of limestone, the pH and the liquid to gas ratio are optimum, good SO_2 removal efficiencies will not be achieved unless the scrubbing slurry is sprayed evenly into the flue gas. To mix the slurry with the flue gas as rapidly and evenly as possible, it is best to have a lot of small nozzles distributed across the scrubber cross section. If one or two nozzles only are used, pockets of flue gas can escape the scrubber without being treated. Unfortunately, small nozzles have a tendency to plug, so the final design must be a compromise between many small nozzles that evenly distribute the scrubbing slurry but have a tendency to plug and a few large nozzles that do not evenly distribute the slurry but will not plug.

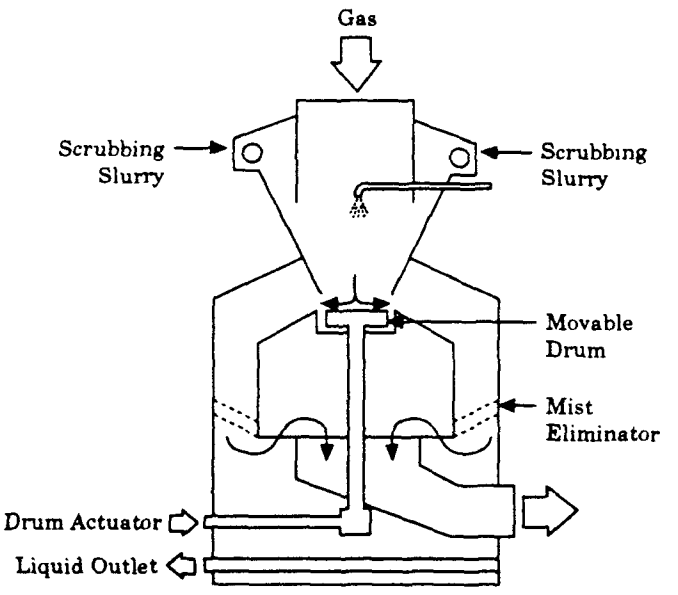
Finally, care must be taken to ensure that the flue gas flow is evenly distributed across the scrubber. For example, if most of the flue gas goes up the right

side of the scrubber, there will not be enough scrubbing solution to react with all the SO_2 on the right side, causing poor SO_2 reduction. There will be unreacted scrubbing solution on the left side. The flue gas inlet duct at the bottom of the scrubber is designed to promote even distribution of the flue gas across the scrubber cross section. In some cases, perforated plates are used to help distribute the flow, but these cause the pressure drop across the scrubber to increase resulting in a higher electricity consumption by the fan.

System Hardware

Slide 26-2 showed a spray tower type wet scrubber, but there are several other designs in use. These include the venturi, tray, and packed tower scrubbers. As seen in Slide 26-6, the most prominent feature of the venturi design is a converging throat section which causes acceleration of the flue gas flow. The scrubbing slurry is introduced at the inlet of the throat and is sheared into fine droplets by the high velocity flue gas stream. A turbulent zone downstream of the throat promotes thorough mixing of the gas and slurry droplets. As the droplets slow down through the diverging section, the droplets collide and agglomerate and are separated from the cleaned gas stream by gravity as the gas passes on to the stack.

Venturi scrubber schematic



Slide 26–6

Venturi scrubbers are usually employed to remove particulate as well as SO_2 since they can remove submicron size particulate matter. Despite the small slurry droplet size, they do not absorb as much SO_2 as other scrubber types because the amount of time available in the scrubber is short, and because the scrubbing slurry is not injected against the flue gas flow. Many venturi scrubbers have adjustable throat diameters to maintain constant flue gas velocity as the boiler load varies.

A tray tower scrubber is similar in design to the spray tower. The flue gas enters at the base and passes upward through the holes in a perforated plate mounted across the scrubber. Scrubbing slurry is sprayed onto the top of the tray from above. The slurry on the tray becomes a froth due to the gas passing through it, providing very good contact of the flue gas SO_2 with the slurry. The main disadvantage of tray tower scrubbers is that they can not handle load variations (flue gas flow variations). At low boiler loads, the slurry will drop through the sieve (weeping) while at too high of a load, the slurry mixture is blown out of the scrubber. Additionally, the tray holes are prone to plugging, and the scrubber must be shutdown and cleaned periodically.

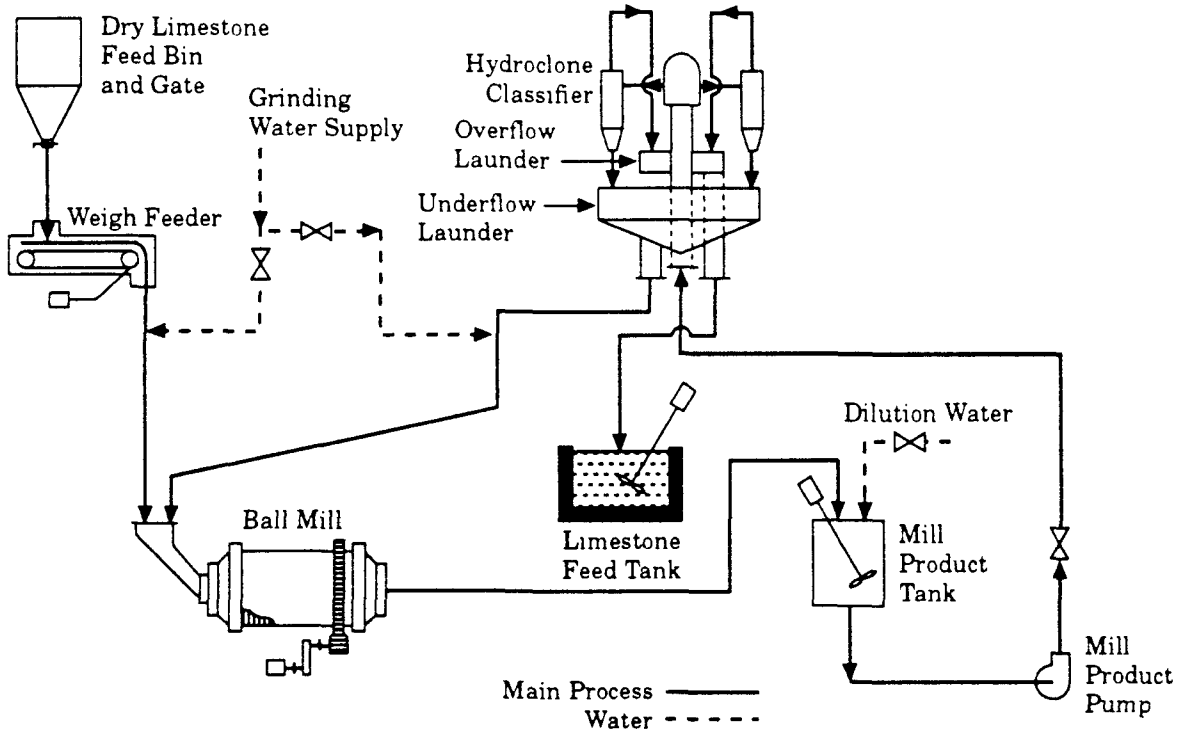
Packed tower scrubbers incorporate a bed of packing material (normally small glass balls) mounted across the scrubber vessel. The flue gas enters at the base of the tower and flows up through the packing against the slurry flow which is introduced at the top of the scrubber. The packing slows the flue gas down and provides increased surface area for the gas to contact the slurry, resulting in high SO_2 removal efficiencies.

Reagent Preparation and Injection Equipment

Typically, wet limestone and lime scrubbers employ on–site wet grinding (slaking for lime) for slurry preparation. Slide 26-7 shows a typical limestone reagent preparation system. The raw limestone with a diameter of approximately 1 inch is fed through a weigh belt feeder to a ball mill. Water is added at the feed chute of the mill. From the mill, the limestone is sent to a classifier which separates the coarse limestone from the fine limestone. The classifier sends the fine limestone to the limestone feed tank to be made into scrubber slurry. The coarse limestone is sent back to the mill for more grinding. Grinds ranging from coarse (70 percent of the limestone passing through a 200 mesh sieve) to fine (95 percent passes through a 325 mesh sieve). The finer the grind, the better the SO_2 reduction will be, but the energy consumption for fine grinding is high.

The spray nozzles used to control the slurry mixing with the flue gas typically operate between 5 and 20 psi and have corkscrew tips. The nozzles produce many droplets of approximately 2500 to 4000 microns in diameter. The SO_2 reduction chemistry occurs on the droplet surfaces, so the smaller the droplets, the more surface area is available for reaction, improving SO_2 removal efficiency. However, to decrease the droplet size, nozzles with smaller openings are required. The pressure required to push the slurry through smaller nozzles is high, and smaller nozzles tend to plug.

Limestone reagent preparation system

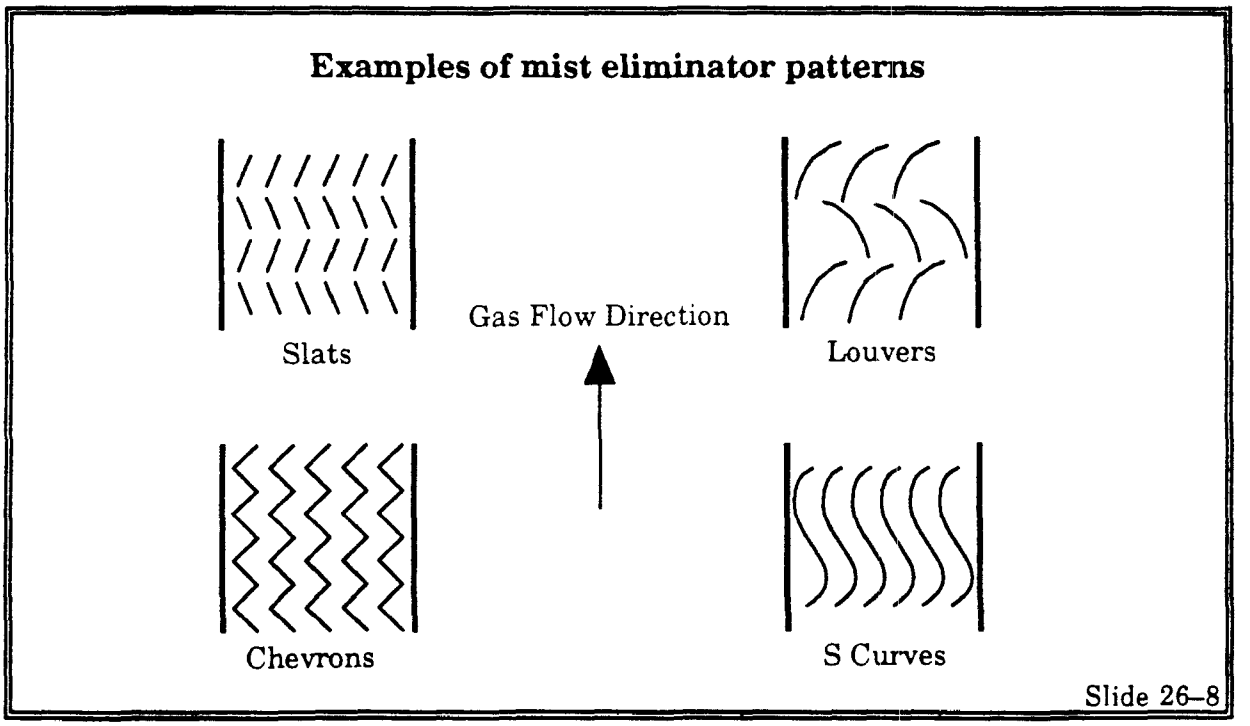


Slide 26–7

Mist Eliminators

Mist eliminators are used on wet scrubbers to collect slurry droplets entrained in the scrubbed flue gas stream and return them to the scrubbing liquor at the bottom of the scrubber. Mist eliminators are located at the exit to the scrubber as shown earlier in Slide 26-2. Most of the droplets drop out of the flue gas flow due to gravity, but the small droplets can be carried out with the gas. If these droplets are not removed from the gas before it exits the scrubber it can deposit on the ductwork, the induced draft fan, and the walls of the stack. This may lead to pluggage and corrosion.

Most mist eliminators are of the impingement type – the small liquid droplets impact a collection plate, coalesce and fall by gravity back into the scrubbing liquor. Slide 26-8 shows typical mist eliminator designs. The chevron vane is the most widely used type. The mist eliminators are sprayed with wash water to remove accumulated solids. The wash water is generally a mixture of fresh water and clear water from the slurry dewatering system.



Waste Treatment and Disposal

There are several types of waste treatment and disposal methods currently in use. The earliest method of waste disposal was simply to discharge the spent wet slurry to a settling pond. However, site availability and pond management costs have limited ponding in recent years. The most popular disposal approach in practice in the U.S. today is to perform two separate stages of dewatering and then sending the filter cake to a landfill.

The first stage of dewatering (primary dewatering) can consist of using thickeners or hydroclones. After the primary dewatering, the sludge is between 20 to 30 percent solids. Secondary dewatering is accomplished with vacuum filters, or centrifuges. Vacuum drum filters make up 80 percent of the secondary dewatering equipment population. Normally before the dried sludge goes to a landfill, the sulfites must be mixed with flyash and lime. Since gypsum needs no further treatment before it can be landfilled or sold to wallboard manufacturers, some scrubbers employ forced oxidation equipment in the reaction tank to convert the calcium sulfite hemihydrate to gypsum.

Operation and Maintenance of Wet Scrubbers

No matter how well the scrubber has been designed, it will only work as well as the operation system allows it to. Effective control of the scrubber system requires effective communication between the scrubber operators and the boiler operators. Operators must constantly monitor and control the system to ensure proper performance. For example, when load changes occur, the scrubber operator needs to reset the limestone feed rate and use the pH monitor as a backup. In addition to good operation and communication, a preventive maintenance program specified by the manufacturer should be implemented. Table 1 is an example checklist.

TABLE 1. WET SCRUBBER INSPECTION CHECKLIST

Equipment	Action	Frequency
Scrubber Module	Visually inspect for scale & corrosion	Annually
Agitators	Inspect for corrosion and erosion Check bearings and seals.	Annually
Mist Eliminators	Check for scale	Based on history
Wash Water Nozzles	Monitor pressure	Once per shift
Dampers, Fans, Ducts	Inspect for corrosion and erosion	Annually
Limestone Mill	Inspect visually, lubricate	Each usage
Slurry pump	Check lining, bearings and seals	Annually
Slurry pipes	Check for deposits and wear	Annually
Valves	Test functionality, leakage, packing	Annually
Thickener	Check coating for corrosion Check moving parts for wear Lubricate motor	Annually Annually Frequently
Instrumentation	Flush slurry lines Calibrate	Daily Once per shift

Slide 26–9

Visual inspection of the scrubber section and tanks should be performed on a regular basis to identify leaks, scaling, corrosion and erosion problems. Visual inspection can allow identification of small problems before damage becomes so extensive that major repair is required.

Mist eliminators tend to be subject to buildup of slurry solids and chemical scale causing the passages to restrict the flow of the flue gas. The first sign of scale buildup is typically noticed by an increase in pressure drop across the scrubber. Water washing is typically sufficient to prevent serious buildup problems.

Because the scrubber control system is based on flue gas and scrubber flow rates, the operating staff should routinely monitor and record readings from all instruments used to measure these flows. If any of the readings appear abnormal, they should be investigated. To verify liquid flow rates or evaluate pump/nozzle erosion, the operator should monitor pressure in the slurry header and the recirculation pump discharge. An increase in the pressure usually indicates plugging of nozzles. A decrease can indicate wear of the nozzles or pump impellers. Slurry flow in pipes can be checked by touching the pipe. If it is cold at the normal operating temperature, then the line is plugged.

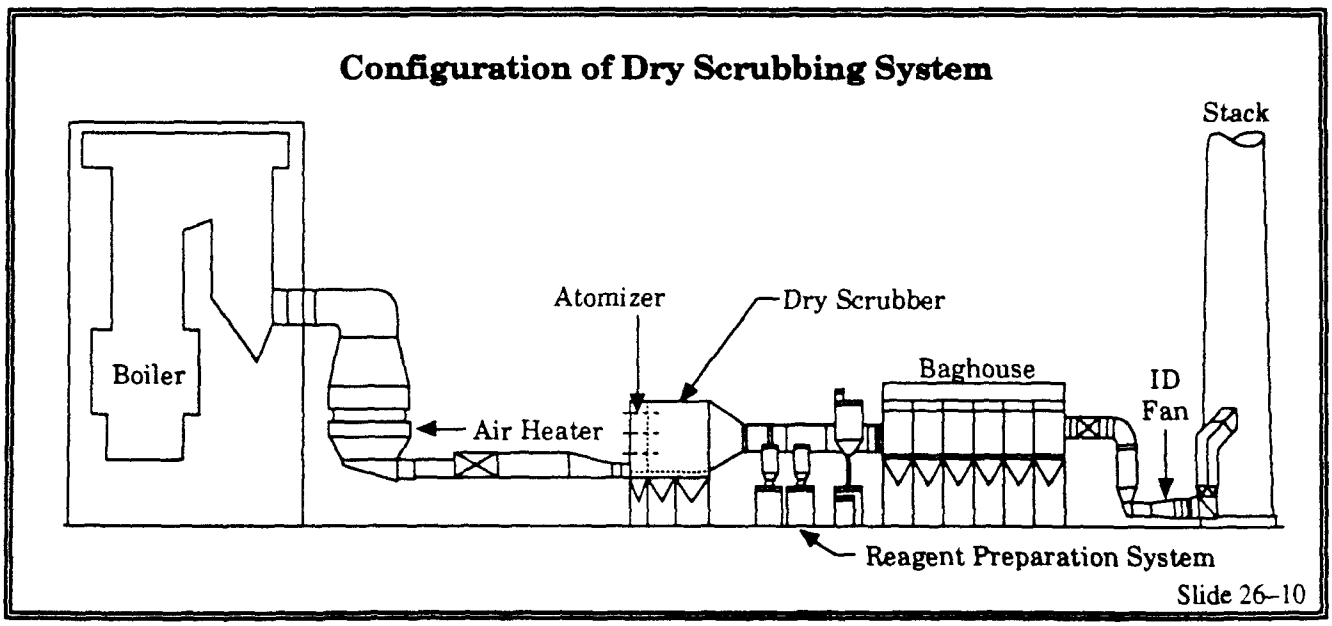
The slurry feed requirement is usually controlled by the pH indicator. The sensor lines where pH measurement elements are used should be frequently backflushed and calibrated with buffer solutions to ensure reliable operation.

26.3 Dry Scrubbers

Dry scrubbing is the second most popular form of FGD in the United States after wet scrubbing. However, since dry scrubbing is a newer technology than wet scrubbing, less than 50 systems have been installed to date. There are two types of dry scrubbers: *spray dryer* (or semi-wet scrubber) and *dry injection* (or duct injection).

Spray Dryer

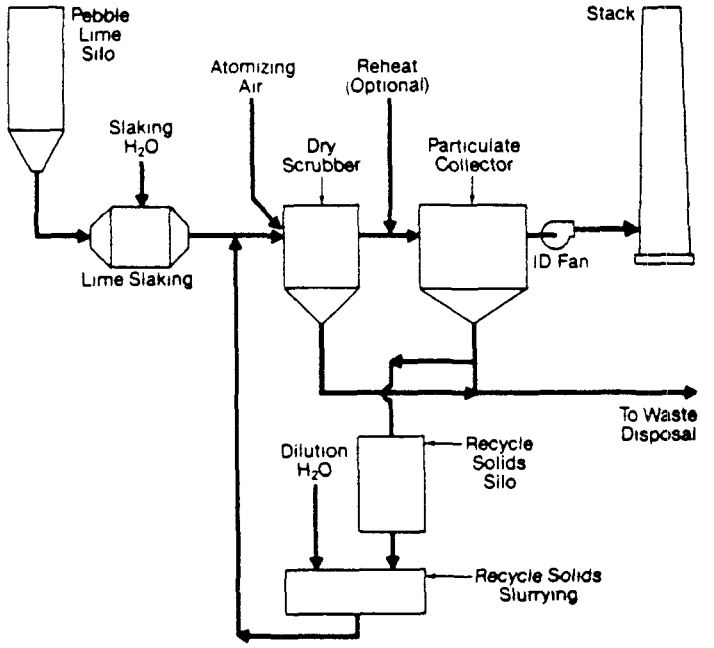
In dry scrubbing, the hot flue gas exiting the air heater enters the dry scrubber where it is sprayed with a scrubbing slurry. The SO_2 in the flue gas reacts with the scrubbing reagent and forms a solid particle. The hot flue gas dries the sulfur solids formed before exiting the scrubber and traveling through either a conventional baghouse or electrostatic precipitator. In the dust collection device, the fly ash and newly formed sulfur particles are captured and disposed of. The general arrangement of a dry scrubbing system is shown in Slide 26-10.



The main difference from wet scrubbing is that dry scrubbing systems place the dust collector after the scrubber.

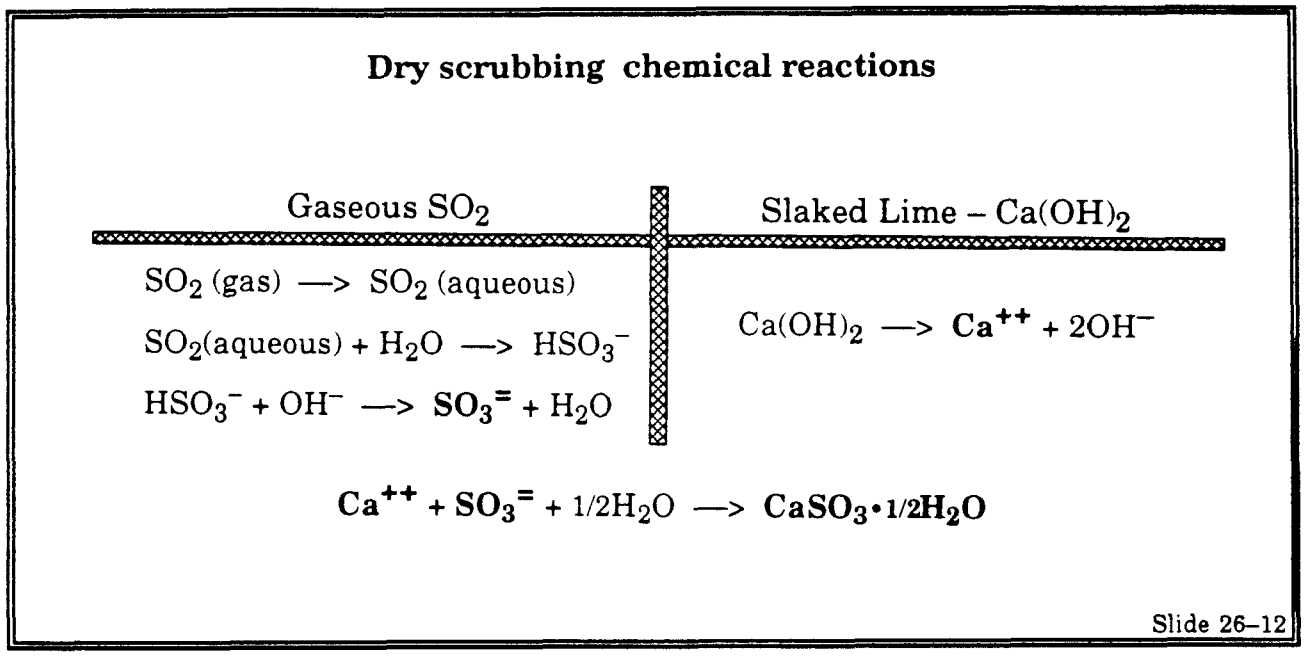
Typically, flyash from the dust collector is recycled and mixed with the fresh lime before injection into the scrubber. Atomization of the slurry is accomplished by pneumatic or rotary atomization. Air is often used to help atomize the slurry into fine droplets and to promote rapid and thorough mixing of the flue gas with the lime. A schematic of a dry FGR scrubber system is shown in Slide 26–11.

Dry FGR Scrubber System Schematic [3]



Slide 26-11

The dry scrubbing chemistry is slightly different from wet scrubbing chemistry. Almost always, slaked lime is used as the reagent. Pebble lime (CaO) is the raw ingredient. In the slaker, the pebble lime is reacted with water to form slaked lime which is calcium hydroxide ($Ca(OH)_2$). The chemical reactions governing SO_2 removal are shown in Slide 26-12. As in wet scrubbing, the gaseous SO_2 is first absorbed into water (becomes aqueous). Next, the aqueous SO_2 combines with water and forms bisulfite ion (HSO_3^-). At the same time, the calcium hydroxide dissolves to form Ca^{++} and OH^-. The bisulfite ion reacts with the OH^- to form $SO_3^=$. Finally, the calcium and sulfite ions combine to form the solid $CaSO_3 \cdot 1/2H_2O$. This solid is captured in the dust collector along with the unreacted lime and boiler fly ash. A portion of the captured ash is recycled to the slurry nozzles and the rest is landfilled.



The operating parameters that impact the SO_2 removal efficiency of dry scrubbers also differ somewhat from their wet scrubber counterparts. The two main controlling parameters are:

- Flue gas temperature at scrubber exit,
- Amount of lime injected.

The following paragraphs describe each of these parameters.

Flue Gas Temperature: It is important to realize that the flue gas exiting the dry scrubber is dry. In fact, the amount of water sprayed in with the slaked lime is set by requiring the outlet gas to be dry. Typically, the gas temperature at the

scrubber exit is set at 25°F above the saturation temperature (approximately 300°F), and then the amount of water that will cool the gas to this temperature is calculated. It has been shown that the closer the exit temperature is to the saturation temperature (the colder it is), the better the SO_2 removal efficiency will be. However, the downstream equipment needs to be protected from condensation of corrosive acid gases that can damage the induced draft fan or baghouse bags. In some applications where high levels of SO_2 removal are required, the scrubber exit temperature is very close to the saturation temperature. In these cases, the flue gas is heated after it exits the scrubber to prevent condensation in the downstream equipment.

Lime Injection: Because the water flow rate into the dry scrubber is set by the scrubber exit temperature, liquid to gas ratio is not a parameter that can be varied to improve SO_2 removal efficiency as it is with wet scrubbers. However, the concentration of lime in the solution can be varied. In wet scrubbing, less than 1.2 molecules of calcium can be injected for every molecule of SO_2 in the flue gas because the solution pH must remain below 6.3. In dry scrubbers, the pH does not limit the amount of calcium that can be injected, and the calcium to sorbent ratio can go as high as 4.

Slide 26-13 illustrates the effect of calcium to sulfur ratio on SO_2 removal efficiency. As can be seen, at calcium to sulfur ratios above 2, the amount of improvement in SO_2 removal falls off. Typically, dry scrubber operators try to minimize the amount of lime injected while still maintaining acceptable SO_2 removal efficiency. This is done to minimize the costs of raw materials and disposal – the more limestone injected, the more waste which must be disposed of.

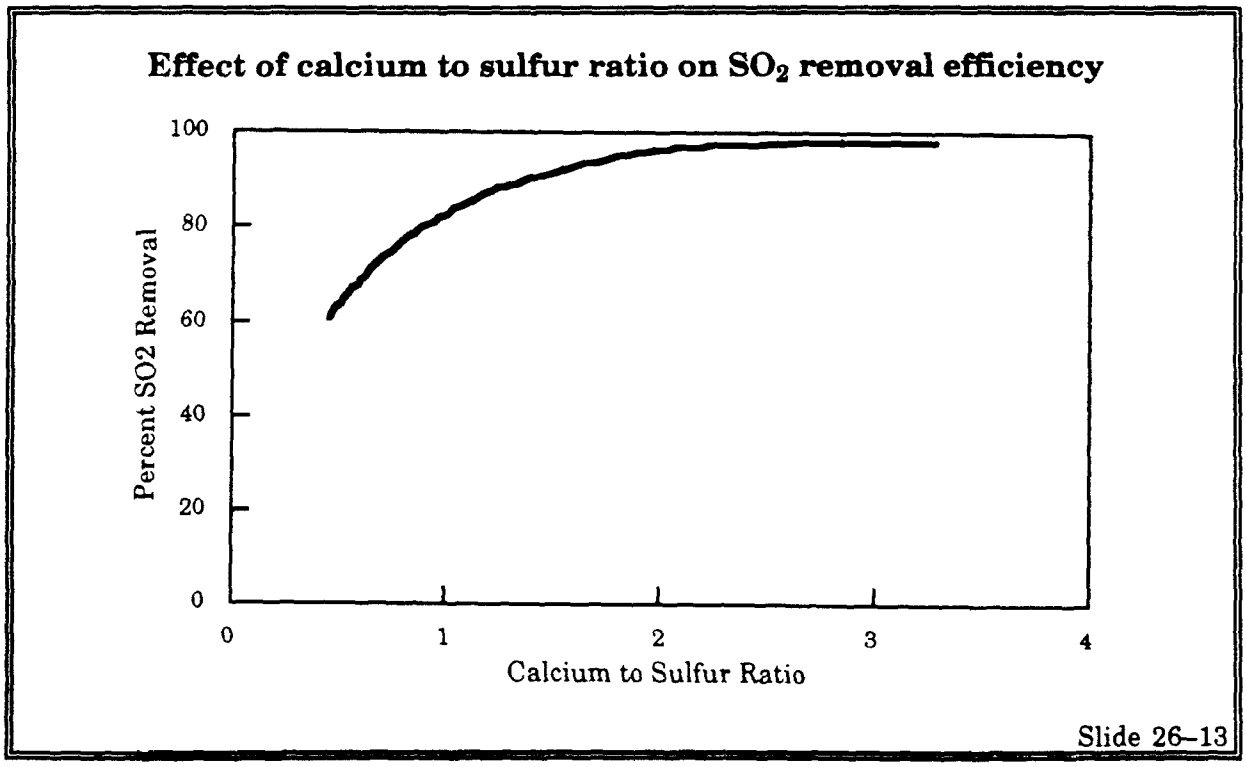
It is interesting to note that when dry scrubbing is combined with baghouses, SO_2 at the exit of the baghouse is lower than at the inlet. Apparently the unreacted lime in the layer of ash on the bags reacts with the uncaptured SO_2 and removes it. On the other hand, ESP manufacturers point out that the scrubber exit temperature is allowed to be lower for ESPs than for baghouses, thus enhancing SO_2 removal efficiency. Therefore, neither system has a clear advantage over the other.

Dry Scrubber Advantages/Disadvantages: The principle advantages of dry scrubbing over wet scrubbing include:

1. Simpler operation
2. Dry waste products
3. Less expensive

Perhaps the most important advantage is the dry waste. This eliminates the need for a costly sludge handling system. Capital costs are lower than wet scrubber costs because less equipment is needed (thickeners, centrifuges, mixers, etc). Operating costs are lower because less maintenance is required.

The principle disadvantages of dry scrubbing are that more reagent is required, and thus the amount of collected solids to dispose of is higher. In addition, if sodium is used as the reagent, it can leach into ground water supplies after it is landfilled because it is very water soluble.



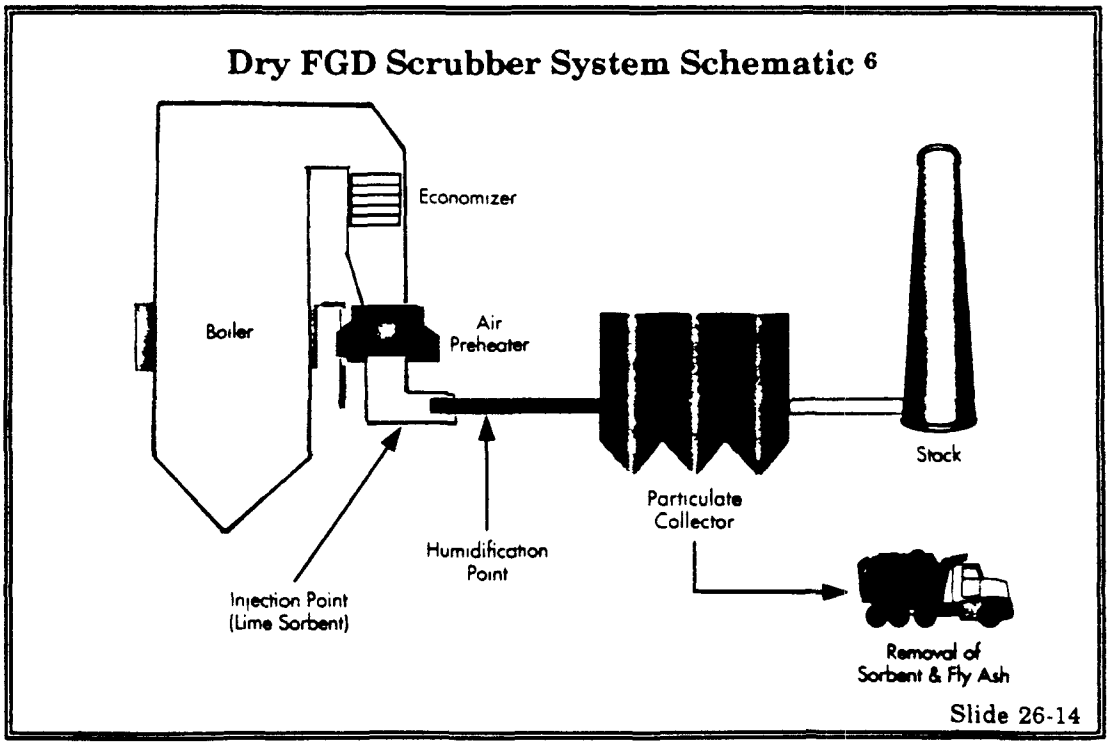
Operating and Maintenance: Operational experience with spray dryer systems indicates that only a few problems may typically be associated with these systems. Some problems encountered include:

- Acid attack of the downstream particulate collection equipment. This is due to acid condensation at some small, cornered areas in the baghouse or the ESP not exposed to the flue gas. Acid condensate usually corrodes the equipment supporting cages or fractures the bag cloth.

- Wall deposits in the spray absorber. This is caused by fluctuations in the solids contents (caused by plugging in the recycled solids preparation system) to the atomizers. During operation, wall deposits automatically fall down which causes plugging in the bottom of the spray dryer absorber.

Dry (Duct) Injection

In the dry injection process, a dry, hydrated lime sorbent is injected directly in to the flue gas downstream of the air preheater. Recycled solids, which are collected from the ESP can be injected with the fresh lime to improve sorbent utilization.Water is injected separately from the sorbent to cool and humidify the gas to the optimum temperature and to wet the sorbent to enhance the sorbent–SO_2 reactions. Optimum performance occurs in the dry injection process when the water is injected in the same plane as the sorbent. The fly ash, reaction products, and unused sorbent are collected in the ESP, a portion can be recycled, and the remaining solids are taken to the plant's disposal area. A process flow diagram of the dry sorbent injection process is shown in Slide 26-14.



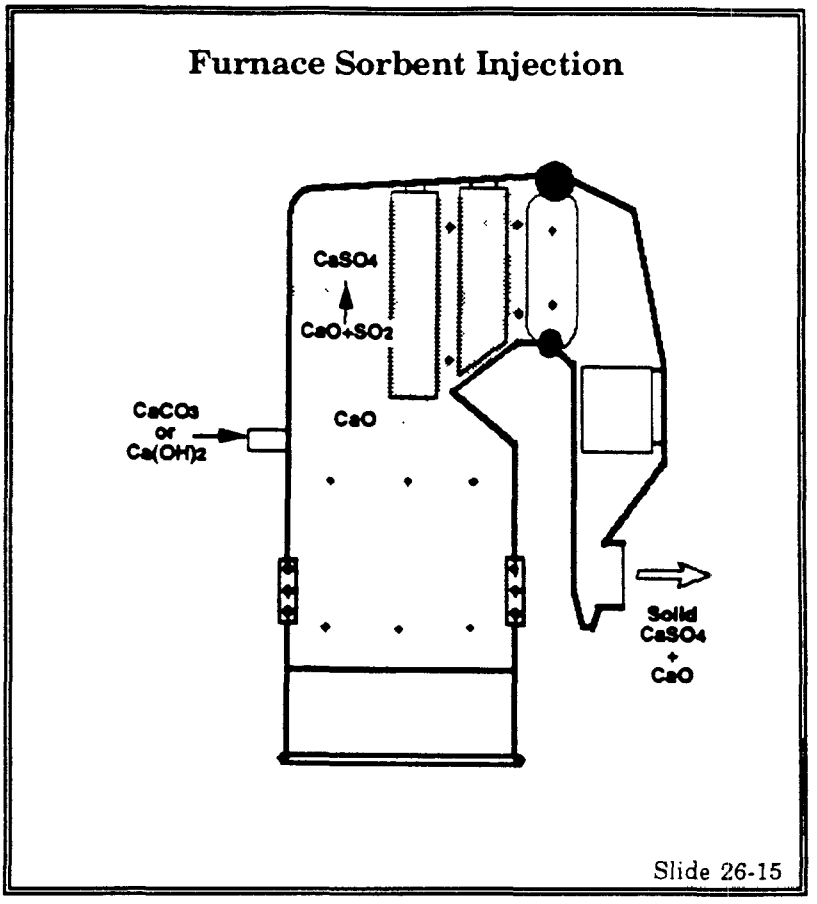
Unlike the FGD scrubber technologies, duct injection technology in relative new and full scale application is still very limited. Duct sorbent injection technology offers a low capital cost alternative to the conventional scrubber systems that are currently in use. This is offset by higher operating costs; but for may older plants that have very limited space for retrofitting SO_2 control technology and have a short remaining plant life, lower life-cycle SO_2 control cost are anticipated. Other benefits include process simplicity, minimal operation and maintenance requirements, and non-hazardous solid waste product that can be disposed of easily. In addition, duct injection technology, by using existing ductwork, requires very little additional space for installation and results in few changes to the existing flue gas system. The time required to install this technology should be significant shorter than that required for conventional FGD scrubbers.

Because of the limited contact time and moisture available for the sorbent–SO_2 reactions, SO_2 removal via dry injection is limited to 50 to 75%. Significant reaction rates between lime hydrate and SO_2 occur only if adequate moisture is present on the sorbent particles. Therefore, the relative humidity of the flue gas and the sorbent concentration are the most significant parameters impacting SO_2 removal.

The waste solids generated from duct sorbent injection process have been conducted extensively in laboratories for their physical, chemical and mineralogical characteristics. Leaching tests show that the concentration of relevant elements in the leachates does not exceed Resource Conservation and Recovery Act (RCRA) limits. Therefore, under U.S. Environmental Protection Agency definitions, these materials would not be classified as hazardous. Instead, these materials should be classified as solid wastes under RCRA Subtitle D, and disposal will likely regulated by the states.

26.4 Furnace Sorbent Injection

In a furnace sorbent injection process, a dry calcium based sorbent material ($CaCO_3$ or $Ca(OH)_2$) is injected into the upper region of a boiler furnace firing high to medium sulfur fuels. The optimum temperature location has been shown to be where flue gas temperatures are on the order of 2250°F. Under these conditions, the injected sorbent decomposes to form CaO, which subsequently reacts with SO_2 to form a solid, dry $CaSO_4$. The dry product, which consists of $CaSO_4$ and unreacted CaO, mixed with the fuel ash, is removed in downstream particulate collection equipment. The basic furnace sorbent process is shown conceptually in Slide 26-15.



Although the basic furnace sorbent injection process is well known, and has been demonstrated and applied in many full scale utility boilers world wide, major impediments to its commercial acceptance have been relatively low utilization of the sorbent (typically 25% for $Ca(OH)_2$) and an inability to achieve high rates of SO_2 removal (greater than 60%) without adverse impacts on boiler operation.

Like dry sorbent injection process, furnace sorbent injection is a simple process and is most suitable for older boiler units having limited space around the boilers and moderate SO_2 removal requirements.

The most impacts that furnace sorbent injection have on the boiler operation are in the area of sootblowing and particulate removal equipment. Since the sorbent material is injected upstream of the superheater and reheater platens, it tends to increase the deposit (fouling) on these surfaces, thus requiring more frequent sootblowing to keep them clean. In addition, sorbent injection increases the particulate loading and changes the fly ash characteristics in the flue gas, thus affecting the removal performance of the particulate collection equipment. In some

furnace sorbent injection applications, a humidification system was added upstream of the particulate collector (usually electrostatic precipitator) to enhance collection efficiency.

Similar to duct injection process, the waste solids produced by the furnace sorbent injection process would not be considered hazardous, and their disposal would also be regulated by the states.

REFERENCES

1. "Fossil Fuel Fired Industrial Boilers – Background Information Volume 1", EPA–450/3–82–006a, U.S. Environmental Protection Agency, March, 1982.

2. "Overview of the Regulatory Baseline, Technical Basis, and Alternative Control Levels for Sulfur Dioxide (SO_2) Emission Standards for Small Steam Generating Units", EPA–450/3–89–12, May, 1989.

3. *Steam, It's Generation and Use*, 40th Edition, Babcock and Wilcox, 1992.

4. M. Satriana, *New Developments in Flue Gas Desulfurization Technology*, Noyes Data Corporation, Park Ridge, New Jersey, 1981.

5. D.S. Henzel and B.A. Laseke, *Handbook for Flue Gas Desulfurization Scrubbing with Limestone*, Noyes Data Corporation, Park Ridge, New Jersey, 1982.

6. *Duct Injection Technology Approaches Commercialization*, PECT Review, Issue 8, Spring 1993, Pittsburgh Energy Technology Center, Office of Fossil Energy, U.S. Department of Energy.

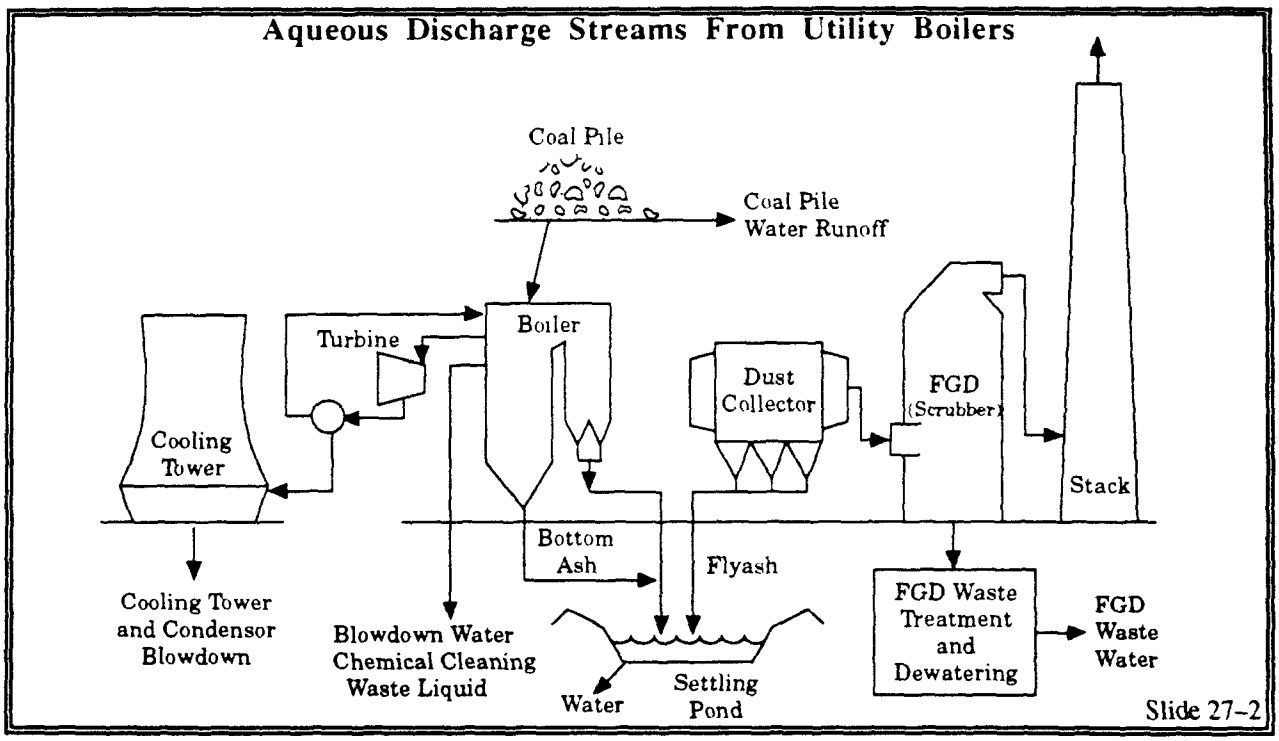
7. Felsvang, K., H. Spannbauer, and P. Gedbjerg. "*Scrubbing of Medium to High Sulfur Coal – Industrial Operation Experience with Spray Dryer Absorbers*." 1990 SO_2 Control Symposium, Vol. 2. Sponsored by U.S. EPA/EPRI, New Orleans, LA, May 8–11, 1990.

CHAPTER 27. WATER POLLUTION

Slide 27-1

27. WATER POLLUTION

An issue of increasing concern over the past decade has been pollution of rivers and lakes from industrial processes and utility boilers. Normal operation of a boiler requires aqueous discharges, such as boiler blowdown. In addition, for some air pollution control technologies aqueous and solid wastes are generated which may pose a threat to water quality if proper operation and procedures are not followed. The Federal Water Control Act of 1972, the Clean Water Act of 1977, and the 1982 Amendments to the Clean Water Act authorize the Environmental Protection Agency (EPA) to control discharges of 129 toxic chemicals into U.S. waterways by 21 different industrial categories, including boilers. The typical aqueous discharge streams from a coal-fired utility boiler are shown in Slide 27-2. Oil fired boilers are regulated on the operation and monitoring of the oil storage tanks to prevent discharge of oil from reaching water.



For regulatory purposes, the EPA has grouped the coal-fired boiler discharges into several categories as follows:

1. Low volume wastes
2. Non–chemical metal cleaning wastes
3. Flue gas desulfurization
4. Flyash transport water
5. Bottom ash transport water
6. Chemical metal cleaning wastes
7. Coal pile runoff
8. Once through cooling water
9. Cooling tower blowdown
10. Thermal discharges

Four of these types of waste discharges have not yet been regulated: non–chemical cleaning wastes, flue gas desulfurization (FGD) wastes, runoff from materials other than coal pile, and thermal wastes. However, local water district and storm water regulations do apply to any substance disposed of through these means.

TABLE 1. ALLOWABLE CONCENTRATIONS OF POLLUTANTS

Waste Streams and Pollutants	Concentration Limits (mg/liter)	
	Daily Maximum	30 Day Rolling Average
All Discharges		
pH (except once through cooling)	6 – 9	6 – 9
PCBs	0	0
Low Volume Waste*		
Total Suspended Solids	100	30
Oil and Grease	20	15
Bottom and Flyash Transport Water		
Total Suspended Solids	100	30
Oil and Grease	20	15
Chemical Metal Cleaning Waste		
Total Suspended Solids	100	30
Oil and Grease	20	15
Copper	1.0	—
Iron	1.0	—
Once Through Cooling Water		
Total Residual Chlorine	0.2	—
Cooling Tower Blowdown		
Free Available Chlorine	0.5	0.2
Zinc	1.0	1.0
Chromium	0.2	0.2
Other 126 Priority Pollutants	0	0.0
Coal Pile Runoff		
Total Suspended Solids	50	—

* Includes: water treatment, evaporator and boiler blowdown, lab and floor drains, FGD waste water.

Slide 27–3

Table 1 summarizes the allowable concentrations of pollutants in the seven different discharge categories. The emissions from each of the discharge categories are explained in more detail in the following paragraphs.

Low Volume Wastes

Low volume wastes are defined as the collective discharges from sources that are not individually regulated. These are discharges from:

1. Ion exchange water treatment
2. Evaporator and boiler blowdown
3. Laboratory and floor drains
4. Cooling tower basin cleaning wastes
5. House water system

The total amount of waste discharge in this category is very low compared to other sources. Within the category, the biggest sources of pollutants are water treatment and blowdown discharges. To demineralize and polish boiler makeup and condensate, processes such as ion exchange regeneration, fixed bed polishing, and powdered resin are used. In these processes, sodium, calcium and magnesium chlorides, ammonia, iron, copper and zinc are waste products.

The amount and composition of evaporator and boiler blowdown water depends upon many factors including boiler size, age, operating pressure and the composition of the feedwater. Iron, copper, nickel and chromium may be present in small amounts in the blowdown water since these metals can become entrained in the boiler water as it travels through the tubes. Some boilers using phosphates for cleaning may discharge very small amounts of phosphate.

Non-Chemical Metal Cleaning Wastes

One to four times a year, boiler tube deposits on the fireside are cleaned with high pressure water hoses. The deposits are contained in the wash water discharge which is approximately 6 million gallons per wash for a 500 MW coal fired boiler. Since non-chemical metal cleaning is not currently specifically regulated, it is classified under low volume wastes. Deposits from the furnace walls resemble bottom ash while deposits from the superheater region are similar to flyash.

Flue Gas Desulfurization Waste Water

As described in Chapter 26, most wet scrubbers are designed to have no aqueous discharge streams. The water that is removed in the drying step is typically recycled back to the scrubber reaction tank. However, chlorides and flyash that escape the dust collector can buildup in the slurry, and upset the delicately balanced scrubber chemistry. These contaminants are removed by blowdown. The blowdown stream contains calcium sulfate, calcium sulfite, and sodium chloride and trace amounts of metal. Since FGD waste water is not currently specifically regulated, it is commonly included in the low volume waste category. After the coal ash, the solids byproduct from the FGD scrubbing process is the second major source of solids for coal-fired boilers.

Bottom and Fly Ash Transport Water

Bottom and fly ash become sources of pollution when they are transported from their respective hoppers to a settling pond. Bottom ash is typically coarse and tends to settle rapidly and not to dissolve. Flyash, is finer than bottom ash and can dissolve into the water. Pollutants of concern are: calcium, magnesium, potassium, sodium, iron sulfates and hydrous oxides.

Chemical Metal Cleaning Wastes

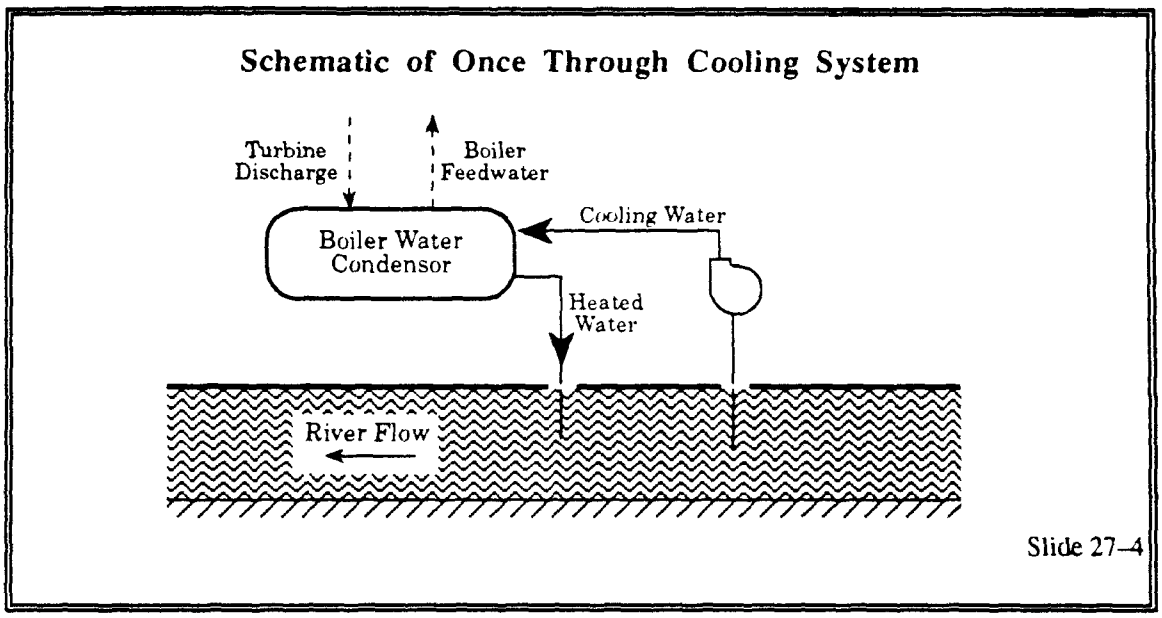
Every three to five years, the water side of the boiler tubes are cleaned with chemical solvents to remove any corroded metal. Between 80,000 and 400,000 gallons of waste water are generated during a cleaning depending upon boiler size. Iron, copper, nickel, zinc, chromium, calcium and magnesium are typically found in the waste water. The concentrations of these pollutants in the discharge stream will depend upon the cleaning system used, the materials that the boiler tubes are made of and the age and condition of the boiler.

Coal Pile Runoff

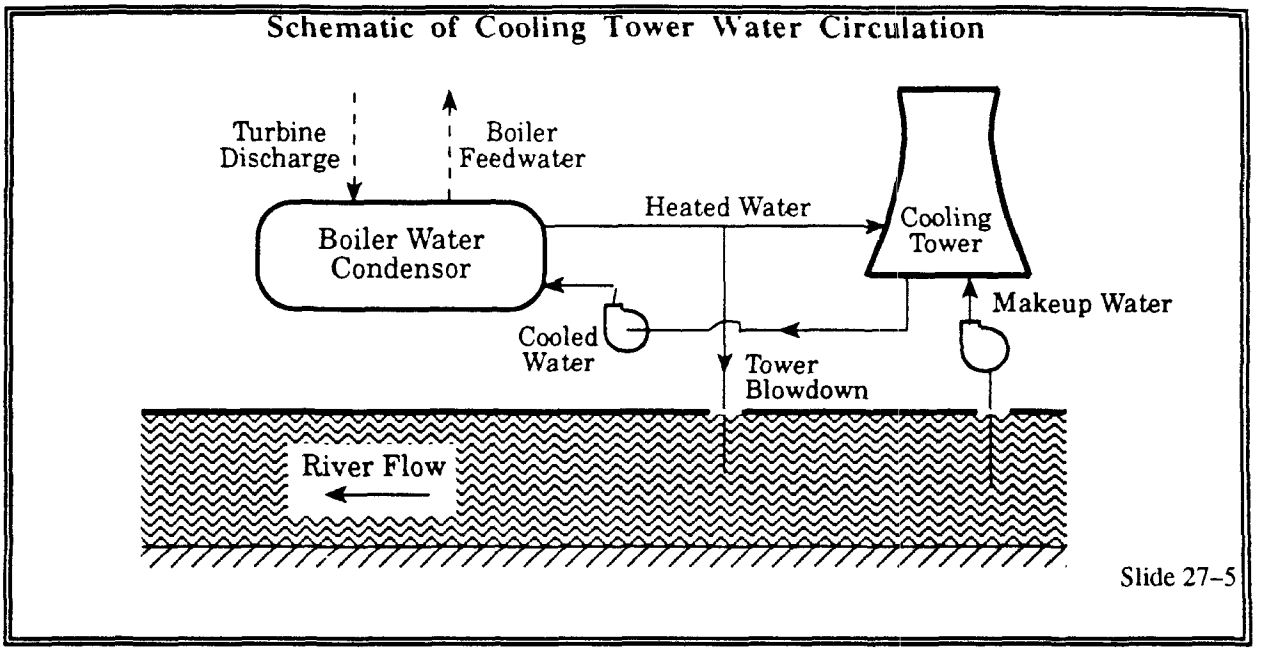
Coal pile runoff is a result of rain water which falls on the coal storage piles and travels to a drain, carrying coal particles with it. Total suspended solids are regulated.

Once Through Cooling

After the steam exits the turbine, it needs to be condensed back to water before it starts the cycle over again. Slide 27-4 illustrates a once through cooling system used to condense the boiler water. The turbine discharge enters the condenser where it is cooled and exits to the feedwater pump. The cooling water is pumped from a river or lake. It passes through the condenser, cooling the boiler water and heating up in the process. The heated water is injected back into the river.



The pollutant of primary concern with a once through cooling system is chlorine. Chlorine is typically added to the cooling water at the inlet of the boiler to prevent biological growth (fungus and algae) on the tubes of the condenser which would hamper the heat transfer. Typically, chlorine is injected into the condenser inlet for less than 2 hours each day. When the hot chlorinated water is exhausted back into the river or lake, it is very toxic to the plant and animal life in the area.



Cooling Tower Blowdown

Perhaps the single biggest contributor to aqueous pollution discharge is cooling tower blowdown. In areas where water is scarce, the condenser cooling water must be recycled. In this case, cooling towers are used rather than the once through system. A cooling tower is shown in Slide 27-5.

The primary sources of pollutants in the cooling tower blowdown include:

1. Contaminants already present in makeup water
2. Chemicals added to control corrosion and deposits
3. Tower materials.

Contaminants present in the fresh makeup water to the cooling tower may include a variety of compounds including pesticides and herbicides added to the water from upstream discharges. Small amounts of these compounds may become significant over time when they become concentrated in the blowdown.

Chlorine is typically added to inhibit biological growth in the cooling tower due to organisms in the makeup water. To inhibit tube corrosion, combinations of chromate and zinc or zinc and polyphosphates can be added to the cooling water. However, since the discharge regulations are very stringent, only cooling towers in very arid climates that must utilize zero discharge systems are able to use chromate or zinc. One alternative to using additives is to use corrosion resistant materials for the tubes.

Cooling towers are often built of wood that is treated with acid copper chromate, chromated copper, arsenate creosote, or pentachlorophenol to prevent fungus attack. These wood preservatives may leach into the cooling water – especially when they have been recently treated.

Asbestos has been used as a packing material inside cooling towers, and asbestos fibers can be released to the water through disintegration due to severe temperature swings, overly acidic cooling water and by biological causes.

Thermal Pollution

Thermal pollution is the heating up of natural water sources such as rivers and lakes due to discharge of hot cooling water. The elevated temperatures can change the natural ecological balance of the water source. For example, certain species of fish may perish if the temperatures are too high, and vegetation can grow rapidly, choking small offshoot streams. Thermal pollution has not been regulated to date.

Fuel Oil Supply Tanks

For oil fired boilers, the oil storage tanks general operating procedures and leak detection are required to prevent contamination of water. Procedures to prevent spilling and overfilling must be followed. Depending on the local requirements, a secondary barrier is often required to contain any release from the tank. Accurate oil inventory records must be kept to determine the fuel oil consumption by the boiler and to alert the operator to any loss of oil through a leak in the tank or piping. In addition, manual or automatic tank gauging, vapor monitoring in the surrounding soil, and ground-water monitoring may be incorporated into the release monitoring system. In addition, the facility must have a plan in place to deal with releases. This plan should include corrective actions to be taken and specific reporting and investigation procedures.

REFERENCES

1. "Steam, Its Generation and Use", 40th Edition, Edited by S.C. Stultz and J.B. Kitto. The Babcock and Wilcox Company, Barberton, Ohio, 1992.

2. T.C. Elliot, "Standard Handbook of Power Plant Engineering", McGraw Hill Publishing Company, 1989.

CHAPTER 28. WASTEWATER TREATMENT

28.1 Removal of Suspended Solids

28.2 Neutralization

28.3 Dechlorination

Slide 28-1

28. WASTEWATER TREATMENT

In Chapter 27, the sources of waste water from utility boilers were identified. The current federal regulations governing aqueous discharges were also discussed, and it was noted that the pollutants of primary concern are total suspended solids, toxic metals, and chlorine. In addition, the pH of the discharge is controlled. The methods commonly employed to ensure that discharges are within the bounds of the applicable regulations are discussed in the following sections.

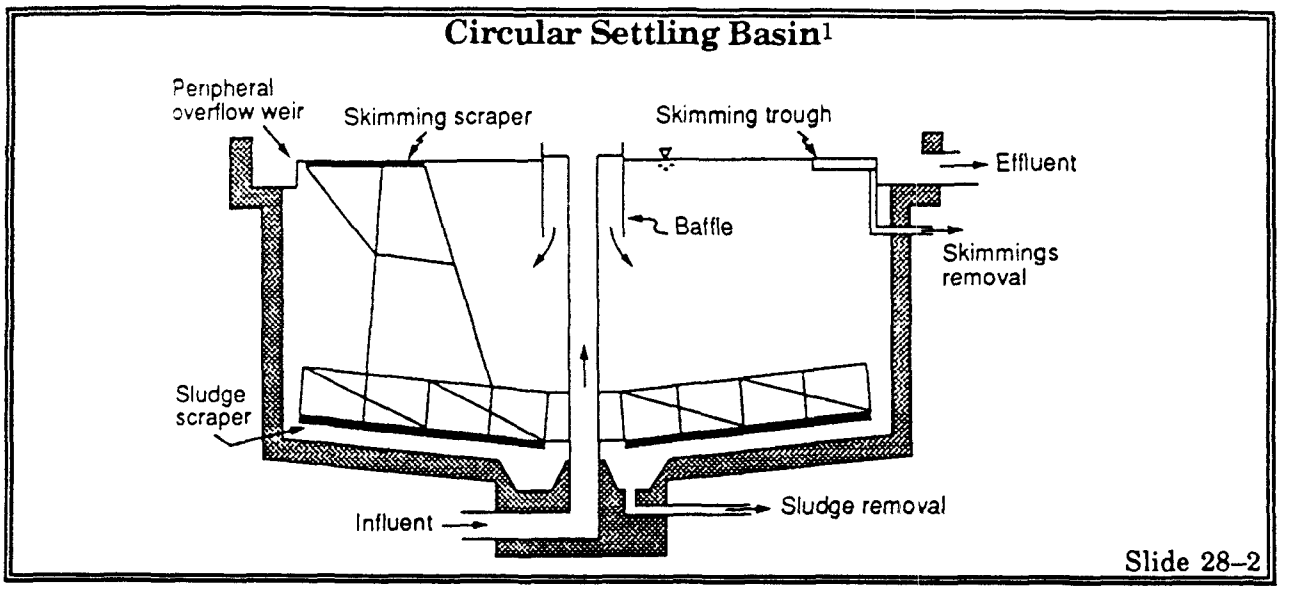
28.1 Removal of Suspended Solids

Suspended solids are typically removed through two process: clarification and filtration. Clarification is the removal of sediments through sedimentation. Large suspended particles settle out of the water stream leaving the remaining water clear. Filtration is commonly used after clarification to remove fine suspended solids. The combination of clarification and filtration can result in part per billion levels of suspended solids. Each of theses solid removal systems are described in more detail in the following paragraphs.

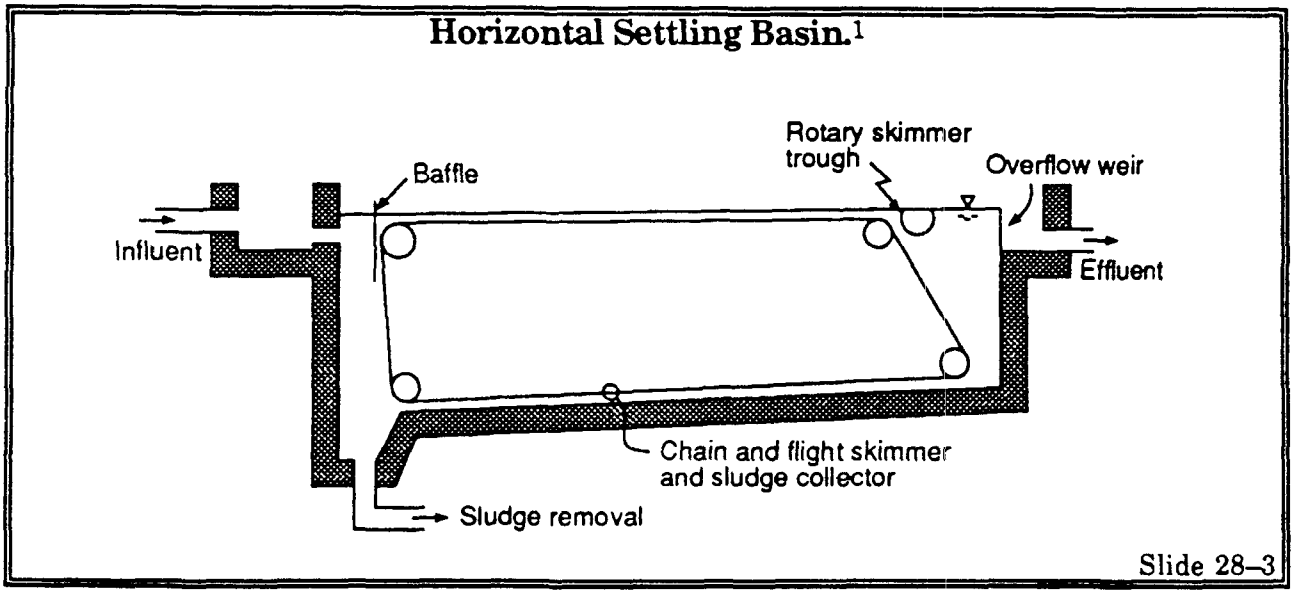
Clarification

Settling basins or ponds are used to remove suspended solids in the clarification process. Sedimentation is generally classified into either plain or chemical sedimentation. When gravity is relied upon to separate the heavy particles from the water, the process is termed plain sedimentation. When chemicals (coagulants) are added to force the particles to join and form heavier/bigger particles, the process is called chemical sedimentation. The settling basins may be either of the horizontal or vertical flow design. Horizontal flow basins are more commonly used in the United States.

Slide 28-2 shows a circular settling basin. The water containing suspended solids enters at the bottom and travels up the central passageway. After a series of 180° turns, the fluid enters the main compartment and remains a sufficient amount of time to ensure that the particles drop to the bottom. The sludge that forms on the bottom is scraped and removed through an exit passage. The particle free water exits at the top of the basin.



Rectangular basins, shown in Slide 28-3, are also widely used. The fluid to be treated enters horizontally from the side at the top of the basin. A chain is typically used to move the sludge deposited on the bottom to the exit passage. The clean water exits at the top of the basin on the side opposite to the inlet duct.



The design of settling basins must provide for effective removal of suspended solids from the wastewater, and effective collection and removal of the collected solids (sludge) from the basin. To yield high particle removal efficiencies, the design must minimize "short circuiting". The term short circuiting refers to fast pathways from the inlet to the outlet, not allowing sufficient time for the solids to settle out. To minimize short circuiting, four main design principles are followed:

BASIN DESIGN PRINCIPLES

1. Inlet Design
   Minimize inlet velocities to avoid turbulence and short circuiting.

2. Settling Zone
   Provide for calm conditions.

3. Sludge Zone
   Allow sufficient depth to allow sludge thickening.

4. Exit Design
   Minimize exit velocities to prevent short circuiting.

Slide 28–4

Chemical coagulants are used to enhance the settling characteristics of suspended solids, since bigger particles will settle out more rapidly than smaller particles. Some commonly used coagulants include: Alum, ferric chloride, sulfate, ferrous chloride, ferrous sulfate, lime and sodium aluminate.

Filtration

The oldest technique for treating wastewater is filtration with screens. Typically, a combination of coarse and fine screens are used to filter wastewater. The coarse screens are used to filter out larger particles while the fine screens are later used to remove the finer particles.

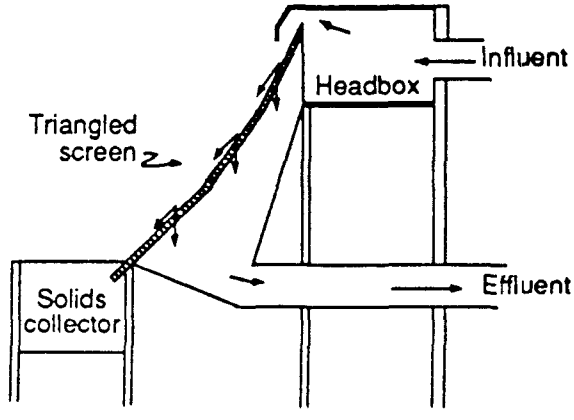
The most common type of coarse screen is the *bar screen*. Bar screens simply consist of a series of equally spaced steel bars placed across the channel. The screen is either vertical or sloped. The debris is captured by the screen and removed with rakes. The spacing of the bars can range from 1 to 6 inches and is determined by expected materials in stream.

Traveling screens are most commonly used for coarse screening. In particular, traveling screens may be used for influent screening or effluent polishing. In this process, an endless belt of stainless steel (or other noncorrosive material) is extended perpendicular to the wastewater flow. The screens are cleaned by mechanical trays which collect and remove the collected solids.

Vibrating screens can also be used to filter wastewater consisting of coarse or fine particles. Common uses for these filters are for pretreatment and by–product recovery in the food industry (and other industries). These circular, rectangular, and square shaped screens can be used in place of static and rotary wedge wire screens when there is little or no grease present in the wastewater stream.

Wedge wire screens can be used to filtrate wastewater for pretreatment or removal of coarse or fine particles. Removal of finer particles requires screens with smaller openings. Slides 28-5 and 28-6 display the static and rotary screens designs that are available for this process.

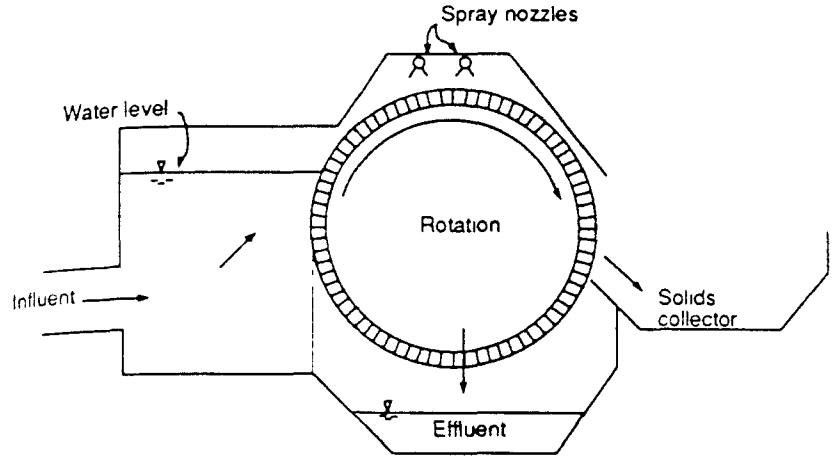
Static screen schematic[1]



Slide 28–5

Fine solids can be removed using static or rotary schematics with *fine screens*. The screen openings can be as small as 0.01 to 0.06 mm, consisting of materials such as stainless steel or fabric. Rotary microscreens are also available for removing residual suspended solids such as from a biological treatment process.

Rotary screen schematic[1]



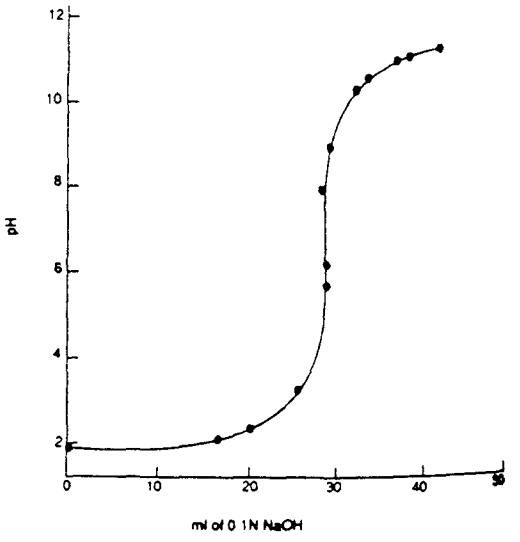
Slide 28–6

28.2 Neutralization

A very common requirement for chemical treatment is neutralizing excess acidity or alkalinity in a wastewater stream. The pH level indicates the acidity or the alkalinity. Streams consisting of a pH below 7 are considered acidic, streams above 7 are alkaline. Corrosive problems to equipment are expected to occur if the pH value is outside the range of 6 to 10. Wastewater discharges to the environment must usually range between 6 and 9.

In order to neutralize a given wastewater stream, the nature of the ions causing the acidity or alkalinity must be determined. Titration curves prepared in a laboratory can be used to determine the quality of the neutralizing material needed to adjust the pH of the non–neutralized wastewater. Slide 28-7 shows the titration curve for acidic wastewater. The shape of this curve will vary with wastewater composition. Some wastewaters will require more of the neutralizing chemical to reach a desired pH (this would be a highly buffered wastewater). Others will change dramatically with little chemical addition. When close control of pH is required (±1 pH), and the wastewater is extremely sensitive to neutralizing agent addition, longer residence times and multistage neutralization systems may be required.

Titration curve for acidic wastewater[1]



Slide 28–7

A typical system utilizes one to three stages for the neutralization process. The mixing characteristics of the reaction stages vary; some tanks are well–mixed and some are not. This process depends on the reaction characteristics of the reagents and the desired fluctuations in pH. Laboratory experiments can aid in the design of a given neutralization system.

When good mixing is required, the influent and effluent devices are commonly placed on opposite sides of the reaction tank. Sidewall baffles are often included in circular tanks to improve mixing. In all cases, the pH probe should be located at the outflow of the reactor for the most representative sample.

Selection of the neutralizing agent depends on the required cost, quantity, by–product formation and availability. Common neutralizing agents for acid wastes are caustic soda, lime, calcium or sodium carbonate, and limestone. For alkaline wastes, nitric, sulfuric, and hydrochloric acids are commonly used. Slide 28-8 summarizes some characteristics of some common neutralization agents.

NEUTRALIZATION AGENTS

Chemical Reagent	Formula	Neutralization Requirements, mg/L*	Neutralization Factor†
		Basicity	
Calcium carbonate	$CaCO_3$	1.0	1.0/0.56 = 1.786
Calcium oxide	CaO	0.560	0.56/0.56 = 1.000
Calcium hydroxide	$Ca(OH)_2$	0.740	0.74/0.56 = 1.321
Magnesium oxide	MgO	0.403	0.403/0.56 = 0.720
Magnesium hydroxide	$Mg(OH)_2$	0.583	0.583/0.56 = 1.041
Dolomitic quicklime	$[(CaO)_{0.6}(MgO)_{0.4}]$	0.497	0.497/0.56 = 0.888
Dolomitic hydrated lime	$\{[Ca(OH)_2]_{0.6}$ $[Mg(OH)_2]_{0.4}\}$	0.677	0.677/0.56 = 1.209
Sodium hydroxide	$NaOH$	0.799	0.799/0.56 = 1.427
Sodium carbonate	Na_2CO_3	1.059	1.059/0.56 = 1.891
		Acidity	
Sulfuric acid	H_2SO_4	0.98	0.98/0.56 = 1.750
Hydrochloric acid	HCl	0.72	0.72/0.56 = 1.285
Nitric acid	HNO_3	0.63	0.63/0.56 = 1.125

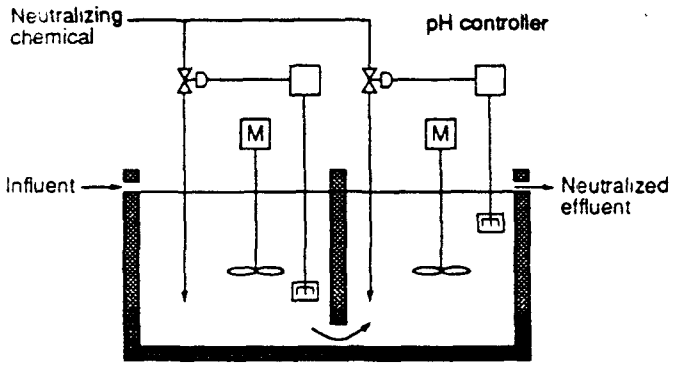
* The quantity of reagent required to neutralize 1 mg/L of acidity or alkalinity, expressed as calcium carbonate.

† Assumes 100 percent purity of all compounds.

Slide 28–8

A typical two–stage, continuous neutralization system is shown in Slide 28-9. The performance of such a system depends highly upon the condition of the primary elements (pH probe, etc.) and other instruments. Proper maintenance and system design are critical in insuring that the set–point pH is achieved. The key parameters in the system design include selecting the appropriate: neutralizing agent, reactor retention time, number of reaction stages, control concept, and hydraulic design of the system to assure proper mixing.

Two–stage, continuous neutralization system[1]



Slide 28–9

28.3 Dechlorination of Wastewater

De-chlorination systems have become more popular since the discovery that compounds formed through chlorinated water supplies and wastewater effluents may be toxic to humans and aquatic life. Dechlorination is performed using one of several reducing agents, such as sodium sulfite, sulfur dioxide, activated carbon, sunlight, prolonged storage, or aeration for certain volatile forms of chlorine.

Sulfur dioxide is useful for dechlorinating large volumes. This method currently has the most development and is the least expensive. Sulfur dioxide is fed to the wastewater as a gas, where it immediately forms sulfurous acid. This acid reacts with free and combined chlorine almost instantaneously. The product is small amounts of sulfuric and hydrochloric acid which are neutralized by the wastewater's buffering capacity.

Sulfites are used for dechlorination primarily at treatment facilities with flows less than one million gallons per day. Sulfite salts can be added as a solid or liquid. The most commonly used sulfites are sodium sulfite (Na_2SO_3), sodium bisulfite ($NaHSO_3$), and sodium metabisulfite ($Na_2S_2O_5$).

Activated carbon physically removes free chlorine, chlorinated amines, and chlorinated organics through sorption. This process is easy to operate and is very effective and reliable. It also has the added benefit of removing residual refractory organics and possibly toxic chlorinated organics. Activated carbon dechlorination beds are typically designed to handle 9.5 ft^3 / (ft^2-min) with a contact time of 15 to 20 minutes.

REFERENCE

1. R. A. Corbitt, "Standard Handbook of Environmental Engineering", McGraw Hill Publishing Company, 1990.

CHAPTER 29. SOLID WASTES

29.1 Introduction

29.2 Bottom Ash and Fly Ash

29.3 Ash Removal and Handling Techniques
- A. Bottom Ash Removal and Handling
- B. Boiler Back Pass Ash Handling
- C. Fly Ash Removal and Handling

29.4 Ash Characterization and Testing
- A. Classification of Coal Ash
- B. Elemental Analysis
- C. Fusion Temperatures
- D. Fuel Oil Ash Characteristics

29.5 Flue Gas Desulfurization Wastes

29.6 Handling of FGD Wastes
- A. Wet Scrubbing Waste Handling
- B. Dry Scrubbing Waste Handling
- C. Sorbent Injection Waste Handling

29.7 Groundwater Contamination from Ponds and Landfills

29. SOLID WASTES

29.1 Introduction

SOURCE OF SOLID WASTES

Fuel Ash

Flue Gas Desulfurization Waste

Slide 29–2

The principal sources of solid waste from boilers are from the combustion of coal and fuel oil and the use of lime/limestone for sulfur dioxide removal. During combustion of coal and fuel oil, the inert portion (ash content) of the fuels become unreacted and emitted from the boiler systems in solid forms commonly known as ash. Depending on its physical and chemical properties, ash is collected at several places along the boiler system. Significant amounts of ash are normally collected at the furnace bottom hopper and at the particulate control device.

Lime and limestone are commonly used as flue gas desulfurization (FGD) reagents to reduce sulfur dioxide emissions in the flue gas. FGD processes typically yield a calcium–based solid volume, which is either discarded or utilized.

This chapter presents a discussion about the solids wastes that are generated from the boiler system. It will provide a brief summary of the solid wastes' characteristics and their handling techniques. It also presents a short discussion on the impacts of solid waste on water contamination. Approaches to solid waste management including disposal, treatment and utilization are discussed in Chapter 30.

29.2 Bottom Ash and Fly Ash

BOTTOM ASH AND FLY ASH

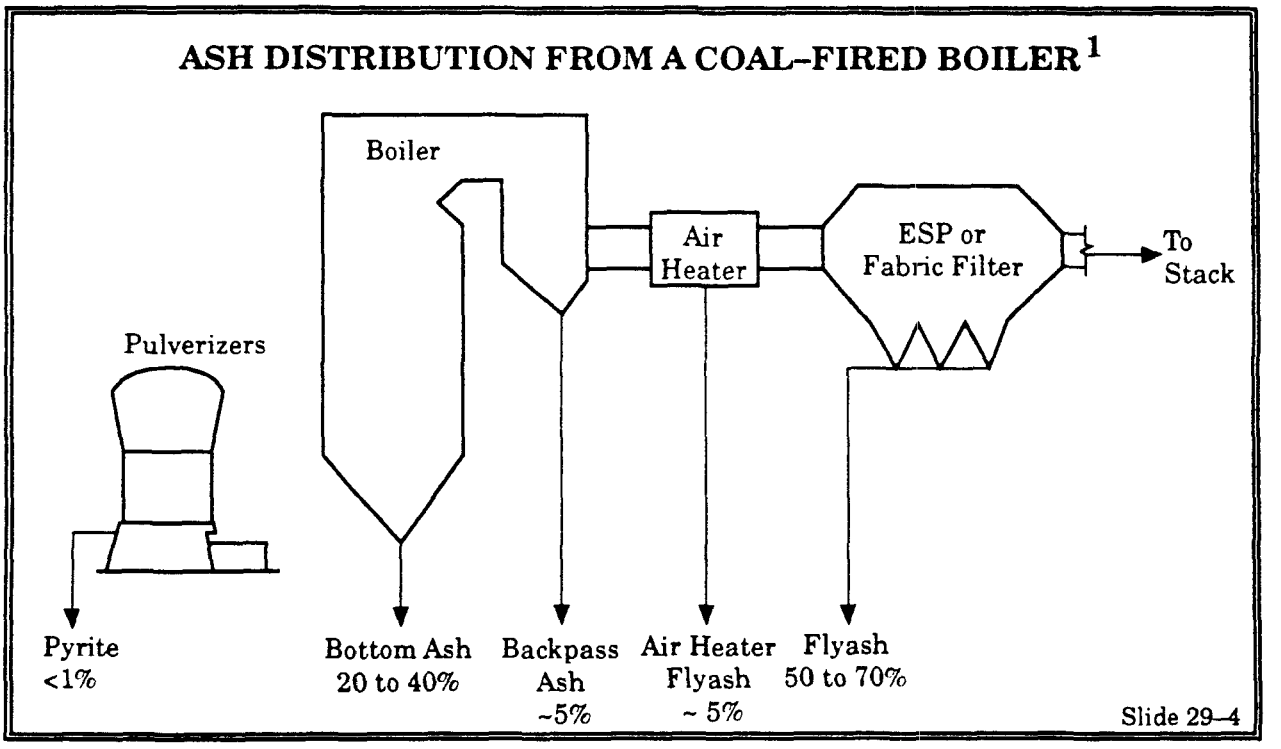
Source of Ash
Definition of Bottom Ash
Definition of Fly Ash

Slide 29–3

The use of fossil fuels in the generation of steam/power depends on the effectiveness of the steam generating equipment's ability to handle the inert residuals

of combustion commonly known as ash. Fossil fuels such as coal and oil can contain up to 40 percent ash by mass but this can very considerably from region to region. The characteristics of the ash are major concerns not only to the designer but also to operators interested in evaluating different fuel sources. Natural gas has the advantage that it contains little if any amounts of ash.

In the combustion process, the ash is released from the fuel at temperatures exceeding the melting temperature of most compounds in the ash. These high temperatures produce a soft slag type material which can adhere to heat transfer surfaces such as furnace walls or pendant superheaters (see Chapter 2). This slag either is removed from the surfaces with the use of sootblowers or eventually falls off by its own weight as a result of load changes. The ash and slag that falls from the walls pass through the bottom opening of the furnace into an ash hopper or into a submerged scraper conveyor. Ash that is collected in the hopper directly under the furnace is referred to as *bottom ash*.



The ash that is entrained with the combustion products passes through the unit's convective pass and is referred to as *fly ash*. A small portion of the fly ash is typically collected in an economizer or air heater hopper. Further downstream a majority of the fly ash is collected in dust collection equipment such as *baghouses* or *electrostatic precipitators* (ESP). Some fly ash may adhere to the heat absorbing surfaces in the convective pass and need to be removed with sootblowers. This ash is reentrained with the combustion products and collected in the economizer hopper or dust collection device. The distribution of the ash in a pulverized coal fired boiler is shown in Slide 29–4.

29.3 Ash Removal and Handling Techniques

ASH REMOVAL AND HANDLING

Bottom Ash Removal
Wet Bottom Systems
Dry Bottom Systems

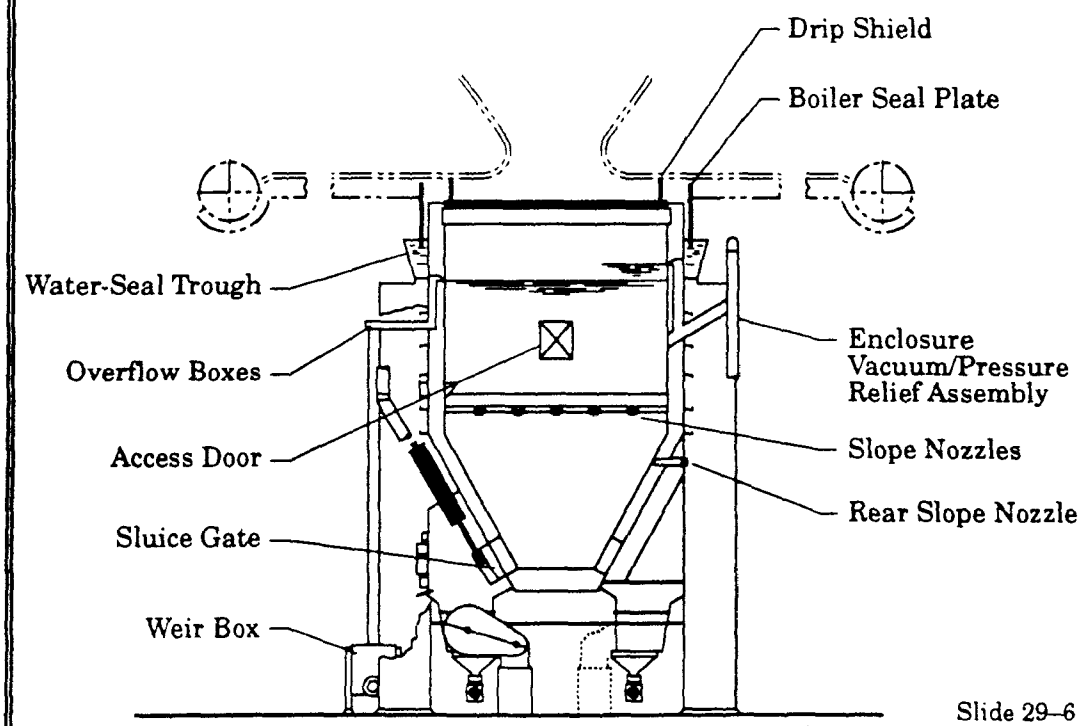
Fly Ash Removal
Vacuum Pneumatic Systems
Pressure Pneumatic Systems

Slide 29–5

In the design of coal and oil fired boilers, special consideration is given to the ash content of the fuel to determine the most efficient collection and handling procedures. Three methods of removing ash from its collection point to their respective storage or disposal areas are currently utilized at fossil fuel–fired plants: hydraulic, pneumatic, and mechanical. Hydraulic systems utilize streams of water as the carrier fluid to convey the material in a closed pipeline or open sluiceway and is known as *sluicing*. In pneumatic systems, air is used as the carrier fluid in a closed pipeline. The third method, mechanical, can very from its simplest form consisting of a shovel to the more sophisticated type being the conveyor.

Bottom Ash Removal and Handling

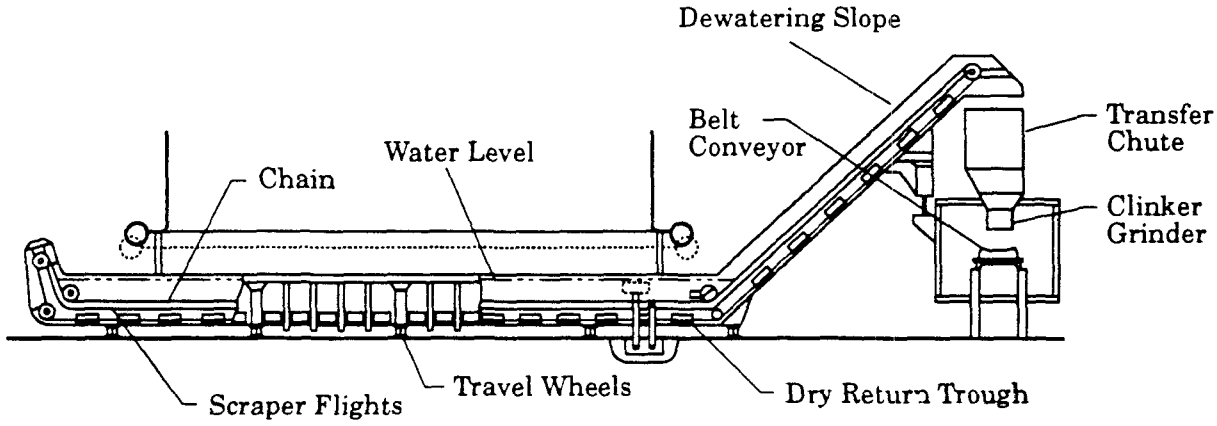
TYPICAL WET BOTTOM ASH SYSTEM [1]



Slide 29–6

The removal of bottom ash can be through a wet bottom system or through a dry bottom system. In *wet bottom systems*, the ash drops from the furnace into a water impounded hopper where the ash is received, quenched, and stored until there is sufficient ash to convey to the disposal site or settling tank. Slide 29–6 shows a schematic of a typical wet bottom system. The hopper floors are sloped so that gravity will help remove the ash from the hopper. Gravity alone will not remove all of the ash from the sides of the hopper. Some of the ash will tend to stick to the sides, therefore jet nozzles are used on the side of the hoppers to assist in dislodging the material. From the hopper discharge, the ash passes through a clinker grinder to reduce the size of the ash particles to facilitate transport to the disposal or storage site. Jet pumps or centrifugal pumps are then used to convey the ash water mixture (sluice) to the disposal site.

SUBMERGED SCRAPER CONVEYOR FOR BOTTOM ASH [1]



Slide 29–7

Submerged conveyor systems can also be used in units designed for water impoundment systems. The submerged conveyor, shown schematically in Slide 29–7, consists of a water, at 140°F, filled upper trough and a dry lower trough. Seal plates are attached to the bottom of the furnace and immersed in the water of the upper trough to maintain the gas seal. Ash is conveyed by a series of flights which pull the ash up an incline and out of the water. Ash is continually evacuated and is transported to trucks or a holding area on belt conveyors for disposal.

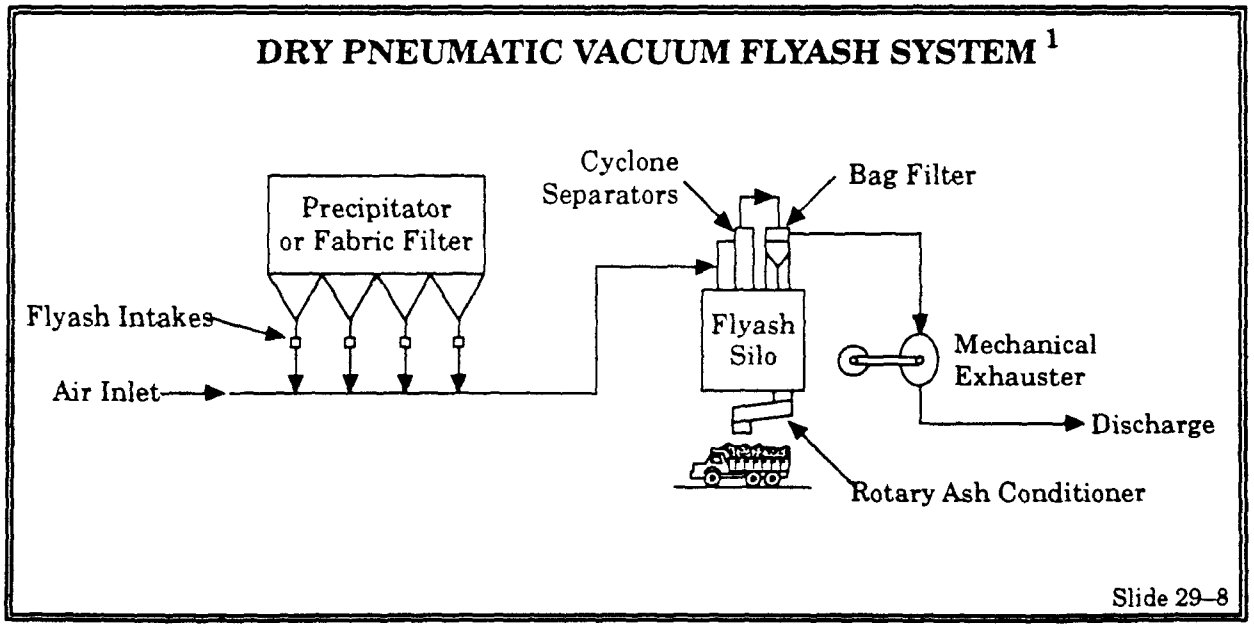
Dry bottom systems are used when there is no need for water impoundment and automation is not necessary or required. Like the hoppers used for wet bottom systems, dry bottom hoppers use flushing nozzles but unlike wet bottom hoppers use a greater slope on the walls of the hopper to insure that the dry ash flows through the discharge opening. Ash is removed from the hopper through a series of water cooled discharge gates. Clinker grinders are sometimes used to reduce the size of larger clinkers and facilitate the flow of the ash through a pneumatic or hydraulic conveying system. Sizing grids for manual handling of the bottom ash may be placed at the discharge gate outlet.

Boiler Back Pass Ash

Ash that is collected below the economizer section of the boiler where the combustion gases usually make a 90–degree turn is referred to as *economizer hopper ash*. Economizer hopper ash is usually at a temperature of about 700°F, are neither fine like fly ash or coarse like bottom ash and is sometimes transported along with the bottom ash or the fly ash. Some units will transport the economizer hopper ash separate from the bottom ash or the fly ash using a pneumatic or hydraulic conveying system. Removal of the economizer ash should be continual since it may contain unburnt carbon which may combust. Ashes that are low in calcium content may be stored in water filled tanks beneath the economizer hopper outlet. Certain ashes that are high in calcium content show cementitious properties when dropped into or mixed with water. High calcium ashes have used dry transfer tanks below the economizer hopper outlet for continuous removal.

Fly Ash Removal and Handling

Ash that is collected in air heater hoppers, precipitator hoppers, or baghouse hoppers is referred to as flyash and is removed intermittently by either vacuum or pressure type pneumatic systems. Because of the dusty nature of fly ash, these systems need to be totally enclosed and air tight. In general, pneumatic conveying systems utilize air streams as the carrier fluid through a piping system to transport the ash from the hoppers to a storage silo or holding tank.



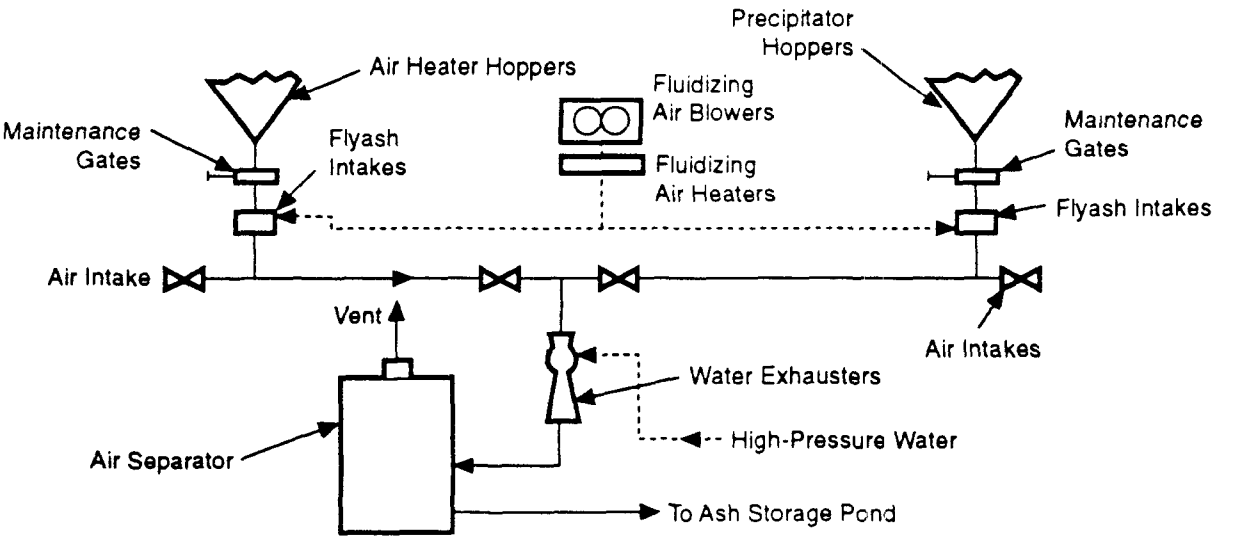
In a *vacuum type conveying system*, a negative pressure is produced in the pipeline network by locating a mechanical, water or steam exhauster at the discharge end of the fly ash silo or other storage area. A fly ash intake valve is used at the outlet of each hopper to regulate the flow of ash. Manual isolation valves are provided for maintenance purposes at the outlet of each hopper. A logic control system

insures the proper sequence of events and positioning of the valves. Since the system operates on a vacuum, only one hopper valve is actuated at a time to avoid plugging the discharge line. Each fly ash intake valve is actuated automatically by the system logic. To protect the mechanical blower from the abrasive nature of the fly ash, most of the ash must be collected. A cyclone separator and a bag filter are used in series to separate the air–ash mixture and reduce the possibility of damage to the blower. The ash is then emptied from the silos into enclosed trucks or rail cars. A dry vacuum fly ash conveying system is shown schematically in Slide 29–8.

A water exhauster is another method of transporting fly ash through the conveying line. High–pressure water supplied to the water–exhauster inlet nozzles creates the transport vacuum; fly ash, air and water are mixed in the exhaust venturi. Water exhausters normally have hardened ductile iron bodies, wear–resistant liners and stainless–steel nozzles.

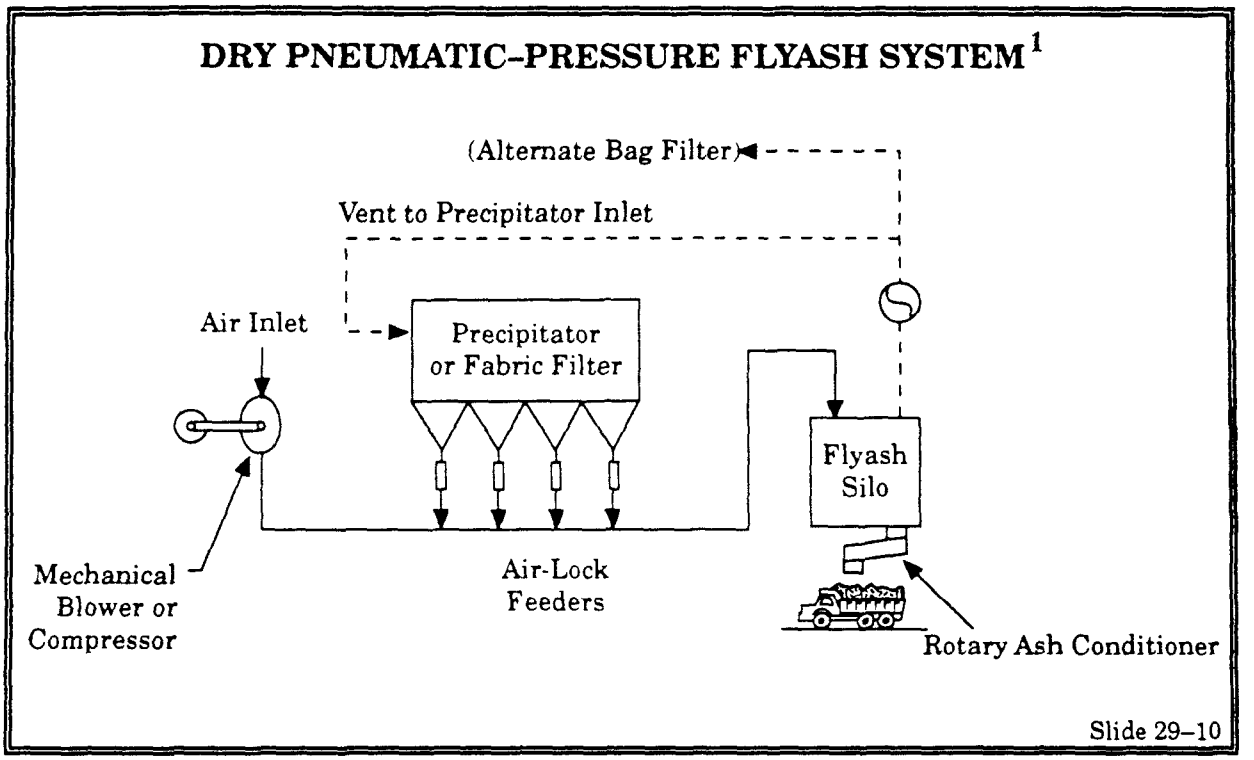
Following the water exhausters, an air separator is provided to separate and vent the air from the fly ash–water–air mixture. Separators are made of cast iron or carbon steel with an abrasion–resistant basalt or ceramic liner. The separator discharge is elevated sufficiently to allow the ash–water slurry to flow by gravity to a pond or disposal area. Fly ash slurry is never discharged to a dewatering bin because it is very difficult to settle out the fine fly ash particles in the dewatering bin; most fine particles would pass over the overflow weir. A dry pneumatic transport fly ash system using water exhausters as vacuum producers is shown schematically in Slide 29–9.

DRY PNEUMATIC FLYASH TRANSPORT SYSTEM USING WATER EXHAUSTERS AS VACUUM PRODUCERS

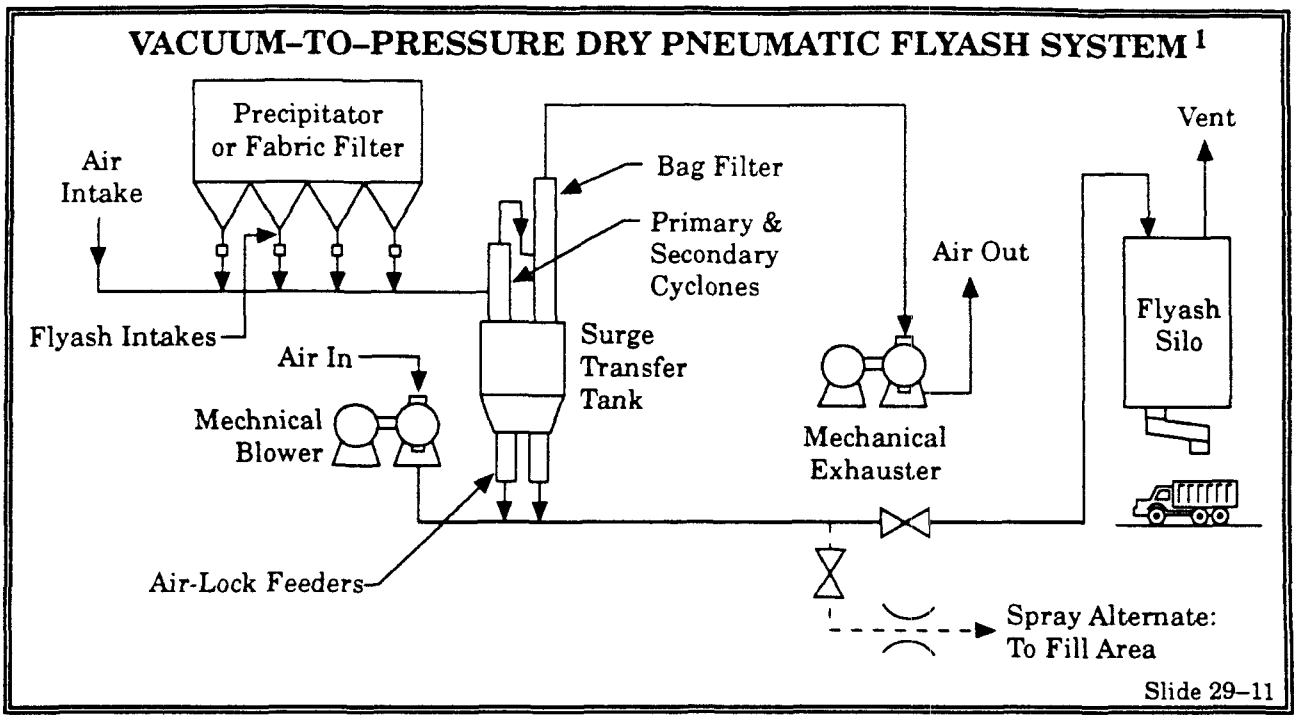


Slide 29-9

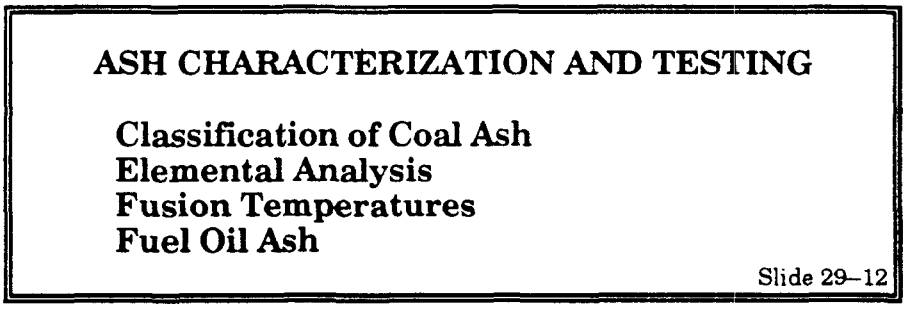
Pressure systems, shown in Slide 29–10, utilize compressors or blowers upstream of the hoppers to create the high pressure necessary to transport the ash. Air–lock feeders regulate the transfer of the fly ash from the low pressure hoppers to the high pressure transport line. Fluidizing air is provided at the inlet and outlet of each feeder to ensure ash flow through the feeder. Uniform loading of ash is accomplished by automatically controlling the air–lock feeders. The air–lock feeders are volumetric feeders which are controlled to empty selected groups of hoppers thus providing a uniform flow to the conveyor system.



When the number of fly ash collection hoppers is relatively high, a combination of the two systems described above is utilized. In a *vacuum/pressure system* the fly ash moves by vacuum from the hoppers to a nearby transfer silo as shown in Slide 29–11. From the transfer silo the fly ash transported to the main ash silos for disposal.



29.4 Ash Characterization and Testing



Classification of Coal Ash

The nature, composition, and properties of ash should be studied in order to determine their effect on boiler performance. The behavior of ash once the fuel has been fired in the boiler can be determined from an elemental analysis of the ash which often helps designers to determine the slagging and fouling potential of a specific ash.

Classification of coal ash is often based on the elemental analysis, in particular, the presence of iron, calcium, and magnesium compounds. Lignitic ash is described when the total percentage of the calcium and magnesium compounds (CaO + MgO) is greater than the percentage of the iron compound Fe_2O_3. On the other hand, if the amount of the iron compound is greater than the calcium and magnesium compounds then the coal ash is described as being Bituminous. In general, eastern coals tend to be bituminous while western coals tend to have lignitic ash although there are exceptions.

Elemental analysis

EXAMPLE ELEMENTAL ANALYSIS OF COAL ASH

Analysis of ash, % by wt.

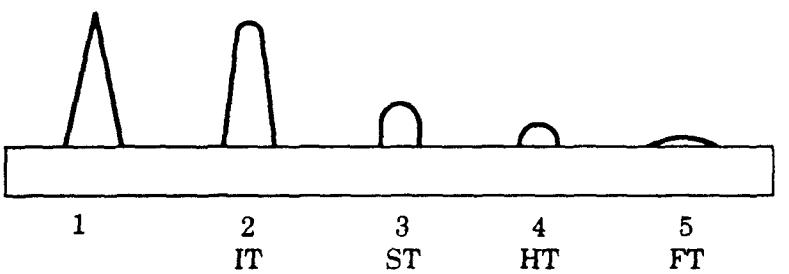
SiO_2	46.34
Al_2O_3	33.34
TiO_2	1.24
Fe_2O_3	11.62
CaO	1.76
MgO	1.75
Na_2O	0.25
K_2O	1.27
SO_3	2.08
P_2O_5	0.17
Mn_3O	0.11
Other	0.07
Total	100.00

Slide 29–13

In general, an *elemental analysis* of ash will report the constituents listed in Slide 29–13 . The ash is prepared by the ashing technique described by the American Society of Testing and Materials (ASTM) D 3174. The elemental analysis report will specify the weight percent for each constituent present as an oxide.

Fusion Temperatures

INFLUENCE OF TEMPERATURE ON SPECIFIC ASH SHAPES [1]



1. Cone before heating
2. IT Initial deformation temperature
3. ST Softening temperature (H=W)
4. HT Hemisherical temperature (H=0.5W)
5. FT Fluid temperature

Slide 29–14

The behavior of the ash at elevated temperatures can be determined by measuring the ash *fusibility temperature*. Fusibility temperatures of ash can have many uses for boiler operators. Fusion temperatures can provide an indication of the temperature range over which a certain ash will be in the molten state. High fusion temperatures will generally indicate a low slagging potential which is advantageous for a dry bottom furnace. Low fusion temperatures would indicate a higher potential for slagging since the ash will remain in a molten state over a wider temperature range.

The procedure is referred to as ASTM D 1857, *Fusibility of Coal and Coke Ash*. This test involves observing the shape of an ash sample that is pressed into a mold. The ash sample is prepared by burning coal under oxidizing conditions at temperatures of 1,470 to 1,650°F. The ash that is produced is then pressed into a triangular mold. The cone is heated in a oxidizing or reducing furnace at a controlled rate of 15°F per minute. As the cone deforms, the temperature at which the cone deforms to a specific shape as shown in Slide 29–13, is recorded.

Other measures also give an indication of the behavior of the ash. For example the iron content of bituminous ashes can have a significant influence on the slagging and fouling potential of the ash. Other measures are also considered in the slagging potential of the ash such as the Base to Acid ratio, Silica to Alumina ratio and the iron to calcium ratio.

Fuel Oil Ash Characteristics

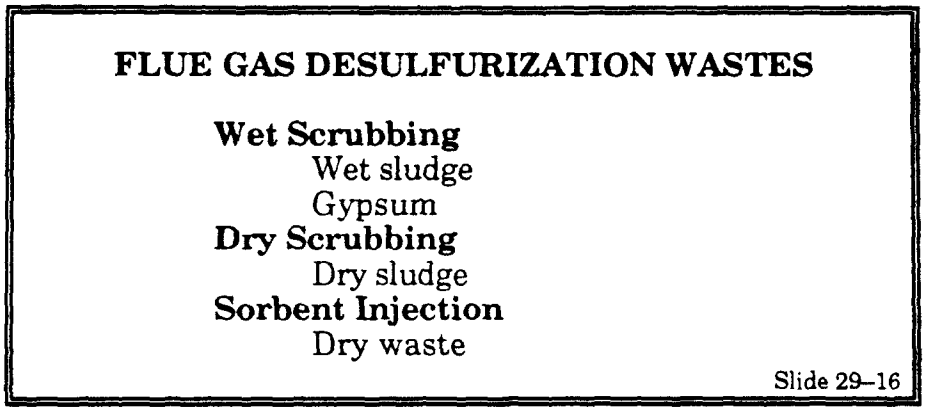
FUEL OIL ASH CHARACTERISTICS

Vanadium
Sulfur
Sodium

Slide 29–15

Even though fuel oil contains very small amounts of ash compared to coal, the characterization of the ash is very important to the designer as well as to the operator. The most important compounds that may appear in fuel oil ash are those of vanadium, sodium, and sulfur. These elements are significant because they tend to form complex compounds that have low fusion temperatures. The low fusion temperatures can lead to significant slagging and fouling.

29.5 Flue Gas Desulfurization Wastes



FGD solid waste characteristics vary depending on the particular technology employed (see Chapter 26 for discussions of FGD technologies):

Wet Scrubbing: Using *natural oxidation* produces a *wet sludge* containing a mixture of calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) reaction products, trace amount of flyash and un-reacted limestone. In a *forced oxidation*, the main difference in the waste is that the reaction product is almost totally in the form of $CaSO_4$ or *gypsum*, which is more easily dewatered to a filter cake for landfill or other use.

Dry Scrubbing: Waste is dry and contains $CaSO_3$, $CaSO_4$, flyash, and un-reacted sorbent.

Sorbent Injection: Waste is dry and contains calcium sulfate, a large proportion of calcium oxide (CaO), and fly ash.

29.6 Handling of FGD Wastes

Wet Scrubbing Waste Handling

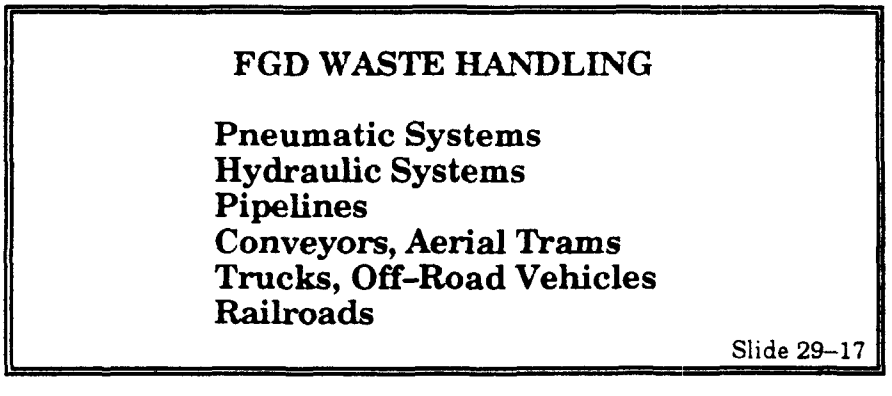
Different types of handling equipment are employed depending on whether the solid waste is disposable sludge or by–product gypsum.

Disposable Sludge: The wet sludge is typically treated first before being disposed to a landfill. The underflow slurry from a thickener is *pumped* to a slurry tank, then pumped to a rotary vacuum filter which produces a gypsum (disposable) filter cake with higher solid content. The filter cake is transported by means of a *conveyor belt* to a temporary storage area and then *trucked* directly to a landfill site. The thickener overflow and vacuum filtrate are pumped to a storage tank and returned to the process.

By–Product Gypsum: The forced–oxidation product containing high percentage of $CaSO_4$ is typically dewatered before being removed from the plant for sale. The bleed stream from a recirculation tank is pumped to a thickener. The thickener overflow is recycled to a process water storage tank, where a polymer is usually added to help control fine gypsum particle concentrations. The thickener underflow is pumped to a gypsum slurry tank, then to belt filters where the required solid content is obtained. The gypsum cake is washed with fresh water to remove any residual chlorides. The dewatered gypsum is discharged from the belt filters onto belt conveyors which transfer the gypsum to a storage area via a propelled tripper. A portal reclaimer is used in conjunction with several belt conveyors to reclaim and transfer gypsum from the storage area to a truck load–out bin prior to removal from the plant.

Dry Scrubbing Waste Handling

Positive pressure pneumatic conveying systems are typically used to transfer the solids from hoppers of the APCD to disposal silos. The solid material is wetted with water for dust control and loaded into off–highway trucks by either a shuttle loader (belt conveyor) or a front–end loader. The trucks transport the solids to a landfill disposal area.

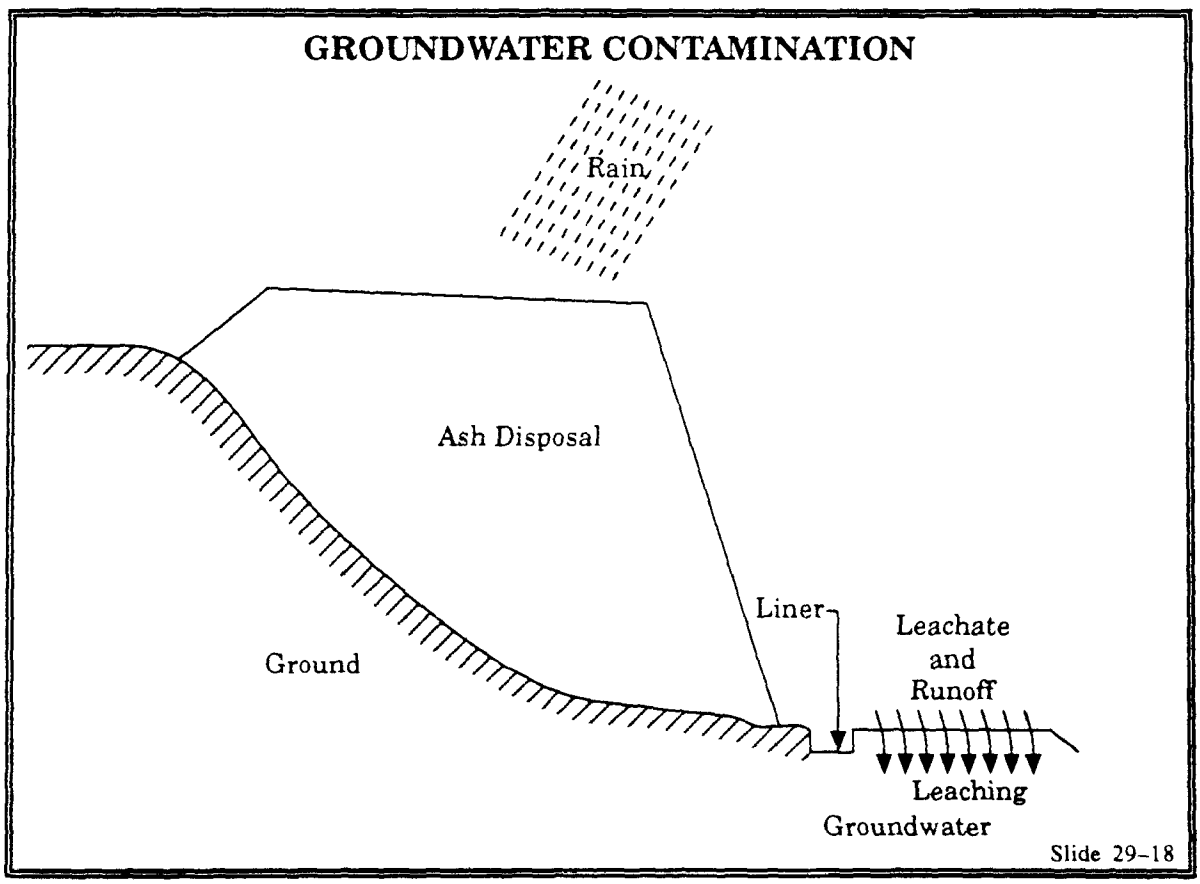


Dry Sorbent Injection Waste Handling

Similar to the techniques employed for dry scrubbing, solid waste handling in sorbent injection typically uses positive pressure *pneumatic conveying system* to transport solids from the APCD hopper to disposal silos. The solids is wetted and transported to a disposal landfill via trucks.

In some cases, however, disposal regulations require the waste solid to be treated first before being disposed due to high amounts of CaO content. A *hydraulic conveying system* is typically used for these situations. The solid waste is mixed with water and sluiced in a pipeline system, along which several locations are provided for carbon dioxide or sulfuric acid injection to adjust the pH level of the waste material.

29.7 Groundwater Contamination From Ponds or Landfills



The disposal of solid wastes can be handled through an on–site settling pond, or the material can be transported from the plant to a landfill. In either case, potential *leaching* of pollutants contained in the waste is of concern. In a landfill, pollutants are leached from the materials when rain water infiltrates the landfill and leaches the pollutants from the waste into an aqueous solution which can than seep into the groundwater. To avoid contamination of the groundwater, many landfills and ponds, use liners to contain the *leachate and surface runoff*, use collection system to remove leachate, and monitor the groundwater for pH level.

REFERENCES

1. Singer, J. G., *Combustion: Fossil Power Systems*, 3rd edition, Combustion Engineering, Inc., 1981.

2. *Steam, Its Generation and Use*, 40th Edition, Babcock and Wilcox Company, 1992.

3. Elliot, C.T., *Standard Handbook of Powerplant Engineering*, McGraw Hill Publishing Company, New York, 1989.

4. Hanzel, D.S., Laseke, B.A., Smith, E.O., Swenson, D.O., *Handbook for Flue Gas Desulfurization Scrubbing with Limestone*, Noyes Data Corporation, New Jersey, 1992.

5. *Economic Evaluation of Flue Gas Desulfurization Systems*, Electric Power Research Institute, GS–7193 Volume 1, Research Project 1610–6, Final Report, February 1991.

CHAPTER 30. SOLID WASTE MANAGEMENT

30.1 Introduction

30.2 Disposal Methods

30.3 Wet Disposal — Ponds
- A. Pond Configurations

30.4 Dry Disposal — Landfills
- A. Landfill Configurations

30.5 Treatment Methods

30.6 Dewatering
- A. Settling Ponds
- B. Dewatering Bins
- C. Thickeners
- D. Cyclones
- E. Centrifuges
- F. Vacuum Filters

30.7 Stabilization

30.8 Fixation

30.9 Utilization
- A. Ash Utilization
- B. FGD By–Product Utilization
- C. Site Utilization

30. SOLID WASTE MANAGEMENT

30.1 Introduction

SOLID WASTE MANAGEMENT

Disposal
Treatment
Utilization

Slide 30–2

This chapter addresses the management of large–volume solid wastes such as bottom ash, flyash, and scrubber by–products at coal–fired plants. The approaches to solid–waste management include *disposal, treatment or utilization* of the wastes. In some cases, the wastes can be disposed to a landfill or a reservoir. In other cases, the wastes require treatment to satisfy regulations before disposal. In addition, utilization is an attractive option for managing the solid wastes.

30.2 Disposal Methods

DISPOSAL METHODS

Wet Disposal
Ponds or Reservoirs
Dry Disposal
Landfills

Slide 30–3

In simple terms, all disposal methods are either *wet* or *dry* depending on the physical condition of the material delivered to the disposal area. Wet disposal involves the handling and placement of the material in slurry or liquid form while dry disposal involves receiving and placement of the material as a bulk solid. Wet disposal systems are generally referred to as *ponds* or *reservoirs*; dry disposal systems as *landfills*.

Complete design of any wet disposal systems must include facilities for removal, treatment, and either recycle or release of inevitable supernatant (small solid particle floating on surface of a liquid). Both wet and dry systems must provide for the management of precipitation falling on the disposal area.

30.3 Wet Disposal — Ponds

Pond Configurations

POND CONFIGURATIONS

Diked Disposal Ponds
Incised Disposal Ponds
Sidehill Disposal Ponds
Cross-Valley Disposal Ponds

Slide 30–4

Wet disposal requires the safe containment of the waste slurry until it has settled, stabilized and fixated. Impermeable barriers must be provided to contain the full volume of waste slurry anticipated during the life of the disposal site.

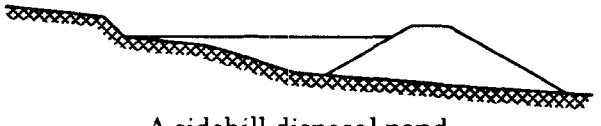
The configuration and general arrangement are controlled by the terrain, geology, hydrology, and other features of the site. The simplest approach is to construct a *dike* around the perimeter of the site. Where the geology and hydrology of the site permit, it is often less costly to excavate the dike material within the future disposal area, creating a site that is partially diked and *partially excavated* or incised in the site. Another option is to excavate for the entire disposal volume and to use the removed soil for other purposes. Sloping sites offer the possibility of taking advantage of the terrain to provide portions of the containment, as with a *sidehill* disposal area diked on three sides or a *valley* impoundment diked only on one side. Graphical illustrations of the pond configurations are shown Slide 30–5.

GRAPHICAL ILLUSTRATION OF POND CONFIGURATIONS[1]

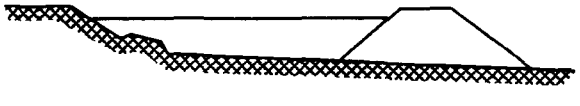
Diked pond constructed above grade.

Diked pond partially excavated below grade.

An incised disposal pond.



A sidehill disposal pond.



A cross-valley pond configuration.

Slide 30–5

Landfill Configurations

LANDFILL CONFIGURATIONS

Heaped Landfill Configuration
Sidehill Landfill Configuration
Valley-fill Disposal Configuration

Slide 30–6

The simplest method of landfill construction is a *heaped* fill in which the waste material is placed and compacted in lifts to form a mound or artificial hill. This approach is generally used in flat terrains. For greater stability and reduced visual impact, sloping terrain is usually utilized. A sloping site allows the construction of a *sidehill* landfill, and a valley site leads naturally to a *valley–fill* configuration. Graphical illustrations of the landfill configurations are shown in Slide 30–7.

GRAPHICAL ILLUSTRATION OF LANDFILL CONFIGURATIONS[1]

A heaped landfill configuration.

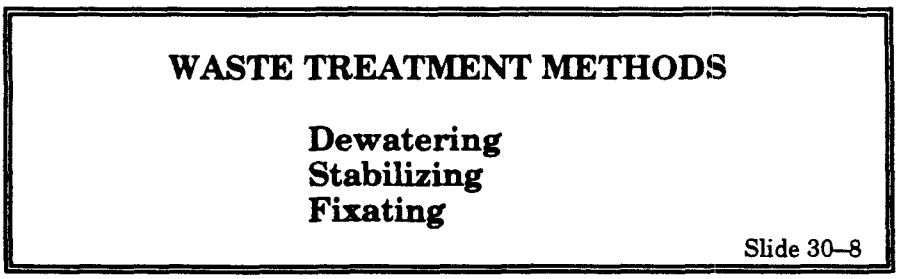
A sidehill landfill.

A valley-fill disposal configuration.

Slide 30–7

In practice, a landfill site may employ more than one of these configurations as it is developed over the life of the power plant. In the new waste disposal facilities, there is a trend toward dry disposal. This technique leads to smaller volumes for the same useful life, more options for site or material reclamation, and higher reliability.

30.5 Treatment Methods



The treatment method can be considered in three broad categories:

Dewatering: Physically separating water and solids to recover the water and/or increase the solids content of the product.

Stabilizing: Adding dry solids to the slurry to increase the solids content of the product.

Fixating: Adding an agent to cause a chemical change in the product to bind the water into the solids to produce a physically dry solid.

30.6 Dewatering

DEWATERING METHODS

Settling Ponds
Dewatering Bins
Thickeners
Cyclones
Centrifuges
Vacuum Filters

Slide 30–9

Dewatering encompasses a wide range of mechanical devices to separate water and particulate solids. Among the separation techniques are settling ponds, dewatering bins, thickeners, cyclones, centrifuges, and vacuum filters. Each of these techniques will be briefly described below.

Settling Ponds

SETTLING PONDS

Range of solid concentrations
- 10–50% FGD slurry
- 20–70% ash

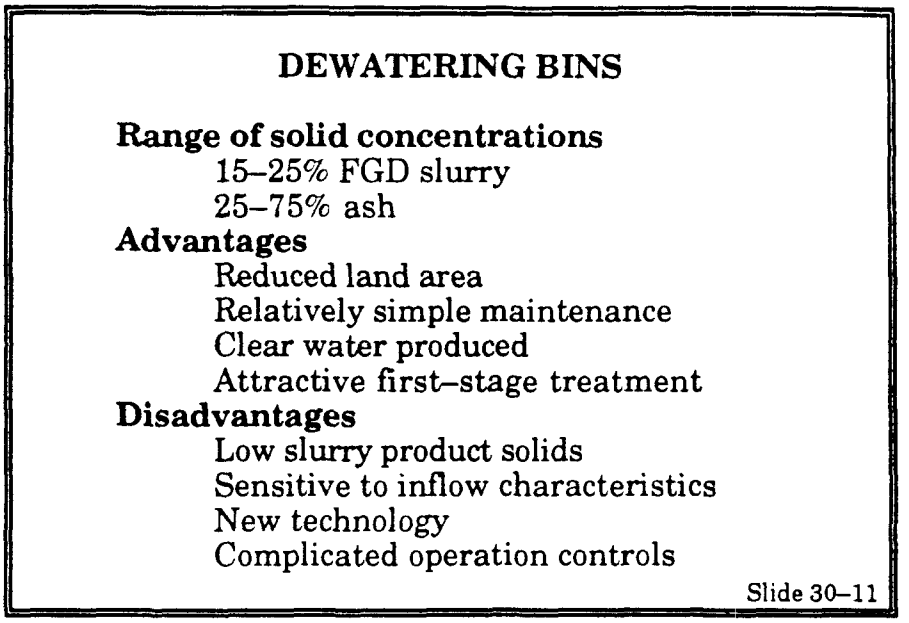
Advantages
- Simple operation
- Not sensitive to inlet solid content
- Low maintenance costs
- High reliability

Disadvantages
- Substantial land area
- Unpopular with regulatory agencies
- Solid removal difficult

Slide 30–10

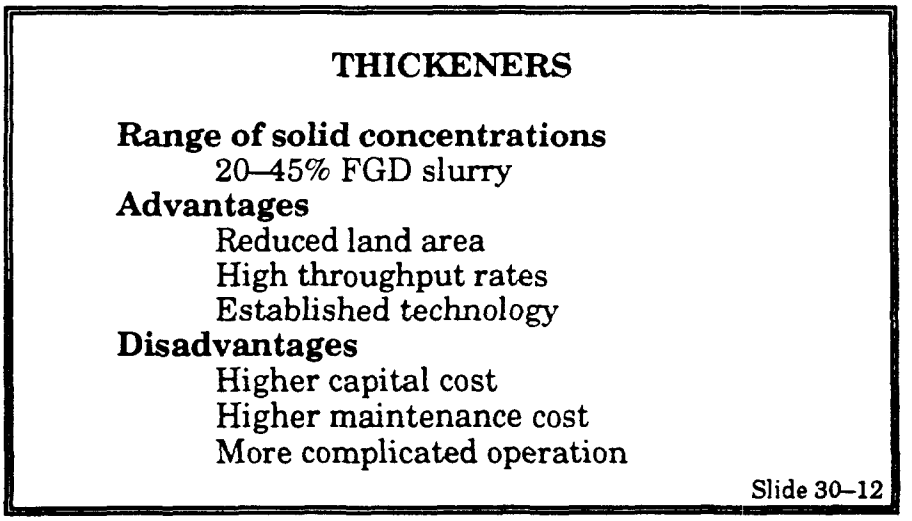
Often used alone with ash or limestone scrubber slurries, settling ponds are the simplest dewatering method. The pond is sized to provide a large volume so that flow velocities are very slow and gravity acts to settle the solids. The liquid fraction is drawn off at a clear well and the solids are collected during periodic cleaning of the pond bottom.

Dewatering Bins



Dewatering bins includes a wide variety of devices ranging from the simple to the complex. The simplest are the hoppers with a simple sloping, perforated plate to separate granular materials such as bottom ash from the slurry water fraction. In more complex units, multiple plates collect the heavy solids from scrubber sludges on a moving belt at the bottom of the bin. The plates provide a large surface area in a small volume to settle the solids and to separate particles from the moving fluid.

Thickeners



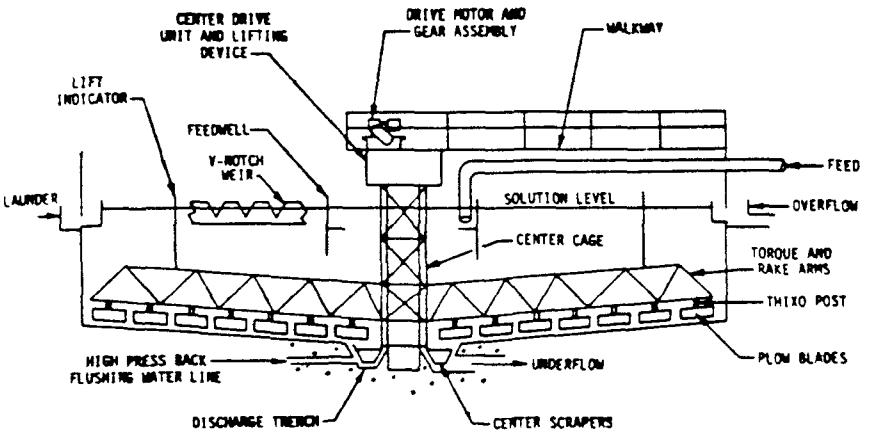
Thickeners operate much as ponds or bins, relying on gravity to separate high–specific–gravity solids from water. Typical thickeners are large cylindrical tanks with a center column, which supports the drive mechanism for two or more long radial raking arms extending from the bottom of the shaft. These carry a series of plows to stir the material at the bottom of the tank which slopes toward the center.

The plows push the settled solids toward the underflow discharge point.

The center column also contains a feedwell that delivers the inflow slurry to the midpoint of tank depth. The initial separation is made by gravity, and the clear flow exists over a weir around the top perimeter of the tank. The thickened solids are compacted by the rakes and discharged by a pipe at the bottom center of the tank. Thickeners are sized according inflow volume, solids, loading, settling characteristics, and target outflow solid concentrations.

A cross–section view of a conventional thickener is shown in Slide 30–13.

A CONVENTIONAL GRAVITY THICKENER



Slide 30–13

Cyclones

CYCLONES

Range of solid concentrations
35–65% FGD slurry

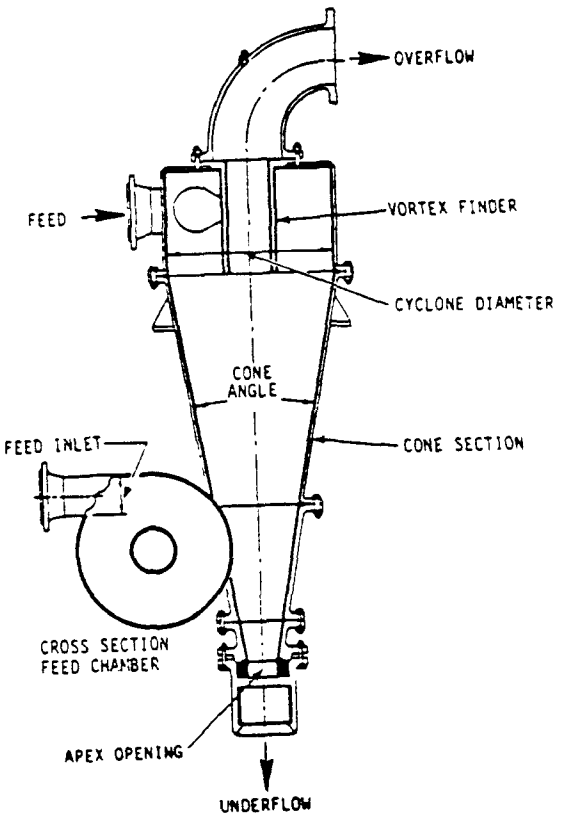
Advantages
Low space requirements
Relatively low cost
Recover high portion of large particles
Low solid content in liquid fraction

Disadvantages
Do not recover fine particles
Inefficient with feeds over 15% solids
Susceptible to abrasion and corrosion
High liquid content in solid fraction

Slide 30–14

Cyclones promote free vortex separation that removes solids from slurries by the combined effects of centrifugal force and liquid shear. The pressure energy of the liquid slurry pumped into the cyclone changes to velocity energy at the inlets and into rotational energy as the liquid moves down and through the cyclone. This rotation causes a natural vortex that moves the heavier solids particles to the outside of the vortex and the lighter liquid particles to the center. The heavier solids are discharged from an orifice in the cyclone's tip. Slide 30–15 shows a schematic of a cyclone.

A CYCLONE [3]



Slide 30–15

Centrifuges

CENTRIFUGES

Range of solid concentrations
- 40–65% FGD slurry

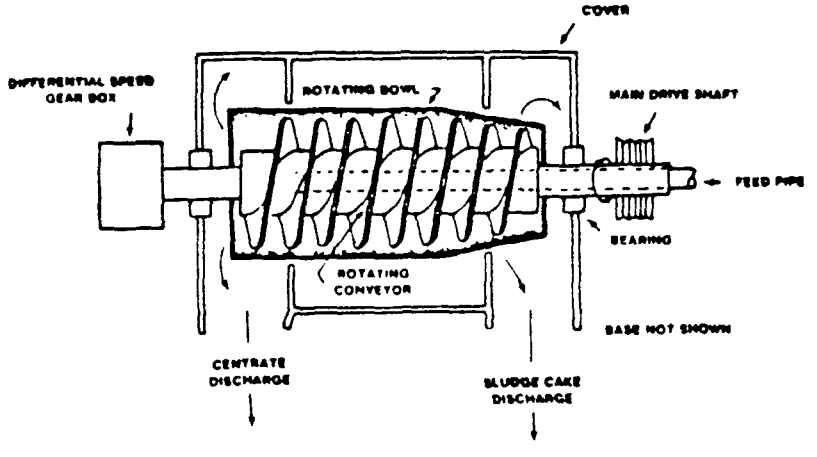
Advantages
- Low space requirements
- Accept variation in inflow
- High product solid content
- Established technology

Disadvantages
- Do not produce clear liquid
- High cost
- High maintenance
- Subject to abrasion and corrosion

Slide 30–16

Centrifuges are normally a secondary dewatering step that follows an upstream thickener. They are basically compact, high–intensity settling basis; centrifugal force is the principal cause of solid–liquid separation. Centrifuges can produce 1,500 to 4,000 times the acceleration force of gravity—the limiting force in settling basis. Centrifuge reliability and efficiency are improving. The solid fraction is consistent and can reach 65 percent solid concentration. Centrifuges are not effective in producing a clear liquid fraction and are subject to abrasion and corrosion. The major problem in centrifuge operation is the disposal of the liquid fraction, which is high in solid content. Slide 30–17 shows a schematic of a centrifuge.

A SOLID-BOWL CENTRIFUGE[3]



Slide 30–17

VACUUM FILTERS

Range of solid concentrations
- 35–65% FGD slurry
- 60–75% ash

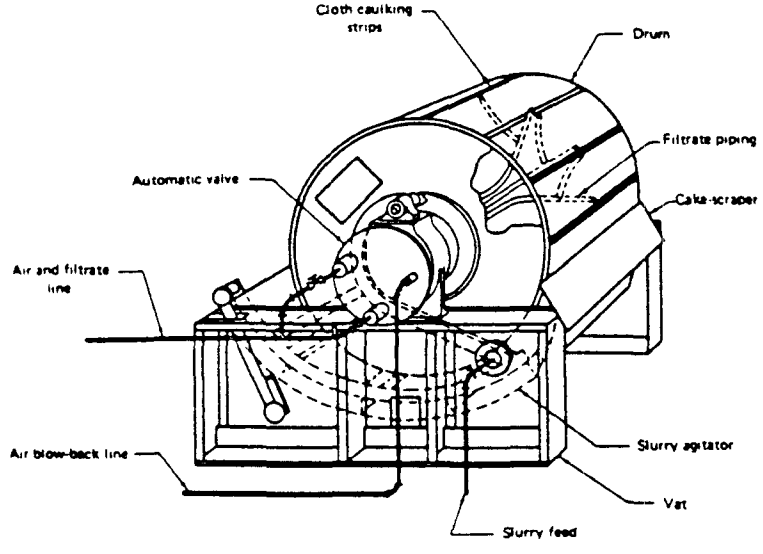
Advantages
- Low space requirements
- High product solid content
- Consistent product quality
- Established technology

Disadvantages
- High cost
- High maintenance
- Complicated operation
- Do not produce clear liquid

Slide 30–18

Two types of vacuum filters, drum and belt, are commonly selected for second–stage dewatering of slurries in fossil fuel–fired plants. The *rotary–drum filter* is the most popular type since it is usually the least expensive. The drum carrying the filter media is divided into sections. Feed is held in the tank at the bottom of the unit. As the drum rotates, each section passes in turn through the feed holding tanks. From within the drum the vacuum draws slurry to the drum's face. As the drum rotates, the vacuum draws the filtrate through the filter media until a high–solid filter cake remains on the outside of the filter. The drum continues to turn past a scraper, which removes the filter cake so that the process can repeat. Slide 30–19 shows a cutaway view of a rotary drum vacuum filter.

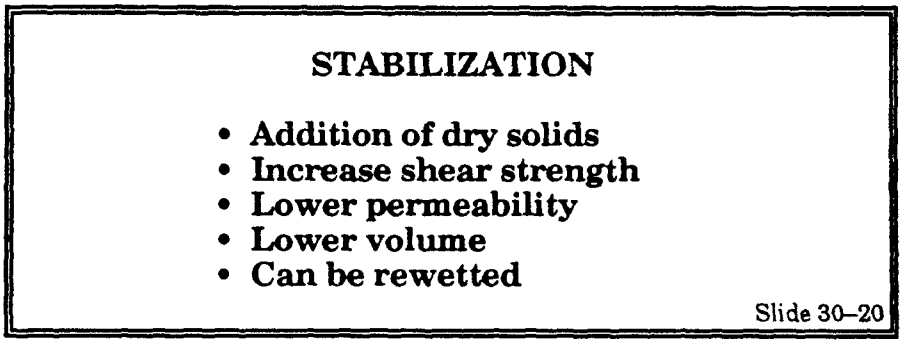
A ROTARY DRUM VACUUM FILTER [3]



Slide 30–19

Belt filters are improved versions of the rotary–drum filter. The filter medium lifts from the drum after the dewatering portion of the cycle and passes over a small–diameter roller to remove the cake. This small roller completely discharges the cake without a scraper, thus increasing filter cloth life. Since the belt is lifted from the drum, the drying time is only a fraction of the total cycle.

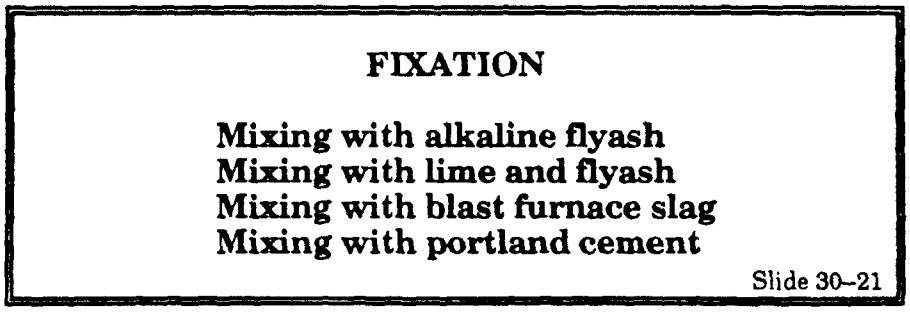
30.7 Stabilization



Stabilization is a simple mixing of a relatively dry solid such as soil or flyash with the slurry material to be treated. Physical stabilization is most applicable where dry disposal is advantageous. The proportions are chosen to optimize the moisture content of the resulting mixture so that it is a stable solid and can be compacted to a maximum density in the landfill. The addition of the dry material spreads the water entrained in the slurry through a larger weight of solids and improves the particle size distribution so that closer packing can be obtained in the disposal area. These produce increased shear strength, lower permeability, and lower combined volume. However, the material is subjected to erosion, saturation, and leaching.

Stabilization can be reversed since it is not a chemical process. If a mixture is rewetted or saturated, it may fluidize, causing a rapid decrease in shear strength and possible structural failure.

30.8 Fixation



Many powerplants burn coal that produces alkaline flyash. Mixing this ash with the wet scrubber product yields a chemical reaction combining stabilization and fixation. So far, four fixation processes have been identified:

Mixing with alkaline flyash: Depending on the chemistry of the coal, the flyash may contain sufficient calcium oxide (CaO) to produce a chemical reaction when dry ash is mixed with scrubber slurry. Western utilities use this method with brown coals and lignite. When adequate CaO is present and ash and sludge are mixed in a suitable ratio, compressive strength close to that of concrete can be obtained. This method reduces product permeability, which enhances placement efficiency and minimizes water–related problems.

Mixing with lime and flyash: When the coal does not produce an alkaline flyash, lime may be added with the flyash to provide the CaO needed for the fixation reaction. The lime is added at about 4 percent of the weight of the combined ash and sludge solids. Generally, the ash and sludge are mixed in equal proportions by weight of solids. The resulting cementitious reaction provides the necessary physical properties for disposal and utilization.

Mixing with blast furnace slag: Ground and basic blast furnace slag may produce the cementitious reaction needed to fix the scrubber sludge. This process works under water, so the slurry can be pumped to a pond or an interim pond where the reaction will continue. At the pond, the material is allowed to cure, the supernatant is removed, and the material is excavated as a dry solid and taken to a landfill. In other cases, the slurry is mixed with flyash and ground slag to produce a table, fixed material suitable for immediate placement on a structural fill.

Mixing with portland cement: A group of utilities have experimented with the use of portland cement to fix both scrubber sludges and flyash slurries. When portland cement is added at about 5 percent of the sludge solid weight, the process may be cost–competitive in some areas. The resulting materials cure under water and produce material suitable for structural fills.

30.9 Utilization

UTILIZATION

Ash Utilization
- Cement manufacturing
- Concrete materials
- Substituted for sand or gravel

FGD By–Product Utilization
- Agriculture
- Metals recovery
- Sulfur recovery
- Gypsum

Site Utilization
- Landfill construction material

Slide 30–22

One of the attractive options to waste management is to utilize the waste material. Plant personnel find this option attractive since it improve the plant economics and also reduces the burden of disposal cost and landfill requirements.

Ash Utilization

Only bottom ash and flyash are utilized in any significant quantities. The actual uses are mainly bulk consumption of the wastes with minimum processing. As a result, the material values derived from utilization are very low, and the principal advantage is avoidance of disposal costs. Utilization is also limited by the cost of transportation. The product values are typically so low that transportation distances are limited to areas where the plant is the closest source.

The major areas of ash utilization are ones in which the ash material can be substituted for sand or gravel. Because its strong, granular nature, bottom ash is an attractive material for use as blasting grit, controlled fills, and roofing granules. Flyash is typically used in the manufacture of portland cement and in the preparation of concrete mixes.

FGD By–Product Utilization

Some of the methods that have been studied for FGD by–product utilization are as follows::

Agriculture: Generally, FGD by–products contain large amounts of lime and thus may be suitable for substitution for natural agricultural lime. However, such use has been blocked in practice by two facts: (1) available lime is lower in the FGD by–product than in the natural material, so more is required for similar effectiveness, and (2) trace elements in the FGD byproducts may have an unacceptable impact.

Metals recovery: FGD by–products usually contain aluminum, iron, silica, and other metals in very low concentrations. The technology is not fully developed yet for recovery of trace elements, so this approach does not appear cost–effective at current metal prices. Furthermore, the final waste volume is not significantly reduced by the extraction of the trace metals.

Sulfur recovery: FGD by–products are also rich in sulfur which can be recovered for sale. The obstacles are the incomplete development of the recovery technology, the low price of elemental sulfur, and the large volume of waste still remaining after the recovery of sulfur.

Gypsum: Many FGD systems that are operated with forced oxidation can be made to produce gypsum suitable for drywall and other construction uses. This is a very effective utilization, but actual application has been limited by the price of natural gypsum and by the trace materials in the by–product gypsum that may bleed through to the finished wall surfaces.

Site Utilization

The solid waste products are sometimes used on–site at the plant. Most uses are in the area of landfill preparation. Some disposal sites which could not be chosen because of terrain problems. The by–products are placed in systematic, compacted lifts designed to recontour the site to correct the terrain problems.

REFERENCES

1. Elliott, C.T., *Standard Handbook of Plant Engineering*, McGraw Hill Publishing Company, New York, 1989.

2. Corbitt, A.R., *Standard Handbook of Environment Engineering*, McGraw Hill Publishing Company, New York, 1990.

3. Hanzel, D.S., Laseke, B.A., Smith, E.O., Swenson, D.O., *Handbook for Flue Gas Desulfurization Scrubbing with Limestone*, Noyes Data Corporation, New Jersey, 1992.

CHAPTER 31. GLOSSARY

31. GLOSSARY

Note: Terms in this glossary are defined as they relate to boilers.

A

absolute pressure: Pressure above a perfect vacuum. See *vacuum.*

absolute temperature: Degrees in Fahrenheit above absolute zero. See *absolute zero.*

absolute zero: Theoretical temperature at which it is so cold that all molecular movement ceases (–460°F).

acid dew point: Temperature at which acids begin to settle out of flue gases. See *gas.*

after-treatment: Water treatment processes that occur after steam is generated.

alloy: Blend of two or more different metals.

alternating current: Electric current that reverses direction periodically, usually many times per second.

ambient temperature: Temperature of the surrounding air.

amine: Chemical that prevents corrosion in condensate and steam piping. See *filming amine* and *neutralizing amine.*

ampere: Unit of measure for electric current.

analog signal: A continuous electrical signal that varies in amplitude or frequency in response to changes in sound, light, heat, position, or pressure.

anion: Ion that has a negative electrical charge. See *ion.*

annunciator: Audible alarm that is created electronically.

anthracite coal: Coal that contains a high percentage of fixed carbon and a low percentage of volatiles. Also called *hard coal.* See *fixed carbon* and *volatiles.*

anthracite (coal) filter: Filter that removes sludge suspended in water before the water is used in the boiler.

APCD: Air Pollution Control Device

area: The number of unit squares equal to the surface of an object.

ash fusion temperature: Temperature at which ash begins to become molten.

ASME: American Society of Mechanical Engineers.

aspirating pump: Pump that automatically removes air from a process liquid and discharges the air to the atmosphere. See *pump.*

attemperator: See desuperheater.

"A" style boiler: Watertube boiler with a top steam and water drum and two bottom mud drums. See *boiler.*

atmospheric pressure: Force exerted by the weight of the atmosphere on the earth's surface. See *force.*

atomization: Process of breaking a liquid fuel stream into a mist of tiny droplets.

attemperator: See *desuperheater.*

available NPSH: Pressure, in feet absolute, available at the pump datum exerted by weight of the column of liquid pushing down on the pump and process pressure, minus vapor pressure of the liquid in feet absolute. See *net positive suction head.*

B

backflow: Condition in which there is not enough pressure to maintain flow in forward direction. This drop in pressure causes a reverse in flow direction. See *pressure.*

backpass: Region of boiler convective section downstream of 90° turn away from furnace.

backwash: In a water softener, the upward flow of water through resin beads that flushes out impurities through the top of the softener.

baffle: Plate that directs the flow of gases of combustion for maximum boiler heating surface contact.

ball valve: Quick-acting, two position shutoff valve. See *valve.*

banking: Process that greatly slows the combustion of coal or some other solid fuel.

battery of boilers: Group of boilers that feeds steam into the same header.

bituminous coal: Coal that contains a high percentage of volatiles and a low percentage of fixed carbon. Also called *soft coal.* See *volatiles* and *fixed carbon.*

blast furnace gas: Gas recovered as a by-product from a gas furnace.

blended fuel oil: Mixtures of distillate oils and residual oils that may contain some crude oil.

blowback: See *blowdown.*

blowdown: Pressure in a pressure vessel that must be reduced before the safety valve will reseat. Should not exceed 4% of the popping pressure. Also called *blowback.* See *popping pressure.*

boiler: Closed vessel in which water under pressure is transformed into steam by application of heat.
boiler horsepower (BHP): Evaporation of 34.5 lb of water at 212°F into steam at 212°F in 1 hour.
boiler load: Amount of steam being produced by a boiler.
boiler bent valve: See *air cock.*
boiling point: Temperature at which water changes into steam.
bottom blowdown: Periodic draining of part of the water in a boiler to remove heavy sludge that settle to the bottom of a vessel.
Bourdon tube: Tube in side a mechanical steam pressure gauge that converts the steam pressure in the boiler into a reading on the gauge.
breeching: Ductwork that carries spent flue gases from the exit of the boiler to the stack.
bridge wall: Firebrick wall across a furnace that supports and encloses the rear end of the grates.
brine: Strong solution of salt and water. Used to regenerate water softeners.
British thermal unit (Btu): Amount of heat necessary to raise the temperature of 1 lb of water 1°F.
buckstay: Metal brace used to support a brick or block wall to a steel framework.
butane: Gas that is derived from refining crude oil into gasolines.
by-product: A product from a manufacturing process that is not considered the principal material.

C

C_2H_6: Ethane
C_3H_8: Propane
calcium (Ca): Metallic element that accounts for much of the hardness in boiler water. See *element.*
calibrate: To determine, by measurement or comparison with a standard, the correct value of each scale reading on a meter or other device, or the correct value for each setting of a control knob.
calorimeter: An apparatus for measuring heat quantities generated in or emitted by materials in processes such as chemical reactions, changes of state, or formation of solutions.
carbon (C): Nonmetallic element which is a constituent of coal and petroleum products. See *element.*
carbon dioxide (CO_2): Heavy, colorless gas that does not support combustion. Formed from the combustion of carbon and oxygen. See *carbon* and *oxygen.*
carbon monoxide (CO): Colorless, odorless, highly toxic gas that burns to carbon dioxide with a blue flame. Formed from the incomplete combustion of carbon. See *carbon* and *carbon dioxide.*
carryover: Entrainment of small water droplets with the steam leaving the boiler. See *entrainment.*
cascade controller: An automatic control system in which various control units are linked in sequence, each control unit regulating the operation of the next control unit in line.
cast iron sectional boiler: Boiler in which hot gases of combustion pass through openings in hollow cast iron sections that contain water. See *boiler.*
cation: Ion with a positive electrical charge. See *ion.*
cavitation: Condition caused when a portion of water or other liquid entering the eye of a pump impeller flashes into steam bubbles. Causes pitting of pump impellers.
Celsius (Centigrade): Temperature scale commonly used with the metric system of measurements. The freezing point of water on this scale is 0° and the boiling point of water is 100° at normal atmospheric pressure. See *Fahrenheit.*
centrifugal pump: Pump that has a rotating impeller that slings liquid from its vanes. See *pump.*
CH_4: Methane
chain-grate stoker: Mechanical stoker designed for gravity-feeding of coal onto the small grate segments. See *stoker.*
check valve: One-way flow valve for fluids. See *valve.*
chelants: Chemicals that keep the hardness in boiler water in solution so that it does not settle on boiler surfaces.
chimney: See *stack.*
circumference: Outside boundary of a circle.
classifier: Spinning set of vanes located at the coal and air outlet from the pulverizer that allows very fine coal dust to pass through, but throws out the larger coal particles. See *pulverizer.*
clinker: Coal or other solid fuel that has fused together during combustion.
clinker grinder: Large set of mechanical steel rollers with heavy teeth that grind ash and clinkers before they enter the ashpit. See *clinker.*

closed heat exchanger: Heating unit in which heating medium and fluid being heated do not mix but are separated by tube walls or other heating surfaces.
closed heating system: Heating system in which the condensate is recovered and returned to the boiler. See *condensate.*
coal burned in suspension: Coal that is burned as a dust as it is blown into the furnace.
coke oven gas: Gas consisting mainly of hydrogen and methane. It is produced when coke is made from coal in coke ovens.
combined-cycle boiler system: Waste heat recovery boiler that uses hot exhaust gases as its heat source. See boiler.
combustion: The burning of gas, liquid, or solid, in which the fuel is oxidized, evolving heat and often light.
combustion chamber: Area of boiler where the burning of fuel occurs.
complete combustion: Burning fuel with the proper amount of oxygen so that the fuel is completely consumed without forming any smoke. See *incomplete combustion* and *perfect combustion.*
compression: Exertion of equal forces from opposite sites of an object that push toward the middle.
condensate: Steam that has lost its heat and returned to water.
condensate polisher: Ion-exchange water softener that uses resin that can withstand high temperatures. See *ion-exchange water softener.*
condensate receiver: Small vessel for receiving condensate from the various steam-using equipment. See *condensate.*
condenser: A heat transfer device that reduces a fluid from its vapor phase to its liquid phase.
conductance: Measurement of the ability of an electric circuit to allow current to flow. Letter symbol is G. See *current* and *mho.*
conduction: Transfer of heat by actual physical contact, molecule to molecule.
conductor: A wire, cable, or other body or medium that is suitable for carrying electric current.
continuous blowdown: Small stream of water that constantly drains from a boiler to control the quantities of impurities in a boiler on a continuous basis.
control valve: Valve driven by an actuator that receives a command signal from a controller and converts the signal into a movement of the valve. See *valve.*
convection: Transfer of heat by a conveying medium, such as air.
cooling tower: *Evaporative heat exchanger* that removes heat from water.
current: Flow of electrical charge.
cut-in pressure: Automatic pressure control setting at which the boiler turns ON. See *differential setting.*
cut-out pressure: Automatic pressure control setting at which the boiler turns OFF. See *differential setting.*
cycles of concentration: Number of times solids in a particular volume of water are concentrated as compared to concentration of the solids in the original volume of water.
cyclone separator: Cylindrical separator found in many watertube boilers that swirls the steam and water mixture and throws water out by centrifugal force.

D

damper: Device in the flue of a furnace that controls draft.
deaerator: Pressure vessel that removes oxygen from the feedwater going to a boiler.
dealkalizer: Ion-exchange unit that works exactly like a sodium zeolite water softener, but removes anions and replaces them with chloride. See *sodium zeolite water softener.*
desuperheater: Mechanism located after the superheater in the steam line that slightly cools the superheated steam. Also called *attemperator.*
dewatering: Removal of water from solid material.
differential pressure: Difference between two pressures at different points.
differential setting: Difference between the pressure at which the automatic pressure control turns the burner ON, and the pressure at which the automatic pressure control turns the burner OFF. See *cut-in pressure* and *cut-out pressure.*
digital control: The use of digital or discrete technology to maintain conditions in operating systems.
diode: A two-electrode electron tube containing an anode and cathode.
direct current: Electric current which flows in one direction, as opposed to alternating current. Abbreviated dc.
dispersants: Chemicals that prevent solids in boiler water from sticking together and forming deposits.
dissolved gases: Gases that have passed into solution.
dissolved oxygen: Oxygen that has passed into solution.

dissolved solids: Impurities that have passed into solution.
distillate fuel oil: Fuel oil produced by distilling crude oil and containing the lighter, more volatile hydrocarbons. See *hydrocarbons.*
distilled water: Water that has changed to steam and then condensed. Distilled water contains no impurities.
double seated valve: Valve that has two discs on one stem and two valve seats. See *valve.*
downcomer tubes: Tubes that contain cool, descending water that replenish water supply to riser tubes.
draft: Movement of air and/or gases of combustion from a point of high pressure to a point of low pressure.
drift: A gradual deviation from a set adjustment.
drip leg: Downward extension of a steam line that collects condensate.
drum vent valve: See *air cock.*
dry lay-up: Method of long-term boiler storage that keeps the boiler free from moisture on the inside, which prevents damage from corrosion. See *laying up.*
D-slide vales: Valves that control the admission and exhaust of steam to the steam pistons in a duplex pump.
"D" style boiler: Watertube boiler with a top steam and water drum and a bottom mud drum. Similar to the "O" style boiler except that steam-generating tubes on one side are extended to leave an open D-shaped area close to the center for combustion. See *boiler.*
ductility: Plasticity exhibited by a material under tension loading and measured by the amount the material can be permanently elongated.

E

economizer: Series (bank) of boiler tubes through which feedwater travels to the boiler drum.
efficiency: Comparison of the power input to the power output of a mechanical apparatus.
electric potential: The work which must be done against electric forces to bring a unit charge from a reference point to the point in question.
element: Any of over 100 basic substances consisting of atoms of one kind that individually or collectively make up all matter.
embrittlement: Condition in which metal becomes brittle due to crystalline cracking.
entrainment: Suspension of contaminant particles carried along with the flow. See *carryover.*
evaporator: Set of heat exchangers that generates water suitable for boiler use from water that contains large quantities of impurities.
excess air (EA): Amount of air added to the combustion process over and above that which is theoretically necessary.
external header cast iron sectional boiler: Boiler containing cast iron sections individually connected to external manifolds (headers) with screwed nipples.
externally-fired fire-tube boiler: Firetube boiler with a separate furnace area built on refractory brick.

F

Fahrenheit: Temperature scale commonly used with the U.S. system of measurements. The freezing point of water on this scale is 32° and the boiling point of water is 212° at normal atmospheric pressure. See *Celsius.*
feedwater: Water that is supplied to the boiler.
feedwater regulator: Mechanism that automatically maintains a constant safe water level in a boiler.
filming amine: Chemical that forms a protective coating on condensate piping. See *amine.*
firebox boiler: Firetube boiler in which the furnace is surround on the sides by a water leg area. See *boiler.*
firetube boiler: Boiler in which hot gases of combustion pass through the tubes and water contacts the outside surfaces of the tubes. See *boiler.*
fixed carbon: Portion of coal that remains in a solid form when the coal is heated.
flame impingement: Flame from burning fuel that strikes the boiler tubes or refractory brick. See *refractory.*
flame scanner: Device that confirms that the pilot and main burner flames exist.
flared: Spread outward.
flashback: Ignition of a small volume of volatile vapors or gases that causes pressurization of the furnace for a brief period.
flash point: Lowest temperature at which vapors given off by a substance will make a flash of flame, but not continue to burn when an open flame is passed over it.
flash steam: Steam produced when water that is saturated with heat is released to a lower pressure.

flue: 1. Pipe that increases heating surface and carries flame or gases of combustion around or through water in a firetube boiler. 2. Channel in a stack for directing smoke and gases of combustion out of the area.
flue furnace boiler: Firetube boiler in which the furnace consists of a large tube or pipe that passes the length of the shell. See *boiler.*
fluid: Any material that can flow from one point to another.
flyash: Small particles of ash from the combustion process that are carried along with the draft through a boiler furnace and ductwork.
foaming: Development of froth on the surface of boiler water.
foot-pound: Unit of measure that equals the movement of an object by a constant force (in pounds) to a specific distance (in feet).
force: Energy exerted or brought to bear on.
forced draft: Introduction of combustion air into a furnace to combine with fuel for combustion.
forced draft cooling tower: Cooling tower with a fan located at the bottom to force a draft through the tower. See *cooling tower.*
fossil fuel: Fuel derived from plants and other organic matter that have decayed below the earth's surface while subjected to great pressure over millions of years.
fractions: Separation of individual materials from the deposit crude oil in the refining process.
fusibility temperature: The temperature at which a material is liquified by heat.

G

gas: Fluid that has no particular shape or volume.
gate valve: Valve used to shut off or admit flow. See *valve.*
gauge glass: Glass connected to a water column or directly to a boiler that allows an operator to see the water level inside a boiler. See *flat gauge glass* and *tubular gauge glass.*
gauge pressure: Pressure above atmospheric pressure. Assumes atmospheric pressure as being zero. See *atmospheric pressure.*
globe valve: Valve having a tapered, rounded, or flat disc held horizontally on the stem. See *valve.*
grade of coal: Size of coal.
gravity: Natural force that makes objects on earth fall to the lowest point possible.

H

H_2: Hydrogen
H_2O: Water
H_2S: Hydrogen Sulfide
hard coal: See *anthracite coal.*
header: Manifold that feeds several branch pipes or takes in steam or water from several smaller pipes.
heating surface: Any part of boiler metal that has hot gases of combustion on one side and water on the other.
HHV: Higher Heating Value = gross heating value = the total heat obtained from combustion of a specified amount of fuel at stoichiometric conditions.
high water: Higher-than-acceptable water level in a boiler.
horizontal return tubular (HRT) boiler: Externally-fired firetube boiler consisting of a horizontal shell set on a brick furnace. See *boiler.*
horsepower (HP): Unit of measure that equals 33,000 ft-lb (foot-pounds) of work in 1 minute.
hot process water softener: Pressure vessel that uses steam to heat makeup water by direct contact and remove hardness.
hot water boiler: Boiler that is completely full of water that produces only hot water, not steam. The water transports heat.
hydraulics: The brand of science and technology concerned with the mechanics of fluids.
hydrocarbons: Any number of compounds composed of hydrogen and carbon atoms.
hydrostatic test: Water test for leaks in a boiler. The boiler is filled with water and pressurized to 1-1/2 its MAWP. See *maximum allowable working pressure.*
hyperbolic cooling tower: Distinctively shaped cooling tower that has no fan. See *cooling tower.*

I

ignition arch: Curved arch where green coal enters the furnace in a chain-grate stoker-fired boiler.
impeller: Rotating part of centrifugal pump that slings liquid from its vanes. See *pump.*
implosion: An inward collapse caused by external pressure.
inches of mercury (in. Hg): Units of measure for vacuum. See *vacuum.*

incomplete combustion: Burning fuel without proper amount of oxygen, adequate mixing of fuel and oxygen, or a temperature sufficient enough to cause satisfactory reaction of the fuel and oxygen.
induced draft: Use of a fan or stack to create a negative pressure in the furnace to keep smoke and hot gases of combustion from leaking out. See *draft.*
induced draft cooling tower: Cooling tower with a fan located at the top to induce a draft in the tower. See *cooling tower.*
in-line steam separator: Cylindrical vessel that contains baffles or stationary vanes that swirl the steam and water mixture as it passes through the separator, which makes the water drop out.
inside diameter (ID): Distance from inside edge to inside edge of circle through the center of the circle. See *circle.*
insulator: A device having high electrical resistance and used for supporting or separating conductors to prevent undesired flow of current from them to other objects.
intercooler: Cooler located between two compressing stages of an air compressor.
internally-fired firetube boiler: Firetube boiler with a furnace area surrounded by the pressure vessel. See *boiler.*
inverse solubility: Tendency of certain scale-forming impurities in boiler water to settle out as temperature of the boiler water increases.
ion: Atom with a positive or negative electrical charge.
ion exchange: Reversible interchange of an ion on an insoluble solid with another ion in a solution surrounding the solid. See *ion.*
ion-exchange water softener: Device that uses a brine solution and resin beads to soften water.

J

joint: Area where metal is riveted or welded together. Also called *seam.*

K

kW: Kilowatt

L

latent heat: Heat in Btu that is added so that boiling water at a given temperature will change into steam at the same temperature.
laying up: Taking a boiler out of service for longer than a normal period of time. See *dry lay-up* and *wet lay-up.*
leaching: The dissolving, by liquid solvent, of soluble material from its mixture with an insoluble solid.
lead and lag: Starting and stopping boilers in a battery of boilers so that they meet the steam demand without all the boilers running at once.
lean mixture: A fuel-air mixture containing a low percentage of fuel and a high percentage of air, as compared with stoichiometric conditions.
LHV: Lower Heating Value = net heating value = the gross heating value minus the latent heat of vaporization of the water vapor formed by the combustion of the hydrogen in the fuel. For a fuel with no hydrogen, net and gross heating values are the same.
lift check valve: Type of check valve that uses a piston, ball, or disc to stop backflow. See *check valve* and *backflow.*
lift pump: A pump for lifting fluid to the pump's own level.
light refraction: Deflection of light or an energy wave from a straight path when it passes from one medium (e.g., air) to another medium (e.g., water) in which its velocity is different.
lignite: Very soft coal that has a high moisture content and low heat value.
longitudinal joint: Joint that runs along the length of a boiler drum or shell.
low water: Lower-than-acceptable water level in a boiler that is dangerous because it can cause overheating of a boiler.
low water fuel cutoff: Device located slightly below the NOWL of a boiler that shuts OFF the boiler burner in the event of low water. See *normal operating water level.*

M

main steam stop valve: Gate valve in the main steam line between the boiler and the steam header. See *gate valve.*
makeup water: Water that is added to the system to replace water that is lost or drained.
manhole: Hole on the steam and water side of a boiler used to clean, inspect, and repair a boiler.
manometer: Instrument that measures draft. See *draft.*
maximum allowable working pressure (MAWP): Highest legal pressure at which a pressure vessel may be operated.
maximum capacity: Maximum rating in pounds of steam that a boiler is designed to produce in 1 hour at a given pressure and temperature.
mechanical draft: Draft created by one or more fans. See *draft.*

mechanical seal: Assembly installed around a shaft to prevent leakage of process liquids.
metering orifice: A fluid nozzle designed to accurately control fluid-flow rates.
mercury switch: Control device that uses the movement of mercury in a glass tube to control electrical flow in a circuit.
methane: Bacterial by-product gas formed in waste-water treatment plants, landfills, and other areas.
mho: Unit of conductance equal to the reciprocal of an ohm. See *conductance.*
micromho: On-millionth (1/1,000,000) of a mho. See *mho.*
microprocessor: A single silicon chip on which the arithmetic and logic functions of a computer are performed.
milliamp: One-thousandth (1/1000) of an ampere. See *ampere.*
modulating pressure control: Control device that regulates the burner for a higher or lower fuel-burning rate depending on steam pressure in the boiler.
MW: Megawatt

N

N_2: Nitrogen
NAAQS: National Ambient Air Quality Standards.
natural draft: Draft that occurs without mechanical aid. See *draft.*
natural gas: Gas obtained from natural sources in the earth. See *gas.*
negative-suction pump installation: Any installation where a pump must draw liquid up from a source below the pump. See *pump.*
NESHAPS: National Emission Standards for Hazardous Air Pollutants (NESHAPs).
net positive suction head (NPSH): Numerical value that equals the minimum suction conditions that must be maintained to prevent cavitation of a pump.
NH_3: Ammonia
neutralizing amine: Chemical that raises the pH level of the condensate. See *amine.*
noncondensable gas: Any gas that will not change into a liquid when its temperature is reduced.
nonreturn valve: Combination shutoff and check valve that allows steam to pass out of the boiler, but a backflow of steam from a drop in pressure causes the valve to close. See *valve.*
nonrising stem valve: Valve with a disc that threads up onto the stem as the stem is turned. The stem does not back out of the valve. See *valve.*
normal operating water level (NOWL): Level of the boiler water at normal operation.
NOx: Nitrogen Oxides
NSPS: New Source Performance Standards.

O

ohm: The unit of electrical resistance, equal to the resistance through which a current of 1 ampere will flow when there is a potential difference of 1 volt across it.
opacity: Quality of being opaque. See *opaque.*
open heat exchanger: Heating unit in which steam or another heating medium and fluid being heated come into direct contact.
open impeller: Impeller that has vanes that are not enclosed or supported by a shroud (side wall) on either side. See *impeller.*
optical pyrometer: An instrument which determines the temperature of a very hot surface from its incandescent brightness; the image of the surface is focused in the plane of an electrically heated wire, and current through the wire is adjusted until the wire blends into the image of the surface.
Orsat analyzer: Aspiring flue-gas analyzer that measures the percentages of carbon dioxide, carbon monoxide, and oxygen in flue gases.
"O" style boiler: Watertube boiler with a top steam and water drum and a bottom mud drum. See *boiler.*
outside diameter (OD): Distance from outside edge to outside edge of a circle through the center of the circle.
overfire air: Secondary air in a boiler fired by sold fuel. See *secondary air.*
oxidizing flame: A flame, or the portion of it, that contains an excess of oxygen.
oxygen (O_2): Colorless, tasteless, odorless gas that is approximately 21% of the air. Oxygen is necessary for combustion.

P

package boiler: Boiler supplied complete from the manufacturer with controls and appliances attached.
particulate: Flyash particles carried along with flue gases.
part per billion (ppb): One part in a billion.
part per million (ppm): One part in a million.
passes: Number of times gases of combustion flow the length of the pressure vessel as they transfer heat to the water.

perfect combustion: Burning fuel with precisely the right quantity of oxygen so that no fuel or oxygen remains. Attainable only in a laboratory.
pH: Value representing how acidic or alkaline water is.
phosphates: Chemicals that cause hardness particles to settle out as a heavy sludge.
plenum: Area of furnace between combustion chamber and stack.
PM_{10}: Particulate Matter less than 10 microns in size.
pneumatics: Fluid statics and behavior in closed systems when the fluid is gas.
popping pressure: Lowest pressure that will pop the safety valve.
positive-displacement pump: Reciprocating or rotary pump in which every stroke or revolution moves a predetermined amount of liquid.
pounds of steam per hour (lb/hr): Unit of measure that expresses the amount of steam produced by a boiler in 1 hour.
pounds per square inch (psi): Number of pounds of pressure exerted on 1 sq. in. of a given area. See *pressure.*
power: Unit of measure that equals the amount of foot-pounds of work in a given period of time. See *foot-pound.*
prenumericator: Air-actuated fuel level device.
pressure: Application of force. Commonly measured in psi. See *force.*
pressure gauge: An instrument having metallic sensing element or a piezoelectric crystal to measure pressure.
pretreatment: Water treatment processes that occur before water enters the boiler.
primary air: Initial volume of air that enters the furnace with the fuel for most of the combustion process.
priming: Severe form of carryover in which large slugs of water leave the boiler with the steam. See *carryover.*
programming clock: Rotating cam sequencer or microprocessor timing device that controls the sequence and length of the programmed device.
propane: Liquefied hydrocarbon gas derived from the petroleum refining process. See *gas.*
proximate analysis: Percentage of moisture, volatiles, fixed carbon, and ash in coal.
pulverizer: Grinding mill that grinds coal to a very fine powder.
pump: Device that moves or compresses fluids or gases.
pyrometer: Instrument that measures temperature above the temperature range of mercury thermometers.

Q

quality of steam: Measure of steam expressed as a percentage of its dryness.
quick-opening valve: Valve that requires only a 90° turn of the lever to move from fully closed to fully open. See *valve.*

R

radiation: Transfer of heat from a hot body to a cold body without physical contact or a conveying medium.
radius: One-half of the diameter of a circle. See *diameter* and *circle.*
rank: Hardness of coal.
reagent: Chemical used in water treatment test to show the presence of a particular substance.
recirculation line: Line that provides a minimum flow through a pump to prevent overheating.
reducing flame: A flame having excess fuel and being capable of chemical reduction, such as extracting oxygen from other chemical compounds.
rectifier: Electrical device that converts alternating current (AC) to direct current (DC).
refractory: Brickwork used in boiler furnaces and for boiler baffles.
representative sample: Sample that is exactly the same as the sample being tested.
required NPSH: Net positive suction head calculated by the manufacturer and supplied with the pump. See *net positive suction head.*
reseat pressure: The pressure at which a safety valve will reseat. It will pop above this pressure.
residual fuel oil: Fuel oil that remains after the lighter, more volatile hydrocarbons have been distilled off.
resistance: Measure of the ability of an electrical circuit to oppose current flow.

retort stoker: Mechanical stoker in which coal in the retort chamber overflows onto tuyeres and quickly set on fire. See *stoker, retort chamber,* and *tuyere.*
rich mixture: an air-fuel mixture that is high in its concentration of combustible component.
riser tubes: Tubes containing rising water that are exposed to the highest temperatures in the furnace area.

rising stem valve: Valve in which the handwheel and stem move outward from the body of the valve as the valve is opened. See *valve.*
root-mean-square: The square root of the average of the squares of a series of related values.
rotor: The rotating member of an electrical machine or device.
rotary cup burner: Assembly that mixes fuel oil with air.

S

safety valve: Valve that keeps the boiler from exceeding its MAWP. See *maximum allowable working pressure* and *valve.*
saturated steam: Steam that has absorbed all the Btu per pound that the steam can hold at its particular pressure.
scale: Mineral deposits formed on the heating surfaces of a boiler.
scotch marine boiler: Internally-fired firetube boiler that has a flue furnace and horizontal shell. See *boiler.*
secondary air: Air added to fuel to ensure that sufficient oxygen is available to complete the combustion process.
sediment: Matter that settles to the bottom of a liquid.
sensible heat: Heat that can be measured by a change in temperature.
set point: The value selected to be maintained by an automatic controller.
shear: Exertion of equal forces in opposite directions in the same plane. See *force.*
sight glass: See *gauge glass.*
single-acting pump: Reciprocating pump that moves fluid in only one direction. See *pump.*
siphon: A loop or tube that holds water and is placed between the steam gauge connection and the steam gauge. A siphon protects the Bourdon tube from the high temperature of the steam. See *Bourdon tube.*
SIPs: State Implementation Plans
slag: Solid deposits that accumulate on furnace walls and boiler tubes.
slag screen: Loosely spaced bank of water tubes placed between the superheater and the combustion area of the furnace.
slaker: Conveyor in which lime is mixed with water to make a soluble paste.
slow-opening valve: Valve that requires five or more full turns of the handwheel to move the valve from fully closed to fully open. See *valve.*
SO_2: Sulfur Dioxide
soft coal: See *bituminous coal.*
solubility: Relative ease with which a material dissolves in a solution.
soot: Fine powder consisting primarily of carbon that results from incomplete combustion.
spalling: Breaking up by chipping.
specific gravity: Weight of a given volume of a material divided by the weight of an equal volume of water measured at 60°F.
spray pond: Shallow pond with a network of spray nozzles that spray the water into the air for cooling.
stack: Outlet to the atmosphere for the gases of combustion. Used to create draft. Also called *chimney.*
static: Stationary, not moving, at rest.
static head pressure (SHP): Pressure at the bottom, or at some specified point, of a column of still liquid.
stator: The portion of a rotating machine that contains the stationary parts of the magnetic circuit and their associated windings.
steam: Gaseous form of water. Steam is odorless, colorless, and tasteless.
steam scrubber: Series of corrugated plates that force the steam and water mixture to follow a zigzag pattern as the steam passes through when leaving the boiler drum. Also called *chevron scrubber.*
steam trap: Mechanical device used to remove condensate from steam piping.
Stirling boiler: Watertube boiler with three steam and water drums on the top and a mud drum beneath, interconnected by a large number of water tubes. See *boiler.*
stoichiometric: The ideal mixture of fuel and air for complete combustion.
stoker: **1.** Mechanical device that automatically feeds green coal or other solid fuel to a furnace. See *green coal.* **2.** Bituminous coal that is 3/4" to 1-1/4" in size. See *bituminous coal.*
submerged conveyor: Heavy steel pan or apron conveyor immersed in a water trough.
submerged-tube (wet-top) vertical boiler: Fire-tube boiler with fire tubes completely covered with water all the way to the tube sheet. See *boiler.*
sump: Pit or reservoir serving as a drain for liquids.
superheated steam: Steam that has been raised in temperature above the temperature that corresponds with its pressure.
superheater: Bank of boiler tues through which only steam passes, not water. Steam is given additional heat in a superheater.

surge tank: Storage tank that holds a reserve of water for periods when a boiler demands feedwater faster than the deaerator can provide it.
suspended solids: Impurities that do not pass into solution.
swell: Expansion of water when it is heated.
swing check valve: Type of check valve that uses a disc to stop backflow. See *check valve* and *backflow*.
synchroscope: A cathode-ray oscilloscope designed to show a sort-duration pulse by using a fast sweep that is synchronized with the pulse signal to be observed.

T

tee: T-shaped restriction or fitting in piping that changes the direction of flow.
test gauge: Gauge used for calibrating other gauges.
THC: Total Hydrocarbons
therm: Unit of measure indicating 100,000 Btu. See *British thermal unit.*
thermal shock: Stress imposed on boiler metal by sudden and drastic change in temperature.
thermocouple: Temperature measuring device consisting of two dissimilar metals bonded together that produce a voltage proportional to the temperature.
thermohydraulic feedwater regulator: Continuously operating control that controls feedwater flow in direct response to a change in the NOWL. See *feedwater regulator.*
throttling: Controlling the amount of flow that passes through a valve by partially closing it.
titration test: Test that determines the concentration of a dissolved substance.
ton: Unit of measure that equals 2000 lb.
total force: Area of a surface multiplied by pressure (in psi) being exerted. Always expressed in pounds, not psi. See *psi.*
total heat: Sum of sensible heat and latent heat. See *sensible heat* and *latent heat.*
transformer: An electrical component consisting of two or more multi-turn coils of wire placed in close proximity to cause the magnetic field of one to link the other.
transistor: An active component of an electronic circuit consisting of a small block of semiconducting material to which at least three electrical contacts are made. It may be used as an amplifier, detector, or switch.
transmitter: A device which move data from one location to another.
tubular gauge glass: Gauge glass used for pressures up to 400 psi. See *gauge glass.*
turbulators: Devices that swirl hot gases from combustion as the gases pass through fire tubes to make more intimate contact with the tubes.
turndown: Ratio of the highest capacity of the device to the lowest capacity.
tuyere: Air-admitting grate designed to rapidly establish combustion of entering fuel.

U

ultimate analysis: Percentages of nitrogen, oxygen, carbon, ash, sulfur, and hydrogen (NOCASH) in coal.

V

vacuum: Pressure lower than atmospheric pressure.
vacuum breaker: Vent on top of a vessel that allows air to be pulled into the tank to prevent formation of a vacuum. See *vacuum.*
vacuum gauge: Pressure gauge used to measure pressures blow atmospheric pressure.
valance: Degree of combining power of an element or chemical group.
valve: Mechanical device that starts, stops, or regulates the flow of a liquid, gas, or loose bulk material.
vapor: Diffused matter in a gaseous state.
vapor pressure of water: Absolute pressure at which water begins to form steam at a certain temperature.
vent condenser: In-line heat exchanger installed in the vent from the deaerator to the roof.
venturi: Nozzle with a slight hourglass-shaped taper.
vibrating-grate stoker: Mechanical stoker with inclined grates that vibrate causing the ashes to fall off of the grates. See *stoker.*
viscosity: Ability of liquid or semi-liquid to resist flow.
viscous liquid: Liquid that maintains an amount of shearing stress based on the velocity of its flow. A viscous liquid offers continued resistance to flow.
volatiles: Constituents that distill out of coal and burn off as a gas when the coal is heated.

W

waste heat recovery boiler: Firetube or water-tube boiler in which heat that would otherwise be discarded is used to make steam. See *boiler.*

water column: Metal vessel installed on the outside of a boiler shell or drum at the NOWL that helps an operator determine the water level in a boiler See *normal operating water level.*

water conductivity: Degree to which a water sample will conduct a small electrical current. See *conductance.*

water hammer: Hydraulic shock that results from water buildup in steam piping.

watertube boiler: Boiler in which water passes through the tubes and hot gases of combustion pass over the outside surfaces of the tubes. See *boiler.*

waterwall: Large flat surface of many tubes placed side by side against the furnace walls that increases the heating surface of a boiler and helps prevent refractory damage to furnace walls because of overheating.

wet lay-up: Method of short-term boiler storage that keeps the boiler free from oxygen on the inside, which prevents damage from corrosion. See *laying up.*

windbox: Plenum to which the forced draft fan supplies air before the air enters the furnace. See *plenum.*

work: The transference of energy that occurs when a force is applied to a body that is moving in such a way that the force has a component in the direction of the body's motion.

working pressure: Maximum allowable working pressure or the pressure at which the boiler is normally operated. **Caution:** When using this term, always clarify the way the term is being used. See *maximum allowable working pressure.*

Z

zeolites: Synthetic sodium aluminosilicate cation-exchange materials. See *cation.*

TECHNICAL REPORT DATA

(Please read Instructions on reverse before completing)

1. REPORT NO.	2.	3. RECIPIENT'S ACCESSION NO.
EPA-453/R-94-056		

4. TITLE AND SUBTITLE	5. REPORT DATE
High Capacity Fossil Fuel Fired Plant Operator Training Program - Student Handbook	September 1994
	6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S)	8. PERFORMING ORGANIZATION REPORT NO.
Shirley Pearson, Matt Gardner, Quang Nguyen	
9. PERFORMING ORGANIZATION NAME AND ADDRESS	10. PROGRAM ELEMENT NO.
Energy and Environmental Research Corporation 18 Mason Irvine, California 92718	11. CONTRACT/GRANT NO. 68-D1-0117
12. SPONSORING AGENCY NAME AND ADDRESS	13. TYPE OF REPORT AND PERIOD COVERED
U.S. Environmental Protection Agency Office of Air Quality Planning and Standards Research Triangle Park, NC 27711	Final 14. SPONSORING AGENCY CODE

15. SUPPLEMENTARY NOTES

James Eddinger, Office of Air Quality Planning and Standards

16. ABSTRACT

This Student Handbook is part of a model State training program which addresses the training needs of high capacity fossil-fuel fired plant (boiler) operators. Included are generic equipment design features, combustion control relationships, and operating and maintenance procedures which are designed to be consistent with the purposes of the Clean Air Act Amendments of 1990. This training program is not designed to replace the site-specific, on-the-job training programs which are crucial to proper operation and maintenance of boilers.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution Control Technology Boilers High Capacity Fossil Fuel-Fired Plants Operator Training	Boilers Air Pollution Control Training	

18. DISTRIBUTION STATEMENT	19. SECURITY CLASS *(Report)*	21. NO. OF PAGES
Release Unlimited	Unclassified	582
	20. SECURITY CLASS *(Page)*	22. PRICE
	Unclassified	

EPA Form 2220-1 (Rev. 4-77) PREVIOUS EDITION IS OBSOLETE

U.S. Environmental Protection Agency
Region 5, Library (PL-12J)
77 West Jackson Boulevard, 12th Floor
Chicago, IL 60604-3590