•••POWER ENGINEERING

Fourth Class

Edition 3.5

Elements of Boiler Systems

Part A

Unit A-12

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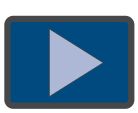
MEDIA 	Media icons show that some form of supporting medium is available. These media may include videos, animations, 2D and 3D models, multi-views of cutaways, simulations, and more. Media elements are available to registered textbook purchasers online via MyPower Study.
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4th Class Edition 3.5 • Part A

UNIT A-12

ELEMENTS OF BOILER SYSTEMS

Unit Introduction

Good boiler design, construction, and installation ensure that heat generation and transformation is efficient, safe, and reliable.

There are many different types of boilers; most have been developed to suit specific purposes. Although boiler types may vary significantly in their configuration and makeup, most have a similar set of required functions. Simply stated, a boiler's basic function is to add energy to a feedwater supply to generate steam or heated water.

A boiler is essentially a closed vessel, inside which water is stored. It has two major sections:

1. A heat generating section or combustion chamber (often called a furnace).
2. A heat transfer section in which the energy created in the combustion chamber is transferred to water.

Fuel, either a solid, liquid, or gas, burns with air in the furnace, and hot gases are produced. These gases contact the metal boiler surfaces, transfer heat to the water, and generate steam or hot water. This hot fluid is then piped to a separate section of the plant, where its energy is transferred, or converted into other useful energy forms.

Successful plant operation depends on the design of the boiler and its associated systems. This is centered on the ongoing creation of heat, and its transfer to external processes. To ensure this happens, the boiler's support systems must be understood. The chapters in this unit address those systems:

Combustion: Describes the principles and practical aspects of combustion when using different types of fuel. These include solid, liquid, and gaseous fuels.

Fuel Delivery and Firing Systems: Describes different fuel delivery and firing systems.

Draft: Describes the delivery of combustion air to, and removal of combustions gases from, the furnace.

Feedwater Systems: Describes how condensate, make-up water, and feedwater are sourced, treated, and delivered to the boiler.

Blowoff and Blowdown Systems: Describes the processes for maintaining stable boiler water concentrations.

Boiler Fireside Cleaning Systems: Describes common methods to maintain combustion chamber cleanliness, and other thermal transfer surfaces that are in direct contact with heated gases.

Unit Rationale

Generally, operators are not major decision makers regarding the design, construction, and installation of a plant and its equipment. Understanding the plant systems design limitations, though, provides an important knowledge base. But, this is only the start of the operator's role. It is of immediate importance to understand the ***operation*** of critical plant components.

The boiler is most often the centre of any plant's thermal processes. Plant operators will interact with boiler systems on an ongoing basis, both while the plant is in service as well as during scheduled maintenance periods.

CHAPTER 1

Combustion

Learning Outcome

When you complete this chapter you should be able to:

Discuss the basic theory of combustion, and the equipment used to provide proper combustion conditions within a boiler.

Learning Objectives

Here is what you should be able to do when you complete each objective:

1. *Discuss combustion, combustion equations, and the relationship between theoretical and excess air.*
2. *Discuss the characteristics of solid, liquid, and gaseous fuels.*
3. *Explain the effects of fuels and combustion on refractory materials.*

Chapter Introduction

Except for electric varieties, boilers have two main components: a heat exchanger and a burner. The burner converts chemical energy to heat energy. The heat exchanger transfers heat to the boiler water.

The term "combustion" refers to the burning (or rapid oxidation) of a fuel, that produces light and heat. Combustion is a chemical reaction between the constituents of the fuel and oxygen, provided by air.

Fuels have different chemical and physical properties. Fuels may be solid, liquid, or gaseous. They may be very high or low viscosity liquids. They may be solids with a high proportion of volatile matter, or low volatile matter. They may be high or low in sulfur. They may be high in ash. They may be high in moisture.

Fuels are not all alike. Therefore, to optimize energy conversion, fuels must be evaluated to determine the best way to prepare and burn them, so that compete combustion will result. Incomplete combustion wastes fuel and energy, which is inefficient. As well, toxic environmental pollutants and soot form when combustion is incomplete. Gaseous unburned combustion products may also create explosion hazards.

Power Engineers must fully understand the combustion process, for both safety and efficiency. To understand the combustion process, it is necessary to know the chemical and physical properties of the fuels they burn, and how best to burn them.

OBJECTIVE 1

Discuss combustion, combustion equations, and the relationship between theoretical and excess air.

PRINCIPLES OF COMBUSTION

Combustion is the rapid oxidation of a fuel, resulting in the release of heat energy. Fuels may be solids (biomass, coal, or hog fuel), liquids (biodiesel or fuel oil), or gaseous (propane, syngas, or biogas).

A common gaseous fuel is **natural gas**, which is a homogeneous mixture of gases containing hydrogen and carbon atoms. Oxygen, most often obtained from air, is normally required for combustion to occur. When hydrogen, carbon, and oxygen are in the correct proportion, and are exposed to an ignition source, combustion occurs. Products of combustion include gases, light, and heat. Below is a general equation for this process:

$$\text{Fuel} + \text{Oxygen} \rightarrow \text{Products of combustion} + \text{Energy}$$

Fuels can be solid, liquid, or gaseous. Gaseous fuels, like natural gas, are simple in molecular composition. Liquid and solid fuels are more complex. Fuels used for combustion may contain varying amounts of the elements hydrogen, carbon, or sulfur which readily oxidize in the combustion process.

Most non-gaseous fuels contain non-combustibles, especially solid fuels like coal and wood. The non-combustible elements can include:

a) Moisture (water)
b) **Ash**
c) Other trace elements (nitrogen, chlorine, etc.)

Biomass, for example, can contain all of the combustibles and many non-combustible elements. An acronym that can be used to remember the base fuel components is:

NOCASH

N Nitrogen
O Oxygen
C Carbon
A Ash
S Sulfur
H Hydrogen

Some gaseous fuels, such as digester gas, also contain considerable moisture.

During the boiler combustion process, the hydrogen, carbon, and sulfur in the fuel directly combine with oxygen supplied in the combustion air, releasing energy in the process. If chemical analysis shows the fuel contains oxygen, it is assumed to be in a form combined with hydrogen as moisture. For this reason, oxygen in a fuel is used as an indicator of the amount of hydrogen unavailable for combustion. Typically, in calculating the amount of oxygen required for combustion, the amount required to react with the hydrogen portion is reduced by that amount of oxygen already in the fuel. If it is a dry fuel, this subtraction is usually not done.

Water is one of the products of combustion. It is produced when hydrogen combines with oxygen. In this reaction, two atoms of hydrogen will combine with one atom of oxygen to form one molecule of water. However, some of the moisture in flue gas may not be due to combustion. It could be due to the pre-existence of water physically held in the fuel. When moisture exists in a solid fuel, such as wood, it may be due to the exposure to environmental moisture, such as rain or snow. It may also be the result of the chemical combination of hydrogen and oxygen prior to combustion.

The ash (inorganic) component of a fuel is non-combustible, and remains as a residue after the combustion process has finished.

Nitrogen may be classified as both a combustible and non-combustible component. It is usually assumed that the nitrogen in the air is non-reactive at combustion temperatures. This means that there are as many moles of pure nitrogen in the products as there were in the combustion air.

Fuel based nitrogen (FBN) reacts readily in the furnace, depending on the fuel makeup. At higher furnace temperatures, nitrogen in the fuel may react with oxygen to form oxides of nitrogen (**NO_X**). It is important to limit the release of NO_X because it is a pollutant. NO_X emissions are monitored and controlled to meet the terms of the plant environmental license.

Side Track

Biomass fuels can have significantly higher levels of FBN than other fuels.

Biomass fuels are waste materials sourced from the forestry and agricultural industries. For some plants, biomass is free fuel, since this waste byproduct is costly to dispose of in other ways.

Because of their biological origins, biomass fuels often have a higher percentage of nitrogen in their makeup than hydrocarbon based fuels. These percentages can vary significantly even within the same type of fuel. Wood waste normally has about 0.25% nitrogen. This percentage can increase to over 5% in the case of wood veneers or laminates. This nitrogen, bound within the chemical makeup of the fuel, has a higher probability of reacting with oxygen than the nitrogen in the air.

Although a number of reaction products may be created, the release of NO_X is of greatest concern. Environmental regulations are primary governing factors that must be addressed when designing a new system. The associated costs to comply with mandated NO_X emissions limits can be significant, especially if it requires the addition of costly flue gas treatment equipment.

There are a number of strategies used to lower the potential for NO_X production. These include:

- Increasing the fuel to air ratio
- Lowering the combustion temperature
- Lowering the mixing time in the burner
- Treating the combustion gases with chemicals that react with the NO_X to produce other compounds

Theory of Combustion

In the process of combustion, the main combustible elements of the fuel – carbon, hydrogen, and sulfur – combine chemically with oxygen, normally from the air. The products of **complete combustion** are carbon dioxide (CO_2), water (H_2O), and sulfur dioxide (SO_2), respectively. This is called complete combustion because the products of these reactions cannot continue to react with oxygen. When the products of complete combustion are formed, the greatest amount of heat energy is released.

Certain conditions must be met to ensure complete combustion of the fuel in the furnace.

a) **Enough Air**. Adequate combustion air must be supplied to the furnace to provide all the oxygen, to react with all the combustible matter of the fuel.

b) **Turbulence**. The air and fuel must be thoroughly mixed together, so that each particle of fuel has the necessary oxygen to burn. Turbulence aids in this mixing.

c) **Temperature**. The furnace temperature must be high enough to ignite the fuel as it enters.

d) **Time**. The furnace must be large enough to allow sufficient time for the combustion to complete, before combustion products contact cooler surfaces.

The above conditions may be summarized as enough air, plus adequate time, temperature and turbulence. The last three terms are often referred to as the **Three Ts of Combustion (3 Ts)**. If poor combustion is taking place in a furnace, then one or more of the four conditions is not being met.

Combustion Equations

Products of Complete Combustion

Of the combustible elements in a fuel, carbon usually forms the greatest percentage by mass. If the combustion is complete:

a) Each atom of carbon (C) combines with two atoms of oxygen (O) to produce gaseous carbon dioxide (CO_2), plus heat.

b) Two atoms of hydrogen (H) combine with one atom of oxygen (O) to produce water vapour (H_2O), plus heat.

c) Each atom of sulfur (S) combines with two atoms of oxygen (O) to produce gaseous sulfur dioxide (SO_2), plus heat.

The combustion process can be expressed in simple chemical equations. These represent the combination of these combustible elements with oxygen during complete combustion:

1. Carbon + Oxygen → Carbon Dioxide + Heat

$$C + O_2 \rightarrow CO_2$$

2. Hydrogen + Oxygen → Water Vapour + Heat

$$2H_2 + O_2 \rightarrow 2H_2O$$

3. Sulfur + Oxygen → Sulfur Dioxide + Heat

$$S + O_2 \rightarrow SO_2$$

The non-combustible elements of fuel will not combine with oxygen. Instead, they will form ash or pass through the furnace unchanged.

Products of Incomplete Combustion

If any of the requirements for complete combustion are missing, then the combustible elements will not combine completely with oxygen. The resulting products may react further when exposed to additional oxygen and a source of ignition, and will release more heat. This process is called **incomplete combustion**. Equations 4–7 show the incomplete combining of oxygen and combustibles.

4. Carbon + Insufficient oxygen → Carbon monoxide + Heat

$$2C + O_2 \rightarrow 2CO$$

Equation 4 shows the formation of carbon monoxide (CO) instead of carbon dioxide. This reaction is undesirable because carbon monoxide is a combustible compound. If it passes from the furnace without burning, CO represents a loss of heating value, and a waste of fuel. As well, CO contributes to pollution. However, if carbon monoxide combines with more oxygen before leaving the furnace, then its combustion will come to completion. Carbon dioxide will then form (Equation 5), with an additional release of heat.

5. Carbon monoxide + Oxygen → Carbon dioxide + Heat

$$2CO + O_2 \rightarrow 2CO_2$$

Equation 6 shows the formation of free hydrogen. This process is undesirable because hydrogen is a combustible element. If left unburned, there will be a waste of fuel and a loss of heating value.

6. Hydrogen + Insufficient oxygen → Water Vapour + Free hydrogen + Heat

$$3H_2 + O_2 \rightarrow 2H_2O + H_2$$

Similarly, the formation of free sulfur (Equation 7) is undesirable. Because it is combustible, it represents a waste of fuel. In actual practice, the sulfur in most fuels is considered an impurity. This is because it produces relatively little heat when it burns, and produces corrosive acids in the presence of water. The sulfur dioxide discharged into the atmosphere also contributes to air pollution (acid rain).

7. Sulfur + Insufficient oxygen → Sulfur dioxide + Free Sulfur

$$2S + O_2 \rightarrow SO_2 \quad S$$

Hydrogen is extremely reactive and will normally burn completely. The amount of sulfur in most fuels is very small. Neither of these elements, then, are of major concern when considering incomplete combustion. The main concern is the formation of carbon monoxide. If the combustion reaction is very poor, free carbon can also be produced. This occurs when carbon in the fuel is vaporized, but some of it does not combine with any oxygen. As this carbon leaves the combustion zone, it appears as black smoke. Some of the unburned carbon deposits on heat transfer surfaces as soot. Note that the formation of carbon oxides (CO and CO_2) does not create visible smoke, because they are colourless gases.

A major responsibility of any operator is to ensure combustion processes are driven to completion. This ensures:

- The maximum amount of energy has been removed from the fuel.
- Efficiency targets are being met.
- The plant is meeting the terms of its environmental license.

Theoretical and Excess Air

Theoretical Air and Excess Air

Air is a mixture of about 21% oxygen, 78% nitrogen, and 1% other constituents by volume. The other components are normally combined with the nitrogen for the purpose of combustion calculations so the volume relationship will be considered to be 21% O_2 and 79% N_2.

The oxygen required for complete combustion must come from the air supplied to the furnace. The exact amount of air required to supply oxygen for complete combustion is called the **theoretical air**. In actual practice, it is necessary to supply more than this theoretical amount of air in order to make sure that all particles of fuel are exposed to oxygen. The amount of air in excess of the theoretical air is called **excess air**. This is usually expressed as a percentage of the theoretical air. The total **combustion air** delivered is equal to the theoretical air plus the excess air.

Example 1

If the theoretical air required for complete combustion of 1 kg of coal is 12 kg, and 18 kg of air are actually supplied, what is the percentage of excess air?

Solution 1

The amount of excess air is 6 kg (18 − 12 = 6). Expressed as a percentage of the theoretical air (12 kg), this would be:

$6 \div 12 \times 100\% = 50\%$ **(Ans.)**

Self-Test 1

The theoretical air to burn one kilogram of Powder River Basin coal is 7.5 kg. How much combustion air is needed to burn 25 kg of Powder River Basin coal if 20% excess air is required?

225 kg (Ans.)

The percentage of excess air required for proper combustion of a fuel may vary from 10% to 60%, or even higher. The amount required depends on:

a) The time available for the fuel to mix with the air before it comes in contact with the relatively cool heating surfaces, and is cooled below ignition temperature. (Time)

b) How well the fuel and air can mix together. (Turbulence)

c) The temperature that exists within the furnace. (Temperature)

A gaseous fuel, such as natural gas, that can easily mix with the combustion air requires less excess air than a solid fuel, such as wood waste. Coal and biomass solids are variable in their makeup, and have variable optimal excess air percentages.

It is desirable to reduce the amount of excess air supplied to the furnace, as much as possible. Excess air improves combustion, but does not actually participate in the combustion reaction. It is heated to a high temperature in the furnace, and then exhausted through the chimney. The excess air contributions carry away heat and lower boiler efficiency. In addition, when excess air increases, the power required for forced and induced draft fans also increases.

However, if the excess air is reduced too much, there will be a possibility of incomplete combustion. This will result in the formation of carbon monoxide and free hydrogen.

Calculating Theoretical Air

Excess air requirements are often determined by the design characteristics of the combustion system. However, fuel characteristics can vary, even if the form remains the same and the three Ts are followed. The chemical composition of the fuel will most often determine the theoretical air required. The theoretical air for a fuel composed of methane (CH_4) would obviously be very different than the theoretical air for diesel fuel or wood waste. These differences are illustrated in Examples 2 and 3.

Example 2: Theoretical Air for Wood Waste

The mass of a fuel is measured in kg. To determine theoretical air, the amount of oxygen required to completely burn the fuel must first be calculated. The elements in fuel that react with oxygen are carbon, hydrogen, and sulfur. The theoretical air is usually measured in units of volume (m^3 per kg of fuel).

A typical analysis of dry wood waste has an overall composition (by mass) of 51.55% C, 5.62% H_2, and 0.08% S, with the remainder being ash (42.75% - includes a minimal amount of FBN). What is the theoretical air for 100 kg of this fuel, if the fuel undergoes complete combustion?

Step 1: Convert the % combustible elements into mass (kg) in the sample.

In a 100 kg sample, the composition by mass is:

$$\begin{aligned} C &= 51.55\% \times 100 \text{ kg} = 51.55 \text{ kg} \\ H_2 &= 5.62\% \times 100 \text{ kg} = 5.62 \text{ kg} \\ S &= 0.08\% \times 100 \text{ kg} = 0.08 \text{ kg} \\ \text{Remainder (Ash)} &= 42.75\% \times 100 \text{ kg} = 42.75 \text{ kg} \end{aligned}$$

Step 2: Convert the mass of each combustible element into moles.

Divide the mass of each element by its molar mass (Atomic Weight/Mass – see Periodic Table) to determine the moles of the element.

Note: Although ash may be important in the economics of using the fuel, it is not important in calculating the theoretical air.

$$\begin{aligned} C &= 51.55 \text{ kg} \div 12.0107 \text{ kg/Kmol} = 4.29 \text{ Kmol C} \\ H_2 &= 5.62 \text{ kg} \div 2.0158 \text{ kg/Kmol} = 2.79 \text{ Kmol } H_2 \text{ (Note the use of Hydrogen as a molecule.)} \\ S &= 0.08 \text{ kg} \div 32.065 \text{ kg/Kmol} = 0.0025 \text{ Kmol S} \end{aligned}$$

Step 3: Calculate the number of moles of oxygen theoretically required to completely combust the mass of each element.

These elements will react with oxygen according to the following combustion equations and molar ratios:

$C + O_2 \rightarrow CO_2$	Molar Ratio of $C:O_2 = 1:1$
$2H_2 + O_2 \rightarrow 2H_2O$	Molar Ratio of $H_2:O_2 = 2:1$
$S + O_2 \rightarrow SO_2$	Molar Ratio of $S:O_2 = 1:1$

Therefore, the theoretical amount of oxygen required to combust these masses of elements equals:

4.29 kmol C will react with 4.29 kmol O_2

2.79 kmol H_2 will react with 1.40 kmol O_2

0.0025 kmol S will react with 0.0025 kmol O_2

For a total O_2 required = 5.6825 kmol

Step 4: Convert moles of O_2 required, to volume of theoretical O_2 required.

One mole of any gas occupies a volume of 22.4 L at standard temperature and pressure (0°C and 101.3 kPa). Therefore, the volume of oxygen required to combust the fuel will theoretically be:

$5.6825 \text{ kmol} \times 22.4 \text{ L/mol} = 127.29 \text{ kL}$

$1000 \text{ L (1kL)} = 1 \text{ m}^3$

Therefore, theoretical volume of O_2 required = 127.29 m^3

Step 5: Calculate the volume of theoretical air required.

Composition of air (volume basis) = 21% oxygen, 79% everything else (N_2 + CO_2 + other gases)

Ratio of total air to O_2 = 100/21 = 4.76

Therefore, the total volume of air required to theoretically combust 100 kg of fuel equals:

$127.29 \text{ m}^3 \times 4.762 = 606.15 \text{ m}^3$ for 100 kg

Therefore, theoretical air = 6.06 m^3/kg

An alternative measure for theoretical air is a mass measurement (kg/kg). In this calculation, the theoretical air (kg/kg fuel) is calculated by considering the mass percentages of carbon, sulfur, and hydrogen (after subtracting the hydrogen due to moisture). The shortened form of this calculation is provided in the **PanGlobal Academic Supplement**.

A S

Example 3: Theoretical Air and Combustion Air for Fuel Oil

An analysis of the composition of a fuel oil shows that it contains (by mass) 86.47% C, 11.65% H_2, 1.35% S, and the balance ash. This oil is burned in a steam-generating furnace with a 15% excess air requirement. Calculate the volume of feed air (m^3) per kg of oil.

Step 1: Convert the % combustible elements into mass (kg) in the sample.

In a 100 kg sample, the composition by mass is:

$$C = 86.47\% \times 100 \text{ kg} = 86.47 \text{ kg}$$

$$H_2 = 11.65\% \times 100 \text{ kg} = 11.65 \text{ kg}$$

$$S = 1.35\% \times 100 \text{ kg} = 1.35 \text{ kg}$$

$$\text{Remainder (Ash)} = 0.53\% \times 100 \text{ kg} = 0.53 \text{ kg}$$

Step 2: Convert the mass of each combustible element into moles.

Divide the mass of each element by its molar mass (Atomic Weight/Mass – see Periodic Table) to get the moles of the element.

Note: Although ash may be important in the economics of using the fuel, it is not important in calculating the theoretical air.

$$C = 86.47 \text{ kg} \div 12.0107 \text{ kg/kmol} = 7.199 \text{ kmol C}$$

$$H_2 = 11.65 \text{ kg} \div 2.0158 \text{ kg/kmol} = 5.779 \text{ kmol } H_2$$

$$S = 1.35 \text{ kg} \div 32.065 \text{ kg/kmol} = 0.042 \text{ kmol S}$$

Step 3: Calculate the number of moles of oxygen required to theoretically completely combust the mass of each element.

These elements will react with oxygen (combustion) in the following chemical equations and molar ratios:

$C + O_2 \rightarrow CO_2$ Molar Ratio of $C:O_2 = 1:1$

$2H_2 + O_2 \rightarrow 2H_2O$ Molar Ratio of $H_2:O_2 = 2:1$

$S + O_2 \rightarrow SO_2$ Molar Ratio of $S:O_2 = 1:1$

Therefore, the total oxygen required to theoretically combust these masses of elements equals:

7.199 kmol C will react with 7.199 kmol O_2

5.779 kmol H_2 will react with 2.89 kmol O_2

0.042 kmol S will react with 0.042 kmol O_2

For a total O_2 required = 10.131 kmol

Step 4: Convert the theoretical moles O_2 required to the theoretical volume O_2 required.

One mole of any gas occupies a volume of 22.4 L at standard temperature and pressure (0°C and 101.3 kPa). Therefore, the volume of oxygen required to combust the fuel will theoretically be:

$10.131 \text{ kmol} \times 22.4 \text{ L/mol} = 226.93 \text{ m}^3$

Therefore, theoretical volume of O_2 required is 226.93 m^3

Step 5: Calculate the volume of theoretical air required.

Therefore, the total volume of air required to theoretically combust 100 kg of the fuel equals:

$226.93 \text{ m}^3 \times 4.76 = 1080.21 \text{ m}^3$ for 100 kg

Therefore, theoretical air = 10.8 m^3/kg

Step 6: Calculate the volume of combustion air required.

Theoretical air = 10.8 m^3/kg

Excess air = 15%

Therefore, combustion air = 10.8 m^3/kg × 1.15 = 12.42 m^3/kg

When comparing the theoretical air requirements in these two examples, the differences between a solid and liquid fuel are clear. The liquid fuel has a much lower ash content and higher carbon content. Its theoretical air requirement is almost twice that of the wood waste. This higher requirement has a significant effect of the air handling equipment requirements for this fuel.

Self-Test 2

What is the theoretical air for a liquid fuel that has the following composition: 75.4% C, 12.6% H_2, and 0.25% S, with the remainder being ash? What is the combustion air if 15% excess air is required?

10.0 m^3/kg, 11.5 m^3/kg (Ans.)

Flue Gases

Power Engineers can determine whether combustion is complete by analyzing the **flue gas**. Depending on the composition of the fuel, flue gas is comprised of CO_2, H_2O, SO_2, O_2, N_2, and possibly very fine ash (**fly ash**). Oxygen is present because of the excess air necessary to assure complete combustion.

Most of the nitrogen contained in the flue gas comes from combustion air (N_2). Some fuels contain elemental nitrogen (N) as a component. This nitrogen will combine with oxygen to produce a variety of nitrogen oxides, often called NO_X. NO_X is a regulated component in a plant's environmental license.

The percentage of oxygen and nitrogen involved in the combustion process will depend on how the quantity of fuel is measured. Some fuels are measured by volume, such as natural gas (m^3), or biodiesel (L). Some fuels are measured by mass, such as coal.

For fuels measured by volume, the percentage of oxygen and nitrogen in the combustion air is taken as 21% oxygen and 79% nitrogen, volume or molar percentages.

For fuels measured by mass, the percentage of oxygen and nitrogen in the combustion air is taken as 23% oxygen and 77% nitrogen by mass.

Most nitrogen enters in the air, mixed with oxygen. Nitrogen is heated in the furnace, and leaves the chimney at a relatively high temperature. The heat carried away by the nitrogen represents a heat loss to the atmosphere. Therefore, the amount of excess air should be reduced to a minimum that supports complete combustion. The ideal amount of excess air required is determined by the following factors:

a) Composition and condition of the fuel fired.

b) Method used for burning the fuel. This mostly relates to the burning of solid fuels. For example, coal ground to a fine powder will require less excess air than coal supplied to the furnace in the form of large particles.

Table 1 shows the approximate amounts of excess air typically required for the various firing methods and types of fuels.

Table 1 – Typical Excess Air and O_2 Required

Fuel	Excess Air ($N_2 + O_2$)	O_2%
Coal Stoker firing	25 - 35% by mass	6 - 8% by mass
Coal Pulverized	15 - 20% by mass	3 - 5% by mass
Fuel Oil	10 - 15%	2 - 3%
Gaseous Fuel	3 - 10%	1 - 2%

Incomplete combustion will result if the amount of air supplied is insufficient, or if any other requirement for complete combustion is not met. The presence of CO, SO, H_2, or soot (carbon) in the flue gases indicate incomplete combustion. This residue represents a serious waste of fuel. In addition, there is a possibility of a furnace explosion, due to pockets of CO being formed in parts of the furnace.

Boiler Room Combustion Air Supply

It is extremely important for combustion air to be provided to boiler rooms. These openings provide the amount of outside air to permit satisfactory combustion.

These openings must be not be merely open doors and windows. These can be shut in cold weather. A shortage of combustion air results in incomplete combustion of the fuel. This can cause:

a) Fouling of heating surfaces with soot
b) Plugging of gas passages
c) Poor heat transfer
d) Increased fuel consumption
e) Possibility of a disastrous explosion, when firing oil or gas
f) Carbon monoxide poisoning to anyone entering the room

CSA B149.1, the **Natural Gas and Propane Installation Code**, specifies the type, location, and size of outside air supply openings into buildings with gas burning equipment of various capacities with natural or mechanical draft. **CSA B139**, the **Installation Code for Oil Burning Equipment**, contains similar requirements for oil burning appliances. Strict adherence to these codes is required.

Some atmospheric conditions can cause the formation of "hoar frost" on building air inlet screens. This can restrict the amount of air entering the building, and reduces the combustion air.

Objective 2

Discuss the characteristics of solid, liquid, and gaseous fuels.

Solid Fuels

Solid fuels are any combustibles that are solid at atmospheric pressure and temperature. They contain elements of hydrogen, carbon, and sulfur in varying proportions. Coal, wood, biomass, and municipal waste are the common solid fuels used for steam production. Their main form of transport to a plant site is either by truck or railcar.

Because of their variable nature, solid fuels require more preparation and handling than either liquid or gaseous fuels. The composition of solid fuels is analyzed much more regularly than the other two types. Two important analyses performed on solid fuels include:

Proximate Analysis: A measure of the moisture, **fixed carbon**, **volatile combustible material (VCM)**, and ash content of a fuel.

Ultimate Analysis: A measure of the elemental composition of the fuel in percent by mass, including C, H, O, N, S, and ash.

Coal has been widely used as an economical fuel source; however, it also produces the greatest amount of atmospheric pollution. Coal is recognized as being the largest single source of industrial CO_2. The **2015 Paris Accord** identified the need to reduce the number of coal-fired steam generating plants worldwide.

Coal is composed of carbon, hydrogen, oxygen, sulfur, nitrogen, moisture, and ash. Of these components only carbon, hydrogen, and sulfur are combustible. The hydrogen combines with some of the carbon to form hydrocarbons. These hydrocarbons are known as volatile matter since they pass off as gas when the coal is heated. The rest of the carbon, which is not combined with hydrogen, is referred to as fixed carbon. The sulfur represents a very small percentage of a coal's composition. Although the sulfur is combustible, it is considered to be an impurity. Its combustion product, sulfur dioxide, produces corrosion in the boiler and chimney. Sulfur also contributes to air pollution.

There are many different types of coal found in the world. These are classified by:

- Percentage of fixed carbon
- Percentage of volatile material
- **Calorific value**

Wood, **biomass**, and other organic materials were historically important sources of boiler fuel. The growth in pulp and paper, and wood manufacturing industries, combined with the development of coal, oil, and gas led to the decline of wood as a fuel. Coal, oil, and gas are sources of chemical energy that are more concentrated and easier to transport.

Nevertheless, the byproducts of wood processing, such as bark, chips, and sawdust, continue to be used as fuel where there are plentiful affordable supplies. Being **carbon-neutral**, wood byproduct use is an increasingly important option in North America's carbon sensitive economy. These materials are often referred to collectively as hog fuel. They can include the following:

Wood Chips: These are chipped woody biomass in the form of pieces, with a defined particle size. Wood chips are produced mechanically with sharp knives.

Hog Fuel: Hog fuel consists of wood in pieces of varying sizes and shapes. Blunt tools, such as rollers or hammers, crush the wood pieces to produce hog fuel.

Wood Pellets: Wood pellets are products that have been pulverized and pelletized under heat and high pressure. The resulting product is a fuel of consistent size and shape.

Urban Wood Fuels: These are wood residues derived from urban activities. They include packaging materials, off-cuts from manufacturing, construction and demolition wood residues, yard trimmings, urban tree residues, and from land clearing.

Herbaceous Fuels: These wood-like fuels are sourced from grasses and straw. They may be in the form of chips, hogs, pellets, or bales.

Also used as fuels are residual organic materials, like sugar cane stalks (**bagasse**) and shells from nuts. These fuels are common to the food industry, and to community waste processing plants. Recently, the term biomass has been applied collectively to this type of source material.

Hog fuel and other biomass fuels can be burned either on their own, or in conjunction with coal, oil, or gas firing systems. Various arrangements have been developed to handle the solid materials. These include refractory-lined chambers, and stationary, travelling, and vibrating grates.

Much like the Pulp and Paper industry, some food processing plants (like coffee and sugar producers) burn their waste products to produce usable energy.

Municipal Solid Waste (MSW) combustion recovers energy and decreases the volume of solid waste destined for landfills. However, they can also recover energy from the waste burning process. This generates a renewable energy source, and reduces carbon emissions by offsetting the need for energy from fossil sources. Burning MSW also reduces methane generation from landfills. Two types of facilities encompass the majority of MSW sites including:

Mass Burning Facilities: which burn MSW in a single combustion chamber with excess air, due to the highly varied composition of the municipal waste.

Refuse Derived Fuel Systems: which use mechanical methods to shred incoming MSW, and separate out non-combustible materials. They produce a combustible mixture that is suitable as a fuel in a dedicated furnace or as a supplemental fuel in a conventional boiler system.

RDF can have potential negative effects on both air and water quality around facilities. Jurisdictions like the **Canadian Council of Ministers of the Environment (CCME)** provide guidelines and regulations on the management of this fuel and its emissions. Typical regulated parameters include:

- A minimum temperature that is high enough to ensure the destruction of organics. (1000°C)
- A minimum retention time after combustion has completed. (more than one second at 1000°C)
- Air supply designs need to ensure efficient mixing between burning waste and incoming air. (Secondary supply required to be greater than 40% of capacity)
- Sufficient oxygen at outlet minimizes quenching or mixing problems. (mass burning: 6 to 12% O_2; refuse derived fuel: 3 to 9% O_2)
- A maximum level of carbon monoxide allowed in the flue to ensure complete combustion (less than 50 ppm).

Liquid Fuels

Liquid fuels used for boiler firing that derive from petroleum are often referred to collectively as **fuel oils**. Petroleum, called crude oil in its unrefined state, is a mixture of a large variety of hydrocarbon compounds. These include very light gaseous hydrocarbons, progressively heavier liquid hydrocarbons, and very heavy hydrocarbons in the semi-solid state.

In the refinery, the fractional distillation process is used to separate crude oil into a number of distinguishable groups. This is done according to specific characteristics, such as boiling point, specific gravity, and viscosity. These groups include:

- Gases such as methane and ethane
- Gasoline
- Jet fuel
- Kerosene
- Diesel fuel
- Light fuel oils
- Lubricating oils
- Heavy oils
- Residue

The distinction between these groups is not always sharply defined. For example, the diesel fuel range overlaps the light fuel oil range. This overlapping means that some diesel fuels are quite similar in composition and characteristics to light fuel oils. In fact, No. 2 diesel fuel is nearly identical to No. 2 fuel oil, which is the most widely used oil for packaged boilers.

The main components of fuel oils are carbon and hydrogen combined as hydrocarbons.

They also contain small amounts of oxygen, sulfur, nitrogen, and traces of ash. Fuel oils are typically classified into commercial grade numbers according to such characteristics as:

Relative Density (specific gravity): The ratio of the mass of a certain volume of oil to the mass of an equal volume of water.

Viscosity: A measure of the internal resistance of the oil to flow.

Flash Point: The lowest temperature at which the fuel oil gives off sufficient vapour to ignite when exposed to an open flame. The flash point is a good indication of the fire hazard involved in the storage and pumping of the oil. Since the flash point of fuel oils is well above ambient temperatures, they are relatively safe fuels to store, even inside a building.

An overview of common values for the characteristics of various classes of fuel oil and their typical usage application is shown in Table 2.

Table 2 – Characteristics of Fuel Oils

Commercial Grade #	Relative Density (Water = 1)	Viscosity (SSU)	Heating Value (kJ/L)	Minimum Flash Point		Typical Application
				°C	°F	
1	0.815	31	37905	38	100	Domestic
2	0.86	32 - 39	38602	38	100	Domestic/Industrial
4	0.92	45 - 120	39299	54	130	Industrial
5	0.95	140 - 700	40414	54	130	Industrial
6	0.98	> 900	40832	66	150	Industrial

Grades 1 and 2 are often called furnace oils. They have relatively low viscosity, and low relative density. Their flashpoint is low enough that they generally do not require heating before being fired in the boiler furnace. Grade 2 oil is the most popular fuel oil for domestic and small commercial or industrial furnaces and boilers.

Grades 4, 5, and 6 are (respectively) light, medium, and heavy industrial fuel oils. They require heating during storage and pumping, and additional heating (usually to about 95°C) before they can be satisfactorily burned in a furnace.

Fuel oils have certain advantages over solid fuels as a boiler fuel:

- Oil needs less storage space.
- Oil flow is easier to measure and control.
- Oil requires less fuel handling equipment.
- Oil burns more cleanly and efficiently.

Two major disadvantages are that oil is more expensive and less abundant than solids like coal.

There are several methods to transport liquid fuels to facilities. These include tanker trucks, rail cars, and pipelines.

On the plant site, fuel oils are commonly stored in aboveground storage tanks, surrounded by containment berms. The berms are designed to hold 110% of the volume of the storage tank, in order to provide spill protection (Figure 1).

Figure 1 – Fuel Oil Tank with Containment Berm

Gaseous Fuels

Gaseous fuels commonly used for combustion in boilers include:

- Natural gas
- Liquefied petroleum gases
- Biogas

Natural gas is obtained from gas wells drilled in rock formations, or as a secondary product from oil wells that contain mixed fluids. Processing is usually performed to remove undesirable components, such as moisture, CO_2, and sulfur compounds. Some undesirable components have economic value, so they are recovered, processed further, and sold. The remaining natural gas is a homogenous mixture of methane (80 to 90%), and ethane (10 to 20%). Natural gas may also contain traces of propane, butane, nitrogen, oxygen, carbon dioxide, and hydrogen sulfide.

The advantages of natural gas as a boiler fuel are:

a) Natural gas produces no ash when burned.
b) Natural gas requires little handling equipment.
c) Natural gas flow is easily measured and controlled.
d) Natural gas mixes easily with air, so no preheating or atomization equipment is required.
e) Natural gas is a very clean fuel. It does not spill, and leaves no residue.
f) Natural gas requires no storage space.

Natural gas, however, is more expensive than coal. Natural gas is delivered from gas fields to plants via pipeline. Regions not served by pipeline do not have access to natural gas. The cost and supply of natural gas and oil depends on a number of factors, and varies from location to location.

Liquefied petroleum gases (LPGs) are petroleum products that consist of light hydrocarbons (butane, propane, or a mixture of the two). These fuels are gaseous at atmospheric pressure, but can be condensed to their liquid state by the application of moderate pressure. In other words, they are petroleum gases that can be easily liquefied.

In liquid form, LPGs take as little as 1/120th of the space needed as a gas. This makes large quantities of LPG easy to store and transport in relatively small containers. To burn, LPGs are first converted to gas. This is done through a reduction in pressure, and the absorption of latent heat of evaporation.

The boiling point of butane at atmospheric pressure is 0°C (32°F), and propane is –42°C (–44°F). In cold weather, propane and butane are heated so that adequate vapour is produced to burn in the boiler. LPGs burn completely and cleanly with a bright flame.

Biogas is the gaseous emissions from anaerobic degradation of organic matter (from plants or animals) by bacteria. Biogas is mainly a mixture of methane (CH_4) and carbon dioxide (CO_2), along with other trace gases.

Table 3 shows properties of gaseous hydrocarbon fuels. Note that propane and butane have significantly more heating value, in MJ/m^3, than natural gas. This is in part due to the greater density of the vapourized product. Also, note that propane and butane are heavier than air, and natural gas is lighter than air. In the event of a leak, propane collects in low places, where it may form a combustible mixture with air. Natural gas accumulates in high places, where it may form a combustible mixture with air.

Table 3 – Properties of Gaseous Hydrocarbon Fuels

Fuel	Relative Density of Vapour (Air = 1)	Heating Value MJ/m^3 (vapour)
Propane	1.86	93.8
Butane	2.45	121.5
Natural Gas	0.676	37.24

Objective 3

Explain the effects of fuels and combustion on refractory materials.

Effects of Combustion on Refractory

The term **refractory** refers to materials that can withstand very high temperatures. Boiler refractory comes in many forms, such as bricks, boards, gunnable material (injected by a gun), **castable** material, plastic material (putty), and blankets.

Bricks are assembled to form protective walls.

Boards and **blankets** are attached to various surfaces as protective barriers. Blankets are flexible, and resist vibration.

Gunnable refractory is low-density material, suitable for filling cracks in monolithic (one-piece) refractory.

Castable refractory is mixed like concrete. It is then cast into forms, used to produce monolithic refractory walls or burner throats.

Plastic refractory is malleable, and can be hammered into final shape before curing.

All these refractory compounds have specific uses in boiler applications.

Boiler refractory is sourced from natural or synthetic material. Most types are non-metallic. They can be comprised of compounds and minerals, such as fireclays, bauxite, silicon carbide, zirconia, chromite, alumina, dolomite, or magnesite. A common refractory is **firebrick**, a clay that consists of aluminum silicates, with silica (SiO_2) content varying up to 78%, and alumina (Al_2O_3) content up to 44%.

Earlier designs of boilers used refractory materials for furnace walls. However, the use of the water-cooled furnace wall in the modern boiler has largely reduced the use of refractory. Since water filled tubes absorb heat from the furnace quickly, some refractory is still used in the furnace area to keep the furnace temperature high enough to ensure complete combustion.

Refractory is still in use in certain areas in the modern boiler. These areas include:

- Burner throats
- Inspection door openings
- Combustion chambers
- Baffles

There are important properties to consider when selecting refractory for a boiler. Some of these include:

- Melting point
- Creep (deformation) at high temperature
- Brick size
- Density
- Thermal conductivity

The fuel used in the boiler will affect the refractory. Some fuels burn at higher temperatures, and are more destructive to refractory.

Stoker fired units that burn coal or wood produce ash slag, which will both corrode and erode refractory.

Ash clinkers adhere to brickwork, and cause portions of refractory to break away.

Fluidized bed boilers similarly affect refractory, as they may produce significant clinkers that may adhere to walls.

In the case of oil-fired boilers, the refractory may be corroded by the ash from the oil. Also, if the flame from the burner impinges directly on the brickwork, the surface will tend to break off. If the oil burner is not positioned correctly, carbon can also build up on the burner throat refractory.

When natural gas is used as fuel, the refractory problems are usually reduced. As with the oil burner, impingement of the flame directly on the brickwork surface will cause deterioration.

Chapter Summary

Operators responsible for furnace operations require a good understanding of fuels and combustion. Incomplete combustion will result in inefficient operation with added costs, and increases to atmospheric pollution.

Conventional fuels consist of hydrogen and carbon. Some fuels contain significant sulfur. Though sulfur is a combustible, it is undesirable because its combustion products are corrosive and contribute to acid rain. Complete combustion of the three combustibles results in carbon dioxide, sulfur dioxide, and water vapor in the flue gas. Incomplete combustion will result in some carbon monoxide, sulfur, and free hydrogen showing in the flue gas.

Boiler fuels exist in many forms. This chapter covered a number of solid, liquid, and gaseous fuels, and identified some of their key characteristics.

CHAPTER 2

Fuel Delivery and Firing Systems

LEARNING OUTCOME

When you complete this chapter you should be able to:

Describe common fuel systems found in boiler systems.

LEARNING OBJECTIVES

Here is what you should be able to do when you complete each objective:

1. *Describe solid fuel delivery systems.*
2. *Describe the main types of solid fuel firing systems.*
3. *Describe gaseous fuel delivery systems.*
4. *Describe the main types of gaseous fuel firing systems.*
5. *Describe liquid fuel delivery systems.*
6. *Describe the main types of liquid fuel firing systems.*
7. *Describe flue gas analysis and how it relates to boiler efficiency.*

Chapter Introduction

The basic purpose of a fuel-fired device is to convert chemical energy into thermal energy. In the case of a boiler, that thermal energy is transferred to a fluid, such as water or steam, for process use. Inside a combustion chamber, two fundamental processes must occur to achieve this objective.

First, the fuel must be mixed with sufficient oxygen to allow sustained and complete combustion. The heated gases produced by the combustion process must then transfer the thermal energy to a fluid, such as water or steam. Various components inside the boiler are required to promote efficient combustion and heat transfer. Their design depends on factors such as the type of fuel and the method selected to transfer thermal energy.

Plants are designed to consider fuel availability, cost, and regulatory concerns about fuel usage. The equipment needed to burn a particular fuel varies according to the type of fuel used. However, there are certain basic requirements for fuel-burning equipment, regardless of the type of fuel used. Fuel burning equipment must:

- Thoroughly mix the fuel with air to ensure complete combustion.
- Rapidly adjust the amount of fuel fed to the furnace on changes in boiler load.
- Handle and dispose of ash.
- Be easily cleaned and maintained.

A central role of an operator or Power Engineer is to oversee this process of converting chemical energy, from various fuels, into usable energy to do work. It is important for the operator to understand how fuels are burned to convert their internal energy into heat that will be used by the plant's processes.

This chapter introduces fuel delivery and firing systems that are typically managed by the operator or Power Engineer.

Objective 1

Describe solid fuel delivery systems.

Solid fuels are often used to fire field-erected watertube boilers, designed specifically for the fuel being burned. The main types of solid fuels are biomass, coal, and organic wastes.

Biomass boilers have many features similar to those used in the burning of coal. They are often custom designed to use wood waste, bark, wood shavings, sawdust, leaves, grasses, bamboo, vine clippings, sugar cane, coffee grounds, and rice hulls.

Organic waste materials can also be burned to produce steam. Solid wastes can be disposed of by incineration (burning).

Increasingly, basic incinerators with waste heat recovery have evolved into watertube boilers with integral stokers, large enough to supply steam for turbine generator sets, and commercial power production.

Solid fuels are much more difficult to handle than gaseous or liquid fuels. Preparing the fuel for combustion is generally necessary and may involve techniques, such as crushing or shredding. Before combustion can occur, the individual fuel particles must be transported from a storage area to the boiler. Mechanical devices, such as conveyors, augers, hoppers, slide gates, vibrators, and blowers are often used for this purpose. The method selected depends primarily on the size of the individual fuel particles, and the properties and characteristics of the fuel.

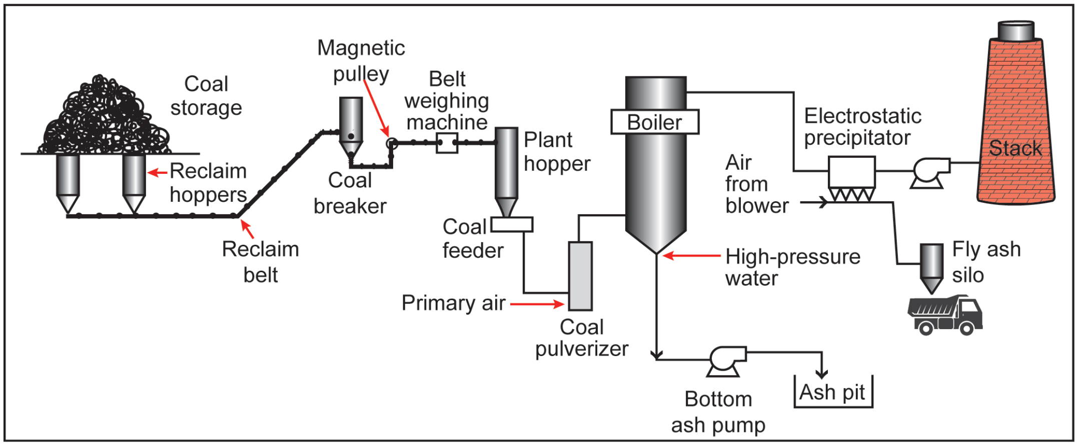
Coal is a traditional fuel still used in many large industrial facilities and power plants. Increasingly stringent environmental regulations have had some impact on their continued use, but most industry projections indicate their continued importance. The type of coal burning equipment used depends on whether the coal is in large particles or in powdered form. Common options for burning coal include:

- **Mechanical stokers**, which move larger fuel particles into the furnace using mechanical means, and burn them on a grate.
- **Coal pulverizers** (or **mills**) that grind the fuel into a fine combustible dust for burning in suspension.
- **Fluidized beds** which burn intermediate sized fuel particles at lower temperature, in a floating mass of coal and limestone.
- **Cyclone furnaces** that burn coal in a special, highly turbulent, high temperature combustion chamber adjacent to the main furnace.

Coal Storage and Handling

The coal is unloaded from the ships, trains, or large coal haulers (if the mine is next to the plant). See Figure 1 for an example of a coal handling system.

Figure 1 – Power Station Coal Handling System



Sizing and Weighing

Incoming coal requires processing to ensure optimal size for burning or pulverizing. Larger pieces of coal are broken up, usually to smaller than 5 cm. The harder and larger lumps of coal may be further reduced by a **hammer mill**. The hammer mill also removes **tramp metal** from the coal.

The crushed coal then moves to a belt-weighing machine that measures the amount of coal brought into the plant. The quantity of coal delivered by the conveyor belt is determined by the weight of the belt and the belt speed.

Coal Feeders

After weighing, the coal enters the plant hoppers or **bunkers**, which store coal in case the supply is temporarily interrupted. Normally each bunker supplies a feeder that supplies a pulverizer, stoker, fluid bed, or cyclone. The bunker has a capacity of three to twelve hours, depending on the boiler load and plant design.

Biomass – Wood Waste

Solid biofuels can come from a range of sources. The ones generally classified include:

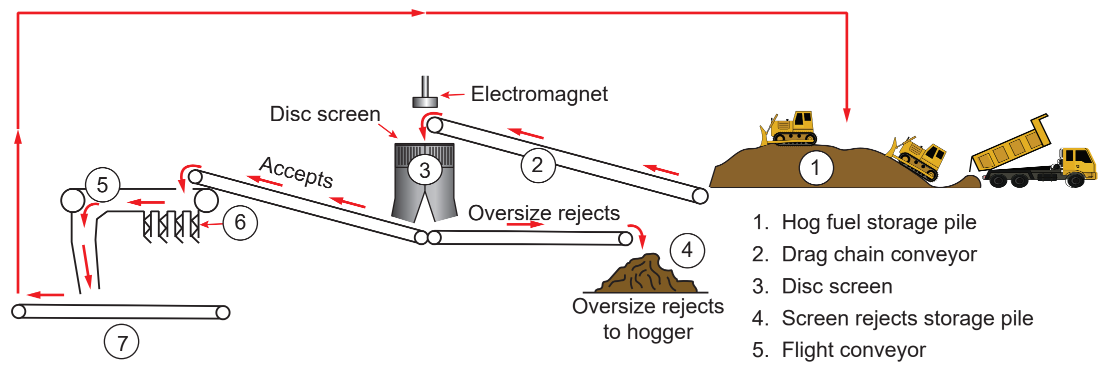
- Vegetable waste from food processing industries
- Wood processing waste
- Fibrous waste from pulp and paper operations
- Selected processed wood fuels (e.g. wood pellets and briquettes)
- Municipal wastes

Hog Fuel

Hog fuel is fuelwood in the form of pieces of varying size and shape, produced by crushing with blunt tools such as rollers or hammers. Hog fuel is transported to the mill by barge, rail car, or truck. The hog fuel is stored in a large hog pile, and reclaimed from this pile as needed.

From the pile, the hog fuel is screened and pressed before travelling to a hog fuel storage bin. This storage bin feeds onto the hog boiler conveyor, which feeds fuel to the power boiler as needed. An overview of one type of hog fuel storage and handling arrangement is shown in Figure 2.

Figure 2 – Hog Fuel Supply System



In this example, most of the hog fuel is supplied by truck. Other facilities are fed by barge and railcar.

a) The boiler feed system starts with the drag chain conveyor (2), which pulls hog fuel from the bottom of the storage pile (1).

b) The fuel passes under an electromagnet that picks up any tramp ferrous metal before the wood dumps onto the disk screen (3). The disk screen removes rocks and large pieces of wood.

c) The acceptable fuel drops from the disk screen onto the supply conveyor, and then moves onto a flight conveyor (5).

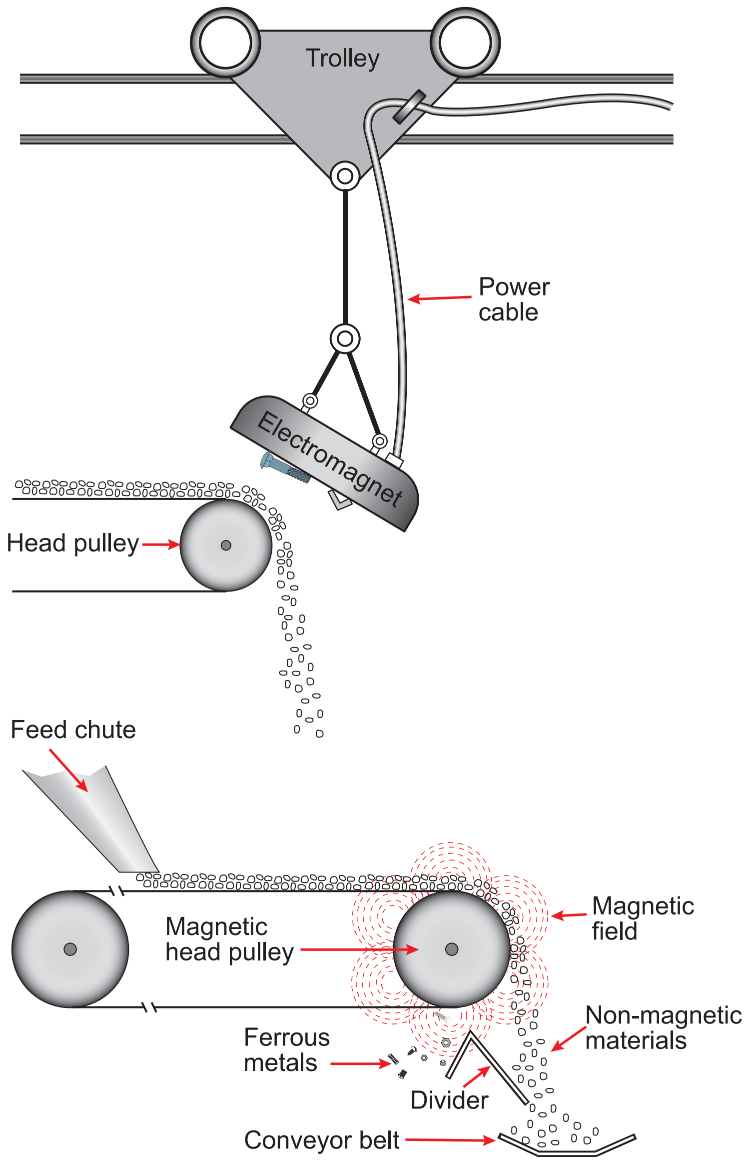
d) The flight conveyor supplies the feed chutes (6) of a power boiler with air swept spouts. The excess fuel travels to the end of that conveyor.

e) The fuel then feeds onto the return conveyor (7) and returns either to the hog pile, or back to the drag chain for another pass.

Tramp Metal in Wood-Waste

Ferrous metals are attracted by magnetic fields. Powerful magnets are used to remove ferrous metal contamination from solid wood-based fuel in two ways, shown in Figure 3.

Figure 3 – Removal of Tramp Iron from Solid Fuels



Electromagnet: The upper image in Figure 3 shows an electromagnet suspended above a hog-fuel belt conveyor. The electromagnet is mounted on a movable trolley, and is powered through a flexible cable. When an electric current passes through it, the magnet attracts any ferrous metal on the belt beneath it.

When it is necessary to dump the collected metal, the magnet is moved away from the belt. The magnet is then positioned over a collection chute, and the electric current to the magnet is switched off, which eliminates the magnet field. The magnet then releases the metal, and drops it into the collection chute.

Magnetic Head Pulley: The lower image in Figure 3 shows a hog-fuel belt conveyor equipped with a magnetic head pulley. Ferrous metal travels along the top of the belt with the hog fuel, and is collected by the magnetic head pulley. The magnetic pulley holds the metal on the belt until the belt changes direction. As the belt clears the pulley and its magnetic field, the metal drops off the bottom of the belt into a collection chute.

Biomass – Municipal Refuse

Municipal refuse refers to solid biofuels derived largely from urban sources. Some sources are:

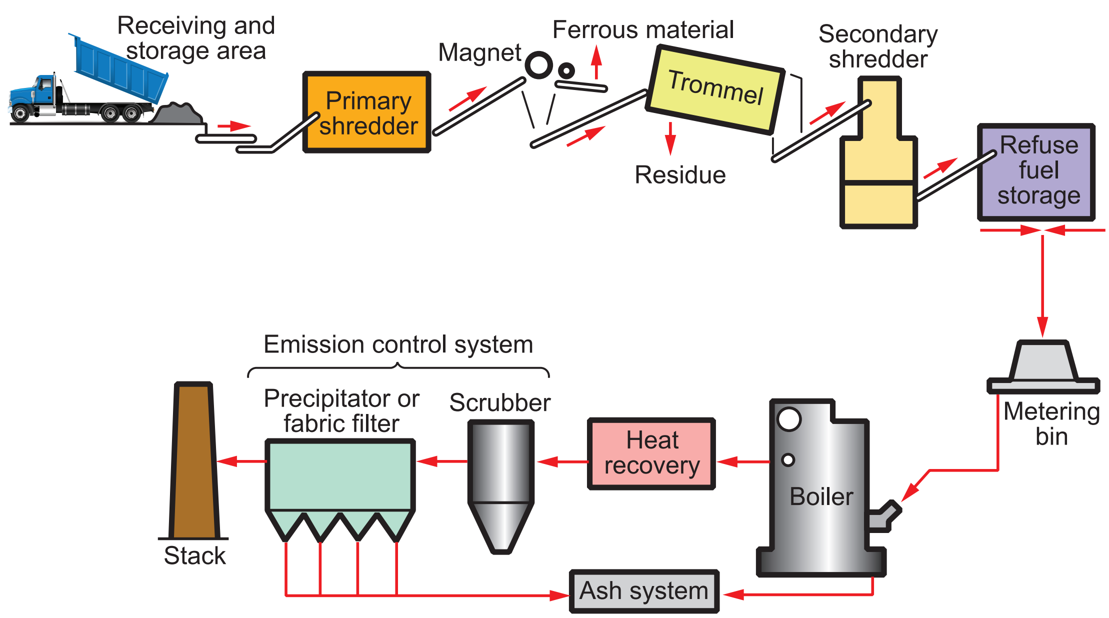
- Freight companies
- Storage, warehousing, and distribution centres
- Furniture, home wear, pallet, and board manufacturers
- Demolition and construction waste
- Household waste recycling

These sources are not exclusive to urban areas. However, the volumes necessary to make processing economically viable usually means that this type of solid fuel production is located close to urban areas.

There are two main techniques for burning refuse. They differ in the amount of preparation the fuel goes through. **Mass burning** is the first technique. It uses the fuel as received, with little preparation. Only large non-combustible or bulky items are removed.

The second technique involves more preparation of the refuse before combustion. The resulting fuel is called **Refuse Derived Fuel (RDF)**. The refuse is separated, classified, and sorted to remove recyclable products, before it is burned in the boiler. See Figure 4.

Figure 4 – Municipal Refuse Based Fuel Preparation



a) Trucks deliver the refuse and it is fed into the primary shredder.

b) From the primary shredder, the refuse is fed over a magnetic separator, which removes any ferrous materials.

c) The refuse passes to the secondary shredder, to reduce the size of the pieces. It is then stored before being metered into the boiler.

d) The combustion takes place on the grates as they move along the bottom of the furnace. Non-combustible material and ash drop into the ash pit at the end of the grate.

e) Boiler ash and fly ash from the scrubbers and precipitators are disposed of in the ash system.

Hog fuel and biomass fuels can be burned either on their own, or in conjunction with coal, oil, or gas firing systems. To handle the solid materials, a variety of arrangements have been developed, including refractory-lined chambers and stationary, travelling, and vibrating grates. The hog fuel may be burned together with, or separate from, coal. When burned with oil or gas, these fuels have their own burners, separate from the hog fuel.

Biomass Fuels – Other Effects

A number of other biomass-derived fuels are currently being used to generate heat. Some common examples include animal byproducts, bagasse (sugar cane waste), coconut hulls, coffee grounds, corncobs, palm oil waste, peanut hulls, rice husks, and poultry litter, amongst others. The increasing use of biomass fuels, and the variety of sources for biomass, have expanded to almost all possible combustible matter with biological origin. Each source has its own custom handling, storage, and preparation processes. Specific processes in the each production chain, such as manufacturing of pellets, biomass drying, and large-scale biomass storage can direct emissions to air, water, and soil.

Table 1 identifies a number of the processes used in biomass preparation and handling as a fuel source, and their potential environmental effects.

Table 1 – Biomass Processing Steps and Environmental Concerns

Biomass Processing Step	Potential Environmental Effect
Handling at growing site	Disturbance, vehicle damage, noise, particulates
Transportation to facility	Emissions, littering, noise, particulates
On site Storage	Microbial activity, odour, particulates, Volatile Organic Compounds (VOCs)
Crushing and chipping	Noise, particulates
Drying, moisture reduction	Odour, NO_X, particulates, SO_X, VOCs
Grinding – pelletizing- packing	Noise, particulates, VOC

Objective 2

Describe the main types of solid fuel firing systems.

Solid-fuel boilers differ in several respects from boilers designed to burn gas or liquid fuel. The combustion chamber, fuel feed, and pollution control equipment on the flue gas side of the boiler are all significantly different. A solid-fuel boiler combustion chamber is designed to completely burn the fuel, and support the fuel during the burning process. The boiler also includes equipment to control the combustion process and to discharge the products of combustion.

Most liquids and gases burn in suspension, and produce only gaseous by-products. Solid fuels burn at least partly in a bed supported by the furnace floor, and produce ash. Most of the ash remains at the base of the furnace after the fuel is burned. However, some fly ash is carried by the flue gas, and must be removed from boiler convection surfaces to maintain boiler efficiency. Fly ash must also be removed from the flue gas stream to reduce environmental impact.

The chemical composition, moisture, and amount of contamination in solid fuels can vary over a wide range. For example, the moisture content of waste wood or sludge can vary from 10% to 65%, and the heating value of these fuels can vary from 6980 to 22100 kJ/kg. A heating value of 8140 to 17450 kJ/kg, as fired, is a typical range.

The methods of firing or igniting these fuels vary, as well. The major technologies used can be classified into three different categories:

- Mechanical stokers
- Pulverized fuel firing
- Fluidized Beds

Mechanical Stokers

A mechanical stoker is a device that supports a burning solid fuel bed, and transports it through a furnace. Fuel is introduced onto the surface of the stoker by various mechanical means. A firing rate control system adjusts fuel feed, and in some cases the grate speed, to match the boiler load.

There are two main stoker categories: the **overfeed stoker** and the **underfeed stoker**. Overfeed stokers add fuel to above the burning bed. Underfeed stokers introduce fuel from below the bed.

Overfeed Stokers

One type of overfeed stoker is the **spreader stoker**. This stoker feeds fuel onto the grate using a rotating bladed wheel that throws the fuel onto the bed. Smaller fuel particles mix with the air while still in flight, and ignite before reaching the fuel bed. Larger fuel particles travel farther, and ignite when they reach the fuel bed. Spreader stokers are typically fed with solid fuel in three different ways: with a belt feeder, a reciprocating feeder, or a drum feeder. These are shown in Figure 5.

Figure 5 – Rotary Spreader Stoker

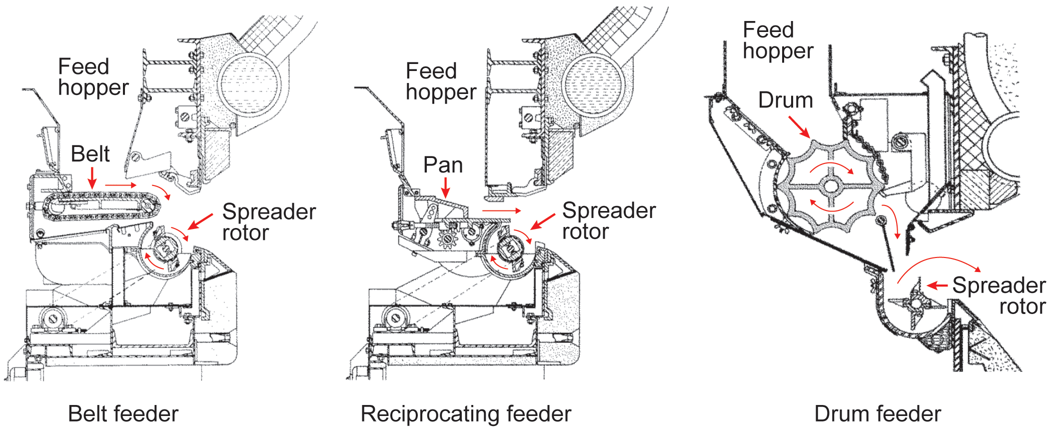


Figure 6 shows a type of overfeed stoker designed to burn both coal and wood waste. The fuel lands on the grate, which is comprised of metal links attached to form a conveyor. A mechanical drive systems moves the fuel bed toward an ash pit at the front of the boiler. Heavier particles travel to the rear of the travelling grate. These particles take longer to burn. Smaller particles land near the front of the boiler, and take less time to burn. Regardless of the initial particle size, when the particles reach the front of the boiler, they have completely burned, and are discharged into the ash pit.

Figure 6 – Dual Fuel Overfeed Travelling Grate Stoker

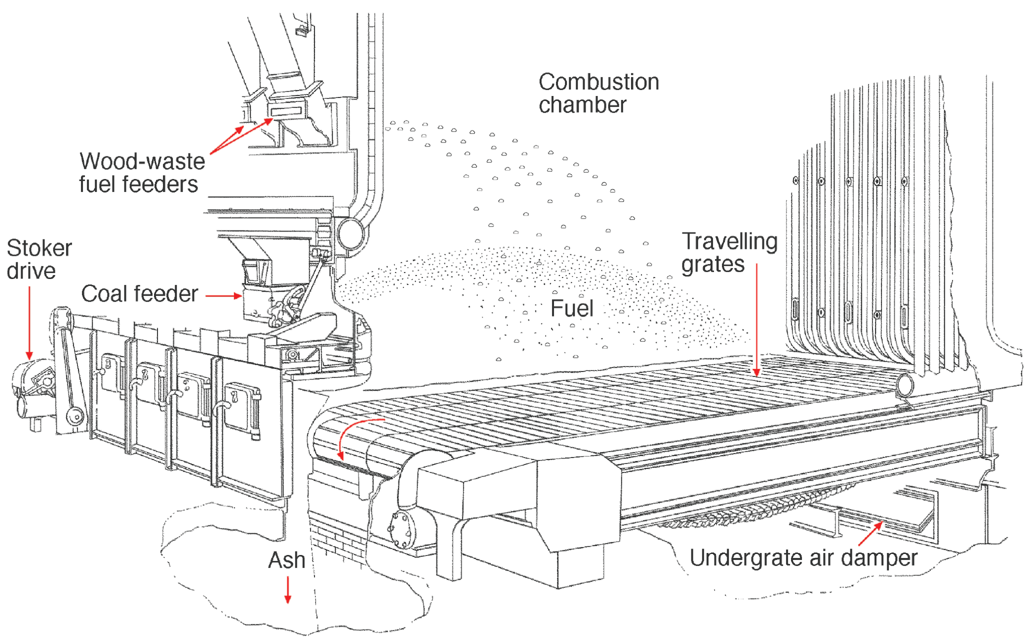
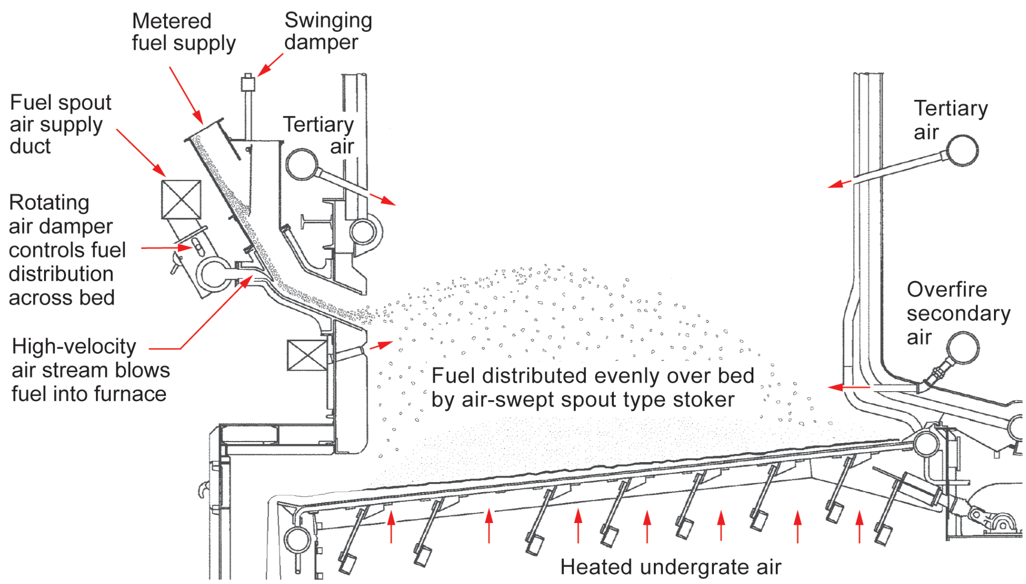


Figure 7 shows an **air jet overfeed stoker**. In this type, jets of combustion air propel the fuel through the furnace to the grate. Overfire air and tertiary air are fed to ensure turbulence and complete combustion. This stoker is also a **vibrating grate stoker**. These stokers use inclined grates and vibrating elements to transport the fuel through the furnace, instead of a travelling grate. The grate sections periodically vibrate, which causes the fuel particles to move from the front of the furnace to the back. Ash is collected at the lower end of the grate. Vibrating grate stokers can also be gravity fed at the top of the inclined grates, instead of using a mechanical spreader.

Figure 7 – Air Jet Overfeed Vibrating Grate Stoker

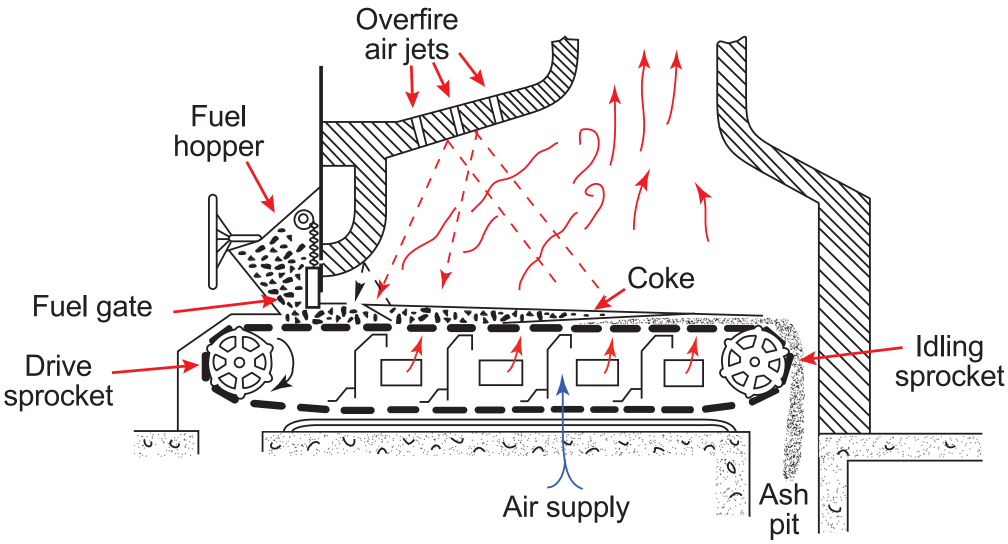


The **crossfeed stoker** is considered a type of overfeed stoker. These stokers are also known as **travelling grate stokers** and **chain grate stokers**. These stokers have travelling grates comprised of numerous links that support the fuel bed. The grate surface is an endless moving belt that extends into the furnace from the boiler front.

These stokers differ from spreader stokers in that fuel is gravity fed at the front end of the grate, and ash is deposited in a pit at the back end of the boiler. To maintain a steam pressure set point, a controller varies the speed at which the grate travels. This varies the amount of fuel introduced to the furnace. The fuel bed height can also be varied with an adjustable fuel gate, located at the point where fuel is introduced to the grate. Underfire combustion air is supplied by a draft fan, and passes up through the grate to the fuel bed. Fuel burning continues to progress as the belt moves from the front to the back of the furnace. Combustion is complete at the back end of the belt and the remaining ash is dumped into an ash pit.

Figure 8 shows the arrangement of a crossfeed stoker. Note the overfire air, which provides turbulence, and aids in the combustion of volatile fuel components.

Figure 8 – Crossfeed Stoker



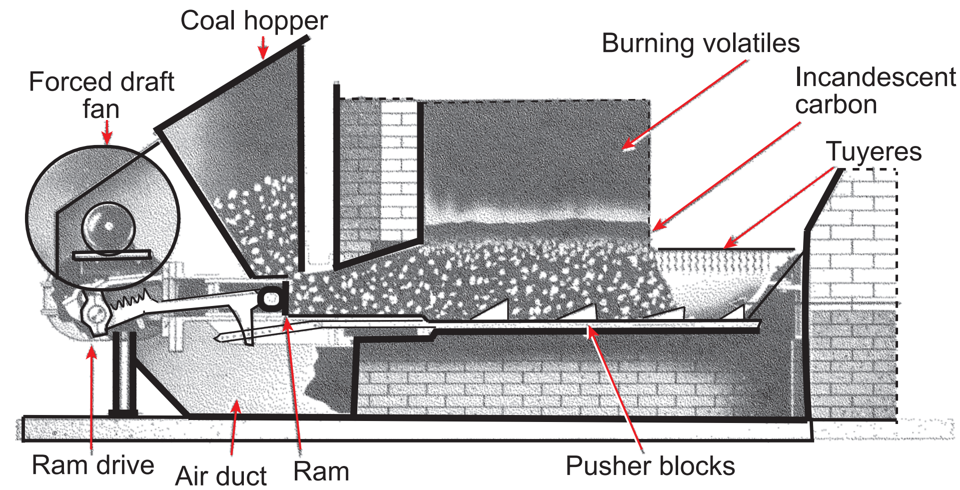
Underfeed Stokers

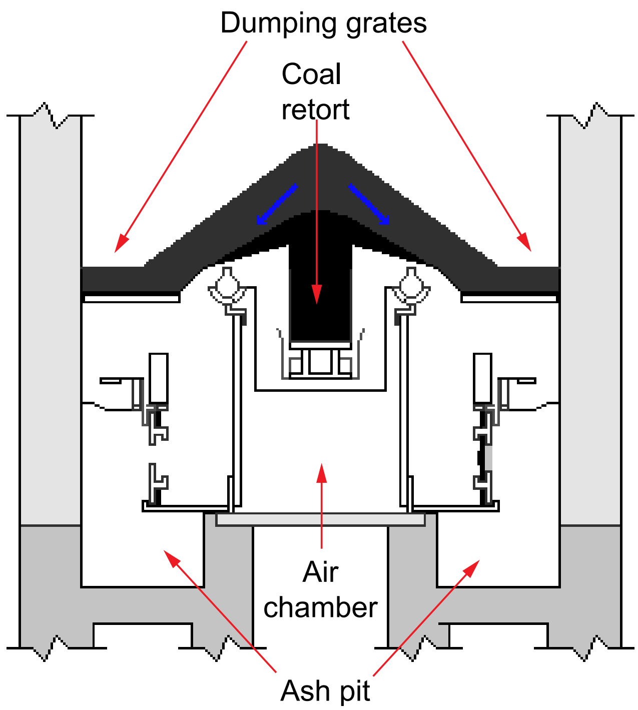
Underfeed stokers introduce fuel from below the surface of the bed. An underfeed stoker is shown in Figure 9. The fuel is fed up through the fire bed by means of a ram and pusher blocks. The channel through which the fuel is fed is a called a **retort**. The ram is operated by steam, compressed air, or oil pressure. The fuel fed at the bottom is gradually forced upward, to the incandescent layer, at the top of the bed. Here, the fuel ignites and spills over onto the side grates.

The combustion air is supplied under the grates with a forced draft fan. This underfire air passes through openings in the grate called **tuyeres** (pronounced "tweerz"), which run the length of the fuel bed, on either side. As the fuel burns, the ashes collect on dumping grates located at each side of the retort. When ash accumulates, these powered grates dump ash into pits located on either side of the retort.

Figure 9 shows a single retort underfeed stoker. Larger boilers have multiple retort underfeed stokers. The retorts run parallel to each other. Underfeed stokers are particularly suitable for burning high volatile, low ash coal.

Figure 9 – Single Retort Underfeed Stoker



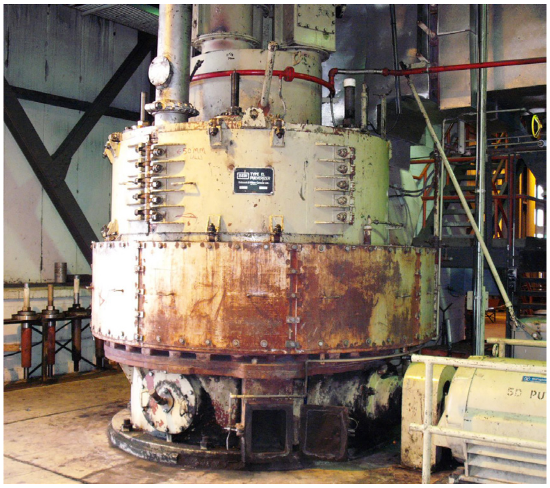


Pulverized Fuel Mills and Burners

Pulverized fuels are solid fuels ground to a fine powder or dust. This finely ground fuel is carried by means of airflow, through pipes from the grinding mills, to the burners in the boiler furnace. Because the fuel is powdered, it burns rapidly and thoroughly, with relatively little excess air. Pulverizing the fuel allows lower grades of coal to be burned satisfactorily. Better combustion control is possible with pulverized coal firing than stoker firing.

Figure 10(a) shows a ball and race pulverizer. Figure 10(b) shows the grinding balls and the lower rotating grinding ring, located inside the pulverizer. Crushed coal is fed between this lower ring and an upper spring-loaded stationary grinding ring (not shown). The upper ring rides on top of the pulverizer balls. When the lower ring turns, the coal is ground to a fine powder by the pulverizer balls, as they roll. A powerful fan (called a **primary air fan** – not shown) draws preheated combustion air from the windbox, and blows it through the side of the pulverizer. This carries the pulverized coal through the coal pipes at the top of the pulverizer to the burners.

Figure 10 – Ball and Race Pulverizer

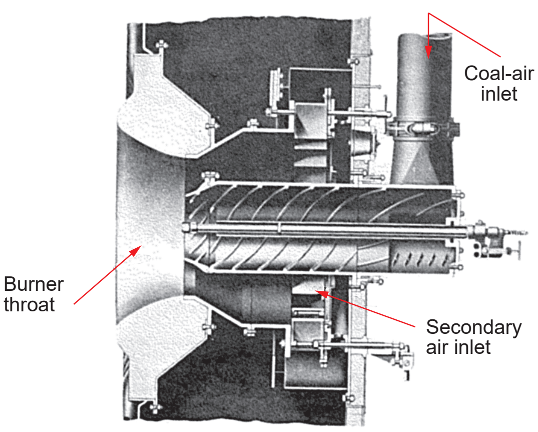


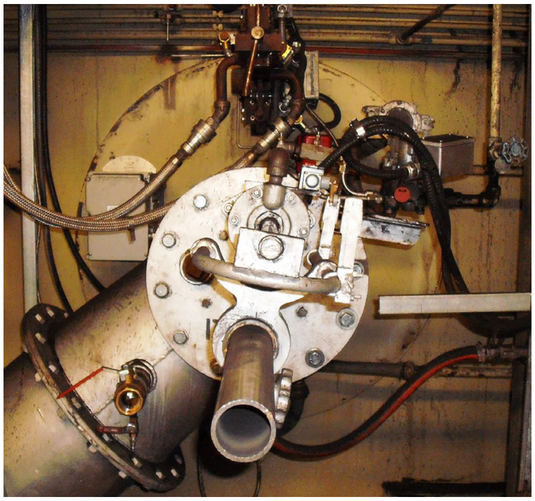
(a)

(b)

A pulverized coal burner is shown in Figure 11. The powdered coal and primary air from the pulverizer enters, and flows through a large central nozzle. The additional air required for combustion (secondary air) passes through the windbox and a set of louvres. Combustion occurs at the burner throat.

Figure 11 – Pulverized Coal Burner





(Courtesy of Combustion Engineering)

Cyclone Furnace

The cyclone furnace was originally developed to burn low quality fuel, containing large amounts of ash, with a low **ash fusion temperature**. In addition to coal and petroleum byproducts, the cyclone furnace is capable of firing wood byproducts, biomass, and municipal solid wastes.

The cyclone furnace is a horizontal cylindrical water-cooled furnace, with one end open to the main boiler furnace. The tubes that surround the cyclone furnace are part of the boiler water circuit. The combustion process occurs in the cyclone with high heat release rates and high temperatures, often exceeding 1650°C. If coal that has a low ash fusion temperature is burned, the resulting ash is molten, and it flows from the cyclone furnace in liquid form.

The fuel is premixed with approximately 20% of the combustion air (primary air). This mixture is introduced tangentially into the cyclone furnace. High velocity secondary air then enters the cyclone chamber. This creates an internal vortex that thoroughly mixes the fuel with the air. This significant turbulence produces ideal conditions for rapid combustion.

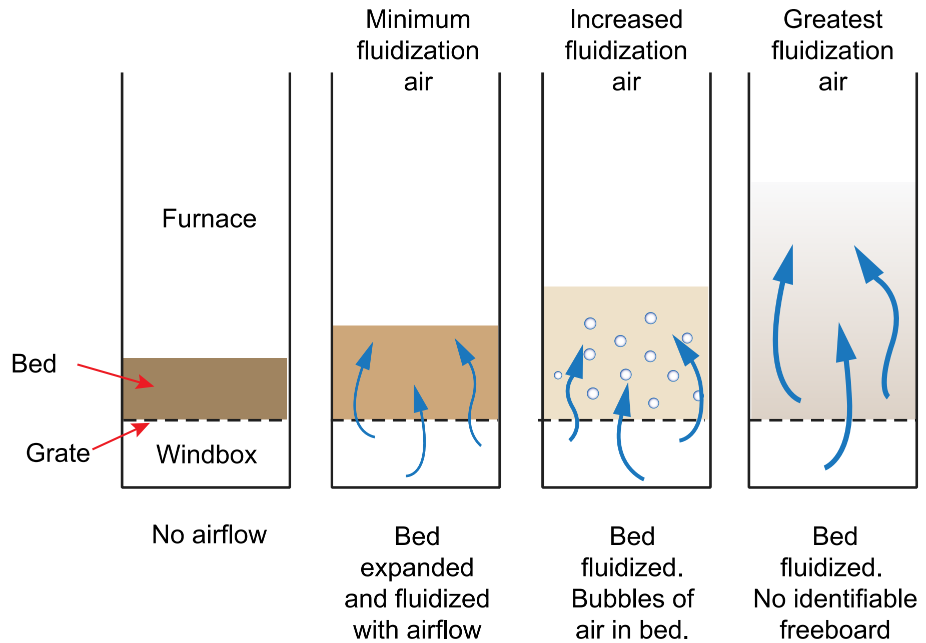
The combustion products discharge at a very high temperature from the rear of the cyclone and into the boiler furnace. A fundamental difference between cyclone furnaces and pulverized coal-fired furnaces is the manner in which combustion takes place. In pulverized coal–fired furnaces, particles of coal move along with the gas stream. Consequently, relatively large furnaces are required to complete the combustion of the suspended fuel. With cyclonic firing, the coal is held in the cyclone, and the air is passed over the fuel. Thus, large quantities of fuel can be completely burned in a relatively small volume. The main boiler furnace is used primarily to cool the products of combustion.

Fluidized Bed Combustion (FBC)

Fluidized bed combustion (FBC) refers to a method of burning solid fuel in suspension. Figure 12 shows a cross-sectional view of a fluidized bed furnace. At the base is a windbox, to which combustion air is delivered under pressure. Between the furnace and the windbox is a grate that supports a bed of granular solid material (gravel, limestone, and coarse sand). The grate has sufficient openings to permit airflow.

If air with sufficient velocity is blown through the bottom of the grate, the solid particles above the grate will flow like a liquid. Additional air velocity increases the circulation of the solid particles, and creates air bubbles in the bed. A further increase in airflow causes the bed to lose a defined upper limit. At this rate of airflow, bed material leaves the furnace.

Figure 12 – Fluidized Bed Combustion



In a fluidized bed boiler, the bed material supports and mixes with the burning fuel. Ash and gypsum that accumulate in the bed are removed by using in-bed ash drainage systems. Fuel is introduced with overfeed stokers, or other arrangements that feed fuel directly into the bed. Coal fired units are usually fed with limestone, to react with sulfur compounds and reduce emissions.

Types of Fluidized Bed

There are two major types of fluidized bed boilers: the **bubbling fluidized bed** and the **circulating fluidized bed**.

Bubbling Fluidized Bed

The bubbling bed boiler has a fluidized bed comprised of both fuel and bed materials. Bubbles of fluidizing air create vigorous bed circulation, and intimate contact between the combustion air and the fuel.

To fluidize the bed, there must be sufficient force on the particles, due to the air velocity, to counteract gravitational forces. The force must not be so great as to transport the bed materials along with the gas stream. Despite this, some smaller fuel and bed particles do get carried off.

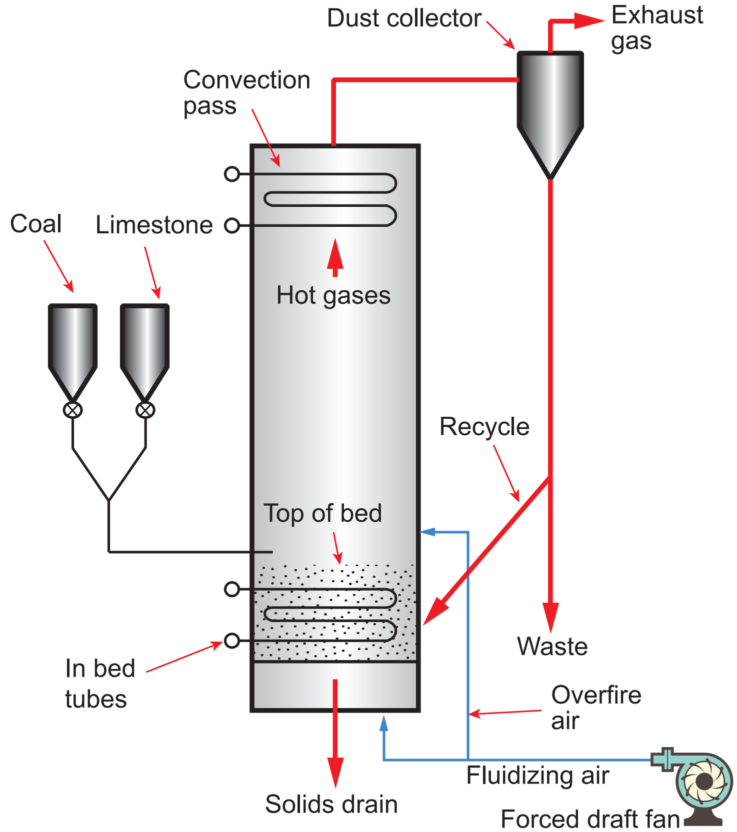
Figure 13 shows a typical bubbling bed boiler. In this example, coal and limestone are fed to the furnace, and suspended in fluidizing air from the forced draft fan.

This boiler has watertubes submerged in the limestone-coal bed. These in-bed tubes receive heat through radiation and conduction (from direct contact with the bed material). The in-bed tubes help to keep the combustion temperature fairly low, when high heating value fuels are used. At lower combustion temperatures, limestone effectively reacts with fuel-derived sulfur products to form gypsum, which reduces the formation of SO_X. The combustion temperature is also low enough to inhibit the formation of thermal NO_X.

Not all bubbling bed boilers have in-bed tubes. Solid fuels with higher moisture content or lower heating values (like wood chips and hog fuel) can be burned at lower combustion temperatures, without in-bed tubes.

The flue gases exiting the furnace pass through a cyclone dust collector. Here, bed materials carried over with the flue gas are intercepted and returned to the bed.

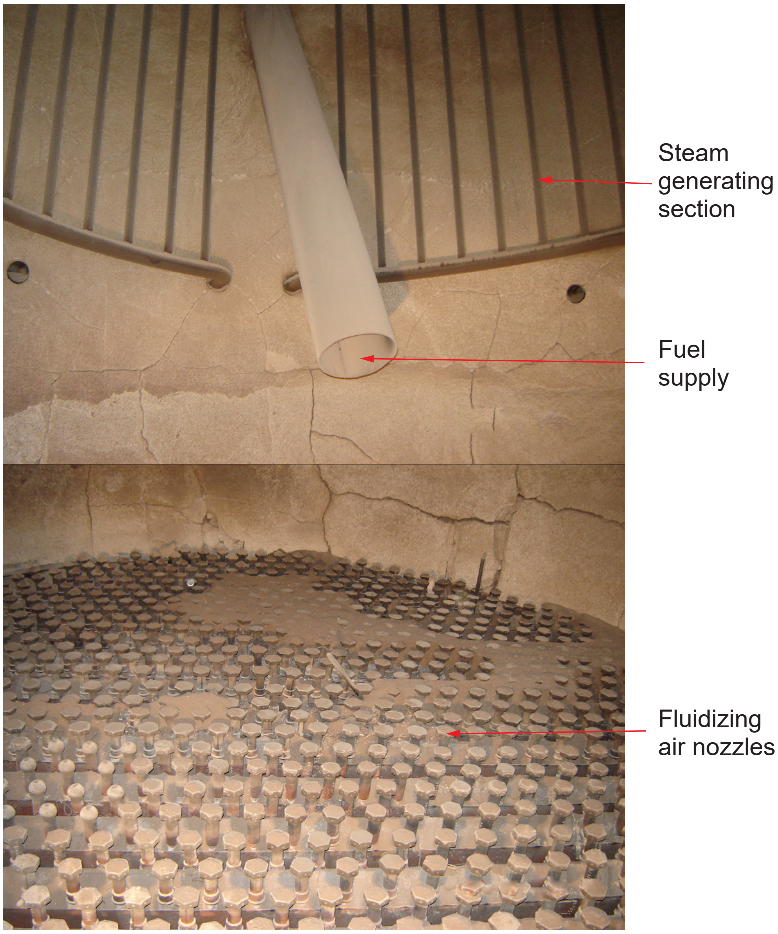
Figure 13 – Bubbling Fluidized Bed Boiler with In-Bed Tubes



The region above between the top of the bed and the top of the furnace is called the **freeboard** zone. Here, bed and fuel particles disengage from the air stream. All bubbling bed boilers have an easily identifiable interface between the bed level and the freeboard.

Figure 14 shows the furnace of a bubbling fluidized bed boiler. The bed has been cleaned out for maintenance. Combustion air flows from the windbox through these air nozzles to fluidize the bed. Considerable refractory surrounds the furnace to protect the surrounding watertubes from the abrasive effects of the turbulent fuel and bed materials. This particular boiler burns waste wood products for district heating. Because the heating value of the fuel is fairly low, and its moisture is fairly high, this boiler achieves stable lower temperature combustion without in-bed tubes. The tube for feeding fuel to the bed can also be seen in this photo.

Figure 14 – Bubbling Fluidized Bed Boiler – Air Nozzles



It is difficult to modulate the firing rate of bubbling fluidized bed boilers. One way is to divide the windbox into different sections, and to control the fluidization air to each section individually. At reduced loads, air may be shut off to one or more sections, which causes that portion of the bed to slump. Without combustion air, the slumped bed smolders and gives off less heat.

In bubbling bed boilers, the combustion air pressure is typically 2.5 kPa at the FD fan, 1.6 kPa at the base of the active bed, and atmospheric pressure at the top of the combustion mass. Fluidization air velocity is in the range of 2 to 3 m/s.

Circulating Fluidized Bed

At high fluidization air velocities, the air bubbles disappear. Bed materials, including burning fuel particles, are carried from the bed and fill the entire furnace. When this occurs, there is no visible distinction between bed and freeboard. Because the bed materials are carried through the furnace, the fuel and bed particles must be captured and reintroduced to the base of the furnace. Bed and fuel materials continuously circulate, either within the furnace or by using external collectors. This is called a circulating fluidized bed boiler.

Some recirculated materials may be disengaged from the combustion gas flow by using staggered beams located near the furnace outlet. Coarser materials impinge on the beams, or fall out of the flue gas stream when forced to change direction. These bed materials recirculate within the furnace.

Finer materials carry through to a large cyclone separator lined with watertubes. Here, the fuel and bed materials are collected and reintroduced to the base of the bed. This combination of internal and external recirculation provides enough time for the fuel to burn completely before leaving the steam generating parts of the boiler.

In circulating bed boilers, the fluidization air velocity is in the range of 6 to 10 m/s.

Atmospheric and Pressurized Fluidized Beds

Bubbling and circulating bed boilers may be atmospheric fluidized beds or pressurized fluidized beds. The difference is in the furnace pressure. An **atmospheric fluidized bed combustion (AFBC)** boiler operates with its furnace pressure near atmospheric. A **pressurized fluidized bed combustion (PFBC)** boiler operates with its furnace pressure well above atmospheric pressure. The AFBC boiler is used for steam production only. The PFBC is used for combined cycle applications.

Atmospheric Fluidized Bed Combustion (AFBC)

In an AFBC boiler, the combustion air pressure is typically 2.5 kPa at the FD fan, 1.6 kPa at the base of the active bed, and atmospheric pressure at the top of the combustion mass. The bubbling bed boiler shown in Figure 13 is an atmospheric bubbling bed boiler.

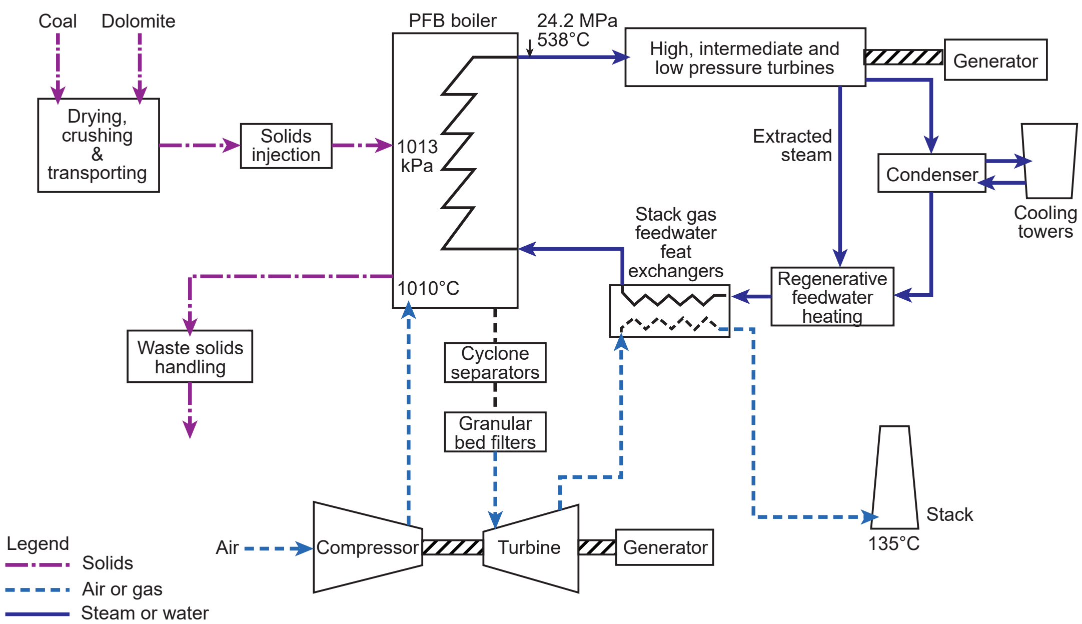
Pressurized Fluidized Bed Combustion (PFBC)

PFBC boilers are quite uncommon, due to the complex engineering challenges designers must face. Theoretically, coal-fired PFBCs have the potential of being up to 5 percent more efficient than conventional pulverized coal-fired plants. However, considering the design challenges of PFBC, the efficiency of ultra-supercritical boiler designs, and the recent development of carbon capture technology, interest in the development of large commercial scale PFBCs has waned.

The type of combined gas/steam cycle shown in Figure 15 uses a bubbling PFBC boiler, a steam turbine, and a gas turbine. About 1/3 of the electrical power is provided by the gas turbine, and 2/3 by the steam turbine.

Coal and limestone (dolomite) are treated and fed to the furnace. The gas turbine compressor delivers the fluidizing air (combustion air). The hot pressurized combustion gases transfer most of their heat to the boiler. The hot flue gas contains ash and possibly entrained bed materials. These hot gases pass through a cyclone separator and a filter for cleaning, before driving the gas turbine and its generator.

Figure 15 – Pressurized Fluidized Bed Combined Cycle Plant



This plant design uses the pressurized furnace as the gas turbine's combustor. For this reason, the boiler furnace is pressurized to 1013 kPa. The steam produced in the boiler goes to the steam turbine and condenser in a conventional power plant cycle.

The potential advantages of this type of combined cycle include:

- Larger total electrical power output compared to a gas turbine alone
- Increase in overall power generation efficiency

Compared to AFBC systems, the PFBC boiler has some drawbacks. These must be weighed against its advantages when choosing between the two for a specific application. The drawbacks include:

- Complexity
- Erosion, corrosion, and fouling of gas turbine blades
- Low furnace temperatures, which limits the steam temperature
- Difficulty of feeding fuel and bed materials into the pressurized system

General Operating Guidelines for FBC

The control systems of an FBC boiler are quite different than that of a conventional steam generator. This is due to the specialized fuel handling system, rates of furnace heat transfer, ash removal, and the equipment that treats flue gas.

For example, in a bubbling bed boiler, the expanded bed depth is kept to about one metre. The operator must maintain the correct expanded bed height, in order to keep in-bed tubes covered. This maximizes conductive heat transfer. During operation, the working bed height can be adjusted through changes in limestone feed rate and bed drain rate.

To begin the combustion process, the bed materials must be made hotter than the auto-ignition temperature of the solid fuel (500°C to 700°C for coal, 300°C to 350°C for wood). This takes about one hour of firing. Preheating is accomplished with auxiliary burners.

After preheating the bed, the fuel is supplied continuously, and will ignite immediately on contact with the bed. During operation, the bed attains a uniform operating temperature of between 800°C and 900°C.

Two common methods of heating include:

1. Firing auxiliary oil or gas burners, located above the bed.
2. Firing auxiliary burners to heat the fluidizing air before it passes through the bed.

Benefits of FBC

There are a number of advantages of fluidized bed combustion which make it a more attractive option for burning solid fuel. These include:

- Flexibility of Fuels
- Smaller Plant Size
- Fuel Preparation
- Fuel Feed
- High Combustion Efficiency in Coal Fired Units
- Improved Regulatory Compliance in Coal Fired Units

Flexibility of Fuels

Just about anything that has sufficient heating value to sustain steady combustion can be burned using fluidized bed combustion. FBCs are extremely tolerant of variations in fuel characteristics, so low-grade fuels with high moisture, high sulfur, wood, heavy oils, coal mine tailings, waste gas, municipal refuse, shredded scrap tires, and agricultural waste can all be used. High ash content fuels (up to 70%) that will not burn successfully in other furnaces can be successfully burned using FBC technology.

Smaller Plant Size

FBC plants have a smaller footprint than pulverized coal plants. This is due to the high heat transfer rate in the furnace, and the absence of wet exhaust gas scrubbing equipment. This means the steam generator can be reduced by up to 25% in overall size: a significant savings in material and construction costs. However, FBCs are still quite tall. They need to provide adequate room for disengagement of fuel and bed particles from the flue gas stream.

Fuel Preparation

In comparison to pulverized coal firing, FBCs require less equipment and energy for fuel preparation. This is primarily because fuel pulverizers are not required.

Fuel Feed

Fuel feed is simplified in an FBC. There are no additional fans required to convey powdered fuel. Instead, a traditional spreader stoker may add fuel, over bed air nozzles, or feed tubes located in the furnace bottom.

High Combustion Efficiency in Coal-Fired Units

The combustion efficiency of a coal-fired circulating fluidized bed boiler is generally in the range of 97.5 to 99.5%. A bubbling bed is lower, in the range of 90 to 98%. The major contributors to this include better mixing of air and fuel, and higher burning rates.

Improved Regulatory Compliance in Coal-Fired Units

FBC has the potential to significantly increase power generation efficiency. At the same time, it meets increasingly stringent sulfur oxide (SO_X) and nitrogen oxide (NO_X) emission regulations.

Crushed limestone is easily mixed with the crushed coal to act as a desulfurizing agent. At 850°C, the limestone is converted to calcium oxide. This combines with the sulfur dioxide released from coal to form calcium sulfate (gypsum). This gypsum becomes part of the residual ash that is continuously withdrawn from the furnace. It can be used as a construction aggregate so that even the furnace waste can be put to good use.

The combustion temperature in a fluidized bed boiler (800°C to 900°C) is too low for the nitrogen in the air to be oxidized into NO_2. This significantly reduces NO_X emissions.

Disadvantages of Fluidized Bed Combustion

Disadvantages of fluidized bed combustion include:

- **High power requirements for combustion air**. For a given boiler output, an FD fan on an FBC unit may require as much as three times the power of a stoker fired system.
- **Carryover**. Gradual loss of the fluidized bed, including the fuel particles, results in lower efficiency, and higher cost dust collectors.
- **Poor combustion control at low operating rates**. This cannot be avoided without adding expensive control equipment.
- **Additional cost to transport limestone**.

Objective 3

Describe gaseous fuel delivery systems.

Gaseous fuels in common use include:

- **Natural gas**
- **Liquefied Petroleum Gas (LPG)**
- Biogas

Gaseous fuels are far easier to handle than solid fuels. Natural gas requires no on-site storage. Liquefied petroleum gas is stored at the plant site in pressure vessels; however, it requires little storage space because it is stored in a liquid rather than vapour form. Biogas is often stored in pressure vessels on the site where it is manufactured, so that adequate fuel is available to meet changing fuel demands. Other than LPG and biogas storage, gaseous fuels require very little equipment for utilization in a power plant.

Natural Gas

Natural gas is obtained from wells drilled in gas-bearing rock formations, or as a by-product from oil wells. Processing is usually required to remove any undesirable components before it is piped to the markets. The main components of natural gas supplied to the consumer are methane (80 - 90%) and ethane (10 - 20%). Natural gas may also contain traces of propane, butane, nitrogen, oxygen, carbon dioxide, and hydrogen sulfide. **Mercaptan**, an **odourant**, is added for leak detection purposes.

The availability and cost of natural gas depends primarily on end-user location. Remote locations may have no access to natural gas pipelines. Other remote locations that have natural gas supplies may pay more due to the cost of transportation. This includes the cost of pipeline infrastructure, recompression, and (in the case of liquefied natural gas) shipping and storage. The gas from some plants travel great distances to the users. Therefore, there are booster stations along the way that maintain pipeline pressures of about 7000 kPa.

Processing and Storing Natural Gas

Unprocessed natural gas contains undesirable components that vary, depending on the natural gas source. Some are impurities, such as carbon dioxide, hydrogen sulfide, and water. Others are heavier hydrocarbon liquids with market value (**natural gas liquids** or **NGLs**). Natural gas is processed to separate the different hydrocarbons, impurities, and liquids from the base gas, usually methane.

Natural gas is usually processed before it can be transported long distances. Except for some separation of liquids near the wellhead, most natural gas processing takes place at a processing plant, usually located in a natural gas producing region. The extracted natural gas is transported to these plants through a network of small-diameter low-pressure pipelines called gathering lines.

After processing, natural gas is stored, either in above ground tanks or underground. Natural gas is stored underground in porous rock zones overlaid by impermeable barriers. In Canada, the majority of gas storage is found in Ontario and Alberta. In Alberta, storage facilities are owned by utilities, midstream companies, pipelines, and producers. Storage facilities in Ontario are owned primarily by utilities.

Safety Check

Natural gas leaks may occur at piping joints, flanges, or valves. Mercaptan, which smells like rotten eggs, is added to natural gas to aid in leak detection. When a leak is suspected, the source of the leak should be identified using a gas detector. All piping connections must be tested on a regular basis.

When re-assembling gas piping, a leak testing solution of dish soap and water, or a commercially available leak detection solution, must be used to check all joints. Leaks are identifiable by soap bubbles that form and grow in size.

NEVER use a match, candle, flame, or other source of ignition to determine the location of leaks!

The advantages of natural gas as a boiler fuel are:

- No ash is produced when gas is burned.
- Little handling equipment is required.
- The amount fed to the furnace is easily controlled.
- It is easily mixed with air.
- It is very clean.
- No storage space is required if delivered by pipeline.

Disadvantages of using natural gas as a fuel include:

- Natural gas is highly flammable and explosive in certain concentrations with air.
- Unless treated with an odourant, natural gas is colourless, odourless, and tasteless, which makes leak detection difficult.

Liquefied Petroleum Gases (LPG)

Liquefied Petroleum Gases (LPG) are petroleum products that consists of light hydrocarbons (butane, propane, or a mixture of the two). These are in a gaseous state at atmospheric pressure, but can be condensed to form a liquid by the application of moderate pressure. In other words, they are petroleum gases that can be easily liquefied.

In liquid form, an LPG takes as little as 1/120th of the space it needs in gas form. This makes it easy to store and transport, and then burn as a gas. The liquid converts to gas by a reduction of pressure and absorption of latent heat of evaporation from the surrounding area. The boiling point of butane at atmospheric pressure is 0°C. The boiling point of propane is –42°C.

Both propane and butane burn completely and cleanly with a bright flame.

Biogas

Biogas is the gaseous emissions from the **anaerobic** digestion of organic matter from plants or animals. Anaerobic digestion is a natural process whereby bacteria convert organic materials into methane and carbon dioxide. It occurs naturally in marshes and wetlands, and in the digestive tract of some animals. The bacteria are also active in landfills.

Biogas is processed to remove undesirable components such as carbon dioxide, sulfur compounds, and moisture. This process increases the concentration of methane, and removes components that can cause corrosion of the boiler fireside and internal piping.

Most biogas is used as it is produced so the need for biogas storage is usually of a temporary nature. This occurs mostly during times when production exceeds consumption, or during maintenance of digester equipment.

Advantages of using biogas include:

- Reduced greenhouse gas emissions
- Odour control

Disadvantages of using biogas include:

- Lack of widespread availability.
- Corrosive action of wet biogas.
- Need for storage, to accommodate times when biogas production exceeds consumption, or when consumption exceeds production.
- Need for alternate fuel supplies if biogas is unavailable or of insufficient quality to burn.

Objective 4

Describe the main types of gaseous fuel firing systems.

A gas burner must:

a) Mix fuel and air (oxygen).
b) Ignite the fuel and maintain stable ignition.
c) Monitor the combustion, and maintain fuel and air in correct proportion.
d) Monitor the flame presence and stability, and shut down the burner if the flame fails, or if unstable firing conditions exist.
e) Control the firing rate in accordance to steam or hot water demand.
f) Shut down when certain process set points are met, such as steam pressure or water temperature.
g) Shut down when non-combustion-related safety limits are exceeded, such as low water or lack of water flow.
h) Shut down when combustion-related safety limits are exceeded, such as high gas pressure, low gas pressure, or low windbox pressure.

Because gas is already in an atomized condition, gas burners do not need to atomize the fuel.

Premix and After Mix Burners

Gas burners differ mainly in the way air and fuel mix. They can be divided into two general classes: the **premix burner** and the **after mix burner**. These names describe whether combustion air is mixed with the gas before it enters the burner (premix), or after it leaves the burner (after mix).

Premix Burners

Premix burners mix some combustion air (primary air) with fuel inside the burner venturi. This type of burner is used on relatively small heating and power boilers, with capacities generally under 500 kW.

Figure 16 shows a type of premix burner with ports drilled into the burner head for even fuel distribution. Similar designs (called **ribbon burners**) have herringbone shaped stainless steel ribbons instead of drilled ports. The ribbons travel the length of the burner head. Ribbon burners are quieter in operation, and provide more stable flame conditions. They also light faster when the burner starts.

The supplied gas travels at high velocity through a small orifice into the venturi. The high velocity gas forms a low-pressure zone within the venturi, which draws primary air into the venturi through an adjustable air shutter. The shutter is adjustable to ensure the correct amount of premix air. At the burner head, the velocity of the fuel-air stream decreases, resulting in a pressure increase inside the burner head. This pressure is greater than the furnace pressure, so that the fuel and air mixture continues through ports drilled in the burner head.

Ignition is sustained at the burner head, and the fuel burns cleanly in the presence of additional combustion air (secondary air) that surrounds the burner head.

This burner is also called an **atmospheric burner**, because the furnace pressure is at or near atmospheric pressure. For an atmospheric burner, the difference in pressure between the gas/air mixture in the burner head and the furnace is adequate to provide the rated gas flow through the burner. No mechanical draft devices are necessary with atmospheric burners.

On smaller burners, both the gas flow through the orifice and the primary air opening are not adjustable. The fuel flow depends on the size of the orifice and the gas supply pressure (which is regulated to a constant value). The primary airflow on smaller burners is also non-adjustable. The gas flow in some larger burners may be adjusted with a small needle valve. For most atmospheric burners installed in boilers, the amount of primary air can be varied by adjusting the size of the primary air shutter opening.

Figure 16 – Upshot, Drilled Port, Atmospheric Premix Burner

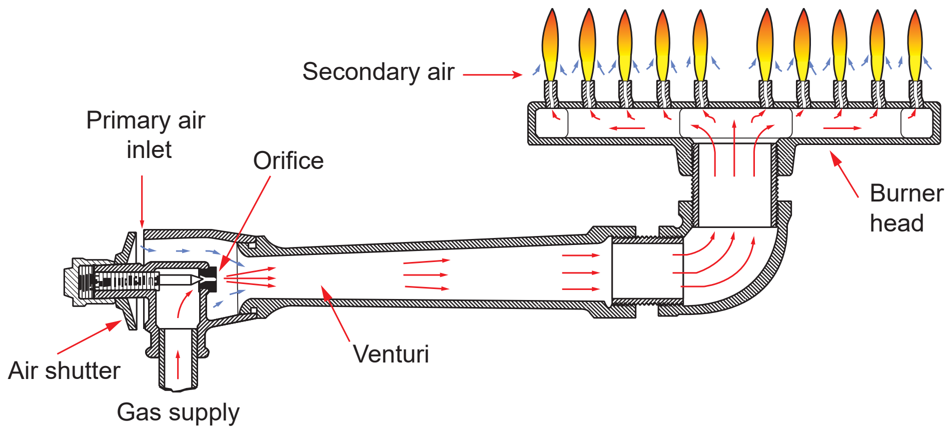


Figure 17 shows an upshot premix atmospheric burner, with a flame spreader at the top of the burner. This burner, and the burner shown in Figure 16, are called "upshot" burners because the air/fuel mixture turns 90 degrees upward before entering the furnace.

Figure 17 – Upshot Premix Atmospheric Burner

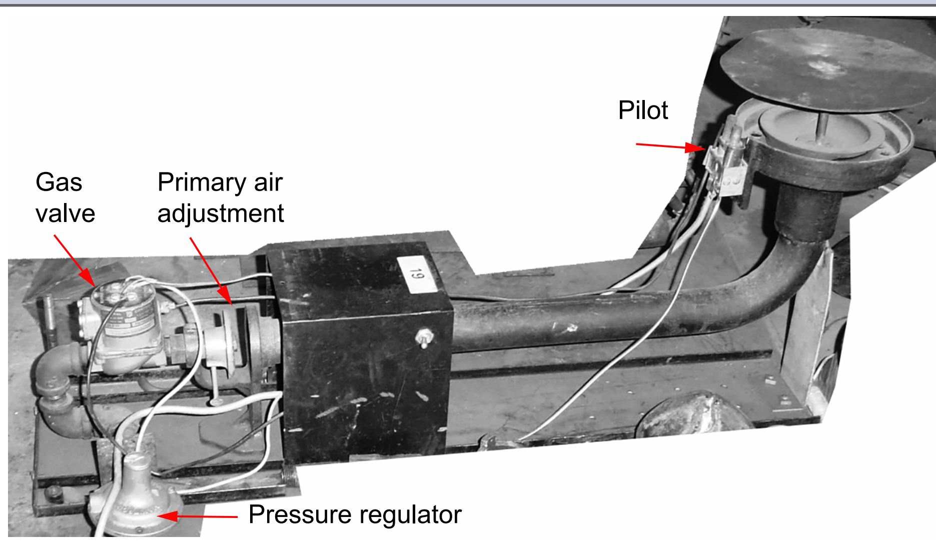
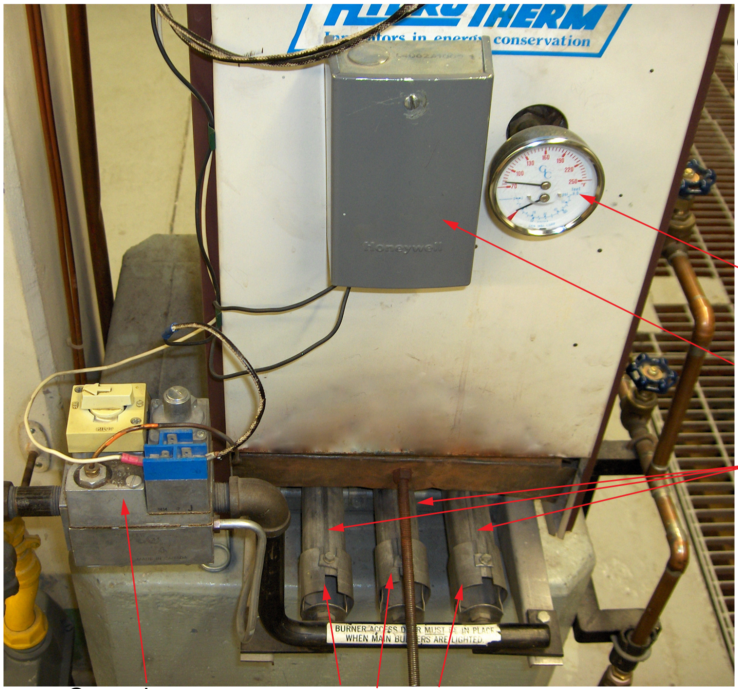


Figure 18 shows a cast iron sectional steam boiler with three atmospheric premix burners. Note each burner is fed from a common fuel rail. The primary air shutters are clearly visible.

Figure 18 – Atmospheric Premix Burners Installed in a Cast Iron Sectional Boiler



Premix Percentage

If the burner orifice size and shape is fixed, and the gas pressure is at a set value, the nature of the flame depends largely on the amount of primary air or premix. With the premix low, the flame is long and pale blue. It may have a yellow tip indicating some hydrocarbon cracking and the presence of free carbon.

Increasing the primary air shortens the length of the flame. The fuel burns faster, and a greenish inner cone appears. Excessive primary air can cause the flames to “lift” from the surface of the burner. This creates noisy operation, a reduction in combustion efficiency, and the formation of toxic aldehydes and carbon monoxide. When speed of burning or flame propagation exceeds the velocity of the gas issuing from the ports, the flame flashes back into the mixing tube. This causes noisy operation, and overheating of the burner head and venturi.

Burner operation is generally satisfactory with a 30 to 40% premix, which should produce a blue, non-luminous flame. In some special designs, 100% primary air is used.

Although physically simple, the gas burner must be proportioned with considerable skill to conserve the relatively small amount of energy in the low-pressure gas stream. It is this energy which entrains the primary air. How well this is done depends on primary air percentage, gas orifice size, ratio of mixer throat to burner port area and, in boilers especially, furnace draft.

After Mix Burner

An example of an after mix gas burner used in packaged firetube boilers is shown in Figure 19. It consists of a hollow cylindrical ring, to which gas is fed. The ring has holes or nozzles at the end closest to the furnace. A forced draft fan provides combustion air, and the air travels through the centre of the burner ring. To create turbulent airflow, some sort of diffuser vane is usually placed in the airflow, inside the centre of the burner ring. The gas and air meet and mix at the point of discharge from the burner ring. The air/fuel mixture ignites immediately, filling the furnace tube with fire. This type of burner is called an after mix type, because the gas and air mix together after leaving the burner.

Figure 19 – Packaged Boiler After Mix Gas Burner

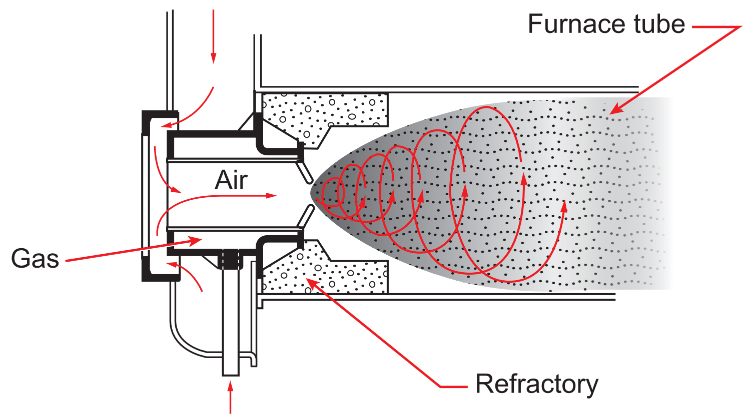
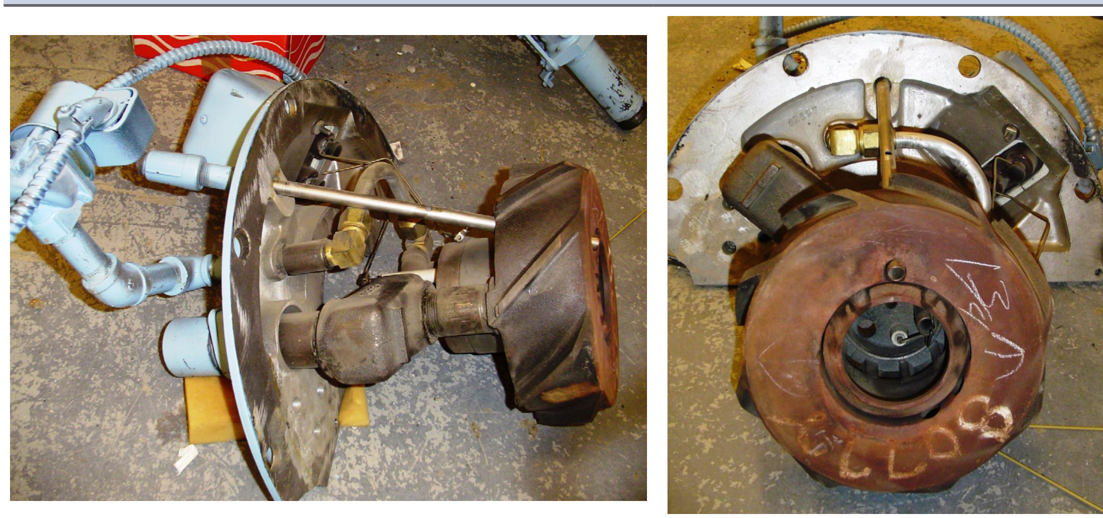


Figure 20 shows two views of an after mix burner from a packaged firetube boiler. The large cylindrical casting is the burner ring. Note that combustion air is delivered through both the inside and the outside of the burner ring. Vanes are cast into the outside of the burner ring to impart a swirling motion on the combustion air. This ensures thorough mixing of fuel and air.

Figure 20 – Package Boiler Gas Burner



Types of After Mix Burners

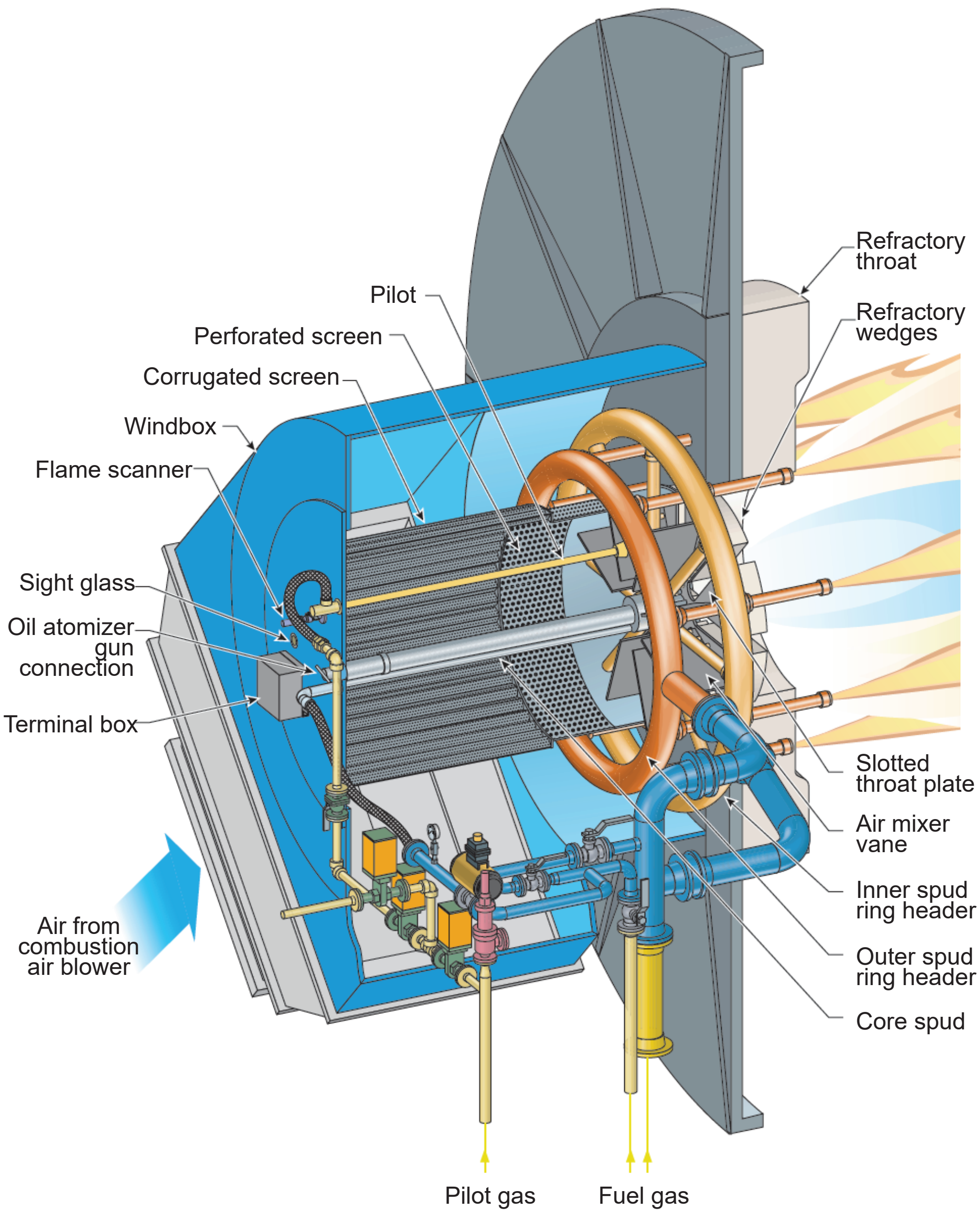
There are many types of after mix gas burners in use. These burners are available from relatively small kW inputs, to extremely large burners used in utility boilers. All use mechanical draft to overcome the resistance of the burner, furnace, and other heat exchange surfaces.

Multi-Spud Burner

The multi-spud burner is used for a wide variety of boiler sizes. The gas in this burner is supplied to a circular manifold (or ring manifold), which has several gas **spuds** (or pipes) branching off. The ring manifold may be located inside or outside the windbox. If located outside the windbox, the spuds will be long enough to extend through the windbox to the burner throat. Many burners have the ring manifold located inside the windbox. In this case, the spuds can be shorter (see Figure 21).

The spuds terminate at the burner throat. Gas flows out of multiple holes or slots formed into the end of each spud. By adjusting the orientation of the jets on the spuds, the flame pattern can be adjusted for optimum combustion. Figure 21 shows a burner with two ring manifolds. The inner ring manifold directs the gas to the centre of the burner, near a set of diffuser vanes. The outer spud ring manifold directs the fuel to near the refractory lining, around the burner throat.

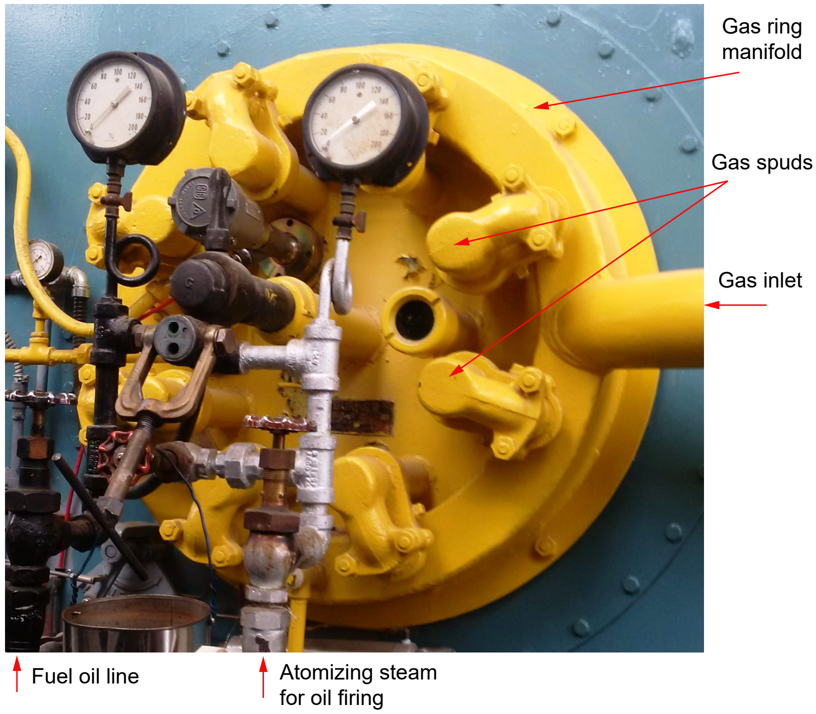
Figure 21 – Multi-Spud Burner



(Courtesy of Cenovus Energy)

Figure 22 shows the front of a multi-spud burner installed on a large packaged watertube boiler. This type of burner has a ring manifold located outside the windbox. This burner can fire natural gas or fuel oil. The oil burner is of the steam-atomized variety.

Figure 22 – Multi-Spud Burner Installed on a Packaged Boiler

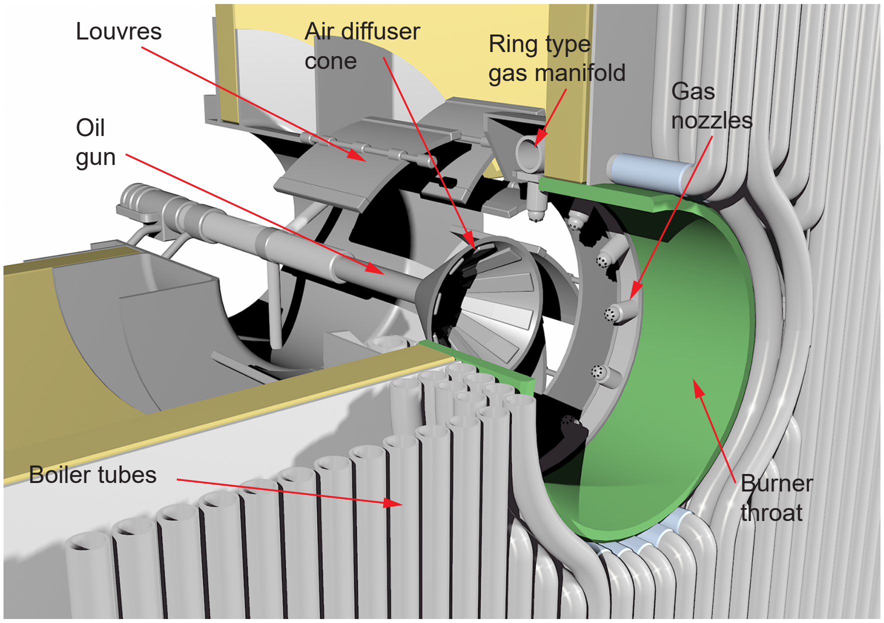


Some larger multi-spud burners permit the isolation of individual spuds, in case they become damaged or plugged. This allows the spud to be removed, cleaned, repaired, and replaced without having to shut down the boiler.

Ring Burner

A ring burner suitable for use on a large boiler is shown in Figure 23. In this type of burner, gas is supplied to a ring manifold that has numerous gas outlet holes. Air is admitted through the registers (louvres) and mixes with the gas leaving the ring holes. The combustion air is supplied through the centre of the gas ring. An air diffuser cone gives the air a swirling motion before it enters the furnace in order to promote intensive mixing of gas with air.

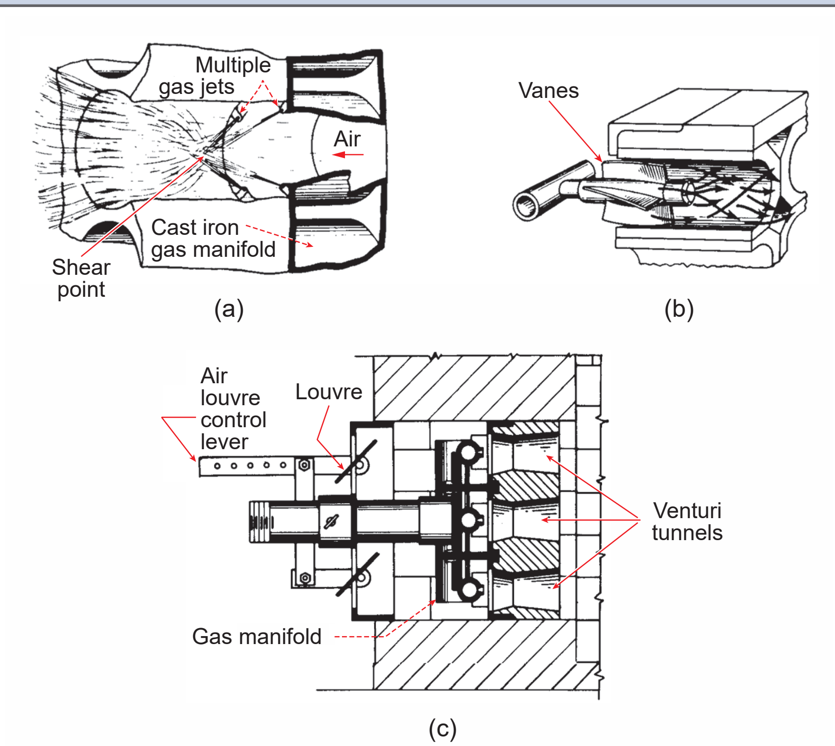
Figure 23 – Ring Type Gas Burner



Refractory Burners

Refractory burners are no longer commonly used, but may still be found in smaller packaged firetube boilers. They consisted of refractory material containing a number of circular holes called mixing tubes or tunnels, placed at the entrance of the furnace. Gas was supplied into each tunnel by small orifices. It then mixed with the combustion air that passed through the tunnels. Combustion air was provided by mechanical draft, though smaller boilers may have used natural draft. This mixture was heated by the refractory, ignited, and entered the furnace where combustion was completed. Three different refractory burner designs are shown in Figure 24.

Figure 24 – Refractory Burners



The burner in Figure 24(a) has a flat, hollow cast-iron gas manifold mounted in front of the refractory slab. Gas is admitted into each tunnel through several small jets. As a result, a highly efficient mixing of gas and air is achieved.

Figure 24(b) shows a burner having the gas admitted to each tunnel by a small jet. The use of vanes gives the air a swirling motion, and properly mixes the gas with the combustion air.

Figure 24(c) shows a cross-sectional view of a completely assembled refractory burner with fifteen venturi-shaped tunnels (three vertical and five horizontal). The gas is admitted through small jets mounted on a grid-type manifold. Louvres in front of the burner assembly control the amount of combustion air.

The use of refractory burners has the following advantages:

a) The gas and air mixture is thoroughly preheated before it enters the furnace. This results in high combustion efficiency with a minimum of excess air.

b) The metal burner parts are protected against high temperatures by the refractory.

c) The short, relatively luminous flame spreads over a large cross-section of the furnace, which results in a high radiant heat transfer.

The main disadvantage, however, is a higher cost due to the more complex design. The refractory tunnels are difficult to replace or repair when deteriorated. The high temperature at the burner tunnels contributes to thermal NO_X formation. For these reasons, refractory burners are no longer common.

Pilot Burners

The main burners of gas-fired heating equipment are lit by smaller **pilot burners**. The most common types of pilot burners are categorized as:

- Continuous
- Intermittent
- Interrupted

A **continuous pilot** (or **standing pilot**) burns at all times, and must be manually ignited. Continuous pilots only shut down on failure of the pilot flame. Continuous pilots are mainly found on boilers and other appliances smaller than 120 kW input.

ASME CSD-1 permits continuous pilots on natural draft boilers up to 3663 kW input. However, for boilers with power burners (those using mechanical draft), **ASME CSD-1** does ***not*** permit continuous pilots if the main burner input is greater than 733 kW.

The continuous pilot is most often used on smaller boilers, hot water heaters, and warm air furnaces equipped with atmospheric burners. It has a dual function. Besides being used to light the main burner, it also forms part of the safety circuit. This ensures that the main gas valve cannot be opened if the pilot is not burning. It also shuts off the gas supply, in case the pilot flame goes out.

An **intermittent pilot** is a form of pilot that automatically ignites at the start of each burner operating sequence, and continues to burn throughout the main burner "on" period. When the main burner cycles off, the intermittent pilot also shuts off. **ASME CSD-1** permits this type of pilot on natural draft boilers up to 1465 kW input. For boilers with power burners, intermittent pilots cannot be used on boilers with greater than 733 kW input.

An **interrupted pilot** ignites and is proven at the beginning of the main burner run sequence. After the main burner flame is proven for about ten seconds, the interrupted pilot is extinguished. **ASME CSD-1** permits this type of pilot for natural draft and power burners up to 3663 kW input.

Of the three types of pilot mentioned above, the interrupted pilot provides the greatest margin of safety when in operation. That is why interrupted pilots are exclusively used for larger input burners.

Gas Burner Operation and Maintenance

Gas shut-off cocks should be lubricated periodically with grease. Air registers should be checked for freedom of movement, and lubricated when necessary. The flame color should be blue with yellow tips. The flame pattern should show symmetry and vigorous swirling. The flame must not impinge on refractory or boiler heat transfer surfaces.

A licensed commercial gas fitter should perform an annual combustion analysis. Adjustments should be made to provide maximum combustion efficiency. The amount of air admitted to the burner should be adjusted to give a stable flame. The pilot should be adjusted so that it is only large enough to effectively and consistently ignite the main burner. The function of all combustion safety limit controls should be verified and documented at this time. This includes **low fire start** interlock, high airflow purge switch, high and low gas pressure cut-off switches, and the combustion air-proving switch. The flame scanner, flame rod, or thermocouple flame detector should be cleaned, tested, and replaced, if necessary.

Fuel train pressure gauges should be checked for damage and replaced, if necessary. After verifying the pressure gauges work satisfactorily, pilot and main burner **safety shut-off valves** should be leak tested. Leaking safety shut-off valves must be replaced, not repaired. This work should be done by a licensed **Class A gas fitter.**

Gas burners should be cleaned whenever the boiler is shut down for routine maintenance or inspection. Carbon deposits can usually be removed with a wire brush and solvents used to cut grease deposits. Burner components such as diffusers, venturi tubes, spuds, and burner heads should be inspected for signs of overheating and deterioration. Damaged parts should be replaced, and a Class A gas fitter employed to address the conditions leading to the component failure.

Fireside soot deposits are another sign of incorrect burner operation. The refractory should be inspected for signs of deterioration due to flame impingement. Burner orifices, if seriously plugged, can be drilled out with a proper sized drill. This should be performed by a Class A gas fitter.

Automatic Safety Shut-Off Valves

Safety shut-off valves are used to provide fuel to burners when there is a call for heat, and to quickly extinguish burners upon adverse conditions. Main fuel gas valves must open slowly (4 to 5 seconds), and must close instantly when de-energized. Main safety shut-off valves must also be normally closed. Failure of power to the control system de-energizes the valves to prevent uncontrolled combustion from occurring.

The most common valves used to control the flow of gas to the burners of heating and power boilers are the diaphragm valve, the solenoid valve, and the Hydramotor®, or Fluid Power Gas Valve®.

Diaphragm Gas Valve

The **diaphragm gas valve** shown in Figure 25 is commonly used as a safety shut-off valve for lower capacity gas-fired boilers and furnaces.

Figure 25 – Diaphragm Gas Valve

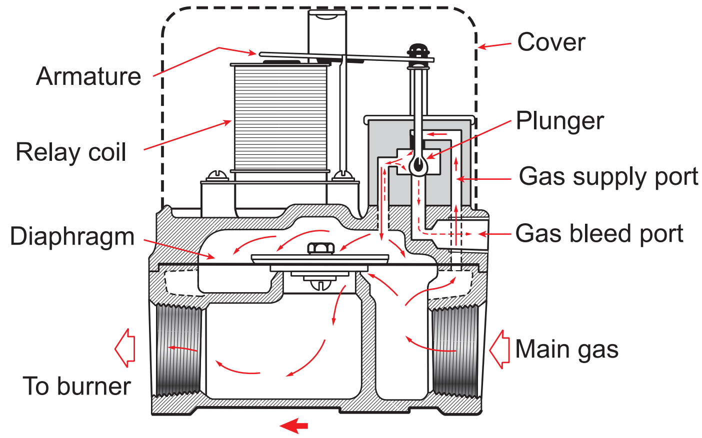


Figure 25 shows a diaphragm gas valve in the closed position. Gas, at inlet pressure, enters through a supply port, past a small 3-way valve, and to the top of the diaphragm. The force of the gas at inlet pressure, applied to the top of the weighted diaphragm, is larger than the force of the gas pressure acting under the diaphragm. This holds the valve disc firmly on its seat.

The burner starts when there is a call for heat. The relay coil energizes, only if the pilot burner is proven on. When the relay energizes, it lifts the plunger. This seals off the upstream gas pressure, and bleeds the gas trapped on top of the diaphragm to the lit pilot burner.

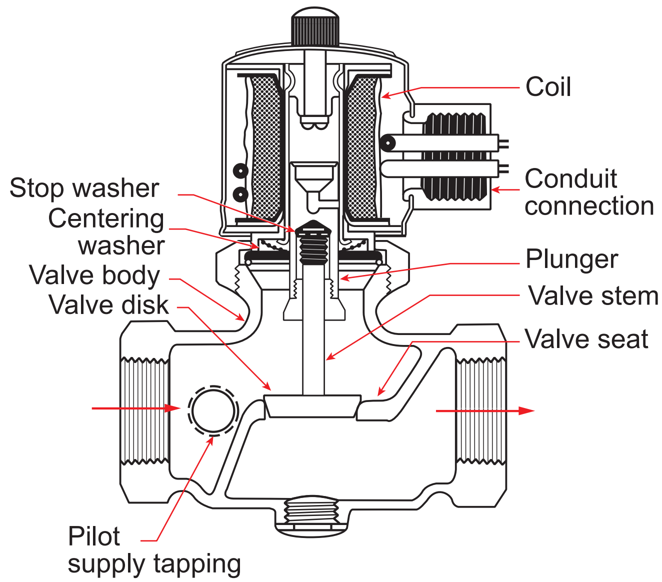
When gas bleeds from the top of the diaphragm, the pressure beneath the diaphragm exceeds the pressure above the diaphragm, and causes the valve to open. The speed at which the valve opens can be adjusted with a small valve on the gas bleed port line (not shown). By throttling the bleed gas, the valve opens slowly.

When the heat demand is satisfied, the contacts of the operating control open, and de-energizes the relay coil. The armature de-energizes, drops the plunger, opens the gas supply port, and closes the bleed port. The increased pressure on top of the diaphragm, plus its weight, overcome the pressure under the diaphragm and valve disc, quickly closing the valve.

Solenoid Valve

Solenoid valves are used on gas and oil fired boilers and furnaces. Normally closed solenoid valves, like that shown in Figure 26, are commonly used as safety shut-off valves in pilot lines. Normally open solenoid valves are used as main, and pilot bleed valves when burners are equipped with **double block and bleed** systems.

Figure 26 – Normally Closed Solenoid Gas Valve



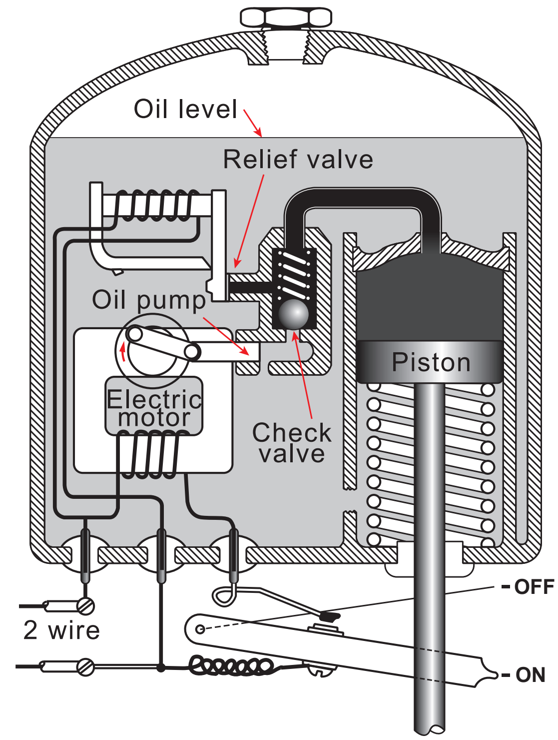
The valve and valve housing are quite similar to those used on manually operated globe valves. However, the valve stem is connected to a soft iron plunger, which can move up and down in the centre core of an electro-magnetic solenoid. When the solenoid is energized, it draws the plunger up into the core, thus opening the valve. The gas is supplied above the valve disk. When the coil is de-energized, the disc is forced back onto the valve seat by the weight of the disc, stem, plunger, and from the action of the gas on the valve disc.

Ignition is not always instant; therefore, larger capacity burners must not receive a full flow of fuel on startup. A slight accumulation of unburned fuel could result in a furnace explosion when ignition finally occurs. To prevent furnace explosions, solenoid safety shut-off valves for main burner applications are special designs that open slowly and close quickly. These valves may have adjustable hydraulic brakes affixed to the stem that slow the rate of opening, but do not affect the time to close.

Motorized Gas Valve (Hydramotor® or Fluid Power Gas Valve®)

The **Hydramotor® valve** or **Fluid Power Gas Valve®** consists basically of two components: the valve operator and the valve body. The valve is hydraulically opened, and spring-loaded to close. The valve operator consists of a hydraulic cylinder, a piston, a small hydraulic oil pump driven by an electric motor, and a solenoid-operated relief valve. All components are completely submerged in the hydraulic fluid filled housing (Figure 27).

Figure 27 – Hydramotor® Gas Valve



When the control circuit of the fuel valve is energized, the oil pump starts. At the same time, the relief valve on the pump housing closes. The pump forces hydraulic fluid into the cylinder, moving the piston against the force of a powerful spring. Since the piston stem is directly connected to the valve stem, the movement of the piston opens the valve.

When the piston reaches the end of its stroke, the valve is wide open. When this occurs, the power to the electric motor is interrupted by a set of contacts operated by the shaft. The open contact stops the pumping action, but keeps the relief valve circuit energized. The relief valve maintains the hydraulic fluid pressure on top of the piston, keeping the valve open.

When the power to the valve shuts off, the solenoid de-energizes, and opens the relief valve. This allows the compressed spring behind the piston to rapidly force hydraulic fluid out of the cylinder through the relief valve. The piston rapidly returns to its original position, and closes the valve.

The opening of the valve is relatively slow, which gives the advantage of gradual fuel admission during ignition. The closing of the valve is quite fast, due to the action of the spring.

Objective 5

Describe liquid fuel delivery systems.

Liquid fuels include traditional petro-chemical fuel oils and alternative liquid fuels, such as ethanol and biodiesel. Although there is increasing capacity in the market for alternative liquid fuels, fuel oil remains the dominant liquid fuel used in power plants. Because of its flammability and potential volatility, its production, processing, transportation, and storage are regulated by national jurisdictions.

Onsite Fuel Oil Storage

In Canada, fuel oil systems and storage tanks must be installed in accordance with:

- **CSA B139 Installation Code for Oil-Burning Equipment**
- The **National Fire Code of Canada**
- Local codes, bylaws, and regulations

A typical furnace and oil storage tank installation for small commercial and residential applications is shown in Figure 28. It includes a double wall tank, hand shutoff valve, filter and trap combination, and a copper supply line between the tank and burner. This is a one-pipe system. The tank may be located in the furnace or boiler room.

CSA B139 has many requirements for oil storage installations, including:

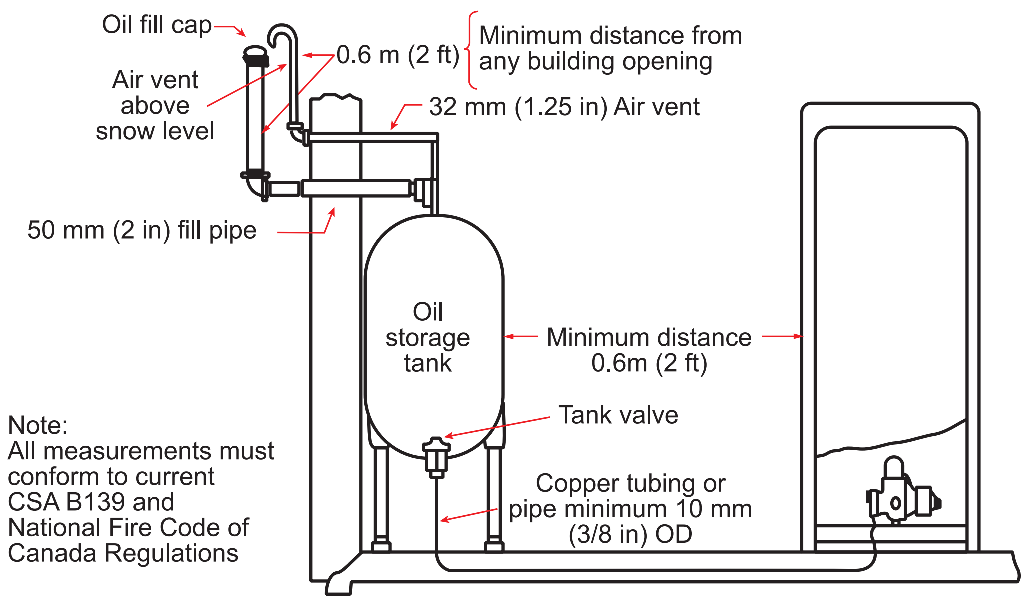
a) The storage tank must be at least 0.6 m away from the furnace, with a minimum of 1 m working space from any electrical panel or apparatus.

b) The fuel tank temperature shall not exceed 38°C.

c) The oil fill cap must be at least 1 m above ground level, 4 m maximum above the bottom of the fuel tank, and 0.6 m away from any building opening.

d) The tank must be vented. The vent must be a minimum of 150 mm above the fill cap, and at least 0.6 m from any building opening.

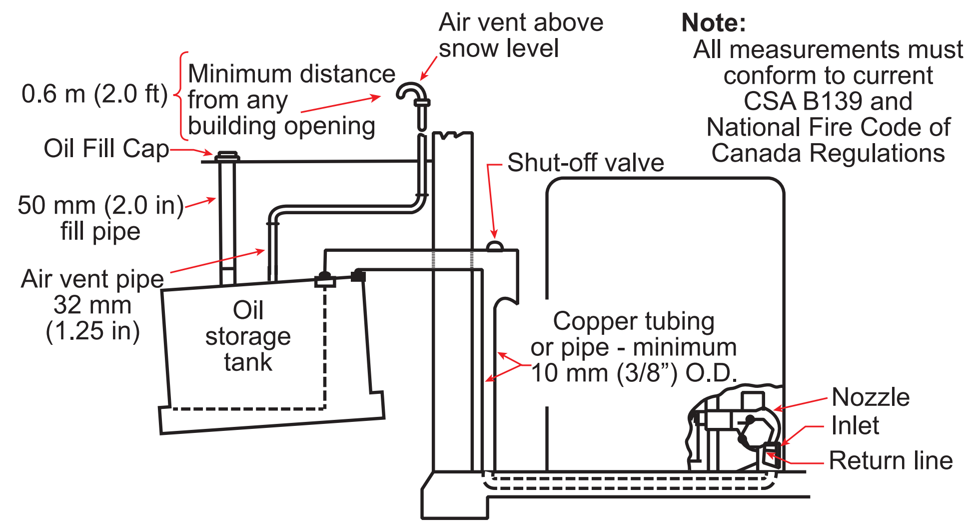
Figure 28 – Fuel System with Indoor Storage Tank



The highest oil level in the tank should produce less than 35 kPa static head pressure at the inlet of the fuel pump. The tank is equipped with an outside filling pipe, which should be capped when not in use. The tank also has an air vent with a gooseneck (upside down 'U' to keep out dirt and rain), which should be well above the snow level.

Larger installations usually have the storage tank placed outside the building, either above or below ground level. The tank should be within reasonable distance from the oil burner. Figure 29 shows the tank below the ground, with the burner in the basement, below the tank level. This is a two-pipe system. The supply line carries the oil to the burner. The return line takes the excess oil back to the tank.

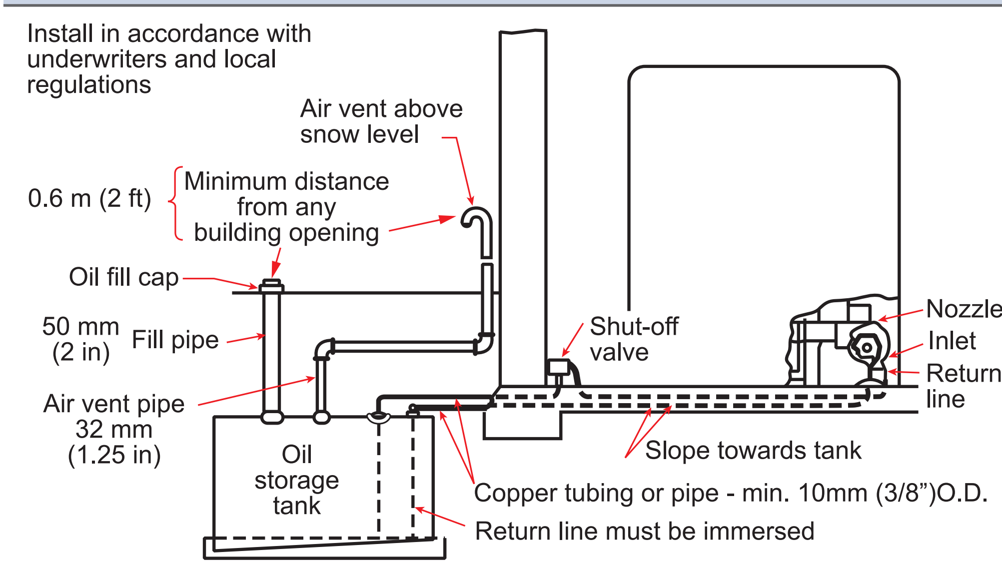
Figure 29 – Fuel System with Outdoor Storage Tank above Burner Level



Oil tanks should be installed with a slight slant, away from the pump supply line intake, in order to provide a low spot where water and dirt can accumulate. Additionally, many heavy oil tanks are equipped with a high and low suction, allowing the system to continue operation if sludge accumulates in the tank, and begins plugging pump suction strainers. Normally, fuel is drawn from the low suction. If fuel was regularly drawn from the high suction, the fuel delivery system would need to be shut down if sludge built up to that level.

An underground oil storage tank installed below burner level is shown in Figure 30.

Figure 30 – Fuel System with Outdoor Storage Tank below Burner Level



Locating and Maintaining Fuel Oil Storage on the Plant Site

In larger power plants, fuel oil may be stored above or below ground. The location chosen for oil storage should be:

a) Level
b) A safe distance from service drains, streams, and wells
c) Secure to prevent unauthorized access
d) Visible for supervision and inspection
e) Readily accessible for filling and maintenance
f) Protected against accidental impact

Fuel storage tank specifications must meet all regulatory requirements. These include requirements for secondary containment (berms). Where a secondary containment area contains only one above-ground tank, the secondary containment volume must be of sufficient size to contain a volume of liquid at least 10% greater than the volume of the tank. Figure 31 also shows:

a) The filling connection in the foreground, attached to the containment berm.
b) The vent at the top of the vessel, located to the left of where the filling line enters the tank.

When a secondary containment area contains more than one above-ground tank, the secondary containment volume must be large enough to hold the greater of

- the volume of the largest tank plus 10% of the total volume of all the other tanks, or
- 10% more than the volume of the largest tank.

The safety berm may be constructed of concrete or other non-porous fill surrounding the tank to contain the tank contents if the tank were to leak.

Figure 31 – Diesel Fuel Storage Tank Located in a Secondary Containment Berm

Another way to achieve secondary containment is through the use of storage tanks with integral secondary containment. This involves double-walled construction. Several containment options exist:

a) Double-wall tanks with a vacuum between the two walls. The vacuum of the interstitial space must be monitored, and provided with a visual vacuum gauge or electrical monitoring device of the interstitial space. The vacuum indicates the integrity of the inner container.

b) Double-wall tanks with the interstitial space designed to contain at least 100% of the tank volume. They must be provided with a visual or electrical monitoring device of the interstitial space, to detect fluid.

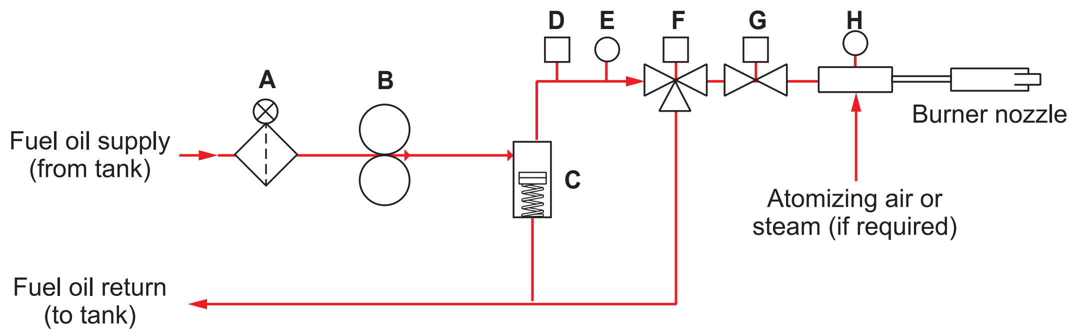
c) Open or closed secondary containment designed to contain at least 100% of the tank volume, and provision for examination or monitoring of the contained space. These tanks usually have inspection ports at the top of the interstitial space to insert a dip rod, to check for inner wall leakage.

Figure 32 shows the same fuel tank shown in Figure 31, but from another angle. Fuel supply and return lines can be seen going to the top of the tank at the near end. The return recirculates unused fuel oil from the boiler back to the storage tank. Numerous concrete barricades protect the fuel lines from vehicular traffic. A waste drain is located inside the berm (not shown). A bubbler-style level gauge can be seen in the foreground, attached to the berm.

Figure 32 – Diesel Fuel Storage Tank Showing Supply and Return Lines

From the storage tank, oil is delivered by pump to the boiler burners. Figure 33 shows a typical oil fuel train for boilers up to 3663 kW (366 BoHP), according to **ASME CSD-1**. The oil from the supply tank must be filtered, to prevent entrained solids from plugging the small burner orifices. The fuel pump provides the necessary pressure for proper fuel atomization. A pressure relief valve diverts fuel of excess pressure back to the storage tank. As well, this valve diverts all the fuel flow when the safety shut-off valves close. The safety shut-off valves (F and G) are solenoid-operated valves. Some burners use atomizing steam or atomizing air. If this atomizing media should fail, a low atomizing air/steam switch trips the safety shut-off valves.

Figure 33 – Typical Oil Fuel Train



A = Fuel filter
B = Fuel pump
C = Shutoff valve and/or pressure relief valve
D = Low oil temperature cut-off switch
E = Low oil pressure cut-off switch
F = Safety shut-off valve
G = Safety shut-off valve
H = Low atomizing media pressure cut-off switch

Objective 6

Describe the main types of liquid fuel firing systems.

Liquid Fuel Burner Types

Oil is a more challenging fuel to burn than gaseous fuels. Before fuel oil can be burned properly, it must first be broken up into a fine spray or vapor. This increases the surface area of the oil, so that it vapourizes easily, and mixes well with the combustion air.

The process of breaking liquid fuel oil into small particles is called **atomization**. Atomization must occur in order for the combustion air to mix well with the oil. Heavy oils (such as number 5 and number 6) must be heated to approximately 90°C before they can be atomized. Light fuel oils (number 1 and number 2) do not require heating. Atomization is performed in one of the following four ways:

1. Air Atomizing
2. Steam Atomizing
3. Mechanical Atomizing
4. Rotary Cup Oil Burner

1. Air Atomizing Burner

Air atomizing burners are most suitable for light oils, though they can fire heavier oils if the oil is sufficiently preheated. Air atomizing oil burners are classified as modulating burners, because the amount of fuel delivered by the burner can vary to meet changing load requirements. Some modulating air-atomized burners achieve **turndown ratios** as high as 8:1.

On Track

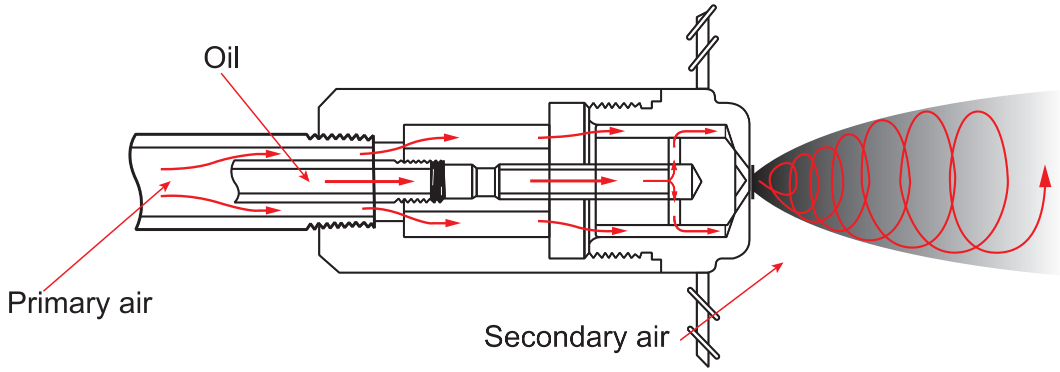
Turndown ratio refers to the difference between a burner's maximum firing rate and its minimum firing rate. A high turndown burner does not need to cycle on and off as frequently as a constant capacity or low turndown burner.

High turndown burners have turndown ratios as high as 20:1. Low turndown ratio burners have turndown ratios as low as 2:1 or 3:1.

The air atomizing oil burner shown in Figure 34 is commonly used in packaged boilers. It uses compressed air at about 100 to 250 kPa for atomizing air (or primary air). For packaged boilers, the compressed air is often supplied by a small rotary air compressor. The compressor is mounted near the front of the boiler, and driven by a small electric motor.

The atomizing air mixes with the oil near the burner tip, resulting in a fine mist of fuel particles. The secondary air necessary for complete combustion mixes with the atomized oil as it leaves the burner.

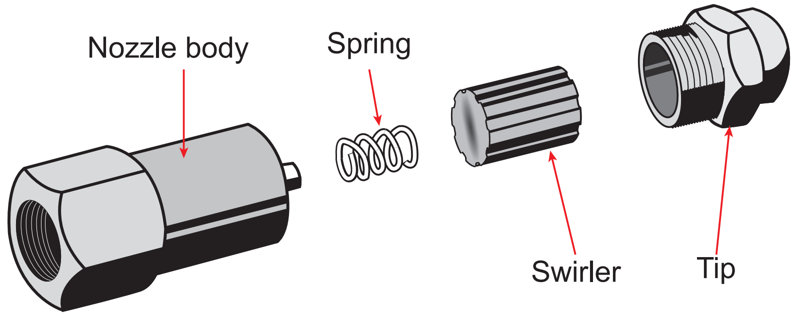
Figure 34 – Air Atomizing Burner



The oil is supplied under pressure to the burner tip through the centre tube, while the air flows through the outer tube. Oil travels through the centre tube to permit easy cleaning. In the swirler, the oil is forced through a number of small holes into the path of the air. The air-oil mixture then leaves the burner through the tip. The tip is designed to force the mixture into a swirling cone shape, so it will mix easily with the secondary air supplied around the burner.

The secondary air vanes are angled to swirl the secondary air counter to the direction of the oil swirl pattern. This promotes turbulent mixing of the fuel and secondary air. Details of the parts of the burner nozzle are shown in Figure 35.

Figure 35 – Burner Nozzle Parts



2. Steam Atomizing Burner

Most industrial burners use steam for atomization instead of air. The steam atomizing oil burner shown in Figure 36 is frequently used in larger packaged and field-assembled boilers. Its principle of operation is much the same as the air-atomizing burner, except that steam is used to produce atomization. The combustion air then mixes with the atomized oil as it sprays from the burner.

Figure 36 – Burner Nozzle Parts

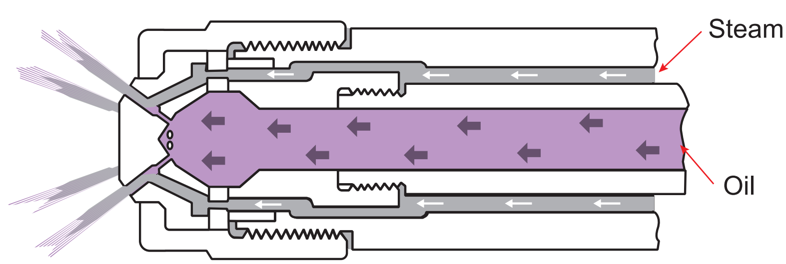
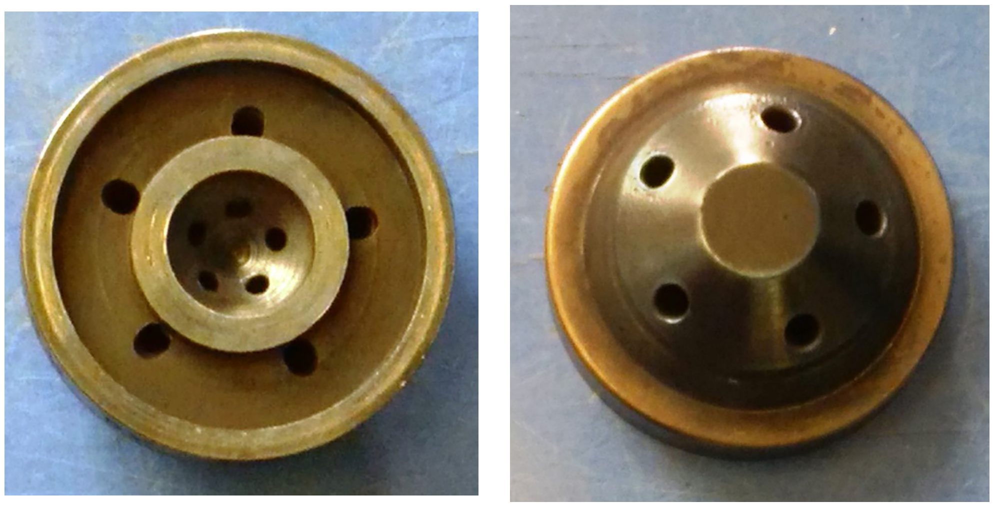


Figure 37 shows the nozzle for the burner shown in Figure 36. Two rings of five holes can be seen on the underside of the nozzle. The outer set of holes are for atomizing steam. The inner set of holes are for fuel oil. Each hole in the outer ring is paired with a hole from the inner ring. The holes intersect within the nozzle plate. The combination of steam and oil exit the five holes seen on the nozzle surface. The steam expands rapidly when leaving the nozzle, and causes very fine oil atomization.

Figure 37 – Steam Atomized Burner Nozzle: Surface and Underside Views



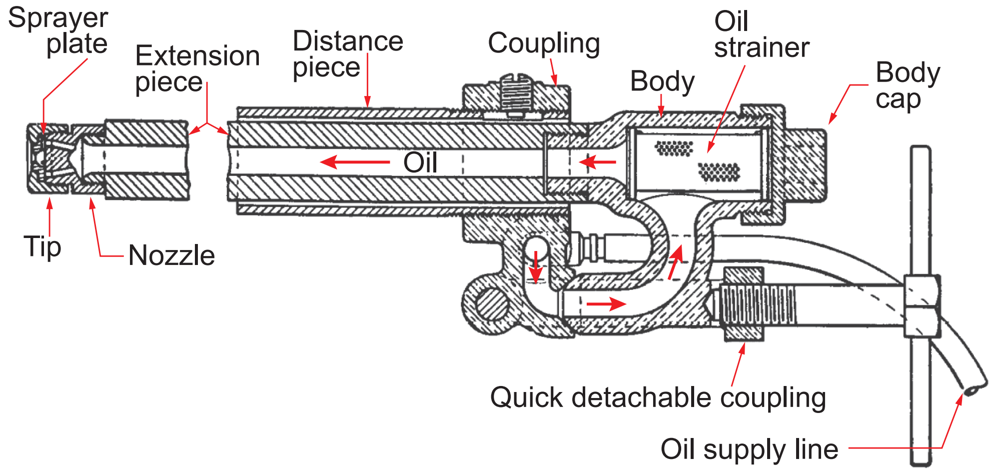
Steam-atomizing burners are fully modulating designs. Though suitable for firing light fuel oil, steam-atomizing burners are best suited for heavier grades of oil, due to the additional heat the steam provides to the oil. The additional heat provided by the steam decreases the viscosity of heavier oils, and improves atomization.

These modulating burners vary in firing rate by varying the oil pressure to the burner. Oil is delivered at between 1035 and 1380 kPa. To achieve proper atomization at all loads, and economy in steam consumption, the atomizing steam pressure is maintained at 100 to 200 kPa above the oil pressure. Steam atomizing burners achieve turndowns of around 6:1.

3. Mechanical Atomizing Burner

A **mechanical atomizing oil burner** is shown in Figure 38. In this type, the oil is pumped under high pressure through slots in a **sprayer plate**. The sprayer plate has tangential slots arranged around a central hole, and creates a rotating motion in the oil. This allows for faster mixing and improved atomization. Mechanical atomization is used in boilers of all sizes, ranging from small packaged boilers to utility boilers, where they may be used as pulverized coal igniters.

Figure 38 – Mechanical Atomizing Burner



This type of burner comes in two varieties:

- The **constant capacity burner**, which supplies a constant flow of oil. These burners are designed for on-off operation.
- The **modulating pressure burner**, which supplies variable amounts of oil to meet varying heat demands. This type of burner can be kept in continuous operation, except when boiler loads are very low.

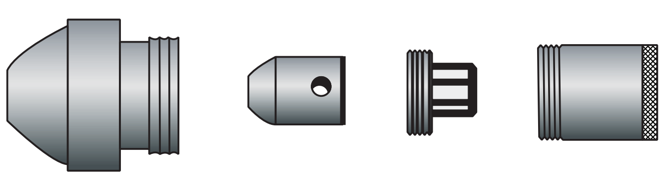
Constant (Fixed) Capacity Mechanical Atomizing Oil Burner

The oil is supplied to the burner nozzle under high pressure (at 700 to 1400 kPa, depending on the burner) by the fuel pump. In the nozzle, oil is forced through small radial slots cut in the tip of the disc (sprayer plate). The radial slots give the oil a swirling action. The oil then passes through the orifice in the tip and enters the furnace. When the oil passes through the orifice, its pressure drops to furnace pressure, resulting in a large increase in velocity. The nozzle also causes the oil to break up into a spray of minute droplets in the shape of a spinning cone. This action is similar to the adjustable nozzle on a garden hose when adjusted, so that a fine mist is obtained.

The angle and depth of the slots in the disc determine the amount of spin imparted, and the angle of spray. The size of the orifice in the tip determines the nozzle capacity.

Because of the high oil pressure used in this type of burner, the slots in the disc and the orifice in the tip are very small, and therefore more susceptible to clogging. For this reason, this burner must always be equipped with a fine strainer, either directly fitted in the nozzle, as shown in Figure 39, or in the supply line near the burner.

Figure 39 – Mechanical Atomizing Burner Nozzle Parts



Since this burner is designed for a specific pressure at the burner tip, reduction of oil pressure to reduce the firing rate will result in poor atomization. Therefore, this burner can only be operated continuously when the boiler is on full load. When the load is less than maximum boiler capacity, the fuel supply can only be reduced by on-off control.

Low Capacity Packaged Burner

The high-pressure atomizing oil burners used for low-capacity residential and commercial heating boilers are often supplied as packaged units. Packaged burners come complete with:

- Oil pump
- Draft fan
- Electric motor
- Ignition transformer
- Igniter

The unit, mounted on an adjustable pedestal, is placed in front of the boiler so that the air tube with burner sticks through the furnace opening. Figure 40 shows a sectional view of a small packaged burner used for light domestic fuel oils (No. 1 and No. 2).

Figure 40 – Packaged Low-Capacity Mechanical Atomizing Oil Burner

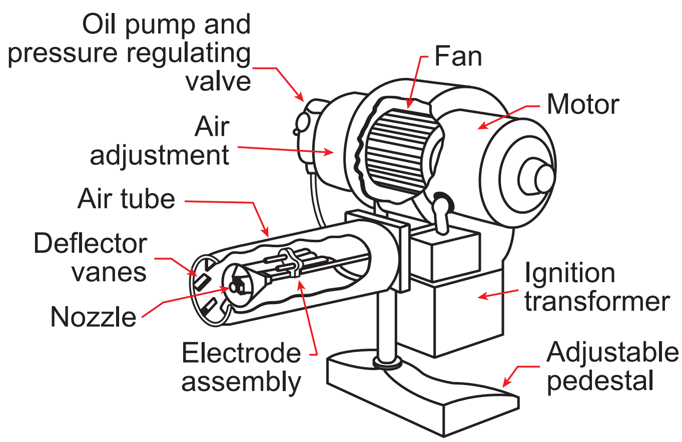


Figure 41 shows a schematic diagram of the packaged burner type shown in Figure 40. Note the turbulator vanes that impart a swirl to the combustion air. Combustion air is adjusted and set with an adjustment damper. The electric motor drives both the forced draft fan and the fuel oil pump.

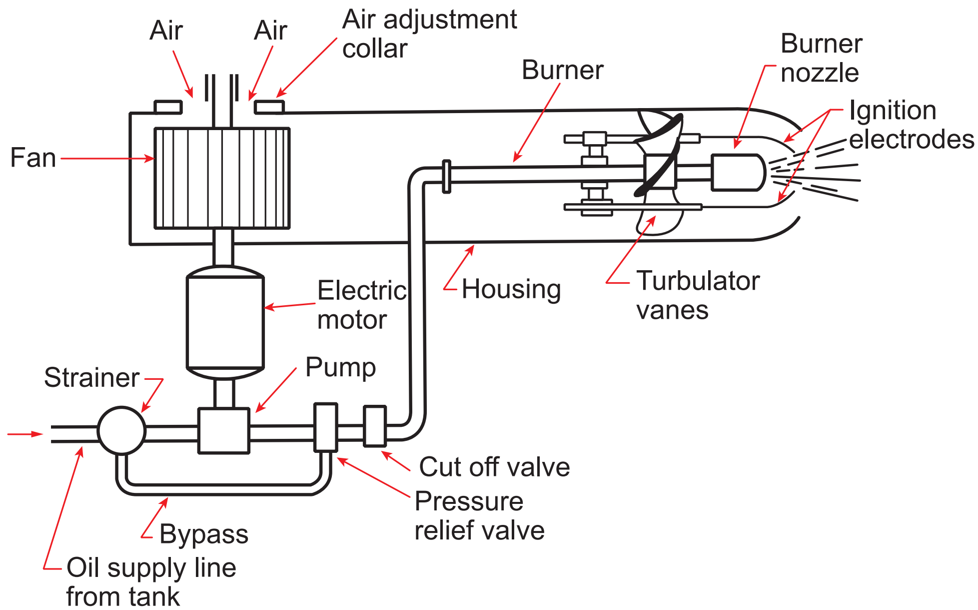
This burner is direct spark ignition; there is not pilot flame. A high voltage ignition transformer (Figure 40) provides the ignition spark. The ignition spark occurs between the two electrodes located near the burner tip.

The cut-off valve (Figure 41) shuts off oil flow to the burner when oil pressure is too low to maintain proper combustion. It also ensures no fuel drips into the furnace during the burner off-cycle.

The pressure relief valve returns fuel oil to the inlet of the pump if the oil pressure to the nozzle is excessive. Too much oil pressure results in a rich air-to-fuel ratio, incomplete combustion, soot formation, and general unsafe and uneconomical operation.

These packaged burners are on-off control only. The burner is started and stopped by the boiler operating pressure or temperature control.

Figure 41 – Schematic of Low-Capacity Mechanical Atomizing Oil Burner



When the operating control calls for heat, it energizes a programming relay which, in the proper sequence, starts the electric motor driving the combustion air fan and fuel pump. The operating control also energizes the ignition system and the fuel solenoid valve in the oil supply line from the fuel tank (not shown). The burner fires and continues to fire until the operating control is satisfied (temperature or pressure is at the upper limit). The system then shuts down and waits for the operating control to sense demand again.

Multiple Fixed Capacity Burner Systems (Cluster Burners)

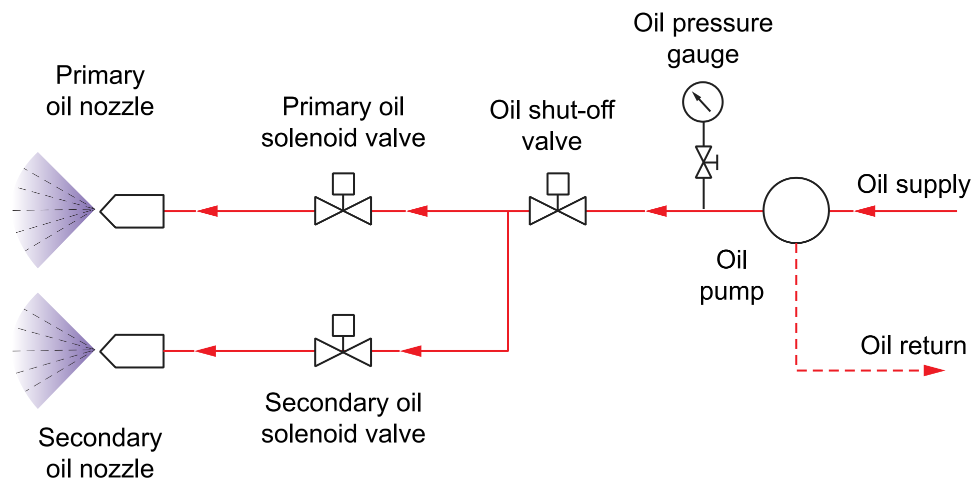
Many packaged firetube boilers are equipped with two or three constant capacity oil burners, grouped together in a cluster. By turning off one or two of the burners, the firing rate can be better matched to the steam demand. One of the burners (the low-fire nozzle) is lit by direct spark ignition, or with an interrupted or intermittent gas pilot. This low-fire nozzle remains on whenever the boiler calls for heat. If the remaining burners in the cluster are required, this primary burner will light them.

Cluster burners, depending on their configuration, are capable of off-low-high firing, or off-low-intermediate-high firing control.

Two Fixed Capacity Nozzles

Figure 42 shows a diagram of a burner system with two fixed capacity nozzles. The primary nozzle is used for startup and low demand firing. The secondary nozzle is used in conjunction with the primary nozzle when the heat demand is high. The oil pump is arranged for a two-pipe system (supply and return). The oil supply pressure to the nozzles is maintained at about 1035 to 1380 kPa (depending on the burner design) by a pressure relief valve in the discharge of the pump.

Figure 42 – Firing System with Two Fixed Capacity Nozzles



The burner starts on low-fire, to permit gradual warm up of the boiler metal and water content. After thoroughly purging the furnace at maximum airflow, the burner air damper assembly returns to the low-fire, minimum air position. Next, the spark ignition system lights only the primary nozzle. Ignition occurs as soon as the primary oil solenoid and the oil shut-off valves open. The primary oil nozzle fires at constant capacity throughout the boiler run period.

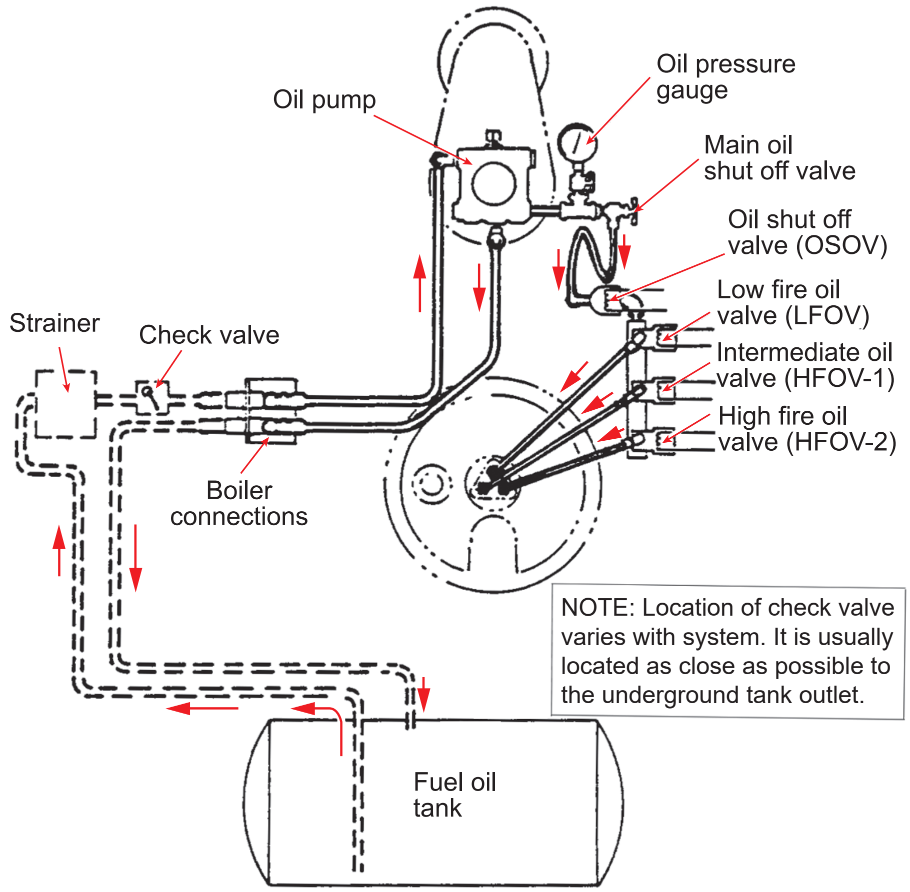
After startup, and when heat demand is high, the secondary high-fire nozzle enters into operation. The secondary oil solenoid opens when the boiler pressure or temperature is less than a set point value. The primary nozzle ignites the secondary nozzle. The secondary oil solenoid valve cannot open unless the fuel leaving the primary nozzle has been ignited, and the flame is recognized by the combustion control.

Depending on heat demand, the firing rate alternates between high and low firing. When demand is very low, the burner cycles off and on, igniting only the primary nozzle.

Three Fixed Capacity Nozzles

Boilers with cluster burners that have three nozzles can more closely match the firing rate to the load demand. These nozzles may have equal fuel capacities, but on some boilers, the capacities of the intermediate and high fire nozzles are higher than that of the low fire nozzle. This arrangement makes it possible to warm the boiler up slowly at the lowest firing rate. A diagram of the oil supply to the three-nozzle burner is shown in Figure 43.

Figure 43 – Oil Flow Diagram to Three Nozzle Burner



This burner has a fuel pump driven by the forced draft fan motor with a belt. The pump has more capacity than the maximum firing rate. Any oil not used by the burner nozzles is returned to the fuel storage tank.

The pump has an integral pressure regulator, adjusted to provide the necessary atomizing pressure to the burner nozzles. This pressure is read on the oil pressure gauge.

Oil flow to the burner is controlled by four solenoid valves. The oil flows through a primary oil safety shutoff valve (labeled OSOV) into a manifold. This valve and the low fire valve are energized simultaneously by the programming control. When opened, these solenoid valves allow oil to flow to the low fire nozzle.

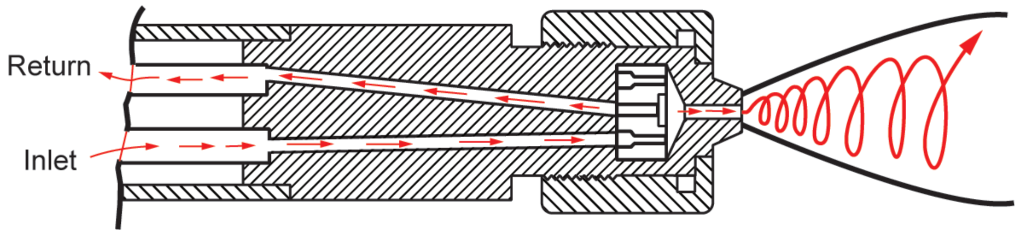
As the air damper motor moves to high fire position, cam-operated switches close to energize the intermediate and the high fire oil valve in sequence. The intermediate valve energizes when the damper motor is at about 50% firing rate. Intermediate fire is obtained when the primary and intermediate nozzles are firing. The tertiary valve energizes when the damper motor reaches about 75% firing rate. High fire is obtained when all three nozzles are firing.

The burner nozzles require a minimum oil pressure of 1380 kPa to properly atomize the fuel. A low oil pressure cut-off switch closes the safety shut-off valves if the oil pressure drops to 1035 kPa.

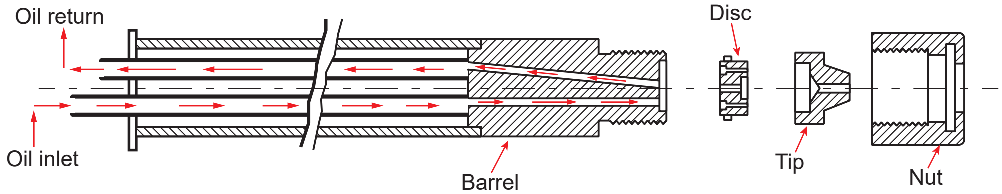
Modulating Mechanical Atomizing Oil Burner

The operation of this burner, also called a wide-range pressure-atomizing burner, is quite similar to that of the constant capacity oil burner. However, this burner has an adjustable firing rate. A cross sectional view of this burner is shown in Figure 44(a). The main parts of this type of burner are broken out in Figure 44(b).

Figure 44 – Modulating Mechanical Atomizing Oil Burner



(a)



(b)

As in the constant capacity burner, the oil is delivered to the furnace via radial slots in the sprayer plate, the swirling chamber, and the orifice in the tip. Fuel flow is dependent on the fuel pressure at the nozzle. At maximum firing rate, the nozzle pressure is greatest, and only a small amount of oil returns to the oil tank.

When the firing rate is turned down, the nozzle pressure must be reduced. The pressure reduction is achieved by bleeding off part of the oil from the swirling chamber through a channel in the disc and barrel. This bleeds off more oil through the return lines to the storage tank. The remainder of the oil passes through the orifice into the furnace. The amount of oil bled off is regulated by a firing rate control valve in the return line.

A modulating pressure atomizing oil burner keeps the burner in continuous operation. At the same time, it maintains constant steam pressure or hot water temperature at widely varying loads. These burners require very high fuel supply pressure so that, even when turned down to minimum fire, there is still adequate pressure for atomizing. Typical fuel oil pressures range between 2050 and 2750 kPa. Mechanical atomizing burners have relatively low turndown ratios (about 3:1).

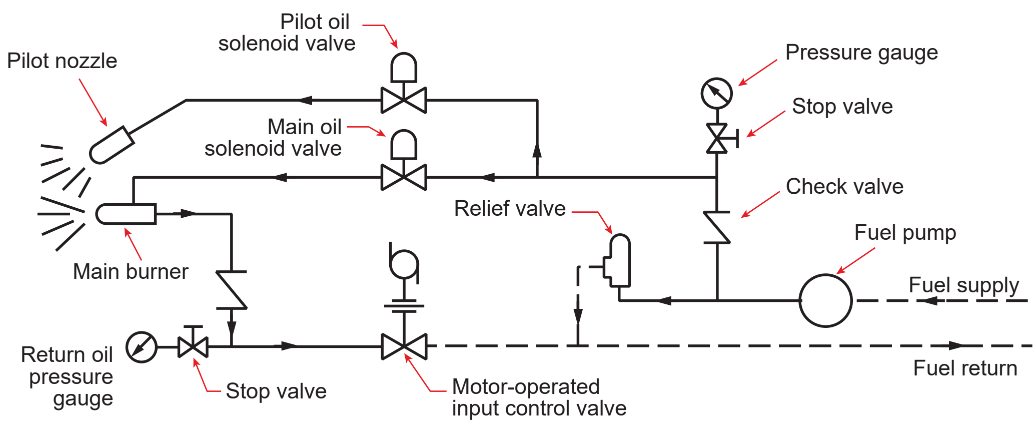
Mechanical atomizing oil burners can be used for light and heavy fuel oils. Heavy oils require preheating to around 90°C.

System with Modulating Burner and Pilot

Some boilers are equipped with one constant capacity pressure atomizing burner for start-up and low firing, combined with a modulating type burner to provide variable firing when load demand increases.

A schematic of a modulating burner and pilot system is shown in Figure 45. Oil is pumped to the burner nozzles at around 1380 kPa. The pilot nozzle is of fixed capacity and supplied via a solenoid valve operated by the programmed combustion control. The main nozzle is of the variable capacity type. Oil supply to this nozzle is controlled by a solenoid valve also operated by the combustion control. The flow rate of the oil through the nozzle is regulated by a modulating valve in the return line from the nozzle, which bleeds off part of the oil supplied to the nozzle depending on the required firing rate. This modulating valve is operated by the boiler steam pressure control.

Figure 45 – Schematic of Fuel System with Modulating Burner and Pilot



a) On a low fire start, the pilot solenoid valve is opened by the programming control in the proper startup sequence. The pilot flame then ignites.

b) The flame sensor lights the pilot flame and signals the programming control. The control then opens the main oil solenoid valve.

c) The main oil solenoid valve opens supplying oil to the main nozzle. However, the modulating input control valve is kept open during startup so that oil flow through the main nozzle is kept at the minimum firing rate. The pilot now ignites the main nozzle flame.

d) After the main nozzle flame is established, the pilot solenoid valve closes. The modulating valve is adjusted by the firing rate controller to regulate the oil flow to the main nozzle to match the heat demand.

4. Rotary Cup Oil Burner (Centrifugal Atomizing Burner)

The **rotary cup oil burner** (Figure 46) is often used for larger sized packaged boilers. They are common in marine boiler service. Rotary cup oil burners are effective at burning heavy fuel oils (No. 5 and No. 6), but are also available for burning light fuel oils (No. 1 and No. 2).

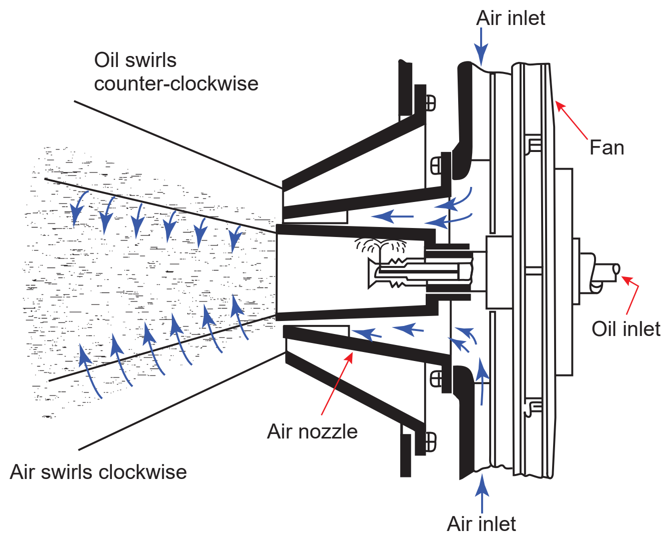
The rotary cup burner may be considered a mechanical atomizing burner, because it uses mechanical means to atomize the fuel. It can also be considered an air-atomized burner, because high velocity air is used in combination with the mechanical means to atomize the fuel. Therefore, rotary cup burners are best considered as an independent burner category.

In this burner type, the oil is pumped to the inside of a cup, and rotated at high speed by an electric motor (3000 to 8000 r/min, depending on the burner design). Centrifugal force causes the oil to be thrown off the cup's rim in a fine spray. Primary air is forced by a fan into the path of the oil spray, in a whirling motion. Additional secondary air for combustion is supplied to the oil spray as it leaves the burner.

As the oil leaves the end of the rotating cup, it enters the primary air stream at or near a right angle. Here, the primary air tends to shear and atomize the oil.

Rotary cup burners are fully modulating. They can achieve turndowns of 10:1.

Figure 46 – Rotary Cup Oil Burner



Oil Burner Maintenance and Operation

If a fuel oil installation is new, the fuel lines should be thoroughly cleaned by blowing out with compressed air or steam before putting the burners into operation. This will prevent dirt and other foreign materials from plugging the small holes and passageways in the burner.

When oil burners become dirty, they should be replaced promptly with clean spare burners. The dirty burners should then be cleaned. When cleaning burners, use a clean work area, and take care not to damage the delicate parts of the burner. Kerosene or special solvents can be used, along with compressed air, to blow out the burners. Always wear goggles when using compressed air.

To avoid damaging the nozzle holes or the oil grooves, burner nozzles should be cleaned with a wood splinter rather than with a metal piece. After cleaning burners, hang them vertically with the tips immersed in kerosene. When shutting off air or steam atomizing burners, shut off the oil first, and then blow out the burner with steam or air.

Check louvres and registers regularly to ensure they move freely, and lubricate the linkages. When the burner is in operation, the registers must be adjusted to give the proper air to fuel ratio. Too little air will produce dark, heavy smoke. Too much air will produce a gray coloured smoke. If a flame is dark and smoky, it is important to reduce the fuel flow to the burner nozzle, and not to increase the airflow. Otherwise, unburned fuel or products of incomplete combustion could ignite, creating a furnace explosion.

When the boiler is operating at low load, the number of burners in service should be reduced. This will maintain adequate oil pressure, and will ensure a stable flame at the burners still in service. When burners are not in use, they should be removed from the furnace. Otherwise, the heat may cause carbon to form within them.

Auxiliary Equipment for Fuel Oil Systems

Fuel oil systems require several types of auxiliary equipment. These include fuel pumps, fuel oil piping systems, igniters, fuel filters, cutoff valves, pressure relief valves, and time delay valves.

Fuel Oil Pumps

All oil-fired boilers require fuel oil pumps to transfer oil from the storage tank to the burner. The pumps also build up sufficient oil pressure in the burner nozzle to achieve proper atomization. Rotary pumps, such as the external or internal gear pumps, are commonly used for this purpose.

The **CSA B139 Installation Code for Oil Burning Equipment** states that for fuel oil pumps, the maximum lift imposed on a fuel oil pump, measured from the bottom of the supply tank, shall be 4.9 m. When the fuel oil pump is located above the supply tank, the pump and supply piping shall be installed to avoid air locks, and shall be a two-pipe system. If the fuel oil pump is single stage, the lift from the bottom of the supply tank shall be less than 2.4 m. If the lift is greater than 2.4 m, a two-stage pump shall be used. When the burner fuel pump is more than 4.9 m above the bottom of the fuel tank, an auxiliary pump shall be used to supply the burner with adequate pressure for the burner.

Single-Stage Pumps

A single-stage pump has one set of gears to act as suction and pressurized discharge. The theoretical limit for a single-stage pump for suction lift is under 2.4 meters. For lifts over 2.4 meters, a two-stage pump must be used.

Two-Stage

The two-stage pump has two sets of gears. The first set draws oil into the pump, and discharges it into a reservoir in the pump body. The second stage gears pressurize the oil in this reservoir, and discharge the oil to the burner.

In either case, the lines must be air tight to eliminate air leaks into the oil lines. This is especially crucial when the oil tank is below the burner pump, and the oil must be lifted to the pump suction.

Fuel Oil Piping

Single-Pipe

A single-pipe system is only used where the pump and burner are matched in capacity. In this situation, the pump sends only enough oil to the burner. Such is the case with constant capacity burners.

Smaller packaged burners use single-pipe systems. The oil pumps are equipped with internal relief valves that recirculate oil around the pump. This maintains constant pressure at the burner nozzle.

Two-Pipe or Double-Pipe

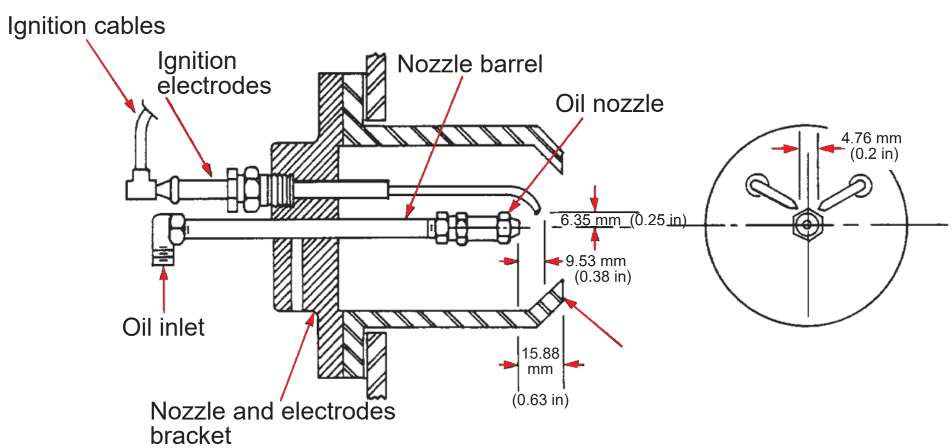
The two-pipe system is used with modulating burners and multiple burner systems. The fuel oil pump must be sized to supply the maximum oil flow when the maximum number of burners are in service. This amount of oil is not necessary at most loads. A pressure regulator or modulating firing rate control valve bypasses the extra oil back to the tank.

Electric Ignition

Electric ignitors are generally used for the oil burners on packaged firetube boilers. The main components of an electric ignition system are a step-up transformer and two electrodes. To ignite the fuel-air mixture at startup, a very powerful spark is required between the tips of the two electrodes. To achieve this spark, the ignition transformer boosts the applied voltage from 120 volts to around 10 000 to 12 000 volts. The electrodes are made of stainless steel mounted in ceramic insulators. The tips of the electrodes are positioned somewhat above and slightly in front of the tip of the burner.

The diagram in Figure 47 shows the proper setting of the electrodes in relation to the burner tip, as used by one manufacturer. Keep in mind that these settings differ on other boilers. Always check the boiler owner's manual for the correct setting before making adjustments.

Figure 47 – Electrode Settings



(Courtesy of Volcano)

When the burner consists of a cluster of nozzles operating independently, only the low fire nozzle (pilot nozzle) is lit electrically. The flame of the pilot nozzle then lights the other nozzles.

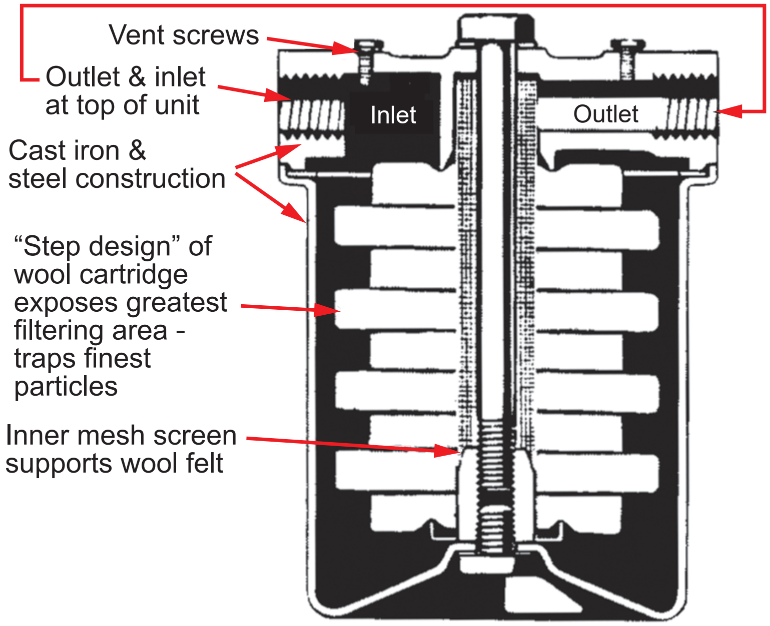
Instead of electrodes, a spark plug is sometimes used to light the burner. In principle, the ignition procedure is the same as with the use of electrodes. Weak ignition, improper adjustment of the electrodes, and poor insulation may cause delayed ignition. This can result in a small furnace explosion, called a **puff back**.

A puff back is caused by a larger than normal amount of combustible mixture in the furnace, combined with delayed ignition. When ignited, a momentary high pressure is created, causing blow back into the boiler room through air intakes and observation openings. Immediate attention should be given to the ignition system, and to light-off procedures when puff back occurs. Neglecting this situation may lead to a more serious furnace explosion.

Fuel Oil Filters and Strainers

To prevent clogging of the small nozzle channels and the orifices, the oil supplied to a burner must be completely free of dirt, rust particles, and other impurities. It is common practice to install a filter in the supply line between the storage tank and fuel pump, even when the pump or burner is equipped with an internal filter. A common type of filter used for this purpose is the cartridge filter illustrated in Figure 48.

Figure 48 – Fuel Oil Filter



(Courtesy of General Filters Inc.))

The filter consists of three main parts:

1. Cast-iron top with inlet and outlet openings, and vent screws.
2. Filter cartridge made of layers of wool felt.
3. Steel cap which encloses the cartridge.

A single bolt holds the entire assembly together. This filter is not only effective in the removal of fine particles, but it also absorbs a certain amount of moisture.

Figure 49 shows another type of fuel filtration device. This duplex oil strainer is used to remove dirt and debris from fuel oil piping systems. Duplex strainers are used where continuous flow must be maintained with no flow interruption.

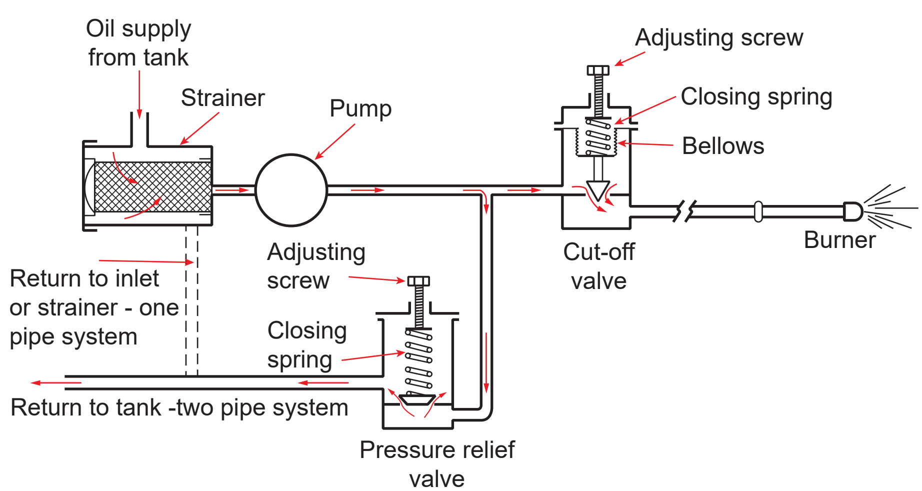
The strainer consists of two basket strainers. A built-in tapered plug valve, located between the two strainer bodies, directs flow through either one of the two strainers without interrupting the flow. The plug valve handle can be seen at the top of the image. The valve handle swings over the inlet port of the strainer in service. Drain valves are provided in each of the strainer basket chambers to drain the strainer before disassembly and cleaning.

Figure 49 – Duplex Fuel Oil Strainer

Cutoff and Pressure Relief Valves

In fuel oil supply systems for mechanical pressure atomizing burners, the oil pump draws the oil from the fuel tank via the supply line and filter. The pump discharges the oil under high pressure into the burner supply line, as shown in Figure 50. For light oils, this pressure is in the 550 to 700 kPa range. Higher pressures are often used for heavier oils.

Figure 50 – Oil Pressure Relief Valve



The capacities of the nozzle of a fixed capacity burner and the fuel pump usually do not match. Often, the oil pump supplies more oil than the burner nozzle is designed to discharge. This situation could result in an excessive pressure buildup.

The oil pressure at the burner must be kept at a constant value near the design pressure. Too high a pressure would cause an excessive amount of fuel to enter the furnace. Since the fan is adjusted to supply the amount of combustion air required for the oil discharged from the nozzle at design pressure, incomplete combustion would take place.

To prevent the fuel pressure at the burner from exceeding the design pressure, a relief (or regulating) valve is installed in the discharge line of the pump. This valve is spring-loaded. It opens and releases excess fuel as soon as the set pressure is reached. The released oil is then bypassed back to the strainer or pump inlet or back to the fuel tank in a two-pipe system. Figure 50 shows the basic design of this valve.

The oil pressure at the burner nozzle should not drop too low; otherwise, atomization quality will deteriorate. A cutoff valve (Figure 50) is installed in the line to the burner to prevent oil flow at a pressure at which poor atomization would occur. The valve stem is connected to a bellows. The oil exerts an upward force on it, which tends to open the valve. A closing spring exerts a downward force on the bellows, which tends to close the valve.

When the oil pressure is below the minimum needed for proper atomization, the spring will keep the valve closed. As soon as the pressure builds up above this minimum, the upward force of the oil on the bellows overcomes the downward force of the spring and the valve opens, allowing oil to flow to the burner.

The pressures at which cutoff and pressure relief valves open will vary from one system to another. It depends on the type of sprayer plate used and the properties of the fuel. For each valve, this pressure can be adjusted by increasing or decreasing the tension of the closing spring by means of the adjusting screw. Cutoff and pressure relief valves are usually combined as a single unit.

Time-Delay Oil Valve

When an oil or gas-fired boiler with mechanical draft is started, it is necessary to pass a flow of air through the boiler first. This purges the furnace and the flue gas passages of any combustible vapours left behind from the previous combustion cycle, or introduced by leakage of fuel valves. To prevent the possibility of a furnace explosion, this purging must be done before the igniter is energized and fuel is supplied to the burner nozzle.

On larger automatically fired heating boilers, the duration of the purging cycle, time of ignition, and fuel supply are all controlled in the proper sequence by a programming control. This program also controls a solenoid valve to delay the fuel supply to the burner.

Smaller oil-fired heating boilers are often equipped with a packaged burner system. These burners are controlled by a simple control relay. This type of burner uses a single electric motor to drive the combustion air fan, as well as the fuel pump.

To delay the flow of oil to the burner on startup until the furnace has been properly purged, a time-delay oil valve is installed between the pressure-regulating valve and the burner. When the control relay starts the burner motor on demand for heat, it allows a purging cycle of 10 to 15 seconds before the igniter energizes. The time-delay oil valve is adjusted to open automatically, and allow oil flow to the burner from 5 to 15 seconds after the start of the igniter.

The proper timing and operation of this valve are vital to prevent a furnace explosion during startup. Should the valve malfunction, the burner should be taken out of service for repair immediately.

Objective 7

Describe flue gas analysis and how it relates to boiler efficiency.

Flue Gas Analysis

Excess air is necessary to obtain complete combustion. Recall that too much excess air causes a decrease in boiler efficiency, since the nitrogen in the air carries a large amount of heat out through the chimney. To check the amount of excess air in the flue gas, a sample must be taken, and analyzed for CO_2 content.

The mass of CO_2 produced per unit mass of fuel burned will be constant, but the percentage of CO_2 in the flue gases depends on the amount of combustion air supplied. CO_2 is a product of complete combustion. If combustion is incomplete due to inadequate combustion air, CO is produced instead of CO_2. Therefore, the percentage of CO_2 in the flue gas drops, and the percentage of CO rises. The CO_2 concentration in the flue gas also decreases if combustion air is excessive. This is because extra nitrogen and unreacted O_2 dilute the CO_2 concentration.

When combustion is complete, all carbon reacts to form CO_2. When stoichiometric amounts of fuel and air are mixed perfectly and ignited, complete combustion results. In such a case, the flue gas CO_2 concentration will be at a maximum. Therefore, ideal combustion results when CO_2 is analyzed and shown to be at a maximum.

By determining the percentage of CO_2 in the flue gases, the amount of excess air supplied can be calculated, or looked up in combustion tables. The mass of CO_2 in the flue gases (per unit of fuel burned) depends on the kind of fuel burned. This is because different fuels contain different proportions of carbon. Therefore, the combustion tables are different for each type of fuel.

Electronic Flue Gas Analyzers

Flue gas analysis ensures safety, operational efficiency, and environmental impact targets are met. Due to advances in electronics, it is now easy, inexpensive, and therefore more common, to analyze flue gases. With tightening environmental regulations, flue gas monitoring may be mandatory. The electronic instruments used for analysis range from inexpensive small hand-held devices that produce reasonable accuracy, to larger permanently installed units that are capable of producing lab quality results on a continuous basis. The latter, often referred to as **continuous emissions monitoring systems (CEMS)**, are the standard for regulated emissions compliance.

The combustion process inputs are fuel and air. Therefore, the components of flue gas are primarily made up of compounds of oxygen, nitrogen, sulfur, hydrogen, and carbon. The components that are of interest are primarily oxygen (O) and carbon (C), because they affect efficiency. In boilers that use biomass or coal as fuel, the components that are of most interest from an environmental perspective are nitrogen oxides (NO_X), carbon dioxide (CO_2), carbon monoxide (CO), and sulfur oxides (SO_X). Often a continuous or periodic mercury analysis is also commonly performed in regulated emissions testing programs.

Testing Procedures

Flue gas analysis is performed in one of two ways. The first is by inserting an analyzer probe directly into the breeching or vent connector of the furnace or boiler. The second is by pumping a flue gas sample to a sampling chamber within an external analyzer. The latter is typically used for continuous monitoring equipment. It is also used for very large systems where it is not easy to reach a spot in the flue to insert a probe, or to locate a portable meter. Depending on the gas being measured, most electronic analyzers use infrared sensors, or undergo some sort of electrochemical reaction.

The environment within an external analyzer unit varies according to the type of analysis and sensor. The sampling chamber may need to be heated in order to keep the product to be measured from condensing out, such as NO_2, SO_2, and HCl. In other cases, the flue gases must be cooled and dried to prevent moisture damage to the probe. Instruments often use a **Peltier cooler**, which is a thermoelectric device that produces a cool surface. This condenses moisture out of the flue gas before it reaches the measuring sensor.

Probes and sensors do not last forever. Some electrochemical sensors are consumed by the measurement process. Others wear out with use as they are exposed to high temperatures and corrosive gases. Infrared (IR) sensors are therefore becoming more popular for many applications. However, IR sensors are more expensive, less accurate, and affected by dirt, fogged lenses, and other application issues. This limits where and how IR sensors can be used.

Measurement values are either provided in parts per million (ppm) or percentage (%), depending on the size of the reading. Larger numbers, such as oxygen and carbon dioxide are generally provided in percentages. Small numbers, such as NO_X and CO are provided in ppm.

Excess Air Calculations

When the CO_2 or O_2 content of the flue gas is known, the amount of excess air can be found either by calculation or from tables or graphs. Using tables or graphs is the simplest way.

Table 2 shows the percentages of CO_2 and O_2 that can be expected to be found by flue gas analysis for the various percentages of excess air supplied when burning coal, oil, or natural gas. If the type of fuel oil or coal used in the boiler is not represented in Table 2, the equivalent figures for the fuel being used should be available from the fuel supplier or utility.

Table 2 – CO_2 and O_2 Percentages in Flue Gas

Fuel	Combustion products	Percentage of Excess Air								
		0	10	20	30	40	50	60	80	100
Coal (Bituminous)	CO_2	18.6	16.9	15.5	14.3	13.2	12.2	11.3	10.2	9.2
	O_2	0	2.0	3.5	5.0	6.1	7.1	8.0	9.4	10.6
Fuel Oil (Light)	CO_2	15.4	13.8	12.6	11.5	10.6	10.0	9.3	8.2	7.4
	O_2	0	2.0	3.7	5.2	6.3	7.3	8.2	9.6	10.8
Natural Gas	CO_2	12.2	10.9	9.9	9.1	8.4	7.9	7.3	6.4	5.7
	O_2	0	2.1	3.9	5.4	6.4	7.5	8.4	9.8	10.9

Example 1

A flue gas analysis for a natural gas-fired boiler reads 9.6% CO_2. What is the percentage of excess air being supplied to the boiler?

Solution 1

Using Table 2, follow the horizontal CO_2 line for natural gas, and see if 9.6% is shown on this line. If it is not shown, the values above and below 9.6 (9.1 and 9.9) must be used to interpolate the approximate value of excess air for a CO_2 percentage of 9.6.

Record the percentage of excess air on top of the vertical column for each of 9.1 and 9.9. In this case, the excess air is 20% when the percentage of CO_2 is 9.9% and 30% when the CO_2 is 9.1%.

These readings show that, in this range, the percentage of CO_2 in the flue gas drops 0.8% when excess air is increased by 10%. This is equivalent to a drop of 0.1% CO_2 for each 1.25% increase in excess air.

Since the reading of 9.6% CO_2 is 0.3% below 9.9% CO_2, the excess air will be:

$$3 \times 1.25\% = 3.75\% \text{ higher or}$$

$$\text{Excess Air} = 20\% + 3.75\%$$

$$= \mathbf{23.75\%\ (Ans.)}$$

The results of the analysis should be used as a guide to regulate the air supply so that no more excess air is supplied than is necessary to obtain complete combustion.

Self-Test 1

After analyzing a sample of flue gas from a light oil-fired boiler, the analyzer reading shows 14.2% CO_2.

a) What is the percentage of excess air being supplied to the boiler?

b) What is the percentage of excess air if the same reading was taken from a boiler fired with bituminous coal?

7.5% (Ans. a)

30.9% (Ans. b)

The ideal amount of excess air varies for different types of boilers and firing equipment. Boiler operators are advised to consult the boiler manufacturer's service manual for their particular boiler for the recommended amount of excess air. Keep in mind that a clean-burning flame together with the correct amount of CO_2 in the flue gas are essential for good combustion.

Combustion Efficiency (Boiler Efficiency)

The combustion efficiency indicates what percentage of the heat produced by the combustion of the fuel is actually absorbed by the water in the boiler. Consequently, it also indicates how much of the heat is disappearing up the chimney.

A certain amount of heat loss cannot be avoided since the flue gases carry away some heat. The boiler operator can limit this heat loss by keeping the excess air down to the minimum required for complete combustion, and keeping the heat transfer surfaces as clean as possible. Waterside and fireside cleanliness ensures maximum heat transfer from the flue gases to the water before the gases leave the boiler.

Boiler operators and service technicians can determine the efficiency of a boiler simply through the use of a combustion efficiency chart (Figure 51). To use these charts, two things must be known:

1. The percentage of CO_2 in the flue gases leaving the boiler (found by flue gas analysis).
2. The **net stack temperature**, which is the difference between the temperature of the flue gases leaving the boiler (found by inserting a thermometer in the boiler flue outlet) and the temperature of the air entering the combustion chamber (found by inserting a thermometer in the wind box).

By applying this information to the chart pertaining to the fuel used, the efficiency of the boiler can be found.

Figure 51 – Combustion Efficiency Charts

Light Oil

	PERCENT CO_2										
STACK TEMP. °F	15	14	13	12	11	10	9	8	7	6	5
300	90.0	89.0	89.0	88.0	87.5	87.0	86.0	85.5	84.5	82.0	80.5
350	88.0	87.5	87.0	86.5	86.0	85.0	84.5	83.0	81.5	80.5	77.0
400	86.0	85.5	85.0	84.5	84.0	83.0	81.5	81.0	79.0	75.5	73.0
450	85.0	85.5	84.5	83.5	82.0	81.0	79.5	77.5	75.5	73.5	70.0
500	83.5	83.0	82.0	81.5	80.5	79.5	77.5	75.5	73.5	70.0	66.0
550	82.0	81.5	81.0	79.5	79.0	77.0	75.0	73.5	71.0	67.0	63.0
600	81.0	80.5	79.5	78.0	77.0	75.0	73.0	71.0	66.0	64.0	60.5
650	79.5	79.0	78.0	77.0	75.0	73.0	71.5	68.5	65.0	61.5	56.0
700	78.0	77.5	76.5	74.0	73.0	71.5	68.5	66.0	63.0	58.0	52.5
800	75.5	74.0	73.0	71.5	69.5	67.5	64.5	62.0	57.0	52.5	45.0
900	73.0	71.5	70.0	68.0	66.0	63.5	59.0	56.5	52.5	46.0	38.0

Bituminous Coal

	PERCENT CO_2										
STACK TEMP. °F	15	14	13	12	11	10	9	8	7	6	5
300	91.5	91.0	90.5	89.5	88.5	87.5	86.5	85.0	82.5	80.0	76.0
350	90.0	89.0	88.5	87.5	86.5	85.0	83.5	81.5	79.0	75.5	70.0
400	88.0	87.0	86.0	85.0	83.5	82.0	80.0	77.5	75.0	70.5	65.0
450	86.5	85.0	84.0	83.0	81.5	79.5	77.5	75.0	71.5	66.5	60.5
500	84.5	83.5	82.0	81.0	79.0	77.5	75.5	71.5	68.0	62.0	55.0
550	82.5	81.5	80.0	78.5	77.0	74.5	72.0	68.0	64.0	57.5	50.0
600	81.0	79.5	78.0	76.5	74.5	72.0	68.5	65.0	60.5	53.5	45.0
650	79.0	78.0	76.0	74.5	72.0	69.0	66.0	61.5	56.5	49.0	40.0
700	77.5	76.0	74.0	72.0	69.5	68.5	63.0	58.5	53.0	45.0	35.0
800	74.0	72.5	70.0	67.5	65.0	61.0	57.0	52.0	46.0	36.5	25.5
900	70.0	68.5	66.0	63.0	60.0	56.0	51.5	46.0	38.0	28.0	16.0

Natural Gas (39.12 kJ per m^3, 1.5 Btu per ft^3)

	PERCENT CO_2								
STACK TEMP. °F	11	10	9	8	7	6	5	4	3
300	82.5	82.0	81.5	81.0	80.0	79.5	78.0	76.0	72.5
400	80.0	79.5	79.0	78.5	77.0	75.5	74.0	71.0	65.5
500	78.0	77.5	76.5	75.5	74.0	72.0	69.5	65.5	59.0
550	77.0	76.0	75.0	74.0	72.5	70.5	67.5	63.0	58.0
600	76.0	75.0	74.0	72.5	71.0	68.5	65.5	60.5	52.5
650	75.0	74.0	72.5	71.0	69.5	67.0	63.0	58.0	51.0
700	74.0	73.0	71.5	70.0	68.0	65.0	61.0	55.5	46.0
800	71.5	70.5	69.0	67.0	64.5	61.5	57.5	50.5	40.0
900	69.5	68.0	66.5	64.5	61.5	58.0	52.5	45.5	33.5

°F	300	350	400	450	500	550	600	650	700	800	900
°C	149	177	204	232	260	288	316	343	371	427	482

Example 2

The flue gas analysis of an oil-fired boiler shows a 12% CO_2 content while the net stack temperature is 275°C (527°F). Find:

a) The percentage of excess air supplied.

b) The combustion efficiency of the boiler.

Solution 2

a) The CO_2 line for fuel oil in Table 2 indicates that at 12.6% CO_2, excess air is 20%. At 11.5%, CO_2 excess air is 30%. Thus, CO_2 content drops 1.1% for a 10% increase in excess air. Since CO_2 content is 12%, 0.6% below 12.6%, the excess air increase will be:

$0.6/1.1\% \times 10\% = 5.5\%$ above 20%.

Thus, the percentage of excess air is **25.5% (Ans)**.

b) Using the efficiency chart for oil in Figure 51, follow the CO_2 column for 12% to the intersection with the net stack temperature column, and read the efficiency.

Since the 527°F net stack temperature falls between the 500°F and 550°F temperature columns given on the chart, take the readings at the intersections of both columns. At 12% CO_2 content, and a 500°F net stack temperature, the efficiency is 81.5%. At 12% CO_2 content, and a net stack temperature of 550°F, the efficiency is 79.5%.

The stack temperature is 527°F, which is almost exactly halfway between 500°F and 550°F. The corresponding efficiency value of 80.5% (halfway between 79.5% and 81.5%) can be used, and would be very close to the exact calculated value. (Using linear interpolation, the answer is 80.42%).

With a 12% CO_2 content, and a net stack temperature of 527°F, the boiler efficiency will be approximately **80.5% (Ans)**.

Self-Test 2

The flue gas analysis of a natural gas-fired boiler shows a 7.5% CO_2 content. The temperature of the flue gas is 600°F. The combustion air temperature is 26.1°F at the windbox. Find:

a) The percentage of excess air supplied.

b) The combustion efficiency of the boiler.

56.66% (Ans. a)

72.53% (Ans. b)

The efficiency charts show us that:

a) An increase in excess air results in a drop in percent CO_2 content in the flue gases. This lowers the boiler efficiency. The opposite is also true: a decrease in excess air results in a higher boiler efficiency.

b) A rise in net stack temperature at a specific firing rate results in a drop in boiler efficiency. A reduction in net stack temperature results in higher boiler efficiency.

c) A rise in net stack temperature can be caused by the heating surfaces fouling due to waterside scale, or fireside soot and ash deposits. A net stack temperature rise can also be caused by an increase in excess air. Because the extra air increases the total volume of flue gases that have to pass through the boiler during a specific time, the gases must travel faster through the boiler. This results in a lower time of contact between gas and heating surfaces, less heat transferred to the water, and hence lower efficiency.

Chapter Summary

Whenever something contains the elements carbon and hydrogen, it is combustible. Although sulfur is combustible, and is found in some conventional fuels, it is considered to be an undesired element. Combustion of sulfur produces SO_2, which is a major contributor to atmospheric pollution. Sulfur is removed from fuel prior to burning, or neutralized before emission.

A major concern of boiler operators is the protection of the environment and operational efficiency. This is why operators must always be aware of how efficiently and safely the plant is operating. This awareness comes from understanding how the heart of the plant produces its central product: heat.

Heat is transferred from fuel in many ways, but always through a combustion process. Different fuel types have different characteristics that require unique handling, storage, and firing processes. This chapter has identified many of the boiler and heat generation system components. It has also provided overviews of their uses both singly and collectively.

CHAPTER 3

Draft

LEARNING OUTCOME

When you complete this chapter you should be able to:

Describe basic concepts and equipment used to supply combustion air to boiler furnaces.

LEARNING OBJECTIVES

Here is what you should be able to do when you complete each objective:

1. *Describe the various air streams that deliver combustion air to a furnace.*
2. *Relate differential pressure to the creation of draft.*
3. *Describe forced, induced, and balanced mechanical draft.*
4. *Discuss common methods of controlling combustion airflow.*
5. *Discuss common methods of measuring furnace pressures.*

Chapter Introduction

The **National Board of Boiler and Pressure Vessel Inspectors** identifies "fuel-rich mixture" as one of the causes of furnace explosions. A fuel-rich mixture occurs when a furnace contains insufficient combustion air for the fuel being burned. It is therefore important for Power Engineers to understand how to provide the proper amount of combustion air. A continuous fuel supply requires the continuous supply of combustion air, in the correct quantities. Otherwise, a fuel-rich condition can rapidly develop, and a furnace explosion may occur.

The term draft refers to a difference in pressure that causes a flow of gas. In the case of a boiler furnace, draft is the pressure difference between the furnace and the combustion air supply, which causes the flow of combustion air to the furnace. Draft may also refer to the difference of pressure between the furnace and the chimney, which causes flue gases to move from the furnace to the chimney. In fact, boiler draft is commonly measured at several points in the boiler gas passes:

- In the windbox
- In the furnace
- After each superheater bank
- After the reheater
- After the economizer
- After the air heater
- At the base of the chimney

At each location, the pressure decreases enough to provide adequate flow through the boiler.

Power Engineers operate draft equipment in order to maintain safe and efficient combustion in boilers and other fired equipment for which they are responsible.

Objective 1

Describe the various air streams that deliver combustion air to a furnace.

Draft equipment is used to supply combustion air to burners or other fuel-burning mechanisms. Burners mix air with fuel, bringing fuel particles into intimate contact with oxygen. In this way, burners facilitate rapid and complete combustion, reduce emissions, and maximize efficiency. The air going to burners and to other fuel-burning devices (such as stokers and fluidized beds) is often separated into different streams to facilitate the mixing of air and fuel.

The method and amount of air supplied for combustion depends on the type of fuel being burned. The total combustion air supplied can be divided into three streams:

1. **Primary air**
2. **Secondary air**
3. **Tertiary air**

Primary air, depending on the fuel-burning system, is one of the following:

a) Air that is premixed with the fuel before being admitted to the furnace.
b) Air admitted to a solid fuel stoker, below the grates (underfire air).
c) Air that expands and mobilizes the bed of a fluidized bed boiler.

Secondary air is additional combustion air, supplied:

a) Close to the burner tip, in the combustion zone.
b) Above the fuel bed, in a stoker or fluidized bed boiler (overfire air).

Depending on the burner system, secondary air may provide the remaining combustion air requirements. However, some burner systems require tertiary air.

For systems where the primary air and secondary air do not provide the required combustion air, tertiary air must also be supplied. Some burners are designed to prevent combustion from proceeding to completion in a single step. Instead, some combustion air is withheld, and the burner initially produces carbon monoxide instead of carbon dioxide. This results in less heat release from the fuel, lower combustion temperatures, and less NO_X production. Tertiary air is admitted after the formation of carbon monoxide, in order to burn the resulting carbon monoxide and release the remaining heat of combustion.

With a **fluid-fired burner**, in order to promote thorough mixing of fuel and air, primary air is swirled in a clockwise direction. The secondary air is given a counter-clockwise rotation to create a turbulent mixture.

With solid fuel fired systems, jets of overfire air may be introduced above the burning fuel bed to create turbulence.

Objective 2

Relate differential pressure to the creation of draft.

Differential Pressure and Draft

To move a fluid from one location to another, there must be a difference in pressure between the fluid source and the destination. In the case of combustion air, this pressure difference is called **draft.**

On Track

All fluids move from regions of high pressure to regions of low pressure, in accordance with the Second Law of Thermodynamics.

The difference in pressure can be naturally occurring, or it can be produced mechanically. Natural fluid flow is caused by fluid density differences, usually caused by localized heating that reduces fluid density. This is how wind is generated. Air from high pressure zones flows to low pressure zones. The same phenomenon creates boiler water circulation in most steam boilers. The water/steam mixture in risers is less dense than the water in downcomers. The dense water flows into the base of the risers, and displaces the water/steam mixture.

Mechanical means can provide greater pressure differences than natural means. Pumps are used to increase the source pressure of a liquid. Fans or compressors may be used to increase the source pressure of a gas. Each of these devices works by adding energy to fluid, which raises its pressure.

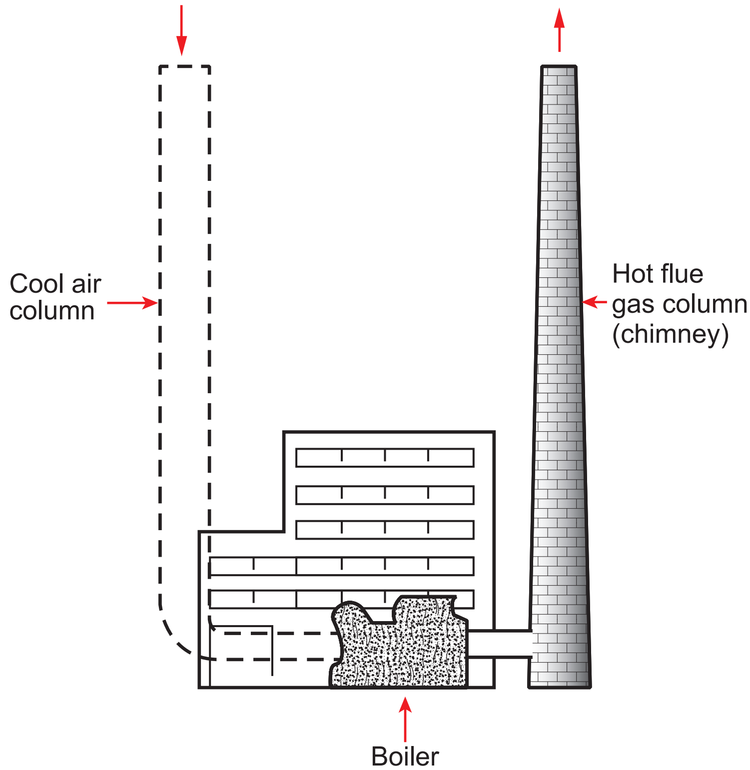
The rate of fluid flow between two points depends on the pressure difference between them. As the pressure difference increases, flow increases. The opposite is also true. Fans, pumps, and compressors increase flow by increasing the fluid pressure at its point of origin.

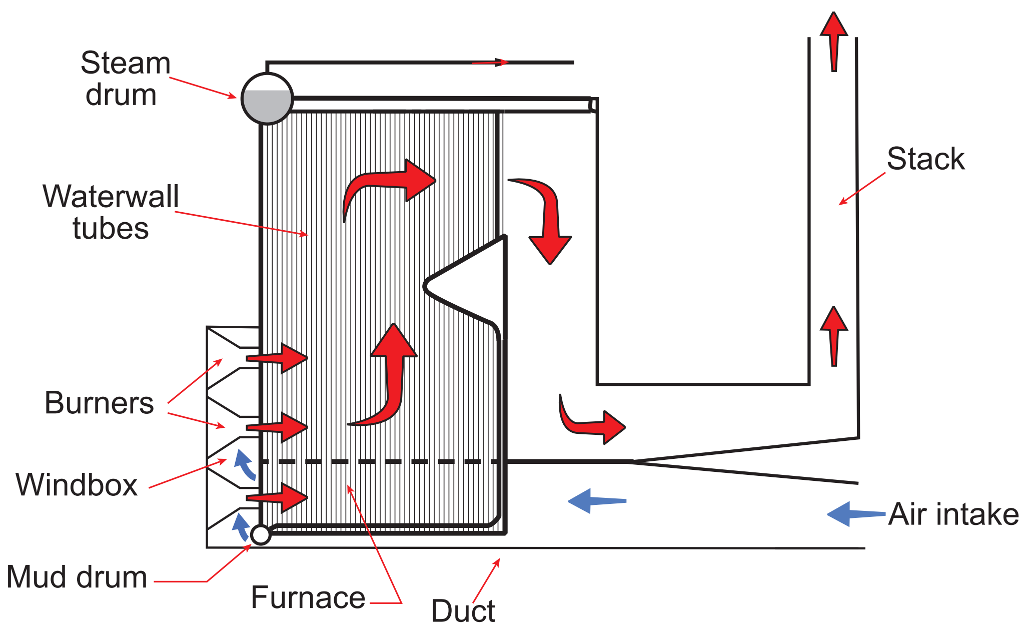
Natural Draft Equipment

When a gas is heated, it expands in volume so that each cubic meter has less mass than it did prior to heating. Or, it can be said that each unit of mass of a gas occupies more space when heated. Referring to Figure 1, the hot gases in the chimney have less mass than an equal height column of colder atmospheric air. **Natural draft** systems rely on this difference in density to provide combustion air to a furnace.

The pressure at the base of the column of colder air will be greater than the pressure at the base of the hot flue gases in the chimney. The heavier, colder air displaces the lighter gas. Because gas is continually heated in the furnace, colder denser atmospheric air continually enters the furnace, and displaces the hot flue gas.

Figure 1 – The Relationship between Natural Draft and Chimney Height





Referring to Figure 1, the flow of combustion air depends on three things:

1. **The temperature of the cool air column (the ambient air temperature).** The colder the ambient air temperature, the greater the temperature difference between the outside air and the flue gases, the greater the density difference, and the greater the pressure differential.
2. **The temperature of the flue gas.** The hotter the flue gas, the greater the temperature difference between the outside air and the flue gases, the greater the density difference, and the greater the pressure differential.
3. **The height of the chimney.** The taller the chimney, the greater the pressure difference between the flue gas at the base of the chimney and the ambient air.

The first point explains why draft increases during cold winter weather. However, Power Engineers have no control over the ambient air temperature.

The second point shows that increasing chimney temperature also increases draft. However, high chimney temperatures are undesirable, because excessive heat loss through the chimney reduces boiler efficiency, wastes fuel, and increases the overall production costs.

The third point suggests that increasing chimney height is a viable way of increasing draft. However, there are economic considerations that limit the height of the chimney. Tall chimneys are extremely costly to build. Also, as chimneys become taller, the overall effect on draft diminishes. This is because:

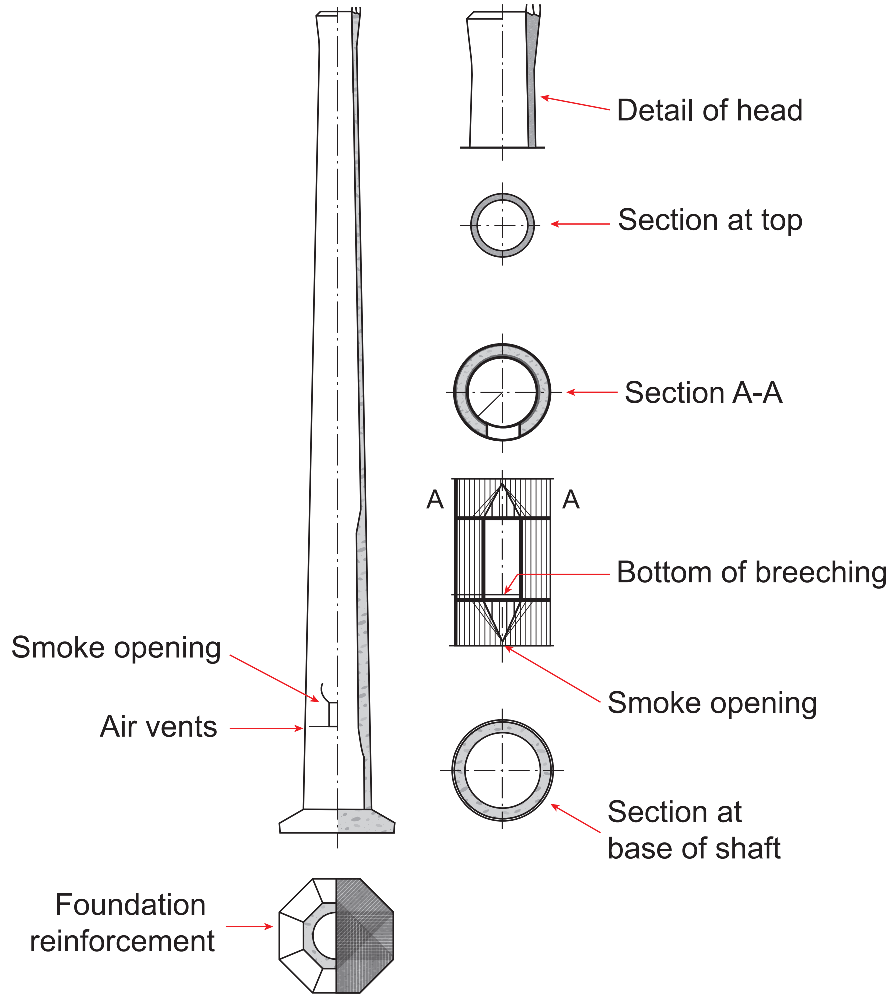
a) The flue gas cools inside of the chimney, which makes the flue gas increasingly dense.
b) There is additional resistance to flow in a tall chimney.

Besides creating draft, another function of the chimney is to disperse particulate and combustion products over a large area. However, tall chimneys do not solve pollution issues. Tall chimneys are subject to the same emissions restrictions as shorter chimneys. To aid in reducing emissions from solid fuel fired boilers, dust collectors, precipitators, and various scrubbers are installed in the ductwork between the furnace and the chimney.

The chimney is the only means of providing draft in natural draft systems. Therefore, chimney design and construction are important considerations for natural draft boilers. However, most boilers today use mechanical draft. In mechanical draft boilers, draft is carefully controlled independently of chimney height.

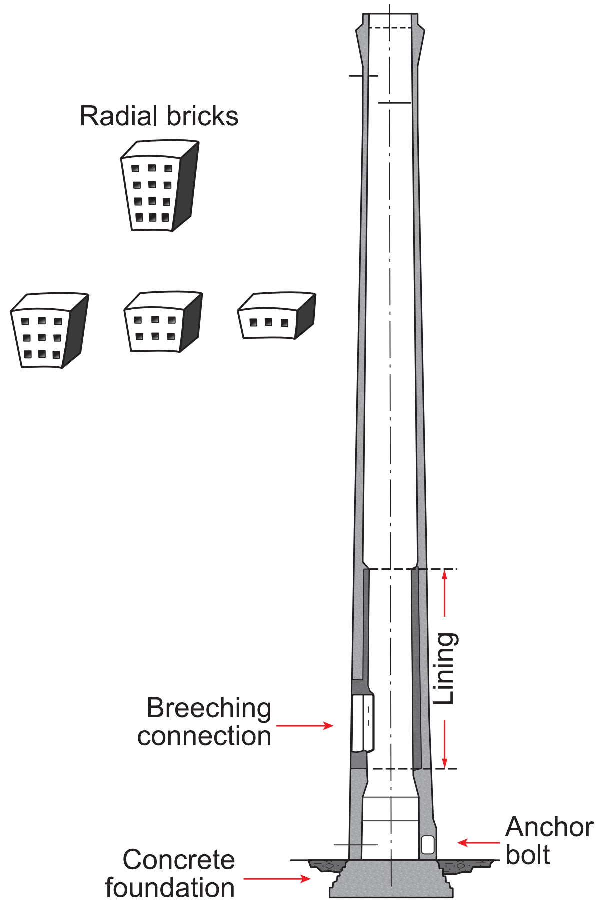
Chimneys are commonly constructed of reinforced concrete, brick, or steel. The reinforced concrete chimney is the most durable type. Figure 2 shows the arrangement and details of this design. These are constructed for large thermal generating stations and industrial plants, such as pulp and paper mills.

Figure 2 – Reinforced Concrete Chimney



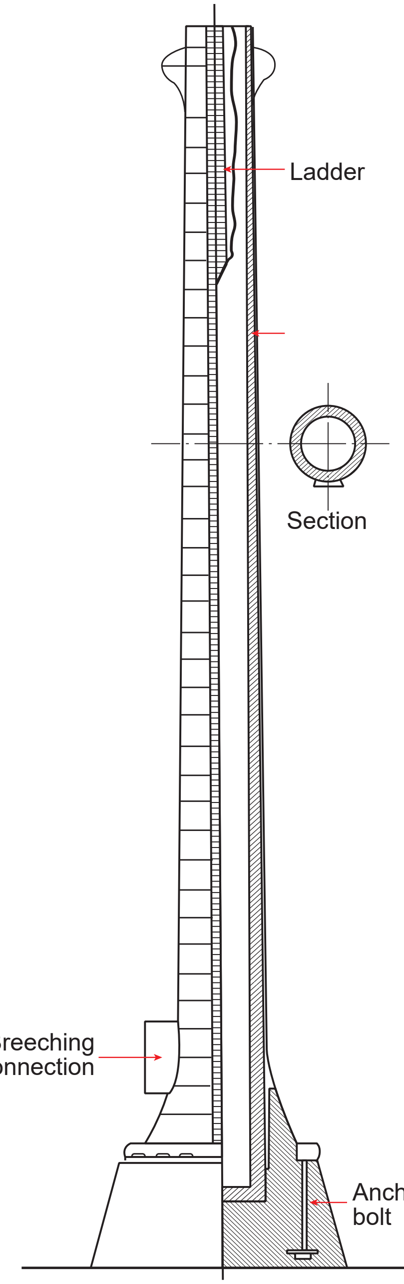
A brick chimney, as shown in Figure 3, gives a nice finished appearance. Common brick is not heat resistant; therefore, the chimney requires a **firebrick** or clay lining. Mortar tends to disintegrate with time, and permits air infiltration, which reduces the available draft.

Figure 3 – Masonry Chimney Details



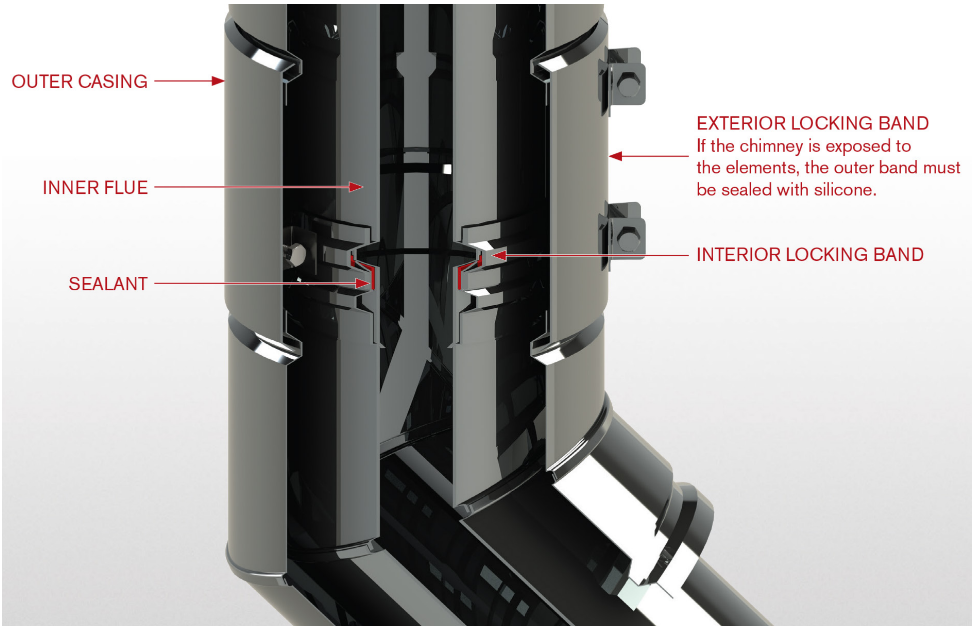
A steel chimney, like the one in Figure 4, is less costly to construct, and lighter than masonry or concrete chimneys. Because they are lighter, the foundations for steel chimneys do not need to be overly robust. Steel chimneys require considerable maintenance, in part due to their refractory lining. The lining requires periodic inspection and regular maintenance. In order to reduce cost and weight, the lining may extend to only one third of the total height.

Figure 4 – Self-Supporting Steel Chimney



Factory-built chimneys are commonly used for packaged boiler installations. These inexpensive chimney systems are designed with interlocking sections, in diameters up to 1.2 m. The sections are made of two walls. The inside wall is made of high-temperature, corrosion-resistant stainless steel. The outer wall may be made of stainless steel or aluminum. Several centimetres of high-temperature insulation are sandwiched between the inner and outer walls.

Figure 5 – Sectional View of Factory Made Chimney



(Courtesy of ICC – Industrial Chimney Company Inc.)

The chimney sections are available in various configurations, including straight lengths, tees, wyes, elbows, reducers, and transition pieces to adapt round chimney sections to square or rectangular boiler outlets. When assembled, no flue gas can leak out of the section joints, even when the chimney is under positive pressure. Factory-built chimneys are called **PS chimneys**, meaning they are positively sealed.

Figure 6 – Components of a PS Factory-Built Chimney System

(Courtesy of ICC – Industrial Chimney Company Inc.)

Objective 3

Describe forced, induced, and balanced mechanical draft.

Mechanical Draft Equipment

Draft must be able to provide the combustion air needs across the entire firing range of a boiler. At low firing rates, natural draft can be adequate. However, natural draft cannot provide the airflow necessary to burn large amounts of fuel.

Natural draft is limited by atmospheric conditions, flue gas temperature, and chimney height. Chimney height is fixed, and it cannot vary with changes in firing rate. Atmospheric conditions do vary, but not according to the firing rate. In fact, depending on the atmospheric pressure, draft may decrease when additional draft is required. Finally, varying flue gas temperature is an inefficient, wasteful, and environmentally unsound way of controlling draft.

Mechanical draft uses machinery to regulate draft according to the firing rate. Mechanical draft systems always provide the exact amount of combustion air required, regardless of atmospheric conditions.

There are three basic methods used to produce mechanical draft:

- **Induced draft**
- **Forced draft**
- **Balanced draft**

Each method uses fans. These fans create differential pressure to overcome the various boiler components that restrict the flow of combustion air or flue gas.

Induced Draft

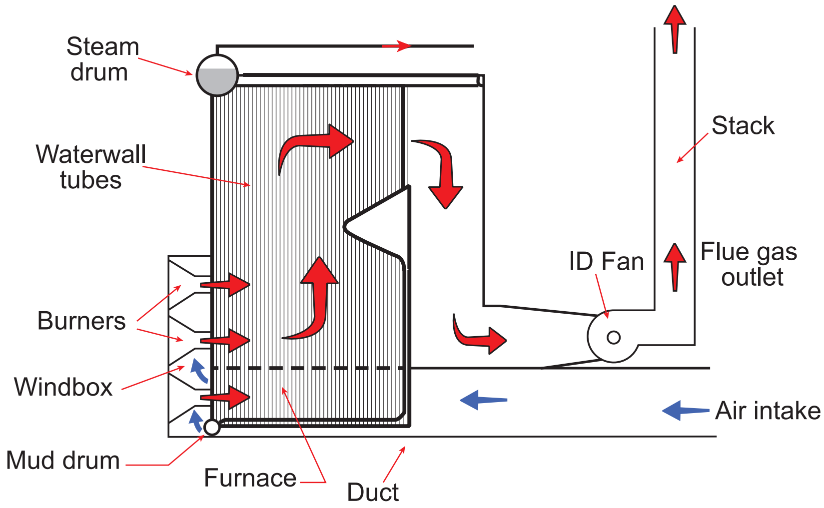
Induced draft works by creating a low furnace pressure, and by raising the pressure of the flue gas before it enters the chimney. This increases the differential pressure between:

a) The atmospheric air pressure and the furnace.

b) The furnace and the base of the chimney.

In doing so, the **induced draft fan (ID Fan)** increases the flow of combustion air into the furnace, and increases the flow of flue gas into the chimney. The ID fan is located between the boiler flue gas outlet and the boiler breeching (the ductwork that connects the boiler flue outlet to the vertical chimney). This is shown in Figure 7.

Figure 7 – Induced Draft Arrangement



Induced Draft (ID) Fan

Fans are mechanical devices that add energy to gases, thereby raising the gas pressure and increasing the gas flow. Figure 8 shows the cut-away of a double-inlet centrifugal fan, used for induced draft service. The fan consists of an impeller mounted on a rotating shaft, riding on bearings. The impeller is housed within a steel casing. Gases flow in, from each end of the shaft, to the centre of the impeller (called the "eye"). Variable inlet vane dampers adjust the flow of gas into the impeller eye. The rotating impeller conveys energy to the incoming gases. The gases leave the impeller in a radial direction, with high velocity.

The fan casing is volute-shaped. The fast moving gas slows after exiting the impeller, converting the gas velocity to pressure.

When used as an induced draft fan, this unit is located at or near the furnace outlet. ID fans may be motor or steam turbine driven. It draws the gases through the furnace and forces them up into the chimney.

An induced draft fan has the effect of producing a lower pressure in the furnace. Boilers with only an ID fan operate with their furnaces below atmospheric pressure. Because of this, boilers using only induced draft may draw in uncontrolled excess air through their settings, resulting in lower efficiency. To prevent this, boilers using induced draft must be sealed against air leakage.

Figure 8 – Induced Draft Fan

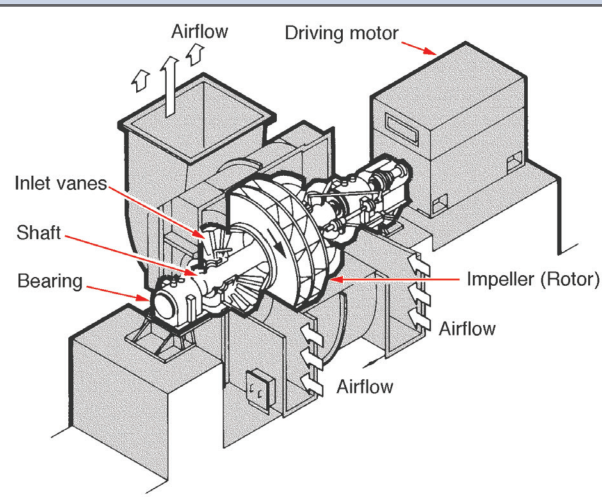
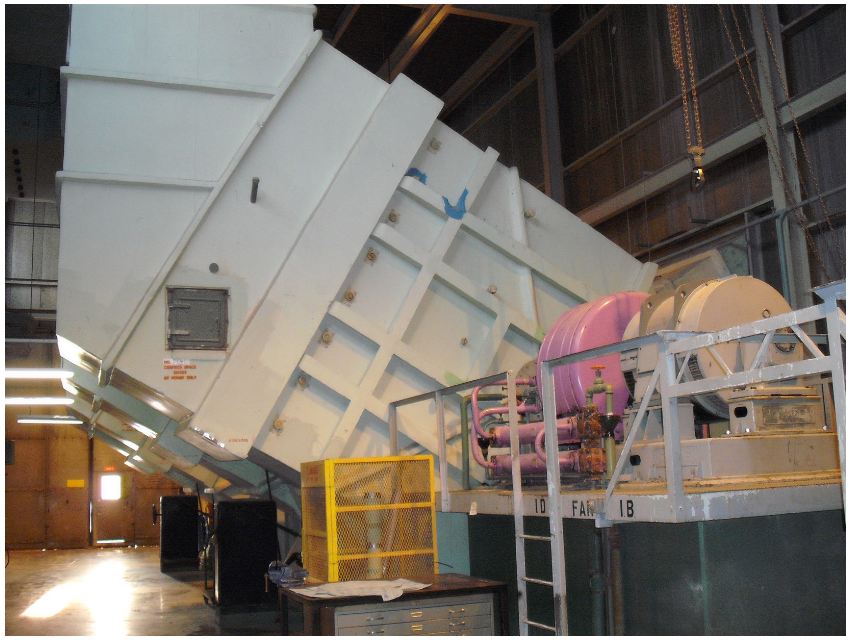


Figure 9 shows a large double-inlet induced draft fan, in use at a thermal generating station. The electric motor that drives the fan is shown at the right-hand side of the image. Between the motor and the fan is a variable speed coupling (shown in purple).

Figure 9 – Induced Draft Fan



Forced Draft

Forced draft works by creating a high differential pressure between the discharge of a fan and the furnace. This high differential pressure drives combustion air into the furnace.

When using a forced draft system, the entire furnace casing is under positive pressure. To prevent the escape of combustion products into the powerhouse, the furnace and all furnace openings must be sealed against leakage. Also, the boiler casing must be strong enough to withstand the internal pressure. The resulting furnace is called a pressurized furnace.

The quantity of air admitted is usually regulated by a damper. The atmospheric air is drawn into the side of the casing via a set of dampers which control the amount of air handled by the fan.

Figure 10 – Forced Draft Arrangement

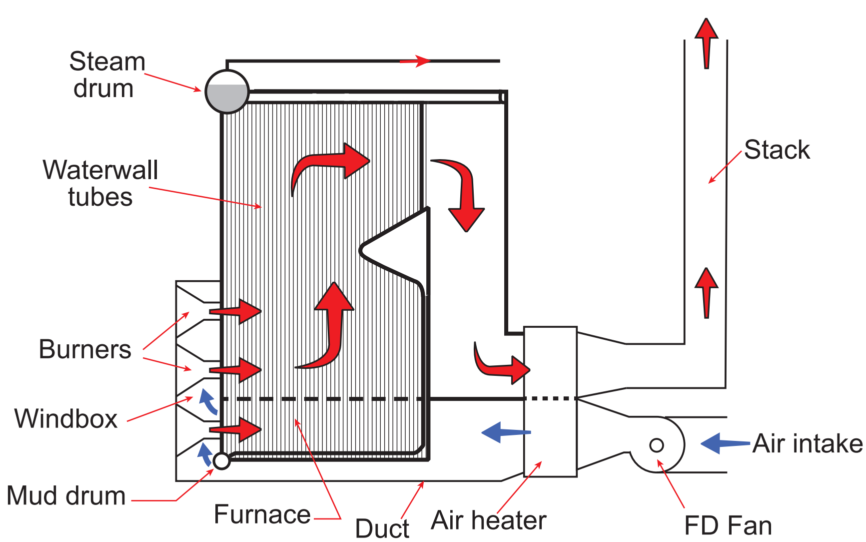
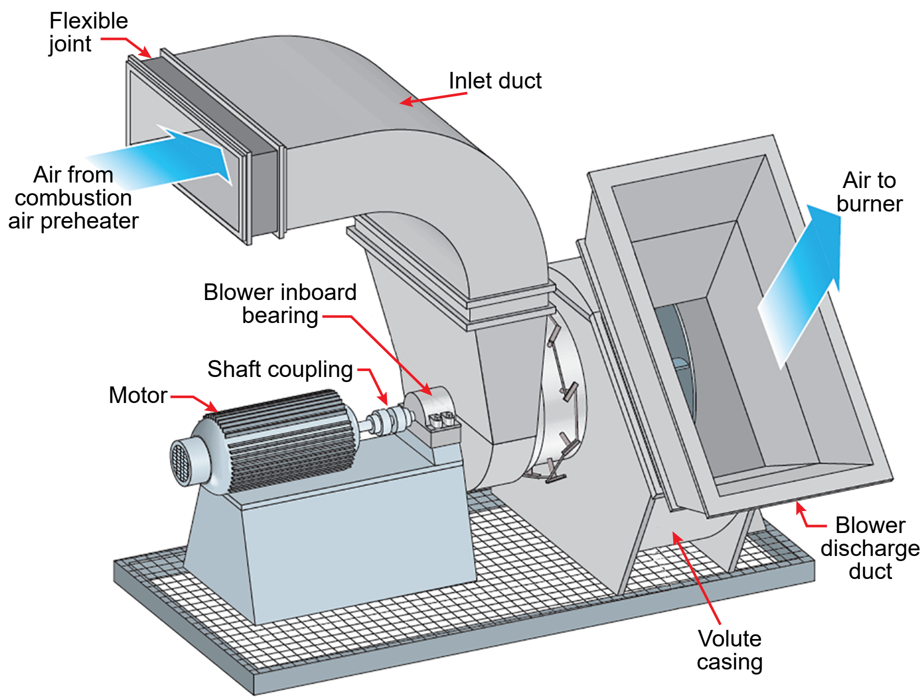


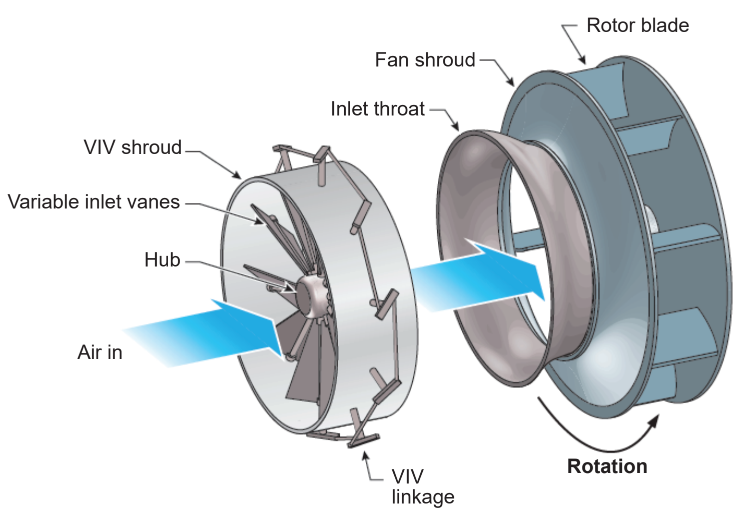
Figure 10 shows a forced draft boiler with an air heater. The **forced draft fan (FD fan)** is connected by ductwork to the lower inlet of the air heater. Preheated combustion air travels beneath the floor of the boiler to a **windbox**. The windbox is a pressurized air chamber that surrounds the burners. In this diagram, the windbox distributes combustion air to an upper and a lower burner row. Adjustable louvres are situated around each burner opening, to balance the airflow through each burner.

The flue gas discharges from the boiler at the bottom rear. After passing through the air heater, the flue gas continues through the breeching to the chimney.

The fan capacity is regulated according to combustion air requirements. Capacity is controlled by varying fan speed, varying the position of a damper assembly, or both. Figure 11(a) shows a large single-inlet FD fan, with an inlet vane damper assembly for capacity control. Figure 11(b) shows a detailed view of the inlet valve damper assembly. The damper vanes open or close to meet the combustion airflow demand.

Figure 11 – Forced Draft Fan and Inlet Vane Damper Assembly





(Courtesy of Cenovus)

When multiple burners share a windbox, it is possible for one burner to receive excessive combustion air, and for other burners to starve of air, even though the correct amount of air is delivered to the windbox. The louvres permit the balancing of air between operating burners. As well, if one burner in a multiple-burner installation is removed from service, louvres allow the air to be shut off from the out-of-service burner. This way, the remaining on-line burners will not starve of air.

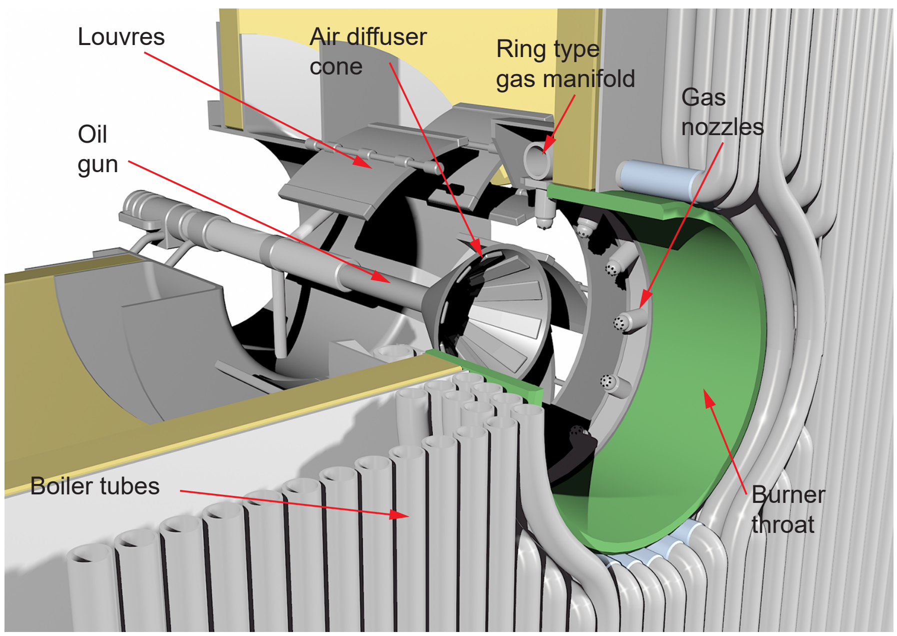
Side Track

Louvres are also commonly called registers or **air registers**.

When the boiler is taken off-line, all the louvres are shut. This allows the boiler to cool slowly, at a controlled rate. It is important that boilers change temperature slowly. This reduces stress on tube and stay attachments, and helps prevent damage to the boiler due to restricted thermal expansion.

In order to maintain the proper air/fuel ratio, louvres require adjustment. Louvres may adjust automatically as firing rates change, or they may require manual adjustment. In dual-fuel burners, like that shown in Figure 12, the louvre settings would be different when burning gas or oil.

Figure 12 – Dual-Fuel Burner Showing Louvres



Balanced Draft

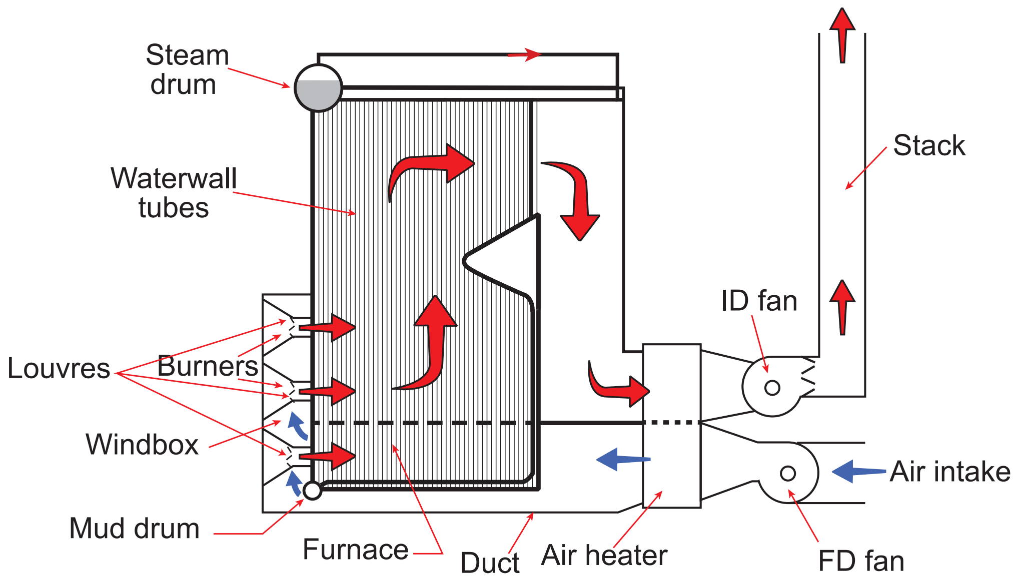
A balanced draft system uses both induced and forced draft. An FD fan forces air into the furnace. The combustion gases are removed from the furnace with an ID fan. This arrangement is shown in Figure 13.

The forced draft fan provides all the combustion air. The FD fan varies in capacity according to the fuel flow to the furnace. As the firing rate increases, the FD fan provides more combustion air. As the firing rate decreases, the FD fan provides less combustion air.

The induced draft fan maintains a negative furnace pressure set point (slightly below atmospheric pressure). In this way, combustion products do not leak from the boiler setting, regardless of the firing rate. When the boiler firing rate changes, both draft fans respond. The capacity of the ID fan is then adjusted to maintain the furnace pressure set point.

Balanced draft is commonly used for large boilers and steam generating units, where the gases travel a long distance through numerous heat exchangers (superheaters, reheaters, economizers, and air heaters). Figure 13 shows a balanced draft system.

Figure 13 – Balanced Draft System



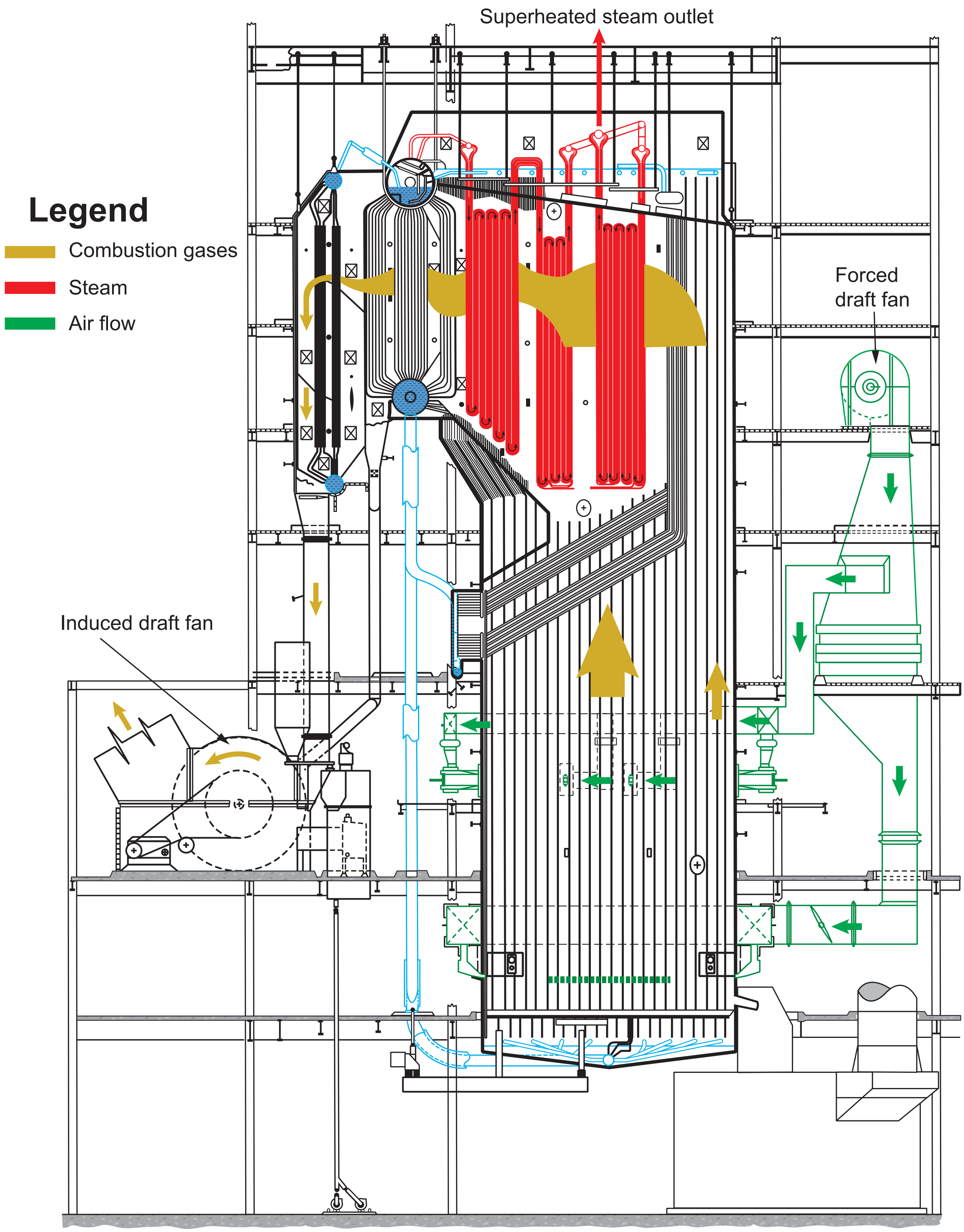
When burning solid fuels, there must be openings provided to introduce fuel to the furnace, and to remove ash. Therefore, a negative furnace pressure is required to keep combustion products from being expelled through openings. So, when burning solid fuels, an induced draft fan is normally used. However, using only an induced draft fan causes very low furnace pressure. This draws a lot of air into the furnace from these openings, negatively affecting boiler efficiency. Therefore, solid fuel fired boilers are usually balanced draft designs.

When burning natural gas or liquid fuels, the boiler furnace can be designed airtight. These boilers require only a forced draft fan.

Induced draft fans are larger than forced draft fans, because ID fans handle a larger volume of gas. This large volume is partly due to the high temperature of the flue gas. ID fans cost more to maintain because of the high temperatures, and because they may handle ash. Since ID fans are larger, they are more costly to purchase and to build.

Figure 14 shows a typical balanced draft system used on a large black liquor recovery boiler.

Figure 14 – Black Liquor Recovery Boiler



Advantages of Mechanical Draft over Natural Draft

a) Mechanical draft systems supply combustion air regardless of atmospheric conditions.

b) Chimney temperature does not affect the flow of combustion air.

c) Mechanical draft systems permit the installation of heat recovery equipment in the flue gas stream (including economizers and air heaters). These components restrict gas flow. Natural draft systems cannot develop enough draft to move adequate quantities of combustion air and flue gas in systems with air heaters and economizers. By permitting the use of economizers and air heaters, mechanical draft increases overall boiler plant efficiency.

d) Mechanical draft systems permit the installation of flue gas cleaning equipment. This includes mechanical ash separators, baghouses, electrostatic precipitators, and flue gas scrubbers. This equipment is necessary for lowering flue gas particulate, SO_X and NO_X emissions. This helps plants to meet their environmental targets.

e) Mechanical draft systems can accurately regulate combustion air over a wide range of firing rates. Better draft regulation increases combustion efficiency, reduces fuel consumption, and reduces emissions.

f) Mechanical draft systems can rapidly respond to changes in firing rate, as steam load changes. At the same time, these systems can maintain correct fuel–air ratios across the designed firing range.

g) Chimneys used in mechanical draft systems only need to be tall enough to adequately disperse the flue gases.

Comparison of Forced Draft and Induced Draft

Forced draft fans handle clean cool air. So in comparison to ID fans, FD fans:

a) Are smaller, and take up less space.

b) Cost less to manufacture and purchase.

c) Require less maintenance.

Induced draft fans handle hot, potentially dirty gases (especially if solid fuel is burned). Flue gas components may include ash and corrosive gases. Therefore, ID fans:

a) Are larger, to accommodate the greater mass and greater volume of flue gas.

b) Are more expensive to manufacture and construct, because of their larger sizes.

c) Require more maintenance, especially if solid fuel is burned. Ash may erode fan blades and fan housings. Ash can also accumulate on fan blades, which creates imbalance. High temperatures have negative effects on the shaft bearings, which makes it more important to cool the ID fan bearings.

An advantage of induced draft is that it maintains the furnace pressure below atmospheric, and prevents combustion products from entering the boiler room. Also, furnace inspection and burner openings do not require pressure sealing, as is the case with pressurized furnaces.

Objective 4

Discuss common methods of controlling combustion airflow.

Draft Control

The combustion process in the boiler furnace must be regulated in accordance with the steam demand. Regulation is attained by controlling fuel and airflow into the furnace. The control system makes sure that sufficient fuel and air are admitted. The system must also maintain the proper ratio of air to fuel in order to achieve safe and efficient combustion.

When balanced draft is used, the control system must ensure the correct flue gas flow from the furnace in order to maintain the correct furnace pressure.

Control of Air and Flue Gas Flow

Combustion airflow to the furnace, and flue gas flow from the furnace, are controlled with:

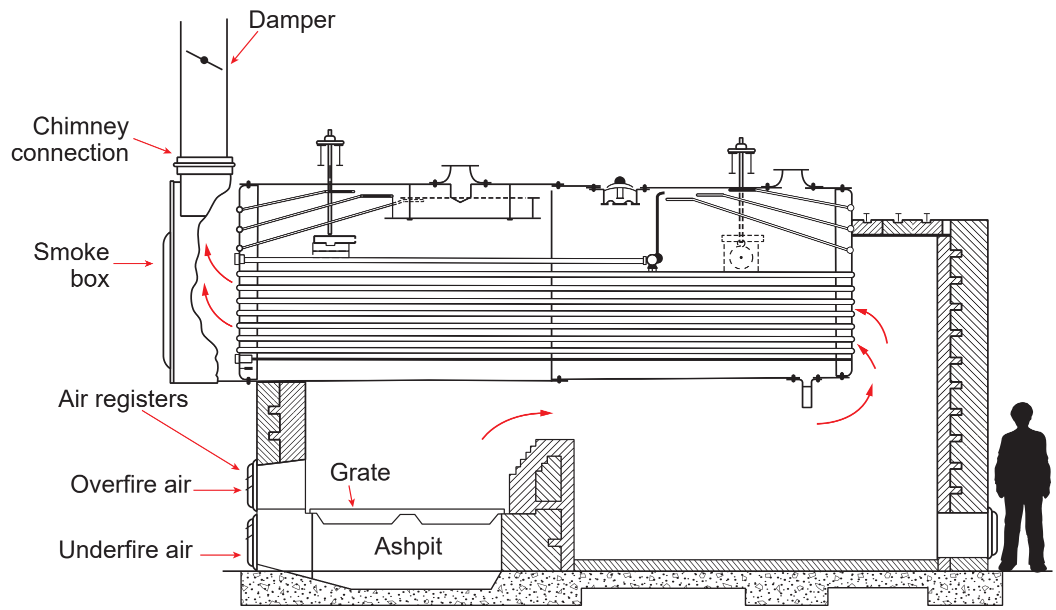
- Register or damper control
- Fan speed control
- Outlet damper control
- Inlet damper control

Register or Damper Control

For natural draft boilers, the flow of combustion air is controlled with air registers at the point where the air enters the furnace, or by a damper or louvres at the chimney inlet. Figure 15 shows an old HRT boiler, with air registers for **overfire air** and **underfire air**, and a chimney uptake damper.

Usually, the chimney damper is perforated so that when the damper is in the closed position and the boiler is shut down, a slight flow of air is maintained through the furnace. This helps prevent the formation of an explosive gas mixture in the furnace.

Figure 15 – Natural Draft Control



Fan Speed Control

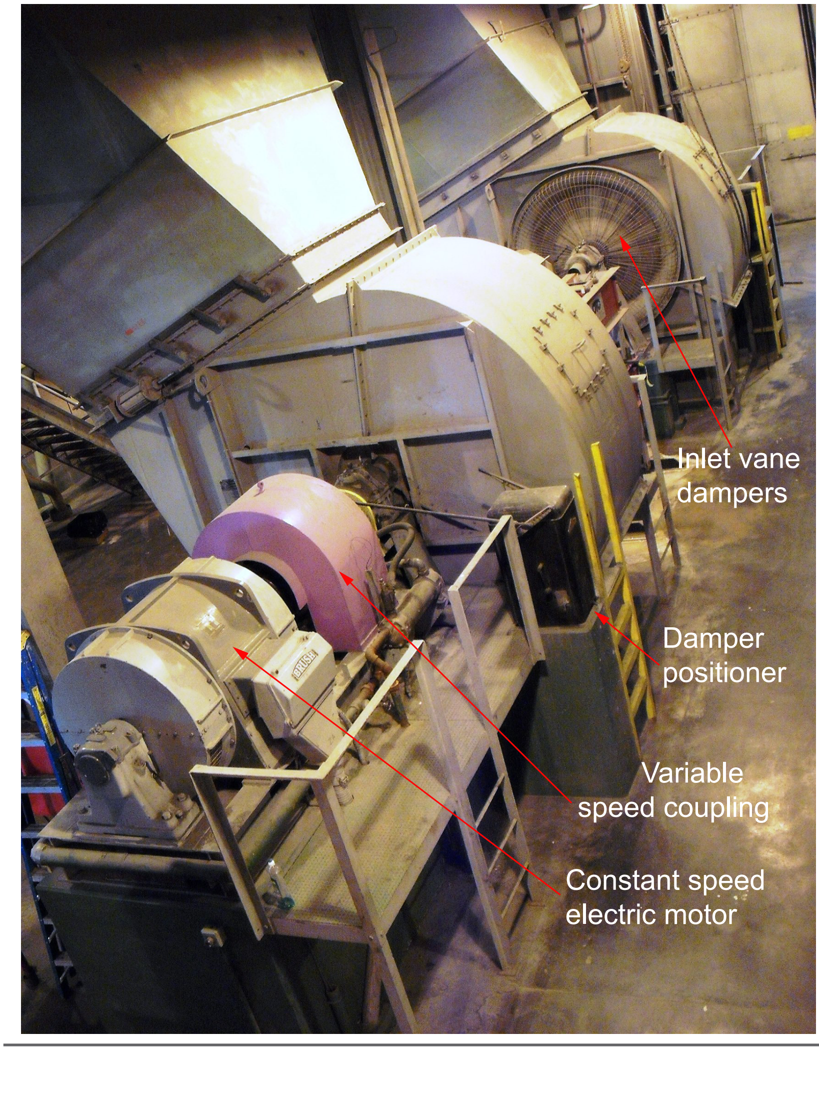
Airflow to the boiler can also be controlled by a variable speed fan, driven by one of the following three methods:

1. Steam turbine with a variable speed governor
2. Electric motor with a variable frequency drive
3. Constant speed electric motor with a variable speed coupling

Variable speed fans, like other draft fans, must supply just the right amount of air for complete combustion. The speed of a steam turbine driven fan can be automatically controlled with a throttle valve that regulates the turbine steam flow. Variable frequency drives change the speed of draft fans by changing the frequency of the alternating current supplied to the electric drive motor.

Variable speed couplings have been used for electric motors too large for a variable frequency drive. These devices work similarly to automotive torque converters. Constant speed electric motors are coupled directly to the variable speed coupling input shaft. The variable speed coupling has an output shaft coupled to the fan shaft. Figure 16 shows two forced draft fans. Each fan is powered by a constant speed electric motor and a variable speed coupling. Variable speed couplings are expensive, but give excellent fan speed control.

Figure 16 – Variable Speed Coupling

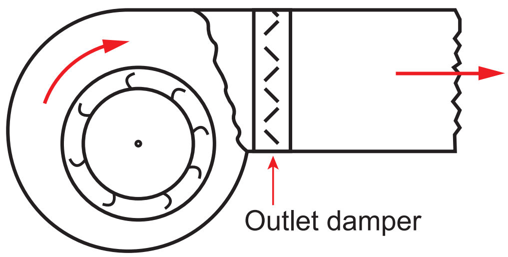


Outlet Damper Control

If a fan does not have variable speed control, other methods are used to control the flow of gases. A simple method is to place a set of dampers at the fan outlet. Outlet dampers throttle the fan outlet, restricting the flow from the fan. The fan output can be easily controlled from minimum to maximum output.

Figure 17 shows a schematic of an outlet damper control. Normally, damper control is automatic, but it can also be manually controlled.

Figure 17 – Outlet Damper Location

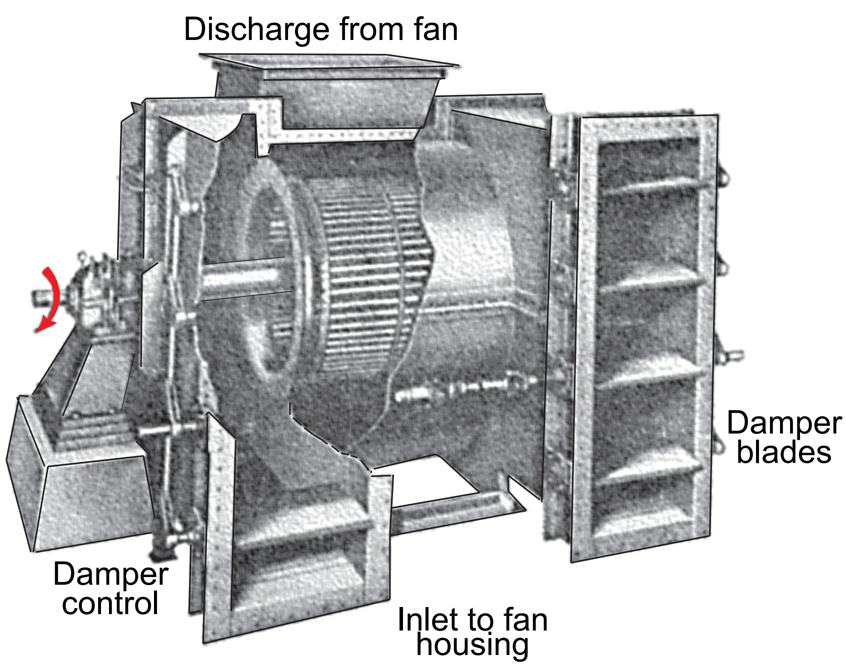


Inlet Damper Control

Figure 18 illustrates an induced draft fan with dual fan inlet damper control. This figure also shows the control linkage used for outlet or inlet dampers.

The damper for controlling the combustion airflow may be located directly at the forced draft fan inlet. Figure 11 shows this arrangement. Though more complicated in design, inlet vane dampers reduce fan power consumption at reduced loads.

Figure 18 – ID Fan Inlet Damper Control



The combustion control system is responsible for controlling the flow of combustion air. The combustion control system varies the amount of steam produced, in accordance with either the boiler or the main steam header pressure. If steam pressure falls, more steam production is necessary. This requires an increase to the fuel and air supplied to the furnace.

Combustion controls for large boilers must ensure the furnace is never fuel rich. For large boilers, when the steam demand increases, the combustion air supply increases before the fuel flow. When the steam demand decreases, the fuel supply decreases before the airflow. This ensures the fuel has sufficient air when the boiler load changes.

In a balanced draft system, the induced draft fan capacity is controlled by furnace pressure. When the airflow and fuel flow are changed to meet steam demand, the furnace pressure varies. An increase in air and fuel flow causes furnace pressure to increase. The opposite is true when the air and fuel flows decrease. The furnace pressure controller varies the output of the induced draft fan to maintain a furnace pressure set point.

Objective 5

Discuss common methods of measuring furnace pressures.

Draft Measuring Instruments

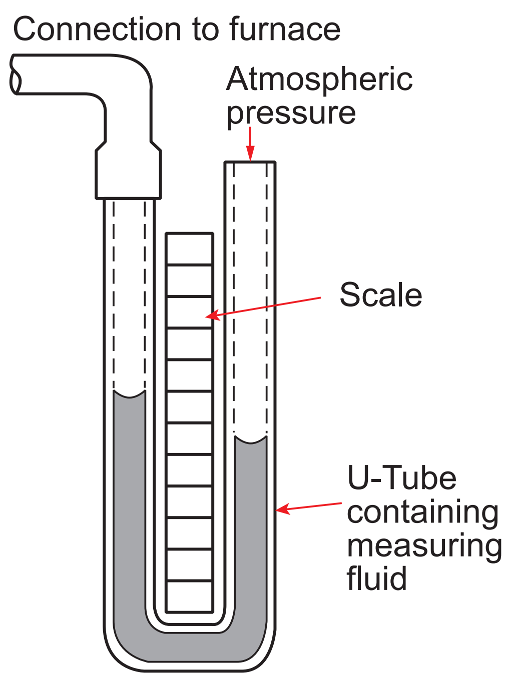
Furnace draft must be carefully controlled, to maintain efficiency, for safe operation, and to reach environmental targets. In any control system, process variables must be measured. To control draft, pressures of combustion air and flue gas are measured at various locations. These pressures often include ambient air pressure, windbox pressure, furnace pressure, and boiler flue gas outlet pressure. More complicated systems may also measure the flue gas pressures before and after superheaters, reheaters, economizers, and air heaters.

The pressures in combustion air systems are relatively low. Therefore, the measuring instruments must be sensitive to small pressure changes. The simplest device is the "U" tube manometer shown in Figure 19.

The tube is made of glass, or any other transparent material, bent to form of a "U". With no pressure connection and both legs open to the atmosphere, the tube is filled about half full. The surface of the liquid in each leg will be at the same height. If pressure is applied to one leg, the liquid in that leg will be forced down, and the liquid level in the other leg will rise. The difference in the height in each of the legs indicates the pressure being measured.

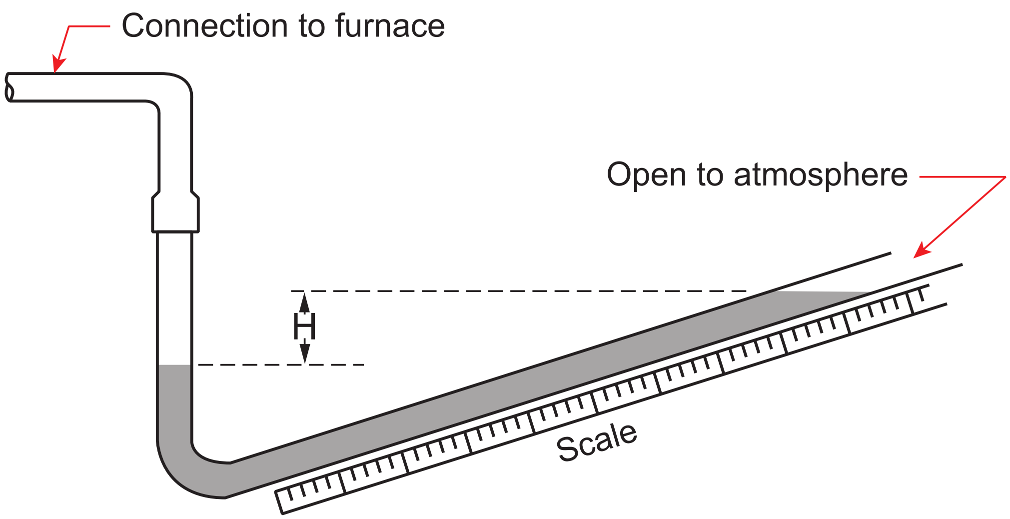
If the manometer is filled with water, the pressure can be read directly in millimetres of water.

Figure 19 – "U" Tube Draft Gauge (Manometer)



For more accurate pressure readings, an inclined U-tube manometer can be used (Figure 20).

Figure 20 – Inclined Tube Manometer

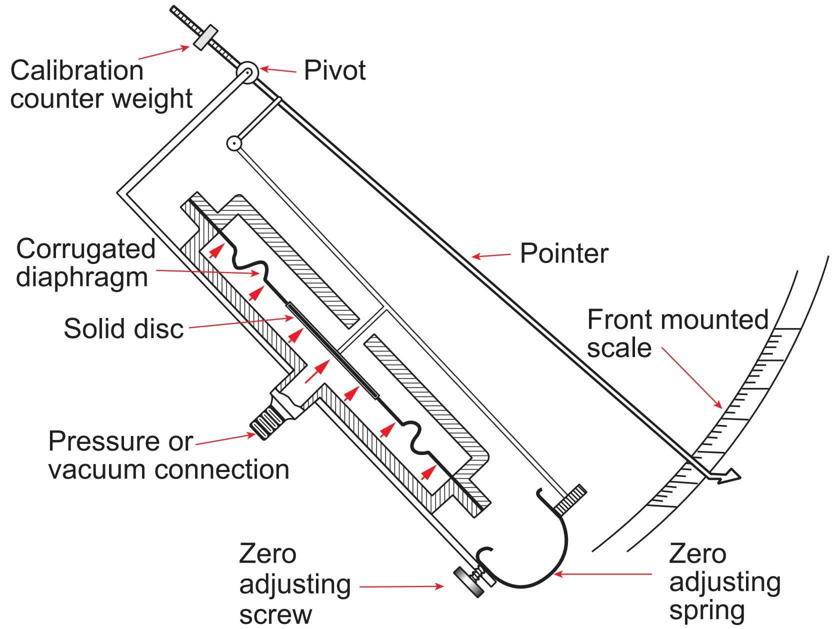


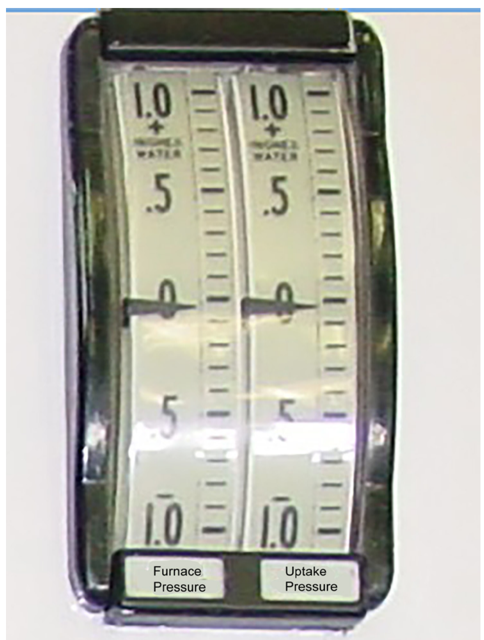
Another type of sensing element used for low-pressure measurements is the diaphragm gauge. Refer to Figure 21. The diaphragm is made of limp, flexible material. The pressure to be measured is applied to the housing below the diaphragm. This causes the diaphragm to be moved upward as the pressure increases. This movement is transferred through a system of linkages to a pointer. The pointer indicates the applied pressure. The gauge can be calibrated using the zero adjusting screw. The diaphragm gauge can be calibrated to indicate boiler draft in millimetres of water, or some other suitable low pressure.

On Track

One millimeter of water is equal to 9.81 Pa – a very small pressure!

Figure 21 – Diaphragm Draft Gauge





Size of Air Openings

It is very important to provide indoor fuel-burning equipment with fresh outside air, for combustion. Boiler room doors and operable windows are not considered combustion air openings, because they can be shut.

If the combustion air provisions are inadequate, draft equipment may not be able to supply the air requirements for combustion. In the case of natural draft appliances (including many boilers), inadequate combustion air provision may cause combustion products to "spill" from the boiler vent hood, directly into the boiler room. In worst-case scenarios, flue gas recirculates from the vent hood back to the burner, and creates a hazardous fuel-rich condition in the furnace. Soot may be produced, which will plug flue gas passages. The carbon monoxide produced will be unable to escape up the chimney. Instead, it will accumulate in the boiler room, where it can poison or kill those entering.

The carbon monoxide and soot produced by incomplete combustion are also combustible products. Inadequate combustion air can result in the development of explosive concentrations of combustion products.

Side Track

The **CSA B149.1** code is used to determine the minimum combustion air and ventilation air requirements for natural gas and propane-fired appliances, including boilers. For oil-fired appliances, **CSA B139** code applies.

Chapter Summary

This chapter introduced the theory of natural draft, draft methods (both natural and mechanical), draft equipment, draft measurement, and draft regulation.

Maintaining proper draft, and controlling the air-to-fuel ratio, are two primary concerns for Power Engineers. The majority of furnace explosions occur due to insufficient air supply. Conversely, a great source of efficiency loss is due to the provision of too much combustion air. Vigilance is therefore very important when operating boilers and other fired equipment.

Further studies in Power Engineering go into greater depth on these topics.

CHAPTER 4

Feedwater Systems

LEARNING OUTCOME

When you complete this chapter you should be able to:

Describe feedwater systems used with boilers.

LEARNING OBJECTIVES

Here is what you should be able to do when you complete each objective:

1. *Describe the overall layout of feedwater, condensate, and make-up water systems.*
2. *Describe the valves used in feedwater systems.*
3. *Describe the control strategies for single-element, two-element, and three-element boiler feedwater systems.*
4. *Describe methods of supplying feedwater to steam heating boilers.*
5. *Explain the operation of condensate receiver make-up water controls.*
6. *Describe the return of condensate, and the supply of feedwater to high-pressure boilers.*

Chapter Introduction

Regardless of whether a Power Engineer works in a low-pressure steam heating plant, or a high-pressure steam plant, the supply of boiler feedwater is a critical job function. In fact, it has been said that the primary responsibility of a Power Engineer on shift is to maintain boiler water level!

Power Engineers must know the intricacies and dynamics of the feedwater systems in the plants where they work. One of the first jobs for new hires is to trace the feedwater piping system. In doing so, the novice engineer learns the locations of feedwater control valves, bypass valves, make-up water systems, and condensate returns.

Only by experience do Power Engineers learn a particular feedwater system's design limitations. Over time, they learn how it will respond to changing loads, power outages, and mechanical failures.

This chapter includes an overview of:

- Feedwater systems
- Types and functions of the valves used in these systems
- Control methodologies for maintaining proper and safe boiler water levels
- Condensate return systems

Objective 1

Describe the overall layout of feedwater, condensate, and make-up water systems.

Boilers produce steam or hot water. In a perfectly sealed system, for each kilogram of steam or hot water leaving the boiler, at least one kilogram of water must enter the boiler.

However, steam boilers lose water from blowoff, blowdown, and soot blowing. Steam heating systems lose additional water from steam leaks and processes that consume steam (processes that do not create **condensate**, such as humidification).

Hot water heating systems should not lose water at all. However, faulty heat exchangers and system leaks create a need for replacement water.

The total water fed to a boiler is called **feedwater**. Feedwater consists of the water returned from the system (condensate returns in a steam system, or return water in a hot water system), and water added to compensate for water losses (**make-up water**). This chapter focuses on the feedwater systems of steam plants.

Make-Up Water System

Make-up water for steam systems can originate from various sources, such as:

- Municipal water
- Rivers
- Lakes
- Wells

Each of these water sources has unique qualities. Well water may be very hard, meaning it will form waterside scale. Surface water, such as lakes and rivers, may contain biological material, such as algae and aquatic life, as well as suspended solid material, such as silt or sand. Municipal water may be hard or soft, depending on the municipality.

On Track

Untreated source water is also called **raw water**.

Regardless of the make-up water source, some form of water treatment will be necessary. Because of the variability in water quality from source to source, no single make-up water treatment system is appropriate for all. High quality sources need simpler treatment systems, and little treatment to make boiler-quality water. Poorer quality sources require more extensive and complicated make-up water treatment systems.

Figure 1 shows a relatively simple feedwater system. Make-up water (shown in blue) is from a municipal source. Due to the quality of the source, the make-up water only requires softening and deaeration. Make-up water may be directed to the condensate receiver or the **deaerator**. In Figure 1, the make-up is directed to the condensate receiver.

Figure 1 – Simplified Feedwater System

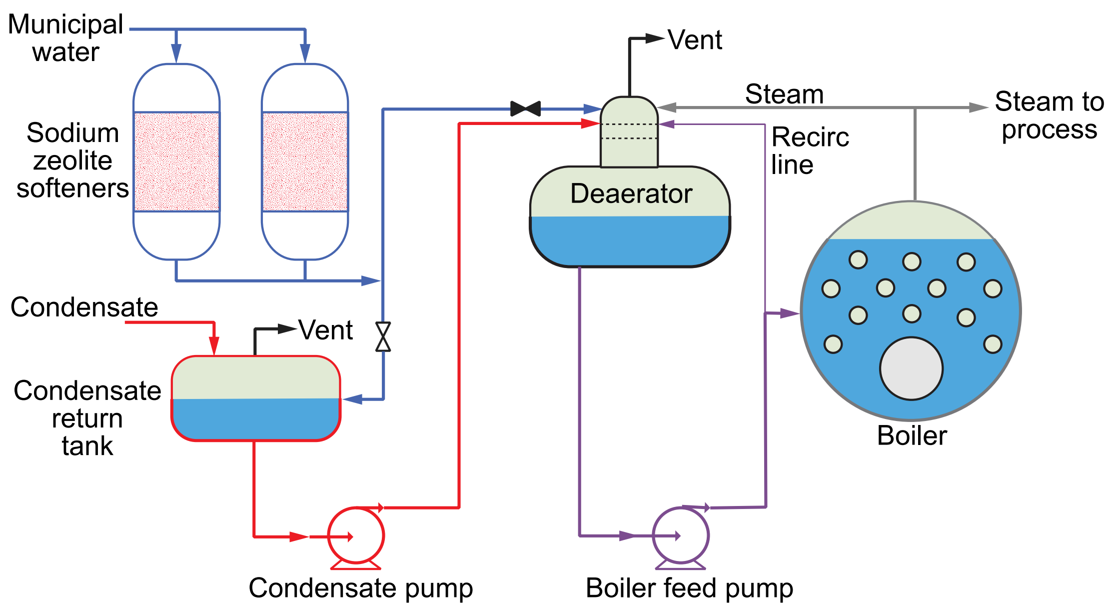


Figure 2 shows a more complex system, like that found in larger plants, or ones with poor quality raw water. The raw water first enters a clarifier. Here, organics and suspended matter are removed from the water. Prior to being deaerated, the water is filtered and purified using demineralizers. Storage receivers provide system capacity to accommodate changes in feedwater demand. After every storage receiver, pumps (not shown) must re-pressurize the water.

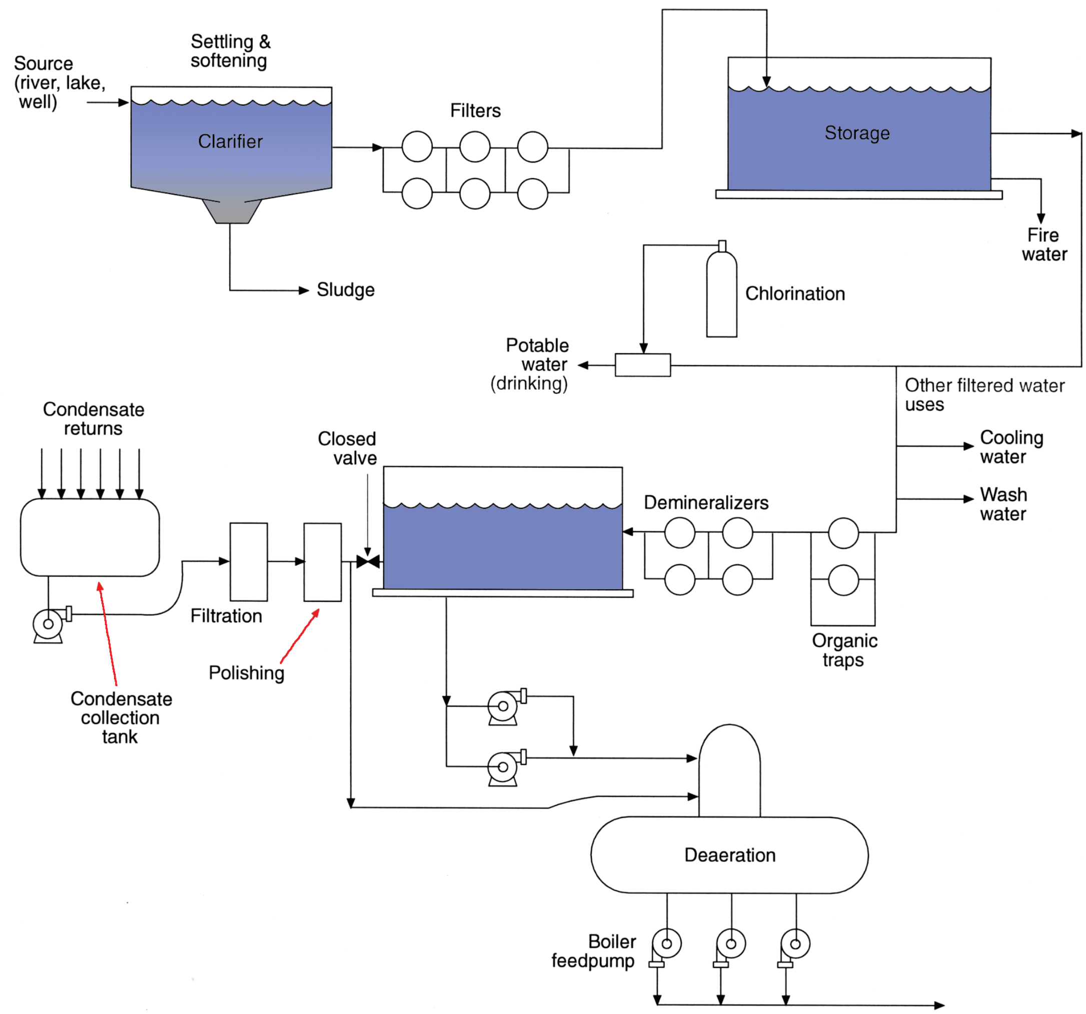
Certain water streams do not need to be as pure as boiler make-up water. The plant wash water, fire water, and cooling water only need clarification and filtration. After these steps, potable water only needs further chlorination, to destroy harmful bacteria.

The feedwater reserve receiver is sized to provide up to 24 hours of make-up water, if the water treatment plant is out of service. From the storage receiver, the water is fed to the deaerator, which is the final stage of external water treatment. The deaerator level controls accept condensate as the main water supply. If too little condensate returns, the deaerator level will drop. To maintain the deaerator level, make-up water is automatically added, compensating for the reduction in condensate return.

On Track

Make-up water and condensate are treated outside of the boiler drum or shell. For this reason, all water treatment performed on make-up or condensate is called **external water treatment**. Water treatment performed by adding chemicals to the boiler drum or shell is **internal water treatment**.

Figure 2 – Larger Complex Feedwater System



Condensate Return System

When steam transfers latent heat of evaporation to process equipment, it reverts to its liquid state. This liquid is called condensate. In many cases, condensate is quite pure (essentially, distilled water). Condensate contains considerable sensible heat; its temperature may be between 80°C and 100°C. Because of its purity and its heat content, it is important to recover and reuse condensate, for two important reasons:

1. When a greater volume of condensate is reused, a smaller volume of raw water needs treatment. This means that less treatment chemicals are used, and water treatment plants can be smaller.

2. Because condensate is hot, it requires less boiler heat input to raise its temperature to saturation. Therefore, by using hot condensate, overall plant thermal efficiency increases. This reduces fuel consumption and emissions.

In some cases, condensate is impure, and must not be re-used without considerable treatment.

Figure 1 shows a simple condensate return system (in red), comprised of a vented condensate receiver, condensate return lines, and a condensate pump. Smaller heating plants (both low and high pressure) may have only a single condensate receiver and pump combination.

Figure 1 shows a system with make-up directed to the condensate receiver. In this system, the condensate return receiver will drop in water level if system water losses occur. If the condensate receiver is taken out of service for maintenance, the make-up water will be directed to the deaerator. From the deaerator, the combined make-up water and condensate are fed to the boiler, with the boiler feed pump.

Figure 2 shows a more complex condensate return system. In larger facilities, multiple receivers and pumps return condensate to a single main receiver, usually located in the power house. Clean process condensate enters the main condensate receiver, which then returns it to the boiler, via the deaerator.

Some of the returns contain impurities. These may be scale-forming compounds from leaking heat exchangers in domestic water heaters or turbine condensers, or rust from corroding condensate return system piping. In the plant shown in Figure 2, the condensate is filtered and then "polished" to return it to a pure condition

Side Track

Steam-assisted gravity drainage (SAGD) plants create condensate that is highly contaminated with bitumen. In these plants, the condensate requires extensive treatment before it can be reused.

Feedwater Systems

Make-up and condensate return systems terminate where the two fluid streams meet. This is typically the condensate receiver or the deaerator. The combined water is called feedwater. The feedwater system is comprised of:

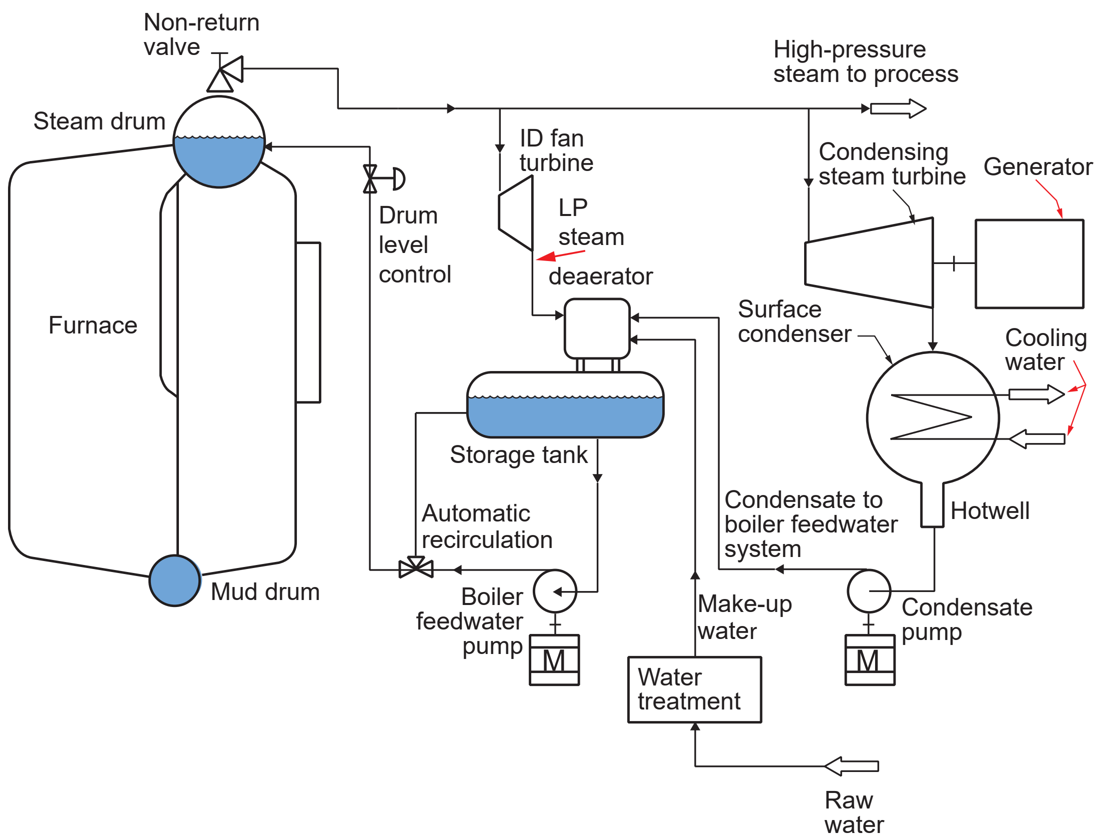
- A condensate receiver or condenser **hot well**
- Condensate pumps
- Low and high pressure feedwater heaters
- A deaerator
- Boiler feedwater pumps
- Boiler feedwater control valves
- Isolation valves, bypass valves, and check valves

The condensate receiver and condenser hot well are included in this list because in some larger plants, make-up water is introduced at the condenser hot well.

Figure 3 shows a schematic of a feedwater system in which steam is provided to two turbines and to a process. The process consumes steam, and does not return condensate to the boiler. This water is lost from the system, and must be replenished with make-up water. The steam does work in the condensing steam turbine, and exhausts to the condenser. Here, the steam reverts to its liquid phase and accumulates in the condenser hot well. A condensate pump removes condensate from the hot well as it accumulates, and pumps it to the deaerator.

Steam lost from the system is made up with treated water from the water treatment plant. The condensate and make-up water are preheated, deaerated, and stored in the deaerator. A boiler feedwater pump, running continuously, returns the water to the boiler. A level control valve ensures the boiler is fed enough water to maintain a constant drum level. The water supplied by the feedwater pump, but not required by the boiler, is recirculated to the deaerator.

Figure 3 – Overview of Feedwater System



Objective 2

Describe the valves used in feedwater systems.

Valves

Feedwater systems use valves at several locations. These valves are used to control flow or to isolate equipment. They include:

- Gate valves, for equipment isolation.
- Globe valves, to throttle feedwater flow.
- Level control valves, to adjust the flow of feedwater or make-up water.
- Check valves, to prevent backflow.

All valves must be strong enough for the pressure and temperature conditions they will encounter. The **valve class** specifies the service designation for valves. These range from Class 150 (the weakest) to Class 4500 (the strongest). Any replacement valve in the feedwater system must be of a class strong enough for the pressures and temperatures it will encounter.

On Track

High-pressure plant piping falls under the scope of the **ASME B31.1 Power Piping Code**. Low-pressure heating plant piping does not. **ASME B31.1 Code** has specific requirements for the construction of high-pressure boiler piping systems.

Isolation Valves

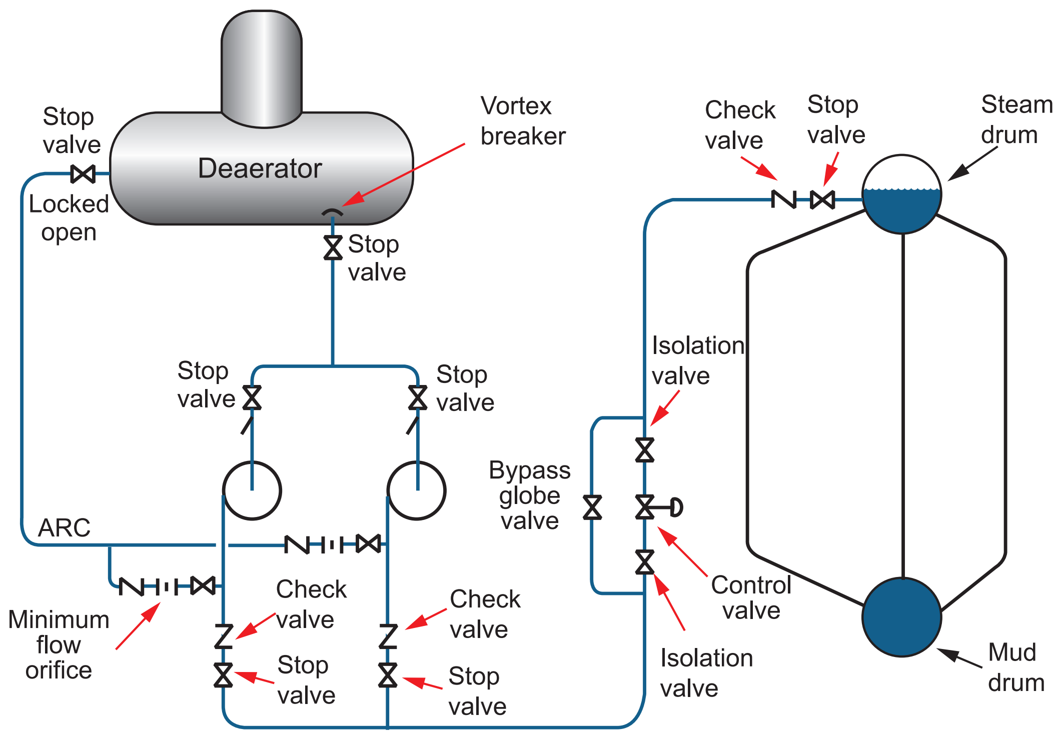
Feedwater system isolation valves are required by code. They are necessary to operate, maintain, and isolate feedwater system components.

The **ASME B31.1 Power Piping Code 122.1.7** states that (with few exceptions) the feedwater piping for all power boilers shall be provided with a check valve and a stop valve or cock between the check valve and the boiler (see Figure 4). The stop valve at the boiler allows for maintenance of the check valve without having to drain the boiler. The check valve keeps the water from draining out of the boiler when the feedwater pump is not operating.

SAFETY

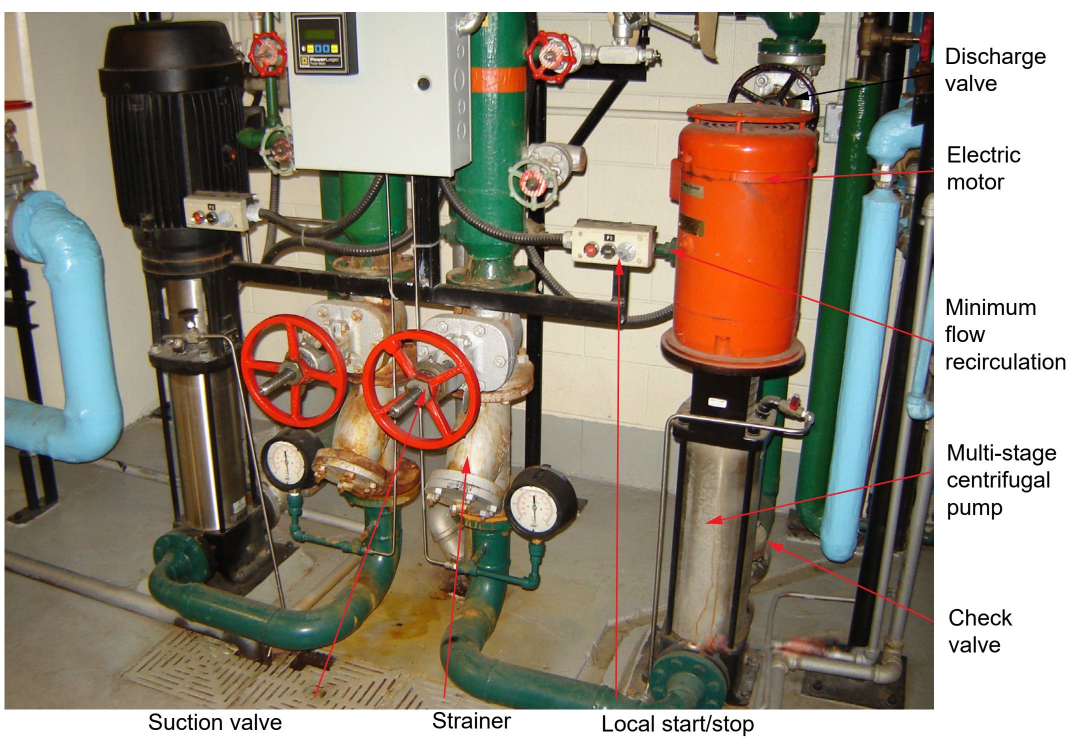
Never attempt to service a feedwater check valve when the boiler is hot or under pressure. Valves must only be serviced after appropriate lockout is performed and safe work permits obtained.

Figure 4 – Feedwater System Showing Required Valves



Isolation valves in a feedwater system must seal tight. For this reason, gate valves are commonly used. Figure 5 shows gate valves used for boiler feedwater pump isolation.

Figure 5 – Feedwater Pumps with Isolation and Check Valves



Check Valves

ASME B31.1 Power Piping Code 122.1.7 requires a check valve installed at the boiler feedwater pump discharge. If the feedwater pumps stop, this valve prevents boiler water from flowing back to the feed pumps. If backflow occurs, the boiler water level could drop enough to cause a boiler to trip off on low water. If the low water cut-off is defective, the boiler could be damaged by a low water condition.

Some smaller single-boiler plants use boiler feedwater pumps that operate intermittently. These pumps start when boiler water level is low, and stop when the boiler water level is normal. In such a plant, the check valve may open and shut on a regular basis.

In larger plants, and plants where more than one boiler is fed from a common feedwater source, the boiler feedwater pumps operate continuously. In this situation, the check valve operates less frequently.

Like all feedwater system components, check valves must meet the temperature and pressure requirements of **ASME B31.1** code. Therefore, the design pressure of the check valve must exceed the maximum allowable working pressure of the boiler by either 25% or 1550 kPa, whichever is less. The design temperature must be at least the saturation temperature of the boiler water.

Control Valves

In a feedwater system, control valves are used to control level, flow, and pressure. Level control valves regulate:

- Deaerator level
- Condensate receiver level
- Condenser hot well level
- Boiler water level

Flow control valves regulate the steam flow to the deaerator, and the recirculation flow from the boiler feed pumps.

Pressure control valves are used to relieve excess pressure from deaerators or other feedwater system components, especially when positive displacement, turbine-style, or multi-stage centrifugal pumps are used to provide feedwater. These pumps are capable of developing enough pressure to damage piping components. Pressure control valves are also used to regulate the steam pressure supplied to the deaerator.

Control valves may be self-powered, or the final control element in a control loop. They may be two-position (on – off), or fully modulating.

Small single-boiler plants use boiler feedwater pumps that operate only when the boiler water level drops. In such plants, less accurate boiler water level control is acceptable. Floats or probes are used as primary sensing elements. Both respond to changes in the boiler water level. When the boiler water level drops, the float or probe activates a switch to start the boiler feedwater pump. When the water level recovers, the switch opens, and shuts off the pump.

In plants where more than one boiler is fed from a common feedwater source, the boiler feedwater pumps operate continuously. According to **ASME B31.1 122.1.7**, plants with multiple boilers fed water from a common pumping system must have level control valves in the feedwater line to each boiler. This control valve must be located between the check valve and the boiler feed pump. This setup permits the feedwater flow to match the steam production rate of each boiler on the feedwater header.

In such plants, boiler water level can be maintained using either two-position (on – off) control or fully modulating control. Two-position control is used with smaller boilers, where less accurate water level control is acceptable. This is achieved by using a solenoid valve as the feedwater control valve. When the boiler water level is low, a float- or probe-actuated switch energizes the feedwater solenoid valve. The valve stays open until the water level reaches set point.

With fully modulating feedwater control systems, the control valves may be self-powered or part of a **PID control** loop. In either case, the feedwater control valve can take any intermediate position between fully closed and fully open. Loop controllers must be tuned carefully to properly regulate boiler water level. These controllers may use level, water flow, and steam flow-sensing elements to maintain precise water level control.

Figure 6 shows a fully modulating control valve, used as the final control element in a feedwater PID control loop. The valve is equipped with inlet and outlet isolation valves, and flanged connections. This permits the removal of the valve for repair or replacement. While the control valve is out of service, a globe bypass valve can be used to manually regulate the feedwater flow.

Figure 6 – Modulating Feedwater Control Valve Station

Self-Powered Level Control Valves

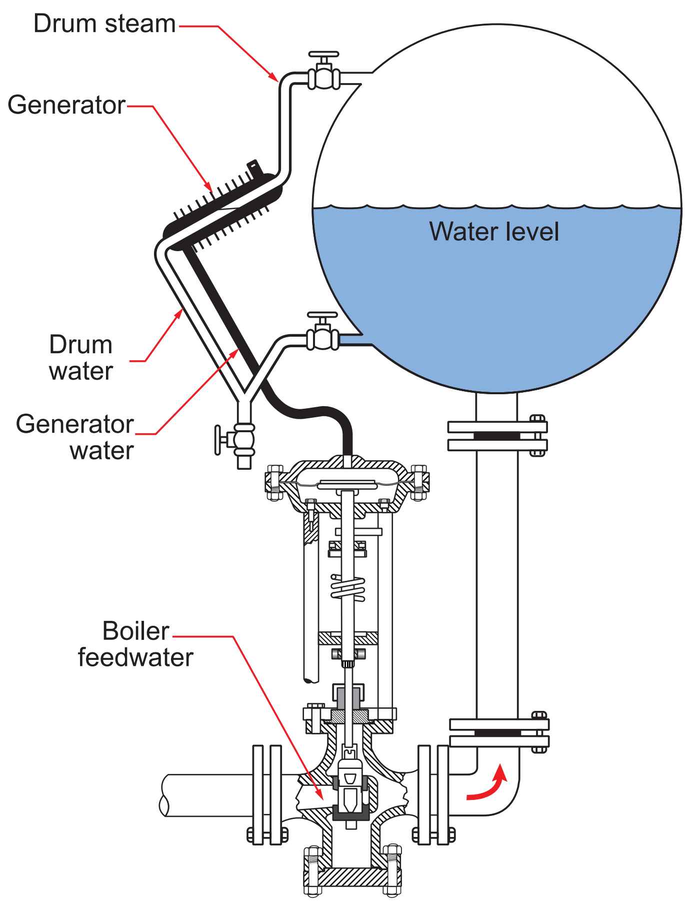
Self-powered valves do not rely on an external energy supply, such as compressed air, hydraulic pressure, or electrical current. Instead, they develop the force needed to operate their valve mechanisms on their own. A power failure has no effect on the ability of self-powered valves to perform their function.

Self-powered level control valves respond proportionally to drum level. They do not respond to feedwater or steam flow.

Thermo-Hydraulic Feedwater Regulator

A thermo-hydraulic feedwater regulator is shown in Figure 7. It consists of a generator, a regulating valve, and drum connections. The generator consists of two concentric tubes. The outer tube is connected to the bellows of a regulating valve, and is surrounded by heat dissipating fins. The ends of the inner tube are directly connected to the steam and water spaces of the drum. The level in the inner tube will always equal the boiler drum level, as indicated in Figure 7.

Figure 7 – Thermo-Hydraulic Feedwater Regulator



To put the regulator into service, the outer tube and the bellows are filled with distilled water and sealed. During boiler operation, the heat from the inner tube transfers to the surrounding water in the outer tube at a higher rate than the fins are able to dissipate. This forces water down into the bellows until the level in the inner and outer tubes are equal. The force of the water and steam in the outer tube causes the bellows to expand. The bellows then opens the feedwater valve in direct proportion to the level in the generator and boiler.

If the water in the boiler drops, the level in the inner tube also drops. When this occurs, a greater proportion of steam fills the inner tube. Because the steam transfers heat to water at a higher rate than the water, the larger steam volume in the inner tube will cause increased heating of the water in the outer tube. The outer tube fins cannot remove the additional heat at the same rate. This raises the temperature and pressure in the outer tube. The additional pressure is transferred through to the bellows, which opens the valve further, allowing additional water into the boiler.

If the water level in the boiler and inner tube rises, the opposite sequence occurs.

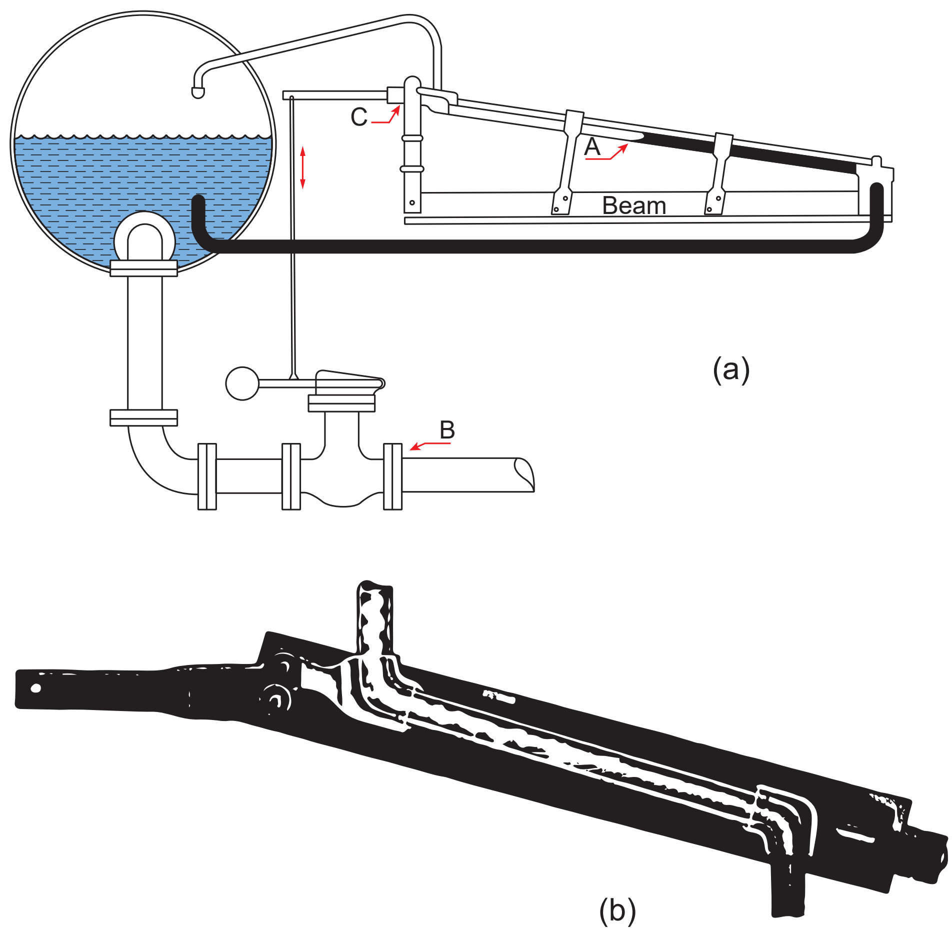
A handle permits manual positioning of the feedwater regulator valve.

Single-Element Thermal Expansion Regulator

An example of a thermal expansion feedwater regulator is shown in Figure 8. It consists of a tube ("A") mounted on a rigid beam as shown in Figure 8(a). The tube and its connecting link are illustrated in Figure 8(b). Because the two ends of the tube are connected to the steam and water spaces in the boiler, the water level in the tube equals the level in the boiler drum.

When boiler water level drops, the water level will also drop in tube "A" and expose more of its length to steam. This causes the tube to expand and move arm "C" so the linkage moves downward to open the regulating valve "B". If the water level increases, the tube will contract due to the effect of the comparatively cool water, so the opposite action will occur.

Figure 8 – Copes-Vulcan Thermal Expansion Feedwater Regulator



Globe Valves

Gate valves are appropriate for isolation service, not throttling. When throttling service is required, globe valves with suitable trim are used. Figure 6 shows a globe valve used to throttle feedwater flow when the main feedwater control valve is out of service. This valve is commonly called the feedwater bypass valve.

A E

ASME B31.1 122.1.7 requires that wherever globe valves are used in a feedwater system, the flow must enter under the disk of the valve. This is to ensure the valve disc does not become dislodged, and suddenly stop the feedwater flow.

Objective 3

Describe the control strategies for single-element, two-element, and three-element boiler feedwater systems.

There are three main strategies for controlling boiler water level. These are known as single-element, two-element, and three-element feedwater control systems. The elements under consideration are drum level, steam flow, and water flow.

Single-Element Feedwater Control

Single-element feedwater control systems respond only to drum level. Almost all steam heating boilers, and most power boilers, use single-element control. When applied to power boilers, single-element systems provide satisfactory boiler water level control when boilers have:

- Large steam drums or shells
- Steady steam demand
- Slowly fluctuating steam demand

Power boilers with small diameter drums or rapidly fluctuating steam loads require more sophisticated and costly feedwater control systems.

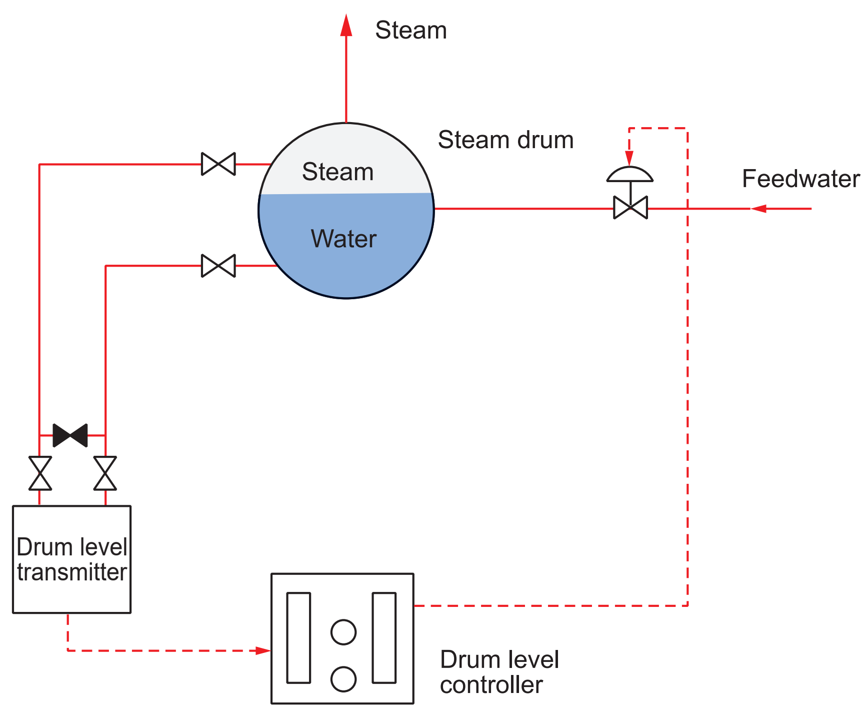
Single-element systems can be two-position or fully modulating. Modulating control valves can be self-powered or control loop operated. Two-position single-element controls can operate feedwater solenoid valves, or start and stop feedwater pumps. Despite these differences, these systems all respond only to boiler water level. Primary sensing elements may be floats, probes, or differential pressure (DP) cells.

Figure 9 shows a fully modulating single-element feedwater control system. The drum level is sensed by a DP cell. The DP cell has two drum connections. The connection to the steam space is called the reference head. This pipe fills with condensed steam, and forms a constant column of water. The pressure at the base of this column does not vary.

The other DP cell connection is the variable head. The pressure at the base of this piping connection varies with boiler drum level. Variations in drum level are transmitted to the drum level controller. The controller compares the process variable (the drum level) to its set point, and sends a signal to the feedwater control valve. Water level below set point will cause the controller to open the valve. Water level above set point will cause the controller to close the valve.

The control output signal may be proportional, PI, or PID. The controller faceplate has a hand/auto selector to permit manual feedwater valve operation. The controller also accepts changes in drum level set point. Drum level controllers usually have a set point of "zero," which corresponds to the normal water level. The drum level is expressed as millimetres above or below set point.

Figure 9 – Single-Element Feedwater Control



Swell and Shrinkage

When steam demand (or load) changes quickly, the drum level responds in unexpected ways. When steam flow increases, it is reasonable to expect drum level to drop, as more water leaves the drum as steam. Similarly, when steam flow decreases, it is reasonable to expect drum level to increase. However, in each of these situations, the opposite occurs.

In reality, when the boiler steam flow suddenly increases, there is a momentary drop in drum pressure. This slightly decreases the saturation temperature of the water. Immediately, some of the saturated boiler water flashes to steam, forming more bubbles. The existing steam bubbles expand in size, due to the pressure decrease. Steam occupies more volume than water. Therefore, when there is an increase in steam flow, the drum level will momentarily rise. This phenomenon is called **swell**.

When swell occurs, a single-element feedwater control detects an increase in drum level. Because of the level increase, the single-element control reduces the feedwater flow. However, because of the increase in steam flow, the controller should increase feedwater flow.

When boiler steam flow suddenly decreases, there is a momentary increase in drum pressure. Some steam bubbles immediately collapse, and existing steam bubbles become smaller, due to the pressure increase. With less internal steam volume, the water level decreases. This phenomenon is called **shrinkage**.

When shrinkage occurs, a single-element feedwater control detects a decrease in drum level. Because of the decrease in level, the single-element control increases the feedwater flow. However, because of the reduction in steam flow, the controller should reduce feedwater flow.

Therefore, for boilers that have fluctuating steam loads and smaller diameter drums, steam flow, feedwater flow, and drum level must all be considered when designing the feedwater control system.

On Track

Two- and three-element feedwater control systems are only used in larger power boilers.

Heating boilers (low-pressure steam) only use single-element control. This is because:

a) Heating boilers have a larger shell size to water content ratio, so they do not experience the negative consequences of swell and shrinkage.

b) Two- and three-element control systems are cost prohibitive to install and maintain in low pressure heating plants.

c) Heating loads are quite stable. Changes in steam demand occur gradually, so swell and shrinkage are not of consequence.

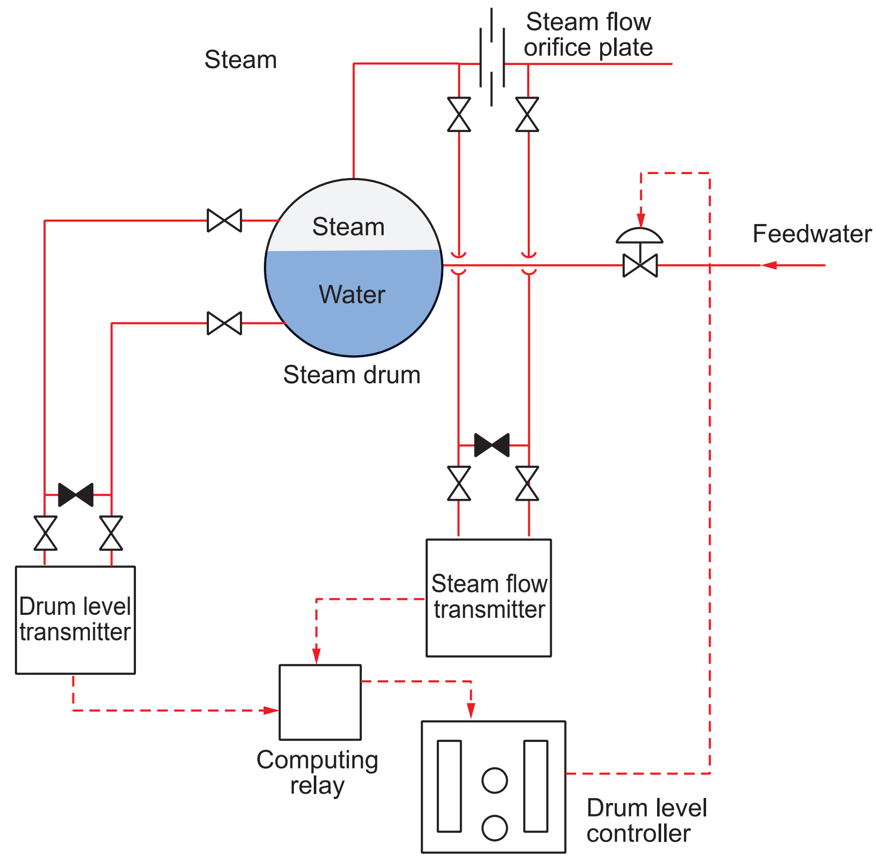
Two-Element Feedwater Control

Two-element feedwater control will significantly reduce the effect of swell and shrinkage on the control system. One element responds to drum level, and the other element to steam flow. In effect, the level and steam flow "consult" each other to verify the circumstances of the water level change. This control is effective when the feedwater pressure is fairly constant, and the drum capacity is small.

Figure 10 shows a two-element feedwater control system. As in the single-element system already described, a DP cell senses and transmits the drum level. An orifice plate and another DP cell detect steam flow.

When steam flow increases, the steam flow transmitter sends an increasing signal to the drum level controller. The controller responds by opening the feedwater valve in anticipation of a drop in drum level. At the same time, the drum level transmitter senses an increase in level due to swell. Its signal will attempt to change the controller output to close the valve, and reduce the feedwater flow. The steam flow transmitter output momentarily overrides that of the level transmitter until the effects of swell are overcome. This override feature is completed by the computing relay.

Figure 10 – Two-Element Feedwater Control



When steam flow decreases and shrinkage occurs, the drum level transmitter will attempt to increase the feedwater flow. The steam flow transmitter will again override the drum level signal. This will cause the controller to close the feedwater valve further, and reduce the feedwater flow in anticipation of a reduction in boiler load.

When the boiler adjusts to the change in steam demand, swell and shrinkage cease, and the water level stabilizes. When stable, the controller uses the drum level transmitter signal to adjust the control valve. This restores the drum level to set point. The transmitter also compensates for any changes in feedwater pressure and boiler blowdown losses.

Like the single-element control, the control output signal may be proportional, PI, or PID. The controller faceplate has a hand/auto selector to permit manual feedwater valve operation. The controller also accepts changes in drum level set point.

When the boiler is being put into service, the operator can control the drum level manually, until there is sufficient steam flow to produce a reliable steam flow signal.

The controller may also have a drum level recorder that continuously tracks drum level.

Three-Element Feedwater Control

Three-element feedwater control systems reduce the effect of swell and shrinkage more effectively than two-element systems. Drum level, steam flow, and feedwater flow are all measured. Steam flow and feedwater flow are maintained in the same ratio. When steam flow changes, feedwater flow is changed in proportion. A drum level transmitter signal is used to correct the level when swell and shrinkage are not occurring.

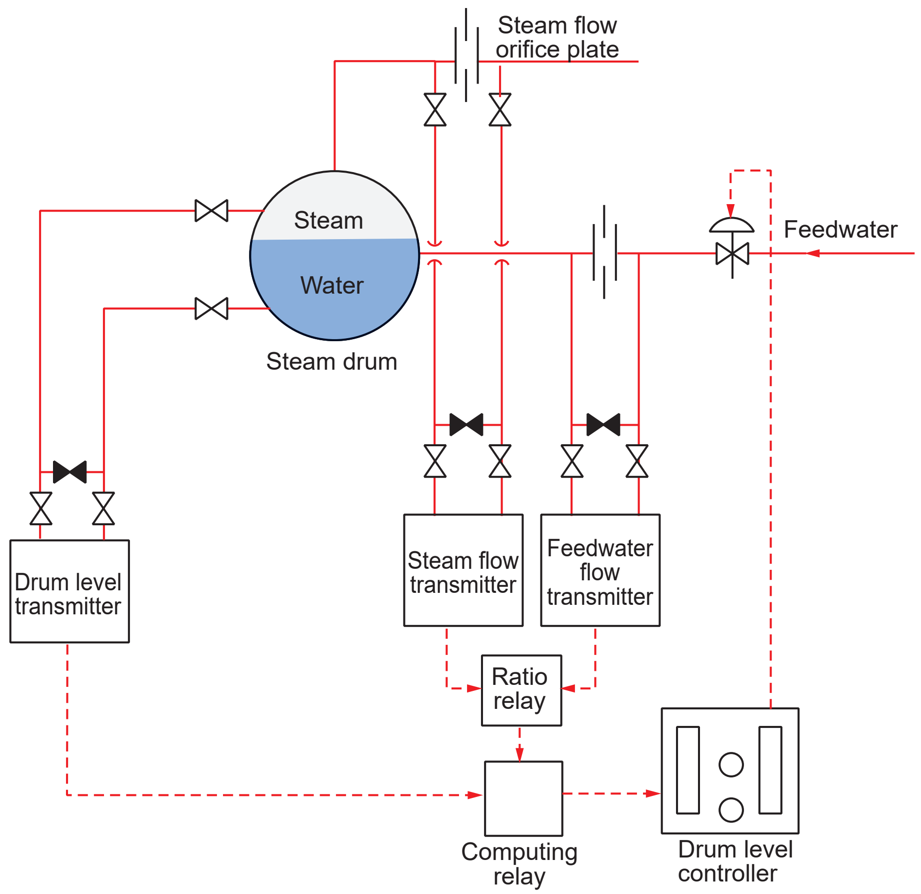
Like the single- and two-element control systems, the control output signal may be proportional, PI, or PID. The controller faceplate has a hand/auto selector to permit manual feedwater valve operation, and drum level set point adjustment.

When the boiler is being put into service, the operator can control the drum level manually, until there is sufficient load on the boiler to produce stable control. In automatic operation, the controller regulates the flow of water to the boiler.

The controller may also have a drum level recorder that tracks the level continuously.

Figure 11 shows a three-element feedwater control system. A DP cell senses and transmits the drum level. One orifice plate and DP cell are used to detect steam flow. Another orifice plate and DP cell detect feedwater flow.

Figure 11 – Three-Element Feedwater Control



When steam flow increases, the steam flow transmitter output to the ratio controller increases. The feedwater flow signal, however, is unchanged. Therefore, the error between the steam flow and feedwater flow increases. Based on the flow signal error, the ratio relay sends a signal to open the feedwater valve.

As the steam flow increases, the drum level swells. The drum level transmitter signal increases when the drum level swells, in an effort to reduce feedwater flow and lower the drum level.

The computing relay momentarily overrides the drum level signal, and sends the error signal from the ratio relay to the controller. The controller uses the flow error signal, rather than the drum level signal, to open the feedwater valve. The feedwater valve opens until the feedwater/steam flow ratio is restored and no signal error exists. The override function lasts until the effects of swell are overcome.

When the boiler water stabilizes, the controller uses the drum level transmitter signal to adjust the feedwater control valve. This action restores the drum level to set point.

The opposite sequence occurs during a reduction in steam flow.

A manual-automatic transfer station is usually installed in the control room. When the boiler is being put into service, the operator can control the drum level manually, until there is sufficient steam flow to produce a reliable steam flow signal.

These systems usually have recorders for steam flow, feedwater flow, and drum level.

Objective 4

Describe methods of supplying feedwater to steam heating boilers.

Heating Boiler Feedwater System Components

Heating plants with steam heating boilers are fed by numerous components, arranged in a variety of ways. These components include:

- Low water cut-offs (LWCO)
- Combined feeder/cut-off controls
- Float controlled switches
- Condensate receivers
- Return loops
- Condensate pumps
- Boiler feed pumps
- Feedwater control valves

Heating plants will have various combinations of the above items, depending on the plant size and complexity. Some of these components are described below.

Low Water Fuel Cut-Off

The **low water fuel cut-off (LWCO)** is a float or probe-operated switch that directly detects the level of water in a boiler. Its function is to shut off the boiler burner system if boiler water level drops to an unsafe level.

Each boiler has a **lowest permissible water level (LPWL)**, identified by the boiler manufacturer. This is the lowest water level at which a boiler can be safely operated. The LWCO turns off the burner system before the water level drops to the LPWL. As such, it is a very important boiler safety control.

CSA B51 Code 6.3.2 states:

> *"Steam boilers not continuously attended by a certified operator shall be equipped with at least two low-water fuel cut-off devices, each of which shall be independent of the other or others. These devices shall be installed so that they cannot be rendered inoperative."*

Note that in the case of boilers under continuous supervision, **CSA B51** does not require LWCO installation. Despite this, most jurisdictions mandate LWCOs, regardless of the degree of operator supervision.

CSD-1 CW-120 states that the two cut-off devices must operate at different levels. The lowest cut-off must be situated above the LPWL, and in no cases lower than the lowest visible part of the gauge glass. This is so that when a cut-off occurs, the boiler water level can be identified and determined to be high enough to prevent boiler damage.

CSD-1 also states that the lowest of the cut-off devices must cause safety shutdown and lockout. This will prevent the boiler from restarting if the water level is restored to normal. In other words, a low water condition requires manual operator intervention to reset the cut-off, and restart the boiler. The assumption is that the operator will determine the cause of the low water condition, and take steps to correct the root cause before restarting the boiler.

Combined Feeder/Cut-off Controls

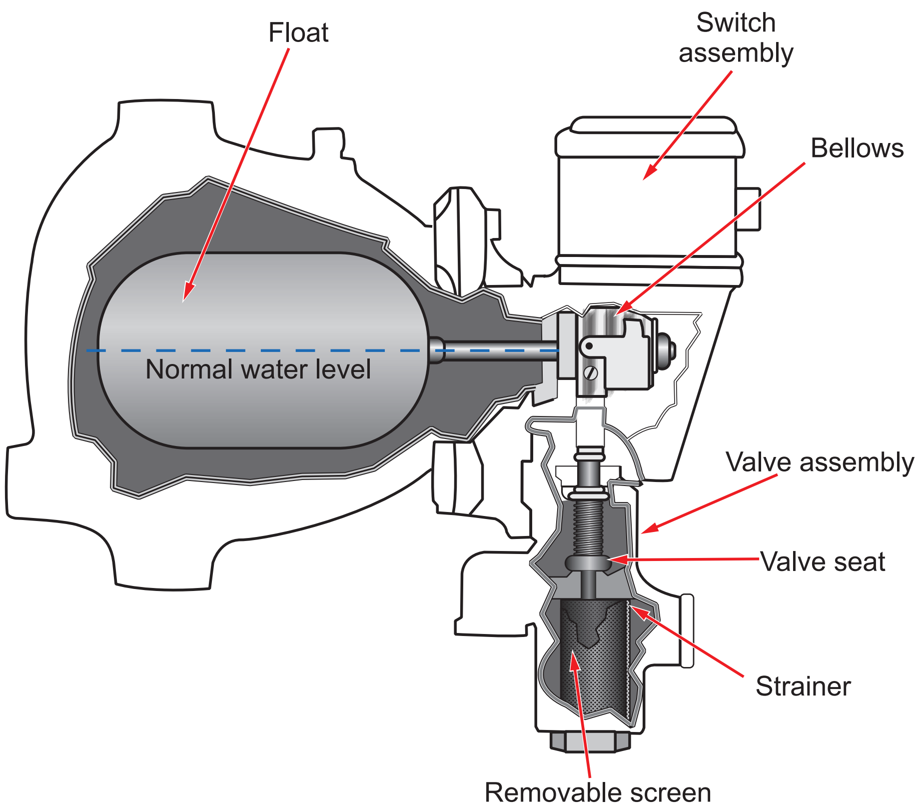
ASME CSD-1 allows one of the two required cut-offs to be a combined feedwater control and cut-off device. Combined feeder/cut-off controls are used to add water to a steam boiler, and cut-off the boiler when a low water condition occurs.

The first action of this device is to restore boiler water level by adding municipal water. If the boiler water level does not recover, its low water cut-off function stops the burner. When the water level recovers, the cut-off automatically resets, and the burner restarts.

Figure 12 shows the construction of a combined feeder/cut-off control. Because the control is not a single-purpose cut-off control, an additional dedicated cut-off must be installed to satisfy **CSA B51** and **ASME CSD-1**.

The float resides in a float cage that is attached to the boiler, with piping to the water space and the steam space. Make-up water connections are provided on the valve assembly. The valve fully modulates, based on the position of the float. A strainer removes particles from the make-up water that may interfere with the valve operation. Switches are provided so the control can be used as a low water cut-off.

Figure 12 – Combined Feeder/Cut-off Control



Float Controlled Switches

Float controlled switches are similar to combined feeder/cut-offs, except they do not have integral mechanically operated control valves. The operating head has two switches that can be used for a number of purposes, such as:

- Low water alarm actuator
- High water alarm actuator
- Feed pump start/stop controller
- Feedwater control valve controller
- Low water cut-off

The switches can be connected normally open or normally closed. This allows a switch to open when there is a drop in water level (as in a low water cut-off), or to close (as in a pump control). The switches are adjusted so that one switch operates prior to the other. For example, a feed pump can be started (or a feedwater solenoid can be opened) before a low water cut-off switch is activated.

The operating head may be equipped with a manual reset button.

Figure 13 shows the construction of a float-controlled switch. Only one single-throw single-pole switch is shown in this diagram. As the boiler water level drops, the mercury in the switch moves away from the electrical leads. This opens the burner circuit.

Figure 13 – Basic Diagram of a Float Operated Low Water Fuel Cut-Off

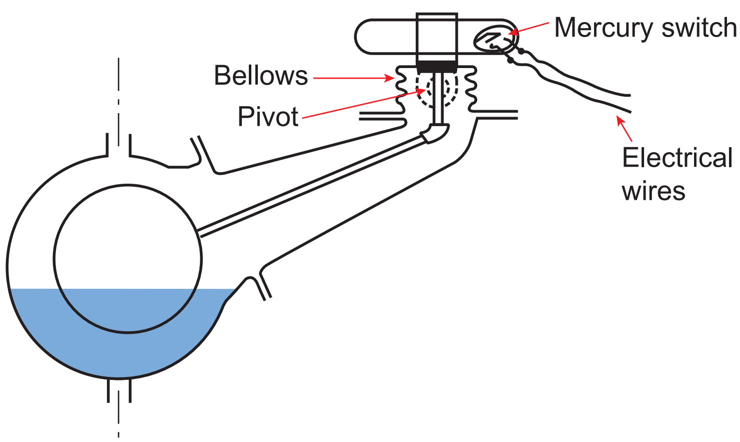
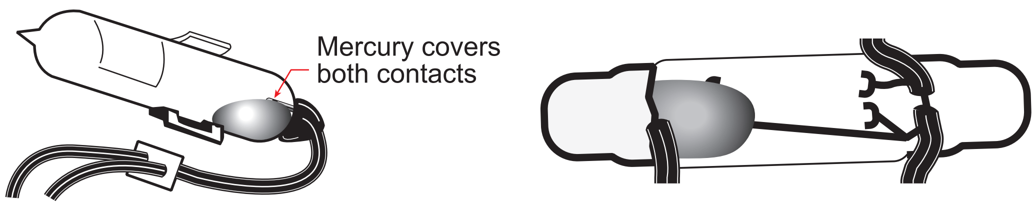


Figure 14 shows mercury switches from older style float units. As the float moves it causes the mercury in the sealed glass bulb to move, either making contact with the enclosed terminals, or breaking contact. Figure 14(a) is a single pole single throw switch, usually used to operate the feed pump or feedwater solenoid valve. Figure 14(b) is a single pole, double throw switch. While the boiler is running, the low water cut-off circuit is closed, and the alarm circuit is open.

Figure 14(b) shows a three-wire single-pole double-throw switch, used as a burner cut-off switch and an alarm switch. Figure 14(a) shows a two-wire, single-pole single-throw switch, used to control the operation of either a feedwater pump, or a feedwater control valve.

Figure 14 – SPST and SPDT Mercury Switches



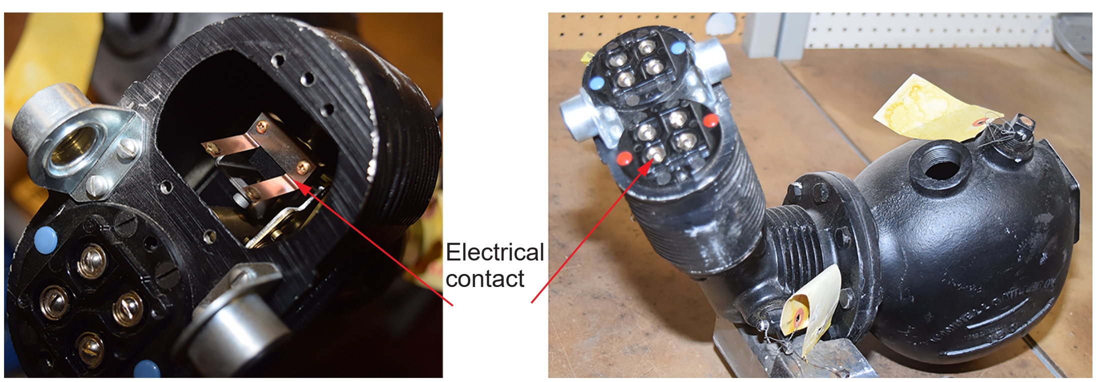
(a) (b)

SAFETY

Many float-actuated switches contain mercury. When these switches require replacement, the mercury must be treated as a hazardous material, and disposed of in accordance to environmental regulations. Always handle equipment that contains mercury with appropriate PPE.

Figure 15 shows a LWCO with mechanical snap switches instead of mercury switches. Other common devices used for drum level control include electric probes and magnetic float switches.

Figure 15 – Miniature Single-Pole and Double-Pole Switches



Condensate Receivers

Condensate receivers collect the recovered condensate from various heat exchangers or equipment in the heating system. They are equipped with:

- Float switches
- Pumps
- Vents
- Drains
- Gauge glasses
- Make-up feeders

Some of these are discussed below.

If make-up water is introduced to the condensate receiver, the receiver will be equipped with a mechanical make-up feeder control and a feeder bypass valve.

The float switch is used to start the condensate pump when the condensate level in the receiver is high. The pump continues to run until the receiver level drops to a set level.

Condensate receivers are vented for several reasons:

a) To accommodate changes in water level as the receiver alternately fills and empties. As it empties, the receiver draws in air through the vent. When the receiver is filling up, it expels air out through the vent.
b) Vents prevent carbonic acid from forming in the condensate.
c) If defective steam traps blow steam, the vents will relieve pressure in the receiver. This last point is important, because condensate receivers are not designed as pressure vessels. If unvented, condensate receivers can explode.

SAFETY

Never cap off or plug a condensate receiver vent. If steam or water comes from the vent, investigate the cause and repair it.

Some condensate receivers have gauge glasses. By regularly observing the gauge glass it can be determined if the condensate pump switch and the condensate pump are working correctly.

On normal rounds, operators should check for:

a) **Water on the floor around the receiver**. This may indicate a corroded receiver, defective pump seal, or leaking pump packing.
b) **Water flowing from the vent**. This may indicate a broken pump coupling, a failed pump motor, a defective float switch, or a tripped breaker. If a float becomes waterlogged, or dislodged from its actuating rod, the pump will not start, and the receiver will overflow.
c) **Steam issuing from the vent**. Small amounts of steam are normal. Large amounts of steam indicate defective steam traps. The faulty traps should be located and repaired.

While on rounds, it is normal to manually activate the condensate receiver float switch to start the pump. This allows the pump operation to be observed. In many plants, operators take condensate samples and test them for pH. This test is done to ensure the proper amount of water treatment chemical is added to the steam to protect the condensate return lines from corrosion.

In large heating systems, smaller condensate receivers and pumps are located at numerous locations throughout the system. These pumps feed to a large condensate receiver located in the boiler room.

Return Loop (Hartford Loop)

A **return loop** or **Hartford Loop** is a special condensate return piping connection that prevents low-pressure steam boilers from sustaining low water conditions, under certain circumstances. In some small, older heating plants, the condensate from the various parts of the heating system is piped to a common condensate return line, or return main, which feeds the condensate directly back into the boiler by gravity. These systems do not have condensate receivers or pumped returns. The height of condensate in the return lines is adequate to force water into the boiler.

Figure 16(a) shows a gravity-fed steam heating boiler in a two-pipe steam heating system. If the heating demand is low, and the boiler is in operation, the pressure in the steam line can exceed the pressure in the condensate return line. The boiler pressure can then force water out of the boiler and into the condensate lines. If the boiler is not equipped with a low water cut-off, or if the cut-off is defective, the boiler will sustain damage due to low water.

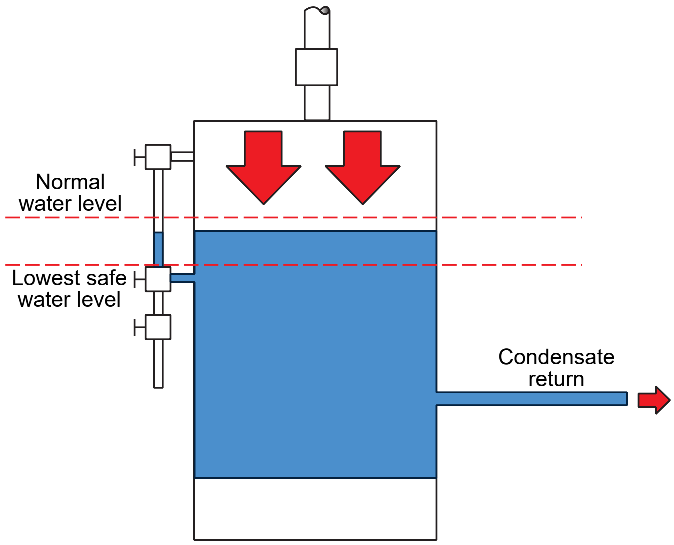
Figure 16(b) shows the same boiler, but with a return loop. The return loop has an additional equalizing pipe that connects the boiler steam outlet to the boiler's water inlet piping. The condensate returns to the boiler through a piping connection located at the lowest safe water level. The steam pressure above the water in the boiler and loop will also be equal (shown with red arrows). Since the steam pressure in both the boiler and return loop are balanced, boiler water cannot be forced out to below the lowest safe water level. This ensures the boiler will have sufficient water to cover the heating surfaces to prevent overheating.

A E

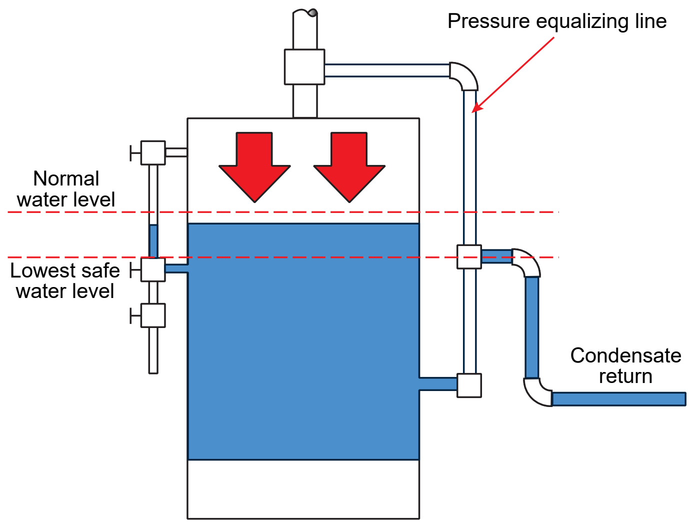
ASME IV HG-703.2 and **ASME VI 3.05** require steam heating boilers with gravity condensate returns to have return loops. **ASME IV** also requires the installation of a stop valve and check valve in the condensate return lines feeding each boiler in the system.

Figure 16(c) shows a check valve installed in place of a return loop. It performs a similar function by preventing the backup of condensate into the return receiver when the condensate pump is not in operation. In pumped return systems, the use of check valves without a return loop is permissible. If a return loop is used with a pumped return, **ASME VI 3.05** recommends the return line connection to the boiler be made at the base of the return loop, to prevent objectionable noise or water hammer.

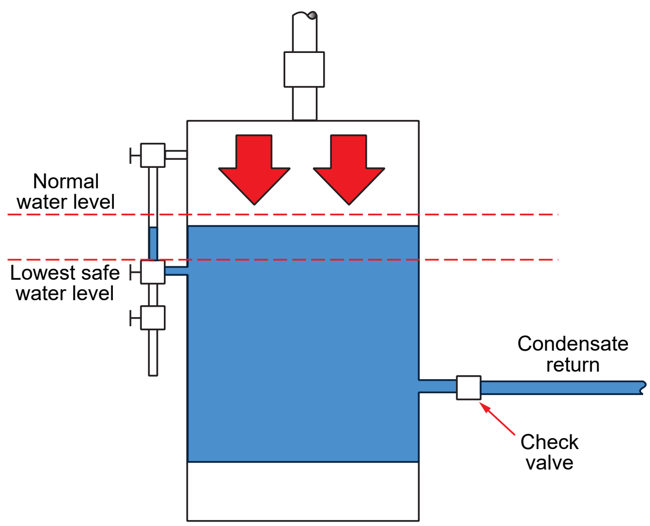
Figure 16 – Return or Hartford Loop



(a)



(b)



(c)

Heating Boiler Feedwater Systems

Heating boiler feedwater systems can be classified according to whether condensate returns to the boiler by gravity or by pump. Gravity, acting on a head of condensate, can provide enough feedwater pressure to overcome boiler pressure, because heating boilers operate at low pressure. Pumps are used in larger heating plants, where condensate must flow long distances to return to the boiler.

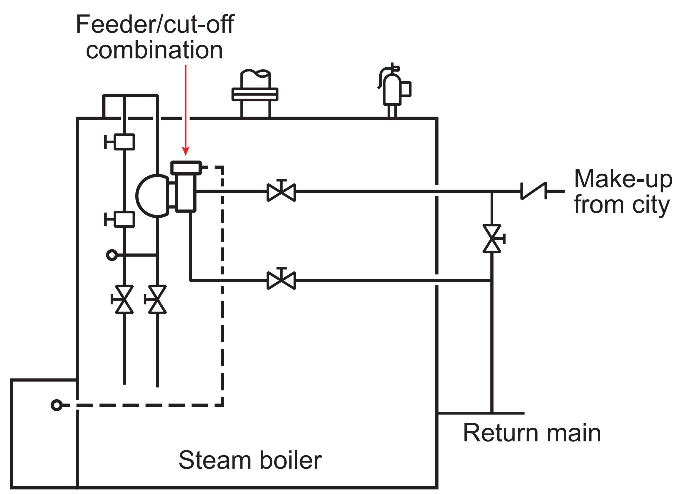
Some of the more common arrangements are discussed here.

Gravity Return Systems

In gravity return heating system, make-up water is added to the boiler, using a combined feeder/cut-off control, or a float operated solenoid valve. The make-up water source may be raw untreated municipal water, softened well water, or softened municipal water. Typical plants such as these have minimal make-up water requirements. Internal water treatment may be minimal or non-existent.

Figure 17 shows a gravity return system that uses a combined feeder/cut-off control to add make-up water to the boiler. If the combined feeder/cut-off control valve fails, it can be bypassed, and water can be fed manually.

Figure 17 – Gravity Fed Heating Boiler with Combined Feeder/Cut-Off



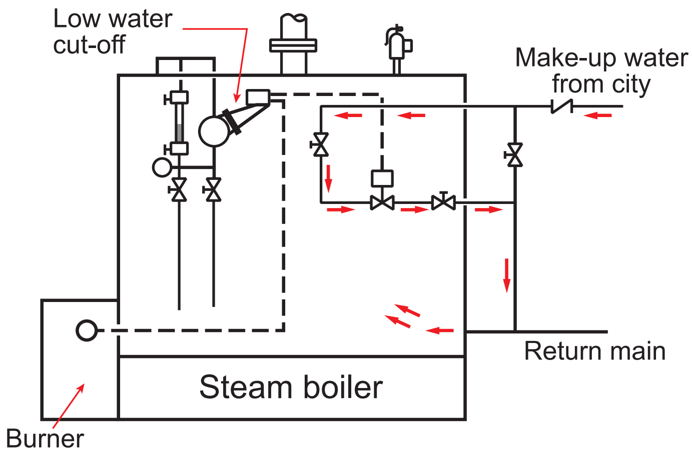
When the boiler water level drops below normal, the float opens the make-up water valve via mechanical linkage. This admits municipal water to the boiler. When the water level is restored, the float closes the make-up water valve.

If the supply of make-up water fails or is insufficient, the water level will continue to drop. If this occurs, the float will cut-off the burner before the level drops to the lowest permissible water level. If the combined feeder/cut-off control fails, the additional dedicated low water cut-off required by **CSA B51** and **ASME CSD-1** (not shown) will stop the burner.

With this system, no electrical power is necessary to feed make-up water to the boiler. The contact switches in the feeder may be used as "dry contacts" in a millivolt burner safeguard system, to shut off the burner if a low water condition arises. With a millivolt system, then, the boiler operation can continue even during an electrical power outage. If the burner safeguard system is not self-powered, the contacts on the combined feeder/cut-off interrupt the burner firing circuit if a low water condition occurs.

Figure 18 shows a gravity return system that uses an electric solenoid as a make-up water control valve. This system differs from that in Figure 17 in that it requires an external electric power supply to operate the make-up water solenoid valve. However, the feed solenoid valve can be bypassed, if necessary, to feed water manually.

Figure 18 – Gravity Fed Heating Boiler with Float Operated Feedwater Control/Cut-Off



The low water cut-off shown has two float controlled switches. One switch operates the make-up water solenoid valve. The other switch is a low water cut-off. When the boiler water level drops below normal, the float energizes the make-up water solenoid. This admits municipal water to the boiler. When the water level is restored, the float de-energizes the solenoid valve.

If the supply of make-up water fails or is insufficient, the water level will continue to drop. If this occurs, the float will cut-off the burner before the level drops to the lowest permissible water level. If this cut-off fails, the additional dedicated low water cut-off required by **CSA B51** and **ASME CSD-1** (not shown) will stop the burner.

Pumped Return Systems

Gravity return systems are limited to smaller heating plants. Larger plants need pumps to overcome the resistance of long condensate return lines, and still provide adequate pressure to overcome boiler pressure.

Where pumped return systems are used, make-up goes into a condensate receiver, not the boiler. Make-up water contains dissolved oxygen and carbon dioxide that cause waterside corrosion. It is preferable to introduce corrosive water to a condensate receiver than a boiler. This is because condensate receivers and feed piping are less expensive to replace than boilers.

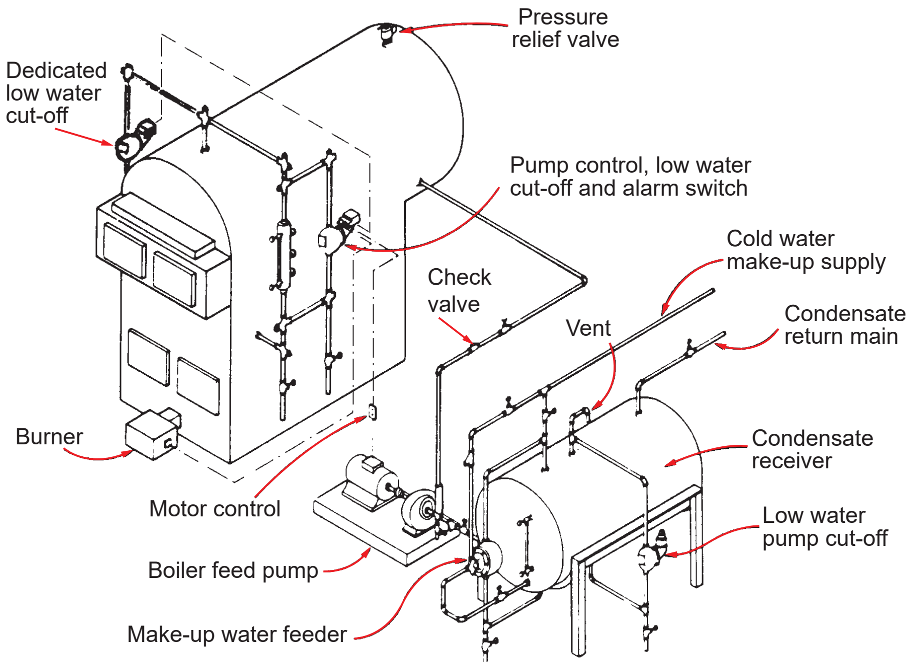
Single Boiler Installations with Two-Position Feedwater Control

Figure 19 shows a single steam heating boiler plant with pumped condensate returns. This system uses two float operated controls mounted to the boiler, and a mechanical water feeder mounted to the condensate receiver. One of the float controls operates the boiler feed pump, a low water alarm, and a low water cut-off. When the boiler water level falls, the boiler feed pump starts, adding water to the boiler. When the water level is restored, the pump stops.

If the pump fails, the float shuts down the burner. Pump failure could be due to a broken coupling, a plugged suction inlet, a defective motor, a tripped breaker, or other reasons. If the combined pump control/cut-off fails, the dedicated low water cut-off will shut down the burner.

A check valve prevents water from flowing back to the condensate receiver when the boiler feed pump stops. This system does not use a return loop.

Figure 19 – Single Boiler Steam Heating System with Pumped Condensate Return



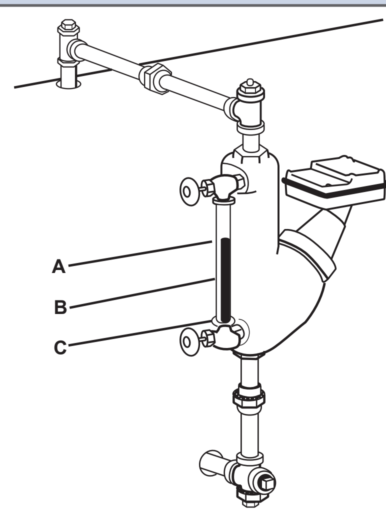
Make-up water to this system is via an external float mounted to the condensate receiver. The float cage is connected to the water space and the air space, so that the float cage level equals the level in the condensate receiver.

The float mechanically operates a make-up water valve to admit water to the receiver if its level gets low. Water can be manually added to the condensate receiver if the feeder is out of service or malfunctioning. A low water cut-off mounted on the condensate receiver turns off the boiler feed pump if the feeder fails, insufficient condensate returns from the heating system, and the receiver level falls too low. This keeps the pump from running dry and sustaining damage.

Normally, adequate condensate returns from the system so that the float does not call for make-up water addition. The make-up water source may be raw untreated municipal water, softened well water, or softened municipal water.

The pump control/low water cut-off mounted on the boiler in Figure 19 is designed to operate as shown in Figure 20.

Figure 20 – Water Level Control for a Steam Boiler



Level A is the highest normal operating level in the boiler. At level A, the feedwater supply switch is open, and the boiler feed pump is off. When the water level drops to level B, the control switch closes, the feedwater pump starts, and feedwater supply resumes. During normal operation, water level alternates between level A and level B.

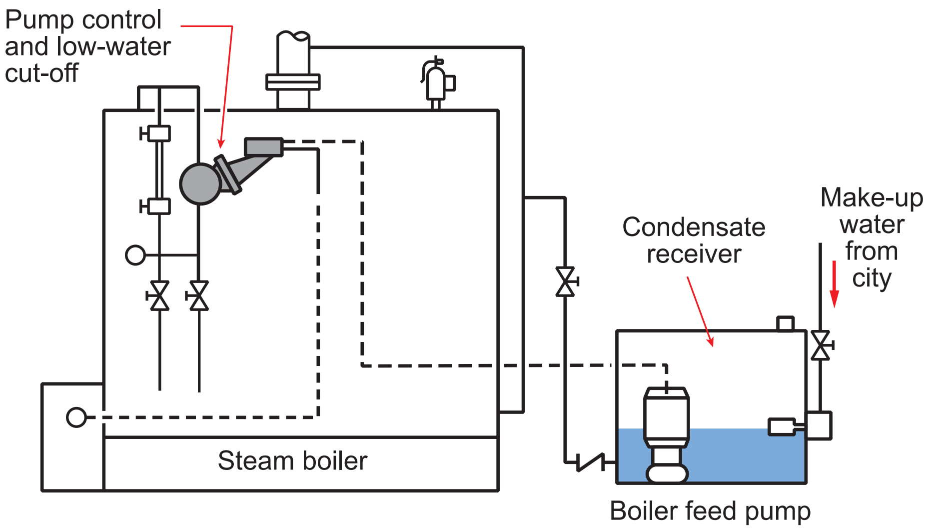
If the supply of make-up water fails or is insufficient, the water level will continue to drop. When the water level drops to level C, the cut-off switch opens the burner circuit before the level drops to the lowest permissible water level. At the same time, the alarm switch closes, energizing the alarm circuit. The boiler cannot restart until the water level is restored to above level C.

On Track

In a steam boiler, the low water cut-off must shut down the burner before the water level reaches the lowest visible part of the gauge glass. This requirement is the same for both heating boilers and power boilers.

Figure 21 shows a simplified schematic of the type of heating system shown in Figure 19. This system has both a feedwater line check valve and a return loop. An internal float operated valve controls the make-up water going to the condensate receiver.

Figure 21 – Single Heating Boiler with Pumped Condensate Return



Steam Heating Boilers in Battery

When multiple steam heating boilers are installed in a common system (installed "in battery"), the boilers may have independent two-position feedwater controls, or independent modulating feedwater controls. Individual controls are needed because boilers can be operated independent of each other. For example, when heating loads are low, only one boiler may be in operation. When heating loads are higher, both boilers may operate, but at different firing rates.

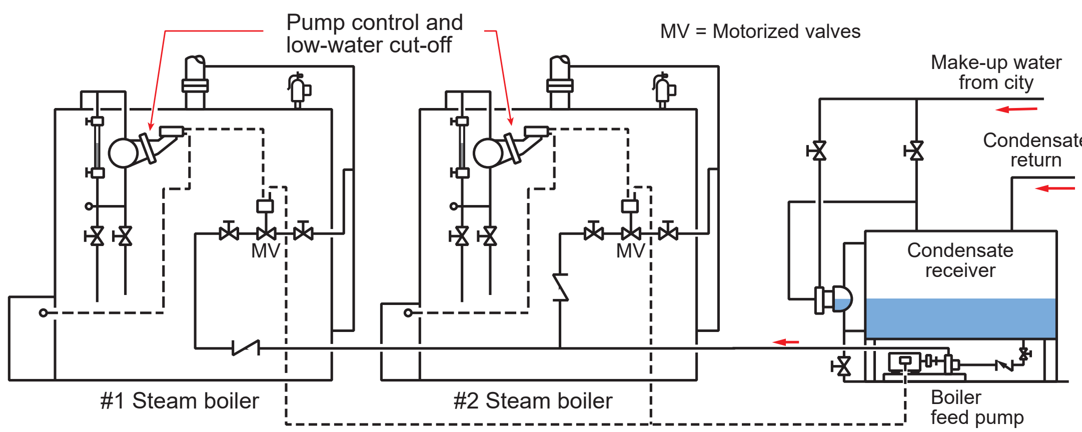
Figure 22 shows a battery of two steam heating boilers, with motorized two-position feedwater control valves. Note that the feedwater connections to each individual boiler are similar to those used for single boiler installation. The pump control/low water cut-offs open or close the motorized feedwater control valves (shown as "MV") as feedwater is required. The motorized valves have end switches that close when the valve is fully open. These switches start or stop the boiler feed pump.

When a boiler needs water, a float operated switch closes to energize and open the motorized feedwater valve. When the motorized valve is fully open, the boiler feed pump starts. When the water level in the boiler is restored, the motorized valve closes, and the boiler feed pump stops. The same sequence occurs when the other boiler requires water. If both boilers call for water at the same time, the boiler feed pump runs until both boilers are satisfied.

If the water level in an individual boiler continues to drop, that boiler's float control turns off the burner. If this low water cut-off should fail, a dedicated low water cut-off (not shown) shuts down the burner, only for the boiler with the low water condition.

Make-up water is added to the condensate receiver by a mechanical feeder, or through a bypass valve.

Figure 22 – Heating Boilers in Battery with Single Pumped Condensate Return



Larger heating plants with boilers in battery are arranged similarly to Figure 22. These plants may have boiler feedwater pumps that run continuously, and fully modulating feedwater control valves.

Objective 5

Explain the operation of condensate receiver make-up water controls.

Well-designed boiler feedwater systems have appropriately sized condensate receivers. These systems must also have a reliable way to add make-up water. Undersized condensate receivers may overflow, resulting in a waste of heat and purified water. An unreliable make-up feeder could result in boiler shutdowns due to low water conditions, or could waste water by feeding too much make-up water, which will cause the receiver to overflow.

During seasonal heating system startup, it becomes quite evident whether a condensate receiver is sized properly. The receiver must contain sufficient water at startup, and must have sufficient ability to replace the water fed to the boilers, to keep the receiver from running dry.

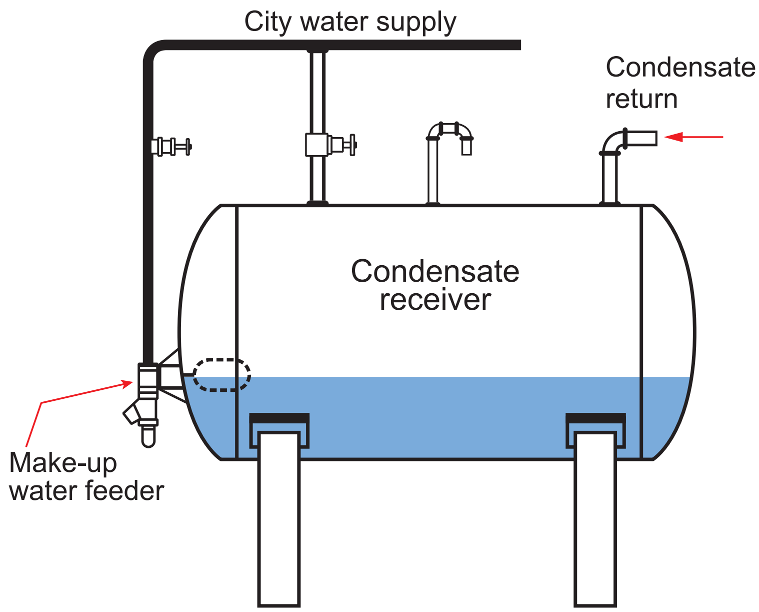
On startup, the steam lines and heat exchangers fill up with steam nearly as fast as it is produced. However, it takes longer for condensate to return to the receiver, because steam needs time to exchange heat, condense, and travel the length of the return piping. Therefore, the receiver needs adequate space to handle the initial condensate return surge that occurs shortly after the system is charged and hot. Receivers with insufficient volume and make-up capabilities may run dry during the initial startup. Also, they may overflow when condensate initially returns.

As a rule, a condensate receiver should have enough capacity to hold a volume that is equivalent to the water evaporated by the boiler in a twenty to thirty minute period at normal load. A smaller size receiver may be used when the condensate returns easily, as in heating systems used in high-rise buildings. In systems that cover a large area (factories, warehouses, and large campuses), condensate takes longer to return. In this situation, a larger size receiver should be used.

The make-up water valve should have sufficient capacity to supply the water required at the normal firing rate of the boiler. If a smaller capacity valve is sufficient, the float mechanism is commonly installed in the lower part of the receiver. Make-up water then feeds through the valve mechanism into the receiver (see Figure 23). The make-up float maintains the water level, so that make-up is never introduced when the receiver is greater than 1/3 full. In this way, a large volume remains for condensate to accumulate without overflowing the receiver. With the receiver a minimum 1/3 full, enough water is available to supply feedwater to the pump during normal operations.

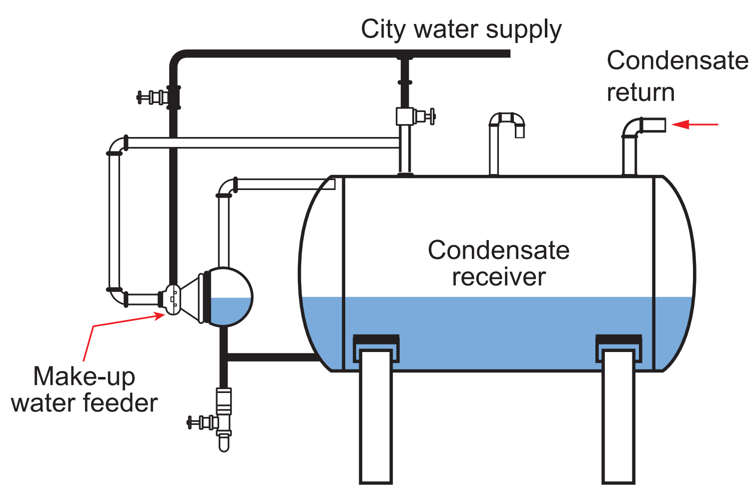
Two arrangements of make-up water feeders and controls are shown in Figures 23 and 24. The feeder float in Figure 23 is mounted inside the receiver. With this arrangement, condensate that returns in slugs can disrupt the operation of the float. This will cause unsteady valve operation.

Figure 23 – Receiver with Internal Float Make-up Valve



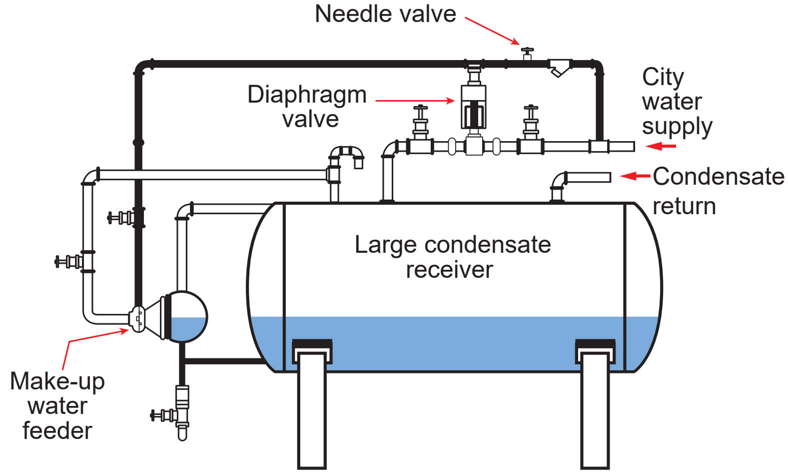
An externally mounted float controlled feeder valve is preferred on most installations (Figure 24). The float chamber is attached to the outside of the receiver with piping connections. This arrangement dampens the receiver level fluctuations, resulting in a smoother flow of make-up water.

Figure 24 – Receiver with External Float Make-up Valve



A large capacity receiver, such as one serving a multiple boiler plant, requires a higher volume of make-up water, and a larger size feeder valve. The float controlled feeder valve, as installed in Figure 25, serves as a pilot valve that actuates a high capacity diaphragm valve in a make-up water line.

Figure 25 – Receiver with Float Controlled Hydraulically Operated Make-Up Valve

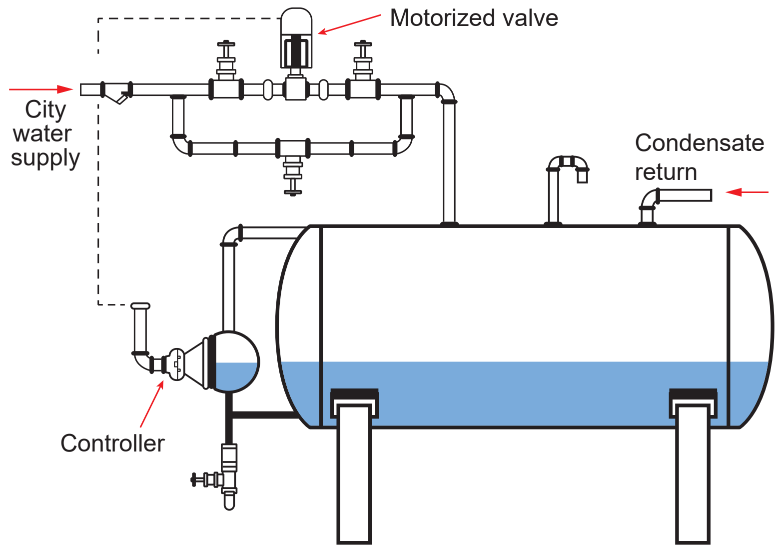


Municipal (or city) water is supplied on top of the diaphragm of the make-up valve and to the float-controlled valve through a small diameter control line which has a needle valve to control the water flow. When the level in the receiver is normal and no make-up is required, the float control valve is closed. The full pressure of the municipal water will act on the diaphragm of the make-up valve, keeping it closed. When the level drops slightly below normal, the float control valve opens slightly, bleeding some of the water out of the control line. The bleed-off will cause the pressure in the control line to drop. This reduces the force on the diaphragm, and allows spring pressure to open the make-up valve slightly.

If the receiver level continues to drop, the control valve will bleed more water, further reducing the force of municipal water on the diaphragm. This allows the make-up valve to open further, permitting make-up water to flow more freely to the condensate receiver.

Figure 26 shows an electric float control actuating a motorized valve in the make-up water line to the receiver. This modulating control valve opens in proportion to the drop in water level in the receiver.

Figure 26 – Receiver with Float Controlled Electrically Operated Make-Up Valve



Some condensate receivers are equipped with a low water cut-off switch. If the level in the receiver drops so low that the condensate pump could lose suction, the switch will cut off the power supply to the motor, and prevent damage to the pump.

Objective 6

Describe the return of condensate, and the supply of feedwater to high-pressure boilers.

High-pressure heating plants have feedwater system components similar to those used in heating plants. These include

- Low water cut-offs and float controlled switches
- Feedwater control valves
- Condensate receivers and condensate pumps
- Deaerators
- Boiler feedwater pumps

Unlike heating plants, combined feeder/cut-off controls and return loops are not used in high-pressure steam plants.

Plants will have various combinations of the above items, depending on plant size and complexity. Some of these components, and their combinations, are discussed below.

Low Water Cut-Offs and Float Controlled Switches

The code requirements of **CSA B51, 6.3.2** apply equally to high-pressure and low-pressure boilers. Steam boilers not continuously attended by a certified operator shall have at least two independent low water fuel cut-off devices that cannot be rendered inoperative. Jurisdictions may require them on all boilers regardless of these minimum standards.

ASME VII Recommended Guidelines for the Care of Power Boilers, C5.100 recommends that each automatically fired boiler have two independent low water cut-offs.

ASME BPVC Section I, PG-61.2 permits the installation of low water cut-offs as an alternative to a secondary means of feeding water to boilers fired by gaseous, liquid, or solid fuels in suspension. It also stipulates the LWCO must function prior to the boiler water reaching the lowest permissible water level.

ASME CSD-1, CW-140 states that:

> *"Each automatically fired high-pressure steam boiler shall have at least two automatic low-water fuel cut-off devices. When installed external to the boiler, each device shall be installed in individual chambers (water columns), which shall be attached to the boiler by separate pipe connections below the waterline. A common steam connection is permissible. Each cut-off device shall be installed to prevent startup and cut off the boiler fuel or energy supply automatically when the surface of the water falls to a level not lower than the lowest visible part of the gage glass. One control shall be set to function ahead of the other."*

The cut-off controls and float operated switches used in high-pressure service operate identically to those used in low-pressure service, but are designed strong enough for high-pressure service.

Feedwater Control Valves

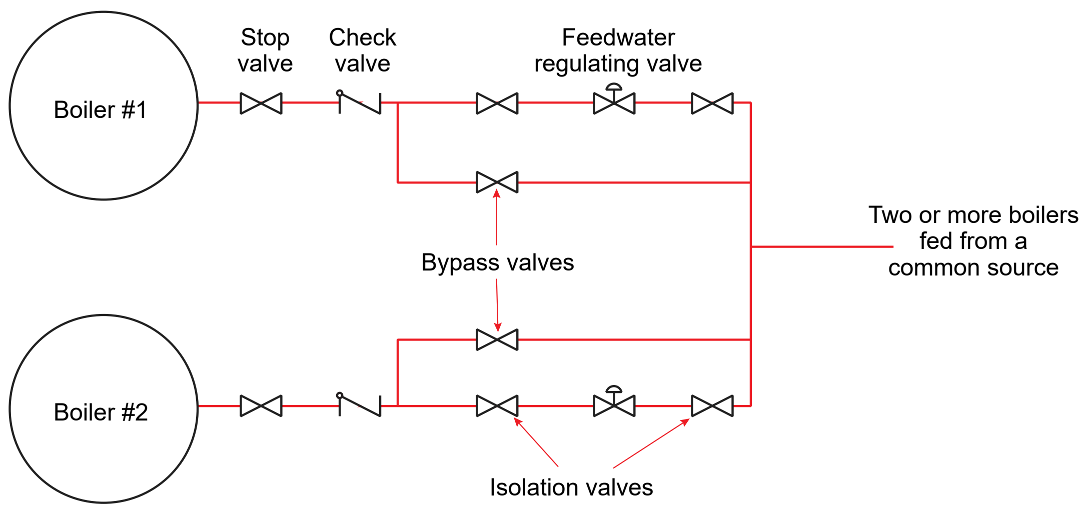
Feedwater control valves may be simple on-off solenoid valves, self-powered modulating control valves, or fully modulating valves installed as part of a control loop. Larger capacity boilers use fully modulating control valves, and multi-element feedwater control strategies. Small power boilers may use float operated switches to operate solenoid valves or boiler feedwater pumps.

A E

The feedwater connection to drum boilers must be in accordance with **ASME BPVC Section I Figure PG-58.3.1(a)**. For multiple boilers fed from a common source, each boiler's feedwater connection must have a stop valve as close as practicable to the boiler, with a check valve upstream of it, preceded by a feedwater regulating valve. The feedwater regulating valve must be equipped with an isolation valve and a bypass, to permit the addition of water to the boiler if the regulating valve fails (see Figure 6).

Figure 27 shows the **ASME BPVC Section I** requirements for multiple boilers fed from a common source. This is essentially a schematic of the arrangement shown in Figure 6.

Figure 27 – ASME BPVC Section I Multiple Boiler Feedwater System



Condensate Receivers and Condensate Pumps

Condensate receivers and condensate pumps serve the same purpose, and operate in the same manner, as those used in low-pressure steam plants.

All high-pressure steam plants use condensate receivers. This is because all high-pressure boilers must have pumped returns, and therefore require a reservoir from which to pump.

DEAERATORS

Deaerators are pressure vessels made of two main sections. One section (the heater section) heats water and drives off dissolved gases from the water. The second section is a storage compartment for deaerated, reheated feedwater.

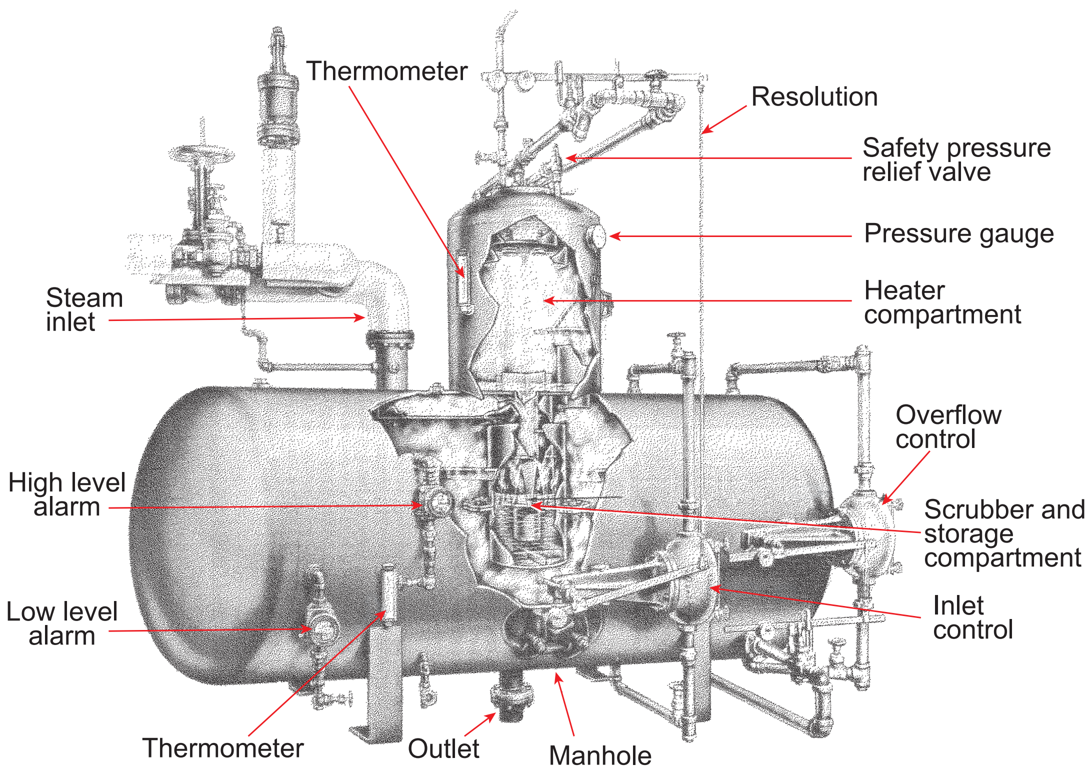
The deaerator serves four main purposes:

1. It preheats the feedwater to lessen thermal shock at the boiler.
2. It accommodates feedwater surges on change in boiler load.
3. It stores about 20 minutes of reserve feedwater.
4. It removes dissolved gases (O_2 and CO_2) from the feedwater.

The deaerator may use exhaust steam from a turbine, flashed steam from a continuous blowdown system, or boiler steam to heat the deaerator. The deaerated, preheated water it produces flows to the boiler feedwater pumps. The deaerator is always situated well above the boiler feedwater pumps. This provides enough water head to prevent **cavitation** and vapour binding of the boiler feedwater pumps.

Deaerators must be equipped with several controls and instruments. These include a thermometer, pressure gauge, gauge glass, level controller and control valve, make-up water control valve, overflow controller and control valve, safety valve, vent, and alarms for low or high levels. (See Figure 28)

Figure 28 – Deaerator with Controls



Thermometer and Pressure Gauge

The thermometer and pressure gauge are very important for proper deaerator operation. Operators regularly compare the temperature and pressure. These readings should correspond to the saturation temperature and saturation pressure of the water in the vessel. If the pressure is higher than the corresponding saturation temperature, then non-condensable gases are being trapped in the vessel. These gases (carbon dioxide and oxygen) will cause severe waterside corrosion in the deaerator, feedwater piping, and boilers. Such a condition could arise if the deaerator vent is inadvertently shut or blocked.

Gauge Glass

The gauge glass shows the water level in the storage compartment of the deaerator. It provides a way to confirm the operation of level controls and alarms. A quick glance at a gauge glass can inform operators of problems before they become serious.

Level Controller and Control Valve

There are several strategies for controlling deaerator water level. All strategies share two common concerns:

1. Keep boiler feedwater pumps from running dry.
2. Maintain an uninterrupted boiler feedwater supply.

This is achieved by controlling both condensate return and make-up water flow. Float controls, attached with mechanical linkages to control valves, have been traditionally used for this purpose.

Figure 29 provides an operational overview of a feedwater system. In this system, the deaerator does not use a level control valve on the condensate return. Instead, it uses two-position control to start and stop the condensate transfer pumps. If the water reaches the condensate make-up pump stop level, a switch stops the condensate transfer pumps. When the water level in the deaerator drops to the condensate pump start level, the transfer pumps restart.

The condensate is pumped from various smaller condensate receivers located in outbuildings to the main condensate receiver. If condensate fails to return, the condensate receiver level will drop. A cut-off switch protects the condensate transfer pumps from running dry.

Make-Up Water Control Valve

If the condensate transfer pumps fail when the deaerator is calling for water, the deaerator water level will drop to the “make-up start” level. A control valve then opens to admit treated make-up water to the deaerator. When the water level rises to the “make-up stop” level, the valve closes.

The deaerator is equipped with a feedwater pump cut-off switch, in case the make-up water valve and the condensate transfer pumps fail to maintain deaerator water level. If the feedwater pumps shut off, the boilers will trip on low water shortly afterward.

Overflow Controller and Control Valve

If the deaerator water level rises too high, a mechanical overflow valve or a control valve opens to drain the deaerator to the condensate receiver. Deaerators need overflow valves because they are internally pressurized with steam and cannot have open drains.

Safety Valve

Deaerators are pressure vessels, designed to **ASME BPVC VIII**. Depending on the design, they operate with between 70 and 400 kPa steam pressure. Some operate at higher pressures.

Like all pressure vessels, deaerators require pressure relief valves. The pressure relief valve cannot be set higher than the MAWP of the deaerator.

Vent

Deaerators must be able to vent carbon dioxide and oxygen to the atmosphere. Otherwise, these gases will stay in solution in the feedwater, and corrode the feedwater piping and boiler. Vent lines may have valves to adjust the amount of gases being expelled. If equipped with a valve, it must be a gate-type with a reasonably large hole drilled through the gate. In this way, a minimum vent flow can be maintained, even if the vent valve is completely shut.

Alarms for Low or High Levels

Many deaerators are equipped with alarms to alert the operator of high or low water levels. High alarms activate before the overflow opens. Low alarms activate before the feed pumps trip off.

Boiler Feedwater Pumps

Boiler feedwater pumps draw from the bottom of the deaerator. In larger, more complex plants, feedwater is pumped through feedwater heaters and a boiler economizer before reaching the boiler.

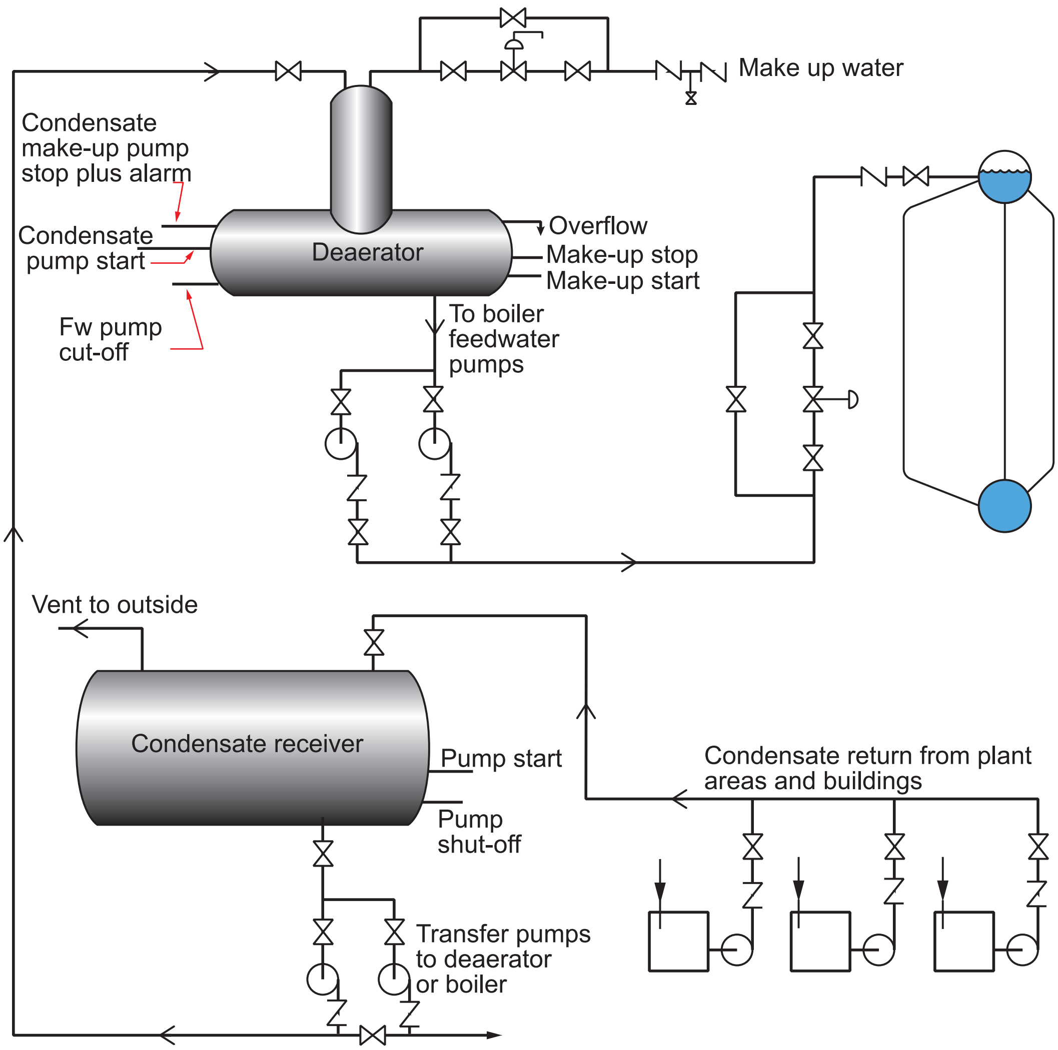
Boiler feedwater pumps must be large enough to provide all the feedwater required, at maximum firing rate. Boilers rarely operate under such conditions. Mostly, the boiler drum level control valve is only partially open, and the flow is throttled. This causes the boiler feedwater pumps to churn water, cavitate, overheat, and sustain damage.

To prevent this from occurring, boiler feedwater pumps, in systems where the pumps operate continuously, are equipped with minimum flow recirculation systems. These systems bypass a portion of feedwater to the deaerator. They may simply be pipes with minimum flow orifices, or pipes fed by **automatic recirculation valves (ARC valves)**.

Typical power plants have redundant equipment, so if one device should fail, the other one can be immediately placed into service. Often, the second (or standby) device enters service automatically. This applies to boiler feedwater pumps.

Figure 29 shows an arrangement with redundant boiler feedwater pumps. Each pump has adequate capacity to feed all the boilers in the system. During normal operation, one pump is on standby. Both pumps are left with their inlet and outlet valves open, and their breakers closed. This ensures that the standby pump can start immediately to restore feedwater flow. Either pump can act as standby. To prevent recirculation of feedwater through a standby pump when it is not operating, the pumps have discharge outlet check valves.

Figure 29 – Operations Overview of Feedwater System



Feedwater Piping Shock Service for High Pressure Plants

According to **ASME BPVC Section I**, a feedwater pump must be capable of supplying all the water a boiler can evaporate on high fire, at a pressure of 3% higher than the highest setting of any pressure relief valve on the boiler. When the boiler drum level control valve is partially shut, the water pressure between the feedwater pump and the control valve will far exceed this value. Therefore, feedwater piping must be designed for pressure considerably higher than the boiler MAWP. **ASME B31.1 Power Piping Code 122.1.3** states that the feedwater piping design pressure shall exceed the maximum allowable working pressure of the boiler by either 25% or 1550 kPa, whichever is the less.

Chapter Summary

This chapter explored feedwater systems, the types and functions of the valves used in these systems, the control methodologies for maintaining proper and safe boiler water levels, condensate return systems, and make-up systems.

In particular, this chapter covered:

- Layouts for the feedwater, condensate, and make-up water systems.
- Manual valves and automatic control valves used in feedwater systems.
- Single-element, two-element, and three-element boiler feedwater strategies.
- Low-pressure boiler feedwater systems.
- High-pressure boiler feedwater systems.
- Condensate receiver construction and operation.
- Make-up water controls.

Maintenance of water at a safe level in the boiler is of vital importance, regardless of whether a Power Engineer works in a low-pressure steam heating plant or a high-pressure steam plant. With this information, novice Power Engineers can learn to effectively and safely operate the feedwater systems they will encounter in the workplace.

CHAPTER 5

Blowoff and Blowdown Systems

Learning Outcome

When you complete this chapter you should be able to:

Describe the equipment, operation, and purpose of boiler blowoff and blowdown systems.

Learning Objectives

Here is what you should be able to do when you complete each objective:

1. *Describe blowoff, blowoff equipment, and blowoff procedures.*
2. *Describe continuous blowdown, blowdown equipment, and blowdown procedures.*
3. *Describe the maintenance and repair of blowoff systems.*

Chapter Introduction

No water treatment regime is completely effective at preventing impurities from entering boilers. Impurities are dissolved compounds, dissolved elements, and suspended matter. The source of these impurities includes make-up water and condensate returning from steam-utilizing processes. If left unaddressed, these impurities create waterside scale and corrosion.

One method of addressing waterborne impurities is to add water treatment chemicals directly to the boiler water, or indirectly through the feedwater system. Many of the water treatment chemicals react with the impurities and form new compounds that precipitate from solution. These precipitates remain suspended in the boiler water, or collect at the base of shells, drums, and headers. Accumulations that settle out can bake onto heat transfer surfaces or, in severe cases, obstruct boiler water circulation. In either of these situations, boiler metal can overheat and fail. Precipitates also settle out in low water cutoff float cages, water columns, and interconnecting piping. These impurities interfere with cutoff and gauge glass operation.

The impurities that remain dissolved in the boiler water increase in concentration while the boiler operates. As concentration increases, the tendency for boilers to carry-over impurities with the steam also increases. Carryover may lead to deposits of scale-forming compounds in the superheater tubing, which leads to superheater overheating and failure. Carryover also leads to deposits of silica on turbine blading, resulting in reduced turbine efficiency, imbalance, and vibration. Very high concentrations of dissolved solids can also cause foaming and priming. When this occurs, enough liquid can be carried with the steam to cause destructive water hammer.

To prevent the accumulation of sediment and dissolved solids, all steam boilers require blowdown and blowoff. Both are performed with the boiler under pressure.

The operation of the blowdown system is an important part of routine boiler care. Specific operational guidelines are found in **Sections VI** and **VII** of the **ASME BPVC**. Design and installation instructions for blowoff and blowdown systems are found in the **ASME B31.1 Power Piping Code** and in the **CSA B51 code**. These codes will be referred to in this chapter. Refer to **PanGlobal ASME Extracts**.

On Track

Heating boiler blowoff and blowdown systems are less robust than those for power boilers. This is because heating boilers operate at less than 100 kPa. Therefore, most of this chapter refers specifically to power boiler systems.

Objective 1

Describe blowoff, blowoff equipment, and blowoff procedures.

The term **blowoff** refers to:

- The intermittent removal of sediment accumulated in drums, shells, and headers (**bottom blowoff**).
- The intermittent or continuous discharge of impurities from the surface of the boiler water (**surface blowoff**).

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The **ASME BPVC Section I, Part PG-59.3** describes a blowoff line as:

> *"A pipe connection provided with valves located in the external piping through which the water in the boiler may be blown out under pressure, excepting drains such as are used on water columns, gage glasses, or piping feedwater regulators."*

Bottom Blowoff

Boilers produce steam as a heat transfer medium. The steam circulates through piping systems to the various processes that use steam. During its utilization, the steam reverts to liquid **condensate**. The boiler feedwater source may be pure condensate (also called **returns**). The returns may also be contaminated with process fluids, such as hard water, glycol, or bitumen. This impure water requires treatment before it can be reused.

Ideally, every process should return every kilogram of the steam produced back to the boiler, in a 100% pure state. However, this is rarely the case. Inevitably, both steam and water leak from process equipment and piping. Water lost from the system, or heavily contaminated, must be replaced. This is called **make-up water**.

The make-up water added to the system may be from a variety of sources: city (municipal) water, well water, or surface water (lakes and rivers). Make-up water is a primary source of boiler water impurity. Depending on the source, the water may have varying amounts of **suspended matter**, **dissolved solids**, and **dissolved gases**. This water is normally treated to reduce its **hardness** (dissolved calcium and magnesium salts), and to remove suspended matter (organic matter, sand, and silt).

Regardless of the treatment method used, impurities still enter boiler water. For example, dissolved calcium and magnesium compounds cause waterside scale formation. External water treatment equipment, such as **ion exchange water softeners**, are often used to convert these calcium and magnesium compounds to sodium compounds. Sodium compounds will not cause waterside scale. However, they are still dissolved solids, and become concentrated as the boiler operates.

Even with external water treatment methods, some scale-forming compounds reach the boiler. These may be from contaminated condensate returns, or from fluid that leaked past the external water treatment equipment. To prevent scale formation in steam boilers, additional internal chemical treatment is required.

Chemicals are added to boiler water to precipitate the scale-forming calcium and magnesium. These precipitates, together with any suspended matter brought in with the make-up water, fall to the base of the shell or drum. Collectively, the precipitated and suspended matter that accumulate in the base of the shell are called **mud**. This is why the lower drum of a watertube boiler is called a mud drum.

The rate of precipitate formation depends on the make-up water quality, and the amount of make-up water used. For example, a boiler system may have very poor make-up water. Consider a system where only 2% of the water required is make-up water. In such a system, impurities in the boiler build up slowly. However, if the make-up water usage increased to 50%, the impurities would build up rapidly. In addition, if the system used poor quality make-up water, the boiler would develop mud and scale, and plug up in a very short amount of time. For this reason, boilers with high make-up requirements must use high quality make-up water.

The rate of precipitate formation also depends on the rate of steam production.

Frequency of Bottom Blowoff

The frequency and duration of blowoff depends on the rate at which precipitates form, and require removal. In other words, blowoff depends on:

- The rate of steam production.
- The type and concentration of impurities in the make-up water.
- The percentage of make-up water added.

The frequency and duration are often recommended by a water treatment practitioner. In addition to the above, the water treatment practitioner will consider the type of chemicals added to the boiler to control scale and sludge deposition, and operational experience.

Bottom blowoff is performed intermittently to remove accumulated sediment at the base of the boiler. Depending on the above factors, bottom blowoff may be performed once a shift, once a day, once a week, or at even longer intervals. The amount of water blown off (the duration of time the valves are left open) also varies. Short, frequent bottom blowoff may be more effective than long, less frequent blowoff. **ASME VII** recommends that in general, bottom blowoff should be performed at least once every 24 hours.

On Track

Hot water heating boilers and hot water power boilers do not require blowoff unless the initial charge of treated water is lost through process, leaks, or other reasons.

Bottom Blowoff Piping System Design

According to **ASME BPVC Sections I and IV**, all boilers (with few exceptions) must be designed with provision for removal of sediment (**PG-59** and **HG-715**).

Shock Service

Blowoff is performed while the boiler is operating and under pressure. Consider what happens when blowoff valves are opened. The pressure of the saturated boiler water drops as it passes through the blowoff valves. Therefore, some of the boiler water flashes into steam. The flashing water and the sudden temperature rise causes:

a) Vibration and shaking in the blowoff line.
b) Reaction forces (axial thrust) on the blowoff pipe.
c) Rapid thermal expansion of the blowoff piping.
d) Thermal shock of the piping and fittings.

For these reasons, **ASME B31.1** specifies that blowoff piping must be designed for **shock service**. This means the blowoff piping must be stronger than the boiler it serves. Provisions for shock service include:

a) A minimum design pressure of the blowoff piping system components that exceeds the MAWP of the boiler.

b) A minimum diameter requirement for the boiler blowoff connections and piping system.

c) A minimum piping schedule number.

d) Restrictions on methods of blowoff system piping assembly.

e) Specific requirements for blowoff valve types and their installation.

Bottom Blowoff System Components

Bottom blowoff systems consist of **blowoff valves**, blowoff piping, and **blowoff vessels**.

Blowoff Valves

Blowoff valves are specially designed for severe service. These valves are made of materials that are strong at high pressures and temperatures. They are resistant to the erosive effects of **cavitation** and entrained solid materials. Blowoff valves must be able to carefully control blowoff water flow, as well as to provide tight shutoff after blowoff is complete.

The rules for blowoff valves and blowoff piping are in **ASME B31.1** and **ASME IV**. The following table summarizes the blowoff valve requirements. (Blowoff piping requirements for power boilers falls under the jurisdiction of **ASME B31.1 Power Piping** code.)

Table 1 – ASME BPVC Bottom Blowoff Requirements

	ASME IV	ASME B31.1 Single Blowoff Line	ASME B31.1 Multiple Blowoff Line
Minimum Piping Diameter	20 mm	25 mm*	25 mm*
Maximum Piping Diameter	50 mm	65 mm	65 mm
Design Pressure	Minimum, the greater of 200 kPa, or the boiler MAWP	MAWP, plus the lesser of 25% of the MAWP or 1550 kPa†	MAWP, plus the lesser of 25% of the MAWP or 1550 kPa†
Number of Valves	One	Two‡	One master valve One additional valve on each individual blowoff line located closest to the boiler
Notes	*Very small capacity boilers may have blowoff connections as small as 15 mm. †In all cases, the design pressure cannot be less than 690 kPa. ‡ Traction engine boilers, electric boilers that hold 380 litres of water or less, and portable boilers require only one slow-opening blowoff valve.		

For power boilers, **ASME B31.1** specifies the style and the construction materials of valves permitted in blowoff service. The construction materials vary with boiler pressure and temperature. For example, for power boilers operating at pressures less than 1725 kPa, bronze, cast iron, and steel body valves can be used. At higher pressures, only steel-bodied valves can be used.

Blowoff valves can be slow opening or quick opening. Slow-opening valves can be hard-seated or seatless designs.

Hard-Seated Slow-Opening Blowoff Valves

According to **ASME B31.1**, at least one boiler blowoff valve must be a slow-opening design. Figure 1 shows a blowoff valve that can be described as:

a) **Hard-Seated**: A **hard-seated valve** is a globe-type valve with a seat and a plug made of hard, wear resistant metal alloy. As a type of globe valve, hard-seated valves are suitable for throttling service.

b) **Y-Type Globe Valve**: A **Y-type valve** has its stem at an angle. This arrangement reduces the pressure drop across the valve, which reduces the effects of flashing and cavitation. As well, sediment and water can freely discharge through the valve, without being obstructed by 90° turns in the flow path of a regular globe valve. Because the flow through this valve is fairly straight, sediment and debris cannot build up under the valve seat to eventually interfere with the closing of the valve.

c) **Slow-Opening**: A **slow-opening valve** requires at least five 360° turns of the operating mechanism to change from fully closed to fully open.

Figure 1 shows an angle blowoff valve, with the inlet below the seat. The lower valve is a welded bonnet Y-type valve.

Figure 1 – Slow-Opening Angle Valve and Y-Type Blowoff Valve

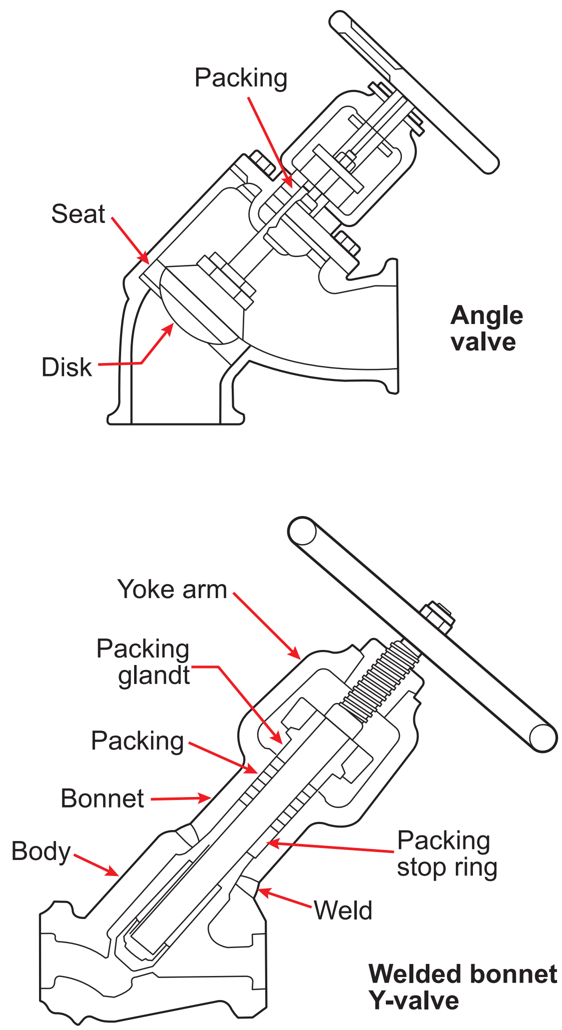
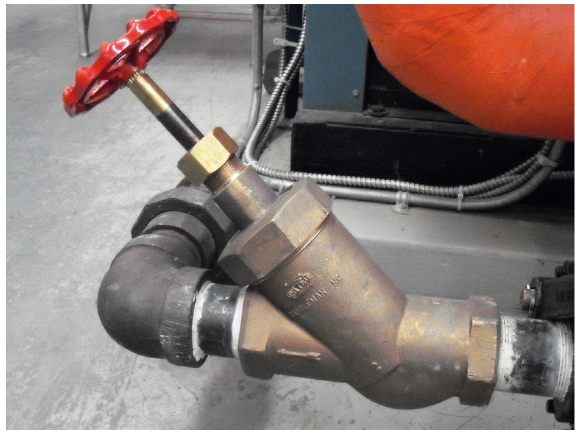
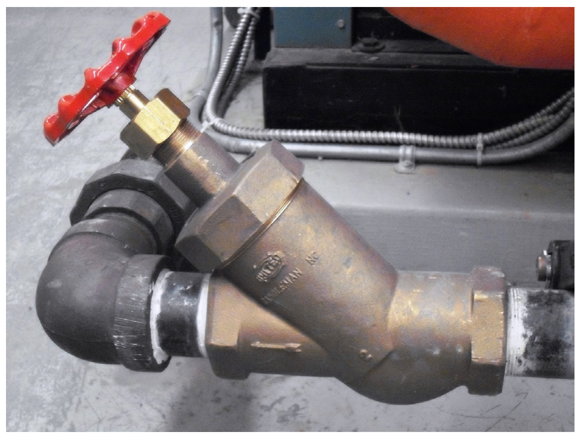


Figure 2 shows a bronze body Y-type globe valve in service. Note this is a **rising stem valve**. The top image shows the valve in the open position. The bottom image shows the valve shut.

Figure 2 – Bronze Body Y-Type Blowoff Valve

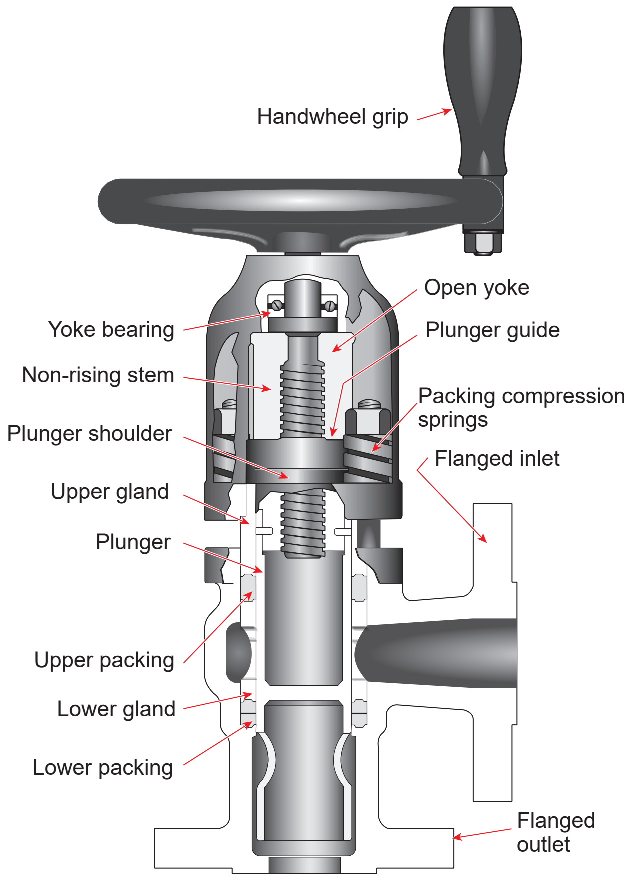




Seatless Slow-Opening Blowoff Valves

Figure 3 shows a slow-opening **seatless valve**. This commonly used valve has a plunger that slides through the valve body as the handle is operated. The lower part of the plunger is hollow, and has a port through which boiler water can flow. When the plunger hole aligns with the valve inlet, boiler water flows through the valve. To stop the flow, the plunger hole is moved downward, so the plunger port and the water inlet are no longer aligned. Note that this valve does not have a plug or a seat.

Figure 3 – Slow-Opening Seatless Blowoff Valve



Quick-Opening Valves

A **quick-opening valve** can be fully opened or shut by moving a lever through a small arc of about 90°. Figure 4 shows a typical design with the major parts identified.

Figure 4 – Quick-Opening Blowoff Valve

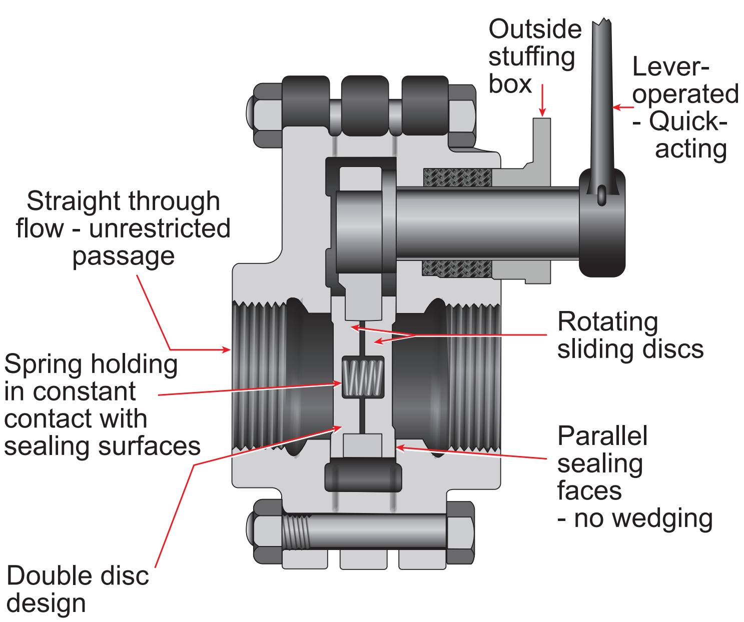
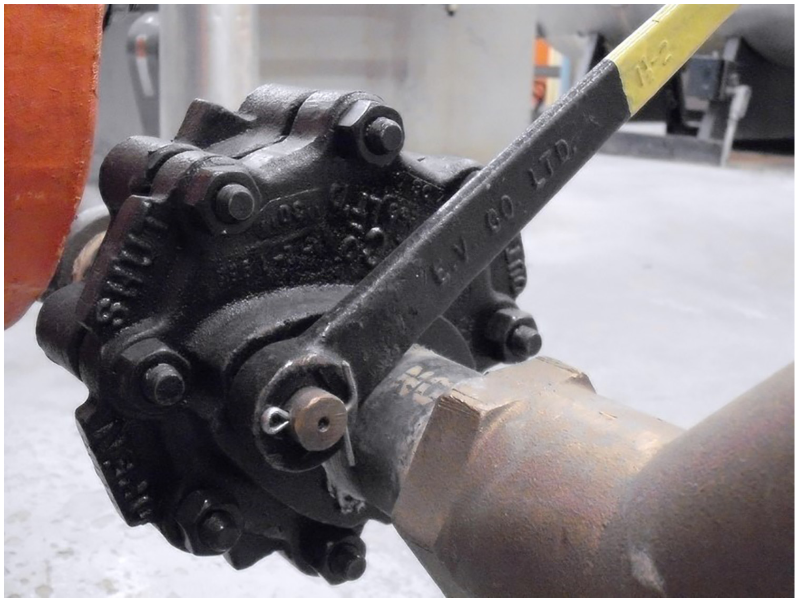


Figure 5 shows a quick-opening valve installed in blowoff service.

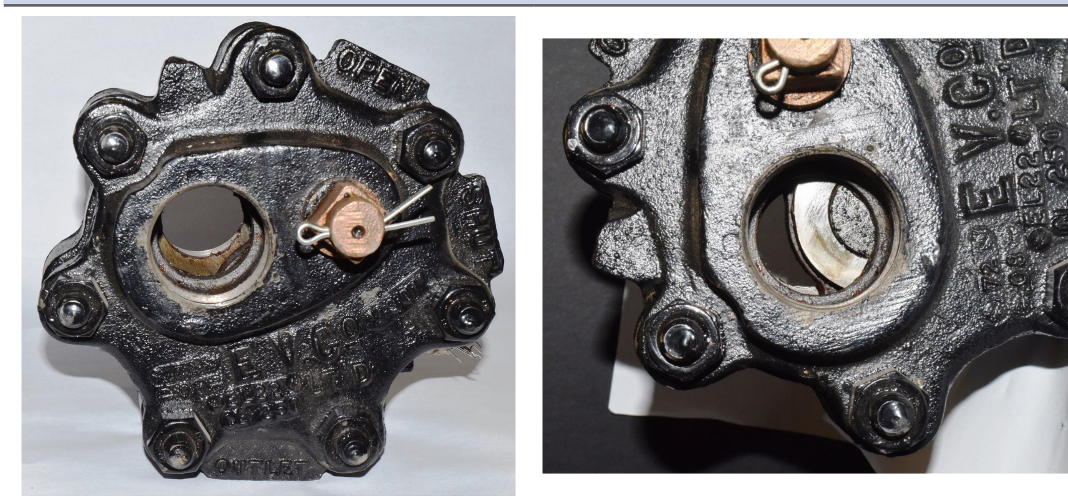
Figure 5 – Quick-Opening Blowoff Valve



It is difficult to tell whether this style of valve is open or shut by looking at the handle position. Therefore, the valve has markings cast into the body that read OPEN and SHUT. The operator can compare the position of the handle with the markings to see if the valve is open.

Figure 6 shows the operation of the valve disc with the handle in the open and 50% open positions.

Figure 6 – Open Blowoff Valve



The quick-opening valve has a polished two-piece sliding disc that mates with the valve seat. A spring between the halves of the disc forces the disc against the seat. This forms a tight seal, and helps prevent leakage. The sliding disc can cut through impurities (such as scale) as the disc closes. If the valve does pass water when closed, re-opening the valve will usually flush out the blockage between the valve disc and the seat. Caution must be taken that the valve does not leak for very long, because this will cause the valve seat and disc to **wire draw**. Then, the valve will not seal properly, and will need to be rebuilt or replaced.

Power boilers may be equipped with one slow-opening valve and one quick-opening valve, or they may be equipped with two slow-opening valves. If there are two slow-opening valves, they may be hard-seated or seatless. The opening and closing sequence of these valves depends on the valve type and arrangement.

Blowoff Piping

In most cases, blowoff piping leads from the discharge of the boiler blowoff valves to a **blowoff tank** or **blowoff separator**. This piping is subject to water flows of short duration, followed by longer cool-off periods. This means the piping will experience rapid changes in temperature when **blowdown** occurs.

Allowance must be made for this piping to expand and contract. If this allowance is not made, the piping and fittings will become stressed due to restricted thermal expansion. Worse yet, the piping could exert force against the boiler mud drum, shell, or header, which would place heavy stresses on boiler parts already working at high pressure and temperature. Therefore, the piping must be anchored in such a way that this type of motion cannot be transmitted back to the boiler. Provision must also be made so the piping can be inspected for leakage.

The **ASME B31.1 Power Piping Code** specifies the materials, pressure ratings, and required sizes for power boiler blowdown piping. It also contains rules for assembling blowoff-piping systems, using welded, flanged, and threaded connections.

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Blowoff Vessel

Blowoff vessels are steel pressure vessels, designed and constructed according to **ASME BPVC Section VIII**. Figure 7 shows a typical blowoff vessel.

When performing a bottom blowoff, hot, pressurized, saturated water flows for short periods of time. Because the water is at its saturation temperature, some of the water immediately flashes to steam downstream of the blowoff valves. The combination of pressure and high temperature would seriously damage sewer piping if the blowoff water entered directly from the boiler. To prevent this from occurring, the blowoff pipes are routed through a blowoff vessel (also called a blowoff tank or blowoff separator) before entering the sewer piping.

The blowoff vessel performs two main functions:

- It depressurizes the blowoff water by venting steam to the atmosphere.
- It cools the remaining blowoff water to a temperature suitable for the sewer system.

The inlet line from the boiler discharges below the blowoff vessel water level, so that incoming hot water mixes with the cooler water. Incoming water also agitates the water in the tank so that sludge is kept dispersed. As new water enters, the tank overflows to the waste drain, carrying the sludge along with the water. The anti-siphon hole prevents the vessel from draining completely. The water that remains in the tank continues to cool off when the blowoff is complete. In this way, the tank contains considerable quantity of cool water for the next boiler blowoff.

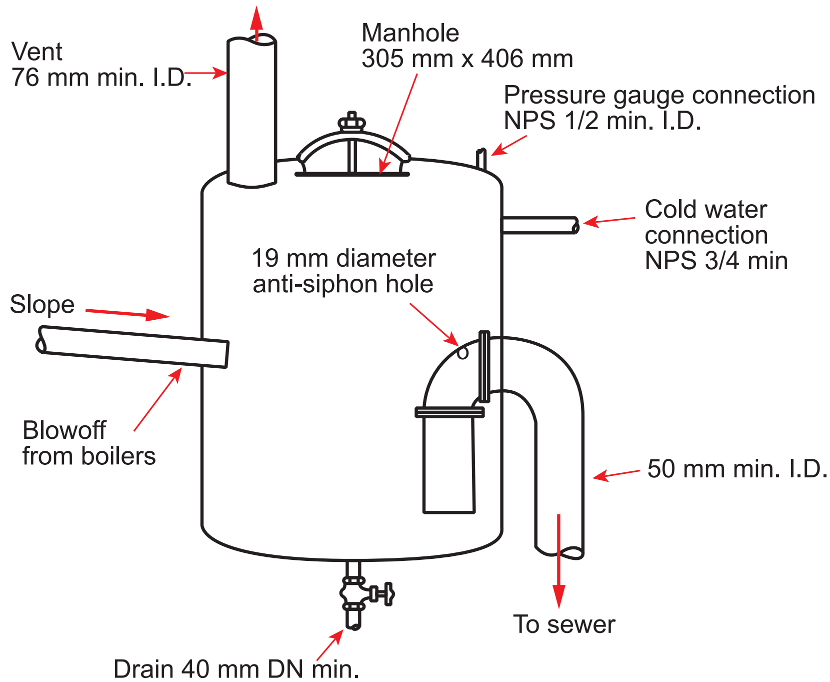
CSA B51 Code, 6.5 requires the installation of a blowoff vessel or other suitable registered device for all boilers operating above 103 kPa, if the vessel discharges into a sewer system. The blowoff vessel is not required for steam heating boilers (operating below 103 kPa gauge), or if the boiler discharges to a separate pond, such as often occurs in large, remote boiler installations.

According to **CSA B51**, the water temperature at the blowoff tank outlet must not exceed 65°C. Some blowoff vessels are equipped with cold water piping connections to help cool the blowoff water. The cooling (or quenching) water flow may be automatic, based on a discharge temperature setpoint. In many situations, quenching water is started manually, before beginning a bottom blowoff.

CSA B51, 7.5 also specifies the required:

- Vessel and piping thicknesses, including corrosion allowances
- Design pressures
- Required internal volume
- Corrosion allowance for thickness
- Inspection and cleaning access

Figure 7 – Blowoff Tank



Bottom Blowoff Procedures

Bottom blowoff (also called **intermittent blowoff**) is performed only as needed. Bottom blowoff should discharge only the amount of water necessary to control sediment accumulation. Inadequate blowoff will allow sediment to accumulate and adhere to heat transfer surfaces and other boiler parts. Excessive blowoff discharges treated water, internal treatment chemicals, and heat from the boiler. This adds to the overall operating cost and the environmental impact of boiler operations.

On Track

Large steam generating units use very high purity make-up water. For this reason, utility boilers do not accumulate much waterside sediment. Therefore, these boilers are blown off infrequently, and only under light loads or when not in operation.

Waterwall header blowoff is never performed when these boilers are in operation. To do so might cause a temporary loss of water circulation, and expose the tubes to failure from overheating.

For large steam generating units, bottom blowoff valves are mostly operated during boiler startup and for draining.

Bottom blowoff is a manual operation. The blowoff valves are connected to the lowest parts of the boiler (at the base of shells, drums, and headers). This is for two reasons:

1. Although small amounts of suspended matter are dispersed throughout the boiler, the greatest point of deposition and accumulation occurs at the bottom of the water space.
2. Bottom blowoff valves are also used to drain the boiler waterside for maintenance and inspection.

Bottom blowoff valves are also used to control boiler water level on initial startup. As the boiler water temperature increases and develops steam bubbles, the water level can increase dramatically. Blowoff valves can be operated to lower the water level during warmup. Bottom blowoff valves can also be used to rapidly lower boiler water in the case of unusually high water level.

Bottom Blowoff Best Practice

CAUTION

Bottom blowoff is hazardous, due to the mechanical forces and the potential for thermal shock. Blowoff piping components weaken over time, and can explode during a blowoff. This can cause serious injury or death.

The following are key considerations when conducting a bottom blowoff.

1. In a multiple boiler plant, the valves and boilers should be visibly numbered or identified, so there is no chance of blowing off the wrong boiler.
2. In a multiple boiler plant, the boilers may share a common blowoff vessel. Ensure that any boilers open for maintenance or inspection are properly locked out and tagged. The blowoff valves must be locked in the shut position, or physically removed, and the blowoff line blanked off. In this way, blowoff water from one boiler cannot enter the open drum of another boiler.
3. During bottom blowoff, unless the drum level can be clearly seen, an assistant should watch the gauge glass. This assistant must be able to warn the operator if the boiler water gets too low.
4. Quenching water must be verified on before beginning the blowoff procedure.
5. Never leave the blowoff valves unattended during a blowoff. Never leave the blowoff valves until both blowoff valves are confirmed shut.
6. Do not perform any other tasks while performing a bottom blowoff.
7. Open the blowoff valves slowly, and in the proper sequence. This will permit the blowoff piping to warm up and expand gradually. As well, this will prevent water hammer.
8. Close the blowoff valves slowly, and in the proper sequence.
9. Only one boiler should be blown down at a time.
10. Perform bottom blowoff when the boiler load is low or moderate. During a blowoff, boiler water circulation is disrupted. There is less circulation disruption at low or moderate firing rates.

Case Study: Near Miss

Dave was Jack's shift charge engineer a few years back. Jack was inside the mud drum of boiler number two. When they did the lockout for boiler number three, they did not disconnect and blank off the blowoff line, even though all three boilers shared the same blowoff tank.

It was a good thing Jack saw Dave walking over to boiler number two. He scrambled out of the mud drum just before Dave opened up the blowoff valves for number two. Jack was furious! He could have died in there!

I knew Jack's story well, but I wasn't thinking of it a few years later when I blew off boiler number three. It happened at the beginning of my set of days. Boiler number two was opened for inspection during my days off. Again, the same dumb mistake was made. Nobody blanked off the blowoff connection to the open boiler.

When I blew off number three, scalding hot water shot out of the mud drum of number two, covering the boiler room floor, and making a big, embarrassing mess. I'm lucky my assistant was on rounds and not inside the drum when that happened.

Blowoff Valve Operation

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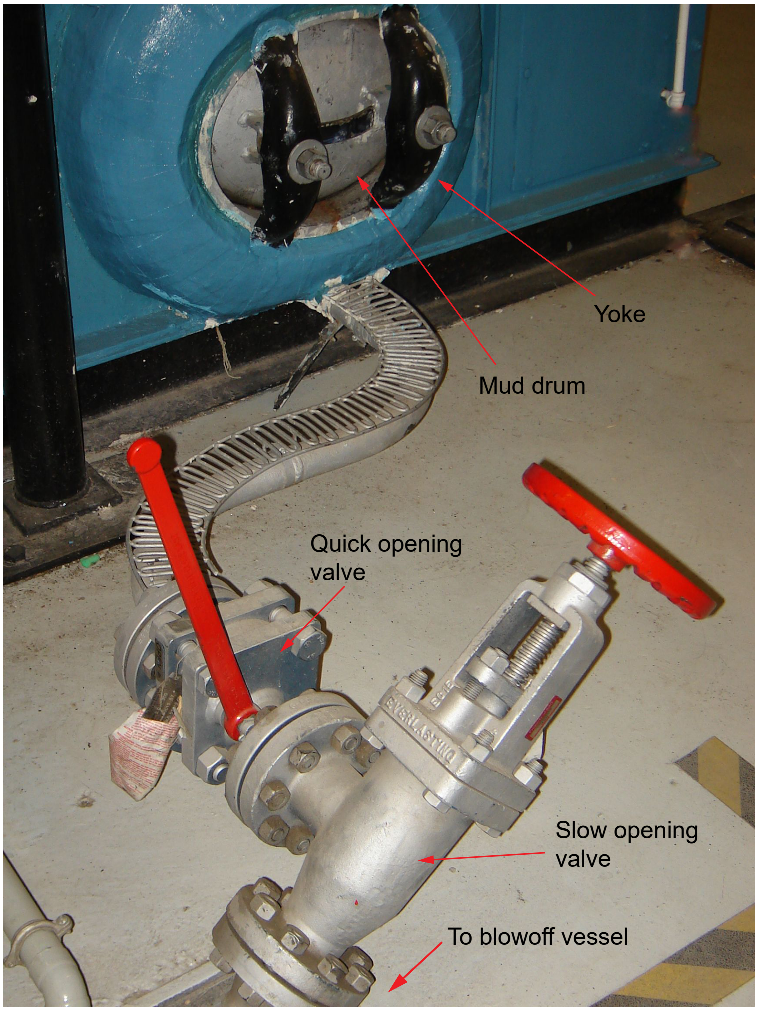
ASME B31.1 (122.1.7) describes various blowoff valve combinations permitted on boilers. The operation of any individual valve should follow the manufacturer's instructions. However, when combined with valves of other types, specific blowoff valve operating sequences must be followed. These sequences are dependent on the valve combination.

In general, the valve closest to the boiler is protected from the erosive action of the boiler water. This valve is not throttled. Instead, it is always opened first and closed last. In this way, the valve closest to the boiler only operates in still (non-flowing) water, and suffers less wear. Throttling is done with the valve furthest from the boiler. This arrangement assures that there will always be a leak-tight shut-off valve adjacent to the boiler.

Combination Quick-Opening and Slow-Opening Valve

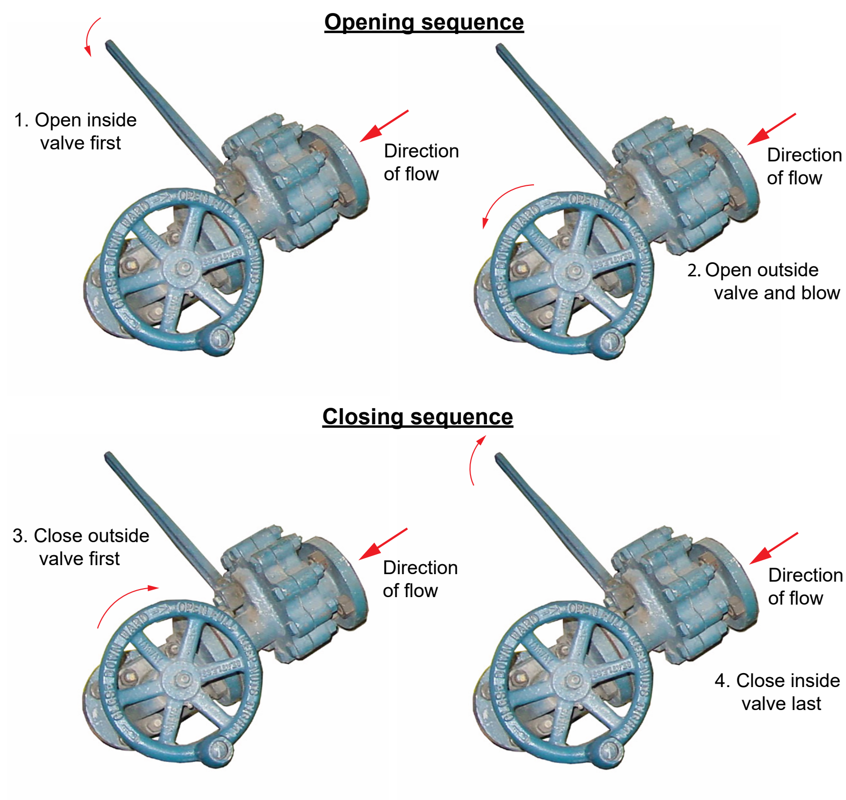
If a quick-opening valve is used with a slow-opening valve, then the quick-opening valve should be installed closer to the boiler. It then acts as a **guard valve** (or **sealing valve**). The slow-opening valve is used for blowing off. Figure 8 shows a typical arrangement.

Figure 8 – Quick and Slow-Opening Blowoff Valve



The guard valve is opened first and closed last. The blowoff valve is opened last and closed first. Figure 9 shows the correct valve sequence for this combination of valves.

Figure 9 – Opening and Closing Sequence for One Slow and One Quick Valve



The fact that the blowoff valve is slow opening reduces the possibility of water hammer, and subsequent damage to pipe and fittings when blowoff begins and ends.

CAUTION

Never pump the handle of the quick-opening valve to blow off the boiler. Such action could cause water hammer, damage to piping and valves, and personal injury.

Two Hard-Seated Slow-Opening Valves

When two hard-seated slow-opening valves are used, the same procedure is used as in a slow-opening and a quick-opening valve. The same sequence must be used to ensure one valve is the guard valve, and the other is the blowing valve.

Two Seatless Slow-Opening Valves

This type of valve uses a cylindrical plunger as the flow control element (see Figure 3). The plunger moves within the valve body, and permits flow only when the plunger port and the inlet port align.

For this type of valve to close, the plunger must descend within the valve body. As the plunger descends, it displaces water from the valve body. If the water in the valve body has nowhere to go, the valve cannot fully shut. If forced to close further, the plunger will attempt to compress the water, resulting in enough force to crack the valve body. It is therefore very important to follow the correct operating sequence for two seatless valves in order to prevent valve damage.

When two seatless valves are used in combination, the valve furthest from the boiler is opened first and closed last. If closed first, water would become trapped between the valves. The unfamiliar operator could then try to force the valve shut with a long handle or a wrench, damaging the valve in the process.

With this combination, the valve closest to the boiler is no longer a guard valve. Therefore, this system of two slow-opening seatless valves may incorporate a third guard valve, located immediately next to the boiler. This valve is usually kept wide open so that it experiences no wear on the valve disk. It is only closed when the boiler is shut down and isolated.

Surface Blowoff Systems

Some boilers have condensate returns that may be contaminated with material that accumulates at the boiler water surface. These boilers may be equipped with surface blowoff systems, used intermittently (or in some cases, continuously) to remove water surface impurities.

Impurities on the boiler water surface can increase surface tension, which disrupts the natural separation of steam from water. These impurities may be oily or greasy materials that lead to carryover, **foaming**, and **priming**. When priming occurs, destructive water hammer can occur.

Surface blowoff systems consist of a perforated pipe installed within the boiler steam drum or shell. The pipe runs the length of the boiler, and is situated about 15 cm below the normal operating water level. This internal pipe connects to an external piping system that leads to a blowoff vessel. An isolation valve is situated adjacent to the boiler, followed by a valve rated for blowoff service. If the surface blowoff is operated continuously, the blowoff valve will be a graduated metering valve.

To perform an intermittent surface blowoff, the boiler must be under pressure. Several short blows may be more effective than longer, single blows. The surface blowoff is operated until the boiling action, observed in the gauge glass, settles out.

Continuous surface blowoffs skim the boiler water continuously. In this case, the opening of the metering valve is adjusted based on tests that determine the presence of surface contaminants.

Objective 2

Describe continuous blowdown, blowdown equipment, and blowdown procedures.

Purpose of Continuous Blowdown

There are numerous compounds dissolved in boiler water. These compounds are not solids or precipitated matter. Rather, this is matter that is in solution with boiler water.

Examples of dissolved solids include various sodium compounds, such as carbonates, bicarbonates, chlorides, phosphates, sulfites, sulfates, and hydroxides. There may also be chelants, amines, organic compounds, molybdates, silica, and iron compounds dissolved in the boiler water.

The compounds listed above may be:

a) Impurities that entered the boiler with the make-up water.

b) Impurities that returned to the boiler dissolved in condensate.

c) Compounds produced by external feedwater treatment.

d) Compounds formed in the boiler drum by chemical reactions between impurities and treatment chemicals.

e) Chemicals fed to the boiler drum to control corrosion and scale deposits.

During operation, the dissolved solids concentrate in the boiler water. These high concentrations carry over with the wet steam produced in the boiler. This dissolved material may deposit in the superheater banks, which impedes heat transfer and leads to superheater failure. A high concentration of dissolved solids can also lead to forms of carryover that are more destructive, such as foaming and priming.

Therefore, it is necessary to control the dissolved solids concentration in boiler water. The only way of reducing this concentration is to remove a portion of highly concentrated water and replace it with water of greater purity. This is done by:

- **Producing high quality feedwater**. Feedwater is made of returns and make-up water. If returns are hard, or contain suspended matter, they can be filtered and softened with condensate polishing equipment. Ultra-pure make-up water can be produced with filtration, **coagulation**, **precipitation softening**, **ion exchange**, and **reverse osmosis** equipment.
- **Draining the appropriate amount of concentrated water from the boiler**. This is done by measuring the solids concentration of the boiler water, and operating a metering valve to maintain the solids concentration at the prescribed level. This process is called **continuous blowdown (CBD)**.

As boiler operating pressures increase, the need for higher quality feedwater and higher steam purity also increase. Higher-pressure boilers generally use sophisticated equipment to produce ultra-pure make-up water. This reduces the need for the addition of internal boiler water treatment chemicals, because no scale-forming compounds should enter the boiler. These water treatment systems are costly to operate and install.

Smaller plants, with lower pressure boilers, have less stringent feedwater quality requirements. These plants use less costly external water treatment equipment that do not produce ultra-pure water. The make-up water is much higher in quality than the boiler water, and can be effectively used to reduce dissolved solids concentrations.

Continuous blowdown is the ongoing removal of dissolved solids from boiler water. This maintains boiler water dissolved solids concentration within prescribed limits. The word "continuous" is used because CBD is performed whenever a steam boiler is in operation. This means that dissolved solids continue to concentrate as long as a boiler produces steam.

Dissolved solids concentration limits may be provided by a boiler manufacturer, or a water treatment specialist. The **American Boiler Manufacturers Association** and the **ASME Research Committee on Steam and Water in Thermal Power Systems** are the sources most often cited for boiler water quality parameters.

Table 2 provides a brief overview of the current ASME recommendations for a number of boiler water parameters for industrial steam boilers operating at different pressures, including dissolved solids. The electrical conductivity of water increases in proportion to its dissolved impurities. Conductivity measurement is often used to determine dissolved solids concentration. The term **specific conductance** on Table 2 is therefore a reference to the **total dissolved solids (TDS)** concentration.

Table 2 – ASME Recommended Limits for Boiler Water Dissolved Solids

	Drum Operating Pressure (kPa)					
Parameter	**0-2070**	**2071-3100**	**3101-4140**	**4141-5170**	**5171-6210**	**6211-6890**
Silica (mg/L SiO_2)	<150	<90	<40	<30	<20	<8
Total alkalinity (mg/L $CaCO_3$)	<350	<300	<250	<200	<150	<100
Specific Conductance (µS/cm)	<3500	<3000	<2500	<2000	<1500	<1000

Source: ASME "Consensus on Operating Practices for the Control of Feedwater and Boiler Water Quality in Modern Industrial Boilers"

Determining the Continuous Blowdown Rate

The continuous blowdown rate depends on the TDS of the boiler water. The TDS depends on the:

- Rate of steam production.
- Type and concentration of impurities in the make-up water.
- Percentage of make-up water added.

Regular water tests must be conducted to determine the boiler water TDS, typically at the beginning of every shift. The continuous blowdown valve is adjusted according to the test results.

The overall blowdown rate is expressed as a percent of the boiler feedwater flow. For example, if a boiler feedwater flow is 5000 kg/h and its blowdown flow is 250 kg/h, its blowdown rate is 5%. For many boilers, the blowdown rate is not metered directly. In this case, the blowdown can be assumed to be the difference between the steam flow and the feedwater flow. Using the previous example, if a boiler produces 4750 kg of steam per hour, and has a feedwater flow of 5000 kg/h, its blowdown rate is 5%.

Self-Test 1

1) A boiler produces 6700 kg of steam per hour. During the same hour, the feedwater flow was 6920 litres. Calculate the blowdown rate.

3.2 % (Ans.)

Continuous Blowdown Piping Systems and Components

According to **ASME B31.1**, blowdown systems are "*primarily operated continuously to control the concentrations of dissolved solids in the boiler water.*" Blowdown piping is considered pressure piping. Like blowoff piping, **B31.1** has specific rules for blowdown system assembly methods, valve ratings, design pressure, pipe material, methods of piping support, and provision of expansion and contraction.

Shock Service

Blowdown piping does not see the same service conditions as blowoff piping. Blowdown piping is normally in service and hot. Blowdown piping is never exposed to intermittent bursts of hot pressurized water like blowoff piping. So, blowdown piping is not in shock service. Therefore, CBD piping is only designed to the boiler MAWP. As well, CBD lines only require a single shut-off valve. This valve is placed as near as possible to the boiler shell or drum, with the CBD valve located downstream. The piping downstream of the CBD valve is also a pressure pipe. It eventually terminates in a blowoff vessel.

ASME B31.1 (122.1.4) states that boilers operating at 690 kPa or less can use non-ferrous blowdown piping material. For pressures higher than 690 kPa, all blowdown piping must be steel, and at least **Schedule 80**.

Internal CBD Collection Pipe

Steam separates from water in the steam drum, at the point of discharge from the risers. Here, at the initial point of separation, dissolved solids concentration is the greatest. In practical terms, this point is about 15 cm below the normal operating water level. An internal continuous blowdown collection pipe is installed in the steam drum or boiler shell at this location, and travels nearly the full length of the boiler. The collection pipe has a series of inlet holes along its length for collecting boiler water.

Valves

ASME B31.1 requires a single shut-off valve (typically a gate valve) in the CBD line. This valve can be used to isolate the boiler when taken out of service, or to shut off the flow of blowdown water if the TDS concentration is low.

The CBD valve is installed downstream of the required isolation valve. CBD valves are usually needle valves or V-notch plug valves, with an external valve position indicator (a vernier scale). On very high-pressure systems, more than one valve may be needed to accurately control the flow, due to the pressure difference between the steam drum and the blowoff tank. Typically, CBD valve adjustments are only a portion of a turn.

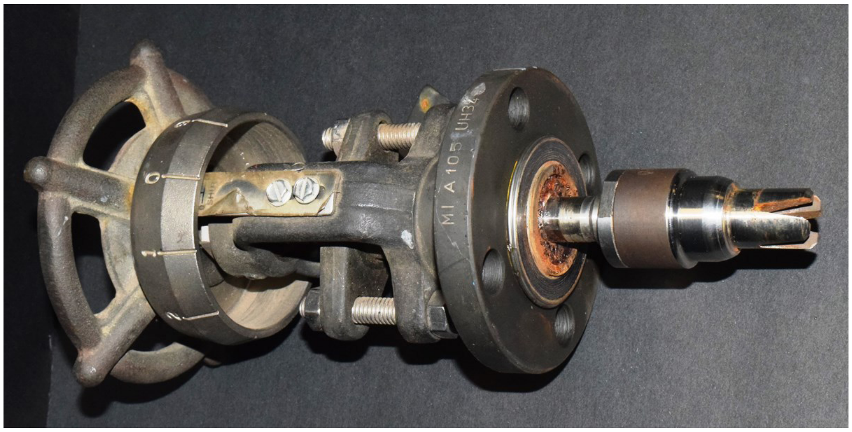
Figure 10(a) shows a CBD valve installed in a power plant. The vernier scale indicates the valve is open 1/20 of a turn. Figure 10(b) shows a close-up of the vernier scale of a valve open 2½ turns.

Figure 10 – Vernier Scale on a Continuous Blowdown Valve

(a) (b)

Figure 11 shows a v-notch style of CBD valve. The plug has notches that assist with fine flow control. They also give the valve more desirable flow characteristics as it opens.

Figure 11 – V-Notch Continuous Blowdown Valve



If the valve is not opened sufficiently, the TDS will rise. At a certain concentration, excessive carryover will occur. Therefore, the TDS must be controlled at a sufficiently low level by adjusting the CBD. On many boilers, the CBD flow is about 1% or more of the overall boiler steam flow rate. However, on boilers using pure treated water, the continuous blowdown valve may be left completely closed under normal operation. If the valve is opened too much, the TDS will be low. This is not a problem in itself, but if the boiler is meant to operate with higher TDS water, expensive treated water will be wasted with no advantage.

Reducing Losses from Continuous Blowdown

Like excessive bottom blowoff, excessive continuous blowdown wastes treated water, chemicals, and heat. For this reason, manual continuous blowdown must be carefully monitored and controlled.

To conserve energy, heat recovery systems can be installed in the blowdown system. To conserve heat energy, treated water, and chemicals, continuous blowdown systems can be fully automated. Some systems combine automated blowdown with blowdown heat recovery. Choosing the appropriate system depends on the required blowdown rate. Recall that blowdown and blowoff requirements all depend on the:

- Rate of steam production.
- Type and concentration of impurities in the make-up water.
- Percentage of make-up water added.

Systems that consume process steam or that have a low percentage of condensate return have greater make-up water requirements. Lower quality make-up water requires a higher continuous blowdown rate.

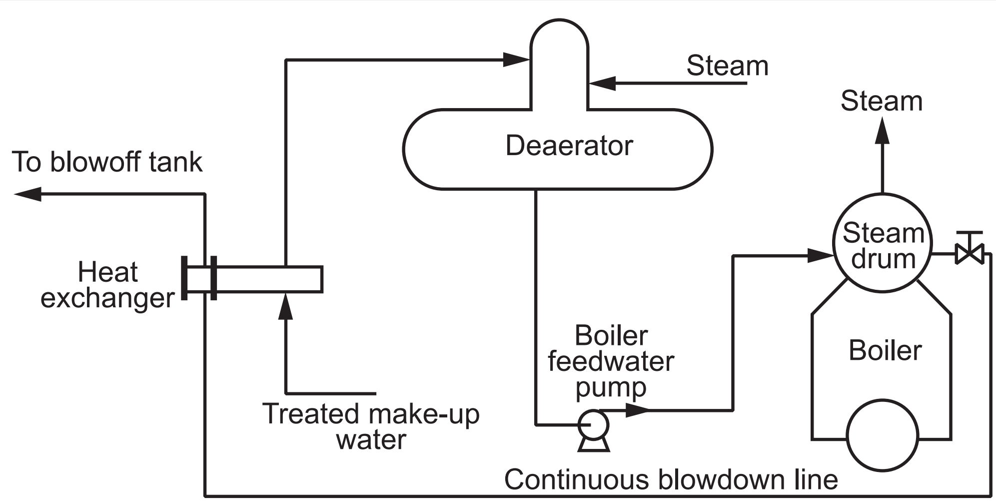
Automated CBD systems can substantially reduce the total amount of blowdown, which reduces both fuel and chemical costs. They also eliminate the wide swings in TDS that occur with manual blowdown control. These systems continuously measure blowdown water conductivity, and compare it to a set point.

To maintain the set point conductivity, a controller either modulates a continuous blowdown control valve or operates a solenoid valve. Less sophisticated automatic systems operate the CBD with timers, or use self-powered thermostatic control valves. Almost all automatic systems have solenoid valves that shut off the CBD flow when the boiler is off.

The heat energy in the CBD water can be used effectively to preheat boiler feedwater, using a heat recovery system. A 5°C increase in feedwater temperature can result in a 1% improvement in efficiency.

Blowdown heat recovery systems can have various components. A common type of heat recovery system is shown in Figure 12.

Figure 12 – Continuous Blowdown System with Heat Recovery



Hot blowdown water flows from the boiler through the continuous blowdown line to the heat exchanger. Inside the exchanger, this water gives up some its heat to the incoming make-up water. The cooled CBD then continues to the blowoff tank, and eventually to the sewer system. The make-up water continues to the deaerator and boiler, along with the heat recovered from the CBD heat exchanger.

Objective 3

Describe the maintenance and repair of blowoff systems.

Case Study:

Alert: To Power Boilers Owners/Operators and Equipment Suppliers

Brass Ball Valve Failure in Power Boiler Service

A threaded NPS 2 forging brass ball valve, with a marked steam working pressure of 150 psig, failed while in service as a high-pressure steam boiler blowoff valve. The boiler was designed to operate at a maximum allowable pressure of 125 psi. The failure occurred when the body of the valve, which was of two-piece construction, came apart, resulting in the release of high temperature water and steam from the boiler. In this incident, a worker in the vicinity of the boiler received serious burns, and later died in hospital.

The preliminary findings of ABSA's investigation into the incident indicate the forging brass material specification of the valve was not permissible for a boiler external piping application.

...The material specification of the valve body design was identified as ASTM B283 C37700, forging brass. While this material is permitted by ASME B31.1 for use in some applications, its use in boiler external piping is specifically prohibited.

Source: Alberta Boilers Safety Association Information Bulletin No. IB04-002

Bottom blowoff is a hazardous procedure. There is potential for thermal shock due to the mechanical forces, and the wear and tear blowoff components receive over time.

Blowoff piping components erode, corrode, weaken, and crack. These components can explode during a blowoff procedure. Therefore, blowoff system inspection must be performed on a regular basis. Some areas that should be examined:

- **Boiler blowoff vessel**: Corrosion at the waterline, erosion of internal wear plate, leaks, scale deposits, and pressure gauge operation.
- **Blowoff valves**: Cracks, packing leaks, wire drawing, corrosion, and erosion.
- **Blowoff piping**: Leaking joints, leaking elbows, damaged or missing pipe supports, wrong materials, uncertified welds, and lack of room for expansion.

If inspection reveals problems, immediate repairs should be made. Below are important guidelines to follow when repairing or maintaining blowoff system components.

Piping System

If leaks or corroded components are observed, it may be necessary to change lengths of piping or piping fittings.

a) **Galvanized piping** must never be used in a blowoff or blowdown system.
b) For boilers operating above 690 kPa, blowoff piping must be at least Schedule 80 steel.
c) Piping bends should use 45° elbows, if possible. Avoid using 90° elbows.
d) Threaded elbows and connectors on blowoff lines must be strong enough for shock service. Malleable iron fittings of Class 150 and Class 300 are prohibited in blowoff use. So are cast iron fittings of Class 125 and Class 250. For Schedule 80 pipe, only Class 2000# (or stronger) fittings can be used.
e) Welded pipe installations and weld repairs must be approved by the jurisdictional inspector prior to commencing the work. Welding must be performed by a certified pressure welder. The completed installation or repair must be inspected by the jurisdictional inspector.

Valves

If a valve is found damaged, it must be repaired or replaced. A common repair is the rebuilding of quick-opening valves. Kits are available to replace packing, springs, and discs. If valve bodies, threaded connectors, or attachment flanges are cracked, the valve MUST be replaced. Valve bodies cannot be safely repaired by brazing or welding.

Always replace a valve with the exact same valve. Do not substitute other materials, service ratings (temperature/pressure/valve class), or manufacturers.

WHEN IN DOUBT, ASK THE INSPECTOR! Consult with the jurisdictional inspector before proceeding with any new installation, repair, or replacement. The inspector will provide guidance on what components and materials are acceptable. By following the advice of the inspector, the work will proceed smoothly, will likely pass final inspection, and will be safe to operate.

Chapter Summary

Carefully controlled boiler blowoff and blowdown are important for safe and efficient boiler operation. A lack of blowoff and blowdown leads to scale and sludge deposits, overheating, failure of heat transfer surfaces, carryover, priming, and water hammer. Excessive blowoff and blowdown can result in the loss of heat, treatment chemicals, and treated water.

Impurities build up in the water of operating steam boilers. Intermittent blowoff discharges solid impurities from the lowest parts of drums, shells, and headers. Blowoff may also be used to discharge impurities from the boiler water surface. Blowdown is a continuous activity for controlling the concentration of dissolved impurities.

The frequency of blowoff, and the blowdown rate, varies from plant to plant, based upon the make-up water purity, the percent make-up water, and the steam production rate. Significant gains in energy and chemical savings can be realized by installing automatic blowdown and heat recovery systems.

Blowoff is a dangerous procedure. Blowoff and blowdown systems need to be carefully inspected and repaired when necessary. The jurisdictional inspector should be consulted before repairs or modifications are made to these systems.

4th Class Edition 3.5 • Part A • Unit 12

CHAPTER 6

Boiler Fireside Cleaning Systems

Learning Outcome

When you complete this chapter you should be able to:

Describe types of boiler fireside cleaning equipment, their purpose, and their operation.

Learning Objectives

Here is what you should be able to do when you complete each objective:

1. *Describe common options for in-service fireside cleaning.*
2. *Describe the construction and operation of retractable soot blowers.*
3. *Describe the construction and operation of stationary soot blowers.*
4. *Describe falling shot cleaning methods.*

Chapter Introduction

In modern steam generators using solid or heavy fuel oils, routine fireside cleaning is essential. It ensures continuous boiler availability, maintains boiler efficiency, and maintains boiler steaming capacity. As well, soot and ash deposits affect steam temperature control in boilers with superheaters and reheaters.

Fireside surfaces tend to become coated with soot and ash, which insulates heat transfer surfaces. This reduces the heat transfer rate through the heating surface and lowers both the efficiency and steaming capacity of the boiler. In addition, these deposits tend to obstruct the passage of the combustion gases through the boiler and so increase the draft power required.

The accumulation of ash can restrict flow and impede heat transfer in other essential heat transfer components of the system, such as superheaters, economizers, or reheaters. A reduction in heat transfer will lower boiler efficiency. Blockage of heat transfer components will restrict gas flow, causing forced boiler outage.

The principal efficiency-related maintenance aspects of heat transfer surfaces are surface cleanliness and good flue gas flow. Flue fireside cleanliness can be maintained with soot blowers, periodic water washing, or mechanical cleaning.

Poor heat transfer performance is indicated by high flue gas temperatures, and a reduction in steam production at a given firing rate. These conditions can be attributed to a gradual buildup of fireside or waterside deposits. Waterside deposits require a review of water treatment procedures and cleaning to remove deposits. Fireside deposits can result from normal ash accumulations on heat transfer surfaces, or may be the result of excessive carbon formation on solid or oil-fired units.

Heavy fireside deposits may also be indicated by increased draft loss through the boiler, economizer, superheater banks, or air heaters.

To permit in-service fireside cleaning, soot blowers are normally installed on:

- Solid fuel-fired units
- Pulverized fuel-fired units
- Heavy oil-fired units
- Waste-fired units

If the soot blowers are operating effectively, there should be a decrease in exit gas temperature after each soot blow. Visual examination of deposit patterns during an outage may disclose the need for increased soot blower pressure, or relocation of soot blowers to provide more effective cleaning.

To remove stubborn deposits, it may be necessary to periodically clean equipment when out-of-service. These surfaces include radiant furnace surfaces, boiler tube banks, economizers, and air heaters.

Objective 1

Describe common options for in-service fireside cleaning.

Fireside Cleaning Events

Two different options need to be considered when preparing to clean fireside heat transfer surfaces. Options include both in-service and out-of-service cleaning. The method used depends on many factors including:

a) The amount and type of fireside deposit.

b) The trends in operating parameters, such as flue gas temperature, pressure differential across heat transfer surfaces, and steam temperature.

c) The length of time until the next planned **outage**.

d) The amount of out-of-service time required, since any cleaning procedure that increases downtime is avoided whenever possible.

e) The associated cleaning costs.

The cleaning procedures used will need to consider whether the outage is:

A major outage – Wash and potential sandblasting. During the annual or semiannual scheduled outages, a thorough cleaning is done of the entire furnace and boiler. The furnace water walls are brushed, scraped, blasted with compressed air, sandblasted, or any combination in order to remove slag and dust. The convection zones may also be washed with high-pressure water until the tubes are cleaned to bare metal. This results in a very low differential pressure across each section, lower flue gas temperatures, improved heat transfer, and greater steam production. A chemical treatment, recommended by a qualified external contractor, may also be utilized at this time. Water should be introduced with great care to ensure that corrosive compounds are not made soluble.

A short outage – Wash only. When there is a forced outage that is expected to last more than 36 to 48 hours, and the maintenance work is not in the convection zones, the downtime is occasionally utilized to do a high-pressure wash of the tubes. Normally the focus is on the generating bank. The quality of the cleaning varies depending on the time available.

Zero outage - In-service cleaning only. The choices for in-service cleaning include the use of heat resistant equipment such as soot blowers, **acoustic horns**, and falling shot.

In-Service Fireside Cleaning

Ash, soot, **slag**, and dust coat and insulate boiler fireside surfaces. These deposits increase in thickness as long as the boiler is in operation. As deposit thickness increases, so does its effect on boiler operation. These effects include the following:

a) Lower boiler efficiency due to reduced heat transfer. This is evident in:
- Reduced steam production
- Higher fireside temperatures
- Higher flue gas temperatures
- Lower boiler efficiency

b) Increased pressure differential through flue gas passes. This requires an increase in draft fan power to maintain a flow of gases into and out of the boiler.

c) Increased fireside corrosion on tubes, especially if moisture is present.

Therefore, it is necessary to remove or reduce these deposits. This will ensure the efficient operation and continuous availability of the boiler.

Continuous in-service cleaning is preferred, because it optimizes a boiler's heat transfer efficiency and availability on an on-going basis.

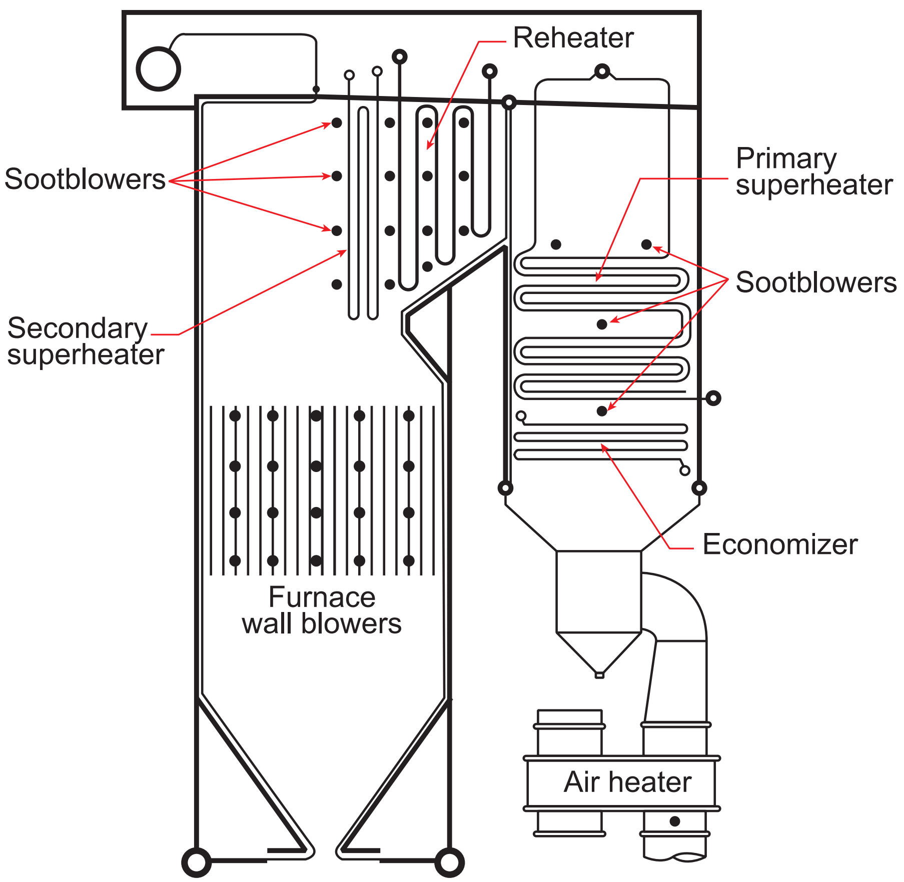
Soot Blowers

Soot blowers are the most common method of in-service fireside cleaning. Soot blowers are steel lances that are inserted into the boiler between rows of tubes. These lances blow high-pressure steam or air, and blast the impurities off the heat transfer surfaces.

Soot Blower Arrangement

Figure 1 shows a typical soot blower arrangement for a large steam-generating unit. Soot blowers (shown as dots) are strategically located in both radiant and convection zones of the furnace. The soot blowers in radiant zones must be designed to withstand more heat than those installed in convection zones.

Figure 1 – Soot Blower Arrangement



Soot blowers for smaller packaged boilers are usually operated manually. In large steam-generating units (like in Figure 1), they are activated automatically, in a set sequence, to clear from the hottest zones first. The soot blowing sequence can be altered to increase the frequency of blowing when differential pressures across a tube bank decrease or high superheater temperatures occur.

Soot Blowing Media: Steam, Air, and Water

The fluid used by soot blowers to remove deposits can be saturated steam, superheated steam, compressed air, or water.

On larger boilers, steam is usually the preferred choice. Dry, high-pressure steam is introduced into the lance through a poppet valve. It is important to drain the condensate from the soot blower lance, and allow the lance to warm up before using it. This will prevent erosion from moisture or condensate that may be in the lance. The steam systems are usually supplied from the boiler through a pressure reducing station. After pressure reduction, a dry superheated steam is available at the soot blower nozzle. Steam has the advantage of being available whenever the boiler is in service.

Air soot blowers are mostly used on small oil or solid fuel-fired boilers. They have the advantage of being compact, simple in construction, and relatively inexpensive. As well, there is no moisture in the air to contribute to fireside corrosion.

Air soot blowers are usually manually operated. Large air compressors must be installed with an integrated piping system around the boiler. When using air as a medium, the soot blowers will be unavailable when the compressor is out of service.

Water is often used when deposits strongly adhere to the heat transfer surfaces. Some small packaged boilers are equipped with water soot blowers, commonly called soot washers.

Acoustic Cleaning Systems

Another option for boiler cleaning is **acoustic cleaning** (or **sonic cleaning**). These systems knock ash off boiler tubes with acoustic energy, without risking damage or fatigue to the units.

This system uses compressed air injected into a wave generator. This produces a series of sound induced pressure fluctuations that emit loud, low-frequency noise. These sound waves propagate inside the boiler in all directions. This adds energy to ash particles, which then loosen from the surfaces, and are carried away by the flue gas stream.

Acoustic cleaning requires less energy than other soot blowing operations. Acoustic cleaning systems operate continuously, in successive short cycles. The cleaning effect is controlled by cycle time. In general, the "on" time is measured in seconds, and the "off" time is measured in minutes.

Acoustic cleaning works especially well on dry and dusty deposits.

Rapping

Horizontal heat transfer paths (i.e. superheaters, heat exchangers) may be cleaned in-service by a mechanical or pneumatic rapping system. This has shown to be especially useful for waste, biomass, and industrial plants.

Rapping systems remove deposits from the heating surfaces without any additional cleaning medium like steam, air, or water. The rapping of the heating tube bundles causes an oscillation. This shakes off the material buildup. Mechanical hammers or pneumatically driven impact cylinders have both been effective methods in this application. Pneumatic rapping systems are recommended for heavy deposits. They enable higher impact energies, and have a better cleaning effect.

Falling Shot

Falling **shot** systems drop small steel balls from the upper boiler sections onto deposits in the lower section. The impact of the shot on the ash removes deposits from the tube surfaces. The dropped balls are subsequently collected at the dust outlet. The balls are returned pneumatically to the upper section until the next drop.

Explosion

Many solid fuel-fired power plants have ongoing issues with slag buildup. Other slag removal methods must be used if conventional in-service methods, such as sootblowing, rapping, or falling shot are insufficient. These include the use of picks, jackhammers, shotguns, water cannons, and CO_2 blasting. Each of these methods is labour intensive, requires substantial downtime, and may not dislodge larger deposits.

Periodically, explosives are used for in-service cleaning. This removes slag deposits from heat transfer surfaces that cannot be dislodged with conventional cleaning techniques. Explosives have been used successfully in waste fired, coal-fired, crude oil-fired, hog-fired, and black liquor-fired boilers.

All operators involved with explosive procedures must be properly trained and certified. Local jurisdiction approval should be obtained before using these processes.

Objective 2

Describe the construction and operation of retractable soot blowers.

Retractable soot blower systems are used for cleaning solid fuel-fired boilers.

Retractable Soot Blowers

Retractable soot blowers are required in the radiant zone of the boiler. Heat transfer surfaces in the radiant zone include the furnace waterwalls, radiant superheaters, and reheaters. In these high temperature zones, the soot blowers retract when not in use. If they remain in place without steam flowing through them, they overheat, sustain damage, and require replacement.

Short Retractable Wall Blower

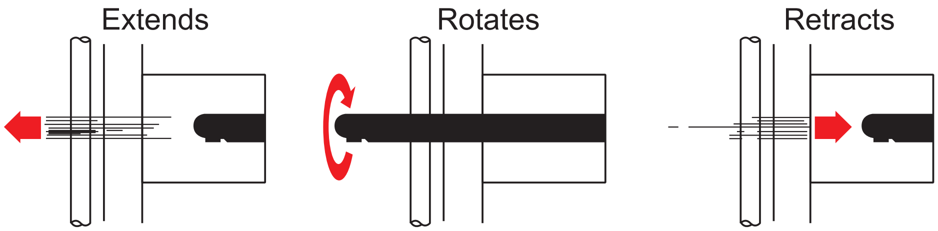
A short single-nozzle retractable wall blower removes waterwall ash deposits (Figure 2). With some fuels, such as coal and municipal waste, ash contained in the fuel may melt in the high temperature found in the radiant zone of the furnace. The ash may then come into contact with the comparatively cool furnace wall tubes. This causes the molten ash to solidify on the tube walls. Additional ash that is created adheres to this original mass. This buildup of ash, referred to as slag, can greatly restrict heat transfer.

The retractable blower has a short-stroke lance that penetrates the furnace waterwall 25 to 50 mm, through special openings. The lance has a jet at its end. This jet is angled back slightly toward the furnace wall, and blasts superheated steam or air against the slag deposits. The lance rotates through 360°and cleans approximately a 1.5 m radius.

Figure 2 – Motor-Driven Retractable Waterwall Soot Blower

Figure 3 illustrates the operation of a retractable waterwall soot blower. The wall blower operates automatically, in sequence with other blowers.

Figure 3 – Retractable Furnace Wall Soot Blower



Long Retractable Soot Blowers

Long retractable soot blowers remove deposits from the convection and radiant heating surfaces, such as those located in the superheater and reheater banks.

These radiant and higher temperature convection zones are cleaned with long, fully retractable lances (Figure 4). The lances penetrate the spaces between major heat absorbing sections.

Figure 4 – Long Retractable Soot Blower

Figure 4 shows a photo of an installed soot blower.

The long retractable soot blower has a drive motor mounted to a carriage. When retracted, the soot blower remains out of the direct heat of the flue gas. Unlike the wall-mounted soot blower, this blower hangs from a carriage that is supported outside the boiler furnace.

The soot blower lance is made of two cylindrical concentric tubes. The inner tube (the internal feed tube) remains stationary, and conveys steam from the poppet valve to the outer tube. The outer tube (the lance) has a nozzle at the end for blowing steam, and extends into the radiant zone. A sealing arrangement prevents steam from escaping between the internal feed tube and the lance. The lance is motor driven in spiral fashion by an electric motor.

When the soot blower drive is energized, the drive motor rotates a pinion gear which moves along a toothed rack. As the pinion rotates, it pushes the soot blower lance into the furnace. At the same time, the drive motor causes the lance to rotate through a chain and sprocket arrangement. The lance moves along guide rails located on each side of the beam, into the boiler. Rollers on the inner support assist in supporting the lance.

A linkage connected to the carriage opens the soot blower poppet valve as the lance begins to move inward. This admits steam to the soot blower feed tube and lance, and begins the cleaning cycle.

The carriage advances the lance tube into the boiler until a forward position limit stop is reached. The carriage then reverses direction and retracts from the boiler. When the carriage begins to retract, it slips back a defined amount. This causes the lance tube to return on a different nozzle path, and a different portion of the tubes are cleaned.

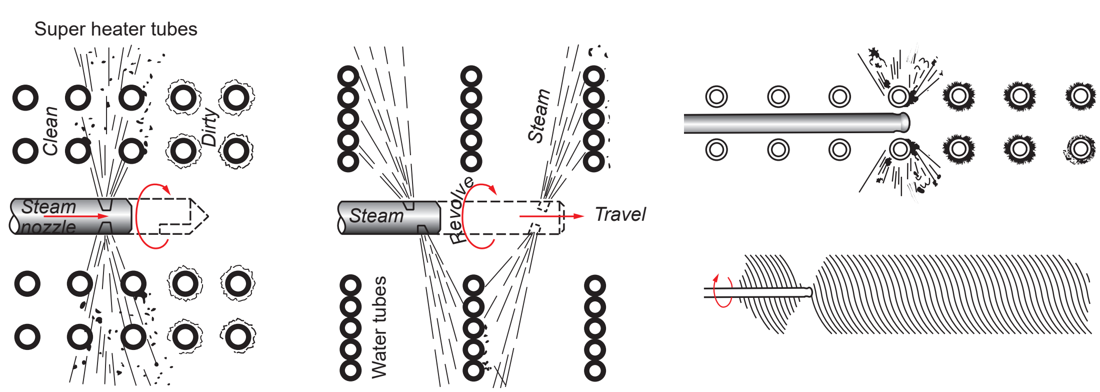
When the lance is nearly fully retracted, it strikes the poppet valve linkage, and closes the valve to shut steam off to the soot blower. Once fully retracted, the carriage strikes a limit switch and shuts down the drive motor. This also initiates the next soot blower, if the system is using an automatic soot blower program.

If a retractable soot blower lance becomes stuck in the boiler furnace, it must be removed manually. An alarm will activate when this occurs. Steam flow to the soot blower must be maintained until it is fully retracted, because the steam is necessary to cool the lance. If the steam is shut off, the lance will overheat and sag, making it impossible to remove without shutting down the boiler.

The lance normally has two opposed nozzles at the tip. The nozzles emit a jet of superheated steam or compressed air perpendicular to the lance, as illustrated in Figure 5.

While the lance traverses the boiler, it rotates. This forms a helical blowing pattern which effectively cleans the tubes and spaces between tubes in a superheater, reheater, or economizer bank of tubes.

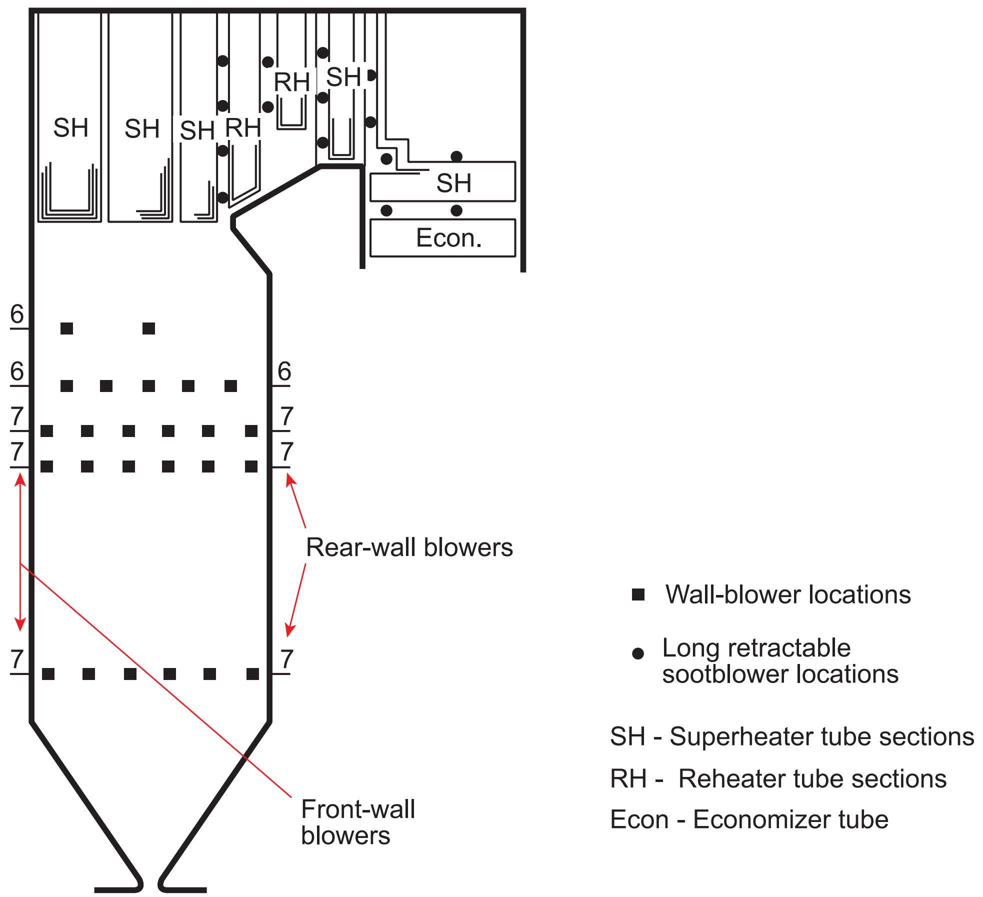
Figure 5 – Long Retractable Soot Blower Cleaning Patterns



It is important that soot blowers be adjusted so that they do not impinge directly upon tubes. If they do, the tubes will rapidly erode. Erosion occurs more rapidly if the blowing medium contains moisture. Therefore, if air is used, it must be dry. If steam is used, it must be dry or preferably superheated.

Figure 6 illustrates a typical solid fuel steam-generating unit. It shows the furnace wall and long retractable soot blower locations.

Figure 6 – Soot Blower Locations for a Solid Fuel Steam-Generating Unit



Objective 3

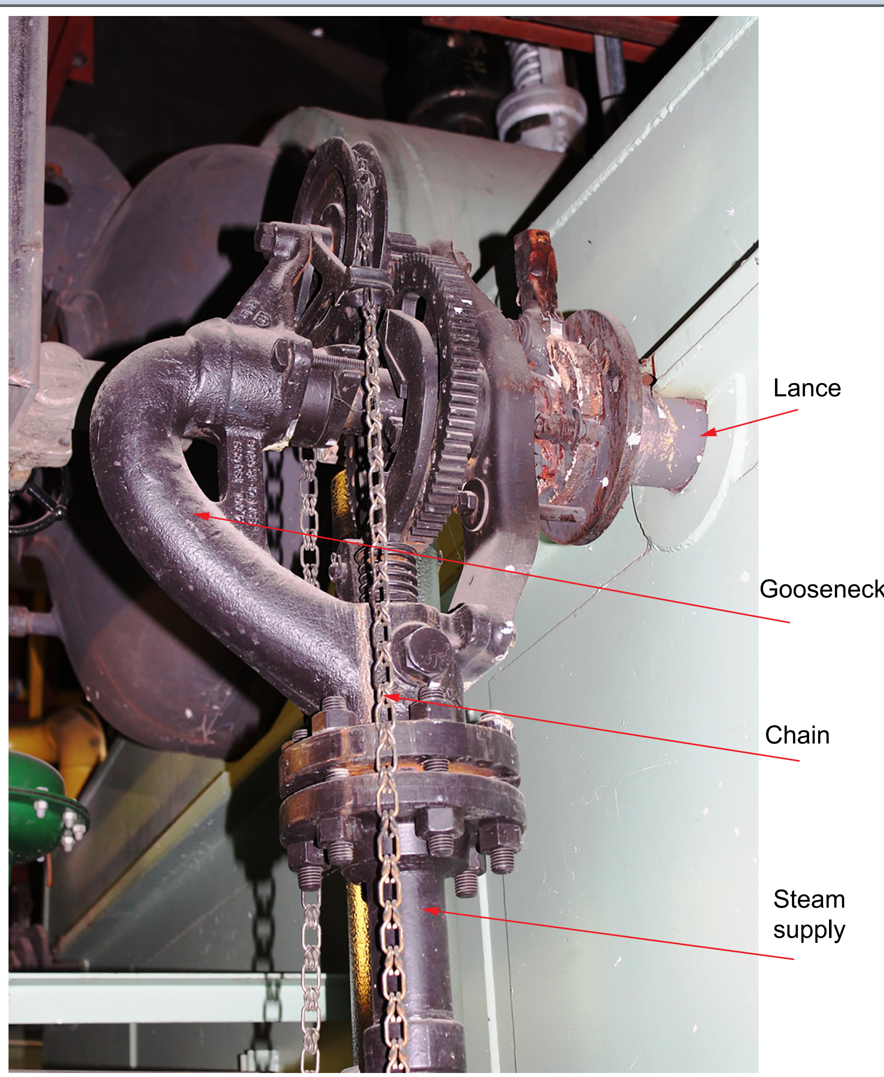
Describe the construction and operation of stationary soot blowers.

Stationary Soot Blowers

Stationary non-retractable soot blowers are used in lower temperature zones (convection zones), such as the economizer, generating bank, and air heaters. This is because the lower temperatures in these zones will not damage the soot blower lance.

Stationary soot blowers, like that shown in Figure 7, are used in the convection tube banks and economizer sections of watertube boilers. Where a number of soot blower units are installed, their use is normally sequenced, starting at the combustion chamber through to the economizer. This allows the ash and soot to be moved to a specific point in the boiler for removal.

Figure 7 – Stationary Soot Blower

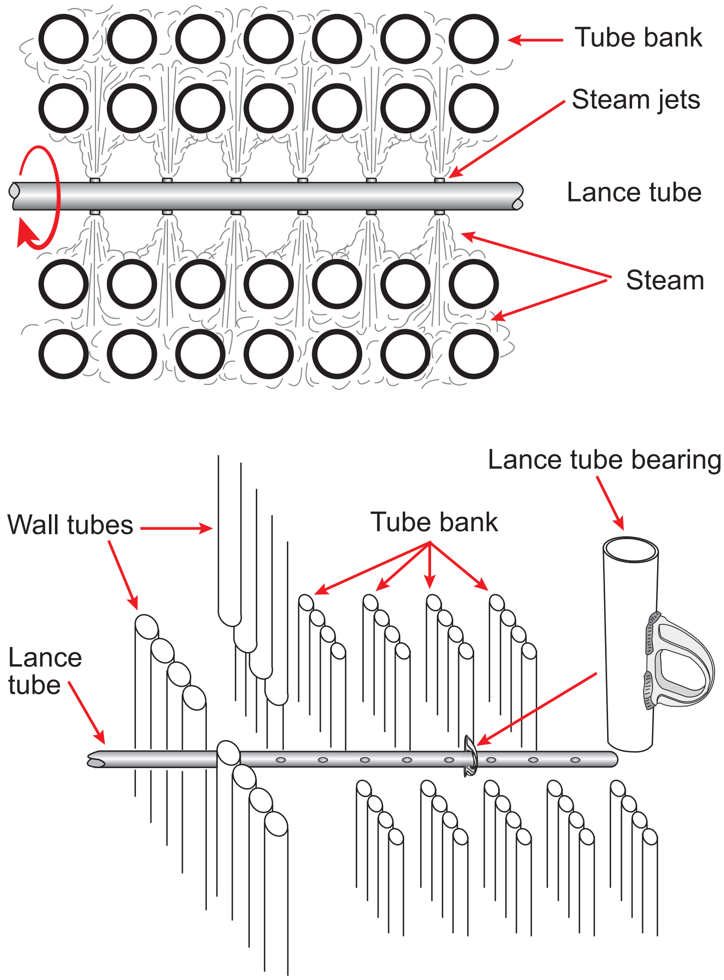


With stationary soot blowers, the lance tube is not retractable; however, it is free to rotate. The lance is held in place with bearings. The bearings are clamped or welded to the watertubes. The lance has holes that blast jets of steam between the rows of tubes, keeping the flue gas passages clear. The pressure at each steam jet must be strong enough to clean the flue gas passages. This requires a properly sized steam supply, and adequate steam pressure.

This type of soot blower can be operated manually with a chain, or with a crank handle at the back of the blower. It can also be equipped with a motor and operated automatically with a control system. Figure 7 shows a typical stationary soot blower inserted into a packaged boiler. Note the chains and reduction gear mechanism used for rotating the lance.

Figure 8 shows the blowing pattern of a multi-nozzle stationary soot blower. It is used where there is not enough space for the single-nozzle type, and where the flue gas temperature is sufficiently low to allow the nozzles or elements to remain permanently in the gases. By rotating, the lance cleans substantially more area than a non-rotating lance.

Figure 8 – Multi-Nozzle Stationary Soot Blower Pattern



Air Heater Soot Blowers

Air heater soot blowers are of a different design and operation. They consist of a series of flat stationary nozzles, situated over the top of the heat exchange surface. These nozzles blow high-pressure steam down onto the surfaces. Ash is blown free, and falls from the tubes into a dust collection hopper below. Some finer ash particles are carried in the flue gas stream, where they are separated by using mechanical means, electrostatic precipitators, or both.

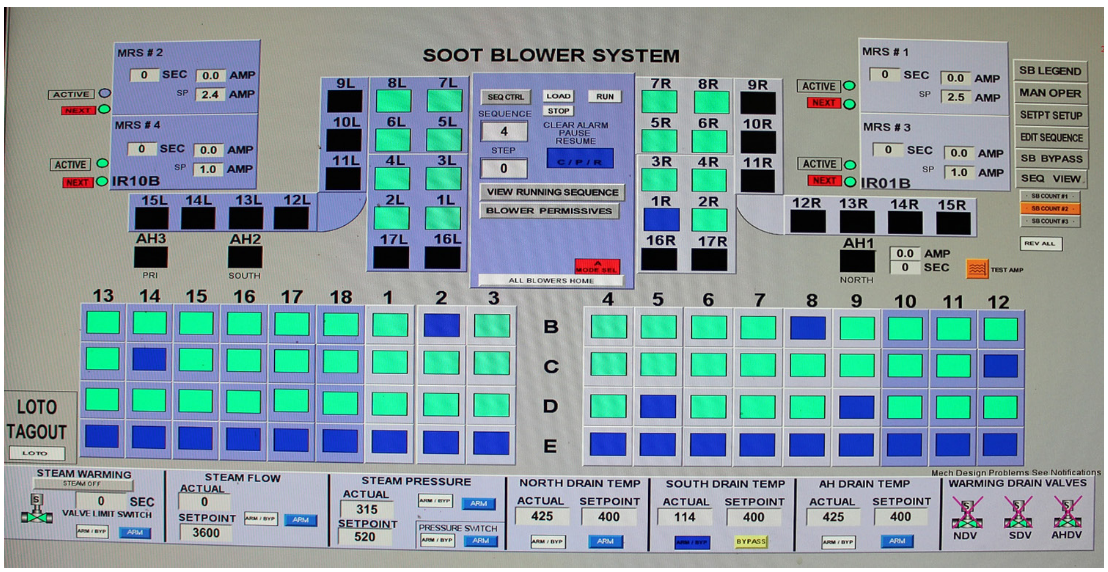
Soot Blower Operation

According to **ASME BPVC Section VII**, during soot blowing periods, the boiler should be operating at a minimum 50 percent load to ensure stable combustion. Furnace pressure should be below atmospheric, to prevent blowback through inspection doors and other openings.

On smaller packaged and field-assembled boilers, the operation and sequencing of soot blowers is done manually. For large boilers with multiple soot blowers, the correct soot blowing sequence and timing is performed under automatic control.

Figure 9 shows the control screen for soot blower sequencing and operation. This screen tells the operator which blower is in operation, and which blower is next in the sequence. The operator can bypass soot blowers that are out of service, or change the soot blower sequence. Operators can conduct full blows, or partial blows, based on certain operating criteria (such as draft conditions and temperatures). The system also alerts the operators of soot blowers that may be stuck inside the furnace.

Figure 9 – Control Screen for Automatic Soot Blower Operation



Objective 4

Describe falling shot cleaning methods.

Falling Shot Cleaning

Falling shot cleaning is a method for removing soot and ash deposits from economizer, tubular air heater, and superheater tubes. Its use is generally restricted to large watertube boilers with the superheater, economizer, and air heater zones installed directly above each other. The system is fully automatic, and can be continuous or intermittent in operation.

Iron shot or pellets, 6 mm in diameter, fall by gravity onto the surface of the tubes and ricochet from one tube to another, thereby dislodging deposits. A hopper at the bottom of the boiler section collects the shot. The shot is then returned pneumatically to a distributing chamber at the top of the section for recycling.

Most of the ash removed by the shot is carried away in the flue gas stream. Any large particles fall with the shot into the collecting hopper. These ash particles are recirculated with the shot until they are broken up into fine particles, and carried away by the flue gas.

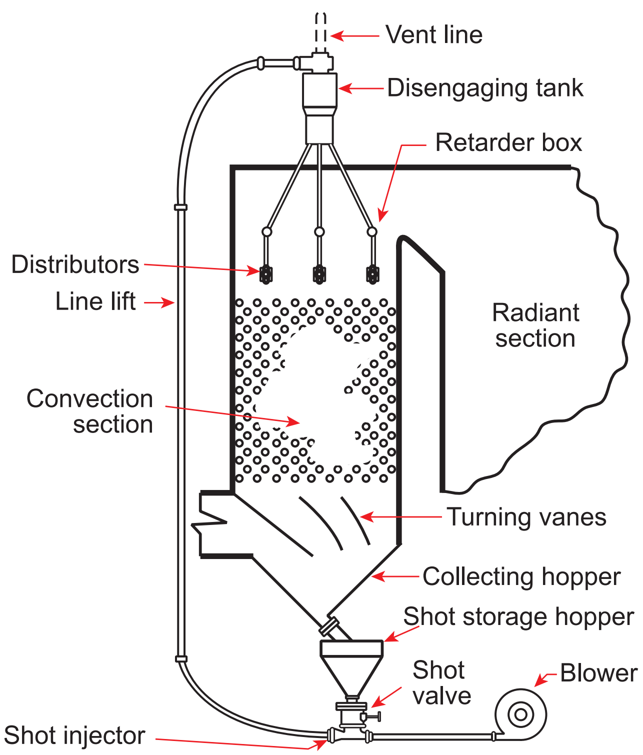
Advantages of this method of cleaning the surface of boiler tubes include:

a) A supply of air or steam for the operation of soot blowers is not required. However, air is required for the pneumatic conveying system to return the shot to the top distributing chamber.

b) In small plants, the turbine steam supply is not affected by the steam consumption of the soot blowers.

Figure 10 shows an arrangement for shot cleaning.

Figure 10 – Shot Cleaning



Chapter Summary

Steam generators, especially those burning solid fuels, create significant amounts of ash. For example, a single coal-fired unit may produce 15 tonnes of ash per hour. Much ash carries away with the flue gas stream, and it is removed mechanically or with electrostatic precipitators.

The remaining ash accumulates on the boiler fireside. This ash must be removed from the boiler, or it will negatively affect boiler efficiency and steam production. If its flue passages become plugged with ash, the accumulation can force a boiler offline. Fireside cleaning is therefore essential to ensuring unit availability and maximum boiler efficiency.

This chapter discussed the following fireside cleaning methods:

a) In-Service Methods
  i. Soot blowers
    - Retractable
    - Non-Retractable
  ii. Sonic Horns
  iii. Rapping
  iv. Falling Shot
  v. Explosions

b) Out-of-Service Methods
  i. Hand Lances
  ii. Scraping
  iii. Sand Blasting
  iv. Chemical Cleaning

Power Engineers are responsible for the safe and efficient operation of the plant systems under their control. Fireside cleaning is an important aspect of this responsibility, regardless of the size and type plant under their control.

Unit Summary

This unit addressed the different types of systems designed to ensure successful operation of boilers. Combustion, fuel, draft, feedwater, blowoff, blowdown, and soot blowing systems are essential for maintaining efficient and safe heat transfer.

This unit emphasized two major operations in a plant's thermal processes:

1. The production of heat, through the interaction of different fuels, fuel firing systems, and combustion air systems.
2. The production of heat transfer fluid (steam or water). This included treating makeup water, recovering condensate, maintaining feedwater flow, controlling the waterside solids concentration, and maintaining fireside cleanliness.

A self-assessment tool is available on MyPower LMS. Login using the unique user ID and password found on the inside front cover of Unit 1.

Notes

Notes

Notes

UNIT A-12

Knowledge Exercises and Unit Glossary

Knowledge Exercises – Chapter 1

Name: ______________________________ Date: ________________________________

Instructor: ___________________________ Course: ______________________________

Objective 1

1. List three combustible elements found in boiler fuels, and identify the compounds they produce when burned with oxygen.

2. What are the potential sources for water in a fuel like coal?

3. Why is carbon monoxide identified as a product of incomplete combustion?

4. Why is excess air supplied in the combustion process?

5. Why is nitrogen considered undesirable in the combustion process?

6. Identify four negative effects of incomplete combustion.

Chapter 1 (Cont.)

Objective 2

7. What does a proximate analysis measure?

8. What does an ultimate analysis measure?

9. How does the 2015 Paris Accord affect the use of boiler fuels?

10. What is hog fuel?

11. Identify the two main types of facilities utilizing MSW.

12. Of the commercial grades of fuel oil covered, which is the lightest? Why?

13. What are the main hydrocarbon components of natural gas?

14. What are the advantages of liquefying petroleum gases?

Chapter 1 (Cont.)

Objective 3

15. What is refractory?

16. Where is refractory used in a boiler?

17. Why has the use of refractory in boilers been reduced?

Knowledge Exercises – Chapter 2

Name: ______________________________ Date: ________________________________

Instructor: ___________________________ Course: ______________________________

Objective 1

1. In what form is coal burned? List two.

2. How is coal transported to the end user?

3. How is tramp metal removed from solid fuels?

4. What are the normal sources for biofuel?

5. How is the fuel burned in a mass burning incinerator different from that burned in an RDF incinerator?

Objective 2

6. In an underfeed stoker, what is a ram used for?

7. What are other names for a chain grate stoker?

Chapter 2 (Cont.)

8. What are the advantages of a cyclone furnace?

9. What are the “bubbles” in a bubbling FBC furnace?

10. In a circulating fluidized bed, why are bed materials recirculated?

11. What advantage does an FBC unit have in meeting NO_X emission requirements?

Objective 3

12. Why is an odourant added to natural gas?

13. Why are heavier petroleum gases liquefied?

14. What are several disadvantages of biogas production?

15. What are the principal gases in a biogas mixture?

Chapter 2 (Cont.)

Objective 4

16. What differentiates a premix burner from an after mix burner?

17. Differentiate between a ring type burner and a multi-spud burner.

18. Identify several advantages in using a refractory burner.

Objective 5

19. What are the guidelines to consider before placing an oil storage tank on a plant site?

20. Why does an oil storage tank on a plant site have a return line?

21. What is the recommended capacity of a safety berm containing one oil storage tank?

Objective 6

22. Why are there no atomizing burners for gaseous fuels?

Chapter 2 (Cont.)

23. When would steam atomization be used instead of air atomization?

24. Compare how constant capacity and modulating pressure burners react to changes in heat demand.

25. How does a rotary cup burner achieve mixing of air and fuel?

26. When are two-stage fuel oil pumps preferred over single-stage pumps?

27. What is puff back in a furnace?

28. Why is a relief valve placed in the discharge line of a fuel oil pump?

29. Modulating burners always start on ____________ fire.

Chapter 2 (Cont.)

Objective 7

30. What flue gas components are typically measured by a CEMS?

31. What is the boiler efficiency if a light fuel oil produces a CO_2 measurement of 8.4% at a net stack temperature of 260°C?

Knowledge Exercises – Chapter 3

Name: ______________________ Date: ______________________

Instructor: ______________________ Course: ______________________

Objective 1

1. In a stoker-fired boiler, ________________ air is known as underfire air. Overfire air is known as ________________ air.

2. Explain why some burners do not complete the combustion process in a single step.

Objective 2

3. Explain the factors that affect natural draft.

a)

b)

c)

Chapter 3 (Cont.)

4. Describe the construction of a factory-built chimney system used for boilers.

Objective 3

5. List the three mechanical draft systems.

6. Why are ID fans larger than FD fans?

7. Why are louvres installed between windboxes and burners?

Chapter 3 (Cont.)

8. Which three draft systems create negative furnace pressure?

9. Identify seven advantages of mechanical draft systems over natural draft systems.

a)

b)

c)

d)

e)

f)

g)

Objective 4

10. State three methods for controlling draft fan capacity, when the fan is driven by a constant speed motor.

Chapter 3 (Cont.)

11. An induced draft fan operates to maintain a constant ____________________ ______________________ setpoint.

Objective 5

12. A packaged boiler has a positive furnace pressure of 20 mm of water. What is the windbox pressure in Pa?

____

____

13. Why are boiler room doors and windows not adequate to meet combustion air requirements?

____

____

14. The CSA B___________ code is used to determine combustion air requirements for natural gas and propane fired boilers. The CSA B___________ code is used to determine combustion air requirements for oil fired boilers.

Knowledge Exercises – Chapter 4

Name: ______________________________ Date: ________________________________

Instructor: ___________________________ Course: ______________________________

Objective 1

1. The treatment of make-up water will be determined by the:

2. In Figure 3, other than for driving machinery, what is the purpose of the non-condensing turbine?

3. List three economic reasons for recovering and reusing condensate.

Objective 2

4. Why must the design pressure of feedwater piping systems exceed the MAWP of the boiler?

Chapter 4 (Cont.)

5. If the MAWP of a boiler is 2500 kPa, what is the required pressure rating for its feedwater check valve?

6. From ASME B31.1, 122.1.7, identify an important difference between single and multiple boilers, fed from a single feedwater source.

7. Identify the actions that occur within a thermo-hydraulic feedwater regulator if the boiler water rises.

Objective 3

8. A single-element two-position feedwater control can also be described as ________________ ________________ or _______________ ______________ control.

9. What does PID control mean?

Chapter 4 (Cont.)

10. Identify the ideal system application for single-element feedwater control, and explain why.

11. How does a two-element feedwater control overcome the challenges of swell and shrinkage?

Objective 4

12. Identify a critical difference between code requirements for continuously and intermittently attended steam boilers according to CSA B51 Code 6.3.2.

13. Why would it be critical for operating efficiency and safety for a Power Engineer to always be involved in low water occurrences under CSD-1?

14. What differentiates float controllers from combined feeders/cut-offs?

15. Venting reduces the production of carbonic acid in the condensate receiver. Why would Carbonic Acid be a problem in the condensate system?

Chapter 4 (Cont.)

Objective 5

16. What is the typical level above which make-up water is not introduced into a condensate receiver?

17. Why is it more appropriate to have the level controller in a condensate receiver situated outside the tank?

Objective 6

18. What common elements of low-pressure steam plants are not used in high-pressure plants?

19. High-pressure steam plants ____________________ condensate receivers and pumped returns.

20. What required ancillary equipment is attached to a deaerator?

21. Why do high-pressure boilers have redundant feedwater pumps?

Knowledge Exercises – Chapter 5

Name: ______________________ Date: ______________________

Instructor: ______________________ Course: ______________________

Objective 1

1. With regard to boiler water, what is mud, and how does it form?

2. What determines the frequency and duration of boiler blowoff?

3. Why must high-pressure boiler blowoff piping be designed for shock service?

Chapter 5 (Cont.)

4. The ASME ________________________________ code covers blowdown and blowoff piping requirements for power boilers.

5. What is a slow-opening valve?

6. Sketch a boiler blowoff tank, and describe how it works.

Chapter 5 (Cont.)

7. Bottom blowoff should be performed when the boiler is operating at a ___________ load.

8. Describe the opening and closing sequence of a quick and slow-opening blowoff valve arrangement.

9. With reference to the boiler water level, where is the internal surface blowoff pipe located?

Objective 2

10. What is the only way to reduce dissolved solids concentration in a steam boiler?

11. A boiler operates at 2050 kPa. A water sample shows the specific conductance of the boiler water to be 1500 μS/cm. Should the CBD valve be adjusted? Why or why not?

12. A boiler produces 3800 kg of steam per hour. The feedwater supply is 1.1 litres per second. What is the blowdown rate?

Chapter 5 (Cont.)

Objective 3

13. A boiler operates at 1050 kPa. What type of pipe and pipe fitting shall not be used for its blowoff system?

14. Describe the regular inspections that must be made to a high-pressure steam boiler blowoff system.

Knowledge Exercises – Chapter 6

Name: ______________________ Date: ______________________

Instructor: ______________________ Course: ______________________

Objective 1

1. What are the two main options for boiler fireside cleaning?

2. Deposits on boiler tubes have high insulating value. Why is this a concern?

3. What fluids do soot blowers use to remove deposits?

4. What is the main advantage of using an acoustic cleaning system for boiler tubes?

Objective 2

5. What is the radiant zone of the boiler?

6. Why are retractable soot blowers used to remove ash from radiant superheater tubes?

Chapter 6 (Cont.)

Objective 3

7. What is the convection zone of the boiler?

8. Why are stationary soot blowers sequenced? How does a typical sequence proceed?

9. How are stationary soot blowers rotated?

Objective 4

10. When is falling shot cleaning considered as an option for removing fireside deposits?

11. How are fireside deposits removed from the boiler when falling shot cleaning is used?

12. What are several advantages of falling shot cleaning?

Unit A-12 Glossary

Term	Definition
2015 Paris accord	A United Nations agreement, ratified by over 150 countries, that recognizes a need to eliminate coal-fired power plants.
3 Ts	Time, temperature, and turbulence.
Acoustic cleaning	A boiler fireside cleaning method that uses horns to create sound waves that dislodge ash or slag from heat transfer surfaces.
Acoustic horns	Loud sound generators used in acoustic cleaning systems.
AFBC	See *atmospheric fluidized bed combustion* (AFBC).
After mix burner	A burner designed to burn gaseous fuels, where the mixing of fuel and air occurs as fuel enters the combustion chamber.
Air jet overfeed stoker	An overfeed stoker that uses primary air to propel fuel particles through a furnace toward a fuel bed.
Air register	A damper with adjustable openings, through which combustion air is fed and controlled.
Anaerobic	Occurring in an environment that has no oxygen.
ARC valve	An Automatic Recirculation Valve (ARC Valve).
Ash	The non-combustible product of combustion left from the burning of solid fuel.
Ash clinker	A mass of partially melted ash remaining from the combustion of solid fuels.
Ash fusion temperature	The temperature at which ash begins to melt, deform, and turn sticky.
Atmospheric burner	A device for burning gaseous fuels, where combustion air is delivered to the burner at atmospheric pressure, with no additional mechanical means.
Atmospheric fluidized bed combustion (AFBC)	A form of fluidized bed combustion, wherein the furnace pressure is at or near atmospheric.
Atomization	The process of changing a liquid to minute particles or a fine spray.
Automatic recirculation valve (ARC valve)	A device installed to protect a boiler feedwater pump from damage. It automatically diverts a portion of the feedwater to a deaerator. This maintains a minimum rate of water flow through the pump.
Bagasse	Pulpy, fibrous waste product that remains after sugarcane is crushed to extract its juice.
Balanced draft	The maintenance of a fixed value of draft in a furnace at all combustion rates, by control of incoming air and outgoing products of combustion.
Biogas	A gaseous fuel primarily composed of methane, which is created through anaerobic biological fermentation of organic waste matter.
Biomass	A fuel made of organic material, usually plant based.
Blowdown	With regard to boiler waterside operations, the continuous removal of a portion of boiler water for the purpose of reducing dissolved solids concentration.
Blowoff	With regard to boiler waterside operations, the intermittent removal of a portion of boiler water to discharge sludge.
Blowoff separator	A vented and drained container equipped with internal baffles, or an apparatus for the purpose of separating moisture from flash steam as it passes through the vessel.

Term	Definition
Blowoff tank	A vented and drained pressure vessel into which water is discharged above atmospheric pressure from a boiler blowoff line.
Blowoff valve	A specially designed, manually operated valve connected to a boiler for the intermittent discharge of boiler sediment, for lowering a boiler's water level, or for draining a boiler.
Blowoff vessel	A pressure vessel that intercepts, cools, and depressurizes boiler blowoff water, in order to protect municipal sewer systems.
Bottom blowoff	The intermittent removal of a portion of the boiler water to discharge sludge from the bottom of shells, drums, and headers.
Bubbling bed	A fluidized bed in which the fluidizing velocity is less than the terminal velocity of individual bed particles, where part of the fluidizing gas passes through the bed as bubbles.
Bunker	A large steel container used to store solid fuel.
Calorific value	The amount of energy produced by the complete combustion of a mass of fuel. Also called heating value.
Canadian council of ministers of the environment. (CCME)	CCME is the primary minister-led intergovernmental forum for collective action on environmental issues of national and international concern.
Carbon-neutral	Fuels or energy systems which have no net greenhouse gas emissions.
Castable	Materials that can be cast into different shapes.
Cavitation	The sudden vapour cavity formation, growth, and subsequent collapse, that occurs in a saturated liquid. Cavitation is caused by local pressure fluctuations.
CBD	See *continuous blowdown* (CBD).
CCME	See *Canadian Council of Ministers of the Environment* (CCME).
CEMS	See *continuous emissions monitoring system* (CEMS).
Chain grate stoker	A stoker which has a moving endless chain as a grate surface, onto which fuel is fed directly from a hopper.
Circulating fluidized bed	A fluidized bed in which the fluidizing velocities exceed the terminal velocity of individual bed particles.
Class A gas fitter	A tradesperson certified and competent at installing and servicing gas fired appliances of any capacity.
Cluster burner	A burner comprised of two or more constant capacity burners that activate sequentially to provide several discrete firing rates.
Coagulation	The use of chemicals that cause suspended matter to join together into larger particles. This makes it easier to remove the suspended matter from the liquid by settling, skimming, draining, or filtering.
Coal pulverizer	A machine that reduces coal to a fineness suitable for burning in suspension.
Combustion	A rapid chemical reaction in which oxygen combines with a fuel and releases heat and/or light.
Combustion air	The air provided to ensure complete combustion of a fuel.
Complete combustion	A combustion process that produces no combustible products.
Condensate	Fluid formed when steam is cooled to below its saturation temperature.
Constant capacity burner	A burner with no ability to turn down. It is only suited for on-off operation.

Term	Definition
Continuous blowdown (CBD)	The continuous removal of concentrated boiler water from a boiler. This reduces the total solids concentration in the remaining water.
Continuous emissions monitoring system (CEMS)	An instrument that provides uninterrupted measurement of actual emissions (such as carbon dioxide, carbon monoxide, sulfur oxides, and nitrogen oxides) from industrial sources, for the purposes of analysis, monitoring, and reporting.
Continuous pilot	A pilot that burns without turndown throughout the entire time a burner is in service, whether or not the main burner is firing.
Crossfeed stoker	A chain grate stoker.
Cyclone furnace	A specialty furnace designed for high intensity heat release from solid fuels, so named because of its swirling gas and fuel flows.
Deaerator	A component used for removing oxygen and other corrosive non-condensable gases that may be dissolved in boiler feed water.
Diaphragm gas valve	A safety shut-off valve for gaseous fuels that uses the differential pressure across a flexible diaphragm to drive it open or shut.
Dissolved gases	Gases, such as oxygen and carbon dioxide, which may be in solution in water.
Dissolved solid	A solid impurity in solution with water. In boilers, calcium and magnesium salts are scale-forming dissolved solids.
Double block and bleed	An arrangement of normally closed valves, with a normally open valve affixed to a take-off located between the normally closed valves. It is designed to ensure a positive interruption of fluid flow, especially a fuel.
Draft	A difference in pressure that causes gases to flow into and out of a furnace.
Excess air	Air in addition to the amount of theoretical air needed for complete combustion.
External water treatment	Treatment of boiler feedwater prior to its introduction into the boiler.
Factory-built chimney	A chimney made of various factory-built, interlocking, modular components.
FBC	See *fluidized bed combustion* (FBC).
FBN	See *fuel based nitrogen* (FBN).
FD fan	See *forced draft fan* (FD Fan).
Feedwater	Water introduced into a boiler during operation. It includes make-up and return condensate.
Firebrick	A common form of refractory made of aluminum silicates, with silica (SiO_2) content varying up to 78%, and alumina (Al_2O_3) content up to 44%.
Fixed carbon	The solid combustible residue that remains after a fuel particle is heated, and the volatile matter is expelled.
Flash point	The temperature at which a flammable liquid produces sufficient vapour to momentarily support combustion.
Flue gas	The gaseous products of combustion in the flue to the stack.
Fluid power gas valve®	A brand name for a motorized gas safety shut-off valve.
Fluid-fired burner	A device for mixing liquid, gaseous, or pulverized solid fuel with oxygen, for the purpose of combustion.
Fluidized bed	A process where a bed of granulated particles is maintained in a mobile suspension by an upward flow of air or gas.

Term	Definition
Fluidized bed combustion (FBC)	A process where a fuel is burned in a bed of granular particles that are maintained in mobile suspension by the flow of air and combustion products.
Fly ash	A product of the combustion of solid fuel. Fly ash is comprised of very fine particles, which are carried out of the furnace with the flue gases. Fly ash ranges in size from about 1 micron to 300 microns.
Foaming	The continuous formation of bubbles with sufficiently high surface tension, so they remain as bubbles above the disengaging surface. This interferes with the natural steam disengagement process and can result in priming.
Forced draft	The use of mechanical devices to provide positive gas passage into and out of a furnace.
Forced draft fan (FD fan)	A fan that supplies combustion air, under pressure, to fuel burning equipment.
Freeboard	The space or volume above the upper surface of the bubbling bed, and below the furnace exit.
Fuel based nitrogen (FBN)	Nitrogen found within the chemical makeup of a fuel, through ultimate analysis.
Fuel oil	Homogeneous hydrocarbon mixtures, in liquid form, used in combustion processes to provide heat.
Galvanized piping	Steel pipe coated with zinc, in order to prevent corrosion.
Guard valve	In a piping system, a valve that is only operated in still liquid, so that it suffers little wear and can therefore maintain a tight seal.
Hammer mill	A device used to reduce the size of solid particles, such as coal, by repeated blows.
Hardness	With regard to water quality, a measure of the amount of calcium and magnesium salts in boiler water. Usually expressed as grains per gallon or ppm as $CaCO_3$.
Hard-seated valve	A globe-type valve with seats and plugs made of hard metallic material.
Hartford loop	See *return loop*.
Herbaceous fuel	Fuels sourced from grasses and straw. These may be in the form of chips, hog, pellets, or bales.
Hog fuel	A fuel made of coarse wood chips and tree bark.
Hot well	A reservoir at the base of a steam condenser in which condensate accumulates.
Hydramotor® valve	A brand name for a motorized gas safety shut-off valve.
ID fan	See *induced draft fan* (ID Fan).
Incomplete combustion	A combustion process that produces combustible products. These products can subsequently react with oxygen to produce non-combustible products, heat, and light.
Induced draft	The use of mechanical devices to withdraw gases from a furnace.
Induced draft fan (ID fan)	A fan that exhausts hot gases from a furnace, as the combustion products develop.
Intermittent blowoff	The blowing off of boiler water at intervals.
Intermittent pilot	A pilot that lights automatically each time there is a call for heat, and burns during the entire period that the main burner is firing.
Internal water treatment	The softening, deaeration, and conditioning of water inside the boiler shell or drum, through the addition of chemicals.

Term	Definition
Interrupted pilot	A pilot that lights automatically each time there is a call for heat. The pilot fuel is cut off automatically at the end of the main burner flame establishing period.
Ion exchange	A process in which undesirable ions in water are exchanged with more desirable ions.
Ion exchange water softener	Equipment used to soften water, using the principles of ion exchange.
Liquefied petroleum gas (LPG)	Petroleum products that consist of light hydrocarbons (butane, propane, or a mixture of the two) which have been liquefied through the application of pressure.
Low fire start	The requirement for a burner to have its fuel and combustion air flows at their minimum respective settings prior to ignition. Burners with proven low fire start use interlock switches to prevent ignition if the fuel and air are not in low fire position.
Low water fuel cut-off (LWCO)	A safety device that will shut off a boiler if its water level becomes too low.
Lowest permissible water level (LPWL)	The lowest water level at which a boiler can be operated without sustaining damage due to overheating, as determined by the boiler manufacturer.
LPG	See *liquefied petroleum gas* (LPG).
LPWL	See *lowest permissible water level* (LPWL).
LWCO	See *low water fuel cut-off* (LWCO).
Make-up water	The water added to a boiler system to compensate for water lost through exhaust, blowdown, blowoff, leakage, and others.
Mass burning	The act of burning municipal solid waste in a single combustion chamber.
Mass burning facilities	Facilities that burn municipal solid waste in a single combustion chamber.
Mechanical atomizing oil burner	A burner that uses the pressure of the oil for atomizing.
Mechanical stoker	A device consisting of a mechanically operated fuel feeding mechanism and a grate. It feeds solid fuel into a furnace, distributes it over a grate, admits air to the fuel for the purpose of combustion, and provides a means for removal or discharge of ash.
Mercaptan	A foul-smelling odourant added to natural gas and propane to aid in leak detection.
Mill	See *coal pulverizer*.
Modulating pressure burner	An oil burner of variable firing rate, achieved by varying (modulating) its nozzle pressure.
MSW	See *municipal solid waste* (MSW).
Mud	With regard to boiler waterside operations, a combination of suspended matter and precipitates that settle and accumulate in the lowest-situated parts of boilers.
Municipal refuse	Untreated solid waste material as collected from household and commercial establishments. It is highly variable in appearance, density, and BTU content.
Municipal solid waste (MSW)	Untreated solid waste material as collected from household and commercial establishments. It is highly variable in appearance, density, and heat content.

Term	Definition
Natural draft	Where no mechanical means is used to provide air for combustion. Airflow into the combustion chamber is the result of warm air being less dense than cool air.
Natural gas	A homogeneous, combustible mixture of light gaseous hydrocarbons, primarily methane and ethane.
Natural gas liquids (NGL)	Hydrocarbon liquids found in natural gas at the wellhead. NGLs include ethane, propane, butane, isobutene, and pentane.
Net stack temperature	The difference between the ambient temperature of combustion air, and the flue gas temperature at the flue outlet of an appliance.
NGL	See *natural gas liquids* (NGL).
NO_x	Oxides of nitrogen, including NO, N_2O, and NO_2.
Odourant	A chemical added to gaseous fuels and liquefied petroleum gases to aid in leak detection. See Mercaptan.
Outage	The planned or unplanned stoppage of boiler operation.
Overfeed stoker	A stoker in which fuel is fed onto grates above the point of air admission to the fuel bed.
Overfire air	In a stoker-fired boiler, combustion air delivered above the burning fuel bed. Overfire air promotes turbulence and complete combustion.
Peltier cooler	A thermoelectric device that produces a cool surface that condenses any moisture out of the flue gas before it reaches the measuring sensor.
PFBC	See *pressurized fluidized bed combustion* (PFBC).
PID control	A controller which combines the features of proportional, integral, and derivative controllers. Commonly referred to as a three-mode controller.
Pilot burner	A small burner used to ignite a large burner.
Precipitation softening	To soften water through the addition of chemicals that precipitate dissolved calcium and magnesium compounds.
Premix burner	A burner designed to burn gaseous fuels, where the mixing of fuel and air occurs within a venturi or mixing tube prior to entering the combustion chamber.
Pressurized fluidized bed combustion (PFBC)	A form of fluidized bed combustion wherein the furnace pressure is several times greater than atmospheric pressure.
Primary air	Combustion air that is premixed with fuel before being admitted to a furnace, or the combustion air admitted below the fuel bed of a stoker-fired boiler.
Primary air fan	A fan to supply primary air for combustion of fuel.
Priming	With regard to boiler operation, an undesirable condition, in which excess quantities of water are carried along with the steam to the steam outlet.
Proximate analysis	A measure of the moisture, fixed carbon, volatiles, and ash content of a fuel.
PS chimney	A factory-built chimney, designed to maintain a positive internal pressure without leaking combustion products through its assembled sections.
Puff back	A minor combustion explosion within a pulverizer system, boiler furnace, or setting.
Quick-opening valve	A valve that requires a 90 degree turn (or less) of its operating mechanism to change from fully closed to fully opened.
Raw water	Untreated water.
RDF	See *refuse derived fuel* (RDF).

Term	Definition
Refractory	Temperature-resistant ceramic material used in boiler furnaces to protect metal surfaces around burners, line fireboxes, seal openings, or make baffles.
Refuse derived fuel (RDF)	A solid fuel prepared from municipal solid waste. The waste material is usually refined by shredding, air classification, magnetic separation, or other means. The fuel may be packed, chopped, pelletized, pulverized, or be subjected to other mechanical treatment. Further refinement to either a gas or liquid yields a fuel of the synthetic type.
Refuse derived fuel facilities	Facilities that use mechanical methods to shred municipal solid waste, remove its non-combustible components, and burn the remainder to produce thermally generated power.
Retort	A trough or channel in an underfeed stoker, extending within the furnace, through which fuel is forced upward into the fuel bed.
Return loop	A condensate return piping arrangement, installed on steam heating boilers. It prevents low water conditions by stopping the backflow of boiler water into condensate return lines.
Returns	Condensate that returns from steam-consuming processes.
Reverse osmosis	A method of reducing the dissolved solids in raw water by passing it through a semi-permeable membrane.
Ribbon burner	An atmospheric premix burner design that uses rows of serpentine metal plates as burner head orifices.
Rising stem valve	A gate or globe valve whose handle or stem changes in position when operated from fully closed to fully open.
Rotary cup oil burner	A burner in which atomization is accomplished by feeding oil to the inside of a rapidly rotating cup.
Safety shut-off valve (SSOV)	A fast-closing valve that automatically and completely shuts off the fuel supply. This is in response to an operating limit or a safety limit.
SAGD	See *steam-assisted gravity drainage* (SAGD).
Saybolt seconds universal (SSU)	A measurement of oil viscosity, as determined using a Saybolt Viscosimeter.
Schedule 80	A pipe weight designation that is similar to extra-strong.
Sealing valve	A guard valve.
Seatless valve	A valve that seals without forceful contact between a plug or gate and a corresponding seat. Seatless valves have ported plungers that permit flow only when the plunger port coincides with a corresponding opening in the valve body.
Secondary air	Air needed to complete the combustion process, admitted near the combustion zone.
Shock service	Piping or piping system components designed to withstand sudden cyclical loading due to changes in pressure, temperature, or other mechanical forces.
Shot	Small diameter steel balls, sometimes used in fireside cleaning systems.
Shrinkage	A sudden reduction in boiler water level as the steam production rate decreases.
Single-element feedwater control	A boiler water control strategy that determines the position of the feedwater control valve only based on drum level.
Slag	In boilers, a mass of fused ash, in its molten or solid state, formed in high temperature furnace zones.

Term	Definition
Slow-opening valve	A valve that requires at least five 360 degree turns of the operating mechanism to change from fully closed to fully opened.
Sonic cleaning	See *acoustic cleaning*.
Soot blower	A mechanical device for discharging air, steam, or water to clean the fireside of boiler heat transfer surfaces.
Specific conductance	The conductance of a 1 cm^3 cube of a solution. Specific conductance is often used to measure the concentration of dissolved solids in water.
Sprayer plate	A metal plate used to atomize the fuel in an atomizer of an oil burner.
Spreader stoker	A stoker that distributes fuel into the furnace from a location above the fuel bed, with a portion of the fuel burned in suspension, and a portion burned on the grates.
Spud	A pipe equipped with a nozzle at one end, for burning gaseous fuels in a multi-spud burner.
SSOV	See *safety shut-off valve* (SSOV).
SSU	See *saybolt seconds universal* (SSU).
Standing pilot	A continuous pilot.
Steam-assisted gravity drainage (SAGD)	The use of high-pressure steam to enhance heavy oil recovery from underground formations.
Stoker	A device consisting of a mechanically operated fuel feeding mechanism and a grate; used for the purpose of feeding solid fuel into a furnace, distributing it over a grate, admitting air to the fuel for the purpose of combustion, and providing a means for removal or discharge of refuse.
Surface blowoff	The intermittent or continuous removal of water, foam, and impurities from the water surface of a boiler.
Suspended matter	Solid material entrained in water, such as sand, mud, clay, sewage, and vegetable matter. Suspended matter may float on the water surface, or it may be dispersed.
Swell	A sudden increase in boiler water level as the steam production rate increases.
TDS	See *total dissolved solids* (TDS).
Tertiary air	Combustion air provided in addition to primary and secondary air; used to complete the combustion process in some burner designs.
Theoretical air	The amount of air required to supply the oxygen theoretically necessary to react all combustible elements in a fuel.
Three Ts of combustion (3 Ts)	Time, temperature, and turbulence.
Three-element feedwater control	A boiler water control strategy that determines the position of the feedwater control valve by considering drum level, steam flow, and feedwater flow.
Total dissolved solids (TDS)	The concentration of dissolved solids in a sample of a solution, usually expressed in ppm (parts per million by mass). It is often estimated from conductivity or sodium concentration measurements.
Tramp metal	Ferrous metal contaminants entrained within a solid fuel.
Travelling grate stoker	A stoker similar to a chain grate stoker except it has grate elements attached to, and driven by, chains.
Turndown ratio	For a burner, the ratio of maximum rated firing rate to minimum stable firing rate, as determined by the burner manufacturer.

Term	Definition
Tuyeres	Forms of grates, located adjacent to a retort, through which air is introduced.
Two-element feedwater control	A boiler water control strategy that determines the position of the feedwater control valve by considering drum level and steam flow.
Ultimate analysis	A measure of the elemental composition of a fuel, including the percentages of carbon, hydrogen, oxygen, nitrogen, sulfur, and ash.
Underfeed stoker	A solid fuel firing system that introduces fuel through retorts located below the point of air admission to the fuel bed.
Underfire air	In a stoker-fired boiler, combustion air delivered below the burning fuel bed. Underfire air ensures stoker grates do not overheat, and helps prevent formation of clinkers.
Urban wood fuels	Wood fuel derived from urban activities. These fuels include packaging materials, off-cuts from manufacturing, wood remainders from construction and demolition, yard trimmings, urban tree removal, and from land clearing.
Valve class	A number that represents a combined temperature and pressure service rating for a valve or piping fitting, in accordance with American National Standards Institute B16.34 Code.
VCM	See *volatile combustible material* (VCM).
Vibrating grate stoker	A sloping grate conveyer that delivers solid fuel into the combustion zone of a boiler by using vertical plates that oscillate back and forth in a rectilinear direction. This causes the fuel to move into the active combustion zone.
Viscosity	The measure of the internal friction or the resistance to flow of a liquid (thickness).
VOC	See *volatile organic compounds* (VOC).
Volatile combustible material (VCM)	In a solid fuel, such as wood or coal, the substances that vapourize and burn during combustion.
Volatile organic compounds (VOC)	Organic chemicals (typically hydrocarbons) with a high vapor pressure (low saturation temperature) at room temperature. This causes molecules to readily evaporate from the liquid state, or sublimate from the solid state, and enter the surrounding air, a trait known as volatility.
Windbox	A chamber below a stoker grate or surrounding a burner, through which pressurized combustion air is introduced to a boiler furnace.
Wire drawing	Damage to the surface of a valve seat, gate, or plug, caused by long-term throttling of process fluid, that prevents shut valves from completely stopping fluid flow. Wire drawing has the appearance of "cuts" on the valve trim surfaces.
Wood chips	Chipped woody biomass with a defined particle size, produced mechanically with sharp knives.
Wood pellets	Wood that has been pulverized and pelletized under heat and high pressure, to produce a wood derived fuel of consistent size.
Y-type valve	A type of globe valve with the bonnet and stem at an acute angle with the valve body. Unlike regular globe valves, Y-type valves feature relatively straight flow paths, and not internal features behind which debris or fluid can accumulate.

Additional Workspace

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