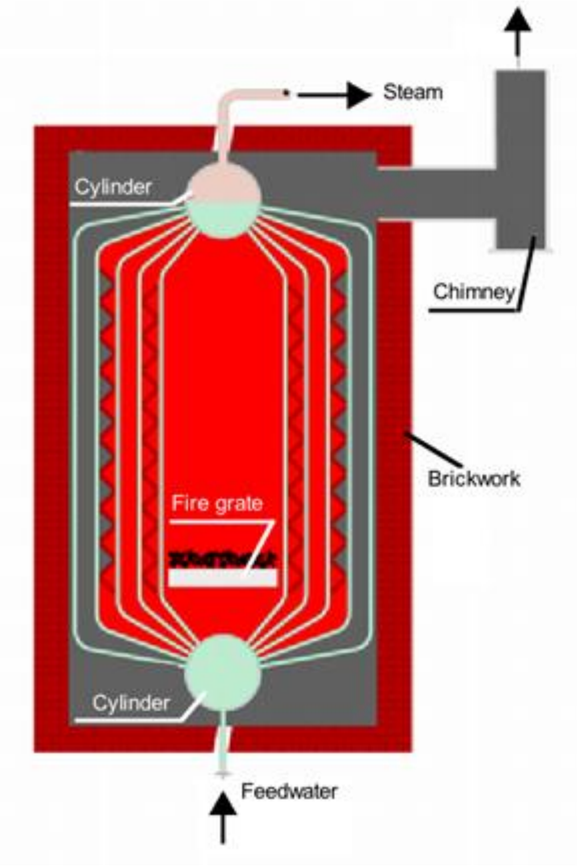
IMPROVING
STEAM BOILER
OPERATING EFFICIENCY



NATIONAL ENERGY CONSERVATION CENTRE

ENERCON

Improving
Steam Boiler
Operating Efficiency

ENERCON
National Energy Conservation Center
ENERCON Building, G-5/2, Islamabad

Ministry of Water and Power
Government of Pakistan

August 2014

Acknowledgements

Much of the material presented in this manual has been derived from published sources. Major contributions were taken from the following;

(1) National Renewable Energy Laboratory, the U.S. Department of Energy

(2) "Improving Steam Boiler Operating Efficiency", 1981; Georgia Tech Engineering Experiment Station, Atlanta, Georgia, USA.

(3) Stoichiometric Calculations, Hsin Chu, Professor, Dept. of Environmental Engineering, National Cheng Kung University

(4) Fuel Efficiency Booklets, 1993; Energy Efficiency Office, Department of Energy, London, England.

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(9) A report on "Identification of Biomass Potential in Punjab", September 2010, Pakistan

(10) Heating Values of Biomass Fuels, PCSIR (Pakistan Council for Scientific and Industrial Research) , Pakistan

(11) Engineering Toolbox, www.engineeringtoolbox.com

Foreword

The current energy situation in Pakistan strongly advocates that the economic survival of our country, its stability and future growth, and socio-economic welfare of the people, all depend on the wise utilization of available domestic energy resources and energy imported to meet our existing and ever-increasing energy demand. Our future lies in taking extreme steps on a war footing basis to combat the wastage of energy caused by its inefficient utilization, resulting from the use of inefficient equipment, and bad operational practices.

Industrial and commercial sectors of any economy are its backbone. Being the major users of energy, and few in number, they are easy to approach and target. Hence, they offer substantial opportunities to harness large amount of wasteful use of energy in their operations through implementation of appropriate energy efficiency measures. It is true that residential unit is rather small in terms of use of energy, and fairy large in number. However, we should not neglect it, since it is a nursery for cultivating energy efficient habits as a nation. Further, one should remember that key to growth and success is innovation. Hence, we, as a nation, need to think ahead and act quickly to utilize our conventional energy resources and to exploit the use of innovative technologies to benefit from abundantly available alternative energy resources in our country. This is the only way out to improve the economy and make our products competitive in the international market.

It is an established fact that efficient operation of the boilers is highly desirable to minimize operating / production costs, save energy, and mitigate undesirable emissions. Where feasible, one should consider the replacement of inherently inefficient boilers on urgent basis.

ENERCON, the national Energy Conservation Centre, is endeavoring to nurture an energy efficient culture in the country. Its efforts aim at creating awareness among energy users and promoting energy efficiency practices in all energy consuming sectors of economy. /accordingly, this manual has been prepared to educate boiler operators, technicians, engineers and industrialists on the basics of industrial boilers, their operating characteristics and the efficiency improvement techniques; and to be equally useful to engineering students looking at their first real application of basic engineering principles. It offers a review of following aspects:

- Basics of combustion, combustion efficiency, and control systems
- Boilers, their characteristics, and energy efficiency and guidelines to operate steam boilers efficiently
- Step by step approach for calculating and implementing energy efficiency opportunities
- Identification and wise utilization of alternative renewable energy resources

It contains appropriate theoretical material and information, and is a practical guide for the professionals to identifying and implementing energy efficiency and conservation opportunities in steam boilers. However, it is not a replacement of textbooks.

With the aid of manuals, training courses, and other technical information and assistance, ENERCON pledges to continue supporting the professionals, engineers and technicians, and work together to achieve energy efficiency and conservation in all sectors of economy.

Managing Director ENERCON

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1 Introduction

Boilers are an integral part of almost every industry, often consuming the largest proportion of the fuel being used by that industry. ENERCON's various programs abundantly reveal that due to the current poor operating practices, steam generation and its usage can be optimized through the implementation of many economically viable energy conservation and efficiency improvement opportunities.

In general, the boilers are not well maintained, and owners frequently complain of the poor quality of technical support services available. No formal training facilities exist in the country for boiler engineers and operators. The Boiler Inspectorates are understaffed and ill-equipped to carry out the important tasks of inspection, monitoring and certification.

As the industrialization of Pakistan proceeds, the population of boilers and their use will undoubtedly increase significantly, and the need for maintaining good combustion and operational efficiency of the boilers will be even greater to assure effective use of energy resources, under increasing costs and paucity of fuels. The purpose of this manual is to draw attention to some of the ways by which the efficiency of boilers can be improved on a day-to-day basis, often without the need to invest money in new equipment. Much can often be done to upgrade the performance of existing plant by careful monitoring and prompt adjustment of operating parameters by a trained and observant operator. ENERCON's extensive experience indicates that even a simple instrumented tune-up of the boilers results in significant improvement in their efficiency.

Increasing boiler efficiency should be approached systematically. Various criteria including boiler size, type, burners and controls, and current level of efficiency will dictate what logical steps should be taken to improve energy efficiency. In general, the following order of priority applies for most boilers:

- Routine maintenance
- Efficiency-related maintenance
- Combustion efficiency
- Control systems
- Burners
- Fuel treatment
- Feed-water treatment
- Waste Heat recovery

The dearth of fossil fuels and their increasing prices have made essential to analyze renewable alternative energy resources and their utilization. It includes the biomass fuels and solar water heating systems. Each of these topics is discussed in this manual in varying levels of detail.

1.1 Units used in this Manual

This manual uses the SI (Le Systeme International d'Unites) metric units of measure.

1.2 This Manual

This manual covers the basic concepts and combustion, boilers, burners, solar water heating systems, and use of biomass fuel in small boilers; and identifying and quantifying energy conservation measures most pertinent to Pakistan.

Chapter 1 is the brief introduction to this manual. Chapter 2 describes fossil fuel fired and biomass fuel fired boilers, boilers rating, and heat and steam release rates. Chapter 3 introduces the fossil and biomass fuels, their combustion, combustion efficiency and boiler efficiency. Chapter 4 explains the losses in boiler systems affecting it efficiency and how to reduce avoidable losses; as reduction in these losses will improve efficiency. The energy conservation opportunities include, excess air control, blowdown and boiler water treatment, steam pressure, boiler exterior heat losses, and effect of fuels. Chapter 5 on efficiency calculations presents an overview of data requirements, instruments needed for monitoring and testing, simplified and comprehensive methods for calculating losses and efficiency.

Chapter 6 introduces boiler instrumentation and controls for pressure, temperature, level control, steam flow metering, flue gas analysis, blowdown control, safety instruments, and monitoring and control techniques for boilers. Chapter 7 discusses different types of burners, burner controls, and combustion control systems. Chapter 8 highlights the importance of water treatment with respect to maintaining boiler water quality essential for efficient operation of steam boilers. It discusses external and internal water treatment and checklist for boiler water treatment. Chapter 9 presents the boiler heat recovery systems including flue gas heat recovery, blowdown heat recovery, and developing a heat recovery project.

Chapter 10 introduces solar water heating systems, and solar collectors, storage tanks, heat exchangers, systems layout, and collectors loop design concepts. It presents thumb rules for sizing of systems, design checklist, and installation and commissioning checklist. Chapter 11 covers performance monitoring. It includes information on spot checks for efficiency, maintenance, water quality, smoke density, flame appearance, burner checks, combustion controls, boiler tubes cleanliness, and boiler tune-up. Chapter 12 offers overview of environmental pollution aspect due to various steam boiler emissions. The manual also includes appendices on properties of steam, worked examples on combustion and energy conservation opportunities in boiler operation, boiler control parameters, and unit conversion tables.

The aim of this manual is to remind the professionals, managers and technical staff energy efficiency measures. However, it must be well understood that this manual is not a replacement of text books and handbooks on the subject. It will serve as a useful guide for energy engineers who work with the use of steam and heat generation equipment and systems, as part of their responsibilities.

2 Description of Boilers

A boiler is a closed vessel in which water or other fluid is heated under pressure. The steam or hot fluid is then circulated out of the boiler for use in various process or heating applications. Sources of heat for the boiler can be the combustion of fuels such as wood, biomass, coal, oil or natural gas. Electric boilers use resistance or immersion type heating elements. Nuclear fission is also used as a heat source for generating steam. Waste-heat boilers or heat-recovery steam generators use the heat rejected from other processes such as gas turbines. Construction of boilers is mainly limited to copper, steel and cast iron.

There are many types of boilers. If operated correctly, all types of modern boilers are more or less equally efficient at converting fuel into steam or hot fluid.

2.1 Boiler Classification

Boilers are classified on the basis of:

- General shape
- Boiler size or capacity
- Steam pressure
- Mode of circulation of working fluid
- Nature of heat source, type of fuel and mode of firing
- Position and type of the furnace
- Special features

2.2 Types of Steam Boilers

The objectives of a boiler are:

- Releasing energy in the fuel as efficiently as possible.
- Transferring released energy to the water, and generating steam as efficiently as possible.
- Separating steam from water ready for export to the plant, where the energy can be transferred to the process as efficiently as possible.

For achieving these objectives, the designers have created innumerable configurations and variations of essentially two general types, i.e., fire-tube and water-tube boilers.

2.2.1 Fire-tube Boilers

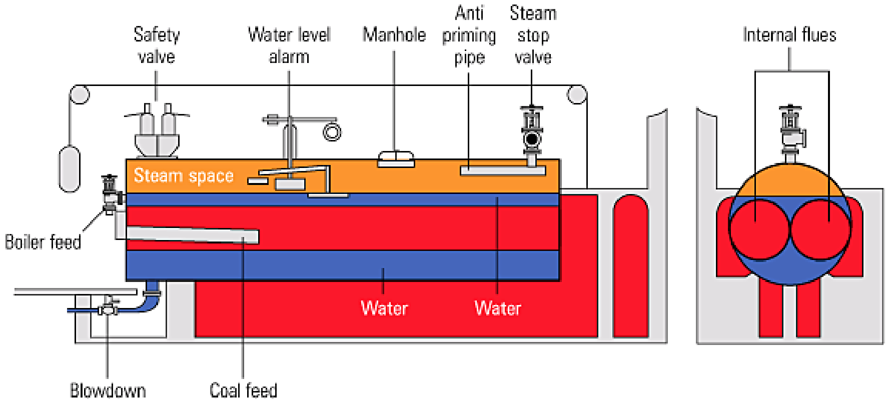
Fire-tube boilers, also commonly known as shell boilers, rely on hot gases circulating through the boiler tubes which in turn transfer heat to the surrounding boiler water. These gases usually make several passes through the tubes, thereby transferring their heat through the tube walls and causing the water to boil on the other side. Fire-tube boilers are generally available in the range of 20 through 800 boiler horsepower (BoHP) and in pressures up to 10 bars.

Different types of shell boilers have been developed, which will now be discussed in detail.

2.2.1.1 Lancashire Boiler

Sir William Fairbairn developed the Lancashire boiler in 1844 (Exhibit 2-1) from Trevithick's single flue Cornish boiler. Although only a few are still in operation, their occurrence showed the way to the development and design of sophisticated and highly efficient boilers being used today. The Lancashire boiler, shown in Exhibit 2-1, comprises of large steel shell usually between 5 - 9 m long through which two large-bore furnace tubes called flues are inserted. Part of each flue is corrugated to take up the expansion when the boiler becomes hot, and to prevent collapse under pressure. A furnace is installed at the entrance to each flue, at the front end of the boiler. Typically, the furnace can be arranged to burn coal, fed either manually or automatically stoked.

Exhibit 2-1: Lancashire Boiler



Capacity	Small	Large
Dimensions	5.5 m long x 2 m dia	9 m long x 3 m dia
Output	1,500 kg/hr	6,500 kg/hr
Pressure	Up to 12 barg	Up to 12 barg

The hot gaseous products of combustion pass from the furnace through the large-bore corrugated flues. Heat from the hot flue gases is transferred to the water surrounding these flues.

The boiler is in a brickwork setting which is arranged to duct the hot gases emerging from the flues downwards and beneath the boiler, transferring heat through the bottom of the boiler shell, and secondly back along the sides of the boiler before exiting through the stack. These two side ducts meet at the back of the boiler and feed the chimney. The passes are designed to extract the maximum amount of energy from the hot product gases before they are released to atmosphere.

The efficiency of Lancashire boiler has been improved by the addition of an economizer. The gas stream, after the third pass, passes through the economizer into the chimney. The economizer pre-heats the feed water and results in an improvement in thermal efficiency. One of the drawbacks of the Lancashire boiler is that the expansion and contraction caused due to repeated heating and cooling of the boiler disturbs its brickwork setting and ducting. This gives rise to infiltration of the air through the cracks, which affects the furnace draft. Production of these boilers has now become uneconomical due to considerable amount of materials and labor required.

These Lancashire boilers have various significant characteristics:

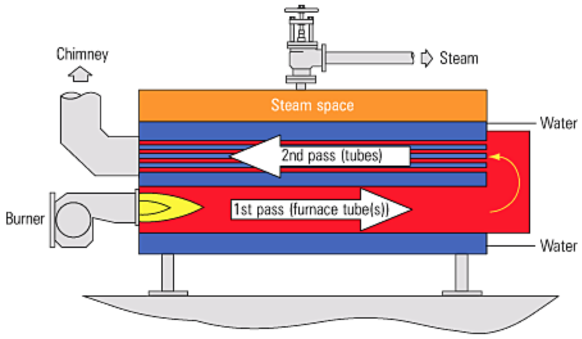
- Due to their large water capacity and size, they can easily tolerate sudden large steam demands because the resulting reduction in boiler pressure releases abundant amount of flash steam from the boiler water held at saturation temperature.
- Since, these boilers are manually stoked, consequently the response to changes in boiler pressure and steam demand is slow.
- The large volume of water means that although the steaming rate might vary widely, the rate of change of the water level is relatively slow.
- Water level control can be manually operated, and the operator can either start a reciprocating, steam powered feedwater pump, or adjust a feedwater valve to maintain the desired water level.

- The low level alarm is simply a float that descends with the water level, and opens a port to a steam whistle when a pre-determined level is reached.
- The large water surface area in relation to the steaming rate means that the rate at which steam is released from the surface (expressed in terms of kg per square meter) is low. This low velocity means that, even with water containing high concentrations of Total Dissolved Solids (TDS), there is plenty of opportunity for the steam and water particles to separate and dry steam to be supplied to the plant.

2.2.1.2 Two-pass, Dry Back Boiler

A typical two-pass boiler with dry back configuration is shown in Exhibit 2-2. It is only about half the size of an equivalent Lancashire boiler and relatively more efficient. It comprises of a cylindrical outer shell containing two large-bore flues, into which the furnaces is set. The hot flue gases pass out of the furnace flues at the back of the boiler into a brickwork setting (dry back) and are deflected through a number of small-bore tubes arranged above the large-bore furnace flues. These small bore tubes present a large heating surface to the water. The flue gases pass out of the boiler at the front and into an induced draught fan, which passes them to the chimney.

Exhibit 2-2: Two Pass, Dry Back Boiler



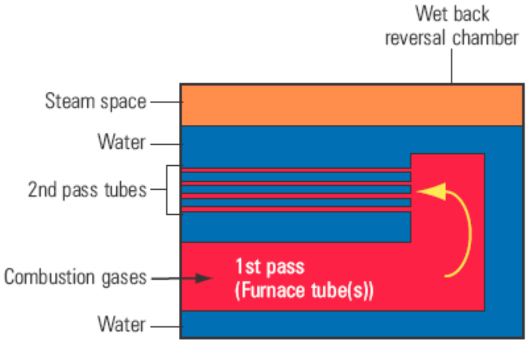
Capacity	Small	Large
Dimensions	3 m long x 1.7 m dia	7 m long x 4 m dia
Output	1,000 kg/h	15,000 kg/h
Pressure	Up to 17 barg	Up to 17 barg

These boilers are not in production any more.

2.2.1.3 Two-pass, Wet Back Boiler

Exhibit 2-3 shows a more efficient method of reversing the hot gases through a two pass wet back boiler configuration. The reversal chamber is contained entirely within the boiler. This allows for a greater heat transfer area, as well as allowing the boiler water to be heated at the point where the heat from the furnace will be greatest - on the end of the chamber wall.

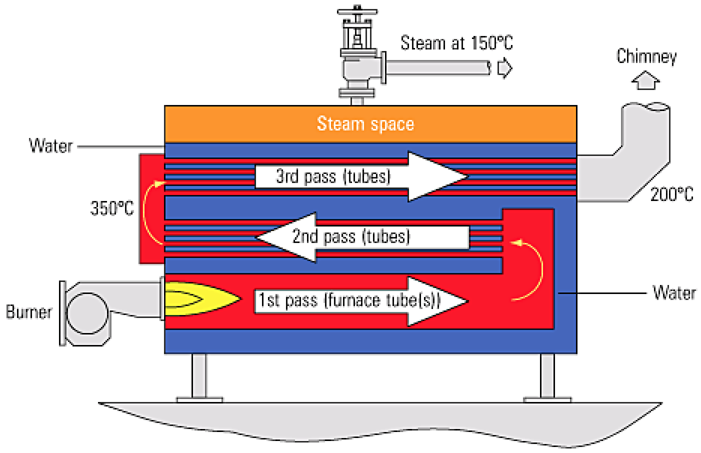
Exhibit 2-3: Two Pass, Wet Back Boiler



2.2.1.4 Three-Pass, Wet Back Boiler

A further development of the fire-tube boiler is the creation of a three-pass wet back boiler which is a standard configuration in use today, (Exhibit 2-4).

Exhibit 2-4: Three Pass, Wet Back Boiler



This design has been evolved with the advancement in materials and manufacturing technology. Thinner metal tubes have been introduced allowing more tubes to be accommodated, improving the heat transfer rate, and the boilers have also become compact.

Typical heat transfer data for a three-pass, wet back, economic boiler is shown in the following table.

	Area of tubes	**Temperature**	**Proportion of total heat transfer**
1st pass	11 m^2	1,600°C	65%
2nd pass	43 m^2	400°C	25%
3rd pass	46 m^2	350°C	10%

2.2.1.5 Four-pass Boiler

Four-pass boiler is potentially most thermally efficient, but fuel type and operating conditions prevent its common use. When this type of unit is fired at low demand with heavy fuel oil or coal, the heat transfer from the combustion gases can be very large. As a result, the exit flue gas temperature falls below the acid dew point, causing corrosion of the flues and chimney and possibly of the boiler itself. The four-pass boiler is also subject to higher thermal stresses, especially with the occurrence of sudden large load swings; these can lead to stress cracks or failures within the boiler structure. For these reasons, four-pass boilers are not accepted for commercial or industrial use.

2.2.1.6 Packaged Boiler

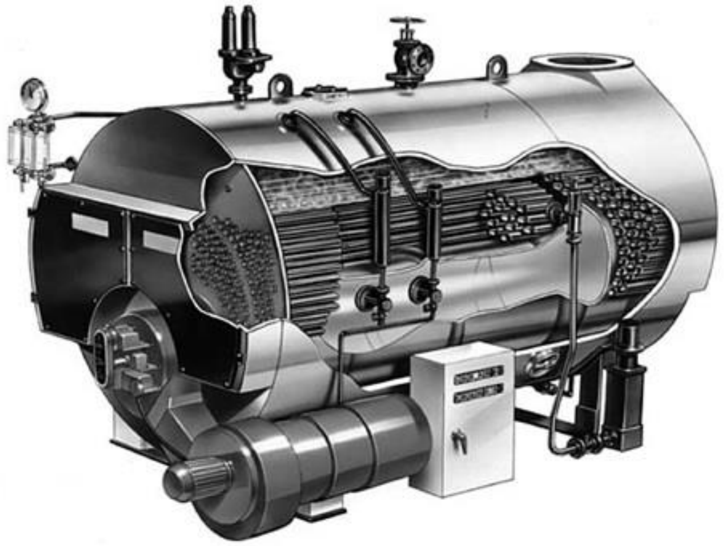
In the early 1950s, concentrated research into improving the size and efficiency of boilers lead to the development of packaged boiler (Exhibit 2-5). It is a further development on the three-pass wet back boiler. These boilers were originally designed to use oil rather than coal.

The packaged boiler comes as a complete package with burner, level controls, feed pump and all necessary boiler fittings and mountings. Once delivered to site it requires only water, steam and blowdown piping work; and fuel supply and electrical connections for it to be operational.

The following factors have played a major role in the development of a modern compact and efficient boiler:

- Manufacturers wanted to make the boilers as small as possible to save on materials and hence keep their product competitive.
- Efficiency is aided by making the boiler as small as it is practical; the smaller the boiler and the less its outer surface area, the less heat is lost to the environment. This issue has also been addressed through general universal awareness of the need for insulation and the availability of high performance modern insulating materials.
- Consumers wanted the boilers to be as small as possible to minimize the amount of floor space needed by the boiler house, and hence increase the space available for other purposes.
- Boilers with smaller dimensions (for the same steam output) tend to be lower in capital cost.

Exhibit 2-5: Modern Packaged Boiler



The following table demonstrates the significant effect of technology developments on the improvement in efficiency of the boilers, reduction in their physical size and other factors:

Boiler type	Fuel	Length (m)	Diameter (m)	Efficiency (%)	Volumetric heat release (kW/m^3)	Steam release rate from water surface (kg/m^{2}s)
Lancashire	Coal	9.0	2.75	74	340	0.07
Two Pass	Coal	6.0	3.00	76	730	0.12
Packaged	Oil	3.9	2.50	82	2,330	0.20
Packaged	Gas	3.9	2.50	80	2,600	0.20

2.2.1.7 Reverse Flame / Thimble Boiler

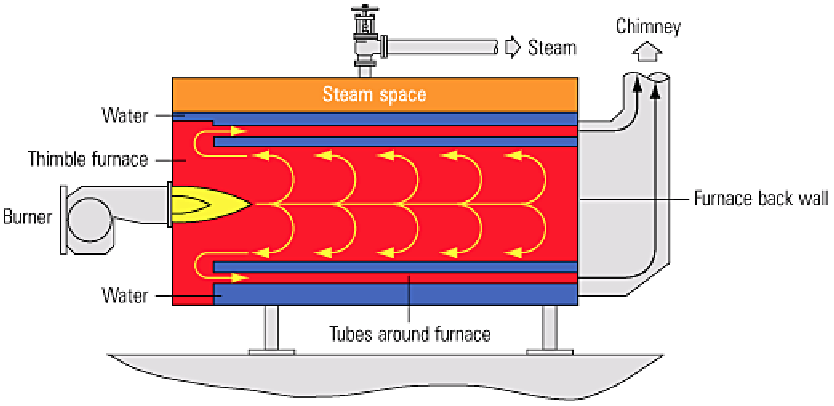
This is a variation on conventional boiler design (Exhibit 2-6). The combustion chamber is in the form of a thimble, and the burner fires down the center. The flame doubles back on itself within the combustion chamber to come to the front of the boiler. Smoke tubes surround the thimble and pass the flue gases to the rear of the boiler and the chimney.

2.2.1.8 Advantages of Fire-tube (Shell) Boilers

- The entire steam generator can be purchased as a complete package. Installation requires securing to basic foundations, and connecting to water, electricity, fuel and steam network before commissioning. This minimizes the installation costs.
- The package arrangement is also simple to relocate a packaged shell boiler.

- A shell boiler contains a substantial amount of water at saturation temperature, and hence has a substantial amount of stored energy which can be called upon to cope with short term, rapidly applied loads.
- The construction of a shell boiler is generally simple, resulting in easy maintenance.
- Shell boilers often have one furnace tube and burner. It makes the control systems fairly simple.
- Although shell boilers may be designed and built to operate up to 27 bar, the majority are designed to operate at 17 bar or less. This relatively low pressure means that the associated ancillary equipment is easily available at competitive prices.

Exhibit 2-6: Thimble or Reverse Flame Boiler



2.2.1.9 Disadvantages of Fire-tube (Shell) Boilers

- The package principle means that approximately 27,000 kg / h is the maximum output of a shell boiler. If more steam is required, then several boilers need to be connected together.
- The large diameter cylinders used in the construction of shell boilers effectively limit their operating pressure to approximately 27 bar. If higher pressures are needed, then a water-tube boiler is required.
- Substantial quantity of water stored in the shell of the boiler. When the boiler is shut down, the energy stored in the boiler water depletes. Therefore, it requires plenty of energy and time at the start-up to build the reserve energy again.

2.2.2 Water-tube Boilers

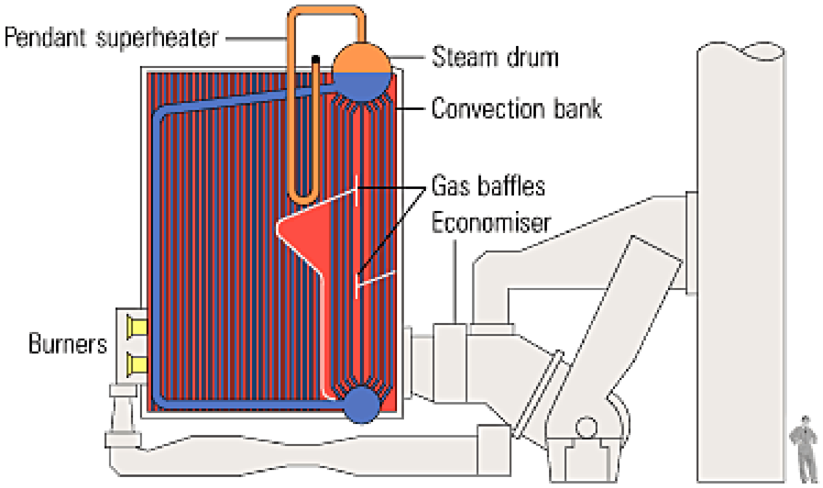
Most high-pressure and large boilers are of water-tube type (Exhibit 2-7). It is important to note that the small tubes in the water-tube boiler can withstand high pressure better than the large vessels of a fire-tube boiler. In water-tube boilers the water is circulated inside the tubes, with the heat source surrounding them. These water-filled tubes are in turn connected to large containers called drums. With the increase in number of tubes of smaller diameter, the heating surface area increases improving the efficiency.

Water-tube boilers are available in sizes ranging from a smaller residential type to very large utility class boilers. Boiler pressures range from 1 bar through pressures exceeding 250 bar. They are mostly used in power station applications that require:

- High steam output (up to 500 kg/s).
- High pressure steam (up to 160 bar).
- Superheated steam (up to 550°C).

However, water-tube boilers are also manufactured in sizes to compete with shell boilers. Small water-tube boilers are manufactured and assembled into a single unit, just like packaged shell boilers, whereas large units are usually manufactured in sections for assembly on site.

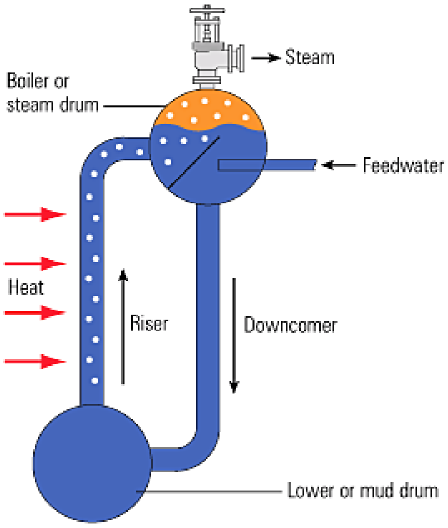
Exhibit 2-7: Water-tube Boiler



Many water-tube boilers operate on the principle of natural water circulation (also known as 'thermo-siphoning'). Exhibit 2-8 helps to explain this principle:

- Cooler feedwater is introduced into the steam drum behind a baffle. Due to its higher density, the cold feed water descends in the 'downcomer' towards the lower or 'mud' drum, displacing the warmer water up into the front tubes.
- Continued heating creates steam bubbles in the front tubes, which are naturally separated from the hot water in the steam drum, and are taken off.

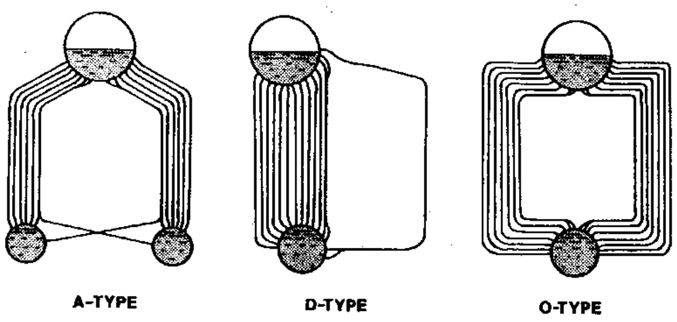
Exhibit 2-8: Natural Water Circulation in a Water-tube Boiler



However, when the pressure in the water-tube boiler is increased, the difference between the densities of the water and saturated steam falls, consequently less circulation occurs. To keep the same level of steam output at higher design pressures, the distance between the lower drum and the steam drum must be increased, or some means of forced circulation must be introduced.

As indicated by Exhibit 2-9, there are many different possible combinations of drums and headers. As the arrangement varies, the circulation pattern can become significantly more complex than the simple model shown in Exhibit 2 8. Nevertheless, the basic princi¬ples involved remain the same.

Exhibit 2-9: Various Water-tube Boiler Configurations



2.2.2.1 Description of Water-Tube Boilers

Water-tube boiler sections

The energy from the heat source may be extracted in the form of radiation, convection or conduction.

Furnace or radiant section (Exhibit 2-10)

This is an open area accommodating the flame(s) from the burner(s). If the flames were allowed to come into contact with the boiler tubes, serious erosion and finally tube failure would occur.
The walls of the furnace section are lined with finned tubes called membrane panels, which are designed to absorb the radiant heat from the flame.

Convection section (Exhibit 2-11)

This part is designed to absorb the heat from the hot gases by conduction and convection.

Large boilers can have several tube banks (also called pendants) in series, in order to gain maximum energy from the hot gases

Exhibit 2-10: Heat Transfer in the Furnace or Radiant Section

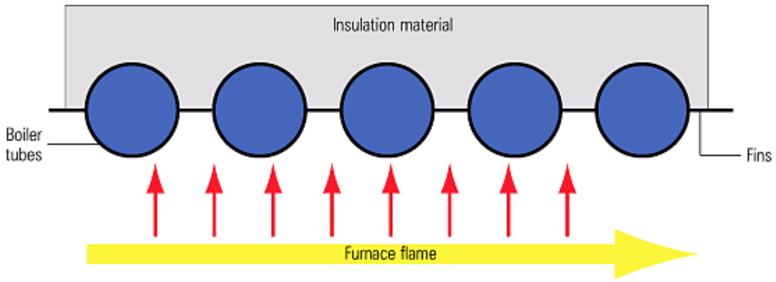
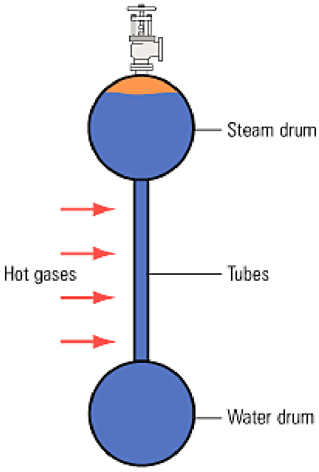


Exhibit 2-11: Heat Transfer in the Convection Section



Water-tube boiler classification

Water-tube boilers are usually classified according to certain characteristics, as given in the following table:

Reservoir drum position	For example, longitudinal or cross drum
Water circulation	For example, natural or forced
Number of drums	For example, two, three
Capacity	For example, 25,000 kg/h, 7 kg/s, 55,000 lbs/h

2.2.2.2 Alternative Water-tube Boiler Layouts

2.2.2.3 Open

The following layouts work on the same principles as other water-tube boilers, and are available with capacities from 5,000 kg/h to 180,000 kg/h.

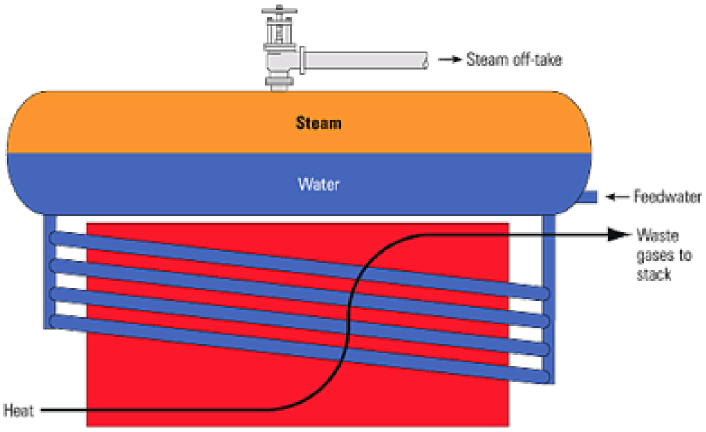
2.2.2.3.1 Longitudinal Drum Boiler

The longitudinal drum boiler was the original type of water-tube boiler, which operated on the thermo-siphon principle (Exhibit 2-12).

Cooler feed water is fed into a drum, which is placed longitudinally above the heat source. The cooler water falls down a rear circulation header into several inclined heated tubes. As the water temperature increases it passes up through the inclined tubes, it boils and its density decreases, therefore circulating hot water and steam up the inclined tubes into the front circulation header which feeds back to the drum. In the drum, the steam bubbles separate from the water and the steam is taken off.

Typical capacities for longitudinal drum boilers range from 2,250 kg/h to 36,000 kg/h.

Exhibit 2-12: Longitudinal Drum Boiler

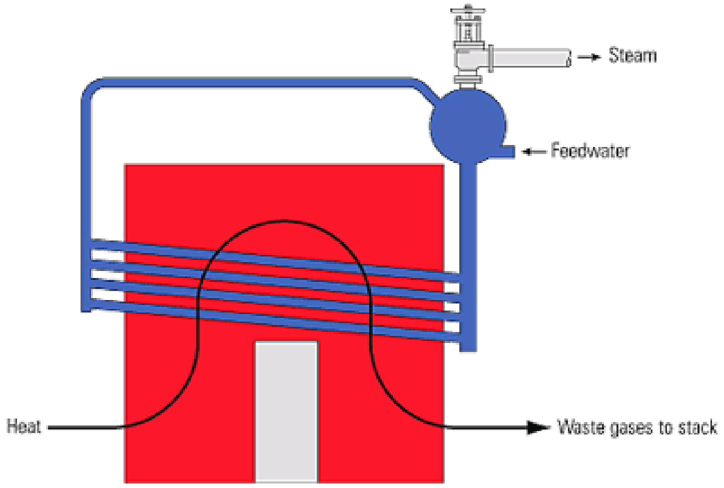


2.2.2.3.2 Cross Drum Boiler

The cross drum boiler is a variant of the longitudinal drum boiler in that the drum is placed cross ways to the heat source as shown in Exhibit 2-13. The cross drum operates on the same principle as the longitudinal drum except that it achieves a more uniform temperature across the drum. However it does risk damage due to faulty circulation at high steam loads; if the upper tubes become dry, they can overheat and eventually fail.

The cross drum boiler has the advantage of being able to serve a larger number of inclined tubes due to its cross ways position. Typical capacities for a cross drum boiler range from 700 kg/h to 240,000 kg/h.

Exhibit 2-13: Cross-Drum Boiler



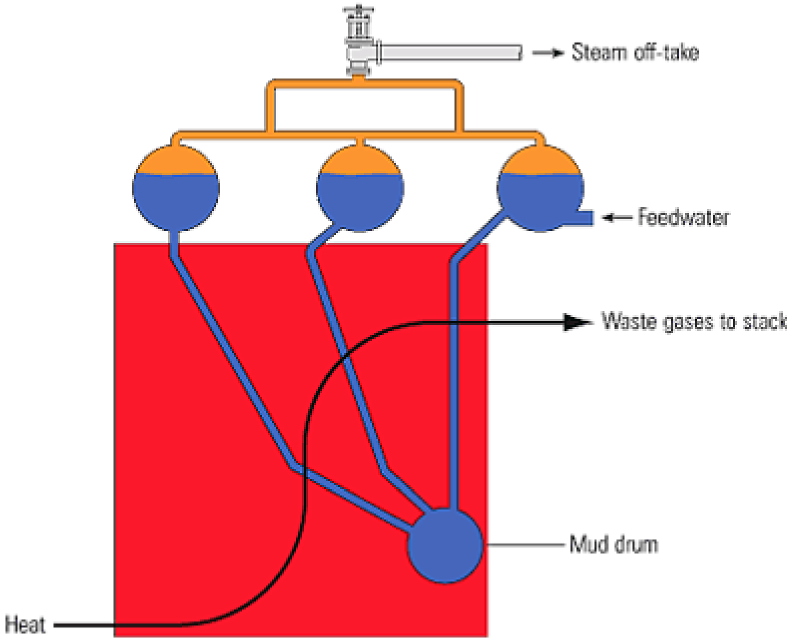
2.2.2.3.3 Bent Tube or Stirling Boiler

A further development of the water-tube boiler is the bent tube or Stirling boiler shown in Exhibit 2-14. Again this type of boiler operates on the principle of the temperature and density of water, but utilizes four drums in the following configuration.

Cooler feed water enters the left upper drum, where it falls due to greater density, towards the lower, or water drum. The water within the water inlet drum and the connecting pipes to the other two upper drums is heated, and the steam bubbles produced rise into the upper drums where the steam is then taken off.

The bent tube or Stirling boiler allows for a large surface heat transfer area, as well as promoting natural water circulation.

Exhibit 2-14: Bent Tube or Stirling Boiler



2.2.2.4 Advantages of Water-tube Boilers

- They have small water content, and therefore respond rapidly to load change and heat input.
- The small diameter tubes and steam drum mean that much higher steam pressures can be tolerated, and up to 200 bars can be used in power stations.

- The design may include many burners in any of the walls, giving horizontal, or vertical firing options, and the facility of control of temperature in various parts of the boiler. This is particularly important if the boiler has an integral superheater, and the temperature of the superheated steam needs to be controlled.

2.2.2.4 Disadvantages of Water-tube Boilers

- They are not as simple to make in the packaged form as shell boilers, which mean that more work is required on site.
- The option of multiple burners may give flexibility, but the 30 or more burners used in power stations means that complex control systems are necessary.

2.3 Coal Based Boilers

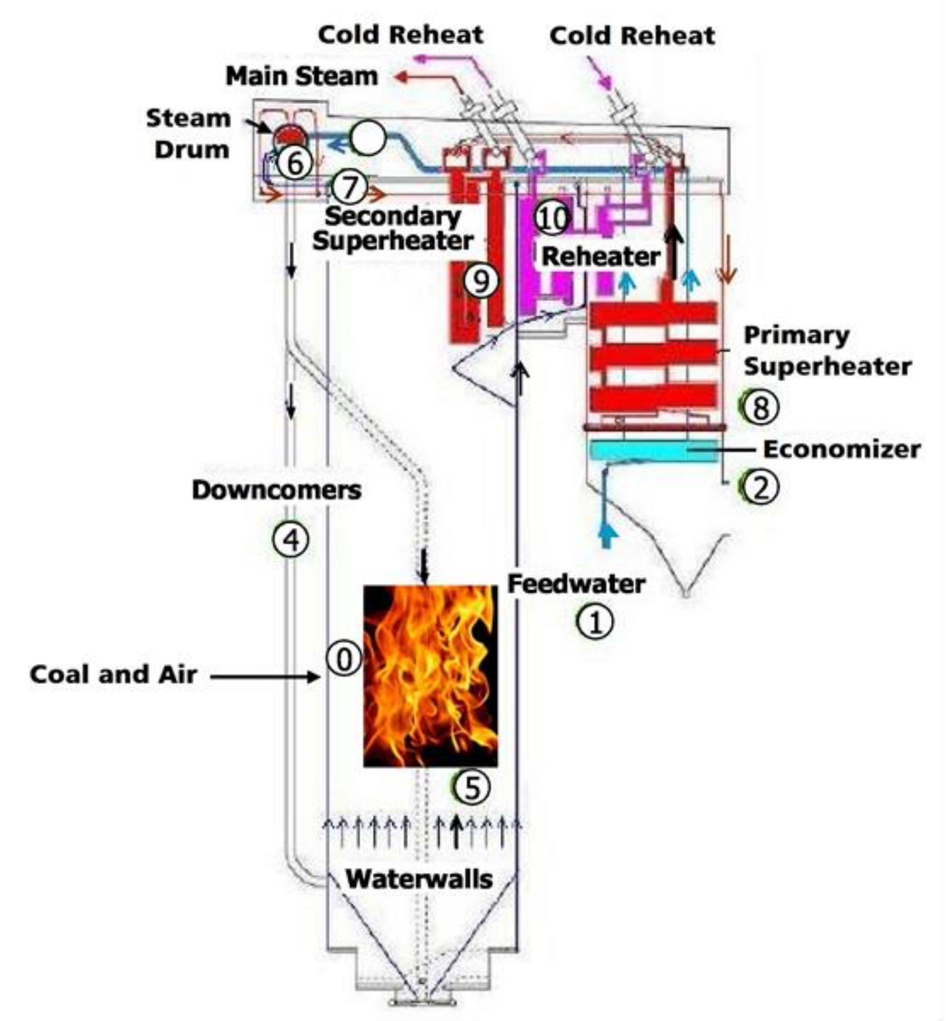
The combustion systems for solid fuels, i.e. coal and biomass, overlap; and have many common principles and features. The combustion system are similar, and their choice depends on the properties of the fuel, whether coal or biomass. Mostly, the coal boilers are used in power generation. They are very large in capacity as compared to biomass fuel based boilers. Combustion systems for solid fuels have been discussed in Chapter 7.

The hot gases from the combustion process move from the bottom left to the top and then down the right hand side of the boiler structure. As the hot gas moves through the boiler it loses energy to the water and the gases becomes cooler as a result. There are various heat exchangers in the boiler which extract energy from the hot gases and transfer it to water.

The following Exhibit 2-15 shows the inner workings of a coal fired boiler. The numbers in the exhibit are described below.

0. Coal powder and air are blown into the boiler and combust to form a fireball.
1. Cool feedwater enters the boiler at the bottom right.
2. The feedwater is heated in the economizer by the warm exhaust gases exiting the boiler.
3. The warm feedwater is sent to the steam drum (6) where liquid water is separated from steam formed in the waterwall. In a super critical coal plant steam is not created. Liquid water becomes a supercritical fluid in the superheaters at a pressure of greater than 221 bar and a temperature of greater than 400C. Therefore there is no steam drum. In a supercritical boiler warmed feedwater passes directly into the downcomers.
4. Liquid water flows down the downcomers on the outside of the boiler to the bottom of the boiler.
5. Water flows up the tubes in the waterwalls of the boiler and surround the fireball of burning coal. The water in the tubes is heated by radiation from the fireball. Some of the water in these tubes turns into steam.
6. The steam and water in the waterwall tubes is sent to the steam drum, where steam is separated from liquid water. Liquid water in the steam drum flows down the downcomers on the outside of the boiler.
7. Steam from the steam drum is sent to the primary superheater.
8. Steam is super-heated to a high temperature and pressure in the primary superheaters and then moves to the secondary superheaters.
9. In the secondary superheaters steam meets the very hot gases exiting the top of the boiler. The steam is heated to its final temperature and pressure before leaving the boiler as main steam. The main steam is sent to the high pressure steam turbine. The steam turbines drive a generator which produces electricity.
10. Steam exiting the high pressure steam turbine is called cold reheat. It is reheated in the reheater and sent back to the second steam turbine.

Exhibit 2-15: Typical Coal Fired Boiler



By the time the flue gas exits the boiler most of the energy in the coal will be transferred to the water in the boiler. The hot gases are cleaned up before they are sent to a stack. Feedwater is generally supplied by condensed steam from the low pressure steam turbine. Large amounts of cooling water are used to condense this steam into liquid water in the condenser.

2.4 Small Scale Biomass Fuel Based Boilers

Use of biomass as fuel in small-scale boilers is gaining momentum as the energy demand is out-weighing supply. The following section will discuss the efficient operation of small boilers and heating systems based on biomass fuels.

2.4.1 Classification of Different Small-scale Biomass Combustion Systems

Based on technologies for small-scale biomass boilers, they can be classified as:

- Manually fed boilers for log wood
- Automatically fed boilers for wood chips
- Automatically fed boilers for wood pellets
- Dual-fuel boilers
- Automatically fed boilers for non-wood fuels

2.4.1.1 Manually Fed Boilers for Log Wood

This is a downdraft boiler; and shows a more stable combustion than in over-fire boilers, which were based on old technology. These are microprocessor controlled.

Usually the capacity ranges from 15 to 70 kW; fuel used is wood logs with 33 or 50 cm length. One can use wood briquettes instead. While fuel loading is manual, the burning operation is automatic during combustion batches. Primary and secondary air feed is separate for combustion zones.

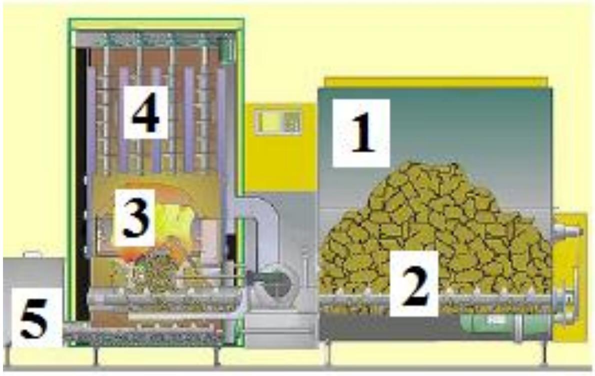
Draught is regulated by combustion air fan. It produces very low emissions due to improved mixing of fuel and air. Automatic controlled operation typically with lambda (O_2) sensor.

Exhibit 2-16: Manually Fed Boiler for Log Wood

2.4.1.2 Automatically Fed Boilers for Wood Chips

This boiler is based on automatic underfed wood chip stoker burner, having capacity ranging from 50 to 100 kW). Fully automatic operation needs only ash box emptying. Its salient features are:

- Micro-processor controlled load and combustion control similar to pellet boilers
- Proven automatic fuel feeding (screw conveyors, agitators) with burnback protection
- Application in residential heating and micro grids
- Air staging (primary and secondary combustion zone with separate air feed)
- Typically vertical fire tube boilers with automatic or semi-automatic boiler cleaning (with a clear tendency towards automatic boiler cleaning systems)
- Flue gas condensation partly applied



Explanations:

1. 1. Storage container;
2. 2. Feeding screw;
3. 3. Combustion chamber with radiation plate
4. 4. Heat exchanger with tabulators and cleaning system;
5. 5. Ash container

The significant features are:

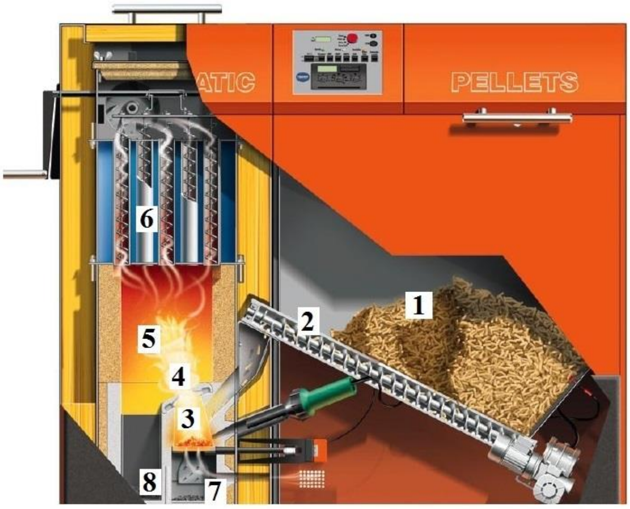
- Capacity range: >15 up to several 100 kW
- Fuels used: wood chips
- Types: underfed burners, horizontally fed burners, moving grate systems
- Efficiencies of wood chips boilers in the early 1980´s: around 70%
- Average efficiency of modern wood chips boilers: 91%

2.4.1.3 Automatically Fed Boilers for Pellets

Exhibit 2-17 shows a typical automatically fed boiler for pellets. Features of such boilers are:

- Fully automatic operation (only ash box emptying is needed)
- Micro-processor controlled (load and combustion control)
  - Load control by regulation of the fuel and primary air feed guided by the feed water temperature
  - Combustion control by regulation of the secondary air feed usually guided by the O_2 concentration in the flue gas (lambda sensors)
- Proven automatic fuel feeding (flexible or inflexible screw conveyors, pneumatic systems, agitators or combinations) with burn-back protection
- Air staging (primary and secondary combustion zone with separate air feed)
- Typically vertical fire tube boilers with automatic or semi-automatic boiler cleaning (with a clear tendency towards automatic boiler cleaning systems)
- Pellet boilers with flue gas condensation units available
- Capacity range: 6 to 300 kW

Exhibit 2-17: Automatically Overfed Pellet Boiler



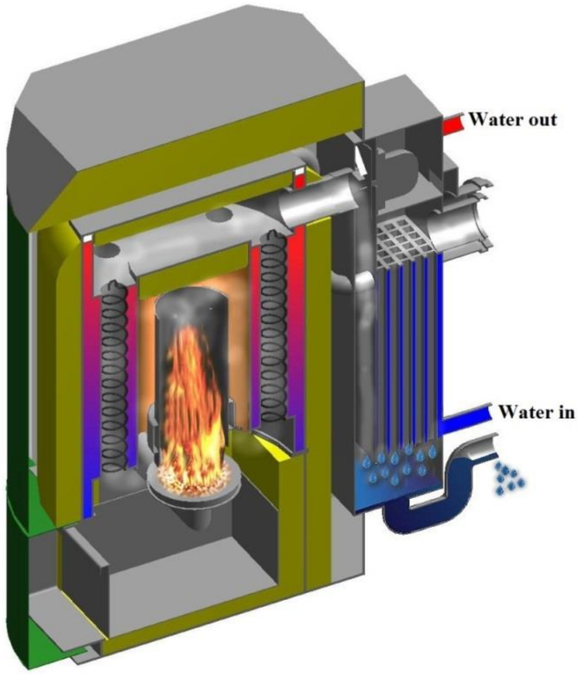
Explanations:

1. Fuel container
2. Stoker screw
3. Primary combustion chamber with primary air addition
4. Secondary air addition

5. Secondary combustion chamber
6. Heat exchanger with cleaning device
7. Bottom ash container
8. Fly ash container

Further, an automatically fed boiler for wood pellets with integrated flue gas condensation is shown in Exhibit 2-18. It is a very efficient boiler due to flue gas condensation feature.

Exhibit 2-18: Automatically Fed Boiler for Pellets with Integrated Flue Gas Condensation



2.5 Boiler Ratings

Boiler rating refers to the manufacturers stated capacity of a boiler capable of handling the boiler load. Rating of a boiler is commonly expressed in terms of:

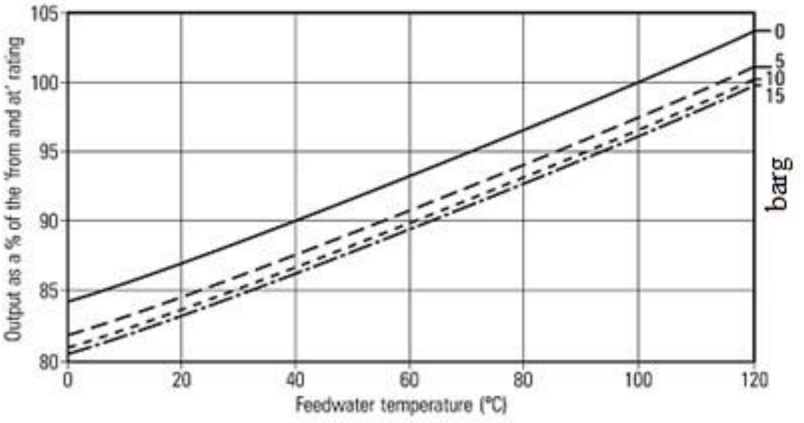
- 'From and At' and Capacity Rating to indicate equivalent evaporation (i.e. kg of steam generated per hour "from and at" 100°C) or kg per hour of steam generated at specified pressure and temperature
- kW Rating for utilities plants and industrial / domestic boilers
- Boiler Horsepower (BoHP) for industrial / domestic boilers
- Heating Surface Area to indicate rate of heat generation / transfer in the furnace

2.5.1 'From and At' and Capacity Rating

Normally, boilers are rated by the evaporation rate, i.e. kg/h, tonnes/h, or pounds/h. Now widely boilers are designated with 'From and At' rating, which is used as a datum by boiler manufacturers. This boiler rating shows "the amount of steam in kg/h which the boiler can produce 'from and at 100°C', at atmospheric pressure". Each kilogram of steam would then have received 2,257 kJ of heat from the boiler. The rating incorporates the concept of heating surface area, capacity and pressure in one definition.

The boilers are often operated with feed water temperatures lower than 100°C. Consequently, the boiler is required to supply heat energy to bring the water up to boiling point. Further, most of the boilers operate at pressures higher than atmospheric pressure for meeting the process requirements, as steam at an elevated pressure attains higher temperature and carries more heat energy than does steam at 100°C. Both these effects reduce the actual steam output of the boiler, for the same consumption of fuel. The graph in Exhibit 2-19 shows feed water temperatures plotted against the percentage of the 'from and at' figure for operation at pressures of 0.5, 10 and 15 bargauge.

Exhibit 2-19: Feedwater Temperature vs %age of 'From and At' Value at Different Pressures



The application of the 'From and At' rating graph (Exhibit 2-19) is shown in the following example, as well as a demonstration of how the values are determined.

Example

A boiler has a 'From and At' rating of 2,000 kg/h and operates at 15 barg. The feed water temperature is 68°C.

Using the graph:

Where

The percentage 'from and at' rating ≈ 90%

Therefore actual output = 2,000 kg/h × 90%

Boiler evaporation rate = 1,800 kg/h

The use of the following equation will determine a factor to produce the same result:

$$\text{Evaporation factor} = \frac{A}{B - C}$$

Where

A = Specific enthalpy of evaporation at atmospheric pressure (0 barg)
B = Specific enthalpy of steam at operating pressure (in barg)
C = Specific enthalpy of water at feedwater temperature
Note: These values are all from steam tables

Using the information from the example and the above equation, the evaporation factor can be calculated:

$$\text{Evaporation Factor} = \frac{2{,}257\ \text{kJ/kg}}{2{,}794\ \text{kJ/kg} - 284.9\ \text{kJ/kg}}$$

Evaporation factor = 0.9

Therefore: boiler evaporation rate = 2,000 kg/h × 0.9

Boiler evaporation rate = 1,800 kg/h

2.5.2 kW Rating

Some manufacturers will give a boiler rating in kW. This is not an evaporation rate, and is subject to the same ‘from and at’ factor.

To establish the actual evaporation by mass, it is first necessary to know the temperature of the feed water and the pressure of the steam produced, in order to establish how much energy is added to each kg of water. The following equation can then be used to calculate the steam output:

$$\text{Steam Output (k / h)} = \text{Boiler Rating (kW)} \times \frac{\text{3,600 s / h}}{\text{Energy to be added (kJ / kg)}}$$

Example

A boiler is rated at 3,000 kW rating and operates at 10 barg pressure with a feed water temperature of 50°C. How much steam can be generated? (1 kW = 1kJ/s)

Using steam tables:
Energy content of feed water at 50°C = 209.5 kJ/kg
Energy content of steam at 10 barg = 2,782 kJ/kg
Energy provided by the boiler = 2,782 – 209.5
= 2,572.5 kJ/kg

$$\text{Steam output} = \frac{\text{3,000 kJ/s} \times \text{3,600 s/h}}{\text{2,572.5k J/kg}}$$

= 4,198 kg/h

2.5.3 Boiler Horsepower (BoHP)

Commonly accepted definition of a boiler horsepower is the amount of energy required to evaporate 34.5 lb per hour of water at 212°F under atmospheric conditions (i.e. evaporation of 15.65 kg per hour of water at 100°C).

Therefore, the steam output of a boiler rated at 500 BoHP will be:

= 500 BoHP × 15.65 kg/h = 7,825 kg/h

In some countries, the BoHP is taken as a function of the heat transfer area in the boiler, and a boiler horsepower relates to 1.58 m^2 (17 ft^2) of heating surface.

BoHP rating is essentially the same as a 'from and at' rating, so using feed water at lower temperatures and steam at higher pressures will reduce the amount of steam generated.

In practice, a BoHP figure of 28 to 30 lb/h (12.7 to 13.6 kg/h) would be a more realistic maximum continuous rating, taking into account the steam pressure and average feed water temperatures.

2.5.4 Heating Surface Area

Boiler size is also designated by its capacity to produce steam or the rate of heat transfer, usually in Btu/h or kcal/h. The heating surface area in sq. meters or sq. feet of the tubes and other combustion area is also common method of designating the boiler size. Boilers vary in the ratio of heating surface to boiler horsepower, from 0.186 to about 0.93 m^2 (2 – 10ft^2) per boiler horsepower.

Heating surface requirements depend upon duty of evaporating tubes, super-heaters, furnace convection and radiation sections, economizers and air pre-heaters.

2.6 Heat and Steam Release Rates

2.6.1 Volumetric Heat Release (kW/m^3)

This factor is calculated by dividing the total heat input by the volume of water in the boiler. It effectively relates the quantity of steam released under maximum load to the amount of water in the boiler. The lower the factor the greater is the amount of reserve energy in the boiler.

The volumetric heat release for a modern boiler relative to a Lancashire boiler is larger by a factor of almost eight, indicating a reduction in stored energy by a similar amount. This means that a reduced amount of stored energy is available in a modern boiler. This development has been made possible by control systems which respond quickly and with appropriate actions to safeguard the boiler and to satisfy demand.

It characterizes the energy release rate per unit volume (q_v), kW/m^3 of the furnace according to following equation:

$$q_v = G_s \times H / V_f$$

Where
G_s = Steaming capacity of the boiler, kg/s
H = Calorific value of the fuel, kJ/kg
V_f = Volume of furnace, m^3

2.6.2 Steam Release Rate ($kg / m^2 s$)

This factor is calculated by dividing the amount of steam produced per second by the area of the water plane. The lower this number, the greater the opportunity for water particles to separate from the steam and produce dry steam. Its value for the modern boilers is larger by a factor of almost three. This means that there is less opportunity for the separation of steam and water droplets. The situation further worsens with increase in total dissolved solids (TDS) in boiler water. Therefore, accurate control is essential for efficiency and the production of dry steam.

At times of rapidly increasing load, the boiler will experience a reduction of pressure, which, in turn, means that the density of the steam is reduced, and even higher steam release rates will occur, and progressively wetter steam is exported from the boiler.

3 Fuels, Combustion and Efficiency

3.1 Fossil fuels

Fuels such as coal, oil and natural gas were formed over millions of years from organic matter like plankton, plants and other life forms. Over time, sand, sediment and rock buried the organic matter and it eventually formed large quantities of fuels. These underground resources, known as fossil fuels, are still the primary fuel source for electricity, heating and powering vehicles around the globe.

There are three major forms of fossil fuels: coal, oil and gas.

Coal is a combustible black or brown sedimentary rock made mostly of organic carbon. It is typically found as layers (coal beds) or veins (coal seams).

There are two main types of coal: ‘thermal’ coal is mostly used for power generation, and ‘metallurgical’ coal is mostly used for steel production. Thermal coal is more abundant, has lower carbon content and is higher in moisture than metallurgical coal.

Natural gas is a combustible mix of hydrocarbon gases. It is colorless and consists mainly of methane ($CH4$). ‘Conventional gas’ is easily extracted; ‘unconventional gas’ requires more sophisticated extraction technologies.

Conventional natural gas is found in permeable sandstone reservoirs and is easy to get out of the ground through traditional well drilling techniques.

Unconventional gas is just standard natural gas, but found in places other than permeable sandstone reservoirs. There are two main types of ‘unconventional gas’: (1) coal seam gas (CSG), found in coal deposits, usually 200 to 1,000 meters below the ground; and (2) shale gas, found in shale rock deposits. The wells for extracting this gas are generally a lot deeper than those for CSG.

Oil is liquid fuel made of hydrocarbons. It is mostly known as crude oil or condensate, but includes all liquid hydrocarbon fossil fuels and other liquid organic compounds. Petroleum and liquefied petroleum gas (LPG) are the most common types of fuel obtained from oil extraction and refining. Liquefied petroleum gas or LPG is heavier than natural gas. The term petroleum refers to both naturally occurring unprocessed crude oils and petroleum products made of refined crude oil.

3.2 Biomass Fuels

Biomass is biological material derived from living, or recently living organisms. In the context of biomass for energy this is often used to mean plant based material. The term can equally apply to both animal and vegetable derived materials.

It is any organic matter-wood, crops, forestry residues, seaweed, animal wastes – that can be used as an energy source. Biomass is probably our oldest source of energy after the sun. For thousands of years, people have burned wood to heat their homes and cook their food. Biomass is a renewable energy source because its supplies are not limited. People can always grow trees and agriculture crops and waste will always exist.

3.2.1 Chemical Composition of Biomass Fuels

Biomass is carbon based and is composed of a mixture of organic molecules containing hydrogen, usually including atoms of oxygen, often nitrogen and small quantities of other elements, including alkali, alkaline earth and heavy metals. These metals are often found in functional molecules such as the porphyrins, which include chlorophyll which contains magnesium.

The carbon used to construct biomass is absorbed from the atmosphere as carbon dioxide (CO_2) by plant life, using energy from the sun. Plants may subsequently be eaten by animals and thus converted into animal biomass. However the primary absorption is performed by plants. If plant material is not eaten it is generally either broken down by microorganisms or burned:

- If broken down it releases the carbon back to the atmosphere, mainly as either carbon dioxide (CO_2) or methane (CH_4), depending upon the conditions and processes involved.
- If burned the carbon is returned to the atmosphere as CO_2.

These processes have happened for as long as there have been plants on earth and is part of what is known as the carbon cycle. A continuous program of replanting with the new growth will take up CO_2 from the atmosphere at the same time as it is released by combustion of the previous harvest. This maintains a closed carbon cycle with no net increase in atmospheric CO_2 levels. However, biomass also includes plant or animal matter used for production of fibers or chemicals.

The vital difference between biomass and fossil fuels is one of time scale.

3.3 Categories of Biomass Materials

There are five basic categories of material:

- Virgin wood: from forestry, from wood processing
- Energy crops: high yield crops grown specifically for energy applications
- Agriculture residues: residues from agriculture harvesting and processing
- Food waste: from food and drink manufacture, preparation and processing, and post-consumer waste
- Industrial waste and co-products from manufacturing and industrial processes.

3.4 Thermal Properties of biomass

Each type of biomass has specific properties that determine its performance as a fuel in combustion or gasification devices or both. The most important properties relating to the thermal conversion of biomass are as follows:

- Moisture content
- Ash content
- Volatile matter content
- Elemental composition
- Heating value
- Bulk density

3.4.1 Moisture Content

The moisture content of biomass is the quantity of water in the material, expressed as a percentage of the material's weight. This weight can be referred to on a wet basis, on a dry basis and on a dry and ash-free basis. If the moisture content is determined on a "wet" basis, the water's weight is expressed as a percentage of the sum of the weight of the water, ash and dry-and-ash-free matter. Similarly, when calculating the moisture content on a "dry" basis, the weight of water is expressed as a percentage of the weight of the ash and dry-and-ash-free matter. Finally, the moisture content can be expressed as percentage for the "dry-and-ash-free" matter content. In that last case, the water's weight is related to the weight of the dry biomass. Because the moisture content affects the value of biomass as a fuel, the basis on which the moisture content is measured must always be mentioned. This is of particular importance because biomass materials exhibit a wide range of moisture content (on a wet basis), ranging from less than 10 percent for cereal grain straw up to 50-70 percent for forest residues. The following table explains basis of analysis:

Basis of Analysis of Solid Fuels including Biomass

To obtain:	Air Dry	Dry Basis	As Received
multiply			
ar by:	$\frac{100 - IM\%}{100 - TM\%}$	$\frac{100}{100 - TM\%}$	
ad by:		$\frac{100}{100 - IM\%}$	$\frac{100 - TM\%}{100 - IM\%}$
db by:	$\frac{100 - IM\%}{100}$		$\frac{100 - TM\%}{100}$
[For daf, multiply db by 100/(100-A)]			

Definitions

As Received (ar):	includes Total Moisture (TM)
Air Dried (ad):	includes Inherent Moisture (IM) only
Dry Basis (db):	excludes all Moisture
Dry Ash Free (daf):	excludes all Moisture and Ash

The Proximate Analysis of any solid fuel i.e. the % content of Moisture, Ash (A), Volatile Matter (VM), Fixed Carbon (FC) – also Sulfur (S) and Calorific Value (CV) – can be expressed on any of the above bases.

3.4.2 Ash Content

The inorganic component (ash content) can be expressed in the same way as the moisture content on a wet, dry and dry-and-ash-free basis. In general, the ash content is expressed on a dry basis. The inherent ash value, an integral part of the plant structure, which consists of a wide range of elements; represent less than 0.5 percent in wood, 5 to 10 percent in diverse agricultural crop materials and up to 30 to 40 percent in rice husk.

The total ash content in the biomass and the chemical composition of the ash are both important. The composition of the ash affects its behavior under the high temperatures of combustion and gasification.

3.4.3 Volatile Matter Content

Volatile matter refers to the part of the biomass that is released when the biomass is heated (up to 400 to 500 °C). During this heating process, the biomass decomposes into volatile gases and solid char. Biomass typically has a high volatile matter content (up to 80 percent), whereas coal has a low volatile matter content (less than 20 percent) or in the case of anthracite coal, a negligible one.

3.4.4 Elemental Composition

The composition of the ash-free organic component of biomass is relatively uniform. The major components are carbon, oxygen and hydrogen. Most biomass also contains a small proportion of nitrogen. Following table presents the average range of percentages.

Elementary composition of typical biomass as derived from Ultimate Analyses

Element	Symbol	Weight percent (dry-and-ash-free basis)
Carbon	C	44-51
Hydrogen	H	5.5-6.7
Oxygen	O	41-50
Nitrogen	N	0.12-0.60
Sulfur	S	0.0-0.2

3.4.5 Heating Value

The heating value of a fuel is an indication of the energy chemically bound in the fuel with reference to a standardized environment. The standardization involves the temperature, state of water (vapor or liquid) and the combustion products (CO_2, H_2O etc.). The energy chemically bound in the fuel is given by the heating value of the fuel in energy (Joules) per amount of matter (kg). This energy cannot be measured directly but only with respect to a reference state. Reference states may differ, so a number of different heating values exist. The best known are the lower heating value (LHV) and higher heating value (HHV); also called as Net and Gross Calorific Values respectively. For the LHV, the reference state of water is gaseous state; for the HHV; the reference state of water is its liquid state.

Biomass always contains some water, which is released as vapor upon heating. This implies that some of the heat liberated during the chemical reactions is absorbed by the evaporation process. For this reaction, the net heating value (LHV) decreases as the moisture content of the biomass increases (even apart from the fact that a higher moisture content of combustible matter, which on a wet basis also decreases the net heating value per kilogram of biomass). The only effect of moisture content on HHV is the lower content of combustible matter per kilogram of biomass fuel. The heat of evaporation is recovered completely by condensation of the water vapor when the flue gases are brought into the reference state belonging to HHV.

3.4.6 Bulk Density

Bulk density refers to the weight of material per unit of volume. For biomass, this is commonly expressed on an oven-dry-weight (moisture content= 0 percent) or an as-is basis, with a corresponding indication of moisture content (MCw). Similar to biomass moisture contents, biomass bulk densities show extreme variation from lows of 150-200 kg/m^3 to 600-900 kg/m^3. Together, heating value and bulk density determine the energy density, that is, the potential energy available per unit volume of the biomass. In general, biomass energy densities are approximately one-tenth that of fossil fuels such as petroleum or high quality coal.

3.5 Biomass Fuels and Pakistan

In Pakistan, most common biomass fuels are cotton stalk, wheat straw, rice husk, sugarcane trash, bagasse and other crops residues. Currently, most of these biomass products are treated as biomass waste and is usually burned in the fields. Biomass burning has a significant impact on global atmosphere chemistry since it provides large sources of carbon monoxide, nitrogen oxides and hydrocarbons.

The waste products which are the main contributors to biomass burning are bagasse, rice straw and husk, cotton wastes, barley residue, maize stalks and leaves, and millet and sorghum stalks. Sugar cane provides the next sizeable residue with two major crop wastes; the leaves and stalk and bagasse, the crop processing residue from sugar mills. The cotton crop also gives significant residue in the form of stalks and husks.

Biomass resources, particularly residues from wood processing, agricultural crops and agro-processing, are under-utilized in Pakistan. These resources are renewable, environmentally friendly in energy production and sustainable in terms of supply.

Some of these residues are already used as raw materials for other products (such as particle board and fiber-board) as fodder and fertilizer or as household and industrial fuels. However, large portions are still unused and represent potential sources of energy. Energy generation technologies specifically designed to use biomass residues are available and are becoming more and more economical. Pakistan has yet to make optimum use of the additional power generation potential from its biomass residue resources, which could help it to partially overcome the long-term problem of energy supply. The following data of major agro-based biomass will certainly help to way forward for the implantation of power projects.

3.6 Bagasse

Bagasse is comprised of lingo cellulosic residues and is a by-product of Sugar cane. Bagasse is essentially the fibrous waste left containing 48-50% cellulose; after the Sugar cane is extracted for crystallizing into sugar. Bagasse has considerable potential as biomass fuel since it arises mainly at sugar factories. Each fresh tonne of sugar cane brought into the sugar factory for processing yields around 300 kg of the residual fiber which has useful energy content. Sugar cane top and cane trash normally ranges from 15 to 23% by weight of sugar cane.

Sugar cane top and trash is usually used as a fodder for animals. Presently, almost all power requirements of sugar mills are met by using bagasse as a fuel but it is pertinent to mention that some of sugar mills are producing surplus power to the grid. In fact, sugar mills in Pakistan either have established the improved technology in their existing facilities or these are in process for generating surplus power to the National Grid at the moment.

Approximately 96-98% bagasse produced from cane is consumed in all sugar mills (operating) in the country to meet the steam requirements for sugar and for in house and surplus power requirements.

Annual production of sugar cane top and trash, and bagasse is in the range of:

Sugar cane top and trash: 13 million tonnes
Bagasse: 20 million tonnes

3.7 Cotton Wastes and Cotton Stalks

Cotton is one of the most important crops of Pakistan; due to local production of raw cotton Pakistan’s textile industry is dependent on its production volume. Pakistani cotton is best in the world in medium and short staple, the waste/contamination produced from cotton can be a huge source for energy generation. Significant cotton wastes are produced; one from the raw cotton at the time of ginning and the other waste produced from its lint after processing it in spinning and recycling units. These wastes can be successfully used for combustion in biomass fired plants in order to meet energy requirements commercially.

Average annual ginning waste: 121,920 tonnes
Average annual waste after Spinning and recycling: 98,425 tonnes

3.8 Rice Husk

Rice husks are one of the commonest global agricultural residues and by-products of rice paddy milling industries. Rice husks have 45-53% cellulose and hemicelluloses, lignin and protein ranges 25-30%. The husks have a relatively high silica content of about 13-17% which can cause an ash problem and possible slagging within the boiler on combustion. However, their homogeneous nature lends this biomass resource to more efficient combustion.

As per the research, 100 kg of paddy contains almost 67 kg of rice and 33 kg of bran powder, and husk and dust.

Rice husk produced	3.4 million tonnes
Annual quantity of Paddy straw	20.6 million tonnes

3.9 Wheat Straw

Cereal straw from small cereal crops as wheat is produced at around 2.5-5/ha depending on crop type, variety and the growing season. It is estimated that equivalent yield of wheat straw is produced by weight from wheat crops. Wheat straw is almost 40% cellulosic in nature. It is also pertinent to mention that almost all the wheat straw is generated in the field when the wheat crops are to be processed through ripper machines, combined harvesters or manually cutting tools and readily available to Flour Mills for producing flour. No countable/significant wastages are produced in Flour Mills or in the field that can be used as a burning fuel because all wheat is converted into flour and farina (cream of wheat). In terms of comparative gross energy values, 1 tonne of straw equates approximately 0.5 tonne of coal or 0.3 tonne of oil. It has higher silica content than other forms of biomass, leading to ash contents of up to 10% by weight.

Wheat straw produced in Pakistan is heavily consumed as fodder to about 88% of its overall production. Wheat straw is utilized as a basic raw material to approximately 5% of its overall production for pulp manufacturing for producing paper and paper board in the country.

Equivalent production of wheat straw = 23 million tonnes
Approximately 88% utilization of wheat straw as fodder to animals = 21.05 million tonnes
About 5% is utilized for pulp, paper and paperboard manufacturing = 1.196 million tonnes
About 5% is taken by brick manufacturers for burning it as a fuel = 1.196 million tonnes

Exhibit 3-1: Properties of different Biomass Resources

Biomass Resource	Moisture Contents (%)	Volatile Matter (%)	Ash Contents (%)	Fixed Carbon (%)	High Heating Value (kcal/kg)
Rice Husk	10.4	64.25	14.08	11.27	3826.96
Cotton Stalk	20.86	60.66	6.28	12.2	3296
Wheat Straw	6.34	61.73	17.64	14.29	3712.37
Bagasse	25.25	48.98	13.45	12.32	3673.6

Appendix-B describes the processing of solid fuel prior to combustion.

3.10 Combustion Principles

Carbon and hydrogen are the main ingredients of common fossil biomass fuels. Their reaction with oxygen, existing in the air, is called "Combustion or Burning". It is an exothermic chemical reaction and produces carbon dioxide and water in case of complete combustion. Complete combustion is generally impossible to achieve unless the reaction occurs under carefully controlled conditions. Sulfur is often present in fuels but is usually of minor importance from the energy point of view, although its effect may be very significant in terms of corrosion and environmental problems.

Appendix-C further explains the combustion calculations.

Complete combustion reaction of carbon and hydrogen is symbolized by the following equation:

Fuel		**Air**	**Combustion**	**Heat**
$C + H_2$	+	$O_2 + N_2$	$\longrightarrow$	$CO_2 + H_2O + N_2$

The stoichiometric equation of combustion reactions is:

$$C + O_2 \longrightarrow CO_2$$
$$2H_2 + O_2 \longrightarrow 2H_2O$$

Combustion of Natural Gas is as below:

$$CH_4 + 2O_2 \longrightarrow CO_2 + 2H_2O$$

Where

C = Carbon
H = Hydrogen
O = Oxygen
N = Nitrogen

For a fuel with a given carbon and hydrogen content, it is therefore possible to calculate the theoretical amount of oxygen needed for complete combustion. This quantity of oxygen is referred to as the stoichiometric requirement for oxygen (this may also be expressed in terms of equivalent air). The stoichiometric oxygen or air requirement is of primary interest in the evaluation of combustion efficiency and provides an important reference point against which the actual combustion conditions can be compared. Values of the stoichiometric air requirement for several common fuels are given in Exhibit 3-2.

Exhibit 3-2: Stoichiometric Air Requirements for Combustion

FUEL	**Air required (1)**	
	lb/10,000 Btu	**kg/10,000 kcal**
Anthracite	6.87	12.37
Bituminous coal (medium volatile)	**7.77**	**13.99**
Subbituminous coal	7.56	13.61
Lignite	7.52	13.54
High temperature coke	7.96	14.33
Petroleum coke	7.73	13.91
Hardwoods	7.15	12.87
Softwoods	7.11	12.80
Bagasse	6.59	11.86
Naphtha (60^{0}API)	7.46	13.43
Kerosene (45^{0}API)	7.42	13.36
Gas oil (30°API)	7.45	13.41
Fuel oil (15^{0}API)	7.58	13.64
Natural Gas (pure methane)	7.20	12.96
Propane	7.24	13.03
Butane	7.26	13.07
Blast furnace gas	5.82	10.48
Coke oven gas	6.80	12.24

(1) Expressed per 10,000 Btu or 10,000 kcal of higher heating value of fuel fired

In practice, since combustion conditions are never ideal, more than the theoretical amount of air must be supplied to achieve complete combustion. The actual quantity of combustion air required for a particular boiler depends on many factors, such as fuel type and composition, furnace design, firing rate, and the design and adjustment of the burners. The additional supply of combustion air above the theoretical requirement is called excess air and is usually expressed as a percentage of the stoichiometric requirement. Thus, use of double the amount of air theoretically required would result in an excess air rate of 100%.

Some typical excess air requirements are shown in Exhibit 3-3. Note that these are typical figures which represent "good' combustion practice", and there will be some installations able to demonstrate consistent operations at excess air rates lower than those indicated in Exhibit 3-3.

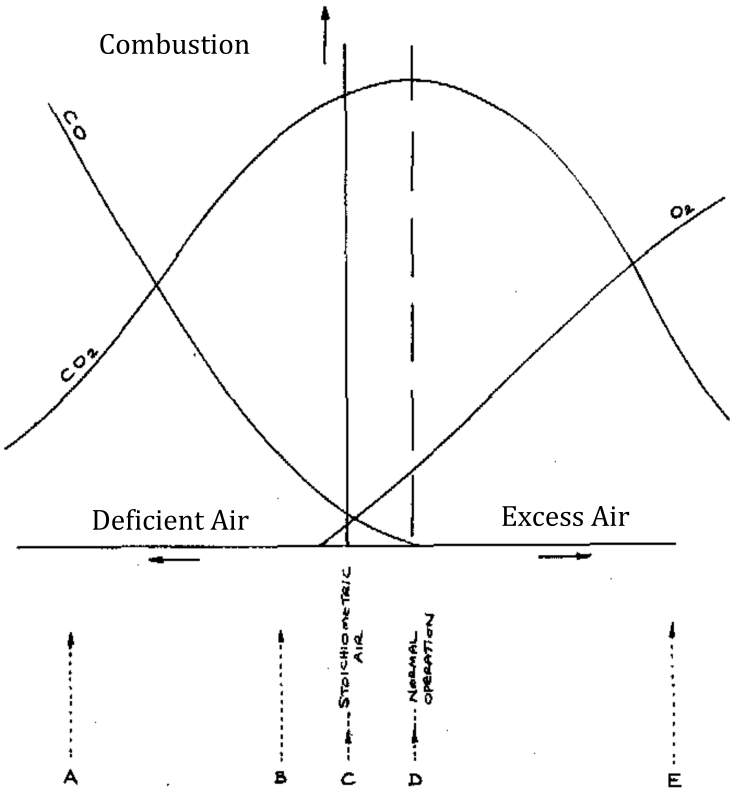
Exhibit 3-3: Typical Air Requirements

Fuel	Type of Furnace or Burners	Excess air % by weight
Pulverised coal	Fully water-cooled furnace with slag tap or dry ash removal	15 – 20
Coal	Spreader stoker	30 – 60
	Chain grate and traveling grate	15 – 50
	Underfeed stoker	20 – 50
Fuel oil	High capacity/efficiency register burners	5 – 10
	Typical industrial boiler unit	10 – 20
Natural gas	Register type burners	5 – 10
	Multifuel burners	7 – 12
Blast furnace gas	Intertube nozzle burners	15 - 18
Biomass / Wood	Dutch oven and Hoffit type	20 - 25
Bagasse	All furnaces	25 - 35
Black liquor	Recovery furnaces for kraft and soda pulping processes	5 - 7

3.11 Combustion Exhaust Gas Composition

The addition of either more or less air to a fuel than the stoichiometric requirement causes changes to be observed in the composition of the combustion gases leaving the boiler. The importance of this is that by measuring these exhaust gases; a good understanding of the combustion process within the boiler can be obtained. The principles involved are graphically presented in Exhibit 3-4 and explained as follows:

Exhibit 3-4: Relationship Between Excess Air, CO_2, O_2, and CO in flue gases



1. At air rates below those required for complete combustion (point A), it is not possible to convert all the carbon contained in the fuel to carbon dioxide. Under these conditions, carbon monoxide is produced as a result of partial combustion:

   $$2C + O_2 \rightarrow 2CO + \text{heat}$$

   Hence, the composition of combustion exhaust gases will show a high level of CO and a low level of CO_2.
2. As more air is added (point B), some of the CO is converted to CO_2 with the release of more heat:

   $$2CO + O_2 \rightarrow 2CO_2 + \text{heat}$$

   The CO level in the combustion exhaust gas falls sharply and the CO_2 level rises.
3. At the point where the stoichiometric air requirement is supplied (point C), the entire CO would have been converted to CO2 in an ideal system. Since no practical combustion system is perfect, we would expect the CO to have reached a low level and the CO2 to be near a maximum in the exhaust gases.

   A small amount of oxygen will normally be present in the combustion exhaust gas just prior to reaching the stoichiometric air point. This is because no practical burner system ensures perfect mixing of oxygen with the fuel, and hence there will always be some oxygen present at the same time as CO.
4. To achieve "complete" combustion, a small amount of air must be added over and above the stoichiometric requirement. The minimum excess air required is shown as "normal operation" (point D) in Exhibit 3-4. At this point, the CO2 level reaches a peak (typically. around 15-16% for oil fuels, and 11-12% for natural gas). The exhaust gas oxygen level at the normal operating point will typically be around 2%, and there should be no visible smoke, while the CO concentration should be very low, not exceeding 100-200 ppm in a well-maintained boiler.
5. As further air is added (Point E), the exhaust gas CO2 level drops due to dilution with the excess air, while the oxygen level builds towards 20.9%. High excess air rates are wasteful because of the introduction of oxygen and associated nitrogen (which does not take part in the combustion process) enter the system as cool air and leave it as hot flue gas, thus taking away valuable sensible heat from the combustion system.

The amount of excess air can be readily estimated for conventional combustion processes by using the following equation:

$$\%\ \text{Excess Air} = 100 \times \frac{\left(\%O_2\ -\ 0.5 \times \%CO\right)}{\left\{\left(0.264 \times \%N_2\right) - \left(\%O_2\ -\ 0.5 \times \%CO\right)\right\}}$$

Where $\%O_2$ is the percent oxygen, %CO is the percent carbon monoxide, if any, and $\%N_2$ is the percent nitrogen in the exhaust stream. The concentrations may be on a wet or dry basis as long as they are consistent. The percent nitrogen in the exhaust stream is usually not measured and is estimated by subtracting the sum of the carbon dioxide, oxygen, and carbon monoxide percentages from one hundred. That is:

$$\%\ N_2 = 100 - \left(\%CO_2 + \%O_2\ + \%CO\right)$$

The factor 0.264 in the denominator of the excess air equation [discussed below] is the ratio of the percent oxygen to nitrogen by volume in air (20.9 / 79.1). When nitrogen in the exhaust stream is multiplied by this ratio, it provides an estimate of the oxygen entering the process. This occurs because the amount of nitrogen leaving the process is assumed to be the same as the nitrogen entering the process in the air. This estimate assumes that there is little or no nitrogen in the fuel and that air is the source of oxygen. This equation should thus not be used for processes using coke oven or blast furnace off gas as fuel, since they have high levels of nitrogen, or when oxygen enrichment is used. The relatively small amount of nitrogen that reacts to form nitrogen oxides is negligible in this estimate.

The percent excess air equation thus relates the oxygen left over in the exhaust gas to the oxygen required in the process. The oxygen required in the process is equal to the amount of oxygen entering the process minus the amount left over as measured in the exhaust stream. The oxygen content in the exhaust stream must be "adjusted" or corrected for any carbon monoxide remaining in the stream. It is done by subtracting one-half of the measured carbon monoxide, if any, from the oxygen concentration. The resulting value represents the oxygen concentration that would be present if all the carbon monoxide had been combusted to carbon dioxide. Only one-half of a mole of oxygen is required to complete the combustion of carbon monoxide to carbon dioxide.

Example

The following example illustrates the excess air calculation procedure:

CO_2 measured in the exhaust duct = 10.0%
O_2 measured in the exhaust duct = 8.0%
CO measured in the exhaust duct = 0.05%

The estimated nitrogen content would be:

$$\%N_2 = 100 - (10.0 + 8.0 + 0.05) = 81.95\%$$

The estimated excess air oxygen would be:

$$\%\ \text{Excess Air} = 100 \times \frac{(8.0 - 0.5 \times 0.05)}{\{(0.264 \times 81.95) - (8.0 - 0.5 \times 0.05)\}} = 58.4\%$$

The importance of accurately measuring the carbon dioxide, oxygen, and carbon monoxide in the exhaust stream cannot be overemphasized when estimating excess air rates for a combustion operation and for correcting atmospheric emission concentrations to a specific basis or standard such as 12 percent CO_2, seven percent O_2 or 50 percent excess air. Correcting or adjusting an emission concentration such as the particulate concentration to a specific carbon dioxide or oxygen concentration, or excess air rate accounts for dilution of the exhaust stream. Dilution is caused by high excess air rates or by outside air leaking into the exhaust duct, which in turn reduces or dilutes pollutant concentrations. The excess air rates do not affect the rate or quantity of emissions (e.g. kg per hour or kg per million kcal of heat input) only the emission concentrations.

An estimate of excess air is of course only as good as the values used in the calculation, and great care must be used in making measurements for carbon dioxide, oxygen and carbon monoxide. An Orsat apparatus or other analytical instrument should be used to measure these gaseous concentrations in an integrated sample taken during a period of stable operation. Alternatively, instrumental gas analyzers could be used if carbon monoxide was also measured.

Calculations involving combustion gas composition and the estimation of excess air are also discussed in a later chapter.

3.12 Boiler Efficiency

Efficiency is used as a measure of economic performance of any piece of equipment. There are several terms used to define efficiency when used in the context of a boiler. These include simply efficiency, combustion efficiency, thermal efficiency, boiler efficiency, and fuel-to-steam efficiency. Following are their definitions.

3.12.1 Combustion Efficiency

Combustion efficiency is the effectiveness of the burner only and relates to its ability to completely burn the fuel. The boiler has little bearing on combustion efficiency. A well-designed burner will operate with as little as 15 to 20% excess air, while converting all combustibles in the fuel to thermal energy.

Combustion efficiency equals the total heat released in combustion, minus the heat lost in the stack gases, divided by the total heat released in combustion. For example, if 1,000 kcal/h are released in combustion and 180 kcal/h are lost in the stack, then the combustion efficiency is 82%:

$$= \frac{\left(1{,}000\ -\ 180\ \right)}{1{,}000} \times 100 = 82\%$$

3.12.2 Thermal Efficiency

Thermal efficiency is the effectiveness of heat transfer in a boiler. It does not take into account boiler radiation and convection losses - for example, from the boiler shell, water column piping, etc.

3.12.3 Fuel to Boiler Efficiency (Fuel-to-Steam Efficiency)

The term "boiler efficiency" is often substituted for combustion or thermal efficiency. True boiler efficiency is the measure of fuel-to-steam efficiency as discussed in this section.

Fuel-to-Steam efficiency is the most important, because it is a measure of the energy that is converted to steam. Fuel-to-Steam efficiency is equal to combustion efficiency less the percent of heat losses through blowdown, radiation and convection. For example, as in the example above, 20 kcal/h are lost to blowdown, and convection and radiation then these losses are 2%:

$$\text{Convection and Ratiation Losses} = \frac{20}{1{,}000} \times 100 = 2\%$$

If the combustion efficiency for this same case is 82% then the Fuel-to-Steam efficiency is 80%:

$$\text{Fuel to Steam Efficiency} = 82\% - 2\% = 80\%,\ \text{or}$$

$$\text{Fuel to Steam Efficiency} = \frac{1000 - \left(180 + 20\right)}{1{,}000} \times 100 = 2\%$$

Fuel-to-steam efficiency is the correct definition to use when determining boiler efficiency. In this manual, the term boiler efficiency is used in place of fuel-to-steam boiler efficiency calculated under steady operating conditions.

(Note: When comparing efficiencies it is important to know if the efficiency is based on the Gross calorific value {high heat value (HHV)} or Net calorific value {low heat value (LHV)} of the fuel. Both are essentially "correct" but comparing an efficiency based on HHV to one based on LHV value would not be correct. In the United States boiler efficiencies are, typically, based on the HHV. In Europe they are, typically, based on the LHV and result in a higher value than when based on HHV. The general relationship is:

For natural gas:

$$\%\ \text{Efficiency based on LHV} = 1.11 \times \%\ \text{Efficiency based on HHV}$$

For diesel fuel oil:

$$\%\ \text{Efficiency based on LHV} = 1.06 \times \%\ \text{Efficiency based on HHV}$$

Typical efficiencies of various types of boilers are:

Type of boiler	Net Efficiency (%)
Packaged, three pass	87
Water-tube boiler with economizer	85
Two pass, economic	78
Lancashire boiler	65
Lancashire boiler with economizer	75

3.13 Computing Boiler Efficiency and Losses

The efficiency of a boiler is defined as the ratio of heat gained by the feed water as it is turned into steam to the total energy available from the fuel supplied. In other words, it is a measure of the ability of a given boiler to efficiently generate the required amount of steam with minimum heat losses from a given fuel supply. To build a boiler that had little or no heat loss would be extremely expensive and practically impossible. Therefore, boiler efficiency is always less than 100%. However, many of the heat losses can be minimized through proper operating and maintenance practices.

Energy losses are sorted principally in five categories:

- Heat carried out of the stack by hot flue gases, excluding water vapor ("dry flue gas loss")
- Heat carried out of the stack by hot water vapor, including both sensible and latent heat
- Unburned fuel and products of incomplete combustion, including solid combustibles in ash and carbon monoxide in flue gas
- Heat lost from the boiler structure through the insulation (radiation and convection losses from the outside surface)
- Heat carried away with the boiler blowdown

Improvements in boiler efficiency result primarily from reductions in waste heat energy losses in the combustion gases, by ensuring that the boiler is well insulated, and by controlling boiler blowdown (with or without heat recovery from the blowdown).

3.13.1 Computing Boiler Efficiency

The following two methods can be used to compute overall boiler efficiency:

3.13.1.1 "Direct Method"

Boiler efficiency simply relates energy output to energy input, usually in percentage terms. It is represented as:

$$\text{Boiler Efficiency \%} = \frac{\text{Heat Exported in Steam}}{\text{Heat Provided by the Fuel}} \times 100$$

The terms 'heat exported in steam' and 'heat provided by the fuel' are covered in detail in the subsequent two Sections.

Heat Exported in Steam

This is calculated (using the steam tables) from availability of following information:

- Feedwater rate and temperature
- Pressure of exported steam
- Steam flow rate

Heat Provided by the Fuel

Heating value of the fuel may be expressed in two ways 'Gross' or 'Net' calorific value, and are defined below.

Gross calorific value

This is the theoretical total of the energy in the fuel. However, all common fuels contain hydrogen. It burns with oxygen to form water, which passes up the stack as steam.

The gross calorific value of the fuel includes the energy used in evaporating this water. Flue gases on steam boiler plant are not condensed; therefore the actual amount of heat available to the boiler plant is reduced. Gross calorific values for different fuels are given in the following table.

Fuel oil type	Grade	Gross calorific value (MJ/liter)
Light	E	40.1
Medium	F	40.6
Heavy	G	41.1
Bunker	H	41.8
Gas type		**Gross calorific value (MJ/m^3 at NTP)**
Natural		38.0
Propane		93.0
Butane		122.0

NTP - Normal Temperature and Pressure - is defined as 20°C (293.15 K, 68°F) and 1 atm (101.325 kN/m2, 101.325 kPa, 14.7 psia, 0 psig, 29.92 in Hg, 760 torr).

While, STP - Standard Temperature and Pressure - is defined by IUPAC (International Union of Pure and Applied Chemistry) as air at 0°C (273.15 K, 32 °F) and 105 pascals

Net Calorific Value

This is the calorific value of the fuel, excluding the energy in the steam discharged to the stack, and is the figure generally used to calculate boiler efficiencies. In broad terms:

$$\text{Net Calorific Value \%} = \text{Gross Calorific Value} - 10\%$$

This method, while direct, is nevertheless hard to apply in practice. In order to determine the useful heat in the steam output, many parameters, such as feed water flow rate, steam flow rate, steam quality, steam pressure and temperatures must be accurately known. Similar quantities must be obtained for the fuel if this method is to be used.

Instruments to properly measure all these quantities are expensive to purchase and must be carefully maintained and calibrated regularly. Most plants do not use such instruments.

3.13.1.2 "Indirect Method"

The indirect method applies the heat balance, which considers stack temperature and losses, excess air levels, blowdown, and radiation and convection losses. Therefore, the heat balance calculation for fuel-to-steam efficiency is:

$$\text{Efficiency \%} = 100 - (\text{Sum of the Losses\%})$$

It indirectly measures the efficiency by quantifying all the losses that contribute toward the inefficiency. This method is usually more practical, and is recommended in this manual. It is discussed in complete detail in Chapter 5 on efficiency calculations.

3.14 Factors Affecting Boiler Efficiency

The logical approach for improving boiler efficiency is to identify the losses, determine their relative magnitude and then to concentrate first on reducing the losses that have the greatest impact on boiler efficiency. In general, the dry flue gas loss is usually a high priority, while the heat losses by radiation and convection may also be important, especially in older boilers and those operated significantly below their rated capacity.

These are briefly discussed below.

3.14.1 Stack Temperature and Losses

Stack temperature is the temperature of the combustion gases (dry and water vapor) leaving the boiler. A well-designed boiler removes as much heat as possible from the combustion gases. Thus, lower stack temperature represents more effective heat transfer and lower heat loss through the stack. The stack temperature reflects the energy that did not transfer from the fuel to steam or hot water. Stack temperature is a visible indicator of boiler efficiency. Clearly, the hotter the gas in the stack, the less efficient is a boiler.

This is probably the largest single source of heat loss, and it can be reduced to a greater extent through proper operation and maintenance of the boiler.

The flue gases may be too hot for one of the following reasons:

- The burner is producing more heat than is required for a specific load on the boiler or air-fuel-ratio is not correct:
- This means that the burner(s) and damper mechanisms require maintenance and re-calibration.
- The heat transfer surfaces within the boiler are not functioning correctly, and the heat is not being transferred to the water:
- This means that the heat transfer surfaces are dirty, and require cleaning.

The number of passes that the flue gas travels before leaving the boiler is also a good criterion when understanding boiler efficiency. As the flue gas travels through the boiler it cools and, therefore, changes volume. Multiple pass boilers increase efficiency because the passes are designed to maximize flue gas velocities as the flue gas cools.

It should also be kept in mind that too much cooling of flue gases may result in temperatures falling below 'dew point', which will increase the potential for corrosion due to the formation of:

- Nitric acid (from the nitrogen in the air used for combustion)
- Sulfuric acid (if the fuel has a sulfur content)
- Water formed due to condensation of water vapors

3.14.2 Excess Air

The performance of boiler with regard to ‘excess air’ has been discussed in detail in the Section 3.10 on combustion principles. The following paragraphs discuss the importance of excess air control from the point of view of boiler efficiency.

Excess air provides safe operation above stoichiometric conditions. A burner is typically set up with 15 to 20% excess air depending on the fuel. Higher excess air levels result in fuel being used to heat the air instead of transferring it to usable energy, increasing stack losses.

Accurate control of the amount of air is essential to boiler efficiency:

- Too much air will cool the furnace, and carry away useful heat.

- Too little air will result in incomplete combustion; therefore, unburned fuel will be carried over and smoke may be produced.

In practice, however, there are a number of difficulties in achieving perfect (stoichiometric) combustion:

- The conditions around the burner will not be perfect, and it is impossible to ensure the complete matching of carbon, hydrogen, and oxygen molecules.
- Some of the oxygen molecules will combine with nitrogen molecules to form nitrogen oxides (NO_x).

To ensure complete combustion, an amount of 'excess air' needs to be provided. This has an effect on boiler efficiency.

At present, the control of the air/fuel mixture ratio on many existing smaller boiler plants is 'open loop' type. That is, the burner will have a series of cams and levers that have been calibrated to provide specific amounts of air for a particular rate of firing. Clearly, being mechanical items, these will wear and sometimes require calibration. They must, therefore, be regularly serviced and calibrated.

On larger plants, 'closed loop' systems may be fitted which use oxygen sensors in the flue to control combustion air dampers.

Air leaks in the boiler combustion chamber will have an adverse effect on the accurate control of combustion.

3.14.3 Radiation and Convection Losses

Radiation and convection losses will vary with boiler type, size, and operating pressure. The losses are typically considered constant in terms of kcal/hr, but become a larger percentage loss as the firing rate decreases. Boiler design factors that also impact efficiencies of the boiler are heating surface, flue gas passes, and design of the boiler and burner package.

Because the boiler is hotter than its environment, some heat will be transferred to the surroundings. Damaged or poorly installed insulation will greatly increase the potential heat losses.

A reasonably well-insulated shell or water-tube boiler of 500 BoHP (5MW) or more will lose between 0.3 and 0.5% of its energy to the surroundings.

This may not appear to be a large amount, but it must be remembered that this is 0.3 to 0.5% of the boiler's full-load rating and this loss will remain constant, even if the boiler is not exporting steam to the plant, and is simply on standby.

Thus to operate more efficiently, a boiler plant should be operated towards its maximum capacity. This, in turn, may require close cooperation between the boiler house personnel and the production departments.

3.14.4 Heating Surface

Heating surface is one criterion used when comparing boilers. Boilers with higher heating surface per boiler horsepower tend to be more efficient and operate with less thermal stress. Many packaged boilers are offered with 0.46 square meter (5 square feet) of heating surface per boiler horsepower as an optimum design for peak efficiency.

3.14.5 Blowdown Losses

Loss of boiler heat due to excessive blowdown can be a major factor in making the boiler inefficient.

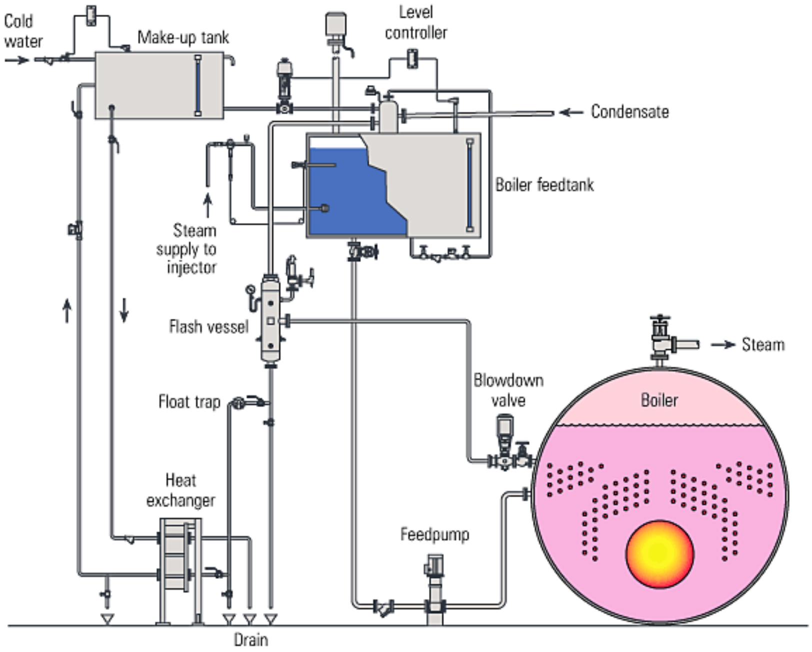
Blowdown of boiler water may be intermittent or continuous. It is necessary to control the level of TDS (Total Dissolved Solids) within the boiler. Blowdown lends itself to the recovery of the heat content of the blowdown water and can enable in realizing considerable savings.

Boiler blowdown contains massive quantities of heat, which can easily be recovered as flash steam in case of continuous blowdown. After it passes through the blowdown control valve, the lower pressure water flows to a flash vessel. At this point, the flash steam is free from contamination and is separated from the condensate, and can be used to heat the boiler feed tank (see Exhibit 3-5).

The residual condensate draining from the flash vessel can be passed through a plate heat exchanger in order to reclaim as much heat as possible before it is dumped to waste. Up to 80% of the total heat contained in boiler continuous blowdown can be reclaimed in this way.

In case of intermittent blowdown, heat is transferred to any fluid; e.g. make-up boiler feed water; by use of a heat exchanger. Heat recovery efficiency will depend on fluid being heated and the design of heat exchanger.

Exhibit 3-5: Typical Heat Recovery from Continuous Boiler Blowdown



3.15 Integral Boiler/Burner Package

Ultimately, the efficiency and performance of the boiler is based on the ability of the burner, the boiler, and the controls to work together. When specifying performance, efficiency, emissions, turndown, capacity, and excess air all must be evaluated together. The efficiency of the boiler is based, in part, on the burner being capable of operating at optimum excess air levels. Burners not properly designed will produce CO or soot at these excess air levels, foul the boiler, and substantially reduce efficiency. In addition to the boiler and burner, the controls included on the boiler (flame safeguard, oxygen trim, etc.) can enhance efficiency and reduce the overall operating costs. A true packaged boiler design includes the burner, boiler, and controls as a single, engineered unit.

4 Reducing the Losses Affecting Efficiency

The following discussion relates to the nature and magnitude of the effects of various factors on boiler efficiency, which were introduced briefly in the previous chapter. Graphical means of estimating quantifiable effects are presented, where possible.

4.1 Excess Air Rate

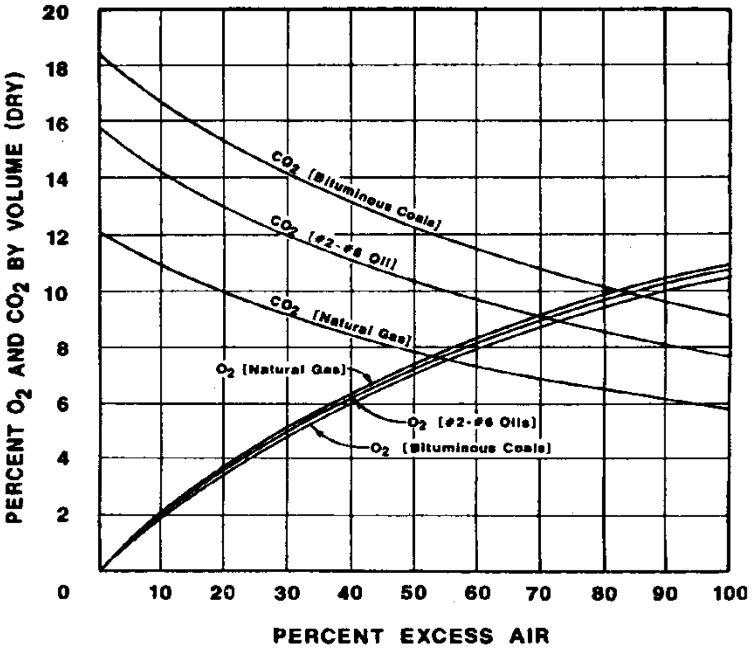
As discussed in a previous chapter, boilers should always be supplied with more combustion air than theoretically required in order to ensure complete combustion and safe operation. At the same time, however, boiler efficiency is dependent on the excess air rate. Excess air should be kept at the lowest practical level, to reduce the quantity of unneeded air which is heated and exhausted at the stack temperature.

If the air rate is too low, there will be a rapid buildup of carbon monoxide in the flue gas and, in extreme cases, smoke will be produced (i.e. unburned carbon particles). In the case of boilers firing gaseous fuels, the onset of smoke will not be as obvious as with oil, bagasse, or coal-fired systems.

To check whether the air-to-fuel ratio is correct, the usual method is to analyze the flue gases leaving the boiler. This is the basis for all boiler efficiency testing. By determining the composition of these gases, the actual excess air can be estimated.

Exhibit 4-1 describes the relationship between the exhaust gas composition measurements (CO_2 and O_2) and the excess air being fed into the boiler. The oxygen and carbon dioxide compositions are related by chemical balance and each of their values must give the same excess air percentage. If the excess air rates corresponding to the oxygen and carbon dioxide compositions do not agree, there is some error in the measurements.

Exhibit 4-1: Relationship between O_2, CO_2 and Excess Air



Efficiency losses due to excess air can be calculated if the exhaust gas temperature corresponding to the O_2 and CO_2 compositions is known. A full discussion of the calculation method, with useful charts and typical examples, is given in the Chapter 5 and Appendix B.

4.2 Burners

Burner performance is not an "operating parameter" in the same sense as excess air rate. However, burner performance is critical to boiler efficiency and is therefore addressed in this section.

The function of a burner is to mix the fuel and air in proportions that are within the limits of flammability, as well as to provide conditions for steady, continuous combustion. A well designed burner will mix the fuel and air so that a minimum amount of excess air is needed to achieve complete combustion. There are different types of burners commercially available for all types of fuels, each burner having its own characteristics, advantages and limitations. Their operation is discussed in more detail in the Chapter on burners.

The performance of a burner directly affects boiler efficiency because of the excess air required to obtain complete combustion at the burner. A poorly adjusted burner, or one incapable of efficiently mixing fuel and air at all load ranges, will increase excess air requirements and waste fuel.

Provided that the burners are clean and well maintained, the air to fuel ratio controls on modern boilers should be able to maintain the recommended excess air through much of the turndown ratio of the burner, although the excess air will increase at low turndown ratios.

Experience, however, shows that many burners are incorrectly adjusted. Changes take place due to wear on cams, linkages, pins, etc., often resulting in a change in the air-to-fuel ratio and a consequent loss of efficiency. Poorly maintained, worn or damaged burner parts also contribute to inefficiencies. For example, a scored or scratched burner tip on a pressure jet oil burner can lead to incorrect atomization of the fuel: some droplets may be small, some large. This often results in inadequate mixing of fuel and air, and an excessive formation of carbon monoxide. It is thus possible to have high oxygen levels in the flue gas (i.e. high excess air) at the same time as having high carbon monoxide. A similar effect can be caused by a burner tip which has been worn by “over-enthusiastic” cleaning (using abrasive tools) of the small hole or jet nozzle in the center, whose dimensions are critical for the proper atomization of a given fuel oil.

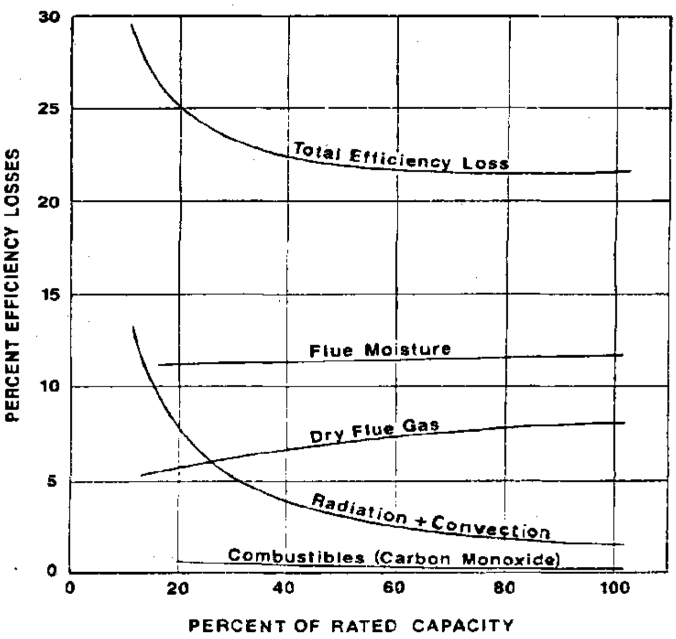
It is therefore important to understand that attaining the optimum excess air rate may be prevented by the use of damaged or incorrectly adjusted burner parts. Whenever high oxygen levels are found in conjunction with high combustibles (i.e. carbon monoxide or, in extreme cases, smoke), the mechanical integrity of the burner and air distribution system is suspect and should be checked. (Refer to Chapters 7 and 11 on burners and performance monitoring respectively).

4.3 Firing Rate

Exhibit 4-2 illustrates that there are significant changes in losses and boiler efficiency as the firing rate is varied. Especially obvious are the radiation and convection losses, which increase in percentage terms at lower firing rates, and the dry flue gas losses which tend to increase at higher firing rates (due to higher stack gas temperatures).

The highest efficiencies typically occur over the range of firing rates from 70 to 90% of rated capacity, and therefore boiler efficiency can be kept high by using the equipment in this range as much as possible. Indeed, where the process allows, it may be desirable to shut the equipment down from time to time and operate at approximately 90% capacity the rest of the time, rather than operate steadily at approximately 50% of capacity.

Exhibit 4-2: Variation in Boiler Efficiency Losses with Firing Rate



4.4 Flue Gas Temperature

Flue gas temperature is second only to excess air level in importance as a parameter controlling boiler efficiency. Exhibit 4-3 shows changes in combustion efficiency with flue gas temperature at various excess air levels for a boiler fired on natural gas. It is obvious that flue gas temperature must be held to a minimum in order to maximize boiler efficiency.

The two basic causes of high flue gas temperature are:

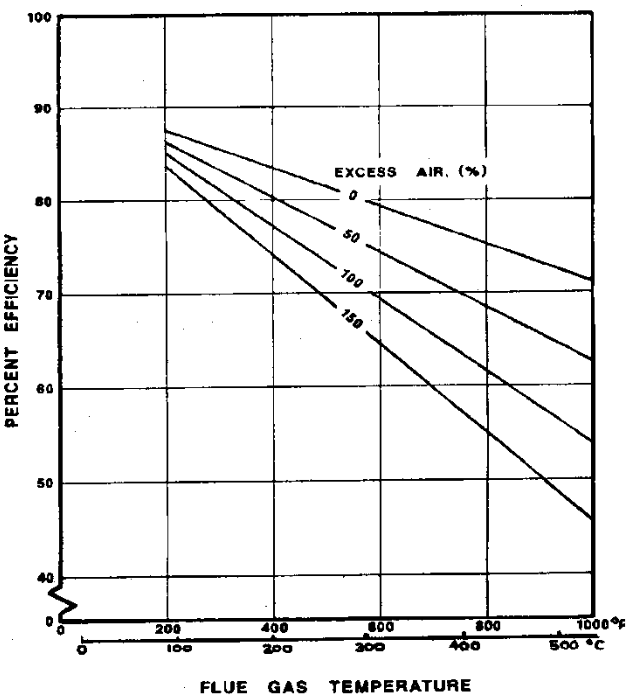
- Insufficient heat transfer surface
- Fouling of heat transfer surfaces

The boiler heat transfer surface may be increased by installing an air pre-heater or economizer to preheat combustion air or feed water, respectively. Proper feed water treatment and external tube cleaning is effective in minimizing fouling of heat transfer surfaces. The effects of feed water temperature, combustion air temperature and fouled heat transfer surfaces on boiler efficiency will be discussed further in subsequent sections of this chapter.

It may be seen from Exhibit 4-3 that efficiency decreases much more rapidly with increasing flue gas temperature at higher excess air levels. This emphasizes the importance of careful control of excess air level on boilers with insufficient heat transfer surface.

It is also well known that flue gas temperature cannot be reduced below its dew point as this might result in corrosion problems. Another negative factor might be reduction in stack draft or plume rise.

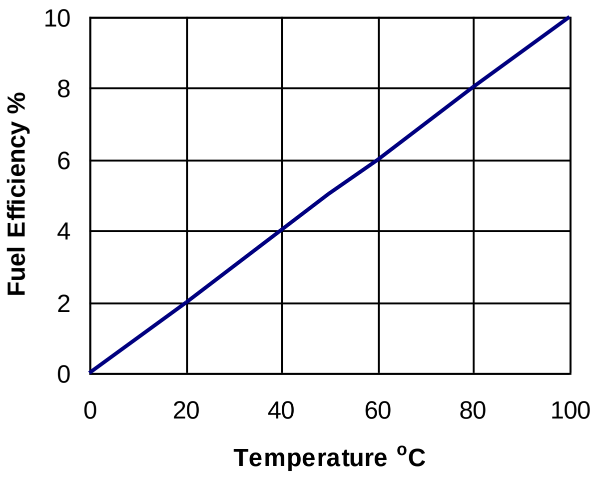
Exhibit 4-3: Variations in Combustion Efficiency with Flue Gas Temperature for Various Excess Air Levels



4.5 Feed Water Temperature

Boiler efficiency can be increased by preheating feed water in an economizer thus recovering waste heat from the flue gas. Exhibit 4-4 illustrates typical magnitude of efficiency improvements that might be expected from increased feed water temperatures. These results are based on efficiency increases for feed water preheat for a boiler originally producing saturated steam at 175°C from feed water at 90°C. In general, an increase in feed water temperature of 6°C (11°F) will result in 1% less fuel being burned at the boiler.

Exhibit 4-4: Efficiency Improvement from Feed Water Preheating



It is important to note that, while an increase in boiler feed water temperature will decrease the fuel used to generate steam, this will only affect the efficiency of the boiler if the boiler exhaust gases are used to heat this feed water.

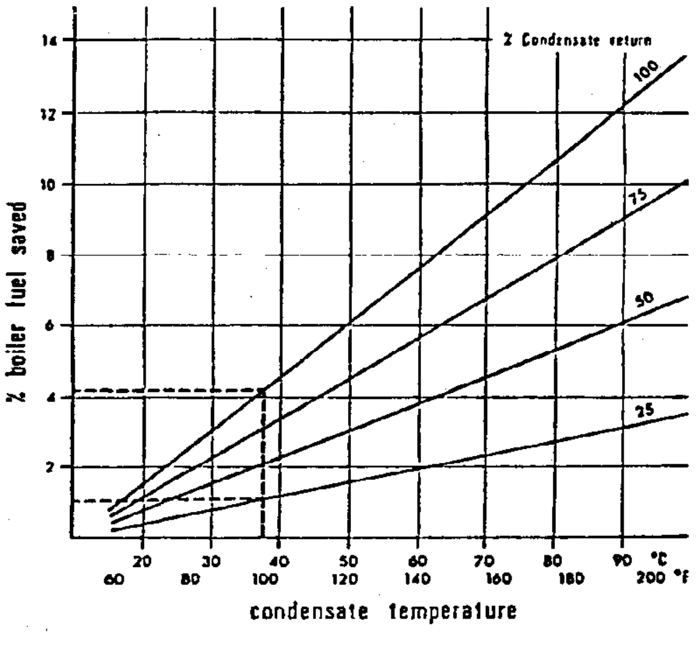
4.6 Condensate Recovery

Although this manual is not directly concerned with steam distribution systems and steam usage, condensate recovery is an important aspect of efficient boiler house operation and is discussed here.

When steam gives up energy in a typical process plant, it is often only the super heat and latent heat which is utilized, the steam condensate normally being removed as it is formed. This condensate is usually quite hot and thus contains much of the original energy that was put into the boiler feed water. Provided no contamination occurs, the condensate also represents a valuable source of pure water. Condensate can therefore be ideal boiler feed water, being both hot and free of impurities. Whenever possible, condensate should be recovered from the process and returned to the boiler house. In this way, the temperature of the feed water will be increased and, every 6°C (11°F) rise in this temperature will result in 1% less fuel being burned at the boiler.

Exhibit 4-5 indicates the levels of savings which can be obtained by increasing condensate recovery in a plant. Of course, there may be situations where the capital cost of installing condensate recovery lines and associated pumps cannot be justified by the savings in water, fuel and water treatment costs, but this is relatively unusual.

Exhibit 4-5: Boiler Fuel Saved by Condensate Return



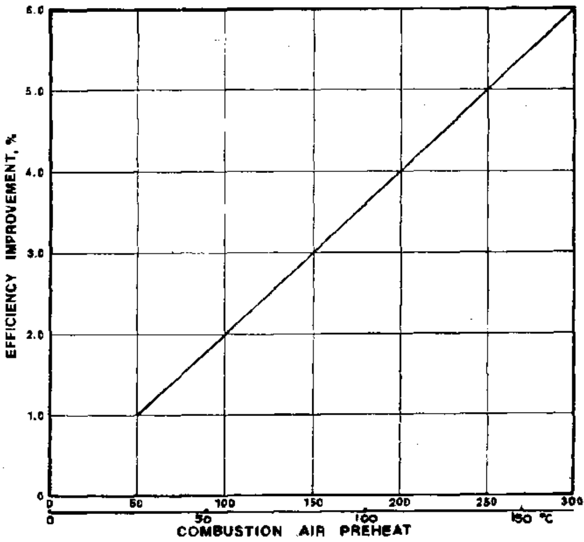
One reason sometimes given for not returning condensate is that it can be contaminated (or that there exists a risk of contamination, for example, in a sugar refinery). In such cases, there may be other uses for hot condensate which do not depend on having an entirely pure water supply. Alternatively, heat may be usefully recovered from contaminated condensate by passing it through a heat exchanger. In other situations, the condensate is passed through some type of "contamination detector" which will detect traces of impurities in the water and give appropriate warning.

4.7 Combustion Air Temperature

Boiler efficiency can be increased by recovering waste heat from the flue gas and preheating the combustion air. Exhibit 4-6 illustrates typical magnitudes of efficiency improvements to be expected from increased combustion air temperatures. These results suggest an efficiency increase of about 2% for every 55°C (100°F) increase in combustion air temperature.

As with feed water preheat, air preheat only improves the boiler efficiency when the boiler exhaust heat is used to preheat the combustion air. Any other source of heat, however, while it will save fuel at the boiler, will not improve the boiler efficiency.

Exhibit 4-6: Boiler Efficiency Improvement by Combustion Air Pre-heating with Boiler Exhaust Gases

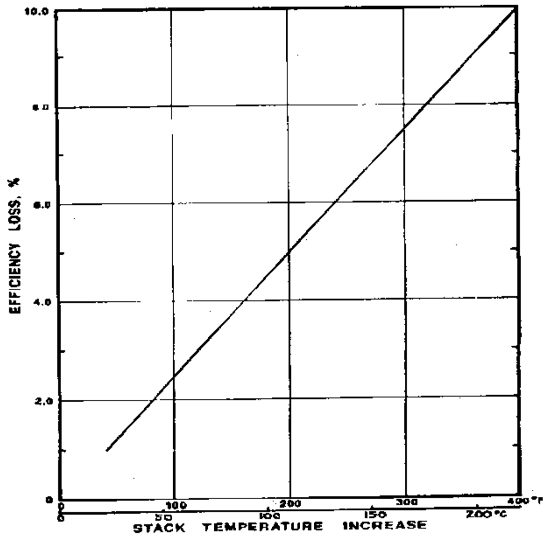


4.8 Fouling of Heat Transfer Surfaces

Deposits and fouling on the external tube surfaces of a water tube boiler, or similar gas-side conditions on internal tube surfaces of a fire tube boiler, will inhibit the transfer of heat from combustion products to the boiler water and thus lead to lower efficiencies. Water-side deposits resulting from inadequate water treatment will also impede heat transfer and lead to increased flue gas temperatures and reduced efficiencies. In the case of water-side scale build-up, tube failures due to overheating can occur.

Gas-side fouling of tube surfaces will also be reflected in increased flue gas temperatures when compared to "clean" conditions at a similar firing rate and excess air level. Exhibit 4-7 shows that the resulting loss in boiler efficiency is of the order of 1% for every 20°C increase in flue gas temperature. Therefore, the cost of gas-side fouling of tube surfaces may be estimated on the basis of an increase in stack temperature above "clean" baseline temperatures.

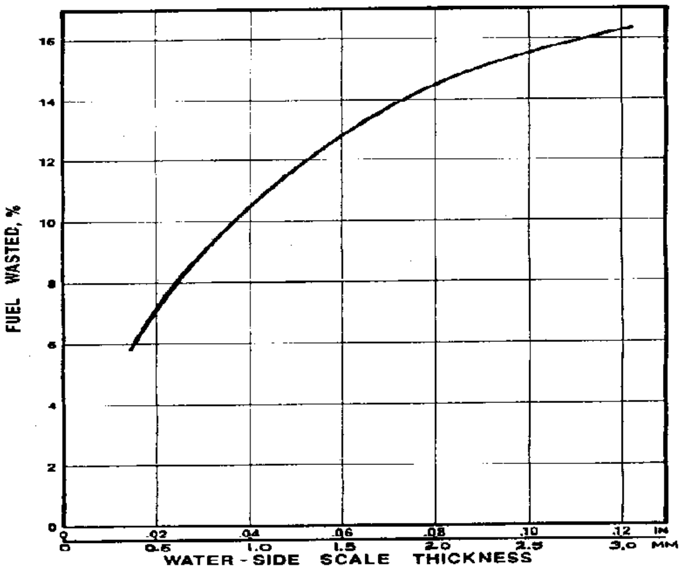
Exhibit 4-7: Boiler Efficiency Loss due to Stack Temperature Increase



Saturated steam boilers are usually designed to have stack temperatures of the order of 25°C to 40°C above the saturated steam temperature at high firing rates. In the absence of any reference temperatures, this design criterion may be used to estimate temperatures at "clean" conditions. Boilers equipped with economizers or pre-heaters would obviously not fit to this design criterion. If necessary, the boiler manufacturer should be able to supply a normal range of stack temperatures for a particular boiler design.

Fouling of water-side tube surfaces will retard heat transfer and increase tube metal temperatures due to the insulating effect of the water-side scale. Increased stack temperatures will indicate water-side tube fouling in the absence of gas-side tube fouling. Even though the most important effect of water-side tube fouling is the probability of tube failure, efficiency losses due to reduced heat transfer can also be substantial. Exhibit 4-8 presents typical percentages of fuel waste for various thicknesses of water-side scale deposits. A proper water treatment program will minimize fuel waste due to fouling by eliminating part or all of the scale-forming impurities introduced with the boiler make-up water.

Exhibit 4-8: Typical Fuel Wasted due to Scale Deposits



4.9 Blowdown

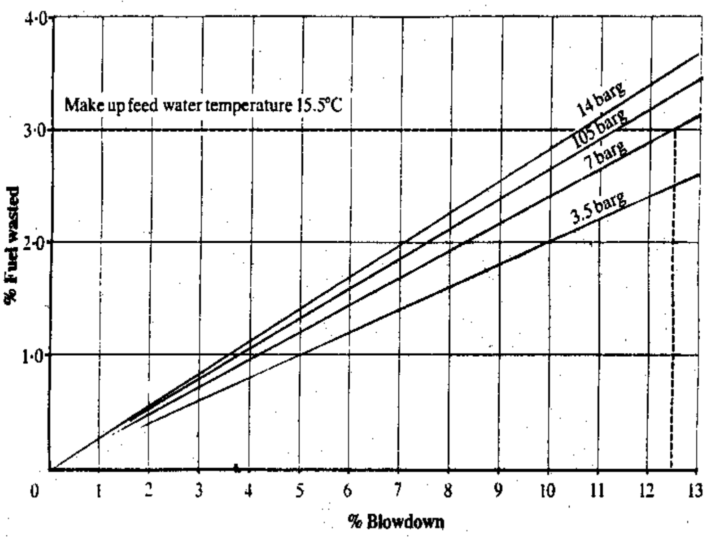
Loss of boiler heat due to blowdown can be a major factor in the inefficiency of a boiler. This section presents a discussion of the factors necessitating blowdown, types of blowdown, blowdown control, and recovery of heat from blowdown.

4.9.1 Solids Concentration

The process of raising steam inevitably results in the concentration of dissolved and suspended solids in the boiler water. Above a certain level of concentration, these solids, because they can be deposited as a scale inside the boiler, can cause local overheating which could lead to tube failure. The scale also impedes heat transfer, reducing the boiler efficiency. Finally, a high concentration of solids can encourage foaming and cause carry-over of water into the steam lines. ("Carry-over" is a general term covering all types of entrainment of boiler water into the steam. The main causes are: too high a water level in the boiler, excessive dissolved solids, excessive alkalinity, the presence of detergents, process fluids and, most commonly, excessive suspended solids.)

It is therefore necessary to control the level of concentration of the solids, and this is done by the process of "blowing down." A certain volume of water is drawn off, and is automatically replaced by feed water, thus maintaining the optimum level of total dissolved solids (TDS) in the water. The blow down, however, represents a loss of hot water, and thus leads to energy inefficiency, a decrease in boiler efficiency (see Exhibit 4-9).

Exhibit 4-9: Effect of Boiler Blowdown Rate on Fuel Wastage (% Fuel Wasted = % Loss in Efficiency)



The problem calls for the careful monitoring and supervision of the water conditions in all boilers, but the modern shell-type packaged units are even more vulnerable than earlier types because of their small water capacity and limited steam space in relation to their output.

The old-style Lancashire/Cornish boiler has a large water capacity. It can normally tolerate a high total dissolved solids content of up to 15,000 parts per million (ppm) without carry-over problems. Slow water movement, characteristic of this type of boiler, leads to the accumulation of precipitated solids in the bottom of the boiler and their removal requires the use of quick-acting full bore blow down valves, usually for 2-10 minutes per shift. This method is very inaccurate, so operators usually err on the safe side with the result that large amounts of sensible heat is lost in the blow down water.

The modern packaged shell-type boiler however, has a very limited water space, and therefore steam generation creates considerable turbulence. This keeps more solids in suspension and is less inclined to precipitate. Therefore TDS levels must be kept at much lower levels than in Lancashire-type boilers, i.e. 2,000-3,500 ppm, otherwise steam quality will deteriorate due to carry-over. American Boiler Manufacturers Association (ABMA) recommendations on TDS levels in modern boilers are summarized in Exhibit 4-10.

Exhibit 4-10: Recommended Limits of Boiler Water Concentration

Pressure at outlet of steam-generating unit, psig (barg)	Total Solids, ppm	Total alkalinity, ppm	Suspended Solids, ppm
0-300 (0-20)	3,500	700	300
301-450 (21-30)	3,000	600	250
451-600 (31-40)	2,500	500	150
601-750 (41-50)	2,000	400	100
751-900 (51-60)	1,500	300	60
901-1,000 (61-67)	1,250	250	40
1001-1500 (68-100)	1,000	200	20
1501-2,000 (101-133)	750	150	10
2,001(134) and higher	500	100	5

4.9.2 Intermittent and Continuous Blowdown

Blowdown may be intermittent and taken from the bottom of the boiler to remove any sludge that has settled. This is generally a manual operation carried out once per shift in a series of short, sharp blasts; the amount of blowdown is estimated from the reduction of level in the gauge glass, or simply from the duration of the blow. This has been the traditional method used with shell boilers.

Blowdown may also be continuous as a bleed from a source near the nominal water level. Since the concentration of solids will be the highest at the surface of the water (where boiling is occurring), surface blow down is an efficient way to reduce the solids concentration. A bleed valve opening is adjusted according to periodic total dissolved solids (TDS) measurements, and the flow is continuous. In more recent years this has become "step-continuous", the valve being opened or closed cyclically from a time signal, or from a signal derived from some property of the boiler water such as electrical conductivity. Automatic TDS control systems, based on this signal, are commercially available.

In modern practice both intermittent and continuous blowdown methods are used, the former mainly to remove suspended solids which have settled out, the latter to control TDS. It is important to carry out the intermittent blowdown sequence at periods of light load. It is also important that it should not be neglected; otherwise, sludge may build up to such an extent that heat transfer is impeded and the boiler fails, perhaps disastrously.

Accepting that blowdown is essential for the health of the boiler and the quality of the steam it supplies, there are two things which require attention.

The first and most important is that the quantity of blowdown should not exceed the minimum amount necessary. Anything in excess is a waste of energy. Proper control is most important.
When control of blowdown has been achieved, recovery of heat from the blowdown should be examined to see whether it is economical. On average, about 50% may be recoverable.

4.9.3 Control of Blowdown

In a simple, manually-controlled system, the blowdown valve must be manually set to give the required amount of blowdown. The aim is to maintain the total dissolved solids in the boiler water (usually expressed in ppm, parts per million) just below the prescribed maximum limit. This must be done by sampling and analyzing the water, and adjusting the blowdown until the desired conditions are achieved.

A simple checklist for estimating the quantity of blowdown from a boiler, if not already known, is presented below:

- If the TDS level of the feed water (mixture of condensate return and make-up) entering the boiler can be obtained, the required percentage of blow down can be calculated as follows:

$$\% \text{ Blowdown} = \frac{S_f \times 100}{\left(S_b - S_f\right)}$$

Where Sf = TDS level of feedwater in ppm
S_b = desired TDS level in boiler in ppm.

- For existing plants, the present blowdown method may consist of blowing down say one inch (25 mm) from the gauge glass at regular intervals. This may be converted to a volume by estimating the water surface area of the boiler (width times length), and multiplying this by the frequency, so that an equivalent continuous blowdown flow rate may be calculated. Remember that this will be related to the present average steam generation rate.

- Alternatively, the existing blowdown method may consist of opening the bottom blowdown valve for a given time at certain intervals. For the standard full-bore valve, the flow rate is controlled by the length and diameter of the blowdown line, and the boiler pressure. A pressure drop calculation may be used for estimating the flow rate when the valve is open, and from the figure obtained, an equivalent continuous blowdown flow rate may be calculated. Again this will be related to the average generation rate.

To check boiler water quality, it is necessary to take samples at regular intervals. It is most important that the sample is properly cooled and not drawn directly off the boiler or the blowdown line, or flash loss will completely upset the true analysis. A sample cooler is essential.

Provided the average blowdown requirement exceeds 40 kg/h (88 lb/h), blowing down a boiler continuously to control the TDS becomes the ideal procedure. With constant make-up water flow and steam-generating conditions, the continuous blowdown rate can be determined and controlled precisely. Within varying conditions, a compromise has to be made, either:

- The average continuous blowdown rate is accepted - resulting in the actual TDS level fluctuating up and down about a norm; or
- The blowdown rate maintains the base level of TDS, and the peaks are controlled intermittently.

Reliable and maintenance-free continuous blowdown can only be achieved using good quality valves. Given the need for fine control, large pressure reduction, and the presence of suspended solids, the valve must:

- Control accurately, and be easily and precisely set for the given flow rate.
- Withstand the arduous duty.
- Be easily moved to a purge position for cleaning the valve of deposits, and be easily reset to the control position.

4.9.4 Blowdown Heat Recovery

It is clear that for every liter of water which is discharged through the blowdown system, an equal quantity of make-up water is required at the boiler and feed tank. Because the blowdown is hot and the feed make-up is cold, waste heat recovery should be considered. Waste heat recovery from a continuous blowdown system is generally more manageable than from an intermittent system for the obvious reason that the supply and demand are constantly matched. Where more than one boiler is operated on an intermittent system, it is an advantage to stagger the blowdown timing cycle to spread more evenly the availability of waste heat.

The details on blowdown heat recovery systems are presented in Chapter 9.

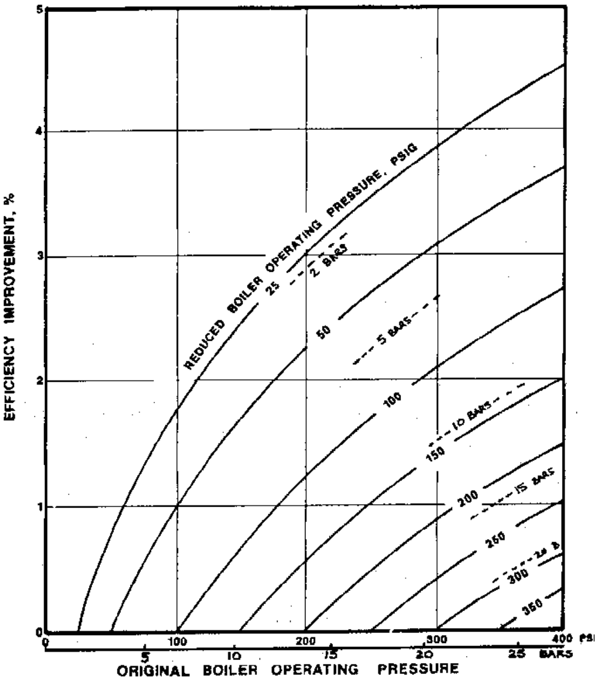
4.10 Steam Pressure

Reducing the boiler steam pressure is not generally viewed as an efficiency improvement technique. However, at those boiler installations where reductions in steam pressure are practical, this can be an effective means for saving up to 1 or 2 percent on the fuel bill. A portion of these savings results from lower stack temperatures and the accompanying increase in boiler efficiency. Lower steam pressures give lower saturated steam temperatures and in cases without stack heat recovery, a similar reduction in final flue gas temperature will result. The actual reduction in temperature for a given drop in steam pressure will depend on the particular pressure levels involved, since the relationship between saturated steam pressure and steam temperature is not linear. This fact is apparent from the steam tables. Exhibit 4-11 illustrates the magnitude of efficiency improvement that might be expected from reduction in boiler operating pressure.

There can be other immediate benefits from operating at reduced pressures which lead to lower fuel consumption. These can include lower radiated heat loss from steam mains, less leakage at flanges and packing glands, reduced boiler feed-pump energy consumption and less energy dissipation at pressure reducing stations.

Where possible, reduction in boiler operating pressure is seen to be an effective means of achieving higher efficiencies. However, it is important to note that the amount of reduction may be limited by process steam requirements, steam distribution piping, water carry-over in the boiler, or boiler design limitations.

Exhibit 4-11: Efficiency Improvement from Reducing Boiler Operating Pressure



4.11 Boiler Exterior Heat Losses

"Radiation and convection loss" refers to heat losses from the exterior surface of the boiler. On modern boilers, this loss is usually less than 1 percent of the heat input at maximum rating. It may, however, be considerably higher on older boilers and it can be as high as 10 percent where insulation is in poor condition and the boiler design is old.

Radiation and convection loss is not readily measurable and it is customarily included in the unaccountable losses to make up a heat balance. This is why it may appear to be higher than would be expected for actual surface losses alone. The loss is constant while the boiler is firing; and when the boiler is running under low load conditions, this loss represents a higher proportion of the total fuel used than under high fire conditions.

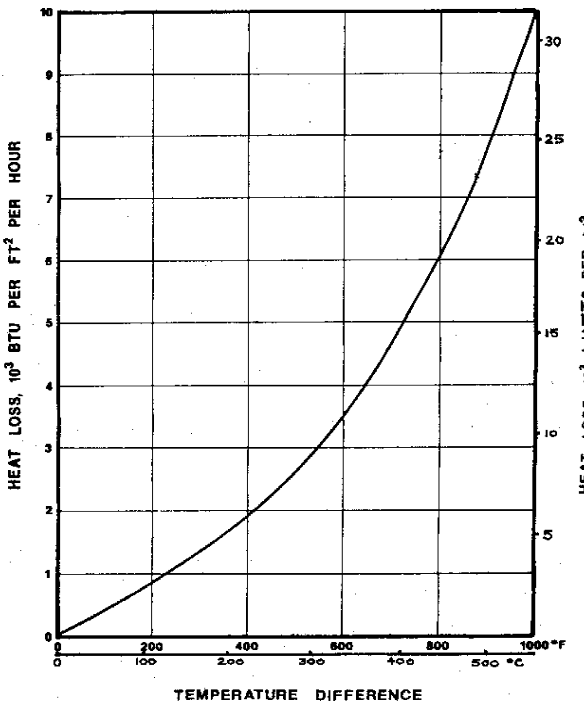
Thus, if a steam load is supplied by two boilers running part loaded at half of their maximum rating, radiation and convection losses (say 4 percent per boiler at full load) will be doubled to 8 percent. For this reason, the actual operating conditions on multiple boiler installations should always be very carefully checked to see if significant improvements might be made by rescheduling operations.

Exhibit 4-12 presents the approximate total rate of heat energy loss by radiation and convection from a bare flat surface based on the temperature difference between the surface and still air. Bare surface temperatures for boilers range from saturated steam temperature on exposed tube surfaces to air and gas temperatures on duct surfaces. Estimates of energy losses can be made for existing insulation by measuring the temperature of external surfaces and the temperature of the surroundings.

A good rule of thumb when evaluating the performance of existing insulation is that it should reduce surface temperatures to approximately 30°C above ambient. In any event, a complete engineering analysis of existing conditions and potential energy savings should be conducted to evaluate the justification for installation of insulating material, either inside the boiler or outside.

Note that great care should be taken with respect to external boiler insulation because this will raise the temperature within the walls of the boiler itself (i.e. brickwork temperatures will be increased). There is, therefore, the risk that the mechanical integrity of the boiler structure may be compromised. A better solution might be the addition of hot face insulation (e.g. ceramic fiber blanket) which will actually reduce the temperature in the walls and probably add to their life.

Exhibit 4-12: Heat Energy Loss from Bare Surface



4.12 Effects of Fuel

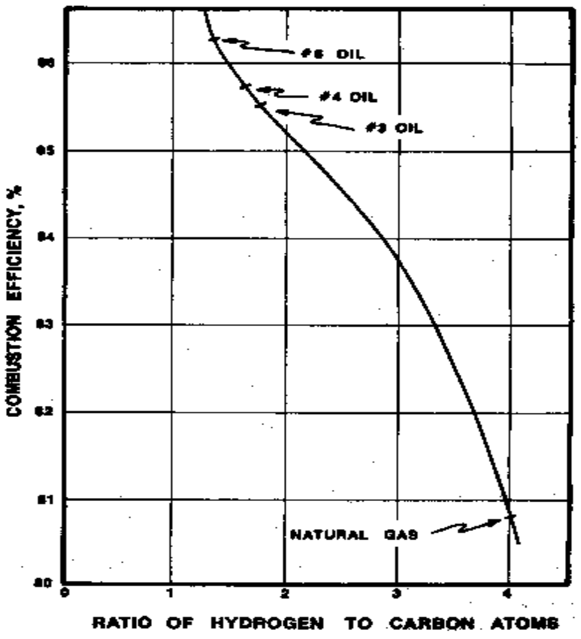
The compositions of different fuels will also have an effect on the boiler efficiency. While most boilers in Pakistan operate on gas, there are enough users of furnace oil to justify the following discussion.

The differences in the combustion of different fuels arise primarily from different hydrogen contents in the fuels, and result in differences in the moisture content in the exhaust gases, variation in the heat release rates causing different steaming rates, and dissimilar slagging, sooting, and fouling characteristics.

Exhibit 4-13 shows combustion efficiency versus carbon to hydrogen ratio for sto-ichiometric combustion and a flue gas temperature of 260°C (500°F). For comparison purposes, the points for natural gas and furnace oil are marked on the curve; these lie at the two extremes, while other gaseous fuels, such as LPG, and distillate oils such as high speed diesel and light diesel oil lie between these two points. As can be deduced from Exhibit 4-13, solid fuels would lie even higher than the furnace oil point. A similar trend, in terms of percent H_2 by weight and the volume percent of CO_2 found in dry flue gas with stoichiometric combustion, is shown in Exhibit 5-1.

The efficiency difference between furnace oil and gas, for example, arise from the fact that the hydrogen atoms form water vapor while the carbon atoms form carbon dioxide in the complete combustion process. The latent heat of vaporization cannot be recovered from the flue moisture since this would result in corrosion problems. Thus, the greater flue moisture production of natural gas, owing to its higher hydrogen content, results in greater flue gas energy losses and reduced boiler efficiencies as compared to furnace oil.

Exhibit 4-13: Variation in Combustion Efficiency with Hydrogen to Carbon Atom Ratio



While the theory clearly supports a higher efficiency for furnace oil compared to gas, the practical aspects of combustion act to reduce the seriousness of this difference. Oil usually requires more excess air than gas to burn completely, and it is much harder to mix well with air. In addition, oil is much more prone to soot formation, which upon accumulation can reduce heat transfer effectiveness and lower boiler efficiency. Finally, oil requires a much more complicated storage and handling system, and the standby losses of heating and pumping residual oil also contribute to reduce overall boiler efficiency.

Nevertheless, the trend shown in Exhibit 4-13 is a fact, and proves that an optimized and properly maintained oil fired system can achieve efficiencies as high as of a gas-fired system.

An additional important effect of the fuel composition is its heat content or calorific value (CV). Hydrogen has a per mass heat value several times that of carbon; thus the relative compositions of the two elements will affect the heating value of a fuel.

Exhibit 4-14 and Exhibit 4-15 summarize heating values for commonly used fuels. The higher heating value or gross heating value is determined when water vapor in the products of fuel combustion is condensed, and the latent heat of vaporization is included in the heating value of fuel. Conversely, lower heating value, or net heating value is obtained when heat of vaporization is not included. The heating values or fuel CVs given in Exhibit 4-14 and Exhibit 4-15 will be useful in the heat loss calculations included in Chapter 5.

Exhibit 4-14: Higher Heating Values or Gross Calorific Values (CV) for Various Chemical Substances

Substance	Molecular symbol	Higher heating values * kcal/kg	Higher heating values * Btu/lb
Carbon (to CO)	C	2,194	3,950
Carbon (to CO_2)	C	7,829	14,093
Carbon monoxide	CO	2,413	4,347
Hydrogen	H_2	33,942	61,095
Methane	CH_4	13,264	23,875
Ethane	C_2H_6	12,402	22,323
Propane	C_3H_8	12,038	21,669
Butane	C_4H_{10}	11,845	21,321
Ethylene	C_2H_4	12,020	21,636
Propylene	C_3H_6	11,693	21,048
Acetylene	C_2H_2	11,946	21,502
Sulfur (to 30_2)	S	2,211	3,980
Sulfur (to 50_3)	S	3,300	5,940
Hydrogen sulfide	H_2S	3,943	7,097

*All values corrected to 16°C (60°F), (30 in. Hg), dry.
For gases saturated with water vapor at 16°C (60°F), deduct 1.74 percent of the heating value

Exhibit 4-15: Higher Heating Values or Gross Calorific Values (CV) for Common Fuels in Pakistan

Natural Gas	*TOE/MMCF	Btu/ft3	kcal/m3
Sui Standard	24.696	980	8,718
Sui Raw	23.514	935	8,317
Mari	18.224	723	6,431
Coal	**TOE/Tonne**	**Btu/Ib**	**kcal/kg**
Lignite	0.305	5,500	3,056
Sub-Bituminous	0.472	8,500	4,722
Steam Coal	0.555	10,000	5,556
Imported Steam Coal	0.583	10,500	5,833
Liquid Fuels	**TOE/Tonne**	**Btu/Ib**	**kcal/kg**
Light Diesel Oil	1.101	19,818	11,010
High Speed Diesel	1.071	19,278	10,710
Furnace Oil	1.028	18,504	10,280
Liquid Petroleum Gas	1.176	21,168	11,760

*TOE = International Ton of Oil Equivalent = 39.68 x 10^6 Btu = 41.87 GJ

5 Efficiency Calculations

Efficiency calculation methods and data requirements are discussed in this chapter. Excess air and boiler stack loss charts are presented as Exhibit 5-2 through Exhibit 5-5. Forms for calculating the chemical balance of the fuel components are shown in Exhibit 5-6 and Exhibit 5-7. Finally, data forms, and forms suitable for calculations are brought together as

through Exhibit 5-12 at the end of the chapter. Worked examples appear in the Appendices.

5.1 Data Requirements

Before any detailed calculations are begun, basic boiler data should be available and understood. at the end of the chapter is a good example of the boiler details of interest.
For a complete calculation of the efficiency of a boiler, the following data are required (these are summarized in Exhibit 5-9 at the end of the chapter):

	Item	Usual units
A	**Fuel Characteristics**	
1.	Gross heating value	kcal/kg
2.	Hydrogen in fuel	Wt %
3.	Water in fuel	Wt %
B	**For Solid Fuels**	
4.	Ash in fuel	Wt % as fired
5.	Fraction of ash dispersed as fly ash	Wt fraction
6.	Combustibles in fly ash	Wt %
7.	Combustibles in slag ash	Wt %
8.	Slag ash exit temperature	°C
C	**For Oil Fuel**	
9.	Fuel preheat temperature	°C
D	**Flue Gas**	
10.	Gas temperature	°C
11.	Ambient temperature	°C
12.	Oxygen content	Volume % (dry basis)
13.	Carbon monoxide content	Volume % (dry basis)
14.	Maximum theoretical CO_2 in dry flue gas	Volume % (dry basis)
E	**Blowdown**	
15.	Blowdown temperature (after any heat recovery)	°C
16.	Blowdown quantity	Wt % of feedwater
17.	Feedwater temperature	°C
F	**Other**	
18.	Radiation and convection heat loss release from fuel	% of gross heat

Some of the data must be obtained by direct observation of the boiler operation and on-site measurements of the relevant parameters. Instruments for this work are described in Section 5.2. Other data are obtained from laboratory measurements, from fuel suppliers or, in the absence of information about a specific fuel, from published data on similar fuels. For example, typical values for hydrogen and water in fuels are shown in Exhibit 5-1.

For fuels which are essentially composed of carbon and hydrogen only, values of the maximum theoretical carbon dioxide content of dry flue gas may be calculated from the fuel analysis:

$$\left(CO_2\right)_{MAX} = \frac{\frac{C_{fuel}}{12}}{\frac{4.78\ C_{fuel}}{12} + \frac{1.89\ H_{fuel}}{2}} \times 100$$

Where

$(CO_2)_{MAX}$ = Volume % CO_2 in dry flue gas at theoretical Stoichiometric combustion

C_{fuel} = Weight % of carbon in fuel

H_{fuel} = Weight % of hydrogen in fuel

Typical values of $(CO_2)_{MAX}$ are given in Exhibit 5-1.

Estimation or calculation of the heat loss by radiation and convection is discussed in Section 5.6.

Exhibit 5-1: Fuel CV Ratios, Hydrogen and Water Contents, and Maximum CO_2 Produced

Fuel	$\frac{\text{Net CV}}{\text{Gross CV}}$	H Wt%	H_2O Wt%	Max. Theoretical CO_2 Volume (mole) % in dry flue gas
Methane	0.90	25.0	-	11.7
Propane	0.92	18.2	-	17.7
Butane	0.92	17.2	-	14.0
Hexane	0.93	16.3	-	-
Gasoline	0.93	14.4	-	14.9
Kerosene	0.93	13.6	-	15.1
Diesel oil	0.94	12.8	-	15.5
Light fuel oil	0.94	12.4	-	-
Furnace oil	0.94	11.8	-	15.9
Coal tar	0.97	6.2	-	-
Anthracite	0.98	3.0	1	20.0
Semi bituminous	0.97	4.4	1	-
Bituminous	0.96	5.5	7	18.5
Lignite	0.94	5.7	15	19.2
Peat	0.91	6.4	20	
Wood	0.90	6.8	15	19.9
Coke	0.99	1.1	2	20.7

NB: For solid fuels, wt% H and wt% H_2O are for good quality commercial fuels (not proximate or ultimate analysis)
CV = calorific value or heating value

5.2 Instruments for Monitoring and Testing

The most important data needed for calculating boiler efficiency are the flue gas oxygen and carbon dioxide content and temperature. With only these two pieces of information, a good estimate of efficiency can be made. It is discussed in the next Section. For a complete calculation, and for carrying out a thorough evaluation of performance and making appropriate adjustments, the carbon monoxide level in the flue gas is also needed. The instruments required for monitoring and testing are presented in Chapter 6 on instrumentation.

5.3 Simplified Flue Gas Loss Calculations

The major losses from an oil or gas-fired boiler are those associated with the sensible heat in the flue gases (and the latent heat of the corresponding water vapor). Losses due to unburned carbon monoxide should normally be small (much lower than 1% of the energy input to the boiler) and due to radiation and convection less than 3% of the energy input. Blowdown losses should normally be less than about 2%. A quick method of estimating boiler efficiency is therefore to calculate the flue gas losses from flue gas temperature and oxygen and carbon dioxide content, and to include a fixed estimate for the other losses.

This method may be applied using the charts provided in Exhibit 5-2 through Exhibit 5-5. All these charts are based on typical gross calorific values of the fuels concerned, and on an ambient temperature (i.e. inlet combustion air temperature) of 20°C. Where the ambient temperature is not 20°C, an appropriate correction must be made.

For example, suppose we have the following data:

Fuel fired : heavy fuel oil
Flue gas temperature : 285°C
Ambient temperature : 30°C
Oxygen content : 4 % by volume, dry basis
Radiation/blowdown losses : 6 %

Exhibit 5-3 refers to heavy fuel oil. Note it is based on gross calorific value and on an ambient temperature of 20°C. The calculation procedure is shown in Exhibit 5-5.

1. Correct the flue gas temperature $T_{(fg)}$ for higher ambient temperature T_a:
   $T_{(fg)corrected} = T_{(fg)} - [T_a - 20] = 275°C$
2. Start from the oxygen composition of 4% on the vertical axis and move horizontally to the oxygen line.
3. Move vertically down to the excess air figure (in this case, 22%).
4. Move vertically up to the flue gas temperature line (275°C) and then horizontally to the "% flue gas loss" axis.
5. Read off the flue gas loss (in this case, 17%).
6. Estimate the boiler efficiency: 100 %
   Less flue gas loss: -17 %
   Less other losses: -6 %
   (radiation/blowdown)
   Approximate efficiency: 77 %

Precise values of the radiation/convection and other losses are not usually needed to improve boiler performance. In most factories, the knowledge of flue gas losses alone is sufficient for the boiler engineer to achieve and maintain improvements in boiler performance, allowing him to approach the optimum performance very closely. By minimizing the flue gas loss, the boiler engineer is improving the boiler efficiency: provided there are no excessive losses due to high carbon monoxide levels, he will be able to operate his boiler at the optimum point without the knowledge of exact value of other losses such as radiation/convection and blowdown.

For this reason the quantity (100 - flue gas loss) is often referred to as the "combustion efficiency": this is what is affected when making adjustments to the combustion process. This is the efficiency obtained from the flue gas measurements, and, therefore, is commonly quoted. It is often used to approximate the overall boiler efficiency, but it is important to remember that there is a difference between the boiler efficiency and the combustion efficiency: that is, the heat and blowdown losses from the boiler.

Knowledge of the excess air rate is particularly important and this comes from the flue gas oxygen content. The excess air rate should be brought down to the lowest level possible consistent with a low carbon monoxide level. In the absence of a carbon monoxide measurement, the excess air can be reduced on oil and coal-fired boilers to the point where the boiler begins to emit smoke and then increased slightly to eliminate all traces of smoke.

Exhibit 5-2: Light and Medium Fuel Oils: Flue Gas Losses and Excess Air based on Gross Calorific Value and Ambient Temperature of 20°C

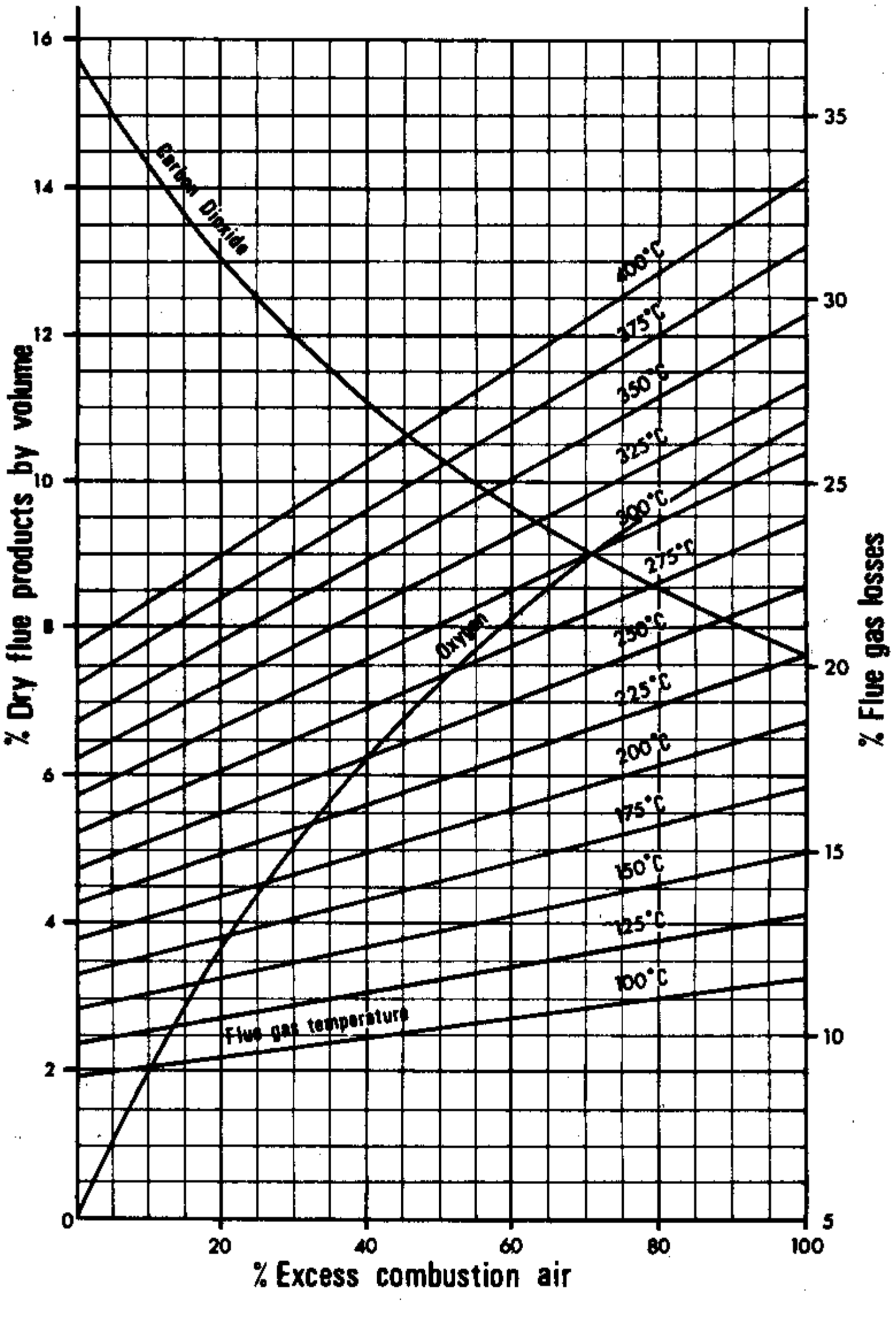


Exhibit 5-3: Heavy Fuel Oil: Flue Gas Losses and Excess Air based on Gross Calorific Value and Ambient Temperature of 20°C

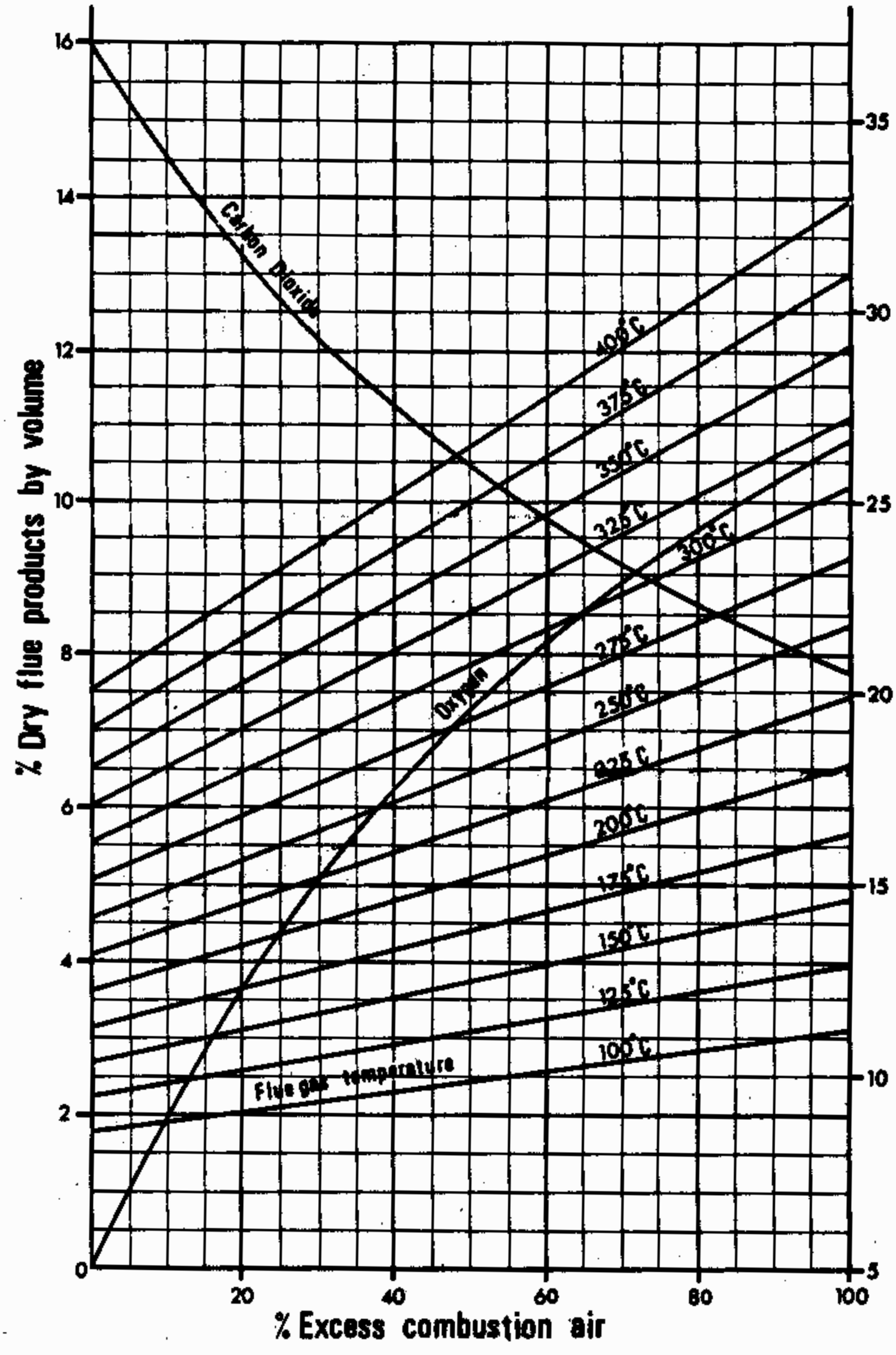


Exhibit 5-4: Natural gas: Flue Gas Losses and Excess Air based on Gross Calorific Value and Ambient Temperature of 20°C

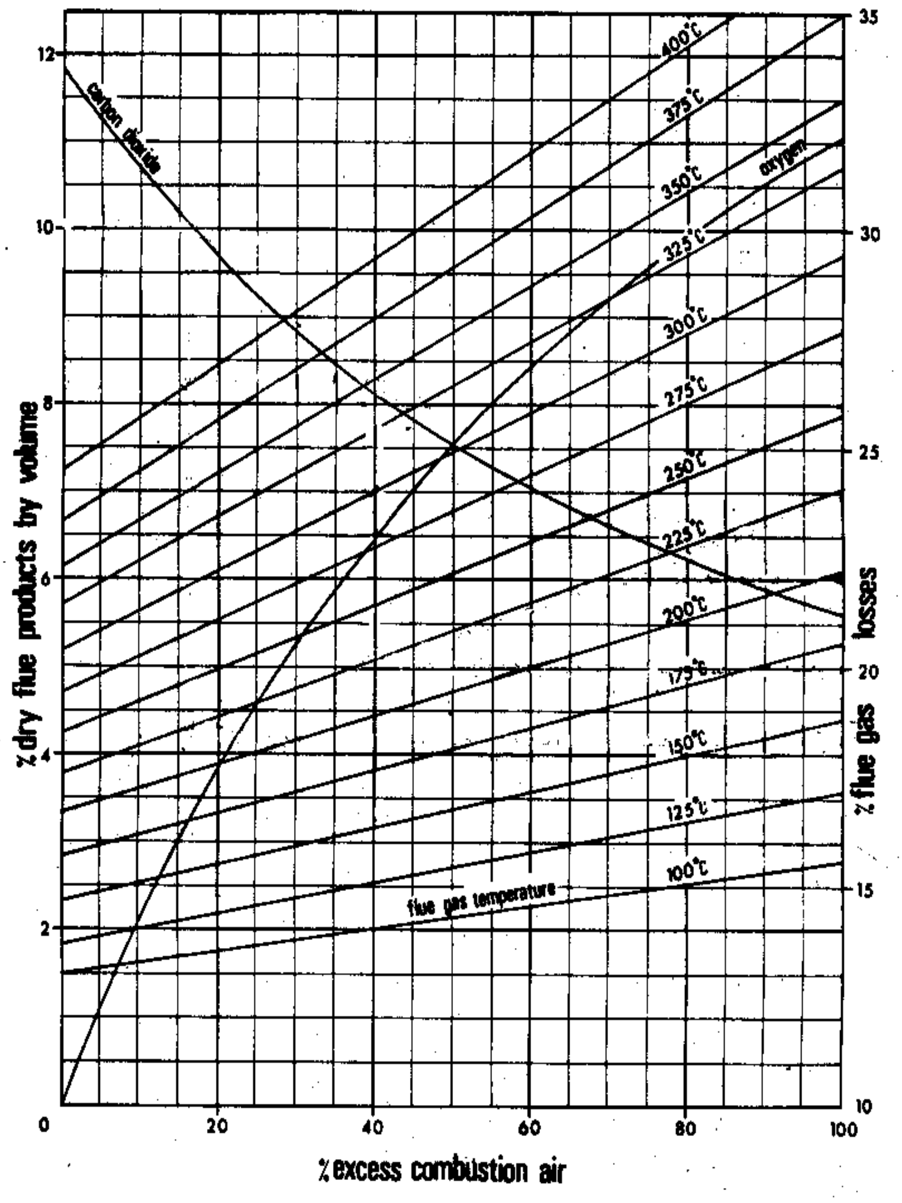
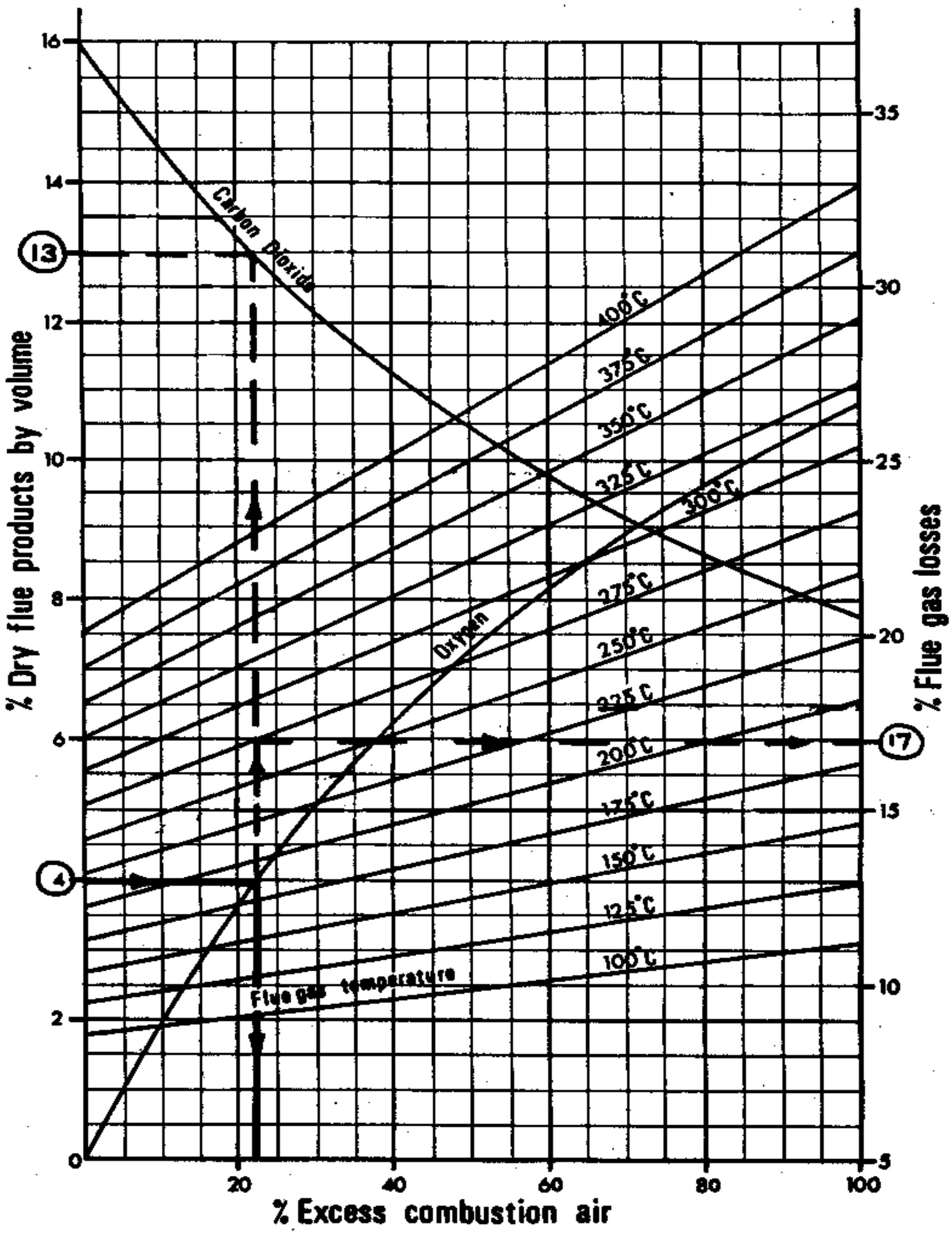


Exhibit 5-5: Heavy Fuel Oil Calculation Example



Note that Exhibit 5-5 can also be used to estimate the flue gas carbon dioxide content (13% in this case) by beginning at the 22% excess air point (corresponding to the measured O_2 value) and reading vertically upward to the carbon dioxide curve, and then across to the left axis.

5.4 Stoichiometric Calculations

The charts shown in Exhibit 5-2 through Exhibit 5-4 are based on the characteristics of typical fuels. The actual fuel used in a boiler will rarely be exactly the same as that used to derive a given chart, although errors due to small changes in fuel composition will generally be insignificant.

However, for the boiler engineer who wishes to calculate his own charts, the following procedure may be used along with the form given in Exhibit 5-6.

1. Obtain the fuel composition (weight % carbon, hydrogen, etc.).
2. Calculate the kilogram moles in 100 kilograms of the fuel.
3. Calculate the corresponding kg-moles of oxygen required for combustion of each component in the fuel.
4. Calculate the kg-moles of each product of combustion.
5. Calculate the total oxygen required, and hence the total nitrogen introduced into the system, for theoretical (stoichiometric) combustion
6. Specify the excess air present (as a percentage of the stoichiometric air) and enter the corresponding kg-moles of nitrogen and oxygen in the combustion gas products.
7. Obtain the total quantities of all components in the combustion gas.
8. Calculate the composition of the gas (wet basis and dry basis).

This calculation gives the complete exhaust gas composition for any fuel and specified excess air rate.

Exhibit 5-7 shows an example calculation using furnace oil (heavy fuel oil) at an excess air rate of 200%.

Exhibit 5-6: Form for Calculating Exhaust Gas Composition based on Fuel Chemistry and Excess Air

Fuel type ______________________					Date ______________		Basic reactions		
Analysis (% weight)			Carbon		__________		$C + O_2 \rightarrow CO_2$		
			Hydrogen		__________		$2H_2 + O_2 \rightarrow 2H_2O$		
			Sulphur		__________		$S + O_2 \rightarrow SO_2$		
			Oxygen		__________				
			Ash etc.		__________				
					100.0				
Basis: 100 kg fuel									
Fuel					Combustion products – kg mols				
	Kg	MW	kg mols	kg mols O_2 reqd.	CO_2	SO_2	H_2O	N_2	O_2
C		12						___ %O_2x 79/21 = ___	
H_2		2							
S		32							
O_2		32		( )					
Other		-							
	100.0								0
		Excess	air ___%						
			Totals						

Analysis of wet products			Analysis of dry products		
Item	kg mols	% vol	Item	kg mols	% vol
CO_2			CO_2		
SO_2			SO_2		
H_2O					
N_2			N_2		
O_2			O_2		
Totals		100.00	Totals		100.00

Exhibit 5-7: Example Calculations of Exhaust Gas Composition with Furnace Oil at 200% Excess Air

Fuel type Heavy fuel oil (example)					Date a / b / cd		Basic reactions		
Analysis (% weight)			Carbon		85.4		$C + O_2 \rightarrow CO_2$		
			Hydrogen		11.4		$2H_2 + O_2 \rightarrow 2H_2O$		
			Sulphur		2.8		$S + O_2 \rightarrow SO_2$		
			Oxygen		-				
			Ash etc.		0.4				
					100.0				
Basis: 100 kg fuel									
Fuel					Combustion products – kg mols				
	Kg	MW	kg mols	kg mols O_2 reqd.	CO_2	SO_2	H_2O	N_2	O_2
C	85.4	12	7.12	7.12	7.12			10.6 × 79/21 = 37.4	
H_2	11.4	2	5.70	2.85			5.70		
S	2.8	32	0.09	0.09		0.09			
O_2	0	32	0	(0)					
Other	0.4	-							
	100.0			10.06	7.12	0.09	5.70	37.4	0
	Excess	air	200%	20.12				75.68	20.12
			Totals	30.18	7.12	0.09	5.70	113.52	20.12

Analysis of wet products			Analysis of dry products		
Item	kg mols	% vol	Item	kg mols	% vol
CO_2	7.12	4.86	CO_2	7.12	5.06
SO_2	0.09	0.06	SO_2	0.09	0.06
H_2O	5.70	3.89			
N_2	113.52	77.46	N_2	113.52	80.60
O_2	20.12	13.73	O_2	20.12	14.28
Totals	146.55	100.00	Totals	140.85	100.00

This calculation may be repeated for different excess air rates so that the appropriate curves, such as seen in Exhibit 5-2 through Exhibit 5-4, can be developed. These curves will allow the boiler engineer to estimate excess air rates from flue gas composition data.

1. To calculate the flue gas losses, it is necessary to continue with the calculation as follows:
2. For a given excess air condition, the previous calculation provides the quantity of combustion gas produced from 100 kg of fuel. For this amount of fuel, the total heat release is known from the calorific value of the fuel. The ambient air temperature should be fixed (for example, Exhibit 5-8 through Exhibit 5-10 are based on 20°C).
3. A flue gas temperature may be assumed, say 200°C.
4. For an exit temperature of 200 °C, calculate the sensible and latent heat losses for the known quantity of combustion products, relative to the ambient temperature chosen. Express these losses as a percentage of the heat content of 100 kg fuel.
5. Repeat the calculation for a different excess air rate for a flue gas temperature of 200°C.
6. Repeat the calculations for other flue gas temperatures.

The loss data calculated in this way may be superimposed on the gas composition/excess air charts.

5.5 Comprehensive Calculation Method

A comprehensive method of estimating boiler efficiency is presented here, taking into account all sources of loss discussed in previous sections. The data required were listed in Section 6.1. The following ten equations are used to calculate efficiency based on the gross calorific value of the fuel; in addition an equation for calculating excess air is given. A data sheet organizing these values is presented as Exhibit 5-10 at the end of the chapter; Exhibit 5-11 is a simplified version of this data sheet for gas and liquid fuels only.

It should be noted that equations 1 through 4 are only applicable for solid fuels. For gas and liquid fuels the LFA, LSA, L^1FA and L^1SA should simply be set to zero.

1. Loss as combustibles in fly ash

$$L_{FA} = \frac{A_{fuel} \times F_{FA} \times C_{FA} \times 8083 \times 100}{(1 - C_{FA}) \times CV_G}$$

L_{FA} = % heat loss as combustibles in fly ash
A_{fuel} = wt. fraction ash in fuel (as fired basis)
F_{FA} = wt. fraction of total ash to fly ash
C_{FA} = wt. fraction combustibles in fly ash
CV_G = gross calorific value (kcal/kg) of fuel as fired

2. Loss as combustibles in slag ash

$$L_{SA} = \frac{A_{fuel} \times F_{SA} \times C_{SA} \times 8083 \times 100}{(1 - C_{SA}) \times CV_G}$$

L_{SA} = % heat loss as combustibles in slag ash
F_{SA} = wt. fraction of total ash to slag ash
C_{SA} = wt. fraction combustibles in slag ash
A_{fuel} and CV_G as above

3. Loss as sensible heat in fly ash

$$L^1_{FA} = \frac{A_{fuel} \times F_{FA} \times (T_{FG} - T_A) \times 0.21 \times 100}{(1 - C_{FA}) \times CV_G}$$

$L^1{}_{FA}$= % heat loss as sensible heat in fly ash
T_{FG} = flue gas temperature, °C
T_A = ambient temperature, °C
F_{FA}, CV_G and A_{fuel} as defined previously.

4. Loss as sensible heat in slag ash

$$L^1_{SA} = \frac{A_{fuel} \times F_{SA} \times (T_{SG} - T_A) \times 0.21 \times 100}{(1 - C_{SA}) \times CV_G}$$

$L^1{}_{SA}$= % heat loss as sensible heat in fly ash
TSG = slag ash exist temperature, °C
A fuel, FSA, CVG, CSA as defined previously.

Note: in (3) and (4) above, the constant 0.21 is the specific heat (kcal/kg °C) of ash and slag

5. Loss in dry flue gas

$$L_{DG} = \frac{K\left(T_{FG} - T_A\right) \times \left[1 - \frac{\left(L_{FA} - L_{SA}\right)}{100}\right]}{\left(CO_2\right)}$$

L_{DG} = heat loss in dry glue gas
(CO_2) = volume % CO_2 in dry flue gas
L_{FA} , L_{SA}, T_{FG} , T_A as defined previously.

Also:

$$CO_2 = \left[1 - \frac{\left(O_2\right)}{21}\right] \times \left(CO_2\right)_{MAX}$$

(O_2) = volume % O_2 in dry flue gas
$(CO_2)_{MAX}$ = theoretical CO_2% in dry flue gas assuming stoichiometric combustion at zero excess air (see Section 5.1)

Values of $(CO_2)_{MAX}$ are shown in Exhibit 5-1 but the above equation may be used if the fuel consists mostly of carbon and hydrogen.

Use the following values for K:

	Net CV basis	**Gross CV basis**
Coke	0.70	0.69
Anthracite	0.68	0.67
Bituminous coal	0.63	0.60
Coal tan	0.60	0.58
Liquid Petroleum fuels	0.56	0.53
Natural gas	0.38	0.34

$$K = \frac{69.7\ C_{fuel}\left(CV_N\right)^2}{\left(CV_G\right)^3}$$

C_{fuel}= wt % carbon in fuel
CV_N= net calorific value (kcal/kg) as fired
CV_G= gross calorific value (kcal/kg) as fired

6. Moisture in flue gas loss

$$L_{H_2O} = \frac{\left[\left(H_2O\right)_{fuel} + 9\ H_{fuel}\right] \times \left[588 - T_A + 0.50\ T_{FG}\right]}{CV_G^1}$$

$(H_2O)_{fuel}$ = wt % water in fuel (as fired)
H_{fuel} = wt % hydrogen in fuel (Exhibit 5-1)
CV^1_G = CV_G for solid or gas fuel, kcal/kg (assumes no external preheating) (Exhibit 4-14 and Exhibit 4-15)
CV^1_G = $CV_G + (T_{fuel} - T_A) \times 0.47$ for oil fuel with external preheating before firing)
T_{fuel} = preheat temperature of fuel oil, °C
0.47 = mean specific heat of fuel oil, kcal/kg °C

7. Loss due to Unburnt CO

$$L_{CO} = \frac{K(CO) \times \left[1 - \frac{(L_{FA} - L_{SA})}{100}\right]}{(CO) + (CO_2)}$$

L_{CO} = % heat loss as unburnt CO in flue gas
(CO) = volume % CO in dry flue gas

Use the following K values:

	K
Coke	70
Anthracite	65
Bituminous coal	63
Coal tar	62
Liquid petroleum fuels	48
Natural gas	32

8. Structure radiation and convection losses

L_{RC} = loss by radiation and convection, % of gross fuel fired

The value of L_{RC} should be calculated from structure surface temperature by a separate calculation (see Section 5.6). Otherwise, use the following approximate relationship:

$$L_{RC} = \frac{100}{(CAP)}$$

(CAP) = % of rated output at which the boiler or burner is operating during test

This equation assumes heat loss L_{RC} is 1% at rated capacity. This will probably be high for well insulated structures and low for those which are poorly insulated. Refer to the manufacturer's specification for the boiler in question to obtain a good number for the particular boiler. A more accurate way to estimate the heat loss is provided in Section 5.6.

9. Blowdown losses

$$L_{BD} = \frac{(T_{BD} - T_{H_2O}) \times (BD) \times [100 - (L)]}{[(T_{BD} - T_{H_2O}) \times (BD)] + [100 - (BD)] \times [660 - T_{H_2O}]}$$

L_{BD} = % loss of fuel fired to blowdown
T_{BD} = temperature of blowdown, °C, after any heat recovery
T_{H2O} = temperature of boiler feed, °C, including makeup and recycled condensate but before economizer
(BD) = % of total feed water blown down (including any flash steam from blowdown) (see Section 4.9.3)
(L) = $L_{FA} + L_{SA} + L^1_{FA} + L^1_{SA} + L_{DG} + L_{H2O} + L_{CO} + L_{RC}$

10. Overall efficiency

$$\% E = 100 - [L_{BD} + L_{FA} + L_{SA} + L^1_{FA} + L^1_{SA} + L_{DG} + L_{H2O} + L_{CO} + L_{RC}]$$

11. Excess air

Excess air can be estimated based either on the exhaust carbon dioxide or the exhaust oxygen measurements:

$$\text{Excess Air \%} = \left[\frac{\left(CO_2\right)_{MAX}}{CO_2} - 1 \right] \times 100 = \frac{O_2 \times 100}{\left(21 - O_2\right)}$$

5.6 Heat Loss Calculations

The losses by radiation and convection from the outside of the boiler may be estimated using surface temperature measurements. A practical calculation method is described below and summarized in Exhibit 5-12 at the end of this chapter.

1. The general equation for heat loss is

$$Q = UA \times \left(T_S - T_A\right)$$

where

			Typical unit	alternative
Q	=	Heat loss	watts	kcal/h
U	=	Overall heat transfer coefficient	W/m²K	kcal/m²h°C
A	=	Area over which heat is lost	m²	m²
T_S	=	Temperature of hot surface	°K	°C
T_A	=	Ambient temperature	°K	°C

2. The heat loss may be divided into the radiation and convection contributions. The overall heat transfer coefficient may therefore be defined:

$$U = U_R + U_C$$

Where
U_R = Radiation heat transfer coefficient watts/m²°K
U_C = Conversion heat transfer coefficient watts/m²°K

3. U_R may be calculated as follows:

$$U_R = 5.67\, E \times \left(\frac{\left(\frac{T_S}{100}\right)^4 - \left(\frac{T_A}{100}\right)^4}{\left(T_S - T_A\right)} \right)$$

where
E = Surface emissivity (a value between 0 and 1.0
T_S = Absolute surface temperature °K
T_A = Absolute temperature of ambient air °K

4. UC may be calculated as follows:

For streamline flow around the structure

$$U_C = \frac{B\,(T_S - T_A)^{0.25}}{D^{0.25}}$$

where
D = Length of the significant dimension of the structure mm
B = Constant depending on structure geometry

T_S = Absolute surface temperature °K
T_A = Absolute temperature of ambient air °K

Select values of B and D from this table:

	D	B
Vertical planes and large cylinders	height	1.35
Horizontal planes facing upwards	Side	1.35
Horizontal planes facing downwards	Side	0.60
Horizontal cylinders and small vertical cylinders	diameter	1.15

For turbulent flow

For structures in still air, if D exceeds 500 mm then turbulent flow can be assumed.

$$U_C = B \times (T_S - T_A)^{0.25}$$

Values of B are:

	B
Vertical planes and large cylinders	1.45
Horizontal planes facing upwards	1.70
Horizontal cylinders	1.20

5. The total heat loss may be calculated:

$$Q = (U_R + U_C) \times A \times (T_S - T_A)$$

5.7 Data and Calculation Forms

For convenience, a number of exhibits have been put together at the end of this chapter to document the data requirements and calculation methods for estimating boiler efficiency. The exhibits and the corresponding sections of the chapter are:

Exhibit 5-8	Boiler details	Section 5.1
Exhibit 5-9	Operating data (boiler tests)	Section 5.1
Exhibit 5-10	Boiler loss calculations	Section 5.5
Exhibit 5-11	Boiler loss calculations (gas/liquid fuels)	Section 5.5
Exhibit 5-12	Boiler heat loss calculations	Section 5.6

The calculation forms are generally self-explanatory. Where data are not available by direct measurement on site (e.g. hydrogen content of fuel) some typical values are given in various exhibits in this chapter. For some items, special calculation procedures are given (e.g. heat loss). Exhibit 5-8 through Exhibit 5-12 should be read in conjunction with the corresponding text in this Chapter.

Additional data forms and log sheets are found in Chapter 11 on performance monitoring. A complete survey of boiler condition and performance should include the data, calculations and observations summarized in the forms presented in both this Chapter and Chapter 11.

Exhibit 5-8: Boiler Details

Company Name:		Date:
Location:		
Nameplate Data:	(1)	(2)
Boiler No.		
Manufacturer		
Date Commissioned		
Model No.		
Type		
Medium used		
Rating (kg/h)		
Operating Pressure (kg/cm^2)		
Operating temp. (°C)		
Burners		
No. of Burners		
Fuel fired		
Burner Manufacturer		
Burner type		
Atomization		
Fuel control system		
Draft control system		

Exhibit 5-9: Operating Data (Boiler Tests)

Fuel			
Gross heating value	kcal/kg	CV_G	
Net heating value	% wt	CV_N	
Carbon in fuel	% wt	C_{fuel}	
Hydrogen in fuel	%	H_{fuel}	
Water in fuel	%	H_2O_{fuel}	
Oil:			
Fuel preheat temperature	°C	T_{fuel}	
Flue gas:			
Exit temperature	°C	T_{FG}	
Ambient temperature	°C	T_A	
Oxygen content (dry basis)	% vol.	O_2	
Carbon monoxide content	% vol.	CO	
Max. theor. CO_2 in dry flue gas		$(CO_2)_{MAX}$	
Smoke number			
Blowdown:			
Temp. after heat recovery	°C	T_{BD}	
Quantity (% wt of Feedwater)		BD	
Feedwater temperature	°C	T_{H_2O}	
Other			
Radiation and convection loss (% of gross heat release)		L_{RC}	
Gases at combustion chamber outlet	°C		
Gases after economizer	°C		
Condensate return temperature	°C		
Water to economizer	°C		
Water from economizer	°C		
Make-up water temperature	°C		
Total dissolved solids			
	ppm		
	ppm		
	ppm		
	ppm		
Fuel			
Fuel flow rate	kg/h		
Water flow rate	kg/h		
Solid fuel			
Ash in fuel (% wt, as fired)		A_{fuel}	
Ash disposed as fly ash	wt fraction	F_{FA}	
Ash disposed as slag ash	wt fraction	F_{SA} $(1-F_{FA})$	
Combustibles in fly ash	wt fraction	C_{SA}	
Combustibles in slag ash	wt fraction	C_{SA}	
Slag ash exit temperature	°C	T_{SA}	

Exhibit 5-10: Boiler Loss Calculations

Boiler Identification _____________ Date of test ___________ Time of test _________

(Losses expressed as percent fuel fired, gross basis)

	Loss	Formula	Result
1	L_{FA} Combustibles in fly ash	$\frac{A_{fuel} \times F_{FA} \times C_{SA} \times 8083 \times 100}{\left(1 - C_{SA}\right) \times CV_G}$	
2	L_{SA} Combustibles in slag ash	$\frac{A_{fuel} \times F_{SA} \times C_{SA} \times 8083 \times 100}{\left(1 - C_{SA}\right) \times CV_G}$	
3	L^1_{FA} Sensible heat in fly ash	$\frac{A_{fuel} \times F_{FA} \times \left(T_{FG} - T_A\right) \times 0.21 \times 100}{\left(1 - C_{FA}\right) \times CV_G}$	
4	L^1_{SA} Sensible heat in slag ash	$\frac{A_{fuel} \times F_{SA} \times \left(T_{SA} - T_A\right) \times 0.21 \times 100}{\left(1 - C_{SA}\right) \times CV_G}$	
5	L_{DG} Dry flue gas	$\frac{K \times \left(T_{FG} - T_A\right) \times \left[1 - \frac{\left(L_{FA} + L_{SA}\right)}{100}\right]}{CO_2}$	
5’		$CO_2 = \left[1 - \left[\frac{O_2}{21}\right]\right] \times \left(CO_2\right)_{MAX}$	
5”		K from tables or $K = \frac{69.7 \times C_{fuel} \times \left(CV_N\right)^2}{\left(CV_G\right)^3}$	
6	L_{H2O} Moisture in flue gas	$\frac{\left(H_2O_{fuel} + 9\,H_{fuel}\right) \times \left(588 - T_A + 0.50\,T_{FG}\right)}{CV^1_G}$	
6’		$CV^1_G = CV_G$ for coal, gas (no preheat) $CV^1_G = CV_G + \left(T_{fuel} - T_A\right) \times 0.47$ (for oilwith preheat)	
7	L_{CO} Unburned co	$\frac{K \times \left(CO\right) \times \left[1 - \left[\frac{L_{FA} + L_{SA}}{100}\right]\right]}{\left(CO\right) + \left(CO_2\right)}$	
8	L_{RC} Radiation and Convection	$\frac{100}{\left(CAP\right)}$ or calculate from surface temperatures	
9	L	$L_{FA} + L_{SA} + L^1_{FA} + L^1_{SA} + L_{DG} + L_{H2O} + L_{CO} + L_{RC}$	
10	L_{BD} Blowdown Losses	$\frac{\left(T_{BD} - T_{H_2O}\right) \times \left(BD\right) \times \left[100 - \left(L\right)\right]}{\left[\left(T_{BD} - T_{H_2O}\right) \times \left(BD\right)\right] + \left[100 - \left(BD\right)\right] \times \left[660 - T_{H_2O}\right]}$	
11	L_{TOTAL} Total losses	$L + L_{BD}$	
12	Efficiency η	$100 - L_{TOTAL}$ $100 - L_{TOTAL}$	
13	Excess air	$\left[\frac{\left(CO_2\right)_{MAX}}{CO_2} - 1\right] \times 100$ or $\left[\frac{O_2}{21 - O_2}\right] \times 100$	

Exhibit 5-11: Boiler Loss Calculations (Gas or Liquid Fuels)

Boiler Identification______________ Date of test ____________ Time of test _________

(Losses expressed as percent fuel fired, gross basis)

	Loss	Formula	Result
1	L_{DG} Dry flue gas	$\frac{K \times (T_{FG} - T_A)}{CO_2}$	
1’		$CO_2 = \left[1 - \left[\frac{O_2}{21}\right]\right] \times (CO_2)_{MAX}$	
1”		K from tables or $K = \frac{69.7 \times C_{fuel} \times (CV_N)^2}{(CV_G)^3}$	
2	L_{H2O} Moisture in flue gas	$\frac{(H_2O_{fuel} + 9 H_{fuel}) \times (588 - T_A + 0.50 T_{FG})}{CV_G^1}$	
2’		$CV_G^1 = CV_G$ for coal, gas (no preheat) $CV_G^1 = CV_G + (T_{fuel} - T_A) \times 0.47$ (for oilwith preheat)	
3	L_{CO} Unburned co	$\frac{K \times (CO)}{(CO) + (CO_2)}$	
4	L_{RC} Radiation and Convection	$\frac{100}{(CAP)}$ or calculate from surface temperatures	
5	L	$L_{DG} + L_{H_2O} + L_{CO} + L_{RC}$	
6	L_{BD} Blowdown Losses	$\frac{(T_{BD} - T_{H_2O}) \times (BD) \times [100 - (L)]}{[(T_{BD} - T_{H_2O}) \times (BD)] + [100 - (BD)] \times [660 - T_{H_2O}]}$	
7	L_{TOTAL} Total losses	$L + L_{BD}$	
8	Efficiency η	$100 - L_{TOTAL}$	
9	Excess air	$\left[\frac{(CO_2)_{MAX}}{CO_2} - 1\right] \times 100$ or $\left[\frac{O_2}{21 - O_2}\right] \times 100$	

Exhibit 5-12: Boiler Heat Loss Calculations

Boiler No. ____________ Date of test ____________ Time of test ____________

Ambient temperature ________ °C + 273 = ______________°K (T_A)

Parameter	Symbol/Formula	Value
Area, m^2	A_S	
Surface temperature, °C	t_S	
Surface temperature, °K	$T_S + 273 = T_S$	
Temp. Difference, °K	$T_S - T_A$	
Emissivity	E	
Radiation coefficient, Watts / m^2 °K	$U_R = 5.67\ E \times \left(\frac{\left(\frac{T_S}{100}\right)^4 - \left(\frac{T_A}{100}\right)^4}{\left(T_S - T_A\right)} \right)$	
Flow type	S = Streamline, T = Turbulent	
Shape factor	B, D (see table below)	
Convection coefficient, watts / m^2 °K	$U_C = \frac{B \times (T_S - T_A)^{0.25}}{D^{0.25}}$	
Overall coefficient, watts / m^2 °K	$U_S = (U_R + U_C)$	
Heat loss, watts	$Q = U_S \times A \times (T_S - T_A)$	
Heat input, watts	H_{IN} = fuel rate x gross cal. value	
Loss as % of boiler input	$\frac{Q}{H_{IN}} \times 100$	

For stream line flow			For turbulent flow		
D is the significant dimension (mm)			For D>500 mm assume turbulent flow: the value of D becomes 1 in the same equation		
	D	B		D	B
Vertical cylinder, large plane	Height	1.35	Vertical planes, large cylinders	1	1.45
Horizontal planes, face up	Side	1.30	Horizontal planes	1	1.70
Horizontal planes, face down	Side	0.60	Horizontal cylinders	1	1.20
Horizontal cylinders, small vertical cylinders	Dia	1.15			

6 Boiler Instrumentation and Controls

Instruments and controls are essential for a boiler to assume safe, efficient and reliable operation. The subject of instruments and controls is extremely broad, and this section limits itself to some brief concepts and underlying fundamentals.

Controls range from simple manual systems to completely automatic computer-assisted systems, and hence the type of control system used in a boiler would depend upon the requirements of the total operation and the cost involved. The following sections cover many of the typical systems used in boilers, and explain their utility and operation.

6.1 Boiler Instrumentation

All steam boilers should be provided with instruments to indicate or record the following variables:

- Steam pressure
- Steam temperature
- Water level
- Feedwater pressure
- Furnace draft or pressure

In addition to the above, units producing 5,000 kg steam/h (11,000 lb/h) or more should also monitor:

- Steam flow
- Feedwater flow
- Combustion air flow
- System drafts or pressures
- Feedwater temperature
- Flue gas temperature
- Fuel flow (if possible)
- Fuel pressures (if relevant)
- Fuel temperatures (if relevant)
- Speed and amperage indicators for fans, pumps, feeders and other power consuming auxiliaries

Other desirable measurements include flue gas analysis, smoke density, and conductivity and pH of the boiler water. The completeness and sophistication of the instrumentation used is usually proportional to the size and complexity of the unit.

6.2 Pressure Measurement

Normally pressure gauges are used to measure pressure at boiler feed water pump, boiler and steam header. Pressure gauge is a device to indicate the pressure of a fluid. Commonly Bourdon-Tube gauges are for pressure measurements. It indicates the amount of deflection under internal pressure of an oval tube bent in a arc of circle and closed at one end.

Other modes of pressure measurements are:

- Liquid Column Method
- Elastic Element Method

- Bellows Elements
- Diaphragm Elements
- Electrical / Electronic Methods

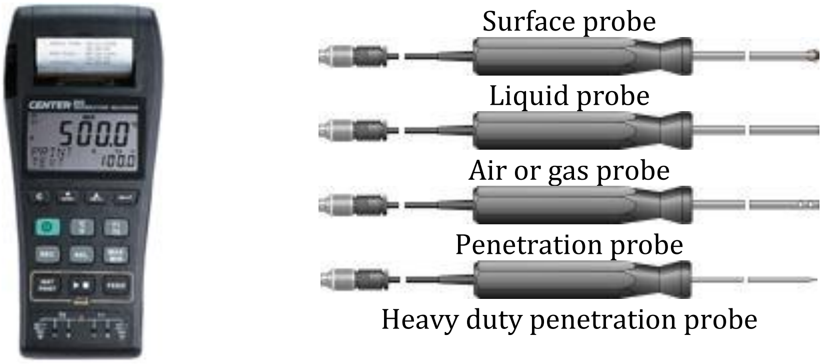
6.3 Temperature Measurement

Temperatures are measured by:

- Thermocouples
- Resistance Thermometers
- Filled-system Thermometers
- Bi-metallic Thermometers
- Liquid-in-glass Thermometers
- Pyrometers

For temperature measurement, a hand-held portable digital temperature indicator is recommended, together with two or three probes. See Exhibit 6-1. A wide variety of probes is available for measuring flue gas temperatures; most can also be used for measuring temperatures around the plant in general (e.g. surface temperatures for calculation of heat losses by radiation and convection).

Exhibit 6-1: Digital Thermometer and Probes for Different Applications



Where access to hot surface or pipe-work is not easy, it is often possible to achieve good results using a non-contact temperature measuring instruments such as an infrared thermometer, illustrated in Exhibit 6-2.

Exhibit 6-2: Typical infrared thermometer for non-contact temperature measurement

6.4 Boiler Water Level Controls

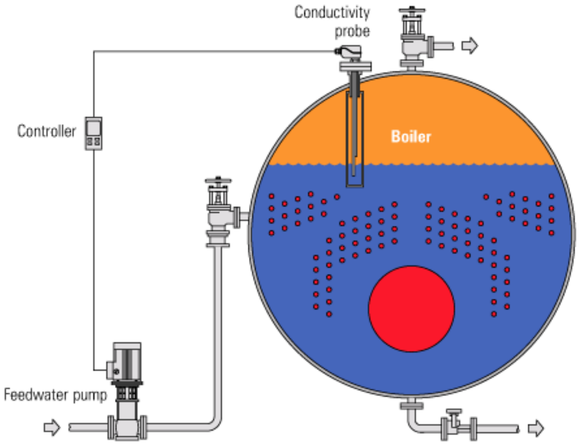
6.4.1 On / off Control

The most common method of level control is simply to start the feed pump at a low level and allow it to run until a higher water level is reached within the boiler (Exhibit 6-3).

With a float level control, a magnetic switch with a built-in hysteresis or dead-band will be used. With conductivity probes, two probes are necessary, (pump on and pump off) which will give fixed switching levels.

A capacitance probe can be used to give adjustable on / off switching levels.

Exhibit 6-3: On / off Control



It can be argued, however, that this type of on / off control is not ideal for boiler control, because the relatively high flow rate of 'cold' feed water when the pump is on reduces the boiler pressure. This causes the burner firing rate to continuously vary as the pump switches on and off.

Taking a typical example, it can be shown by calculation that even with feed water at 80°C, the burner firing rate may have to be 40% higher with the feed pump on, than with the feed pump off. This continuous variation causes:

- Wear on the burner controls
- Temperature cycling of the boiler
- Reduced efficiency
- A 'saw-tooth' type steam flow rate

If steam loads are high, the variable steam flow rate will tend to increase water carryover with the steam, and will tend to make water levels increasingly unstable with the associated danger of low water level lockout, particularly on multi-boiler installations.

However, the fact remains that on / off control is very widely used on boilers of small to medium output, as defined above, and that many problems associated with steam boilers operating with large swings in load are due in part to on/off level control systems.

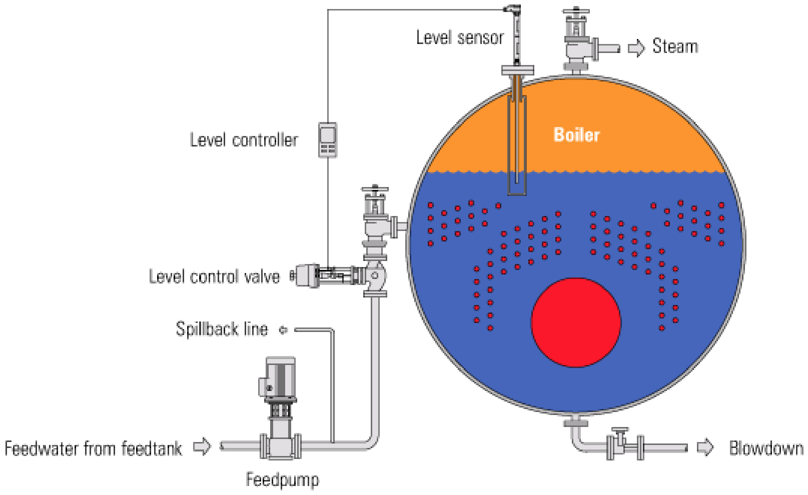
The on / off control systems are simple, inexpensive and good for boilers on standby. Their disadvantages are:

- In case of multi-boilers set up, own / independent feed pump for each boiler
- More wear and tear on the feed pump and control gear
- Variable steam pressure and flow rate
- More boiler water carryover
- Higher chance of daily operating problems under large load swings

6.4.2 Modulating Control

In this type of system (Exhibit 6-4) the feed pump runs continuously, and an automatic valve (between the feed pump and the boiler) controls the feed water flow rate to match the steam demand. When operating correctly, modulating control can dramatically smooth the steam flow rate and ensure greater water level stability inside the boiler.

Exhibit 6-4: Modulating Control



For modulating level control, the following methods can be used to sense the water level:

- Floats with a continuous signal output
- Capacitance probes
- Differential pressure cells

6.5 Steam Flow Metering

There are many types of flow meters available, those suitable for steam applications include:

- Orifice plate flow meters
- Turbine flow meters (including shunt or bypass types)
- Variable area flow meters
- Spring loaded variable area flow meters
- Direct in-line variable area (DIVA) flow meter
- Pitot tubes
- Vortex shedding flow meters

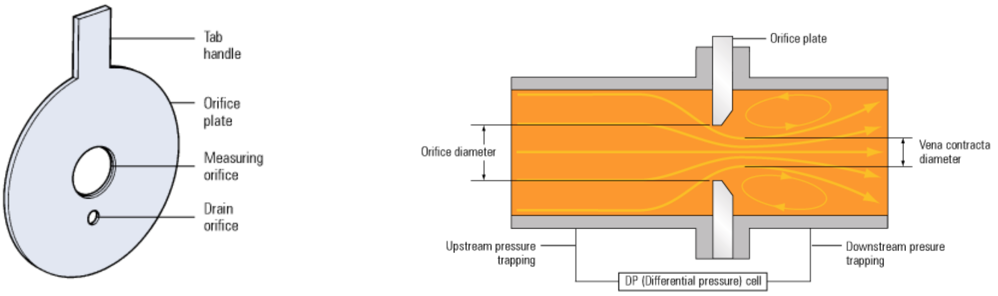
Each of these flow meter types has its own advantages and limitations. To ensure accurate and consistent performance from a steam flow meter, it is essential to match the flow meter to the application.

The subsequent sections present a review of the above flow meter types, and discuss their characteristics, their advantages and disadvantages, typical applications and typical installations.

6.5.1 Orifice Plate Flow Meters

The orifice plate is one in a group known as head loss devices or differential pressure flow meters. In simple terms the pipeline fluid is passed through a restriction, and the pressure differential is measured across that restriction. The relationship between the velocities of fluid passing through the orifice is proportional to the square root of the pressure loss across it. Other flow meters in the differential pressure group include venturies and nozzles. Exhibit 6-5 illustrates the orifice plate flow meter.

Exhibit 6-5: Orifice Plate Flow Meter



With an orifice plate flow meter, the restriction is in the form of a plate which has a hole concentric with the pipeline. This is referred to as the primary element.

To measure the differential pressure when the fluid is flowing, connections are made from the upstream and downstream pressure tapings, to a secondary device known as a DP (differential pressure) cell.

From the DP cell, the information may be fed to a simple flow indicator, or to a flow computer along with temperature and/or pressure data, which enables the system to compensate for changes in fluid density.

In horizontal lines carrying vapors, water (or condensate) can build up against the upstream face of the orifice. To prevent this, a drain hole may be drilled in the plate at the bottom of the pipe. Clearly, the effect of this must be taken into account when the orifice plate dimensions are determined.

Correct sizing and installation of orifice plates is absolutely essential, and is well documented in the International Standard ISO 5167.

Orifice steam flow meters are simple / rugged and low cost, and have good accuracy. They do not require calibration or recalibration provided calculation, tolerance and installation comply with ISO 5167 or instructions of the manufacturer. Their disadvantages are:

- Turndown is limited to between 4:1 and 5:1 because of the square root relationship between flow and pressure drop.
- The orifice plate can buckle due to water hammer and can block in a system that is poorly designed or installed.

The square edge of the orifice can erode over time, particularly if the steam is wet or dirty. This will alter the characteristics of the orifice, and accuracy will be affected. Regular inspection and replacement is therefore necessary to ensure reliability and accuracy.

The installed length of an orifice plate flow metering system may be substantial; a minimum of 10 upstream and 5 downstream straight unobstructed pipe diameters may be needed for accuracy.

6.5.2 Turbine Flow Meters

The primary element of the turbine flow meter consists of a multi-bladed rotor which is mounted at right angles to the flow and suspended in the fluid stream on a free-running bearing. The diameter of the rotor is slightly less than the inside diameter of the flow metering chamber, and its speed of rotation is proportional to the volumetric flow rate.

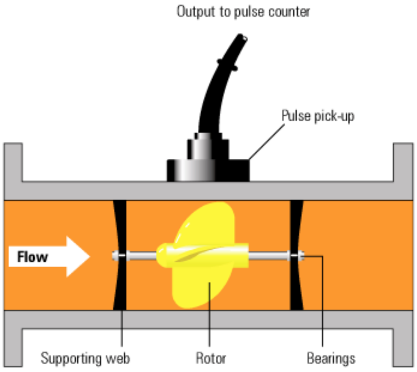
The speed of rotation of the turbine may be determined using an electronic proximity switch mounted on the outside of the pipe work, which counts the pulses, as shown in Exhibit 6-6.

Since a turbine flow meter consists of a number of moving parts, there are several influencing factors that need to be considered:

- Temperature, pressure and viscosity of the fluid being measured
- Lubricating qualities of the fluid
- Wear and friction of bearing
- Conditional and dimensional changes of the blades
- Inlet velocity profile and the effects of swirl
- Pressure drop through the flow meter

Because of these factors, calibration of turbine flow meters must be carried out under operational conditions.

Exhibit 6-6: Turbine Flow Meter

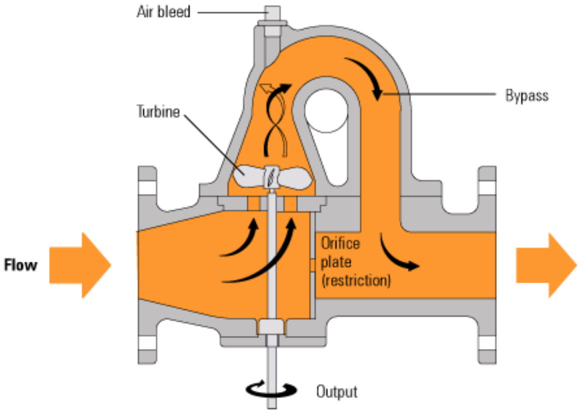


In larger pipelines, to minimize cost, the turbine element can be installed in a pipe work bypass, or even for the flow meter body to incorporate a bypass or shunt, as shown in Exhibit 6-7.

Bypass flow meters comprise an orifice plate, which is sized to provide sufficient restriction for a sample of the main flow to pass through a parallel circuit. Whilst the speed of rotation of the turbine may still be determined as explained previously, there are many older units still in existence which have a mechanical output as shown in Exhibit 6-7.

Clearly, friction between the turbine shaft and the gland sealing can be significant with this mechanical arrangement.

Exhibit 6-7: Bypass or Shunt Turbine Flow Meter



Advantages of turbine flow meters:

- A turndown of 10:1 is achievable in a good installation with the turbine bearings in good condition.
- Accuracy is reasonable (± 0.5% of actual value).

- Bypass flow meters are relatively low cost.

Disadvantages of turbine flow meters:

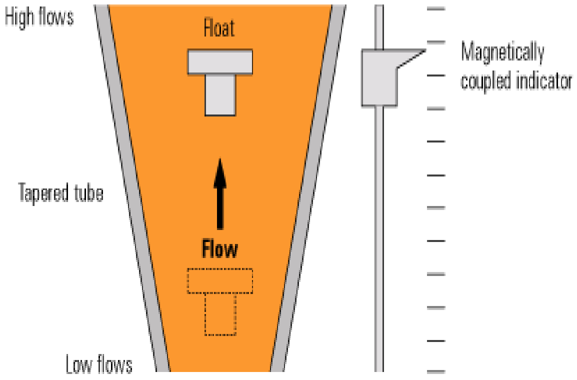
- Generally calibrated for a specific line pressure. Any steam pressure variations will lead to inaccuracies in readout unless a density compensation package is included.
- Flow straighteners are essential.
- If the flow oscillates, the turbine will tend to over or under run, leading to inaccuracies due to lag time.
- Wet steam can damage the turbine wheel and affect accuracy.
- Low flow rates can be lost because there is insufficient energy to turn the turbine wheel.
- Viscosity sensitive: if the viscosity of the fluid increases, the response at low flow rates deteriorates giving a non-linear relationship between flow and rotational speed. Software may be available to reduce this effect.
- The fluid must be very clean (particle size not more than 100 µm) because:
- Clearances between the turbine wheel and the inside of the pipe are very small.
- Entrained debris can damage the turbine wheel and alter its performance.
- Entrained debris will accelerate bearing wear and affect accuracy, particularly at low flow rates.

6.5.3 Variable Area Flow Meters

The variable area flow meter (Exhibit 6-8), often referred to as a Rota meter, consists of a vertical, tapered bore tube with the small bore at the lower end, and a float that is allowed to freely move in the fluid. When fluid is passing through the tube, the float's position is in equilibrium with:

- The dynamic upward force of the fluid.
- The downward force resulting from the mass of the float.
- The position of the float, therefore, is an indication of the flowrate.

Exhibit 6-8: Variable Area Flow Meter



In practice, this type of flow meter will be a mix of:

- **A float** selected to provide a certain weight, and chemical resistance to the fluid.

  The most common float material is grade 316 stainless steel, however, other materials such as Hast alloy C, aluminum or PVC are used for specific applications.

  On small flow meters, the float is simply a ball, but on larger flow meters special shaped floats are used to improve stability.
- **A tapered tube**, which will provide a measuring scale of typically between 40 mm and 250 mm over the design flow range.

Usually the tube is made from glass or plastic. However, if failure of the tube presents a hazard, then either a protective shroud may be fitted around the glass, or a metal tube may be used.

With a transparent tube, flow readings are taken by observation of the float against a scale. For higher temperature applications where the tube material is opaque, a magnetic device is used to indicate the position of the float.

Because the annular area around the float increases with flow, the differential pressure remains almost constant.

Variable area flow meters have linear output and turndown ratio is 10:1. They are simple and robust, and pressure drop is minimal and fairly constant. Their disadvantages are:

- The tube must be mounted vertically.
- Because readings are usually taken visually, and the float tends to move about, accuracy is only moderate. This is made worst by parallax error at higher flow rates, because the float is some distance away from the scale.
- Transparent taper tubes limit pressure and temperature.

Rota meters are sometimes used as a flow indicating device rather than a flow measuring device.

6.5.4 Spring Loaded Variable Area Flow Meters

The spring loaded variable area flow meter (an extension of the variable area flow meter) uses a spring as the balancing force. This makes the meter independent of gravity, allowing it to be used in any plane, even upside-down. However, in its fundamental configuration (as shown in Exhibit 6-9 and Exhibit 6-10), there is also a limitation: the range of movement is constrained by the linear range of the spring, and the limits of the spring deformation.

However, another important feature is also revealed: if the pass area (the area between the float and the tube) increases at an appropriate rate, then the differential pressure across the spring loaded variable area flow meter can be directly proportional to flow.

Exhibit 6-9: Variable Area Flow Meter installed in a Vertical Plane

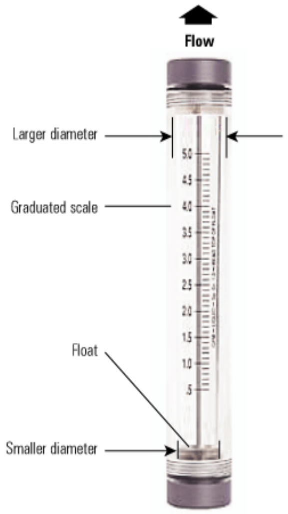
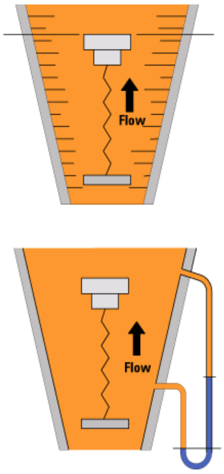


Exhibit 6-10: Spring Loaded Variable Area Flow Meters



6.6 Monitoring / Control Techniques for Boilers

6.6.1 Monitoring Total Dissolved Solids (TDS) in Boiler Water

TDS may be expressed in a number of different units, and Exhibit 6-11 gives some approximate conversions from TDS in ppm to other units. Degrees Baume and degrees Twaddle (also spelt Twaddell) are alternative hydrometer scales.

Exhibit 6-11: Comparison of Units used to Measure TDS

Total dissolved solids ppm	Conductivity (μS/cm)		Relative density at 15.5°C	Degrees Baumé °Be	Degrees Twaddle °Tw
	Neutralised	Unneutralised			
0	0	0	1.000 00	0.000	0.000
200	286	400	1.000 18	0.026	0.036
400	571	800	1.000 36	0.052	0.073
600	857	1 200	1.000 55	0.079	0.109
800	1 143	1 600	1.000 73	0.105	0.145
1 000	1 429	2 000	1.000 91	0.131	0.182
1 200	1 714	2 400	1.001 09	0.157	0.218
1 400	2 000	2 800	1.001 27	0.184	0.255
1 600	2 286	3 200	1.001 45	0.210	0.291
1 800	2 571	3 600	1.001 64	0.236	0.327
2 000	2 857	4 000	1.001 82	0.262	0.364
2 200	3 143	4 400	1.002 00	0.289	0.400
2 400	3 429	4 800	1.002 18	0.315	0.436
2 600	3 714	5 200	1.002 36	0.341	0.473
2 800	4 000	5 600	1.002 55	0.367	0.509
3 000	4 286	6 000	1.002 73	0.393	0.545
3 200	4 571	6 400	1.002 91	0.420	0.582
3 400	4 857	6 800	1.003 09	0.446	0.618
3 600	5 143	7 200	1.003 27	0.472	0.655
3 800	5 429	7 600	1.003 45	0.498	0.691
4 000	5 714	8 000	1.003 64	0.525	0.727
4 200	6 000	8 400	1.003 82	0.551	0.764
4 400	6 286	8 800	1.004 00	0.577	0.800
4 600	6 571	9 200	1.004 18	0.603	0.836
4 800	6 857	9 600	1.004 36	0.630	0.873
5 000	7 143	10 000	1.004 55	0.656	0.909
5 200	7 429	10 400	1.004 73	0.682	0.945
5 400	7 714	10 800	1.004 91	0.708	0.982
5 600	8 000	11 200	1.005 09	0.735	1.018
5 800	8 286	11 600	1.005 27	0.761	1.055
6 000	8 571	12 000	1.005 45	0.787	1.091
6 200	8 857	12 400	1.005 64	0.813	1.127

6.6.2 Sampling for External Analysis

The boiler water TDS may be measured either by:

- Taking a sample, and determining the TDS external to the boiler, or
- A sensor inside the boiler providing a signal to an external monitor.

When taking a sample of boiler water it is important to ensure that it is representative. It is not recommended that the sample be taken from level gauge glasses or external control chambers; the water here is relatively pure condensate formed by the continual condensation of steam in the external glass / chamber. Similarly, samples from close to the boiler feed water inlet connection are likely to give a false reading.

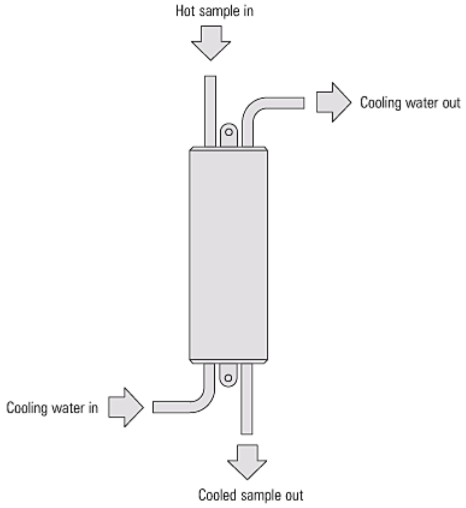
Nowadays, most boilermakers install a connection for TDS blowdown, and it is generally possible to obtain a representative sample from this location.

If water is simply drawn from the boiler, a proportion will violently flash to steam as its pressure is reduced. Not only is this potentially very dangerous to the operator, but any subsequent analysis will also be quite wrong, due to the loss of the flash steam concentrating the sample.

Since a cool sample is required for analysis, a sample cooler will also save considerable time and encourage more frequent testing.

A sample cooler (Exhibit 6-12) is a small heat exchanger that uses cold mains water to cool the blowdown water sample.

Exhibit 6-12: A Sample Cooler



6.6.3 Relative Density Method

The relative density of water is related to its dissolved solids content. For raw water, feed water and condensate the relative density is so near to that of pure water that it cannot be measured satisfactorily using a hydrometer. For boiler water, however, a hydrometer can be used to obtain an approximate measurement of the dissolved solids, since for boiler waters each increase of 0.0001 relative density at 15.5°C is approximately equal to 110 ppm. A very sensitive hydrometer is required which needs careful handling and use if a satisfactory measurement of TDS is to be obtained. The procedure is generally as follows:

- Filter the cooled boiler water sample to remove any suspended solids, which would otherwise give a false reading.
- Cool to 15.5°C.
- Add a few drops of a wetting agent to help prevent bubbles adhering to the hydrometer.
- Place the hydrometer in the sample and spin gently to remove bubbles.
- Read off the relative density.
- Read off the TDS from a table supplied with the hydrometer or calculate the TDS in ppm by using the following equation:

$$\text{TDS (ppm)} = (\text{relative density at } 15.5°\text{C} - 1) \times 1.1 \times 10^6$$

Example

$$\text{Relative density at } 15.5°\text{C} = 1.003\,5$$

$$\text{TDS} = (1.003\,5 - 1) \times 1.1 \times 10^6$$

$$\textbf{TDS} = \textbf{3 850 ppm}$$

The hydrometer is a delicate instrument, which can easily be damaged. To avoid obtaining false readings it should be regularly checked against distilled water.

6.6.4 Conductivity Method

The electrical conductivity of water also depends on the type and amount of dissolved solids contained. Since acidity and alkalinity have a large effect on the electrical conductivity, it is necessary to neutralize the sample of boiler water before measuring its conductivity. The procedure is as follows:

Add a few drops of phenolphthalein indicator solution to the cooled sample (< 25°C).

If the sample is alkaline, a strong purple colour is obtained.

Add acetic acid (typically 5%) drop by drop to neutralize the sample, mixing until the colour disappears.

The TDS in ppm is then approximately as shown in the following equation:

$$\text{TDS (ppm)} = (\text{conductivity in } \mu\text{S/cm}) \times 0.7$$

Note: This relationship is only valid for a neutral sample at 25°C.

Example:

$$\begin{aligned} \text{Conductivity of a neutralised sample at } 25^\circ\text{C} &= 5\,000\ \mu\text{S / cm} \\ \text{TDS} &= 5\,000\ \mu\text{S / cm} \times 0.7 \\ \textbf{TDS} &= \mathbf{3\,500\,ppm} \end{aligned}$$

Alternatively, the battery powered, temperature compensated conductivity meter shown in Exhibit 6-13 is suitable for use up to a temperature of 45°C.

Exhibit 6-13: Hand Held Conductivity Meter

6.7 Monitoring of pH Value

Another term to be considered is the pH value; this is not an impurity or constituent but merely a numerical value representing the potential hydrogen content of water - which is a measure of the acidic or alkaline nature of the water. Water, H_2O, has two types of ions - hydrogen ions (H^+) and hydroxyl ions (OH-). If the hydrogen ions are predominant, the solution will be acidic with a pH value between 0 and 6. If the hydroxyl ions are predominant, the solution will be alkaline, with a pH value between 8 and 14. If there are an equal number of both hydroxyl and hydrogen ions, then the solution will be neutral, with a pH value of 7.

Acids and alkalis have the effect of increasing the conductivity of water above that of a neutral sample. For example, a sample of water with a pH value of 12 will have a higher conductivity than a sample that has a pH value of 7.

The following table illustrated the change in the characteristics of water with variation in pH value.

pH value	Hydrogen ion concentration H+	Hydroxyl ion concentration H-	Nature
0	10^{0}	10^{-14}	Acid
7	10^{-7}	10^{-7}	Neutral
14	10^{-14}	10^{0}	Alkaline

The appropriate pH level for prevention of corrosion on the water side is approximately 8.5-12.7, with most systems operating at a pH level of 10.5-11.5.

Variations in the pH of boiler water can corrosion. If boiler water pH drops significantly below 8.5, a phenomenon called waterside thinning can occur. The normal manifestation of acidic attack is etching. In areas of higher flow, the surfaces are smooth. In addition, any stressed area would be a principal area for attack. The phenomenon is known as acidic attack. And caustic attack or, as it is more commonly known, caustic corrosion / embrittlement, is often encountered due to the extremely high pH.

Exhibit 6-14: Hand Held pH Meter

6.8 Flue Gas Analysis

For flue gas analysis, there are a number of methods available. The traditional method is the "Orsat" apparatus (Exhibit 6-15a) which uses chemical solutions to absorb carbon monoxide, carbon dioxide and oxygen from a flue gas sample. Changes in volume of the sample indicate the gas composition. A simplified version of the Orsat is shown in Exhibit 6-15b. This particular model is the "Fyrite" analyzer (other proprietary names are used by other manufacturers). Each Fyrite kit contains two plastic containers, each with an appropriate chemical fluid, one for oxygen analysis and one for carbon dioxide analysis. A gas sample is introduced into the container through a non-return valve and thoroughly mixed with the absorbing solution. A change in volume indicates directly the volume percentage of the particular component in the flue gas.

While the wet chemical test methods are quite inexpensive to use there are many new instruments available for oxygen measurement based on sensors which give an electronic signal proportional to the oxygen content of the gas. Examples of a typical electronic instrument is shown in Exhibit 6-16. These particular models use a sensor based on an electrolytic cell (similar to a battery): the sensor is inexpensive and robust, and relatively insensitive to contaminants in the flue gas such as sulfur dioxide. The life of a sensor is typically nine months to one year. Similar sensors are available for carbon monoxide (and also other gases, such as hydrogen sulfide and nitrogen oxides).

Exhibit 6-15: Orsat Apparatus and Fyrite Gas Analyzer

a) Orsat Apparatus **b) Fyrite Gas Analyzer**

Other instruments for oxygen measurement are based on zirconium oxide (zirconia), which conducts oxygen ions at temperatures above 650°C. The sensor is maintained at a high temperature, ideally about 800°C, and consists of a heated cell with two electrodes: one electrode is surrounded by a reference gas (usually air) and the other electrode has the sample gas passed over it. Any difference in oxygen content at the electrodes is translated into a potential difference and hence an electronic signal

Because a zirconia cell must have a heater and controls to ensure operation at affixed high temperature, instruments based on zirconia tend to be bulky and heavy. Portable analyzers are available, but the zirconia system is normally restricted to fixed gas analyzers mounted in the stack of medium to large boilers and furnaces, and more recently, package boilers. The life of a zirconia probe in a typical boiler stack should be five years or more.

Exhibit 6-16: Typical Portable Electronic Combustion Analyzer

In addition to ease of operation, the main advantage of the electronic analyzers is the ability to obtain continuous instant feedback on excess air and boiler efficiency while the sensor is in the stack. This greatly facilitates the boiler tuning process.

6.8.1 Sampling

Regardless of what stack measurement is being made, whether it is CO, CO_2, excess O_2, smoke, temperature, etc., it is imperative that the measurement be made on a representative sample of the bulk of the gas flow. The location of the site at which the sample of flue gas and the stack temperature are obtained is as important as the measurement itself

The sample site should be removed from areas of high turbulence, such as immediately downstream of bends, dampers and induced draft fans. Flue gases can stratify or form "pockets" at such areas and lead to-non-representative sampling. Air leakage at any point in the boiler upstream of the sampling site can lead to gross errors when attempting to determine combustion efficiency. Care should be taken to seal all known air leaks upstream of the sampling site.

Flue gas temperature is subject to the same stratification and "pocket" effects as flue gas flow. The location for measuring flue gas temperature should be as close to the exit of the last piece of heat recovery equipment as is practical since temperature losses can occur in the flue gas ducting, especially in un-insulated sections.

6.9 Blowdown Control

Suspended solids can be kept in suspension as long as the boiler water is agitated, but as soon as the agitation stops, they will fall to the bottom of the boiler. If they are not removed, they will accumulate and, given time, will inhibit heat transfer from the boiler fire tubes, which will overheat and may even fail.

The recommended method of removing this sludge is via short, sharp blasts using a relatively large valve at the bottom of the boiler. The objective is to allow the sludge time to redistribute itself so that more can be removed on the next blowdown.

For this reason, a single four-second blowdown every eight hours is much more effective than one, twelve-second blowdown in the first eight hour shift period, and then nothing for the rest of the day.

Blowdown water will either pass into a brick-lined blowdown pit encased below ground, or a metal blowdown vessel situated above ground. The size of the vessel is determined by the flow rate of blowdown water and flash steam that enters the vessel when the blowdown valve is opened.

The major influences on blowdown rate are:

- The boiler pressure.
- The size of the blowdown line.
- The length of the blowdown line between the boiler and the blowdown vessel.

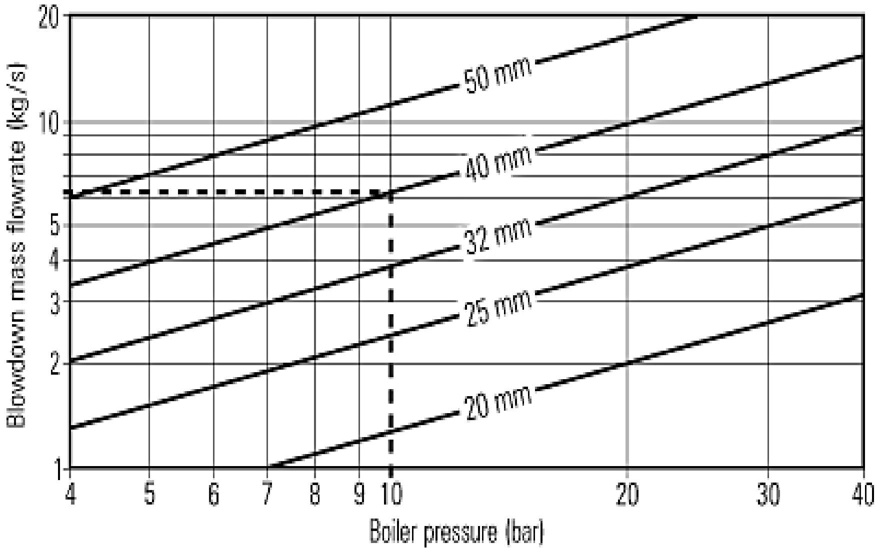
In practice, a reasonable minimum length of blowdown line is 7.5 m, and most blowdown vessels are sized on this basis. Blowdown lines will contain bends, check valves and the blowdown valve itself; and these fittings will increase the pressure drop along the blowdown line. They may be thought of in terms of an ‘equivalent straight length of pipe’, and can be added to the pipe length to give an overall equivalent length. Exhibit 6-17 gives equivalent lengths of various valves and fittings.

Exhibit 6-17: Equivalent Length of Blowdown Line Fittings in Meters (m)

Blowdown line size	20 mm	25 mm	32 mm	40 mm	50 mm
Long radius bend	0.4	0.5	0.6	0.7	0.8
Manifold inlet	0.6	1.0	1.4	1.7	2.1
Globe valve	5.9	9.6	12.2	13.9	17.8
Check valve	2.6	3.6	4.2	4.9	6.2
Blowdown valve	0.1	0.2	0.3	0.4	0.5

In the unlikely event that the total equivalent length is less than 7.5 m, the vessel should be sized to a higher flow rate. In these cases, multiply the boiler pressure by 1.15 to calculate the blowdown rate from Exhibit 6-18. Blowdown lines over 7.5 m can be read straight from this graph.

Exhibit 6-18: Approximate Blowdown Rate (based on an 8 m Equivalent Pipe Length)



Example: For a boiler pressure of 10 barg, an equivalent 40 mm blowdown line length is calculated to be 10 m, consequently, the blowdown rate is 6.2 kg/s.

Exhibit 6-19 provides some broad guidelines on the maximum permissible levels of boiler water TDS in certain types of boiler. Above these levels, problems may occur.

Exhibit 6-19: Typical Maximum TDS for Various Boiler Types

Boiler type	Maximum TDS (ppm)
Lancashire	10 000
Two-pass economic	4 500
Packaged and three-pass economic	3 000 to 3 500
Low pressure water-tube	2 000 to 3 000
Coil boiler and steam generators (TDS in feedwater)	2 000
Medium pressure water-tube	1 500
High pressure water-tube	1 000

Note: The values in Exhibit 6-19 are offered as a broad guide only. The boilermaker should always be consulted for specific recommendations.

When the above information is available the required blowdown rate can be determined using the following equation:

$$\text{Blowdown Rate} = \frac{S_f \times S}{\left(S_b - S_f\right)}$$

S_f = TDS level of feed water in ppm
S_b = desired TDS level in boiler in ppm
S = Steam generation rate

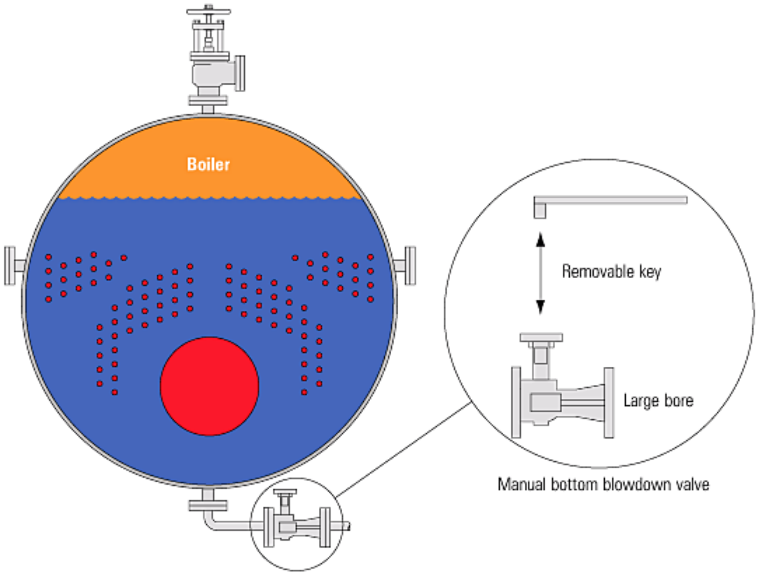
Example: A 10,000 kg / h boiler operates at 10 barg - Calculate the blowdown rate, given the following conditions:

S_f = TDS level of feed water in ppm	=	250
S_b = desired TDS level in boiler in ppm	=	2,500
S = Steam generation rate		10,000 kg/h
Blowdown rate	=	$\frac{250 \times 10{,}000}{\left(2{,}500 - 250\right)}$
Blowdown rate	=	1,111 kg/h

A typical blowdown valve is shown in Exhibit 6-20.

All valves or taps controlling entry of steam or water are closed and securely locked. Where there is a common blowdown pipe or vessel, the blowdown valve is constructed so that it can only be opened by a key which cannot be removed until the blowdown valve is closed; and that this is the only key in use in the boiler house.

Exhibit 6-20: Bottom Blowdown Valve with Removable Key



6.9.1 Timer Controlled Automatic Bottom Blowdown

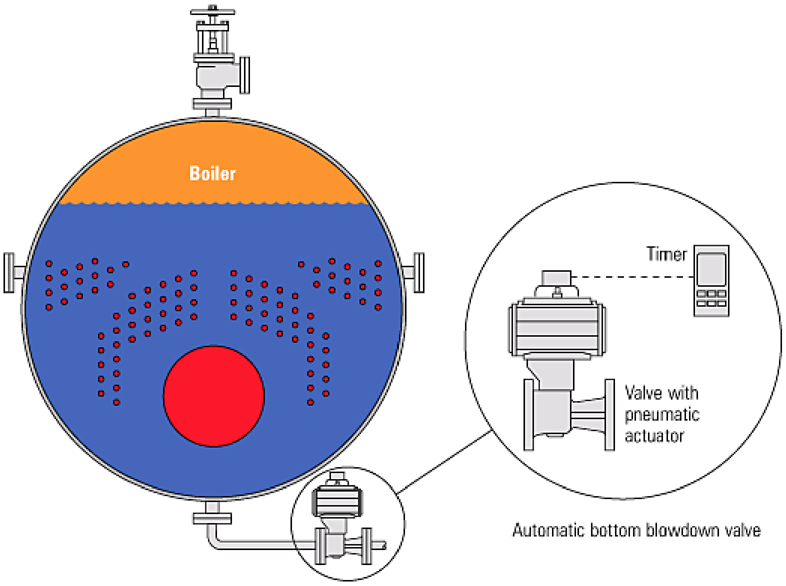
It is now possible to automate the bottom blowdown valve using a proprietary timer linked to a pneumatically operated ball valve.

The timer should be capable of opening the valve at a specific time, and holding it open for a set number of seconds.

The use of automatic bottom blowdown ensures that this important action is carried out regularly and releases the boiler attendant for other duties.

With multi-boiler installations, it is necessary to interlock the valves so that not more than one can be open at any one time, as this would overload the blowdown vessel. This can be done most simply by staggering the setting times of the individual blowdown timers, or by setting the individual blowdown times in sequence.

Exhibit 6-21: Timer Controlled Automatic Bottom Blowdown Valve



6.10 Safety Valve

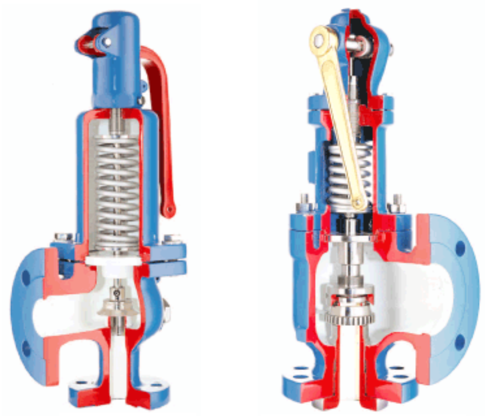
Safety valves should be installed wherever the maximum allowable working pressure (MAWP) of a system or pressure-containing vessel is likely to be exceeded. In steam systems, safety valves are typically used for boiler overpressure protection and other applications such as downstream of pressure reducing controls. Although their primary role is for safety, safety valves are also used in process operations to prevent product damage due to excess pressure. Pressure excess can be generated in a number of different situations, including:

- An imbalance of fluid flow rate caused by inadvertently closed or opened isolation valves on a process vessel.
- Failure of a cooling system, which allows vapor or fluid to expand.
- Compressed air or electrical power failure to control instrumentation.
- Transient pressure surges.
- Exposure to plant fires.
- Heat exchanger tube failure.
- Uncontrollable exothermic reactions in chemical plants.
- Ambient temperature changes.

The terms ‘safety valve’, ‘safety relief valve’ and ‘pressure relief valves’ are generic terms to describe many varieties of pressure relief devices that are designed to prevent excessive internal fluid pressure build-up. A wide range of different valves is available for many different applications and performance criteria. Furthermore, different designs are required to meet the numerous national standards that govern the use of safety valves.

Standards relevant to safety valves vary quite considerably in format around the world, and many are sections within codes relevant to Boilers or Pressure Containing Vessels. Some will only outline performance requirements, tolerances and essential constructional detail, but give no guidance on dimensions, orifice sizes etc. Others will be related to installation and application. It is quite common within many markets to use several in conjunction with each other.

Exhibit 6-22: Typical Safety Valves used on Steam Systems



6.10.1 Basic Operation of Safety Valve

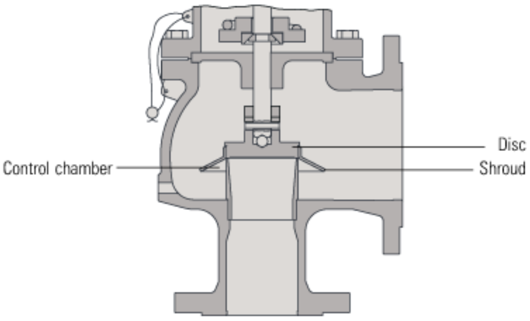
Lifting

When the inlet static pressure rises above the set pressure of the safety valve, the disc will begin to lift off its seat. However, as soon as the spring starts to compress, the spring force will increase; this means that the pressure would have to continue to rise before any further lift can occur, and for there to be any significant flow through the valve.

The additional pressure rise required before the safety valve will discharge at its rated capacity is called the overpressure. The allowable overpressure depends on the standards being followed and the particular application. For compressible fluids, this is normally between 3% and 10%, and for liquids between 10% and 25%.

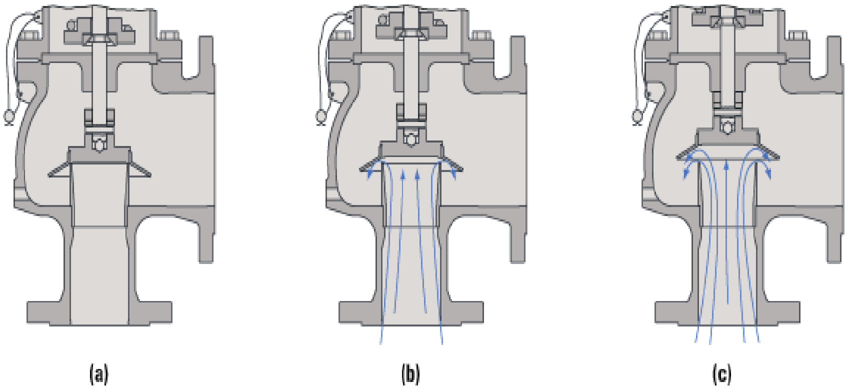
In order to achieve full opening from this small overpressure, the disc arrangement has to be specially designed to provide rapid opening. This is usually done by placing a shroud, skirt or hood around the disc. The volume contained within this shroud is known as the control or huddling chamber.

Exhibit 6-23: Typical Disc and Shroud Arrangement used on Rapid Opening Safety Valves



As lift begins (Exhibit 6-24b), and fluid enters the chamber, a larger area of the shroud is exposed to the fluid pressure. Since the magnitude of the lifting force (F) is proportional to the product of the pressure (P) and the area exposed to the fluid (A); (F = P × A), the opening force is increased. This incremental increase in opening force overcompensates for the increase in spring force, causing rapid opening. At the same time, the shroud reverses the direction of the flow, which provides a reaction force, further enhancing the lift.

Exhibit 6-24: Operation of a conventional safety valve



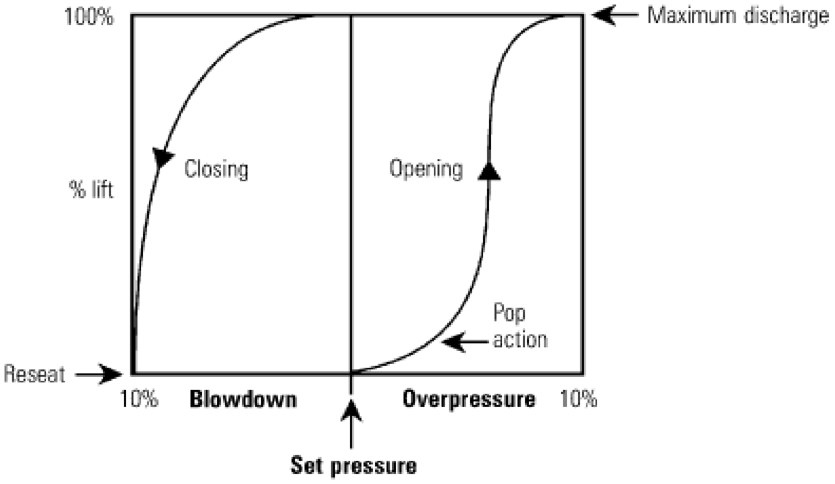
These combined effects allow the valve to achieve its designed lift within a relatively small percentage overpressure. For compressible fluids, an additional contributory factor is the rapid expansion as the fluid volume increases from a higher to a lower pressure area. This plays a major role in ensuring that the valve opens fully within the small overpressure limit. For liquids, this effect is more proportional and subsequently, the overpressure is typically greater; 25% is common.

Reseating

Once normal operating conditions have been restored, the valve is required to close again, but since the larger area of the disc is still exposed to the fluid, the valve will not close until the pressure has dropped below the original set pressure. The difference between the set pressure and this reseating pressure is known as the 'blowdown', and it is usually specified as a percentage of the set pressure. For compressible fluids, the blowdown is usually less than 10%, and for liquids, it can be up to 20%.

The design of the shroud must be such that it offers both rapid opening and relatively small blowdown, so that as soon as a potentially hazardous situation is reached, any overpressure is relieved, but excessive quantities of the fluid are prevented from being discharged. At the same time, it is necessary to ensure that the system pressure is reduced sufficiently to prevent immediate reopening.

Exhibit 6-25: Relationship between Pressure and Lift for a Typical Safety Valve

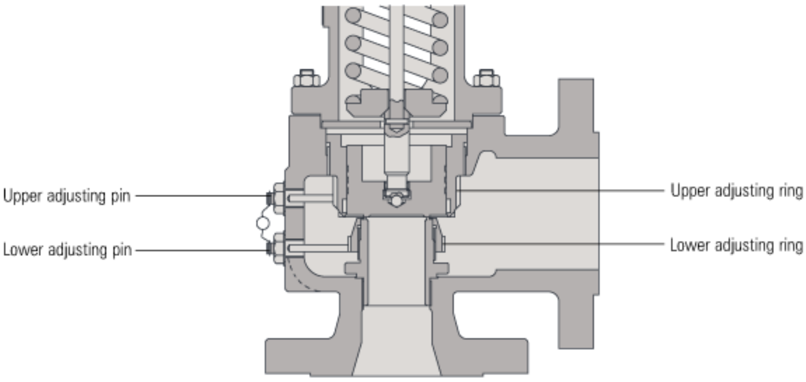


The blowdown rings found on most ASME type safety valves are used to make fine adjustments to the overpressure and blowdown values of the valves (see Exhibit 6-26). The lower blowdown (nozzle) ring is a common feature on many valves where the tighter overpressure and blowdown requirements require a more sophisticated designed solution.

The upper blowdown ring is usually factory set and essentially takes out the manufacturing tolerances which affect the geometry of the huddling chamber.

The lower blowdown ring is also factory set to achieve the appropriate code performance requirements but under certain circumstances can be altered. When the lower blowdown ring is adjusted to its top position the huddling chamber volume is such that the valve will pop rapidly, minimizing the overpressure value but correspondingly requiring a greater blowdown before the valve re-seats. When the lower blowdown ring is adjusted to its lower position there is minimal restriction in the huddling chamber and a greater overpressure will be required before the valve is fully open but the blowdown value will be reduced.

Exhibit 6-26: Blowdown rings on an ASME type safety valve



6.10.2 Types of Safety Valves

There is a wide range of safety valves available to meet the many different applications and performance criteria demanded by different industries. Furthermore, national standards define many varying types of safety valve.

The ASME standard I and ASME standard VIII for boiler and pressure vessel applications and the ASME / ANSI PTC 25.3 standard for safety valves and relief valves provide the following definition. These standards set performance characteristics as well as defining the different types of safety valves that are used:

ASME I valve - A safety relief valve conforming to the requirements of Section I of the ASME pressure vessel code for boiler applications which will open within 3% overpressure and close within 4%. It will usually feature two blowdown rings, and is identified by a National Board 'V' stamp.

ASME VIII valve - A safety relief valve conforming to the requirements of Section VIII of the ASME pressure vessel code for pressure vessel applications which will open within 10% overpressure and close within 7%. Identified by a National Board 'UV' stamp.

Low lift safety valve - The actual position of the disc determines the discharge area of the valve.

Full lift safety valve - The discharge area is not determined by the position of the disc.

Full bore safety valve - A safety valve having no protrusions in the bore, and wherein the valve lifts to an extent sufficient for the minimum area at any section, at or below the seat, to become the controlling orifice.

Conventional safety relief valve - The spring housing is vented to the discharge side, hence operational characteristics are directly affected by changes in the backpressure to the valve.

Balanced safety relief valve - A balanced valve incorporates a means of minimizing the effect of backpressure on the operational characteristics of the valve.

Pilot operated pressure relief valve - The major relieving device is combined with, and is controlled by, a self-actuated auxiliary pressure relief device.

Power-actuated safety relief valve - A pressure relief valve in which the major pressure relieving device is combined with, and controlled by, a device requiring an external source of energy.

The following types of safety valve are defined in the DIN 3320 standard, which relates to safety valves sold in Germany and other parts of Europe:

Standard safety valve - A valve which, following opening, reaches the degree of lift necessary for the mass flowrate to be discharged within a pressure rise of not more than 10%. (The valve is characterized by a pop type action and is sometimes known as high lift).

Full lift (Vollhub) safety valve - A safety valve which, after commencement of lift, opens rapidly within a 5% pressure rise up to the full lift as limited by the design. The amount of lift up to the rapid opening (proportional range) shall not be more than 20%.

Direct loaded safety valve - A safety valve in which the opening force underneath the valve disc is opposed by a closing force such as a spring or a weight.

Proportional safety valve - A safety valve which opens more or less steadily in relation to the increase in pressure. Sudden opening within a 10% lift range will not occur without pressure increase. Following opening within a pressure of not more than 10%, these safety valves achieve the lift necessary for the mass flow to be discharged.

Diaphragm safety valve - A direct loaded safety valve wherein linear moving and rotating elements and springs are protected against the effects of the fluid by a diaphragm.

Bellows safety valve - A direct loaded safety valve wherein sliding and (partially or fully) rotating elements and springs are protected against the effects of the fluids by a bellows. The bellows may be of such a design that it compensates for influences of backpressure.

Controlled safety valve - Consists of a main valve and a control device. It also includes direct acting safety valves with supplementary loading in which, until the set pressure is reached, an additional force increases the closing force.

The British Standard BS 6759 lists the following types of safety valve:

Direct loaded - A safety valve in which the loading due to the fluid pressure underneath the valve disc is opposed only by direct mechanical loading such as a weight, a lever and weight, or a spring.

Conventional safety valve - A safety valve of the direct loaded type, the set pressure of which will be affected by changes in the superimposed backpressure.

Assisted safety valve - A direct loaded safety valve which, by means of a powered assistance mechanism, is lifted at a pressure below the unassisted set pressure and will, even in the event of failure of the assistance mechanism, comply with all the relevant requirements for safety valves.

Pilot operated (indirect loaded) safety valve - The operation is initiated and controlled by the fluid discharged from a pilot valve, which is itself a direct loaded safety valve.

Balanced bellows safety valve - A valve incorporating a bellows which has an effective area equal to that of the valve seat, to eliminate the effect of backpressure on the set pressure of the valve, and which effectively prevents the discharging fluid entering the bonnet space.

Balanced bellows safety valve with auxiliary piston - A balanced bellows valve incorporating an auxiliary piston, having an effective area equal to the valve seat, which becomes effective in the event of bellows failure.

Balanced piston safety valve - A valve incorporating a piston which has an area equal to that of the valve seat, to eliminate the effect of backpressure on the set pressure of the valve.

Bellows seal safety valve - A valve incorporating a bellows, which prevents discharging fluid from entering the bonnet space.

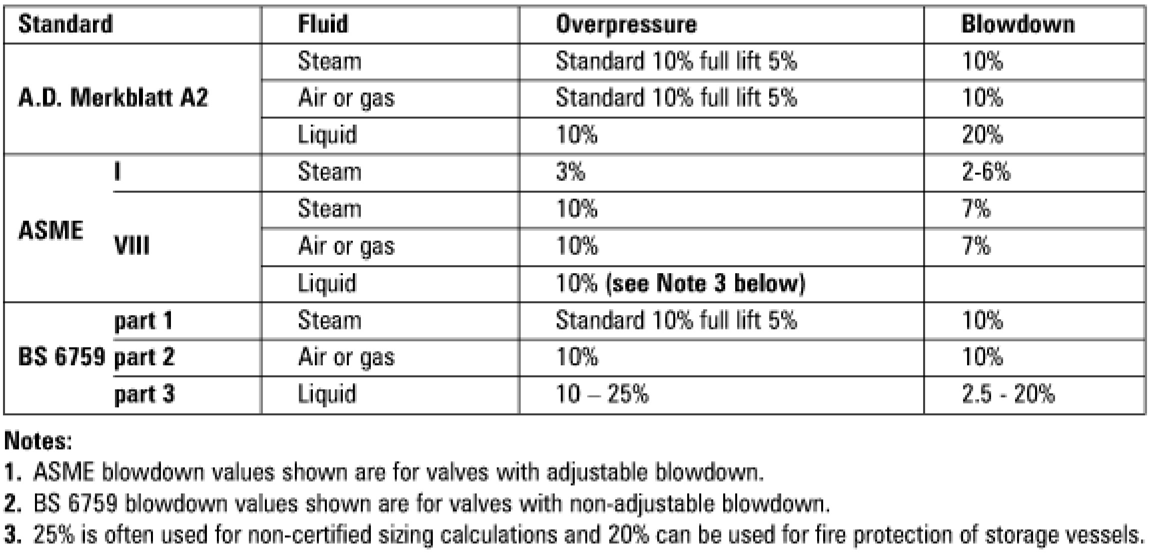
In addition, the BS 759 standard pertaining to safety fittings for application to boilers, defines full lift, high lift and lift safety valves:

Lift safety valve (ordinary class) - The valve member lifts automatically a distance of at least $^1/_{24th}$ of the bore of the seating member, with an overpressure not exceeding 10% of the set pressure.

High lift safety valve - Valve member lifts automatically a distance of at least $^1/_{12th}$ of the bore of the seating member, with an overpressure not exceeding 10% of the set pressure.

Full lift safety valve - Valve member lifts automatically to give a discharge area between 100% and 80% of the minimum area, at an overpressure not exceeding 5% of the set pressure.

The following table summarizes the performance of different types of safety valve set out by the various standards.



Standard		Fluid	Overpressure	Blowdown
A.D. Merkblatt A2		Steam	Standard 10% full lift 5%	10%
		Air or gas	Standard 10% full lift 5%	10%
		Liquid	10%	20%
ASME	**I**	Steam	3%	2-6%
	VIII	Steam	10%	7%
		Air or gas	10%	7%
		Liquid	10% **(see Note 3 below)**	
BS 6759	**part 1**	Steam	Standard 10% full lift 5%	10%
	part 2	Air or gas	10%	10%
	part 3	Liquid	10 – 25%	2.5 - 20%

Notes:

1. ASME blowdown values shown are for valves with adjustable blowdown.

2. BS 6759 blowdown values shown are for valves with non-adjustable blowdown.

3. 25% is often used for non-certified sizing calculations and 20% can be used for fire protection of storage vessels.

7 Burners and Combustion Controls

Burners are the principal equipment used for firing oil, gas and pulverized coal. Performance should be judged according to the following criteria:

1) Safety should be paramount under all operating conditions, including start-up, shutdown, load variation and fuel switching.
2) The combustion efficiency should be as high as possible with minimum excess air.
3) The design should provide adequate "turndown" (i.e. range of firing load) at acceptable efficiency, as well as good operation at full design capacity.
4) The design and materials of construction should be compatible with good reliability and relatively low maintenance requirement.

There are a very large number of companies making burner equipment available in the world market, and all the larger manufacturers have major research and development programs to generate better products than their competitors. Locally made burners are exceedingly common in Pakistan. They range from careful copies of foreign-made burners, to simple pipes or tubes flowing gas into a combustion zone. In general, the inability of these burners to effectively mix fuel and air is a major cause of inefficient combustion in boilers.

Since gaseous fuels are easily dispersed in air, little or no fuel preparation is required and the burner is generally quite simple. Liquid fuels, however, require vaporization or atomization in the combustion air in order to achieve good mixing. Vaporization can be achieved by preheating the liquid fuel before it is mixed with air. This technique is applied in low capacity burners using relatively low-boiling distillate fuels such as kerosene. Most industrial oil burners are of the atomizing type. Atomization may be achieved with steam, compressed air or mechanical power (e.g. high pressure drop across a nozzle, or centrifugal force).

In many burner designs, the air is supplied to the combustion zone in two stages. Primary air is thoroughly mixed with the fuel at or before the burner. Although the primary air is sufficient to promote combustion, it is insufficient for combustion to be complete. Secondary air sufficient to complete the combustion is supplied separately (and without premixing with fuel) to the burner throat or primary to secondary air ratio should be exercised to achieve optimum combustion efficiency.

7.1 Gas Burners

Since gaseous fuels are easily dispersed in air, no fuel preparation is necessary. Combustion time is short, once ignition temperature is reached and proper turbulence is provided. There are basically two types of gas burners: (1) premix burners, and (2) nozzle mix burners, described in the first two sections below. Then the following section describes the natural draft versions of these burners.

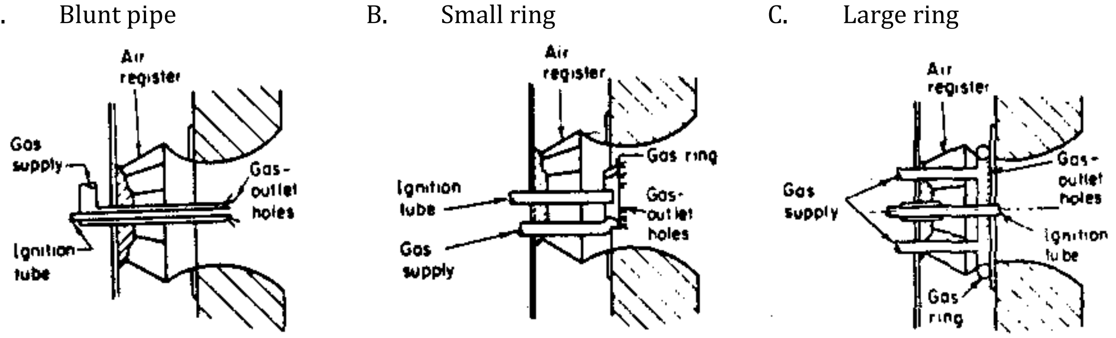
7.1.1 Premix Burners

Premix burners are used primarily for forced-draft applications where accurate furnace conditions must be maintained. Because the premixing of fuel and air gives a short intense flame, this type of burner is often used in furnaces and kilns where a short flame is required in a limited space. Ratio control with a simple pneumatic control system can be very accurately performed. These burners are limited to low heat release rates and are not usually used in boiler applications.

7.1.2 Nozzle-Mix Burners

Nozzle mix burners mix air and gas at the nozzle. As shown in Exhibit 7-1, these burners can take on three arrangements. The burner may be a standard forced draft register with the gas emitted from holes drilled at the end of the supply pipe. This method is easy to build, but in case large holes are used, the gas mixing becomes a problem. These burners frequently produce a luminous gas flame. A small diameter pipe or a large diameter ring can extend into the combustion chamber. This is one of the most commonly found arrangements in most small sized industrial and commercial boilers. Gas is generally introduced through several jets that mix rapidly with the incoming forced combustion air supply before entering the flame field.

Exhibit 7-1: Various types of nozzle-mix burners



A. Blunt pipe B. Small ring C. Large ring

Two types of gas burner are in use 'Low pressure' and 'High pressure'. Industrial boilers generally use low-pressure burners operating at a pressure of 2.5 to 10 millibars. High pressure burners operate at higher pressures, usually between 12 and 175 mbar, and may include a number of nozzles to produce a particular flame shape.

There are many designs for gas burners in use that differ primarily in the orientation of the burner orifices and their location in the burner housing.

In general, nozzle mix burners can provide as good as air to fuel ratio control as the control system installed. The minimum excess air levels, however, will vary with the burner design.

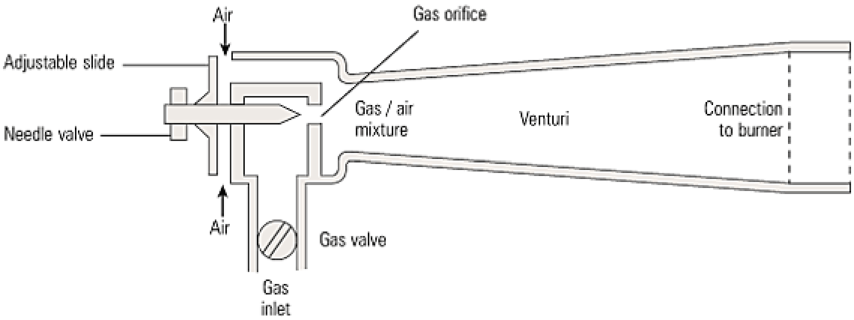
7.1.3 Naturally Aspirated Burners

Some of the commonly used burners for boilers in Pakistan are natural aspirated burners, also referred to as inspirated air burners, inspirators, or gas jet mixers. The great advantage of this burner is its natural draft capability, requiring no forced air delivery. On the other hand, for the same reason, its capacity is very limited. A major additional disadvantage of this burner, however, is the difficulty of close fuel/air control: first, the control is purely manual, and second, by virtue of the design, the control is not very precise.

Most of the naturally aspirated burners are of the premix type, as shown in the schematic of Exhibit 7-2. High velocity gas emerging from the spud or gas nozzle entrains and mixes air induced in proportion to the gas flow. The air flows through the air entry slots, whose size of opening is determined by the manual setting of the air adjusting disk. The combustion is retained on the flame nozzle. The lower half of the nozzle is sectioned in Exhibit 7.2 to show the bypass ports that relight the main flame if it is blown out.

Due to their relatively low capacity, a number of these burners may be installed in a ring pattern to provide the flame down the central tube of a fire tube boiler. A variation on this design is a combination premix/nozzle mix burner, where an additional air flow is induced around the venturi body to mix with the flame at the flame nozzle. Again, the quantity of induced air is manually adjustable. This design offers a more precise control, as well as a slightly higher capacity.

Exhibit 7-2: Naturally aspirated burners



It is difficult to maintain good combustion efficiency with these burners. Any wear, maladjustment, or dirt in the gas spud orifice, the air inlet slots, and the flame nozzle can easily impair the efficiency of combustion. Control of the firing rate requires a manual adjustment of the gas flow. To maintain proper air fuel ratio, a complementary manual air adjustment must be made with every fuel adjustment. It is thus extremely difficult to consistently maintain an optimum air to fuel ratio. Finally, since a large amount of air must enter with a small amount of gas, turndown capability is limited.

7.2 Oil Burners

Oil fuels generally require some type of pretreatment prior to delivery to the burner including the use of strainers to remove solid foreign material and tanks and flow line preheaters to assure the proper viscosity.

In addition to proportioning fuel and air, and mixing them, oil burners must prepare the fuel for combustion. There are two ways of doing this, with many variations of each: (1) the oil may be vaporized or gasified by heating within the burner, or (2) it may be atomized by the burner so vaporization can occur in the combustion space.

Designs of the first group, usually called vaporizing burners, are necessarily limited in range of fuels they can handle and find little power use.

If oil is to be vaporized in the combustion space in the instant of time available, it must be broken up into many small particles to expose as much surface as possible to the heat. This atomization may be effected in three basic ways: (1) using steam or air under pressure to break the oil into droplets, (2) forcing oil under pressure through a suitable nozzle, and (3) tearing an oil film into drop by centrifugal force. All three methods find use in industrial burners.

To approach complete combustion in the burning of oil, high turbulence is a necessity. In addition to breaking the oil into small particles for fast vaporization, the burner must provide motion between oil droplets and air, so vapor "coats" are stripped off as fast as they form and fresh surfaces exposed. This calls for penetration of the oil particles in the proper direction and for a high degree of turbulence in the air. Such relative motion of oil and air helps to produce more uniform mixture conditions over the combustion zone.

Oil burners can be classified into five basic types according to the method of atomization. They are:

1. Steam-Atomizing burners
2. Air-Atomizing burners
3. Mechanical Atomizing burners
4. Return flow variable - nozzle pressure atomizing burners

5. Rotary-cup burners.

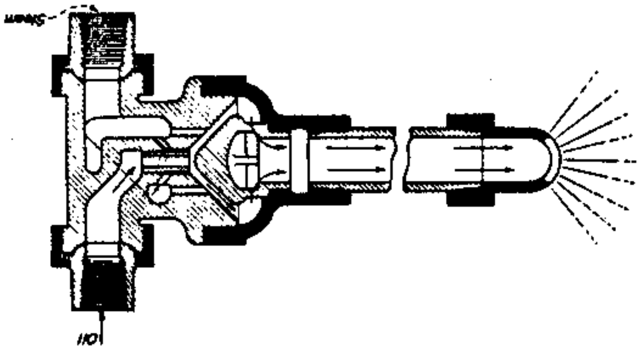
The ability to burn fuel oil efficiently requires a high fuel surface area-to-volume ratio. Experience has shown that oil particles in the range 20 and 40 µm are the most successful. Particles which are:

- Bigger than 40 µm tend to be carried through the flame without completing the combustion process.
- Smaller than 20 µm may travel so fast that they are carried through the flame without burning at all.
- A very important aspect of oil firing is viscosity. The viscosity of oil varies with temperature: the hotter the oil, the more easily it flows. Indeed, most people are aware that heavy fuel oils need to be heated in order to flow freely. What is not so obvious is that a variation in temperature, and hence viscosity, will have an effect on the size of the oil particle produced at the burner nozzle. For this reason the temperature needs to be accurately controlled to give consistent conditions at the nozzle.

7.2.1 Steam-Atomizing Burners

In this system of burners, a steam at pressures in the range 5 to 10 bars is used to atomize the oil. Jets of steam and oil are mixed either just inside or outside the burner through concentric annular channels, (see Exhibit 7-3). Steam atomizing burners, as a class, possess the ability to burn almost any fuel oil, of any viscosity, at almost any temperature. A high turn down ratio of 7:1 is possible. Capacity changes of these burners can easily be made by changing the burner tip. However, steam must be available at the correct pressure; a drop in the steam pressure results in poor fuel atomization.

Exhibit 7-3: Internal mixing steam atomizing burner



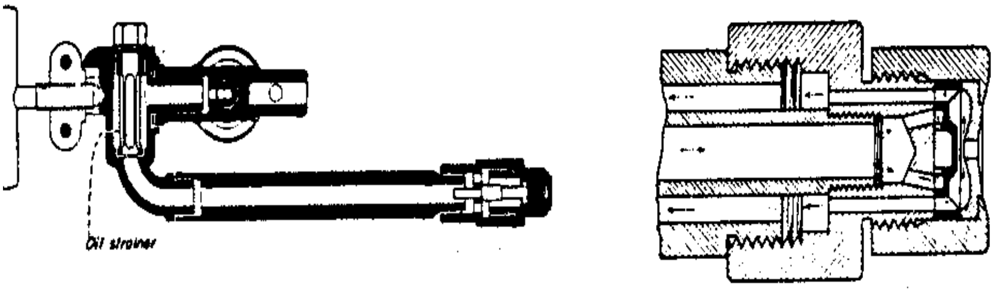
7.2.2 Air-Atomizing Burners

Air atomizing burners operate on the same principle as the steam atomizing burners with air replacing steam. The pressure of air used in these burners varies from below 2 bars to greater than 7 bars depending on the design of the burner. Turndown ratios of 7:1 are also possible at air pressures of 3 bars or greater. Air atomization is less extensively used on large boilers because of its higher operating cost; however, for smaller saturated steam boilers, air atomization is more common.

7.2.3 Mechanical Atomizing Burners

These burners are also called gun-type burners. Good atomization results when oil under high pressure, (usually 5 to 13 bars or higher) is discharged through a small orifice often aided by a slotted disc. The disc gives the oil a whirling motion before it passes on through a hole drilled in the nozzle where atomization occurs. A typical gun-type burner and nozzle are shown in Exhibit 7-4. For a given nozzle opening, atomization depends on pressure and since pressure and flow are related, best atomization occurs over a fairly narrow range of burner capacities. To modulate the load, a number of burners may be installed and turned on or off according to the demand, or different burner tips with different nozzle openings can be used on the same burner body. Gun type burners are normally found in equipment with ratings less than 1.25 million kcal/h.

Exhibit 7-4: Mechanical Atomizing burner and nozzle



7.2.4 Return-Flow Variable Nozzle Pressure Atomizing Burners

These burners, also called as jet pressure burners, operate on the same principle as the mechanical atomizing burners. They can be used with all grades of fuel oil, with the heavier oils heated to the proper viscosity. Oil pressure required is usually 22 bars which is much higher than gun type burners. Turndown ratio of 10 to 1 is possible in this type of burners. These burners allow variable firing rate by allowing part of the oil to return as shown in Exhibit 7-5.

Varying the pressure of the fuel oil immediately before the orifice (nozzle) controls the flow rate of fuel from the burner.

However, the relationship between pressure (P) and flow rate (F) has a square root characteristic, $\sqrt{P}\infty F$, or knowing the flow rate $P\infty F^2$.

For example if: $F_2 = 0.5\ F_1$
$P_2 = (0.5)^2\ P_1$
$P_2 = 0.25\ P_1$

If the fuel flow rate is reduced to 50%, the energy for atomization is reduced to 25%.

This means that the turndown available is limited to approximately 2:1 for a particular nozzle. To overcome this limitation, pressure jet burners are supplied with a range of interchangeable nozzles to accommodate different boiler loads.

Advantages of pressure jet burners:

- Relatively low cost.
- Simple to maintain.

Disadvantages of pressure jet burners:

- If the plant operating characteristics vary considerably over the course of a day, then the boiler will have to be taken off-line to change the nozzle.

- Easily blocked by debris. This means that well maintained, fine mesh strainers are essential.

7.2.5 Rotary-Cup Burners

This type of burner atomizes oil by literally tearing it into tiny droplets. A conical or cylindrical cup rotates at high speed (usually 2500 rpm if motor driven). As the fuel oil moves along the cup (due to the absence of a centripetal force) the oil film becomes progressively thinner as the circumference of the cap increases. Eventually, the fuel oil is discharged from the lip of the cone as a fine spray (Exhibit 7-6). These burners have turn down ratios up to 5 to 1. They are used in automatic fired boilers. These burners operate well but require precision machining. Due to their higher cost compared to other systems, and the relatively favorable performance of air atomization burners, rotary cup burners are on the decline.

Because the atomization is produced by the rotating cup, rather than by some function of the fuel oil (e.g. pressure), the turndown ratio is much greater than the pressure jet burner.

Advantages of rotary cup burners are robust and have good turndown ratio. They are less critical on fuel viscosity. However, they are more expensive to buy and maintain.

Exhibit 7-5: Return-flow burner nozzle

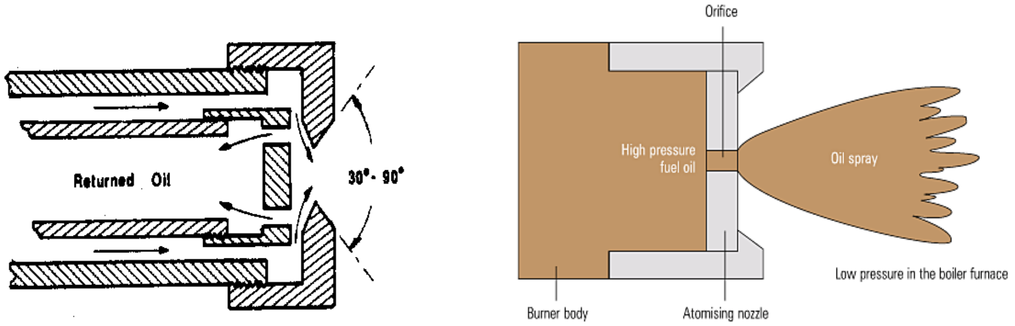
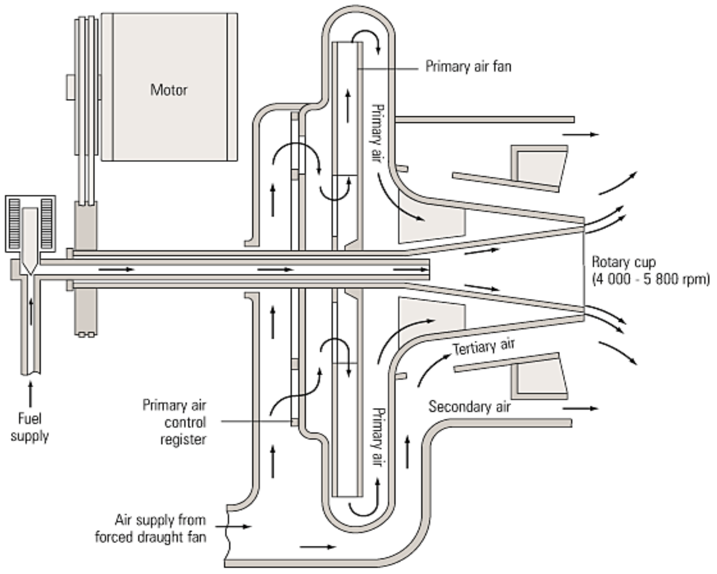


Exhibit 7-6: Rotary cup burner



Operating Parameters of Oil Burners are presented in Exhibit 7-7.

Exhibit 7-7: Parameters of oil burners

Type of Burner	Pressures	Turn-Down Ratio	% Air for Atomization	Oil Viscosity at Burner tip (Redwood-1) seconds)	Capacity Gallons/ Hr.
Low Air Pressure	Oil Pressure 8-12 PSIG Air Pressure 24"W.G.	1.4:1(without Secondary Air) 5:1 (with Secondary Air)	20-25%	70-100 s	1/5-60
Medium Air Pressure	3 to 15 PSIG (Air)	6:1	3-10%	90-180 s	½-200
High Air Pressure	Air Pressure 15 PSIG Oil Pressure Higher	Small-5:1 Large-10:1	2-3%	120-200 s	5 to 500
Steam Jet	Dry Steam 25-175 PSIG Oil Pressure Nearly Same	Small-5:1 Large-10:1	Steam 2-5% of total Output	120-150 s	5 to 400
Pressure Jet	Oil Pressure 50-200 PSIG	Simplex 2:1 Wide Range 6.1 to 10.1	NIL	70-100 s	Up to 3000
Rotary Cup	¼ to 30 PSIG	4:1	15-20%	150-200 s	¾ to 250

7.3 Dual Fuel Burners

Natural gas supply is the first choice of all types of facilities in Pakistan. However, many of these organizations need to continue operation if the gas supply is interrupted.

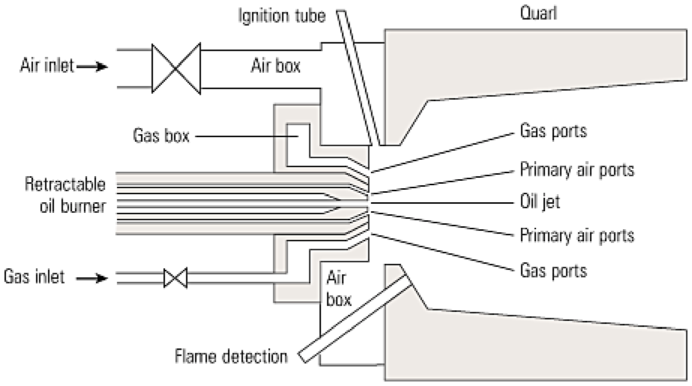
The usual arrangement is to have a fuel oil supply available on site, and to use this to fire the boiler when gas is not available. This led to the development of 'dual fuel' burners.

These burners are designed with gas as the main fuel, but have an additional facility for burning fuel oil.

The notice given by the Gas Company that supply is to be interrupted may be short, so the changeover to fuel oil firing is made as rapidly as possible, the usual procedure being:

- Isolate the gas supply line.
- Open the oil supply line and switch on the fuel pump.
- On the burner control panel, select 'oil firing'
  (This will change the air settings for the different fuel).
- Purge and re-fire the boiler.

Exhibit 7-8: Dual fuel burner



This operation can be carried out in quite a short period. In some organizations the change over may be carried out as part of a periodic drill to ensure that operators are familiar with the procedure, and any necessary equipment is available.

However, because fuel oil is only 'stand-by', and probably only used for short periods, the oil firing facility may be basic.

On more sophisticated plants, with highly rated boiler plant, the gas burner(s) may be withdrawn and oil burners substituted.

7.4 Solid Fuels – Combustion Systems

3.2.4.2 Most common combustion principles/systems

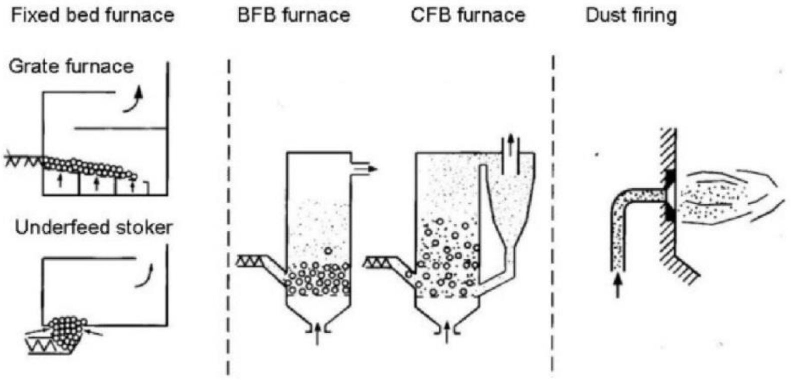
There are different coal and biomass combustion systems available for mid- and large-scale plants. Each system needs to be properly designed for a specific fuel type in order to guarantee adequate combustion quality and low emissions.

Solid fuel combustion systems are generally equipped with mechanical or pneumatic fuel-feeding systems. The following combustion principles can be distinguished:

- Fixed-bed combustion (chain or travelling stokers, spreader stokers, and underfeed stokers)
- Fluidized-bed combustion (bubbling or circulating)
- Dust combustion

The basic principles of these technologies are shown in Exhibit 7-9. Variations of these technologies are available but not further described here.

Exhibit 7-9: Principle Combustion Technologies for Solid Fuels



7.4.1 Fixed-bed combustion

The most important fixed-bed combustion appliances are industrial stokers. They are a mechanical means for feeding coal into, and for burning coal in, a furnace. There are three basic types of stokers. Chain or traveling-grate stokers have a moving grate on which the coal burns; they carry the coal from a hopper into the furnace and move the ash out (see Exhibit 7-10 and Exhibit 7-11). Spreader stokers mechanically or pneumatically distribute the coal from a hopper at the furnace front wall and move it onto the grate which usually moves continuously to dispose of the ash after the coal is burned (Exhibit 7-12). Underfeed stokers are arranged to force fresh coal from the hopper to the bottom of the burning coal bed, usually by means of a screw conveyor. The ash is forced off the edges of the retort peripherally to the ashpit or is removed by hand (see .Exhibit 7-13).

Exhibit 7-10: Chain or Travelling Grate Stoker (a)

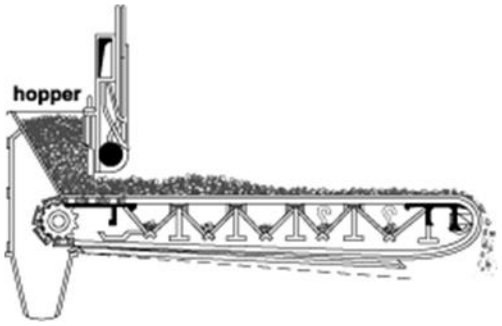


Exhibit 7-11: Chain or Travelling Grate Stoker (b)

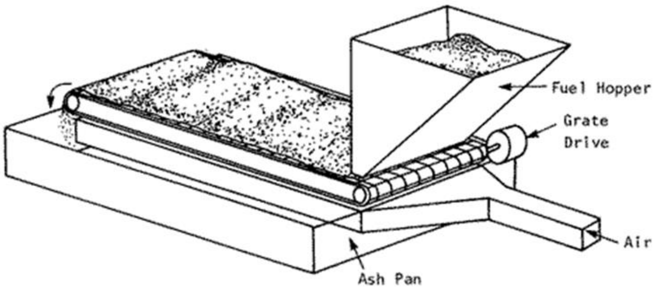


Exhibit 7-12: Spreader Stoker

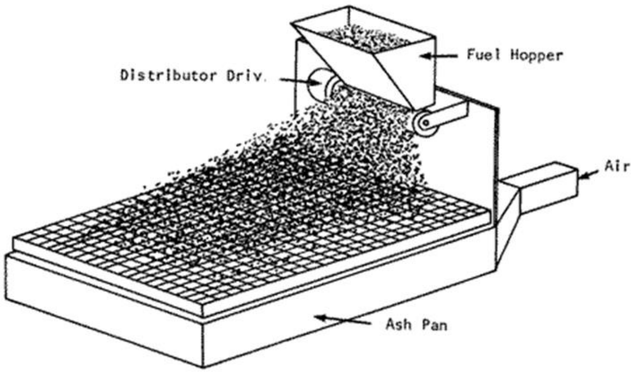
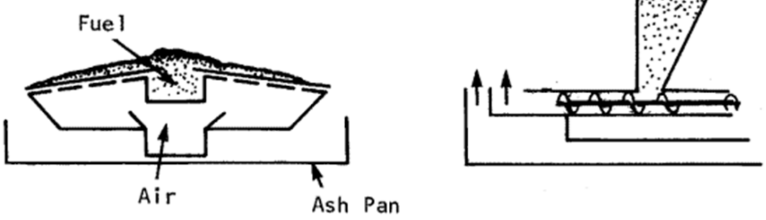


Exhibit 7-13: Underfeed Stoker



7.4.2 Fluidized Bed Combustion (FBC)

Fluidized bed combustion (FBC) has emerged as a viable alternative and has significant advantages over conventional firing system and offers multiple benefits – compact boiler design, fuel flexibility, higher combustion efficiency and reduced emission of noxious pollutants such as SOx and NOx. The fuels burnt in these boilers include coal, washery rejects, rice husk, bagasse & other agricultural wastes. The fluidized bed boilers have a wide capacity range- 0.5 tonnes/h to over 100 tonnes/h.

When an evenly distributed air or gas is passed upward through a finely divided bed of solid particles such as sand supported on a fine mesh, the particles are undisturbed at low velocity. As air velocity is gradually increased, a stage is reached when the individual particles are suspended in the air stream – the bed is called “fluidized”.

With further increase in air velocity, there is bubble formation, vigorous turbulence, rapid mixing and formation of dense defined bed surface. Bed of solid particles exhibits the properties of a boiling liquid and assume the appearance of a “bubbling fluidized bed”.

If sand particles in a fluidized state is heated to the ignition temperatures of coal; and coal is injected continuously into the bed, the coal will burn rapidly and bed attains a uniform temperature. The fluidized bed combustion (FBC) takes place at about 840 °C to 950 °C. Since this temperature is much below the ash fusion temperature, melting of ash and associated problems are avoided.

The lower combustion temperature is achieved because of high coefficient of heat transfer due to rapid mixing in the fluidized bed and effective extraction of heat from the bed through in-bed heat transfer tubes and walls of the bed. The gas velocity is maintained between minimum fluidization velocity and particle entrainment velocity. This ensures stable operation of the bed and avoids particle entrainment in the gas stream.

7.4.2.1 Bubbling Fluidized Bed Combustion (BFBC)

Within a fluidized bed combustion system (Exhibit 7-14), biomass fuel is burned in a self-mixing suspension of gas and solid-bed material into which combustion air enters from below. Depending on the fluidization velocity, bubbling fluidized bed and circulating fluidized bed can be distinguished. A fluidized bed consists of a cylindrical vessel with a perforated bottom plate filled with a suspension bed of hot, inert and granular material. The common bed materials are silica, sand and dolomite. Primary combustion air enters the furnace from below through the air distribution plate and fluidizes the bed so that it becomes a seething mass of particles and bubbles. The combustion temperature has to be kept low (800-900°C) in order to prevent ash sintering in the bed.

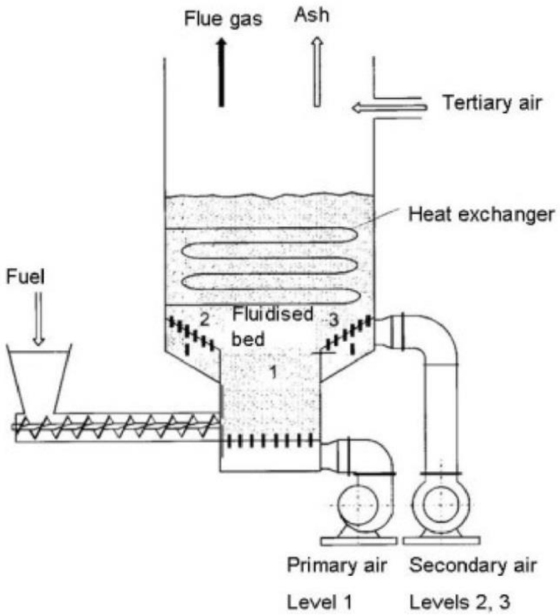
Due to the good mixing achieved, fluidized-bed combustion plants can deal flexibly with various fuel mixtures but are limited when it comes to particles size and impurities contained in the fuel. Therefore, appropriate fuel pre-treatment (particle size reduction, separation of metals) is necessary.

The low excess air quantities necessary increase combustion efficiency and reduce flue gas volume flow. Investment and operation costs are very high for small plants compared with fixed-bed systems.

A disadvantage is that high dust loads entrained with flue-gas make efficient dust precipitators and boiler cleaning systems necessary. Bed material is lost with ash, making it necessary to add new material to the plant periodically.

For bubbling fluidized bed combustion (BFB) particle size below 80 mm is recommended. The fluidization velocity of the air varies between 2.0 and 2.5 m/s. The secondary air is introduced through several inlets in the form of horizontal arranged nozzles at the beginning of the upper part of the furnace to ensure a staged-air supply to reduce nitrogen oxides (NOx) emissions. The fuel amounts only 1-2% of the bed material and the bed has to be heated before the fuel is introduced. The advantage of BFB is their flexibility concerning particle size and moisture content of the biomass fuels. It is also possible to use mixtures of different biomass fuels. One disadvantage is the difficulties they have at partial load operation. It is solved by splitting or staging the bed.

Exhibit 7-14: BFB Furnace with Three Air Introduction Zones



7.4.2.2 Atmospheric Fluidized Bed Combustion (AFBC) Boiler

Most operational boiler of this type is of the Atmospheric Fluidized Bed Combustion. (AFBC). This involves little more than adding a fluidized bed combustor to a conventional shell boiler. Such systems have similarly being installed in conjunction with conventional water tube boiler.

Coal is crushed to a size of 1 – 10 mm depending on the rank of coal, type of fuel fed to the combustion chamber. The atmospheric air, which acts as both the fluidization and combustion air, is delivered at a pressure, after being preheated by the exhaust fuel gases. The in-bed tubes carrying water generally act as the evaporator. The gaseous products of combustion pass over the super heater sections of the boiler flow past the economizer, the dust collectors and the air preheater before being exhausted to atmosphere.

7.4.2.3 Circulating Fluidized Bed Combustion (CFBC)

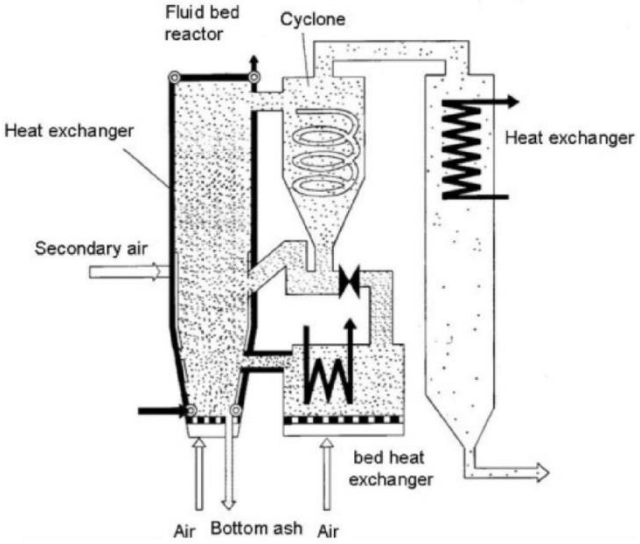
It is a variation of BFBC system. By increasing the fluidizing velocity to 5 to 10 m/s and using smaller sand particles (0.2 to 0.4 mm in diameter) circulating fluidized bed combustion (CFBC) is achieved (see Exhibit 7-15). The sand particles will be carried with the flue gas, separated in a hot cyclone or U-beam separator and fed back into the combustion chamber. The higher bed temperature in CFB furnaces leads to a better heat transfer and a very homogenous temperature distributing in the bed. This is of advantage for stable combustion conditions, the control of air staging and the placement of heating surfaces right in the upper part of the furnace.

The disadvantages are the larger size and therefore the higher price, the even greater dust load in the flue gas leaving the sand particle separator than in BFB systems, the higher loss of bed material in the ash and the small fuel particle size (0.1-40 mm in diameter) required.

In a circulating system the bed parameters are so maintained as to promote solids elutriation from the bed. They are lifted in a relatively dilute phase in a solids riser, and a down-comer with a cyclone provides a return path for the solids. There are no steam generation tubes immersed in the bed. Generation and super heating of steam takes place in the convection section, water walls, at the exit of the riser.

CFBC boilers are generally more economical than AFBC boilers for industrial application requiring more than 75 – 100 tonnes/h of steam. For large units, the taller furnace characteristics of CFBC boilers offers better space utilization, greater fuel particle and sorbent residence time for efficient combustion and SO2 capture, and easier application of staged combustion techniques for NOx control than AFBC steam generators.

Exhibit 7-15: CFB Combustion System with Steam Boiler



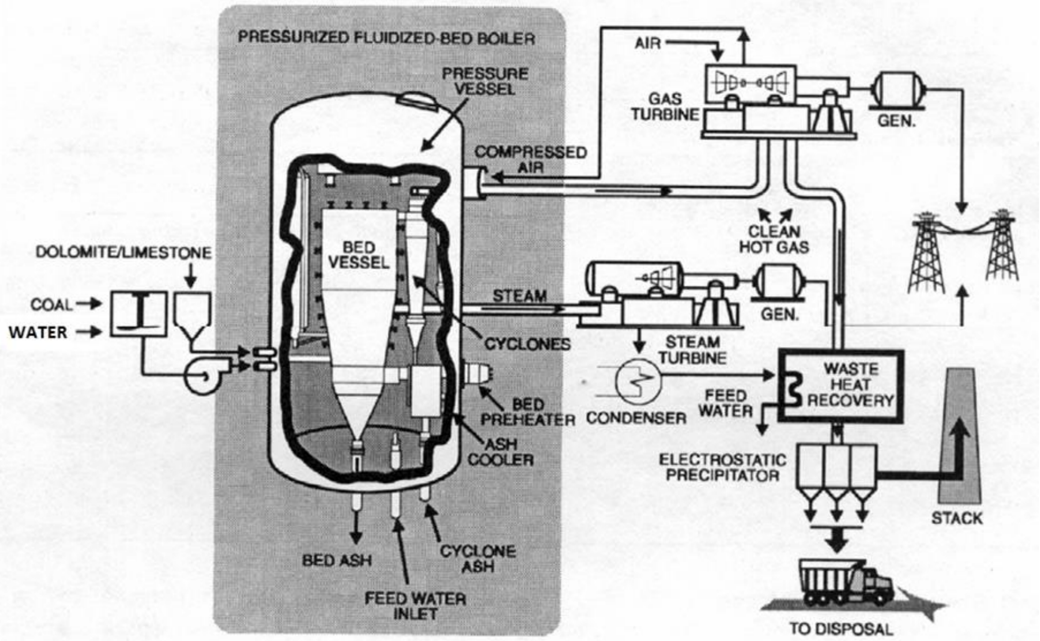
7.4.2.4 6.3.3 Pressurized Fluid Bed Combustion (PFBC)

Pressurized fluidized bed combustion (PFBC) is a variation of fluid bed technology that is meant for large-scale coal burning applications. In PFBC, the bed vessel is operated at pressure up to 16 barg. Exhibit 7-16 depicts a typical PFBC system.

The off-gas from the fluidized bed combustor drives the gas turbine. The steam turbine is driven by steam raised in tubes immersed in the fluidized bed. The condensate from the steam turbine is pre-heated using waste heat from gas turbine exhaust and is then taken as feed water for steam generation.

The PFBC system can be used for cogeneration or combined cycle power generation. By combining the gas and steam turbines in this way, electricity is generated more efficiently than in conventional system. The overall conversion efficiency is higher by 5% to 8%. .

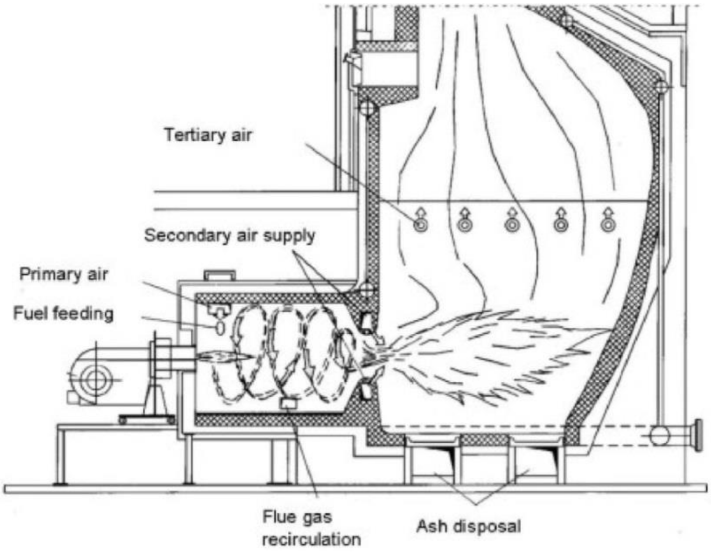
Exhibit 7-16: PFBC Combustion



7.4.3 Dust Combustion

Dust combustion is suitable for fuels available as small particles (average < 2 mm) like sawdust and fine shavings. A mixture of fuel and primary combustion air is pneumatically injected into the combustion chamber (Exhibit 7-17). Combustion takes place while the fuel is in suspension and gas burnout is achieved after secondary air addition. Fuel quality has to be quite constant. A maximum particle size (10-20 mm) has to be maintained and fuel moisture content should not exceed 20 weight %. Due to the explosion-like gasification of the fine and small particles of solid and biomass fuels, the fuel feeding needs to be controlled very carefully.

Exhibit 7-17: Dust Combustion Plant



The fuel/air mixture is usually injected tangentially into the cylindrical furnace muffle to establish a rotational flow. Fuel gasification and charcoal combustion take place at the same time because of the small particle size. Therefore, quick load changes and an efficient load control can be achieved. A disadvantage is that insulation bricks wear out quickly due to the thermal stress and erosion.

7.4.4 Pulverized Fuel Boiler

Most coal-fired power station boilers use pulverized coal, and many of the larger industrial water-tube boilers also use this pulverized fuel. This technology is well developed, and there are thousands of units around the world, accounting for well over 90% of coal-fired capacity.

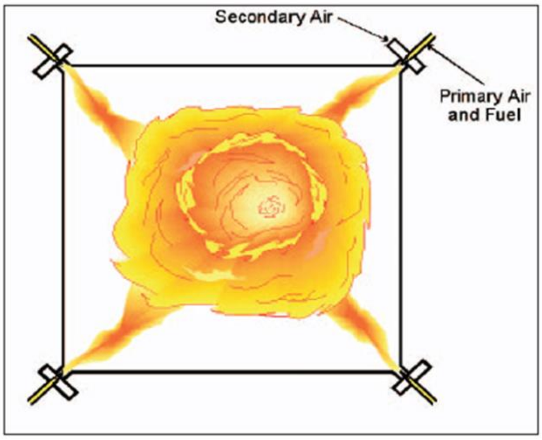
The coal is ground (pulverized) to a fine powder, so that less than 2% is +300 micro meter (µm) and 70-75% is below 75 microns, for a bituminous coal. It should be noted that too fine a powder is wasteful of grinding mill power. On the other hand, too coarse a powder does not burn completely in the combustion chamber and results in higher unburnt losses.

The pulverized coal is blown with part of the combustion air into the boiler plant through a series of burner nozzles. Secondary and tertiary air may also be added. Combustion takes place at temperatures from 1300-1700°C, depending largely on coal grade. Particle residence time in the boiler is typically 2 to 5 seconds, and the particles must be small enough for complete combustion to have taken place during this time.

This system has many advantages such as ability to fire varying quality of coal, quick responses to changes in load, use of high pre-heat air temperatures etc.

One of the most popular systems for firing pulverized coal is the tangential firing using four burners corner to corner to create a fireball at the center of the furnace (see Exhibit 7-18).

Exhibit 7-18: Tangential Firing System

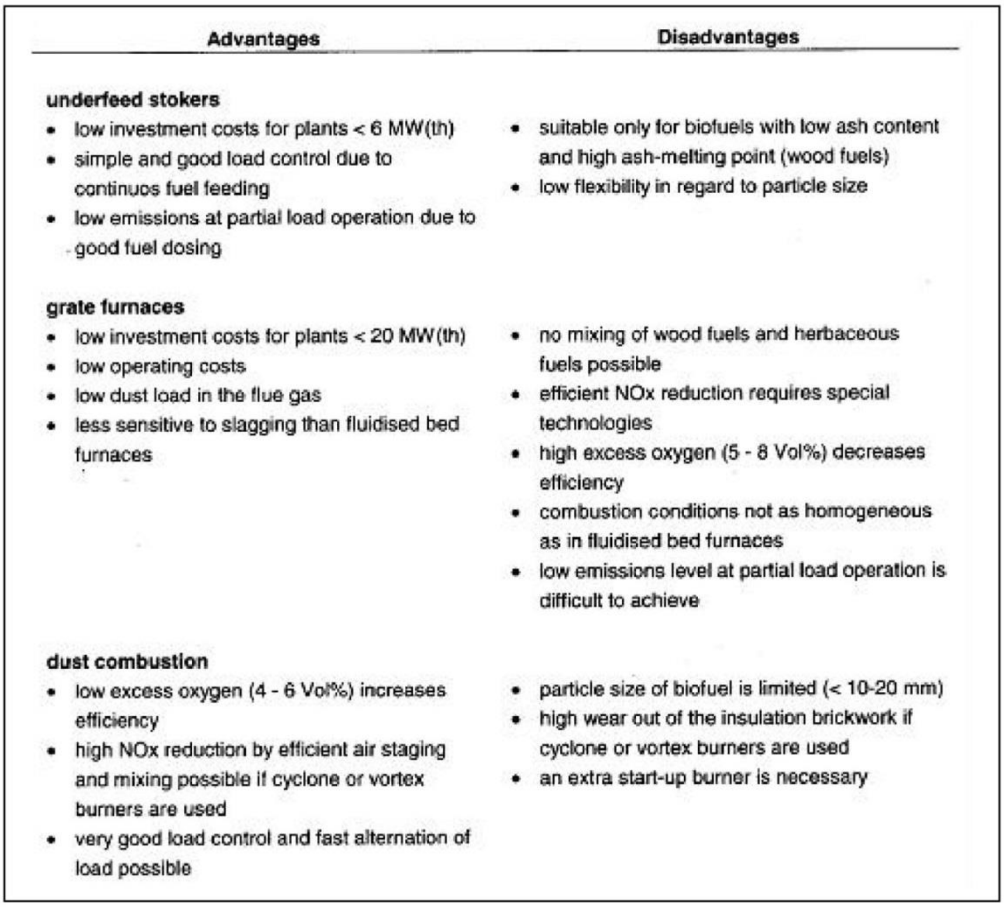


7.4.5 Summary of Solid Fuels Combustion Systems

The following exhibits provide an overview of relevant advantages and disadvantages, and fields of application of different combustion technologies for solid and biomass fuels.

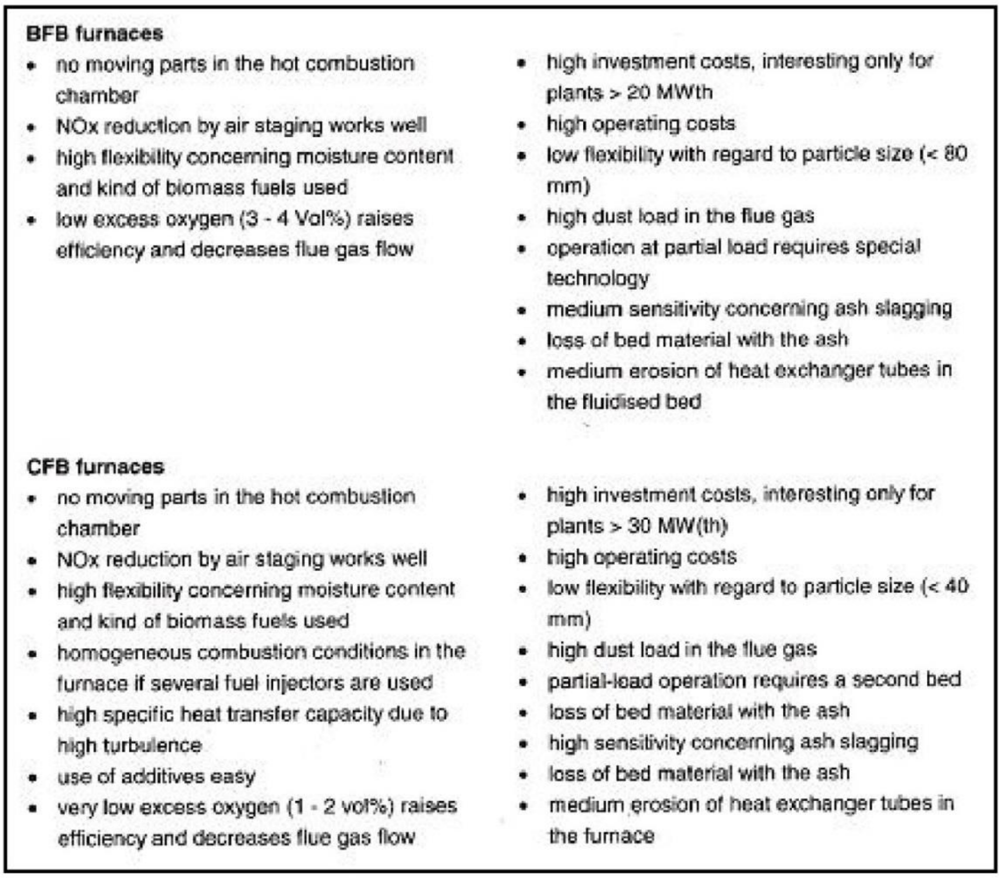
1. Exhibit 7-19: Overview of Advantages, Disadvantages and of Application of Different Solid Fuels Combustion Technologies
2. Exhibit 7-20: Comparison of Most Important Combustion Technologies with Automatically Fuel-Feeding Systems (Ash Content referred to Dry Substance)
3. Exhibit 7-21: Salient Characteristics of Major Combustion Technologies

Exhibit 7-19: Advantages, Disadvantages and of Application of Different Solid Fuels Combustion Technologies



Advantages	Disadvantages
underfeed stokers	
• low investment costs for plants < 6 MW(th) • simple and good load control due to continuos fuel feeding • low emissions at partial load operation due to good fuel dosing	• suitable only for biofuels with low ash content and high ash-melting point (wood fuels) • low flexibility in regard to particle size
grate furnaces	
• low investment costs for plants < 20 MW(th) • low operating costs • low dust load in the flue gas • less sensitive to slagging than fluidised bed furnaces	• no mixing of wood fuels and herbaceous fuels possible • efficient NOx reduction requires special technologies • high excess oxygen (5 - 8 Vol%) decreases efficiency • combustion conditions not as homogeneous as in fluidised bed furnaces • low emissions level at partial load operation is difficult to achieve
dust combustion	
• low excess oxygen (4 - 6 Vol%) increases efficiency • high NOx reduction by efficient air staging and mixing possible if cyclone or vortex burners are used • very good load control and fast alternation of load possible	• particle size of biofuel is limited (< 10-20 mm) • high wear out of the insulation brickwork if cyclone or vortex burners are used • an extra start-up burner is necessary

Exhibit 7-20: Comparison of Most Important Combustion Technologies



BFB furnaces

- no moving parts in the hot combustion chamber
- NOx reduction by air staging works well
- high flexibility concerning moisture content and kind of biomass fuels used
- low excess oxygen (3 - 4 Vol%) raises efficiency and decreases flue gas flow

- high investment costs, interesting only for plants > 20 MWth
- high operating costs
- low flexibility with regard to particle size (< 80 mm)
- high dust load in the flue gas
- operation at partial load requires special technology
- medium sensitivity concerning ash slagging
- loss of bed material with the ash
- medium erosion of heat exchanger tubes in the fluidised bed

CFB furnaces

- no moving parts in the hot combustion chamber
- NOx reduction by air staging works well
- high flexibility concerning moisture content and kind of biomass fuels used
- homogeneous combustion conditions in the furnace if several fuel injectors are used
- high specific heat transfer capacity due to high turbulence
- use of additives easy
- very low excess oxygen (1 - 2 vol%) raises efficiency and decreases flue gas flow

- high investment costs, interesting only for plants > 30 MW(th)
- high operating costs
- low flexibility with regard to particle size (< 40 mm)
- high dust load in the flue gas
- partial-load operation requires a second bed
- loss of bed material with the ash
- high sensitivity concerning ash slagging
- loss of bed material with the ash
- medium erosion of heat exchanger tubes in the furnace

Exhibit 7-21: Salient Characteristics of Major Combustion Technologies

Type	Capacity range	Fuel	Moisture content, %
Underfeed stoker	10 kW – 2,5 MW	Wood chips (ash content) wood pellets	5 – 50
Grate furnace	150 kW – 15 MW	All woody fuels (ash content ≤ 50%)	5 – 60
Bubbling fluidized bed combustion	5 MW – 15 MW	Fuel size !9 10 mm in diameter	5 – 60
Circulating fluidized bed combustion	15 MW – 100 MW	Fuel size !9 10 mm in diameter	5 – 60
Dust furnace	2 MW – 10 MW	Fuel size ≤ 5 mm in diameter	Mainly < 20

Burner Controls

Burners are the devices responsible for:

- Proper mixing of fuel and air in the correct proportions, for efficient and complete combustion.
- Determining the shape and direction of the flame.

Burner turndown

An important function of burners is turndown. This is usually expressed as a ratio and is based on the maximum firing rate divided by the minimum controllable firing rate.

The turndown rate is not simply a matter of forcing differing amounts of fuel into a boiler, it is increasingly important from an economic and legislative perspective that the burner provides efficient and proper combustion, and satisfies increasingly stringent emission regulations over its entire operating range. Turndown ratios for commonly used burners are normally:

Burner type	Turndown ratio
Pressure jet	2 : 1
Rotary cup	4 : 1
Gas	5 : 1

As has already been mentioned, coal as a boiler fuel tends to be restricted to specialized applications such as water-tube boilers in power stations.

The burner control system cannot be viewed in isolation. The burner, the burner control system, and the level control system should be compatible and work in a complementary manner to satisfy the steam demands of the plant in an efficient manner.

The next few paragraphs broadly outline the basic burner control systems.

7.4.6 On / Off Control System

This is the simplest control system, and it means that either the burner is firing at full rate, or it is off. The major disadvantage to this method of control is that the boiler is subjected to large and often frequent thermal shocks every time the boiler fires. Its use should therefore be limited to small boilers up to 500 kg / h.

On / off control systems are simple and least expensive. Their disadvantages are:

- If a large load comes on to the boiler just after the burner has switched off, the amount of steam available is reduced. In the worst cases this may lead to the boiler priming and locking out.
- Thermal cycling.

7.4.7 High / Low / Off Control System

This is a slightly more complex system where the burner has two firing rates. The burner operates first at the lower firing rate and then switches to full firing as needed, thereby overcoming the worst of the thermal shock. The burner can also revert to the low fire position at reduced loads, again limiting thermal stresses within the boiler. This type of system is usually fitted to boilers with an output of up to 5,000 kg / h.

Advantages of a high / low / off control:

- The boiler is better able to respond to large loads as the 'low fire' position will ensure that there is more stored energy in the boiler.
- If the large load is applied when the burner is on 'low fire', it can immediately respond by increasing the firing rate to 'high fire', for example the purge cycle can be omitted.

Disadvantages of a high / low / off control system:

- More complex than on-off control.
- More expensive than on-off control.

7.4.8 Modulating Control System

A modulating burner control will alter the firing rate to match the boiler load over the whole turndown ratio. Every time the burner shuts down and re-starts, the system must be purged by blowing cold air through the boiler passages. This wastes energy and reduces efficiency.

Full modulation, however, means that the boiler keeps firing over the whole range to maximize thermal efficiency and minimize thermal stresses. This type of control can be fitted to any size boiler, but should always be fitted to boilers rated at over 10,000 kg / h.

Advantages of a modulating control system:

The boiler is even more able to tolerate large and fluctuating loads. This is because:

- The boiler pressure is maintained at the top of its control band, and the level of stored energy is at its greatest.
- Should more energy be required at short notice, the control system can immediately respond by increasing the firing rate, without pausing for a purge cycle.

Disadvantages of a modulating control system:

- Most expensive.
- Most complex.
- Burners with a high turndown capability are required.

7.4.9 Safety

A considerable amount of energy is stored in fuel, and it burns quickly and easily. It is therefore essential that:

- Safety procedures are in place, and rigorously observed.
- Safety interlocks, for example purge timers, are in good working order and never compromised.

7.5 Combustion Controls

As introduced in the above paragraphs, the combustion controls regulate the quantity of fuel and air flow in the boiler. The primary objectives of these controls are to

- Provide adequate heat input to meet steam demands
- Protect personnel and equipment
- Minimize pollution
- Minimize fuel usage

The first of these is met by sufficient fuel input while the latter three are dependent on maintaining the proper air flow with respect to the fuel being fired.

There are basically six types of combustion control systems which carry out the above objectives with varying degrees of efficiency for single-fuel firing. They are:

1. Fixed positioning
2. Positioning with operator trim
3. Pressure ratio
4. Fuel and air metering
5. Cross-limited metering
6. Oxygen trim control

7.5.1 Fixed Positioning

A simplified fixed positioning control (jackshaft) system has been extensively applied to industrial boilers, based on minimum control system costs. A single actuator moves both the fuel and air control devices through a mechanical linkage in response to a change in the steam pressure. The system is calibrated by adjusting the cam on the fuel valve for fuel valve settings, and the linkage for proper fan damper travel relative to the fuel valve settings. The result can be a relatively constant fuel/air ratio over the load range. A manual control override of the main actuator is usually provided.

Since the system merely positions fuel valve and air damper openings, it cannot compensate for changes in fuel or air density, fuel supply pressure or heating value. Wear in the fuel valve orifice, burner tips, fan dampers, and in the linkage itself will also alter fuel/air ratios. This type of control system results in considerable variations of excess air, depending on the particular conditions existing at a given time. As a result, high excess air levels must always be maintained to avoid going below the minimum excess air requirements at any time. In actual operation, excess air will vary over a considerable range.

7.5.2 Parallel Positioning With Operator Trim

A lower margin of excess air can be achieved by substituting a pneumatic or electronic positioning system which reduces the variations caused by mechanical linkages. Separate actuators for the fuel valve and fan damper acting in parallel from a single steam pressure controller are installed. In addition, individual manual bias control of the fuel or air input can be used to adjust the fuel/air ratio. This system requires a combustion guide in the form of steam flow or air flow meters or a flue gas analyzer to assist the operator in setting the excess air flow. The gas analyzer can be a portable instrument or a fixed monitor: very large boilers will often use a fixed unit.

The parallel positioning control is a widely used combustion control system for units below 50 tonnes steam per hour. By adjusting the fuel/air ratio, compensations for variations in fuel characteristics, combustion conditions or control system equipment can be made by an alert operator.

7.5.3 Pressure Ratio

The fuel pressure at the burner and the differential pressure between the windbox and the combustion chamber may be used as simple indications of fuel and air flows. A basic parallel pneumatic or electronic system is used with the windbox-to-furnace differential and the burner pressure signal to trim the fuel and air flows. Manual bias control is normally provided to take account of variations in fuel characteristics and ambient conditions: use of a flue gas analyzer is required to allow the operator to make the appropriate adjustments.

This system eliminates inaccuracies due to fuel pressure and fan discharge variations but it requires that the pressure-flow relationships for the fuel and air have similar characteristics. Alignment problems often exist, causing inaccuracies. Variations in fuel heating value and fuel or air densities cannot be reconciled automatically.

7.5.4 Fuel and Air Metering

If the control system is further refined to include actual metering of fuel and air, additional error sources can be eliminated, further reducing the excess air levels. Several types of flow metering devices are available; however, there are some limitations as to the types of fuels that can be accurately metered.

Several combinations of components can be used in a metering control system. Feedback loops are employed to allow the fuel and air to self-correct flows to meet system demands. Some additional excess air is normally required to allow for the differences in speed of response between the fuel and air flow loops.

7.5.5 Cross-Limited Metering

An additional refinement to the metered system is the "cross-limited" metering system. This system limits the change in fuel flow (through control logic) to match the available air flow at all times. The quantity of air flow is also tied to the existing fuel flow and must be equal to or greater than the equivalent fuel flow. Required excess air levels are thereby slightly reduced.

A common form of the cross-limited metering system is a pneumatic or electronic parallel system using the steam pressure as the master controller. A manual override of the fuel/air ratio is provided to trim excess air levels.

7.5.6 Oxygen Trim

The effects on excess air of variations in fuel heating value and combustion air conditions can often be eliminated almost entirely by using a continuously monitored flue gas oxygen level to trim the fuel/air ratio. In principle, a single-burner system can thereby be operated at a preset oxygen level in the combustion gases, resulting in constant excess air levels at all loads, and minimizing fuel consumption.

In practice, oxygen trim control requires knowledge of the burner characteristics. If the level of oxygen can be accurately monitored over the full range of load conditions, this information may be used to continuously reset the fuel/air ratio. The purpose of an oxygen trim control system is to maintain the burner line. It is of course necessary to check this line with respect not only to carbon monoxide formation but also to the formation of large particulate matter, soot, and to possible flame distribution changes.

The effective trimming of oxygen level requires three basic components:

1. Knowledge of the ideal oxygen profile for the burner/ boiler combination
2. Reliable and accurate measurement of the oxygen level at the end of the combustion zone
3. An actuator/control mechanism which can interface with the existing air/fuel ratio control system.

The trim actuation system should not be able to alter the air/fuel ratio by more than about 10% for a good safety margin. The movement of the trim actuator needs to be electrically and/or mechanically limited to achieve this. As an extra safety factor, the trim control line may be set on the excess air side of the burner line.

Continuous flue gas oxygen analyzers are normally based on the zirconia measuring cell (see Section 6.8).

8 Water Treatment

Power generation and industrial plants use substantial quantities of water for steam generation. The treatment of water for steam generation is one of the most sophisticated branches of water chemistry.

The pressure and design of a boiler determine the quality of water it requires for steam generation. Municipal and plant water of good quality for domestic use is seldom good enough for boiler feed water. These sources of makeup are nearly always treated to reduce contaminants to acceptable levels; in addition, corrective chemicals are added to the treated water to counteract any adverse effects of the remaining trace contaminants.

The sequence of treatment depends on the type and concentration of contaminants found in the water supply and the desired quality of the finished water to avoid the three major boiler system problems – deposits, corrosion and carryover.

8.1 Contaminants and Impurities in Water

The common impurities in raw or plant water can be classified as follows:

Dissolved solids

These are substances that will dissolve in water. The principal ones are the carbonates and sulfates of calcium and magnesium, which are scale-forming when heated. There are other dissolved solids, which are non-scale forming. In practice, any salts forming scale within the boiler should be chemically altered so that they produce suspended solids, or sludge rather than scale.

Suspended solids

These are substances that exist in water as suspended particles. They are usually mineral, or organic in origin. These substances are not generally a problem as they can be filtered out.

Dissolved gases

Oxygen and carbon dioxide are readily dissolved by water. These gases are aggressive instigators of corrosion.

Scum forming substances

These are mineral impurities that foam or form scum. One example is soda in the form of carbonate, chloride, or sulfate.

The amount of impurities present is extremely small and they are usually expressed in any water analysis in the form of parts per million (ppm), by weight or alternatively in milligrams per liter (mg/l).

Exhibit 8-1 shows the common water contaminants, their effect and methods employed to remove them.

8.2 Characteristics of Raw Water

The following sections describe the characteristics of water.

Exhibit 8-1: Common Boiler Feed Water Contaminants

IMPURITY	UNDESIRABLE EFECTS	TREATMENT	COMMENTS
Soluble Gases			
Hydrogen Sulphide (H_2S)	Water smells like rotten eggs: Tastes bad, and is corrosive to most metals.	Aeration, Filtration, and Chlorination.	Found mainly in groundwater, and polluted streams.
Carbon Dioxide (CO_2)	Corrosive, forms carbonic acid in condensate.	Deaeration, neutralization with alkalis.	Filming, neutralizing amines used to prevent condensate line corrosion.
Oxygen (O_2)	Corrosion and pitting of boiler tubes.	Deaeration & chemical treatment with (Sodium Sulphite or Hydrazine)	Pitting of boiler tubes, and turbine blades, failure of steam lines, and fittings etc.
Suspended Solids			
Sediment &Turbidity	Sludge and scale carryover.	Clarification and filtration.	Tolerance of approx. 5ppm max. for most applications, 10ppm for potable water.
Organic Matter	Carryover, foaming, deposits can clog piping, and cause corrosion.	Clarification; filtration, and chemical treatment	Found mostly in surface waters, caused by rotting vegetation, and farm run offs. Organics break down to form organic acids. Results in low of boiler feed-water pH, which then attacks boiler tubes. Includes diatoms, molds, bacterial slimes, iron/manganese bacteria. Suspended particles collect on the surface of the water in the boiler and render difficult the liberation of steam bubbles rising to that surface.. Foaming can also be attributed to waters containing carbonates in solution in which a light flocculent precipitate will be formed on the surface of the water. It is usually traced to an excess of sodium carbonate used in treatment for some other difficulty where animal or vegetable oil finds its way into the boiler.
Dissolved Colloidal Solids			
Oil & Grease	Foaming, deposits in boiler	Coagulation & filtration	Enters boiler with condensate
Hardness, Calcium (CA), and Magnesium (Mg)	Scale deposits in boiler, inhibits heat transfer, and thermal efficiency. In severe cases can lead to boiler tube burn thru, and failure.	Softening, plus internal treatment in boiler.	Forms are bicarbonates, sulfates, chlorides, and nitrates, in that order. Some calcium salts are reversibly soluble. Magnesium reacts with carbonates to form compounds of low solubility.
Sodium, alkalinity, $NaOH$,$NaHCO_3$, Na_2CO_3	Foaming, carbonates form carbonic acid in steam, causes condensate return line, and steam trap corrosion, can cause embrittlement.	Deaeration of make-up water and condensate return. Ion exchange; deionization, acid treatment of make-up water.	Sodium salts are found in most waters. They are very soluble, and cannot be removed by chemical precipitation.
Sulfates (SO_4)	Hard scale if calcium is present	Deionization	Tolerance limits are about 100-300ppm as CaCO3
Chlorides, (CI)	Priming, i.e. uneven delivery of steam from the boiler (belching), carryover of water in steam lowering steam efficiency, can deposit as salts on superheaters and turbine blades. Foaming if present in large amounts.	Deionization	Priming, or the passage of steam from a boiler in "belches", is caused by the concentration sodium carbonate, sodium sulfate, or sodium chloride in solution. Sodium sulfate is found in many waters in the USA, and in waters where calcium or magnesium is precipitated with soda ash.
Iron (Fe) and Manganese (Mn)	Deposits in boiler, in large amounts can inhibit heat transfer.	Aeration, filtration, ion exchange.	Most common form is ferrous bicarbonate.
Silica (Si)	hard scale in boilers and cooling systems: turbine blade deposits.	Deionization; lime soda process, hot-lime-zeolite treatment.	Silica combines with many elements to produce silicates. Silicates form very tenacious deposits in boiler tubing. Very difficult to remove, often only by flourodic acids. Most critical consideration is volatile carryover to turbine components.

8.2.1

8.2.2 Hardness

Water is referred to as being either ‘hard’ or ‘soft’. Hard water contains scale-forming impurities while soft water contains little or none. The difference can easily be recognized by the effect of water on soap. A large amount of soap is required to make lather with hard water than with soft water.

Hardness is caused by the presence of the mineral salts of calcium and magnesium and it is these same minerals that encourage the formation of scale.

There are two common classifications of hardness:

8.2.2.1 Alkaline Hardness (also known as temporary hardness)

Calcium and magnesium bicarbonates are responsible for alkaline hardness. The salts dissolve in water to form an alkaline solution. When heat is applied, they decompose to release carbon dioxide and soft scale or sludge.

The term ‘temporary hardness’ is sometimes used, as it can be removed by simple boiling. This effect can often be seen as scale on the inside of an electric kettle.

See Exhibit 8-2and Exhibit 8-3; the later Exhibit represents the situation within the boiler.

Exhibit 8-2: Alkaline or Temporary Hardness

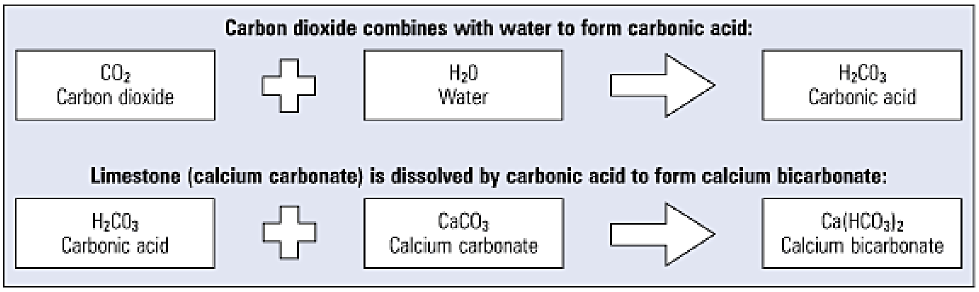
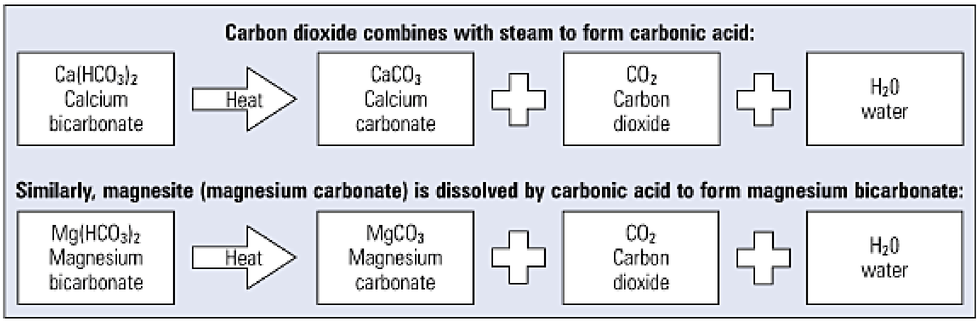


Exhibit 8-3: Non-alkaline or permanent hardness



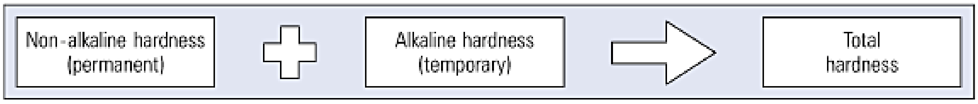
8.2.2.2 Non-alkaline Hardness and Carbonates (also known as permanent hardness)

This is also due to the presence of the salts of calcium and magnesium but in the form of sulfates and chlorides. These precipitate out of solution, due to their reduced solubility as the temperature rises, and form hard scale, which is difficult to remove.

In addition, the presence of silica in boiler water can also lead to hard scale, which can react with calcium and magnesium salts to form silicates which can severely inhibit heat transfer across the fire tubes and cause them to overheat.

8.2.3 Total Hardness

Total hardness is not to be classified as a type of hardness, but as the sum of concentrations of calcium and magnesium ions present when these are both expressed as $CaCO_3$. If the water is alkaline, a proportion of this hardness, equal in magnitude to the total alkalinity and also expressed as $CaCO_3$, is considered as alkaline hardness, and the remainder as non-alkaline hardness.



Non-hardness salts, such as sodium salts are also present, and are far more soluble than the salts of calcium or magnesium and will not generally form scale on the surfaces of a boiler, as shown below.

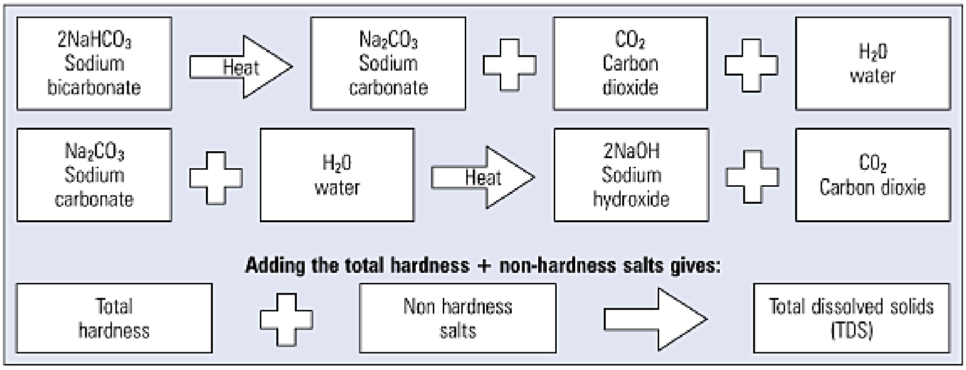


Exhibit 8-4: Scale Formation in Boilers

Comparative units

When salts dissolve in water they form electrically charged particles called ions. The metallic parts (calcium, sodium, magnesium) can be identified as cations because they are attracted to the cathode and carry positive electrical charges. Anions are non-metallic and carry negatively charged bicarbonates, carbonate, chloride, sulfate, which are attracted to the anode.

Each impurity is generally expressed as a chemically equivalent amount of calcium carbonate, which has a molecular weight of 100.

A partial list of boiler deposits is provided in the following table.

A Partial List of Boiler Deposits

Name	Formula
Acmite	$Na_2O{\cdot}Fe_2O_3{\cdot}4SiO_2$
Analcite	$Na_2O{\cdot}Al_2O_3{\cdot}4SiO_2{\cdot}2H_2O$
Anhydrite	$CaSO_4$
Aragonite	$CaCO_3$
Brucite	$Mg(OH)_2$
Calcite	$CaCO_3$
Cancrin	$4Na_2O{\cdot}CaO{\cdot}4Al_2O_3{\cdot}2CO_2{\cdot}9SiO_2{\cdot}3H_2O$
Hematite	Fe_2O_3
Hydroxyapatite	$Ca10(OH)_2(PO_4)_6$
Magnetite	Fe_3O_4
Noselite	$4Na_2O{\cdot}3Al_2O_3{\cdot}6SiO_2{\cdot}SO_4$
Pectolite	$Na_2O{\cdot}4CaO{\cdot}6SiO_2{\cdot}H_2O$
Alpha-Quartz	SiO_2
Serpentine	$3MgO{\cdot}2SiO_2{\cdot}2H_2O$
Thenardite	Na_2SO_4
Wallastonite	$CaSiO_3$
Xonotlite	$5CaO{\cdot}5SiO_2{\cdot}H_2O$

8.3 Boiler Water Quality

The operating objectives for steam boiler plant include:

- Safe operation.
- Maximum combustion and heat transfer efficiency.
- Minimum maintenance.
- Long working life.

The quality of the water used to produce the steam in the boiler will have a profound effect on meeting these objectives.

There is a need for the boiler to operate under the following criteria:

8.3.1 Freedom from Scale

If hardness is present in the feed water and not controlled chemically, then scaling of the heat transfer surfaces will occur, reducing heat transfer and efficiency - making frequent cleaning of the boiler necessary. In extreme cases, local hot spots can occur, leading to mechanical damage or even tube failure.

8.3.2 Freedom from Corrosion and Chemical Attack

If the water contains dissolved gases, particularly oxygen, corrosion of the boiler surfaces, piping and other equipment is likely to occur.

If the pH value of the water is too low, the acidic solution will attack metal surfaces. If the pH value is too high, and the water is alkaline, other problems such as foaming may occur.

Caustic embrittlement or caustic cracking must also be prevented in order to avoid metal failure. Cracking and embrittlement are caused by too high a concentration of sodium hydroxide. Older riveted boilers are more susceptible to this kind of attack; however, care is still necessary on modern welded boilers at the tube ends.

8.4 Factors Affecting Steam Quality

If the impurities in the boiler feed water are not dealt with properly, carryover of boiler water into the steam system can occur. This may lead to problems elsewhere in the steam system, such as:

- **Contamination of the surfaces of control valves**
  This will affect their operation and reduce their capacity.
- **Contamination of the heat transfer surfaces of process plant**
  This will increase thermal resistance, and reduce the effectiveness of heat transfer.
- **Restriction of steam trap orifices**
  This will reduce steam trap capacities, and ultimately lead to waterlogging of the plant, and reduced output.

Carryover can be caused by two factors:

Priming

This is the ejection of boiler water into the steam take-off and is generally due to one or more of the following:

- Operating the boiler with too high a water level.
- Operating the boiler below its design pressure; this increases the volume and the velocity of the steam released from the water surface.
- Excessive steam demand.

Foaming

This is the formation of foam in the space between the water surface and the steam off-take. The greater the amount of foaming, the greater the problems which will be experienced. The following are indications and consequences of foaming:

- Water will trickle down from the steam connection of the gauge glass; this makes it difficult to accurately determine the water level.
- Level probes, floats and differential pressure cells have difficulty in accurately determining water level.
- Alarms may be sounded, and the burner(s) may even 'lockout'. This will require manual resetting of the boiler control panel before supply can be re-established.

These problems may be completely or in part due to foaming in the boiler. However, because foaming is endemic to boiler water, a better understanding of foam itself is required:

Agitation increases foaming - The trend is towards smaller boilers for a given steaming rate. Smaller boilers have less water surface area, so the rate at which steam is released per square meter of water area is increased. This means that the agitation at the surface is greater. It follows then that smaller boilers are more prone to foaming

Hardness - Hard water does not foam. However, boiler water is deliberately softened to prevent scale formation, and this gives it a propensity to foam.

Colloidal substances - Contamination of boiler water with a colloid in suspension, for example. milk, causes violent foaming. Note: Colloidal particles are less than 0.000 1 mm in diameter, and can pass through a normal filter.

TDS level - As the boiler water TDS increases, the steam bubbles become more stable, and are more reluctant to burst and separate.

8.5 External Water Treatment

It is generally agreed that where possible on steam boilers, the principal feedwater treatment should be external to the boiler. A summary of the treated water quality that might be obtained from the various processes, based on a typical hard raw water supply, is shown in Exhibit 8-9. This is the water that the external treatment plant has to deal with. External water treatment processes can be listed as:

Reverse osmosis - A process where pure water is forced through a semi-permeable membrane leaving a concentrated solution of impurities, which is rejected to waste.

Lime; lime / soda softening - With lime softening, hydrated lime (calcium hydroxide) reacts with calcium and magnesium bicarbonates to form a removable sludge. This reduces the alkaline (temporary) hardness. Lime / soda (soda ash) softening reduces non-alkaline (permanent) hardness by chemical reaction.

Ion exchange - It is by far the most widely used method of boiler water treatment. The methods include base exchange, dealkalization and demineralization.

Deaeration - Mechanical and chemical deaeration is an integral part of modern boiler water protection and control. Deaeration, coupled with other aspects of external treatment, provides the best and highest quality feed water for boiler use. The purposes of deaeration are:

To remove oxygen, carbon dioxide and other non-condensable gases from feed water
To heat the incoming makeup water and return condensate to an optimum temperature for:
Minimizing solubility of the undesirable gases
Providing the highest temperature water for injection to the boiler

8.5.1 Lime; Lime-Soda Softening

8.5.1.1 Lime Process

The lime process is used for waters containing bicarbonates of lime and magnesia. Slaked lime in solution, as lime water, is the reagent used. This combines with the carbonic acid which is present, either free, or as bicarbonates, to form an insoluble carbonate of lime. The soluble bicarbonates of lime and magnesia, losing their carbonic acid, thereby become insoluble, and precipitate. The bicarbonate hardness is eliminated:

$$HCO_3^- + OH^- \rightarrow H_2O + CO_3^{2-}$$

$$Ca^{2+} + CO_3^{2-} \rightarrow CaCO_3 \text{ (precipitates)}$$

Magnesium hardness is reduced:

$$Mg^{2+} + 2OH^- \rightarrow Mg(OH)_2 \text{ (precipitates)}$$

8.5.1.2 Soda Process

The soda process is used for waters containing sulfates of lime and magnesia. Carbonate of soda, and hydrate of soda (caustic soda) are used either alone, or together as reagents. Carbonate of soda added to the make-up water, decomposes the sulfates to form insoluble carbonates of lime or magnesium, which precipitate, the neutral soda remaining in solution. If free carbonic acid (carbon dioxide) is present in the water, soluble bicarbonates of lime or magnesium are formed. When heated (deaerator) the carbon dioxide will be driven off and insoluble carbonates will be formed. Caustic soda, when used in this process, absorbs the free carbonic acid and converts the bicarbonates of lime and magnesia into insoluble the carbonates, at the same time forming either sodium carbonate or bicarbonate, according to the amount present, which in turn decomposes the sulfates present, into either carbonates or bicarbonates.

8.5.1.3 Lime-Soda Process

This process, which is a combination of the first two, is the most commonly used treatment process, is the most widely used method in boiler water purification, and is used where sulfates of lime and magnesia are present in the water, with such a quantity of carbonic acid or bicarbonates, as to impair the action of the soda. Sufficient soda is used to break down the sulfates of lime and magnesia, and sufficient lime is added in order to absorb the carbonic acid not eliminated in the soda reaction.

$$CaCl_2 + Na_2CO_3\text{-} \rightarrow CaCO_{3\ \text{precipitates}} + 2NaCl$$

$$MgSO_4 + Na_2CO_3\text{-} \rightarrow MgCO_{3\ \text{precipitates}} + Na_2SO_4$$

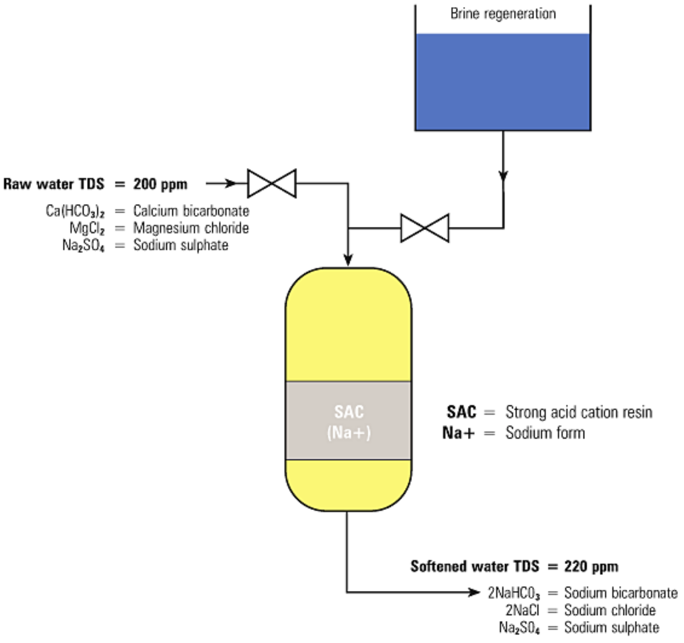
8.5.2 Ion Exchange

An ion exchanger is an insoluble material normally made in the form of resin beads of 0.5 to 1.0 mm diameter. The resin beads are usually employed in the form of a packed bed contained in a glass reinforced plastic pressure vessel. The resin beads are porous and hydrophilic - that is, they absorb water. Within the bead structure are fixed ionic groups with which are associated mobile exchangeable ions of opposite charge. These mobile ions can be replaced by similarly charged ions, from the salts dissolved in the water surrounding the beads.

8.5.2.1 Base Exchange Softening

This is the simplest form of ion exchange and also the most widely used. The resin bed is initially activated (charged) by passing a 7 - 12% solution of brine (sodium chloride or common salt) through it, which leaves the resin rich in sodium ions. Thereafter, the water to be softened is pumped through the resin bed and ion exchange occurs. Calcium and magnesium ions displace sodium ions from the resin, leaving the flowing water rich in sodium salts. Sodium salts stay in solution at very high concentrations and temperatures and do not form harmful scale in the boiler. See Exhibit 8-5.

Exhibit 8-5: Base-exchange Softening



From Exhibit 8-5 it can be seen that the total hardness ions are exchanged for sodium. With sodium base exchange softening there is no reduction in the total dissolved solids level (TDS in parts per million or ppm) and no change in the pH. All that has happened is an exchange of one group of potentially harmful scale forming salts for another type of less harmful, non-scale forming salts. As there is no change in the TDS level, resin bed exhaustion cannot be detected by a rise in conductivity (TDS and conductivity are related). Regeneration is therefore activated on a time or total flow basis.

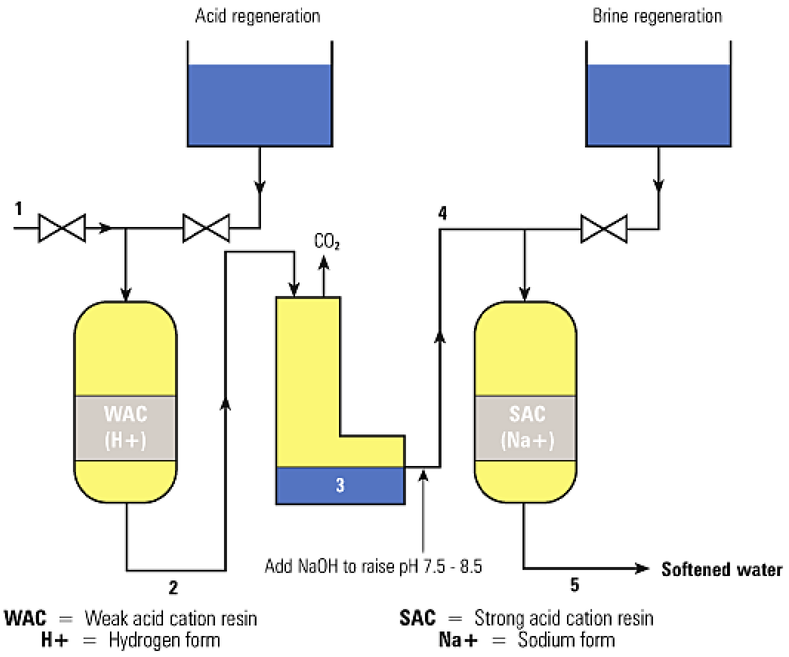
Softeners are relatively cheap to operate and can produce treated water reliably for many years. They can be used successfully even in high alkaline (temporary) hardness areas provided that at least 50% of condensate is returned. Where there is little or no condensate return, a more sophisticated type of ion exchange is preferable.

Sometimes a lime / soda softening treatment is employed as a pre-treatment before base exchange. This reduces the load on the resins.

8.5.2.2 Dealkalization

The disadvantage of base exchange softening is that there is no reduction in the TDS and alkalinity. This may be overcome by the prior removal of the alkalinity and this is usually achieved through the use of a dealkalizer. There are several types of dealkalizer but the most common variety is shown in Exhibit 8-6. It is really a set of three units, a dealkalizer, followed by a degasser and then a base exchange softener.

Exhibit 8-6: Dealkalization Process

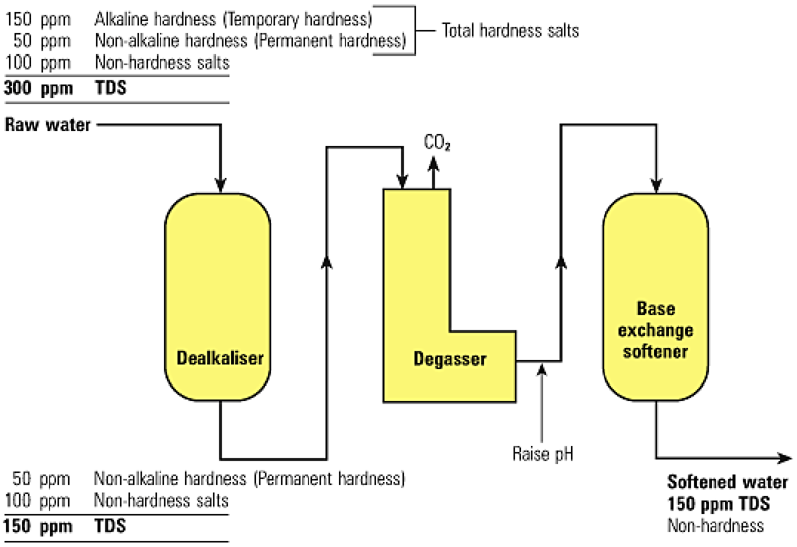


1	2	3	4	5
$Ca(HCO_3)_2$	$2H_2CO_3$	H_2O	H_2O	H_2O
$MgCl_2$	$MgCl_2$	$MgCl_2$	$MgCl_2$	2NaCl
Na_2SO_4	Na_2SO_4	Na_2SO_4	Na_2SO_4	Na_2SO_4
pH 7.6	pH 4.5 – 5.0	pH 4.5 – 5.0		pH 7.5 – 8.5

Dealkalizer - The system shown in Exhibit 8-7 is sometimes called 'split-stream' softening. A dealkalizer would seldom be used without a base exchange softener, as the solution produced is acidic and would cause corrosion, and any permanent hardness would pass straight into the boiler.

A dealkalization plant will remove temporary hardness as shown in Exhibit 8-7. This system would generally be employed when a very high percentage of make-up water is to be used.

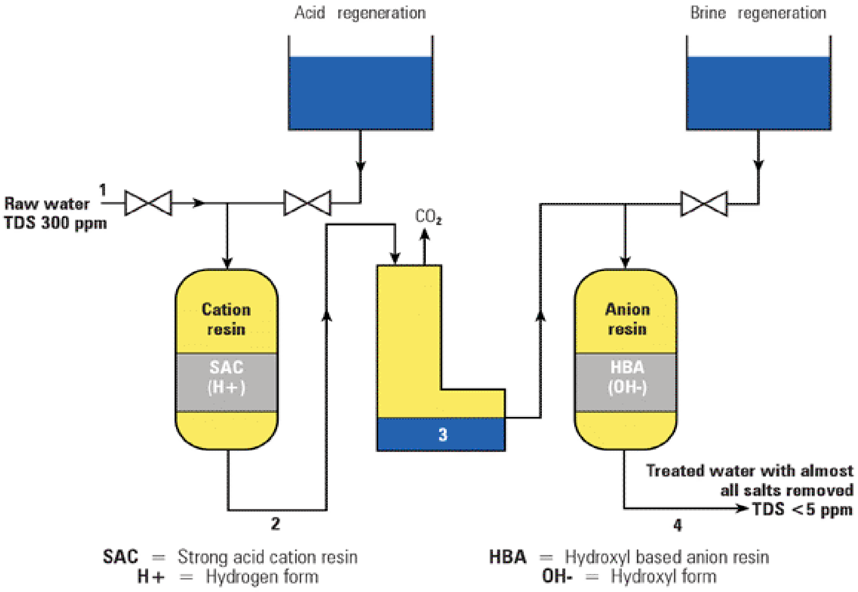
Exhibit 8-7: Dealkalization Process



8.5.2.3 Demineralization

This process will remove virtually all the salts. It involves passing the raw water through both cation and anion exchange resins (see Exhibit 8-8). Sometimes the resins may be contained in one vessel and this is termed 'mixed bed' demineralization. The process removes virtually all the minerals and produces very high quality water containing almost no dissolved solids. It is used for very high pressure boilers such as those in power stations.

Exhibit 8-8: Demineralization Process



1	2	3	4
$Ca(HCO_3)_2$	$2H_2CO_3$	H_2O	H_2O
$MgCl_2$	2HCl	2HCl	H_2O
Na_2SO_4	H_2SO_4	H_2SO_4	H_2O
Na_2SiO_3	H_2SiO_4	H_2SiO_3	H_2O
pH 7.6	pH 2.0 – 2.5	pH 2.0 – 2.5	pH 8.5 – 9.0

If the raw water has a high amount of suspended solids this will quickly foul the ion exchange material, drastically increasing operating costs. In these cases, some pre-treatment of the raw water such as clarification or filtration may be necessary.

8.5.3 Selection of External Water Treatment Plant

Exhibit 8-9 leads to thinking that a demineralization plant should always be used. However, each system has involvement of capital cost and running cost, as Exhibit 8-10 illustrates, plus the demands of the individual plant need to be evaluated.

Exhibit 8-9: Comparison of Effectiveness of Different Water Treatment Processes

Process	Hardness ppm Alkaline	Hardness ppm Non-alkaline	Non-hardness salts ppm	TDS ppm
Raw water	200	50	60	310
Lime	30	50	58	138
Lime/soda	30	0	108	138
Lime/base exchange	5	0	133	138
Base exchange	5	0	255	260
Dealkalisation	5	50	60	115
Dealkalisation + base exchange	5	0	110	115
Demineralisation	1	0	2	3
Reverse osmosis	20	5	6	31

Exhibit 8-10: Cost Comparison Ratio for Different Water Treatment Processes

Type of system	Comparative cost scale Capital cost	Comparative cost scale Running cost
Base exchange	1	1
Dealkalisation + base exchange	4	2
Demineralisation	8	3

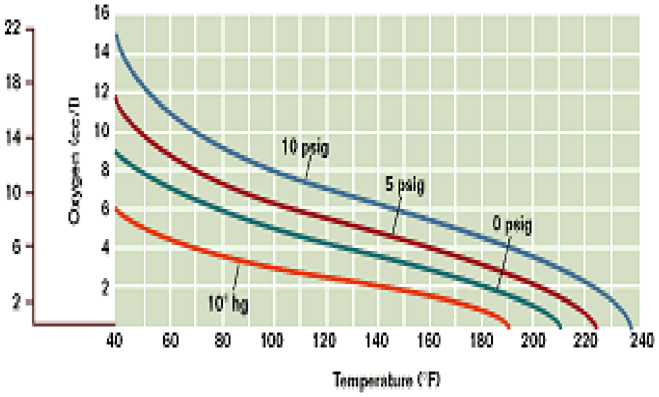
8.5.4 Deaeration

Mechanical deaeration is the first step in eliminating oxygen and other corrosive gases from the feed water. Free carbon dioxide is also removed by deaeration, while combined carbon dioxide is released with the steam in the boiler and subsequently dissolves in the condensate. This can cause additional corrosion problems.

Solubility of oxygen in water is the function of temperature and pressure (Exhibit 8-11).

The two major types of deaerators are the tray type and the spray type. In both cases, the major portion of gas removal is accomplished by spraying cold makeup water into a steam environment.

Exhibit 8-11: Oxygen Solubility vs. Temperature Graph at Different Pressures

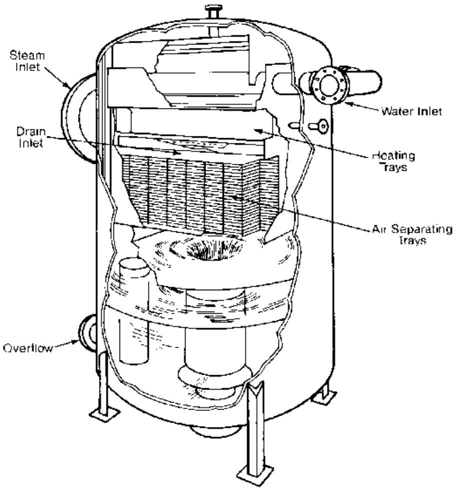


8.5.4.1 Tray-type Deaerating Heaters

Tray-type deaerating heaters release dissolved gases in the incoming water by reducing it to a fine spray as it cascades over several rows of trays. The steam that makes intimate contact with the water droplets then scrubs the dissolved gases by its counter-current flow. The steam heats the water to within 3-5°F of the steam saturation temperature and it should remove all but the very last traces of oxygen. The deaerated water then falls to the storage space below, where a steam blanket protects it from recontamination.

Nozzles and trays should be inspected regularly to insure that they are free of deposits and are in their proper position (Exhibit 8-12).

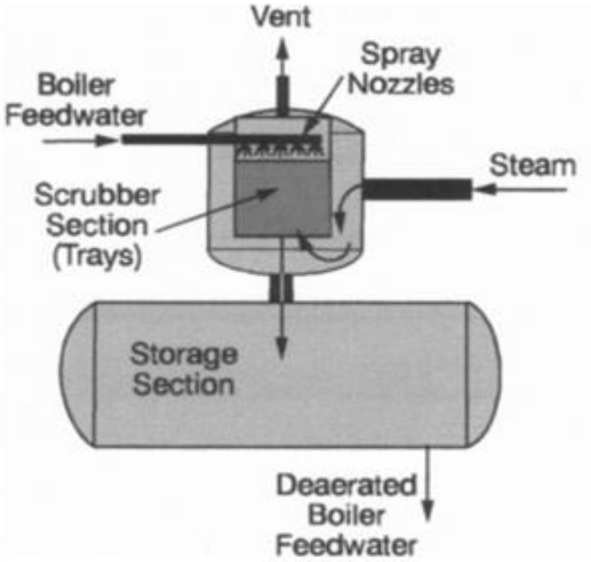
Exhibit 8-12: Tray-type Deaerating Heater



8.5.4.2 Spray-type Deaerating Heaters

Spray-type deaerating heaters (Exhibit 8-13) work on the same general philosophy as the tray-type, but differ in their operation. Spring-loaded nozzles located in the top of the unit spray the water into a steam atmosphere that heats it. Simply stated, the steam heats the water, and at the elevated temperature the solubility of oxygen is extremely low and most of the dissolved gases are removed from the system by venting. The spray will reduce the dissolved oxygen content to 20-50 ppb, while the scrubber or trays further reduce the oxygen content to approximately 7 ppb or less.

Exhibit 8-13: Spray-type Deaerating Heater



During normal operation, the vent valve must be open to maintain a continuous plume of vented vapors and steam at least 18 inches long. If this valve is throttled too much, air and non-condensable gases will accumulate in the deaerator. This is known as air blanketing and can be remedied by increasing the vent rate.

8.5.5 Selection of External Water Treatment

8.5.5.1 Shell Boilers

Generally, shell boilers are able to tolerate a fairly high TDS level and the relatively low capital and running costs of base-exchange softening plants will usually make them the first choice.

If the raw water supply has a high TDS value, and/or the condensate return rate is low (<40%), there are a few options which may be considered:

- Pre-treatment with lime / soda will cause the alkaline hardness to precipitate out of solution as calcium carbonate and magnesium hydroxide, and then drain from the reaction vessel.
- A dealkalization plant to reduce the TDS level of the water supplied to the boiler plant.

8.5.5.2 Water-tube Boilers

Water-tube boiler plant is much less tolerant of high TDS levels, and even less so as the pressure increases. This is due to a number of reasons, including:

- Water-tube boilers have a limited water surface area in the steam drum, relative to the evaporation rate.
- This results in very high steam release rates per unit of water area, and turbulence.
- Water-tube boilers tend to be higher rated perhaps over 1 000 tonnes / h of steam. This means that even a small percentage blowdown can represent a high mass to be blown down.
- Water-tube boilers tend to operate at higher pressures, usually up to 150 barg. The higher the pressure, the greater the energy contained in the blowdown water.
- Higher pressures also mean higher temperatures. This means that the materials of construction will be subjected to higher thermal stresses, and be operating closer to their metallurgical limitations. Even a small amount of internal contamination hindering the heat transfer from tubes to water may result in the tubes overheating.
- Water-tube boilers often incorporate a superheater.
- The dry saturated steam from the steam drum may be directed to a superheater tubes situated in the highest temperature area of the furnace. Any carryover of contaminated water with the steam would coat the inside of the superheater tubes, and inhibit heat transfer with potentially disastrous results.

The above factors mean that:

- High quality water treatment is essential for the safe operation of this type of plant.
- It may be economically viable to invest in a water treatment plant that will minimize blowdown rates.

In each of these cases, the selection will often be a demineralization or a reverse osmosis plant.

The quality of raw water is obviously an important factor when choosing a water treatment plant. Although TDS levels will affect the performance of the boiler operation, other issues, such as total alkalinity or silica content can sometimes be more important and then dominate the selection process for water treatment equipment.

8.6 Internal Water Treatment

Internal treatment of boiler is the conditioning of impurities within the boiler system itself, the reactions occurring either in the feed lines or inside the boiler. Internal treatment may be used alone or in combination with external treatment. Internal treatment is designed to take proper account of feed water hardness, to control corrosion, to scavenge oxygen, and to prevent boiler water carry-over. Through internal treatment, the alkaline hardness in the raw water is decomposed and precipitated as the water is heated, and the permanent hardness is precipitated in the boiler by the addition of alkali in the form of sodium carbonate, caustic soda, or sodium phosphates. The latter are the most effective precipitants, but because of their cost they are not generally used in the substantial amounts needed when hardness of the feed water is high; however, for treating feed water for boilers working at pressures above approximately 14 bar (200 psi) or low-hardness feed water, they are essential.

8.6.1 Lime Soda Processes

In the lime soda or lime soda/sodium aluminate or other coagulant process, calcium and magnesium are precipitated as compounds of very low solubility, namely CaCO3, and $Mg(OH)_2$, by the addition of hydrated lime and sodium carbonate, or by' hydrated lime alone when the raw water contains sodium bicarbonate. The amounts of chemicals added must be in proportion to the Ca and Mg present in the water and will therefore require adjustment if the composition of the water changes. The process can be worked hot (70-90°C) (160-200°F) or cold, the former usually giving better clarity and hardness removal, particularly with turbid waters or waters containing organic matter. The amount of sodium aluminate required for coagulation of the magnesium hydroxide is approximately 10 ppm in the hot softening process and 20 ppm in the cold, irrespective of the amount of hardness to be removed; it is, however, used only when the raw water contains appreciable amounts of magnesium salts. A small amount of residual hardness is always present in the treated water and amounts to about 10-15 ppm $CaCO_3$ in the hot process and 15-25 ppm in the cold. Aluminum sulfate and modified (activated) silicate may also be used as coagulants.

8.6.2 Phosphate Treatment

The solubility of calcium phosphate is less than that of $CaCO_3$; a precipitation process using sodium phosphates instead of sodium carbonate should thus give a lower residual hardness. This is in fact the case, but phosphates are expensive, and their use is limited in practice to a second stage of softening at high temperatures for the special purpose of treating water for use in boilers working in the higher pressure range, i.e. above 34.5 bar (500 psi).

The procedure is to submit the water to hot lime soda or lime soda/sodium aluminate softening at 70-90°C (160-200°F), and then to pass the treated water containing about 10-15 ppm residual hardness to a similar plant in which sodium phosphate is added in sufficient amount to precipitate the residual calcium hardness. The water leaving the lime soda section should contain enough caustic alkali to precipitate the magnesium as $Mg(OH)_2$. After settling, the water is passed through filters, and the hardness should be reduced to about 2 ppm.

8.6.3 Organic Materials

Organic materials such as tannins, starches, lignins, and synthetic polymers are often used in conjunction with the inorganic precipitants with the object of forming a more mobile sludge and reducing deposits on heating surfaces. Magnesium salts may also be used for the same purpose. Sodium polyphosphates or mixtures of these with tannins help to keep economizers and preheaters cleaner by delaying the precipitation of calcium carbonate from the raw water passing through them.

The main features of the process are:

1. Continuous addition of polyphosphates or mixtures of polyphosphates and tannin to delay precipitation of hardness.
2. The intermittent addition of precipitating alkalies alone or mixed with organic materials, to the boiler itself by means of a pump or pressure pot.
3. The continuous addition of catalyzed sodium sulfite or hydrazine to feed water to remove dissolved oxygen.
4. A carefully operated program of continuous and/or intermittent blowdown to keep the dissolved solids content of the boiler water at a specified concentration and prevent undue accumulation of suspended solids.
5. Chemical control of the process by regular tests on samples of boiler and feed water.

8.6.4 Feeding of Chemicals

The various internal treatment chemicals are fed in many different ways. Common feeding methods include the use of chemical solution tanks and proportioning pumps. In general, boiler treatment chemicals (phosphates, chelates, caustics) are added directly to the feed water at a point after deaeration but before the entrance to the boiler drum. Certain phosphate (ortho type) may also be fed through a separate line discharging into the steam drum of the boiler. The chemicals should discharge in the feed water section of the boiler system so that reactions occur in the water before it enters the steam generating areas.

Chemicals added to react with dissolved oxygen (e.g. sulfite, hydrazine) should be fed continuously as far back in the feed water system as possible. Similarly, chemicals used to prevent scale and corrosion in the feed water system (e.g. caustic soda, organics) should be fed continuously. Chemicals used to prevent condensate system corrosion may be fed directly to the steam, to the feed water, or to the boiler, depending on the chemical used. Neutralizing amines are usually fed directly to the feed water line or boiler drum, while volatile filming amines are almost always fed directly to a steam header where good distribution will occur and thus effective condensate system corrosion protection should be achieved.

Chemical dosages are primarily based upon the amount of impurities in the feed water. For example, the amount of boiler treatment chemicals depends on the feed water hardness; the amount of sodium sulfite or hydrazine depends on the amount of dissolved oxygen in the feed water. In addition, a set amount of extra chemical treatment is added to provide a residual amount in the boiler water to take care of fluctuations in water properties.

Routine control tests of the boiler water vary according to the type of chemical treatment used, but they may include tests for alkalinity, phosphate, chelate, hydrazine, sulfite, organic color, pH, and total dissolved solids.

8.7 Corrosion

Important factors affecting corrosion of steel at ambient temperatures, namely, acidity and dissolved oxygen also come into play with boilers and their feed systems. The alkalis previously mentioned in relation to hardness precipitation therefore serve a double purpose, in that they also neutralize acidity, and their concentration in both feed and boiler waters is adjusted accordingly. Dissolved oxygen can be removed by mechanical deaeration: this may in any case be desirable to improve the heat-transfer properties of the steam. In any case, an oxygen scavenger such as catalyzed sodium sulfite or hydrazine is normally used, either to remove residual oxygen after mechanical deaeration, or to deal with the entire oxygen content where a deaerator is not available.

Without treatment, returned condensate from steam users attacks the return system, and brings back appreciable amounts of iron and copper oxides to the boilers: these can initiate boiler corrosion and interfere with water circulation in water tube boilers causing tube starvation. As mentioned previously, volatile amines are used to counter these effects. They are of two main types, neutralizing amines and filming amines. Neutralizing amines such as cyclohexylamine volatilize with the steam and condense with it. In condensing, they neutralize acid gases such as carbon dioxide, thus preventing attack at the condensation point of water in the condensate return system; usually the pH of the condensate is thereby adjusted to 8.8 - 9.3. The amount of neutralizing amine needed is proportional to the quantity of carbon dioxide present in the steam, and treatment costs therefore rise to uneconomical heights if a high percentage of a make-up is used which releases a large amount of carbon dioxide in the boiler. Filming amines, on condensing with the steam, form a uni-molecular film on the metal which is water-repellent, and thus do not permit the usual reactions to occur at the metal surface, i.e. the film is protective. Filming amines are mostly used where the neutralizing type would be uneconomical.

8.8 Anti-foam Agents

Foam formation arises in boilers from the presence of traces of such foam forming agents as soaps, certain compounded lubricating oils, detergents, etc. Apart from carry-over, difficulty arises in the working of boilers with foam present because the true water level cannot be distinguished. High water levels then tend to be carried as a precaution against low water and overheating of the boiler, but high levels also increase the risk of carry-over. Efficient antifoams which will deal with these problems have been available for many years; on addition of an adequate quantity, foam suppression is instantaneous. It is now usual for proprietary chemicals used in water treatment to contain some antifoam to offset minor contamination. Antifoam formulations can also be obtained as separate items for the larger usage required by severe contamination with foam forming agents.

8.9 Checklist for Boiler Water Treatment

The principles of water treatment are summarized below, although not all the qualities mentioned are essential in any given case. It cannot be emphasized strongly enough that expert advice should be sought when choosing a treatment.

8.9.1 External Treatment

External treatment is used to obtain:

(a) low hardness - to avoid sludge in the boiler
(b) low bicarbonate - to reduce corrosion by steam
(c) low dissolved solids - to reduce boiler blowdown
(d) low silica and low alumina where necessary.

Objectives (a) and (b) may be reached by external process such as lime soda, and sodium ion exchange. Such processes are generally appropriate for boilers working below 24 bar (350 psi).

As pressures progress upwards, boilers are worked at increasingly lower dissolved solids. Hence objective (c) requires that evaporation or deionization of low-grade supplies be considered.

For objective (d), coagulation and precipitation processes can be useful in reducing silica and alumina. Complete elimination is desirable - certainly for boilers operating at and above 42 bar (600 psi). To accomplish this, strongly acidic and strongly basic resins must be included in the ion exchange train.

8.9.2 Conditioning Treatment

The number and types of additives which may form part of a conditioning treatment have increased appreciably over the past twenty years. Brief notes on a not all-inclusive list are given below. A program devised for a particular boiler plant would be unlikely to include all items shown.

(a) Sodium Carbonate: Used to promote zero hardness in low-pressure boilers operating below about 14 bar (200 psi) and so prevent scale; also to raise alkalinity of feed so as to minimize corrosion. Some external treatment processes provide adequate sodium carbonate in the treated make-up water.

(b) Caustic Soda: Can be used in place of sodium carbonate in low-pressure boilers as above. Again, sufficient softening may be provided by external treatment processes.

(c) Phosphate: All forms are used for scale prevention at boiler pressures above about 14 bar (200 psi). Glassy phosphates can also reduce precipitation of calcium carbonate in hot feed lines. Both glassy and acidic phosphate may be used to eliminate caustic soda from the boiler water.

(d) Chelating Agents: Used as an alternative to phosphates as preventatives of scale in boilers. Application limited (by economics) to good quality feed water.

(e) Antifoams: Used to prevent foam formation in boilers. Proprietary boiler-chemical mixtures often contain an antifoam agent. Antifoams can also be obtained separately for individual application to severe cases.

(f) Neutralizing Amines: Used to neutralize carbon dioxide in steam condensate and feed lines and so diminish corrosion. Not economic in systems with high make-up of untreated water. Unsuitable where steam comes into direct contact with foods, beverages, or pharmaceutical products.

(g) Sodium Sulfite: Used to eliminate dissolved oxygen and so diminish corrosion. Catalyzed sodium sulfite is reputed to react 20 to 500 times as fast as the uncompounded material, and this offers more protection to short feed systems.

(h) Hydrazine: Also used to eliminate dissolved oxygen and so diminish corrosion. Has the advantage of not increasing dissolved solids. Reacts slowly at temperatures below about 245°C (500°F). Not used where steam processes food or beverages.

(i) Sodium Sulfate: Used to prevent caustic cracking in riveted boilers.

(j) Sodium Nitrate: Also used to prevent caustic cracking.

(k) Sludge Mobilizers: Natural and synthetic organic materials are used to reduce adherence of sludge to boiler metal. Some of these materials have temperature limitations; the advice of the vendors should be followed closely in their use.

8.9.3 Blowdown Control

Control of blowdown is necessary to maintain the TDS or SiO_2 content of the boiler water in the ranges given in Exhibit 6-19, Exhibit 8-14and Exhibit 8-15. Intermittent blowdown is used to reduce the amount of sludge in the boiler to the lowest possible amount, without excessive loss of heat.

8.9.4 Testing

The institution of a schedule of regular testing to observe and control the treatment at all stages is of basic importance to maintaining feed water quality.

General guidelines for water quality are given in Exhibit 8-14 and Exhibit 8-15.

Exhibit 8-14: ASME Guidelines for Water Quality in Modern Industrial Water Tube Boilers for Reliable Continuous Operation

Boiler Feed Water				**Boiler Water**		
Drum Pressure (psi)	**Iron (ppm Fe)**	**Copper (ppm Cu)**	**Total Hardness (ppm $CaCO_3$)**	**Silica (ppm SiO_2)**	**Total Alkalinity** (ppm $CaCO_3$)**	**Specific Conductance (micromhos/cm) (unneutralized)**
0-300	0.100	0.050	0.300	150	700*	7000
301-450	0.050	0.025	0.300	90	600*	6000
451-600	0.030	0.020	0.200	40	500*	5000
601-750	0.025	0.020	0.200	30	400*	4000
751-900	0.020	0.015	0.100	20	300*	3000
901-1000	0.020	0.015	0.050	8	200*	2000
1001-1500	0.010	0.010	0.0	2	0***	150
1501-2000	0.010	0.010	0.0	1	0***	100

ASME (American Society of Mechanical Engineers)

Exhibit 8-15: ABMA Standard Boiler Water Concentrations for Minimizing Carryover

Drum Pressure (psig)	**Total Silica* (ppm SiO_2)**	**Specific** Alkalinity (ppm $CaCO_3$)**	**Conductance (micromhos/cm)**
0-300	150	700	7000
301-450	90	600	6000
451-600	40	500	5000
601-750	30	400	4000
751-900	20	300	3000
901-1000	8	200	2000
1001-1500	2	0	150
1501-2000	1	0	100

* This value will limit the silica content of the steam to 0.25 ppm as a function of selective vaporization of silica.

** Specific conductance is un-neutralized.

ABMA (American Boiler Manufacturers Association)

9 Boiler Heat Recovery Systems

Recovery of boiler waste heat can make a significant contribution towards improving the boiler efficiency and saving fuel costs. This chapter begins with a step by step guide to developing a heat recovery project; later sections discuss typical equipment applications.

9.1 Developing a Heat Recovery Project

Heat recovery systems are usually specific for the particular boilers in question in a particular factory, and it is rare that an identical system can be applied at different boiler plants. It is important therefore that all aspects of the system be studied at the design stage. The proper procedure to follow in developing a heat recovery project is to:

- Identify and characterize the heat source and the possible heat use;
- Obtain data, perform measurements and analysis; and
- Design and specify the system.

9.1.1 Identification of the Project

Heat recovery from boiler flue gas is only worth considering if certain key criteria can be met, such as:

- There must be sufficient heat available at a suitable temperature.
- A use for the recovered heat must exist.
- Heat demand must coincide with the availability of the waste heat. (Storage can in some cases overcome mismatching of supply and demand.)
- The waste heat source and heat user should not be too far apart'
- For the application of heat exchangers (as opposed to heat pumps) the waste heat source must be at a higher temperature than the stream to which the heat is to be transferred.

The development of a heat recovery system starts with the identification of suitable waste heat sources at the boiler and heat sinks (the potential users of recovered heat). Potential sources are the boiler flue gases and the blowdown. Potential heat sinks are sometimes more difficult to find and there is an obvious attraction in matching heat sources and sinks within the same plant or process. Where this is not possible, heat may be recovered in one plant for utilization in another, in which case operating cycle times must be carefully matched. Many over estimates of conservation potential occur because appropriate uses for waste heat are not properly identified. For most boiler heat recovery schemes, the heat is best used for feedwater preheating or for combustion air preheating.

Heat sources must be characterized initially in terms of the following parameters:

1. Temperature or "grade" for sources and sinks
2. Source moisture (potential for latent heat recovery, possible condensation problems)
3. Source physical properties (potential chemical and particulate contamination).

Where favorable waste heat sources and sinks are believed to exist, the next step will be to establish the quantities of heat (or energy) involved.

9.1.2 Perform Measurements and Analysis

Comprehensive data are required at this stage, such as the following:

1. Mass flow rates of streams, including potential variations
2. Temperatures, and variations likely each day/month/ year
3. Gas moisture contents
4. Analysis of chemical and physical contamination
5. Flue gas analysis
6. Boiler operating conditions (steam temperatures and pressures)
7. Boiler operating cycles
8. Details of existing plant, including equipment specifications, plant layout and dimensions

It is particularly important to note that careful on-site measurements should always be taken. Design data may be useful, but actual conditions are frequently quite different from design data for a variety of reasons. Indeed, proper analysis of the heat source can lead to efficiency improvements which remove the need for heat recovery systems altogether. Without proper investigation, serious mistakes can be made.

The potential for heat recovery must then be determined. This will include the following stages:

- Compilation of heat and material balances
- Matching of potential heat sources with heat sinks, including estimates of possible heat transfer and resulting changes in fluid conditions
- Consideration of possible methods of heat recovery
- Estimation of budget costs, including energy savings, capital investments and operating costs
- Evaluation of return on investment

It should be noted that the actual consideration of heat recovery devices is left until the latter stages of project development. Pre-conceived ideas of the type of heat recovery system to employ must be avoided. When all relevant data have been gathered, and a thorough understanding of the process gained, consideration can be given to the heat recovery device. Note that "efficiency" of heat recovery may seem a useful concept, but is often best avoided when developing a heat recovery scheme. The objective is to achieve maximum heat recovery at an acceptable capital and operating cost, that is, to increase profitability of the plant.

9.1.3 Design the System

Details to consider with respect to the design (and cost) of heat recovery systems include:

1. Materials of construction (suitability and cost)
2. Effects of temperature changes on existing plant and its operability
3. Effects of changes in system pressure drop (positioning of fans, etc.)
4. Fouling (prevention, cleaning)
5. Maintenance (means of access, frequency, costs)
6. Any other operating costs
7. Controls (automatic operation, safety)
8. Condensate removal (drainage needs, potential corrosion problems)
9. Explosion risks

Many different types of heat exchangers exist for a wide range of applications. Manufacturers can always advise on the operating performance of their equipment. However, a heat recovery system will not comprise a heat exchanger alone. The application of the total system approach is therefore recommended to assure success for any heat recovery project.

For boilers, typical sources for heat recovery projects are the flue gases, and the blowdown flow. Typical uses are feedwater and combustion air preheating. These are discussed in the following sections.

9.2 Flue Gas Heat Recovery

The waste heat recovered from boiler flue gases is usually used to heat boiler feedwater or boiler combustion air. Heat exchangers built into the flue gas ducting are frequently used for both duties.

9.2.1 Feedwater Preheating

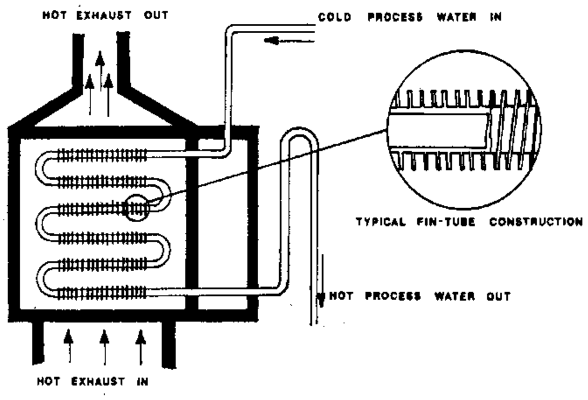
Flue gas heat exchangers used for water heating are known as "economizers". Typically these consist of banks of finned tubes (tubes with extended external surface area) through which cold boiler feedwater is passed (Exhibit 9-1).

Simple locally-fabricated economizers are often used to recover exhaust heat. These normally consist of banks of un-finned cast iron tubes. While these heat exchangers are not very efficient, their use may be justified by considerations of cost and availability, especially for smaller boiler plants.

Economizers are typically installed downstream of the boiler feed pump, immediately before the feedwater enters the boiler. This provides two important advantages:

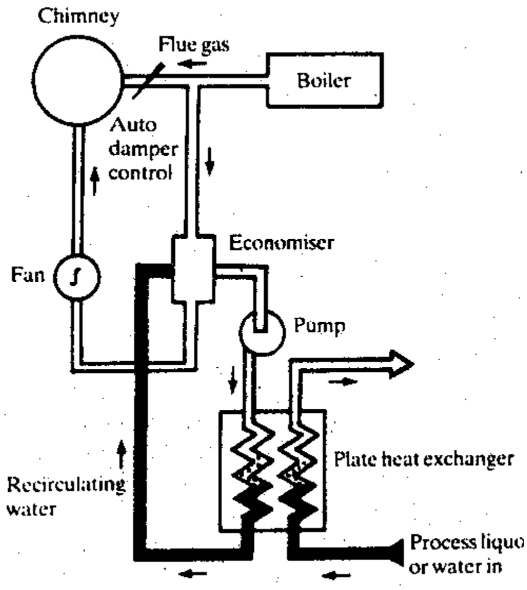
- Water passing through the economizer is at boiler pressure, effectively eliminating the danger of it boiling in the economizer; and
- Where acid dewpoint is a problem, the feedwater (from the deaerator or condensate tank) enters the economizer already preheated, thus reducing local condensation of the flue gases due to cold surface temperature of the economizer.

Exhibit 9-1: Typical Boiler Economizer Installation



For heating fluids some distance away from the boiler, a closed-loop re-circulating system, using water or oil as the heat transfer medium may also be used. This system can be used to heat process liquids indirectly, providing some measure of protection from excessively high temperatures to heat sensitive process streams (Exhibit 9-2).

Exhibit 9-2: Closed Loop Re-circulating System for Boiler Waste Heat Recovery



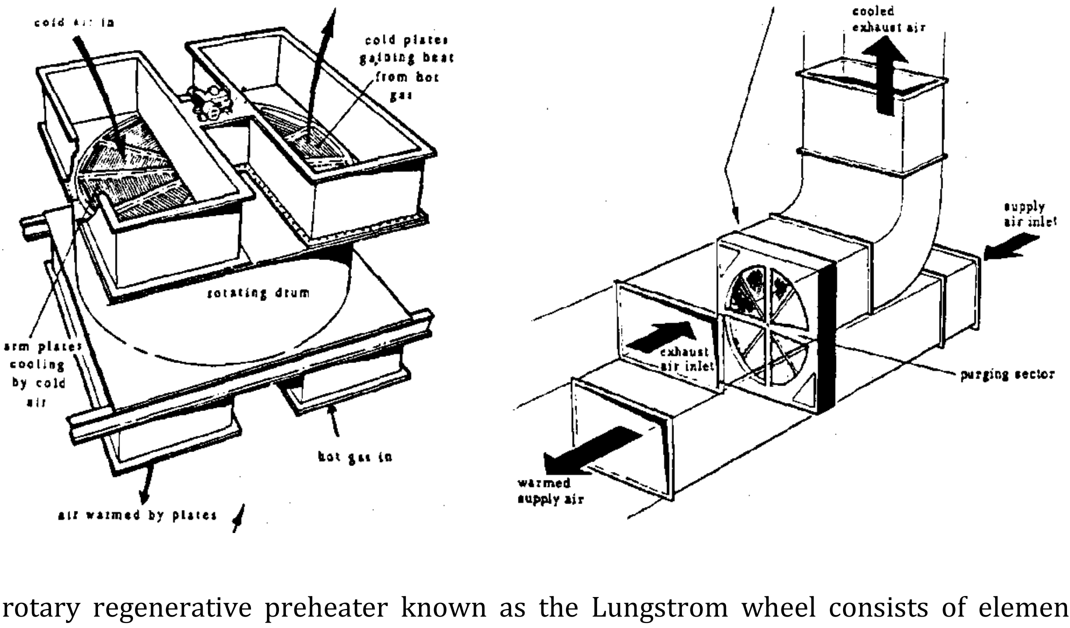
9.2.2 Air Preheating

Three commonly used air preheat systems may be classified as regenerative, recuperative, or liquid-coupled.

9.2.2.1 Regenerative Air Preheaters

In this type of preheater (Exhibit 9-3), heat is transferred from the flue gases to a solid matrix which is then cooled by the combustion air, thereby preheating the air. For fired heater and boiler applications, regenerators are usually of the rotary type.

Exhibit 9-3: Rotary Regenerative Air Preheater



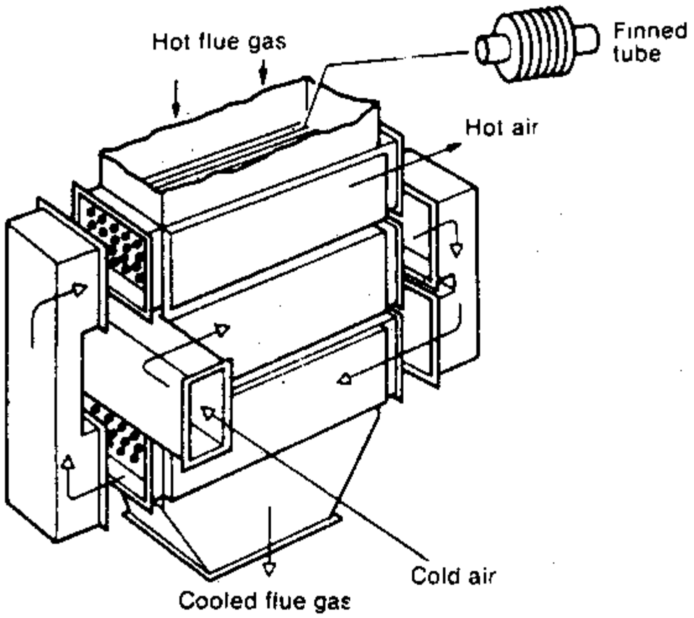
The rotary regenerative preheater known as the Lungstrom wheel consists of elements, usually metallic, which are contained in a cylinder that rotates inside a casing. The elements are heated by the flue gas which flows through one side of the cylinder and is subsequently cooled by the combustion air on the other side as the wheel rotates. There are seals between the cylinder and casing to limit the amount of leakage from the air side to the flue gas side. This leakage lowers the gas exit temperature by 10 to 15°C which in turn limits the level of efficiency attainable without cooling the flue gas below its acid dew point. Corrosion will normally occur at the cold end of the elements which will require periodic replacement. For boiler and fired process heater applications, both forced and induced draught fans are required.

9.2.2.2 Recuperative Air Preheaters

For the relatively moderate flue gas temperatures generally encountered leaving boilers and process heaters, recuperators are generally of two types, those using externally and internally finned rectangular cast iron tubes and those using externally finned steel tubes. For both the types, forced air and induced draught flue gas fans are required.

The steel finned tube recuperator (Exhibit 9-4) is most likely to find application where flue gases are relatively clean and low in sulfur content. Air flows through the tube banks in multiple cross flow passes which may be arranged to avoid dew point problems. Twisted tapes may be used to improve the in-tube heat transfer coefficient and soot blowers are used to maintain the finned surface in a clean condition.

Exhibit 9-4: Finned Steel Tube Recuperator



9.2.2.3 Liquid-coupled Air Preheat Systems

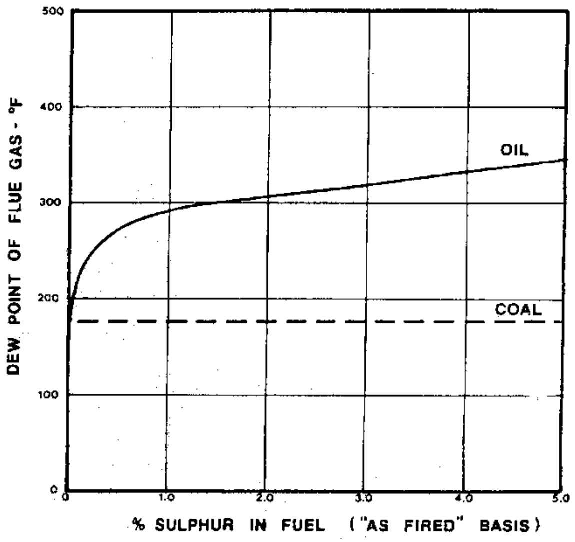
An example of a closed loop system was shown in Exhibit 9-2. Such a system can be used to transfer heat to any suitable medium, including cold combustion air. The system is sometimes known as a "run-around coil system" and has the advantage that heat can be transferred from a boiler to a heat sink which is some distance away.

9.2.3 Acid Dew Point

The lowest temperature to which flue gases may be cooled in a heat recovery system is limited by the temperature at which condensation of water vapor in the flue gas occurs. Depending on the fuel composition, droplets of water which form will contain sulfur dioxide (and possibly sulfur trioxide), and are therefore a potential source of corrosion in the heat recovery device itself, as well as in the flue gas ducting and stack. The flue gas dew point (also known as the "acid dew point") is a function of the sulfur content of the fuel and of the excess air rate. A dew point graph, based on excess air rates close to the optimum value, is presented in Exhibit 9-5.

Consideration of the acid dew point will allow a proper design of a heat recovery system to be made, ensuring that the "cold end" of the system is always above the dew point (a margin of 20°C would be reasonable). However, there may be certain conditions under which the risk of corrosion is present; such as during start-up (as the whole system warms up) or during periods of low load when the flue gas flow is significantly less than the design rate. For this reason, the materials of construction of the heat recovery system must be selected with care, and it may often be desirable to include a bypass duct around the heat recovery device to reduce the corrosion risk during periods of "non-standard" operation.

Exhibit 9-5: Flue Gas Due Point



Acid dew point is primarily a consideration for oil and coal fuels. For these fuels, exhaust temperatures after the economizer are maintained well above 163°C (325°F), depending on the sulfur content in the fuel. For gas, these considerations are not as important; nevertheless, gas-fired boiler exhausts after economizer are usually maintained well above the dew point temperature of pure water.

Finally, it should be stressed that the temperature to which the flue gas is cooled for any specific design of heat recovery system should be set by economic considerations: the acid dew point merely sets a lower "technical" limit to that temperature.

9.2.4 Flue Gas Latent Heat Recovery

A major part of the heat lost in the flue gases is due to the latent heat of vaporization of water vapor in the combustion gases. In some installations, and under some conditions, it can be attractive to recover this heat by condensing the water vapor.

Where the combustion gases are known to be relatively clean and to contain little or no sulfur oxides, a "direct contact" heat recovery method can be applied. In this system, a cold water spray is introduced into the top of a vessel through which the hot combustion gases flow counter current. The water contacts the gases and falls to the bottom of the vessel; this hot water may be utilized directly in a process, or as a heat transfer medium through heat exchangers to heat other process fluids. Because of the intimate contact of the water spray and the combustion gases, good heat transfer rates are achieved.

Where sulfur content precludes the direct contact heat recovery, specially designed condensing heat exchangers have been used. The tubes of these exchangers are coated with Teflon to protect the tubes from the acidic condensate formed. Due to the special technology, the high cost of these heat exchangers makes them applicable only to very large boiler installations with very high fuel costs.

9.3 Blowdown Heat Recovery

It has been discussed previously that the water is blown down from a boiler in order to maintain an acceptable TDS level. This water has a number of characteristics:

- The water is generally unsuitable for other applications.
- It is hot and a proportion of the blowdown water flashes to steam at atmospheric pressure.
- The hot water may present a disposal problem.
- A heat recovery system can solve many of these problems.

Example - energy flow rate in blowdown

The following example explains the energy flow rate in blowdown. Boiler operating pressure is taken as 10 barg and it is assumed that the blowdown water is released to a flash steam system operating at 0.5 barg.

The blowdown water released from the boiler is water at the saturation temperature appropriate to the boiler pressure. At 10 barg, the temperature of blowdown is 184°C. Clearly, water cannot exist at 184°C under atmospheric conditions, because there is an excess of enthalpy or energy in the blowdown water.

Boiler pressure	=	10 barg	
Boiler rating	=	10,000 kg/h	
Maximum allowable boiler TDS	=	2,500 ppm	
Feedwater TDS	=	250 ppm	
Blowdown rate	=	1,111 kg/h	$\frac{10{,}000 \times 250}{2{,}500 - 250}$
Blowdown rate per second	=	0.31 kg/s	$\frac{1{,}111\ \text{kg/h} \times 1\ \text{h}}{3{,}600\ \text{s}}$
Specific enthalpy of water at 10 barg	=	782 kJ/kg	Obtained from steam tables
Specific enthalpy of water at 0.5 barg	=	468 kJ/kg	
Specific enthalpy of steam at 0.5 barg		2,694 kJ/kg	
Specific enthalpy of evaporation at 0.5 barg	=	2,226 kJ/kg	
Rate of total energy blown down	=	241 J/s	0.31 kg/s × 782 kJ/kg
Rate of total energy blown down	=	241 kW	
Excess energy in blowdown	=	314 kJ/kg	782 - 468
% Flash steam	=	14.1 %	$\frac{314}{2{,}226} \times 100$
Rate of flash steam generation	=	157 kg/h	1,111 kg/hr × 14.1%
Rate of flash steam generation	=	0.043 5	0.31 kg/s × 14.1%
Energy flowrate in flash steam	=	117 kJ/s	0.043 5 kg/s × 2,694 kJ/kg
Energy flowrate in flash steam		0.421 GJ/h	117 kJ/s × 3,600 × 10^{-6}
Energy flowrate in flash steam	=	117 kW	
% of total energy present in blowdown	=	48.5 %	$\frac{117}{247} \times 100$

Note: 1 kJ/s = 1 kW

Using the values from steam tables for the above calculations assumes that feed-water will be supplied at a temperature of 0°C. For greater accuracy, the actual change in feed-water temperature should be used.

This excess energy (314 kJ/kg) evaporates a proportion of the water to steam, and the steam is referred to as flash steam. The quantity of flash steam is readily determined by calculation or can be read from tables or charts. Therefore, 14.1% of the water blown down from the boiler will change to steam as its pressure drops from 10 to 0.5 barg across the blowdown valve. It may be possible to use this flash steam. In the above example, it represents almost 49% of the energy flow rate in the blowdown, and 14.1% of the water blown down.

There are two options:

- Vent this flash steam to atmosphere via the blowdown vessel with the associated waste of energy and potentially good quality water from the condensed steam.
- Utilize the energy in the flash steam, and recover water by condensing the flash steam. It is useful to quantify the energy flow rate in the flash steam. This can be done using steam tables.

9.3.1 Recovering and Using Flash Steam

The flash steam becomes available for recovery at the flash vessel. In essence, a flash vessel (Exhibit 9.6) provides a space where the velocity is low enough to allow the hot water and flash steam to separate, and from there to be piped to different parts of the plant.

The design of the flash vessel is important not only from a steam / water separation point of view, but structurally it should be designed and built to a recognized pressure vessel standard.

The most obvious place for the flash steam to be used is in the boiler feedtank.

The water temperature in the feedtank is important. If it is too low, chemicals will be required to de-oxygenate the water; if it is too high the feed pump may cavitate. Clearly, if heat recovery is likely to result in an excessive high feedtank temperature, it is not practical to discharge flash steam into the tank. Other solutions are possible, such as feedwater heating on the pressure side of the feed pump, or heating the combustion air.

Exhibit 9-6: Flash Vessel

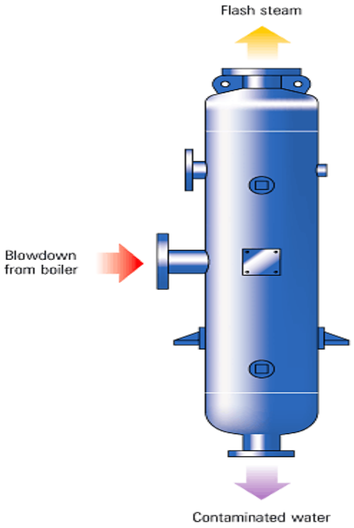
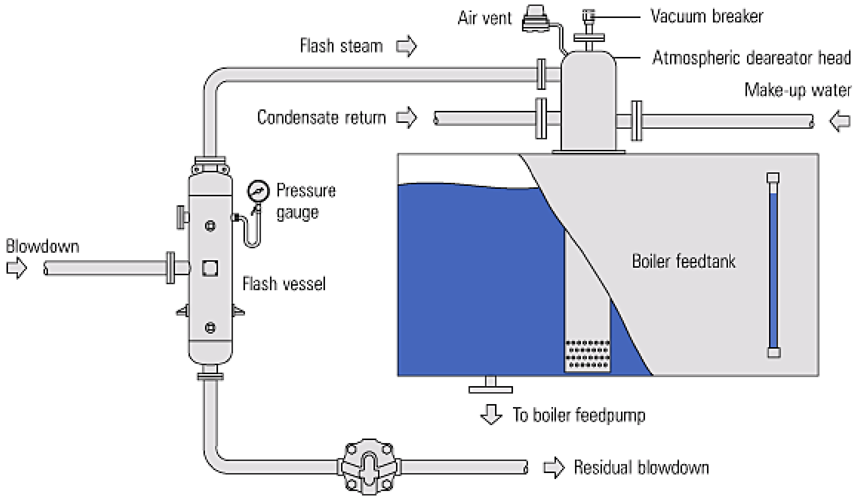


Exhibit 9-7 shows a simple installation for recovery of energy from flash steam, and is extremely cost effective.

Exhibit 9-7: Using a Flash Vessel to Return Energy to the Feedtank



Equipment required is:

Flash vessel - Manufacturers will have sizing charts for vessels. Note: the steam velocity in the top section of the vessel should not exceed 3 m/s.

Steam trap to drain the vessel - A float trap is ideal for this application as it releases the residual blowdown water as soon as it reaches the trap.

The flash vessel is working at low pressure so there is virtually no energy to lift the residual blowdown after the steam trap, so this must drain by gravity through the trap and discharge pipe work.

Note: because of the low pressure, the trap will be fairly large. This has the additional advantage that it is unlikely to be blocked by the solids in the residual blowdown water.

Sometimes strainers are preferred before the steam trap; for this application the strainer cap should be fitted with a blowdown valve to simplify maintenance, and the strainer screen should not be too fine.

Vacuum breaker - There will be occasions when the boiler does not need to blowdown. At these times any steam in the flash vessel and associated pipe work will condense and a vacuum will be formed. If this vacuum is not released then water will be drawn up from the boiler feedtank into the pipe work. When the boiler blows down again this water will be forced along the pipe at high velocity and water hammer will occur.

A vacuum breaker fitted to the deaerator head will protect against this eventuality.

Steam distribution equipment - Proper distribution of the flash steam in the feedwater tank is clearly important in order to ensure condensation and recovery of the heat and water. The equipment required to do this include, in order of effectiveness:

1. Atmospheric deaerator
2. Steam distributor
3. Sparge pipe

9.3.2 Heat Recovery from Residual Blowdown

About 49% of the energy in boiler blowdown can be recovered through the use of a flash vessel and associated equipment; however, there is scope for further heat recovery from the residual blowdown itself.

Continuing on from the above example, if the flash vessel operates at a pressure of 0.2 barg, this means that the residual blowdown passes through the flash vessel float trap at about 105°C. Further useful energy can be recovered from the residual blowdown before passing it to drain. The accepted method is to pass it through a heat exchanger, heating make-up water en route to the feedtank. This approach typically cools the residual blowdown to about 20°C. This system not only recovers the energy in the blowdown effluent, it also cools the water before discharging it into the drainage system.

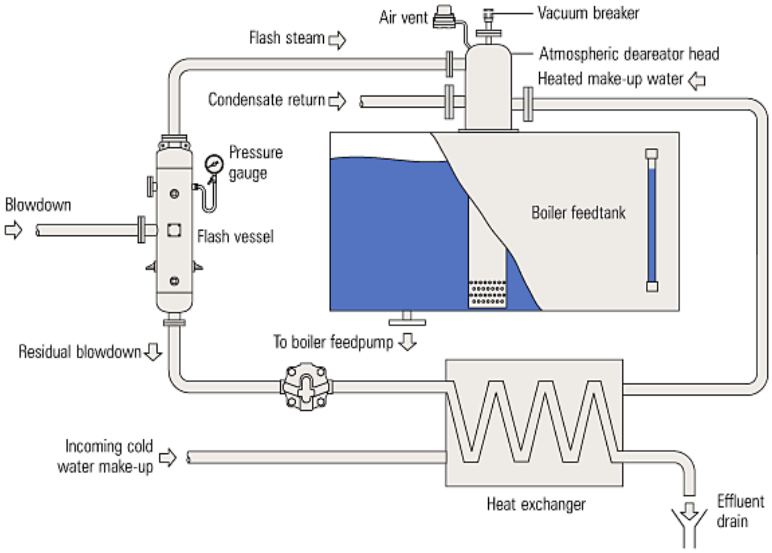
Continuing from previous example:

Blowdown rate	=	1,111 kg/hr	
Blowdown rate	=	0.31 kg/s	$\frac{1{,}111\ \text{kg}/\text{h} \times 1\ \text{h}}{3{,}600\ \text{s}}$
Rate of flash steam generation	=	157 kg/hr	1,111 kg/hr × 14.1%
Rate of flash steam generation	=	0.044 kg/s	0.31 kg/s × 14.1%
Rate of blowdown water		954 kg/hr	1,111 - 157
Rate of blowdown water		0.265 kg/s	$\frac{954\ \text{kg}/\text{h} \times 1\ \text{h}}{3{,}600\ \text{s}}$
Specific enthalpy of water at 0.2 barg	=	440 kJ/kg	
Specific enthalpy of water at 20 °C		84 kJ/kg	
Energy available to heat up make-up water	=	356 kJ/kg	440 - 84
Energy recovered	=	94 kJ/s	0.265 kg/s × 356 kJ/kg
Energy recovered	=	94 kW	
Total heat recovered	=	211 kW	117 + 94

Design Considerations

A problem with the arrangement shown in Exhibit 9-8 is that the simultaneous flow of incoming cold make-up water and residual blowdown from the flash vessel may not be guaranteed.

Exhibit 9-8: Energy Recovery using a Heat Exchanger



One preferred arrangement is shown in Exhibit 9-9, where a cold water break tank is used as a heat sink. A thermostat is used to control a small circulating pump so that when the residual blowdown is at a high enough temperature, water is pumped through the heat exchanger, raising the average tank temperature and saving energy.

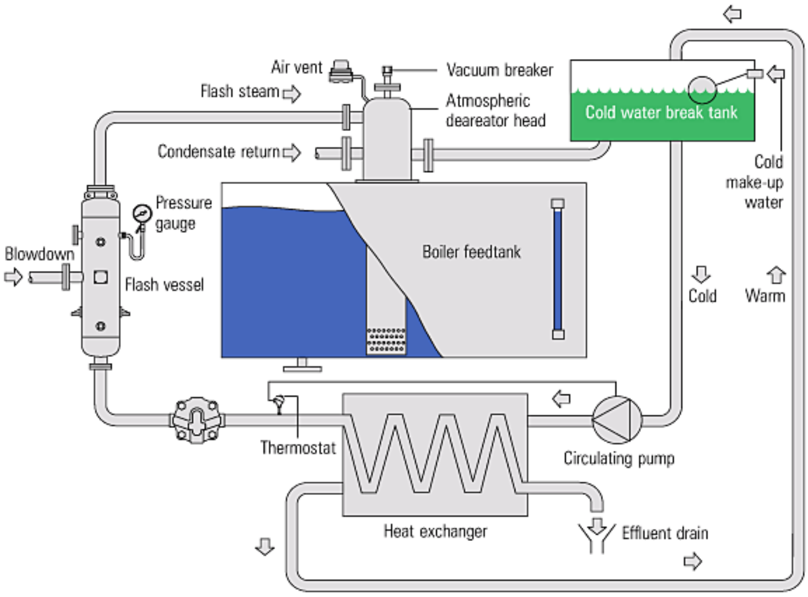
When energy is recovered from the flash steam and the condensate, 87% of the total energy contained in the original blowdown has been recovered.

In addition, 14% (by mass) of the water has been recovered, making a further contribution to savings.

In case, there is a risk that feedwater could be contaminated by foaming of the blowdown water in the flash drum, some boiler operators prefer the simple heat exchanger system.

The cost of heat exchange surfaces is a major factor in the total cost of heat exchange equipment; this becomes of particular importance when the temperature differences are not large.

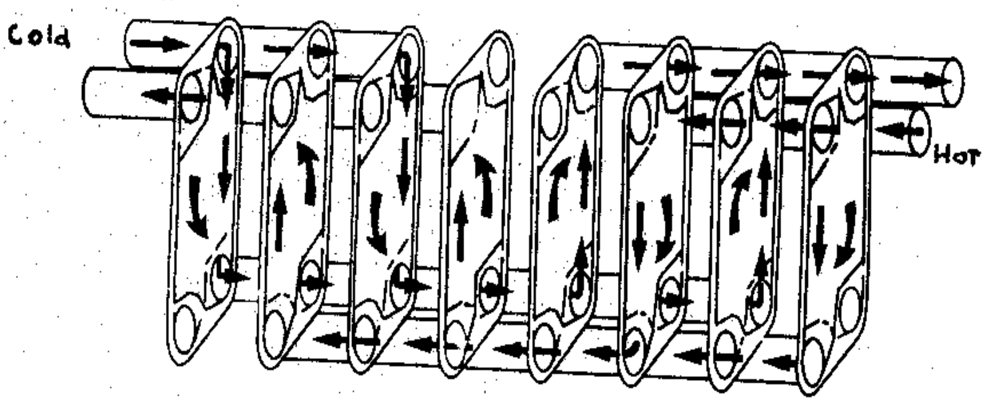
Exhibit 9-9: Heating Make-up Water in a Cold Break Tank (Level Controls have not been shown on the Feedtank)



Preferred Type of Heat Exchanger

The cleaning of a shell and tube heat exchanger is more complex, and will involve a complete strip down and often the tubes themselves cannot be removed for cleaning. One way of meeting this problem is the use of the plate type heat exchanger (Exhibit 9-10).

Exhibit 9-10: Plate Type Heat Exchanger



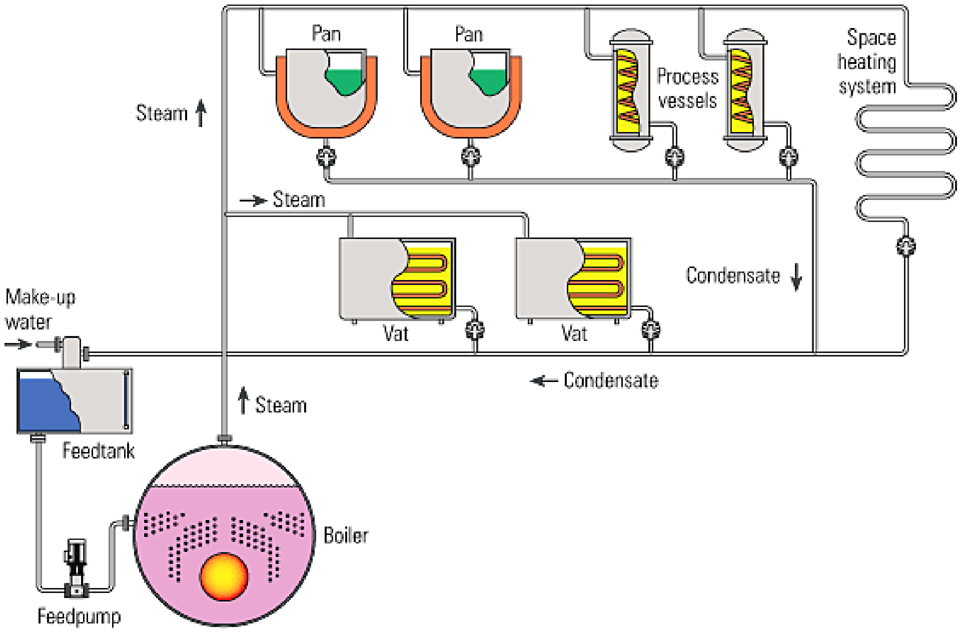
The plate heat exchanger consists of a series of separate parallel plates forming thin flow passages. Each plate is separated from the next by gaskets and the hot stream passes in parallel through alternative plates whilst the liquid to be heated passes in parallel between the hot plates. To improve heat transfer the plates are pressed into corrugations which cause turbulence in the fluids.

Advantages of this type of heat exchanger include ease of access for cleaning, ability to add additional heating surfaces if process conditions alter and the ease of replacement of faulty plates or gaskets.

9.4 Condensate Return

An effective condensate recovery system, collecting the hot condensate from the steam using equipment and returning it to the boiler feed system, can pay for itself in a remarkably short period of time. Exhibit 9-11 shows a simple steam and condensate circuit, with condensate returning to the boiler feedtank.

Exhibit 9-11: Typical Steam and Condensate Circuit



Advantages of condensate recovery may be:

Financial Reasons

Condensate is a valuable resource and even the recovery of small quantities is often economically justifiable. The discharge from a single steam trap is often worth recovering.

Un-recovered condensate must be replaced in the boiler house by cold make-up water with additional costs of water treatment and fuel to heat the water from a lower temperature.

Water Charges

Any condensate not returned needs to be replaced by make-up water, incurring further water supply costs.

Effluent Restrictions

Water above 43°C should not be returned to the public sewer, because it is detrimental to the environment and may damage earthenware pipes. Condensate above this temperature must be cooled before it is discharged, which may involve extra costs.

Maximizing Boiler Output

Colder boiler feedwater will reduce the steaming rate of the boiler. The lower the feedwater temperature, the more heat, and thus fuel needed to heat the water, thereby leaving less heat to raise steam.

Boiler Feedwater Quality

Condensate is distilled water, which contains almost no total dissolved solids (TDS). Boilers need to be blown down to reduce their concentration of dissolved solids in the boiler water. Returning more condensate to the feedtank reduces the need for blowdown and thus reduces the energy lost from the boiler.

The proportion of flash steam can be calculated by using graph given in Exhibit 9-12.

Exhibit 9-12: Quality of flash steam graph

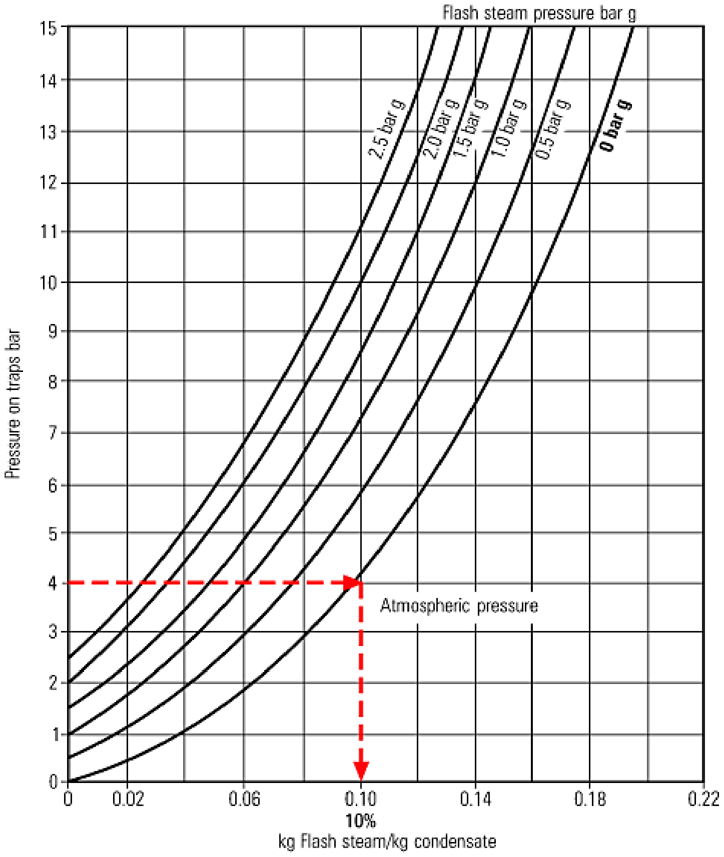
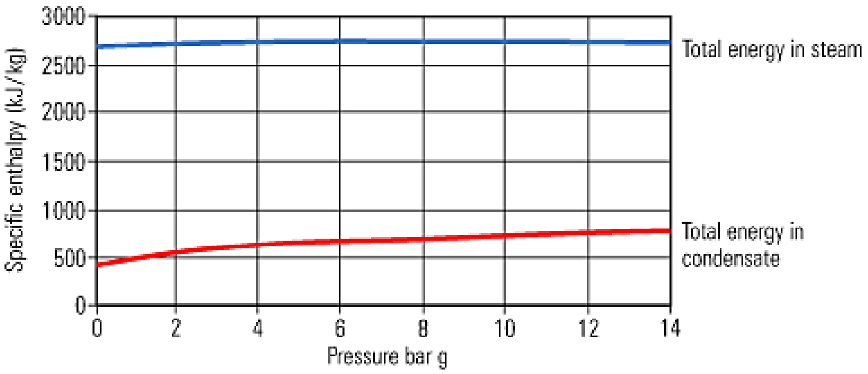


Exhibit 9-13 compares the amount of energy in a kilogram of steam and condensate at the same pressure. The percentage of energy in condensate to that in steam can vary from 18% at 1 barg to 30% at 14 barg; clearly the liquid condensate is worth reclaiming.

Exhibit 9-13: Heat content of steam and condensate at the same pressures



10 Solar Water Heating Systems

These systems use the sun to heat either water or a heat-transfer fluid, such as a water-glycol antifreeze mixture, in collectors generally mounted on a roof. The heated water is then stored in a tank similar to a conventional gas or electric water tank. Some systems use an electric pump to circulate the fluid through the collectors. The components are discussed below.

10.1 Solar Collectors

10.1.1 Collector types

There are two basic types of solar collectors and these are usually classified as concentrating and non-concentrating. The latter will be discussed first because their use is far more widespread.

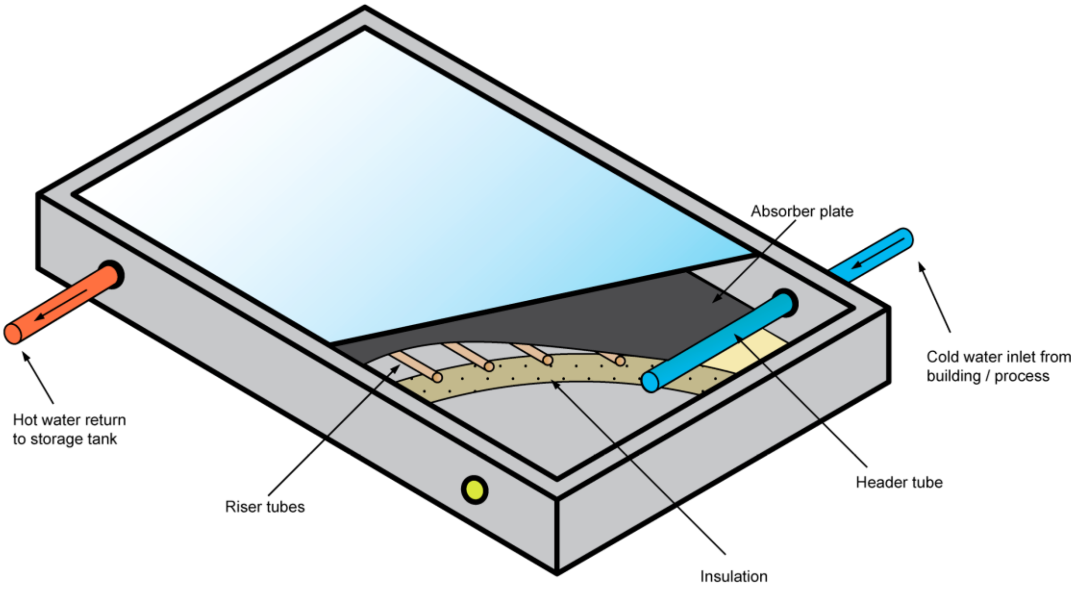
10.1.1.1 Non-concentrating Collectors

There are two main types of non-concentrating collectors: flat plate and evacuated tube.

10.1.1.1.1 Flat Plate Collector

The flat plate collector is the most commonly used solar collector around the world. Although there are a number of variations possible in the design of the flat plate collector, the basic cross section is shown in Exhibit 10-1.

Exhibit 10-1: Typical Cross-section through a Conventional Flat Plate Solar Collector



An absorber plate, usually metal, is connected to a series of riser tubes (or pipes), which are in turn connected at the top and bottom to larger diameter pipes, called headers. The solar energy incident on the absorber plate is transferred to the fluid flowing through the riser tubes. Cool water enters at the bottom header and warmed water exits from the top header. The absorber is usually contained in an insulated box with a transparent cover. The temperature range of flat plate collectors is approximately 30–80°C.

Flat plate collectors can be constructed from a variety of materials and different construction methods are possible. As a result, they may have different performance and costs and be designed for different applications. For example, two layers of glazing are sometimes used to improve thermal performance. Some of the other variations are discussed below.

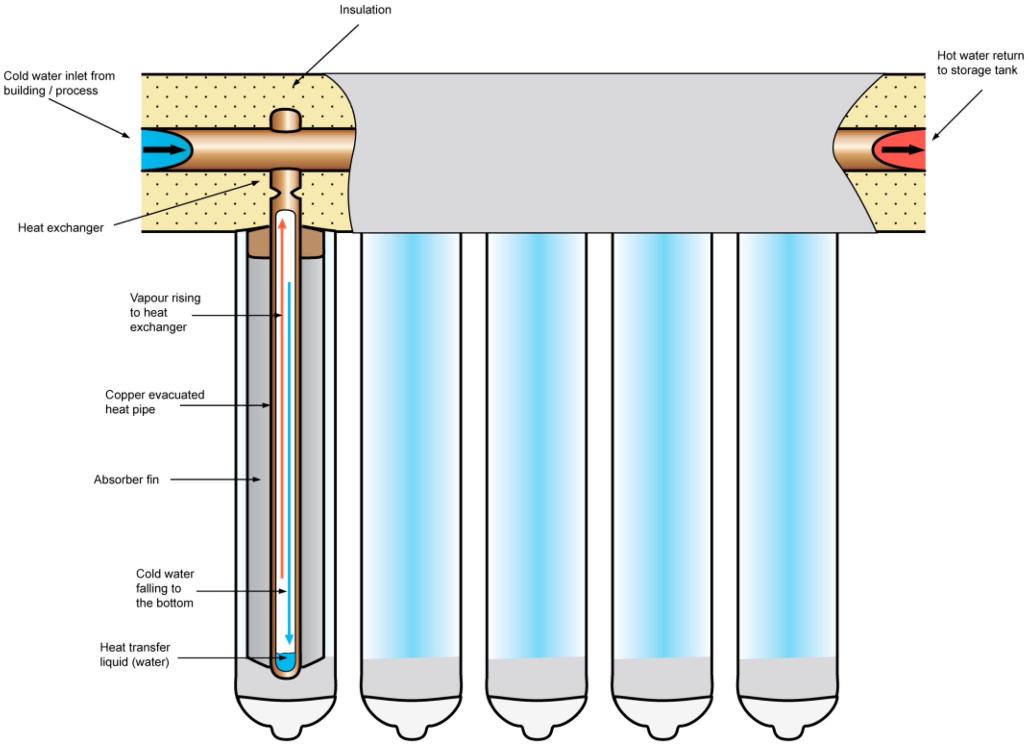
Unglazed collectors have no glazing or insulation, and usually consist of extruded polymer tubes. Their use in LSTS (Large-scale Solar Thermal Systems) is rare, although they have been used in the horticultural sector for greenhouse heating and swimming pool heating where lower water temperatures are required. These collectors have the largest share of the flat plate solar collector market.

10.1.1.1.2 Evacuated Tube Collector

There are two common types of evacuated tube collectors: heat pipe and U-tube. Both collector types are formed from an array of evacuated tubes joined to a manifold through which the heat transfer liquid (water or water/glycol) flows.

The solar absorber is located inside a double glass tube with a vacuum between the two tubes, similar to an elongated thermos flask. The tubes are connected to a manifold through which the heat transfer fluid is passed (Exhibit 10-2 and Exhibit 10-3). The inner glass tube has a selective surface facing outward to absorb the sun's energy. The heat is transferred into the inner glass tube and removed by a heat pipe or a copper tube through which the heat transfer fluid flows. The loss of heat from the absorber by natural convection is eliminated by the vacuum and, as a result, high operating fluid temperatures of up to 120°C can be achieved. The possibility of higher temperatures is of particular importance for solar industrial process heating application because it increases the number of applications where solar energy can be used.

Exhibit 10-2: Typical Heat Pipe Evacuated Tube Array



Heat Pipe Evacuated Tube Collector

A heat pipe evacuated tube collector uses heat pipes to transfer the collected solar heat from the tube into the fluid in the manifold. Heat pipes are made up of copper tubes which contain a very small amount of water in a partial vacuum. The heat pipe is encased in the inner glass tube.

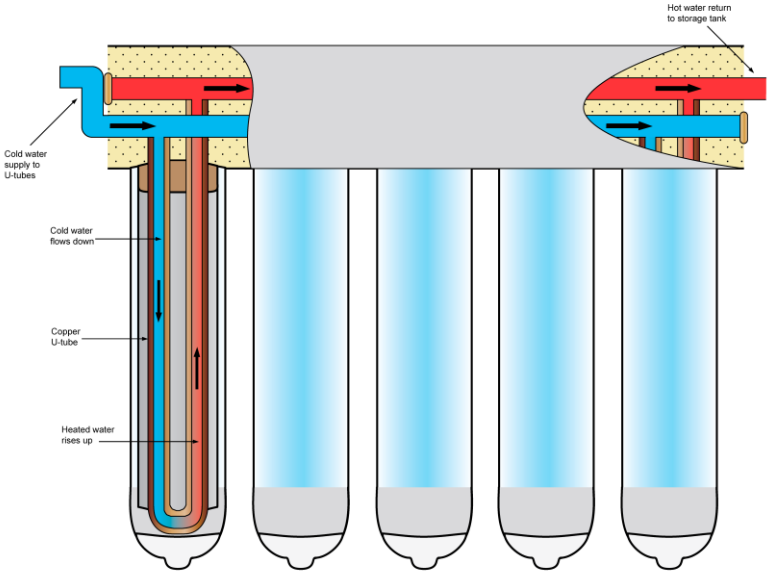
As the heat pipe is heated, the small amount of water inside vaporizes and rises to the top of the heat pipe into the heat exchanger in the manifold. The cold water is heated as it flows through the manifold and at the same time cools the vapor inside the heat pipe where it condenses and falls to the bottom of the heat pipe. The process is repeated, thus creating a highly effective method of transferring the sun's energy, which strikes the tubes into the fluid.

Heat pipe evacuated tube collectors are not suitable for horizontal installation, as inclination should be at least 25° to function.

U-tube Evacuated Tube Collector

Evacuated U-tube collectors have the fluid heated as it flows through a 'U' shaped copper pipe inside the glass tubes.

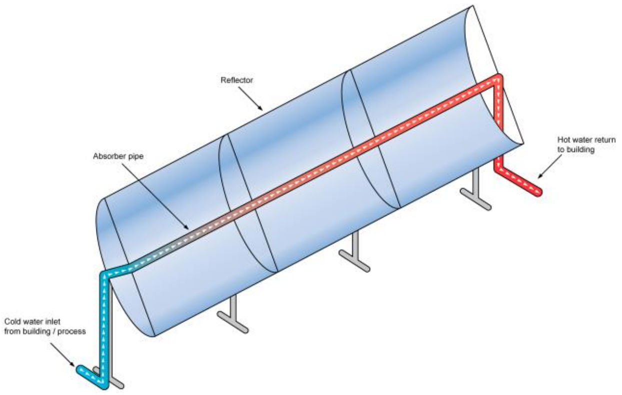
Exhibit 10-3: Typical Evacuated U-tube Array



10.1.1.2 Concentrating Collectors

Concentrating solar collectors use reflectors either as a trough (Exhibit 10-4) to focus on a line absorber or a dish to focus on a point absorber. They can reach far higher temperature levels than non-concentrating collectors. Concentrating collectors will collect only direct radiation (the solar energy coming directly from the sun) and consequently perform better in areas with predominantly clear sky (not cloudy) conditions.

Exhibit 10-4: Typical Concentrating Collector



The collectors are designed with either one or two axis tracking so that the concentrator can track the sun and the incident rays are always right-angled to the aperture areas. Common systems include the parabolic trough, linear Fresnel, parabolic dish and central receivers (solar tower). These collectors are typically used where temperatures above 100°C are needed, i.e. process heat or electricity generation.

Concentrating collectors are typically specified by their concentration ratio. The concentration ratio is the ratio of the area of the reflector to the absorber area. High concentration ratios are used for higher temperature collectors, but require more accurate tracking of the sun's path.

10.2 Storage Tanks and Heat Exchangers

Temperature stratification in hot water storage tanks is the formation of layers of water of different temperatures within a storage tank. The hot water is at the top and gets cooler further down the tank. Temperature stratification can provide substantial operational performance benefits. Convection in the storage tank induced by collector loop or load side heat exchangers affects thermal stratification. Therefore, correct integration of the tank and heat exchangers in a low-flow system is essential.

Three configurations of heat exchangers are shown in Exhibit 10-5, Exhibit 10-6 and Exhibit 10-7. The degree of thermal stratification that can be achieved in tanks with collector loop heat exchangers depends on the location of the heat exchanger and the flow rate in the collector loop. Storage tanks with internal helical coil heat exchangers, either for a closed collector loop (Exhibit 10-5) or a load side heat exchanger (Exhibit 10-6), will have less stratification than storage tanks with an external heat exchanger based on low-flow design (Exhibit 10-7).

Exhibit 10-5: Tank with Helical Coil Heat Exchanger

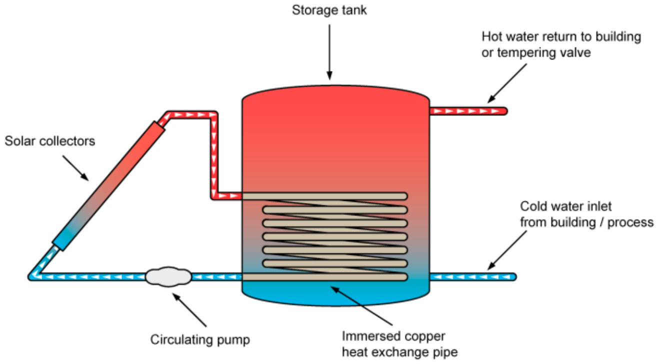


Exhibit 10-6: Load Side Heat Exchanger Tank

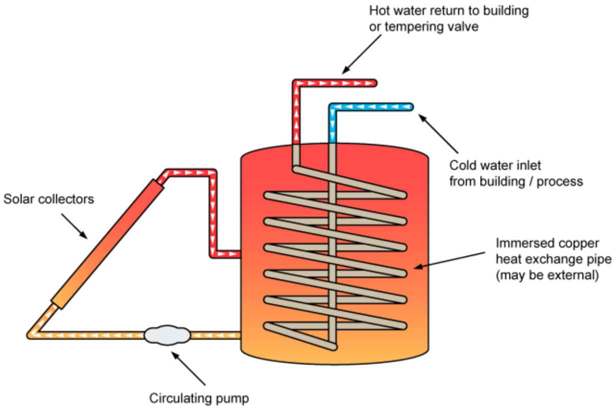
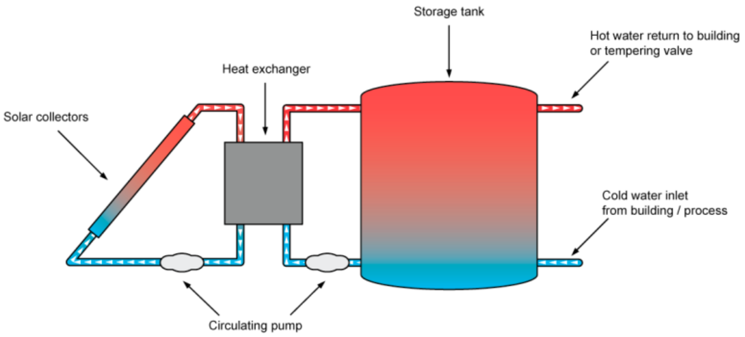


Exhibit 10-7: Tank with External Heat Exchanger



10.2.1 External Heat Exchanger Configurations

External heat exchangers can be either plate or shell and tube heat exchanger configurations. Plate heat exchangers operated in the counter flow mode have higher effectiveness and, as a result of a higher outlet temperature in the tank, loop flow can be configured to maximize thermal stratification in the tank.

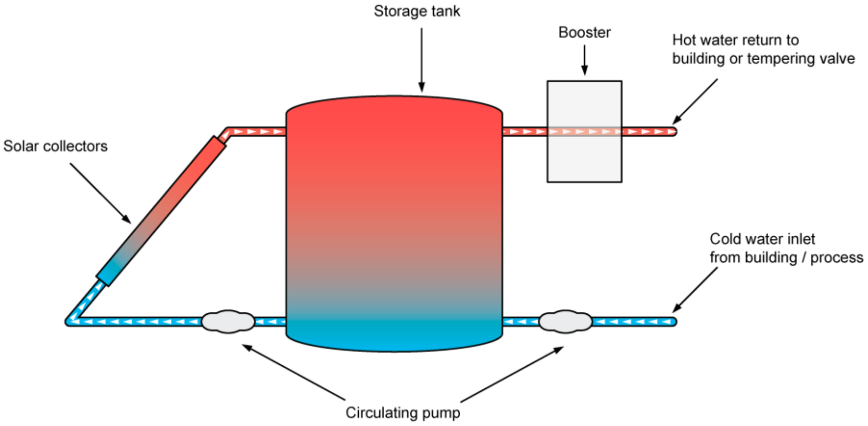
10.3 System Layouts

There are two basic system layouts used in LSTS. These are the open and closed loop systems. The closed loop system is the most common one.

10.3.1 Open Loop Systems

In an open loop system, the sun directly heats the (potable) water and no heat exchanger is needed. The water is pumped from the storage tank to the collector array and then returned to the tank after it has been heated. The same water is taken from the tank to the process circuit (Exhibit 10-8).

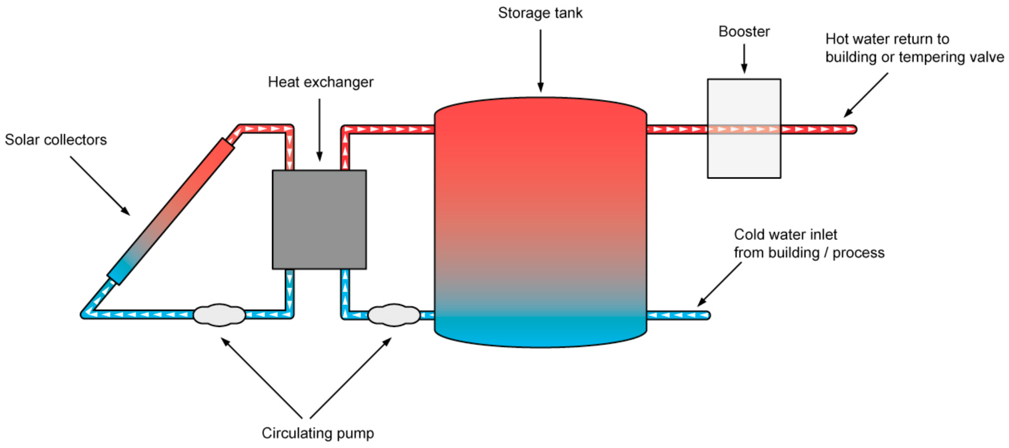
Exhibit 10-8: Typical Open Loop System



10.3.2 Closed Loop Systems

Closed loop systems use a heat exchanger to transfer the heat to a secondary circuit or thermal storage tank. The collector heat transfer fluid (water or water/glycol) remains in a sealed system. This configuration allows the use of non-potable water as the heat transfer fluid and anti-freezing agent may be added to the fluid in order to prevent damage from freezing (Exhibit 10-9).

Exhibit 10-9: Typical Closed Loop System



10.4 Collector Loop Design Concepts

The most effective system design will depend on the selection of the most cost-effective solar collector for the application and careful system design. A system that is incorrectly configured may result in stagnation in some sections of the collector array and thus a significant reduction in heat output. The most common fault in designing LSTS is bad hydraulic design that results in uneven flow distribution or air locks in the collector array.

A high flow rate through a solar collector will maximize energy collection for a given collector inlet temperature, but the collector outlet temperature of the fluid may be too low to be useful. In addition, high flow rates require larger pumps and cause significant amounts of parasitic electrical energy. On the other hand, a flow rate that is too low will result in high fluid temperatures, high heat losses from the collector array and therefore a low heat collection efficiency.

10.5 Thumb Rule for Sizing of LSTS (Typical Case)

Solar collector:

- A collector consists 9 copper tubes (C) with copper fins (B) encased in an aluminum box (usually powder coated in yellow) with a glass top (A).

  Copper used should be 99.9% pure electrolytic copper with selective coating using 'Black chrome technology'.
- A reflective surface at the bottom (D) and rock-wool ensures that any energy that passes between the fins gets reflected back onto the copper fins to ensure optimum performance in any condition.
- The collectors measure approximately 2m x 1m and are fixed at an angle (with respect to the horizontal equal to the latitude of the site) facing the South sky in a shadow free flat surface area.

Principle of Heating Water through Solar System:

The technology to heat water using solar energy is based on two simple principles:

- Thermo-siphon action: Is based on a simple principle that hot water is less dense and hence tends to rise above colder water.
- Black body absorption: It is a well-known fact that a black body absorbs heat which can be used to heat water.

- The Sun's rays heats the black powder coated copper fins (larger surface area) which in turn heats the cold water in the copper tubes. The heated water slowly rises in the copper pipes thro thermo-siphon action and eventually gets stored in the hot water storage tank.
- This principle ensures that no electricity is used in the entire system.

Applications for LSTS:

- Large scale hot water usage for bathing & laundry applications in hotels, hospitals, hostels and even hi-rise apartment buildings.
- Pre-feed for boilers for steam generation for various industrial applications.
- Milk dairies for applications such as pasteurization, condensation & cleaning.
- Leather processing industry for drying and tanning.
- Metal finishing industry for degreasing and phosphating.
- Resin emulsification in polymer industry.
- Drying & related processes in pharmaceutical industry.
- Solar drying thro air-heating is an area of growing interest.
- Swimming pool heating is a popular concept in India and abroad.

Thumb Rules:

- Surface area of each collector: 2m x 1m
- Flat / roof area required per collector: 3.5 sq m

Exhibit 10-10: Calculate no. of collectors for 1,000 liters hot water per day

	Cold Climate	Rest of the Country
60 °C	10	8
70 °C	12	10
80 °C	15	12

Total Flat/Roof Area required for installing LSTS (m^2)=

$$\left(\frac{\text{Hot Water required (liters/day)}}{1{,}000}\right) \times \text{No. of Collectors from Exhibit 10-11} \times 3.5\ \text{m}^2$$

Notes:

- 3.5 m^2 assumes area required per collector, interconnecting insulated piping between collectors & hot water storage tank fixed vertically.
- 1 $m^2 \sim 10.75\ ft^2$ or 3.5 $m^2 \sim 37.5\ ft^2$.

10.6 Design Checklist

- Hot water load
- Quantification of hot water load
- Demand patterns e.g. daily, seasonal, etc.
- Climatic data
- Typical meteorological year weather data file or statistically generated hourly model based on Monthly average weather data
- Measured component performance
- Solar collector efficiency
- Storage tank heat loss
- Hydraulic design

- Collector loop flow rate (intersection of pump head characteristic and piping friction pressure drop characteristic)
- Pump power at above flow rate
- Product configuration
- Open loop no heat exchanger
- Closed loop with collector loop heat exchanger
- Closed loop with load side heat exchanger
- Auxiliary boosting
- Electric in tank
- Electric series boost tank
- Gas instantaneous
- Gas series boost tank
- Controller
- Controller logic map
- Product details
- Solar array
    - Solar module area
    - Number of collectors in array
    - Efficiency coefficients
    - Collector inclination
    - Collector orientation
    - Flow rate through each collector
- Collector to tank piping
    - Diameter of collector inlet/outlet pipes
    - Thickness of insulation on connecting pipes
    - Inlet pipe length
    - Outlet pipe length
    - Thermal conductivity of insulation
- Solar preheat tank
    - Tank volume
    - Tank diameter
    - Volume of water above the auxiliary element
    - Volume of water above the thermostat
    - Volume of water above the collector return level
- Auxiliary boost tank
    - Set temperature
    - Thermostat dead band
    - Auxiliary power
    - Height of cold inlet above bottom of tank
    - Heat loss from tank
    - Thickness of inner tank wall (m)
    - Thermal conductivity of inner tank wall
- Pump
    - Pump flow rate
    - Maximum tank temperature for pump operation
    - Pump power input
    - Pump controller turn on difference
    - Pump controller turn off difference

10.7 Installation and Commissioning Checklist

The installation of LSTS shall be undertaken as per design. However, the following checklist gives valuable information on the correct installation of LSTS.

Environment

- Water quality is suitable for contact with components
- Components and materials chosen will not react to other materials in contact (e.g. galvanic reaction)
- All components are suitable for the environment and climatic conditions
- There are no known impacts to the environment by this installation

Solar collectors

- Collector is pitched and oriented to achieve good solar gain
- The collector is positioned to avoid shading right throughout the year
- Collectors connected in parallel are plumbed for balanced flow conditions (if applicable)
- Collectors are installed to roof structure as per the manufacturer's recommendations

Storage tank

- Pressure and temperature relief valve installed on water storage tanks (if applicable)
- Tanks connected in parallel are plumbed for balanced flow conditions (if applicable)
- Tanks are installed in a way to promote effective stratification (if applicable)
- Adequate access is allowed for maintenance
- If tank is to be roof-mounted, is the roof structurally strong enough to carry the weight of the full tank
- Storage tank is full of water before turning the system on

Flow and return pipe work

- Suitable pipework sizes for solar flow and return have been installed as per design
- No plastic components or pipework is used on the solar flow and return
- A high-quality, temperature-rated, ultraviolet-protected and weather-protected thermal insulation has been installed on solar flow and return pipes

Valves and fittings

- Air relief valves installed at highest points of collector array (if applicable)
- Low meter installed (if applicable)
- Balancing valves before collector rows installed (if applicable)
- Pressure limiting device installed (if applicable)
- Temperature limiting device installed to prevent scalding
- Non-return valve installed (if applicable)
- Expansion control valve installed (if applicable)
- Freeze protection device installed (if applicable)
- Stagnation or overheating protection device has been installed (if applicable)
- Thermal sensor cables are not in contact with the flow and return lines

High temperature/pressure

- Consideration has been given to the expansion and contraction of materials under high temperature conditions
- All materials, fittings, connection points and components are suitable for use under the expected temperature and pressure conditions

Regulatory

- All collector attachment points meet regulatory requirements
- Installation meets the requirements of AS/NZS 3500.4 and other applicable Standards covering the work completed
- All components have been installed to meet regulatory requirements

Boosting

- The auxiliary boosting option is functional and is connected to the correct fuel or energy tariff (if applicable)
- A timer has been installed on the auxiliary boost and is operational (if applicable)

Pump controller

- The temperature sensors have been installed to the correct outlets and the leads connected to the controller
- The electricity supply has been connected and the unit switched on to ensure it operates

Commissioning

- All the installed components have been thoroughly tested over a wide range of operating conditions
- Flow rates have been tested and balancing valves set to equalise flows through different collector arrays
- Controller transducers and controller operation have been tested
- The system has been tested whilst operating under realistic load and climate conditions
- The 'as installed' performance has been documented, including flow rates through each collector bank, balancing vales setting etc.

General

- Proper clearances have been observed and there are provisions for future maintenance
- All components have been installed to manufacturers' specifications
- The system has been tested, is operational and has been checked for leaks
- Descriptive labels have been applied to pipe work and components
- The site is neat and tidy. A full risk assessment of the site has been conducted
- All paper work has been completed
- Client has been provided with all necessary documentation and operating instructions

11 Performance Monitoring

11.1 Log Sheets

A boiler operating log is an invaluable trial for identifying efficiency changes and their causes. By keeping a continuous record of actual operating data, deviations from normal performance stand out very soon and serve to indicate areas needing attention.

The specific readings that should be taken and the frequency of recording will vary according to the size and complexity of the equipment. Large boiler houses usually record data on hourly basis, smaller installations may find once per shift is adequate for most items, and daily for others. The data collection program should be designed to be useful in maintaining the operational efficiency of the particular boiler.

A comprehensive boiler operating log will include the following information:

1. General data to establish unit steam output
    a. Steam flow rate
    b. Steam pressure
    c. Feed water temperature
    d. Feed water flow rate
    e. Superheated steam temperature (if applicable)
2. Firing system data
    a. Fuel Type
    b. Fuel flow rate
    c. Fuel supply pressure (not applicable for coal)
    d. Pressure at burners
    e. Fuel temperature
    f. Burner damper settings
    g. Windbox-to-furnace air pressure differential
    h. Other special system data unique to the particular installation
3. Air flow indication
    a. Air flow (where meter fitted)
    b. Forced draft fen damper position
    c. Forced draft fan amperes
4. Flue gas data
    a. Flue gas temperature at boiler outlet
    b. Flue gas temperature at economizer or air preheater outlet
    c. Ambient air temperature
    d. Oxygen content of flue gas to the air preheater
    e. Oxygen content of flue gas to the stack
5. Unburned combustible indication
    a. CO measurement
    b. Stack appearance
    c. Flame appearance
6. Air and flue gas pressures
    a. Forced draft fan discharge pressure
    b. Combustion chamber pressure
    c. Boiler outlet pressure

    d. Economizer differential pressure
    e. Air-preheater air and gas side pressures
7. Unusual conditions
    a. Steam leaks
    b. Abnormal vibration or noise
    c. Equipment malfunctions
    d. Excessive makeup water
8. Blow down operation
9. Soot blower operation

11.2 Spot Checks for Efficiency

A spot check of combustion conditions can be an effective maintenance tool. An integral part of any spot check program is an analysis of stack gas samples. The percent composition of any or all of several gases in the sample is an indication of combustion efficiency, as discussed in Chapters 3 and 4. For example, high excess air will be indicated by high O_2 readings, while an insufficient air supply will be characterized by low O_2 and high CO readings. A good approximation of overall boiler operating efficiency can be determined from the flue gas composition analysis and accompanying temperature reading, as discussed in Section 5.3.

The frequency of these spot checks depends on the requirements of the specific installation. A general rule would be at least weekly for smaller units and daily for larger boilers. It is suggested that a rapid visual check should also be made at the same time as the efficiency is checked. A checklist is given in Exhibit 11-1. The same checklist can be used whenever a boiler test is run or a tune-up carried out, in order to document the general condition of the boiler at that time.

Exhibit 11-1: Boiler evaluation checklist

Item / Equipment	**Comments**
Physical appearance	
Boiler house	
Boiler	
Burner	
Water system	
Heated medium distribution	
External structure	
Boiler house	
Boiler	
Safety equipment and instrumentation	
Boiler	
Burner	
Water system	
Fuel system	
Heated medium distribution	
Valves, fittings and insulation	
Boiler	
Burner	
Water system	
Fuel system	
Heated medium distribution	

11.3 Maintenance

For achieving maximum benefit from its tune-up, it is important that the boiler and its ancillary equipment be in proper working order. Deficiencies in the equipment may be observed by visual inspection, but routine checking of boiler efficiency, as suggested above, will often reveal the start of mechanical problems long before a major deterioration has become obvious.

A list of maintenance items which can affect boiler efficiency is provided in Exhibit 11-2. The list is a supplement to the manufacturers operating and maintenance manual: both the list and the manual should be used to check a boiler on a regular basis to ensure good operating conditions.

Exhibit 11-2: Boiler inspection checklist

BURNERS
Gas Firing
Condition and cleanliness of gas injection orifices
Cleanliness and operation of filter and moisture traps
Condition and orientation of diffusers, spuds, gas canes, etc.
Condition of burns refractory
Condition and operation of air dampers
Oil Firing
Condition and cleanliness of oil rip passages
Oil burning temperature
Atomizing steam pressure
Condition and orientation of burner diffusers
Position of oil guns
Cleanliness of oil strainer
Condition of burner throat refractory
Condition and operation of air dampers
Pulverized Coal Firing
Condition and operation of pulverizers, fenders end conveyors
Coal fineness
Condition of coal pipes
For any signs of excessive erosion or turnoff
Condition end operation of air dampers
Stoker Firing
Wear on grates
Position end opera tins of stoker.
Positioning of all air proportioning dampers
Coal sizing
Operation of cinder re-injection system
Combustion Controls
Cleanliness and proper movement of fuel valves
Excessive "play" in control link ages or air dampers
Adequate pressure to all Pressure regulators
Unnecessary cycling of firing rate
Proper operation of all safety interlocks and boiler trap circuits
Furnace
Excessive deposits of fouling of gas-side boiler tubes
Proper operation of soot blowers
Casing and duct leaks
Clean and operable furnace inspection ports

11.4 Water Quality and Treatment Methods

As discussed in Section 4.9, it is necessary to blow down the boilers regularly to remove sludge deposits and to maintain boiler water conditions which will prevent the foaming and carryover of salts into the steam distribution mains. Blow-down should be kept at as low a level as possible to achieve the necessary water quality, otherwise unnecessary heat and water losses will be incurred.

Recommendations for the quality of boiler water are normally given by the boiler manufacturers, or in national standards. Some typical total dissolved solids standards were given in Section 4.9. The general recommendations from different authorities (Appendix-C) for shell type (smoke-tube) and water-tube type boilers provide guidelines for operating the boiler under the best possible working conditions.

A routine check of key items should be made and the results logged. The most important items to check, and where to check them is summarized as follows:

	Makeup Water	Condensate	Boiler Feed	Boiler Water	Blowdown
Total dissolved solids	x	x	x	x	x
Alkalinity	x	x	x	x	
Chlorides	x	x	x	x	x
Hardness	x	x	x	x	
pH	x	x	x		

The quality of water may be checked quite quickly using water test kits: total dissolved solids may be checked by measuring water density or by using electronic conductivity meters.

Where a high blowdown rate is required to achieve the recommended water quality, capital expenditure on heat recovery equipment or additional feed water treatment plant may be justified. Increased condensate recovery will often allow blowdown to be reduced significantly.

Water treatment of some sort is necessary for the boiler make-up water. Its objectives are:

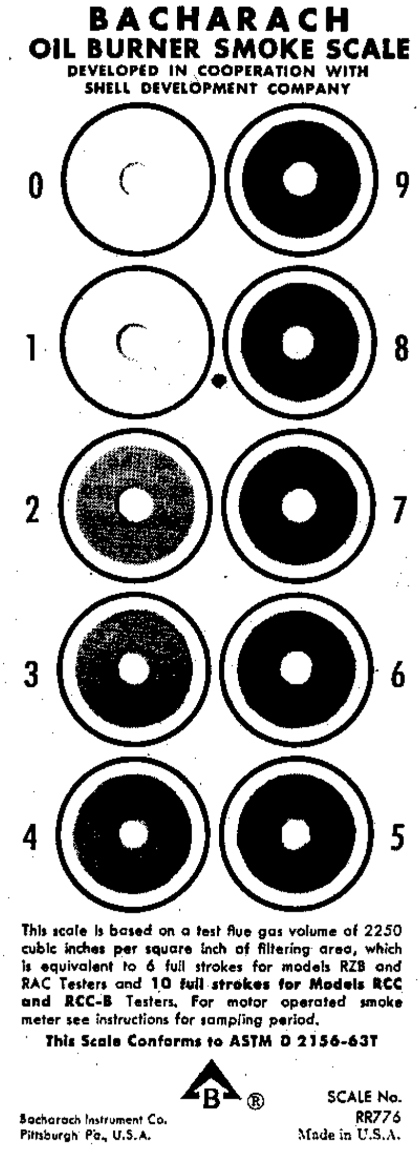
- Maximizing the boiler efficiency
- Preventing the scale formation in boiler and ancillary equipment to avert disastrous failure due to boiler metal overheating
- Minimizing the foaming to avoid contamination of steam by carry-over of boiler water
- Minimizing the corrosion in boiler due to dissolved oxygen in the feed water, and in the steam mains due to carbon dioxide in the steam

11.5 Smoke Density

Smoking can occur with oil and coal fuels, and is a certain indication of flue gas combustibles or unacceptable flame conditions; it should always be avoided. Some oil and coal-fired boilers, especially the larger ones, are equipped with smoke detectors which can be very useful in providing an early indication of poor combustion conditions. With gaseous fuels, smoking is generally not a problem, even with poor combustion.

Smoke density should be measured regularly on smaller boilers using an inexpensive portable “soot pump” (or smoke pump). It is not advisable to rely on visual observations alone, because high excess air rates can often dilute the particulates and disguise a poor combustion situation. A smoke pump provides a simple but useful check. It works on the principle of drawing a gas sample through filter paper: a specified number of strokes of the pump will displace a known volume of gas from which the particulates are removed by the filter paper. The darkness of the spot formed by the particulates on the paper is used as a measure of the smoke density. A typical chart supplied with a smoke pump is shown in Exhibit 11-3, from which a "smoke number" can be estimated.

Exhibit 11-3: Smoke scale for burner smoke test, primarily applicable to liquid and solid fuels



BACHARACH
OIL BURNER SMOKE SCALE
DEVELOPED IN COOPERATION WITH
SHELL DEVELOPMENT COMPANY

This scale is based on a test flue gas volume of 2250 cubic inches per square inch of filtering area, which is equivalent to 6 full strokes for models RZB and RAC Testers and **10 full strokes for Models RCC and RCC-B** Testers. For motor operated smoke meter see instructions for sampling period.

This Scale Conforms to ASTM D 2156-63T

Bacharach Instrument Co.
Pittsburgh Pa., U.S.A.

SCALE No.
RR776
Made in U.S.A.

Smoke Reading	Burner Performance
1	Excellent-little if any, sooting of furnace or boiler surfaces.
2	Good-May be light sooting with some type of furnace or boiler but little, if any, increase in flue gas temperature.
3	Fair-Substantial sooting with some types of furnace or boiler but rarely will require cleaning more than once a year.
4	Poor-This is a borderline smoke-some units may soot only moderately, others may soot rapidly.
5	Very Poor-Heavy sooting in all cases-may require cleaning several times during heating season.
6	Extremely Poor-Severe and rapid sooting may result in damage to stack control and reduce overfire draft to danger point.

As a guide to acceptable conditions, the smoke number observed at low excess air rates should not exceed the following:

Fuel Used	Maximum Smoke Number
Coal	4
No. 2 fuel oil (light diesel oil)	1
No. 5 fuel oil	3
No. 6 fuel oil (furnace oil)	4
Natural gas	1

It is not unusual to observe high smoke numbers in the stack of oil-fired boilers which are running with high excess air. This indicates the possibility of a mechanical defect in the burner system, resulting in poor atomization conditions. Large droplets of oil may be present and these are not completely burned in the combustion chamber. Alternatively, there may be a defect in the air distribution system which is preventing the proper mixing of air and fuel droplets, some of which are incompletely burned and pass through to the stack as particulates.

A further possibility is a deficiency in the atomizing steam, where this is used. The pressure of the steam and of the oil at the burner tip should be checked.

11.6 Flame Appearance

The appearance of the flame can provide a good initial indication of combustion conditions. It is difficult to generalize the characteristics of a "good" flame since there will be variations depending on the burner design. Operator experience is useful, especially where coal-fired stokers are involved. A symmetrical flame is normally sought; short, bright and turbulent oil and pulverized coal flames are desirable, with no long "streaks" of oil or coal at the edge of the flame and no excessive quantity of sparks ("fireflies") which would indicate poor oil-atomization or oversized particles of coal.

Blue flames, almost invisible and with little or no streaks, are usually desirable with gaseous fuels.

The stability of the flame at the burner tip is important, and the flame should be steady within the combustion chamber. It should not "move" unduly away from the axis of the burner.

11.7 Burner Checks

It is always worth checking that oil burner atomizers are of the proper design and size for the boiler. Burner tips should be cleaned regularly in accordance with the manufacturer's instructions. At the same time, the oil tip passages and orifices should be checked for excessive erosion, scratching or scoring. The temperature of the oil at the burner should also be checked to ensure that the recommended levels are being maintained for the burner in question. The burner itself should be properly located within the burner throat. Deficiencies or variations in any of these items could cause alterations in the flame appearance and flue gas composition, indicative of combustion inefficiencies.

Similar checks of burner cleanliness and dimensions should be made for gas burners. Clean filters and moisture traps should be in place, preventing plugging of gas orifices.

Pulverized coal burner components should be checked regularly for signs of malfunction, including excessive erosion or burn off. The particle size of the coal should be within recommended limits. Stoker grates should not be excessively worn, causing air channeling and the resultant incomplete combustion of carbon in the ash or high fly ash carryover. The stoker spreaders should be working properly and be correctly positioned to ensure an even, consistent, bed depth. Air dampers should be working properly.

11.8 Combustion Controls

All fuel valves should be inspected to verify proper movement and clean internal surfaces. Gas and oil valve surfaces may erode with time. There should not be excessive “play” in control linkages or air dampers. Fuel supply inlet pressures to all pressure regulators should be adequate to ensure constant regulator outlet pressure for all firing rates. Atomizing steam or air systems should deliver the proper flows. Any control elements which fail to respond smoothly to varying steam demand should be corrected. Unnecessary cycling of firing rate due to improperly adjusted regulators or automatic master controllers can waste fuel. All gauges should be functioning and calibrated to aid in identifying any control problems as they occur. All safety interlocks and boiler trip circuits must be operable.

11.9 Boiler Tube Cleanliness

In order to ensure good heat transfer characteristics in the boiler, it is necessary to keep the tubes free of deposits and fouling. Poor firing conditions at the burner are generally a major cause of deposits on the external tube surfaces of a water tube boiler or in the gas tubes of a fire-tube boiler. Waterside deposits result primarily from inadequate water treatment. In either case, the problem will result in poor heat transfer rates and elevated flue gas temperatures.

The poor firing conditions mentioned above are usually related to either insufficient burner excess air or improper burner adjustment and maintenance. This results in excessive carbon and soot formation in the furnace; soot builds up on both furnace wall tubes and convective tube banks in a water tube boiler, and inside the tubes of a fire-tube boiler. A boiler inspection will disclose whether soot blowers are positioned and functioning properly.

When evaluating stack temperatures, they should be compared to readings obtained when the tubes were known to be clean. Since stack temperature usually increases with firing rate and excess air, these comparisons are best performed for similar boiler operating conditions whenever possible. A graph of daily stack temperature readings is often helpful in identifying any upward trend due to fouling. To generalize, stack temperatures will normally range 25 to 40°C (40 to 75°F) above the saturated steam temperature for boilers which are not equipped with economizers or air preheaters.

Tube cleaning can be performed by either in-house maintenance personnel or commercial boiler repair and service companies. Various cleaning methods are used, depending on factors such as the severity and composition of deposits, age of the boiler, boiler construction, and access to tube surfaces.

11.10 Boiler Tune-up

The boiler tune-up is a method for determining the lowest practical excess air level at which the boiler can be operated, and adjusting the boiler to that condition. The method consists of a series of tests which involve operating the boiler at various firing rates and excess air levels while recording boiler operating conditions and stack measurements.

11.10.1 Setting up the Boiler Test

To obtain maximum benefit from the boiler tests, all pertinent test data should be recorded. A permanent record of boiler operating conditions and stack measurements will not only document the boiler’s efficiency and emission characteristics, but also enable future comparisons to be made to help diagnose any of efficiency or emission problems. The test data should be recorded on prepared data sheet forms and include the following items:

1. Identification of boiler, fuel types, date of tests and names of operating personnel involved
2. Steam, feed water and fuel conditions (flow rates, pressure and temperature) to document boiler firing rate and steam generation
3. Combustion control position and burner settings
4. Furnace pressures, temperatures, and damper settings
5. Stack measurements (O_2, CO_2, CO, smoke, temperature)
6. All relevant comments on flame appearance, flame carryover and furnace conditions
7. Recording any new permanent changes made to combustion controls or burner settings

The actual boiler readings included will of course depend on the available instrumentation. It is important that adequate data be obtained so that exact boiler operating conditions can be repeated for future comparative purposes.

11.10.2 Conducting the Tests

Readings should be recorded only after steady boiler conditions are reached. This is usually indicated by steady stack temperatures, fuel input, and steam conditions (pressure and temperature and drum level). Steady oxygen readings in the stack are a good indication that fuel and air flows have stabilized.

It is very desirable that these tests be conducted at normal steam pressures. This will ensure that stack temperatures and furnace temperatures are representative of normal operating conditions. Since it will usually be necessary to control the boiler firing rate manually during the tests to obtain stable conditions, there may be some problems in satisfying normal steam demands. When alternate steam generating capacity is available, the loading at other boilers should be modulated to maintain constant system pressures. When this is not possible, it may be necessary to make provisions to dump unneeded steam or temporarily interrupt plant process.

The boiler tune-up will establish the excess air level at some operating margin above the absolute minimum which is at the threshold of smoke or combustible emissions formation. Although peak boiler efficiency will occur close to the minimum, it is not practical to operate at this condition unless the boiler is equipped with highly sophisticated combustion controls and flame quality monitoring to prevent any small deviations into unsafe or unacceptable combustion conditions. Since these control features are not typical of most industrial boilers, some margin or operating “cushion” above the minimum air rate will be necessary to accommodate normal variations in fuel properties and atmospheric conditions, repeatability and response characteristics of the combustion control system, and other operational factors.

11.10.3 Achieving Low Excess Air Operation

This section provides general guidelines for determining the lowest practical flue gas oxygen levels for a particular boiler. This will require that the minimum oxygen level and the appropriate operating margin above this minimum be established and evaluated with respect to typical levels for the type of fuel and burning equipment used. If minimum oxygen levels are found to be excessive, then burner adjustments are recommended as a possible means for reducing the burner’s minimum oxygen requirement. High minimum oxygen can also result from improper maintenance of burner equipment (plugged orifice, broken diffusers, etc.).

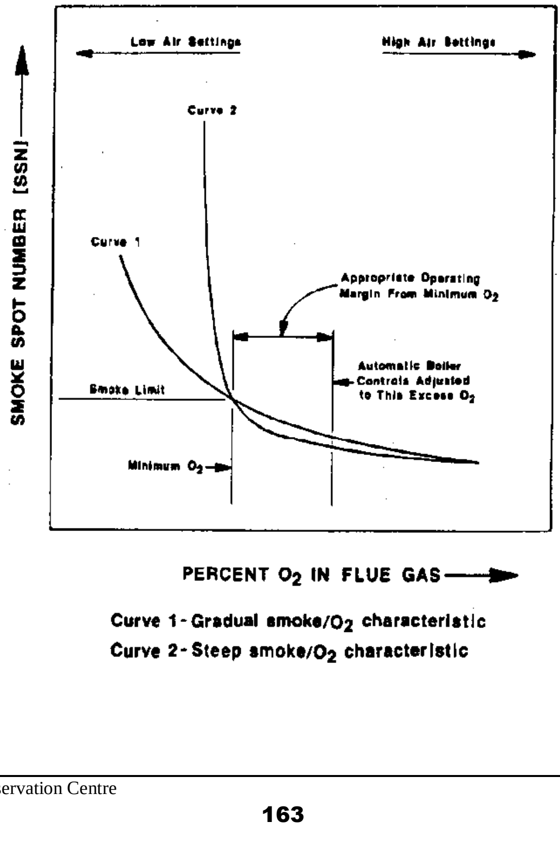
Setting up a boiler for low excess air firing will be accomplished through a systematic, organized series of tests. Following a test to document “as found” conditions, the lowest possible level of excess oxygen for the boiler should be established. The lowest level should be found at several firing rates within the boiler's operating range. The actual number of firing rates tested will depend on the design of the boiler control system. Enough firing rates should be tested to ensure that after the final control adjustments are made, the optimum excess air conditions are maintained at all the intermediate firing rates. At each firing rate tested, the flue gas oxygen level should be varied over a range from 1 or 2% above the normal operating point down to the point where the boiler just starts to smoke or the CO emissions rise above 400 ppm. This low excess air condition is referred to as the smoke or CO threshold (limit) and corresponds to the "minimum oxygen". The smoke limit is usually applied to coal and oil firing since smoking will generally occur before CO emissions reach significant levels. The CO limit applies to gas fuels and is the lowest excess oxygen level achievable while maintaining carbon monoxide below 400 ppm.

When performing the boiler tests to determine minimum excess oxygen, curves such as those in Exhibit 11-4 and Exhibit 11-5 can be constructed. Based on measurements obtained during the tests, these curves will show how the boiler-smoke and CO levels change as the excess oxygen is varied. Each of the figures contains two distinct curves to illustrate the extremes in smoke and CO behavior which may be encountered. The curves labeled (1) exhibit a very gradual increase in CO or smoke as the minimum oxygen condition is reached.

In contrast, the curves labeled (2) are gradual at first, but as the excess oxygen is reduced further, and minimum oxygen is approached, the smoke or CO emission increases rapidly. In this case, unpredictably high levels of smoke or CO, or potentially unstable conditions, can occur with small changes in excess oxygen, and extreme caution is required. When making changes near the smoke or CO limit, these should be done in very small steps until there are enough data to show whether the boiler has a gradual or steep characteristic curve for smoke and CO. It is important to note that the boiler may exhibit a gradual smoke or CO behavior at one firing rate and a steep behavior at another.

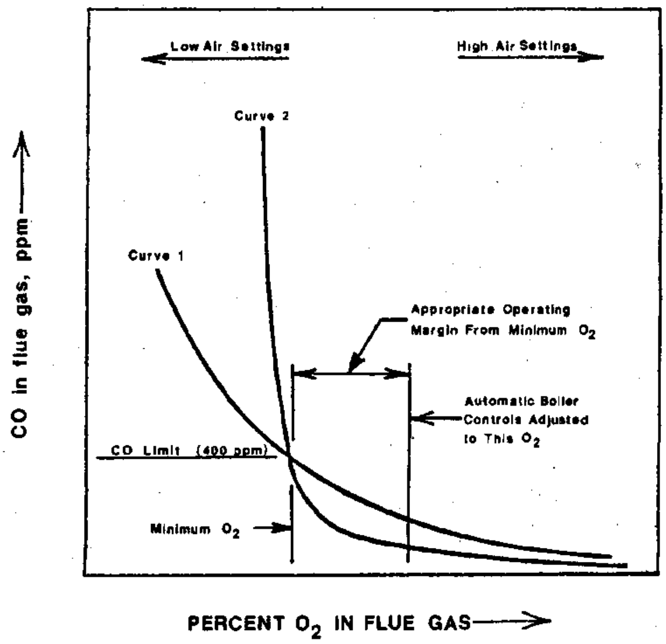
High minimum oxygen may be an indication of a burner malfunction or other fuel or equipment related problems. However, it should also be realized that different burner designs and fuels will in general have different minimum oxygen requirements. Many burners will also exhibit higher minimum oxygen at lower firing rates. For these reasons it is impossible to give precise figures for minimum oxygen levels which would be considered normal. Exhibit 11-4 and Exhibit 11-5 present some typical values for optimum excess air levels for different fuels and firing methods.

Exhibit 11-4: Typical smoke - O_2 characteristic curves for coal or oil fired industrial boilers



Curve 1 - Gradual smoke/O_2 characteristic
Curve 2 - Steep smoke/O_2 characteristic

Exhibit 11-5: Typical CO_2 - O_2 characteristic curves



Curve1-Gradual CO/O_2 characteristic
Curve2-Steep CO/O_2 characteristic

11.11 Troubleshooting

Most boiler operational problems encountered can be traced back to a limited number of probable causes. The boiler log will aid in identifying symptoms by indicating deviations from normal operational levels. The accompanying Exhibit 11-6 will serve as a general guide to causes underlying some common operating problems related to boiler efficiency.

Exhibit 11-6: Boiler troubleshooting: summary table

System		Problem		Possible Causes
Combustion	1)	High Excess air ($High O_2$)	a) b) c) d)	Improper control system operation Low fuel supply-pressure Change in fuel heating value Change in oil fuel viscosity
	2)	Low excess air (Low O_2)	a) b) c)	Improper control system operation Fan limitations Increased ambient air temperature
	3)	High CO and combustible emission (0_2 satisfactory or high)	a) b) c) d) e) f) g) h) i)	Improper air register settings Oil burner damage Air distribution incorrect Obstructed on plugged gas burners Unbalanced fuel/air distribution in multi-burner furnaces Deterioration of burner throat refractory Improper overfire air systems Stoker grate Stoker fuel distribution orientation
Heat Transfer	1)	High exit gas temperature	a) b) c)	Buildup of gas or water-side deposits Inadequate water treatment procedures Improper sootblower operation

12 Environmental Pollution Aspect

12.1 Air Pollution due to Fossil-fuel Burning

The boiler plants pollute the atmosphere by injecting into it following gaseous emissions.

1. Oxides of Nitrogen ($NO_X = NO + NO_2$)
2. Oxides of Sulfur ($SO_X = SO_2 + SO_3$)
3. Solid ash particles as suspended matters or particulates
4. Vanadium pentoxide V_2O_5

However, the type of gaseous pollutants depends on the nature of the fuel burned. When coal is burned, the major pollutants are fly ash, soot, sulfur dioxide and NO_x. However, in case of natural gas and fuel oil combustion, the major gaseous effluents of concern are SO_2 and NO_x. In addition, the flue gases may contain carbon-monoxide (CO) and hydrocarbons like CH_4, C_2H_4 and $C_{20}H_{12}$ (benzpyrene).

Of course, certain components of gaseous effluents from fossil-fuel burning systems are harmless to human beings. These include water vapor, carbon dioxide, oxygen and nitrogen. Other ingredients as cited above are harmful to the biosphere in varying degrees. While, Carbon monoxide is potentially quite dangerous,. It is odorless, colorless and tasteless. The human body can tolerate CO in concentrations up to 10 ppm without any noticeable effect.

Nitrogen dioxide and sulfur trioxide are highly dangerous air pollutants. NO and NO_2 are produced in the high-temperature zones of the flame – the yield of NO2 being 10% (usually) of the total NO_x formation. NO_x may undergo a photochemical reaction with the hydrocarbons in the atmosphere in the presence of sunlight to release some toxic substances in the air.

Sulfur in the fuel burns off to liberate SO2 which forms SO3 in the final stage of flame burning when there is an exigency of atomic oxygen. SO3 is also produced from SO_2 on the surface of the superheater deposits that act as a catalyst at elevated temperatures. Sulfur trioxide reacts with atmospheric moisture to form an aerosol of sulfuric acids which rains down as acid rain.

Sulfur dioxide is a moderately harmful substance. But because of its acidic nature, like SO_3 and NO_2, it attacks the delicate membrane lining the eyes, nose and respiratory tract. These air pollutants are known to cause four major types of respiratory damage: bronchitis, bronchial asthma, and lung cancer. They affect plants as well. They burn the leaf's chlorophyll causing red or brown blotches on leaves between the veins.

Suspended particulates cause smog and obscure visibility.

12.2 Air Pollution Control in Fossil Fuel Burning Systems

12.2.1 Control of SO_2 Emission

With the increased industrial utilization of high-sulfur coal and fuel oils, it has become growing concern to reduce the SO_x emission to atmosphere. A number of options are available in this regard:

Burning low sulfur coals.

Desulphurization of coal prior to its combustion.

Desulphurization of petroleum.

Subjecting fuel oil and high sulfur coal to deep thermal processing to produce gaseous fuel.

Post combustion SO2 removal from waste gases.

Fluidized bed combustion.

12.2.2 Control of NO_x Emission

The removal of nitrogen oxides from flue gas presents greater engineering difficulties than that of SO_2. That is due to:

- Lower concentration of NO_x in flue gases.
- Chemical inactivity of NO which is usually present in flue gases in much larger concentration than NO_2.

Unlike SO_2 whose presence in flue gas is unavoidable until and unless the sulphur content of fuel is eliminated beforehand, the concentration of NO_x in combustion gases largely depends on the combustion technique in the furnace. Nitrogen oxides are produced in two ways during fuel combustion:

- Chemical reaction between aerial nitrogen and oxygen in the high-temperature combustion zone (above 1600°C)
- Oxidation of nitrogen content in fuel. This can take place below 1600°C.

Since the bulk of NO_x generation produced in the combustion process comes from reaction (1) the chief means of limiting NO_x generation is to lower the temperature in the combustion zone, i.e. to carry out a low-temperature combustion technique as well as reduce the quantity of excess air. This can be achieved by:

- Adopting the fluidized bed combustion technique. As this process contains the combustion temperature in the range 800-900°C, the chances of NO_x formation are minimum.
- Carrying out combustion with minimum excess air
- Flue gas recirculation
- Double-stage combustion, particularly with gas fired large boilers.

12.2.3 Control of Particulate Matter Emission

Several devices are available for the removal of particulate solids from the stack gas of thermal power plants and steam generation plants. These are:

- Cyclone separator
- Fabric filters
- Dust scrubbers
- Electrostatic precipitators

12.3 Water Pollution and Solid Waste Disposal Problem in Boiler Plants

Boilers of thermal power stations and of process industries contribute to water pollution by way of discharging into the water basin the:

- Boiler blowdown
- SO_2 scrubber waste
- Waste waters from water treatment plants and demineralizing units
- Waste waters contaminated with petroleum products
- Waste waters from hydraulic ash-disposal system.

These discharged waste waters carry a rich load of harmful impurities, viz. heavier metal cations, organic substances and coarse-dispersed solids besides dissolved salts.

12.3.1 Waste Water from Water Treatment Plants

All boilers need water-treatment plant and demineralizing (DM) unit for the production of makeup water for boiler feed. The reagents used in the water-treatment plant and DM-unit and the salts resulting from their chemical action must be discharged off as wastes.

Waste water of water treatment plants (WTP) contains slime, coarse-dispersed solids, organic substances, magnesium hydroxide, calcium carbonate and salts of iron and aluminum. The composition and concentration of various impurities in waste water depends on the quality of raw water and the methods adopted for water treatment.

12.4 Pakistan – National Environmental Quality Standards (NEQS)

The maximum allowable limits under NEQS for boiler emissions are presented below:

NO_x	Natural Gas Fired	=	400 mg/Nm^3
	Oil Fired	=	600 mg/Nm^3
	Coal Fired	=	1200 mg/Nm^3
SO_x		=	700 mg/Nm^3
CO		=	800 mg/Nm^3
Particulate Matter	Oil Fired	=	300 mg/Nm^3
	Coal Fired	=	500 mg/Nm^3

Appendix-A Properties of Saturated Steam (Pressure in Bars)

Absolute pressure	Boiling point	Specific volume (steam)	Density (steam)	Specific enthalpy of liquid water		Specific enthalpy of steam (total heat)		Latent heat of vaporization		Specific heat
(bar)	**(°C)**	**(m^3/kg)**	**(kg/m^3)**	**(kJ/kg)**	**(kcal/kg)**	**(kJ/kg)**	**(kcal/kg)**	**(kJ/kg)**	**(kcal/kg)**	**(kJ/kg)**
0.02	17.51	67.006	0.015	73.45	17.54	2533.64	605.15	2460.19	587.61	1.8644
0.03	24.1	45.667	0.022	101	24.12	2545.64	608.02	2444.65	583.89	1.8694
0.04	28.98	34.802	0.029	121.41	29	2554.51	610.13	2433.1	581.14	1.8736
0.05	32.9	28.194	0.035	137.77	32.91	2561.59	611.83	2423.82	578.92	1.8774
0.06	36.18	23.741	0.042	151.5	36.19	2567.51	613.24	2416.01	577.05	1.8808
0.07	39.02	20.531	0.049	163.38	39.02	2572.62	614.46	2409.24	575.44	1.884
0.08	41.53	18.105	0.055	173.87	41.53	2577.11	615.53	2403.25	574.01	1.8871
0.09	43.79	16.204	0.062	183.28	43.78	2581.14	616.49	2397.85	572.72	1.8899
0.1	45.83	14.675	0.068	191.84	45.82	2584.78	617.36	2392.94	571.54	1.8927
0.2	60.09	7.65	0.131	251.46	60.06	2609.86	623.35	2358.4	563.3	1.9156
0.3	69.13	5.229	0.191	289.31	69.1	2625.43	627.07	2336.13	557.97	1.9343
0.4	75.89	3.993	0.25	317.65	75.87	2636.88	629.81	2319.23	553.94	1.9506
0.5	81.35	3.24	0.309	340.57	81.34	2645.99	631.98	2305.42	550.64	1.9654
0.6	85.95	2.732	0.366	359.93	85.97	2653.57	633.79	2293.64	547.83	1.979
0.7	89.96	2.365	0.423	376.77	89.99	2660.07	635.35	2283.3	545.36	1.9919
0.8	93.51	2.087	0.479	391.73	93.56	2665.77	636.71	2274.05	543.15	2.004
0.9	96.71	1.869	0.535	405.21	96.78	2670.85	637.92	2265.65	541.14	2.0156
1	99.63	1.694	0.59	417.51	99.72	2675.43	639.02	2257.92	539.3	2.0267
1.1	102.32	1.549	0.645	428.84	102.43	2679.61	640.01	2250.76	537.59	2.0373
1.2	104.81	1.428	0.7	439.36	104.94	2683.44	640.93	2244.08	535.99	2.0476
1.3	107.13	1.325	0.755	449.19	107.29	2686.98	641.77	2237.79	534.49	2.0576
1.4	109.32	1.236	0.809	458.42	109.49	2690.28	642.56	2231.86	533.07	2.0673
1.5	111.37	1.159	0.863	467.13	111.57	2693.36	643.3	2226.23	531.73	2.0768
1.5	111.37	1.159	0.863	467.13	111.57	2693.36	643.3	2226.23	531.73	2.0768
1.6	113.32	1.091	0.916	475.38	113.54	2696.25	643.99	2220.87	530.45	2.086
1.7	115.17	1.031	0.97	483.22	115.42	2698.97	644.64	2215.75	529.22	2.095
1.8	116.93	0.977	1.023	490.7	117.2	2701.54	645.25	2210.84	528.05	2.1037
1.9	118.62	0.929	1.076	497.85	118.91	2703.98	645.83	2206.13	526.92	2.1124
2	120.23	0.885	1.129	504.71	120.55	2706.29	646.39	2201.59	525.84	2.1208
2.2	123.27	0.81	1.235	517.63	123.63	2710.6	647.42	2192.98	523.78	2.1372
2.4	126.09	0.746	1.34	529.64	126.5	2714.55	648.36	2184.91	521.86	2.1531
2.6	128.73	0.693	1.444	540.88	129.19	2718.17	649.22	2177.3	520.04	2.1685
2.8	131.2	0.646	1.548	551.45	131.71	2721.54	650.03	2170.08	518.32	2.1835
3	133.54	0.606	1.651	561.44	134.1	2724.66	650.77	2163.22	516.68	2.1981
3.5	138.87	0.524	1.908	584.28	139.55	2731.63	652.44	2147.35	512.89	2.2331
4	143.63	0.462	2.163	604.68	144.43	2737.63	653.87	2132.95	509.45	2.2664
4.5	147.92	0.414	2.417	623.17	148.84	2742.88	655.13	2119.71	506.29	2.2983
5	151.85	0.375	2.669	640.12	152.89	2747.54	656.24	2107.42	503.35	2.3289
5.5	155.47	0.342	2.92	655.81	156.64	2751.7	657.23	2095.9	500.6	2.3585
6	158.84	0.315	3.17	670.43	160.13	2755.46	658.13	2085.03	498	2.3873
6.5	161.99	0.292	3.419	684.14	163.4	2758.87	658.94	2074.73	495.54	2.4152

Absolute pressure	Boiling point	Specific volume (steam)	Density (steam)	Specific enthalpy of liquid water		Specific enthalpy of steam (total heat)		Latent heat of vaporization		Specific heat
(bar)	(°C)	(m³/kg)	(kg/m³)	(kJ/kg)	(kcal/kg)	(kJ/kg)	(kcal/kg)	(kJ/kg)	(kcal/kg)	(kJ/kg)
7	164.96	0.273	3.667	697.07	166.49	2761.98	659.69	2064.92	493.2	2.4424
7.5	167.76	0.255	3.915	709.3	169.41	2764.84	660.37	2055.53	490.96	2.469
8	170.42	0.24	4.162	720.94	172.19	2767.46	661	2046.53	488.8	2.4951
8.5	172.94	0.227	4.409	732.03	174.84	2769.89	661.58	2037.86	486.73	2.5206
9	175.36	0.215	4.655	742.64	177.38	2772.13	662.11	2029.49	484.74	2.5456
9.5	177.67	0.204	4.901	752.82	179.81	2774.22	662.61	2021.4	482.8	2.5702
10	179.88	0.194	5.147	762.6	182.14	2776.16	663.07	2013.56	480.93	2.5944
11	184.06	0.177	5.638	781.11	186.57	2779.66	663.91	1998.55	477.35	2.6418
12	187.96	0.163	6.127	798.42	190.7	2782.73	664.64	1984.31	473.94	2.6878
13	191.6	0.151	6.617	814.68	194.58	2785.42	665.29	1970.73	470.7	2.7327
14	195.04	0.141	7.106	830.05	198.26	2787.79	665.85	1957.73	467.6	2.7767
15	198.28	0.132	7.596	844.64	201.74	2789.88	666.35	1945.24	464.61	2.8197
16	201.37	0.124	8.085	858.54	205.06	2791.73	666.79	1933.19	461.74	2.862
17	204.3	0.117	8.575	871.82	208.23	2793.37	667.18	1921.55	458.95	2.9036
18	207.11	0.11	9.065	884.55	211.27	2794.81	667.53	1910.27	456.26	2.9445
19	209.79	0.105	9.556	896.78	214.19	2796.09	667.83	1899.31	453.64	2.9849
20	212.37	0.1	10.047	908.56	217.01	2797.21	668.1	1888.65	451.1	3.0248
21	214.85	0.095	10.539	919.93	219.72	2798.18	668.33	1878.25	448.61	3.0643
22	217.24	0.091	11.032	930.92	222.35	2799.03	668.54	1868.11	446.19	3.1034
23	219.55	0.087	11.525	941.57	224.89	2799.77	668.71	1858.2	443.82	3.1421
24	221.78	0.083	12.02	951.9	227.36	2800.39	668.86	1848.49	441.5	3.1805
25	223.94	0.08	12.515	961.93	229.75	2800.91	668.99	1838.98	439.23	3.2187
26	226.03	0.077	13.012	971.69	232.08	2801.35	669.09	1829.66	437.01	3.2567
27	228.06	0.074	13.509	981.19	234.35	2801.69	669.17	1820.5	434.82	3.2944
28	230.04	0.071	14.008	990.46	236.57	2801.96	669.24	1811.5	432.67	3.332
29	231.96	0.069	14.508	999.5	238.73	2802.15	669.28	1802.65	430.56	3.3695
30	233.84	0.067	15.009	1008.33	240.84	2802.27	669.31	1793.94	428.48	3.4069

Example - Boiling Water at 100°C, 0 bar Atmospheric Pressure

At atmospheric pressure (0 bar g, absolute 1 bar), water boils at 100°C, and 417.51 kJ of energy are required to heat 1 kg of water from 0°C to its evaporating temperature of 100°C.

Therefore the specific enthalpy of water at 0 barg (absolute 1 bar) and 100°C is 417.51 kJ/kg, as shown in the table.

Another 2 257.92 kJ of energy are required to evaporate 1 kg of water at 100°C into 1 kg of steam at 100°C. Therefore at 0 bar g (absolute 1 bar) the specific enthalpy of evaporation is 2 257.19 kJ/kg, as shown in the table.

Total specific enthalpy for steam: h_s = 417.51 + 2,257.92 = 2,675.43 kJ/kg

Example - Boiling Water at 170°C, 7 bar Atmospheric Pressure

Steam at atmospheric pressure is of a limited practical use because it cannot be conveyed under its own pressure along a steam pipe to the point of use.

At 7 barg (absolute 8 bar), the saturation temperature of water is 170.42°C. More heat energy is required to raise its temperature to saturation point at 7 bar g than would be needed if the water were at atmospheric pressure. The table gives a value of 720.94 kJ to raise 1 kg of water from 0°C to its saturation temperature of 170°C.

The heat energy (enthalpy of evaporation) needed by the water at 7 bar g to change it into steam is actually less than the heat energy required at atmospheric pressure. This is because the specific enthalpy of evaporation decreases as the steam pressure increases. The evaporation heat is 2,046.53 kJ/kg according to the table.

Note! Because the specific volume also decreases with increasing pressure, the amount of heat energy transferred in the same volume actually increases with steam pressure.

Appendix-B Processing of Biomass Fuels

B.1 Drying of Biomass Fuels

There are several established methods, plus some promising technology, for drying biomass fuels for use in combustion boilers and gasifiers. Drying biomass fuel provides significant benefits to boiler operation, but they must be balanced against increased capital and operating costs. Using dry fuel in a direct combustion boiler results in improved efficiency, increased steam production, reduced ancillary power requirements, reduced fuel use, lower emissions, and improved boiler operation.

B.2 Dryer Principles

There are three requirements for drying:

1. A source of heat,
2. A method of removing the water evaporated,
3. Some form of agitation to expose new material for drying.

B.2.1 Types of Dryers

Dryers can be broadly divided into two categories based on how heat is provided for drying. In direct dryers, the material gets heat from direct contact with a fluid providing the heat--either hot air or hot steam. With indirect drying, the material being dried is separated from the heat source by a heat exchange surface. One important consequence of indirect drying is that it is possible to recover the latent heat of evaporated water because the water vapor is not diluted by air. This can be done by drawing a vacuum on the material as it is drying and condensing the water vapor before a vacuum pump, or if the dryer is operated at a sufficiently high temperature, the water evaporates at an elevated pressure.

B.2.2 Stages of Drying

There are several steps to drying. First, the material must be heated from the temperature at which it entered the dryer, up to the wet bulb temperature, to produce a driving force for water to leave the wet material. Next, any surface moisture on the material is evaporated--this occurs fairly quickly. Once all the surface moisture is removed, the material must be heated to drive water from the inside of the biomass to the surface so it can evaporate. This occurs during the "falling rate period" when the rate of drying drops as the material becomes drier. During the falling rate period, the surface temperature of the material remains close to the wet bulb temperature. Once the material is completely dry, it begins to heat up to the surrounding temperature, because water is no longer present to keep its temperature low.

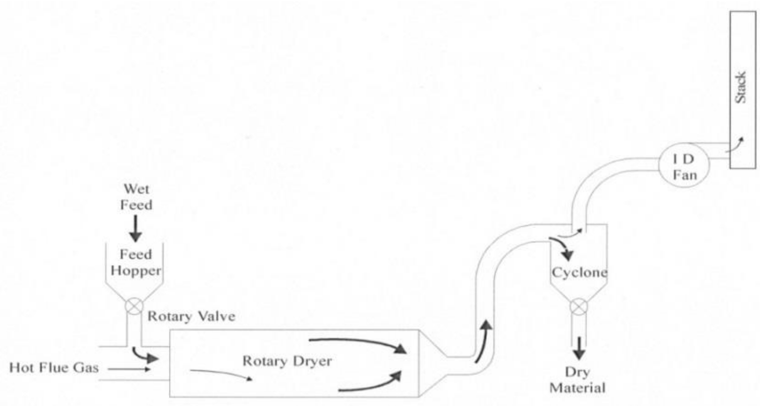
B.3 Dryers Description

B.3.1 Rotary Dryers

Rotary dryers are the most common type used for biomass drying. There are several variations of rotary dryers, but the most widely-used is the directly heated single-pass rotary dryer (see Exhibit B-1). In this type of dryer, hot gases come into contact with biomass material inside a rotating drum. Rotation of the drum, with the aid of flights, lifts the solids in the dryer so they tumble through the hot gas, promoting better heat and mass transfer. If contamination is not a concern, hot flue gas can be fed directly into the dryer. Other options include using a burner or a steam heater to raise the temperature of incoming air.

The biomass and hot air normally flow co-currently through the dryer so the hottest gases come in contact with the wettest material, but for materials where temperature is not a concern, the flue gas and solids flow in opposite directions, so the driest solids are exposed to the hottest gases with the lowest humidity. This latter configuration produces the lowest moisture leaving the dryer, but for biomass this exposes essentially dry material to a high flue gas temperature, which would increase the fire risk.

Exhibit B-1: Single-Pass Rotary Dryer



The exhaust gases leaving the dryer may pass through a cyclone, multicyclone, baghouse filter, scrubber or electrostatic precipitator (ESP) to remove any fine material entrained in the air. An ID (induced draft) fan may or may not be required depending on the dryer configuration. If one is needed, it is usually placed after the emissions control equipment to reduce erosion of the fan, but may also be placed before the first cyclone to provide the pressure drop through downstream equipment.

Single-pass dryers can take larger material. The basic single-pass rotary dryer design can be modified to allow three passes of the air and material through the dryer.

Indirectly heated rotary dryers use a heat source--steam or hot air--passing through the outer wall of the dryer or through an inner central shaft to heat the dryer by conduction. This is more common with materials that would be contaminated by direct contact with flue gases or with materials that react with air.

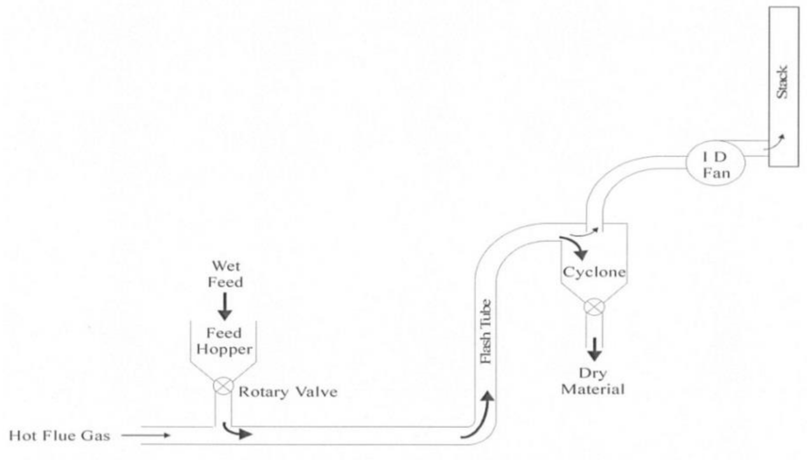
The inlet gas temperature to rotary biomass dryers can vary from (225° - 1,000°C). Outlet temperatures from rotary dryers vary from (70° - 110°C), with most of the dryers having outlet temperatures higher than 104°C to prevent condensation of acids and resins. Retention times in the dryer can be less than a minute for small particles and 10-30 minutes for larger.

B.3.2 Flash Dryers

In a flash or pneumatic dryer, the solids are mixed with a high-velocity hot air stream. The intimate contact of the solids with the air results in very rapid drying. The solids and air are separated using a cyclone, and the gases continue through a scrubber to remove any entrained particulate material. A simple flash dryer (without a scrubber) is shown in **Exhibit B-2**.

Because of the short drying time in a flash dryer, the equipment is more compact than for a rotary dryer. However, the electricity consumption is higher because of the faster air flows through the unit, and because biomass must pass through a shredder or grinder to reduce its size so it can be suspended in the air stream. For wet or sticky materials, such as sludge, some of the dry material can be recycled back and mixed with the incoming wet material to improve material handling.

Exhibit B-2: Typical Flash Dryer Configuration



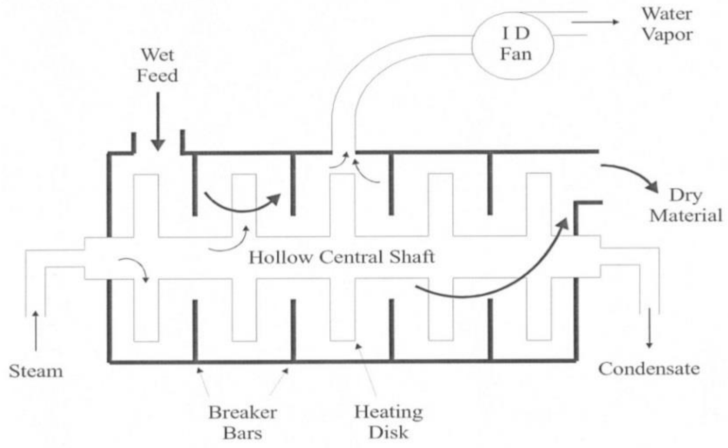
Flash dryers have been used successfully for drying most biomass materials, including wood, sludge, and bagasse.

Gas temperatures are slightly lower for flash dryers than for rotary dryers, but they still operate at temperatures above the combustion point. The solids retention time in a flash dryer is typically less than 30 seconds, minimizing the fire hazard.

B.3.3 Disk Dryers

For smaller flows of material, a disk dryer or "porcupine" dryer (**Exhibit B-3**) is an option. In a disk dryer, solids are heated by condensing steam inside of a central shaft with many hollow disks that increase the area for heat transfer. Fingers or "breaker bars" mix the material and act to keep the heat transfer surfaces free of buildup. The disk dryer can be operated under a vacuum or under pressure, and the condensate from inside the heating shaft can be recovered and returned to the boiler.

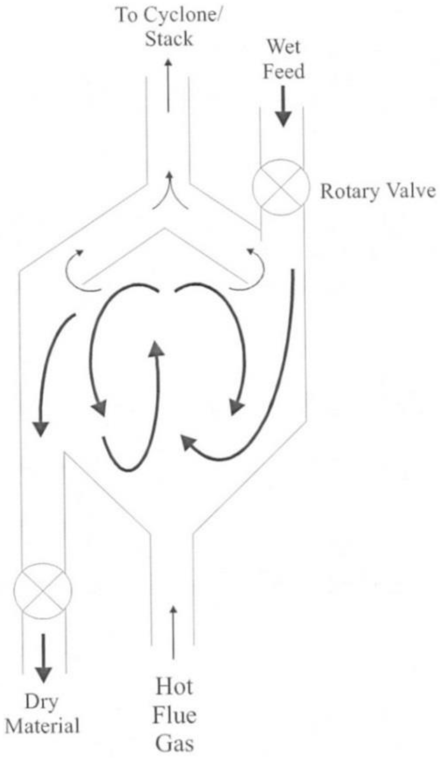
Exhibit B-3: Side View of a Disk Dryer



B.3.4 Cascade Dryers

Cascade or spouted dryers (**Exhibit B-4**) are commonly used for drying grain, but they can be used for other types of biomass. Material is introduced to a flowing stream of hot air as it enters an enclosed chamber. The material is thrown into the air, then falls, or cascades, back to the bottom to be lifted again. Some of the material is drawn out through openings in the side of the chamber that control the residence time and amount of drying. The typical residence time for a cascade dryer is a couple of minutes.

Exhibit B-4: Side View of a Cascade Dryer

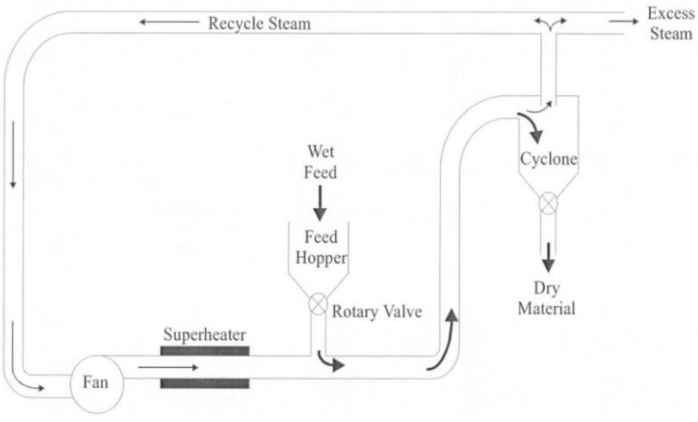


B.3.5 Superheated Steam Dryers (SSDs)

Most SSDs are similar to flash dryers, except that the fluid suspending the solids and providing heat is steam instead of air. Under normal operation, the wet material is mixed with enough superheated steam to dry the material and still end up with superheated steam. Typically 90% of the steam leaving the dryer is recirculated while 10% of the steam, representing the amount of water evaporated from the biomass, is removed and either condensed or used directly in other parts of the plant.

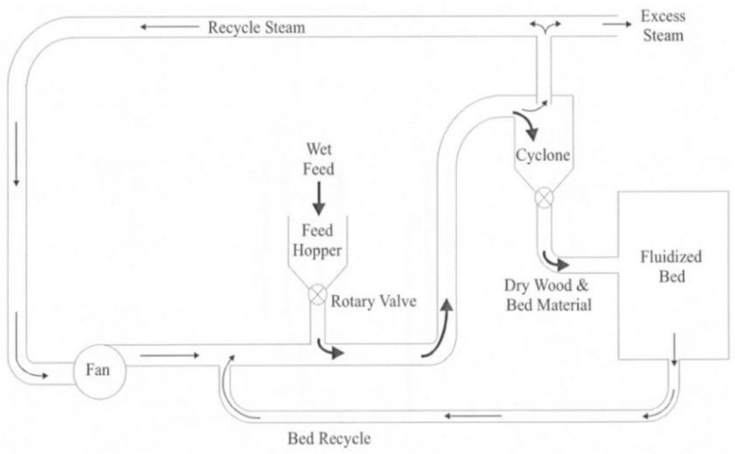
Several SSD designs are in development or in limited operation. **Exhibit B-5** illustrates a basic SSD.

Exhibit B-5: Basic Superheated Steam Dryer Design



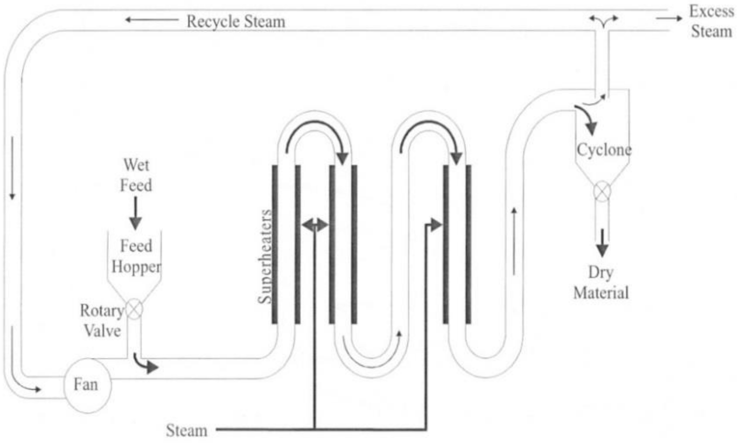
Another design called a bed mixing dryer (**Exhibit B-6**) can be used with a fluidized bed gasifier or boiler. Some of the hot bed material from the combustion chamber is mixed with the incoming wet biomass in a steam atmosphere. The sensible heat from the bed material evaporates the water from the fuel. The fuel can then be fed, along with the bed material back into the process, while the steam can be recycled, with the excess steam being used for other process heating.

Exhibit B-6: Bed Mixing Superheated Steam Dryer



Still in another SSD design, like the basic SSD dryer, the biomass is introduced into a superheated steam stream, but in this case, the walls of the flash tube are heated with high-temperature steam, providing the heat to evaporate the water in the biomass. Like the other superheated steam processes, this dryer can be operated at low or high pressure depending on the process needs, and the excess steam can be recaptured for other uses. This process is shown in **Exhibit B-7**.

Exhibit B-7: Typical Superheated Steam Dryer



B.4 Heat Recovery

Drying tends to be energy intensive because, in addition to the heat of vaporization of the water removed, energy goes into heating the biomass solids and into heating the air or steam used for drying. Recovery of some of this heat improves the overall efficiency of the drying process and boiler, but usually requires a significant capital investment.

B.4.1 Heat Recovery in Air Drying

Energy efficiency in air-drying can be improved by:

1. Using heat exchangers,
2. Recirculating exhaust gases,
3. Using exhaust gases for burner air,

4. Using multistage drying,
5. Using a run-around coil,
6. Using a heat pump.

Two types of heat exchangers are possible: recuperative, where the heat is transferred directly from the exhaust gas through the wall of a heat exchanger to the inlet gas; or regenerative, where an intermediate material is heated by the exhaust gases, then exposed to the cold inlet gas.

The air leaving a directly heated air dryer is usually not saturated, so some of the hot exhaust gas can be recirculated to the inlet of the dryer. Because it is still warm, energy is not needed to heat it, increasing the drying efficiency. This exhaust gas, if high enough in oxygen can also be used as preheated burner air to incinerate some of the volatile organic compounds in the exhaust gas. The amount of recycle depends on the specific dryer configuration.

Multistage drying can be used when high inlet temperatures are a concern. Instead of diluting the entire hot gas stream with cool air to reduce the temperature, some of the hot gas can be introduced to later stages of the dryer to boost the air temperature. In this way, less dilution air is required.

A run-around coil can be used where the physical layout of the dryer does not allow the exhaust gas to be close to the inlet gas. An intermediate heat carrier, such as antifreeze, oil, or a commercial heating fluid is first pumped through a heat exchanger coil in the exhaust gas duct, then through a heat exchanger in the inlet air duct to give up its heat to the colder inlet air. The disadvantage of this method is that two heat exchangers are needed instead of one recuperative heat exchanger, but this is sometimes cheaper than running extra duct work.

A heat pump is similar to a run-around coil, but because it uses a refrigerant and compressor, it can recover part of the latent heat of vaporization by condensing or dehumidifying the exhaust gas and can then provide this heat to the inlet air at a higher temperature. Although energy efficient, the capital costs for the compressor can be very high with significant compressor energy requirements. Heat pumps are also generally limited to providing heat at no more than 60° - 66°C.

B.4.2 Superheated Steam Heat Recovery

In the case of superheated steam drying and vacuum drying, the latent heat of vaporization is easier to recover because the water vapor that leaves the fuel is not diluted by air, so it can be condensed directly to recover the heat.

Depending on the dryer and plant configuration, there are several possibilities for heat recovery. In cases where the power plant also provides hot water for heating, the SSD can be operated at atmospheric pressure and still produce hot water at a reasonable temperature. However, if process steam is required, the dryer must either be operated at a higher pressure, or the steam from the dryer must be compressed to increase the temperature it condenses at. The steam from the dryer can then be used directly, or it can be condensed on the outside of boiler tubes to produce clean steam without any impurities.

Another option for integrating an SSD with a combined-cycle gasifier is to inject high-pressure dryer steam into the fuel to the gas turbine. The steam will provide a boost in output by passing a greater volume of gas through the turbine without requiring compression of the dryer steam.

B.5 Drier Choices

The choice of dryers will depend on the characteristics of the material being dried, the source of heat for the dryer, and integration options available.

An important consideration is the size of the material to be dried. For flash dryers and most SSDs, a small particle size is needed to suspend the material in a moving air or steam stream. Triple-pass rotary dryers will accept larger material, but may experience plugging with very large material. Cascade dryers need a very uniform particle size. For large or variable material, a single-pass rotary dryer might be best. For some materials, reducing the size of the material may be an option, but often this is an energy-intensive operation.

The heat source and temperature for drying are important considerations. Flue gas is an efficient source of heat, but the temperature may be too low to provide enough heat for complete drying. Using a process stream for heating may be energy efficient, but will require the capital investment in a heat exchanger and the interactions between the dryer and process must be considered. SSDs typically require a high-temperature heat source. If saturated steam is available, the disk dryer or modified SSD dryer would be an option. The goal should be to determine what excess heat is available in the system, then design the drying system to take advantage of it. If all else fails, a burner can be installed with an auxiliary fuel source to provide the heat for drying.

High-pressure operation can improve material handling in many cases when dealing with gasifiers. In those cases, the basic or modified superheated dryer would be favored. Again, SSDs have advantages when used for combined heat and power plants or combined cycle plants.

B.6 Benefits and Disadvantages of Different Types of Dryers

As mentioned earlier, the choice of dryers depends on many factors. A brief summary of the benefits and disadvantages of each type of dryer follows. The particular type of dryer, its configuration, and operating conditions should be determined case-by-case.

Rotary Dryers

Rotary dryers are less sensitive to particle size and can accept the hottest flue gases of any type of dryer. They have low maintenance costs and the greatest capacity of any type of dryer. However, material moisture is hard to control in rotary dryers because of the long lag time for material in the dryer. Rotary dryers also present the greatest fire hazard and require the most space. Compared to single-pass dryers, triple-pass dryers have higher capital costs, higher maintenance costs, higher blower costs and pose more of a fire hazard.

Flash Dryers

Flash dryers are much more compact than rotary dryers, but have higher installation costs. They can be used on most types of biomass, but have high blower power costs in addition to the heat requirements for drying. The particles being dried must be small to be suspended in the air stream. With the short retention time in the dryer, the hydrocarbon emissions may be slightly lower than for a rotary dryer. Like the rotary dryer, heat recovery can be difficult because of the air mixed with the water vapor. Flash dryers, because of their shorter retention time and lower operating temperature, have a lower fire risk than rotary dryers.

Disk Dryers

The main advantage of disk dryers is that saturated steam can be used for heating. Because they are indirectly heated, condensing the vapor from the dryer is possible to recover some of the latent heat of vaporization. Operation is fairly straightforward and maintenance costs are reasonable. The main disadvantage is the limited capacity because of the relatively low operating temperature compared to other dryers.

Cascade Dryers

Cascade dryers are similar to flash dryers, except they can handle slightly larger particles. However, for a good cascading effect in the dryer, the particle size must be fairly uniform. Like other air-heated dryers, heat recovery is difficult and expensive.

Superheated Steam Dryers (SSDs)

The main benefit of all SSDs is that the latent heat of vaporization from drying can be recovered and no heat losses occur from heating air for the dryer. There are normally no air emissions from a SSD; all the vapor, including organics, is condensed. This does, however, mean the condensate from the process will require wastewater treatment. The mixed bed SSD design has the advantage of requiring no heat exchangers for drying. A high-pressure SSD integrated with a gas turbine eliminates the wastewater stream by combusting the organics in the turbine.

SSDs have higher heat transfer and faster drying, and because of the inert steam atmosphere presents no fire hazard. Some disadvantages are the need for small particle size to allow mixing of the steam and particles, high capital costs for a stainless steel pressure vessel, and in the case of the modified SSD design, the need to consume process steam for drying.

Exhibit B-8 summarizes the main considerations in choosing among the dryer types.

Exhibit B-8: Summary of the Advantages and Disadvantages of Each Dryer

Dryer Type	Requires Small Material?	Requires Uniform Size?	Ease of Heat Recovery	Fire Hazard	Steam Use
Rotary Dryer	No	No	Difficult	High	Can use steam
Flash Dryer	Yes	No	Difficult	Medium	None
Disk Dryer	No	No	Easy	Low	Saturated steam
Cascade Dryer	No	Yes	Difficult	Medium	None
Superheated Steam Dryer	Yes	No	Easy	Low	Excess steam produced

B.7 Fuel Powdering, Pelleting and Briquetting

Depending on the combustion technology used fuel products must fulfill different requirements. The demand to get the fuel product either powdered or as fluff, in pelletized form, or as briquettes or chips of defined size is not uncommon.

B.7.1 Powdering

Fuel material of small particle size (e.g. sawdust) is being generated by many production processes. With the appropriate combustion technology in place, such fuels can be directly utilized. The storage of fuel products with a small particle size can be done in flat bunkers and in silos. However, special provisions are also made with respect to fire protection and prevention of explosions during the storage of these materials.

B.7.2 Pelletizing and Briquetting

Pellets are a solid biomass fuel with consistent quality – low moisture content, high energy density and homogeneous size and shape. The problems of conventional biomass fuels as an alternative to coal, oil or gas, which are attributed mainly to their low energy density, high moisture content and heterogeneity, can be lessened or even prevented altogether by the use of pellets. Consistent fuel quality makes pellets a suitable fuel type for all areas of application, from stoves and central heating systems to large-scale plants, and with practically complete automation in all these capacity ranges.

Advantages of solid biomass fuels are:

- Reduced storage volume through an increased bulk density of the lose fuel material,
- Better flow properties and dosage,
- Avoidance of bridges and clumping in silos and conveyor aggregates
- Enhancement of the energy density and calorific content by pressure and heat.

Aside from compression pressure and grain size, also water content plays an essential role in the process. Adding binding agents can help to improve the physical and chemical quality and enhance the burnout.

The shape and particle size of a fuel usually determine the correct choice of feeding and furnace technologies as they influence the conveying and combustion behavior of the fuel. The bigger the fuel particles are, the more robust feeding appliances have to be and the longer becomes the required time for complete combustion.

Biomass pellets are usually 6-8mm diameter cylindrical high density sticks, while briquettes can be 22-70mm diameter cylindrical blocks, or cuboid and hexagon shape with a hole in the middle.

Exhibit B-9: Pellets and Briquettes

- Pellets

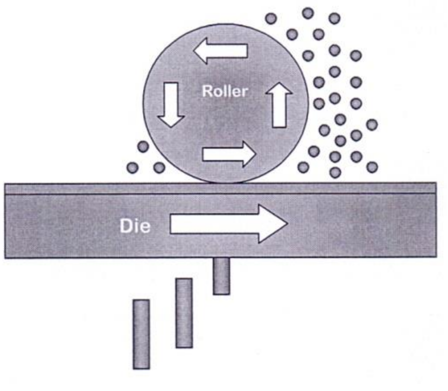
- Briqettes

Different types of pellets mills include:

Flat Die Pellet Mill

The image to the right depicts the basic design and process of the flat die pellet mill. A solid metal plate sits below a series of compression rollers. Material enters from above and falls between the rollers, which is then compressed through the die. The finished pellets then emerge from the base of the die and leave the pellet mill.

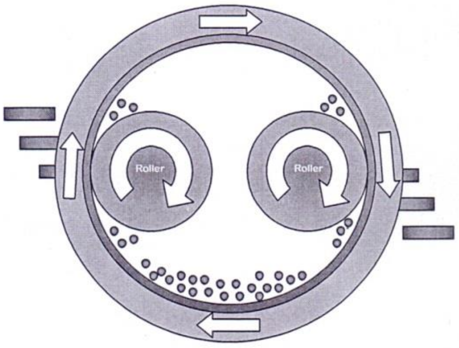
Exhibit B-10: Flat Die Pellet Mill



Ring Die Pellet Mill

The image to the right depicts the basic design and operation of the ring die pellet mill. Unlike the flat die pellet mill design the ring die is positioned vertically instead of horizontally. The raw material enters the centre of the die and is compressed through the die witha series of compression rollers. Most ring die pellet mills have two compression rollers, however some ring die pellet mills have three maybe four compression rollers. The most common design of ring die pellet mill is where the die is powered and rotating, and the rollers move due to the friction and movement of the die.

Exhibit B-11: Ring Die Pellet Mill



Briquetting

Briquetting presses operate as piston compressors with a fly wheel, slider crank, crosshead and plunger or with a hydraulic drive. After initial compression in a screw conveyor the material passes under pressure batch wise through the compression tools, cone for pre-compression and the press nipper. Within the press nipper a heating or cooling can be done. The briquette is wedged from the pneumatic press nipper in a pressure variable way

Piston rod presses are being used for the compression of sawdust, splinter, straw, paper fibers and similar materials.

Through the production of briquettes in various shapes, an optimal burning (burnout, burning duration) of the fuel material can be achieved.

Appendix-C Combustion Calculations

C.1 1. Applications of the Combustion Equation

1. Stoichiometric proportions for finding the correct air supply rate for a fuel
2. Composition of the combustion products is useful during the design, commissioning and routine maintenance of a boiler installation

On-site measurements of flue gas composition and temperature are used as a basis for calculating the efficiency of the boiler at routine maintenance intervals.

C.2 Combustion Air Requirements: Gaseous Fuels

Calculating the air required for gaseous fuels combustion is most convenient to work on a volumetric basis.

The stoichiometric combustion reaction of methane is:

CH4 + 2O2 → CO2 + 2H2O

It shows that each volume (normally 1 m3) of methane requires 2 volumes of oxygen to complete its combustion.

If one ignores the components, which are present in the parts per million range, air consists of about 0.9% by volume argon, 78.1% nitrogen and 20.9% oxygen (ignoring water vapor). Carbon dioxide is present at 0.038%.

For the purposes of combustion calculations the composition of air is approximated as a simple mixture of oxygen and nitrogen:

Oxygen	21%
Nitrogen	79%

The complete relationship for stoichiometric combustion:

$$CH_4 + 2\,O_2 + 7.52\,N_2 \rightarrow CO_2 + 2\,H_2O + 7.52\,N_2$$

As the volume of nitrogen will be: $\frac{2 \times 79\%}{21\%} = 7.52$

A very small amount of nitrogen is oxidized but the resulting oxides of nitrogen (NOX) are not formed in sufficient quantities. They are not of concern here.

However, they are highly significant in terms of air pollution.

It can be seen that the complete combustion of one volume of methane will require (2+7.52=9.52) volumes of air, so the stoichiometric air-to-fuel ratio (AFR) for methane is 9.52.

In practice it is impossible to obtain complete combustion under stoichiometric conditions. Incomplete combustion is a waste of energy and it leads to the formation of carbon monoxide, an extremely toxic gas, in the products.

Excess air is expressed as a percentage increase over the stoichiometric requirement and is defined by:

$$\frac{\text{Actual AFR - Stoichiometric AFR}}{\text{Stoichiometric AFR}} \times 100\%$$

Excess air will always reduce the efficiency of a combustion system.

It is sometimes convenient to use term excess air ratio, defined as:

$$\frac{\text{Actual AFR}}{\text{Stoichiometric AFR}}$$

Where sub-stoichiometric (fuel-rich) air-to-fuel ratios may be encountered, for instance, in the primary combustion zone of a low-NOX burner, the equivalence ratio is often quoted. This is given by:

$$\frac{\text{Stoichiometric AFR}}{\text{Actual AFR}}$$

C.3 Flue Gas Composition-Gaseous Fuels

The composition of the stoichiometric combustion products of methane is:

1	Volume	CO_2
7.52	Volumes	N_2
2	Volumes	H_2O

Given a total product volume, per volume of fuel burned, of 10.52 if water is in the vapor phase, or 8.52 if the water is condensed to a liquid.

The two cases are usually abbreviated to “wet” and “dry”.

The proportion of carbon dioxide in this mixture is therefore

$$\frac{1}{10.52} \times 100\% = 9.51\% \text{ wet} \quad \text{and}$$

$$\frac{1}{8.52} 100\% = 11.74\% \text{ dry}$$

The instruments used to measure the composition of flue gases remove water vapor from the mixture and hence give a dry reading, so the dry flue gas composition is usually of greater usefulness.

Considering the combustion of methane with 20% excess air, the excess air (0.2×9.52) of 1.9 volumes will appear in the flue gases as (0.21×1.9)=0.4 volumes of oxygen and (1.9-0.4)=1.5 volumes of nitrogen.

The complete composition will be:

Constituent	Volume/Volume Methane (Wet)	Volume/Volume Methane (Dry)
CO2	1	1
O2	0.4	0.4
N2	9.02	9.02
H2O	2	
Total Volume	12.42	10.42

The resulting composition of the flue gases, expressed as percentage by volume, is:

Constituent	% Volume (Wet)	% Volume (Dry)
CO2	8.1	9.6
O2	3.2	3.8
N2	72.6	86.6
H2O	16.1	0
Total Volume	**100**	**100**

Example 1:

A gas consists of 70% propane (C3H8) and 30% butane (C4H10) by volume. Find:

1. The stoichiometric air-to-fuel ratio and
2. The percentage excess air present if a dry analysis of the combustion products shows 9% CO2 (assume complete combustion).

Solution:

The combustion reactions for propane and butane are:

$$C_3H_8 + 5\,O_2 + 18.8\,N_2 \rightarrow 3\,CO_2 + 4\,H_2O + 18.8\,N_2$$

$$C_4H_{10} + 6.5\,O_2 + 24.5\,N_2 \rightarrow 4\,CO_2 + 5\,H_2O + 24.5\,N_2$$

Stoichiometric Air Requirement

On the basis of 1 volume of the fuel gas, the propane content requires 0.7 × (5 + 18.8) = 16.7 volumes air and the butane requires 0.3 × (6.5 + 24.5) = 6.3 volumes air. Hence the stoichiometric air-to-fuel ratio is 23:1.

Excess Air

The combustion products (dry) will contain:

(0.7 × 3) + (0.3 × 4) = 3.3 volumes CO_2

(0.7 × 18.8) + (0.3 × 24.5) = 20.5 volumes N_2

plus υ volumes excess air, giving a total volume of products of (23.8 + υ).

Since, the measured CO_2 in the products is 9%, the equation is:

$$\frac{9}{100} = \frac{3.3}{23.8 + \upsilon}\ ;\ \text{Hence, } \upsilon = 12.87 \text{ volumes}$$

The stoichiometric air requirement is 23 volumes so the percentage excess air is:

$$\frac{12.87}{23} \times 100\% = 55.9\%$$

C.4 Combustion Air Requirements-Solid and Liquid Fuels

The way in which the combustion equation is used reflects the available information on the analysis of the solid or liquid fuels.

This takes the form of an element-by-element analysis (referred to as an ultimate analysis) which gives the percentage by mass of each element present in the fuel.

An example of an ultimate analysis of a liquid fuel (oil) might be:

Component	% by mass
Carbon (C)	86
Hydrogen(H2)	14

Each constituent is considered separately via its own combustion equation.
For the carbon:

$$\begin{array}{cccc} C & + & O_2 & \rightarrow & CO_2 \\ 12kg & & 32kg & & 44kg \end{array}$$

or for 1 kg of fuel

$$0.86 + 0.86 \times \frac{32}{12} \rightarrow 0.86 \times \frac{44}{12} = 3.15 \text{ kg } CO_2 \text{ produced}$$

$$\text{While, } 0.86 \times \frac{32}{12} = 2.29 \text{ kg } O_2 \text{ required}$$

So each kg of oil requires 2.29 kg oxygen for combustion of its carbon and produces 3.15 kg CO2 as product.

Similarly

$$\begin{array}{ccccc} H_2 & + & \tfrac{1}{2}O_2 & \rightarrow & H_2O \\ 2kg & & 16kg & & 18kg \end{array}$$

Or per kg of fuel for Hydrogen:

$$0.14 + 0.14 \times \frac{16}{2} \rightarrow 0.14 \times \frac{18}{2} = 1.26 \text{ kg } H_2O \text{ produced}$$

$$\text{While, } 0.14 \times \frac{16}{2} = 1.12 \text{ kg } O_2 \text{ required}$$

In order to burn the hydrogen content of the oil 1.12 kg oxygen are needed and 1.26 kg water is formed.

The total oxygen requirement is thus (2.29 + 1.12) or 3.41 kg.

A given quantity of air consists of 21% by volume of oxygen.

We can simply transform to a mass basis thus:

Component	**volume fraction (vf)**	**Mass (vf × MW)**	**Mass fraction**
Oxygen	0.21	0.21 × 32 = 6.72	$\frac{6.72}{28.84} = 0.233$
Nitrogen	0.79	0.79 × 28 = 22.12	$\frac{22.12}{28.84} = 0.767$
Total		**28.84**	**1**

Therefore, 3.41 kg oxygen, which is the stoichiometric requirement, will be associated with:

$$3.41 \times \frac{0.767}{0.233} = 11.23 \text{ kg Nitorogen}$$

$$\text{Oxygen} + \text{Nitrogen} = 3.41 + 11.23 = 14.6 \text{ kg}$$

The stoichiometric air-to-fuel ratio is thus 3.41 + 11.23 = 14.64 : 1

C.5 Combustion Products-Solid and Liquid Fuels

The stoichiometric combustion products from combustion of the oil are:

Component	**Mass kg (Wet)**	**Mass kg (Dry)**
CO_2	3.15	3.15
H_2O	1.26	0
N_2	11.23	11.23
Total	**15.64**	**14.38**

The combustion products would normally be needed as a volume percentage, so the reverse operation to that which was performed for air above is required.

Hence, if a dry volume percentage of the combustion products is required the following tabular procedure is convenient:

Component	Mass kg (Dry)	Molecular Weight	Moles/kg Fuel	Mole Fraction	% Fraction
CO_2	3.15	44	$\frac{3.15}{44} = 0.0716$	0.151	15.1
N_2	11.23	28	$\frac{11.23}{28} = 0.4011$	0.849	84.9
Total	**14.38**		**0.4727**	**1**	**100**

The stoichiometric combustion products are thus 15.1% CO_2 and 84.9% N2.

Solid fuels, and many liquid fuels, contain compounds of sulfur. For the purposes of stoichiometric calculations this is assumed to burn to sulfur dioxide:

$$S + O_2 \rightarrow SO_2$$

In reality a mixture of sulfur dioxide and sulfur trioxide (SO_3) is produced, but it is conventional to assume combustion to SO_2 when calculating air requirements.

Solid fuels and some oils produce ash when they burn. The percentage of ash in the fuel is part of the ultimate analysis and, as far as we are concerned at the moment, ash is simply treated as a totally inert substance.

Many solid fuels contain small amounts of oxygen and nitrogen. The oxygen present in the fuel is considered to be available for burning the carbon, hydrogen and sulfur present.

The nitrogen in the fuel is taken to appear as gaseous nitrogen in the combustion products.

Example 2: Combustion Calculation for Coal

A coal has the following ultimate analysis:

Constituent	% Mass
Carbon	90
Hydrogen	3
Sulfur	0.5
Oxygen	2.5
Nitrogen	1
Ash	3
Total	**100**

Calculate:

1. Volumetric air supply rate required if 500 kg/h of coal is to be burned at 20% excess air and
2. Resulting %CO2 (dry) by volume in the combustion products.

Solution:

Lay out the calculation on a tabular basis using 1 kg coal:

Constituent	Mass/kg Coal	O2 Required kg	Products kg
Carbon	0.9	$0.9 \times \frac{32}{12} = 2.4$	$0.9 \times \frac{44}{12} = 3.3$
Hydrogen	0.03	$0.03 \times \frac{16}{2} = 0.24$	$0.03 \times \frac{18}{2} = 0.27$
Sulfur	0.5	$0.005 \times \frac{32}{32} = 0.005$	$0.005 \times \frac{64}{32} = 0.01$
Oxygen	0.025	- 0.025	-

Nitrogen	0.01	-	0.01
Ash	0.03	-	-
Total	**1**	**2.62**	**3.59**

(a) Oxygen required to burn 1 kg coal = 2.62 kg.

$$\text{Air Required} = \frac{2.62}{0.233} = 11.25\ \text{kg}$$

$$\text{Where, Oxygen / kg Air} = \frac{0.21 \times 32}{0.21 \times 32 + 0.79 \times 28} = 0.233\ \text{kg}$$

$$\text{Actual Air Supplied (20\% in Excess)} = 11.25 \times 1.2 = 13.5\ \text{kg}$$

Assuming a density for air of 1.2 kg/m^3, the air flow rate will be:

$$\text{Air Flow Rate} = 13.5 \times \frac{500}{1.2 \times 3600} = 1.56\ \text{m}^3/\text{s}$$

(b) To get the %CO_2 in the combustion products, the amounts of oxygen and nitrogen in the flue gases are needed.

Air supplied = 13.5 kg per kg coal, of which:

Oxygen = 13.5 × 0.233 = 3.14 kg, and

Nitrogen = 13.5 – 3.14 = 10.36 kg.

The combustion products will thus contain:

3.14 – 2.62 = 0.52 kg Oxygen and

10.36 + 0.01 = 10.37 kg Nitrogen.

A following tabular procedure can now be used for the volumetric composition of the flue gases:

Component	Mass kg (Dry)	Molecular Weight	Moles/kg Fuel	Mole Fraction	% Fraction
CO_2	3.3	44	$\frac{3.3}{44} = 0.075$	0.1625	16.25
SO_2	0.01	64	$\frac{0.01}{64} = 0.000156$	0.0003	0.03
O_2	0.52	32	$\frac{0.52}{32} = 0.0162$	0.0351	3.51
N_2	10.37	28	$\frac{10.37}{28} = 0.3703$	0.8022	80.22
Total	**14.20**		**0.4616**	**1**	**100**

C.6 Practical Significance of the Flue Gas Composition

It is comparatively easy to make on-site measurements of the dry volumetric concentration of either carbon dioxide or oxygen in the flue gases.

Either of these measurements can be used to calculate the air-to-fuel ratio (or excess air) if the composition of the fuel is known and the combustion of the fuel is complete.

The volume percentage of oxygen or carbon dioxide in the flue gas will be influenced by the level of excess air and also by the carbon to hydrogen ratio present in the fuel.

If pure carbon is burnt, the only combustion product is carbon dioxide, so each molecule of oxygen in the combustion air becomes a molecule of carbon dioxide in the flue gas. This means that the stoichiometric combustion of carbon will produce 21% by volume CO_2.

Considering for the moment that hydrocarbon fuels consist only of carbon and hydrogen, as the carbon : hydrogen ratio of the fuel decreases the stoichiometric air-to-fuel ratio will increase.

This is because 1 kg carbon requires 32/12=2.67 kg of oxygen for complete combustion but 1 kg hydrogen requires 8 kg oxygen.

The percentage CO_2 in the flue gases will fall as the carbon to hydrogen ratio in the fuel decreases as

1. less carbon dioxide will be produced per kilogram of fuel, and
2. the increased air requirement means that the carbon dioxide produced will be diluted by the extra nitrogen in the flue gas.

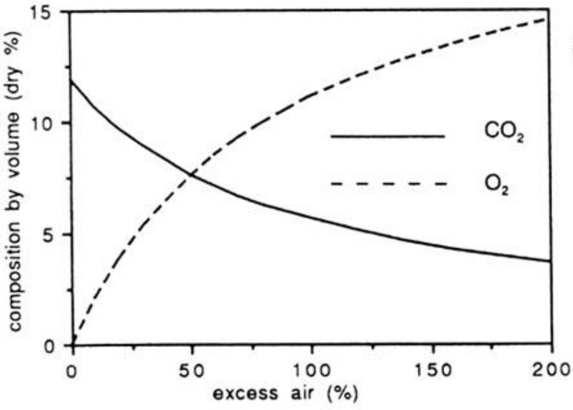
This effect is illustrated in Exhibit C-1. The carbon to hydrogen ratio in fuels lie between the limits of 75:25 (methane) to around 95:5 (high carbon coals).

Exhibit C-1: Carbon Dioxide Concentration in Flue Gases

C	:	H (by Mass)	Stoichiometric % CO2
100	:	0	21.00
95	:	5	18.67
90	:	10	16.62
85	:	15	14.81
80	:	20	13.19
75	:	25	11.73
70	:	30	10.42
65	:	35	9.23

There is a unique relationship between the composition of the flue gas and the excess air for any given fuel.

Exhibit C-2: Flue Gas Composition for Natural Gas

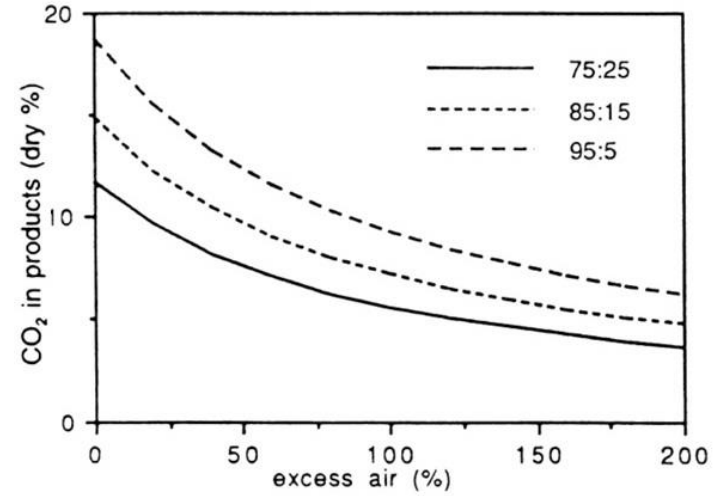


Constituent	% by vol.
CH_4	92.6
C_2H_6	3.6
C_3H_8	0.8
C_4H_{10}	0.2
C_5H_{12} (and higher)	0.1
CO_2	0.1
N_2	2.6

A plot of the percentage CO_2 in the flue gases over a range of values of excess air for C:H ratios ranging from 75:25 to 95:5.

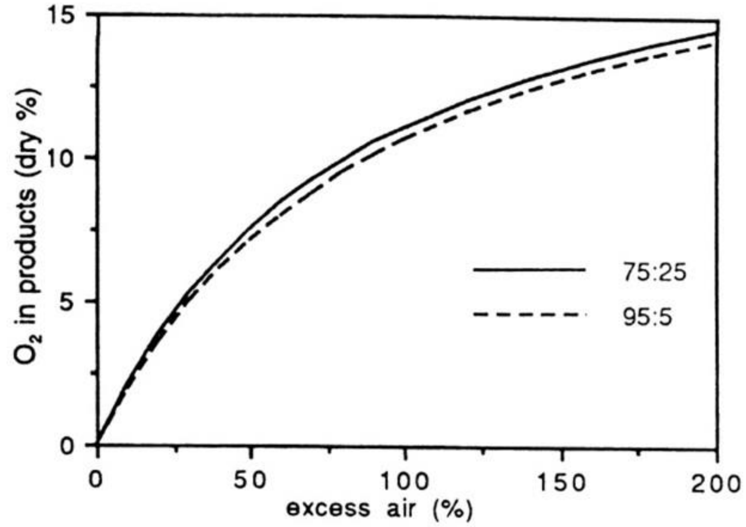
The curves for fuels with higher C:H ratios lie above those for fuels with a lower value of this ratio.

Exhibit C-3: Carbon Dioxide in Combustion Products



The relationship between the percentage oxygen in the flue gas and the excess air is very similar for a wide range of fuels. This is different from the CO_2 curves.

Exhibit C-4: Oxygen in combustion products



Take the combustion of two "extreme" cases: one kg mole of carbon and one kg mole of methane. In each case we will consider 100% excess air.

The combustion of carbon under these conditions is described by:

$$C + 2\,O_2 + 7.52\,N_2 \rightarrow 1\,CO_2 + 1\,O_2 + 7.52\,N_2$$

The percentage of oxygen in the flue gas is thus:

$$\frac{1}{1 + 1 + 7.52} \times 100 = 10.5\%\ \text{Oxygen}$$

The corresponding equation for methane is:

$$CH_4 + 4\,O_2 + 15.05\,N_2 \rightarrow 1\,CO_2 + 2\,H_2O + 2\,O_2 + 15.05\,N_2$$

It gives a percentage of oxygen:

$$\frac{2}{1 + 2 + 15.05} \times 100 = 11\%\ \text{Oxygen}$$

C.7 Sub-stoichiometric Combustion

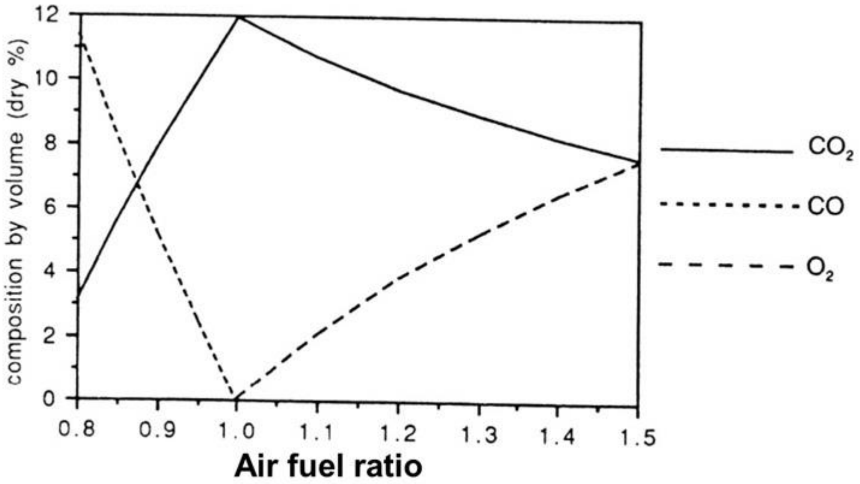
There are circumstances in which localized fuel-rich combustion can take place, such as where combustion of the fuel is a two-stage process with secondary air added downstream of the primary combustion zone.

The mechanism of combustion of a fuel with less than the stoichiometric air requirement consists of the following sequence of events:

1. The available oxygen firstly burns all the hydrogen in the fuel to water vapor.
2. All the carbon in the fuel is then burned to carbon monoxide.
3. The remaining oxygen is consumed by burning carbon monoxide to carbon dioxide.

It can be seen that as the air supply falls below the stoichiometric requirement the percentage of carbon monoxide in the flue gas increases very quickly.

Exhibit C-5: Sub-stoichiometric combustion of natural gas



Example 3: Combustion of a Fuel under Sub-Stoichiometric Conditions

Estimate the wet and dry flue gas composition if propane is burned with 95% of the stoichiometric air requirement.

Solution:

The stoichiometric reaction for this fuel is:

$$C_3H_8 + 5\ O_2 \rightarrow 3\ CO_2 + 4\ H_2O$$

On a volumetric basis we have (5 × 0.95) = 4.75 volumes of O_2 available. This means that the accompanying nitrogen is 17.87 volumes.

Firstly all the hydrogen in the fuel is burned to water. This will produce 4 volumes of water vapor and consume 2 volumes of oxygen, leaving 2.75 volumes for further combustion of the carbon in the fuel.

It is assumed that all the carbon initially burns to carbon monoxide and then the remaining oxygen is used in burning the carbon monoxide to carbon dioxide.

Burning the carbon to CO will produce 3 volumes of CO and use up 1.5 volumes of oxygen, leaving (2.75-1.5)=1.25 volumes of oxygen for further combustion.

Next reaction is:

$$1\ CO + \tfrac{1}{2}\ O_2 \rightarrow 1\ CO_2$$

So, 1.25 volumes oxygen can burn 2.5 volumes of carbon monoxide, producing 2.5 volumes of carbon dioxide.

The remaining carbon monoxide is therefore (3-2.5) = 0.5 volume.

The products of combustion are thus:

Product	Volumes	% Wet	% Dry
Nitrogen	17.87	71.9	85.6
Carbon monoxide	0.5	2.0	2.4
Carbon dioxide	2.5	10.0	12.0
Water	4.0	16.1	-
Total	**24.87**	**100**	**100**

Appendix-D Energy Conservation Opportunities in Boiler Operations (Worked Example)

D.1 Introduction

In the preceding chapters various aspects of efficient boiler operation have been discussed in detail. The discussions have identified a number of areas where significant energy savings could be made by an observant boiler engineer. A summary of these energy saving opportunities is presented in Exhibit D-1: Energy conservation opportunities in boiler operations.

Most of these opportunities offer quick paybacks on the investment made. However, some are more capital intensive than others, and all should be carefully evaluated for the particular condition of each boiler installation. Simpler and more cost effective measures-should obviously be implemented first; the returns from these simple and low cost measures can then be ploughed back into the more cost intensive measure to bring the boiler to its maximum efficiency.

D.2 Worked Example

In order to explain the various energy-saving opportunities and their possible interaction, a worked example is given below. The data and calculations forms (Exhibits 5-8 – 5-12) have been used to demonstrate the method of filling in the forms.

D.2.1 Boiler Description

In any boiler survey, the first thing is to become familiar with the boiler plant, to find what facilities are available e.g. type of boilers, fuel fired, water treatment etc. This example covers a package water tube boiler rated at 10 tonnes/h, providing saturated steam at 16 bar (235 psi). The boiler is fired by natural gas. Exhibit D-2: (Case Study) (Exhibit 5-8: Boiler Details) is an example of the kind of data collected on this boiler.

D.2.2 Boiler Data Collection

The next step is to collect the necessary data for boiler efficiency analysis. It includes the flue gas analysis, boiler loading, percentage of condensate returned, fuel consumed, boiler surface temperatures and analysis of dissolved solids in make-up, feed, and blowdown water. Exhibit B.3 gives the details of the actual data collected for the worked example. This data forms the basis for boiler efficiency calculation. Information regarding the calorific value of the fuel can be obtained from energy bills or from the supplier. In addition to this information, data regarding the boiler operating hours, fuel cost and consumption need to be obtained.

Observations regarding boiler operating practices likely to effect the boiler efficiency need to be recorded. This is an important procedure, and involves more than simply filling out a form: actual observations of boiler conditions and operations must be recorded. Exhibit B.4 shows the kind of information that is likely to influence boiler operation.

The example refers to a boiler fired by natural gas, therefore not all the information in the standard exhibits (Exhibits 5-8 – 5-12) is required. These exhibits can, of course, be adapted or simplified for data collection at any particular boiler plant.

D.3 Boiler Efficiency

To calculate boiler efficiency both procedures described in Chapter 5 have been used. Exhibit D-2, Exhibit D-3, Exhibit D-5, Exhibit D-6, and Exhibit D-7 (taken directly from Chapter 5) provide the data used in the calculations. Exhibit D-3 presents the basic data obtained for the efficiency calculation.

D.3.1 Excess Air

The excess air can be calculated from the formulas given in Equation 9, Exhibit D-6. A high excess air percentage indicates problems with the combustion system. In this case, excess air of 96.3% is much too high, and is wasting fuel.

D.3.2 Boiler Surface Heat Losses

The heat losses from the boiler are calculated based on boiler surface temperature measurements, and boiler geometry. The method described in Section 5.6 is used; Exhibit D-5 presents the procedure and calculations.

D.3.3 Blowdown

The percentage Blowdown (BD) used in Exhibit D-6 has been calculated from the equations given in Section 4.9:

$$\%\ \text{Blowdown} = \frac{S_f \times 100}{\left(S_b - S_f\right)}$$

Where S_f = TDS level of feedwater in ppm = 420
S_b = desired TDS level in boiler in ppm. = 2,000
Therefore, BD = 26.6 %

The heat loss due to blowdown, L_{BD} has been calculated in Exhibit D-6. In this case the blowdown heat loss is 6.25%. This is extremely high for a boiler at this pressure, and is due primarily to keeping the boiler TDS level lower than recommended for this type of boilers.

D.3.4 Other Losses

The other losses such as loss due to unburned carbon L_{CO} and radiation and convection losses, L_{RC} are also calculated from Equations 3 and 6 given in Exhibit D-6. It is also a common practice to include a fixed percentage for unaccountable losses. This loss is included to take into account factors such as purge losses, variation in firing rates etc. This loss is dependent on the age and condition of the boiler and can reduce the efficiency by 1 to 2 percentage points. For the present example these unaccountable losses have been ignored.

D.3.5 Overall Boiler Efficiency

$$E = 100 - L_{Total} = 100 - (L_{DG} + L_{H2O} + L_{RC} + L_{BD})$$
$$= 100 - (12.15 + 11.47 + 0.303 + 6.25) = 69.83\ \%$$

In this overall worked example (see Equation 7, Exhibit B.6), the losses amount to 30.17% and thus overall efficiency is 69.83%. Note that the dry flue gas losses (L_{DG}) and the moisture in flue gases (L_{H2O}) total to give the stack loss; in this case stack loss is 23.62%.

D.3.6 Boiler Efficiency Using the Graph Method

Although the equations given in Exhibit D-6 are fairly simple to perform, an even simpler method is to use the chart provided in Exhibit 5-4. From the given information of gas analysis i.e.:

O_2 : 10.3%
Flue gas temperature : 250°C
Ambient temperature : 37°C

Exhibit 5.5 gives:

Stack loss : 23.3%
Excess air : 87%

Adding blowdown loss of 6.25% and radiation and convection losses ^{L}RC of 0.303% (Exhibit B.7) gives the boiler efficiency, E as:

$$\begin{aligned} E &= 100 - (\%\ \text{stack loss} + \%\ \text{BD loss} + \%\ \text{R\&C loss}) \\ &= 100 - (23.3 + 6.25 + 0.303) \\ &= 70.15\ \% \end{aligned}$$

Comparison of this result with that of Section D.3.5 immediately above, illustrates an important point. There is a slight error in using the graph, compared to using the detailed equations. Nevertheless, the graphical method is much quicker and provides adequate results: the error is less than one half of one percent.

When the final calculations of savings based on efficiency improvements are performed, the error between equations and graphical results is minimized. **However, it is of utmost importance to consistently use the same method (whether graphical or by equations) for calculating efficiency to accurately measure efficiency losses or gains**.

D.3.7 Boiler Steam Production Rate

The present steam production rate can be calculated as follows:

Present fuel consumption : 27.79 GJ/h
Present boiler efficiency : 70.15%
Steam heat content at 16 kg/cm^2 : 2795.7 kJ/kg
Feedwater heat content at 55°C : 230.5 kJ/kg
Net heat required at boiler to produce steam : 2562.2 kJ/kg

$$\text{Steam Production} = \frac{27.79 \times 10^6\ \text{kJ}/\text{hr}}{2{,}565.2\ \text{kJ}/\text{kg}} \times 0.7015 \times \frac{\text{tonnes}}{1000\ \text{kg}} = 7.6\ \text{Tonnes}/\text{h}$$

Thus, at the so-called high fire, the boiler designed to produce 10 tonnes/h of steam is producing only about 7.6 tonnes/hr. As we have been informed, the boiler was originally designed for oil firing and later converted to gas firing. It is possible that the gas burner is of lower rating, and up-grading the burner could provide the company an increase in steam capacity without the cost of installation of a new boiler.

D.4 Opportunities for Boiler Efficiency Improvement

The calculations given in Section B.3 highlight a few noteworthy points:

(a) The boiler is operating on high excess air; with proper air/ fuel ratio control and burner adjustments, to the existing modern nozzle mix burner, the boiler should be able to operate with at most 20% excess air over the whole range of boiler operation, from low to high fire.

(b) The boiler's Blowdown TDS level is quite low. A boiler of this type can operate satisfactorily up to a maximum permitted level of 3,500 ppm.

(c) Although the cylindrical section of the boiler is well insulated, the front and back plates have high surface temperature and need to be insulated to reduce radiation and convection losses.

In this section, eight boiler efficiency recommendations are evaluated in detail. They are:

1. Reduce Excess Air
2. Reduce Blowdown
3. Reduce Surface Heat Losses
4. Improve Tube Cleaning/Maintenance
5. Reduce Steam Pressure
6. Install O_2 Trim System
7. Install Boiler Economizer
8. Recover Heat from Blowdown

D.4.1 Reduce Excess Air

D.4.1.1 Detailed Recommendation

The measures to be carried out include:

(a) Buy stack gas analyzers (CO_2 and/or O_2, and CO)

(b) Analyze stack gas daily and record

(c) Use analyzers to determine optimum air/fuel ratio settings for low to high fire; adjust settings. Carbon monoxide concentration should be adjusted to 100 - 200 ppm.

(d) Repair and/or replace components in burner

(e) Control air/fuel linkages to manufacturer's original specifications

(f) Operate at 20% excess air level.

D.4.1.2 Savings Calculation

The excess air level in the given example is around 90%, while with proper operational adjustments it could be reduced to around 20%. Assuming that the stack gas temperature will remain unchanged (250°C), the anticipated stack loss can be calculated following the procedure used in Exhibit D-6 by calculating oxygen percentage as follows:

$$\text{Excess air} = 20\% = \left[\frac{O_2}{21 - O_2}\right] \times 100$$

$$O_2 = 3.5\%$$

With this number, the new stack losses can be recalculated. Using the equation method, the new summary is presented' in Exhibit D-7; stack loss is equal to 19.07%.

The stack loss for 20% excess air condition can also be calculated by the graphical method (Exhibit 5-4) which gives, for 20% excess air and a stack temperature of 250°C, anticipated stack loss equal to 19.3%.

Savings are calculated based on annual fuel consumption and improvement in the efficiency (graphical method):

$$\% \text{ Fuel Savings} = \frac{\left(\dfrac{1}{\text{Old Efficiency}} - \dfrac{1}{\text{New Efficiency}}\right)}{\left(\dfrac{1}{\text{Old Effiency}}\right)}$$

$$\% \text{ Fuel Savings} = \frac{\left(\text{New Effiency - Old Efficiency}\right)}{\left(\text{New Efficiency}\right)}$$

From graphical method:

Old efficiency : 70.15%
New efficiency : 74.15%

$$\text{Fuel Savings} = \frac{74.15 - 70.15}{74.15} \times 100 = 5.4\%$$

Annual fuel consumption : 173,400 GJ/yr
Fuel savings : 9,364 GJ/yr
New reduced fuel consumption : 164,036 GJ/yr

D.4.1.3 Implementation Cost Estimate

Costs of implementation can be estimated as follows:

$$\text{Simple Payback period, years} = \frac{\text{Cost of Implementation, PKR}}{\text{Annual Savings, PKR / year}}$$

Cost of implementation will include, such as, the cost of TDS meter, and investment in repairing or upgrading the water treatment system' while the annual savings will be calculated based on the value of fuel saved.

D.4.2 Reduce Blowdown

D.4.2.1 Detailed Recommendation

The present blowdown TDS level of 2,000 ppm is well below the maximum permitted level of 3,500 ppm thus wasting valuable energy unnecessarily. In this case the recommendations should be:

(a) The dissolved solids in the boiler water should be monitored regularly (at least once per shift). For this purpose the plant should purchase a TDS meter.

(b) The frequency of blowdown should be decreased to control the dissolved solids in the boiler to around 3,500 ppm.

(c) The quality of make-up water could also be improved to reduce the necessary blowdown frequency even further, and thus reduce heat loss.

D.4.2.2 Savings Calculation

With the reduced blowdown we need to recalculate the anticipated heat loss due to blowdown. The percentage of blowdown would be:

$$\% \text{ Blowdown} = \frac{S_f \times 100}{\left(S_b - S_f\right)}$$

Where

S_f = TDS level of feed water in ppm = 420
S_b = New TDS level in boiler in ppm. = 3,500
Therefore, BD = 13.64%

The heat loss can be calculated by the equations used earlier and is given in Exhibit B.7 as 3.04%.

Old efficiency : 100 - 19.3 - 6.25 - 0.303 = 74.15%

New efficiency : 100 - 19.3 - 3.04 - 0.303 = 77.36%

Fuel savings : $\frac{(77.36\ -\ 74.15)}{77.36} \times 100$ = 4.1%

Annual fuel consumption : 164,036 GJ/yr
Fuel savings : 6,725 GJ/yr
New reduced fuel consumption : 157,311 GJ/yr

D.4.3 Reduce Boiler Surface Heat Losses

D.4.3.1 Detailed Recommendation

In percentage radiation and convection heat loss terms, this boiler could be regarded as well insulated (heat loss = 0.303%). However, the front and back plates have high surface temperature (Exhibit D-5).

Insulation of front and back plates should be improved on the inside. Refractory or calcium silicate insulation should be used.

D.4.3.2 Savings Calculation

Assume that insulating the front and back plates will reduce the heat loss by 80%, or to a maximum surface temperature of 55°C. The radiation and convection losses will then be as follows:

	Present Heat Loss, Watts	Heat Loss After Insulation, Watts
Front Plate	5,353	1,107
Back Plate	8,027	1,605
Cylindrical Section	10,027	10,047
Total	23,427	12,759

Loss as % of boiler heat input after insulation = 0.17%
Old efficiency : 100 - 19.3 - 3.04 - 0.303 = 77.36%
New efficiency : 100 - 19.3 - 3.04 - 0.17 = 77.49%
% fuel savings : $\frac{(77.49 - 77.36)}{77.49}$ = 0.17%
Annual fuel consumption = 157,311 GJ/yr
Fuel savings = 267 GJ/yr
New reduced fuel consumption = 157,044 GJ/yr

D.4.3.3 Implementation Cost Estimate

Typical present cost (2006) for insulating boiler plant internally is estimated at PKR 2,000/m^2. On this basis, insulation cost for 12.32 m^2 surface area becomes PKR 24,640. It gives a simple payback of only 6 months.

D.4.4 Improve Boiler Tube Cleaning/Maintenance

D.4.4.1 Detailed Recommendation

Boiler maintenance, cleaning the tubes of scale, also affects the boiler performance. In this example the flue gas temperature is fairly high, indicating problems with heat transfer. Scale formed on the tube surface can reduce the heat transfer to the boiler water. Not having had a chance to inspect the boiler internally, the recommendations should be:

(a) Inspection of boiler tubes at the time of next scheduled maintenance and clean the tubes, if necessary

(b) Conducting boiler maintenance at regular intervals as specified by the boiler manufacturer

Cleaning the tubes of scale can reduce the flue gas temperature. The actual drop in temperature will depend on the nature and thickness of scale. Here it is assumed conservatively that flue gas temperature will drop by 20°C.

D.4.4.2 Savings Calculation

Using the graphical method, assuming a new flue gas temperature of 230°C and ambient temperature of 37°C, the stack gas loss is found to be 18.3%.

Since the blowdown quantity will remain the same regardless of the reduced stack temperatures, the proportion of the blowdown loss to the total loss will increase.

This can be recalculated through Equation 6 in Exhibit D-6 and Exhibit D-7, but reduces to:

$$L_{BD,\,New} = L_{BD,\,Old} \times \frac{\left(100 - L_{New}\right)}{\left(100 - L_{Old}\right)}$$

$$L_{BD} = \frac{\left(81.53 \times 3.04\right)}{80.53} = 3.08$$

Old efficiency : $100 - 19.3 - 3.04 - 0.17 = 77.49\%$

New efficiency : $100 - 18.3 - 3.08 - 0.17 = 78.45\%$

% fuel savings : $\frac{\left(78.45 - 77.49\right)}{78.45} = 1.22\%$

Annual fuel consumption = 157,044 GJ/yr

Fuel savings = 1,916 GJ/yr

New reduced fuel consumption = 155,128 GJ/yr

D.4.4.3 Implementation Cost Estimate

The cost of a good cleaning of boiler tubes, whether mechanical or chemical or both can vary widely from boiler to boiler. In this particular case, the cost of cleaning is estimated at PKR50,000, including chemicals, labor, and reduced output of the standby boiler:

Simple payback period is, therefore, estimated at 1.6 months.

D.4.5 Reduce Steam Pressure

D.4.5.1 Detailed Recommendation

The information collected (Exhibit D-4) shows the plant requires steam at 8kg/cm^2. The boiler is producing steam at 16 kg/cm^2. Allowing for pressure drops in the steam distribution system, it may be possible to reduce the boiler pressure to 10 kg/cm^2.

Possible problems that occur when reducing the boiler pressure are (i) increased carryover of water (and chemicals) into the steam lines and (ii) reduced capacity of the steam distribution system. For these reasons, pressure should be reduced 1 bar at a time, over a period of weeks. The system should be carefully monitored to ensure that carryover and capacity, as well as boiler operation are not a problem.

D.4.5.2 Savings Calculation

Savings from pressure reduction results from decreased steam generation and distribution temperatures which reduce the heat losses. The savings can be estimated using Exhibit 4-11 of the manual.

From Exhibit 4-11, an efficiency improvement of 0.9% can be read off the chart. It can be interpreted as a 0.9% reduction in losses from the steam distribution system. It is important to note that the “efficiency” referred to in Exhibit 4-11 is not the boiler efficiency but an overall steam utilization efficiency.

The savings estimate is as follows:

Reduction in losses = 0.9%
Reduction in fuel at the boiler : 0.9 / 78.45 = 1.15%
% fuel savings = 1.15%
Annual fuel consumption = 155,128 GJ/yr
Fuel savings = 1,783 GJ/yr
New reduced fuel consumption = 153,345 GJ/yr

Thus, fuel is saved, although boiler efficiency remains constant at 78.45%.

D.4.5.3 Implementation Cost Estimate

There is no cost for this measure. If the steam users can use the lower pressure, and the distribution system can supply adequate steam, the savings and payback are immediate.

D.4.6 Install O_2 Trim System

D.4.6.1 Detailed Recommendation

Purchase and install an automatic on-line oxygen trim control system. The stack-mounted oxygen analyzer should be connected to the control system for the modulating burner.

D.4.6.2 Savings Calculation

With the gas burner in good condition, after the recommendations in D.4.1, the O_2 trim control system should enable the boiler to operate at an average excess air of 10%. Using the graphical method, referring to Exhibit 5-4, the new stack loss will be 17.5%. As in D.4.4.2, the blowdown loss will change slightly:

L_{BD} : $\frac{(82.33 \times 3.08)}{81.53}$ = 3.11%
Old efficiency : 100 – (18.3 + 3.08 + 0.17) = 78.45%
New efficiency : 100 – (17.5 + 3.11 + 0.17) = 79.22%
Annual fuel consumption : = 153,345 GJ/yr
Fuel savings : = 1,487 GJ/yr
New reduced fuel consumption : = 151,858 GJ/yr

D.4.7 Install Boiler Economizer

D.4.7.1 Detailed Recommendation

Size, design and install a boiler economizer to preheat boiler feedwater at boiler pressure just before entering the boiler. The economizer should be sized to give a flue gas outlet temperature of approximately 150°C (300°F). The economizer should be of finned tube design, with entering feedwater temperature of 55°C (131°F).

D.4.7.2 Savings Calculation

The savings calculation can be performed in either of two ways: (1) the heat recovered can be calculated based on the exhaust gas flow (assuming 10% excess air compared to stoichiometric firing) and the temperature difference (230°C – 150°C) across the economizer, or (2) via the graphical method using Exhibit 5.4 using 150˚C as the final flue gas temperature at 10% excess air. The latter method is used below.

Again, the level of blowdown will not change, so its proportion must go up.

L_{BD} : $\frac{(85.43 \times 3.11)}{82.33}$ = 3.23%
Old efficiency : 100 – (17.5 + 3.11 + 0.17) = 79.22%
New efficiency : 100 – (14.4 + 3.23 + 0.17) = 82.20%
% fuel savings : $\frac{(82.20 - 79.22)}{82.20}$ = 3.6%
Annual fuel consumption = 151,858 GJ/yr
Fuel savings = 5,477 GJ/yr
New reduced fuel consumption = 146,381 GJ/yr

D.4.7.3 Implementation Cost Estimate

The cost of a typical economizer for a boiler of similar duty has been quoted as PKR700,000. Assuming installation and start-up costs of PKR50,000, the total cost estimate is PKR750,000. The simple payback based on savings of PKR1.024 million is 9 months.

Before pursuing the economizer purchase and installation, a more thorough design or feasibility study should be conducted. Payback or rate of return calculations should be performed for a series of different capacity economizers at different costs, in order to determine the size with the optimum economic value for this project.

D.4.8 Recover Heat from Blowdown

D.4.8.1 Detailed Recommendation

A blowdown heat exchange system should be purchased and installed on the continuous blowdown line from the boiler. A system which will recover heat from both flash steam and blowdown water is recommended. A system such as pictured in Exhibits 9-7 or 9-8 is recommended; blowdown heat should be used to preheat cold make-up water for the boiler.

D.4.8.2 Savings Calculation

A detailed savings calculation can only be performed once the exact specifications of the heat recovery system as determined. An estimate can be made by assuming that a properly designed heat exchange system can recover 60% of the available heat.

At 60% recovery, the blowdown losses will only be:

L_{BD} = 1.29%

Old efficiency : 100 – (14.4 + 3.23 + 0.17) = 82.20%
New efficiency : 100 – (14.4 + 1.29 + 0.17) = 84.14%
% fuel savings : $\frac{(84.14 - 82.20)}{84.14}$ = 2.3%
Annual fuel consumption = 146,381 GJ/yr
Annual fuel savings = 3,367 GJ/yr
New reduced fuel consumption = 143,014 GJ/yr

D.4.8.3 Implementation Cost Estimate

The cost of a heat exchange unit along with associated control and piping to recover heat from both flash steam and hot blowdown water will be estimated including installation. Accordingly, the simple payback of this measure will be calculated for the cost of fuel saved.

D.5 Notes on the Calculations

As with all calculations, assumptions must be clearly described in order to understand the applicability and accuracy of the calculation. This section offers some general comments on the calculations.

The calculations in Section D.4 have been carefully prepared in order to reflect as accurately as possible the actual savings that would occur as a result of each recommendation. Nevertheless, due to necessity of assumptions, real world differences from theory, the complexity of interactions in a boiler, and limitations of time, the calculations still only represent estimates of savings. The following notes further explain the method, accuracy, and limitations of the calculations.

D.5.1 Effect of Excess Air on Stack Temperature

Regarding recommendation D.4.1, reduce excess air, it has been shown in theory and practice that a reduction in excess air also tends to decrease the stack gas temperature. This is due primarily to higher flame temperature which improves radiation heat transfer rates in the initial part of the boiler. Since this will be different for each boiler, dependent on flow and heat transfer configuration, no estimate is ventured in this calculation. The effect could be to actually increase the savings from this recommendation (although the savings from recommendation D.4.4 might then be slightly reduced).

D.5.2 Losses as Percent of Total Heat Input

In Section B.4.4 a correction was made to the blowdown loss; since it stayed the same while the total heat input was reduced, the percentage of loss was actually higher. This same correction should have been made to the radiation and convection losses which are also independent of the total heat input. Since these losses are very small the correction was not made.

D.5.3 Steam Pressure Effect on Boiler Efficiency

In Section D.4.5, the reduction in steam pressure caused savings in the steam distribution system, which reduced the boiler fuel input. It was stated that the boiler efficiency remained unchanged. In actuality, the same effect that a lower steam pressure has on the steam lines, it has on the boiler itself. Due to lower temperature of steam, the overall operating temperature of the boiler is slightly lower and exhaust gas temperature may be slightly lower. However, these effects are very small, perhaps even not measurable in operation. In any case, they are small compared to steam distribution savings. It was therefore assumed that boiler efficiency remained essentially the same.

D.5.4 O_2 Trim Attractiveness

The savings from the O_2 trim installation was estimated simply as a reduction in excess air. While this is a clear and calculable benefit, another important benefit of O_2 trim control in many boilers is the following. In a boiler whose load fluctuates of ten, the control system is always trying to keep up. While a good parallel positioning control can maintain 20% excess air at full fire, it cannot always keep up under fluctuations, and during this period excess air may go up significantly before the control point stabilizes again. In some boilers, this loss of efficiency is included as "unaccountable loss", and in reality, it cannot be accurately estimated. If however, this loss were approximately 1%, the installation of the O_2 trim system could bring it down significantly, to say 0.2 or 0.3%.

D.5.5 Blowdown Heat Recovery

In Recommendation D.4.8, a percentage of the blowdown loss was taken as potentially recoverable. It should be remembered, however, that the blowdown loss was calculated relative to the feedwater temperature of 55°C. If a blowdown heat recovery system were to be installed, it would be more economical to use makeup water at 30°C rather than the warmer feedwater as the cold side fluid. In this case, the heat recovery could be as much as 15% higher than calculated in D.4.8.2.

D.6 Summary

The various recommendations given in this appendix are some of the ways to conserve energy and save money by operating the boiler more efficiently. These are only a few of the methods listed in Exhibit D-1. The financial viability of these other methods can be checked, and if found attractive, considered for implementation.

An impressive and attractive program has been developed for the example boiler (see Exhibit B.8). Savings of PKR 1.1 million can be obtained with a payback of less than one year. The boiler efficiency increases by 14%, from a low of 70.15% to 84.14%.

Exhibit D-1: Energy conservation opportunities in boiler operations

	Energy Conservation. Measure	Refer to Chapter
1	Adjust (tune-up) burners for optimal air fuel ratio	4.1, 7.4, 7.5
2	Monitor boiler efficiency and improve control capability	6; 11
3	Install boiler insulation or upgrade to optimal thickness	4.11, 5.6
4	Repair faulty insulation in boilers	4; 5
5	Use warmest room air for combustion air	
6	Establish burner maintenance schedule	11.3
7	Minimize boiler blowdown with better feedwater treatment	8
8	Heat oil to proper temperature for good atomization	
9	Keep boiler tubes clean, both fireside and waterside	4.4, 4.8
10	Reduce steam pressure if allowed by the process requirements	4.10
11	Use air instead of steam for oil atomization	7.2.1, 7.2.2
12	Install turbulators in fire tubes	
13	Recover heat from boiler blowdown to preheat boiler feedwater	4.9.4, 9.3
14	Use hot flue gases to preheat boiler feedwater	9.2
15	Use hot flue gases to preheat combustion air	9.2
16	Use hot flue gases to heat process or service hot water	9.2
17	Add automatic (0 =trim) control	7.5.6
18	Replace obsolete burners with more efficient ones	7
19	Replace obsolete boiler	
20	Replace and upgrade equipment	

Exhibit D-2: (Case Study)
(Exhibit 5-8: Boiler Details)

Company Name:	ABC Chemicals	Date: 08/09/04
Location:	Karachi	
Nameplate Data:	(1)	(2)
Boiler No.		
Manufacturer	Trane	
Date Commissioned	1970	
Model No.	2357	
Type	Water tube package	
Medium used	Steam	
Rating (kg/hr)	10,000	
Operating Pressure (kg/cm2)	16	
Operating temp. (^{o}C)	204	
Burners		
No. of Burners	1	
Fuel fired	Nat. Gas	
Burner Manufacturer	Ray	
Burner type	Nozzle mix	
Atomization	----	
Fuel control system	Auto / Manual	
Draft control system	----	

Exhibit D-3:
(Exhibit 5-9: Operating Data – Boiler Tests)

Fuel			
Gross heating value	kcal/kg	CV_G	*13,264*
Net heating value	% wt	CV_N	
Carbon in fuel	% wt	C_{fuel}	*75%*
Hydrogen in fuel	%	H_{fuel}	*25%*
Water in fuel	%	H_2O_{fuel}	---
Oil:			
Fuel preheat temperature	°C	T_{fuel}	---
Flue gas:			
Exit temperature	°C	T_{FG}	*250*
Ambient temperature	°C	T_A	*37*
Oxygen content (dry basis)	% vol.	O_2	*10*
Carbon monoxide content	% vol.	CO	*0.0*
Max. theor. CO_2 in dry flue gas		$(CO_2)_{MAX}$	*11.7*
Smoke number			---
Blowdown:			
Temp. after heat recovery	°C	T_{BD}	*204*
Quantity (% wt of Feedwater)		BD	*26.6 %*
Feedwater temperature	°C	T_{H2O}	*55*
Other			
Radiation and convection loss (% of gross heat release)		L_{RC}	*Exh. B-6*
Gases at combustion chamber outlet	°C		*250*
Gases after economizer	°C		--
Condensate return temperature	°C		*98*
Water to economizer	°C		--
Water from economizer	°C		--
Make-up water temperature	°C		*30*
Total dissolved solids			
Boiler water	ppm		*2,000*
Feedwater	ppm		*420*
Condensate	ppm		*25*
Make-up water	ppm		*650*
Fuel			
Fuel flow rate	kg/h		--
Water flow rate	kg/h		--

Exhibit D-4: Background information

Operating Hours:	The plant operates 24 hours a day, 5 days a week, 52 weeks every year giving 6240 hours of operation in a year
Price of Fuel:	PKR187/GJ
Observations:	The boiler is operated with a continuous blowdown. The feedwater tank is not insulated There are no gas analyzers for flue gas analysis and the boiler water quality is also not analyzed The company is short of steam and needs at least 1000 Kg/hr more steam to meet plant requirement. The company is considering installation of one more boiler to meet steam requirement The boiler was originally designed for furnace oil firing but due to cheaper cost of natural gas was converted to natural gas in 1974. Although mechanical linkages between air and fuel supply lines exist, they are fairly worn out. No proper records are being kept of the boiler operation. Maximum pressure at which the steam is being used in the plant is 8 kg/cm^2.
Annual fuel consumption:	173,400 GJ/yr
Hourly fuel consumption:	27.79 GJ/hr

Exhibit D-5: Heat Loss Calculations

(Exhibit 5-12: Boiler Heat Loss Calculations)

Boiler No. 1 Date of test 08/09/04 Time of test 12:45p.m.

Ambient temperature 37^{o}C + 273 = 310^{o}K (T_A)

Parameter	Symbol/Formula	*Front Plate*	*Back Plate*	*Cylindrical Section*
Area, m^2	A_S	*6.16*	*6.16*	*58.94*
Surface temperature, °C	t_S	*104*	*128*	*55*
Surface temperature, °K	$T_S + 273 = T_S$	*377*	*401*	*328*
Temp. Difference, ^{o}K	$T_S - T_A$	*67*	*91*	*18*
Emissivity	E	*0.95*	*0.95*	*0.95*
Radiation coefficient, Watts / m^2 ^{o}K	$U_R = 5.67\ E \times \left(\dfrac{\left(\dfrac{T_S}{100}\right)^4 - \left(\dfrac{T_A}{100}\right)^4}{(T_S - T_A)} \right)$	*8.82*	*9.84*	*7.0*
Flow type	S = Streamline, T = Turbulent			
Shape factor	B (see table below)	*1.45*	*1.45*	*1.2*
Shape factor	D (see table below)	*1.0*	*10*	*1.0*
Convection coefficient, Watts / m^2 ^{o}K	$U_C = \dfrac{B \times (T_S - T_A)^{0.25}}{D^{0.25}}$	*4.15*	*4.48*	*2.47*
Overall coefficient, Watts / m^2 ^{o}K	$U_S = (U_R + U_C)$	*12.97*	*14.32*	*9.47*
Heat loss, Watts	$Q = U_S \times A \times (T_S - T_A)$	*5,353*	*8,027*	*10,047*
Total heat loss, Watts			*23,427*	
Heat input, Watts	H_{IN} = fuel rate x gross cal. value			
Loss as % of boiler input	$\dfrac{Q}{H_{IN}} \times 100$		*0.303*	

For stream line flow			For turbulent flow		
D is the significant dimension (mm)			For D>500 mm assume turbulent flow: the value of D becomes 1 in the same equation		
	D	B		D	B
Vertical cylinder, large plane	Height	1.35	Vertical planes, large cylinders	1	1.45
Horizontal planes, face up	Side	1.30	Horizontal planes	1	1.70
Horizontal planes, face down	Side	0.60	Horizontal cylinders	1	1.20
Horizontal cylinders, small vertical cylinders	dia	1.15			

Exhibit D-6
(Exhibit 5-11: Boiler Loss Calculations - Gas or Liquid Fuels)

Boiler Identification TRANE Date of test 08/09/04 Time of test 12:30 p.m.

(Losses expressed as percent fuel fired, gross basis)

	Loss	Formula	*Result*
1	L_{DG} Dry flue gas	$\frac{K \times (T_{FG} - T_A)}{CO_2}$	*12.15*
1'		$CO_2 = \left[1 - \left[\frac{O_2}{21}\right]\right] \times (CO_2)_{MAX}$	*5.96*
1"		K from tables or $K = \frac{69.7 \times C_{fuel} \times (CV_N)^2}{(CV_G)^3}$	*0.34*
2	L_{H2O} Moisture in flue gas	$\frac{(H_2O_{fuel} + 9\ H_{fuel}) \times (588 - T_A + 0.50\ T_{FG})}{CV_G^1}$	*11.47*
2'		$CV_G^1 = CV_G$ for coal, gas (no preheat) $CV_G^1 = CV_G + (T_{fuel} - T_A) \times 0.47$ (for oilwith preheat)	*13,264 kcal/kg*
3	L_{CO} Unburned co	$\frac{K \times (CO)}{(CO) + (CO_2)}$	*0*
4	L_{RC} Radiation and Convection	$\frac{100}{(CAP)}$ or calculate from surface temperatures	*0.303*
5	L	$L_{DG} + L_{H_2O} + L_{CO} + L_{RC}$	*23.92*
6	L_{BD} Blowdown Losses	$\frac{(T_{BD} - T_{H_2O}) \times (BD) \times [100 - (L)]}{[(T_{BD} - T_{H_2O}) \times (BD)] + [100 - (BD)] \times [660 - T_{H_2O}]}$	*6.25*
7	L_{TOTAL} Total losses	L + L_{BD}	*30.17*
8	Efficiency η	100 - L_{TOTAL}	*69.83*
9	Excess air	$\left[\frac{(CO_2)_{MAX}}{CO_2} - 1\right] \times 100$ or $\left[\frac{O_2}{21 - O_2}\right] \times 100$	*96.3*

Exhibit D-7:
(Exhibit 5-11: Boiler Loss Calculations (Gas or Liquid Fuels)

Boiler Identification TRANE Date of test 08/09/04 Time of test 12:30 p.m.

(Losses expressed as percent fuel fired, gross basis)

(Reduction to 20% excess air, reduced heat and blowdown losses)

	Loss	Formula	*Result*
1	L_{DG} Dry flue gas	$\frac{K \times (T_{FG} - T_A)}{CO_2}$	*7.43*
1’		$CO_2 = \left[1 - \left[\frac{O_2}{21}\right]\right] \times (CO_2)_{MAX}$	*9.75*
1”		K from tables or $K = \frac{69.7 \times C_{fuel} \times (CV_N)^2}{(CV_G)^3}$	*0.34*
2	L_{H2O} Moisture in flue gas	$\frac{(H_2O_{fuel} + 9 H_{fuel}) \times (588 - T_A + 0.50 T_{FG})}{CV_G^1}$	*11.47*
2’		$CV_G^1 = CV_G$ for coal, gas (no preheat) $CV_G^1 = CV_G + (T_{fuel} - T_A) \times 0.47$ (for oilwith preheat)	*13,264 kcal/kg*
3	L_{CO} Unburned co	$\frac{K \times (CO)}{(CO) + (CO_2)}$	*0*
4	L_{RC} Radiation and Convection	$\frac{100}{(CAP)}$ or calculate from surface temperatures	*0.17*
5	L	$L_{DG} + L_{H_2O} + L_{CO} + L_{RC}$	*19.07*
6	L_{BD} Blowdown Losses	$\frac{(T_{BD} - T_{H_2O}) \times (BD) \times [100 - (L)]}{[(T_{BD} - T_{H_2O}) \times (BD)] + [100 - (BD)] \times [660 - T_{H_2O}]}$	*3.04*
7	L_{TOTAL} Total losses	L + L_{BD}	*22.11*
8	Efficiency η	100 - L_{TOTAL}	*77.89*
9	Excess air	$\left[\frac{(CO_2)_{MAX}}{CO_2} - 1\right] \times 100$ or $\left[\frac{O_2}{21 - O_2}\right] \times 100$	*20.0*

Exhibit D-8: Boiler Example Savings Summary

Energy Conservation Recommendation	Percent Improvement in Boiler Efficiency	Annual Savings (PKR)	Implementation Cost Estimate (PKR)	Payback (Months)
Reduce excess air	4.00	1,751,000	210,000	1.4
Increase blowdown	3.21	1,263,000	30,000	0.3
Improve insulation	0.13	50,000	24,640	6.0
Reduce pressure	-	333,421	-	0
Improve maintenance	0.96	358,292	50,000	1.6
Install O_2 - trim	0.77	278,069	900,000	38.0
Install. economizer	2.98	1,024,000	700,000	9.0
Recover blowdown heat	1.94	629,619	560,000	11.0
Total	13.99	5,687,411	2,474,640	5.2

Appendix-E   Boiler Control Parameters

Boiler manufacturers usually recommend the control limits for their boilers and these recommendations should be implemented in practice.

The general recommendations from different authorities for shell type (smoke tube) and water tube type boilers provide guidelines for operating the boiler under the best possible working conditions. The characteristics recommended in Exhibit E-1, Exhibit E-2, and Exhibit E-3 for boiler waters and the feedwaters represent the limits or the ranges of conditions that should exist following the correct application and control of appropriate water treatment.

The large number of parameters precludes presentation in other than tabular form but it would be misleading to read the values as if they were 'ideal' water analyses. The tables indicate the trend of the recommended parameters whether they result from a natural impurity or from the addition of treatment chemicals. Where single values of limits are shown they represent points in a continuous series and have no other special significance.

E.1 Shell Boilers

E.1.1 Recommended Characteristics

The recommendations in Exhibit E-1 apply to high efficiency shell (fire-tube) boilers operated under design conditions. In view of the great variety of boiler designs in this category it is not possible to stipulate the precise feedwater characteristics required for all boilers.

The advice of the boiler manufacturer should be obtained with regard to the maximum limit recommended for suspended solids, and hence for feedwater hardness, that may be tolerated in the particular type of boiler employed, taking into consideration the following factors:

- Boiler design;
- Blowdown facilities including those of the water level controls;
- Intermittent operation;
- Operation of the boiler at less than the design pressure.

Limit may be increased or decreased by factors 1 and 2 but can only be decreased by factors 3 and 4.

The values given in Exhibit E-1 under the various levels of feedwater hardness take into consideration the collective effect on steam purity of dissolved solids, alkalinity, and suspended solids produced as a result of hardness precipitation. Because of these variations in boiler tolerance to feedwater hardness and suspended solids, Exhibit E-1 is divided into three categories which cover three qualities of feedwater. These are 2 mg/l hardness as, for example, from sodium ion exchange softening; 20 mg/l hardness as from a lime-soda softener; and 40 mg/l hardness as from an un-softened supply. These water qualities may also arise from other treatments or by mixing waters of suitable qualities.

Where the feedwater hardness is likely to be in excess of 40 mg/l, expressed in terms of $CaCO_3$, the raw makeup water should be treated by external methods.

E.1.2 Comments on Exhibit E-1

When applying the recommendations in Exhibit E-1 the following additional comments are also relevant:

1. **Feedwater hardness:** Boilers with high output relative to water content and/or employing high heat flux density usually require feedwater of low hardness, not only to avoid scale formation on heat transfer surfaces but also to minimize the formation of suspended solids or sludge in the boilers. Consequently water with the characteristics given for the 2 mg/l category of Exhibit C.1 should be used in these situations.
2. **Oxygen:** Dissolved oxygen in the feedwater should be reduced to the lowest practicable level before adding an oxygen scavenger.

   Hydrazine is recommended as an alternative to sodium sulfate only when it is dosed to the feedwater at a substantial distance from the boiler and where the feedwater is sufficiently hot to enable the removal of oxygen to be 90% complete before entry to the boiler.

   Caution: Hydrazine is toxic, and suitable precautions for its handling should be observed. Its use is usually prohibited in hospitals, food manufacturing industry, and where steam may come into contact with food or beverages. The use of sodium sulfite may also be unacceptable in some of these applications. The existence of any regulations governing the use of either should be ascertained and they should be observed.
3. **Solids, alkalinity and silica in feedwater:** The concentrations of these constituents in the feedwater should not be so high as to require blowdown of boiler water in quantities exceeding the boiler design value or exceeding the feed pump capacity.
4. **Organic matter:** Organic matter other than oil may be innocuous in a boiler depending on the temperature of operation and the amount and type of the organic matter.

   Maximum values that would be universally applicable cannot be stated, and the operator should therefore be alert to the operating difficulties that may be associated with the presence of organic matter; such as:

   - Interference with heat transfer, usually attributable to the presence of organic matter that is immiscible with water, e.g., hydrocarbons.
   - Foaming, attributable to organic surface-active agents.
   - Diminished alkalinity, attributable to thermal decomposition of organic matter to acidic compounds.
   - Impairment of steam purity, attributable to thermal decomposition of organic matter to volatile compounds. This is especially important where steam is used directly in processing food, pharmaceuticals or beverages.
   - Modification of suspended solids to form adherent deposits or intractable sludges.

     Where such difficulties can be positively associated with the presence of organic matter a practical limit to its amount should be set if it is not possible to eliminate the contamination. Some amelioration may be gained by the rejection of contaminated condensate, by extra blowdown, or by washing out the boiler.
   -
5. **Carbonate and phosphate control:** If a minimum carbonate alkalinity of 250 mg/l expressed in terms of $CaCO_3$ is consistently maintained when carbonate control or sodium ion exchange softening is used, a reserve of soluble phosphate need not be maintained. A residual of soluble hardness, up to 5 mg/l expressed in terms of $CaCO_3$, is then usually found in the boiler water but scale formation may be minimized by conditioning treatment. Polymers may act as weak chelating agents and thus retain hardness salts in solution in boiler water. In this event the hardness as determined by EDTA methods is measurable and particular attention should then be given to maintaining the recommended level of carbonate or phosphate. In appropriate circumstances chelating agents may be used in place of phosphate.
6. **Suspended solids:** These figures represent theoretical values, and are not necessarily measurable in practice. They can be used as one basis for calculating boiler blowdown requirements, based on the actual feedwater hardness.

Exhibit E-1: Recommended water characteristics for shell boilers

For Pressures up to 25 bar[1], Total Hardness in Feed Water, mg/l in Terms of $CaCO_3$ max.	2	20	40

Feed Water

pH value	7.5 to 9.5	7.5 to 8.5	7.5 to 9.5
Oxygen	[2]	[2]	[2]
Total solids, alkalinity, silica	[2]	[2]	[2]
Organic matter	[2]	[2]	[2]

Boiler Water

Total hardness, mg/l in terms of $CaCO_3$ max.	ND[3]	ND[3]	ND[3]
Sodium phosphate, mg/l as Na_3PO_4[4]	50 to 100	50 to 100	50 to 100
Caustic alkalinity, mg/l in terms of $CaCO_3$ min.	350	300	200
Total alkalinity, mg/l in terms of $CaCO_3$ max.	1,200	700	700
Silica, mg/l as SiO_2 max.	Less than 0.4 of the caustic alkalinity		
Sodium sulfite, mg/l as Na_2SO_3 or	30 to 70	30 to 70	30 to 70
Hydrazine, mg/l max.	0.1 to 1.0	0.1 to 1.0	0.1 to 1.0
Suspended solids, mg/l max.	50	200	300
Dissolved solids, mg/l max.	3,500	3,000	2,000

[1] 1 bar = 10^5 N/m = 100 kPa = 14.5 Ib/in^2.

[2] Numerical values depend upon circumstances but the comments are relevant.

[3] Not Detectable.

[4] Phosphate is usually added as sodium phosphate but determined as phosphate (PO_4^3); Na_3PO_4 = 1.73 x PO_4^3.

Chemical precautions against caustic cracking are generally not necessary for boilers of welded and stress-relieved construction but they should be applied for older boilers of riveted construction.

E.2 Water-tube Boilers

E.2.1 Recommended Characteristics

The recommendations in Exhibit E-2 apply to water-tube boilers of the integral furnace type and of current design and rating. Boilers with lower heat flux ratings may tolerate higher concentrations of hardness. Similarly, future designs may have higher flux ratings and might require lower levels of hardness and other impurities that can lead to the formation of scale or deposits and interference with heat transfer.

Chemical precautions against caustic cracking are generally not necessary for boilers of welded and stress-relieved construction but they should be applied for older boilers of riveted construction.

Where the heat flux density at localized 'hot spots' is expected to exceed about 300 kW/m^2 in boilers operating at a pressure below 40 bars, hardness in the feedwater should be strictly limited to less than 0.3 mg/l in terms of $CaCO_3$ and iron, copper and nickel should be limited as for an operating pressure of 60 bars.

A high-pressure boiler plant, operating at above 80 bar, is generally more sensitive than a low-pressure plant to on-load corrosion and the circumstances that may allow corrosion to occur are less well understood here. In general, the concentrations of all constituents in the feed and boiler water should be as low as practicable. Furthermore, should it be found that boiler water salts are subject to 'hideout,' every endeavor should be made to operate at the lowest practicable concentration.

The values tabulated are for normal, steady operation. It is acknowledged that, for economic reasons, higher concentrations of total solids, iron, copper, silica, have to be tolerated during periods of starting-up. For boilers operating above 130 bars, consideration should be given to condensate polishing.

The operation of boilers at less than designed pressures may adversely affect the performance of steam-purifying equipment, so that it may be necessary to adopt lower concentrations in the boiler water than the maxima listed for total alkalinity, suspended solids and dissolved solids.

E.2.2 Comments on Exhibit E-2

When applying the recommendations in Exhibit E-2 the following additional comments are also relevant.

1. **pH value of feedwater:** With feedwater heaters made from copper or copper alloys, the range of pH values should be limited to between 8.5 and 9.2. Otherwise it should range between 9.2 and 9.5. For spray attemperation (see (d) below) the feedwater should be dosed only with volatile chemical; if necessary, caustic soda should be injected direct to the boiler drum.
2. **Oxygen:** The oxygen limits in Exhibit E-2 are those obtained after physical deaeration. In addition to physical deaeration, the use of a chemical oxygen scavenger is recommended.

   Sodium sulfite should not be used in boilers operating above 80 bars except where hydrazine cannot be used and then only if strict control is maintained to prevent damage due to its decomposition.

   Sodium sulfite should not be added to water used for spray attemperation.

   For low-pressure plants, hydrazine is recommended as an alternative to sodium sulfite only when it is dosed to the feedwater at a substantial distance from the boiler and where the feedwater is sufficiently hot to enable the reaction with oxygen to be 90% complete before entry to the boiler. Thus, for smaller industrial plants, sodium sulfite would generally be preferred.

   Concentrations of hydrazine in the boiler water are not given for operation above 80 bars because, owing to its decomposition and/or volatilization, low concentrations remain in the boiler water and are extremely difficult to determine; thus the residual concentration is not a practical basis for controlling the dose. In such cases, the feedwater should be dosed with hydrazine equivalent to twice the residual oxygen remaining after physical deaeration.

   Caution: Hydrazine is toxic, and suitable precautions for its handling should be observed. Its use is usually prohibited in hospitals, food manufacturing industry and where the steam may come into contact with food or beverages. The use of sodium sulfite may also be unacceptable in some of these applications. The existence of any regulations governing the use of either should be ascertained and they should be observed.
3. **Iron, copper, nickel:** The maxima for the sum of these impurities should be regarded as concentrations not to be exceeded during continuous running conditions.
4. **Solids, alkalinity and silica in feedwater:** The concentrations of these impurities should not require blowdown of boiler water in quantities exceeding the design value or exceeding the feed pump capacity. Where spray attemperation is employed, the spray water should contain as little solid matter and silica as possible. In general, in order to prevent deposition in the superheater, the spray attemperator should not be fed with water containing more than 3 mg/l solid matter. If the superheater contains an austenitic steel section, solids in the spray water should be less than 0.1 mg/l. When steaming a turbine, the spray water should contain less than 0.02 mg/l silica.
5. **Organic matter:** See comments (d) on Exhibit E-1 above.
6. **Phosphate:** Phosphate need not be employed if hardness is completely eliminated at all times, and should not be employed when operating above 130 bars except in an emergency. In any case, phosphate should not be employed above the value at which it is found to 'hideout.' In appropriate circumstances, chelating agents or polymers may be used.

7. **Solids and alkalinity in boiler water:** The maxima for total alkalinity, suspended solids and dissolved solids are set in relation to steam purity. Exceeding these values may lead to carryover of boiler water with the steam. The recommended alkalinity may require dealkalization of the makeup water.

   Owing to the risk of on-load corrosion it is recommended that boilers at pressures in excess of about 80 bars should operate at the lowest practicable concentrations of impurities.

8. **Silica in boiler water:** Lower concentrations of silica may be advisable for steam for turbines, which generally require less than 0.02 mg/l silica in steam. Exhibit E-3shows the maximum concentrations of silica in boiler water to ensure that this is achieved. These values should also be applied to all boilers operating above 80 bars.

Note: Exhibit E-4 provides further guidelines for reliable operation.

Exhibit E-2: Recommended Water Characteristics for Water-tube Boilers

Pressures at Boiler Outlet bar[1]	*2*	*40*	*60*	*80*	*100*	*120*	*Above 130*
Feed Water at Economizer Inlet							
Total hardness, mg/l in terms of $CaCO_3$ max.	10	2	0.5	ND[2]	ND[2]	ND[2]	ND[2]
pH value	8.5 to 9.5	8.5 to 9.5	8.5 to 9.5	8.5 to 9.5	8.5 to 9.5	8.5 to 9.5	8.5 to 9.5
Oxygen mg/l as O_2 max.	0.05	0.02	0.01	0.01	0.005	0.005	0.005
Iron + copper + nickel, mg/l max.	–	–	0.02	0.02	0.01	0.01	0.01
Total solids, alkalinity, silica	[3]	[3]	[3]	[3]	[3]	[3]	[3]
Oil	ND[2]	ND[2]	ND[2]	ND[2]	ND[2]	ND[2]	ND[2]
Organic matter	[3]	[3]	[3]	[3]	[3]	[3]	[3]
Boiler Water							
Sodium phosphate, mg/l as Na_3PO_4[4]	50 to 100	30 to 70	20 to 50	10 to 40	5 to 20	3 to 10	[3]
Caustic alkalinity, mg/l in terms of $CaCO_3$ max.	300	150	60	30	10	5	2
Total alkalinity, mg/l in terms of $CaCO_3$ max.	700	500	300	200	100	40	10
Silica[3], mg/l as SiO_2 max.	Less than 0.4 of the	caustic alkalinity	20	10	[3]	[3]	[3]
Sodium sulfite, mg/l, as Na_2SO_3	30 to 50	20 to 40	15 to 30	10 to 20	[3]	[3]	–
or							
Hydrazine, mg/l as N_2H_4	0.1 to 1.0	0.1 to 0.5	0.05 to 0.3	0.05 to 0.3	[3]	[3]	[3]
Suspended solids, mg/l max.	200	50	–	–	–	–	–
Dissolved solids, mg/l max.	300	2,000	1,200	700	350	100	15
Chloride, mg/l as Cl^- max	–	–	–	–	10	5	–

–	Not Applicable.
[1]	1 bar = 105 N/m = 100 kPa = 14.5 Ib/in^2.
[2]	Not Detectable.
[3]	Numerical values depend upon circumstances but the comments are relevant.
[4]	Phosphate is usually added as sodium phosphate but determined as phosphate (PO_4^3); Na_3PO_4 = 1.73 x PO_4^3.

Exhibit E-3: Maximum Concentration of Silica in Boiler Water

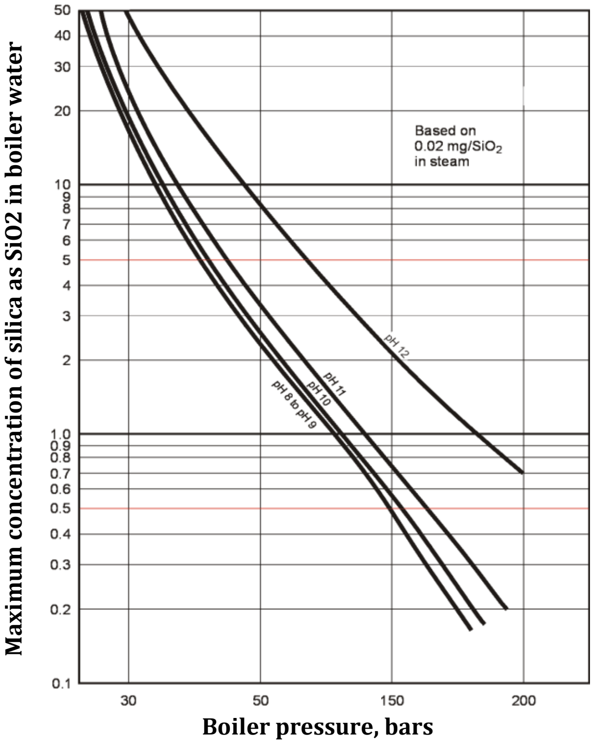


Exhibit E-4: Water Quality Guidelines Recommended for Industrial Water-tube Boilers

Drum Pressure psig	Iron ppm Fe	Copper ppm Cu	Total Hardness ppm $CaCO_3$
0-300	0.100	0.050	0.300
301-450	0.050	0.025	0.300
451-600	0.030	0.020	0.200
601-750	0.025	0.020	0.200
751-900	0.020	0.015	0.100
901-1,000	0.020	0.015	0.050
1,001-1,500	0.010	0.010	ND[1]
1,501-2,000	0.010	0.010	ND[1]

Boiler Water

Drum Pressure psig	Silica ppm SiO_2	Total Alkalinity,[2] ppm $CaCO_3$	Specific Conductance, µmho/cm
0-300	150	350[3]	3,500
301-450	90	300[3]	3,000
451-600	40	250[3]	2,500
601-750	30	200[3]	2,000
751-900	20	150[3]	1,500
901-1,000	8	100[3]	1,000
1,001-1,500	2	NS[4]	150
1,501-2,000	1	NS[4]	100

[1] Not Detectable.

[2] Minimum level of hydroxide alkalinity in boiler below 1,000 psi must be individually specified with regard to silica solubility and other components of internal treatment.

[3] Maximum total alkalinity consistent with acceptable steam purity. If necessary, the limitation on total alkalinity should override conductance as the control parameter. If make-up is demineralised water at 600-1,000 psig, boiler water alkalinity and conductance should be shown in the table for the 1,001-1,500 psig range.

[4] Not Specified in these cases refers to free sodium or potassium-hydroxide alkalinity. Some small variable amount to total alkalinity will be present and measurable with the assumed congruent control or volatile treatment employed at these high pressure ranges.

Appendix-F SI Conversion Table

1 Unit of: **EQUALS**

WEIGHT	**Tonne**	**kg**	**sh. ton**	**L ton**	**lbs.**
Tonne (metric ton)	1.000E+00	1.000E+03	1.102E+00	9.840E-01	2.205E+03
Kilogram (kg)	1.000E-03	1.000E+00	1102x10^{-6}	0.984x10^{-6}	2.205E+00
Short ton (sh.ton)	9.072E-01	9.072E+02	1.000E+00	8.930E-01	2.000E+03
Long ton (I.ton)	1.016E+00	1.016E+03	1.120E+00	1.000E+00	2.240E+03
Pound (lb)	0.45x10^{-3}	4.540E-01	0.5x10^{-3}	0.446x10^{-3}	1.000E+00

1 Unit of: **EQUALS**

WEIGHT	**tonne**	**kg**	**sh. ton**	**l. ton**	**lbs.**
1 Tonne (metric ton)	1.000E+00	1.000E+03	1.102E+00	9.840E-01	2.205E+03
1 Kilogram (kg)	1.000E-03	1.000E+00	1.102E-03	9.840E-07	2.205E+00
1 Short ton (sh.ton)	9.072E-01	9.072E+02	1.000E+00	8.930E-01	2.000E+03
1 Long ton (I.ton)	1.016E+00	1.016E+03	1.120E+00	1.000E+00	2.240E+03
1 Pound (lb)	4.500E-04	4.540E-01	5.000E-04	4.460E-04	1.000E+00

1 Unit of: **EQUALS**

LENGTH	meters	kilometer	inch	feet	miles
1 meter	1.000E+00	1.000E-03	3.937E+01	3.281E+00	6.214E-04
1 kilometer	1.000E+03	1.000E+00	3.937E+04	3.281E+03	6.214E-01
1 inch	2.540E-03	2.540E-05	1.000E+00	8.330E-02	1.578E-05
1 foot	3.048E-01	3.048E-04	1.200E+01	1.000E+00	1.894E-04
1 mile	1.609E+03	1.609E+00	6.336E+04	5.280E+03	1.000E+00

1 Unit of: **EQUALS**

AREA	m2	cm2	ft2	inch2
1 square meter	1.000E+00	1.000E+04	1.076E+01	1.550E+03
1 square centimeter	1.000E-04	1.000E+00	1.076E-03	1.550E-01
1 square foot	9.290E-02	9.290E+02	1.000E+00	1.440E+02
1 square inch	6.452E-04	6.452E+00	6.944E-03	1.000E+00

1 Square mile = 27,878,400 ft2 = 640 acre 1 acre = 43,560 ft2

1 hectare = 10,000 mi2 = 2.471 acre

1 Unit of: **EQUALS**

VOLUME	m3	cm3	ft3	Inch3
1 cubic meter	1.000E+00	1.000E+06	3.531E+01	6.102E+04
1 cubic centimeter	1.000E-06	1.000E+00	3.531E-05	6.102E-02
1 cubic foot	2.832E-02	2.832E+01	1.000E+00	1.728E+03
1 cubic inch	1.639E-05	1.639E+01	5.787E-04	1.000E+00

1 U.S. fluid gallon = 4 quarts = 8 pints = 128 fluid ounces = 231 cubic inches

1 liter = 1000 cubic centimeters (1 cubic foot of water = 62.4 pounds of water)

1 Unit of: **EQUALS**

MASS	gram	kilogram	lb-mass (lbm)	Slug	ton-mass
1 gram	1.000E+00	1.000E-03	2.205E-03	6.852E-05	1.102E-06
1 kilogram	1.000E+03	1.000E+00	2.205E+00	6.852E-02	1.102E-03
1 pound mass	4.536E+02	4.536E-01	1.000E+00	3.108E-02	5.000E-04
1 slug	1.459E+04	1.459E+01	3.217E+01	1.000E+00	1.609E-02
1 ton-mass	9.072E+05	9.070E+02	2.000E+03	6.216E+01	1.000E+00

1 metric ton = 1000 kg = 2205 pounds 1 stone = 14 pounds 1 carat = 0.2 grams

1 Unit of: **EQUALS**

TIME	year	day	hour	minute	second
1 year	1.000E+00	3.652E+02	8.766E+03	5.259E+05	3.156E+07
1 day	2.739E-03	1.000E+00	2.400E+01	1.440E+03	8.640E+04
1 hour	1.141E-04	4.167E-02	1.000E+00	6.000E+01	3.600E+03
1 minute	1.901E-06	6.944E-04	1.667E-02	1.000E+00	6.000E+01
1 second	3.169E-08	1.157E-05	2.778E-04	1.667E-02	1.000E+00

1 Unit of: **EQUALS**

FORCE	dyne	kgf	N	Lb	pdf
1 dyne	1.000E+00	1.020E-06	1.000E-05	2.248E-05	
1 kilogram force	9.807E+05	1.000E+00	9.807E+00	2.205E+00	7.093E+03
1 newton	1.000E+05	1.020E-01	1.000E+00	2.248E-01	7.233E+00
1 pound	4.448E+05	4.536E-01	4.448E+00	1.000E+00	3.217E+01
1 poundal	1.383E+04	1.410E-02	1.383E-01	3.108E-02	1.000E+00

1 Unit of: **EQUALS**

PRESSURE	atmosphere	inches of water	cm of Hg	pascal (Pa)	lb/in2 (psi)
1 atmosphere	1.000E+00	4.068E+02	7.6 E01	1.013E+05	1.470E+01
1 inch of water	2.458E-03	1.000E+00	1.868E-01	2.491E+02	3.613E-02
1 cm of Hg	1.316E-02	5.353E+00	1.000E+00	1.333E+03	1.934E-01
1 pascal (Pa)	9.869E-06	4.105E-03	7.501E-04	1.000E+00	1.450E-04
1 lb/in2	6.805E-02	2.768E+01	5.171E+00	6.895E+03	1.000E+00

1 pascal (Pa) = 1 N/m2

1 bar = 105 N/m2 = 105 pascals (Pa)

1 atm = 1.01325 bar = 1.01325 × 105 N/m2 = 29.92 in of Hg (mercury) = 33.92 ft of water = 2,117 lb/ft2

1 cm of water = 98.07 N/m2 1 torr = 1 mm of Hg 1 ft of water = 62.43 lb/ft2

1 Unit of: **EQUALS**

ENERGY	Btu	ft-lb	J	kcal	kWh
1 British themal unit	1.000E+00	7.779E+02	1.055E+03	2.520E-01	2.930E-04
1 foot-pound	1.285E-03	1.000E+00	1.356E+00	3.240E-04	3.766E-07
1 joule	9.481E-04	7.376E-01	1.000E+00	2.390E-04	2.778E-07
1 kilocalorie	3.968E+00	3.086E+03	4.184E+03	1.000E+00	1.163E-03
1 kilowatt-hour	3.412E+03	2.655E+06	3.600E+06	8.602E+02	1.000E+00

1 Btu = 252 calories = 778 ft-lb = 1,055 joules 1 joule = 0.239 calories

1 calorie = 3.09 ft-lb = 4.18 joules 1 ft-lb = 0.324 calories 1 kcal = 1,000 calories

1 Unit of: **EQUALS**

POWER	Btu/hr	ft-lb/sec	hp	kcal/sec	W
1 Btu/hr	1.000E+00	2.161E-01	3.929E-04	7.000E-05	2.931E-01
1 ft-lb/sec	4.628E+00	1.000E+00	1.818E-03	3.239E-04	1.356E+00
1 horsepower	2.545E+03	5.500E+02	1.000E+00	1.782E-01	7.457E+02
1 kcal/sec	1.429E+04	3.087E+03	5.613E+00	1.000E+00	4.184E+03
1 watt	3.413E+00	7.376E-01	1.341E-03	2.390E-04	1.000E+00

1 Unit of: **EQUALS**

HEAT	Btu/h	Btu/min	Ton (refrigeratio	kcal/s	Watt
1 Btu/h	1.000E+00	1.670E-02	8.330E-05	7.000E-05	2.931E-01
1 Btu/min	6.000E+01	1.000E+00	5.000E-03	4.200E-03	1.757E+01
1 ton (refrigeration)	1.200E+04	2.000E+02	1.000E+00	8.400E-01	3.514E+03
1 kcal/s	1.429E+04	2.381E+02	1.191E+00	1.000E+00	4.183E+03
1 watt	3.413E+00	5.690E-02	2.846E-04	2.391E-04	1.000E+00

1 ton (refrigeration) = 12,000 Btu/hr

1 Unit of: **EQUALS**

ENERGY	BoHP	kW	kcal/s	Btu/s	lbs/h Steam	kg/h Steam
1 Boiler Horspower (BoHP)	1.000E+00	9.810E+00	2.350E+00	9.328E+00	3.450E+01	1.565E+01
1 Kilowatt (kW)	1.019E-01	1.000E+00	2.396E-01	9.509E-01	3.517E+00	1.595E+00
1 Kilocalories/second (kcal/s)	4.255E-01	4.180E+00	1.000E+00	3.968E+00	1.468E+01	6.660E+00
1 Btu/Second (Btu/s)	1.072E-01	1.052E+00	2.519E-01	1.000E+00	3.699E+00	1.678E+00
1 Pounds/hour steam	2.899E-02	2.843E-01	6.812E-02	2.704E-01	1.000E+00	4.536E-01
1 kilograms/hour steam	6.390E-02	6.268E-01	1.502E-01	5.960E-01	2.204E+00	1.000E+00

1 Unit of: **EQUALS**

LNG	cubic meters of LNG	metric tonnes of LNG	cubic meters of gas	cubic feet of gas	million Btu of gas	therms	gigajoules	kilowatt hours	Barrels of crude
1 cubic metre of LNG	1.000E+00	4.050E-01	5.840E+02	2.063E+04	2.104E+01	2.104E+02	2.219E+01	6.173E+03	3.830E+00
1 metric tonne of LNG	2.470E+00	1.000E+00	1.379E+03	4.869E+04	5.200E+01	5.200E+02	5.480E+01	1.522E+04	9.430E+00
1 cubic metre of gas	1.710E-03	7.250E-04	1.000E+00	3.530E+01	3.600E-02	3.600E-01	3.800E-01	1.054E+01	6.500E-03
1 cubic foot of gas	5.000E-05	2.000E-05	2.830E-02	1.000E+00	1.020E-03	1.020E-02	1.080E-03	2.990E-01	1.900E-04
1 million Btu	4.800E-02	1.920E-02	2.780E+01	9.810E+02	1.000E+00	1.000E+01	1.054E+00	2.927E+02	1.820E-01
1 therm	4.800E-03	1.920E-03	2.780E+00	9.810E+01	1.000E-01	1.000E+00	1.054E-01	2.927E+01	1.820E-02
1 gigajoule	4.500E-02	1.800E-02	2.630E+01	9.300E+02	9.500E-01	9.500E+00	1.000E+00	2.775E+02	1.730E-01
1 kilowatt hour	1.620E-04	6.500E+01	9.490E-02	3.300E+00	3.415E-03	3.415E-03	3.600E-03	1.000E+00	6.200E-04
1 barrel of crude	2.610E-01	1.060E-01	1.530E+02	5.390E+03	5.500E+00	5.500E+01	5.790E+00	1.610E+00	1.000E+00

GROSS CALORIFIC VALUES
BEING USED IN PAKISTAN

Refer to Explanation Given Below.

Gas	**Million Btu per MMCFT**	**Giga Joule per MMCFT**	**PTOE/ MMCFT**	**TOE/ MMCFT**
Sui Standard Natural Gas	980	1033.9	23.4	24.6984
Badin & Condensates Average	1,047	1104.6	25.0	26.3869

Oil	**Million Btu per Tonne**	**Giga Joule per Tonne**	**PTOE/ Tonne**	**TOE/ Tonne**
Indigenous Crude Oil	41.895	44.20	1.0000	1.0559
Imported Crude Oil	43.313	45.7	1.0338	1.0916
Avgas	43.659	46.1	1.0421	1.1003
JP-1	43.218	45.6	1.0316	1.0892
JP-4	44.144	46.6	1.0537	1.1125
Motor Spirit	44.761	47.2	1.0684	1.1281
HOBC	44.541	47.0	1.0632	1.1225
HSD	44.045	46.5	1.0513	1.1100
LDO	43.648	46.0	1.0418	1.1000
Furnace Oil	40.792	43.0	0.9737	1.0281
Kerosene	43.218	45.6	1.0316	1.0892
Nephtha	44.761	47.2	1.0684	1.1281
LPG	45.326	47.8	1.0819	1.1423
MTBE	34.128	36.0	0.8146	0.8601

Electricity	**Million Btu per GWh**	**Giga Joule per GWh**	**PTOE/ GWh**	**TOE/ Tonne**
As Primary Energy Input for Hydro/Nuclear	10,000	10,550	238.69	252.0240
As Final Energy	3,412	3,600	81.44	85.9906

Coal	**Million Btu per Tonne**	**Giga Joule per Tonne**	**PTOE/ Tonne**	**TOE/ Tonne**
Indigenous	18.74	19.8	0.4474	0.4724
Imported	27.56	29.1	0.6579	0.6947

1 international TOE (TOE)	0.9471	Pakistani TOE (PTOE)
1 international TOE (TOE)	39.680	Million Btu
1 Pakistani TOE (PTOE)	41.895	Million Btu
MMCFT	1	Million CFT

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