ANALYSIS OF BOILER EFFICIENCY– CASE STUDY OF THERMAL POWER STATIONS

1.0 INTRODUCTION

Looking to the statically data, rate which power demand increases is extremely very high compared to the rate at which generation capacity increase. Boiler is a heart of power plant, so its efficiency is directly affected to the all over efficiency of the plant.

It is quite obvious that approximately 65% to 70% power generation comes out from Thermal Power Plant uses Coal as fuel available from various parts of India, where transportation is also made easy and timely. Power is one of the basic infrastructures necessary for the Industries and socio economic development in the State. Installed capacity of the State has increased from 315 MW in 1960-61 to 11711 MW in 2009-2010. Per capita consumption of power in the State of Gujarat in 2008-09 was 1446 Units (as per CEA revised formula) which is almost double of all India average.

For finding out the Power Plant efficiency and its performance, the Ukai and Gandhinagar Thermal Power Plants are being selected for the present study.

The performance of boiler was carried out by way of calculating the efficiency of Boiler by direct method and indirect method. It has been also discussed the methods how GSECL (Gujarat State Electricity Corporation Ltd.) calculate the efficiency of Boiler. The important discussion on the point how to increase the efficiency of Boiler.

The study scope encompassed the following major tasks:

• Discussion of methods to reduce the heat rate of existing power plants.

• Preparation of case studies quantifying heat rate reductions resulting from the methods described herein.

• Survey of existing plants and published literature to assess heat rate reductions typically achieved in the industry.

While the study presented in this thesis was motivated by the need to evaluate and rehabilitate data for the specific processes noted above, the objective of this study is to develop a broadly useful finding the methods of Boiler efficiency of Thermal Power Plant boilers when some metered data is either missing or obviously erroneous. The methodology should be able to analyze conflicting measurements and utilize additional one-time or short-term measurements to deduce the measurement or measurements which are substantially in error without shutting down the power plant and recalibrating all instrumentation. It is also desirable to be able to: 1) determine key plant operating parameters such as the overall plant boiler efficiency and individual boiler efficiency by testing and using available metered data; 2) correct the historical data and generate boiler performance characteristic curves (i.e., boiler efficiency versus load profile) as a guide for optimal load allocation; 3) identify operational and maintenance problems; and 4) give suggestions for operational improvements.

Today's process and heating applications continue to be powered by steam and hot water. The mainstay technology for generating heating or process energy is the packaged water tube boiler. The packaged water tube boiler has proven to be highly efficient and cost effective in generating energy for process and heating applications.

Conducting a thorough evaluation of boiler equipment requires review of boiler type, feature and benefit comparison, maintenance requirements and fuel usage requirements. Of these evaluation criteria, a key factor is fuel usage or boiler efficiency.

Selection of a boiler with "designed-in" low maintenance costs and high efficiency can really provide savings and maximize boiler investment. Efficiency is only useful if it is repeatable and sustainable over the life of the equipment. Choosing the most efficient boiler is more than just choosing the vendor who is willing to meet a given efficiency value.

2.0 LITERATURE REVIEW:

2.1 Introduction

Boiler is an apparatus to produce steam. Thermal energy released by combustion of fuel is transferred to water, which vaporizes and gets converted into steam at the desired temperature and pressure.

The steam produced is used for:

(i) Producing mechanical work by expanding it in steam engine or steam turbine.

(ii) Heating the residential and industrial buildings

(iii) Performing certain processes in the sugar mills, chemical and textile industries.

Boiler is a closed vessel in which water is converted into steam by the application of heat.

Usually boilers are coal or oil fired. A boiler should fulfill the following requirements

(i) **Safety.** The boiler should be safe under operating conditions.

(ii) **Accessibility.** The various parts of the boiler should be accessible for repair and maintenance.

(iii) **Capacity.** The boiler should be capable of supplying steam according to the requirements.

(iv) **Efficiency.** To permit efficient operation, the boiler should be able to absorb a maximum amount of heat produced due to burning of fuel in the furnace.

(v) It should be simple in construction and its maintenance cost should be low.

(vi) Its initial cost should be low.

(vii) The boiler should have no joints exposed to flames.

(viii) The boiler should be capable of quick starting and loading.

The performance of a boiler may be measured in terms of its evaporative capacity also called power of a boiler. It is defined as the amount of water evaporated or steam produced in kg per hour. It may also be expressed in kg per kg of fuel burnt or kg/hr/m2 of heating surface.

2.2 Types of Boilers

Boiler systems are classified in a variety of ways. They can be classified according to the end use, such as foe heating, power generation or process requirements. Or they can be classified according to pressure, materials of construction, size tube contents (for example, waterside or fireside), firing, heat source or circulation. Boilers are also distinguished by their method of fabrication. Accordingly, a boiler can be pack aged or field erected. Sometimes boilers are classified by their heat source. For example, they are often referred to as oil-fired, gas-fired, coal-fired, or solid fuel –fired boilers.

The boilers can be classified according to the following criteria.

According to flow of water and hot gases.

2.2.1. Water tube.

2.2.2. Fire tube.

In water tube boilers, water circulates through the tubes and hot products of combustion flow over these tubes. In fire tube boiler the hot products of combustion pass through the tubes, which are surrounded, by water. Fire tube boilers have low initial cost, and are more compacts. But they are more likely to explosion, water volume is large and due to poor circulation they cannot meet quickly the change in steam demand. For the same output the outer shell of fire tube boilers is much larger than the shell of water-tube boiler. Water tube boilers require less weight of metal for a given size, are less liable to explosion, produce higher pressure, are accessible and can response quickly to change in steam demand. Tubes and drums of water-tube boilers are smaller than that of fire-tube boilers and due to smaller size of drum higher pressure can be used easily. Water-tube boilers require lesser floor space. The efficiency of water-tube boilers is more.

2.2.1 Fire tube boilers

Fire tube boilers consist of a series of straight tubes that are housed inside a water-filled outer shell. The tubes are arranged so that hot combustion gases flow through the tubes. As the hot gases flow through the tubes, they heat the water surrounding the tubes. The water is confined by the outer shell of boiler. To avoid the need for a thick outer shell fire tube boilers are used for lower pressure applications. Generally, the heat input capacities for fire tube boilers are limited to 50 mbtu per hour or less, but in recent years the size of fire tube boilers has increased.

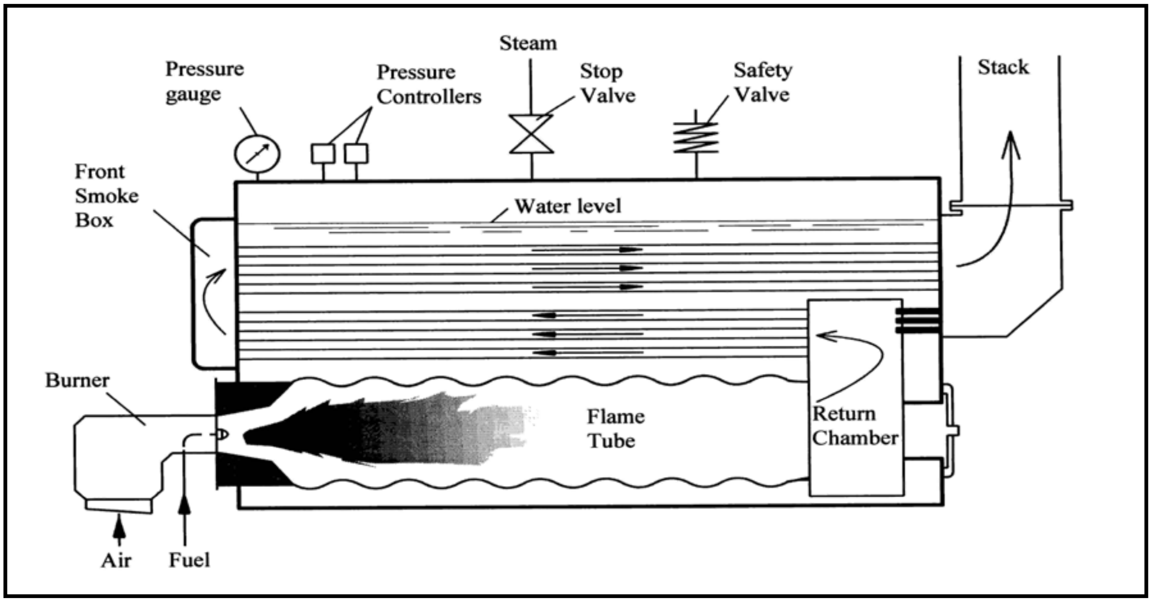


Fig2.2.1. Three-P Fire-Tube Boiler

The fire-tube boiler is sold as a package consisting of the pressure vessel, burner, controls, and other components assembled into a fully factory-fire-tested unit. Most manufacturers test their models as a unit before it is shipped to the site, basically delivering a product that is pre-engineered and ready for quick installation and connection to services such as electricity, water, and fuel.

Fire tube boilers are subdivided into three groups. Horizontal return tubular (HRT) boilers typically have horizontal, self-contained fire tubes with a separate combustion chamber. Scotch, Scotch marine, or shell boilers have the fire tubes and combustion chamber housed within the same shell. Firebox boilers have a water-jacketed firebox and employ at most three passes of combustion gases.

Most modern fire tube boilers have cylindrical outer shells with a small round combustion chamber located inside the bottom of the shell. Depending on the construction details, these boilers have tubes configured in either one, two, three, or four pass arrangements. Because the design of fire tube boilers is simple, they are easy to construct in a shop and can be shipped fully assembled as a package unit.

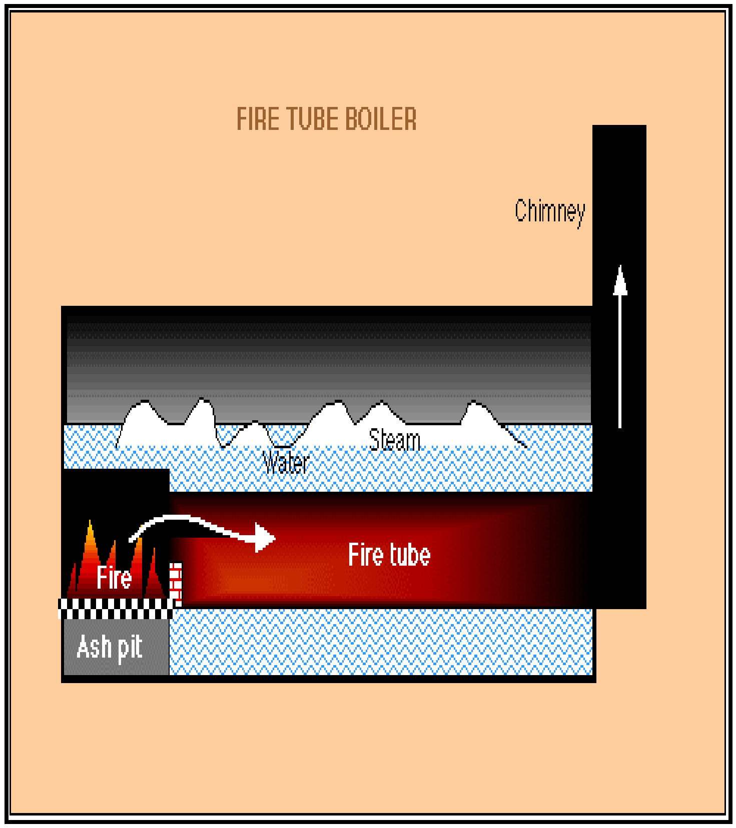


Fig 2.2.2 Schematic diagram of locomotive fire tube boiler

These boilers contain long steel tubes through which the hot gases from the furnace pass and around which the hot gases from the furnace pass and around which the water circulates. Fire tube boilers typically have a lower initial cost, are more fuel efficient and are easier to operate, but they are limited generally to capacities of 25 tonnes per hour and pressures of 17.5 kg per cm^2.

2.2.2 Water tube boilers

Water tube boilers are designed to circulate hot combustion gases around the outside of a large number of water filled tubes. The tubes extend between an upper header, called a steam drum, and one or more lower headers or drums. In the older designs, the tubes were either straight or bent into simple shapes. Newer boilers have tubes with complex and diverse bends. Because the pressure is confined inside the tubes, water tube boilers can be fabricated in larger sizes and used for higher-pressure applications.

Small water tube boilers, which have one and sometimes two burners, are generally fabricated and supplied as packaged units. Because of their size and weight, large water tube boilers are often fabricated in pieces and assembled in the field. In water tube or “water in tube” boilers, the conditions are reversed with the water passing through the tubes and the hot gases passing outside the tubes. These boilers can be of a single- or multiple-drum type. They can be built to any steam capacity and pressures, and have higher efficiencies than fire tube boilers.

Almost any solid, liquid or gaseous fuel can be burnt in a water tube boiler. The common fuels are coal, oil, natural gas, biomass and solid fuels such as municipal solid waste (MSW), tire-derived fuel (TDF) and RDF. Designs of water tube boilers that burn these fuels can be significantly different.

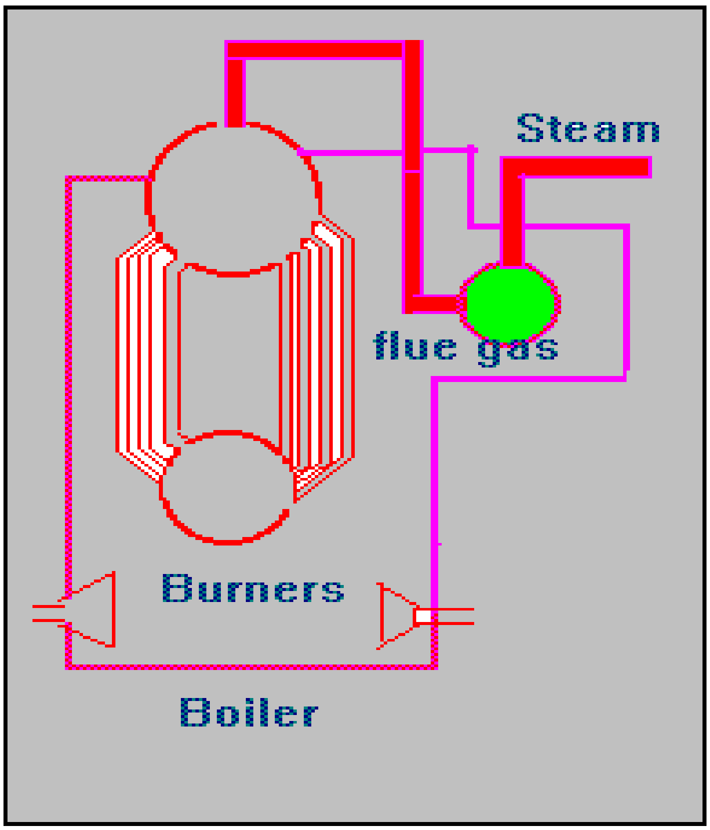


Fig.2.2.3 Schematic diagram of a marine type water tube boiler

Coal-fired water tube boilers are classified into three major categories: stoker fired units, PC fired units and FBC boilers. Package water tube boilers come in three basic designs: A, D and O type. The names are derived from the general shapes of the tube and drum arrangements. All have steam drums for the separation of the steam from the water, and one or more mud drums for the removal of sludge. Fuel oil-fired and natural gas-fired water tube package boilers are subdivided into three classes based on the geometry of the tubes. The "A" design has two small lower drums and a larger upper drum for steam-water separation. In the "D" design, which is the most common, the unit has two drums and a large-volume combustion chamber. The orientation of the tubes in a "D" boiler creates either a left or right-handed configuration. For the "O" design, the boiler tube configuration exposes the least amount of tube surface to radiant heat. Rental units are often “O” boilers because their symmetry is a benefit in transportation.

The boiler-heated surfaces consist of a bundle of tubes, some of which are exposed to the fire, others to the flow of hot gases produced by the combustion process. Baffles are provided in the bank of tubes to create a number of gas paths and thus increase the effectiveness of the heated surface. In this manner, the heat is transferred to the water in the boiler through tubes of relatively thin section when compared with the thickness of a fire-tube boiler shell. Hence, the working pressure could be raised considerably above that of a fire-tube boiler. Moreover, should a tube rupture occur, the consequences would

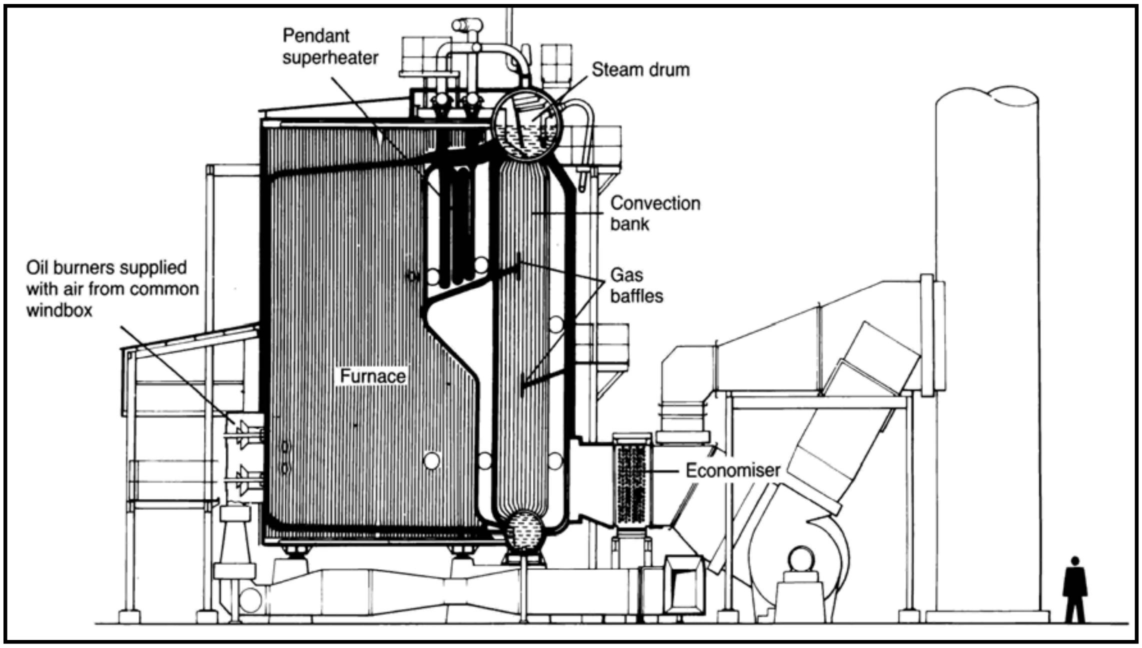


Fig.2.2.4 Two-Drum Oil- or Gas-Fired Water-Tube Boiler

be less serious than if the furnace or shell of a fire-tube boiler ruptured. Boiler water impurities settle at the bottom.

2.2.3 Classification of Water tube boilers:

1. Horizontal straight tube boilers
   - (a) Longitudinal drum
   - (b) Cross-drum.

2. Bent tube boilers
   - (a) Two drum
   - (b) Three drum
   - (c) Low head three drum

(d) Four drum.

3. Cyclone fired boilers

2.2.4 Various advantages of water tube boilers are as follows.

(i) High pressure of the order of 140 kg/cm2 can be obtained.

(ii) Heating surface is large. Therefore steam can be generated easily.

(iii) Large heating surface can be obtained by use of large number of tubes.

(iv) Because of high movement of water in the tubes the rate of heat transfer becomes large resulting into a greater efficiency.

2.2.5 Classification of Fire tube boilers:

l. External furnace:

(i) Horizontal return tubular

(ii) Short fire box

(iii) Compact.

2. Internal furnace:

(i) Horizontal tubular

(a) Short firebox

(b) Locomotive

(c) Compact

(d) Scotch.

(ii) Vertical tubular.

(a) Straight vertical shell, vertical tube

(b) Cochran (vertical shell) horizontal tube.

According to position of furnace.

(i) Internally fired

(ii) Externally fired

In internally fired boilers the grate combustion chamber are enclosed within the boiler shell Whereas in case of extremely fired boilers and furnace and grate are separated from the boiler shell.

According to the position of principle axis.

(i) Vertical

(ii) Horizontal

(iii) Inclined.

According to application.

(i) Stationary

(ii) Mobile, (Marine, Locomotive).

According to the circulating water.

(i) Natural circulation

(ii) Forced circulation.

According to steam pressure.

(i) Low pressure

(ii) Medium pressure

(iii) Higher pressure.

Various advantages of fire tube boilers are as follows.

(i) Low cost

(ii) Fluctuations of steam demand can be met easily

(iii) It is compact in size.

2.3 Boiler Operation

The basic purpose of a boiler is to turn water into steam, in this case saturated steam. This operation sounds relatively simple but is actually more complicated. Other components and processes such as the deaerator and economizer are necessary to help the overall operation run more efficiently. The boilers utilized on campus are of the stack drum type, which means there are drums within the boilers stacked one above the other. In these particular boilers there are two drums. The upper drum is called a steam drum and is where saturated steam leaves the boiler. While the lower drum is called the mud drum and is where liquid feed water enters. It is also where sediment carried into the boiler settles. Tubes called risers and down comers are used to connect the two drums.

All of the energy required within the boiler is produced by the combustion of a fuel. The burner acts very similar to the gas stove at home, just more complicated. It is comprised of a wind box, air register assembly, igniter, fuel manifold and/or atomizing gun, and observation port and flame safety scanner. Currently the boilers can burn either No. 2 fuel oil or natural gas. As drivers with Flex fuel cars are finding out, the option of changing fuels is a large benefit. Fluctuating prices of fuel can raise or lower the cost to produce steam. Having the choice between two different fuels gives the option of burning the lower cost fuel.

Operation of the boiler begins with feed water entering the mud drum where it is heated. The combustion of fuel within the furnace provides the required energy which is imparted by a combination of convection and radiation. A two-phase water mixture forms within the riser and begins to ascend to the steam drum due to its decreasing density. Boiling to 100% quality in the tubes is undesirable because water vapor has different heat transfer characteristics than liquid water. This can lead to high wall temperatures and eventual tube burnout. Once it reaches the steam drum the majority of saturated vapor will be removed from the two-phase mixture; thereby increasing the remaining mixtures density. The increase in density will initiate its descent in the down comers back to the mud drum. This natural circulation occurs continuously allowing for a constant flow of saturated steam exiting the boiler.

2.4 Water Circulation

2.4.1 Principle of Natural Circulation

Boilers are designed with Economizer, Evaporator and Super heater depending on the Design parameters.

Economizers add sensible heat to water. The Economizer water outlet temperature will be closer to saturation temperature. The water is forced through the Economizer by the boiler feed pumps.

Super heaters add heat to steam. That is the heat is added to steam leaving the Boiler steam drum / Boiler shell. The steam passes through the Super heater tubes by virtue of the boiler operating pressure.

Evaporators may be multi tubular shell, Water wall tubes, Boiler bank tubes or Bed coils as in FBC boiler. In evaporators the latent heat is added. The addition of heat is done at boiling temperature. The Flow of water through the evaporator is not by the pump but by the fact called thermo siphon. The density of the water, saturated or sub cooled is higher as compared the water steam mixture in the heated evaporator tubes. The circulation is absent once the boiler firing is stopped.

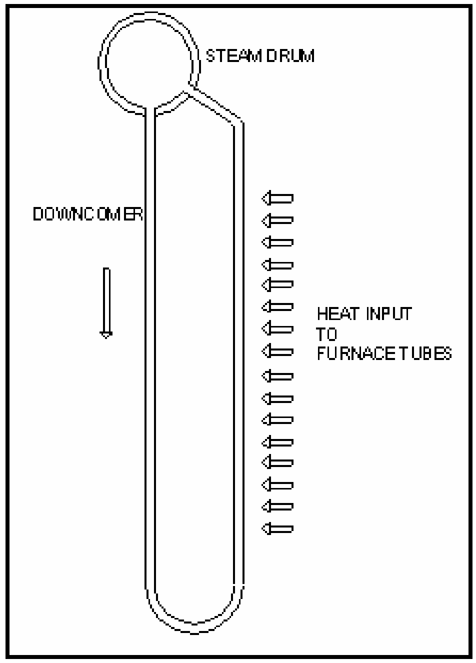


Fig.2.4.1 Flow due to density difference

2.4.2 Boiling mechanism

There are two regimes of boiling mechanisms, namely, the nucleate boiling and the film boiling. Nucleate boiling is formation and release of steam bubbles at the tube surface, with water still wetting the surface immediately. Since the tube surface temperature is closer to saturation temperature the tube is always safe against failure.

Film boiling is the formation of steam film at the tube surface, in which the metal temperature rises sharply. This leads to instantaneous or long term overheating of tubes & failures. Film boiling begins due to high heat flux or low velocity or inclined tubes.

2.4.3 Circulation Ratio / Number

The flow of water through a circuit should be more than the steam generated in order to protect the tube from overheating. The Boiler tubes, its feeding down comer pipes, relief tubes /pipes are arranged in such a way that a desired flow is obtained to safeguard the tubes. The ratio of the actual mass flow through the circuit to the steam generated is called circulation ratio.

$$\text{CIRCULATIO N RATIO} = \frac{\text{TOTAL FLOW THRO THE CIRCUIT}}{\text{STEAM GENERATED IN THE CIRCUIT}}$$

Depending the Boiler Design parameters, configuration of the boiler this number would be anywhere between 5 & 60. In low pressure boilers, this number is on the higher side as the density difference between water & steam is high.

2.4.4 Factors which affect Circulation

- No of down comers, diameter, thickness, layout
- Heated down comers
- Down comer location & entry arrangement inside the drum
- Arrangement of evaporator tubes
- Improper operation of boiler
- Feed pump operation
- Arrangement of evaporative sections and the interconnection between sections
- No of risers , pipe Inside diameter, bends, branches
- Arrangement of risers in the drum
- Feed distributor inside the steam drum
- Drum Internals arrangement
- Slagging of furnace tubes
- Critical heat flux, Allowable steam quality, recommended fluid velocity

2.4.5 Type of Circulation

Water-tube boilers are further classified according to the method of water circulation. Water-tube boilers may be classified as natural circulation boilers and forced circulation boilers.

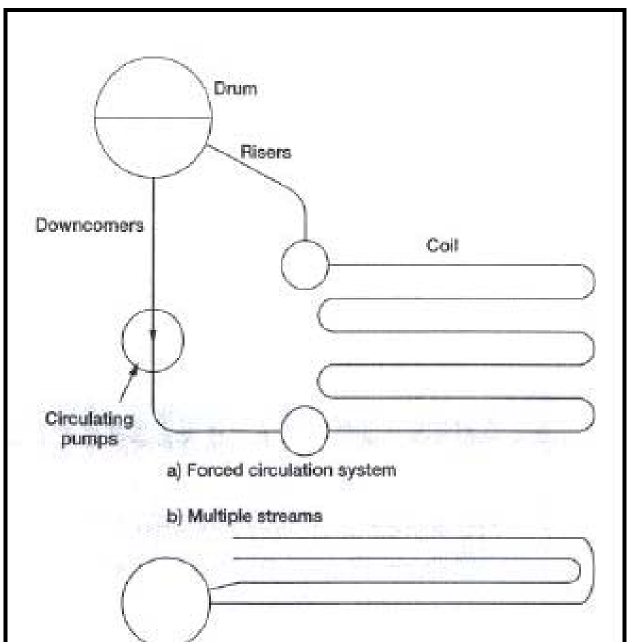


Fig.2.4.5 A forced-circulation system showing multiple streams to reduce pressure drop

In natural circulation boilers, the circulation of water depends on the difference between the density of an ascending mixture of hot water and steam and a descending body of relatively cool and steam-free water. The difference in density occurs because the water expands as it is heated, and thus, becomes less dense. Another way to describe natural circulation is to say that it is caused by convection currents which result from the uneven heating of the water contained in the boiler. Natural circulation may be either free or accelerated. In a boiler with free natural circulation, the generating tubes are installed almost horizontally, with only a slight incline toward the vertical. When the generating tubes are installed at a much greater angle of inclination, the rate of water circulation is definitely increased. Therefore, boilers in which the tubes slope quite steeply from steam drum to water drum are said to have natural circulation of the accelerated type. Most naval boilers are designed for accelerated natural circulation. In such boilers, large tubes (3 inches or more in diameter) are installed between the steam drum and the water drum. These large tubes, or down comers, are located outside the furnace and away from the heat of combustion. They serve as pathways for the downward flow of relatively cool water. When enough down comers are installed, all small tubes can be generating tubes, carrying steam and water upward, and all downward flow can be carried by down comers. The size and number of down comers installed varies from one type of boiler to another, but down comers are installed in all naval boilers. Forced circulation boilers are, as their name implies, quite different in design from the boilers that use natural circulation. Forced circulation boilers depend upon pumps, rather than upon natural differences in density, for the circulation of water within the boiler. Because forced circulation boilers are not limited by the requirements that hot water and steam must be allowed to flow found in forced circulation boilers.

Total thermal head

The total thermal head available in psi = H/v/144

Where H is the thermal head, meter

v is the specific volume of water, m^3/Kg

Down comer losses

Let the average CR for the system = CR and the total steam generation = WS meter/hr.

The total mixture flowing through the system =WS * CR

Let the effective length (including bends) of the down comer piping in meter = Le

The frictional pressure drop, psi = $3.36 * 10^{-5} * f$

Le v $(Wd)^2/di^5$

(Here, it is assumed that the average flow in each down comer pipe is Wd).

di is the inner diameter of the down comer pipe in mm.

f is the friction factor.

If there are several parallel paths or series -parallel paths, then the flow and pressure drop in each path is determined using electrical analogy. This calculation may require a computer.

In addition to the frictional drop, the inlet (0.5 * velocity head) and exit losses (1 * velocity head) must be computed. Sometimes the pipe inner diameter is larger than the inner diameter of the nozzle at the ends, in which case the higher velocity at the nozzles must be used to compute the inlet/exit losses. Velocity V in meter/s = 0.05 Wd v/die and velocity head, psi = $V^2/2$ g v/144.

2.4.6 Arrangement of steam and water spaces

Natural circulation water-tube boilers are classified as drum-type boilers or header-type boilers, depending on the arrangement of the steam and water spaces. Drum-type boilers have one or more water drums (and usually one or more water headers as well). Header-type boilers have no water drum; instead, the tubes enter many headers which serve the same purpose as water drums. What is a header, and what is the difference between a header and a drum? The term header is commonly used in engineering to describe any tube, chamber, drum, or similar piece to which tubes or pipes are connected in such a way as to permit the flow of fluid from one tube (or group of tubes) to another. Essentially, a header is a type of manifold or collection point. As far as boilers are concerned, the only distinction between a drum and a header is size. Drums maybe entered by a person while headers cannot. Both serve basically the same purpose. Drum-type boilers are further classified according to the overall shape formed by the steam and water spaces—that is, by the tubes. For example, double-furnace boilers are often called M-type boilers because the arrangement of the tubes is roughly M-shaped. Single-furnace boilers are often called D-type boilers because the tubes form a shape that looks like the letter D.

2.5 Blow down

Blow down is a common procedure for a boiler to control the contaminants in the boiling water.

Two types of blow down exist, manual and continuous. For a continuous blow down, a calibrated valve continuously takes water from the top of the boiling surface in the steam drum. In this case, many of the contaminants consist of oils floating on top of the water. Once a shift, the collected blow down water is cooled in a tank and returned to the city's waste water. To replace the water removed from the system, conditioned city water is added to the holding tank where the condensate is collected after returning from campus.

$$\% \text{ Blow down} = \frac{B_f}{B_f - B_b} \times 100\%$$

Where:

B_f = Total dissolved solids in feed water (ppm or mg/l)

B_b = Maximum allowable TDS in boiler water (ppm or mg/l)

For example, typical figures for a package boiler might be:

B_b = 3000 ppm and B_f = 100 ppm. Thus,

$$\% \text{ Blow down} = \frac{100}{3000 - 100} \times 100\% = 3.45\% \text{ of the steam production.}$$

2.6 Economizer

An economizer is employed to utilize the waste heat generated from the combustion process to improve overall efficiency in the boiler. Flue gas exiting the combustion chamber is still very hot and can be used as a preheater for the feed water. The economizer used for these boilers is a horizontal counter current shell and tube heat exchanger. Feed water enters finned tubes while hot flue gases pass over the outside. This allows for the recovery of energy which would otherwise be wasted.

2.7 Soot blower

When combustion occurs, the flue gas contains numerous compounds. Some of these compounds will collect on surfaces within the furnace and start to buildup. Soon the buildup will start to affect the overall performance of the boiler by obstructing the heat transfer. To cure this problem, two soot blowers are installed inside the furnace. One is a rotating soot blower, while the other is a non-rotating soot blower. Both the rotating and non-rotating soot blower will extract steam from the steam drum and spray the internal components of the boiler. The rotating blower is positioned on a power screw which cleans the steam generating tubes and the non-rotating blower is in a fixed position to clean the duct blower and induced draft fan.

2.7.1 Intelligent soot blowers

The use of ISB systems for improving system efficiency also enhances the performance of the furnace and longevity of the tubing material, while minimizing cycling effects to the steam turbine. The ISB system functions by monitoring both furnace exhaust gas temperatures and steam temperatures. A sophisticated ISB will receive various inputs from the boiler system, which are then digitally processed to evaluate real-time performance. The ISB system then interacts with the DCS, plant historian, or other data acquisition systems, to strategically allocate steam to specific areas to remove ash buildup. As soot and ash build up on heat transfer tubing, from the super heaters to the economizers, the transfer of heat from flue gas to the tubing is reduced, adversely affecting steam conditions. The ISB uses the real-time data to identify affected areas that require soot blowing. Traditional soot blowing systems depend on power plant operator directions and generally are used on a specified-time basis. Overuse of soot blowers erodes the boiler tubing and wastes steam that could be used in the power cycle. Soot blowing improvements affect performance at both full-load and turndown, since less steam is removed from the power cycle.

The boiler efficiency improvements obtained by installing ISB systems on older boilers have ranged from 0.3-0.9%pt. For units firing PRB coals and lignite where slugging and fouling result in a large, rapid decrease in thermal efficiency, the boiler efficiency improvement may be as high as 1.5%pt. The specific performance improvement depends on the type of fuel used and the age of the furnace. The average gain in boiler efficiency is approximately 0.6%pt, which translates to a reduction in net heat rate of 60 Btu/kWh for a plant that installs an ISB system.

The cost to implement an ISB system is relatively inexpensive if the necessary hardware is already installed, such as the soot blowers, steam lines, controls, etc. The system comprises proprietary software, and the majority of man hours expended to implement the system are for effectively engaging the current DCS with the ISB system controls. The cost to install an ISB system ranges from $300,000 to $500,000 and is not affected by the size of the boiler unit. The annual operating cost would be approximately $50,000. The separate improvements obtained via NN and ISB systems are not necessarily cumulative. The overall improvement via either system could be nearly the same as that achieved by the use of an advanced NN system integrated with an ISB system. The O&M expenditures are representative of software updates, onsite training, and computer hardware replacement.

Table summarizes the ISB heat rate reductions and costs.

Table 2.7.1 Summary of ISB Heat Rate Reductions and Costs

Parameter	210 MW
Heat rate reduction, Btu/kWh	30-150
Capital cost, $ million	0.3
Fixed O&M cost, $/yr	50,000
Variable O&M cost, $/yr	0

2.8 Air heaters

Air pre-heaters are paramount in maintaining a highly efficient power plant. Such systems provide heat recovery to the unit by cooling the flue gas counter-currently with cool incoming pre-combustion air. Cooling of the flue gas transfers the heat that is necessary both for coal drying and overall boiler efficiency. The air pre-heater is located downstream (flue gas path) of the economizer. There are two primary types of air pre-heaters - regenerative, rotating-type and recuperative, stationary-type. The stationary-type generally is classified as tubular or plate, with more advanced systems using heat pipes. The majority of air pre-heaters used with utility-scale boilers is the regenerative design, which is the type discussed in this report. Two methods are identified for air heater improvement, either singly or in combination:

- Limit air heater leakages to 6% of incoming air flow
- Lower air heater outlet temperature by controlling acid dew point

2.8.1 Air Heater and Duct Leakage

The most common, regenerative air pre-heater used on utility plants is the LjungstrÖm type. The heat exchanger is a cylindrical container filled with corrugated metal consisting of carbon steel in the hotter regions of the flue gas path and either an alloy- or enamel-coated carbon steel material at the cooler end due to acid deposition. The cylinder rotates during operation, absorbing heat from the hot flue gas and transferring it to the counter- flowing, cold precombustion air. The cylinder rotates on an axle. Ductwork manifolds on the top and bottom direct air and flue gases into separate portions of the cylinder. A major difficulty associated with the use of regenerative air pre-heaters is air leakage from the higher-pressure pre-combustion air side to the flue gas side. Generally, the combustion air leaks across the faces of the rotating section, thus bypassing the boiler and flowing out on the flue gas side. A second area of air leakage is around the outer perimeter of the cylinder. Leakage affects boiler efficiency due to lost heat recuperation. Fans are affected by the leakage since the combustion air requirement is fixed and any leakage requires additional fan capacity. The forced draft (FD) and induced draft (ID) fan must operate at higher capacities due to the increased flow incurred by the air bypassing the furnace.

Commissioning of air pre-heaters generally results in air leakage from the combustion air side to the flue gas side in the range of 5-15%, with the higher percentages representative of older style air heaters. As a unit ages, the percentage of air leaking past the seals increases, which lowers the plant efficiency due to the increase of air flow sent through the FD fans to maintain sufficient O2 levels in the boiler. The increased air flow raises the auxiliary power consumption of the FD fan; and if ID fans are used, even more auxiliary power is required to transfer the extra air through the flue gas ductwork, emissions control equipment, and stack. Air leakage measurements are difficult to accurately quantify and usually underestimate the actual leakage rate due to improperly located flow sensors. The effects of air pre-heater leakage are evident in the loads on the fans as compared to the original design loads if all other leakages are taken into account.

Regulatory mandates to retrofit existing units with environmental controls such as SCR, FGD, or bag houses have increased the auxiliary power needed to force the boiler flue gas through the added ductwork and emissions control equipment. The increased fan power generally requires a booster fan to be installed or possibly new ID fans if the plant does not already have an existing FGD system. If the air pre-heater allows a substantial amount of leakage and that is not addressed, the extra gas flow will increase the power consumption of either the new ID fans or booster fan more than necessary.

Improvements to seals on regenerative air pre-heaters have enabled the reduction of air leakage to roughly 6%. The improved seals offered by vendors are applied to the sectors, outer perimeter, and rotor section. The range of heat rate reductions that may be achieved by reducing air heater leakage varies significantly from unit to unit, but is approximately 10-40 Btu/kWh. If substantial improvements to a unit are implemented that include new environmental control technology, which results in an increase in flue gas pressure drop, then reducing the air heater leakage can decrease the plant heat rate by even more.

Table summarizes the air heater and duct leakage control heat rate reductions and costs.

Table 2.8.1 Summary of Air Heater and Duct Leakage Control Heat Rate Reductions and Costs

Parameter	210 MW
Heat rate reduction, Btu/kWh	10-40
Capital cost, $ million	0.3-0.5
Fixed O&M cost, $/yr	50,000
Variable O&M cost, $/yr	0

2.9 Feed water heaters

Feed water heaters are used within a power plant's thermal cycle to improve overall efficiency. The number and placement of feed water heaters are determined during the original plant design and are highly integrated with the overall performance of the steam turbine. Feed water heaters preheat the boiler feed water prior to it entering the boiler for steam generation. The heat used to increase the feed water temperature comes directly from the thermal cycle, as steam extracted from various turbine sections.

The feed water heaters in a power plant are either LP or HP shell and tube heat exchangers. From an efficiency standpoint, the primary means of improving the operation of such heat exchangers is to maintain their operational effectiveness. Feed water heating surface could be added to improve efficiency. However, the costs associated with either increasing the heat transfer surfaces of existing heaters, or adding additional heaters for efficiency purposes only, is prohibitive due to the small incremental reductions in heat rate that would be obtained.

2.10 Boiler feed pumps

The boiler feed pumps consume a large fraction of the auxiliary power used internally within a power plant. Boiler feed pumps pressurize and force feed water through the HP feed water heaters and boiler. Boiler feed pumps can require power in excess of 10 MW on a 500-MW power plant, therefore the maintenance on these pumps should be rigorous to ensure both reliability and high-efficiency operation.

Table 2.10.1 Summary of Boiler Feed Pump Heat Rate Reductions and Costs

Parameter	210 MW
Heat rate reduction, Btu/kWh	25-50
Capital cost, $ million	0.25-0.35
Fixed O&M cost, $/yr	0
Variable O&M cost, $/yr	0

Boiler feed pumps wear over time and subsequently operate below the original design efficiency. The most pragmatic remedy is to rebuild a boiler feed pump in an overhaul or upgrade. The overhaul of the pumps is justifiable in the industry and can yield heat rate reductions estimated to be in the range of 25-50 Btu/kWh. The estimated cost to rebuild the boiler feed pumps for a power plant unit ranges from $250,000 to $800,000.

2.11 Emissions

Special attention must be made to the flue gas temperature within the exhaust stack. Sulfur dioxide and trioxide are formed during the combustion process. If the flue gas temperature lowers below the dew point of the exhaust, sulfuric acid will condense on the stack walls causing corrosion. A procedure used to reduce nitrogen oxide (NOX) emissions is called flue gas recirculation (FGR) where exhaust from the combustion is recalculated into the combustion chamber again. FGR reduces the NOX emissions, decreases the peak combustion temperature, and lowers the percentage of oxygen in the combustion air/flue gas mixture, thereby slowing down the formation of NOX caused by high flame temperatures.

Table 2.11.1 Relationship between Boiler Thermal Efficiency and Emissions

Boiler Thermal Efficiency	Emissions per Heat Output (Kg CO_2/MMBtu)
80%	66.3
81%	65.5
82%	64.7
83%	63.9
84%	63.2
85%	62.4
86%	61.7
87%	61.0
88%	60.3
89%	59.6
90%	59.0
91%	58.3
92%	57.7
93%	57.1
94%	56.4

The amount of emissions produced by the boilers is closely monitored by the utility plant staff and the state government. Minnesota State University is allotted a certain quantity of emissions to expel each year. At the end of the year, MSU must pay per ton of emissions were emitted. If they exceed their allotted amount, additional fines are added on. When the boilers were still running on No. 6 fuel oil, the emissions had to be very closely monitored. The high sulfur content in this fuel resulted in the facility almost exceeding their sulfur discharge limit on a regular basis.

2.12 ELECTROSTATIC PRECIPITATORS

2.12.1 Introduction (ESP)

A device which separates particles from a gas stream by passing the carrier gas between pairs of electrodes across which a unidirectional, high-voltage potential is placed. The particles are charged before passing through the field and migrate to an oppositely charged electrode. These devices are very efficient collectors of small particles, and their use in removing particles from power plant plumes and in other industrial applications are widespread.

An electrostatic precipitator (ESP) is a particle control device that uses electrical forces to move the particles out of the flowing gas stream and onto collector plates. The particles are given an electrical charge by forcing them to pass through a corona, a region in which gaseous ions flow. The electrical field that forces the charged particles to the walls comes from electrodes maintained at high voltage in the center of the flow lane.

Once the particles are collected on the plates, they must be removed from the plates without re entraining them into the gas stream. This is usually accomplished by knocking them loose from the plates, allowing the collected layer of particles to slide down into a hopper from which they are evacuated. Some precipitators remove the particles by intermittent or continuous washing with water.

2.12.2 Types of ESPs

ESPs are configured in several ways. Some of these configurations have been developed for special control action, and others have evolved for economic reasons. The types that will be described here are:

(1) The plate-wire precipitator, the most common variety,

(2) The flat plate precipitator,

(3) The tubular precipitator,

(4) The wet precipitator, which may have any of the previous mechanical configurations,

(5) The two-stage precipitator.

Plate-Wire Precipitators

Plate-wire ESPs are used in a wide variety of industrial applications, including coal-fired boilers, cement kilns, solid waste incinerators, paper mill recovery boilers, petroleum refining catalytic cracking units, sinter plants, basic oxygen furnaces, open hearth furnaces, electric arc furnaces, coke oven batteries, and glass furnaces.

In a plate-wire ESP, gas flows between parallel plates of sheet metal and high-voltage electrodes. These electrodes are long wires weighted and hanging between the plates or are supported there by mast-like structures (rigid frames). Within each flow path, gas flow must pass each wire in sequence as flows through the unit.

The plate-wire ESP allows many flow lanes to operate in parallel, and each lane can be quite tall. As a result, this type of precipitator is well suited for handling large volumes of gas. The need for rapping the plates to dislodge the collected material has caused the plat to be divided into sections, often three or four in series with one another, which can be rapped independent.

The power supplies are often sectionalized in the same way to obtain higher operating voltages, and further electrical sectionalization may be used for increased reliability. Dust also deposits on the discharge electrode wires and must be periodically removed similarly to the collector plate.

The power supplies for the ESP convert the industrial ac voltage (220 to 480 V) to pulsating DC voltage in the range of 20,000 to 100,000 V as needed. The supply consists of a step-up transformer, high-voltage rectifiers, and sometimes filters capacitors. The unit may supply either half-wave or full-wave rectified dc voltage. There are auxiliary components and controls to allow the voltage to be adjusted to the highest level possible without excessive sparking and to protect the supply and electrodes in the event a heavy arc or short-circuit occur.

The voltage applied to the electrodes causes the air between the electrodes to break down electrically, an action known as a "corona". The electrodes usually are given a negative polarity because a negative corona supports a higher voltage than a positive corona before sparking occurs. The ions generated in the corona follow electric field lines from the wires to the collecting plates. Therefore, each wire establishes a charging zone through which the particles must pass.

Particles passing through the charging zone intercept some of the ions, which become attached. Small aerosol particles (<1 μm diameter) can absorb tens of ions before their total charge becomes large enough to repel further ions, and large particles (>10 μm diameter) can absorb tens of thousands. The electrical forces are therefore much stronger on the large particles. As the particles pass each successive wire, they are driven closer and closer to the collecting walls. The turbulence in the gas, however, tends to keep them uniformly mixed with the gas.

The collection process is therefore a competition between the electrical and dispersive forces.

Eventually, the particles approach close enough to the walls so that the turbulence drops to low levels and the particles are collected.

If the collected particles could be dislodged into the hopper without losses, the ESP would be extremely efficient. The rapping that dislodges the accumulated layer also projects some of the particles (typically 12 percent for coal fly ash) back into the gas stream. These reentrained particles are then processed again by later sections, but the particles reentrained in the last section of the ESP have no chance to be recaptured and so escape the unit.
Practical considerations of passing the high voltage into the space between the lanes and allowing for some clearance above the hoppers to support and align electrodes leave room for part of the gas to flow around the charging zones. This is called "sneakage" and amounts to 5 to 10 percent of the total flow. Antisneakage baffles usually are placed to force the sneakage flow to mix with the main gas stream for collection in later sections. But, again, the sneakage flow around the last section has no opportunity to be collected.

These losses play a significant role in the overall performance of an ESP. Another major factor is the resistivity of the collected material. Because the particles form a continuous layer on the ESP plates, the entire ion current must pass through the layer to reach the ground-plates. This current creates an electric field in the layer, and it can become large enough to cause local electrical breakdown. When this occurs, new ions of the wrong polarity are injected into the wire-plate gap where they reduce the charge on the particles and may cause sparking. This breakdown condition is called "back corona".

Back corona is prevalent when the resistivity of the layer is high, usually above 2 x 1011 ohmcm. For lower resistivity, the operation of the ESP is not impaired by back coronas, but resistivity much higher than 2 x 1011 ohm-cm considerably reduce the collection ability of the unit because the severe back corona causes difficulties in charging the particles. At resistivity below 108 ohm-cm, the particles are held on the plates so loosely that rapping and nonrapping reentrainment become much more severe. Care must be taken in measuring or estimating resistivity because it is strongly affected by variables such as temperature, moisture, gas composition, particle composition, and surface characteristics.

Flat Plate Precipitators

A significant number of smaller precipitators (100,000 to 200,000 acfm) use flat plates instead of wires for the high-voltage electrodes. The flat plates (United McGill Corporation patents) increase the average electric field that can be used to collect the particles, and they provide an increased surface area for the collection of particles. Corona cannot be generated on flat plates by themselves, so corona-generating electrodes are placed ahead of and sometimes behind the flat plate collecting zones. These electrodes may be sharp-pointed needles attached to the edges of the plates or independent corona wires. Unlike place-wire or tubular ESPs, this design operates equally well with either negative or positive polarity. The manufacturer has chosen to use positive polarity to reduce ozone generation.

A flat plate ESP operates with little or no corona current flowing through the collected dust, except directly under the corona needles or wires. This has two consequences. The first is that the unit is somewhat less susceptible to back corona than conventional units are because no back corona is generated in the collected dust, and particles charged with both polarities of ions have large collection surfaces available. The second consequence is that the lack of current in the collected layer causes an electrical force that tends to remove the layer from the collecting surface; this can lead to high rapping losses.

Flat plate ESPs seem to have wide application for high-resistivity particles with small (1 to 2 μm) mass median diameters (MMDs). These applications especially emphasize the strengths of the design because the electrical dislodging forces are weaker for small particles than for large ones. Fly ash has been successfully collected with this type of ESP, but low-flow velocity appears to be critical for avoiding high rapping losses.

Tubular Precipitators

The original ESPs were tubular like the smokestacks they were placed on, with the high-voltage electrode running along the axis of the tube. Tubular precipitators have typical applications in sulfuric add plants, coke oven by-product gas cleaning (tar removal), and, recently, iron and steel sinter plants. Such tubular units are still used for some applications, with many tubes operating in parallel to handle increased gas flows. The tubes may be formed as a circular, square, or hexagonal honeycomb with gas flowing upwards or downwards. The length of the tubes can be selected to fit conditions. A tubular ESP can be tightly sealed to prevent leaks of material, especially valuable or hazardous material.

A tubular ESP is essentially a one-stage unit and is unique in having all the gas passes through the electrode region. The high-voltage electrode operates at one voltage for the entire length of the tube, and the current varies along the length as the particles are removed from the system.

No sneakage paths are around the collecting region, but corona nonuniformities may allow some particles to avoid charging for a considerable fraction of the tube length.

Tubular ESPs comprise only a small portion of the ESP population and are most commonly applied where the particulate is either wet or sticky. These ESPs, usually cleaned with water, have reentrainment losses of a lower magnitude than do the dry particulate precipitators.

Wet Precipitators

Any of the precipitator configurations discussed above may be operated with wet walls instead of dry. The water flow may be applied intermittently or continuously to wash the collected particles into a sump for disposal. The advantage of the wet wall precipitator is that it has no problems with rapping reentrainment or with back coronas. The disadvantage is the increased complexity of the wash and the fact that the collected slurry must be handled more carefully than a dry product, adding to the expense of disposal.

Two-Stage Precipitators

The previously described precipitators are all parallel in nature, i.e., the discharge and collecting electrodes are side by side. The two-stage precipitator invented by Penney is a series device with the discharge electrode, or ionizer, preceding the collector electrodes. For indoor applications, the unit is operated with positive polarity to limit ozone generation.

Advantages of this configuration include more time for particle charging, less propensity for back corona, and economical construction for small sizes. This type of precipitator is generally used for gas flow volumes of 50,000 acfm and less and is applied to sub micrometer sources emitting oil mists, smokes, fumes, or other sticky particulates because there is little electrical force to hold the collected particulates on the plates. Modules consisting of a mechanical profiler, ionizer, collecting-plate cell, after-filter, and power pack may be placed in parallel or series-parallel arrangements. Preconditioning of gases is normally part of the system. Cleaning may be by water wash of modules removed from the system up to automatic, in-place detergent spraying of the collector followed by air-blow drying.

Two-stage precipitators are considered to be separate and distinct types of devices compared to large, high-gas-volume, single-stage ESPs. The smaller devices are usually sold as pre-engineered, package systems.

2.13 Boiler mountings and Control equipment for process steam

Boiler Mountings is the overall description applied to the valves and items of equipment that not only control the services to and from the boiler, but also indicate what is happening to the fluid inside the boiler, give warning should dangerous conditions arise and finally operate to ensure the safety of plant and personnel.

These mountings must be carefully selected from proven designs as the availability of any boiler is dependent on their trouble-free operation. Their construction should be robust (without over-designing), all materials carefully selected and quality controlled during all phases of manufacture. Finally, the design should enable maintenance to be carried out simply and effectively with a minimum of expense.

2.14 Safety and Inspection

One of the biggest maintenance and inspection issues for the facilities plant concerns the boilers.Boiler explosions were quite frequent and extremely dangerous in the late 1800's and early 1900's. Hundreds of people were killed du e to boiler failures. In large part this led to the creation and adoption of industry standards such as the ASME Boiler and Pressure Vessel Code. The majority of the boilers in the late 1800's and early 1900's were a fire tube type. This design is very similar to the water tube type except that the hot combustion gases used to heat the water were passed through tubes within the boiler surrounded by water. The problem which arose was that the boiler could not be safely pressurized and explosions resulted when the pressure vessel failed. This design issue helped usher in the current water tube boiler. With the water inside the small diameter tubes, the water can reach extremely high pressures with a greater degree of safety. Below is a picture of the hole a boiler inspector must crawl up to check. The boilers at Minnesota State are inspected once a year by a State Boiler Inspector. As part of this inspection individuals with contortionist-like abilities will actually crawl into the boiler. Click on the picture to hear Jeff Rendler, the State Boiler Inspector, talk about what happens with inadequate sized boiler tubes.

2.15 Troubleshooting

Faulty operation of auxiliary boilers is indicated by various symptoms. These symptoms may indicate one or more conditions in the boiler. Each condition must be corrected. Consult the manufacturer’s technical manual for detailed information on troubleshooting a particular boiler. Knowing the probable causes of a particular symptom can assist you in correcting any trouble quickly and efficiently. Some of the troubles encountered in the operation of auxiliary boilers and their causes are listed below.

Table 2.15.1 Troubleshooting Table

Symptom or Difficulty	Condition may be due to
Ignition failure	Faulty transformer. Broken or grounded high tension leads. Cracked high tension electrode insulator. Carbon deposits on electrodes or insulators. Incorrect electrode setting. Malfunctioning programming control cams. Faulty ignition cable connector. Solenoid oil or air valve fails to open. Water in the oil. Dirty or clogged burner tip.

Flame failure	Dirty glass in the photocell. Abnormal ambient temperature. Bad electron tube in the photo- cell. Damaged photocell. Faulty electron tubes in the combustion safeguard control. Loose connection on the photo- cell. Out of oil or have water in the oil. Clogged fuel oil nozzle. Clogged fuel oil line or strainer. Broken pressure regulates or spring. Faulty solenoid valve. Broken belt (V-belt drive).
Burner smokes or pulsates	Dirty nozzle. Excessive return line oil pres- sure (return flow system). Nozzle not positioned correctly. Insufficient air for combustion. Low oil pressure. Incorrect burner linkage set- ting. Incorrect setting of primary air. Low voltage (d-c machinery). Fluctuating voltage.
Oil pump fails to deliver	Leak in the suction line. Insufficient fuel in the tank. Clogged or dirty strainers. Worn pump members.
Oil pump fails to deliver (continued)	Improper oil relief valve set- ting. Defective gasket on the oil pump. Leaky pump seal.
Blower fails to deliver	Slipping V-belts. Driver pulley loose on the shaft. Misalignment. Dirty fan blades. Restriction at the blower inlet. Seized bearings in the blower or the blower drive. Bent or broken shaft. Dirty air inlet screen. Insufficient supply voltage to motor (d-c machinery). Fluctuating voltage.
Feed pump fails to deliver	Dirty suction strainer. Abnormally high water temperature. Leak in the suction line. Pump packing gland leaks badly. Plugged inlet piping. Excessive discharge head. Slipping or broken drive coup- ling. Jammed pumps impeller. Dirty water level relay contacts (electrode-probe type control). Malfunctioning pump time delay relay. Grounded water probes (electrode - probe

	type control). Pump vapor locked. Insufficient water supply. Reversed rotation. Worn-out impeller. Defective water pressure gage.
Excessive vibration	Combustion pulses. Loose hold-down bolts. Badly worn bearings. Insufficient air to the burner. Loose mechanical fasting. Misalignment of rotating auxiliaries. Dynamic unbalance of rotating auxiliaries.

2.16 Auxiliary machinery

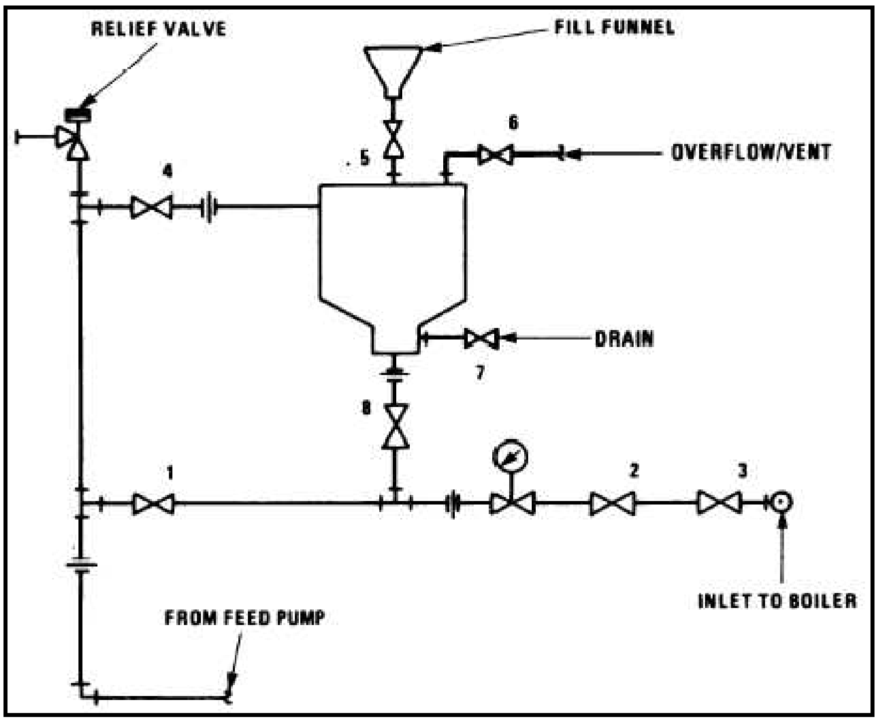


Fig.2.16.1 Auxiliary Boiler Chemical Injection Procedure

2.16.1 General procedure for adding chemical

(Assuming valves set for normal operation, i.e., valves 1, 2, 3 open and valves 4, 5, 6, 7, 8 closed**)**

1. Slowly open valves 7 (drain), 6 (overflow/vent), and then 5 (funnel fill).
2. Close valve 7.
3. Charge the injection tank with treatment chemicals already in solution through the funnel.
4. Top off tank with feed water obtained in bucket until an overflow just starts.
5. Close valves 5 and 6.

6. Open valves 4 and 8.

7. Close valve 1.

8. Maintain a flow of water for 10 minutes to wash out the injection tank.

2.16.2 Injection tank securing procedure

1. Open valve 1.
2. Close valves 4 and 8.
3. Drain injection tank by first slowly opening valve 7 and then valve 6.
4. Close valves 6 and 7.

Freshly filled, chemically treated boiler, prior to light off, is not representative and is therefore meaningless. The freshly filled and treated boiler shall be steamed immediately but not later than 24 hours after being filled. Preferably, the boiler should not be filled unless it is expected to be fired within 24 hours. If the boiler cannot be steamed within 24 hours.

Alkalinity and phosphate,Since the addition of TSP to raise the alkalinity also raises the phosphate, the control of alkalinity and phosphate are linked. The DSP provides additional phosphate as needed. The boiler water volume for chemical treatment must be determined as described earlier. Using this volume, the dosages of TSP and DSP are calculated. The boiler volume is multiplied by the factor and the dosage of TSP is entered to the nearest one- half ounce in the appropriate space. The increase in phosphate due to TSP is given in the last column.

The procedures for determining the chemical treatment dosages for the completed dosage steps are described below:

1. Determine the alkalinity and phosphate concentrations in the boiler water from sample results
2. Locate the boiler water alkalinity .Then read across to the weight of TSP required for the correct volume. Enter this weight in the log.
3. Continue to the last column to find the phosphate correction. This is the amount the phosphate will increase due to the TSP. Record the phosphate correction in the log.
4. Add the phosphate correction caused by TSP to the measured boiler water phosphate. This gives the corrected phosphate concentration; record this in the log.

5. Read across the table to the weight of DSP required for the correct volume. Enter this weight in the log. 6. Weigh the chemicals, dissolve them together in the 10-liter safety dispensing bottle, and inject the solution into the boiler.

2.16.3 Auxiliary boiler water treatment

The auxiliary boiler feed water is exposed to the same contaminants as the propulsion boiler feed water. Auxiliary boilers are generally used for hotel service loads, and shore water used for feed water is usually the prime source of con- termination. The shore water may contaminate the feed water system by leakage through malfunctioning galley mixing valves, laundry equipment, and hot water heaters. Shore water is usually hard water which contains high concentrations of dissolved solids and silica. Although it can have either high or low pH, in a boiler, shore water usually causes high pH. High concentrations of dissolved solids lead to boiler water carryover with the steam. Silica may be deposited on the boiler watersides and in the steam system as it vaporizes. Water hardness leads to excessive usage of boiler water treatment chemicals which causes corrosion, scale, and sludge buildup. Excessively high pH causes caustic embrittlement and subsequent erosion of boiler metal parts. Fire tube and water tube auxiliary boilers are natural circulation boilers. The water treatment for natural circulation auxiliary boilers is maintained in the same manner as the propulsion boiler water. The control parameters for auxiliary boiler water are alkalinity, phosphate, and chloride. In auxiliary boilers, the alkalinity of the auxiliary boiler water is measured instead of the pH because its higher alkalinity level can be more easily measured by the alkalinity test than by the pH meter test. The alkalinity range is equivalent to a pH range of 11.0 to 11.3. The same treatment chemicals, trisodium phosphate dodecahydrate (TSP) and disodium phosphate anhydrous (DSP), are used for auxiliary boiler water treatment except that a higher level must be maintained due to the lower operating pressures. The TSP provides alkalinity and phosphate. The DSP provides additional phosphate without significantly affecting the alkalinity.

2.17 Schematic diagram of power plant

In order to energy targeting and pinch point specification, a tool called "Program Table Algorithm" is used. In this way, the solution process is initiated to achieve energy targeting. After receiving inputs such as number of hot and cold streams, thermal capacity, and initial and final temperature, the program processes like this in order to get the pinch point and utilities: At first, all the quantities of hot and cold streams are placed in two separate matrices. Then the repetitive quantities are omitted in each of them and " $\frac{\Delta Tmin}{2}$ " is reduced from hot streams and is added to the cold streams. ΔTmin is the minimum temperature difference between cold and hot streams. Then, repetitive quantities are omitted between the new matrixes of the cold and hot stream temperatures and all the quantities are put in one matrix. After ascending the order of numbers in the combined matrix, the cascade analysis is started. At the end, the program obtains cold and hot utility and the pinch point, also data about composite curve (CC) and grand composite curve (GCC) are the main outputs.

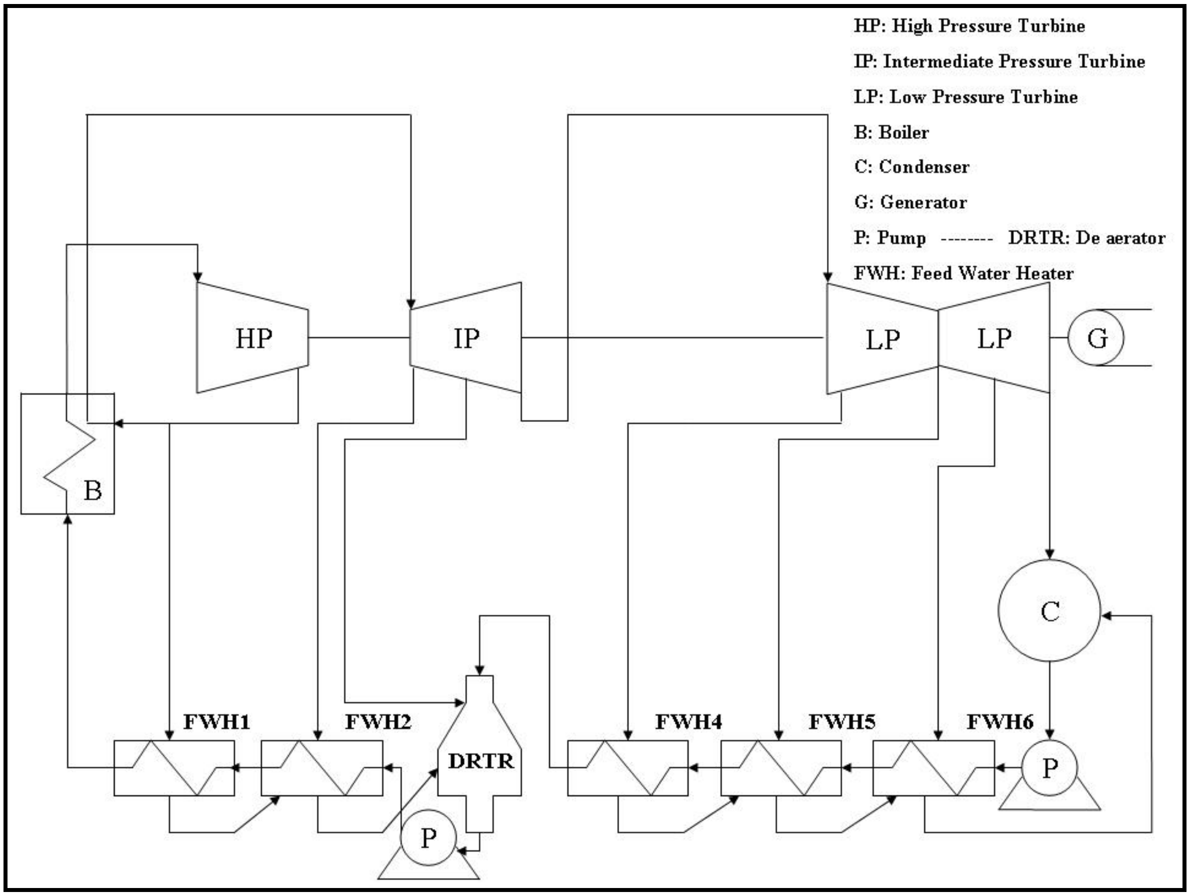


Fig.2.17.1 Schematic arrangement of the cycle

2.18 Other Types of boiler

[1] Open Flue Boilers

Also known as conventional flues boilers, these can be a back boiler, wall mounted or free standing. Open flue boilers are less efficient and in certain situations dangerous. An open flue boiler must sacrifice some efficiency in order to vent unwanted products of combustion from the house. By allowing flue gases to retain high temperature, the natural force of rising hot air creates chimney draft, which contains water vapour, carbon dioxide and oxides of nitrogen: all products of combustion. At the same time, air from the room is drawn into the burner to maintain combustion. In most cases it will be the heated air.

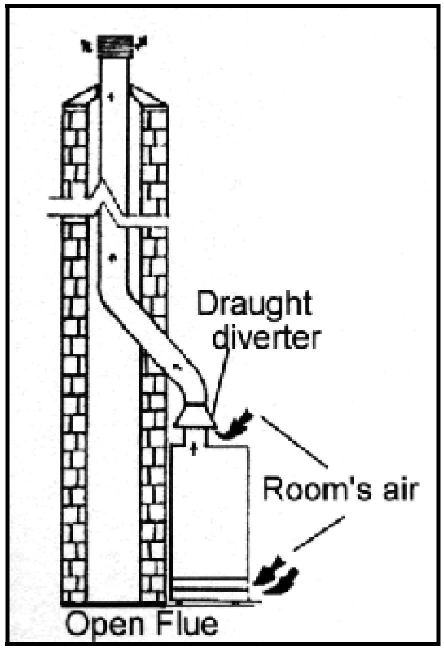


Fig.2.18.1 Open Flue Boilers

If there is insufficient air for the combustion process, poisonous carbon monoxide will be produced at the burner. When there is down draft in the chimney this poisonous gas will be carried into the room.

[2] Balanced Flue Boilers

A balanced flue consists of two ducts, one inside the other. The fresh air for the combustion is taken from the outer duct and the products of combustion are taken out by the central duct to outside the house. Hence the balanced flue terminal may only be fitted on an external wall. The combustion is independent of any air supply within the room; these boilers are often called room sealed.

Balanced flue are normally less than a meter, hence they are more efficient than open flue boilers.

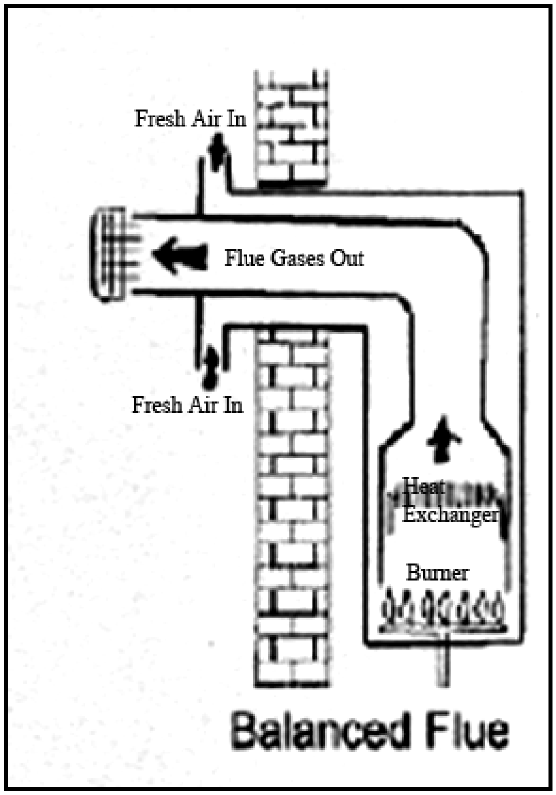


Fig 2.18.2 Balanced Flue Boilers

[3] Fan Assisted Boilers

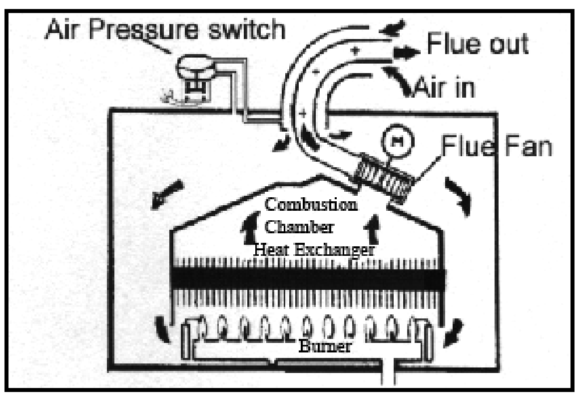


Fig. 2.18.3 Fan Assisted Boilers

Most boilers now are fan assisted. They have small cross sectional flue ducts. The flue fan provides the fresh air to the burner and also removes the products of combustion from the combustion chamber. The combustion is independent of any air supply within the room. Hence these are room sealed boilers. There is no need for the flue gases to have thermal energy to drive the gases out, these boilers are more efficient than the balanced flue.

[4] Back Boiler

This type of boiler can provide controlled central heating and an independent gas fire of room heater at the front. The back boiler and the gas fire or room heater share the same open flue in the chimney.

Most importantly the fresh air supply to the boiler and gas fire should come from the air in the room. Hence the room must have adequately sized fresh air vents fitted for the boiler and gas fire to function without danger. Otherwise the boilers can poisonous carbon monoxide. In very cold days these air vents may create a cold draught in the room, for safety reason never partly or totally block them. If you have draught proofed or double glazed your house call in a CORGI registered professional to check out the fresh air requirements for the boiler & fire, and obtain a safety certificate from him. It’s a good practice to check & service the boiler & fire every year, is a legal requirement if you are a land load. As back boiler uses open flue which demand high temperature flue gas these are not very energy efficient even the new ones rated at about 78%.

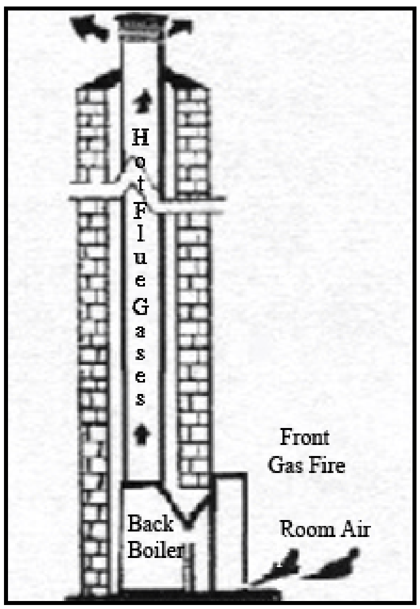


Fig. 2.18.4 Back Boiler

[5] Wall Mounted Boiler

This is popular because in most kitchens floor space is at a premium. They are similar to free standing boilers but and light enough to be fixed to a wall and do not have to rest on the floor. Most wall mounted boilers now are fan assisted, there balanced flue models both are room sealed and the open flue version is not available. Wall mounted boilers are also know as low-water content boilers because the heat exchanger in them have very little capacity, there some with cast iron heat exchanger, which can hold reasonable water capacity. Because of the low water content their heat Exchanger can easily overheat; hence high flow rate of water through the boiler must be maintained. A wall mounted boiler is not suitable gravity central heating system or gravity hot water system. It is common to hide them in a kitchen cupboard, although the room sealed boiler does not need air from the room to burn, do not fill the space in the cupboard the boiler need air circulation to prevent overheating. This is known as boiler compartment ventilation.

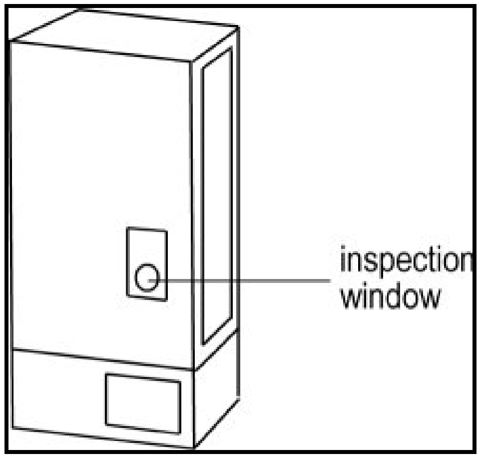


Fig. 2.13.5 Wall Mounted Boiler

[6] Free Standing Boiler

These are very popular in 70s and 80s, usually positioned on the floor in the kitchen or in an out boiler house. They have cast iron heat exchanger. All oil boilers are free standing, free standing gas boilers, because they take floor space are not normally considered for small houses, auto hopper feed solid fuel boilers are normally free standing ones.

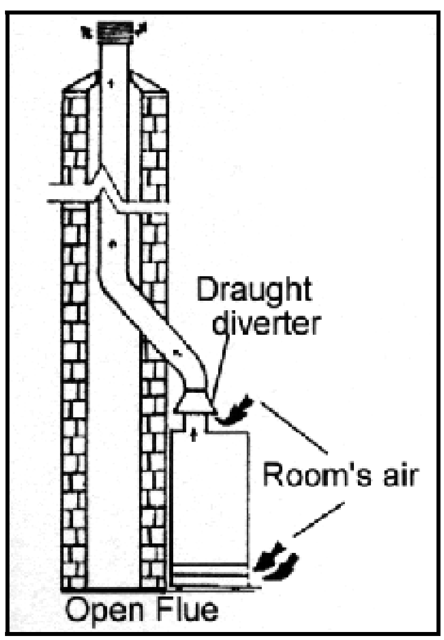


Fig. 2.18.6 Free Standing Boiler

A Free Standing Boiler can be a conventional boiler, combination boiler or condensing boiler and they can have open flue, balanced flue or fan assisted flue.

[7] Condensing Boiler

Traditional gas boiler discharges hot flue gases directly into the atmosphere, and in doing so throw away a considerable amount (nearly 25%) of heat which has been generated at a cost.

The condensing boiler is designed to extract more heat from a same quantity of gas than is possible when using traditional boilers. Hence saving gas and money in the process. This increase in efficiency of the boiler is obtained by retrieving most of the heat from the hot flue gases which would otherwise have gone to waste. The Condensing Boiler uses a secondary heat exchanger or condensing coil to recover heat from the hot flue gases. In gas combustion heat is produced along with water vapour (steam) and mixture of carbon & Nitrogen oxides. The temperature of this flue gas will be near to that of flame. The flue fan draws the hot flue gas through the primary heat exchanger (the main heat exchanger as in the traditional boiler) which is situated over the flame. The system water is heated when it passes through it and fed to the radiators. The returning water from the system after circulating through the radiators will be at low temperature. This low temperature returning water enters the secondary heat exchanger. This is heated by the hot flue gas that went through the primary heat exchanger. The water in the secondary heat exchanger will now recover some heat that normally lost on standard boilers.

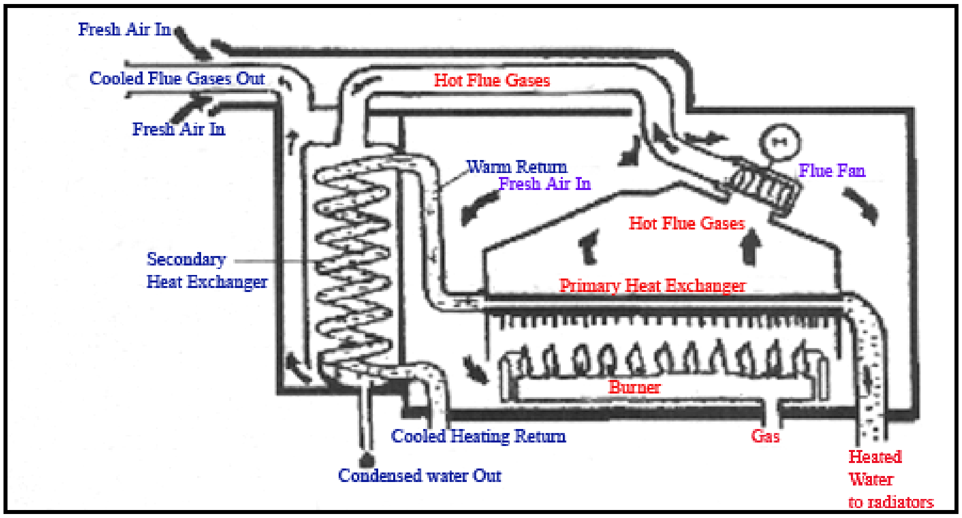


Fig. 2.18.7 Condensing Boiler

[8] Combination Boiler

A Combination Boiler (Combi) can provide central heating and hot water without the need for a hot water cylinder. There no need to store hot water at higher temperatures where heat will be lost, hence a Combi can save money. The problem with them is that they can only supply one tap at a time and hot water priority that is they will stop the central heating while heating water.

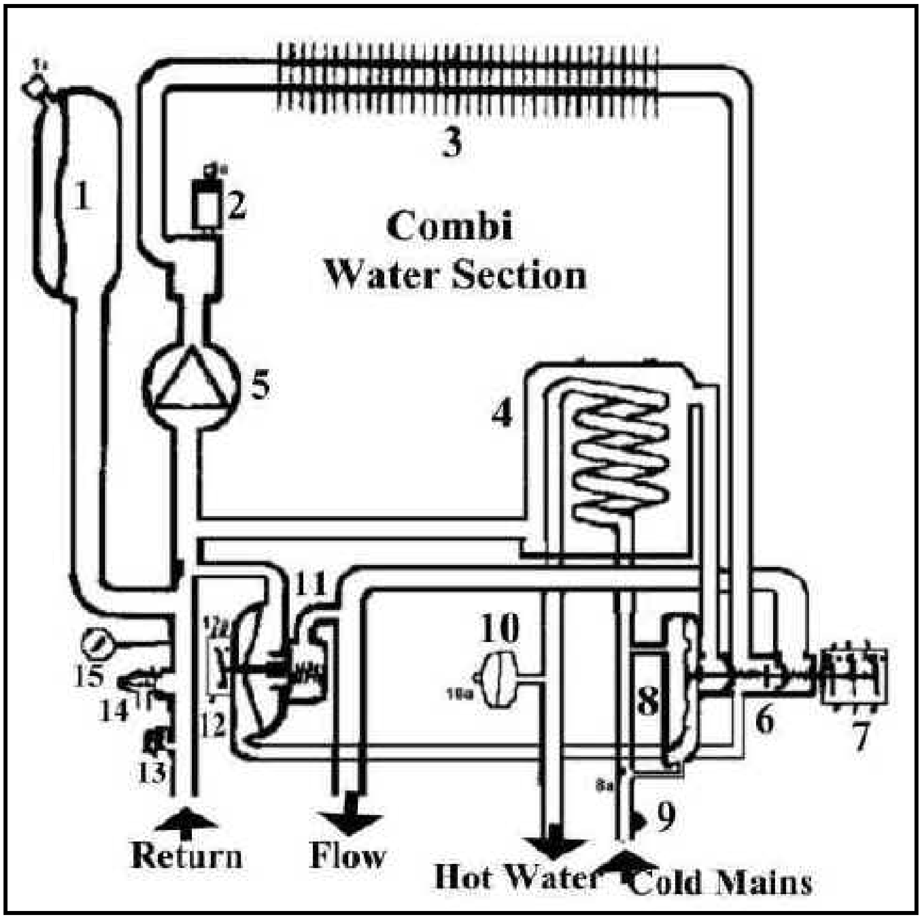


Fig. 2.18.8 Combination Boiler

Components:

1. Expansion Vessel
2. Auto Air Vent
3. Heat Exchanger
4. Domestic Hot Water Heat Exchanger
5. Pump
6. Diverter Valve
7. Micro Switches
8. Differential Pressure Unit
9. Water Governor

10. Domestic Hot water Expansion Vessel
11. by Pass Valve
12. Flow Switch
13. Low Pressure Sensor
14. Pressure Relief Valve
15. Pressure Gauge

[9] "D" Type boilers

"D" type boilers have the most flexible design. They have a single steam drum and a single mud drum, vertically aligned. The boiler tubes extend to one side of each drum. "D" type boilers generally have more tube surface exposed to the radiant heat than do other designs. "Package boilers" as opposed to "field-erected" units generally have significantly shorter fireboxes and frequently have very high heat transfer rates (250,000 btu per hour per sq foot). For this reason it is important to ensure high-quality boiler feed water and to chemically treat the systems properly. Maintenance of burners and diffuser plates to minimize the potential for flame impingement is critical.

[10] "A" Type boilers

This design is more susceptible to tube starvation if bottom blows are not performed properly because "A" type boilers have two mud drums symmetrically below the steam drum. Drums are each smaller than the single mud drums of the "D" or "O" type boilers. Bottom blows should not be undertaken at more than 80 per cent of the rated steam load in these boilers. Bottom blow refers to the required regular blow down from the boiler mud drums to remove sludge and suspended solids.

[11] "O" types boilers

"O" design boilers have a single steam drum and a single mud drum. The drums are directly aligned vertically with each other, and have a roughly symmetrical arrangement of riser tubes. Circulation is more easily controlled, and the larger mud drum design renders the boilers less prone to starvation due to flow blockage, although burner alignment and other factors can impact circulation.

[12] Electric boilers

Electric boilers can use electric resistance heating coils immersed in water and are normally very low-capacity units. Other types of electric boilers are electrode-type units that generate saturated steam by conducting current through the water itself. Boiler water conductivity must be monitored and controlled. If the conductivity is too low, the boiler will not reach full operating capacity. When the conductivity is too high, over-current protection will normally shut off the power.

Proper conductivity and high-quality water as well as effective water treatment is required. Solids from the saturated steam tend to accumulate slowly on the insulators supporting the electrodes from the grounded shell. The unit must be shut down periodically so that the insulators can be washed off to prevent arcing. Finally, voltages of up to 16 kV may be used. Protection is needed for ground faults, over-current and, for three-phase systems, loss of phase. The main electrical disconnect switch must be locked out before performing maintenance on the boiler.

[13] Cast Iron boilers

Cast iron boilers are fabricated from a number of cast iron sections that are bolted together. The design of each section includes integral water and combustion gas passages. When fully assembled, the interconnecting passage creates chambers where heat is transferred from the hot combustion gases to the water. These boilers generally produce low-pressure steam (15 psig) or hot water (30 psig) and burn either oil or natural gas.

Because of their construction, cast iron boilers are limited to smaller sizes. Because the components of these boilers are relatively small and easy to transport, they can be assembled inside a room with a conventional size doorway. This feature means that cast iron boilers are often used as replacement units, which eliminate the need for temporary wall removal to provide access for larger package units. They consist simply of a firebox surrounded by a water chamber for heat to be transferred directly from the firebox to the boiling water or to tube-type water heaters, while there are no boiler tubes. There is minimal need for feed water, and the boiler water does not concentrate.

[14] Tubeless boilers

Another boiler type that is sometimes used to produce steam or hot water is the tubeless boiler. The design of tubeless boilers incorporates nested pressure vessels with water located between the shells. Combustion gases are fired into the inner vessel where heat is transferred to water located between the outside surface of the inner shell and the inside surface of the outer shell. For oil-fired and natural gas-fired vertical tubeless boilers, the burner is typically located at the bottom of the boiler.

Some special applications of boilers require specific designs and operating procedures. These include waste to steam (trash to steam), waste heat recovery and heat recovery steam generators (HRSG).

[15] Trash to steam boilers

Trash to steam boilers uses trash (paper, plant material, plastics, etc.) as fuel. The steam is used for electrical power generation or central plant steam delivery. The main consideration is that the fuel has a widely varying heat value. Temperatures and heat fluxes can vary significantly over time. Water flows and the effects on chemical treatments can also vary widely. These units need more exhaustive monitoring and control. Fireside fouling is frequently a problem.

[16] Waste heat recovery boilers

If the waste heat stream is at 600 ^{o}F or higher, a boiler can be used cost effectively to generate steam by recovering the heat value in the stream. Such boilers can be of either water tube or fire tube design. These types of systems are common in the process industries.

[17] Packaged boilers

Boilers are occasionally distinguished by their method of fabrication. Packaged boilers are assembled in a factory, mounted on a skid, and transported to the site as one package, ready for hookup to auxiliary piping. Shop assembled boilers are built up from a number of individual pieces or subassemblies. After these parts are aligned, connected, and tested, the entire unit is shipped to the site in one piece. Field erected boilers are too large to be transported as an entire assembly. They are constructed at the site from a series of individual components. Sometimes these components require special transportation and lifting considerations because of their size and weight.

The packaged boiler is so called because it comes as a complete package. Once delivered to the site, it requires only the steam, water pipe work, fuel supply and electrical connections to be made for it to become operational. Packaged boilers are generally of shell type with fire tube design so as to achieve high heat transfer rates by both radiation and convection.

The features of packaged boilers are:

• Small combustion space and high heat release rate resulting in faster evaporation.

• Large number of small diameter tubes leading to good convective heat transfer.

• Forced or induced draft systems resulting in good combustion efficiency.

• A number of passes resulting in better overall heat transfer.

• Higher thermal efficiency levels compared with other boilers.

Owning to the evolution of boiler technology over time, it may be said with near surety that the types of boilers will grow over time. And many of these classifications may very well be overlapping.

2.19 Defining Boiler Efficiency:

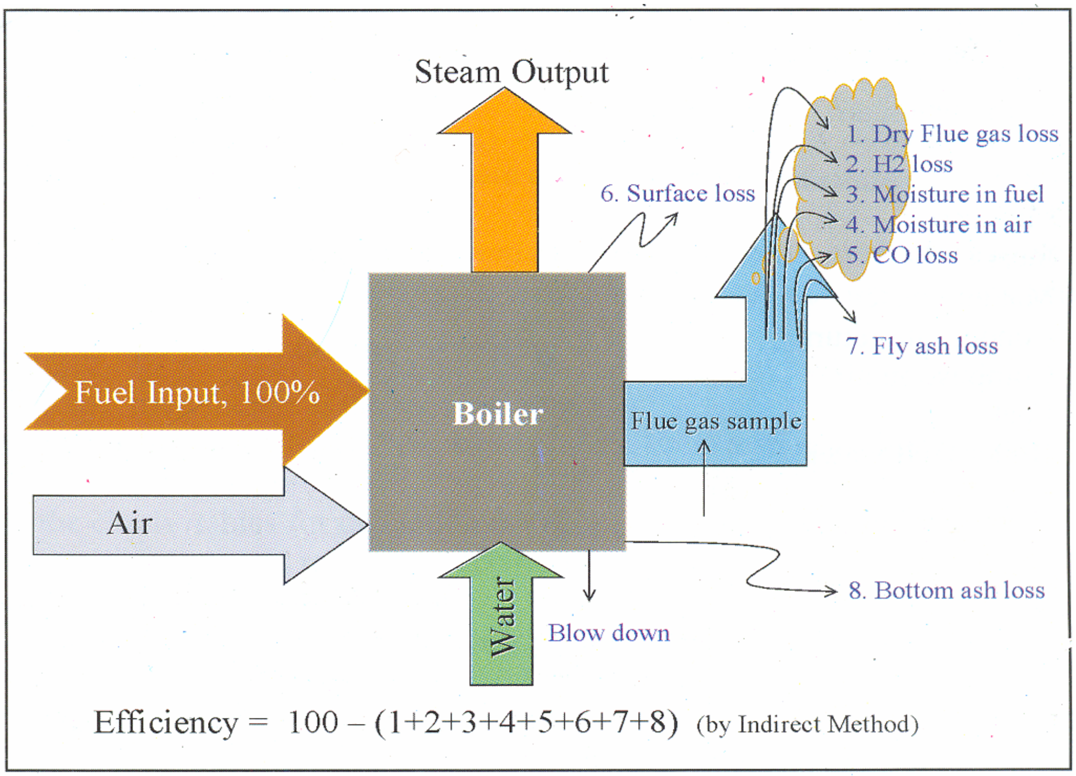


Fig. 2.19.1 Diagram of boiler efficiency

Boiler efficiency is defined as the heat added to the working fluid expressed as a percentage of the heat in the fuel being burnt. Boiler efficiency to the greater extent depends on the skill of designing but there is no fundamental reason for any difference in efficiency between a high pressure or low pressure boiler. Large boilers generally would be expected to be more efficient particularly due to design improvements.

A typical boiler will consume many times the initial capital expense in fuel usage annually. Consequently, a difference of just a few percentage points in boiler efficiency between units can translate into substantial savings.

There are listing some of the design requirement of boilers:

a. Should be able to produce at required parameters over an appreciable range of loading.
b. Compatible with feed water conditions which change with the turbine load.
c. Capable of following changes in demand for steam without excessive pressure swing.
d. Reliable.

This Efficiency Facts Booklet is designed to clearly define boiler efficiency. It will also give you the background in efficiency needed to ask the key questions when evaluating efficiency data, and provide you with the tools necessary to accurately compare fuel usage of boiler products, specifically fire tube type boilers**.**

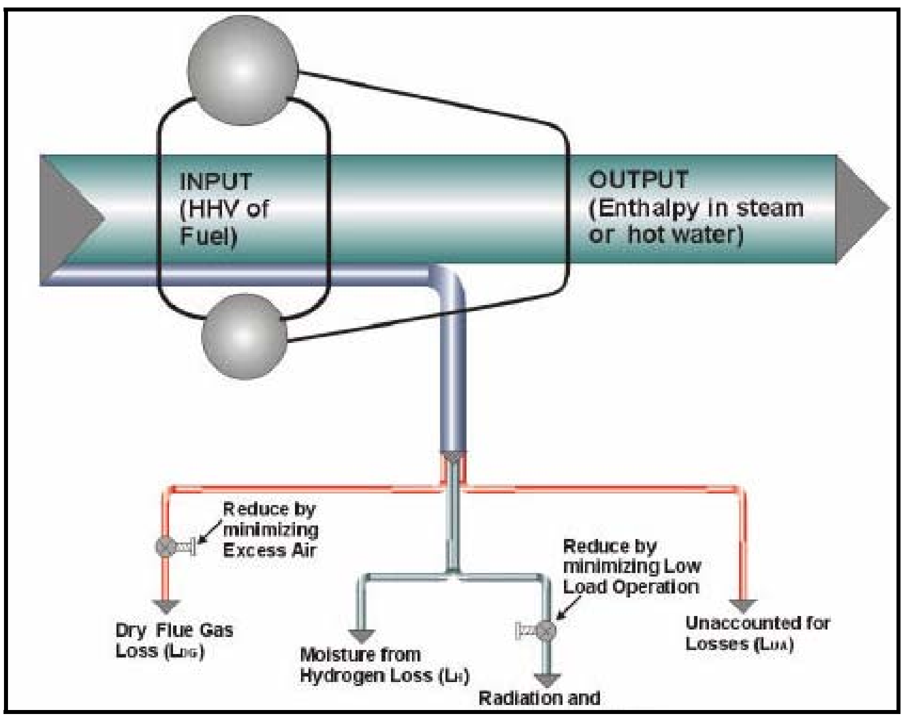


Fig.2.19.2 Simplified Boiler efficiency

2.20 Boiler Terminology

MCR: Steam boilers rated output is also usually defined as MCR (Maximum Continuous Rating). This is the maximum evaporation rate that can be sustained for 24 hours and may be less than a shorter duration maximum rating.

Boiler Rating

Conventionally, boilers are specified by their capacity to hold water and the steam generation rate. Often, the capacity to generate steam is specified in terms of equivalent evaporation (kg of steam / hour at 100 ^{o}C).Equivalent evaporation- “from and at” 100 ^{o}C. The equivalent of the evaporation of 1 kg of water at 100 ^{o}C to steam at 100 ^{o}C.

Efficiency: In the boiler industry there are four common definitions of efficiency:

2.20.1 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 useful energy.

Combustion efficiency is an indication of the burner’s ability to burn fuel. The amount of unburned fuel and excess air in the exhaust are used to assess a burner’s combustion efficiency. Burners resulting in low levels of unburned fuel while operating at low excess air levels are considered efficient. Well designed burners firing gaseous and liquid fuels operate at excess air levels of 15% and result in negligible unburned fuel. By operating at only 15% excess air, less heat from the combustion process is being used to heat excess air, which increases the available heat for the load. Combustion efficiency is not the same for all fuels and, generally, gaseous and liquid fuels burn more efficiently than solid fuels.

2.20.2 Thermal efficiency

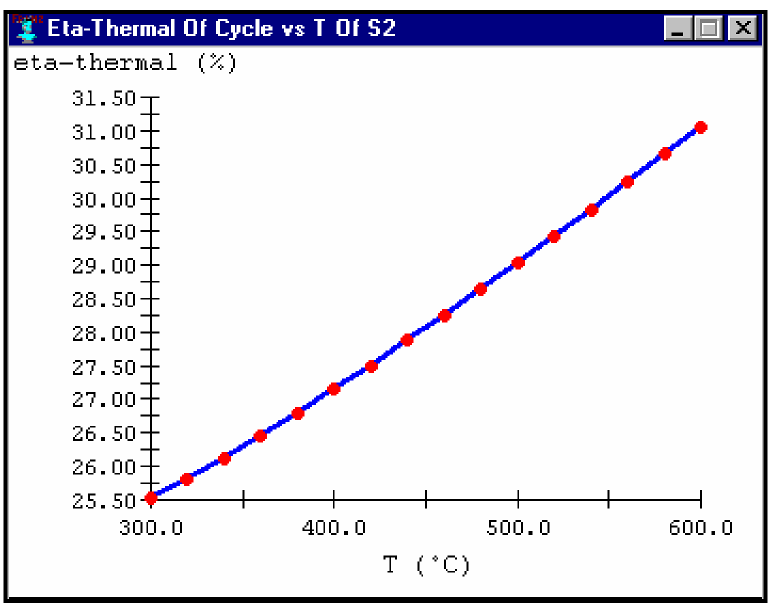


Fig.2.20.2 Thermal percentage vs. Temperature

Thermal efficiency is the effectiveness of the 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.

Thermal efficiency is a measure of the effectiveness of the heat exchanger of the boiler. It measures the ability of the exchanger to transfer heat from the combustion process to the water or steam in the boiler. Because thermal efficiency is solely a measurement of the effectiveness of the heat exchanger of the boiler, it does not account for radiation and convection losses due to the boiler's shell, water column, or other components. Since thermal efficiency does not account for radiation and convection losses, it is not a true indication of the boilers fuel usage and should not be used in economic evaluations.

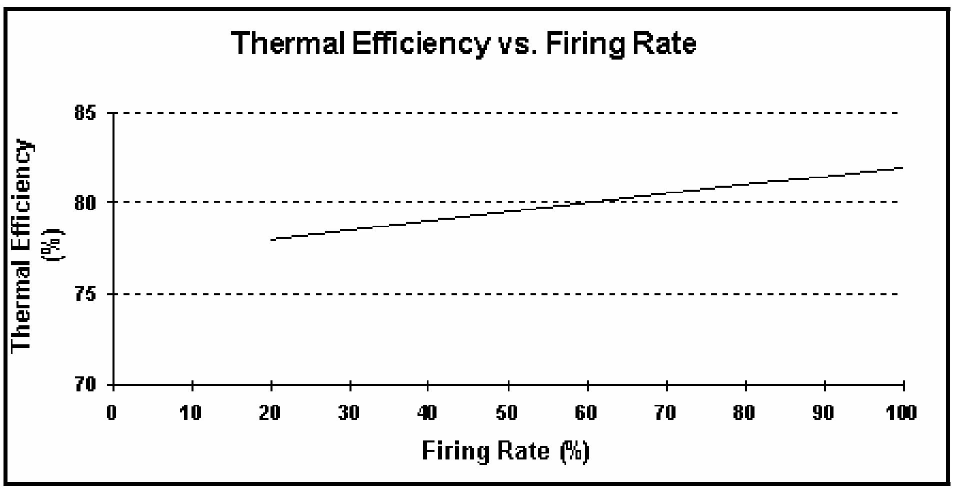


Fig.2.20.3 Thermal Efficiency vs. firing rate

2.20.3 Boiler efficiency

The term boiler efficiency is often substituted for combustion or thermal efficiency. True boiler efficiency is the measure of fuel to steam efficiency**.**

The term "boiler efficiency" is often substituted for thermal efficiency or fuel-to-steam efficiency. When the term "boiler efficiency" is used, it is important to know which type of efficiency is being represented. Because thermal efficiency, which does not account for radiation and convection losses, is not an indication of the true boiler efficiency. Fuel-to-steam Efficiency, which does account for radiation and convection losses, is a true indication of overall boiler efficiency. The term "boiler efficiency" should be defined by the boiler manufacturer before it is used in any economic evaluation.

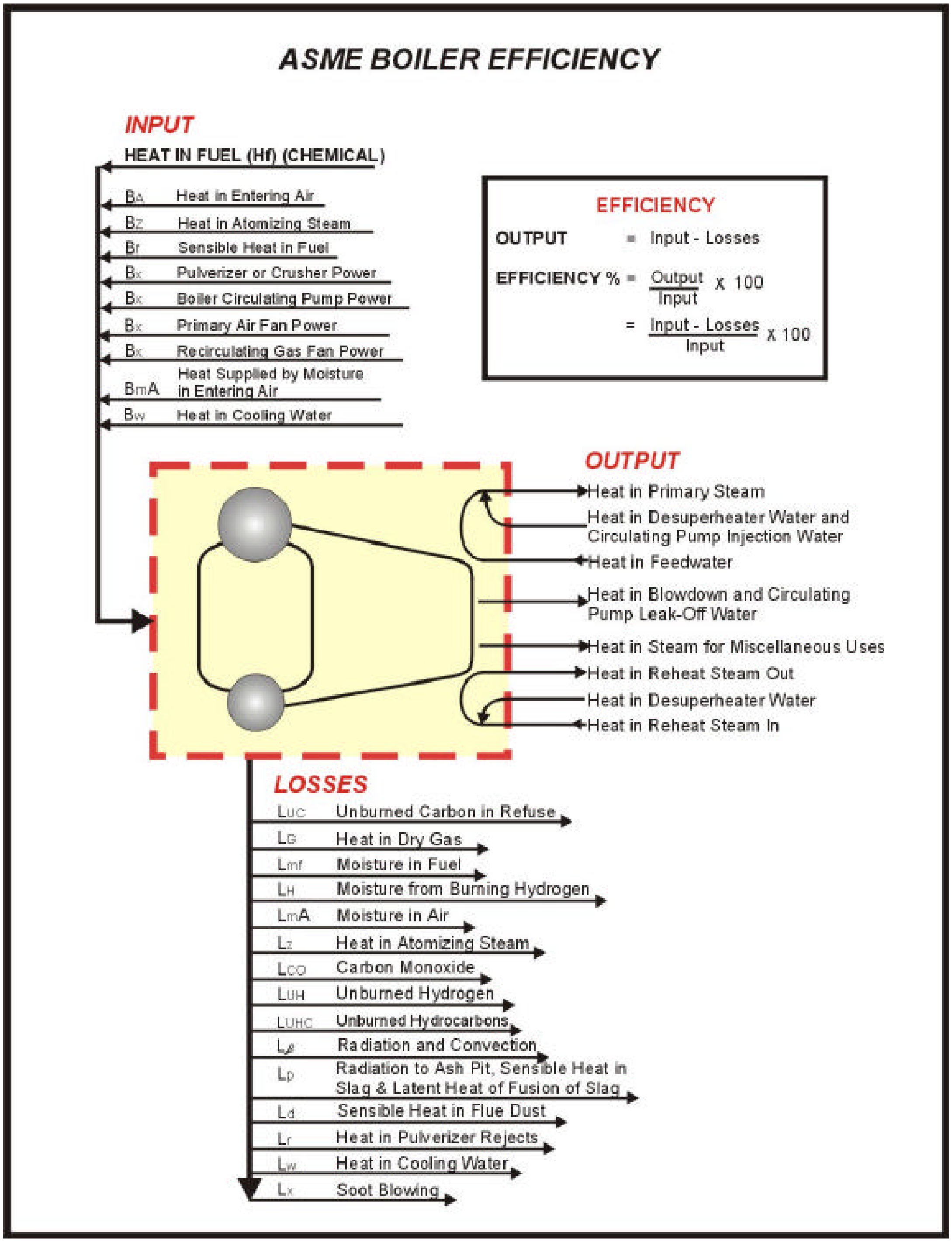


Fig. 2.20.4 ASME Boiler Efficiency

2.20.4 Fuel to steam efficiency

Fuel to steam efficiency is calculated using either of the two methods as prescribed by the ASME (American Society for Mechanical Engineers) power test code, PTC 4.1. The first method is input output method. The second method is heat loss method.

Fuel-to-steam efficiency is a measure of the overall efficiency of the boiler. It accounts for the effectiveness of the heat exchanger as well as the radiation and convection losses.

It is an indication of the true boiler efficiency and should be the efficiency used in economic evaluations**.** As prescribed by the ASME Power Test Code, PTC 4.1, and the fuel-to team efficiency of a boiler can be determined by two methods; the Input-Output Method and the Heat Loss Method.

[A]Input-Output Method

The Input-Output efficiency measurement method is based on the ratio of the output-to-input of the boiler. It is calculated by dividing the boiler output (in BTUs) by the boiler input (in BTUs) and multiplying by 100. The actual input and output of the boiler are determined though instrumentation and the data are used in calculations that result in the fuel-to-steam efficiency.

[B]Heat Loss Method

The Heat Balance efficiency measurement method is based on accounting for all the heat losses of the boiler. The actual measurement method consists of subtracting from 100 percent the total percent stack, radiation, and convection losses. The resulting value is the boiler's fuel-to-steam efficiency. The heat balance method accounts for stack losses and radiation and convection losses.

Stack Losses: Stack temperature is a measure of the heat carried away by dry flue gases and the moisture loss. It is a good indicator of boiler efficiency. The stack temperature is the temperature of the combustion gases (dry and water vapor) leaving the boiler and reflects the energy that did not transfer from the fuel to the steam or hot water. The lower the stack temperature is, the more effective the heat exchanger design and the higher the fuels-to-steam efficiency.

Radiation and Convection Losses: All boilers have radiation and convection losses. The Losses represent heat radiating from the boiler (radiation losses) and heat lost due to air flowing across the boiler (convection losses). Radiation and convection losses, expressed in Btu/hr, are essentially constant throughout the firing range of a particular boiler, but vary between different boiler types, sizes, and operating pressures.

2.21 Boiler turndown

Boiler turndown is the ratio between full boiler output and the boiler output when operating at low fire. Typical boiler turndown is 4:1. The ability of the boiler to turndown reduces frequent on and off cycling. Fully modulating burners are typically designed to operate down to 25% of rated capacity. At a load that is 20% of the load capacity, the boiler will turn off and cycle frequently.

A boiler operating at low load conditions can cycle as frequently as 12 times per hour or 288 times per day. With each cycle, pre and post purge airflow removes heat from the boiler and sends it out the stack. Keeping the boiler on at low firing rates can eliminate the energy loss. Every time the boiler cycles off, it must go through a specific start-up sequence for safety assurance. It requires about a minute or two to place the boiler back on line. And if there is a sudden load demand the start up sequence cannot be accelerated. Keeping the boiler on line assures the quickest response to load changes. Frequent cycling also accelerates wear of boiler components. Maintenance increases and more importantly, the chance of component failure increases.

Boilers capacity requirement is determined by many different type of load variations in the system. Boiler over sizing occurs when future expansion and safety factors are added to assure that the boiler is large enough for the application. If the boiler is oversized the ability of the boiler to handle minimum loads without cycling is reduced. Therefore capacity and turndown should be considered together for proper boiler selection to meet overall system load requirements.

Primary air: That part of the air supply to a combustion system which the fuel first encounters.

Secondary air: The second stage of admission of air to a combustion system, generally to complete combustion initiated by the primary air. It can be injected into the furnace of a boiler under relatively high pressure when firing solid fuels in order to create turbulence above the burning fuel to ensure good mixing with the gases produced in the combustion process and thereby complete combustion possible.

Tertiary air: A third stage of admission of air to a combustion system, the reactions of which have largely been completed by secondary air. Tertiary air is rarely needed.

Stoichiometric: In combustion technology, stoichiometric air is that quantity of air, and no more, which is theoretically needed to burn completely a unit quantity of fuel. ‘Sub-stoichiometric’ refers to the partial combustion of fuel in a deficiency of air

Balanced draught: The condition achieved when the pressure of the gas in a furnace is the same as or slightly below that of the atmosphere in the enclosure or building housing it.

Gross calorific value (**GCV**): The amount of heat liberated by the complete combustion, under specified conditions, by a unit volume of a gas or of a unit mass of a solid or liquid fuel, in the determination of which the water produced by combustion of the fuel is assumed to be completely condensed and its latent and sensible heat made available.

Net calorific value (**NCV**): The amount of heat generated by the complete combustion, under specified conditions, by a unit volume of a gas or of a unit mass of a solid or liquid fuel, in the determination of which the water produced by the combustion of the fuel is assumed to remain as vapour.

Absolute pressure The sum of the gauge and the atmospheric pressure. For instance, if the steam gauge on the boiler shows 9 kg/cm^2 g the absolute pressure of the steam is 10 kg/cm^2.

Atmospheric pressure The pressure due to the weight of the atmosphere. It is expressed in pounds per sq. in. or inches of mercury column or kg/cm^2. Atmospheric pressure at sea level is 14.7 lbs. / sq. inch. Or 30 inch mercury column or 760mm of mercury (mm Hg) or 101.325 kilo Pascal (kPa).

Carbon monoxide (CO): Produced from any source that burns fuel with incomplete combustion, causes chest pain in heart patients, headaches and reduced mental alertness.

Blow down: The removal of some quantity of water from the boiler in order to achieve an acceptable concentration of dissolved and suspended solids in the boiler water.

Complete combustion: The complete oxidation of the fuel, regardless of whether it is accomplished with an excess amount of oxygen or air, or just the theoretical amount required for perfect combustion.

Perfect combustion: The complete oxidation of the fuel, with the exact theoretical (stoichiometric) amount of oxygen (air) required.

Saturated steam: It is the steam, whose temperature is equal to the boiling point corresponding to that pressure.

Wet Steam Saturated steam which contains moisture

Dry Steam Either saturated or superheated steam containing no moisture.

Superheated Steam heated to a temperature above the boiling point or saturation temperature corresponding to its pressure

Oxygen trims sensor measures flue gas oxygen and a closed loop controller compares the actual oxygen level to the desired oxygen level. The air (or fuel) flow is trimmed by the controller until the oxygen level is corrected. The desired oxygen level for each firing rate must be entered into a characterized set point curve generator. Oxygen Trim maintains the lowest possible burner excess air level from low to high fire. Burners that don't have Oxygen Trim must run with Extra Excess Air to allow safe operation during variations in weather, fuel, and linkage.

Heat transfer mediums

There are different types of heat transfer medium e.g. steam, hot water and thermal oil. Steam and Hot water are most common and it will be valuable to briefly examine these common heat transfer mediums and associated properties.

Thermic Fluid

Thermic Fluid is used as a heat transfer mechanism in some industrial process and heating applications. Thermic Fluid may be vegetable or mineral based oil and the oil may be raised to a high temperature without the need for any pressurization. The relatively high flow and return temperatures may limit the potential for flue gas heat recovery unless some other system can absorb this heat usefully. Careful design and selection is required to achieve best energy efficiency.

Hot water

Water is a fluid with medium density, high specific heat capacity, low viscosity and relatively low thermal conductivity. At relatively low temperature e.g. $70^{o}C$ -$90^{o}C$, hot water is useful for smaller heating installations.

Steam

When water is heated its temperature will rise. The heat added is called sensible heat and the heat content of the water is termed its enthalpy. The usual datum point used to calculate enthalpy is $0^{o}C$.

When the water reaches its boiling point, any further heat input will result in some proportion of the water changing from the liquid to the vapour state, i.e. changing to steam. The heat required for this change of state is termed the 'latent heat of evaporation' and is expressed in terms of a fixed mass of water. Where no change in temperature occurs during the change of state, the steam will exist in equilibrium with the water. This equilibrium state is termed 'saturation conditions'. Saturation conditions can occur at any pressure, although at each pressure there is only one discrete temperature at which saturation can occur.

If further heat is applied to the saturated steam the temperature will rise and the steam will become 'superheated'. Any increase in temperature above saturated conditions will be accompanied by a further rise in enthalpy.

Steam is useful heat transfer medium because, as a gas, it is compressible. At high pressure and consequently density, steam can carry large quantities of heat with relatively small volume.

2.22 Component of Efficiency:

Boiler efficiency, when calculated by the ASME heat balance method, includes stack losses and radiation and convection losses. The basic boiler design is the major factor. However, there is room for interpretation when calculating efficiency. Indeed if desired, you can make a boiler appear more efficient than it really is by using a little creativity in the efficiency calculation. The following are the key factors to understanding efficiency calculations.

2.22.1 Flue gas temperature (Stack temperature)
2.22.2 Fuel specification
2.22.3 Excess air
2.22.4 Ambient air temperature
2.22.5 Radiation and convection losses.

2.22.1 Flue Gas Temperature

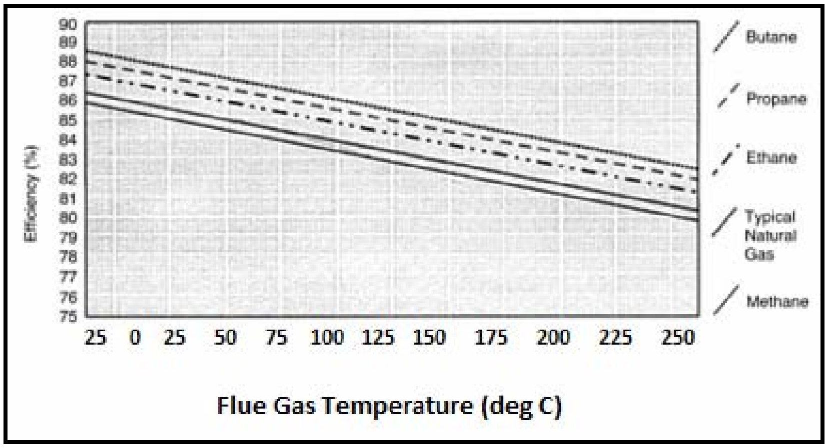


Fig. 2.22.0 Fuels-to-steam efficiency vs. flue gas temperature

Flue gas temperature or “stack temperature” is the temperature of the combustion gases as they exit the boiler. The flue gas temperature must be a proven value for the efficiency calculation to be reflective of the true fuel usage of the boiler. A potential way to manipulate an efficiency value is to utilize a lower-than-actual flue gas temperature in the Calculation. When reviewing an efficiency guarantee or calculation, check the flue Gas temperature. Jobsite conditions will vary and have an effect on flue gas temperature. However, if the efficiency value is accurate, the flue gas temperatures should be confirmable in existing applications. Don’t be fooled by estimated stack temperatures. Make sure the stack temperature is proven.

Figure (2.22.1) shows flue gas temperature vs. theoretical fuel-to-steam efficiency. This table represents the maximum theoretical efficiency you can achieve at a given flue gas temperature. The table can be used as follows. If a boiler is represented to be 85% efficient firing natural gas, follow the 85% on the left to the natural gas line and down to the flue gas temperature. The result is approximately 0 deg. C. This shows the boiler would have to operate at a 0 deg. C. stack temperature to meet the 85% efficiency, or the efficiency calculation was based on an unrealistically low hydrogen content fuel. If a boiler is represented to be 85% efficient on natural gas at a 75° F stack temperature, check the fuel specification. A Boiler cannot operate at 85% efficiency at 75° F stack temperature when firing natural gas per Figure (2.22.1).

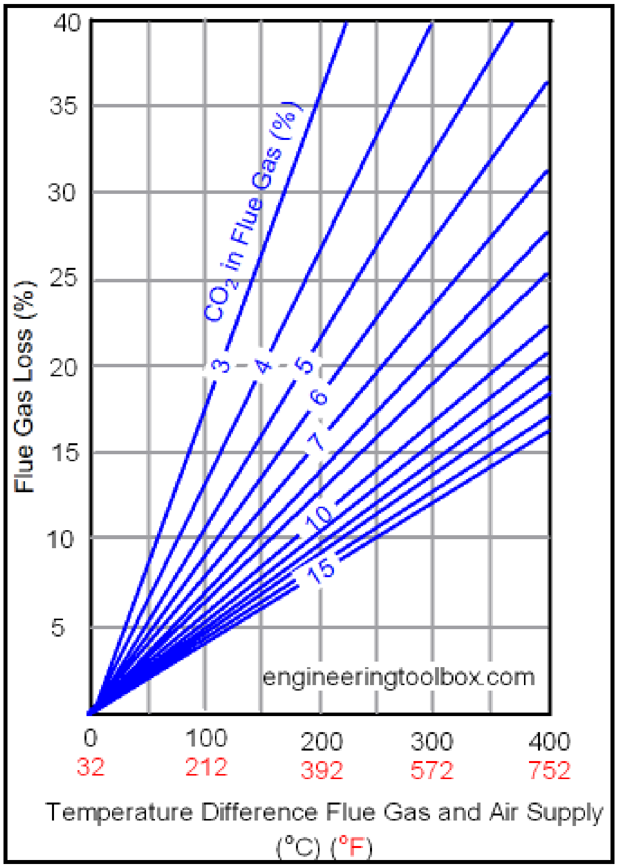


Fig. 2.22.1 Flue gas loss vs. temperature difference flue gas and air supply

2.22.2 Fuel Specification

The fuel specification can also have a dramatic effect on efficiency. In the case of gaseous fuels, the higher the hydrogen content, the more water vapor is formed during combustion. This water vapor uses energy as it changes phase in the combustion process.

Higher water vapor losses when firing the fuel result in lower efficiency. This is one reason why fuel oil fires at higher efficiency levels than natural gas. To get an accurate efficiency calculation, a fuel specification that represents the jobsite fuel to be fired must be used. When reviewing an efficiency guarantee or calculation, check the fuel specification. The representation of efficiency using fuel with low hydrogen content will not provide an accurate evaluation of your actual fuel usage.

Figure (2.22.2) shows the degree to which efficiency can be affected by fuel specification. The graph indicates the effect of the hydrogen-to-carbon ratio on efficiency for five different gaseous fuels. At identical operating conditions, efficiencies can vary as much as 2.5-3.0% based solely on the hydrogen-to-carbon ratio of the fuel. When evaluating boiler efficiency, knowing the actual fuel specification is a must.

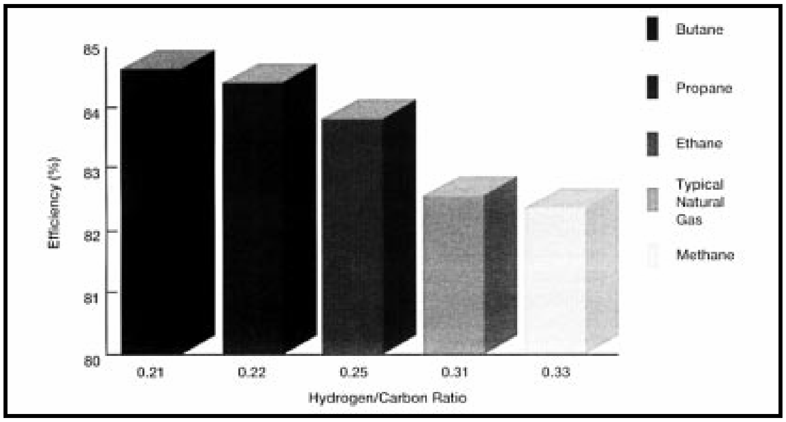


Fig.2.22.2 Efficiency vs. H/C ratio

2.22.3 Excess Air

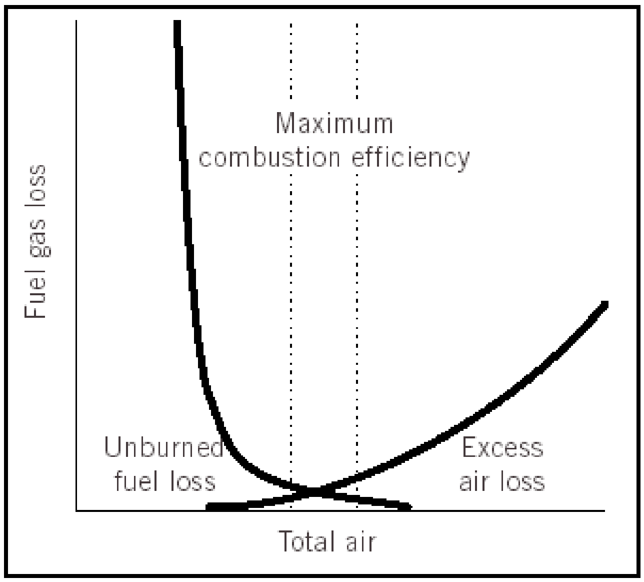


Fig. 2.22.3 Flue gas vs. total air

Excess air is the extra air supplied to the burner beyond the required air for complete combustion. Excess air is supplied to the burner because a boiler firing without sufficient air or “fuel rich” is operating in a potentially dangerous condition. Therefore, excess air is supplied to the burner to provide a safety factor above the actual air required for combustion. However, excess air uses energy from combustion, thus taking away potential energy for transfer to water in the boiler. In this way, excess air reduces boiler efficiency. A quality burner design will allow firing at minimum excess air levels of 15% (3% as O_2).

Seasonal changes in temperature and barometric pressure can cause the excess air in a boiler to fluctuate 5% - 10%. Furthermore, firing at low excess air levels can result in high CO and boiler sooting, specifically if the burner has complex linkage and lacks proper fan design. The fact is even burners theoretically capable of running at less than 15% excess air levels rarely are left at these settings in actual practice. A realistic excess air level for a boiler in operation is 15% if an appropriate safety factor is to be maintained. When reviewing an efficiency guarantee or calculation, check the excess air levels. If 15% excess air is being used to calculate the efficiency, the burner should be of a very high quality design with repeatable damper and linkage features. Without these features, your boiler will not be operating at the low excess air values being used for the calculation, at least not for long. If less than 15% excess air is being used for the calculation you are probably basing your fuel usage on a higher efficiency than will be achieved in your day to day operation. You should ask the vendor to recalculate the

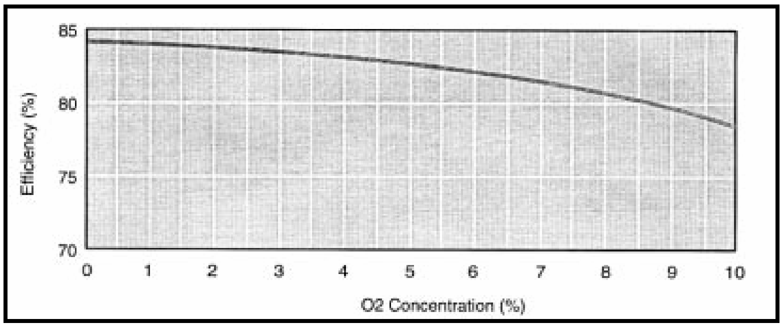


Fig. 2.22.4 Efficiency vs. O_2 concentration

efficiency at realistic excess air values. Figure (2.22.2) shows excess air concentration vs. efficiency. The chart can be used to review the impact of variations in excess air values on efficiency.

2.22.4 Ambient Temperature

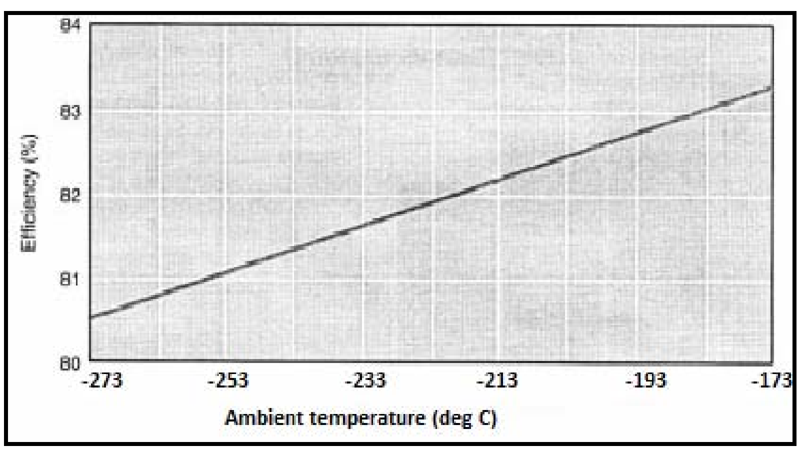


Fig 2.22.5 Efficiency vs. Ambient Temperature

Ambient temperature can have a dramatic effect on boiler efficiency. A 40 degree variation in ambient temperature can affect efficiency by 1% or more. Most boiler rooms are relatively warm. Therefore, most efficiency calculations are based on -193° C ambient temperatures. When reviewing an efficiency guarantee or calculation, check the ambient air conditions utilized. If a higher than -193° C value was utilized, it is not consistent with standard engineering practice. And, if the boiler is going to be outside, the actual efficiency will be lower due to lower ambient air temperatures regardless of the boiler design. To determine your actual fuel usage, ask for the efficiency to be calculated at the lower ambient conditions. Or, use Figure (2.22.5) to estimate the effect the lower ambient air levels will have on the boiler efficiency.

2.22.5 Radiation and Convection losses

Radiation and convection losses represent the heat losses radiating from the boiler vessel. Boilers are insulated to minimize these losses. However, every boiler has radiation and convection losses. Some times efficiency is represented without any radiation and convection losses. This is not a true reflection of fuel usage of the boiler. The boiler design also can have an effect on radiation and convection losses. For example, a water back design boiler tends to have much higher rear skin temperatures than a dry back design. This is easy to prove. Just go to the back of a quality dry back boiler and touch the rear door.

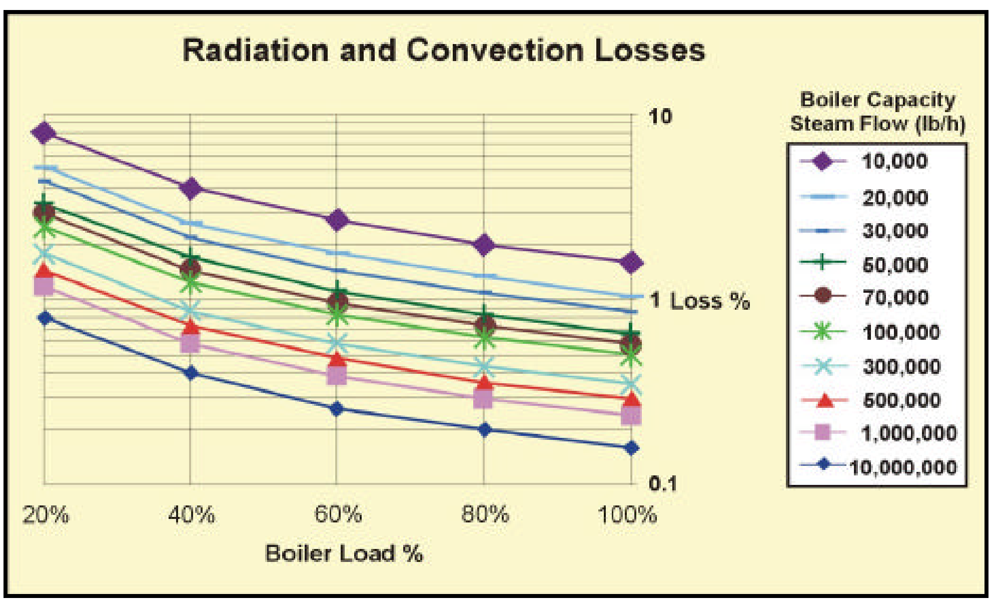


Fig. 2.22.6 Radiation and Convection Losses for Various Boiler Sizes

Table 2.22.5 4-Pass boiler—radiation and convection losses

Firing Rate (% of Load)	100-350 BHp		400-800 BHp	
	Op. Pressure = 10 PSIG	Op. Pressure = 125 PSIG	Op. Pressure = 10 PSIG	Op. Pressure = 125 PSIG
25%	1.6%	1.9%	1.0%	1.2%
50%	7%	1.0%	5%	6%
75%	5%	7%	3%	4%
100%	4%	5%	2%	3%

Cool rear temperatures are the result of low radiation and convection losses in the rear of the boiler. Boilers operating with high rear temperatures are wasting energy every time the unit is fired. Radiation and convection losses also are a function of air velocity across the boiler. A typical boiler room does not have high wind velocities. Boilers operating outside, however, will have higher radiation and convection losses. Table 1 shows expected radiation and convection losses for 4-pass fire tube boilers designed and insulated for high efficiency.

2.23 Boiler performance:

The purpose of a steam boiler is to evaporate water by heat obtained by the combustion of fuel and the amount of water evaporated is therefore one of the quantities to be considered in dealing with the performance of a steam boiler.

The amount of steam generated by the boiler in kilograms per hour at the observed pressure and temperature, quality of steam and feed water temperature is called Total Evaporation. The Actual Evaporation (m_a) is expressed in terms of kilograms of steam generated per kilogram of fuel used. i.e. Actual Evaporation, m_a = (total evaporation per hour) / (fuel used per hour) But the amount of water evaporated by a boiler is not a sufficiently definite measure of its performance because under different conditions as to temperature of feed water, and temperature and dryness of steam produced, a given evaporation will represent different amounts of heat utilized by the boiler. Therefore, to provide common basis for comparing the evaporative capacity of boilers working under different conditions, it is necessary that the water be supposed to be evaporated under some standard conditions. The standard conditions adopted are: feed water supplied to the boiler at 100^o C and converted in to dry saturated steam at 100^o C and the working pressure 1.01325 bar (atmospheric pressure at sea level). Under these conditions, the evaporation of 1 Kg of water at 100^o C requires 2.257 kJ to be converted into dry saturated steam at 100^o C, which is the enthalpy of evaporations of steam at 100^o C.

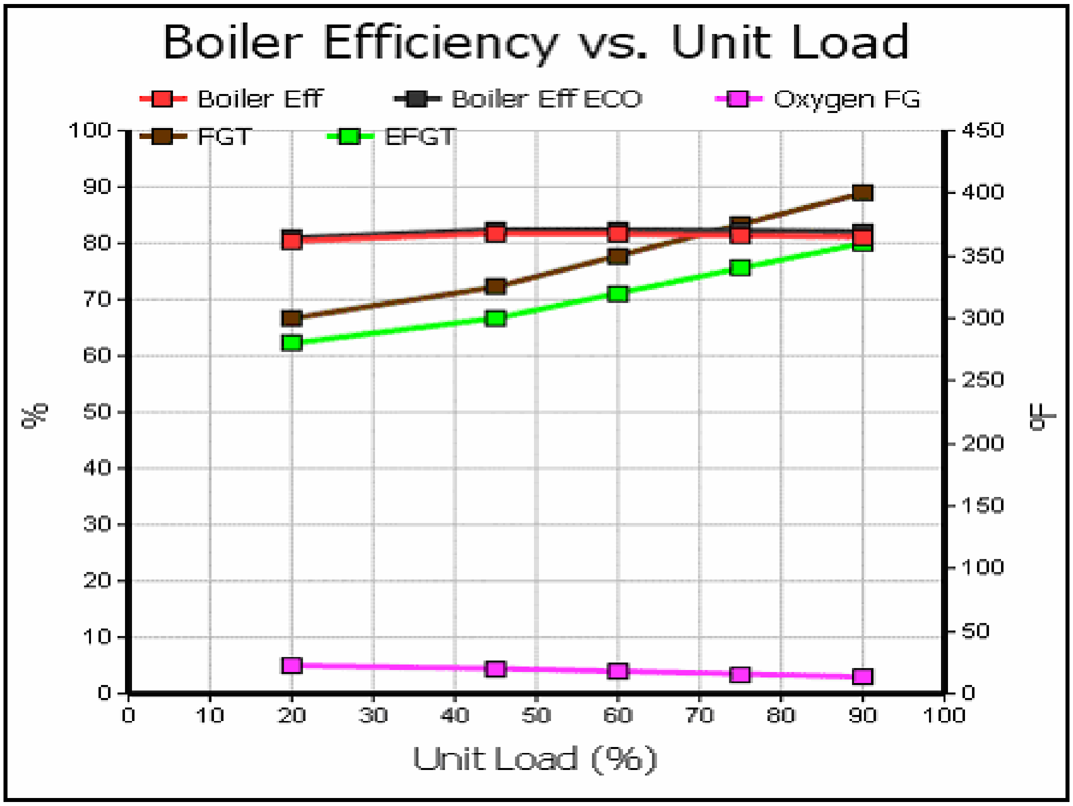


Fig. 2.23.1 Boiler efficiency vs. unit load

2.24 Factors Affecting Boiler Performance

The various factors affecting the boiler performance are listed below:

- Periodical cleaning of boilers
- Periodical soot blowing
- Proper water treatment programmers and blow down control
- Draft control
- Excess air control
- Percentage loading of boiler
- Steam generation pressure and temperature
- Boiler insulation
- Quality of fuel

All these factors individually/combined, contribute to the performance of the boiler and reflected either in boiler efficiency or evaporation ratio. Based on the results obtained from the testing further improvements have to be carried out for maximizing the performance. The test can be repeated after modification or rectification of the problems and compared with standard norms. Energy auditor should carry out this test as a routine manner once in six months and report to the management for necessary action.

3.0 METHODS OF FINDING BOILER EFFICIENCY OF THE BOILER:

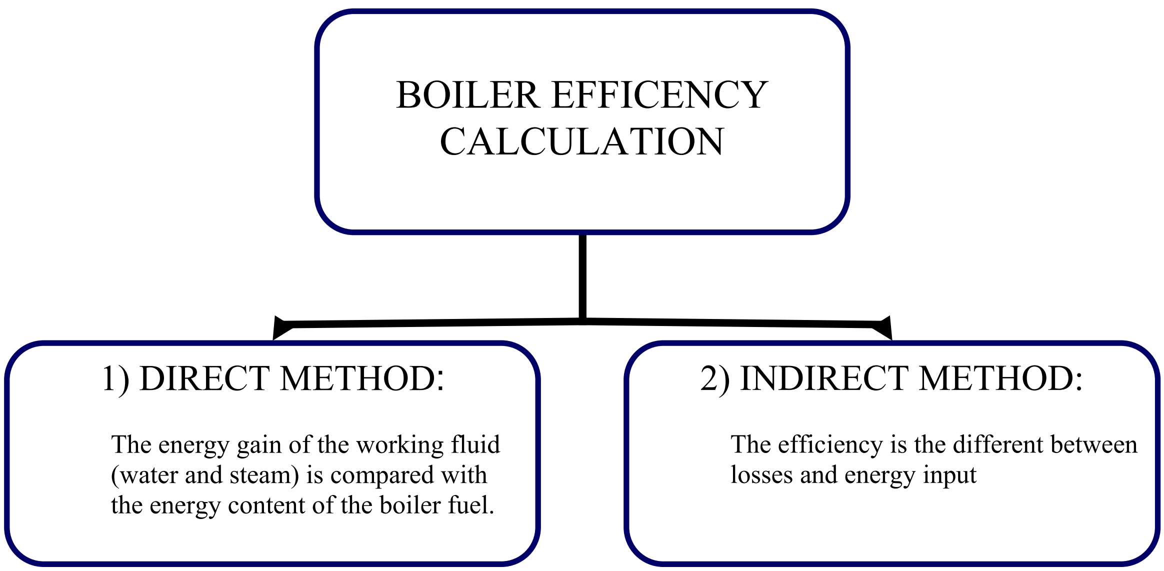
Boiler efficiency determination:-

There are two basic ways of determining the efficiency of a boiler:

(3.2) The Direct Method (Input-Output method);

(3.3) The indirect Losses Method (Heat Loss method).

Both are recognized by the American Society of Mechanical Engineers (ASME) and are mathematically equivalent. They would give identical results if all the required heat balance factors were considered and the corresponding boiler measurements could be performed without error.



3.1 Equivalent Evaporation:

Equivalent evaporation may be defined as the evaporation which would be obtained if the feed water were supplied at 100^{o} C and converted into dry saturated steam at $100^{o}C$ (1.01325 bar pressure).

Under actual working conditions of the boiler, suppose

m_a = actual weight of water evaporated in kg per kg of fuel,

h_0 = Enthalpy of 1 Kg of steam produced under actual working condition in kJ,

h = Enthalpy of 1 kg of feed water entering the boiler in kJ,

L_S = Enthalpy of evaporation of 1 kg of steam at $100^{o}C$ (2257 kJ), and

m_e = equivalent evaporation in kg of water from and at $100^{o}C$ per Kg of fuel burnt.

Then, heat transferred to 1 kg of feed water in converting it to dry saturated steam or heat required to produce 1 kg of steam = $(h_0\text{-}h)$ kJ and

Heat required producing m_a kg of steam under actual working conditions

$= m_a (h_0\text{-}h)$ kJ.

Equivalent evaporation in kg of water from and at 100°C per kg of fuel burnt,

$$\mathbf{m_e = m_a (h_0\text{-}h) / Ls = m_a (h_0\text{-}h) / 2257}$$

For wet steam, $\mathbf{m_e = m_a (h_{0wet} - h) / 2257}$

3.1.1 Factor of Equivalent Evaporation:

Factor of Equivalent Evaporation is the ratio of heat absorbed by 1 kg of feed water under actual working conditions to that absorbed by 1 kg of feed water evaporated from and at 100°C (i.e. standard conditions)".

Factor of equivalent evaporation = $(h_0 – h) / L_s = (h_0 – h) / 2257$

The mass of water evaporated is also expressed in terms of "Evaporation per hour per square meter of heating surface of the boiler"

Evaporation per m^2 of heating surface

= m kg per hour / Total area of heating surface in m^2

Where, m is the actual mass of water evaporated in kg

3.2 The Direct Method

This was standard for a long time, but is little used now. According to this method the boiler efficiency is defined as, the ratio of the heat utilized by feed water in converting it to steam, to the heat released by complete combustion of the fuel used in the same time, i.e., output divided by the input to the boiler. The output or the heat transferred to feed water is based on the mass of steam produced under the actual working conditions. The input to a boiler or heat released by complete combustion of fuel may be based on the higher calorific value of the fuel.

Boiler Efficiency = $m_a (h_0\text{-}h)$ / C.V.

Where, m_a = actual evaporation in kg per kg of fuel burnt,

h_0 = Enthalpy of 1 kg of steam produced under actual working condition in kJ,

h = Enthalpy of 1 kg of feed water entering the boiler in kJ and.

C.V. = calorific value of fuel in kJ/kg

If a boiler is provided with an economizer and a super heater, then each of these elements of a boiler will have its own efficiency. If the boiler, economizer & super heater are considered as a single unit, the efficiency in that case is known as the overall efficiency of the boiler plant or efficiency of the combined boiler plant.

Economizer efficiency

Economizer is placed in between boiler and chimney to recover heat from the hot flue gases which are released in atmosphere through chimney.

The efficiency of the economizer is the ratio of the heat gained by the feed water passing through the tubes of economizer and the heat given away by the hot flue gases passing over the tubes of the economizer.

Economizer efficiency = $m_a (t_2 - t_1) / m_f \times C_p (t_{f1} - t_{f2})$

Where,

m_a = mass of steam produced per kg of fuel burnt

m_f = mass of flue gases produced per kg of fuel burnt.

C_p = specific heat of flue gases

t_1 = Feed water temperature entering economizer

t_2 = Feed water temperature leaving economizer

t_{f1}= Temperature of hot flue gases entering economizer

t_{f2} = Temperature of hot flue gases leaving economizer.

Super heater efficiency

Super heater is normally placed directly after the furnace in the way of hot flue gases or in the furnace itself. The dry saturated steam is drawn from the boiler steam drum and passed through the super heater coil where, at constant pressure, maximum heat is observed by the steam & converted into superheated steam.

The efficiency of super heater may be stated as the ratio of the heat gained by the dry saturated steam passing through super heater coils & heat given away by the hot gases passing over the super heater coils.

If super heater is placed in the furnace, in front of burners, radiation heat is also absorbed.

Super heater efficiency = $m_a [H + C_{ps} (t_{sup} - t_{sat})] / m_f C_{pf} (t_{fi} - t_{fo})$

Where,

m_a = weight of steam produced in kg per kg of fuel burnt

m_f = weight of hot flue gases generated in kg per kg of fuel burnt

t_{sat} = Temperature of steam entering the super heater,

t_{sup} = Temperature of steam leaving the super heater,

t_{fi} = Temperature of hot gases entering the super heater.

t_{fo} = Temperature of hot gases leaving the super heater,

C_{pf} = specific heat of hot gases at constant pressure

C_{ps} = specific heat of steam at constant pressure.

3.2.1 **Advantages** (Of Direct Method)

- Quick evaluation
- Few parameters for computation
- Few monitoring instruments
- Easy to compare evaporation ratios with benchmark figures

3.2.2 **Disadvantages** (Of Direct Method)

- No explanation of low efficiency
- Various losses not calculated

3.3 The Indirect Losses Method

The efficiency of a boiler equals 100% minus the losses. Thus, if the losses are known the efficiency can be derived easily. This method has several advantages, one of which is that errors are not so significant: for example, if the losses total 10% then an error of 1.0% will affect the result by only 0.1%.

The losses method is now the usual one for boiler efficiency determination. In fact there is no provision on many modern boilers for fitting coal weighing equipment, in which case the direct method cannot be used.

Another point to bear in mind is that if a boiler is tested and found to have an efficiency of, say 94%, it would be quite wrong to imagine that it is operated normally at that efficiency. During testing, particular care is taken to keep the steam pressure, temperature and so on, as steady as possible and there is neither blow down nor soot blowing. Also the boiler is probable tested immediately after a soot blow. So there are many factors common to normal operation that are absent when testing. Thus the test efficiency is probable the best that can be attained and for normal operation the value will be less.

3.4 Heat Losses in Boiler Plant

Heat Losses in boiler Plant is mainly divided in to four parts.

3.4.1 Heat lost to chimney gases or flue gases (i.e. heat carried away by the products of combustion.)

3.4.2 Heat lost due to incomplete combustion

3.4.3 Heat lost due to sunburn fuel.

3.4.4 Heat lost to external radiation.

We will illustrate these losses one by one.

3.4.1 Heat Lost to Chimney Gases or Flue Gases

The flue gases going out of chimney are made up of

(i) Dry flue gases

(ii) Steam in flue gases formed from the combustion of hydrogen present in the fuel together with any moisture present in the fuel

(i) Heat lost to dry flue gases per kg of fuel burnt = $\mathbf{m_g \times C_p (t_1 - t_o)}$

Where, m_g = weight of dry flue gases in kg per kg of fuel

C_p = specific heat of dry flue gases in kJ per kg K

$t_1 - t_o$ = rise in temperature of flue gases (difference between temperature of flue gases leaving the boiler t_1 and temp. of the boiler room t_o)

(ii) Heat lost to steam in flue gases per kg of fuel burnt

Mass of steam formed per kg of fuel burnt = $9H_2$ + mass of moisture per kg of fuel (m)

Assuming that the steam in flue gasses exist as superheated steam at atmospheric pressure and at flue gas temperature,

Heat lost to steam in the flue gases per kg of fuel burnt.

$$= [9\,H_2 + m] \times [H_{sup} - h]$$

$$= [9\,H_2 + m] \times [2676.1 + C_p\,(t_1 - 100) - h] \text{ kJ}$$

Where,

t_1 = the temperature of flue gases leaving the boiler

H_{sup} = enthalpy of 1 kg of superheated steam at atmospheric pressure (1.01325 bar) and at flue gas temperature in kJ

C_p = Specific heat of superheated steam in kJ per kg K

h = enthalpy of 1 kg of water at boiler house temperature in kJ

m = mass of moisture present in 1 kg of fuel and

H_2 = weight of hydrogen present in 1 kg of fuel.

3.4.2 Heat Lost Due to Incomplete Combustion (burning of carbon to CO)

For complete combustion of any fuel, all the carbon should be converted to CO_2 (carbon dioxide). Any CO present in flue gases is due to insufficient air supply. Incomplete combustion means burning of carbon (C) to CO (carbon monoxide),
1 kg of carbon burnt to CO_2 releases 33,830 kJ, while 1 kg of carbon burnt to CO releases only 10,130 kJ.

Thus, 33,830 – 10,130 = 23,700 kJ heat is lost due to incomplete combustion or in other wards, we can say that 23,700 kJ heat is available in CO per kg of carbon,

3.4.3 Heat Lost Due to Unburnt Fuel

When solid fuels are used, some of the fuel falls through the grate bars and is lost with ash. The heat loss is calculated by multiplying mass of unburnt fuel lost through grate bars by the calorific value of the fuel.

In oil fired boilers, due to improper conditions of burns, sometimes, oil droplets falls inside the furnace which is not burnt and is considered as loss.

Heat Loss = c $m_{a\,/100}$ × 33,820 kJ/kg fuel,

Where c = % carbon in dry ash

m_a = mass of ash kg/kg fuel

33,820 = calorific value of carbon burnt to CO_2 in kJ/kg

3.4.4 Heat Lost to External Radiation

Effective lagging of the surface of boiler exposed to atmosphere is necessary to reduce such loss to minimum. These losses range for 110/210 Mw units from 0.93% to 1% on higher side. They can be calculated by graphical methods and alignment charts.

3.5 Operational Factors

The losses over which the operator can exert a control are dry flue gas loss, carbon in ash loss and incomplete combustion (combustible in gas loss).

a. Dry flue gas loss - % excess air and gas temperature at air heater outlet
b. Carbon in ash loss - % excess air and p.f. fineness
c. Combustible in gas loss – excess air

The boiler operation should be aimed at reducing the sum of above losses. The final gas temperature should be above flue gas dew point. It is important to remember that dew point for water vapor is not 100ºC but lower than this, because of partial pressure. Most coal fired boilers have specified air heater gas outlet temperature of the order of 130ºC being the minimum practical temperature which is consistent with minimizing air heater corrosion. A high air heater gas outlet, temperature reduces boiler efficiency drastically. (A 22ºC rise in air heater gas outlet temperature reduces boiler efficiency by 1%).
Boiler operation should be aimed at minimizing the causes of high gas exit temperature which could be due to

- Lack of soot blowing
- Deposits on boiler heat transfer surface
- High excess air
- Low final feed temperature
- Higher type of burner (+ve lift of burner angle) at low load
- Incorrect S/Air to P/Air ratio

3.6 **Advantages** (of indirect method)

- Complete mass and energy balance for each individual stream
- Makes it easier to identify options to improve boiler efficiency

3.7 **Disadvantages** (of indirect method)

- Time consuming
- Requires lab facilities for analysis

3.8 Comparison of Direct and Indirect methods:

Table 3.8.1 Comparison of direct and Indirect methods

ERROR of 1%	
DIRECT METHOD IF 90%	INDIRECT METHOD
90 ± 0.9 = 89.1 to 90.9	100-(10 ± 0.1) = 90 ±0.1 = 89.9 to 90.1

3.9 Energy losses in boiler (Equations for Calculation)

Energy loss in Boiler can be worked by indirect method as per B.S.S. 2885 code. It can be seen that main losses in the boilers are as follows.

3.9.1 Dry stack loss.

3.9.2 Loss due to % moisture and hydrogen in fuel.

3.9.3 Combustible in ash loss.

3.9.4 Radiation loss.

These losses have been discussed in detail as follow:

3.9.1 Dry stack loss

As a thumb rule loss in increased two factors. One is flue gas temperature leaving APH and second is CO_2 in flue gas. Flue gas temperature leaving APH should be kept as near as to design values. If this temperature is observed raising them heat exchange is not taking place correctly may be due to checking ect. This can be eliminated perfect cleaning. Secondary, decrease in % CO_{2+} i.e. more air is used in terms of excess air will also cause dry stack loss to increase and more-+ heat will be carried away in the atmosphere without giving heat exchange. These two types of losses can very well be controlled to obtain optimum efficiency. A rise of flue gas temperature leaving air heater of about 22 ^{0}C will reduce the boiler efficiency by 1.0 %. Similarly drop in % CO_2 by about 1.0 % will reduce the boiler efficiency by about 0.5 to 1.0 %.

Dry gas loss can be calculated by:

$$\text{Dry gas losses} = \frac{\text{Dry gas} * \text{Sp. Heat of dry gas} * \text{temp. difference}}{\text{Gross C.V.}} * 100$$

$$\text{Dry gas} = \frac{1}{12 * \%\, CO_2} \left(\%\, C + \frac{\%\, S}{2.67} - \%\, U\right)$$

Where U = Unburnts

CO_2 = % CO_2 at air heater outlet

Calculation of U = % combustible

(A) Ash collected per kg. of Fuel:

(a) Fly Ash collected per kg of fuel =

$$\frac{(\text{\% of Fly Ash in fuel})*(\text{\% of Ash appearing as ashes in dust collector \& Chimney})}{100 - \text{\% combustible of fuel in fly ash}}$$

(b) Bottom Ash collected per kg of fuel =

$$\frac{(\text{\% of Bottom Ash in fuel})*(\text{\% of Ash appearing as Ashes in dust collector and Chimney})}{100 - \text{\% combustible of fuel in bottom ash}}$$

(B) Combustible matter in ash:

(a) Combustible matter in fly ash=

$$\frac{(\text{Fly Ash collected per kg of fuel})*(\text{\% combustible of fuel in fly ash})}{100}$$

(b) Combustible matter in Bottom ash =

$$\frac{(\text{Bottom Ash collected per kg of fuel})*(\text{\% combustible of fuel in bottom ash})}{100}$$

% U Total combustibles = (combustible matter in fly ash) + (combustible matter in Bottom ash)

Sensible heat = Dry gas* Sp. Heat of dry gas*(APH flue gas O/P temp.-ambient air temp)

$$\text{Dry gas losses} = \frac{\text{Sensible heat} * 100}{\text{Gross C.V.}}$$

3.9.2 Loss due to % moisture and % hydrogen in fuel:

Here also flue gas temperature leaving APH is playing role in increasing the losses if temperature is high. Other factors however are beyond the control like moisture and hydrogen in fuel. However, still efficiency can be obtained in case of fuel is having lesser *% of moisture and hydrogen.

Losses due to % moisture & Hydrogen in fuel =

$$\frac{(\text{Total moisture})*(\text{heat per kg. of moisture})*100}{\text{Gross C.V.}}$$

$$\text{Total moisture} = \frac{\text{\% moisture}}{100} + \frac{9*\text{\% H}}{100}$$

Heat per kg. of moisture =

1.88(APH flue gas O/Ltemp.-25) + 2442 + 4.2 (25-Ambient air temp.)

3.9.3 Combustion in ash loss:

Higher the combustible in ash will lead to the direct loss of heat available in the carbon. This loss is very high when there is little or no excess air because mixing of combustible material and oxygen is so poor. As the air quality is increased the loss falls rapidly. However it does not reach zero because the loss depends upon two factors when burning coal. Firstly the air/coal mixture must be correct. Secondly, it depends upon the fineness of grinding in the case of firing or the grate speed in the case of stocker firing. Reducing the combustible in ash means complete heats is being utilized from the fuel and get optimum efficiency.

Combustible in ash loss can be calculated by the following formula

$$\text{Losses due to combustible} = \frac{(\%\ U\ \text{Total combustible})*(\text{C.V. of carbon})*100}{\text{Gross C.V.}}$$

3.9.4 Radiation loss:

These losses are of very minor nature and can increase in longer run of the boiler if the proper care is not taken during each overhauling like lagging, sealing, of various pressure parts etc. Radiation loss can be found out from American boiler manufacturer's association graph.

Other energy losses:-

(1) Coal mill power requirement because high if mill in poor performance or if coak is being ground too fine. Poor grinding can increase carbon loss.
(2) Excessive blow down is nothing but net heat loss which can avoid by monitoring the concentration of solids in boiler water.
(3) Steam leakages should be stopped as quickly as possible to avoid net heat loss.
(4) Excessive soot blower operation consumes steam. Check the effectiveness of each blower and maintained the steam pressure to minimum requirement for effective cleaning.

So, the boiler efficiency can be calculated by,

Boiler Efficiency = 100-(total losses)

The design of a large boiler is such that there is not much change in efficiency with load or steaming output. A boiler plant, which is capable of giving 86% boiler efficiency at 100% MCR, would fall in efficiency by 1% at 80% load, 2% at 70 to 60% loads.

However, a slight decline in efficiency due to uncontrolled losses may cost extra money for fuel. If losses are reduced by 2% i.e. increased in efficiency 2% will save huge amount of fuel and results in saving of good amount of money, which is named as potential saving.

$$\text{Potential saving} = \frac{\text{fuel cost}*(\text{new efficiency }\% - \text{old efficiency }\%)}{\text{New efficiency }\%}$$

Fuel cost = 2000 T * 240 Rs. /ton per day. = 480000 Rs.

New efficiency = 86%

Old efficiency = 84%

$$\text{Potential saving} = \frac{480000*(86-84)}{86}$$

Hence saving in fuel per year would be Rs. 40, 88,000

Thus the reduction in fuel will can be achieved though raising the efficiency or controlling the losses of the unit. In addition load working increased the heat losses and auxiliary power proportionately which finally increases in the cost of fuel for power generation.

4.0 CASE STUDY AND EFFICIENCY CALCULATION

4.1 Ukai Thermal Power Station

TECHNICAL DATA OF POWERPLANT

DESIGN DATA OF 200 MW BOILER

Boiler Type: - Direct tangentially coal fired, balanced draught, natural circulation, Radiant reheat, dry bottom with Raymond Bowl Mills

Design Fuel: - Bituminous coal

Table 4.1.1 properties of fuel

Fixed carbon	37.3%
Vol. matter	27.7%
Moisture	10.0%
Ash	25.0%
Grind ability	50 – 55 hard grove Index

Furnace: - Fusion welded panel type

Table 4.1.2 Furnace dimensions

Width	13.868 m
Depth	10.592 m
Volume	5494 m^3

Super heater: -

Table 4.1.3 Super heaters Stage

Stage 1	Low temp super heater heating surface
Stage 2	Platen super heater 945 m^2
Stage 3	Final super heater 1036.3 m^2

Attemperator: - Single stage, with feed water spray

Reheater: - Pendant with 2648.2 m^2 H.S.

Economizer: - Tubular with 3978 m^2 H.S.

Air Heater: - Vertical, Trisected, Rotary, Regenerative Air heater – Two nos. with 19093 m^2 H.S. each (27VI74)

FUEL BURNING:

Equipment: - Tilting Tangential burners located in furnace corners.

Table 4.1.4 Types and no. of burners

No. of coal burners	24
No. of warm up oil burners	8
No. of load carrying oil burners	8
Igniters	16

Mills: -

Table 4.1.5 Data of mills

Type	XRP 763 Bowl mills
System	Prerufised
Capacity	33.87 T/hr for coal 55 Grind. 70% thro, 200 mesh
Motor	320 KW 990 RPM 6.6 KV
Nos.	6

Boiler Auxiliaries: -

Table 4.1.6 Boiler Auxiliaries

Duty	Type	Nos.	Design Quantity m^3/sec	Value pressure mm of wc	Temp ^{o}C	Motor KW	RPM
I D Fan	Axial Impulse 25e6	2	236.5	440	149	1700	990
F D Fan	Axial Impulse 20e6	2	107.2	445	49	650	290
P A Fan	RadialND	2	70.8	1252	49	1250	1480

Soot Blowing System: - (Medium: - Steam)

Furnace: - Wall blowers RW SE 56 Nos.

Platen, Super heater Reheaters and Convection Zone: - Long retractable (20Nos.)

(T 30 Mark I-E)

Economizer: - Half retractable T-30 Mark –I-E 4 Nos.

Air heater: - Swiveling 4 Nos.

SEAFTY VALVES:

Drum: - 3 Nos.Dressor make 3" – 1759 WA

Super heater: - 2 Nos. Dressor make 3" – 1749 WA & 2V2"1538 WA

Reheater inlet: - 3 Nos. Dressor make 6" – 1705 RWA

Reheater outlet: - 1 No. Dressor make 6" – 1705 RWA

ELECTROSTATIC PRECIPITATORS:

Type: - 2 FAA (36) – 4 * 36 – 9590 – 2

Nos.: - Two with 4 sections each.

Working Fields: - 16

Dummy Fields: - 4.

4.2 Boiler Efficiency Calculation by Indirect Method

Calculation for 200MW.

C	56.02	APH flue gas O/L temp	165
H	4.48	ambient air temp	29
S	0.44	% CO_2	15.66

4.2.1 Dry gas losses

$$\text{Dry gas losses} = \frac{\text{Dry gas*Sp. Heat of dry gas*temp. Difference}}{\text{Gross C.V.}} *100$$

$$\text{Dry gas} = \frac{1}{12*\% CO_2}\left(\% C + \frac{\% S}{2.67} - \% U\right)$$

Where U = Unburnts

% CO_2 =% CO_2 at air heater 1 outlet

Calculation of % U Total combustible:

% combustible of fuel in fly ash: 2.92

% combustible of fuel in Bottom ash: 0.74

% of ash appearing as ashes in dust collector and chimney: 20.79

% Rejected Coal: 28.76

% moisture: 11.9

C.V. (kJ/kg): 53.17 * 4.186 = 22256.96

(1) Ash collected per kg of fuel

(a) Fly ash collected per kg of fuel =

$$\frac{(\% \text{ of fly ash in fuel})*(\% \text{ of ash appearing as ashes in dust collector \& chimney})}{100 - \% \text{ combustible of fuel in fly ash}}$$

$$= \frac{0.9*20.79}{100-2.92}$$

Fly ash collected per kg of fuel = 0.1927 kg/kg of fuel.

(b)Bottom ash collected per kg of fuel =

$$\frac{(\% \text{ of Bottom ash in fuel})*(\% \text{ of ash appearing as ashes in dust collector and chimney})}{100 - \% \text{ combustible of fuel in bottom ash}}$$

$$= \frac{0.1*20.79}{100-0.74}$$

Bottom ash collected per kg of fuel = 0.0209 kg/kg of fuel

(B) Combustible matter in ash

(a) Combustible matter in fly ash =

$$\frac{\text{Fly ash collected per kg of fuel} * \% \text{ combustible of fuel in fly ash}}{100}$$

$$= \frac{0.1927*2.92}{100}$$

Combustible matter in fly ash =0.0056 kg of C/kg of fuel

(b) Combustible matter in Bottom ash =

$$\frac{(\text{Bottom Ash collected per kg of fuel})*(\% \text{ combustible of fuel in bottom ash}}{100}$$

$$= \frac{0.0209*0.74}{100}$$

= 0.0002 kg of C/kg of fuel

% U Total combustibles = (combustible matter in fly ash) + (combustible matter in bottom ash)

= 0.0056 + 0.0002

= 0.0058 %

Say 0.006%

$$\text{Dry gas} = \frac{1}{12*\% CO_2}\left(\% C + \frac{\% S}{2.67} - \% U\right)$$

$$\text{Dry gas} = \frac{1}{12*15.66}\left(56.02 + \frac{0.44}{2.67} - 0.006\right)$$

Dry gas = 0.29895059 kg mole/kg

Sensible heat = Dry heat * Sp. Heat of dry gas * (APH flue gas O/L temp. – ambient air temp.)

(Sp. Heat of dry gas = 30.6)

= 0.29895059 * 30.6 * (165.0-29.0)

Sensible heat = 1244.113 kJ/kg

$$\text{Dry gas losses} = \frac{\text{Sensible heat} * 100}{\text{Gross C.V.}}$$

$$= \frac{1244.113 * 100}{22256.96}$$

Dry gas losses = 5.59 %

(2) Losses due to combustible

$$\text{Losses due to combustible} = \frac{(\%\ \text{U Total combustible})*(\text{C.V. of carbon})*100}{\text{Gross C.V.}}$$

(Gross C.V. of carbon = 8077.8 * 4.186 = 33810.32 kJ/kg)

$$= \frac{0.006 * 33810.32 * 100}{22256.96}$$

Losses due to combustible = 0.91%

(3) Losses due to sensible heat in ash

(a) loss due to sensible heat in ash fly ash = (0.9 * % of ash appearing as ashes in dust collector & chimney)*(Sp.heat of ash)*(APH flue gas O/L temp. - ambient air temp.)

Gross C.V.

(Sp. Heat of ash = 0.2 * 4.186 = 0.8372)

$$= \frac{0.9 * 20.79 * 0.8372 * (165-29)}{22256.96}$$

Losses due to sensible heat in ash fly ash = 0.0957%

(b) Losses due to sensible heat in ash bottom ash =

(0.1 * % of ash appearing as ashes in dust collector & chimney)*(Sp.heat of ash)*(APH flue gas O/L temp. - ambient air temp.)

Gross C.V.

(Temp.of bottom ash = 627.68 ^{0}C)

$$= \frac{0.1 * 20.79 * 0.8372 * (627.68-29)}{22256.96}$$

Losses due to sensible heat in ash bottom ash = 0.047%

Losses due to sensible heat in ash =

(Losses due to sensible heat in ash fly ash)+(losses due to sensible heat in ash fly ash)

= 0.0957+0.0470

Losses due to sensible heat in ash = 0.143%

(4) Radiation losses

Radiation loss = As per design the loss due to radiation taken from American boiler manufacturer's association graph is = 0.41%

(5) Losses due to % moisture & Hydrogen in fuel

Losses due to % moisture & Hydrogen in fuel =

$$\frac{\text{Total moisture*heat per kg of moisture*100}}{\text{Gross C.V.}}$$

$$\text{Total moisture} = \frac{\%\text{ moisture}}{100} + \frac{9 * \%H}{100}$$

$$= \frac{11.90}{100} + \frac{9*4.48}{100}$$

Total moisture = 0.5222

Heat per kg of moisture = 1.88(APH flue gas O/L temp.-25)+2442+4.2(25-ambient air temp.)

= 1.88(165-25) + 2442+42(25-29)

Heat per kg of moisture = 2688.40 kJ/kg

Losses due to % moisture and % Hydrogen in fuel =

$$\frac{\text{Total moisture*heat per kg of moisture*100}}{\text{Gross C.V.}}$$

$$= \frac{0.522 * 2688.40 * 100}{22256.96}$$

Losses due to % moisture and % Hydrogen in fuel = 6.31%

TOTAL LOSS:

(1)Dry gas losses = 5.59%

(2)Losses due to combustible = 0.91%

(3)Losses due to sensible in ash =0.14%

(4)Losses due to radiation = 0.41%

(5)Losses due to moisture = 6.31%

(6)Losses due to manufacture = 1.50%

Margin and unaccounted ______

Total losses = 14.86%

Boiler Efficiency =100-Total losses

=100-14.86 %

Boiler Efficiency = 85.14 % (By Indirect method)

4.2.2 Assessment of a Boiler (Heat Balance)

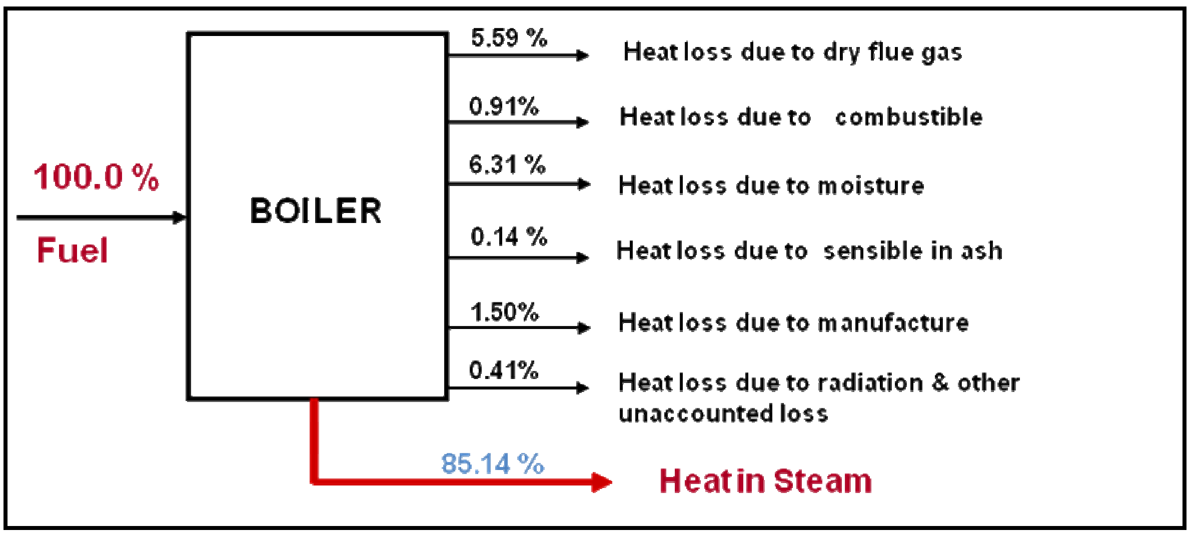


Fig. 4.2.2 Heat Balance Chart

4.3 Boiler Efficiency Calculation by Direct Method

Mass of coal burnt = 85 T/hr.

= $0.85 * 10^5$ T/hr.

Mass of steam generated = 600 t/hr.

= $6.0 * 10^5$ kg/hr.

Coal

Fixed carbon = 39%

Volatile matter = 25%

Moisture = 8%

Ash = 28%

High calorific value = 4900 kcal/kg

= 20501.6 kJ/kg

Mean feed water temp. =35^0C

Pr, of steam = 131.9 kg/cm^2

= 129.5 bar

Dryness fraction = 0.85

At 129.35 bar ~ 130 bar

h_f = 1531.5 kJ/kg

h_{fg} = 1130.7 kJ/kg

$h = h_f + h_{fg}$

= 1531.5+ (0.85) (1130.7)

= 2492.595 kJ/kg

Heat of feed water

= 1*4.18*(35-0)

=146.3 kJ/kg

Total net heat given to produce 1 Kg of steam

= h- h_{f1}

=2492.595-146.3

2346.295 kJ/kg

Factor of equivalent evaporation

$$Fe = \frac{h - h_{f1}}{2257}$$

= 1.0395

Equivalent evaporation

$$m_e = \frac{m_a (h - h_{f1})}{2257}$$

$$m_e = \frac{6.0 * 10^5}{0.85 * 10^5} = 7.058 \frac{\text{kg of steam}}{\text{kg of fuel}}$$

$$= 7.058 * 1.0646 = 7.5148 \frac{\text{kg of steam}}{\text{kg of fuel}}$$

$$\text{Boiler efficiency} = \frac{m_a (h - h_{f1})}{\text{C.V.}}$$

$$= \frac{7.058 * (2346.295)}{20501.6}$$

= 0.8077

Boiler efficiency = 80.77% (By Direct method)

4.4 Gandhinagar Thermal Power Station

TECHNICAL DATA OF POWERPLANT

CHEMICAL LABORATORY REPORT

BOILER TYPE :

Radiant Reheat, Natural Circulation, Tilting Tangential

(1) FLUE GAS ANALYSIS AT APH INLET

Table 4.4.1 Flue gas analysis at APH inlet

1	% CO_2	14.80
2	% CO	0.012
3	% O_2	4.20
4	AMB.TEMP.(^oC)	33.00
5	AMB.TEMP.WET(^oC)	33.00
6	AMB.TEMP.DRY(^oC)	33.00
7	% HUMUDITY	-

(2) FLUE GAS ANALYSIS AT APH OUTLET

Table 4.4.2 Flue gas analysis at APH outlet

1	% O_2	2.20
2	% CO_2	14.00
3	% CO	-

(3) PROXIMATE AND ULTIMATE ANALYSIS OF COAL

[A]

Table 4.4.3 Proximate and ultimate analysis of coal for A

SR NO	Parameters	PROXIMATE ANALYSIS AS FIRED
1	% MOISTURE	9.94
2	% ASH	36.29
3	% VM	23.59
4	% F.C.	30.18
5	COAL C.V.(kcal/kg)	4097
6	Reject Coal C.V.(kcal/kg)	1159

[B]

Table 4.4.4 Proximate and ultimate analysis of coal for B

SR NO	Parameters	ULTIMATE
1	% MOISTURE	9.94
2	% ASH	36.29
3	% TOTAL CARBON	42.70
4	% HYDROGEN	2.96
5	% NITROGEN	1.82
6	% SULPHER	0.53
7	% OXYGEN	5.76

(4)

Table 4.4.5 Ash data

1	% Combustible in Fly Ash	1.17
2	% Combustible in Bottom Ash	3.34
3	Specific Gravity of LSHS	0.96
4	C. V. of LSHS in kcal / kg	10501

(5) Specific heat of Dry Gas in kcal / kg / ^{o}C is taken as :- **30.6**

(6) Ash appearing as ashes in dust collector & Chimney is taken as :- **0.90**

(7) Ash appearing as ashes in bottom half is taken as :- **0.10**

(8) Calorific Value of Carbon in kcal / kg is taken as :- **8077.8**

(9) Specific heat of Fly Ash in kcal / kg / ^{o}C is taken as :- **0.20**

(10) Specific heat of Bottom Ash in kcal / kg / ^{o}C is taken as :- **0.25**

(11) Temp.(in ^{o}C) of Bottom Ash is taken as :- **627.68**

(12) As per design the loss due to Radiation is taken from American boiler Manufacturer's Association graph as: **-0.20** (in % age.)

(13) Latent Heat in kcal / kg. of Moisture is taken as: **- 2442.00**

(14) Calorific Value of CO in kcal / kg is taken as: **- 2415.00**

(15) Weight of Moisture in kg / kg air is taken as: **- 0.0229**

(From Psychometrics charts)

4.5 Calculations for finding Boiler Efficiency (by indirect method)

4.5.1 Dry gas loss:-

Dry gas loss =

$$\frac{100 \times (\text{Dry Gas}) \times (\text{Sp.heat of Dry Gas}) * (\text{Temp. of Gas leaving - Ambient Temp.})}{(4.186 * \text{Gross C.V.})}$$

= **7.2729 %**

Where Dry Gas = (1/ (12 * CO_2)) * (% C + % S/2.67 -100 * U)

= 0.28830 kg / kg of fuel

Where U = Un burnt = % Combustible in Fly Ash & Bottom Ash

= 0.00512 kg / kg of fuel

CO_2 = % CO_2 at APH Outlet

[A] Ash collected per kg. of Fuel :-

(a) Fly Ash

$$= \frac{(\text{\% of Ash in fuel}) * (\text{\% of ash appearing as ashes in dust collector \& Chimney})}{(100 - \text{\% Combustible})}$$

= 0.3305 kg/kg of fuel

(b) Bottom Ash $= \frac{(\text{\% of Ash in fuel}) * (\text{\% of ash appearing as ashes in bottom half})}{(100 - \text{\% Combustible})}$

= 0.0375 kg / kg of fuel

[B] Combustible matter in Ash: -

(a) Fly Ash $= \frac{(\text{Ash collected per kg of fuel}) * (\text{\% combustible of fuel})}{100}$

= 0.00387 kg / kg of fuel

(b) Bottom Ash =

$$\frac{(\text{Ash collected per kg of fuel in bottom ash}) * (\text{\% combustible of fuel in bottom ash})}{100}$$

= 0.00125 kg / kg of fuel

i.e. U = 0.00387 + 0.00125 = 0.00512 kg / kg of fuel

4.5.2 Loss due to Combustible:-

$$= \frac{(\text{Total combustible in Ash}) * (\text{Cal. Value of Carbon}) \times 100}{\text{Gross Cal. Value}}$$

= **1.0095 %**

4.5.3 Loss due to Sensible heat in ash:-

(a) Fly Ash =

$$\frac{0.9 * (\text{\% of Ash in fuel}) * (\text{Sp.heat of Ash}) * (\text{Temp. of Gas leaving APH - Ambient Temp.})}{\text{Gross Cal. Value}}$$

(Where Ash appearing as ashes in dust collector & Chimney is taken as 0.90 of total ash in fuel.)

= **0.2292 %**

(b) Bottom Ash =

$$\frac{0.1 * (\text{\% of Ash in fuel}) * (\text{Sp. heat of ash}) * (\text{Temp. of Bottom Ash - Ambient Temp.})}{\text{Gross Cal. Value}}$$

(Where Ash appearing as ashes in bottom half is taken as 0.10 of total ash in fuel.)

= **0.1317 %**

Total loss = (a) + (b) = 0.3609 %

4.5.4 Radiation loss: - As per design the loss due to Radiation is taken from American boiler Manufacturer's Association graph.

= **0.2000 %**

4.5.5 Loss due to % Moisture & % Hydrogen in fuel: -

$$= \frac{(\text{Total Moisture}) * (\text{Heat per kg. of Moisture}) * 100}{4.186 * \text{Gross C.V.}}$$

= **5.7480 %**

Where Total Moisture = $\frac{\text{\% age Moisture}}{100} + \frac{9 * (\text{\% age } H_2)}{100}$

= **0.3630** Moisture / kg. of fuel

Where Heat per kg. of Moisture

= 1.88 (Temp. of Gas leaving APH - 25) + Latent Heat per kg. of Moisture + 4.2 (25-Ambient Temp.)

= **2693.69** kJ / kg

4.5.6 Loss due to Coal mill rejects: -

$$= \frac{\text{Weight of Reject Coal in kg / hr.} * \text{C.V. of Reject Coal} * 100}{1000 * \text{Coal flow rate in T / Hr.} * \text{Gross C.V.}}$$

= **0.0253 %**

4.5.7 Loss due to carbon monoxide (CO): -

$$\frac{7 * (\text{\% Age of CO in Flue gas}) * (\text{\% Age Fix Carbon in Fuel}) * \text{C.V. of Carbon Monoxide}}{3 * (CO_2 + CO) * \text{Gross C.V.}}$$

= **0.0476 %**

4.5.8 Loss due to Moisture in air: -

$$= \frac{\text{Total Moisture in Air} * 1.88 * (\text{Temp. of Gas leaving - Ambient Temp.}) * 100}{4.186 * \text{Gross C.V.}}$$

= **0.2256 %**

Where, Total Moisture in Air

= Stoichiometric Air * Excess Air * Weight of Moisture in Air

= **0.1456** kg / kg

Stoichiometric Air

= (2.664 * % age Carbon + 7.937 * % age Hydrogen +0.996 * % age Sulpher - % age O_2 in Coal)

= **5.6960** kg / kg of coal

Excess Air = 21 / (21 – O_2 at APH Outlet)

= **1.117 %**

BOILER EFFICIENCY: -

1	DRY GAS LOSS	--->	7.273	%
2	LOSS DUE TO COMBUSTIBLE	--->	1.010	%
3	LOSS DUE TO SENSIBLE HEAT IN ASH	--->	0.361	%
4	RADIATION LOSS	--->	0.200	%
5	LOSS DUE TO % AGE MOISTURE &			

	% AGE HYDROGEN IN FUEL	--->	5.748	%
6	LOSS DUE TO COAL MILL REJECTS	--->	0.025	%
7	LOSS DUE TO CARBON MONOXIDE (CO)	--->	0.048	%
8	LOSS DUE TO MOISTURE IN AIR	--->	0.226	%
9	TOTAL LOSSES	--->	14.890	%
10	**BOILER EFFICIENCY** (100 - TOTAL LOSSES)	--->	**85.11**	%

5.0 RESULT AND DISCUSSION

A performance test was carried out on unit no. 3 at 210 MW (100% of MCR) load at Gujarat State Electrical Corporation Ltd. Gandhinagar, also on unit no. 3 at 200 MW load at Gujarat State Electrical Corporation Ltd. Ukai and actual value has been deviated from the standard value due to loss.

Result of the Energy analysis with heat balance chart carried out on indirect method of a thermal power plant at full load operating conditions are presented.

In case of Gandhinagar, it has one of the higher generation capacity coal fired power station. There are five units, first two have generation capacity of 120 MW each, and unit number three, four and five have generation capacity of 210 MW each. So, the total generation capacity of Gandhinagar Thermal Power Plant is 870 MW.

In case of Ukai, it has one of the higher generation capacity coal fired power station. There are five units, first two have generation capacity of 120 MW each, and unit number three, four and five have generation capacity of 200 MW each. So, the total generation capacity of Gandhinagar Thermal Power Plant is 850 MW. So, brief discussion about the various parts of Gandhinagar and Ukai Thermal Power Plants and also finding out its performance has been carried out in present case.

In present work, Boiler efficiency is calculated by two methods. i. e. by Direct method and by Indirect method. From the calculation of Boiler efficiency by direct method, it comes out to be 80.77%, while by indirect method Boiler efficiency is 85.14% in Ukai Power Plant and 85.11% by Indirect method in Gandhinagar Power Plant. Boiler efficiency by direct method is derived from the indirect method due to leakage of steam and unaccounted losses.

The suitable computer program is also developed to calculate boiler efficiency by indirect method in present work.

From test results, efficiency calculated which found lower than its designed value and the efficiency which found by indirect method is more than direct method.

6.0 Program to calculate Boiler efficiency of unit # 3 Ukai (of 200 MW)

```
#include<stdio.h>
#include<conio.h>
#define Flyfuel 0.9
#define BOTTOMFUEL 0.1
#define SPDRY 30.6
#define CVC 33810.32
#define SPASH 0.8372
void main()
{
float perC,perH,perS,aph_temp,air_temp,perco2,per_fly,per_bottom;
float rejcoal,CV per_chim,per_mois,result1,result2,result3,result4;
float result5,result6,result7.result8,result9,result110,result11.result12;
float result13,result14,result15,result16,bot_temp,temp,pressure,result17;
float result18,result19,ms_temp,ms_pressure,ms_enth,crh_temp;
float crh_pressure,crh_enth,hrh_temp,hrh_pressure,hrh_enth,sens_eco;
float result20,result21,result22load(kw),result23,result24,result25;
clrscr();
printf("********1.DRY GAS LOSSES********\n");
printf("\t(a) FLY ASH COLLECTED PER Kg. OF FUEL \n");
printf("Enter the value of per_chim and per_fly");
scanf("%f %f,&per_chim,&per_fly);
result1=FLYFUEL*per_chim/(100-per_fly);
printf("FLY ASH COLLECTED PER Kg. OF FUEL=%f kg/kg of fuel\n",result1);
printf("\t(b) BOTTOM ASH COLLECTED PER kg OF FUEL \n");
printf("Enter the value of per_bottom.");
scanf("%f,&per_bottom");
result2=BOTTOMFUEL*per_chim/(100-per_bottom);
printf("BOTTOM ASH COLLECTED PER kg OF FUEL=%f kg/kg of fuel\n",result2);
printf("B COMBUSTIBLE MATTER IN ASH\n");
printf("\t(a)COMBUSTIBLE MATTER IN FLY ASH\n");
result3=result1*per_fly/100;
printf("COMBUSTIBLE MATTER IN FLY ASH=%f kg of C/kg of fuel\n",result3);
printf("\t(b)COMBUSTIBLE MATTER IN BOTTOM ASH\n");
result4=(result2*per_bottom)/100;
```

```
printf("COMBUSTIBLE MATTER IN BOTTOM ASH=%f kg of C/kg of fuel\n",result4);
result5=result3+result4;
printf("TOTAL COMBUSTIBLE=%f percentage\n",result5 ");
printf("DRY GAS\n");
printf("Enter the value of perco2,perC,&perS");
scanf("%f %f %f",&perco2,&perC,&perS);
result6=((1/(12*perco2))*(perC+(perS/2.67)-result5));
printf("DRY GAS=%f kg mole/kg\n",result6);
printf("SENSIBLE HEAT\n");
printf("Enter the value of ash_temp and air_temp");
scanf("%f %f %f",&ash_temp,&air_temp);
result7result6*SPDAY*(aph_temp_air_temp);
printf("SENSIBLE HEAT=%f kJ/kg\n",result7);
printf("DRY GAS LOSSES\n");
printf("Enter the value of CV in kJ/kg");
scanf("%f",&CV);
result8=result7*100/CV;
printf("DRY GAS LOSSES=%f percentage\n",result8);
printf("********2.LOSSES DUE TO COMBUSTIBLE********\n");
result9=result5*CVC*100/CV;
printf("LOSSES DUE TO COMBUSTIBLE=%f percentage\n",result9);
printf("******3.LOSSES DUE TO SENSIBLE HEAT IN ASH******\n");
printf("(a)LOSSES DUE TO SENSIBLE HEAT IN FLY ASH\n");
result10=((FLYFUEL)*per_chim*SPASH*(aph_temp_air_temp))/CV;
printf("LOSSES DUE TO SENSIBLE HEAT IN FLY ASH=%f percentage\n",result10);
printf("(b)LOSSES DUE TO SENSIBLE HEAT IN BOTTOM ASH\n");
printf("Enter the value of temp of bottom ash");
scanf("%f,&bot_temp");
result11=(BOTTOMFUEL*per_chim*SPASH*(bot_temp-air_temp))/CV;
printf("LOSSES DUE TO SENSIBLE HEAT IN BOTTOM ASH=%f percentage\n",result11);
result12=result10+result11;
printf("LOSSES DUE TO SENSIBLE HEAT IN ASH=%f percentage\n",result12);
printf("********4.RADIATION LOSSES********\n");
```

```
printf("AS PER DESIGN THE LOSSES DUE TO RADIATION TAKEN FROM AMERICAN BOILER MANUFACTURER'S ASSOCIATION GRAPH IS 0.41\n");
printf("********5.LOSSES DUE TO % MOISTURE AND % H IN FUEL********\n");
printf("TOTAL MOISTURE\n");
printf("Enter the value of perH and per_mois");
scanf("%f %f,&perH,&per_mois");
result13=(per_moist+9*perH)/100;
printf("TOTAL MOISTURE=%f percentage\n",result13);
printf("HEAT PER kg OF MOISTURE\n");
result14=(1.88*(aph_temp-25)+2442+4.2\925-air_temp));
printf("HEAT PER kg OF MOISTURE=%f kJ/kg\n",result14);
printf("LOSSES DUE TO PERCENTAGE MOISTURE AND PERCENTAGE H ON FUEL\n");
result15=(result13*result14*100)/CV;
printf("LOSSES DUE TO PERCENTAGE MOISURE AND PERCENTAGE H IN FUEL=%f percentage\n",result15);
printf("********6.LOSSES DUE TO MANUFACTURE MARGIN AND UNACCOUNTED=1.5 PERCENTAGE********");
printf("LOSSES DUE TO MANUFACTURE MARGIN AND UNACCOUNTED=1.5% percentage\n");
printf("TOTAL LOSSES\n");
result16=result8+result(+result12+result15+1.91;
printf("TOTAL LOSS=%f",result16);
printf("TOTAL LOSS=%f",result16);
printf("BOILER EFFICIENCY\n");
result17=100=result16;
printf("BOILER EFFICIENCY=%f percentage\n",result17);
getch();
}
```

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