Auxiliary Boiler Performance Evaluation and Enhancement

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May 2018

Certificate

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Dedication

This work is dedicated to our beloved parents and teachers.

Acknowledgement

We are thankful to Allah Almighty for all His blessings and gifts. For it was Him who gave us the capability and strength to complete this project and the thesis.

After that, we thank our teacher and supervisor Dr. Erum Pervaiz at SCME who guided us throughout the project. Along with that, we are also thankful to our Industrial supervisor Sania Ijaz who as assigned to us by Engro Fertilizers. We also would like to thank the IPO (SCME) for the efforts they made for the final year projects.

In the end, we would also mention our parents who have been supportive throughout and keep giving us hope and encouragement to succeed in everything we do.

Nomenclature

Na_3PO_4	Tri-sodium Phosphate	$Ca_3(PO_4)_2$	Calcium Phosphate
$CaCl_2$	Calcium Chloride	NaCl	Sodium Chloride
N_2H_4	Hydrazine	O_2	Oxygen
CH_4	Methane	N_2	Nitrogen
H_2O	Water	CO_2	Carbon Dioxide
PFD	Process Flow Diagram	CI	Cast Iron
TPH	Tons per hour	BFW	Boiler Feed Water
Ar	Argon	NOx	Nitrogen Oxides
NH_3	Ammonia	C_2H_6	Ethane
CO	Carbon monoxide	SO_3	Sulphur Trioxide
H_2SO_3	Sulphurous Acid	H_2NO_3	Nitric Acid
H_2SO_4	Sulphuric Acid	T	Temperature
P	Pressure	V	Volume
MS	Mild Steel	C.S	Carbon Steel
S.S	Stainless Steel	Q	Heat Transfer Rate
T_1	Inlet Temperature of hot fluid	t_1	Inlet Temperature of cold fluid
T_2	Outlet Temperature of hot fluid	t_2	Outlet Temperature of cold fluid
U	Overall Heat Transfer Co-efficient	N_t	Number of Tubes
L_b	Baffle Spacing	L	Tube Length
P_t	Tube Pitch	D_s	Shell Diameter
D_b	Bundle Diameter	De	Equivalent Diameter
m	Mass Flow Rate	u	Velocity
k	Thermal Conductivity	T_{LM}	Logarithmic Mean Temperature Difference
R	Universal Gas Constant	n	Number of Moles
C_p	Heat Capacity	As	Cross Flow Area
F_t	Temperature Correction Factor	J_h	Heat Transfer Factor
u_t	Linear Velocity	h_{od}	Fouling Factor for Shell Side
h_i	Tube side Fluid Heat Transfer Co-efficient	h_o	Shell side Fluid Heat Transfer Co-efficient

Re	Reynold's Number	lb	Pounds
NMC	Normal Meter Cube	BTU	British thermal unit
°F	Fahrenheit	℃	Degree Celsius
K	Kelvin	ft^3	cubic feet
cm^2	Square centimetre	mg	Milligram
kg	Kilogram	g	Gram
kJ	Kilo Joule	kW	Kilo Watt
kmol	Kilo mole	m	meter
psi	Pounds per square inch	kmol	Kilo mole
MW	Mega watt	hr	Hour
kg/cm^2	kilo gram per square centimetre		

Abstract:

Boilers are very important components in the industries. Usually, a fluid such as water is used to generate high pressure steam for the heating purposes. In a fertilizer plant, there is a large requirement of this high-pressure steam in various operations of the fertilizer industry.

Major components of the water tube boiler are economizer i.e. a tubular type heat exchanger which preheats the BFW to economize the process, steam drum which is located at the top of the water tubes which acts as the reservoir for the water and steam. It is the difference in densities on the basis of which they are stored together in the steam drum in two different layers. There is also a furnace in which the combustion takes place. There are convective and radiative zones in the combustion. There is also a mud drum for the blowdown separation and a blowdown drum to store it. Economy is the most important factor in the industry so we increase the boiler efficiency by certain methods which is the main focus of our project.

Auxiliary boilers generate steam by using heat of combustion of fuel. The performance of an auxiliary boiler is taken in terms of its efficiency which tells the ratio of steam generated (Output) using the fuel input. Our project focuses on efficiency enhancement by preheating the air being fed to the furnace and excess air control for loss minimization. This eventually will lead to fuel savings and efficiency enhancement.

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Chapter 1: Introduction and Literature Review

1.1 Objective:

The main objective of this project is to evaluate the current performance of the auxiliary boiler at the Engro Fertilizers by calculating the existing efficiency and capacity. There is a need for the increment in the efficiency of the boiler performance. It was noticed that the average attainable efficiency for the boilers is 65-75% whereas it is possible to attain as high as 85% efficiency. This makes us focus on the other 25% of the efficiency which can be improved. One of the major considerations for the boiler efficiency improvement is to enhance the fraction of the fuel out of the total fuel provided which is actually being burnt in the process. The excess air is used for achieving complete combustion which in turn prevents us to have sooty appearances or explosive natured flue gas presence. A large percentage of flue gas turns to decrease the efficiency and hence by controlling the flue gas percentage and finding an optimal point, we can enhance the efficiency of the boiler. Another possibility is to recover the waste heat going into the blowdown which is currently 1.5% of the water going to the boiler. The amount of heat wasted with the waste can be recovered by implementation a heat exchanger and heating the makeup water or the BFW by using this heat. It can also be heated using the heat wasted in the flue gas. Boiler capacity is also directly related to the boiler efficiency and hence by increasing the capacity of the boiler, we can increase the efficiency but this would lead us to design the boiler with the increased capacity.

1.2 Boiler:

Boiler is an equipment which is used to generate high pressure and high temperature steam out of water. Steam is a very important utility and is used in the power generation processes, stream stripping and reforming in different fertilizer, chemical, polymers, power generation, foods and many other industries. Boilers are also sometimes known as the steam generators as the main purpose of the boiler is to convert the liquid into the vapor. Furnace of the boiler is the most important part in the boiler where the burning of fuel takes place and the flue gases produced as a result of the combustion heat the water to generate the steam which then goes to the super heater for further increase in temperature. Sometimes, we can use a nuclear reactor for the source of heating the water which then produces steam.

1.3 Types of Boilers:

There are two main types of the boilers on the basis of the construction and the application of the steam generated. These two types are as follows:

- Water Tube Boiler
- Fire Tube Boiler

1.3.1 Water Tube Boiler:

A water tube boiler is a high-pressure boiler in which the water coming from the economizer is circulating in the tubes (also known as water tubes) and is heated by the heat of the flue gases produced as a result of combustion of the fuel taking place in the furnace of the boiler. The water heated by these hot gases then goes to a steam drum by its natural motion and then here any r left over water entrapped goes back to the tubes for further heating and the steam produced goes to the super heater and comes out as superheated steam. This is the steam which can be defined as the steam at a temperature above its boiling point at a fixed pressure.

This superheated steam can be thought of as dried gas containing no water droplets because its applications require zero water presence as it can cause corrosion in the related equipment. Cool water which is going down flows through the down comer tubes. For the economic purposes, usually the heat of the flue gas is used to heat the boiler feed water.

Water tube boilers are mostly used for the processes where the steam production rates are very high. This means that the main focus is the amount of steam produced and not the heating facility provided by the steam produced.

The diagram below explains how steam is generated from the water present in the tubes with the help of the heat provided by the combustion gases.

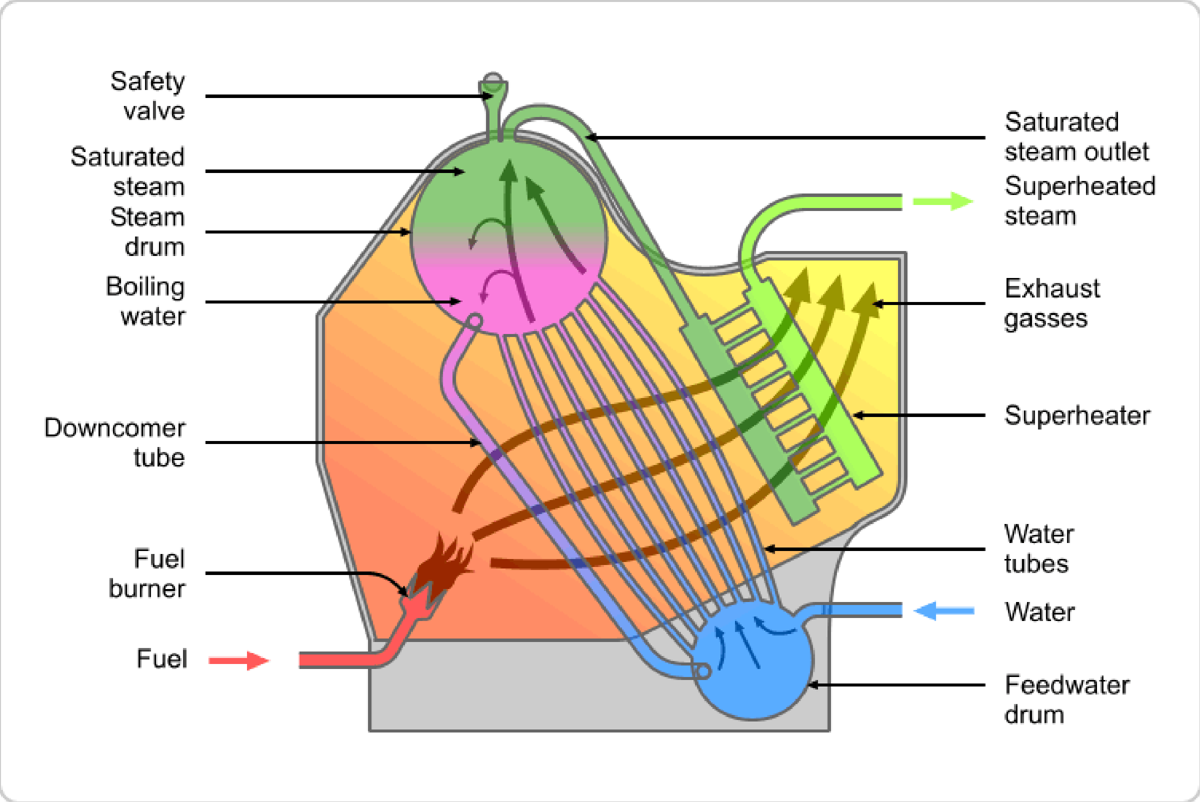


Figure 1.1: Water Tube Boiler

Applications of Water tube Boiler:

- Water tube boilers find their use in the power generation purposes.
- They are used in different process industries.
- One of their major use is in the divisions of chemical processing.
- They are a very vital component of the pulp making and paper manufacturing industries.
- They are also used for the steam reforming in fertilizer plants.

Advantages of Water tube Boiler:

- There is a flexibility in achieving the heating surface area as the increase in the number of tubes increases the surface area
- In the thermosiphon, the flow is based upon the natural convection, so a higher flow rate of water can be achieved.
- It is capable of generating a large quantity of steam.
- It can achieve a pressure as high as 5000 psig.
- Very large temperatures can be attained.

Disadvantages of water Tube Boiler:

- Due to large flowrates and pressures, the capital cost of the equipment is very high.
- The cleaning of the water tubes is very difficult to attain.
- They occupy more space due to their larger sizes.
- There is no commonality in between the water tubes if the boiler.

Stationary Water Tube Boilers:

Usually on all the processes the operating pressures and the flow rates required are very high so the boiler used is completely water tube type. Whereas, sometimes the main chemical purpose is the heating facility so there is a little niche for the fire tube type.

Marine Water Tube Boilers:

These boilers contain an improved version of the boiler design. They contain the turbines which are used for the propulsion which is exchanged with the older design in which the reciprocating engines containing pistons were being used.

1.3.2 Fire Tube Boilers:

This is a type of boiler in which the hot combustion gases or the flue gases pass from the fire through the tubes and the water is present in a container and is surrounding the tubes. The heat of the gases heats the water surrounding the tubes by the phenomena of conduction taking place through the walls of the tube between the flue gases and the water. This heating in turn produces the steam.

These boilers are better in working than the flued boilers containing only one large fluid because the presence of a large number of tubes provides a greater heat transfer surface area and hence better efficiency.

The tank containing water is usually cylindrical in shape as it is the best possible shape for pressurized vessels. The tank can be horizontal or vertical depending upon the application for which it is made.

Below is a figure of a common fire tube boiler.

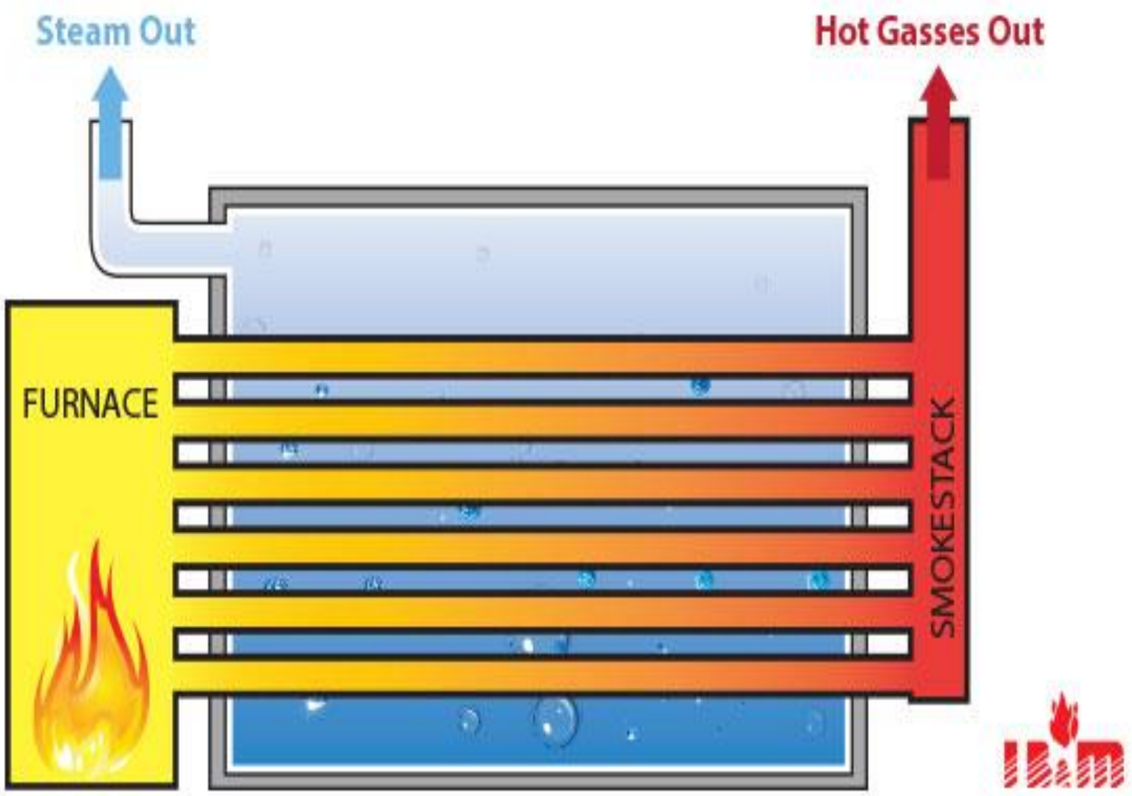


Figure 1.2: Fire Tube Boiler

1.3.3 Types of Fire Tube Boiler:

Cornish boiler:

This is the earliest type of fire tube boiler and it contains only one flue which also contains fire. This fire is placed on an iron grating through the fluid. It also contains a container at the bottom of it to collect all the residual gases. This type of boiler operates at 170 kPa and is usually categorized as a low-pressure boiler whereas now a days, there is a possibility to use it for high pressure operations by the use of cylindrical pressure vessel.

Lancashire boiler:

This is a type of fire tube boiler which is similar to the Cornish type but differs in one aspect that there are two flues each containing fire. This is an improved version of the former boiler in which the laws of thermodynamics were considered to increase the surface area of the gate of furnace compared to the volume of the water used for steam making purposes. Galloway tubes can also be used to increase the surface area of the heat transfer. These tubes are used crosswise and they have small lengths and large diameters. They are also tapered for easier installation of the water tubes.

Scotch marine boiler:

This type of boiler is completely different from the former ones discussed before. The tubes installed in this boiler have very small diameters and the number of tubes used is greater. This provides a greater heat transfer area. There is no difference in the construction of furnace and the tubes are arranged above it through a combustion chamber. The combustion chamber facilitates the flow of flue gases from back to front because it is contained inside the boiler shell completely. A smokebox is also present on the upward side of the chimney which covers the tubes.

Locomotive boiler:

It is the kind of boiler in which there are three key components present. These are:

- A firebox which is double walled.
- A horizontal boiler barrel which is cylindrical in shape.
- A smokebox along with a chimney for the removal of the exhaust gases.

The tubes present in the boiler barrel are larger in size. A forced draft is maintained in this type of boiler and this achieved by sending the exhaust gases coming out of the chimney back to the exhaust with the help of the blast pipe present in the smoke box.

Applications:

- They find their use in the working of steam locomotives.
- They are used in the plant operations where the capacities and loads are relatively smaller.
- The can also be used in the domestic heating facilities.

Advantages of Fire Tube Boilers:

- Due to the easy construction of such boilers, it is very easy to purchase them from the market in the form of readily available packages.
- The transport of these boilers is very easy as they do not exist in the form of separate parts.
- Due to the simple operation and construction of these boilers, it is very easy to carry out the cleaning and maintenance of these boilers.

- The heating solutions provided by these boilers are very simple.
- The boiler shell can be easily replaced due to its simple design.

Disadvantages of Fire Tube Boilers:

- Operations where the production rates and capacities are higher, this boiler is usually not suitable for use.
- This boiler cannot perform at pressures of 250 psig and above.

1.4 Types (on the basis of application):

On the basis of their use or application, boilers can be divided into three main types which are as follows:

- Utility steam generators
- Waste heat recovery boilers
- Auxiliary boilers

1.4.1 Utility steam generators:

This is a type of boiler which produces the steam for the whole pant unit. It resembles the flash type steam boiler and thus has a low water content. The water tubes of the boiler are in the form of spiral tubes which are joined into one single tube. The circulation in the boiler is usually forced type which is achieved by using a pump. The diameters of the tubes is very small which reduces the risk of explosions when the operating pressures are relatively higher. The flowrate of water passing through the pump can be adjusted depending upon the steam requirement at that particular time. To maintain a constant operating temperature, the output of the burner is being throttled.

The capacity of the steam generated usually reaches to about 100MW and the operating pressure is usually more than 300 bar. Temperature of the live steam is about 600 degrees Celsius.

Waste Heat Recovery Boilers:

These are the types of boilers which carry out the steam generation by extracting the useful heat from a waste process steam such as a hot flue gas stream. These gases are usually coming out of the gas turbines and the internal combustion engines.

Other heat sources than the waste stream are also sometimes used in order to carry out the steam generation. These sources may include firing of other by products or by the burning of fuels such as light oil or gas.

Advantages of Waste Heat Recovery Boilers:

There are both direct and indirect advantages of waste heat recovery boilers

Direct Advantages:

These boilers increase the efficiency of the system by decreasing the capital cost and hence making the system cost effective and energy efficient.

Indirect Advantages:

These are some of the indirect advantages of waste heat recovery boilers:

- The help to decrease the pollution by reducing the flue gas content being exhausted into the atmosphere as it is being used for the heat recovery purposes.
- Since there is a decrease in the fuel requirement, the equipment size that is required to carry out the processes also decreases.
- There can be seen a decrease in the energy requirement of the auxiliary equipment such as fans, blowers, pumps etc.

Disadvantages of Waste Heat Recovery Boilers:

- There is an obvious increase in the capital cost of the process due to the installation of an additional equipment.
- The quality of the steam produced is not very good i.e. low temperature steam is produced.
- An extra equipment leads to more maintenance.

1.4.2 Auxiliary Boiler:

Auxiliary boiler is an extra boiler which is installed in addition to the main boiler. This boiler is only used for the start-up of the steam production. It basically generates steam when the main boiler is shut down for the maintenance purposes. A typical auxiliary boiler usually produces steam at a rate of about 10,000 lb/hr and operates at a pressure of 120 psi whereas the pressure of the inlet steam used is about 600 psi.

Chapter 2: Process Description

2.1 Overview of the Project:

The project assigned by Engro Fertilizers is to evaluate the performance of an auxiliary boiler and devise some methods to improve the efficiency of the existing boiler. In order to understand the process in detail, it is necessary to understand the existing process flow diagram thoroughly.

2.2 Process flow Diagram (PFD) of Boiler:

The figure shown below is the process flow diagram of the existing auxiliary boiler at Engro Fertilizers along-with the proposed air preheater to the furnace. The combustion air being fed to the furnace is being preheated by the flue gases from the economizer and enhancing the temperature of air from 38°C to 100°C. This pre-heated air takes less fuel energy than the cold air resulting in the combustion efficiency increase of about 3%. Also, excess air reduction of 5% has contributed to the overall combustion efficiency increase of 4%.

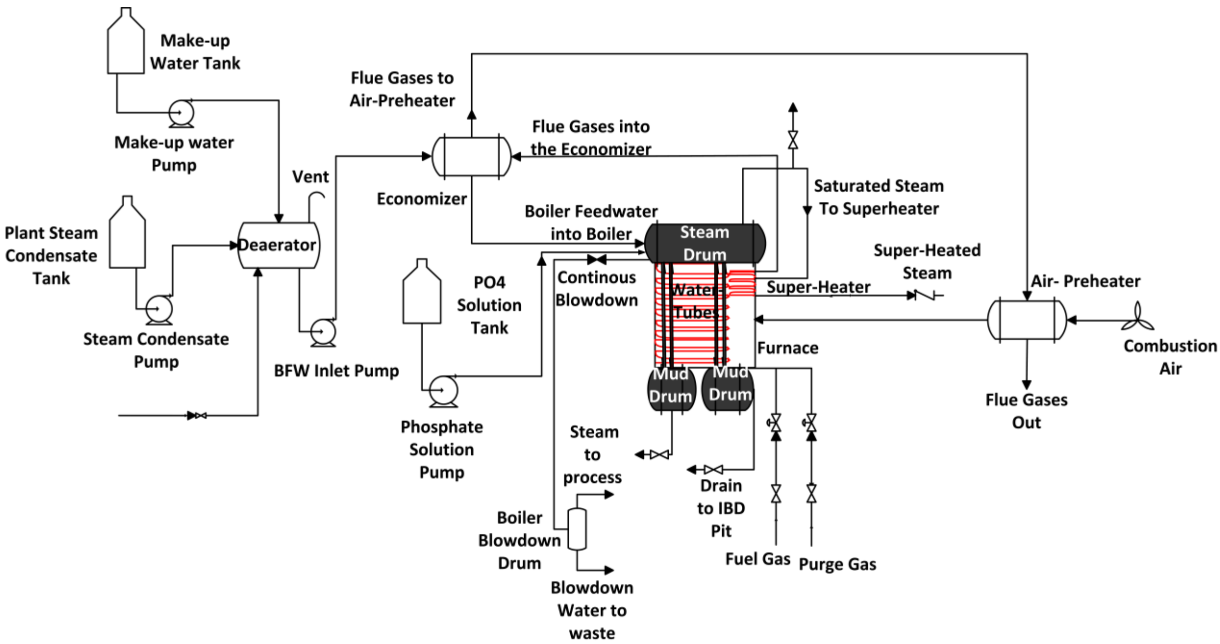


Figure 2.1: Process Flow Diagram

2.3 Makeup Water or Boiler Feed Water:

Boiler Feed water or the makeup water is the treated water after the demineralization. This water after the deaeration process is carried to the steam drum through a feed pump as shown above in the figure. Water is used in the boilers as it has high heat capacity than most of other substances. It is being circulated in the Rankine cycle. Since it is not in contact with the outer atmosphere, it can be reused after some treatment. This brings up efficiency in the system. If water is not treated properly there is a chance of occurrence of many problems such as scaling, priming, foaming, and corrosion etc. These problems are caused due to multiple reasons some of which are discussed below.

An ideal boiler feed water should be free from the impurities discussed below and should not form scaling, fouling, priming, corrosion etc. in the boiler.

Calcium Hardness:

This is caused due to the carbonates and bicarbonates of calcium. These salts settle on the boiler surface and cause scaling. This type of hardness can be minimized by adding phosphate because it forms a sludge that can flow freely and it can be removed along with the blowdown.

Magnesium Hardness:

It causes the scaling of magnesium salts inside the boiler. This type of hardness can be reduced by maintaining a solution of hydroxide and residual of silica in the feed water which forms a free flowing solution of magnesium silicate and magnesium hydroxide sludge which can also be removed along with the blowdown waste.

Free Oxygen:

Free oxygen is also present in the boiler feed water as an impurity and it can cause corrosion in the boiler tubes. In order to remove this dissolved oxygen, we add the eliminox solution with the water. Eliminox is an oxygen scavenger and it contains cabohydrazide in it. This process is called deaeration and it takes place in the deaerator.

Carbon dioxide:

Carbon dioxide can cause corrosion in the boiler. This type of corrosion is used my adding ammonia to the reflux system. Ammonia acts as an inhibitor and it can neutralize the CO_2 present.

Scale Formation of Salts:

The problem of scale formation inside the boiler is of primary importance as the salts causing these scale depositions show a decrease in their solubility at the elevated temperatures. Another reason is that when the steam is formed out of water, water gets evaporated and the steam composition is rich in salts. Corrosion products along with the hardness and silica present can also act as a major source of scale formation inside the boiler. At first the salts present in the water crystallize due to the formation of steam at high temperatures. After this, these crystallized salts settle down in the boiler; this is also known as sedimentation. For example, the scale formation of $CaCO_3$ salts takes place in the boiler feed water where the hardness content is higher.

2.3.1 BFW Pump:

This is the pump which supplies the water which is used to generate steam to the boiler. Usually, fresh water is used as boiler feed water but sometimes returning condensates from the steam condensed from the boiler can also be used. Both centrifugal and positive displacement types can be used as the boiler feed pumps and they operate at high pressures and the suction is at the condensate returning system or boiler feed water storage tanks. The pump must be able to generate enough pressure to overcome the pressure of the steam generated in the boiler. In order to achieve this, usually a centrifugal pump serves the purpose.

Electrical corrosion sometimes takes place inside the mechanical seal of the boiler water feed pump. This happens when the sliding ring of the pump generates static charges when it slides on the stationary ring. These charges do not flow to the other parts due to less electrical conductivity of the seal. Due to this corrosion, loss in the material of stationary and sliding rings can be seen sometimes. In order to avoid this, mechanical seals coated with diamond (DLC) can be used.

2.4 Working of Water Tube Boiler:

The boiler feed water coming out of the economizer goes straight into the boiler tubes. These boiler tubes are surrounded by the furnace atmosphere. Fuel gases burn inside the boiler furnace to generate hot flue gases which heat up the water inside the tubes to generate steam. Due to the natural flow, the heated water goes up into a steam drum through the risers where the saturated steam is collected by the super heater for further heating. The droplets which are not heated enough come down from the steam drum through down comers for further heating.

2.5 Steam drum:

This is a vital component of a water tube boiler. It is basically a separation tank for the steam and water mixture. The separation takes place on the natural density difference basis. As water has a higher density as compared to steam. It forms a bed at the bottom and steam tends to rise naturally so it makes a layer above the water strata. This steam is separated from the water in order to convert this saturated steam into the super saturated steam by further heating in super heater. The water-steam mixture enter the steam drum through the tubes called risers. Inside the steam drum, demisters are present which separate the water droplets and the steam. This results in the formation of dry steam.

Saturated water goes down to the mud drum through the tubes called down comers and is heater again.

This steam re-enters the furnace through the super heater. Sometimes, this super heater is considered as the part of the boiler.

2.5.1 Types of steam Drums:

Three or Four Drum Boilers:

This is the type of boiler which was used as a daily use boiler. Now a days, they are sometimes used in the industry.

Bi Drum Boiler:

These types of boilers find their application in the steam and power generation boilers. In the power generation boilers, single drum boilers are now being used instead of bi drum boilers due to non-reheating of these boilers. A single drum boiler can more efficiently bear high heat rates. Whereas in steam generation boilers, high load fluctuations can be observed so bi drum boilers are best suited because they are flexible and can easily adapt to these irregularities.

Single Drum Boiler:

This is the type of boiler which is typically used in the power generation systems. They operate at pressures comparatively higher than the bi drum boilers. The down comers are attached to the boiler by welding. These boilers are flexible in operation with both reheat and non-reheat types of boilers.

2.6 Boiler Tubes:

2.6.1 Generating Tubes:

These are the tubes with small diameters and are located in the direction of the hot combustion gases. This arrangement provides a larger heat transfer surface area. The steam is generated by convective heat transfer phenomena. There is a minimum value of the tube diameter which is allowed for the respective water flow rate. If the value gets very small, the steam to water ratio becomes very large and it can result in the overheating.

The heat transfer area provided to the gases must also be low. If too much heat transfer surface is provided, the exit temperature of the flue gas can fall. This temperature should not be less than the acid dew point otherwise corrosion can take place.

The number of these tubes in the modern boiler is kept lower.

2.6.2 Screen tubes:

These tubes are placed with thee furnace so they are the recipient of heat coming from the flue gases and also the heat of the furnace flame. In order to achieve a low steam to water ratio, the diameter of the tubes should be high in order to prevent the problem of overheating. The main purpose of these tubes is to save the tubes of super heater from the direct radiant heat of the furnace flames.

2.6.3 Water Wall Tubes:

These tubes absorb the heat of the furnace. Use of these tubes minimizes the need for the refractory material. Sometimes, there is a need for refractory cells which are water cooled and they consist of tubes on which studs are welded. The refractory material coated on these tubes help to prevent the damage that can be caused at elevated temperatures. Other portion of these tubes is open for the radiant heat so that the steam can be generated using this heat.

2.6.4 Down Comer Tubes:

These are the tubes which are larger in diameter. These tubes are surrounded by the hot flue gases and take the saturated water from the steam drum to the header and mud drum.

2.6.5 Riser tubes:

These tubes take the water and steam mixture to the steam drum where the separation of these two takes place and they can also be thought as feeders for the steam drum.

2.7 Deaerator:

Deaerator generally solves the purpose for removal of unwanted dissolved oxygen and other gasses from the feed water to steam boilers. They are normally helpful in Chemical Process Industry or in Power plant sector where steam production is carried out from boiler feed water. The deaerators are devised in such a way that the amount of oxygen in the outlet water is around 7ppb by weight percent.

Deaeration is desired to govern the corrosion procedures in the downstream method. In water, the existence of dissolved gases, mainly oxygen and carbon dioxide, enhances corrosion. Oxygen is more violent of both. The removal of oxygen cannot be overlooked. Even little presence of oxygen gas instigates serious corrosion and other serious problems. The primary function of the deaeration process is to avoid this corrosion by eliminating the dissolved gases from all the originating sources of water inflowing the downstream technique such as lines, piping, particularly boilers and condensate lines.

2.7.1 Principle of Deaerators:

Following are the principles on which a deaerator works:

Henrys Law:

There is a direct proportionality between the solubility of gas in a liquid and the partial pressure of dissolved gasses. Thus, by decreasing the partial pressure by adding steam in deaerator solubility decreases, further resulting in removal of gas from water.

Inverse Solubility of Water:

When there is an increase in temperature of water, the dissolved oxygen content in water is reduced. Therefore, steam is added in deaerator to increase the water temperature, the dissolved gas solubility will decrease which will ultimately remove gases from water.

2.7.2 Working of Deaerator:

In Boiler Deaerator working principle, water is heated up to a saturation temperature with least pressure drop and smallest vent for ensuring the finest thermal operating efficiency. The process takes place by applying the feed water over various layers of tray in order to provide vast contact area between the liquid surface and deaeration steam. The scrubbing steam is entered from the lower side of deaerator. When the boiler feed water interacts with steam, it reaches the saturation temperature and the gases are omitted through the feed water from the vent valve. This treated water is poured in the storage tank that is under the deaerator.

2.7.3 Types of Deaerator:

Deaerator is classified in the following three types:

1. Spray type Deaerator.
2. Tray type Deaerator.
3. Vacuum type Deaerator.

Spray type Deaerator:

The spray type deaerator has both horizontal and vertical vessel, which acts as both the storage feed water tank and deaeration section.

A standard spray type deaerator is a horizontal vessel that contains a pre-heating part and a deaeration section. The separation between two vessels is called baffle. Low-pressure steam inserts from a sparger in the base of the vessel. The boiler feed water is sprayed in the portion where the steam occurring from sparger heats up. The aim of the pre heat section and feed water spray nozzle is to warm up the boiler feed water to a saturation temperature to exit the gasses in the deaeration section. This feed water further flows to the deaeration section, where the steam that arises from the sparger further deaerates it. The gases are removed from the water through a vent present at the upper side of the vessel. The deaerated feed water is pushed out of the bottle from the vessel to the steam that results in the generation of boiler system.

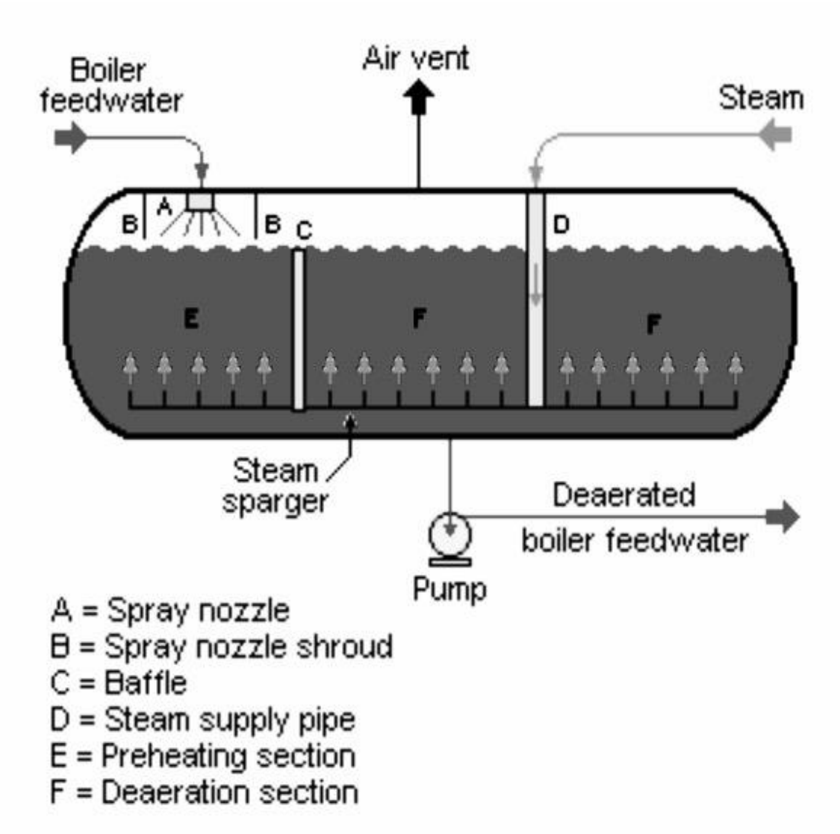


Figure 2.2: Spray Type Deaerator

Tray type Deaerator:

The tray type deaerator also known as the Cascade type deaerator is vertical deaeration section fixed over the horizontal vessel serving as a deaerated storage feed water tank. This boiler feed water gets into the vertical deaeration that is placed above the perforated tray and is designed to flow downwards the perforation. Low-pressure steam passes into the perforation tray and ascends upward through the perforation. Some designs prefer using packed bed rather than perforated trays in order to provide good contact between the feed water and steam. The steam exerts the gas through the boiler feed water and exits the vent valve at the top of round section. This deaerated water is then moved down in the horizontal vessel from where it is further pumped into the generating boiler system. Low-pressure steam that was entered through the sparger pipe in the base of the vessel is used to preserve the stored boiler feed water warm.

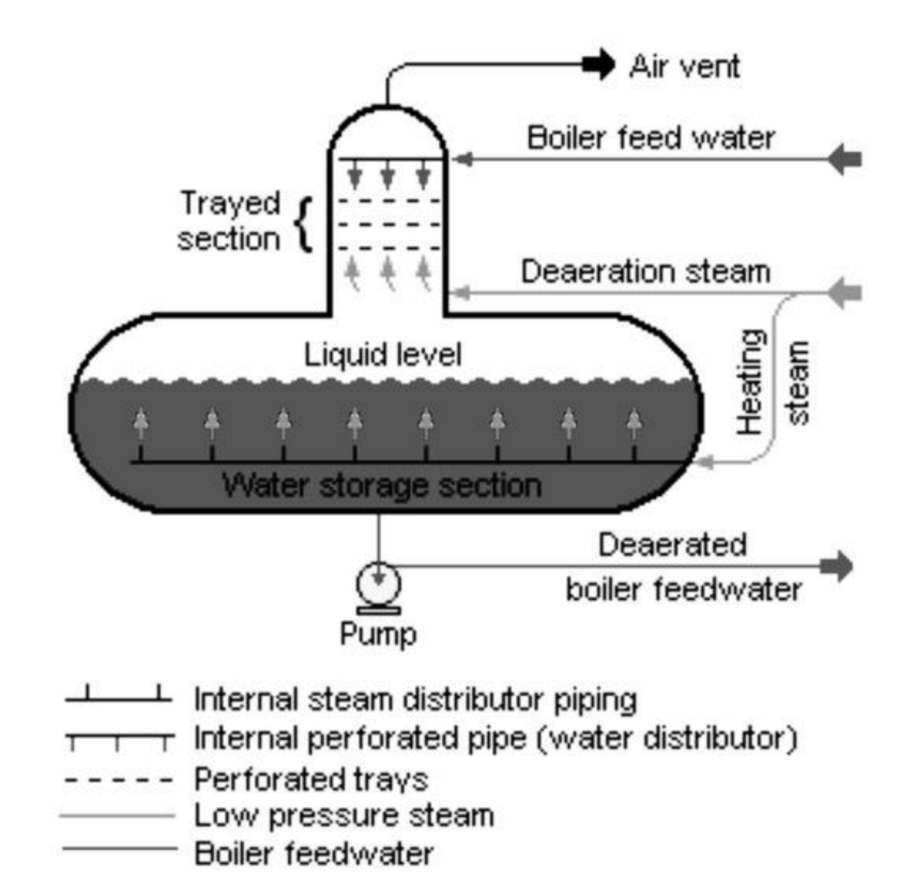


Figure 2.3: Tray Type Deaerator

Vacuum type Deaerator:

The Vacuum type deaerator consist of three elements:

- Vacuum Deaerator
- A Vacuum pump unit

- A boiler feed water pump

Deaerator is normally constructed in a way that the deaeration tank contains galvanized steel or stainless steel. Internally, the tank is furnished with a transitional bottom, underneath which is a reservoir of deaerated water fixed. Filters are fitted on top of the transitional bottom. A vacuum pump also known as liquid ring pump is attached with the deaerator for the purpose of sucking the released dissolved gasses. Thus maintaining a negative pressure in the deaerator system to increase the discharge of dissolved gasses through the boiler feed water.

After the deaerator has been connected and fixed, the initializing test of safe valve should take place in the local for avoiding the issue of being jammed. When the turbine functions, the two deaerator water boilers should be activated in parallel. The steam pressure, water level, and temperature should be kept the same and they cannot be operated individually. Before delivering water and steam to the deaerator, the vent valve of deaerator should be untied first. One part of the pressure amendable device and the water level controller is used mutually for the two deaerators. Before the vacuum is not established in the condenser, prevent the steam and water of deaerator drain to the condenser. When the turbine shuts down and the principal feed water pump is closed, the plant start-up and shutdown feed-water pump should retain operation for some time to calm the key coolant system. In that moment, the deaerator should be functioning continuously till the plant start-up and the shutdown feed water pump discontinues. To prevent surpassing of the design stress the deaerator has to be furnished with two safety valves and to intercept the vacuum the deaerator should be equipped with vacuum breakers.

Deaerator also performs the function of an additional storage device, which delivers reserve amount of boiler feed water during upstream water supply breakdown for temporary period normally for about 20 minutes. In few Plants, Deaerator is also helpful for treating oxygen-scavenging substances like Hydrazine or Hydroquinone.

2.8 Economizer:

An "economizer" is a heat recovery device that is used to preheat BFW by the using the heat energy of waste stream for heat optimization. It also prevents the flooding of the boiler system with very cold water i.e. too cool to be boiled given the design of the boiler and flow rates of the inlet and the outlet streams. An economizer can reduce the costs by 5-10% and pays for itself in less than two years by recovering waste heat energy.

Chapter 3: Material Balance

Material balance was applied on all the component separately to find out the unknown flowrates, compositions of certain gases such as flue gases and to verify the results in certain cases. Manual calculations were performed first and then Aspen HYSYS model was created in order to verify all the results.

3.1 Deaerator:

The first component was the deaerator for which there were three inlets i.e. makeup water or demineralized water, steam condensates coming from different plant processes and steam injections and there were two outlets i.e. vent and the deaerated water coming out of the deaerator.

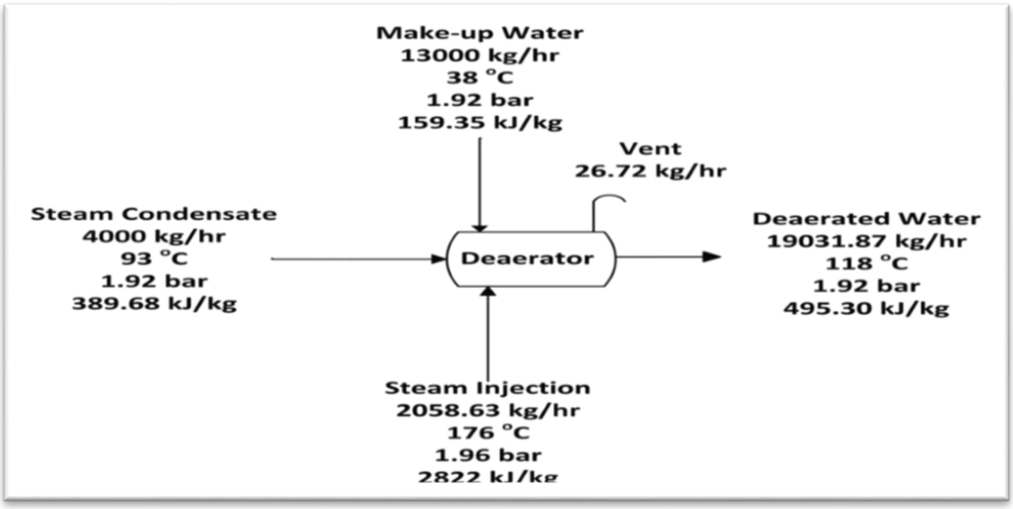


Figure 3.1: Deaerator

Deaerator Material Balance:

By applying,

In = Out

Stream 1: Demineralized Water:

Flow rate m_1= 13000 kg/hr

Pressure =1.92 bar

Temperature =38℃

At these temperatures and pressure, specific enthalpy was calculated.

Specific enthalpy = 159.35kJ/kg

Stream 2 = Steam Injections:

m_2 =2058.63 kg/hr

Temperature = 176℃

Pressure = 1.96 bar

Hence,

Specific enthalpy = 389.68 kJ/kg

Stream 3: Steam Condensates:

m_3= 4000 kg/hr

Temperature= 93℃

Pressure= 1.92 bar

Specific Enthalpy = 389.68 kJ/kg

Stream 4: Deaerated water outlet:

m_4= unknown flowrate

Temperature= 118℃

Pressure= 1.92 bar

Specific Enthalpy = 495.3 kJ/kg

$m_1H_1+m_2H_2+m_3H_3=m_4H_4$

Putting all the values and $m_4= m_1+m_2+m_{3,}$

$(13000)\ (159.35) + (m_2)\ (2822) + (4000)\ (389.68) = (13000+m_2+4000)\ 495.3$

This gives,

m_2= 2058.63 kg/hr

And similarly,

Inlet = $m_1+m_2+m_3$ = 19058.63 kg/hr

Vent= 1.3% of steam injection = 26.762 kg/hr

$m_4 = m_1+m_2+m_3$- (vent) = 19031.87 kg/hr

Inlet = 19058.63 kg/hr

Outlet = m_4 + vent = 19058.63 kg/hr

Hence, it is verified that inlet= outlet.

3.2 Water Tube Boiler:

There are two inlets to the boiler i.e. boiler feed water and the Phosphate solution injection and there were three outlets that being superheated steam, saturated steam vent and the blowdown. A percentage of saturated steam is vented and the other part goes to the super heater which generates super-heated steam.

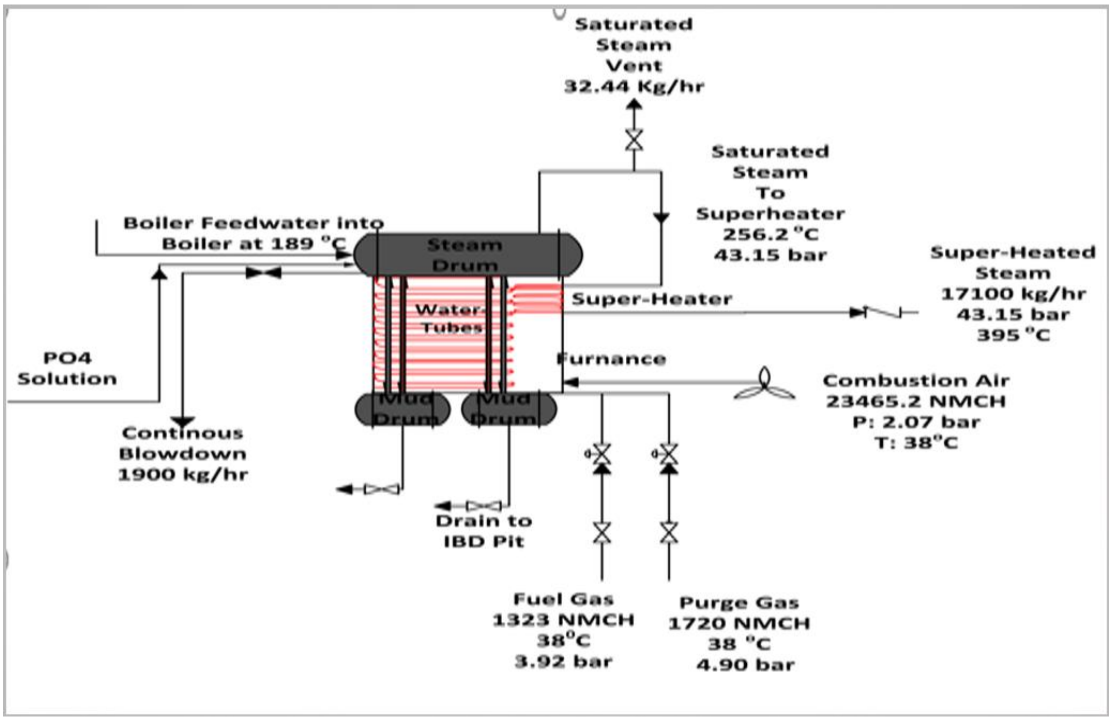


Figure 3.2: Water Tube Boiler

By applying water balance across the boiler,

Mass In = Mass Out

BFW + Water in PO4 solution = Super-heated steam + Vent+ Blowdown

19031.87 + 0.57 = 17100 + 1900 +Vent

Thus,

Vent= 32.44 kg/hr

Overall Material Balance:

In order to validate the balances applied above, an overall material balance across the whole PFD was applied.

Applying material balance,

Inlet = Outlet

Inlet water + Steam Condensate+ Water in phosphate Solution+ Steam to Deaerator= Steam Produced + Blowdown+ Vent 1(Deaerator) + Vent 2(Saturated steam)

13000 + 4000 + 0.57 + 2058.63= 17100 + 1900 + 26.76 + 32.44

19059.20 kg/hr = 19059.20 kg/hr

Hence, the material balance is validated.

3.3 Furnace Balance:

Furnace balance was applied in order to calculate the composition of flue gas leaving the boiler furnace. The compositions of fuel and purge gases (coming from different plant processes) were provided by the industry.

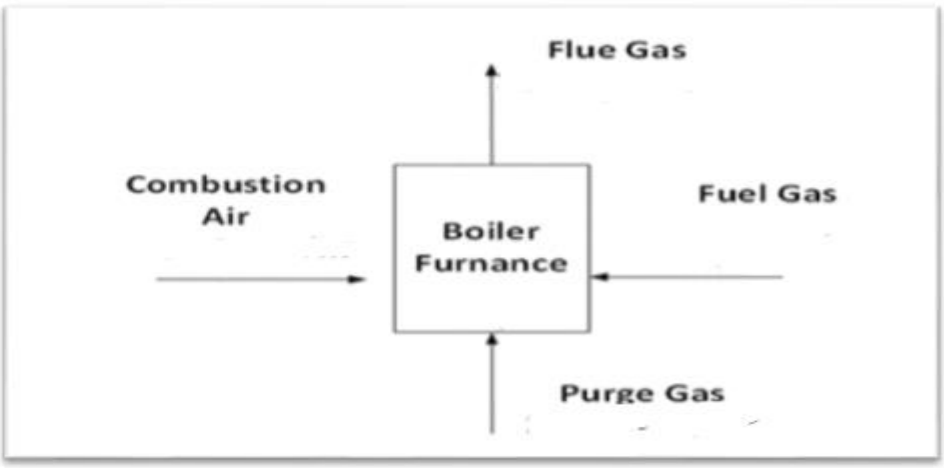


Figure 3.3: Boiler furnace

3.3.1 Fuel Gas Composition:

Table 3.1: Fuel Gas Composition

Component	**Percentage(%)**
Methane	76.97
Ethane	0.09
Carbon Dioxide	0.39
Nitrogen	22.53
Hexane	0.02

3.3.2 Purge Gas Composition:

Table 3.2: Purge Gas Composition

Component	**Percentage(%)**
Hydrogen	12.82
Argon	7.9
Nitrogen	56.6
Methane	22.6

3.3.3 Reactions:

The combustion reactions of fuel and purge gases were as follows:

$$CH_4 + \frac{3}{2}O_2 \rightarrow CO + 2H_2O$$

$$C_2H_6 + \frac{5}{2}O_2 \rightarrow 2CO + 3H_2O$$

$$C_6H_{14} + \frac{13}{2}O_2 \rightarrow 6CO + 7H_2O$$

$$H_2 + \frac{1}{2}O_2 \rightarrow H_2O$$

By combining the ammounts of carbon and hydrogen in both fuel and purge gas, we found out the total moles present.

Table 3.3: Total Moles to Furnace

Component	**Component (kg moles)**	**Component**
Methane	72.50	32.50
Ethane	0.03	0.01
Carbon dioxide	0.09	0.04
Nitrogen	41.61	18.7
Hexane	0.00238	0.00106
Argon	3.27	1.46
Hydrogen	105.00	47.19

With 88 % combustion efficiency

The total moles of oxygen required were found out by the stoichiometric equations shown above.

Moles of O_2 Required = 171.03 kgmoles

The percentage of excess air used was 10% and using this, the extra moles of oxygen provided by the excess air were provided.

Moles of O_2 supplied by 10 percent excess air = 188.14 kgmoles

Similarly, the amount of total nitrogen was found out which was the sum of nitrogen in the fuel and purge gas and the amount of N2 present in air.

Total N2 = N2 in fuel + N2 in Air = 749.38 kgmoles.

Similarly, the percentage of unreacted O2 which was coming out in the flue gas was also calculated by the difference of oxygen supplied and reacted.

O2 in flue gas= 17.10 kgmoles

H2O produced = 222.58 kgmoles

CO Unreacted = 9.65 kgmoles

CO2 Produced = 54.98 kgmoles

Moles of Argon in Fuel = 3.26524 kgmoles

Thus the composition of the fue gas came out to be as follows and similarly the mass flow rates were also calculated.

Table 3.4: Composition of Flue Gas

Component	Moles	Mole Percent	Mass Flow (kg/hr)
CO_2	54.98	8.50	2419.71
CO	9.65	0.95	270.29
O_2	17.10	1.92	547.32
N_2	749.38	73.60	20993.15
Ar	3.26	0.46	130.44
H_2O	222.58	14.05	4008.80
Unburnt Fuel		0.53	151.53
		Total	28521.25

3.3.4 Elemental Balance:

An elemental balance was also applied across the furnace in order to validate the overall balance and thus we found out that all the inlets were equal to the outlets.

Table 3.5: Elemental Balance

Elemental Balance		
Component	**Moles In**	**Moles Out**
Carbon	64.63	64.63
Oxygen	376.40	376.40
Nitrogen	1498.76	1498.76
Argon	3.27	3.27
Hydrogen	445.17	445.17

3.4 Blowdown flash Tank:

The blowdown flash tank uses the continuous blowdown to draw the useful amount of heat.

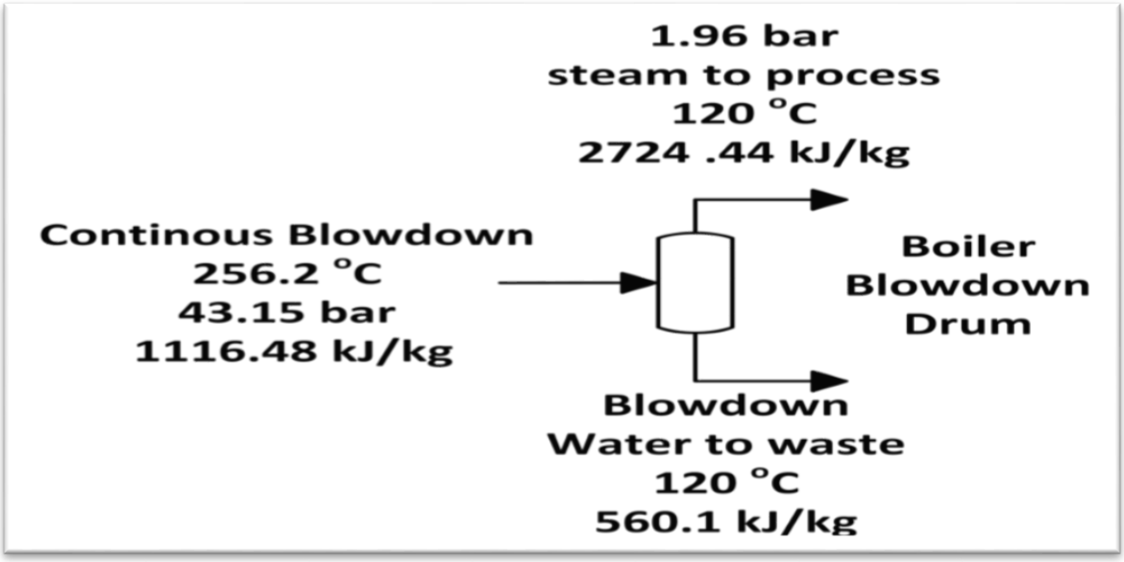


Figure 3.4: Blowdown Flash tank

3.4.1 Percentage of flash Steam:

First of all the percentage of flash steam was calculated by using the formula:

$$Percentage\ of\ Flash\ Steam = \frac{H_b - H_f}{V_t}$$

Where,

$$H_b = Specific\ Enthalpy\ of\ liquid\ at\ boiler\ pressure = 1116.48\ kJ/kg$$
$$H_f = Specific\ Enthalpy\ of\ liquid\ at\ flash\ pressure = 560.1\ kJ/kg$$
$$V_t = Latent\ heat\ of\ vapourization\ at\ flash\ pressure = 2201.59\ kJ/kg$$

Thus,

Percentage of Flash Steam = 25.2 %

It means that the flash steam coming out of the blowdown flash tank was 25.2% of the continunous blowdown and the rest was going to the waste.

Flow rate of blowdown water= 19000 kg/hr

Flow rate of flash steam= (0.25)(19000)= 478.8 kg/hr

Flow rate of waste water= 1421.2 kg/hr

Thus it can be seen that the inlet is equal to the outlet.

Table 3.6: Blowdown Flash Tank Material Balance

Mass In (kg/hr)	**Mass Out (kg/hr)**	
Blowdown Water(kg/hr)	Flash Steam(kg/hr)	Waste water(kg/hr)
1900	478.8	1421.2
1900	1900	

3.4.2 TDS Balance:

At the end, TDS balance was applied in order to validate the overall material balance.

Table3.7: TDS Balance

TDS Balance			
In		**Out**	
Boiler Feed water (kg/hr)	TDS (ppm)	Blowdown (kg/hr)	TDS (ppm)
19031.87	100	1900	1001.677368

Chapter 4: Energy Balance

For the energy balance, the main equation used is as follows:

$$\Delta\left[\boldsymbol{m}\ \left(\boldsymbol{H}+\frac{\mathbf{1}}{\mathbf{2}}\boldsymbol{u}^{\mathbf{2}}+\boldsymbol{zg}\right)\right]=\boldsymbol{Q}+\boldsymbol{W}_{\boldsymbol{s}}$$

4.1 Deaerator:

For the deaerator energy balance, we use the temperatures and pressures of different stream flows and calculated their specific enthalpies.

m_1= mass flowrate of Demin Water= 13000 kg/hr

m_2= mass flowrate of steam injection =2058.63 kg/hr

m_3=mass flowrate of steam condensate = 4000 kg/hr

m_4= mass flowrate of deaerated water outlet= 19031.87 kg/hr

H1= Specific Enthalpy of Make-up Water = 159.35 kJ/kg

H2=Specifc Enthalpy of Steam Injection= 2822 kJ/kg

H3= Specific Enthalpy of Steam Condensates = 389.68 kJ/kg

H4= Spcific Enthalpy of Deaerated Water Outlet =495.6 kJ/kg

Table 4.1: Deaerator Energy Balance

Deaerator Energy Balance				
Stream Name	**Mass Flow (kg/hr)**	**Temperature (ºC)**	**Pressure (bar)**	**Specific Enthalpy(kJ/kg)**
m_1= Demin Water	13000	38	1.922	159.35
m_2=Steam Injection	2058.63	176	1.961	2822
m_3=Steam Condensates from Process	4000	93	1.922	389.68
m_4= Deaerated water Outlet	19031.87	118	1.922	495.3

Energy Absorbed in Deaerator= m_4H_4-(m_1H_1+m_3H_3)

m_4H_4 =9.43 x 10^6 kJ/hr

m_1H_1 =2.07 x 10^6 kJ/hr

m_3H_3 =1.56 x 10^6 kJ/hr

m_4H_4-(m_1H1+m_3H_3) =5.80 x 10^6 kJ/hr

Energy Lost in Vent = 1.32 x 10^4 kJ/hr

Energy Provided by Steam to Deaerator= m2H2 =5.81 x 10^6 kJ/hr

By applying the formula,

Heat in = Heat out

Demin Water m1H1+ Steam Injection m2H2+ Steam Cond m_3H_3= Deaerated Water m_4H_4 Vent

$2.07 \times 10^6 + 5.81 \times 10^6 + 1.56 \times 10^6 = 9.43 \times 10^6 + 1.32E \times 10^4$

9.44×10^6 kJ = 9.44×10^6 kJ

This shows that inlet is equal to the outlet.

4.2 Boiler Furnace:

The composition of flue gas is as follows:

Table 4.2: Flue Gas Composition

Flue Gas Composition	
Component	**Mole Percentage**
CO2	8.50
CO	0.95
O2	1.92
N2	73.60
Ar	0.46
H2O	14.05
Unburnt Fuel	0.53

Energy absorbed by water in economizer = m_1 x Delta =5.83×10^6 kJ/hr

Energy given by flue gases in economizer =$m_2 \times C_p \times (T_1\text{-}T_2)$ = 5.83×10^6 kJ/hr

Heat in= 5.83×10^6

Heat Out= 5.83×10^6

4.3 Boiler and Economizer:

Mass flow of water changed to Saturated Steam= 17132.44 kg/hr

Enthalpy of Saturated Steam=2799.18 kJ/kg

Enthalpy of Inlet Water= 804.63 kJ/kg

Heat Required to Produce Saturated Steam= m x ΔH = 3.42 x 10^7 kJ/hr

Mass flow of water changed to Saturated Steam= 17100 kg/hr

Enthalpy of Saturated Steam= 3196.85 kJ/kg

Enthalpy of Inlet Water= 2799.18 kJ/kg

Heat Required to Produce Superheated Steam= m x ΔH = 6.80 x 10^6 kJ/hr

Heat Utilized in Economizer= 5.82 x 10^6 kJ/hr

HHV of Fuel Gas= 28987.5 kJ/m^3

HHV of Purge Gas= 10059.915kJ/m^3

Flowrate of Fuel Gas=1323 m^3/hr

Flowrate of Purge Gas= 1720 m^3/hr

Heat of Combustion of Fuel= 5.57 x 10^7 kJ/hr

Mass Flowrate of Blowdown= 1900 kJ/hr

Temperature= 256.2 ℃

Enthalpy of Blowdown= 1116.48 kJ/kg

Energy Loss in Blowdown= 2.12 x 10^6 kJ/hr

Mass Flow of Flue Gases= 33039.21 kg/hr

Cp Flue gas= 1.38 kJ/kg.K

Stack Temp= 182.15 ℃

Ambient Temp= 38 ℃

Energy Losses= 6.57×10^6 kJ/hr

Miscellaneous Losses= 1.67×10^5 kJ/hr

Heat in= 5.57×10^7 kJ/hr

Heat Out= 5.57×10^7 kJ/hr

4.4 Blowdown Flash Tank:

Specific enthalpy of Continuous blowdown= H_1=116.48 kJ/kg

Mass Flow Rate of Continuous Blowdown= m_1=1900 kg/ hr

Energy Flow=m_1H_1= 2.12×10^6 kJ/hr

Specific enthalpy of Flash Steam = H_2= 2724.44 kJ/kg

Mass Flow Rate of Flash Steam =m_2= 478.8 kg/hr

Energy Flow of Flash steam = m_2H_2 =1.30×10^6 kJ/hr

Specific Enthalpy of Blowdown Water to Waste = H_3=560.1 kJ/kg

Mass Flow Rate of Blowdown Water to Waste = m_3=1421.2 kg/hr

Energy of Blowdown Water to Waste= m_3H_3=7.96×10^5 kJ/hr

Heat in= 2.12×10^6 kJ/hr

Heat Out = $2.10 \times 10^6 + 2.08 \times 10^4 = 2.12 \times 10^6$ kJ/hr

4.5 Pumps And Compressors:

Table 4.3: Pumps and Compressors Energy Balance

Pump	**Specific Volume (m^3/kg)**	**Volume Expansivity Factor (1/K)**	**Temperature (K)**	**Pressure Out (kPa)**	**Pressure In (kPa)**
Steam Condensate Pump	1012.83	6.95×10^{-4}	366	192.21	101.33
Demin Water Pump	1007.85	3.85×10^{-4}	311	192.21	101.325
Boiler Feed water Pump	1017.85	8.60×10^{-4}	391	4511.06	192.2103
PO4 Solution Pump	1007.85	3.85×10^{-4}	311	5687.86	101.325

Pressure Diff (kPa)	Enthalpy Change/Work (kJ/kg)	Efficiency of Pump	Actual Enthalpy Change/Work (kJ/kg)	Mass Flowrate (kg/hr)	Total Work (kJ/hr)
90.89	0.07	0.75	0.09	4000	366.06
90.89	0.08	0.75	0.11	13000	1397.61
4318.85	2.92	0.75	3.89	19031.87	74040.62
5586.54	4.87	0.75	6.49	1.142	7.41

4.6 Efficiency Calcualtions:

Boiler Efficiency = $\frac{Q\ (H-h)}{q\ x\ GCV}\ x\ 100$

Q = Quantity of steam generated per hour (kg/hr)

H = Enthalpy of Superheated Steam (kJ/kg)

h = enthalpy of feedwater (kJ/kg)

q = quantity of fuel used per hour = m^3/hr

GCV = Gross calorific value of the fuel = kJ/kg

Boiler Efficiency = $\frac{Q\ (H-h)}{q\ x\ GCV}\ x\ 100$

Old efficiency without fuel savings (3043 m^3/hr) = 73.6 percent

New Efficiency with fuel savings of 132.4 m^3/hr (2910.69 m^3/hr) = 76.9 percent.

Chapter 5: Process Modelling (Simulation)

5.1 Simulation:

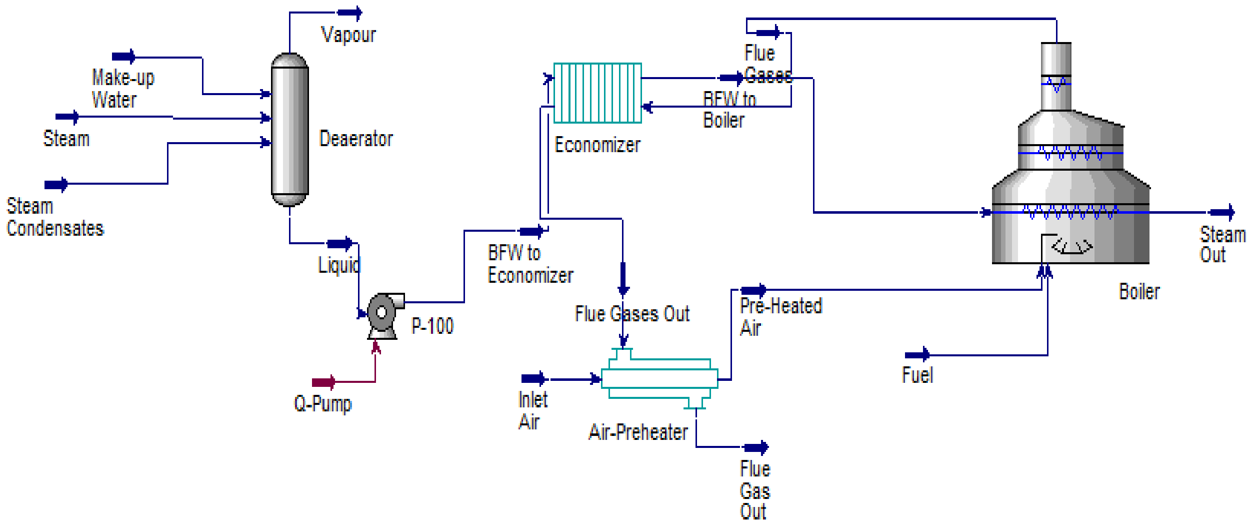
Simulation in this project is one of the most important steps because proposed plant is to be designed and we need to set the working conditions of the whole PFD. Simulation also gives the idea of the workability of the plant we have proposed.

5.2 Property Packages:

Before we start simulations, we need some data and we need to decide the major equipment and the type of equipment. We also need to select a suitable property package based on the type of components. Our simulations are all based on water and fuel gases such as methane, ethane and hexane. The best suited fluid package for high pressure water systems and hydrocarbons is the Peng- Robinson fluid package. As we are going to evaporate water, the NBS steam suits our system. For simulation, we will consider water only system and TDS or impurities calculations can be done manually. The impurities won't affect, the temperature and pressure conditions as they are in very minute amounts. Following are the six major property packages in aspen Hysys.

- Ideal Models
- Specialty Models
- Activity Models
- Vapor Pressure Models
- Equation of State Models
- Semi Empirical Models

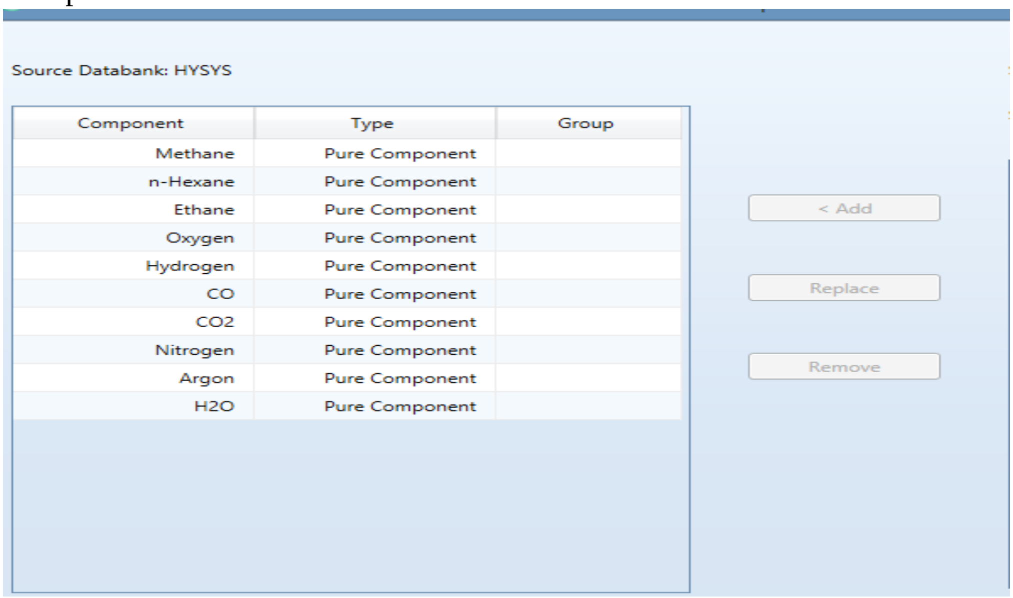
For nonpolar or slightly polar hydrocarbons equation of state is most suited. Volatile mixtures are treated well in the vapor pressure models and this gives satisfactory results for low level non-ideal behaviour. Highly non-ideal behaviour is well suited in activity models. For specific components that show wide deviations from ideal trends, there are specialty models. Under these six property packages there are different fluid packages and the fluid package we are choosing for our simulations is Peng-Robinson property package as it compensates for both the gaseous hydrocarbons and water.



5.3Process Modelling Steps:

Following were the steps performed in the process modelling in Aspen HYSYS v8.8

1. Components were added as follows:


Source Databank: HYSYS

Component	Type	Group
Methane	Pure Component	
n-Hexane	Pure Component	
Ethane	Pure Component	
Oxygen	Pure Component	
Hydrogen	Pure Component	
CO	Pure Component	
CO2	Pure Component	
Nitrogen	Pure Component	
Argon	Pure Component	
H2O	Pure Component	

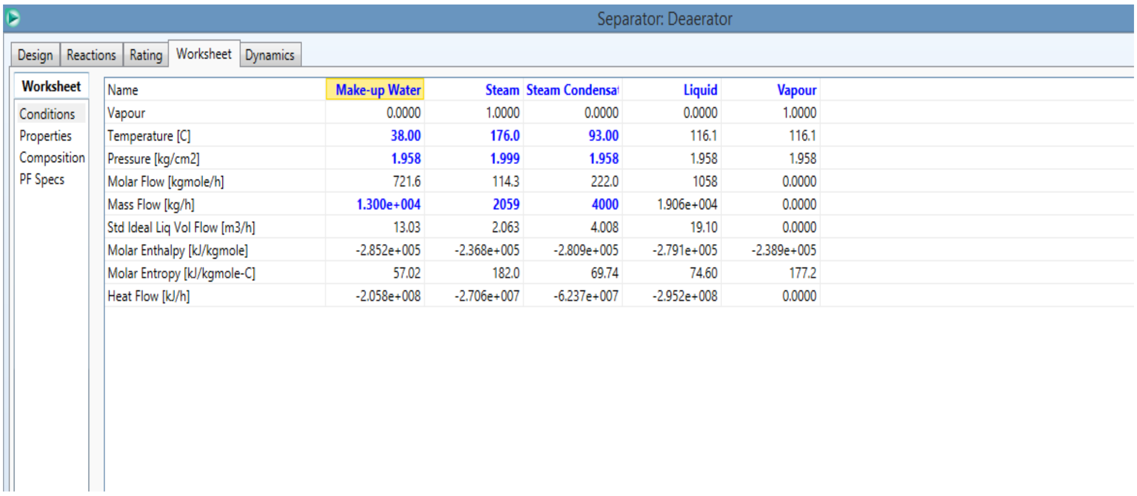
< Add
Replace
Remove

Figure 5.1: Addition of components

2. Peng- Robinson Selected as the fluid package.
3. Added 3 material streams namely Make-up water, Steam condensates and the steam injection. The conditions of all three streams were specified.
4. Added a deaerator. These three streams were added as the inlets of the deaerator. Two outlets of the deaerator are vapour outlet and the liquid outlet.
5. The liquid outlet of the deaerator is then pumped to the economizer which is a shell and tube heat exchanger.
6. Then the boiler is added which uses 10 percent excess air for combustion. The combustion air is preheated through an installed air-preheater which uses the

waste gases from the economizer outlet. The water inlet to the boiler is converted into the superheated steam.

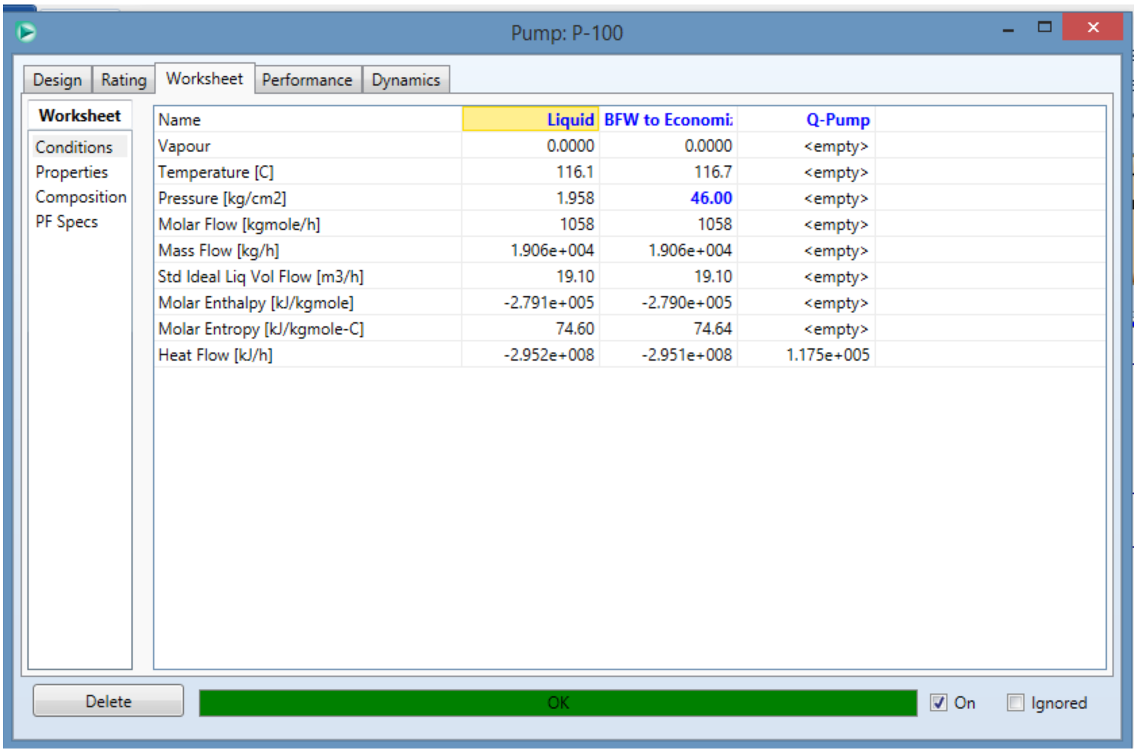
Deaerator:



Name	Make-up Water	Steam	Steam Condensa	Liquid	Vapour
Vapour	0.0000	1.0000	0.0000	0.0000	1.0000
Temperature [C]	38.00	176.0	93.00	116.1	116.1
Pressure [kg/cm2]	1.958	1.999	1.958	1.958	1.958
Molar Flow [kgmole/h]	721.6	114.3	222.0	1058	0.0000
Mass Flow [kg/h]	1.300e+004	2059	4000	1.906e+004	0.0000
Std Ideal Liq Vol Flow [m3/h]	13.03	2.063	4.008	19.10	0.0000
Molar Enthalpy [kJ/kgmole]	-2.852e+005	-2.368e+005	-2.809e+005	-2.791e+005	-2.389e+005
Molar Entropy [kJ/kgmole-C]	57.02	182.0	69.74	74.60	177.2
Heat Flow [kJ/h]	-2.058e+008	-2.706e+007	-6.237e+007	-2.952e+008	0.0000

Figure 5.2 Simulation of Deaerator

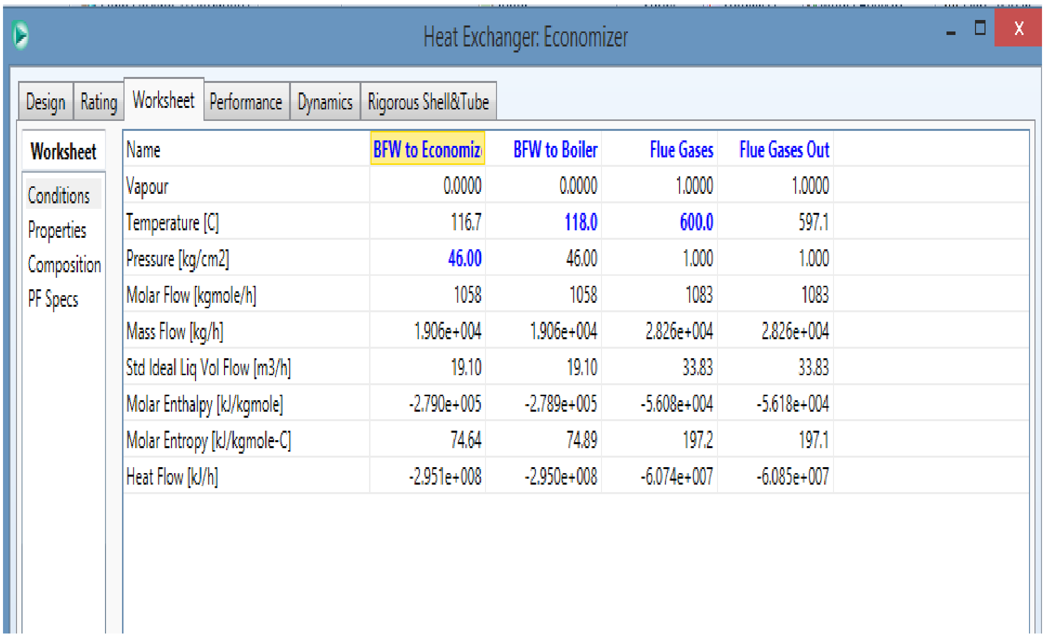
Pump:



Name	Liquid	BFW to Economi:	Q-Pump
Vapour	0.0000	0.0000	<empty>
Temperature [C]	116.1	116.7	<empty>
Pressure [kg/cm2]	1.958	46.00	<empty>
Molar Flow [kgmole/h]	1058	1058	<empty>
Mass Flow [kg/h]	1.906e+004	1.906e+004	<empty>
Std Ideal Liq Vol Flow [m3/h]	19.10	19.10	<empty>
Molar Enthalpy [kJ/kgmole]	-2.791e+005	-2.790e+005	<empty>
Molar Entropy [kJ/kgmole-C]	74.60	74.64	<empty>
Heat Flow [kJ/h]	-2.952e+008	-2.951e+008	1.175e+005

Figure 5.3: Simulation of Pump

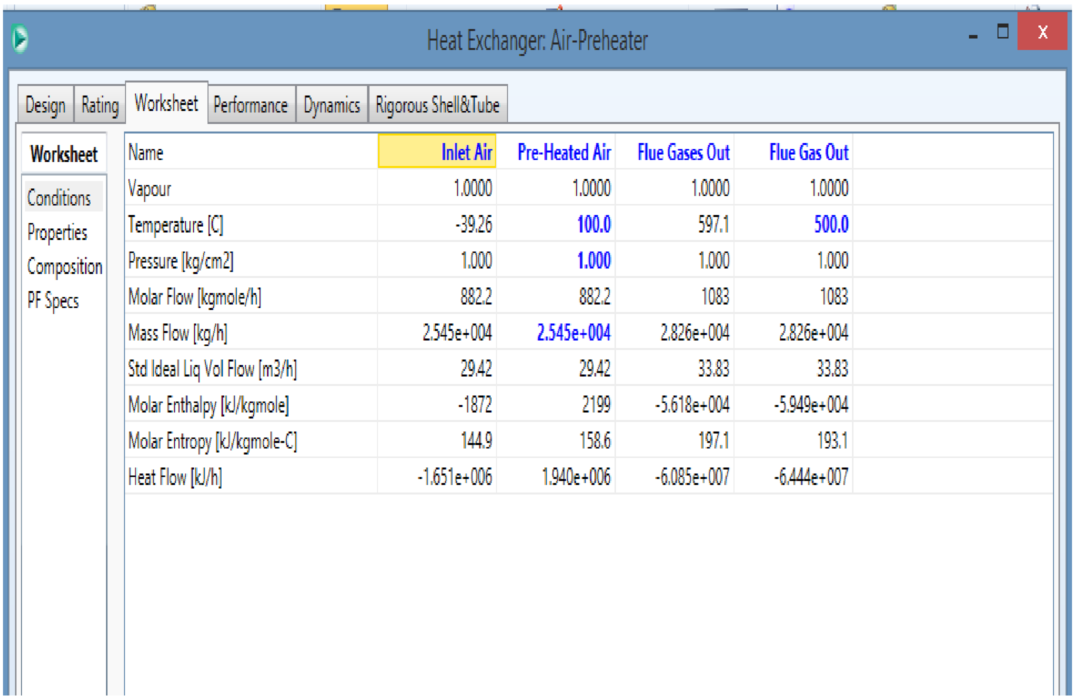
Economizer:



Name	BFW to Economiz	BFW to Boiler	Flue Gases	Flue Gases Out
Vapour	0.0000	0.0000	1.0000	1.0000
Temperature [C]	116.7	118.0	600.0	597.1
Pressure [kg/cm2]	46.00	46.00	1.000	1.000
Molar Flow [kgmole/h]	1058	1058	1083	1083
Mass Flow [kg/h]	1.906e+004	1.906e+004	2.826e+004	2.826e+004
Std Ideal Liq Vol Flow [m3/h]	19.10	19.10	33.83	33.83
Molar Enthalpy [kJ/kgmole]	-2.790e+005	-2.789e+005	-5.608e+004	-5.618e+004
Molar Entropy [kJ/kgmole-C]	74.64	74.89	197.2	197.1
Heat Flow [kJ/h]	-2.951e+008	-2.950e+008	-6.074e+007	-6.085e+007

Figure 5.4: Simulation of Economizer

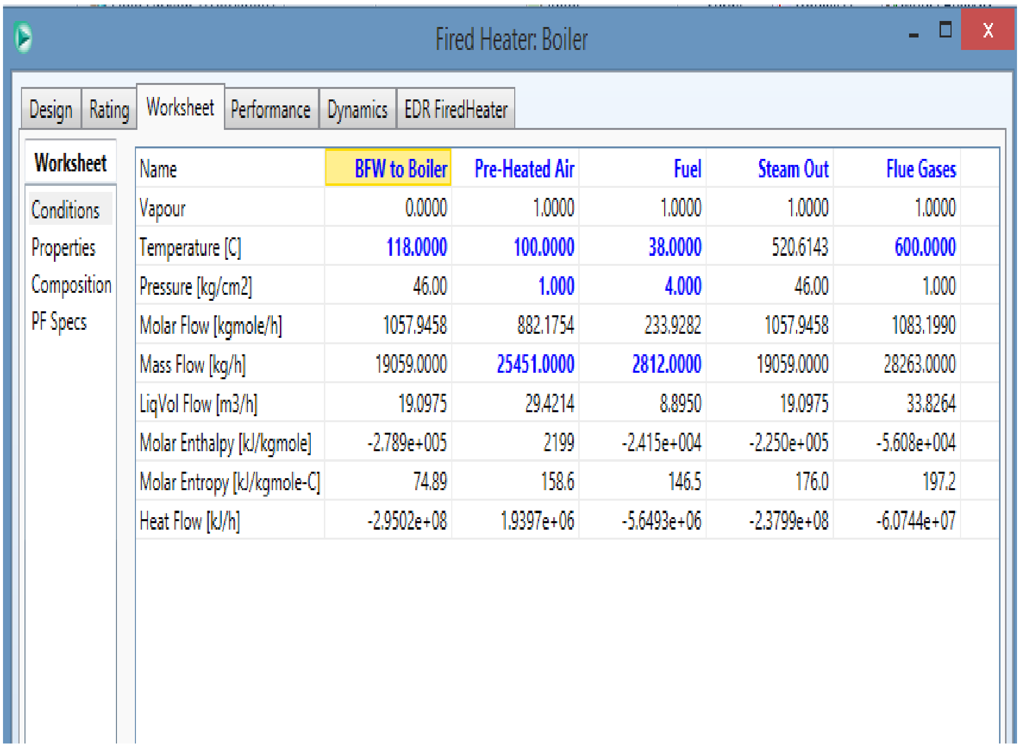
Air-Preheater:



Name	Inlet Air	Pre-Heated Air	Flue Gases Out	Flue Gas Out
Vapour	1.0000	1.0000	1.0000	1.0000
Temperature [C]	-39.26	100.0	597.1	500.0
Pressure [kg/cm2]	1.000	1.000	1.000	1.000
Molar Flow [kgmole/h]	882.2	882.2	1083	1083
Mass Flow [kg/h]	2.545e+004	2.545e+004	2.826e+004	2.826e+004
Std Ideal Liq Vol Flow [m3/h]	29.42	29.42	33.83	33.83
Molar Enthalpy [kJ/kgmole]	-1872	2199	-5.618e+004	-5.949e+004
Molar Entropy [kJ/kgmole-C]	144.9	158.6	197.1	193.1
Heat Flow [kJ/h]	-1.651e+006	1.940e+006	-6.085e+007	-6.444e+007

Figure 5.5: Simulation of Air Preheater

Boiler:



Name	BFW to Boiler	Pre-Heated Air	Fuel	Steam Out	Flue Gases
Vapour	0.0000	1.0000	1.0000	1.0000	1.0000
Temperature [C]	118.0000	100.0000	38.0000	520.6143	600.0000
Pressure [kg/cm2]	46.00	1.000	4.000	46.00	1.000
Molar Flow [kgmole/h]	1057.9458	882.1754	233.9282	1057.9458	1083.1990
Mass Flow [kg/h]	19059.0000	25451.0000	2812.0000	19059.0000	28263.0000
LiqVol Flow [m3/h]	19.0975	29.4214	8.8950	19.0975	33.8264
Molar Enthalpy [kJ/kgmole]	-2.789e+005	2199	-2.415e+004	-2.250e+005	-5.608e+004
Molar Entropy [kJ/kgmole-C]	74.89	158.6	146.5	176.0	197.2
Heat Flow [kJ/h]	-2.9502e+08	1.9397e+06	-5.6493e+06	-2.3799e+08	-6.0744e+07

Figure 5.6: Simulation of Boiler

Chapter 6: Design of Major Equipment

6.1 Economizer Design (Shell and Tube Heat Exchanger):

This is a shell and tube heat exchanger (we have considered it so for the ease of calculations). The shell side contains the flue gases from the furnace of the auxiliary boiler. The tube side contains the boiler feedwater coming from the de-aerator. The water in the tube side will get heated from the flue gases in the shell side from 118 ^oC to 189 ^oC. The flue gas temperature is decreased from 310 ^oC to 182.15 ^oC.

So, starting with the design we will calculate the heat load of the heat exchanger.

Heat Capacity of Flue Gases = 1.38 kJ/kg ^oC

Heat Load = $\frac{28521.25}{36000} \times 1.38 \times (310 - 182.15)$ = 1619 kW

Heat Capacity Water = 4.2 kJ/kg ^oC

$\Delta T_{lm} = \frac{(310-189)-(182.15-118)}{\ln\frac{(310-189)}{(182.15-118)}}$ = 89.6 ^oC

Using one shell and two tubes passes.

$$R = \frac{310 - 182.15}{189 - 118}$$

$$S = \frac{189 - 118}{310 - 118}$$

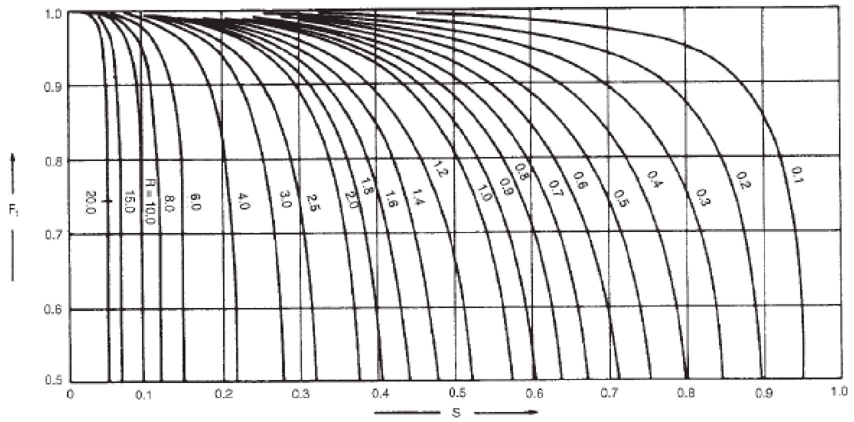


Figure 6.1: LMTD Correction Factor Chart

$$F_t = 0.75$$

$\Delta T_m = 89.6 \times 0.75 = 67.3$ °C

From the figure taking the heat transfer coefficient to be

U= 250 W/m^2 °C

Provisional area comes out to be

A= $\frac{1619 \times 10^3}{67.33 \times 250} = 96.19\ m^2$

Choosing 20mm o.d, 16 mm i.d, 4.88m- long tubes ($\frac{3}{4}$ $inch \times 16\ ft$), carbon steel.

Allowing for the tube sheet thickness, take

L = 4.83 m.

Area of one tube = πdl = π x 4.83 x 20 x 10^{-3}= 0.303 m^2.

Number of tubes = $\frac{96.19}{0.303}$ = 317

As there are four passes so number of tubes per pass would be = 79

As the shell- side fluid is relatively clean we will use the 1.25 triangular pitch.

Bundle diameter = $D_b = d_o \left(\frac{N_t}{k_1}\right)^{\frac{1}{n_1}}$

$D_b = 20 \left(\frac{317}{0.175}\right)^{\frac{1}{2.285}}$ = 0.533 m

Using a split- ring floating head type

Bundle diametrical clearance = 0.0125 m

Shell Diameter D_s = 0.545 m

6.1.1 Tube- Side Coefficient:

Mean Water Temperature = $\frac{189+118}{2}$ = 153.5 °C

Tube cross-sectional area = $\frac{\pi}{4} \times 16^2$ = 201 mm^2

Tubes per pass = 79

Total flow area = 79 x 201 x 10^{-6} = 0.0158 m^2

Water linear velocity = 0.196 m/sec

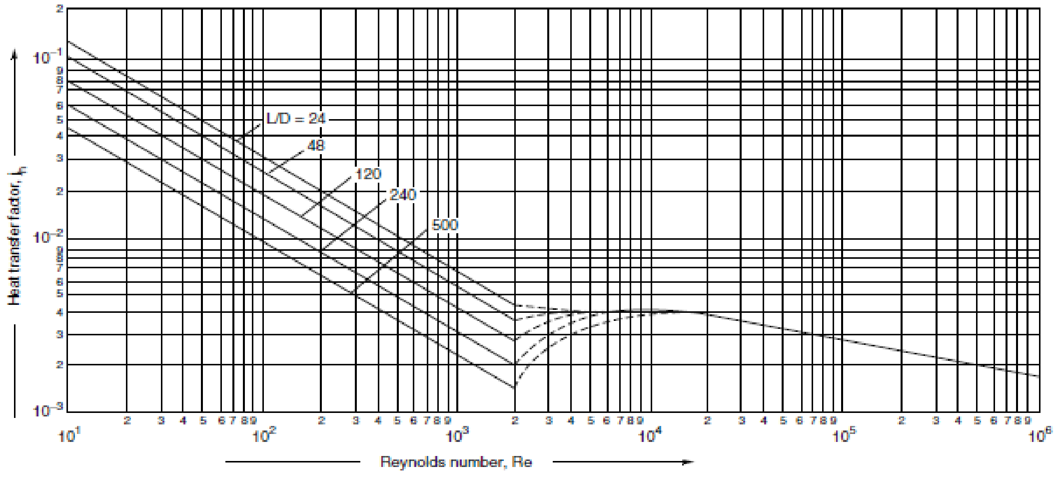


Figure 12.23. Tube-side heat-transfer factor

Figure 6.2: Tube Side heat transfer factor Chart

h_i = 3988.44 W/m^2.°C

6.1.2 Shell Side Coefficient:

Choose baffle spacing = $\frac{D_S}{5} = \frac{0.545}{5}$ = 0.109 m

Tube pitch = 1.25 x 0.020 = 0.025 m

Cross flow-area = $\frac{(25-20)}{25} \times 0.545 \times 0.109$= 0.0118 m^2

Mass Velocity = G_s = $\frac{28521.25}{3600} \times \frac{1}{0.032} = 286.79$ kg/s.m^{2l}

Equivalent diameter d_e =$\frac{1.1}{20} \times$ (25^2 -0.917 x 20^2) = 14.4 mm

Mean Shell side temperature = $\frac{310+182.15}{2} = 246.07$ °C

Density of flue gas = 0.61 kg/m^3

Specific heat of flue gas = 1.38 kJ/kg. °C

Thermal Conductivity = 0.03997 W/m. °C

Viscosity = 0.0255 mNs/m^2

$R_e = \frac{Gsde}{\mu} = \frac{868 \times 14.4 \times 10^{-3}}{0.34 \times 10^{-3}} = 155{,}982$

$Pr = \frac{Cp\mu}{k} = \frac{868 \times 14.4 \times 10^{-3}}{0.34 \times 10^{-3}} = 1$

Choosing 25 percent baffle cut,

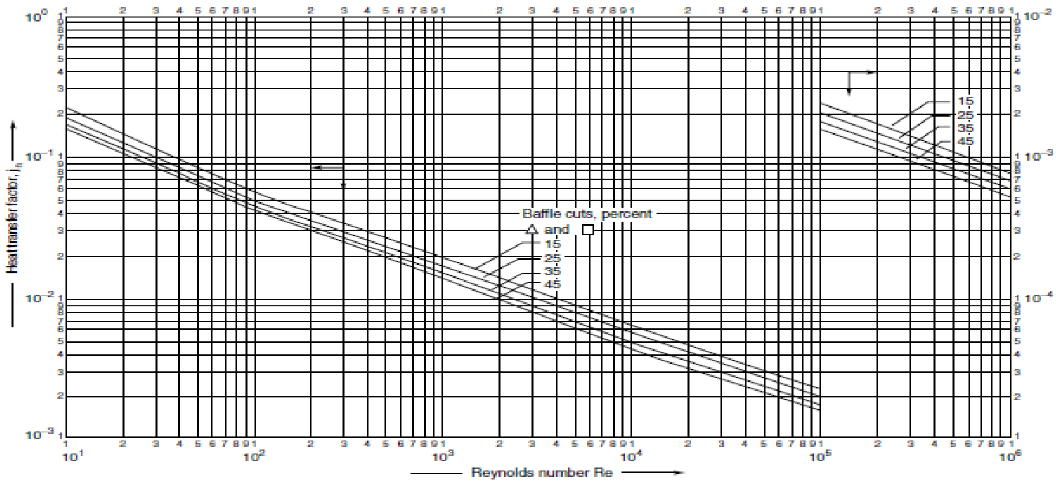


Figure 12.29. Shell-side heat-transfer factors, segmental baffles

Figure 6.3: Shell side heat transfer factor chart

$j_h = 0.00070$

Neglecting the viscosity correction term,

$h_o = \frac{k_f}{d_i}$ x $j_h\, R_e\, Pr^{0.33} (\frac{\mu}{\mu_w})^{0.14}$

$h_o = \frac{0.19}{14.4 \times 10^{-3}}$ x 0.00070 x 155,982 x $1^{/3}$= 2946 W/m^2. ^{o}C

6.1.3: Thermal Overall Coefficient:

Conductivity of carbon-steel = 45 W/m ^{o}C

Taking the fouling coefficient for water and the flue gas

$$\frac{1}{U_o} = \frac{1}{h_0} + \frac{1}{h_{od}} + \frac{d_o \ln(\frac{d_o}{d_i})}{2k_w} + \frac{d_o}{d_i} \times \frac{1}{h_{id}} + \frac{d_o}{d_i} \times \frac{1}{h_i}$$

U_o= the overall coefficient based on the outside area of the tube, W/m^2 ^{0}C,
h_o =outside fluid film coefficient, W/m^2 ^{0}C,

h_i = inside fluid film coefficient, W/m^2 ^{0}C,

h_{od} = outside dirt coefficient (fouling factor), W/m^2 ^{0}C,

h_{id} = inside dirt coefficient, W/m^2 ^{0}C,

k_w = thermal conductivity of the tube wall material, W/m^2 ^{0}C,

di = tube inside diameter, m,

d_o = tube outside diameter, m.

$$\frac{1}{U_o} = \frac{1}{3988.44} + \frac{1}{2500} + \frac{20 \times 10^{-3} \ln(\frac{20}{16})}{2\ x\ 45} + \frac{20}{16} \times \frac{1}{2000} + \frac{20}{16} \times \frac{1}{2946}$$

U_o = 624.0 W/m^2.^{o}C

6.1.4 Pressure Drop:

Tube Side:

From the figure, for R_e = 31,411.

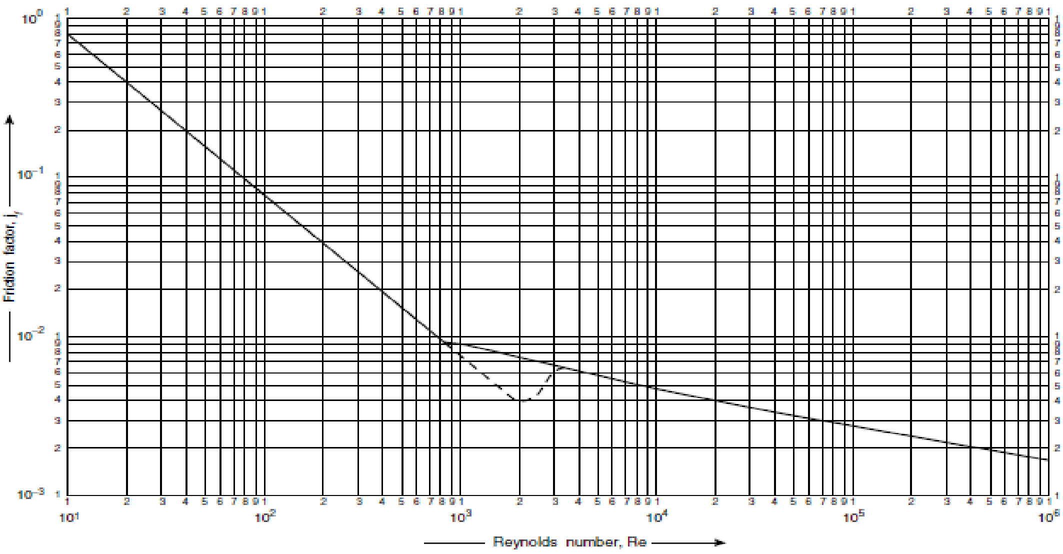


Figure 6.4: Tube side friction factor chart

j_f = 0.00032

Neglecting the viscosity correction term,

$$\Delta P_t = 2 \text{ x } N_p \left(8 \text{ x } j_f \left(\frac{L}{d_i}\right) + 2.5\right) \frac{\rho \times v^2}{2}$$

$$\Delta P_t = 2 \text{ x } 2 \left(8 \text{ x } 0.00032\left(\frac{4.83 \times 10^3}{16}\right) + 2.5\right) \frac{995 \times 0.75^2}{2}$$

$\Delta P_t = 0.781$ kPa

Shell Side:

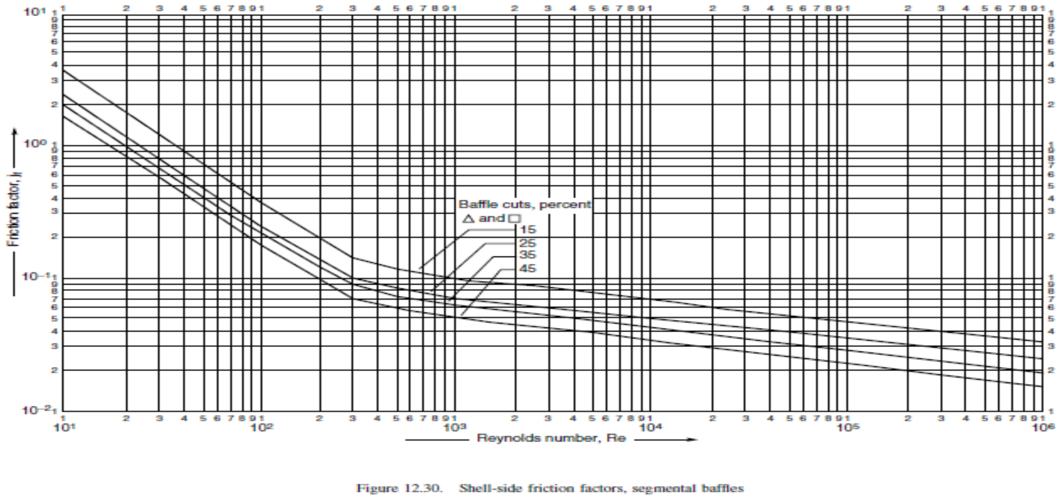


Figure 6.5: Shell side friction factor chart

J_f =0.00070

$\Delta P_s = 8\ j_f \left(\frac{D_s}{d_e}\right)\left(\frac{L}{l_b}\right) \frac{\rho \times v^2}{2}$

$\Delta P_s = 8\text{x } 0.0070 \text{ x } \left(\frac{D_s}{d_e}\right)\left(\frac{L}{l_b}\right) \frac{\rho \times v^2}{2}$

ΔP_s= 49 kPa

6.2 Air Preheater Design (Shell and Tube Heat Exchanger):

This is a shell and tube heat exchanger (we have considered it so for the ease of calculations). The shell side contains the flue gases from the outlet of the economizer. The tube side contains combustion gases from the forced draft fan. The air in the tube side will get heated by the flue gases in the shell side from 38^{o}C to 100 ^{o}C. The flue gas temperature is decreased from 182.15 ^{o}C to 140 ^{o}C.

So, starting with the design we will calculate the heat load of the heat exchanger.

Heat Capacity of Flue Gases = 1.38 kJ/kg ^{o}C

Heat Load = $\frac{28521.25}{36000} \times 1.38 \times (\ 182.15 - 140)$ = 534 kW

Heat Capacity Water = 4.2 kJ/kg ^{o}C

$\Delta T_{lm} = \frac{(182.15-100)-(140-38)}{\ln\frac{(182.15-100)}{(140-38)}}$ = 91.8^{o}C

Using one shell and 2 tubes passes.

$$R = \frac{182.15-140}{100-38}$$

$$S = \frac{100-38}{182.15-38}$$

By using figure 6.1

$$F_t = 0.79$$

$\Delta T_m = 91.8 \times 0.79 = 73.4$ ^{o}C

From the figure taking the heat transfer coefficient to be

U= 200 W/m^2 ^{o}C

Provisional area comes out to be

A= $\frac{534 \times 10^3}{73.4 \times 200} = 36.35\ m^2$

Choosing 20mm o.d., 16 mm i.d., 3.8m- long tubes ($\frac{3}{4}$ $inch \times 16\ ft$), carbon-steel.

Allowing for the tube sheet thickness, take

L = 3.6 m

Area of one tube = πdl = π x 3.6 x 20 x 10^{-3} = 0.226 m^2

Number of tubes = $\frac{36.35}{0.226}$ = 134

As there are four passes so number of tubes per pass would be = 80

As the shell- side fluid is relatively clean we will use the 1.25 triangular pitch.

Bundle diameter = $D_b = d_o\,(\frac{N_t}{k_1})^{\frac{1}{n_1}}$

$D_b = 20\,(\frac{257}{0.175})^{\frac{1}{2.285}}$ = 0.396 m

Using a split- ring floating head type

Bundle diametrical clearance = 0.0125 m

Shell Diameter D_s = 0.408 m

6.2.1 Tube- Side Coefficient:

Mean Water Temperature = $\frac{38+100}{2}$ = 69 ^oC

Tube cross-sectional area = $\frac{\pi}{4} \times 16^2$ = 201 mm^2

Tubes per pass = 80

Total flow area = 80 x 201 x 10^{-6} = 0.0160 m^2

Air linear velocity = 218.77 m/sec

Using the figure 6.2

h_i = 1311.27 $W/m^2.\ ^oC$

6.2.2 Shell Side Coefficient:

Choose baffle spacing = $\frac{D_S}{5}$ = $\frac{0.316}{5}$ = 0.0632 m

Tube pitch = 1.25 x 0.0200 = 0.025 m

Cross flow-area = $\frac{(25-20)}{25} \times 0.316 \times 0.0632$= 0.00399 m^2

Mass Velocity = G_s = $\frac{33039.21}{3600} \times \frac{1}{0.00399} = 868$ kg/s.m^2

Equivalent diameter d_e =$\frac{1.1}{20} \times (25^2 - 0.917 \times 20^2)$ = 0.0142 m

Mean Shell side temperature = $\frac{182.15+140}{2} = 161.07$ ℃

Density of flue gas = 0.61 kg/m^3

Specific heat of flue gas = 1.38 kJ/kg. ^oC

Thermal Conductivity = 0.03997 W/m. ^oC

Viscosity = 0.0255 mNs/m^2

$R_e = \frac{Gsde}{\mu} = \frac{868 \times 14.4 \times 10^{-3}}{0.34 \times 10^{-3}} = 277{,}993$

$Pr = \frac{Cp\mu}{k} = \frac{868 \times 14.4 \times 10^{-3}}{0.34 \times 10^{-3}} = 1$

Choosing 25 percent baffle cut. Using figure 6.3

$j_h = 0.0070$

Neglecting the viscosity correction term,

$h_o = \frac{k_f}{d_i} \times j_h R_e Pr^{0.33} (\frac{\mu}{\mu_w})^{0.14}$

$h_o = \frac{0.19}{14.4 \times 10^{-3}} \times 0.0070 \times 277{,}993 \times 5.1^{1/3} = 5252$ W/m^2. ^{o}C

6.2.3 Overall Coefficient:

Thermal Conductivity of cupro-nickel alloys = 45 W/m ^{o}C

Taking the fouling coefficient for water and the flue gas

$$\frac{1}{U_o} = \frac{1}{h_0} + \frac{1}{h_{od}} + \frac{d_o \ln(\frac{d_o}{d_i})}{2k_w} + \frac{d_o}{d_i} \times \frac{1}{h_{id}} + \frac{d_o}{d_i} \times \frac{1}{h_i}$$

U_o= the overall coefficient based on the outside area of the tube, W/m^2 ^{0}C,
h_o =outside fluid film coefficient, W/m^2 ^{0}C,
h_i = inside fluid film coefficient, W/m^2 ^{0}C,
h_{od} = outside dirt coefficient (fouling factor), W/m^2 ^{0}C,
h_{id} = inside dirt coefficient, W/m^2 ^{0}C,
k_w = thermal conductivity of the tube wall material, W/m^2 ^{0}C,
di = tube inside diameter, m,
d_o = tube outside diameter, m.

$$\frac{1}{U_o} = \frac{1}{1311.27} + \frac{1}{2500} + \frac{20 \times 10^{-3} \ln(\frac{20}{16})}{2\ x\ 45} + \frac{20}{16} \times \frac{1}{2100} + \frac{20}{16} \times \frac{1}{5252}$$

U_o = 471 W/m^2. ^{o}C

6.2.4 Pressure Drop:

Tube Side:

From the figure 6.4, for R_e = 31,411.

j_f = 0.00032

Neglecting the viscosity correction term

$\Delta P_t = 2 \text{ x } N_p \left(8 \text{ x } j_f \left(\frac{L}{d_i}\right)+2.5\right) \frac{\rho \times v^2}{2}$

$\Delta P_t = 2 \text{ x } 4 \left(8 \text{ x } 4.3 \text{ x } 10^{-3}\left(\frac{4.83 \times 10^3}{16}\right)+2.5\right) \frac{995 \times 0.75^2}{2}$

$$\Delta P_t = 29.7\ kPa$$

Shell Side:

From the figure 6.5

J_f =0.00070

$\Delta P_s = 8\ j_f \left(\frac{D_s}{d_e}\right)\left(\frac{L}{l_b}\right) \frac{\rho \times v^2}{2}$

$\Delta P_s = 8\text{x } 0.0070 \text{ x } \left(\frac{D_s}{d_e}\right)\left(\frac{L}{l_b}\right) \frac{\rho \times v^2}{2}$

ΔP_s= 54.0 kPa

6.3 Flash Vessel Design:

From steam tables, 2 kg/cm3; saturation temperature = 133.25°C, liquid density = 932.102 kg/m3, vapour density = 1.1078 kg/m3.

$U_t = 0.07\left[\frac{932.102 - 1.1078}{1.1078}\right]^{0.5}$

U_t = 2.135 m/s

As the separation of condensate from steam is unlikely to be critical, a demister pad will not be specified.

So, U_t = 0.15 x 2.135 = 0.32025 m/s

Flow rate of liquid = 1421.2 kg/h

Flow rate of gas = 478.8 kg/h

$Vapour\ volumetric\ flow\text{–}rate$ = $[(\frac{478.8}{(3600 \text{ x } 1.1078)})]$ = 0.0120 m^3/s

$$D_v = \sqrt{\frac{4 \text{ x } 0.0120}{\pi \text{ x } 0.3205}} = 0.218 \text{ m}$$

$Liquid\ volumetric\ flow\text{–}$= $[(\frac{1421.2}{(3600 \text{ x } 932.102)})]$ = 4.235 x 10–4 m^3/s

Allowing a minimum of 10 minutes hold-up time in vessel:

$Volume\ held\ in\ vessel$ = 4.235 x 10–4 x (10 x 60) = 0.1577 m^3

$Liquid\ depth\ required,$

$$hv = \frac{\text{volume held−up}}{\text{vessel cross−sectional area}}$$

$$hv = \frac{0.1577}{\pi \text{ x } \frac{0.218^2}{4}} = 4.22 \text{ m}$$

Add 0.15 m to allow space for positioning the level controller.

Therefore, h_v = 4.37 m

6.4 Superheater Design

Steam to be superheated= 4.75 kg/sec (17100 kg/hr)

Superheated Steam Pressure = 4.135 MPa

Superheated Steam Temperature = 395 ^oC

Designed such that the flue gas is in cross-flow with steam

OD/ID =35/30 mm

Thermal Conductivity of the material of the tube = 25 W/m ^oC

Average velocity of the steam = 18 m/sec

Velocity of the flue gases in the narrow sections of the banks of the tubes = 15 m/sec

The tubes are to be dispose in the mode of incline arrangement with the longitudinal and traverse pitch ratio as 1.2 and traverse pitch = 2.5 x O.D of tubes

Flue Gas Composition:

Inlet Temperature = 500 ^{o}C

Flowrate = 9.17 kg/sec

6.4.1 Heat Load of the Superheater:

$Q = m_s (H_{out} - H_{in})$

Q = 4.75 x (3196.85 -2799.18)

Q = 1888.9 kW

Properties of the Superheated Steam at 395 ^{o}C and 4.315 MPa

Density of Steam = ρ = 15.3 kg/m^3

k = 7.1 x 10 $^{-2}$ W/ m. ^{o}C

Pr = 0.981

V = 0.703 x 10^{-6} m/sec

6.4.2 Coefficient of transfer from wall to steam:

$Re = D_i \times v/V$

$= 30 \times 10^{-3} \times \frac{18}{0.703 \times 10^{-6}}$

Re = 768, 136

Nusselt Number for Steam:

$Nu = 0.201 \times Re^{0.8} \, Pr^{0.43} \times (0.981)^{0.43}$

$Nu = 0.201 \times (768136)^{0.8} \times (0.981)^{0.43}$

Nu = 1064.11

Co-efficient of heat transfer from the tube wall to steam:

h_i = Nu.$\frac{k}{d_i}$

= 1064.11 x $\frac{7.1\ x\ 10^{-2}}{30\ x\ 10^{-3}}$

h_i = 2578.39 W/m^2. ^{o}C

Properties of Flue gases:

$\rho = 0.345\ kg/m^3$

k = 0.089 W/m^2 ^{o}C

v = 1.28 x 10^{-4}

Pr =0.602

6.4.3 Heat Transfer Coefficient from the flue gas to Superheater Wall:

Reynolds Number for the flue Gas:

Re = d_o ($\frac{u}{v}$)

= 35 x 10^{-3} x ($\frac{u}{v}$)

= 4104.56

Nusselt No. for the flues Gases:

Nu = 0.026 x Re$^{0.65}$ x Pr$^{0.33}$ x ϵ

ϵ= ($\frac{d_o}{P_2}$)

P_1 = Traverse Pitch

P_2 = Longitudinal Pitch

Given

P_1= 2.5 x 35 x 10^{-3}

P_2/P_1 = 1.2

P_2= 1.2 x P_1

P_2 = 1.2 x 2.5 x 3.5 x 10^{-3}

P_2 = 0.105 m

$\epsilon = (\frac{35\ x\ 10^{-3}}{0.105})$

= 0.848

Nu = 0.206 x $(4101.56)^{0.65}$ x $(0.602)^{0.33}$ x (0.848)

Nu = 41.50

Heat Transfer Coefficient:

h_g = (Nu. k)/D_o

= 41.59 x (0.089/ (35 x 10^{-3}))

h_g = 105.7 W/ m^2 ^oC

6.4.4 Overall Heat Transfer Coefficient:

$$\frac{1}{U} = \frac{1}{h_i} + \frac{\Delta x}{k} + \frac{1}{h_0}$$

$$U = \frac{1}{\frac{1}{h_i}+\frac{\Delta x}{k}+\frac{1}{h_0}}$$

$$U = \frac{1}{\frac{1}{2518.39}+\frac{2.5\ x\ 10^{-3}}{25}+\frac{1}{105.7}}$$

U = 100.33 W/m^2. ^{o}C

6.4.5 Log Mean Temperature Difference:

Q = UAΔT_m

A = (1888.9 x 10^3)/ (88.4 x100.4)

A =86.3 m^2

6.5 Steam Drum Design

1. Calculation of the required liquid volume (V_{liq}) based on liquid holdup time. The liquid volume is given by

   $V_{liq}=\tau_{liq}.\varphi_{v.liq}$
   V_{liq}= the liquid volume for hold-up (m^3)
   τ_{liq}= the liquid holdup (sec)
   $\varphi_{v.liq}$= the liquid volumetric flowrate (m^3/sec)

   V_{liq}= 19.03 x120
   =2,283.6 m^3

   As a final estimate as the pressure is > 35 bar taking the L/D ratio to be 6

   $$D = \left(\frac{V_{liq}}{\frac{1}{4}\pi\left(\frac{L}{D}\right)\times 0.6}\right)^{1/3}$$

   D = the diameter of the vessel (m)

   $$D = \left(\frac{2283.6}{\frac{1}{4}\pi(6)\times 0.6}\right)^{1/3}$$

   D = 9.31 m

2. Low liquid Level (LLL)
   Typically, LLL is set at = 0.4 m
   Calculation of A_{LLL} (The cross -sectional area below LLL) (m^2)
   A_{Total} = The cross-sectional area of the vessel (m^2)
   H_{LLL} = The height of the low liquid level (m)

   φ = the angle between the centre and liquid- vapour interface at the vessel surface

   $$\frac{A_{LLL}}{A_{Total}} = \frac{\varphi - \sin\varphi}{2\pi}$$

$$\frac{H_{LLL}}{D} = \frac{1}{2}(1 - \cos\frac{\varphi}{2})$$

$$\frac{0.4}{9.31} = \frac{1}{2}(1 - \cos\frac{\varphi}{2})$$

$$0.914 = \frac{1}{2}(1 - \cos\frac{\varphi}{2})$$
$$\varphi = 3.18^{o}$$

$$\frac{A_{LLL}}{A_{Total}} = \frac{\varphi - \sin\varphi}{2\pi}$$

$$A_{LLL} = A_{Total}(\frac{\varphi - \sin\varphi}{2\pi})$$

$$A_{LLL} = 68.0\ (\frac{3.18 - \sin 3.18}{2\pi})$$

$$A_{LLL} = 33.81\ m^2$$

$$A_{Tot,\ Liq} = A_{LLL} + \frac{V_{liq}}{L}$$

$$= 40.8\ m^2$$

Maximum Allowable Vapour Velocity:

$V_{max} = K_t \text{ x } \sqrt{\frac{\rho_t - \rho_v}{\rho_v}}$

V_{max} = Maximum vapour velocity (m/se

ρ_t = Liquid Density (kg/m^3)

ρ_v = Vapour density (kg/m^3)

K_t = Separation factor or gas handling capacity (m/sec)

For horizontal Vessels K_t shall be taken as 0.08 m/sec

$V_{max} = 0.08 \text{ x } \sqrt{\frac{789.516 - 22.260}{22.260}}$

V_{max} = 0.46 m/sec

6.5 Furnace Design

Steam production rate = 17.1 TPH

Efficiency = 73.6%

Duty = 3.85×10^7 kJ/hr (3.66×10^7 Btu/hr)

Exposed Tube Length = 38.5 ft. (11.73 m)

OD= 0.42ft. (0.13 m)

Ctc distance = 0.71 ft. (0.22 m)

Average Flux = 12,000 Btu/hr-ft.^{2} (1.36×10^5 kJ/hr-m^2)

Assuming hourly heat transfer rate = $\frac{Q}{\alpha \times Acp}$ = 2 × (average flux) = 24,000 Btu/hr-ft.^{2} (2.72×10^5 kJ/hr-m^2)

Taking overall exchange factor 'f' as 0.80

$\frac{\Sigma Q}{\alpha \times Acp \times f} = \frac{24,000}{0.80}$ = 30,000 Btu/hr-ft.^{2} (3.40×10^5 kJ/hr-m^2)

Using this and tube temperature 'T_S'= 800 °F (426.6°C), outlet gas temperature, 'T_G' from fig. comes out to be 1570 °F (854.4 °C)

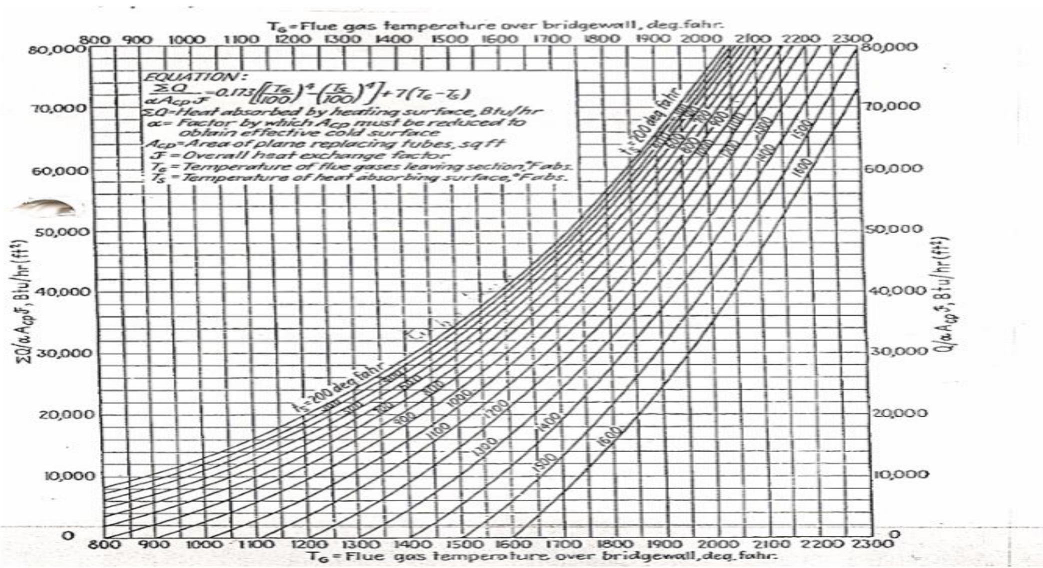


Figure 6.6: Flue Gas Temperature Chart

$Q_{\text{Fuel}} = \frac{36{,}580{,}829}{0.736} = 4.97 \times 10^{7}$ Btu/hr (5.24×10^{7} kJ/hr)

Fuel Quantity = 5,868.3 lb. /hr (2,661.83 kg/hr)

Air Required = 5,868.3 × AFR = $5{,}868.3 \times \frac{66952.76}{5868.3}$

= 5,868.3 × 11.4

= 6.68×10^{4} lb. /hr (3.03×10^{4} kg/hr)

$Q_{\text{Air}} = m_{\text{air}} \times C_{p\ \text{air}} \times (T_{\text{air in}} - T_{\text{ref}})$

= $6.68 \times 10^{4} \times 0.24 \times (100.4 - 77)$

= 3.75×10^{5} Btu/hr (3.96×10^{5} kJ/hr)

$Q_{\text{Fuel}} + Q_{\text{Air}} = 5.01 \times 10^{7}$ Btu/hr (5.28×10^{7} kJ/hr)

$Q_{\text{Wall}} = 2\%\ Q_{\text{Fuel}} = 9.94 \times 10^{5}$ Btu/hr (1.05×10^{6} kJ/hr)

$Q_{\text{Net}} = Q_{\text{Fuel}} + Q_{\text{Air}} - Q_{\text{Wall}}$

= 4.9×10^{7} Btu/hr (5.18×10^{7} kJ/hr)

$Q_{\text{Exhaust gases}} = H_{\text{flue gas}}\ x\ (m_{\text{fuel}} + m_{\text{air}})$

= 497 (5868.3 + 66898.62)

= 3.62×10^{7} Btu/hr (3.82×10^{7} kJ/hr)

The overall heat liberated is

$Q_{\text{Overall}} = Q_{\text{Net}} - Q_{\text{Exhaust gases}}$

= 49,083,871.7 – 36,165,159.24

= 1.29×10^{7} Btu/hr (1.36×10^{7} kJ/hr)

Surface per tube, A = 38.5 ft. × π ×0.42 ft. = 50.4 ft.^{2} (4.68 m^{2})

Estimated no. of tubes $N_t = \frac{\text{QOverall}}{\text{Av.flux} \times \text{Asurface}} = \frac{12918712.46}{12000 \times 50.4} = 21.6$

Trying 21 Tubes

Equivalent cold plane surface $A_{cp} = \text{ctc} \times L \times N_t$

= 0.71 ft. × 38.5 ft. × N = 27.2 ft.^{2} x N_t

Total α for single row arrangement of tubes, using fig. and $\frac{\text{Ctc distance}}{\text{O.D}} = \frac{0.71}{0.42} = 0.17$

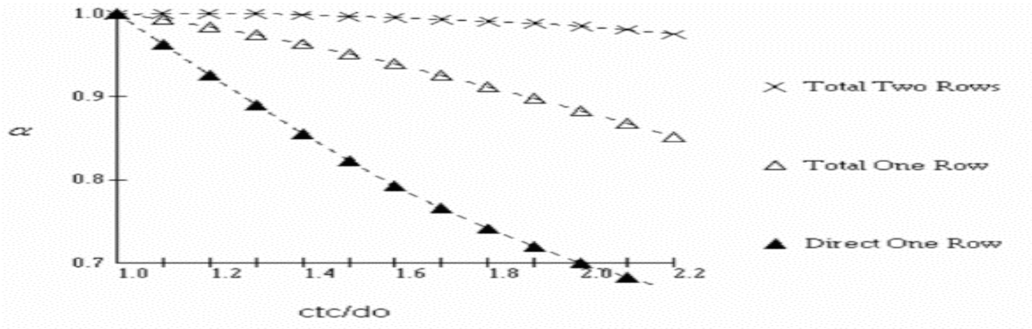


Figure 6.7: Gas Absorptivity Chart

α = 0.94

$\alpha \times A_{cp} = 0.94 \times 27.2 \times 21 = 25$ ft.$^2 \times 21 = 525$ ft.^{2} (48.7 m^2)

Refractory surface:

Assuming L: W: H = 38.5 ft.: 20.46 ft.: 14.92 ft. = 3:2:1

End walls = 2 x 20.46 x 14.92 = 611 ft.^{2} (56.7 m^2)

Side wall = 14.92 x 38.5 = 575 ft.^{2} (53.42 m^2)

Bridge wall = 9.79 x 38.5 = 377 ft.^{2} (35.02 m^2)

Floor and arch = 2 x 20.46 x 38.5 = 1575 ft.^{2} (146.32 m^2)

Total exposed area = A_T = 3,138 ft.^{2} (291.53 m^2)

Effective refracting surface $A_R = A_T - \alpha \times A_{cp}$ = 3138 ft.^{2} – 525 ft.^{2} = 2,613 ft.^{2} (242.76 m^2)

$A_R / \alpha \times A_{cp} = \frac{2613}{525} = 4.97$

Mean beam length:

Taking box shaped furnace

$L = \frac{2}{3} \times \sqrt[3]{\text{Volume}} = \frac{2}{3} \text{ x } \sqrt[3]{38.5 \times 20.46 \times 14.92}$ = 15 ft. (4.57 m)

Gas emissivity:

Depending upon fuel quality, the partial pressures of CO_2 and H_2O are 0.1084 atm. and 0.1248 atm.

$ÞCO_2 \times L$ = 1.63 atm-ft. and $ÞH_2O \times L$ = 1.87 atm-ft.

Here L is the mean beam length

Using Þ × L value and fig. emissivity comes out to be 0.49

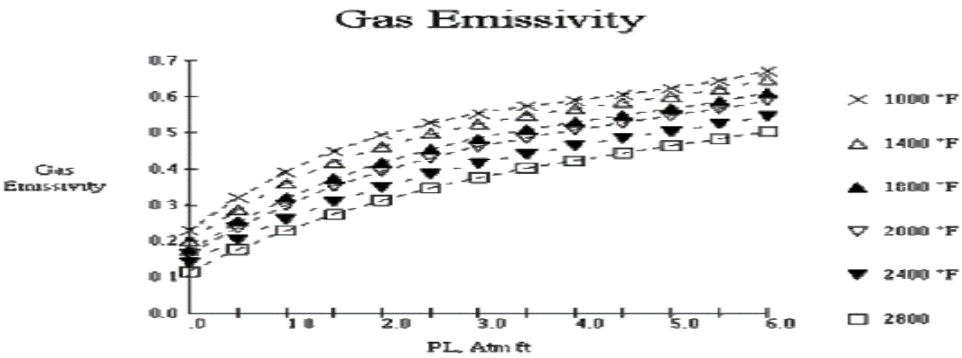


Figure 6.8: Gas Emissivity Chart

Using ε = 0.49, A_R / α× A_{cp} = 4.97 and the figure below overall exchange factor '*f*' value is obtained to be 0.83.

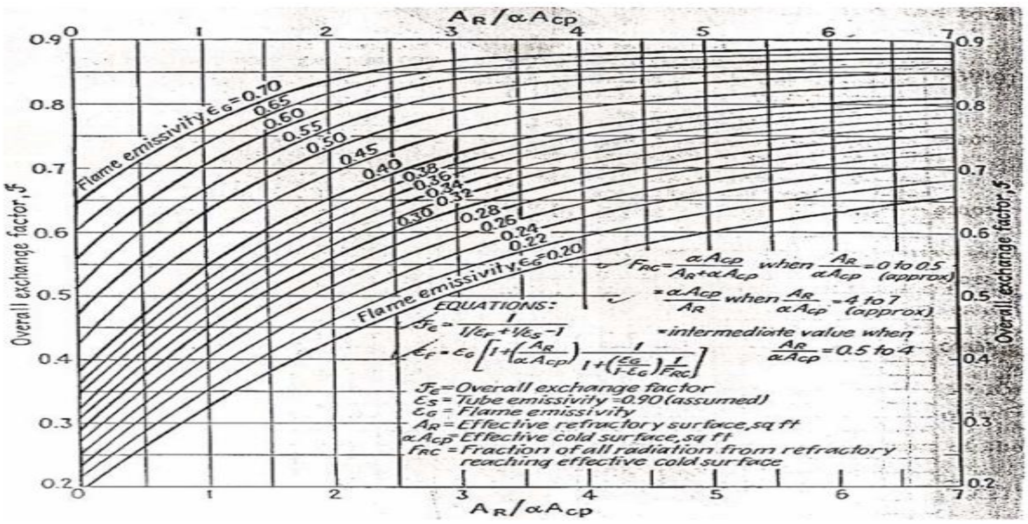


Figure 6.9: Overall exchange factor chart

Using this value of '*f*'

$\frac{\Sigma Q}{\alpha \times Acp \times f} = \frac{12{,}918{,}712.46}{525 \times 0.83}$ = 2.96 × 10^4 Btu/hr-ft^2 (3.36 × 10^4 kJ/hr-ft^2)

Using the above value for $\frac{\Sigma Q}{\alpha \times Acp \times f}$, '*f*' and fig. the new value for 'T_G' is

1556 °F

The error between obtained and assumed '*f*' and 'T_G' is negligible.

Chapter 7: Costing of the Project

7.1 Total Plant Capital Expenditure:

7.1.1 Equipment Cost:

Cost of the Air Preheater

Area of the air Preheater = 36.3 m^2

Pressure Factor = 1.0

Type Factor = 1.0

Purchased Cost = $20,000

Using Lang Factors, the total physical plant cost is calculated as follows:

Table 7.1: Lang Factors

f_1	Equipment Erection	0.4
f_2	Piping	0.70
f_3	Instrumentation	0.20
f_4	Electrical	0.10
f_5	Building process	------
f_6	Utilities	------
f_7	Storages	-----
f_8	Site development	------
f_9	Ancillary buildings	------

Total Physical Plant Cost (PPC) = PCE (1+0.4+0.7+0.2+0.1)

Total Physical Plant Cost (PPC) = $20,000 (2.4)

Total Physical Plant Cost (PPC) = $48,000

7.1.2 Indirect Capital Cost

f_{10}	Design and Engineering	0.25
f_{11}	Contractor's Fee	0.05
f_{12}	Contingency	0.1

Fixed Capital = \$48,000 (1+0.25+0.05+0.1)

Fixed Capital = \$67,200

Working Capital (5% of fixed capital) = \$3360

Total Investment = \$70,560

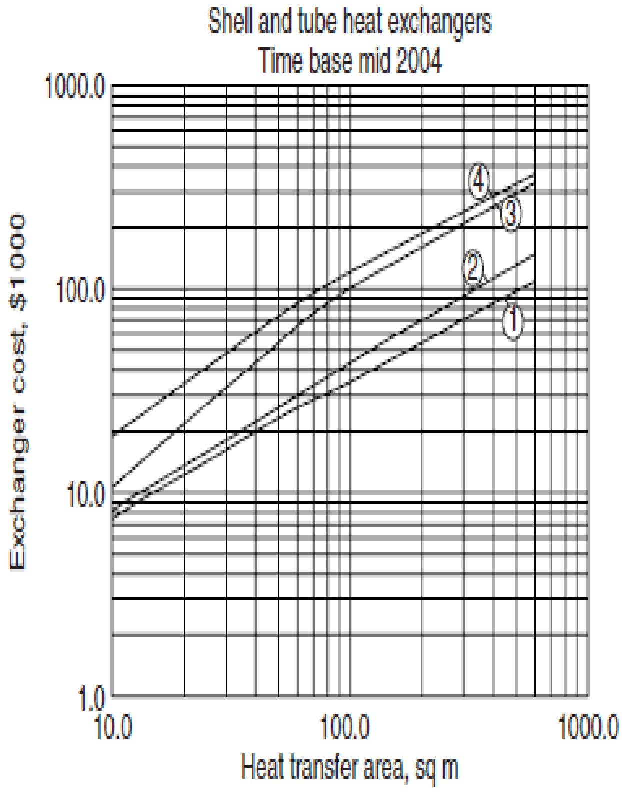
Rate of Return for the Project = $\frac{Cost\ Savings}{Total\ Investment}$

Rate of Return for the Project = $\frac{\$129,775}{\$70,560}$

Rate of Return for the Project = 1.83

Payback Period = 1/1.83

Payback Period = 0.54 Years



(*b*) US dollars

Materials: Shell	Materials: Tubes	Pressure factors		Type factors	
		1–10 bar	× 1.0	Floating head	× 1.0
1 Carbon steel	Carbon steel	10–20	× 1.1	Fixed tube sheet	× 0.8
2 C.S.	Brass	20–30	× 1.25	U tube	× 0.85
3 C.S.	Stainless steel	30–50	× 1.3	Kettle	× 1.3
4 S.S.	S.S.	50–70	× 1.5		

Figure 6.3*a*, *b*. Shell and tube heat exchangers. Time base mid-2004
Purchased cost = (bare cost from figure) × Type factor × Pressure factor

Chapter 8: Instrumentation and Process Control

8.1 Instrumentation:

Instrumentation is central imperative to control a process system. The control can be automatic, semi-automatic or manual. The quality of control determines the quality of product and the applied accuracy methods.

Table 8.1 Measuring devices

Parameters (process variables)	**Equipment**	**Measuring device(s)**
Temperature	Heat exchanger, super-heater & de-aerator	Thermocouples, resistance thermometers
Pressure	Compressors, boiler, turbines & de-aerator	Pressure gauges (diaphragm or bellows gauges)
Flow	De-aerator, steam drum & furnace	Variable head (venture-meter) and variable area devices (rota-meter)
Level	De-aerator, steam drum, boiler & storage vessel	Level indicators

8.2 Types of Control Systems

The process variables controlled by manipulating the input variable of the system. There exist two major types of control system:

8.2.1 Open Loop Control System

Such a system has no link between output and the overall control system. Control is applied on the basis of input variable only. There is no feedback so disturbances are minimal. Economic approach but less accurate.

8.2.2 Closed Loop Control System

Such a system utilizes feedback to take a corrective action on manipulated variable to attain a set point. The process variable conditions are compared to a set point for applicability of control on manipulated variable. A suitable control action is determined on the basis of the error signal generated to bring the system output to the desired value.

It has two types based on set point and the error value i.e. feed forward feed backward.

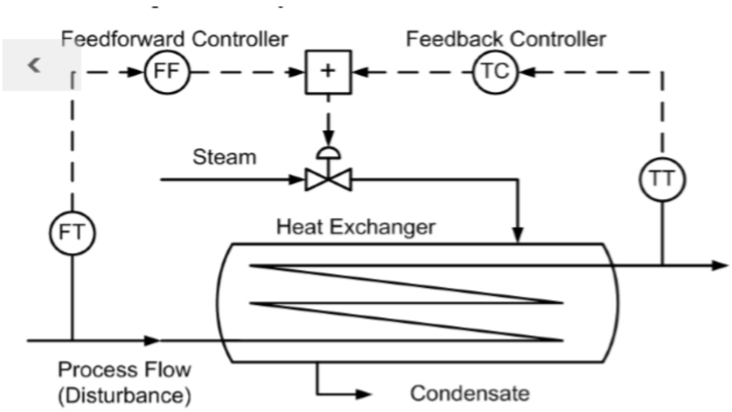


Figure 8.1 Closed Loop control System

8.3 Major closed loop controls in boiler

8.3.1 Drum level control

Single element drum level control

In such a control, the level transmitter on the steam drum will transmit the level signal to the controller. Level controller will compare the signal with the set point and send an output signal to the feed water control to increase or decrease the feed water flow to the boiler by opening or closing the valve.

Three element drum level control

In this setup, in addition to receiving the drum level signal, steam flow and feed water flow transmitter signals are also received. This type of control will keep the drum level control to function correctly even when the boiler load changes.

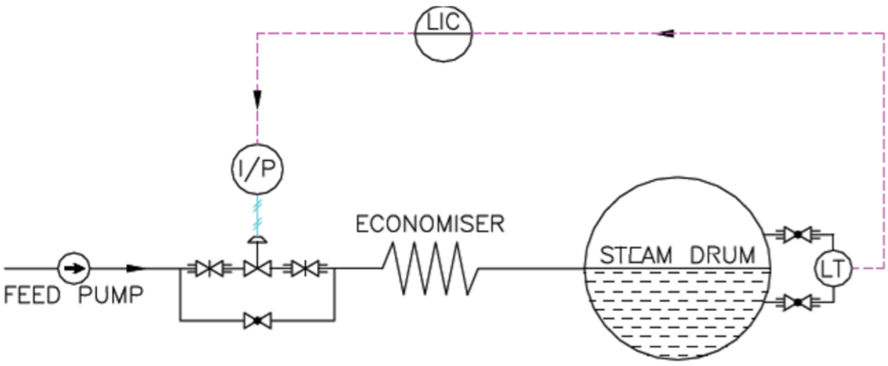


Figure 8.2: Single Element Drum Level Control

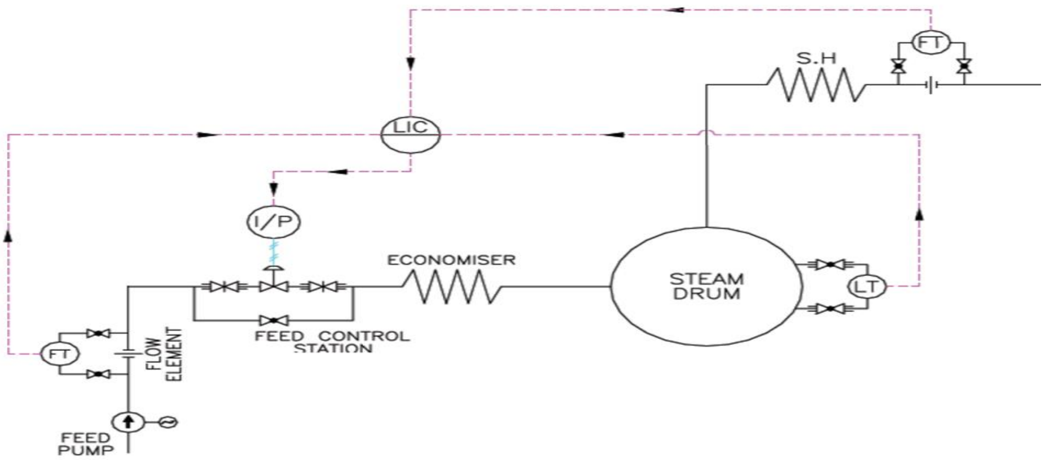


Figure 8.3: Three Element Drum Level Control

8.3.2 Super heater steam temperature control

Super heater temperature control is necessary for the protection of equipment like steam turbine. The super heater temperature may fluctuate as per boiler load fluctuations. The steam temperature leaving the boiler is required to be maintained constant in many applications. The super heater outlet temperature is sent to the controller by the temperature transmitter. The controllers compare the same with the set point and gives a resultant signal to the spray control valve to change the spray water quantity.

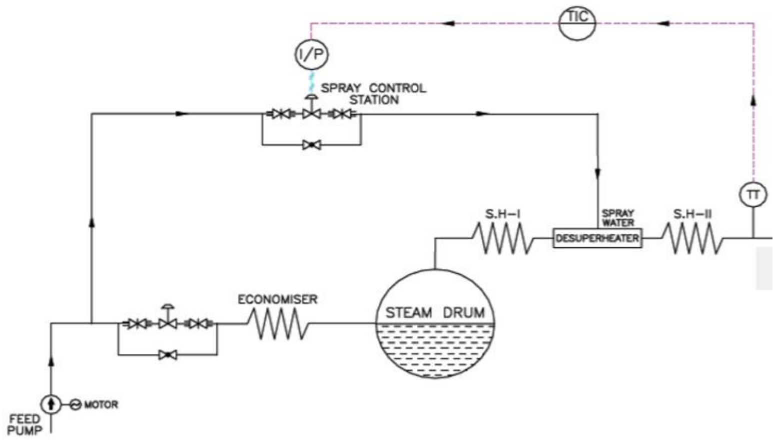


Figure 8.4: Super heater steam temperature control

8.3.3 Combustion control

Steam demand from a boiler may vary as per load fluctuations. Fuel control is important to have necessary steam quantity. The steam demand increase or decrease is indicated by the boiler outlet pressure. The steam pressure transmitter in the main steam line sends the signal to the controller which in turn sends an output signal to the fuel control valve in the case of oil and gas fired boilers. Air flow control will be semi-automatic. The forced draught fan guide vane/damper will be controlled remote manually by the operator to match the fuel flow.

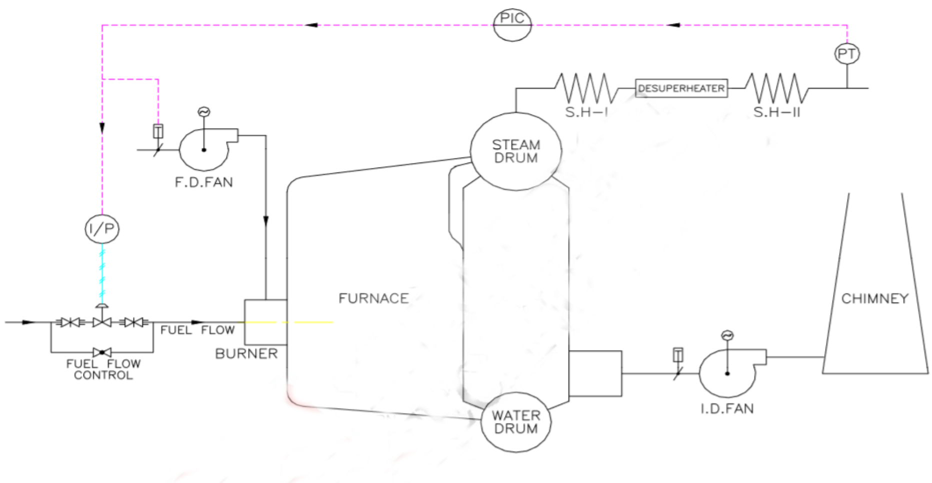


Figure 8.5: Combustion control in gas fired boiler

8.4 De-aerator controls

It has three controls which are as follows:

8.4.1 Pressure control:

Pressure control in the de-aerator is important to maintain temperature inside the de-aerator for the removal of dissolved gases.

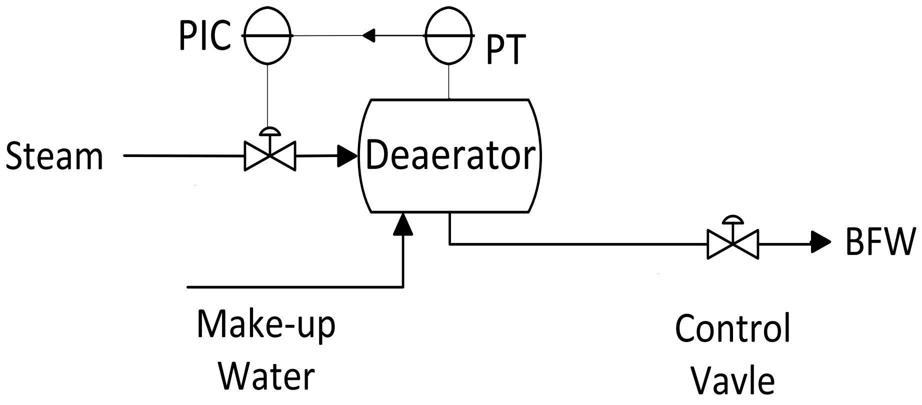


Figure 8.6: De-aerator pressure control

8.4.2 Level control:

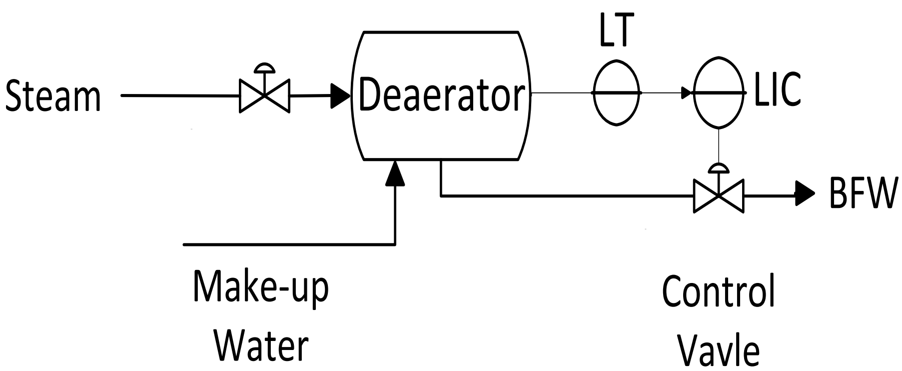


Figure 8.7: De-aerator level control

8.4.3 Flow and Temperature control:

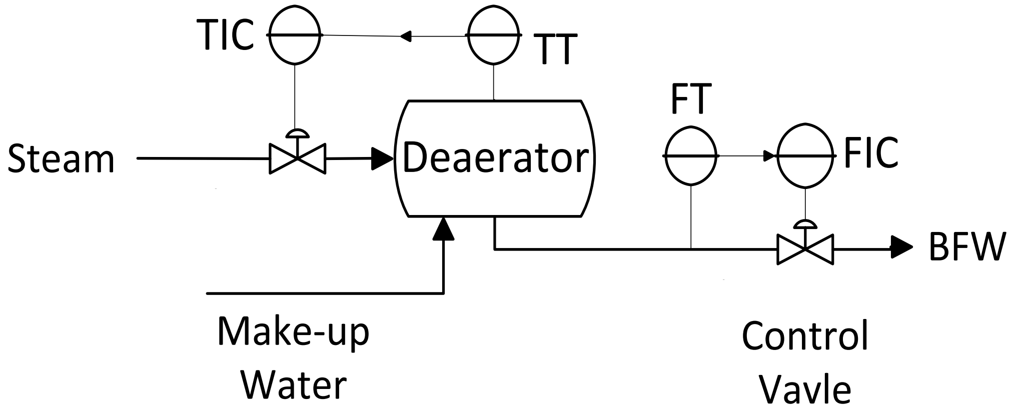


Figure 8.8: De-aerator temperature and flow control

Chapter 9: HAZOP Analysis

9.1 Introduction:

Health of employees and safety of the equipment and environment holds tremendous importance in an industry. The employers are legally bound by numerous regulations to ensure this. The processes in industry are prone to accidents and hazards, and a firm and effective strategy is needed in order to prevent any kind of accidents and promote safe work practices.

A HAZOP study helps to find out the hazards and their intensity in an industry. It enables to determine risks and their possible extent of damage.

The following steps must be done to carry out a HAZOP study.

- Determination of hazards.
- Measures to control for the possible hazards
- Improvising the process
- Minimizing the loss due to liability

9.2 HAZOP:

The aim of HAZOP study is to find the issues that may be present in the process. Solution to those issues may he easy but identification may be the difficult part. HAZOP study is based on two factors which are:

Operability:

The operation that could be the cause of violation of regulations due to underlying hazards. It can have an adverse effect on the process and the plant and may hinder overall working.

Hazards:

Any threat capable of causing damage or harm is considered to be a hazard. Toxicity, flammability and chemical hazards are few examples. Identification and then assessment of risk of a hazard is done on the basis of extent of damage, probability and the people affected by it.

HAZOP and Associations:

HAZOP study is extremely valuable for the plant and the people working there. This is because it can identify any practices which may be harmful to the people and the plant which will ultimately ensure safe work practices and enhanced productivity. HAZOP study is usually done at the end of project to ensure the safety of the whole project and all of its parts but it can be done on certain parts of project separately as well.

9.3 Outcome of HAZOP Study:

HAZOP study can have a huge effect on the project. The personnel conducting the HAZOP study have the technical insights and the whole process can reveal threats and their respective outcomes. Furthermore, preventive measures can be taken to tackle such issues and to lower the chance of loss. The following points should be tested in order to conduct a hazard study and will contribute to the HAZOP study.

Intentions:

These are the expected operational outcomes of the plant. It is expected to be devoid of any deviation or variance from study notes. The intentions for HAZOP can be diagrammatic or descriptive.

Deviations:

The outliers or abnormalities in intentions are called deviations. Their evaluation can be done by using guide words which have to be applied systematically for accurate evaluation.

Causes:

These are the reason for the existence of deviations. Correct identification of deviation can help to find the cause. The causes can include human error, systematic error, disruptions and unexpected incidents.

Consequences:

These are the outcomes of the causes. They can be in the form of any unwanted circumstances like eruption of a vessel, fire or release of toxic chemicals.

Guide Words:

The basis on which deviations can be evaluated. They aid in the assessment process. Separate teams have their own guide words pertaining to their section of the plant for HAZOP study.

9.4 Types of HAZOP:

- Process HAZOP is done to find any abnormalities in the sequence of operations of plant.
- Software HAZOP is used for the programs, devices and software being used in the plant.
- Human HAZOP is done on the personnel involved in the functions of plant to identify any mistakes on their part.

9.5 Procedure for HAZOP Study:

HAZOP study involves the following steps:

- Division of the system into different sections
- Choosing the basis as study notes
- Depicting the intention of the section
- Selecting the involved parameters
- Applying the guide word
- Determination of causes of deviation
- Evaluating the consequences
- Recommendations
- Recording the information

9.6 HAZOP Analysis on Different Equipment:

Equipment: De-aerator

Intention: Maximum removal of oxygen

Table 9.1: Deaerator HAZOP Analysis

Guide word	**Deviation**	**Cause**	**Consequence**	**Action**
High	Flow	• Treated water flow increases. • Condens-ate return increases.	• Excessive high level in de-aerator.	• Reduce treated water flow to the de-aerator.
Low	Temperat ure	• Low pressure steam. • Faulty control	• Depressuriza -tion of gas.	• Installati on of temperat ure control.

Equipment: Preheater

Intention: Air preheating by flue gas

Table 9.2: Preheater HAZOP Analysis

Guide word	Deviation	Cause	Consequence	Action
Reverse	Process Fluid Flow	• Failure of process fluid inlet valve.	• Product offset	• Installation of check valve.
High	Shell side pressure	• Exchanger outlet discharge valve closes.	• Exchanger shell side will be over pressurized.	• High pressure security must be installed on shell outlet.
High	Tube side pressure	• Tube rupture.	• Tube may over pressurize and temperature variations may occur.	• High pressure security must be installed on tube outlet.

Equipment: Boiler

Intention: Steam generation

Table 9.3: Boiler HAZOP Analysis

Guide word	Deviation	Cause	Consequence	Action
High	BFW Pressure	• Sudden steam load fluctuation.	• BFW Leakage may occur from valves, glands, bonnets etc.	• Check BFW pumps. • Adjust steam pressure by vent controls.
Low	BFW Pressure	• BFW pumps failure. • Sudden steam load increase.	• Low level may Occur at boilers and HRSG's. • Steam load could be reduced.	• Check BFW pumps. • Adjust steam pressure by vent controls.
High	Steam Pressure	• Malfunctioning of PRC.	• Air-fuel ratio disturbance. • Damage to super-heater.	• Adjust air flow to boilers as per steam load. • Adjust steam pressure by vent controls.
Low	Steam Pressure	• Malfunctioning of PRC	• Air fuel ratio disturbance. • Temperature of super-heater increases.	• Adjust air flow to boilers as per steam load

Equipment: Super heater

Intention: To superheat saturated steam to superheated steam

Table 9.4: Superheater HAZOP Analysis

Guide word	Deviation	Cause	Consequence	Action
High	Temperature	• Sudden increase in steam load. • Low air flow as per steam load.	• Air-fuel ratio disturbance • Damage to super heater coils.	• Increase air flow to boilers as per steam load.
Low	Temperature	• Sudden decrease in steam load. • High air flow as per steam load.	• Air-fuel ratio disturbance. • Temperature of outlet steam decreases	• Decreased air flow to boilers as per steam load. • Adjust steam pressure by vent controls.

Equipment: Steam drum

Intention: To separate steam and water and provide hold up for incoming BFW

Guide word	Deviation	Cause	Consequence	Action
High	Level	• BFW flow will increase.	• BFW will carry over to outlet steam.	• Check LIC.

			• Excessive hammering will occurs in steam circuit.	
Low	Level	• BFW will decrease.	• Excessive leakage in boilers tubes.	• Check BFW pumps. • Adjust steam load.

Equipment: Furnace

Intention: Air uptake for combustion

Guide word	**Deviation**	**Cause**	**Consequence**	**Action**
High	Air flow	• Increased RPM of FD fans. • Sudden pressure increase of steam.	• Air-fuel ratio disturbance. • Temperature decreases at super-heater.	• Decrease air flow to boilers as per steam load.
Low	Air flow	• Decreased RPM of FD fans. • Sudden pressure of steam.	• Air-fuel ratio disturbance. • Temperature increase at super heater. • Steam load will reduce.	• Increase air flow to boilers as per steam load.

Chapter 10: Summary and Conclusion

10.1 Summary:

We have summarized our Final year project into three phases.

- Collection of data and literature review
- Design, uprate and simulation.
- Thesis writing

Phase 1:

In the initial phase of the project, all the available information on boilers and its different parts was gathered by consulting different books, literature and the information present on internet. After understanding the operation, we gathered the required data for our project in order to carry out different calculations. This data was provided to us by our Industrial supervisor Sania Ijaz. After that, we calculated the existing efficiency of the boiler and studied different improvement techniques for efficiency.

Phase 2:

After that, the design specifications for the economizer, air preheater and other boiler components was carried out. After the uprating, and other calculations, Aspen HYSYS model of the project was made. The results showed different fluctuations from that of the manual readings as shown above.

Phase 3:

In the end, the thesis writing was carried out which was tricky as we had to be precise and clear at the same time. Thesis phase was a task that taught us many things including but are not limited to organizational skills, strengthened group communication, how to co-operate and come up with a decision during a conflict and much more.

10.2 Conclusion:

The existing combustion efficiency of the boiler was calculated as 73.6% and a number of solutions were considered in order to improve the efficiency. Some of these were:

- By reducing the excess air that is going to the furnace. As excess air tends to cool down the flue gases being released. It is important to control the excess air as it will result in O_2 presence in flue gas and incomplete combustion.

- Adding an air pre-heater is a good option in terms of operating cost vs. efficiency increase comparison but it is shadowed by the capital cost of the pre-heater.

It was found that efficiency was enhanced 1% by excess air control and 3% by air preheating. This leads to the fuel savings of about 9.35×10^5. The themal efficiency of the boiler was increased to 76.6 percent.

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