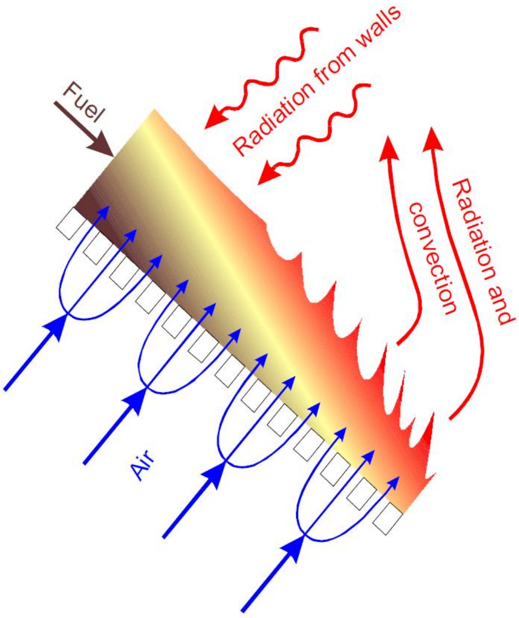
ANEXOS

Apendix A. Types and Applications of modern boilers

Modern boilers can be classified by different criteria. Combustion method, application, or type of steam/water circulation is one of them.

Grate furnace boilers

This is the most common type during the beginning of the industrialization. With a solid fuel combustion in small and medium-sized (15 kW - 30MW) has been replaced by fluidized bed technology in unit sizes over 5MW. Usually, it burn waste and biofuels. In every combustion, there are three different phases: Removal of moisture, Pyrolysis (thermal decomposition) and combustion of volatile matter, and combustion of char.



The grate furnace is made up a grate that can be horizontal or conical. It can consist of a conveyor chain that transports the fuel forward. Also, some parts of the grate can be mechanically movable or all can be fixed in which the fuel is fed by its own weight (sloping grate). Fuel is supplied by the hopper and moved by horizontal grate (forward) or sloping grate (downward) sequentially.

Combustion of air is in two steps. Primary combustion, from underneath air is blown through the bed, dried, ignited and burned. Secondary (and sometimes tertiary), from above air is supplied to burn combustible gases, fuel is subjected to self-sustained burning and is discharged as ash.

Cyclone firing

The main purpose of this type of boiler is creating a strong swirl with cyclone furnace chambers that are mounted outside the main shell with a narrow base together with an arrangement for slag removal. Combustion is already in three phases. Primary, in which air carries particles into the furnace with relatively large coal/char particles. These are retained in the cyclone for promoting reaction. Secondary air is injected tangentially for creating the swirl and tertiary enter through the center of the burner directly into the central vortex along the cyclone axis. Tertiary air is used to displace the position of the main combustion.

It is possible to classify into different criteria:

- Based on the axis of the cylinder: horizontal or vertical arrangements
- Based on the ash behavior in the cyclone: cry or molten
- Based on the cooling media: water or air-cooled

One of the advantages is that the heat transfer is more effectively to the boiler´s water-filled tubes because of the high-intensity and high-velocity cyclonic flames. The words drawbacks are the problems with removal of ash and the narrow operating range. Furthermore, combustion temperature is higher compared with other methods which produce a high rate of thermal NO_x formation.

Pulverized coal fired boilers

The PCF technology has increase the boiler size from 100MW 1950´s to far over 1GW. Nowadays, the coal-fired water tube boilers systems generate approximately 38% of the electricity in the world and will continue being a major contribute in the future. They have a high efficiency but a costly Sox and NOx control. Any kind of coal can be reduced, used and burned like a gas in PCF-boiler. New pulverized coal-fired systems generate power at net thermal cycle efficiencies ranging from 40 to 47% in lower heating value (LHV) and 34 to 37% in higher heating value (HHV) while removing up to 97% of the combined, uncontrolled air pollution emissions.

For removing the higher amount of ash that coal has, the bottom of the furnace is shaped like a ‘V’. Coal is a heterogeneous substance with an organic and inorganic content. Only the organic particles can be combusted. It is needed particle filters of the flue gas and the tear and wear of furnace tubes for removing the inorganic particles like ash and slag.

Finer particles (less than 150mm) are faster combusted because can be mixed with the air and fed to the boiler though jet burners. Combustion is more complete and formation of soot and carbon monoxide are reduced.

Two layouts are possible in these boilers:

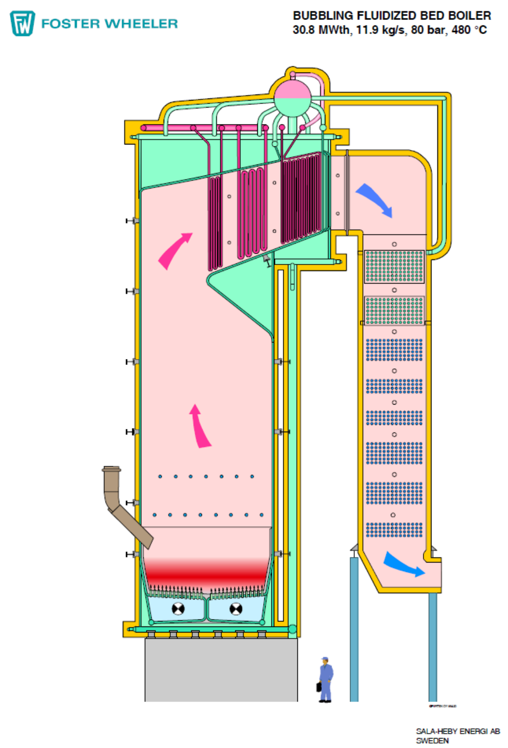
- Two-pass: Furnace chamber are topped by some heat transfer tubing to reduce the FEGT in which flue gas turn through 180° and pass downwards through the main heat transfer and economic section.
- Tower boiler: All the heat transfers are mounted vertically above each other over the combustion chamber.

Oil and gas fired boilers

This type of boilers is similar to PCF-Boiler with the exception of the bottom of the furnace. It can be horizontal because of the low ash content of oil and gas. Configuration with horizontal wall firing is the most common alternative. Also, radiation of flue gas in oil and gas fired boilers is too high in order to use both fuels in the same boiler because the differences in temperature are up to 100C

Fluidized bed boilers

This type of boiler has been used during the last decades after the implementation in 1970´s. The principal advantage is that it can burn different type of fuels, even low quality, with high efficiency. Also, the combustion temperature is not so high and that induce to lower NOx emissions. SOx emissions can be controlled by injection of lime directly in the furnace.



This boiler consists of a layer of sand or a sand-like media where the fuel is introduced and burned. Combustion air is blown through the sand layer from an opening in the bottom. Velocity of combustion air modified the fluid-like behavior. The principal merits are:

- Fuel flexibility
- High combustion efficiency
- Low NOx emission
- Control of SOx by desulfurization
- Wide range of acceptable fuel particles sizes
- Small installation

There are two main types of fluidized bed combustion boilers:

- Bubbling fluidized bed (BFB): Combustion is in the bed because the air velocity is low and medium particles are not carried out above.

- Circulating fluidized bed (CFB): High slip velocity between the gas and solids with intensive solids mixing encourages high mass transfer rates. It enhances rates of oxidation and desulfurization reactions. Particles are carried out of the combustor and they are captured by a cyclone installed outlet and after they are sent back to the bottom part again of the combustor to combust unburned particles.

Principles advantages of CFB boilers against BFB are:

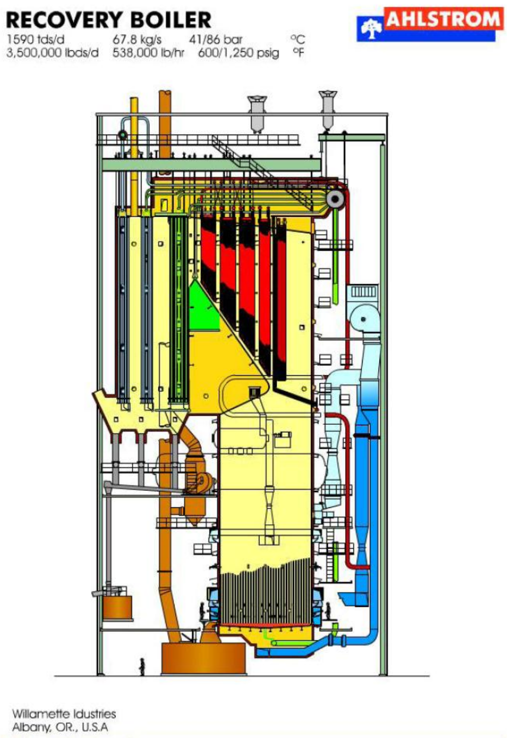
- Higher combustion efficiency
- Lower consumption of limestone as a bed material
- Lower NOx emission
- Quicker response to load changes

Furthermore, BFB boilers are much flexible to fuel quality with a typically power output lower than 100MW against 100MW to 500MW of CFB.

Refuse boilers

This type of boiler incinerates solid or liquid waste products. Combustion of waste varies with properties of waste. The goal is not produce energy, but to reduce the volume and weight of waste and to make it more inert.

Main method is to combust it in a grate boiler with a mechanical grate. Other ways are fixed grate furnace, a fluidized bed for sludge or rotary kilns for chemical and problematic waste. This waste is burned in the shape it was delivered with minimal preparation or separation (only grinding and crushing of the waste and removal of large objects).



Waste can be refined into fuel by splitting inert and inorganic material with a method called refuse derived fuel (RDF) for being used in FBB.

Recovery boilers

It is the largest pieces of equipment in power and recovery operations. The main purposes are to recover chemicals in the black liquor through the combustion process by reduction to be recycled to the pulping process, and to burn the organic materials in the black liquor and produces process steam and supplies high pressure steam for other process.

Bio-energy boilers

These boilers are based on a local fuel supply which provides price stability, secure supply of heat and power and local employment. Biofuels are increasingly becoming locally traded commodities. It secures fuel price stability and availability. Also, green certificates and emissions trading offer new opportunities for financing bio-energy projects.

Biofuels are only used to produce electricity but they are mostly used combined to heat and power (CHP) plants and district heating plants. They are designed to combust very different fuels, since extremely wet fuels like wood chips, bark and sawdust. Smaller plants use grate firing technology with fire tube boilers (<10MWth), and larger use fluidized bed combustion technology fitted with integrated water/fire tube boilers.

Package boilers

They are small self-contained boiler units used as hot water boilers, aiding utility boilers and process steam producers. These boilers can work with oil and gas as fuel.

Benefits of packaged boilers are short installation time and low cost, small space usage, lower acquisition cost, better quality surveillance in work, and standardized units. Like drawbacks it can be consider the higher power consumption, and very frequent cleaning periods.

Apendix B. Feedwater and Steam System Components

Steam boiler plant consist of a join of different machinery and construction like pressurized steam system and electrical equipment, called auxiliary equipment, aiding the operation of the main equipment. (Andritz 1999)

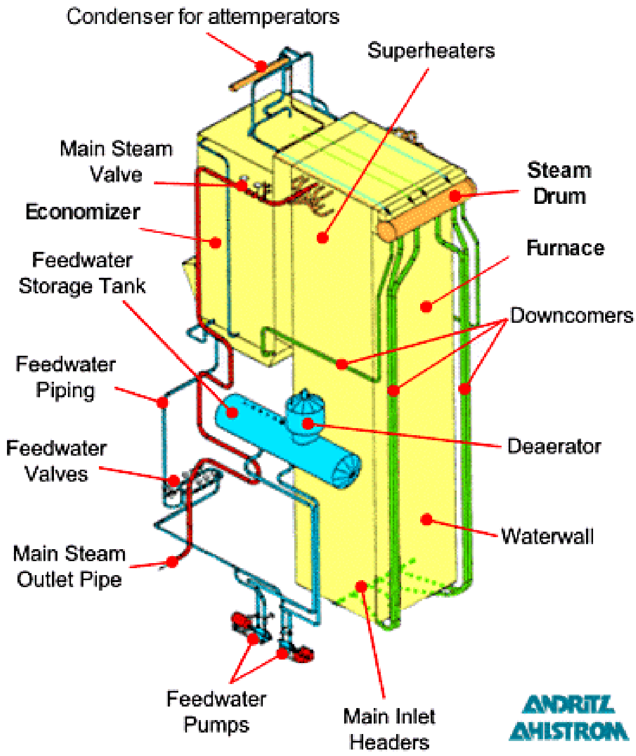


Figure 1: Feedwater circulation of a recovery boiler with natural circulation

Steam drum

This unit is the key component of natural, forced and combined circulation boilers (in once-through boilers it is not used). The functions are mixed fresh feedwater with the circulation boiler water, supplying circulating water to the evaporator through downcomers, receiving water/steam from risers, and separating water and steam. Furthermore, it is used to remove impurities, to control water chemical balance, to supply saturated steam, to store water for load changes, and to act as a reference point for feedwater control.

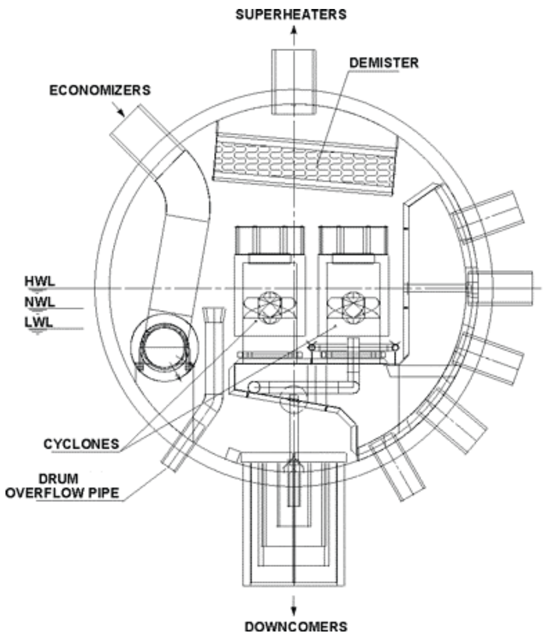


Figure 2: Steam drum cross section

Principle of operation

Feedwater from economizer enters from the steam drum and it is routed through the steam drum sparger nozzles, directed towards the bottom of the drum and then through the downcomers to the supply headers. It operates by natural circulation and drum internals helps to separates steam from water. They flow in opposite directions, where water leaves the bottom to the downcomers and the steam exits the top to the superheaters. Residence time is between 5-20 seconds.

Steam separation

It is based on density difference and it is performance in different kinds of devices such as plate baffles for changing the flow direction, separators based on centrifugal forces (cyclones) and also steam purifiers like screen dryers (bank of screens) and washers. The main problem of this device is the deposition of impurities on the dryer material and on the free area of the dryer.

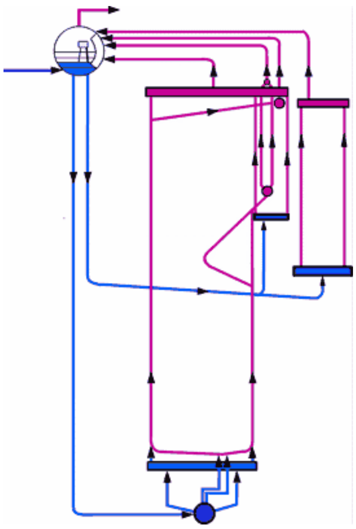


Figure 3: Steam drum process with natural circulation

Steam purity and quality

Impurities changes the heat transfer rate causing overheat (CO_3 and SO_4 are harmful). Turbine blades are sensitive for impurities like Na+ and K. Salts are dissolved in water to prevent superheating and thereby into the turbine. Content after evaporator should be less than 0,01% by weight to avoid impurity deposition, less in subcritical and supercritical-pressure boilers.

Continuous blowdown

Feedwater is added continuously replacing steam, causing impurities to build up. Blowdown piping is used to blow accumulations out of the drum.

Steam drum placement

In natural circulation boilers, it is placed in the higher part of the installation, defining the driving force of the circuit with the height difference between the water level in the steam drum and the point where water begins its evaporation. For assisted/forced and controlled circulation, placement is more freely because of the pump-based circulation.

Feedwater system

It consist of feedwater tank, pump and (if needed) high-pressure water preheaters. They are placed between the condenser (after the turbine) and the economizer. They supply water at all load rates.

Feedwater tank

It is a large feedwater reserve needed for safe shutdown. Standards are used to determine the exact capacity. Residence time is about 20 minutes in most standards, depending of fuel and firing method. For fluidized bed boilers, capacity is even larger than in common boilers. It is used also like an open-type heat exchanger. It operates at low pressure, between 3-6bar (Singer 1981).

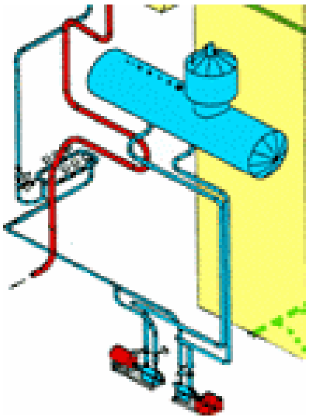


Figure 4: Feedwate system

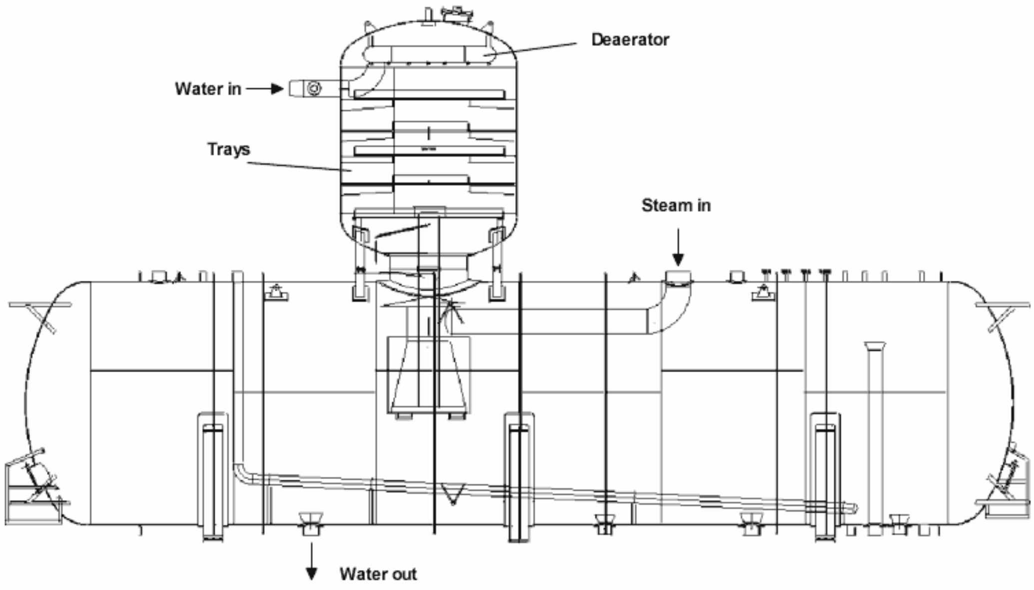


Figure 5: Feedwater cross section

Feedwater pump

It leads feedwater from the tank to the boiler, pressurizing the boiler. Usually, two similar and parallel-connected pumps with enough individual power to singularly supply in case that one of them result damaged. Furthermore, they are over dimensioned in relation to mass flow rate in order to reserve capacity for blowdown water and soot blowing steam. Normally, they are placed under the tank and boiler room to prevent cavitation in the installation. (El-Wakil 1984)

Feedwater heaters

This unit heat feedwater before entering the economizer, using the low-pressure turbine exhaust steam. Two types of heaters exist: high-pressure (HP) and low-pressure (LP). HP is situated after the feedwater pump and before the economizer, since LP is placed between the condenser and feedwater tank. HP is also called close-type feedwater heater because flows are not mixed inside while construction of HP and LP is based in shell-and-tube heat exchanger. Typically, a larger plant use to integrate from 3 to 4 LP and from 3 to 5 HP.

Steam temperature control

Steam consumers need constant steam temperatures (±5C), which is the reason why a control is required. Benefits of a control are to maintain high turbine efficiency, reasonable temperature in materials at load changes. Uncontrollable system produces a rise in steam temperature with a steam output increase.

The most common methods for steam temperature control are water spraying superheating steam, steam bypass (superheater bypass), flue gas bypass, flue gas re-circulation, heat exchanger system, and firing system adjustment.

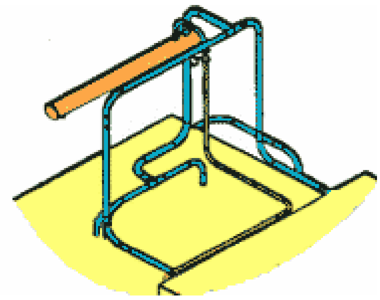


Figure 6: Attemperator

Spray water group

Control with water spraying is the most common method; the advantages are the speed and the affectivity of the regulation. It can be used also for reheating steam temperature control but it is usually performance by combining with other method like flue gas bypass.

Operation of this unit is performance by injecting water into the steam flow which prevents superheated. Spray water can be feedwater (normally), or condensate (condensate steam) also called attemperator.

Water atomizer types

Two types of steam coolers exist: Atomized based on pressurized water flow, and atomization by steam flow. They are chosen depend on the operation range.

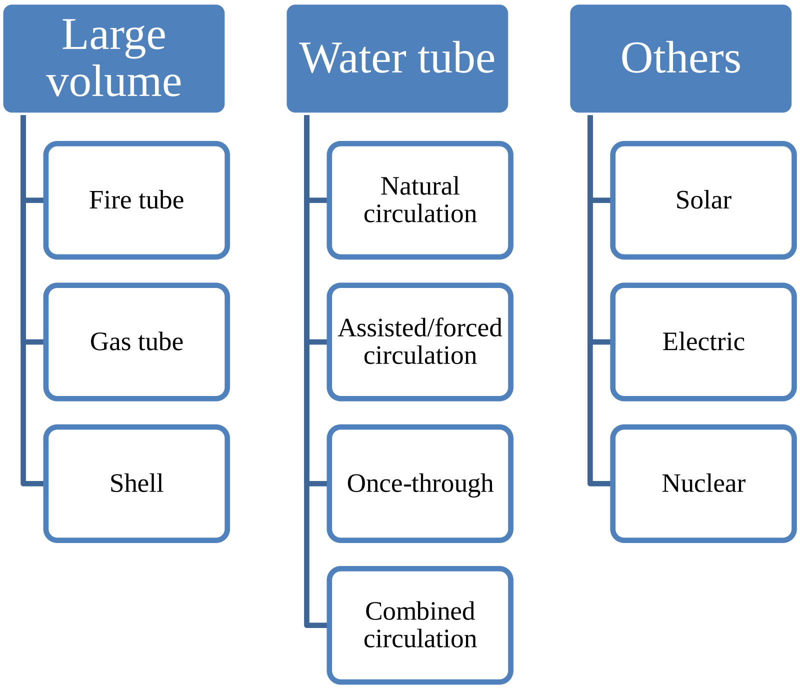
Atomizer principle based on pressurized water flow can be combined with many kinds of water spraying directions and nozzle types but it can be applicable when variations in steam flow are not large and temperature difference between incoming steam and outgoing cooled is big enough.

Steam based atomizer uses steam medium for atomization, which uses low and medium-pressure to get more effective cooling. It is constant and about the 20% of the cooling water flow.

Apendix C. Steam Water Circulation

Introduction

Steam boilers could be classified by different methods like combustion, application or type of steam water circulation.



Large volume boilers

Three different types could be classified as large volume boilers: fire tube, gas tube and shell.

Shell

Shell boilers have similar construction to a shell and tube heat exchanger. Chamber, where the burner is situated, is surrounded by water in a pressure vessel. There, the water turn into saturated steam and the flue gas go through tubes to the stack. This type of boilers is used in small-scale and commonly used to hot-water production.

Fire tube boilers

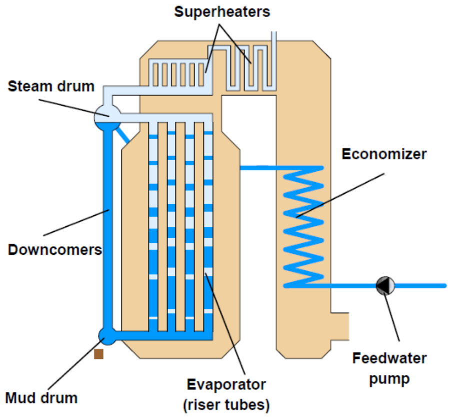
These types of boilers have a tube construction. They are used for moderate demands and pressures. In those tubes, fuel is burned and the flue gas is conducted. It is located in a pressurized vessel containing water and is adapted to work with liquid and gaseous fuels as oil, natural gas and biogases. Usually are used for supplying steam and warm water in small-scale applications.

Water tube boilers

This class of boilers differs from large volume in that the steam and water is inside the tubes and is heated by an external combustion flames and flue gas. Nowadays, all the boilers used to power generation are of this type.

Natural circulation boilers

Being one of the oldest, this type has decreased this operation. It is implemented in small and medium sized, with a pressure drop from 5 to 10% of the steam pressure in the steam drum and maximum temperature from 540 to 560C.



Principle of circulation

Circulation stars in the feed water tank and it is pumped raising the pressure to the wanted boiler pressure up to 170bar for a proper work. Then, water is preheated in the economizer almost up to the boiling point at that pressure. Usually, that temperature is 10 degrees under the boiling temperature to prevent boiling in the economizer pipes and it is called approach temperature.

Feed water flows to steam drum where it is mixed with the existing water for reducing thermal stresses. After the steam drum, saturated water flows through downcomer tubes to a mud drum (header). These tubes use to be a couple and they are unheated. In mud drum, impurities are collected by settle and removed from there.

Saturated water goes through riser tubes situated on the walls of the boiler for efficient furnace cooling where suffer partially evaporation. Riser tubes are also called generating tubes because their capability to absorb heat efficiently forming the evaporator unit.

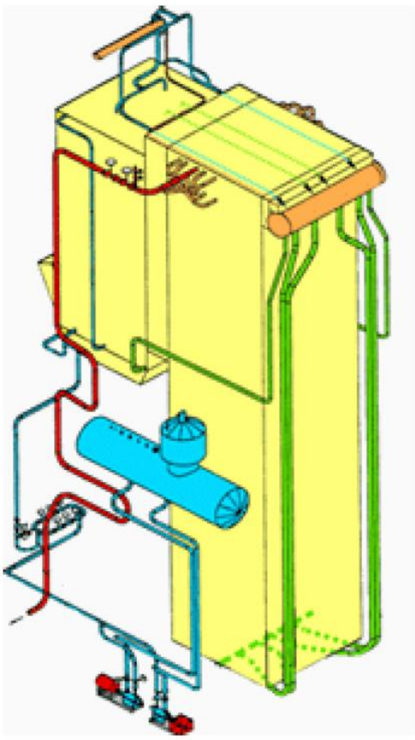
After that, mixture come back to the steam drum where is separated into saturated water that will return to the downcomer tubes, and saturated steam that continue to the superheater tubes. In this point, salts, minerals and other impurities are taken off to protect superheaters tubes and turbine from impurities deposition.

From the steam drum, working fluid continues to the superheater. In there is heated beyond its saturation point and after, it leaves the boiler.

Main reason of water circulation is the difference of densities in the fluid in the different stages of the boiler. Some advantages and disadvantages appear comparing with other types of boiler.

Advantages	Disadvantages
- **Feed water impurities are better tolerated** - **Electricity consumption is lower** - **Simple construction which means lower cost and higher reliability** - **Wide partial load range** - **Constant heat transfer areas are independent from boiler load** - **Process control is simple**	- High circulation ratio leads up to massive dimensions of evaporator - Large diameters of all tubes - More accurate dimensions - Slow start-up and stop situations because of the amount of fluid - Only suitable for subcritical pressure levels due to the lack of difference in density in supercritical steam - Frequently tube damages - Sensitive to pressure variations - Steam drum needed

Natural circulation design



Circulation ratio is the most important variable while designing boilers. It is the mass rate of water fed to the steam-generating tubes (raisers) divided by the mass rate of generated steam. Variation the circulation ratio result on pressure level of the boiler. It is also affected by height of the boiler, heating capacity, and tube dimension differences between riser and downcomers tubes. Circulation ratio usually varies from 5 to 100.

Driving force can be explained with the density difference between water/steam mixture in riser and downcomer tubes. In steam drum contains supersaturated water. While traveling through the downcomer tubes, its pressure suffers a slight increase because of the hydrostatic pressure. Water is subcooled in the mud drum after downcomer tubes. That is the reason why water has to be heated firstly up till evaporation temperature before it can be evaporate.

Relatively large diameter of downcomer tubes are needed to allow the entire water amount circulation. Normally there is between one and six tubes. These tubes are placed outside the boiler to prevent evaporation and possible bubbles travel upwards that will increase the pressure loss. Ideally, downcomer tubes must be short and permit the higher flow velocity as possible.

Upwards-rising arrangement must be in wall tubes. Pressure loss caused by these should be low because of the natural circulation principle.

Header is the unit that collects all the distributor pipes including the mud drum which has the diameter as the most important parameter in design. Defined by the flow rate and the number of tubes, is can be defined as a simple steam drum with lower dimensions.

Boiling process begin with a single-phase of water flow. After that, some steam bubbles appear with the heat transferred increasing the steam content until the annular state, where steam mixture the wall and it is covered by a water film. Last state is called misty/drop state.

Departure from nucleate boiling (DNB) is called to the critical value that the heat flux can reach which results in sudden decrease of the heat transfer capacity of the tube. It is caused in the transition from annular state to misty/drop state. Drastic fall in the waterside heat transfer coefficient is caused by the dryout. It depends on operating pressure, steam quality, type of tube, tube diameter, flux profiles, and tube inclination.

There are some methods that help to optimize the design of these boilers. First of all, increasing furnace height or elevate the steam drum, second increasing density in downcomer, and third decreasing density in riser tubes. It can be achieved by increasing steam separation efficiency in the steam drum and increasing the temperature in lower furnace respectively.

Assisted or forced circulation boilers

The main difference with natural circulation boilers is based on a pump-assisted internal water/steam circulation. That is the reason why the operation pressure level can be slightly higher but they are not suitable for supercritical pressures (>221bar). Maximum operation pressure is about 190bar with a pressure drop of 2-3bar.

Principle of circulation

Circulation begins in the feed water tank. From there, water is pumped raising the pressure until 190bar, subcritical region. Then, economizer preheats water almost up to boiling point in the pressure of work. Steam drum is similar as those used in natural circulation boilers.

Driving force is provided by the circulation pump, reason why evaporator tubes can be built in almost any position. Moreover, it can be tolerated greater pressure losses with results in a smaller diameter and cheaper tubes.

Saturated water flows through downcomer tubes to a mud drum (header) close to the steam drum, which are unheated and outside. Header distributes water to the evaporator tubes and they are equipped with chokers (flow limiters) for distributing the water evenly. After that, water continues through riser tubes where it evaporates. Steam is separated in the steam drum and continues through the superheaters.

Flow distribution between parallel riser tubes

To prevent overheating in the riser tubes from header, smooth flow distribution is required by pushing water through evaporator tubes with a pump. Water distribution between several parallel-coupled tubes is defined by pressure loss. Tubes with biggest steam fraction (highest pressure loss) get thus the least amount of water.

A way to proceed is using tubes with orifices (chokers, flow limiters) giving an extra pressure loss thus the proportional differences in flow losses between parallel tubes become insignificant. Every orifice is dimensioned separately to provide a smooth distribution.

Another possibility is to place small diameter tubes as mouthpieces in each riser however tubes orifices are more common practice.

Advantages and disadvantages

Advantages	**Disadvantages**
• **It can use small diameter tubes because they are more efficient** • **Wide suitability** • **Freedom for placement of heat transfer surfaces** • **Low circulation ratio (3-10)** • **Water circulation not reliable on density differences**	• Restrictions regarding in the placement of circulation pump because of possible cavitation bellow steam drum • Higher internal electrical consumption (0,1-1%) • Higher level of water quality • Maximum pressure levels with flow rate of 1000-2000kg/m^2s • Only suitable for subcritical pressures • Circulation pump and flow limiting orifices increase capital cost • Sensitive to pressure variations • Require control and regulation of the co-operation between feed water pump and circulation pump • Steam drum required • Reliability is lower due to possible clogging of orifices and failures in circulation pump

Once-through boilers

Universal pressure boiler is an external heated tube with circulation ratio as 1. It do not have steam drum and the length of the evaporator is not fixed. Usually, it is a large sized boiler that can apply all different pressure and temperatures. A large modern plant of 900MWth can be over 160m high with a furnace height of 100m.

They are the only type suitable for supercritical pressure that can reach 250-300bars with a temperature range between 560-600C. One of the drawbacks is that pressure losses are between 40-50bar and they need advanced automation and control systems besides of the low buffer capacity.

Spiral wall tubes

Rifles wall tube is a special design of once-through boilers. Tube wall and steam/water mixture is improved incrementing wall wetting, which is more resistant against dryouts. It is more expensive than regular smooth wall tubes. For instance, smooth wall tubes are used in tilted wall tube design.

Multiple pas design

Efficiency tube cooling can be achieved dividing the lower part of the furnace in two sequential water flow paths, formed by altering the first and second pass tubes around the furnace. Water from the economizer flows up the first pass tubes to the outlet headers, mixing there and leading to the second pass tubes, where it is collected and mixed in the second pass header. After that, water mixture goes through the 3rd pass tubes, which the rest of the evaporator consist of.

Two passes increases up to twice the mass flow and thanks to the headers, temperature differences between individual tubes are decreased.

Advantages and disadvantages

Advantages	**Disadvantages**
• **Small diameter of tubes because of the lack of internal circulation** • **Secure external water circulation** • **Resistant against dryouts** • **Circulation ratio unit, no regulation needed for internal circulation** • **Only design able to operate at supercritical pressures** • **No steam drum necessary**	• High level of water control • Complicated regulation control: fuel, air, and water mass flows are proportional to power output • Require a large mass flow rate from 2000 -3000 kg/(m2s) • No buffer capacity because of lack of a steam drum and the once-through nature

Operation

The main differences between once-through boilers are the point of total evaporation in tubing. On the other hand, supercritical pressure range operation removes this difference between water and steam states. In general, certain special arrangements are needed in all once through boilers for heating-up procedure and low capacity operation.

Combined circulation boilers

Combined circulation is a combination of once-through with superimposed recirculation that can be used for both subcritical and supercritical steam pressure operation. Operation between firing rate from 60-100% is once-through, combined circulation with lower than 60% capacity load.

The main drawback is the troublesome co-operation between feed water pump and circulation pump, also the high level needed for water treatment.

Apendix D. Feedwater and Steam System Components

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Steam drum

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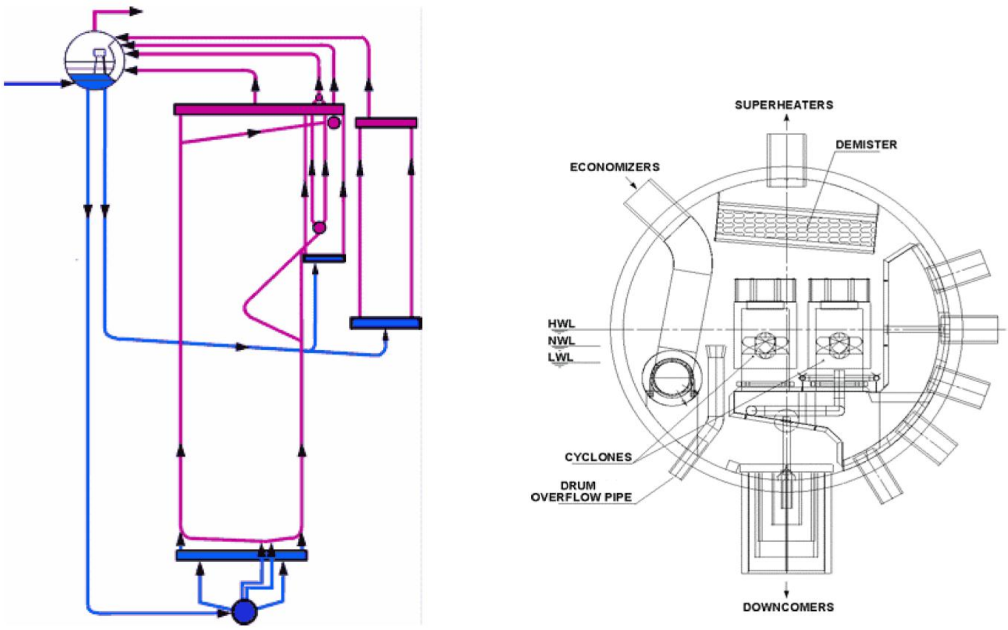

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Feedwater system

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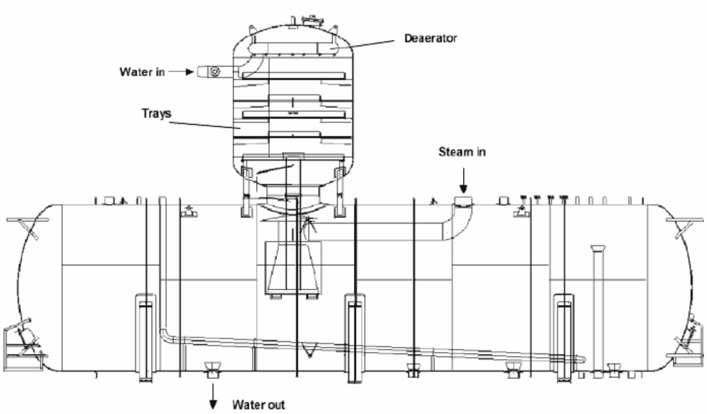

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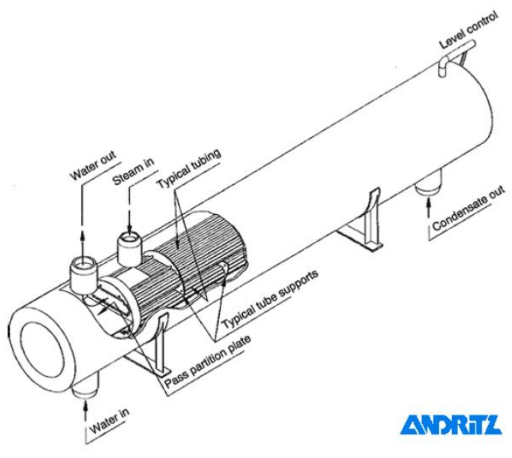
It leads feedwater from the tank to the boiler, pressurizing the boiler. Usually, two similar and parallel-connected pumps with enough individual power to singularly supply in case that one of them result damaged. Furthermore, they are over dimensioned in relation to mass flow rate in order to reserve capacity for blowdown water and soot blowing steam. Normally, they are placed under the tank and boiler room to prevent cavitation in the installation.

Feedwater heaters

This unit heat feedwater before entering the economizer, using the low-pressure turbine exhaust steam. Two types of heaters exist: high-pressure (HP) and low-pressure (LP). HP is situated after the feedwater pump and before the economizer, since LP is placed between the condenser and feedwater tank. HP is also called close-type feedwater heater because flows are not mixed inside while construction of HP and LP is based in shell-and-tube heat exchanger. Typically, a larger plant use to integrate from 3 to 4 LP and from 3 to 5 HP.

Steam temperature control

Steam consumers need constant steam temperatures (±5C), which is the reason why a control is required. Benefits of a control are to maintain high turbine efficiency, reasonable temperature in materials at load changes. Uncontrollable system produces a rise in steam temperature with a steam output increase.



The most common methods for steam temperature control are water spraying superheating steam,

steam bypass (superheater bypass), flue gas bypass, flue gas re-circulation, heat exchanger system, and firing system adjustment.

Spray water group

Control with water spraying is the most common method; the advantages are the speed and the affectivity of the regulation. It can be used also for reheating steam temperature control but it is usually performance by combining with other method like flue gas bypass.

Operation of this unit is performance by injecting water into the steam flow which prevents superheater. Spray water can be feedwater (normally), or condensate (condensate steam) also called attemperator.

Water atomizer types

Two types of steam coolers exist: Atomized based on pressurized water flow, and atomization by steam flow. They are chosen depend on the operation range.

Atomizer principle based on pressurized water flow can be combined with many kinds of water spraying directions and nozzle types but it can be applicable when variations in steam flow are not large and temperature difference between incoming steam and outgoing cooled is big enough.

Steam based atomizer uses steam medium for atomization, which uses low and medium-pressure to get more effective cooling. It is constant and about the 20% of the cooling water flow.

Apendix E. Combustion process equipment

A steam boiler can be considered as a join of different machinery, a construction, a pressurized steam system and electrical equipment. Auxiliary equipment dealing with the combustion process is:

- Hoppers, silos, crushers
- Burners
- Fans, ducts, dampers
- Air heaters
- Sootblowers, conveyors

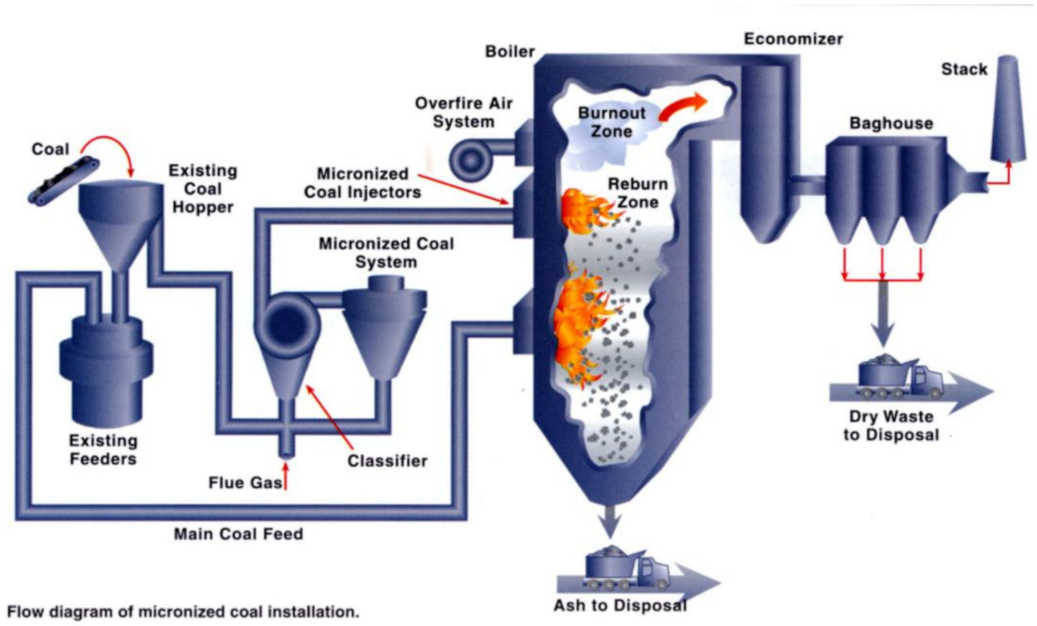


Figure 7: Fuel feed system on a PCF boiler (The Babcock & Wilcox Company 2003)

Combustion System

Two main methods can be choice depend on economic factors and emissions. Using a burner, it is possible to use single burner, arrangements of several burners in a furnace and a cyclone firing. On the other hand, burning in suspension can be performance in grate firing, fluidized bed combustion and chemical recovery boilers.

Burners

Burners are devices that combust liquids or gases by continuously feeding of air and fuel to a nozzle, where they are mixed and combusted, producing a flame. Different types of burners can be considered based on fuel air mixing: Diffusion burners premixed burners and kinetically controlled burners.

Furthermore, the disposition of burners can be:

- Single wall firing: Economical arrangement, it uses overfire air to control NO_x.
- Front and back wall firing.
- Corner or tangential firing: Drawback is that flames can hit one to each other.
- Roof firing: Low grade fuels and low combustion temperature.

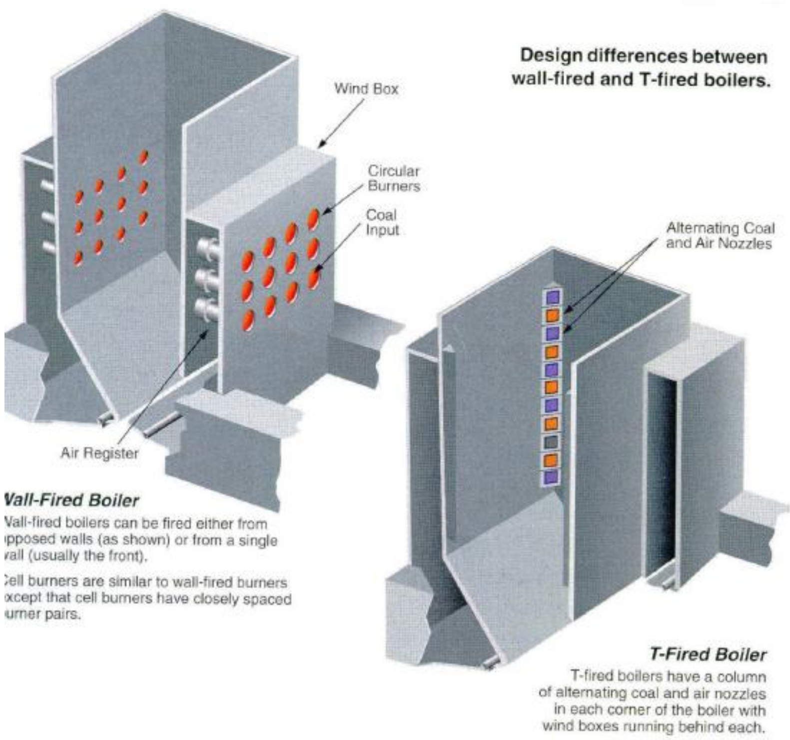


Figure 8: Wall fired and corner fired boilers

The main difficulties of burners design are to achieve the optimal parameters: form of flame, flame stability, temperature, emissions, and formation of soot. The main goal during the last years is to decrease the formation of NO_x.

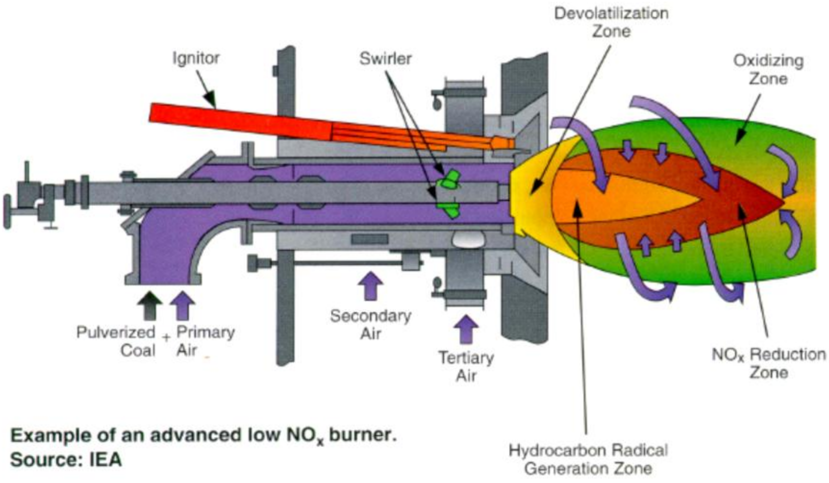


Figure 9: Advanced low NOx burner

Combustion of solids

Solid fuels such as coal, paper sludge, biomass, peat, RDF (Refuse Derived Fuel), and municipal waste are fired in industrial and utility boilers. Fuels can be divided into high grade fuel and low grade fuel and its heating value depends on the fixed carbon content.

Pulverized Coal Firing (PCF) is the most common method for firing coal grinded into a fine particle size. The main advantage is the high heat release rates and the high temperatures that can be achieved. The disadvantages are the additional units for SO_x and NO_x controls are required.

Grate firing was the main technique until 1930´s when PFC started to gain hold. Combustion takes place in a bed at the bottom of the furnace. One of the advantages is that it can be combusted all kind of coals, including crushed but the disadvantage in grate firing is the slow change in firing rate because of the large amount of unburned fuel in the grate. (Huhtinen and Hotta 2000)

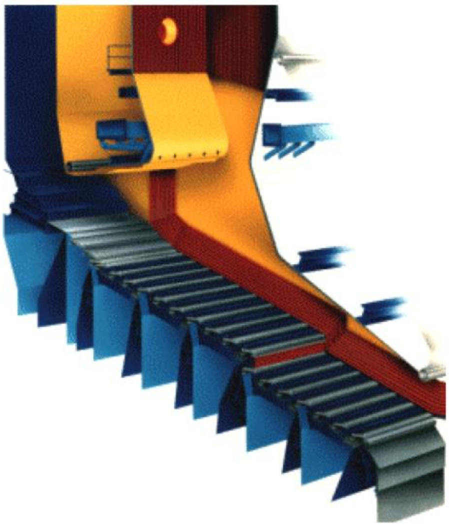


Figure 10: Stationary fuel feeder

Different types of grates are used in this technique:

- Stationary grates
- Traveling grate
- Mechanical grates

- Spreader design
- Mechanical grate for biofuels
- Roll grate

Fans and blowers

Fans are used in steam boilers basically to supply air to the furnace used in combustion and also it is utilized in pneumatic transport of fuels and other solids. It makes possible to control the oxygen in the combustion.

Fan categories

There are four fan categories used in boilers:

- Forced-draft (FD) fans: They supply stoichiometric plus excess air for combustion, air to make up for air preheater leakage and sealing-air requirements.
- Primary air fans: They provide air needed to dry and transport coal.
- Induced draft (ID) fans: They exhaust combustion gases from the boiler by creating the enough negative pressure to set up a slight suction in the furnace, typically placed downstream of any particulate removal system.
- Gas recirculation fans: They draw gas from a point between the economizer outlet and the air-preheater inlet and discharge it for steam-temperature control into the bottom of the furnace. In FBB, it can be also equipped with a flue gas recirculation fan for bed temperature control.

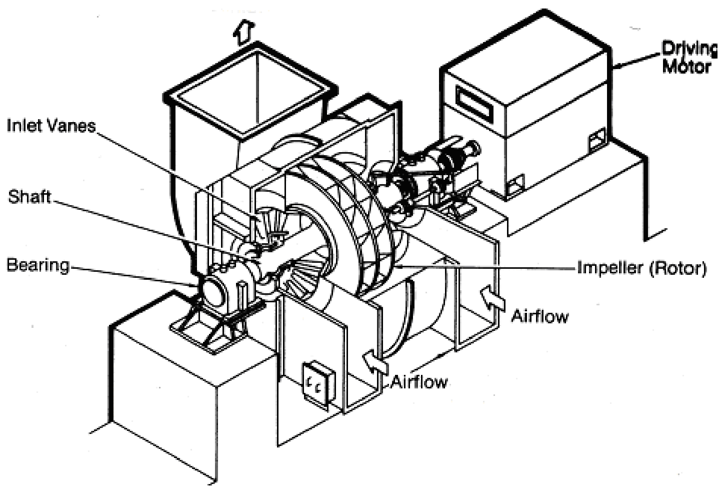


Figure 11: Radial air fan

Fuel handling equipment

It is important to store fuel in safe manner, to transport it to the furnace and sometimes, to modify for better burning properties. Those issues are possible thanks to fuel handling equipment.

Coal feeders

This device supplies the pulverized uninterruptedly raw coal. It is possible to find different types:

- Belt feeder: It is a looped belt running on two separated rollers that receive coal from above at one end and discharging it at the other end.
- Overshot roll feeder: It is a multi-bladed rotor that turns about a fixed, hollow, and cylindrical core. It is also fed with air to minimize the wet coal accumulation. A spring-loaded leveling grate mounted over the rotor limits the discharge.

Crushers

There different types but the most commonly used is the swing-hammer crusher. It consists of a casing that encloses a rotor which pivoted hammer ore rings attached. Fuel is fed through the top and then removed.

Pulverizers

Pulverizers or mills are used to reduce the particle size of coal to less than 0,1mm. Basic principles are impact, attrition and crushing. Different kinds of pulverizers can be found:

- Bad-tube mill: It is a hollow horizontal cylinder, rotated in its axis, filled with steel or cast alloy balls from 2 to 10 cm. It rotates slowly pulverizing coal. It is a high power consumer due to the large size.
- Impact mill: It is a series of hinged or fixed hammers in an enclosed chamber that impact on the larger particles and produce attrition of the smaller particles on each other. It has a high maintenance cost.
- Attrition mills: It consists of pegs and lugs mounted on a disc that rotates in a chamber. The characteristics are similar to impact mill.
- Ring-roll and ball-race: It is the most common unit used for coal grinding nowadays, crushing and attiring of particles to obtain reduction. It is medium

speed. It takes place between two surfaces, one (ball or roll) rolling over the other (race or ring).

Ash handling equipment

Two types of ash are produced in a furnace: Bottom ash and fly ash. Bottom ash is slag, it is added to the heat-absorbing surfaces, superheater, reheater and economizer, and eventually it falls off by its own weight or by soot blowing. Other ash are mixed with and carried away by flue gas stream. On the other hand, ashes that are collected in equipment hoppers are called fly ash. So many factors determine the technique of handling and storing:

- Fuel source and content of ash forming elements
- Plant site (land availability, presence of aquifers, adjacent residential areas)
- Environmental regulations
- Steam-generator size
- Cost of auxiliary power
- Local market for ash
- Cementations character of the ash

Ash collection points

There are several points where ash is collected. Hoppers and conveyors under the furnace bottom collect material. Hoppers are also used under the reject discharge spouts of the pulverizer to collect pyrites and tramp iron, besides the finer particles.

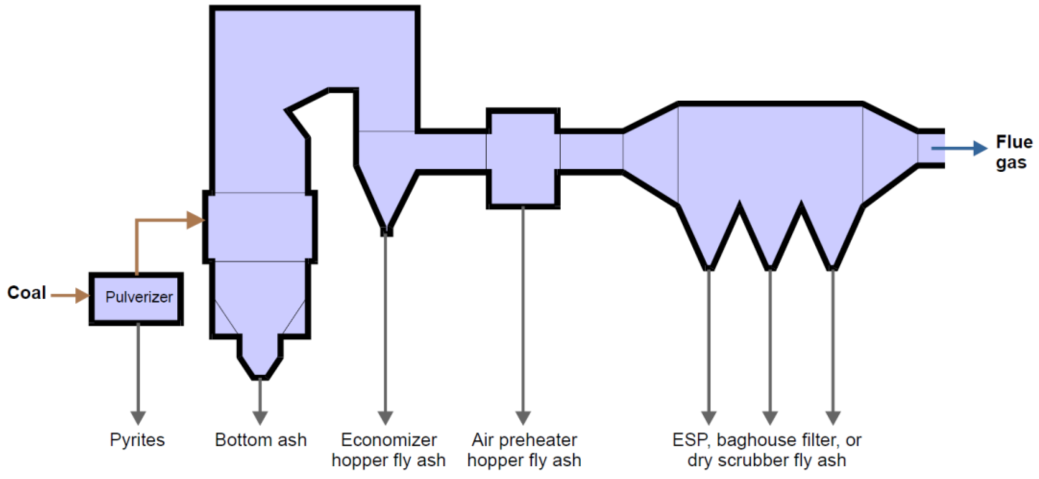


Figure 12: Ash collection points

Ash conveyors

In PFC, ash is continuously taken out from the bottom. A conveyor submerged under water is use also to cool ashes and dragged to a chute by a bottom scraper conveyor.

Electrostatic precipitator

ESP (Electrostatic precipitator) is the most common method used to control emissions. It only acts in the particles and not in the flow. Corona particle charging employs ions generated in the discharge electrodes, which create an electric field with the collector plates. It uses a voltage of the order 30-75kV that attract the charged particles.

The main advantages of this unit are the very high efficiencies to handle particles with low pressure drops, dry collection of valuable materials, or wet collection of fumes and mist, possibility of design for a wide range of gas temperatures and low operating cost. As drawbacks: high capital cost, inability to control gaseous emissions, inflexibility to change in operating conditions once installed, and the high amount of space used.

Soot blowing

Sootblowers are used to keep flue gas passages open and surface clean from ash. They use high-pressure steam to remove ash layers. Different methods are used:

- Stationary sootblower: A lance is placed inside from where is injected steam at sonic speed. These blowers are used in oil and gas boilers.
- Retractable sootblower: A rotate lance injects steam at sonic speed from the tip along wall. It is used in PCF boilers.

Sootblowers consume from 4 to 12% of the total steam produced. Optimizing soot blowing, it is possible to maximize deposit removal efficiency and steam savings. Many parameters are involved such as peak impact pressure (PIP), soot blowing sequence and frequency, traverse speed, distance from the nozzle to the deposit, deposit thickness, mechanical strength and deposit-tube adhesion strength. (Harja 2002)

Apendix F. Heat Exchangers in Steam Boilers

Heat transfer surfaces

Heat transfer surfaces are the elements that transfer the heat to the water/steam from the flue gases. The most important objective is to optimize thermal efficiency and economic investment by arranging the heat transfer surfaces and the fuel-burning equipment.

Radiation is the main heat transfer process in the furnace, whereas convection and radiant is in superheaters and reheaters, and convectional heat transfer in air heaters and economizers.

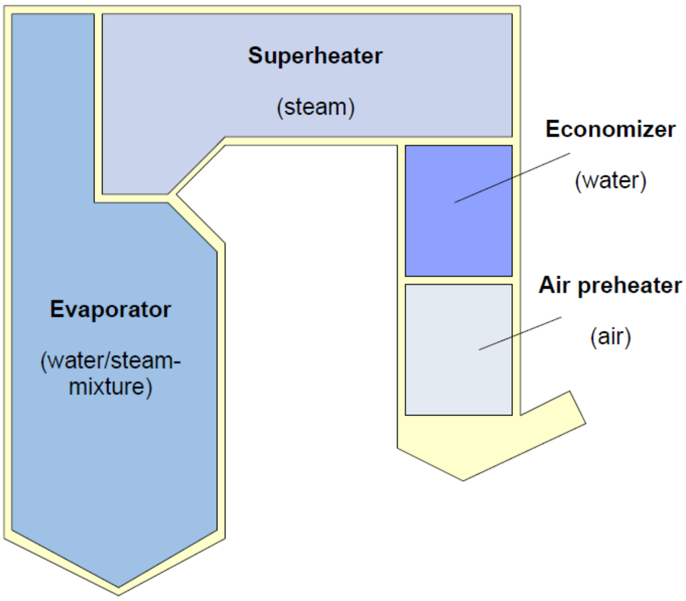


Figure 13: Heat exchange surfaces

Furnace exit gases are cooling down to the dew point in the preheaters and economizers in order to reduce flue gas outlet temperature, preheat combustion air and use the heat to increase the temperature of the incoming feed water to the boiler.

Arrangement of heat transfer surfaces

Temperature of the flue gas must be higher than the heat absorption fluid (working fluid); it can be easily explained with the second law of thermodynamic. The correct arrangement of heat transfer surfaces effect on the durability of material, fouling of material, temperature of steam and final temperature of flue gas. Phase change occurs because a heat transfer in the furnace, working fluid turns water into steam or fluid gas.

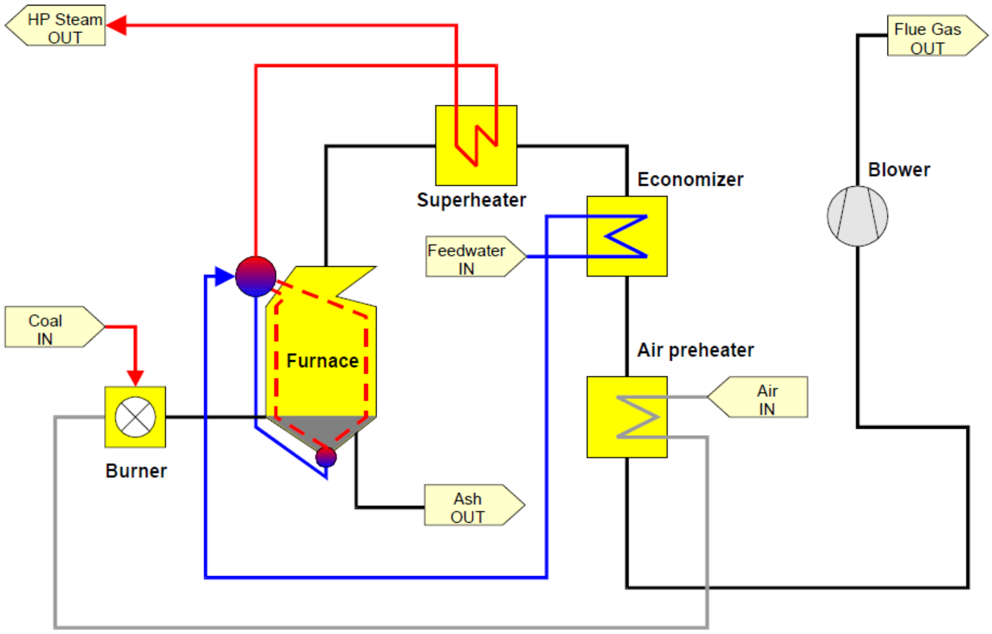


Figure 14: Heat exchange process

Furnace

It is the place where combustion takes place. Fuel must be burn complete and stable, unburned material leaving the furnace decrease heat efficiency and increase emissions, which are the reason why combustion must be performance in an environmentally sustainable way.

The walls of this unit are made of vertical tubes that function as the evaporator part. Roof of the furnace is also part of the evaporator as well as the flue gas channel walls in the economizer and the air preheater parts.

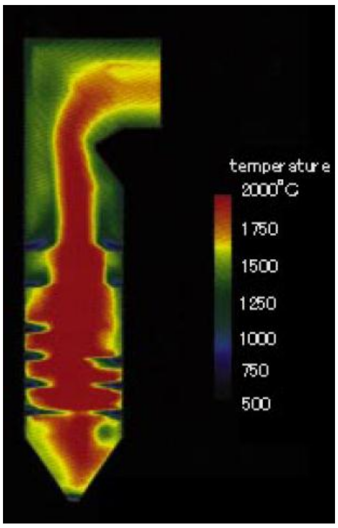


Figure 15: Temperature distribution in a furnace

Optimal furnace cooling is very important. However, with wet fuels and wood chips some parts of the furnace do not need to be cooled in order not to remove too much heat from the furnace. Thus a part of the furnace using such fuels consists of a refractory material, which reflects the heat of combustion to the incoming wet fuel. It is important that the temperature of the flue gas leaving the furnace must not be too high, problems with deposition and corrosion of tubes on superheater can occur.

The main parts of the furnace are:

- Membrane wall: It is constructed as a gas-tight membrane wall made of tubes welded separate by a flat iron strip.
- Convection evaporators: In low steam pressure boilers, the share of the heat needed for evaporation is bigger than in a high-pressure boiler. This unit is placed after superheater stage and it supplies the heat needed.
    - Boiler tank: This kind of convection evaporator uses two drums, one on the top and other on the bottom. It is used in parallel with the natural circulation based furnace.

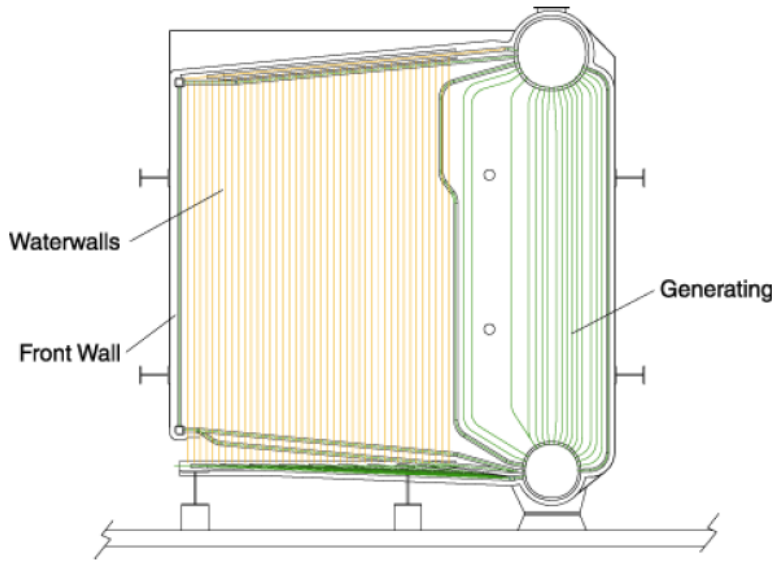


Figure 16: Boiler generating bank

Economizer

This heat exchanger is placed after the pump when water has been pressurized to enter the boiler. The principle of this unit is to cool down the flue gases that leave the superheater increasing the boiler efficiency. While flue gases are cool down with feedwater and water is preheated up to its saturation temperature. It is necessary to prevent water boils in the economizer, that is the reason why feedwater existing is regulated with a safety margin bellow its saturation temperature (about 10ºC). Furthermore, the flue gas temperature must be higher than the dew point of the gases to prevent corrosion of the precipitators and ducts.

Superheater

Superheater is the unit that overheats (superheats) the saturated steam. Steam temperature is increased beyond the temperature of saturation and efficiency of the whole system can be raised. Benefits of superheating are zero moisture content, no condensate in steam pipes, and higher energy production efficiency.

Superheater is composed of tubes that conduct steam heated by flue gases passing outside the tubes, normally connected in parallel. Usually there are several superheaters units in the same boiler, as well as reheaters (superheater for heating external steam).

Different kind of superheater surfaces can be found:

- Radiation superheaters: It is located in the top of the furnace.
- Convection superheaters: It is used with low steam temperature and it is placed after the furnace to prevent corrosive radiation of the flames.
- Panel superheaters: Convection and radiation are used and it is located first in the flue gas stream after the furnace with low heating fuel. It is resistant to fouling and can be withstand high heat flux.
- Wing wall superheater: Very popular in CFB applications, this panel is extended from a furnace.
- Back-pass superheater set: It is located in the flue gas stream when it starts to flow downwards.

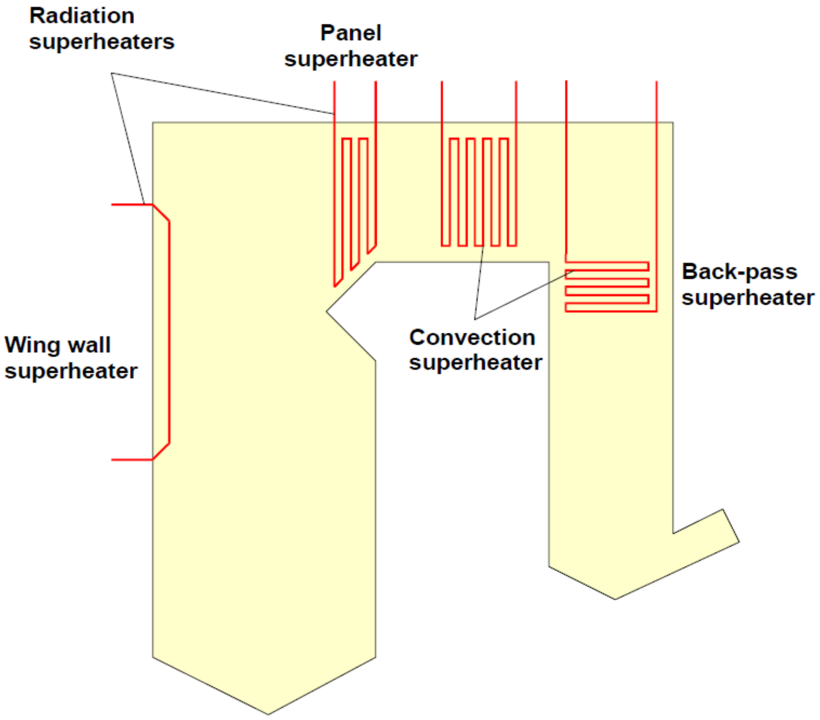


Figure 17: Arrangement of various superheaters units

Reheater

Reheater is a superheater that is used to reheat (superheat) steam existing in a high-pressure stage of a turbine sending it to a low-pressure stage. This step increases the electrical efficiency of the power plant beyond 40%.

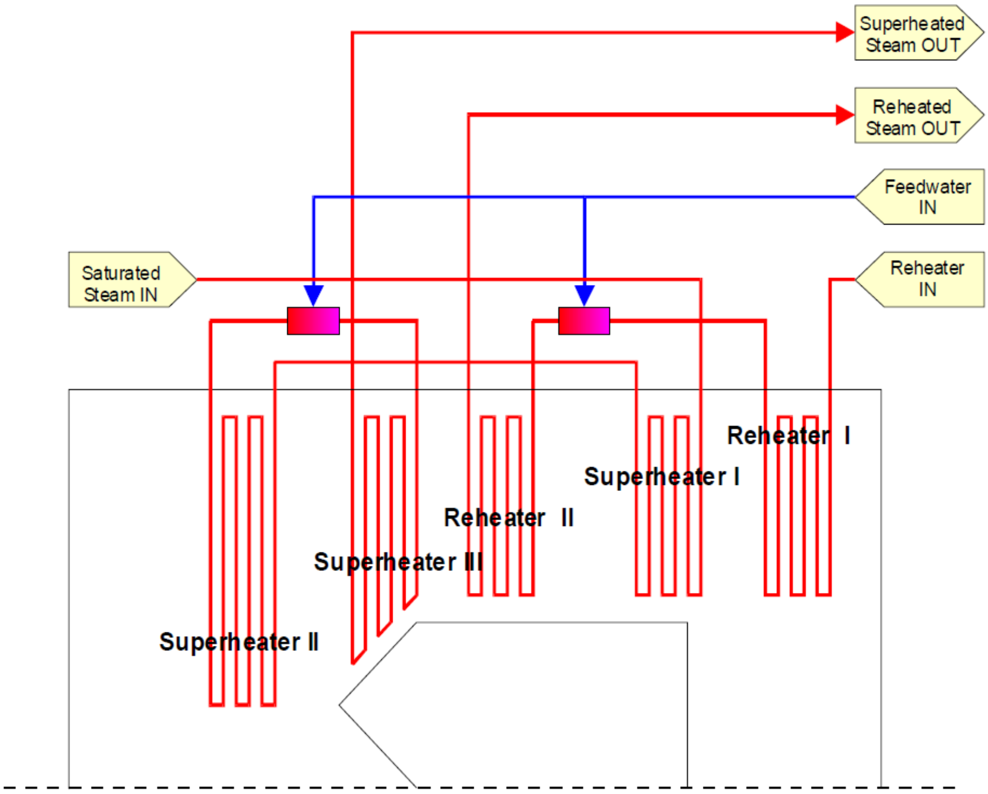


Figure 18: Connection of superheaters and reheaters

Air preheater

Two are the finalities of the air preheater: cool gases before going to the atmosphere and raising the temperature of the incoming combustion air. Benefits are the increase of the efficiency and faster dried of the solid fuel. Also it is used to transport fuel in PCF and FBB boilers.

There are two different types of air preheaters

Regenerative air preheaters

This kind of preheater does not use any media for heat transfer, it uses heat accumulation capacity of a slowly rotating rotor, which is heated in the flue gas stream and cooled in the air stream. Heat storage is provided by the mass of the packs that consists of closely spaced metal sheets. This unit occupies little space, about 1/4 or 1/6 of the space in recuperative air preheater, being easily to

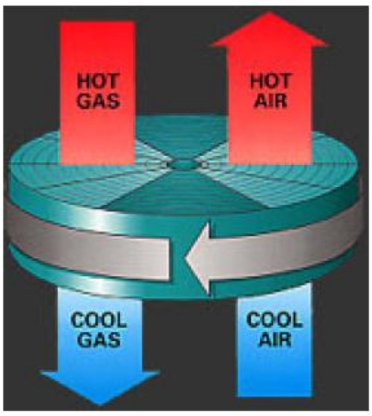


Figure 19: Regenerative air preheater process

produce also. His tendency to reduce the dew point corrosion should also be noted, in particular, when fuels containing sulfur are used. One of the problems is the gas outflow from one area to another.

Recuperative air preheaters

The main difference with regenerative air preheaters is that flue gas passes through a heat transfer surface to cooler air, mediums that are completely separated. One of the advantages is that there is not leakage between mediums but on the other hand, this unit is bigger than the regenerative air preheater.

Two different types of recuperative air preheaters can be found:

- Tubular recuperative air preheaters: is composed of a nest of long, straight steel or cast-iron tubes expanded into tube sheets at both ends, and an enclosing casing provided with inlet and outlet openings. Flue gas can flow through horizontally or vertically, with single pass or multiple passes with either splitter or deflecting baffling.
- Plate recuperative air preheaters: This unit has the same heat transfer capacity with less weight and size. One of the drawbacks is the cleaning difficulties, reason why its use is diminishing. It consist of a series of thing, flat, parallel plates assembled into a series of thin, narrow compartments and passages.

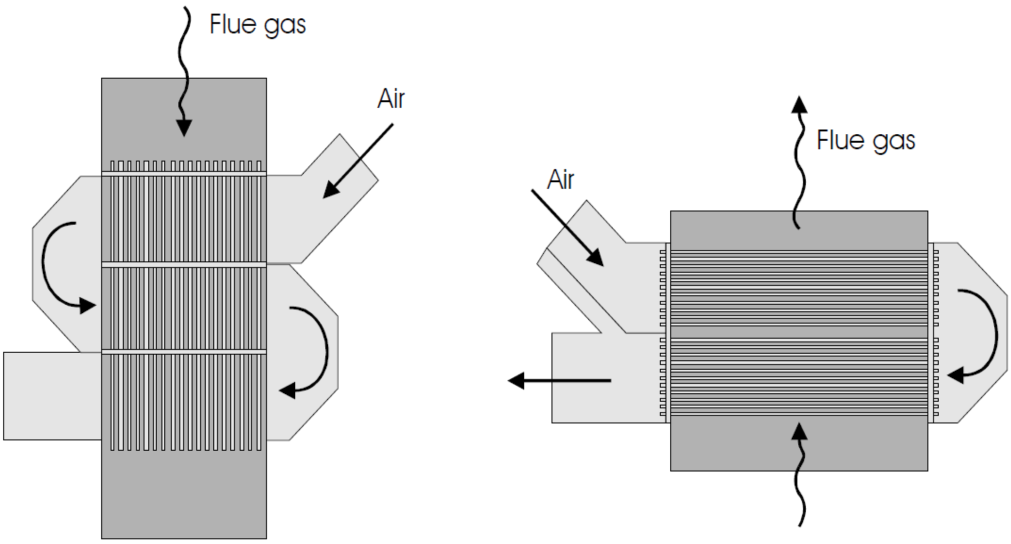


Figure 20: Tubular and plate recuperative air preheaters

Apendix G. Circulating fluidized Bed Boilers

Introduction to Fluidized Bed Boilers

It is usual to use a desulfuration plant, including bag-house filters for desulfuration and electrostatic precipitators for fly ash for controlling emission levels from coal combustion, besides advanced combustion technologies and pollutant capture technologies. During the last decades, FBC has been developed introducing new features that permit SO_2 removal during combustion, low NO_x emissions and multi-fuel flexibility.

There are three types of FBB: bubbling fluidized bed (BFB), atmospheric circulating fluidized bed (ACFB or CFB), and pressurized circulating fluidized bed (PCFB).

Fluidized Bed Principles

Basically, fluidization is a process in which fine solids are transformed into a fluid-like state with mixing in a fluid (gas or liquid). Particles are suspended and acquire physical characteristics of fluids when are dragging by the fluid. At low gas velocity, gas flow through a fixed bed of particles but when the gas velocity increases, solids are completely dragged in the gas steam. The furnace of a CFB operates between these two extremes.

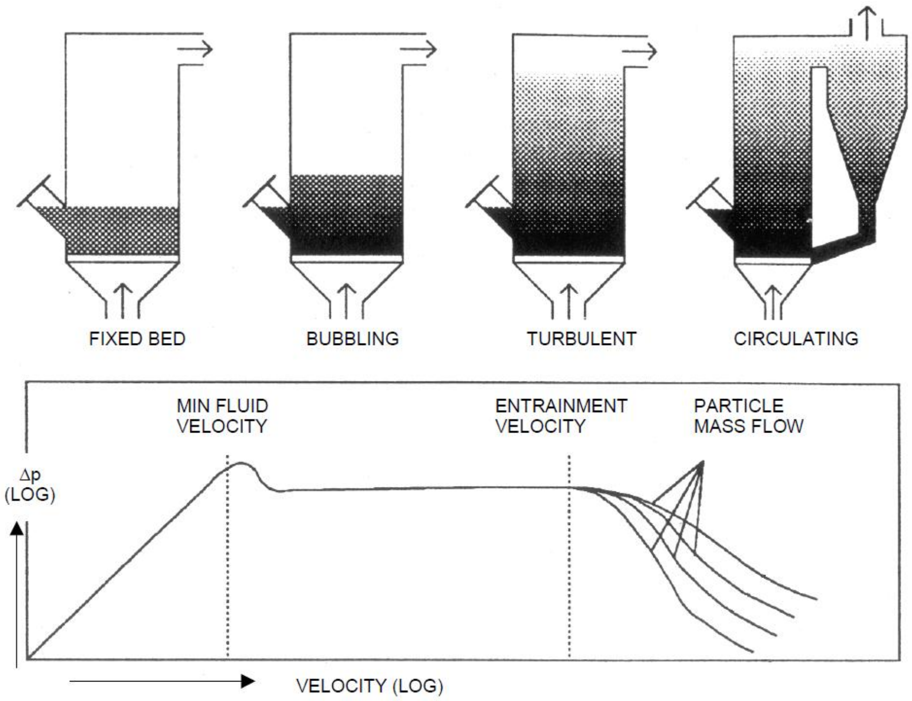


Figure 21: Regime of fluidized bed system

While gas velocity increases from the minimum fluidization velocity, the bed begins to extend and the particles are fluidized. As the gas flow rate during the fixed bed increases, the pressure drop is still raising until the superficial gas velocity reaches the critical minimum fluidization velocity, U_{mf}. At that velocity, gravitational forces are beat by the buoyant drag forces and they become suspended.

Over the U_{mf}, the pressure drop is constant and equals to the weight of solids per unit area as the drag forces on the particles barely overcome gravitational forces. At these velocities, the differential pressure is almost constant until the bed material begins to elutriate at the entrainment velocity, increasing the turbulent mixing.

Further than the entrainment velocity (or terminal velocity), particles are dragged out the vessel and they can be only maintained by collecting and recirculating or by adding additional solid particles. The entrainment velocity marks the transition from bubbling bed to a circulating bed.

The CFB mode of fluidization has a high slip velocity between the gas and solids that encourage high mass transfer rates enhancing the rates of oxidation (combustion) and desulfurization reactions while the intensive solid mixing guarantee the optimal mixing of fuel and combustion products with the air and flue gas emissions reduction reagents.

Basic principles of CFB boilers

In a CFB boiler, particles are transported and mixed in the furnace at a velocity greater than the average terminal velocity. Almost all the particles are captured by the solid separator and recirculated back, reason why the solid mixing and evens out combustion are intensified.

Two sections can be identified in a boiler: the first is the furnace, solid separator, recycle device and sometimes external heat exchanger surfaces while the second one, called back-pass, is the reheater, superheater, economizer, and air-preheater.

In the lower part of the furnace is injected coal and limestone (sorbent for SO_2 capture), being fluidized by the primary air (less than stoichiometric amount). Coal is heated above the ignition temperature by hot segregated particles for burning it. Limestone reacts with the sulfur in the coal, lowering the formation of SO_2 formation and emissions. With the injection of the secondary air, the combustion is completed.

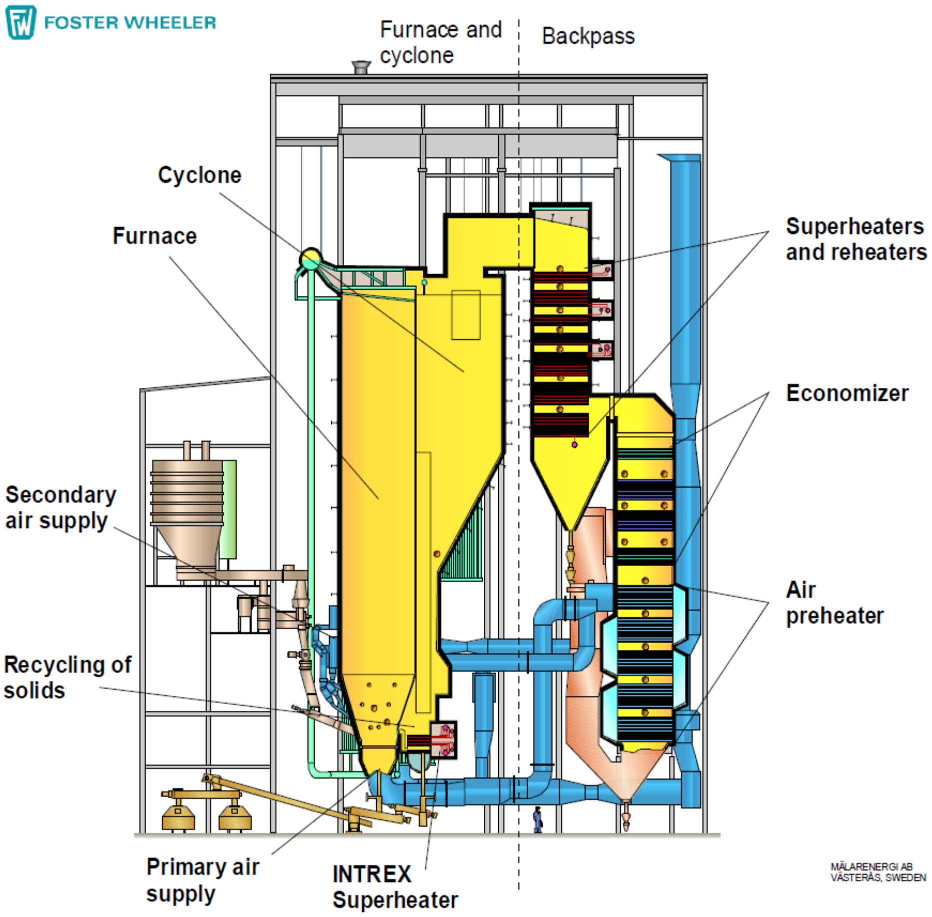


Figure 22: CFB boiler (157 MWth, 55.5/48 kg/s, 170/37 bar, 540/540 °C)

A uniform bed temperature in the range of 800-900ºC is ensured by the well mixed bed solids. Some of the particles return to the bed while others are captured in a gas-solid separator (e.g. cyclone) and recycled back to the furnace. The efficiency of the high solid collection is above 100 for particles bigger than 60microns of diameter. Bag-house filters or electrostatic precipitators are installed for the finer dust that is not firstly collected.

The solids are returned to the chamber via the loop seal. The positive pressure in the bottom of the furnace and the negative draft in the solids separator provide the pressure seal, which prevents flue gas from circuiting up the separator dipleg and collapsing the separator collection efficiency. It is just needed a high pressure fluidizing air into the loop seal to move back the solids to the bottom of the furnace.

Characteristics of CFB system

The fluid dynamic region in which CFB systems operate is between a Bubbling Fluidized Bed and a transport reactor (pulverized combustion). The bed level is not well defined and it is characterized by a high turbulence and solid mixing due to the high turbulence, reason why the solids are distributed throughout the furnace with a steadily decreasing density from the bottom to the top of the furnace.

The main characteristics of a CFB are the high fluidizing velocity (about 4,0-6,0 m/s), dense bed region in lower furnace without a distinct bed level, water-cooled membrane walls (evaporator), solids separator, aerated sealing device, and sometimes an in-furnace heat transfer surfaces.

There are important advantages of CFB boilers that have increased the use of these systems:

- Extensive fuel flexibility
- High combustion efficiency
- Efficient sulfur removal
- Low NO_x emission
- Compact structure
- Good turndown and load following capacity

Figure 23: CBF furnace and cyclone

Combustion in CFB boilers

Good combustion efficiency is the main research in CFB boilers since it impacts in operation cost. Besides, the time, temperature, and turbulence, the exceptional internal and external re-circulation of hot solids at combustion temperature offering a long residence time and good heat transfer. In addition to this, the efficient SO2 capture during the combustion is ensured by the high efficiency of combustion.

Usually, furnace in CFB operates between 800 and 900ºC because of low combustion temperature prevents sand and ashes from fusing. Furthermore, that temperatures ensure optimum sulfur capture reaction, alkali metals in coal cannot be vaporized and the formation of NO_x is reduced.

To avoid the NO_x formation, the distribution of air between primary and secondary air location must be determined. Primary air varies from 40-70% depending on the fuel with a remaining portion of the combustion air divided in the upper and lower secondary air levels.

Fuel Flexibility

One of the best advantages of CFB technology is the fuel flexibility. Combustible and fresh fuel represents less than 1-3% by weight of the hot solids in the furnace. The rest of the hot solids are divided into sorbents, sands and other inert such as fuel ash, all of them noncombustible. It provides an extremely stable combustion environment insensitive to variations in fuel quality.

Since CFB provides an exceptional gas-solid and solid-solid mixing, particles are rapidly heat and dispersed into the furnace, reason why it is possible to burn any fuel without auxiliary fuel support because its heating value is enough to elevate the combustion air and the fuel itself above its ignition temperature. The range of fuels that can be burned is wide including plant wastes, de-inking sludge, sewage waste, tire derived fuel, low ash fusion coals, petroleum coke and others in combination or alone.

It is necessary to absorb a certain portion of the generated heat to maintain the combustor temperature. It varies with the type of fuel. Some CFBs achieve this variation with an external heat exchanger. If not, the fluid dynamic condition must be controlled to alter the heat absorbed changing air split and/or excess air, flue gas recycle and bed inventory.

Combustion zones in a CFB boiler

From the combustion point of view, furnace can be divided into three zones:

- Lower zone: This part is fluidized by primary air. Also char particles, re-circulated by the separator are feed. It is denser than other zones and it serves as insulated storage of hot solids. Fuel is feed in the lower part of the furnace and is quickly and uniformly mixed with bed materials. Bed density decreases progressively with the height.
- Upper zone: Between lower and upper zone, secondary air is injected and it is in the upper zone where the oxygen amount is high and most of the combustion occurs. Char particles are transported upwards through the core and slide down the wall, mainly entrapped by falling clusters.

- Gas/solid separator: Here, the unburned char particles are captured and transported back to the bed.

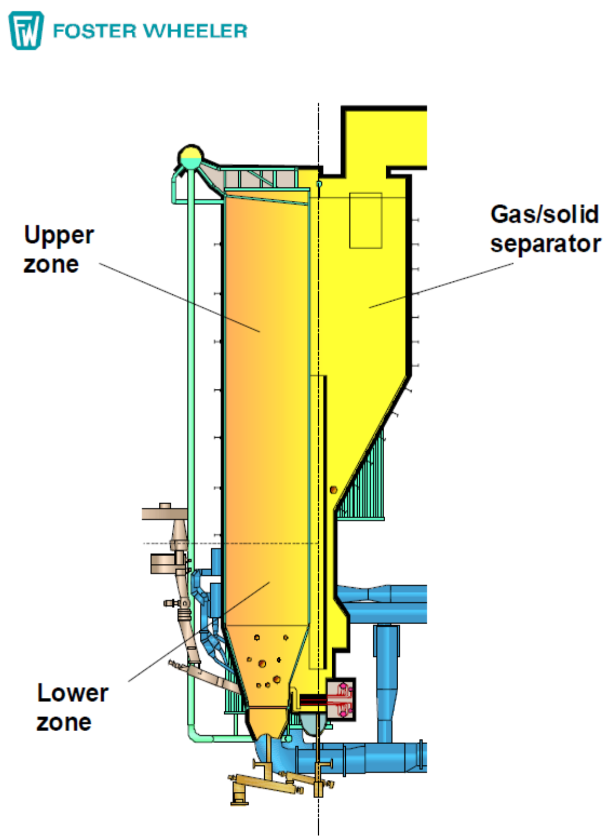


Figure 24: CBF furnace

Usually, it is possible to ensure the complete combustion because the residence time of particles is longer than the needed.

Heat transfer in a CFB boiler

The main purpose of a boiler is to convert energy, so the energy conversion efficiency is the most important consideration in the design. The most important heat transfer processes are:

- Gas to particle
- Bed to water walls
- Bed to the surfaces immersed in the furnace
- Bubbling bed to immersed surfaces in the external heat exchanger
- Circulating particles to particle separator/cyclone
- Gas to water and steam in the back pass

The main heat transfer mechanism is convective heat transfer, especially bed to water walls and the heat exchange in external heat exchanger. Above the bed, heat transfer rate decreased because of the decreasing of the temperature differences.

Bed to wall heat transfer

Particles flow upwards through the core and then flow downwards along the wall. Transfer heat from cluster and particle suspension to the walls is by conduction and radiation, where density is one of the most important parameters.

The relation of the heat transfer coefficient is proportional to the square root of the density but it is not affected by the fluidization velocity although it decreases with the height of the bed because of the temperature difference until it reaches an asymptotic value. It also increases with bed temperature, attributed to the higher radiation and thermal conductivity at high temperature. Furthermore, finer particles result in high coefficients when the heat transfer surface is short.

Bubbling bed to external heat surfaces

Variable load and enhances fuel flexibility is possible due to the external heat exchanger, supplementing the heat transfer with tubes immersed in the bed. The design depends on particle size, bed temperature and fluidizing velocity.

Load control in CFB boiler

Control of the heat absorption by water or steam can be achieved by several ways as:

- Controlling the solid flow through the external exchanger surfaces
- Dividing the bubbling bed into two sections, one with heat exchangers and another without
- Controlling bed density by adjusting the recirculation of solids from bubbling bed to the furnace
- Adjusting gas velocity in the lower section to change the density at the upper section of the bed

Emissions

SO2 emissions

One of the advantages in CFB boilers is the removing of SO2 from the flue gas, it is captured by sorbent. Usually is used limestone or dolomite, which after being calcined absorbs sulfur effectively. The reactions are:

- Limestone: $CaCO_3 \rightarrow CaO + CO_2$

$$CaO + CO_2 + \frac{1}{2}O_2 \rightarrow CaSO_4$$

- Dolomite: $CaO + MgO + SO_2 + \frac{1}{2}O_2 \rightarrow CaSO_4 + MgO$

Products of the reaction leave the combustor with fuel ash. The requirement of the sorbent is determined as Ca/S-mole ratio, which is the ratio between the molar flow of calcium in the limestone feed and the molar flow of sulfur absorption reaction. Calcination conditions are good in FBC and no inertization of limestone occurs. Usually, younger and amorphous limestone has a better reactivity to absorb SO_2.

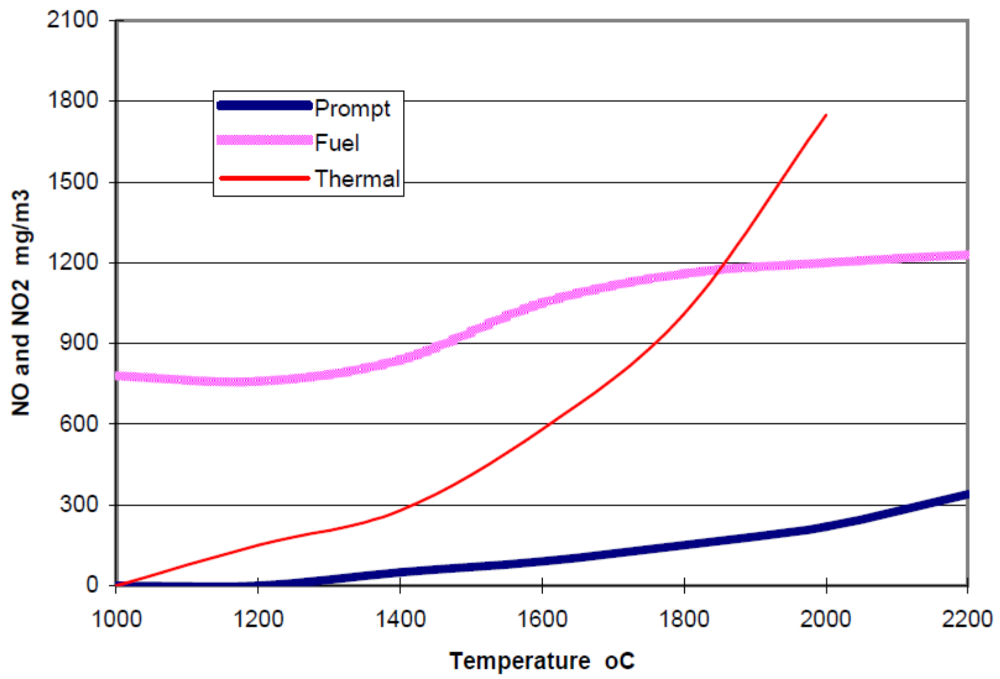


Figure 25: Temperature effect on NO_x formation

Crushing limestone in CFB combustion increases the surface area of the particles which improves the ability to capture sulfur and reduces sensitivity to the reaction. Thus, retention time in the combustor is affected by the particle size of a sorbent, besides friability of the collection efficiency and the collection efficiency of the solids separator must be consider in the efficient utilization of sorbent.

The consumption of the limestone is affected by the fuel quality resulting of the capability of the ash to absorb part of the sulfur. Fuel volatility has an influence on the distribution of sulfur in the chamber which involves the local concentrations of sorbent and SO_2.

Also, efficiency in sulfur capture is higher when the sulfur content of the fuel is high; otherwise it requires a greater surplus of unreacted limestone to accomplish the same sulfur reduction %. Furthermore, the optimal reaction temperature is 840-880ºC.

In practice, if O_2 content in flue gas drop below 2,5%, a negative effect in sulfur capture is observed due to the reaction of SO_2 with calcium oxide to calcium sulfate requires oxygen.

NOx emissions

One of the principal advantages of CFB boiler is its low NO_x emission level due to the much lower combustion temperature formed from fuel nitrogen with negligible amounts of thermal NO_x (less than 5%). The formation mechanism is very complex: in the initial fuel pyrolysis NH_3 and HCN are the precursors of NO_x emissions. Products are mostly NO and N_2O, just a few part of NO is oxidized to NO_2. Of these oxides, only NO and NO_2 are regulated. Small amounts of N_2O are created with combustion at 800-900ºC, increasing with the pressure, which is a greenhouse gas.

The best tactic for limiting NO_x formation is applying a staged combustion. Using the sub-stoichiometric firing at lower zone limits the NO_x generation, while the combustion efficiency is assured with the injection of secondary air at the higher furnace locations promoting high carbon burnout and CO and hydrocarbon conversion.

The staged combustion is the main way to design a CFB combustor. Above the primary air distributor are one, two or three levels air ports, depending of the design fuel. It allows more flexibility helping to obtain an optimal NO_x reduction while still ensuring high combustion and sulfur capture efficiencies. One of the contributors for the low formation is the high amount of CO generated in the lower bed.

Moreover, the flue gas recirculation is used to control combustion and steam temperature, which helps in the reduction of NO_x. In typical operating conditions, the NO_x ranging is 70-180ppm. Applying these methods, it is possible to maintain NO_x emissions below 120ppm. Also, injecting ammonia or urea into the solids separator is possible to reduce up to 40-65ppm.

Particle matter (PM) emission

An extremely low stack of PM emissions is possible using reverse-air baghouse filter, a pulse-jet baghouse filter or an electrostatic precipitator. Fugitive dust control elimination makes possible to use the exhaust as combustion air.

Carbon monoxide and hydrocarbons

Control of both carbon monoxide and hydrocarbons can be achieved with an efficient gas-solid mixing, sufficient combustion temperature and excess air. Unfortunately, these factors increase NO_x generation thus the level of both must be balanced against the NO_x emissions

Apendix H. PTC 4 - 2008 Fired Steam Generators calculations

	Parameter	W Flow Klbm/hr	T Temperature F	P Presure psig	H, Enthalpy Btu/lbm	Q, Absortion MKBtu/hr
1	FEEDWATER	526.49	1675.91	439.91	418.6	220.388714
2	SH SPARAY WATER: Ent 1 to Calc HB					
3	Ent SH-1 Attemp					
4	Lvg SH-1 Attemp					
5	SH-1 SPRAY FLOW					
6	Ent SH-2 Attemp					
7	Lvg SH-2 Attemp					
8	SH-2 SPRAY FLOW					
	INTERNAL EXTRACTION FLOWS					
9	Blowdown Flow /Drum Press					
10	Sat Steam Extraction					
11	Sootblowing Steam					
12	SH Steam Extraction 1					
13	SH Steam Extraction 2					
14	Atomizing Steam					
	AUXILIARY EXTRACTION FLOWS					
15	Aux Steam 1					
16	Aux Steam 2					
17						
18	MAIN STEAM	526.5	1005.0	1517.0	1492.2	785.633643
19	HIGH PRESS STEAM OUTPUT					565.244929
	REHEAT UNITS					
20	REHEAT OUTLET					
21	COLD REHEAT ENT ATTEMPERATOR					
22	RH SPRAY WATER					
23	COLD REHEAT EXTRACTION FLOW					
24	TURB SEAL FLOW & SHAFT LKG, % MS					
	FW HEATER NO. 1					
25	FW Entering: 1=FW+Spray					
26	FW Leaving					
27	Extraction Steam					
28	Drain					
29	FW HEATER NO.1 EXTR FLOW					
	FW HEATER NO. 2					
30	FW Entering					
31	FW Leaving					
32	Extraction Steam					
33	Drain					
34	FW HEATER NO2. EXTR FLOW					
35	COLD REHEAT FLOW					

36	REHEAT OUTPUT	0
37	TOTAL OUTPUT	565.244929

COMBUSTION CALCULATIONS, FORM CMBSTNa

1	HHV, Higher Heating Value of Fuel, Btu/lbm as fired					10936.71
4	Fuel Flow:	a) calculated	55.874	b) Measured		61.9
6	Fuel Efficiency, %(estimate initially)					**88.38**
8	Barometric Pressure, in Hg					29.50
9	Dry Bulb Temperature, F					83.2
10	Wet Bulb Temperature, F					0.0
11	Relative Humidity, %					38.0
15	Gas Temp Lvg AH, F Primary/Secondary or Main	15B	276.08	15A		280.70
16	Air Temp Ent AH, F Primary/Secondary or Main	16B	84.9	16A		85.7
17	O2 in Flue Gas Ent AH, % Primary/Secondary or Main	17B	3.9	17A		3.875
18	O2 in Flue Gas Lvg AH, % Primary/Secondary or Main	18B	5.5	18A		5.569
18C	O2 Measurement Basis Dry (0) or Wet (1)					0
18D	Primary AH Lkg to Gas for Trisector Air Heater, % of Total					0.00
20	Sorbent Rate, Klbm/hr					0.0

HOT AIR QUALITY CONTROL EQUIPMENT

26	O2 in FG Ent HAQC Equipment %	0.0
	O2 in FG Lvg HAQC Equipment same as entering AH´s, %	
	See Form EFFa for HAQC Flue Gas Temperatures	

COMBUSTION CALCULATIONS, FORM CMBSTNb

30		Fuel Ultimate Analysis, % Mass	
	A	Carbon	63.680
	B	Unburned Carbon in Ash (Calculated by program)	
	C	Sulfur	2.925
	D	Hydrogen	4.315
	E	Moisture	10.050
	F	Moisture (vapor for gaseous fuel)	0.000
	G	Nitrogen	1.235
	H	Oxygen	7.315
	I	Ash	10.48
	J	Volatile Matter, AF, Required for Enthalpy Coal	45.00
	K	Fixed Carbon, AF, Required for Enthalpy Fuel Oil	45.00
50		Flue Gas Temperature Entering Primary Air Heater	659.17
		Flue Gas Temperature Entering Secondary Air Heater	660.21
51		Combustion Air Temperatuer Leaving Primary Air Heater	511.70
		Combustion Air Temperatuer Leaving Secondary Air Heater	494.10

CORRECTED AH PERFORMANCE, INPUT SHEET

1	Air Temp Ent Fans, F Primary/Secondary	1B	0.0	1A	0.0
2	Air Temp Lvg Fans, F Primary/Secondary	2B	0.0	2A	0.0

UNBURNED CARBON & RESIDUE CALCULATIONS - FORM RES

5		Residue mass Flow	Klbm/hr	Split, %
	A	Bottom Ash Change Location	0.00	15.00
	B	Economizer Names as Applicable	0.00	10.00
	C	Fly Ash	0.00	75.00
	D		0.00	0.00
	E		0.00	0.00
6		Carbon in Residue, %		
	A	Bottom Ash		0.10
	B	Economizer		4.78
	C	Fly Ash		6.75
	D			
	E			
7		Carbon Dioxide in Residue, %		
	A	Bottom Ash		0.00
	B	Economizer		0.00
	C	Fly Ash		0.00
	D			
	E			
24		Temperature of Residue, F		
	A	Bottom Ash		2000.0
	B	Economizer		660.2
	C	Fly Ash		280.7
	D			
	E			

SORBENT CALCULATION SHEET

MEASURED C AND CO2 IN RESIDUE - FORM SRBa

7A		SO2 in Flue Gas, ppm	0
8		O2 in Flue Gas at Location Where SO2 is measured, %	3.00
9		SO2 & O2 Basis, Wet [19] or Dry [0]	0
20		Sorbent Products, % Mass	
	A	CaCO3	0.00
	B	Ca(OH)2	0.00
	C	MgCO3	0.00
	D	Mg(OH)2	0.00
	E	H2O	0.00
	F	Inert	0.00

SORBENT CALCULATION SHEET

MEASURED C AND CO2 IN RESIDUE - FORM SRBb

none

SORBENT CALCULATION SHEET

EFFICIENCY - FORM SRBc

61	Sorbent Temperature, F	0.0

EFFICIENCY CALCULATIONS DATA REQUIRED - FORM EFFa

4	Fuel Temperature, F				84.0
5	Gas Temperature Entering Hot Air Quality Control Equipment, F				0.0
6	Gas Temperature Leaving Hot Air Quality Control Equipment, F (Use Entering AH)				
31	Auxiliary Equipment Power, MKBtu/hr				0.0
32	Loss Due to Surface Radiation and Convection, % (use only if not area calculated)				0.0
	Surface Radiation & Convection Loss Location	**B**	**A**	**C**	
33A	Flat Projected Surface Area, 10^3 ft^2	0.0	0.0		50.0
33B	Average Velocity of Air Near Surfacem fb /sec	0.0	0.0		1.7
33C	Average Surface Temperature, F	0.0	0.0		127.0
33D	Average Ambient Temperature Near Surface, F	0.0	0.0		77.0

37A	Average Air Temperature Entering Pulverizers, F (Enter "0" for no Pulv and/or Temp Air)	350.6
38A	Average Pulverizer Tempering Air Temperature, F	84.9
40	Primary Air Flow (Entering Pulverizer), Klb/hr	103.0
	Estimated flue gas split, % primary - Not required for computer generated results	0.0

EFFICIENCY CALCULATIONS - FORM EFFb

none

EFFICIENCY CALCULATIONS - FORM EFFb

none

EFFICIENCY CALCULATIONS OTHER LOSSES AND CREDITS - FORM EFFc

	Losses, %	
85A	CO in Flue Gas	131mg/ m3N
85B	Formation of Nox	0.00
85C	Pulverizer Rejects	0.09
85D	Air Infiltration	0.00
85E	Unburned Hydrocarbons in Flue Gas	0.00
85G	Other	0.14
	Losses, MKBtu/hr	
86A	Wet Ash Pit	0.000
86B	Sensible Heat in Recycle Streams - Solid	0.000
86C	Sensible Heat in Recycle Streams - Gas	0.000
86D	Additional Moisture	0.000

86E	Cooling Water	0.000
86F	Air Preheat Coil (Supplied by units)	0.000
86G	Other	0.000
	Credits, %	
87A	Other	0.00
	Credits, MKBtu/hr	
88A	Heat in Additional Moistre (External to Envelope)	0.000
88B	Other	0.000

	Parameter		**W Flow Klbm/hr**	**T Temperature F**	**P Presure psig**
1	FEEDWATER		433.8	439.5	1676.6
2	SH SPARAY WATER: Ent 1 to Calc HB		0.0	312.5	2006.4
3	Ent SH-1 Attemp			0.0	0.2
4	Lvg SH-1 Attemp			0.0	
5	SH-1 SPRAY FLOW		26.431		
6	Ent SH-2 Attemp			0.0	0.5
7	Lvg SH-2 Attemp			0.0	
8	SH-2 SPRAY FLOW		0.0		
	INTERNAL EXTRACTION FLOWS				
9	Blowdown Flow /Drum Press		0.0		0.0
10	Sat Steam Extraction		0.0		
11	Sootblowing Steam		0.0	0.0	0.0
12	SH Steam Extraction 1	0	0.0	0.0	
13	SH Steam Extraction 2	0	0.0	0.0	
14	Atomizing Steam		0.0	0.0	0.0
	AUXILIARY EXTRACTION FLOWS				
15	Aux Steam 1		0.0	0.0	0.0
16	Aux Steam 2		0.0	0.0	0.0
17					
18	MAIN STEAM		0.0	1005.4	1517.2
	REHEAT UNITS				
20	REHEAT OUTLET			1001.7	365.0
21	COLD REHEAT ENT ATTEMPERATOR			651.5	369.0
22	RH SPRAY WATER		0	0.0	0.0
23	COLD REHEAT EXTRACTION FLOW		48		
24	TURB SEAL FLOW & SHAFT LKG, % MS		3.42		
	FW HEATER NO. 1				
25	FW Entering: 1=FW+Spray		0	344.5	1676.6
26	FW Leaving			439.5	
27	Extraction Steam			651.5	369.0
28	Drain			0.0	
	FW HEATER NO. 2				

30	FW Entering		0.0	
31	FW Leaving		0.0	
32	Extraction Steam		0.0	0.0
33	Drain		0.0	

Unburned Carbon and Residue Calculation

1	Ash in Fuel, %	10.475	**2**	HHV Fuel, Btu/lb "as fired"	10936.70
3	Fuel Mass Flow Rate, Klbm/hr	61.9			

		5		**6**	**7**	**8**		**9**	**10**
		Residue Mass Flow		**C**	**CO2**	**Residue Split %**		**C**	**CO2**
Location		**Input Klbm/hr**	**Calculated Klbm/hr**	**in Residue %**	**in Residue %**	**Input**	**Calculated**	**Wtd Ave %**	**Wtd Ave %**
A	Bottom Ash	0.00		0.10	0.00	15.00		0.015	0
B	Economizer	0.00		4.78	0.00	10.00		0.478	0
C	Fly Ash	0.00		6.75	0.00	75.00		5.0625	0
D									
E									
F	TOTAL	0	0	11.63	0	100		5.5555	0

UNITS WITHOUT SORBENT

11	Unburnd Carbon, lbm/100 lbm Fuel	0.616
20	Total Residue, Lbm/100 lbm Fuel	11.091

UNITS WITH SORBENT

11	Unburnd Carbon, lbm/100 lbm Fuel	0.616
20	Total Residue, Lbm/100 lbm Fuel	11.091

TOTAL RESIDUE

21	Total Residue, Klbm/hr	6.865
22	Total residue, lbm/10KBtu	0.101

23	SENSIBLE HEAT RESIDUE LOSS, %		H residue	
		Temperature		**Input**
A	Botom Ash	2000	515.610	0.078
B	Economizer	660.2	132.010	0.013
C	Fly Ash	280.7	39.922	0.030
D				
E				
TOTAL			**25**	0.122

	DATA REQUIRED				
1	HHV - Higher Heating Value of Fuel, Btu/lbm as fired				10936.7077
2	UBC - Unburned Carbon, lbm/100 lbm				0.61616995
3	Fuel Flow, Klbm/hr				61.9
4	a. Measured Fuel Flow				55.874
	b. Calculated Fuel Flow				61.9
5	Output, MKBtu/hr				565.244929
6	Fuel Efficiency, % (estimate initially)				88.38
7	Moisture in air, lbm/lbm Dry Air				0.010
8	Barometric Pressure, in Hg				29.50
9	Dry Bulb Temperature, F				83.2
10	Wet Bulb Temperature, F				0
11	Relative Humidity, %				38
	Additional Moisture (Measured)				
	Atomizing Steam				0
	Sootblowing Steam				0
	Other				
12	Summation Additional Moisture				0
13	Additional Moisture, lbm/100lbm Fuel				0
14	Additional Moisture, lbm/10 Kbtu				0
	If Air Heater (Excl Stm/Wtr Coll)				
15	Gas Temp Lvg AH, F	**15B**	276.08	**15A**	280.70
16	Air Temp Ent AH, F	**16B**	84.9	**16A**	85.70
17	O2 Entering Air Heater	**17B**	3.9	**17A**	3.88
18	O2 Leaving Air Heater	**18B**	5.5	**18A**	5.57
18C	Pri air to gas/Sec air to gas leakage split for Trisector Type AH			**18C**	0.00
18D	*Primary AH Leakage for Trisector Type AH, % of total*			*18D*	*0.00*
	Fuel Analysis, % Mass as fired - In col [30]				99.995
19	Mass Ash, lbm/10KBtu				0.09577837
	If mass of ash (item[19] exceeds 0,15 lbm/10KBtu or Sorbent				
	utilized, Enter Mass Fraction of Refuse in Col [79] for each location				
	SORBENT DATA (Enter 0 if Sorbent not Used)				
20	Sorbent Rate, Klbm/hr				0
21	CO2 from Sorbent, lbm/100lbm Sorb				0
22	H2O from Sorbent, lbm/100lbm Sorb				0
23	Sulfur Capture, lbm/lbm Sulfur				0
24	Spent Sorbent, lbm/100 lbm fuel				0
25	Sorb/Fuel Ratio, lbm Sorb/lbm Fuel				0
	HOT AIR QUALITY CONTROL EQUIPMENT DATA				
26	O2 in FG Ent HAQC equipment				0
	O2 in FG Lvg HAQC equipment same as entering AH's, %				0

COMBUSTION PRODUCTS

		Ultimate Analysis % Mass		Theo Air F lbm/100lbm Fuel		Dry Prod F Mol/100lbm Fuel		Wet Prod F Mol/100lbm Fuel		H2O Fuel lbm/10KB	
A	C	63.68									
B	UBC		0.61617								
C	Cb		63.06383	11.51	725.8647	12.001	5.254881				
D	S	2.925		4.31	12.60675	32.065	0.091221				
E	H2	4.315		34.29	147.9614			2.0159	2.140483	8.937	0.352603
F	H2O	10.05						18.0153	0.557859	1	0.091892
G	H2Ov	0						18.0153	0	1	0
H	N2	1.235				28.0134	0.044086				
I	O2	7.315		-4.32	-31.6008						
J	ASH	10.475									
K	VM	45									
L	FC	45									
M	TOTAL	**30**	99.995	**31**	854.832	**32**	5.390188	**33**	2.698342	**34**	0.444495

35	Total Theo Air Fuel check, lb/10KB	7.88102

CORRECTIONS FOR SORBENT REACTIONS AND SULFUR CAPTURE

40	CO2 from Sor	lb/100lb fuel	0
41	H2O from Sor	lb/100lb fuel	0
42	SO2 Reduction	Mol/100lb fuel	0
43	Dry Prod Com	Mol/100lb fuel	5.390188
44	Wet Prod Co	Mol/100lb fuel	8.088531
46	Theo Air Corr,	lb/100lb fuel	854.832
47	Theo Air Corr,	Mol/100lb fuel	29.5534
48	Theo Air Corr,	lb/10KBtu	7.816173
49	Wet Gas from Fuel	lb/10KBtu	0.81294

	LOCATION	**HAQC in**	**Sec AH in**	**Sec AH out**	**Pri AH in**	**Pri AH out**
50	Flue Gas Temperature Entering Air Heater, F		660.21		659.17	
51	Air Temperature Leaving Air Heater, F			494.1		511.7
52	Flue Gas Oxygen Content, %		3.9	5.5	3.88	5.57

	FLUE GAS ANALYSIS, Mol/100lb Fuel				Dry	Wet
53	Moisture in Air				0	0.006489
54	Dry/Wet Products Comb				0	8.088531
55	Additional Moisture					0
56						23.55372
57	Summation					31.64225
58			17.02469	15.41431	17.04986	15.34487
60	Excess Air, %	*0*	24.52705	38.20309	24.33386	38.85743

	LOCATION			*HAQC in*	**Sec AH in**	**Sec AH out**	**Pri AH in**	**Pri AH out**
60	Excess Air, %			*0*	24.52705	38.20309	24.33386	38.85743
	O2, CO2, SO2, WHEN EXCESS AIR KNOWN							
61								
62	Dry				30.61053	34.65227	30.55344	34.84565
63	Wet				0	0	0	0
64	Dry Gas, Mol/100lb Fuel				36.00072	40.04246	35.94363	40.23584
65	Wet Gas, Mol/100lb Fuel				0	0	0	0
		Dry	**Wet**					
66	O2, %	[64]	[65]		3.9	5.5	3.875	5.569
67	CO2, %	[64]	[65]		14.58566	13.11344	14.60883	13.05041
68	SO2, %	[64]	[65]		2533.944	2278.177	2537.969	2267.228
	FLUE GAS PRODUCTS, lbm/10KBtu							
69	Dry Air				9.733249	10.80219	9.718149	10.85334
70	Wet Gas from Fuel				0.81294	0.81294	0.81294	0.81294
71	CO2 from Sorbent				0	0	0	0
72	Moisture in Air				0.101553	0.112706	0.101395	0.11324
73	Water from Sorbent				0	0	0	0
74	Additional Moisture				0	0	0	0
75	Total Wet Gas				10.64774	11.72784	10.63248	11.77952
76	H2O in Wet Gas				0.546048	0.557201	0.545891	0.557735
77	Dry Gas				10.10169	11.17064	10.08659	11.22178
78	H2O in Wet Gas, % Mass				5.128301	4.751099	5.134179	4.734786
79	Residue, lb/lb Total Refuse at each location				0	0	0	0
80	Residue, lb/10KBtu							0.101412

81	Residue in Wet Gs, lb/lb Wet Gas			0	0	0	0
82	Leakage, % Gas Entering				10.1439		10.788
	GAS TEMPERATURE CORRECTION FOR AH LAKAGE						
83	Gas Temp Lvg (INCL LKG), F				280.70		276.08
84	Air Temp Ent, F			85.7		84.9	
85	H Air Lvg, Btu/lbm				49.11992		47.9994
86	H Air Ent, Btu/lbm			2.089761		1.897587	
87	Cpg, Btu/lbm F				0.2543		0.2541
88	Corrected AH Gas Outlet Temperature			299.4601		295.6529	
	AIR, GAS, FUEL & RESIDUE MASS FLOW RATES, Klbm/hr						
90	Input from Fuel from Efficiency Form, Million Btu/hr						499.5635
91	Fuel Rate, Klb/hr						45.67768
92	Residue Rate, Klb/hr						5.066189
93	Wet Flue Gas, Klb/hr			531.9223	585.8799	531.1601	588.4616
94	Wet Flue Gas, Klb/hr	Entering Air Heaters		531.9223	Leaving Air Heaters		585.8799
95	Excess Air Lvg Blr, %	Entering HAQC Equip		0	Entering Air Heaters		24.52705
96	Total Air to Blr, Klbm/hr			394.5414			491.3108

Efficiency Calculations Data Required

	TEMPERATURE, F					
1	Reference Temperature	77	1A	Enthalpy Water (32F Ref)	45.00	Btu/lbm
2	Average Entering Air Temp	85.6	2A	Enthalpy Dry Air	2.07	Btu/lbm
	from CMBSTNa [16] or EFFa [44]		2B	Enthalpy Water Vapor	3.81	Btu/lbm
3	Average Exit Gas T(Excl Lkg)	298.6	3A	Enthalpy Dry Gas	53.47	Btu/lbm
	from CMBSTNA [15] r EFFa [51]		3B	Enthalpy Steam @1 PSIA	1194.99	Btu/lbm
			3C	EnthalpyWater Vapor	99.90	Btu/lbm
4	Fuel Temperature	84.0	4A	Enthalpy Fuel	2.68	Btu/lbm
	HOT AIR QUALITY CONTROL EQUIPMENT					
5	Entering Gas Temperature	0.0	5A	Enthalpy Wet Gas	0.00	Btu/lbm
6	Leaving Gas Temperaure	0.0	6A	Enthalpy of Wet Gas	0.00	Btu/lbm
			6B	Enthalpy Of Wet Air	0.00	Btu/lbm
			6C	Enthalpy of Wet Air @ T=[3]	0.00	Btu/lbm

RESULTS FROM COMBUSTION CALCULATION FORM CBSTN

10	Dry Gas Weigh	[77]	10.10169	18	Unbuned Carbon, % [2]	0.616	
11	Dy Air Weight	[69]	9.733	19	LHV Btu/lbm 'as fired' [1]	10936.71	
12	Water from H2 Fuel	[34E]	0.337		**HOT AQC EQUIPMENT**		
13	Water from H2O fuel	[34F]	0.088	20	Wet Gas Entering [75E]	0.00	
14	Water from H2Ov fuel	[34G]	0.000	21	H2O in Wet Gas, % [78E]	0.00	
15	Moisture in Air lb/lb DA	[7]	0.010	22	Wet Gas Leaving [75L]	0.00	
16	Moisture in Air lb/10KB	[72]	0.102	23	Residue in Wet Gas, % [81E]	0.00	
17	Fuel Rate Est. Klb/hr	[3]	61.90				
				25	Excess Air, % [95]	22.1	
	Miscellaneous						
30	Unit Output, MKBtu/hr		565.2449	31	Aux Equip Power, MKBtu/hr	0.0	
32	Loss Due to Surface Radiation and Convection, %		0.00				
33A	Flat Projected Surface Area, ft^2	0/0/	50	33C	Average Surface Temperature, F	0/0/	127
33B	Average Velocity r Air Near Surface, ft/sec	0/0/	1.7	33D	Average Ambient Temperature Near Surface, F	0/0/	77

ENT AIR TEMP (Units with primary and secondary air flow) Item No's CMBSTN

35A	Pri AirTemp Entering, F CMBSTNa [16B]	84.9	35B	Enthalpy Wet Air, Btu/lb	1.91	Btu/lbm
36A	Pri AirTemp Leaving Air Htr, F CMBSTNA [51]	511.7	36B	Enthalpy Wet Air, Btu/lb	106.72	Btu/lbm
37A	Average Air Temp Entering Pulverizers, F	350.6	37B	Enthalpy Wet Air, Btu/lbm	66.73	Btu/lbm
38A	Average Pulverizer Tempering Air Temp, F	84.9	38B	Enthalpy Wet Air, Btu/lbm	1.91	Btu/lbm
39	SecAir Temp Entering, F CMBSTNa [16A]	85.7	40	Primry Airflow (Ent Pulv), Klb/hr	103.00	
41	Pulverizer Tempering Airflow, Klb/hr	39.3				
42	Total Airflow, Klb/hr from Form CMBSTNc [96]	588.6	43	Secondary AirFlow, Klb/hr	485.6	
44	Average Enering Air Temperature, F	85.6				

GAS FLOW ENT PRI AH AND AVG EXIT GAS TEMP (Units with primary and secondary AH's)

45A	Flue Gas Temp Ent Pri AH, F CMBSTNb [50]		659.2	45B	Enthalpy Wet Flue Gas, Btu/lbm	144.9139
46A	Flue Gas Temp Lvg Pri AH, F CMBSTNc [88]		293.2	46B	Enthalpy Wet Flue Gas, Btu/lbm	51.93456
47	Flue Gas Temp Lvg Sec AH, F CMBSTNc [88]		299.3	48	Total Gas Ent Air Htrs, Klb/hr CMBSTNc [93]	531.9
49	Flue Gas Flow Ent Pri Air Htr, Klb/hr		70.0			
50	Flue Gas Flow Ent Sec Air Htr, Klb/hr		568.3			
51	Average Exit Gas Temperature, F		358.4			
	Iteration of flue gas split, % primary AH gas flow	Inicial estimate	10.9		Calculated	11

Efficiency Calculations

	LOSSES, % Enter Calculated Result in % Column [B]	**A | MK**	**B | %**
60	Dry Gas		5.653
61	Water from H2 Fuel		0.352

62	Water from H2O Fuel		0.092
63	Water from H2Ov Fuel		0.000
64	Moisture in Air		0.106
65	Unburned Carbon in Ref		0.855
66	Sensible Heat of refuse from Form RES		0.128
67	Hot AQC Equip		0.000
68	Other Losses, % Basis from Form EFFc Item [110]		0.055
69	Summation of Losses, %		7.241
	LOSSES, MKBtu/hr Enter in MKB Column [A]		
75	Surface Radiation and Convection from Form EFFa Item [32]	4.250	0.779
76	Sorbent Calcination/Dehydratation from Form SRBc Item [77]	0.000	0
77	Water from Sorben from Form SRBc Item [65]	0.000	0
80	Other Losses, MKBtu/hr Basis from Form EFFc Item [111]	0.000	0.000
81	Summation of Losses, MKBtu/hr Basis	4.250	0.779
	CREDITS, % Enter Calculation Result in % Column [B]		
85	Entering Dry Air		0.210
86	Moisture in Air		0.004
87	Sensible Heat in Fuel		0.026
88	Sulfation from Form SRBc Item [80]		0.000
89	Other Credits, % Basis from Form EFFc Item [112]		0.000
90	Summation of credits, %		0.240
91	Credit from air heated in AH	38.148	6.749
92	Summation of all credits, %	39.506	6.989
	CREDITS, MKBtu/hr Enter Calculated Result in MKB Column [A]		
95	Auxiliary Equipment Power [31]	0.000	0.000
96	Sensible Heat from Sorbent -from Form SRBc Item [85]	0.000	0.000
97	Other Credits, MKBtu/hr Basis -from Form EFFc Item [113]	0.000	0.000
98	Summation of Creditsm MKBtu/hr	0.000	0.000
100	Fuel Eff, %		99.004
101	Input from Fuel, MKB	570.933	
102	Fuel Rate, Llbm/hr		52.203
104	Efficiency LHV, %		**91.980**
105	RHV	1.047	

EFFICIENCY CALCULATIONS OTHER LOSSES AND CREDITS

	T or E	LOSSES, % Enter Calculated Result in %	A | MK	B | %
110A		CO in Flue Gas		0.052
110B		Formation of Nox		0.000
110C		Pulverizer Rejects		0.000
110D		Air Infiltration		0.000
110E		Unburned Hydrocarbons in Flue Gas		0.000
110F		Other		0.000
110G				
110		Summation of Other Losses, % Basis		0.052
		LOSSES		
111A		Wet Ash Pit	0.000	
111B		Sensible Heat in Recycle Streams, Solid	0.000	
111C		Sensible Heat in Recycle Streams, Gas	0.000	
111D		Additional Moisture	0.000	
111E		Cooling Water	0.000	
111F		Air Preheater Coil (Supplier by unit)	0.000	
111G		Other	0.000	
111		Summation of Other Losses, MKBtu/hr Basis	0.000	
		CREDITS, % Enter Calculation Result in %		
112A		Other		0.000
112		Summation of Credtis, % Basis		0.000
		CREDITS, MKBtu/hr Enter Result in MKB		
113A		Heat in Additional Moisture (External to envelope)	0.000	
113B		Other	0.000	
113		Summation of Credits, MKBtu/hr Basis	0.000	

Apendix I. EN 12952-15 Water-tube boilers and auxiliary installations - Part 15: Acceptance tests calculations

1.	**Fuel**								
1.1	- LHV, dry (25°C)	=	25.57	MJ/kg BD					
	- LHV, as fired	=	22.75	MJ/kg as fired					
	- HHV, dry (25°C)	=	26.63	MJ/kg BD					
	- HHV, as fired	=	23.95	MJ/kg as fired					
1.2	- moisture	=	10.05	%					
1.3	- amount								
	Fuel	=	571.20	TBD/d					
	mass fow	=	7.3	kg/s as fired					
	LHV	=	25.57	MJ/kg BD					
1.4	- analysis of dry solids (weight)								
	C	=	70.78	%					
	H	=	4.79	%					
	N	=	1.37	%					
	S	=	3.25	%					
	Ash	=	11.64	%					
	O	=	8.17	%					
	Total	=	100	%					
			SLAG			ECON. SLAG		DUST	
	Ash flow	=	9.50	t/d		6.34	t/d	47.51	
	Ash flow	=	16.637	g/kg BD		11.091	g/kg BD	83.183	
	C in ash	=	0.1	%		4.8	%	6.75	
	Temperature	=	1093.0	ºC		349.0	ºC	138.10	
	Ash %	%	0.15			0.1		0.75	
1.5	- impurities in ash (weight of dry fuel)								
	Cl	=	0.02	%					
	Na	=	0.01	%					
	K	=	0.15	%					
	Ca	=	0.29	%					
2.	**Main Steam**								
	- pressure	=	104.60	bar(a)					
	- temperature	=	540.67	°C					
3.	**Feed Water**								
	- pressure	=	115.55	bar(a)					
	- temperature	=	226.28	°C					
4.	**Blowdown**								
	- mass flow	=	0.00	kg/s					
	- pressure	=	103.60	bar(a)					
5.	**Combustion Air**								
	- ambient air temperature	=	28.44	°C					
	- water in air	=	10.00	g/kg da					
	- excess air	=	24.52	%					
	- infiltration air	=	0.00	%					
	- primary air percentage	=	17.50	%					
	- primary air temperature	=	177.00	°C					
	- Secondary air percentage	=	82.50	%					

	- Secondary air temperature	=	177.00	°C	
	- total air percentage	=	100.00	%	
	- total air temperature	=	177.00	°C	
5.	**Emission (6% O_2,dry)**				
	- Dust after ESP	=	30	mg/m^3n	
	-NO_x as NO_2	=	131	mg/m^3n	
	-SO_x as SO_2	=	75	mg/m^3n	25.63 ppm
	-CO	=	131	mg/m^3n	
7	**Sootblowing**	=	1	(Outside=0, Inside=1)	
	- pressure	=	20	bar(a)	
	- temperature	=	330	°C	
	- mass flow	=	0	kg/s	
	- mass flow	=	0.00000	kg/kg BD	
8	**Direct Desulfurization, if needed**				
	CaO used	=	0	kg/d	
	$CaCO_3$ used	=	0.00	kg/d	
		=	0.0000	g $CaCO_3$/kgBD	
		=	0.0000	mol $CaCO_3$/kgBD	
8.1	Calcination				
	- stoich $CaCO_3$	=	101.4629	g/kgBD	
	- CO_2 produced	=	0.0000	mol/kgBD	
			0.0000	g/kgBD	
8.2	Sulfation				
	- CaO	=	0.0000	g/kgBD	
	- O_2 required	=	0.0000	mol/kgBD	
	- SO_2 reacted	=	0.0000	g SO_2/kgBD	
		=	0.0000	mol SO_2/kgBD	
	- $CaSO_4$ produced	=	0.0000	g $CaSO_4$/kgBD	
	Lime ratio	=	0.0000	Ca/S	
	Desulfurizaton efficiency	=	0.00	%	

BALANCE CALCULATIONS

Dry solid amount	=	571.20	TBD/d
DS content as fired	=	89.95	%

g/kg BD	H_2O	C-BTM. SLAG	C-ECON. SLAG	C-DUST	H_2	O_2	N_2	S

As fired	g/kgBD	1111.729	111.729	707.800	707.800	707.800	47.900	81.700	13.700	32.500
	Molar weight		18.0152	12.0110	12.0110	12.0110	2.0158	31.9988	28.0134	32.0600
			mol/kgBD	mol/kgBD	mol/kgBD	mol/kgBD	mol/kgBD	mol/kgBD	mol/kgBD	mol/kgBD
Biomass fuel		1111.7	6.202	8.839	5.893	44.197	23.762	2.553	0.489	1.014
Recycle ash		0.0	-	0.000	0.000	0.000	-	0.000	-	0.000
Biomass to boiler		**1111.7**	**6.202**	**8.839**	**5.893**	**44.197**	**23.762**	**2.553**	**0.489**	**1.014**
Steam to preheater		0.0	0.000	-	-	-	-	-	-	-
As fired		**1111.7**	**6.202**	**8.839**	**5.893**	**44.197**	**23.762**	**2.553**	**0.489**	**1.014**
Recycle ash		0.0	-	0.000	0.000	0.000	-	0.000	-	0.000
Chem. loss to stack		0.0	-	0.000	0.000	0.000	-	0.000	-	0.000
To ash and flue gas		**1111.7**	**6.2**	**8.8**	**5.9**	**44.2**	**23.8**	**2.6**	**0.5**	**1.0**
Other		0.0	-	-	-	-	-	-	-	-
Total to ash			0.000	0.001	0.044	0.467	0.000	0.000	0.000	0.000
Total to flue gas		**1111.7**	**6.202**	**8.838**	**5.849**	**43.730**	**23.762**	**2.553**	**0.489**	**1.014**
Temperature average	ºC			1093.000	349.000	138.100				
Specific heat	kJ/kgk			1.260	1.260	0.840				

STOICHIOMETRIC AIR, DRY FLUE GAS AND WATER VAPOUR / kgBD

Air				Dry Gas				Water vapour			
	mol	m3n	g		mol	m3n	g		mol	m3n	g
C	58.929	-	-	CO_2	58.929	1.312	2593.467	H_2O	6.202	0.139	111.729
S	1.014	-	-	SO_2	1.014	0.022	64.938		-	-	-
H_2	23.762	-	-	-	-	-	-	H_2	23.762	0.532	428.082
O_2-required	71.824	-	-	-	-	-	-				
O_2 in BD	2.553	-	-	-	-	-	-				
O_2 from air	69.271	1.551	2216.588	O_2	0.000	0.000	0.000				
N_2 in BD	0.489	0.011	13.700	-	-	-	-				
N_2 from air	259.970	5.824	7282.637	N_2	260.459	5.835	7296.337				
CO_2 from air	0.099	0.002	4.366	CO_2	0.099	0.002	4.366	Scrubber	0.000	0.000	0.000
H_2O from air	5.275	0.118	95.036					From air	5.275	0.118	95.036
				lime CO_2	0.000	0.000	0.000				
Stoichiom. wet air	**334.615**	**7.496**	**9598.625**	**Dry flue gas**	**320.501**	**7.172**	**9959.107**	**H2O in FG**	**35.240**	**0.790**	**634.847**

SO2 before desulf	2470.900403	after:	2470.9004

EXCESS AIR, TOTAL FLUE GAS AND SOOTBLOWING STEAM AMOUNTS / kgBD

Excess air	%	24.52	O_2,dry	O_2,wet	3.882

0.200306
0.049032

Air	mol	m3n	g
excess O_2	16.985	0.380	543.507
excess N_2	63.745	1.428	1785.677
excess CO_2	0.024	0.001	1.070
excess H_2O	1.293	0.029	23.303
Excess wet air	82.048	1.838	2353.557
Stoich.wet air	334.615	7.496	9598.625
Total wet air	**416.663**	**9.334**	**11952.183**
H_2O in stoich. air	5.275	0.118	95.036
H_2O in excess air	1.293	0.029	23.303
Total water in air	**6.569**	**0.147**	**118.338**
Total dry air	**410.094**	**9.187**	**11833.844**
		m^3n/s	kg/s
Mass flow (wet)		**61.707**	**79.018**
Mass flow (dry)		**60.734**	**78.235**

Flue gas	mol	m3n	g	
Theor.dry FG	320.501	7.172	9959.107	
excess dry air	80.754	1.809	2330.255	
Dry flue gas	401.255	8.981	12289.362	
H_2O comb	29.964	0.671	539.811	
H_2O air	6.569	0.147	118.338	
H_2O sum	**36.533**	**0.819**	**658.149**	
	437.788	9.799	12947.511	(w/o sootblowing steam)
Sootbl.s.	0.000	0.000	0.000	0.084
	437.788	9.799	12947.511	(with sootblowing steam)
Scrubber	0.000	0.000	0.000	
Wet FG	**437.788**	**9.799**	**12947.511**	
		m^3n/s	kg/s	
Mass flow (wet)		**64.785**	**85.598**	
Mass flow (dry)		**59.373**	**81.247**	

	Theoretical dry FG		Theoretical wet FG		Dry FG		Wetl FG no sootb.		Wet FG	
Composition of FG	mol	vol	mol	vol	mol	vol	mol	vol	mol	vol
CO_2	18.42	18.32	16.59	16.51	14.72	14.64	13.49	13.42	13.49	13.42
H_2O	0.00	0.00	9.91	9.92	0.00	0.00	8.34	8.35	8.34	8.35
SO_2	0.31629	0.30942	0.28080	0.27465	0.25264	0.24709	0.23156	0.22645	0.23156	0.22645
N_2	81.27	81.37	73.22	73.30	80.83	80.91	74.08	74.15	74.08	74.15
O_2	0.00	0.00	0.00	0.00	4.23	4.24	3.88	3.88	3.88	3.88
TOTAL	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**	**100.0**

T_{ref}	=	25	°C
$\eta_{(N)\ LHV}$	=	**92.32**	%

Enthalpies				P (bar a)	T (°C)
Steam	=	3471.93	kJ/kg	104.60	540.67
Feedwater	=	975.09	kJ/kg	115.55	226.28
Blowdown	=	1423.53	kJ/kg	103.60	
Sootblowing steam	=	3093.84	kJ/kg	20	330
Steam at fg out temp	=	2782.26	kJ/kg	0.21	150
Steam at air in temp		119.23	kJ/kg	1.000	28.44
Fwah ent diff	=	0.00	kJ/kg		

Wet flue gases			
Temperature	=	148	°C
Enthalpy	=	127.97	kJ/kg

Combustion air				EN 12952	
Ambient air enthalpy	=	36.941	kJ/m^{3}n	4.466	kJ/m^{3}n
Heated air enthalpy	=	231.225	kJ/m^{3}n	197.316	kJ/m^{3}n
Reference enthalpy	=	32.4712208	kJ/m^{3}n		

Steam production	=	10.0337	kg/kg BD	66.334	kg/s
Sootblowing steam	=	0.0000	kg/kg BD	0.000	kg/s
Continuous blowdown	=	0.0000	kg/kg BD	0.000	kg/s
Feed water flow	=	10.0337	kg/kg BD	66.334	kg/s

Boiler capacity	=	165.63	MW_t	1.116727273
CO_2 production rate	=	373.31	kg/MWh	

TOTAL OUTPUT

manufacturers margin	=	0.000	kJ/kg BD	0.000	% of heat input
radiation/convection losses	=	170.108	kJ/kg BD	0.627	% of heat input
loss due to unburnt CO	=	14.213	kJ/kg BD	0.052	% of heat input
flue gas losses	=	1656.943	kJ/kg BD	6.106	% of heat input
loss due to bottom slag	=	24.595	kJ/kg BD	0.091	% of heat input
loss due to econ slag	=	22.504	kJ/kg BD	0.083	% of heat input
loss due to dust,	=	195.416	kJ/kg BD	0.720	% of heat input
correction of HV to ref. T	=	0.000	kJ/kg BD	0.000	% of heat input
loss due to calcination	=	0.000	kJ/kg BD	0.000	% of heat input
credit due to sulfation	=	0.000	kJ/kg BD	0.000	% of heat input
TOTAL LOSSES	=	2083.778	kJ/kg BD	7.679	% of heat input

fwah	=		kJ/kg BD
Sootblowing steam	=	0.000	kJ/kg BD
Continuous blowdown	=	0.000	kJ/kg BD
Steam production	=	34836.14	kJ/kg BD

Total Output	**=**	**36919.92**	**kJ/kg BD**

TOTAL INPUT

fuel LHV, 25C	=	25568.57	kJ/kg BD		
water in fuel	=	-260.89	kJ/kg BD	-0.707	
unheated dry air	=	41.024	kJ/kg BD		
heated dry air	=	1771.643	kJ/kg BD		
infiltration dry air	=	0.000	kJ/kg BD		
moisture in air	=	14.110	kJ/kg BD		
Sensible heat coal	=	1.7000	kJ/kg BD	0	W
TOTAL HEAT INPUT	=	27136.16	kJ/kg BD		
NET HEAT TO STEAM	=	25052.38	kJ/kg BD		
Feedwater	=	9783.7647	kJ/kg BD		
Total Input	**=**	**36919.92**	**kJ/kg BD**		

prEN 12952-15:1999

Combustion air/flue gas mass to fuel mass ratios, based on Ultimate Analysis for solid fuels

μ_{Aod}	=	5.7960	kg/kg BW	6.4436	kg/kg BD	dry combustion air mass to fuel mass ratio	
μ_{God}	=	6.1740	kg/kg BW	6.8638	kg/kg BD	mass of dry flue gas to fuel mass ratio	
V_{God}	=	4.4154	m^3/kg BW	4.9087	m^3/kg BD	flue gas volume (STP condition)	
μ_{CO2o}	=	1.7168	kg/kg BW	1.9086	kg/kg BD	carbon dioxide content	
μ_{H2OF}	=	0.6078	kg/kg BW	0.6757	kg/kg BD	water coming from fuel (water stored and produced by combustion) to fuel mass ratio	
μ_{AS}	=		kg/kg	atomizing steam content			
x_{H2OAd}	=		kg/kg	moisture content of flue gas			
y_{CO2Ad}	=	0.00033	m^3/m^3	carbon dioxide content of dry air			see prEN 12952-15:1999
y_{O2Ad}	=	0.20938	m^3/m^3	oxygen content of dry air			see prEN 12952-15:1999
ρ_{nCO2}	=	1.977	kg/m^3	standart density of carbon dioxide			see prEN 12952-15:1999
ρ_{nAd}	=	1.293	kg/m^3	standart density of dry air			see prEN 12952-15:1999

x_{CO2Ad}	=	0.000505	kg/kg	carbon dioxide content of dry air	see prEN 12952-15:1999

		dry basis			wet basis
γ_C	=	0.52000	kg/kg	carbon content	0.46774
γ_H	=	0.06310	kg/kg	hydrogen content	0.05676
γ_S	=	0.00010	kg/kg	sulfur content	0.00009
γ_O	=	0.39510	kg/kg	oxygen content	0.35539
γ_N	=	0.00580	kg/kg	nitrogen content	0.00522
γ_{H2O}	=	0.00000	kg/kg	water content	0.10050
γ_{ash}	=	0.01410	kg/kg	ash content	0.01268
$\Sigma\gamma_i$	=	1.00			1.00

V_{CO2o}	=	0.9654	m^3CO_2/kg BD	carbon dioxide volume
$\hat{y}_{CO2d}$	=	0.1967	m^3CO_2/m^3fg	

Flue gas losses

$Q_{(N)G} = m_F[\mu_{Gd}*c_{pGd}*(t_G-t_r) + \mu_{H2O}*c_{pST}*(t_G-t_r)]$

$c_{pG0} = c_{pAd0} + P_{1m}*x_{H2O} + P_{2m}*x_{CO2}$

$c_{pA0} = c_{pAd0} + P_{1m}*x_{H2OA}$

m_F	=	571203.2373	kg BD/d	
μ_{Gd}	=	12.289	kg/kg BD	flue gas content (with excess air)
t_G	=	148	°C	flue gas temperature
t_r	=	25	°C	reference temperature
μ_{H2O}	=	0.6581	kg/kg BD	mass of water in flue gas to fuel mass ratio
c_{pGd0}	=	0.995098405	kJ/(kg K)	integral specific heat between t_G and t_r, of dry flue gas
c_{pAd0}	=	1.005098982	kJ/(kg K)	integral specific heat of dry air between t_G and t_r
c_{pST}	=	1.9	kJ/(kg K)	integral specific heat of steam between t_G and t_r
$Q_{(N)G}$	=	10971.033	kJ/s	

P_{1m}	=	0.873661	
P_{2m}	=	-0.04984	
c_{pAd0}	=	1.005099	kJ/(kg K)
c_{pG0}	=	1.039508	kJ/(kg K)
c_{pA0}	=	1.013749	
c_{pGd0}	=	0.995098	
x_{H2Of}	=	0.050832	kg/kg fg
x_{CO2}	=	0.200643	kg/kg fg
x_{H2Oa}	=	0.009901	kg/kg air

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Losses due to unburned CO

R_{CO}	=	0.2964	kJ/(kg K)	gas constant of CO	
R	=	0.27226	kJ/(kg K)	gas constant of dry flue gases	$Q_{CO} = V_{Gd} * y_{COd} * H_{COn}$
V_{Gd}	=	9.187	m^3/kg BD	dry flue gas volume	
y_{COd}	=	0.000122498	m^3/m^3	CO content by volume of dry flue gas	
? H_{COn}	=	12.63	MJ/m^3	CV per m3 of carbon monoxide, related to standard conditions	
Q_{CO}	=	14.2130	kJ/kg BD		

Losses due to enthalpy and unburned combustibles in slag and flue dust

Direct desulfuristaion, if needed

m_K	=	0	kg/d	mass of additive	1.575621322
m_{fo}	=	571203.2373	kg BD/d	fuel mass flow	
n_{Ca}	=	0.000	Ca/S	lime ratio	measured SO2 is needed
ySO_2	=	15	ppm	measured SO2	
ySO_2	=	0.000015	m^3/m^3	measured SO2	
η_S	=	0.9998	%	desulf. Eff	

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