EMISSION REDUCTION TECHNIQUES & ECONOMICS IN COAL-FIRED POWER PLANTS.

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0. Summary

It is clear that Greece shall relay on lignite for a very high percentage of its electricity production supplemented by Natural Gas. This approach requires that the relevant improvement measures for lignite combustion, have to be clearly specified, decided and taken.

The purpose of this work is to demonstrate the various methods of emission reduction, in connection with the cost of installation, operational cost and experience of operation as well as good environmental performance.

The work had been performed mainly for the study of the BAT (Best Available Techniques) in the framework of the IPPC Directive and, applies to Greece and its power plants (existing or planned in future).

Clean Coal Technologies (CCTs) are those which facilitate the use of coal in an environmentally satisfactory and economically acceptable way. Among other aspects, clean coal technologies should meet various regulations covering emissions, effluents, and residues. In some situations, CCTs offer the possibility of satisfying even more stringent standards, at an acceptable cost.

A basic approach to the cleaner use of coal is to reduce emissions by reducing the formation of pollutants such as NOx, and/or cleaning the flue gases after combustion. Another approach is to develop more thermally efficient systems so that less coal is used to generate the same amount of power, together with improved techniques for flue gas cleaning, for effluent treatment and for residues use or disposal.

Emissions considered are: particulate matter, SO2 and NOx.

Reduction Measures considered, are primary and secondary (end of pipe).

- particulate emissions control technologies are mainly secondary measures
- NOx emissions, primary measures & secondary flue gas treatment
- SO2 emissions, primary difficult & mainly secondary measures FGD etc.

1. Particulate emissions control technologies

Primary particulate matter is generated by a variety of physical and chemical processes. It is emitted to the atmosphere through combustion, industrial processes, fugitive emissions and natural sources. Secondary particulate matter is formed in the atmosphere from condensation of gases and is predominantly found in the fine range. During coal combustion, the mineral matter (inorganic impurities) is converted to ash. Part of the ash is discharged from the bottom of the furnace as bottom ash. The particles suspended in the flue gas are known as fly ash. Fly ash constitutes the primary particulate matter, which enters the particulate control device. Particulate matter is in general referred to as "PM", "PM_{10}", "PM_{2.5}" (particulate matter (PM) with an aerodynamic equivalent diameter of 10 microns or less and 2.5 microns or less, respectively).

Technologies used to control particulate emissions from coal combustion are:

- Electrostatic precipitators (ESP’s)
- Fabric filters (baghouses)
- Wet particulate scrubbers
- Mechanical-inertial collectors (cyclones / multicyclones)
- High temperature / high pressure (HTHP) particulate control

Quantity and characteristics of the fly ash and particle size distribution depend on the coal mineral matter content, combustion system, and boiler operating conditions. Mineral
composition of the coal and the amount of carbon in the fly ash determine the quantity, resistivity and cohesivity of the fly ash. Combustion technique mainly determines the particle size distribution in the fly ash and hence the final particulate emissions. Common combustion systems in pulverised coal firing include dry bottom, wall (front, opposed) and corner (tangential) burners and wet bottom cyclone furnaces. In dry bottom boilers, 10-20% of the ash is discharged as dry, bottom ash. In wet bottom boilers, 50-60% of the ash is discharged at the bottom of the boiler as slag. However, the higher temperatures in cyclone boilers result in higher emissions of NO\textsubscript{x}. The combustion temperature may also affect the cohesivity of the fly ash. Higher operating temperatures can result in greater particle cohesivity leading to improved fly ash cake removal by reducing re-entrainment. Boiler operating conditions can affect the amount of unburnt carbon in the fly ash.

Electrostatic precipitators (ESP)
Cold side (dry) ESP is located after the air preheater and operates in a temperature range of 130-180°C. The cold side ESP, with fixed/rigid electrodes, makes up a large portion of the current market although ESP with moving electrodes are becoming more widely used. Hot side (dry) ESP, used mainly in the USA and Japan, is located before the air preheater where the operating temperature range is 300-450°C. A 1990 study showed 150 hot side ESP were built in the USA between 1935 and 1990. In wet ESP, a liquid film is maintained on the collection plates using spray nozzles. The process eliminates the need for rapping as the liquid film removes any deposited fly ash particles. Thus, problems with re-entrainment, fly ash resistivity and capture of fine particles become obsolete. However, wet ESP require saturation of the flue gas stream with water, generate waste water and sludge and operate at low temperatures. ESPs filters are highly efficient particulate removal devices with design efficiencies in excess of 99.5%. ESPs are the particulate emissions control technology which is most widely used on coal-fired power generating facilities. The trend is expected to continue at least for the next couple of decades. Conditioning the fly ash in the flue gas is an established technique used to improve-restore the performance of an ESP in coal-fired power plants with high-resistivity fly ash resulting from burning low sulphur coals. Elemental sulphur, ammonia (NH\textsubscript{3}), and sulphur trioxide (SO\textsubscript{3}) are the main conditioning agents currently used.

Characteristics
- Removal efficiency >99->99.99%
- Particle size range 0.01- >100 µm
- Installation availability: High
- Electricity consumption: increase at about 1.2-1.8%
- Installation cost: >70 Euro/kW\textsubscript{th},
- Operational cost: 100 Euro/tn.

Types
- Cold side (dry) ESP downstream air preheater, operating Temp.: 130-180°C
- Hot side (dry) ESP, in USA & Japan, upstream air preheater, operating temperature: 300-450°C.
- Wet ESP, using spray nozzles. No rapping; the liquid film removes any deposited fly ash particles BUT generates waste water and sludge and operate at low temperatures.
Fabric filter (baghouses)

Fabric filters, which generally operate in the temperature range 120-180°C, have been more widely used since the 1970s, especially at industrial scale. The choice between ESP and fabric filtration generally depends on coal type, plant size and boiler type and configuration. There are three types of fabric filters based on the cleaning mechanisms of each. The two fundamental parameters in sizing and operating baghouses are the air to coal (A/C) ratio (m/s) and the pressure drop (mm water gauge, Pascals or in.H2O). Other important factors which affect the performance of the fabric filter include the flue gas temperature, dew point and moisture content; particle size distribution and chemical composition of the fly ash.

Fabric filters are increasing their market share year by year but mainly in industry. The benefits of flue gas conditioning in fabric filters include achieving lower emissions at higher bag air to cloth ratio, reducing pressure drop and improving fly ash cake cohesivity thus leading to better dislodgement in larger agglomerates and less re-entrainment. Elemental sulphur, ammonia (NH3), and sulphur trioxide (SO3) are the main conditioning agents currently used.

Characteristics
- Removal efficiency >97%.
- Particle size range 0.01- >100 µm
- Installation availability: High
- Electricity consumption: small
- Installation cost: 50 EURO/kWth.
- Operational cost: 90 Euro/tn.

Wet scrubbers for particulate control

Wet scrubbers for particulate control at coal-fired power plants are used in a few coal-fired plants with most of these installations located in the USA to capture fly ash in addition to sulphur dioxide (SO2). In the most widely used venturi scrubber, water is injected into the flue gas stream at the venturi throat to form droplets. Fly ash particles impact with the droplets forming a wet by-product which then generally requires disposal. The system efficiency is reduced as the particle size decreases. The process can also have a high energy consumption due to the use of sorbent slurry pumps and fans. Many of the wet particulate scrubbers are designed to control both SO2 and particulates by utilising the alkaline fly ash as sorbent. Lime is frequently used to boost SO2 removal efficiencies. The method has not been used over 300MWel power plants.

Characteristics
- Removal efficiency ≥90%.
- Particle size range 0.01- >100 µm
- Installation availability: High
- Electricity consumption: small
- Installation cost: 50 EURO/kWth.
- Operational cost: Unknown.
Mechanical/inertial collectors (cyclones/multicyclones)

Cyclones are robust technologies that can deal with the cyclic operation and load changes, which is quite common in these types of plants. However, their efficiency is moderate when compared with ESP or fabric filtration.

**Characteristics**
- Removal efficiency: 45-87%
- Particle size range: 0.01-100 µm
- Installation availability: 99%
- Electricity consumption: small
- Installation cost: Low
- Operational cost: Unknown

2. Gaseous emissions control technologies

2.1. NOx emissions reduction and control

2.1.1. NOx emissions abatement and control by primary measures

Emissions of NOx can be either abated or controlled by primary measures or flue gas treatment technologies.

Primary measures for NOx control may be divided into the following categories:
- Burner optimization (excess air control, burner fine tuning)
- Air staging (overfire air or two stage combustion)
- Flue gas recirculation
- Fuel staging (some burners out of service, reburning)
- Low NOx burners

*a) Burner optimization for NOx control (excess air control, burner fine tuning)*

Optimisation is achieved by modifying boiler-operating conditions. Excess air control, boiler fine tuning and balancing the fuel and air flow to the various burners are in use and continue to be investigated to achieve minimum NOx formation in the burner. As the oxygen level is reduced (during excess air control), combustion may become incomplete and the amount of unburned carbon in the ash & level of carbon monoxide may increase. In addition, the steam temperature may be decreased. The result of these changes can be a reduction in the boiler efficiency, slagging, corrosion and a counteractive overall impact on boiler performance. Potential safety problems, which may result from the use of this technique without a strict control system include, fires in air preheaters and ash hoppers as well as increases in opacity and in rates of waterwall wastage.

Fine tuning the boiler settings include mill balancing, adjusting air registers, air and coal flow balancing, tuning firing configuration and improving the plant control system. It is known (for example in IEA Coal Research reports) that controlling the varying burner tilt angles to control steam temperature and changing oxygen flow, mill loading and air register settings during different burner loads can also contribute to reducing NOx formation.

**Characteristics**
- Retention efficiency: 20-30%
- Installation availability: 100%
- Electricity consumption: none
Installation cost: 1 EURO/kWth.
Operational cost: 1 EURO/kWth.

b) Flue gas recirculation for NO\textsubscript{x} control
Flue gas recirculation for NO\textsubscript{x} control includes gas recirculation into the furnace or into the burner. In this technology 20-30\% of the flue gas (at 350-400°C) is re-circulated and mixed with the combustion air. The resulting dilution in the flame decreases the temperature and availability of oxygen (vitiated air) therefore reducing thermal NO\textsubscript{x} formation. When flue gas recirculation into the burner is used in low NO\textsubscript{x} burners, the flue gas is usually re-circulated subject to the operational constraints of flame stability and impingement, as well as boiler vibration. Flue gas recirculation in combination with other primary measures for NO\textsubscript{x} control is installed at 49 pulverised coal-fired units on a total capacity of >15 GWe. Retrofitting an existing coal-fired unit with flue gas recirculation involves installation of a system to extract the flue gas from the boiler unit, additional ductwork, fan and a fly ash collecting device. Heat distribution in the furnace may be affected due to the increase in throughput. Excessive flue gas recirculation can also result in flame instability problems and increased steam temperatures. Flue gas recirculation alone in coal-fired boilers achieves a low NO\textsubscript{x} reduction efficiency (<20\%). This is because the ratio of thermal-NO\textsubscript{x} to total NO\textsubscript{x} emissions is relatively low in coal-fired plants.

\textbf{Characteristics}
Retention efficiency ≈15\% (for solid fuel), 30\% (for oil fuel), up to max. 75\% (for gaseous fuel).
Installation availability: 100\%
Electricity consumption: none
Installation cost: 2 EURO/kWth.
Operational cost: Unknown.

c) Air staging for NO\textsubscript{x} control (overfire air (OFA) or two-stage combustion)
Air staging (internal air staging) or two-stage combustion, is generally described as the introduction of overfire air into the boiler or furnace. Furnace overfire air (OFA) technology requires the introduction of combustion air to be separated into primary and secondary flow sections to achieve complete burnout and to encourage the formation of N\textsubscript{2} rather than NO\textsubscript{x}. Primary air is mixed with the fuel producing a relatively low temperature; oxygen deficient, fuel-rich zone and therefore moderate amounts of fuel NO\textsubscript{x} are formed. The secondary air is injected above the combustion zone through a special wind-box with air introducing ports and/or nozzles, mounted above the burners. The location of the injection ports and mixing of overfire air are critical to maintain efficient combustion. Retrofitting overfire air on an existing boiler involves waterwall tube modifications to create the ports for the secondary air nozzles and the addition of ducts, dampers and the wind-box. This technique is currently used in 116 pulverised coal-fired units, on a total capacity of 50 GWe as a stand-alone measure. It is used in combination with other primary measures for NO\textsubscript{x} control, in 175 coal-fired units on a total capacity of 53 GWe.

\textbf{Characteristics}
Retention efficiency ≈40\% (for solid fuel), 45\% (for oil fuel), up to max. 65\% (for gaseous fuel).
Installation availability: 100\%
Electricity consumption: none
Installation cost: 5 EURO/kWth.
Operational cost: Unknown.

d) Low NO\textsubscript{x} burners
Low NO\textsubscript{x} burners are designed to control fuel and air mixing at each burner in order to create larger and more branched flames. Peak flame temperature is thereby reduced, and results in less NO\textsubscript{x} formation. The improved flame structure also reduces the amount of oxygen available in the hottest part of the flame thus improving burner efficiency. Combustion, reduction and burnout are achieved in three stages within a conventional low NO\textsubscript{x} burner. In the initial stage, combustion occurs in a fuel rich, oxygen deficient zone where the NO\textsubscript{x} are formed. A reducing atmosphere follows where hydrocarbons are formed which react with the already formed NO\textsubscript{x}. In the third stage internal air staging completes the combustion but may result in additional NO\textsubscript{x} formation. This however can be minimised by completing the combustion in an air lean environment.
A large number of low NO\textsubscript{x} burners have been developed and are currently used in over 370 coal-fired units (125 GWe).

Characteristics
- Retention efficiency ≈40%.
- Installation availability: 100%
- Electricity consumption: none
- Installation cost: 5 EURO/kWth.
- Operational cost: Unknown.

2.1.2. NO\textsubscript{x} emissions abatement and control by flue gas treatment
Flue gas treatment for NO\textsubscript{x} control can be categorised into three areas:
- Selective catalytic reduction (SCR)
- Selective non-catalytic reduction (SNCR)
- Combined SO\textsubscript{2}/NO\textsubscript{x} control techniques

a) Selective catalytic reduction (SCR) for NO\textsubscript{x} control
In SCR systems, ammonia vapour is used as the reducing agent and is injected into the flue gas stream, passing over a catalyst. NO\textsubscript{x} emission reductions over 80-90% are achieved. The optimum temperature is usually between 300°C and 400°C. This is normally the flue gas temperature at the economiser outlet.
There are three typical layout arrangements of SCR systems applied to coal-fired power stations. High dust position is the most widely used SCR configuration, especially with dry bottom boilers, because it does not require particulate emissions control prior to the denitification process. Low dust positioning has the advantage of less catalyst degradation caused by fly ash erosion, but requires a more costly hot-side ESP. Tail end position SCR has been used primarily with wet bottom boilers with ash recirculation to avoid catalyst degradation caused by arsenic poisoning. The configuration is also favoured with retrofit installations (due to SCR space requirements) between the economiser outlet and ESP.

The efficiency of SCR process reactions (reagent stoichiometry and utilisation nearly 1.0) allows very close and effective reagent injection-control based on feedback, of measured NO\textsubscript{x} concentrations in the flue gas at the economiser outlet. The temperature of the flue gas in the SCR reactor is controlled by mixing the flue gas exiting the economiser with the flue gas from the economiser bypass. The ammonia injection grid is located in the
ductwork leading to the SCR catalyst, far enough upstream to ensure optimum gas and reagent distribution across the catalyst cross-section.

The catalysts can have different compositions: based on titanium oxide, zeolite, iron oxide or activated carbon. Most catalysts in use in coal-fired plants consist of vanadium (active catalyst) and titanium (used to disperse and support the vanadium) mixture. However, the final catalyst composition can consist of many active metals and support materials to meet specific requirements in each SCR installation. Catalyst geometry may typically be a flat plate or honeycomb. A moving bed is used for granular activated carbon. German experience shows that plate types generally have a higher resistance to deposition and erosion than honeycombs. In this case, catalytic converters are used in an air preheater.

There are now about 15 GWe of coal-fired SCR capacity in Japan and nearly 30 GWe in Germany, out of a total of about 53 GWe worldwide.

b) Selective non-catalytic reduction (SNCR) for NOx control
In SNCR systems, a reagent is injected into the flue gas in the furnace within an appropriate temperature window. Emissions of NOx can be reduced by 30% to 50%. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, because of higher stoichiometric ratios, both ammonia and urea SNCR processes require three or four times as much reagent as SCR systems to achieve similar NOx reduction.

The temperature window for efficient SNCR operation typically occurs between 900°C and 1,100°C depending on the reagent and condition of SNCR operation. When the reaction temperature increases over 1000°C, the NOx removal rate decreases due to thermal decomposition of ammonia. On the other hand, the NOx reduction rate decreases below 1000°C and ammonia slip may increase. The optimum temperature window generally occurs somewhere in the steam generator and convective heat transfer areas. The longer the reagent is in the optimum temperature window, the better the NOx reduction. Residence times in excess of 1 second yield optimum NOx reductions. However, a minimum residence time of 0.3 second is desirable to achieve moderate SNCR effectiveness.

Ammonia slip from SNCR systems occurs either from injection at temperatures too low for effective reaction with NOx or from over-injection of reagent leading to uneven distribution. Controlling ammonia slip in SNCR systems is difficult since there is no opportunity for effective feedback to control reagent injection. An injection system that has too few injection control points or injects a uniform amount of ammonia across the entire section of the boiler will almost certainly lead to a poor distribution ratio and high ammonia slip. Distribution of the reagent can be especially difficult in larger coal-fired boilers because of the long injection distance required to cover the relatively large cross-section of the boiler. Multiple layers of reagent injection as well as individual injection zones in cross-section of each injection level are commonly used to follow the temperature changes caused by boiler load changes.
A potentially troublesome reaction is unreacted ammonia combining with SO₂ to form ammonium bisulphate. Ammonium bisulphate will precipitate at air heater operating temperatures and can ultimately lead to air heater fouling and plugging. Although no SO₂ is oxidised by the SNCR system, naturally occurring SO₃ concentrations are sometimes high enough (especially from higher sulphur coals) to be a concern with potentially high ammonia slip rates.

An SNCR process can produce nitrous oxide (N₂O), which contributes to the greenhouse effect. N₂O formation resulting from SNCR depends upon the reagent used, the amount of reagent injected and the injection temperature. In Western Europe, Japan & the USA, SNCR systems have been used commercially on coal-fired power plants since 1980, 1970 & the early 1990s, respectively.

**Characteristics**
- Retention efficiency <50%.
- Installation availability: 95%
- Electricity consumption: increase 0.2%
- Installation cost: 15-30 EURO/kWth.
- Operational cost: 750-900 EURO/tn.

c) Combined SO₂/NOₓ removal processes (WSA-SNOₓ Method)
Combined SO₂/NOₓ removal processes remain considered fairly complex and costly. However, emerging technologies have the potential to reduce SO₂ and NOₓ emissions for less than the combined cost of conventional FGD for SO₂ control and selective catalytic reduction (SCR) for NOₓ control. The method is used in one unit of 300MWₑ in Denmark & planned for low to medium-sulphur coal-fired plants.

**Characteristics**
- Retention efficiency ≈ up to 95% for SO₂ & 95% for NOₓ.
- Installation availability: Unknown
- Electricity consumption: increase 0.2%
- Installation cost: 80-110 EURO/kWth.
- Operational cost: 600 EURO/tn.

### 2.2. SO₂ emissions reduction and control

#### 2.2.1. Primary measures
These are mainly fuel preparation that is practically impossible for coal and furnace injection of sorbent (limestone) & Mg.

#### 2.2.2 Secondary measures

Flue gas desulfurization (FGD) can be classified into the following main categories:
- Wet scrubbers
- Spray dry scrubbers sorbent injection processes
- Dry scrubbers
- Regenerable processes

FGD units are installed in 27 countries. Wet scrubbers take the lead followed by spray dry scrubbers and sorbent injection systems in the FGD market throughout the world.
Regenerable and combined SO$_2$/NO$_x$ processes have a small share and the trend is not expected to change in the short-term according to current plans for new FGD installations. New developments in sorbent injection technologies are in progress and this type of FGD is expected to become more widely used in older coal-fired plants.

a) Wet scrubbers for SO$_2$ control

Calcium-, sodium- and ammonium-based sorbents have been used in a slurry mixture, which is injected into a specially designed vessel to react with the SO$_2$ in the flue gas. The preferred sorbent in operating wet scrubbers is limestone followed by lime. In the simplest configuration in wet lime/limestone/gypsum scrubbers, all chemical reactions take place in a single integrated absorber resulting in reduced capital cost and high energy consumption. There is experience of the application of the method, with plants up to 800MW$_{el}$. Another similar method is retention of SO$_2$ with wet scrubbing and use of sea water. Final Product sea water with high Sulphates content; at the moment the method is applied to units up to 125MW$_{el}$.

**Characteristics**

Retention efficiency $\approx$ 70% to 98%, with fuels which have S from 0.3% to 4.8% & for sea water method 70% to 99%, with fuels which have S from 0.35% to 0.5% for coal and up to 3% for oil.

Installation availability: 90%

Electricity consumption: increase 2-3%

Installation cost: 80-120 EURO/kW$_{th}$ & 100 EURO/kW$_{th}$ for sea water method

Operational cost: 175-600 EURO/tn & 450 EURO/kW$_{th}$ for sea water method

b) Spray dry scrubbers for SO$_2$ control

Spray dry scrubbers require the use of an efficient particulate control device such as an ESP or fabric filter. The sorbent usually used is lime or calcium oxide. The lime slurry, also called lime milk, is atomised/sprayed into a reactor vessel in a cloud of fine droplets. Water is evaporated by the heat of the flue gas. The residence time (about 10 seconds) in the reactor is sufficient to allow for the SO$_2$ and the other acid gases such as SO$_3$ and HCl to react simultaneously with the hydrated lime to form a dry mixture of calcium sulphate/sulphite. Waste water treatment is not required in spray dry scrubbers because the water is completely evaporated in the spray dry absorber. The by-product also contains unreacted lime which may be recycled and mixed with fresh lime slurry to enhance sorbent utilisation as not all of the lime reacts with the SO$_2$. Factors affecting the absorption chemistry include flue gas temperature, SO$_2$ concentration in the flue gas and the size of the atomised or sprayed slurry droplets. The use of lime in the process increases its operational costs.

Spray dry scrubbers application is limited to flue gas volume from about 200 MWe plants on average. Larger plants require the use of several modules to deal with the total flue gas flow. Spray dry scrubbers in commercial use have achieved removal efficiency in excess of 90% with some suppliers giving $>95\%$ SO$_2$ removal efficiency as achievable.

**Characteristics**

Retention efficiency $\approx$ 50% to 70%, in coal fired installations with 0.5% to 1.9% S content.

Installation availability: 95%

Electricity consumption: increase 0.5%

Installation cost: 40-80 EURO/kW$_{th}$

Operational cost: 700-1000 EURO/tn
c) Sorbent injection systems for SO$_2$ control

Sorbent injection systems can be divided into four types. These are:

- furnace sorbent injection;
- economiser sorbent injection;
- duct sorbent injection; and
- hybrid sorbent injection.

The simplest technology is furnace sorbent injection where a dry sorbent is injected into the upper part of the furnace to react with the SO$_2$ in the flue gas. The finely grained sorbent is distributed quickly and evenly over the entire cross section in the upper part of the furnace in a location where the temperature is in the range of 750-1,250°C. Commercially available limestone (CaCO$_3$) or hydrated lime (Ca(OH)$_2$) is used as sorbent. Whilst the flue gas flows through the convective pass, where the temperature remains above 750°C, the sorbent reacts with SO$_2$ and O$_2$ to form CaSO$_4$. This is later captured in a fabric filter or ESP together with unused sorbent and fly ash. If the temperature can be kept within 750-1,250°C, the major part of SO$_2$ transformation occurs within 1-2 seconds. At temperatures below 750°C, reactions practically cease. Sorbent injection can be carried out at several levels to deal with part load conditions. The process is optimised by using adjustable injection nozzles.

Removal efficiency of up to 50% can be obtained with a Ca/S ratio of 2 with Ca(OH)$_2$ used as sorbent. If CaCO$_3$ is used as sorbent the removal efficiency will be considerably lower, or the Ca/S ratio will have to be much higher. Fine sorbent particle size (<5 µm) and an even distribution of the sorbent over the cross-section of a boiler could significantly improve the process performance.

In an economiser sorbent injection process, hydrated lime is injected into the flue gas stream near the economiser zone where the temperature is in the range of 300-650°C. In contrast to the furnace sorbent injection process, where the reaction temperature is around 1100°C, Ca(OH)$_2$ reacts directly with SO$_2$ since the temperature is too low to dehydrate Ca(OH)$_2$ completely. In this temperature range, the main product is CaSO$_3$ instead of CaSO$_4$ and the reaction rate is comparable to or higher than that at 1100°C. The production of carbonate in the process is undesirable, since it not only consumes the sorbent but also blocks the access of SO$_2$ to active sorbent surfaces.

In duct sorbent injection, the aim is to distribute the sorbent evenly in the flue gas duct after the preheater where the temperature is about 150°C. At the same time, the flue gas is humidified with water if necessary. Reaction with the SO$_2$ in the flue gas occurs in the ductwork and the by-product is captured in a downstream filter. An 80% SO$_2$ removal efficiency has been reported in actual commercial installations. A dry sorbent has to be finely grained and a sorbent in suspension must be atomised into small droplets. The flue gas must be kept above the dew point in order to minimise the risk of undesired deposits in the flue gas duct and process equipment after sorbent injection.

There are many factors, which influence the performance of a duct sorbent injection process, such as sorbent reactivity, quantity of injected sorbent, relative humidity of the flue gas, gas & solids residence time in the duct, flow conditions in the flue gas ductwork, and quantity of recycled, unreacted sorbent from the particulate control device. The Hybrid sorbent injection process is usually a combination of the furnace and duct sorbent injection systems aiming to achieve higher sorbent utilisation and greater SO$_2$ removal. Various types of post furnace treatments are practised in hybrid systems, such as:

- injection of second sorbents such as sodium compounds into the duct; and
humidification in a specially designed vessel. Humidification reactivates the unreacted CaO and can boost SO₂ removal efficiency up to 90% depending on the process. The hybrid process offers the following advantages:

- relatively high SO₂ removal;
- low capital and operating costs;
- easy to retrofit;
- easy operation and maintenance with no slurry handling;
- reduced installation area requirements due to compact equipment; and
- no waste water treatment.

d) Dry scrubbers for SO₂ control
Circulating fluid bed and moving bed technologies, which utilise a dry sorbent to reduce SO₂ emissions in a flue gas stream in a dedicated reaction chamber are categorised as dry scrubbers. In the circulating fluidized bed (CFB) dry scrubber process, hydrated lime is injected directly in the CFB reactor. Water is also injected into the bed to obtain an operation close to the adiabatic saturation temperature. The process achieves SO₂ removal efficiency of 93-97% at a Ca/S molar ratio of 1.2-1.5. The process can achieve >95% SO₂ removal efficiency. In the moving bed dry scrubber, a dry absorbent made of coal ash and lime is injected into the absorber. There is currently one plant using this technology and achieving 90% SO₂ removal efficiency.

e) Regenerable processes for SO₂ control
In regenerable processes, the sorbent is regenerated chemically or thermally and re-used. Elemental sulphur or sulphuric acid is recovered from the SO₂ removed. The revenue from these by-products can compensate partially for the higher capital costs required in such FGD systems. Regenerable processes generally require no waste disposal, produce little waste water and have low sorbent make-up requirements. However, in most such systems, a prescrubber is essential to control chlorides. Although these processes can achieve high SO₂ removal efficiencies (>95%) they have in general high capital costs and power consumption (3-4%).

4. Conclusions
The purpose of this work was to demonstrate the various methods of emission reduction, in connection with the cost of installation, operational cost and experience of operation as well as good environmental performance.

The authors examined the various methods for pollutant reduction, for all kind of fuels but mainly focused on solid fuels, as set in the bibliography. Especially, the authors examined the various pollution reduction methods on a common basis of:

- Method used
- Short Description
- Retention efficiency
- Electricity consumption
- Installation availability
- Installation cost per kWth
- Retention cost per tonne of pollutant
Thus, this work was focused not only to the emission reduction techniques themselves but, also to the cost of installation and operation of anti-pollution equipment. Finally, the experience from the operation of such equipment (capture efficiency etc.) as well as installed units, were reported.

A basic approach to the cleaner use of coal is to reduce emissions by reducing the formation (primary measures) of pollutants such as NOx, and/or cleaning the flue gases after combustion (secondary measures). Another approach is to develop more thermally efficient systems so that less coal is used to generate the same amount of power, together with improved techniques for flue gas cleaning, for effluent treatment and for residues use or disposal.

Clean Coal Technologies (CCTs) are those which facilitate the use of coal in an environmentally satisfactory and economically acceptable way. Among other aspects, clean coal technologies should meet various regulations covering emissions, effluents, and residues. In some situations, CCTs offer the possibility of satisfying even more stringent standards, at an acceptable cost.

5. References


