

Appendix D
Air Quality Control Technology
Descriptions

CONTROL TECHNOLOGY DESCRIPTIONS

NO_x Reduction Technologies

Low NO_x Burners (LNB)

The new-generation LNB have better NO_x removal performance than the first-generation LNB and are a fundamental component of the boiler design. The term ultra-low NO_x burners applies only to gas fired applications and does not apply to coal fired boilers.

LNB control the mixing of fuel and air in a pattern designed to minimize flame temperatures and quickly dissipate heat. These burners typically reduce NO_x by maintaining a reducing atmosphere at the coal nozzle and diverting additional combustion air (to complete combustion) to secondary air registers. This minimizes the reaction time at oxygen-rich, high-temperature conditions. Conventional burners, however, typically mix the secondary air with the primary air/fuel stream immediately following injection into the furnace, creating a high intensity combustion process.

Wall mounted LNB are typically a multiple-register (damper) type with two separate secondary airflow paths through the burner and into the furnace. Common features include dedicated total secondary airflow control dampers and separate dedicated dampers or vanes to control the flow and spin of the individual secondary airflows through the burner. The vanes that control spin or flame shape are typically set during initial startup and then locked in place.

Control and balancing of the secondary air, primary air, and coal distribution among the burners is a basic requirement of all manufacturers. Typical allowable flow deviations from the mean are 10 percent for individual burner air and coal flows. This requirement may necessitate changes in operating procedures related to individual burner level turn down at part load. Conversely, additional control provisions and flow monitoring capability is required to preserve the option to operate with unbalanced firing at part load.

The basic NO_x reduction principles for LNB are to control and balance the fuel and air flow to each burner, and to control the amount and position of secondary air in the burner zone so that fuel devolatilization and high-temperature zones are not oxygen rich. Figure D-1 shows the low NO_x burners

Low NO_x Burner Systems

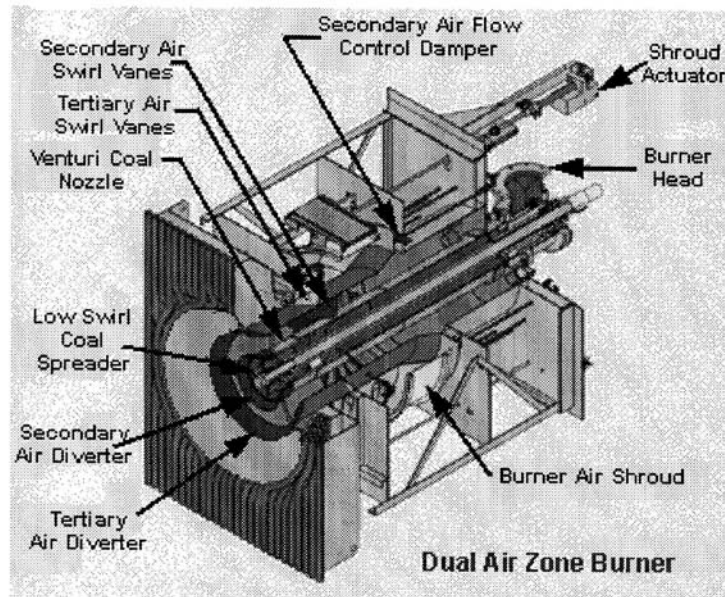


Figure D-1
Low NO_x Burners (Courtesy: DB Riley)

Overfire Air (OFA)

OFA is an air staging NO_x reduction technique that is based on withholding 15 to 20 percent of the total combustion air conventionally supplied to the high temperature zone of the furnace. OFA can be used in conjunction with the LNB system. Unburned carbon and combustible materials may increase as a result of the addition of OFA because of the staging of the combustion process.

With the installation of an OFA system, the main combustion burners are operated at or near stoichiometric ratio to limit available oxygen, flame temperature, and NO_x formation. The remainder of the combustion air is then injected through the OFA ports to complete combustion. The quantity of OFA introduced is sufficient to increase the overall excess air in the boiler to 15 to 20 percent to ensure complete combustion and maintain flue gas flow through the convective sections of the boiler.

OFA systems reduce NO_x formation by creating a fuel rich combustion zone. The OFA is introduced above the main combustion zone (fuel is introduced in an oxygen-starved environment) where fuel burnout can be completed at a lower temperature with fewer volatile nitrogen-bearing combustion products.

The OFA ports will be designed to allow adequate mixing of the combustion air and flue gas and with sufficient temperatures and residence times to ensure complete combustion to achieve optimum NO_x reductions. The location of the OFA ports is critical in achieving optimum NO_x reductions without affecting unburned carbon losses. Figure D-2 shows the overfire air

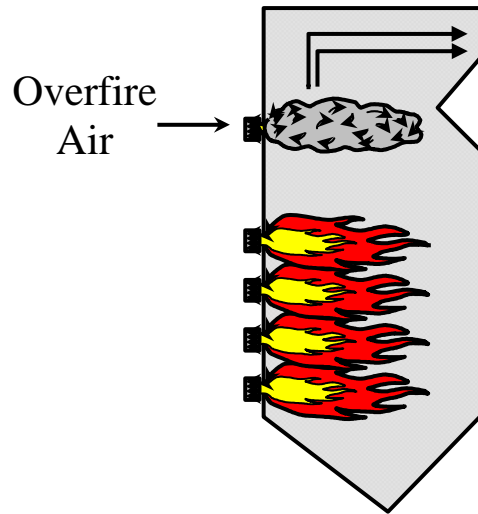


Figure D-2
Overfire Air System

Selective Noncatalytic Reduction System (SNCR)

Selective non-catalytic NO_x reduction systems rely on the appropriate reagent injection temperature and good reagent/gas mixing rather than a catalyst to achieve NO_x reductions. SNCR systems can use either ammonia (Thermal DeNO_x) or urea (NO_xOUT) as reagents.

The optimum temperature range for injection of ammonia or urea is 1,550 to 1,900° F. The NO_x reduction efficiency of an SNCR system decreases rapidly at temperatures outside this range. Injection of reagent below this temperature window results in excessive ammonia slip emissions. Injection of reagent above this temperature window results in increased NO_x emissions. A PC boiler operates at temperatures of between 2,500 and 3,000° F. Therefore, the optimum temperature window in a PC boiler occurs somewhere in the backpass of the boiler. To further complicate matters, this temperature location will change as a function of unit load. In addition, residence times in this temperature range are very limited, further detracting from optimum SNCR

performance. Finally, there is no provision for feedforward control of reagent injection, relying only on feedback control. This results in over injection of reagent and high ammonia slip emissions.

SNCR systems are less efficient NO_x reduction systems than SCR systems. In general, SNCR systems on large PC-fired boilers will be capable of only up to 50 percent NO_x reduction. Figure D-3 shows a schematic of SNCR system.

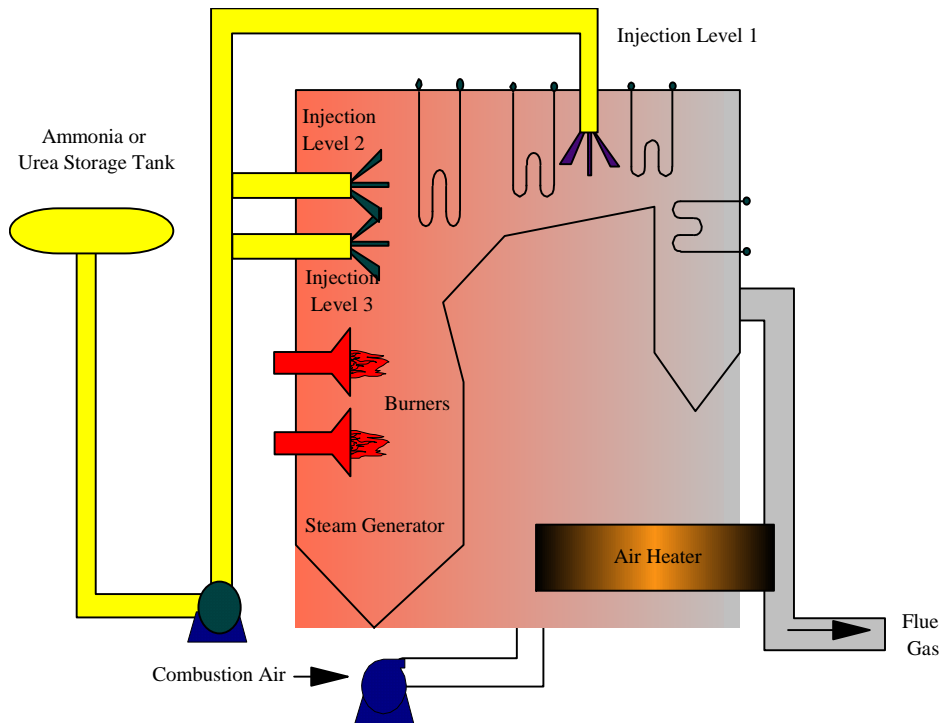


Figure D-3
Schematic of SNCR System with Multiple Injection Levels

Selective Catalytic Reduction System (SCR)

In an SCR system, ammonia is injected into the flue gas stream just upstream of a catalytic reactor. The ammonia molecules in the presence of the catalyst dissociate a significant portion of the NO_x into nitrogen and water.

The aqueous ammonia is received and stored as a liquid. The ammonia is vaporized and subsequently injected into the flue gas by compressed air or steam as a carrier. Injection of the ammonia must occur at temperatures above 600° F to avoid chemical reactions that are significant and operationally harmful. Catalyst and other considerations limit the maximum SCR system operating temperature to 840° F. Therefore, the system is typically located between the economizer outlet and the air heater inlet. The SCR catalyst is housed in a reactor vessel, which is separate from the

boiler. The conventional SCR catalysts are either homogeneous ceramic or metal substrate coated. The catalyst composition is vanadium-based, with titanium included to disperse the vanadium catalyst and tungsten added to minimize adverse SO₂ and SO₃ oxidation reactions. An economizer bypass may be required to maintain the reactor temperature during low load operation. This will reduce boiler efficiency at lower loads.

The SCR process is a complex system. The SCR requires precise NO_x-to-ammonia distribution in the presence of the active catalyst site to achieve current BACT levels. In the past, removal efficiencies were the measure of catalyst systems because of extremely high inlet NO_x levels. Current technology SCR systems do not use removal efficiency as a primary metric because the current generation of LNB/OFA systems limits the amount of NO_x available for removal. Essentially, as NO_x is removed through the initial layers of catalyst, the remaining layers have difficulty sustaining the reaction.

A number of alkali metals and trace elements (especially arsenic) poison the catalyst, significantly affecting reactivity and life. Other elements such as sodium, potassium, and zinc can also poison the catalyst by neutralizing the active catalyst sites. Poisoning of the catalyst does not occur instantaneously, but is a continual steady process that occurs over the life of the catalyst. As the catalyst becomes deactivated, ammonia slip emissions increase, approaching design values. As a result, catalyst in a SCR system is consumable, requiring periodic replacement at a frequency dependent on the level of catalyst poisoning. However, effective catalyst management plans can be implemented that significantly reduce catalyst replacement requirements.

There are two SCR system configurations that can be considered for application on pulverized coal boilers: high dust and tail end. A high dust application locates the SCR system before the particulate collection equipment, typically between the economizer outlet and the air heater inlet. A tail end application locates the catalyst downstream of the particulate and FGD control equipment.

The high dust application requires the SCR system to be located between the economizer outlet and the air heater inlet in order to achieve the required optimum SCR operating temperature of approximately 600° to 800° F. This system is subject to high levels of trace elements and other flue gas constituents that poison the catalyst, as previously noted. The tail end application of SCR would locate the catalyst downstream of the particulate control and FGD equipment. Less catalyst volume is needed for the tail end application, since the majority of the particulate and SO₂ (including the trace elements that poison the catalyst) have been removed. However, a major disadvantage of this alternative is a requirement for a gas-to-gas reheater and supplemental fuel firing to achieve sufficient flue gas operating temperatures downstream of the FGD operating at approximately 125° F. The required gas-to-gas reheater and supplemental firing

necessary to raise the flue gas to the sufficient operating temperature is costly. The higher front end capital costs and annual operating cost for the tail end systems present higher overall costs compared to the high dust SCR option with no established emissions control efficiency advantage. Figure D-4 shows a schematic diagram of SCR.

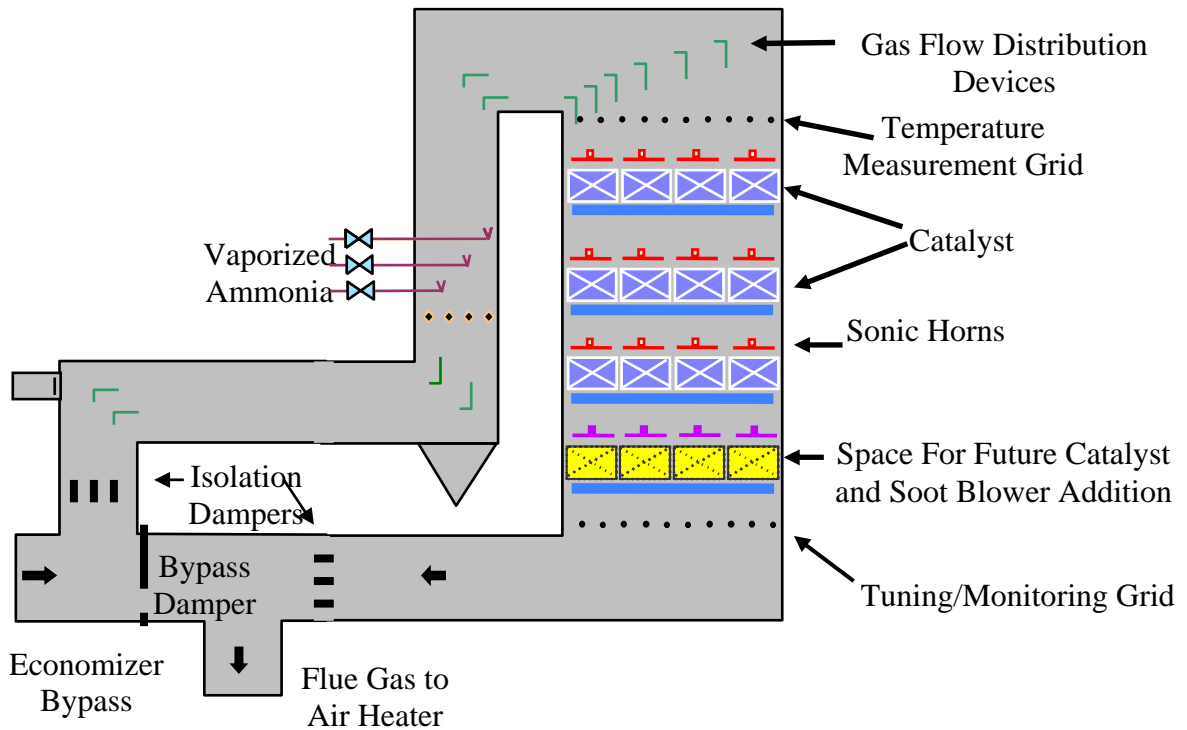


Figure D-4
Schematic Diagram of a Typical SCR Reactor

SNCR/SCR Hybrid System

The SNCR/SCR hybrid system uses components and operating characteristics of both SNCR and SCR systems. Hybrid systems were developed to combine the low capital cost and potential for high NH₃ slip associated with SNCR systems with the high reduction potential and low NH₃ slip inherent with catalyst based SCR systems. The result is an NO_x reduction alternative that can meet initial NO_x reduction requirements but can be upgraded to meet higher reductions at a future date, if required. Typically, installation of an SCR system with a single layer of in-duct catalyst is capable of reducing NO_x emissions from 40 to 70 percent, depending on the amount of NH₃ slip from the SCR and the volume of the single layer of catalyst.

The SNCR component of the hybrid system is identical to the SNCR system, except that the hybrid system may have more levels of multiple lance nozzles for reagent injection. This will increase the capital cost of the SNCR component of the hybrid system. During operation, the SNCR system would inject higher amounts of reagent into the flue gas. This increased reagent flow has a two-fold effect: NO_x reduction within the boiler is increased while NH_3 slip is also increased. The NH_3 that slips from the SNCR is then used as the reagent for the single layer of catalyst.

There are two design philosophies for using this excess NH_3 slip. The most conservative hybrid systems will use the catalyst simply as an NH_3 slip “scrubber” with some additional NO_x reduction. Similar to in-duct systems, the flue gas velocity through the catalyst is an important factor in design. Operating in this mode allows maximum NO_x reduction within the boiler by the SNCR while minimizing the catalyst volume requirement. While some NO_x reduction is achieved at the catalyst, the relatively small catalyst requirement of this design has the potential to fit all the catalyst in a true in-duct arrangement, with no significant ductwork changes, arrangement interference, or structural adaptations.

The second philosophy uses adequate catalyst volume to obtain significant levels of additional NO_x reduction. The additional reduction is a function of the quantity of NH_3 slip, the catalyst volume, and the distribution of NH_3 to NO_x within the flue gas. Using NH_3 slip that is produced by the SNCR system is not a high efficiency method of introducing reagent, due to the low reagent utilization. Therefore, even though the reaction at the catalyst requires 1 ppm of NH_3 to remove 1 ppm of NO_x , the SNCR must inject at least 3 ppm of NH_3 to generate 1 ppm of NH_3 at the catalyst.

Catalyst volume is strongly influenced by the NO_x reduction required and the NH_3 distribution. The impact of catalyst volume on the design of a hybrid system is on the size of the reactor required to hold the catalyst. If multiple levels of catalyst operating at low flue gas velocity are required, some modifications will be required to the typical ductwork. If widening the ductwork cannot provide for adequate catalyst volume, then a separate reactor is required, which quickly negates the capital cost advantage of a hybrid system. Figure D-5 represents a schematic diagram of a typical SNCR/SCR Hybrid system.

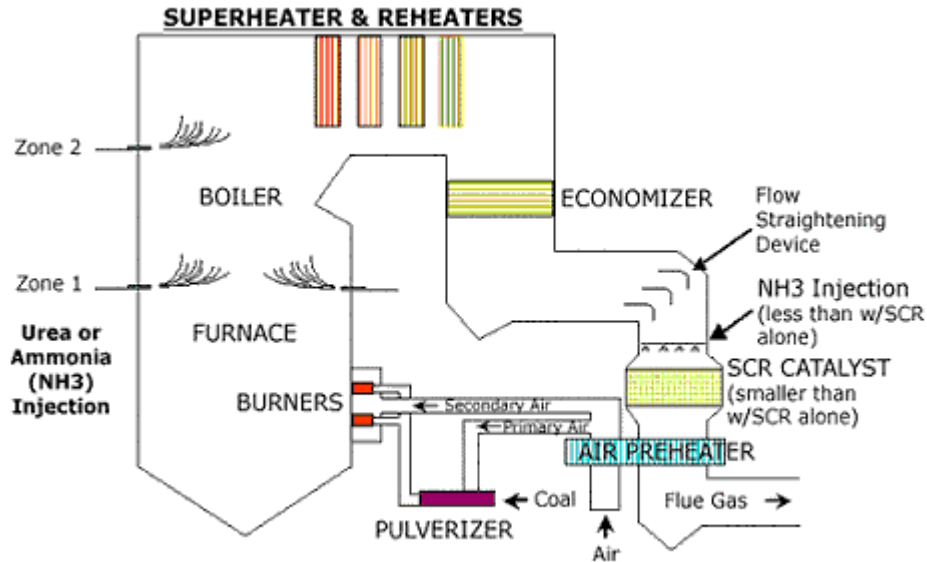


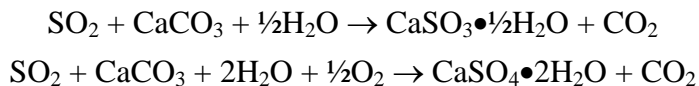
Figure D-5
Schematic Diagram of a Typical SNCR/SCR Hybrid System (Courtesy: Clean Environmental Protection Engineering Co. Ltd.)

SO₂ and HCl Reduction Technologies

Wet Flue Gas Desulfurization (FGD) System

Wet limestone-based FGD processes are frequently applied to pulverized coal fired boilers that burn medium-to-high sulfur eastern coals. All of the FGD systems installed in response to Phase I of the 1990 CAA were based on a wet FGD system using either lime or limestone as the reagent. Typically, the wet FGD processes on a pulverized coal facility are characterized by high efficiency (> 98 percent) and high reagent utilization (95 to 97 percent) when combined with a high sulfur fuel. The ability to realize high removal efficiencies on higher sulfur fuels is a major difference between wet scrubbers and semi-dry/dry FGD processes. It is well known that SO₂ removal efficiencies for wet FGD systems are generally higher for high sulfur coal applications than for low sulfur coal applications, for the fundamental physical reason that the chemical reactions that remove SO₂ are faster if the inlet SO₂ concentration is higher. The absolute emissions level becomes a limiting factor due to a reduction in the chemical driving forces of the reactions that are occurring. Thus, the calculated removal efficiency of the various types of wet scrubbers declines as the fuel sulfur content decreases; this is the case for low sulfur western and PRB coals.

In a wet FGD system, the absorber module is located downstream of the induced draft (ID) fans (or booster ID fans, if required). Flue gas enters the module and is contacted with a slurry containing reagent and byproduct solids. The SO₂ is absorbed into the slurry and reacts with the calcium to form CaSO₃•1/2H₂O and CaSO₄•2H₂O. SO₂ reacts with limestone reagent through the following overall reactions:



The flue gas leaving the absorber will be saturated with water, and the stack will have a visible moisture plume. Because of the chlorides present in the mist carry-over from the absorber and the pools of low pH condensate that can develop, the conditions downstream of the absorber are highly corrosive to most materials of construction. Highly corrosion-resistant materials are required for the downstream ductwork and the flue stack. Careful design of the stack is needed to prevent the “rainout” from condensation that occurs in the downstream ductwork and stack. These factors contribute to the relatively high capital costs of the wet FGD SO₂ control alternative.

The reaction products are typically dewatered by a combination of hydrocyclones and vacuum filters. The resulting filter cake is suitable for landfill disposal. In early lime- and limestone-based FGD processes, the byproduct solids were primarily calcium sulfite hemihydrate (CaSO₃•1/2H₂O), and the byproduct solids were mixed with fly ash (stabilization) or fly ash and lime (fixation) to produce a physically stable material. In the current generation of wet FGD systems, air is bubbled through the reaction tank (or in some cases, a separate vessel) to practically convert all of the CaSO₃•1/2H₂O into calcium sulfate dihydrate (CaSO₄•2H₂O), which is commonly known as gypsum. This step is termed “forced oxidation” and has been applied to both lime- and limestone-based FGD processes. Compared to calcium sulfite hemihydrate, gypsum has much superior dewatering and physical properties, and forced oxidized FGD systems tend to have few internal scaling problems in the absorber and mist eliminators. Dewatered gypsum can be landfilled without stabilization or fixation. Many FGD systems in the United States are using the forced-oxidation process to produce a commercial grade of gypsum that can be used in the production of portland cement or wallboard. Marketing of the gypsum can eliminate or greatly reduce the need to landfill FGD byproducts.

The absorber vessels are fabricated from corrosion-resistant materials such as epoxy/vinyl ester-lined carbon steel, rubber-lined carbon steel, stainless steel, or fiberglass. The absorbers handle large volumes of abrasive slurries. The byproduct dewatering equipment is also relatively complex and expensive. These factors result in

relatively higher initial capital costs. Wet FGD processes are also characterized by higher raw water usage than semi-dry FGD systems. This can be a significant disadvantage or even a fatal flaw in areas where raw water availability is in short supply.

A countercurrent spray tower has become one of the most widely used absorber types in wet limestone-based FGD service. Flue gas enters at the bottom of the absorber and flows upward. Slurry with 10 to 15 percent solids is sprayed downward from higher elevations in the absorber and is collected in a reaction tank at its base. The SO_2 in the flue gas is transferred from the flue gas to the recycle slurry. The hot flue gas is also cooled and saturated with water. Recycled slurry is pumped continuously from the reaction tank to the slurry spray headers. Each header has numerous individual spray nozzles that break the slurry flow into small droplets and distribute them evenly across the cross section of the absorber. Prior to leaving the absorber, the treated flue gas passes through a two-stage, chevron-type mist eliminator that removes entrained slurry droplets from the gas. The mist eliminator is periodically washed to keep it free of solids.

In the reaction tank, the SO_2 absorbed from the flue gas reacts with soluble calcium ions in the recycle slurry to form insoluble calcium sulfite and calcium sulfate solids. In forced-oxidization processes, air is bubbled through the slurry to convert all of the solids to calcium sulfate dihydrate (gypsum). A lime or limestone reagent slurry is added to the reaction tank to replace the calcium consumed.

To control the solids content of the recycle slurry, a portion of the slurry is discharged from the reaction tank to the byproduct dewatering equipment. Depending on the ultimate disposal of the byproduct solids, the dewatering equipment may include settling ponds, thickeners, hydrocyclones, vacuum filters, and centrifuges. The liquid that is separated from the byproduct solids slurry is stored in the reclaim water tank. Water in the reclaim water tank is returned to the absorber reaction tank as makeup water and used to prepare the reagent slurry.

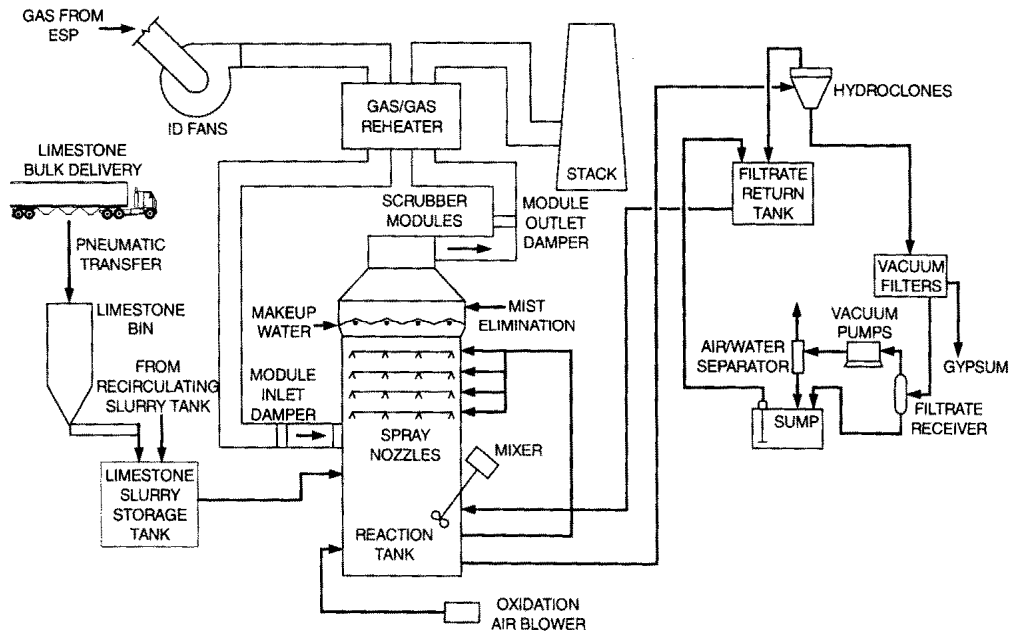


Figure D-6
Process Flow Diagram of FGD Process

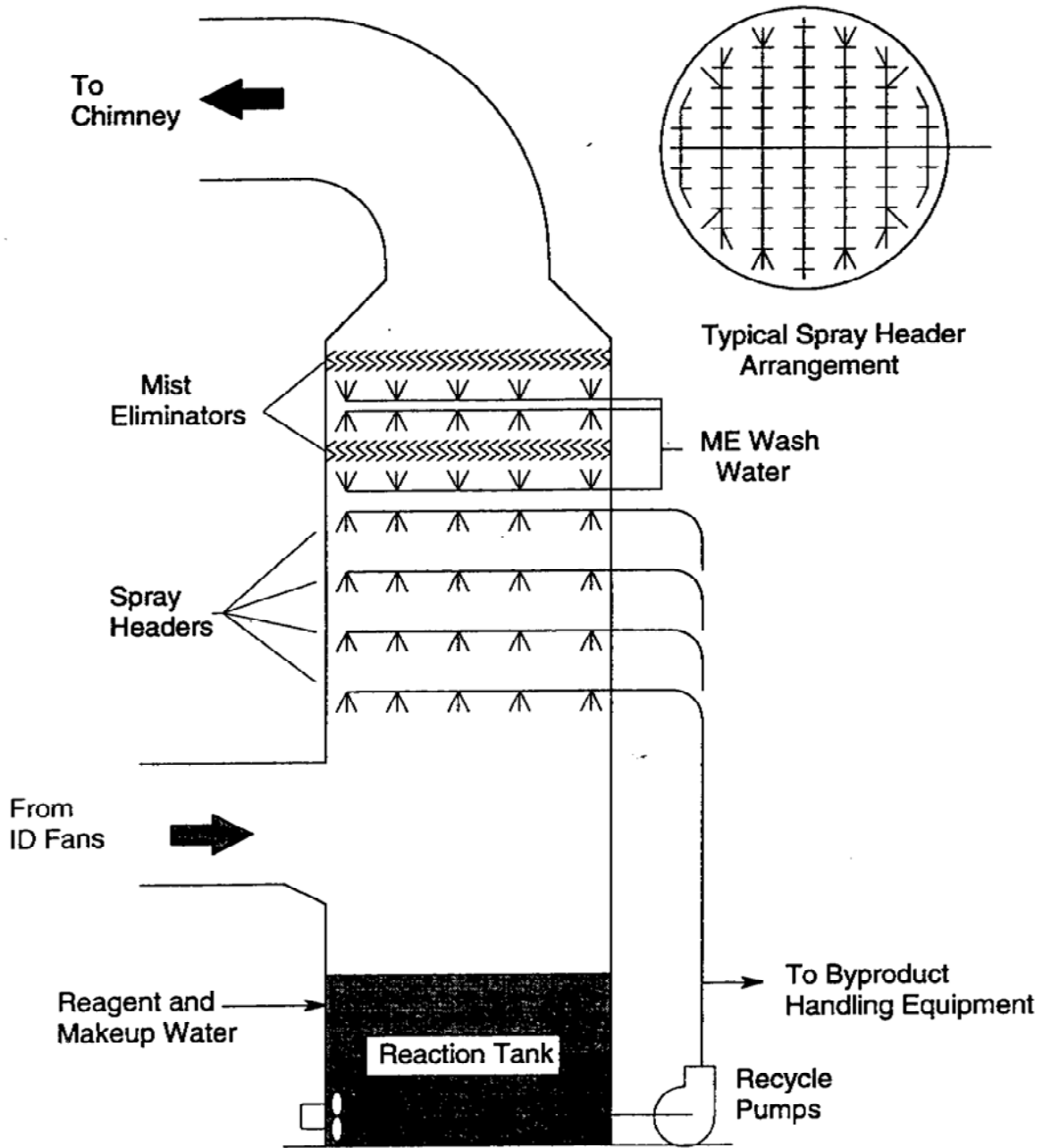


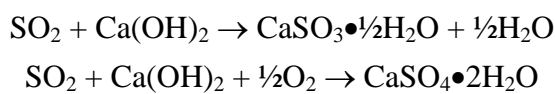
Figure D-7
 Countercurrent Spray Tower FGD Process

Spray Dryer Absorber

Spray dryer absorber (SDA) FGD processes have been extensively used. US utilities have installed numerous SDA FGD systems on boilers using low sulfur fuels.

These installations, primarily located in the western United States, use either lignite or subbituminous coals such as PRB as the boiler fuel and generally have spray dryer systems designed for a maximum fuel sulfur content of less than 2 percent. The SDA lime-based FGD system has an inherent removal efficiency limitation of 94 percent from inlet concentration.

The SDA FGD process uses calcium hydroxide [Ca(OH)₂] produced from the lime reagent as either a slurry or as a dry powder to the flue gas in a reactor designed to provide good gas-reagent contact. The SO₂ in the flue gas reacts with the calcium in the reagent to produce primarily calcium sulfite hemihydrate (CaSO₃•1/2H₂O) and a smaller amount of calcium sulfate dihydrate (CaSO₄•2H₂O) through the following reactions:



Water is also added to the reactor (either as part of the reagent slurry or as a separate stream) to cool and humidify the flue gas, which promotes the reaction and reagent utilization. The amount of water added is typically sufficient to cool the flue gas to within 30° to 40° F of the flue gas adiabatic saturation temperature. Significantly less water is used in these SDA FGD processes compared to wet FGD processes.

The reaction byproducts and excess reagent are dried by the flue gas and removed from the flue gas by a particulate control device (either fabric filter or DESP). Fabric filters are preferred for most systems, because the additional contact of the flue gas with the particulate on the filter bags provides additional SO₂ removal and higher reagent utilization. A portion of the reaction byproducts collected is recycled to the reagent preparation system in order to increase the utilization of the lime.

Because of the large amount of excess lime present in the FGD byproducts, the byproducts (and fly ash, if present) will experience pozzolanic (cementitious) reactions when wetted. When wetted and compacted, the byproduct makes a fill material with low permeability (low lengthening characteristics) and high bearing strength. However, other than as structural fill, this byproduct has limited commercial value and typically must be disposed of as a waste material.

The SDA FGD processes offer benefits in addition to SO₂ removal, including the lack of a visible vapor plume and SO₃ removal. Because the SDA FGD systems do not saturate the flue gas with water, there is no visible plume from the stack under most weather conditions. Environmental concerns with SO₃ emissions are also reduced with the SDA scrubber. SO₃ is formed during combustion and will react with the moisture in the flue gas to form sulfuric acid (H₂SO₄) mist in the atmosphere. An increase in H₂SO₄

emissions will increase PM₁₀ emissions. The gas temperature leaving the reactor is lowered below the sulfuric acid dew point, and significant SO₃ removal will be attained as the condensed acid reacts with the alkaline reagent. By removing SO₃ in the flue gas, the condensable particulate matter emissions can be reduced. This will reduce the potential for any SO₃ plume that may cause opacity in stacks. Similar type of SO₃ removal is not achievable with a wet scrubber.

All current SDA designs use a vertical gas flow absorber. These absorbers are designed for co-current or a combination of co-current and countercurrent gas flow. In co-current applications, gas enters the cylindrical vessel near the top of the absorber and flows downward and outward. In combination-flow absorbers, a gas disperser located near the middle of the absorber directs a fraction of the total flue gas flow upward toward the slurry atomizers.

In both cases, the atomizers are located in the roof of the absorber. Both rotary and two-fluid nozzles have been applied to this approach. The atomizer produces an umbrella of atomized reagent slurry through which the flue gas passes. The SO₂ in the flue gas is absorbed into the atomized droplets and reacts with the calcium to form calcium sulfite and calcium sulfate. Before the slurry droplet can reach the absorber wall, the water in the droplet evaporates and a dry particulate is formed.

Some vendors base their designs on a single large rotary atomizer per absorber; others use up to three smaller rotary atomizers per absorber. Two-fluid atomizers are installed as an array of up to 16 nozzles per atomizer; all three approaches to spray atomizers have been successfully applied.

The flue gas, then containing fly ash and FGD byproduct solids, leaves the absorber and is directed to a fabric filter. The fly ash and byproduct solids collected in the fabric filter are pneumatically transferred to a silo for disposal. To improve both reagent utilization and spray solids drying efficiency, a large portion of the solids collected is directed to a recycle system, where it is slurried and re-injected into the spray dryer along with the fresh lime reagent.

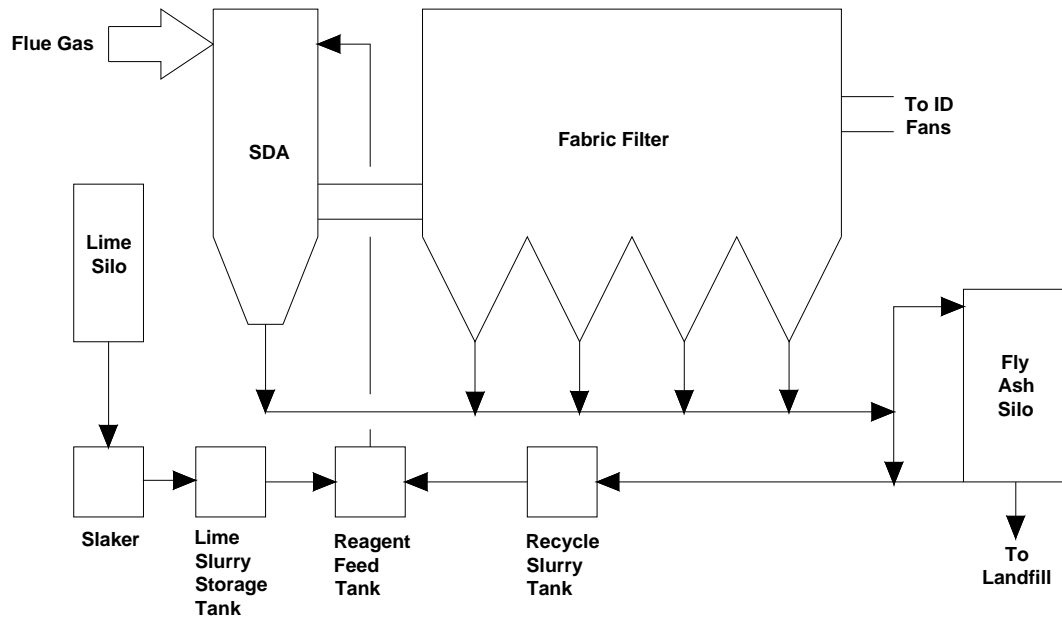


Figure D-8
SDA FGD Process

Circulating Dry Scrubber (CDS)

The CDS FGD process is a semi-dry, lime-based FGD process that uses a circulating fluid bed contactor rather than an SDA. The CDS absorber module is a vertical solid/gas reactor between the unit's air heater and its particulate control device. Water is sprayed into the reactor to reduce the flue gas temperature to the optimum temperature for reaction of SO_2 with the reagent. Hydrated lime $[\text{Ca}(\text{OH})_2]$ and recirculated dry solids from the particulate control device are injected cocurrently with the flue gas into the base of the reactor just above the water sprays. The gas velocity in the reactor is reduced and a suspended bed of reagent and fly ash is developed. The SO_2 in the flue gas reacts with the reagent to form predominately calcium sulfite. Fine particles of byproduct solids, excess reagent, and fly ash are carried out of the reactor and removed by the particulate removal device (either a fabric filter or electrostatic precipitator [ESP]). Over 90 percent of these solids are returned to the reactor to improve reagent utilization and increase the surface area for SO_2 /reagent contact.

The CDS FGD system produces an extremely high solids load on the particulate removal device due to the recycling of the byproduct/fly ash mixture. For this reason, some CDS FGD system vendors prefer to use an ESP rather than a fabric filter. Most of the recycled material can be collected in the first field of an ESP with minimal effect on the overall ESP sizing. On the other hand, a fabric filter in this same service would require special design features to avoid reduced bag life associated with frequent bag cleaning. Figure D-9 provides an illustration of the CDS FGD system.

The CDS can be considered an acceptable FGD removal technology in some applications because of its ability to remove significant amounts of SO₂, the commercial status of the technology, and the use of conventional reagents. It has disadvantages relating to the downstream particulate load imposed on collectors but its implementation schedule and minimal impact on local communities adds to its acceptability.

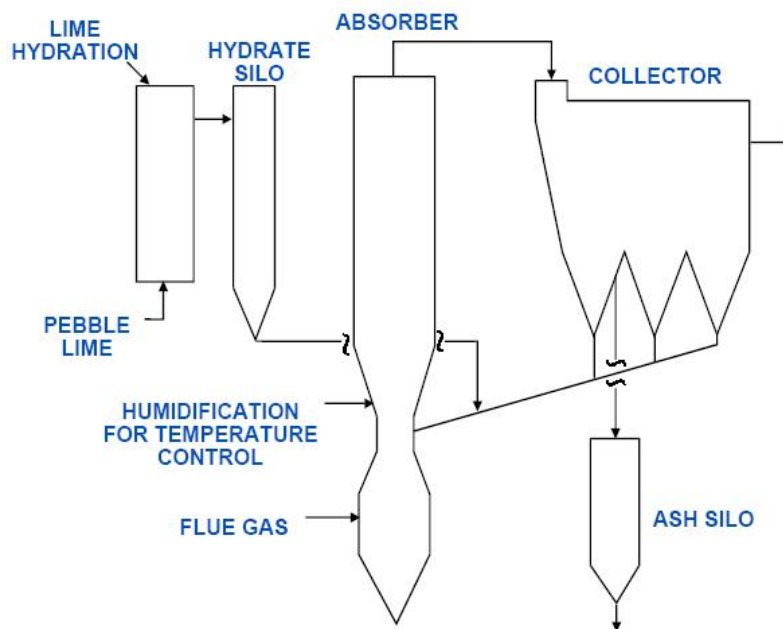


Figure D-9
Circulating Dry Scrubber System (Courtesy: Lurgi Lentjes North America)

Particulate Matter (PM) Reduction Technologies

Dry Electrostatic Precipitator (ESP)

ESPs are the most widely installed utility particulate matter (PM) removal technology. ESPs use transformer/rectifiers (TRs) to energize “discharge electrodes” and to produce a high voltage, direct current electrical field between the discharge electrodes and the grounded collecting plates. PM entering the electrical field acquires a negative charge and migrates to the grounded collecting plates. This migration can be expressed in engineering terms as an empirically determined effective migration velocity, but takes place in a turbulent flow regime with the particulate entrained within the turbulent gas patterns. Thus, the charged particles are actually captured when the combined effect of electrical attraction and gas flow patterns moves the PM close enough for it to attach to the collecting surfaces. A layer of collected particles forms on the collecting plates and is removed periodically by mechanically impacting or “rapping” the plates. The collected

particulate matter drops into hoppers below the precipitator and is removed by the ash handling system. Some particulate is also re-entrained and either collected in subsequent electrical fields or emitted from the ESP. A graphic showing the sections of an ESP is shown on Figure D-10.

The required particulate removal efficiency, the expected electrical resistivity of the fly ash to be collected, and the expected electrical characteristics of the energization system determine the physical size of an ESP. Many parameters determine the ESP's capability for particulate collection including the following major items:

- The first parameter is the Specific Collection Area (SCA). ESP size is often measured in terms of SCA. SCA is defined as the total collecting area in square feet (ft²) divided by the volumetric flue gas flow rate (1,000's of actual cubic feet per minute [acfm]).
- The treatment time of the flue gas within the electric collection fields of the ESP is an important aspect of particulate collection. High efficiency ESPs typically have treatment times between 7 and 20 seconds. Treatment time is becoming a major design parameter as lower particulate emissions are being mandated.
- Flue gas velocity, which is the speed at which the flue gas moves through the ESP, is important in the design and sizing of an ESP. Design gas velocities that range between 3 to 4 fps are common. The aspect ratio of the treatment length to the collection plate height is also important in the design and sizing of the ESP. As the aspect ratio increases, the re-entrainment losses from the ESP are minimized. Many existing ESPs have aspect ratios of approximately 0.8 to 1.2; newer ESPs, especially those meeting new particulate emission limits, have aspect ratios of approximately 1.2 to 2.0.
- The gas distribution for optimum particulate removal requires a uniform gas velocity throughout the entire ESP treatment volume, with minimal gas bypass around the discharge electrodes or collecting plates. If flue gas distribution is uneven, the particulate removal efficiency will decrease, and re-entrainment losses will increase in high velocity areas and reduce overall collection efficiency.
- Fly ash resistivity is a measure of how easily the ash or particulate acquires an electric charge. Typical coal fly ash resistivity values range from 1×10^8 ohm-cm to 1×10^{14} ohm-cm. The ideal resistivity range for electrostatic precipitation of fly ash is 5×10^9 to 5×10^{10} ohm-cm. Operating resistivity varies with flue gas moisture, SO₃ concentration, temperature, and ash chemical composition. As a result of fly ash resistivity being sensitive to these constituents, ESPs can be affected greatly by changes in fuel or operating conditions.

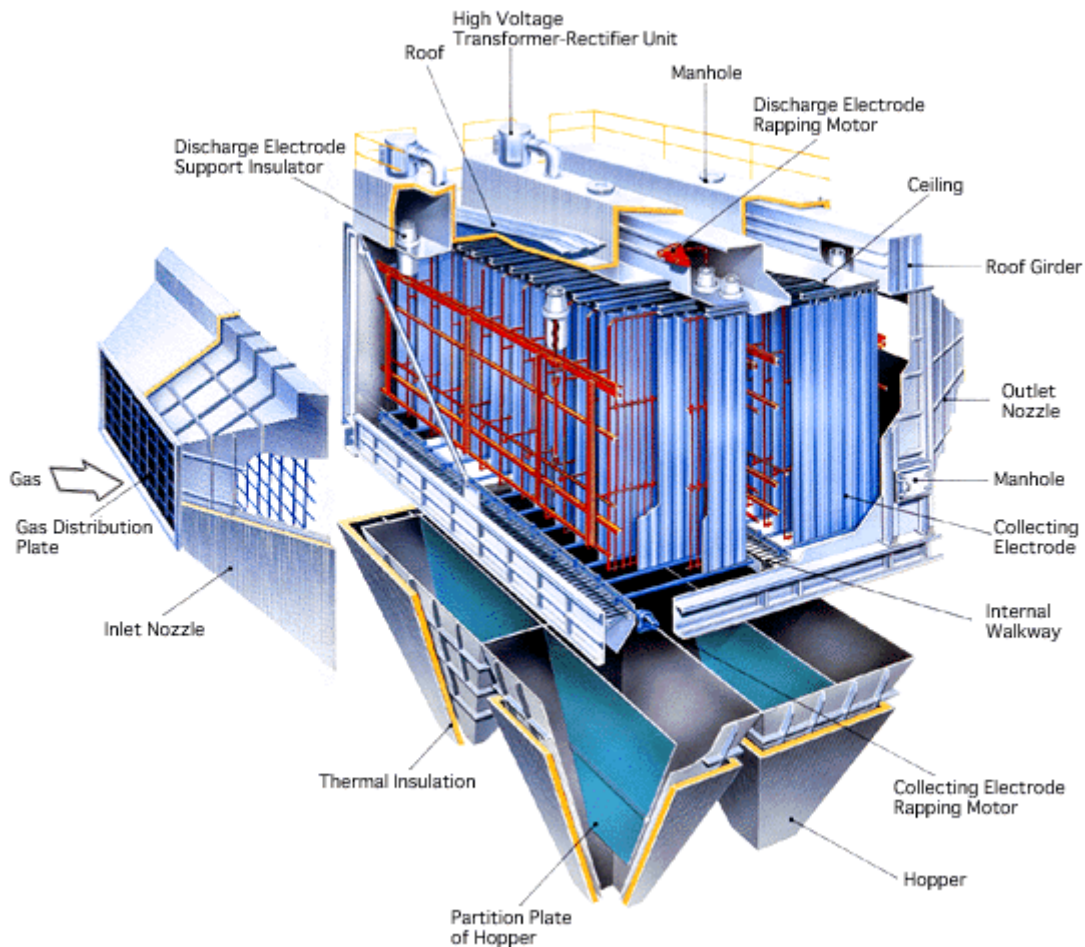


Figure D-10
Electrostatic Precipitator System (MHI)

Pulse Jet Fabric Filter (PJFF)

Fabric filters have been used for over 20 years on existing and new coal fired boilers and are media filters through which flue gas passes to remove the particulate. The success of FFs is predominately due to their ability to economically meet the low particulate emission limits for a wide range of particulate operations and fuel characteristics. Proper application of the FF technology can result in clear stacks (generally less than 5 percent opacity) for a full range of operations. In addition, the FF is relatively insensitive to ash loadings and various ash types, offering superb coal flexibility.

FFs are the current technology of choice when low outlet particulate emissions or Hg reduction is required for coal fired applications. FFs collect particle sizes ranging from submicron to 100 microns in diameter at high removal efficiencies. Provisions can be made for future addition of activated carbon injection to enhance gas phase elemental

Hg removal from coal fired plants. Some types of fly ash filter cakes will also absorb some elemental Hg.

FFs are generally categorized by type of cleaning. The two predominant cleaning methods for utility applications are reverse gas and pulsejet. Initially, utility experience in the United States was almost exclusively with Reverse Gas Fabric Filters (RGFF). Although they are a very reliable and effective emissions control technology, RGFFs have a relatively large footprint, which is particularly difficult for implementations. PJFFs can be operated at higher flue gas velocities and, as a result, have a smaller footprint. The PJFF usually has a lower capital cost than a RGFF and matches the performance and reliability of a RGFF. As a result, only PJFFs will be considered further.

Cloth filter media is typically sewn into cylindrical tubes called bags. Each FF may contain thousands of these filter bags. The filter unit is typically divided into compartments that allow on-line maintenance or bag replacement after a compartment is isolated. The number of compartments is determined by maximum economic compartment size, total gas volume rate, air-to-cloth ratio, and cleaning system design. Extra compartments for maintenance or off-line cleaning not only increase cost, but also increase reliability. Each compartment includes at least one hopper for temporary storage of the collected fly ash. A cutaway view of a PJFF compartment is illustrated on Figure D-11.

Fabric bags vary in composition, length, and cross section (diameter or shape). Bag selection characteristics vary with cleaning technology, emissions limits, flue gas and ash characteristics, desired bag life, capital cost, air-to-cloth ratio, and pressure differential. Fabric bags are typically guaranteed for 3 years but frequently last 5 years or more.

In PJFFs, the flue gas typically enters the compartment hopper and passes from the outside of the bag to the inside, depositing particulate on the outside of the bag. To prevent the collapse of the bag, a metal cage is installed on the inside of the bag. The flue gas passes up through the center of the bag into the outlet plenum. The bags and cages are suspended from a tubesheet.

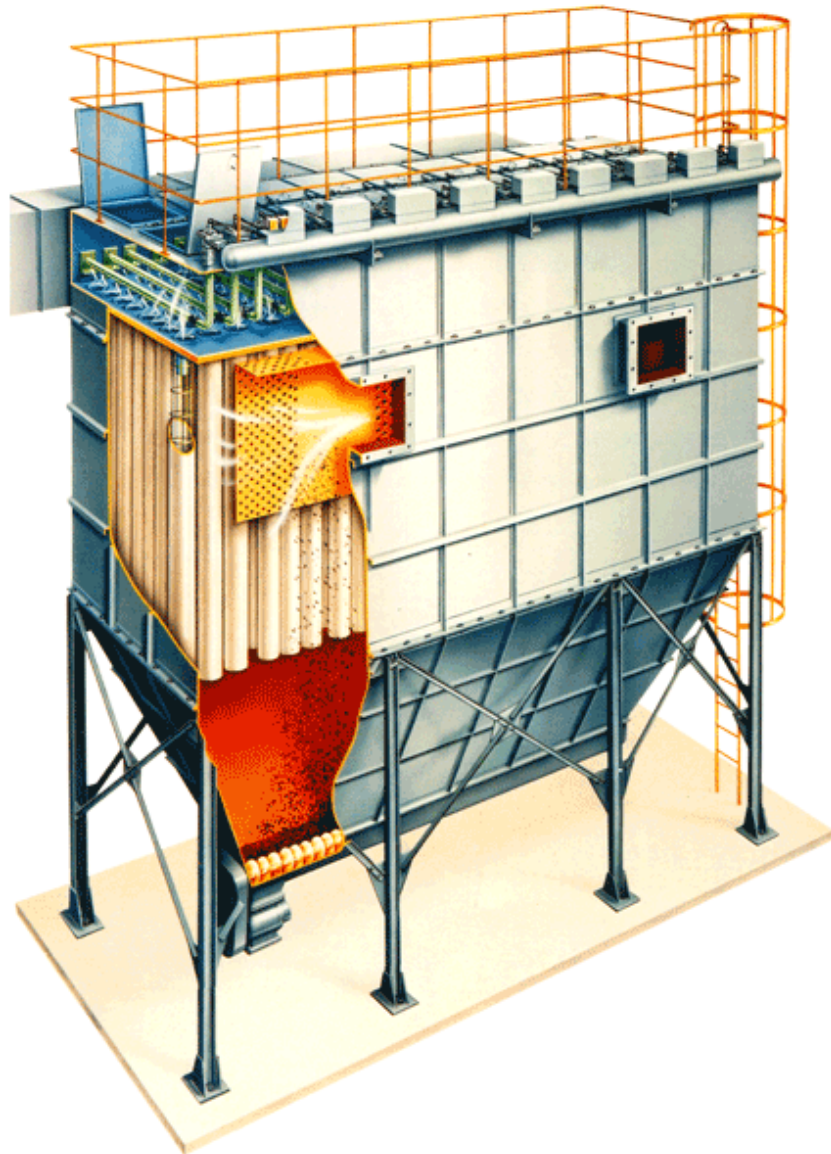


Figure D-11
Pulse Jet Fabric Filter Compartment

Cleaning is performed by initiating a downward pulse of air into the top of the bag. The pulse causes a ripple effect along the length of the bag. This dislodges the dust cake from the bag surface, and the dust falls into the hopper. This cleaning may occur with the compartment on line or off-line. Care must be taken during design to ensure that the upward velocity between bags is minimized so that particulate is not re-entrained during the cleaning process.

The PJFF cleans bags in sequential, usually staggered, rows. During on-line cleaning, part of the dust cake from the row that is being cleaned may be captured by the

adjacent rows. Despite this apparent shortcoming, PJFFs have successfully implemented on-line cleaning on many large units.

The PJFF bags are typically made of felted materials that do not rely as heavily on the dust cake's filtering capability as woven fiberglass bags do. This allows the PJFF bags to be cleaned more vigorously. The felted materials also allow the PJFF to operate at a much higher cloth velocity, which significantly reduces the size of the unit and the space required for installation.

Compact Hybrid Particulate Collector (COHPAC™)

Another control technology that is effective in removing particulate matter is a high air-to-cloth ratio fabric filter installed after an existing cold-side ESP. Commonly referred to as a Compact Hybrid Particulate Collector (COHPAC™), this technology was developed and trademarked by the Electric Power Research Institute (EPRI). The COHPAC™ filter typically operates at air-to-cloth ratios ranging from 6 to 8 ft/min. compared to a conventional fabric filter that typically operate at air-to-cloth ratios of about 4 ft/min. For a COHPAC™ system, the majority of the particulate is collected in the upstream ESP. Therefore, the performance requirements of a high air-to-cloth ratio fabric filter is reduced allowing installation of this technology in a smaller footprint area, with less steel and filtration media to substantially lower both capital and operating costs compared to conventional fabric filters.



Figure D-12
COHPAC™ I Arrangement (Courtesy: Hamon Research-Cottrell)

Mercury and Dioxin/Furan Reduction Technologies

Powdered Activated Carbon (PAC) Injection

With reported Hg removals of more than 90 percent for bituminous coal applications, PAC injection is an effective and mature technology in the control of Hg in Municipal Solid Waste (MSW) and Medical Waste Combustors (MWC). Its potential effectiveness on a wide range of coal fired power plant applications is gaining acceptance based on recent pilot and slipstream testing activities sponsored by the Department of

Energy (DOE), Environmental Protection Agency (EPA), Electric Power Research Institute (EPRI), and various research organizations and power generators. However, recent pilot scale test results indicate that the level of Hg control achieved with a PAC injection system is impacted by variables such as the type of fuel, the speciation of Hg in the fuel, operating temperature, fly ash properties, flue gas chloride content, and the mechanical collection device used in the removal of Hg.

PAC injection typically involves the use of a lignite based carbon compound that is injected into the flue gas upstream of a particulate control device as illustrated on Figure D-13. Elemental and oxidized forms of Hg are adsorbed into the carbon and are collected with the fly ash in the particulate control device.

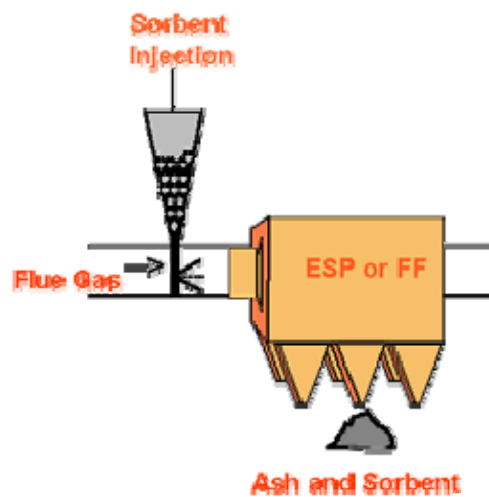


Figure D-13
Activated Carbon Injection System

PAC injection is generally added upstream of either PJFFs or ESPs. For ESPs, the Hg species in the flue gas are removed as they pass through a dust cake of unreacted carbon products on the surface of the collecting plates. Additionally, a significantly higher carbon injection rate is required for PAC injection upstream of a ESP than is required for PAC injection upstream of a high air-to-cloth ratio PJFF or a PJFF that is located downstream of a SDA FGD system. Literature indicates that PAC injection upstream of a cold ESP can reduce Hg emissions up to 60 percent for units that burn a sub-bituminous or lignite coal, and up to 80 percent for units that burn a bituminous coal. The addition of activated carbon does not directly affect the function of the ash handling system. The additional activated carbon in the fly ash does, however, affect the quality of the ash that is produced. For units that currently sell fly ash, this will negatively impact their continued ability to sell the ash.

Since the sale of fly ash depends on the carbon content of the ash, increasing the amount of carbon in the ash also makes it unsuitable for sale. To maintain the ash quality required for sale, the ash must either be removed upstream of the PAC injection system or the activated carbon should be injected into the flue gas so that it is not mixed with all the collected fly ash or is mixed with only a small portion of the total fly ash that is collected in the particulate control device. This can be accomplished by using a high air-to-cloth ratio PJFF downstream of cold ESP.

Numerous testing efforts and studies have shown that most of the Hg resulting from the combustion of coal leaves the boiler in the form of elemental Hg, and that the level of chlorine in the coal has a major impact on the efficiency of Hg removal with PAC injection and the particulate removal system. Low chlorine coals, such as sub-bituminous and lignite coals, typically demonstrate relatively low Hg removal efficiency. Sub-bituminous and lignite coals produce very low levels (approximately 100 parts per million [ppm]) of HCl during combustion and; therefore, normal PAC injection would be anticipated to achieve very low elemental Hg removal.

The removal efficiency that is attained by halogenated PAC injection can be significantly increased by the use of PAC that has been pretreated with halogens, such as iodine or bromine. Recent testing results indicate that halogenated PAC injection upstream of a cold ESP can reduce Hg emissions up to 80 percent for units that burn a sub-bituminous or lignite coal and up to 90 percent for units that burn a bituminous coal. Pretreated PAC is more expensive than untreated PAC: (approximately \$5.00/lb of iodine, \$1.00/lb of bromine, and \$0.50/lb of PAC). However, less pretreated PAC is required to achieve significant removals, if such removal rates are dictated by more stringent Hg control regulations.

PAC can also be injected upstream of a PJFF located downstream of a semi-dry lime FGD. When a semi-dry lime FGD and a PJFF is injected with PAC upstream of the FGD, the activated carbon absorbs most of the oxidized Hg. This is a result of the additional residence time in the FGD and will basically allow greater contact between the Hg particles and the activated carbon. Because of the accumulated solids cake on the bags, the activated carbon is given another opportunity to interact with the Hg prior to disposal or recycle. Since the ash and reagent collected in the PJFF are already contaminated, the additional carbon collected in the PJFF will not affect ash sales or disposal. Recent literature indicates that PAC injection upstream of a semi-dry FGD and PJFF can reduce Hg emissions by 60 to 80 percent.

Halogenated PAC injection upstream of a semi-dry lime FGD and PJFF is basically similar in design to standard PAC, as described previously. Halogenated PAC includes halogens such as bromine or iodine. Literature indicates that halogenated

sorbents require significantly lower injection rates (in some cases the difference is as much as a factor of 3) upstream of a semi-dry lime FGD and PJFF combination, as compared to an ESP, and can reduce Hg emissions of up to 95 percent.

CO Reduction Technologies

Good Combustion Controls

As products of incomplete combustion, CO and VOC emissions are very effectively controlled by ensuring the complete and efficient combustion of the fuel in the boiler (i.e., good combustion controls). Typically, measures taken to minimize the formation of NO_x during combustion inhibit complete combustion, which increases the emissions of CO and VOC. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO and VOC emissions. These parameters also increase NO_x generation, in accordance with the conflicting goals of optimum combustion to limit CO and VOC, but lower combustion temperatures to limit NO_x. The products of incomplete combustion are substantially different and often less pronounced when the unit is firing high sulfur bituminous coals, which is the rationale for the slightly higher BACT emissions limits found on units permitted to burn low sulfur PRB subbituminous coals. In addition, depending on the manufacturer, good combustion controls vary in terms of meeting CO emissions limits.

Neural Networks

Neural networks utilize a DCS based computer system that obtains plant data such as load, firing rate, burner position, air flow, CO emissions, etc. The computer system analyzes the impact of various combustion parameters on CO emissions. The system then provides feedback to the control system to improve operation for lower CO emissions. With this combustion system performance monitoring equipment in place, it is expected that sufficient information would be available to maintain the performance of each burner at optimum conditions to enable operations personnel to maintain the most economical balance of peak fuel efficiency and emissions of NO_x, and CO. In addition to burner performance these monitoring systems also allow continuous indication of pulverizer, classifier and fuel delivery system performance to provide early indication of impending component failures or maintenance requirements. This system is also used to improve heat rate and often provides operational cost savings along with CO control. It is commercially proven and has demonstrated CO reductions. However, CO emission reductions due to installation of NN vary from unit to unit based on each unit's specific equipment configuration and operation.

It is recommended that detailed studies be performed to determine the potential benefit from NN installation.

Sulfuric Acid Mist Reduction Technologies

Sorbent Injection

Injection of finely divided alkalis into the flue gas has been demonstrated for the removal of SO_3 from flue gases. Most commercial experience is from units firing high sulfur oil where trace metals, mainly vanadium, increase SO_2 oxidation. Magnesium-based compounds have been used successfully for decades to capture SO_3 in oil fired units. As coal fired units burning high sulfur bituminous coals have been retrofitted with SCR systems, interest in the injection of alkali compounds directly into the flue gas duct of a unit has increased. Sorbents such as sodium bisulfite, trona, and hydrated lime have recently been used on large coal fired units, with reported results showing the achievement of high control efficiencies of SO_3 in high sulfur applications.