CIRCULATING FLUIDIZED BED-
FLUE GAS DESULFURIZATION TECHNOLOGY EVALUATION

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1. CIRCULATING FLUIDIZED BED FLUE GAS DESULFURIZATION DESCRIPTION

Circulating fluidized bed (CFB) technology is a dry scrubbing process that is generally used for low-sulfur coal. Similar to CFB flue gas desulfurization (FGD) scrubbing, the CFB-FGD system is typically located after the air preheater, and the waste products are collected in either a baghouse or electrostatic precipitator (ESP). A number of minor variations on the CFB-FGD technology are offered by three process developers. Lurgi Lentjes offers the technology under the generic name "CFB-FGD"; Babcock Borsig Power offers the technology under "Turbosorp^{TM} FGD"; and Wulff Deutschland GmbH offers the technology under "GRAF/WULFF."

Flue gas is treated in an absorber by mixing the gas stream counter-currently with hydrated lime mixed with recycled waste. The water is injected in the scrubber in the throat of a venturi to maintain a temperature of approximately 160°F. The velocity in the scrubber is maintained to develop fluidized bed in the scrubber. The sprayed water droplets evaporate, cooling the gas at the inlet from 300°F or higher to approximately 160°F, depending on the relationship between approach to saturation and removal efficiency. The hydrated lime absorbs SO_2 from the gas and form calcium sulfite and calcium sulfate. The desulfurized flue gas passes out of the CFB scrubber, along with reaction products, unreacted hydrated lime, calcium carbonate, and the fly ash to the ESP or baghouse.

1.1 PROCESS CHEMISTRY

The SO_2 absorbed in the atomized slurry reacts with lime in the slurry to form calcium sulfite ($CaSO_3$) in the following reaction:

$$SO_2 + CaO + 1/2\ H_2O \Rightarrow CaSO_3 \bullet 1/2\ H_2O$$

A part of the CaSO3 reacts with oxygen in the flue gas to form calcium sulfate (CaSO4):

$$CaSO_3 + \tfrac{1}{2}O_2 + 2H_2O \Rightarrow CaSO_4 \bullet 2H_2O$$

A small amount of carbon dioxide also reacts with hydrated lime to form calcium carbonate:

A part of the CaSO3 reacts with oxygen in the flue gas to form calcium sulfate (CaSO4):

$$Ca(OH)_2 + CO_2 \Rightarrow CaCO_3 + H_2O$$

1.2 REAGENTS AND WASTE PRODUCTS

Preparation of the hydrated lime reagent involves atmospheric lime hydrator. The hydrated lime also can be purchased as a reagent; however, converting commercially available lime into hydrated lime on the plant premises offers a low-cost solution. The hydrated lime is stored in a day silo for later use. Typically, the hydrated lime is fed to the absorber by means of a rotary screw feeder. The reagent is fed to the absorber to replenish hydrated lime consumed in the reaction, and the feed rate is typically controlled based on the removal efficiency required.

The waste product contains $CaSO_3$, $CaSO_4$, calcium hydroxide, calcium carbonate, and ash.

1.3 COMMERCIAL STATUS

CFB-FGD systems are in operation at many facilities ranging in size from less than 10 MW to 300 MW (multiple modules are required for plants greater than 300 MW in capacity). The largest CFB unit, in Austria supplied by WULFF Deutschland GmbH, is on a 275 MW size oil-fired boiler burning 1.0-2.0% sulfur oil.

CFB-FGD is commercially available from three process developers/vendors:

- Lurgi Lentjes
- Babcock Borsig Power
- WULFF Deutschland GmbH

2. CFB-FGD PROCESS ADVANTAGES AND DISADVANTAGES COMPARED TO WET FGD TECHNOLOGY

2.1 PROCESS ADVANTAGES

The CFB-FGD process has the following advantages when compared to wet limestone FGD technology:

1. The absorber vessel can be constructed of unlined carbon steel, as opposed to lined carbon steel or solid alloy construction for wet FGD. For units less than 300 MW, the capital cost is typically lower than for wet FGD. For units larger than 300 MW, multiple module requirements typically cause the CFB-FGD process to be more expensive than the wet FGD process.

2. Pumping requirements and overall power consumption are lower than for wet FGD systems.

3. Waste produced is in a dry form and can be handled with conventional pneumatic fly ash handling equipment.

4. The waste is stable for landfill purposes and can be disposed of concurrently with fly ash.

5. The CFB-FGD system uses less equipment than does the wet FGD system, resulting in fixed, lower operations and maintenance (O&M) labor requirements.

6. The pressure drop across the absorber is typically lower than for wet FGD.

7. High chloride levels improve (up to a point), rather than hinder, SO_2 removal performance.

8. Sulfur trioxide (SO_3) in the vapor above approximately 300°F, which condenses to liquid sulfuric acid at a lower temperature (below acid dew point), is removed efficiently with CFB-FGD. Wet limestone scrubbers capture less than 25% to 40% of SO_3 and would require the addition of a wet ESP to remove the balance or hydrated lime injection. The emission of sulfuric acid mist, if above a threshold value, may result in a plume visible after the vapor plume dissipates.

9. Flue gas following a CFB-FGD is unsaturated with water (30°F to 50°F above dew point), which reduces or eliminates a visible moisture plume. Wet limestone scrubbers produce flue gas that is saturated with water, which requires a gas-gas heat exchanger to reheat the flue gas

to operate as dry stack. Due to the high costs associated with heating the flue gas, all recent wet FGD systems in the United States have used wet stack operations.

10. CFB-FGD systems have the capability of capturing a high percentage of gaseous mercury in the flue gas if the mercury is in the oxidized form. Further, due to the nature of the filter cake present in the fabric filter associated with CFB-FGD, the CFB-FGD equipment with a fabric filter will tend to capture a higher percentage of oxidized mercury than would LSD equipment with an ESP. The major constituent that will influence the oxidation level of mercury in the flue gas has been identified as chlorine. Considering the typical level of chlorine contained in coals in the United States, we can expect that CFB-FGD systems applied to high-chlorine bituminous coals will tend to capture a high percentage of the mercury present in the flue gas. Conversely, CFB-FGD systems applied to low-chlorine sub-bituminous coals and lignite will not capture a significant amount of the mercury in the flue gas.

11. There is no liquid waste from a CFB-FGD system, while wet limestone systems produce a liquid waste stream. In some cases, a wastewater treatment plant must be installed to treat the liquid waste prior to disposal. The wastewater treatment plant produces a small volume of waste, rich in toxic metals (including mercury) that must be disposed of in a landfill. A CFB-FGD system provides an outlet for process wastewater from other parts of the plant when processing residue for disposal.

2.2 PROCESS DISADVANTAGES

The CFB-FGD process has the following disadvantages when compared to limestone wet FGD technology:

1. The largest absorber module used in the industry is 250 MW to300 MW. Some suppliers of CFB-FGD systems have proposed absorbers as large as 350 MW for eastern bituminous coal-fired units. For units sized at 500 MW, two modules will be required. This will also result in large inlet and outlet ductwork and damper combinations.

2. The CFB-FGD process uses a more expensive reagent (hydrated lime) than limestone-based FGD systems, and the reagent has to be stored in a steel or concrete silo.

3. Reagent utilization is lower than for wet limestone systems to achieve comparable SO_2 removal. The lime stoichiometric ratio is higher than the limestone stoichiometric ratio (on the same basis) to achieve comparable SO_2 removal.

4. CFB-FGD produces a large volume of waste, which does not have many uses due to its properties, i.e., permeability, soluble products, etc. Researchers may yet develop some

applications where the CFB-FGD waste can be used. Wet FGD can produce commercial-grade gypsum.

5. Combined removal of fly ash and waste solids in the particulate collection system precludes commercial sale of fly ash if the unit is designed to remove FGD waste and fly ash together. In some cases, FGD could be backfit after the existing ESP, which would allow the sale of fly ash.

6. The CFB-FGD process is applicable mostly for base-load applications, as high velocities are required to maintain fluidized bed.

3. DESIGN BASIS

3.1 SPECIFIC DESIGN CRITERIA – CFB-FGD

Table 3.1-1 lists the specific design criteria.

TABLE 3.1-1
SPECIFIC DESIGN CRITERIA

Unit capacity	500 MW	500 MW
Heat input to boiler, MBtu/hr	5,000	5,186
Fuel	Low-sulfur - Appalachian	Low-sulfur - Powder River Basin
Fuel analysis, % wt:		
Moisture	6.0	30.4
Ash	9.1	6.4
Carbon	72.6	47.8
Hydrogen	4.8	3.4
Nitrogen	1.4	0.7
Sulfur	1.3	0.6
Oxygen	4.7	10.8
Chlorine	0.1	0.03
High heating value, Btu/lb	13,100	8,335
SO_2 generation, lb/Mbtu	2.0	1.44
Coal feed rate, tons/hr	191	311
Flue gas flow at FGD inlet, macfm	1.79	1.97
Flue gas temperature at FGD inlet, °F	280	280
Flue gas flow at FGD outlet, macfm	1.60	1.75

TABLE 3.1-1
SPECIFIC DESIGN CRITERIA

Flue gas temperature at FGD outlet, °F	160	165
SO_2 reduction efficiency, %	95	95
SO_2 outlet, lb/Mbtu	0.10	0.072
Mercury concentration in coal, ppmd	0.06-0.10	0.08-0.12

Table 3.1-2 summarizes the parameters used for the FGD comparison.

TABLE 3.1-2
PARAMETERS USED FOR FGD COMPARISON

Unit capacity	500 MW	500 MW
Heat input to boiler, MBtu/hr	5,000	5,186
Fuel	Low-sulfur - Appalachian	Low-sulfur - Powder River Basin
SO_2 removal, %	95	95
SO_2 emission, lb/MBtu	0.10	0.072
By-product	Dry waste	Dry waste
Power consumption, %	0.65 new (without baghouse), 0.85 for retrofit	0.70 new (without baghouse), 0.90 for retrofit
Reagent	High-calcium lime	High-calcium lime
Reagent cost, $/ton	60	60
Reagent purity, %	93	93
Reagent stoichiometry, moles of CaO/mole of inlet sulfur	1.5	1.2
Load factor	80	80
FGD system life, years:		
New unit application	30	30
Retrofit unit application	20	20
Capital cost leveling factor, %/year:		
New unit application	14.5	14.5
Retrofit unit application	15.43	15.43

TABLE 3.1-2
PARAMETERS USED FOR FGD COMPARISON

Discount rate, %	8.75	8.75
Inflation rate, %	2.5	2.5
Operating cost levelization factor:		
New unit application	1.30	1.30
Retrofit unit application	1.22	1.22

3.2 SYSTEM DESIGN (SUBSYSTEMS)

The FGD system overall design consists of the following subsystems:

3.2.1 Reagent Handling and Preparation

Lime is received by truck (or barge) and conveyed to storage. Lime is stored in a 14-day capacity bulk storage lime silo. The lime is pneumatically conveyed to a 16-hour capacity day bin. The lime day bin and a gravimetric feeder supply the lime to a 150% atmospheric hydrating system. This will allow two-shift operations for the unit operating continuously at 100% load. A conventional commercially available atmospheric lime hydrator is used. The equimolar amount of water is added to the hydrator to convert lime into hydrated lime. The hydrated lime is pneumatically transported to a hydrated lime day silo (16-hour capacity). The hydrated lime is fed to the CFB absorber with a rotary screw feeder.

3.2.2 SO_2 Removal

Two absorbers, each treating 50% of the flue gas, are provided to achieve 95% SO_2 removal efficiency in the absorber and ESP. The absorber is a CFB reactor where the solids are fluidized with the flue gas. The pressure drop across the absorber will be approximately 8 to 10" w.c. The flue gas is introduced to the absorber through a venturi to facilitate the fluidization. The water is injected into the tower at the throat of the venturi using high-pressure atomizers. The absorber is a carbon steel absorber. The absorber will be operated at 30^oF adiabatic approach to saturation temperature. The hydrated lime, along with the recycle waste, is introduced just above the venturi. The counter-current flow thus offers large residence time and significant turbulence to enhance particle flue gas interaction to achieve high SO_2 reduction efficiency. The particle interaction also helps remove the layer of product formed on the particle surface enhancing the reagent utilization.

3.2.3 ESP/Baghouse

For the retrofit application, it is assumed that the existing ESP can be modified. The first field will be converted to a mechanical dust curtain with slide gate hopper design. The collected fly ash will be sent directly to the scrubber.

For the new application, a knockdown chamber, followed by a conventional full-scale pulsejet baghouse with an air-to-cloth ratio of 3.5 ft/min, is provided. The baghouse is provided with a spare compartment for offline cleaning to maintain the opacity at 10% or less. The waste will be pneumatically conveyed to a waste storage silo with a 3-day storage capacity, which is in accordance with typical utility design.

3.2.4 Flue Gas System/Stack

The flue gas from the air preheater will be sent to the absorbers. The gases from the absorber will be sent to the baghouse to collect the waste products and the fly ash. The booster fan is sized to provide an additional 10" H_2O (8" operating) pressure drop for the retrofit application and 16”H_2O (14" w.c. operating) pressure drop for the new application through the absorber and ESP/baghouse. The existing stack will be used for the retrofit case.

3.2.5 Waste Handling

The waste will be collected in the baghouse. A portion of the waste will be stored in a recycle storage silo, which will then be used to mix with lime slurry to increase the reagent utilization. Pug mills (2 x 100%) are provided to treat the CFB-FGD waste before it is loaded onto the trucks for disposal or sale.

3.2.6 General Support

The general support equipment includes the seal water system, instrument air compressor, makeup water system, and control room.

3.2.7 Miscellaneous

Equipment considered as miscellaneous includes onsite electrical power equipment, such as transformers and grounding, which is required to supply electrical power to the FGD system.

Table 3.2–1 lists the equipment used in each subsystem.

TABLE 3.2-1
EQUIPMENT USED IN EACH SUBSYSTEM

Reagent Handling and Preparation
Truck unloading system
Lime bulk storage steel silo (14 days' storage)
Lime live storage transport
Lime day bin (16 hours' storage)
Atmospheric lime hydrator(150% capacity)
Hydrated lime storage silo (16 hours' storage)
SO_2 Removal System
CFB absorbers (2 x 50%)
Water nozzles (4 per absorbers)
High-pressure water pumps (3 x 50%)
ESP/Baghouse System
Retrofit Units/ESP System:
ESP modifications
Mechanical dust curtain
Waste unloading system modifications
Waste storage steel silo (3 days' storage)
New Units/Baghouse System:
Pulse jet baghouse (air to cloth ratio – 3.5 ft/min)
Baghouse inlet ductwork

TABLE 3.2-1 EQUIPMENT USED IN EACH SUBSYSTEM
Baghouse outlet ductwork
Waste unloading system
Waste storage steel silo (3 days' storage)
Flue Gas System
Booster induced draft fans (2 x 50%)
Absorber inlet ductwork/dampers
Absorber outlet ductwork/dampers
Waste Handling and Recycle System
Recycle waste storage bin (16 hours' storage)
Recycle waste conveying
Recycle waste slurry tank
Pug mills (2 x 100%)
General Support System
Slaking water tank
Slaking water pumps (2 x 100%)
Instrumentation/plant air compressors (2 x 50%)
Miscellaneous
Transformers/switchgear
Electrical wiring, cables, etc.

4. IDENTIFICATION OF APPLICATION CONSTRAINTS

Summarized below are the application constraints that we have identified.

4.1 UNIT/ABSORBER SIZE

LSD FGD systems are in operation at many facilities, ranging in size from 50 MW to 300 MW. However, multiple modules are required for plants greater than 250 MW to 300 MW in capacity.

4.2 COAL SULFUR CONTENT

CFB-FGD systems are applied mainly to low-sulfur coal. Most of these systems are applied to inlet sulfur dioxide less than 3.0 lb/MBtu. In the United States, the system is installed at the Neil Simpson Station, Unit 2, which uses Powder River Basin coal. In Europe, bituminous plants with this system installed have experienced sulfur dioxide as high as 3.0 lb/MBtu. Due to requirement of a large amount of reagent, these systems are not likely to be installed on high-sulfur bituminous coal plants.

4.3 PERFORMANCE EXPECTATIONS

The SO_2 removal guarantees of 95% are available from the system supplier. The process has been demonstrated to achieve 90-95% SO_2 reduction efficiency. However, the higher efficiency also results in poor reagent utilization.

4.4 SO_2 REDUCTION

Suppliers of FGD systems have guaranteed SO_2 reduction efficiency up to 95% with the inlet SO_2 concentration up to 3.0 lb/MBtu. The equivalent guarantees are estimated to be 0.08 lb/MBtu or 95%, whichever is achieved first.

4.5 REAGENT UTILIZATION

The reagent utilization is limited due to the mass transfer limitations. Suppliers of FGD systems are using alkalinity in the waste by recycling the waste along with the active reagent. The alkalinity of Powder River Basin ash has resulted in good reagent utilization compared to acidic fly ashes from eastern bituminous coal. For example, to achieve a reduction efficiency of 90% SO_2, a stoichiometric ratio of 1.2 could be used, compared to 1.5 stoichiometric ratio for bituminous coals with waste recycling. The stoichiometric ratio for CFB-FGD is based on the inlet SO_2 concentration.

4.6 WASTE/BY-PRODUCT QUALITY

The waste product contains $CaSO_3$, $CaSO_4$, calcium hydroxide, calcium carbonate, and ash. This material cannot be used in the cement industry or for wallboard; however, there is potential for use as an agricultural soil conditioner and for preparation of bricks or aggregates by mixing with other waste components, such as fly ash. If there is currently significant income from the sale of fly ash, it may be prudent to install the CFB-FGD/baghouse combination after the existing particulate collector, such that the fly ash is segregated from the CFB-FGD waste and can continue to be sold.

4.7 ENERGY CONSUMPTION

The primary energy consumption is in the form of pressure drop across the absorber. Nearly 80% of the energy required for FGD operation is due to increase in draft (8-10” w.c. including inlet and outlet ductwork), with 20% of the energy required for the rest of the subsystems.

4.8 RETROFIT VERSUS NEW UNITS

The CFB-FGD technology is installed between the air heater outlet and particulate collector. Most existing units have very short ductwork between the air heater outlet and ESP inlet. This makes it very difficult to take the gas from the air heater outlet to the CFB equipment and return it to the ESP inlet. Also, most existing ESPs are not designed to handle increased particulate loading resulting from the CFB waste products. This will require modifications to the existing ESP to accommodate collection of the additional particulate from the CFB. The existing ESP will have to be modified and a mechanical dust curtain will have to be installed.

However, new units are expected to be installed with a baghouse. Again, before the gas enters the baghouse, the mechanical dust curtain will have to be installed along with slide gate valve to facilitate the recycling of the waste to improve utilization. The utilization will be better on the units installed with baghouse compared to retrofit units installed with modifications to an ESP.

5. COSTS ANALYSIS

5.1 CAPITAL COSTS

Estimated capital costs for the CFB-FGD system were determined for new and retrofit applications, which includes the equipment, materials, structural, and electrical components associated with the retrofit installation of these technologies.

The costs were developed using Sargent & Lundy's database as well as price quotes obtained from manufacturers for the equipment/work needed.

The capital cost estimates provided herein are essentially "total plant cost," and include the following:

- Equipment and material
- Direct field labor
- Indirect field costs and engineering
- Contingency
- Owner's cost
- Allowance for funds during construction (AFUDC)
- Initial inventory and spare parts (1% of the process capital)
- Startup and commissioning

Finally, the capital cost estimates provided do not include taxes and property tax. License fees and royalties are not expected for the proposed control strategies.

Salient features of each capital cost estimate prepared for FGD installations include:

- Demolition of existing ductwork to provide access to the flue gas from the air heater outlet
- Inlet and outlet ductwork to absorber and baghouse
- 2 x 50% absorbers

- ESP modifications/baghouse
- ID fan modifications for retrofit application
- Auxiliary power system upgrade (for retrofit)

No range estimate was performed to assess the relative accuracy of this budgetary estimate. Based on experience, it is believed that the relative accuracy of the estimate is ±20%.

Additionally, the underlying assumption, unless specifically stated otherwise, is that the contracting arrangement for the project is large, multiple lump sum work packages. If the client expects to execute the project on an engineer, procure, construct or turnkey basis, a separate risk allocation should be added to the estimate of 5% to 20% (1.05 or 1.2 multiplier) for this method of construction, with actual value dependent on the relative risk of labor, construction difficulty, etc.

Exhibit 5–1 and Exhibit 5–2 present the capital costs for new units and retrofit units, respectively.

5.2 OPERATIONS AND MAINTENANCE COSTS

Exhibit 5–3 and Exhibit 5–4 present the estimated O&M expenses associated with CFB-FGD systems. These costs include both fixed and variable operating costs, defined as follows:

5.2.1 Fixed O&M Costs

The fixed O&M costs determined for this study consist of sulfur oxides (SO_X) emission control technology, O&M labor, maintenance material, and administrative labor.

For purposes of this study, the installation of the FGD system has been anticipated to add an additional five operators to the current pool of operating labor for new units and eight operators for the retrofit application. It is assumed that the plant layout for the retrofit application is not optimized, which would require more operating labor than for the new unit.

Maintenance material and labor costs shown herein have been estimated based on technology operating experience in the United States and Europe. The maintenance cost includes periodic replacement of atomizers and maintenance material for various subsystems, and the labor required to perform the maintenance.

5.2.2 Variable O&M Costs

Variable O&M costs determined for each technology include the cost of lime, waste disposal, bags and cages replacement, water, and power requirements. The cost of fly ash is not included in this study as it is assumed that even if the fly ash is currently disposed of or sold, the proposed configuration will not affect the current operation. For new unit operations, if the fly ash sale creates significant revenue, an ESP can be installed upstream of the CFB-FGD. This analysis assumes that the ash will be disposed of along with FGD waste for the new unit application and thus the only differential cost will be applicable to FGD waste.

No added penalty for lost production has been included due to forced downtime to maintain the FGD systems because the availability (measure of random outage rates) of FGD systems is expected to be greater than 99%.

Auxiliary power costs reflect the additional power requirements associated with the operation of the existing ID fans as well as the estimated power consumption for atomizers, compressor for baghouse, lime preparation system, and various electrical and control users typically needed for FGD operations. The Owner will be responsible for the power cost of $30/MWh if the power is purchased from the open grid. This cost includes the replacement energy and capacity charges.

Exhibit 5–3 and Exhibit 5–4 present the fixed and variable O&M costs for new and retrofit applications, respectively.

5.3 LEVELIZED COSTS

Levelized costs, also referred to as "life cycle costs," take into account the impacts of capital costs and O&M costs during the operation of a plant over the period of analysis. The levelized fixed charge rate (impact due to capital cost) was calculated based on an assumption that a typical customer is a regulated utility. The levelized fixed charge rate includes depreciation of the property, return on capital (50% debt and 50% equity), income tax, property tax, and insurance. Based on an 8.75% discount rate and 30-year or 20-year life expectancy for new or retrofit facilities, respectively, the levelized fixed charge rates are 14.50% (30-year life) and 15.43% (20-years life). The levelized cost analysis was performed based on current dollars, as most regulated utilities base their analysis on current dollars.

The levelized O&M cost factor takes into account the discount rate, escalation rate, and annuity rate. The levelized O&M cost factors were 1.30 for the 30-year period and 1.22 for the 20-year analysis.