Comparison of Economic and Technical Features of Fluid Bed and Spray Dryer FGD Systems

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Abstract

Current US environmental regulations, fuel costs, and competition within the power generation industry have resulted in significant impacts on smaller and older coal-fired boilers. Special challenges are required for these boilers for environmental upgrades, especially flue gas desulfurization (FGD). Technology and economic conditions require owners of these power-generating facilities to look at dry FGD technologies as an alternative to Wet FGD systems.

High efficiency, Dry FGD technologies are generally divided into two categories: Circulating Fluid Bed (CFB) and Spray Dryer (SD) technologies. The spray dryers are further divided into two categories: dual fluid and rotary atomizer technologies. While CFB FGD systems such as Turbosorp® are not new to the US market, new applications in Europe and Asia have advanced the technology so that larger systems are now available with higher desulfurization removal rates.

This paper will review the following design features of wet and dry FGD technologies:

- Capital cost
- Sorbent use and cost
- Water requirements
- Power requirements
- Options for mercury control

Background

There are over 1,100 coal-fired utility boilers, or Electric Generation Units (EGUs) as defined by USEPA, operating in the US. When you look at the database of these operating units, 220 of these facilities were built between 1950 and 1959 and are producing power in the range of 100 to 300 MWs each.

There are 705 coal-fired EGU boilers currently in service at an operating capacity of 250 MWs or less. These 705 boilers represent over 21% of our installed coal-fired generation capacity. The extrapolation of this information means that these "older/smaller" boilers have the potential to contribute a substantial portion to our annual SO_2 emissions cap. Unless this segment of the industry can economically control SO_2 emissions, it may negatively impact our ability to meet the 2010 and 2015 SO_2 caps established in the CAIR regulations.

The challenge for the owner/operators of these facilities is how much capital they are able to invest in upgrading these plants taking into consideration:

- The age of these plants and their expected life
- Some of these plants have high heat rates and are not high on the dispatch curve.
- Many of these plants do not have high availability factors.
- Many of the older plants were constructed on small sites or in urban areas, which limits the space available for upgrades.

Project History

AES's Greenidge plant consists of two generating units, Unit 3 (Boilers 4 and 5) and Unit 4 (Boiler 6). Unit 3 is rated at 55 MW net and Unit 4 is rated at 109 MW net. Unit 3 initially began operations in 1950 and Unit 4 in 1953. Both Units burn bituminous coals from central Pennsylvania. The sulfur content of the coal burned ranges from 1.5 to 2.5%.

In 2000, the AES Greenidge management team undertook an evaluation as to determine the most beneficial approach to reducing air emissions from their plant. They were faced with all of the challenges listed above. AES was aware that before 2010 they would either have to make significant upgrades to the plant or the plant would not be able to continue operation. AES approached CONSOL Energy to assist them in this evaluation. They jointly surveyed the technology options and rapidly concluded:

> SNCR would not be able to achieve the required NOx reductions, but that their economics would not allow for the application of an SCR system.
>
> The economics of Wet FGD for SO_2 control were not viable to their plant, the site has limited capacity for a wet system, and they would have to install a wet stack or suffer an extensive outage. The Team then began investigating "dry" FGD technologies. Based on the research that CONSOL developed, it was concluded that spray dryer FGD technology could not achieve the SO_2 reduction levels required for the economic use of local coals, which can range in sulfur contents from 1.5% to 2.5%

Dry FGD systems have the following distinctions from wet systems:

- Less water consumption than WFGD
- Carbon steel can be used throughout the system eliminating the need for expensive alloys
- Easy to handle dry residue byproduct
- High chlorides improve SO_2 capture (there are specific limits)
- Lower initial capital cost than WFGD
- No saleable byproduct
- No need for a wet stack/mitigates visible plume
- Multi-pollution capabilities
  –PM_{10}, SO_3, Hg

To further develop the project, AES partnered with CONSOL Energy and applied to the DOE for a grant under the Power Plant Improvement Initiative Technology Focuses on Nation's 500 Small Coal-Burning Energy Producers.

AES and CONSOL undertook an extensive evaluation of the applications, comparing spray dryer technologies and circulating fluid bed (CFB) FGD technologies. CFB FGD technology was developed in Germany and had been applied in eastern European countries in coal-fired and waste-to-energy plants. There are three engineering/OEM vendor firms that produced CFBs and there were three applications of the CFB technology in the US; however, none were integrated into a multi-pollutant application. CFB FGD technology has the following advantages over SD technology:

- Fewer moving parts resulting in high availability and lower maintence cost
- Independent injection of lime and water resulting in improved operating range and better utilization of lime resulting in lower sorbent usage and lower cost.
- Lower power consumption than SD technology
- Can remove higher SO_2 removal rates (98%) on high sulfur fuels up to 2.9% sulfur in the fuel.
- The system eliminates the need for handling high solids slurries resulting in lower operating cost.
- “Gray” wastewater can be used for cooling.

The Team concluded that while there was not a significant capital cost differential between SD FGD and CFD FGD technology, there are significant operating cost benefits to the CFB and the CFB had a better operating range for coals that AES wanted to use.

The following chart summarizes the operating ranges of CFBs and spray dryers. This data was developed for 95% SO_2 removal for bituminous coal without ash recirculation. The approach temperature for the CFB is 42°F and 30°F for the spray dryer.

% Sulfur in Coal	0.5%.	1.0%	1.5%	2.0%
SO_2 lb/MMBtu	0.808	1.616	2.425	3.233
SO_2 ppm	419	837	1257	1675
Spray dryer Stoichometric ratio	1.60	1.75	2.2	***NA***
Fluid bed Stoichometric ratio (inlet)	1.35	1.36	1.43	1.52

In addition, a life cycle cost analysis was performed comparing WFGD, spray dryer and Babcock Power's Turbosorp CFB. The parameters of the analysis were:

- 95% SO_2 removal
- 2 x 180 MW plant retrofit
- One Turbosorp reactor per boiler, One Spray Dryer Absorber per boiler and One FGD vessel for the two boilers
- Baghouses were included for both the Turbosorp and Spray Dryer
- Lime cost were \$115/ ton and limestone \$15/ton
- 14 inch pressure drop for the CDS system, 12 inches for the SDA, and 6 inches for the WFGD

The results of the analysis were:

- Turbosorp had the following advantages:
    - –Initial capital costs for Turbosorp lower than DFGD
    - –Better lime utilization than SDA (19% less)
    - –Lower power than WFGD (20% less)
    - –No need for wet stack
    - –Water consumption for Turbo is 75% of a WFGD

The NPV results of the study for 0.7% sulfur coal are:

- Turbosorp \$67.7 MM
- Spray Dryer \$79.1 MM
- WFGD \$77.9 MM

Based on the team's evaluation, they concluded that a CFB FGD system would best suit AES's needs and proceeded to obtain proposals for the technology application. AES selected Babcock Power's proposal and CONSOL proceeded in filing for a grant from DOE.

CONSOL Energy Inc. received a contract from DOE on May 19th, 2006 to demonstrate a cost-effective multi-pollutant control technology applicable to approximately 500 of the nation's smaller power plants, ranging in size from 50 to 600 megawatts. DOE's share of the $38 million project is about $14.5 million; AES Greenidge, LLC, the host site and one of CONSOL's partners in the project, will contribute the remainder.

CONSOL, in support of AES Greenidge and Babcock Power Environmental Inc., will install a combination of technologies at the AES Greenidge Unit 4. Babcock Power Environmental is the EPC contractor as well as the prime supplier of the multi-pollutant technologies. The technologies include a hybrid system to reduce emissions of NOx and an advanced flue gas scrubber to reduce emissions of SO_2, mercury, and acid gases. Specifically, the control system will use selective non-catalytic reduction/in-duct selective catalytic reduction for NOx control and a circulating fluidized-bed dry scrubber system with activated carbon injection for mercury control and recycled baghouse ash to control SO_2, mercury, and acid gas emissions.

The goal of this multi-pollutant approach is to demonstrate significant improvements in the control of mercury, acid gases, and fine particulates, and substantial reductions in the cost of NOx and SO_2 control, when compared to conventional technologies for small boilers. The project will also demonstrate the performance of the multi-pollutant control system during periods when the plant co-fires biomass with coal.

The Greenidge Unit 4 is representative of our small coal-fired power plant fleet that collectively total about one-fourth of the nation's coal-fired generating capacity. These smaller units have become increasingly vulnerable to retirement or fuel switching as a result of more stringent state and federal regulations.

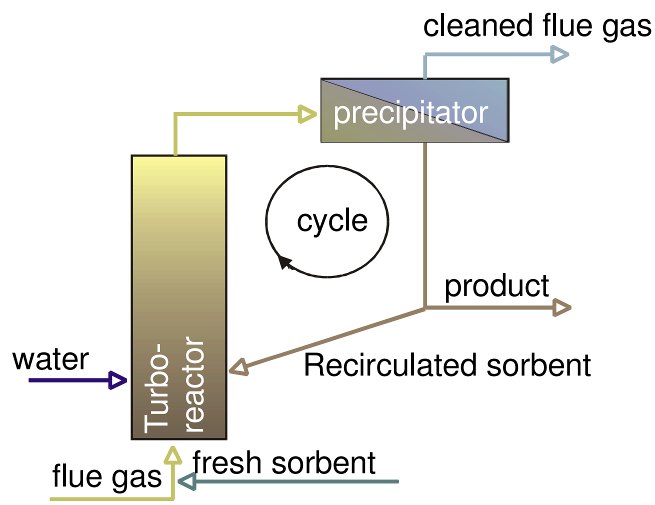
The conditions that make conventional selective catalytic reduction and wet scrubbers viable for large plants are not applicable to smaller coal-fired units. Also, these smaller units are usually constrained by space, which restricts the installation of typically larger selective catalytic reduction and wet scrubber systems. CONSOL Energy's project will demonstrate the commercial readiness of an emissions control system that is well suited to meeting regulations at these smaller plants.

FGD Process Technology

In the TURBOSORP® process, the flue gas flows through a cylindrical apparatus (fluidized bed reactor) from the bottom to the top. The bed material is made up of solids consisting of calcium hydroxide, calcium carbonate, the solid reaction products of the flue gas cleaning process, and ashes from the combustion process. Fresh and active material, either $Ca(OH)_2$ or CaO, is injected into the reactor while solids that have already undergone several cycles are recirculated into the reactor (refer to Fig. 1). The term "cycle" means a complete circulation of the sorbent particles through the whole plant (Turboreactor, separator, and any buffering tanks that may be installed).

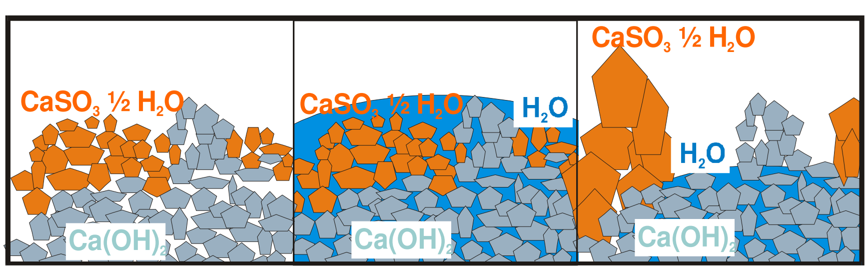
In order to lower the flue gas temperature for achieving increased desulfurization capacity, water is injected either horizontally or vertically, usually by means of a water nozzle situated in the vicinity of the flue gas inlet. In addition to the temperature reduction of the flue gas, this also leads to an increase in the relative humidity of the flue gas. Moreover, the wetting of the recirculated sorbents in the reactor makes new and reactive surfaces accessible in the solid particles as product layers, which already formed, become detached again by this wetting (refer to Fig. 2)

Figure 1: Principle of TURBOSORP®-Process



Apart from this activation by means of the water injection, a mechanical activation of the recirculated solid particles is also achieved by means of the turbulent flow in the fluidized bed reactor as the solids particles collide with each other and with the wall. The operating state of the fluidized bed lies within the range of the so-called “fast fluidized beds”, i.e. within the transition zone to pneumatic conveying.

Figure 2: Mechanism for the activation of recirculated sorbent



The flue gas inlet of the Turboreactor is designed as a Venturi nozzle. Due to the high flue gas velocities in the Venturi nozzle, the collapse of the fluidized bed and the falling down of solid particles through the Venturi nozzle is avoided.

After passing through the outlet of the Turboreactor, the solid particles are separated from the flue gas in a separator. When using the TURBOSORP® process for flue gas desulfurization, either electrostatic precipitators or fabric filters, preferably with mechanical pre-separators, can be used. When cleaning the flue gases of a waste incineration plant, only a fabric filter may be installed. The recirculation of the separated material in the reactor can be made either pneumatically (fluidizing conveyor) or mechanically (screw conveyor). Fig. 3 shows the process flow diagram of the TURBOSORP® process.

Figure 3: TURBOSORP® Process Flow Diagram

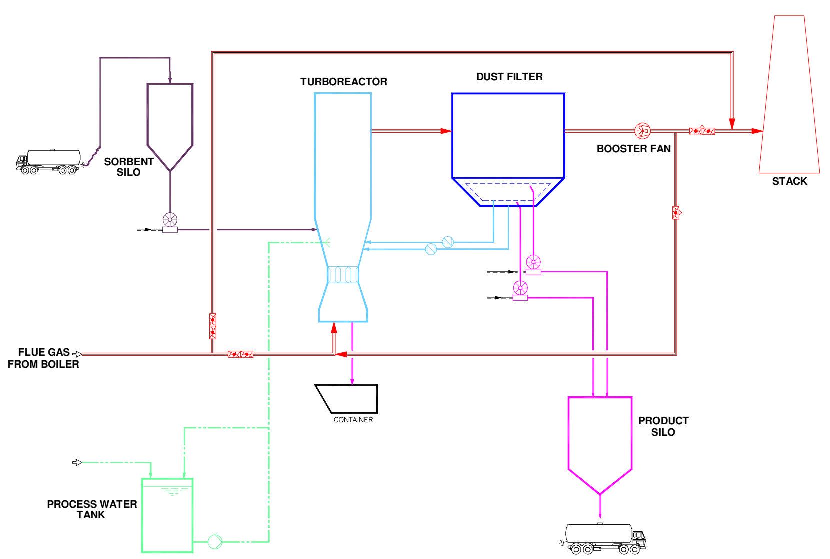
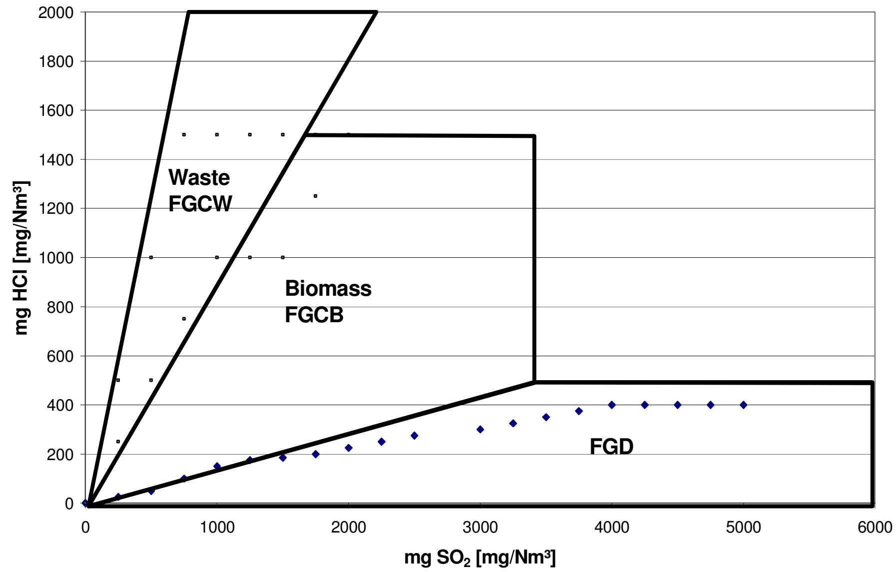


Fig. 4 shows the different applications for the TURBOSORP® process. Depending on the relation between SO_2 and HCl there are three types of applications, the TURBOSORP®-FGD (flue gas desulphurization), the TURBOSORP®-FGCB (flue gas cleaning after biomass boilers) and the TURBOSORP®-FGCW (flue gas cleaning after waste incinerators).

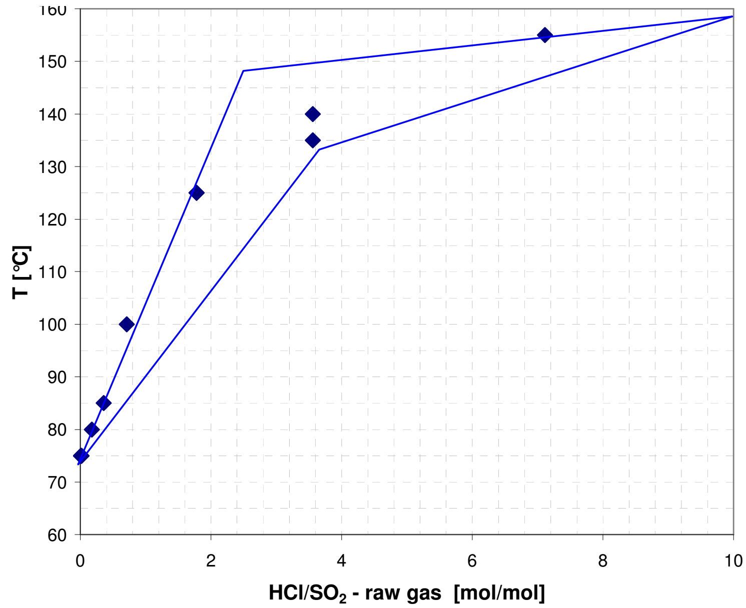
Figure 4: Different TURBOSORP® applications



In the TURBOSORP®-FGD process, the minimum operating temperature depends on the situation of the water dew point of the gas to be cleaned. It is advisable to maintain a minimum of 20 to 25°C from the dew point. This prevents caking or agglomeration of the solids on the walls in the Turboreactor. The content of chlorine in the flue gas has to be considered as well as the reaction product $CaCl_2 * nH_2O$, which is strongly hygroscopic, and may lead to caking and agglomeration.

For the use of the TURBOSORP®-FGCW process in the field of flue gas cleaning of waste incineration plants, the chlorine content of the flue gas is higher than the content of SO_2. Furthermore, in the TURBOSORP®-FGC process, open-hearth oven coke (HOK) is injected along with the sorbent containing calcium, which guarantees the separation of dioxins/furans and the separation of the volatile heavy metals like mercury, cadmium, and thallium. In the TURBOSORP®-FGCB process, the relation of HCl/SO_2 will be between the FGD and the FGCW. The typical range of the operation temperature can be found in Fig. 5. The exact temperature depends also on the relative humidity, the fly ash input into the process and the demanded separation efficiency for the SO_2.

Figure 5: Operation temperature in TURBOSORP® applications



The product of the TURBOSORP®-FGD process can be dumped in a landfill for non-hazardous waste without further treatment. Stabilized product can also be used for special building purposes like sound insulation or the final covering of landfills.

Project Scope of Work

Babcock Power has the overall responsibility to implement the project including construction, technology and commissioning. Nicholson and Hall is Babcock Power's erection subcontractor. CONSOL will conduct the testing and evaluation program.

Babcock Power's scope of supply includes the following major systems or equipment:

- **Combustion System**: modifications to this system include replacing the existing coal nozzles, combustion air and overfire air nozzles, and rebuild the overfired air system using Riley Power's combustion technology.

- **Superheater**: demolition of existing high temperature superheater (HTSH) elements and screen tubes and the installation of new HTSH elements and screen tubes to increase heat transfer surface for increasing steam temperature.

- **SNCR**: the supply and installation of a SNCR system for reducing flue gas NO_X emissions in the boiler. This system will operate in conjunction with a hybrid in-duct SCR at higher operating loads for overall NO_X emission control, supplying the reagent (NOxOUT®) necessary for both the SNCR and SCR reactions. The NOxOUT® reagent is a 50% urea based solution, which is supplied via tank truck. This system includes the supply and installation of a reagent storage tank; delivery and injection system that supplies reagent to both the SNCR and the SCR. Fuel Tech is supplying the SNCR and urea systems.

- **Ductwork** work includes the supply and installation of new ductwork connecting the new air pollution control equipment to the existing plant equipment.

- **SCR** scope of work includes the supply and installation of a Riley Power SCR system for further reducing flue gas NO_X emissions. The SCR is an in-duct configuration, with a single layer of catalyst modules located between the economizer outlet and the AH inlet. The scope includes the demolition of the existing flue gas ductwork and the installation of the new reactor ductwork. Cormetech is supplying the SCR catalyst. The hybrid SCR system is designed to remove 66% of the NOx emissions.

- **Mercury Control System** this system is based on an activated carbon technology that includes the supply and installation of a dedicated outdoor powder activated carbon (HOK) system. This system includes a storage silo, feed silo, and HOK injection system based on the designs used by RWE in Germany.

- **Turbosorp® FGD Scrubber** includes the supply and installation of a single Turbosorp® FGD reactor vessel that is 10.5 meters in diameter. The vessel has a multiple venturi inlet section and cylindrical reaction chamber. Water injection lances are used to lower the flue gas temperature, while the lime and ash particulates are recirculated from the baghouse via the ash recycle system. The Turbosorp® reactor vessel is designed for 281,367 SCFM (416,054 ACFM) at 300 °F, with turndown capability down to 37 MW achieved through flue gas recirculation. The Turbosorp FGD system is designed to reduce the SO_2 emissions by 95% based on a 2.9% S coal. Babcock Power used the technology provided by Austrian Energy & Environment to design and supply the Turbosorp® technology

- **Lime Hydration/Injection** includes the supply and installation of a dedicated outdoor lime hydration system, including a Quicklime receiving silo, followed by a hydrating system with milk of lime circuit discharging to an air classifying- slipstream milling system, and a hydrated lime silo with pneumatic injection into the FGD reactor

- **Baghouse** includes the supply and installation of a single eight compartment dedicated pulsejet fabric filter (baghouse) to accommodate the flue gas from the upstream FGD reactor. The particulate leaving the FGD reactor is removed from the flue gas and collected in the baghouse; where it is recycled back to the reactor via the ash recycle system.

- **Physical and CFD models** of the entire system is included in Babcock Power's scope of work.

- **Booster Fan** includes the supply and installation of a single flue gas booster fan and motor to account for the increased pressure drop incurred by the inclusion of the SCR, FGD reactor and baghouse. The booster fan and motor are located downstream of the baghouse but before the existing plant ID fans. The booster fan is also utilized to assure a clean flue gas recirculation to the FGD reactor to maintain adequate fluidizing velocity, as required at lower plant loads. A booster fan bypass system is also included to aid in the plant start-up practice normally adopted by the existing ID fans.

- **Civil engineering and construction:** civil and structural steel design for construction of the new equipment provided demolition removal or relocation of existing equipment or utilities; site clearing and grubbing plans; grading and drainage; erosion and sedimentation control; design and detailing for fire main header and connection to existing drains; and ground covers of disturbed pavement.

- **Electrical** work includes the electrical tie-in of the new equipment to the plant's existing 2400V electrical system. A new 2400V MCC, a new 480V transformer and MCC's will be provided for feeding power to the new equipment.

- **Ash Recycle and Disposal** work includes the supply and installation of a system for recycling the ash (flyash and lime) from the baghouse back into the Turbosorp® reactor, which is an inherent feature of this FGD control technology. In this case, more than 95% of the solids captured in the baghouse are recycled back to the reactor through the use of air slides located under the baghouse. The remaining ash/process-residue requiring disposal is separated from this recirculation path and removed and discharged to collection silos, which are tied into the existing plant ash (pneumatic vacuum) disposal system.

  Instrumentation and Controls includes the supply and installation of field instrumentation for the operation of the systems. Included in the scope of supply are packaged equipment systems that are controlled by programmable logic controllers (PLC). I/O will be wired to local junction boxes for interface with Owner DCS. Interconnection of wiring (DCS to local junction boxes) is by others. All additional analog and discrete control is performed through the Owner distributed control system (DCS). A dilution extractive type analytical measurement system is provided to measure the percent SO_2 and NO_X of flue gas exiting the SCR, and the percent SO_2 of flue gas at the booster fan discharge. The analytical signals are used for control of the CDS and the SNCR.

Mercury and SO_3 Control

At the present time, there is no CFB FGD operating on any coal-fired boiler that employ mercury controls. However, there are numerous CFB systems operating throughout the world on waste-to-energy plants. Most of these plants use the HOK technology. CFB technology should be an excellent candidate for carbon-based technologies. The high contact time in the reactor and the high ash recirculation will provide significant time for the carbon particles to contact the mercury in the flue gas resulting in lower consumption rates.

Both CFB and SD technology are excellent technologies for SO_3 capture. There are numerous reports of SO_3 capture > 98%.

Project Schedule

Babcock Power received the notice to proceed for the project on September 1, 2005. The construction activities began on the site in November 2005. The seven-week tie-in outage is scheduled to begin on September 29, 2006. Hot commissioning will begin immediately following the completion of the tie-in.

Figure 6 shows the construction activities and the completed erection of the Turbosorp system in August 2006.

Conclusions

The multi-pollutant control project at AES Greenidge is designed to evaluate emission control technologies that have been developed for economical application to small coal-fired boilers. This complex project has been executed in a short time frame. The current testing program, scheduled to begin in the 1st quarter of 2007, will provide results to owner/operators of small coal-fired plants with alternative approaches to control SO_2, NOx, mercury, and SO_3

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Figure 6 Turbosorp Reactor and Baghouse Completing Construction