The Greenidge Multi-Pollutant Control Project: Demonstration Results and Deployment of Innovative Technology for Reducing Emissions from Smaller Coal-Fired Power Plants

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ABSTRACT

There are more than 420 coal-fired electric generating units (EGUs) in the United States with capacities of 50-300 MW that currently are not equipped with selective catalytic reduction (SCR), flue gas desulfurization (FGD), or mercury control systems. Many of these units, which collectively represent almost 60 GW of installed capacity, are difficult to retrofit for deep emission reductions because of space constraints and unfavorable economies of scale, making them increasingly vulnerable to retirement in the face of progressively more stringent environmental regulations.

The Greenidge Multi-Pollutant Control Project is being conducted as part of the U.S. Department of Energy's (DOE) Power Plant Improvement Initiative to demonstrate a solution for these units. The project seeks to establish the commercial readiness of a multi-pollutant control system that is designed to meet the needs of smaller coal-fired EGUs by offering deep emission reductions, low capital costs, small space requirements, applicability to high-sulfur coals, mechanical simplicity, and operational flexibility. The system comprises an innovative combination of technologies including combustion modifications, a NOxOUT Cascade® hybrid selective non-catalytic reduction (SNCR) / in-duct SCR system, and a Turbosorp® circulating fluidized bed dry scrubbing system with baghouse ash recycling and activated carbon injection. These technologies were retrofitted to the 107-MW AES Greenidge Unit 4 by Babcock Power Environmental Inc. (BPEI) in 2006, with a total plant cost of ~ \$340/kW and a footprint of < 0.5 acre. Extensive testing has been carried out through mid-2008 to evaluate the performance of the multi-pollutant control system during its first year-and-a-half of commercial operation.

This paper summarizes performance and cost results from AES Greenidge Unit 4 and discusses commercial deployment of the demonstration technology. Guarantee tests conducted at AES Greenidge in 2007 proved that the multi-pollutant control system was capable of reducing NO_x emissions to 0.10 lb/mmBtu, SO_2 emissions by 96%, SO_3 and HCl emissions by 97%, and mercury emissions by > 95% while the unit fired 2.4-3.2% sulfur eastern U.S. bituminous coal. Additional tests have since been conducted to characterize the performance of the system as a function of unit operating conditions; the results of these tests are presented. The predominant operating challenges encountered to-date have arisen from the combustion system and from accumulation of large particle ash (LPA) in the in-duct SCR catalyst; as a result, the unit has required several outages for catalyst cleaning and has routinely operated with NO_x emissions slightly greater than 0.10 lb/mmBtu. The Turbosorp® scrubber has operated commendably, routinely achieving > 95% SO_2 removal efficiency while the unit is firing mid-to-high sulfur coals (e.g., containing 2.5-5.0 lb SO_2 / mmBtu). Moreover, all tests performed to-date have demonstrated 93-99% mercury removal as a co-benefit of the hybrid NO_x control and Turbosorp® systems, without the need for any activated carbon injection.

As a result of the success at AES Greenidge, three additional retrofit applications of the Turbosorp® system have been announced for small to moderate-sized coal-fired EGUs (i.e., 50-300 MW) in the United States. Additional announcements are anticipated. Key characteristics of these announced deployments, including unit and fuel characteristics and performance targets, are discussed.

INTRODUCTION

The Greenidge Multi-Pollutant Control Project is being conducted as part of the U.S. Department of Energy's Power Plant Improvement Initiative to demonstrate an air emissions control retrofit option that is well-suited for the nation's vast existing fleet of smaller, uncontrolled coal-fired electric generating units. There are about 420 coal-fired EGUs in the United States with capacities of 50-300 MW_e that currently are not equipped with selective catalytic reduction, flue gas desulfurization, or mercury control systems. These smaller units are a valuable part of the nation's energy infrastructure, constituting almost 60 GW of installed capacity. However, with the onset of various state and federal environmental regulations requiring deep reductions in emissions of SO_2, NO_x, and Hg, the continued operation of these units increasingly depends upon the ability to identify viable air pollution control retrofit options for them. The large capital costs and sizable space requirements associated with conventional technologies such as SCR and wet FGD make these technologies unattractive for many smaller units.

The Greenidge Project seeks to establish the commercial readiness of a multi-pollutant control system that is designed to meet the needs of smaller coal-fired EGUs by offering deep emission reductions, low capital costs, small space requirements, applicability to high-sulfur coals, low maintenance requirements, and good turndown capabilities. The system includes combustion modifications and a NOxOUT CASCADE® hybrid SNCR/SCR system for NO_x control, as well as a Turbosorp® circulating fluidized bed dry scrubber for SO_2, SO_3, HCl, and HF control. A baghouse, integral to the Turbosorp® system, provides particulate control. Baghouse ash is recycled to the scrubber to improve sorbent utilization. Mercury control is accomplished via the co-benefits afforded by the in-duct SCR, Turbosorp® scrubber, and baghouse, and, if required, by injection of activated carbon upstream of the scrubber.

The multi-pollutant control system is being demonstrated at the 107 MW_e (Energy Information Administration net winter capacity) AES Greenidge Unit 4 in Dresden, NY. Unit 4 (Boiler 6) is a 1953-vintage, tangentially-fired, balanced draft, reheat unit that fires pulverized eastern U.S. bituminous coal as its primary fuel and can co-fire biomass (waste wood) at up to 10% of its heat input. As such, it is representative of many of the 420 smaller coal-fired units described above. Before the multi-pollutant control project, the unit was equipped with a separated overfire air (SOFA) system for NO_x control and an electrostatic precipitator (ESP) for particulate matter control; fuel sulfur content was restricted in order to meet its permitted SO_2 emission rate of 3.8 lb/mmBtu.

The Greenidge Project is being conducted by a team including CONSOL Energy Inc. Research & Development (CONSOL R&D) as prime contractor (responsible for project administration, performance testing, and reporting), AES Greenidge LLC as host site owner (responsible for site management, permitting, and operation of the multi-pollutant control system), and Babcock Power Environmental Inc. as engineering, procurement, and construction (EPC) contractor. The NOxOUT CASCADE® technology was supplied by Fuel Tech under subcontract to BPEI; the SCR reactor was supplied by BPEI, and the Turbosorp® technology was supplied by BPEI under license from Austrian Energy and Environment. All funding for the project is being provided by the U.S. DOE, through its National Energy Technology Laboratory, and by AES Greenidge. The overall goal of the Greenidge Project is to show that the multi-pollutant control system being demonstrated, which had a capital cost of less than $350/kW and occupies less than 0.5 acre for the AES Greenidge Unit 4 application, can achieve full-load NO_x emissions of ≤ 0.10 lb/mmBtu, reduce SO_2 and acid gas (SO_3, HCl, and HF) emissions by ≥ 95%, and reduce Hg emissions by ≥ 90%, while the unit is firing 2-4% sulfur eastern U.S. bituminous coal and co-firing up to 10% biomass.

Start-up and commissioning of the multi-pollutant control system at AES Greenidge were completed in early 2007, and the system has now operated commercially for more than a year. During that time, the performance of the multi-pollutant control system has been monitored closely using plant operating data and data that were generated during a series of performance testing campaigns led by CONSOL R&D.

This paper summarizes performance testing results, operating and maintenance (O&M) experience, and costs from the first commercial deployment of the multi-pollutant control system at AES Greenidge Unit 4.

Moreover, the successful implementation of the Turbosorp® system at AES Greenidge has led to three additional announced deployments of that technology in the United States. All three of these announced deployments involve retrofit application of the technology to coal-fired EGUs with capacities between 50 and 300 MW, consistent with the population of EGUs targeted by the Greenidge Project. Key characteristics of these additional applications of the Turbosorp® technology, including similarities and differences relative to the application at AES Greenidge Unit 4, are discussed.

PROCESS DESIGN

Figure 1 presents a schematic of the multi-pollutant control process that is being demonstrated as part of the Greenidge Project. The design for the AES Greenidge Unit 4 retrofit is based on the use of a 2.9%-sulfur bituminous coal, co-fired with up to 10% waste wood, and on a baseline full-load NO_x emission rate of ~ 0.30 lb/mmBtu prior to the installation of the new combustion modifications.
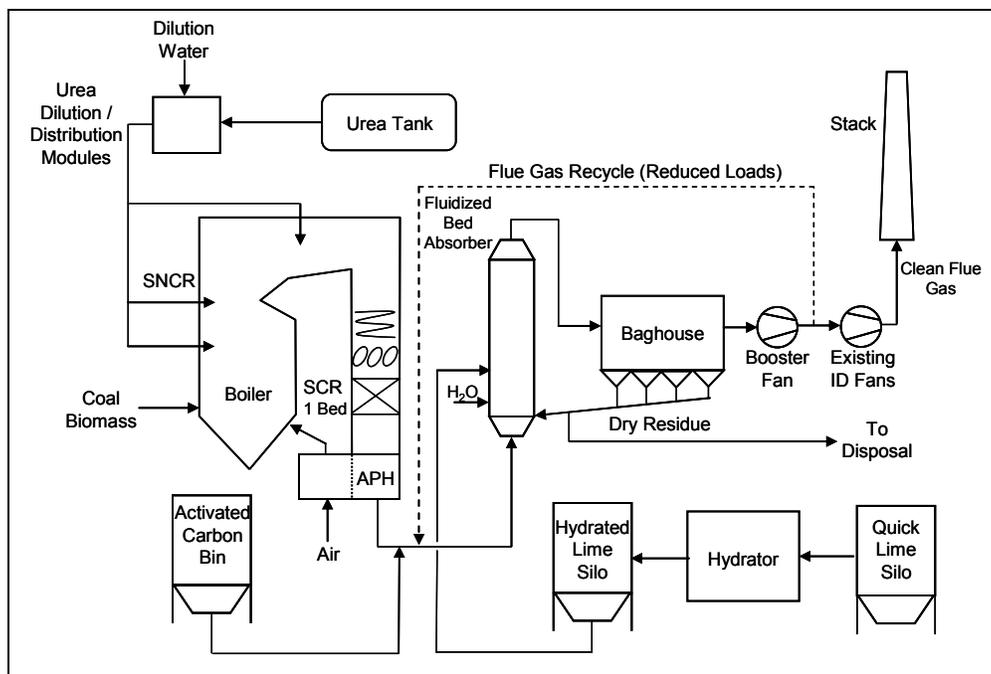
Figure 1. Schematic of the multi-pollutant control process being demonstrated at AES Greenidge Unit 4.

NO_x control is the first step in the process and is accomplished using urea-based, in-furnace SNCR followed by a single-layer SCR reactor that is installed in a modified section of the ductwork between the unit's economizer and its two air heaters. The SCR process is fed exclusively by ammonia slip from the SNCR process. Static mixers located just upstream of the SCR are used to homogenize the velocity, temperature, and composition of the flue gas to promote optimal ammonia utilization and NO_x reduction across the relatively small SCR catalyst, which consists of a single layer that is ~ 1.3 meters deep. Because the SCR reactor is able to consume ammonia slip (typically a limiting factor in SNCR design), the upstream SNCR system can operate at lower temperatures than a stand-alone SNCR system would, resulting in improved urea utilization and greater NO_x removal by the SNCR system, as well as sufficient NH_3 slip to permit additional NO_x reduction via SCR. The hybrid NO_x control system at AES Greenidge Unit 4 also includes combustion modifications (low-NO_x burners and SOFA) to achieve further reductions in NO_x emissions and to improve the performance of the hybrid SNCR/SCR system. Hence, the system is designed to achieve a full-load NO_x emission rate of ≤ 0.10 lb/mmBtu by combining the combustion

modifications, which are designed to produce NO_x emissions of 0.25 lb/mmBtu, the SNCR, which is designed to reduce NO_x by ~ 42% to 0.144 lb/mmBtu, and the SCR, which is designed to further reduce NO_x by ≥ 30% to ≤ 0.10 lb/mmBtu. The SNCR system at AES Greenidge includes three zones of urea injection. At high generator loads, urea is injected into the mid- and low-temperature zones to maximize NO_x removal and generate ammonia slip for the SCR reactor. At generator loads that produce economizer outlet temperatures below the minimum operating temperature for the SCR reactor, urea injection into the lowest-temperature zone is discontinued; however, urea continues to be injected into one or both of the mid- and high-temperature zones until the minimum SNCR operating temperature is reached, resulting in continued NO_x removal via SNCR. Below the minimum SNCR operating temperature, NO_x emissions continue to be controlled by the unit's low-NO_x combustion system.

Emissions of SO_2 and other acid gases are reduced by ≥ 95% in the Turbosorp® circulating fluidized bed dry scrubber system, which is installed downstream of the air heaters. In the Turbosorp® system, water and dry hydrated lime ($Ca(OH)_2$), which is produced from pebble lime in an onsite hydrator installed as part of the project, are injected separately into a fluidized bed absorber. There, the flue gas is evaporatively cooled to within 45 °F of its adiabatic saturation temperature and brought into intimate contact with the hydrated lime reagent in a fast fluidized bed. The basic hydrated lime reacts with the acidic constituents of the flue gas (i.e., SO_2, SO_3, HCl, and HF) to form dry solid products (i.e., hydrates of $CaSO_3$ and $CaSO_4$, $CaCl_2$, CaF_2), which are separated from the flue gas in a new eight-compartment pulse jet baghouse. More than 95% of the collected solids are recycled to the absorber via air slides in order to maximize pollutant removal and lime utilization. As shown in Figure 1, a flue gas recycle system is also included to provide sufficient flue gas flow to maintain a fluidized bed in the absorber at low-load operation. A new booster fan, which was installed upstream of the unit's existing induced-draft (ID) fans to overcome the pressure drop created by the installation of the in-duct SCR, fluidized bed absorber, and baghouse, provides the motive force for flue gas recycle. The booster fan accounts for a majority of the multi-pollutant control system's parasitic power requirement, which totals about 1.8% of the net electric output of AES Greenidge Unit 4.

Because water and dry hydrated lime are injected separately into the Turbosorp® absorber vessel, the hydrated lime injection rate is controlled solely by the SO_2 loading in the flue gas and by the desired SO_2 emission reduction, without being limited by the flue gas temperature or moisture content. As a result, the Turbosorp® system affords greater flexibility than a spray dryer for achieving deep emission reductions from a wide range of fuels, including high-sulfur coals. This is an important feature, as more than 80% of the 420 candidate units identified earlier are located east of the Mississippi River, where high-sulfur coal is a potential fuel source. The high solids recycle rate from the baghouse to the absorber vessel promotes efficient sorbent utilization in the Turbosorp® system. The projected calcium-to-sulfur (Ca/S) molar ratio for the design fuel (4.0 lb SO_2 / mmBtu) is 1.6-1.7, based on moles of inlet SO_2. Finally, unlike wet FGD systems and spray dryers, the Turbosorp® system does not require slurry handling. This is expected to result in reduced maintenance requirements relative to the alternative technologies.

Mercury control in the multi-pollutant control system is accomplished via the co-benefits afforded by the combustion modifications, in-duct SCR, circulating fluidized bed dry scrubber, and baghouse, and, if required, by injection of activated carbon just upstream of the scrubber. From a mercury control perspective, the Greenidge multi-pollutant control process is similar to a conventional air pollution control configuration comprising an SCR, spray dryer, and baghouse. Measurements have demonstrated that this configuration, when applied to plants firing bituminous coal, achieves a high level of mercury removal (i.e., 89-99%) without the need for any mercury-specific control technology.[1] This high level of removal likely results from a combination of factors, including the conversion of elemental mercury (Hg^0) to oxidized mercury (Hg^{2+}) across the SCR catalyst, the removal of Hg^{2+} (a Lewis acid) and SO_3 (which can interfere with Hg adsorption on carbon particles) by moistened, basic $Ca(OH)_2$ particles in the scrubber, and the removal of Hg^{2+} and Hg^0 via adsorption onto carbon-containing fly ash and $Ca(OH)_2$ at low temperatures in the baghouse, which facilitates contact between gaseous mercury and carbon or other sorbent contained in the dust cake that accumulates on its numerous filter bags. The Greenidge multi-pollutant control process includes all of these features, and hence, it might be expected that its combination of an in-duct SCR, $Ca(OH)_2$-based scrubber, and baghouse would result in high mercury removals without any activated carbon injection when applied to bituminous coal-fired units. The combustion modifications (including those that were in place prior to installation of the multi-pollutant control system) also contribute to Hg

removal by increasing the unburned carbon content of the fly ash, thereby improving its capacity for Hg capture. In addition, the multi-pollutant control system includes an activated carbon injection system upstream of the Turbosorp$^®$ absorber vessel. Relative to simple duct injection, very effective utilization of the activated carbon and high mercury capture are expected to result from the high solids recycle ratio, long solids residence time, and low temperature (~160 ^{o}F) provided by the circulating fluidized bed dry scrubber and baghouse.

Figures 2 and 3 present photographs of the in-duct SCR reactor and Turbosorp$^®$ system, respectively, at AES Greenidge Unit 4. The SCR reactor fits within the existing boiler building in a space with horizontal dimensions of 52 ft by 27 ft and a vertical height of 23 ft. (The cross section of the reactor is 45 ft by 14 ft). Because of this compact reactor design, the hybrid SNCR/SCR system avoids many of the capital costs associated with the multi-layer reactor, structural support steel, foundations, and new ductwork runs required for a conventional stand-alone SCR system. The arrangement of the circulating fluidized bed dry scrubber, baghouse, and associated equipment is also compact. As shown in Figure 3, the various pieces of equipment are vertically tiered to permit gravity-assisted transport of solids where possible, and as a result, the entire installation at AES Greenidge requires only ~ 0.4 acre of land. Unlike a wet FGD system, the Turbosorp$^®$ system does not produce a saturated flue gas, and therefore it is constructed from carbon steel and does not entail the installation of a new corrosion-resistant stack. These factors, coupled with the mechanical simplicity of the Turbosorp$^®$ system relative to a wet FGD system, contribute to its comparatively lower capital costs.

RESULTS FROM AES GREENIDGE UNIT 4

## Hybrid NO$_x$ Control System

Emission Reduction Performance

The hybrid NO$_x$ control system has significantly reduced the NO$_x$ emissions from AES Greenidge Unit 4, although it has fallen slightly short of the project's performance target for NO$_x$ during long-term operation. Guarantee testing of the multi-pollutant control system at AES Greenidge Unit 4 was completed in March-May 2007. On March 28, 2007, the combustion modifications and hybrid SNCR/SCR system demonstrated an average full-load NO$_x$ emission rate of 0.10 lb/mmBtu, thereby satisfying the project's performance target for NO$_x$ emissions. However, AES Greenidge has been unable to achieve this emission rate in the long term while also maintaining acceptable combustion characteristics, sufficiently high steam temperatures, and sufficiently low ammonia slip for routine operation. During the guarantee test period, the unit experienced flame attachments that damaged several burners, forcing plant personnel to reduce the aggressiveness of low-NO$_x$ firing. This change in turn caused boiler conditions to deviate from the design basis for the SNCR system, promoting less-than-optimal performance of that system. The NO$_x$ control problems have been exacerbated by the accumulation of large particle ash in the in-duct SCR reactor, which contributes to decreased NO$_x$ removal efficiency and increased ammonia slip from the reactor. As a result, the unit generally has operated with high-load NO$_x$ emissions of 0.10-0.15 lb/mmBtu since the guarantee testing period.

Figure 4 shows average NO$_x$ emissions from AES Greenidge Unit 4 as a function of gross generator load during the first six months of 2008. As illustrated in the figure, the unit's permit limit varies according to the turndown strategy for the hybrid NO$_x$ control system. The permitted NO$_x$ emission rate is 0.15 lb/mmBtu for gross generator loads above 68 MW, but it increases to 0.28 lb/mmBtu when the gross generator load is between 53 and 68 MW and to 0.35 lb/mmBtu when the gross generator load is between 43 and 52 MW. The overall average NO$_x$ emission rate during January-June 2008 was 0.15 lb/mmBtu for gross generator loads above 42 MW. The average NO$_x$ emission rate for gross generator loads above 68 MW was 0.14 lb/mmBtu, and the average rate for gross generator loads between 53 and 68 MW was 0.22 lb/mmBtu. This NO$_x$ emission profile is typical of that observed at AES Greenidge Unit 4 during routine operation of the multi-pollutant control system, and it represents a substantial improvement relative to the NO$_x$ emission profile observed prior to the multi-pollutant control project. For comparison, during the first six months of 2005, before the hybrid NO$_x$ control system was installed, AES Greenidge Unit 4 had an average NO$_x$

emission rate of 0.32 lb/mmBtu when it operated above 42 MW$_{gross}$. The average NO$_x$ emission rate was 0.31 lb/mmBtu for gross generator loads above 68 MW, and it was 0.40 lb/mmBtu for gross generator loads between 53 and 68 MW. Hence, the combustion modifications and hybrid SNCR/SCR system have reduced the unit's NO$_x$ emissions by more than 50% (high-load NO$_x$ emissions have decreased by more than 50%, and reduced-load NO$_x$ emissions have decreased by more than 40%) and enabled the unit to satisfy its permit requirements for NO$_x$.

Figure 2. Photograph of the in-duct SCR reactor at AES Greenidge Unit 4.
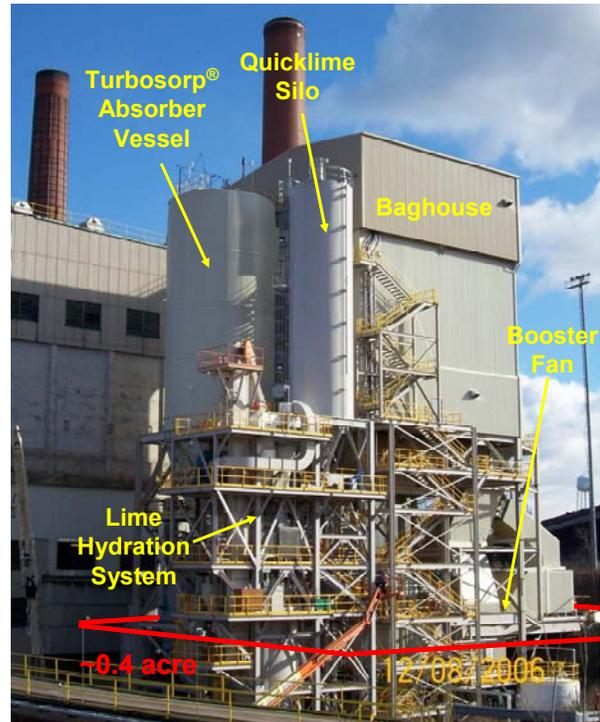
Figure 3. Photograph of the Turbosorp® system at AES Greenidge Unit 4.
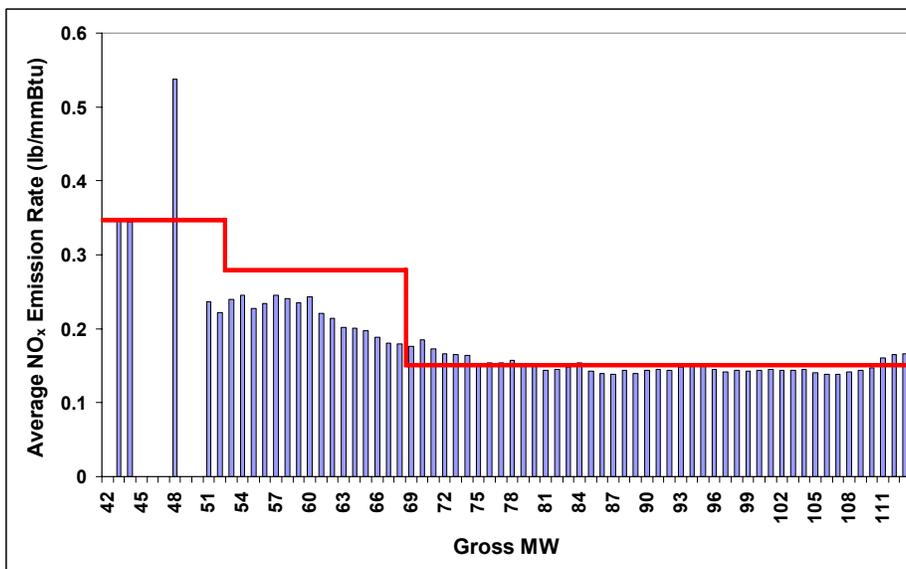
Figure 4. NO$_x$ emissions (stack continuous emissions monitor) as a function of gross load at AES Greenidge Unit 4 during January-June 2008. The red line indicates the unit's permit limit (30-day rolling average).

Operating and Maintenance Experience

Day-to-day maintenance requirements for the hybrid NO_x control system at AES Greenidge Unit 4 are minimal. However, the system has been affected by problems with large particle ash and greater-than-expected ammonia slip. These problems are discussed in more detail below.

The most troublesome problem encountered during operation of the multi-pollutant control system at AES Greenidge has been the accumulation of large particle ash in the in-duct SCR reactor. The LPA, which consists of pieces of slag that in many cases are too large to pass through the honeycomb catalyst, becomes lodged in the catalyst channels and promotes subsequent accumulation and bridging of fly ash, eventually plugging a substantial portion of the catalyst. Figure 5 presents a photograph showing LPA in the SCR catalyst at AES Greenidge. The accumulation of LPA and fly ash causes an increase in the pressure drop across the SCR reactor. At AES Greenidge, the pressure drop becomes substantial enough over time that it could cause downstream ductwork to collapse. As a result, the unit must be derated and/or taken offline for catalyst cleaning. Several outages were held for this purpose during the first year of operation of the multi-pollutant control system. LPA accumulation in the SCR catalyst can also contribute to decreased NO_x removal efficiency, increased ammonia slip, and increased catalyst erosion.

Figure 5. Photograph showing large particle ash accumulation in the in-duct SCR catalyst at AES Greenidge Unit 4.

The development of an effective LPA removal system for the in-duct SCR at AES Greenidge Unit 4 has been challenging. The flue gas flows vertically downward between the economizer and SCR reactor, with no available 90° bends or hoppers that can be used for inertial capture of the LPA (as is often done in conventional SCR installations). The solution that was implemented consists of a sloped screen installed in the ductwork between the economizer and the catalyst to remove the LPA from the flue gas. The screen crosses an expansion joint, and hence, it is installed in two sections. Eight vacuum ports are installed at the base of the screen to remove the collected LPA; soot blowers are located beneath the screen to help transport the LPA to the vacuum ports. The screen, vacuum ports, and two soot blowers were originally installed in May 2007. In September 2007, the two soot blowers were replaced with four rotary soot blowers, and a spring seal was installed to close the gap between screen sections. A rake soot blower was also installed above the SCR catalyst to aid in resuspending accumulated fly ash. In spite of these improvements, however, LPA particles that were large enough to plug the catalyst still passed the screen. In late 2007, patches were installed to eliminate openings in several areas of the screen, and the catalyst was replaced with a clean layer. Unit 4 operated from January 3-May 2, 2008, without an outage, although it was derated for the last month of this period because of elevated pressure drop across the in-duct SCR

reactor and air heaters. In May 2008, the original LPA screen was removed and replaced with a new, smaller-pitch screen to more effectively remove small pieces of LPA from the flue gas. It is expected that this will significantly reduce the severity of the SCR plugging problem; experience to date has been good.

Ammonia slip from the hybrid SNCR/SCR system at AES Greenidge Unit 4 has also been greater than expected during the first year of operation. This problem is much less troublesome than the LPA problem. Nevertheless, since AES Greenidge Unit 4 fires high-sulfur coal, ammonia slip is a particular concern because it can cause ammonium bisulfate fouling in the air heaters, thereby decreasing their heat transfer capability and adding pressure drop. As discussed above, the accumulation of LPA in the SCR catalyst contributes to the ammonia slip, although ammonia concentrations greater than the target of 2 ppmvd @ 3% O_2 have been observed at the air heater inlet even when the unit was operating with a relatively clean catalyst. Thirty-eight ammonia slip measurements were performed at the air heater inlet between May 2007 and June 2008 while AES Greenidge Unit 4 was operating at intermediate or high loads (i.e., 79 MW_{gross} or above). Ammonia concentrations measured during these tests ranged from 1.6 to 7.3 ppmvd @ 3% O_2. During all of the tests, one or both of the mid- and low-temperature urea injection zones were in service.   (In contrast, six low-load tests conducted at 55-56 MW_{gross}, with only the high-temperature urea injection zone in service, had ammonia slip concentrations of 0.1 to 0.3 ppmvd @ 3% O_2). Thus far, the greatest consequence of the higher-than-expected ammonia slip has been some pressure drop resulting from ammonium bisulfate fouling in the air heaters. This adds to the pressure drop caused by LPA accumulation in the in-duct SCR catalyst, and plant personnel have had to wash the air heater baskets during several outages. (Ammonium bisulfate fouling has not directly caused any outages, though). The higher-than-expected ammonia slip has not affected byproduct handling. The effect of ammonia slip will continue to be monitored as catalyst activity decreases with time.

Process Economics

The total EPC capital cost for the hybrid NO_x control system at AES Greenidge Unit 4, expressed in 2005 dollars (consistent with the start of construction at AES Greenidge), was $114/kW. This cost includes the combustion modifications, SNCR system, in-duct SCR system, static mixers, large particle ash removal system, and all supporting equipment.

Table 1 summarizes the levelized costs, including levelized capital costs and fixed and variable O&M costs, for the NO_x control system. Process economics were calculated using design information and actual cost and operating data (where available) from the AES Greenidge installation. Key assumptions are listed below the table.

Table 1. Process economics (constant 2005 dollars) for the hybrid NO_x control system at AES Greenidge Unit 4.

	$/MWh	$/ton NO_x removed
Levelized Capital (Total Capital Requirement)[a]	$2.24	$2,251
Fixed O&M	$0.39	$395
Variable O&M	$0.84	$841
Urea	$0.62	$626
Replacement Catalyst	$0.17	$168
Power and Water	$0.05	$48
Total Levelized Cost	$3.47	$3,487

[a]Includes combustion modifications, SNCR, in-duct SCR, static mixers, and LPA removal system. Assumptions: plant size = 107 MW net, capacity factor = 80%, inlet NO_x = 0.30 lb/mmBtu, NO_x emission = 0.10 lb/mmBtu, urea NSR = 1.35, 50% urea solution = $1.35/gal, Internal cost of electricity = $40/MWh, plant life = 20 years, fixed charge factor = 13.05%, allowance for funds used during construction = 2.35%; other assumptions based on Greenidge design basis, common cost estimating practices, and market prices.

Fixed O&M costs were derived using common cost estimating practices. Actual fixed O&M costs will be tabulated at the end of the project's performance evaluation period. No new employees were required to operate the NO_x control system. However, the fixed O&M costs presented in Table 1 preliminarily assume 4 hours per day of operating labor to account for increased overtime and training arising from the system. Maintenance labor and materials costs are estimated as 1.5% of the total plant cost (40% labor, 60% materials), and administrative and support labor costs are estimated as 30% of total O&M labor costs.

Variable O&M costs were calculated using actual pricing and operating data from AES Greenidge, where available. Costs for urea were computed assuming a normalized stoichiometric ratio (NSR = 2 x moles of urea ÷ moles of inlet NO_x) of 1.35, consistent with that observed during guarantee testing of the multi-pollutant control system in March 2007. In addition, the process economics in Table 1 assume a NO_x emission rate of 0.10 lb/mmBtu, even though NO_x emissions have averaged higher than this during routine operation of the multi-pollutant control system.

The total levelized cost for the hybrid NO_x control system at AES Greenidge Unit 4 is about $3,487 / ton of NO_x removed. The cost for urea, which is the portion of the cost that figures into the economic dispatch calculations for Unit 4, is $626 / ton of NO_x removed. (AES Greenidge is a merchant plant that dispatches when its variable cost of producing electricity is less than the market price of electricity).

Circulating Fluidized Bed Dry Scrubber

Emission Reduction Performance

The Turbosorp[®] system at AES Greenidge Unit 4 has performed commendably since it started up in early 2007. During the guarantee test period, the Turbosorp[®] system surpassed its performance target for SO_2 removal efficiency (≥ 95%), achieving 96% removal on March 29, 2007, while Unit 4 fired coal with a sulfur content of 3.8 lb SO_2 / mmBtu. (SO_2 was measured at the scrubber inlet using EPA Method 6C and at the stack using the unit's continuous emissions monitor).

This level of performance continued throughout the first year of operation of the Turbosorp[®] system while Unit 4 fired mid-to-high sulfur eastern U.S. bituminous coals. To exemplify the longer-term SO_2 reduction efficiency of the circulating fluidized bed dry scrubber, Figure 6 shows the hourly SO_2 rates measured at the Turbosorp[®] inlet and stack during January-June 2008, as well as the hourly SO_2 removal percentages calculated from these data. Hourly average inlet SO_2 rates ranged from 2.62 to 4.52 lb/mmBtu during the six-month period. Overall, the Turbosorp[®] system reduced SO_2 emissions from 3.41 lb/mmBtu to 0.11 lb/mmBtu during January-June, resulting in an average removal efficiency of 96.6%.
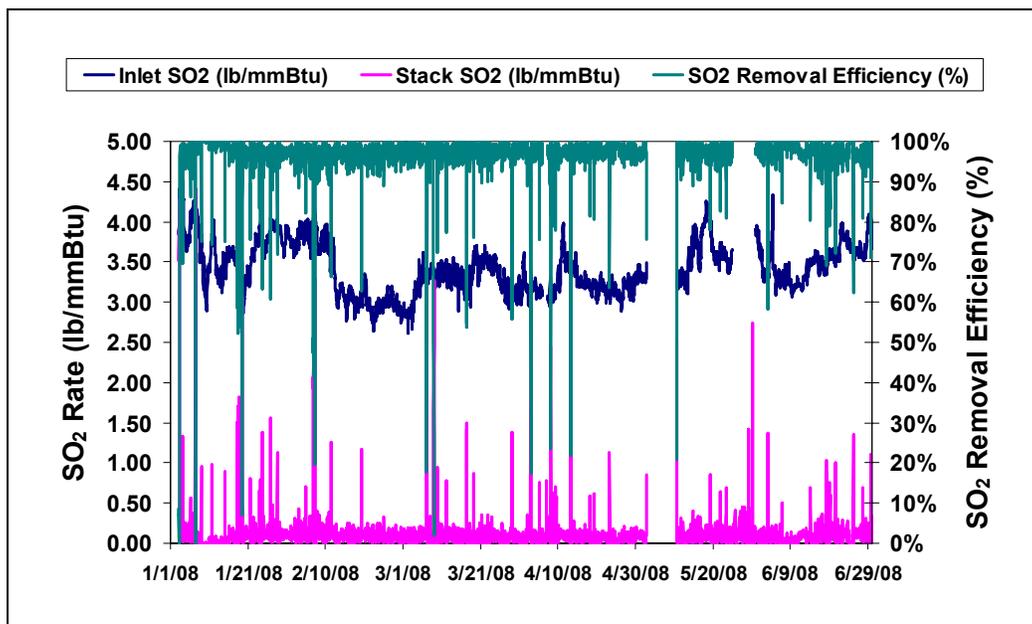
Figure 6. SO_2 removal performance of the Turbosorp[®] system at AES Greenidge Unit 4 during January-June 2008. Data were obtained from the unit's air heater outlet SO_2 monitor and stack continuous emissions monitor.

AES Greenidge routinely operates the scrubber with an SO_2 emission rate set point of 0.10 lb/mmBtu, which is below its permitted emission rate of 0.19 lb/mmBtu (30-day rolling average), in order to provide a margin for transient upsets in system performance. These upsets, which are evidenced by the spikes in stack SO_2 emission rate in Figure 6, can be caused either by routine operating and maintenance activities (e.g., change-out of the water injection lance) or by unexpected equipment problems (e.g., frozen valves and pressure transmitters during cold weather periods). However, such upsets occur infrequently, and the Turbosorp® system has easily maintained SO_2 emissions within the unit's permit limit. The system is also capable of attaining very deep SO_2 removal efficiencies, even when the unit fires high-sulfur coals. During the six months depicted in Figure 6, removal efficiencies ≥ 99% were observed during 24% of the one-hour periods for which SO_2 data were available.

The variable operating costs of the Turbosorp® process depend strongly on the amount of lime that is required to achieve a given level of SO_2 removal. Sorbent utilization in the Turbosorp® system was analyzed over the same six-month period that is depicted in Figure 6 using lime delivery data (i.e., truck weights) and SO_2 data from the plant's online analyzers. During this period, lime consumption (measured as available CaO) totaled 9,980 tons, and the amount of SO_2 fed to the scrubber totaled 6,161 tons, resulting in an average Ca/S molar ratio of 1.85. This is slightly greater than the targeted ratio of 1.6-1.7; however, some deviation from the target might be expected, because the six-month lime total includes excess lime that is wasted during periods when SO_2 emissions are over-controlled (e.g., the aforementioned periods with ≥ 99% SO_2 removal efficiency) or when lime is over-fed to the scrubber to compensate for temperature upsets resulting from load swings or maintenance activities (e.g., change-out of the water injection lance). The calculation is also susceptible to a number of sources of measurement error, including errors in the truck weights, stack flow rate measurements, available CaO measurements, and SO_2 measurements. For example, the SO_2 content measured at the scrubber inlet historically has been biased low relative to the measured coal sulfur content; this would cause the calculated Ca/S to be biased high.

Parametric testing of the Turbosorp® system at AES Greenidge Unit 4 was conducted on June 16-19, 2008, to enable an evaluation of lime consumption under controlled measurement and operating conditions, thereby reducing the possibility that results would be biased by measurement error or by operational upsets that cause excess lime consumption. The set points for SO_2 removal and Turbosorp® operating temperature were varied over the four test days so that the effects of these variables on lime consumption could be studied. On the morning of each test day, after the unit reached full load, the desired set points were established, and the system was allowed to reach apparent steady state. It was then operated at steady state for approximately 6.5 hours. During that time, plant operating data were recorded by the plant's data historian, and samples of coal, hydrated lime, and fly ash (sampled upstream of the scrubber) were collected for use in determining the Ca/S ratio. At the conclusion of the period of steady-state operation, 5-gal samples of product ash (i.e., mixture of solid scrubber byproduct and fly ash) from the Turbosorp® system were collected in duplicate. These samples were analyzed by inductively coupled plasma-atomic emission spectroscopy to determine Ca and S. In all cases, the duplicate sample analyses from a given test day agreed within 5% (relative percent difference). Ca/S molar ratios were then computed from the concentrations of Ca and S determined in the product ash samples. These ratios were corrected to remove the Ca and S that are attributable to coal fly ash, to adjust for the available $Ca(OH)_2$ content of the hydrated lime being used in the process (determined by ASTM C25), and to base them on moles of inlet sulfur (as opposed to moles of sulfur removed).

Figure 7 shows the Ca/S molar ratios that were determined in this way, as well as relevant plant operating data from each test day. The coal sulfur content during the test period was 3.5-3.7 lb SO_2 / mmBtu. During the first three test days, the Turbosorp® operating temperature was held constant at 160 ºF while the SO_2 removal efficiency was increased from 92% to 98%. As expected, the Ca/S ratio increased with increasing SO_2 removal efficiency, varying from about 1.3 at 92% SO_2 removal to about 1.9 at 98% SO_2 removal. The Ca/S molar ratio was 1.6 for 95% SO_2 removal efficiency with a 160 ºF scrubber operating temperature. This is at the low end of the projected range of 1.6-1.7 cited earlier in this paper, perhaps because the coal sulfur content (3.7 lb SO_2 / mmBtu) was slightly less than the design basis of 4.0 lb SO_2 / mmBtu. On the last day of testing, the SO_2 removal efficiency was held at 95% while the Turbosorp® operating temperature was raised by 5 ºF to 165 ºF. As anticipated, increasing the operating temperature (and, hence, moving

further from the adiabatic saturation temperature in the fluidized bed absorber) caused an increase in the Ca/S ratio that was required to achieve 95% SO_2 removal (to approximately 1.8).
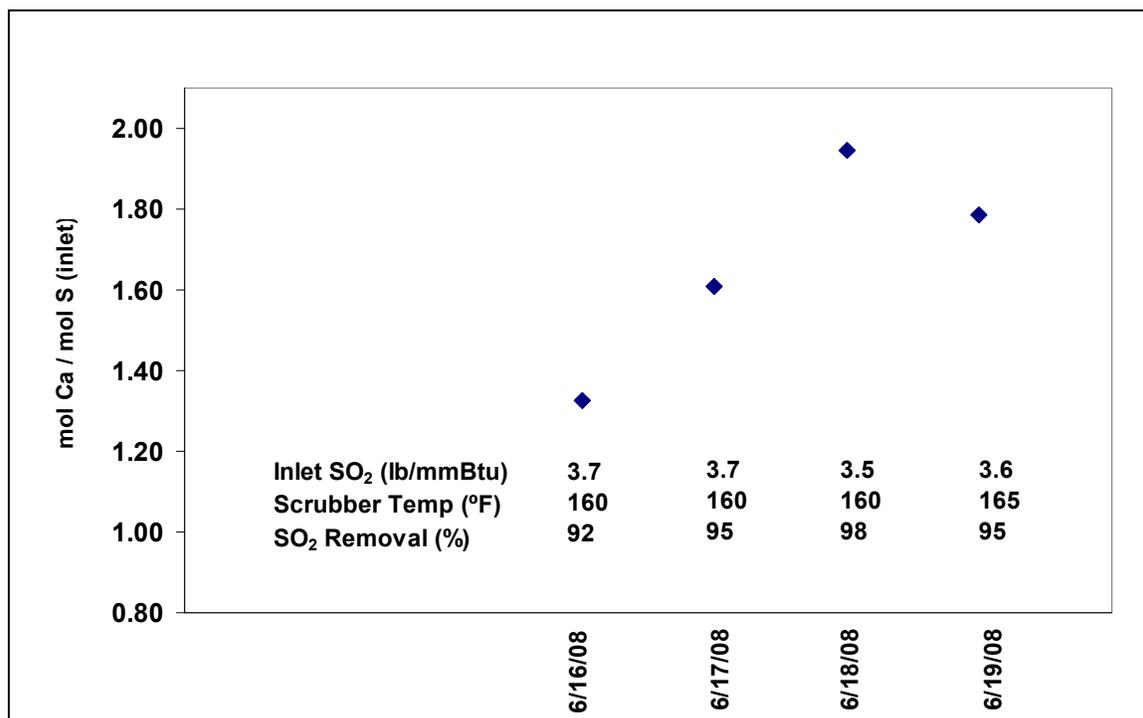
Figure 7. Calcium-to-sulfur molar ratios determined during parametric testing of the Turbosorp® system at AES Greenidge Unit 4 in June 2008. Relevant plant operating conditions are also shown.

The multi-pollutant control system at AES Greenidge Unit 4 has also consistently exceeded its performance target of ≥ 90% Hg removal efficiency. As shown in Figure 8, twenty-five mercury tests were completed at AES Greenidge between March 2007 and May 2008. For each test, Hg concentrations at the stack were determined using the Ontario Hydro method (ASTM D 6784-02), and Hg concentrations in the coal were determined by ASTM D 6722. (For the first six tests, Hg was determined in the Ontario Hydro method samples using cold vapor atomic absorption spectroscopy (CVAAS), and all Hg concentrations at the stack were below the method detection limit. Cold vapor atomic fluorescence spectroscopy was employed for subsequent tests so that stack Hg concentrations could be detected). All of the tests surpassed the project's target for Hg removal; measured coal-to-stack Hg removal efficiencies ranged from 92.8% to 99.8%. Moreover, 20 of the 25 tests were conducted without any activated carbon injection; the average Hg removal efficiency observed during these tests was 98.1%. (The activated carbon injection rate during the five tests that included ACI was approximately 3 lb/mmacf). High mercury removal efficiency was observed irrespective of plant operating conditions. During all of the test periods, AES Greenidge Unit 4 fired typical eastern U.S. bituminous coals containing 6.4 – 13.7 lb Hg / TBtu, 3.3 – 4.9 lb SO_2 / mmBtu, and 0.07 – 0.11 % Cl. For the four tests on March 11-12, 2008, it also co-fired sawmill waste wood at less than 5% of the total heat input. The gross generator load during the reduced-load tests on November 13-15, 2007, and May 19-20, 2008, ranged from 56 to 84 MW; during the other 19 tests, the unit operated between 105 and 109 MW_{gross}. AES Greenidge Unit 4 produces fly ash with appreciable amounts of unburned carbon. The fly ash carbon content ranged from 9.2 to 25.3% over the course of the 25 Hg tests, likely contributing to the high Hg removal efficiencies that were observed.

The Turbosorp® system also achieved its performance targets for SO_3 and HCl removal efficiency (both ≥ 95%) during guarantee testing in May 2007. The average SO_3 removal efficiency measured during the May test period (using the controlled condensation method) was 97.1%, and the average HCl removal efficiency measured during that period (using U.S. EPA Method 26A) was 97.2%. (HF concentrations were also measured using Method 26A; however, concentrations at the inlet and outlet of the scrubber were

near or below the method detection limit, precluding the determination of a removal efficiency). Table 2 summarizes all of the SO_3 and HCl measurements that have been performed at AES Greenidge Unit 4 through May 2008. The average HCl removal efficiency observed during 18 tests between March 2007 and May 2008 was 96.1%. SO_3 removal efficiencies measured since the guarantee test period have varied considerably, owing largely to variations in SO_3 concentrations at the Turbosorp® inlet. These variations in removal efficiency are likely due to fluctuations in fuel sulfur content, boiler operating conditions, scrubber operating conditions, and SO_3 removal across the air heater. (During the SO_3 tests, unit loads varied from 55 MW_g to 109 MW_g; coal sulfur content varied from 3 lb/mmBtu to 5 lb/mmBtu, and SO_2 removal efficiency varied from < 85% to > 99%). The average SO_3 concentration measured at the stack since the installation of the multi-pollutant control system is 0.7 ppmvd @ 3% O_2; 23 of the 26 stack SO_3 concentrations measured to-date were less than 1 ppmvd, which approaches the practical field detection limit of the controlled condensation method. Hence, installation of the Turbosorp® system has resulted in very low SO_3 emissions from AES Greenidge Unit 4.
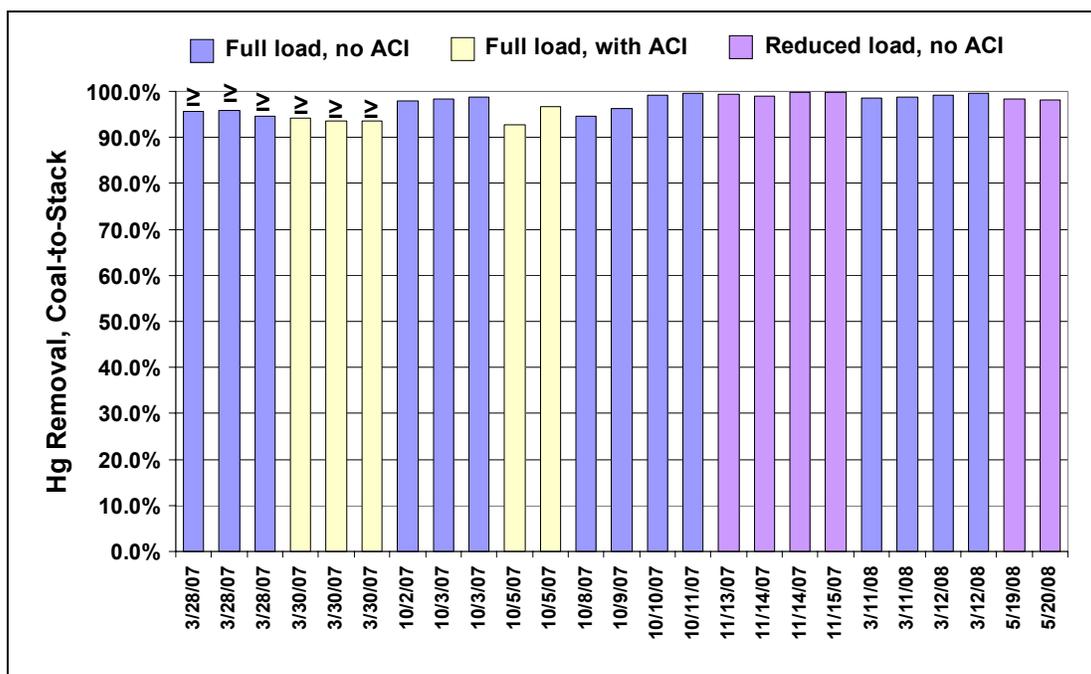

Figure 8. Summary of coal-to-stack Hg removal efficiencies, March 2007 – May 2008.

Table 2. Summary of results from SO_3 and HCl testing performed at AES Greenidge Unit 4 between March 29, 2007, and May 22, 2008. SO_3 was measured using the controlled condensation method, and HCl was measured using U.S. EPA Method 26A.

Analyte	Number of Tests	Concentration at Turbosorp® Inlet, ppmvd @ 3% O_2 Mean (Range)	Concentration at Stack, ppmvd @ 3% O_2 Mean (Range)	Removal Efficiency, % Mean (Range)
SO_3	26	12.1 (4.7 - 28.7)	0.7 (0.2 - 1.7)	93.0 (78.8 - 98.4)
HCl	18	36.9 (26.1 - 48.6)	1.4 (0.2 - 2.9)	96.1 (89.5 - 99.4)

Installation of the Turbosorp® system, including a new baghouse, at AES Greenidge Unit 4 has resulted in a substantial reduction in primary (non-condensable) particulate matter (PM) emissions from the unit. Figure 9 compares PM emission rates measured before and after installation of the system (using U.S. EPA Method 5 or 17). The average PM emission rate measured during 30 full-load tests between March 2007 and March 2008, following the installation of the multi-pollutant control system, was < 0.001 lb/mmBtu. This represents a more-than 98% reduction over the baseline full-load PM emission rate of 0.063 lb/mmBtu measured in November 2004. (The average PM emission rate observed during 11 reduced-load tests in November 2007 and May 2008 was similarly < 0.001 lb/mmBtu). The improvement in

PM emissions has occurred in spite of the substantial increase in flue gas particulate loading brought about by the hydrated lime, reaction products, and high solids recycle rate in the Turbosorp® system. It results largely from the superior performance of the baghouse relative to the unit's old ESP.   Particle agglomeration in the fluidized bed absorber may also contribute to improved PM capture efficiency.
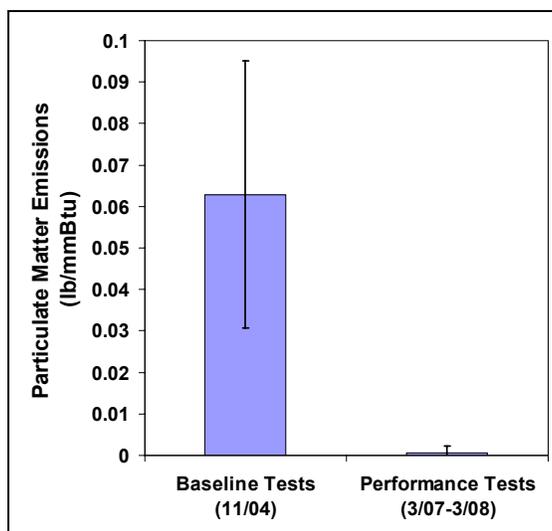
Figure 9. Summary of primary particulate matter emission rates measured at AES Greenidge Unit 4 before and after installation of the multi-pollutant control system.   Error bars represent ± 1 standard deviation.

Operating and Maintenance Experience

As discussed earlier, the Turbosorp® system is mechanically simple relative to many alternative FGD technologies, and therefore, it is expected to afford low maintenance requirements. This has generally been true at AES Greenidge during the first year of operation of the system. AES has been able to operate and maintain the Turbosorp® system (and the rest of the multi-pollutant control system) without adding any new O&M personnel. The majority of the O&M requirements associated with the Turbosorp® system have involved the lime hydration system, which is the most mechanically complex part of the process. The most common problem has been plugging in the hydrated lime milling and classification system. Problems with the lime hydration system have usually been resolved without impacting the operation of the Turbosorp® scrubber.   Plant personnel can continue to operate the scrubber while the hydrator is offline by using hydrated lime from their onsite inventory or by taking deliveries of hydrated lime. However, in a few instances, lack of hydrated lime availability has forced the unit to derate. Hence, AES is increasing the plant's onsite storage capacity for hydrated lime.   Other routine maintenance requirements in the Turbosorp® system include changing out and cleaning the Turbosorp® water injection lance (preventative maintenance performed about once per week) and unplugging the vents from the ash disposal silos (several times per day). In addition, there have been occasional problems with malfunctioning instruments and with plugging and formation of deposits in the ash recirculation and disposal system. However, no condensation problems have been observed in the absorber vessel or baghouse.

The only major byproduct from the multi-pollutant control system is the product ash from the Turbosorp® system, which is very similar to spray dryer ash in that it is a dry powder (~ 1% moisture) containing hydrates of $CaSO_3$ and $CaSO_4$, fly ash, $CaCO_3$, $Ca(OH)_2$, CaO, $CaCl_2$, and CaF_2. Approximately 3.2 tons of scrubber byproduct (excluding fly ash) are produced for each ton of SO_2 removed, assuming design conditions. AES Greenidge generally disposes of the product ash at a landfill adjacent to the plant site. However, plant personnel succeeded in supplying 3,500 tons of product ash for use as flowable fill, and the project team continues to seek potential beneficial reuses for the ash, which could also include use in mine reclamation or use in manufactured aggregate production. The product ash contains the Hg captured by

the multi-pollutant control process. Mercury leaching tests were performed on seven product ash samples using the Synthetic Precipitation Leaching Procedure (U.S. EPA Method 1312). For each of these samples, the amount of Hg in the leachate was < 0.35 µg/L (the detection limit for the CVAAS method), which equates to < 1.5% of the total Hg in the ash.

Process Economics

The total EPC capital cost for the Turbosorp® system at AES Greenidge Unit 4, expressed in 2005 dollars (consistent with the start of construction at AES Greenidge), was $229/kW. This cost includes the absorber vessel, process water system, lime storage and hydration system, baghouse, ash recirculation system, booster fan, and all supporting equipment. The cost for the activated carbon injection system is not included in this total, because testing has shown that the ACI system is not needed to achieve the project's Hg removal target. If included, the ACI system would add about $6/kW to the EPC capital cost.

Table 3 summarizes the levelized costs, including levelized capital costs and fixed and variable O&M costs, for the Turbosorp® system. As with the process economics for the hybrid NO_x control system, economics for the Turbosorp® system were calculated using design information and actual cost and operating data (where available) from the AES Greenidge installation. Key assumptions are listed below the table.

Fixed O&M costs were derived using common cost estimating practices. Actual fixed O&M costs will be tabulated at the end of the project's performance evaluation period. As discussed above, no new personnel were required to operate the Turbosorp® system. However, the fixed O&M costs presented in Table 3 preliminarily assume 12 hours per day of operating labor to account for increased overtime and training arising from the system. Maintenance labor and materials costs were estimated according to the same assumptions described above for the NO_x control system.

Variable O&M costs were calculated using actual pricing and operating data from AES Greenidge, where available. Costs for lime assume a Ca/S molar ratio of 1.68, based on measurements made at AES Greenidge in October 2007 when the unit was operating near design conditions (i.e., 4.1 lb SO_2 / mmBtu coal, 95% SO_2 removal efficiency, 160 ºF scrubber operating temperature).

Table 3. Process economics (constant 2005 dollars) for the Turbosorp® system at AES Greenidge Unit 4.

	$/MWh	$/ton SO_2 removed
Levelized Capital (Total Capital Requirement)[a]	$4.54	$241
Fixed O&M	$0.88	$47
Variable O&M	$5.62	$298
Lime and Waste Disposal	$4.79	$254
Power and Water	$0.70	$37
Baghouse Bags and Cages	$0.12	$6
Total Levelized Cost	$11.04	$586

[a]Includes scrubber, process water system, lime storage and hydration system, baghouse, ash recirculation system, and booster fan. Assumptions: plant size = 107 MW net, capacity factor = 80%, coal sulfur = 4.0 lb SO_2 / mmBtu, Ca/S = 1.68 mol/mol, pebble lime available CaO = 90%, SO_2 removal efficiency = 95%, pebble lime = $115/ton, waste disposal = $17/ton, internal cost of electricity = $40/MWh, plant life = 20 years, fixed charge factor = 13.05%, allowance for funds used during construction = 2.35%; other assumptions based on Greenidge design basis, common cost estimating practices, and market prices.

The total levelized cost for the Turbosorp® system at AES Greenidge Unit 4 is about $586 / ton of SO_2 removed, and the cost for lime and waste disposal, which is the portion of the cost that figures into the economic dispatch calculations for Unit 4, is $254 / ton of SO_2 removed. These prices also cover mercury control, acid gas control, and improved primary particulate matter control, which are co-benefits of the Turbosorp® system and add no incremental cost.

DEPLOYMENT OF THE DEMONSTRATION TECHNOLOGY

Following the successful demonstration at AES Greenidge, three additional projects are underway to retrofit Turbosorp® circulating fluidized bed dry scrubbers to coal-fired EGUs in the United States. Key

features of these additional projects are summarized in Table 4. (Key features of the AES Greenidge application are also included for comparison). All are designed to achieve SO_2 removal efficiencies of 95% or more, with fuel sulfur contents ranging from 2.3 to 4.6 lb SO_2 / mmBtu.

Table 4. Turbosorp® projects at coal-fired electric generating units in the United States.

	AES Greenidge 4	AES Westover 8	GRU Deerhaven 2	FirstLight Mt. Tom 1
Unit Capacity MW_e	107_{net}	84_{net}	248_{gross}	155_{gross}
Turbosorp® Start-Up	Spring 2007	Fall 2008	Spring 2009	Fall 2009
Fuel	Bituminous Pulverized Coal	Bituminous Pulverized Coal	Bituminous Pulverized Coal	Bituminous Pulverized Coal
Inlet SO_2 lb/mmBtu	4.0	3.4	2.3-3.9	2.7-4.6
Outlet SO_2 lb/mmBtu	≤ 0.2	≤ 0.17	≤ 0.10	0.14-0.23
SO_2 Removal %	≥ 95	≥ 95	≥ 95.6-97.4	≥ 95
Hydrator	1 x 100%	No	2 x 100%	No
Existing ESP	Cold Side Abandon	Cold Side Abandon	Hot Side Retain	Cold Side Retain
New Baghouse	Yes	Yes	Yes	Yes
Activated Carbon Injection System	Yes	No	Provisions	Yes
SCR	Compact/Hybrid	Yes	Yes	Existing

As discussed above, a particulate control device is an integral part of the Turbosorp® technology. Although it is possible to install a Turbosorp® system with an ESP to remove the reaction products and spent sorbent from the flue gas, baghouses are generally preferred because they provide for deeper emission reductions. All of the projects in Table 4 include a new baghouse as part of the Turbosorp® system. The existing particulate control device can be either retired (as it was at AES Greenidge) or retained (because of economic and/or operating considerations). At AES Westover Unit 8, as at AES Greenidge Unit 4, the existing cold-side ESP will be abandoned, with fly ash being collected along with the spent sorbent and reaction products in the new baghouse. At these sites, both the booster fan and the existing ID fans are located downstream of the Turbosorp® reactor and baghouse. The hot-side ESP at GRU Deerhaven Unit 2 will be retained, allowing the new SCR reactor and the existing air heater to operate with low dust loading. The cold-side ESP at Mt. Tom will also be retained. In both plants, the Turbosorp® system will be located downstream of the existing ID fan; retaining the ESP allows the fly ash to be disposed or sold separately from the scrubber product, if desired. However, the ESP can be operated at reduced power, because the baghouse provides supplemental particulate emission control.

The hydrated lime required by the Turbosorp® system can be either produced from pebble lime in an onsite hydrator, as it is at AES Greenidge, or it can be purchased and delivered to site for direct use in the process. The Turbosorp® installations at AES Westover and FirstLight Mt. Tom do not include hydrators; both of these units will use hydrated lime that is delivered by truck. At GRU Deerhaven, two complete hydration trains will provide fully redundant, on-site hydration capacity, while allowing for delivery of both pebble lime and hydrated lime. The lime hydration system specified for the Deerhaven project completely eliminates post-hydrator milling and classification, with a significant reduction in equipment and maintenance requirements relative to the lime hydration system at AES Greenidge.

None of the three additional announced deployments of the Turbosorp® system are being installed in combination with the hybrid SNCR/SCR system that was included at AES Greenidge. However, all of these deployments will include a conventional SCR upstream of the Turbosorp® system. Two of the projects include SCR as part of the retrofit; an SCR system was recently installed at Mt. Tom Unit 1 and will continue in service.

The Turbosorp® projects currently in construction closely match the population of coal-fired EGUs targeted by the Greenidge Project. In addition, BPEI is developing projects that involve application of the Turbosorp® process to low sulfur-coals, to opportunity fuels such as petroleum coke and biomass, and as a polishing scrubber to achieve very low emissions from a circulating fluidized bed boiler.

SUMMARY

The Greenidge Project has demonstrated the commercial viability of a multi-pollutant control system that is designed to meet the needs of small coal-fired power plants that have traditionally been difficult to retrofit. The system, which includes combustion modifications, a hybrid SNCR/SCR system, and a circulating fluidized bed dry scrubber (with new baghouse), required an EPC capital cost of \$343/kW (\$2005) and a footprint of < 0.5 acre at the 107-MW AES Greenidge Unit 4. This is substantially less than the capital cost and space that would have been required to retrofit AES Greenidge Unit 4 with conventional SCR and wet FGD systems. The multi-pollutant control system has operated commercially for more than a year, and it has generally met or exceeded the project's performance targets. Tests completed since start-up of the system in early 2007 have consistently shown $\geq$ 95% SO_2 removal, $\geq$ 95% mercury removal (with no activated carbon injection), and very low emissions of SO_3, HCl, HF, and particulate matter while the unit fires mid-to-high sulfur eastern U.S. bituminous coals (e.g., containing 2.5 - 5.0 lb SO_2 / mmBtu). The performance of the hybrid SNCR/SCR system has been affected by problems with large particle ash, ammonia slip, and less-than-optimal combustion characteristics, and NO_x emissions have typically averaged closer to 0.15 lb/mmBtu than to the targeted emission rate of 0.10 lb/mmBtu. Nevertheless, the system has substantially improved the unit's NO_x emission profile. Installation of the multi-pollutant control system has enabled AES Greenidge Unit 4 to satisfy its air emissions requirements while remaining profitable, thereby contributing to a 20-30 year life extension for the unit.

Following the successful demonstration of the Turbosorp® circulating fluidized bed dry scrubber at AES Greenidge Unit 4, three additional deployments of that technology have been announced for coal-fired EGUs in the United States. These announced deployments are consistent with the objectives of the Greenidge Project. All are designed to achieve at least 95% SO_2 removal from smaller coal-fired units (80-250 MW) that fire mid-to-high sulfur coals (2.3-4.6 lb SO_2 / mmBtu). Additional projects involving application of the Turbosorp® technology to a wide variety of units are anticipated.

ACKNOWLEDGMENT AND DISCLAIMER

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