

# National Energy Technology Laboratory

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## GREENIDGE MULTI-POLLUTANT CONTROL PROJECT

A DOE Assessment

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## **EXECUTIVE SUMMARY**

The Power Plant Improvement Initiative (PPII) is a successor to the U.S. Department of Energy's (DOE) Clean Coal Technology Demonstration Program (CCTDP) that was successfully implemented in the 1980s and 1990s. The purpose of the CCTDP was to offer the energy marketplace more efficient and environmentally friendly coal-fired power production options by demonstrating these technologies in commercial settings. On October 11, 2000, the PPII was established under U.S. Public Law 106-291 for the commercial-scale demonstration of technologies to ensure a reliable supply of energy from the Nation's existing and future coal-fired electricity generating facilities.

The Greenidge Multi-Pollutant Control Project was one of the projects selected for negotiation and ultimately awarded a Cooperative Agreement from the PPII solicitation, which was issued in February 2001. The proposal was submitted by CONSOL Energy Inc. (CONSOL). The project was originally estimated to cost \$32.7 million. However, the final project cost was \$34.7 million due primarily to increases in the prices for consumables (lime and urea). The Cooperative Agreement was modified to reflect the higher total cost, although all of the increase was borne by the power plant. DOE provided \$14.3 million (41 percent) with the remaining \$20.4 million (59 percent) provided by AES Greenidge LLC. The demonstration facility, which occupies a total of approximately 0.4 acres of land, is located at the AES Greenidge Power Plant in Dresden, New York. The multi-pollutant control system was installed and tested on AES Greenidge Unit 4, a 107-MWe, 1953-vintage tangentially-fired boiler. AES Greenidge operates as a merchant plant that frequently fires high-sulfur eastern U.S. bituminous coal. It can also burn up to 10 percent (by heat content) biomass.

The objective of this project was to demonstrate a technology suite that can meet increasingly stringent environmental requirements and that is applicable to older, smaller coal-fired plants. Such a technology was needed because retrofitting these smaller plants is often impractical due to the relatively high capital cost per kilowatt of conventional technologies and space constraints more typical of older plants.

The performance goals included reducing high-load nitrogen oxide (NO<sub>x</sub>) emissions to 0.10 lb/mmBtu and reducing sulfur dioxide (SO<sub>2</sub>), sulfur trioxide (SO<sub>3</sub>), hydrogen chloride (HCl), and hydrogen fluoride (HF) emissions by at least 95 percent. The mercury emissions were to be reduced by at least 90 percent. These reductions were to be achieved while the unit fired 2-4 percent sulfur eastern U.S. bituminous coal and co-fired up to 10 percent biomass.

Construction was completed in late 2006, and startup followed immediately. The operational phase of the demonstration project continued until October 2008, and CONSOL's final report was accepted in May 2009.

The Greenidge Project comprised the design, permitting, procurement, construction, start-up, operation, and performance testing of a multi-pollutant control system. The project was conducted by a team that included CONSOL, AES Greenidge LLC, and Babcock Power Environmental Inc. (BPEI). CONSOL, as the Participant, was responsible for managing the project, conducting tests, and evaluating the results. The host site owner and CONSOL subcontractor, AES Greenidge LLC, was responsible for co-funding, environmental permitting, and operation of the demonstration plant. BPEI was the main technology supplier and was responsible for the engineering, procurement, and construction (EPC) of the demonstration facility. BPEI was a subcontractor to AES Greenidge. Project oversight was provided by the DOE National Energy Technology Laboratory (NETL).

The multi-pollutant control system consisted of a NO<sub>x</sub>OUT CASCADE<sup>®</sup> hybrid selective non-catalytic reduction (SNCR) / selective catalytic reduction (SCR) system, a Turbosorp<sup>®</sup> circulating fluidized bed dry scrubbing system, a baghouse, and an activated carbon injection (ACI) system. Combustion modifications were installed by the plant owner outside of the scope of this project. The SNCR system consists of multiple injection points at which urea (CO(NH<sub>2</sub>)<sub>2</sub>) is injected into the furnace. The precise locations are selected based on locations within the furnace where the temperature is

optimum for the urea to react with the  $\text{NO}_x$  to form molecular nitrogen ( $\text{N}_2$ ), carbon dioxide ( $\text{CO}_2$ ), and water vapor. The mechanism of these reactions also results in the formation of ammonia ( $\text{NH}_3$ ), which exits in the flue gas and serves as the reagent for further  $\text{NO}_x$  reduction in the single catalyst layer SCR unit. The SCR is installed in a modified section of ductwork between the economizer and the air heater. When needed for mercury removal, the ACI system is used to inject activated carbon into the ductwork upstream of the dry scrubber. Sorbent (hydrated lime ( $\text{Ca}(\text{OH})_2$ )) and humidification water are separately injected into the dry scrubber where  $\text{SO}_2$  and other acid gases are removed. The partially reacted sorbent and fly ash are removed from the flue gas in the baghouse. Most of the sorbent and fly ash are sent back to the absorber to promote more complete utilization of the sorbent.

Overall, the operation of the demonstration plant went smoothly with one exception: AES Greenidge experienced problems with periodic plugging of the SCR catalyst bed. The problem was determined to result from large particle ash (LPA) that was plugging the SCR catalyst. BPEI designed a screen to remove the LPA. Initial results were unsatisfactory; however, after several design and operating modifications, the problem was solved and the unit was operated successfully for the duration of the project.

## I. INTRODUCTION

The Power Plant Improvement Initiative (PPII) is a successor to the U.S. Department of Energy's (DOE) Clean Coal Technology Demonstration Program (CCTDP) that was successfully implemented in the 1980s and 1990s. The purpose of the CCTDP was to offer the energy marketplace more efficient and environmentally friendly coal-fired power production options by demonstrating these technologies in commercial settings. On October 11, 2000, the PPII was established under U.S. Public Law 106-291 for the commercial-scale demonstration of technologies to ensure a reliable supply of energy from the Nation's existing and future coal-fired electric generating facilities. Congress directed that the PPII was to "demonstrate advanced coal-based technologies applicable to existing and new power plants.... The managers expect that there will be at least a 50 percent industry cost share for each of these projects and that the program will focus on technology that can be commercialized over the next few years. Such demonstrations must advance the efficiency, environmental controls, and cost-competitiveness of coal-fired capacity well beyond that which is in operation now or has been operated to date."

To fund the PPII, \$95 million in previously appropriated funds were transferred from the DOE's CCTDP. The PPII program solicitation was issued on February 6, 2001, and twenty-four applications were received. On September 26, 2001, eight applications were selected for negotiation leading to a Cooperative Agreement. One of the projects selected was the "Greenidge Multi-Pollutant Control Project". Following protracted negotiations, the Cooperative Agreement was awarded on May 19, 2006, with design and construction activities already under way. The proposal was submitted by CONSOL Energy Inc. (CONSOL) with AES Greenidge LLC and Babcock Power Environmental Inc. (BPEI) rounding out the core project team. Their respective roles were:

- CONSOL Energy Inc., Participant (i.e., prime contractor) responsible for managing the project, testing, and evaluation.

- AES Greenidge LLC (subcontractor to CONSOL) provided the host site and co-funding, and was responsible for environmental permitting and operation of the demonstration facility.
- Babcock Power Environmental Inc. (BPEI), subcontractor to AES Greenidge and main technology supplier responsible for engineering, procurement, and construction (EPC) of the multi-pollutant control facility.

Project oversight was provided by the DOE National Energy Technology Laboratory (NETL).

The project was originally estimated to cost \$32.7 million. However, the final project cost was \$34.7 million due primarily to increases in the prices for consumables (lime and urea). The Cooperative Agreement was modified to reflect the higher total cost although all of the increase was borne by the power plant. DOE provided \$14.3 million (41 percent) with the remaining \$20.4 million (59 percent) provided by AES Greenidge LLC. The project team had been authorized by DOE to proceed with permitting, design, and construction prior to the signing of the Cooperative Agreement on an at-risk basis. When the Cooperative Agreement was signed, construction was already underway. Proceeding on an at-risk basis means that once the Cooperative Agreement is signed, DOE would reimburse the Participant for the Government share of project costs that were incurred after the authorization was granted. However, if no Cooperative Agreement is awarded, no such reimbursements will be made and all costs are borne by the Participant. Therefore, the design phase of the project was completed and construction was underway when the Cooperative Agreement was signed.

The Cooperative Agreement called for the installation and operation of several technologies, integrated to achieve deep reductions in the emissions of the pollutants that are of major concern. These pollutants are sulfur dioxide (SO<sub>2</sub>), nitrogen oxides (NO<sub>x</sub>), mercury (Hg), sulfur trioxide (SO<sub>3</sub>), hydrogen fluoride (HF), and hydrogen chloride (HCl). The technology also had to maintain low emission rates of particulate matter. The technologies that were installed and integrated to achieve these reductions were Fuel

Tech's NO<sub>x</sub>OUT CASCADE® hybrid selective non-catalytic reduction/selective catalytic reduction (SNCR/SCR) process, BPEI's Turbosorp® circulating fluidized bed dry scrubbing technology (including a new baghouse), and an activated carbon injection system. Overall, the system operated well and experienced only one significant problem: catalyst plugging by large particle ash (LPA). This problem was experienced early in the operational phase, and it was eventually solved by installing a screen upstream of the SCR catalyst.

This report is an assessment of the Greenidge Multi-Pollutant Control Project.

## II. PROJECT AND PROCESS DESCRIPTION

### A. Project Site

The project was carried out at the AES Greenidge power plant located in Dresden, New York, on a 153-acre site on the western shore of Seneca Lake. The multi-pollutant control technology occupied only 0.43 acres of the site. AES Greenidge is a merchant plant that sells its power to the New York Independent System Operator. The total capacity of AES Greenidge is 161 MWe (net).

The plant consists of Units 3 and 4, both of which are served by boilers that are primarily fired with bituminous coal. Unit 3 is a 54 MWe (net) wall fired unit that is served by Boilers 4 and 5. Unit 4 (107 MWe (net)) is served by Boiler 6, the host boiler for the demonstration project. Boiler 6 came online in 1953. It is a tangentially-fired dry-bottom boiler that, in addition to bituminous coal, is permitted to burn up to 10 percent waste wood based on heat input. Prior to the installation of the demonstration project, SO<sub>2</sub> emissions were limited by restricting the plant to fuel that would produce maximum SO<sub>2</sub> emissions of 3.8 pounds per million Btu (lb/mmBtu) of heat input. NO<sub>x</sub> was controlled to 0.3 lb/mmBtu with overfire air, and particulate emissions were controlled by a cold side electrostatic precipitator (ESP).

In conjunction with this project, AES Greenidge Unit 4 underwent several modifications. These modifications included a major turbine overhaul; replacement of the unit's high-temperature superheater elements; installation of low-NO<sub>x</sub> burners; and upgrades to the unit's distributed control system (DCS), air preheaters, and ash handling system. Although these modifications were not part of the project, they are mentioned here because they contributed to the success of the demonstration. This is especially true of the low-NO<sub>x</sub> burners.

## B. Project Goals

The demonstration technology is intended to provide a relatively low-cost option for smaller coal-fired power plants to achieve the emission reductions required by increasingly stringent regulations. Due to reverse economies of scale, the capital cost per unit of capacity often makes it uneconomical to retrofit these smaller, often older, generating units with wet flue gas desulfurization (FGD) systems and SCR to meet emission limits and continue operation. These units also tend to be space-constrained. Although the technology can be effective on units rated at up to 600 MW, the primary market is viewed as plants in the 50 to 300 MW range. The Participant estimates that there are over 400 such units with a combined capacity of approximately 55 gigawatts (GW) in the United States.

Therefore, the goal of this project was to prove that the multi-pollutant control system can effectively control emissions, has a substantially lower capital cost than conventional SCR and wet FGD technologies, and can be installed in a limited space. The specific environmental goals of the project were to:

- Demonstrate that the NO<sub>x</sub>OUT CASCADE® hybrid SNCR/SCR system, when combined with low NO<sub>x</sub> burners, can reduce high-load NO<sub>x</sub> emissions to ≤0.10 lb/mmBtu while the unit is firing coal with greater than 2 percent sulfur content and co-firing up to 10 percent biomass.
- Demonstrate ≥95 percent SO<sub>2</sub> emission reduction by the Turbosorp® circulating fluidized bed dry scrubber while the unit is firing coal with greater than 2 percent sulfur content and co-firing up to 10 percent biomass.
- Demonstrate ≥90 percent mercury removal by the combination of the NO<sub>x</sub>OUT CASCADE® hybrid SNCR/SCR system, the Turbosorp® system, and, as required, carbon or other sorbent injection.
- Demonstrate ≥95 percent removal of acid gases (SO<sub>3</sub>, HCl, and HF) by the Turbosorp® system.

An additional goal of the project was to establish process economics and fully evaluate technical performance to demonstrate the commercial readiness of the demonstration technology.

## **C. Project Description**

The project consisted of the design, installation, and operation of the multi-pollutant control technology. Much of the construction was carried out while the plant continued to operate normally with tie-in occurring over a fifty-day period ending in November 2006. The major construction activities that occurred prior to the tie-in outage include:

- Installation of the Turbosorp® absorber vessel and the associated baghouse
- Installation of the ash recirculation system
- Installation of the lime storage, hydration, and injection system
- Installation of the process water system
- Installation of the activated carbon injection system
- Installation of the booster fan
- Installation of the urea storage tank, delivery module, skid-mounted modules, and piping for the SNCR system
- Installation of ductwork interconnecting new pieces of equipment
- Installation of electrical supplies and controls

The above work was essentially completed with the exception of the tie-ins to the existing equipment. The necessary ductwork modifications and installation of the SCR were made during the tie-in outage in late 2006. Parametric testing and demonstration continued until October 18, 2008.

## D. Technology Description

As mentioned previously, AES Greenidge primarily burns eastern U.S. bituminous coal along with wood waste that can constitute up to 10 percent of the total heat input.

Typical fuel properties are presented in Table 1.

Table 1. Assumed Fuel Characteristics for the Design Case

	<b>Coal</b>	<b>Wood</b>	<b>Blended Fuel</b>
Higher Heating Value (Btu/lb)	13,097	8,592	12,426
Carbon (wt %)	72.17	45.13	68.14
Hydrogen (wt %)	4.79	5.78	4.94
Nitrogen (wt %)	1.36	2.8	1.57
Chlorine (wt %)	0.1	0.22	0.12
Sulfur (wt %)	2.9	0.2	2.5
Oxygen (wt %)	5.04	38.72	10.05
Moisture (wt %)	5.8	6.3	5.87
Ash (wt %)	7.85	0.82	6.8

The multi-pollutant control technology consists of SNCR followed by an in-duct SCR. The SCR is located between the economizer and the air heater. An activated carbon injection system is located downstream of the air heater, just upstream of the Turbosorp® dry scrubbing system. Fly ash and sorbent are removed from the flue gas in a baghouse before it is discharged to the atmosphere through the existing stack. The overall process schematic is shown in Figure 1.

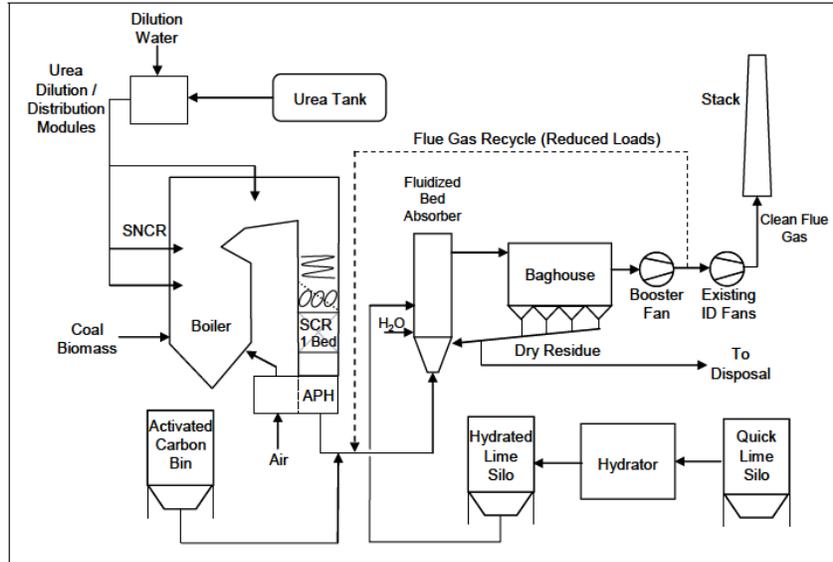


Figure 1. Overall Process Schematic

### Selective Non-Catalytic Reduction

The SNCR system basically consists of multiple reagent injection points in the furnace. The urea ( $\text{CO}(\text{NH}_2)_2$ )-based SNCR system operates synergistically with the in-duct SCR reactor to reduce  $\text{NO}_x$  emissions. At full load operation, the SNCR system is designed to reduce  $\text{NO}_x$  from 0.25 to 0.144 lb/mmBtu at the economizer outlet, a 42.4 percent reduction. The SNCR reactions also supply a controlled amount of ammonia ( $\text{NH}_3$ ) slip to feed the downstream in-duct SCR reactor.

At generator loads below about 86 MWe, the economizer outlet temperatures fall below the minimum SCR operating temperature of 600 °F. At this point, the SNCR is designed to reduce  $\text{NO}_x$  emissions by 20–25 percent while producing minimal ammonia slip. SNCR operation is discontinued when generator load falls below about 54 MWe, which corresponds to an economizer outlet temperature of less than 528 °F. This is done to prevent the formation of ammonium salts in the SCR catalyst.

The SNCR system design includes three separate zones of urea injection into the boiler. Zone 1 is closest to the combustion zone, Zone 2 is in the upper furnace, and Zone 3 is located in the superheater section. In Zones 1 and 2, diluted urea reagent is injected by

air-cooled wall injectors that are installed through penetrations in the water wall. In Zone 3, diluted urea reagent is injected through retractable, water-cooled, multiple-nozzle lances. SNCR performance depends strongly on temperature and reagent distribution; therefore, the optimal placement and spray patterns for injectors and lances were determined based on fluid dynamic and chemical kinetic modeling results.

The use of multiple urea injection zones is necessary to ensure thorough coverage of the reagent throughout the flue gas and to allow injection of urea into different temperature regions of the furnace, which is critical to the load-following capabilities of the hybrid SNCR/SCR system. At high load, when greater levels of ammonia slip are desired to feed the in-duct SCR reactor, urea can be injected into lower temperature regions of the furnace (Zones 2 and 3) to promote greater NO<sub>x</sub> removal by SNCR and greater ammonia slip. At reduced loads, when ammonia slip from the SNCR needs to be limited, urea injection is restricted to higher temperature regions of the furnace by using only the Zone 1 or Zone 2 injectors.

The liquid, urea-based reagent used by the SNCR process is delivered to the site by tank truck and stored in a 15,000-gallon, fiberglass reinforced plastic tank. The tank is heated and insulated to maintain its temperature above 80 °F to prevent the urea from crystallizing. A high flow delivery and circulation module is used to supply filtered urea-based reagent from the storage tank to the urea injection system.

#### In-Duct Selective Catalytic Reduction

The SCR system basically consists of a layer of catalyst installed in the duct between the economizer and air heater where the temperature is suitable for SCR operation. The size of the in-duct SCR reactor is limited by the space available in the duct between the economizer and the air heater.

The flue gas flows from the SNCR process to the in-duct SCR installation, which is designed to further reduce NO<sub>x</sub> emissions to  $\leq 0.10$  lb/mmBtu with ammonia slip limited to  $\leq 2$  ppm when the unit is operating at full load. All of the ammonia required for NO<sub>x</sub>

reduction across the SCR catalyst is generated in the SNCR process, thus avoiding the need for ammonia handling, storage, and injection equipment.

The minimum operating temperature for the SCR catalyst is 600 °F. The SCR system at AES Greenidge does not include an SCR bypass so the flue gas continues to flow through the catalyst even when temperatures are lower. However, the SNCR process is restricted to  $\leq 2$  ppm ammonia slip for economizer outlet temperatures between 528 °F and 600 °F, and SNCR operation is discontinued for economizer outlet temperatures below 528 °F to prevent ammonium bisulfate formation.

In addition to the SCR catalyst and modified ductwork, the SCR system also includes Delta Wing™ static mixers and a sonic horn system. Delta Wing™ static mixers are used in domestic SCR installations by Riley Power under an exclusive license from Balcke-Durr, GmbH. A previous demonstration of in-duct SCR highlighted the importance of achieving uniform distributions of flue gas temperature, velocity, composition, and fly ash loading across the reactor cross section in order to maximize NO<sub>x</sub> reduction, minimize NH<sub>3</sub> slip and ammonium bisulfate formation, and prevent fly ash plugging. The number, size, and orientation of the static mixers at AES Greenidge were determined based on physical flow modeling. Sonic horns are used to prevent ash buildup on top of the SCR catalyst. A catalyst loading facility is used for manual replacement of deactivated catalyst modules with new modules at the end of the catalyst's useful operating life.

The SCR system did not originally include an LPA removal system because LPA was not expected to be a problem. However, soon after start-up, it became apparent that LPA was accumulating in the in-duct SCR catalyst, and the SCR was modified to include an LPA removal system, which is now considered to be an essential part of the system design. The installation of the LPA removal system was done outside the scope of the Cooperative Agreement and the cost was fully borne by AES Greenidge. It should be mentioned that there were no available 90° bends or hoppers at AES Greenidge that could be used for inertial capture of the LPA.

A sloped screen was installed in the ductwork between the economizer and the catalyst, intersecting the Delta Wing™ static mixers, to capture the LPA from the flue gas. The screen consists of perforated carbon steel sheets. Since the screen crosses an expansion joint it is installed in two sections that are connected by a hinged seal, allowing it to move with the ductwork. Four rotary soot blowers are located beneath the screen to help transport the collected LPA to the base of the screen, where it is removed by eight vacuum ports. A rake soot blower was also installed above the SCR catalyst to aid the sonic horns in re-suspending accumulated fly ash. The arrangement of the catalyst and screen is shown in Figure 2.

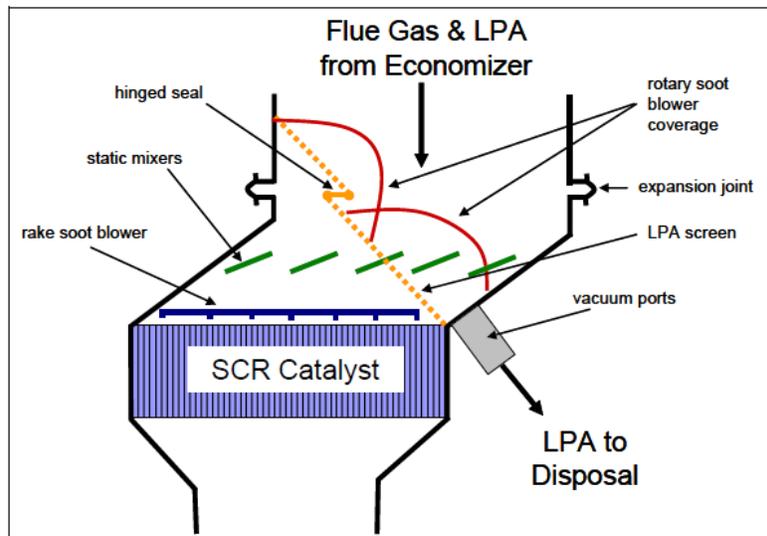


Figure 2. SCR Catalyst and Screen

### Activated Carbon Injection System

The activated carbon injection system allows powdered activated carbon (PAC) to be injected into the flue gas downstream of the air heaters and upstream of the Turbosorp® absorber vessel. Although the mercury removal benefits afforded by the in-duct SCR, circulating fluidized bed dry scrubber, and baghouse were expected to result in substantial mercury removal, it was not known if these systems alone could achieve the goal of 90 % mercury removal. Therefore, the decision was made to include the PAC injection system in the multi-pollutant control demonstration project.

The activated carbon injection system includes a carbon storage silo and a carbon feed and injection system. Activated carbon, which adsorbs both oxidized mercury species and elemental mercury vapor, is injected into the flue gas immediately upstream of the Turbosorp® absorber vessel. The PAC injection rate is controlled based on the flue gas flow rate measured at the stack. Effective utilization of the activated carbon and high mercury capture are expected to result from the long solids residence time provided by the circulating fluidized bed scrubbing system's high solids recycle ratio and the caking of the carbon sorbent on the baghouse filter bags. The baghouse is used to remove spent carbon, along with fly ash and sorbent, from the flue gas.

### Turbosorp® Circulating Fluidized Bed Dry Scrubber

The Turbosorp® Circulating Fluidized Bed Dry Scrubber system consists of an absorber; baghouse; and hydrated lime, process water, and recirculated solids injection systems.

The overall process schematic is shown in Figure 3.

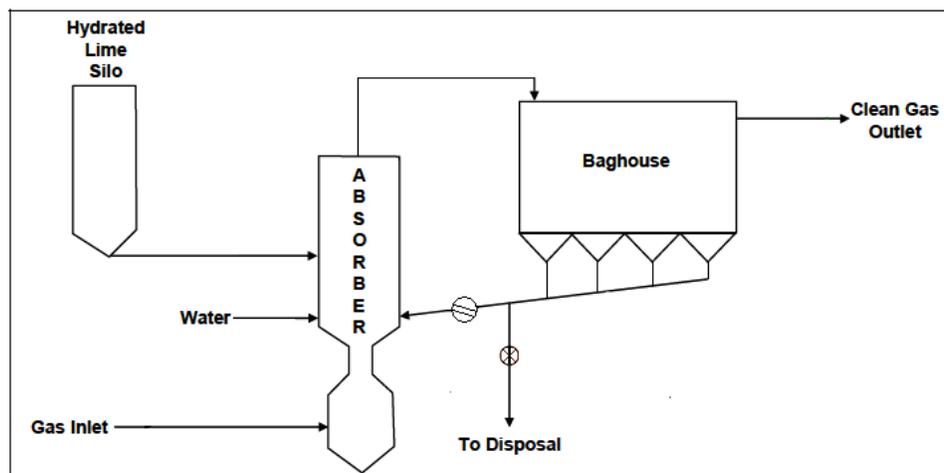


Figure 3. Turbosorp® Process Schematic

After PAC injection (if needed), the flue gas next flows to the Turbosorp® circulating fluidized bed dry scrubbing system, which is designed to remove at least 95 percent of the SO<sub>2</sub>, SO<sub>3</sub>, HCl, and HF from the flue gas. A lime hydration and injection system, process water system, baghouse, and ash recirculation system are integral parts of the circulating fluidized bed dry scrubbing system. The Turbosorp® scrubber is a single absorber vessel constructed of carbon steel. The vessel consists of a venturi inlet section

and a cylindrical reaction chamber. The reactor is designed to treat 423,700 cubic feet per minute of incoming flue gas at 300 °F. At the inlet of the absorber vessel, the flue gas passes through a horizontal duct and a 90° turn. A hopper collects any ash that falls out of the gas at this bend. Once past the bend, the upward flowing gas passes through a single venturi nozzle that accelerates the gas just prior to the injection of water, dry hydrated lime, and recycled solids. The accelerated flue gas establishes a fast fluidized bed of the solid materials in the reaction section where contaminants in the flue gas react with the hydrated lime and recirculated solids. The water is injected to cool and humidify the flue gas and moisten the surface of the injected solids.

The flue gas leaving the absorber carries the entrained fly ash, reacted and unreacted lime, and, if used, PAC. The solids-laden flue gas then enters the pulse-jet baghouse associated with the Turbosorp® system. The choice of a baghouse for particulate removal allows for additional pollutant removal as the gas passes through the caked solids on the bags. The bulk of the solids collected in the baghouse are recycled to the absorber and the rest are sent to disposal. The clean flue gas exits the plant through a stack after passing through the new booster fan and the existing induced draft fan. The Turbosorp® system also includes a flue gas recycle stream to enable turndown for continued operation at low generator loads.

Sulfur dioxide concentrations, measured at the Turbosorp® system inlet and the stack, control the hydrated lime injection rate. The temperature in the Turbosorp® absorber and the flue gas flow rate at the stack determine the rate at which cooling water is injected separately from the sorbent. The fluid bed density within the absorber controls the amount of ash and scrubber reaction products that are recycled to the absorber vessel. Ash and reaction products that are rejected from the system are sent to a disposal facility.

#### Lime Storage, Hydration, and Injection System

The only major ancillary system associated with the multi-pollutant control system is the hydrated lime system. The multi-pollutant control system at AES Greenidge includes a lime hydration system to produce hydrated lime ( $\text{Ca}(\text{OH})_2$ ) from quicklime ( $\text{CaO}$ ) to

avoid the high cost of directly purchasing hydrated lime. The lime hydration system consists of a quicklime storage silo, a lime hydration system, a hydrated lime classification and milling system, a hydrated lime storage silo, and an injection system.

Quicklime is delivered to the AES Greenidge site by truck and pneumatically unloaded into a storage silo. A weigh feeder is used to supply quicklime from the silo to the hydrator, where it is mixed with water and agitated. The quicklime reacts exothermically with the water to form raw, dry hydrated lime. The hydrator exhaust is sent directly to the Turbosorp® scrubber. The raw hydrated lime from the hydrator is transferred to an air classifier, which separates out coarse hydrated lime particles and sends them to a ball mill for grinding. The powdered hydrated lime from the classifier is captured using a cyclone and sent to the hydrated lime silo for injection into the absorber. The lime hydration system also includes the facilities needed to receive hydrated lime directly from a delivery truck in the event of a hydration system outage.

#### Plant Modifications Outside Project Scope

Several plant upgrades were made that were outside the scope of the DOE project. Two of these upgrades are briefly mentioned here since they are important to the success of the demonstration of the multi-pollutant control system. Combustion modifications included modified burner assemblies and modifications to the overfire air system, which contributed to the reduction in NO<sub>x</sub> emissions. These modifications included replacement of the existing coal nozzles, combustion air nozzles, and overfire air nozzles. The result is better mixing in the upper furnace and reduced CO concentrations which created more ideal conditions for SNCR. In addition to the combustion modifications, substantial modifications were made to the air preheater, rendering it less susceptible to ammonium bisulfate deposits.

### **III. REVIEW OF TECHNICAL AND ENVIRONMENTAL PERFORMANCE**

#### **A. Technical Performance**

The bulk of the commissioning and start-up took place between mid-November 2006 and late March 2007. Over the course of the project, the system worked well and generally performed as expected. The goals that were set out were essentially all met. Stated briefly, the project demonstrated a technology that provides an effective option for an older, smaller, coal-fired power plant to meet environmental requirements and continue operation.

As might be expected with first-of-a kind installations, some problems occurred during start-up and the demonstration period. In addition to some minor, readily corrected problems, several more serious problems were encountered with the new system. These problems were associated with the lime hydration system and the accumulation of LPA in the in-duct SCR reactor. These issues were largely resolved during the demonstration period.

The lime hydration system is the most mechanically complex part of the Turbosorp® process and several problems occurred with this system during start-up and operation. Most of them occurred in the hydrated lime milling and classification system. In late 2007, several episodes of plugging occurred in the hydrated lime classification loop.

After start-up of the lime hydration system, it was quickly determined that modifications to the system were required to prevent excessive overflow of milk of lime. The system originally included a wet scrubber to remove particulate matter from the hydrator exhaust gas. It also included a milk of lime circuit that was partially fed by the scrubber bottom liquid. The wet scrubber and milk of lime circuits were eliminated from the hydration system and the exhaust was routed to the Turbosorp® system.

The most noteworthy episode occurred in early October 2007, when Boiler 6 was firing a higher-than-normal sulfur coal for performance testing, resulting in an increased hydrated

lime demand. The demand was well within the design limits, but the hydrated lime classifier plugged numerous times, causing the hydration system to trip. While plant personnel unplugged the lime system, the scrubber continued to operate using purchased hydrated lime. Operation returned to normal when the unit returned to firing coal with more typical sulfur content. Several minor equipment and operational changes reduced the severity of the plugging problem.

The escape of balls from the ball mill was another recurring problem. The first occurrence was several months after the initial plugging problem. Several balls escaped causing minor damage to the lime hydration system. Similar problems were encountered during the first quarter of 2008. On several subsequent occasions, balls escaped from the ball mill and jammed the rotary feeder that removes heavy material from the hydrated lime classifier. Plant personnel installed magnets at the inlet and outlet of the bucket elevator to capture any escaped balls before they reached the classifier. This action mitigated the problem.

Several other relatively minor mechanical and control problems have occurred with the lime hydration system. While these have also been largely mitigated, the net effect of these issues has been that the lime hydration system's operation has not been fully satisfactory. The existing hydrated lime storage silo holds sufficient lime to allow the scrubbing system to operate at full load for about six hours. Since it is not always possible to have lime delivered so quickly, AES Greenidge is considering installing a larger silo.

In order to maintain Turbosorp® operation at low load, a flue gas recirculation system was installed to return flue gas to the absorber to maintain sufficient velocity in the fluidized bed. The booster fan was installed close to, and upstream of, the existing induced draft (ID) fans. In order to avoid moving the existing fans, the take-off for the recirculation stream was installed between the booster fan discharge and the suction of the existing fans. This results in unstable operation at very low flows. Prior to the project, the unit minimum load was 37 MW<sub>net</sub>. Due to the instability, the unit minimum

load was increased to 45 MW<sub>net</sub>, resulting in a loss of 8 MW of turn-down capability. The Participant states that, in retrospect, it might have been better to move the existing fans or to replace the existing fans with larger-capacity ID fans (rather than installing a booster fan). The Participant also states that this should be a consideration in future installations.

The most troublesome problem encountered during operation of the multi-pollutant control system was LPA accumulating on the SCR catalyst. LPA consists of porous slag pieces of varying shape and size believed to be formed in the upper furnace or on heat exchange surfaces. Some of the LPA particles are too large to pass through the honeycomb catalyst. The LPA must be captured upstream of the SCR. If not, it will accumulate on the top of the catalyst or lodge in the catalyst channels. This can cause subsequent accumulation of fly ash in and on top of the catalyst. Plugging of the SCR catalyst led to various operational problems.

In early January 2007, increasing pressure drop across the SCR catalyst was noted. It was decided to shut down the unit for its steam turbine screen outage a few days earlier than planned to allow for inspection of the SCR system. The inspection showed that the pressure drop was caused by refractory, miscellaneous construction debris, and LPA which had accumulated on the catalyst inlet. The collected material was removed and the unit was brought back online and operated normally for a few weeks. In late January 2007, the operators again observed an increase in pressure drop across the catalyst. The catalyst was cleaned and inspected and LPA was again determined to be the cause of the increased pressure drop. The LPA problem affected the operation of AES Greenidge Unit 4 throughout much of the project.

The frequency of outages for SCR cleaning decreased once an LPA removal system was installed. The LPA removal system was installed outside of the scope of the DOE cooperative agreement, but is discussed here because it was essential to the successful operation of the multi-pollutant control system. The final configuration of an effective LPA removal system required several iterations between May 2007 and May 2008. The

initial design included a sloped screen above the SCR catalyst to capture LPA from the flue gas, eight vacuum ports to remove captured LPA from the base of the screen, and two soot blowers beneath the screen to aid in transporting the LPA to the vacuum ports. The iterations included additional soot blowers, installation of a rake soot blower to re-entrain material on the top of the catalyst, installation of a hinged seal between the two screen sections, installation of a screen with smaller openings, and installation of catalyst with larger openings. The outages, their cause, and actions taken during all outages during the project are summarized in Table 2.

Table 2. Outages, Causes, and Actions during the Project

<b>Outage Dates</b>	<b>Outage Cause</b>	<b>Actions With/Around SCR</b>
January 3–7, 2007	Steam turbine screen	LPA, fly ash, construction debris removed from catalyst
February 2–4, 2007	SCR cleaning	LPA and fly ash cleaned from SCR
February 9–10, 2007	Superheater tube leak	LPA and fly ash cleaned from SCR
March 2–4, 2007	SCR cleaning	LPA and fly ash cleaned from SCR
March 22–24, 2007	SCR cleaning	LPA and fly ash cleaned from SCR
April 19–22, 2007	SCR cleaning	LPA and fly ash cleaned from SCR
May 17–25, 2007	Catalyst change/LPA screen system installation	Catalyst changed; LPA screen system installed
June 15–16, 2007	Tube leak	LPA and fly ash cleaned from SCR
July 12–14, 2007	ID fan cable failure	LPA and fly ash cleaned from SCR
August 10–12, 2007	SCR cleaning	LPA and fly ash cleaned from SCR
September 4–7, 2007	LPA screen system modifications	LPA and fly ash cleaned from SCR; LPA system modification completed
September 18–21, 2007	Oil leak	LPA and fly ash cleaned from SCR
November 9–12, 2007	SCR cleaning	LPA and fly ash cleaned from SCR; Minor repair to LPA screen system
December 27, 2007 to January 3, 2008	Catalyst change	Catalyst changed; Minor LPA screen system repairs
May 2–10, 2008	Planned plant outage	LPA screen changed; Catalyst replaced; Other minor modifications
July 4–6, 2008	Economizer tube leak	LPA and fly ash cleaned from SCR
October 3–6, 2008	Damaged coal burners	LPA and fly ash cleaned from SCR

It can be seen from this table that the frequency of outages caused by LPA diminished following changes to the cleaning system. AES Greenidge continues to consider ways to further reduce the impact of LPA.

At the end of the project, all problems have been fully overcome with the exception of the LPA. This problem has been mitigated to the point where it has little impact on plant operation. It should be noted that the problems were not associated with the major components of the multi-pollutant control system (scrubber, SNCR/SCR, baghouse), but with peripheral systems such as particulate removal and lime hydration. The lessons learned in this demonstration will be incorporated in future designs.

The participant reports that three additional Turbosorp projects were underway by the end of the project. These three plants are all in the size range that was anticipated as the primary market for the technology—84 MW (net), 248 MW (gross), and 155 MW (gross). All are designed to achieve greater than 95 percent SO<sub>2</sub> removal with inlet SO<sub>2</sub> levels ranging from 2.3 to 4.6 lb/mmBtu. All three have or will have SCR units. One will have ACI, one will not, and the third will have provision to use ACI. One will abandon an existing cold-side ESP, and the other two will retain their ESPs (one hot-side and one cold-side). These installations demonstrate the applicability of the technology to plants having different configurations.

## **B. Environmental Performance**

### Nitrogen Oxides

The hybrid NO<sub>x</sub> control system significantly reduced the NO<sub>x</sub> emissions from Unit 4, but it fell slightly short of the project's performance target for NO<sub>x</sub> during long-term operation. Guarantee testing of the multi-pollutant control system was completed in March-June 2007. During the guarantee testing, the combustion system and SNCR system were configured to operate as closely as possible to design conditions, and testing demonstrated that the hybrid NO<sub>x</sub> control system could attain high-load NO<sub>x</sub> emissions at or below the targeted emission rate of 0.10 lb/mmBtu. The performance guarantee for NO<sub>x</sub> emissions of 0.10 lb/mmBtu or less at high load was satisfied on March 28, 2007, when the hybrid NO<sub>x</sub> control system attained an average NO<sub>x</sub> emission rate of 0.096

lb/mmBtu over 12 hours while the unit was operating at approximately 105 MW. Similar performance was observed in May and June.

AES Greenidge was unable to achieve the targeted emission rate in the long term tests while also maintaining acceptable combustion characteristics, sufficiently high steam temperatures, and sufficiently low ammonia slip for routine operation. During the guarantee test periods, a substantial amount of overfire air was required in order to achieve a NO<sub>x</sub> emission rate of 0.10 lb/mmBtu or less. As a result, the unit did not have sufficient windbox pressure to avoid flame attachments, and several burners were damaged. In order to achieve more suitable combustion characteristics and sufficiently high steam temperatures for routine, long-term operation, plant personnel had to deviate from the design basis for the SNCR system which resulted in non-optimal system performance. Although the NO<sub>x</sub> emission target of 0.10 lb/mmBtu was not met, NO<sub>x</sub> reduction was and continues to be sufficient to meet AES Greenidge's permit limit of 0.15 lb/mmBtu.

#### Sulfur Dioxide Removal

The Turbosorp® system at AES Greenidge Unit 4 consistently met or exceeded its performance target for SO<sub>2</sub> removal efficiency during the Operation and Testing Phase of the project. Guarantee testing for SO<sub>2</sub> removal efficiency was completed on March 29, 2007. Three one-hour tests were performed while Unit 4 fired eastern bituminous coal containing about 2.7 percent sulfur or about 3.8 lb SO<sub>2</sub>/mmBtu, while operating at full load. The average SO<sub>2</sub> removal efficiency observed during the three tests was 96.0 percent, exceeding the performance target of 95 percent minimum removal.

The Turbosorp® system continued to exhibit a high level of performance during longer-term operation. Between August 1, 2007, and September 30, 2008, the system reduced SO<sub>2</sub> emissions from 3.62 lb/mmBtu to 0.13 lb/mmBtu. This represents an average removal efficiency of 96.3 percent, which exceeds the performance target of 95 percent SO<sub>2</sub> removal.

### Mercury Removal

As can be seen in Table 3, the mercury removal goal of 90 percent was consistently exceeded. Although the results indicate better removal without carbon injection, the Participant points out that this could be the result of slightly less than complete closure on the material balance. In spite of this discrepancy, it is clear that the multi-pollutant control system can effectively remove mercury without carbon injection. In all, 34 Hg tests were conducted during the operation and testing phase of the project, covering a range of plant operating conditions, and all showed greater than 90 percent Hg removal efficiency.

Table 3. Mercury Removal Test Results

	Average HG in Coal, lb/TBtu	Average HG at Stack, lb/TBtu	Average Hg Removal, %
March 28–30, 2007			
Without ACI	7.46	<0.35	>95.4
With ACI	6.58	<0.41	>93.8
October 2–5, 2007			
Without ACI	7.50	0.13	98.3
With ACI	7.10	0.25	96.5

### Sulfur Trioxide Removal

The Turbosorp® system attained its performance target for SO<sub>3</sub> removal efficiency during the Operation and Testing Phase of the project. On average, the Turbosorp® scrubber and baghouse reduced SO<sub>3</sub> in the flue gas from 14.1 ppm to 0.7 ppm, resulting in an overall removal efficiency of 95.3 percent. This satisfied the performance target of at least 95 percent removal efficiency. These results are based on 42 valid tests conducted between May 2007 and June 2008.

### Hydrogen Chloride Removal

The Turbosorp® system attained its performance target for HCl removal efficiency during tests performed in 2007 and 2008. Thirty valid tests were completed between

March 2007 and June 2008. These tests included simultaneous sampling at the air heater outlet and stack. On average, the Turbosorp® scrubber and baghouse reduced HCl in the flue gas from 38.4 ppm to 1.3 ppm, resulting in an overall removal efficiency of 96.7 percent, which exceeded the performance target of at least 95 percent HCl removal.

#### Hydrogen Fluoride Removal

The Greenidge Project sought to demonstrate 95 percent or greater removal of HF across the Turbosorp® system. However, the HF tests conducted as part of the Operation and Testing Phase of the project were inconclusive with respect to this performance target. Thirty-one HF tests were completed at AES Greenidge between March 2007 and June 2008. Each test included simultaneous sampling at the air heater outlet and stack. The tests were generally inconclusive due to the very low concentrations of HF observed at both sampling locations. In a number of tests, the concentrations were below the detection limit. When HF was detected, the concentrations were too low to get reliably accurate measurements. Therefore, no conclusion can be stated regarding the goal for HF removal.

#### Particulate Matter Removal

The new baghouse that was installed as part of the multi-pollutant control system substantially reduced primary particulate emissions from the unit. Prior to the project, an ESP was used to control PM emissions from Unit 4. The particulate emission rate achieved by the ESP was measured as 0.063 lb/mmBtu. After the baghouse was installed, particulate emissions averaged less than 0.001 lb/mmBtu during long term operation. Measurements made at the air heater outlet and stack showed a removal efficiency exceeding 99.9 percent. The actual removal efficiency was significantly greater since the solids fed to the absorber are not included in the incoming material.

#### IV. DISCUSSION OF RESULTS

The multi-pollutant system installed at AES Greenidge has been retained for commercial operation. It has largely met the emission control goals set at the beginning of the project. It has also demonstrated that, as expected, it has lower capital and fixed operating costs compared to conventional technologies, as well as somewhat higher variable operating costs. The variable operating costs were somewhat higher than expected due largely to higher-than-anticipated costs for pebble lime. Some of the equipment experienced typical startup problems that were readily corrected. After startup, the major equipment generally functioned as expected.

There are two instances where problems with equipment continued. One subsystem, the lime hydration system, required significant changes to enable satisfactory operation. AES Greenidge is considering the installation of additional hydrated lime storage so that intermittent problems do not interfere with plant operation. Newer Turbosorp® installations include an improved lime system design that is expected to eliminate the problems encountered during the demonstration.

The other major problem is with LPA blocking the SCR catalyst, which reduces its activity and causes increased pressure drop. It should be noted that the extremely limited space in the ductwork between the economizer and the air preheater required that the SCR catalyst be installed in a vertical duct and there are no upstream bends that would cause inertial capture of LPA from the flue gas. In addition, the gas flows downward through the catalyst. Locating the screen in the vertical duct makes it more difficult to remove the material on the screen. Sufficient progress in keeping the catalyst clear has been made so that catalyst plugging is typically no longer the cause of shutdowns, but cleaning is performed when the plant is shut down for other reasons.

With two exceptions, the environmental goals of the project have been met or exceeded during long term operation. Due to levels of HF near or below the detection limit, no

claim of success or failure is valid. Although the NO<sub>x</sub> reduction goal was met during guarantee testing, it could not be sustained during long term operation without causing burner damage.

Overall, the multi-pollutant control system is operating as expected and has enabled AES Greenidge to continue operating as a commercial unit. It should be noted that the problems encountered in this demonstration have been largely overcome and the knowledge gained will help preclude similar problems in future installations.

It is noteworthy that the multi-pollutant control system removes well over 90 percent of the mercury without carbon injection.

The members of the Participant's team are to be commended for their efforts in overcoming the peripheral issues that might have caused the project to be less than successful—particularly those issues associated with LPA and the lime system.

## **V. MARKET ANALYSIS**

### **A. Potential Market**

The demonstration technology is intended to help ensure the continued availability of reliable, low-cost electricity from the nation's existing, smaller to midsize coal-fired power plants. Although the technology is applicable to units with capacities of 50-600 MWe, its potential benefits are greatest for units in the lower part of this size range (50-300 MWe). There are currently about 400 operating coal-fired units in this range that are equipped with neither flue gas desulfurization nor selective catalytic reduction technologies, and a majority of these units have not announced plans for air pollution control retrofits. These 400 smaller coal-fired units represent more than 55 GW of installed electric generating capacity and are subject to progressively more stringent environmental regulations. Conventional control technologies (SCR, wet FGD) are capable of achieving the emission rates required by these regulations, but require large capital investments and large space requirements that make them unattractive and sometimes impractical for this fleet of older, smaller units. These units represent a substantial prime market for the demonstration technology.

### **B. Capital, Operating, and Maintenance Costs**

The multi-pollutant control system that was demonstrated at AES Greenidge was designed to provide an affordable emissions control option for smaller coal-fired power plants. It was expected that the system would offer lower capital costs and fixed operating and maintenance (O&M) costs while incurring somewhat higher variable O&M costs than conventional technologies. This scenario is consistent with the needs of these smaller units.

Process economics were derived using common cost estimating practices as well as design, performance, and cost information obtained from the AES Greenidge

demonstration. The assumptions used in the economic analysis are shown in Table 4 below.

Table 4. Assumptions Used in Economic Analysis

Unit capacity (MWe, net)	107
Fuel feed rate (lb/h)	85,692
Fuel HHV (Btu/lb)	12,426
Fuel sulfur content (% , weight)	2.5
Fuel Hg content (ppmw)	0.1
Baseline NO <sub>x</sub> emission rate (lb/mmBtu)	0.30
Flue gas flow rate at air heater outlet (acfm)	423,700
Annual capacity factor (%)	80

Capital costs for the multi-pollutant control system at AES Greenidge are summarized in Table 5.

Table 5. Capital Cost Summary

	Total Plant Cost		Total Plant Investment		Total Capital Requirement	
	\$MM	\$/kW <sub>net</sub>	\$MM	\$/kW <sub>net</sub>	\$MM	\$/kW <sub>net</sub>
Hybrid NO <sub>x</sub> Control System	12.2	114	12.5	117	12.9	120
Circulating Dry Scrubber System	24.5	229	25.14	234	26.1	244
Activated Carbon Injection System	0.6	6	0.6	6	0.6	6
TOTAL	37.3	349	38.2	357	39.6	370

The total plant costs presented in Table 5 include the costs to design, procure, fabricate, deliver, install, and commission the multi-pollutant control system. Total plant investment accounts for interest accrued during the construction period. The total capital requirement is the sum of total plant investment, pre-production cost, and inventory capital. The costs presented in Table 5 are somewhat higher than the project costs given earlier in this report. The costs for the burner modifications and the LPA screens were

outside the project scope, but are presented here since they were critical to the success of the project and are more indicative of the actual cost of a Multi-Pollutant Control System. Costs for the hybrid NO<sub>x</sub> control system include the costs for the combustion modifications, SNCR system, in-duct SCR system, static mixers, sonic horns, the LPA removal system, and all supporting equipment. Combustion modifications and the large particle ash removal system are included in this cost estimate because they are essential to the performance and operability of the installation. Costs for the scrubber system include the costs for the absorber vessel, process water system, lime storage, hydration, and injection system, baghouse, ash recirculation system, booster fan, and all supporting equipment.

Fixed operating and maintenance costs include operating labor costs; maintenance, labor, and materials costs; and administrative and support labor costs. These are estimated by the Participant at \$880,000 per year.

The variable operating and maintenance costs associated with the multi-pollutant control system include costs for pebble lime, urea, activated carbon, waste disposal, electricity, water, compressed air, replacement catalyst, and replacement baghouse bags and cages. Costs for reagents reflect approximate market prices during start-up of the multi-pollutant control system in early 2007. The total estimated variable O&M cost is \$6.55 per MWh (\$4.91 million per year) for the design case and \$6.77 per MWh (\$5.08 million per year) for the actual performance case.

## VI. CONCLUSIONS

The Participant's team successfully designed, installed, and operated the multi-pollutant control system at AES Greenidge. Over the course of the project, the demonstration technology effectively controlled SO<sub>2</sub>, SO<sub>3</sub>, NO<sub>x</sub>, Hg, PM, and HCl. Although not all problems have been fully mitigated, they have been mitigated to the point that the demonstration technology continues to operate effectively and is no longer the cause of regular outages. The LPA problem was especially difficult due to the limited ductwork at AES Greenidge. As a result of the LPA experience during this project, future designs will account for LPA and it should not be a significant problem.

While there are still some issues associated with the lime hydration system, it also continues to perform much better than it did early in the project. Furthermore, lime hydration systems are in widespread use and future installations should not present this level of difficulty given the wide range of experience with this kind of system.

Although the NO<sub>x</sub> control system has not quite met its goal in long term operation, it has effectively reduced NO<sub>x</sub> emissions. The other pollutant removal goals were met or exceeded. It should also be noted that the project demonstrated excellent mercury removal without carbon injection.

Significant problems did not occur with the core technologies such as the hybrid NO<sub>x</sub> control system, Turbosorp® scrubber, and baghouse. Instead, the significant problems were associated with items such as LPA removal, burner modifications, and the lime hydration system.

The cost goals were essentially met, demonstrating a technology that is applicable to the target market as demonstrated by the Participant reporting three retrofit projects underway by the end of the project.

When all factors are taken into consideration, the project should be considered an overall success. It demonstrated an effective, economic technology that provides an option to allow about 400 older plants representing 55GW of electrical generating capacity to continue operation.

## VII. ACRONYMS AND ABBREVIATIONS

ACI	activated carbon injection
acfm	actual cubic feet per minute
BPEI	Babcock Power Environmental, Inc.
CaO	quicklime
Ca (OH) <sub>2</sub>	hydrated lime
CCTDP	Clean Coal Technology Demonstration Program
CONSOL	CONSOL Energy Inc.
CO <sub>2</sub>	carbon dioxide
DCS	distributed control system
DOE	U.S. Department of Energy
EPC	engineering, procurement, and construction
FGD	flue gas desulfurization
GW	gigawatts
HCl	hydrogen chloride
HF	hydrogen fluoride
HHV	higher heating value
Hg	mercury
ID	induced draft
kW	kilowatt
LPA	large particle ash
mmBtu	million British thermal units
MWe	Megawatts electrical
NETL	National Energy Technology Laboratory
N <sub>2</sub>	nitrogen
NH <sub>3</sub>	ammonia
NO <sub>x</sub>	nitrogen oxides
O&M	operating and maintenance
PAC	powdered activated carbon
ppm	Parts per million
ppmw	Parts per million by weight
PPII	Power Plant Improvement Initiative
SCR	selective catalytic reduction
SNCR	selective non-catalytic reduction
SO <sub>2</sub>	sulfur dioxide
SO <sub>3</sub>	sulfur trioxide
TBtu	Trillion British Thermal Units

## **VIII. REFERENCE**

Connell, Daniel P., CONSOL Energy Inc., Greenidge Multi-Pollutant Control Project - Final Report of Work Performed May 19, 2006 – October 18, 2008, April 2009.