

GREENIDGE MULTI-POLLUTANT CONTROL PROJECT

U.S. DOE Cooperative Agreement No. DE-FC26-06NT41426

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**QUARTERLY PROGRESS REPORT
FOR WORK PERFORMED DURING THE PERIOD
April 1, 2007 to June 30, 2007**

August 7, 2007

1.0 Executive Summary

As part of the Greenidge Multi-Pollutant Control Project, CONSOL Energy Inc. (CONSOL), AES Greenidge LLC (AESG), and Babcock Power Environmental Inc. (BPEI) are installing and testing an integrated multi-pollutant control system on one of the nation's smaller existing coal-fired power plants - the 107-MWe AES Greenidge Unit 4 (Boiler 6). The overall goal of this approximately 2.5-year project, which is being conducted as part of the U.S. Department of Energy's (DOE's) Power Plant Improvement Initiative (PPII), is to demonstrate that the multi-pollutant control system being installed, which includes a hybrid selective non-catalytic reduction / selective catalytic reduction (SNCR/SCR) system and a Turbosorp[®] circulating fluidized bed dry scrubbing system with baghouse ash recycling and activated carbon injection, can cost-effectively reduce emissions of NO_x, SO₂, Hg, acid gases (SO₃, HCl, HF), and particulate matter from coal-fired electrical generating units (EGUs) with capacities of 50 MWe to 600 MWe. Smaller coal-fired units, which constitute a significant portion of the nation's existing generating capacity, are increasingly vulnerable to retirement or fuel switching as a result of increasingly stringent state and federal environmental regulations. The Greenidge Project will demonstrate the commercial readiness of an emissions control system that is particularly suited, because of its low capital and maintenance costs and small space demands, to meet the requirements of this large group of existing EGUs. All funding for the project is being provided by the U.S. DOE, through its National Energy Technology Laboratory (NETL), and by AES Greenidge.

The multi-pollutant control system is depicted in Figure 1. The NO_x control system consists of commercially available combustion modifications (installed outside of the scope of the DOE project), a urea storage, dilution, and injection system (SNCR), and a single-bed, in-duct SCR reactor that is fed by ammonia slip from the SNCR process. The Turbosorp[®] system for SO₂, SO₃ (visible emissions), mercury, HCl, HF, and particulate matter control consists of a lime hydrator and hydrated lime feed system, a process water system, the Turbosorp[®] vessel, a baghouse for particulate control, an air slide system to recycle solids collected in the baghouse to the Turbosorp[®] vessel, and an activated carbon injection system for mercury control. A booster fan is also installed to overcome the pressure drop resulting from the installation of the SCR catalyst, Turbosorp[®] scrubber, and baghouse.

Specific objectives of the project are as follows:

- Demonstrate that the hybrid SNCR/SCR system, in combination with combustion modifications, can reduce high-load NO_x emissions from the 107-MWe AES Greenidge Unit 4 to ≤0.10 lb/mmBtu (a reduction of ≥60% following the combustion modifications) while the unit is firing >2%-sulfur coal and co-firing up to 10% biomass.
- Demonstrate that the Turbosorp[®] circulating fluidized bed dry scrubber can remove ≥95% of the SO₂ emissions from AES Greenidge Unit 4 while the unit is firing >2%-sulfur coal and co-firing up to 10% biomass.

- Demonstrate $\geq 90\%$ mercury removal via the co-benefits afforded by the SNCR/SCR and Turbosorp[®] circulating fluidized bed dry scrubber (with baghouse) systems and, as required, by carbon or other sorbent injection.
- Demonstrate $\geq 95\%$ removal of acid gases (SO_3 , HCl , and HF) by the Turbosorp[®] circulating fluidized bed dry scrubber.
- Evaluate process economics and performance to demonstrate the commercial readiness of an emission control system that is suitable for meeting the emission reduction requirements of boilers with capacities of 50 MWe to 600 MWe.

This quarterly report, the fifth to be submitted for the Greenidge Multi-Pollutant Control Project, summarizes work performed on the project between April 1 and June 30, 2007. During the period, we completed guarantee testing of the multi-pollutant control system at AES Greenidge. Tests conducted in late March and early May demonstrated that the system is capable of achieving a full load NO_x emission rate of 0.10 lb/mmBtu, an SO_2 removal efficiency of 96%, and SO_3 and HCl removal efficiencies of 97% while the unit is firing an approximately 2.5-3.0% sulfur eastern U.S. bituminous coal, thereby meeting or exceeding the performance targets for these parameters. Moreover, these tests demonstrated $\geq 95\%$ Hg removal by the multi-pollutant control system without the need for any activated carbon injection. NH_3 slip from the hybrid NO_x control system has generally been greater than anticipated. The NH_3 slip guarantee of 2 ppmv was demonstrated on June 20, following extensive tuning of the combustion and SNCR systems, but the plant has generally had trouble simultaneously achieving the performance targets for NO_x emissions and NH_3 slip while also maintaining acceptable combustion performance and steam temperatures during more routine operation. The performance of the system will continue to be evaluated and optimized during the upcoming quarter. The Turbosorp[®] system has generally operated without problem. Also during the quarter, a screen was installed above the in-duct SCR reactor to overcome the large particle ash problem that has affected the unit since January.

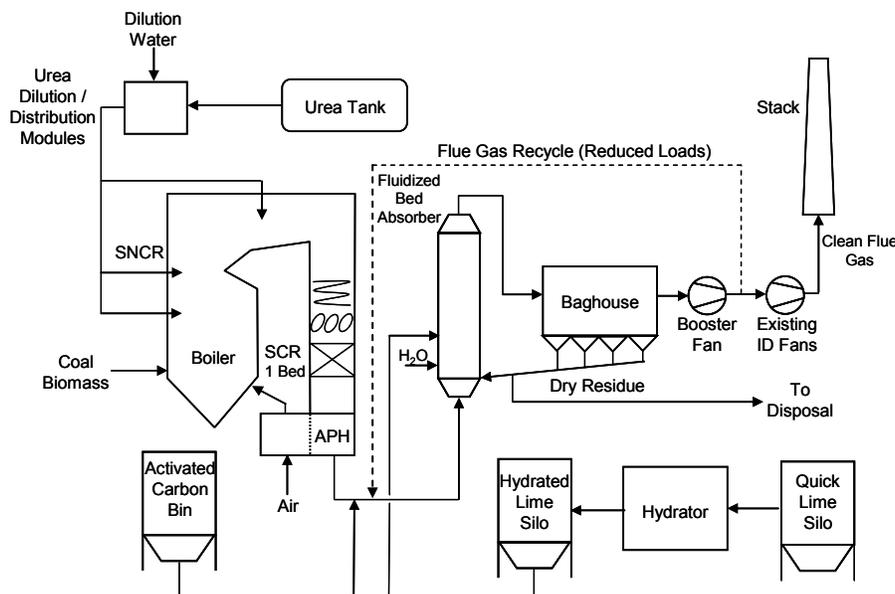


Figure 1. Schematic of the multi-pollutant control system being demonstrated at AES Greenidge.

2.0 Work Performed and Results Obtained During the Reporting Period

Highlights of the Greenidge Multi-Pollutant Control Project during the period from April 2007 through June 2007 included the completion of guarantee testing of the multi-pollutant control system, the implementation of a solution for the large particle ash (LPA) problem that had affected the in-duct SCR reactor since start-up, and the completion of the Preliminary Public Design Report for the project. Work performed and results obtained between April 1, 2007, and June 30, 2007, are described below by Statement of Project Objectives task number.

Tasks 1.1 and 2.1 – Project Management

These tasks are complete. Project management activities during the second quarter of calendar year 2007 are summarized below under Task 3.1 – Phase 3 Project Management.

Task 1.2 – Total Process Definition and Design

As discussed in the quarterly progress report for the third calendar quarter of 2006, this task is complete.

Task 1.3 – Procurement

As discussed in the quarterly progress report for the fourth calendar quarter of 2006, this task is complete.

Task 1.4 – Environmental/Regulatory/Permitting

As discussed in the project's first quarterly progress report, all permits and clearances required for construction of the multi-pollutant control facility were obtained. In addition to these permits, AESG must amend its Title V air permit as part of the regularly scheduled renewal process for that permit in order to reflect the emission requirements set forth in its consent decree with the State of New York. During the second quarter of calendar year 2007, AESG received its Notice of Complete Application for its Title V permit from the New York State Department of Environmental Conservation (DEC). The permit notice has been published in the local newspaper; comments are due to the DEC by August 20. AESG is also still in the process of applying for modifications to its solid waste permit and to the State Pollutant Discharge Elimination System (SPDES) permits for the plant and for its Lockwood ash disposal site, as required to reflect changes resulting from the installation of the multi-pollutant control system.

Task 1.5 – Environmental Information Volume

As discussed in the quarterly progress report for the second calendar quarter of 2006, this task is complete.

Task 1.6 – Baseline Testing

As discussed in the quarterly progress report for the second calendar quarter of 2006, this task is complete.

Tasks 2.2 and 2.3 – General Civil/Structural and Process System Construction

As discussed in the quarterly progress report for the first calendar quarter of 2007, these tasks are complete.

Task 2.4 – Plant Start-Up and Commissioning

As discussed in the quarterly progress report for the first calendar quarter of 2007, all major activities associated with start-up and commissioning of the multi-pollutant control system are complete. However, several engineering, procurement, and construction (EPC) contract milestones that are associated with Task 2.4 (i.e., achievement of substantial completion, issuance of final release and waivers, completion of reliability run, achievement of final completion, submittal of final documents), but contingent on certain activities under Tasks 3.2 and 3.3, had not yet been attained as of the end of the current reporting period. We expect that all of these milestones will be achieved during the upcoming quarter.

Task 3.1 – Phase 3 Project Management

Project management activities during the second quarter of calendar year 2007 focused especially on reporting the results of the project thus far. The Preliminary Public Design Report was revised to incorporate the project team's comments, and the final draft was submitted to DOE on May 25. We submitted an abstract titled "Operation of an Advanced Circulating Fluidized Bed Air Pollution Control System at an Existing Smaller, Older Coal-Fired Unit at a Cost-Effective Price" to the organizers of POWER-GEN International, which will be held in New Orleans, LA, on December 11-13. That abstract, which is included as Attachment A to this report, was accepted. Our abstract titled "Mercury Removal Performance of the Greenidge Multi-Pollutant Control System" which had also been submitted to POWER-GEN International, was not accepted for presentation at that conference. However, a revised version of the abstract (included as Attachment B) was submitted for presentation at the EUEC Energy & Environment Conference, which will be held in Tucson, AZ, in January 2008.

On May 3, we gave a presentation titled "Initial Cost and Performance Results from the Greenidge Multi-Pollutant Control Project" at the Electric Power Conference & Exhibition in Rosemont, IL, and on June 27, we gave a presentation titled "The Greenidge Multi-Pollutant Control Project: Key Technical and Economic Features of a New Approach for Reducing Emissions from Smaller Coal-Fired Units" at the Air & Waste Management Association's 100th Annual Conference & Exhibition in Pittsburgh, PA. Copies of these presentations are included as Attachments C and D, respectively, to this report. We also submitted our paper titled "Preliminary Performance Testing Results from the

Greenidge Multi-Pollutant Control Project” to COAL-GEN, which is being held in Milwaukee, WI, in early August. A copy of that paper is included as Attachment E to this report.

On May 22, a project status review meeting including representatives from DOE, CONSOL, and AES was held at the AES Greenidge site. The Final Public Design Report for the project is being drafted and will be finalized during the next quarterly reporting period. The project’s cost and schedule performance are discussed in Section 3.0 of this report.

Task 3.2 – Plant Operations

Operation of the multi-pollutant control system continued during the second quarter of calendar year 2007. The Turbosorp[®] system operated regularly throughout the quarter, achieving SO₂ emission rates that were well within the current permitted rate of 0.38 lb/mmBtu. (The average SO₂ emission rate measured by the plant’s stack CEM during April-June was ~0.25 lb/mmBtu). Few operational problems have been encountered with this system thus far. On May 3, the water feed rate to the lime hydrator was out of limits, causing the hydrator to plug and require cleaning. The problem was quickly resolved, though, and the control logic for the hydrator was modified to prevent this problem from occurring again in the future. The compressed air demand from the baghouse has also exceeded expectations. The plant has brought in a mobile compressor to temporarily handle the excess demand, and they are evaluating options for increasing their compressed air capacity in the long term.

Most of the operational challenges encountered to-date have been associated with the hybrid NO_x control system. As discussed in the last quarterly progress report, in January 2007 the plant began to experience problems with large particle ash accumulating on the surface of the in-duct SCR catalyst. These problems continued into the first half of the current quarterly reporting period, until a screen was installed in mid-May to overcome them. AES Greenidge Unit 4 was derated during the week of April 16 because of increasing pressure drop across the SCR reactor that resulted from the accumulation of LPA; an outage was held on April 19-22 so that the LPA could be removed from the surface of the catalyst. This was the first outage for catalyst cleaning since March 22-24. The unit’s air heater baskets were also cleaned during the outage, as they too had exhibited a slight increase in pressure drop during early April. Pressure drops across both the in-duct SCR reactor and the air heater returned to acceptable levels following the outage.

On May 4, the Unit 4 combustion system experienced flame attachments that damaged several burners, forcing them out of service. As a result, the unit was derated until the burners could be repaired during the large particle ash screen installation outage, which began on May 17. During the outage, a sloped screen was installed in the ductwork above the SCR catalyst (intersecting the Delta Wing static mixers) to filter LPA from the flue gas and prevent it from accumulating on the surface of the catalyst. The collected LPA is removed from the screen by a series of vacuum ports (Figure 2) installed

through the wall of the SCR inlet duct at the base of the screen; two soot blowers were also installed below the screen to aid in transporting the LPA to the vacuum ports. In addition, during the outage, AES replaced the existing SCR catalyst layer with a new layer so that the existing layer can be thoroughly cleaned. (It will then be stored on site and be available as a spare in case it is needed in the event of an economizer tube leak, etc.) Moreover, the plant took advantage of the screen installation outage to complete various routine maintenance activities so that they will not have to hold their usual outage in September for these activities. The outage was completed on May 25.

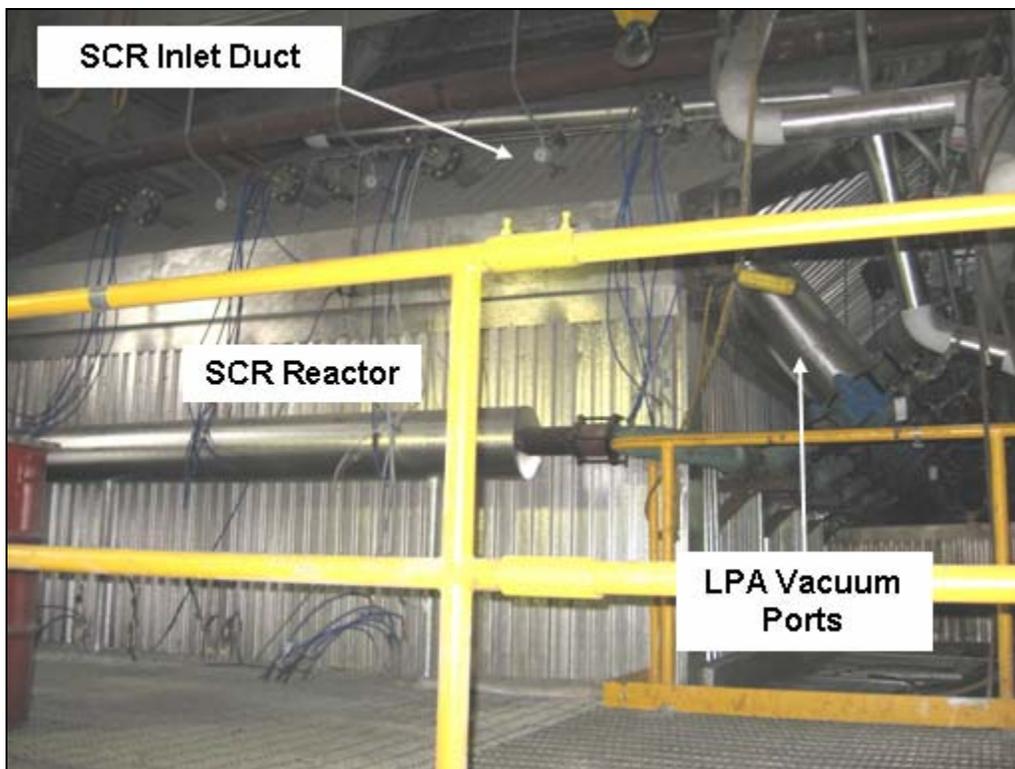


Figure 2. Photograph showing the vacuum ports that are used to remove large particle ash from the base of the sloped screen that was installed above the in-duct SCR reactor at AES Greenidge Unit 4.

The large particle ash screen generally operated without problem for the remainder of the quarter, although a small increase in pressure drop across the screen was observed in mid-June. The screen was inspected during a tube leak outage on June 15-17; the inspection indicated that the soot blowers installed below the screen were missing several areas of the screen, allowing large particle ash to accumulate in those areas. As of the end of the quarter, the plant was evaluating options for modifying the soot blowers to improve their coverage of the screen.

Although the multi-pollutant control system demonstrated attainment of its NO_x emission performance target of 0.10 lb/mmBtu during guarantee testing in late March (see Task 3.3), the plant has generally had trouble achieving this emission rate during routine operation while also maintaining a combination of acceptable combustion characteristics, sufficiently high steam temperatures, and sufficiently low ammonia slip.

As a result, they have generally operated the NO_x control system closer to its current permitted high-load emission rate of 0.15 lb/mmBtu than to its performance target of 0.10 lb/mmBtu. The project team continues to work on optimizing the performance of the integrated system and evaluating options for long-term operation.

Task 3.3 – Testing and Evaluation

Guarantee testing of the multi-pollutant control system was completed during the second quarter of calendar year 2007. The guarantee tests were conducted while AES Greenidge Unit 4 was firing approximately 2.5-3.0% sulfur eastern U.S. bituminous coal and operating at or near full load. Results concerning the emissions reduction performance of the system are summarized in Table 1. These results indicate that the multi-pollutant control system succeeded in demonstrating attainment of all of its performance targets for air emissions reductions. Additional detail concerning the testing is provided below, and full detail will be provided in a forthcoming topical report.

Table 1. Summary of guarantee testing results for the multi-pollutant control system at AES Greenidge Unit 4. All measured performance results represent the average of multiple valid test runs.

Parameter	Performance Target	Measured Performance	Date	Measurement Method
NO _x emission rate	≤ 0.10 lb/mmBtu	0.10 lb/mmBtu	03/28/07	Stack CEM
NH ₃ slip ^a	≤ 2 ppmvd @ 3% O ₂	2 ppmvd @ 3% O ₂	06/20/07	EPA CTM 027
SO ₂ removal	≥ 95%	96%	03/29/07	Stack CEM (outlet), EPA Method 6C (inlet)
Hg removal Without ACI With ACI	≥ 90%	≥ 95% ^b ≥ 94% ^b	03/28/07 03/30/07	Ontario Hydro Ontario Hydro
SO ₃ removal	≥ 95%	97%	05/02/07	Controlled Condensation
HCl removal	≥ 95%	97%	05/04/07	EPA Method 26A
HF removal	≥ 95%	Indeterminate ^c	05/04/07	EPA Method 26A

^aMeasured at the air heater inlet. ^bStack concentration was less than the method detection limit for all tests. ^cConcentrations at both the air heater outlet and stack were less than the method detection limit, preventing the calculation of a removal efficiency.

Tests of Week of March 26, 2007

As discussed in our last quarterly project report, CONSOL conducted the first round of field sampling for guarantee testing of the multi-pollutant control system during the week of March 26. The flue gas and process samples collected during that testing campaign were analyzed during April. Preliminary results for all of the flue gas parameters of interest were available by April 18. These results indicated that the system performed near or above the guaranteed removal efficiencies or emission rates for NO_x, SO₂, Hg, and HCl. Mercury removal results were particularly encouraging; coal-to-stack Hg removal efficiencies greater than 90% were observed consistently across all six tests that were conducted in late March, regardless of whether or not activated carbon was being injected into the system. Results for several other analytes, however, were either inconsistent with the guarantees or inconclusive. The measured NH₃ slip of 9.9 ppmvd (corrected to 3% O₂) at the northeastern corner of the SCR outlet was greater than the guaranteed value of 2 ppmvd, and the results for SO₃ removal across the Turbosorp[®]

system, which indicated less than 95% removal, were deemed invalid because the NH_3 present in the flue gas likely interfered with the measurement. Also, HF was not detected at either the air heater outlet or stack, making it impossible to calculate a removal efficiency for this species.

Tests of Week of April 30, 2007

Hence, CONSOL repeated the guarantee tests for NH_3 slip at the SCR outlet / air heater inlet and for SO_3 and HF removal across the Turbosorp[®] system on May 1-4. HCl was also measured again during this testing period, because only two (rather than the desired three) valid measurements were obtained for this analyte during the March testing period. Modifications were made to the methods used to sample NH_3 and SO_3 in an effort to improve the representativeness and sensitivity of the measurements. NH_3 slip measurements were completed on May 1. Sampling was conducted through two ports on the eastern wall of the SCR outlet duct (rather than through the single port that had been used in March), as well as through two additional ports located at the inlets of the unit's two air preheaters, in an attempt to generate samples that better represented average conditions throughout the ductwork between the SCR and air heaters. In spite of this more representative sampling configuration, however, NH_3 concentrations were still greater than the guaranteed maximum slip of 2 ppmvd. The average NH_3 concentration measured through the two ports on the eastern side of the SCR outlet duct was 11.3 ppmvd (corrected to 3% O_2), and the average NH_3 concentration measured through the ports located at the center of each of the unit's two air heater inlet ducts was 4.2 ppmvd (corrected to 3% O_2). SO_3 sampling was completed on May 2 using the controlled condensation method. To avoid possible NH_3 interference, the controlled condensation samples were analyzed by ion chromatography (IC) rather than by BaCl_2 titration, which had been used to analyze the samples collected in March. To further improve the sensitivity and representativeness of the measurements, the sampling durations were increased and traverses were performed at the air heater outlet and stack (sampling in March was conducted at a single point at each location). The SO_3 removal efficiency across the Turbosorp[®] system (including the baghouse) was greater than the guaranteed removal efficiency of 95% for each of the three tests conducted on May 2. A problem with the lime hydration system prevented any sampling from occurring on May 3 (see Task 3.2). The HCl and HF sampling that had been scheduled for that day was performed on the morning of May 4. However, because of a flame attachment problem that affected several of the Unit 4 burners (see Task 3.2), only two test runs (rather than the three that were planned) could be completed. The average HCl removal across the Turbosorp system during these two tests was 97%, which is greater than the guaranteed removal efficiency of 95%. As with the testing conducted in late March, no HF was detected at either the Turbosorp[®] system inlet or the stack during the testing on May 4.

Tests of Week of May 28, 2007

On May 29-June 1, following the installation of the LPA screen and new SCR catalyst described above under Task 3.2, CONSOL and Clean Air Engineering performed NH_3 ,

NO_x, CO, CO₂, and O₂ testing at the inlet and outlet of the in-duct SCR reactor. The objectives of this series of measurements were to determine the effects of the newly installed LPA screen on the NO_x removal performance of the in-duct SCR and to determine whether installation of the screen and replacement of the catalyst enabled the hybrid SNCR/SCR system to achieve its ammonia slip target. Grid-point NO_x, CO, CO₂, and O₂ measurements were taken throughout the day on May 30 and May 31 as personnel from BPEI and Fuel Tech worked to tune the Unit 4 combustion system and the SNCR system. In spite of this tuning, however, an appreciable stratification in NO_x removal percentages continued to be observed across the cross section of the SCR catalyst (suggesting ammonia and/or flow distribution problems). CONSOL and Clean Air Engineering conducted NH₃ slip testing at the air heater inlet on the evening of May 31 (1 test) and during the first half of the day on June 1 (2 tests). Both groups measured greater than 2 ppmv of NH₃ slip during each of the three tests, indicating that the system still was not meeting its ammonia slip guarantee, even after the installation of the large particle ash screen and new catalyst.

Tests of Weeks of June 18 and June 25, 2007

During the next two weeks, BPEI and Fuel Tech continued to make adjustments to the hybrid NO_x control system in an effort to reduce the ammonia slip. CONSOL and Clean Air Engineering returned to the plant on the week of June 18 to perform additional ammonia slip testing and SCR grid point testing. A test conducted on the morning of June 20 indicated greater than 5 ppmv of ammonia slip at the air heater inlet. However, BPEI and Fuel Tech spent the rest of the day tuning the NO_x control system (they were informed during this process by NO_x, CO, and O₂ measurements made by Clean Air Engineering at the SCR inlet and outlet sampling grids), and by the evening, they had succeeded in reducing the ammonia slip to 2 ppmvd (corrected to 3% O₂). Hence, the NH₃ slip guarantee was achieved. Nevertheless, BPEI will develop a longer-term ammonia slip monitoring/evaluation plan, because the measured ammonia slip exceeded the value that had been predicted for this stage of the SCR catalyst's life.

Having satisfied the ammonia slip guarantee, AES, BPEI, and Fuel Tech worked on June 21 to establish a set of acceptable boiler operating conditions for routine operation of the NO_x control system. CONSOL and Clean Air Engineering provided ammonia slip and SCR grid point measurements to support this effort. (Figure 3 presents a photograph showing an NH₃ slip sample being drawn from the air heater inlet on June 21). As of the end of the day, Unit 4 was operating with NO_x emissions below 0.15 lb/mmBtu (thereby satisfying its current permitted NO_x emission rate) and with ~2 ppmv of ammonia slip. Additional combustion system tuning and SCR grid point measurements were completed during the week of June 25.

Process Performance Testing

Because it took longer than expected to demonstrate attainment of the ammonia slip guarantee, process performance testing did not begin during the quarter as originally planned. (The tuning and SCR grid point measurements that were performed while

pursuing attainment of the NH₃ slip guarantee did, however, provide an abundance of information concerning the performance of the hybrid SNCR/SCR system). We expect that these tests, which are designed to examine the effects of changes in plant operating conditions on the performance of the multi-pollutant control system, will commence during the next quarterly reporting period.



Figure 3. Photograph showing NH₃ slip sampling at the air heater inlet on June 21, 2007.

3.0 Status Reporting

3.1 Cost Status

Table 2 summarizes the cost status of the Greenidge Multi-Pollutant Control Project through the end of the second quarter of calendar year 2007. As shown in the table, actual incurred costs for the second quarter of 2007 were \$408,616 greater than baseline planned costs for that quarter, whereas cumulative actual incurred costs were \$3,159,601 less than cumulative planned costs as of the end of the quarter.

The positive cost variance for the second quarter of 2007 arose largely because costs for consumables (i.e., urea and pebble lime) were about \$276,000 greater than originally budgeted for the quarter and because an EPC contract payment milestone with a value of about \$287,000 that had been planned for a previous quarter was instead achieved during the current quarter. The higher-than-expected costs for consumables resulted primarily from significant price escalation that has occurred since the baseline cost plan was developed. These positive variances were offset partially by lower-than-anticipated testing costs during the quarter, as the process performance testing that had been planned for the quarter was delayed. However, costs for

guarantee testing, which extended into the quarter, were greater than budgeted, as several unplanned testing campaigns were required to demonstrate attainment of the ammonia slip guarantee for the multi-pollutant control system.

In spite of the positive cost variance for the second quarter of 2007, the project's cumulative actual incurred costs continued to be appreciably less than its baseline planned costs as of the end of June 2007. The negative cumulative cost variance of \$3,159,601 does not indicate that the project is significantly under budget; rather, it is largely the result of schedule delays that will cause these monies to be spent later than originally planned. Much of this variance is attributable to EPC contract milestones with a collective value of about \$2.8 million that were originally scheduled for completion during the first calendar quarter of 2007 but had not yet been achieved as of the end of June. The continued delay in achieving these milestones resulted from the multi-pollutant control system's large particle ash problem and from its inability to demonstrate attainment of the ammonia slip guarantee. As discussed in Section 2.0, however, these problems were overcome during the current quarterly reporting period. Hence, we expect that the outstanding milestones will be achieved during the upcoming quarter, significantly reducing the magnitude of the project's cumulative cost variance. The large particle ash and ammonia slip issues also delayed the start of process performance testing of the multi-pollutant control system (and hence the realization of costs associated with this testing), further contributing to the project's negative cumulative cost variance. We do not, however, currently expect that these delays will impact the overall project end date of October 18, 2008, as the project schedule affords flexibility for completing the process performance tests during the more-than year-long period between the guarantee tests and follow-up tests.

3.2 Milestone Status

The critical path project milestone plan (from the Statement of Project Objectives) and status for the Greenidge Multi-Pollutant Control Project are presented in Table 3. As shown in the table, the fourth of the project's six critical path project milestones ("Begin routine plant operation and data collection for long-term testing") was achieved as planned during the current quarterly reporting period. As discussed under Task 3.3 in Section 2.0 above, guarantee testing of the multi-pollutant control system at AES Greenidge was completed on June 20, when tests demonstrated attainment of the system's ammonia slip guarantee. Routine operation and testing of the system began the next day, on June 21. Data concerning the day-to-day operation and performance of the multi-pollutant control system are being logged continuously by the plant's data historian for future analysis.

The next critical path project milestone calls for follow-up testing of the multi-pollutant control system to begin during the second quarter of calendar year 2008. We do not anticipate that any changes to the project schedule will be required to complete this critical path milestone.

Table 2. Cost plan/status for the Greenidge Multi-Pollutant Control Project.

Baseline Reporting Quarter	YEAR 1 Start: 1/1/2006 End: 12/31/2006				YEAR 2 Start: 1/1/2007 End: 12/31/2007				YEAR 3 Start: 1/1/2008 End: 12/31/2008			
	Q1	Q2 ^a	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
<u>Baseline Cost Plan By Calendar Quarter</u>												
Federal Share	\$7,276,205	\$1,806,841	\$2,135,468	\$1,581,828	\$365,626	\$239,208	\$228,040	\$235,068	\$292,521	\$176,448	\$4,170	
Non-Federal Share	\$9,336,136	\$2,318,366	\$2,740,030	\$2,029,651	\$469,137	\$306,930	\$292,599	\$301,617	\$375,335	\$226,402	\$5,351	
Total Planned (Federal and Non-Federal)	\$16,612,341	\$4,125,207	\$4,875,498	\$3,611,479	\$834,763	\$546,138	\$520,639	\$536,685	\$667,856	\$402,850	\$9,521	
Cumulative Baseline Cost	\$16,612,341	\$20,737,548	\$25,613,047	\$29,224,525	\$30,059,288	\$30,605,426	\$31,126,065	\$31,662,750	\$32,330,606	\$32,733,456	\$32,742,976	
<u>Actual Incurred Costs^b</u>												
Federal Share	\$6,610,049	\$1,878,193	\$1,644,001	\$1,105,221	\$544,600							
Non-Federal Share	\$8,481,387	\$2,409,918	\$2,109,425	\$1,418,114	\$698,779							
Total Incurred Costs-Quarterly (Federal and Non-Federal)	\$15,091,436	\$4,288,111	\$3,753,426	\$2,523,335	\$1,243,379							
Cumulative Incurred Costs	\$15,091,436	\$19,379,547	\$23,132,973	\$25,656,308	\$26,899,687							
<u>Variance^c</u>												
Federal Share	(\$666,156)	\$71,352	(\$491,467)	(\$476,607)	\$178,974							
Non-Federal Share	(\$854,749)	\$91,552	(\$630,605)	(\$611,537)	\$229,642							
Total Variance-Quarterly (Federal and Non-Federal)	(\$1,520,905)	\$162,904	(\$1,122,072)	(\$1,088,144)	\$408,616							
Cumulative Variance	(\$1,520,905)	(\$1,358,001)	(\$2,480,074)	(\$3,568,217)	(\$3,159,601)							

Notes: Some numbers may not add perfectly because of rounding. ^aCosts for Q2 2006 include costs for that quarter as well as pre-award costs incurred beginning in January 2002. Unallowable direct costs totaling \$359,077 and indirect costs totaling \$25,135 that were applied to these direct costs have been removed from the baseline costs for Q2 2006, consistent with Amendment No. A002 to Cooperative Agreement DE-FC26-06NT41426. ^bActual incurred costs are all costs incurred by the project during the quarter, regardless of whether these costs were invoiced to DOE as of the end of the quarter. ^cNegative variance, (), means that actual incurred costs are less than baseline planned costs.

Table 3. Milestone plan / status report.

Critical Path Project Milestone Description	Project Duration - Start: 5/19/06 End: 10/18/08												Planned Start Date	Planned End Date	Actual Start Date	Actual End Date	Comments (notes, explanation of deviation from baseline plan)
	2006				2007				2008								
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4					
Initiate scrubber system installation		A	P										9/30/06	9/30/06	5/30/06	5/30/06	
Commence tie-in outage			A	P									12/31/06	12/31/06	9/29/06	9/29/06	
Begin guarantee/performance testing					P A								3/31/07	3/31/07	3/28/07	3/28/07	
Begin routine plant operation and data collection for long-term testing						P A							6/30/07	6/30/07	6/21/07	6/21/07	See text under Section 3.2.
Begin follow-up testing										P			6/30/08	6/30/08			
Complete analyses of process performance and economics											P		9/30/08	9/30/08			

NOTE: "A" indicates actual completion; "P" indicates planned completion.

4.0 Significant Accomplishments during the Reporting Period

Significant accomplishments during the second quarter of calendar year 2007, which are described more fully in Section 2.0 above, were as follows:

- Completion of Guarantee Testing of the multi-pollutant control system
- Demonstration of attainment of emissions reduction targets for NO_x (0.10 lb/mmBtu), SO₂ (>95% removal), Hg (>90% removal with no activated carbon injection required), SO₃ (>95% removal), and HCl (>95% removal), while the unit was firing a 2.5-3.0% sulfur eastern U.S. bituminous coal
- Submittal of the Preliminary Public Design Report for the project
- Installation of a screen, vacuum ports, and soot blowers to prevent accumulation of large particle ash on the in-duct SCR catalyst
- Demonstration of operation of the hybrid NO_x control system with the targeted ammonia slip of 2 ppmv

5.0 Problems/Delays and Actions Taken/Planned to Resolve Them

As described in detail under Section 2.0 above, several problems were encountered during the quarterly reporting period that caused delays in the project schedule. The problem posed by the accumulation of large particle ash on the surface of the in-duct SCR catalyst, which began last quarter, continued into the first half of the current quarter and forced an outage for catalyst cleaning in mid-April. A resolution to this problem was implemented in mid-May, as a large particle ash removal system (consisting of a screen, soot blowers, and vacuum ports) was installed in the ductwork immediately above the SCR reactor to capture and dispose of the LPA before it reaches the catalyst.

Also, the multi-pollutant control system was unable to demonstrate attainment of its performance guarantee for ammonia slip during the first several rounds of testing in March and May. To resolve this problem, the project team performed extensive combustion system and SNCR system testing and tuning during late May and early June, and the guarantee was achieved on June 20.

As a result of the LPA problem and the ammonia slip problem, as well as the start-up problems that were described in our progress report for the first quarter of 2007, guarantee testing was completed about four months behind schedule. Moreover, process performance testing, which was originally scheduled to begin in mid-March 2007, still had not begun as of the end of June 2007. As discussed in Section 3.1 of this report, however, we still expect to be able to complete the overall project on schedule in October 2008, as the schedule affords flexibility for completing the process performance tests during the more-than year-long period between the guarantee tests and follow-up tests.

Finally, although the multi-pollutant control system has demonstrated attainment of both its NO_x emission guarantee and its ammonia slip guarantee during relatively short

testing periods, the plant has generally had trouble simultaneously achieving the performance targets for NO_x emissions and ammonia slip while also maintaining acceptable combustion performance and steam temperatures during more routine operation. The project team continues to work on evaluating and optimizing the performance of the hybrid NO_x control system for longer-term operation.

6.0 Products Produced and Technology Transfer Activities Accomplished During the Reporting Period

As discussed in Section 2.0 above, we completed the Preliminary Public Design Report for the project and submitted it to DOE. Abstracts on the project and on the performance of the multi-pollutant control system were submitted to the organizers of the POWER-GEN International and EUEC Energy & Environment conferences, which will be held in New Orleans, LA, in December 2007 and in Tucson, AZ, in January 2008, respectively. Copies of these abstracts are included as Attachments A and B to this report. In addition, we gave presentations on the project at the Electric Power Conference & Exhibition in Rosemont, IL, on May 3 and at the Air & Waste Management Association's Annual Conference & Exhibition in Pittsburgh, PA, on June 27. These presentations are included as Attachments C and D, respectively, to this report. Finally, we submitted our paper titled "Preliminary Performance Testing Results from the Greenidge Multi-Pollutant Control Project" to the organizers of COAL-GEN, which will be held in Milwaukee, WI, in August 2007. A copy of the paper is included as Attachment E to this report.

ATTACHMENT A

Operation of an Advanced Circulating Fluidized Bed Air Pollution Control System at an Existing Smaller, Older Coal-Fired Unit at a Cost-Effective Price

Accepted for presentation at POWER-GEN International, December 11-13, 2007, New Orleans, LA

Operation of an Advanced Circulating Fluidized Bed Air Pollution Control System at an Existing Smaller, Older Coal-fired Unit at a Cost-Effective Price

Richard F. Abrams

Babcock Power Environmental Inc.

Douglas J. Roll, P.E.

AES Greenidge LLC

Daniel P. Connell

CONSOL Energy Inc. Research & Development

There are currently over 400 coal-fired electric generating units (EGUs) in the United States with capacities of 50-300 MW_e that are not equipped with SCR, flue gas desulfurization (FGD), or mercury control systems. These smaller coal-fired units represent more than 60 GW of installed electric generating capacity; hence, curtailment or loss of their generation would exacerbate electricity supply and distribution problems throughout the United States. Smaller coal-fired EGUs are, however, increasingly vulnerable to retirement or fuel switching as it is difficult for these units to afford the relatively large capital costs and space requirements associated with conventional control technologies capable of achieving the necessary air emissions reductions required by ever-increasing environmental regulations such as the Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and various state actions.

An innovative approach to multi-pollutant control is being demonstrated at the coal-fired, 107 MWe AES Greenidge Unit 4 in Dresden, NY, as part of the U.S. Department of Energy's Power Plant Improvement Initiative. The multi-pollutant control system includes combustion modifications and a hybrid selective non-catalytic reduction (SNCR) / in-duct selective catalytic reduction (SCR) system to control NO_x to ≤ 0.10 lb/MMBtu, followed by a Turbosorp[®] circulating fluidized bed dry scrubber system with baghouse ash recycling to reduce emissions of SO₂, SO₃, HCl, and HF by $\geq 95\%$. Mercury removal of $\geq 90\%$ is also targeted via the co-benefits afforded by the in-duct SCR, Turbosorp dry scrubber, and baghouse and by injection of activated carbon into the scrubber if required. The objective of the project was to substantiate that this combination of technologies can cost-effectively provide deep emissions reductions when retrofitted on existing coal-fired electrical generating units smaller than 300 MWe, allowing these units to continue to operate while complying with progressively more rigorous environmental regulations.

The paper will primarily focus on the operational performance of the Turbosorp system in removing acid gases and mercury. It will also discuss the start-up and testing issues associated with the overall system. Operation of the system have demonstrated that it economically addresses the emissions reduction needs for older, smaller coal-fired units.

ATTACHMENT B

Mercury Removal Performance of the Greenidge Multi-Pollutant Control System

Submitted to the EUEC Energy & Environment Conference, January 27-30, 2008, Tucson, AZ

Mercury Removal Performance of the Greenidge Multi-Pollutant Control System

Daniel P. Connell and James E. Locke

CONSOL Energy Inc. Research & Development, South Park, PA

Douglas J. Roll, P.E.

AES Greenidge LLC, Dresden, NY

Wolfe P. Huber, P.E.

U.S. Department of Energy, National Energy Technology Laboratory, Pittsburgh, PA

Richard F. Abrams

Babcock Power Environmental Inc., Worcester, MA

As part of the Greenidge Multi-Pollutant Control Project, which is being conducted under the U.S. Department of Energy's Power Plant Improvement Initiative, an innovative combination of air pollution control technologies was retrofitted on the coal-fired, 107-MWe AES Greenidge Unit 4 in Dresden, NY. The technologies, which include combustion modifications, a hybrid SNCR/SCR system, and a Turbosorp[®] circulating fluidized bed dry scrubber with baghouse ash recycling and activated carbon injection, are being demonstrated as an affordable means for coal-fired electrical generating units with capacities less than 300 MWe to achieve deep air emissions reductions and improved dispatch economics in an environment of increasingly stringent emissions regulations. The multi-pollutant control system at AES Greenidge, which was installed in 2006 at an EPC cost of ~\$340/kW_{net}, is designed to reduce full-load NO_x emissions to ≤0.10 lb/mmBtu, SO₂, SO₃, HCl, and HF emissions by ≥95%, and Hg emissions by ≥90%, while the unit is firing >2%-sulfur eastern U.S. bituminous coal and co-firing up to 10% biomass.

This presentation focuses on the mercury removal performance of the system. Results from the first round of performance testing at AES Greenidge, which was completed in March 2007 while Unit 4 was firing a 2.5%-sulfur eastern U.S. bituminous coal, indicate that the multi-pollutant control system was able to remove greater than 95% of the mercury in the flue gas without the need for any activated carbon injection. This high mercury removal likely resulted from a combination of factors, including the conversion of elemental mercury (Hg⁰) to oxidized mercury (Hg²⁺) across the SCR catalyst, the removal of Hg²⁺ via chemisorption by moistened Ca(OH)₂ particles in the scrubber, and the removal of Hg²⁺ and possibly some Hg⁰ via adsorption onto carbon-containing fly ash and Ca(OH)₂ at low temperatures in the baghouse. Additional tests are being conducted to evaluate the effects of unit operating conditions (e.g., fuel, load, fly ash LOI, scrubber operating conditions, etc.) and activated carbon injection rate (if needed) on the mercury removal performance of the system. The results of these tests will be presented, and the system's incremental cost of mercury removal will be discussed. These data will help to inform the decision making of generators seeking affordable multi-pollutant control retrofit options for their smaller coal-fired units.

ATTACHMENT C

Initial Cost and Performance Results from the Greenidge Multi-Pollutant Control Project

Presented at the Electric Power Conference & Exhibition, May 1-3, 2007, Rosemont, IL

ELECTRIC POWER
CONFERENCE & EXHIBITION

Initial Cost and Performance Results from the Greenidge Multi-Pollutant Control Project

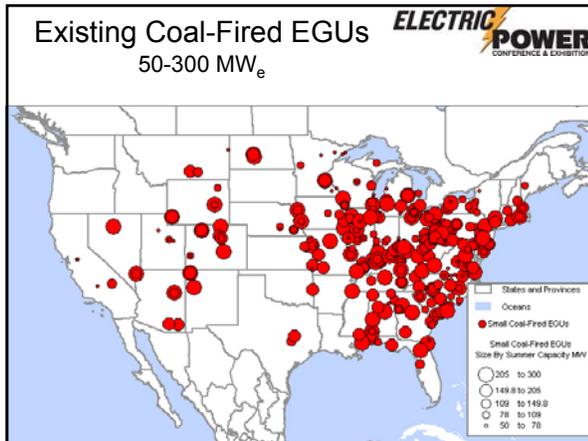
Daniel P. Connell
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AES Greenidge LLC
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Babcock Power Environmental Inc.
Wolfe P. Huber, P.E.
U.S. Department of Energy, National Energy Technology Laboratory

Chicago, IL May 3, 2007

ELECTRIC POWER
CONFERENCE & EXHIBITION

Greenidge Multi-Pollutant Control Project

- Part of U.S. DOE's Power Plant Improvement Initiative
- Participants
 - CONSOL Energy Inc. (administration, testing, reporting)
 - AES Greenidge LLC (host site, operations)
 - Babcock Power Environmental Inc. (EPC contractor)
- Funding
 - U.S. Department of Energy, National Energy Technology Laboratory
 - AES Greenidge LLC
- Goal: Demonstrate a multi-pollutant control system that can cost-effectively reduce emissions of NO_x, SO₂, mercury, acid gases (SO₃, HCl, HF), and particulate matter from smaller coal-fired power plants



Existing Coal-Fired EGUs
50-300 MW_e

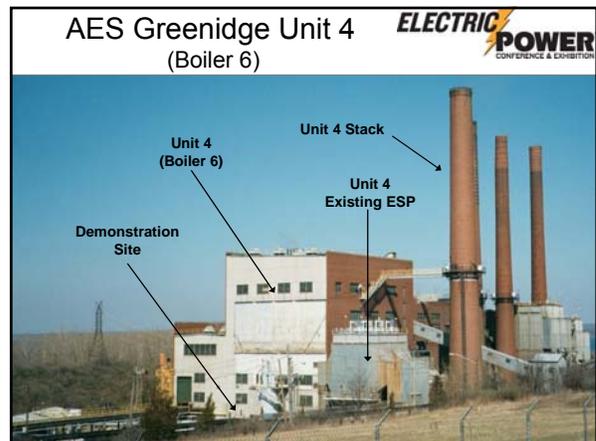
ELECTRIC POWER
CONFERENCE & EXHIBITION

- ~ 440 units not equipped with FGD, SCR, or Hg control
 - Represent ~ 60 GW of installed capacity
 - Greater than 80% are located east of the Mississippi River
 - Most have not announced plans to retrofit
- Increasingly vulnerable to retirement or fuel switching because of progressively more stringent environmental regulations
 - CAIR, CAMR, CAVR, state regulations
- Difficult to retrofit for deep emission reductions
 - Large capital costs
 - Space limitations
- Need to commercialize technologies designed to meet the environmental compliance requirements of these units

AES Greenidge Unit 4
(Boiler 6)

ELECTRIC POWER
CONFERENCE & EXHIBITION

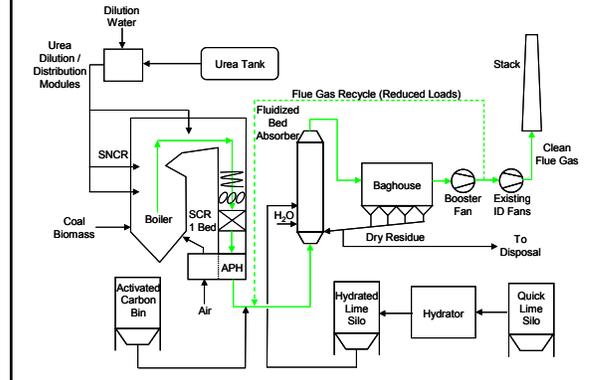
- Dresden, NY
- Commissioned in 1953
- 107 MW_e (net) reheat unit
- Boiler:
 - Combustion Engineering tangentially-fired, balanced draft
 - 780,000 lb/h steam flow at 1465 psig and 1005 °F
- Fuel:
 - Eastern U.S. bituminous coal
 - Biomass (waste wood) – up to 10% heat input
- Existing emission controls:
 - Overfire air (natural gas reburn not in use)
 - ESP
 - No FGD - mid-sulfur coal to meet permit limit of 3.8 lb SO₂/MMBtu



Multi-Pollutant Control Process

- Combustion modifications (outside DOE scope)
- Hybrid SNCR / SCR
 - Urea-based, in-furnace selective non-catalytic reduction
 - Single-bed, in-duct selective catalytic reduction
- Activated carbon injection
- Turbosorp® circulating fluidized bed dry scrubber
- Baghouse

Process Flow Diagram



Single-Bed SCR

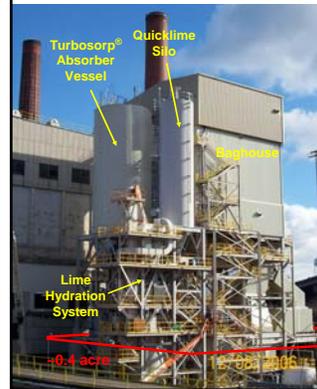


Reactor Cross Section: 45' x 14'
Bed Depth: 1330 mm



- Fed by NH₃ slip from SNCR
- NO_x Reduction: ≥ 30%
- SO₂ → SO₃: ≤ 1.0%
- NH₃ slip from SCR: ≤ 2 ppmv

Turbosorp® System



- Completely dry
- Separate control of reagent, water, and recycled solid injection
- High solids recirculation
- Applicable to high-sulfur coals
- 15-25% lower reagent consumption than SDA
- Low capital and maintenance costs relative to other FGD technologies

Performance Targets

Fuel: 2-4% sulfur bituminous coal, up to 10% biomass

Parameter	Goal
NO _x	≤ 0.10 lb/MMBtu (full load)
SO ₂	≥ 95% removal
Hg	≥ 90% removal
SO ₃ , HCl, HF	≥ 95% removal

Assumptions Base Plant

Plant Size	107 MW _e (net)
Fuel	90% coal / 10% biomass
Fuel HHV	12,426 Btu/lb
Fuel Sulfur Content	2.5% (w/w as fired)
Baseline NO _x Emissions	0.30 lb/MMBtu (as NO ₂)
Annual Capacity Factor	80%

Assumptions Financing

- Constant 2005 dollars
- 20-year plant life
- 1.67-year construction period
- 7.09% discount rate (before tax)
 - 45% debt @ 9% nominal return
 - 10% preferred stock @ 8.5% nominal return
 - 45% common stock @ 12% nominal return
 - 3.0% inflation
- Tax Rates
 - 35% federal, 4% state, 2% property

Fixed Charge Factor: 13.05%
AFUDC: 2.35%

Assumptions O&M Costs

Urea (50% w/w, \$/gal)	\$1.25
Quicklime (\$/ton)	\$110
Powdered Activated Carbon (\$/lb)	\$0.45
Electricity (\$/MWh)	\$30
Plant Service Water (\$/1000 gal)	\$0.20
Replacement Catalyst (\$/layer)	\$300,000
Baghouse Bags/Cages (\$/bag+cage)	\$140
Waste Disposal (\$/ton)	\$12
Operating Labor (\$/hr)	\$35

Economic Projections Overall System – Summary

	\$MM/y	\$/MWh
Levelized Capital	\$5.02	\$6.70
Fixed O&M	\$0.88	\$1.17
Variable O&M	\$4.23	\$5.64
Total Levelized Cost	\$10.13	\$13.51

Economic Projections Overall System – Capital

	\$MM	\$/kW _{net}
Total Plant Cost (TPC)	\$36.3	\$339
Total Plant Investment (TPI)	\$37.2	\$347
Total Capital Requirement (TCR)	\$38.5	\$360

• ~40% less than estimated cost of \$540/kW_{net} for full SCR + wet scrubber

Notes:
 TPI = TPC x (100% + AFUDC), TCR = TPI + Pre Production Cost + Inventory Capital,
 Pre-Production Cost = 0.02 x TPI + (Annual O&M Cost) x 12, Inventory Capital = 0.005 x TPC,
 Full SCR + wet scrubber cost estimated using Integrated Environmental Control Model

Economic Projections Overall System – Fixed O&M

Assumptions

- Operating Labor
 - 16 h/day
- Maintenance Labor & Materials
 - 1.5% of TPC
 - 40% labor, 60% materials
- Administrative & Support Labor
 - 30% of total labor

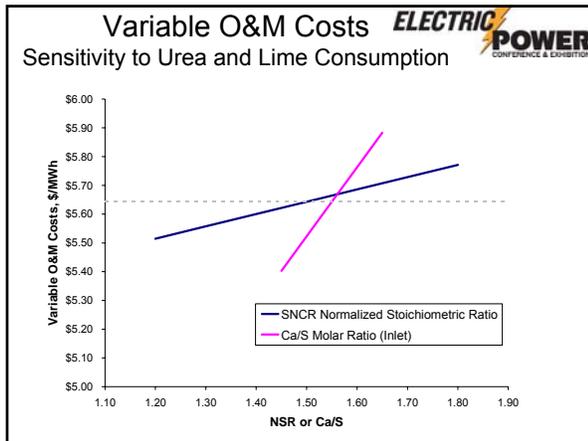
Category	Percentage
Maint. Labor & Material	62.2%
Operating Labor	23.3%
Admin. & Support Labor	14.5%
Total	\$1.17/MWh

- Fixed O&M costs expected to be less than for competing technologies
- Actual costs will be determined during 20-month operation period

Economic Projections Overall System – Variable O&M

Category	Percentage
Quicklime	56.3%
Waste	12.8%
Urea	11.3%
Electricity	8.2%
PAC	6.6%
Catalyst	2.4%
B-bags/Cages	2.1%
Water	0.3%
Total	\$5.64/MWh

Assumptions: SNCR NSR = 1.50, catalyst life = 3 yr, Ca/S molar ratio (inlet SO₂) = 1.55,
 CaO purity = 95% (w/w), PAC feed rate = 3.5 lb/MMacf, baghouse bag / cage life = 5 yr



- ### Variable O&M Costs Mercury Control
- System design favors high baseline Hg removal without activated carbon injection
 - Hg oxidation across in-duct SCR catalyst
 - Low temperature (~170 °F) in scrubber / baghouse
 - High residence time for fly ash and Ca(OH)₂ in scrubber / baghouse
 - Similar to SCR / SDA / FF with bituminous coal
 - Field sampling shows 90% Hg removal often achieved with no ACI
 - Expect ≥ 90% removal with low carbon injection rate
 - Projected activated carbon requirement: 0.0 – 3.5 lb/MMacf
 - Economic projections assume maximum rate
 - Activated carbon accounts for \$0.37/MMWh of variable O&M cost
 - Actual cost likely to be less than this - will be determined as part of DOE demonstration project

Economic Projections NO_x Control Only

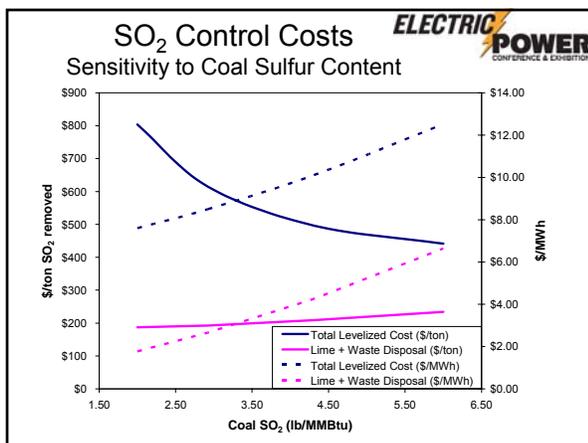
	\$/MWh	\$/ton NO ₂ removed
Levelized Capital	\$2.08	\$2,086
Fixed O&M	\$0.36	\$365
Variable O&M	\$0.83	\$839
Urea	\$0.64	\$643
Replacement Catalyst	\$0.13	\$134
Power/Water	\$0.06	\$62
Total Levelized Cost	\$3.27	\$3,290

• Improved dispatch economics relative to purchasing allowances

Economic Projections SO₂ Control Only

	\$/MWh	\$/ton SO ₂ removed
Levelized Capital	\$4.52	\$238
Fixed O&M	\$0.79	\$42
Variable O&M	\$4.44	\$233
Lime + Waste Disposal	\$3.90	\$205
Power/Water	\$0.42	\$22
Baghouse Bags/Cages	\$0.12	\$6
Total Levelized Cost	\$9.75	\$513

• Improved dispatch economics relative to purchasing allowances
• Acid gas control and improved primary particulate control for "free"



- ### Conclusions Greenidge Multi-Pollutant Control System
- Capital cost of \$339/kW_{net} for 107 MW unit (2005\$)
 - About 40% less than estimated cost of full SCR + wet scrubber
 - Projected total levelized cost of \$13.51/MMWh (2.5%-sulfur fuel)
 - Footprint of < 0.5 acre
 - Deep emission reductions
 - NO_x to ≤ 0.10 lb/MMBtu (full load)
 - SO₂ and acid gases by ≥ 95%
 - Hg by ≥ 90%
 - Helps to enable 20-30 year life extension
 - Improves dispatch economics
-

Project Status and Plans



- System started up in early 2007
- 20-month period of operation and testing underway
- Specific goals:
 - Confirm emissions reduction performance
 - Determine / optimize reagent consumption rates
 - Characterize Hg removal co-benefits, ACI requirements
 - Determine actual fixed O&M costs
 - Assess effects of fuel / load
 - Evaluate balance-of-plant impacts

Disclaimer



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ATTACHMENT D

The Greenidge Multi-Pollutant Control Project: Key Technical and Economic Features of a New Approach for Reducing Emissions from Smaller Coal-Fired Units

Presented at the Air & Waste Management Association's 100th Annual Conference & Exhibition, June 26-29, 2007, Pittsburgh, PA

The Greenidge Multi-Pollutant Control Project: Key Technical and Economic Features of a New Approach for Reducing Emissions from Smaller Coal-Fired Units

Daniel P. Connell

CONSOL Energy Inc. Research & Development

Douglas J. Roll, P.E., and William B. Rady
AES Greenidge LLC

Richard F. Abrams
Babcock Power Environmental Inc.

Wolfe P. Huber, P.E.
U.S. Department of Energy, National Energy Technology Laboratory

A&WMA Annual Conference & Exhibition, June 27, 2007, Pittsburgh, PA

Greenidge Multi-Pollutant Control Project

- Part of U.S. DOE's Power Plant Improvement Initiative
- Participants
 - CONSOL Energy Inc. (administration, testing, reporting)
 - AES Greenidge LLC (host site, operations)
 - Babcock Power Environmental Inc. (EPC contractor)
- Funding
 - U.S. Department of Energy, National Energy Technology Laboratory
 - AES Greenidge LLC
- Goal: Demonstrate a multi-pollutant control system that can cost-effectively reduce emissions of NO_x, SO₂, mercury, acid gases (SO₃, HCl, HF), and particulate matter from smaller coal-fired power plants

Existing U.S. Coal-Fired EGUs 50-300 MW_e



Existing U.S. Coal-Fired EGUs 50-300 MW_e

- ~ 440 units not equipped with FGD, SCR, or Hg control
 - Represent ~ 60 GW of installed capacity
 - Greater than 80% are located east of the Mississippi River
 - Most have not announced plans to retrofit
- Increasingly vulnerable to retirement or fuel switching because of progressively more stringent environmental regulations
 - CAIR, CAMR, CAVR, state regulations
- Difficult to retrofit for deep emission reductions
 - Large capital costs
 - Space limitations
- Need to commercialize technologies designed to meet the environmental compliance requirements of these units

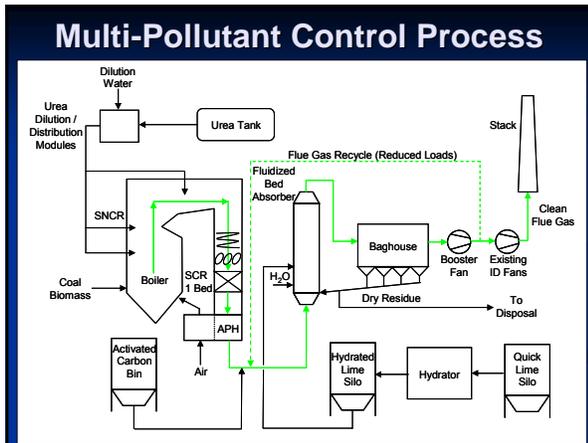
AES Greenidge Unit 4 (Boiler 6)

- Dresden, NY
- Commissioned in 1953
- 107 MW_e reheat unit
- Boiler:
 - Combustion Engineering tangentially-fired, balanced draft
 - 780,000 lb/h steam flow at 1465 psig and 1005 °F
- Fuel:
 - Eastern U.S. bituminous coal
 - Biomass (waste wood) – up to 10% heat input
- Existing emission controls:
 - Overfire air (natural gas reburn not in use)
 - ESP
 - No FGD - mid-sulfur coal to meet permit limit of 3.8 lb SO₂/MMBtu



Design Objectives

- Deep emission reductions
- Low capital costs
- Small space requirements
- Applicability to high-sulfur coals
- Low maintenance requirements
- Operational flexibility

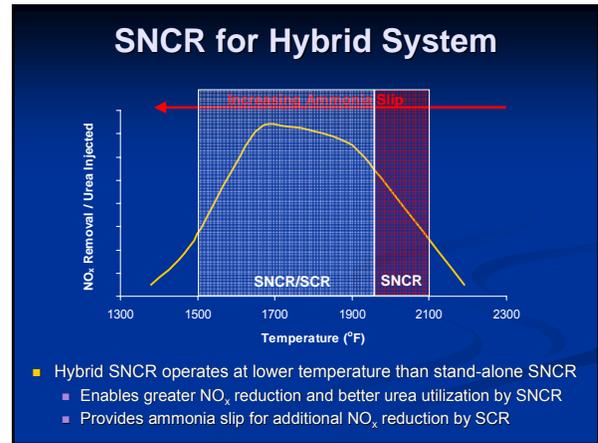


Performance Targets

Fuel: 2-4% sulfur bituminous coal, up to 10% biomass

Parameter	Goal
NO _x	≤ 0.10 lb/mmBtu (full load)
SO ₂	≥ 95% removal
Hg	≥ 90% removal
SO ₃ , HCl, HF	≥ 95% removal

- ### Hybrid NO_x Control
- Combustion Modifications
 - Replace coal, combustion air, and overfire air nozzles
 - Improve fuel/air mixing, burner exit velocity, secondary airflow control, and upper furnace mixing; reduce CO
 - Reduce NO_x to 0.25 lb/MMBtu
 - SNCR
 - Three zones of urea injection
 - Reduce NO_x by ~ 42.5% (to 0.144 lb/MMBtu)
 - SCR
 - Single-bed, in-duct design
 - Fed by ammonia slip from SNCR
 - Reduce NO_x by > 30% (to ≤ 0.10 lb/MMBtu)



Single-Bed, In-Duct SCR

Same as Conventional SCR, EXCEPT:

- Compact design
 - Bed depth ~ 1.3 m
 - Cross section ~ 45' x 14'
- No ammonia injection grid
- Designed for lower NO_x removal efficiency

Turbosorp® Circulating Fluidized Bed Dry Scrubber

Different From a Spray Dryer:

- Completely dry (no slurries)
- Separate control of reagent, water, and recycled solid injection
- Applicable to high-sulfur coals
- High solids recirculation
- 15-25% lower reagent consumption

Turbosorp® System

Advantages Over Wet FGD

- Requires less space
- Carbon steel construction
- Uses existing stack
- Better SO₃ removal
- Less maintenance requirements
 - Fewer moving parts
 - No slurries
 - No dewatering

Mercury Control

- System design favors high baseline Hg removal without activated carbon injection
 - Hg oxidation across in-duct SCR catalyst
 - Low temperature (~170 °F) in scrubber / baghouse
 - High residence time for fly ash and Ca(OH)₂ in scrubber / baghouse
 - Similar to SCR / SDA / FF with bituminous coal
 - Field sampling shows 90% Hg removal often achieved with no ACI
- To ensure ≥ 90% Hg removal, demonstration at AES Greenidge includes an activated carbon injection system
 - Turbosorp® system expected to enable better carbon utilization than simple duct injection
 - Projected activated carbon requirement: 0.0 – 3.5 lb/MMacf

Turndown Capabilities

NO_x Control

SO₂, Acid Gas, and Hg Control

- Flue gas recycle enables continued operation to 42 MW_g (minimum load)

Economics

AES Greenidge Unit 4 – Design Case

System	Capital	Fixed O&M	Variable O&M	Total
Greenidge MPC System	~7.5	~1.0	~5.5	~14.0
SCR+ Wet FGD	~11.5	~4.0	~3.5	~19.0
SCR + SDA	~11.5	~4.0	~0.5	~16.0

Not Feasible for 2-4% Sulfur Coal

SCR + Wet FGD modeled using Integrated Environmental Control Model with technical assumptions from Greenidge design basis; both systems modeled using common set of economic assumptions

Economics

AES Greenidge Unit 4 – Design Case

- Advantages of Greenidge multi-pollutant control system over SCR / wet FGD for an ~110 MW unit
 - ~25% lower levelized annual costs
 - ~40% lower capital costs
 - Significantly lower fixed O&M costs
 - Includes new baghouse for improved PM control
 - Better SO₃ (and possibly Hg) removal performance
- Drawbacks of Greenidge multi-pollutant control system relative to SCR / wet FGD
 - Slightly lower NO_x and SO₂ removal efficiency
 - Variable O&M costs are nearly 2 times as great

Trade-off is consistent with the needs of many smaller units

Initial Performance Testing Results

Fuel: 2.5-3.0% sulfur eastern U.S. bituminous coal

Parameter	Target	Measured
NO _x emissions	≤ 0.10 lb/mmBtu	0.10 lb/mmBtu (Stack CEM, 3/28/07)
SO ₂ removal	≥ 95%	96% (Stack CEM, 3/29/07)
Hg removal	≥ 90%	≥ 95% (Ontario Hydro, 3/28/07) ≥ 94% (Ontario Hydro, 3/30/07)
SO ₃ removal	≥ 95%	97% (Controlled Condensation, 5/2/07)
HCl removal	≥ 95%	97% (EPA Method 26, 5/4/07)

Operating Experience

- Emissions reduction performance has been encouraging
 - Currently evaluating reagent utilization, effects of fuel and unit operating conditions
- Accumulation of large particle ash on surface of in-duct SCR hampered operation for first few months
 - Screen has since been installed to alleviate problem
- Ammonia slip
 - Target was 2 ppmvd @ 3% O₂
 - Measured values have been 2-5 ppmvd @ 3% O₂
 - Effects on performance will be evaluated

Conclusions

Key Technical & Economic Features of the Greenidge Multi-Pollutant Control System

- Deep emission reductions
 - NO_x to ≤ 0.10 lb/MMBtu
 - SO₂ and acid gases by ≥ 95%
 - Hg by ≥ 90%
 - Initial performance tests indicate these are achievable
- Low capital costs
 - TPC is ~ \$340/kW for a 110 MW unit, or ~40% less than cost of SCR + wet FGD
- Small space requirements
 - < 0.5 acre for a 110 MW unit

Conclusions

Key Technical & Economic Features of the Greenidge Multi-Pollutant Control System

- Applicability to high-sulfur coals
 - Separate injection of water and lime
 - Greenidge system being demonstrated with 2-4% S coal
- Low maintenance requirements
 - Does not require slurry handling or dewatering
 - Costs projected to be substantially less than for SCR + wet FGD
- Operational flexibility
 - Hybrid NO_x control system has load-following capability
 - Flue gas recycle enables turndown of Turbosorp® system to minimum stable generator load
 - Can accommodate wide range of fuels and SO₂ removal efficiencies

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ATTACHMENT E

Preliminary Performance Testing Results from the Greenidge Multi-Pollutant Control Project

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Preliminary Performance Testing Results from the Greenidge Multi-Pollutant Control Project

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INTRODUCTION

There are about 440 coal-fired electrical generating units (EGUs) in the United States with capacities of 50-300 MW_e that currently are not equipped with selective catalytic reduction (SCR), flue gas desulfurization (FGD), or mercury control systems. These smaller units are a valuable part of the nation's energy infrastructure, constituting about 60 GW of installed capacity. However, with the onset of the Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), Clean Air Visibility Rule (CAVR), and various state environmental actions requiring deep reductions in emissions of SO₂, NO_x, and mercury, 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 Multi-Pollutant Control Project, which is part of the U.S. Department of Energy's (DOE's) Power Plant Improvement Initiative (PPII), seeks to demonstrate a solution for these units. As part of the project, an innovative combination of technologies including combustion modifications, a hybrid selective non-catalytic reduction/selective catalytic reduction (SNCR/SCR) system, and a Turbosorp[®] circulating fluidized bed dry scrubbing system with baghouse ash recycling and activated carbon injection, were installed on the 107 MW_e AES Greenidge Unit 4 in Dresden, NY. Figure 1 presents a photograph of the plant taken prior to the installation of the multi-pollutant control system. 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 co-fires biomass at up to 10% of its heat input. As such, it is representative of many of the 440 smaller coal-fired units identified 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 SO₂ 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. (BPEI) as engineering, procurement, and construction (EPC) contractor. 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 has a capital cost of about \$340/kW and occupies a <0.5-acre footprint for the AES Greenidge Unit 4 application, can achieve full-load NO_x emissions of ≤0.10 lb/mmBtu, reduce SO₂ and acid gas (SO₃, 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.

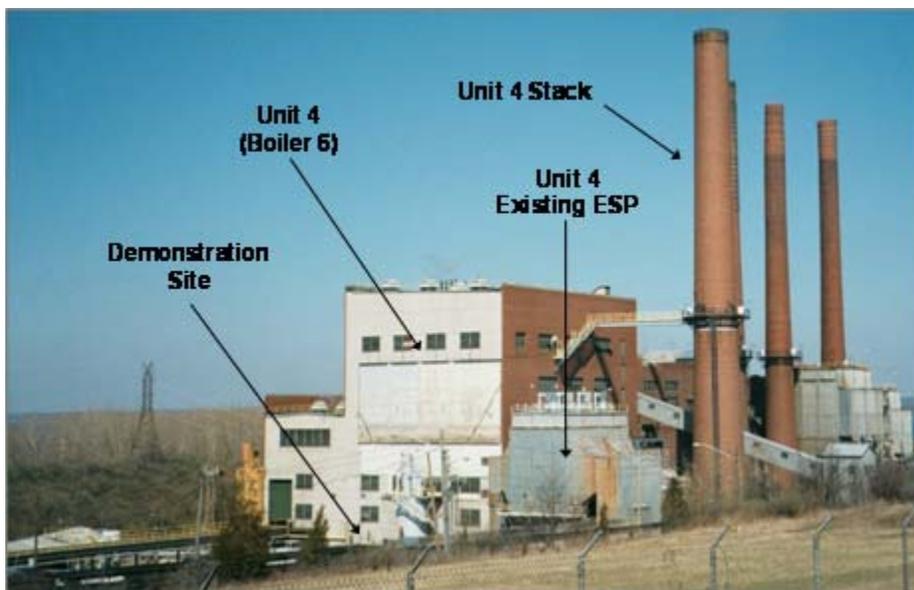


Figure 1. Photograph of the AES Greenidge plant prior to the installation of the multi-pollutant control system.

Start-up and commissioning of the multi-pollutant control system at AES Greenidge were completed in early 2007, and the project recently entered an approximately 1.5-year period of operation and testing of the new system. This paper presents emissions reduction results from the first round of performance tests, which were conducted at AES Greenidge in late March and early May 2007. The design of the multi-pollutant control system is also discussed, and key features of the system that make it well-suited for application to smaller coal-fired EGUs are highlighted. Data generated as part of the Greenidge Project are useful for evaluating the applicability of the multi-pollutant control system to the large fleet of existing, smaller coal-fired units.

MULTI-POLLUTANT CONTROL SYSTEM DESIGN

Figure 2 presents a schematic of the process that is being demonstrated as part of the Greenidge Multi-Pollutant Control Project. The design for AES Greenidge Unit 4 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.

NO_x control is the first step in the process and is accomplished using urea-based, in-furnace SNCR followed by a single-bed 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 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 NH₃ slip to permit additional NO_x reduction via SCR. The hybrid NO_x control system at AES Greenidge Unit 4 also includes combustion modifications to achieve further reductions in NO_x emissions and to improve the performance of the hybrid SNCR/SCR system. Hence, a full-load NO_x emission rate of ≤0.10 lb/mmBtu results from the combination of 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 ≥31% to ≤0.10 lb/mmBtu.

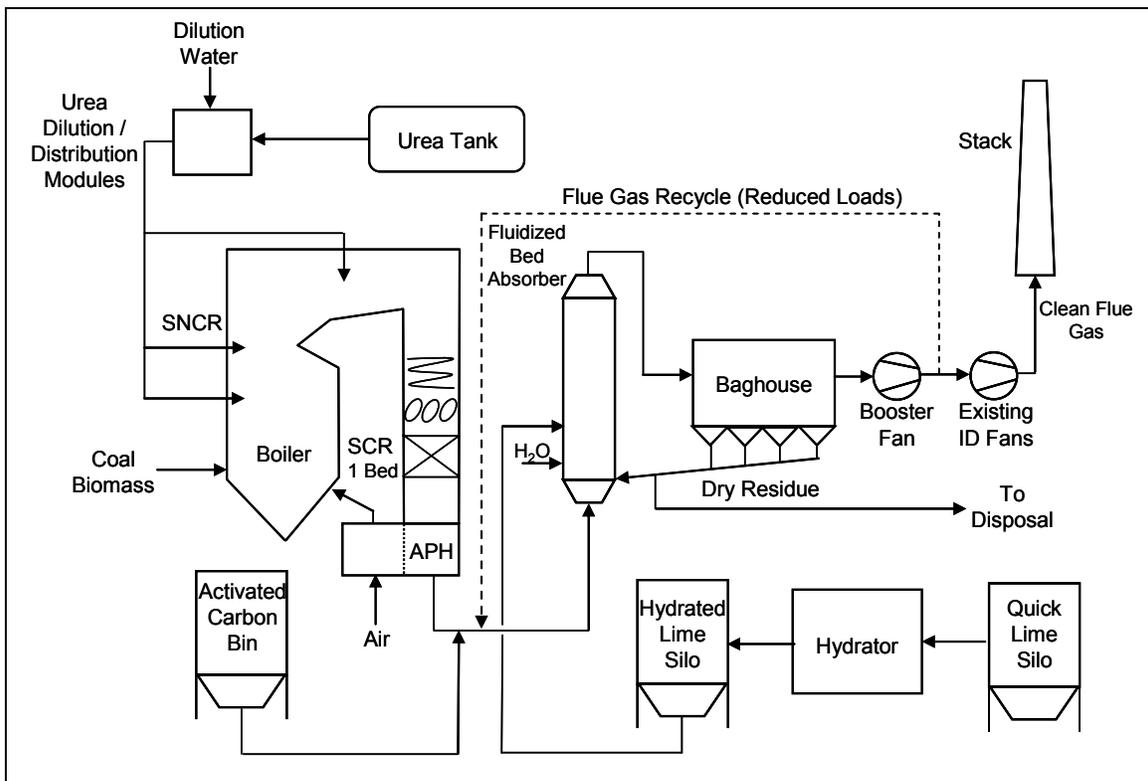


Figure 2. Schematic of the multi-pollutant control process being demonstrated on AES Greenidge Unit 4.

Emissions of SO₂ 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 supplied from an on-site hydrator installed as part of the project at AES Greenidge, are injected separately into a fluidized

bed absorber, where the flue gas is evaporatively cooled 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., SO₂, SO₃, HCl, and HF) to form dry solid products (i.e., CaSO₃·½H₂O, CaSO₄·½H₂O, CaCl₂, CaF₂), which are separated from the flue gas in a new eight-compartment pulse jet baghouse and recycled to the absorber via air slides at a high ratio to the inlet solids in order to maximize pollutant removal and lime utilization. As shown in Figure 2, 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 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.

Mercury control in the multi-pollutant control system is accomplished via the co-benefits afforded by the in-duct SCR, circulating fluidized bed dry scrubber, and baghouse, as well as by injection of activated carbon just upstream of the scrubber as required. From a mercury control perspective, the Greenidge multi-pollutant control process is very 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 coals, achieves a high level of mercury removal (i.e., 89-99%) without the need for any mercury-specific control technology.¹⁻² This high level of removal likely results from a combination of factors, including the conversion of elemental mercury (Hg⁰) to oxidized mercury (Hg²⁺) across the SCR catalyst,³ the removal of Hg²⁺ (a Lewis acid) via chemisorption by moistened, basic Ca(OH)₂ particles in the scrubber,⁴⁻⁵ and the removal of Hg²⁺ and possibly some Hg⁰ via adsorption onto carbon-containing fly ash and Ca(OH)₂ at low temperatures in the baghouse,⁶ 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 components, and hence, it is likely that its combination of an in-duct SCR, Ca(OH)₂-based scrubber, and baghouse will result in high mercury removals without any activated carbon injection when applied to bituminous coal-fired units. To ensure high mercury removal efficiencies, the multi-pollutant control system also includes an activated carbon injection system installed upstream of the 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 (~170°F) provided by the circulating fluidized bed dry scrubber and baghouse.

APPLICABILITY TO SMALLER COAL-FIRED UNITS

As discussed in the Introduction, the multi-pollutant control system being demonstrated at AES Greenidge was designed with the overall goal of providing an integrated process that is well suited for reducing emissions of a number of pollutants from smaller (i.e., 50-300 MW_e) coal-fired EGUs. Therefore, the design responded to a number of objectives that are consistent with the needs of these smaller units. These objectives, which are synonymous with the advantages of the multi-pollutant control system over technologies that have conventionally been applied to smaller coal-fired units, are discussed below.

Deep Emission Reductions

Conventional low-capital-cost air pollution control options for smaller coal-fired units, such as low-NO_x burners or stand-alone SNCR to reduce NO_x emissions and combustion of low-sulfur coal or use of sorbent injection in the furnace or ductwork to limit SO₂ emissions, in most cases do not produce emission rates consistent with the low levels established in environmental regulations that recently have been promulgated or proposed. Hence, units employing these options are increasingly vulnerable to highly volatile allowance costs or even retirement as new regulations are enacted. Thus, it was essential that the Greenidge multi-pollutant control process be designed to achieve deeper emissions reductions than these conventional low-capital-cost options and to meet or exceed applicable state and federal regulatory requirements for air emissions.

The process being demonstrated at AES Greenidge is well suited for achieving NO_x emission reductions of about 50-75%, compared with the 20-35% reduction typically achievable by SNCR.⁷ It also is designed to achieve greater than 95% removal of SO₂, comparable to the 95-98% removals characteristic of today's best available wet scrubbing technologies for larger coal-fired units.⁸ Both NO_x and SO₂ are regulated under CAIR. Furthermore, the multi-pollutant control system is designed to achieve greater than 90% capture of mercury, which is regulated under CAMR and is a topic of many state environmental actions, and to reduce emissions of SO₃, HCl, and HF by at least 95%. SO₃, HCl, and HF contribute to the formation of acid aerosols, and emissions of these compounds must be reported to the U.S. Environmental Protection Agency (EPA) as part of the national Toxics Release Inventory (TRI) program. Elevated concentrations of SO₃ in flue gas can also result in the formation of visible emissions (i.e., "blue plumes"), which are often particularly problematic for coal-fired power plants with SCR systems because SO₃ can be generated by oxidation of SO₂ across the SCR catalyst. Although the Greenidge multi-pollutant control process includes an SCR reactor, the downstream circulating fluidized bed dry scrubber is designed for deep SO₃ removal, eliminating the potential for plume visibility problems due to SO₃. Finally, for plants currently using an ESP to control particulate matter emissions, installation of the circulating fluidized bed dry scrubber and baghouse is expected to afford a substantial improvement in particulate matter control.

Low Capital Costs

There are commercially-available conventional technologies, such as full-scale SCR systems and limestone forced oxidation wet scrubbers, that are capable of achieving or exceeding the deep emissions reductions targeted for the Greenidge multi-pollutant control process. However, operators of smaller coal-fired EGUs, which are penalized by economies of scale, often cannot afford the large capital costs associated with these technologies. Hence, the multi-pollutant control process being demonstrated at AES Greenidge was designed to achieve deep emission reductions while offering substantially reduced capital costs compared to these conventional state-of-the-art technologies.

By using a compact, single-bed SCR reactor that is installed in a modified section of ductwork between the unit's economizer and air heater, the hybrid SNCR/SCR system avoids many of the capital costs associated with the multi-bed reactor, structural support steel, foundations, and new

ductwork runs required for a conventional stand-alone SCR system. Also, unlike wet FGD systems, the Turbosorp[®] system does not produce saturated flue gas, and therefore is constructed from carbon steel rather than from the expensive corrosion-resistant materials required for wet scrubbers. For the same reason, use of the Turbosorp[®] system also does not entail the installation of a new corrosion-resistant stack, which is commonly required for wet scrubber retrofits. Because of these factors, as well as the mechanical simplicity of the Turbosorp[®] system relative to wet scrubbers, the EPC capital cost of the multi-pollutant control system at AES Greenidge was only about \$340/kW, which is almost 40% less than the estimated capital cost for a conventional system comprising a stand-alone SCR and wet limestone forced oxidation scrubber as applied to that unit.⁹

In exchange for its substantially reduced capital costs, the Greenidge multi-pollutant control system has higher variable operating costs (because of its lower reagent utilization and its use of more expensive urea and lime reagents rather than the ammonia and limestone reagents commonly used in stand-alone SCR and wet scrubber systems, respectively) and lower NO_x removal efficiency relative to a conventional stand-alone SCR / wet FGD system (SCRs are capable of achieving 80-90% or greater NO_x reduction). Variable operating & maintenance costs for the AES Greenidge system are projected to average \$5.64/MWh, or \$233/ton of SO₂ removed and \$839/ton of NO_x removed.¹⁰ Whereas this tradeoff between capital costs and variable operating costs may be unattractive for large coal-fired EGUs, it is consistent with the needs of owners of smaller units, who in many cases cannot justify or afford the large capital costs (per unit of electrical output) needed to retrofit with conventional technologies for deep emissions reductions.

Small Space Requirements

The relatively large amount of space required to install conventional SCR and wet FGD systems further prevents these technologies from being widely applied to smaller coal-fired EGUs. Many smaller coal-fired units do not have sufficient physical space to easily accommodate both an SCR and a wet scrubber; this increases the difficulty, and hence the capital cost, of retrofitting these technologies. Therefore, an objective in designing the Greenidge multi-pollutant control system was to minimize its required footprint.

The SNCR portion of the multi-pollutant control process requires only a small amount of space for a urea storage tank, a small shed containing a urea circulation module, and several small urea distribution skids located around the boiler. Unlike a conventional stand-alone SCR reactor, the single-bed SCR reactor requires essentially no new land area, as it is installed in a modified ductwork section between the economizer and air heater and needs only a few new support beams. The in-duct SCR reactor at AES Greenidge fits within the existing boiler building in a space with horizontal dimensions of 52 ft x 27 ft and a vertical height of 23 ft. (The cross-sectional area of the reactor itself is 45 ft x 14 ft). The arrangement of the circulating fluidized bed dry scrubber, baghouse, and associated equipment is also compact. The various pieces of equipment are vertically tiered to permit gravity-assisted transport of solids where possible, and as a result, required only ~0.4 acre of land for the installation at AES Greenidge. Figures 3 and 4 present photographs showing the installations of the in-duct SCR reactor and the Turbosorp[®] system, respectively, at AES Greenidge.



Figure 3. Photograph of the in-duct SCR reactor installed on AES Greenidge Unit 4.

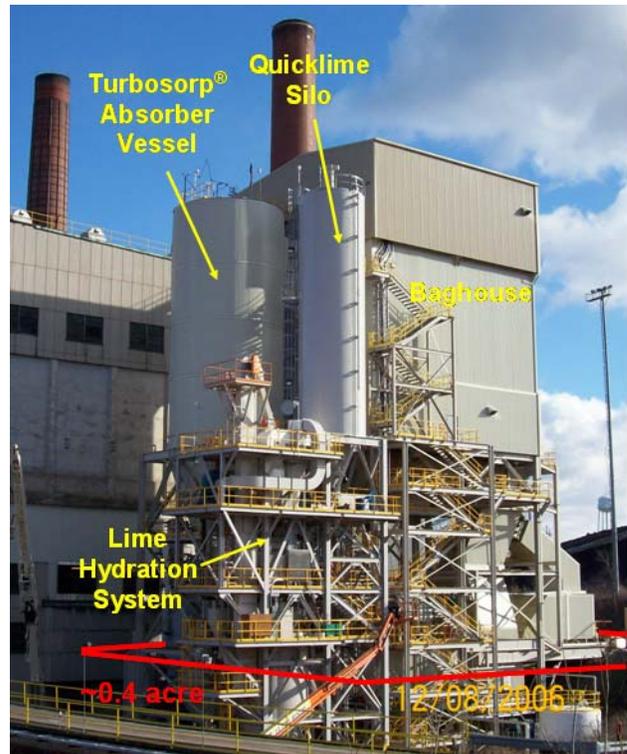


Figure 4. Photograph of the Turbosorp® system installed on AES Greenidge Unit 4.

Applicability to High-Sulfur Coals

Greater than 80% of the 440 smaller existing coal-fired units that are candidates for the multi-pollutant control process being demonstrated at AES Greenidge are located east of the Mississippi River, where high-sulfur eastern U.S. bituminous coal is a candidate fuel source. The dispatch economics of these units improve significantly with the installation of low-cost SO₂ removal systems that allow the use of higher-Btu, higher-sulfur, less-expensive coals with a net reduction in SO₂ emissions and a corresponding reduction in the need for high-cost allowances. Hence, an important design objective for the Greenidge multi-pollutant control system was that it be able to achieve deep SO₂ emission reductions when applied to units firing high-sulfur (i.e., >2%-sulfur) coals.

Lime spray dryers provide a relatively low-capital-cost means for achieving deep reductions in SO₂ emissions, as does the Turbosorp® circulating fluidized bed dry scrubber being installed as part of the multi-pollutant control process at AES Greenidge. However, spray dryers are only capable of achieving these deep reductions (i.e., >90%) when applied to units that fire coals with sulfur contents of about 2% or less. In spray dryer systems, lime and water are injected into the absorber vessel together as a slurry, rather than separately as in the Turbosorp® system. As a result, flue gases with high SO₂ concentrations require slurry injection rates so great that the water in the slurry cannot be completely evaporated. This causes plugging and binding of the bags used in the downstream fabric filter, as well as plugging of discharge feeders and conveyers. As discussed above, in the Turbosorp® system, water injection and hydrated lime

injection are carried out separately, such that the $\text{Ca}(\text{OH})_2$ injection rate is controlled solely by the pollutant loading and desired emission reduction, without being limited by the temperature or moisture content of the flue gas. As a result, the Turbosorp[®] can be operated to achieve deep emission reductions for a wide range of fuels, including high-sulfur coals.

Low Maintenance Requirements

Insofar as the PPII seeks to improve the reliability of the nation's energy supply, minimization of maintenance requirements was an objective in the design of the Greenidge multi-pollutant control system, such that system maintenance will not adversely affect unit availability. A drawback of both wet scrubbers and lime spray dryers is their use of slurries to introduce the limestone or lime into the system, resulting in high maintenance requirements and potential for operational problems. Problems arising from the use of slurries can include pipe plugging, nozzle plugging, solids build-up, and erosion and abrasion of pumps, pipes, and vessels. Wet scrubbers in particular are relatively complex, as they produce a slurry product and require pumps for slurry recirculation as well as maintenance-intensive dewatering equipment.

The Turbosorp[®] circulating fluidized bed dry scrubber being installed as part of the Greenidge multi-pollutant control system is expected to afford substantially reduced maintenance requirements compared to these more conventional FGD technologies. In the Turbosorp[®] process, lime is injected into the absorber as a dry hydrate rather than as a slurry. A blower is used to pneumatically convey the dry hydrated lime to the absorber for injection. The solids collected in the baghouse are also completely dry and are recycled to the absorber using air slides. Gravity provides the motive force for injection via the differential height between the bottom of the baghouse and the injection point on the absorber tower. Apart from the lime hydration system, the system's only pump is used to inject liquid water into the absorber vessel. Hence, the process avoids the problems with plugging, erosion, abrasion, and scaling that can result from pumping and handling slurries in other types of scrubbing systems. The Turbosorp[®] system also includes comparatively few moving parts, and as implied in the preceding subsection, is less likely to cause plugging and binding of fabric filter bags than a spray dryer is.

Operational Flexibility

Unlike larger baseload units, many smaller coal-fired EGUs routinely cycle their loads in response to electricity demand. Hence, a multi-pollutant control system designed for these smaller units should feature turndown capabilities to permit continued emissions reductions at reduced operating loads. The design of the multi-pollutant control system being demonstrated at AES Greenidge includes these capabilities.

For conventional SCR systems, low-load operation is constrained by reduced flue gas temperatures, which can cause incomplete ammonia consumption across the SCR catalyst, resulting in high ammonia slip and ammonium bisulfate fouling in the air heater. At sufficiently low temperatures, catalyst plugging and deactivation can also occur via the formation of salts in the SCR reactor. These constraints are particularly stringent for units that fire high-sulfur coals. Stand-alone SCR installations typically employ an economizer gas bypass and/or water flow circuit modifications to raise the flue gas temperature at the SCR inlet during low-load operation.

However, because of the hybrid NO_x control strategy included as part of the Greenidge multi-pollutant control process, NO_x removal capabilities are available to some extent at lower operating loads without the need for any such modifications.

The operating strategy for the hybrid system is shown conceptually in Figure 5. As illustrated in the figure, operation of the system varies with generator load, resulting in three distinct operating ranges: a high-load range in which NO_x reduction is accomplished via SCR, SNCR, and low-NO_x burners; an intermediate-load range in which NO_x reduction is accomplished via SNCR and low-NO_x burners (but not SCR), and a low-load range in which NO_x reduction is accomplished via low-NO_x burners (but not SCR or SNCR). At generator loads that produce economizer outlet temperatures below the minimum operating temperature for the SCR reactor (~600°F for AES Greenidge Unit 4), urea injection into the upper region of the furnace, which is used to generate ammonia slip for the SCR, is discontinued. However, urea continues to be injected into higher-temperature areas of the furnace until the minimum SNCR operating temperature is reached, resulting in continued NO_x removal of 20-25% via SNCR. Below the minimum SNCR operating temperature, which is the minimum economizer outlet temperature at which it is safe to introduce very small amounts of ammonia into the SCR catalyst, urea injection into the furnace is discontinued. However, NO_x emissions continue to be controlled via the unit's low-NO_x combustion system. Hence, for smaller units that regularly cycle loads based upon peak and off-peak demands, the load-following capabilities of the hybrid SNCR/SCR process can help to contribute to lower NO_x emission averages.

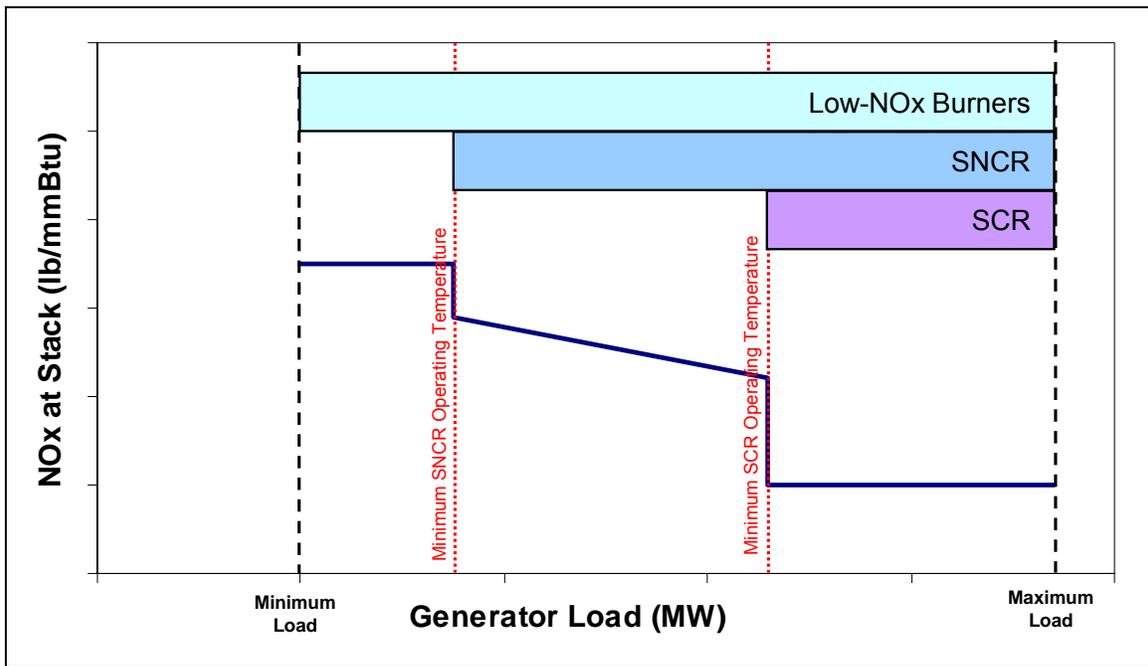


Figure 5. Operating strategy for the hybrid NO_x control system being demonstrated at AES Greenidge.

The circulating fluidized bed dry scrubber and activated carbon injection systems are designed to achieve $\geq 95\%$ SO₂ and acid gas removal and $\geq 90\%$ Hg removal when the unit is operating at any

point between its minimum load (42 MW_g) and full load. Flue gas recycle is required at low loads to provide sufficient flow to the absorber so that a fluidized bed can be maintained.

PRELIMINARY PERFORMANCE RESULTS

Construction of the multi-pollutant control system at AES Greenidge was completed largely in 2006, and commissioning of the system was completed in March 2007. The first series of tests evaluating the emissions reduction performance of the system were conducted during March 28-30 and May 1-4, 2007. The objective of these tests was to determine whether the system was capable of achieving its performance targets (i.e., NO_x emissions ≤0.10 lb/mmBtu, SO₂ and acid gas removal efficiency ≥95%, Hg removal efficiency ≥90%) when AES Greenidge Unit 4 was operating at design conditions. Additionally, Hg removal across the Turbosorp[®] system was determined both with and without activated carbon injection (ACI) in order to provide a preliminary indication of whether ACI is needed to achieve 90% Hg removal.

NO_x, SO₂, and Hg measurements were performed on March 28-30, 2007. During that period, AES Greenidge Unit 4 was operated at design load (~105 MW_g) using Pittsburgh seam coal with an average sulfur content of 2.5% (as-fired), or 3.8 lb SO₂/mmBtu. NO_x and SO₂ measurements were performed by Clean Air Engineering (CAE) using EPA Method 7E (modified to incorporate the use of CAE's Multi-Point Automated Sampling System) and EPA Method 6C, respectively. Hg measurements were performed by CONSOL R&D using the Ontario Hydro method (ASTM D6784-02).

NO_x testing was completed on March 28. Flue gas samples were extracted from 24-point sampling grids located at both the inlet and the outlet of the SCR catalyst to enable the NO_x reduction contributed by the SCR to be differentiated from that contributed by the combustion modifications and SNCR. Three approximately one-hour-long tests including simultaneous sampling at the SCR inlet and SCR outlet were completed. Results are summarized in Table 1. The NO_x concentration of 51.8 ppmvd (corrected to 3% O₂) at the SCR outlet equates to a NO_x emission rate of 0.07 lb/mmBtu, which is below the performance target for NO_x emissions of ≤0.10 lb/mmBtu. (The NO_x emission rate measured by the plant's stack CEM during the same period was 0.096 lb/mmBtu, substantially greater than the value measured at the SCR outlet, but still below the performance target of 0.10 lb/mmBtu. We are still investigating the cause of this measurement discrepancy). The NO_x removal performance of the system (as measured by CAE at the SCR inlet and outlet) was better than the targeted performance, owing to the combination of a NO_x emission rate at the inlet to the SCR (0.12 lb/mmBtu) that was less than the design value of 0.144 lb/mmBtu (implying that the combustion modifications and/or SNCR system reduced NO_x emissions to a greater extent than they were projected to) and a NO_x removal efficiency across the single-bed SCR (41%) that was greater than the design value of 31%.

Table 1. Summary of results of NO_x testing at AES Greenidge Unit 4 on March 28, 2007.

	Duration (min)	NO_x at SCR Inlet (ppmvd @ 3% O₂)	NO_x at SCR Outlet (ppmvd @ 3% O₂)	NO_x Removal Across SCR (%)
Test # 1	63	92.6	52.7	43.1
Test # 2	71	86.3	52.7	38.9
Test # 3	71	84.6	50.1	40.8
AVERAGE		87.8	51.8	41.0

Although preliminary performance testing results demonstrated the ability of the hybrid NO_x control system to exceed its performance target for NO_x emissions, operation of the system was hampered for several months after start-up by the accumulation of large particle ash (LPA) on the surface of the in-duct SCR catalyst. Accumulation of LPA repeatedly caused gradual increases in the pressure drop across the SCR reactor, forcing several outages for catalyst cleaning. Also during this period, ammonia slip concentrations greater than the target of 2 ppmvd were observed. A solution to the LPA problem was implemented in mid-May 2007, consisting of a sloped screen installed between the economizer and SCR reactor to filter out the LPA before it reaches the catalyst. The screen, which was designed by BPEI, had to be engineered to effectively remove LPA in spite of the challenges posed by the vertical downflow configuration and limited space above the SCR reactor. Sootblowers were installed to prevent LPA from accumulating in the screen; the collected LPA is removed from the base of the screen by a series of vacuum ports. The performance of the hybrid SNCR/SCR system, including both its NO_x removal performance and its ammonia slip performance, were reevaluated following the installation of the screen. Results were not yet available when this paper was submitted.

Table 2 presents the results of SO₂ measurements that were performed at AES Greenidge Unit 4 on March 29. Three one-hour test runs were conducted, each including simultaneous measurements of SO₂ concentrations at the air heater outlet (upstream of the Turbosorp[®] system) and at the baghouse outlet (downstream of the Turbosorp[®] system). The average measured SO₂ removal efficiency across the Turbosorp[®] system (including the baghouse) during these three test runs (94.1%) was slightly less than the targeted removal efficiency of 95%, although the plant's continuous emission monitors at the air heater outlet and stack have frequently indicated removal efficiencies >95% during the first several months of operation of the multi-pollutant control system. Hence, preliminary results suggest that the Turbosorp[®] system is capable of attaining 95% SO₂ removal efficiency when the unit is firing >2%-sulfur coal. Additional tests are planned to evaluate the performance of the system as a function of fuel sulfur content, hydrated lime consumption rate, and approach to adiabatic saturation temperature in the absorber vessel.

Table 2. Summary of results of SO₂ testing at AES Greenidge Unit 4 on March 29, 2007.

	Duration (min)	SO₂ at Air Heater Outlet (ppmvd @ 3% O₂)	SO₂ at Baghouse Outlet (ppmvd @ 3% O₂)	SO₂ Removal Across Turbosorp[®] System (%)
Test # 1	61	1842	105	94.3
Test # 2	61	1822	92	95.0
Test # 3	60	1847	131	92.9
AVERAGE		1837	109	94.1

Figure 6 summarizes the results of Hg measurements that were performed at AES Greenidge on March 28 and 30. Three approximately two-hour-long test runs were performed on March 28, when the activated carbon injection system was not in service. Each test run included simultaneous sampling at the air heater outlet (upstream of the Turbosorp[®] system) and at the stack (downstream of the Turbosorp[®] system). Complete traverses of the duct cross section were performed during each test at each location. This testing protocol was repeated on March 30, except that the ACI system was operating on that day. The results shown in Figure 6 represent the averages of the three test runs performed at each location on each day. As shown in the

figure, the average Hg concentrations measured at the air heater outlet were 10.06 $\mu\text{g}/\text{dscf}$ on March 28 and 9.38 $\mu\text{g}/\text{dscf}$ on March 30 (both concentrations corrected to 3% O_2). On both days, Hg concentrations at the stack were less than the analytical limit of detection. Thus, Hg removal efficiencies across the Turbosorp[®] system (including the baghouse) were >94% on March 28, when no activated carbon was being injected into the system, and >93% on March 30, when activated carbon was being injected. Hence, these initial results suggest that the multi-pollutant control system at AES Greenidge may be capable of achieving >90% Hg removal without the need for any activated carbon injection, although additional testing is required to confirm that this result is reproducible across a variety of plant operating conditions.

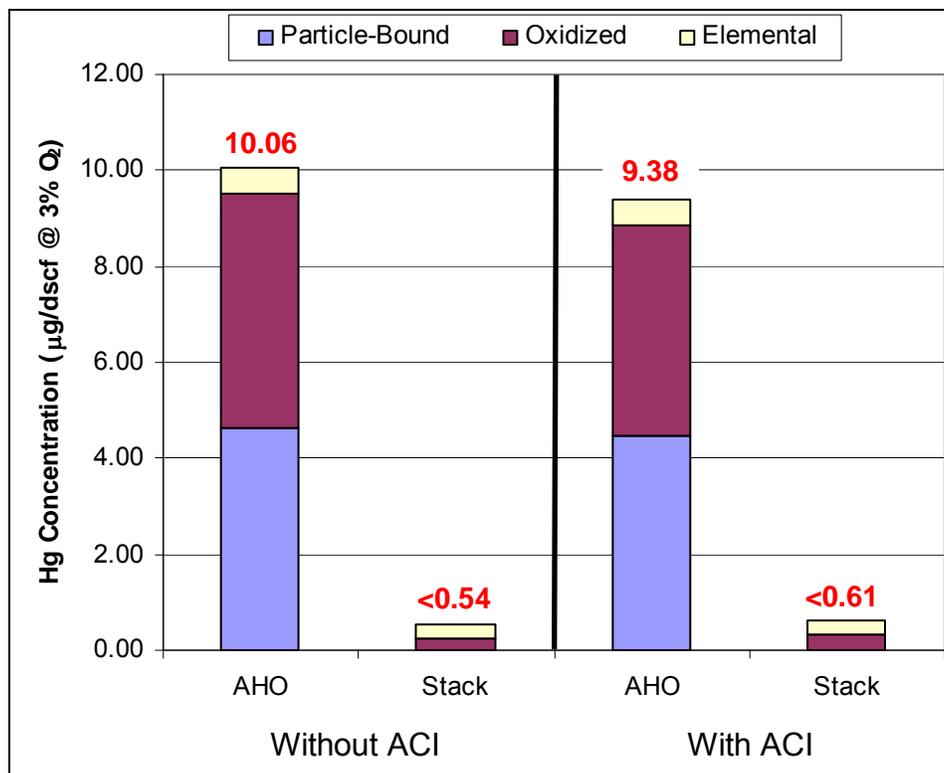


Figure 6. Summary of results of Hg testing at AES Greenidge Unit 4 on March 28 and 30, 2007. Each bar represents the average of three measurements conducted using the Ontario Hydro method at the air heater outlet (AHO) or stack. Triplicate measurements were performed on March 28 with no activated carbon injection (ACI) and again on March 30 with ACI.

The results presented in Figure 6 include a breakdown of Hg concentrations by Hg species (i.e., particle-bound, oxidized, and elemental), as determined according to the Ontario Hydro method. However, these speciation results should be interpreted cautiously. Whereas total Hg concentrations determined using the Ontario Hydro method are expected to be reliable, even in high-dust locations, Hg speciation results determined using that method can be biased in high-dust locations by adsorption of Hg onto the fly ash collected on the sample filter or by reaction of Hg with the fly ash.¹¹ This can lead to artificially high particle-bound and/or oxidized mercury concentrations, and artificially low elemental and/or oxidized mercury concentrations. (The

direction of the bias in the oxidized mercury results depends upon the extent to which mercury is adsorbed as opposed to oxidized by the fly ash). Hence, it is likely that the mercury speciation observed at the air heater outlet, which included 46-48% particle-bound Hg, was biased relative to actual flue gas speciation as a result of this artifact. The air heater outlet is a high-dust location, containing 2.2-2.5 gr/dscf of particulate matter, and the high unburned carbon content of the fly ash sampled there (15-21%) would tend to promote adsorption of gas-phase Hg onto the ash. This high unburned carbon content may also have contributed to the high Hg removal efficiency observed when no activated carbon was being injected into the system; the relationship between the carbon content of the fly ash and the Hg removal performance of the system will be evaluated as part of future testing.

Acid gas testing was performed by CONSOL R&D at AES Greenidge Unit 4 on May 2-4, 2007. SO₃ was measured on May 2 using the controlled condensation method as described by DeVito and Smith,¹² but modified to allow for determination of SO₄²⁻ by ion chromatography rather than by BaCl₂ titration. HCl and HF were measured on May 4 using EPA Method 26A. Results are summarized in Table 3. (Each result represents the average of multiple measurements performed on the indicated test date; for each parameter, sampling was performed simultaneously at the air heater outlet and stack locations). As shown in the table, the Turbosorp[®] system (including the baghouse) removed about 97% of the SO₃ and HCl contained in the flue gas, thereby exceeding its performance target of ≥95% removal efficiency for these parameters. No HF was detectable at either the air heater outlet or the stack, making it impossible to calculate a removal efficiency for this species.

Table 3. Summary of AES Greenidge Unit 4 acid gas testing results from May 2-4, 2007.

Parameter	Test Date (mm/dd/yy)	Average Concentration at Air Heater Outlet (ppmvd @ 3% O ₂)	Average Concentration at Stack (ppmvd @ 3% O ₂)	Removal Efficiency (%)
SO ₃	05/02/07	25.0 ^a	0.7	97.1
HCl	05/04/07	40.1	1.1	97.2
HF	05/04/07	<0.23	<0.16	N/A

^aO₂ concentration at air heater outlet estimated from measured stack O₂ concentration for purposes of correction.

Hence, preliminary performance testing results suggest that the multi-pollutant control system being demonstrated on AES Greenidge Unit 4 is capable of meeting or exceeding its performance targets for air emissions of NO_x, SO₂, Hg, and acid gases. Additional testing is underway to determine the repeatability of these results and the effect of variations in plant operating conditions on the performance of the system.

CONCLUSIONS

In conclusion, the multi-pollutant control system being demonstrated at AES Greenidge Unit 4, which includes the combination of combustion modifications, a hybrid SNCR/SCR system, and a Turbosorp[®] circulating fluidized bed dry scrubber with activated carbon injection (as required) and baghouse ash recycling, provides a relatively low-capital-cost means for smaller coal-fired EGUs to achieve deep reductions in emissions of SO₂, NO_x, Hg, and acid gases. In addition to its low capital cost (\$340/kw for the 107-MW_e AES Greenidge Unit 4 installation) and deep

emission reduction capabilities (≤ 0.10 lb/mmBtu NO_x emissions, $\geq 95\%$ removal of SO₂ and acid gases, $\geq 90\%$ removal of Hg), key features of the system are its small space requirements (<0.5-acre for AES Greenidge Unit 4), applicability to high-sulfur coals, low maintenance requirements, and operational flexibility. Commissioning of the demonstration unit at AES Greenidge Unit 4 was completed in March 2007, and preliminary results from performance testing of that unit during the spring of 2007 indicate that it succeeded in achieving emission removal efficiencies near or above the targets for NO_x, SO₂, Hg, and acid gases. Hg measurement results were particularly encouraging, as they suggest that the multi-pollutant control system is capable of achieving 90% Hg removal without the need for any activated carbon injection when the unit is operated according to design conditions. Operation of the multi-pollutant control system was hampered for several months after start-up by the accumulation of large particle ash on the surface of the in-duct SCR catalyst; however, a screen has since been installed above the catalyst to overcome that problem. The performance of the system will continue to be evaluated through October 2008 as part of the demonstration project being funded by DOE and AES Greenidge; results will provide valuable information for evaluating the applicability of the multi-pollutant control system to the large fleet of existing, smaller coal-fired units.

ACKNOWLEDGMENT AND DISCLAIMER

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