GREENIDGE MULTI-POLLUTANT CONTROL PROJECT

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

CONSOL Energy Inc.
Research & Development
4000 Brownsville Road
South Park, PA 15129-9566

D. P. Connell
Principal Investigator
(412) 854-6559
danielconnell@consolenergy.com

QUARTERLY PROGRESS REPORT
FOR WORK PERFORMED DURING THE PERIOD
July 1, 2007 to September 30, 2007

November 9, 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) installed and are 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, SO_2, Hg, acid gases (SO_3, 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 progressively more 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 SO_2, SO_3 (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 SO_2 emissions from AES Greenidge Unit 4 while the unit is firing >2%-sulfur coal and co-firing up to 10% biomass.

- Demonstrate ≥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 ≥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 sixth to be submitted for the Greenidge Multi-Pollutant Control Project, summarizes work performed on the project between July 1 and September 30, 2007. During the period, routine operation of the multi-pollutant control system at AES Greenidge continued. The system satisfied its current permit limits of 0.15 lb/mmBtu for NO_x (at high load) and 0.38 lb/mmBtu for SO_2 throughout the quarter. However, whereas the Turbosorp® system frequently operated within its performance target of 0.19 lb/mmBtu for SO_2 emissions, AESG generally had to operate the hybrid NO_x control system above its performance target of 0.10 lb/mmBtu for high-load NO_x emissions in order to achieve acceptable combustion characteristics, steam temperatures, and ammonia slip. The unit also continued to experience periodic increases in the pressure drop across the in-duct SCR during the quarter, in spite of the large particle ash (LPA) removal system that was installed in May to prevent this from occurring. The LPA removal system was modified during an outage in September to try to improve its performance, but it is unclear whether the modifications will succeed in resolving the problem. In addition, during the quarter, BPEI completed several major remaining milestones under their engineering, procurement, and construction (EPC) contract with AESG, and the project team developed plans for process performance testing of the multi-pollutant control system. Preparations were completed for the first process performance test series, which is scheduled for October 1-12.

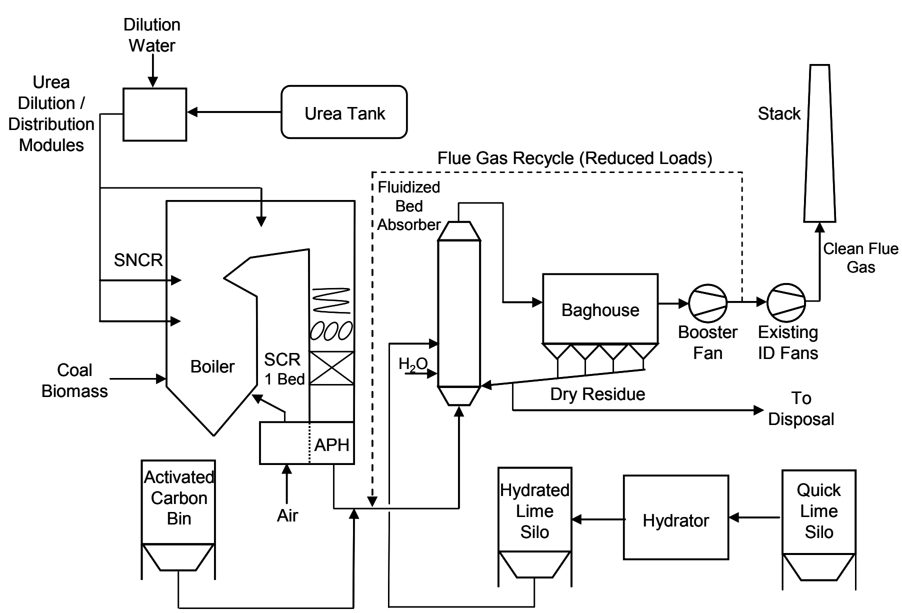


Figure 1. Schematic of the multi-pollutant control system being demonstrated at AES Greenidge.

2.0 Work Performed and Results Obtained During the Reporting Period

Highlights of the Greenidge Multi-Pollutant Control Project during the period from July 2007 through September 2007 included the completion of several major remaining EPC contract milestones, the implementation of modifications to the large particle ash removal system above the in-duct SCR catalyst, the development of plans for process performance testing of the multi-pollutant control system, and the presentation of guarantee testing results at a major power industry conference. Work performed and results obtained between July 1, 2007, and September 30, 2007, are described below by Statement of Project Objectives task number.

<u>Tasks 1.1 and 2.1 – Project Management</u>

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

<u>Task 1.2 – Total Process Definition and Design</u>

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

<u>Task 1.3 – Procurement</u>

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

<u>Task 1.4 – Environmental/Regulatory/Permitting</u>

The public comment period for the revised Title V air permit for AES Greenidge ended on August 20. No comments were received. As discussed in previous quarterly progress reports, the Title V permit was revised as part of its regularly scheduled renewal process so that it reflects the emission requirements set forth in the consent decree between AES and the State of New York. Following the August 20 deadline, the revised Title V permit was submitted to the U.S. Environmental Protection Agency for comment. It is anticipated that the permit will be finalized during the fourth calendar quarter of 2007.

Also during the quarter, AES Greenidge submitted a Request for Information (RFI) application to the New York State Department of Environmental Conservation (DEC) for its State Pollutant Discharge Elimination System (SPDES) permit.

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 project's last quarterly progress report, all major activities associated with start-up and commissioning of the multi-pollutant control system were completed by the end of the first quarter of calendar year 2007. 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 beginning of the third quarter of 2007. Three of these milestones (achievement of substantial completion, issuance of final release and waivers, and completion of reliability run) were achieved during the current quarter, and we expect that the remaining two milestones will be completed by the end of the fourth quarter of 2007.

Task 3.1 – Phase 3 Project Management

Project management activities during the third quarter of calendar year 2007 focused on communicating project results and on planning for future testing of the multi-pollutant control system at AES Greenidge.

On August 2, we presented a paper titled "Preliminary Performance Testing Results from the Greenidge Multi-Pollutant Control Project" at the COAL-GEN conference in Milwaukee, WI. A copy of that presentation is included as Attachment A to this report. In addition, our abstract titled "Mercury Removal Performance of the Greenidge Multi-Pollutant Control System" was accepted for presentation at the EUEC Energy & Environment Conference, which will be held in Tucson, AZ, in January 2008, and we submitted an abstract titled "Results from the First Year of Operation of a Circulating Fluidized Bed Dry Scrubber with High-Sulfur Coal at AES Greenidge Unit 4" to the organizers of the 2008 Electric Power Conference, which will be held in Baltimore, MD, on May 6-8. A copy of the first abstract was included in our last quarterly progress report; a copy of the second abstract is included as Attachment B to this report. Also during the quarter, we completed a draft report describing the results of the guarantee testing that was performed at AES Greenidge on March 28-30 and May 1-4, 2007; the report is currently being reviewed by the project team and will likely be issued during the next quarterly reporting period.

In July and August 2007, we developed revised plans for process performance testing of the multi-pollutant control system. The process performance tests had originally been scheduled for March-July 2007, but were delayed because of the extra time required to demonstrate attainment of the multi-pollutant control system's ammonia slip guarantee and to implement a solution for the large particle ash problem that affected the in-duct SCR. Three test series are planned to examine the performance of the system as a function of coal sulfur content, biomass co-firing, unit load, and scrubber operating conditions. We now expect that process performance testing will begin in October 2007 and will be completed by the end of the first quarter of 2008. The project schedule was updated to incorporate the revised testing plans. Additional details concerning the plans for the October 2007 test series are provided in the discussion under Task 3.3 below.

A project status review meeting including representatives from DOE, CONSOL, and AES was held at the AES Greenidge site on September 5. The project's cost and schedule performance through the end of the third quarter of 2007 are discussed in Section 3.0 of this report.

Task 3.2 – Plant Operations

AES Greenidge continued routine operation of the multi-pollutant control system throughout the third quarter of calendar year 2007. The Turbosorp® system operated regularly throughout the quarter, achieving an average SO_2 emission rate of ~0.20 lb/mmBtu when AES Greenidge Unit 4 was operating above 42 MW_{gross} (based on preliminary hourly average data from the unit's stack CEM). This was well within the unit's current permitted SO_2 emission rate of 0.38 lb/mmBtu. In general, any operational problems encountered to-date with the Turbosorp® system and ancillary equipment have been relatively minor and have centered on the lime hydration system, which is the most mechanically complex part of the process. In late July, several balls escaped from the lime hydration system's ball mill and caused minor damage to the system. As a result, the plant had to operate the Turbosorp® system using purchased hydrated lime while the lime hydration system was repaired. The ball mill and hydrated lime classifier again required maintenance in mid-August to overcome some minor operational problems; the project team is now considering whether one or both of these components can be either modified or bypassed to simplify the operation of the hydrated lime system. Also, during the week of August 20, the lime hydration system had to be taken offline because the bucket elevator shaft failed. Again, the plant was able to continue operation of the Turbosorp® system using purchased hydrated lime, and the problem was easily repaired. The plant plans to add to its on-site hydrated lime storage capacity to afford greater flexibility for taking the lime hydration system offline for maintenance.

As discussed in the last quarterly report for the Greenidge Project, most of the operational challenges encountered to-date with the multi-pollutant control system have been associated with the hybrid NO_x control system. Although the system demonstrated attainment of its NO_x emission performance target of 0.10 lb/mmBtu during guarantee testing in late March, the plant has generally had trouble achieving this emission rate while also maintaining acceptable combustion characteristics, sufficiently high steam temperatures, and sufficiently low ammonia slip for routine operation. As a result, they have generally operated the NO_x control system so that it achieves a high-load NO_x emission rate between its performance target of 0.10 lb/mmBtu and its current permitted high-load emission rate of 0.15 lb/mmBtu.

AESG, BPEI, and Fuel Tech completed another round of combustion system and SNCR/SCR tuning during the week of July 23. The process was informed by NO_x and CO grid point measurements performed by Clean Air Engineering at the SCR inlet and outlet. During the tuning period, the plant developed a set of full-load combustion and SNCR operating conditions that allow them to achieve their required steam temperatures and an acceptable NO_x removal distribution across the SCR catalyst (i.e., such that there are no areas of extremely high NO_x removal efficiency that would tend to indicate high NH_3 slip) while maintaining a NO_x emission rate of ~0.13-0.14 lb/mmBtu. These conditions require that zone two of the SNCR system is operated near its maximum capacity; the project team is considering whether modifications should be made to the system to increase the zone two urea injection capacity. Tuning and characterization of the combustion and SNCR/SCR systems were also completed at intermediate loads that produce economizer outlet temperatures near or just below the minimum operating temperature for the in-duct SCR.

Also during July, the plant observed increasing pressure drop across the large particle ash screen that was installed above the in-duct SCR reactor in May 2007 to prevent LPA from accumulating on the surface of the SCR catalyst. The screen was inspected and cleaned during an outage in July brought about by an ID fan cable failure; the inspection indicated that the soot blowers installed beneath the screen were not affording adequate coverage to keep it clean. Moreover, in spite of the presence of the screen, AESG observed in August that some LPA was still reaching the SCR catalyst, presumably by passing through the small gap between the two sections that form the LPA screen. (Because the top of the screen is affixed to the ductwork above an expansion joint, the screen was installed in two sections to allow it to move with the duct as furnace temperatures change – e.g., during start-up and shut-down). A short outage was held on August 10-11 to allow the plant to remove LPA that had accumulated on the screen and catalyst. The pressure drop across the SCR (including the screen) returned to normal following the outage, but was again increasing as of the end of the month, eventually forcing AESG to derate Unit 4.

AES Greenidge completed an outage in early September to modify the large particle ash removal system in response to the problems identified above. During the outage, which began on the evening of September 4, the two soot blowers that had been installed in May to clean the LPA screen were replaced with four rotary soot blowers to provide improved cleaning coverage, and a spring seal was installed to close the gap between the two sections of the LPA screen. The plant also installed a rake soot blower containing ~350 blow points immediately above the catalyst to aid in resuspending any fly ash that accumulates on its surface. (The rake is expected to keep the catalyst cleaner than the existing sonic horns). The outage ended at around 12:00 a.m. on September 10, and the plant successfully completed troubleshooting of a cam problem with the new soot blowers during the next several days. Unit 4 was then taken offline again on September 18-21 so that plant personnel could diagnose and repair an oil leak that was unrelated to the multi-pollutant control system. An inspection of the in-duct SCR during this outage confirmed that only a minor amount of LPA was present on the LPA screen. However, as of the end of the quarterly reporting period, it appeared that the pressure drop across the in-duct SCR was again increasing. The pressure drop will be monitored closely during the upcoming quarter to determine whether any further remedial actions are required.

Task 3.3 – Testing and Evaluation

As discussed under Task 3.1, during the third calendar quarter of 2007, we completed a draft report describing the results of the guarantee testing that was performed at AES Greenidge on March 28-30 and May 1-4, 2007, and we developed a plan for process performance testing of the multi-pollutant control system.

Pre-test preparations were completed for the first series of process performance tests, which was scheduled for October 1-12. This test series includes one week of testing to evaluate the performance of the multi-pollutant control system when AES Greenidge Unit 4 fires high-sulfur (i.e., ~4.7 lb SO_2 / mmBtu) coal, and a second week of testing to characterize the performance of the Turbosorp® system as a function of the calcium-to-sulfur ratio and the approach to adiabatic saturation temperature in the fluidized bed absorber. Details of the test plan were refined during a meeting at AES Greenidge on September 5 and a conference call on September 21; the flue gas sampling matrix is summarized in Table 1 below. In addition to the flue gas samples identified in the table, solid and liquid process samples (i.e., coal, fly ash, Turbosorp® system product ash, pebble lime, hydrated lime, urea, process water, activated carbon, and bottom ash) will be collected during the test period and analyzed for use in evaluating the performance of the multi-pollutant control system.

Once the October tests are completed, we anticipate two other series of process performance tests: one series in November 2007 focusing on the performance of the multi-pollutant control system when Unit 4 operates at low load and when it co-fires biomass with coal, and another series in early 2008 including additional parametric testing of the system. The sampling matrix for the early 2008 tests will be developed in part based on the outcome of the October and November tests.

Table 1. Flue gas sampling plan for process performance testing of the multi-pollutant control system at AES Greenidge on October 1-12, 2007.

Conditions	Analyte	Testing Locations	Testing Method
~4.7 lb SO_2/mmBtu Coal, No Carbon Injection, Normal Setpoints	Hg	SCR inlet, SCR outlet, Air heater outlet, Stack	Ontario Hydro
	SO_2	Air heater outlet, Stack	Plant CEMS
	NO_x	Stack	Plant CEMS
~4.7 lb SO_2/mmBtu Coal, Carbon Injection, Normal Setpoints	Hg	Air heater outlet, Stack	Ontario Hydro
	SO_3	SCR inlet, SCR outlet, Air heater outlet, Stack	Controlled Condensation
	HCl, HF	Air heater outlet, Stack	EPA Method 26A
	NH_3 Slip	Air heater inlet	EPA CTM 027
	SO_2	Air heater outlet, Stack	Plant CEMS
	NO_x	Stack	Plant CEMS
~3.8 lb SO_2/mmBtu Coal, No Carbon Injection, Ca/S Ratio #1, Approach Temperature A	Hg	Air heater outlet, Stack	Ontario Hydro
	SO_3	Air heater outlet, Stack	Controlled Condensation
	HCl, HF	Air heater outlet, Stack	EPA Method 26A
	SO_2	Air heater outlet, Stack	Plant CEMS
~3.8 lb SO_2/mmBtu Coal, No Carbon Injection, Ca/S Ratio #2, Approach Temperature A	Hg	Air heater outlet, Stack	Ontario Hydro
	SO_3	Air heater outlet, Stack	Controlled Condensation
	HCl, HF	Air heater outlet, Stack	EPA Method 26A
	SO_2	Air heater outlet, Stack	Plant CEMS
~3.8 lb SO_2/mmBtu Coal, No Carbon Injection, Ca/S Ratio # 3, Approach Temperature A	Hg	Air heater outlet, Stack	Ontario Hydro
	SO_3	Air heater outlet, Stack	Controlled Condensation
	HCl, HF	Air heater outlet, Stack	EPA Method 26A
	SO_2	Air heater outlet, Stack	Plant CEMS
~3.8 lb SO_2/mmBtu Coal, No Carbon Injection, Ca/S Ratio #1, Approach Temperature B	Hg	Air heater outlet, Stack	Ontario Hydro
	SO_3	Air heater outlet, Stack	Controlled Condensation
	HCl, HF	Air heater outlet, Stack	EPA Method 26A
	SO_2	Air heater outlet, Stack	Plant CEMS

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 third quarter of calendar year 2007. As shown in the table, actual incurred costs for the third quarter of 2007 were $2,920,149 greater than baseline planned costs for that quarter, whereas cumulative actual incurred costs were $239,452 less than cumulative planned costs as of the end of the quarter.

The positive cost variance for the third quarter of 2007 arose largely because three EPC contract payment milestones with a cumulative value of $2.55 million that had been planned for the first quarter of 2007 were instead achieved during the third quarter. In addition, costs for consumables (i.e., urea and pebble lime) were about $340,000 greater than originally budgeted for the quarter, accounting for most of the remaining quarterly cost variance. As discussed in the project's last quarterly progress report, the higher-than-expected costs for consumables resulted primarily from significant price escalation that has occurred since the baseline cost plan was developed.

In spite of the positive cost variance for the third quarter of 2007, the project's cumulative actual incurred costs continued to be less than its baseline planned costs as of the end of September 2007. The negative cumulative cost variance of $239,452 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. This variance includes $266,084 for two EPC contract payment milestones that were originally planned for completion during the first calendar quarter of 2007 but had not yet been achieved as of the end of September, as well as $445,636 for process performance testing that was originally scheduled for March through July 2007 but had not been completed as of the end of the third quarter. The negative cost variance attributed to these delayed expenditures is further augmented by $61,327 of net negative variance associated with miscellaneous project management, operation, and testing costs, but partially offset by $533,595 in cost overruns for consumables.

We anticipate that the project's cumulative cost variance will turn positive during the upcoming quarter, as we expect to incur the costs associated with the remaining EPC contract milestones and certain process performance testing activities, and we project that spending for consumables will continue to outpace our original budget.

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. None of the project's six critical path project milestones were scheduled for the current reporting period, and all previous critical path milestones have been achieved on or ahead of schedule. 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.

As discussed in Section 3.1 above, the project's current negative cost variance is largely attributable to delays in the completion of two EPC contract payment milestones and process performance testing activities that were originally scheduled for completion in the first half of 2007 but had not been completed as of the end of the third quarter. We expect that the remaining EPC contract payment milestones will be attained during the fourth quarter of 2007, and we do not anticipate that the delay in completing these milestones will affect any other project activities. Moreover, as discussed in Section 2.0, the process performance tests are scheduled to begin in October 2007. We do not expect that the delay in commencing these tests, which were originally scheduled for completion in July 2007, will impact the overall project end date of October 18, 2008, as the project schedule affords flexibility for completing them during the more-than year-long period between the guarantee tests and follow-up tests.

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
Baseline Cost Plan By Calendar Quarter												
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
Actual Incurred Costs[b]												
Federal Share		$6,610,049	$1,878,193	$1,644,001	$1,105,221	$544,600	$1,518,234					
Non-Federal Share		$8,481,387	$2,409,918	$2,109,425	$1,418,114	$698,779	$1,948,053					
Total Incurred Costs-Quarterly (Federal and Non-Federal)		$15,091,436	$4,288,111	$3,753,426	$2,523,335	$1,243,379	$3,466,287					
Cumulative Incurred Costs		$15,091,436	$19,379,547	$23,132,973	$25,656,308	$26,899,687	$30,365,974					
Variance[c]												
Federal Share		($666,156)	$71,352	($491,467)	($476,607)	$178,974	$1,279,026					
Non-Federal Share		($854,749)	$91,552	($630,605)	($611,537)	$229,642	$1,641,123					
Total Variance-Quarterly (Federal and Non-Federal)		($1,520,905)	$162,904	($1,122,072)	($1,088,144)	$408,616	$2,920,149					
Cumulative Variance		($1,520,905)	($1,358,001)	($2,480,074)	($3,568,217)	($3,159,601)	($239,452)					

Notes: Some numbers may not add perfectly because of rounding. [a]Costs 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. [b]Actual 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. [c]Negative 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	
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 third quarter of calendar year 2007, which are described more fully in Section 2.0 above, were as follows:

- Presentation of guarantee testing results at COAL-GEN in Milwaukee, WI
- Attainment of the EPC contract milestones for substantial completion and for completion of the reliability run of the multi-pollutant control system
- Implementation of modifications to the large particle ash removal system to improve its performance
- Continued operation of the multi-pollutant control system within its current permit limits for NO_x and SO_2
- Development of plans for process performance testing of the multi-pollutant control system

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

As described under Section 2.0 above, during the third quarter of 2007, the plant continued to experience problems with large particle ash accumulating on the surface of the in-duct SCR catalyst and on the LPA screen that was installed above the catalyst in May. To try to resolve this problem, AESG modified the LPA removal system in September by installing four rotary soot blowers to provide improved cleaning coverage of the LPA screen, installing a spring seal to close the gap between the two sections of the screen, and installing a rake soot blower to provide online cleaning of the catalyst surface. Despite these modifications, though, the pressure drop across the in-duct SCR appeared to be increasing again at the end of the quarter. The situation will be monitored closely during the upcoming quarter to determine whether further modifications are required.

The continued problems with large particle ash accumulation in the SCR rector further delayed the start of process performance testing of the multi-pollutant control system. The process performance tests were originally scheduled to begin in mid-March 2007, but still had not begun as of the end of September 2007. However, as discussed in Section 2.0 of this report, we developed plans during the current reporting period for completing the process performance tests during the fourth quarter of 2007 and the first quarter of 2008. We do not anticipate that the delay in beginning these tests will impact the overall project end date of October 2008, because the project schedule affords flexibility for completing them during the year-long period between the guarantee tests and follow-up tests.

Finally, as described earlier, minor operational problems were encountered with the lime hydration system during the quarter. AESG was able to resolve these problems, which involved the system's ball mill, classifier, and bucket elevator, while continuing to operate the Turbosorp® scrubber using purchased hydrated lime. They plan to increase their on-site hydrated lime storage capacity so that they will have greater flexibility to take the lime hydration system offline for repairs when necessary. The project team is also investigating whether the ball mill and/or classifier can be modified or bypassed to simplify operation of the system.

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

As discussed in Section 2.0 above, we presented a paper titled “Preliminary Performance Testing Results from the Greenidge Multi-Pollutant Control Project” at the COAL-GEN conference in Milwaukee, WI, on August 2. We also submitted an abstract titled “Results from the First Year of Operation of a Circulating Fluidized Bed Dry Scrubber with High-Sulfur Coal at AES Greenidge Unit 4” to the organizers of the 2008 Electric Power Conference, which will be held in Baltimore on May 6-8. Copies of the COAL-GEN presentation and Electric Power abstract are included as Attachments A and B, respectively, to this report.

ATTACHMENT A

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

Presented at COAL-GEN, August 1-3, 2007, Milwaukee, WI

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

Daniel P. Connell and James E. Locke
CONSOL Energy Inc. Research & Development

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

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

COAL-GEN, August 2, 2007, Milwaukee, WI

Greenidge Multi-Pollutant Control Project

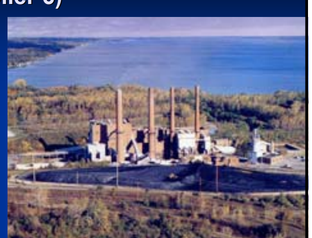
- Part of U.S. DOE's Power Plant Improvement Initiative
- Participants
  - CONSOL Energy Inc. (administration, testing, reporting)
  - AES Greenidge LLC (host site, operations)
  - Babcock Power Environmental Inc. (EPC contractor)
- Funding
  - U.S. Department of Energy, National Energy Technology Laboratory
  - AES Greenidge LLC
- Goal: Demonstrate a multi-pollutant control system that can cost-effectively reduce emissions of NO_x, SO_2, mercury, acid gases (SO_3, HCl, HF), and particulate matter from smaller coal-fired EGUs

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
- Difficult to retrofit for deep emission reductions
  - Large capital costs
  - Space limitations
- Increasingly vulnerable to retirement or fuel switching because of progressively more stringent environmental regulations
  - CAIR, CAMR, CAVR, state regulations
- Need to commercialize technologies designed to meet the environmental compliance requirements of these units

AES Greenidge Unit 4
(Boiler 6)

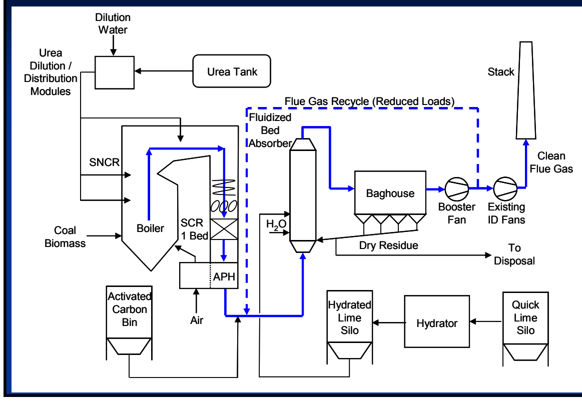


- Dresden, NY
- Commissioned in 1953
- 107 MW_e reheat unit
- Boiler:
  - Combustion Engineering tangentially-fired, balanced draft
  - 780,000 lb/h steam flow at 1465 psig and 1005 °F
- Fuel:
  - Eastern U.S. bituminous coal
  - Biomass (waste wood) – up to 10% heat input
- Existing emission controls:
  - Overfire air (natural gas reburn not in use)
  - ESP
  - No FGD - mid-sulfur coal to meet permit limit of 3.8 lb SO_2/MMBtu

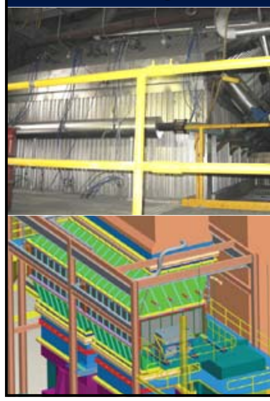
Design Objectives

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

Multi-Pollutant Control Process

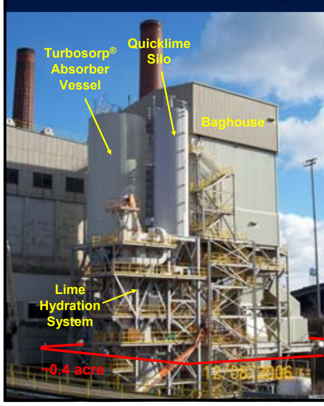


Hybrid NO_x Control



- Combustion Modifications
  - Replace coal, combustion air, and overfire air nozzles
  - Reduce NO_x to 0.25 lb/MMBtu
- SNCR
  - Three zones of urea injection
  - Provide NH_3 slip for SCR
  - Reduce NO_x by ~ 42.5% (to 0.144 lb/MMBtu)
- SCR
  - Single catalyst bed (1.3 m)
  - Cross section = 45' x 14'
  - Fed by NH_3 slip from SNCR
  - Reduce NO_x by > 30% (to ≤ 0.10 lb/MMBtu)

Turbosorp® System



- Completely dry
- Separate control of reagent, water, and recycled solid injection
- Applicable to high-S coal
- High solids recirculation
- 15-25% lower reagent consumption than SDA
- Carbon steel construction
- No wet stack
- Low maintenance requirements
  - Few moving parts
  - No slurries
  - No dewatering

Mercury Control

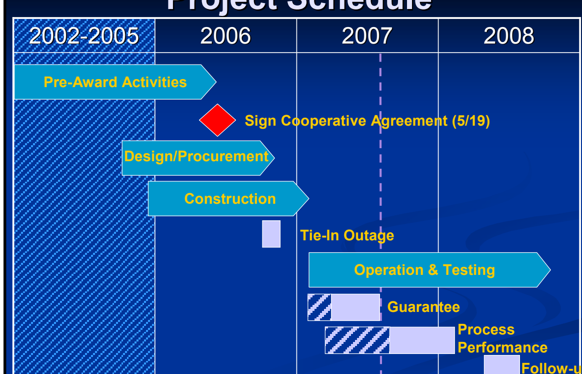
- System design favors high baseline Hg removal without activated carbon injection
  - Hg oxidation across in-duct SCR catalyst
  - Low temperature (~170 ºF) in scrubber / baghouse
  - Ample gas / solids contact in scrubber / baghouse
  - Similar to SCR / SDA / FF with bituminous coal
    - Field sampling 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 provides high carbon residence time
  - Projected activated carbon requirement: 0.0 – 3.5 lb/mmacf

Performance Targets

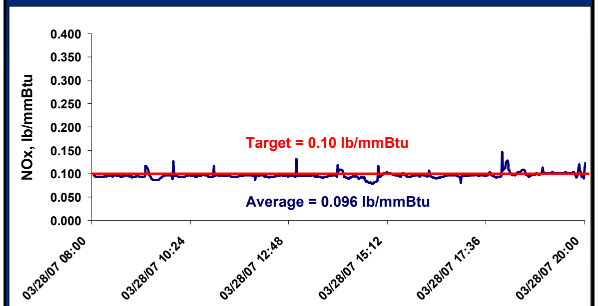
Fuel: 2-4% sulfur bituminous coal, up to 10% biomass

Parameter	Goal
NO_x	≤ 0.10 lb/mmBtu (full load)
SO_2	≥ 95% removal
Hg	≥ 90% removal
SO_3, HCl, HF	≥ 95% removal

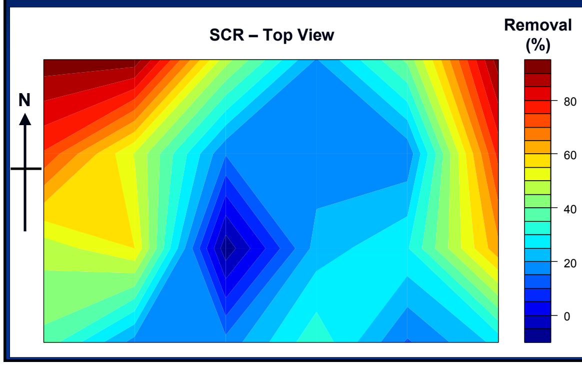
Project Schedule



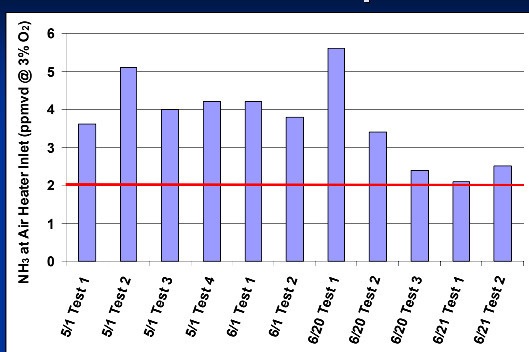
NO_x Emission Rate
March 28, 2007



NO_x Removal Across SCR
March 28, 2007 – Three-Test Average



Ammonia Slip

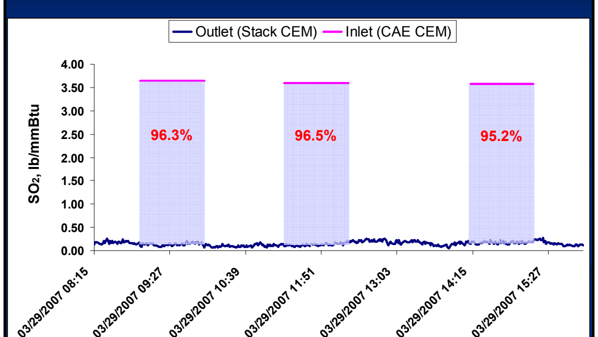


Large Particle Ash

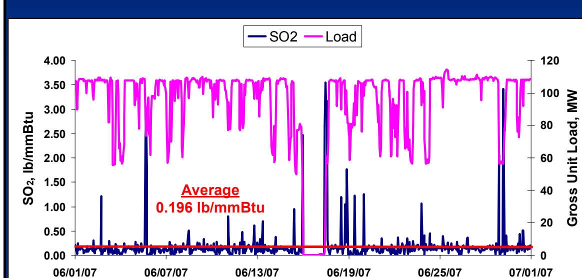
Solution - May 2007

- Sloped screen above catalyst
- Soot blowers
- Vacuum ports

SO_2 Removal Efficiency
March 29, 2007

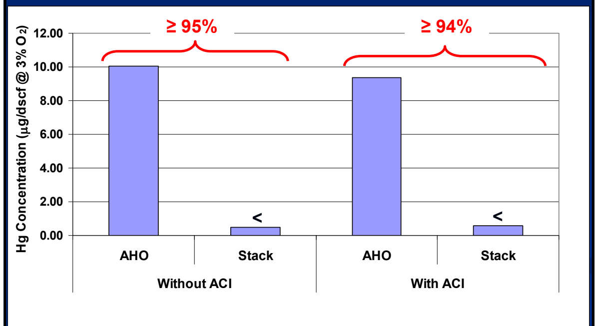


SO_2 Emissions
June 2007



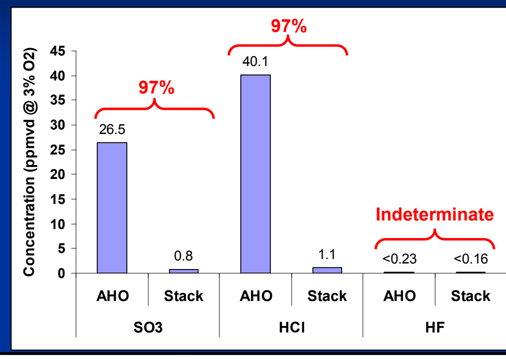
Mercury

March 28-30, 2007



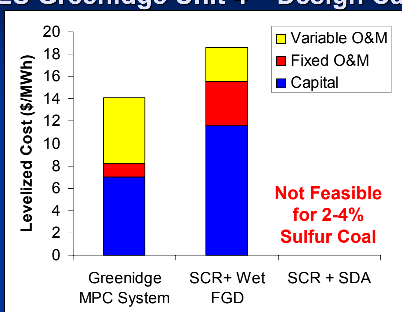
Acid Gases

May 2-4, 2007



Economics

AES Greenidge Unit 4 – Design Case



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

Summary

- Greenidge MPC process uniquely designed to meet needs of smaller coal-fired units
  - Deep emission reductions
  - Low capital costs
  - Small space requirements
  - Applicability to high-sulfur coals
  - Low maintenance requirements
  - Operational flexibility
- Preliminary performance testing results are encouraging
  - Demonstrated ability of system to achieve emission targets for NO_x, SO_2, Hg, and acid gases
  - Still optimizing NO_x control system, evaluating effects of higher-than-expected NH_3 slip
- Additional testing planned for September 2007 – June 2008

Disclaimer

ATTACHMENT B

Results from the First Year of Operation of a Circulating Fluidized Bed Dry Scrubber with High-Sulfur Coal at AES Greenidge Unit 4

Submitted to the Electric Power Conference, May 6-8, 2008, Baltimore, MD

Results from the First Year of Operation of a Circulating Fluidized Bed Dry Scrubber with High-Sulfur Coal at AES Greenidge Unit 4

Douglas J. Roll, P.E.
AES Greenidge LLC, Dresden, NY

Daniel P. Connell
CONSOL Energy Inc. Research & Development, South Park, PA

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

A Turbosorp circulating fluidized bed dry scrubber was retrofitted on the 107-MWe, 1953-vintage AES Greenidge Unit 4 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. In the Turbosorp system, water and dry hydrated lime are injected separately into a fluidized bed absorber, where the flue gas is evaporatively cooled and brought into intimate contact with moistened hydrated lime reagent. The hydrated lime reacts with SO_2 and other acid gases to form solid products, which are separated from the flue gas in a baghouse and recycled to the absorber at a high ratio to the inlet solids. Circulating fluidized bed dry scrubbers are increasingly garnering recognition as an attractive SO_2 control option for units firing low-to-medium sulfur coals because of their relatively low capital costs, low maintenance requirements, high removal efficiency, and high reagent utilization. However, the Greenidge Project seeks to demonstrate that these scrubbers are also technically and economically attractive for units firing high-sulfur coals. The Turbosorp system at AES Greenidge was constructed in 2006 with a footprint of ~0.4 acre and an EPC capital cost of ~$235/kW, including the costs for an on-site lime hydration system, pulsejet baghouse, and booster fan. Guarantee testing of the system in 2007 demonstrated that it is capable of reducing SO_2 emissions by 96% while the unit is firing 2.5%-sulfur coal. Moreover, the system succeeded in reducing SO_3 and HCl emissions by 97% and Hg emissions by >95% without the need for any activated carbon or other sorbent injection.

This presentation focuses on AES Greenidge's operating and maintenance experience with the Turbosorp scrubber during its first year of commercial service, while Unit 4 routinely fired coals containing 2.0-3.5% sulfur. The system's reagent utilization and its long-term SO_2, Hg, and acid gas emissions reduction performance are discussed, as are experiences with start-up, turndown, on-site lime hydration, and byproduct handling. Operating costs and their effect on the unit's dispatch economics are also presented. This information is valuable for informing the decision making of generators seeking cost-effective retrofit options for the large existing fleet of smaller coal-fired units.