Mercury Capture in a Circulating Fluidized Bed Dry Scrubber at AES Greenidge Unit 4

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Project Background

- Part of U.S. Department of Energy'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 (43.8%)
  - AES Greenidge LLC (56.2%)
- 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

Motivation

- There are ~ 440 existing coal-fired units in the United States that are not equipped with FGD, SCR, or Hg control systems
  - Represent ~ 60 GW of installed capacity
  - Greater than 80% are located east of the Mississippi River
  - Most have not announced plans to retrofit
- It is difficult to retrofit these smaller units for deep emission reductions
  - Large capital costs
  - Space limitations
- These units are increasingly vulnerable to retirement or fuel switching because of progressively more stringent environmental regulations
  - CAIR, CAMR, CAVR, state regulations
- Hence, there is a need to commercialize technologies designed to meet the environmental compliance requirements of these units
- The Greenidge Project seeks to demonstrate an innovative combination of technologies that are designed to satisfy this need by affording deep emission reduction capabilities, low capital costs (~$340/kW*), small space requirements (~0.5 acre*), applicability to high-sulfur coals (2-4%*), low maintenance requirements, and operational flexibility *For AES Greenidge Unit 4 installation

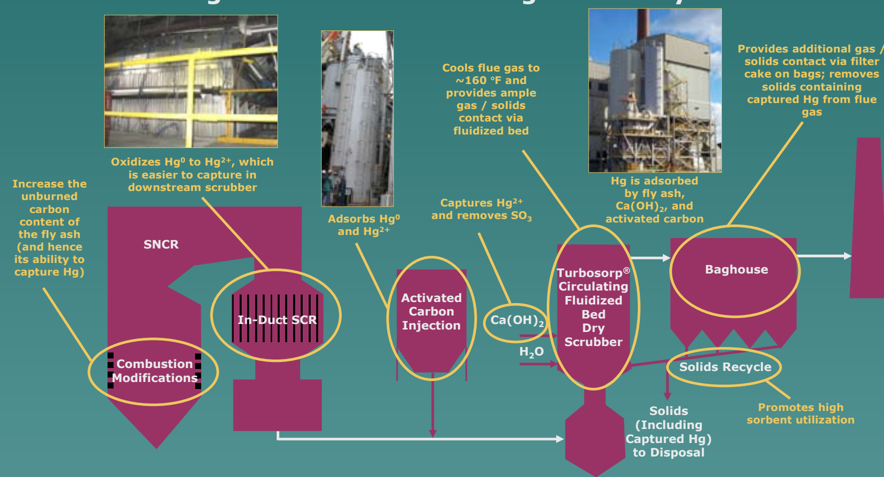
Host Site
AES Greenidge Unit 4 (Boiler 6)

- 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% of total 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

Technology

- Combustion Modifications (low-NO_x burners, overfire air)
- Hybrid Selective Non-Catalytic Reduction / Selective Catalytic Reduction (SNCR/SCR) System
  - SNCR includes 3 zones of urea injection; it is designed to reduce NO_x by ~42% and provide NH_3 for the downstream SCR reactor
  - SCR is an in-duct design with a single layer of catalyst (1.3 m deep); it is fed entirely by NH_3 slip from the SNCR and designed for ~30% NO_x removal efficiency
- Powdered Activated Carbon Injection System
  - Projected injection rate for 90% Hg capture: 0 – 3.5 lb/mmacf
- Turbosorp® Circulating Fluidized Bed Dry Scrubber
  - Water and dry hydrated lime injected separately; operating temperature ~ 160 °F, nominal Ca/S ~ 1.6 mol/mol for 2.5% sulfur coal; designed to accommodate coals containing up to 4.0% sulfur
  - Lime hydration system installed as part of project for onsite production of $Ca(OH)_2$ from pebble lime
- Baghouse
  - 8-compartment pulse jet fabric filter; nominal air-to-cloth ratio = 3 (ft^3/min)/ft^2
  - ~95% of baghouse solids are recycled to Turbosorp® scrubber using air slides
  - Booster fan installed downstream of baghouse to overcome pressure drop

Design Features Contributing to Mercury Control



Hg Reduction Target: ≥90% (coal-to-stack)

Guarantee Testing Results

March – May 2007, 2.4-3.2% Sulfur Eastern U.S. Bituminous Coal

Parameter	Performance Target	Measured Performance
NO_x emission rate	$\leq$ 0.10 lb/mmBtu	0.10 lb/mmBtu[a]
SO_2 removal	$\geq$ 95%	96%
SO_3 removal	$\geq$ 95%	97%
HCl removal	$\geq$ 95%	97%
HF removal	$\geq$ 95%	Indeterminate[b]

[a]Although the target of 0.10 lb/mmBtu was demonstrated in short-term testing, the plant routinely has had to operate at ~0.13 lb/mmBtu to maintain acceptable combustion characteristics, steam temperatures, and ammonia slip; [b]Concentrations at both the inlet and outlet of the Turbosorp® scrubber were less than the detection limit

Mercury Testing Methodology

- All sampling and analysis performed by CONSOL Energy Research & Development
- All flue gas Hg measurements conducted using the Ontario Hydro Method (ASTM D 6784-02)
  - Liquid samples analyzed by cold vapor atomic absorption spectroscopy (March 2007) or cold vapor atomic fluorescence spectroscopy (October 2007)
  - Particulate samples analyzed in accordance with ASTM D 6414 or ASTM D 6722
- Coal samples (composite of all feeders) collected at the beginning and middle of each test and analyzed for Hg by ASTM D 6722
- Solid and liquid process samples (e.g., ash, lime, urea, water) and plant operating data also collected during each test to assess process performance
- QA/QC
  - Pre- and post-test leak checks performed for each test
  - O_2 concentration monitored continuously at meter exhaust
  - Blank sampling trains analyzed to check for contamination
  - Laboratory procedures included use of independent calibration verification standards, duplicate or triplicate analyses, matrix spikes, digestion duplicates, and digestion spikes, with a 10% relative percent difference criterion for duplicates/triplicates and a 100±10% recovery criterion for standards and spikes
  - Material balances performed for each of the March tests to ensure that the total mercury output from the process agreed reasonably well with the total mercury input to the process (material balances for the October tests have not yet been completed)

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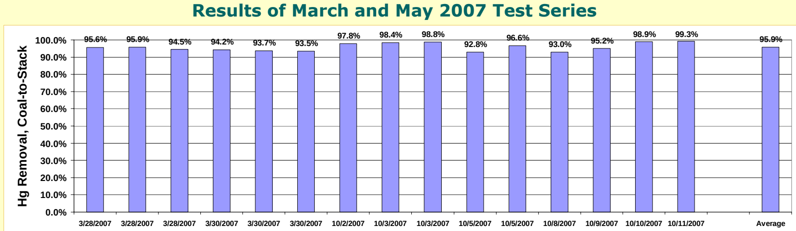
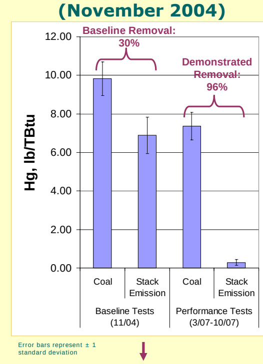
Mercury Testing Results To-Date

Results of March and May 2007 Test Series



	3/28/2007	3/28/2007	3/28/2007	3/30/2007	3/30/2007	3/30/2007	10/2/2007	10/3/2007	10/3/2007	10/5/2007	10/5/2007	10/8/2007	10/9/2007	10/10/2007	10/11/2007	Average
Gross Generation (MW)	105.1	105.7	105.1	105.4	105.4	105.4	108.7	107.3	106.6	107.7	108.3	108.0	106.1	108.2	107.5	Range: 105.1 – 108.7
Hg from Coal (lb/TBtu)	7.34	8.19	6.86	6.92	6.45	6.38	7.64	7.42	7.43	7.33	6.87	7.47	7.11	7.94	9.21	Range: 6.38 – 9.21
Hg Emission Rate (lb/TBtu)	<0.32	<0.34	<0.38	<0.40	<0.41	<0.42	0.17	0.12	0.09	0.53	0.23	0.53	0.34	0.08	0.06	Range: 0.06 – 0.53
Coal Sulfur (lb SO_2/mmBtu)	3.89	3.90	3.77	3.72	3.80	3.80	4.70	4.87	4.75	4.51	4.42	4.12	4.03	4.24	4.30	Range: 3.72 – 4.87
SO_2 Removal (%)	95.5	95.4	94.0	92.9	95.3	95.5	96.6	96.8	96.2	96.0	96.0	99.0	99.0	93.5	94.6	Range: 92.9 – 99.0
Scrubber Outlet Temperature (°F)	163.2	163.3	162.8	162.1	161.9	161.7	158.6	158.7	159.1	160.4	160.0	159.9	160.2	160.5	165.2	Range: 158.6 – 165.2
Unburned Carbon in Fly Ash (%)	20.9	16.9	17.9	17.9	17.5	15.6	20.5	14.4	25.3	21.9	17.5	15.4	17.1	18.7	16.4	Range: 14.4 – 25.3
PAC Injection Rate (lb/mmacf)	0	0	0	3	3	3	0	0	0	3	3	0	0	0	0	Range: 0 – 3
Hg Mass Balance Closure (%)	100.3	93.0	108.8	118.7	119.2	120.6	NA	NA	NA	NA	NA	NA	NA	NA	NA	Range: 93.0 – 120.6

Comparison with Baseline Tests (November 2004)



Error bars represent ± 1 standard deviation

94% Hg Reduction Over Baseline

Process Economics

Constant 2005 Dollars

	Capital Cost ($/kW)	Fixed & Variable O&M Cost ($/MWh)	Total Levelized Cost ($/ton removed)
NO_x Control	106	1.19	$3,290 / ton NO_2
SO_2 Control	229	5.23	$513 / ton SO_2
Hg Control (incremental)[a]	0	0	0

Assumptions: Plant size = 107 MW, Capacity factor = 80%, Coal sulfur = 4.0 lb SO_2/mmBtu, Baseline NO_x emission rate = 0.30 lb/mmBtu, SNCR normalized stoichiometric ratio = 1.5, Ca/S = 1.55, Quicklime = $110/ton, Urea (50% w/w) = $1.25/gal, Waste disposal = $12/ton, Plant life = 20 years, Fixed charge factor = 13.05%, Other assumptions based on common estimating practices and current market prices

[a]Based on performance testing results to-date

Conclusions

- The multi-pollutant control system being demonstrated at AES Greenidge Unit 4 is uniquely designed to meet the needs of smaller coal-fired units
  - Has demonstrated deep reductions in SO_2 emissions (> 95%) and NO_x emissions (> 60%) while requiring a capital investment of only $340/kW and a footprint of < 0.5 acre for a 107 MW unit
  - Deep SO_3 and HCl removal and reduced PM emissions are zero cost co-benefits
- Testing results thus far have shown the system to be very effective in achieving deep Hg removal efficiency
  - Greater than 90% Hg removal efficiency (coal-to-stack) observed in all 15 tests conducted to-date
  - Average demonstrated removal efficiency (96%) represents 94% reduction over baseline
- Based on results to-date, projected incremental cost to achieve 90% Hg capture is $0
  - Ten tests have shown >90% Hg capture in the circulating fluidized bed dry scrubber and baghouse without any activated carbon injection

Future Plans

- Testing and evaluation will continue at AES Greenidge Unit 4 through October 2008
- Additional Hg tests will focus on:
  - Hg removal at reduced boiler loads
  - Hg removal with biomass co-firing
  - Role of the in-duct SCR in oxidizing Hg
  - Hg removal as a function of fly ash unburned carbon content, fuel, and scrubber operating conditions
  - Stability of the captured Hg in the scrubber solids / ash