Mercury Removal Performance of the Greenidge Multi-Pollutant Control System

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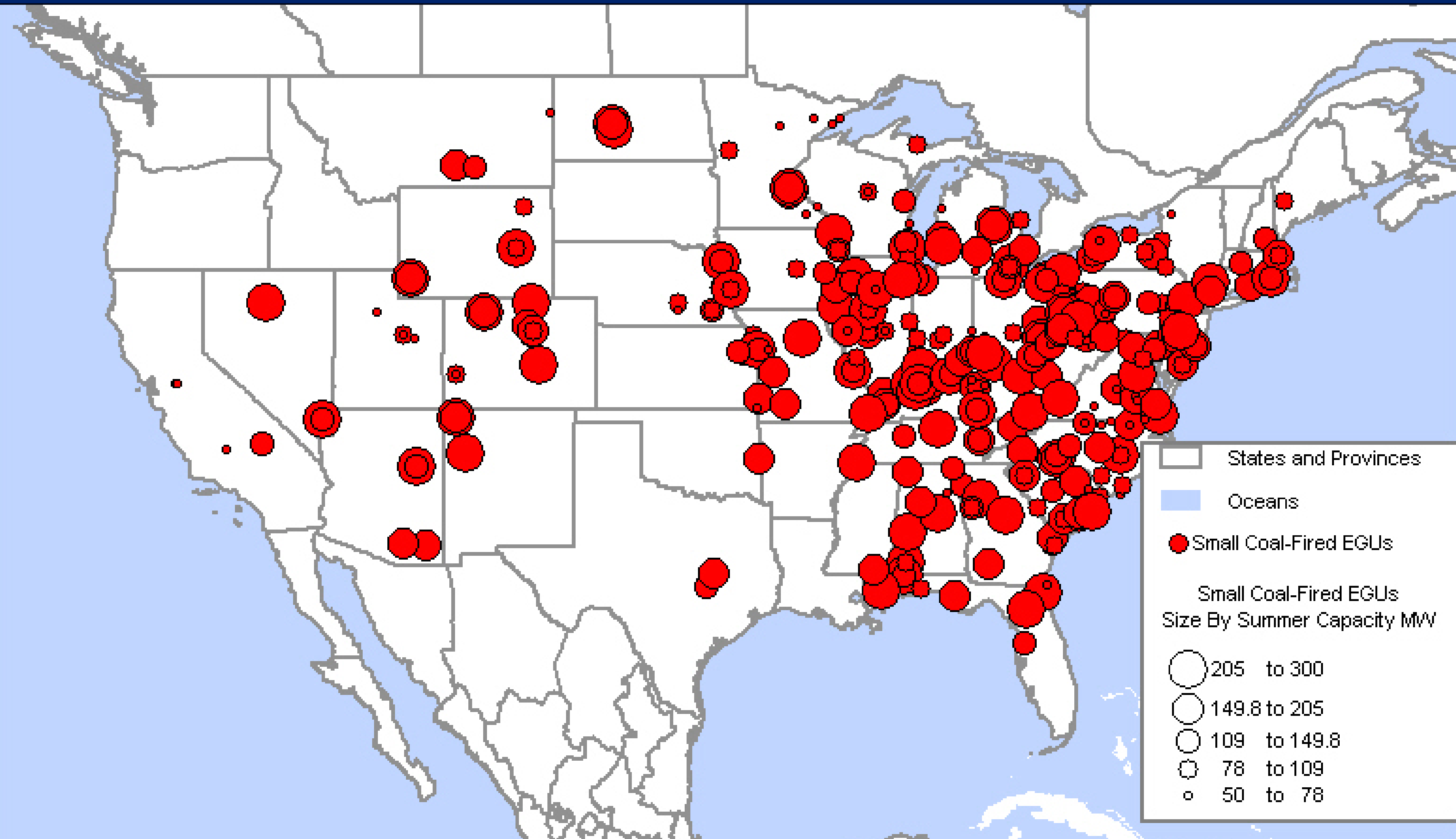
Greenidge Multi-Pollutant Control Project

- 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

- ~ 420 units not equipped with FGD, SCR, or Hg control
  - Represent almost 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 (net) reheat unit
- Boiler:
  - Combustion Engineering tangentially-fired, balanced draft
  - 780,000 lb/h steam flow at 1465 psig and 1005 ^oF
- 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/high-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 System

- Combustion modifications
  - Low-NO_x burners and overfire air
- Hybrid SNCR / SCR
  - Single-bed, in-duct SCR fed by NH_3 slip from urea-based SNCR

- Activated carbon injection
- Turbosorp® circulating fluidized bed dry scrubber
  - Separate injection of water and dry hydrated lime
  - Includes onsite lime hydrator
- Pulsejet baghouse
  - ~95% of solids recycled to scrubber via air slides
  - Booster fan installed downstream

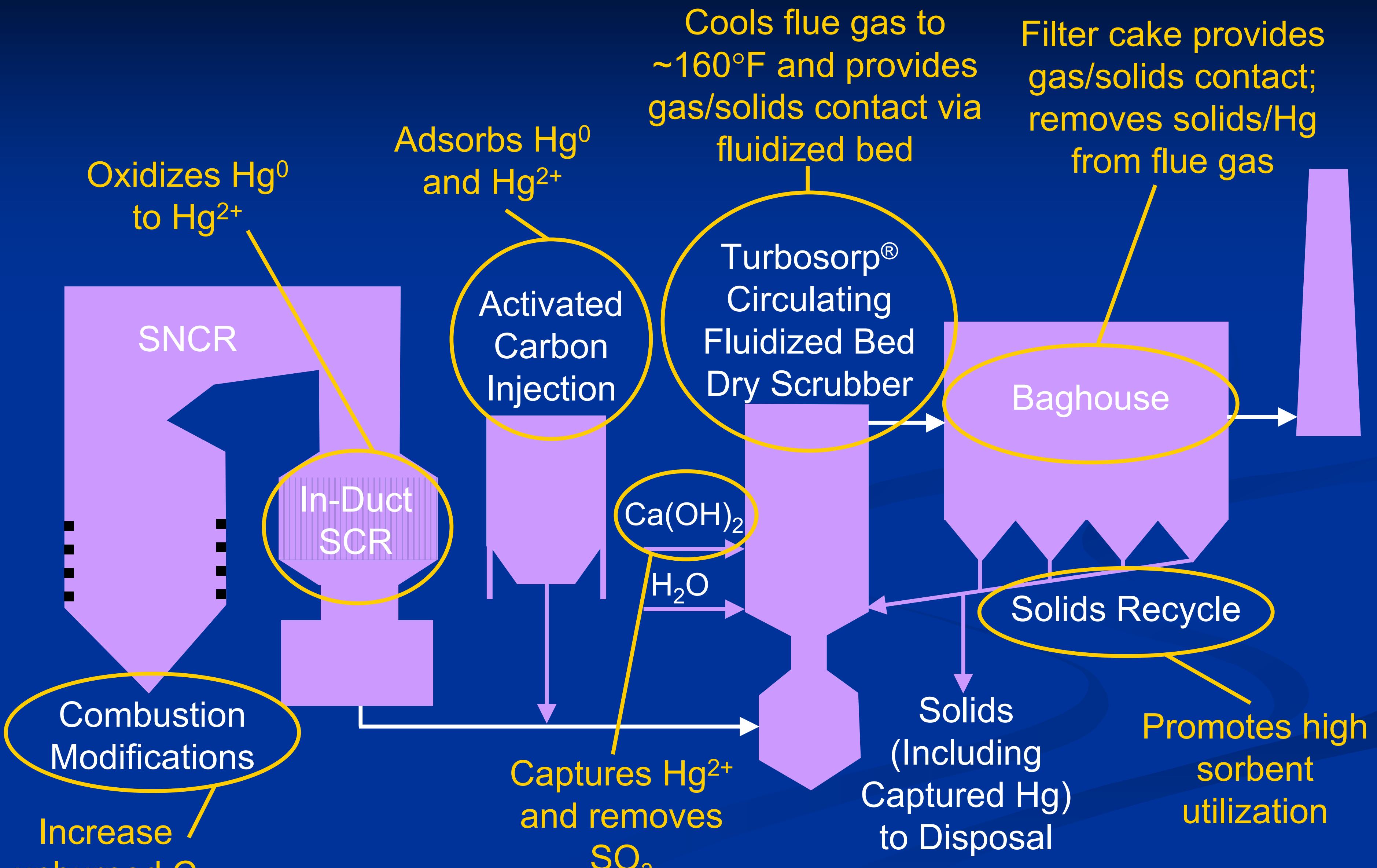
Guarantee Testing Results

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

Parameter	Performance Target	Measured Performance
NO_x emission rate	≤ 0.10 lb/mmBtu	0.10 lb/mmBtu*
SO_2 removal	≥ 95%	96%
SO_3 removal	≥ 95%	97%
HCl removal	≥ 95%	97%
HF removal	≥ 95%	Indeterminate

* Performance of hybrid NO_x control system has been affected by large particle ash and ammonia slip. Plant typically operates at 0.10-0.15 lb/mmBtu to maintain acceptable combustion characteristics.

Design Features for Mercury Control



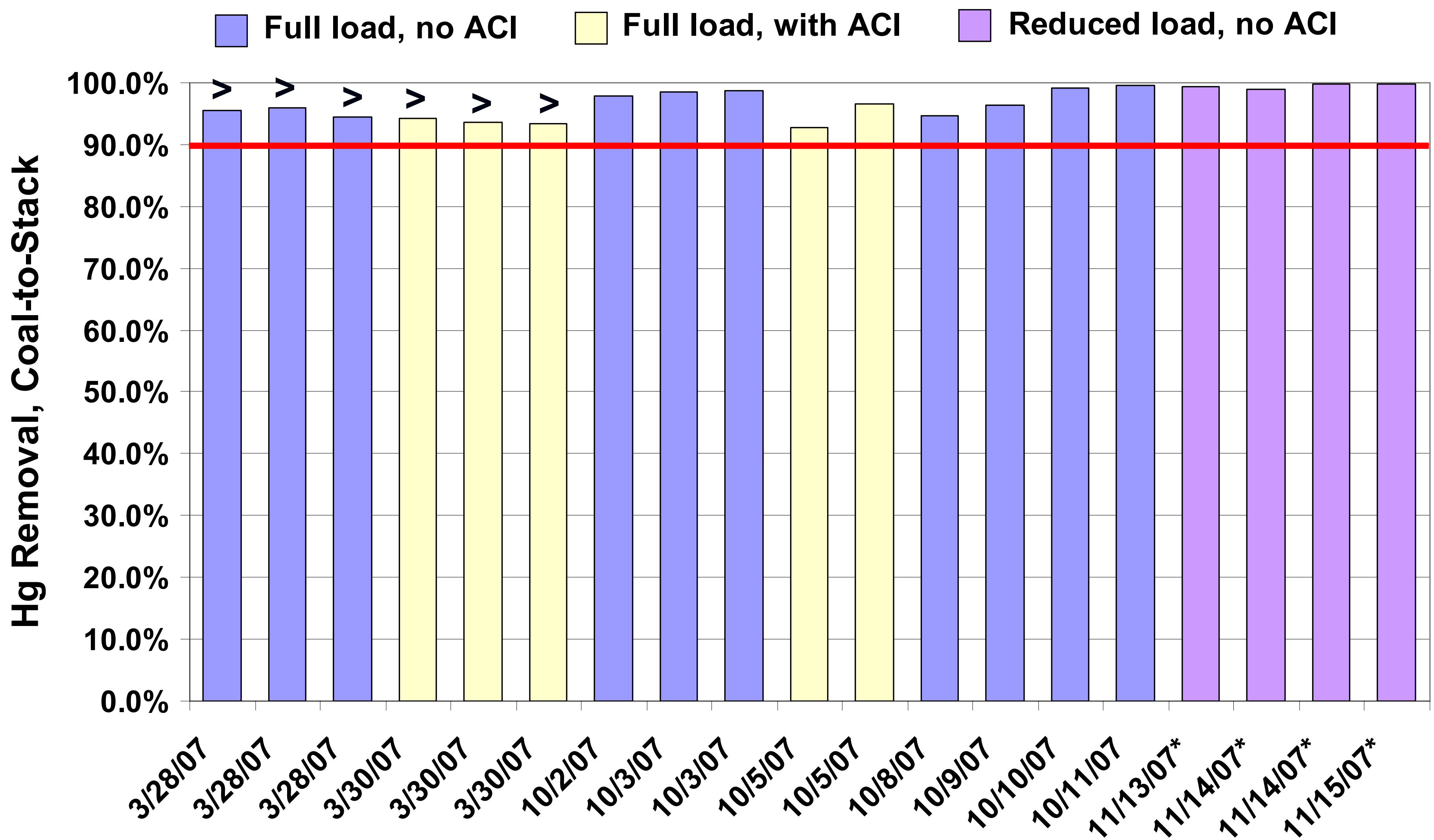
Hg Reduction Target: ≥ 90% (coal-to-stack)

Mercury Testing Methodology

- Flue gas measurements
  - Ontario Hydro Method (ASTM D 6784-02)
  - Liquid samples analyzed by CVAAS (3/07) or CVAFS (10/07-11/07)
  - Particulate samples analyzed per ASTM D 6414 or ASTM D 6722

- Coal samples
  - Collected at beginning / middle of each test (composite of all feeders)
  - Analyzed for Hg by ASTM D 6722
- QA/QC
  - Pre- and post-test leak checks
  - O_2 monitored at meter exhaust
  - ICV standards, duplicate/triplicate analyses, matrix spikes, digestion duplicates, digestion spikes; 100±10% RPD or recovery required
  - Material balance performed for each test

Mercury Removal Efficiency

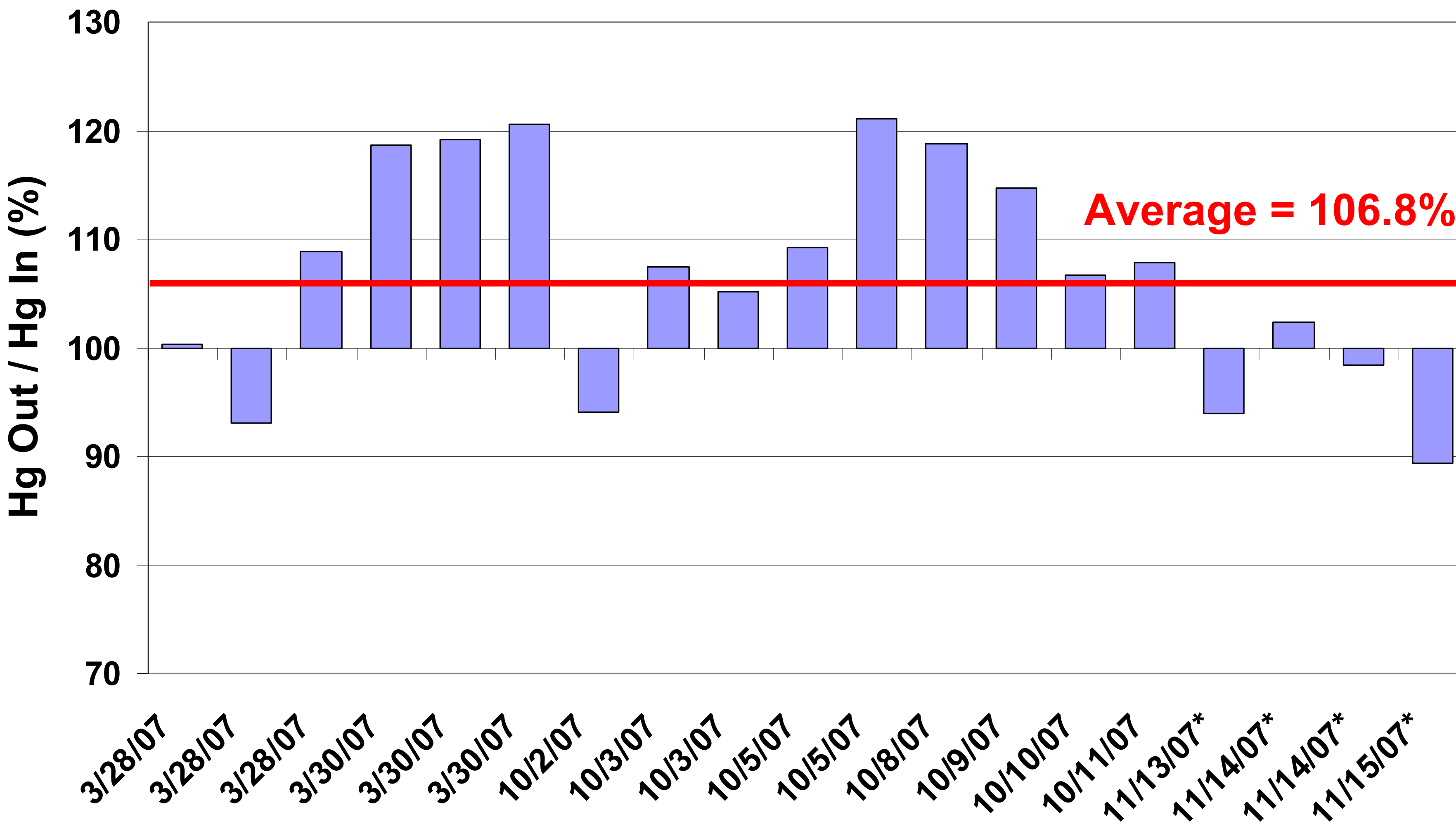


* Preliminary Result

Plant Conditions During Hg Tests

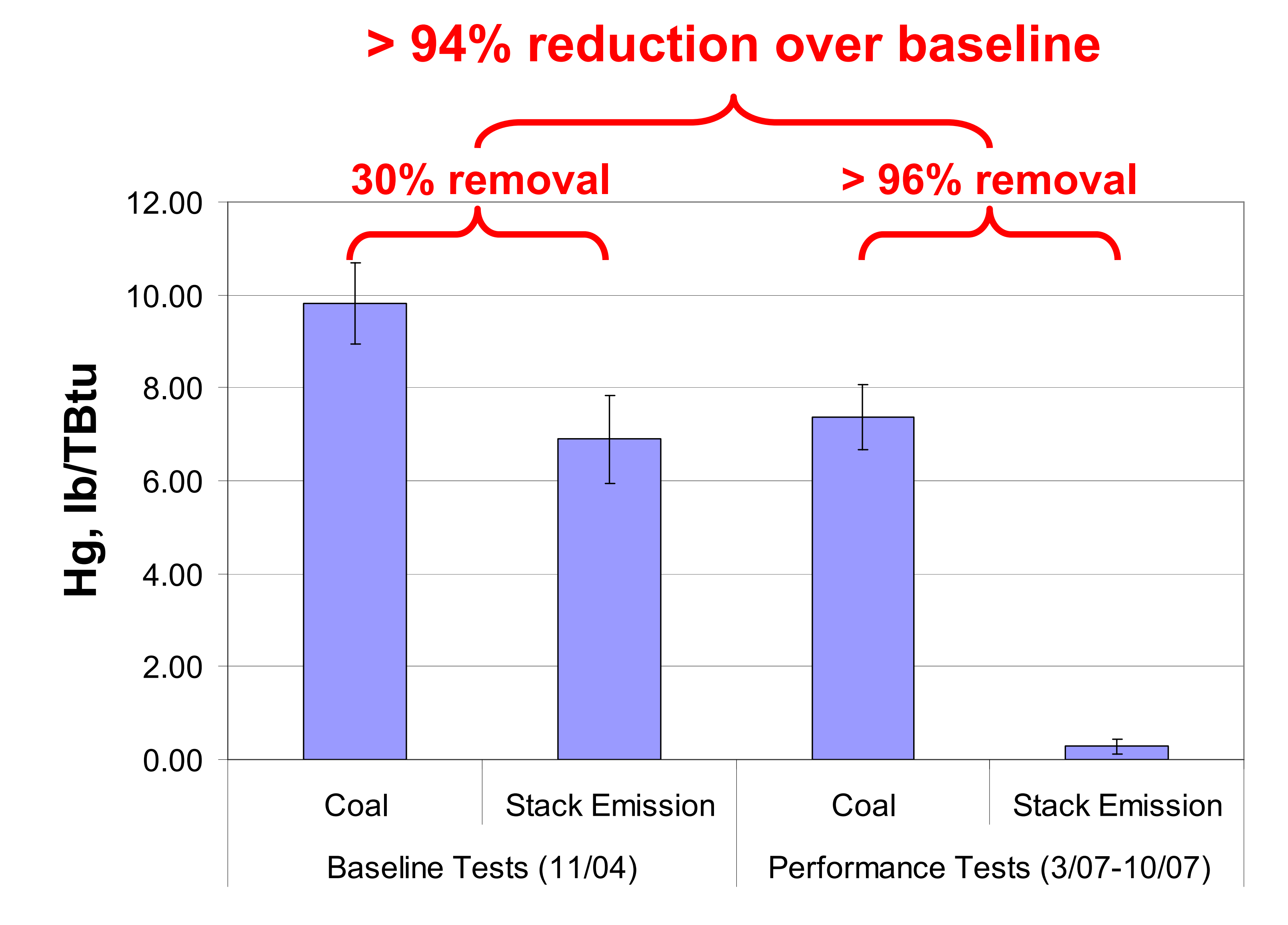
Parameter	Range
Coal Hg content (lb / TBtu)	6.4 – 13.7
Coal S content (lb SO_2 / mmBtu)	3.7 – 4.9
Coal Cl content (wt. %, dry)	0.07 – 0.11
Gross generation (MW)	56.4 – 108.7
Fly ash unburned carbon (%)	9.2 – 25.3
Activated carbon injection rate (lb / mmacf)	0 - 3
SO_2 removal efficiency (%)	92.9 – 99.0
Scrubber outlet temperature (°F)	158.6 – 165.2

Mercury Material Balances



* Preliminary Result

Mercury Reduction Over Baseline
Full-Load Data



Leachability of Captured Hg from Turbosorp® Product Ash

Synthetic Precipitation Leaching Procedure (EPA Method 1312)

	11/14/07	11/15/07	11/16/07
Hg in product ash sample, mg/kg	0.464	0.602	0.667
Hg leached from sample, mg/kg	<0.007	<0.007	<0.007
Hg leached from sample, %	<1.51	<1.16	<1.05

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 NOx 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

- Greenidge MPC process uniquely designed to meet needs of smaller coal-fired units
  - Demonstrated > 95% SO_2 removal and > 60% NO_x removal with capital cost of ~ $340/kW and footprint of ~ 0.5 acre for 107 MW unit
  - Deep SO_3 and HCl removal and reduced PM emissions are zero cost co-benefits
- Testing results have shown deep Hg removal efficiency
  - Greater than 90% removal efficiency observed in all 19 tests completed thus far, regardless of operating conditions
  - Average demonstrated full-load removal efficiency (> 96%) represents > 94% reduction over baseline
- Projected incremental cost for 90% Hg capture is $0
  - Ten full-load tests and four reduced-load tests have shown > 90% Hg capture with no 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 with biomass co-firing
  - Hg speciation and role of the in-duct SCR in oxidizing Hg
  - Hg removal as a function of fly ash unburned carbon content, fuel, load, and scrubber operating conditions

  - Stability of the captured Hg in the scrubber solids / ash

Disclaimer