# The Greenidge Multi-Pollutant Control Project: Performance and Cost Results from the First Year of Operation


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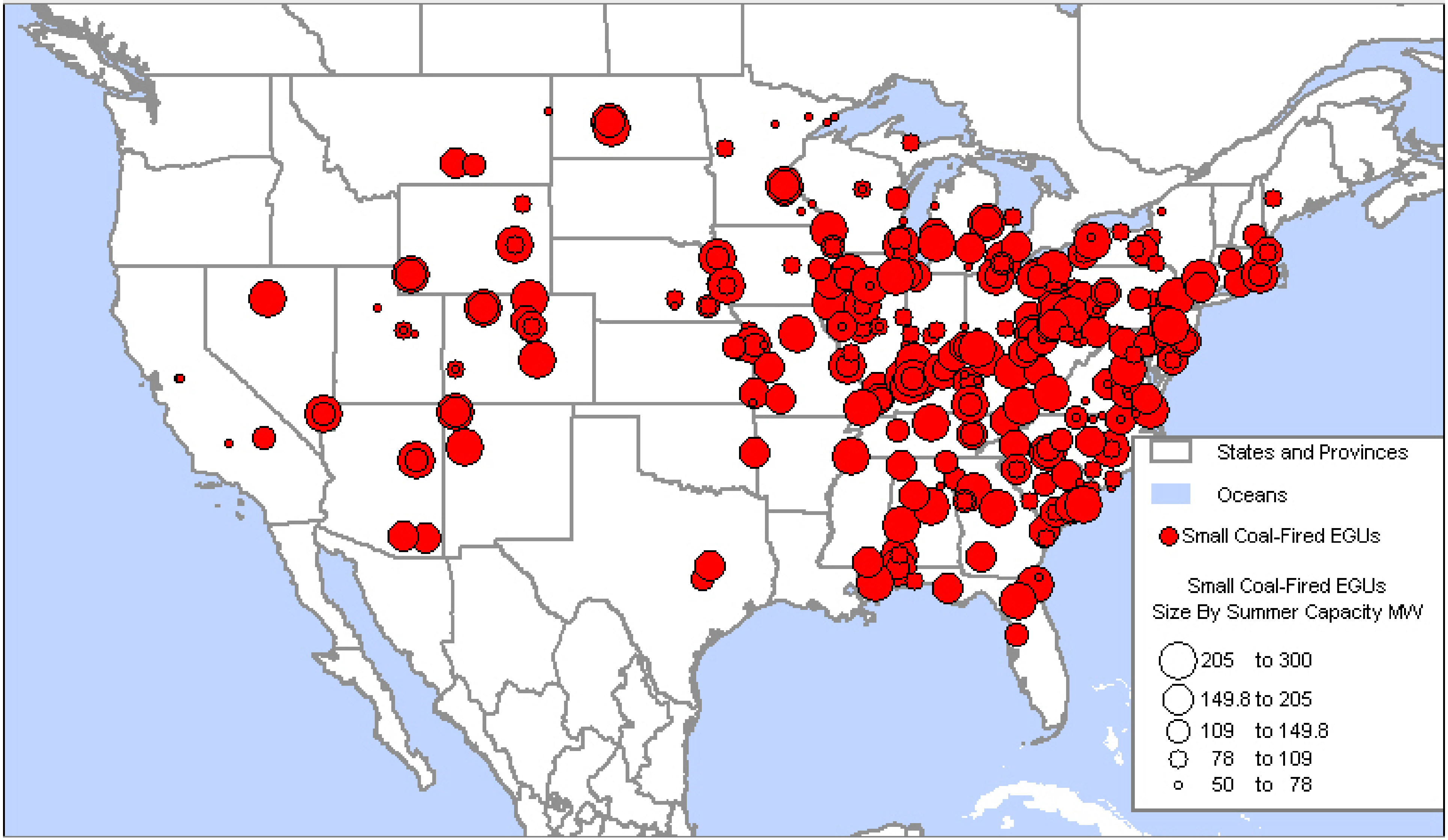
# Greenidge Multi-Pollutant Control Project

- 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 $MW_e$



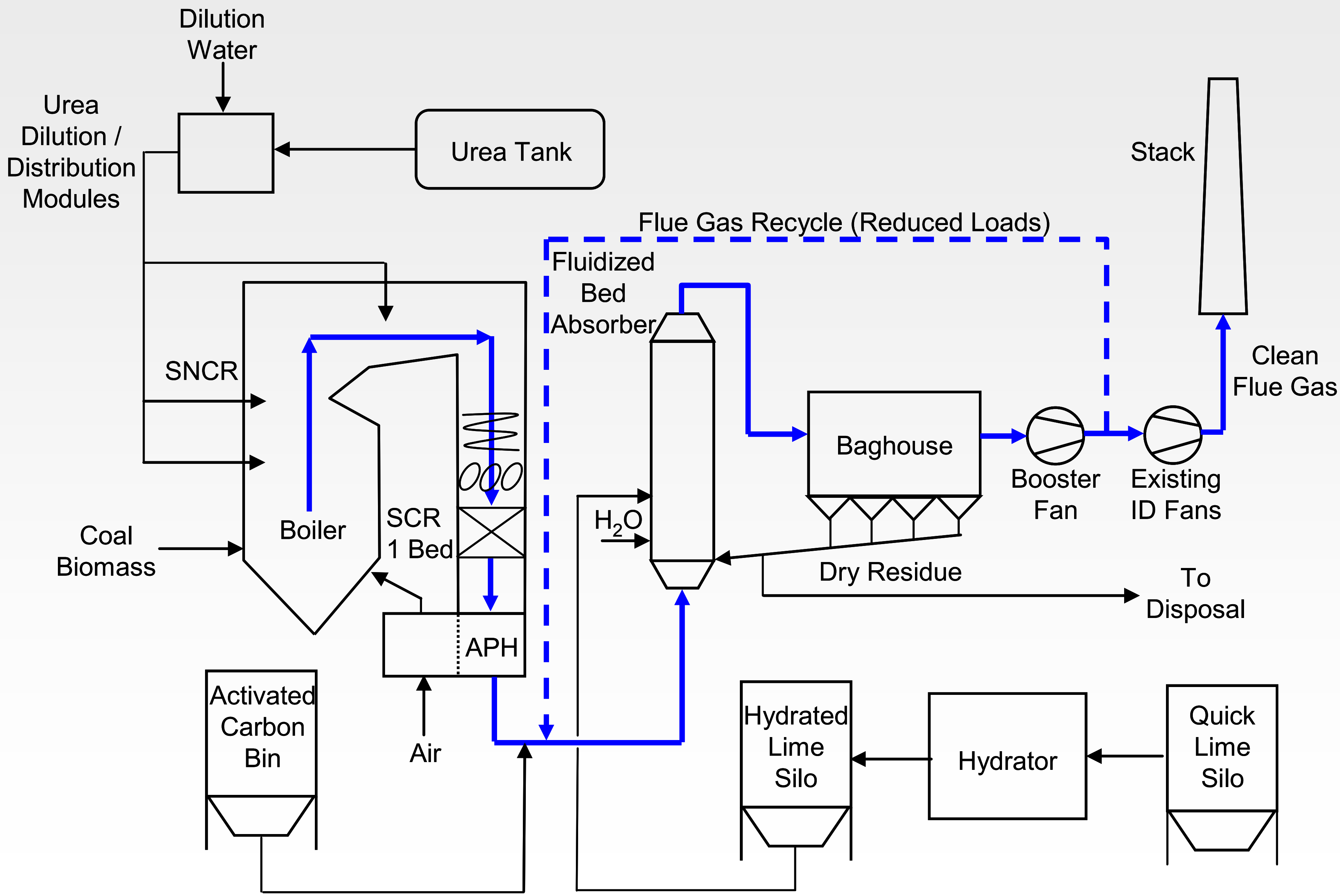
# Existing U.S. Coal-Fired EGUs
## 50-300 $MW_e$

- ~ 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
  - State and federal
- 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 $MW_e$ (EIA net winter capacity)
- Reheat unit
- Boiler:
  - Combustion Engineering tangentially-fired, balanced draft
  - 780,000 lb/h steam flow at 1465 psig and 1005 $^{o}F$
- 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/high-sulfur coal to meet permit limit of 3.8 lb $SO_2$/mmBtu

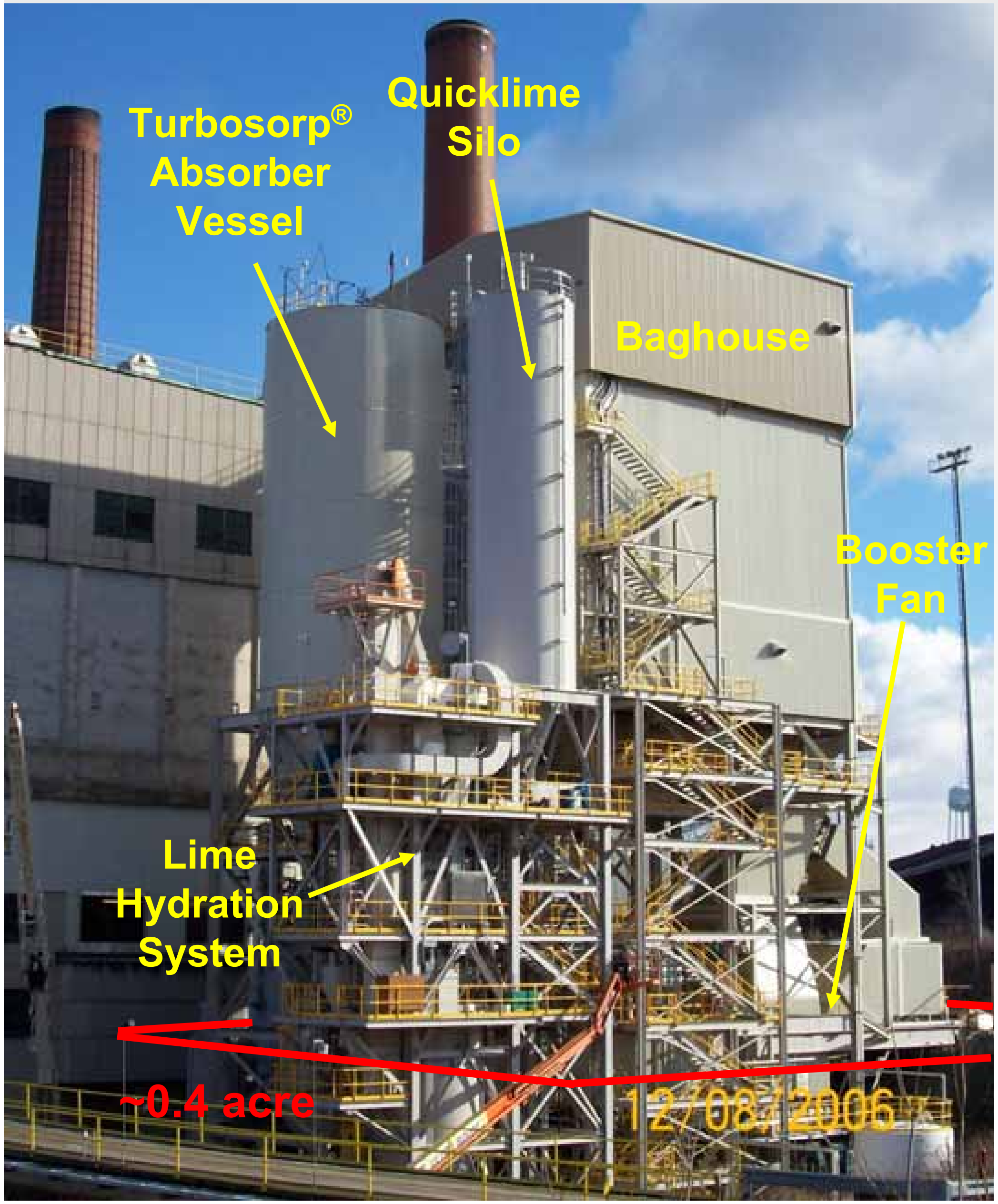
# Process Flow Diagram



# Hybrid $NO_x$ Control System

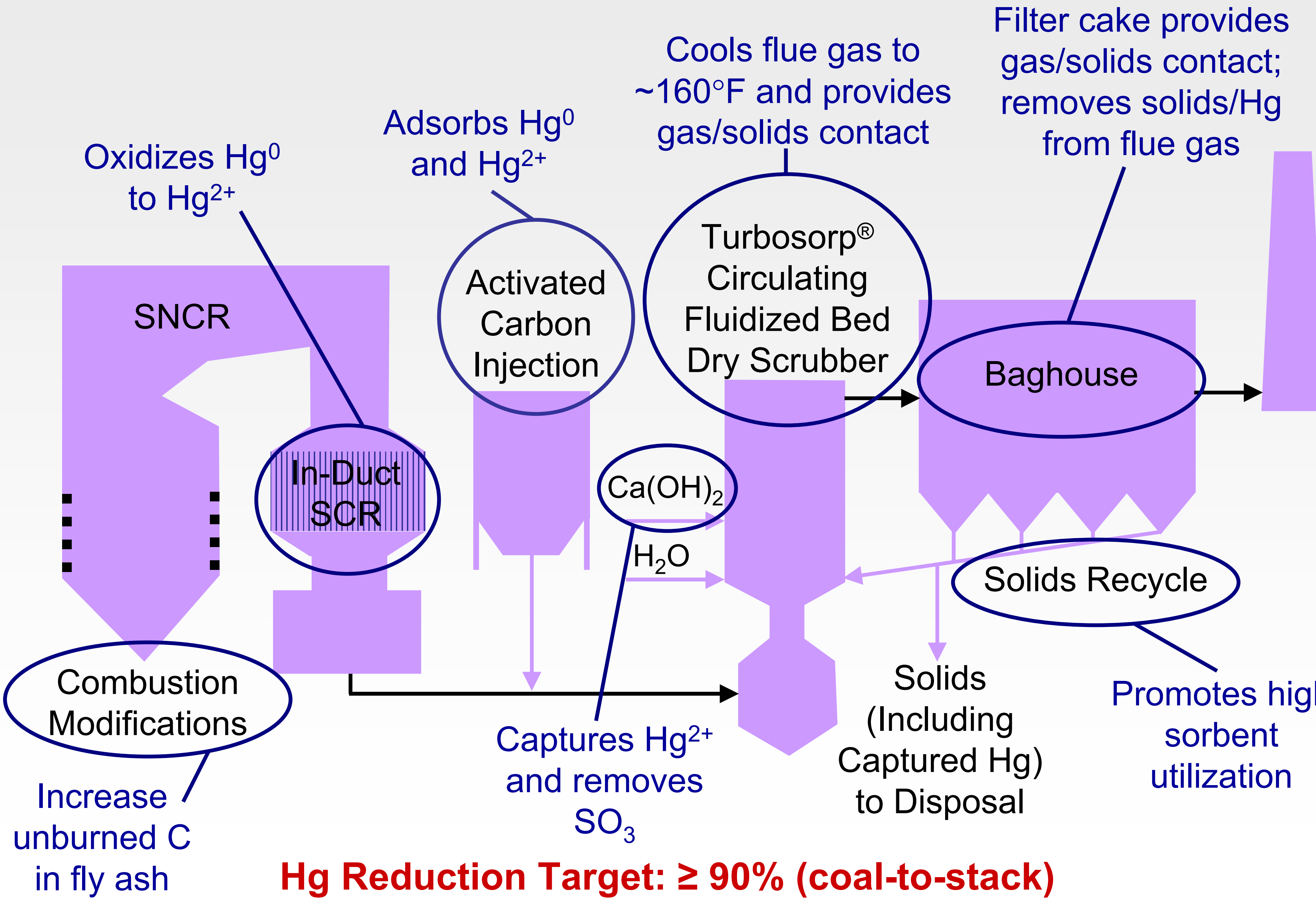
- Combustion Modifications
  - Low-$NO_x$ burners, SOFA
  - Reduce $NO_x$ to 0.25 lb/mmBtu
- SNCR
  - Three zones of urea injection
  - Provide $NH_3$ slip for SCR ($NO_x$OUT CASCADE®)
  - Reduce $NO_x$ by ~ 42.5% (to 0.14 lb/mmBtu)
- SCR
  - Single catalyst layer (1.3 m)
  - Cross section = 45’ x 14’
  - Fed by $NH_3$ slip from SNCR
  - Reduce $NO_x$ by ≥ 30% (to ≤ 0.10 lb/mmBtu)

# Turbosorp® Circulating Dry Scrubber




- Completely dry
- Separate control of hydrated lime, water, and recycled solids injection
- High solids recirculation
- Small footprint
- Carbon steel construction
- No wet stack
- Few moving parts
- Projected Ca/S is 1.6-1.7 mol/mol for design fuel

# Design Features for Mercury Control




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

# Guarantee Testing Results

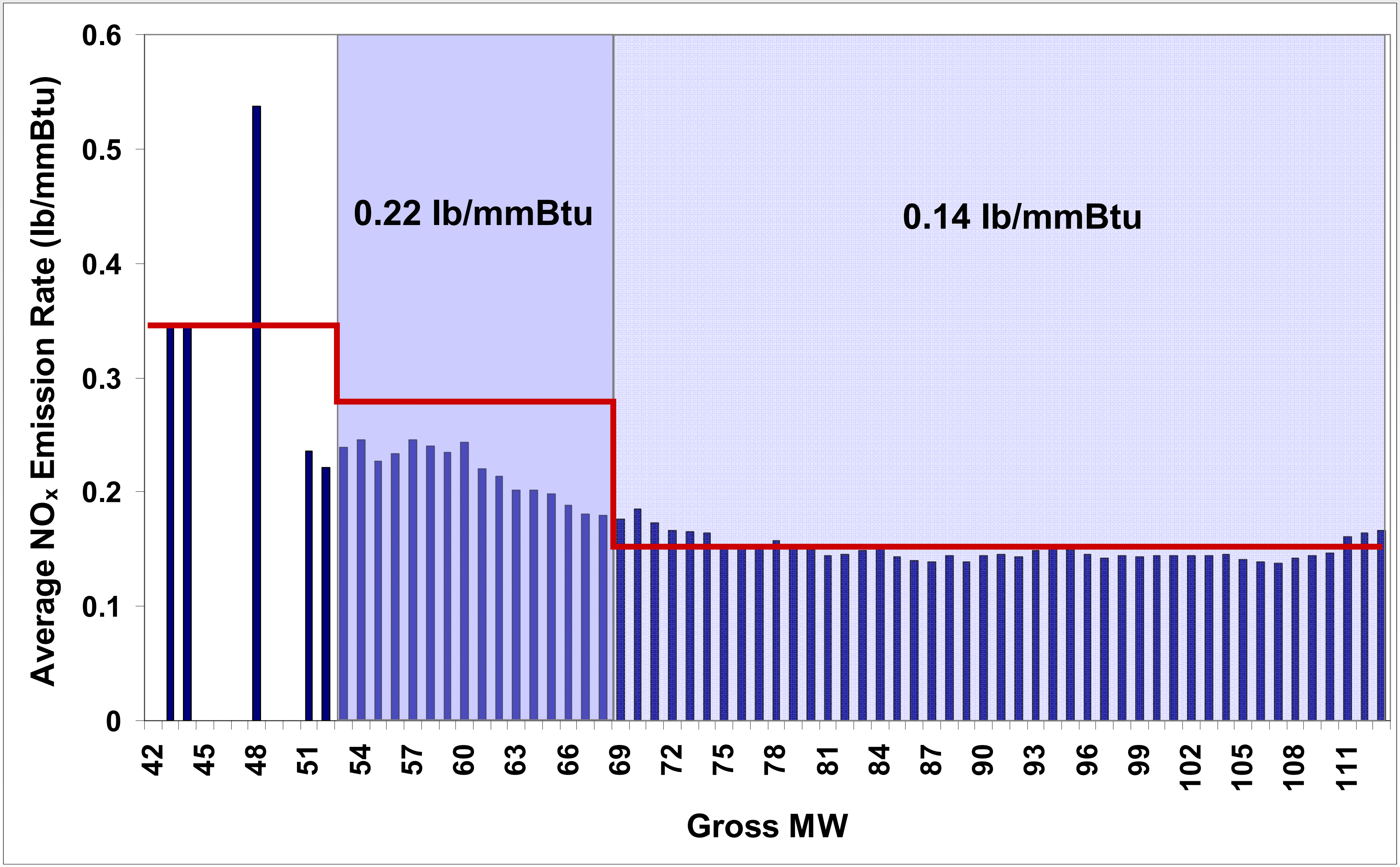
## March-May 2007, 2.4-3.2% Sulfur Eastern U.S. Bituminous Coal

| Parameter | Performance Target | Measured Performance |
|---|---|---|
| $NO_x$ emission rate | ≤ 0.10 lb/mmBtu | 0.10 lb/mmBtu |
| $SO_2$ removal | ≥ 95% | 96% |
| Hg removal<br>Activated C Injection<br>No Activated C Injection | ≥ 90% | <br>≥ 94%<br>≥ 95% |
| $SO_3$ 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.**

# $NO_x$ Emissions vs. Load

## January - June 2008

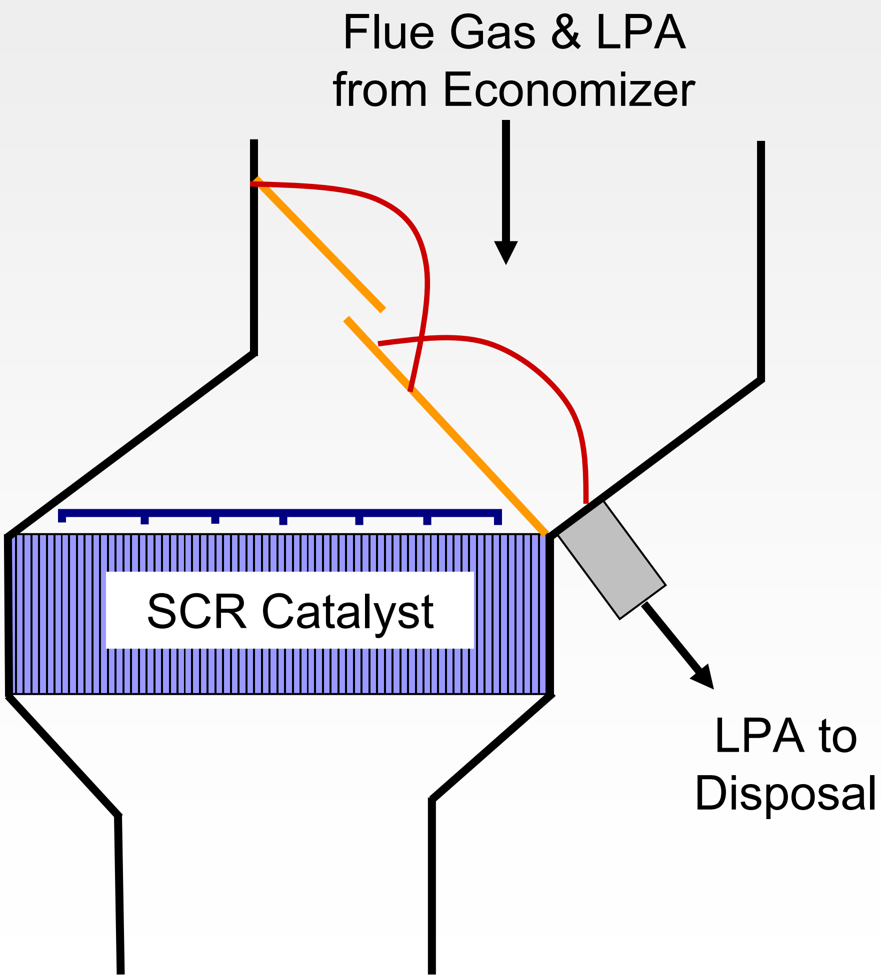


# Large Particle Ash

## The Problem

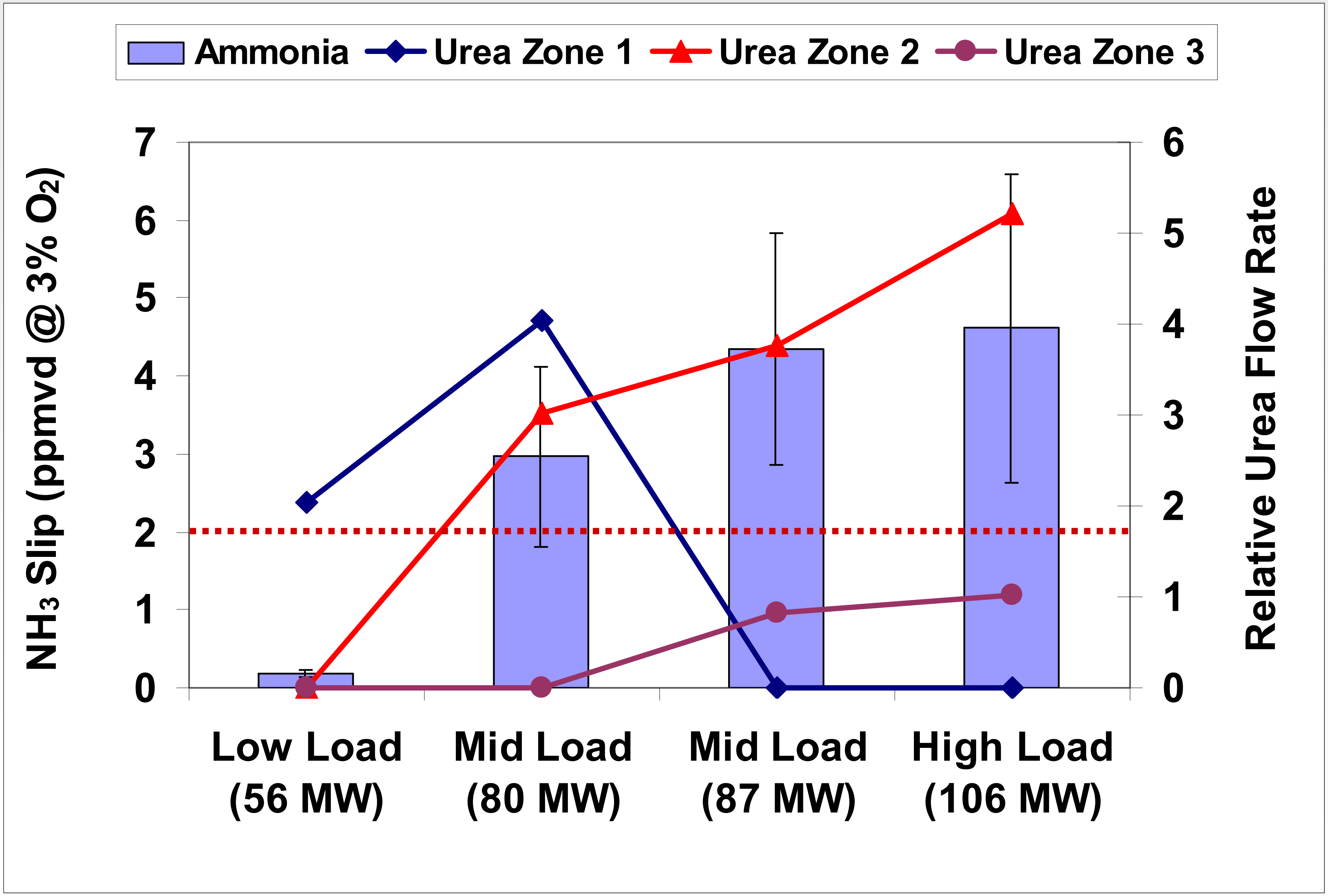
- More pressure drop
- Less $NO_x$ removal
- More urea consumption
- More ammonia slip

## The Solution



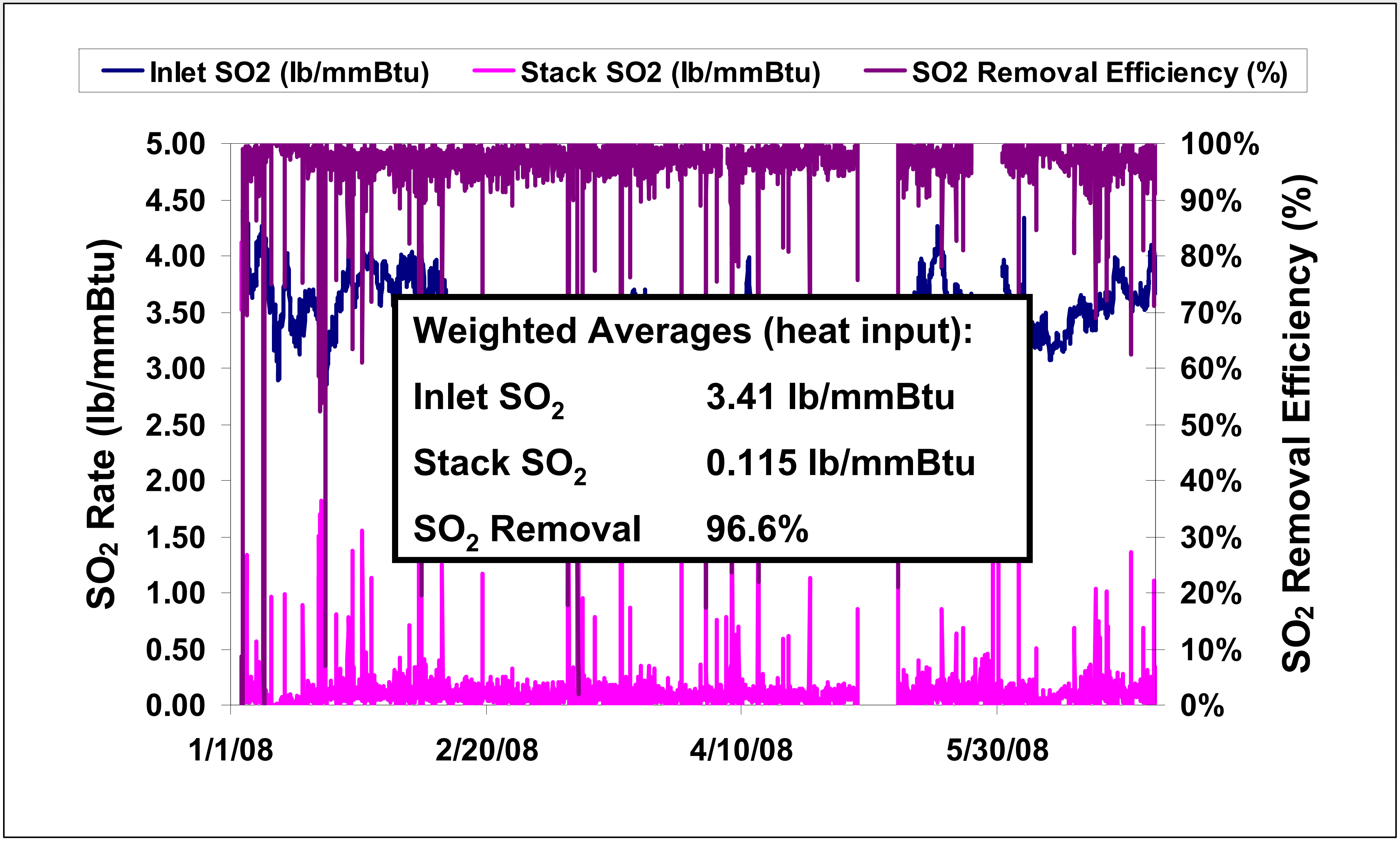
# Ammonia Slip Parametric Testing

## Nov 2007 / May 2008, EPA CTM 027, Air Heater Inlet



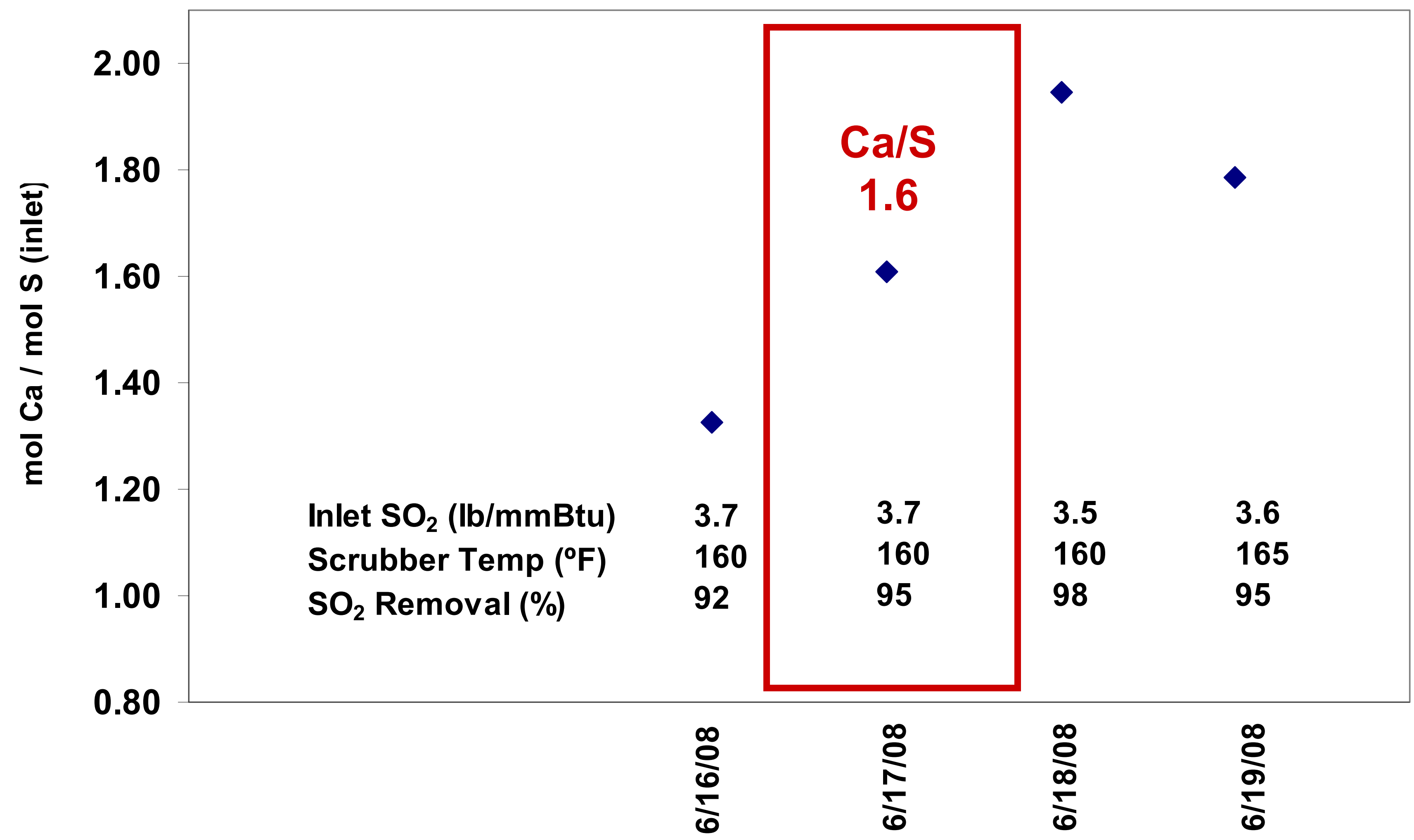
# $SO_2$ Removal Performance

## January - June 2008



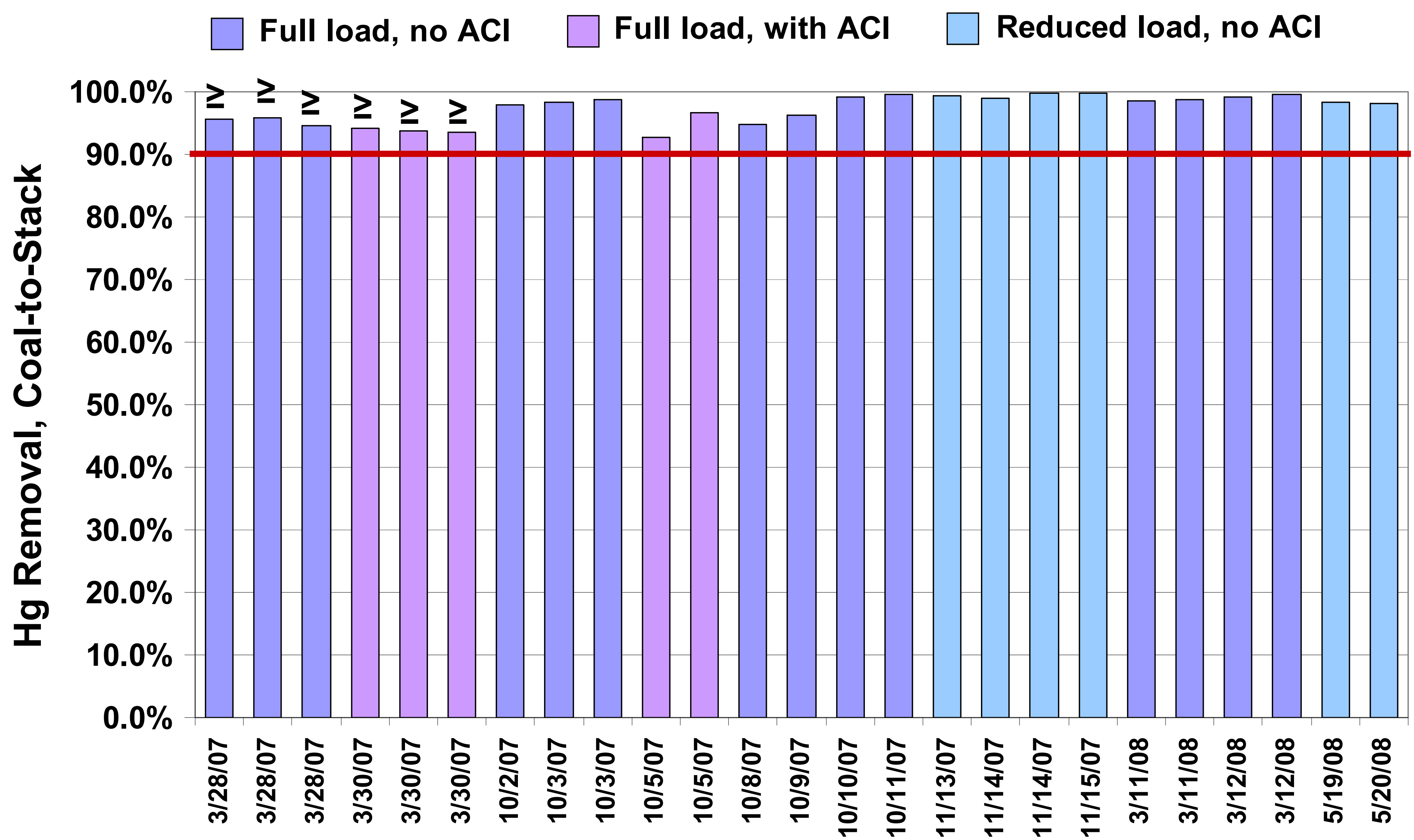
# Lime Utilization

## June 2008 Parametric Testing



# Mercury Testing Results

## Ontario Hydro Method



# $SO_3$ Testing Results

## Controlled Condensation Method

Summary Data from 42 Tests
May 2007 - June 2008

| | **Scrubber Inlet, ppmvd @ 3% $O_2$** | **Stack, ppmvd @ 3% $O_2$** | **Removal Efficiency, %** |
|---|---|---|---|
| Average | 14.1 | 0.7 | 95.3 |
| Range | 4.7 – 28.7 | 0.1 – 1.7 | 78.8 – 99.4 |

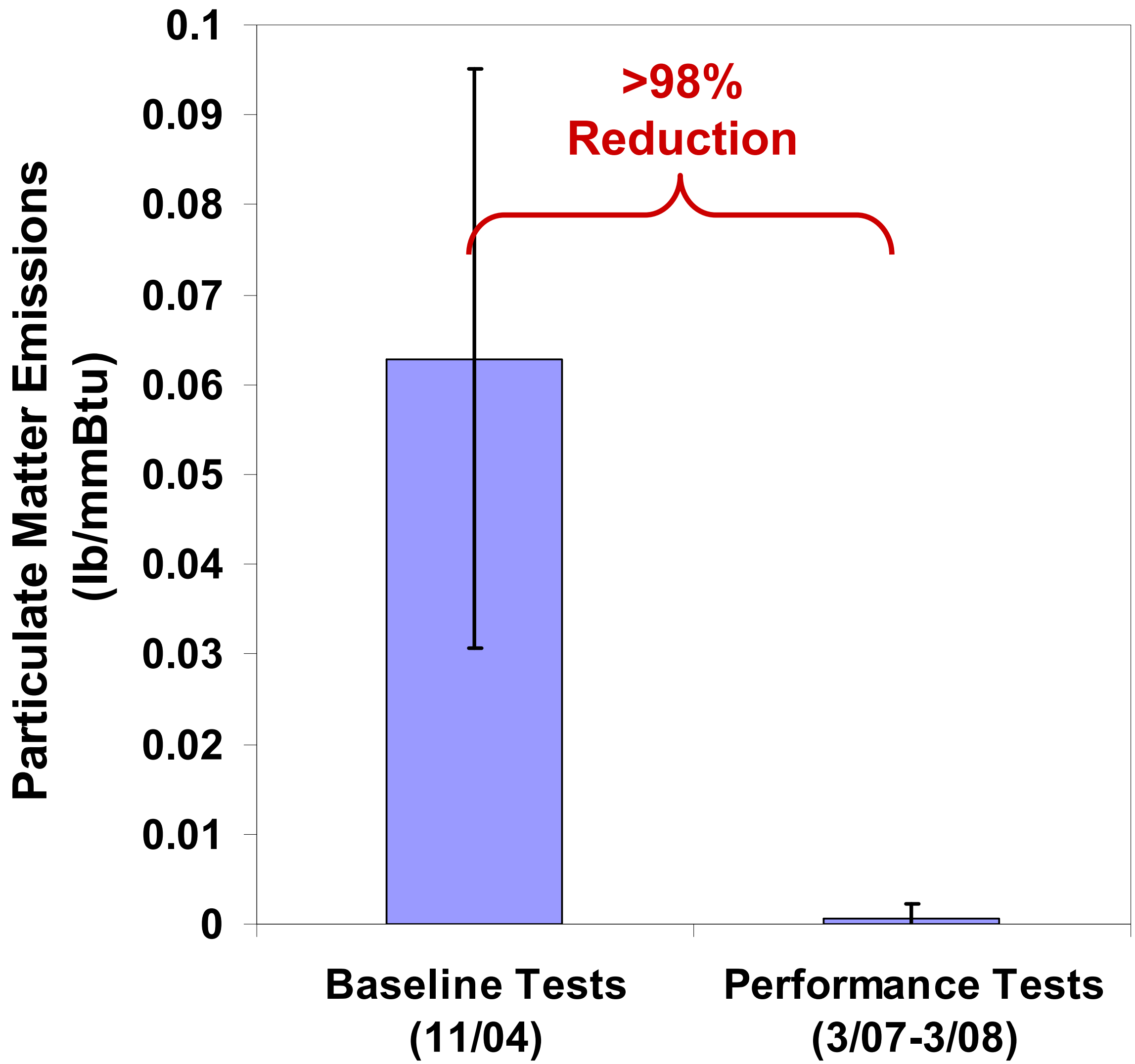
# HCl Testing Results

## U.S. EPA Method 26A

Summary Data from 18 Tests
March 2007 - May 2008

| | Scrubber Inlet, ppmvd @ 3% $O_2$ | Stack, ppmvd @ 3% $O_2$ | Removal Efficiency, % |
|---|---|---|---|
| Average | 36.9 | 1.4 | 96.2 |
| Range | 26.1 – 48.6 | 0.2 – 2.9 | 89.5 – 99.4 |

# Particulate Testing Results
## EPA Method 5/17, Full Load




**New baghouse significantly reduces particulate matter emissions relative to old ESP, in spite of increased particle loading from Turbosorp® scrubber**

Error bars represent ± 1 standard deviation

# Turbosorp® System O&M Experience

- O&M handled by existing plant staff
- Lime hydration system is most maintenance-intensive part
  - Use delivered / stored hydrated lime to allow offline maintenance
  - Most problems involve ball mill and classifier
- Had to add compressed air capacity to satisfy baghouse demand
- Flue gas recycle not used because of problems with reverse flow

- Occasional issues with plugging in the ash recirculation / disposal system
- No condensation issues in the scrubber or baghouse

# Process Economics

## AES Greenidge Unit 4 Design Case

**Constant 2005 Dollars**

| | EPC Capital Cost ($/kW) | Fixed & Variable O&M Cost ($/MWh) | Total Levelized Cost |
|---|---|---|---|
| $NO_x$ Control | 114[a] | 1.23 | $3,487 / ton $NO_x$ |
| $SO_2$ Control | 229[b] | 6.49 | $586 / ton $SO_2$ |

[a]Includes combustion modifications, SNCR, in-duct SCR, static mixers, and LPA removal system

[b]Includes scrubber, process water system, lime storage and hydration system, baghouse, ash recirculation system, and booster fan

Assumptions: Plant size = 107 MW net, Capacity factor = 80%, Coal sulfur = 4.0 lb $SO_2$/mmBtu, SNCR NSR = 1.35, Ca/S = 1.68, 50% Urea = $1.35/gal, Quicklime = $115/ton, Waste disposal = $17/ton, Internal COE = $40/MWh, Plant life = 20 years, Fixed charge factor = 13.05%, AFUDC = 2.35%, Other assumptions based on Greenidge design basis, common cost estimating practices, and market prices

# Summary

## Results from AES Greenidge Unit 4 (107 MW)

- EPC capital cost = \$343/kW (2005)
- Footprint < 0.5 acre
- Performance tests have consistently shown:
  - ≥ 95% $SO_2$ removal (for coals up to 4.9 lb $SO_2$ / mmBtu)
  - ≥ 95% Hg removal (no activated carbon required)
  - PM emissions < 0.001 lb / mmBtu
  - Very low emissions of $SO_3$ and HCl


- $NO_x$ emission profile significantly improved
- O&M handled by existing plant staff
- Plant continues to operate profitably (20-30 year life extension)
- Commercial viability demonstrated after a year of operation

# Disclaimer