The Greenidge Multi-Pollutant Control Project:

Key Technical and Economic Features of a New Approach for Reducing Emissions from Smaller Coal-Fired Units

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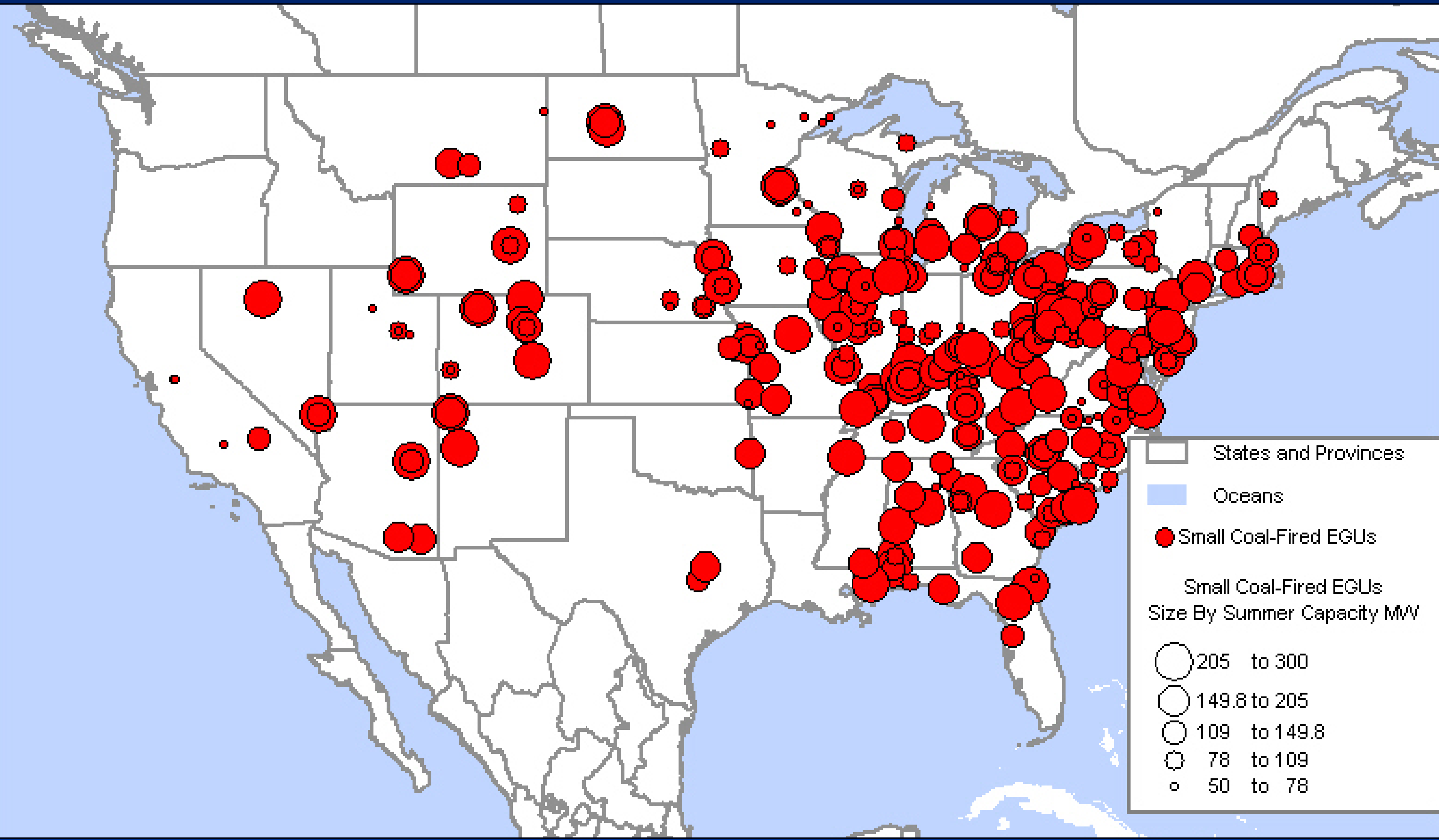
A&WMA Annual Conference & Exhibition, June 27, 2007, Pittsburgh, PA

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, SO_2, mercury, acid gases (SO_3, 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

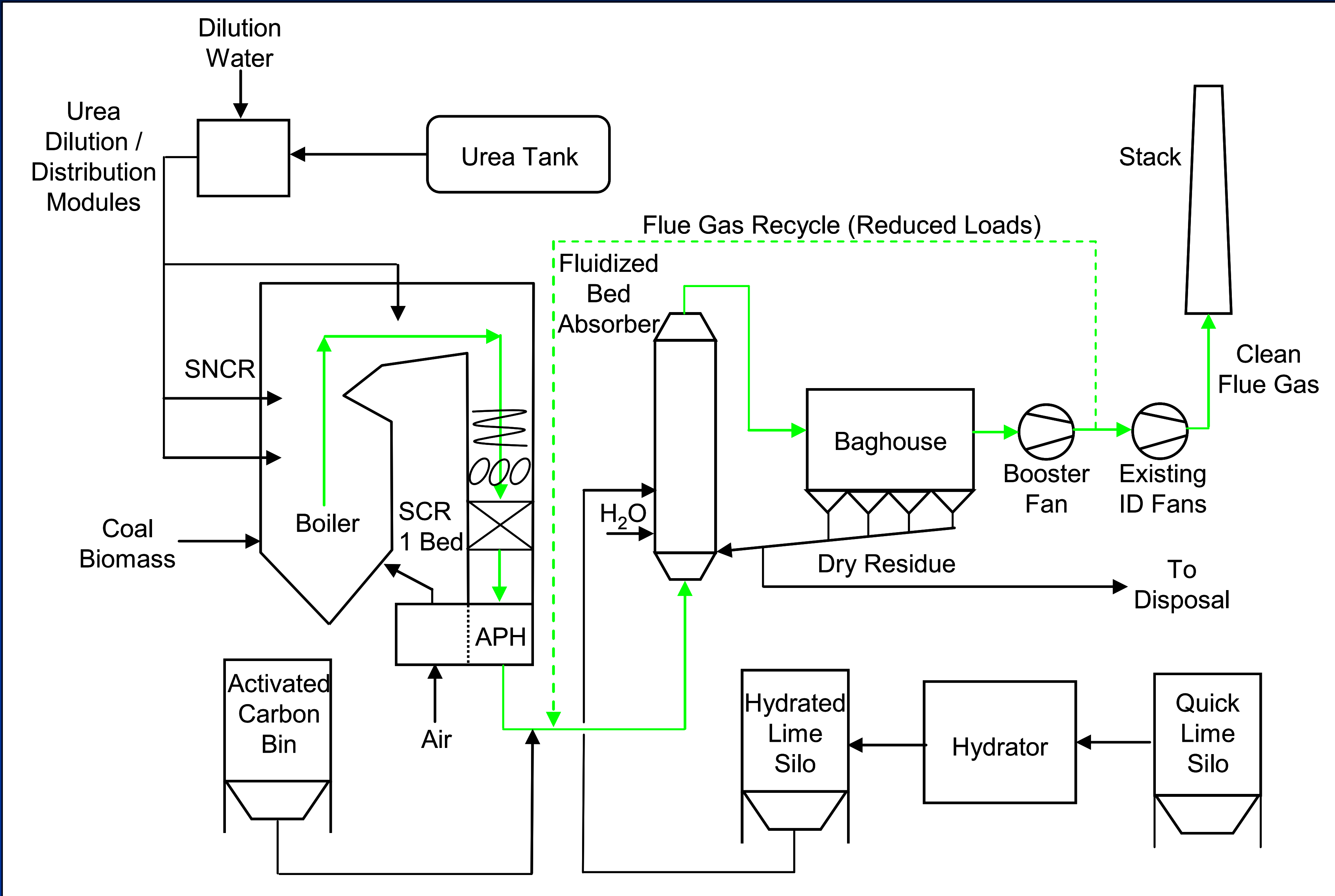
AES Greenidge Unit 4
(Boiler 6)

- 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 ^{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-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



Performance Targets

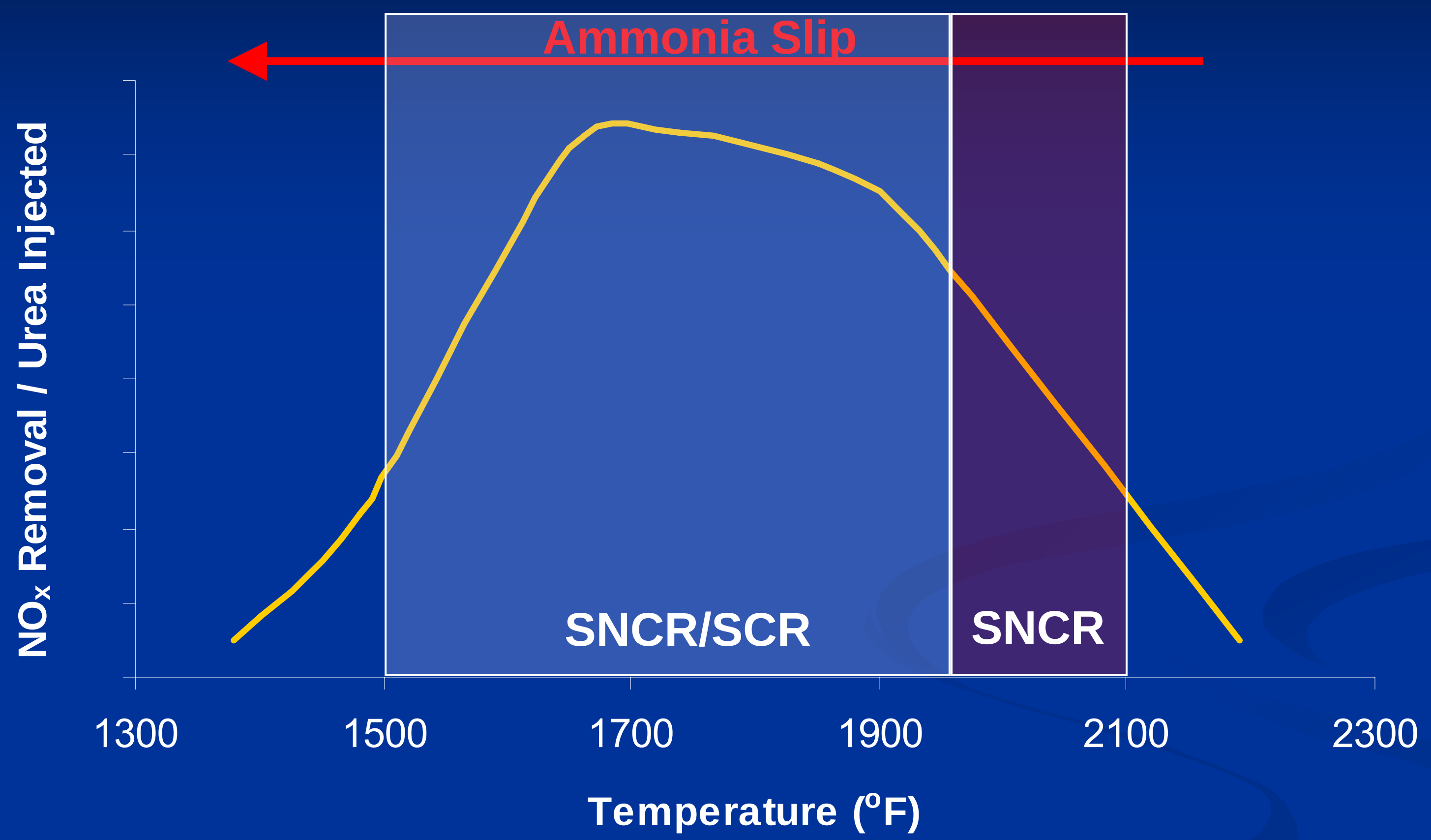
Fuel: 2-4% sulfur bituminous coal, up to 10% biomass

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

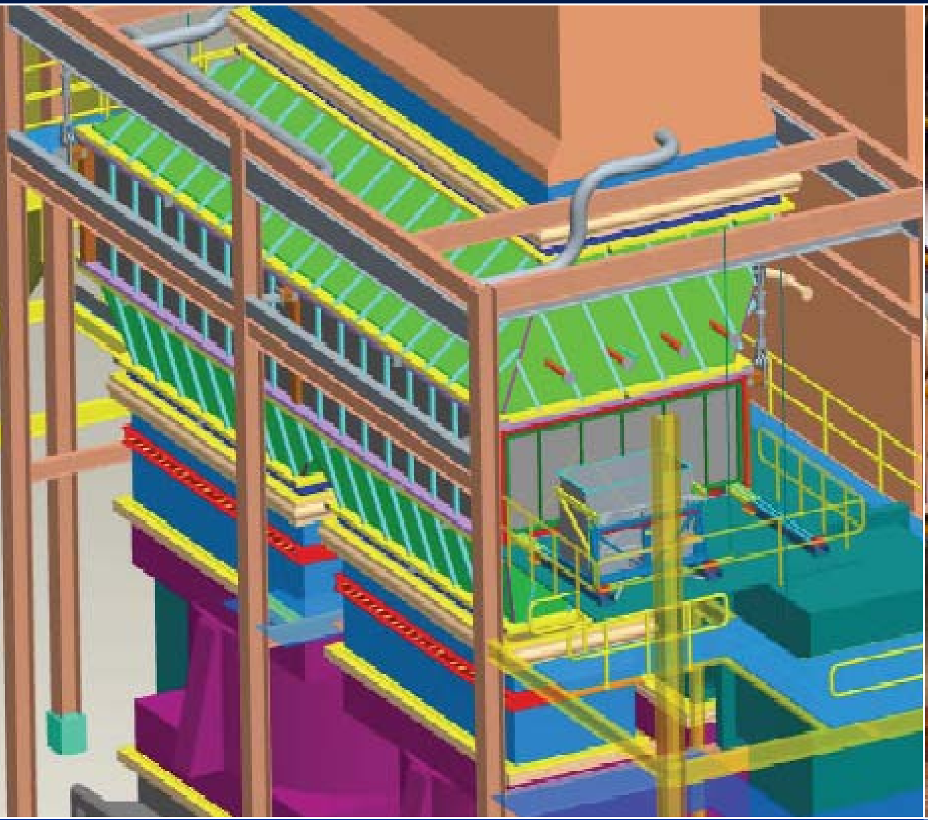
- Combustion Modifications
  - Replace coal, combustion air, and overfire air nozzles
  - Improve fuel/air mixing, burner exit velocity, secondary airflow control, and upper furnace mixing; reduce CO
  - Reduce NO_x to 0.25 lb/MMBtu
- SNCR
  - Three zones of urea injection
  - Reduce NO_x by ~ 42.5% (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)

SNCR for Hybrid System



- SNCR operates at lower temperature than stand-alone SNCR
  - Enables greater NO_x reduction and better urea utilization by SNCR
  - Provides ammonia slip for additional NO_x reduction by SCR

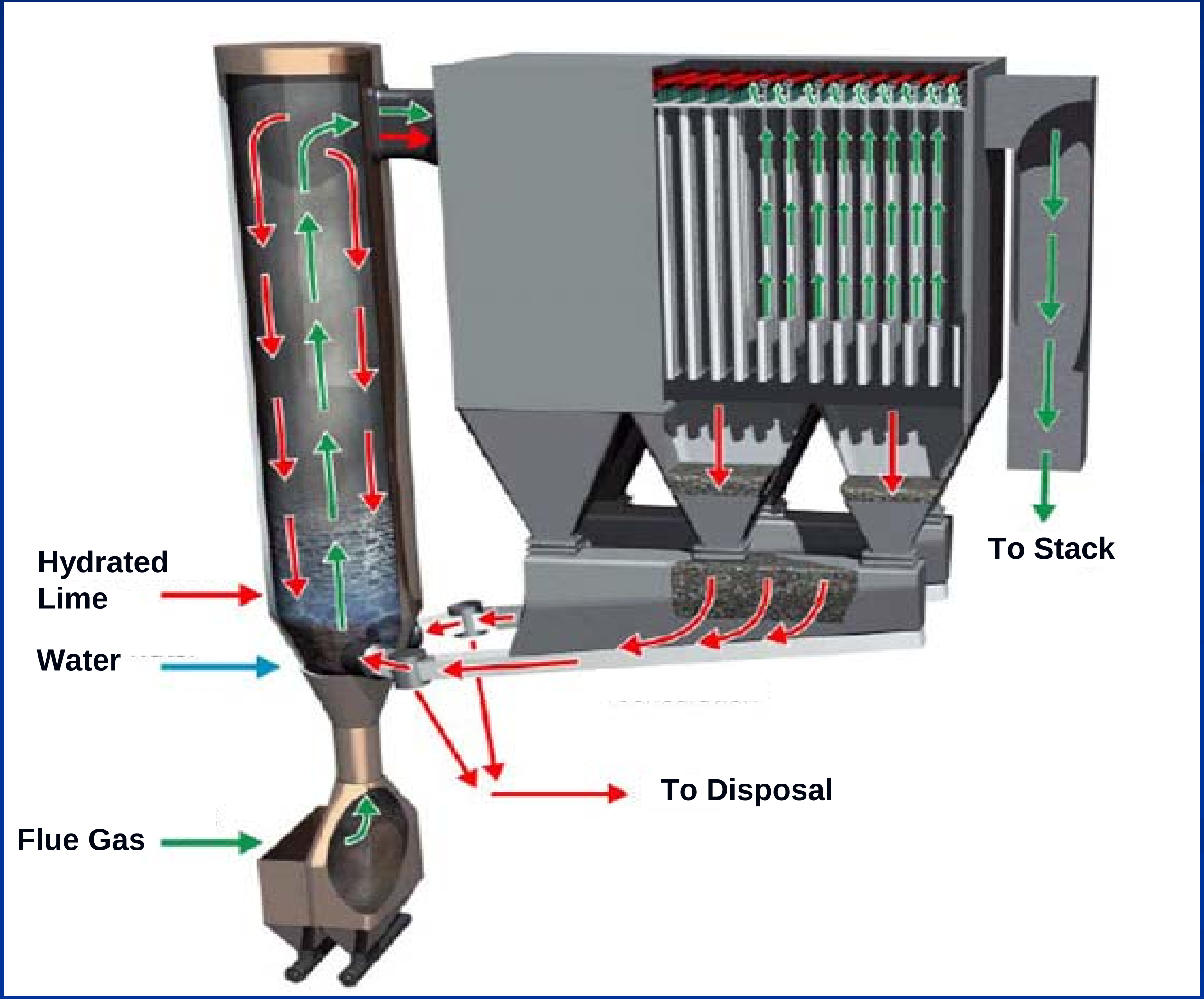
Single-Bed, In-Duct SCR



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

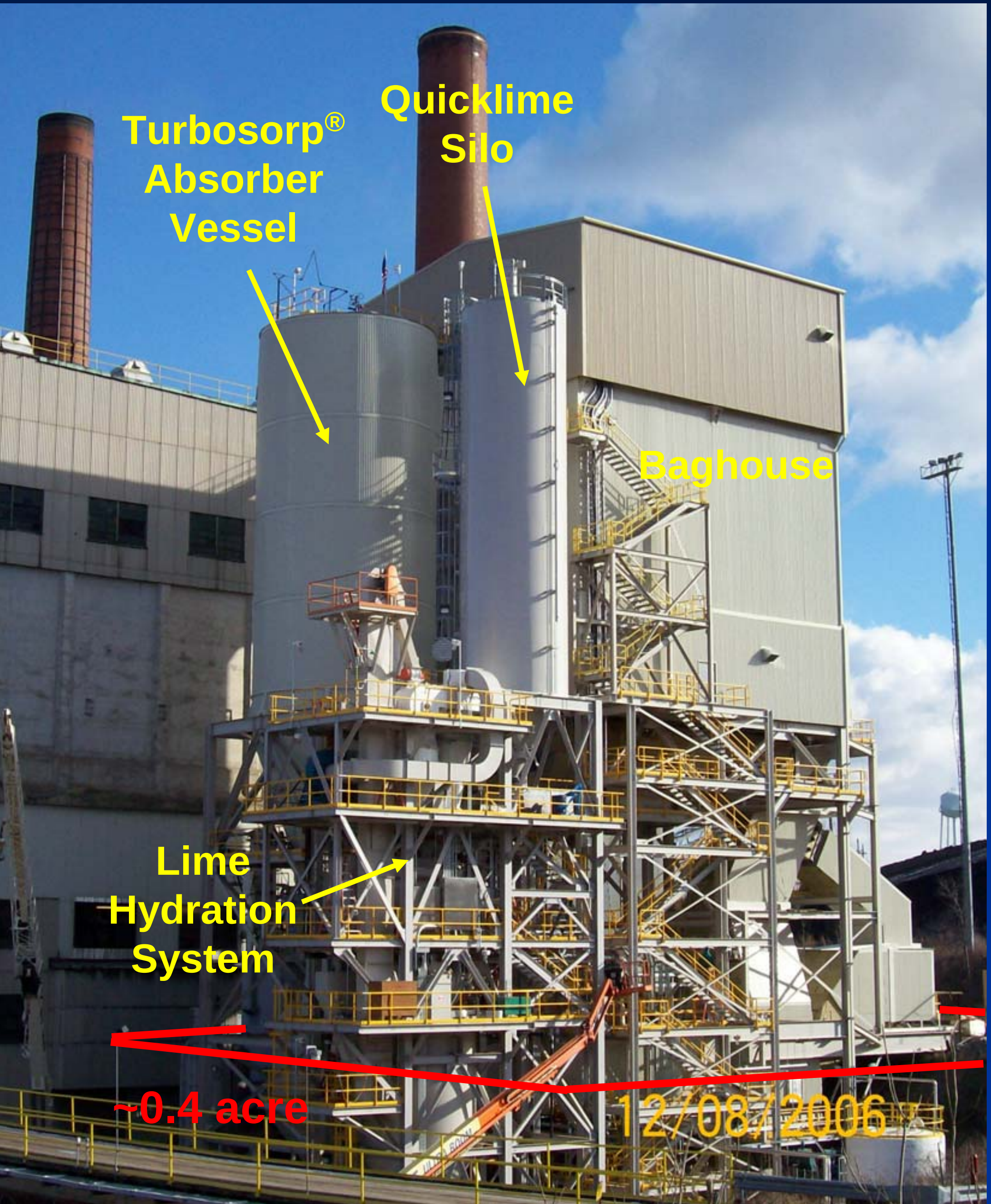
Turbosorp® Circulating Fluidized Bed Dry Scrubber



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 SO_3 removal
- Less maintenance requirements
  - Fewer moving parts
  - No slurries
  - No dewatering

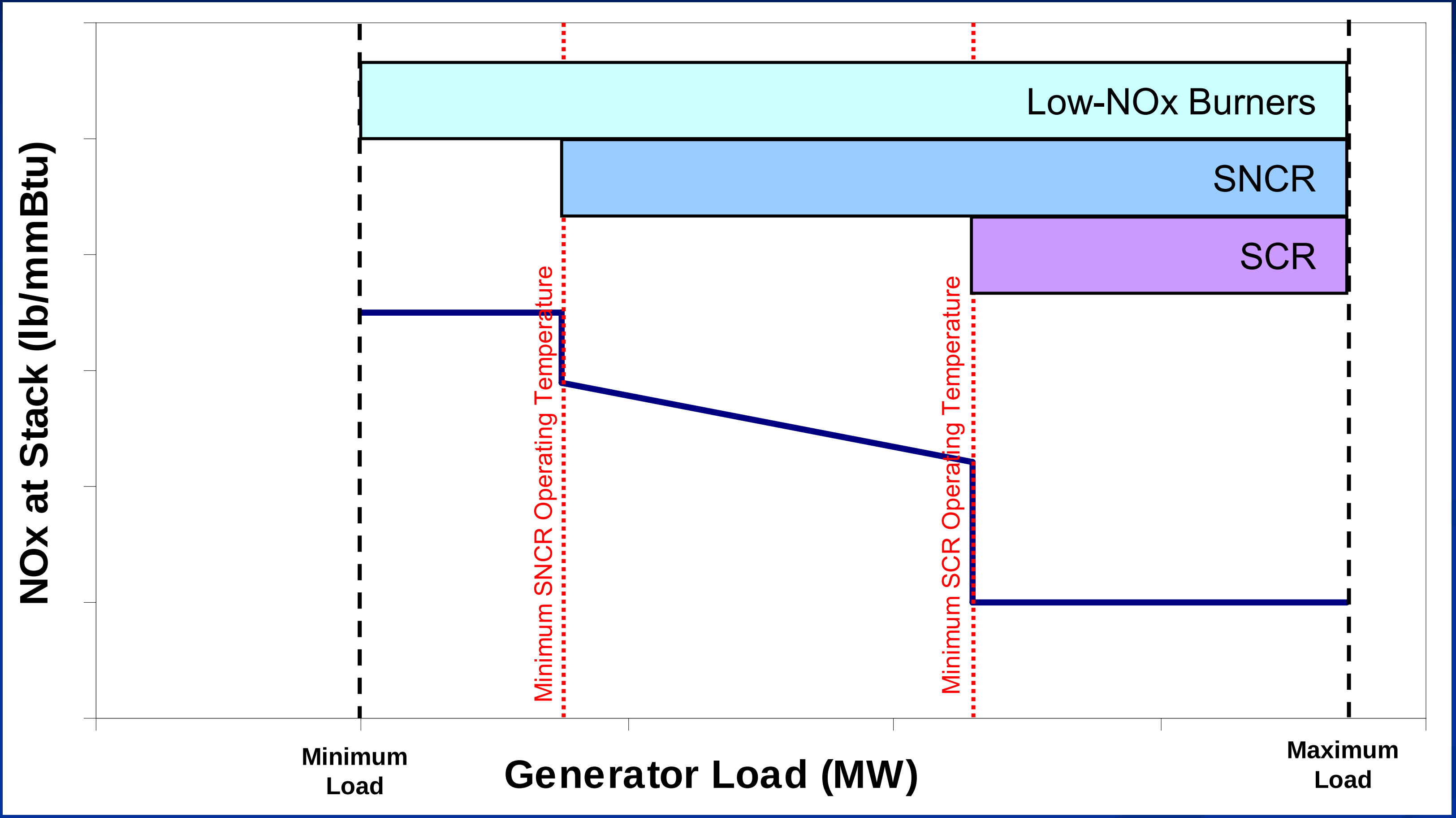
Mercury Control

- System design favors high baseline Hg removal without activated carbon injection
  - Hg oxidation across in-duct SCR catalyst
  - Low temperature (~170 ^{o}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

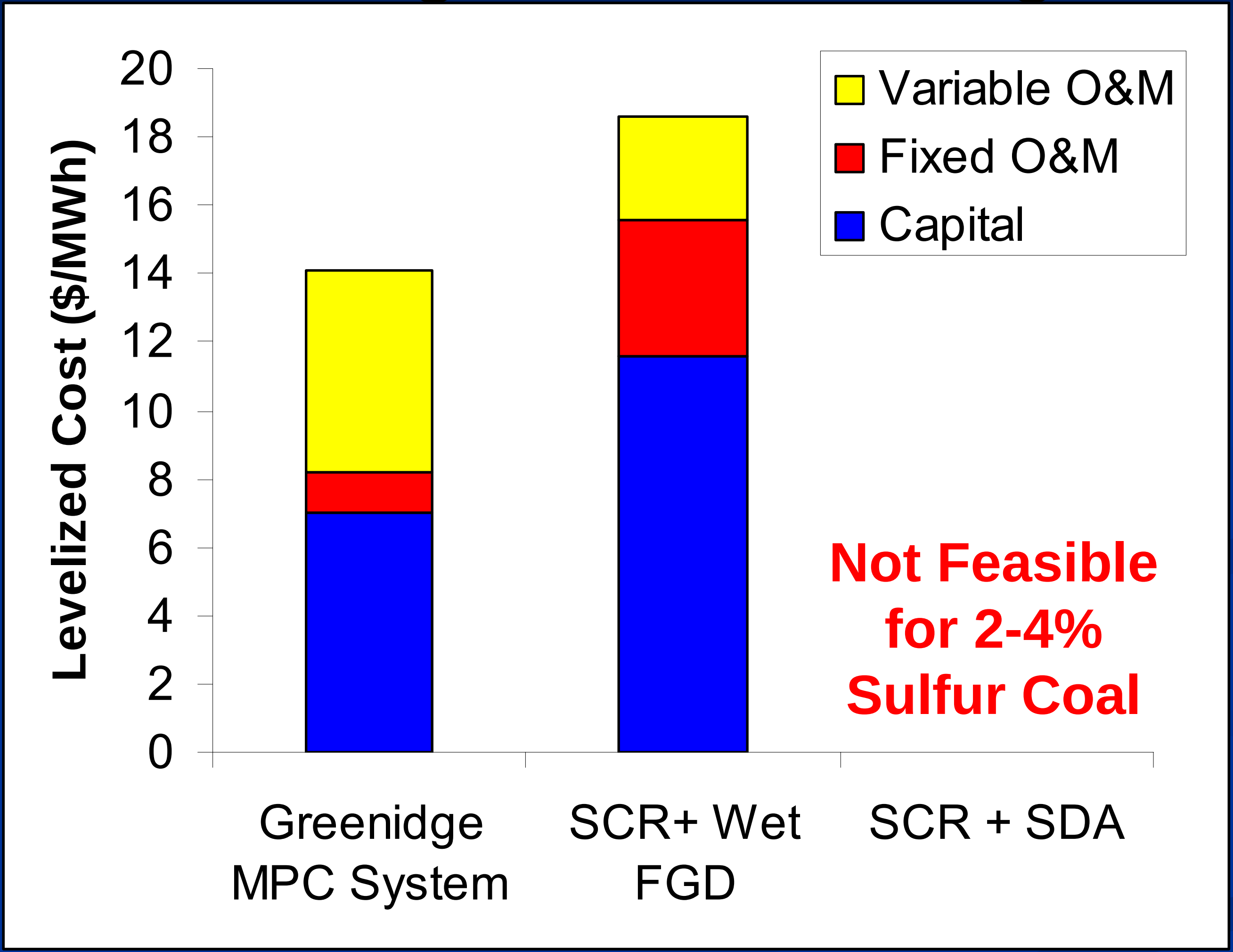
NOx Control



SO_2, Acid Gas, and Hg Control

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

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

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 SO_3 (and possibly Hg) removal performance
- Drawbacks of Greenidge multi-pollutant control system relative to SCR / wet FGD
  - Slightly lower NO_x and SO_2 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%	
Without ACI		≥ 95% (Ontario Hydro, 3/28/07)
With ACI		≥ 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% O_2
  - Measured values have been 2-5 ppmvd @ 3% O_2
  - 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
  - SO_2 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 SO_2 removal efficiencies

Disclaimer