Impact of EPA Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) on Regional Coal Markets

Electric Power Generation Association

September 2005

Preface to Presentation That Follows

- Clear Skies legislation
  - Defeated by a 9/9 vote in March in the Senate Environment and Public Works Subcommittee
  - Combined SO_2, NOx, and mercury reductions in one bill
  - Would have provided more certainty than regulations
  - Would have reduced potential for litigation
  - Reduced states "opt-out" rights
- Relationship to CAIR and CAMR rule
  - Emission reductions similar to Clear Skies
  - Litigation initiated but qualitative conclusions should not change regardless of outcome
  - Assumption of our analysis is that states follow rules as presented
    - Few "opt-out"

EPA Regulations Promulgated

- Clean Air Interstate Rule (CAIR) - March 10, 2005
  - Applies to mostly eastern and Midwestern states
  - Reduces allowable SO_2 emissions starting 2010
  - Reduces allowable NOx emissions starting 2009
  - Proposed Cap and Trade approach to reductions
- Clean Air Mercury Rule (CAMR) - March 15, 2005
  - First nationwide mercury limits applied to U.S. power plants
  - Limits emissions to 38 tons in 2010
  - Limits emissions to 15 tons in 2018
  - Proposed Cap and Trade approach to reductions

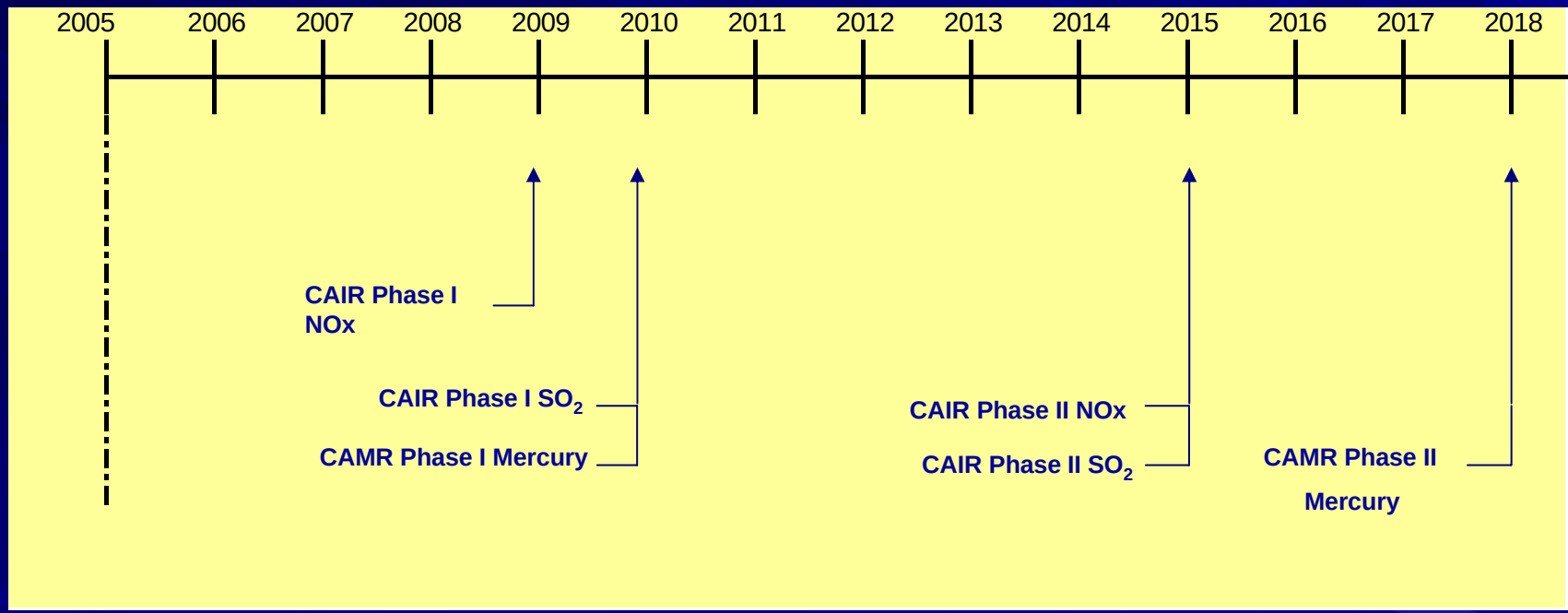
These rules need to be assessed collectively.

Environmental Control Technologies

- NO_x control technology
  - Selective Catalytic Reduction (SCR) systems
- SO_2 control technology
  - Flue Gas Desulfurization (FGD) systems (scrubbers)
- Mercury specific control technology
  - Still being developed
    - Commercially available after 2010
  - Probably activated carbon injection

Technology for SO_2 and NO_x control is well established while technology for mercury control is still being developed.

Regulation Implementation Timeline



Phase I implemented in less than five years.

Clean Air Interstate Rule (CAIR)

Clean Air Interstate Rule

- Affects sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emission limits, mostly in states east of Mississippi River
- SO_2 limits vs 2003 emissions
  - 45 % reduction in 2010
  - 57 % reduction in 2015
  - 73% at full compliance
  - 23 states affected
- NO_x limits vs 2003 emissions
  - 53 % reduction in 2009
  - 61 % reduction in 2015
  - 25 states affected
- Trading program to achieve limits

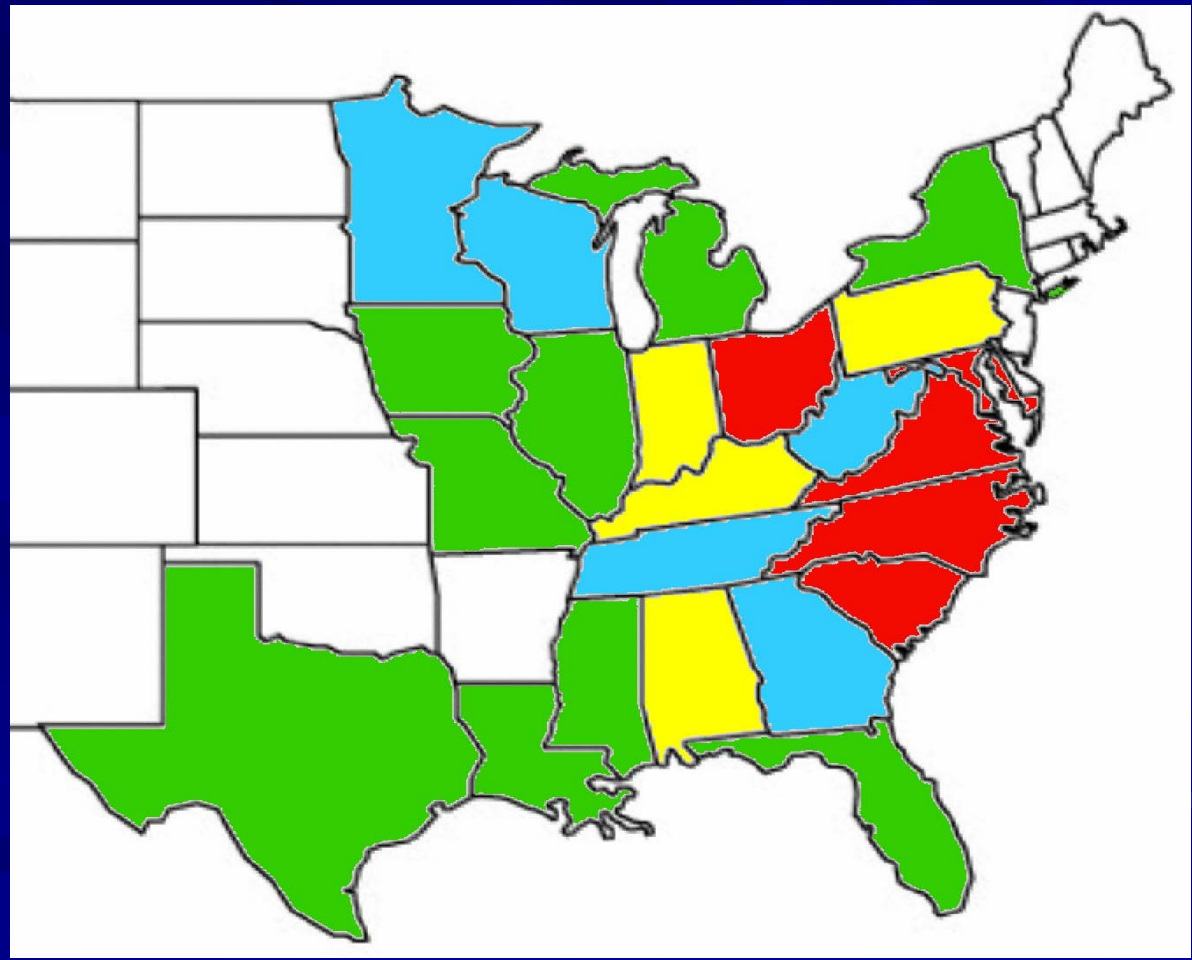
CAIR requires substantial reductions in SO_2 and NO_x emissions

Sulfur Dioxide Reductions Required

SO_2

- < 50%
- 50-60%
- 60-70%
- > 70%

Reductions from 2003 levels by 2010

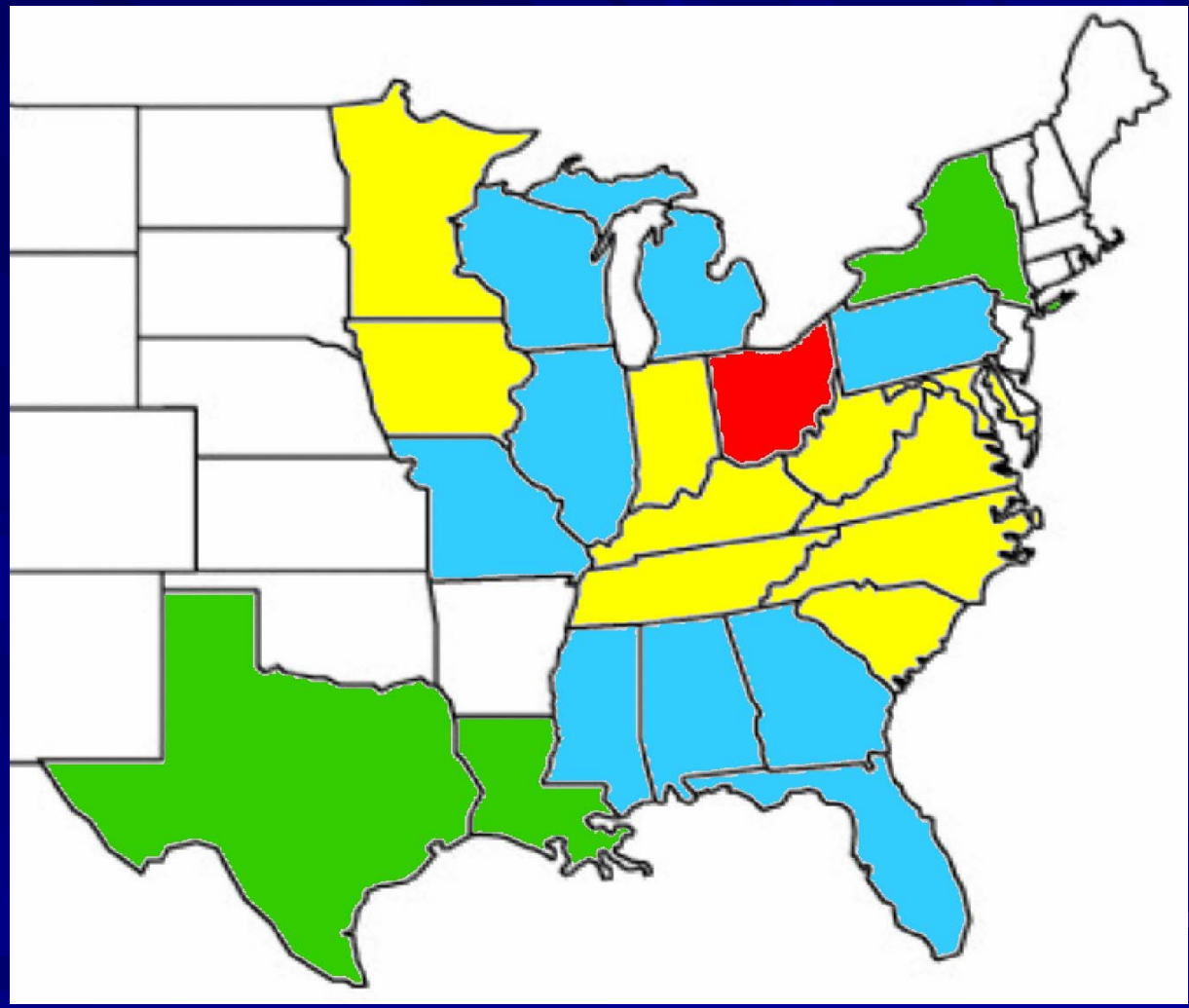


Nitrogen Oxide Reductions Required

NOx

- < 50%
- 50-60%
- 60-70%
- > 70%

Reductions from 2003 levels in 2009



States subject to annual NOx reductions shown above

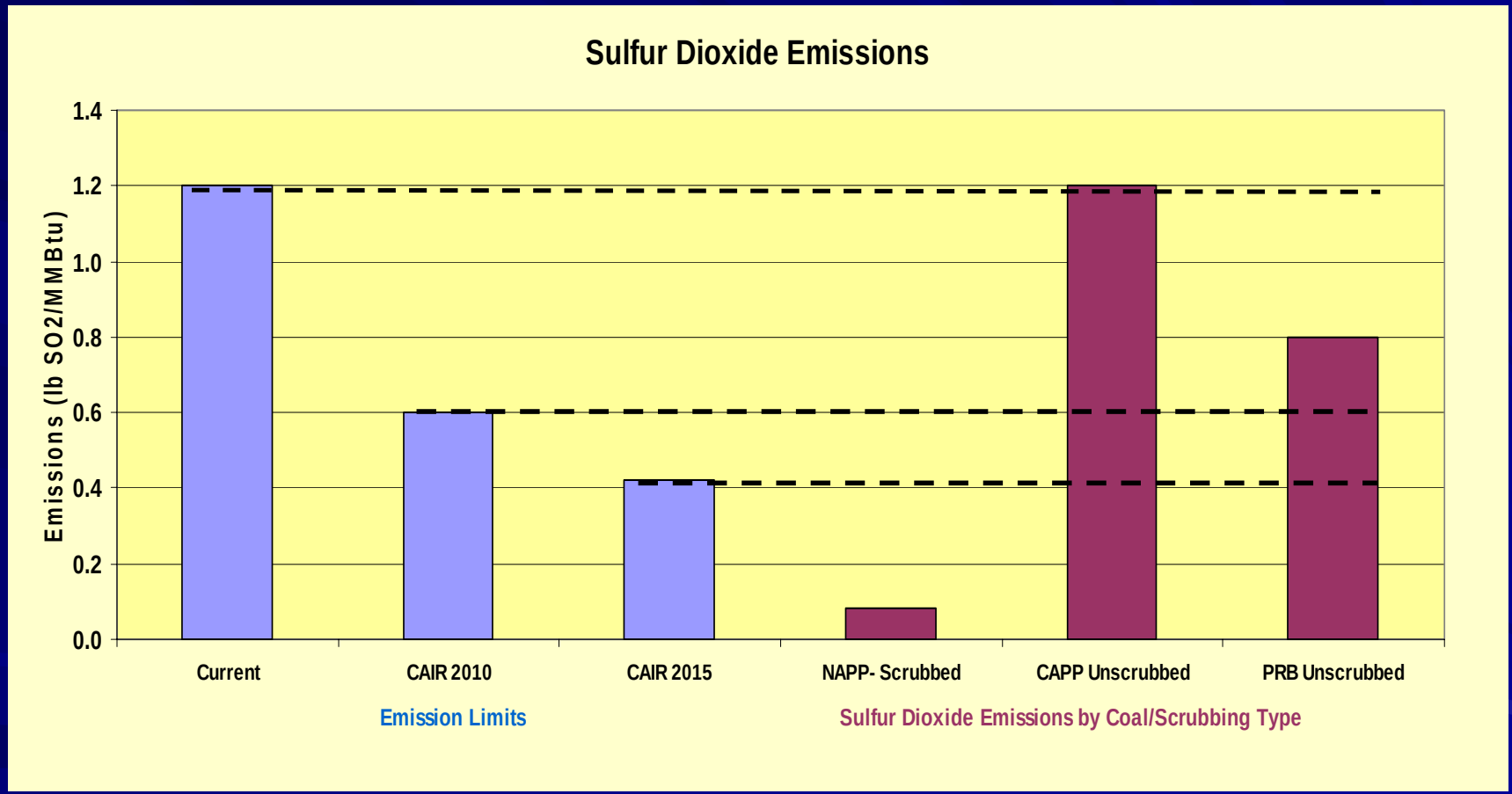
Five states have only ozone season emission caps: AR, CT, DE, MA, and NJ

Sulfur Dioxide Reductions

	Allowance Allocations		% Reduction
	CAIR Affected States	Nationwide	CAIR Affected States
Current Allowance Allocation 2010 (mm tons)	7.3	8.95	-
Post CAIR Allowance Allocation 2010 (mm tons)	3.7	5.3	50%
Post CAIR Allowance Allocation 2015 (mm tons)	2.5	4.2	65%

	Projected Actual Emissions	
	CAIR Affected States	% Reduction
2003 Emissions	9.56	-
Projected 2010 Emissions	5.26	45%
Projected 2015 Emissions	4.16	57%
Ultimate (2018 ?)	2.5	73%

"Compliance" Coal Concept Disappears



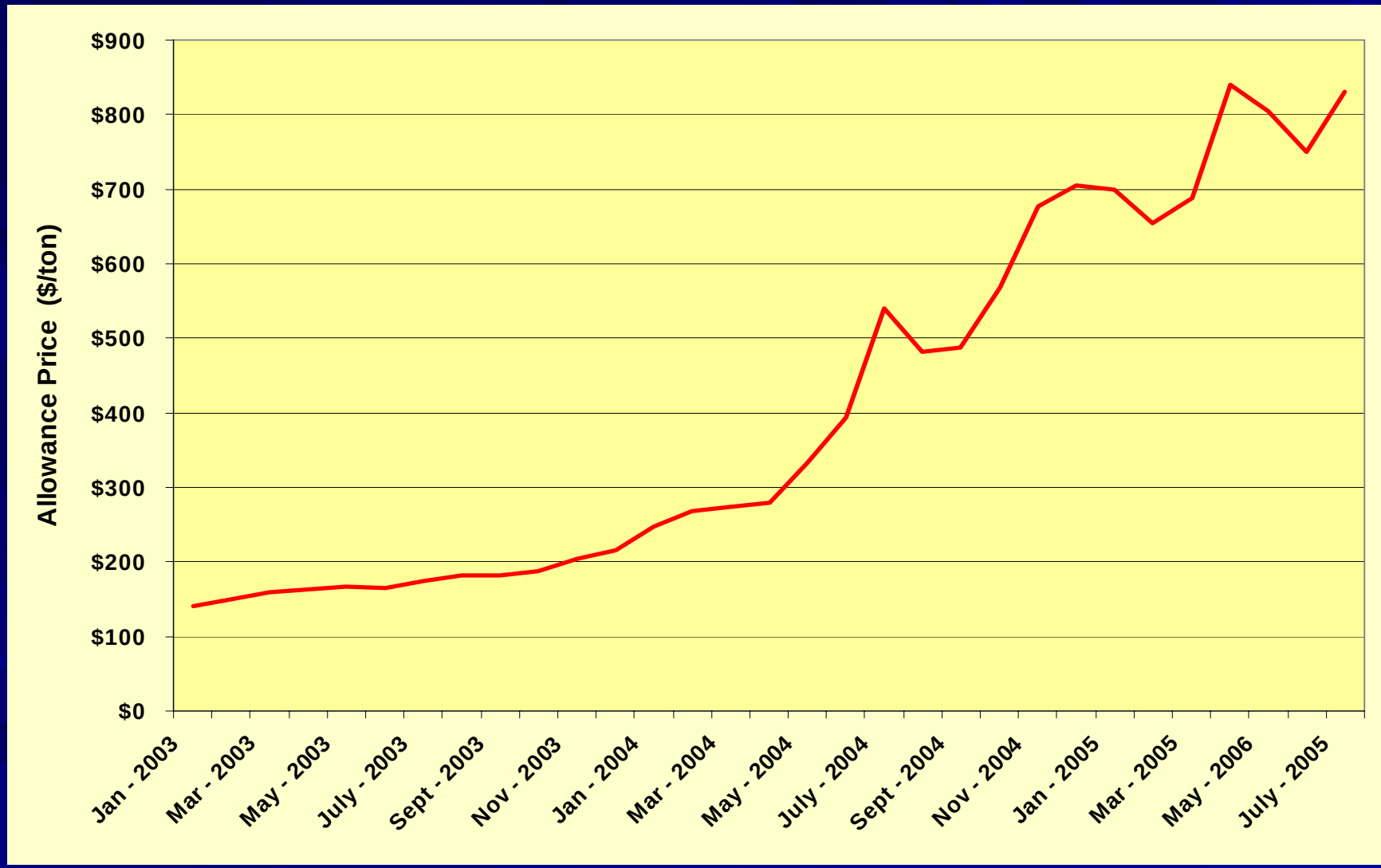
Compliance requires scrubbing.

All Allowances Are Not Created Equal

- The 1990 Clean Air Act Amendments created the SO_2 allowance trading program under Title IV
- One Title IV SO_2 allowance banked by 12/31/09 allows one ton of SO_2 to be emitted at any time in the future
- Two Title IV allowances created during 2010-2014 are required to emit one ton of SO_2 after 1/1/2010
- 2.86 Title IV allowances created after 2015 are required to emit one ton of SO_2 after 1/1/2015

Sulfur dioxide allowances generated before 2010 are more valuable than those generated afterwards, which creates an incentive for early scrubbing

SO_2 Allowance Price Trend



Economics Favor Scrubber Installations

- Levelized cost of installing scrubber ranges from $450 to $600/ton of sulfur dioxide removed
  - Includes capital
  - Includes operating costs
- 2005 SO_2 allowance prices range from $650-880/ton
- Costs of scrubbing are reduced when one considers dispatch benefits

Current allowance prices create a significant incentive to install scrubbers.

High SO_2 Allowances Prices Accelerating Scrubber Installation Schedules

Plant/Boiler	Original Scrubber Installation Date	Latest Scrubber Installation Date
Mitchell #1	2007	2006
Belews Creek #2	2008	2007
Allen #1,2,3,4,5	2011	2009
Cliffside #5	2009	2008
Brunner Island #3	2010	2008

"Utilities are moving up their scrubber installation dates to take advantage of the higher allowance prices"

McIlvaine E-Alert August 5, 2005

Scrubbers Proliferating

Projected Scrubber Retrofits Or New Units with Scrubbers
Cumulative Total East of Mississippi River, MW (000)

Generator	Plant	2005	2006	2007	2008	2009	2010	2011	2012
AES	Greenidge #4; Harding #7		108	543	543	543	543	543	543
American Electric Power	Amos #1-3; Big Sandy #2; Cardinal #1-2; Conesville #4; Mitchell #1-2; Mountaineer #1; Muskingum #5		816	1,632	4,162	4,777	6,905	9,353	9,353
Allegheny Energy	Fort Martin #1-2						1,107	1,107	1,107
Cinergy	Cayuga #2; Gibson #2-3; Miami Fort #7-8		668	2,294	2,294	2,294	2,929	2,929	2,929
Dayton Power & Light	Killen #2; Stuart #1-4		0		3,121	3,121	3,121	3,121	3,121
Dominion Resources	Chesterfield #5-6				694	1,053	1,053	1,053	1,053
Duke Power	Allen #1-5; Belews Creek #1-2; Cliffside #5-6; Marshall #1-4		1,296	3,076	4,752	5,907	6,707	6,707	6,707
Dynegy/Illinois Power	Baldwin #1-3; Havana #6						629	1,258	2,369
East Kentucky Power	Gilbert #1 (1) (2); Smith #1 (1) (2); Spurlock #4 (1) (2)	268	268	268	546	824	824	824	824
FirstEnergy	Sammis #6-7					637	1,274	1,274	1,274
Gainesville Regional Utilities	Deerhaven #2						218	218	218
LGE Energy	Coleman #1-3; Trimble County #2 (2)		521	521	1,253	1,253	1,253	1,253	1,253
PPL Generation	Brunner Island #1-3; Montour #1-2				2,376	3,130	3,130	3,130	3,130
Progress Energy	Asheville #1-2; Cape Fear #5-6; Mayo #1; Roxboro #1-4; Sutton #3	207	414	2,561	3,297	3,708	3,708	3,896	4,484
PSEG	Hudson #2; Mercer #1-2		660	660	660	660	986	986	1,312
Santee Cooper	Cross #3-4 (2); Winyah #1-2			580	1,210	1,790	1,790	1,790	1,790
Seminole Electric	Seminole #3 (2)								750
Southern Company	Barry #5; Bowen #1-4; Gorgas #8-10; Wansley #1-2			952	4,017	5,759	6,548	7,337	7,337
Tennessee Valley Authority	Bull Run #1 Colbert #5; Kingston #1-9; Paradise #3		1,700	1,700	1,700	1,700	3,400	3,400	3,400
Vectren	Warrick #4						300	300	300
We Energies	Elm Road #1-2 (2); Oak Creek #7-8; Pleasant Prairie #1-2				1,234	1,894	2,554	2,554	3,196
	Subtotal Publicly Announced	475	6,451	14,787	31,859	39,050	48,979	53,033	56,450
Other (3)	Various	-	-	877	4,767	8,383	10,198	11,492	11,492
	Total All Sources	**475**	**6,451**	**15,664**	**36,626**	**47,433**	**59,177**	**64,525**	**67,942**

(1) Fluidized bed combustion units.
(2) New coal-fired unit.
(3) Based on CONSOL Energy market intelligence.

Clean Air Mercury Rule (CAMR)

Clean Air Mercury Rule

- Mandatory reduction limits for power plants
  - 48 ton current national emissions
  - 38 ton national limit in 2010
  - 15 ton national limit in 2018
- Allowance allocation adjustment by coal rank
  - Bituminous-fired : 1.0
  - Subbituminous-fired : 1.25
  - Lignite-fired : 3.0

State Budgets and Allocations within States

- State mercury budget allocations based on coal burn and heat input during 1998-2002 (avg of 3 highest years used)
  - Bituminous-fired : 1.0
  - Subbituminous-fired : 1.25
  - Lignite-fired : 3.0
- EPA recommended that states apply heat input adjustment factors when allocating allowances to individual units
  - Based on heat input during 2000-2004 period
  - Fuel switching now would not affect allowance allocation
  - Each unit's baseline heat input adjusted to reflect the rank of coal
- "States' may decline to adopt the allocation provisions set forth (in the rule) and may instead adopt any methodology for allocating mercury allowances"

Provisions

- January 1, 2001 is the cut-off date for considering a unit existing.
- Banking allowed
  - Retention of unused allowances in one calendar year for use in a later calendar year
- No early reduction credit program
- New units must comply with NSPS standards
  - New units must fit under state allocation cap

NSPS

- Coal-fired utility units for which construction, modification, or reconstruction commenced after January 30, 2004.

Type	Hg Limit (lb/MWh)
Bituminous	21×10^{-6}
Subituminous – Wet FGD	42×10^{-6}
Subituminous – Dry FGD	78×10^{-6}
Lignite	145×10^{-6}
Coal Refuse	1.4×10^{-6}
IGCC	20×10^{-6}

Synergy Between CAIR and CAMR

- In certain cases, an SCR combined with a scrubber will achieve high mercury removal with bituminous coal

- Why?
  - Mercury exists in 3 forms: elemental, oxidized, and particulate
  - Scrubbers do not remove a significant portion of the elemental mercury
  - The catalyst in an SCR converts elemental mercury to oxidized mercury if sufficient chlorine is present

- Which coals contain sufficient chlorine?
  - Bituminous : Yes (800 -1,200 ppm chlorine)
  - PRB : No (~120 ppm chlorine)

- Plants equipped with SCRs and scrubbers achieve a co-benefit of high (70 to 90%) mercury reductions when burning bituminous coal
  - Little to no mercury reduction for subbituminous coals in same plants

Test Results

- Under a cooperative agreement with the Department of Energy, CONSOL Energy measured mercury emissions from 10 power stations with SCR/Scrubber combinations burning bituminous coals.

- On a coal-feed basis, Hg removals were:
  - 89% and 95% for the two lime spray dryer units tested
  - 84% to 89% for the lime and limestone wet scrubber units.

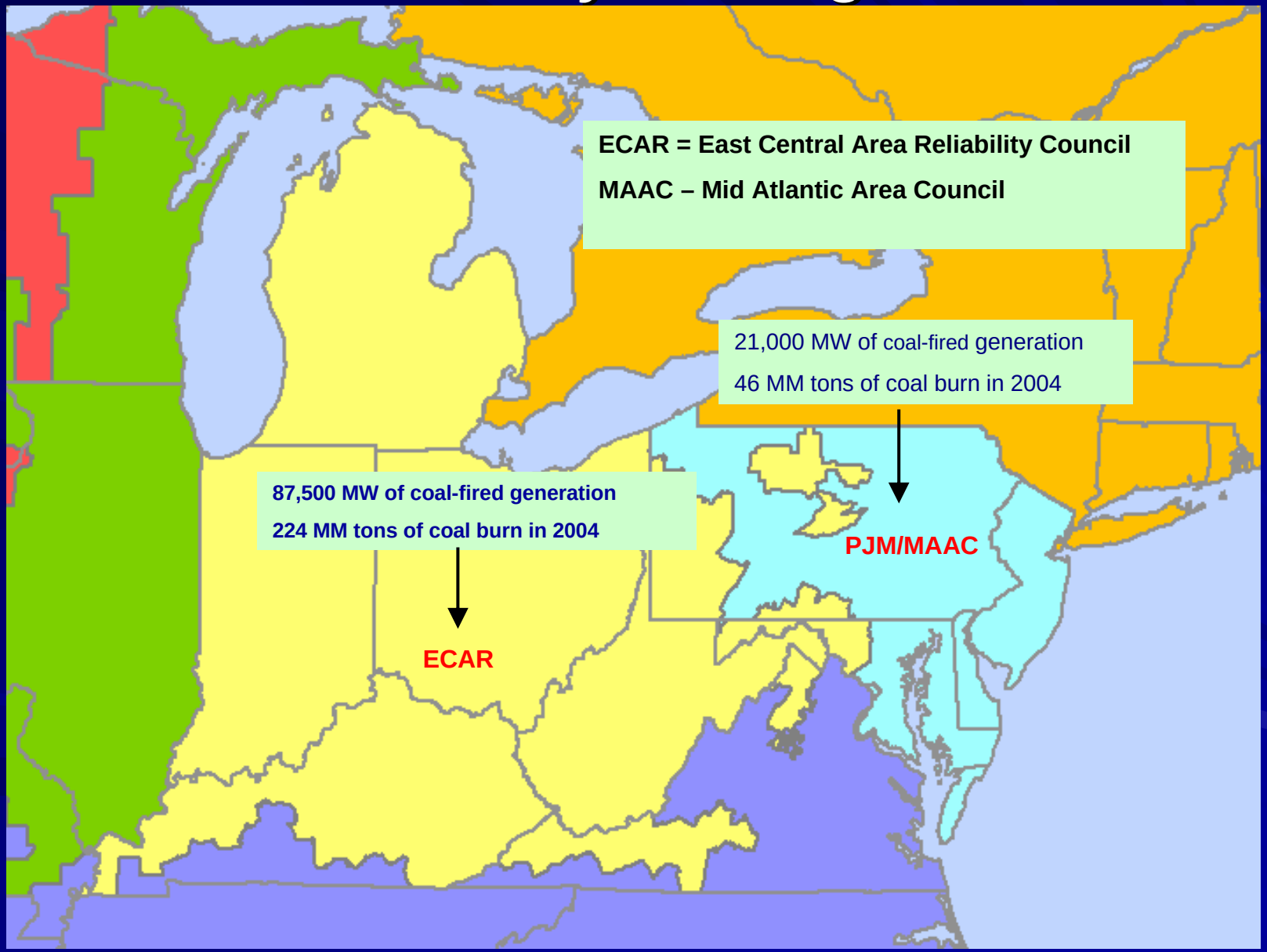
- Testing by Babcock & Wilcox at Dominion Energy's 563 MW Mt. Storm Unit #2 indicated greater than 90 % mercury reduction

Litigation

- 19 States, several environmental groups, two power companies, and other organizations have filed petitions appealing the CAMR rule.
- Rules advanced under CAA section 111
  - Cap and Trade to Meet Limits
- EPA rescinded finding that Hg should be regulated under CAA section 112
  - Maximum Achievable Control Technology (MACT) Applied to each Generator
- Subcategorization also contested by many litigants

CONSOL MARKET ANALYSIS

CONSOL Analysis Regions



CONSOL Dispatch Model Features

- Selects optimum coal from one of 22 categories
  - FOB mine prices by coal
  - Transportation costs from specific mines to specific power plants
- Load based on NERC region 10 year projection
  - ECAR
  - PJM (MAAC)
- Applies unit specific parameters
  - Capacity (MW)
  - Heat rates
  - Emissions control equipment (and future projections)

All ECAR and PJM Power Generators Included

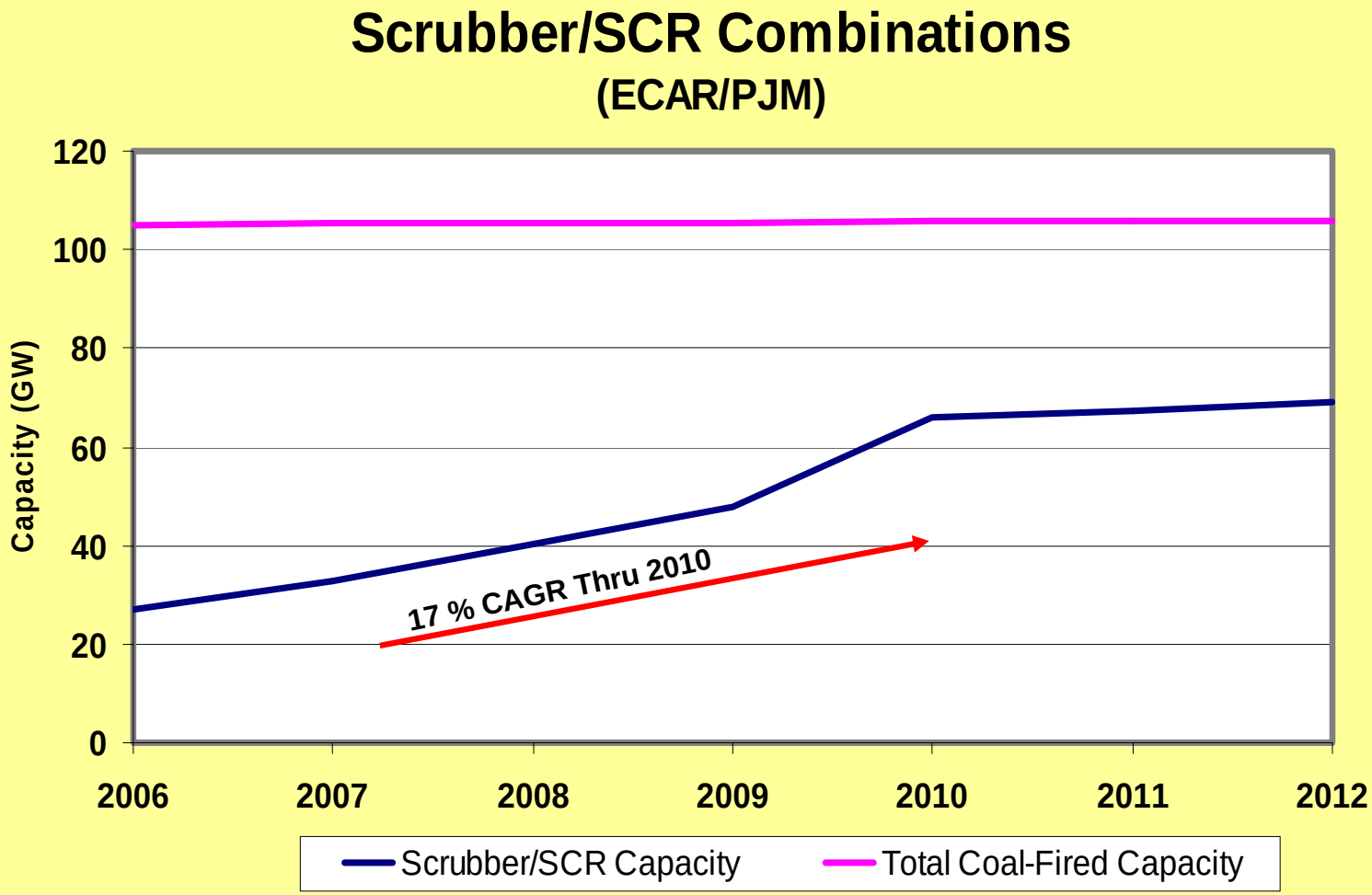
Generating Units					
Coal-Fired Boilers	Renewable Generators	Oil-Fired Generators	Natural Gas Fired Peakers	Natural Gas Combined Cycle	Nuclear
459	599	685	612	76	21

TOTAL	
Units	**Capacity (MW)**
2,452	**205,000**

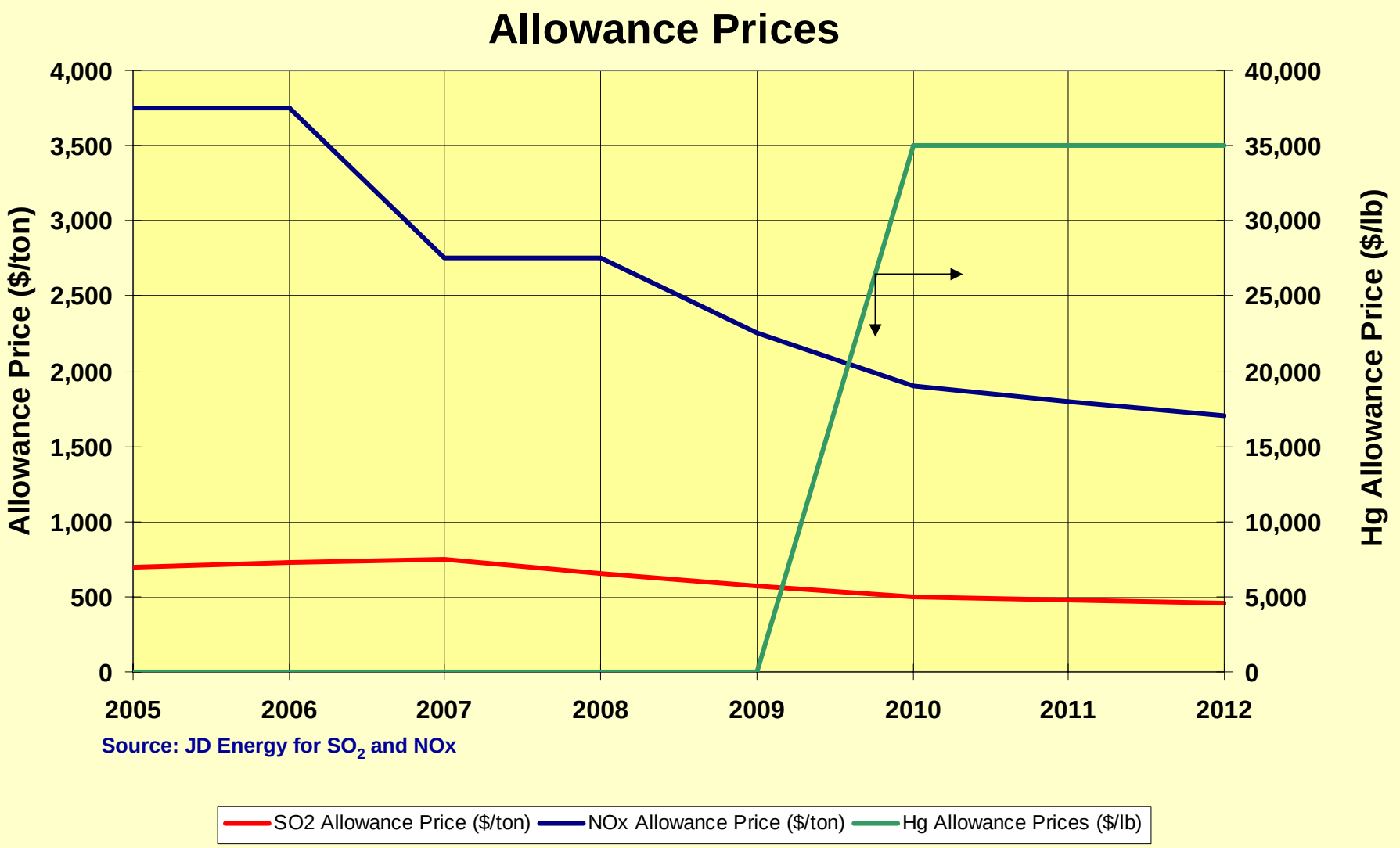
What Impacts Plant Dispatch ?

- Delivered Fuel Prices
- Allowance Prices (SO_2, NOx, Mercury)
- Plant Characteristics (Size, Efficiency)
- Plant Configuration (SCR, Scrubber)
- Hourly Demand for Power

Technology Solutions Rapidly Expanding

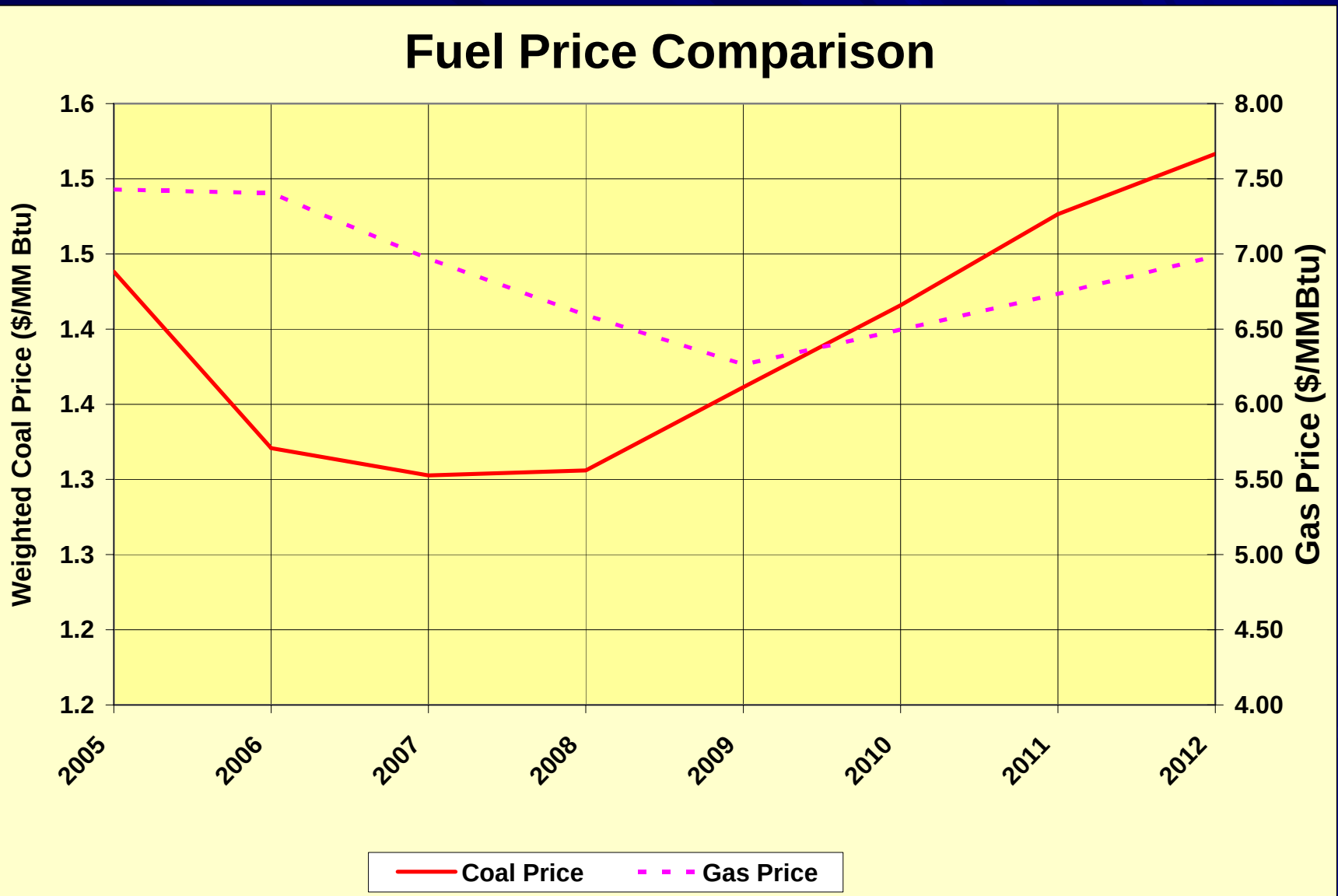


Allowance Prices Affect Power Dispatch



Source: JD Energy for SO_2 and NOx

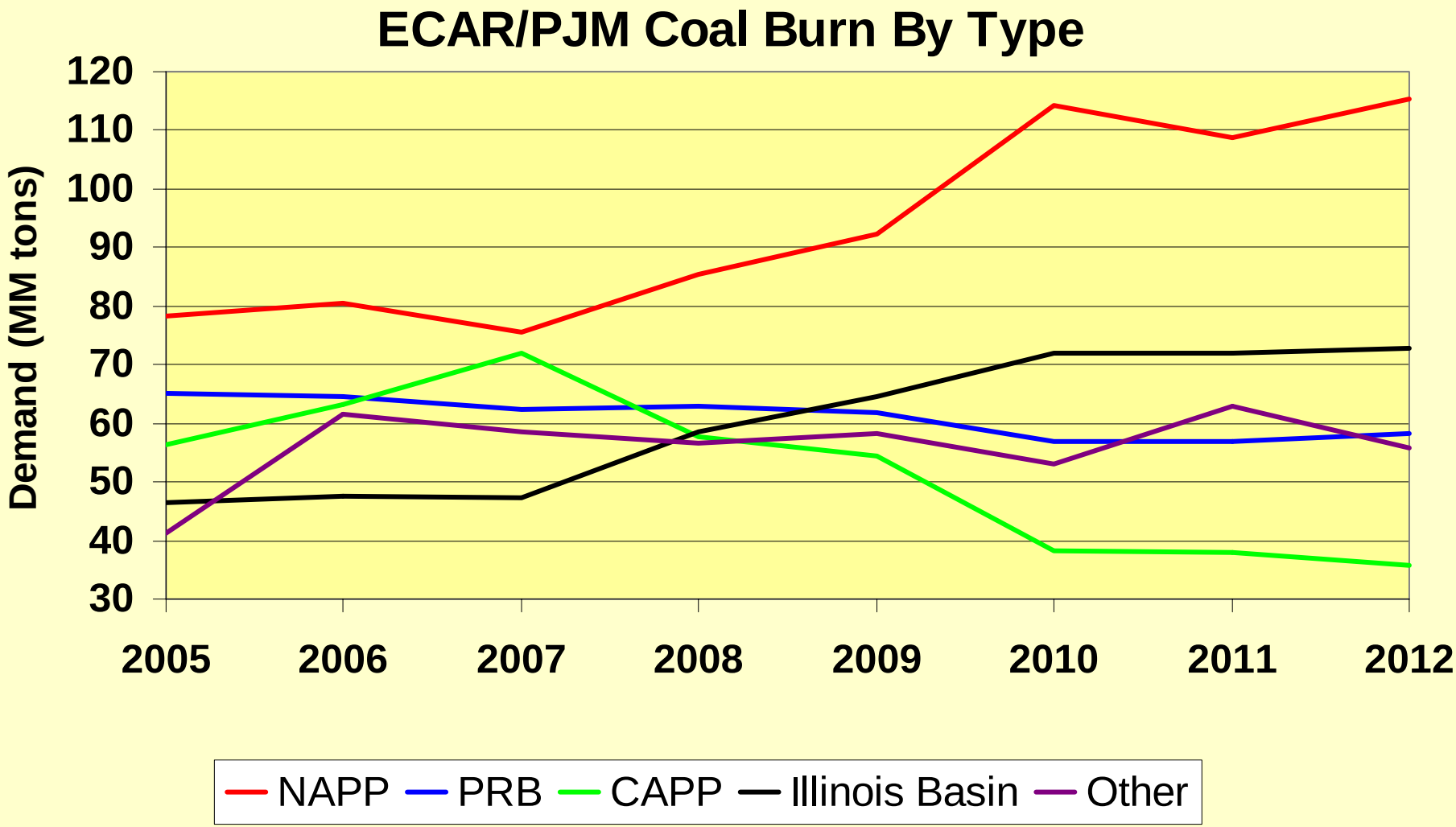
Fuel Prices Used for Modeling



Mercury Reductions Used for Modeling

	Fuel	
Controls	**PRB Coal**	**Bituminous Coal**
ESP	**10%**	**10%**
ESP/SCR	**10%**	**10%**
ESP/FGD	**27%**	**55%**
ESP/FGD/SCR	**27%**	**85%**

Coal Market Dynamics Now Favor High Btu over Low Sulfur

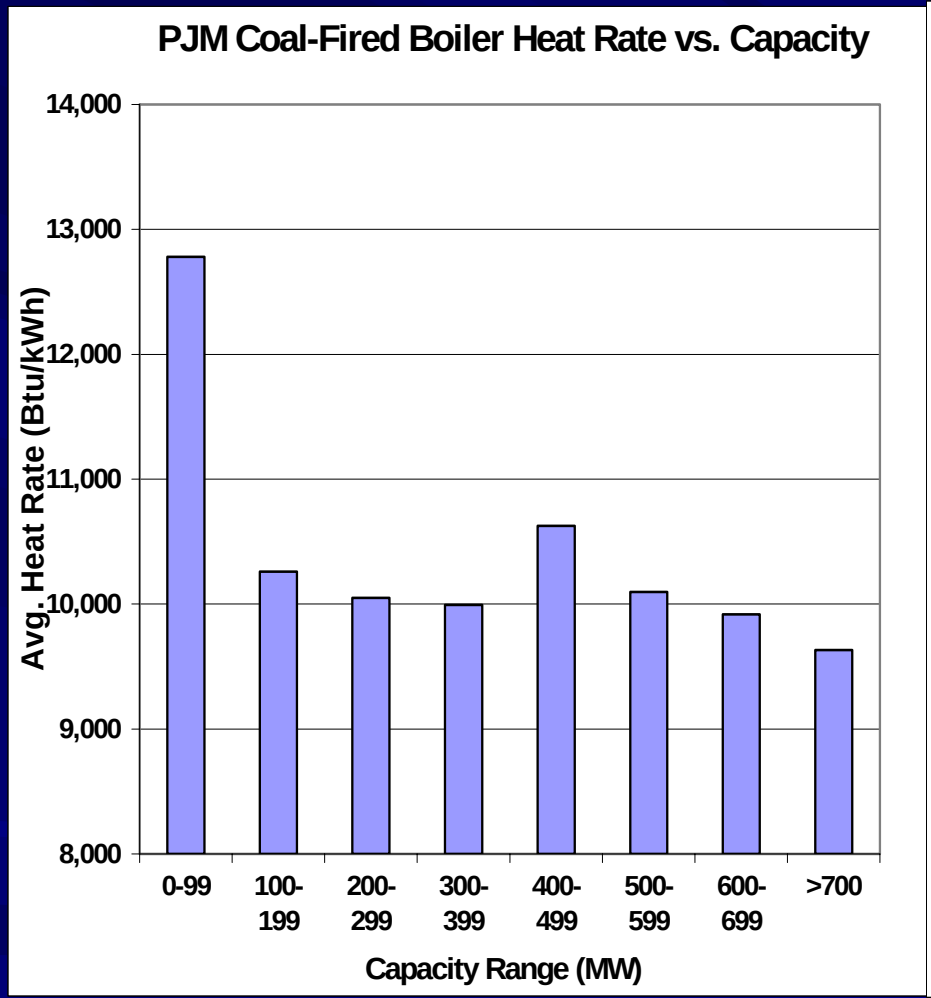


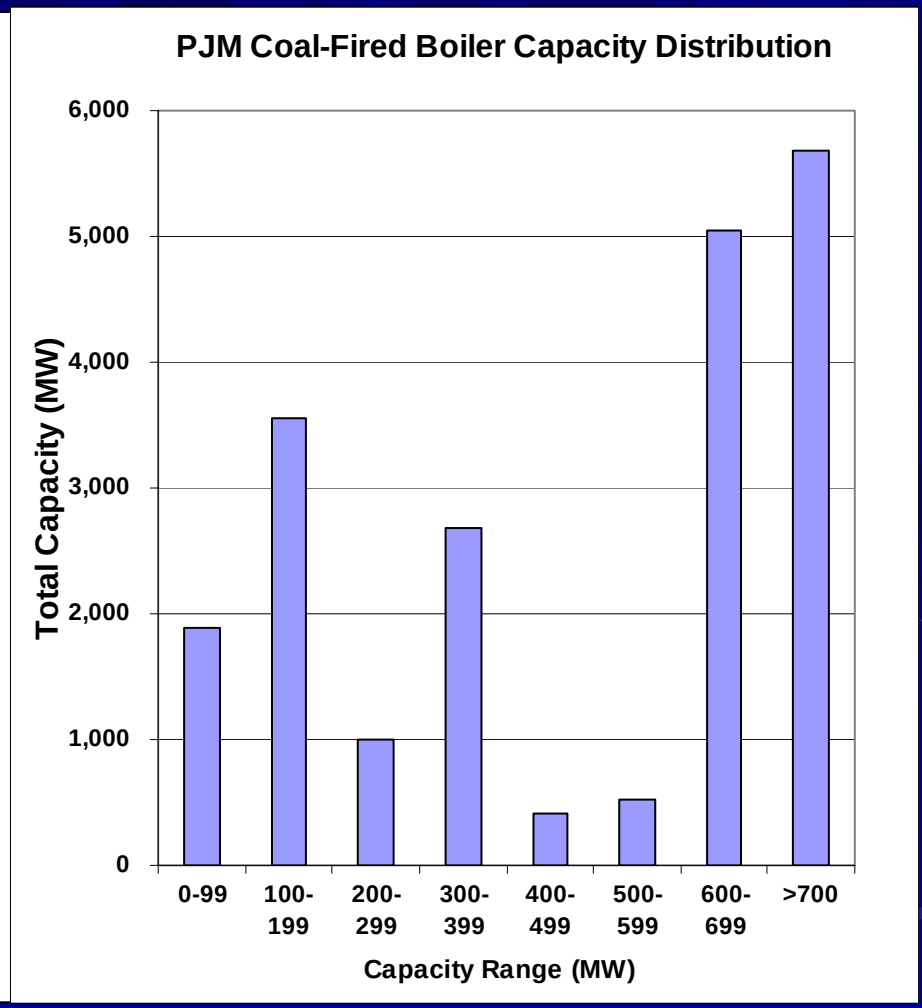
Gas Versus Coal

Fuel:	Existing Coal		New Natural Gas		
			Current	Long-range	Breakeven
Fuel Price @ Origin ($/MMBtu)	1.50	1.50	7.00	5.00	2.32
Fuel Delivery ($/MMBtu)	0.40	0.40	0.50	0.50	0.50
Delivered Fuel Price ($/MMBtu)	1.90	1.90	7.50	5.50	2.82
Plant Heat Rate (Btu/kWh)	9,600	9,726	7,030	7,030	7,030
Scrubber Installed	No	Yes	-	-	-
SCR Installed	No	Yes	No	No	No
Fuel Costs ($/MWh)	18.24	18.48	52.73	38.67	19.80
Non-Fuel Variable O&M ($/MWh)	2.25	2.85	2.80	2.80	2.80
NOx Emissions ($/MWh)	1.36	0.61	0.15	0.15	0.15
SO_2 Emissions ($/MWh)	16.13	0.82	0	0	0
Dispatch Costs ($/MWh)	38	23	56	42	23

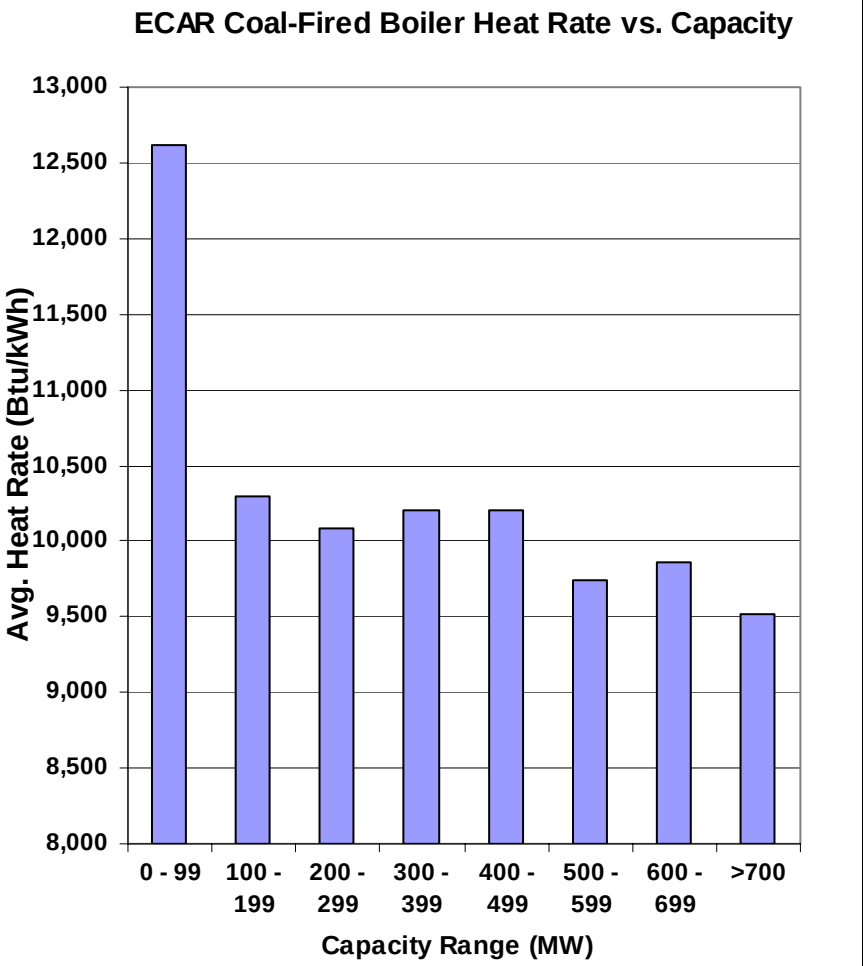
Notes: 1) Breakeven gas price compared to scrubbed coal unit
2) Assumes 3.0 % sulfur bituminous coal rail delivery
3) Does not include capital recovery for new gas plant
4) State-of-the-art gas combined cycle system compared to existing coal-fired unit

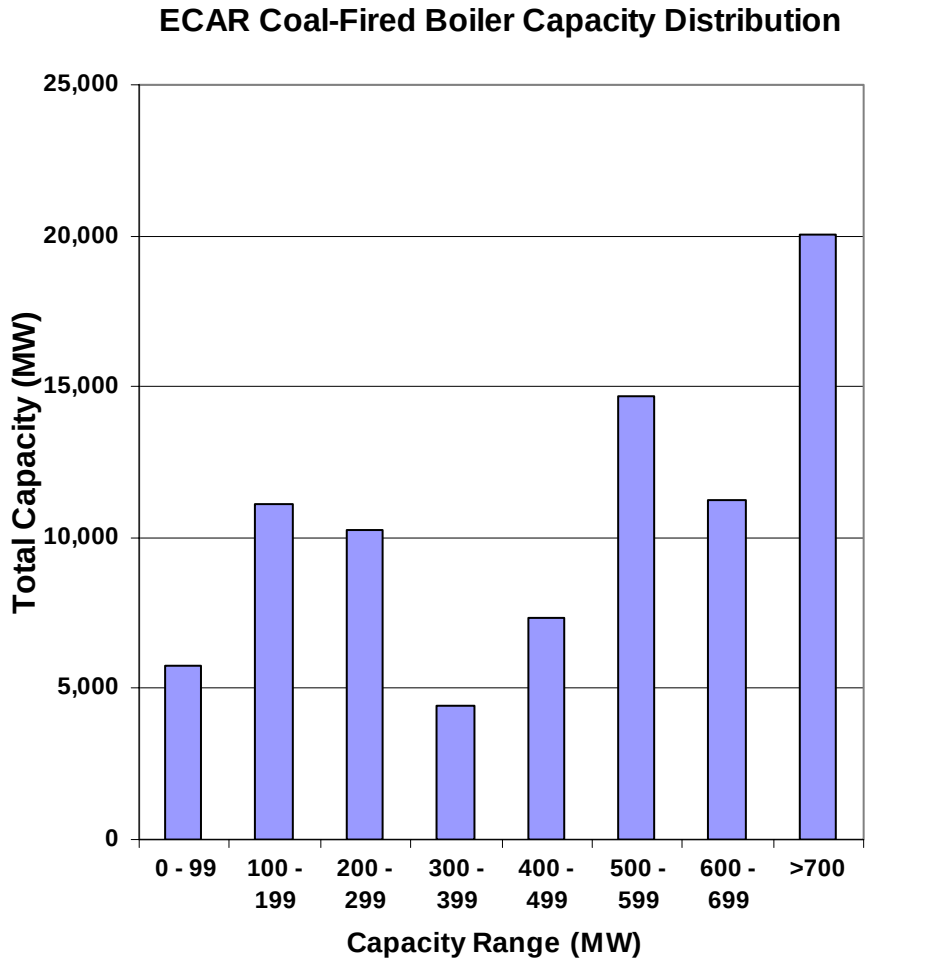
PJM Profile


PJM Coal-Fired Boiler Heat Rate vs. Capacity
Avg. Heat Rate (Btu/kWh)
14,000
13,000
12,000
11,000
10,000
9,000
8,000
0-99
100-199
200-299
300-399
400-499
500-599
600-699
>700
Capacity Range (MW)

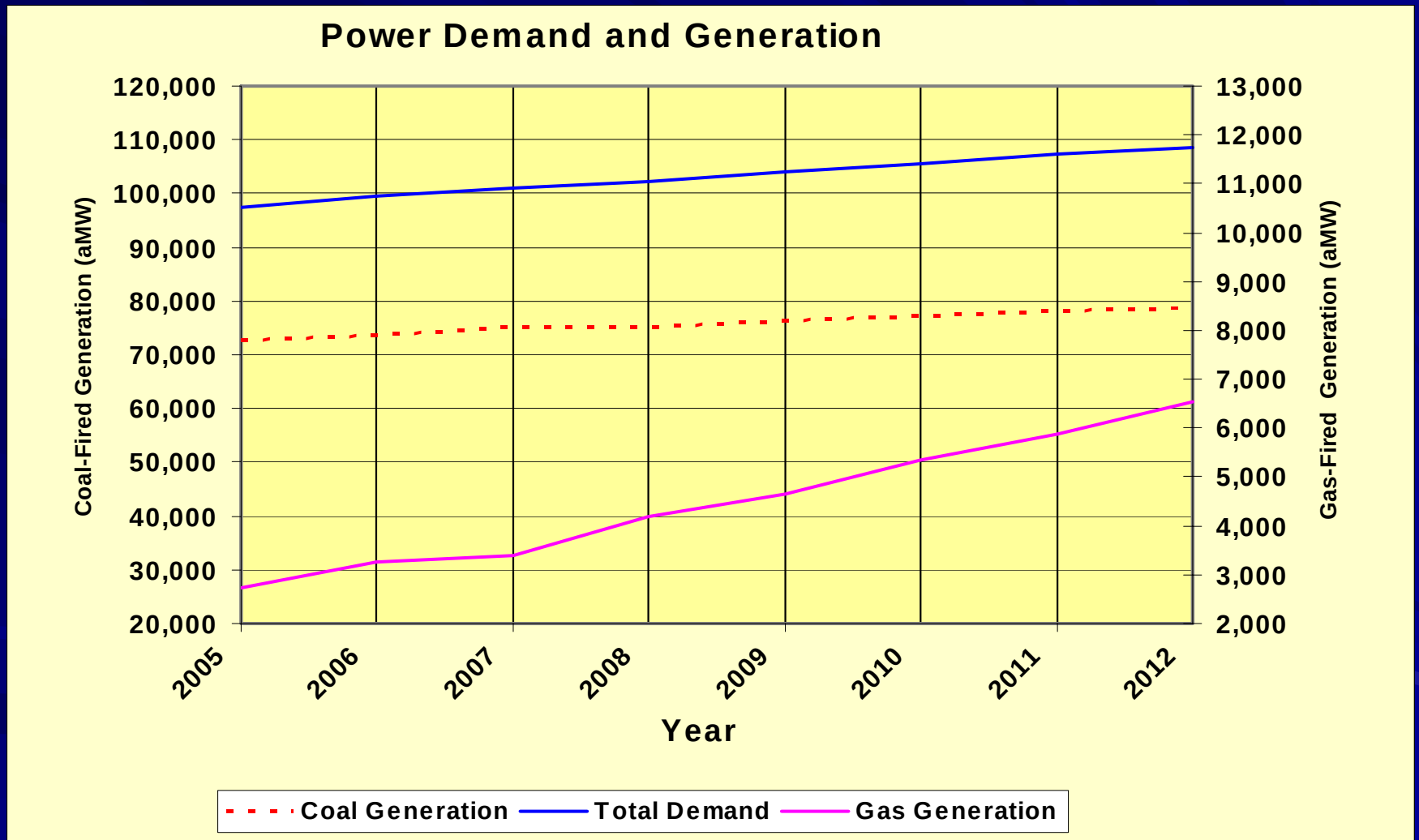

PJM Coal-Fired Boiler Capacity Distribution
Total Capacity (MW)
6,000
5,000
4,000
3,000
2,000
1,000
0
0-99
100-199
200-299
300-399
400-499
500-599
600-699
>700
Capacity Range (MW)

ECAR Profile





Gas Gains Because Coal Is Near Capacity



Conclusions

- CAIR and CAMR Regulations have changed the landscape for coal-fired power generation
- “Compliance” coal concept disappears
- Most utilities will use technology to meet SO_2 and NOx limits
- Plants equipped with SCRs and scrubbers achieve a co-benefit of high (70 – 90%) mercury reductions when burning bituminous coal
- As technology solutions are implemented, generators are becoming less sensitive to sulfur content and more sensitive to Btu content and delivered cost