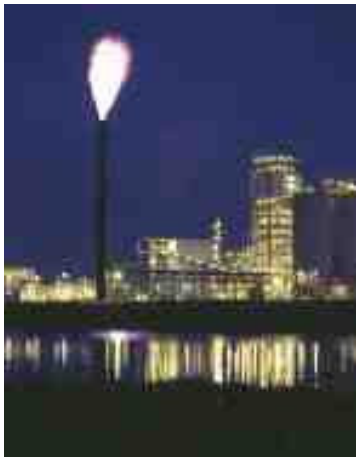

Air Permitting for Gasification and IGCC Plants

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CH2M HILL

Gasification Technologies Council Workshop
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CH2MHILL

Gasification Technologies Council

Topics

- Emission controls for gasification and IGCC
- Applicable regulations for IGCC
- How does IGCC compare to PC and NGCC?
- New Source Performance Standards
- IGCC emission rate comparison charts
- Startup and shutdown emissions

Air Emissions

IGCC – Sulfur Removal

- Gasification occurs in a reducing atmosphere (oxygen-starved)
- Sulfur compounds are liberated as H_2S and COS, not SO_2
- H_2S/COS removed by refinery industry technologies to levels ≥99%
- Recovered as molten sulfur or sulfuric acid
- Sulfur compounds remaining in the syngas are burned in the gas turbine and become low-level SO_2 in the HRSG exhaust

IGCC – NOx Removal

- Controlled by moisturizing the syngas and injecting N_2 diluent
  - dilutes and cools the flame, and reduces thermal NOx
- CO_2 in the syngas stream also acts as a diluent
- Gas turbines use diffusion burners vs the dry low NOx burners used in NGCC
- SCR is an option for additional NOx removal

What Regulations Apply to IGCC?

New Source Performance Standards

- IGCC is covered under Subpart Da as an Electric Utility Steam Generating Unit (just like PC boilers) if:

  "The combined cycle gas turbine is designed and intended to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas on a 12-month rolling average basis"

- IGCC gas turbines are not covered by Subpart KKKK, even when natural gas is used

NSPS for IGCC

Emission	NSPS	NSPS on Gasifier Input Basis (calculated)	NSPS on Gas Turbine Input Basis (calculated)
NOx	1.0 lb/MWh*	0.143 lb/MMBtu	0.188 lb/MMBtu
SO_2	1.4 lb/MWh* and minimum 95% removal	0.2 lb/MMBtu	0.263 lb/MMBtu
Particulate Matter	Lesser of 0.14 lb/MWh* or 0.015 lb/MMBtu**	0.011 lb/MMBtu	0.015 lb/MMBtu**
Mercury	20 x 10^{-6} lb/MWh*	2.87 lb/TBtu	3.75 lb/MMBtu

***Output-based standards are on a gross generation basis**

**** Gas turbine heat input basis, filterable PM only**

Emission Rate Units

- Some IGCC permits list emission rates in lb/MMBtu of gasifier (coal) heat input
- Others list emission rates on gas turbine (syngas) heat input basis (like NGCC)
- EPA addressed this issue:
  - *"The heat input for an IGCC facility is the heat content of the syngas burned in the stationary combustion turbine and not the heat content of the coal fed to the gasification facility. The gasification facility is not part of the affected source under subpart Da, only the stationary combustion turbine (turbine and heat recovery steam generator) are covered."*

Emission Rate Units

- Permit limits are to be expressed on basis of syngas input to the gas turbine
- Permit applications or permits can list "equivalents" on gasifier input basis, as well as lb/hr and ppm
- Important to specify heat input basis in permit application and in permit

Permit Limit Units - NOx Example

NOx Emissions from Gas Turbine	Emission Rate Gasifier (Coal) Input Basis	Emission Rate Gas Turbine (Syngas) Input Basis
161 lb/hr	0.059 lb/MMBtu	0.077 lb/MMBtu

30% difference!

Emission Rate Units

EMISSION UNIT	DESCRIPTION	POLLUTANT	EMISSION LIMITATION BASED ON CT HEAT INPUT	EMISSION LIMITATION BASED ON GASIFIER HEAT INPUT
HRSG1 & HRSG2	Combustion Turbine 1 & 2 (each)	**PM_{10} filterable** (syngas & Natural gas) **PM_{10} Total**	0.0085 lb/MMBtu 0.0217 lb/MMBtu	0.0063 lb/MMBtu filterable (BACT) 0.0161 lb/MMBtu Total
		Opacity	20%	20 %
		CO – syngas	0.0485 lb/MMBtu	0.036 lb/MMBtu
		CO - natural gas	0.0449 lb/MMBtu	
		NO_X syngas	0.0331 lb/MMBtu	0.0246 lb/MMBtu
		NO_X natural gas	0.0246 lb/MMBtu)	
		SO_2 – syngas	0.0158 lb/MMBtu	0.0117 lb/MMBtu (BACT)
		SO_2 - natural gas	0.001 lb/MMBtu	
		VOC – syngas	0.0015 lb/MMBtu	0.0011 lb/MMBtu
		VOC natural gas	0.0017 lb/MMBtu	
		H_2SO_4 – syngas	0.0035 lb/MMBtu	0.0026 lb/MMBtu (BACT)
		H_2SO_4 - natural gas	0.0001 lb/MMBtu	
		Hg – syngas		20×10^{-6} lbs/MWh
		Hg - natural gas		2.6×10^{-4} lbs/MMscf*

Source: KY DAQ – Cash Creek Generation permit

Emission Rate Units

Table A-3. Polk Power Station Unit 6 IGCC; CT/HRSG Emissions (Per CT/HRSG Unit)
NO_x, SO_2, CO, VOC, PM_{10}, and Pb Emission Rates - Syngas

Pollutant	Averaging Period	Units	Operating Case									Maximums
			1 - Syn 0° F Amb. 100% Load	2 - Syn 0° F Amb. 80% Load	3 - Syn 0° F Amb. 60% Load	4 - Syn 59° F Amb. 100% Load	5 - Syn 59° F Amb. 80% Load	6 - Syn 59° F Amb. 60% Load	7 - Syn 100° F Amb. 100% Load	8 - Syn 100° F Amb. 80% Load	9 - Syn 100° F Amb. 60% Load	
Operating Hours	Annual	hrs/yr	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760
Output[1]	Maximum	MW, gross	413.3	341.4	275.5	408.0	336.8	268.7	398.5	308.4	245.0	413.3
Gasifier Heat Input[2]	Max. Hourly	10^6 Btu/hr (HHV)	3,200	2,691	2,265	3,073	2,577	2,138	3,047	2,373	1,982	3,200
CT Heat Input	Max. Hourly	10^6 Btu/hr (HHV)	2,571	2,162	1,820	2,469	2,071	1,718	2,448	1,907	1,593	2,571
NO_x	30-day Rolling	lb / 10^6 Btu[2]	0.031	0.029	0.028	0.032	0.029	0.028	0.031	0.028	0.028	0.032
		lb / MWh, gross	0.24	0.23	0.23	0.24	0.22	0.22	0.23	0.22	0.22	0.24
		ppmvd @ 15% O_2	9.1	9.0	9.0	9.0	9.1	9.1	8.6	9.1	9.1	9.1
		tpy	N/A	N/A	N/A	433.6	N/A	N/A	N/A	N/A	N/A	433.6
		lb/hr	100	77	64	99	74	60	93	67	55	100
		g/s	12.6	9.7	8.1	12.5	9.3	7.6	11.7	8.4	6.9	12.6

Air Emissions

- Same HRSG stack emission points as NGCC
- Same fugitive dust issues as PC
  - Haul roads, coal delivery, unloading and handling
- Similar air permitting requirements
  - Air dispersion modeling
  - BACT analysis
  - Emission controls determination

Air Emissions

- Unique emission points depend on technology provider
  - Flare
  - Sulfur Recovery Unit tail gas incinerator
  - Sulfuric Acid Plant stack
  - Tank vent incinerators
  - ASU cooling tower

What About SCR for IGCC?

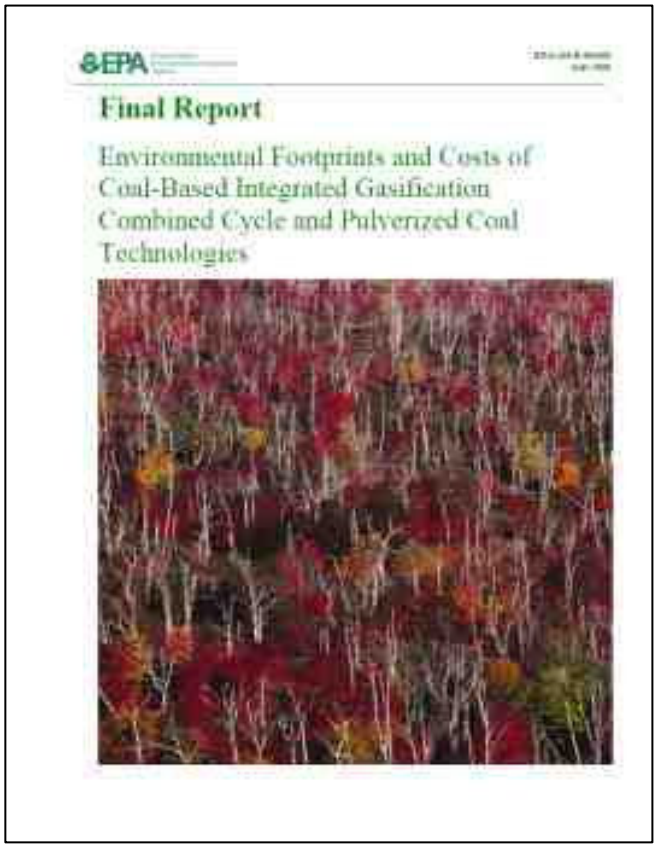
- Technical issues
  - The fuel is syngas, not natural gas as in NGCC
  - Ammonium sulfate/bisulfate deposit in the HRSG, causing corrosion and plugging, requiring numerous washdowns and downtime
  - No coal-based IGCC system in the world uses SCR
- Economic Issues
  - No commercial guarantees yet with syngas
  - Deep sulfur removal, i.e. Selexol, is required, with higher capital cost than MDEA

Why SCR?

- SCR has been proposed for a wide variety of reasons by IGCC applicants:
  - As BACT
  - As Innovative Control Technology to reduce emissions beyond diluent injection
  - As a trial/experiment, with emission limits only for natural gas use
  - To evaluate SCR as part of DOE demonstration program with a syngas-fired combined cycle unit
  - To minimize NOx emissions in order to reduce NOx emission allowance costs

NOx BACT

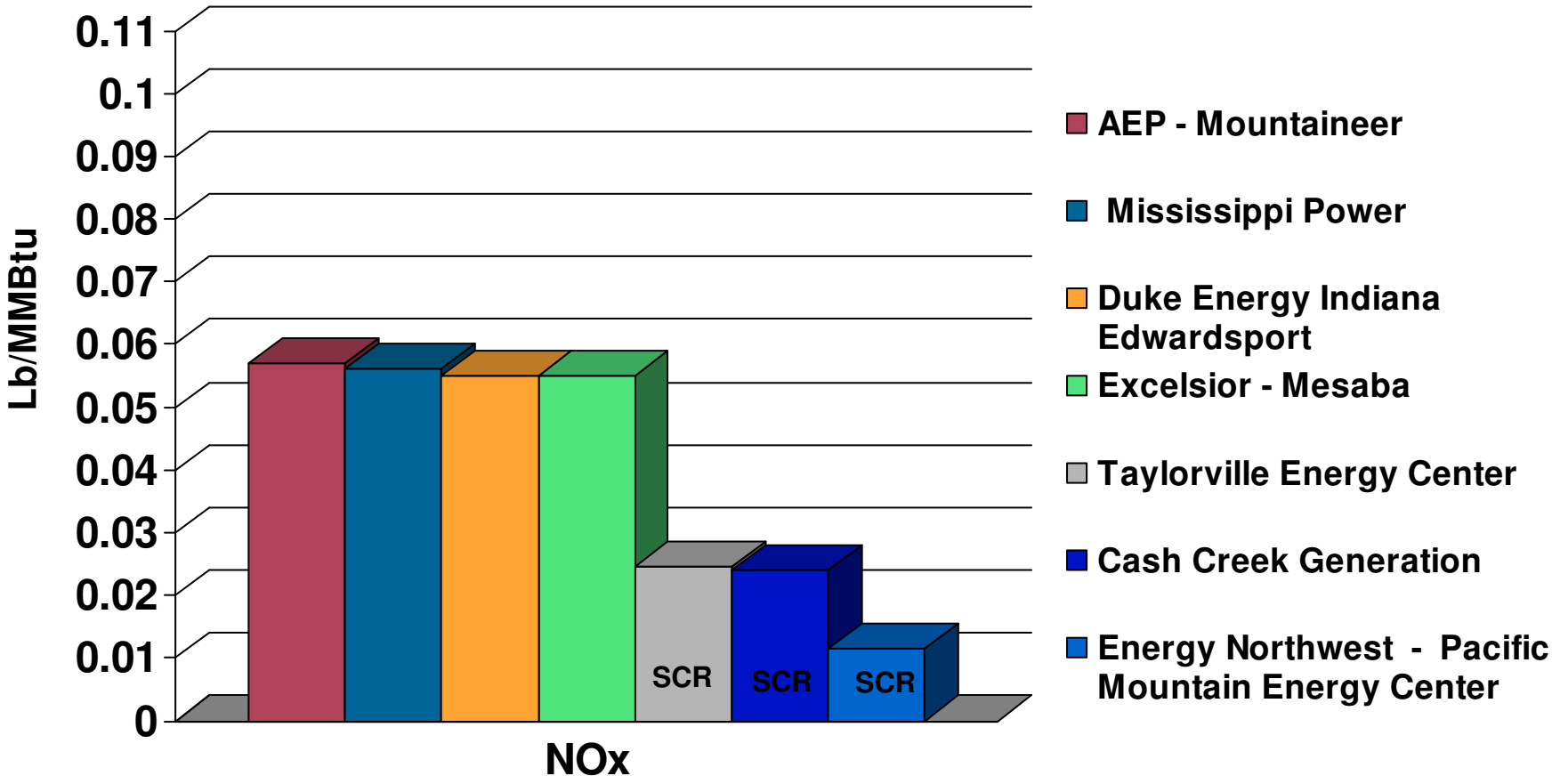
- EPA addressed this in report
- Study notes technical problems with using SCR w/IGCC
- Looked at SCR, w/Selexol for deep sulfur removal
- EPA concluded that:
  - even w/Selexol, problems are not solved
  - additional cost and reduced output are negative impacts to IGCC
  - BACT will continue to be a <u>case-by-case issue</u>



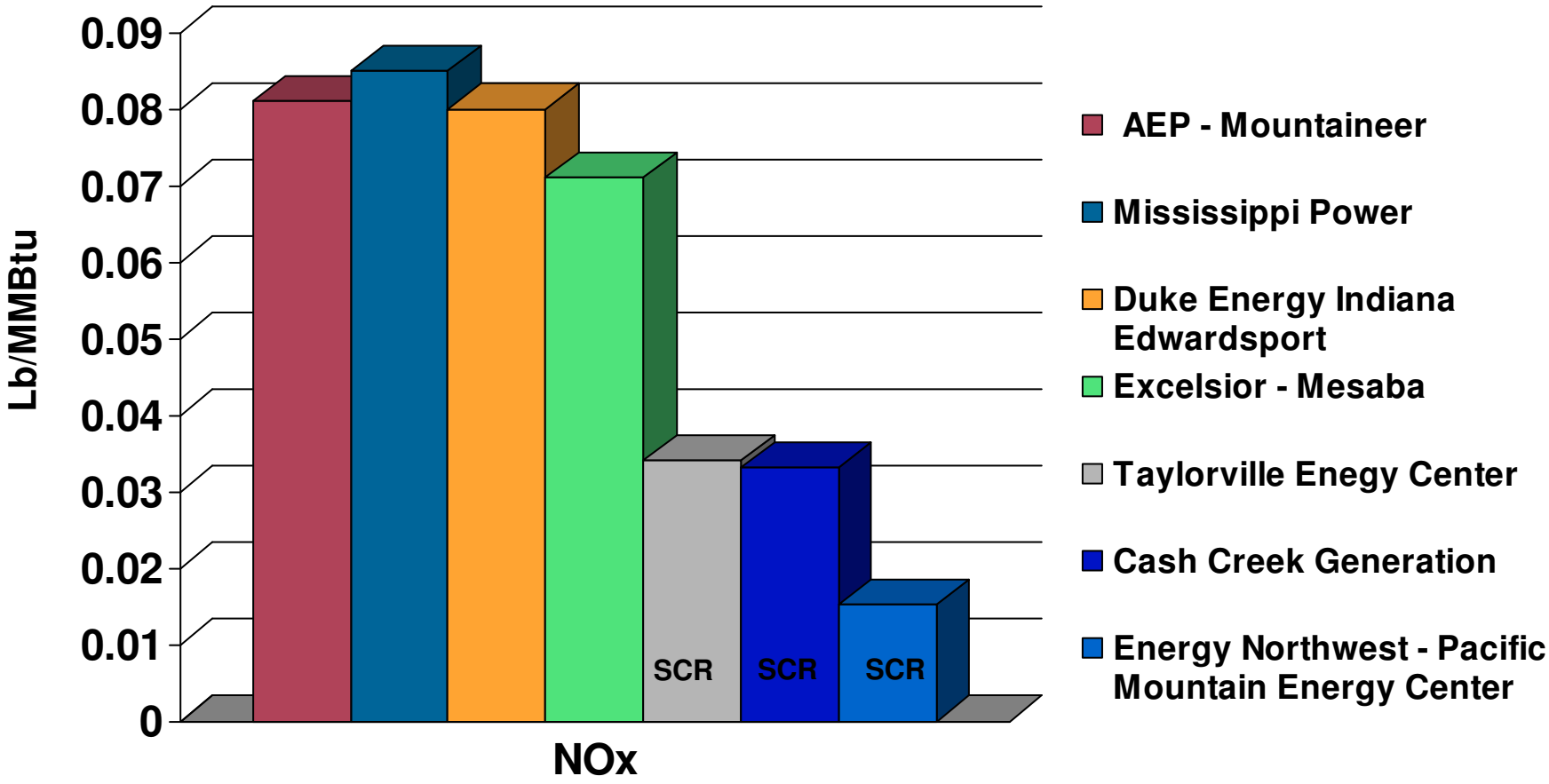
Permit Limit Comparisons

- Publicly available information
  - Permit applications
  - Draft permits
  - Final permits
  - Submittals to other agencies
  - Some units have been cancelled
- Values are provided on gasifier and gas turbine heat input bases

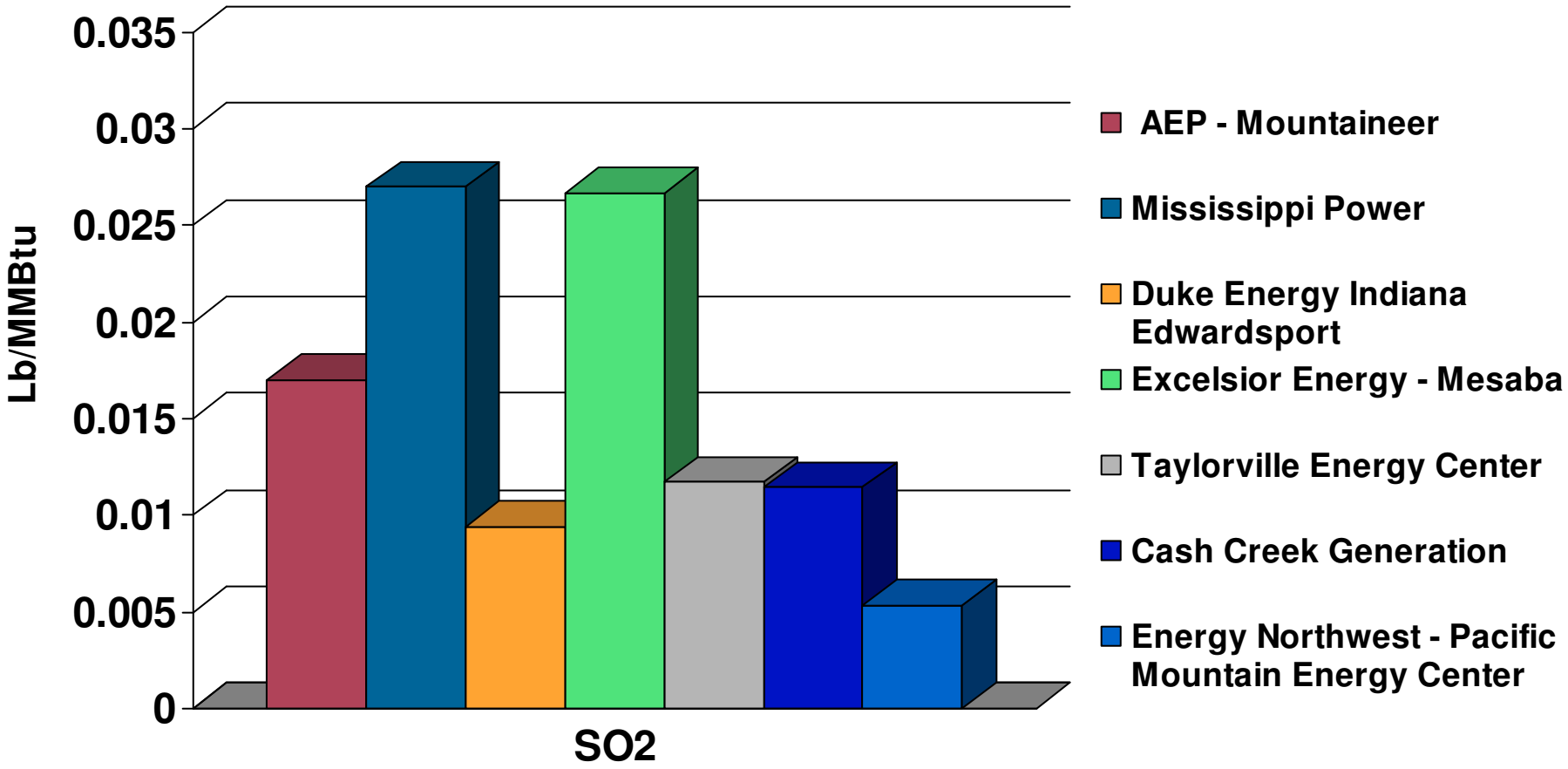
NOx Emission Rate Comparison
Gasifier Heat Input Basis



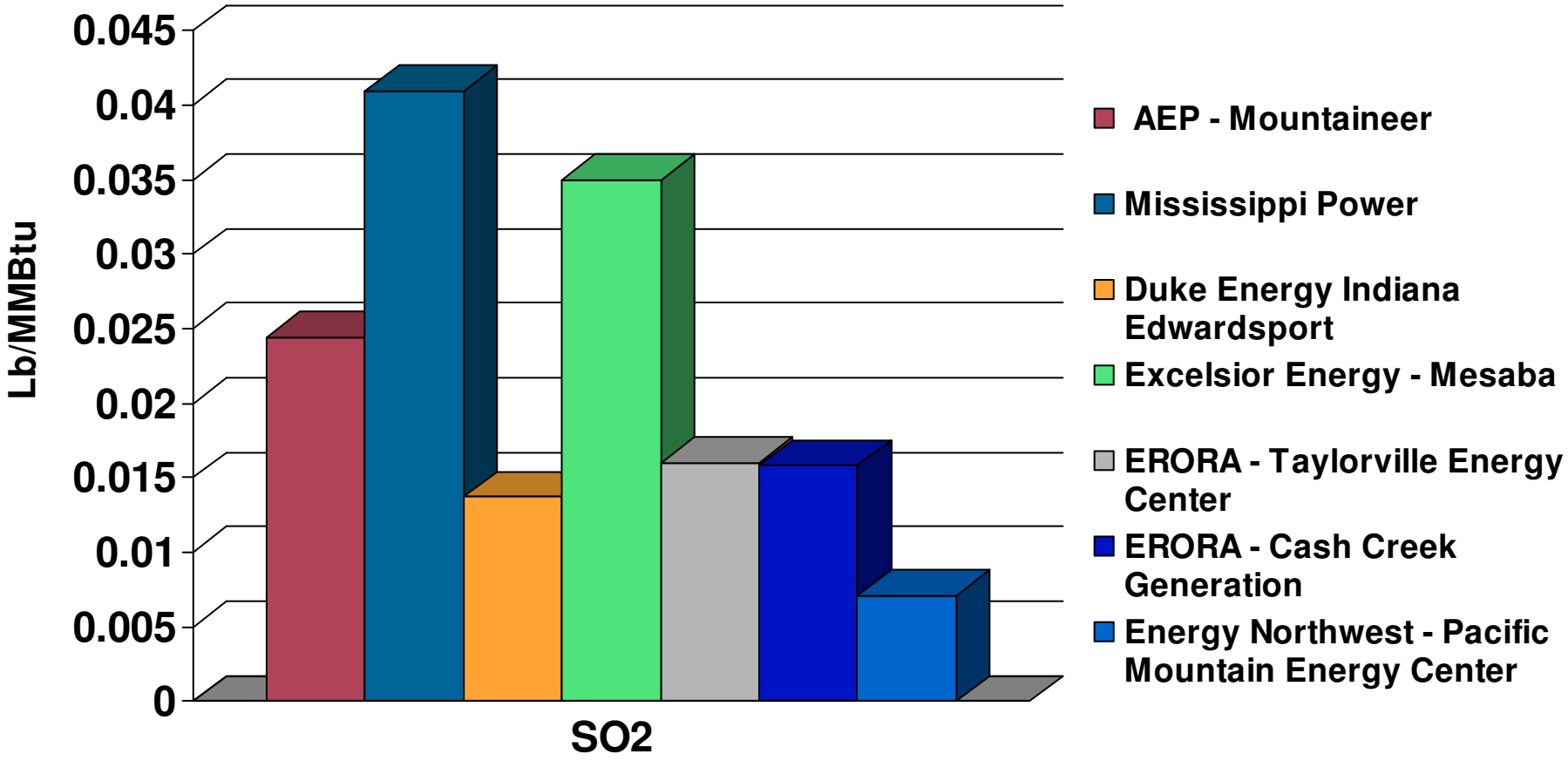
NOx Emission Rate Comparison
Gas Turbine Heat Input Basis



SO_2 Emission Rate Comparison Gasifier Heat Input Basis



SO_2 Emission Rate Comparison Gas Turbine Heat Input Basis



Mercury Removal

- Pre-sulfided carbon beds
- >94% removal of vapor-phase mercury at Eastman Chemical
- Forms a mercury-sulfur complex
- Spent carbon disposed of in drums once/year
- Most IGCC plants plan to use this technology

Source: Eastman Chemical

Start-up and Shutdown Emissions

- Can be a significant source of annual emissions
- Dependent on:
  - Number of start-ups and shutdowns
  - Startup procedures, i.e. starting first gasifier, then second, or both in parallel
  - Startup “fuel”
  - Duration
  - Flaring of raw/treated syngas or acid gas
  - Recycling through acid gas removal system
- Industry has made design and operational enhancements to minimize these emissions

Questions?

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