A Joint Workshop on the Industrial Alliance for IGCC and Coproduction
and
CO_2 Capture and Storage

CO_2 Capture-Related Activities in US

Robert H. Williams
Princeton Environmental Institute
Princeton University

Railway Hotel
Beijing
23-24 May 2007

INTRODUCTION

- Focus
  - Mostly (*but not exclusively*) on existing technology
  - Energy and cost penalties for CO_2 capture
- Outline
  - Review of IPCC (2005) findings on performance/cost penalties
  - Impacts of recent construction cost escalations on capture costs
  - Other implication of CO_2 capture (*on H_2O requirements, Hg control*)
  - Some large-scale capture projects planned for US
    - Post-combustion—aqueous ammonia (*AEP*)
    - Precombustion—IGCC using petcoke
      - Carson Refinery (*BP*)
      - Lockwood Project (*Goldman Sachs/Hunton Energy*)
  - Systems with current low CO_2 capture costs and opportunities they offer for early capture/storage projects
  - Low C obligation as strategy for launching CCS technologies for coal power in market in preparation for "full-blown" carbon policy

ENERGY PENALTY FOR CO_2 CAPTURED IN GENERATING ELECTRICITY—EXISTING TECHNOLOGY (% more input per MWh)

Technology	Where captured	Representative Value	Range
New NGCC	Post-combustion	16	11 – 22
New pulverized coal (PC)	Post-combustion	31	24 – 40
Existing PC	Post-combustion		43 – 77
New coal IGCC	Pre-combustion	19	14 – 25

Source: *IPCC Special Report on Carbon Dioxide Capture and Storage*, 2005

INCREASE IN CAPITAL COST FOR CO_2 CAPTURE IN GENERATING ELECTRICITY—EXISTING TECHNOLOGY (%)

Technology	Where captured	Representative Value	Range
New NGCC	Post-combustion	76	64 - 100
New pulverized coal (PC)	Post-combustion	63	44 - 74
Existing PC	Post-combustion		n.a.
New coal IGCC	Pre-combustion	37	19 – 36

Source: *IPCC Special Report on Carbon Dioxide Capture and Storage*, 2005

INCREASE IN GENERATION COST FOR CO_2 CAPTURE IN GENERATING ELECTRICITY—EXISTING TECHNOLOGY (%)

Technology	Where captured	Representative Value	Range
New NGCC	Post-combustion	**46**	**37 - 69**
New pulverized coal (PC)	Post-combustion	**57**	**42 - 66**
Existing PC	Post-combustion		**149 - 291**
New coal IGCC	Pre-combustion	**33**	**20 – 55**

Source: *IPCC Special Report on Carbon Dioxide Capture and Storage*, 2005

COST OF CO_2 CAPTURED IN GENERATING ELECTRICITY—EXISTING TECHNOLOGY ($ per tonne of CO_2)

Technology	Where captured	Representative Value	Range
New NGCC	Post-combustion	44	33 - 57
New pulverized coal (PC)	Post-combustion	29	23 - 35
Existing PC	Post-combustion		31 - 56
New coal IGCC	Pre-combustion	20	11 – 32

Source: *IPCC Special Report on Carbon Dioxide Capture and Storage*, 2005

Capture cost = [(Generation cost with capture) – (generation cost with venting)] /(CO_2 captured)

COST OF CO_2 EMISSIONS AVOIDED IN GENERATING ELECTRICITY—EXISTING TECHNOLOGY ($ per tonne of CO_2)

Technology	Where captured	Representative Value	Range
New NGCC	Post-combustion	53	37 - 74
New pulverized coal (PC)	Post-combustion	41	29 - 51
Existing PC	Post-combustion		45 – 73
New coal IGCC	Pre-combustion	23	13 – 37

Source: *IPCC Special Report on Carbon Dioxide Capture and Storage*, 2005

Avoided cost = [(Generation cost with capture) – (generation cost with venting)] /[(CO_2 emissions with venting) – (CO_2 emissions with capture)]

NEW NETL STUDY

COST AND PERFORMANCE COMPARISON OF FOSSIL ENERGY POWER PLANTS

Volume 1: Bituminous Coal and Natural Gas to Electricity

DOE/NETL-0401/053106

Final Report

Prepared for Office of Systems, Analyses and Planning

National Energy Technology Laboratory

www.netl.doe.gov

15 May 2007

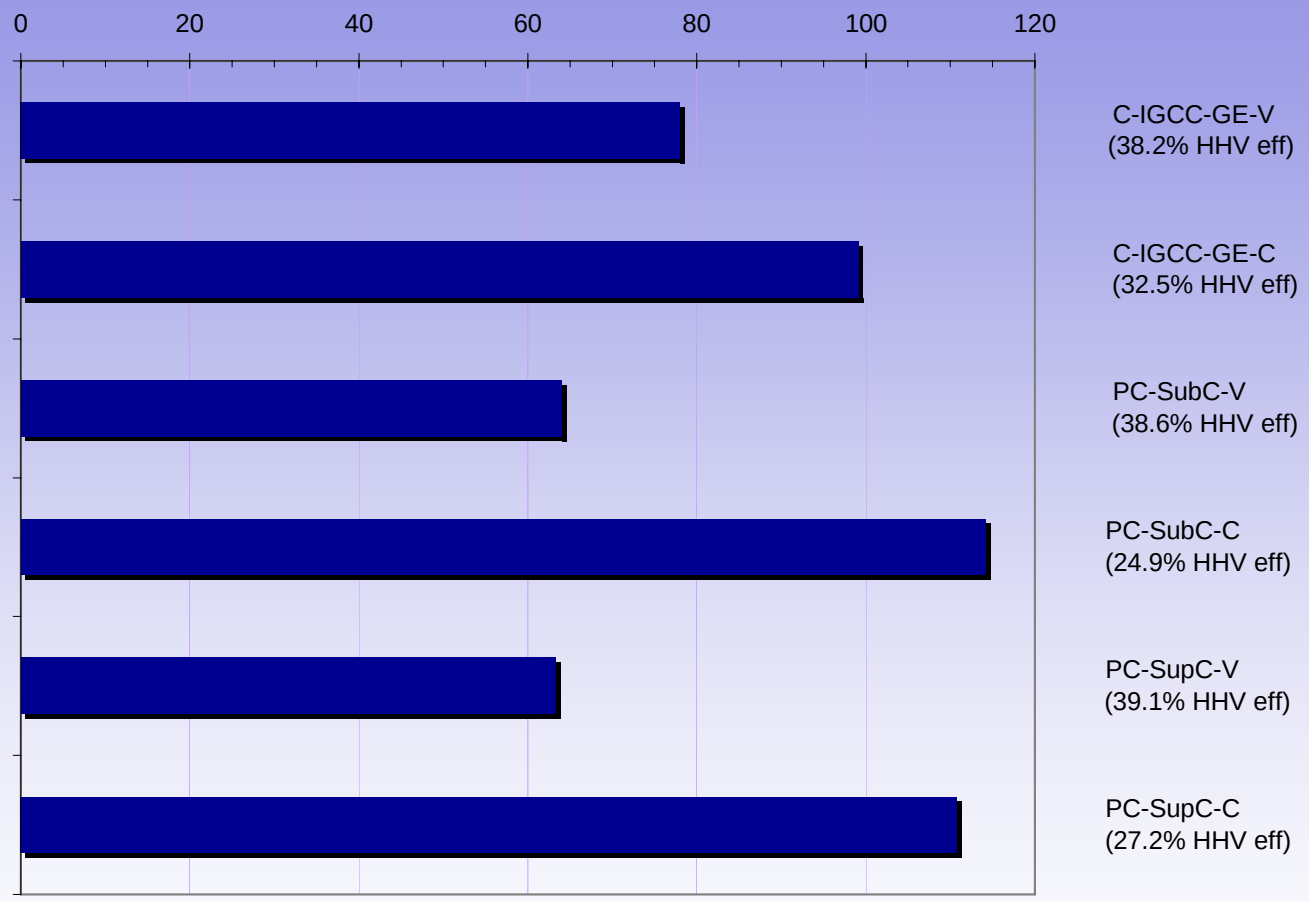
TECHNOLOGY CHOICES FOR NEW NETL STUDY

Plant Type	ST Cond. (psig/°F/°F)	GT	Gasifier/ Boiler	Acid Gas Removal/ CO_2 Separation / Sulfur Recovery	CO_2 Cap
IGCC	1800/1050/1050 (non-CO_2 capture cases) 1800/1000/1000 (CO_2 capture cases)	F Class	GE	Selexol / - / Claus	
				Selexol / Selexol / Claus	90%
			CoP E-Gas	MDEA / - / Claus	
				Selexol / Selexol / Claus	88%[1]
			Shell	Sulfinol-M / - / Claus	
				Selexol / Selexol / Claus	90%
PC	2400/1050/1050		Subcritical	Wet FGD / - / Gypsum	
				Wet FGD / Econamine / Gypsum	90%
	3500/1100/1100		Supercritical	Wet FGD / - / Gypsum	
				Wet FGD / Econamine / Gypsum	90%
NGCC	2400/1050/950	F Class	HRSG		
				- / Econamine / -	90%

[1] CO_2 capture is limited to 88% by syngas CH_4 content

GEE – GE Energy
CoP – Conoco Phillips

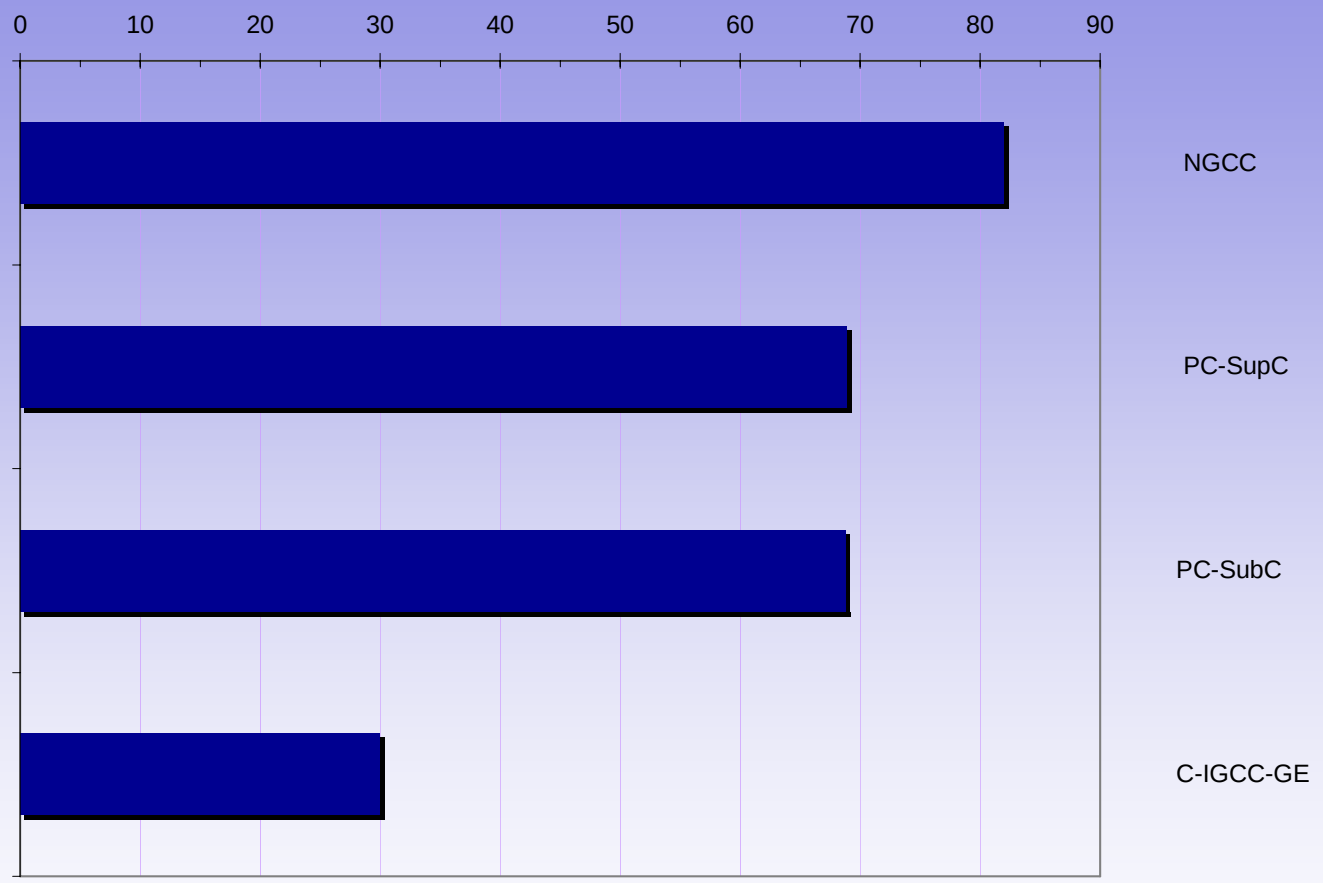
GENERATION COST FOR ELECTRICITY, $/MWh (*from new NETL study*)



IGCC still least costly capture option—but generation cost with capture up 60% and incremental cost with capture up 30% compared to IPCC (2005)

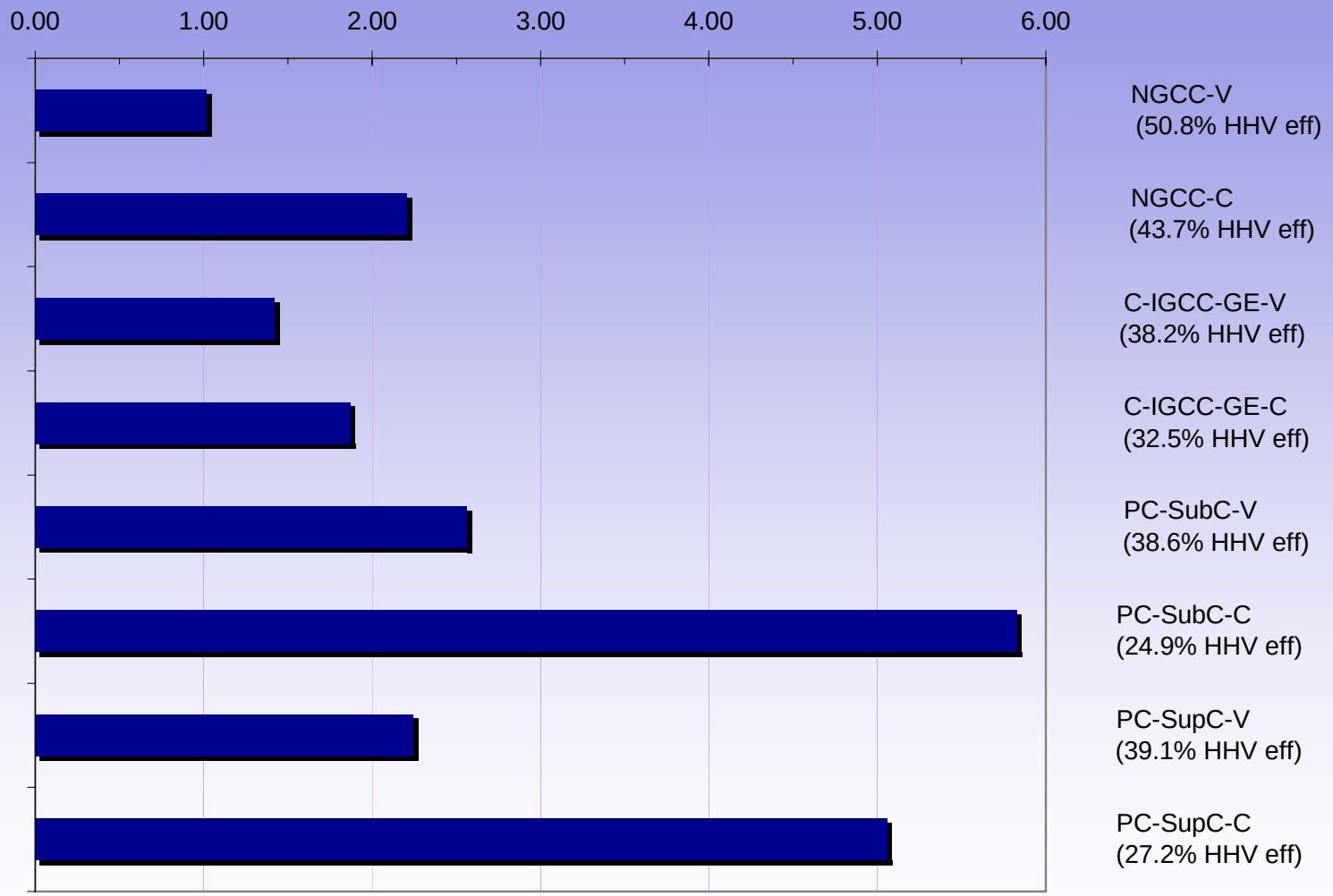
Current technologies; capacity factors: 80% for IGCC, 85% for PC; coal @ $\$1.7/GJ_{HHV}$;
Huge recent increases in costs for construction materials/labor taken into account

COST OF CO_2 EMISSIONS AVOIDED FOR CAPTURE, $/tonne CO_2 (*from new NETL study*)



Avoided cost estimates are much higher than estimates in IPCC (2005)
(*up ~ 30% for C-IGCC-GE*)

WATER USE FOR POWER GENERATION, m^3/MWh (*from new NETL study*)



H_2O use (*relative to PC-SupC-V*): 2.3 (*PC-SupC-C*); 0.83 (*C-IGCC-GE-C*)

The econoamine process used with PC & NGCC plants has a huge cooling demand

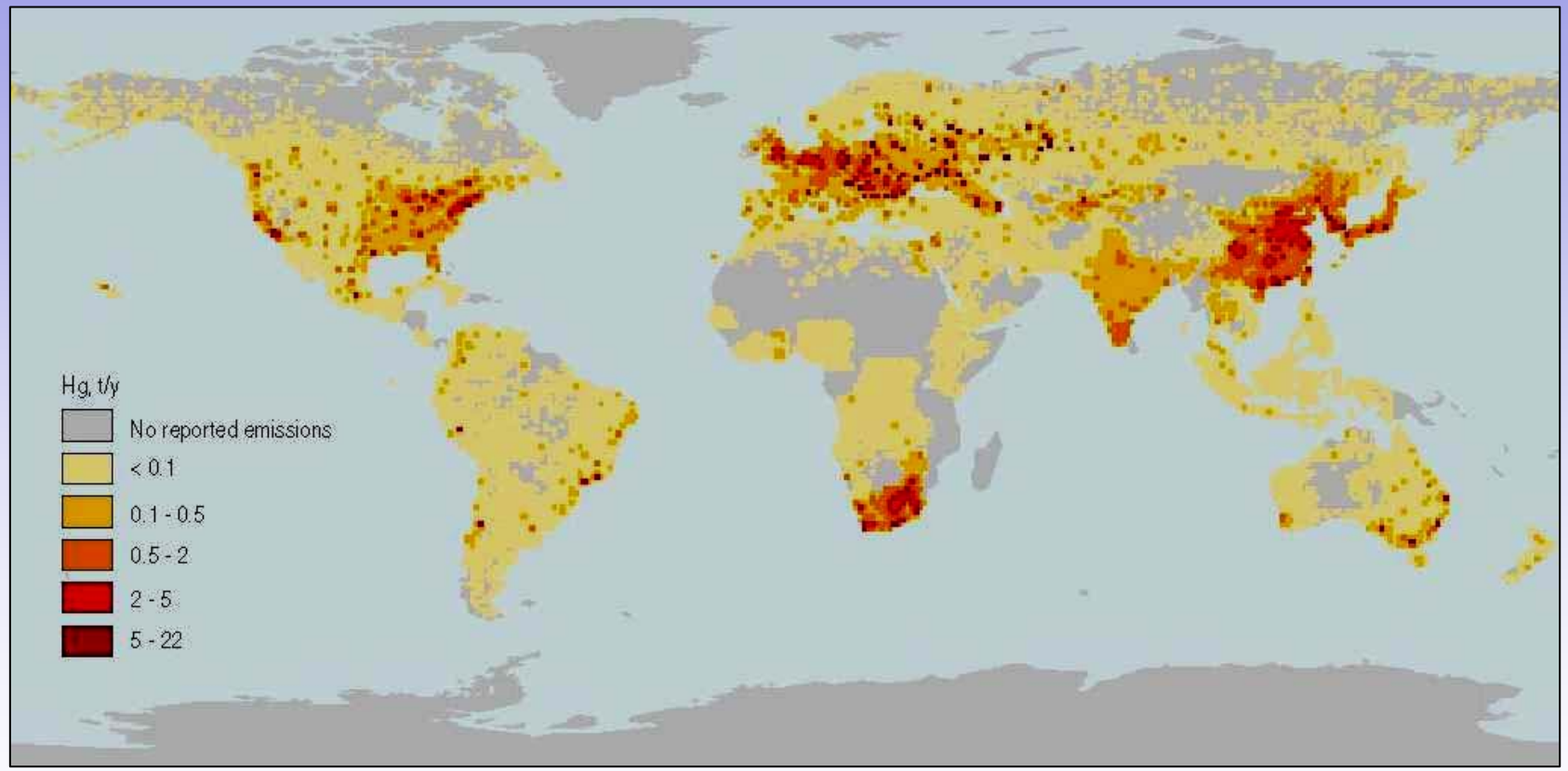
Hg—RISING CONCERN ABOUT BURNING COAL

- US coal plants emit ~ 48 t/y of Hg
- Accumulates in fish tissues after transforming into methyl Hg
- Ingested Hg is particularly detrimental to developing fetuses, young infants—causing developmental/neurological damage
- Damages arise despite extremely low Hg concentrations in coal [< *0.15 ppm in Illinois #6 coal (dry)*]
- China's anthropogenic Hg emissions ~ 536 $\pm$ 236 t/y in 1999[a] --of which 202 t/y was from coal combustion
- Control strategies:
  - Pre-combustion removal to is easy/cheap for IGCC using S-impregnated carbon beds (~ *95% capture with one bed, 99% with two beds*)
  - Using such an approach is very costly for post-combustion removal…but 70%-90% capture is feasible via co-benefits strategy (*SCR, wet FGD scrubber, fabric PM filters*)

[a]D. Streets et al., "Anthropogenic Mercury Emissions in China," *Atmospheric Environment*, **39**: 7789-7806, 2005.

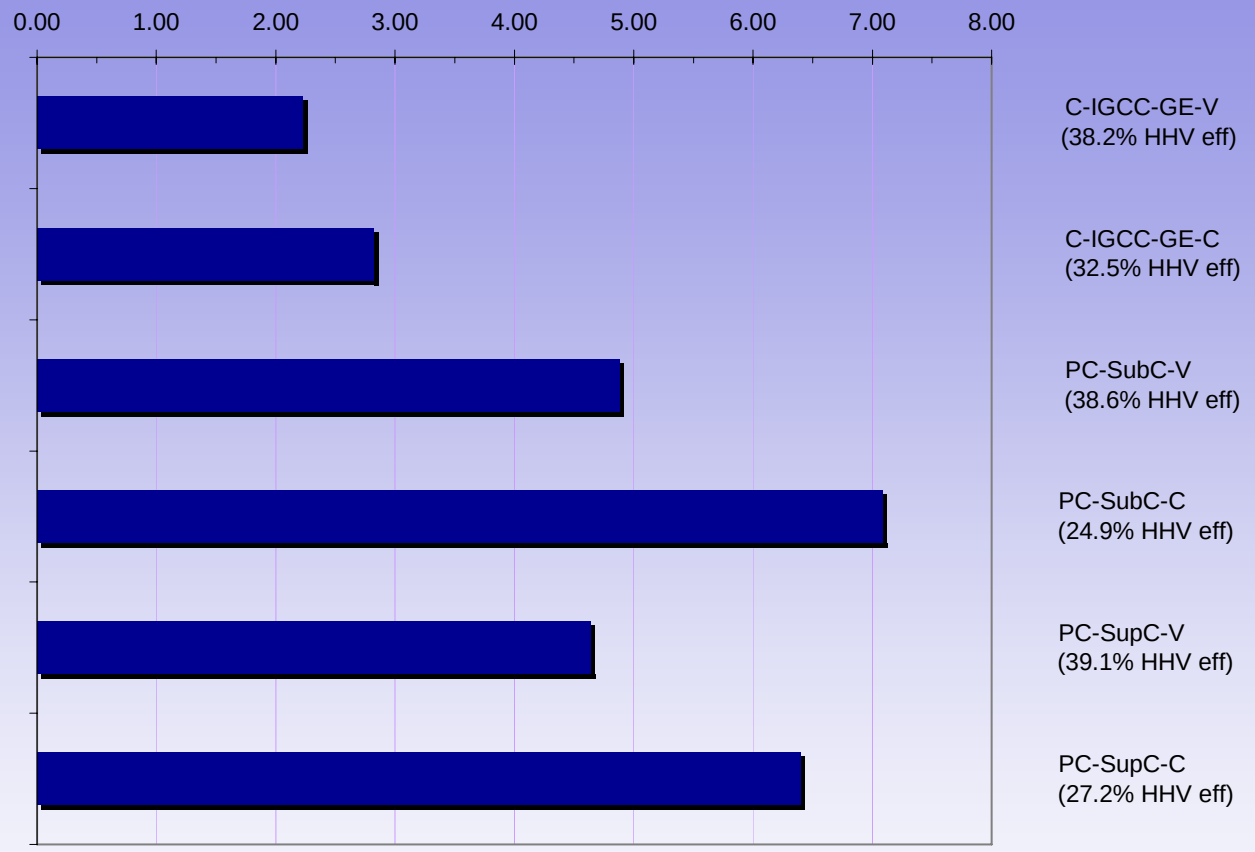
SPATIAL DISTRIBUTION OF GLOBAL AIR EMSSIONS OF HG

(*t/y per 1º x 1º of Latitude/Longitude Grid*)



Source: UNEP, Chemicals, *Global Mercury Assessment 2002*, Inter-Organization Programme for the Sound Management of Chemicals, Geneva, 2002

Hg EMISSIONS FOR POWER GENERATION, mg/MWh (*from new NETL study*)



Hg emissions (*relative to PC-SupC-V*): 1.4 (*PC-SupC-C*); 0.6 (*C-IGCC-GE-C*)

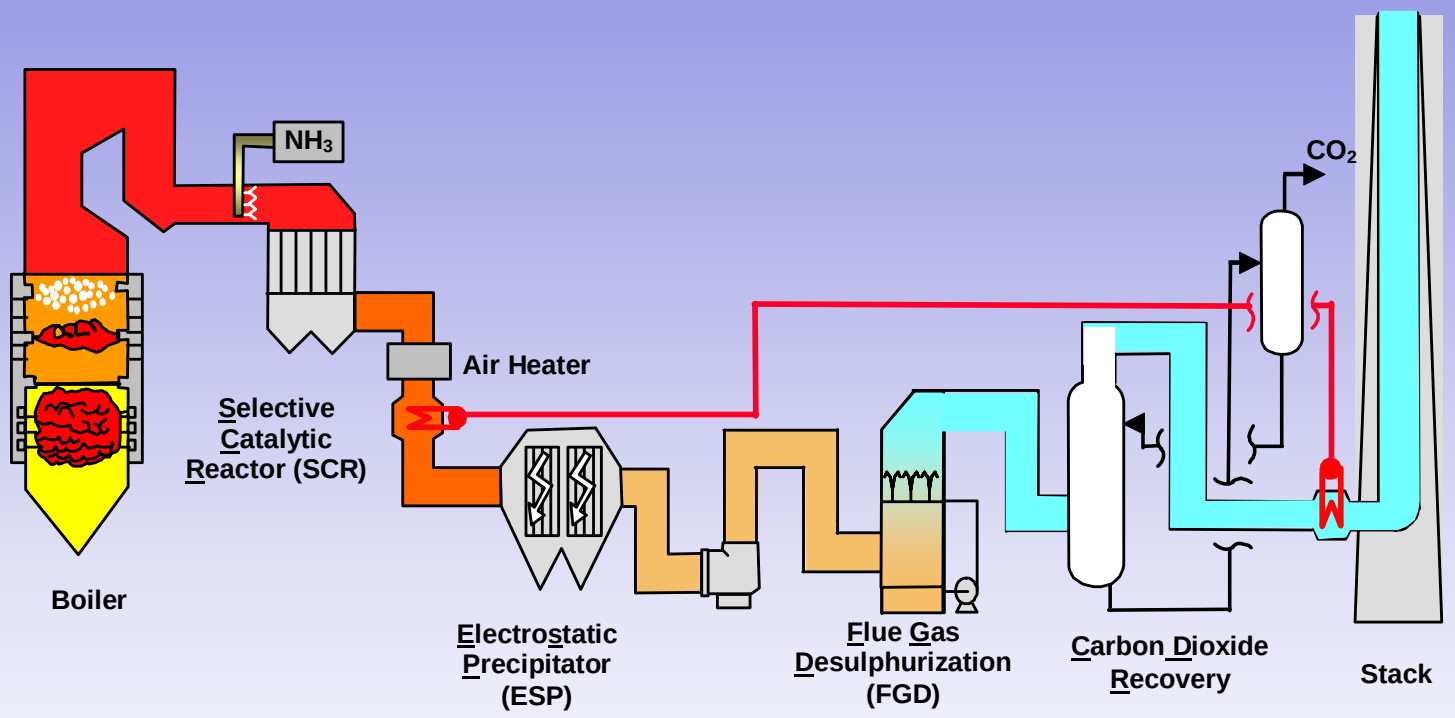
PC :90% capture via co-benefits strategy

IGCC: 95% capture in one bed of S-impregnated carbon

COMMERCIAL-SCALE CAPTURE PROJECTS PLANNED FOR US

- Chilled NH_3 for post-combustion capture—AEP
- Pre-combustion projects based on petcoke IGCC
  - Carson Project—BP
  - Lockwood Project—Goldman Sachs/Hunton Energy

PC POWER PLANT w/AMINE-BASED CO_2 CAPTURE SYSTEM & OTHER EMISSION CONTROLS.



Amine scrubbers capture CO_2 from dilute stack gases by binding CO_2 chemically ➔ very high energy penalties for regenerating chemical solvent/recovering CO_2 for storage…are there less costly, less energy-intensive ways to do this?

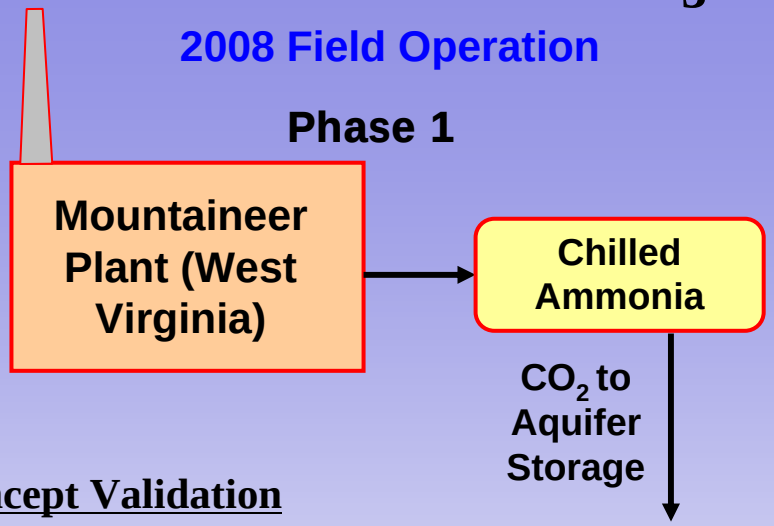
ALSTOM'S CHILLED AMMONIA CAPTURE PROCESS

- Process:
  - Cool flue gas to 0-10 C to condense H_2O, reduce gas volume, increase CO_2 concentration, increase CO_2 capture efficiency, and minimize NH_3 emissions.
  - Contact chilled flue gas with NH_3 in absorption tower, capturing >90% CO_2.
  - Increase pressure (> *20 bar*) and temperature (> *120 C*) of rich solvent and strip off CO_2 at relatively high pressure
- Advantages:
  - High CO_2 capture efficiency
  - Low heat of reaction (*6-8 kcal/mole; MEA=20-22*)
  - High capacity of CO_2 per unit of solvent (*0.1-0.2 kg/kg solvent; MEA=0.05*)
  - Easy regeneration at modest temperatures (120 C)
  - Low cost reagent (*$0.3/kg; MEA= 1.5*)
  - Claim: no solvent degeneration during cycle, and high tolerance to O_2 and contaminants in flue gas ➔ low solvent makeup requirements (*0.2 kg/ton CO_2; MEA=2.0*).
  - Low estimated cost of CO_2 emissions avoided (~ *$20/ton vs ~ $50 for MEA*)

AEP CHILLED NH_3 TECHNOLOGY PROGRAM

2008 Field Operation

Phase 1



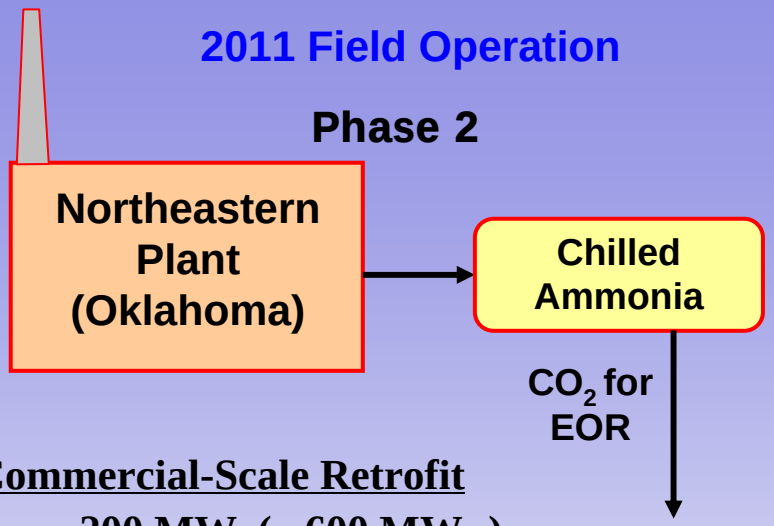
Concept Validation

- **30 MW_{th} (*scale up of Alstom/EPRI 5 MW_t pilot plant at WE Energies, Wisconsin*)**
- **In operation: 4th Quarter 2008**
- **Estimated capital cost: $50 – $80M**
- **Site: AEP Mountaineer Plant, West Virginia**
- **Aquifer storage of CO_2**

Phase 1 will capture and store 10^5 tonnes of CO_2/year

2011 Field Operation

Phase 2



Commercial-Scale Retrofit

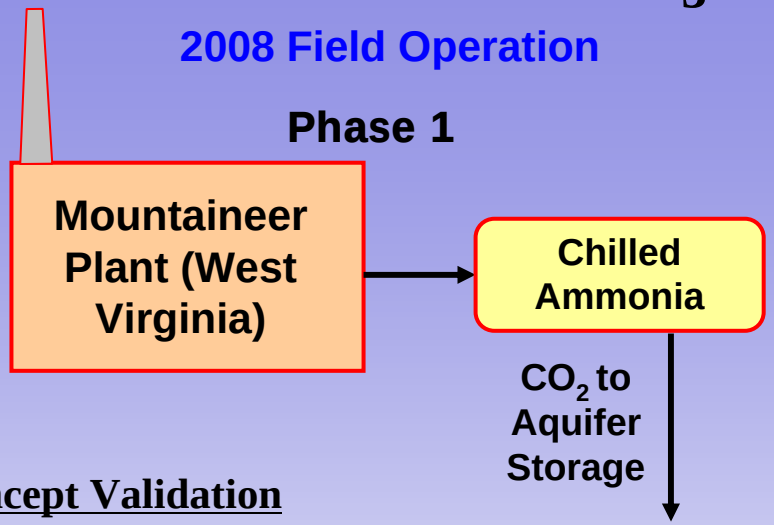
- **~ 200 MW_e (~ 600 MW_{th})**
- **In operation: late 2011**
- **Estimated capital cost: $250 – $300M (*for CO_2 capture, including compression*)**
- **Estimated O&M cost: $12M/year**
- **Energy penalty:**
  - **35 – 50 MW_t steam**
  - **25 – 30 MW_e for CO_2 compression**
- **Retrofit wet FGD + SCR: ~$225 – $300M (*required for CO_2 capture equipment*)**
- **Site: AEP Northeastern Plant, Unit 3 or 4**
- **CO_2 for enhanced oil recovery (EOR)**

Phase 2 will capture and store 1.5×10^6 tonnes CO_2/year

AEP CHILLED NH_3 TECHNOLOGY PROGRAM

2008 Field Operation

Phase 1



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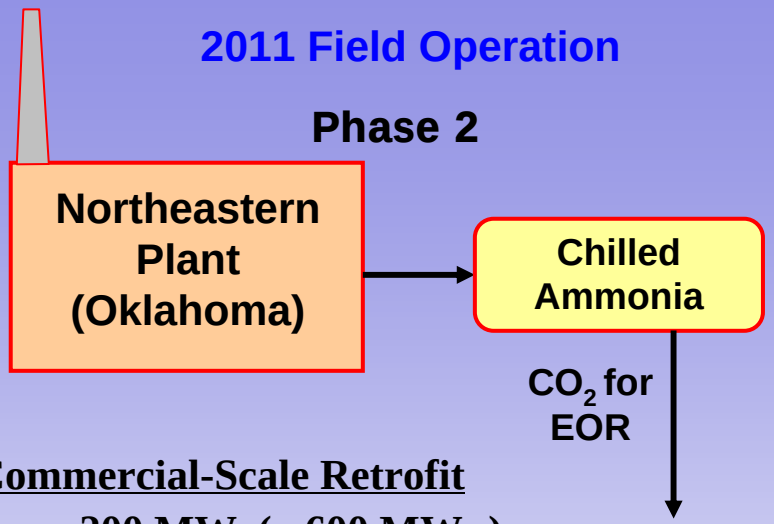

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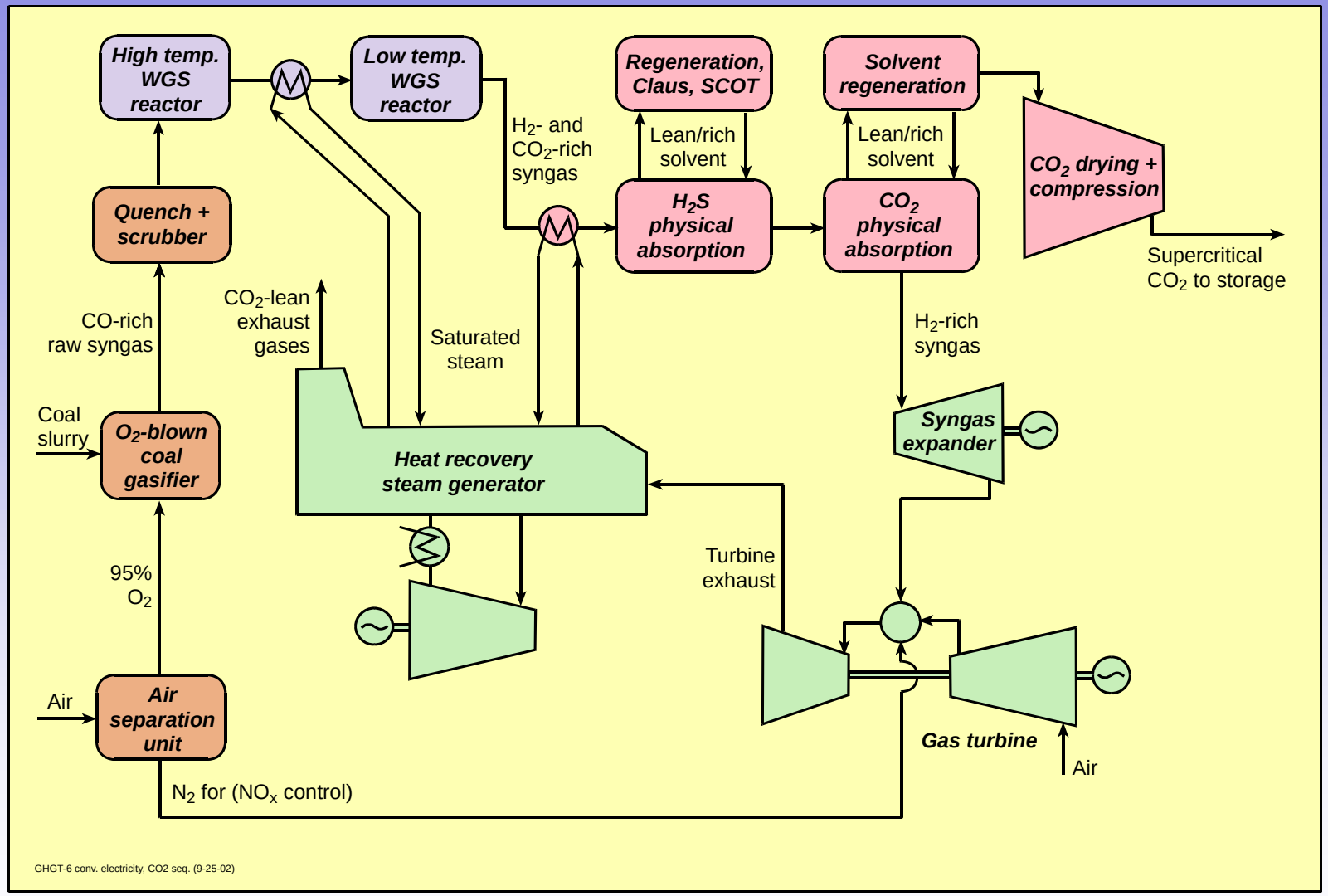
- **Site: AEP Northeastern Plant, Unit 3 or 4**
- **CO_2 for enhanced oil recovery (EOR)**

If chilled NH_3 proves to be viable, it could also be used to reduce capture costs for IGCC, especially by reducing CO_2 compression requirements

COAL IGCC WITH PRECOMBUSTION CO_2 CAPTURE



Precombustion CO_2 at high partial pressure ➔ can use physical solvent

IGCC capture technology will be deployed first with petroleum coke

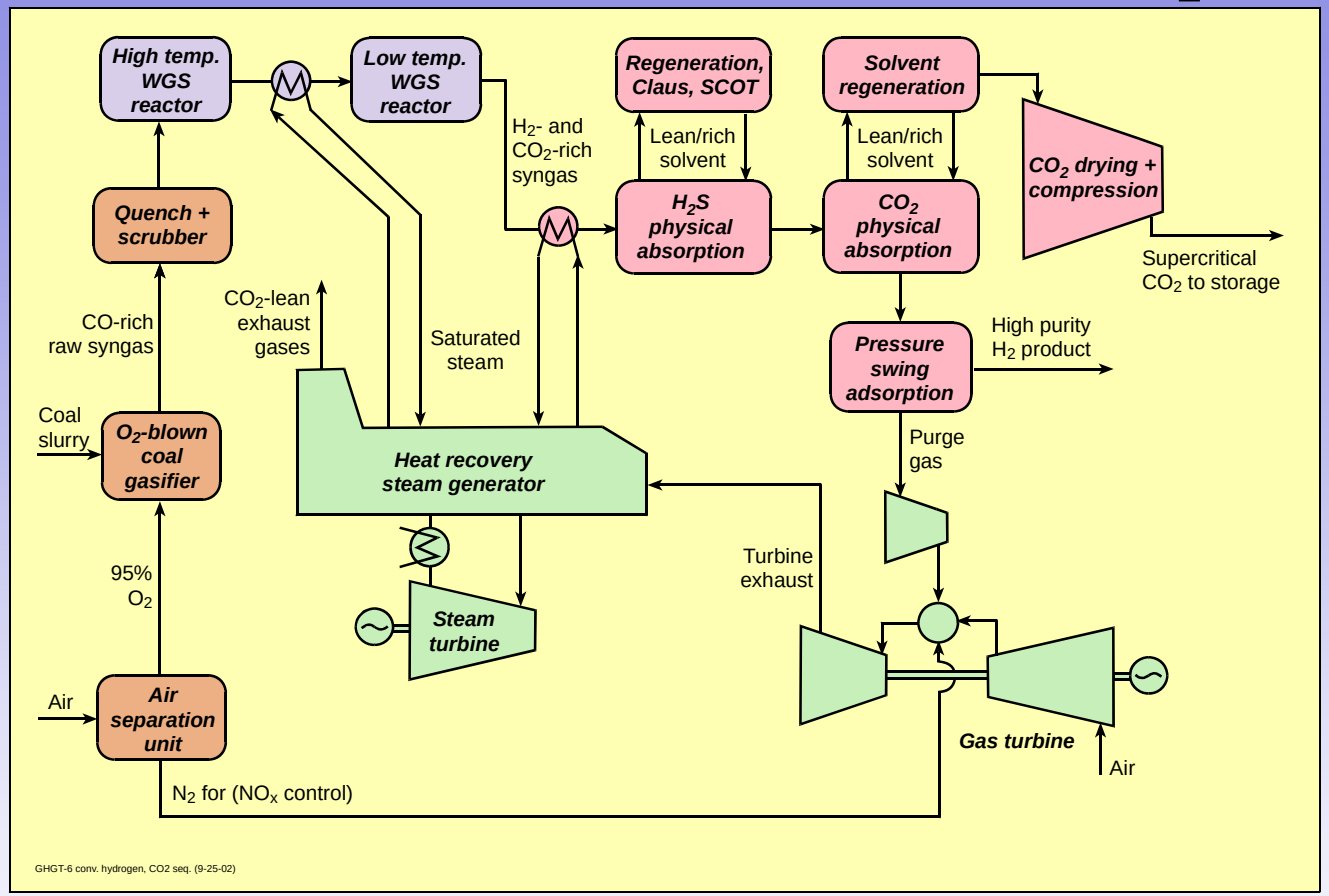
BP CARSON H_2 POWER PROJECT

- Location: BP Carson Refinery, Los Angeles, California
- Plant design:
  - Fuel: 5000-6000 tonnes per day of petcoke
  - 3 GE quench gasifiers (*slurry fed, O_2-blown, entrained flow*)
  - 2 GE 7FB H_2-fired gas turbines
- Products:
  - 500 MW_e
  - 5-6 million tonnes per year of CO_2 for EOR (*~90% capture*)
  - 170-200 MW_t of H_2 for refinery
  - 0-230 tonnes per hour of high pressure steam for refinery
- Project Time Line:
  - 2006 to present: "Select' phase—engineering studies
  - 3Q 2007: "Define' phase—begin FEED study and permitting
  - 3Q 2008: Investment decision and "Execute" phase—begin EPC
  - 1Q 2011: Plant commissioning
  - 1Q 2012: "Operate" phase—plant startup

LOCKWOOD IGCC PROJECT

- Location: Fort Bend County, Texas
- Equity partners: Goldman Sachs/Hunton Energy
- Plant design:
  - Fuel: > 95% petcoke
  - Shell gasifier (*dry fed, O_2-blown, entrained flow*)
- Products:
  - 1200 MW_e
  - 5-6 million tonnes per year of CO_2 for EOR (*up to 75% capture*)
- Project time line:
  - First 600 MW_e unit online 2011
  - Second 600 MW_e unit online 2013

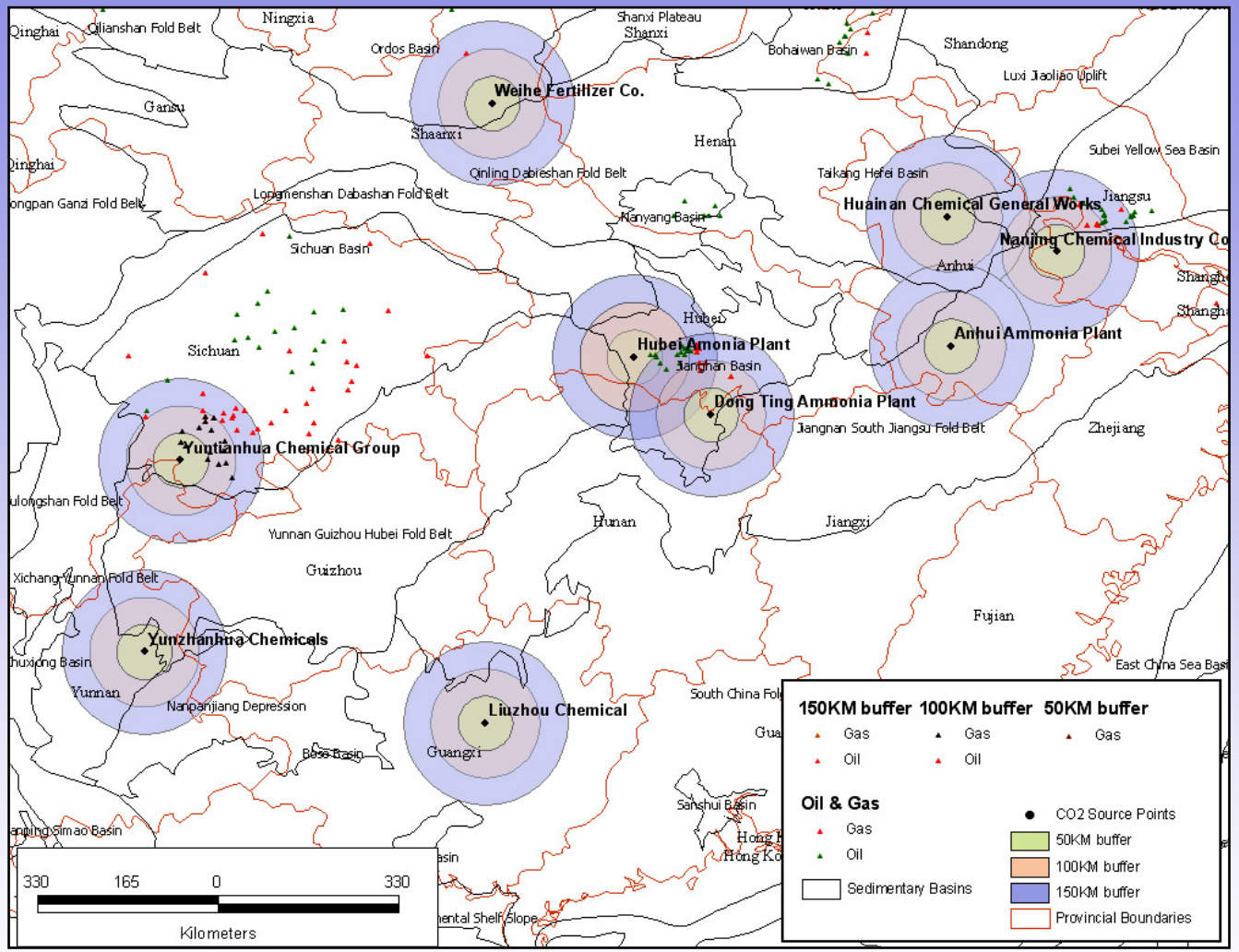
H_2 PRODUCTION FROM COAL WITH CO_2 CAPTURE



Similar to coal IGCC…but WGS reactors + CO_2 capture + solvent regeneration are inherent to H_2 making➔ low CO_2 capture cost

China has many plants making NH_3 from coal using modern gasifiers in this manner …candidate CCS capture demo projects in China?

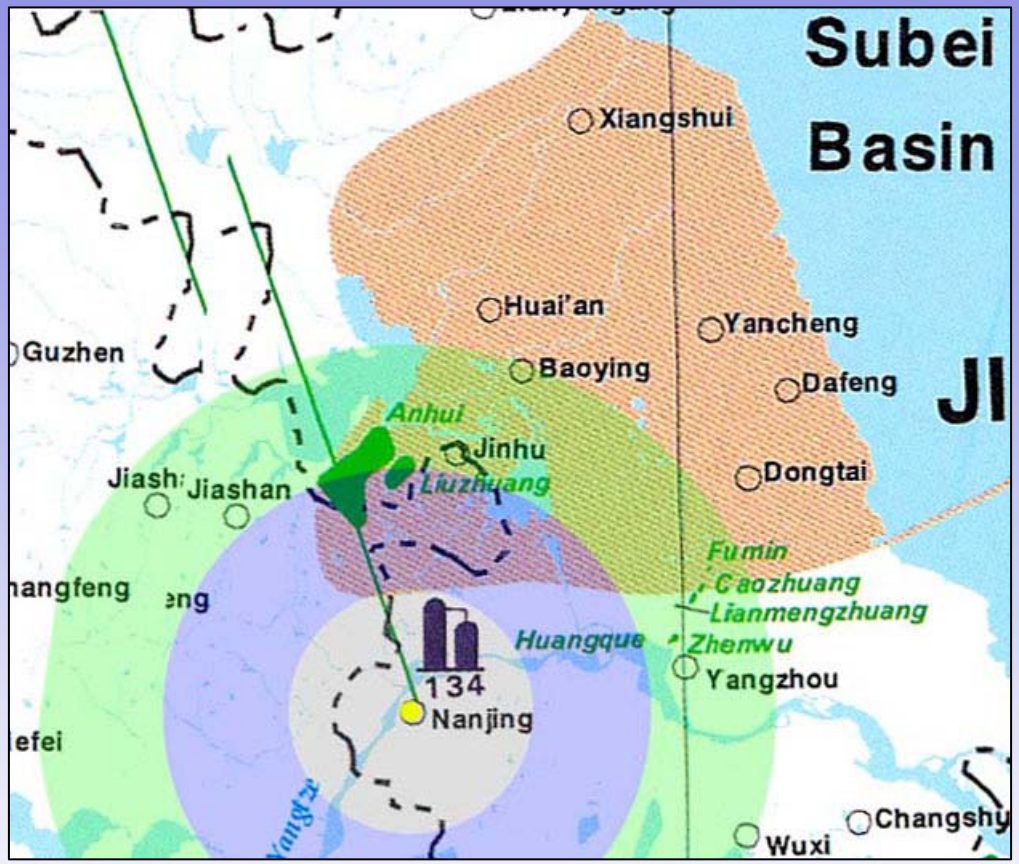
Modern NH_3 Plants in Relation to Known Oil/Gas Fields



4 of these 9 plants are within 150 km of known oil/gas fields

Source: K. Meng, R. Williams, and M. Celia, "Opportunities for Low-Cost CO_2 Storage Demonstration Projects in China, *Energy Policy*, **35**: 2368-2378, 2007

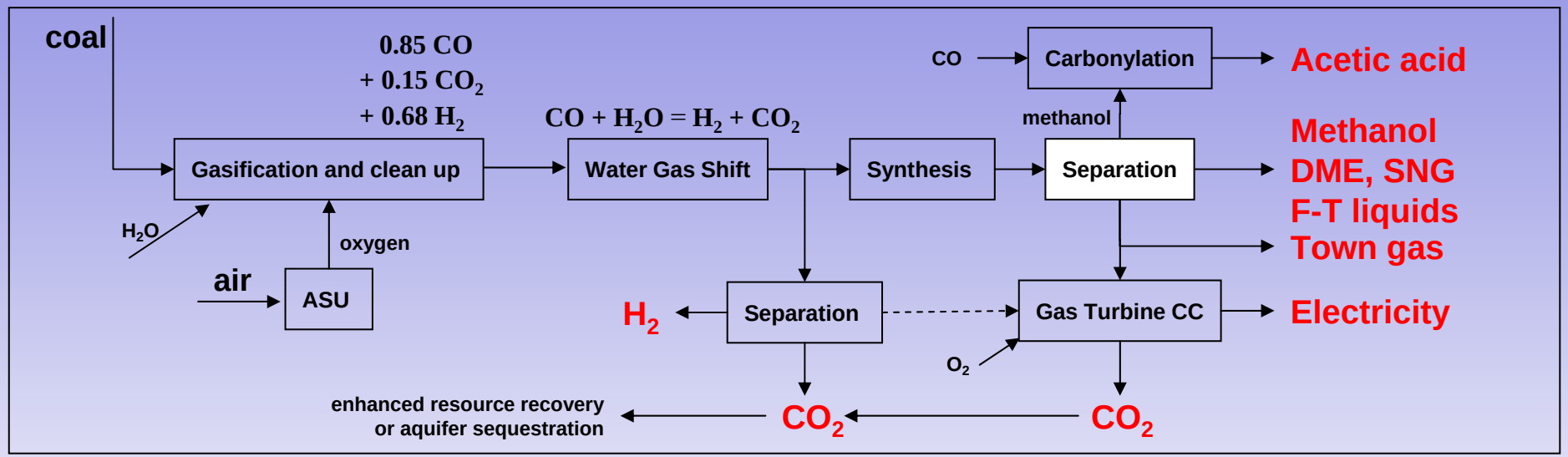
Nanjing NH_3 Plant is 120 km from Zhenwu Oil Field



Nanjing plant (*Jiangsu*) produces (*via Texaco coal gasifier*) 300 kt/y NH_3 + 1493 kt/y CO_2—381 kt/y + 40 kt/y of CO_2 used to make urea + dry ice, and 1071 kt/y potentially available for CCS demo project

Source: K. Meng, R. Williams, and M. Celia (Energy Policy, 2007)

COAL POLYGENERATION – GENERAL SCHEME



As in H_2 case, producing high H/C ratio fuels (*for liquid hydrocarbon fuels, H/C ~ 2*) from coal (*H/C ~ 0.8*) ➔ relatively pure CO_2 coproduct

SASOL plants in South Africa produce 150,000 barrels/day of Fischer-Tropsch (F-T) liquids from coal and vents stream of ~ 20 million tonnes a year of nearly pure CO_2.

As in the case of H_2 plants, the CO_2 at such plants could be captured at very low incremental cost—essentially the cost of CO_2 drying/compression

Sixth Annual Conference on Carbon Capture & Sequestration

Technical Session: Coal to Liquid with Sequestration

Technical, Cost, and Financial Impacts for Carbon Separation and Compression on Large-Scale Coal to Liquids Plants

Michael E. Reed (NETL) and Scott Olson (Nexant)

May 7-10, 2007 • Sheraton Station Square • Pittsburgh, Pennsylvania

HIGHLIGHTS OF F-T Liquids Plant Designs from Reed/Olson (2007)

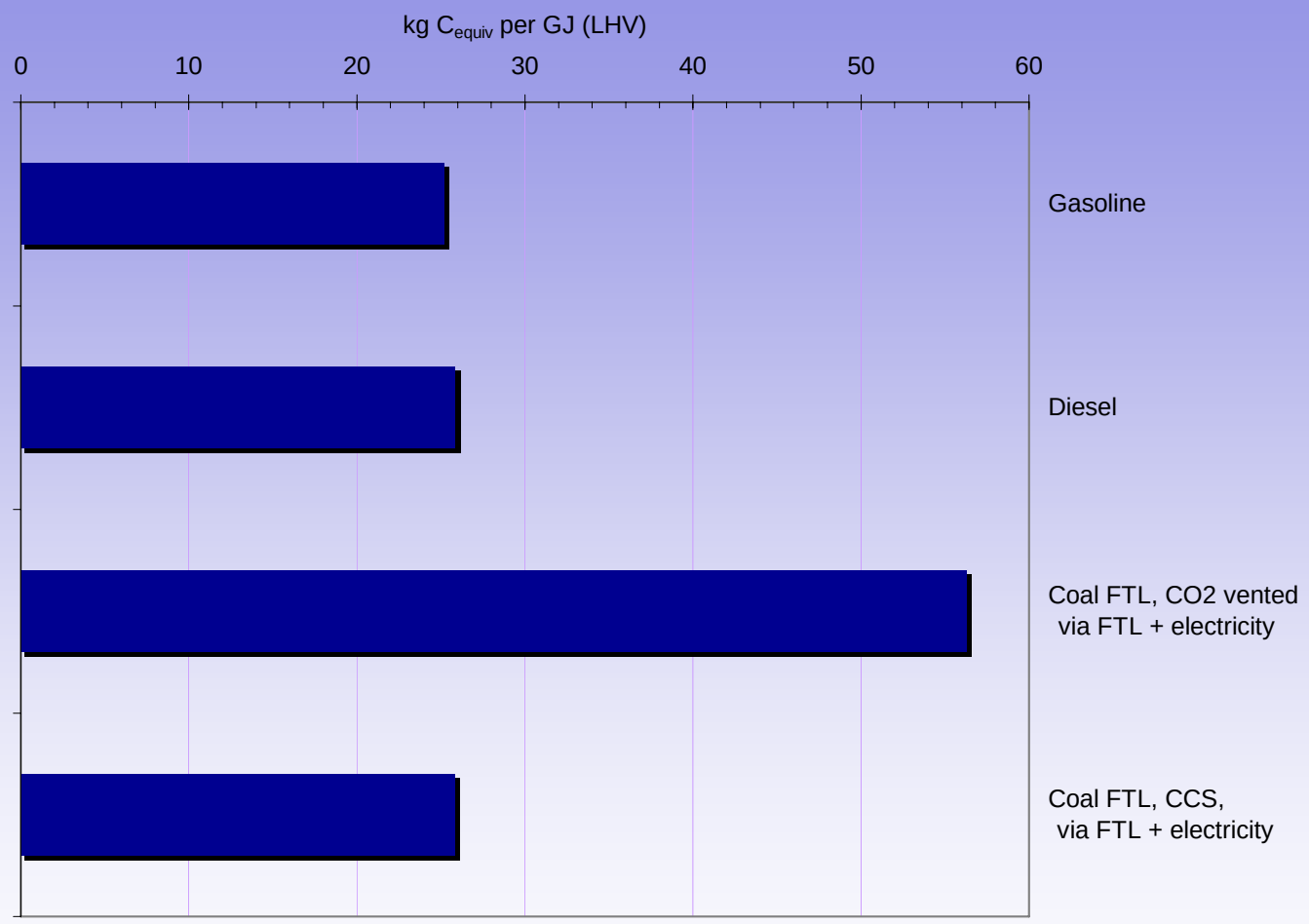
	MW_{LHV}		kgC/s	
Coal input	6666		164.4	
Naptha output	1257		23.8	
Diesel output	1676		33.5	
	Vent	Capture	Vent	Capture
Electricity for export	85.8	23.7	-	
Vented at plant	-	-	105.8	12.9
Captured	-	-	0	92.9
Char in coal ash			1.2	

Alternative F-T liquids plants 50,000 b/d (*1.8×10^6 t/y*). Most CO_2 released at plant in pure stream. Capital cost for plant with CO_2 vented ~ $3.5 billion.

Only cost of capture is CO_2 drying/compression + loss of 62 MW_e of power needed for CO_2 compression that otherwise could be exported/sold into electric grid.

Purchase of CO_2 compressors adds ~ 2% to capital cost of plant

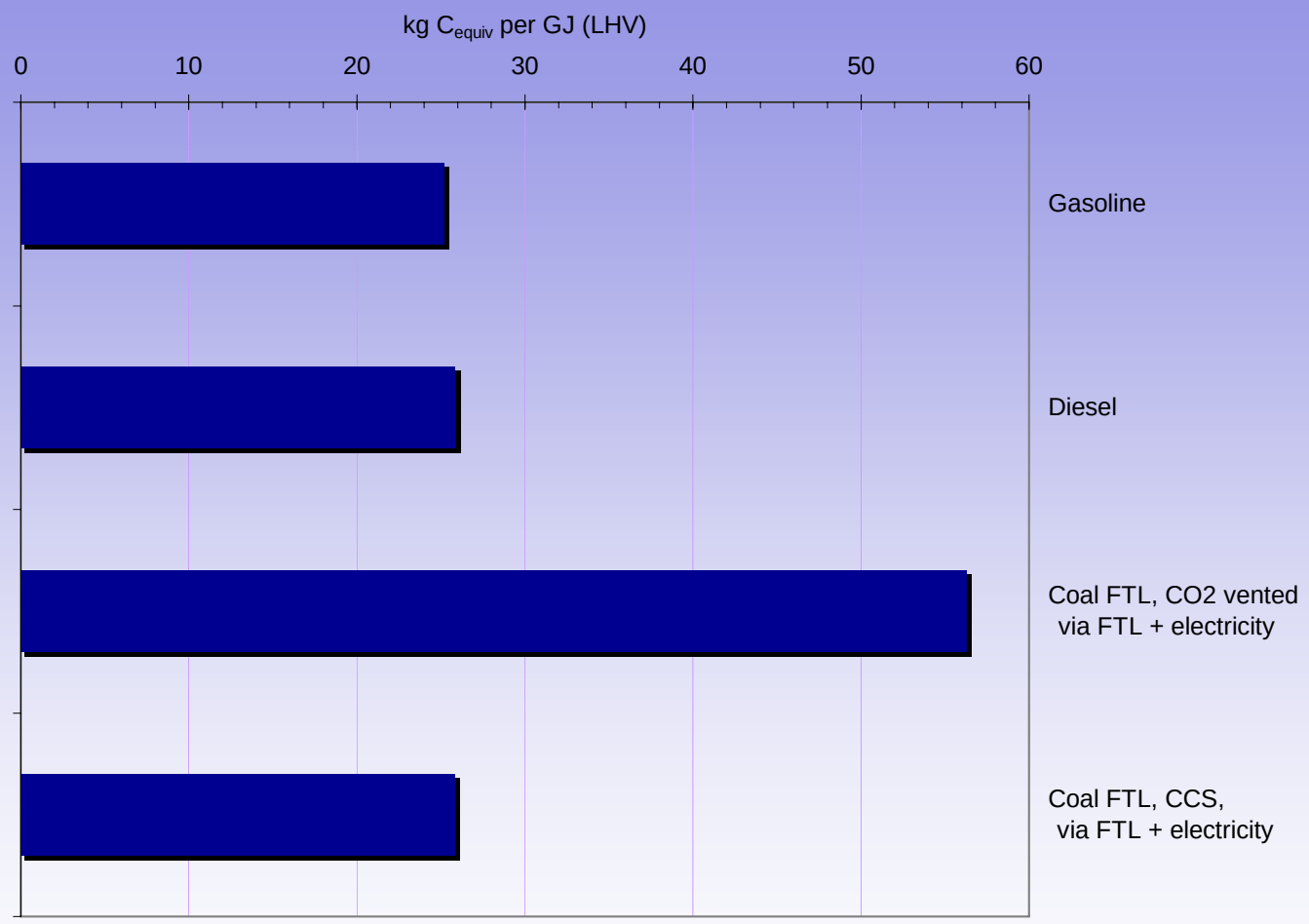
GHG Emission Rates For Fuel Production And Use



With CO_2 vented, GHG emission rate for FTL is more than double that for crude oil-derived hydrocarbon fuels

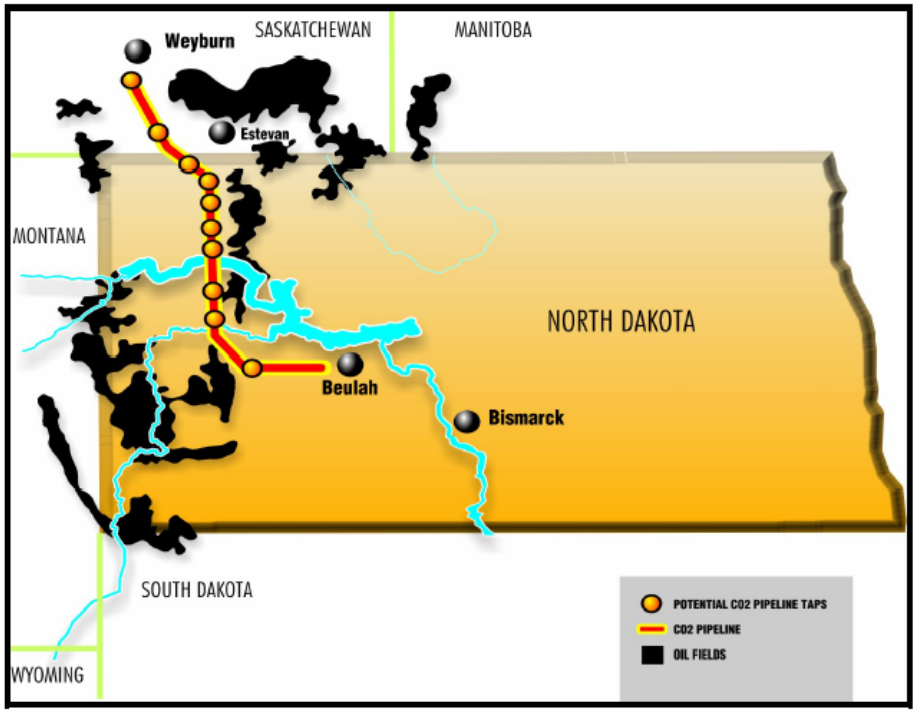
CCS reduces emission rate to that for crude oil-derived HC fuels

GHG Emission Rates For Fuel Production And Use



Based on Reed/Olson (2007), capture cost for reducing FTL GHG emission rate to that for crude oil products displaced is low (~ *\$6/t* CO_2)
—making FTL plants strong candidate CO_2 sources for EOR projects

FIRST PROJECT TO EXPLOIT COAL SYNFUEL-DERIVED CO_2 FOR ENHANCED OIL RECOVERY



- Synfuel plants are source of cheap CO_2 that can be used for EOR
- The $2.1 billion Great Plains Synfuels Plant at Beulah, ND, with capacity to produce up to 4.6 million Nm^3 of methane daily from 16,800 tonnes of lignite, went on line in 1984.
- The GPSP generates as coproduct up to 10,500 tonnes per day of nearly pure CO_2.
- Since 2000 the GPSP has sold 5000 tonnes of CO_2 per day to Encana Corporation for CO_2-EOR at the Weyburn oil field in Saskatchewan, Canada.
- The CO_2 is transported 330 km to the CO_2-EOR site via pipeline.

FTL-CO_2 EOR SYNERGISM

- Synfuels plant with CO_2 capture producing 50,000 barrels/day would produce ~ 9 x 10^6 t CO_2/y (*0.6 tonnes/barrel*) @ $6/tonne CO_2
- ARI (2006) study for US DOE[a] found for US:
  - With state of art CO_2 EOR technology US economic CO_2 EOR potential is ~ 47 x 10^9 barrels (*6.3 x 10^9 tonnes*)
  - Average CO_2 purchase rate = ~ 0.2 tonnes per incremental barrel of crude
  - One of main obstacles to exploitation of potential = adequate/reliable supplies of low cost CO_2
  - At $40 a barrel oil prices, willingness to pay for CO_2 ~ $30/tonne
- Thus making 1 barrel of synfuel could support production of 2.5-3.0 incremental barrels of crude oil via CO_2-EOR
- ➔ Desirable to site synfuel plants near prospective CO_2–EOR sites

[a]Advanced Resources International, *Basin-Oriented Strategies for CO_2 EOR*, reports prepared for the Office of Fossil Energy, Office of Oil and Gas, US Department of Energy, February 2006.

LOW C OBLIGATION FOR COAL ELECTRICITY IN PREPARATION FOR CARBON POLICY

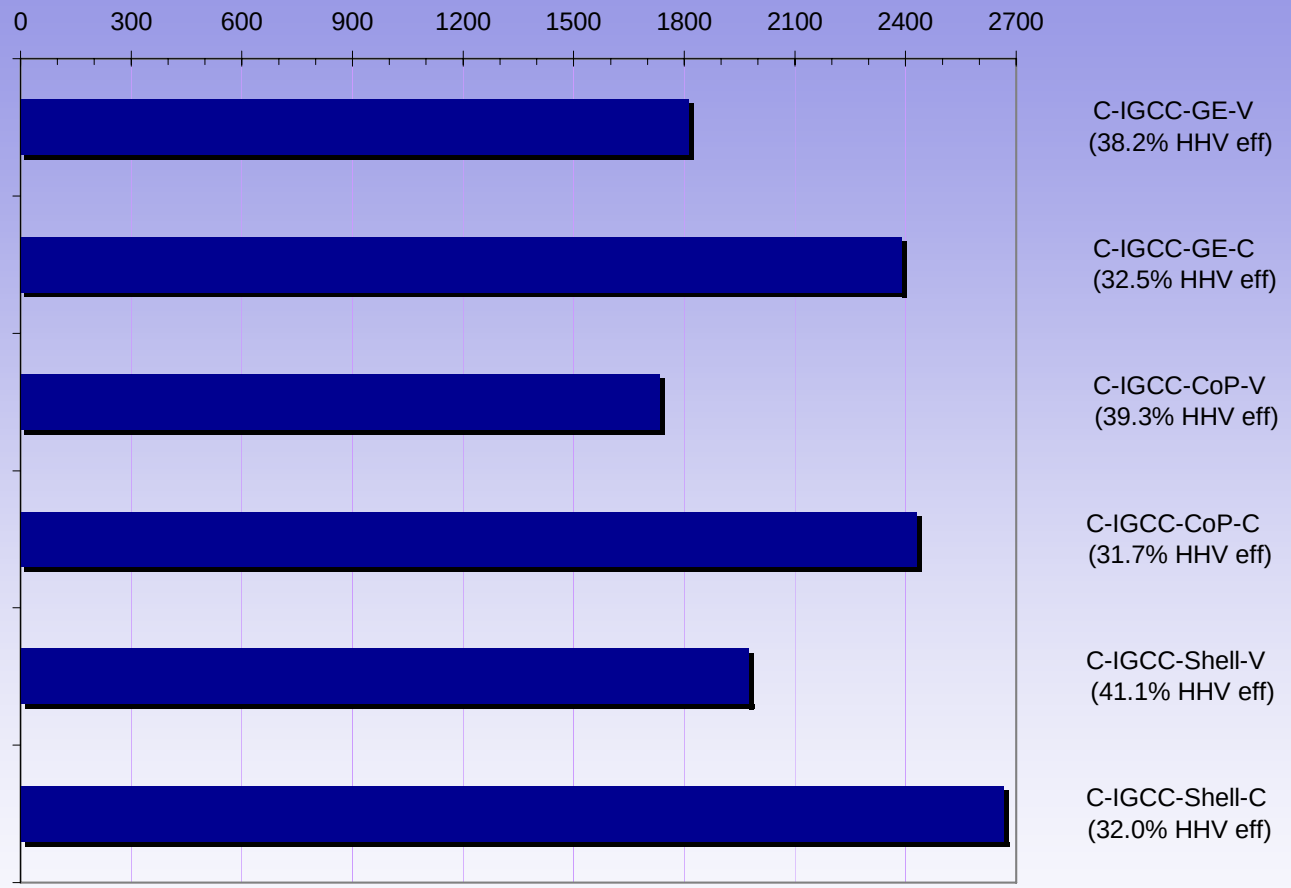
- Suggestion: Establish CCS technologies in market for coal power in preparation for "full-blown" carbon policy by requiring that a growing fraction of coal electricity be decarbonized
- Strategy: Let market pick "winning technologies" via credit trading system like RPS that spreads incremental cost over all coal power generation
- Guaranteed market over fixed period would enable CCS financing
- Competition would foster innovative cost-cutting
- Decarbonization thought experiment for China:
  - 1 GW, 2015 (*0.2% of coal generation*) → 50 GW, 2025 (*6.7% of coal generation*)
  - Make worst case cost assumption: current US incremental cost ($\Delta \sim$ *$40/MWh*)
  - → Incremental cost in 2025 = $14 billion/year
  - Cost increment in 2025 averaged over all coal power generation = $2.7/MWh
- Question: Should international C trading mechanism be developed to help pay for incremental cost?

Thank You!

- Questions?

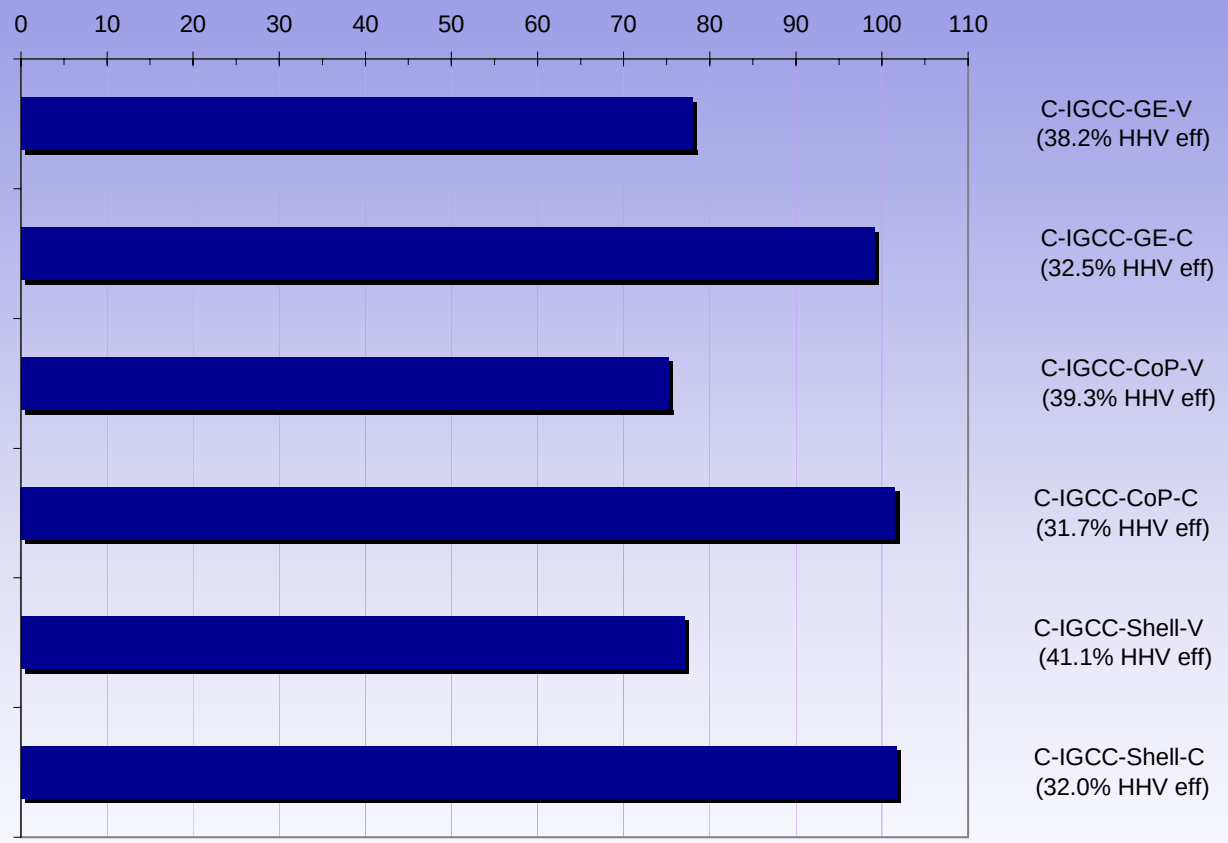
Extra Slides

CAPITAL COST FOR IGCC POWER GENERATION, $/kW$_e$ (*from new NETL study*)

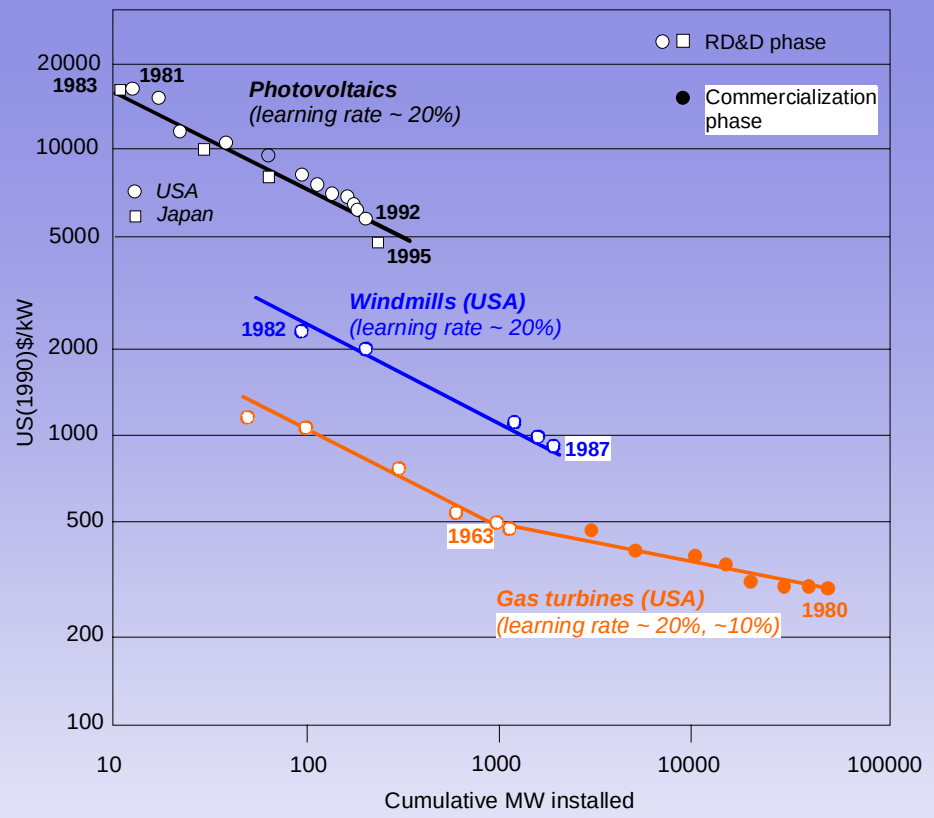


Costs for GE and CoP designs very comparable;
Recently introduced "Quench" design for Shell ➔ all will likely have comparable costs

GENERATION COST FOR IGCC ELECTRICITY, $/MWh (*from new NETL study—with slight modification*)



Very little cost variation among options;
Have assumed CF = 85% for Shell (*no refractory replacement required*)



Experience Curves for Energy Technologies

Source: Nakicenovic, N., A. Grübler, and A. MacDonald, *Global Energy Perspectives*, Cambridge University Press, Cambridge, U.K., 1998.

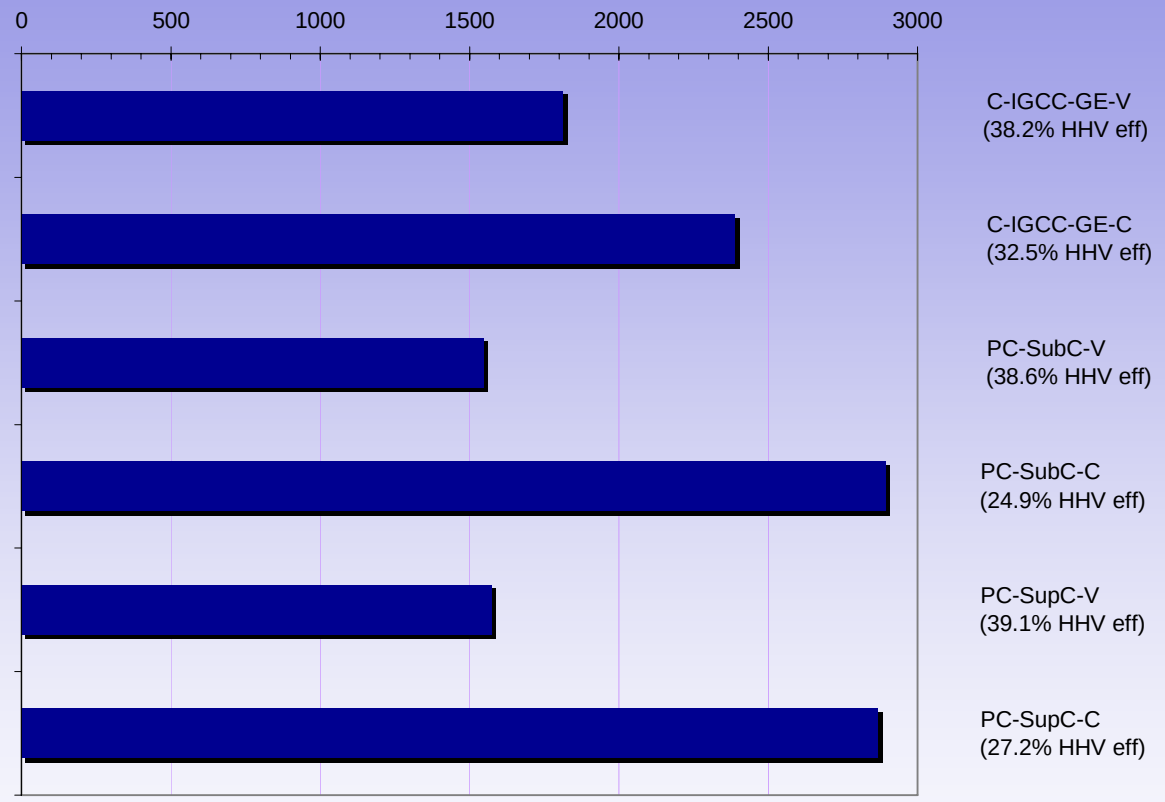
These curves illustrate the well-established phenomenon that technology prices tend to decline with cumulative production—so that costs decline much more rapidly over time for new technologies (*e.g., IGCC power plants*) than for mature technologies (*e.g., steam-electric power plants*)

EXPECTED COST REDUCTION AFTER INSTALLATION OF 100 GW_e OF COAL POWER PLANTS WITH CO_2 CAPTURE

Technology	% change in:		Electricity cost ($/MWh)	
	Capital cost	Electricity cost	Initial	Final
Steam-electric plant, post-combustion capture	9	14	73	63 (58 – 69)
IGCC, pre-combustion capture	18	18	63	52 (46 – 58)
Oxy-combustion	9	10	79	71 (67 – 76)

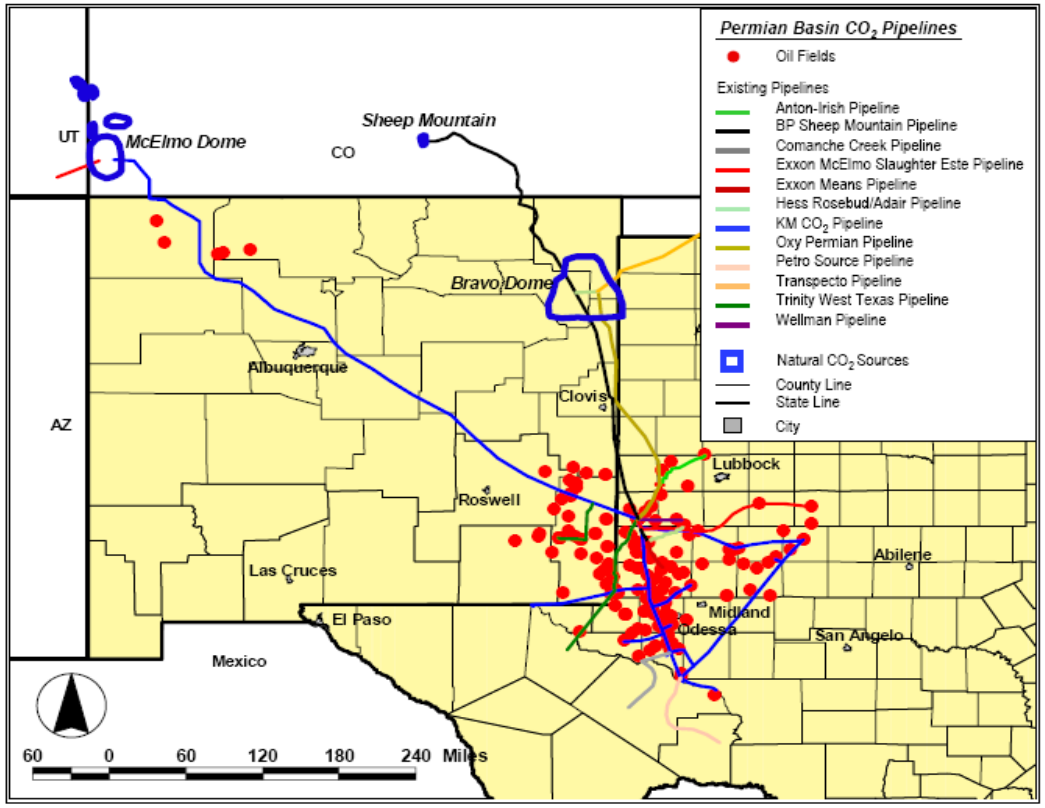
Source: E.S. Rubin (*Department of Engineering and Public Policy, Carnegie Mellon University*), M. Antes, S. Yeh, and M. Berkenpas, *Estimating the Future Trends in the Cost of CO_2 Capture Technologies*, Report Number: 2006/6, Greenhouse Gase R&D Programme of the International Energy Agency, February 2006.

CAPITAL COST FOR POWER GENERATION, $/kW$_e$ (*from new NETL study*)



Capital cost (*relative to PC-SupC-V*): 1.82 (*PC-SupC-C*); 1.52 (*C-IGCC-GE-C*)

Current technologies;
Huge recent increases in costs for construction materials/labor are taken into account



There is already a highly developed CO_2 pipeline transport infrastructure for CO_2 EOR in the Permian Basin

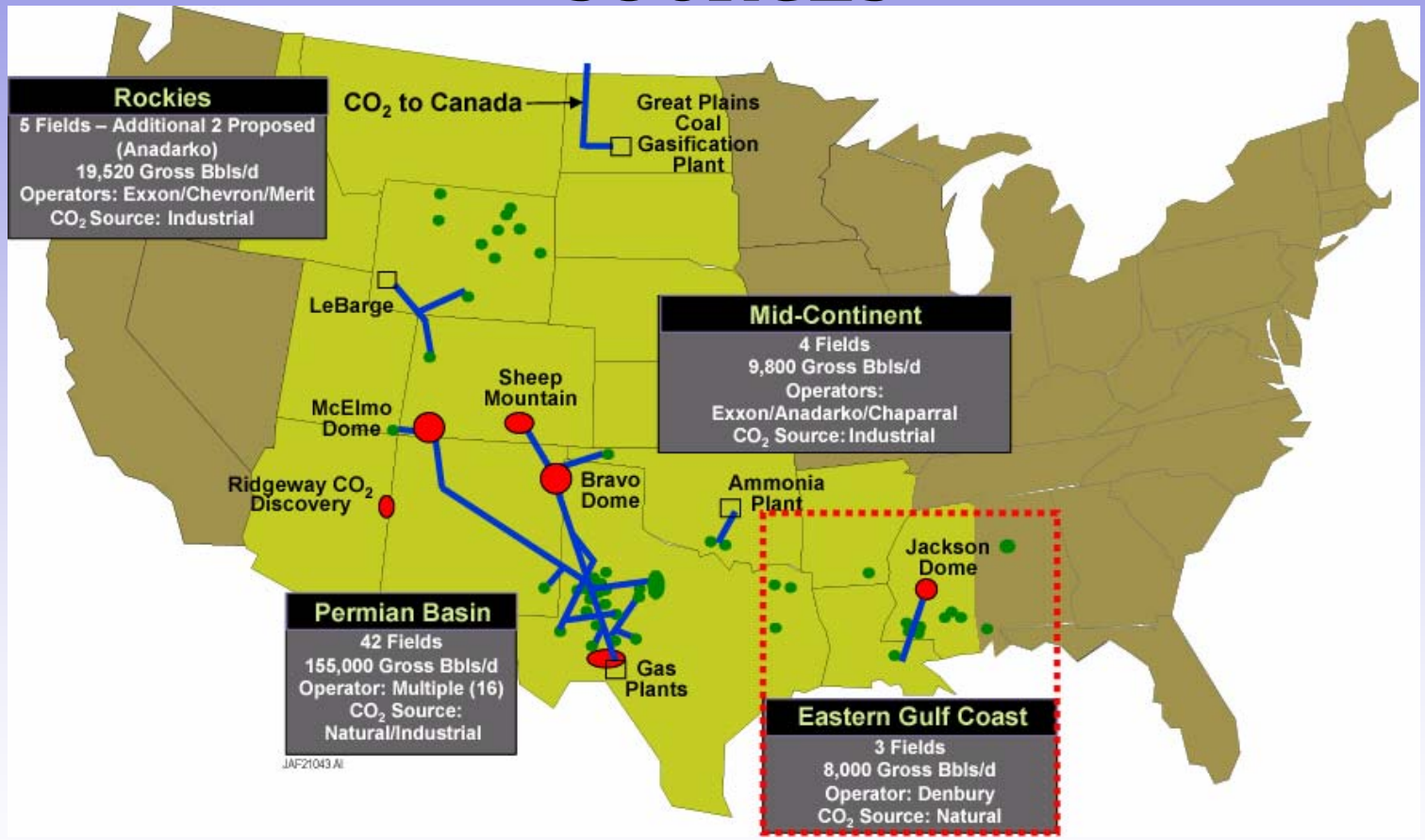
CO_2 EOR Potential—West Texas in Permian Basin

[15%/year rate of return, $40/barrel oil price, $30/tonne CO_2 price]

Economic Potential = 8.6 x 10^9 barrels (*1.2 x 10^9 tonnes*)

Source: Advanced Resources International, *Basin-Oriented Strategies for CO_2 EOR: Permian Basin*, report prepared for the Office of Fossil Energy, Office of Oil and Gas, US Department of Energy, February 2006.

EXTENSIVE US EXPERIENCE WITH CO_2 TRANSPORT FOR ENHANCED OIL RECOVERY …MOST CO_2 IS FROM NATURAL SOURCES



This pipeline network provides CO_2 to support crude oil production at 200,000 barrels per day—4 % of total US crude oil production