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Clean Coal Technology Status: CO_2 Capture & Storage

Technology Briefing for
COLORADO RURAL ELECTRIC ASSOCIATION
February 19, 2007

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Context

- U.S. DoE Energy Information Agency 2007 Annual Energy Outlook projects ~40% load growth by 2030
- Consensus is that some form of CO_2 emissions control legislation will emerge.
- Electricity sector represents ~40% of U.S. CO_2 emissions.
- ~51% of U.S. electricity generation is coal-based – EIA projects ~60% in 2030.
- Analyses indicate that a portfolio of technologies will be required to have a good chance to meet probable CO_2 emissions goals.
- Coupling of energy independence priority and CO_2 concerns make coal a critical part of the portfolio.

Outline

- IGCC

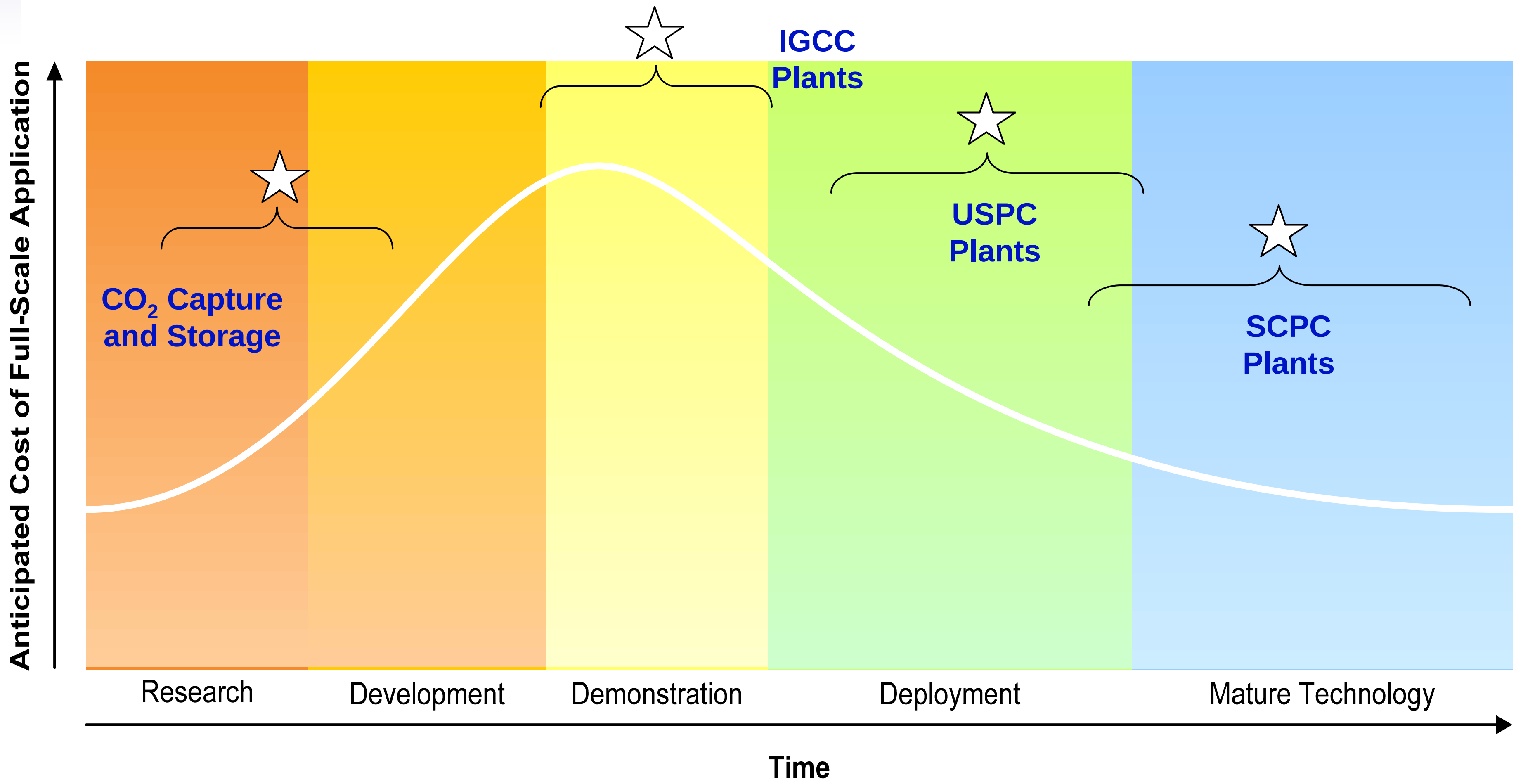
  Status, New Plants with Water-Gas Shift and Capture, Potential Improvements

- PC Post-Combustion Removal

  Status, Potential Improvements, EPRI-Alstom Chilled Ammonia Pilot

- CO_2 Capture and Storage Options

New Technology Deployment Curve



CO_2 Capture from Coal Gasification Plants

- IGCC and CO_2 removal are offered commercially, but have not operated in a mature integrated manner
  - **Big issues: IGCC Cost (particularly with low- rank coals and high elevation), Integration, H_2 Turbines, and CO_2 Storage**
- **Vital Need for Multiple Integrated CCS Demos at >1 million ton-CO_2/year**
- No coal-gasification-based power plant (IGCC) currently recovers CO_2 from the process
  - Three U.S. non-power facilities (Coffeyville, Eastman, and Great Plains) and many plants in China recover CO_2
  - Recovered CO_2 from the Great Plains plant is used for enhanced oil recovery – 2.7 million ton-CO_2/yr (~300 MWe if it were an IGCC)

Great Plains Synfuels Plant
http://www.dakotagas.com/Companyinfo/index.html

Weyburn Pipeline
http://www.ptrc.ca/access/DesktopDefault.aspx

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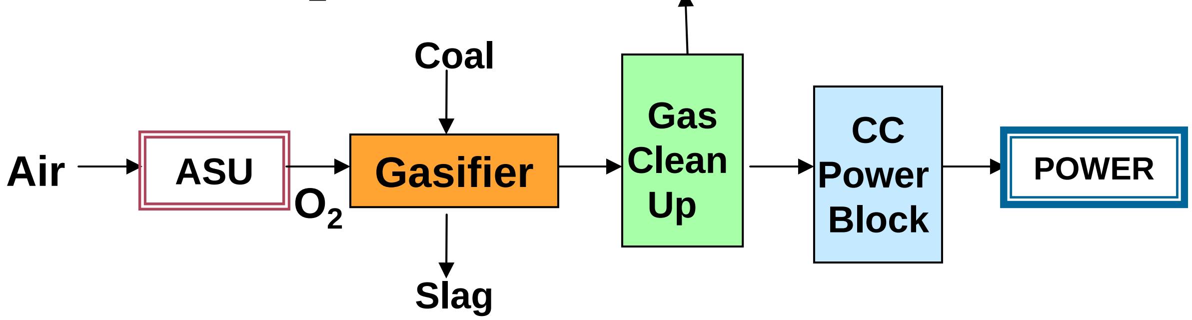
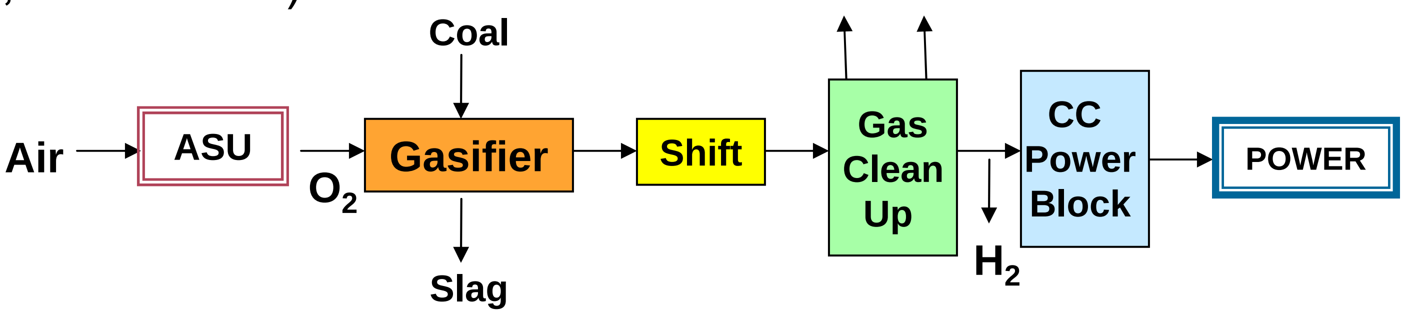
IGCC Without and With CO_2 Removal

IGCC without CO_2 Capture



IGCC with CO_2 Capture

(e.g., FutureGen)



CO_2 Capture = $, Space, Shift, H_2 Firing, CO_2 Removal, Energy

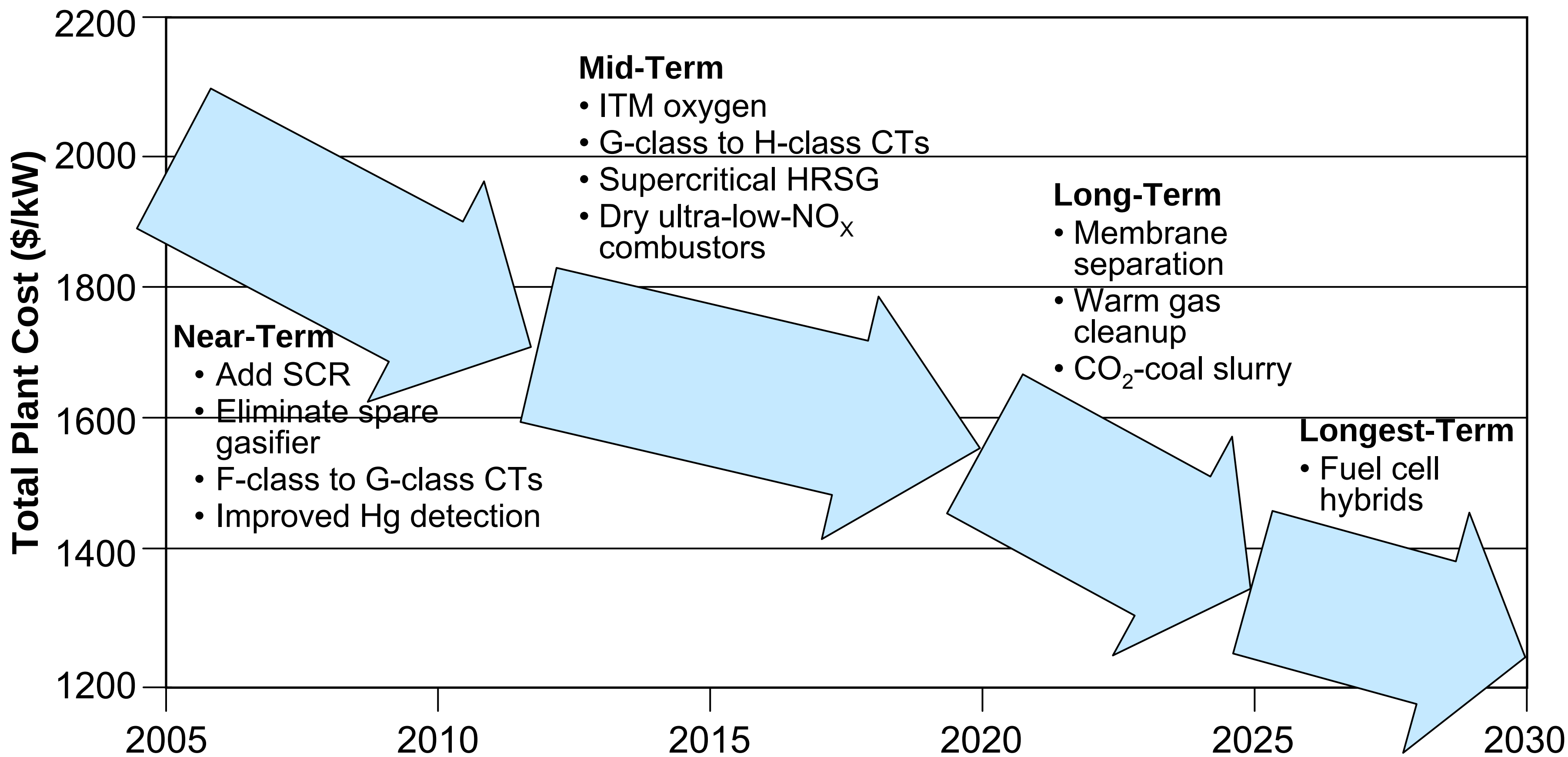
IGCC/Gasification Improvements Needed for More Cost-Effective CO_2 Capture

- Need gas turbines that enable air extraction across the ambient temperature range and with hydrogen firing

- Need larger, higher pressure, lower cost quench gasifiers for CO_2 capture and new GTs for IGCC to have a potential advantage over PC for CCS

IGCC RD&D Augmentation—Expected Capital Reductions

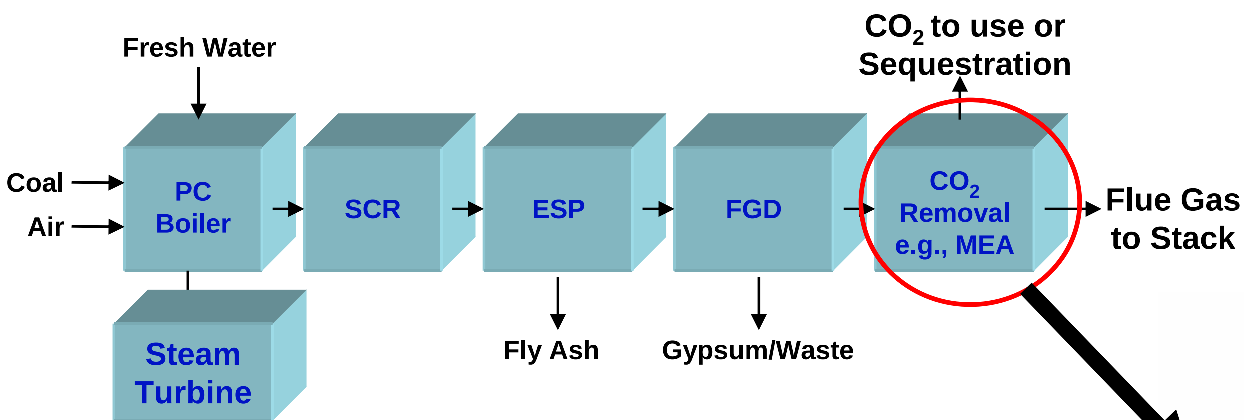
Case: Slurry-fed gasifier, Pittsburgh #8 coal, 90% availability, 90% CO_2 capture, 2Q 2005 dollars

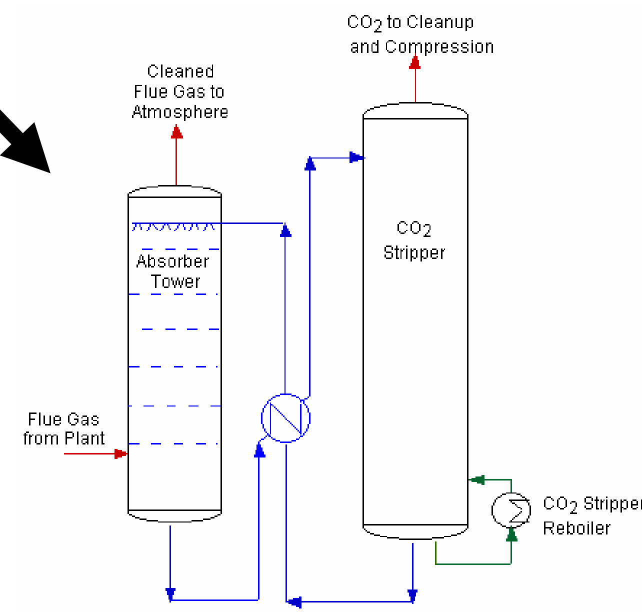


IGCC Pre-Investment Options for Later Addition of CO_2 Capture

- **Standard Provisions**
  – Space for additional equipment, BOP, and site access at later date
  – Net power capacity, efficiency, and cost penalty upon conversion to capture
- **Moderate Provisions**
  – Additional ASU, gasification, and gas clean-up is needed to fully load the GTs when shift is added
  – If this oversizing is included in the initial IGCC investment, the capacity can be used in the pre-capture phase for supplemental firing or co-production
  – This version of "capture ready" would then permit full GT output with hydrogen (at ISO) when capture is added. Mitigates the cost and efficiency penalty.
  – However, when shift is added, considerable AGR modifications will be required (See following slides)
- **Extensive Provisions**
  – Design with conversion-shift reactors, oversized components, AGR absorber sized for shifted syngas, but no CO_2 absorber and compressor
  – No need for major shutdown to complete the conversion to CO_2 capture

Pulverized Coal with CO_2 Capture





- Amine commercially available (multiple suppliers)

- 3 U.S. plants in operation
  - MEA, $\leq$15 MWe, $\geq$90% ΔCO_2

- Key requirements
  - ~5-6 acres for 600 MW plant
  - Near-zero SO_2 and NO_2
  - Large reboiler steam (MEA>KS-1>Ammonia)

- Many new process options being explored

Potential Improvements for Post-Combustion CO_2 Capture

- **Alternative equipment arrangements and designs**
  - Membrane absorbers, regenerator, separation
- **Alternative solvents**
  - Hindered amine (MHI KS-1)
  - Piperazine addition (promoter) to K_2CO_3
  - Other amines
  - Ionic liquids
  - MOF
  - Ammonia and chilled ammonia
- **Adsorption technologies**
  - Amine-enriched solids
  - K, Na, and Ca carbonates
  - Lithium oxide
- **Cryogenic cooling of flue gas**

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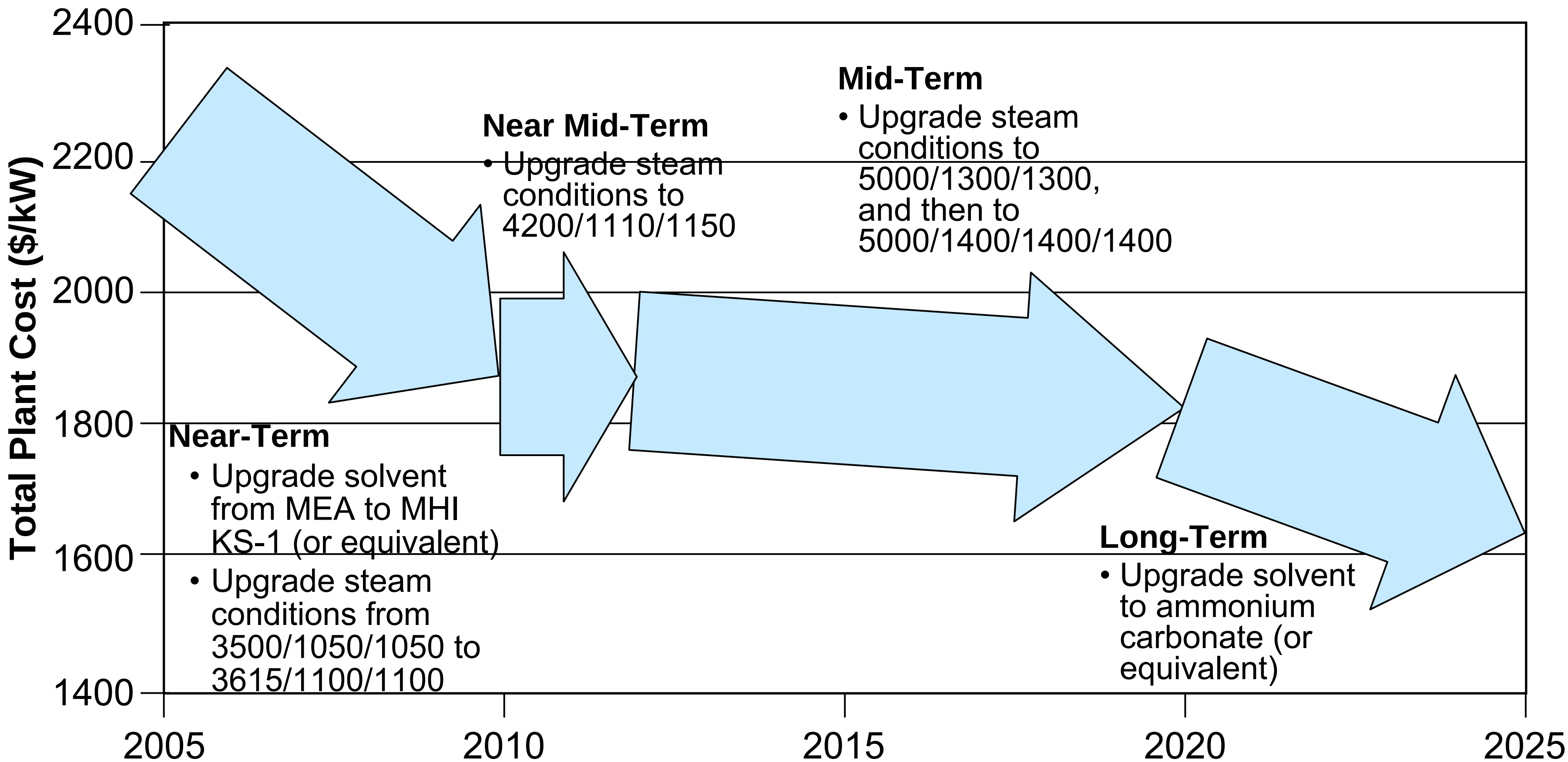
USC PC RD&D Augmentation—Expected Capital Reductions

Case: Pittsburgh #8 coal, 90% availability, 90% CO_2 capture, as-reported data from various studies (not standardized)



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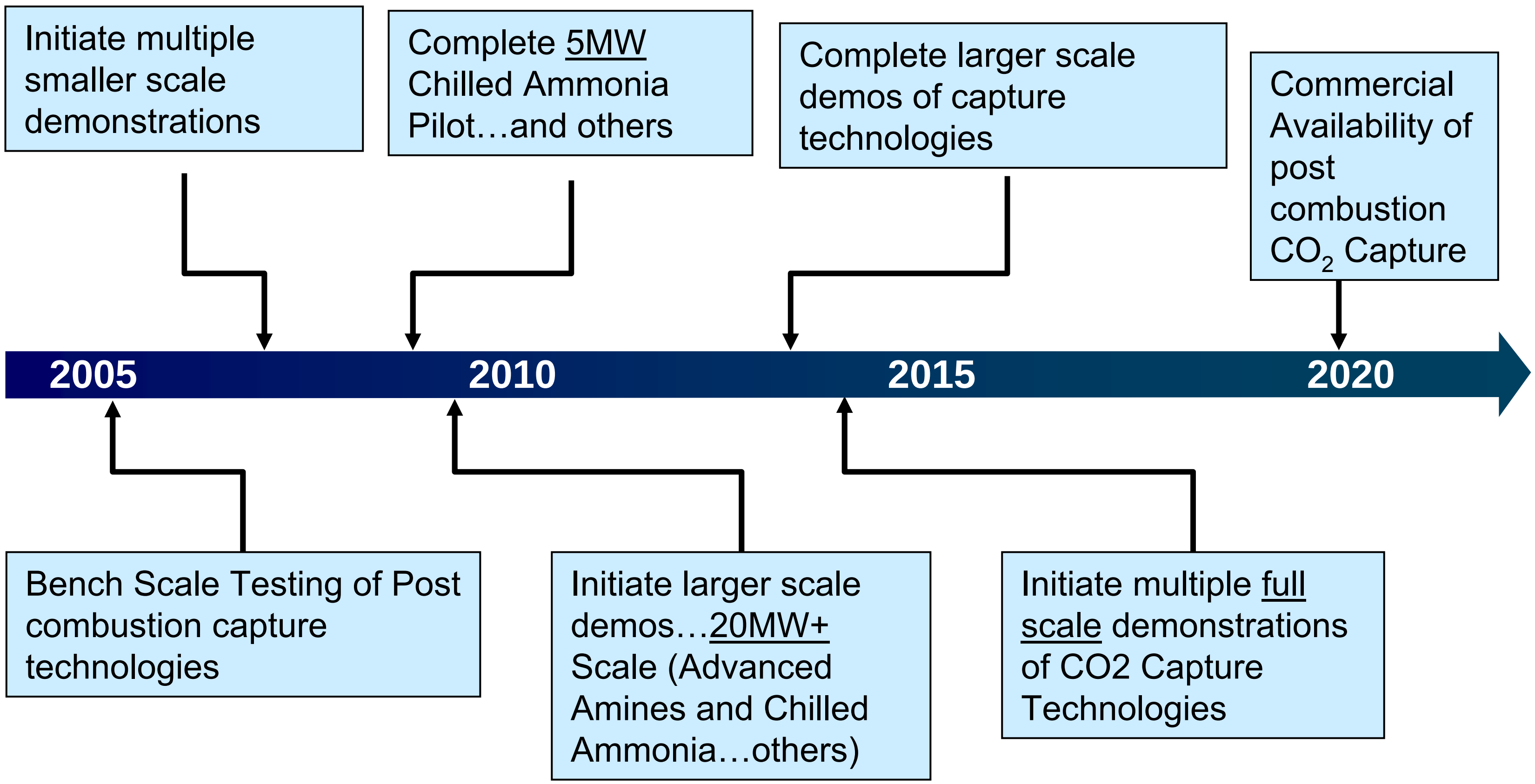
Timeline: Post Combustion Capture



Source: DOE-NETL Carbon Sequestration R&D Roadmap

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Chilled Ammonia Process Performance Prediction (Early Data Only)

Used Parsons Study for basis	Supercritical PC Without CO_2 Removal	Supercritical PC With MEA CO_2 Removal	Supercritical PC With NH_3 CO_2 Removal
LP steam extraction, lb/hr	0	1,220,000	270,000
Power loss, kWe	0	90,000	20,000
GROSS POWER, kWe	491,000	402,000	471,300
AUXILIARY LOAD, kWe			
Induced draft fan	5,000	19,900	10,000
Pumping CO_2 system	0	1,900	5,000
Chillers	0	0	8,900
CO_2 compressor	0	30,000	9,500
NET POWER OUTPUT	462,000	330,000	415,000
% POWER REDUCTION		29	10

Source: Nexant

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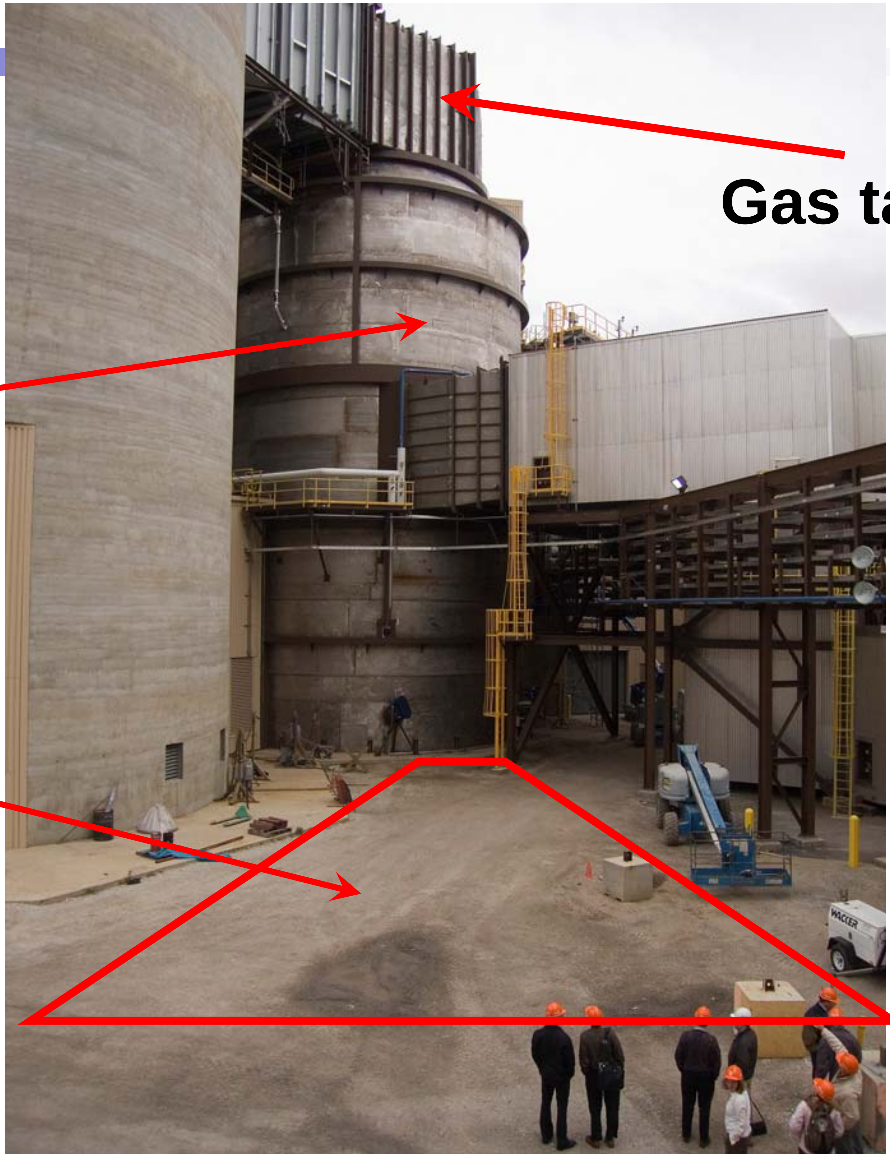
5-MW Chilled Ammonia CO_2 Capture Pilot Participants

AEP
Ameren
CPS Energy
Dairyland
DTE Energy
Duke
Dynegy
E.ON U.S.
Exelon

First Energy
Great River Energy
Hoosier
KCPL
MidAmerican
NPPD
Oglethorpe
PacifiCorp
PNM

Sierra Pacific
SRP
Southern Co.
Tri-State
TXU
TVA
We Energies
Xcel

5-MW Chilled Ammonia CO_2 Pilot Capture Pilot



Gas takeoff

Scrubber module

CO_2 pilot location

CO_2 Capture - Key Factors

- **Coal type**
- **Site Characteristics**
  - Elevation (e.g. at 5000 ft. elevation, IGCC MW reduced by ~15%, so PC with capture probably favored economically)
  - Average Ambient Temperature
  - Water Availability/Quality
- **Plant Technology**
  - IGCC - gasifier type
  - USC/SCPC – post combustion capture technology
  - To achieve CO2 emissions <1100 lb/MWh, need 90% removal on 50% of the syngas or 50% of PC flue gas
- **Financing – Municipal vs. IOU**

Performance Attributes – No CO_2 Capture

	PC Fleet Average	NSPS 2006	SCPC (1050°F Steam) w/ SCR	USPC (1100°F Steam) w/ SCR	IGCC (E-Gas Gasifier) No SCR	NGCC (GE 7FB) w/SCR
Efficiency (HHV Basis) PRB / Bit.	33%	--	37% 38%	38% 39%	36% 39%	50%
CO_2 lb/MW-hr	2,249	--	1,930 1,825	1,900 1,800	1,860 1,770	790
SO_2 lb/MW-hr	13	1.4	0.2 1.1	0.2 1.1	0.11	nil
NOx lb/MW-hr	6	1.0	0.27 0.45	0.27 0.44	0.55	0.1
Particulate lb/MW-hr	1	0.2	0.135	0.135	0.1	nil
Relative LCOE	↑	--	↑	↑	↑	↑

Emissions profiles for SOA PC and IGCC are similar

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City Public Service San Antonio

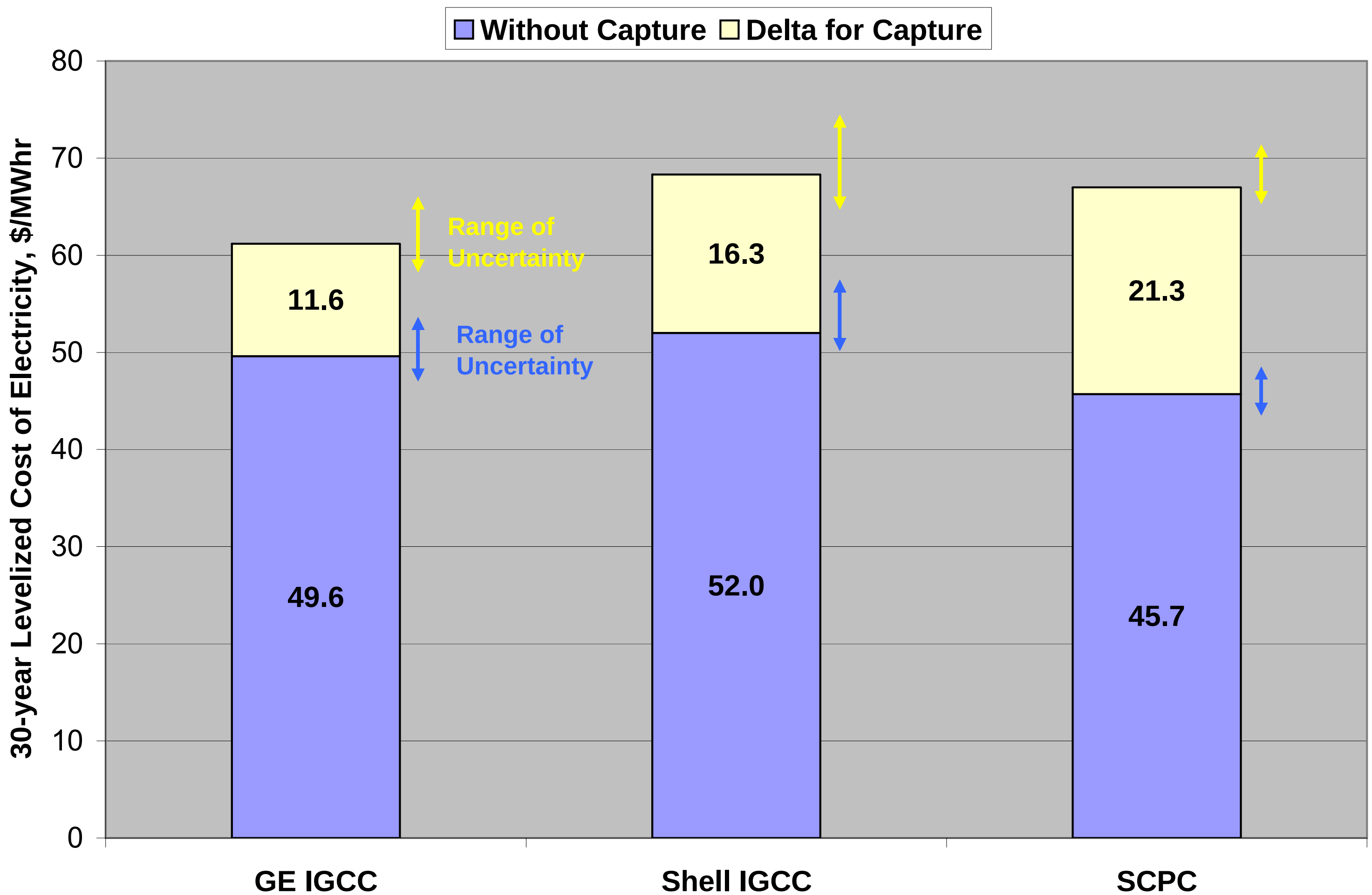
IGCC/SCPC with and without CO_2 Capture PRB Study

	NSPS 2006	SCPC	SCPC w/ Capture	IGCC	IGCC* w/ Capture
Efficiency	--	37%	26%	37%	27%
CO_2 lb/MW-hr	--	1,970	280	1,980	280
SO_2 lb/MW-hr	1.4	0.55	0.003	0.17	0.05
NOx lb/MW-hr	1.0	0.5	0.6	0.6	0.8
Particulate lb/MW-hr	0.2	0.14	0.19	0.07	0.09

*IGCC with CO_2 capture case optimization forthcoming. Efficiency improvements are anticipated.

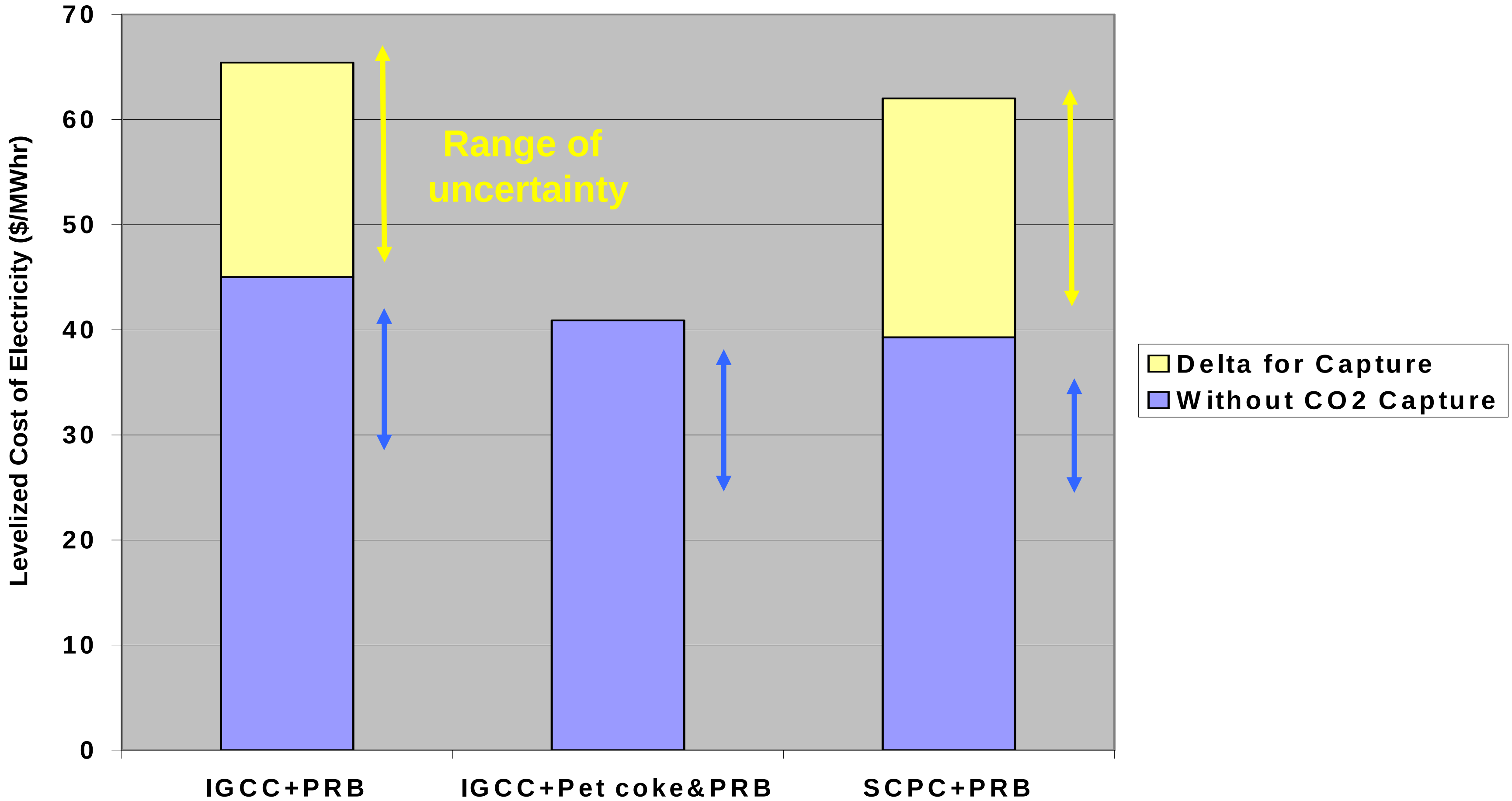
IGCC/SCPC Comparable Emissions Performance

IEA Study IGCC & SCPC w/ and w/o Capture
(Bituminous coal-fired power generation)



IGCC has apparent Advantage for CO_2 Capture with Bituminous coal

EPRI/CPS Study IGCC & PC w/ and w/o CO_2 Capture
(Low-Rank Coal) (2006 EPRI study 1014510)
(Texas location and municipal utility financing)



SCPC has apparent Advantage for CO_2 Capture with PRB coal

Drivers Affecting Technology Selection– N^{th} Plant Economics

	IGCC w/ CCS	PC w/ CCS
Bituminous Coal **Water Use Limits** **Low Elevation** **Co-production of H_2, SNG, Liquids**	Favored	
Sub-bituminous coal	Water use limits Lower elevation Lower moisture Lower ash	Higher elevation Higher moisture Higher ash Higher ambient temp.
Lignites (high moisture, high ash)		Favored

EPRI Programs for 2007

- **P66: CoalFleet for Tomorrow – Future Coal Generation Options**

  Focus on Deployment of New Plants, Designs for Capture Readiness, and Capture

  - 66A Economic and Technical Overview (IGCC, PC, CFBC)
  - 66B Gasification – IGCC and Co-production (Hydrogen, SNG, F-T, etc.)
  - 66C Combustion – USC PC, Advanced materials, CFBC, Oxy-Fuel

- **P165: CO_2 Capture & Storage**

  Focus on Post-Combustion Capture and Sequestration

  - Participation in U.S. Regional Carbon Sequestration Partnerships, CCP2, IEA GHG
  - Capture focus – process development
  - Chilled Ammonia (ABS) 5-MW Pilot Plant

Questions?

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Supplemental Slides –
CPS Study on IGCC and PC

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CPS San Antonio IGCC Study—Project Background and Overview
Source EPRI Report 1014510

- CPS Energy is constructing a 750-MW subcritical PC plant fired with PRB coal. The plant is known as Spruce 2, southeast of San Antonio.
- The plan was opposed by some environmental groups because of the projected greenhouse gas and mercury emissions
- As part of a settlement with the environmental group, CPS Energy agreed to enhance its energy conservation and renewable energy programs and to pay increased attention to CO_2 emissions from future coal plants
- CPS Energy also committed to fund a study of IGCC with combinations of fuels such as PRB and pet coke. Under the terms of the settlement, the IGCC study will be made available to the public.
- CPS Energy selected Burns & McDonnell to perform the study, with assistance from EPRI
- **Study adds CO_2 capture to existing designs – as distinct from designing plants with capture from the start (as in nearly all previous studies by DOE, IEA, and EPRI)**

CPS IGCC Study—Cost and Performance Summary

Source EPRI Report 1014510

Notes: • All analysis at 73⁰F • 50%/50% PRB-Petcoke blend by weight	IGCC 100% PRB	IGCC 50%/50%	SCPC 100% PRB	IGCC 100% PRB CO_2 Capt	SCPC 100% PRB CO_2 Capt
Gas Turbine Output (MW)	450	453		427	
Steam Turbine Output (MW)	260	258	615	203	521
Gross Plant Output (MW)	710	711	615	630	521
Auxiliary Load (MW)	157	158	65	217	132
Net Plant Output (MW)	553	553	550	413	390
Net Heat Rate, HHV (Btu/kWh)	9,220	9,070	9,150	12,800	12,911
EPC/TPC ($/kW)	2,390	2,330	1,950	3,630 [1]	3,440 [1]
20-yr LCOE ($/MWh) (Constant 2006$) [2]	45.0	40.9	39.2	65.4	62.0
Cost of CO_2 Avoided ($/tonne CO_2)				26.3	29.6

Notes

1. CO_2 Capture capital costs are based on retrofit of the existing IGCC or PC facilities as provided in the base case alternatives. $/kW values reflect total installed cost to date (including original costs provided in the base case) divided by net plant output with CO_2 capture.
2. COE based on 85% Capacity Factor, Public Power Financing (30 yr loan), $1.65/MMBtu PRB and $1.14/MMBtu Petcoke

CPS IGCC Study—Environmental Performance Summary

Source EPRI Report 1014510

Notes: 1. All analysis at 73^{0}F 2. 50%/50% PRB-Petcoke blend by weight	IGCC 100% PRB	IGCC 50%/50%	SCPC 100% PRB	IGCC 100% PRB CO_2 Capt	SCPC 100% PRB CO_2 Capt
NO_X, lb/mmBtu (HHV)	0.063	0.062	0.050	0.061	0.045
lb/MWh (Net)	0.581	0.562	0.458	0.781	0.581
ppmvd @ 15% O_2	15	15	N/A	15	N/A
SO_2, lb/mmBtu (HHV)	0.019	0.023	0.060	0.004	0.0003
lb/MWh (net)	0.173	0.210	0.549	0.051	0.003
CO_2, lb/mmBtu (HHV)	215	213	215	22	22
lb/MWh (net)	1,985	1,934	1,967	276	278
Total Makeup Water (acre-ft/yr) (85% CF)	6,830	7,170	7,950	8,430	10,640

CPS IGCC—Areas of Further Study

- Potential efficiency improvements
  - Gas turbine inlet chilling
  - Upgrade syngas cooler from IP to HP steam
  - Two-pressure HRSG instead of three-pressure
- Use higher pressure flash for recovery of CO_2 in Selexol
- Investigate use of SCR with syngas-firing
  - NO_X allowance cost is high in Gulf Coast area
- Investigate other gasification processes that may have more favorable cost and performance with CO_2 capture
- CO_2 storage capital and operating costs
- CO_2 pre-investment tradeoffs
- Legal and regulatory aspects of CO_2 storage

CPS Study Results Will Differ for an IOU

- CPS San Antonio as a public entity has access to low-cost financing
- Investor-owned utilities (IOU) have higher financing costs
- IOU financing costs lead to higher COE
- Higher COE means higher Avoided Cost of CO_2
- **COE used for calculating Avoided Cost of CO_2 should include the estimated cost of transportation, storage/sequestration, and monitoring. EPRI uses a nominal $10/tonne**
- EPRI has recalculated the CPS results for 30-year LCOE for IOU financing and included $10/tonne for transportation and sequestration

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CPS Results Compared to IOU

(30-year LCOE. CCS includes $10/tonne for transportation and sequestration)

COE $/MWh	**CPS**	**IOU**
IGCC, No Capture	47.3	64.9
SCPC, No Capture	41.1	55.5
IGCC with Capture & Seq. (CCS)	80.1	106.9
SCPC with CCS	76.7	102.1
Avoided Cost of CO_2, $/tonne for IGCC w/ Capture and w/ CCS	27.9/42.4	39.7/54.2
Avoided Cost of CO_2, $/tonne for SCPC w/ Capture and w/ CCS	31.7/46.5	46.1/60.8

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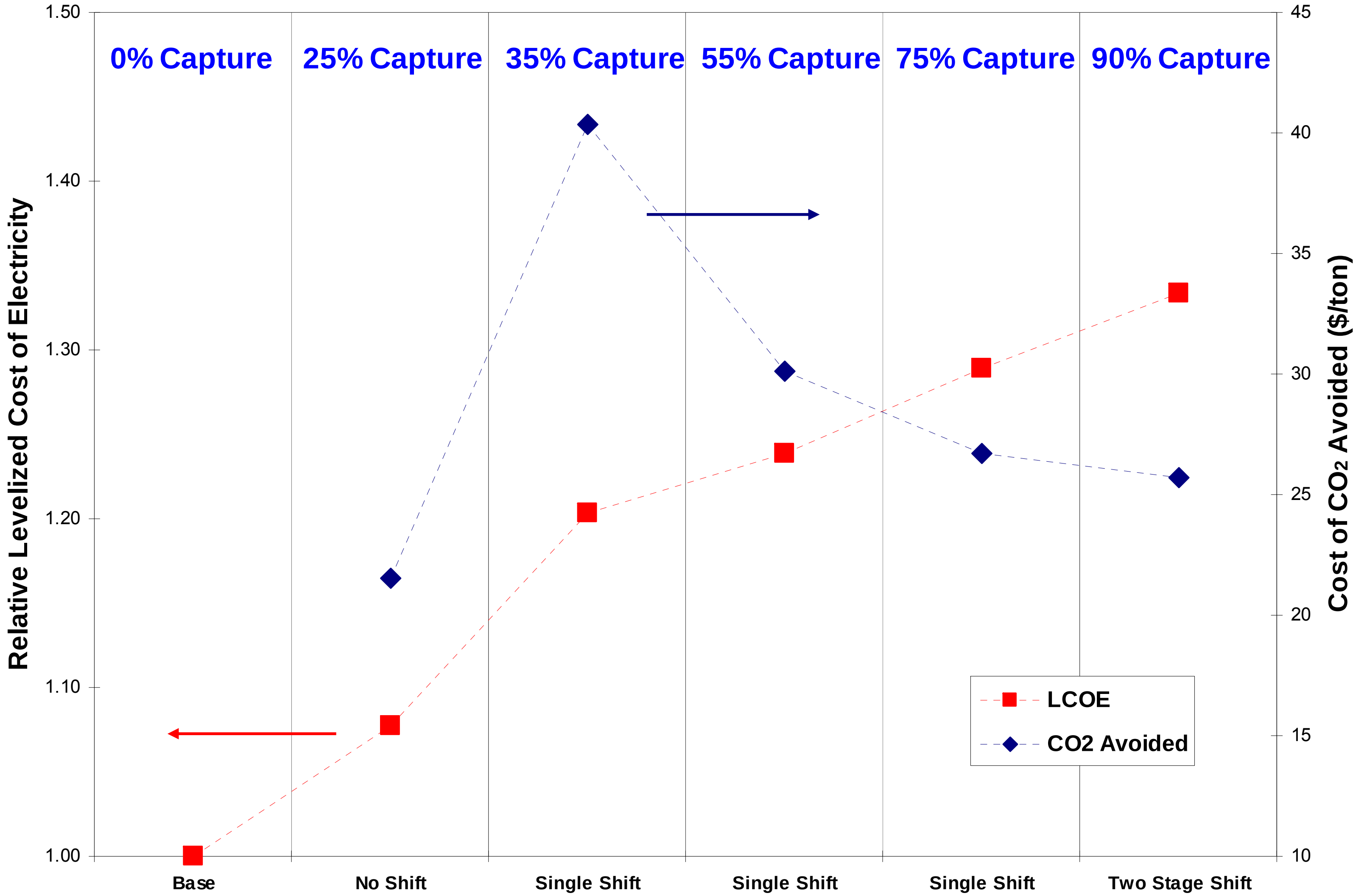
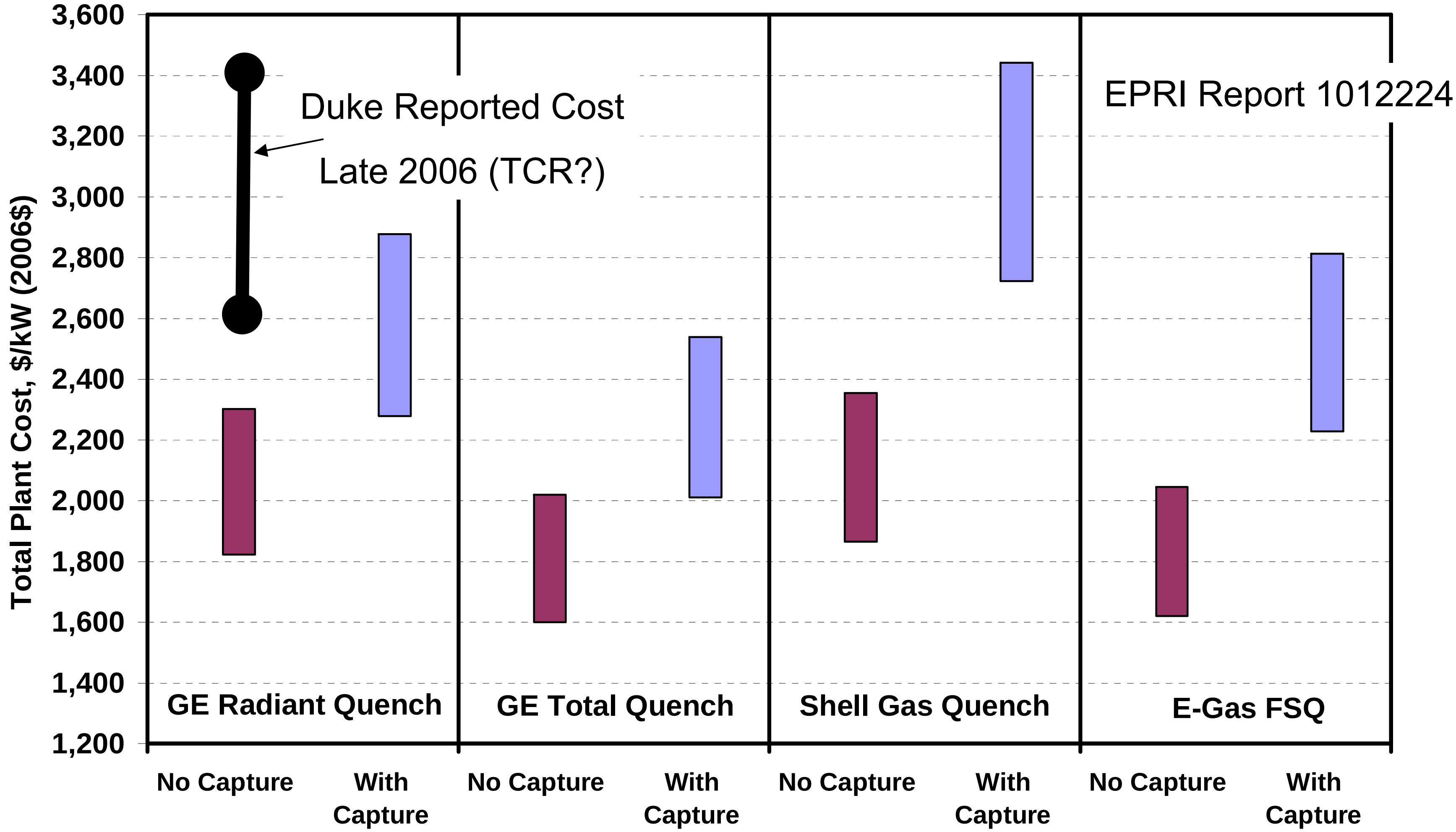
Supplemental Slides – IGCC Technology

Impact of CO_2 Capture on IGCC Cost-of-Electricity and Cost of CO_2 Avoided (June 2006$ Basis, Bituminous Coal)



EPRI IGCC Capital Cost Estimates: Mid-2006$, Eastern Bituminous Coal, Does Not Include Owner Costs



Reported IGCC costs not as expected

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IGCC CO_2 Capture Design Options

- For slurry-fed gasifiers, the CO_2 in the syngas can represent 20–25% of the coal's carbon, which could be removed without using the water-shift reaction. This relatively small amount of capture is unlikely to generate much support from federal or state authorities.
- For all gasification technologies, can use sour, high-temperature shift followed by two-column AGR. Maybe still use standard syngas GT combustors? This could result in 60–80% CO_2 capture, which would satisfy California's criterion that the CO_2/MWh be no more than that from NGCC. Lower COE than maximum capture option.
- Alternatively could capture 90% of CO_2 from 50% of syngas (one train) to satisfy proposed California/New Mexico criterion
- If >90% removal is required, then both high- and low-temperature shift beds can be used. Need hydrogen combustors for GT. Higher COE.

Gas Compositions and Flows Before and After Shift (Mol % Clean Dry Basis—Typical Bituminous Coal)

Gasifier	GE no Shift	GE with Shift	CoP no Shift	CoP with Shift	Shell no Shift	Shell with Shift
Pressure psig	500-1000	500-1000	600	600	600	600
H_2	37	81	30	76	28	88
CO	47	3	49	3	64	4
CH_4	<0.1	<0.1	6	6	<0.1	<0.1
CO_2	14	58	12	58	2	62
N_2 + A	2	2	3	3	6	6
Total Flow Mols	100	144	100	146	100	160

IGCC Design Issues for Adding Capture to a Plant Designed Without Capture

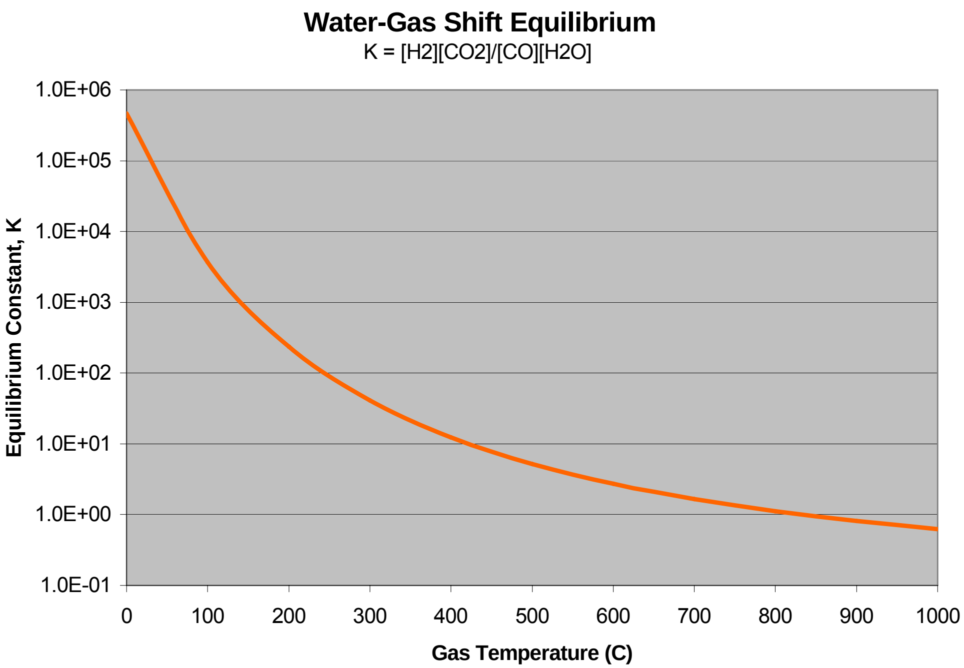
- Addition of sour shift increases gas flow to the AGR, particularly for the dry coal fed gasifiers with high CO content. Unlikely that the AGR would be able to take the extra flow unless there was pre-investment oversizing. May need to add a parallel absorber, or replace the entire AGR plant (with a new two-column absorption system), if capture is to be added to an existing IGCC designed without capture.
- Alternatively the original AGR (focused on H_2S removal) could be retained and a sweet shift added after the AGR with a simpler bulk CO_2 removal AGR (ADIP, MDEA, Selexol) added after shift. This would minimize intrusion into existing plant. This trade-off of sour versus sweet shift needs to be examined and may differ among the gasification technologies. Sweet shift may incur additional efficiency and output penalties. Quench gasifiers would probably favor sour shift.

Interim Conclusions on IGCC with Provisions for Later Addition of CCS

- IGCC with "Standard Provisions" (e.g., plot space) not very CCS-ready
- IGCC with some "Moderate Provisions" is much more CCS-ready – Incremental capital may be justified
- AGRU/SRU for CCS – Selexol more CCS-ready than MDEA, particularly with Moderate Provisions
- "Sour shift" more CCS-ready than "sweet shift"
- Quench with sour shift is CCS-ready. Syngas cooler designs with either sour or sweet shift are less ready for CCS
- Major Issues
  - H_2S content of CO_2
  - Thermodynamic penalty for syngas reheat and HP steam injection (with sweet CO shift and non-quench gasifiers)

Water-Gas (CO-) Shift Reaction

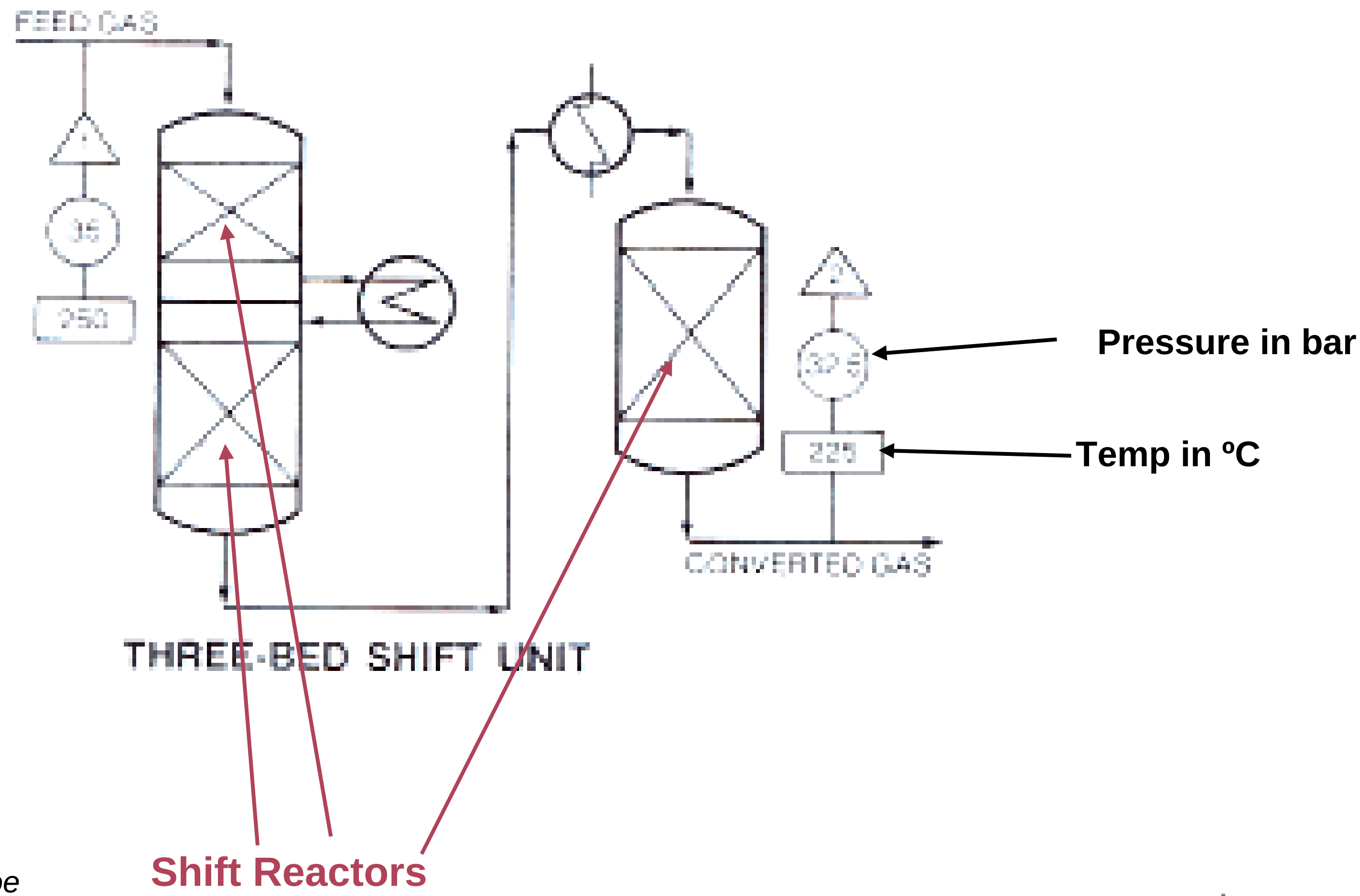
- $CO + H_2O \Leftrightarrow H_2 + CO_2$
  - Equilibrium (trim conversion) favored by low temperature
  - Kinetics (bulk conversion) favored by high temperature
  - Left-to-right reaction very exothermic (40 kJ/kg-mol at ~400°F or 200°C)
  - Inter-stage bed cooling required to limit catalyst temperature and generate HP steam
  - Need H_2O/CO molar ratio >3:1 to insure adequate conversion of CO and to avoid C formation
  - Widely used in NH_3 and H_2 plants



Syngas Composition Affects Shift Steam Requirements (Need >3:1 H_2O/CO Ratio) and Overall Performance

Technology	Pressure Psig	H_2O/CO Molar Ratio	Relative HP Steam Flow to Shift	Steam Turbine MW Output
GE Radiant Quench	800	1.3	1.0	270
GE Total Quench	1000	>3.0	Zero	242
COP E-Gas Full Slurry Quench	600	0.4	2.0	216
Shell Gas Recycle Quench	600	0.1	2.8	202

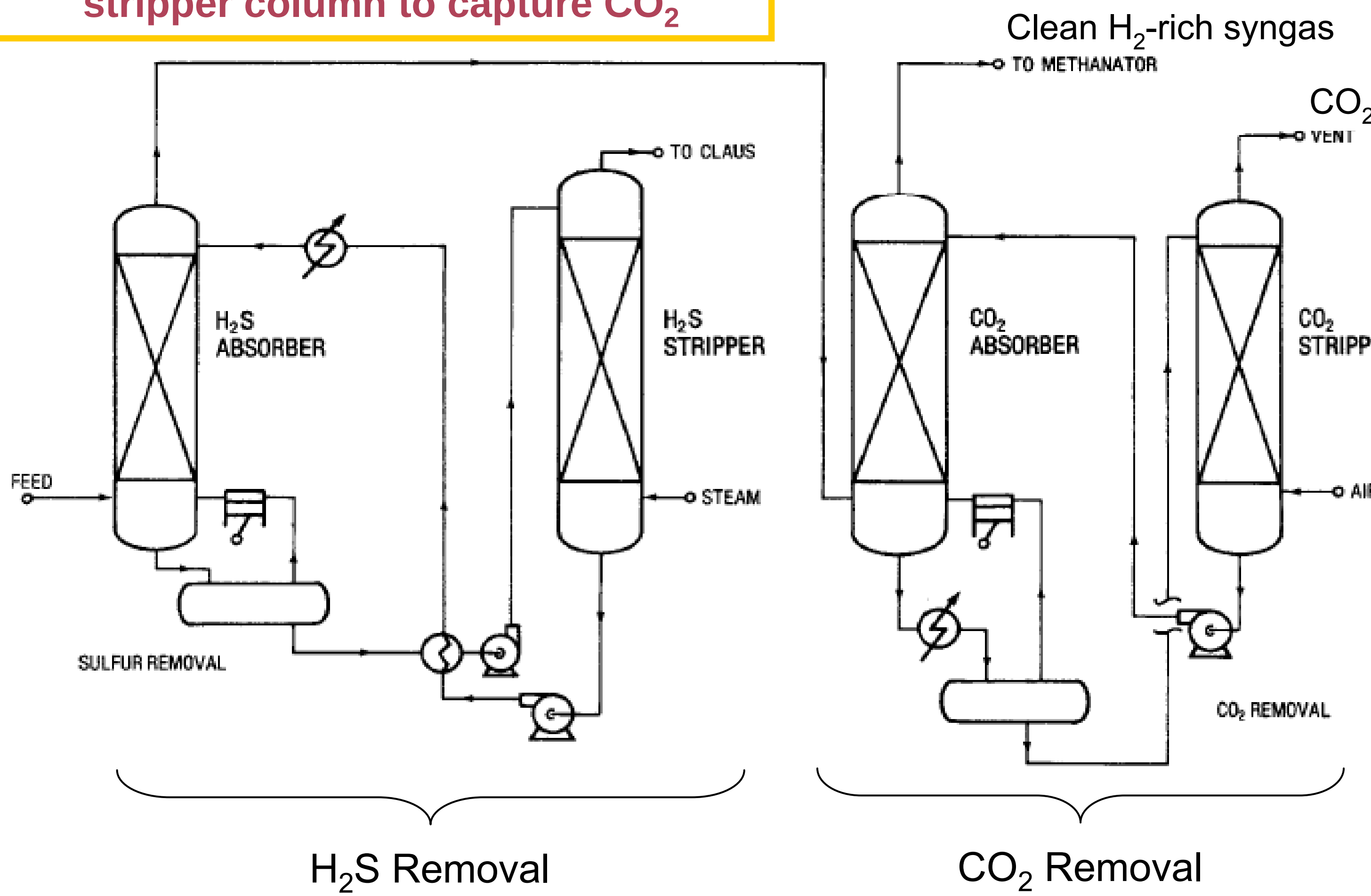
Water-Gas Shift: Typical Process Configuration



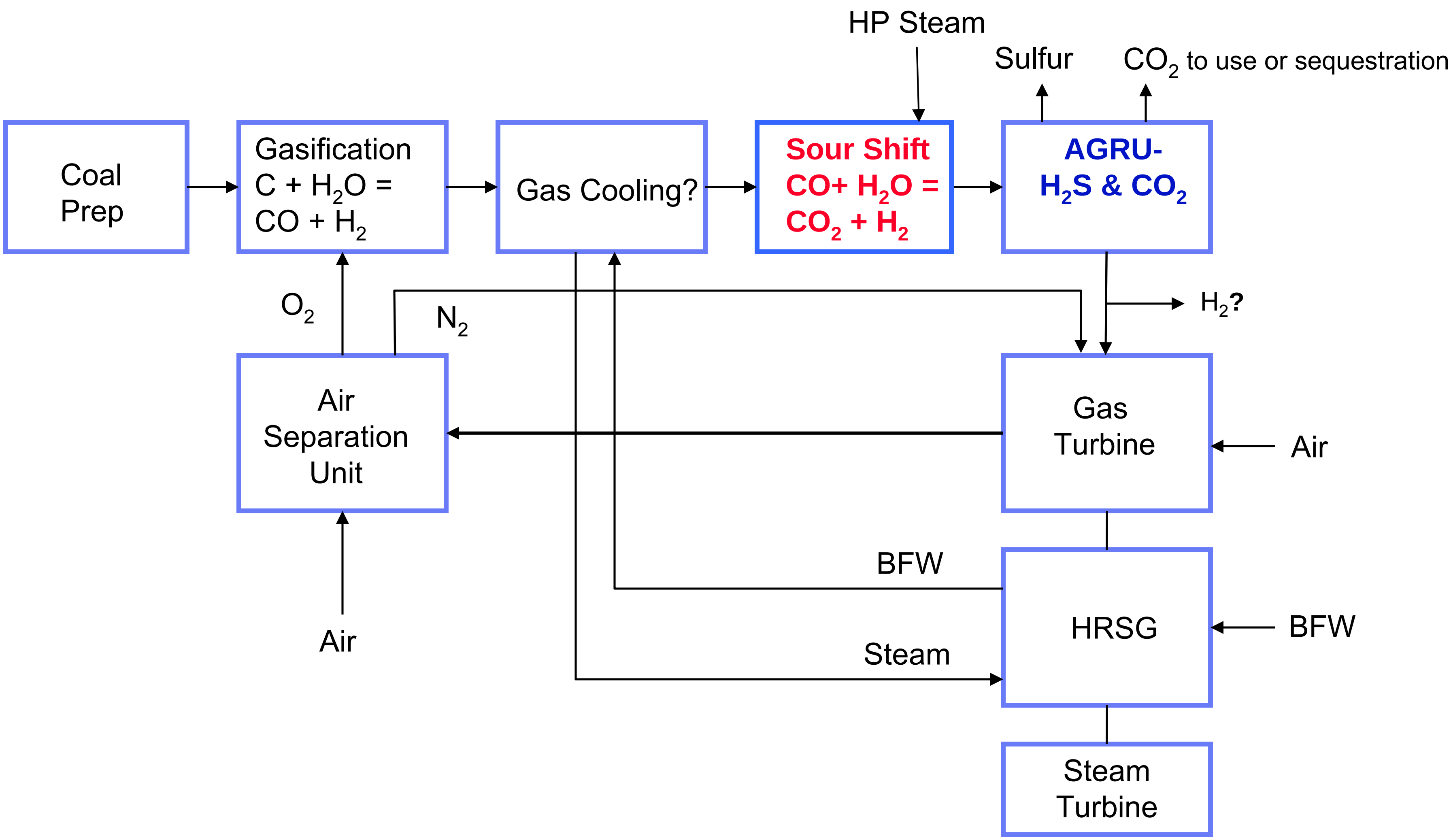
Source: Haldor Topsoe

Solvent Absorption for IGCC Generic Process Flow Diagram with CO_2 Capture Added

Have to add second absorber and stripper column to capture CO_2



IGCC with CO_2 Removal via SOUR CO-Shift



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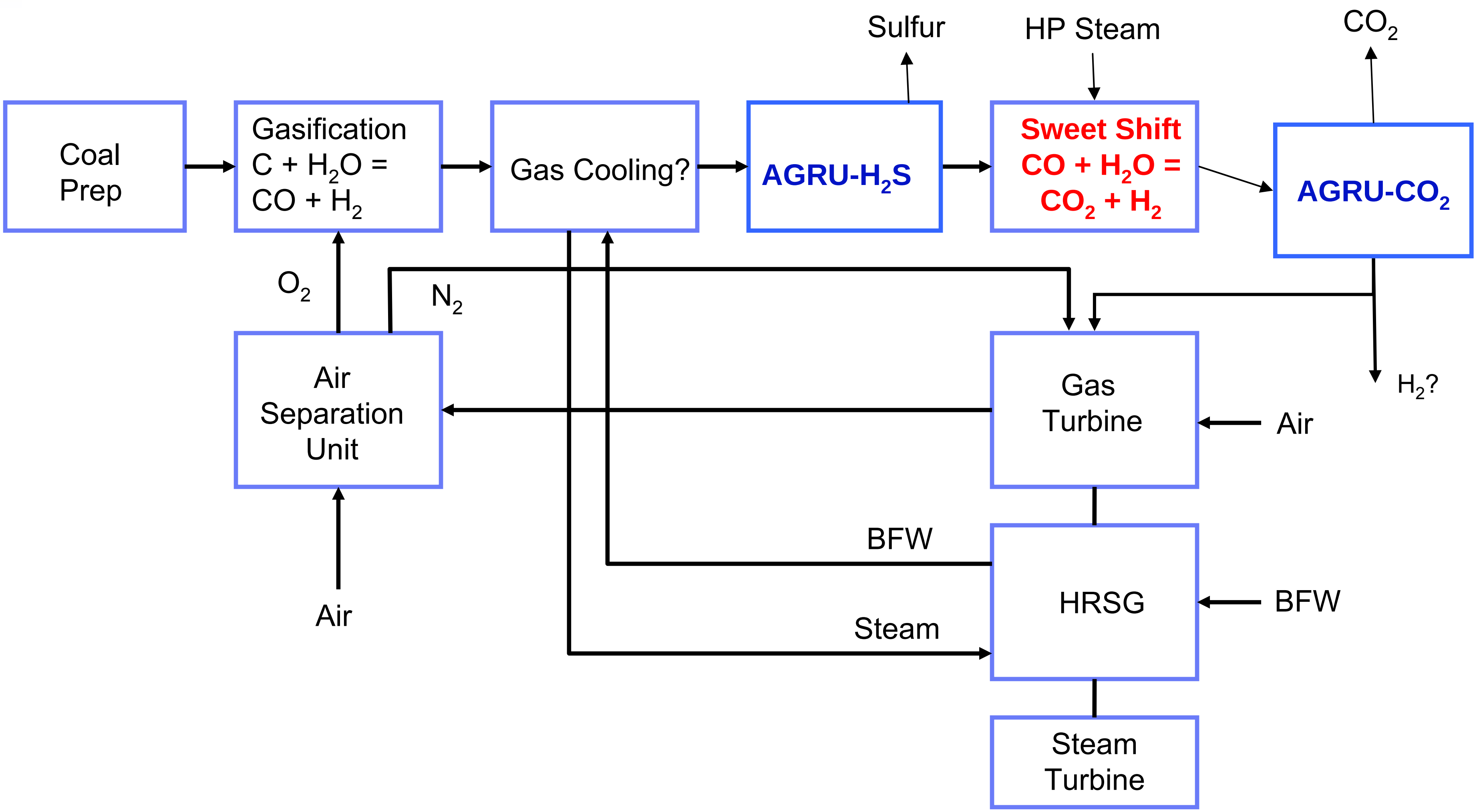
IGCC with CO_2 Removal via SWEET CO-Shift



CO_2 Solvent Absorption Technology Options – Chemical or Physical Solvent

Two Generic Types of "Acid Gas" (i.e., CO_2, H_2S, COS) Removal Solvents

- Chemical absorbents (i.e., amines) react with the acid gases and require heat to reverse the reactions and release the acid gases
  - Lower capital cost than physical solvent processes
  - Uses larger amounts of steam-heat for solvent regeneration
- Physical absorbents (i.e., Selexol, Rectisol) dissolve acid gases
  - Favored by higher pressure
  - Released from the solvent when pressure is decreased
  - Require less steam-heat for solvent regeneration
  - Rectisol uses chilled methanol. Highest capital cost, but provides the most complete removal.
- Space requirements for shift, CO_2 removal, drying, and compression are similar for all solvent options—1.5 to 2 acres. Energy requirements for compression are lower with physical solvents.
- Typically >90% CO_2 removal for all solvents, but % capture depends on the amount of water-gas shift conducted

IGCC Designs with Shift and CO_2 Capture

- Water quench is the least cost way of adding moisture for the water-gas shift reaction (to be used at BP Carson)
- Higher pressure (e.g., 800–1000 psig) decreases the cost of CO_2 removal and compression through use of a physical absorption system (e.g., Selexol)
- GE can offer high pressure and either Quench (Q) or Radiant Quench (RQ) designs, which provide more moisture for the shift reaction
- COP E-Gas, Shell, Siemens, and KBR are lower pressure (<600 psig) and have lower moisture in the syngas

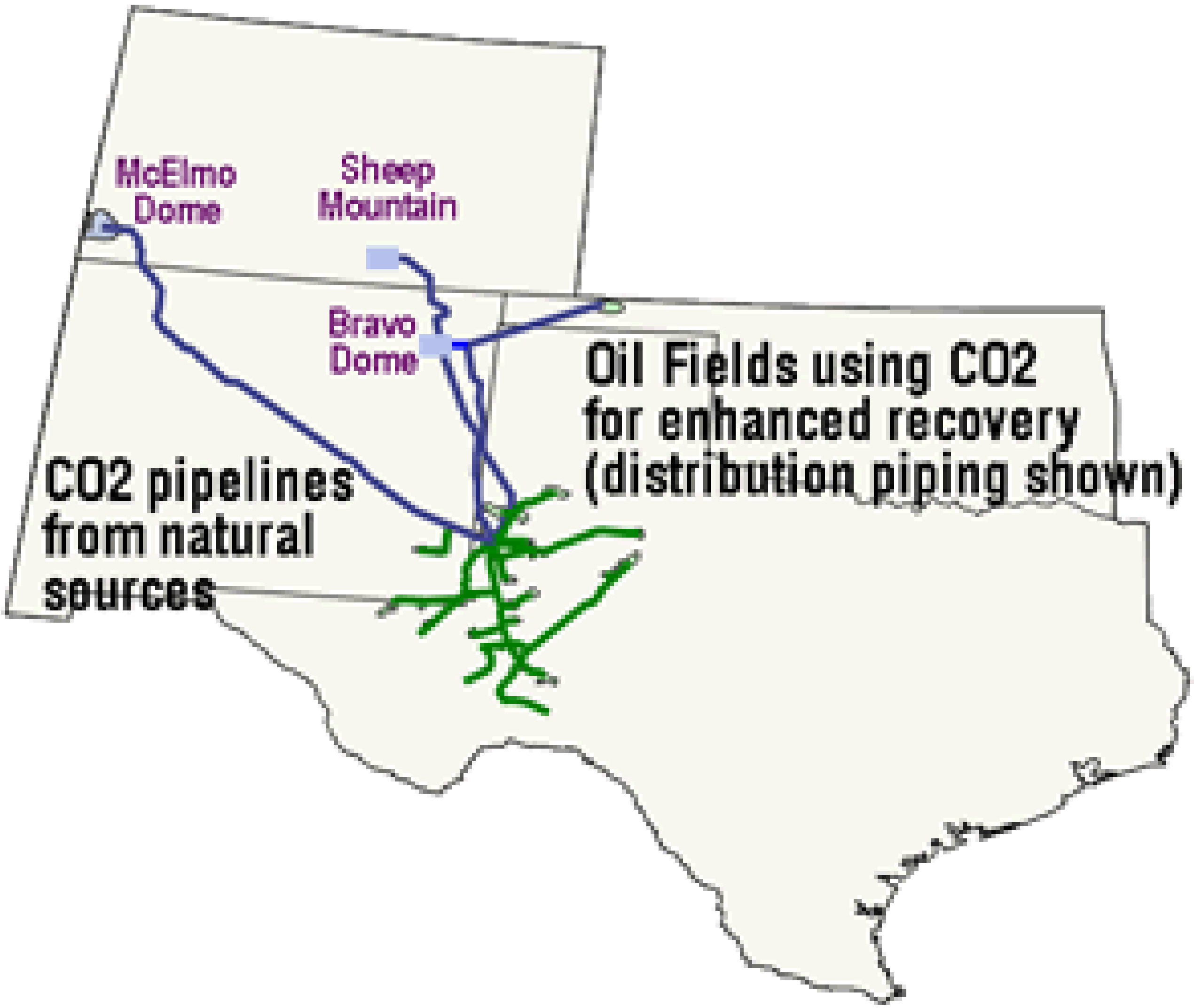
Supplemental Slides – PC Technology

Supplemental Slides – CO_2 Capture

Advanced Coal CO_2 Capture Options

- Post-combustion removal of CO_2 from flue gas by amine (e.g., MEA) or other solvent scrubbing
  - Natural Gas Combined Cycle (NGCC) plants
  - Pulverized Coal (PC) plants
- Pulverized coal combustion with oxygen and recycle CO_2 to give a concentrated CO_2 stream (Oxy-fuel or Oxygen Combustion (OC))
- Coal gasification with water-gas shift reactor and removal of CO_2 from syngas prior to combustion of H_2 in combined cycle (IGCC)
- Coal gasification and syngas combustion with oxygen and recycle CO_2 to give a concentrated CO_2 stream (e.g., Clean Energy Systems, etc.)

Existing CO_2 Pipeline Networks in New Mexico



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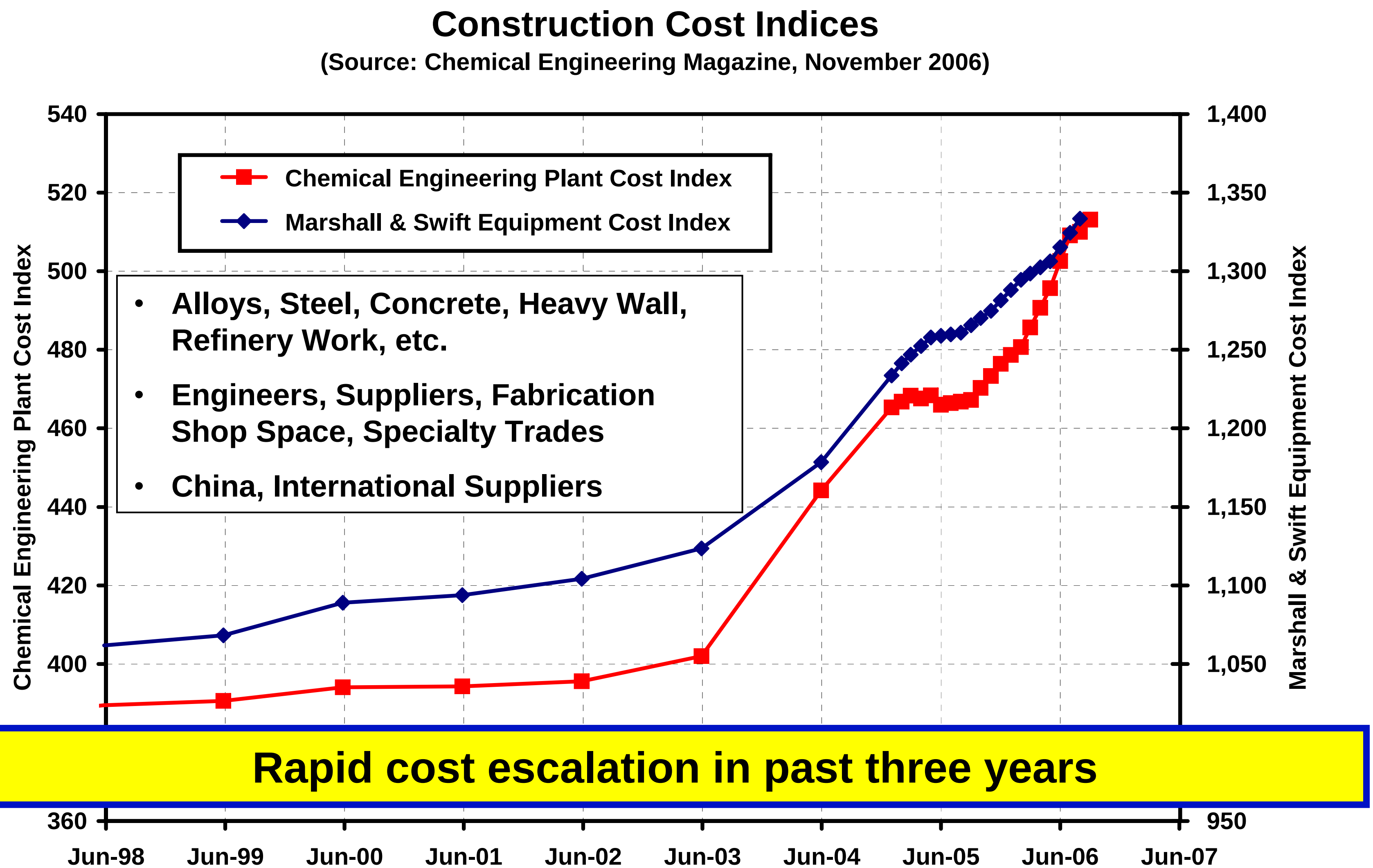
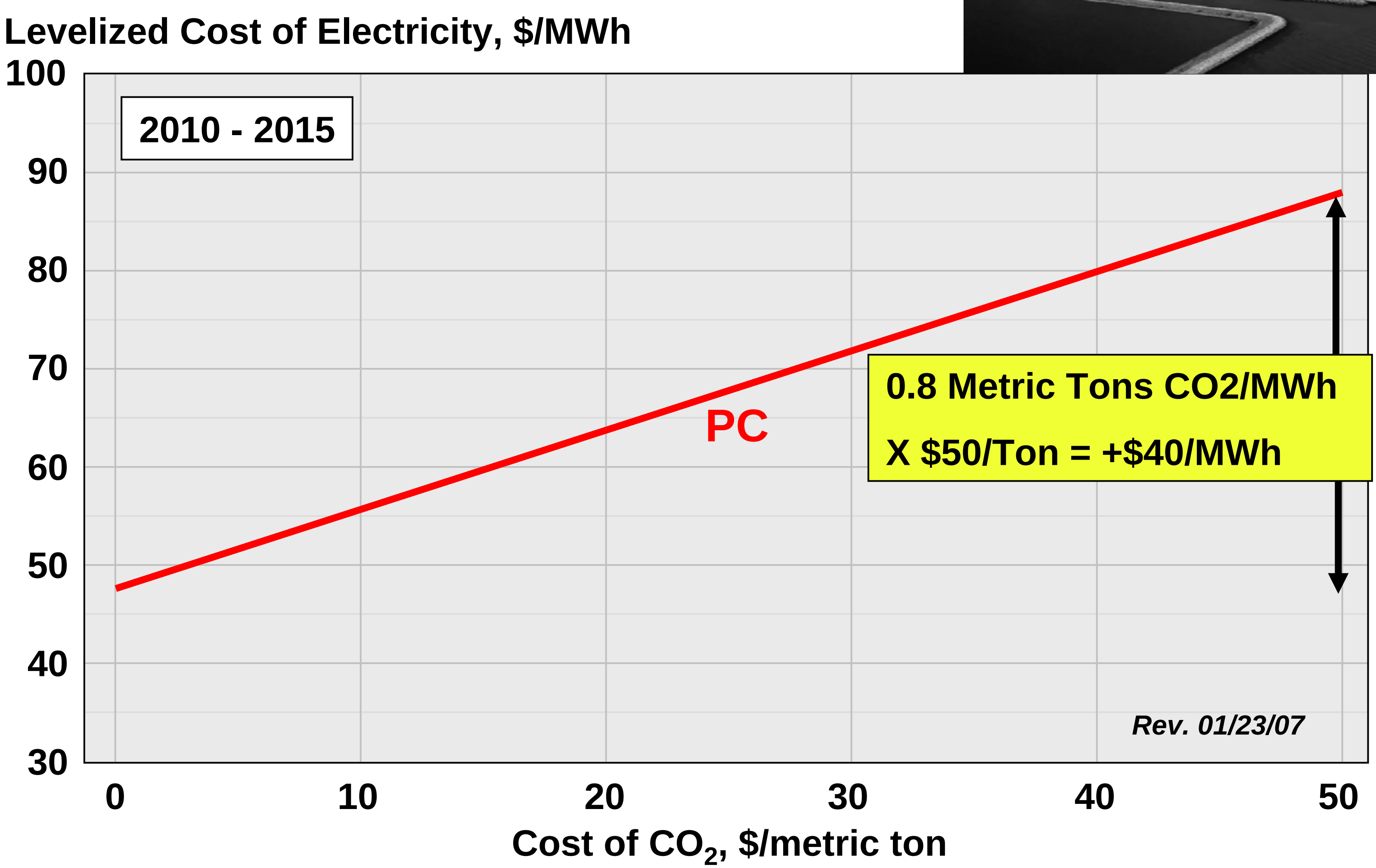
Supplemental Slides –
EPRI Generation Options LCOE Analysis

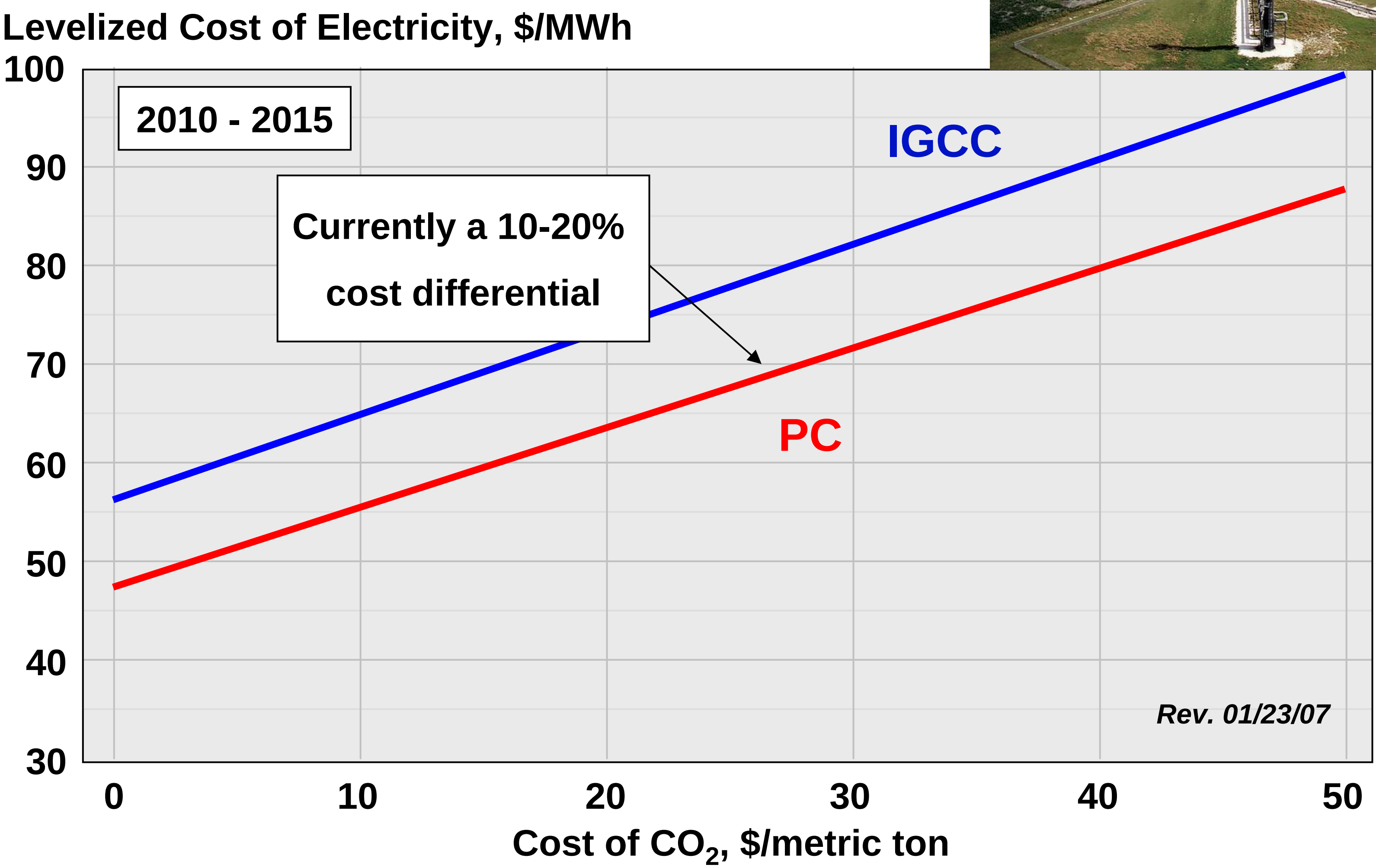
Plant Construction Costs Escalating



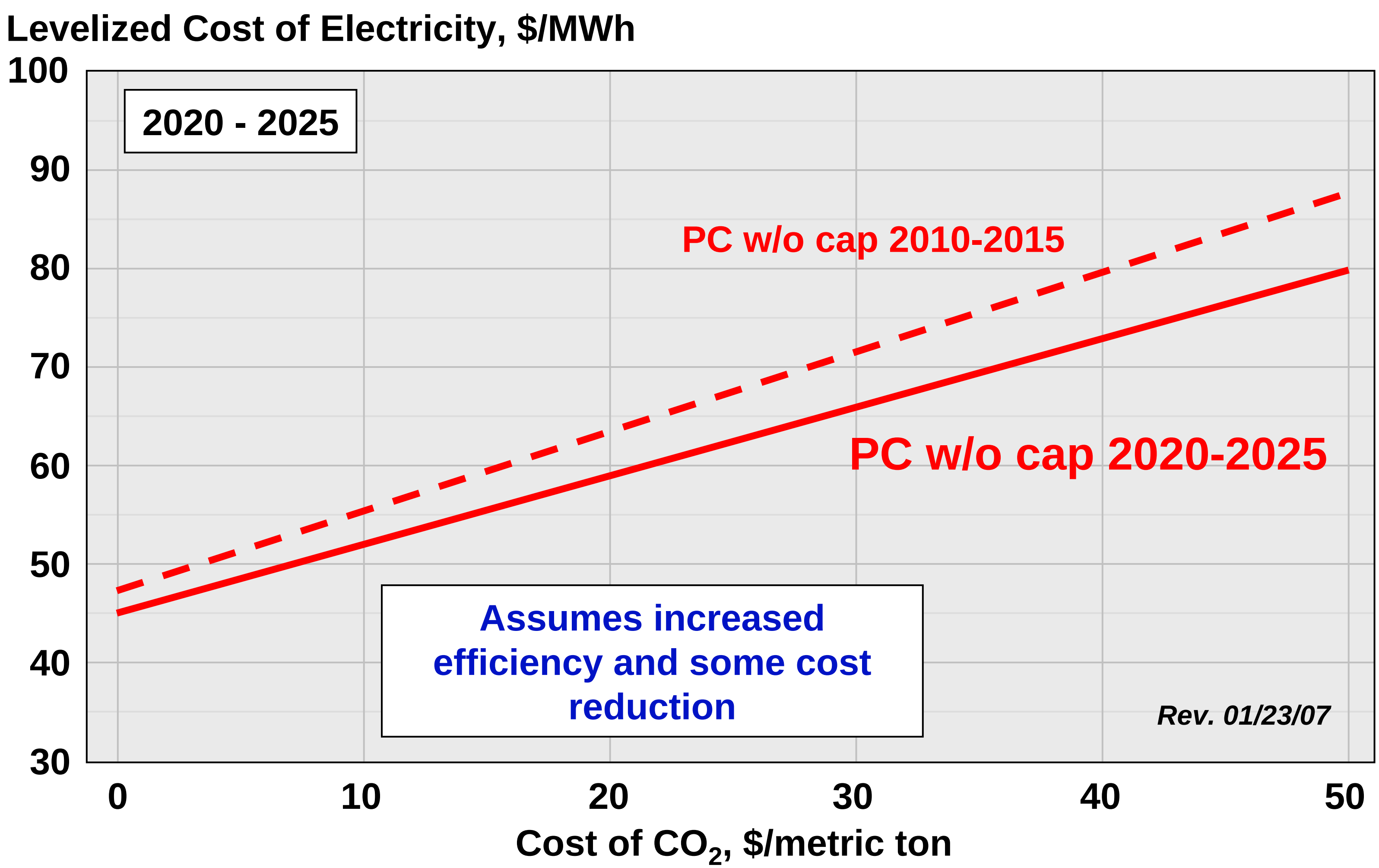
Pulverized Coal



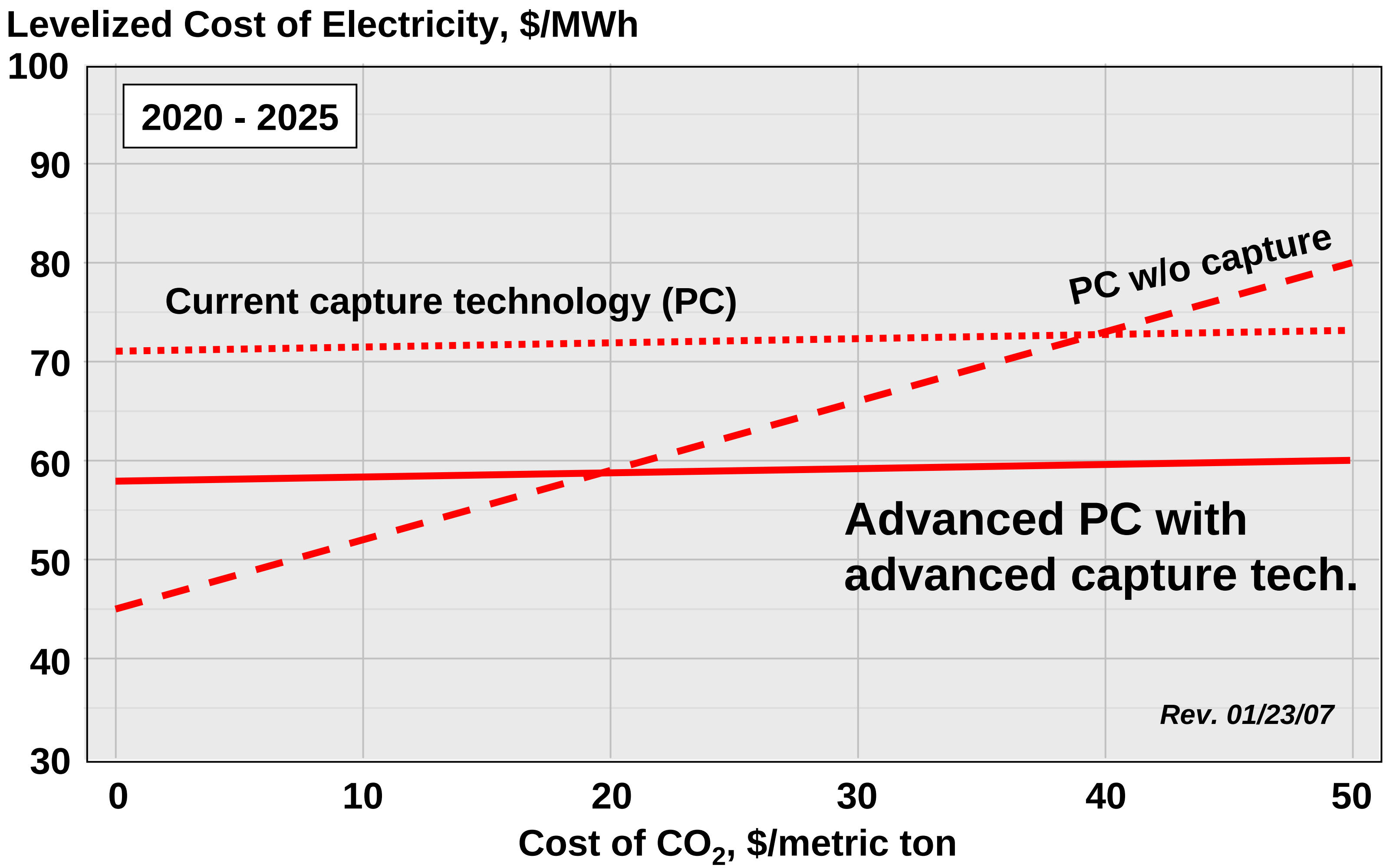
Integrated Gasification Combined Cycle



Pulverized Coal w/o Capture



Pulverized Coal with CO_2 Capture and Storage



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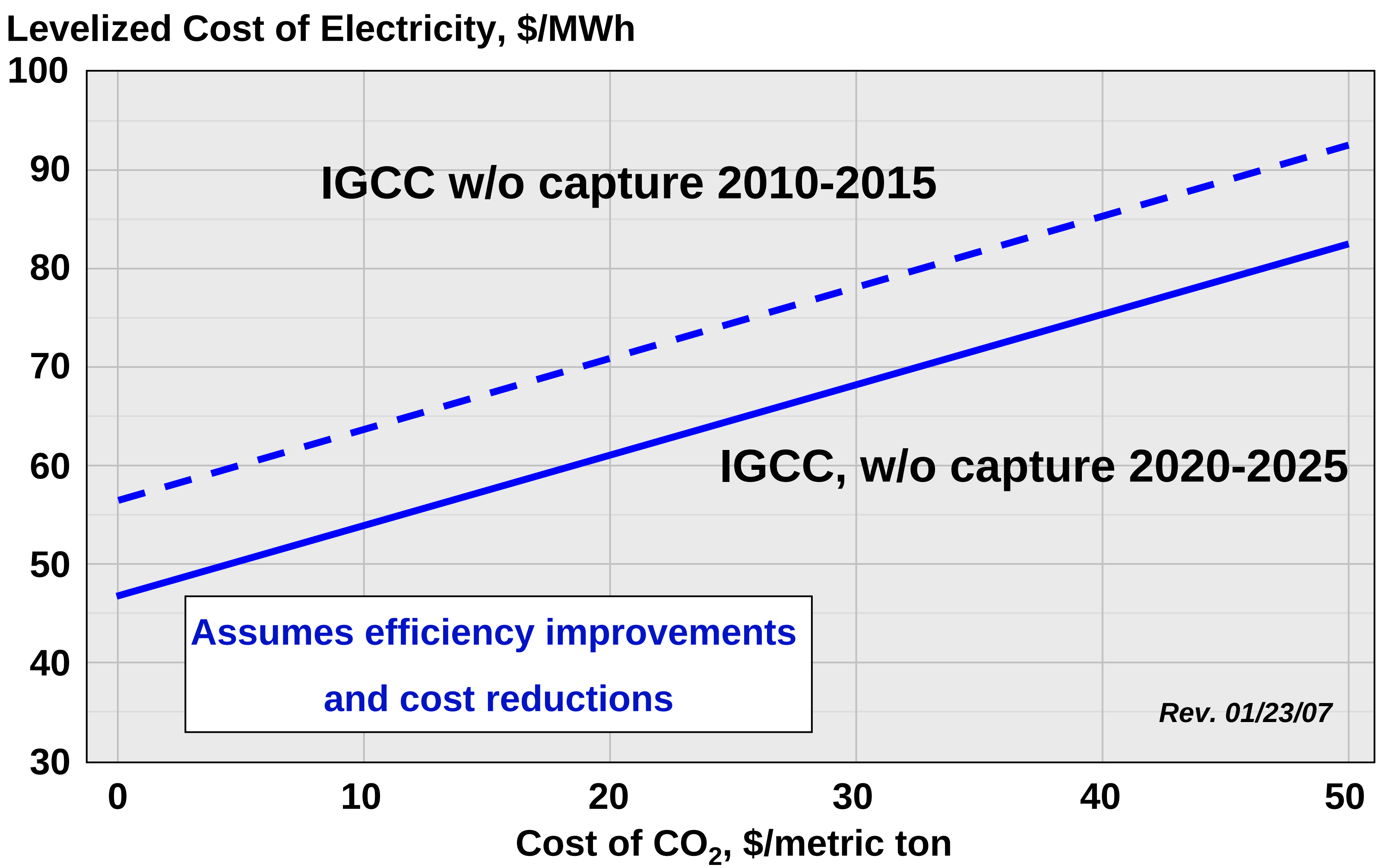
IGCC w/o Capture



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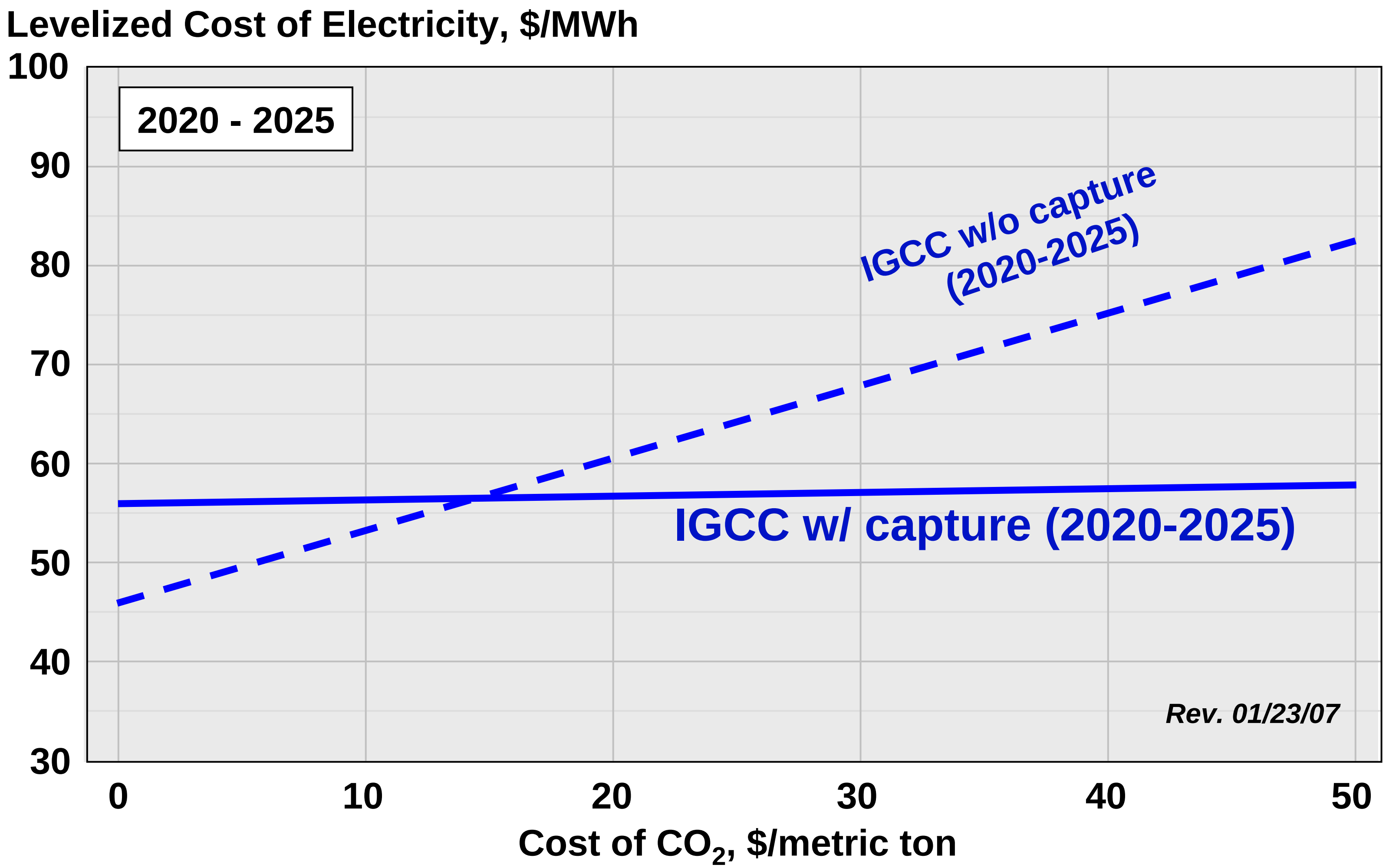
IGCC with CO_2 Capture and Storage



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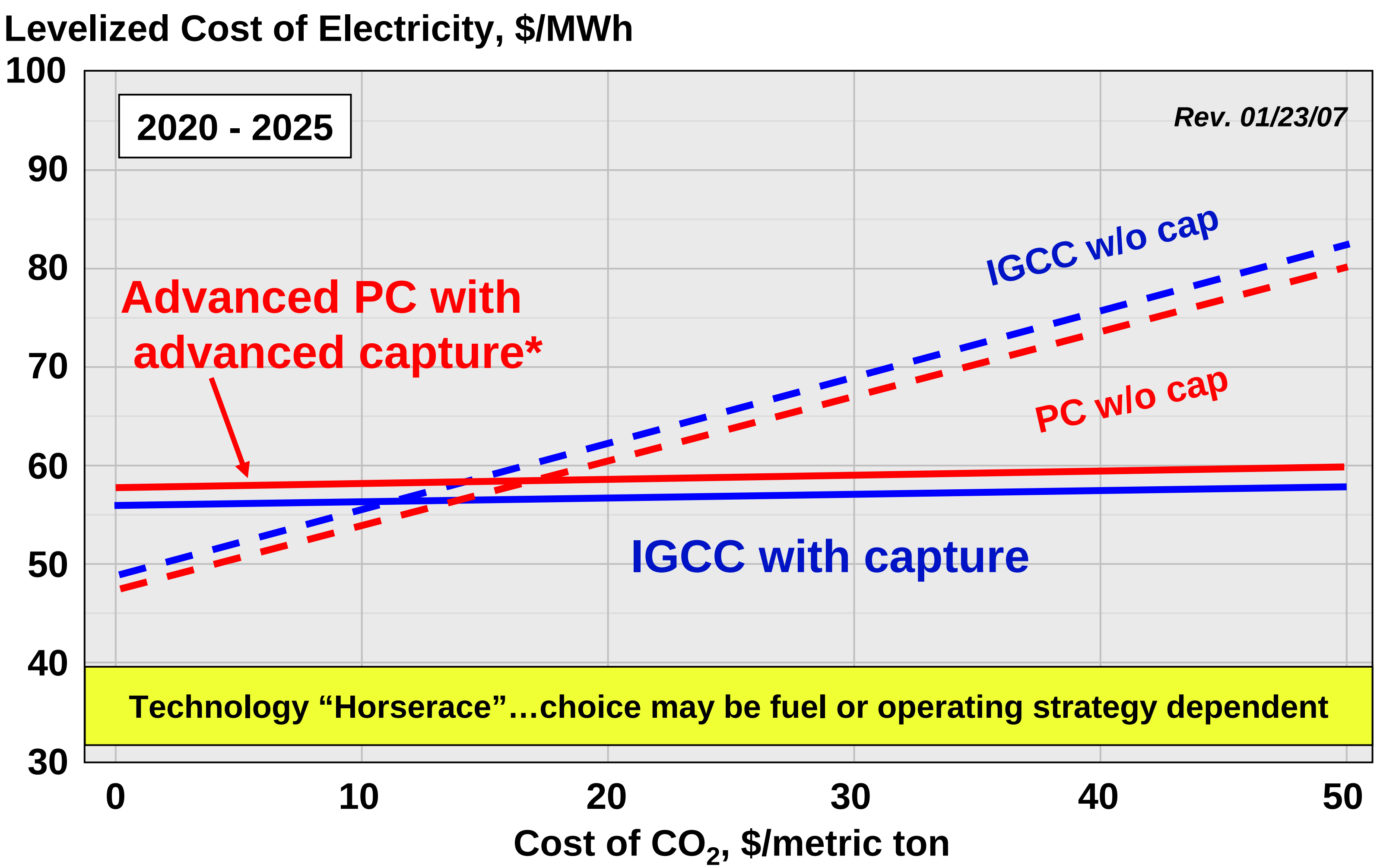
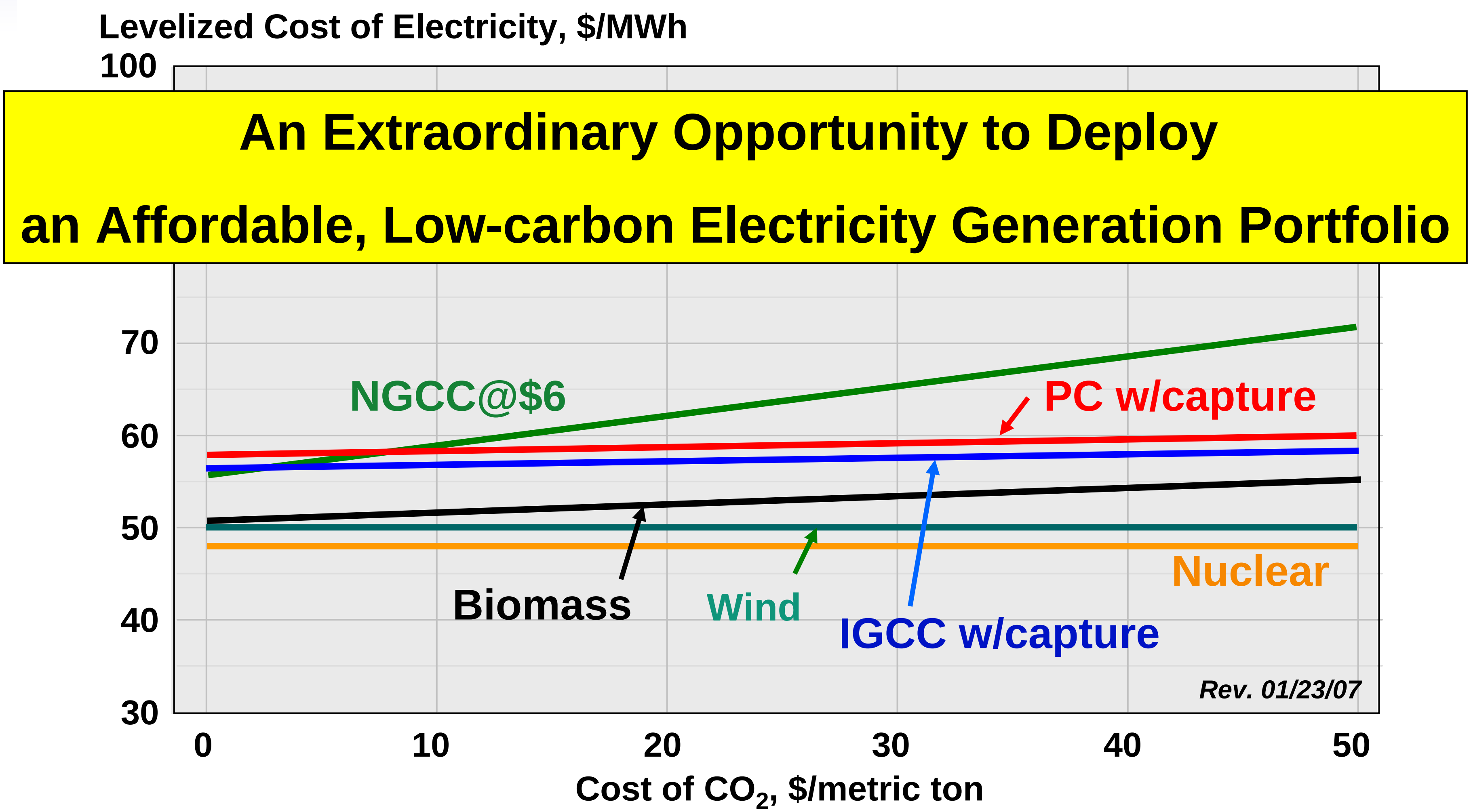
Advanced IGCC and Advanced PC with Capture



*midpoint of Ammonia Carbonate and AC/Membrane/Improvement cases

Comparative Costs in 2020-2025



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Recently Reported Costs Through Late Last Year

Owner	Plant Name /location	Net MW	Technology/Coal	Reported Capital $ Million	Reported Capital $/kW
AEP SWEPCO	Hempstead, AR	600	USC PC/PRB	1300	2167
AEP PSO/OGE	Sooner, OK	950	USC PC/PRB	1800	1895
AEP	Meigs County, OH	630	GE RQ IGCC/ Bituminous	1300	2063
Duke Energy	Edwardsport, IN	630	GE RQ IGCC/ Bituminous	1300-1600	2063-2540
Duke Energy	Cliffside, NC	2 x 800	USC PC/ Bituminous	3000	1875
NRG	Huntley, NY Montvale, CT Indian river, DE	620	Shell IGCC/ Bituminous, Pet Coke and PRB	1466	2365
Otter Tail/GRE	Big Stone, SD	620	USC PC/PRB	1500	2414

Source: CoalFleet for Tomorrow® EPRI Report 1012224

Costs up even with minimal or no provisions for CO_2 Capture

Cost and Heat Rate– With and without CO_2 Jan 2006$

All estimates are for bituminous coals (Ill #6 & Pit #8) without spare gasifiers; probably -5%/+20 % given the state of development and current cost environment

Technology	(DOE)SCPC MEA	GE RQ	GE Q	Shell GQ	E-Gas FSQ
Net Power Net Heat Rate	550 8,860	630 8,830	595 9,600	620 8,470	610 8,870
TPC $/kW, no capture	1,290–1,790	1,760–2,220	1,545–1,950	1,800–2,275	1,565–1,975
TCR $/kW, no capture	1,535–2,130	2,094–2,642	1,839–2,320	2,142–2,707	1,862–2,350
Net Power Net Heat Rate	450 12,660	550 10,460	525 11,300	500 11,160	515 10,895
TPC $/kW, with capture	2,260–3,130	2,200–2,780	1,942–2,453	2,630–3,324	2,152–2,718
TCR $/kW, with capture	2,690–3,720	2,618–3,308	2,311–2,919	3,130–3,955	2,561–3,234

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