PPT Paper Version*

CO_2 Capture Technology Cost Buydown in EOR Applications with Alternative Financing Mechanisms

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* The PPT Paper Version differs from the Delivery Version in that it includes: (a) in an Appendix slides that elaborate on the analysis, and (b) a set of references for the analysis. Both the Appendix Slides (A1 through A18) and the references are referred to as needed in the main slides of PPT Paper Version but not in Delivery Version.

Here technology cost buydown (TCB) refers to the process of reducing costs through experience (learning by doing) for early-mover projects that use promising CO_2 capture technologies—after the technologies have been developed and demonstrated but before their widespread deployment. Costs in excess of market clearing costs are typically very high—often making TCB the most costly part of the innovation chain.

The TCB process is restricted to capture options that offer the potential for coal to compete with gas in the US power market under a carbon policy consistent with limiting global warming to 2 ^oC, the aspirational goal that global leaders have agreed to. As discussed below, the carbon prices implicit in the pursuit of this goal are consistent with what is needed for near-term deployment in the US power market of competitive new coal power plants with CCS, following the research, development, and demonstration phase and the TCB phase of market launch for promising CO_2 capture technologies.

If CCS technologies are not launched in the market in the next 5-15 years under US leadership there is a big risk that CCS will be taken off the table for consideration as a major carbon mitigation option.

These materials provide the analytical basis for a proposal for a new public policy for launching promising capture technologies in the US market that might be presented for consideration by the next Administration and Congress.

National Low-Carbon Electricity Portfolio Standard, 2020-35

- Low-carbon global energy futures probably not feasible without CCS (see A1)…**but global CCS market launch effort stalled**.
- Proposal to "kick-start" US market launch of promising CO_2 capture technologies: **CO_2 EOR Portfolio Standard** = 1 tranche of **National Low-Carbon Electricity Portfolio Standard**.
- **National Low Carbon Electricity Portfolio Standard** would supplant Renewable Portfolio Standard (now in place in 30 states):
  - **Separate tranches** for fossil fuel with CCS options, wind, PV, solar thermal—that depend on state of technology development;
  - **Regional strategies** to reflect regional resource endowments.
- Subsidy winners/amounts selected by market [e.g., reverse auctions (CATF, 2010)] to arrive at contracts for difference (DECC, 2013);
- Two off-budget mechanisms for financing technology cost buydown (TCB) for qualifying technologies:
  - Wires charge (as for Renewable Portfolio Standard);
  - Federal subsidies from an **Energy Security Fund** for options that provide in addition to electricity domestic liquid fuels that displace imported oil.
- Subsidies economically justified by learning-by-doing spillovers for costly early-mover projects based on low-carbon technologies offering good prospects for cost reduction via experience (see A2).

In contrast to the impressive advances in evolving near-zero-carbon renewable energy production and utilization, efforts towards deployment of CCS have effectively stalled, largely because of high costs and inadequate government support for first-of-a-kind projects. Coal, accounting for 30% of global energy today, will continue to be a substantial contributor to the World's primary energy supply for many decades. CCS is the only credible technology for realizing deep reductions in emissions arising from coal use. Not only is CCS essential for coal power's future in a climate-constrained world, but also, according to the *Fifth Assessment Report* of the IPPC (IPCC, 2014a; 2014b), a global energy future for which global warming is limited to 2 ^{o}C is unlikely to be realized without CCS. This is an important consideration because the incentives required for TCB are huge, but this public benefit justifies these expenditures.

Because carbon-mitigation goals for mid-century, just 35 years from now, will require an energy system transformation of magnitude comparable to what normally takes 80-130 years, a market transformation forcing policy is needed. The proposed National Low-Carbon Electricity Portfolio Standard would be a powerful "technology-neutral" market launch policy for promising low carbon electricity technologies that would replace existing policies promoting early deployment of renewables.

The TCB process is inherently so costly per technology that Congressionally appropriated funds are not likely to be adequate for providing the needed incentives. This is why the financing mechanisms considered here for TCB are off-budget policy instruments. The Energy Security Fund associated with one of these instruments would be made up of the new federal corporate income tax revenue streams that arise from the energy systems launched under the National Low-Carbon Electricity Portfolio Standard that provide in addition to electricity new domestic liquid fuels that displace imported oil—see also NEORI (2012).

CO_2 EOR Portfolio Standard, 2020-2035

- **CO_2 EOR Portfolio Standard** would:
  - Mandate that a rising amount of low-carbon electricity be provided by plants that capture CO_2 and sell it for EOR;
  - Transform CO_2 EOR market into one for which marginal CO_2 supplies come from anthropogenic sources ➔ CO_2 prices would be higher than at present (see A3).
- **Subsidy amount determined by assumption that LCOE with subsidy = LCOE for new baseload NGCC power plant (basis for contract for difference)**

The CO_2 EOR Portfolio Standard might be aimed at capturing by 2035 enough CO_2 from power plants to enable exploitation of the US potential ~ 3 x 10^6 bbls/day via anthropogenic CO_2 (ARI, 2010; NETL, 2011);

Screening Process for CO_2 EOR Portfolio Standard

- Candidates for TCB under **CO_2 EOR Portfolio Standard** are options that can compete with **NGCC** when CO_2 stored in deep saline formations (DSFs), as indicated by LCOE vs GEP analysis when costs are based on **scoping study cost estimates (SSCEs)**
- Warning: Costs for FOAK and several subsequent early-mover projects will be considerably higher than these **SSCEs.**
- GEPs are considered that are consistent with realizing the aspirational global energy future that leaders of major economies have agreed to, which would limit global warming to 2 ^{o}C (see next slide).

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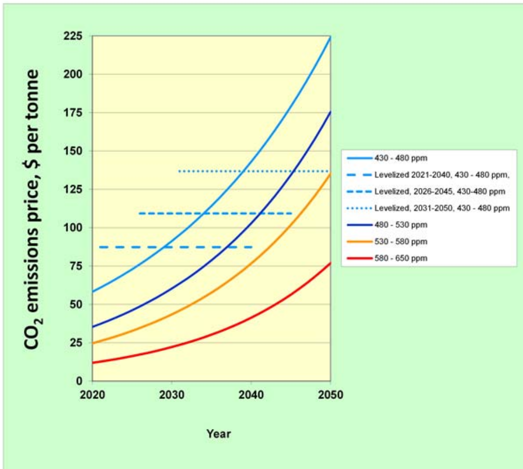
LCOE ≡ Levelized cost of electricity

GEP ≡ Greenhouse gas emissions price.

A “scoping study” is a performance and cost analysis such as the NETL baseline power studies. Recent experience has shown that first-of-a-kind (FOAK) costs for energy technologies that are not yet well established in the market tend to be much higher than scoping study cost estimates (SSCEs).

If FOAK costs are much higher than SSCEs, what is the value of a SSCE? In essence, if a capture option cannot compete with a natural gas combined cycle (**NGCC**) based on a SSCE, there is no point in considering that option further. On the other hand, if a capture option is shown to be able to compete with a **NGCC** based on a SSCE, that option would become a candidate for TCB under the CO_2 EOR Portfolio Standard, but it would not be known with confidence if that option will really be able to compete with a **NGCC** until a few plants have been built.

Median Estimates of CO_2 Emissions Price vs Time To Enable Alternative 2100 Atmospheric CO_{2e} Concentrations, According to 5th Assessment Report of IPCC



From Figure TS-12 of IPCC (2014a).

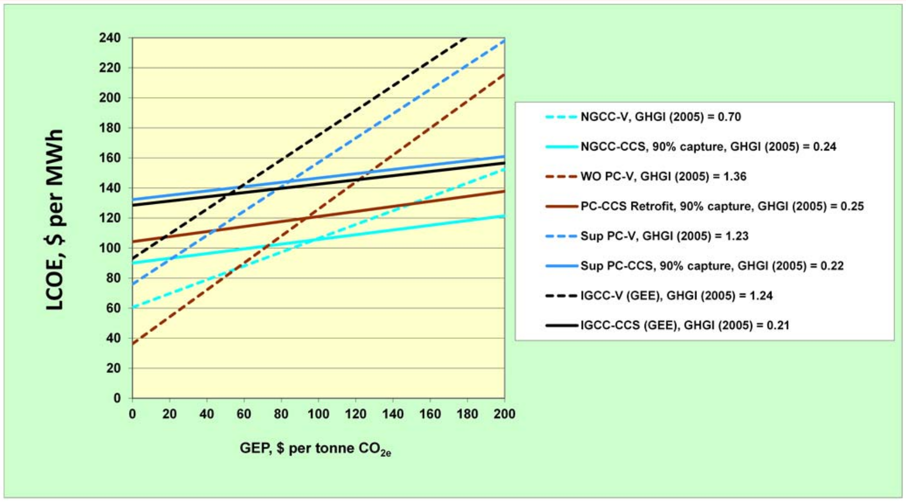
For **2DS** global energy scenario, global CO_2 emissions prices increase from ~ \$60/t, 2020 to > \$200/t, 2050.

CO_2 emissions price levelized over 20-year economic lifetime of new plant coming on line in middle of next decade > \$100/t. Prices in this range needed if CCS technologies are to be launched in market before 2030.

CO_2 price trajectories represent atmospheric CO_{2e} concentrations in 2100 of: (a) 430-480 ppm CO_{2e} (**light blue**), (b) 480-530 ppm CO_{2e} (**dark blue**), (c) 530-580 ppm CO_{2e} (**orange**), and (d) 580-650 ppm CO_{2e} (**red**). **Light blue** trajectory roughly consistent with limiting global temperature rise to 2 °C—referred to here as **2DS** (2 Degree Scenario for global energy).

Here the focus is on the topmost (**2DS**) curve, which represents the minimum CO_2 price implicit in the aspirational global carbon-mitigation goal that the leaders of all the world's major economies have agreed to.

LCOE vs GEP: Current Fossil Fuel Power Options in US



Dashed curves: CO_2 vented; **Paired solid curves**: CO_2 captured/stored in deep saline formations; scoping study cost estimates (see A4-A7).

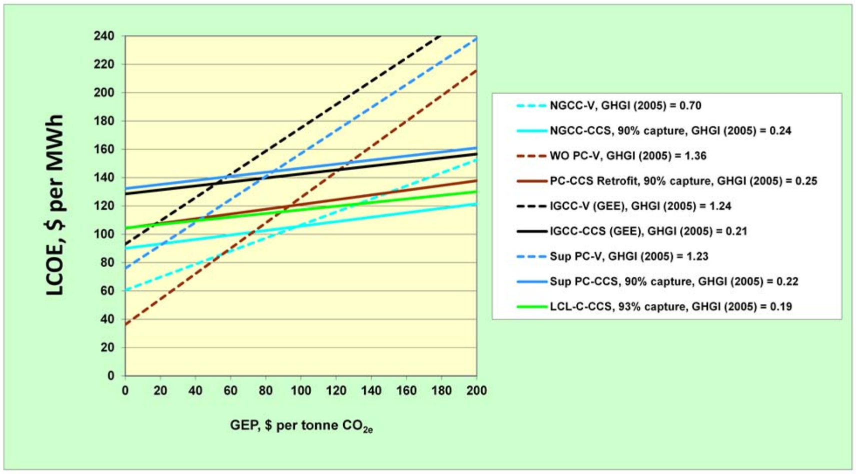
New coal power plants (current technologies), shale gas revolution casualties, cannot compete with **NGCC**.

Included technologies are options for post-combustion capture (for **Coal Retrofit** and new **Supercritical Coal** and new **NGCC** plants) and pre-combustion capture (**IGCC**). Notably:

- CO_2 venting options (dashed curves) have LCOE vs GEP curves that rise rapidly with GEP;
- CCS options (solid curves) rise more slowly but rise with GEP nevertheless—not an attractive feature for a carbon-constrained world in which the GEP is expected to rise continually;
- For GEP > $60/t ($CO_2$ price in 2020 for energy path consistent with 2 ^{o}C warming according to IPCC *5AR* —see previous slide), no coal option offers a lower LCOE than **NGCC** (light-blue dashed/sold curves);
- So none of these "current" coal-based capture technologies are candidates for TCB;
- The minimum GEP for enabling a transition from **NGCC-V** to **NGCC-CCS** for new plants is ~ $100/t CO_2.

This analysis is based on not the current NG price (averaging $3.5/MMBTU for US power plants) but rather $6.3/MMBTU (levelized US average NG price, 2021-2040, based on the Reference Scenario of the EIA's *AEO 2015,* which is 2.6 X levelized US average coal price for this period—see A7.

LCOE vs GEP: Current FF + LCL-C-CCS Power Options



Even advanced technologies such as **chemical looping** (offering possible large cost reductions over longer tem) cannot overcome **NGCC** LCOE advantage relative to new coal power plants—as illustrated for the most evolved chemical looping option: limestone chemical looping for combustion power (**LCL-C-CCS—**being advanced by Alstom)—see A8 and A7.

There are R&D efforts underway to develop advanced capture options that are both more energy-efficient and less capital-intensive than current coal capture options—among which chemical looping offers especially large potential reductions in LCOE.

In this figure the LCOE for a new **LCL-C-CCS** plant is ≤ LCOE for all current-technology CCS options, including the post-combustion retrofit…but it still can't compete with new **NGCC** plants at any GEP. Although not considered here, an **LCL-C-CCS Retrofit** is highly likely to be competitive with **NGCC** at high GEP values.

Do these findings imply that there is no hope for new coal plants in US market? No—as will be shown.

CCS and BECCS: Keys to Low-Cost, Low-Carbon Energy

- Coal/biomass coprocessing with CCS is key to:
  - Improved competitiveness for coal in power markets under carbon policy;
  - Realization of carbon-mitigation goals for energy generally.
- According to IPCC's 5th *Assessment Report—see A1*:

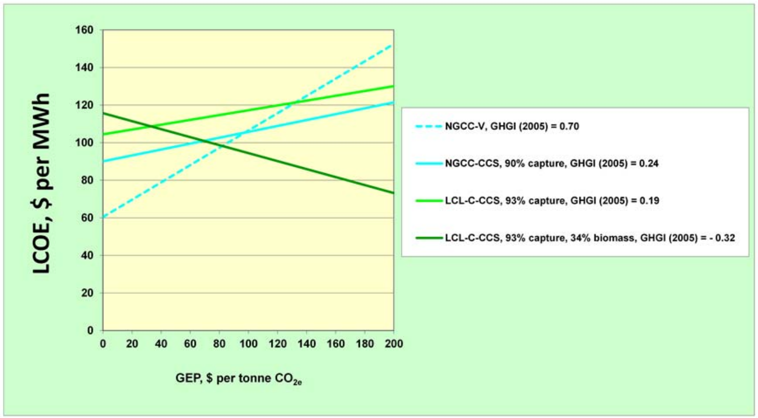
  "Many models could not limit *likely* [global] warming to below 2°C if bioenergy, CCS, and their combination (BECCS) are limited *(high confidence)*."
- According to *GCEP Workshop on Energy Supply with Negative Carbon Emissions,* Stanford University (Milne and Field, 2012):

  "An integrated system of biomass and fossil fuel with capture may be one of the most cost-effective, efficient and practical ways to move toward achieving net negative emissions on large stationary sources."
- 2 candidate coal/biomass coprocessing options considered for TCB:
  - **LCL-C-CCS** (limestone chemical looping combustion electricity)—see A8;
  - **CBTLE-CCS** (coal/biomass to synthetic liquid fuels + electricity)—see A9, A10.
- Such options designed to provide zero or negative GHG emissions would enable expanded coal use without violating carbon-budget constraint—severe for coal (see A12 and A13).

Even though biomass is much more expensive than coal (assumed here to be 2.2 X as costly), the value under a serious carbon policy of negative emissions arising from photosynthetic CO_2 storage more than compensates for higher biomass prices.

On a global energy path consistent with limiting global warming to 2 °C (3 °C), ~ 5/6 (2/3) of coal reserves worldwide would have to be kept underground without CCS + biomass coprocessing—see A12. (Reserves ≡ identified resources recoverable at current prices with current technologies = 137 year supply at the current coal consumption rate.)

Add LCL-C-CCS Power Option Coprocessing 34% Biomass

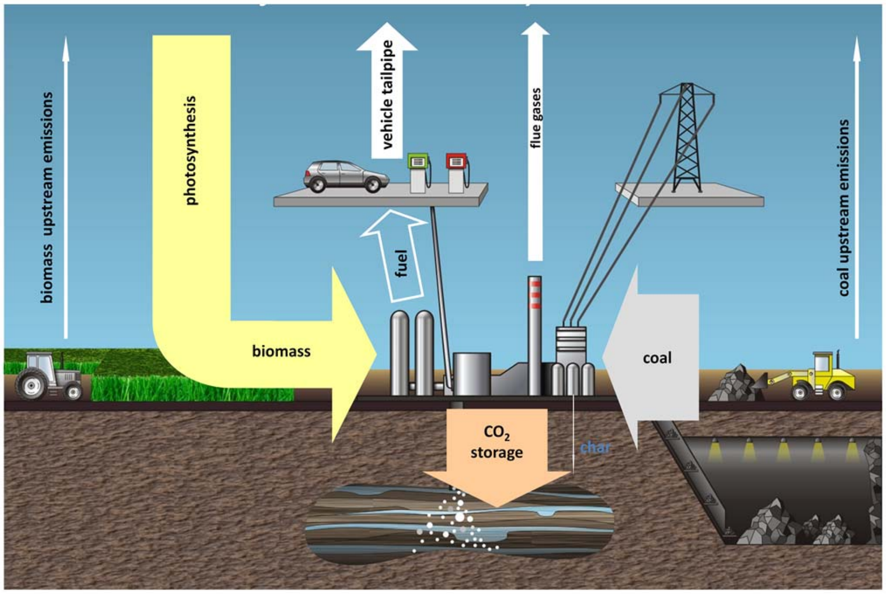


- **LCL-C-CCS** with biomass coprocessing:
  - **Downward-sloping LCOE vs GEP curve** (because of negative emission rate) **is attractive feature with expectation of continually rising GEP**;
  - **LCL-C-CCS** can compete with **NGCC** at high GEP ➔ strong candidate for TCB…but not ready for TCB before 2030+.

The next slide shows why a 34% biomass coprocessing rate (energy basis) was chosen for **LCL-C-CCS.**

As for **LCL-C-CCS** based on only coal as feedstock, **LCL-C-CCS** with biomass coprocessing is an advanced technology option that is unlikely to be ready for TCB until post-2030. So this option is not a coal-based capture option that might compete with **NGCC** before 2030. The **CBTLE-CCS** option discussed in the next three slides might be able to do this, however.

Carbon Flows for CBTLE-CCS with Zero Net Emissions



Sum of carbon flows to atmosphere = photosynthetic carbon flow from atmosphere with 34% biomass coprocessing (Liu *et al.*, 2011).

For an energy system coprocessing biomass provided on a renewable basis (so that 1 tonne of new biomass is grown for each tonne consumed) + coal, the carbon in the biomass is extracted from the atmosphere as CO_2 during photosynthesis. At some percentage of coprocessing, this CO_2 extraction rate will become equal and opposite to the total flow of CO_{2e} to the atmosphere from production and consumption of the energy products (in this case liquid fuels + electricity): CO_2 that goes up the stack + CO_2 from the eventual liquid fuel consumption + the CO_{2e} associated with the primary production of biomass and coal and their trans-port to the energy conversion facility. For the **CBTLE-CCS** system considered here that percentage is 34%.

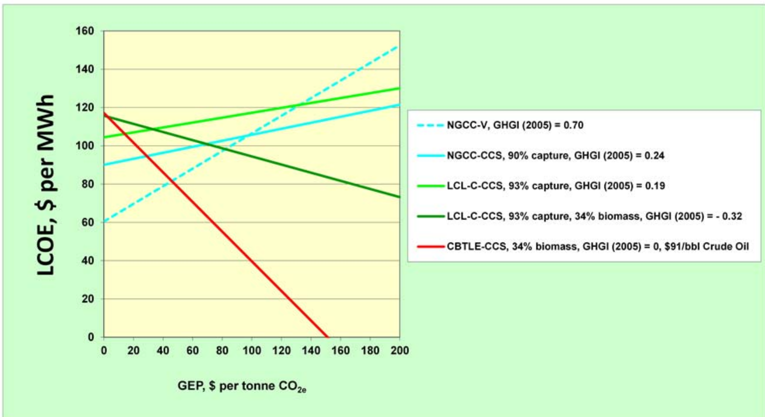
The energy conversion process for **CBTLE-CCS** is made up of the following steps (see A9 and A10):

- Synthesis gas (syngas) is made from biomass + coal via gasification;
- Syngas with an appropriately adjusted H_2/CO ratio is passed once through a synthesis reactor in which synthetic liquid fuels are made;
- The unconverted syngas is burned in a combined cycle power plant to make coproduct electricity;
- A zero GHG-emitting **CBTLE-CCS** system consuming 1 million dry tonnes/year of biomass (a practical maximum) would provide 9,200 bbls/day of synthetic diesel and gasoline + 248 MW_e of net electricity (30% of energy output); 66% of feedstock carbon would be captured as CO_2 and stored underground; 24% of feedstock carbon would end up in synfuels.

Why power companies should seriously consider pursuing a **CBTLE-CCS** option:

- This coal-based option has the potential to compete at high GEP with **NGCC** in the US power market;
- It can be launched in the US market before 2030;
- Its minimum dispatch cost is ultra-low [negative at GEP = \$0/t (\$100/t) of CO_{2e} for crude oil prices > \$70/bbl (> \$20/bbl)] so that **CBTLE-CCS** systems will be dispatched before any conventional power system and thus might be designed to be must-run baseload plants (like nuclear).

Add CBTLE-CCS Coprocessing 34% Biomass



Biomass coprocessing + comprehensive GEP are keys to indicated attractive **CBTLE-CCS** economics—see A14, A15.

Coal heat rates for **CBTLE-CCS** & **LCL-C-CCS** with 34% biomass are 2.1 and 0.8 X HR for **Sup PC-V,** respectively.

- **CBTLE-CCS** offers stronger downward-sloping LCOE vs GEP curve under a comprehensive GEP;
- **CBTLE-CCS** coprocessing < 30% biomass is ready for demonstration; Could be ready for TCB by 2025 if demo successfully carried out earlier (see A16).

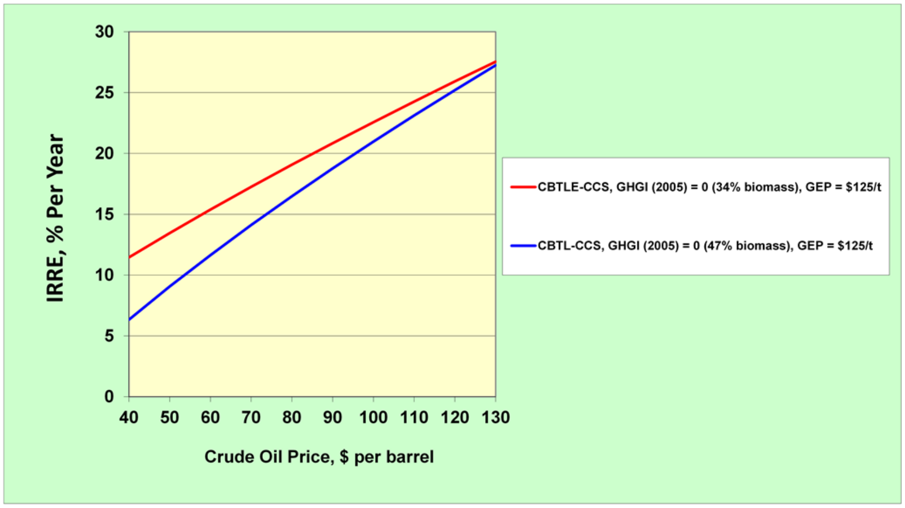
Key to the economic attractivenes of **CBTLE-CCS** are:

- Having a comprehensive GEP in place [if instead the carbon price were a trading price applied only to the power sector (e.g., as under the CPP), the LCOE curve for **CBTLE-CCS** would be flat at the GEP = $0/t level (see A15), and the option would be hopefully uneconomic]; with a comprehensive GEP the value of the synthetic fuel coproducts rises with GEP, leading to an LCOE curve that is a sharply declining function of GEP instead of being flat.
- Coprocessing a substantial biomass percentage—if the biomass percentage were 0 (i.e, for a **CTLE-CCS** system having the same synthetic fuel output capacity as **CBTLE-CCS**—see A9) the LCOE would be > LCOE for the **NGCC** options at all GEP values (see A14).

The assumed $91/bbl crude oil price is the 20-year levelized price, 2021-2040, of imported crude oil based on the Reference Scenario projection of the Energy Information Administration's *Annual* Energy Outlook 2015. The expectation in *AEO 2015* is that, as excess oil production capacity declines, oil prices will rise over time—from $49/bbl in 2015 to $70/bbl in 2020, $81bbl in 2025, $96/bbl in 2030, and $129/bbl in 2040.

However, investors will be concerned about the possibility that instead future oil prices will be low. How to address the financial risk posed by possible low future oil prices is discussed in the next slide.

Internal Rate of Return on Equity (IRRE) vs Crude Oil Price
(CO_2 storage in deep saline formations at GEP = $125/t)



- High GEP (needed for realization of a **2DS** energy future) would protect **CBTLE-CCS** investors against financial risk of low future oil prices.
- **CBTLE-CCS** more profitable than **CBTL-CCS** (providing mainly liquid fuels—see A9) because of scale economies and lower feedstock cost.

Both **CBTLE-CCS** and **CBTL-CCS** are designed with enough biomass coprocessing (34% for **CBTLE-CCS** and 47% for **CBTL-CCS** on an energy basis) to realize zero net cradle-to-grave GHG emissions, and it is assumed that each system consumes biomass at a rate of 1 million dry tonnes per year [the maximum practical rate—see Larson et al., (2010)].

Electricity from **CBTLE-CCS** represents a major coproduct (248 MW_e, accounting for 30% of energy output) while it is a minor byproduct in the **CBTL-CCS** case (51 MW_e, accounting for 8% of output)—see A9.

CBTLE-CCS is the more profitable because (a) the average feedstock cost for **CBTLE-CCS** is 10% less (the assumed biomass price is 2.2 X the coal price), and (b) a scale economy impact (the coal processing rate of **CBTLE-CCS** is 67% higher). Even though the **CBTL-CCS** is designed to maximize liquid fuel output, the two systems have comparable liquid fuel output capacities (9,200 bbls/day for **CBTLE-CCS** and 9,500 bbls/day for **CBTL-CCS**).

Assumed High Costs for Early-Mover CBTLE-CCS Projects Deployed in US CO_2 EOR Applications

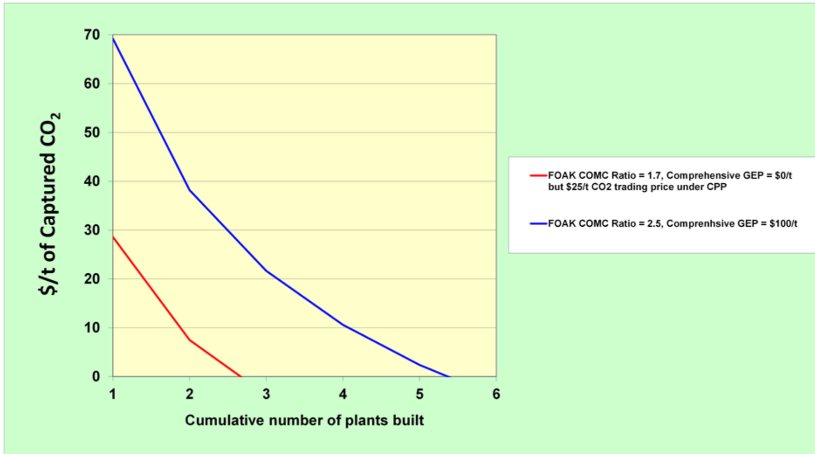
- FOAK Capital + O&M Cost Ratio (**COMC Ratio**) might be:
  - **1.7 X [scoping study cost estimate (SSCE)]** (Boundary Dam and Edwardsport experiences), or
  - Up to **2.5 X SSCE** (Kemper County experience).
- Technology cost buydown (**TCB**) process discussed for **CBTLE-CCS** coprocessing 29% biomass (technology ready to be demonstrated—see A16) with government subsidy financing via **Energy Security Fund** for 2 cases:
  - **FOAK COMC Ratio = 1.7** (assume $0/t GEP but $25/t trading price for direct CO_2 emissions under US Clean Power Plan);
  - **FOAK COMC Ratio = 2.5** (assume $100/t GEP).

Prospects for Cost Reduction Through Experience (Learning by Doing)

- Assumption: learning rate = **11%** [based on consideration of experience listed below—chemical industry examples most relevant (**CBTLE-CCS** involves extensive chemical processing)]:
  - **21%** [capex for X-silicon PV modules, 1976-2006, van Sark et al. (2010)];
  - **15%** [capex for onshore wind, 1990-2001 (Spain), Junginger et al. (2010)];
  - **11%** [urea production cost, 1961-2003; [range for 11% to 36% for 20 chemical industry products (fertilizers and plastics), Patel et al. (2010)].
- Word of caution to and guidance for policymakers:
  - Learning rate cannot be known *a priori*—it might even turn out to be negative [nuclear experience in France (Grūbler, 2010) as well as US];
  - But relatively small **CBTLE-CCS** scales ➔ much of the construction can be carried out in factories, where prospective cost reductions via learning by doing are reasonably good;
  - Policymakers should design TCB process under proposed **CO_2 EOR Portfolio Standard** with aim of facilitating LBD among successive projects.

For the purposes of the present analysis, the learning rate is the assuming reduction in capital + operation and maintenance cost (**COMC)** for each cumulative doubling of the number of plants deployed. Thus, for the assumed 11% learning rate, the **COMC** cost of the 2nd plant deployed is 11% less than the **COMC** for the 1st plant, the **COMC** for the 4th plant is 11% less than the **COMC** for 2nd plant, etc.

Subsidies Required for the Two CBTLE-CCS TCB Cases, (29% Biomass, CO_2 Sold for EOR, \$91/bbl Crude Oil Price)



For **FOAK COMC Ratio = 2.5** Case, 14 projects w/o subsidy (4.0 GW_e) in addition to 5 subsidized projects must be deployed in CO_2 EOR applications in order to enable **CBTLE-CCS** to compete with **NGCC** in deep saline formation applications at high GEPs.

Required subsidies are measured in \$ per tonne of CO_2 captured and made available for EOR.

The LCOEs for FOAK versions of **CBTLE-CCS** with subsidy are shown disaggregated by component in A17, along with disaggregated LCOE values for the corresponding **NGCC** systems.

Two plants require subsidy for the FOAK COMC Ratio = 1.7, and

Five plants require subsidy for the FOAK COMC Ratio = 2.5, with a \$100/t GEP.

If the 20-year levelized crude oil price were less than \$91/bbl for **CBTLE-CCS** plants that would come on line no earlier than 2025, the required subsidies would be higher and more plants would have to be subsidized. Likewise, if the learning rate turns out to be less than 11%, the required subsidies would be higher and more plants would have to be subsidized.

Required Subsidies and Gross New Federal Corporate Income Tax Revenues for CBTLE-CCS TCB Process

Assumed:		**# of plants requiring subsidy**	**Present Worth (in $\$10^9$) over 20-year economic lifetimes of subsidized plants of:**	
FOAK COMC Ratio	GEP, $/t CO_{2e}		Required subsidies for all subsidized plants	Gross new federal corporate income tax revenues collected from subsidized plants and associated CO_2 EOR activities for all subsidized plants
1.7	0	2	1.4	4.1
2.5	100	5	5.6	13.2

That gross new federal corporate income tax revenues > required subsidies ➔

- Government can afford "to find out" via proposed TCB process what actual learning rate will be (LR must be significant to justify TCB subsidies from theoretical economics perspective).
- Positive new revenue flows to Treasury net of subsidies, making practically feasible proposed **Energy Security Fund** for financing TCB.

Summary of Findings

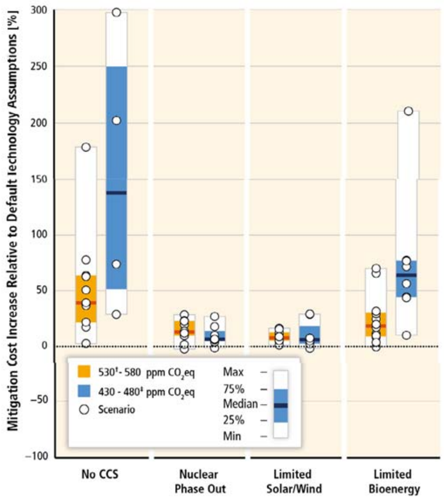
- Coal-only options for new power plants (even via advanced technologies such as **LCL-C-CCS**) not promising for competing with **NCCC** in US power market under carbon policy constraint, although retrofit versions of **LCL-C-CCS** are likely to be competitive in the US and are especially important for applications in "coal renaissance" countries.
- There are promising coal/biomass coprocessing options that could enable major roles for coal in carbon-constrained US power market:
  - **CBTLE-CCS** coprocessing < 30% biomass candidate for early TCB (~ 2025) under **CO_2 EOR Portfolio Standard** if a demo project can be successfully carried out earlier;
  - **CLC-C-CCS** (chemical looping combustion) with biomass coprocessing candidate for TCB later (~ 2030+) if RD^2 successfully carried out earlier.
- Advanced **CBTLE-CCS** based on **LCL-G-CCS** (limestone chemical looping gasification) with biomass coprocessing also good candidate for TCB later (2030+) (Levasseur, 2015) if RD^2 successfully carried out earlier.

Looking Forward

- Urgency of getting RD^2 + TCB activity underway to bring promising coal/biomass capture technologies into the US market:
  - There will be huge (hitherto overlooked) demand for new baseload power in US even with near-flat electricity demand, as result of declining capacity factors as US coal power plants age, according to recent NETL study (Kern, 2015) (perhaps > 140 GW_e by 2040—see A18);
  - This baseload power demand will be met largely with new **NGCC** plants, and US will end up having much less diversified electric power portfolio than at present unless new coal power options that can compete with gas can be brought into US market quickly.
- Coal and coal/biomass with CCS options that can be successfully launched in US market under proposed **CO_2 EOR Portfolio Standard** are likely to be competitive anywhere in world where there are adequate CO_2 storage opportunities and sustainable biomass supplies because the competition facing coal in power markets is not likely to be as fierce as in the US.

Appendix—Extra Slides in Support of the Analysis (not presented)

A1: CCS, BECCS: Keys to Least-Cost 2DS Energy Path



According to IPCC's *AR5* (IPCC, 2014a; 2014b):

- "Many models cannot reach concentrations of about 450 ppm CO_{2e} by 2100 in the absence of CCS".
- "Many models could not limit *likely* warming to below 2°C if bioenergy, CCS, and their combination (**BECCS**) are limited *(high confidence).*

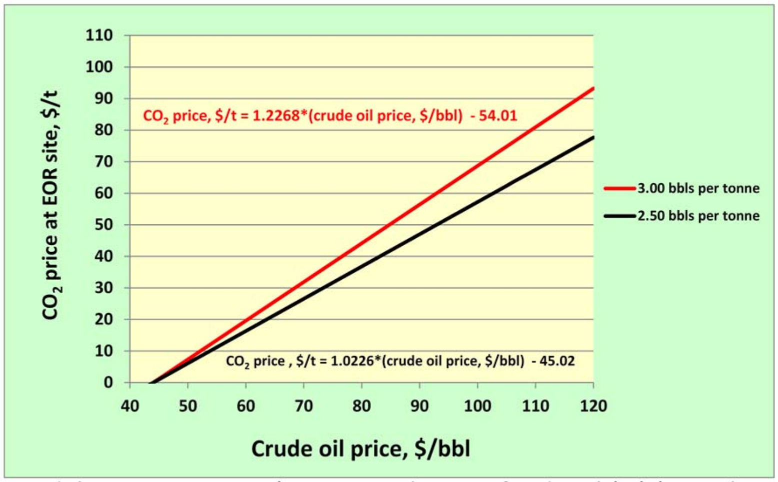
In graph at left, dark blue horizontal lines on light blue bars represent median estimates (from integrated assessment models) of increases in cost to society relative to base case assumptions if each of these four sets of technologies is constrained as indicated below when global energy system is on **2DS** track.

No CCS(unavailability of CCS) ➔ **mitigation cost + 138%;**
Nuclear Phase Out (no additional nuclear power plants beyond those under construction) ➔ **mitigation cost + 7%;**
Limited Solar/Wind (20% limit on solar/wind electricity) ➔ **mitigation cost + 6%;**
Limited Bioenergy (100 EJ/y maximum) ➔ **mitigation cost + 64%.**

A2: Rationale for Public-Sector Support of TCB Process for New Energy Technologies Offering Major Public Benefits and Have Good Prospects for Cost Reduction via LBD

- It is widely recognized (PCAST Energy R&D Panel, 1997) that spillovers associated with research, development, and demonstration (RD^2) activities for promising new energy technologies offering major public benefits imply need for government subsidies for these activities.
- Many believe that once new energy technologies offering major public benefits have been adequately demonstrated, private sector should shoulder costs in excess of market clearing costs for subsequent costly early-mover projects, via forward-pricing strategies. However, Duke (2002) has shown that:
  - Private firms will not be willing to shoulder costs in excess of market cleaning costs for costly early-mover projects (post-demonstration) because of inevitable spillovers in the learning-by-doing (LBD) process, so that they cannot fully appropriate benefits of such a forward pricing strategy; and
  - Based on fundamental economic principles, this spillover externality implies that new energy conversion technologies offering major public benefits that have good prospects for cost reductions via experience (LBD) warrant public-sector support (even with full societal cost pricing of air pollutant and GHG emissions)—as a complement to warranted public-sector support for RD^2 for such technologies.

A3: Estimates of CO_2 Price at Oil Field for CO_2 EOR Market In Which Marginal Supply Is Anthropogenic CO_2



CO_2 price modeling assumptions (see Liu et al., 2015 for details): (a) equal pre-tax income ($/bbl) to CO_2 provider and to CO_2 consumer, (b) distribution of other WAG CO_2 EOR costs and benefits for the Permian Basin, as estimated in ARI (2010) and private communication from Vello Kuuskraa, December 2012, and (c) for two crude oil yields. **For present TCB analysis curve for 3 bbls per tonne yield is assumed.**

A4: Some Near-Term Electric Power-Only Options

System	WO PC-V	PC-CCS Retrofit	NGCC-V	NGCC-CCS
Fuel input capacity, MW_t, HHV	1495	1495	1223	1223
Net electric capacity, MW_e	550	415	630	559
Capacity factor, %	60	85	85	85
Conversion efficiency (HHV), %	36.8	27.8	51.5	45.7
Lifecycle GHG emission rate, kg CO_{2e} per MWh_e	897	168	460	167
GHGI (2005)	1.36	0.25	0.70	0.24
CO_2 storage rate, 10^6 t/y (% of coal C captured as CO_2)	0 (0)	3.2 (90)	0 (0)	1.5 (90)
Total plant cost (TPC) based on SSCE, \$2012 10^9	0	0.74	0.43	0.83

Here WO = "written off."

Mass/energy balances & total plant cost (TPC) estimates are from NETL (2013) and NETL (2015a). TPC values are scoping study cost estimates (SSCEs). US average GREET values are assumed for GHG emissions arising from outside plant boundaries. GHGI (2005) carbon footprint metric is defined in A6

A5: More Near-Term Electric Power-Only Options

System	Sup PC-V	Sup PC-CCS	IGCC (GEE)-V	IGCC (GEE)-CCS
Fuel input capacity, MW_t, HHV	1351	1692	1597	1665
Net electric capacity, MW_e	550	550	622	543
Capacity factor, %	85	85	85	85
Conversion efficiency (HHV), %	40.7	32.5	39.0	32.6
Lifecycle GHG emission rate, kg CO_{2e} per MWh_e	811	144	821	140
GHGI (2005)	1.23	0.22	1.24	0.21
CO_2 storage rate, 10^6 t/y (% of coal C captured as CO_2)	0 (0)	3.6 (90)	0 (0)	3.4 (88.5)
TPC based on SSCE, \$2012 10^9	1.1	1.9	1.5	1.8

Mass/energy balances and TPC estimates are from NETL (2015a) and NETL (2015b). US average GREET values are assumed for GHG emissions arising from outside plant boundaries. GHGI (2005) carbon footprint metric is defined in A6.

A6: GHGI (2005)—a "Carbon Footprint" Metric

GHGI is widely applicable carbon footprint metric [first introduced in Liu *et al.* (2011)]. GHGI is especially helpful in measuring carbon footprint of polygeneration systems because it does not require specifying how emissions are allocated among outputs. The version of GHGI considered here is GHGI (2005):

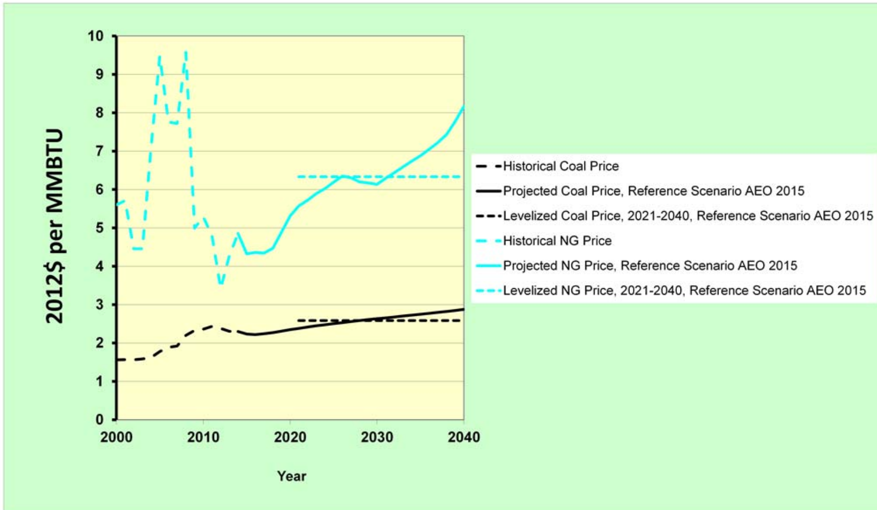
$$\equiv \frac{\text{(Fuel cycle wide GHG emissions for energy production + consumption)}}{\text{(GHG emissions for same energy amounts via 2005 US ave. electricity \& CODP)}}$$

GHGI (2005) measures system's carbon footprint relative to US average electricity and crude oil-derived products (CODP) in 2005 when emission rates averaged:

- 661 kg CO_{2e}/MWh_e for US grid electricity;
- 90.5 kg CO_{2e}/GJ LHV for COPD that would be displaced by F-T diesel + gasoline.

25

A7: Coal, Natural Gas, & Biomass Prices for Power Plants



For this analysis, delivered coal and natural gas prices at power plants are assumed to be $2.58 and $6.33 per MMBTU, respectively—levelized prices over the 20–year economic lifetimes of plants that would come on line in 2021, based on the Reference Scenario of *AEO 2015* (EIA, 2015). Also, assumed delivered biomass price is $5.73/MMBTU.

A8: Limestone Chemical Looping Combustion (LCL-C-CCS) Power-Only Options

Feedstock:	100% Coal	68% Coal + 34% Biomass
Fuel input capacity, MW_t, HHV	1686	1686
Net electric capacity, MW_e	550	550
Biomass consumed annually, 10^6 dry tonnes/year	0	0.88
Capacity factor, %	85	85
Conversion efficiency (HHV), %	32.6	32.6
Lifecycle GHG emission rate, kg CO_{2e} per MWh_e	113	-212
GHGI (2005)	0.19	- 0.32
CO_2 storage rate, 10^6 t/y (% of feedstock C captured as CO_2)	3.6 (93)	3.6 (93)
TPC based on SSCE, \$2012 10^9	1.4	1.4

Mass/energy balances and TPC estimate for 100% coal case are from NETL (2014). GREET values are assumed for GHG emissions upstream of power plant (4.42 kg CO_{2e}/MMBTU HHV).

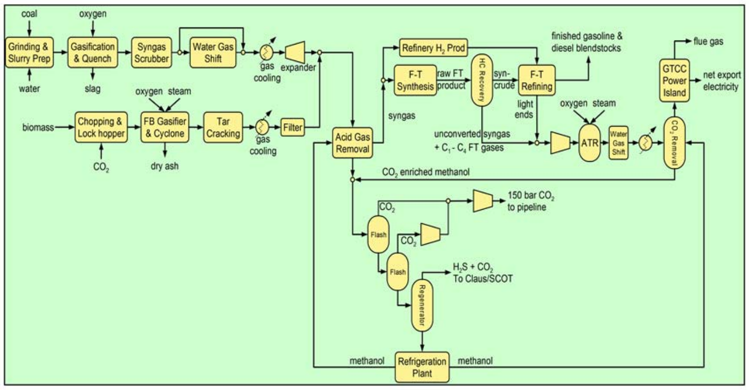
Coal/biomass case is based on a simplified model. Because carbon contents of coal (25.1 kgC/MMBTU) and biomass (26.5 kgC/MMBTU) are so similar, it is assumed that key features of this option are the same as for 100% coal case except for: (a) upstream emissions via GREET for biomass feedstock (6.28 kg CO_{2e}/MMBTU), (b) allowance for extraction of CO_2 from atmosphere during photosynthesis for biomass grown on renewable basis (represented as – 96.8 kgCO_2/MMBTU of biomass), and (c) biomass feedstock prices are taken into account.

A9: CTLE-CCS, CBTLE-CCS, and CBTL-CCS Options

	CTLE-CCS	CBTLE-CCS		CBTL-CCS
GHGI (2005)	0.79	0.095	0.0	0.0
Net electric capacity, MW_e (% of energy output)	273 (32)	287 (29)	248 (30)	51 (7.8)
Capacity factor, %	90	90	90	90
Coal input capacity, MW_t	1953	1616	1265	756
FTL output capacity, kbbls/day	9.2	10.9	9.2	9.5
Conversion efficiency (HHV), %	46.1	45.1	45.4	49.3
Biomass input, 10^6 tonnes/y (% of energy input)	0 (0)	1.0 (29)	1.0 (34)	1.0 (47)
Lifecycle GHG emission rate, kg CO_{2e} per MWh_e	1067	138	0	0
GHGI (2005)	0.79	0.095	0.0	0.0
CO_2 storage rate, 10^6 t/y (% of C captured as CO_2)	2.5 (52)	3.7 (65)	3.2 (66)	1.9 (54)
TPC based on SSCE, \$2012 10^9	1.6	2.0	1.8	1.5

Mass/energy balances, TPC estimates, and GHG emission rates are based on Liu et al. (2011) (see also A10). GHGI (2005) carbon footprint metric is defined in A6.

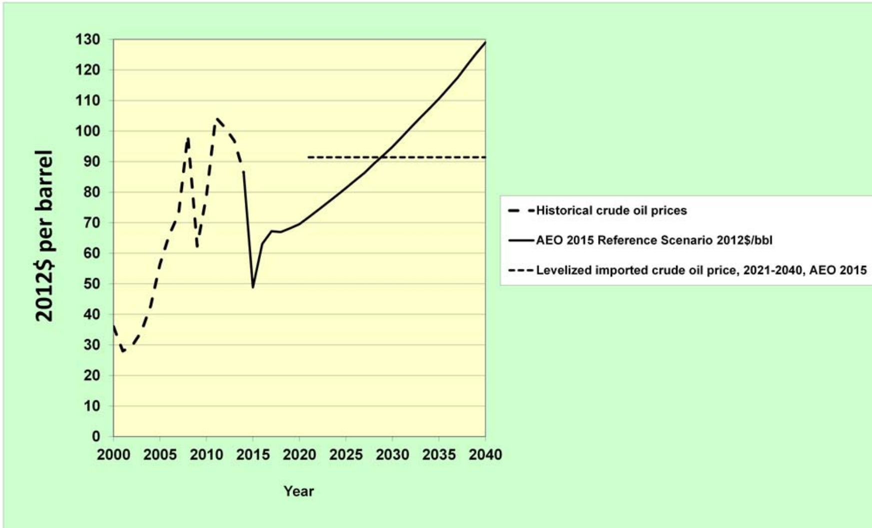
A10: CBTLE-CCS Schematic



This FTL system [based on Liu et al. (2011)] was designed to make diesel + gasoline + electricity with CCS from coal and biomass (switchgrass) via slurry-phase F-T synthesis (iron catalyst) in a once-through synthesis reactor. Process starts with gasification: GEE entrained flow gasifier for Illinois # 6 coal + separate GTI fluidized bed gasifier for switchgrass.

CBTLE-CCS system designs discussed (A9): 1 coprocessing 29% biomass [GHGI (2005) = 0.095]; 1 coprocessing 34% biomass [GHGI (2005) = 0.0].

A11: *AEO 2015* Projection of Average Refinery Acquisition Cost for US Imported Crude Oil



Base case crude oil price assumed for present analysis is \$91/bbl, the 20-year levelized price seen by new energy conversion plants that come on line in 2021—based on Reference Scenario of *Annual Energy Outlook 2015* (EIA, 2015).

A12: Carbon Budget Constraints on Fossil Fuel Reserves

- Table below shows fossil fuel reserves, how long they would last if used at current rates, and corresponding amounts of CO_2 added to atmosphere if all reserves were used without CCS/biomass coprocesssing.
- Also shown: (a) carbon budgets for 2 global warming limits (GWLs), &
- (b) % of reserves left underground for each GWL—assuming each fossil fuel gets an equal carbon budget share.

Fossil Fuel	**Reserves, EJ (BGR, 2013)**	**Years that reserves would last at 2012 global consumption rate**	**Gt CO_2 released if all reserves are burned**	**Global Warming Limit**	
				2.0 °C	**3.0 °C**
				% of reserves left underground	
Oil	9052	52	663	58	-4
Natural gas	7455	63	423	34	-63
Coal	22,320	137	1995	**86**	**65**
All fossil fuel reserves	38,827	85	3081	73	33
Average of Low/High CO_2 budgets, 2013-2100, 10^9 Gt CO_2 (Table TS.1, IPCC (2014a)]				841	2017
Estimated global CO_2 storage potential , Gt CO_2 (Benson et al., 2012)				5,050 to 24,500	

- There might be enough capacity to store CO_2 from all FF reserves.

A13: Carbon Implications of Recent & Prospective Coal Power Projects from Around the World

Coal generating capacity	Coal generating capacity, GW_e	Committed emissions, Gt CO_2	% of committed emissions from Asia	% of Asian committed emissions from China	% of Asian committed emissions from China + India
Newly operating, 2010-2014	408	49.6	90%	64%	84%
Under construction	230	27.8	86%	30%	68%
Planned	958	115.3	88%	41%	72%
Total	1596	192.6	88%	46%	74%
Coal generating capacity in 2010	1649				

Total committed emissions as % of:

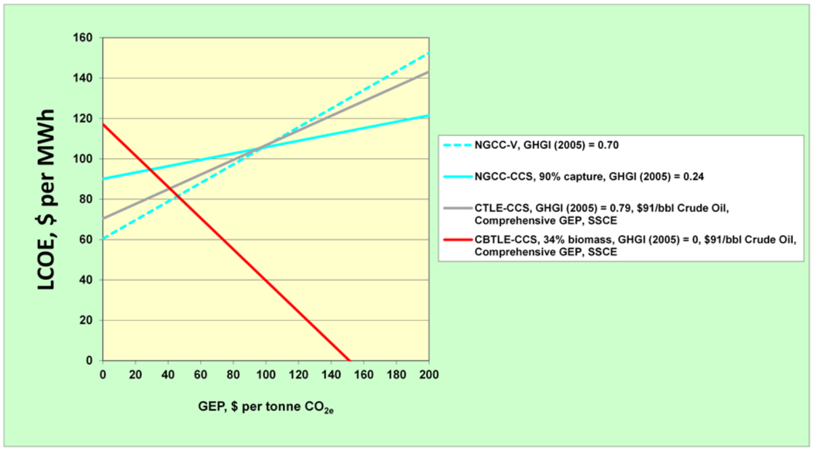
	Carbon budget for coal	Emissions from burning coal reserves
2 ^oC global warming limit	69%	9.7%
3 ^oC global warming limit	29%	9.7%

The data presented here for coal plants on line since 2010, under construction, and planned were obtained via personal communication with Phillip Hannam, based on data and the methodology explained in Hannam et al. (2015).

Estimates of lifetime commitments for CO_2 emissions for these power plants are estimated under the following assumptions:

- The average coal power plant capacity factor and plant life are assumed to be 44% and 40 years, respectively, in accord with the analysis presented in Davis and Socolow (2014);
- The average supercritical percentage of deployed coal capacity is (personal communication from Phillip Hannam, November 2015): (i) 60% for plants brought on line 2010-2014, (ii) 70% for plants under construction, and (iii) 80% for plants planned, and the remaining capacity is assumed to be for subcritical coal plants.
- Higher heating value efficiencies and direct CO_2 emission rates for new coal power plants are assumed to be 39.0%/867 kg CO_2/MWh for new subcritical pulverized coal plants and 40.7%/ 773 kg CO_2/MWh for new supercritical plants, following NETL (2015a).

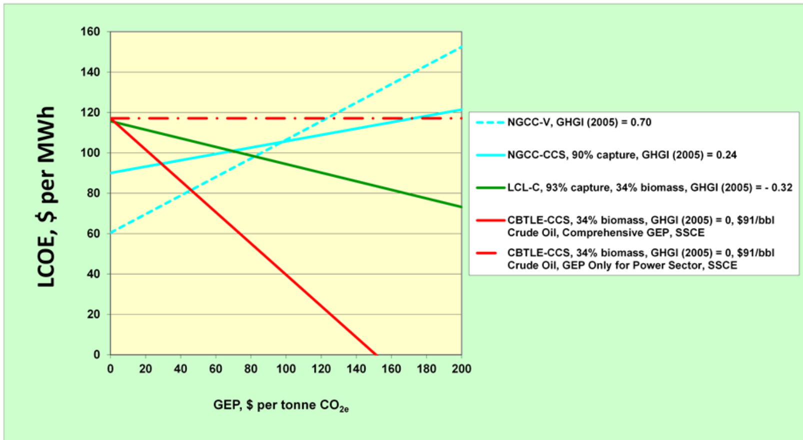
A14: Comparing CBTLE-CCS to CTLE-CCS (no biomass but same liquid fuel output capacity) (SSCEs)



- LCOE for **CTLE-CCS** (see A9) always > LCOE for **NGCC** ➔

Negative emissions from photosynthetic CO_2 storage is key to attractive CBTLE-CCS economics in DSF applications at high GEP values.

A15: Adding LCOE vs GEP Curve for CBTLE-CCS When GEP Is Applied Only to Power Sector (SSCEs)



- LCOE curve is added for GEP applied only to power sector and not to crude oil-derived products (e.g., GEP implicit in carbon trading system allowed under US Clean Power Plan) ➔

Comprehensive GEP is key to attractive CBTLE-CCS economics in DSF applications.

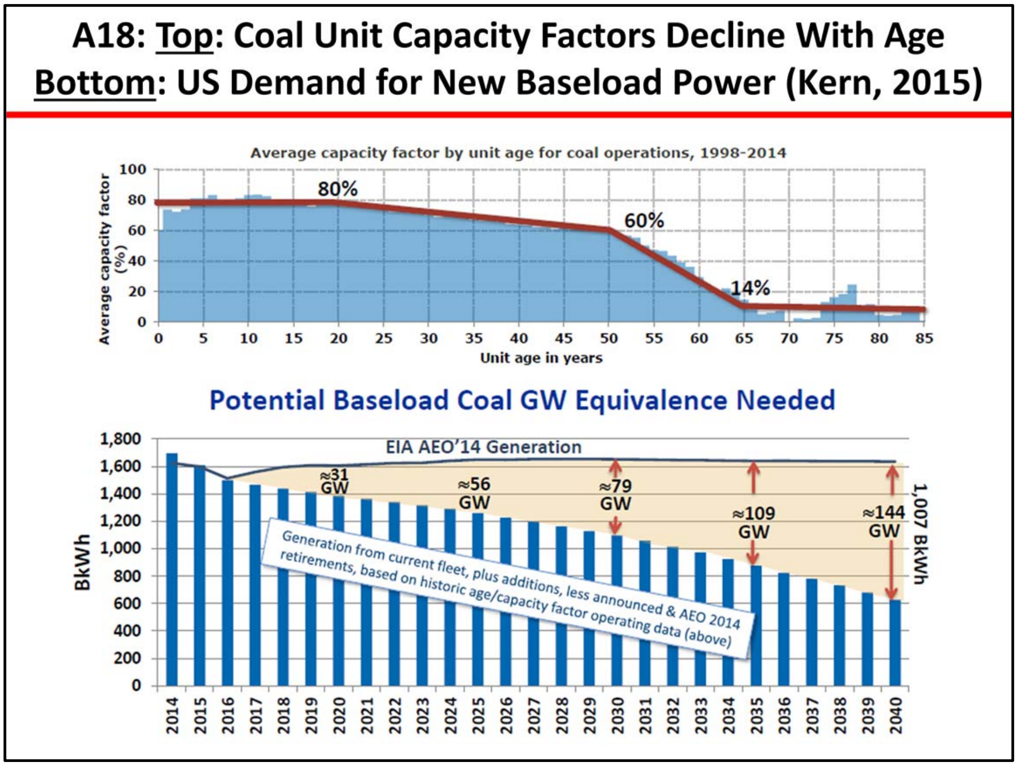
A16: CBTLE-CCS Can Be Ready for TCB Under CEPS by 2025

For CO_2 EOR applications, all system components are commercial or demonstration-ready:

- CO_2 storage via CO_2 EOR is commercial technology;
- Coal gasification and FTL technologies are commercially available;
- Technology for CO_2 separation upstream of synthesis has been commercial since 1983-84, when win Sasol plants producing 140,000 bbls/day of FTL from coal came on line—these two plants represent largest point source on planet of nearly pure CO_2 emissions (~ 20 x 10^6 t/y);
- Technology for capturing this separated pure CO_2 has been commercial since 2000, when Basin Electric began capturing a stream of essentially pure CO_2 at Dakota Gasification plant and selling it for CO_2 EOR in Canada;
- Technologies for biomass/coal cogasification are ready to be demonstrated:
  - Via co-gasification of black pellets with coal using dry-feed, entrained-flow gas gasifiers (Vattenfall, 2010) [Black pellets are conventional "white" biomass pellets thermally processed via torrefaction or steam explosion so that product can be ground (with coal) to small particle sizes needed for entrained-flow gasifiers], or
  - Via co-gasification of biomass and low-rank coal using transport gasifier (TRIG^{TM}) that Southern Company has deployed in Kemper County **IGCC-CCS** plant in Mississippi; Southern Company has carried out successful tests of O_2-blown cogasification of biomass and low-rank coal with up to 30% biomass in its experimental TRIG^{TM} at Wilsonville, Alabama (SCS, 2010; SCS, 2012).
- ➔ **CBTLE-CCS** will be ready for **CEPS** TCB by 2025 if demonstrated in interim.

A17: LCOE by Component for Subsidized FOAK CBTLE-CCS Projects in CO_2 EOR Applications (2 Cases @ $91/bbl Crude Oil)

Assumed COMC Ratio for FOAK CBTLE-CCS		**1.7**		**2.5**
Assumed GEP, $/t CO_2	0	0	100	100
LCOE by component , $/MWh				
Component of LCOE:	**NGCC-V**	**CBTLE-CCS**	**NGCC-CCS**	**CBTLE-CCS**
Capital	12.1	205.9	25.3	302.8
O&M	3.0	59.6	5.5	87.6
Natural Gas	43.0	0	50.5	0
Coal	0	49.6	0	49.6
Biomass	0	44.9	0	44.9
F-T liquids sales	0	- 179.5	0	-258.4
GHG emissions	0	0	16.7	13.8
CO_2 T&S or Sale for EOR ($/t)	0	- 87.1 (-$53.2/t)	3.5 ($9.2/t)	- 87.1 (-$53.2/t)
Carbon Trading Credit ($/t)	0	- 31.5 (- $25/t)	0	0
Subsidy ($/t)	0	- 46.9 (-$28.6/t)	0	- 113.5 (-$69.2/t)
Corporate Income Tax	2.7	45.8	5.6	67.4
Total	**60.8**	**60.8**	**107.1**	**107.1**



As coal power plants age, power companies make continual investments as needed to enable sustained operation of these plants. However, this figure shows that the capacity factor falls precipitously after coal power plant age 50 is reached—which will be realized for the average US coal unit in 2023. Post age-50 capacity factors are so low that investment cost recovery prospects become poor, so that the continual investments needed to sustain operation might cease and these old coal plants might be retired.

Retirements of old coal power plants in the post-2020 time frame are likely to be far in excess of retirement rates projected by the Energy Information Administration in its Reference Scenario (EIA, 2015). That projection, which envisions that the average coal power plant capacity factor for the period 2021 (when the average age of existing coal units will be 67 years) through 2040 is 75% (up from an actual average capacity factor of 56% in 2012) overlooks this coal plant aging challenge.

As a consequence, there is likely to be a completely unanticipated huge, rapidly growing demand for new baseload power plants in the US in the post-2020 time frame—despite the expectation of roughly flat US electricity demand. This demand for new baseload power will be satisfied largely by deploying new natural gas combined cycle plants unless ways can be found to bring new low-carbon coal-based power technologies into the US market.

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