Clean Air Task Force
Office of Management and Budget Meeting 8-22-13.
Update on the Availability of Geologic Carbon Storage

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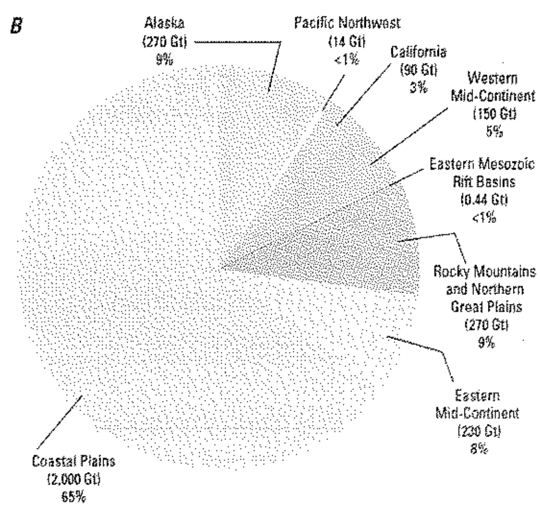
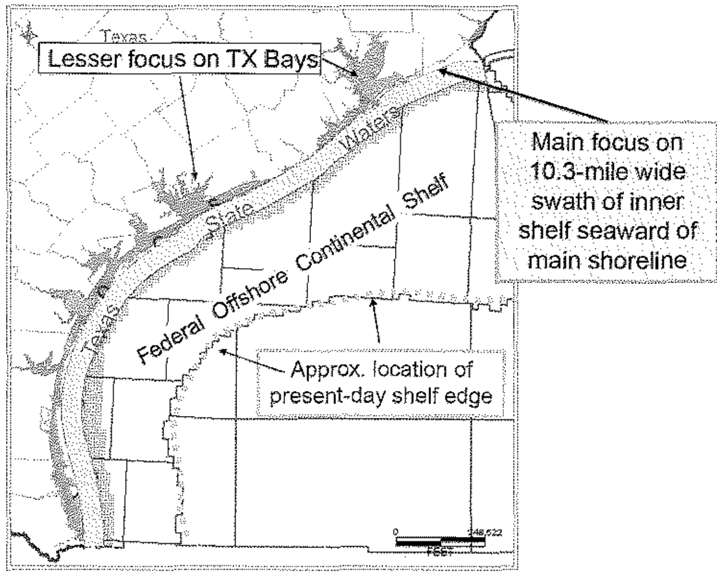
I. Storage Capacity

How Much: In its 2013 National Assessment of Geologic Carbon Dioxide Storage Resources, the U.S. Geological Survey assessed the technically accessible geologic carbon storage resources in 36 sedimentary basins in the onshore and beneath state waters of the United States. [1] The assessment only inventoried geologic formations below 3,000 feet with adequate porosity and permeability to accept commercial volumes of CO_2. The assessment estimates that there are approximately 3,000 Gt of subsurface storage capacity. This represents more than 500 times the 2011 annual 5.5 Gt of energy-related CO_2 emissions in the U.S. today. In addition, DOE estimates that 500 to 7,500 Gt of CO_2 could be sequestered in all U.S. offshore formations on the outer continental shelf.[2]

Where: The analysis suggests storage potential in nearly all regions of the U.S.[3] Capacity and transportation and injection infrastructure currently available in EOR fields in the parts of the Rocky Mountains, Midwest, Southeast and parts of California provide a model for expansion. Where formations that have capacity for CO_2 don't exist, research suggests that the expansion and build-out of today's 4,000-mile CO_2 pipeline network is feasible and would reach much of the rest of the U.S. Offshore areas are under investigation.

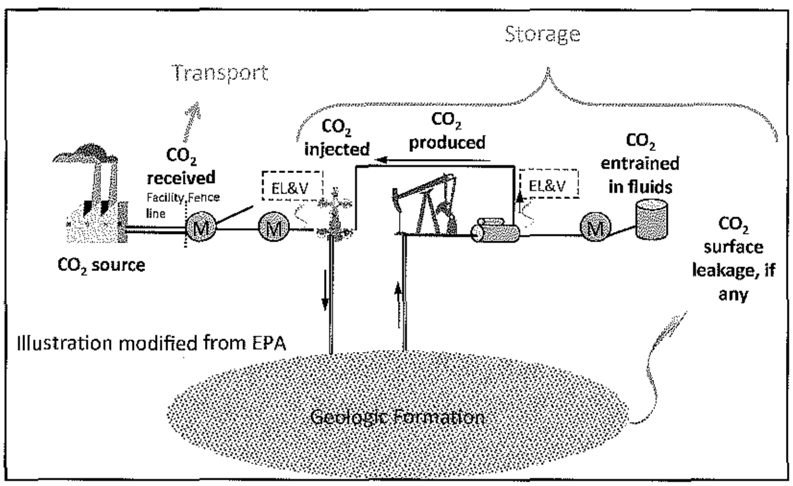


Gulf Coast: A Hub for U.S. CO_2? Recent work done by the Gulf Coast Carbon Center (GCCS) at the University of Texas, Austin has mapped and in the process of estimating the magnitude of the large storage volumes in 30 Mt sites within 10 miles of shore in the Gulf of Mexico (see map below). The "Megatransect Project" has documented capacity for billions, if not trillions of tons of CO_2 in geologic formations below the Gulf of Mexico. [4] [5] [6] Combined with existing pipelines and future potential for pipelines from the Midwest, the Gulf Coast could potentially be a hub for CO_2.



II. CO2 Capacity in Depleted Oil Fields

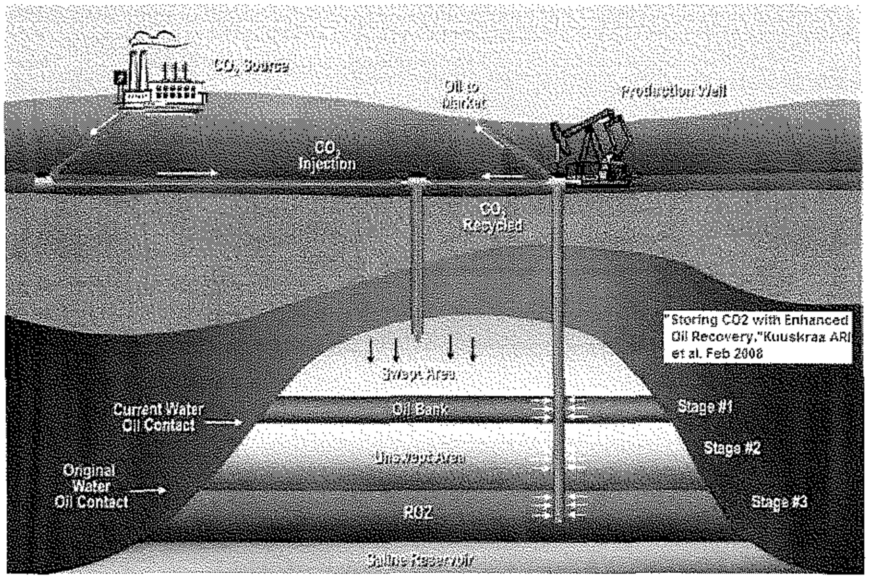
In early 2012 there were 127 U.S. CO_2 EOR projects with approximately 7,100 CO_2 injection wells and 10,500 producing wells. According to the National Petroleum Council, approximately 3 billion cubic feet per day of CO_2 (57 Mt/yr) of newly purchased CO_2 are presently injected for tertiary EOR producing 286,000 barrels of oil per day (105 million barrels per year).



The graphic above (EPA) illustrates how CO_2 that is received at a project site is a recycled and subsequently accounted for in EPA's greenhouse gas accounting scheme (Subpart RR). During the progressive injection and reinjection of CO_2 nearly all of the CO_2 is stored in geologic formations. Very little is lost to the atmosphere. Recently released filed life carbon balance data from the Kinder Morgan SACROC project suggest that 93% of the purchased CO_2 that was injected for EOR was stored (taking into account stationary and mobile emissions associated with the project.[7]

Residual Oil Zones (ROZ): Residual oil zones (ROZs) are naturally waterflooded formations below the oil water contact in oilfields (see illustration below). They are formed when meteoric water flushes out the primary oil deposit over geologic time leaving only residual (stubborn) oil behind. That residual oil can be substantial-- in some cases as large as the primary deposit (e.g.

Hess Seminole Field, TX) -- but it can only be produced using tertiary EOR methods since water flooding will not be effective. Because oil is soluble in CO_2 at pressure, residual oil zones represent another frontier for CO_2-EOR oil production while at the same time promising capacities for large volumes of CO_2 to be stored. Significant ROZs have been discovered in Texas (and produced) and Wyoming and are being investigated elsewhere.



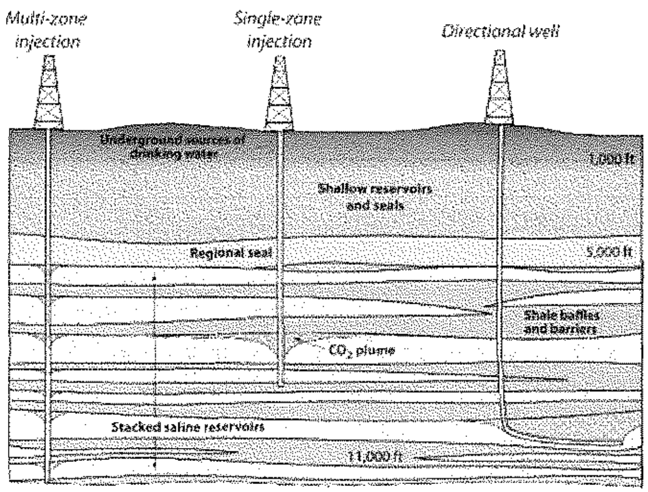
(ARI)

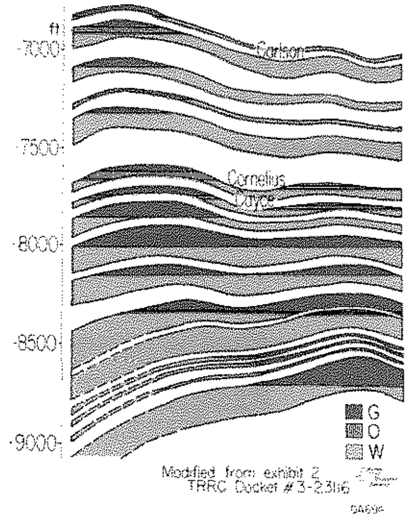
<u>CO2 Demand:</u> Advanced Resources Inc. (ARI) has estimated that next generation EOR combined with currently limited estimates of ROZ production could produce a demand for approximately 33 Gt of CO_2.[8,9,10,11] This suggests EOR/ROZ could accept/store approximately one dozen years of US EGU system CO2 (at 2.2 Gt/y). Currently there is an estimated 2 to 3 Gt of naturally occurring CO_2 available to meet this demand. The remaining future demand must be made up by captured sources.

III. Stacked Storage: A Bridge to Commercial Storage.

<u>What is Stacked Storage?</u> Thick sedimentary sequences commonly are characterized by repeating layers of interbedded sand and mud. Stacked storage takes advantage of these repeating sequences in the geologic section to build storage capacity vertically (See illustrations below). Utilizing multiple layers for storage is advantageous because instead of creating a large plume, CO_2 volumes can be managed --along with formation pressures-- by spreading out the CO_2 vertically in the geologic section.

<u>Advantages of Stacked Storage:</u> stacked storage, when used in combination with EOR, would allow for commercial volumes of CO_2 to be stored by the same existing facilities that are being used to produce tertiary oil by EOR. EOR combined with stacked storage therefore takes advantage of existing pipeline transportation and injection infrastructure and could allow EOR operators to transition from oil production once the field is depleted, to storage with incidental EOR. As a result, is a potential for large commercial volumes to be stored not only in oilfields but in the formations associated with oilfields at a lesser capital cost.





Illustrations above-- Left: Illustration of stacked saline storage (J Pashin). Right: Illustration of layered oil, gas and saline formations (and intervening caprock in white) at the SECARB Frio project, TX that could be accessed in stacked storage.

IV. Updates on North American Commercial CO2 Storage Projects

1. DOE Regional Carbon Sequestration Partnership Updates

SECARB/Southern Co. Plant Barry-Cintronelle . CO_2 is captured at Plant Barry with Mitsubishi Heavy Industries amine technology and transported 12 miles by pipeline to Denbury Resources' Cintronelle oilfield. The plant began capturing CO_2 in the 4th quarter of 2011 at a rate of up to 650 of naturally occurring CO_2 per day, amounting to a target of approximately 50,000 tons per year.[12] Alabama Power has constructed a pipeline from Plant Barry to Denbury's nearby Cintronelle oilfield where injection of the captured CO_2 into a saline unit in the Paluxy Formation began in 2012. During this project, a consortium led by LBNL and EPRI have developed an innovative new method that will allow the continuous monitoring of subsurface parameters such as pressure, temperature and microseismicity.

SECARB Cranfield, MS Project: The Cranfield Mississippi oilfield geologic carbon storage project began injection operations in 2008 and had purchased, transported and injected 4 Mt CO_2 into the Tuscaloosa Formation as of summer 2013. In March 2012 it was reported that 1.5 Mt had been produced and recycled, summing to about 6 Mt injected. The project has been the site of numerous monitoring efforts and experiments that have substantially improved scientists' understanding of what is needed to ensure secure geologic storage of CO_2.

Big Sky Partnership. Kevin Dome, MT.[13 14] Injection of 1 Mt of CO_2 into a northern Montana saline aquifer is planned to begin in 2015 and continue through 2018 to demonstrate the viability of Kevin Dome as a secure target for regional CO_2 emissions. Kevin Dome is a geologic structure with naturally occurring CO_2 that has been trapped for 50 Ma, that promises the ability to hold commercial volumes of captured CO_2. In the test, CO_2 will be produced from the dome, then transported 6 miles to the injection site into the Duperow Formation Formation at the edge of the dome. The injections will be accompanied by monitoring demonstration and research projects.

MGSC Partnership Illinois Basin Decatur Project: A successful 7,000 foot deep saline injection test is underway in Decatur IL, including a comprehensive monitoring program. It is a cooperative project of the Archer Daniels Midland (ADM), The Midwest Geological Sequestration Consortium (MGSC) and Schlumberger with $4.4 million of DOE support.[15] During the 3-year injection program, 1.1 million tons of CO_2 will be captured at ADM's ethanol plant using Alstom's amine capture process and will be injected into the Cambrian Mt. Simon Formation. A second well is planned which will bring the total to approximately 1 million tons per year. Monitoring tools utilized at the site include four shallow groundwater wells and soil gas measurements, 3-D seismic profiling, a dedicated monitoring well with embedded geophones for walk-away vertical seismic profiling (VSP) and a dedicated in-zone monitoring well. The success of this project underscores the availability of commercial scale saline geologic sequestration in the Mt. Simon Formation under the Midwest United States, a locus of coal-based electric power generation. The project has injected 0.5 Mt of captured CO_2 as of June 2013.[16]

PCOR Regional Partnership. Bell Creek, WY: Beginning Spring 2013, 1 million tons of CO_2, sourced from the Lost Cabin natural gas separation plant, is being injected for EOR.[17] Cost-effective monitoring protocols will be the focus of this study.

MRCSP Partnership Northern Lower Michigan project: 1 Mt of CO_2 captured at a Antrim Shale natural gas separation facility is being injected over a 4 year period into several small oil fields in Niagran Pinnacle Reef carbonate formations for the purposes of EOR and storage and accompanying monitoring development.[18] [19]

2. Other North American Projects

Dakota Gasification/Weyburn, Saskatchewan, Canada: Weyburn-Midale oil field is an EOR-storage project located in Saskatchewan Canada and is the receptor site for captured CO_2 from the Beulah Dakota gasification site in the U.S.[20] Over the life of the field, approximately 44 Mt will be injected at Weyburn, with approximately 17 million tons to date). The IEAGHG, in conjunction with Canada's non-profit Petroleum Technology Research Centre (PTRC), has implemented a monitoring demonstration and research program to investigate the most effective methods for ensuring CO_2 injected for EOR is securely stored. In 2011 it was alleged that CO_2 from the project was leaking at the surface at Kerr Farm. Subsequent independent, peer-reviewed analysis by the University of Texas suggests, however, that the methane in the soils at the farm are of biologic and not geologic origin.[21]

Aquistore/Boundary Dam, Saskatchewan Canada: This SaskPower project will add post-combustion capture to a 110 MW EGU (Unit 3 at Boundary Dam Power Station) and will capture 90% of the CO_2 , approximately 1 million tons per year.[22] [23] SaskPower received approval from the Saskatchewan Government to build the project in April 2011 and construction is underway. Operation of the plant will begin in 2014. CO_2 capture from Boundary Dam will be injected at the Sasketchewan Aquistore facility and at the Weyburn EOR project. The IEAGHG's Aquistore Program, a collaborative industry and government program, is being operated by Canada's non-profit Petroleum Technology Research Centre (PTRC).[24] Aquistore is a 3-kilometer deep 100 meter thick Cambro-Ordovician age saline sandstone reservoir located in the Williston Basin in Saskatchewan, Canada.[25] Aquistore is set to be drilled in 2013 and will also accept CO_2 from a nearby refinery at the end of 2013. Captured CO_2 from the SaskPower Boundary Dam project two kilometers away where it will most likely become the largest commercial and fully integrated carbon dioxide capture and storage facility in the world.

Fort Nelson BC: A PCOR partnership planned saline test and MVA strategy development effort will inject1-2.2 Mt/yr CO_2 from the Fort Nelson natural gas processing plant in British Columbia. When completed this could be the largest deep saline test in North America.[26]

Shell Quest, Alberta: Quest will capture 35% of the CO_2 emissions, 1 Mt/y, from the Scotford upgrader (Alberta oil sands) near Fort Saskatchewan, Alberta, will be injected into a saline aquifer into the Basal Cambrian Sands starting in 2015.[27]

References.

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[1] See USGS at: http://pubs.usgs.gov/ds/774/

[2] DOE, *The National Carbon Storage Atlas* (2012) (Available at http://www.netl.doe.gov/technologies/carbon_seq/refshelf/NACSA2012.pdf). Attached as Exh.III-71.

[3] New England could, access storage in the Midwest by pipeline, or in the offshore outer continental shelf (OCS) along Georges Bank as was suggested by an abandoned CCS project that would have stored its CO2 in the Mississauga Formation 70 miles off of the coast of New Jersey.

[4] Meckel, et al., *Offshore CCS in the Northern Gulf of Mexico and South Atlantic*, Poster, Regional Carbon Sequestration Partnership Meeting Pittsburgh (September 2011), attached as Exh. III-89.

[5]http://www.netl.doe.gov/publications/proceedings/11/carbon_storage/tuesday/11_1115_Meckel_DOE_Review_mtg_offshore_compress.pdf

[6] http://www.aapg.org/explorer/2010/09sep/co2storage0910.cfm

[7] See: http://www.co2conference.net/wp-content/uploads/2013/05/Fox-KM-Presentation-SACROC.pdf

[8] Vello Kuuskraa, Advanced Resources International, Inc. (2012). Using the Economic value of CO2-EOR to accelerate the deployment of CO2 capture, utilization and storage. (CCUS, EPRI Cost Workshop, Palo Alto, CA, April 25-26, 2012.

[9] Meckel, et al., *Offshore CCS in the Northern Gulf of Mexico and South Atlantic*, Poster, Regional Carbon Sequestration Partnership Meeting Pittsburgh (September 2011), attached as Exh. III-89.

[10]http://www.netl.doe.gov/publications/proceedings/11/carbon_storage/tuesday/11_1115_Meckel_DOE_Review_mtg_offshore_compress.pdf

[11] http://www.aapg.org/explorer/2010/09sep/co2storage0910.cfm

[12] Koperna, et al., *The SECARB anthropogenic test: the first U.S. integrated CO2 capture, transportation and storage test* (2011) (Available at: http://www.adv-res.com/pdf/Pitt_Coal_Conference_Paper_FINAL.pdf). Attached as Exh. III-42.

[13] See: http://sequestration.mit.edu/tools/projects/kevin_dome.html

[14] See: http://www.bigskyco2.org/research/geologic/kevinstorage

[15] *See* http://sequestration.mit.edu/tools/projects/decatur.html. Attached as Exh. III-102.

[16] See: http://sequestration.org

[17] See PCOR project site: http://www.undeerc.org/pcor/co2sequestrationprojects/default.aspx

[18] See: http://216.109.210.162/MichiganBasin_development.aspx

[19] See: http://216.109.210.162/userdata/Presentations/MRCSP%20Poster_GHGTnov%202012.pdf

[20] See: http://www.ieaghg.org/docs/general_publications/weyburn.pdf . Attached as Exh. III-45.

[21] Romanak, *Analysis of Gas Chemistry at the Kerr Site*, IPAC Publication (2012). Attached as Exh. III-46.

[22] Global CCS Institute, *The Global Status of CCS: 2011*, pp. 25, 102 (2011). Attached as Exh. III-66.

[23] http://www.saskpower.com/sustainable_growth/assets/clean_coal_information_sheet.pdf. Attached as Exh. III-65.

[24] For more information on Aquistore, see: http://www.google.com/url?sa=t&rct=j&q=aquistore&source=web&cd=2&ved=0CF0QFjAB&url=http%3A%2F%2Fwww.ifpenergiesnouvelles.com%2Fcontent%2Fdownload%2F67983%2F1473837%2Ffile%2F26_Whittaker.pdf&ei=x2ixT7KoBKig6QHCmaGICQ&usg=AFQjCNH-h5UNO2_dyK9_8-yDUxK1zdUwkQ. Attached as Exh. III-48.

[25] See: http://www.ptrc.ca/aquistore_overview.php. Attached as Exh. III-49.

[26] See: http://www.netl.doe.gov/technologies/carbon_seq/infrastructure/rcsp/pcor.html

[27] See: http://www.shell.ca/en/aboutshell/our-business-tpkg/upstream/oil-sands/quest.html

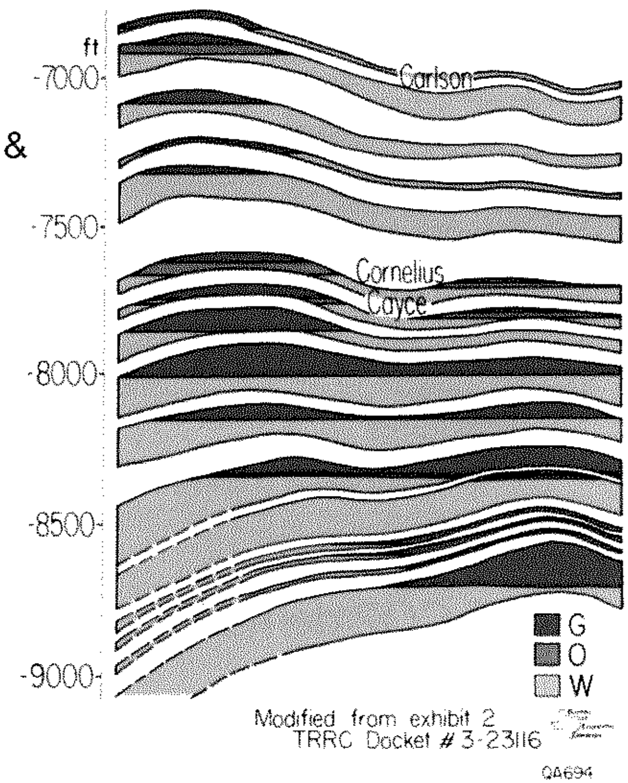
Saline and EOR "Stacked" Storage

- Existing Transportation and Injection Infrastructure
- Revenue early when needed to support capture
- Vertically stacked capacity, pressure management vs one large plume
- Existing surveillance tools and reservoir knowledge
- Multiple caprock seals

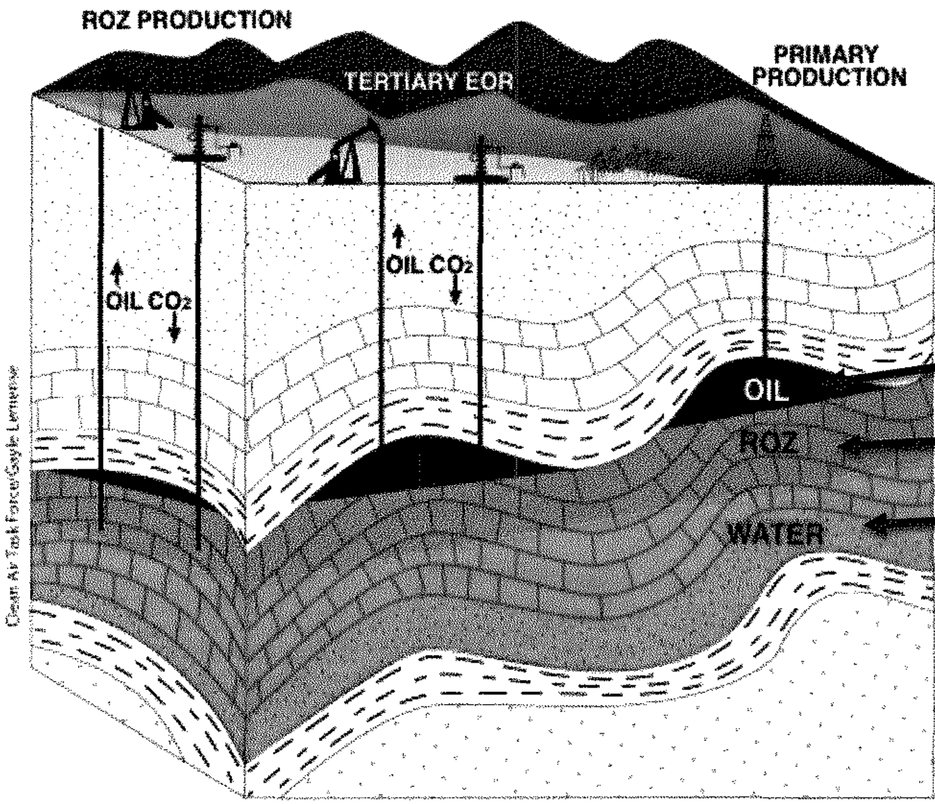
System	Series	Stratigraphic Unit	Major Sub Units	Potential Reservoirs and Confining Zones
Tertiary	Plio-Pleistocene		Citronelle Formation	Freshwater Aquifer
Tertiary	Miocene	Undifferentiated		Freshwater Aquifer
Tertiary	Oligocene		Chicasawhay Fm.	Base of USDW
Tertiary	Oligocene	Vicksburg Group	Bucatunna Clay	Local Confining Unit
Tertiary	Eocene	Jackson Group		Minor Saline Reservoir
Tertiary	Eocene	Claiborne Group	Talahatta Fm.	Saline Reservoir
Tertiary	Eocene	Wilcox Group	Hatchetigbee Sand	Saline Reservoir
Tertiary	Paleocene		Bashi Marl	Saline Reservoir
Tertiary	Paleocene		Salt Mountain LS	Saline Reservoir
Tertiary	Paleocene	Midway Group	Porters Creek Clay	Confining Unit
Cretaceous	Upper	Selma Group		Confining Unit
Cretaceous	Upper	Eutaw Formation		Minor Saline Reservoir
Cretaceous	Upper	Tuscaloosa Group	Upper Tusc.	Minor Saline Reservoir
Cretaceous	Upper	Tuscaloosa Group	Mid Tusc. Marine Shale	Confining Unit
Cretaceous	Upper	Tuscaloosa Group	Lower Tusc. Pilot Sand, Massive sand	Saline Reservoir
Cretaceous	Lower	Washita-Fredericksburg	Dantzler sand	Saline Reservoir
Cretaceous	Lower	Washita-Fredericksburg	Basal Shale	Primary Confining Unit
Cretaceous	Lower	Paluxy Formation	'Upper' 'Middle' 'Lower'	Proposed Injection Zone
Cretaceous	Lower	Mooringsport Formation		Confining Unit
Cretaceous	Lower	Ferry Lake Anhydrite		Confining Unit
Cretaceous	Lower	Donovan Sand	Rodessa Fm. 'Upper'	Oil Reservoir
Cretaceous	Lower	Donovan Sand	'Middle'	Minor Saline Reservoir
Cretaceous	Lower	Donovan Sand	'Lower'	Oil Reservoir

Example of Stacked Storage potential in Citronelle Field, MS (Esposito/Southern Co)

Stacked oil, gas & saline aquifers SECARB Frio project, TX



Depleted Oil Fields and Residual Oil Zones (ROZ)



Storage targets:

Main Pay Zone / Tertiary EOR

Residual Oil Zone

Saline Water

EOR & ROZ CO2 demand: 33 Gt--30 Gt must be supplied by captured sources.

Offshore Storage Progress: Gulf Coast "Mega Transect"

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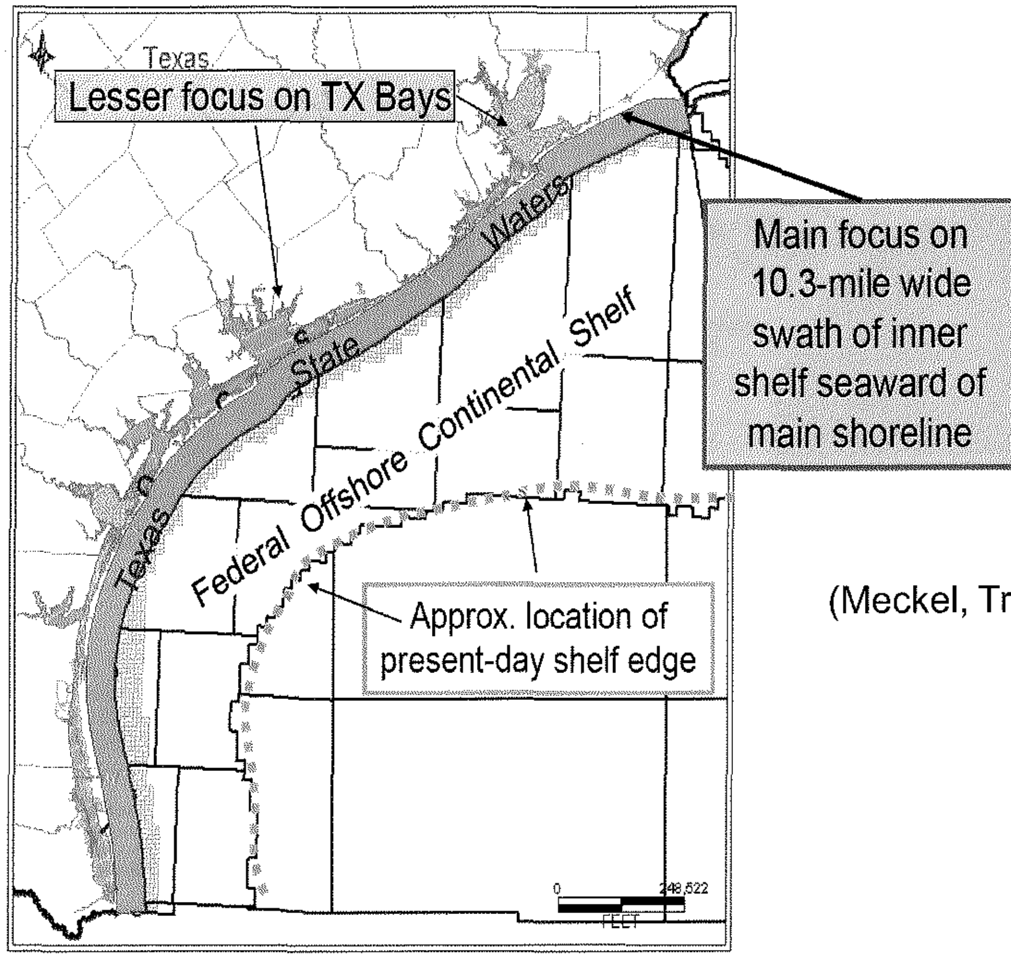

(Meckel, Trevino/TX BEG et al)

TX BEG screening 30 Mt-size reservoirs: suggests billions to trillions of tons of capacity

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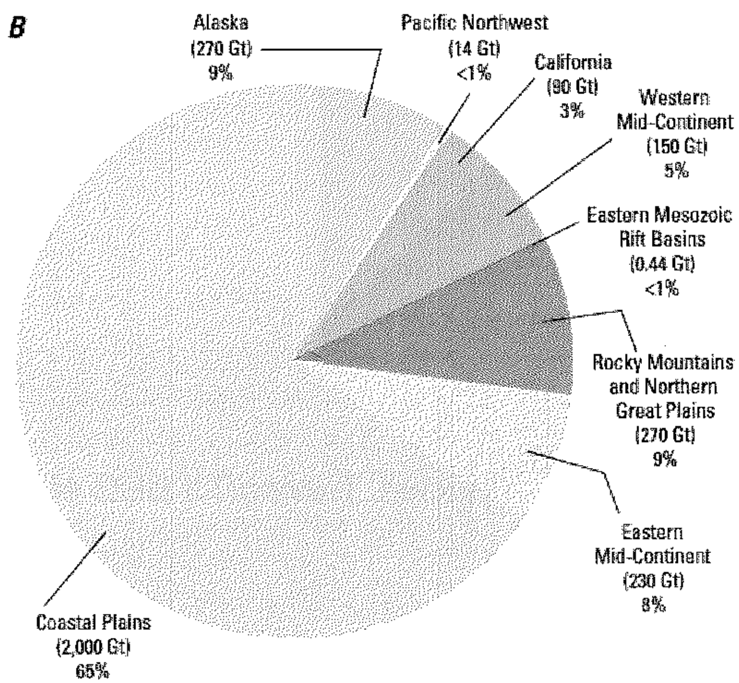
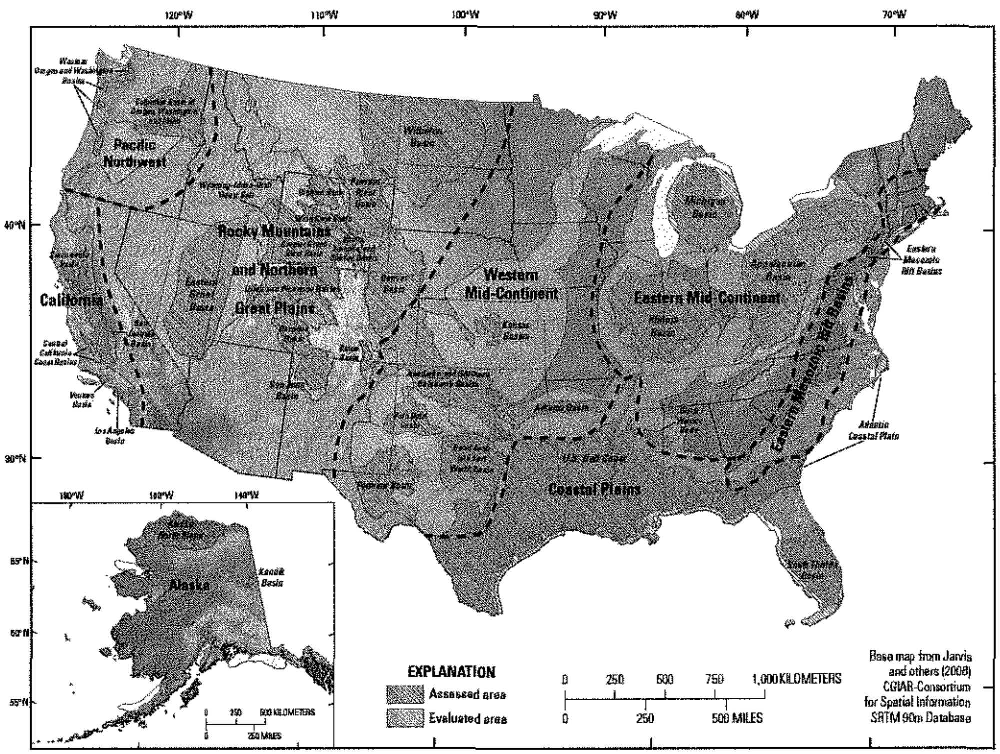
USGS (2013): Estimated Storage = 3,000 Gt





Map of the conterminous United States and Alaska showing 8 regions (separated by bold dashed lines), evaluated areas (bluish gray) that were not assessed, and 36 areas (pattern) that were assessed by the U.S. Geological Survey for carbon dioxide (CO_2) storage. Resources in federally owned offshore areas were not assessed, and Hawaii was considered unlikely to have significant storage resources. Regions and study areas are plotted over a shaded-relief image showing higher elevations in brown and tan and lower elevations in green.

USGS-screened storage resources met technical criteria – adequate data, depth, volume & injectivity in 36 basins.

How Much Does CCS *Really* Cost?

An Analysis of Phased Investment in Partial CO_2 Capture and Storage for New Coal Power Plants in the United States

December 20, 2012

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John Thompson, Clean Air Task Force

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The Clean Air Task Force

The Clean Air Task Force (CATF) is a nonprofit organization dedicated to reducing atmospheric pollution through research, advocacy, and private sector collaboration. CATF acknowledges the contributions of Douglas Cortez in developing the coal power plant capital cost and performance data utilized in this analysis, including the cases where the construction of CCS facilities is deferred, and acknowledges the contributions of Bruce Phillips for his advice on the financial models used to estimate cost of electricity.

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Introduction

There is no shortage of cost estimates for carbon capture and storage (CCS).[1] Frequently, however, when these estimates are applied to some particular policy purpose differences in their cost bases and methodology obscure the underlying trends of most general interest. As a result, in this short paper, we have attempted to provide some clarity around a basic policy-relevant CCS question: what is the increase in cost of electricity for a new coal power plant in the Midwestern United States as a result of CCS used to comply with proposed US Environmental Protection Agency CO_2 emission standards?

Our methodology and analysis are described in detail below. In summary, we find that while the increase in cost of electricity (COE)[2] for new coal power due to CCS may be 35% or more in some cases, the opportunity to delay the installation of CCS and to use partial removal of CO_2, as contemplated in EPA's proposed rule, and the opportunity to sell the captured CO_2 for enhanced oil recovery (EOR), would reduce this electricity cost premium due to CCS to just under 13%. Without revenue for sales of CO_2 for EOR the premium would rise to just over 19%. Optimization of plant design and operations during the early years of a phased-in CCS approach, development of more robust CO_2 sales markets, and realizing technology cost and performance innovations over time could further reduce the estimated cost premium.

The Clean Air Task Force has previously published a lengthy description of CCS that included a limited analysis of CCS economics, including partial capture.[3] This paper updates and extends the previous economic analysis and provides additional detail on our methodology and data sources.

Our CO_2 Emission Target -- US EPA's Proposed CO_2 Limits for Power Plants

The CO_2 emissions limits proposed by EPA for new power plants include significant implementation flexibility.[4] One compliance option includes producing power by burning natural gas in a modern combined cycle power plant. This is the direction most new power plants in the United States are already headed, because today's low natural gas fuel prices have made this technology the lowest all-in cost source of new generation under most circumstances. For developers who choose to build coal-fired power plants, however, EPA's rule offers two options: either the project proponent must a) install CCS so that the power plant emits no more than an annual average of 1000 pounds of CO_2 for each one million watt-hours of gross electricity generated ("MWh") from the start of operations (which we call a "Day 1" option), or b) ensure that the power plant will emit no more than an annual average of 1800 pounds of CO_2 for each MWh of electricity generated during its first 10 years of operation followed by no more than 600 pounds of CO_2 for each MWh of electricity generated after that. Under the latter option, which effectively delays the time at which CCS must be operating on the plant, the average CO_2 emissions of the power plant over 30 years also must not exceed 1000 pounds per MWh (we call this a "Phased" option).

The Basis for Our CCS Cost Estimates

A number of organizations, including the US DOE, MIT, EPRI, and others, have developed estimates of the cost of building new coal power plants with CCS. Of all of these the US DOE estimates -- which are produced under contract to the National Energy Technology Laboratory (NETL) by engineering firms using 'bottom-up' estimates of the procurement and installation cost and performance of individual plant components -- include the broadest range of plant configurations, contain the most detail, and are most widely used in industry, academia, and policy circles. The costs associated with capturing CO_2 are generally significantly higher than the costs associated with sequestering that captured CO_2 geologically, and so we pay particular attention to these capture costs in our analysis.

Of particular advantage for our current purposes, the NETL studies include detailed estimates of performance and cost for new coal power plant configurations that use so-called partial capture of CO_2. This level of detail is helpful because the costs of producing power from a coal power plant will generally increase as the amount of CO_2 captured increases (due to larger capture equipment, larger CO_2 compressors, greater auxiliary loads, etc.) and the NETL estimates include these effects.[5] Furthermore, inter-comparison efforts suggest that where comparable configurations and cost metrics are used, the NETL results are similar to or more conservative (i.e. higher cost and greater loss of efficiency for CCS) than other studies.[6]

Several coal power plant configurations studied by NETL would meet EPA's proposed CO_2 standards. The NETL case for a new supercritical coal power plant with 50% CO_2 capture would emit 939 pounds of CO_2 per MWh, for example (hereinafter our "Case 1"), while a new supercritical coal power plant with 70% CO_2 capture would emit 592 pounds of CO_2 per MWh (hereinafter our "Case 2"). For comparison, NETL estimates that a new supercritical coal power plant without CCS would emit 1675 pounds of CO_2 per MWh (hereinafter our "Case 0").[7] This latter case is the typical type of coal power plant built around the world today. In addition to performance estimates, the NETL studies include extensive estimates of operation and maintenance and construction costs (the latter category including process equipment, supporting equipment, direct and indirect construction labor, engineering-procurement-construction services such as detailed design and construction management, and various process and project contingencies).

Our Methodology for Deriving Incremental Costs Due to CCS Requirements

To derive the incremental COE for a coal power plant with CCS over and above the COE for an otherwise similar coal power plant without CCS, we start with the raw overnight installed equipment costs, project development costs, operation and maintenance costs, and performance estimates produced by NETL for Cases 0, 1, and 2 above, which reflect year 2007 price levels expressed in year 2007 dollars. We then assume that the power plant cases we are evaluating will come into service in 2017, and we escalate the raw NETL costs accordingly, finally expressing our results in year 2017 dollars and projected year 2017 cost levels.[8] For comparison purposes in our analysis we also include a case for combined cycle natural gas without CCS, which we call Case 4.

We calculate COE for each case using an economic methodology broadly used in the power project development industry. In this analysis, all of the cash flows for the project, including initial construction costs,[9] operating and maintenance costs, fuel, taxes, and revenue from the sale of power are projected for each year of the project lifetime (here 30 years) on an 'unlevered' basis, and the resulting free cash flow that would be returned to project owners each year is discounted back to the initial day of operation to produce a single net present value estimate for the project.[10] Obviously the NPV depends strongly on the assumed discount rate, and by standard convention the 'internal rate of return' of the project is that discount rate for which the NPV on day one is zero.

In our analysis, we specify a nominal, unlevered, after tax internal rate of return of 10%, and derive the initial sales price for electricity from the project that is required for the investment to earn that rate of return. This 2017 electricity sales price is the COE measured in dollars per net MWh, assumed in our analysis to escalates at 2.5% per year over the project lifetime (as a proxy for the long-term US inflation rate). Other economic inputs to the calculation are also assumed to increase at 2.5% per year, including O&M, fuel, and, where it has been assumed, revenue from sales of CO_2 captured by the project and used for enhanced oil recovery.

Our Assumptions About Coal Power Project Design Meeting EPA's Standard

In addition to updating NETL's 2007-era raw overnight installed equipment costs and applying our own project economics analysis framework, we make several key assumptions about CCS project development that significantly impact our cost assessment. In particular:

- Unlike NETL's analysis where a *cost* of $8.48 per tonne of CO_2 captured is assessed to the coal power plant for sequestration site development, injection, and monitoring associated with CCS, we assume that captured CO_2 *will be sold* by the power plant to a different entity for $16.56 per tonne, and used for EOR (both in 2017 terms). $16.56 per tonne is the difference between prevailing CO_2 sales prices in Texas (reported to be in excess of $37.83 per tonne in late 2011) and US EPA estimates of the cost to transport CO_2 from the Midwest US to Texas ($18.59 per short ton in 2007 terms) after both are adjusted for inflation.[11] The net difference to the coal power plant between paying for sequestration and selling CO_2 by pipeline for EOR in Texas is $25.04 for each tonne captured. Although we have assumed sales of CO_2 by pipeline to Texas for this analysis, other sales opportunities may be present which could be more or less favorable than our assumption (e.g., sales of CO_2 for EOR along the Gulf Coast or closer to the Midwest). Ultimately, given the uncertainties in the price for which CO_2 might be sold we also include a sensitivity case in which we assume that no revenue from sales of CO_2 for EOR will be available.

- We develop a new analytical case (which we call Case 3) representing a supercritical coal power plant that is initially put into service without CCS, but with a certain level of investment in CCS readiness (e.g., an oversized boiler), and for which 70% CCS is added at year 11 of operation. Such a configuration would perform better than EPA's proposed Phased option, emitting 1692 pounds of CO_2 per MWh for the first 10 years, and 592 pounds per MWh thereafter, and averaging 995 pounds per MWh over 30 years. This case, which we call Case 3, is the same power plant as in our Case 2, except that the amine-based CO_2 removal system and CO_2 compression system (which together represent close to 20% of the overnight construction cost of the power plant) are constructed during years 8 – 10 of operation of the base power plant and come into service in the 11th year.

- Because amine-based CO_2 removal systems require significant quantities of steam for operation, and because the CO_2 removal system in Case 3 is not in service until the 11th year of power plant operation, there is a significant surplus of low pressure steam from the plant's boiler during the prior years. In order to utilize this energy, we specify that an additional low-pressure steam turbine generator, condenser, condensate pumping system and associated cooling water systems would be operated during this initial 10-year period. We estimate the performance of this system using the same steam conditions and equipment used by NETL in the Case 2 design. Based on those steam conditions we estimate that this additional turbine in our Case 3 would produce an additional net 100.2 MWe, and would increase initial construction costs by $38 million (2007 basis) above NETL's estimate.[12] Our cost estimates for this additional steam bottoming cycle are based on scaling data provided in the NETL reports. We assume that this additional turbine/generator is retired after the 10th year of plant operation.[13]

- Because the CO_2 removal system in Case 3 does not operate until year 11, the auxiliary electrical loads associated with that equipment (14.8 MWe for the amine system, 31.7 MWe for the CO_2 compressors, and several MWe for other system loads) are similarly absent during that period. Due to those adjustments and the presence of the additional low-pressure steam turbine generator system, we estimate a plant heat rate of our Case 3 during years 1 – 10 of operation of 8.752 MMBtu of fuel input per MWh of net electricity produced. Owing to the design changes in Case 3 made in preparation for CCS this heat rate is slightly higher than the heat rate of a new coal plant without CCS (8.687 MMBtu/MWh for Case 0) but significantly lower than the heat rate of Case 3 after CCS is installed and operational (11.151 MMBtu/MWh), all measured in terms of the higher heating value of the fuel needed to produce a net MWh of electricity.

- All of our cases include significant expenditures for project development activities and other 'owners costs' in advance of commercial operation. We follow NETL's treatment of these expenditures directly, adding between $208 million for our case without CCS and $312 million for our case with 70% CCS (both in 2007 terms, which we later inflate). For our Case 3 we apportion the owners cost between the initial construction period and later addition of CCS in accordance with other construction expenditures.

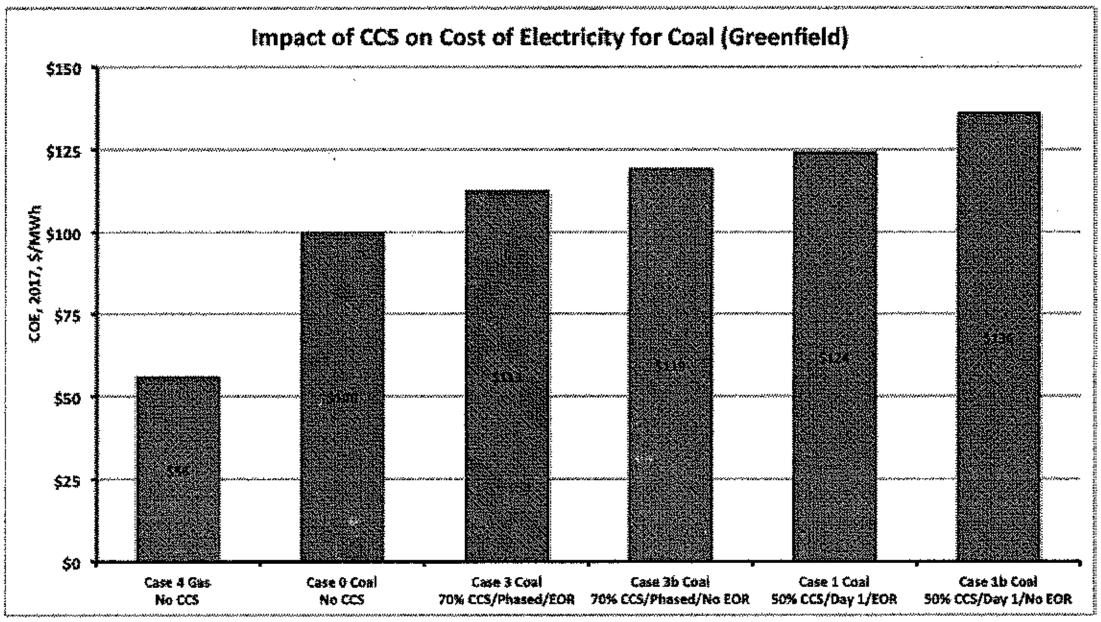
Table 1 of our Appendix lists all of the key cost and performance assumptions for our cases 0, 1, 2, 3, and 4, in the original (2007-era) NETL terms. Fuel costs in our analysis are derived from current projections of coal market prices and transportation charges for a generic Midwestern US location. We estimate the 2017 price of this delivered coal at $2.98/MMBtu.[14] In our NGCC case, we assume a 2017 price for delivered gas of $4.73/MMBtu.[15]

Our Results

Our results for key project economic metrics are summarized in Table 2 of our Appendix. We find that the 2017 COE for a new natural gas combined cycle plant would be $56/MWh (Case 4), while that for a new supercritical coal power plant without CCS would be $100 per MWh (Case 0), and that for a new supercritical coal power plant with enough CCS to meet EPA's Day 1 standard would be $124 per MWh (Case 1, including revenue from sales of CO_2 for EOR). $124 per MWh represents roughly a 24% premium on the price of power the facility owner must charge in order to comply with the proposed Day 1 standard by using CCS. If, however, the investment in CCS is delayed by 10 years consistent with EPA's proposed standard, and the appropriate anticipatory work done, a new supercritical coal power plant might be constructed which meets EPA's Phased standard for only $113 per MWh, representing only a 13% power price premium over the uncontrolled coal case (again after accounting for CO_2 sales revenue).

For Case 1 (50% CCS from Day 1) without EOR revenue the COE premium is 36% (versus 24% with EOR revenue). For Case 3 (70% CCS, Phased approach) without EOR revenue the COE premium rises is 19% (versus 13% with EOR revenue). These cases are labeled Case 1b and Case 3b, respectively in Table 2. Relative power costs for our primary cases are indicated in Figure 1 below.

Figure 1



Conclusions and Further Analysis

Our analysis indicates that with phased implementation of partial CCS, the COE premium for a new coal power plant in the Midwest US could be under 20%, and under 13% if revenue from sales of CO_2 for EOR purposes is considered. In this analysis we have been somewhat conservative, however, and it is likely that additional reductions in the 13% cost premium for the phased construction case with EOR CO_2 sales would be possible both through a refined study and in actual practice. For example, better optimized low-pressure steam system design in the early years of the Phased case could increase power output and sales, while the construction cost contingencies for CCS equipment included in our estimate likely will decrease over time. Additionally, there is uncertainty in future CO_2 revenues for EOR, and as markets develop actual prices may exceed the values we have assumed here. Exploration of these issues is beyond the scope of our current analysis.

Notes

[1] See for example Cost and Performance of Carbon Dioxide Capture for Power Generation, International Energy Agency, 2011 (hereinafter IEA 2011)

[2] The key economic metric in our analysis is the 'cost of electricity' (COE) for each power plant case, which we derive following NETL as "the revenue received by the generator per net megawatt-hour during the power plant's first year of operation, assuming that the COE escalates thereafter at a nominal annual rate equal to the general inflation rate, i.e., that it remains constant in real terms over the operational period of the power plant". Cost and Performance Baseline for Fossil Energy Plants, Volume I, Revision 2, NETL, (November, 2010) at 58 – 59 (hereinafter "NETL A"). This current-dollar metric (also sometimes called a 'real levelized price' because the price is constant in real terms) reflects the all-in construction cost, operation and maintenance cost, fuel costs, and return on investment for the power plant owner, and is one of a number of different approaches for calculating annualized lifecycle economics used in the industry.

[3] See Technical Options for Lowering Carbon Emissions from Power, available at http://www.coaltransition.org/filebin/pdf/Technical_Options_for_Lowering_Carbon_Emissions_from_Power.pdf

[4] See Federal Register Vol. 77, No. 72, Friday, April 13, 2012, at 22436-22421.

[5] NETL A and Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture, NETL (May, 2011) (hereinafter "NETL B"). These studies include identical cost and performance baselines, with some overlap in plant configurations studied.

[6] See IEA 2011 at Table 4.

[7] See NETL A at 9 and NETL B at 35 – 39.

[8] Specifically, we update NETL's costs to a 2017 period using our estimates of inflation in power plant overnight construction costs between 2007 and today (39.4%) and our projection of further inflation in power plant overnight construction costs between today and 2017 (assuming 2.5% per year). This yields an estimate of the construction costs for each case. To derive operation and maintenance costs, we begin with NETL's estimates, which again are for a 2007 period, and apply our estimate of inflation in those costs from 2007 through 2017 (2.5% per year). Our estimate of inflation during the period 2007 to 2012 is considerably larger (more conservative for our overall calculation) than a recent cost update by NETL (see Updated Costs (June 2011) Basis for Selected Bituminous Baseline Cases, August, NETL, August, 2012).

[9] We assume a 5-year construction period for each coal case and apportion the overnight construction costs, including owners costs, escalated to constant year 2017 dollars, to June 1 of each year of the construction period (10%/30%/25%/20%/15%). For each year's construction expenditure we then add interest compounded annually at a real rate of 7.32% up to the commercial operation date of January 1, 2017. We treat the natural gas case (Case 4) in the same way except that the construction period is three years (10%/60%/30%). These costs, with interest up through the first day of operation of each plant, form the initial lump-sum investment against which the operational cash flows of the project in later years are balanced in the NPV calculation. The delayed CCS addition in Case 3 is treated slightly differently. For that case we apportion the construction expenditures and associated owner's costs evenly over operational years 8 – 10 of the project (33%/34%/33%). We fund these expenditures from cash flow generated by the operating project, so we do not charge interest for them in our analysis. We use overnight costs escalated to year 2027 for this purpose, providing some measure of conservatism to the calculation.

[10] By 'unlevered' we mean the capital to construct the project is assumed to be financed entirely from equity, with no debt. Actual power projects typically include some level of debt, with the amount of debt depending on the level of financial risk associated with the project. Using an 'unlevered' cash flow analysis is common in the industry, however, when comparing generally similar projects for which the precise capital structure is not yet determined. 10% is a typical nominal discount rate used for these purposes, reflecting a balance between long-term debt and equity return expectations, although other

values are also used (e.g., weighted average cost of capital in some utility ratemaking cases). We use 10% for all projects here, with no adjustment for project type or risk, because it is not clear that the financial risks associated with the projects considered in this paper are materially different from one another. In addition, we do include, following NETL, a contingency on CCS capital costs reflecting the newness of the technology.

[11] We derive an estimated cost of \$6.62/tonne for CO_2 sequestration from NETL B at p. 475, in 2007 terms. This is \$8.47 in 2017 terms. Reported CO2 prices at Denver City, Texas were above \$2 per thousand standard cubic feet (\$37.83/tonne) and rising at the end of 2011. See "North American CO_2 Supply and Developments", Glen Murrell, Wyoming Enhanced Oil Recovery Institute, University of Wyoming 10th Annual Carbon Management Workshop, December 6, 2012, Midland Texas. For transportation costs see Technical Support Document (TSD) for the Transport Rule Docket ID No. EPA-HQ-OAR-2009-0491, US EPA, July 2010, at 6-2.21.

[12] Steam at 73.5 psia and 556.3 F supplies both the amine system and the low-pressure turbine in NETL's design (1.26 million pounds per hour, and 1.80 million pounds per hour, respectively), returning to the plant systems as very low-energy steam from the turbine (1.0 psia and 101.1 F).and hot water from the amine system. See NETL B at p. 100. Based on these steam conditions and the performance of the existing steam system in NETL's design we estimate that an additional low pressure steam system used in lieu of the amine system (including an additional low pressure turbine with steam extraction, condenser, feedwater heaters, and condensate pump to return steam to the existing deaerator) could produce 100.2 MWe additional power for the plant and would cost \$38 million dollars (in 2007 terms, including both turbine system and associated buildings and electrical plant). In part due to economies of scale in the NETL estimates for the boiler, main steam turbine generator, and other systems in their 70% CCS case, the specific capital cost of our Case 3 (in \$/kW-net) prior to CCS installation is less than that of NETL's case for a supercritical coal plant without CCS.

[13] We assume that this equipment is salvaged after fully depreciated, at no net cost to the facility owner. In fact this would probably occur in year 11 when the equipment would be sold at a value which offsets the amount of undepreciated basis.

[14] We estimate \$47.75 per short ton at 11800 Btu per pound for Illinois coal, per http://www.eia.gov/coal/news_markets/ for August 2012, escalated at 2.5%, plus 30% for transportation.

[15] The current price for natural gas futures contracts for June, 2017 delivery at the Henry Hub in Louisiana is \$4.433/MMBtu according to The CME Group (http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html). We assume an additional \$0.30/MMBtu for gas transportation between Henry Hub and our generic Midwestern US location.

APPENDIX

Table 1 - Inputs Comparison	CATF Case 0	CATF Case 1	CATF Case 2	CATF Case 3		CATF Case 4
	No CCS	50% CCS	70 % CCS	0% Yr 1-10	70% Yr 11 - 30	NGCC
Heat Input (kWth, higher heating value used throughout)	1400162	1672956	1797570	1797570	1797570	1105812
Heat Input (MMBtu/hr)	4778	5708	6134	6134	6134	3773
Main STG Output (MWe) (CT in NGCC case)	580.4	618.2	637.8	637.8	637.8	362.2
Auxiliary LP STG Output (MWe) (STG in NGCC case)	0.0	0.0	0.0	100.2	0.0	202.5
Gross Output (MWe)	580.4	618.2	637.8	738.0	637.8	564.7
Amine System Loads (MWe)	0.0	-9.9	-14.8	0.0	-14.8	0.0
CO2 Compression Loads (MWe)	0.0	-21.2	-31.7	0.0	-31.7	0.0
Other Auxiliary Loads (MWe)	-30.4	-37.1	-41.2	-37.2	-41.2	-9.6
Net Output (MWe)	550.0	550.0	550.0	700.8	550.0	555.1
Heat Rate (MMBtu/MWe)	8.687	10.379	11.151	8.752	11.151	6.798
CO2 Emitted (lb/MWh-net)	1768	1055	687	1781	687	804
CO2 Captured (lb/MWh-net)	0	1057	1582	0	1582	0
Base Plant Cost w/o CCS (million $)	$906	$992	$1,042	$1,042	$0	$324
Auxiliary Steam Turbine Generator System (million $)	$0	$0	$0	$38	$0	$0
CO2 Removal and Compression (million $)	$0	$267	$337	$0	$347	$0
Owners Costs (million $)	$208	$285	$312	$248	$80	$74
Total Overnight Cost (million $)	$1,113	$1,544	$1,691	$1,329	$427	$398
Fixed Operation and Maintenance Cost (million $/yr)	$32.64	$43.68	$47.00	$47.00	$47.00	$12.25
Non-Fuel Variable O&M ($/MWh-net)	$5.04	$6.21	$6.95	$5.04	$6.95	$1.32
Thermal Efficiency, %	39.3%	32.9%	30.6%	39.0%	30.6%	50.2%
CO2 Emitted (lb/MWh-gross)	1675	939	592	1692	592	790
Overnight Cost, $/kW-net after construction	$2,024	$2,808	$3,075	$1,896	$775	$718
Fixed O&M, $/kW-net per year after construction	$59.35	$79.42	$85.45	$67.07	$85.45	$22.07

All above costs are 2007 price levels, 2007 dollars, overnight basis

Table 2 - Outputs Comparison	CATF Case 0	CATF Case 1	CATF Case 2	CATF Case 3		CATF Case 4	CATF Case 1b	CATF Case 3b
	No CCS	50% CCS/EOR	70 % CCS/EOR	0% Yr 1-10	70% Yr 11 - 30	NGCC	50% CCS no EOR	Phsd 70% no EOR
Net Power, MWe	550	550	550	701	550	555	550	-
Gross Power, MWe	580	618	638	738	638	565	580	-
CO2 Emissions, lb/MWh, Gross basis, 1-year avg	1675	939	592	1692	592	790	939	-
30-Year Total Net Energy, million MWh	123	123	123	134		124	123	
30-Year Total Gross Energy, million MWh	130	138	142	150		126	138	
30-Year Total CO2 Emitted, million lb	217,211	129,614	84,410	149,227		99,691	129,614	
CO2 Emissions, lb/MWh, Gross basis, 30-year avg	1675	939	592	995		790	939	-
All-In Construction, $M	$2,103	$2,917	$3,194	$2,509	$861	$689	$2,917	-
All-In Construction, $/kW-net	$3,824	$5,304	$5,807	$3,581	$1,565	$1,242	$5,304	
Non-Fuel VOM, $/MWh-net	$6.45	$7.95	$8.90	$6.45	$8.90	$1.69	$7.95	-
Fuel, $/MMBtu	$2.98	$2.98	$2.98	$2.98	$2.98	$4.73	$2.98	-
FOM, $/kWnet-yr	$75.97	$101.66	$109.38	$85.85	$109.38	$28.25	$101.66	-
CO2 Revenue, $/tonne captured	$0.00	$16.56	$16.56	$0.00	$16.56	$0.00	-$8.47	-$8.47
COE, $/MWh-net, 2017	$99.92	$124.18	$132.08	$112.52		$56.00	$136.18	$119.11
COE, % Above Case 0	-	**24.3%**	**32.2%**	12.6%		**-43.9%**	**36.3%**	**19.2%**

All above costs are 2017 price levels, 2017 dollars (except Case 3 CCS retrofit CAPEX which is 2027 basis)