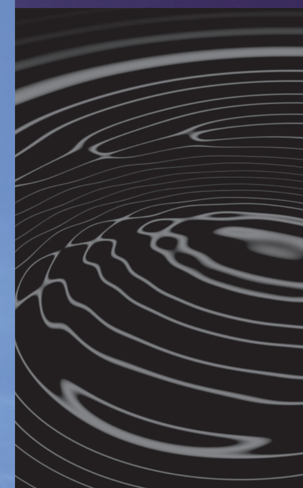
Role of Enhanced Oil Recovery in Accelerating the Deployment of Carbon Capture and Sequestration



An MIT Energy Initiative and Bureau of Economic Geology at UT Austin Symposium

July 23, 2010

Massachusetts Institute of Technology

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SUMMARY FOR POLICY MAKERS

On July 23, 2010, the MIT Energy Initiative (MITEI) and the Bureau of Economic Geology at the University of Texas (UT-BEG) co-hosted a symposium on the Role of Enhanced Oil Recovery (EOR) in Accelerating the Deployment of Carbon Capture and Sequestration (CCS). The motivation for the symposium lies with the convergence of two national energy priorities: enhancement of domestic oil production through increased tertiary recovery; establishment of large-scale CCS as an enabler for continued coal use in a future carbon-constrained world. These security and environmental goals can both be advanced by utilizing the carbon dioxide (CO_2) captured from coal (and natural gas) combustion for EOR, but many questions remain about the efficacy and implementation of such a program at large scale. The symposium aimed to lay out the issues and to explore what might be an appropriate government role.

We summarize for policy makers the key points that we drew from the lively symposium discussions. *We stress that the observations in this summary are those of the authors and are not offered as a consensus view of the participants.*

1. Framework

About 65 million metric tons (MT) of new CO_2 are used annually for EOR in the United States. Total use is approximately 115 million MT, which include new and recycled CO_2. Most of this CO_2 is from natural sources and is delivered to EOR sites through a few thousand miles of commercial CO_2 pipeline. This yields nearly 300K barrels of oil per day (BOPD), or just over 100 million barrels (bbl) per year — about 5% of domestic crude oil production. However, estimates of economically recoverable oil from underground injection of carbon dioxide for enhanced oil recovery (CO_2-EOR) are in the range of 35 to 50 billion barrels of oil (BBO), suggesting that larger volumes of CO_2 could be employed.

Coal power plants in the US today produce about 2 billion MT of CO_2 annually, about 80% of total power sector emissions. Thus, the 65 million MT of new CO_2 used for EOR today represents only about 3% of coal plant emissions. 65 million MT is equivalent to that emitted by about 10 GigaWatts electric (GWe) of high efficiency (supercritical) baseload coal power plant capacity, generating a bit over 4% of coal plant electricity in the US.

The US has not enacted legislation to cap CO_2 emissions, but the overwhelming majority of climate scientists continue to anticipate major impacts from increased greenhouse gas (GHG) emissions and to call for CO_2 limits. At a minimum, prudence suggests preparing the technology options for a future marketplace in which CO_2 emissions are significantly below today's levels because of regulation and/or pricing, and this cannot practically be achieved without dramatic reductions in CO_2 emissions from coal. Indeed, for these reasons, the federal government continues to invest significantly in CCS research, development, and demonstration (RD&D), as do many other countries.

The CCS program has two major objectives. The first is to establish the science, the monitoring regime, and the regulatory apparatus to store large amounts of CO_2 in deep geological formations. Understanding capacity, injectivity limits, and the permanence of storage are key research goals. Extended time periods are needed for this research, so an aggressive CCS program is required in this decade if the option is to be established in a timely way.

The second objective is to lower the financial cost and energy penalty of CO_2 capture for power plants. With today's post-combustion capture technology, a quarter to a third of the coal plant's energy output is needed to implement the capture process. It is estimated that the cost of CO_2

capture with evolutionary technology advances and engineering experience may reach as low as \$50 to \$70/ton CO_2 for a fully commercial (i.e., nth) integrated coal/CCS plant, but that the costs for the first-mover plants are roughly twice as high. This is well above the price range paid today for carbon dioxide injection for enhanced oil recovery (CO_2-EOR), which is more in the \$25 to \$40/ton range with recent oil prices. Consequently, *while CO_2-EOR can materially lower the costs for an anthropogenic CCS project, government support is likely required to help motivate the first-mover demonstrations.*

The integration of EOR and CCS programs poses a number of challenges, the most fundamental of which is the different motivations of the various players. CO_2 is treated as a commodity by EOR operators and the Bureau of Land Management (BLM), but as a pollutant by the Environmental Protection Agency (EPA) and the power plant operator. The EOR operator wants to minimize the CO_2 needed for producing a barrel of oil, while the power plant operator and EPA want to maximize CCS. Even within the EPA, regulation of oil and gas wells and of CO_2 disposal wells would need to be harmonized. In addition, CO_2 pipeline issues have not been in the federal domain but rather are regulated at the state level. These challenges are certainly not insurmountable, but they do highlight the range of issues that will enter into shaping the value proposition for different stakeholders.

2. Scale of CO_2 Storage through EOR

The focus of sequestration programs has been on deep saline formations (DSFs) because of the enormous CO_2 storage potential. However, the symposium discussion brought into sharper focus a key outcome: *an organized CO_2-EOR program using anthropogenic CO_2 could, with the appropriate CO_2 transportation infrastructure, kick-start larger-scale sequestration in the US and meet sequestration needs for a significant period if CO_2 emissions pricing is introduced*. Of course, this will depend on reaching a satisfactory understanding of the scale and permanence of CO_2 storage in EOR.

It appears that up to 3,500 GWe-years of CO_2 from coal power plant generation could be accommodated in the EOR Main Pay Zones (MPZs). This represents about 15 years of total output from all US coal plants, or equivalently about 60 years of output from 25% of the US coal fleet; the latter would represent an increase from 65 million MT of EOR CO_2 annually today to over 300 million MT annually. We do not suggest that this "theoretical maximum" can be achieved anytime soon, so the available capacity can be expected to be sufficient for a considerable time:

- It takes time to scale-up any industrial enterprise, including EOR, several-fold.

- EOR with CO_2 from coal power plants will not be commercially viable absent government subsidy or until CO_2 emissions are priced substantially, and such pricing does not appear imminent.

- It will take a considerable time to retrofit as much as 50 GWe of the coal fleet for carbon capture and the opportunities may not be much beyond this level: with today's capture technology, as little as 20% of the existing US coal plants may be serious candidates for CO_2 capture retrofit (see *Retrofitting of Coal-fired Power Plants for CO_2 Emissions Reductions*, proceedings of a 2009 MITEI Symposium, web.mit.edu/mitei).

Beyond this, Residual Oil Zones (ROZs) may hold an even greater potential according to estimates made for the Permian Basin by the US Department of Energy/National Energy Technology Laboratory (DOE/NETL). There is much to be understood before this assertion can be verified, and the DOE should support a research program to quantify the promise of ROZ for enhanced oil recovery for carbon capture and sequestration (EOR-CCS).

3. Storage Issues with EOR

A key issue for gauging the appropriateness of government support of a major EOR-CCS effort is verifiable permanence of CO_2 storage. Tertiary recovery obviously implies that the reservoir has been produced through many wells over a considerable period of time. This calls into question the integrity of the CO_2 confinement over centuries. Clearly, *monetization of the stored CO_2 will require development of both well integrity standards and an adequate and affordable monitoring system and verification protocol*.

Second, the EOR process entails repeated recycling of the CO_2, as a substantial fraction (20% to 40%) of the injected amount can accompany the produced oil, is separated from that oil, and then reinjected. Therefore, CO_2 "accounting" needs to be monitored throughout the entire operation. Further, overall system operation may be complicated by the declining demand for CO_2 during a well's EOR operating period.

However, *EOR also has attractive features for CO_2 storage relative to DSFs*. Some of the potential advantages are:

- a much reduced footprint (perhaps an order of magnitude in area) for the underground CO_2 plume;
- oil production can lower sequestration technical risk because of lower reservoir pressure requirements for CO_2 storage;
- a baseline of reservoir data and production history;
- known trap and seal integrity tested over geologic time;
- existing infrastructure at the site;
- buildup of public acceptance for large-scale sequestration.

These features should be captured and advanced in design of a government-assisted CCS program focused around CO_2-EOR with anthropogenic sources.

4. Implementation Issues for CO_2-EOR

The combination of the high cost of integrated first-mover CCS projects, the benefits of enhanced domestic oil production, and the rough equivalence of CO_2 needs for EOR and CO_2 sequestration potential in the next two to three decades merits a serious look at scaling up CO_2-EOR with government support. However, in addition to the research needed to quantify storage performance, several other implementation issues need to be addressed.

• Infrastructure

Federal CCS programs have paid relatively little attention to the CO_2 transportation infrastructure, but this is a key enabler for building both EOR and DSF sequestration. Looking well into the future, a CO_2-EOR program utilizing hundreds of millions of tons of CO_2 annually will likely require tens of thousands of miles of CO_2 pipeline. A "giant horseshoe" configuration was discussed at the symposium, linking the major CO_2 sources of the Midwest with the producing regions of the Gulf Coast, West Texas, and the Rockies. Clearly, such an ambitious undertaking should occur with public support only with evidence that large-scale CO_2-EOR using anthropogenic sources will materialize as an opportunity for both climate risk mitigation and enhanced oil production. Satisfying these needs will probably require sustained "high" (i.e., current) oil price levels and a price (or cap) on CO_2 emissions. However, even the *initial steps to implement anthropogenic CO_2-EOR should be taken with a view toward beginning to build the physical infrastructure in a way that would be needed for a future major scale-up*.

In the longer term, other issues will certainly arise as to how a large pipeline infrastructure is built and regulated when part of its purpose is to serve an environmental public good (CO_2 "disposal"). For example, will major pipelines be required to serve as common carriers? Will the federal government take on some measure of siting authority, as it does with natural gas pipelines (and more recently with electricity transmission lines)? These questions do not need to be answered immediately, but they merit near-term stakeholder discussion to map out the regulatory landscape in case the value proposition becomes attractive sooner rather than later.

• Managing CO_2 supply and demand

The supply of CO_2 from a large baseload coal plant, which is essentially continuous unless down for repairs, will not always match the demand requirements of individual EOR operators. How supply and demand are matched is an important issue for the value proposition and for capture and storage of most of the produced CO_2. Simple "take or pay" long-term contracts are not likely to be attractive or economical for individual EOR projects.

Some of the supply/demand balancing can be facilitated by an infrastructure that links sources to multiple EOR projects. However, the most straightforward approaches discussed at the symposium appear to be employment of available pore space in depleted natural sources of CO_2 and "stacked storage," that is, use of the CO_2 for EOR when possible, and storage of "excess" CO_2 in a DSF at other times. It is anticipated that such storage options will be available at or near most EOR locations.

Stacked storage will require that the federal government continue its program for resolving science and regulatory issues for sequestration in DSFs. It will also call for an evolved public-private business model, since some of the CO_2 goes for commercial purposes (and storage), while some is directed towards CO_2 "disposal." *A fair allocation of costs and benefits among the EOR operator, the CO_2 supplier, the transportation provider, and governments must be analyzed and put into contractual terms*.

• Regulation

Multiple regulatory issues need to be faced, some of which have been alluded to already. *Liability is a key issue*. There was considerable disagreement among symposium participants about the extent to which government should assume long-term liability for CO_2 storage and/or is compensated for assuming that liability. This discussion mirrors that for CO_2 sequestration quite independent of the EOR possibility.

Our view is that a phased approach is called for, testing out the scalability of anthropogenic CO_2-EOR while answering the scientific, verification, infrastructure, and business questions. In this context, some combination of state and federal governments should assume long-term liability for a small set of first-mover projects while the regulatory regime is proposed, debated, and evolved based on the first-mover experience. Clearly, historical liabilities associated with the site history or with a possible "orphan" site future are not acceptable. This assumption of liability can be negotiated into the terms for monetizing the stored CO_2 in these first few projects. The alternative is further delay in establishing the CCS option and deferral of the domestic oil production opportunity.

A second set of issues deals with *ownership of pore space*. Conventional approaches to mineral extraction rights are inappropriate for CO_2 storage rights. An essential step is that the EPA recognizes EOR as providing storage, subject to verification. Unitizing — legal agreements that enable oil reservoirs to be operated as a single system even if different landowners are affected — needs to be carried over to CO_2 storage in order to facilitate monitoring, reporting, and verification (MRV) needed for monetizing stored CO_2.

5. Recommended actions

Anthropogenic CO_2 capture, transportation, and use for EOR has the potential to be a significant contributor to domestic oil production and, if increased several-fold from today's injected volumes, to accommodate anticipated sequestration needs for at least a couple of decades, quite possibly more. The high cost of integrated CCS projects has slowed down the implementation of CCS demonstrations, and the economic benefits of EOR, especially with continuing high oil prices, can provide a major stimulus for advancing such projects. Several DOE projects already target EOR, but there has not been a commitment to this option as a key part of the overall CCS program design. We strongly *urge that the DOE develop and implement a comprehensive RD&D program that*:

- Provides data on permanence of CO_2 storage in EOR;
- Develops the tools for end-to-end systems analysis of CO_2 capture at power plants, transportation infrastructure, and stacked storage;
- Provides an analytical framework for the value proposition for power plant, pipeline, and EOR operators and for the government;
- Puts forward principles for resolving regulatory issues, such as pipeline siting and access, long-term liability, and pore rights;
- Explores the potential for EOR in ROZs; and
- Maps out a phased implementation program for CO_2-EOR, including build-out of transportation infrastructure.

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MIT Energy Initiative and Bureau of Economic Geology at UT Austin Symposium

The Role of Enhanced Oil Recovery in Accelerating the Deployment of Carbon Capture and Sequestration

FINDINGS IN BRIEF

FROM THE RAPPORTEURS' REPORT ON THE SYMPOSIUM

MITEI and UT-BEG at Austin co-hosted a symposium on the role of EOR in accelerating the deployment of CCS. This summary report reflects the major points of discussion and the general findings and recommendations of the event's participants. This is a report on the proceedings and the papers that informed those proceedings; this is not a study. This report represents a range of participant views and, where possible, includes consensus or general recommendations of the presenters and participants; *it is in no way intended to represent the views of all the participants, of individual participants, or of the rapporteurs.*

Symposium Structure

The symposium's participants helped to frame the issues, opportunities, and challenges associated with the geosciences, implementation, and policy and regulatory aspects for carbon sequestration through the use of CO_2 in EOR activities. The findings identify a range of possible "next steps" for the consideration of policy makers and other interested individuals and entities.

Participants engaged in moderated discussions after reading commissioned white papers and other materials provided to them in advance of the symposium. Symposium participants Michael Ming of the Research Partnership to Secure Energy for America (RPSEA), Stephen Melzer of Melzer Consulting, and James Dooley of the Joint Global Change Research Institute at the Pacific Northwest National Laboratory each provided high-level framing of the issues associated with EOR.

During the symposium, the authors of the pertinent white papers, Susan Hovorka of the UT-BEG, for geosciences; Vello Kuuskraa of Advanced Resources International, for implementation; and Scott Anderson of the Environmental Defense Fund (EDF), for policy and regulation, highlighted key points from their papers and selected discussants offered brief responses to those points. Symposium participants then engaged in a discussion framed by the white papers exploring the issues associated with carbon sequestration in oil and gas fields (in conjunction with EOR and otherwise).

Several participants also provided papers and slides in advance of the symposium to further inform and focus the discussion. Data, points of view, and information from such documents are integrated, where applicable, into the text of this report and are available at the MITEI Web site. Ernest Moniz, the director of MITEI, and Scott Tinker, the director of UT-BEG, provided summary remarks at the symposium and led a concluding discussion. A summary of the issues and findings of the symposium follows.

Framing of the Issues

Issues Summary: Large-scale CCS includes a suite of critical enabling technologies for the continued combustion of fossil fuels in a carbon-constrained environment. The oil industry has for several decades been using subsurface injection of CO_2 for EOR. The key focus of the symposium was assessing the potential of the availability of additional anthropogenic CO_2-EOR as both a value proposition for industry *and* an opportunity for demonstrating large-scale sequestration for meeting climate change mitigation objectives.

The volume of EOR pore space was a central focus of the discussion, viewed as both an opportunity as well as a limitation by various participants. Hydrocarbon pore volume in current and potential EOR operations is readily available, accessible, and may be significantly larger than typically recognized. New research and field demonstrations have identified the opportunity for EOR in ROZs,[1] geologic formations that historically have not been targets for commercial oil production. The ROZs may have the potential to expand known usable pore volume by orders of magnitude although, given current understanding, there is a high degree of uncertainty about total ROZ capacity.

Another key issue addressed by the participants was the framework that would be needed to transform current CO_2-EOR operations into a viable CCS option. Participants noted that current EOR operations were designed to maximize oil production rather than permanently store CO_2, and that data, research, and analysis to support regulations on the permanency and safety of CO_2 injected into hydrocarbon pore space are not complete or comprehensive.

Linking carbon capture, CO_2 transportation, and enhanced oil recovery for EOR-CCS activities will require the development of new business models. Alternative models were discussed, ranging from evolutionary expansion of the current CO_2-EOR business model to the creation of a broad new framework requiring an active governmental role in establishing the vision, leadership, and possible financing of certain activities.

Value sharing between those entities capturing carbon and providing the CO_2 supply (i.e., upstream participants in CCS, e.g., utilities) and those entities acquiring CO_2-EOR projects (i.e., oil industry participants downstream in the CCS value chain) was identified as an important issue for the development of a viable business model. Past analyses were discussed which show the West Texas CO_2 market to be oligopolistic in nature, as the current CO_2 sellers influence pricing by controlling supply. A large-scale CO_2 capture program could lead to a situation in which the supply of CO_2 would most likely exceed demand; therefore, the rents from CO_2-EOR would accrue to the downstream participants, not the CO_2 suppliers. Sharing of value between suppliers and downstream users is critical to a successful business model. Absent such a scheme, the value proposition of CO_2-EOR may not adequately incentivize power plant owners to capture carbon and supply the downstream market.

With today's capture technologies, the cost of capture from power plants would not be offset by the CO_2 value for EOR. Therefore, absent a price on CO_2 emissions, some form of government incentive would be needed. Government incentives are justified as needed to demonstrate CCS for a future in which CO_2 emissions carry a price.

Development of a CO_2 transportation network was identified as a critical element to connect the CO_2 sources to potential EOR applications. The design of a transportation network and its implementation and financing were identified as major issues by participants. Linking current CO_2 pipeline segments in a "giant horseshoe" arrangement could, for example, form the backbone for a national CO_2 pipeline system.

Concern about a regulatory regime for CO_2-EOR was a recurring theme of the symposium. The value proposition of CO_2-EOR depends in large part on the ability of CO_2-EOR operators to comply with any emerging CCS regulatory requirements and to obtain the appropriate carbon credits if and when they become available. Care would need to be taken by those establishing regulations and credit structures to ensure that CO_2-EOR project sponsors are adequately covered in any regulatory or statutory regimes, particularly for early-mover projects that preceded the establishment of the regulations. Otherwise, CO_2-EOR project sponsors could be faced with a potential environmental liability rather than an environmental credit.

The current EOR infrastructure in the Permian Basin in West Texas was discussed as a possible starting point for the evolution of an EOR-CCS program, in large part because of the economic opportunities associated with the potential to substantially increase the producible oil resource base in that region. It is highly unlikely that EOR would enable the complete recovery of the remaining one-third of oil resources left from conventional production; if this were possible, however, it would create nearly $1 trillion of value. Some participants noted that EOR activities in the Permian Basin benefited from targeted R&D, regulatory, and tax subsidies spanning decades. Taking full advantage of the Permian Basin EOR opportunities in the future might entail the need for similar incentives.

Framing of the Issues: Key Findings

Finding: The expansion of EOR programs to increase domestic oil production while simultaneously sequestering CO_2 in hydrocarbon pore volume offers a value proposition that can create wealth, contrasting with the view of geologic sequestration of CO_2 as a waste disposal activity.

Finding: The magnitude of hydrocarbon pore space available for sequestering CO_2 through EOR operations is significantly greater than generally recognized.

Finding: New research and field experiments have identified the feasibility of EOR developments in partially oil-saturated structures, known as ROZs, that could possibly expand potential hydrocarbon pore space volume by orders of magnitude. There is significant uncertainty surrounding the capacity of these zones, and additional research and analysis are required to fully understand ROZ potential.

Finding: New business models are needed to create the necessary linkages between CO_2 sellers (i.e., power plant owners who install carbon capture), CO_2 pipeline transporters, and CO_2-EOR operators. Business arrangements that share the added value created by CO_2-EOR opportunity will be an important aspect of any successful business model.

Finding: Establishment of a regulatory framework that enables CO_2-EOR activities to be recognized as a viable carbon sequestration option is essential to realizing the full potential of CO_2-EOR.

Finding: Additional CO_2 pipeline infrastructure will be needed to link anthropogenic CO_2 sources to regions of EOR potential. A smartly designed "source-to-sink" pipeline system could minimize the amount of new pipelines. Even so, up to 30,000 miles of new pipelines, developed over decades, will be needed.

Finding: The public policy purposes associated with EOR-CCS merit consideration for federal policy and financial incentives to overcome the current barriers to widespread commercial deployment. The current volume cap on Section 45Q of the Internal Revenue Code sequestration tax credit is too small to incentivize significant commercial deployment of EOR-CCS.

Panel One: Geosciences

Issues Summary: From a technical perspective, the degree to which the subsurface can be characterized both qualitatively and quantitatively will have major impacts on the ultimate success of any EOR-CCS project. The geosciences provide the tools for understanding the subsurface. Many of these tools (e.g., imaging, reservoir, and fluid modeling) have been highly developed by the oil and gas industry.

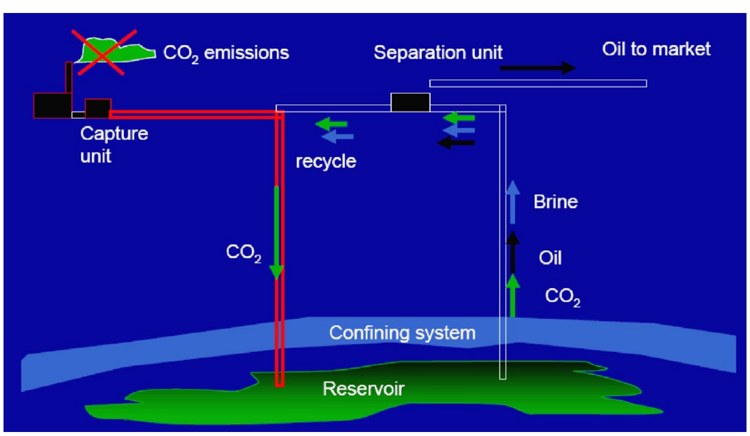
While these tools can be applied to any EOR-CCS project, their accuracy in resolving and characterizing the subsurface is directly proportional to the density of available data. CO_2-EOR projects are high-data-density environments with a number of well penetrations and production records that contain information on pressure and fluid flow, as well as iterative modeling of fluid flow through the reservoir, often complemented by seismic data. In short, from the perspective of the geosciences, the long operating history and data density associated with EOR provide an opportunity to advance both the science and practice of EOR-CCS.

There is an established base of geosciences information for EOR reservoirs that does not exist for deep saline formations (DSFs). There is direct evidence — oil confined over geologically significant time — of the quality of the confining system (cap rock) of an EOR project, a property that can only be inferred in a saline formation. In addition, the storage volume (exclusive of ROZ volumes) and injection rate of an EOR field are well known; in saline formations, these key properties must be measured and extrapolated over the planned storage volume.

EOR projects already provide substantial experience useful for monitoring CO_2 injection and movement in the subsurface. Economic incentives for more robust demonstration of storage in EOR can test the effectiveness of monitoring approaches and provide data for assessing subsurface storage risks. However, at the decadal time frame of EOR projects, direct measurements of permanence are difficult or impossible to make with adequate precision to assure performance over centuries. Making long-term projections (centuries plus) requires indirect methods such as models and comparison to analogous natural systems.

Understanding the geosciences issues associated with the subsurface behavior of large-scale CO_2 injection — plume size at expected injection rates for both EOR and saline aquifer injection, for example — is critical to advancing the understanding and confidence in CCS as a climate mitigation measure. Fully instrumented and monitored CCS demonstration projects can be linked to EOR in order to accelerate experience gains and provide data at scale.

Figure 1 – Schematic of a CO_2-EOR System. Components required for sequestration in brine formations that are also common CO_2-EOR are highlighted in red.



Source: Hovorka

Coincidence of sedimentary formations of suitable depth for sequestration in DSFs with hydrocarbon basins and stationary CO_2 sources suggests that much US brine-formation storage could be accessed through infrastructure developed for CO_2-EOR using the stacked-storage concept. Additional screening to determine which reservoirs are economically accessible for EOR and the scope of pipeline construction that would be motivated by EOR has not been undertaken.

Geosciences: Key Findings

Finding: There currently exists a wealth of information and experience, including massive data sets, on CO_2 injection for EOR projects. This information on CO_2-EOR is held by the oil industry. There is a need to determine how to share this information to educate the public and advance the understanding of and confidence in EOR-CCS.

Finding: The potential pore volume available for CO_2 injection into DSFs (i.e., brine) is several orders of magnitude greater than for EOR. However, much less is known about the geoscience of CO_2 injection into DSFs, and there may be challenges associated with pressure management and confinement.

Finding: Because of the economic incentive, test and measurement in EOR projects are much more practical than in "greenfield" DSFs. Acquiring these kinds of data for a "greenfield" brine project will be expensive and time consuming. EOR provides the dense data needed to test tools, methodologies, and long-term monitoring.

Finding: Subsurface monitoring to determine the permanence of CO_2 injection will be critical in any carbon regulatory scheme. Mass balances may be too simplistic. There are many different monitoring techniques that need to be integrated, but all require some pre-injection baseline to fully understand the movement of CO_2 in the subsurface.

Finding: CO_2-EOR projects can accelerate CCS demonstration and serve as test beds for understanding geoscience issues and increasing confidence in the correctness of monitoring and modeling.

Panel Two: Implementation

Issues Summary: A recurring theme of the symposium was that widespread adoption of CO_2-EOR as a matter of public policy could accelerate the implementation of CCS. Some participants thought that the potential for sequestration in conjunction with EOR activities was sufficient to meet CO_2 storage needs through 2050. Other systematic estimates expressed were much more conservative. Some noted that the lack of CO_2 supplies could actually restrict additional CO_2-EOR development.

Participants discussed analysis of the economic potential of CO_2-EOR in the MPZs, which suggested that there is sufficient capacity in the EOR sector to sequester CO_2 supplies from 57 1-gigawatt (GW) coal-fired power plants for 30 years. Estimates were even greater when the pore volume in the ROZs is included, although the understanding of these zones is limited. While the resource potential is yet to be quantified, an assessment by the US Department of Energy/National Energy Technology Laboratory (DOE/NETL) of the ROZs in the Permian Basin determined that an additional 12 to 18 gigaTons (GT) of CO_2 storage capacity exists in the ROZs, compared to 6.4 GT storage capacity in MPZs.

There is a geographic mismatch between some of the existing anthropogenic CO_2 sources and the oil basins. To fully integrate the potential CO_2 supply from these sources into the EOR projects, an extensive pipeline network linking the large anthropogenic CO_2 sources to EOR projects will be needed.

Implementation: Key Findings

Finding: There are over 100 active CO_2-EOR projects in the US, currently providing 281,000 BOPD, about 5.0% of total domestic crude oil production. Natural sources of CO_2 account for over 80% of the total CO_2 supply to these projects. Current EOR operations can store around 0.26-0.32 MT of CO_2/bbl produced.

Finding: It is estimated that there are 38 to 58 billion barrels of economically recoverable oil from CO_2-EOR, under current assumptions. Recovery of this oil will require a significant expansion of CO_2 supply.

Finding: The potential for retrofitting carbon capture at existing coal power plants for retrofit could be as low as 20% of the fleet. Emissions from this subset translate to a few hundred million MT of CO_2 which is a good match to the CO_2-EOR potential. This raises the possibility that brine may not be needed as primary storage capacity in the near and intermediate term.

Finding: While the potential amounts of CO_2 supply and use in EOR match well, there are transportation constraints. Additional CO_2 pipeline capacity will be needed to link regions of coal generation plants with carbon capture potential to the areas of EOR potential.

Finding: The area of the CO_2 plume in a DSF created from the injection of CO_2 from a 1-GW coal power plant over 30 years could reach over 200 square miles. Because of its greater pore space, the size of the plume from a comparable amount of CO_2 injection into an EOR reservoir is estimated at 20 square miles, or one-tenth the size of the plume in the brine formation.

Finding: CO_2 sequestration in DSFs can be used as backup storage to deal with operational EOR issues. Short-term and long-term operational mismatches between anthropogenic supplies and EOR demand raise the need for a secondary storage capacity that can accommodate the CO_2 supply during periods of high electricity generation and associated large CO_2 production. Moreover, backup brine storage can serve as a secondary sequestration site in case oil production decreases to a point at which CO_2-EOR no longer becomes economically feasible. It is evident that there is substantial overlap between oil reservoirs and DSF; however, the details for co-deployment mechanisms for EOR and DSF need further assessment on a basin-by-basin scale.

Finding: There are 10 CO_2 geologic storage projects in operation or development in the US. Seven of the 10 projects are employing CO_2-EOR as the method of storage. The three projects using CO_2 injection into brine are projects located in areas in proximity to DSF and not convenient to CO_2 transportation infrastructure. The CO_2-EOR projects have an advantage in terms of lower technical risk, greater value proposition, and the potential for greater public acceptance.

Finding: Implementation of CO_2-EOR as a major national strategy for carbon sequestration will likely need to occur in phases. The initial phase of pioneering projects will involve "learning by doing" and developing the data to support an effective regulatory regime. This phase needs to be followed by a major effort to reduce cost, in order to ensure that a mature CO_2-EOR industry will be commercially viable. Even under a climate bill, very little CO_2-EOR as a means of CCS will take place without incentives until a price is set on CO_2 emissions.

Panel Three: Policy and Regulation

Issues Summary: Participants focused on policy and regulatory frameworks that would enable CO_2-EOR activities to qualify as a viable and effective carbon sequestration strategy. Much of the discussion centered on questions related to the permanency of carbon sequestration in hydrocarbon pore space and whether current EOR field practices were adequate to prevent leakage. The availability of baseline data from existing EOR fields was identified as an important factor that would facilitate regulatory determinations. Public acceptance also was noted as an important consideration.

Participants discussed whether there should be a distinction, for regulatory purposes, between enhanced oil recovery-business as usual (EOR-BAU), i.e., EOR activities designed to maximize oil production with incidental carbon sequestration, and EOR-CCS, i.e., EOR activities designed to maximize carbon sequestration with oil production as a corollary benefit that lowers CCS cost.

The major elements for an effective regulatory regime were also discussed. These include criteria for siting, operations, closure, and MRV. This discussion centered on the requirements applicable for new CO_2-EOR projects planned for the purpose of carbon sequestration (EOR-CCS).

Participants were also concerned about appropriate requirements for existing CO_2-EOR operations, i.e., EOR-BAU. The current EPA Underground Injection Control (UIC) program, established under the Safe Drinking Water Act of 1974, is an imperfect framework for achieving comprehensive regulation. Aspects of EOR-CCS activities fall within both the Class II and Class VI wells established in the EPA UIC regulations.[2] In addition, the Safe Drinking Water Act currently does not have explicit authority to authorize standards for CO_2 emissions leakage to the atmosphere that may result from underground injection activities.

Participants discussed the importance of legal issues, such as ownership of pore space. Current leasing regulations were designed to convey mineral rights, including the use of pore space as reasonably necessary for extracting minerals. However, current leasing regimes did not anticipate the use of pore space for permanent storage of CO_2. This may require changes in regulations to recognize the distinctions between mineral extraction rights and storage rights. This issue is currently under review for federal lands leased by the Department of Interior (DOI) BLM.

Another important legal issue for EOR fields is “unitization” — legal agreements that enable oil reservoirs to be operated as a single system in order to increase oil recovery. Such agreements typically involve the equitable sharing of royalties between landowners likely to be affected by the drilling, production, or injection activities on the unitized properties. Failure to achieve full unitization of EOR fields planned for CO_2 storage could present major obstacles to compliance with MRV requirements needed for carbon sequestration credits. Participants recognized that unitization was an issue under the jurisdiction of the states. Many state legislatures have enacted compulsory unitization requirements for oil and gas extraction. Texas, which has by far the largest extent of CO_2-EOR activity and future EOR potential, does not currently have a state law on compulsory unitization.

The issue of liability protection received a great deal of attention at the symposium. Many participants felt that CO_2-EOR operations should not receive any form of liability protection from the migration of sequestered CO_2 into the groundwater or atmosphere under the theory that these operations are no more risky than those of other industries that do not receive such protections.

Others noted at least two areas in which inadequate information or market failures may justify a governmental role in liability protection. Early movers of pioneer EOR-CCS projects have inadequate information for the marketplace to appropriately price risk and provide risk management tools. Also, "orphan" sites, which may require remedial action, may require some kind of government-supported liability protection or coverage.

Participants also heard about and discussed possible "pooling" arrangements among CO_2-EOR project sponsors. These arrangements would enable private sector entities to achieve standardization and economies of scale in long-term MRV activities, and possible risk sharing, without the need for a governmental role in providing financial protection or subsidies.

Finally, participants discussed legislative scenarios for a national EOR-CCS program and there was general agreement that such a program could advance only in the context of a national requirement for CO_2 emissions reductions. Participants generally agreed that comprehensive climate change legislation *would* provide the necessary incentives to spur a national EOR-CCS program. Participants also noted that legislation proposed in 2010 provided special incentives for EOR-CCS in the form of bonus allowances under the proposed cap-and-trade regulator regime.

At the time of the symposium, some participants were unwilling to preclude the possibility that the 111th Congress might take action on comprehensive climate change legislation, although the general feeling was that this was highly unlikely. Consequently, there was less focus on policy and legislative options for CO_2-EOR / CCS separate from comprehensive climate change legislation. Absent comprehensive climate change legislation, there was a view that CO_2-EOR would evolve slowly as a niche activity providing an opportunity for "learning by doing" to inform future discussions of policy and regulation. [Note: the 111th Congress did not act on comprehensive climate change regulation.]

Policy and Regulation: Key Findings

Finding: Regulation of EOR-CCS activities requires a comprehensive framework that should address siting, operations, closure, and long-term monitoring of EOR sequestration projects.

Finding: EOR-BAU, EOR-CCS, and carbon sequestration in brine formations, have different operational characteristics, such as injection rates and pressures. These differences will require different regulatory approaches.

Finding: There will be challenges in adapting existing CO_2-EOR projects to a new CCS regulatory regime. While carbon sequestration is clearly taking place, current projects may lack sufficient data on baseline conditions, migration patterns, and leakage points needed to make a regulatory determination of long-term sequestration and verifiable carbon credits.

Finding: Extensive planning is currently underway to establish MRV plans for EOR-CCS demonstration projects. MRV plans are intended to support compliance with anticipated regulatory requirements; however, they have not yet been fully demonstrated. Consequently, the emerging regulatory framework for EOR-CCS will need to have some flexibility to allow for learning by doing.

Finding: The process of development of the regulatory framework for EOR-CCS has involved extensive dialogue among stakeholder groups. This process appears to have contributed significantly to early identification and discussions of key issues. While there is not necessarily a consensus on a number of issues, the process of dialogue has appeared to significantly advance regulatory development efforts.

Finding: Ownership rights to pore space in EOR reservoirs, as well as unitization of EOR fields, pose potential barriers to EOR-CCS projects. Resolution of the legal questions surrounding these issues is generally the responsibility of the states, except for federal lands which are administered by the DOI BLM.

Finding: Liability protection for post-closure CCS projects remains a contentious issue. While the risk profile associated with EOR-CCS operations may not be significantly higher than certain other types of industrial activities, there are significant uncertainties associated with pioneer projects and there may be challenges associated with the long time scales for post-closure monitoring, including the possibility of “orphan” sites. There is a broad range of potential options to address the liability issue, including possible liability-sharing or “pooling” arrangements among EOR-CCS operators, as well as limited government intervention.

I. Framing of the Issues

The maturity of oil fields globally and more specifically in the US creates a continuing private interest in CO_2-EOR. Likewise, there is an increasing public interest in controlling CO_2 emissions. CCS in geologic formations is one pathway towards achieving this objective. The overarching theme of the symposium was to explore the possibility of aligning private and public interests in this intersection of CO_2-EOR and CCS. Moreover, if such an alignment were possible, would there be a case for public policy to accelerate CO_2-EOR that is driven by CO_2 control and possibly by energy security concerns?

Ernest Moniz and Scott Tinker opened the symposium with introductory comments to set the stage for the day's discussion. Following these introductory comments, Michael Ming, Stephen Melzer, and James Dooley made presentations on framing the issues for discussion. Tracy Evans provided additional comments. Participants made additional comments and raised questions throughout this process. A topical summary of the discussion follows.

The symposium sought to address this issue by focusing on the "three legs of the stool"[3] with regard to CO_2-EOR as a CCS option:

1. Is it technically possible from an engineering and geologic perspective?

2. Is it doable? This addresses the implementation aspect of CO_2-EOR and deals mostly with surface issues.

3. Is it sensible? This is the most contentious issue of the three because it encompasses policy, economics, and public perceptions and acceptance.

The Oil Field Opportunity for CCS

CCS is a future technology option for mitigating CO_2 emissions from traditional fossil fuel power generation and other industrial processes. Employing CCS on a meaningful scale relative to CO_2 emissions volumes is a longer-term option, as:

- Costs of retrofitting existing coal-fired facilities to capture CO_2 appear to be unacceptably high;

- The distribution network to move the CO_2 from power plants to repositories is inadequate;

- The regulatory framework to enable the determination of safe and acceptable permanent CO_2 repositories is not yet in place; and

- The public generally lacks knowledge of or information on CO_2 sequestration.

Despite these barriers to near-term, large-scale CCS deployment as a technology for reducing CO_2 emissions into the atmosphere, there is high current demand and even higher future potential for CO_2 in EOR operations, where both pore volume and established CO_2-related infrastructure and expertise are available.

Two of the recurring themes and discussion topics of the symposium were:

1. Hydrocarbon pore volume in current/potential EOR operations is readily available, accessible, and larger in scale than generally recognized. In addition, utilization of partially oil-saturated reservoirs, ROZs, has the potential to increase usable hydrocarbon pore volume by orders of magnitude.

2. Transforming CO_2-EOR operations from commercial oil production operations to commercial operations *plus* CCS (i.e., EOR-CCS) to reduce atmospheric emissions requires a strategically planned and commercially incentivized research program. To employ existing EOR operations as acceptable CO_2 storage sites, such a program would need to address both the source and sink ends of the process and advancement of a yet-to-be-completed distribution system.

Underlying Driving Factors Needed to Shift to a New Paradigm

To facilitate accelerated CCS development, policy and regulatory frameworks need to acknowledge several key factors including:

- The critical importance of a commercial economic driver to create wealth and incentivize the robust participation of the private sector;

- The necessity of an extensive pipeline distribution network; and

- The establishment of a program that is broader than a simple "clean coal technology" demonstration program and one that, in its design, reconciles the "chicken and egg" problem — the need to significantly reduce capture technology costs while simultaneously ensuring that repositories are established for economically captured CO_2.

Wealth Creation as a Principal Driver for EOR-CCS

Wealth creation from expanded use of CO_2 for EOR can serve as an essential motivator for accelerating the demonstration, deployment, and public acceptance of CCS as a tool for GHG emissions mitigation. This vision and the leadership required for its implementation could enable a change in the public mind-set about sequestration — a shift from the current view of CCS as a waste disposal option to an avenue for wealth creation. This transition would link near-term CCS deployment with EOR to achieve multiple objectives: job creation, decreased cost for a public good, enhanced national security, and improved balance of trade through the expansion of domestic oil production.

Participants generally recognized this core argument — that CO_2-EOR could provide a bridge to large-scale commercial EOR-CCS deployment, providing revenues to the private sector while meeting essential public goods in the following ways:

- Revenues from CO_2 sales to the oil industry can offset some of the costs of CO_2 capture from both natural gas- and coal-fired power plants, as well as other industrial facilities producing large volumes of CO_2.

- New integrated gasification combined cycle power plants employing CCS technologies could be built by 2020 with the incremental cost of these plants being offset by a market and a positive price for all the CO_2 captured by this new fleet of power plants.

- If CO_2 emissions pricing is in place, the scale of the rents associated with selling CO_2 for CO_2-EOR could decrease wholesale electricity prices by 1% to 5% in the regions where credits for EOR-CCS are available. Revenues from CO_2-driven EOR could create benefits of up to $55 per ton of CO_2 for the supplier. This creates the potential for encouraging early adopters of CCS technology as well as providing an incentive for commercial deployment and infrastructure build-out for large-scale commercial CCS.

These arguments assume that CO_2-EOR is undertaken as a profitable endeavor, motivated by revenues from recovered oil. There is currently a positive price for pipeline quality CO_2 in regions that already employ CO_2-EOR. Over the last several years, CO_2 prices have risen along with oil prices. It may not be possible to extrapolate previous experience into the future *unless* the positive price for pipeline quality CO_2 persists for a significant period of time and the rents associated with oil production are shared with upstream CO_2 suppliers.

If pipeline quality CO_2 remains scarce, CO_2 suppliers will receive a reasonable price for their commodity. If, however, GHG emissions constraints force the widespread deployment of CCS systems with a corresponding increase in CO_2 supply, there is a risk of over-supply, creating a very different market structure in which rents do not necessarily accrue to the upstream supplier of CO_2 for EOR purposes. Under these market conditions, downstream CO_2-EOR would likely remain profitable, but upstream supplies would be devalued, diminishing opportunities for offsetting CO_2 capture costs from anthropogenic sources and reducing the profitability of the current suppliers of natural CO_2 to EOR operations.

Also, evaluations of economy-wide CCS deployment have typically assumed that 100% of the potential storage capacity for a given formation is available on the first day of operations. They also assume injection rates and fluid volumes over the course of a year consistent with the number of wells, making them cost, not technically, driven calculations.

Storing CO_2 for climate change mitigation in a field undergoing CO_2-EOR, however, is subject to a set of constraints that CO_2 storage in DSFs is not. The most important constraint is variable demand for CO_2 in EOR operations. This operational mismatch may strongly influence the ability of an EOR field to serve as a base-load storage formation for commercial-scale CCS projects. While each EOR field will be unique and will respond to CO_2 stimulation in different ways based on reservoir-specific characteristics and project design, the general pattern will be high initial demand for new CO_2 coupled with a decrease in demand as recycled CO_2 is used for an increasingly larger portion of the total injection volume. Regional CO_2 supply systems can help mitigate the variability.

Alternative Business Models

Two historical analogies were highlighted at the symposium, features of which may inform the development of possible business models for implementation of the EOR-CCS concept. The first was the development of the transcontinental railroad. The transcontinental railroad was created from scratch by the unique confluence of factors. Central to its success were a solid vision and committed high-level leadership. It also required the development and adherence to a road map so that simultaneous development of infrastructure from the east and the west would converge at the right point. The unprecedented logistical complexity required a level of expertise that only could be provided by the experienced military leaders from the Civil War. And finally, it required a unique financing structure with bonds authorized on the basis of miles of line actually laid.

The second historical model was development of unconventional natural gas resources in the US which occurred coincident to conventional gas development, for which an infrastructure already existed. This existing infrastructure was convenient, efficient, and effective for logically leveraging and extending technologies from conventional resource development to the development of unconventional resources. Consequently, a service infrastructure and pipeline network developed incrementally and markets developed logically. Mineral issues were resolved through legislation and court decisions over time, and effective regulatory policies were developed to protect the environment and the public interest. These developments provided the requisite economic incentives for the capital markets to work efficiently and be protected under the law, which in turn bred investor confidence.

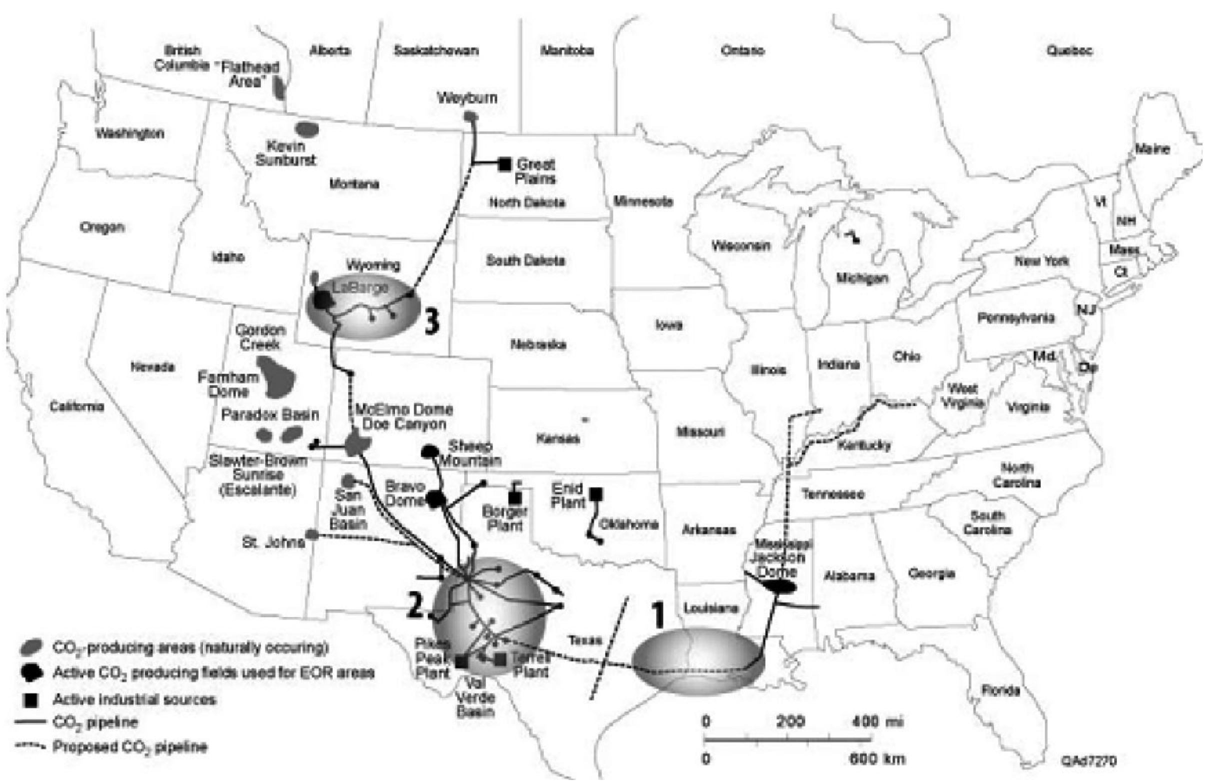
Participants discussed a hybrid model for EOR-CCS in which new elements would be grafted onto the existing CO_2-EOR model, where the oil and gas industry already has significant expertise in subsurface operations and experience in managing CO_2, pipeline systems, and public concerns about CO_2 injections. New elements include:

- CO_2 measurement, verification, and permanency;
- Long-term stewardship;
- Pore volume ownership;
- New pipelines and distribution networks; and
- New financing arrangements.

This hybrid model would address the "chicken and egg" problem, by matching large-scale, readily available carbon sinks with anthropogenic sources in order to incentivize the development of economic capture technologies. The private sector would provide the sources and the sinks, a combination of private and public investments would fund the connection of the sources and the sinks, and the public sector would fund effective RD&D programs to advance the science and technologies to enable economical large-scale CCS.

An issue that was discussed in detail by participants was the need for a pipeline infrastructure to move CO_2 from power plants to EOR locations. One concept was to link existing CO_2 pipeline segments into a national "horseshoe pipeline" that would form the backbone of a national CO_2 pipeline network.

Figure 2 – A Framework Depiction of a National CO_2 Pipeline Network ("The Horseshoe"). The shaded ellipses represent three areas where very large EOR/CCS projects are active or proposed.



Leveraging the Value of an Effective EOR-CCS Program through a Comprehensive and Effective National Policy

The value of the EOR-CCS program could be magnified if combined with complementary energy policies. For example, more efficient energy use across the entire continuum could substantially reduce the total volume of CO_2 that needs to be sequestered; coordinated and appropriately sequenced policies should be developed to maximize the value of CO_2-EOR for public purposes. Also, replacement of legacy generation with low or no-carbon generation could dramatically reduce the volumes of CO_2 requiring capture and sequestration.

Absent a global commitment to significantly reduce GHG emissions, the world will likely expand its use of unconventional oil to replace declining conventional supplies. Production of unconventional oil is generally more energy (carbon) intensive. However, the implementation of effective climate change policies could fundamentally alter the mix of energy resources on which the world draws to augment declining conventional oil resources. Stabilization of atmospheric GHG concentrations will require an increase over time in costs of carbon-intensive fuels. As the cost of emitting GHGs to the atmosphere increases, the energy and carbon intensity of these unconventional hydrocarbons will likely make them less competitive with other options to displace petroleum-based fuels, such as biomass-derived fuels, natural gas vehicles, and electric passenger vehicles. Under this scenario, the ability to reduce the cost of CO_2 for EOR will become increasingly important in order to maximize the value of remaining oil resources, and minimize the shift to more carbon-intensive unconventional resources.

Participants agreed that EOR-CCS is best addressed in the context of effective and more fully integrated national energy policy. A promising area for demonstrating such integration is in the Permian Basin in West Texas. The Permian Basin is home to the most extensive current CO_2-EOR activities in the world. It also is the home to a large wind energy resource. Thus, the Permian Basin represents a happy confluence of geology, geography, and an established and growing energy industry.

The Permian Basin as the Starting Point for Implementing the EOR-CCS Business Model

The Permian Basin has been an important location for traditional EOR operations. Two new scientific developments could greatly expand this opportunity.

- Work originally sponsored by the DOE and accelerated by RPSEA has demonstrated both the origin and distribution of what have come to be known as ROZs, reservoirs of saline solution (i.e., brine) that are partially saturated with oil. Further resource assessments indicate that ROZs exist in both "brownfield" areas where there are existing producing wells in the MPZs, and in "greenfield" areas where there is no existing oil production.

- Additional work has demonstrated the commercial feasibility of oil production from ROZs using CO_2-EOR in the Permian Basin over the next 30 to 50 years.

There is significant uncertainty associated with ROZs. Taking advantage of any new opportunities presented by ROZs would likely require additional research and characterization to determine the actual size of the producible resource base and to determine suitability for sequestration.

These activities could be beneficial because the value proposition and pore space for sequestration could be quite large. Participants recognized that there is limited understanding of ROZs. It is estimated that concurrent EOR and CCS operations could potentially extract 1.5 to 2.0 barrels of oil per ton (bbl/t) of CO_2 sequestered in ROZ zones, but substantial further analysis is required to determine the scale of this opportunity.[i]

The issue of the role of federal incentives in achieving the economic benefits of EOR in the Permian Basin and West Texas was discussed. Projections of future growth are rooted in the significant expansion of EOR activities that have taken place in the US, particularly in West Texas, over the last 40 years. However, relatively little attention is paid to the underlying drivers for this expansion.

Expansion of CO_2-EOR in the US was not driven by the many technical and scientific factors often used to compute the theoretical potential of EOR fields to store anthropogenic CO_2. Instead, the principal drivers were economic and political:

- Federal efforts to explicitly support CO_2-EOR go back to the early 1970s. Since the oil price spikes of the late-1970s, steps to encourage domestic EOR have been taken when the politics were favorable.

- Direct federal support for EOR, specifically CO_2-driven EOR, can be traced back to at least 1976, when the Emergency Petroleum Allocation Act (EPAA) was amended to provide price incentives for *bona fide* tertiary EOR techniques under the national oil price controls then in effect.

- President Carter's 1977 National Energy Plan called for decontrolling the price of domestic oil produced via EOR, which would provide a significant monetary incentive to begin seriously exploring ways to deploy nascent EOR production technologies on a large scale.

- The Crude Oil Windfall Profits Tax Act of 1978 established differential tax rates for different categories of crude oil, with a more favorable tax treatment for crude oil from EOR. The differential tax treatment created an incentive that favored CO_2 flood development for crude oil produced from the Permian Basin, as well as construction of the necessary CO_2 pipeline infrastructure needed to support expanded EOR activity. Between 1994 and 2005, the IRS credited an estimated $1.3 to $1.9 billion (in 2005 US dollars) under the Section 43 Enhanced Oil Recovery Tax Credit, which directly subsidized the creation of new CO_2-EOR floods, the expansion of existing CO_2-EOR projects, and associated purchases of CO_2.

While there was a lag between the application of these federal subsidies and the production of oil from CO_2-EOR floods, and significant private funding invested into oil fields and their associated infrastructures, federal subsidies designed to enhance energy security played a decisive role in establishing the existing CO_2 pipeline network. More than 60% of the existing 3,900 miles of CO_2 pipeline, mostly in and around West Texas, was built in the 1980s. These existing CO_2 pipelines represent an implicit subsidy for any CO_2-EOR flood that accesses the lines. It is unclear the extent to which it is appropriate to extrapolate field-level CO_2-EOR production cost data from areas that are served by these lines to regions of the US where there is CO_2-EOR potential but no extant pipeline infrastructure.

A waste disposal-driven model without a commercial driver would most likely result in a longer, more costly avenue for sequestering carbon, given the magnitude of the required investment and very large volumes of waste. EOR-CCS would not only provide meaningful storage volumes, but would also provide an accelerated path forward for the commercial deployment of CCS through the efficient and effective merging of the public interest in CO_2 emissions reductions with the capability and financial interests of private industry.

Distinguishing Between CO_2-EOR and EOR-CCS

It is important to clarify the distinction between CO_2-EOR and EOR-CCS. CO_2-EOR is the process by which CO_2 is injected into depleted oil fields for the purpose of enhancing the recovery of oil left over from primary and secondary production. Though it shares certain technical characteristics and methods with CO_2-EOR, EOR-CCS includes technologies whose objective is the long-term isolation of CO_2 in the deep subsurface as part of a program to reduce atmospheric CO_2 emissions. Depleted oil and gas fields, along with DSFs, are among the types of geologic formations being targeted for CO_2 sequestration. EOR-CCS could be attractive in locations with significant available capacity and conditions amenable to both long-term CO_2 storage and EOR.

Discussants noted that CO_2-EOR as currently implemented is considerably dissimilar from commercial-scale EOR-CCS *per se*. Large-scale adoption of the technology is unlikely unless significant changes are made in the current deployment practices. These changes would include the broadening of subsurface understanding to include ROZs and DSFs (e.g., brine aquifers), along with a new policy and regulation framework to incentivize the expansion to include anthropogenic sources, transportation on a national scale, and appropriate monitoring to assure permanent sequestration. Past experience with CO_2-EOR operations and the incentives that have driven the development of the industry are insufficient bases for informing public policy and investment in the current climate-laden regulatory regime.

CO_2-EOR-BAU does not meet the emerging regulatory thresholds for EOR-CCS, and significant effort and cost might be required to bring current practice up to the level required for qualification for CCS. Four large complete end-to-end commercial CCS facilities in the world were noted. Only one employs CO_2-EOR: the Dakota Gasification–Weyburn CCS project. The Weyburn project has incorporated significant risk assessment and monitoring programs to verify the secure storage of the injected CO_2 which is essential to the regulatory concept of a “complete end-to-end CCS project” at the core of the CO_2-EOR / CCS distinction. No other CO_2-EOR projects are viewed as EOR-CCS projects due to missing operational and CO_2 monitoring elements critical to demonstrating CO_2 sequestration.

The other three noted large-scale CCS projects inject CO_2 into “non-value-added” DSFs and, thus, do not generate revenue via recovered hydrocarbons. There are likely a number of reasons for this, including the distance of EOR fields to the source of captured CO_2, availability of transportation infrastructure, and the cost and complexity of CO_2-EOR projects, such as the need for additional injection and production facilities.

GHG Emission Reduction Credits

Essential to a successful GHG emissions strategy are specific, verifiable emissions reductions. This is especially true for capital-intensive, single-purpose systems like CCS, which are employed to ensure regulatory compliance to avoid penalties. Certification protocols will demand rigor beyond simply demonstrating deep subsurface CO_2 injection to issue certified GHG emissions reductions credits for CCS projects. Moreover, the degree of regulatory rigor applied is heightened by the trading of credits in which each ton of reduced emissions is fungible and interchangeable with any other ton of reduced emissions, irrespective of activity type.

In the context of climate change, the test for CO_2-EOR is not as simplistic as establishing that the use of CO_2 from anthropogenic sources for CO_2-EOR results in lower overall GHG emissions than CO_2-EOR from natural sources. Instead, certified, fungible CCS-derived GHG emissions reduction credits for any mitigation/offset project will likely be based on the net volume of CO_2 injected less the emissions from operating the CCS project, including the energy required to separate and re-inject the more than half to two-thirds of the injected CO_2 produced along with the oil after breakthrough. Life cycle analysis tools will likely be needed for these calculations.

Proposed or enacted regulations for CO_2 storage draw a distinction between CO_2 stored in geologic structures, such as DSFs, and CO_2 used for CO_2-EOR. For example, the EPA's proposed Mandatory Reporting Rule (MRR) makes it clear that different levels of reporting will be required for conventional CO_2-EOR than will be required for what the EPA defines as geologic sequestration. The MRR would require the calculation of CO_2 entrained in the produced oil as well as different (albeit lesser) reporting of fugitive CO_2 emissions for CO_2-EOR-based projects. Still, the reporting threshold for geologic sequestration projects would be significantly higher. This was likely done to limit interference with current CO_2-EOR practices, but may also present a barrier to entry for those wishing to convert CO_2-EOR projects to certified geologic sequestration projects (i.e., EOR-CCS) if the operator cannot produce the appropriate baseline and historical fugitive emissions data.

The *Tax Credit for Carbon Dioxide Sequestration* under Section 45Q of the Internal Revenue Code[4] also explicitly differentiates between injection of CO_2 into DSFs for CCS and CO_2-EOR. Further, the EPA's proposed UIC program regulations for geologic sequestration wells (Class VI wells) make it clear that abandoned wells intersecting the proposed storage reservoir that are within the area of review would need to be identified, located, and plugged prior to using the field for storage. This requirement reflects the fact that storage security in mature oil and gas provinces may be compromised if too many wells penetrate the cap rock.

Even after CO_2-EOR is complete and a depleted oil field is used "purely for CO_2 storage," there will still be a significant quantity of oil remaining in the reservoir. Stored CO_2 could make it possible to extract the remaining oil in the future, depending on advances in technology. Thus, available pore space in a depleted oil field should only be construed as those pores that have been liberated of their formation fluids (oil, water, and gas); pores that contain residual hydrocarbons after production could still be considered a valuable mineral right. This potentially adds a level of complexity for those selecting to store CO_2 in depleted hydrocarbon formations, as reservoir ownership (whether mineral, water, or surface rights) is partly based on the presence or absence of valuable minerals.

It remains to be seen if this differentiated regulatory treatment proves to be problematic or burdensome. At its core, the gap represents a set of activities that would not be undertaken on an EOR-BAU project and which may incur significant cost. Current EOR-BAU monitoring is designed to assess the sweep efficiency of the solvent flood and to deal with health and safety issues. EOR is also required to meet underground injection control program requirements for Class II wells set by the EPA under the authority of the Safe Drinking Water Act. For climate mitigation purposes, there would also be requirements for pre-injection activities, e.g., field characterization and mitigation of leakage pathways, including abandoned wells (many of these activities are already required for EOR-BAU); co-injection activities, e.g., groundwater monitoring, injectate monitoring, iterative reservoir modeling, and efforts to optimize for CO_2 storage and security rather than EOR alone; and post-injection activities, e.g., continued monitoring, modeling, and site closure. Thus, the implication in much of the technical literature that CO_2-EOR is essentially identical to geologic sequestration—except that one "gets paid" for CO_2 injected into the oil field—is false. The requirements necessary to qualify CO_2-EOR as a geologic sequestration project (i.e., EOR-CCS) will likely require disclosure of certain information considered proprietary under current EOR-BAU practice, as well as additional work and cost to meet new MRV requirements.

National CO_2 Pipeline Network?

In view of the geographical differences between the location of anthropogenic sources of CO_2 emissions and the location of EOR opportunities, a national pipeline network (greatly expanding the one in West Texas) is essential to enable deployment of EOR-CCS on a large scale. Estimates of total pipeline length needed for a large-scale national system range from 66,000 to 73,000 miles.

An alternative system configuration that could meet this need would be the construction and operation of dedicated pipelines by individual CCS facilities — a "source-to-sink" system. This configuration of loosely linked "source-to-sink" pipelines could, in effect, form a national CO_2 pipeline system of roughly 30,000 miles, deployed over the course of many decades, and sufficient to de-carbonize the vast majority of existing large CO_2 point sources in the US, including fossil fuel-fired base load power plants and major industrial emitters. Assuming future CO_2 sources are primarily built on "brownfield" sites or use proximity to CO_2 storage reservoirs as a siting criterion, the 30,000 miles of dedicated "source-to-sink" pipelines could represent an upper estimate of the total CO_2 pipelines that need to be built. However, this configuration has been criticized because it would not reflect the cost efficiencies potentially achievable with networked CO_2 pipeline systems.

Other estimates of CO_2 pipeline needs are based on simple volumetric calculations of oil and its associated infrastructure and conclude that CCS would require roughly the same pipeline infrastructure. While a good starting point, these volumetric comparisons assume the dynamics of oil, which is a valuable commodity for which consumers are willing to pay for shipments over long distances. This is not the case for piped anthropogenic CO_2, especially when billions of tons of CO_2 would need to be stored annually. At these scales, CO_2 is a waste product with zero (or, more than likely, a negative) value. Economics suggest that operators will likely seek to dispose of the CO_2 as close to the source as feasible.

Current CCS systems do not generate net revenues; however, the fact that CCS is serving a public good suggests the need for some type of federal incentive. Section 45Q of the Internal Revenue Code sequestration tax credit provides a subsidy of up to $10 per ton for CO_2-EOR, and $20 per ton for geologic sequestration. The incentive is capped at a total of 75 million MT of CO_2, therefore, the total cost of the credit will vary depending on the method of storage. For instance, if all of the CO_2-EOR is used for CO_2-EOR, then the total cost of the credit would be equal to $750 million. It is estimated that in the US in 2008, 17% (about 9 million MT) of the CO_2 used for EOR came from anthropogenic sources. Existing facilities claimed that Section 45Q of the Internal Revenue Code sequestration tax credit would exhaust the total authorized level of the credit in a little more than eight years. The limited nature of this credit is insufficient to incentivize development of new technologies or infrastructure to help achieve climate change mitigation objectives.

Issues Summary

Large-scale CCS includes a suite of critical enabling technologies for the continued combustion of fossil fuels in a carbon-constrained environment. The oil industry has for several decades been using large-scale underground injection of CO_2-EOR. The key focus of the symposium was assessing the potential of the availability of additional anthropogenic CO_2-EOR as both a value proposition for industry and an opportunity for demonstrating large-scale sequestration for meeting climate change mitigation objectives.

The volume of EOR pore space was a central focus of the discussion, viewed as both an opportunity as well as a limitation by various participants. Hydrocarbon pore volume in current and potential EOR operations is readily available, accessible, and may be significantly larger than typically recognized. New research and field demonstrations have identified the opportunity for EOR in ROZs, geologic formations that historically have not been targets for commercial oil production. The ROZs may have the potential to expand known usable pore volume by orders of magnitude although, given current understanding, there is a high degree of uncertainty about total ROZ capacity.

Another key issue addressed by the participants was the framework that would be needed to transform current CO_2-EOR operations into a viable CCS option. Participants noted that current EOR operations were designed to maximize oil production rather than permanently store CO_2 as environmental waste. It was also noted that data, research, and analysis to support regulations on the permanency and safety of CO_2 injected into hydrocarbon pore space were not complete or comprehensive.

Linking carbon capture, transportation, and CO_2-EOR / CCS activities will require the development of new business models. Alternative models discussed ranged from evolutionary expansion of the current CO_2-EOR business model to the creation of a broad new framework requiring an active governmental role in establishing the vision, leadership, and possible financing of certain activities.

Value sharing between those entities capturing carbon and providing the CO_2 supply (i.e., upstream participants in CCS, e.g., utilities) and those entities acquiring CO_2 for EOR projects (i.e., downstream oil industry participants) was identified as an important issue for the development of a viable business model. Past analyses were discussed which have shown the West Texas CO_2 market to be oligopolistic in nature, current CO_2 sellers influence pricing by controlling supply. A large-scale CO_2 capture program could lead to a situation in which the supply of CO_2 would most likely exceed demand; the rents from CO_2-EOR would accrue to the downstream participants, not the CO_2 suppliers. Sharing of value between suppliers and downstream users is critical to a successful business model. Absent such a scheme, the value proposition of CO_2-EOR may not adequately incentivize power plant owners to capture carbon and supply the downstream market.

Development of a CO_2 transportation network was identified as a critical element to connect the CO_2 sources to potential EOR applications. The design of a transportation network and its implementation and financing were identified as major issues by participants. Linking current CO_2 pipeline segments in a "horseshoe" arrangement could, for example, form the backbone for a national CO_2 pipeline system.

Concern about a regulatory regime for CO_2-EOR was a recurring theme of the symposium. The value proposition of CO_2-EOR depends in large part on the ability of CO_2-EOR operators to comply with any emerging CCS regulatory requirements and to obtain the appropriate carbon credits if and when they become available. Care would need to be taken by those establishing regulations and credit structures to ensure that CO_2-EOR project sponsors are adequately covered in any regulatory or statutory regimes, particularly for early-mover projects that preceded the establishment of the regulations. Otherwise, CO_2-EOR project sponsors could be faced with a potential environmental liability rather than an environmental credit.

The current EOR infrastructure in the Permian Basin in West Texas was discussed as a possible starting point for the evolution of an EOR-CCS program, in large part because of the economic opportunities associated with the potential to substantially increase the producible oil resource base in that region. It is highly unlikely that EOR would enable the recovery of the remaining one-third of oil resources left from conventional production; if this were possible, however, it would create nearly $1 trillion of value. Some participants noted that EOR activities in the Permian Basin benefited from targeted R&D, regulation, and tax subsidies spanning decades. Taking full advantage of the Permian Basin EOR opportunities in the future might entail the need for similar incentives.

Framing of the Issues: Key Findings

Finding: The expansion of EOR programs to increase domestic oil production while simultaneously sequestering CO_2 in hydrocarbon pore volume offers a value proposition that can create wealth, contrasting with the view of geologic sequestration of CO_2 as a waste-disposal activity.

Finding: The magnitude of hydrocarbon pore space available for sequestering CO_2 through EOR operations is significantly greater than generally recognized.

Finding: New research and field experiments have identified the feasibility of EOR developments in partially oil-saturated structures, known as ROZs, that could possibly expand potential hydrocarbon pore space volume by orders of magnitude. There is significant uncertainty surrounding the capacity of these zones, and additional research and analysis are required to fully understand ROZ potential.

Finding: New business models are needed in order to create the necessary linkages between CO_2 sellers (i.e., power plant owners who install carbon capture), CO_2 pipeline transporters, and CO_2-EOR operators. Business arrangements that share the value created by CO_2-EOR opportunity will be an important aspect of any successful business model.

Finding: Establishment of a regulatory framework that enables CO_2-EOR activities to be recognized as a viable carbon sequestration option is essential to realizing the full potential of CO_2-EOR.

Finding: Additional CO_2 pipeline infrastructure will be needed to link anthropogenic CO_2 sources to regions of EOR potential. A smartly designed "source-to-sink" pipeline system could minimize the amount of new pipelines. Even so, up to 30,000 miles of new pipelines, developed over decades, will be needed.

Finding: The public policy purposes associated with EOR-CCS merit consideration for federal policy and financial incentives to overcome the current barriers to widespread commercial deployment. The current volume cap on Section 45Q of the Internal Revenue Code sequestration tax credit is too small to incentivize significant commercial deployment of EOR-CCS.

II. Geosciences Perspective: Understanding the Subsurface

From a technical perspective, the degree to which the subsurface can be characterized both qualitatively and quantitatively will have a major impact on the ultimate success of any CCS project. The geosciences provide the tools for understanding the subsurface and many of these tools (e.g., imaging, reservoir, and fluid modeling) have been highly developed within the oil and gas industry.

While these tools can be applied to any CCS project, their accuracy in resolving and characterizing the subsurface is very dependent on the density of data available to constrain them. EOR projects are high-data-density environments with a number of well penetrations and with monitoring of pressure and fluid flow, as well as iterative modeling of fluid flow through the reservoir that is often complemented by seismic data. The net effect is that, from a geosciences perspective, EOR offers the opportunity to advance both the science and practice of CCS given the data density and long operating history.

In CCS, the geosciences are not independent of other factors affecting a project. In other words, possible (science) and doable (legal/regulatory) do not necessarily mean that a given project is sensible (economic). In the end, for any CCS project, geology matters. Fully understanding and characterizing the geologic environment will be a critical success factor in building the most sensible CCS projects possible.

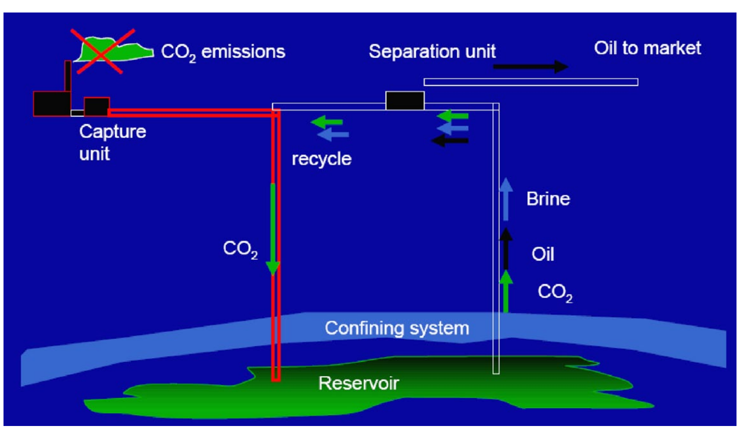
Geoscience and Subsurface Characterization of the EOR Opportunity

CO_2-EOR has been evaluated since the 1950s and full-scale field projects have been in operation since 1972. CO_2-EOR is underway at more than 100 sites in the US (Oil and Gas Journal Enhanced Recovery Survey, 2010) and a lesser number of sites outside the US. In these projects, the geosciences have been critical over the entire project life cycle. Oil companies deployed geologists and geophysicists to find natural sources of pure CO_2 that could be produced and transported to the target oil fields for injection.

Research in the behavior of fluids in porous media led to an early understanding of the characteristics of CO_2 when injected in oil reservoirs highlighting the economic opportunity underlying CO_2-EOR, and the oil industry identified several large candidate fields in West Texas within a reasonable distance of natural sources of pure CO_2 in Colorado. These first large-scale projects established a baseline of experience in CO_2 transportation and handling that is readily transferable to CCS.

CO_2 is placed in the reservoir through injection wells. In most cases, pressure applied via pumping is required to force the CO_2 to the bottom of the well, out through the perforations, and into the pore spaces of the designated injection formation. Typical injection depths for EOR are between 2,500 and 10,000 feet. In the reservoir, CO_2 moves outward away from the injection well in a generally radial manner by entering the brine and/or oil-filled inter-granular or inter-crystalline pores of a generally tabular body of sedimentary rock bounded by an upper confining system that greatly retards vertical movement of the CO_2.

Figure 3 – Schematic of a CO_2-EOR System. Components required for sequestration in brine formations that are in common with CO_2-EOR highlighted in red.



Source: Hovorka

CO_2 will interact with oil and water in the pores and over time periods of months to years, and create a region in which oil saturation and mobility are increased, known as an "oil bank." The flood design places production wells in areas where the "oil bank" is expected to develop. If the flood performs as designed, oil, brine, and CO_2 will enter the production wells through the perforations and will rise or be pumped to the surface. Geometry and timing, in terms of which pores are accessed and the amount of CO_2 that enters them, are controlled by how flood engineering intersects the rock fabric and changing fluid environment. Analytical and geo-cellular flow models are used to make an accurate estimate of how oil is accessed by CO_2. Monitoring techniques, reservoir flow simulation software, and experience in designing CO_2-EOR floods provide the subsurface technical foundation on which confidence in brine sequestration is founded.

To date, CO_2-EOR projects have focused on conventional oil resources that remain trapped in geologic reservoir structures after primary (pressure depletion) and possible secondary (water flood) development. CO_2-EOR currently provides approximately 281,000 BOPD, or about 5%[5] of US crude oil production. This is enabled by the use of some 55 million MT of CO_2 per year from natural (45) and anthropogenic (10) sources[ii]. This is on average, about a third of a metric ton per barrel.

While there are new projects as well as expansions of existing projects in development, the primary barrier to reaching higher levels of CO_2-EOR production is the availability of adequate supplies of affordable CO_2. The volume of oil recoverable in the US using CO_2-EOR ranges from 38 to 126 BBO. This suggests that the MPZs identified for potential CO_2-EOR (conventional hydrocarbon-bearing reservoirs) have the potential to store in the range of 10 to 30 billion MT of CO_2, if they were developed for their EOR potential[iii].

Of growing interest is the potential to significantly expand the CO_2-EOR volume target by including the development of ROZs — saline formations containing a mixture of oil and brine. ROZs can include migration paths for oil in the subsurface, as well as traps that have been breached naturally over geologic time and have been flooded by saline water. ROZs do not represent economic deposits of conventional hydrocarbons and so have not been exploited to date. They had been identified as potential EOR targets more than two decades ago but were never commercially advanced by industry. While much work needs to be done to better characterize the oil production and CO_2 storage potential in ROZs, a DOE/NETL study of a portion of the Permian Basin in West Texas and eastern New Mexico suggests an additional opportunity of 36 BBO of recoverable oil and additional storage capacity of 12 to 18 billion MT of CO_2[iv].

The opportunity for increased oil production from CO_2-EOR greatly outstrips the supply of CO_2 from current, primarily natural CO_2 sources. The volume opportunity in the potential for produced oil could translate into a significant volume opportunity for CCS.

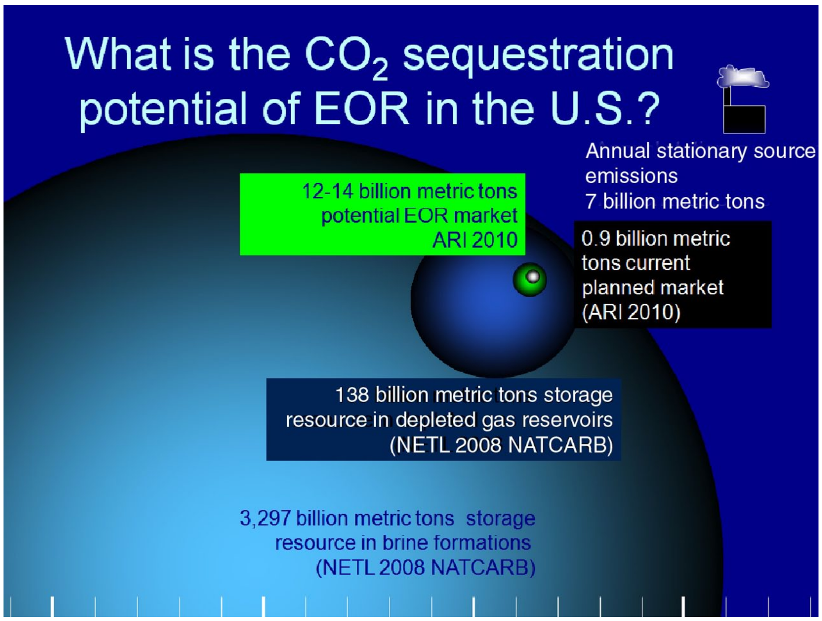
Natural gas reservoirs can also serve as CO_2-EOR targets, but have received less attention. Gas reservoirs may offer storage potential, but may be less attractive than oil reservoirs because gas separation (removing CO_2 from produced natural gas) is expensive and difficult. While gas fields typically have fewer penetrations, which enhances confidence in long-term retention, significant work is necessary to better characterize the subsurface (e.g., volumes, chemistry, value of remaining gas vs. value of pore space).

CO_2-EOR opportunity also exists outside the US (e.g., China), but has not received as much attention, so the potential is currently not well understood.

Subsurface Risk and Uncertainties

The potential pore volume in brine formations dwarfs that of EOR as demonstrated by Figure 4. The potential pore volume in brine formations is estimated to be over 3,000 billion MT of CO_2, while that of EOR is 12 to 14 billion MT. Consequently, if CCS emerges as a significant sustained option to mitigate climate change, then eventually a transition to injection into brine formations will be necessary. The pace at which space or other requirements will force a transition from CCS in conjunction with EOR to CCS in brine formations depends on the magnitude of feasible CO_2-EOR projects, including projects in the ROZ, and the extent to which significant anthropogenic CO_2 becomes available through capture. Another issue is whether CCS proves to be transitional or sustained in the long term.

Figure 4 – US CO_2 Sequestration Potential of EOR



Source: Hovorka

Successful sequestration is dependent on how well the natural geology of the system is able to accept and retain CO_2. Injection processes are designed to interface with these natural systems without damaging or diminishing their function.

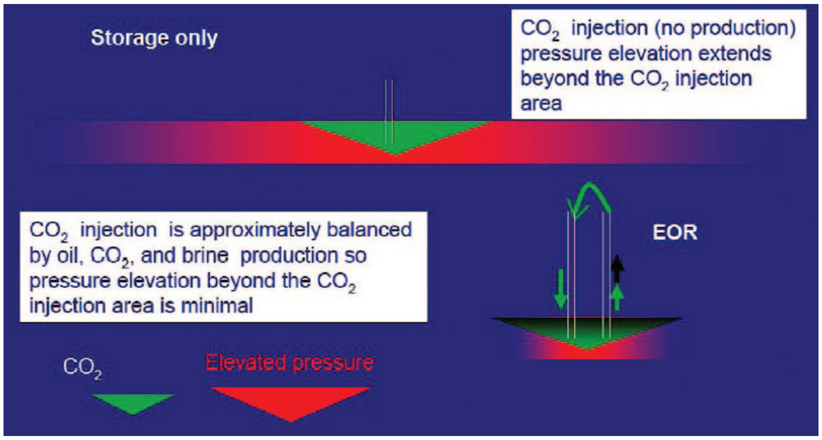
In oil accumulations, the natural confining system called a *reservoir seal* has a well-documented history of retaining buoyant fluids (e.g., oil and natural gas). The seal impedes the upward immigration of these buoyant fluids and, as a result, the trap has retained these fluids over geologic time. This proven retention is in contrast to that of brine formations in which the confinement capacity is only inferred. Retention must be tested by monitoring fluid flow following injection of CO_2. Until this is done, it must be assumed that there is a risk of fluids escaping from the saline aquifer.

Other differences between CO_2-EOR and brine sequestration lie in the ability of the injection zone to accept fluids. In CO_2-EOR, which is often the tertiary stage in oil field development, significant data are available to quantity the fluid flow and characterize the reservoir. Due to the relative abundance of data, field operators are able to develop accurate models that predict the reservoir response to CO_2 injections.

The ability to predict reservoir response to CO_2 injection in brine formations is more uncertain and is considered one of the "main risk factors in brine sequestration projects[v]." Risks are thought to be higher in brine sequestration because sites usually rely on one site to inject large amounts of CO_2. Consequently, site characterization of the sub-regional fluid flow is required to verify that adequate connected pore volume is available to accommodate the injected CO_2 and prevent any significant increases in pressure.

The geo-mechanics of CO_2 storage are very different in terms of the pressure buildup between CCS in brine and EOR. Pressure increases as a function of CO_2 injection rate; the highest pressure occurs around the well bore and decreases with distance. Areas in which the pressure elevation may induce fluid flow into underground sources of drinking water are often referred to as the area of review (AOR). The AOR for large injection brine projects is expected to be large as is shown in Figure 5. As a result, in the absence of large permeable areas, the pressure buildup in brine is limited by the injectivity rather than by the available pore space. Some projects are considering brine withdrawal and disposal to alleviate the pressure buildup.

Figure 5 – Comparison of Pressure Propagation Away from Brine Sequestration and EOR



Source: Hovorka

In contrast to the long-term pressure buildup in brine, EOR projects are characterized by a pressure-controlled operation. Pressure management is inherent in the operation of an EOR project. Production of oil is often accompanied by water and brine, and in some instances brine is recycled and injected back into the reservoir to maintain miscibility pressure.[vi] Due to the different patterns of pressure buildup in brine formations, CO_2 sequestration projects in brine risk premature termination due to the unexpected elevation of the AOR into undesirable areas. As a result, only a small amount of the total pore volume is utilized.

Table 1 – Comparison of Risk Elements for Sequestration of CO_2 in Brine Formations with Those for CO_2-EOR

Risk Element	Sequestration in Brine Formation	CO_2-EOR
Well operations	CO_2 injection (possible brine production)	CO_2 injection plus oil, brine, CO_2 production, with recycle
AOR	Large areas of pressure elevation	Active pressure control through production, smaller magnitude pressure increase, and smaller area of elevated pressure
Injection-zone performance in accepting fluids	Inferred from sparse well data and relatively short duration hydrologic tests	Well known; many wells and extensive fluid production history with information on how the reservoir responded
Confining system performance	Inferred	Demonstrated
Structural or stratigraphic trapping	May or may not be part of system	Demonstrated
Dissolution of CO_2 into fluids	Moderate	High
Wells that penetrate the confining system	Usually sparse	Usually dense
Financial support for injection	All costs	Costs plus revenue from oil production
Permitting and pore-space ownership	Evolving; state-dependent; and uncertain, between water law and mineral law	Historic frameworks for secondary and tertiary recovery are well known
Public acceptance	Uncertain	Relatively good because value of royalties, fees for surface access, and jobs are recognized in host communities

Source: Hovorka

The geosciences affect all of these risks, whether under consideration are the obvious concerns about the nature of the confining system, or how well the subsurface understanding can be translated into public acceptance. Currently, geologic understanding, regulatory framework, and public acceptance give CO_2-EOR advantages over CO_2 injection in saline formations. Many of these advantages are rooted in a long operating history and an economic model in which the entire system not only stores CO_2 but also creates business value in its own right.

To maximize and protect this value, the oil industry has instrumented CO_2-EOR projects to gather significant data on the underground movement of fluids. Specifically, CO_2-EOR is conducted in environments in which trapping of buoyant fluids over geologic time has been demonstrated; the pore space and chemical reactions are reasonably well understood; pressure and fluid flow have been monitored; and the geologic understanding has been coupled to a legal and regulatory framework.

The disadvantage to CO_2-EOR for permanent sequestration is that competent reservoir seals have been penetrated by a number of wells that now offer potential leak points to return CO_2 to the surface. The wells themselves, however, form a large part of the dense data network available in CO_2-EOR reservoirs that makes it possible to understand and characterize the geosciences risks and uncertainties. While it appears that the flow of CO_2 in the subsurface can be managed and controlled, symposium participants generally agreed that the permanence of storage has not been demonstrated. Work is proceeding by entities such as the Texas Bureau of Economic Geology to develop a framework for testing and monitoring permanence of storage.

Many people assume all oil fields are amenable to CO_2 sequestration. However, from an industry perspective, only certain reservoirs containing medium gravity, viscous crude are chosen for CO_2-EOR projects because competing technologies (e.g., steam-flooding or polymer floods) are more economic if the CO_2 supply is limited. Also, CO_2-EOR is not economical in all reservoirs. For the oil industry, estimating how much CO_2 can be sequestered through EOR requires characterizing the reservoir's suitability. This must be done on a field-by-field basis, by building reservoir simulation models that consider many parameters of the field (depth, temperature, reservoir characteristics) as well as properties of the fluids in the reservoir.

The introduction of CO_2 sequestration into the equation substantially changes the calculus and economics of EOR. Large supplies of CO_2 enable a broader selection of potential CO_2-EOR projects, including injection into both deep and heavy oil reservoirs that typically are not targets for EOR projects. To extend the oil industry's knowledge to full-scale CO_2-EOR sequestration, also needed are more robust economic models that better characterize the subsurface risks and uncertainties. What is particularly needed are system-level models in which CO_2 sources are linked to potential storage volume with a full analysis of both costs (e.g., capture and transportation cost for anthropogenic CO_2) and opportunities (e.g., value of incremental produced oil). A complete life cycle estimate of net CO_2 sequestration requires a more complete modeling of the CO_2 cycle to account not only for the carbon stored away in old or depleted oil fields, but also for the incremental carbon that is released by combustion of the produced oil from a new CO_2-EOR project.

The general view of symposium participants was that EOR offers financial incentives needed to explore CCS in the near term and to more fully understand the uncertainties, particularly geologic, of trying to permanently store large volumes of CO_2 in the subsurface. This expansion of the knowledge base will likely lead to a more robust set of potential reservoirs for underground storage in the future that includes oil MPZs as in current CO_2-EOR, as well as ROZs, and ultimately into saline aquifers.

Additional subsurface studies are necessary to establish the proper baseline of data needed to address subsurface uncertainty, including (but certainly not limited to) detection and monitoring of plume migration and understanding the very long-term competence of well completion technologies. It will also be important to consider the geo-mechanical issues of pressure buildup and pressure management. It is possible that, due to issues of pressure management, CCS potential could be, in some cases, limited by injectivity rather than pore space. The learning curve on many of these issues will take decades. EOR has the potential to provide the long-term economic incentive for these studies that may ultimately provide the knowledge necessary for full-scale development of CCS into saline aquifers.

Issues Summary

From a technical perspective, the degree to which the subsurface can be characterized both qualitatively and quantitatively will have major impacts on the ultimate success of any EOR-CCS project. The geosciences provide the tools for understanding the subsurface. Many of these tools (e.g., imaging, reservoir, and fluid modeling) have been highly developed by the oil and gas industry.

While these tools can be applied to any EOR-CCS project, their accuracy in resolving and characterizing the subsurface is directly proportional to the density of available data. CO_2-EOR projects are high-data-density environments with a number of well penetrations and production records that contain information on pressure and fluid flow, as well as iterative modeling of fluid flow through the reservoir, often complemented by seismic data. In short, from the perspective of the geosciences, the long operating history and data density associated with CO_2-EOR provides an opportunity to advance both the science and practice of EOR-CCS.

There is an established base of geoscience information for EOR reservoirs that does not exist for DSFs. There is direct evidence — oil confined over geologically significant time — of the quality of the confining system (cap rock) of an EOR project, a property that can only be inferred in a saline formation. In addition, the storage volume (exclusive of ROZ volumes) and injection rate of an EOR field is well known; in saline formations, these key properties must be measured and extrapolated over the planned storage area.

EOR projects already provide substantial experience useful for monitoring CO_2 injection and movement in the subsurface. Economic incentives for more robust demonstration of storage in EOR can test the effectiveness of monitoring approaches and provide data for assessing subsurface storage risks. However, at a decadal time frame for EOR projects, direct measurements of permanence are difficult or impossible to make with adequate precision to assure performance over centuries. Making long-term projections (centuries plus) requires indirect methods such as models and comparison to analogous natural systems.

Understanding the geoscience issues associated with the subsurface behavior of large-scale CO_2 injection — plume size at expected injection rates for both EOR and saline aquifer injection, for example — is critical to advancing understanding of and confidence in CCS as a climate mitigation measure. Fully instrumented and monitored CCS demonstration projects can be linked to EOR in order to accelerate experience gains and provide data at scale.

Coincidence of sedimentary formations of suitable depth for brine sequestration in DSFs with hydrocarbon basins and stationary CO_2 sources suggests that much US brine-formation storage could be accessed through infrastructure developed for CO_2-EOR using the stacked-storage concept. Additional screening to determine which reservoirs are economically accessible for EOR and how much pipeline construction would be motivated by EOR has not been undertaken.

Geosciences: Key Findings

Finding: There currently exists a wealth of information and experience, including massive data sets, on CO_2 injection for EOR projects. This information on CO_2-EOR is held by the oil industry. There is a need to determine how to share this information to educate the public and advance understanding of and confidence in EOR-CCS.

Finding: The potential pore volume available for CO_2 injection into DSFs (i.e., brine) is several orders of magnitude greater than for EOR. However, much less is known about the geoscience of CO_2 injection into DSFs, and there may be increased challenges associated with pressure management and confinement.

Finding: Because the economics, incentive tests, and measurements in EOR projects are much more practical than in "greenfield" DSFs. Acquiring these kinds of data for a "greenfield" brine project will be expensive and time consuming. EOR provides the dense data needed to test tools, methodologies, and long-term monitoring.

Finding: Subsurface monitoring to determine the permanence of CO_2 injection will be critical in any carbon regulatory scheme. Mass balances may be too simplistic. There are many different monitoring techniques that need to be integrated, but all require some pre-injection baseline to fully understand the movement of CO_2 in the subsurface.

Finding: CO_2-EOR projects can accelerate CCS demonstration and serve as the test bed for understanding geoscience issues and increasing confidence in the correctness of monitoring and modeling.

III. Implementation of EOR for the Purpose of CCS

The key focus of the symposium was assessing the potential of the availability of additional anthropogenic CO_2 for EOR as both a value proposition for industry *and* an opportunity for demonstrating large-scale sequestration to meet climate change mitigation objectives. Several participants thought that CO_2-EOR could accommodate anthropogenic CO_2 up to the year 2050. The factor that was often mentioned as the limiting factor in the further development of CO_2-EOR was the lack of CO_2 supply.

Current CO_2-EOR Activity

CO_2-EOR operations date back to the early 1970s and, as a result, the industry has extensive technical experience in terms of transporting, injecting, and storing CO_2.

As of July 2010, there were 129 CO_2-EOR projects operating around the world, 114 of which were in North America.[vii] The incremental US oil production from these projects was equal to 281,000 BOPD (about 5% of the total US crude oil production) with approximately 60% of this incremental oil production coming from the Permian Basin. Current CO_2-EOR operations use and store between 0.26 and 0.32 MT of CO_2/bbl produced.[viii] This CO_2 remains in the pore space vacated by the oil. The storage potential varies depending on how the operation is optimized; CO_2-EOR currently is practiced to optimize oil recovery although some operations, e.g., Weyburn, are capturing CO_2 as GHG emissions mitigation measures.

Figure 6 – Current US CO_2-EOR Activity

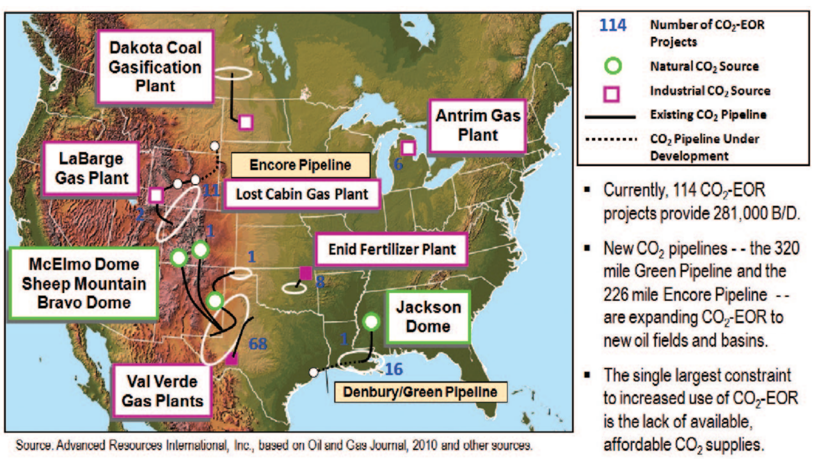
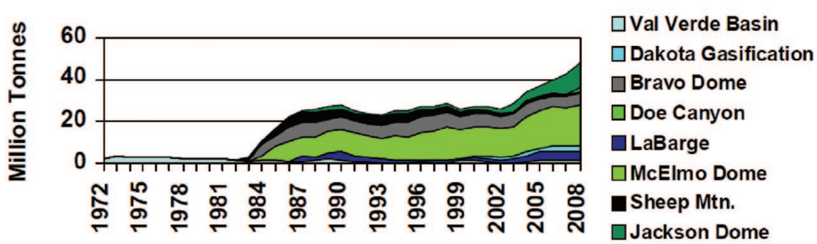


Figure 7 – Anthropogenic and Natural CO_2 Sources Used in EOR Activities



Source: General Technical Support Document for Injection and Geologic Sequestration of Carbon Dioxide

Natural sources of CO_2 account for approximately 81% (45 million MT) of the CO_2 currently injected into EOR projects.[ix] The remaining 19% (10 million MT) are supplied by anthropogenic sources such as the gas processing plants in West Texas and Wyoming and the coal gasification plant in North Dakota. According to industry experts at the symposium, natural supplies of CO_2 are declining; if EOR is to be maximized, anthropogenic sources of CO_2 for CCS are needed. Figure 7 breaks down the CO_2 supply used in EOR by source. Sheep Mountain and Bravo natural domes are witnessing production declines; others are relatively flat.

CO_2-EOR Potential

A recent assessment of the storage capacity in the MPZs by Advanced Resources International (ARI) estimated that the *technically* recoverable oil potential when utilizing today's state-of-the-art technology[6] would be equal to 81 BBO and 126 BBO with next-generation technology.[x] The *economically* recoverable oil, which was calculated using an oil price of $70/bbl, CO_2 cost of $45/MT, and a 15% rate of return, was equal to 38 BBO under state-of-the-art technology and 58 BBO under next-generation technology. A similar calculation for the CO_2 storage capacity was made by estimating the number of 1-GW coal power plants[7] that could provide the estimated CO_2 required for EOR operations, assuming a 30-year operating life. The results are summarized in Table 2 below.

Table 2 – Volume of CO_2 Storage with CO_2-EOR in MPZ

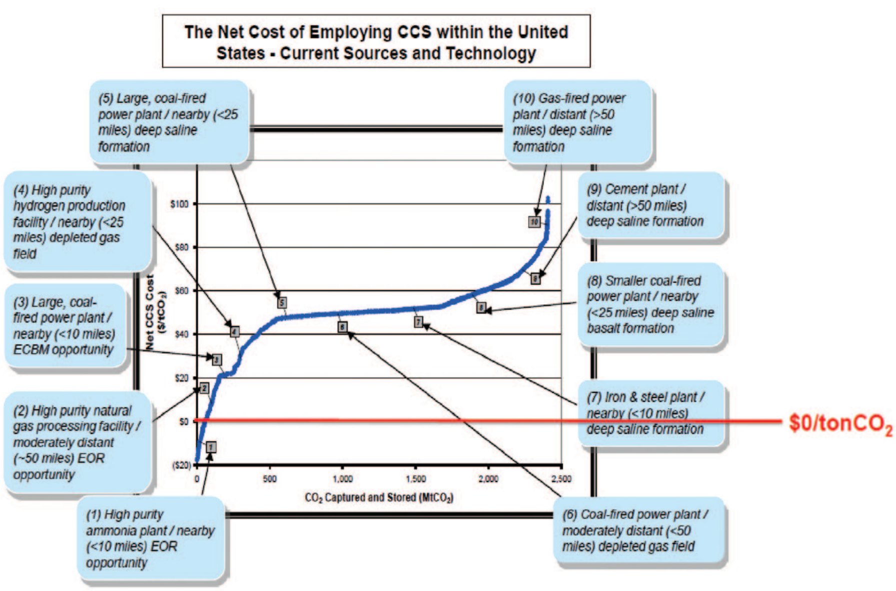
	State of the Art	Next Generation
Technically Recoverable (BBO)	81	126
Economically Recoverable (BBO)	38	58
Number of 1-GW Size Coal-Fired Power Plants needed to support technically recoverable EOR	94	156
Number of 1-GW Size Coal-Fired Power Plants needed to support economically recoverable EOR	56	67

Source: Kuuskraa

Anthropogenic CO_2 Supply

The potential supply of CO_2 from anthropogenic sources more than meets the demand for CO_2 for potential EOR production. Papers submitted for the MITEI symposium on the *Retrofitting of Existing Coal-Fired Power Plants* concluded that a maximum of 59% (184 GW) of the generation capacity of the existing US coal-fired power plant fleet are appropriate candidates for CCS retrofits; taking into account potential plant-specific and location constraints and limitations reduces this potential to about 20% of the fleet, or around 61 GW of coal-fired generation technically and economically suitable for retrofitting.[xi]

Figure 8 – The Net Cost of Employing CCS within the US, Current Sources and Technology



Source: James Dooley presentation at the July 23, 2010, MITEI symposium.

While the potential supply of anthropogenic CO_2 from coal power plants, even with conservative assumptions, is large, the cost of CO_2 from power plants is at the upper end of the cost curve of potential anthropogenic CO_2 supply options. As shown by the cost curve in Figure 8, approximately 50 million MT of CO_2 can be captured and stored at a net negative cost; around 500 million MT can be captured, transported, and sequestered at below \$40/MT of CO_2. The least expensive opportunities seen in Figure 8 are for CO_2 captured from high purity sources with EOR potential or activities within a 50-mile radius of the CO_2 source.

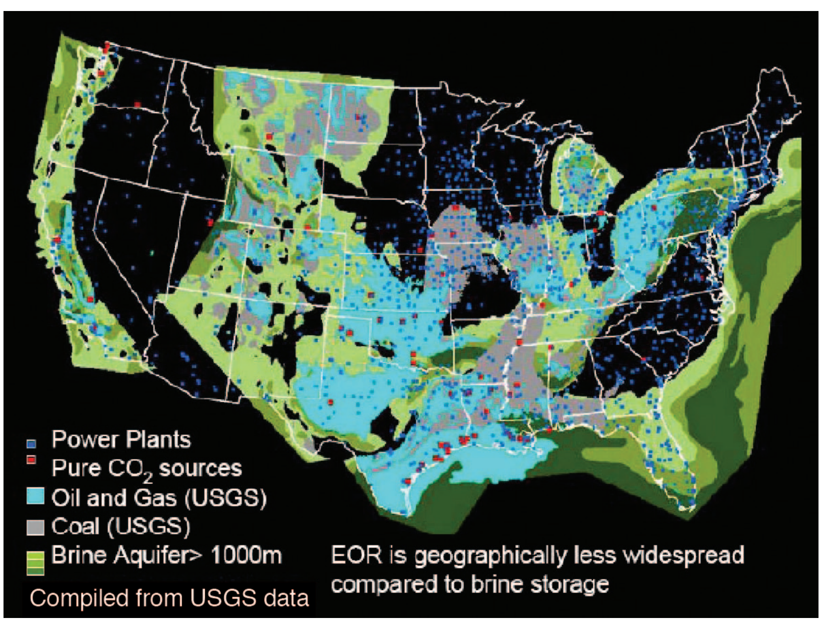
High purity sources of CO_2 such as gas processing and ammonia plants represent least cost suppliers of CO_2 for EOR projects. Capture costs from ammonia plants are in the neighborhood of \$0.55 to \$0.60/thousand cubic feet (Mcf). Other relatively pure CO_2 sources include ethanol plants; however, due to the low volume of CO_2 produced, they are less attractive candidate sources for large-scale EOR operations. Another feasible CO_2 candidate supply source is coal gasification facilities, which have estimated capture costs that are competitive with ammonia plants. Other CO_2 sources include capturing emissions from fertilizer and gas plants which have capture costs in the range of \$1.25 to \$1.55/Mcf. Coal-based electricity generating facilities lie at the upper end of the supply curve due to current relatively high estimated cost for carbon capture. When anthropogenic sources are compared to natural sources of CO_2 such as the Jackson Dome, which costs \$0.20/Mcf, it is evident that most of the anthropogenic sources are not currently cost competitive.

Feasibility of Matching Anthropogenic CO_2 Sources with Large EOR Opportunities

As the distance increases, so does the capital cost for laying more pipeline and the operating cost for compressing and transporting the CO_2 across larger distances. The Intergovernmental Panel on Climate Change (IPCC) report on CCS estimated the cost of transporting one ton of CO_2 over a distance of 100 km in the range of \$1 to \$8[xii] depending on the type of terrain. It is thought that high purity sources within a reasonable radius (100 miles) of an oil field will be the first choice for CO_2-EOR. The International Energy Agency (IEA) Greenhouse Gas R&D Programme surveyed high purity sources of CO_2 (40% CO_2 concentration) within a 100-mile radius of an EOR potential site and found 62 candidates that matched the criteria[xiii]. Some sources were within range of more than one oil field, creating a total of 329 options for high purity sources matched to EOR candidate fields.

Figure 9 depicts existing oil fields and large CO_2 sources from power plants in the US. The Electricity Reliability Council of Texas (ERCOT) has large oil fields that are amenable to CO_2-EOR as well as a large CO_2 supply (100 million metric tons of CO_2 per year). By comparison, areas in the Ohio River Valley represented by the East Central Area Reliability Coordination Agreement (ECAR) release more than 500 million metric tons of CO_2 per year but have limited EOR potential.

Figure 9 – Coincidence of Sedimentary Formations of Suitable Depth for Brine Sequestration with Hydrocarbon Basins and Stationary CO_2 Sources

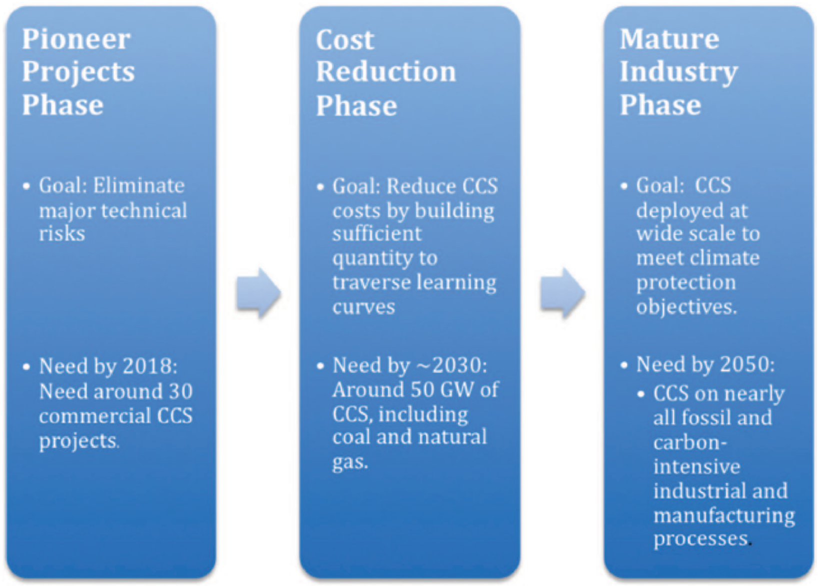


Source: Hovorka

Detailed breakdowns of the potential CO_2 sources and CO_2-EOR potential up to year 2030 are shown in Table 3. The CO_2 supply is based on the modeling analysis conducted by ARI for the Natural Resources Defense Council (NRDC) using the Energy Information Administration (EIA) National Energy Modeling System (NEMS) electricity market model. The analysis shows CCS deployment in 13 US regions based on the implementation of the provisions of the American Clean Energy and Security Act (ACES) passed by the House of Representatives in 2009.

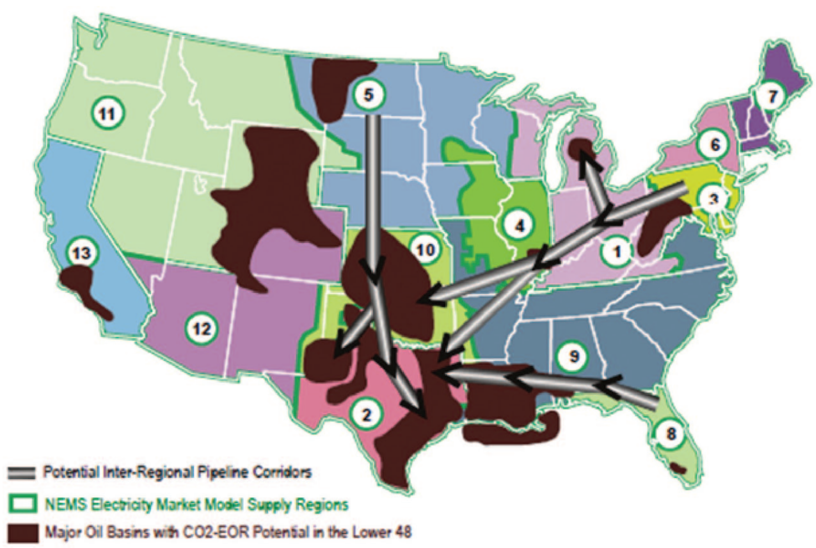
A strategy for the development of a commercial CO_2-EOR industry is illustrated. Initially, incentives will be needed to kick-start early demonstration projects for retrofitting coal power plants and integrating CCS into new coal and natural gas power plants as is shown in Table 3. The crucial first step is establishing the early demonstration or "pioneering phase" in CCS which involves the development of full-scale CO_2 capture demonstrations to determine feasibility, costs, environmental impacts, reservoir impacts, etc., and inform the development of regulatory structures. Participants noted that government incentives will be needed to kick-start the early demonstration projects. Participants discussed the need for up to 30 projects, each of 500 megawatt (MW) scale, in the "pioneering phase." These projects could rely predominately on EOR storage, leveraging the existing infrastructure.

Figure 10 – Possible Phases for CCS Development and Deployment



Source: John Thompson presentation

Figure 11 – Possible Way the US CO_2 Capture/Transport/Storage Could Evolve



Source: Kuuskraa presentation

Using the estimates from the NEMS modeling analysis, ARI examined the possible flow of the captured CO_2 and the oil basins. For instance, the East/Central Texas market for CO_2-EOR is estimated at 1,940 million MT of CO_2 up to 2030; however, the CO_2 supply from that region (ERCOT) over the same time period is only equal to 110 million MT of CO_2. Conversely, the CO_2 supply in the ECAR region is equal to 670 million MT of CO_2 and far exceeds the market for CO_2 in that region which is equal to 130 million MT. If the CO_2 supplied by the ECAR region were integrated into an EOR project, an interstate pipeline would be needed to connect the ECAR region to the more abundant MPZs and possibly ROZs in the Mid-continent part of the US. If the remainder of the CO_2 were to be moved into oil regions as proposed by the ARI study, then a more extensive CO_2 pipeline network would be required as shown in Figure 11.

The ARI study analyzes the technical potential for CCS deployment based on the provisions contained in the House-passed ACES legislation. These estimates would need to be refined to reflect that a significant percentage of the existing US coal-fired power generation fleet is not amenable to retrofitting for capture of CO_2. Industrial sources of CO_2, such as ethanol plants, could provide additional sources of CO_2 supply, but the low pressure of the CO_2 and the relatively limited quantities of the captured CO_2 do not match the operational requirements of EOR operators.

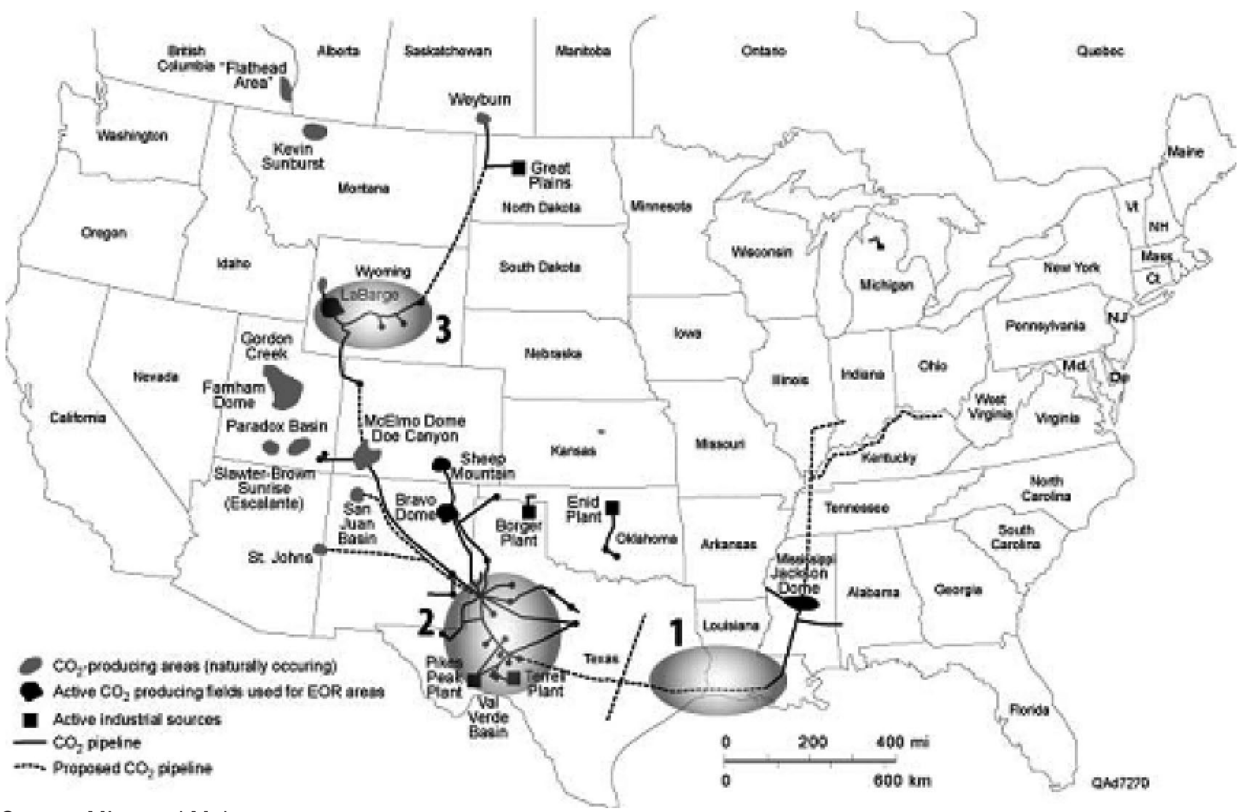
On the sink side, there are similar restrictions that diminish the size of the technical potential EOR opportunities. Currently, there are a limited number of existing EOR fields of substantial size — those that can accommodate at least 1 million MT of CO_2 per year. As such, there is a need for the integration of several smaller oil fields in close proximity of one another to handle the CO_2 emissions from a large CO_2 source. In these instances, implementation of sequestration in DSFs would provide an important supplement in improving the operational feasibility of EOR projects.

Continental-Scale CO_2 Pipeline Network Requirements

The analyses of the scale of the CO_2-EOR opportunity that would be created by the ACES legislation would require new, continental-scale pipeline infrastructure to connect the CO_2 sources to the sinks. Some participants advocated direct public intervention in the development of the necessary infrastructure and proposed a type of hybrid model for funding. The model would combine some of the lessons learned in building the transcontinental railroad system and the development of the unconventional natural gas pipeline system.

Leadership was deemed essential, a characteristic that was critical to the building of the transcontinental railroad, which offers parallels in scale of the project, risk levels, and the involvement of the private markets. The development of unconventional natural gas "piggy backed" on the

Figure 12 – A Framework Depiction of a National CO_2 Pipeline Network ("The Horseshoe"). The shaded ellipses represent three areas where very large EOR/CSS projects are active or proposed.



Source: Ming and Melzer

infrastructure built for conventional gas; the overlap of resource locations for conventional and unconventional gas resources is somewhat analogous to the current co-location of MPZs and ROZs. According to several of the participants, the exploitation of ROZs is only a matter of technology and investment.

Participants discussed a hybrid of both models as a possible avenue for developing a national CO_2-EOR sequestration program. Some components of such a program would have to be built from scratch such as the measurement and verification procedures as well as the new pipelines, analogous to the ground-level development of the railroad system. The experience with the development of unconventional natural gas offers an analogy in terms of leveraging the existing EOR infrastructure and tapping into the subsurface fluid flow expertise of the oil and gas industry.

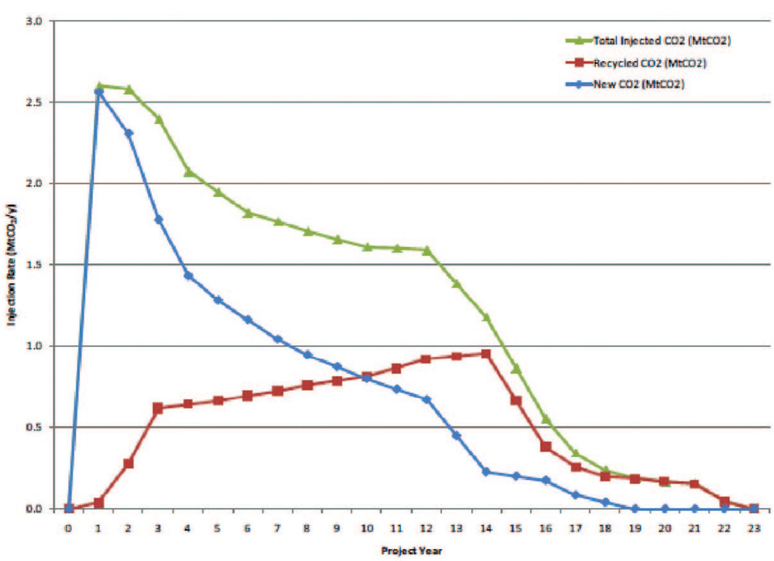
These new pipelines and distribution networks could be financed through a quasi-governmental agency by the issuance of climate change bonds. Significant CO_2 pipeline networks already exist in West Texas and these segments can provide the foundation for the further expansion of the network that will connect the anthropogenic sources of CO_2 to the geologically well-characterized EOR oil basins, both MPZs and ROZs. At later stages, the network could be used to transport the captured CO_2 into the depleted natural CO_2 domes. The resulting infrastructure was described as "the Horseshoe" pipeline concept, as seen in Figure 12. The national pipeline would be constructed by filling in the gaps as shown by the dotted lines; according to the participants, the most important piece in this network would be the connection between East and West Texas. The shaded areas in Figure 12 represent the areas of large CO_2-EOR projects.

Finally, it was argued that establishing the pipeline connection between the source and the sink would expand demand for captured anthropogenic CO_2 and would incentivize the research needed to achieve a multifold reduction in the cost of capture. Thus, the availability of pipeline capacity could facilitate the breakthrough of the "chicken and egg" problem.

CO_2 Storage in DSFs as a Complement to CO_2-EOR

CO_2 supplies from various sources will be available at rates and times that differ from the CO_2 injection patterns in EOR projects on both a short-term basis (daily) and on a more long-term basis (years). A coal-fired power plant operating in base load service will emit a very significant and almost constant amount of CO_2 year round. By comparison, an EOR project might have a fluctuating demand for CO_2 due to operational limitations such as periodic shutdowns for maintenance work. Furthermore, as the EOR project progresses, increased amounts of CO_2 are recycled from production operations. As a result, the amount of virgin CO_2 decreases as the project progresses as shown in Figure 13. Due to these operational mismatches, participants expressed the need for backup storage in DSFs to ensure the long-term success of a CO_2-EOR / CCS project. As seen in Figure 8 earlier, there is some overlap between oil basins and DSFs; however, a thorough evaluation of the coincidence of oil basins with DSFs is needed.

Figure 13 – Annual CO_2 Injection Rates by Year



(Davidson et al., 2010 forthcoming; after Jarrell et al., 2002)

The economics of the CO_2-EOR business are driven by the price of oil. An analysis (Leach et al. 2009) of CO_2-EOR economics shows that oil production from EOR projects is highly inelastic to the cost of CO_2, but highly responsive to oil prices. The high uncertainty in the price of oil translates to a high uncertainty in the EOR potential. Having saline storage as backup will help minimize this volatility when, for example, an EOR operation is shut-in because of falling oil prices.

Value Proposition of CO_2-EOR as a Means to Sequestering CO_2

The CO_2-EOR business model for CO_2 sequestration offers three principal benefits relative to a business model based on geologic sequestration in DSFs: economic value, reduced geologic footprint (due to greater pore volume density), and potential for regulatory acceptance.

Economic Value: CO_2-EOR offers a value proposition that can provide several revenue streams:

- A revenue stream that would accrue to the CO_2 supplier can help offset some of the capture costs for the CO_2 producers;
- A revenue stream that would accrue to the local or federal governments from the royalties and taxes on the produced oil; and
- Revenue from increased employment and equipments sales in the EOR industry.

In addition, the presence of existing infrastructure, such as injection and production wells, makes existing sites more favorable than "greenfield" sites in terms of CCS costs. This is very relevant since the capital investment required for storage infrastructure (production and injection wells, other surface facilities) exceeds the capital costs needed for transportation, compression, or capture infrastructure.[xiv] Improving the economics of CCS could facilitate acceleration of deployment of carbon capture projects.

Finally, using CO_2-EOR as a means to sequester carbon would likely increase the US domestic oil production. According to the analysis provided by the white paper presented on behalf of ARI, EOR has the potential to boost US oil production by as much as three million BOPD by 2030 if adequate supplies of CO_2 are available and affordable. Depending on the degree of substitution between domestic oil production and imported oil, an increase in oil from CO_2-EOR would likely help reduce US oil imports and improve the US trade balance.

Smaller Geologic Footprint: The second advantage of the CO_2-EOR model is the superiority of the known confinement properties in pore volumes. For saline formations, it is conservatively estimated that only 1% to 4% of the pore volume is utilized for geologic sequestration capacity. As described more fully in the Geosciences discussion, pressure increase and/or unacceptable migration of connate saline brine may limit the volume injected.

In contrast, EOR has a higher storage density because production limits pressure buildup. In the structural closure and area of reduced pressure associated with EOR, up to 40% to 60% of pore space may be utilized. For example, the CO_2 plume from a 1-GW plant over 30 years would occupy an area of 200 square miles of a DSF (using 4% geologic efficiency, 20% porosity, and 200 feet of net pay).[xv] Using EOR pore space to confine the same CO_2 plume would require 20 square miles (40% of the pore volume is used), and with next-generation technology, the area could be closer to 10 square miles.

Ease of Regulatory and Public Acceptance: CO_2-EOR projects could help accelerate regulatory acceptance of geologic sequestration as well as establish a technical basis that could extend to sequestration in DSFs. CO_2-EOR already employs significant monitoring practices. In CO_2-EOR, significant data collection and monitoring of prospective CO_2 floods are done to set expectations. Once the CO_2 flooding commences, monitoring of the injected and produced fluids as well as the reservoir pressure is periodically measured. Since monitoring practices are essential to the success of a CCS program, existing EOR monitoring practices can be modified according to regulatory requirements and hence meet the legal requirements of CO_2 storage.

It is likely that public acceptance of CCS will be more easily obtained in legacy areas, where local populations are accustomed to CO_2 injection as well as the presence of pipelines, trucks, etc., from previous oil and natural gas exploration and production activities.

Accelerating the Implementation of CO^2-EOR Projects

Several participants noted that CO_2-EOR as a CCS option has many favorable features that may not be realized without incentives. According to the MIT *Future of Natural Gas Interim Report*, under a scenario where CO_2 emissions from developed nations are reduced 50% by mid-century and from developing nations by 2070, existing coal generating capacity would be driven out of the US power sector by around 2035 because the cost of CCS retrofits is too expensive relative to alternatives for electricity such as demand reduction and alternative generation options with low or no carbon emissions. If full de-carbonization of the electricity sector is a goal, and if CCS were to play a significant role in this process, incentives need to be put in place to establish affordable CCS as an option for coal generation, and eventually for natural gas power generation as well.

Table 3 – Proposed DOE Funded CCS Demonstration Projects

Company	Location	DOE Support (million $)	Size	Technology	Fate
FutureGen	Matton, IL	1,000	275 MW >1 million MT CO_2/yr	IGCC	Saline Formation
Basin Electric	Beulah, ND	100	120 MW 1 million MT CO_2/yr	PCC HTC PurEnergy	EOR
Hydrogen Energy	Kern County, CA	308	390 MW 2 million MT CO_2/yr	IGCC Coal/PetCoke	EOR
AEP	New Haven, WV	334	235 MW 1.5 million MT CO_2/yr	PCC Chilled Ammonia	Saline Formation
NRG Energy	Parish Plant Thompsons, TX	167	60 MW 0.4 million MT CO_2/yr	PCC Fluor	EOR
Summit Energy	Midland-Odessa, TX	350	400 MW 2.7 million MT CO_2/yr	IGCC	EOR
Southern	Kemper County, MS	293	524 MW 3.4 million MT CO_2/yr	IGCC Transport Reactor	EOR
Leucadia Energy	Lake Charles, LA	260	4.5 million MT CO_2/yr	New Methanol Plant	EOR
Air Products & Chemicals	Port Arthur, TX	253	1 million MT CO_2/yr	Existing Steam Methane Reformers	EOR
Archer Daniels Midland	Dacatur, IL	99	1 million MT CO_2/yr	Existing Ethanol Plant	Saline Formation

Source: Howard Herzog presentation.

There are currently 10 CCS projects in various stages of development in the US. Of this total, seven will utilize EOR-CCS. The three projects using carbon sequestration in DSFs, the AEP Mountaineer Project in New Haven, WV, the Archer Daniels Midland ethanol project in Decatur, IL, and the FutureGen project in Mattoon, IL, are located on top of DSFs and do not currently have pipeline infrastructure connection to EOR fields. The complete list of current pioneer-phase CCS projects is shown in Table 3.

Table 4 – Comparison of Estimates of Anthropogenic CO_2 Capture under Proposed Cap-and-Trade Legislation with Potential EOR Uses

CO_2-EOR Oil Basin	"Best Practices" Cumulative CO_2 Market for CO_2-EOR (Lower-48 Onshore) (million MT)	NEMS Electricity Market Model Supply Region	Cumulative Volume of CO_2 Supply (million MT)
Gulf Coast (AL, FL, MS, LA)	650	SERC	650
Texas East/Central	1,940	SERC ECAR MACC ERCOT FRCC	290 540 400 110 70 1,410
Williston (MT, ND, SD)	130	MAPP	130
Illinois/Michigan	130	ECAR	130
Appalachia (WV, OH, KY, PA)	40	MACC	40
Midcontinent	1,420	MAPP SPP MAIN	100 120 100 320
California	1,380	WECC-CA	30
Permian (WTX, NM)	2,140		
Rockies (CO, UT, WY)	500	WECC-RM/SW WECC-NW	20 10 30
Louisiana Offshore	1,370		
?		NPCC-NY	100
Total	9,700		2,840

Source: Advanced Resource, Inc. March 2010

The "learning by doing" achieved in the pioneering phase would then lead to additional innovation and cost reduction. If successful, the CO_2-EOR industry would evolve into a mature, commercially viable enterprise on a national scale.

Ultimate commercial viability will depend on the establishment of a price on carbon. Government incentives would be required along the way, although the financial viability of the CO_2-EOR business would minimize the magnitude of such incentives. The ARI white paper proposed that the incremental incentives needed for large-scale commercial deployment of CO_2-EOR could be funded by tapping 5% of the incremental tax revenues generated from the additional oil produced during the CO_2-EOR operations. The first 20 GWs of generating facilities outfitted with CCS would receive $2.5 billion/GW and the next 52 GWs would receive $2 billion/GW. This would translate into the deployment of 13 GWs of coal-fired power plants with CCS and an additional 56 GW by 2030.

Contractual Agreements Needed for CO_2-EOR Projects

Contractual arrangements and structures were identified as key elements of successful projects. Participants discussed three possible types of contractual arrangements between the various parties involved in a CO_2-EOR:

- Arms-length agreements in which the owner of the captured CO_2 would sell it to the EOR field operator and, in the process, transfer the costs and the liability for storing the CO_2.

- Joint-venture arrangements between the supplier of the CO_2 and the EOR field operator. In this case, both parties share the profits, costs, and risks. The current proposals between KinderMorgan and several oil field operators move in this direction. However, due to the complexities of implementing such a contractual agreement, this type of arrangement has been limited.

- "Single integrated party entity" arrangement in which the EOR oil field operator also is the owner of a CO_2 source (e.g., gas processing plant). In this case, all of the profits, costs, and risks accrue to a single entity.

One participant engaged in construction of a gasification plant indicated that the project would not proceed with capture without a long-term contract for the off-take of CO_2 as a means for reducing overall project costs.

Issues Summary

A recurring theme of the symposium was that widespread adoption of CCS as a matter of public policy would accelerate the implementation of CO_2-EOR. Some participants thought that the potential for sequestration in conjunction with EOR activities was sufficient to meet CO_2 storage needs through 2050. Other systematic estimates expressed were much more conservative. Some noted that the lack of CO_2 supplies could actually restrict additional CO_2-EOR development.

Participants discussed analysis of the economic potential of CO_2-EOR in the MPZs, which suggested that there is sufficient capacity in the EOR sector to sequester CO_2 supplies from 57 1-GW coal-fired power plants for 30 years. Estimates were even greater when the pore volume in the ROZs is included, although the understanding of these zones is limited. While the resource potential is yet to be quantified, an assessment by the DOE/NETL of the ROZs in the Permian Basin determined that an additional 12 to 18 GT of CO_2 storage capacity exists in the ROZs, compared to 6.4 GT storage capacity in MPZs.

There is a geographic mismatch between some of the existing anthropogenic CO_2 sources and the oil basins. To fully integrate the potential CO_2 supply from these sources into the EOR projects, an extensive pipeline network linking the large anthropogenic CO_2 sources to EOR projects will be needed.

Implementation: Key Findings

Finding: There are over 100 active CO_2-EOR projects in the US, currently providing 281,000 BOPD, about 5.0% of total domestic crude oil production. Natural sources of CO_2 account for over 80% of the total CO_2 supply to these projects. Current EOR operations can store around 0.26 to 0.32 MT of CO_2/bbl produced.

Finding: It is estimated that there are 38 to 58 BBO of economically recoverable oil from CO_2-EOR, under current assumptions. Recovery of this oil will require a significant expansion of CO_2 supply.

Finding: The potential for retrofitting carbon capture at existing coal power plants for retrofit could be as low as 20% of the fleet. The emissions from this subset translate to a few hundred million MT of CO_2, which is a good match to the CO_2-EOR potential. This raises the issue that we might not need brine as primary storage capacity in the near and intermediate terms.

Finding: While the potential amounts of CO_2 supply and use in EOR match well, there are transportation constraints. Additional CO_2 pipeline capacity will be needed to link regions of coal generation plants with carbon capture potential to the areas of EOR potential.

Finding: The area of the CO_2 plume in a DSF created from the injection of CO_2 from a 1-GW coal power plant over 30 years could reach over 200 square miles. Because of its greater pore space, the size of the plume from a comparable amount of CO_2 injection into an EOR reservoir is estimated at 20 square miles, or one-tenth the size of the plume in the brine formation.

Finding: CO_2 sequestration in DSFs can be used as backup storage to deal with operational EOR issues. Short-term and long-term operational mismatches between anthropogenic supplies and EOR demand raise the need for a secondary storage capacity that can accommodate the CO_2 supply during periods of high electricity generation and associated large CO_2 production. Backup brine storage can serve as a secondary sequestration site, in case oil production decreases to a point at which CO_2-EOR no longer becomes economically feasible. It is evident that there is substantial overlap between oil reservoirs and DSF; however, the details for co-deployment mechanisms for EOR and DSF need further assessment on a basin-by-basin scale.

Finding: There are 10 CO_2 geologic storage projects in operation or development in the US. Seven of the 10 projects are employing CO_2-EOR as the method of storage. The three projects using CO_2 injection into brine are located in areas in proximity to DSF and not convenient to the CO_2 transportation infrastructure. The CO_2-EOR projects have an advantage in terms of lower technical risk, greater value proposition, and the potential for greater public acceptance.

Finding: Implementation of CO_2-EOR as a major national strategy for carbon sequestration will likely need to occur in phases, with the initial phase of pioneering projects providing "learning by doing" and developing the data to support an effective regulatory regime. This phase needs to be followed by a major effort to reduce cost, in order to ensure that a mature CO_2-EOR industry will be commercially viable. Even under a climate bill, very little CO_2-EOR as a means of CCS will take place without incentives until a significant CO_2 emissions price is in place.

IV. Policy and Regulatory Issues

The discussion of policy and regulatory issues was guided by the following questions:

- What regulatory requirements should be placed on the CO_2-EOR activities for carbon sequestration?
- What verification program would be required to monetize the carbon credits from the sequestered CO_2?
- What effect will these requirements have on the CO_2-EOR value proposition?
- How could the CO_2-EOR activities inform a regulatory program for carbon sequestration in brine formations?
- How should policy address and possibly incentivize the integrated system of public and private interests?

The commissioned white paper was prepared by Scott Anderson of the Environmental Defense Fund. Following his presentation, additional perspectives were provided by Sean McCoy of Carnegie Mellon University, Philip Marston of Marston Law, Allyson Anderson of the US Senate Energy and Natural Resources Committee, and David Hawkins of the Natural Resources Defense Council. These presentations led to a broader discussion among all participants. What follows is a topical summary of the key points made during the discussion.

Establishing the Regulatory Framework for EOR Sequestration

In general, participants supported the view that the regulatory framework should seek to achieve three objectives:

- Create incentives to sequester carbon;
- Verify that sequestration is actually occurring; and
- Foster public education and acceptance of sequestration.

Specifics of a regulatory framework would incorporate elements to achieve: (1) good site characterization; (2) effective operational requirements; (3) MRV; and (4) long-term maintenance and custodial issues that might be associated with the CO_2 that is still in a separate phase, under pressure, and still buoyant relative to the formation into which it has been injected.

A regulatory regime for sequestration should reflect its unique characteristics compared to other forms of underground injection. In particular:

1. Injection and sequestration are two different things.
2. Sequestration is not “sequestration” unless it is verified.
3. Verification means more than compliance with Safe Drinking Water Act regulations designed to prevent contamination of underground drinking water.

Discussants noted that there are two different types of EOR projects that result in the sequestration of CO_2, potentially requiring different regulatory approaches:

- CO_2-EOR projects where the primary purpose is oil extraction for which CO_2 injection rates are set to optimize oil recovery. This category of projects can be referred to as EOR-BAU. In such projects, the goal is to reach miscibility pressure, and in some fields, there may be little "headroom" between miscibility pressure and the amount of pressure that would damage the cap rock forming the reservoir seal; and

- CO_2-EOR projects which are designed to maximize CO_2 sequestration, for which oil recovery is incidental to the sequestration process. To maximize CO_2 sequestration, these projects would operate at higher pressures, potentially approaching levels that could damage cap rock. For purposes of this summary, this category of EOR projects is referred to as EOR-CCS.

The differences between the two types of CO_2-EOR projects as they affect regulatory requirements were discussed at length. Participants were not in agreement that the experience of existing EOR-BAU projects would provide the experience for setting standards for EOR-CCS because of the higher pressures involved in the latter type of projects. Some participants expressed a concern that EOR-BAU may not meet the MRV requirements sufficient to qualify for carbon credits under a mandatory CO_2 emissions reduction program. Other participants agreed that while current EOR-BAU operations may not produce necessary documentation to qualify for carbon credits, current activities could be fairly easily augmented to meet verification requirements.

The EPA's proposed regulations would establish a new class of underground injection wells, Class VI sequestration wells, subject to its own set of requirements under the Safe Drinking Water Act UIC program. Discussants noted that the proposed rules do not address sequestration through EOR-BAU activities, which are currently regulated as Class II oil and gas wells. Discussants noted that the proposed regulatory framework may be drawn too narrowly. The Multi-Stakeholder Group (MSG), an ad hoc organization of industry and environmental groups, supported the concept that sequestration in oil fields can occur: (1) in an EOR-BAU scenario as currently practiced and understood; (2) for projects that may or may not be associated with oil; and (3) when the oil produced is incidental to the sequestration project, and not the primary purpose of the CO_2 injection.

Finally, it was a general view of the participants that safe and effective geologic sequestration in oil and gas fields would require substantial expansion of the regulatory capacity both at the EPA and in state agencies, including the development of new expertise among regulatory personnel and significantly increased agency budgets.

Siting of EOR Sequestration Projects

Permanent retention of CO_2 is essential for successful sequestration, which eliminates certain oil and gas fields as sequestration candidates and requires regulatory reviews for long-term storage of projected CO_2 injection volumes. It will also be important to assess whether injecting a given volume of CO_2 at a given site can be done without contaminating underground water supplies. Potential siting concerns include:

- Reservoir seals that are insufficient for retaining CO_2;
- Poorly constructed or plugged wells;
- Reservoir seals that have been damaged during secondary or tertiary operations by injecting fluid at excessive pressure;
- Reservoir seals that are at risk of being damaged due to insufficient "headroom" between the field's miscibility pressure and pressure that would result in seal failure;
- Hydrogeologic conditions that pose significant risk of injections causing formation fluids to migrate into drinking water supplies; and
- Lateral spill points from which CO_2 could leak if the reservoir is filled beyond capacity.

A key issue in siting EOR-CCS projects is the establishment of baseline data. Such data may not be available for old oil fields in which historical monitoring and record-keeping were not as robust as current practice. In such instances, the lack of background data may eliminate EOR sites as sequestration candidates if, for example, field operators cannot determine with confidence the location of all of the abandoned or plugged wells in the reservior. If data are missing, oil field operators may be able to do work-arounds sufficient to qualify certain fields as sequestration candidates. The same problem does not exist for DSFs in which there has been virtually no previous activity.

Effective Operation of EOR Sequestration Projects

In addition to issues associated with appropriate siting, projects must be properly operated to be effective. Key elements of a regulatory program governing operations include:

- Assuring that wells are properly cased, cemented, and plugged;
- Periodic testing of wells for internal and external mechanical integrity;
- Assuring that injection pressures do not lead to tensile failure[8] or shear failure[9] in the cap rock forming the reservoir seal;
- Requiring that potential leakage pathways be identified for both injected CO_2 and natural formation fluids;
- Requiring a monitoring program to ensure there is no leakage and to otherwise assess the overall efficiency and effectiveness of reservoir performance;

- Requiring adjustments in monitoring and/or injection operations in the event of increased leakage risk or abnormal reservoir behavior relative to initial projections;
- Requiring remediation in the event of leakage; and
- Requiring periodic reports adequate to demonstrate proper project operation.

The requirement for cement bond logs as a means for assuring proper cementing of wells was highlighted. The EPA proposed rules for Class VI underground injection would require cement bond logs as the basis for determining cement integrity. It was pointed out that cement bond logs are an outmoded technology, and thus not reliable as a means of regulation. An alternative compliance evaluation tool is a relatively new technique that takes a 360-degree picture of the cement column and is capable of identifying channels.

Another issue that was discussed in some detail was the need for financial assurance requirements for EOR-CCS operators. Existing financial assurance requirements for EOR-BAU operators applicable during injection, production, and well plugging may not be adequate to address the scale and time frame of environmental risk. One benchmark for comparison is the list of financial assurance requirements for Class I Industrial and Municipal Disposal Wells, shown in Table 5.

Table 5 – UIC Financial Assurance Instrument Types and Requirements for Class I Wells

Instrument Type	Requirements
1. Surety Bond[10]	• Treasury-approved surety companies only • Specify wells covered; new wells require new bonds • Guarantee payment in the amount of the bond (to standby trust fund) for improperly plugged wells; standby trust fund must be established (the EPA is the sole beneficiary) • Provide 120-day notice of cancellation; if owner does not provide substitute assurance to the EPA within 90 days of such notice, amount of bond's face value must be paid into the standby trust fund • Owner may cancel bond with written consent of Regional Administrator (EPA); such consent may be given after substitute assurance is provided or guarantee is paid
2. Letter of Credit	• Regulated (federal or state) financial institutions only • Specify wells covered; new wells require new letters • Funds deposited into standby trust fund if owner fails to properly plug wells; standby trust fund must be established (EPA is the sole beneficiary) • Provide 120-day notice of nonrenewal from institution; if owner does not provide substitute assurance to the EPA within 90 days of such notice, Regional Administrator (EPA) may draw upon the letter of credit • Owner may cancel bond with written consent of Regional Administrator (EPA); such consent may be given after substitute assurance is provided or guarantee is paid
3. Trust Fund[11]	• Regulated (federal or state) financial institutions only • Contain funds equal to required financial coverage • Designate the EPA as sole beneficiary • Specify acceptable ways of investing money in the fund (by the trustee) • Accompanied by "certificate of acknowledgment" • Specify conditions under which the EPA may disburse funds for plugging wells or for returning excess monies to owner
4. Standby Trust Fund[12]	*Required for surety bonds and letters of credit (see footnote)*

Apart from these instruments, Class I well operators have the option to:

- Purchase plugging and abandonment insurance;
- Meet financial criteria and obtain a corporate guarantee for plugging and abandonment; or
- Demonstrate financial responsibility using a combination of the trust fund, surety bond, letter of credit, and insurance options.

Generally, under current UIC regulations, the owner and/or operator of a Class I, II, or III well is required to demonstrate and maintain financial responsibility and resources to close, plug, and abandon the operation until:

- The well has been plugged and abandoned, and a plugging and abandonment report has been submitted to the EPA;
- The well has been converted; or
- In the event of a transfer, the transferor has demonstrated financial responsibility for the well in the form of an EPA-approved financial assurance instrument.

For EPA-administered programs, the owner/operator:

- Must demonstrate assurance no later than one year after the effective date of the UIC program in each state;
- May be required by the Regional Administrator to submit revised evidence of financial responsibility if it is suspected that the original demonstration is no longer adequate to cover the cost of closing, plugging, and abandoning the well;
- Must comply with Class I rules (see Table 5) for a well injecting hazardous waste;
- Must notify the Regional Administrator by certified mail of the commencement of any bankruptcy proceeding within 10 business days, post-commencement; and
- If subjected to any bankruptcy proceeding, will be deemed to be in violation of financial assurance requirements until an alternative financial assurance demonstration is provided, and until such time, injection will be halted.

Participants noted that the EPA Environmental Financial Advisory Board (EFAB) recently issued a report recommending new financial assurance requirements for owners and operators of EOR-CCS injection wells.[13] The principal findings and recommendations include the following:

- Financial test and third-party financial assurance mechanisms should be available to responsible parties.
- Trust funds are “costly measures.” Duplicative and upfront funding of financial responsibilities are not appropriate.
- Class I financial instruments should be used over Class II requirements. Class II financial requirements would result in weakness, but Class I requirements include the use of insurance as well as specific language for other assurance instruments.

- The EPA should consider adding a new category of financial assurance to the Class VI program that provides the EPA "with the flexibility to approve the 'functional equivalent' to the established Resource Conservation and Recovery Act (RCRA) financial assurance tests."

- The amount and timing of financial assurance should be based on the EPA's risk evaluation.

- The EPA should consider whether to require financial assurance for monitoring as well as for plugging wells.

- Financial assurance requirements should be dynamic over the life of a project, taking into account site-specific changes as well as changes in available technology. Toward this end, the EPA might consider regular updates of cost estimates. To facilitate such updates, the EPA should collect various types of data on a rolling basis. The EPA could establish grounds for making adjustments if its proposal to require regular updates of various plans, e.g., monitoring, corrective action, and closure, were coupled with "robust annual reporting requirements that document why updated plans have or have not been necessary."

Closure

The concept of project closure is currently not a formal step in EOR-BAU projects. Individual wells may be plugged, but the entire field is not "closed." By comparison, closure is an important element of the regulatory framework for EOR-CCS. There appears to be a consensus that any regulatory framework for geologic sequestration projects will include a determination by the regulator of the point (if any) at which a project has been closed. If a policy choice is made to include formal closure determinations as part of the regulatory regime, standards and procedures will need to be developed for making such a determination, and it will be necessary to decide what legal and operational consequences follow from a closure decision.

Questions associated with the development of standards and procedures of making a closure determination include:

- What is the technical basis for making a closure determination?

- Should closure be said to occur after a fixed number of years following cessation of injection?

- Should closure occur when the injected CO_2 is "stabilized"?

- Should closure occur when an operator convinces regulators that "no additional monitoring is needed."

- Can a consensus standard be developed?

- Should the rigor with which a closure determination is made depend in part on what is at stake, including what is at stake in terms of legal consequences?

Questions associated with legal and operational consequences that follow from a closure decision include:

- What should the consequences be if regulators deem a site "closed"?

- Can the operator stop monitoring?

- Will the operator still need to perform other actions at the site?

- Will operating bonds be released?
- Does closure mean carbon credits generated by the project are now secure for all time?
- If the operator is sued for damages caused by its operations, does closure of the site create a defense to what otherwise would be a successful lawsuit?

Verification of CO_2 sequestration credits

Participants recognized that it is critically important that any sequestration credits be completely fungible, tradable, and equivalent to any other kind of emissions reductions or avoided emissions in emissions trading programs. This was considered to be an important factor to keep in mind in the development of the regulatory framework for EOR-CCS. Further, it was recognized that the verification requirements for EOR-CCS sequestration may differ from those for sequestration in DSFs.

To obtain credit for sequestration, it is very important to underscore the difference between physical CO_2 sequestration and legal recognition of the avoidance of the CO_2 emissions. The value proposition for sequestration as a carbon mitigation technique is going to be entirely based on its legal regulation. Some participants noted that EOR-BAU, "as practiced," is not sequestration because it does not include verification plans.

Participants discussed the possibility of establishing different levels of regulatory recognition of sequestration. One analogy was the difference used in the designation of probable reserves, proven reserves, and producing reserves. Injection of CO_2 underground in EOR operations generally results in sequestration, and if there is a problem with the sequestration, there will be indicators, such as a drop-off in pressure or some other indicator. But it may not be possible to verify the amount of sequestration to a degree of certainty sufficient to monetize it. There is a general understanding that existing EOR-BAU practices will need to be enhanced with additional monitoring and other requirements in order to reach the level of verifiable CO_2 sequestration. Participants recognized the need to develop clearer terms and categories to characterize the regulatory distinctions between different types of sequestration operations. Participants noted, for example, that the current Class II rules pertaining to oil and gas wells permitted for current EOR-BAU operations also address whether a given oil field is suitable for a projected volume of CO_2 sequestration. Establishing an acceptable level of sequestration should be a requirement that is incorporated into any future geologic sequestration regulatory system.

Another key issue in verification of CO_2 sequestration credits is the determination of potential leakage into the atmosphere. The EPA's proposed rules to regulate the geologic sequestration of CO_2 under the UIC program, authorized in the Safe Drinking Water Act, do not address verification issues associated with leakage into the atmosphere. Thus, compliance with neither the proposed Class VI[14] rules governing wells used for geologic sequestration nor the existing rules for Class II[15] oil and gas wells will be sufficient to establish the basis for carbon credits or other legal recognition of the net amount of carbon sequestration (after consideration of potential losses due to leakage to the atmosphere).

The EPA GHG MRR issued under the Clean Air Act and guidelines issued by the US Treasury Department for purposes of qualification of carbon sequestration tax credits under Section 45Q of the Internal Revenue Code provide guidance for how verification issues in general, including leakage, will be handled for purposes of qualification under those programs. This guidance, which draws heavily from IPCC guidelines, also may serve as a model for a future CO_2 sequestration regulation.

In order to qualify for Section 45Q of the Internal Revenue Code sequestration tax credit, project sponsors are required to conduct the following procedures at geologic sequestration sites:

1. Conduct a site characterization by evaluating the geology of the storage site and surrounding strata and identifying the local and regional hydrogeology and leakage pathways such as deep wells, faults, and fractures.

2. Conduct an assessment of CO_2 leakage risks by evaluating a combination of site characterization and realistic models, e.g., reservoir simulators or numerical modeling techniques, predictive of the movement (timing, location, and flux) of CO_2 over time.

3. Monitor potential leakage pathways, measure leakage at those pathways as necessary, monitor the current and future behavior of the CO_2 and storage system, and use the results of the monitoring plan to validate and/or update models as appropriate.

The EPA-proposed rules for reporting are consistent with the Treasury guidance, but are more detailed. Under the proposed rules, a project that injects CO_2 "to enhance the recovery of oil and gas" does not count as a geologic sequestration facility unless the CO_2 is also injected "for long-term containment" and the operator submits an MRV plan that is explicitly approved by the EPA. Operators who do not submit an MRV plan must still report certain information about their operations. The proposed rules include the following documentation provisions, among other elements, related to verification of secure storage:

- The reporter must report the annual mass of CO_2 emitted from each leakage pathway identified in the MRV plan.

- The reporter must follow the procedures in the MRV plan to determine the quantity of emissions from the subsurface geologic formation and the percent of CO_2 estimated to remain with the produced oil and gas.

- The MRV plan must include an assessment of CO_2 leakage risk; a strategy for detecting and quantifying CO_2 leakage; a strategy for establishing pre-injection baselines; and a summary of the calculation of site-specific variables for a mass balance equation.

- Addenda to the MRV plan must be submitted (and presumably approved) if the plan is adjusted (at the operator's initiative) due to new information, altered site conditions, or detection of leakage. Such addenda must include a description of the leak — with all assumptions, methodology, and technologies involved in leakage detection and quantification, if a leak were detected — and a description of how the monitoring strategy was adjusted, if applicable.

- The operator must revise and resubmit the MRV plan if an EPA audit determines revisions to be necessary.

While the concept of the MRV is recognized by the participants, it also was noted that implementation of the MRV will require a significant amount of development work. Policy makers should be sensitive to the fact that MRV plans are novel and will require much "learning by doing" in the coming years.

Initial application of MRV requirements is under development as part of current CCS R&D and demonstration projects. Significant work is underway on developing commercial-type MRV plans for Summit in West Texas, Tenaska in Sweetwater, Texas, and NRG Energy at its Parish Plant in Texas. Also, the Hydrogen Energy Oxy project for the Elk Hills field in California, was cited as being at the forefront of developing a commercial-type MRV plan. All four projects, which have the most developed sequestration MRV plans, are employing EOR-CCS. EDF and the NRDC are working cooperatively with Oxy to develop its monitoring plan for Elk Hills; the draft plan was recently submitted to the California Energy Commission. While additional work on the plan may be needed, it may be the first commercial-type MRV plan to receive regulatory recognition in the US.

Cost of Regulatory Requirements

The scope of regulatory requirements for EOR-CCS could be extensive. However, it was pointed out that the cost of compliance should be small relative to the value proposition.

For US oil businesses, the value proposition of capturing quantities of anthropogenic CO_2 for use in oil fields is huge. It has been estimated that under certain circumstances, federal climate change legislation could lead to an increase of more than three million BOPD of domestic oil production by 2030.[16]

Although regulation increases transaction costs, regulatory compliance is not likely to be a major component of overall sequestration costs. To put this in perspective: to capture, compress, and transport CO_2 will cost tens of dollars per ton; to select, monitor, and otherwise operate sites will cost dollars per ton; and to take steps required by regulation will cost dimes per ton. Some participants observed that although regulatory compliance costs are relatively small, they should be a cause of concern. If the regulatory requirements are not set prudently, regulatory compliance costs could be much higher, to the point at which they could make the difference between an economically viable project and an uneconomically viable project.

Relationship of Regulation of EOR-CCS to Regulation of Sequestration in DSFs

Participants noted that, in the regulatory framework for CCS, a distinction is made between EOR sequestration and sequestration in DSFs. While acknowledging that a distinction is developing, participants believed that this did not imply that EOR-CCS was not going to be recognized as sequestration. Moreover, there was recognition that some EOR-CCS sequestration projects could yield significant new knowledge or technology that would be particularly helpful for regulation of sequestration in brine formations. Areas of potential commonality between EOR-CCS and brine sequestration include:

- Methods to compensate for shortcomings in baseline monitoring data;
- Methods to determine how much geologic characterization data is needed, including the degree of specificity with which the nature and location of leakage pathways should be identified;
- Improved techniques for assessing well integrity;
- Understanding of reservoir seal performance;
- Reservoir simulation and numerical modeling techniques;
- The necessary scope and detail of MRV plans, to the extent the elements of such plans are relevant in the brine formation context; and
- Above-zone pressure and geochemical monitoring

R&D and Other Capacity Building

Although the discussants were generally of the view that CCS is ready to begin large-scale deployment from a technological standpoint, there was discussion of the need for more R&D to reduce costs. Additional research and educational activities also were needed to develop the human, financial, and technical resources needed to improve the understanding of risks and risk management techniques to achieve economies of scale over time. Most CCS R&D is currently focused on carbon capture and compression since these activities account for most of the cost. However, sequestration has important R&D and capacity-building needs as well, including:

- Workforce education;
- Helping the insurance and financial sectors to understand sequestration risks, identify and assess the effectiveness of risk controls, and develop corresponding financial risk management mechanisms (e.g., insurance, adjustments to the cost of capital, risk-sharing joint ventures, and benefit-cost modeling);
- Fundamental and applied research on reservoir simulation, containment mechanisms, methods to predict and assess geologic heterogeneity, ways to distinguish between problematic faults and innocuous faults, and monitoring technologies and methods;
- Improved methods to estimate geologic capacity, identify and characterize potential leakage pathways, and make efficient use of storage space;
- Developing new techniques to produce oil in reservoirs that do not currently appear to be EOR-BAU candidates;
- Developing new techniques for improving oil production in reservoirs in which CO_2 is injected in quantities that raise reservoir pressure significantly above miscibility pressure;
- Efforts to reduce various costs, focusing in particular on geologic basins where the costs and technical challenges of sequestration are expected to be relatively high;
- Methods to quantify leakage;
- Designing MRV plans that are standardized but take site-specific variation into account;
- Regional and basin-scale hydrogeology; and
- Environmental remediation technologies, including methods to deal with the displacement of excessive amounts of formation water.

Ownership Rights to Pore Space

It is not especially difficult to determine who owns pore space and who has a right to use pore space. As a general rule, owners of surface estates own pore space and owners of mineral estates (subsurface) will have the right to use the pore space as reasonably necessary for extracting minerals. Developers of sequestration projects will generally have to acquire rights from both surface and mineral estate owners, though EOR-BAU operators who inject no more CO_2 than reasonably necessary to product commercial quantities of oil will not need permission.

Participants discussed the question of sequestration in formations in which there were mineral rights but not explicit storage rights. In the case of EOR-BAU, it would appear that the project owner would not need to have storage rights, because the CO_2 would be stored in pore space that was originally occupied by the oil which was produced pursuant to mineral rights. In other words, credit can be provided for sequestration in reservoirs in which the owner has the mineral rights, but not necessarily the storage rights. For a project designed to maximize storage, the project owner would need to obtain storage rights.

Any uncertainties in determining ownership rights can be minimized through appropriate legislation, which should be the responsibility of the states. The states, not the federal government, have always been in charge of real property rules. Legislation also may be needed to clarify any uncertainty regarding a government “taking” of pore space property rights. Otherwise, litigation could be brought against the government on the basis that the government either (a) does not admit to the taking of private property or (b) does not pay just compensation for the taking of private property.

For federal lands, the issue of mineral rights versus storage rights could be a major concern. Currently, a working group in the BLM is examining this question, because there are at least six EOR sites located on federal lands currently, which could potentially be converted into CO_2-EOR projects in the future. Conversion of a mineral project and mineral rights to a storage project and storage rights could have a number of ramifications that are currently unresolved.

Unitization of Pore Space

Another aspect of the legal issue surrounding unitization of oil fields for EOR-CCS projects is certification of the injected volumes for purposes of GHG reporting. In order to monitor and verify that there is no leakage from an EOR-CCS project, it is essential that the project sponsor have control of the entire area of the reservoir. Absent full control, the owner/operators of EOR-CCS projects cannot verify that leakage is not occurring. CO_2 will permeate the entire reservoir including unratified tracts that are not prepared or equipped to handle CO_2 reinjection. If leakage does occur from an non-ratified portion of the reservoir, the anthropogenic emitter would be unable to certify its injected volumes as sequestered and will undoubterly decline to utilize an oil field that was not fully unitized. This also has implications for the EOR industry as a whole which will need increasing volumes of new anthropogenic CO_2 supplies in order to fully re-develop new oil production from the large US inventory of depleted candidate fields.

States have addressed this issue through legislation that establishes compulsory unitization requirements. These statutes provide for a minimum threshold retification requirement from a supermajority of interest owners to form the unit and serve to prevent “holdout” mineral estate owners and lessees from inhibiting secondary and tertiary development. These statutes are an outgrowth of state oil and gas conservation laws that are designed to protect correlative rights of mineral property owners as well as promote the orderly and efficient development of underground oil and gas resources that transcend surface ownership boundaries. Every major oil-producing state, except for Texas, has adopted the necessary enabling legislation to support compulsory unitization.

Regulation of CO_2 Transportation

Symposium participants did not have a consensus view as to the need for any additional federal policy actions for CO_2 transportation, as it is a mature industry. Notwithstanding, the following considerations were noted in the discussion:

- Pipeline locations should be scrutinized and permitted from a public interest perspective, but the government should not design and dictate the details of an entire pipeline system.

- Provided the purity of CO_2 streams captured from power plants and industrial sources is similar to the purity of CO_2 in the existing pipeline network, few (if any) changes should be made to pipeline safety regulations.

- There is no clear need for regulations that limit market entry or govern rates or terms of service. It may become necessary to regulate rates and supplement antitrust laws with regulations that assure nondiscriminatory transportation services at some point, but this is a need in the future. To prematurely impose such regulations could create a disincentive to the rapid development of a comprehensive CO_2 distribution system.

One issue that was highlighted was the need for eminent domain authority. Eminent domain almost certainly will be necessary to develop a more robust CO_2 pipeline infrastructure. Currently, CO_2 pipelines have the authority to invoke eminent domain in some states but not others. Thus, additional state (and possibly federal) legislation may be needed to make such authority uniform nationwide.

CO_2 pipelines could be either common carrier lines or unregulated, private carriers. If they are common carrier lines, there was concern about a definition of common carriage that encompasses the proration of capacity to existing customers in order to accommodate new customers, the definition under the Interstate Commerce Act for oil pipelines before the Federal Dispute Resolution Conference (FDRC). Under this construct, signing a binding contract with the capture supplier could be complicated by new plant entries, creating a high degree of uncertainty in the marketplace.

Some participants also noted that there could be pressure for rate regulation at some point in the future. The most likely cause for such pressure would be the emergence of market dominance by pipelines. However, this is difficult to predict, since the future pipeline infrastructure is yet to be defined and implemented. Market power issues, to the extent they arise, would likely arise when the contracts expire 20 to 30 years from now.

Liability Protection

Participants discussed whether EOR-CCS projects required special liability protection, which provoked extensive discussion from many perspectives.

In framing this discussion, the commissioned white paper pointed out that EOR-CCS is currently liable under the state and federal laws and procedures pursuant to which any industrial operators may be held liable under certain circumstances for damages caused by their operations. The existing liability regime applies to numerous industries, including industries that spend significant sums on projects that entail long-term risks significantly greater than those created by EOR-CCS activities. Nevertheless, such industries are able to attract capital and make investments.

Some participants believed that the concern about liability protection and calls for indemnification were being driven by electric power sector executives who were not familiar with liability regimes in other industries, and thus may be overstating the risk management issues associated with EOR-CCS. These participants held the view that EOR-CCS project owners should not receive any liability protection that is not provided to steel mills or other industrial operations. Further, the electric sector's calls for indemnification were viewed as being potentially counterproductive as they could raise public concern that EOR-CCS was unnecessarily risky and should not be permitted.

Another view expressed by some participants was that the public purpose served by EOR-CCS justified public risk sharing. Current CO_2-EOR operators are engaged in a business with a certain risk profile, undertaken under a set of known rules. But EOR-CCS activities could have a significantly higher risk profile associated with the permanent sequestration of CO_2 needed to realize public policy benefits (i.e., GHG emissions reductions). If this is the rationale, it seems appropriate for the beneficiaries of reduced GHG emissions, i.e., the general public, to share a portion of the incremental risk associated with geologic sequestration.

Other participants pointed out that, unlike the air emissions standards faced by power generation facilities, there is no mandate that CO_2 be managed through geologic sequestration. There are a range of alternatives to CCS, such as energy efficiency, demand side management, production efficiency, renewable energy technologies, nuclear, natural gas, etc. If generators actually choose CCS, it is assumed to be the most economic choice which presumably includes risk management costs.

The general discussion of the need for liability protection focused on the specific areas where liability protection might be appropriate:

1. Stewardship at "orphan" sites, i.e., sites for which responsible parties with financial resources cannot be found. In this instance, the suggestion was made that the issue of "orphan" sites should be addressed through an industry-financed trust fund, the structure of which is designed to make it difficult for Congress to reallocate its monies to other purposes.

2. Possible government assistance (perhaps through a newly created institution) for project developers in performing certain "post-closure" activities for which the developers might otherwise be responsible. In this instance, it was suggested that the issue of limited assistance with long-term stewardship of site infrastructure is worth pursuing, if industry-financed, but should be addressed with caution. Socialized stewardship functions should be few, with government not relieving companies of large amounts of liability but instead handling relatively routine, inexpensive tasks that benefit from standardization or economies of scale if performed for many sites by a single organization.

3. Protection during the initial period when the marketplace is developing risk management tools sufficient to enable other industries to make billion-dollar investments in the face of prolonged risk. It was suggested that initial EOR-CCS deployment projects (perhaps up to the first 40 GW or so of CCS projects) could be addressed through a graded program of risk sharing. For example, these initial projects could be grouped into tranches, with each tranche eligible for a set of layered protection. The first layer would be a significant amount of "first dollar" responsibility in the event of damage awards, which would increase with each tranche. The second layer would consist of "second dollar" responsibility funded from an industry pool, with a fixed dollar cap for each tranche. The "third layer" would be provided through government indemnification, with lower caps for each tranche. The program would be capped in terms of a number of eligible projects and total amount of liability protection, with a phase-down in each succeeding tranche. It is assumed that by the end of the program, sufficient experience would be gained to enable the development of commercial risk management tools.

One of the concerns with any liability protection program is the potential to create a "moral hazard," i.e., providing project developers with an incentive to manage their affairs in ways that run counter to public interest and, thus, harm third parties. Some discussants believed that proper design of the program would minimize the potential for "moral hazard." This includes precise determination of the requirements at the point of liability transfer or relief. If the regulations are developed properly and thoughtfully, it would go a long way to assure assignments of responsibility and an accountability structure for future generations.

Another concern that was discussed by the participants was the scope of activity that might be eligible for liability protections. For example, there may be liability associated with a breach of warranty as to not meeting contract specifications either by the producer and supplier of the CO_2 stream or by the pipeline that transported it to the sequestration site. Alternatively, liability may arise not from the CO_2 stream itself but from the possibility of impurities, such as mercury or arsenic. Thus, the scope of activities that qualify for any liability protection needs to be appropriately defined.

Over time, there are a variety of commercial risk management measures that could be employed to address liability risk in EOR-CCS projects. Insurance is an obvious risk management mechanism. And while insurance exists for EOR-BAU projects (a project owner can insure a project for up to $100 million during the operational phase), it is not yet sufficiently robust for CCS. Risk-adjusted cost of capital is another such tool. Capital markets for other billion-dollar industries have experience in pricing the cost of capital based on the assessed level of risk. This does not yet exist for EOR-CCS. Joint ventures offer another risk management option. Under this model, liability would be allocated in direct proportion to each party's respective view of the project's financial risk; thus, overall liability would be equitably borne by the parties to the joint venture. Lastly, there is simply accepting risk, which is what many industries that perform similar activities do, including: EOR; natural gas storage; underground injection of industrial waste; and underground injection of hazardous waste (even though hazardous waste injection rules require that operators prove lack of migration for 10,000 years). These activities receive no liability protection, which has not impeded their ability to raise capital.

The participants discussed whether trust funds represented a policy mechanism to address future liability. Trust funds, which are designed to effectively prefund future liability, are viewed by many as an effective vehicle for addressing future liability in a manner that avoids imposing future costs on taxpayers. A contrasting view was portrayed by the EPA EFAB, which pointed out that trust funds are not an efficient use of capital, because they gather large sums that then sit idle and collect money market-type interest (assuming Congress does not siphon the money off for other projects in the meantime).

As an alternative to trust funds, the MSG has been developing a proposal for industry-funded pools to provide a cushion for early mover EOR-CCS project sponsors. It is a form of protection that can be targeted to the early EOR-CCS deployment projects as the risk management business takes shape. As with any proposal for liability protection, there is a concern that opponents of CCS could attempt to characterize this concept as a negative public perception.

Another issue raised by the participants was the timing of any legislative action on liability protection. In the wake of the Deepwater Horizon accident, it would be very difficult for Congress to consider any form of liability protection. While the relative risks are well understood by scientists, the public may not understand, and so liability protection proposals could be met with opposition.

Legislative Issues and Outlook

The participants discussed a number of policy and regulatory issues that could be considered by Congress. In recent years, Congress has enacted several important incentives for EOR-CCS.

- The Energy Independence and Security Act of 2007 authorized funding for a broad-scale CCS R&D program.

- The Troubled Assets Recovery Program (TARP) legislation in 2008 also established the current Internal Revenue Code Section 45Q carbon sequestration tax credit; and

- The American Recovery and Reinvestment Tax Act of 2009 which provided a one-time surge of $3.4 billion of funding for industrial CCS technology demonstration projects, as well as other initiatives such as advanced site characterization.

In 2009, the House passed the ACES, which would have established a comprehensive GHG emissions reduction program. In the Senate, there was no final action on climate legislation.

The 111th Congress considered possible legislative changes to modify and expand the sequestration tax credit. The current credit was designed with the best of intentions to induce companies to implement sequestration projects in which operators can actually apply and qualify for the tax credit. However, no one has applied yet, because the threshold cannot be met and there is no guarantee that applicants will receive the credit. Potential changes include increasing the size of the credit, and increasing the certainty of accessing the credit. A specific proposal under consideration would increase the non-EOR tax credit from $20 to $35 per ton of CO_2 sequestered, although this does not alleviate problems associated with the current economy-wide cap of about 75 million MT eligible for credit. This limitation creates significant uncertainty between projects, as the ability to access the credit could be a matter of simple timing and position in the applicant queue. This problem could be alleviated by a simple pre-certification process. Another approach would be to increase the 75 million MT cap.

There also were proposals for Congress to establish an "early-mover" liability protection program that would provide indemnification for 10 early mover projects that meet certain criteria. The federal government would assume future liability on the closure of a facility.

Participants noted that there appears to be broad political support for promoting CCS as an option, and the use of EOR as a method of sequestration does not appear to raise significant political problems. This raised the question as to what the legislative priorities for CCS should be, and in particular, what actions should be advocated for EOR-CCS option.

Several participants from the environmental community recommended advocating legislative provisions for CCS as part of comprehensive climate legislation. There would be no reason to pursue CCS absent a climate policy. However, there appears to be relatively little interest in promoting CCS as a means to achieve incremental domestic oil production from EOR. So the environmental community in particular will continue to press for comprehensive climate policy legislation. In that context, there will continue to be a push for a package of policies that includes performance standards for the power sector for CO_2 emissions and subsidies for the first movers on CCS in order to build out the type of business models discussed in this symposium.

It was also noted there is no need for any special legislative provisions for EOR-CCS. The EPA has regulatory authority to write the regulations for both protection of ground water and for prevention of leaks into the atmosphere. The EPA has not yet grappled with the issue of regulating leakage to the atmosphere, but there was a view that this can be accomplished without the need for additional legislation.

Some participants were wary of policy interventions in EOR markets, noting the government's poor track record in deciding how much of what should be delivered to whom, when, and at what price. Thus, any proposal for government policy intervention should have a clear public interest and a well-defined scope. Certain incentives could be valuable, such as special allowances for CCS or the continuation of Section 45Q of the Internal Revenue Code sequestration tax credit. Participants also suggested that an existing tax deduction for injection costs for EOR (injection costs represent about half of total costs for most EOR projects) be limited to apply *only* to EOR utilizing anthropogenic CO_2. There also may be options for pursuing legislative incentives in state legislatures.

The view that CCS will not be implemented at any significant scale absent climate legislation was echoed by other participants, who thought that absent such a driver, EOR-CCS projects would be niche activities. A certain inevitability of climate change policy was expressed, because of the underlying realities of climate change, but the timing of any policy response is uncertain. As such, businesses will face increasing investment uncertainty. There was a general view among participants that it was prudent to proceed with the policy and regulatory development needed for CO_2-EOR, although rapid deployment will be impeded without a climate policy that sets a price on carbon.

Other participants stated that they did not see the need for additional legislation or any special treatment for CO_2-EOR. There does not appear to be a need for financial incentives for CO_2-EOR, as it could largely pay for itself from the EOR revenue. As part of a broader package of regulation incentives for geologic sequestration, there may be some special issues that need to be addressed so EOR-CCS can be a viable option, such as having verified credits or verified emissions reductions. It would be a good idea to address the question of liability protection, potentially through federal legislation, sooner rather than later. The issues surrounding the legal status of pore space and accessing pore space in DSFs should be addressed at the state level, or potentially, at the federal level.

Finally, several participants noted the need for action at the state level. In particular, state action to allow unitization of pore space was noted as the most important priority. Participants also indicated that initial action by the states on other incentives for EOR-CCS could facilitate first-mover CO_2-EOR projects while awaiting follow-on action at the federal level.

Issues Summary: Participants focused on policy and regulatory frameworks that would enable CO_2-EOR activities to qualify as a viable and effective carbon sequestration strategy. Much of the discussion centered on questions related to the permanency of carbon sequestration in hydrocarbon pore space and whether current EOR field practices were adequate to prevent leakage. The availability of baseline data from existing EOR fields was identified as an important factor that would facilitate regulatory determinations. Public acceptance also was noted as an important consideration.

Participants discussed whether there should be a distinction, for regulatory purposes, between EOR-BAU, i.e., EOR activities designed to maximize oil production with incidental carbon sequestration, and EOR-CCS, i.e., EOR activities designed to maximize carbon sequestration with incidental oil production.

The major elements for an effective regulatory regime were also discussed. These include criteria for siting, operations, closure, and MRV. This discussion centered on the requirements applicable for new CO_2-EOR projects planned for the purpose of carbon sequestration (EOR-CCS).

Participants were also concerned about appropriate requirements for existing CO_2-EOR operations, i.e., EOR-BAU. The current EPA UIC program, established under the Safe Drinking Water Act, is an imperfect framework for achieving comprehensive regulation. Aspects of EOR-CCS activities fall within both the Class II and Class VI wells established in the EPA UIC regulations.[17]
In addition, the Safe Drinking Water Act currently does not have explicit authority to authorize standards for CO_2 emissions leakage to the atmosphere that may result from underground injection activities.

Participants discussed the importance of legal issues, such as ownership of pore space. Current leasing regulations were designed to convey mineral rights, including the use of pore space as reasonably necessary for extracting minerals. However, current leasing regimes did not anticipate the use of pore space for permanent storage of CO_2. This may require changes in regulations to recognize the distinctions between mineral extraction rights and storage rights. This issue is currently under review for federal lands leased by the BLM.

Another important legal issue for EOR fields is “unitization” — legal agreements that enable oil reservoirs to be operated as a single system in order to increase oil recovery. Such agreements typically involve the equitable sharing of royalties between landowners who are likely affected by the drilling, production, or injection activities on the unitized properties. Failure to achieve full “unitization” of EOR fields planned for CO_2 storage could present major obstacles to compliance with MRV requirements needed for verification of carbon sequestration credits. Participants recognized that “unitization” was an issue under the jurisdiction of the states. Many state legislatures have enacted compulsory unitization requirements for oil and gas extraction. Texas, which has by far the largest extent of current CO_2-EOR activity and future EOR potential, does not currently have a state law on compulsory “unitization.”

The issue of liability protection received a great deal of attention at the symposium. Many participants felt that CO_2-EOR operations should not receive any form of liability protection from the migration of sequestered CO_2 into the groundwater or atmosphere under the theory that these operations are no more risky than other industries that do not receive such protections.

Others noted at least two areas in which inadequate information or market failures may justify a governmental role in liability protection. Early movers of pioneer EOR-CCS projects have inadequate information about the marketplace to appropriately price risk and provide risk management tools. Also, “orphan” sites, which may require remedial action, may also require some kind of government-supported liability protection or coverage.

Participants also heard about and discussed possible “pooling” arrangements among CO_2-EOR project sponsors. These arrangements would enable private sector entities to achieve standardization and economies of scale in long-term MRV activities, and possible risk sharing, without the need for a governmental role in providing financial protection or subsidies.

Finally, participants discussed legislative scenarios for a national EOR-CCS program and there was general agreement that such a program could only advance in the context of a national requirement for CO_2 emissions reductions. Participants generally agreed that comprehensive climate change legislation *would* provide the necessary incentives to spur a national EOR-CCS program. Participants also noted that pending legislation provided special incentives for EOR-CCS in the form of bonus allowances under the proposed cap and trade regulatory regime.

At the time of the symposium, some participants were unwilling to preclude the possibility that the 111th Congress might take action on comprehensive climate change legislation, although the general feeling was that this was highly unlikely. Consequently, there was less focus on policy and legislative options for CO_2-EOR / CCS separate from comprehensive climate change legislation. Absent comprehensive climate change legislation, there was a view that CO_2-EOR / CCS would evolve slowly as a niche activity providing an opportunity for “learning by doing” to inform future discussions of policy and regulation.

Policy and Regulation: Key Findings

Finding: Regulation of EOR-CCS activities requires a comprehensive framework that should address siting, operations, closure, and long-term monitoring of EOR sequestration projects.

Finding: EOR-BAU activities, enhanced EOR-CCS, and carbon sequestration in brine formations have different operational characteristics, such as injection rates and pressures. These differences will require different regulatory standards.

Finding: There will be challenges in adapting existing CO_2-EOR projects to a new CCS regulatory regime. While carbon sequestration is clearly taking place, current projects may lack sufficient data on baseline conditions, migration patterns, and leakage points needed to make a regulatory determination of long-term sequestration and verifiable carbon credits.

Finding: Extensive planning is currently underway to establish MRV plans for EOR-CCS demonstration projects. The MRV plans are intended to support compliance with anticipated regulatory requirements. However, they have not yet been fully demonstrated. Consequently the emerging regulatory framework for EOR-CCS will need to have some flexibility to allow for "learning by doing."

Finding: The process of development of the regulatory framework for EOR-CCS has involved extensive dialogue among stakeholder groups. This process appears to have contributed significantly to early identification and discussions of key issues. While there is not necessarily a consensus on a number of issues, the process of dialogue has appeared to significantly advance regulatory development efforts.

Finding: Ownership rights to pore space in EOR reservoirs, as well as unitization of EOR fields, pose potential barriers to EOR-CCS projects. Resolution of the legal questions surrounding these issues is generally the responsibility of the states, except for federal lands which are administered by the DOI BLM.

Finding: Liability protection for post-closure CCS projects remains a contentious issue. While the risk profile associated with EOR-CCS operations may not be significantly higher than certain other types of industrial activities, there are significant uncertainties associated with pioneer projects and there may be challenges associated with the longtime scales for post-closure monitoring, including the possibility of "orphan" sites. There is a broad range of potential options to address the liability issue, including possible liability-sharing or "pooling" arrangements among EOR-CCS operators, as well as limited government intervention.

ENDNOTES

1 Residual Oil Zones are underground reservoirs consisting of a brine or saline solution that is partially saturated with oil. ROZs can be found associated with the MPZs, which are the primary targets for commercial oil production, or in some cases they can be in separate geological structures and associated with breached paleo accumulations or migration paths.

2 The UIC regulations define six different classes of underground injection wells that are subject to regulation. Class II pertains to oil- and gas-related wells. Class VI covers geologic sequestration wells. The regulations establish different standards for each class.

3 These three "legs" were first introduced and described by Scott Tinker in a keynote address titled *Carbon Sequestration: Texas Style,* presented at the Carbon and Climate Change forum hosted by the LBJ School at the University of Texas in February 2010. http://www.beg.utexas.edu/presentations.php

4 Section 45Q was enacted as part of the Energy Improvement and Extension Act of 2008 and amended in the American Recovery and Reinvestment Tax Act of 2009.

5 Dividing 281000 bbl/day (April 2010 EOR survey) by 5361000 bbl/day (2009 US crude oil production EIA) gives 5.2%.

6 Next generation technologies include: i) increasing CO_2 injection rate to 1.5 HCPV, ii) optimization of well design and placement would enable more of the residual oil in a reservoir to be contacted, iii) improving the mobility ratio, iv) extending the miscibility, and v) Integrating Application of "Next Generation" Technology Options.

As seen in *Storing CO_2 and Producing Domestic Crude Oil with Next Generation CO_2-EOR Technology: An Update, April 2010 DOE/NETL*

7 Assuming 6.2 MMmt/yr of CO_2 emissions and 90% capture.

8 Tensile failure refers to the creation of new fractures.

9 Shear failure occurs when rock slips along pre-existing fractures.

10 Two types of surety bonds are permissible: (1) a financial guarantee bond, which guarantees the surety company will fund a standby trust fund in the amount guaranteed by the bond; and (2) a performance bonds, which guarantees the surety company will perform plugging duties or pay the amount of the bond into a standby trust fund if the site owner fails to properly plug the well(s). NOTE: A standby trust fund serves as a depository for funds that may eventually be paid by the surety company.

11 The trust fund instrument requires the owner to deposit funds sufficient to cover financial assurance requirements into the trust fund initially. The trustee's responsibilities include: (1) investing the funds; (2) providing an annual valuation of the fund to the owner and to EPA; and (3) accepting further deposits or releasing funds as new wells are drilled or as wells are plugged, respectively.

12 A standby trust fund is a trust fund that is not fully funded. This instrument is used as a payment mechanism in case of forfeiture of the primary financial instrument, either the surety bond or letter of credit. It differs from a regular trust fund in that periodic payments are not required to be made into it and its cost is much lower.

13 EFAB, "Financial Assurance for Underground Carbon Sequestration Facilities." (March 2010) (Report submitted to Peter Silva, Assistant Administrator, Office of Water, US EPA, March 31, 2010)

14 EPA's proposed rules would establish Class VI injection wells and technical criteria for: site characterization; area of review and corrective action; well construction and operation; mechanical integrity testing and monitoring; well plugging; post-injection site care; and site closure. The Class VI rules, which would apply to EOR plus CCS, build on the existing UIC framework and include modifications based on the unique nature of CO_2 injection for GS.

15 EOR BAU wells are Class II injection wells. Class II wells inject fluids associated with oil and natural gas production. In the EOR process, operators inject brine, water, steam, polymers, or CO_2 into oil-bearing subsurface rock formations to recover residual oil and natural gas. This process is known as secondary or tertiary recovery. The injected fluid decreases the viscosity or displaces small amounts of extractable oil and gas, making it recoverable.

16 Advanced Resources International. "US Oil Production Potential from Accelerated Deployment of Carbon Capture and Storage." (March 10, 2010) (Report prepared for the Natural Resources Defense Council)

17 The UIC regulations define six different classes of underground injection wells that are subject to regulation. Class II pertains to oil- and gas-related wells. Class VI covers geologic sequestration wells. The regulations establish different standards for each class.

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i C. Michael Ming and L. Stephen Melzer. "CO_2-EOR: A Model for Significant Ccarbon Reductions," Provided to MITEI and UTBEG Symposium on the Role of Enhanced Oil Recovery in Accelerating the Deployment of CCS, July 23, 2010.

ii Kuuskraa paper.

iii Kuuskraa.

iv Kuuskraa.

v Susan D. Hovorka, "EOR as Sequestration—Geoscience Perspective," Provided to MITEI and UTBEG Symposium

on the Role of Enhanced Oil Recovery in Accelerating the Deployment of CCS, July 23, 2010.

vi Hovorka, 2010.

vii James Dooley, RT Dahowski, CL Davidson. "CO_2-driven Enhanced Oil Recovery as a Stepping Stone to What?", Provided to MITEI and UTBEG Symposium on the Role of Enhanced Oil Recovery in Accelerating the Deployment of CCS, July 23, 2010.

viii Vello A. Kuuskraa, Robert Ferguson. "Storing CO_2 with Enhanced Oil Recovery," 2008.

ix Vello A. Kuuskraa. "CO_2 Challenges of Implementing Large-Scale CO_2 Enhanced Oil Recovery with CO_2 Capture and Storage," Provided to MITEI and UTBEG Symposium on the Role of Enhanced Oil Recovery in Accelerating the Deployment of CCS , July 23, 2010.

x Kusskraa, 2010.

xi MITEI Symposium *Report on the Retrofitting of Coal-Fired Power Plants for CO_2 Emissions Reductions*, March 23, 2009.

xii Intergovernmental Panel on Climate Change *Report on CO_2 Capture and Storage*, 2005.

xiii IEA Green House R&D Programme, Opportunities for Early Application of CO_2 Sequestration Technology.

xiv Perry M Jarrell, *Practical aspects of CO_2 flooding*, Richardson, Tex. : Society of Petroleum Engineers, 2002.

xv Kuuskraa, 2010.

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ABBREVIATIONS / ACRONYMS

ACES	American Clean Energy and Security Act
API	American Petroleum Institute
ARI	Advanced Resources International
AOR	Area of Review
bbl	Barrels of Oil
BBO	Billion Barrels of Oil
bbl/t	Barrel of Oil per Ton
BLM	Bureau of Land Management
BOPD	Barrels of Oil per Day
CCS	Carbon Capture and Sequestration
CO_2	Carbon Dioxide
CO_2-EOR	Process by which CO_2 is injected into depleted oil fields for the purpose of recovering oil from the primary and secondary products
DOE	Department of Energy
DOE/NETL	Department of Energy/National Energy Technology Laboratory
DOI	Department of Interior
DSF	Deep saline formation
ECAR	East Central Area Reliability Coordination Agreement
EDF	Environmental Defense Fund
EFAB	Environmental Financial Advisory Board
EIA	Energy Information Administration
EOR	Enhanced Oil Recovery
EOR-BAU	Enhanced Oil Recovery-Business as Usual
EOR-CCS	Enhanced Oil Recovery as a means of carbon sequestration
EPA	Environmental Protection Agency
EPAA	Emergency Petroleum Allocations Act
ERCOT	Electricity Reliability Council of Texas
FRDC	Federal Dispute Resolution Conference
GHG	Greenhouse Gas
GT	gigaTon
GW	gigaWatt
GWe	gigaWatt Electric
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
Mcf	Thousand Cubic Feet
MITEI	MIT Energy Initiative
MSG	Multi-Stakeholder Group
MPZ	Main Pay Zone
MRR	Mandatory Reporting Rule
MRV	Monitoring, Reporting, and Verification
MT	Metric Ton
MW	Megawatt
NEMS	National Energy Modeling System
NRDC	Natural Resources Defense Council
R&D	Research and Development
RD&D	Research, Development, and Demonstration
RCRA	Resource Conservation and Recovery Act
ROZ	Residual Oil Zone
RPSEA	Research Partnership to Secure Energy for America
TARP	Troubled Assets Recovery Program
UIC	Underground Injection Control
UT-BEG	University of Texas Bureau of Economic Geology

APPENDICES

A. Symposium Agenda

B. List of Participants

C. White Paper, MITEI and the Bureau of Economic Geology BEG, *CO_2-EOR*: *A Model for Significant Carbon Reductions (Framing)*

D. White Paper, James Dooley, RT Dahowski, CL Davidson, *CO_2-Driven Enhanced Oil Recovery as a Stepping Stone to What? (Framing)*

E. White Paper, Susan D. Hovorka, Bureau of Economic Geology, University of Texas at Austin, *EOR as Sequestration – Geoscience Perspective (Panel 1: Geoscience)*

F. White Paper, Vello A. Kuuskraa, President, Advanced Resources International, Inc., *Challenges of Implementing Large-Scale CO_2 Enhanced Oil Recovery with CO_2 Capture and Storage (Panel 2: Implementation)*

G. White Paper, A Scott Anderson, Environmental Defense Fund, *Carbon Sequestration in Oil and Gas Fields (in Conjunction with EOR and Otherwise): Policy and Regulation Issues, (Panel 3: Policy and Regulation)*

SYMPOSIUM AGENDA

Role of Enhanced Oil Recovery in Accelerating the Deployment of Carbon Capture and Sequestration

Hosted by the MIT Energy Initiative and the Bureau of Economic Geology,
The University of Texas Austin
July 23, 2010

8:30–8:45	**Welcome**		
	Ernest J. Moniz, Director, MIT Energy Initiative		
	Scott Tinker, Director, Bureau of Economic Geology, UT Austin		
8:45–9:45	**Framing the Issue: Accelerating CCS through EOR?**		
	White Paper Authors:	C. Michael Ming, Research Partnership to Secure Energy for America (RPSEA) and Stephen L. Melzer, Melzer Consulting	
	White Paper Author:	James Dooley, Joint Global Change Research Institute, Pacific Northwest National Laboratory	
	Discussant:	Tracy Evans, Denbury Resources Inc.	
9:45–10:15	Break		
10:15–11:30	**Panel**		
	Geoscience		
	What is the CO_2 sequestration potential of EOR in the US? What is the "cost curve" in terms of amounts of CO_2 useful for EOR at various prices? How are issues of "permanence" to be addressed? What is the value of EOR for informing a longer-term large-scale sequestration program, especially in deep saline aquifers?		
	White Paper Author:	Susan Hovorka, Bureau of Economic Geology, UT Austin	
	Discussant #1:	John Tombari, Schlumberger	
	Discussant #2:	Ruben Juanes, MIT	
	Discussant #3:	Daniel Schrag, Harvard University	
11:30–12:30	Lunch		
12:30–1:45	**Panel**		
	Implementation		
	What are the prospects and challenges for implementing a large near-term EOR program with anthropogenic sources? What are the infrastructure needs for connecting sources to EOR sites? What are the economics: value of oil produced? Value of CO_2 sequestered? Impact on the CO_2 generator? What are the technical risks? How will costs and risks be shared?		
	White Paper Author:	Vello Kuuskraa, Advanced Resources International, Inc.	
	Discussant #1:	Ian Duncan, Bureau of Economic Geology, UT Austin	
	Discussant #2:	Howard Herzog, MIT	
	Discussant #3:	John Thompson, Coal Transition Project, Clean Air Task Force	

1:45–3:00 **Panel**

Policy and Regulation

What regulatory requirements should be placed on the EOR activities? What verification program would be required for monetizing the sequestered CO_2? What effect will these requirements have on the EOR value proposition? How would the EOR activity inform a longer-term larger-scale sequestration regulatory program for deep aquifers? How should policy address and possibly incentivize the integrated system of public and private interests?

White Paper Author:	Scott Anderson, Environmental Defense Fund
Discussant #1:	Sean McCoy, Carnegie Mellon University
Discussant #2:	Philip Marston, Marston Law
Discussant #3:	David Hawkins, Natural Resources Defense Council

3:00–3:30 Break

3:30–4:15 **Discussion/Wrap-Up**

Co-Chairs

Ernest J. Moniz, MIT

Scott Tinker, UT Austin

LIST OF PARTICIPANTS

Role of Enhanced Oil Recovery in Accelerating the Deployment of Carbon Capture and Sequestration

Hosted by the MIT Energy Initiative and the Bureau of Economic Geology,
The University of Texas Austin
July 23, 2010

Ernest Moniz	MIT Energy Initiative	Co-Chair
Scott Tinker	Bureau of Economic Geology University of Texas Austin	Co-Chair
Allyson Anderson	US Senate Energy and Natural Resources Committee	
Scott Anderson	Environmental Defense Fund, Texas Regional Office	
Robert Armstrong	MIT Energy Initiative	
Daniel Blankschtein	MIT	
Amy Bowe	Hess Corp.	
Peter Brovero	CCAT	
Danielle Carpenter	Chevron	
Doug Cathro	Leucadia Energy, LLC	
Steve Crookshank	API	
Nicola De Blasio	Eni	
Phil Dipietro	National Energy Technology Laboratory (NETL), DOE	
Jim Dooley	Joint Global Change Research Institute	
Ian Duncan	University of Texas Austin	Discussant
Darick Eugene	Texas Carbon Capture & Storage Association	
Tracy Evans	Denbury Resources Inc.	Discussant
Steve Feldgus	House Natural Resources Committee	
Mike Fowler	Clean Air Task Force	
Scott Frailey	ISGS, Illinois	
Victoria French	TAQA North Ltd	
Bernard Frois	CEA	
David Hawkins	Natural Resources Defense Council (NRDC)	
Howard Herzog	MIT Energy Initiative	Discussant
Joseph Hezir	EOP Group, Inc.	
Paul Hinnenkamp	Entergy	
Susan Hovorka	University of Texas Austin	
Carrie Johnson	Brownstein Hyatt Farber Schreck, LLP	
Hunter Johnston	Steptoe & Johnson LLP	
Ruben Juanes	MIT	Discussant
Melanie Kenderdine	MIT Energy Initiative	
Chris Knepler	Australian Trade Commission	
Vello Kuuskraa	Advanced Resources International, Inc.	
John Litynsky	National Energy Technology Laboratory (NETL), DOE	
Theo Mallinson	Siemens Energy, Inc.	
Thomas Mara	Leucadia Energy, LLC	
Phil Marston	Marston Law	
Sean McCoy	Carnegie Mellon University	

LIST OF PARTICIPANTS continued

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James Rice	ICF International	
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Mohamed Sassi	Masdar Institute	
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Lanny Schoeling	Kinder Morgan CO_2 C.LP	
Daniel Schrag	Harvard University	Discussant
Richard Sears	MIT Energy Initiative	
Tariq Shamim	MIT	
Robert Shannon	Siemens Energy, Inc.	
Kyle Simpson	Brownstein Hyatt Farber Schreck, LLP	
John Stamos	US Department of Energy	
John Steelman	Natural Resources Defense Council (NRDC)	
Vauhini Telikapalli	Alstom Power	
John Thompson	Clean Air Task Force	Discussant
John Tombari	Schlumberger Carbon Services	Discussant
Ibrahim Toukan	MIT Energy Initiative	
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Maher Uraijah	Aramco Services Co.	
Mahendra Verma	US Geological Survey	
Mike Walker	E3 Gasification	
Nick Welch	Global CCS Institute	
Pak Yuet	Dalhousie University	
Kurt Zenz House	MIT	

Symposium on the Role of EOR in Accelerating the Deployment of CCS

CO_2 EOR: A MODEL FOR SIGNIFICANT CARBON REDUCTIONS

The MIT Energy Initiative MITEI
The Bureau of Economic Geology BEG

July 23, 2010

Massachusetts Institute of Technology

Cambridge, Massachusetts

C. Michael Ming and L. Stephen Melzer

Research Partnership to Secure Energy for America

Melzer CO_2nsulting

CO_2 EOR: A MODEL FOR SIGNIFICANT CARBON REDUCTIONS

The Oilfield Opportunity

One of the multiple future technology options required to mitigate carbon emissions from traditional fossil fuel power generation and other industrial processes is to capture and sequester (CCS) those emissions. Yet, at present, CCS at any meaningful scale relative to the extraordinary volumes of CO_2 emissions being produced is still years and possibly decades away. Capture costs appear to be unacceptably high, the "energy penalty" for capture on conventional existing coal fired power is far too high, the distribution network to move the CO_2 to repositories is mostly not in place, and the determination of safe and acceptable permanent repositories is not ready for accepting CO_2 for a multitude of reasons. Yet at the same time there is actually high demand and higher potential for CO_2 in existing oilfield tertiary enhanced oil recovery (EOR) operations where there exists both amenable pore volume and established CO_2 related infrastructure and expertise.

This paper will present two themes. The first theme is that hydrocarbon pore volume in current or potential EOR operations is readily available, accessible and more relevant than has been recognized, but also that new research and field trials of a new class of hydrocarbon pore volume is expanding known usable hydrocarbon pore volume by orders of magnitude. The second theme is that transforming EOR operations from merely commercial oil production operations to carbon storage operations requires a strategically planned and commercially incentivized research program. This program will necessarily be at large scale on both sources and sinks (critically enabled by a yet to be completed distribution system) to provide the necessary framework and risk mitigation to certify the EOR operations as acceptable permanent storage volumes. Without adequate research today at large scale, this paper will present why existing EOR operations are the logical place to begin if CCS is to be proven viable and developed as a mitigation option more broadly.

Too Much or Too Little CO_2?

There is an abundance of combustion-derived anthropogenic CO_2 yet there is virtually no mechanism to utilize it to meet existing or potential EOR demand. What policies, technologies, and science are required to address this mismatch? And with the greenhouse gas effect "cumulative present value" of an emitted molecule today being much higher than that of an equal molecule emitted 10 or 20 years away, there is urgency to both reduce CO_2 emissions short term and accelerate the development of the CCS option to keep the molecule out of the atmosphere in the first place. Perfecting this CCS option for full-scale implementation in 10 or 20 years, while a prudent and necessary component to have in a toolkit where not all the requirements have yet to be defined, is not an acceptable timeframe. And since the CCS option may not be as relevant or applicable to an unknown future energy portfolio in 10 or 20 years, it is imperative to develop and enable some components of the CCS option in a time frame of years, not tens of years.

A Paradigm Shift in Thinking

In order to foster this accelerated CCS development, there are several key attributes that must be acknowledged to meet the desired timing and scale objectives. These are:

1. The critical importance of a commercial driver to create wealth and incentivize the "all-in" participation of the private sector
2. The relevancy and potential of hydrocarbon pore volumes, depleted or not
3. The necessity of an extensive pipeline distribution network
4. A program designed for near term scale
5. A program designed to address the "chicken and egg" problem of science and research to lower capture technology costs multifold versus establishing the repositories for the CO_2 if it can be captured economically
6. The program must be more than a "clean coal" program

Creating Wealth

Acknowledging these attributes can move the needle off of near zero to begin putting meaningful amounts of CO_2 in the ground, and also moves the issue from merely a conference conversation to a reality. In addition the model proposed by this paper meets important parallel goals of creating jobs, minimizing costs to the public, and enhancing national security through the creation of a real and viable industry that can attract market capital and increase domestic oil production. Increasing domestic oil production not only creates wealth and royalties, and improves the balance of trade, but also provides important supply diversity to mitigate the risk of geopolitical oil supply disruptions caused by the combination of an overreliance on imported oil, especially in the vulnerable transportation sector which is virtually totally dependent on petroleum.

Debunking Myths

In order to accept the commercially driven oilfield pore volume option, there are a number of "myths" that must be debunked, including for example the myth that oilfield pore volumes and EOR operations are insufficient in volume to make a difference. Not only are the depleted or partially depleted pore volumes extensive in existing "brown field" tertiary oil developments (Kuuskraa), but there also exist partially oil saturated intervals below the existing oil main pay zones (MPZ), which provide "quaternary" oil development opportunities. These relatively new quaternary opportunities are commonly referred to as residual oil zones (ROZ). These ROZs, which will be discussed in more detail later, are far more extensive in both thickness and areal extent than the significant MPZs which could alone, if effectively exploited, store significant volumes of CO_2. In addition, ROZs are believed to exist outside of the traditional oil provinces and can also provide an important scientific and technical proxy for the future development of pure saline aquifers for CCS.

Getting Started and Managing Risk

So what is the key to unlock this CCS option? Clearly effective policies to address and protect the public interest while incentivizing the private sector are required, and these policies must be science based. Funding a relevant monitoring overlay on existing CO_2 EOR operations at meaningful scale is a public interest and is a must. Also managing long term risk for an endeavor of this magnitude is critical in order to allow the private capital markets to function effectively. An incremental approach is an efficient and effective risk management tool as it allows the exploitation of existing system assets by first enabling the most promising opportunities then providing a build out option at the margin for smaller opportunities. As the cost of both capture and sequestration is reduced with time, the opportunities at the margin grow and the system continues to expand. The incremental approach allows the application of classic tranche based risk management.

Using History to Model a New Public Private Opportunity

An intermediary "agent" between the requisite public R&D and the private sector application for both sources and sinks could be a pseudo public opportunity for the creation of the pipeline distribution network that connects the sources and sinks. Such endeavors have been successful in history including the example of the U.S. ***transcontinental railroad*** after the Civil War. Translating the need for a transcontinental railroad into reality required not only policy and capital but also more importantly leadership and vision. It has been said by some that the development of the transcontinental railroad was one of the most important events in American, if not global, history. It opened up economic development in North America and subsequently the entire world. In a period of less than a decade it reduced the transit time from New York to San Francisco from six months to six days, probably more important than the reduction over ensuing decades of six days to six hours from trains to airplanes.

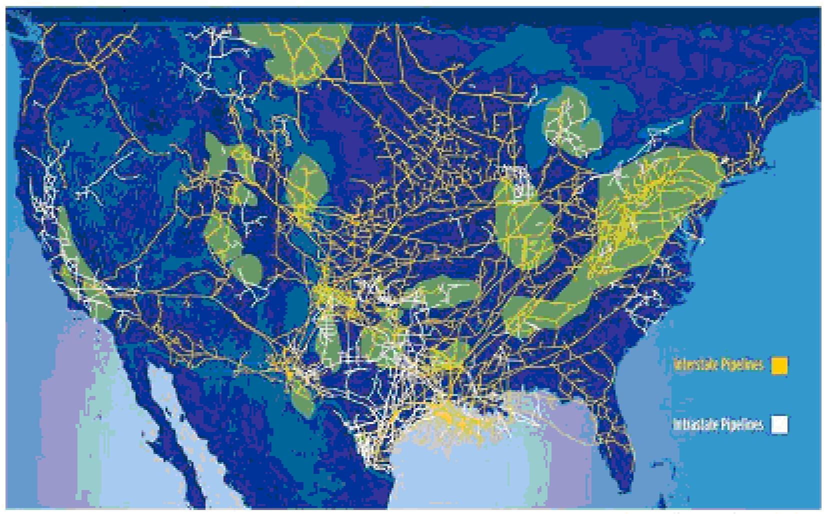
The transcontinental railroad was created by the unique confluence of existing skills. First it required the leadership and endorsement by one of the greatest presidents in U.S. history, Abraham Lincoln. It also had to have the vision of those who understood its profound and immense potential. Due to its unprecedented logistical complexity it required the expertise that could only be provided by the experienced military leaders from the Civil War to actually pull it off. And it required the deal making, and risk taking, financiers to find the capital for it all, incentivized by a unique structure of bonds authorized based on miles of line actually laid. It required new routing, but it also incrementally built and expanded upon existing railroad routes from the Midwest. At its completion it may have been successful because it wasn't perfect, which in some odd ways probably mitigated some of its enormous risk. There were several "routes" that could have been taken, but multiple routes probably would not have garnered the necessary public traction, and certainly would have taxed the available resources, maybe even have killed the whole idea. The project was, in the end, effective although not exactly efficient, and was in fact actually very messy both in financial and human terms. But it happened, and in many respects was instrumental in the establishment of United States as the global superpower it is today. There was a vision, an urgent need, and the national will and perseverance to make it happen.

Leveraging Existing Policy/Infrastructure

While the transcontinental railroad, at least past its Midwestern origin, was built entirely from scratch across mostly uninhabited territory, another example of a game changing development in the U.S. has been the development of ***unconventional natural gas resources***. In contrast to the transcontinental railroad, unconventional gas developed from anything but scratch. In fact unconventional gas was in many ways a serendipitous development resulting from the infrastructure put in place for the development of conventional oil and natural gas resources. This existing infrastructure (Fig. 1) for conventional resources was quite convenient, if not coincidental for the development of unconventional resources, and turned out to be extremely efficient and effective to logically leverage and extend conventional oil and natural gas development for unconventional resource development.

Fig. 1

U.S. Natural Gas Shale Basins Align with Pipeline Grid



Source: EIA, US Natural Gas Pipeline

Geologists had for decades searched for impermeable barriers that "trapped" hydrocarbons in permeable rocks that resulted from the migration of hydrocarbons (or leaks) from the original source rocks. The source rocks, although once thought to be unproduceable, were well documented and mapped. At some point geologists and engineers realized that with the right tools and technology the source rocks may actually be the ultimate prize due to their immense scale. With the infrastructure, regulatory, and legal framework all in place from years of conventional hydrocarbon development, the same framework could be easily utilized for the exploitation of unconventional natural gas resources even though the technical hurdles were formidable and required extraordinary research efforts, iterations, and perseverance to overcome. In hindsight unconventional gas might never have become a reality should it have required complete system development from scratch; that had already been provided by its predecessor - conventional oil and natural gas development. Full system development combined with the technical uncertainties of establishing economical production in meaningful quantities from basically impermeable rocks, rocks once thought only to be unproduceable geologic marker beds, may well have been more risk than the capital markets would be willing to finance.

In the course of developing conventional oil and natural gas reservoirs in a multitude of geologic basins, a service infrastructure and pipeline network developed incrementally, and markets logically developed for this valuable and convenient natural gas energy source. Mineral ownership issues were resolved by legislation and within court rooms over time, and effective regulatory policies were developed to protect the public interest and the environment. All of this provided the requisite economic incentives for the capital markets to work efficiently, all protected by a judicial system, which although not perfect is transparent and effective in providing the requisite legal certainty for the capital markets to function confidently.

Creating a New Hybrid Model

So from the example of the transcontinental railroad developed from scratch to the example of unconventional gas development built on the back of a similar and existing resource, where does this leave the development of CCS? A national CCS implementation could easily be a hybrid of the two different models. Clearly there are components that must be developed either from scratch or pushed out of their infancy of development. Measurement, verification, and permanency are all processes that need refinement and emphasis. Long term stewardship issues have to be resolved, and pore volume usage and ownership must be established. New pipelines and distribution networks need to be financed and built, but could be done so with a pseudo public variation of the transcontinental railroad, for example climate change bonds sold to the public via a quasi governmental agency.

But there are also clearly many existing system components of the hydrocarbon pore volume model that provide a significant and indispensible jump start to accelerate CCS to meet an urgent need and provide the tools to promote the national will to accomplish it. The oil and natural gas industry is where the subsurface fluid flow and storage expertise resides, versus, for instance, the clean coal program which is driven by the surface capture side of the equation due to the volumetric challenges of the emissions from coal fired power generation. Existing tertiary EOR operations are also well along the learning curve of transporting, injecting, processing, and operating with CO_2. There is a well-established CO_2 industry that can be exploited and leveraged. And importantly there are significant CO_2 pipeline segments that could form the critical foundation for a nationally interconnected CO_2 pipeline distribution network from the Midwest through the Gulf Coast to West Texas, up through the Rockies to the Canadian border, with opportunities for spur developments at the margin all along the way (see Fig. 2). And these existing building block pieces of pipe connect to well-characterized geological settings and available pore volume that is ripe for exploitation, both in MPZs and, for the future, ROZs.

Rethinking the Value of Depleted Oil Reservoirs

Once thought to be only a plugging liability at abandonment, depleted pore volume, with its remaining residual oil saturation and partially depleted pressure regime, provides both an economic driver and unexploited storage “vault space.” Existing EOR operations are generally being conducted in legacy operational areas where the public is accustomed to and generally supportive of an extractive industry footprint. Breathing new life into aged fields will generally be welcomed by the public. This public acceptance mitigates many of the risks of costly startup delays such as establishing access, subsurface unitization, and the establishment of effective regulatory oversight and permitting.

The "Horseshoe Pipeline"

The aforementioned foundational CO_2 pipeline building blocks that currently exist could, with a strategic blueprint, provide an efficient and effective grid to interconnect existing EOR basins with anthropogenic sources nationally (Fig. 2). At some later stage, this system could also backhaul CO_2 back to the natural source CO_2 domes, initially to provide volumetric buffering but ultimately to refill the natural source domes as permanent repositories. The critical but small number of natural source CO_2 domes are shrinking and most will find their historical competitive advantage diminished as their pressures deplete. This potential pipeline system "build out," financed by a quasi-governmental effort, could become a wealth creating public asset to mitigate climate change risk caused by carbon emissions while at the same time creating new sources of revenue to finance future transformative R&D efforts in energy.

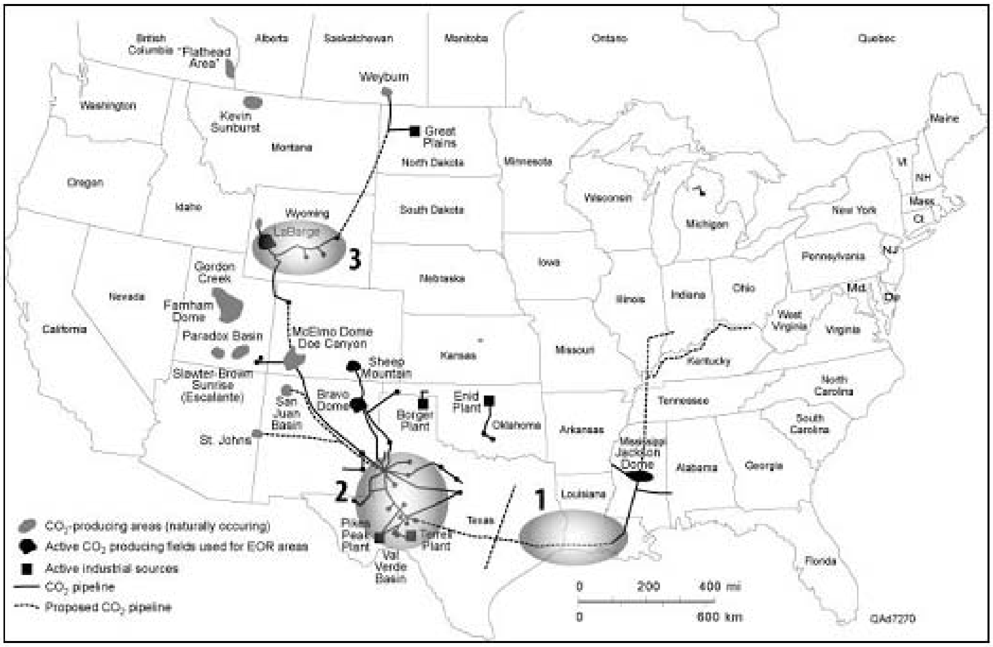


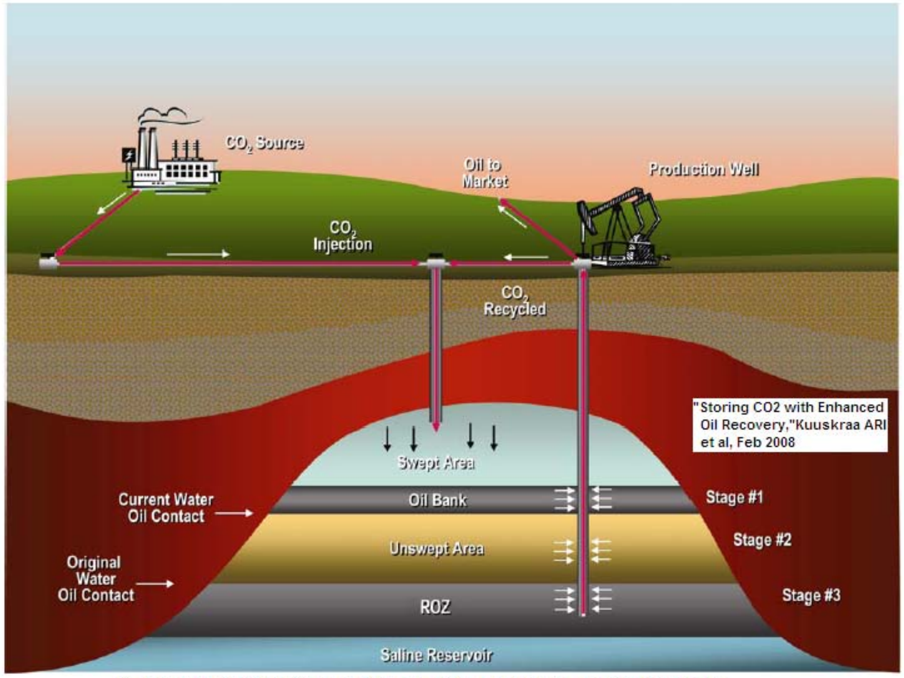
Fig 2: A Framework Depiction of a Natonal CO2 Pipeline Network ("The Horseshoe"). The Shaded ellipses Represent Three Areas Where Very Large EOR/CCS Projects are Active or Proposed

Accelerating the Value with Effective Energy Policy

The hydrocarbon pore volume provides a quick start opportunity at scale. While studies such as Kuuskraa et al have documented the significant volumetric potential for EOR of up to 67 one gigawatt coal fired power stations, the new ROZ potential cold increase that potential by orders of magnitude (Fig. 3). Yet just using the existing potential documented by Kuuskraa could be leveraged even further by effective public policy that could significantly reduce carbon emissions from a much more optimal and integrated energy system.

Efficiency leverages all forms of supply. Deploying an optimal electric power portfolio that incorporates natural gas, efficiency, and renewable power could alone reduce carbon intensity by 10 to 20 fold in certain applications over a current antiquated coal fired system with conventional distribution and end use components (See Fig. 4). MIT and others have estimated that just the replacement of the bottom third of antiquated and worst performing pulverized coal plants could alone reduce carbon emissions by almost 10%.

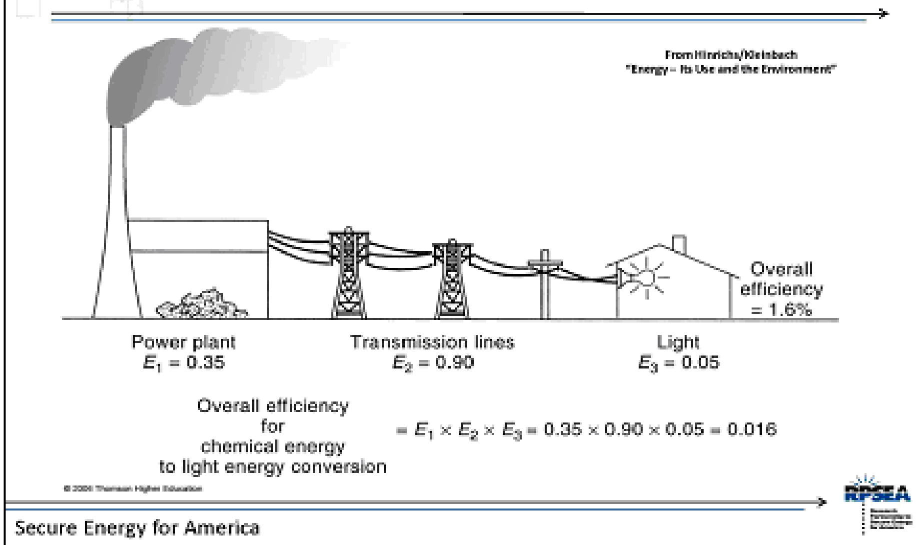
Fig. 3 - Illustration of "Next Generation" Integration of CO_2 Storage and EOR



Capacity of offset 67 ea 1 GW coal fired power plants in 27 states

Fig. 4

Look at the System Backwards



Reducing carbon emissions is the logical and most economical first step to leveraging the potential of CCS, as the CO_2 units that are ultimately sequestered then become a larger percentage of total emissions. Making the emission problem more manageable makes CCS more practical, otherwise the sheer scale of the problem may prove unsolvable. Continuing to unnecessarily combust fossil fuels in inefficient process produces unnecessary CO_2 emissions. It has been estimated by Lawrence Livermore National Laboratory that the U.S. wastes 60% of its primary energy, the energy equivalent of 30 million barrels of oil per day (MMBOPD), mostly in waste heat. Capturing just 10% of that waste, certainly easily technically achievable, with effective public policy would amount to 3 MMBOPD. And that is then 3 MMBOPD that is no longer emitting CO_2 from its combustion. Increasing U.S. domestic oil production by another 3 MMBOPD (by 2030) through state of the art EOR either in MPZs or ROZs (Kuuskraa NRDC), for a total of 6 MMBOPD, would then equal one half of the energy equivalent of the total level of current oil imports of 12 MMBOPD.

The Chicken and Egg Dilemma

So how does this proposal address the previously mentioned chicken and egg problem for R&D? Matching large scale readily available sinks with anthropogenic sources incentivizes the development of economic capture technology which is all enabled by the ability to get the CO_2 from the source to the sink. The private sector provides the sources and the sinks, possibly a quasi governmental agency finances the connection of the sources and the sinks, and effective public R&D provides the funding for the relevant scientific overlay on existing operations to transform those operations from purely commercial EOR to ultimately CCS in the public interest. And in the process an existing industry transforms itself into a larger industry, creating real wealth and real jobs while addressing an urgent risk for future generations. But it is ultimately the certain availability of the large sinks that provides the assurance that is required to develop economical capture technology.

An Integrated Approach

While this proposed model is a logical approach to accelerate CCS at nearer term scale, it still requires an integrated approach, just as the transcontinental railroad required vision, leadership, and a well planned route so that the simultaneous efforts being built from the east and the west would meet at the right point. In addition the railroad required logistical support and expertise and financing. The proposed EOR model requires many of these same attributes but can also significantly leverage a partially yet well developed infrastructure just as unconventional natural gas has done. And the science for CCS is just as formidable as was the development of unconventional gas. It is not without its risks, but it is also achievable with the appropriate engagement of the research community. The analogy to substantiate the value of the integrated approach could be taken one step further to compare the potential of conventional traps to the much larger volume of source rocks for unconventional development – in this case the pore volume potential of MPZs is a small fraction of the larger ROZ volumes, just as unconventional resources have been estimated to be as much as nine times the potential of conventional resources in a given basin by Holdtich et al.

Vision and Leadership

The vision and leadership for CCS has yet to fully emerge, and the public debate seems bogged down in waste disposal type proposals which ignore the difficult issues with waste handling, the valuable potential contribution of the oil and natural gas industry, and the invaluable commercial driver incentive that the oil revenue provides. And finally the continued avoidance of the issue of scale remains problematic in anything energy related, be it production, consumption, waste, or emissions. Utilizing ‘bird-in-the-hand’ pore volume and managing emissions have unique synergies to deal with the scale issues in the near term. The point is CCS is best addressed in the context of effective and integrated national energy policy.

Americans in the 1800’s were no longer willing to continue to sail around South America and risk shipwreck, trek across the Isthmus of Panama and risk malaria, or wagon train across the west and risk attacks from those not happy with them intruding. Each travel option took about six months, and the passenger had the option to choose their risk. So in looking for alternatives such as developing better ships, a cure for malaria, or the complete extermination of native Americans, Americans instead chose to build the railroad. They greatly reduced the travel risks, decreased the travel time ten-fold, created a new industry and global economy, and possibly established a new tourism industry. Today America can step up to the global leadership role the world expects, enhance its national security and the security of the world, and mitigate the risk of filling the atmosphere with carbon. The choice is before us now.

So where and how should this to begin? While there are many hydrocarbon pore volume opportunities where CCS is and will be applicable, certainly one of the largest and most promising areas in the world is the Permian Basin (PB) in West Texas. It is here where groundbreaking ROZ R&D is underway, and it is here where the largest tertiary CO_2 EOR operations in the world are occurring.

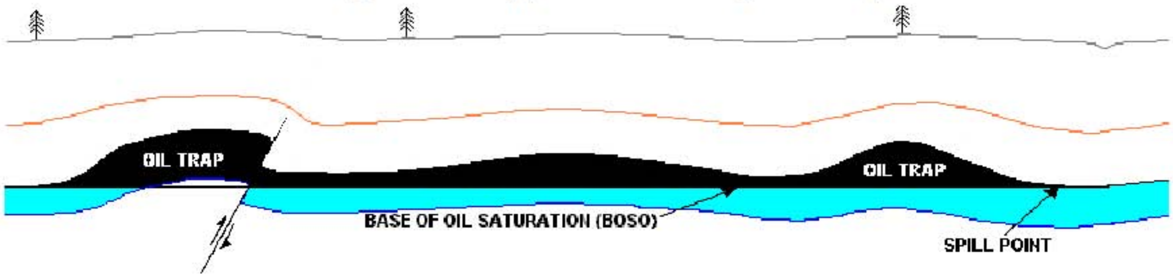
The Permian Basin as an EOR Sink

Two very recent discoveries in the PB have converged with higher oil prices to create a new excitement. The enormity of the prize is just beginning to be understood and is challenging the long held myths that on-shore oil production is scheduled for the ash heap of history and that CO_2 EOR is insignificant in the grand scheme of volumetric requirements for carbon sequestration.

Discovery Number 1: ROZ Science: Zones Below the Oil/Water Contact are Widespread and Rich in Residual Oil Saturation

Work originally sponsored by the U.S. Department of Energy and accelerated by the Research Partnership to Secure Energy for America (RPSEA) has demonstrated both the origin and now the distribution of what have come to be known as Residual Oil Zones (ROZs). For many years, the intervals were believed to owe their existence solely due to capillary forces between the oil, water and rock and called transition zones. Although these forces, including surface tension, are crucial to the oil saturation profile, they do not explain the massive thicknesses observed under existing field's main pay zones (MPZ) nor their presence in places where no MPZs are present. Beyond capillarity, what is additionally at work are two or more stages of tectonics wherein the entrapment phase was followed by a subsequent one that 1) tilted the original entrapment, or partially flushed it by 2) a seal breach that reformed in time and reentrapped hydrocarbons {a vertical flush} or 3) lateral sweep by hydrodynamics (Fig. 5). This third type creates a tilted oil/water contact and offer ROZs with thicknesses of 300 feet or more in the San Andres Formation of West Texas. These reservoirs and the associated phenomena of sulfur generation, pervasive dolomitization and oil wetting are being more fully characterized in the Permian Basin by the RPSEA work conducted by The University of Texas of the Permian Basin (UTPB) .

Figure 5a: Hypothetical Original Trap



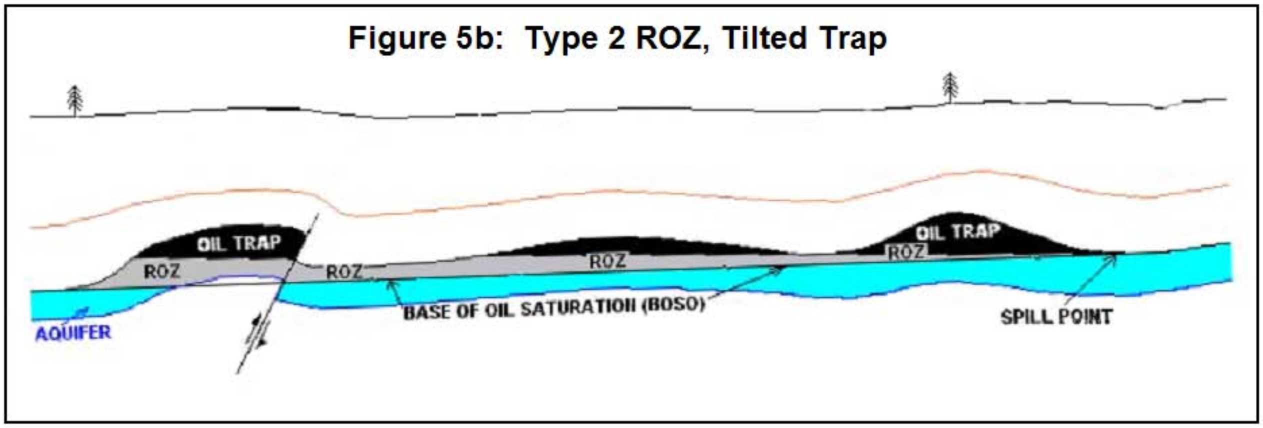
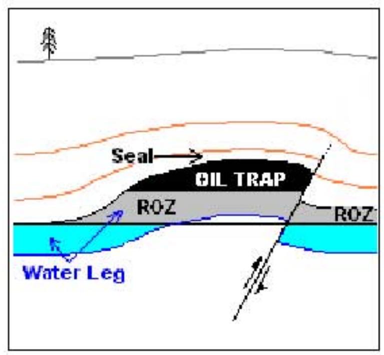
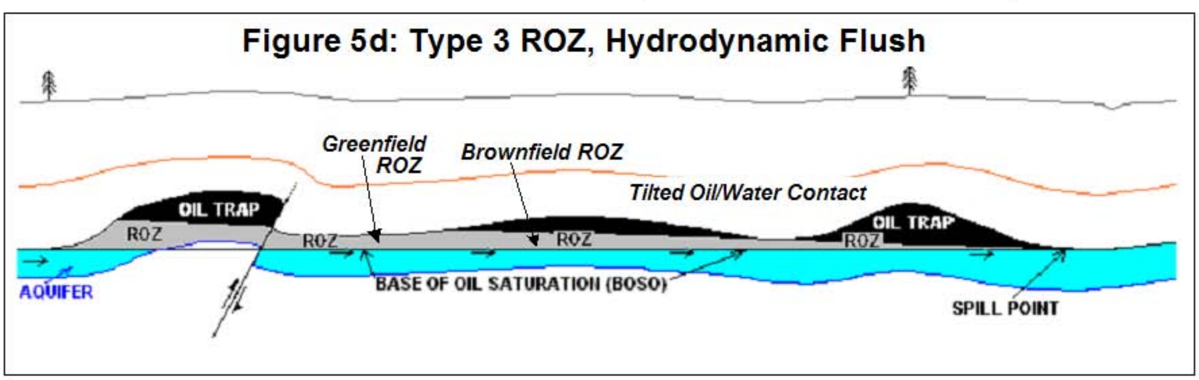


Figure 5c: Type 2 ROZ, Breached & Reformed Seal



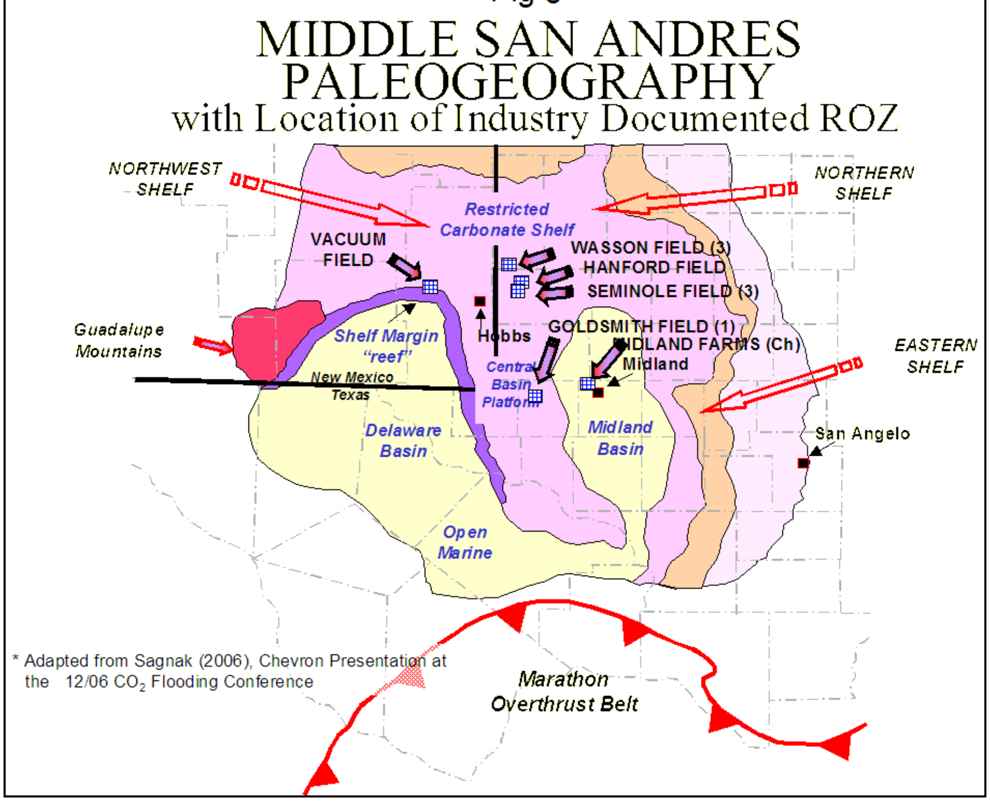


Discovery Number 2: Demonstration of Project Commerciality of CO_2 EOR Below the Oil/Water Contact

The on-going science and resource characterization is accompanied by commercial demonstration projects. The nine CO_2 and one chemical EOR projects are shown in Fig. 6.

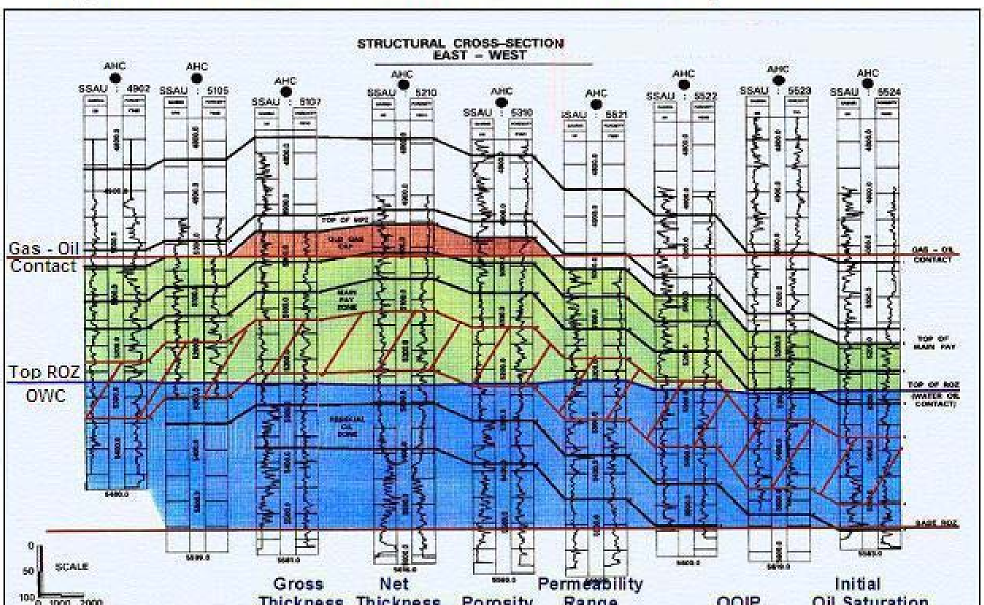
Two operators of these demonstrations have been open about sharing results: Hess Corporation and Legado Resources. Hess operates the Seminole San Andres Unit (SSAU) in Gaines County about 60 miles north of Midland. Fig. 7 illustrates the idealized west to east crossection in the south part of the field. Note the 250' thickness of the ROZ and the in-place oil comparisons in the MPZ and ROZ.

Fig 6



Hess has been operating the SSAU CO_2 project in the MPZ since 1983. It is one of the most successful CO_2 EOR projects in the world and has produced 65% of the billion barrels of original oil in place to date with 20% coming from the CO_2 EOR operations. They had long observed the residual oil saturation targets below the oil/water contact and began their commercial tests of the ROZ in 1997 with a

Fig 7: Crossection of Seminole Field Showing MPZ & ROZ



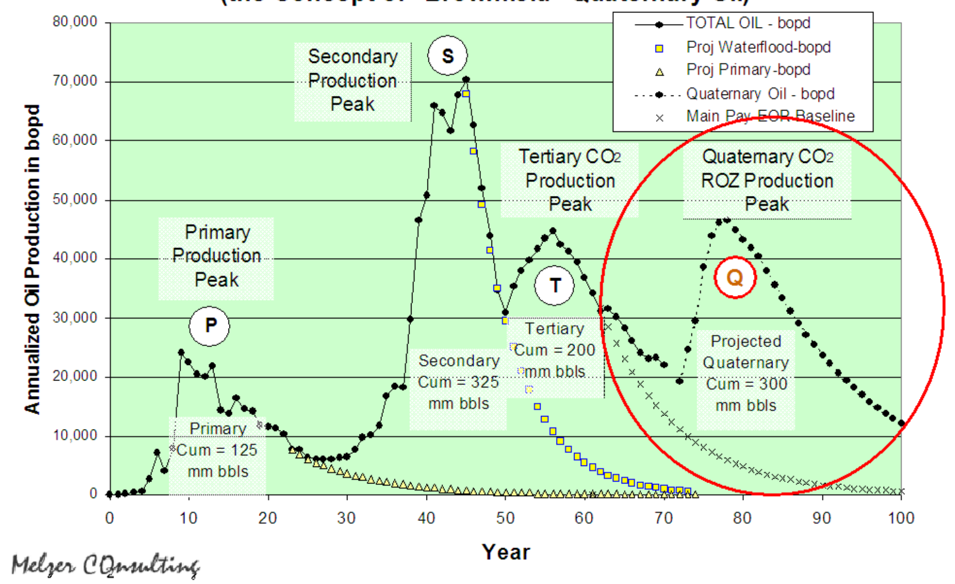
	Gross Thickness	Net Thickness	Porosity	Permeability Range	OOIP	Initial Oil Saturation
Main Pay Zone (MPZ):	160'	126'	12%	0.8-120 md	1 billion stbo	0.84
Residual Oil Zone (ROZ):	246'	197'	12.6%	0.5-270 md	0.96 billion stbo	0.32

commingled MPZ + ROZ ten-pattern pilot. The encouraging results led to the implementation of a dedicated ROZ 9-pattern project in 2002. Results of the second demonstration were even better, leading to a full-field implementation that they began in 2007. They recently provided the

SPE Reservoir Study Group in Houston an update of the progress on Stage 1 of the full field deployment program. The UTPB team has just completed their own analysis and made a forecast for the future given the hypothetical ability of the SSAU project to gain access to unlimited volumes of market based costs of CO_2. The forecast has been termed the “quaternary” phase of oil production at SSAU (Fig. 8).

The data support for the upslope forecast is now present; however, almost no information is available for establishing the actual peak or the decline slope except for the past tertiary phase and some proprietary compositional model simulations. Time will tell which of the two forecasts is closer to reality but, suffice it to say, at present that the quaternary peak will be present and large.

Fig 8:
Total, Primary, Waterflood, Main Pay and ROZ CO_2 Performance (the Concept of "Brownfield" Quaternary Oil)



This fourth phase of activity of reservoirs in the PB is what will be expounded upon in the following paragraphs. This on-going resource assessment is still in its first phase but, what is becoming very clear, the current levels of oil prices could support a very robust future for PB CO_2 EOR in the ROZ for the coming 30-50 years. What is currently missing, however, are the very large volumes of CO_2 that will be necessary.

Brownfields and Greenfields

The lateral hydrodynamic sweep of the paleo San Andres entrapments left a San Andres oil target in the MPZs of approximately 40 billion barrels. It swept an original oil entrapment more than twice as thick as SSAU MPZ. But Seminole was somewhat unique in leaving a 200’ thick M PZ. Many areas have just a few feet or even no MPZ with 300+ feet of ROZ. Since the oil is immobile, those areas had no primary or secondary oil production from the San Andres Formation. We have dubbed these “greenfields” as a developer will not have MPZ wells to deepen into the ROZ and they will be required to drill the pattern injectors and producers. No greenfield examples have been implemented as yet although new wells are currently being drilled as a lateral extension from a new CO_2 EOR brownfield project planned for injection start this fall.

Demand Drivers/Resource Estimations

Breaking the myth of CO_2 EOR as small targets has been difficult. However, the idea of huge new targets below the oil water contact (OWC) has not been considered in most resource assessments of the past. While it is true that these resources will be regional and volumetrically case-by-case specific, at least one area of the country has moved out of the theoretical to proven category

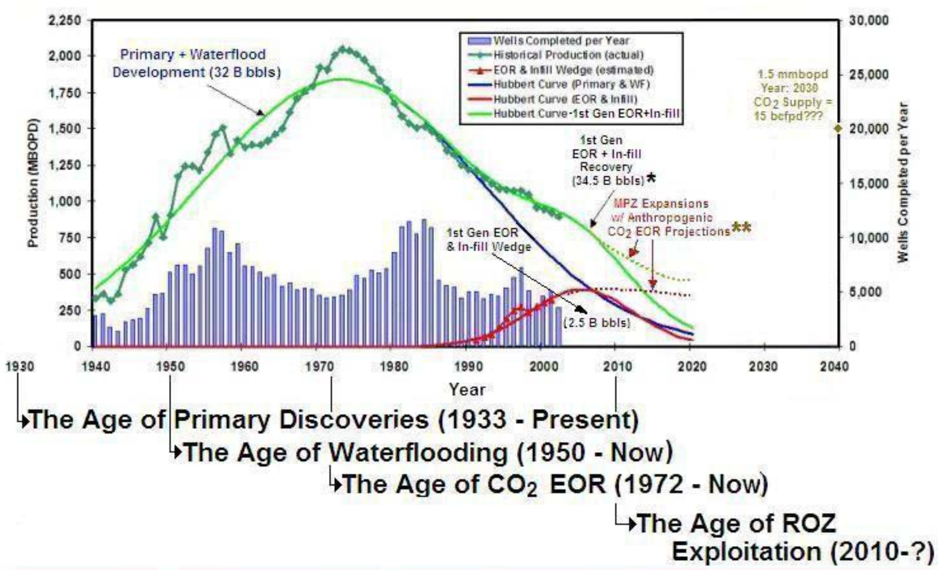
All of the detailed knowledge and the above work is currently concentrated in the PB San Andres Formation. Preliminary work has been done to look at other formations including the Grayburg, Glorieta, Clearfork and Abo/Wichita Albany. Privately sponsored work is also underway to examine other areas of the U.S. and Europe. It could be true that the uniqueness of the ROZ oil resource in the PB San Andres will overwhelm these other formations and regions but they are still quite worthy of assessment studies of their own.

Through work sponsored by the U.S. DOE, Advanced Resources International and Melzer Consulting have conducted a brownfield ROZ resource assessment. The existing fields in the data base were examined and the magnitude of the oil in-place resource in the reports (Refs 2-4) was 30.7 billion in the Permian Basin (with 11.9 billion technically recoverable) and 4.4 billion of in-place oil in the Big Horn and Southern Williston Basins combined. Based upon the greenfield concepts described above, the report dramatically underestimates the total resource. But it is worthy to stop and put the 11.9 billion barrel technically recoverable resource in perspective with the current cumulative oil produced to date from the Permian Basin MPZs. The number commonly given the PB is 32 billion barrels that has been produced through its 80-year life span. If the U.S. can get the 11.9 billion barrels from just these sampled brownfield ROZs, they would add almost 1/3rd as much oil to the Permian Basin (PB) as has been produced to date.

Finally, the process of elongating the tail of the Hubbert curve is alive and well. Fig. 9 illustrates the on-going process in the Permian Basin. Note the recent departure of the production from the Hubbert curve. Some analysis conducted by Occidental and supplemented by Melzer Consulting illustrates the effect of tertiary EOR and concommitant in-field drilling. Note too the four ages of production. It is very clear that the age of ROZ exploitation is not target oil opportunities but CO_2 supply dependent. The immense opportunity for growing reserves is very dependent on the availability of ample supplies of affordable CO_2. The magnitude of the in-situ

Fig. 9: PERMIAN BASIN OIL PRODUCTION

PRIMARY, SECONDARY, TERTIARY, & "QUATERNARY" PROJECTIONS



* Courtesy of Oxy Permian (9/05) ** "Main Pay Zone Project Growth w/ CO_2 Source Expansions" Melzer Consulting (2006)

*** Expanded to ROZ Targets Below OWC – Melzer Consulting (2010) resource could realize a 1.5 mmbopd production level by 2040 but if, and only if, the CO_2 is available.

CCS Monetary Implications

Finally, it is also important to think about the opportunity to store CO_2 from anthropogenic sources while producing this quaternary oil. Concurrent EOR and CCS should easily get 1.5-2.0 barrels of oil for each ton of CO_2 sequestered. Using the 11.9 billion barrel, technically recoverable PB (brownfield only) resource and assuming all of that is recoverable, that equates to 11.9 BBO of new oil. This will require (and sequester) 6-8 billion tons of CO_2. If the value of the stored carbon is say $10/ton, one can easily see the magnitude of this business. Then, if the value of oil is included at say at $70/bbl, it adds another $900 billion for a total of nearly one trillion dollars.

Conclusion

CO_2 EOR not only provides meaningful storage volumes, but importantly it provides the pragmatic path to move CCS from a conversation to a reality in a way that effectively and efficiently merges the public interest in carbon emission reductions with the real capability of the commercial sector for timely implementation. A purely waste-driven model, without a commercial driver, faces a much longer and more difficult path considering the magnitude of the investment which will be required. Getting started can be the most difficult task of all. With the necessary leadership and vision, CO_2 EOR provides that opportunity today.

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CO_2-driven Enhanced Oil Recovery as a Stepping Stone to What?

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July 2010

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ABSTRACT: This paper draws heavily on the authors' previously published research to explore the extent to which near term carbon dioxide-driven enhanced oil recovery (CO_2-EOR) can be "a stepping stone to a long term sequestration program of a scale to be material in climate change risk mitigation." The paper examines the historical evolution of CO_2-EOR in the United States and concludes that estimates of the cost of CO_2-EOR production or the extent of CO_2 pipeline networks based upon this energy security-driven promotion of CO_2-EOR do not provide a robust platform for spurring the commercial deployment of carbon dioxide capture and storage technologies (CCS) as a means of reducing greenhouse gas emissions. The paper notes that the evolving regulatory framework for CCS makes a clear distinction between CO_2-EOR and CCS and the authors examine arguments in the technical literature about the ability for CO_2-EOR to generate offsetting revenue to accelerate the commercial deployment of CCS systems in the electric power and industrial sectors of the economy. The authors conclude that the past 35 years of CO_2-EOR in the U.S. have been important for boosting domestic oil production and delivering proven system components for future CCS systems. However, though there is no reason to suggest that CO_2-EOR will cease to deliver these benefits, there is also little to suggest that CO_2-EOR is a necessary or significantly beneficial step towards the commercial deployment of CCS as a means of addressing climate change.

KEY WORDS: carbon dioxide capture and storage; geologic CO_2 storage; CO_2-driven enhanced oil recovery; climate change; greenhouse gas emissions mitigation

1. Introduction

This paper explores the extent to which near term carbon dioxide-driven enhanced oil recovery (CO_2-EOR) can be "a stepping stone to a long term sequestration program of a scale to be material in climate change risk mitigation."[1] This paper will draw heavily upon our previously published research and our conclusion that, "The greatest impact associated with CO_2 storage in value-added reservoirs may be derived from their ability to produce more domestic oil and gas, rather than their limited ability to fundamentally lower the cost of employing CCS [carbon dioxide capture and storage] as a means of addressing climate change (Dooley et al., 2007)." CO_2-EOR indeed offers benefits to the body of knowledge needed to implement CCS, including useful experience in handling and injecting CO_2, but CO_2-EOR, as commonly practiced today, does not constitute CCS and it does not necessarily represent a fundamental step towards the development of a long-term, commercial scale geologic sequestration industry. This appraisal stands in stark contrast to statements encountered in the literature regarding the singular importance of CO_2-EOR in stimulating the early market for CCS technologies, including:

- Enhancing U.S. energy security (ARI, 2010; SSEB, 2006; Steelman and Tonachel 2010)
- Stimulating economic development and employment growth (Task Force on Strategic Unconventional Fuels, 2007; ARI, 2010; SSEB, 2006; Steelman and Tonachel 2010)
- Delivering non-climate environmental protection benefits (ARI, 2010; Steelman and Tonachel 2010)
- Lowering the cost of deploying CCS for large stationary point sources like fossil fired power plants (ARI, 2010; CCAP, 2004; Fernando et al., 2008); and
- Accelerating the deployment of the "essential" backbone for a national CO_2 pipeline network that would be used by later CCS adopters (ARI, 2010; ICF, 2009; Kelliher, 2008).

Though it runs contrary to conventional wisdom regarding the foundational nature of CO_2-EOR for commercial scale CCS deployment, our research suggests that CO_2-EOR is dissimilar enough from true commercial-scale CCS – in the vast majority of configurations likely to deploy – that it is unlikely to significantly accelerate large scale adoption of the technology. Additionally, past experience with CO_2-EOR operations and the incentives that have driven the development of the industry over the past four decades do not directly translate to form a robust basis for informing public policy or investment in a world defined by stringent and mandatory greenhouse gas (GHG) emissions reduction intended to stabilize atmospheric concentrations of these gases and avert the worst aspects of anthropogenic climatic change. This paper presents what the authors believe to be some of the critical, though seldom discussed,

[1] Quote taken from the scoping document sent out by MIT to participants of this July 2010 conference, for which this paper was invited.

complexities surrounding many of the purported benefits of expanded CO_2-EOR, as well as a discussion of why CO_2-EOR may not be the stepping stone to full-scale CCS deployment that many assume (or hope) it will be.

2. CO_2-EOR and CCS

Before embarking on analyses of the purported cost savings potential, energy security, and environmental benefits of CO_2-EOR, it is important to briefly clarify the distinction between CO_2-EOR and CCS. CO_2-EOR represents the process by which CO_2 is injected into depleting oil fields for the purpose of enhancing the recovery fraction of the oil that remains in the field following primary and secondary production methods (Meyer, 2007). According to recent survey data by Koottungal (2010), there are 129 CO_2-EOR projects operating around the world, with 114 of those in the U.S. Given the lack of binding GHG constraints in the countries where these CO_2-EOR operations are taking place, one must assume that each of these projects is focused on optimizing oil recovery. The vast majority of CO_2-EOR projects inject CO_2 produced from natural underground accumulations; in the U.S. and Canada, naturally-sourced CO_2 provides an estimated 83% of the CO_2 injected for EOR, with anthropogenic sources providing the rest (Moritis, 2010).

Though it shares some technical characteristics and methods with CO_2-EOR, CCS represents technologies focused on a different objective: the long-term isolation of CO_2 in the deep subsurface as a means of mitigating the risks of global climate change. There are a number of potential target geologic formations being examined for sequestering CO_2 deep in the subsurface including depleted oil and gas fields, as well as deep saline-filled reservoirs (IPCC, 2005). Depleted oil and gas fields are attractive options given their proven capability of securely trapping fluids and gas over geologic timescales, but carry with them additional concerns and risks because of the number of wellbore penetrations. A number of studies have examined the candidate CO_2 storage resources available around the world, and deep saline formations (DSFs) consistently provide the bulk of the CO_2 storage potential, orders of magnitude higher than the volumes likely to be found in depleted oil and gas fields (Dahowski et al., 2005; Dahowski et al., 2010; IPCC, 2005; NETL, 2007; Takahashi et al., 2009). For CCS to truly make a difference in the global challenge to reduce emissions, storage in DSFs has been shown repeatedly to be the primary reservoir application for CCS (Edmonds et al., 2007; IPCC, 2005; MIT, 2007; Wise et al., 2007). Still, CCS coupled with CO_2-EOR could be attractive in locations with significant available capacity and where conditions are amenable to both long-term CO_2 storage and EOR (see for example Ambrose et al., 2008; ARI, 2010).

However, CO_2-EOR as commonly practiced today does not meet the emerging regulatory thresholds for CO_2 sequestration, and considerable effort and costs may be required to bring current practice up to this level. Of the four large complete end-to-end commercial CCS facilities on the planet today, only one employs CO_2-EOR: the Dakota Gasification - Weyburn CCS project. Given that the world today lacks the kind of long term commitment to progressively tighter greenhouse gas constraints (a requirement to stabilize atmospheric CO_2 concentrations, see Wigley, et al., (1996)) that would be needed to motivate large scale CCS deployment, the fact that only the Dakota Gasification - Weyburn CCS project makes use of its CO_2 for EOR suggests that CO_2-EOR represents one of a larger set of possible CCS configuration rather than a critical stepping stone for component CCS technologies. The In Salah, Sleipner, Snøvit and (in the near future) Gorgon CCS projects all dispose of their CO_2 into "non-value-added" DSFs and therefore do not generate revenue via recovered hydrocarbons. If the rents associated with selling CO_2 for use in CO_2-EOR were so compelling and necessary for CCS projects then it seems counterintuitive that the majority of these early CCS facilities fail to make use of this valuable revenue stream.

There are likely a number of reasons for this, including the complexity of CO_2-EOR projects and their need for additional injection and production infrastructures that are often overlooked in discussions that equate CO_2-EOR to CCS. Figure 1 for example shows the extensive infrastructures for oil, water and CO_2 required to make CO_2-EOR economically viable at the Weyburn field. Koottungal (2010) states that there are 170 CO_2 injector wells and 320 oil production wells at Weyburn. This large infrastructure should be compared to the much smaller infrastructures required to store CO_2 in deep geologic structures at Sleipner and Snøvit where, due to the high permeability at these sites, both projects are able to inject more than 1MtCO_2/year via a single injector well (Michael et al., 2010). Even at In Salah where the average permeability of the storage formation is up to three orders of magnitude lower than the conditions at Sleipner and Snøvit, CO_2 storage on the order of 1MtCO_2/year is accomplished through only three directional injector wells (Michael et al., 2010). The Gorgon CO_2 storage facility in Australia will be injecting close to 5MtCO_2/year into a relatively low permeability deep saline formation (average permeability of 25 mD) through 9 injector wells along with four water production wells which will be used to manage reservoir pressure (Michael et al., 2010).

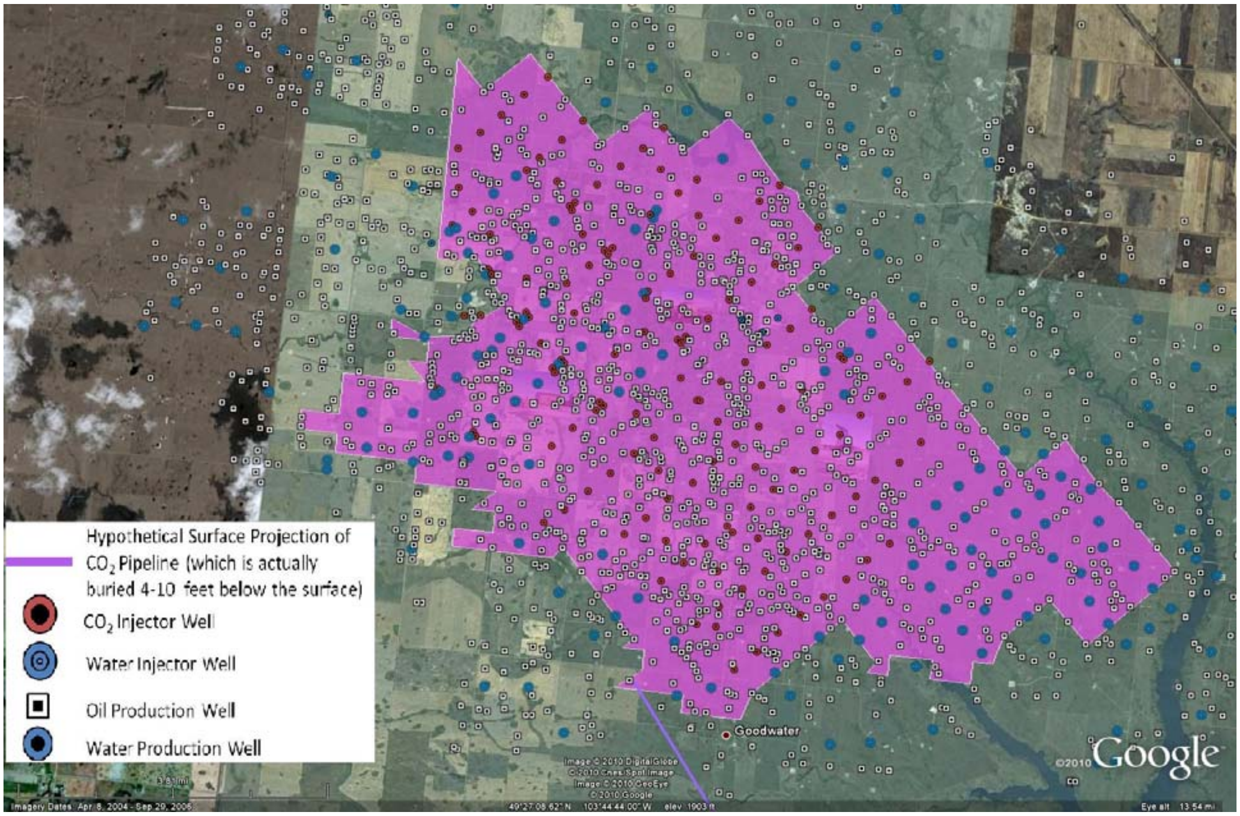


Figure 1: Areal View of Weyburn CO_2-EOR Field and Key Oil, Water, and CO_2 Well Infrastructures (for a description of the data and methods use to prepare this figure please see Dooley, 2009)

Even with nearly 40 years of operational experience, and even with a growing number of projects utilizing anthropogenic CO_2, it is only the Dakota Gasification - Weyburn CCS project that represents a complete end-to-end CO_2-EOR based CCS deployment. No other CO_2-EOR projects are viewed as CCS projects due to missing operational and CO_2 monitoring elements that are critical to demonstrating the effectiveness of the process for safely isolating CO_2 away from the atmosphere for the purpose of addressing climate change. The Weyburn project has incorporated significant risk assessment and extensive monitoring programs to verify the secure storage of the injected CO_2 (IEAGHG, 2005) which are critical aspects of the regulatory concept of a “complete end-to-end CCS project” which lies at the core of the distinction between CO_2-EOR and CCS.

3. The Threshold for Generating Tradable GHG Emission Reduction Credits

It is important to note that deploying GHG emissions reduction strategies is not simply an altruistic enterprise. The purpose of implementing any GHG emissions reduction strategy or technology is to obtain certified documentation that an entity's GHG emissions have been reduced by a specific verifiable quantity. This is especially true when it comes to capital-intensive single purpose technological systems like CCS. One employs these GHG emission reduction technologies to ensure compliance with some form of binding regulation in order to avoid penalties that would be levied for noncompliance. Certification processes are certain to demand rigor beyond simply establishing that CO_2 has been injected into the deep subsurface in order to issue certified GHG emissions reductions credits for CCS projects. Moreover, the degree of regulatory rigor applied is heightened by the need to foster economic efficiency and credibility in the implementation of the GHG emissions reduction policy by requiring that each ton of verified emissions reduction from any certified emissions mitigation activity be equivalent to and interchangeable with any other ton of verified reduced emissions.

Thus, as noted by Jaramillo et al., (2009) in terms of climate mitigation, the test for CO_2-EOR is not as simplistic as establishing that the use of CO_2 from anthropogenic CO_2 sources for CO_2-EOR results in lower overall GHG emissions than CO_2-EOR using CO_2 sourced from natural domes. The issuance of certified and fungible GHG emissions credits for any mitigation / offset project will likely be based upon net avoided emissions within a defined system boundary such that additional emissions created in the process of the mitigation opportunity are subtracted from the gross offset generated. In simple terms, CCS derived GHG emission reduction credits will be based on the net volume of CO_2 injected less the emissions associated with running the CCS project. Lifecycle analysis tools will likely be needed to understand the *net avoided* emissions for a CO_2-EOR project – accounting for both the net CO_2 stored in the reservoir as well as the additional emissions resulting from the CO_2-EOR processes, including the energy required to separate and reinject the more than 50-67% of injected CO_2 that is produced along with the oil after breakthrough (IPCC, 2005).

In reviewing the evolving body of proposed and enacted rules that would govern how CO_2 storage will be regulated in practice, it seems clear that a distinction is being drawn between the regulation of CO_2 stored in a geologic structure like a DSF versus CO_2 used for CO_2-EOR. For example, the U.S. Environmental Protection Agency (USEPA) Proposed Mandatory Reporting Rule (MRR) makes it clear that different levels of reporting will be required for conventional CO_2-EOR than will be required of what the USEPA calls geosequestration. The MRR would require the calculation of CO_2 entrained in the produced oil as well as different (albeit lesser) reporting of fugitive CO_2 emissions for CO_2-EOR based projects (USEPA, 2010). Still, the reporting threshold for geosequestration projects would be significantly higher. This was likely done to limit interference with current CO_2-EOR practices but could also present a barrier to entry for those wishing to convert CO_2-EOR projects to certified geosequestration projects if one cannot produce the appropriate baseline and historical fugitive emissions data.

The recently enacted Tax Credit for Carbon Dioxide Sequestration under Section 45Q also explicitly differentiates between injection of CO_2 into a DSF for CCS and CO_2-EOR (IRS, 2009). Further, the proposed USEPA Underground Injection Control Program Class VI CO_2 Well regulation makes it clear that abandoned wells intersecting the proposed storage reservoir that are within the area of review would need to be identified, located, and plugged prior to using the field for storage (USEPA, 2008). As noted by the IPCC (2005), this requirement reflects the fact that “storage security in mature oil and gas provinces may be compromised if a large number of wells penetrate the caprocks.” Again from the perspective of a regulator being asked to award certified, fungible GHG emission reduction credits, it is imperative that additional risks such as previously drilled wells in depleted oil and gas fields – often dozens (and sometimes hundreds) of wells per square mile – be taken into account (see Figure 2, after USGS, 1996).

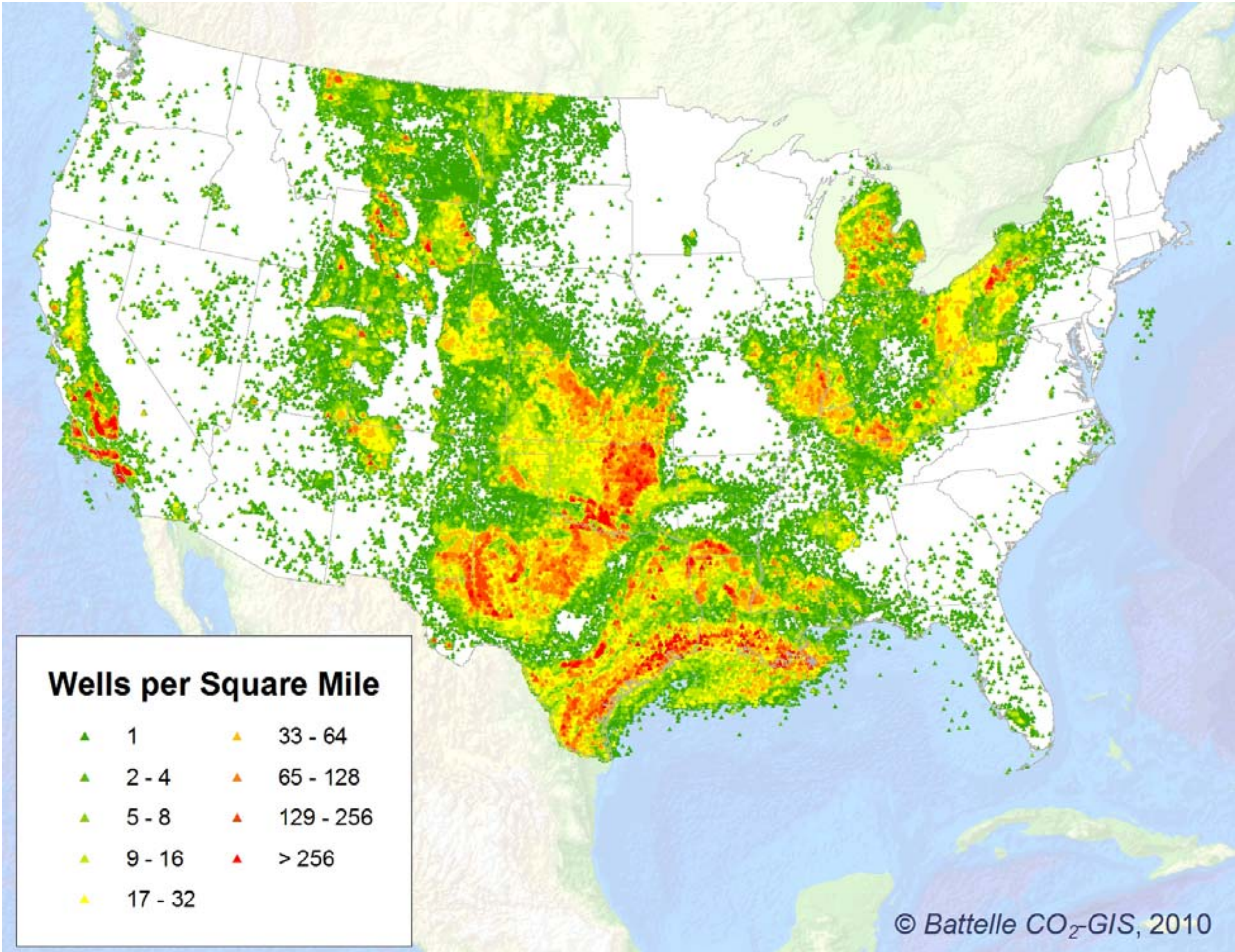


Figure 2: Well density for hydrocarbon exploration and production wells, based on data from the 1995 National Oil and Gas Assessment (USGS, 1996).

An additional factor that speaks to this regulatory distinction between CCS with CO_2-EOR is in regards to mineral ownership rights. Marston and Moore (2008) note that even after CO_2-EOR is complete and a depleted oil field is used "purely for CO_2 storage" there will still be a significant quantity of oil remaining in the reservoir. All of this stored CO_2 could eventually help mobilize some of the remaining oil and there could be future technological progress with respect to oil production techniques that could enable production of additional oil from the field. Thus according to Marston and Moore (2008), “pore space available for CO_2 storage” in a depleted oil field should only be construed as those pores that have been liberated of their formation fluids (oil, water and gas); while the pores that contain residual hydrocarbons after production could still be considered a valuable mineral right. Thus there is potentially an added level of complexity for those selecting to store CO_2 in depleted hydrocarbon formations in that who "owns" the reservoir (whether the mineral, water, or surface rights owner) is based in part upon the presence or absences of valuable minerals in the formation.

The emerging differentiated regulatory treatment of CO_2-EOR is clear, though whether it is problematic or burdensome remains to be seen. These regulations recognize that the gap between simply injecting CO_2 to increase oil recovery and injecting it to ensure that it will never enter the atmosphere is not trivial and cannot be simply addressed by simple mass balance of the volumes of CO_2 injected and produced in a given CO_2-EOR flood. At its core, this "gap" represents a set of activities that would not be undertaken on a business-as-usual EOR project, and may incur significant cost. As noted by the IPCC (2005) "current monitoring for EOR is designed to assess the sweep efficiency of the solvent flood and to deal with health and safety issues." For the purposes of climate mitigation, there would also be requirements for pre-injection activities such as field characterization and mitigation of leakage pathways (including abandoned wells); co-injection activities such as groundwater monitoring, injectate monitoring by multiple methods, iterative reservoir modeling, and efforts to optimize for CO_2 storage and security, rather than oil recovery alone; and post-injection activities such as continued monitoring, modeling and site closeout. Thus, the implication in much of the technical literature that CO_2-EOR is essentially identical to geologic CO_2 storage – except that one "gets paid" for CO_2 injected into the oil field – is simply not true. The requirements necessary to qualify CO_2-EOR as a geosequestration project are not trivial and involve significant work and cost throughout each stage of the project.

4. On the Wisdom of Extrapolating from 40 years of CO_2-EOR in West Texas

While we are all generally comfortable extrapolating from past experiences in our day-to-day lives, significant alterations to the paradigm under which past decisions were made may well result in very different outcomes for future decisions. Nevertheless, much of the technical, legislative, and public policy dialogue about the prospective role of CO_2-EOR is based on a largely implicit extrapolation of the growth of CO_2-EOR in the United States and in particular in West Texas over the past four decades. However, there is relatively little attention paid to the underlying drivers for this significant expansion of CO_2-EOR in the U.S. during this period.

Expansion of CO_2-EOR in the United States was not exclusively driven by some combination of specific gravity of the oil, remaining original oil in place, depth to the oil bearing formation, temperature of the oil bearing formation, the permeability of the formation, the degree of heterogeneity within the oil bearing formation or the many other technical factors which are often used to compute the theoretical potential of

EOR fields to store anthropogenic CO_2 (Gozalpour et al., 2005; IPCC, 2005; Meyer, 2007). Instead, the principal drivers were economic and political. For example:

- Mandelker (1992) makes it clear that federal efforts to explicitly support CO_2-EOR go back to the early 1970s: "Since the oil shocks of the late 1970s whenever the political climate has been right, steps to encourage domestic EOR have been taken [by the federal government]."

- While OTA (1978) makes it clear that direct federal support for enhanced oil recovery -- specifically including CO_2-driven EOR – can be traced back to at least 1976 when the Emergency Petroleum Allocation Act was amended to provide price incentives for "bona fide tertiary enhanced recovery (EOR) techniques." The report goes on to note that the President's 1977 National Energy Plan called for decontrolling the price of domestic oil produced via EOR which would provide a significant monetary incentive to begin seriously exploring ways to deploy nascent EOR production technologies on a large scale.

- As detailed by (Dooley et al., 2009a), there were substantial federal subsidies that funded a significant portion of the existing large CO_2 pipeline network supporting current CO_2-EOR in the United States. As documented in that paper, U.S. oil companies paid $88.5 billion (in constant 2005 US$) between 1980-1985 in Windfall Profits Taxes (WPT) which provided a strong incentive to produce more oil from existing fields rather than bringing new fields into production. Norman (1994) states unequivocally that, "There is no question that for crude oil produced from Permian basin oil fields, this [substantially lower] WPT rate differential favored CO_2 flood development."

- During the period 1994-2005, the Internal Revenue Service paid out an estimated $1.3 to $1.9 billion (in constant 2005 US$) under the Section 43 Enhanced Oil Recovery Tax Credit, which directly subsidized the creation of new CO_2-EOR floods, the expansion of existing CO_2-EOR projects, and associated purchases of CO_2 (Dooley, et al., (2009a).

While there was clearly a lag between the application of these federal subsidies[2] and the production of oil from CO_2-EOR floods and while there was certainly significant private funding invested into these fields and their associated infrastructure, there can be no doubt that federal subsidies in the name of energy

[2] It is also worth noting that there were and in many cases still are significant state level subsidies for CO_2-EOR based domestic oil production in the name of domestic energy security or regional economic growth (Martin, 1992).

security played a decisive role in establishing the existing CO_2-pipeline network. As can be seen from Figure 3, more than 60% of the existing 3900 miles of CO_2 pipeline in the United States was built in the 1980s with the vast majority of these CO_2 pipeline built in and around West Texas (Dooley et al., 2009a).

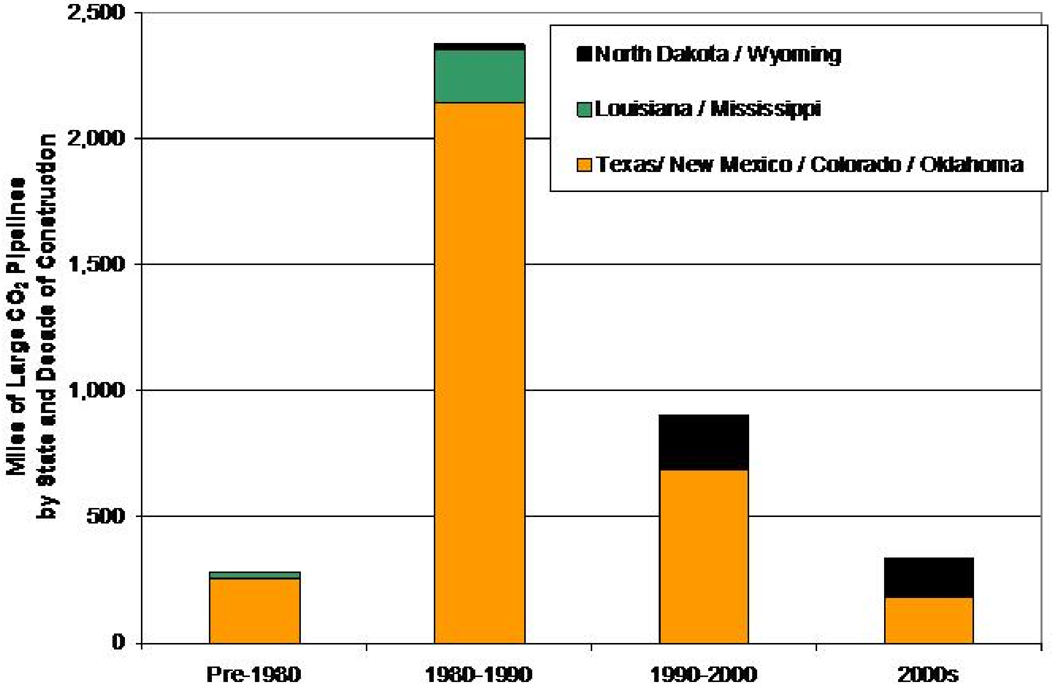


Figure 3: Additions to the US CO_2 Pipeline Infrastructure by decade and by region (taken from Dooley et al., 2009a)

These existing CO_2 pipelines are important "sticky" pieces of capital; they are unlikely to be relocated and their O&M costs are small compared to their construction costs (McCollum and Ogden, 2006; Norman, 1994; Smith, 2009). These existing CO_2 pipelines represent an implicit subsidy for any given CO_2-EOR flood that accesses these existing lines as the new CO_2 flood does not need to pay the entire cost of producing CO_2 from a dome and delivering it to a given field. Thus, it is not clear to the extent to which it is appropriate to extrapolate field level CO_2-EOR production cost data in areas that are served by these existing CO_2 pipelines to regions of the U.S. where there is CO_2-EOR potential but no extant pipeline infrastructure.

5. Is There a Need to Build Out a National CO_2 Pipeline Network before CCS Can Deploy?

The largely overlooked role of the federal government's past subsidization of the existing CO_2-pipeline network in the name of energy security is germane to discussions of the future role of CO_2-EOR as a means of reducing greenhouse gas emissions as there are numerous analyses that suggest there is a need to build out a large CO_2 pipeline network like what exists in West Texas in order for CCS technologies to deploy.

Figure 4 shows three recently published estimates of large continental CO_2 pipeline networks that the authors of these studies say would be needed before 2030 and whose existence would facilitate the commercial deployment of CCS. It is difficult to understand the rationale for a CO_2 pipeline network on this scale. In our bottom-up modeling of CCS deployment in the U.S., we employ an assumption that individual CCS facilities will construct and operate their own dedicated CO_2 pipeline system (Dahowski et al., 2005; Dahowski et al., 2010; Dooley et al., 2006). This assumption of dedicated source-to-sink CO_2 pipeline networks has been criticized as too simplistic in that it overestimates the amount of CO_2 pipeline needed by forgoing the purported cost savings associated with networked CO_2 pipeline systems. However when we employ this assumption in our modeling (see Table 1 for an example of the results of this bottom-up modeling), we see a national CO_2 pipeline system that would plateau at perhaps 30,000 miles which would deploy over the course of many decades. This 30,000 miles would be enough to decarbonize the vast majority of existing large CO_2 point sources in the U.S., including fossil fuel fired baseload power plants and large swaths of industry (Dahowski and Dooley, 2004; Dooley et al., 2009a; Dooley et al., 2005; Wise et al., 2010a). Assuming that future CO_2 sources will largely be built on brownfield sites and/or use proximity to CO_2 storage reservoirs as a siting criterion, the 30,000 miles of one-to-one pipelines we have estimated in our previous work could potentially represent an upper limit on total CO_2 pipeline that needs to be built. In light of this, estimates of 66,000 miles (ICF, 2009) or 73,000 miles (Kelliher, 2008) seem to overestimate the deployment of CO_2 transport infrastructure by a factor of two or more.

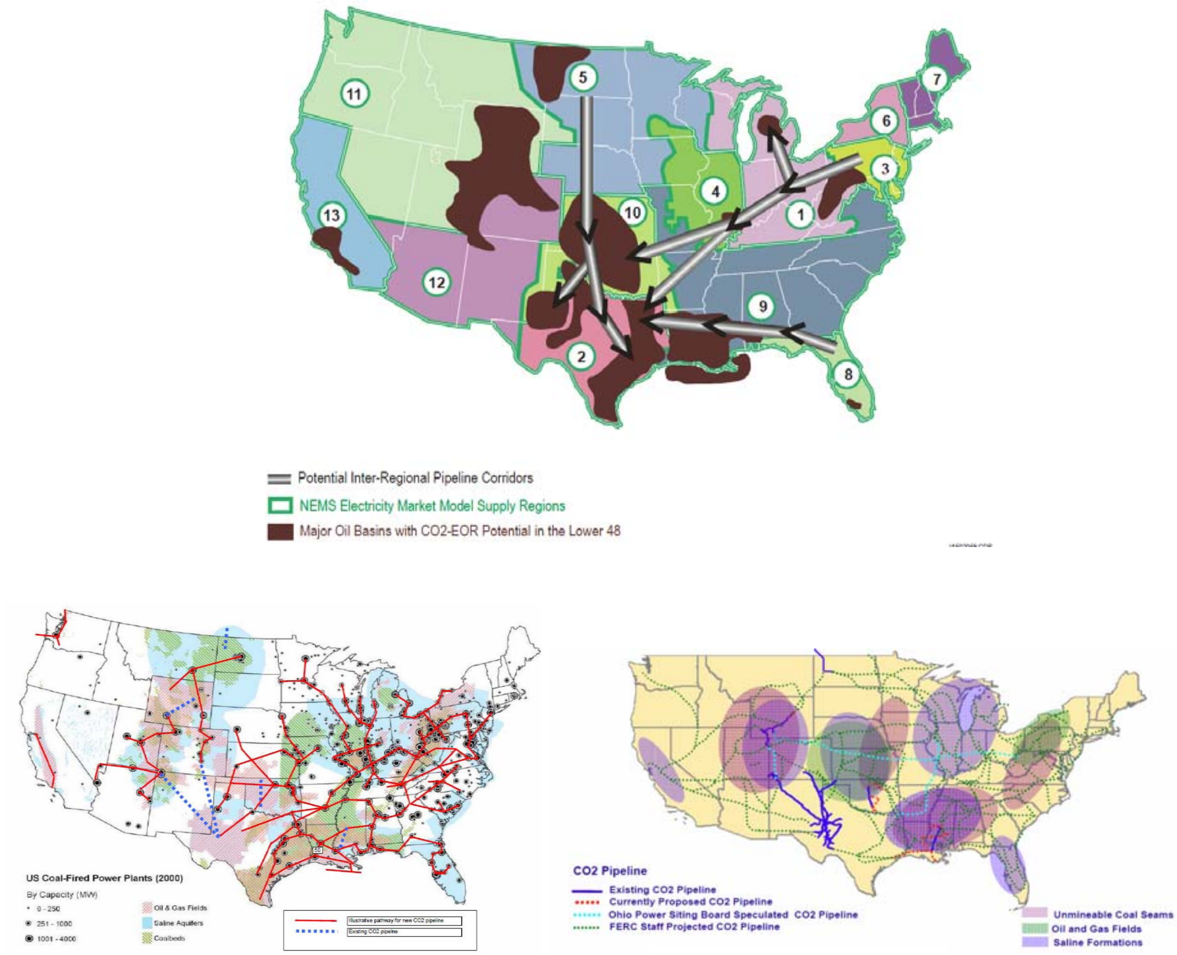


Figure 4: Three views of the need for a large national CO_2 pipeline network by 2030 (top figure, major CO_2 pipeline corridors for CO_2 EOR by 2030 (ARI, 2010), figure in the lower left projection of 66,000 miles of CO_2 pipeline need by 2030 (ICF, 2009); figure in the lower right projection of 73,000 miles of CO_2 pipeline needed by 2030 (Kelliher, 2008)

Others have based their estimates of the need for a large national CO_2 pipeline network upon simple volumetric calculations that compare the volume of oil moved around the world today and its associated infrastructure to the volume of CO_2 that would need to be stored in the future and then state that it would require roughly the same pipeline infrastructure (see for example MIT, 2007; Smil, 2008). Unfortunately, these volumetric comparison-based estimates fail to appreciate the distinction between high and low value-added commodities; oil and natural gas consumers in New York City, Boston, Chicago and Peoria are willing to pay to have these high value-added commodities shipped over large distances so that they can use them to create further value-added products and services. The same cannot be said about pipeline quality CO_2, especially when CCS systems deploy to the extent that there are billions of tons of CO_2 needing to be stored annually. At these scales, CO_2 becomes a waste product that has zero (or as will be discussed below more than likely a negative) value associated with it. Economic analysis suggests that one will likely seek to dispose of the CO_2 as close to the point of generation as feasible, subject to site suitability factors and non-transport cost variables.

Table 1: Rates of CCS Adoption and the Build Out of CO_2 Pipeline Infrastructure under WRE450 and WRE550 Atmospheric CO_2 Stabilization Policies (data taken from (Dooley et al., 2009a)

	WRE 550 Stabilization	**WRE 450 Stabilization**
Average annual number of power plants adopting CCS 2010-2030	1-3 per year	~ dozen per year
CCS Adoption by high purity CO_2 point sources 2010-2030	(relatively) slower adoption of CCS by high purity CO_2 point sources	(nearly) all high purity CO_2 point sources decarbonized within a decade
Average growth in CO_2 pipelines 2010-2030	~ 300 miles/year	<900 miles/year
Average source-sink pipeline length	Tens of miles	Tens of miles
CO_2 Pipelines in Operation 2030	<10,000 miles (i.e., doubling existing CO_2 pipeline system)	~22,000 miles
CO_2 Pipelines in Operation 2050	~16,000 miles	~28,000 miles

Our detailed modeling of CCS adoption across the United States in response to an economic-based climate policy (e.g., a carbon tax or a cap and trade) suggests a temporally and spatially heterogeneous pattern of CCS adoption in response to the climate policy (see for example, Dooley et al., 2005; Wise et al., 2007). This is important and suggests that it is highly likely that the "optimal" placement of a CO_2 pipeline network might only be apparent in hindsight many decades from now. In fact, a recent study by Johnson and Ogden (2010) indicates that only in later phases of CCS deployment for climate mitigation purposes do networked pipelines begin to make economic sense and that for the early to middle stages of deployment, direct pipelines between each source and sink are more cost effective. Further, it particularly does not make a lot of sense from a climate mitigation perspective to develop a long-term transportation backbone to deliver CO_2 to a currently attractive promising area of CO_2-EOR production without establishing that large additional suitable storage capacity exists in the area that can handle storage demand over the long term.

In looking to the future, it is also worth considering the extent to which there are likely to be federal subsidies that would accelerate CO_2 pipeline development. The currently available Section 45Q tax credit provides a subsidy of potentially up to \$10/tonCO_2 for no more than 75 MtCO_2 from anthropogenic sources used for CO_2-EOR (IRS, 2009). Moritis (2010) reports that 17% of the CO_2 used for CO_2-EOR in the United States in 2008 came from anthropogenic (non-dome) sources. That would imply approximately 9 MtCO_2/year of anthropogenic CO_2 is already being used for CO_2-EOR and thus if these existing facilities alone applied for the Section 45 Tax Credit, the entire authorized amount would be exhausted in a little more than 8 years. This would do little to incentivize development of new technologies or infrastructure that would help migrate from early CO_2-EOR based applications to CCS deployed by baseload power plants injecting their CO_2 into non-value-added DSF reservoirs.

The authors remain skeptical of arguments for expanded CO_2-EOR that are, at their core, extrapolations of what happened in the past in an effort to address energy security concerns, a fundamentally different motivation than stabilizing atmospheric concentrations of GHGs.

6. Cost Savings Associated with CO_2-EOR for CCS: Why Share Rents with Your Commodity Supplier?

A core argument made in support of the proposition that CO_2-EOR will provide a bridge to larger CCS deployment is that the revenue associated with selling CO_2 to an EOR operator would result in substantial income for power plants or other large anthropogenic CO_2 point sources that could be used to lower the overall cost of employing CCS and therefore speed the large scale commercial adoption of CCS as a means of addressing climate change. For example:

- "Revenues from CO_2 sales to the oil industry can offset some of the costs of CO_2 capture from both natural gas- and coal-fired power plants, as well as other industrial facilities producing large volumes of CO_2." (ARI, 2010)

- A 2004 report from the Center for Clean Air Policy (CCAP, 2004) projected that as much as 17.5 GW of new IGCC+CCS power plants could be built by 2020 with the incremental cost of these plants being offset by a market and a positive price for all the CO_2 captured by this vast new fleet of power plants. This report's modeling suggested the scale of the rents associated with selling CO_2 for CO2-EOR could be so profitable that "Regional wholesale [electricity] prices decrease by 1 percent to 5 percent in the regions in which enhanced oil recovery credits are available."

- While a 2008 report from the World Resources Institute (Fernando et al., 2008) asserted that "[CO_2-driven] EOR can create benefits of up to $55 per ton of CO_2 (excluding the cost of the wells and CO_2 recycling), which can potentially offset part or even total capture costs … [this] cost advantage could potentially encourage early adopters of CCS technology … [and] may be a way to spearhead commercial deployment and an infrastructure build-out for regular carbon capture and permanent sequestration."

Assertions such as these stem from the fact that CO_2-EOR is undertaken as a profitable endeavor, motivated by revenues from the recovered oil. At present there is a positive price for pipeline quality CO_2 in regions of the U.S. that already employ CO_2-EOR. This positive price has been rising in the past several years along with oil prices. The flawed logic that extrapolates this current situation into the future assumes that (1) the positive price for pipeline quality CO_2 will persist for a significant period of time into the future and (2) the rents associated with the production of a valuable commodity like oil would be shared with the upstream supplier of pipeline quality CO_2, a low value-added commodity.

Both of these premises hinge on whether pipeline quality CO_2 remains a scarce resource relative to the demand. Figure 5 shows supply and demand for pipeline quality CO_2 under a scenario (illustrated at t=0) in which CO_2 supply is scarce relative to demand resulting in a positive price for CO_2 as well as a scenario (t=1) in which the supply of pipeline quality CO_2 is far in excess of any potential demand for this basic commodity. In this second situation, the price paid for pipeline quality CO_2 should drop and eventually become negative. That is, the suppliers of pipeline quality CO_2 (e.g., a large power plant that employs CCS as a means of reducing its GHG emissions) would have to pay a disposal fee rather than be able to demand payment for their CO_2. There would no longer be "buyers" willing to purchase their CO_2.

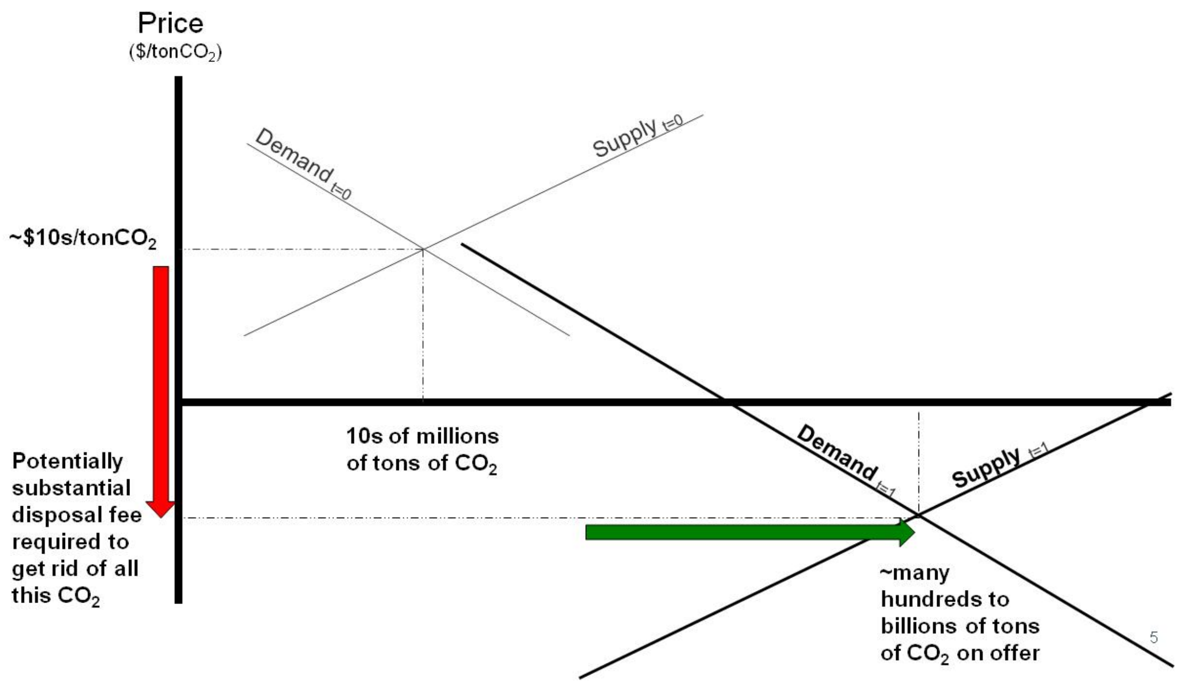


Figure 5: Illustration of supply and demand for pipeline quality CO_2 and the resulting price paid under two scenarios of assumed scarcity (taken from Dooley, 2004)

If pipeline quality CO_2 remains scarce, then it is reasonable to assume that the supplier (i.e., the anthropogenic CO_2 point of origin which might be different from the entity that delivers pipeline quality CO_2 at the boundary of a CO_2 flood) will have some ability to set the price of pipeline quality CO_2 and receive some positive price (i.e., payment) for supplying this commodity. While potentially dated, Norman (1994) examined the market for pipeline quality CO_2 in West Texas in the early 1990s and found the market to be oligopolistic in nature (i.e., a small number of sellers were able to control supply and therefore influence the price paid). This is what one would expect in a market characterized by scarcity and high barriers to entry. However when CCS systems are deployed on a large scale because of GHG emissions constraints, a very different market structure for pipeline quality CO_2 should exist. When the supply of pipeline quality CO_2 on offer significantly exceeds demand, the rents from CO_2-EOR do not accrue to the upstream supplier of CO_2-EOR. Under these market conditions, while CO_2-EOR may remain profitable, the revenue streams would no longer accrue to the anthropogenic CO_2 point source supplier and the cost of capturing the CO_2 would not be offset. For a more rigorous treatment of the evolving pricing of pipeline quality CO_2 for CO_2-EOR in a greenhouse gas constrained world readers are encouraged to consult Leach et al. (2009).

7. Matching CO_2 Supply and Demand for CO_2-EOR

This simplified "Economics 101" discussion of supply and demand and resulting prices for CO_2-EOR is not merely a macroeconomic phenomenon. There is also reason to question the scale and sustainability of revenues received by individual facilities selling CO_2 to individual EOR projects. Here we present preliminary results of work to be formally presented this fall on the role of CO_2-EOR when applied to a large CO_2 point source such as a power plant (Davidson, Dooley and Dahowski 2010).

Previous evaluations of economy-wide CCS deployment have typically applied a simplifying assumption that 100% of the potential storage capacity for a given formation is available on the first day of the analysis, as well as an assumption that the assumed injection rate impacts only the number of wells required to inject a given volume of fluid per year and is thus considered exclusively as a cost driver rather than a technical one. However, as discussed by Dahowski and Bachu (2006), storing CO_2 in a field undergoing CO_2-EOR is subject to a set of constraints to which storage in DSFs is not, and these constraints – particularly variable demand for CO_2 – may strongly influence the ability of an EOR field to serve as a baseload storage formation for commercial scale CCS projects undertaken as a means of addressing climate change mitigation targets. While each EOR field will be unique and will respond to CO_2 stimulation in different ways based on reservoir-specific characteristics and project design, Figure 7 illustrates the general pattern of high initial demand for new CO_2 coupled with a decrease in demand as recycled CO_2 is used for an increasingly larger portion of the total injection volume. This behavior is consistent with most current CO_2-EOR practices and is critical to understanding the impact on commercial-scale CO_2 storage in EOR fields. Again readers are encouraged to consult Leach et al. (2009) which models the same temporal dynamic; SSEB 2006 and IPCC 2005 also both make explicit reference to the changing demand for "new" CO_2 as the CO_2 flood matures and more CO_2 is recycled.

Here we apply the CO_2 demand profile shown in Figure 7 to a hypothetical 1000 MW IGCC+CCS which produces 6 $MtCO_2$ per year. We further assume that the IGCC is employing CCS as an alternative to paying an assumed significant disincentive associated with venting CO_2 to the atmosphere. In order to avoid penalties associated with emitting CO_2 not used by the CO_2-EOR project, excess CO_2 will need to be stored in a suitable nearby deep saline formation under this scenario.

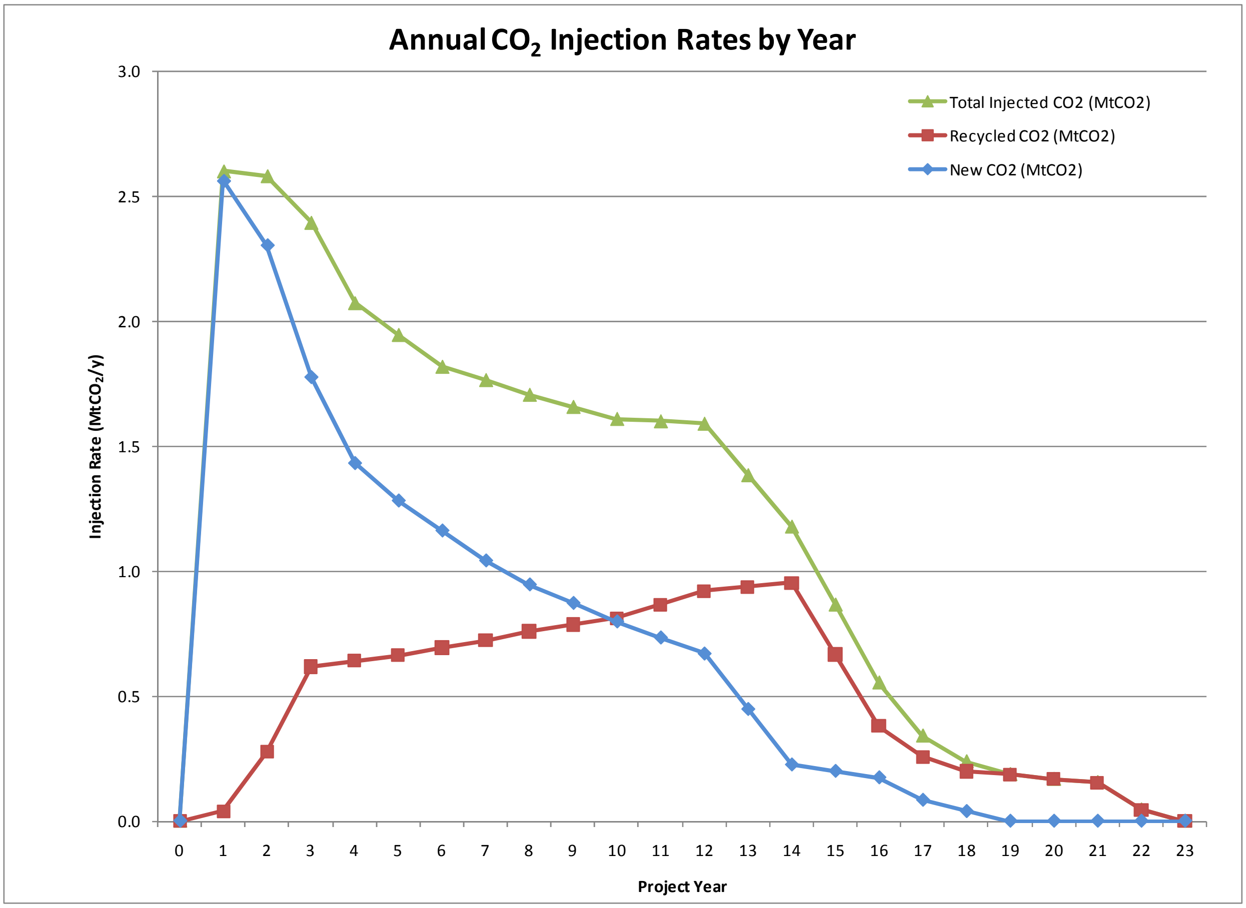


Figure 7. CO_2 demands from a typical west Texas CO_2-EOR project, assuming 20 injection wells per project (Davidson et al., 2010 forthcoming; after Jarrell et al., 2002)

Preliminary modeling indicates that during the first year of injection, this large IGCC+CCS would rely on the "back-up" deep saline formation-based storage for over 50% of its storage needs with the remaining CO_2 utilized in the CO_2-EOR project. The reliance on deep saline formation based storage grows annually, reaching 90% within 15 years and 100% within 20 years (Figure 8). The only way to counteract this inherent declining demand for "new" CO_2 for the flood (i.e., CO_2 derived from the IGCC source rather than via recycling) is to link multiple CO_2 flood-ready projects together to enable a larger fraction of total storage in EOR fields rather than the backup DSF.

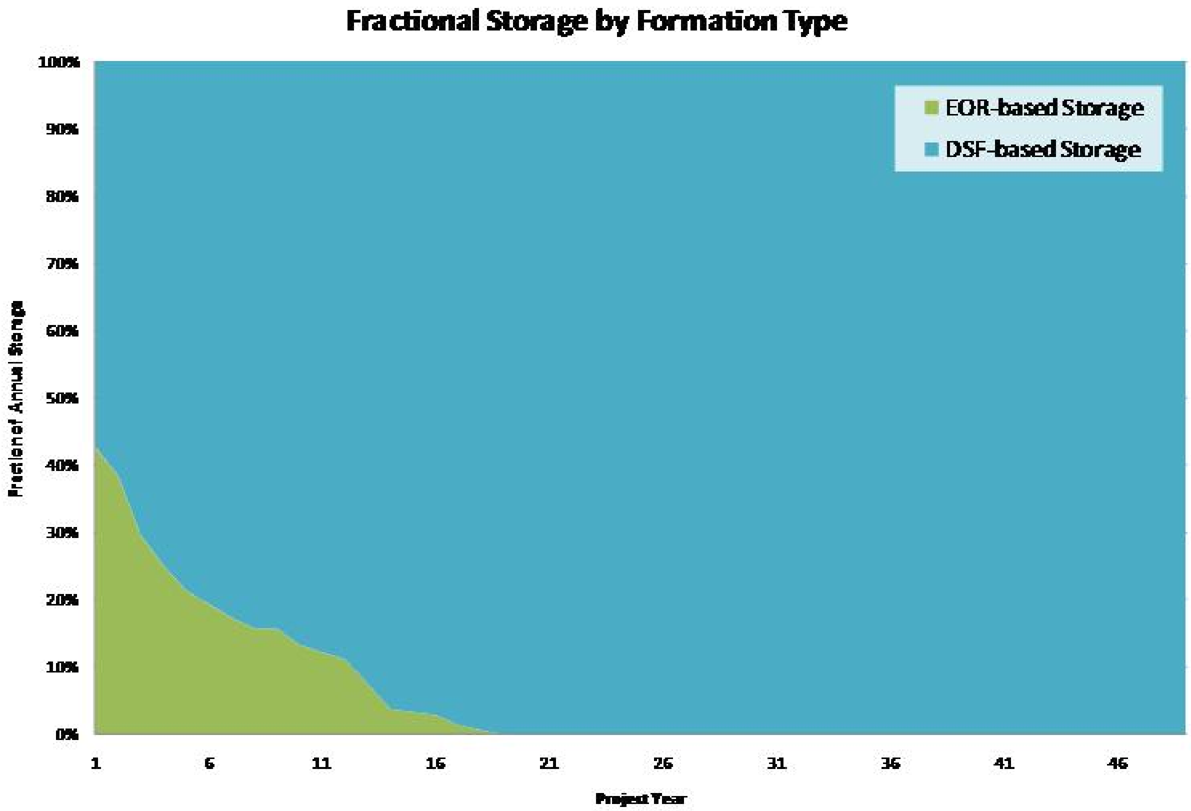


Figure 8: Annual CO_2 Stored by Formation Type for Hypothetical 1000 MW IGCC+CCS storing in a single EOR project and employing a DSF for supplemental storage of the CO_2 not demanded by the EOR project.

As can be seen in Figure 9, those costs need to be captured in the analysis of the economic benefit of CO_2-EOR as it relates to accelerating the deployment of CCS because not fully capturing the cost associated with these additional infrastructures can have a profound effect on the perceived cost reduction potential of CO_2-EOR based storage.

We have also begun to estimate the costs associated with storage in each field type – including revenues from incremental EOR production – along with the cost of CO_2 capture and compression over the assumed 50-year life of this IGCC+CCS facility. In the first year of operation, the assumed offsetting EOR revenues could reduce the net cost *to society* of employing CCS by over 70% (i.e., regardless of which entity(s) captures the incremental EOR revenues) for the IGCC plant relative to simply storing in a DSF, but this savings is halved within the first few years, and decreases until it disappears altogether by the middle of the second decade. This suggests that, under a single-project scenario such as this, EOR-based CCS is not likely to have more than a modest impact on the cost of electricity generated by a large IGCC plant seeking to store the CO_2 produced from round-the-clock operations over its lifetime.

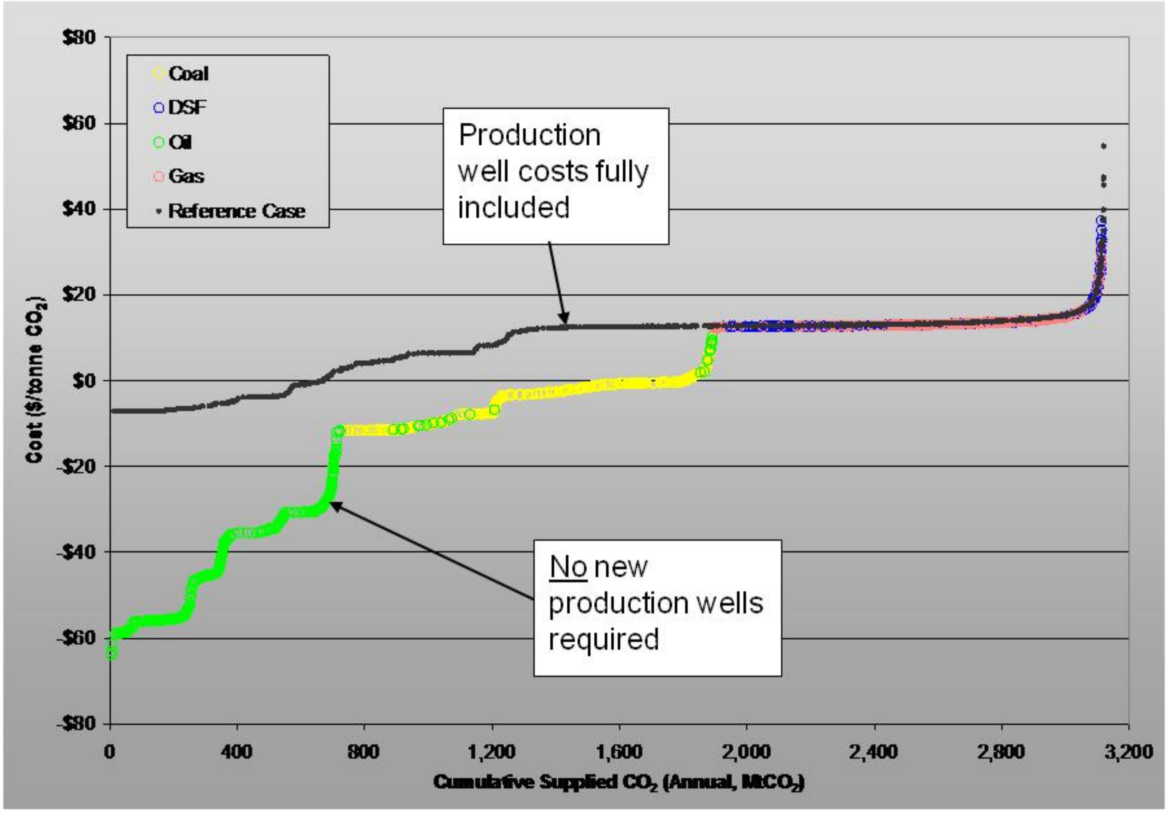


Figure 9. The impact on the cost of transport and storing CO_2 in the US depending upon modeling assumptions regarding the amount of additional infrastructure needed for CO_2-EOR and ECBM based storage options (Dahowski, et al., 2005)

8. A Final Note on CO_2-EOR and Energy Security

As noted above to many, CO_2-EOR looks just like CCS but in fact differs in some fundamental ways. It entails more complexity than is often discussed, and in many cases it is unlikely to appreciably offset the cost of CO_2 emissions mitigation. But can it still provide value by decreasing U.S. reliance on imported oil? Again, the answer is more nuanced and less straightforward than typically presented (ARI, 2010; SSEB, 2006; Steelman and Tonachel 2010) .

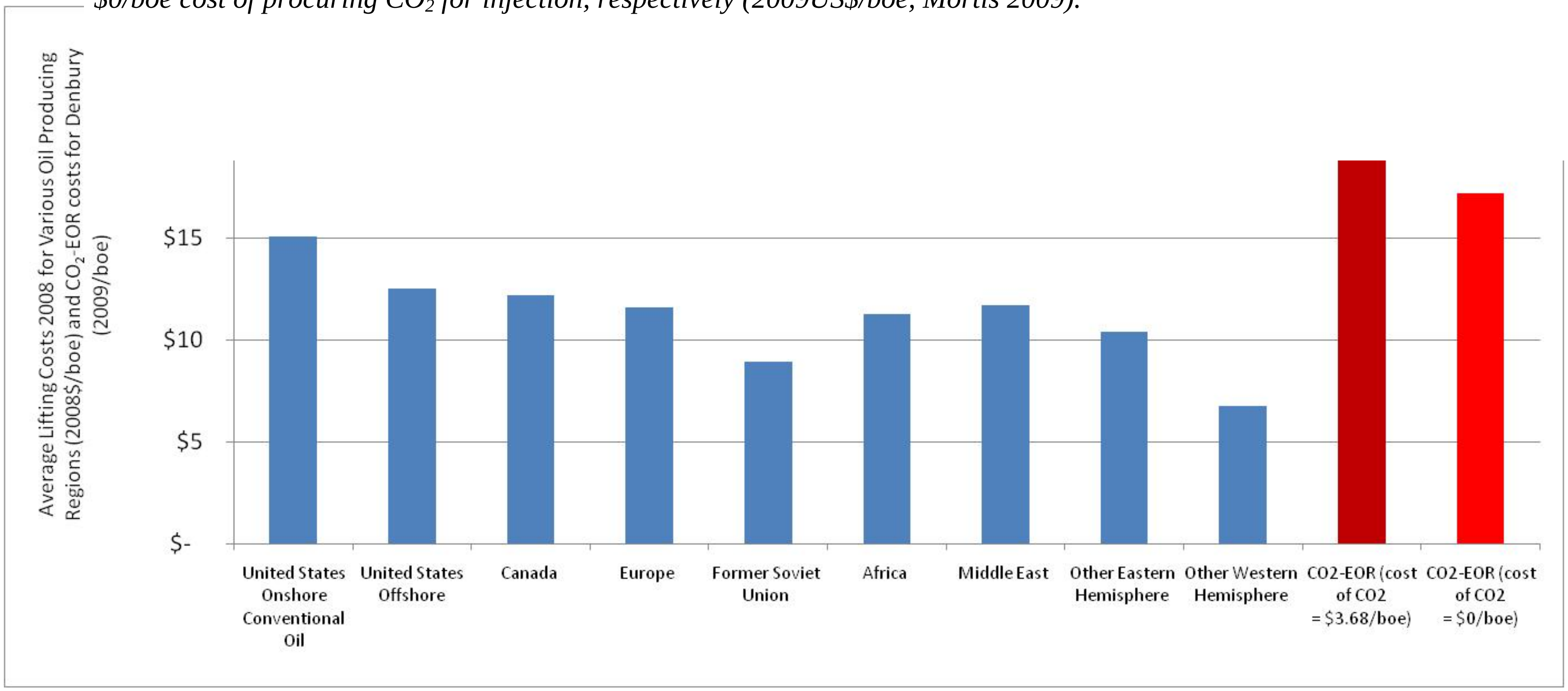
Ample technical literature supports the conclusion that, absent a global commitment to significantly reduce GHG emissions, the world will expand its use of unconventional hydrocarbon resources (e.g., oil shale, tar sands, coal-to-liquids) to replace declining conventional oil production (Dooley et al., 2009b; IPCC, 2007; US Climate Change Science Program, 2007). Given the energy intensity of producing transportation fuels from many of these unconventional hydrocarbon resources (see for example the comprehensive analysis of Brandt and Farrell, 2007), the expansion of unconventional hydrocarbon production in a world without stringent GHG emissions constraints will certainly lead to increased GHG emissions.

However, the imposition of climate policies can fundamentally alter the composition of energy resources that the world draws upon to augment declining conventional oil resources. In order to stabilize atmospheric concentrations of GHGs, the cost associated with releasing these gases to the atmosphere must increase in real terms over time (Wigley et al., 1996). As the cost of emitting GHGs to the atmosphere increases, the energy- and GHG-intensity of these unconventional hydrocarbons will make them less competitive with other options such as biomass-derived fuels and electric passenger vehicle (Dooley et al., 2009b; Luckow et al., 2010; Wise et al., 2010b). This undermines the assertion that there is a beneficial synergy between the need to continue producing crude oil and climate mitigation that can uniquely delivered by CO_2-EOR, despite claims by groups as diverse as the Natural Resources Defense Council (Steelman and Tonachel 2010), Advanced Resources International (ARI, 2010), and the Southern States Energy Board (SSEB, 2006). Fundamentally, this assertion relies on extrapolation of past trends into the future, but if the world is serious about stabilizing atmospheric concentrations of GHGs, simply asserting that the world needs more fossil-derived transportation fuels because electric vehicles and biofuels have not been competitive in the past does not support the conclusion that CO_2-EOR is an inherently beneficial activity that must be sustained and expanded.

There is also no economic or technical justification for assuming that domestically produced CO_2-EOR oil will directly displace oil imported from nations considered hostile to the United States and its allies as argued by Steelman and Tonachel (2010), ARI (2010), and SSEB (2006). Figure 10 shows the average total lifting costs for producing a barrel of oil (including taxes) from major oil producing regions of the world as reported by EIA (2009). As Figure 10 demonstrates, the U.S. tends to be a high cost producer of oil relative to other nations. Figure 10 also includes data for Denbury's CO_2-EOR operating costs for the second quarter of 2009 (Moritis 2009), along with a hypothetical estimate for CO_2-EOR operating costs based upon these Denbury data with the added assumption that delivered pipeline quality CO_2 is free for a CO_2 flood operator.[3] The data in Figure 10 strongly suggest that in a global oil market, increased

[3] This assumes that the EIA's (2010) definition of lifting costs is similar to the costs that Moritis (2009) reports for Denbury. The data reported by Moritis are more detailed than those provided by the EIA making it difficult to verify direct comparability between the datasets. The costs reported by Mortis are comparable to similar figures presented by SSEB (2006) for "Typical CO_2-EOR per Barrel Costs" for a 1st of a kind and an nth of a kind CO_2-EOR flood.

Figure 10: Comparing CO_2-EOR to average oil production costs. Blue bars show 2008 average total lifting costs by region (2008US$/boe, EIA 2010). Red and purple bars show Denbury's reported CO_2-EOR operating costs assuming a $3.68/boe and $0/boe cost of procuring CO_2 for injection, respectively (2009US$/boe, Mortis 2009).



domestic CO_2-EOR driven oil production – even if there were no cost to the CO_2-EOR producer associated with acquiring pipeline quality CO_2 – could just as easily displace oil production from the Gulf of Mexico or lower the marginal global price of crude oil.[4]

Figure 11 shows the historical and projected contribution of domestically produced CO_2-EOR produced oil as a fraction of the nation's annual oil consumption over the 50 year period 1980-2030. The historical data here are from Moritis (2010) and show that domestically produced CO_2-EOR oil grew from virtually nothing in the early 1980s to the point where it now accounts for approximately 2% of US annual oil consumption. The projected data come from the Annual Energy Outlook (EIA, 2010) and reflect EIA's belief that future higher oil prices along with some technical improvement should increase the share of U.S. oil consumption met by domestically produced CO_2-EOR crude to slightly less than 8% by 2030 under the EIA's Reference Case (i.e., no climate policy). Domestically produced CO_2-EOR crude is clearly an important and growing component of the nation's energy portfolio and it is expected to continue its contributions into the future.

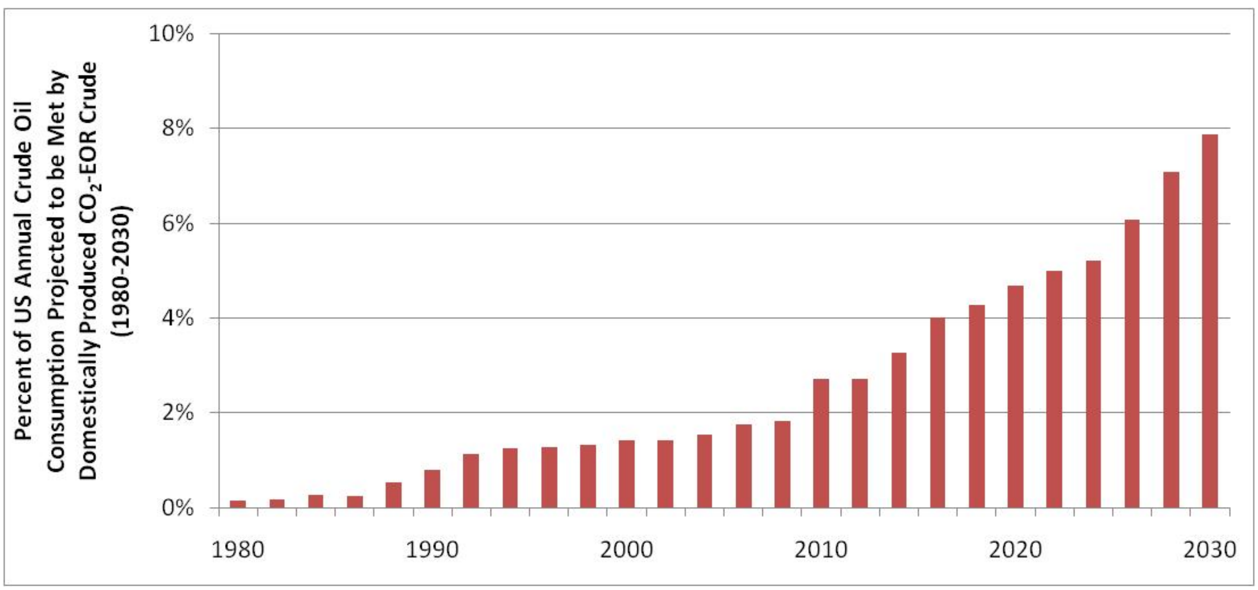


Figure 11. Fraction of U.S. Annual Oil Consumption Met by Domestically Produced CO_2-EOR Crude over the period 1980-2030 (historical data are from Moritis (2010) while future projections are from the Reference Case from EIA (2010))

[4] As noted by Huntington (2006), "The nation is vulnerable to another major [oil] disruption [and the attendant negative economic and security consequences] not because the economy imports oil but primarily because it uses a lot of oil, primarily for gasoline and jet fuel. Even if domestic production could replace all oil imports, which I am not advocating, the economy would remain vulnerable to the[se] types of disruptions."

Figure 12 attempts to put the data in Figure 11 about the growing importance of CO_2-EOR as a source of domestically produced crude oil into a larger economic and geopolitical framework. Figure 12 shows the average annual U.S. dependence on imported oil along with selected efforts to make the U.S. energy independent or less reliant on imported oil over the period 1950-2030. One can see that these efforts to reduce U.S. oil imports have not delivered on their stated goals and have become significantly less ambitious over time. It is also clear from Figure 12 that to date large geopolitical and economic forces have driven significant swings in the degree to which the U.S. imports foreign oil; these swings have often been large and have occurred over relatively short time periods. For example, U.S. dependence on imported oil went from 46% in 1977 to 27% in 1985 and back up to 46% by 1996. This large swing in import dependence dwarfs the 7% reduction in oil imports by 2030 forecasted by Steelman and Tonachel (2010) if one assumes that all additional U.S. oil produced by the recommended aggressive expansion of CO_2-EOR production displaces imports, barrel for barrel.

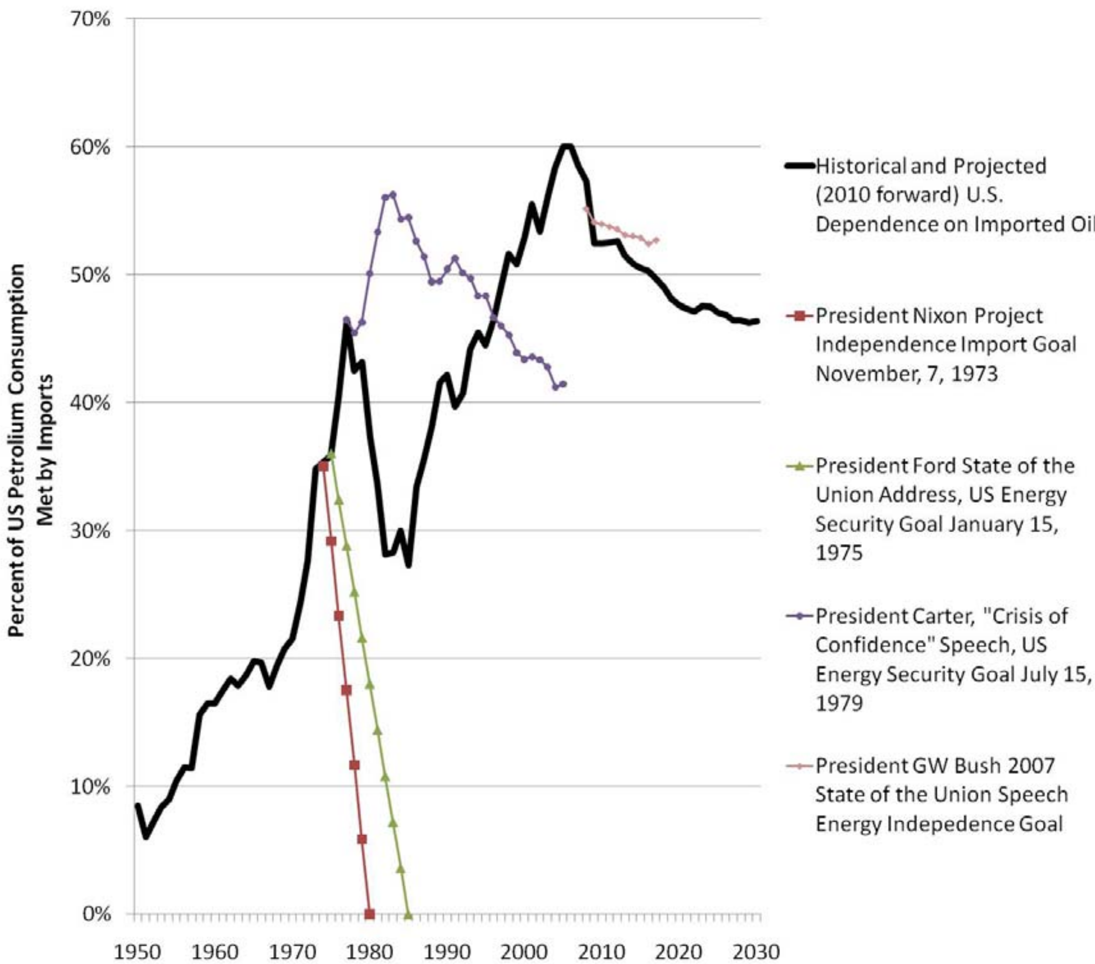


Figure 12: U.S. Historic and Projected Dependence on Foreign Oil and Selected Presidential Energy Security Initiatives (1950-2030)

9. Concluding Comment

It is clear that CO_2-EOR is an important and growing aspect of the United State's energy resource base. The contribution that CO_2-EOR makes to the U.S. economy should not be underestimated or undervalued. It is also clear from the work of Meyer (2007), IPCC (2005) and others that the more than 35 years of experience in using CO_2 for enhanced oil recovery has led to the development of numerous materials, technologies and industrial best practices that should be directly transferable to the large scale commercial adoption of CCS across the global power and industrial economies.

The purpose of this paper is not to call into question the significance of CO_2-EOR as a means of producing oil from domestic fields that are in decline. Rather, the goal was to examine key aspects of conventional wisdom that draws no distinction between CO_2 injection into marginal oil fields to increase hydrocarbon production and the injection, verification and long-term monitoring of CO_2 to ensure retention as a method of complying with binding GHG emissions limits under a future climate policy. This paper has sought to bring some level of rigor to what is often an overly simplified discussion by explicitly distinguishing between the economics of CO_2-EOR and the economics and operational requirements of large scale CCS deployment. CO_2-EOR may offer an opportunity to jumpstart climate protection-motivated CCS deployment in the electric power and other industrial sectors. But overall, it is unlikely to serve as a major stepping stone to commercial-scale CCS deployment. The fact that only one of 129 current CO_2-EOR projects worldwide is regarded or certified as a CCS project, and only 1 of the 4 current commercial scale CCS projects utilizes the CO_2-EOR process, provides significant empirical evidence that CO_2-EOR is not a mandatory step on the path to CCS deployment; it is a useful and in many ways beneficial option for CCS where available and where the extra requirements to document stored CO_2 prove worthwhile, but CO_2-EOR is not core to the deployment of CCS technologies.

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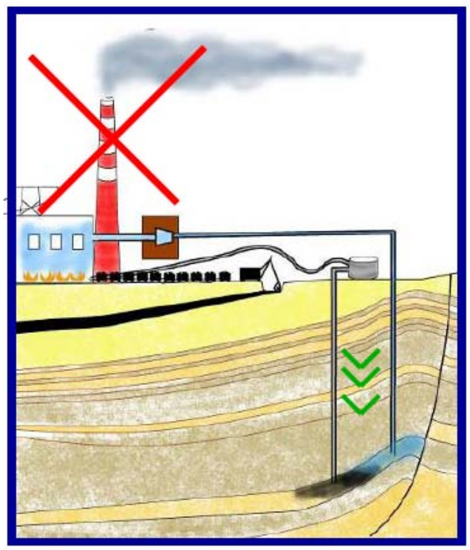
EOR as Sequestration—Geoscience Perspective

White Paper for Symposium on Role of EOR in Accelerating Deployment of CCS



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Abstract

CO_2 Enhanced Oil Recovery (EOR) has a development and operational history several decades older than that of geologic sequestration of CO_2 designed to benefit the atmosphere, and provides much of the experience on which confidence in the newer technology is based. With modest increases in surveillance and accounting, future CO_2 EOR using anthropogenic CO_2 (CO_2-A) captured to decrease atmospheric emissions can be used as part of a sequestration program.

Confidence in the permanence of sequestration of CO_2 as part an EOR project be in some cases higher than that of CO_2 injected into an equivalent brine-bearing system and, in some cases, lower. Confidence increases in the EOR case because

- Quality of the confining system is better documented,
- Pressure and fluid flow are controlled by production,
- More CO_2 is dissolved, and less remains as a separate and phase,
- Reservoir properties are better known because of reservoir characterization and fluid production history, leading to more robust prediction of the long-term fate of the CO_2.

Leakage risk factors that are increased for CO_2 injected as part of an EOR program and that must be assessed both through research and field-specific mitigation include:

- CO_2 that migrates out of a pattern may be produced from nonproject wells and not recycled and
- Numerous well penetrations of the confining system create potential flaws that, if unmitigated, could allow CO_2 to leak slowly over long periods at rates unacceptable to attaining atmospheric goals.

Nongeotechnical factors that favor the use of CO_2 EOR for sequestration and that may be more important than technical factors include

- Economic and societal benefits,
- Mature regulatory and legal environment, and
- Public acceptance.

Use of CO_2 EOR to accelerate sequestration will be most effective if it builds on well-established current best practices by increasing accounting and monitoring requirements on the basis of surveillance already conducted for successful operation of a flood. Documentation that CO_2 is retained in the subsurface will require reporting of some data to stakeholders that operators have traditionally used only in-company. In addition, collection of some new data will be needed to document permanence of sequestration, focusing on areas of leakage risk. Additional studies focused on CO_2 EOR as sequestration are proposed to test how to best meet these needs.

Introduction

Geologic sequestration (also known as *geologic storage*) is a process by which CO_2 released from fossil fuels as part of energy production is captured, compressed, and injected underground for the purposes of reducing the release of CO_2 to the atmosphere. The complete system (Orr, 2004; IPCC, 2005), from capture of the CO_2 prior to release to atmosphere, transportation to a permitted injection site, and injection to depths isolated from freshwater and other resources, is known as *carbon capture and sequestration* (CCS). The idea has been widely considered for about 2 decades (United Nations Framework Convention on Climate Change, 1992). Consideration of future deployment of this new CCS technology at industrially-relevant scales raises questions about cost and effectiveness of the method. Uncertainties remain because feasibility of CCS has been tested only at short-list field tests worldwide (National Energy Technology, 2009, p. 3-7–3-15). The longest running project designed and monitored specifically for geologic sequestration associated with Sleipner gas field in the North Sea began in 1996 (Chadwick and others, 2007).

In contrast, subsurface injection of CO_2 for enhanced oil recovery (CO_2 EOR) has been evaluated since the 1950's and full-scale field projects conducted since 1972. CO_2-EOR is under way at more that 100 sites in the U.S. (Oil and Gas Journal Enhanced Recovery Survey, 2010) and a lesser number of sites worldwide. The present paper considers the proposition that (1) the older and better known process of EOR can: be used to meet part of the newer need to "kick start" the geologic sequestration process and (2) that information derived from past EOR, as well as collected during ongoing EOR, can provide needed information to increase confidence in performance of geologic sequestration at large scales and for long durations.

Subsurface injection of CO_2 as part of CCS designed to reduce atmospheric emission of CO_2 has into a variety of geologic media . In this paper, only the well-known family of injection schemes that utilize porous media (permeable sedimentary geologic formations such as sandstone, conglomerate, and permeable carbonates) are considered. Within the porous-media family, a number of pore-fluid histories are considered (Table 1). Clarity in distinguishing among the members of the family is needed because in the U.S., the differences trigger different legal and ownership issues and historically (and, likely, future) different regulatory requirements.

Table 1. Definitions of members of the porous-media (permeable sedimentary rock) family of geologic sequestration.

Sequestration type	Definition
CO_2-EOR	CO_2 injected into a zone that contains hydrocarbons (of which oil is the target) and brine; CO_2, and commercially significant oil are produced
Depleted reservoir sequestration	CO_2 injected into hydrocarbon reservoirs similar to CO_2 EOR reservoirs (originally containing gas and or oil) but without extraction of any oil
Sequestration in brine (saline) formations	CO_2 injected into a formation that lacks any commercially significant hydrocarbons; brine could be produced to manage the process.
Combination sequestration and other resource extraction	Injection of CO_2 into brine formations or hydrocarbon reservoirs in combination with other processes, such as methane or heat extraction

This paper undertakes to compile, briefly review, and integrate geotechnical information useful to nongeoscientist decision makers on four topics:

- What is CO_2 EOR, and does it serve as geologic sequestration (in an atmospheric context)?
- Is CO_2 injected for EOR permanently stored to benefit the atmosphere?
- What is the CO_2 sequestration potential of EOR in the U.S., and what are the variables that add uncertainty to this calculation?
- How does CO_2 EOR provide information about very large scale injection for atmospheric benefit?

For each topic, currently published and anecdotal information is outlined with selected references provided for further information. Some questions and uncertainties are then posed that illuminate the edges of current knowledge. Recent discussions of the relationship between CO_2 EOR and sequestration include Advance Resources International, Inc. (2010), Cooper (2010, Jaramillo and others, (2009), Bryant (2007).

What is CO_2 EOR, and does it serve as geologic sequestration (in an atmospheric context?)

Primary, secondary, and tertiary recovery

CO_2 EOR is one of a series of engineering strategies designed to increase the rate and ultimate amount of oil produced. As reservoir and mobility of oil decrease, ending the period of primary production, operators of many oil reservoirs increase production by moving into a higher level of engineered assistance, known as *secondary recovery*. Water or recycled natural gas is injected (flooded) into the reservoir through a pattern of injection wells to maintain pressure and guide oil toward production wells. When recovery again declines, tertiary recovery methods can be employed; among the methods commonly used is the injection of substances not native to the reservoir, defined as *EOR* (Lake, 1989, p. 1). Introduction of allochthonous additives at higher cost can once again increase the rate of oil extraction and extend the economic and productive life of the field, increasing the percentage of original oil in place (OOIP) extracted.

EOR techniques include addition of products such as N_2, flue gas, CO_2, acid gases, hydrocarbon products, engineered solvents, polymers, foams, in situ combustion, and steam (Lake, 1989). Cases in which CO_2 is the primary injected fluid are known as *CO_2 EOR floods*. In most CO_2 EOR, the injected fluid is nearly pure (>99%) CO_2 compressed to a dense phase (liquid or supercritical fluid). In some regions mixtures of H_2S and CO_2 (acid gas) are available and used for EOR.

Movement of CO_2 through the reservoir

CO_2 is placed in the reservoir through injection wells.. In most cases pressure applied via pumping is required to force the CO_2 to the bottom of the well, out through the perforations, and into the pore spaces of the designated injection formation. Typical injection depths for EOR are more than 800 m and less than 3,000 m. In the reservoir, CO_2 moves outward away from the injection well in a generally radial manner by entering the brine and/or oil-filled intergranular or intercrystalline pores of a generally tabular body of sedimentary rock bounded by an upper confining system that greatly retards vertical movement of CO_2 (figure 1).

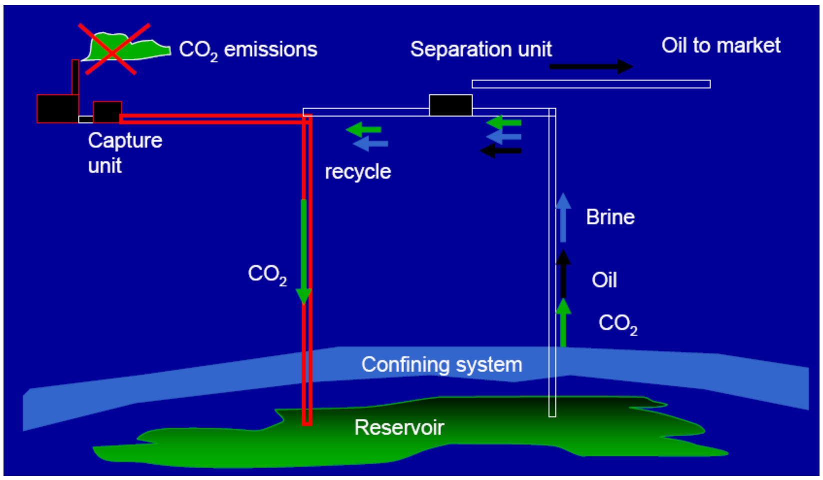

Figure 1.Schematic of a CO_2 EOR system. Components required for sequestration in brine formations that are in common with CO_2 EOR highlighted in red.

CO_2 will interact with oil and water in the pores and over months to years will create a region in which oil saturation and mobility are increased, known as an "*oil bank*". The flood design places production wells in areas where the oil bank is expected to develop. If the flood performs as designed, oil, brine, and CO_2 will enter the production wells through the perforations and will rise or be pumped to the surface. Geometry and timing, in terms of which pores are accessed and amount of CO_2 that enters them, are controlled by how flood engineering intersects the rock fabric and changing fluid environment. Analytical and geocellular flow models, are used to make an accurate estimate of how oil ias accessed by CO_2. Modeling is essential to financing the project, designing the flood, purchasing adequate CO_2, and obtaining a sufficient incremental recovery of oil in a manner timed to support project economics. Monitoring techniques, reservoir flow simulation software, and experience in designing CO_2 EOR floods provide the technical foundation on which confidence in brine sequestration is founded. For examples of this overlap, see lists of techniques of the proposed protocols for monitoring, verification, and accounting of geologic storage (National Energy Technology Laboratory, 2009).

CO_2 recycle

During successful CO_2 EOR operations, CO_2 is produced along with oil and brine through production wells (Figure 1, right side). As fluids are brought from reservoir depths to the surface dense-phase CO_2 (supercritical or liquid) flashes to gas and CO_2 comes out of solution with oil and water. Although venting produced CO_2 to the atmosphere would be permissible, because CO_2 is a valuable commodity, operators invest in separation facilities that extract CO_2 and return it to the injection stream. Efficiency of this return depends on CO_2 handling losses from separation, during equipment maintenance, from connections, and during equipment malfunctions (upsets). Chuck Fox (oral presentation, 7th Annual EOR Carbon Management Workshop, December 2009) presented results of a proprietary assessment from Kinder Morgan's West Texas showing losses during handling of <0.5% of total CO_2 in the system. Accounting for CO_2 losses is not typically done for EOR; therefore, if CO_2 EOR is to be part of a sequestration operation, additional inventory of process losses of CO_2 during handling from the point of sale through the whole system (similar to that required for manufacturing industries) would be needed. Other emissions related to oil production are considered in the section Life-Cycle Analysis (p. 6).

Types of floods

CO_2 EOR can be deployed with great flexibility, so that each operation is in some ways unique. Variablity contributes to the difficulty of forecasting the role of EOR under various CO_2–availability scenarios while adding depth of experience to support sequestration. One key variable influencing the nature of the CO_2 flood is solubility of CO_2 into oil and oil into CO_2, described as *miscibility*. Miscibility is a complex function but depends on (1) the pressure and temperature of fluids under reservoir conditions in which they contact one another and (2) the properties of the oil, with miscibility obtained at lower pressures and temperatures for lower density oils. CO_2 EOR is undertaken under both miscible and immiscible conditions. Current availability of CO_2 mostly favors use for miscible floods; if additional volumes of CO_2 were available and the value of CO_2 vs. oil was favorable, immiscible flooding could be used over a greater geographic area, using larger volumes of CO_2.

In many floods, water is introduced episodically to augment a CO_2 flood as a "chase" fluid (Lake, 1989). This process, known as *water alternating gas* (WAG) (Green and Willhite, 1998, p. 168), is used to reduce the amount of needed high-cost CO_2, as well as increase the amount of oil contacted. Other operators, notably Denbury Onshore LLC, use continuous injection of CO_2 without introducing water once EOR begins. Continuous injection requires more CO_2 purchase, as well as higher recycle rates. However, fluids in the production wells are lifted by the CO_2, avoiding the need for production pumps. Because of large-volume usage, the continuous injection model may be relevant to sequestration. The long production history needed for field validation of sequestration value of continuous injection will soon become available as fields developed using this method mature (Denbury Resources Inc., 2009).

An array of injection wells with respect to production wells (*well patterns*) also have implications for use of EOR as sequestration. The simplest development, typically used to test the reservoir but, in some cases, used for production, is a *huff-n-puff*, in which CO_2 is introduced into the reservoir and allowed to interact with reservoir fluids for a period of weeks or months. Then the mobilized oil, CO_2, and water are produced back through the injection well. This type of test was used for sequestration pilot tests at West Pearl Queen field, New Mexico (Pawar and others, 2006), and Loudon field, Illinois (Finley, 2007). For most floods, injectors and producers are arranged in patterns and act in a balanced way. The ratio of producers to injectors and the spacing between them have a strong impact on project economics, with closer spacing resulting in faster oil recovery but higher investment. Wells can be deviated (directionally oriented) during drilling so that they enter the oil-bearing reservoir interval as horizontal wells—the monitored EOR flood at Weyburn is an example (Wilson and Monea, 2004). Horizontal wells cost more to drill than vertical wells but can access more of the reservoir through a single well.

Well placement can also vary with respect to reservoir architecture, resulting in large differences in cost, rate of oil production, and percent of OOIP recovered. For example, in a steeply dipping closed structure, CO_2 can be injected so that gravity dominates fluid migration. Under these conditions, low-density CO_2 will accumulate at the top of the structure, and denser oil will concentrate in the lower part, where it can be produced. A sequestration test was recently conducted in this setting in an Alberta pinnacle reef (Smith and others, 2010). Wells can be placed in an attempt to force the CO_2 to contact the maximum amount of oil. One example of such an optimization is to place CO_2 low in the formation to access the residual oil zone (ROZ) at the base of the oil-saturated interval not accessed during primary or secondary production (Meltzer, 2006).

Geologic properties of the reservoir and fluids have a strong impact on designing an economically successful CO_2 flood (for technical discussion, see Green and Willhite, 1998, p. 173). However, nongeologic variables also have a strong impact on how the flood is developed and include cost, volume, and delivery rate of CO_2, cost and availability of capital, and surface, property, and mineral-rights issues. Operator experience and technical skills also have an effect on how the flood is designed, CO_2 usage, and ultimate recovery. The impact of changing these nongeologic variables in a model in which CO_2 EOR is used as an element of sequestration has not been systematically assessed.

Stages of a flood

Most floods are developed in stages, with injection at selected patterns of wells started each year because the plan the flood is matched with the availability of CO_2 from the source and through the pipeline as well as investment capital. As CO_2 breaks through to the production wells and begins to be produced, it is separated from oil and brine at the surface and put back into the injection stream. Augmentation of the CO_2 supply by this recycling then allows additional patterns to be developed. A field under flood will be in constant readjustment to optimize oil recovery and minimize costs. Wells in which handling the water and CO_2 are more costly than the value of oil produced will be shut in and the CO_2 diverted to new patterns. At the end of operation of a mature field development, recycling will be the dominant source of CO_2, and CO_2 purchase from sources outside the field will decline. Changing the availability of CO_2 by capturing large additional anthropogenic amounts is likely to have an impact on how floods are staged and, consequently, how much CO_2 is purchased and sequestered.

Trapping CO_2 in the reservoir during EOR

Not all of the CO_2 that is injected for EOR can be recycled. Some CO_2 dissolves into oil and water that remain in the reservoir. Capillary processes trap an additional fraction of the CO_2 within the pore system of the injection zone, a process known as *nonwetting-phase capillary trapping* (Lake, 1989, p. 48–77). The percentage of CO_2 that is not returned to the production well depends on stage of a project, the injection strategy, and reservoir and fluid characteristics, but it is significant, typically estimated at between ⅓ and ½ the injected volume (Smyth, 2008; Han and others, 2010). Language used in industry has sometimes resulted in a misunderstanding that the volume that is not recycled is emitted to the atmosphere. The reverse is actually the case; volumes not recycled are trapped in the reservoir and cannot be extracted. Changes in the ratio and duration of water alternating with CO_2, well spacing, and injection rates that might occur with additional anthropogenic CO_2 availability will most likely increase the amount trapped within the reservoir; however, detailed models and validation of this change are incomplete.

Life-cycle analysis

CO_2 EOR differs from other types of geologic sequestration in that when it is successful, significant additional volumes of oil are produced and sold to market, where they can be combusted and release CO_2 to the atmosphere. In addition, energy use for CO_2 EOR is different from sequestration without production because material such as cement and steel are consumed and energy is expended in producing fluids and in separating and compressing CO_2. Processes that occur offsite, such as refining, further contribute to the atmospheric impact of CO_2-EOR. Jaramillo and others (2009) completed a life-cycle analysis of a sample of current WAG floods, showing that such CO_2 EOR projects have a significant net carbon emission. The carbon emissions profile is variable among the five fields assessed, indicating that sequestration potential is site specific. Further assessment to determine which geologic or operational factors lead to balance between injected CO_2 and emissions related to oil produced would be worth undertaking to support deployment of CO_2-EOR as part of a sequestration program.

Because of its value in EOR recovery, CO_2 is produced from pure CO_2 reservoirs such as Bravo Dome, Sheep Mountain, and Jackson Dome, commonly referred to as *natural sources*. Large volumes of CO_2 are separated from impure natural gas before it is placed in pipeline networks, and some is sold for CO_2-EOR. CO_2 from gas processing has also supplied some initial geologic sequestration tests, including Sleipner, InSalah, and Snövit projects (IEA Greenhouse Gas R&D Programme, 2010). Distribution of geologically sourced CO_2 have had a dominant impact on the development of EOR. In general, the amount of CO_2 available has been a limiting factor in project development. As a corollary, most CO_2 EOR engineering has been designed to conserve CO_2 because of purchase cost and value in terms of bringing additional patterns into production.

Benefit to the atmosphere can occur only when CCS is applied to major sources of atmospheric releases from combustion of fossil fuels to release energy. CO_2 from such sources is known as *anthropogenic CO_2* (CO_2-A). The primary focus of CCS is, therefore, on large, concentrated, stationary sources, including refineries, fossil-fuel-fired power plants producing electricity, cement plants, and steel plants (National Energy Technology Laboratory, 2008). CCS can be combined with other proposed atmospheric reduction methods as well. For example, CO_2 produced during manufacture of ethanol biofuels has been used for EOR at the Hall-Gurney flood, Kansas (National Energy Technology Laboratory, 2010a), and is planned for brine-formation sequestration at Decatur, Illinois (National Energy Technology Laboratory, 2010b).

CO_2 EOR results in geologic sequestration

Injection of captured CO_2-A for EOR results in sequestration of the CO_2 from the atmosphere during operation of the project. Essentially all captured CO_2 is placed underground, a fraction of which is produced with oil, separated, and promptly recycled back underground. At any given time, only a small fraction is in residence at the surface in pipelines and pressure tanks. As part of accounting for volumes sequestered, small amounts of CO_2 that escape during handling and pipeline operations must be assessed and removed from the balance sheet. This assessment is not done during current commercial CO_2 EOR but would be added, as would be done to other operations, if CO_2 emissions were tracked. In addition, for carbon accounting the energy consumed to produce, transport and refine oil and carbon content of combusted oil must be accounted for. This accounting should not, however, be directly attached to the sequestration value of the CO_2 EOR process. Instead, it should be handled in the same manner in which other fossil-fuel extraction processes are handled, such as domestic secondary recovery, oil import, gas production and shipping, and coal mining and shipping.

Is CO_2 injected for EOR permanently stored to benefit the atmosphere?

Retention rates 99% over 1,000 years

To attain atmospheric targets, injected CO_2 must be retained in the subsurface to a high standard. For examples of how slow release from sequestration sites over long time frames reduces the desired impact on the atmosphere, see Pacala, (2003), Lindeberg (2003), IPCC, (2005), and Shaffer (2010). The standard of retention is sensitive to (1) total volume injected, (2) leak-rate temporal-curve assumptions, (3) atmospheric target and associated assumptions, and (4) energy penalty for CCS. The retention target given by the IPPC report of 99% of CO_2 retained in the reservoir 1,000 years after the end of injection has proved durable and conservative. Note that 1,000 years serves as an assessment point; the CO_2 will remain geologically stored at similar rates long after this period; however, quantification is not attempted because of increasing uncertainty in model variables over time periods of 10,000 or 100,000 years.

In this section, the possibility that CO_2 that might escape slowly but over long periods, resulting in long-term failure to achieve the atmospheric target is considered. Previous regulatory experience with injection is inadequate in evaluating permanence over the needed time fame. Analysis of petroleum systems and natural CO_2 accumulations increases confidence in the ability of the geologic properties of the subsurface to sequester buoyant, immiscible fluids over even greater time frames. Confidence that EOR settings have favorable properties are higher than similar brine-sequestration environments. However, current uncertainty in the long-term performance of wells reduces this confidence. CCS research is rapidly developing tools to assess and quantify the permanence of sequestration through risk assessment and monitoring to reduce site-specific uncertainties.

Previous experience: Safe Drinking Water Act

The Federal Safe Drinking Water Act (SDWA) issued in 1974 and managed under the Environmental Protection Agency (EPA) Underground Injection Control (UIC) Program requires all injection to document protection of underground sources of drinking water (USDW)(U.S. Environmental Protection Agency, 2010). Secondary and tertiary injection processes for oil production, including EOR, are regulated under UIC Class II and are controlled in many states by the state oil and gas regulatory agency (IOGCC, 2008). Hazardous and nonhazardous injection into brine formations has been conducted under UIC Class I, and EPA is in the process of developing regulations for CO_2 injection other than that covered by Class II under a new UIC Class VI (U.S. EPA UIC Program, 2008). Although UIC rules do not require assessment of any leakage to the atmosphere, most plausible slow-leak paths pass through the USDW, and, therefore, this requirement provides a broad experience base against which to evaluate leakage. However the SDWA is not stated in terms directly useful for assessing value to the atmosphere in terms of showing retention of 99% of the CO_2 over 1,000 years because it traditionally has been a yes/no evaluation whether the site is sufficiently retentive. Slow leakage rates could be allowed by the SDWA because impact to the USDW may be un-demonstrable, or otherwise thought to be insignificant.

Comparison of risk profile during injection under EOR conditions to risk of brine-formation sequestration

Sequestration relies on natural geologic systems accepting and then retaining CO_2. Injection processes must be designed so as not to damage essential functions of the natural system. Review of permit applications shows that some characterization and operation requirements for UIC Class I are not applied to Class II permits for secondary and tertiary recovery. The historic reason is that prior to tertiary recovery, some uncertainties had been reduced because natural accumulation of hydrocarbon followed by extraction had tested reservoir characteristics. Other uncertainties are reduced because aggressive reservoir management is required for EOR. Comparisons and contrasts between risks in brine sequestration and CO_2 EOR are summarized in table 2.

Table 2. Comparison of generalized risk elements for sequestration in brine formations, with generalized risk elements for CO_2 EOR.

Risk element	**Sequestration in brine formation**	**CO_2 EOR**
Well operations	CO_2 injection (possible brine production)	CO_2 injection+ oil, brine, CO_2 production, with recycle
Area of review	Large areas of pressure elevation	Active pressure control through production, smaller magnitude pressure increase, and smaller area of elevated pressure
Injection- zone performance in accepting fluids	Inferred from sparse well data and relatively short duration hydrologic tests	Well known, many wells and extensive fluid production history with information on how the reservoir responded
Confining system performance	Inferred	Demonstrated
Structural or stratigraphic trapping	May or may not be part of system	Demonstrated
Dissolution of CO_2 into fluids	Moderate	High
Wells that penetrationpenetrate theion confining system	Usually sparse	Usually dense
Financial support for of injection	All costs	Costs + revenue from oil production
Permitting and pore- space ownership	Evolving, state-dependent and uncertain, between water law and mineral law	Historic frameworks for secondary and tertiary recover are well known
Public acceptance	Uncertain	Relatively good because value of royalties, fees for surface access, and jobs are recognized in host communities

Confining-system performance

In a structure that accumulated oil or gas, performance of the confining system, usually referred to as the *reservoir seal*, is relatively well known. If the seal does could not effectively limit upward migration since the reservoir was charged (>10,000 years), no accumulation of buoyant fluids such as CO_2, methane, and oil will form. In contrast, for brine formations, confinement must be inferred, and the risk that small or localized flaws in the seal might escape detection is difficult to eliminate. Reservoir seals in many cases do not trap 100% of the fluids; methane and heavier hydrocarbons in soil gas are a commonly used exploration tool and document slow transport from reservoir to surface (Klusman, 2003). Study of invasion of seals by CO_2 over geologic time (Lu and others, 2009) documents that, in a good seal, migration is very slow and can be disregarded with respect to the 99% retention of 1,000 years' time.

Retention of hydrocarbons over geologic time is not perfect assurance that CO_2 will be retained. Capillary entry pressure of pore systems to oil is higher than it is for CO_2, so invasion might occur when CO_2 enters a system that is impermeable to oil. Statistics on the heterogeneity of typical seals, however, suggest that such a situation is not an expected flaw in most systems (Meckel, in press). More difficult to assess is the possibility of geomechanical damage. Elevated pore-fluid pressure as a result of injection can cause slip in critically stressed fractures and faults (Rogers and others, 2008). Volume decreases occur during depressurization of a reservoir during primary production; volumes may increase during secondary and tertiary operations. Modeling shows that geomechanical damage such as fractures in the seal and that increase its vertical permeability could be significant (Rutqvist and Tsang, 2002; Orlic, 2009); however, field observations to constrain and validate these models are lacking.

Injection-zone performance in accepting fluids

The ability of the selected injection zone to accept CO_2 is one of the main risk factors in brine-sequestration projects, and an extensive site-characterization workflow drawn from experiences in hydrocarbon exploration has been developed to reduce the risk (Forbes and others, 2008, p. 91–92; National Energy Technology Laboratory, 2010c). The risk is especially high when a large-volume CO_2-capture project will be developed that must rely on one injection site. A sequence of geologic assessments at subregional to site scale is required to characterize a brine sequestration site. Such data is used to infer that adequate pore space is well enough connected through the injection zone so that CO_2 can move into the pores and water out into the regional saline aquifer system, allowing injection to continue for many decades at acceptable pressures.

In contrast, by the tertiary stage of production of an oil reservoir, decades of data have been collected to both characterize the reservoir in detail (because of many penetrations) and quantify fluid flow through it. Response to injection of CO_2 is not completely predictable, even in this well-known environment: however, the risk of greatly underpredicting the volumes that can be injected is greatly decreased, providing a significant reduction in the project's risk.

Structural and stratigraphic trapping

Structural and stratigraphic trapping creates an inverted-bowl geometry of the seal that allows economically producible saturations and thickness of hydrocarbons to accumulate (figure 2). If a the seal is dipping, the hydrocarbons produced in the basin will move along thin zones, sometimes only a few centimeters thick, leaving only a thin smear of bubbles of hydrocarbons known as a *hydrocarbon show.* Movement through this thin zone over geologic time will allow hydrocarbons to leak from the basin and be oxidized at the land surface or discharged at seafloor seeps. CO_2 can be introduced into structural or stratigraphic traps, where it will be retained by the same physical processes which retained hydrocarbons. A number of simulations supported by field-test results have suggested that a trap is not essential for sequestration. Fast injection into the thick zone builds a thicker plumes. For thick plumes, lateral migration will be self limited by dissolution into brine and capillary trapping (Hovorka and others, 2005, 2006; Nicot and Hovorka, 2009,).

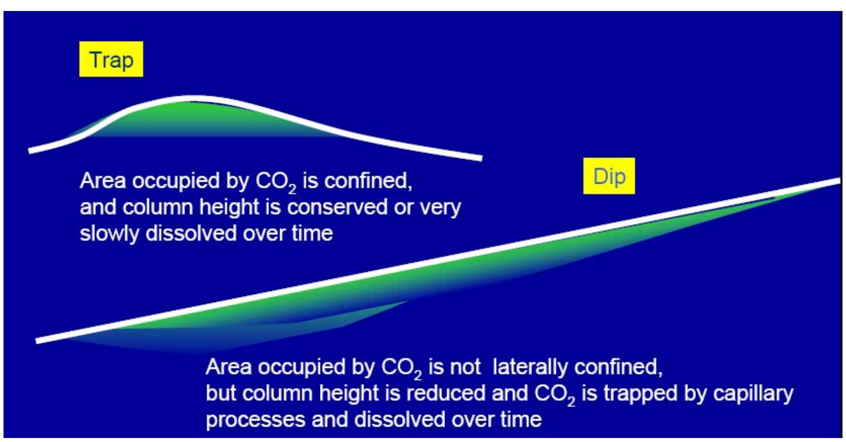

Figure 2. Comparison between trapping mechanisms for a plume confined in a trap, as it would be after EOR, and a plume injected where it will migrate updip, as it would in some brine-sequestration projects.

In the case of CO_2 used for EOR, the same seal geometry that formed the trap for the hydrocarbons serves as a trap for the CO_2. Additionally, in CO_2 EOR, the production wells introduce hydrologic gradients that draw fluids toward them, enhancing the control of fluid flow toward the well-known setting. However, additional work is needed to assess how much CO_2 moves radially away from injection wells and out of the injection pattern. In some previous EOR injections, movement of CO_2 out of the pattern caused it to be produced at wells that are not equipped to capture and separate the CO_2, resulting in atmospheric release of CO_2. A test to calibrate models of downdip movement away from EOR patterns is under way at the SECARB "early" test site at Cranfield, Mississippi (Hovorka and others, 2009).

Well operations and pressure management

Pressure will be elevated in response to injection. Highest pressures occur near the well bore, and the magnitude of pressure increase declines with distance (Kalyanaraman, 2008; Nicot 2008). As more CO_2 is injected, the area and/or magnitude of pressure increase is a function of injection-zone flow properties and injection rate. The area of review (AOR) is the area in which pressure-elevation increases are such that open pathways are assumed to provide a risk of fluid flow upward to USDW. The AOR for large-volume injection projects into brine are expected to be quite large (figure 3). In situations where permeable formations are of limited volume, pressure increase can be a limit on the rate and ultimate amount of CO_2 that can be injected. Some brine-sequestration projects are considering brine-production wells for pressure relief (Jain, 2010, oral presentation, UK-US CCS R&D Workshop, Pittsburg, 2010; Widyantoro, 2010, oral presentation, 6th meeting of the IEAGHG Monitoring Network, Natchez, 2010). In contrast, for EOR, pressure management is intrinsic because CO_2 (and water during WAG) injection is partially balanced by extraction of oil, brine, and CO_2 during production. CO_2 and, in some cases, brine are recycled to maintain the pressure conditions that favor miscibility and drive flow favorable to maximum recovery. Risk of early project termination because of unexpected pressure increase or expansion of the AOR into unacceptable areas is therefore greatly reduced during CO_2 EOR relative to brine sequestration. The same reduction of risks as a result of production applies to other types of leakage, such as via faults and fractures.

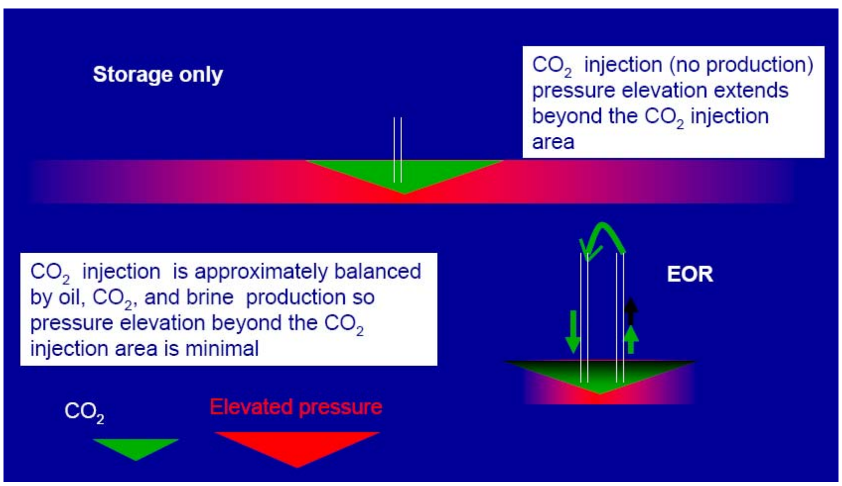

Figure 3. Comparison of pressure propagation away from brine sequestration and EOR.

Role of dissolution

One key difference between brine sequestration and CO_2 EOR is solubility of the CO_2 into the ambient pore fluids. CO_2 is only weakly soluble in water; miscible EOR is defined by solubility of CO_2 into oil. Dissolution of CO_2 has significance for permanence of storage in several ways: reduction viscosity and to some extent buoyancy as factors favoring leakage of CO_2 and decrease in volume occupied by the dissolved fluids compared with the same fluids in free phase.

Simulations of a reservoir with and without residual oil show that much more CO_2 is used during EOR conditions to develop a plume of the same size. Modeling shows a volume decrease of <4% when 0.5 mole of supercritical CO_2 contact 0.5 mole of brine, with pressure ranging from 1,000 to 6,000 psi and temperature from 100 to 350^{o}F. However, for 0.5 mole of supercritical CO_2 contacting 0.5 mole of crude oil under the same conditions (miscible), the decrease in volume from separate phases of CO_2 and oil to CO_2 dissolved in oil could be as high as 40% (Yang, written communication, Volume change for CO_2 and brine mixing, 2010). Recent studies have championed engineering enhancements for dissolution of CO_2 into brine (Burton and Bryant, 2009; Hassan and others, 2009) to mimic the desirable conditions reached in EOR.

Wells that penetrate the confining system

By design, wells provide a rapid pathway from the reservoir to the surface, which is easily controlled at the wellhead. At the end of service, wells are required to be plugged and abandoned to retain zonal isolation. In a properly constructed well, plugging is according to State rules, generally by setting a number of permanent barriers to flow made of steel and cement within the casing, cutting off the well casing below the surface, and welding a plate on the top of the well casing.

Historical data from secondary and tertiary floods document that wells that penetrate the confining system provide risks of leakage as pressure is increased in the reservoir (Skinner, 2003; Watson and Bachu, 2009, anecdotal evidence from Railroad Commission of Texas Abandoned Well Program). Conspicuous difficulties arise in four situations:

- Well design was inadequate to provide good control, generally in old wells,
- Construction failed to meet the design specification,
- Well maintenance and management failed, and
- At the end of service, the well was abandoned without plugging (it is still open), and sometimes documentation of its existence has been lost.

Operator experience shows that surveillance is required to identify conspicuous leakage as injection begins. Production wells that have created hydrologic cones of depression, therefore drawing flow downward toward the perforated interval, undergo a pressure reversal during injection, in which the gradient may be upward. If the well construction is flawed or has been damaged, saltwater may flow upward to pool at the surface or move into the groundwater and damage water resources, crops, and the ecosystem.

Newly-drilled injection wells can use high completion standards to reduce risk of leakage. A caliper log is run that provides detailed information on the volume of the well as drilled, which allows the proper amount of cement to be placed with which to cement the casing to the rock over the injection zone and across the formation seal. Surface casing is completely cemented in place to protect USDW. Class I and VI wells are required to pump additional cement to encase the entire long string, but production wells and Class II injection wells leave an uncemented opening filled with drilling mud between the rock and the casing (figure 4).

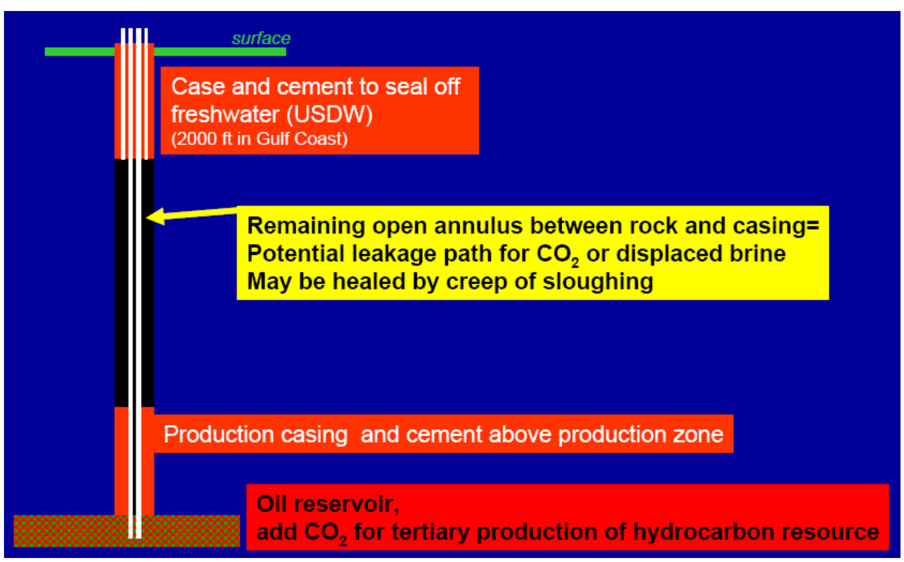

Figure 4. Intervals typically not cemented in Class II production and injection wells provide an unknown leakage risk.

During CO_2 EOR the operator remediates existing wells as needed to accept the increase in pressure and change in fluid composition. Plugged and abandoned wells and wells with incomplete data can be especially problematic because it becomes a matter of judgment whether the condition is adequate to retain fluids as pressure is increased and monitoring options are limited. Experience shows that EOR floods can retrofit thousands of old production wells and install similar numbers of new or retrofitted injection wells without damage to the ecosystem or human health or safety. A recent extensive field assessment of the quality of freshwater aquifers above the long-active SACROC CO_2 EOR project showed no evidence of degradation of aquifer quality from well leakage at depth (Smyth and others, 2009).

However, uncertainties remain regarding whether retrofitting (and, to some extent, new well engineering) is adequate to the purposes of retaining CO_2 in the reservoir to meet the standards needed to benefit the atmosphere. Reasons for concern include the possibility that thermal or geomechanical stresses from sustained injection will open permeable pathways in the well construction and that CO_2-brine mixtures will corrode well-construction materials and enlarge openings. Reasons for optimism about well retention are (1) the natural tendency for weak materials to fill voids and (2) research monitoring and testing programs, including the opportunity for increased surveillance of CO_2 EOR project wells to confirm apparent adequate performance.

Thermal stress

CO_2 is injected at surface temperature, causing cooling of the area around the well. Cooling can cause differential shrinkage of well materials, in turn causing formation of cracks known as *microannuli* (Patterson and others, 2008; Huerta, 2009). In 6 months of injection, bottom-hole temperature at the well at Cranfield that hosts the SECARB early test cooled from 252 to 160°F over 6 months of injection. Note that thermal stress on injection wells is the same for brine sequestration as CO_2 EOR.

Dissolution of well materials

When CO_2 dissolves in water, pH is moderately decreased increasing corrosivity. Therefore, unmitigated small leaks can be self enhancing because of corrosion of well tubulars and dissolution of cements by CO_2-charged brines. Some workers therefore speculate that leakage risk in the presence of wells could increase with time (Kutchko and others, 2007; Bachu and Bennion, 2009; Carey other others, 2010).

Natural filling of voids

Mechanically weak mudstone and shale layers common in sedimentary-rock sequences—and often comprising seals—creep or fracture and fall (slough) over time into open spaces, blocking them and greatly reducing flow. Over thousands of feet of well, inference, limited test cases, and direct measurement of sloughed materials suggest that blockage of voids occur, greatly reducing flow (Stritz and Wiggins, 2002; Warner and McConnell, 1990).

Practices to increase assurance that sequestration will be permanent

A number of CO_2-injection-specific methodologies and site-specific assessments for evaluation of the risk of a sequestration failure and long-term leakage have been developed. Inventories of current work can be obtained from the IEA Greenhouse Gas R&D Program Risk Assessment Network (http://www.ieaghg.org/) and from the National Energy Technology Laboratory (in preparation). CO_2 EOR developers typically assess business risks, whereas sequestration projects are more focused on documenting permanence of storage and avoidance of environmental hazard (Oldenburg and others, 2009). Some stakeholder groups, for example World Resources International (Forbes and others, 2008), think that risk assessment is a key element of CCS. Risk-assessment methodologies for sequestration have been applied to CO_2 EOR environments with favorable outcomes (Chalaturnyk and others, 2004), and future application has the potential to increase confidence in the site-specific permanence of sequestration via EOR.

Role of monitoring in documenting permanence

One outcome of risk assessment is a monitoring program that collects data to assess potential flaws in the system that can be targeted for mitigation. As a project progresses, documentation of performance increases, and any flaws (such as poor well completions) are remediated until, at closure, confidence in long-term sequestration is high.

The U.S. EPA Underground Injection Control (UIC) Program (2008) has proposed a draft rule defining requirements for a Class IV injection well that would be required for CO_2 sequestration projects. The proposed version rule requires a number of monitoring activities to be conducted during injection and for a period after the end of injection. Requirements for CO_2 EOR remain as they have been under Class II. Table 3 highlights some of the main differences between the draft Class VI, typical class II, and typical industry best practices.

Table 3. Informal comparison of monitoring requirements with CO_2 EOR voluntary surveillance for flood optimization.

Activity	**Proposed Class IV requirement**[1]	**Class II requirement**[2]	**Industry voluntary practice (in-company)** [3]
Well integrity	Mechanical-integrity test program	Mechanical-integrity test program	Well-maintenance and corrosion-inhibition program
Reservoir characterization	Detailed	Detailed	Detailed
Modeling	Role of multiphase flow models considered	Analytical models	Analytical models or multiphase flow models
Report of CO_2 injection rates, surface injection pressure, and volumes	Yes	No	Used in-company, economic impact of purchase and recycling, optimization of flood
Pressure away from injection wells	Monitoring wells may be required	No	Pressure at producers regularly measured, used to optimize flood
History matching	Update to AOR calculation may be required	Not reported	Regularly used to optimize flood
Time-lapse surface or well-bore geophysics	Plume tracking required	No	Used as needed, special cases only
Wireline logging of reservoir	No	No	Regularly used to optimize flood
Injection-zone geochemistry	May be required	No	Only in characterization, for oil and brine characterization
USDW geochemistry	May be required	No	No
Soil gas and tracers	May be required	No	No

[1] EPA Class IV rule is in agency revision; this column excerpted from EPA Underground Injection Control (UIC) Program (2008) draft and is not authoritative.
[2] Class II rules mostly enforced by State primacy; therefore, requirements vary among states; this column reflects Texas practices.
[3] Column reflects voluntary operations by operators and is based on public presentations by operators, private conversations, and literature.

Research-oriented monitoring programs have been conducted in a number of EOR settings. The Weyburn CO_2 EOR project in Saskatchewan that started in 2000 and is operated by EnCana has hosted an extensive and continuing research project. The Weyburn project has tested a wide variety of potential monitoring methods in a commercial EOR setting (Wilson and Monea, 2004). Short huff-n-puff tests were monitored to test tools at West Pearl Queen field, New Mexico (Pawar and others, 2006), and Loudon field, Illinois (Finley, 2007). Penn West hosted a series of experiments at the Cardium Formation of Pembina field, Alberta (Hitchon, 2009). Denbury hosted several tests associated with a commercial flood at Cranfield field, Mississippi, as part of the Southeast Regional Carbon Sequestration Partnership at Cranfield (Hovorka and others, 2009). Soil gas methods were tested at the Rangely CO_2 flood by Klusman (2003).

During EOR floods, surveillance beyond what is required by regulation is conducted to benefit the operator and maximize yields on the substantial investment. This surveillance should be used as the foundation of any monitoring program to document sequestration permanence. Regular mechanical test programs to document well integrity are required under Class II. Normally, field technicians conduct regular (daily to weekly) inspections of each well to check for correct surface and subsurface performance and corrosion inhibition. Pressure and fluid flow of the field are assessed through surface and downhole measurements that are more rigorous in some ways than those used in research projects because of the spatial and temporal density of the data. Commercial CO_2 EOR projects do not traditionally conduct programs above the reservoir to test assumptions of permanence of retention in the injection zone. The applicability of methods developed for research projects, such as above-zone, groundwater, and soil-gas monitoring, need further evaluation of their suitability in EOR settings. Projects are in planning that will more specifically develop the link between commercial flood surveillance and monitoring to assure permanence during CO_2 EOR (figure 5).

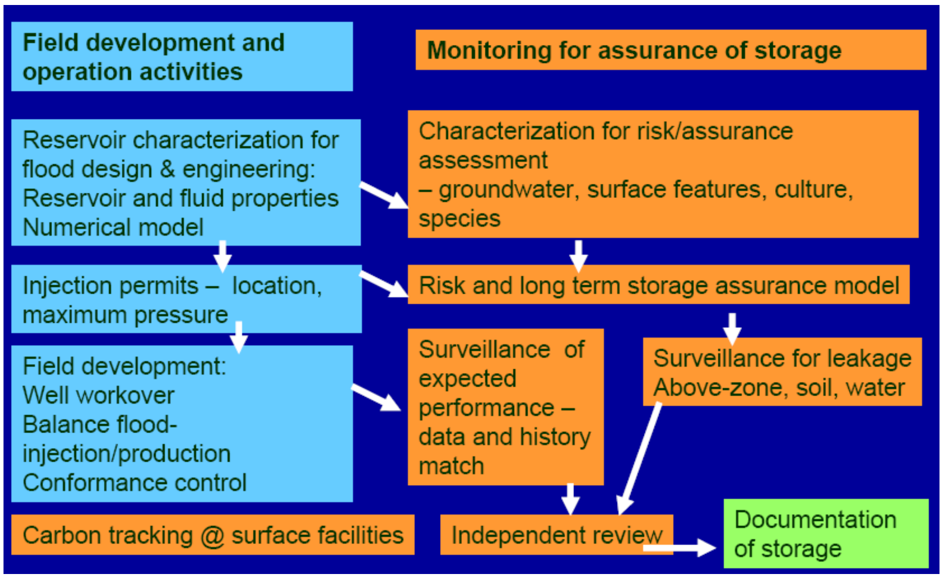

Figure 5. Draft plan linking commercial surveillance for CO_2 EOR with monitoring to document permanence of sequestration.

Monitoring well performance in CO_2 EOR projects

A number of modeling efforts have assessed the range of impacts of well leakage on the basis of available semiquantitative data (for example, Nordbotten and others, 2004). Additional analysis and field-based testing are needed to provide better quantification of frequency and magnitude of well leakage in long-term sequestration. Wide distribution of wells of different ages in U.S. existing wells (Nicot, 2009) can probably not be completely avoided for brine sequestration. Large numbers of actively managed wells in CO_2 EOR are providing the laboratory for which a test program is under way.

Normally after well construction, a variety of tests are run either as best practices or to meet regulatory requirements. A mechanical integrity test (MIT) in which pressure within various well components is elevated and shown to be steady for a certain period of time is required by regulation for all wells. Logging programs the image of casing and cement conditions or diagnose fluid-flow indications (National Energy Technology Laboratory, 2009, Appendix AII-4-8). MIT and sometimes other types of well-integrity tests are also required at regular periods during well operation and prior to plug and abandonment of a well.

Cross-formation hydrologic tests can be used to assess the overall leakage signal across a confining zone (Javandal and others, 1988; Hovorka, 2008), and collection of above-zone pressure has been a noted monitoring strategy in Class VI draft rules (U.S. EPA Underground Injection Control (UIC) Program, 2008). At a specific well, passive observation of casing pressure is a useful diagnostic for leakage (Huerta, 2009). Monitoring casing pressure can be automated to increase data density and serve as an alarm (Hovorka and others, 2009). Very slow leakage from reservoir to atmosphere might be at rates below detection of many methods, presenting a monitoring challenge.

Nongeotechnical factors favoring CO_2 EOR

Three factors outside the geotechnical scope of this report are mentioned and shown at the bottom of Table 3 because in current decisions, financial, social, and regulatory considerations issues strongly influence whether CO_2 EOR be used as part of a sequestration project. Financial support for sequestration CO_2 EOR has been extensively examined (for example, Advanced Resources International, Inc., 2010). Financial benefit from oil production is harmonic with positive societal values of domestic energy production, production from existing (rather than new) sites, and job retention. Recently issues of permitting, pore-space ownership, and liability have been reasons for using CO_2 EOR as sequestration. The legal and regulatory setting for brine sequestration is evolving, State dependent, and uncertain. In contrast, equivalent frameworks for tertiary recovery are well known. Perhaps the most compelling reason for sequestration projects to use CO_2 EOR is public acceptance. Such acceptance is good for CO_2 EOR relative to brine sequestration because the value of royalties, fees for surface access, and jobs are recognized in host communities. Landmen who broker an EOR project have a mature set of tools that can be used to develop the project through the needed stages, and rate of success in project development is known.

In addition to tests of sequestration within the CO_2 EOR setting described earlier, several brine-sequestration tests (Frio, SECARB “early test” at Cranfield, and SECARB “anthropogenic test” at Citronelle) have been set in oil fields because of the pragmatic support these settings provide.

What is the CO_2 sequestration potential of EOR in the U.S.?

The EOR demand for CO_2 is of the right magnitude for accepting CO_2 from major anthropogenic sources, such as power plants. Large EOR projects, for example, SACROC field operated by Kinder Morgan in Scurry County, West Texas, have historically purchased 2 to 4 million metric tons of CO_2 per year (Smyth, 2008; Han and others, 2010)—about ⅓ the annual volume produced from an average coal-fired power plant. Injection has been sustained since 1972 and will continue into the future, reasonably matching in duration a power-plant lifetime. Deployment of CO_2 EOR is possible at SACROC because of proximity (140 miles) of large CO_2 sources from gas separation plants and investment in a pipeline network to bring CO_2 to the field (Kinder Morgan, 2010). To extrapolate the capacity of reservoirs for sequestration, both volumetric and economic assessments have been made.

Volumetric assessments of capacity

The U.S. Regional Carbon Sequestration Partnerships (RCSP) program (Litynski and others, 2008) has completed two volumetric assessments of sequestration capacity on a basinal scale and estimates that 138 billion metric tons of CO_2 could be stored in depleted oil and gas fields of the U.S., compared with at least 3,297 billion metric tons in brine formations (National Energy Technology Laboratory, 2008, p. 18 and 20).

Volumetric estimates of capacity in depleted oil and gas fields are based on replacement of volumes of hydrocarbon produced with equivalent volumes of CO_2 at reservoir conditions. Hydrocarbon production is estimated either as a fraction of the volume of the reservoir (area × thickness ×oil saturation) or by reported cumulative volumes produced (National Energy Technology Laboratory, 2008, p. 122). The advantage of this estimate is that it is relatively simple and can be made using approximately the same assumptions in all fields in the U.S. The annual projected amount of capture can be divided by reservoir volume so that the number of years of captured CO_2 that this resource can accept can be estimated. Because of simplicity, however, volumetric methods are unsuitable for answering the question of how much CO_2 could be sequestered through EOR. Volumetric methods consider oil and gas resources equally, but EOR is applicable only to the subset of oil reservoirs in which investment would yield profitable incremental recovery. The equivalent process of injecting CO_2 for economic recovery of gas (enhanced gas recovery, EGR) was considered (by the GEO-SEQ project team, (2004), but feasibility is not well enough documented to consider here.

Economic assessments of capacity

Assessment of CO_2 usage for EOR requires merging an economic forecasting model with a reservoir simulation model. Extensive assessment has been done by the EOR industry, however most of this work is confidential. An economic model, needed to constrain assumptions on parameters such as value of CO_2 and oil, capital expenses for infrastructure, royalties for mineral rights, and operating expenses, can strongly influence outcomes. For example, the historic range of oil prices from \$20 to \$90/bbl will move many fields in and out of being economic for CO_2 EOR under reasonable assumptions for other economic variables (Holtz and others, 1999). Reservoir simulation models input parameters such as depth, temperature, pressure, oil and other fluid densities and chemical properties, oil saturation distribution, porosity, permeability, capillary characteristics of the rock, and geometry of the reservoir. Repeated runs of the model allow the modeler to estimate what the response of the reservoir will be in terms of recovery of oil and recycling of fluids to different fluid injection rates, durations, and well geometries. Reservoir response can then be integrated with the economic model to determine whether the EOR project is worth the investment. Historically operators have done short-duration pilot tests to gain experience and test validity of the model assumptions in the field.

Regional assessment role of CO_2 EOR

Field-by-field model-based assessment is costly and data intensive and therefore has not been done regionally for the U.S. Regional-scale approximations can be made by estimating the volume of oil that could be recovered and the amount of CO_2 that would need to be injected to accomplish the recovery under a range of assumptions. The ratio of CO_2 used to volume of oil used is described as the *CO_2 utilization factor* (Holtz and others, 2005). Recycled CO_2 is involved in optimizing recovery, but it does not add to the total amount purchased. The amount of CO_2 recycled, as well as the total new purchase over the project period, strongly depends on both reservoir properties and selected flood development and operation (Nuñez-López and others, 2008). Examples of utilization ratios based on current floods from 0.15 to 0.27 metric tons of purchased CO_2 per barrel of oil produced have been reported (McCoy, 2008); however, these ratios should be used as minimal estimates for sequestration via CO_2 EOR.

If large quantities of anthropogenic CO_2 are available and value is assigned to retaining it in the reservoir, ratios could be significantly larger. Recently, a series of studies funded by the National Energy Technology Laboratory and summarized by Advanced Resources International Inc. (2010) have assessed the regional market for CO_2 and how CO_2 EOR could be used to increase domestic oil production, according to a set of assumptions described as *best practices* and *next generation*, and a rate of utilization of 0.21 to 0.28 to metric tons purchased at CO_2 per barrel of oil produced, calculating an economically feasible market for 12 to 14 billion metric tonsof CO_2. Higher utilization numbers can be extracted from Denbury's plans using continuous CO_2 injection (Denbury Resources Inc, 2009) and comments on Denbury's operations (Evans, 2009); however, detailed assessments that would cumulated the sequestration value of continuous injection from new projects through maturity have not been undertaken.

Co-optimizing sequestration and CO_2 EOR

Modeling studies have considered strategies for co-optimizing sequestration and CO_2 EOR (Jessen and others, 2005; Kovscek and Cakici, 2005; Ramirez Salizar, 2009). However, these studies deal mostly with the fine points of “tuning” the flood by modifying engineering, such as well placement, fluids, and injection ratios. Large changes that could result from the availability of much larger supplies of CO_2 to reservoirs have not been fully considered. Beyond sweeping the ROZ (Jessen and others, 2005; Meltzer, 2006), large changes in well spacing, injection rate, more widespread use of gravity displacement and faster development of fields might be favored. If the cost were low enough, CO_2 could be used for repressurization to benefit production and offset subsidence (Jessen and others, 2005

The largest and still unquantified method of increasing the volumes of CO_2 stored during EOR lie in utilization of stacked storage (Figure 6). In typical oil reservoirs, large amounts of brine-filled pore space lie below and laterally adjacent to the productive oil reservoir. In oil-field terms, this is the water leg of the reservoir. Under conditions where value was given to sequestration, the operator would change from the current practice of minimizing CO_2 injection to maximizing injection, largely by using these volumes. Some parts of stacked pore volumes can be accessed from the flood patterns by injecting at higher rates so that balance of injection and production is shifted and CO_2 moves outward from the pattern. Other volumes are isolated by stratigraphic barriers, and recompletion of injection wells into nonproductive strata would be required. SECARB’s “anthropogenic test” has proposed to use this method method at Citronelle oilfield, Alabama. In areas where commercial CO_2 EOR is possible, distribution of hydrocarbon targets (Figure 7) suggests that much of the brine-formation resource could be accessed through the well and pipeline system developed for CO_2 EOR. Only limited and informal assessments of use of stacked storage volumes have been completed. Injection below the producing zone has the benefit of avoiding risks associated with well penetrations. The large-volume field test at Cranfield field, Mississippi, under the SECARB program (Hovorka and others, 2009) has preliminary observations suggesting that increasing injection rates at a downdip water-leg injector above that required for EOR has a favorable impact on both sequestration and CO_2 EOR.

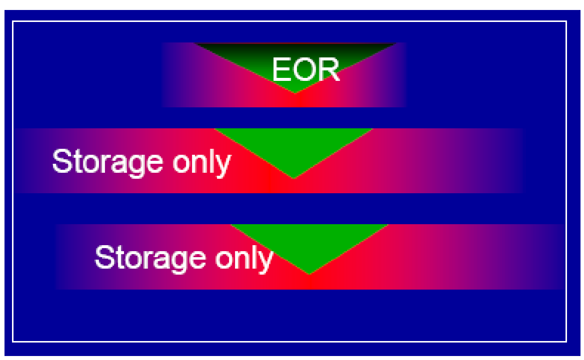

Figure 6. Large volumes of nonproductive brine formations lie below many CO_2 EOR targets. The concept of using them to increase sequestration volume accessed via EOR is called *stacked storage*.

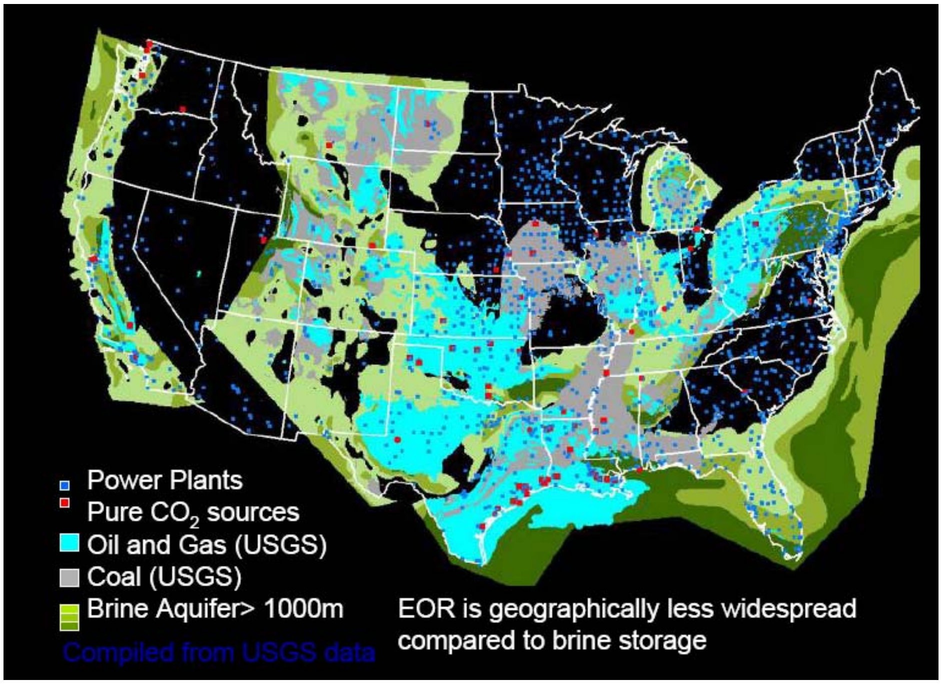

Figure 7. Coincidence of sedimentary formations of suitable depth for brine sequestration with hydrocarbon basins and stationary CO_2 sources suggests that much U.S. brine-formation storage could be accessed through infrastructure developed for CO_2 EOR using the stacked-storage concept. Additional screening to determine which reservoirs are economically accessible for EOR and how much pipeline construction would be motivated by EOR has not been undertaken.

Key uncertainties in how much EOR can be used for sequestration lie in social and policy motivators, which are focused on the cost and volume of CO_2 available. Capture cost for of CO_2 from anthropogenic sources is expected to be significantly higher than the cost for of most current EOR projects. Only by assuming sustained high oil prices can CO_2 prices be elevated to more completely cover the cost of capture. If the price of CO_2 were supported as part of a carbon-emission-reduction program (as it would be for sequestration in brine formations), other social and economic barriers might have to be overcome. CO_2 EOR would have to qualify for this support (be eligible for carbon credits) under conditions economically and logistically compatible with EOR. This harmonization might be especially important in the early stages of anthropogenic capture in a region because operators might not be willing to make major changes to current successful operations until anthropogenic CO_2 has become a major resource. State mechanisms to unitize fields would have to be successfully accessed, so as to ensure that the field is operated under conditions in which CO_2 escape out of injection patterns to producers not linked to separation units did not occur. Capital investment for project development, including pipeline construction and well drilling and remediation, would need to be available. If CO_2 is not available in volumes or at a competitive price, others forms of EOR that do not use CO_2 may be favored. If use of CO_2 for EOR were to become highly valuable, availability of a trained workforce and equipment suppliers could retard the rate of deployment (Bryant and Olsen, 2009). Success of early projects testing CO_2 EOR as sequestration is an essential part of wide deployment. Many technologies have failed to deploy because early failures created a climate that stunted expansion.

Where and how does CO_2 EOR provide information about very large scale injection for atmospheric benefit?

Thirty-eight years of CO_2 EOR has provided CCS a ready-to-use model of how to safely handle large volumes of CO_2 through pipelines and wells. Lessons on materials and corrosion risks are also provided for more severe conditions than would be encountered in brine sequestration (Forbes and others, 2008; Cooper, 2009)

Monitoring-tool testing

CO_2 EOR provides CCS a commercially available and tested tool kit for making measurements of CO_2 distribution as well as an extensive experience base of how CO_2 movement in the subsurface can be predicted via modeling. Tools such as injection and production logging, saturation logs, pressure gages, and surface- and well-based geophysical imagining techniques developed for oil-field use have immediate application to sequestration in brine formations. At the SECARB Cranfield project, which is now under way, and the Frio project (Hovorka and others, 2005, 2006, 2009), oil-field tools performed better in simpler (brine-CO_2) fluid systems that they do in CO_2 EOR with more complex fluids.

Not all of the value of this previous experience has yet been transferred from CO_2 EOR into the sequestration context. The Carbon Capture Project Joint Industry Project recently published a collection of case studies from industry experience using monitoring tools that provide high-value examples of such technology transfer (Cooper, 2010). More transfer from industry experience to sequestration is possible both through assessment of historic data and new data collection at new and ongoing CO_2 EOR projects. In particular, the dense data available in oil-field settings in terms of both reservoir characterization and access points through wells allow assessment of numerical model performance that would not be possible at most brine-sequestration sites. CO_2-EOR-based models of flow processes can be used to increase confidence in modeling at brine sequestration sites; however, complicating factors of oil-CO_2 interaction and fluid production add complexity. Because of this complexity, factors such as the impact of large-volume fluid displacement cannot be directly measured, but the correctness of underlying assumptions can be assessed through a combination of monitoring and modeling. Another example of where CO_2 EOR can prepare the way for brine sequestration is illustrated by a field study that has measured no damage to USDW in the Dockum aquifer as a result of 38 years of CO_2 injection for EOR at SACROC oil field, Scurry County, Texas (Smyth and others, 2009; Romanak and others, 2010). Similar studies at other fields are needed to determine whether these conclusions are broadly applicable.

Lowered whole-project risks for early capture projects

Injection of CO_2 for EOR can simplify and reduce uncertainties in early capture projects. This option has been attractive for a number of capture projects sited in areas where CO_2 EOR is either under way or planned in the near future (for examples, see press on NRG Parrish Plant, Summit Energy, Air Products, and Leucadia capture projects). The process of bringing a field under CO_2 EOR flood is well known in terms of design, cost, regulatory framework, and property rights. Handoff of CO_2 supply “at the plant gate” can significantly reduce the complexity of a capture project. EOR projects under way can accommodate large volumes of additional CO_2 during their early years. As recycling begins to dominate, expansion of the project is the mechanism that can accommodate additional volumes of CO_2 (although not all projects can be expanded). A pipeline network case study (Essandoh-Yeddu and Gulën, 2008) shows that capture from several major power plants would saturate the regional high-quality demand for commercial CO_2 EOR at conventional utilization rates.

Unlike available-on-demand natural CO_2, daily and seasonal fluctuation in capture rate will continue through the lifetime of a CCS project. For new facilities, starts and stops of the capture process are likely as the plant is brought to balanced operation. Brine sequestration of fluctuating CO_2 amounts is possible and is conducted at some test facilities (for example, AEP Mountaineer Capture Plant, West Virginia) and planned at other test sites. Impact of such fluctuation on reservoir performance or the equipment durability is, however, unknown. It is possible that for some markets, intermittent supplies of CO_2 may be of decreased value as compared with on-demand CO_2. Supply fluctuation is not necessarily a strong negative because EOR WAG projects design intermittent input of CO_2 by injecting water.

Conclusions

CO_2 EOR is one of the techniques that is being used now and can be used to a much greater extent in the future for sequestration of CO_2-A. CO_2 EOR results in placing essentially all captured CO_2 into deep subsurface environments. CO_2 extracted from the reservoir as part of the EOR process is, under current practices, effectively returned to the subsurface during recycle.

A key factor that must be considered in assessing the effectiveness of CO_2 EOR as sequestration is the extent to which storage in the subsurface is permanent. Slow rates of leakage over long periods can result in unacceptable performance of a sequestration site with respect to atmospheric targets. Inferential data suggest that for all well-sited and correctly managed geologic sequestration types, permanence is high. Factors that favor more confidence in permanence in EOR settings over brine-formation storage are (1) proven seal performance because of long-term retention of hydrocarbons, (2) active pressure and plume-extent management through production and commercially motivated surveillance, (3) enhanced trapping because of dissolution into oil, and (4) well-known reservoir properties. Unfavorable factors include abundant well penetrations of the confining system and the possibility that CO_2 might escape from the intended pattern and into produced fluids that are not sent through the separation plant for recycling. The risk from these unfavorable factors requires more research to determine frequency and magnitude of occurrence for input into life cycle analysis, as well as effective monitoring approaches that allow flaws to be effectively detected and mitigated. Site-specific risk assessment prior to injection for sequestration would alert project planners to focus their efforts on reducing leakage risks.

Surface aspects of the active CCS operation, including fugitive emissions from CO_2 not recycled; losses from connections; venting for maintenance or during an upset; emissions related to production, refining, and combustion of incremental oil; emissions related to material fabrication and installation, are considered in life-cycle assessments. Emissions from CO_2 EOR would be larger than corresponding emissions for sequestration (without production) in brine-bearing formations. Initial life-cycle assessment (Jaramillo and others, 2009) is based on production data and therefore considers CO_2 EOR as it was practiced historically and does not consider the changes possible if sequestration were to become part of the CO_2 EOR business. Mass-balance considerations during the active phase of all sequestration should be dealt with through the greenhouse-gas accounting mechanism motivating the process.

The extent to which CO_2 EOR can provide and leverage sequestration depends on how the CO_2-A market develops. Minimal deployment will occur if (1) project-developer confidence in future availability of CO_2-A is low, (2) cost of CO_2-A to the operator of CO_2-A is unknown or high, or (3) requirements such as monitoring or assumption of unprecedented liability to obtain low cost, high-availability CO_2 are seen by project developers as prohibitively difficult, expensive, or incompatible with commercial operations.

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WHITE PAPER #2

CHALLENGES OF IMPLEMENTING LARGE-SCALE CO_2 ENHANCED OIL RECOVERY WITH CO_2 CAPTURE AND STORAGE

By
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Advanced Resources International, Inc.

This "White Paper", prepared for the "Symposium on the Role of Enhanced Oil Recovery in Accelerating the Deployment of Carbon Capture and Storage"[*], addresses five topics:

- Status of CO_2-EOR
- CO_2 Markets and Storage Capacity Offered by EOR
- Benefits of Productively Using CO_2 for EOR and Storage
- Feasibility of Large-Scale Implementation of CO_2-EOR/CCS
- Accelerating and Implementing Integrated CO_2-EOR/CCS Projects

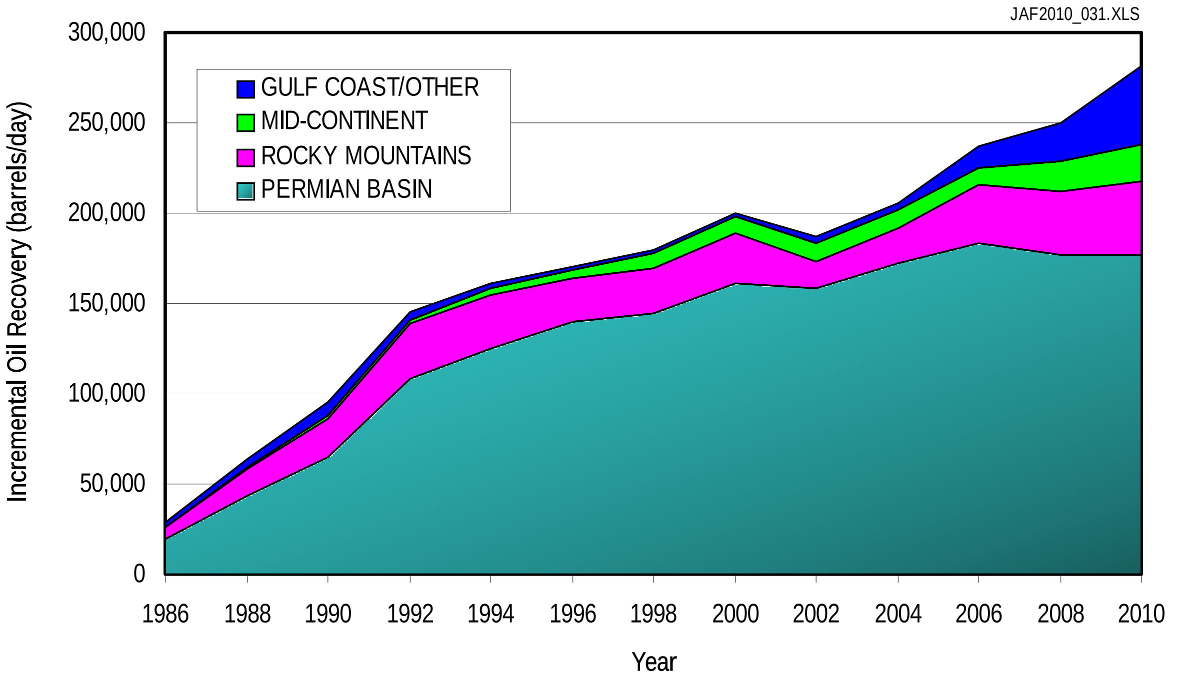
1. STATUS OF CO_2-EOR

In discussing and further examining the role of CO_2-based enhanced oil recovery (CO_2-EOR) for accelerating the deployment of CO_2 capture and storage (CCS), it is useful to recognize the following:

- CO_2-EOR currently provides about 280,000 barrels of oil per day in the U.S.,[1] equal to 6% of U.S. crude oil production. CO_2-EOR has been underway for several decades, starting initially in the Permian Basin and expanding today to numerous other regions of the country, **Figure 1**. The number one barrier to reaching higher levels of CO_2-EOR production is lack of access to adequate supplies of affordable CO_2.

[*] Hosted by MIT Energy Initiative and the Bureau of Economic Geology, University of Texas Austin Symposium, Cambridge, MA, July 23, 2010.
[1] Oil and Gas Journal EOR Survey, April 2010.

Figure 1. Growth of CO_2-EOR Production in the U.S.



Source: Advanced Resources Int'l., based on Oil and Gas Journal, 2010.

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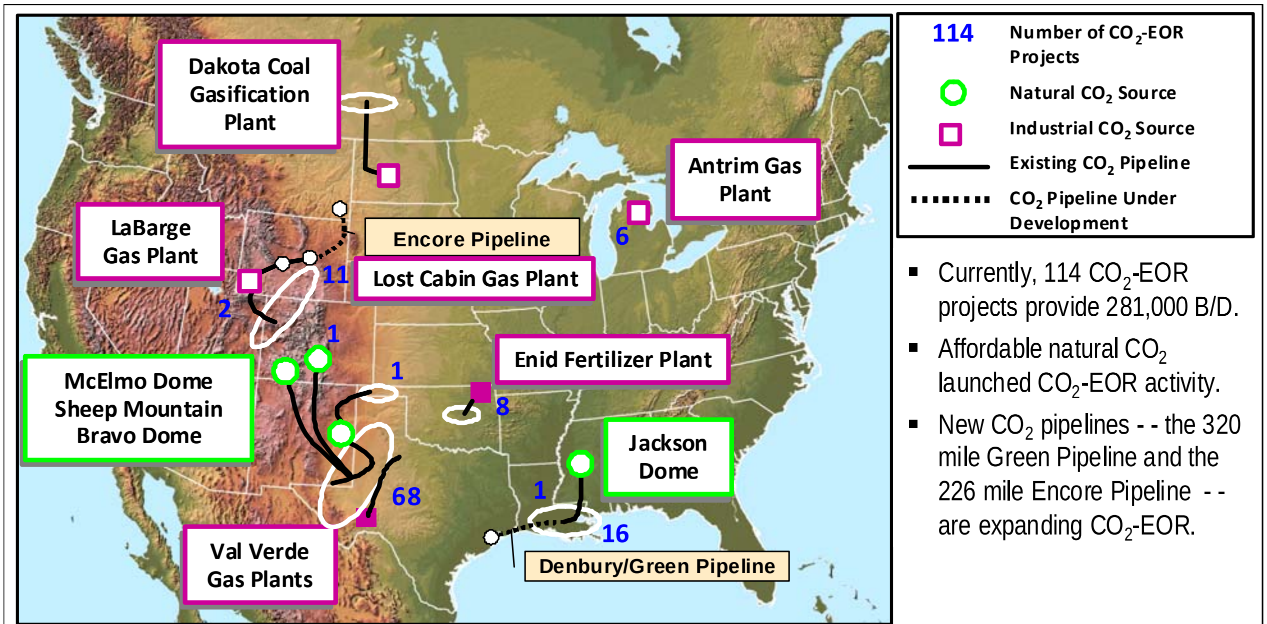
- New CO_2 pipelines and refurbished gas treating plants, such as Denbury's 320 mile Green Pipeline along the Gulf Coast, ExxonMobil's expansion of the Shute Creek (La Barge) gas processing plant, the new proposed 226 mile Encore Pipeline and refurbished Lost Cabin gas plant in the Rockies, and the new Century gas processing plant in West Texas, are all due on-line in late 2010 or early 2011. These new facilities will significantly expand the availability and use of CO_2 in domestic oil fields, leading to increased oil production from CO_2-EOR, **Figure 2**.[2]

- Natural CO_2 fields currently are the dominant source of CO_2 for the EOR market, providing 2.35 Bcfd (equal to 45 million metric tons per year). However, anthropogenic sources account for steadily increasing volumes,

[2] Various industry presentations and publications.

currently providing 0.53 Bcfd (10 million metric tons per year) of CO_2 for enhanced oil recovery, **Table 1**.[3]

Figure 2. Current U.S. CO_2-EOR Activity



Source: Advanced Resources International, Inc., based on Oil and Gas Journal, 2010 and other sources.

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Table 1. Significant Volumes of Anthropogenic CO_2 Are Already Being Injected for EOR

Location of EOR / CO_2 Storage	CO_2 Sources by Type and Location	CO_2 Supply (MMcfd)	
		Natural	Anthropogenic
W. Texas-New Mexico-Oklahoma	Natural CO_2 (Colorado-New Mexico) Gas Processing Plants (W. Texas)	1,670	105
Colorado-Wyoming	Gas Processing Plant (Wyoming)	-	230
Mississippi/Louisiana	Natural CO_2 (Mississippi)	680	-
Michigan	Ammonia Plant (Michigan)	-	15
Oklahoma	Fertilizer Plant (Oklahoma)	-	30
Saskatchewan	Coal Gasification Plant (North Dakota)	-	150
TOTAL (MMcfd)		2,350	530
TOTAL (million mt)		45	10

* Source: Advanced Resources International, 2009.
**MMcfd of CO_2 can be converted to million metric tons per year by first multiplying by 365 (days per year) and then dividing by 18.9 Mcf per metric ton.

[3] Advanced Resources International internal data base, 2010.

- The largest single source of anthropogenic CO_2 used for EOR is the capture of 230 MMcfd (4+ MMmt/yr) of CO_2 from the gas processing plant at La Barge in western Wyoming. This is followed by the "poster child" for integrating large-scale CO_2-EOR with CCS - - the capture of 150 MMcfd (~3MMmt/yr) of CO_2 from the Northern Great Plains Gasification plant in Beulah, North Dakota and its transport, via a 200 mile cross-border CO_2 pipeline, to the two EOR projects at the Weyburn oil field in Saskatchewan, Canada.

- Capture of CO_2 from a series of proposed coal-to-liquids (CTL), integrated gas combined cycle (IGCC) and other carbon conversion projects would add significant volumes of anthropogenic CO_2 for use by CO_2-EOR. Three example projects from a much larger group are listed below:[4]

    – Hydrogen Energy's (BP/Rio Tinto) pet-coke gasification plant in Kern County, California plans to deliver 2 MMt/yr for CO_2-EOR at Elk Hills oil field, **Figure 3**.

    – Southern Company's Kemper County IGCC plant plans to provide 1.1 to 1.5 MMt/yr to Denbury Resources for CO_2-EOR in oil fields in Louisiana and Mississippi.

    – Summit Energy's Texas Clean Energy IGCC project plans to sell 3 MMt/yr for CO_2-EOR in West Texas, **Figure 4**.

- In addition, Denbury Resources has identified 17 MMmt/yr of anthropogenic CO_2 potentially available for EOR in the Rockies, **Table 2**. It has also entered into contingent purchase contracts for 18 MMmt/yr of anthropogenic CO_2 in the Midwest and for 14 MMmt/yr of anthropogenic CO_2 in the Gulf Coast.[5]

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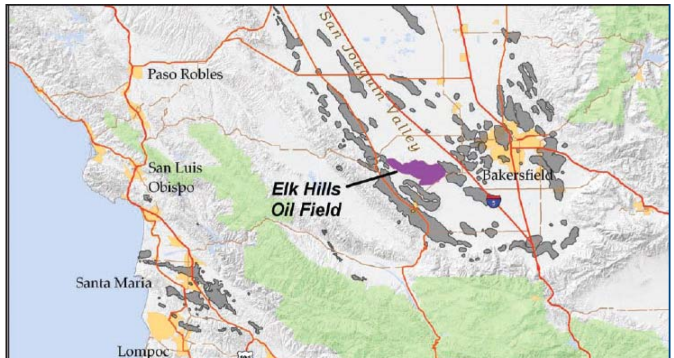
[4] Various industry presentations and publications.
[5] Denbury Resources corporate presentation, June 2010.

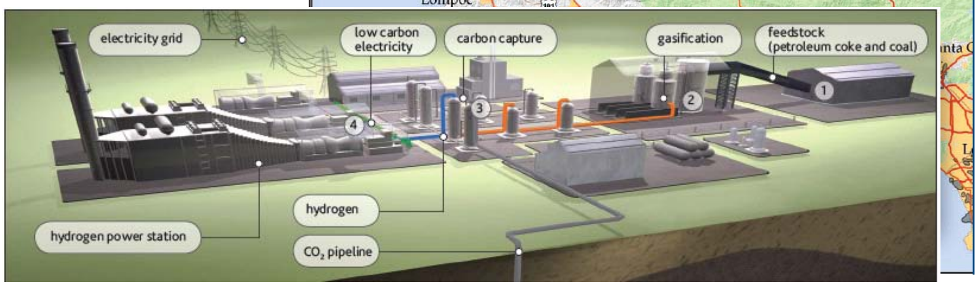
Figure 3. Advanced Power Plants and Use of EOR for CO_2 Storage

Hydrogen Energy's (Rio Tinto/BP) Pet-coke Gasification Plant

- 250MW gasification of pet-coke
- Capture 90% of CO_2; over 2 million tons of CO_2 per year
- Oxy will take CO_2 for EOR at Elk Hills oil field
- Operational by 2015

Elk Hills Oil Field near Bakersfield, CA





Source: Hydrogen Energy

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Figure 4. Advanced Power Plants Using EOR for Storage

Southern Company's Kemper County IGCC Plant

- 582 MW IGCC fueled by Mississippi lignite
- Capture 65% of CO_2
- Negotiating to sell 1.1 to 1.5 million tons of CO_2 per year for EOR
- Cost $2.4 B; operational by 2014

*Source: Mississippi Power, Denbury Resources

Summit's Texas Clean Energy IGCC Project

- 400 MW IGCC with 90% capture
- Located near Odessa in Permian Basin
- Sell 3 million tons of CO_2 per year to EOR market
- Expected cost $1.75 B; $350 MM award under CCPI Round 3.

Source: Siemens Energy

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Table 2. Rockies New Anthropogenic CO_2 Sources

	Location	MMcfd	Million mt/yr	Comments
Natural Gas Treating Plants				
1. Exxon La Barge	SW Wyoming	100	1.9	Plant expansion
2. COP Lost Cabin	Central Wyoming	50	1.0	Under contract
3. Riley Ridge	SW Wyoming	-	-	Under discussion
	Subtotal		2.9	
Proposed Coal to Gas/ Liquids Plants				
1. DKRW/Medicine Bow	SE Wyoming	150	2.9	DOE Loan Guarantee
2. Refined Energy	SE Idaho	80-175	2.3	Diesel/Fertilizer
3. Gas Tech	NE Wyoming	115	2.2	UCG
4. Many Stars	C. Montana	250	4.8	Start in 2012
5. South Heart	SW N. Dakota	100	1.9	Coal to H_2
	Subtotal		14.1	
	TOTAL		17.0	

2. CO_2 MARKETS AND STORAGE CAPACITY OFFERED BY EOR

Clearly, many of the proposed new IGCC and coal to gas/liquids plants look to CO_2-EOR as their CO_2 storage option. Because of this, some power companies have expressed concerns that these initial plants will "use up" all of the available EOR market and CO_2 storage capacity, leaving little for subsequent use. As such, a key question is - - *just how much CO_2 could be stored with CO_2 enhanced oil recovery?*

Storage of CO_2 with enhanced oil recovery is claimed, by some, to be a small, niche opportunity. Many of these claims are based upon anecdotal evidence, outdated characterization of CO_2-EOR performance and past perceptions of the small oil recovery potential offered by CO_2-EOR. A rigorous assessment of the CO_2 storage and oil recovery potential offered by domestic oilfields is summarized in this "White Paper" and is available in the recent DOE/NETL publication - - *"Storing CO_2 and Producing Domestic Crude Oil with Next Generation CO_2-EOR Technology"*, April 2010.[6]

[6] U.S. Department of Energy, National Energy Technology Laboratory, "Storing CO_2 and Producing Domestic Crude Oil with Next Generation CO_2-EOR Technology: An Update", prepared by Advanced Resources International, Publication Number: DOE/NETL-2010/1417, April 2010.

A. CO_2 Storage in the Traditional ("Main") Pay Zone of Oil Fields. The assessment of CO_2 storage capacity set forth in the above NETL report is based on a data base of over 6,000 domestic oil reservoirs, accounting for three-quarters of U.S. oil resources. The study identifies over 1,700 large oil reservoirs with 305 billion barrels of remaining oil in-place (345 billion barrels of remaining oil in-place when extrapolated to national totals) as favorable for CO_2-EOR. These large oil reservoirs were modeled for CO_2–based enhanced oil recovery using ARI's adaptation of the streamline reservoir simulator *PROPHET2*. The amount of CO_2 storage capacity offered by oil fields favorable for CO_2-EOR was then further evaluated as a function of technology and economics:

- The study examined two technology scenarios: "State of the Art" and "Next Generation".
- The study established two recoverable categories: "Technical Potential" (without consideration of prices and costs) and "Economic Potential" (the volume of CO_2 the oil industry could buy at a specified oil price and CO_2 cost).

As shown in **Figure 5**, the volume of technically recoverable oil using CO_2-EOR ranges from 81 to 126 billion barrels, depending on technology; the volume of economically recoverable oil (at an oil price of $70/B, CO_2 costs of $45/Mt and a 15% before tax financial return) ranges from 38 to 58 billion barrels, depending on technology (State of the Art" or "Next Generation").

The associated volumes of CO_2 required to be purchased and subsequently stored to recover the above volumes of oil range from 10 to 28 billion metric tons, depending on technology and economics, as shown on **Table 3**.

Figure 5. New Domestic Oil Supplies From CO_2-EOR

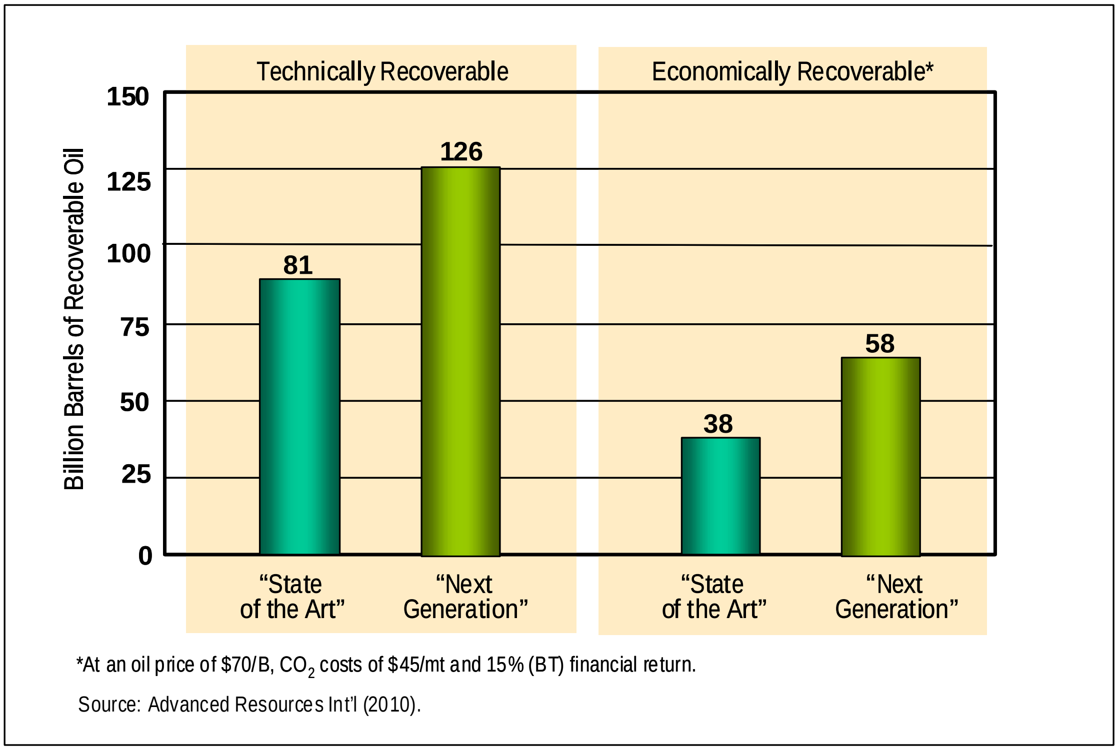

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Table 3. Volume of CO_2 Storage with CO_2-EOR in Main Pay Zone

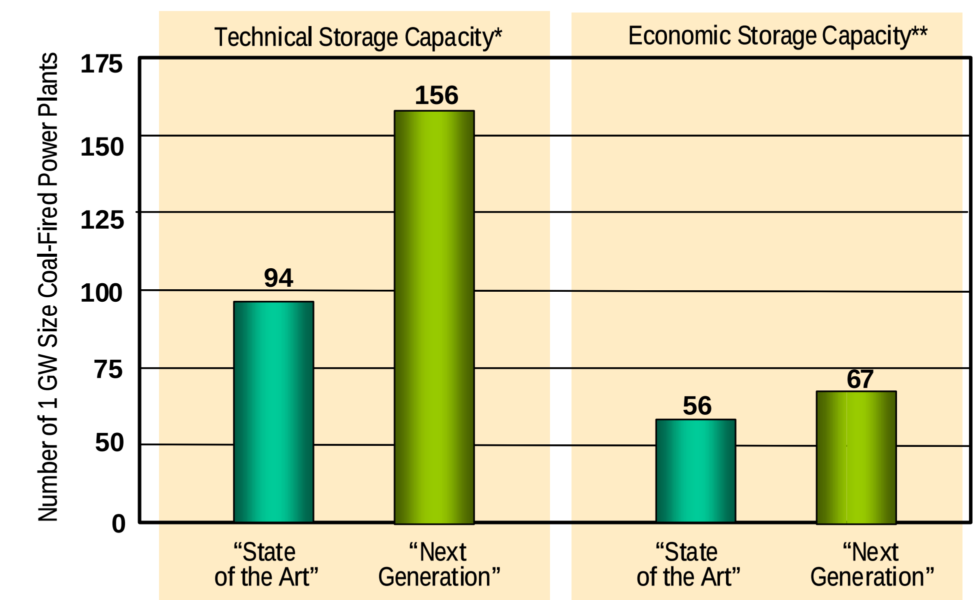
Technology Scenario	Billion Metric Tons of CO_2	
	Technical Potential	Economic Potential*
"Next Generation"	28.4	11.5**
• Permian Basin	6.4	2.8
• Other Basins	22.0	8.7

*At an oil price of $70/B, CO_2 costs of $45/mt and 15% (BT) financial return.
**A portion of this storage capacity (~ 2 billion mt) could be consumed by natural CO_2 sources.

Figure 6 provides an alternative way to characterize the CO_2 storage capacity offered by CO_2-EOR, defined in terms of the number of one-GW size power plants that could rely on CO_2-EOR for storing their captured CO_2. The figure shows that CO_2-EOR offers sufficient technical storage capacity for all of the CO_2 captured from 94 to 156 one-GW size coal-fired power plants for 30 years of operation. The volume of economic

CO_2 storage capacity offered by CO_2-EOR, at the oil price and CO_2 costs presented above, is smaller but still substantial, ranging from 56 to 67 one-GW size coal-fired power plants.

Figure 6. Volumes of CO_2 Storage Capacity Available from CO_2-EOR



*Assuming 6.2 MMmt/yr of CO_2 emissions, 90% capture and 30 years of operations.
**At an oil price of $70/B, CO_2 costs of $45/mt and 15% (BT) financial return.
Source: Advanced Resources Int'l (2010).

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B. CO_2 Storage in the Residual Oil Zone of Oil Fields. Beyond the CO_2 storage capacity offered by the traditional, main pay portion of depleted oil fields, a second potentially much larger, CO_2 storage option is offered by residual oil zones (ROZ) - - saline formations containing residual oil. These regionally extensive (and previously unrecognized) resources are contained in high quality reservoir intervals located below the main pay zone of many oil fields as well as in hydrodynamic ROZ fairways surrounding large oil fields.

While the full volume of CO_2 storage capacity offered by residual oil zones is still to be defined, the ground breaking conceptual framework for this option has been established by Melzer.[7] A more recent DOE/NETL study estimates that the hydrodynamic ROZ fairways in the Permian Basin could add 12 to 18 billion metric tons of CO_2 storage capacity, **Figure 7** and **Table 4**.[8] In comparison, the "traditional" CO_2 storage capacity offered by CO_2-EOR in the Permian Basin is 6.4 billion metric tons, based on the previously cited DOE/NETL report. Additional oil fields with residual oil zones have been identified in other basins, such as the Big Horn and Williston, but are not further discussed in this "White Paper".

Table 4. Volume of CO_2 Storage with CO_2-EOR in Residual Oil Zones (Permian Basin)

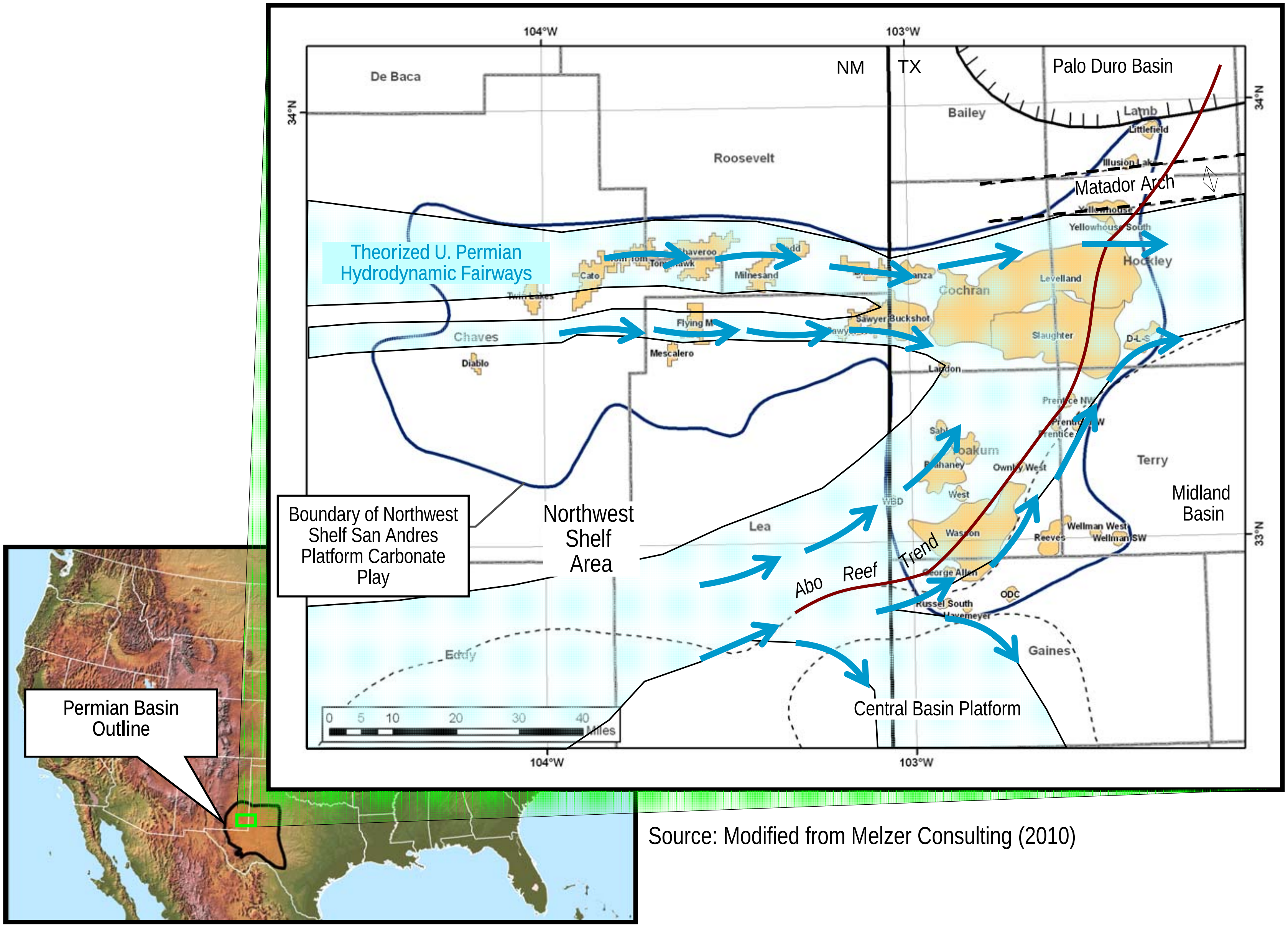
	Estimated ROZ OOIP* (billion barrels)	Calculated ROZ OIP (billion barrels)	Technically Recoverable w/CO_2-EOR		CO_2 Storage Capacity (Billion mt)
			(billion barrels)	% OOIP	
PERMIAN BASIN					
• Discrete Oil Fields (56 fields in 5 plays)	65	31	12	18%	4 to 6
• Hydrodynamic Fairways	210	100	36	17%	12 to 18

*Assuming 52% hydrodynamic flushing of the original oil in-place (OOIP) in the ROZ interval.
Source: Advanced Resources International, 2010.

A number of CO_2-EOR projects are underway in the ROZ that help demonstrate the technical and economic feasibility of producing this resource while storing CO_2. These include significant ROZ projects by Hess at Seminole, by Oxy at Wasson, by Chevron at Vacuum and by Legado at Goldsmith.

[7] "Stranded Oil in the Residual Oil Zone", prepared by Steven L. Melzer, Melzer Consulting for Advanced Resources International and the U.S. Department of Energy, Office of Fossil Energy - Office of Oil and Natural Gas, February 2006.
[8] "White Paper: Establishing the Viability of Storing CO_2 in Deep Saline Formations Containing Residual Oil", prepared by Advanced Resources International, Inc. and Melzer Consulting for the U.S. Department of Energy, National Energy Technology Laboratory, September 8, 2009.

Figure 7. Development of ROZ Fairway w/CO_2-EOR Would Greatly Expand CO_2 Storage Capacity in the Permian Basin.



Source: Modified from Melzer Consulting (2010)

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Advanced Resources International, Inc.

3. BENEFITS OF PRODUCTIVE USE OF CO_2 FOR EOR AND STORAGE

Numerous benefits stem from productively using captured CO_2 emissions for EOR. The most compelling of these benefits include:

- The sale of captured CO_2 would provide a revenue stream to the capturer of the CO_2 as well as to other entities involved in the value chain of productive use of CO_2.

- The use of an oil field for CO_2 storage would significantly help confine the areal extent of the CO_2 plume, reducing the risks of CO_2 leakage and public opposition to CCS.

- Selection of EOR as the CO_2 storage option would enable major CCS projects to be implemented while the still "thorny issues" surrounding using saline formations for storing CO_2 (e.g., pore space rights, regulatory approval, public acceptance) are resolved.

- The productive use of captured CO_2 emissions from implementation of CCS at coal plants could provide 3 million barrels per day of domestic oil production by 2030, greatly improving domestic energy security.

These four benefits of integrating CO_2-EOR with CO_2 capture and storage are further developed below.

A. Revenue Streams from Sale of CO_2 and Production of Oil. A most important benefit from integrating CO_2-EOR and CO_2 storage is that productive use of CO_2 for oil recovery, as opposed to its non-productive disposal in saline formations, would provide a series of revenue streams:

- One of these revenue streams (or cost avoidance) would accrue to the capturer of the CO_2, helping lower the overall cost of conducting CCS.

- A second revenue stream would accrue to state (and local) governments (or the National treasury if the EOR project is on Federal lands) from royalties, plus severance and ad valorem taxes. These revenues, in states such as Texas and Wyoming, are a primary source of funds for school systems and other public services.

- A third revenue stream would accrue to a variety of individuals and entities from royalty payments, equipment sales, jobs and profits stemming from a successful CO_2-EOR project.

B. Confining the CO_2 Plume. Because of buoyancy of the CO_2 and the unconfined nature of saline formations, a CO_2 project is able to productively utilize only 1% to 4% of the geologically available storage capacity offered by saline formations.[9] As a result, the areal extent of the CO_2 plume in a saline formation associated with CO_2 capture from a large one GW power plant can be extensive.

- For example, the CO_2 plume from a one GW coal-fired power plant (with 168 million metric tons of captured CO_2 emissions; 5.6 million metric tons of annually captured and stored CO_2, operated for 30 years) would underlie an area of 200 square miles, assuming a deep saline formation with 200 feet of net pay, 20% porosity, and the upside 4% productive use of available storage capacity.

- In contrast, it is feasible to productively utilize much more (up to 40%) of the geologically available storage capacity in an oil field under a CO_2 flood, assuming the CO_2 flood is properly designed and operated to incorporate CO_2 storage. (In gravity stable, "next generation" CO_2 floods, it may be possible to productively utilize 60% to 70% of the geologically available storage capacity.) As such, use of an oil field would concentrate the CO_2 shape and limit the area of the CO_2 plume by ten-fold, reducing an otherwise 200 square mile CO_2 plume to 20 square miles. By

[9] U.S. Department of Energy, National Energy Technology Laboratory, "Carbon Sequestration Atlas of the United States and Canada", Appendix A: Methodology for Development of Carbon Sequestration Capacity Estimates – Appendix 2, March 2007.

productively utilizing the structurally confined saline aquifer and any residual oil zone below the main pay zone of the oil field, the areal extent of the CO_2 plume could be further reduced by two-fold or more.

C. Accelerating the Application of CO_2 Storage. The integration of CO_2-EOR and CCS would greatly help accelerate the regulatory acceptance and implementation of CO_2 storage:

- Oil fields provide CO_2 storage options that can be permitted under existing (or slightly modified) regulatory guidelines, thereby avoiding the large delays inherent when waiting on new regulations and permitting for large-scale storage of CO_2 in saline formations.

- The pore space, mineral rights and long-term liability issues of oil fields are already well established and thus would not be impediments to a CO_2 storage project.

- Oil fields generally have existing subsurface data and often possess usable infrastructure such as injection wells and gathering systems, enabling more accurate assessment of CO_2 storage capacity and substantial cost savings.

- Oil fields have a proven reservoir caprock (seal) and structural closure, providing reliable vertical and lateral confinement for the injected volumes of CO_2.

Beyond these benefits, a number of other conditions favor the use of oil fields for injecting and storing CO_2. First, oil fields are located in areas with an accepted history of subsurface field activities contributing to public acceptance for storing CO_2. Second, oil fields provide an existing "brown field" storage site versus having to establish a new "green field" site when preparing a saline formation for CO_2 storage. Finally, the early reliance on EOR for storing CO_2 would help build the regional pipeline infrastructure for future CO_2 storage projects in saline formations.

D. Improving Energy Security by Using CO_2-EOR to Increase Domestic Oil Production. The recent report, prepared for the Natural Resources Defense Council by Advanced Resources International, entitled “U.S. Oil Production Potential from Accelerated Deployment of Carbon Capture and Storage”,[10] states that combining CCS with enhanced oil recovery could boost U.S. oil production to 3 million barrels per day by year 2030, assuming that the vast majority of the CO_2 captured from the CCS projects deployed is used for CO_2-EOR. (A portion of this CO_2-EOR production, about 0.6 million barrels per day, would be from continued use of CO_2 from natural sources and gas processing plants.) This would significantly reduce imports of crude oil and reduce annual CO_2 emissions by 500 million metric tons by 2030.

The report draws on past extensive work on the topic of CO_2-EOR sponsored by the U.S. DOE/National Energy Technology Laboratory and assumes that: (1) Federal legislation designed to capture power plant CO_2 emissions (the America Clean Energy and Security Act, H.R. 2454) is adopted; (2) that all of the captured CO_2 is preferentially used for EOR; and (3) that oil prices are $70 per barrel. While clearly not all of the captured CO_2 would be used for EOR, due to a variety of constraints, the report does highlight that policies that encourage the productive use of captured CO_2 emissions could have a significant impact on increasing domestic oil production and improving domestic energy security.

This large volume of CO_2 enhanced domestic oil production would also improve the U.S. trade balance by $700 billion, increase state and Federal revenues by $200 billion and add tens of thousands of jobs between now and year 2030.

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[10] Advanced Resources International, Inc., “U.S. Oil Production Potential from Accelerated Deployment of Carbon Capture and Storage”, prepared for the Natural Resources Defense Council, March 2010.

4. FEASIBILITY OF LARGE-SCALE IMPLEMENTATION OF CO_2-EOR/CCS

A key implementation challenge for using CO_2-EOR to accelerate CCS is matching CO_2 sources from power and industrial plants with large oil fields favorable for enhanced oil recovery.

Certain regions, such as the Electricity Reliability Council of Texas (ERCOT), already contain large oil fields favorable for CO_2. As such, with about 100 billion kilowatt hours of coal-fired generation and about 100 million metric tons of annual CO_2 emissions from coal-fired power (equal to 3 billion metric tons in 30 years), entities within the ERCOT area should be able to relatively easily implement CO_2-EOR and CO_2 storage, assuming proper economic incentives and/or regulations are in place.[11]

Other electricity generation regions are not so fortunate. The CO_2 captured from these regions would need to be transported to markets using long distance, large capacity pipelines.

The largest coal-fired electricity region in the U.S. is the Ohio River Valley represented by the East Central Area Reliability Coordination Agreement (ECAR). This region annually delivers about 500 billion kilowatt hours from coal-fired generation and annually emits about 500 million metric tons of CO_2 (equal to 15 billion metric tons in 30 years). If CO_2-EOR is to have a significant role in accelerating the deployment of CCS in the power sector, there is a need to show that the large CO_2 emissions in the ECAR region can be matched with and used by favorable oil fields[11].

After retirement of older, inefficient coal plants and implementation of CCS in the remainder of the coal-fired power plant fleet in ECAR, approximately 9 billion metric tons of CO_2 (at a rate of 300 million metric tons per year for 30 years) would need to find a "happy home" in oil fields favorable for EOR. With only a very modest EOR-based CO_2 storage capacity of 0.6 billion metric tons offered by the nearby small oil fields in the Illinois Basin, if the captured CO_2 is to be productively used for CO_2-EOR, it

[11] Annual Energy Outlook 2010; U.S. Energy Information Administration

would need to be transported to the giant oil fields of Texas, Oklahoma and the Gulf Coast.

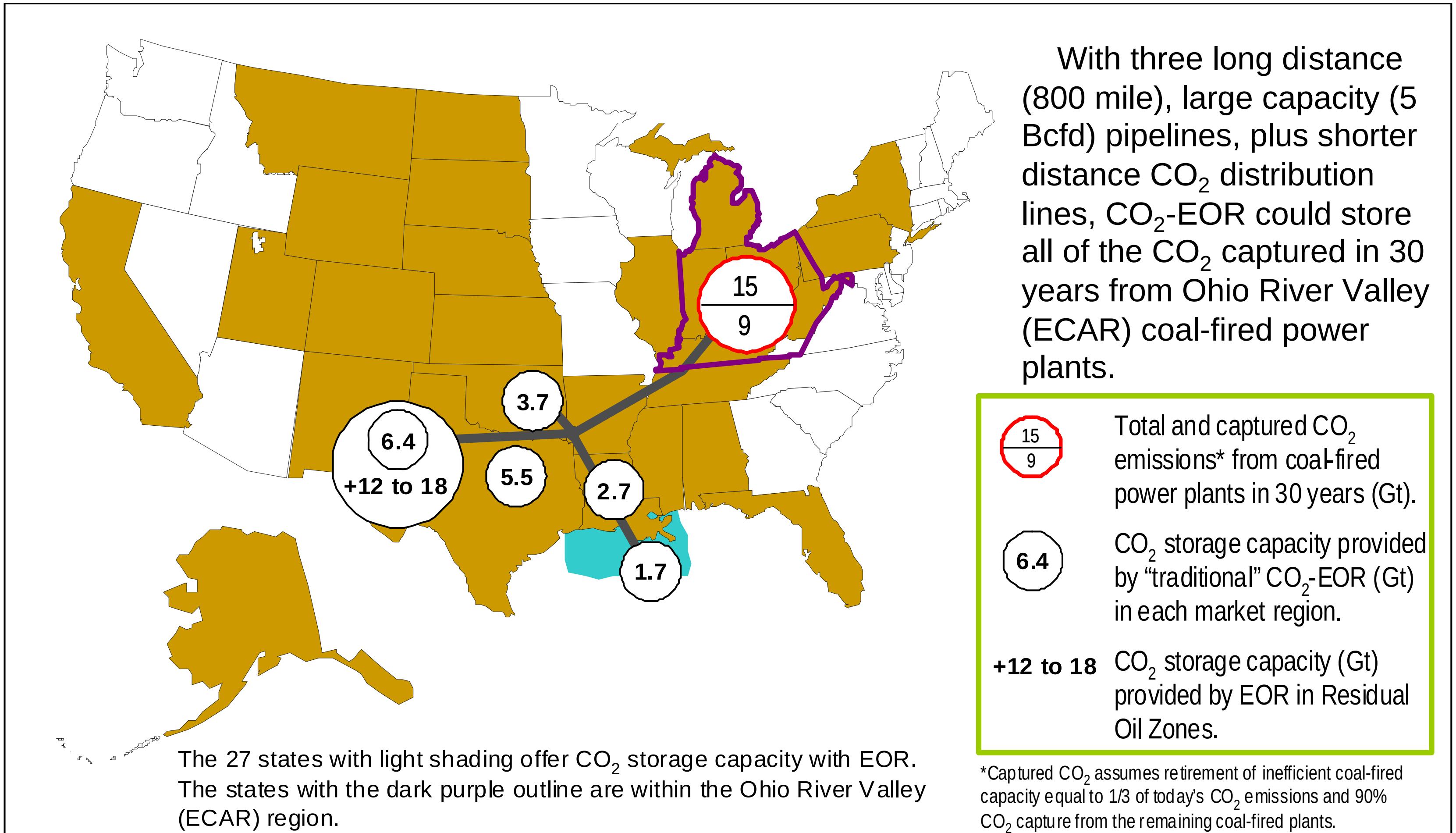
Figure 8 illustrates the feasibility of linking the captured CO_2 emissions from the ECAR Region (Michigan, Indiana, Ohio, Kentucky, West Virginia and the western portions of Pennsylvania and Virginia) with the vast EOR opportunities in Texas, New Mexico, the Mid-continent, and Louisiana.

- The traditional EOR markets, offering about 20 billion metric tons of traditional CO_2-EOR storage capacity, and increasing to 32 to 38 billion metric tons with the inclusion of the hydrodynamic residual oil zone fairways (ROZ) in the Permian Basin, could take all of this CO_2, plus more.

- A series of three 800 mile, large diameter (42 inch) pipelines, each with 5 Bcfd (100 million metric tons per year) of capacity would transport CO_2 from the Ohio/Indiana border to north-east Texas. (Because of the higher compressibility of CO_2, the diameter of the CO_2 pipeline would be smaller than an equivalent volume natural gas pipeline.) From there, a series of shorter distance CO_2 lines would distribute the CO_2 to EOR markets in Oklahoma, Louisiana, East/Central Texas and to the Permian Basin of West Texas/East New Mexico. Similar size natural gas pipelines and distribution systems are in common use. A similar CO_2 pipeline system, linking Ohio Valley CO_2 sources with Texas and Gulf Coast oil fields, is being studied by Denbury Resources.[12]

[12] Denbury Resources Corporate Presentation, June 2010.

Figure 8. Integrating CO_2 Capture from the Ohio River Valley with CO_2 Storage Using CO_2-EOR in Texas, Louisiana and Oklahoma



Source: Advanced Resources Int'l (2010).

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5. ACCELERATING AND IMPLEMENTING INTEGRATED CO_2-EOR/CCS PROJECTS

Two sets of actions will be essential for accelerating the implementation of integrated CO_2-EOR/CCS:

- The first set of actions involves the development of public policies and the structuring of incentives that would first help "jump-start" CCS demonstrations and then would provide significant funds to accelerate its commercial-scale deployment.

- The second set of actions for implementing CO_2-EOR/CCS involves the establishment of contractual and business arrangements between the owner of the captured CO_2 (e.g., the power plant), the transporter of the CO_2 and the oil field operator interested in purchasing and using the CO_2 for enhanced oil recovery.

A. Developing Public Policies and Incentives

In the absence of requirements to capture CO_2 or a sufficiently high price on carbon emissions, the capture of CO_2 from a traditional coal-fired power plant will be uneconomic. As such, significant new financial incentives and funding support will be needed to "jump-start" CCS and accelerate its commercial-scale deployment.

1. "Jump-Starting" CCS Demonstrations. Most of all, it is important to get started. Federal and private funding is helping launch a handful of CCS demonstrations, including:

- The privately-funded (EPRI, Southern Company, MHI) small, 25 MW equivalent, post-combustion CO_2 capture plant at Plant Barry, Alabama, due on-line in early 2011.

- The AEP and Alstom 30 MW (thermal) chilled ammonia post-combustion CO_2 capture plant installed at AEP's Mountaineer Plant in West Virginia; to be followed by a larger 200 MW CO_2 capture plant at Northeastern Station, Oklahoma.

- The publically supported full-scale IGCC demonstration plants by Southern Company in Mississippi and by Summit Energy in West Texas, due on-line in 2014.

However, a significantly larger set of full-scale CO_2 capture demonstrations will be essential for "getting started" with CCS and particularly for introducing lower cost "second generation" CO_2 capture technologies.

The Pew Center Coal Initiative white paper - - "A Program to Accelerate the Deployment of CO_2 Capture and Storage"[13] - - analyzed the rationale, objectives and cost of one CCS strategy for "getting started" in the coal-fired power industry. This strategy would provide funding for retrofitting existing plants with CCS and for incorporating CCS into new plants. The key features of the strategy involved:

- Launching 30 commercial-scale CO_2 capture demonstrations (400 to 500+ MW each) by providing reimbursement of approximately $1 billon per plant.

- Funding this strategy with a fee (wire charge) of $0.0015 (0.15¢ per kWh) on coal-fired power plants.

A companion Pew Center Coal Initiative white paper - - "A Trust Fund Approach to Accelerating Deployment of CCS: Options and Considerations"[14] - - examined alternative funding options for helping CCS "get started".

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[13] Pew Center on Global Climate Change, "A Program to Accelerate the Deployment of CO_2 Capture and Storage", Coal Initiative Reports, White Paper Series, October, 2007.
[14] Pew Center on Global Climate Change, "A Trust Fund Approach to Accelerating Deployment of CCS: Options and Considerations", Coal Initiative Reports, White Paper Series, January, 2008.

2. Accelerating Commercial-Scale Deployment of CCS. Accelerating commercial-scale deployment of CCS in the coal-fired power sector will require substantially larger incentives and funding support than for “getting started”. One such strategy is to draw on the incremental tax revenues that would be generated from productively using the CO_2 captured from coal plants by CO_2-based enhanced oil recovery.

For example, one potential CCS acceleration strategy would direct the Treasury to establish a CCS fund to support CCS deployment by annually depositing 5% of the projected 20 year tax revenues from incremental CO_2-EOR production:

- The first 20 GWs of CCS would receive $2.5 billion per GW, with the next 52 GWs of CCS receiving $2 billion per GW.
- This would enable 13 GWs of coal-fired power to be implemented with CCS by 2020, increasing to 69 GW by 2030.
- Assuming 70% of the captured CO_2 emissions would be used for CO_2-EOR, using the oil price track from AEO 2010, and using a sales price for CO_2 of $15 per ton, significant volumes of oil would be produced with CO_2-EOR (see below). The incremental tax revenues from the oil produced by CO_2-EOR would fund the CCS acceleration strategy.
- Under these assumptions, domestic oil production from CO_2-EOR would reach 2.8 million barrels per day. Approximately 0.56 million barrels per day of this total would be from CO_2-EOR using natural or gas separation plant CO_2. Another 0.60 million barrels per day would be from CO_2-EOR using various sources of new anthropogenic CO_2 (e.g., refinery hydrogen plants) and launched in response to increasing oil prices (the EIA AEO 2010 oil price track exceeds $100 per barrel starting in 2020). The final incremental 1.67 million barrels of CO_2-EOR based oil production would be from the installation of CCS due to the above CCS acceleration strategy, **Table 5**.

- The annual reduction of CO_2 emissions, from the 69 GWs of coal-fired power installed with CO_2 capture and stored with CO_2-EOR (implemented in response to the CCS acceleration strategy), would be on the order of 400 million metric tons.

Table 5. Projected Volumes of Oil Production from CO_2-EOR

CO_2 Sources		CO_2-EOR Production (B/D)			
		2012	2020	2025	2030
Natural/Gas Plant CO_2*		470	620	590	560
Anthropogenic CO_2					
	• Price Driven	-	70	220	600
	• Policy Driven	-	250	840	1,670
	TOTAL	470	940	1,650	2,830

*Includes 45 MMcfd of CO_2 from ammonia and fertilizer plants

B. Establishing the Contractual Agreements

Unless the integrated CO_2-EOR/CCS project is located in or near the Permian Basin or in Wyoming, areas which have a reasonably well established set of rules and historic practices for marketing CO_2, the sale and storage of the captured CO_2 will be established by a negotiated, project-specific contract. Various parties may be involved in this negotiation - - the owner (seller) of the captured CO_2, the CO_2 transporter, and the purchaser (user) of the captured CO_2 (the EOR field operator). The CO_2 user may also provide transportation; a marketing firm may facilitate the process between the CO_2 owner and the CO_2 user.

A great variety of contractual and business arrangements will likely need to be defined for an integrated CO_2 storage/CCS project, depending on the business interests of the various parties. Three potential business and contract arrangements are discussed below.

A. Arms Length Entities. Under this arrangement, the owner of the captured CO_2 (e.g., the power plant) would sell its CO_2 (and potentially transfer its liability for storing the CO_2) to an oil field operator interested in productively using the CO_2 for enhancing oil recovery.

The oil field operator will contract with a CO_2 pipeline (or build the pipeline and gathering system) to transport the CO_2 to the oil field. The sales price for the CO_2 (at the plant gate) will be negotiated and established based on the relative market power of the parties and the competitive market price for CO_2 in the local area. The CO_2 sales price may be indexed to the oil price, providing some upside value to the CO_2 seller and some downside protection to the CO_2 buyer.

Minimum and maximum volumes, as well as take or pay arrangements, may be included in the contract terms. If there is a credit or value for capturing CO_2, this value may be shared, in some way, among the two parties, as set forth in the contract.

Under this arrangement, the oil field operator assumes the major risks and all of the costs of storing CO_2, including providing documentation of its safe and secure storage for obtaining the CO_2 credit.

The Northern Great Plains Gasification and Weyburn oil field project illustrates the "arms length entities" arrangement for initiating CO_2 sales to an enhanced oil recovery project.

B. Joint Venture Entities. Under this arrangement, the owner of the captured CO_2 and the oil field operator enter into a joint venture to share, in some way, in the success of the CO_2-EOR project. The owner of the CO_2 may contribute the CO_2 to the EOR project in return for a portion of the revenues or profits (and CO_2 storage credits). In this case, the two parties will share the risk, costs and profits, if any.

The initial CO_2 sales proposals between KinderMorgan and various oil field operators, when CO_2 supplies in West Texas were plentiful, illustrate the "joint venture entities" approach for initiating CO_2 sales to enhanced oil recovery projects. (Because of complexities, only a few such sales arrangements were completed.)

C. Single Integrated Party Entity. In some cases, the owner of the captured CO_2 from a gas processing plant or a refinery may also be an oil field operator looking to use CO_2-EOR. In this single party situation, while there may be internal transfer costs among the various business units of the company, the costs, risks and rewards accrue to the overall company.

Integrated major oil companies, with CO_2 from refineries and gas processing plants and favorable oilfields, would represent this situation.

* * * * *

The White Paper argues that the CO_2 storage capacity offered by EOR is vast and that the productive use of CO_2 for EOR would significantly accelerate the application of CCS while improving domestic energy security. As such, policies, incentives and regulations that encourage the integrated application of CO_2-EOR and CCS would clearly be in the nation's interest.

Carbon Sequestration in Oil and Gas Fields
(in Conjunction with EOR and Otherwise)

Policy and Regulatory Issues

White Paper for the MIT EOR and Carbon Sequestration Symposium

July 23, 2010

A. Scott Anderson
Environmental Defense Fund

This white paper addresses selected policy and regulatory issues relating to carbon sequestration in conjunction with enhanced oil recovery (EOR). Sequestration in conjunction with CO2 EOR as presently understood [1] raises issues that are intertwined with issues related to sequestration that can take place in oil and gas fields but not in conjunction with EOR. Accordingly, the paper also addresses issues relating to oilfield sequestration outside the EOR business-as-usual (EOR BAU) context.

The policy discussion is founded on the idea that markets generally are better than governments at deciding where, when, and at what price people need to have how much of what. There are many valid reasons for market intervention, but the decision to intervene should not be made lightly even for worthy policy objectives.

The discussion of regulatory issues is informed by the following understandings: (1) injection and sequestration are two different things; (2) sequestration is not "sequestration" unless it is verified; and (3) verification means more than

[1] CO2 EOR as currently practiced (EOR BAU) is based on injecting quantities of CO2 sufficient to reach a reservoir's minimum miscibility pressure. Miscibility pressure is the pressure in a particular reservoir at which oil in the reservoir that is contacted by injected CO2 will mix with the CO2 to form a single phase, thus facilitating production of oil that otherwise would not be produced. For purposes of producing oil, it is generally not necessary (or cost effective) to inject more CO2 than necessary to reach minimum miscibility pressure "plus a little bit." Operating pressures materially above miscibility pressure are not likely to increase the amount or rate of production to a significant extent. Oilfield sequestration can take place either in this EOR BAU context, in which case sequestration can be thought of as being incidental to production, or sequestration can take place in an operation in which CO2 injections and operating pressures exceed what is necessary for EOR BAU, in which case production can be said to be incidental to sequestration. Sequestration might also take place in an oil or gas field where there is no production at all, though reservoirs are never entirely depleted and therefore production in some amount may always be a technical possibility. Whether or not accompanied by production, projects that inject enough CO2 to raise reservoir pressure substantially above miscibility pressure present higher environmental risks than projects that inject only the quantity of CO2 necessary for EOR BAU.

compliance with Safe Drinking Water Act regulations designed to prevent pollution of underground drinking water. The paper does not undertake a comprehensive review of the many legislative and regulatory efforts underway at the state level, [2] although the author has been involved in the development of most of these efforts and this experience has informed the opinions expressed here.

The distinction made in this paper between oilfield sequestration that is in conjunction with EOR BAU and oilfield sequestration that is not in conjunction with EOR BAU, but which nevertheless may be associated with oil or gas production, was first made by a group known as the Multi-Stakeholder Discussion (MSD). MSD is a diverse group of stakeholders without a fixed membership. From time to time, some of the participants jointly submit comments to EPA regarding geologic sequestration issues. Several of the MSD suggestions are worth highlighting. [3]

In comments filed December 23, 2008, in response to EPA's proposal to create a new Underground Injection Control Program (UIC) Class VI for "Geologic Sequestration Wells," various MSD participants asked the agency to clarify that sequestration also can take place using injection wells that are subject to UIC Class II (i.e., wells associated with oil or gas operations).[4] The EPA proposal to create a new UIC Class VI for "Geologic Sequestration Wells" can be read to say that sequestration in oilfield operations will not be eligible for recognition as sequestration until all oil production ceases and the Class II wells qualify for Class VI status. [5] The view taken by the MSD participants (a view that clearly is shared by EPA despite problematical language in the agency's published proposal) is that UIC rules are meant to assure that sequestration projects do not threaten underground drinking water and that separate rules should be developed in order to assure that projects effectively sequester CO2 from the atmosphere. Both sorts of rules are necessary.

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[2] As of this writing, quite a few states have adopted legislation authorizing regulation of CCS and several have developed regulations. Washington, North Dakota, and Kansas have adopted final regulations. Texas and Wyoming are poised to adopt regulations in the coming weeks.

[3] And all are worth adopting.

[4] Comments submitted Dec. 23, 2008 re: Proposed Rule for Geologic Sequestration, Docket No. EPA-HQ-OW-2008-0390. (MSD December 23 Comments).The Comments were submitted by the American Petroleum Institute, Anadarko Petroleum, BP Alternative Energy North America, BP America, Hydrogen Energy International, the Carbon Sequestration Council, Clean Air Task Force, ConocoPhillips, Denbury Resources, Edison Electric Institute, Environmental Defense Fund, Ground Water Protection Council, Occidental Petroleum, Southern Company, and the Texas Carbon Capture and Storage Association. Neither these comments nor other MSD comments would have been possible without the leadership of Bob Van Voorhees of Bryan Cave LLP.

[5] EPA's proposed rule uses the term "Geologic Sequestration Well" to refer to wells in new well class VI and the preamble to the proposed rule suggests continuing to regulate CO2 injection for EOR purposes under Class II "as long as any production is occurring." Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells, 73 Fed. Reg. 43491, 43502 (July 25, 2008).

In addition to asking EPA to recognize that sequestration can take place using either Class II or Class VI wells, the MSD December 23 comments recommended that EPA recognize two possible types of sequestration in oilfields – one in conjunction with EOR BAU and another that would employ pressures higher than those needed for EOR BAU operations. Where sequestration is incidental to EOR BAU operations, the MSD group recommended that it is appropriate to use existing Class II regulations because these regulations currently appear to adequately protect groundwater. For potential projects that would operate at pressures higher than needed for EOR BAU, the MSD group called for new rules that would take account of the different, and likely more significant, risk profile created by increased pressure. In order to distinguish between these two types of oilfield sequestration operations, the group recommended that EOR sequestration projects be eligible for existing Class II treatment "*provided* (i) there is reasonable expectation of more than insignificant future production volumes or rates as a result of carbon dioxide injection and (ii) operating pressures are no higher than reasonably necessary to produce such volumes or rates."[6] In subsequent comments to EPA, submitted on October 9, 2009, MSD participants proposed detailed water-protection rules to govern oilfield sequestration projects that are operated at pressures higher than necessary for EOR BAU.[7]

Until very recently, the effort to develop a U.S. regulatory framework for CCS has focused largely on adapting the Safe Drinking Water Act's UIC Program to meet the unique challenges posed by large scale injection of carbon dioxide for permanent storage. In part this focus has been for reasons of convenience (in the absence of a regulatory program limiting atmospheric emissions, the Safe Drinking Water Act is pretty much all we have to work with) and in part for reasons of necessity (carbon sequestration is a viable greenhouse gas mitigation strategy only if it can be done without polluting groundwater supplies). It is important, however, to keep in mind that rules designed to protect water are not the same as rules designed to protect against atmospheric leakage. As MSD participants recently emphasized in response to EPA's proposed Greenhouse Gas Reporting Rule[8], neither UIC permits nor monitoring, reporting and verification

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[6] MSD December 23 Comments at 2. In 2009, the Texas Legislature adopted legislation incorporating the MSD distinction. SB 1387.

[7] "Recommendation on Requirements for Geologic Sequestration in Oil and Gas Reservoirs where Class II(b)(4) Requirements Are Not Met," Comments submitted Oct. 9, 2009 re: Proposed Rule for Geologic Sequestration, Docket No. EPA-HQ-OW-2008-0390 (MSD October 9 Comments). Twelve of the 15 organizations that joined the MSD Dec. 23 Comments that called in a general way for stronger regulation of high-pressure oilfield injection also joined in the MSD Oct. 9 Comments proposing specific regulations for that purpose. (Anadarko, Denbury and Ground Water Protection Council signed only the Dec. 23 submission). A total of 17 organizations signed the MSD Oct. 9 Comments. (Organizations signing the Oct. 9 comments that had not signed the Dec. 23 comments were AEP, Duke Energy, E.ON U.S., Salt River Project, and Shell Exploration and Production.

[8] Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide; Proposed Rule, 75 Fed. Reg. 18576 (Apr. 12, 2010).

(MRV) plans incorporated in UIC permits are required to verify the absence of atmospheric leakage or to quantify leakage that may occur.[9] Thus, while MRV plans associated with UIC permits can be helpful in verifying that CO2 has been sequestered from the atmosphere, they generally will not be sufficient. This will be true even in the case of operations in brine formations that adhere to the robust monitoring requirements EPA envisions for Class VI projects. The insufficiencies of UIC MRV requirements will be especially noticeable for Class II EOR BAU projects -- for the simple reasons that Class II regulations impose fewer monitoring requirements than are proposed for Class VI and that Class II regulations were not designed with geologic sequestration in mind. If EPA adopts the rules proposed in the MSD October 9 Comments, UIC MRV plans for oilfield sequestration projects using pressures higher than needed for EOR BAU will resemble MRV plans for projects regulated under Class VI.

Regulatory Requirements for Sequestration in Oil and Gas Fields

Assuring that geologic sequestration is done safely and effectively requires much more than simply "getting the rules right." It requires substantial expansion in regulatory capacity both at EPA and in state agencies. Regulators will need to develop new expertise. Agency budgets will need to increase significantly. The Ground Water Protection Council estimates that state agencies will require an additional $50 million per year to handle their portion of the regulatory cost of overseeing sequestration projects.[10] EPA also will need substantial new resources in order to properly regulate this activity.

Key features of a regulatory framework for geologic sequestration are reviewed below.

Siting – Oil and gas fields are where you find them, but not every oil and gas field is a candidate for carbon sequestration. Even though these reservoirs have held petroleum for millions of years, it does not automatically follow that they will retain a given volume of CO2 permanently. Thus it is important that there be a regulatory review of whether a given field is suitable for long-term storage of the projected volume of CO2 injections. It is also important for regulators to assess whether injecting a given volume of CO2 at a given site can be done without damaging underground water supplies.

In order to decide that a site is suitable for sequestration, regulators must review enough information to be able to determine that a site is capable of

[9] Comments submitted June 11, 2010 re: Mandatory GHG Reporting – Docket ID No. EPA-HQ-OAR-2009-0926 (MSD June 11 Comments) at 3. The organizations signing these comments were: American Petroleum Institute, BP Alternative Energy North America, Carbon Sequestration Council, Clean Air Task Force, ConocoPhillips, Denbury Resources, Environmental Defense Fund, Hydrogen Energy International, Occidental Petroleum, and Southern Company.
[10] Personal communication from Mike Paque, Executive Director, Ground Water Protection Council

securely storing a given volume of CO_2 without causing environmental problems. There are a number of conceivable reasons that a particular oil or gas field may not be suitable for long-term retention of CO_2. These potential concerns include:

- seals that have proven competent for retaining oil or gas but do not have the same capacity to retain CO_2[11]
- poorly constructed or plugged wells
- seals that would be competent to hold a given volume of CO_2 but which have been damaged during secondary or tertiary operations by injecting fluid at excessive pressure
- seals that are at risk of being damaged by current or future injection operations because there is very little "headroom" between the field's miscibility pressure and pressure that would cause the seal to experience shear failure or tensile failure
- seals that have been compromised as a result of reducing reservoir pressure during previous production operations
- lateral spill-points from which CO_2 could escape if the reservoir is filled beyond its appropriate capacity
- hydrogeologic conditions posing a significant risk that injection could cause formation fluids to migrate into drinking water supplies

<u>Operations</u> - Geologic sequestration is expected to be effective only at sites that are both properly selected and properly operated. Key elements of a regulatory program governing operations include:

- assuring that wells are properly cased, cemented and plugged
- assuring that wells are tested periodically for internal and external mechanical integrity
- assuring that injection pressures do not exceed the pressure that would lead to tensile failure in the confining rock (i.e., fracture pressure) or that would cause shear failure in the confining rock [12];

[11] A volume of CO_2 exerts more buoyancy pressure than the same volume of oil. CO_2 has lower interfacial tension with brine than do natural gas or oil. See Charles Christopher and James Iliffe, Reservoir Seals: How They Work and How to Choose a Good One. Available: http://esd.lbl.gov/co2sc/co2sc_presentations/Site_Selec_Charact_Gen_Framework/Christopher.pdf . Seals may not be competent to retain all CO_2 on a long-term basis even in situations where CO_2 EOR floods have been conducted successfully for years without leakage. The pressure exerted against the seal by CO_2 may well be less while production is taking place than it will be in the following years.

[12] Tensile failure refers to the creation of new fractures; shear failure occurs when rock slips along pre-existing fractures. Shear failure potentially can cause non-leaky faults and fractures to become leaky even if new fractures have not been created. See J. Rutqvist, J.T. Birkholzer and Chin-Fu Tsang, Coupled Reservoir-GeoMechanical Analysis of the Potential for Tensile and Shear Failure Associated with CO_2 Injection in Multi-Layered Reservoir-Caprock Systems, 45 International Journal of Rock Mechanics and Mining Sciences 132- 143 (Issue 2, February 2008). Neither shear failure nor tensile failure will necessarily cause or reactivate faults or fractures to the extent necessary to transmit CO_2

- requiring that potential leakage pathways be identified both for injected CO_2 and for native formation fluids;
- requiring a monitoring program designed to demonstrate that leakage is not occurring and to assess the degree to which the reservoir is otherwise performing as expected;
- requiring adjustments in the monitoring and/or injection operations in the event the risk of leakage increases or the behavior of the reservoir differs significantly from initial projections
- requiring remediation in the event of leakage
- requiring periodic reports that are adequate to demonstrate that the project is being operated appropriately

Closure

Confusion reigns with regard to what the term "closure" means or ought to mean. Nevertheless, there appears to be almost universal consensus that any regulatory regime for geologic sequestration projects will include a determination by the regulator of the point (if any) at which a project has been "closed." In truth, whether the regulatory system should provide for a "closure certificate" is a policy choice. The concept of project closure is foreign to the EOR world. In the EOR business, *wells* are closed ("plugged") and that is that. EOR regulations neither offer nor require closure certificates at a project level and to date oil producers seem content with this state of affairs. If a policy choice is made to include formal closure determinations as part of the regulatory framework for sequestration, it will be necessary to decide what legal and operational consequences should flow from a "closure" decision. Choices also will need to be made regarding the standards and procedures for making a determination that a site has been "closed."

What should the consequences be if a regulator agrees that a site is "closed?" Can the operator stop monitoring? Will the operator still need to perform other actions at the site? Will operating bonds be released? Does closure mean that carbon credits generated by the project are now secure for all time? If the operator is sued for damages caused by its operations, does "closure" of the site create a defense to what otherwise would be a successful lawsuit?

What should be the technical basis for making a closure determination? Should closure be said to occur a fixed number of years following cessation of injection? [13] Should it occur when the injected CO_2 has "stabilized?" Should closure occur

and other fluids through the confining zone, but prudence dictates that injection pressure remain below levels that would create this risk. The approach to injection pressure limits taken by the federal Underground Injection Control program (including EPA's proposed rules governing wells used for geologic sequestration) focuses on tensile failure and fails to require any consideration of the risk of shear failure despite the fact that shear failure can occur at lower pressures than those necessary to cause tensile failure.

[13] No.

when an operator persuades a regulator that "no additional monitoring is needed" -- even if people have been unable to articulate in any detail how to tell when no additional monitoring is needed? Can we develop a consensus standard? Should the rigor with which a closure determination is made depend in part on what is at stake, including what is at stake in terms of the legal consequences? [14]

Current UIC regulations use the term "closure" to refer to closing individual wells – the term is roughly synonymous with "plugging and abandonment." When a Class II injection well is plugged, the operator's bond or other financial instrument is released. But well closure does not necessarily terminate an operator's responsibilities under the UIC program. In fact, in the case of Class I Hazardous Waste Injection Wells, operators must develop post-closure care plans and "the obligation to implement the closure plan survives the termination of a permit or the cessation of injection activities." [15] After a Class I Hazardous Waste Well is "closed," groundwater monitoring generally is required until pressure in the injection zone decays to the point that a well's "cone of influence" no longer intersects the base of the lowermost Underground Source of Drinking Water (USDW). Agencies may extend post-closure monitoring indefinitely if they determine that a well may endanger a USDW.

EPA's proposed Class VI rules contemplate that there will be some situations where the regulator authorizes "closure" and other situations in which closure might never be authorized.[16] Whether closure is authorized will depend on the operator's ability to demonstrate, "based on monitoring and other site-specific data, that the carbon dioxide plume and pressure front have stabilized and that no additional monitoring is needed to assure that the geologic sequestration project does not pose an endangerment to USDWs." [17] Under the proposed rules, a closure determination would allow an operator to discontinue monitoring (the proposal is silent on whether a monitoring obligation might be re-imposed at some point in the future). Presumably a closure determination would permit release of any outstanding bonds or other financial assurance instruments. Within a short period after closure is authorized, the operator must plug all monitoring wells, submit various sorts of documentation, and place notices in the real property records.

The importance of a closure determination under EPA's proposed Class VI rules is more limited than one might think. A closure determination is not intended to serve as a guarantee that CO2 is securely sequestered from the atmosphere. It simply reflects the agency's judgment, based on data submitted by the operator, that no additional monitoring is needed to assure the project is not endangering

[14] Yes.
[15] 40 CFR sec. 146.72 and sec. 146.71
[16] Proposed sec. 146.93
[17] Proposed sec. 146.93(b)(3)

drinking water. The rules leave open the possibility that the agency could reconsider its decision if new information were to come to light and the preamble to the rules indicates that well operators remain responsible indefinitely for any endangerment of underground sources of drinking water. Moreover, a closure determination says nothing about the existence or significance of any other problems that operations might have caused over the years. [18]

Despite this limited role, it is vital that closure decisions be made on a sound basis. The two-pronged standard proposed by EPA (showing that the plume and pressure front have stabilized and that no additional monitoring is needed for water-protection purposes) leaves much to be desired. Many argue that stabilization is not a good closure standard because some sites may not stabilize for hundreds of years and there sometimes will be circumstances in which it is possible, without showing stabilization, to verify that CO2 is sequestered and water protected. The other prong of the proposed standard, the requirement to show that no additional monitoring is needed to assure a project is not endangering drinking water, does not answer the question that needs to be answered – how can an operator demonstrate that monitoring is no longer needed? Participants in the Multi-Stakeholder Discussion have suggested the following closure provision as a substitute for that proposed by EPA:

> Prior to authorization for site closure, the owner or operator must demonstrate to the Director, based on monitoring, other site-specific data, and modeling that is reasonably consistent with site performance, that no additional monitoring is needed to assure that the geologic sequestration project does not and is not expected to pose an endangerment to USDWs. The Director shall approve closure if the owner or operator demonstrates, based on the current understanding of the site, including monitoring data and/or modeling, all of the following: (i) the estimated magnitude and extent of the project footprint (CO2 plume and the area of elevated pressure); (ii) the estimated location of the detectable CO2 plume; (iii) that there is no significant leakage of either CO2 or displaced formation fluids that is endangering USDWs; (iv) that the injected or displaced fluids are not expected to migrate in the future in a manner that encounters a potential leakage pathway into a USDW; (v) that the injection wells at the site completed into or through the injection zone or confining zone are plugged and abandoned in accordance with these requirements; and (vi) any remaining project monitoring wells at the site are being managed by a person and in a manner acceptable to the Director. [19]

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[18] It has been suggested by some that upon receipt of closure certificates an operator of a sequestration project should be relieved of potential liability for damages under common law and statutes. Nothing in EPA's proposed rule justifies using closure determinations for this purpose.
[19] MSD Dec. 23 Comments at 4-5. MSD participants proposed that essentially the same language be included for UIC purposes in special rules for oilfield sequestration projects operated at higher pressure than needed for EOR BAU. Oct. 9 Comments at 17. MSD also proposed essentially the same

Verification -- As has been discussed, EPA's proposed rules to regulate sequestration under the Safe Drinking Water Act do not purport to address verification issues from the standpoint of leakage to the atmosphere. Compliance with neither the proposed rules nor UIC Class II rules will be enough to qualify for carbon credits or other legal recognition that sequestration has taken place. However, Greenhouse Gas Reporting rules recently proposed under EPA's Clean Air Act authority provide insight into how airside [20] verification issues are likely to be handled in the future. Guidance issued by the Department of the Treasury pursuant to section 45Q of the Tax Code is also instructive. [21] Section 45Q provides a $10 per ton tax credit when anthropogenic CO2 is used for EOR and if the taxpayer can demonstrate if audited that the CO2 has been disposed of in secure geological storage in the sense that the CO2 does not escape into the atmosphere.

The section 45Q Guidance draws heavily (and a portion of Guidance borrows virtually word-for-word) from IPCC Guidelines published in 2005 and subsequently.[22] Generally, taxpayers must conduct the following procedures at the frequency appropriate for site conditions:

> (A) Conduct a site characterization by evaluating the geology of the storage site and surrounding strata and identifying the local and regional hydrogeology and leakage pathways such as deep wells, faults, and fractures.

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closure standards for purposes of Greenhouse Gas Reporting. MSD June 11 Comments. The proposed standards were based on previous work by the World Resources Institute, the American Petroleum Institute, and the Ground Water Protection Council (who worked on the issue in that order). The MSD closure language was adopted in 2009 by Texas in SB 1387.The Interstate Oil and Gas Commission amended it's Model Rules for Geologic Storage of Carbon Dioxide in 2010 to include a modified version of the proposal The author supports the MSD closure language provided that it used for the purpose intended – determining when it is appropriate to release a UIC Program operating bond and to allow an operator to discontinue active monitoring. In the unfortunate event that Congress were to seize upon the "certificate of closure" concept and use it as a tool to relieve operators of responsibility for damages to third parties, it would be important to develop a closure standard that would take additional factors into account and examine them in a more rigorous way. For example, rather than basing the decision on "the current understanding of the site", the review ought to be based on "the best available understanding of the site." Ideally, the understanding of the site available at closure will be "the best available" understanding of the site, but the MSD language doesn't assure that this will be the case.

[20] "Airside verification" is used here to refer simply to monitoring and reporting designed to verify that there is no leakage to the atmosphere. It is not necessarily intended to refer to monitoring of the air (or soil) above the sequestration site. Most sites that are properly located and managed may not require air or soil gas monitoring, though the utility of these techniques should not be ruled out. In fact, air monitoring and monitoring of the soil (or deeper unconsolidated sediments) may prove quite useful in order to verify whether or not wellbores are not leaking.

[21] Internal Revenue Bulletin 2009-44 (November 2, 2009) (Notice 2009-83).

[22] See IPCC, Special Report on Carbon Dioxide and Storage (2005) (Chapter 5, Carbon Dioxide Transport, Injection and Geologic Storage).

(B) Conduct an assessment of the risks of CO2 leakage, or escape of CO2 from the subsurface to the atmosphere, by evaluating the potential for leakage through a combination of site characterization and realistic models that predict the movement of CO2 over time and locations where emissions might occur. A range of modeling tools is available, including reservoir simulators that are widely used in the oil and gas industry and have proved effective in predicting movement of gases and liquids, including CO2, through geological formations. Reservoir simulation can be used to predict likely location, timing, and flux of emissions. Additional numerical modeling techniques may need to be used to analyze aspects of the geology, such as multi-phase reaction transport models and geomechanical models.

(C) Monitor potential leakage pathways, measure leakage at those pathways as necessary, monitor the current and future behavior of the CO_2 and of the storage system, and use the results of the monitoring plan to validate and/or update models as appropriate. Monitoring should be conducted according to a suitable plan. This should take into account the expectations from the modeling on where leakage might occur, as well as measurements made over the entire zone in which CO_2 is likely to be present.

Subpart RR of EPA's Proposed Mandatory GHG Reporting Rule will be merely a reporting rule rather than a rule that directly regulates sequestration activity. Nevertheless, it will impact operational decisions. The proposal can be thought of as the agency's first cut at regulating geologic sequestration from the perspective of atmospheric emissions and a first cut at establishing how to verify sequestration for purposes of carbon credits or other regulatory mechanisms.

The proposed rules are generally consistent with IPCC recommendations and Section 45Q requirements but are more detailed. A project that injects CO2 "to enhance the recovery of oil and gas" does not counts as a geologic sequestration facility unless the CO2 is also injected "for long-term containment" and the operator *chooses* to submit a monitoring, reporting, and verification plan (MRV plan) that is explicitly approved by EPA. Operators of oilfield projects who do not choose to submit an MRV plan must report certain information about their operations even if they do not choose to submit MRV plans.

Proposed Subpart RR includes the following documentation provisions, among other elements, that relate to verifying secure storage.

- Reporters must report "the annual mass of CO2 that is emitted from each leakage pathway indentified in your MRV plan." [23]
- Reporters must follow the procedures in the most recent MRV plan submitted to and approved by EPA to determine the quantity of

[23] Proposed 40 CFR sec. 98.443(c)(3). Proposed sec. 98.445(b)(3) requires the quantification "procedure" used for this purpose to be included in the approved MRV plan.

emissions from the subsurface geologic formation and the percent of CO_2 that is estimated to remain with the produced oil and gas. [24]

- An MRV plan must include: an assessment of the risk of leakage of CO_2 to the surface; a strategy for detecting and quantifying any CO_2 leakage to the surface; a strategy for establishing pre-injection baselines; and a summary of considerations made to calculate site specific variables for a mass balance equation. [25] The risk analysis and the monitoring program will need to be fine grained enough to comply with the requirement of proposed section 98.443(c)(3) to report "from each pathway" identified in the plan.
- Addenda to the MRV plan must be submitted (and apparently approved) if the plan is adjusted due to: new information; altered site conditions; or detection of leakage. [26] It is contemplated that operators will make adjustments at their own initiative when adjustments are needed.
- Such addenda must include: "a description of the leak including all assumptions, methodology, and technologies involved in leakage detection and quantification, if a leak was detected;" and a description of how the monitoring strategy was adjusted if adjustments were made. [27]
- Operators must revise and resubmit MRV plans if EPA audits determine revisions to be necessary. [28]

Implications of Regulation for the Sequestration Value Proposition

From the perspective of the U.S. oil business, the value proposition of capturing large quantities of anthropogenic CO_2 for use in oilfields is huge. Advanced Resources International has envisioned circumstances in which federal climate change legislation could lead to an increase of more than 3 million barrels per day of domestic oil production by 2030. [29]

The most obvious implication of regulation for the sequestration value proposition is that in the absence of regulation there is no value proposition. Regulation is needed in order to create an incentive to sequester carbon and regulation is needed to verify whether those who say they have sequestered carbon have actually done so. Regulation is also necessary in order to foster public acceptance of the sequestration enterprise.

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[24] Proposed 40 CFR sec. 98.444(b)(6)
[25] Proposed 40 CFR sec. 98.445
[26] Proposed 40 CFR sec. 98.448(a)(6)
[27] Proposed 40 CFR sec. 98.448(a)(6)(i) and (ii)
[28] Proposed 40 CFR sec. 98.448(a)(7)(ii)
[29] Advanced Resources International, U.S. Oil Production Potential from Accelerated Deployment of Carbon Capture and Storage (March 10, 2010) (report prepared for the Natural Resources Defense Council).

Regulation adds to transaction costs, but regulatory compliance is not likely to be a major component of the overall cost of sequestration. This is true whether the sequestration is in conjunction with EOR BAU or otherwise. In rough terms, to capture, compress and transport CO_2 will cost tens of dollars per ton, to select, monitor and otherwise operate sites will cost dollars per ton, and to take steps required by regulation that would not have needed doing anyway will cost dimes per ton.

How Regulating Sequestration in the Oilfield Context Can Help Inform Regulation in Brine Formations

Given that sequestering CO_2 in oilfields will generate billions of dollars of economic co-benefits through enhanced oil production, there will be a strong tendency in the opening decades of the business for sequestration projects to be located in oilfields. It is therefore interesting to contemplate in what ways the regulation of oilfield sequestration is likely to inform the regulation of sequestration in brine formations, both in the near term and in the long term. There is no doubt that there will be significant "learning by doing" both in field operations and in the regulatory arena.

Some of the areas in which oilfield sequestration projects are likely to yield significant new knowledge or technology are listed below. All of these items represent areas where progress would be particularly likely to be helpful for regulation in brine formations.

- Methods to compensate for shortcomings in baseline monitoring data
- Methods to determine how much geologic characterization data is enough, including the degree of specificity with which the nature and location of leakage pathways should be identified
- Improved techniques for assessing well integrity
- Understanding of seal performance
- Reservoir modeling and simulation techniques
- The necessary scope and detail of MRV plans to the extent the elements of such plans are relevant to the brine formation context
- Above-zone pressure and geochemical monitoring

New learning in the following areas probably will prove of less significance for regulation in brine formations than the items listed above.

- Surface measurement of CO_2 volumes and fugitive emissions
- Calculation of the Area of Review [30]

[30] The Area of Review is the area surrounding an injection well in which an operator must determine whether there are wellbores (and perhaps other potential conduits) that could serve as leakage

- Understanding of hydrogeology and “far-field” (far away) pressure effects,
  especially regional hydrogeology and “really far away” pressure effects
- Understanding displacement of formation fluids when CO_2 is injected into a formation that is at virgin pressure
- Methods to assess lateral continuity and heterogeneity of seals
- Surface monitoring

Policy Recommendations

As noted at the outset, the following policy recommendations are based on the idea that markets tend to do a much better job of allocating resources than governments do and that decisions to intervene in markets for policy purposes should not be made lightly. A fundamental recommendation and assumption is that one intervention will be that either Congress or EPA will place limitations on carbon emissions. Another fundamental recommendation and assumption is that basic, first-generation regulations for site selection, site management, and emissions accounting will be adopted soon.

Research and Development and Other Capacity Building – Although as a technological matter CCS is ready to begin deployment at scale today, significant work remains in order to reduce costs. Significant work also is needed to develop the resources (human, financial and technical) that will improve our understanding of risks and risk management techniques and enable the market to undertake more than a few large projects at a time. Since most of the cost of CCS occurs during capture and compression it is understandable that the lion’s share of R&D efforts have been focused on these processes. The “S” portion of CCS has meaningful R&D and capacity-building needs as well. These include:

- Workforce education
- Helping the insurance and financial sectors understand sequestration risks, identify and assess the effectiveness of risk controls, and develop corresponding financial risk management mechanisms (e.g., insurance; adjustments to the cost of capital; joint ventures in which parties share risks to different degrees; corporate decisions to simply accept risk on grounds that it is exceeded by benefits)

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pathways. In the EOR context, the focus is only on wellbores and Class II regulations generally establish an AOR that is a fixed radius around a well. EPA’s proposed Class VI regulations require the AOR to cover the area of elevated pressure around the well, defined as the area where pressures would be sufficient to drive CO_2 or formation fluids through the confining zone (in a manner that would endanger USDWs).

- Fundamental and applied research on reservoir simulation, containment mechanisms, methods to predict and assess geologic heterogeneity, ways to distinguish between faults that may cause problems and faults that will not cause problems or may even assist storage, and monitoring technologies and methods
- Improved methods to estimate geologic capacity, identify and characterize potential leakage pathways, and make efficient use of storage space
- Developing new techniques to produce oil in reservoirs that do not presently appear to be candidates for EOR BAU
- Developing new techniques for improving oil production in reservoirs where CO2 is injected in quantities that raise reservoir pressure significantly above miscibility pressure
- Efforts to reduce various costs, focusing in particular on geologic basins where the costs and technical challenges of sequestration are expected to be relatively high [31]
- Methods to quantify leakage
- Designing MRV plans that are standardized and yet take account of site-specific variations
- Regional and basin-scale hydrogeology
- Remediation methods, including methods to deal with the displacement of excessive amounts of formation water

<u>Pore Space</u> -- Contrary to what many believe, it is not particularly difficult to ascertain who owns pore space and who has a right to use pore space. Generally, the rules of construction in common law jurisdictions governing title documents will lead to the conclusion that surface owners own pore space and that mineral owners, where a mineral estate has been severed from the surface, will have the right to use the pore space as reasonably necessary for the purpose of producing minerals. [32] Generally, developers of sequestration projects will be wise to

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[31] Based on informal conversations with several geologists, the author expects that many sequestration projects using brine formations in the Appalachian Basin may cost three or more times as much per ton stored than will many projects in Gulf Coast brine formations.

[32] I. Duncan, S. Anderson, and JP Nicot, Pore Space Ownership Issues for CO2 Sequestration in the U.S., Energy Procedia 1 (2009) 4427 – 4431 (originally presented at GHGT-9). The present author does not believe the notion of declaring pore space to be in the public domain is worthy of discussion, especially if it done for the purpose of subsidizing CCS projects. Pore space is already owned by individual property owners. Transactions are already taking place in which parties to the transaction are either acquiring or retaining pore space rights with the expectation of future income. This situation is easily distinguishable from the situation in the widely cited case United States v. Causby, 328 U.S. 256 (1946). In Causby, a real property owner asserted that he had the right to prevent airplanes from flying above his property. The Court declined to follow the traditional rule that ownership extends from the heavens to the center of the earth and ruled that the flights could take place without acquiring the landowner's permission. The Court noted, however, that the case would be different if the flights had been low enough to damage the property owner's economic interests.

acquire rights from both surface and mineral owners, though perhaps EOR BAU operators who inject no more CO2 than reasonably necessary to produce commercial quantities of oil will not need permission of the surface estate or the mineral estate just because the operations happen to be recognized as sequestration by a regulatory agency. [33]

Although the difficulties of determining who owns or has the right to control pore space tends to be overrated, the difficulties are not trivial and can be minimized through appropriate legislation. Appropriate legislation needs to take place at the state level [34]and should be designed to avoid inverse condemnation problems. [35]

To what degree will developers of sequestration projects in oilfields find it difficult to assemble rights to an adequate amount of pore space? The problems may be significant enough to warrant a legislative response despite the fact that the difficulty of acquiring the necessary permissions is likely to be less significant than it will be for brine formation projects. [36] One reason that it will be easier to assemble the necessary property rights in an oilfield context is that oilfield projects generally will require less pore volume. These projects will tend to be smaller than projects in brine formations and – very significantly – the projects will use reservoirs that are largely depleted rather than formations that are "almost full" and still at virgin pressure. Another reason that it is likely to be

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Once pore space has value, the government cannot seize it for public purposes without paying just compensation.

[33] Whether the operator needs authority from the surface owner and the mineral owner should depend on whether the operator makes use of either estate in a manner that exceeds what is reasonably necessary to produce hydrocarbons in commercial quantities. Certain types of monitoring would be a good example.

[34] States, not the federal government, have always been in charge of real property rules. Many millions of legal documents have been drafted in accordance with rules of construction that vary somewhat by jurisdiction. An effort to establish a unified approach to interpreting these documents would create chaos, i.e. extreme uncertainty and a huge amount of litigation. In the author's opinion, it would also improperly interfere with traditional (and Constitutional) ideas of federalism. An exception might be appropriate for real property rules on federal lands.

[35] The Constitution requires payment of just compensation when government "takes" private property pursuant to its "police powers." Eminent domain (for legitimate purposes) is the quintessential example of a Constitutional taking. When government fails to admit that there has been a taking or fails to pay appropriate compensation, property owners have to right to sue for inverse condemnation. Wyoming has pioneered an elegant approach to clarifying pore space ownership that is likely to avoid inverse condemnation problems. HB 89 (2008) (creating W.S. 34-1-152 and amending W.S. 34-1-202(e). W.S. 34-1-153 was adjusted somewhat in 2009 to help clarify the dominance of the mineral estate. In effect, HB 89 provided that: (a) surface owners will own pore space in the case of real property transfers made on or after July 1, 2008 unless title documents explicitly provide otherwise; and (b) in the case of documents taking effect prior to July 1, there will be a rebuttable presumption that the surface owner owns the pore space. See HB 89 section 3. Thus determining who owns pore space has been simplified and the author of the legislation, Tom Lubnau, still has been able to declare that "everybody came out of the session with the same rights they had going in."

[36] Brine formations located beneath private lands at any rate.

easier to aggregate the pore space needed for an oilfield sequestration project is that such projects will take place in locations where people have made similar "deals" in the past. With any luck the natives will be more disposed to coming to terms than will people in other areas who are not familiar with the oil business.

While the case for authorizing eminent domain or similar proceedings to consolidate pore space may be stronger for brine formation projects than for oilfield projects, such action may be desirable in the oilfield context also. All major oil producing states but Texas have found it necessary to adopt compulsory unitization statutes in order to prevent "hold-out" mineral owners and lessees from standing in the way of secondary and tertiary development, which can only be done if substantial portions of reservoirs can be operated in a coordinated way regardless of fractionated ownership. Statutes similar to the unitization laws may be needed for both mineral owners and surface owners.

<u>Public Lands</u> – As just discussed, one policy response to the practical difficulties of assembling pore space rights is to authorize eminent domain or to enact special statutes patterned after state unitization statutes. In addition, for both onshore and offshore public lands, it should be a priority to develop policies and procedures for identifying areas that are or are not suitable for this activity and to develop appropriate leasing provisions. This is an especially important priority in the offshore context. So far little attention has been paid to special environmental considerations that must be taken into account in coastal and marine environments.

<u>Transportation</u> – CO2 transportation is a mature industry. At this time it is not clear that any major federal policy initiatives are needed in this sector.

Pipeline locations should be scrutinized and permitted from a public interest perspective, but certainly government should not undertake to design and dictate an entire pipeline system -- what lines of what size should be built when and from where to where.

Provided that the purity of CO2 streams captured from power plants and industrial sources is similar to the purity of CO2 in the existing pipeline network, few if any changes will need to be made in pipeline safety regulations.

There is not yet a demonstrated need for regulations that limit market entry or regulate rates and terms of service. The author assumes that at some point it will become necessary to regulate rates and supplement antitrust laws with regulations that assure nondiscriminatory transportation services, but it is not clear at this stage precisely what will be needed. In fact, to prematurely impose strict regulations of this nature could serve as a disincentive to the rapid development of the transportation system.

Eminent domain almost certainly will be necessary in order to develop a more robust CO2 pipeline infrastructure. At this time, CO2 pipelines have the authority to invoke eminent domain in some states but not all. Additional state and possibly federal legislation for this purpose would be desirable.

Financial Assurance during Active Operations -- Existing financial assurance requirements for EOR operators during active operations (injection, production and well plugging) are modest. EPA's proposed Class VI rules refer only vaguely to a duty to demonstrate financial security. The preamble states that more detailed guidance will be developed at a later date. In response to a request for advice, EPA's Environmental Finance Advisory Board (EFAB) recently issued a report making several recommendations. [37] The Board made no recommendations regarding long-term financial stewardship. The recommendations included the following.

- Financial test and third-party financial assurance mechanisms should be available to responsible parties
- Trust funds are "costly measures" and duplicative and upfront funding of financial responsibilities is not appropriate
- Class II financial requirements would result in weakness as compared to Class I requirements if Class II provisions were applied at a facility scale (Class II financial requirements apply to wells). "Class I financial instruments [should] be used, which include the use of insurance as well as specific language for other instruments."
- EPA should consider adding a new category of financial assurance to the Class VI program that provides the Agency "with the flexibility to approve the 'functional equivalent' to the established RCRA financial assurance tests."
- The amount and timing of financial assurance should be based on the Agency's evaluation of risks.
- The Agency should consider whether to require financial assurance for monitoring as well as for plugging wells.
- Financial assurance requirements should be dynamic over the life of a project, taking account of changes at particular sites as well as changes in available technology.
- In order to enable financial assurance requirements to evolve over the life of projects, the Agency might consider regular updates of cost estimates. In order to facilitate these reviews, it would be desirable to collect various types of data on a rolling basis. Grounds for making adjustments could be established if EPA's proposal to require updates when necessary of various plans (e.g. monitoring, corrective action, closure) were coupled with "robust annual reporting requirements that document why updated plans have or have not been necessary."

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[37] EFAB, Financial Assurance for Underground Carbon Sequestration Facilities (March 2010) (Report submitted to Peter Silva, Assistant Administrator, Office of Water, U.S. EPA, March 31, 2010)

The author agrees with the EFAB recommendations.

Verification – Policymakers need to be sensitive to the fact that MVR plans are in their infancy. This is an area where there will be much "learning by doing" in coming years. Both agencies and the technical community need adequate financial support. Industry may continue to need support in this area as well.

Long-Term Stewardship – In a very real sense, there is no liability issue, or at least there should not be. A liability regime for CCS already exists. It consists of the existing state and federal laws and procedures pursuant to which actors can be held liable under certain circumstances for damages caused by their actions. These laws and procedures are designed to make sure that people are treated fairly. Moreover, they are a crucial backstop to regulatory controls in society's effort to prevent "moral hazard" (i.e., to avoid giving people an incentive to consciously or even unconsciously manage their affairs in ways that violate societal expectations and harm third parties as a result. [38]

The existing liability regime applies to many industries, including industries that spend millions and even billions of dollars on projects that entail long-term risks that are much greater than the risks that are expected to be created by CCS. These industries are able to attract capital and make investments. Businesses in many industries routinely conduct operations that expose the owners to potential liability for indefinite periods or even permanently – these financial risks generally persist until statutes of limitation run (if there are applicable statutes of limitation) or companies receive bankruptcy protection.

Steel mills and refineries do not enjoy "liability relief" that allows them to escape this liability regime. Neither do the EOR business, the gas storage business, or the underground injection of industrial or hazardous waste businesses. Yet none of these industries have trouble attracting capital when prices for their goods and services are favorable. It is worth noting in this context that CO2 does not explode or ignite, and that it is not considered a hazardous waste.

What is generally call the liability issue ought to be deconstructed into three other issues: (1) what to do about stewardship at orphan sites (sites for which responsible parties with money in their pockets cannot be found); (2) whether government or a newly created institution ought to assist even solvent project

[38] Moral hazard can be created during the operational period even by a scheme for liability relief that only provides in the "post-closure" period. To the extent actors think there is a chance that sites might qualify for "closure" when they ought not (either because closure rules are too loose or because project defects might not be discovered until after closure review), post-closure liability relief will reduce incentives for companies to manage employs and contractors in a way that assures quality results.

developers perform certain "post-closure" [39] activities for which developers might otherwise be responsible; and (3) whether special rules are needed for the period of time it will take the marketplace to develop the sorts of financial risk management tools that enable other industries to make billion dollar investments in the face of risk that persists for an indefinite period.

The author believes that all three of these issues should be addressed. [40]

- The first issue (orphan sites) should be addressed through an industry-financed trust fund that is established in a manner that makes it difficult for Congress to siphon the funds for other purposes.

- The second issue (limited assistance with long-term stewardship of site infrastructure) is, in the author's opinion, worth pursuing if financed by industry, but it should be approached with caution. The stewardship functions that are to be socialized should be narrowly defined. To the extent government relieves companies of large amounts of potential liability, or alters legal processes in a way that favors defendants, companies are less likely to manage their business in a way that avoids causing harm to others. The "post-closure" stewardship assistance that the author has in mind is akin to a utility service for infrastructure maintenance – the government or a special entity would handle relatively routine, inexpensive tasks that benefit from standardization or economies of scale if performed for many sites by a single organization.

- There are also good policy grounds to consider addressing the third issue (fostering development of market approaches to risk management). [41] In order to help the market gradually develop risk management tools, the author recommends that the first 40 GW (or so) of CCS projects be divided into three tranches based on project starting dates. For each tranche there would be "layers" of financial responsibility assigned to various parties

[39] See previous discussion about the limitations of the closure concept.
[40] The author is grateful to Southern Company, Duke Energy, and Zurich for their roles in developing these ideas.
[41] See the recommendation, made in the earlier section on R&D and other capacity-building, that it would be good to help the insurance and financial sectors understand sequestration risks, identify and assess the effectiveness of risk controls, and develop corresponding financial risk management mechanisms such as insurance, adjustments to the cost of capital, risk sharing arrangements between partners, and corporate decisions to simply accept risks associated with their activities. All of this will take time to develop. In the meantime, project developers will face significant hurdles when deciding whether to undertake CCS projects. During the early years of the CCS business, it probably would be appropriate for government to take actions that reduce the size of these hurdles.

- Developers would have significant “first dollar” responsibility in the event of damage awards and the amount of this first dollar responsibility would increase with each tranche. However, in order to help bound financial risk and provide companies with greater financial certainty, each tranche would include limits on the developer’s first dollar exposure.

- For each tranche there would be a layer of “second dollar” financial responsibility funded by an industry pool. Like the first dollar responsibility, this layer of responsibility would be limited in amount. In the event a claim exceeded the applicable first dollar contribution, the pool would be able to draw a fixed amount of funds from other CCS projects.

- In order to bound and limit the financial risk for projects that might have to contribute to an industry pool, and to further bound and limit the financial exposure of developers who cause damages, the federal government would provide a third layer of indemnity available only if damage awards exceed the funds available from the first and second layers. The amount of the potential indemnity would decline by tranche in recognition that the market should be able to develop normal financial risk management tools over time.

- In the event damage awards exceed the first, second, and third layers of contributions, remaining liability would fall back on the project developer who caused the problem.

In order for this recommendation to foster the development of normal private sector financial risk management mechanisms, it its critical that: (1) the program be available for a sufficient number of projects; (2) the first dollar exposure not be frighteningly large; (3) the first dollar exposure increase over time while potential government exposure decreases; and (4) the program be discontinued once the policy objective is achieved.

In order to minimize creation of moral hazard, it is critical that: (1) the first dollar responsibility be large enough to get the attention of company management; (2) the indemnities provided by the second and third levels not be so generous that developers feel there is no realistic chance that they would be called on to satisfy “fourth layer” liability; and (3) the program be discontinued once the policy objective is achieved.

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