EOR as sequestration: Geoscience perspective

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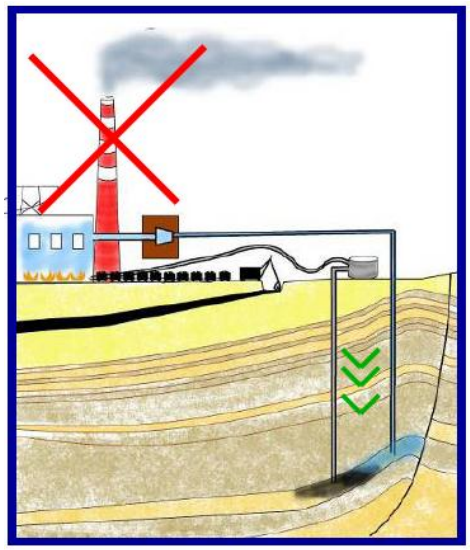
EOR as Sequestration - Geoscience Perspective

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 longer than 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 permanence of sequestration of CO_2 placed as part an EOR program will be in some cases higher than CO_2 placed into an equivalent brine-bearing system, and in some cases lower. Confidence is increased for the EOR case because:

- the quality of the confining system is better documented,
- pressure and fluid flow are controlled by production,
- more CO_2 is dissolved
- the reservoir properties are better known because of reservoir characterization and fluid production history leading to more robust prediction of the long term fate of CO_2.

Leakage risk factors that are increased for CO2 injected as part of an EOR program and must be assessed both through research and field-specific mitigation are:

- CO_2 that migrates out of pattern may be produced from non project wells and not recycled
- Numerous well penetrations of the confining system create potential flaws that, if unmitigated could allow CO2 to leak slowly over long time periods at rates unacceptable to attaining atmospheric goals.

Non-geotechnical factors that favor the use of CO_2 EOR for sequestration may be more important than technical factors. These include:

- Economical and societal benefits
- Mature regulatory and legal environment
- Public acceptance

Use of CO_2 EOR to accelerate sequestration will be most effective if it builds upon well established current best practices by increasing accounting and monitoring requirements based on surveillance already conducted for successful operation of a flood. To document that CO_2 is retained in the subsurface will require reporting 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 the areas of leakage risk. Additional studies focused on CO_2 as EOR are proposed to document how to best collect this data.

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 and injected underground for the purposes of reducing the release of CO_2 to the atmosphere. The complete system (IPCC, 2005; Orr, 2004) from capture of the CO_2 prior to release to atmosphere, transportation to a permitted injection site, and injection to depths isolated from fresh water and other resources is known as carbon capture and sequestration (CCS). The idea has been widely considered for about two decades (United Nations Framework Convention on Climate Change (1992). Consideration of future deployment of this new CCS technology at large scale proportional to current fossil fuel use raises questions about cost and effectiveness of the method. Uncertainties remain because feasibility of CCS has been by tested only at a short list field tests world-wide (National Energy Technology, 2009 3-7 to 3-15). The longest running project designed and monitored specifically for geologic sequestration associated with the 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 underway at more that 100 sites in the US (Oil and Gas Journal Enhanced Recovery Survey, 2010) and a lesser number of sites worldwide. This paper considers the proposition that the older and better known process of EOR can (1) 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 geologic sequestration at large scales and long durations.

Subsurface injection of CO_2 as part of CCS designed to reduce atmospheric emission of CO_2 has been proposed to be possible a number of different 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 fluids histories are considered (table 1). Clarity in distinguishing among the members of the family is needed, because in the US, 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 produced.
Depleted reservoir sequestration	CO_2 injected into hydrocarbon reservoirs similar to CO_2 EOR reservoirs (originally containing gas and or oil) but without extracting 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 non-geoscientist 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 achieve the benefit to the atmosphere?
- What is the CO2 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 current published and anecdotal information is outlined with selected references provided for further information and some questions and uncertainties posed that illuminate the edges of current knowledge. Recent discussions of the relationship between CO_2-EOR and sequestration include Inc., 2010, Cooper, 2010, Jaramillo, 2009, and 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 Enhanced Oil 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 energy 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, in which water or recycled natural gas is injected into the reservoir though a pattern of injection wells to maintain pressure and guide oil toward production wells. This process is commonly known as a water or gas flood. When recovery again declines, tertiary recovery methods can be employed; among the methods commonly used is injecting materials not native to the reservoir, which is 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 and increase the percentage of the 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). The 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 dense phase (liquid or supercritical fluid). In some regions of mixtures of H_2S and CO_2 are available and are used for acid gas 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 3000 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 generally tabular body of sedimentary rock bounded by an upper confining system that greatly retards vertical movement of CO_2 (Figure 1).

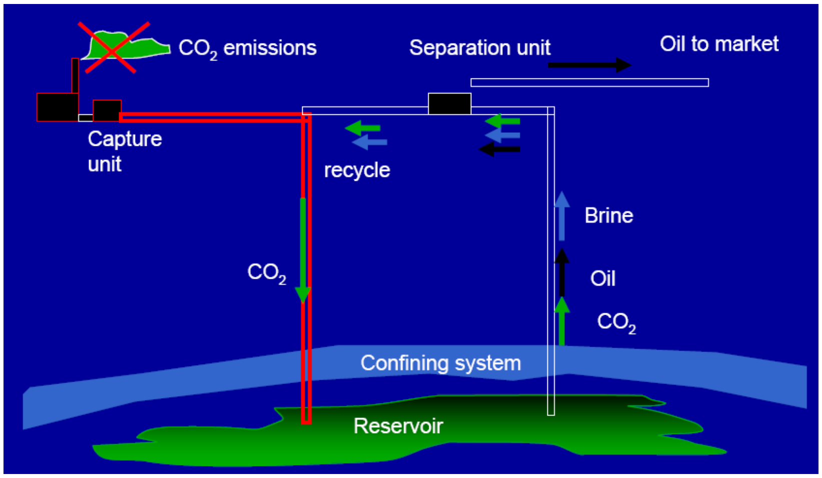

Figure 1.Schematic of a CO_2- EOR system. The components required for sequestration in brine formations in common with CO_2 EOR are highlighted in red.

CO_2 will interact with oil and water in the pores, and over months and years creates a region where oil saturation and mobility is 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 though the perforations, and will rise or be pumped to the surface. The geometry and timing in terms of which pores are accessed and amount of CO_2 that enters them is controlled by the way the flood engineering intersects the rock fabric and changing fluid environment. Geotechnical effort is focused on making an accurate estimate of how this will occur using a variety of types of analytical and geocellular flow models. Modeling is essential to financing the project, design of the flood, purchase of adequate CO_2, and obtaining a sufficiently large incremental recovery of oil in a manner timed to support project economics. Monitoring techniques, software and experience in designing CO_2 EOR floods provides the technical foundation on which confidence for brine sequestration is founded For examples of this overlap, see lists of techniques the proposed protocols for monitoring, verification, and accounting for geologic storage (National Energy Technology, 2009).

CO_2 recycle

During successful CO_2-EOR operations, CO_2 is produced with oil and brine though the production wells. CO_2 comes out of solution with oil and water during pressure drop as fluids are brought from reservoir depths to the surface and dense phase CO_2 (supercritical or liquid) flashes to gas. It would be permissible to vent produced CO_2 to atmosphere, however because CO_2 is expensive, operators invest in separation facilities that extract CO_2 and return it into the injection stream. The efficiency of this separation depends on separation equipment. Chuck Fox (oral presentation, December, 2009) presented results of a proprietary assessment showing losses during separation <0.5% of the total CO_2 in the system from Kinder Morgan's West Texas separation operations. An even smaller amount of CO_2 is emitted during equipment maintenance, from connections, and during upsets. 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 the process losses of CO_2 during handling from the point of sale through the whole system similar to that required for other industries would be needed. Other emissions related to oil production are considered in the section on lifecycle.

Types of floods

CO_2 EOR can be deployed with great flexibility, so that each operation is in some ways unique, which contributes to the difficulty of forecasting the role of EOR under various CO_2–availability scenarios but adds 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 is dependant on the pressure and temperature of the fluids under reservoir conditions where they contact each other, and on 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 favors use dominantly 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 and use larger volumes of CO2.

In many floods, water is introduced episodically to augment a CO_2 flood as a "chase" fluid (Lake, 1989). This processes, known as Water-Alternating-Gas (WAG) (Green and Willhite, 1998, p 168) is used to reduce the amount of high-cost CO_2 needed and as well as increase the amount of oil contacted. Other operators, notably Denbury Onshore LLC, use CO_2 without introduction of water once EOR begins. In the CO_2-only model, larger volumes of CO_2 are cycled through the reservoir requiring more CO_2 in the reservoir as well as higher recycle rates, but fluids in the production wells are lifted by the CO_2, avoiding the need for production pumps. Because of large volume usage, the CO_2-only model may be relevant to sequestration. Assessment of the sequestration values injection of CO_2-only has not been undertaken. The complete field history production needed for field validation are only recently becoming available as fields developed using this method reach mature stages (Denbury Resources Inc., 2009).

A variety of arrays of injection wells with respect to production wells (well patterns) also have implications for using 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, 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 pilots tests at West Pearl Queen field, NM (Pawar and others, 2006) and Loudon Field Ill (Finley, 2007). For most floods injectors and producers are arranged in patterns and act in balance. The ratio of producers to injectors and the spacing between them has a strong impact on project economics, with closer spacing resulting in faster oil recovery but higher investment. Wells can be deviated 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 access more of the reservoir through a single well.

Well placement can also be varied with respect to the reservoir architecture resulting in large differences in cost, rate of oil production, and percent of OOIP recovered. For exampled in a steeply-dipping closed structure the 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 more dense 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 to attempt to force the CO_2 to contact the maximum about 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 that is not accessed during primary and secondary production. (Meltzer, 2006)

Geologic properties of the reservoir and the fluids have a strong impact on designing an economically successful CO_2 flood (for technical discussion, see Green and Willhite, 1989, p. 173). However, non-geologic variables also have a strong impact on how the flood is developed and include cost and volume and rate of available of CO_2, cost and availability of capital, and surface, property, and mineral rights issues that pragmatically influence what is undertaken. Operator experience and available technical skills also have a very strong effect on how the flood is designed, CO_2 usage, and ultimate recovery. The impact of changing these non-geologic variables in a model where CO_2-EOR is used as an element of sequestration have 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 plan for 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 though to the production wells and begins to be produced, it is separated from oil and brine and put back into the injection stream. Augmentation of the CO_2 supply by this recycle then allows additional patterns to be developed. A field under flood will be in constant readjustment to optimize recovery and minimize costs. Older or more poorly performing wells where handling the water and CO_2 production and recycle is more costly than the value of oil produced will be shut in, some wells will be in peak oil production, and new patterns will be brought on from which no CO_2 and little oil are produced. At the end of a operation of a mature build-out recycle will be the dominant source of CO_2 and lesser amounts of CO_2 will be purchased from sources outside the field for make-up fluids.. Because of the staging and continual balancing of the flood, it is difficult to state ratios of oil, CO_2 and water in a simple and consistent way, leading to difficulties in synthesizing numerous reports of CO_2 usage. Changing the availability of CO_2 by capturing additional large amounts are likely have an impact on how floods are staged and consequently how much CO_2 is purchased and sequestered.

Trapping CO2 in the reservoir during EOR

Not all of the CO_2 that is injected can be produced back at the production wells. CO_2 as free phase or dissolved phase moves into spaces in the reservoir from which it cannot be recovered. CO_2 is dissolved in 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 non-wetting phase capillary trapping (Lake, 1989, p, 48-77). The percentage of CO_2 that is not returned to the production wells depends on the injection strategy and reservoir and fluid characteristics, but is significant, typically estimated as between 1/3 and ½ of the injected volume (Smyth, 2008; Han,2010). Language used in the industry has sometimes resulted in a misunderstanding that the volume that is not recycled is emitted to atmosphere. Actually the reverse is the case; volumes not recycled are trapped in the reservoir and cannot be extracted. Changes in the amount of water alternating with CO_2, well spacing, and injection rate that might occur as more CO_2 is available will likely change trapping within the reservoir, however detailed models and validation of this change are incomplete.

Lifecycle analysis

Consideration the carbon balance of CO_2-EOR is described a lifecycle analysis. EOR differs principally 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 contribute CO_2 to the atmosphere. In addition, energy use for CO_2 is different from brine sequestration in brine or depleted reservoirs without production because materials are consumed and energy is expended in producing fluids and in separating and compressing CO_2. as well as other processes that occur offsite such as refining. Jaramillo and others (2009) have completed a lifecycle analysis based on 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. Further assessment to determine which geologic or operational factors lead to balanced 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.

For current EOR operations, most CO_2 comes from geological sources. Because of it's value for 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 also separated from impure natural gas before it is placed in pipeline networks and some of this sold for CO_2 EOR. CO_2 from gas processing has also supplied some of the initial geologic sequestration tests, including Sleipner, InSalah, and Snovit projects (IEA Greenhouse Gas R&D Programme, accessed 2010).

The distribution and amounts of geologically-sourced CO_2 supplies 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 as much as possible because of purchase cost and value in terms of bringing additional patterns on production.

Benefit to the atmosphere can only occur 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 fossil-fuel fired power plants producing electricity, refineries, cement plants, and steel plants (National Energy Technology Laboratory, 2008). It is possible to combine CCS with other proposed atmospheric reduction methods. For example, CO_2 produced during manufacture of ethanol biofuels as been used for EOR at the Hall-Gurney flood, Kansas (National Energy Technology Laboratory, 2010a) and planned for brine formation sequestration at Decatur, Illinois(National Energy Technology Laboratory, 2010b).

CO_2 EOR is geologic sequestration

Injection of captured CO_2 for EOR results in sequestration of the CO_2 from the atmosphere during operation of the project. Essentially all of the CO_2 captured is placed underground; a fraction of that placed underground 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 is not done during current commercial CO_2 EOR, but would be added as it would be to other operations if CO_2 emissions were tracked. In addition, the energy consumed to produce and refine oil and carbon content of combusted oil must be accounted for. However, this accounting should not be directly attached to the sequestration value of the CO_2 EOR process, but should be handled in the same manner other fossil-fuel extraction processes such domestic secondary recovery, imported oil, gas production and shipping, and coal mining and shipping.

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

Retention rates 99% over 1000 years

In order to gain value for the atmosphere, injected CO_2 must be retained 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 Shaffer (2010), IPCC, (2005), Pacala, (2003), and Lindeberg (2003). 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 1000 years after the end of injection has proved durable and conservative. Note that 1000 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 of10,000 or 100,000 years.

In this section, the possibility that CO_2 that might escape slowly but over long times resulting in long term failure to achieve this target are considered. Previous regulatory experience for injection to evaluate permanence is inadequate over the needed time fame. Analysis of petroleum systems provides confidence in the ability of the subsurface to sequester buoyant, immiscible fluids over even greater time frames. Higher levels of confidence can stated for EOR settings than 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 then 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 underground injection control (UIC) program requires all injection to document protection of underground sources of drinking water (US Environmental Protection Agency, 2010). Secondary and tertiary injection processes for oil production including EOR is regulated under UIC Class II and controlled in many states by the state oil and gas regulatory agency (IOGCC, 2008). Injection of hazardous and nonhazardous injection into brine formations has been conducted under UIC Class I, and the Environmental Protection Agency (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 (US EPA Underground Injection Control (UIC) Program, 2008). Although UIC rules do not require assessment of any leakage to atmosphere, most plausible slow leakage paths pass though the USDW, and therefore this requirement provides a broad experience base against which to evaluate leakage. However SDWA is not stated in terms directly useful to conduct evaluation of value to the atmosphere in terms of showing retention of 99% of the CO_2 over 1000 years, because it traditionally a yes/no evaluation if the site is sufficient retentive. It is possible that slow leakage rates could be allowed by the SDWA because damage to USDW was considered to be insignificant.

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

Sequestration relies on the natural system to accept and then retain CO_2.Injection processes must be designed not to damage the 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 for this is that prior to EOR, some uncertainties have been reduced because natural accumulation of hydrocarbon followed by extraction of has tested the reservoir characteristics. Other uncertainties are reduced because aggressive reservoir management is required to conduct EOR. Comparisons and contrasts between risks in brine sequestration and EOR are summarized in table 2 and reviewed below.

Table 2 Comparison of generalized risk elements for sequestration in brine formation 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 penetration confining system	Usually sparse	Usually dense
Financial support for injection	All cost	Cost + 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, the performance of the confining system, usually referred to as reservoir seal, is relatively well known. Buoyant fluids such as natural accumulations of CO_2, methane, and oil escape upward if the top seal did not effectively limit upward migration since the reservoir was charged (>>10,000 years). For brine formations, confinement must be inferred and a 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 heaver 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, transport is very slow and can be disregarded with respect to the 99% retention of 1000 years timeframe.

Retention of hydrocarbons over geologic time is not perfect assurance that CO_2 will be retained. The capillary entry pressure of pores systems to oil are higher than they are for CO_2, so invasion might occur when CO_2 enters a system that is impermeable to oil, however statistics on the heterogeneity of typical seals suggest this is not an important flaw in most systems (Meckel, in press). More difficult to assess is the possibility that extension of the seal as a result of recent reservoir volume changes could fracture the seal and increase its vertical permeability. Volume changes occur during depressurization the reservoir during primary production in the opposite sense as pressure increases during secondary and tertiary production. Modeling show that geomechanical damage could be significant (Orlic, 2009; Rutqvist and Tsang, 2002), however field observations to constrain and validate these models are lacking. Elevated pore fluid pressure as a result of injection can cause slip on critically stressed faults (Rogers and others, 2008)

Injection zone performance in accepting fluids

The ability of the selected injection zone to accept CO_2 is one on the main risk factors in brine sequestration projects, and an extensive site characterization workflow draw from experiences with hydrocarbon exploration has been developed to reduce this risk (National Energy Technology Laboratory, 2010c, Forbes and others, 2008, p. 91-92). The risk is especially high where a large volume CO_2 capture project will be developed depending on one injection site. A sequence of geologic assessments starting at the sub-regional scale and collecting detailed information on rock and hydrologic properties can be used to infer that adequate amount pore space is well enough connected though 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 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 under-predicting the volumes that can be injected is greatly decreased, providing a significant reduction in project 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 hydrocarbon to accumulate (figure 2). If seal is dipping, the hydrocarbon 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 sea-floor seeps. CO_2 can be introduced into structural or stratigraphic traps, where it will be retained by the same mechanism as hydrocarbons. A number of simulations supported by field test results have suggested that a trap is not essential for sequestration because of fast injection into thick zone, thicker plumes may build. For thick plumes lateral migration will be self-limited by dissolution into brine and capillary trapping (Nicot and Hovorka, 2009, Hovorka and others, 2006,Hovorka and others, 2005).

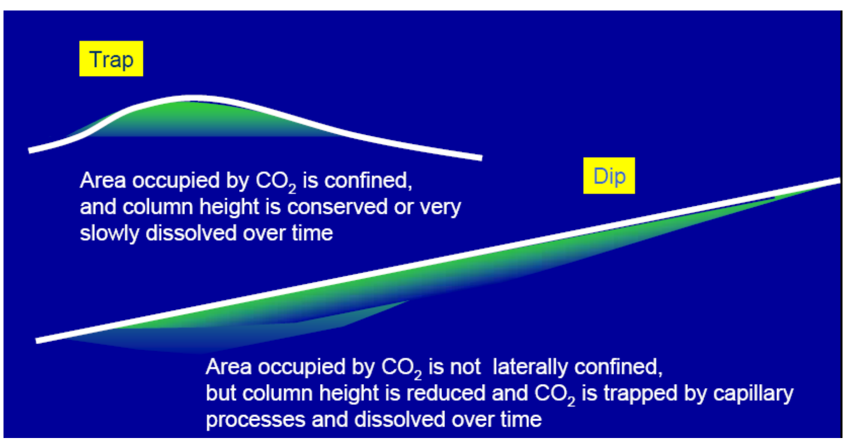

Figure 2. Comparison between the trapping mechanisms for a plume confined in a trap, as it would be after EOR, and a plume injected where it will migrate updip as it would in some brine sequestration projects.

In the case of CO_2 used for EOR, the same seal geometry that formed the trap for the hydrocarbon serves as the trap for the CO_2. Additionally, in 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 underway at the SECARB "early" test site at Cranfield, Mississippi (Hovorka and others, 2009).

Well operations and pressure management

In brine injection, pressure will be elevated in response to injection. Highest pressures occur near the well bore, and the magnitude of pressure increase declines with distance (Nicot 2008, Kalyanaraman, 2008). As more CO_2 is injected, the area and/or magnitude of pressure will increase as a function of injection zone flow properties and injection rate. The area if review (AOR) is the area where pressure elevation increases are such that open pathways would 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 (Widyantoro, 2010 oral presentation; Jain, 2010 oral presentation). In contrast, for EOR, pressure management is intrinsic because CO_2 (and water during WAG) injection is largely balanced by extraction of oil, brine and CO_2 during production. CO_2 and in some cases brine is 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 lowering of risks as a result of production applies to other types of leakage, such as faults and fractures.

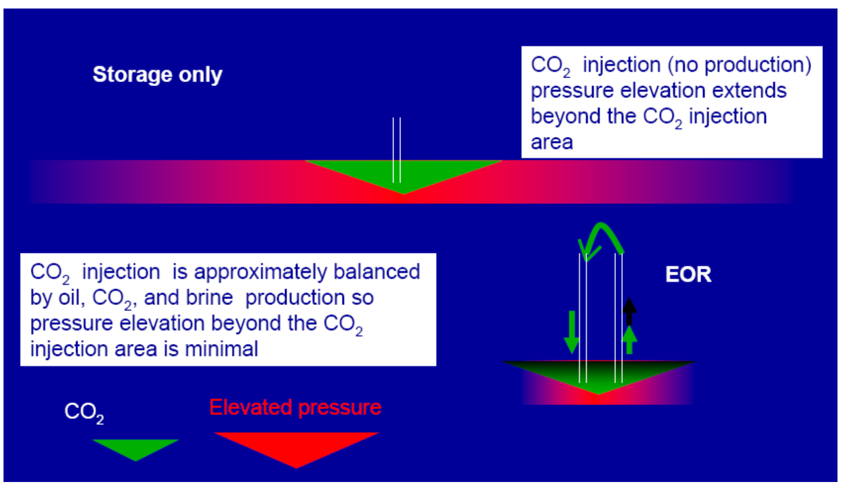

Figure 3 Comparison of pressure propagation away from brine sequestration and EOR.

Role of dissolution

One key difference between brine sequestration and CO_2-EOR is the solubility of the CO_2 into the ambient pore fluids. CO_2 is only weakly soluble in water; miscible conditions typical of most EOR are defined by complete solubility of CO_2 with oil. Dissolution of CO_2 has significance for permanence of storage in two ways: reduce buoyancy and viscosity as factors favoring leakage of the CO_2 and decrease volume occupied by the dissolved fluids compared to the same fluids in free phase. 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 condition reached in EOR.

Simulations of a reservoir with and without 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 less than 4% when 0.5 moles of supercritical CO_2 contact with 0.5 moles of brine with pressure ranging from 1000 to 6000 psi and temperature from 100 to 350 ^{o}F. However for 0.5 moles of supercritical CO_2 contact 0.5 moles of crude oil under the same conditions (miscible) the decrease in volume could be as high as 40% (Yang, 2010).

Wells that penetrate the confining system

By design, wells provide a rapid pathway from the reservoir to the surface. As designed, this pathway is easily controlled at the wellhead. At the end of service, wells are required to be property plugged and abandoned. In a properly constructed well, plugging is done following state rules, generally by setting a number of permanent barriers to flow made of steel and cement within in the casing, cutting off the well casing below surface, and welding a plate on the top of the well.

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

- the 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 it's existence 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 draw flow downward toward the perforated interval, undergo a pressure reversal during injection, where gradient may be upward.. If the well construction is flawed or has been damaged, salt water may flow upward to pool at the surface or move into the groundwater and damage water resources, crops, and the ecosystem.

New-drill 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 to cement the casing to the rock over the injection zone and across the formation seal. Surface casing is completely cemented in to protect USDW. Class I and Class VI wells are required to pump additional cement to encase in the entire long string but production wells and class II injection wells leave an uncemented opening filled with drilling mud between the rock and casing (Figure 4).

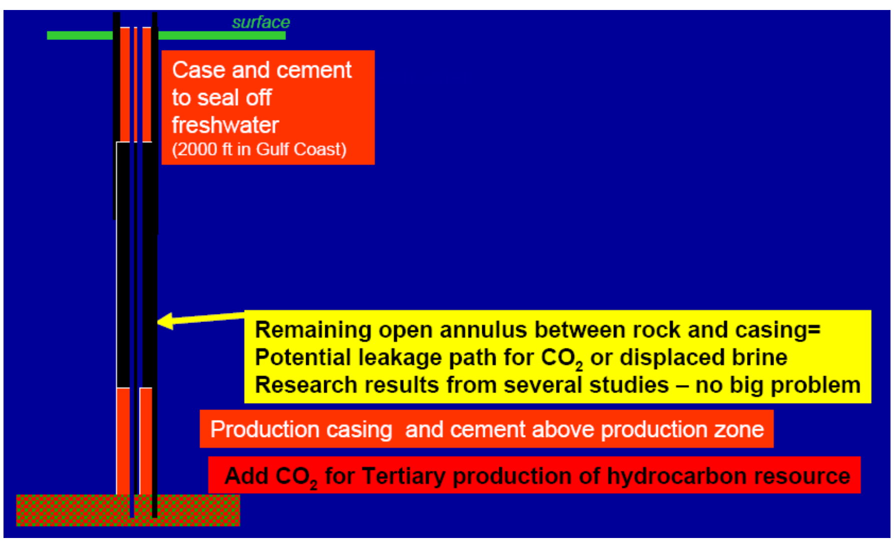

Figure 4. Intervals typically not cemented in class II production and injection wells provide an unknown leakage risk.

During CO_2 EOR the operator will remediate 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, as it 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 retrofit injection wells without damage to the ecosystem or human health and safety. A recent extensive field assessment of the quality of fresh water aquifers above the long active SACROC CO_2 EOR project showed no evidence of degradation of aquifer quality from well leakage from depth (Smyth and others, 2009).

However, uncertainties remain regarding if retrofit (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 will open permeable pathways in the well construction and that CO_2-brine mixtures will corroded to well construction materials and enlarge openings. Reasons for optimism about well retention are the natural tendency for weak materials to fill voids, and research monitoring and testing programs including the opportunity for increased surveillance of CO_2 EOR project wells.

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, causing formation of cracks known as micro annuli (huerta, 2009; Patterson and others, 2008). In six months of injection, bottom-hole temperature at the well at Cranfield that hosts the SECARB early test has cooled from 252 degrees F to 160 F over 6 months of injection.

Dissolution of well materials

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

Natural filling of voids

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

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 risk and simulation best practices manual (in preparation). CO_2 EOR developers typically assess business risks while 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) believe 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 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 to design a monitoring program that collects data to assess potential flaws in the system that can be targeted for mitigation. As the 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.

US EPA Underground Injection Control (UIC) Program (2008) has proposed a draft rule defining the 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. However, under EPA's proposed class IV rule requirements for CO_2-EOR remain as they have been, under class II. The Class IV rule is still in agency review after comments, therefore it is premature to formerly compare the monitoring requirements, however Table 3 highlights some of the main differences.

Table3 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 CO_2 injection rates, surface injection pressure and volumes	yes	No	Used in-company, economic impact of purchase and recycle, optimize flood
Pressure away from injection wells	Monitoring wells may be required	No	Pressure at producers regularly measured, used to optimize flood
History matching	may require update to AOR calculation	not reported	Regularly used to optimize flood
Time-lapse Surface or wellbore geophysics	May be 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 is excerpted from EPA Underground Injection Control (UIC) Program (2008) draft and is not authoritative.
- [2] Class II rules are mostly enforced by state primacy and therefore requirements vary among states, this column reflects Texas practices.
- [3] This 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 started in 2000 and operated by EnCana has hosted an extensive and continuing research project. The Weyburn project that 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, NM (Pawar and others,

2006) and Loudon Field Ill (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).

More work in both the technical and regulatory arenas is needed to determine if additional monitoring would be beneficial or should be required for CO_2 EOR is to qualify as sequestration..

During EOR flood, 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 the monitoring program to provide the expected documentation of the level of retention and safe operation. 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. The pressure and fluid flow of the field is assessed through surface and downhole measurements that are more rigorous in some ways than those used research projects because of the spatial and temporal density of 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 suitability in EOR settings. Projects are in planning that will more specifically develop the linkage between commercial flood surveillance and monitoring to assure permanence during CO_2 EOR (figure 5).

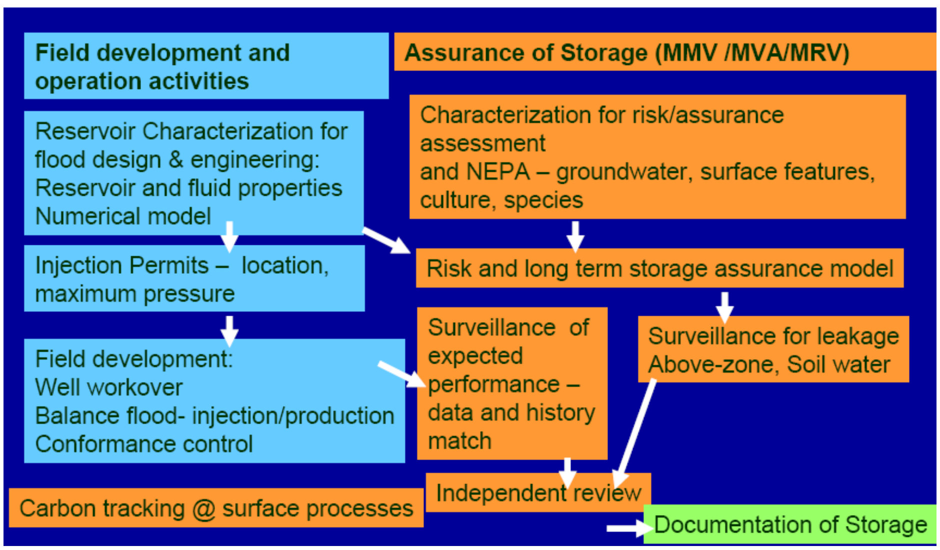

Figure 5 Draft plan linking commercial surveillance for CO_2 EOR with monitoring to document permanence of sequestration.

Testing well performance in CO_2 EOR projects

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

Normally after well construction, a variety of tests are run either as best practices or to meet regulatory requirements. A mechanical integrity test (MIT) where pressure within various well component is elevated and shown to be steady for a period is a required by regulation for all wells. Logging programs the image the condition of the casing and cement or diagnose indications of fluid flow (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 the well.

Cross-formation hydrologic tests can be used to assess the overall leakage signal across a confining zone (Hovorka, 2008;Javandal and others, 1988), and collection of above-zone pressure has been noted a monitoring strategy in the Class VI draft rules (EPA Underground Injection Control (UIC) Program, 2008). At specific well passive observation of casing pressure is a useful diagnostic for leakage at a (Huerta, 2009). Unexpected pressure increase or decrease on any of the annuli between multiple casings is an indication that unexpected fluid migration has occurred, and the well may need remediation. Monitoring casing pressure can be automated to increase data density and serve as an alarm (Hovorka and others, 2009). Very slow leakage from the reservoir to the atmosphere might be at rates below detection of many methods, providing a monitoring challenge.

Non geotechnical factors favoring CO_2 EOR

Three significant 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 are having a strong influence on if CO_2 EOR is used as part of a sequestration project. Financial support for sequestration CO_2 EOR has been extensively considered (for example Advance Resources International, Inc 2010). This is also harmonized with positive societal values for domestic energy production from existing resources, avoiding imported and greenfield sources. In the near term, 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 the equivalent frameworks for tertiary recovery are well known. Perhaps the most compelling reason for sequestration projects to use EOR is public acceptance. Public acceptance is good for CO_2 EOR relative to brine sequestration because 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 the rate of success in project development is good.

In addition to the tests of sequestration within CO_2 EOR setting described above, several brine sequestration tests (Frio, SECARB “Early test” at Cranfield and SECARB “Anthropogenic Test” at Citronelle) have been set within 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 to accept CO_2 from major anthropogenic sources, such as power plants. Large EOR projects, for example, the SACROC Field operated by Kinder Morgan in Scurry County, West Texas, have historically purchased 2-4 million metric tons of CO_2 per year (Han and others, 2010; Smyth, 2008). This purchase volume is about 1/3 the annual volume produced from an average coal-fired power plant. Injection has been sustained since 1972 and will continue into the future, showing a reasonable match in duration to 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 value in terms of CO_2 that could be captured from atmospheric emissions and sequestered in hydrocarbon reservoirs, several types of assessments have been made.

Volumetric methods

Volumetric methods consider the space available in hydrocarbon field. The annual projected amount of capture can be divided by space volume to estimate the number of years of captured CO_2 that this field can accept. The US Regional Carbon Sequestration Partnerships (RCSP) program (Litynski and others, 2008) and has completed two volumetric assessments on a basinal scale and estimate that 138 billion metric tons of CO_2 could be stored in depleted oil and gas fields of the US, compared to at least 3,297 billion metric tons in brine formations (National Energy Technology Laboratory, 2008 p 18 and 20).

Volumetric estimate of capacity in depleted oil and gas fields estimate is based on replacing the volumes of hydrocarbon produced with an equivalent volume of CO_2 under reservoir pressure and temperature. Hydrocarbon production is estimated either as a fraction of the volume of the reservoir (area times thickness time saturation) or by reported cumulative volumes produced converted to the volumes that they would occupy in the subsurface (National Energy Technology Laboratory, 2008 p 122). The advantage of this estimate is that it is relatively simple and can be done using approximately the same assumptions in all fields in the US. However, because of simplicity, volumetric methods are unrealistic 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) has been considered GEO-SEQ project team 2004, but is feasibility is not well enough documented to consider here.

Economic methods

Assessment of CO_2 usage for EOR requires merging an economic forecasting model with a reservoir simulation model. Extensive work has been done by the EOR industry, however most of this work is confidential. An economic model is 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, and has a strong influence on outcomes. For example the historic range of oil prices from \$20/barrel to \$90/barrel 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 would be in terms of recovery of oil and recycle of fluids to different fluid injection rates and durations and well geometries. Reservoir response can then be integrated with the economic model to determine if the EOR project is worthy of investment. Historically operators have done short duration pilot tests to gain experience and test the validity of the model assumptions in the field.

Regional assessment of role of EOR

Field-by field model-based assessment is costly and data intensive, and therefore has not been done regionally for the US. 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 under a range of assumptions. The ratio of CO2 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 does not add to the total amount sequestered. Therefore, utilization for the purposes of assessing sequestration must remove the recycle volumes. The amount of CO_2 recycled, as well as the total new purchase over the project period, is strongly dependent on both the reservoir properties and the 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 purchased CO_2 per barrel of oil produced have been reported (McCoy, 2008), however these ratios should be used as minimum estimates for sequestration via CO2 EOR. If large quantities anthropogenic CO2 are available and value is assigned to retaining it in the reservoir, the ratios could be significantly larger as described in the following sections.

Recently as series of studies funded by 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 can be used to increase domestic oil production, using 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 CO_2 per barrel of oil produced. Higher utilization numbers can be extracted from Denbury's plans using CO_2 injection only (Denbury Resources Inc, 2009), however detailed assessment that would factor in the complete cycle from new project 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 (Ramirez Salizar, 2009; Kovscek and Cakici, 2005; Jessen and others, 2005). However, these studies have dealt 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 (Meltzer, 2006;Jessen and others, 2005), large changes in well spacing and injection rate, more widespread use of gravity displacement, and faster development of fields might be favored. If the cost was 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 production terms, this it the water leg of the reservoir. Under conditions where values was given to sequestration, the operator would change from the current practice of minimizing CO_2 injection to maximizing injection in large part 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 non-productive strata would be required. The SECARB "Anthropogenic test" has proposed to use this method at Citronelle oilfield, Al. In areas where commercial EOR is possible, the 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. A 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.

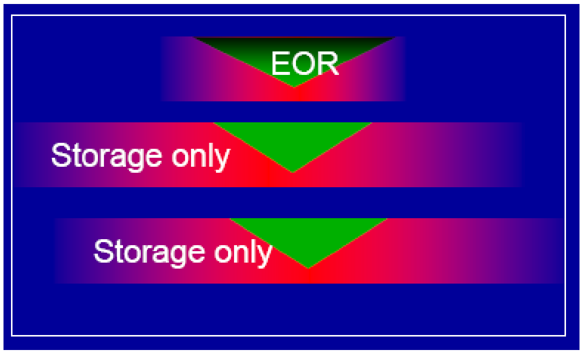

Figure 6. Large volumes of non-productive brine formations lie below many CO_2 EOR targets. The concept of using them to increase the sequestration volume accessed via EOR is called stacked storage.

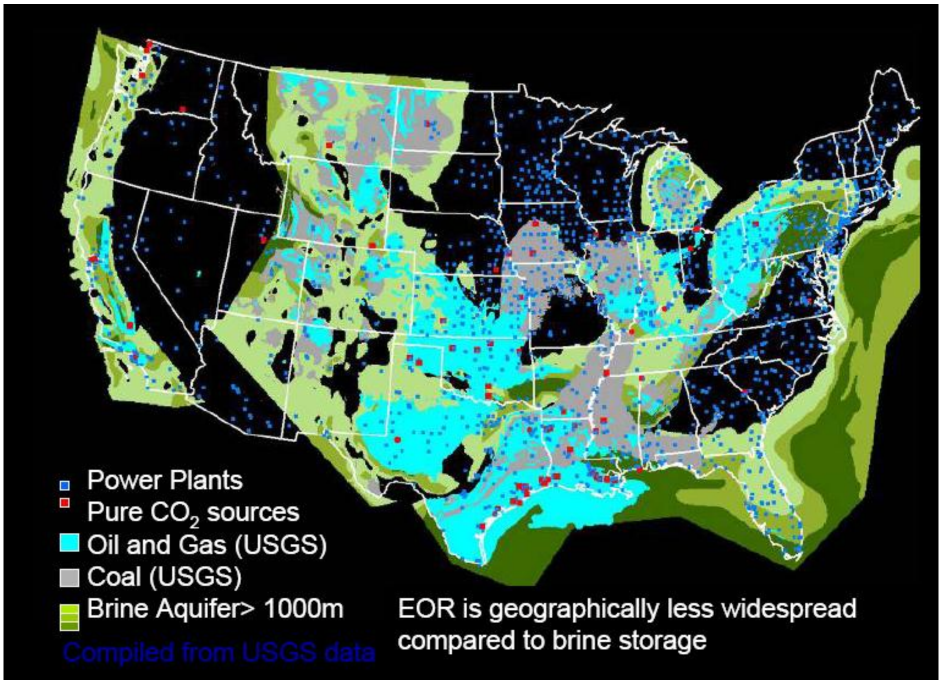

Figure 7. Coincidence of sedimentary formations of suitable depth for brine sequestration with hydrocarbon basins and stationary CO_2 sources suggests that much of the US brine formation storage could be accessed through infrastructure developed for CO_2 EOR using the stacked storage concept. Additional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

Key uncertainties in how much EOR can be used for sequestration lie in social and policy motivators, focused on the cost and volume of CO_2 available. Capture cost CO_2 from anthropogenic sources is expected to be significantly higher than the cost to most current EOR projects. Only by assuming sustained high oil price can CO_2 prices be elevated to more completely cover the cost of capture. If the price of CO_2 was supported as part of a carbon emission reduction program (as it would be totally for sequestration in brine formations) other social and economic barriers might have to be overcome. EOR would have to qualify for this support (be eligible for carbon credits) under conditions economically and logistically compatible with EOR. This might be especially important in the early stages of anthropogenic capture in a region, as operators might not be willing to make major changes to current successful operations until anthropogenic CO_2 was a major resource. State mechanism to unitize fields would have to be successfully accessed, in order to assure that the field was operated under conditions where CO_2 was controlled, and escape out of injection patterns to producers that are not linked to separation units does not occur. Capital investment for project development including pipeline construction and well drilling and remediation would need to be available; in recent times this has been seen as a block to otherwise viable CO_2 EOR projects. If CO_2 is not available in volumes and at a competitive price harmonized with the value of investment, others forms of EOR that do not use CO_2 may favored. Technical and infrastructure development favor continuation of the originally selected EOR processes through the tertiary recovery period. If use of CO_2 for EOR became 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 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 to CCS a ready-to-use model for 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 will be encountered in brine sequestration (Cooper, 2009; Forbes and others, 2008)

Monitoring tool testing

EOR also provides to CCS a commercially available and tested tool kit for making measurements of the distribution of CO_2 and an extensive experience base of how of 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. In the experience at recent projects SECARB Cranfield project underway now and Frio project (Hovorka and others, 2009, Hovorka and others, 2006, Hovorka and others, 2005), oil field tools performed better in simpler (brine-CO_2) fluid systems that they did in EOR context.

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 with monitoring tools that provide high value examples to sequestration (Cooper, editor, 2010). More technology transfer from industry experience to sequestration is possible both through assessment of historic data and new data collection at new and ongoing EOR projects. In particular, the dense data available in oilfield settings in terms of both reservoir characterization and access points though wells allow assessment of numerical model performance that will not be possible at most brine sequestration sites. CO_2-EOR based models of flow processes can be used to increase confidence in modeling for brine storage sites, however the complicating factors of oil-CO_2 interaction and fluid production add complexity. Factors such as the impact of large volume fluid displacement cannot be directly measured but the correctness of the underlying assumptions can be assessed through a combination of monitoring with 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 oilfield, Scurry County Texas (Romanak and others, 2010; Smyth and others, 2009). Similar studies at other fields are needed to determine if these conclusions are broadly applicable.

Lowered whole-project risks for early capture projects

Injection of CO_2 for EOR can simplify and reduce uncertainties for capital and risk intensive early capture projects. This option has been attractive to a number of capture projects sited in areas where CO_2 EOR is underway or planned in the near future (for examples, see press on NRG Parrish plant, Summit Energy, Air Products, Leucadia capture projects). The process of bringing a field under CO_2 EOR flood is well known in terms of design, cost, regulatory framework, property rights. Hand-off of CO_2 supply "at plant gate" can significantly reduce complexity of a capture project. EOR projects underway can accommodate large volumes of additional CO_2 during the early years of a project. As recycle begins to dominate, expansion of the project is the mechanism that can accommodate additional volumes of CO_2, however not all projects can be expanded. A pipeline network case study (Essandoh-Yeddu and Gulen, 2008) shows that is 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 plant is brought to balanced operation. Brine sequestration of fluctuating amounts of CO_2 is in possible and conducted at some test facilities (for example AEP Mountaineer capture plant in West Virginia) and planned at other test sites, however the impact of such fluctuation on the reservoir performance and equipment maintenance schedule is unknown. This is not necessarily a strong negative because EOR WAG projects design intermittent input of CO_2 by injecting water. However it is possible that for some markets intermittent supplies of CO_2 may be of decreased value as compared to on-demand CO_2 .

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 of the captured CO_2 into deep subsurface environments. CO_2 extracted from the reservoir as part of the EOR process is under current practices effectively all returned to the subsurface as recycle.

A key factor that must be considered in the effectiveness of CO_2 EOR as sequestration is the extent to which storage is permanent in the subsurface, as low rates of leakage over long time periods can result in unacceptable performance of a sequestration method with respect to the atmosphere. Inferential data suggests 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 recycle. The risk from these unfavorable factors require more research to determine frequency and magnitude of occurrence for input into lifecycle as well as effective monitoring approaches that allow risk to be effectively detected and mitigated. Site-specific risk assessment prior to injection for sequestration would alert the project planners to focus efforts to reduce 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 materials fabrication and installation are considered in lifecycle assessments The emissions from CO_2 EOR would be larger than corresponding emissions for sequestration (without production) in brine-bearing formations. Initial lifecycle assessment (Jaramillo and others, 2009) is based on production data and therefore considers CO_2 EOR as practiced historically, and does not consider the changes possible if sequestration became part of the EOR business. Mass balance considerations during the active phase of all sequestration efforts 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 is dependant on how the CO_2-A market develops. Minimum deployment will occur if (1) project developer confidence in future availability of CO_2-A is low, (2) cost of CO_2 to the operator 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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