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Comparing carbon sequestration in an oil reservoir to sequestration in a brine formation – field study

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Abstract

Geologic sequestration of CO_2 in an oil reservoir is generally considered a different class than sequestration in formations which contain only brine. In this paper, the significance and validity of this conceptualization is examined by comparing the performance of CO_2 injected into a depleted oil reservoir with the performance of similar injection into non-oil bearing sandstones using a field test at Cranfield Field, Mississippi as a case study. The differences considered are:

(1) Residual oil in the reservoir slightly reduces the CO_2 breakthrough time and rate of pressure build up as compared to a reservoir containing only brine, because under miscible conditions, more CO_2 dissolves into oil than in to brine.
(2) Dense wells provide improved assessment of the oil reservoir quality leading to improved prediction as well as verification of CO_2 movement in this reservoir as compared to the sparsely characterized brine leg. The value of this information exceeds the risk of leakage.

Assessment of the difference made by the presence of residual oil requires a good understanding reservoir properties to predict oil and gas distribution. Stratal slicing, attribute analysis and petrographic analyses are used to define the reservoir architecture. Real-time pressure response at a dedicated observation well and episodic pressure mapping has been conducted in the reservoir under flood since mid-2008; comparison measurements are planned for 2009 in down-dip environments lacking hydrocarbons. Model results using GEM compositional simulator compare well in general to measured reservoir response under CO_2 flood; imperfections in model match of flood history document uncertainties Time laps RST logging is underway to validate fluid composition and migration models. Monitoring assessing the performance of the wells during the injection of CO_2 suggests that the value of wells to provide field data for characterization exceeds the risk of leakage.

Keywords: Brine sequestration; depleted oil reservoir sequestration; real-time monitoring, compositional model history match.

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1. Introduction

Geologic sequestration literature such as the IPPC Special Report (2005) and the DOE Carbon Sequestration Road Map (DOE, 2007) divides sequestration sites into three main types: depleted hydrocarbon reservoirs, brine-bearing “saline” formations, and unminable coal seams. Unminable coal seams are clearly a separate type of storage, having a distinctive trapping mechanism and requiring its own types of capacity and risk assessment. However, hydrocarbon reservoirs are a subset of a regional brine bearing formation, representing the parts of the formation where geometry and fluid migration coincided so that economically significant hydrocarbon accumulated. Hydrocarbon reservoirs are formed of the same types of rocks and have the same types as seals as their host brine formations; CO_2 will move through and be trapped in essentially the same manner in both. Many hydrocarbon reservoirs have a water drive, meaning that as hydrocarbons are withdrawn by production, they are replaced by an approximately equivalent volume of brine. As oil or gas saturation decreases, the mobility of these fluids also decreases so that most depleted fields produce mostly water with a small percentage of hydrocarbon. Depletion is economically defined as the time at which the production of hydrocarbons produced diminishes to sub-economic levels. The result of these changes is that as hydrocarbon reservoirs are depleted, they become more like brine formations. However, hydrocarbon production commonly exceeds the rate at which brine can flow into the reservoir, resulting in pressure depletion in the production interval; this may be the most important common difference between a depleted reservoir and a brine formation.

Injection of CO_2 into a depleted reservoir can reverse the trends of pressure decline and decreasing production. Injected fluids (CO_2 plus in some cases increased brine injection) reduce or reverses pressure decline; miscibility of CO_2 and oil increases volume and decreases viscosity of remaining oil, increasing mobility. This process is known as CO_2 enhanced oil recovery (EOR). EOR provides a significant incentive for bringing depleted fields under CO_2 flood.

We undertake this study to consider how far the results of our current test in the depleted reservoir can be used to design a planned test in an essentially identical brine bearing site. Additionally current policy development both within the US and internationally is exploring how regulation and incentives should be applied to the classes of injection targets. It is therefore timely to consider what the differences are between the performance of CO_2 injected for EOR and CO_2 injected for sequestration only. We put aside the surface engineering issues of recycling CO_2 for EOR, such as separation, compression, and oil production and focus on the subsurface performance.

2. Comparing performance of an oil -bearing site for sequestration to a brine –only site

In this paper we test the extent to which the depleted reservoir and brine –only formations are similar and ways in which they differ. Our conceptualization is framed by comparing two field tests: a monitored EOR site where CO_2 injection begun in July 2008 into a depleted oil reservoir in the lower Tuscaloosa Formation at Cranfield Feild, Mississippi, and a brine test planed for mid 2009 where CO_2 will be injected into the down-dip, non-productive Tuscaloosa formation on the east side of this same field. This study is in mid-data collection for the EOR monitoring and in the middle of analysis for history matching, so that this discussion should be considered an interim report.

Cranfield Field, near Natchez Mississippi, discovered in 1943, is a simple anticlinal four-way closure and had a large gas cap surrounded by an oil ring (Mississippi Oil and Gas Board, 1966). The reservoir is in the lower Tuscaloosa Formation at depths of more than 3000 m. 3-D seismic interpretation shows that the reservoir is composed of stacked and incised channel fills and is highly heterogeneous vertically and horizontally, and that thickness variation of the key units is below the resolution of the seismic image, even using advanced techniques. Interpretation using seismic and open hole SP-resistivity and porosity permeability data from historic side-wall cores confirms this heterogeneity, but is of only modest use in developing needed reservoir models to extrapolate though the interval. Interpretation of modern log suits and whole core allows better definition of flow units, Average porosities of 25 percent and permeability averaging 50 millidarcy (mD), ranging to a Darcy (D). The Tuscaloosa Formation overlies a regional unconformity with some paleotopography; valley-fill-fluvial conglomerates and sandstones are complexly incised and aggregate to form a sheet-like basal sandstone unit. Chlorite, carbonates and quartz are major cements in these relatively immature sediments. Chlorite appears to play a role in preserving primary porosity and dissolution of framework grains and cements, in producing secondary porosity.

This lower sandstone complex, locally known as the “D” and “E” sandstones is the main oil-pay zone produced in the field. Overlying more aggradational fluvial and deltaic sandstones (known as units “A”,”B” and “C”) are separated by finer grained alluvial and overbank making them more discontinuous. Differences in depositional facies and diagenesis (compaction, cementation and dissolution) in “A” through “C” sandstone may play a role in lower porosity in these sandstones, which were not produced for oil, but were perforated for gas production on the crest of the anticline. The regional confining system is the thick dark gray to black marine mudrock-shale portion of the middle Tuscaloosa Formation; seal quality is demonstrated by hydrocarbon accumulation.

During original production, the field was produced to sub-economic water-cut by recycled gas drive (Mississippi Oil and Gas Board, 1966). Then the gas was produced to economic limit, and almost all wells were plugged and abandoned (P&A) in 1966. A strong aquifer drive is documented by return to near hydrostatic pressure before the current injection began, providing a unique situation for EOR, in that pressure and fluids have had more than 40 years to re-equilibrate. More commonly EOR follows a period of primary and secondary (water flood) production, and pressure and fluid compositions are highly perturbed from any equilibrium. The equilibrated condition at Cranfield provides an ideal study site to explore the fundamental differences between a depleted hydrocarbon reservoir and a brine-bearing formation as a host for sequestration.

Denbury Resources Inc. has unitized the Cranfield Field, drilled an array of new injection wells (figure 1) and re-entered formerly plugged and abandoned wells to become producers on the north side of the anticline for a carbon dioxide-enhanced oil recovery (EOR) flood. The field is being injected with CO_2 (no water) and the wells will produce by reservoir drive (no pumps). The combination of these conditions provide a uniquely favorable data-dense experimental setting for measuring pressure response to a large volume CO_2 injection. The first experiment conducted includes the initial seven injection wells, seven producers used for intermittent monitoring, and one dedicated observation well with real-time pressure observation at one-second intervals within the depleted oil ring.

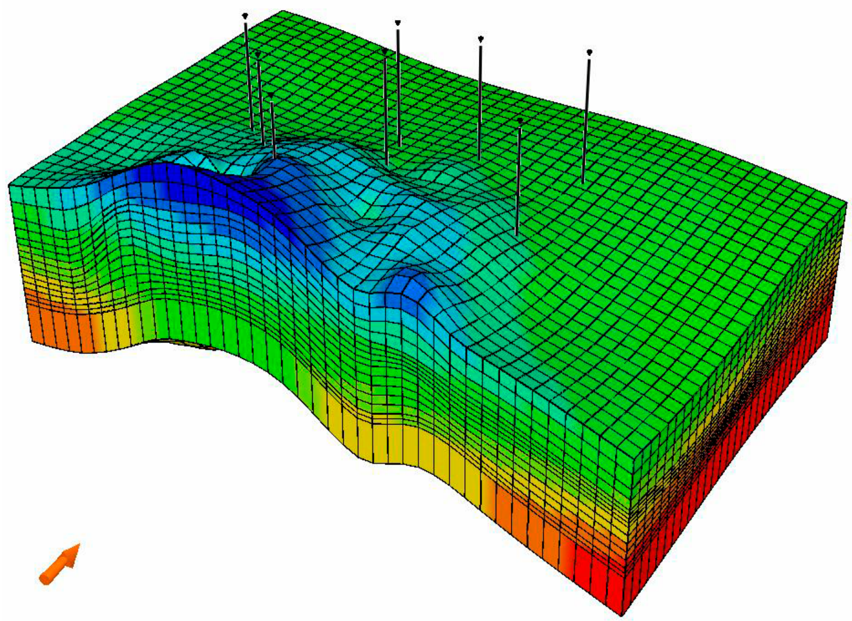

Figure 1. Reservoir model used for history matching the observed changes in the reservoir showing location of eight injectors. Model includes the northern half of the field. Arrow shows north, colors show depth.

Dense wells, production history, side wall and whole core porosity and permeability, petrographic and SEM study and analysis of a 3-D seismic survey of the oil reservoir quality provides input data to the reservoir model for this area. This area has been under CO_2 flood since mid-July 2008, with rates now at 500,000 tones per year. Real-time pressure response at the dedicated observation well and episodic pressure mapping has been conducted in the reservoir under flood. Initial history matching comparing measured pressure and modelled pressure is now possible. Saturation has been predicted and is used as basis for mobilizing to collect pulsed neutron (reservoir saturation logs, RST) to assess fluid saturation and change in saturation.

One disadvantage of the wells that produced this dense data is that whether new drills, re-entered to serve as producers or observation well, or left plugged and abandoned, all wells provide some risk of possible leakage. As is normal for production wells, only the lower part of the production casing was cemented in, above this the rock-casing annulus was left open. Cement bond logging shows that is it likely that some rock-casing annulus has been plugged by creep or spalling and matured 1945 drilling mud, others parts are open fluid-filled voids.

We have designed a monitoring program to assess if well leakage occurs in the study area as pressure increase in the injection zone and as CO_2 breaks through to wells. A 3 m thick, 100mD sandstone in the upper Tuscaloosa Formation that is correlated with little change over the northern part of the field is selected as a monitoring zone. This monitoring zone sandstone is about 100 m above the injection zone and above the main confining zone, the middle Tuscaloosa shale. The monitoring zone was perforated and a Panex pressure gage on wireline installed to measure pressure changes. In the first three months of the program, pressure has risen 550 psi in the injection zone but has not risen in the monitoring zone. The isolation of pressure to the injection zone interpreted as evidence of no significant fluid migration through the annulus at the observation well or at any of the10 1940'swells in the area of the elevated pressure.

A comparison study will be conducted in the down-dip east side of the field, below the oil rim in the water leg. This area is covered by the 3-D seismic survey, however there are no well penetrations in this area, so the reservoir properties in this highly heterogeneous system are poorly constrained until the injection well is cored. The injection in this area will be closely monitored using a multi-physics cross-well array. The brine-only conditions will provide the simpler fluid conditions to make rigours and quantitative measurements of saturation changes. One purpose of this paper is to consider how the information derived from the EOR study should be used to inform the design of the brine-only study: does the presence of hydrocarbon mean that the results of the EOR study must be greatly refined to apply to the brine-only study?

Model results using GEM compositional simulator in general compare well to measured reservoir response under CO_2 flood; imperfections in model match of flood history document uncertainties. Predicted pressure from the GEM model is compared with the measured pressure at representative wells in the field from 07/15/2008 to 9/11/2008. (figure 2) showing that the pressure trends are approximately as predicted, but reservoir heterogeneities not represented in the model result in local mismatches, one 25 psi higher and one 15 lower.

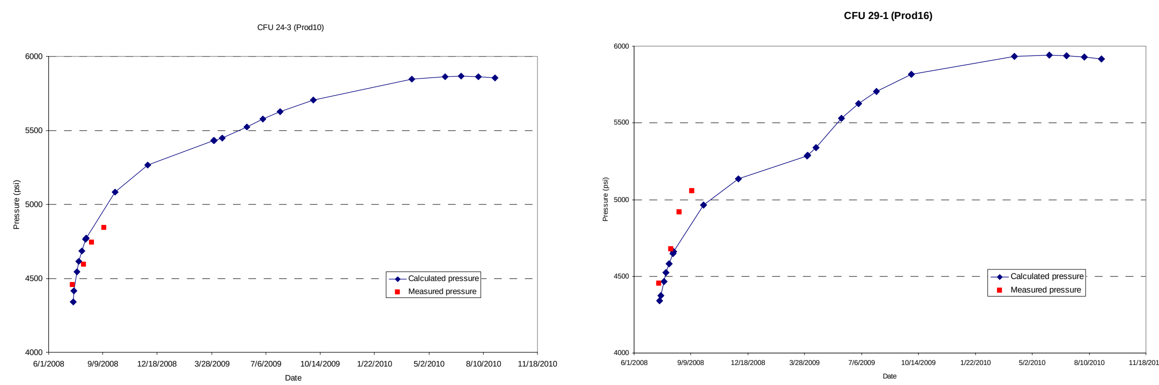

Figure 2. Comparison of pressure between calculated and measured values for CFU 24-3 (left) and CFU 29-1 (right)

Mobility of gas is modelled to be similar within the oil rim as within the same geometry filled with brine, below the resolution of quarterly sampling frequency (figure 3). Intermittent sampling using RST at production wells is planned. The sampling interval is to be guided by the model prediction to validate the model, and therefore repetitions are planned quarterly. However, the comparing the brine-only to the depleted hydrocarbon models show very similar fluid responses. It is unlikely that any retardation due to solubility of CO_2 in oil can be detected. Mobility of gas is modelled to be quite different in brine saturated reservoir than in a reservoir with residual gas, and appears to reflect complex interactions of relative permeability and compressibility. In the reservoir with a residual gas cap, the model shows that at about 9 months after initial injection, CO_2 moves updip toward the gas cap, increasing total gas saturation in some wells. This effect will likely not be observed in the field, as wells in the oil rim will be brought on production prior to this time, limiting pressure build up and CO_2 migration into the gas cap.

The model of water saturation (figure 4) also shows the similar response between the brine-only and residual hydrocarbon cases. Modelled residual hydrocarbon (oil and gas) start the water saturation at different points, however the change in water saturation, reflecting movement of CO2 though the model, are quite similar, especially in the wells in the oil rim.

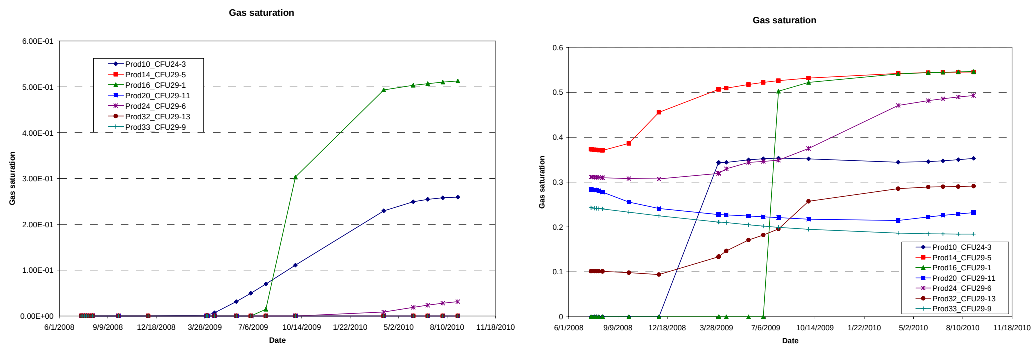

Figure 3. Modelled change in gas saturation (no production) in brine (left) and hydrocarbon reservoir (right) at production wells. Initial higher gas saturation in the hydrocarbon reservoir is reflects the presence of methane gas in the gas cap. As modelled, during injection increasing pressure concentrates methane and also adds CO_2 in updip wells. The later stages of field evolution will not actually occur as predicted in this model, as wells will be put on production.

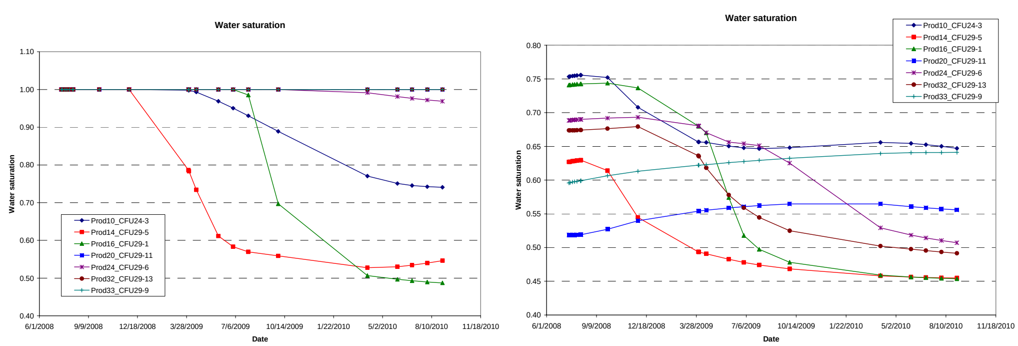

Figure 4 Predicted change in water saturation (no production) in brine (left) and water saturation in the presence of residual oil and gas (right). The main effect of hydrocarbons is that initial water saturation is reduced, but the pattern of displacement of water by CO_2 is similar.

Comparison of modelled increase in pressure at selected monitoring wells (figure 5) shows a subtle but significantly higher increase in pressure in brine than in model depleted oil reservoir, rinsing about 20-30 psi higher in the brine model. This small difference is lower that the errors observed between observed and modelled data because of model imperfections (figure 2), and therefore is expected to be unmeasurable.

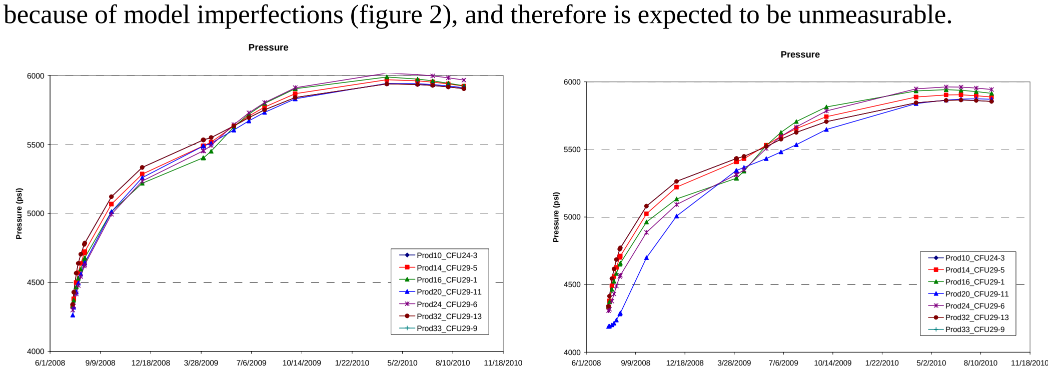

Figure 6. Predicted pressure increase (no production) in brine (left) and residual oil (right). In the real Cranfield case, as pressure increases, wells will start to produce and the pressure field will be strongly influenced by this effect.

Additional work planned includes continued monitoring of ongoing injection at the EOR site through 2009 and monitoring of large volume injection at the brine test site stating in mid-2009, which will allow direct comparison of the performance of these two settings. Monitoring at the EOR site includes continuous pressure measurement at the dedicated observation well in the injection zone and in the above-zone monitoring interval, and repeat RST logging to assess fluid composition and pressure changes. However, as pressure increases and wells begin to be put on production, the reservoir is expected to become increasingly dominated by production and no longer provide such a direct comparison with injection into brine with no production. The brine test site will make high resolution real-time cross-well measurements of pressure and fluid compositional changes during injection.

Continued model refinements are planned. Model refinements will reflect the results of sensitivity analysis that shows the key information that should be better constrained, improved characterization as more data are acquired and integrated into the model, and the improvements made as better production and injection history matches are attempted. Better upscaling and grid refinement are needed to predict breakthrough times and saturation changes at the relevant scales for the brine-only test.

3. Conclusions

Initial history matches in the lower Tuscaloosa Formation depleted oil reservoir that has undergone pressure recovery between the measured and modelled pressure response show that the reservoir model is reasonably validated for pressure. The model predicts that RST wireline log collection in the coming months will measure fluid changes. When these data are collected, comparison of measured with modelled fluid composition will further validate models.

Comparison of modelled differences between the residual hydrocarbon case and the brine-only case show small differences in pressure response and CO_2 breakthrough times to observation and production wells. A slight difference in the long term CO_2 movement in the gas cap as compared to the same model with brine-only is modelled, however it is unlikely that this effect will be observed because production will start, changing the pressure field. The pressure and saturation response of the current EOR monitoring test is a close analog to performance that would be expected in a brine-only situation. Small differences in increase in pressure and breakthrough of CO_2 to wells attributed to greater dissolution of CO_2 into oil than brine are below the range of experimental and modelling uncertainty.

Denser data available in the EOR setting is of value in characterization and reduction of uncertainty in this complex setting, and we plan to use the dense data to improve predictive capability. Initial months of above–zone monitoring to test well performance shows no significant pressure leakage.

This initial assessment of an on-going study suggests that the subsurface performance of an EOR site for CO_2 injection is very close to the performance of a brine only site, and can be used to guide test design in the downdip setting. This result also suggest that policy and market comparisons between brine-only and EOR sequestration should focus on differences in surface engineering, such as mechanisms to quantify and handle the role of separation, compression, and oil production in terms of carbon policy.

4. Acknowledgments

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