Characterization of CO_2 Injection Targets Through Core Analysis Using Technologies Developed for Hydrocarbon Reservoirs

Introduction

Carbon storage represents a substantial opportunity for permanent removal of CO_2 from the atmosphere. Opportunities to apply this technology are available globally with support from many governments and other organizations. To realize this opportunity, potential reservoirs must be thoroughly characterized to enable simulation of injection processes, various scenarios, and uncertainty analysis and fulfill regulatory requirements.

Much of the data required for this characterization is similar to that which has been gathered for nearly a century in oil and gas reservoirs. This similarity provides two key advantages to those exploring CCUS prospects: substantial data may already exist from previous hydrocarbon exploration in existing fields and laboratory procedures have been well established and proven for much of the critical well information. However, because the primary fluid, CO_2, interacting with the rock has changed, some confirmation is required to ensure that results can be transferred, and methods still apply.

This presentation summarizes the results of a joint industry project focused on evaluating core characterization procedures for CO_2 projects. Primary areas of research include assessment of confinement, impacts of reactivity in injection and confining zones, and relative permeability determination. Research in the study was centered on staged laboratory evaluations performed in \yearly cycles as directed by the members from the industry augmented by literature review and simulation activities.

Confining Zone Studies

The first year's focus priority was behavior of confining zones. Core material from five wells were acquired which represented potential seals. Rock types included dolostone and grainstones, mudrocks, calcareous sand and silt, and a lime mudstone from an unconventional oil reservoir selected as a tighter facies. Figure 1 below shows the planned testing program for each core sample with 16 total samples tested from the five wells. However, due to sample quality, not all test types could be performed on all samples.

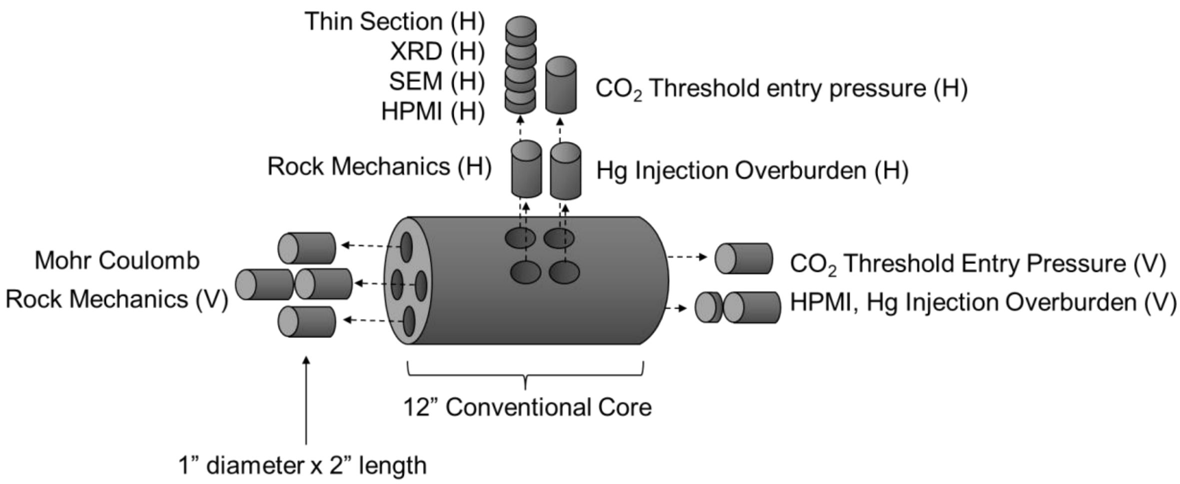

Figure 1 *Confining Zone Testing Protocol.*

The main goal of this characterization study was to determine whether methods for measuring and estimating entry pressure for oil and gas reservoirs could be carried over to CO_2 seals. Mercury injection data were analyzed with the Brooks-Corey model [1]. The intersection of this relationship with a wetting phase saturation of 100% is defined as displacement pressure. Once this value is corrected for clay effects using methods as defined by Juhaz [2], Hill [3] and Martin [4] and for reservoir fluids and conditions, this displacement pressure has been found to correlate well with physically measured threshold entry pressure. Fluid conversion was performed using a contact angle of 30° and interfacial tension of 30 dynes/cm which were used as an average value for supercritical CO_2 and brine as identified through a review of published data [5,6,7,8]. When this procedure was followed for the samples from this study, the same general agreement between estimated and measured entry pressure was obtained. Other independent studies performed outside of this project also confirmed this trend. For typical rock types, pressure at 10% nonwetting phase saturation P_{10} will be very close to displacement pressure and can be used if curve fitting is not desired. Standard relationships between porosity or permeability and entry pressure were also found to hold for quick estimation purposes. Figure 2 below shows an example dataset plotted against porosity with grey circles representing the study dataset, squares representing displacement pressure from a separate seal study, and circles representing direct threshold entry pressure measurement.

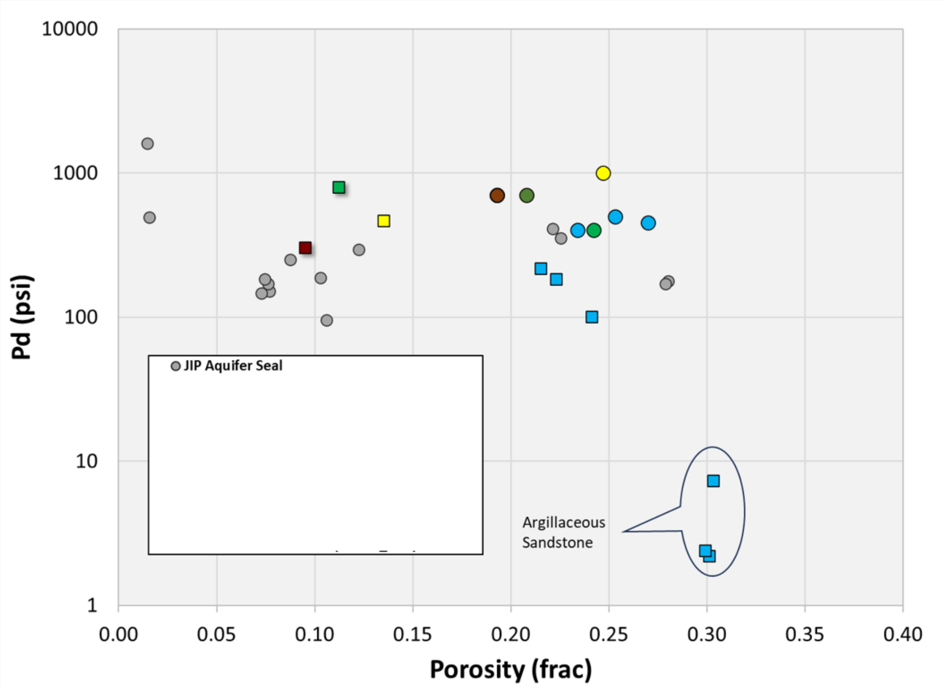

Figure 2 *Entry Pressure Determination by Various Methods*

Additional samples were also acquired for static exposure to CO_2-saturated brine at super critical conditions for periods of one, three, and six months. Even in the more calcareous samples, visual inspection revealed limited evidence of reactivity, and mercury injection profiles as illustrated in Figure 3 showed only minor changes which ultimately led to improved sealing characteristics.

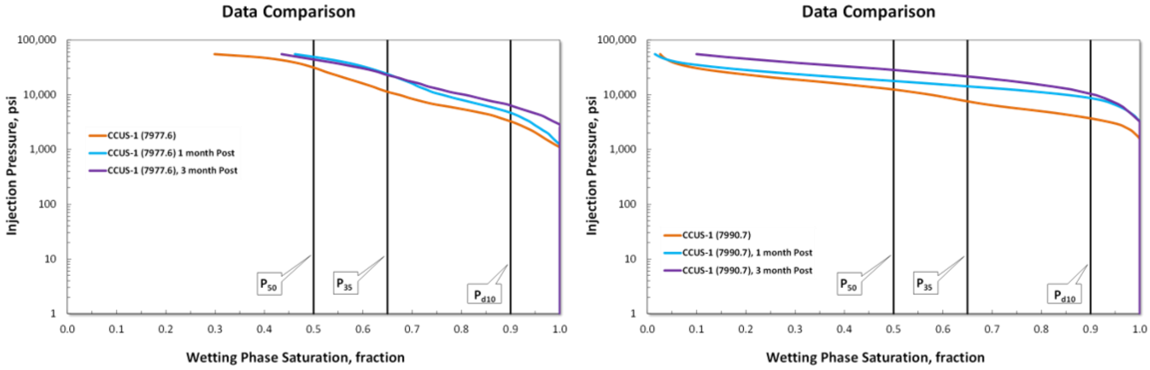

Figure 3 *Mercury Injection Profiles Before and After CO_2 Exposure*

Injection Zone Reactivity

Testing in the second year of the study focused on understanding how reactivity would influence the flow properties of injection zones. Due to the difficulties in finding reservoirs samples and to ensure consistency across the samples testing, twelve quarry rock samples were selected to pass through an organized testing sequence as illustrated in Figure 4. Testing processes centered on characterization performed before and after flowing exposure to CO_2 saturated brine to be able to see differences caused by the reactions. Green circles represent micro-CT measurements to provide additional visualization of the pore space within samples.

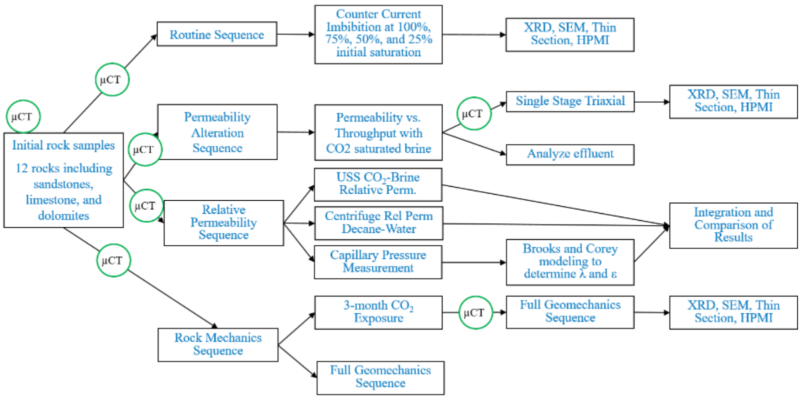

Figure 4 *CO_2 Reactivity Testing Sequence.*

Figure 5 below shows the exposure testing results for the Nugget sandstone sample which is characteristic of how most sandstone type samples behaved. All testing was performed at 150°F and 1500 psi to achieve supercritical conditions. Flow began with brine to establish an initial stable permeability. Then, the CO_2 saturated brine was injected for 5 days with effluent samples collected daily for further analysis. Afterwards, a final permeability to the original brine was measured including a measurement performed after reversing the flow direction to mobilize any fines that may have been created. Modest permeability reduction was observed for the sandstone samples tested. Observed final permeabilities are observed to be typically within around 10% of the initial value. Two of the eight sandstones showed higher decline of 33% and 61%. One dolomite sample showed a permeability reduction of 31%, and the other showed an increase of 24% due to the creation of limited wormholes. Both limestone samples showed permeability increase due to higher reactivity with one sample achieving an 80 times permeability increase resulting from the formation of a wormhole all the way through the sample. Comparison of the microCT images before and after exposure clearly showed the reacted areas and wormholes of the carbonate samples.

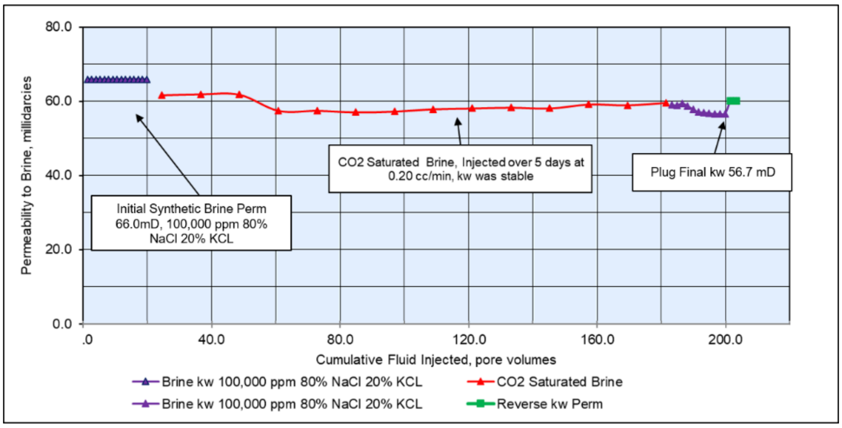

Figure 5 *CO_2 Reactivity Results for Nugget Sandstone.*

Relative Permeability Assessment

The last subject to be discussed is the possibility of using nitrogen as an alternative to CO_2 in relative permeability testing. Three of the quarried rocks from the previous testing program were selected for unsteady state permeability [9] measurement at supercritical CO_2 conditions to compare results with nitrogen and CO_2 displacing brine. All three rocks tested showed a close match between nitrogen and CO_2, especially when tested at the same temperature and pressure. Separate calculations were also performed using Brooks and Corey model [1] and digital rock analysis which also showed similar relative permeability relationships.

Conclusions

- Conventional evaluation methods for hydrocarbon reservoirs can be adapted to evaluate CO_2 injection targets which can significantly speed up some of the measurements such as relative permeability.
- Under static conditions, CO_2 reactivity effects are limited and tend to improve sealing properties.
- Flow of CO_2 saturated brine results in altered permeability in all rock types with calcite dominated facies showing potential for substantial alteration in the near wellbore region
- Nitrogen can be used as a proxy for CO_2 in testing where reactivity effects are ignored or undesired

References

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