SCA2003-22: TRAPPED VERSUS INITIAL GAS SATURATION TRENDS FROM A SINGLE CORE TEST

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ABSTRACT

When gas is displaced by liquid in porous media, the saturation at which gas becomes immobile is referred to as the trapped gas saturation. Trapped gas saturation magnitude is important in reservoir scenarios such as water invasion into a gas reservoir, WAG, or water flooding with pressure below the oil bubble point pressure.

Trapping is related to saturation history. Typically, to describe a relationship between final and initial gas saturation from changes in average or bulk core saturation, many tests with various initial gas saturations are required. Being able to gain similar information from a single test would provide time and cost benefits. This is the primary subject of this paper.

Tests were performed using carbonate core, live fluids, and reservoir conditions to evaluate trapped gas. Pressure was reduced below the oil bubble point pressure to evolve gas within the core. Oil and brine floods subsequently reduced gas saturation to a "trapped" condition. X-ray methods were used to quantify saturation changes in cores. In one test, three-phase saturations at various positions within the core were determined by an x-ray attenuation technique. Although the gas saturation profile after pressure depletion was non-uniform, this "non-uniformity" provided a range of "initial" gas saturations to compare with "final" gas saturations for various positions within the core. Additional data was gained by flooding the core with gas and then brine. The trend in trapped versus initial gas saturation from both data sets was well represented by the Land Correlation. After cleaning the core plug, another test was performed whereby the core was flooded with gas to displace brine. Subsequently, the core was flooded with brine to trap gas. Trapped versus initial gas saturation values for discrete positions along the length of the core fell upon the same trend as that from the more complex depressurization test. The technique of comparing gas saturation change from in situ saturation measurements appears to be particularly useful for providing enough data from a single test to describe a trapped versus initial gas saturation trend.

BACKGROUND

Gas trapping is important in reservoir engineering and prediction of recoverable reserves. Trapped gas saturation magnitude is important in reservoir scenarios such as water invasion into a gas reservoir, WAG, or water flooding to recover oil when reservoir fluid pressure is below the oil bubble point pressure. Trapped gas refers to the immobile gas saturation remaining after the rock is flooded with oil or brine.

Trapping is related to saturation history. To investigate scenarios whereby gas evolves from reservoir fluids during pressure depletion and is subsequently displaced by movement of reservoir liquids, one might consider performing laboratory corefloods with a depressurization step to evolve gas within cores, and subsequent oil and/or waterfloods to displace mobile gas. Various authors who took this approach found that their live oil remained super-saturated during depressurization such that gas saturation did not match behavior predicted by PVT data [1 - 6]. Hawes et al [4] reported that oil did not contact water-wet surfaces within their water-wet etched micromodel during depressurization tests using live oil and brine. As a result, difficulty of nucleating gas bubbles within oil ganglia resulted in very high levels of super-saturation. Danesh et al [5], during micromodel studies of solution gas drive using live North Sea fluids, found that the pressure at which gas first appeared within their micromodel as live fluids (oil and brine) were depressurized was typically 2.48 MPa below the oil bubble point pressure. Kortekaas et al [6] describe that formation of a new gas/liquid interface requires energy, and thus, the liquid has to be super-saturated (ie. at pressure below bubble point) for a gas bubble to form. Clearly it would be advantageous to monitor gas saturation directly during tests of this nature rather than using observations of downstream production and phase behavior to infer in situ saturations.

Others argue that gas injection is a useful alternative to complex depressurization experiments. Holmgren and Morse [1] resorted to this approach during trapped gas tests after finding that gas evolution didn't match phase behavior estimates to the extent and degree of repeatability necessary to obtain core saturations accurately. For Limestone cores of relatively uniform intergranular porosity, Stewart et al[2] found that laboratory measured gas-oil flow behavior is essentially the same for a test simulating solution gas drive as it is for one simulating an external gas drive. For cores of non-uniform porosity, they concluded that oil recovery by solution gas drive depended largely on the influence of pressure depletion rate on bubble growth.

Keelan and Pugh[7] found that gas trapping in carbonate cores sometimes depended on wettability. They resorted to using oil as the displacing fluid to yield trapped gas values representative of a strongly water-wet reservoir.

Suzanne et al [8] identified maximum trapped gas saturation by allowing cores to spontaneously imbibe a refined laboratory oil. From plots of saturation change versus time, they considered maximum trapped gas as the saturation at which the process driving saturation change switched predominantly from spontaneous imbibition to diffusion. They found that trapped gas results were influenced by porosity and clay content. Their tests were performed at ambient pressure and temperature.

Kalaydjian et al [9] reported that three-phase flow parameters are affected by the balance in interfacial tensions (spreading coefficient). Because interfacial tensions are affected by temperature and pressure, one might question whether trapping is also influenced by environmental conditions.

Land [10] proposed a relationship between final (residual or trapped) and initial gas saturation. Typically, to describe such a relationship from changes in average or bulk core saturation, many tests with various initial gas saturations are required.

Ideally one would like to measure in situ saturation changes at reservoir-like conditions to gain confidence in the results, and to have enough data to describe a relationship between final or trapped and initial gas saturation. Being able to gain such information from a single test would provide time and cost benefits. This is the primary subject of this paper.

TRAPPED GAS EXPERIMENTS

During the past several years, five trapped gas tests were performed to characterize gas trapping in chalk cores. Cores were of 3.8 cm diameter with lengths to 13 cm. Porosity ranged from 34-38%. Absolute permeability ranged from 1-7 mD. The cores exhibited water-wet behavior. During four reservoir-condition tests, initial gas was established through pore pressure depletion, causing gas to evolve within the cores from live oil and brine. Subsequent floods were used to reduce gas saturation to trapped conditions. In the fifth test, a brine-saturated core was flooded with gas to establish initial saturation conditions. The core was flooded with brine to trap gas. In all tests, changes in average core saturation were measured during various flood operations. The last 2 tests included measurements of in situ gas saturation profiles. Data analyses showed that reasonable trapped versus initial gas saturation trends could be determined from a single core test by comparing saturation changes at specific positions within the core. Although tests included measurements of hydrocarbon recovery from floods above and below oil bubble point pressure, this paper focuses on measurements related specifically to trapped gas.

Apparatus

Figure 1 is a simplified schematic of the trapped gas apparatus. Cores are mounted vertically in the coreholder. The coreholder and fluid separator are made of carbon fiber composite materials with low x-ray absorption properties. They were designed for measuring in situ core saturation distributions and separator fluid levels using x-ray potentials in the range from 35 to 100 kVp. Oil, brine, and gas saturations in cores are measured using linear x-ray scan techniques. Cesium chloride salt was added to the brine to enhance x-ray contrast between brine and other fluids. Specific details about the x-ray scanning technique are described in detail elsewhere [11, 12, 13]. Produced fluid volumes are measured by monitoring changes in fluid interface levels within the separator and by compensating for fluid volumes elsewhere in the flow system. The apparatus (coreholder, separator, valves, pumps, tubing) resides in temperature-controlled chambers. Fabric "windows" provide for x-ray transmission through the coreholder chamber.

Materials exposed to test fluids are corrosion resistant. The flow system forms a closed loop. The fluid separator holds 750 cm^3 of fluids. It serves as a storage vessel for test fluid (oil, brine, gas), a reservoir for pump fluids, and a produced-fluid separator. The

brine pump draws brine from a tube close to the bottom of the separator. The oil pump draws oil from either of two vertical tubes within the oil-filled portion of the separator. The lower tube is used when gas occupies the top portion of the separator. The gas pump draws gas from the top of the separator. Dual-cylinder Quizix® pumps are used for oil, brine, and gas injection. A large single-cylinder Quizix® pump controls the downstream pressure within the flow system. This brine-filled pump adds or removes brine from the separator to maintain constant downstream pressure, or to increase or decrease pore pressure. An ISCO® syringe pump controls confining pressure within the coreholder.

Remote-control valves (3-way, 4-state) control fluid flow paths within the system, as shown in Figure 1. Valve pairs at the inlet and outlet sides of the core provide for flow across a core face, change in flow direction through the core (such as upward brine injection for gravity-stable waterfloods of this work), and flow through tubing while bypassing the core. Valves are operated using the pump control software.

Live Fluid Tests With Pressure Depletion to Evolve Gas In Situ
Four tests were performed using pressure depletion to establish initial gas saturation in cores. As pressure is reduced below the oil bubble point pressure, gas evolves from live oil and brine within the core. The first 3 tests were performed at 130º C and the fourth at 121º C.

Cores were tested using restored-state techniques. After saturation with live brine, cores were flooded to residual brine saturation using live oil. Pore pressure was initially maintained at 37 MPa. This pressure is above the bubble point pressure of live oils used for these experiments. Following a 2-week aging period and measurements of fluid recovery with pressure above the oil bubble point pressure, pore pressure was depleted below the oil bubble pressure to evolve gas within the core. Depressurization (1 to 2.5 MPa/day rate) was accomplished by withdrawing brine from the separator using the large-volume pump that controlled pressure within the separator. During depressurization, fluids produced from the core could exit the bottom core face and flow to the fluid separator. Subsequently, saturation changes were measured during countercurrent imbibition and low rate oil and/or brine floods, concluding with waterfloods with frontal advance rates to 15 cm/day. Initial versus final (trapped) gas saturation results from these tests are listed in Table 1. These values represent average or bulk saturations for the entire core.

Gas Saturation Profiles, Test 4
Refinements in x-ray measurements and data analysis techniques [12] were used during the fourth test, yielding three-phase saturation data at specific positions along the length of the core. During depressurization, in situ saturation measurements revealed that gas saturation magnitude initially increased consistently throughout the core, but as pressure depletion continued, gas saturation increased significantly toward the top of the core compared to that toward the bottom face of the core (production end).

Saturation changes resulting from spontaneous and forced oil entry into the core were evaluated immediately after depressurization. "Spontaneous" increase in oil saturation was measured by monitoring saturation changes within the core while flowing oil across one face of the core while production from the opposite core face was blocked. This is depicted in figure 1 as "flow across face." By this method, if oil imbibes into the core, oil saturation increases. Displaced fluids are produced from the same face of the core from which oil imbibes, but in a counter-current direction. Forced oil entry, or viscous displacement of other fluids by oil, was tested by monitoring saturation changes within the core while flowing oil through the core. This is also depicted in figure 1. The objective was to mimic the approach and movement of an oil bank into the partially gas-saturated chalk in advance of a waterflood front. The core did not spontaneously imbibe oil following the depressurization step under conditions of residual brine saturation and moderate oil and gas saturation. Subsequently, when oil was injected through the core at very low rate, there was some redistribution of gas within the rock, but the oil flood did not appreciably reduce the average gas saturation within the rock. Spontaneous and forced brine imbibition were evaluated next in a similar manner. Ultimately, the core was brine-flooded with rate approximating a frontal advance of 15 cm/day. Gas saturation at the end of this step was considered trapped. Additional saturation measurements were recorded during a subsequent steady-state gas-brine relative permeability test before terminating the experiment.

Analysis of Trends from In Situ Gas Saturation Data of Test 4
As previously mentioned, during depressurization, gas saturation development within the core was non-uniform – with higher gas saturations toward the top of the core compared to the bottom. Where gas saturations were high, subsequent floods caused an appreciable reduction in gas saturation. Where gas saturation was relatively low, trapped gas saturation was closer to initial gas saturation. Could one compare pairs of initial versus final gas saturation from specific positions along the length of the core to describe a trend in final versus initial gas saturation, saving one from having to perform many tests on similar samples to describe such trend? To assess this question, final versus initial gas saturation data from in situ gas measurements of test 4 were evaluated to see whether a trend existed that compared favorably with a well-known relationship between trapped and initial gas saturation; the Land Correlation.

Figure 2 shows gas saturation immediately after depressurization was stopped and after subsequent floods that yielded final or trapped gas saturation. Note that the gas saturation varied along the length of the core plug, providing a range of "initial" gas saturations. Gas saturations calculated from x-ray measurements were generally considered accurate to within 0.03 saturation units (on a scale from 0.00 to 1.00, with 1.00 indicating complete saturation), although random changes in x-ray flux occasionally yield less accurate measures. For perspective, within this core, a change of 0.03 saturation units represents a change in fluid "thickness" in the x-ray beam path of approximately 0.4 mm. Circles around a couple of the data points on figure 2 mark data that is suspected of being inaccurate because they did not follow the trend. Additional

"initial" and "final" gas saturation data was available from the subsequent steady-state gas-brine test. From the steady-state test, saturation profiles with maximum gas saturation (gas to brine injection ratio of 1:0 at end of sequence with gas saturation increasing) and minimum gas saturation (gas to brine injection ratio of 0:1 from end of sequence with gas saturation decreasing) are shown on figure 3.

The data analysis strategy was to assume that final and initial gas saturation results could be paired for each position within the core, yielding far more data to define a trend compared to evaluations using only bulk or average saturation for the entire core plug.

The Land Correlation [10] is a relationship between final (S_{gf}, residual or trapped) and initial gas saturation (S_{gi}). It is a curve of characteristic shape that is approximated by:

$$1/S^*_{gf} - 1/S^*_{gi} = C \tag{1}$$

Effective saturations S^*_{gf} and S^*_{gi} are expressed as fractions of the pore volume excluding the fraction of pore volume occupied by the irreducible wetting phase. Once "C" has been determined, one might fit measured data according to:

$$S_{gf} = [S_{gi}(1-S_{wr})]/[1 + C(S_{gi}) - S_{wr}] \tag{2}$$

The first step in fitting data with the Land Correlation was to determine a value for the constant, "C". During trapped gas experimentation, residual brine saturation (S_{wr}) was approximately 0.25 (25% residual brine saturation), so this value was used in computations. Figure 4 is a plot of $1/S^*_{gf}$ versus $1/S^*_{gi}$ using data from the steady-state gas-brine test as well as data from measurements following pressure depletion (the 2 questionable data pairs from Figure 2 are omitted). The data was fit with a linear trend with slope of 1 to be consistent with Equation 1. The Y-intercept from this plot yields a value for "C." The next step was to plot the trend of S_{gf} versus S_{gi} from equation 2 and to compare it with the experimental data. This is shown on figure 5. The trend from equation 2 is shown as the solid curve. The difference between the dashed line and curve for a particular S_{gi} is an estimate of gas recovery. The trend fits the data reasonably well, except for the circled points. These points were previously identified as being of suspect accuracy.

Simple Trapped Gas Confirmation Test, Test 5
A fifth experiment was performed using a simpler approach to provide additional data for comparison. The core previously used in the fourth test was used for this experiment. The core was cleaned for a month using alternating cycles of toluene and methanol extraction within a Dean Stark apparatus. Following the final cleaning cycle with methanol, the core was dried in a 60º C vacuum oven. Test fluids were brine (doped with cesium chloride) and the same gas mixture that was used in preparing live oil for the fourth test. Test fluids were equilibrated at test pressure and temperature conditions. In keeping with the concept of a "simple" test, test conditions were moderate: 7 MPa pore

pressure, 9.75 MPa confining pressure, and 79º C temperature. Saturation profiles within the core were determined from x-ray scans.

After saturating the core with live brine at test conditions, the core was gas-flooded with rates to 20 cm^3/hr. Figure 6 shows the gas saturation profile after injecting 8.9 pore volumes of gas. Note the strong end-effect near the outlet face where brine saturation was high because of capillary retention of brine. Next, the core was flooded with 2.3 pore volumes of brine with rates approximating a frontal advance of 15 cm/day. The gas saturation profile after brine injection is also shown on Figure 6. Average initial and final (trapped) gas saturation results from this test are listed in Table 1.

Final (trapped) versus initial gas saturation results were compared for each position along the saturation profiles of Figure 6. Results are plotted on Figure 7 (labeled in the legend as "Gas & brine floods"). Figure 7 also shows final versus initial gas saturation results from average saturation data of Table 1 (labeled in the legend as "From bulk sats, Tests 1-5"), in situ saturation measurements from the fourth depressurization test, the Land fit to the depressurization data of Figure 5, and data from Keelan and Pugh's paper [7] for chalk-like cores. All data results follow a similar trend.

DISCUSSION

Ideally, one would expect gas to evolve from live oil within a coreflood system as a function of pressure identically as predicted from PVT measurements. For those unfamiliar with isothermal phase behavior measurements, PVT measurements on live hydrocarbons (brine is typically excluded) are tested by changing pressure and measuring oil and gas volumes within a cell that is vigorously rocked or agitated between measurements. Vigorous agitation is necessary to equilibrate the fluids to attain repeatable results. In contrast, corefloods are typically conducted with a static set-up and relatively quiescent fluids. Gas evolution during these depressurization tests did not identically match behavior predicted from PVT measurements. From x-ray measurements to determine fluid contents within the fluid separator and core, gas did not appear in the coreflood system until pressure was more than 2 MPa below the oil bubble point pressure predicted from PVT data. Had saturation changes been inferred by comparing fluid production from cores with phase behavior predictions, significant error would have resulted. In this case, monitoring saturation changes via x-ray measurements provided particular benefit.

Although gas saturation profiles after pressure depletion and unsteady-state gas injection were non-uniform, this "non-uniformity" provided a range of "initial" gas saturations to compare with "final" gas saturations for various positions within the core. Referring to Figure 7, it is interesting to note that average gas saturation results from Table 1 fall close to trends described by in situ gas saturations of test 4 or 5. Also of interest is the observation that, at least for these measurements, similar trapped versus initial gas saturation trends occurred whether initial gas saturation was placed in the core by depressurization or injection. Primary difference was that depressurization provided data

for low- to moderately-high gas saturations whereas, when gas was flooded into the core, much of the data was for moderately high gas saturations.

The technique of comparing gas saturation change from in situ saturation measurements appears to be particularly useful for providing enough data from a single test to describe a trapped versus initial gas trend. The depressurization technique seems to offer potential for reasonably describing trapped gas for low initial gas saturations as gas evolution likely occurs in pores of all sizes during depressurization. In contrast, if one were to inject gas into a core in an attempt to establish low initial gas saturation, it is questionable whether gas would invade pores of all sizes and whether subsequent floods would yield trapping behavior similar to that from flooding after depressurization.

CONCLUSIONS
The following are conclusions from this work:
1. Comparing gas saturation changes for discrete positions within a core appears to provide sufficient data to describe the trend in trapped versus initial gas saturation from a single core test. Advantages of this approach include reduction in number of tests necessary to describe the trend and improved confidence in results.
2. The technique is suitable for tests with live fluids and reservoir-like conditions, regardless of whether initial gas saturation is established through depressurization of live fluids or by gas injection.
3. By measuring in situ saturation changes directly, data interpretation problems related to oil super-saturation effects are avoided.

ACKNOWLEDGEMENTS

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Table 1. Initial and final (trapped) gas saturation results from bulk saturation changes.			
Test	Description	S_{gi}, fraction	S_{gf}, fraction
1	Live fluid depressurization, floods	0.17	0.17
2	Live fluid depressurization, floods	0.31	0.21
3	Live fluid depressurization, floods	0.29	0.21
4	Live fluid depressurization, floods	0.20	0.17
5	Gas-Brine floods	0.42	0.21
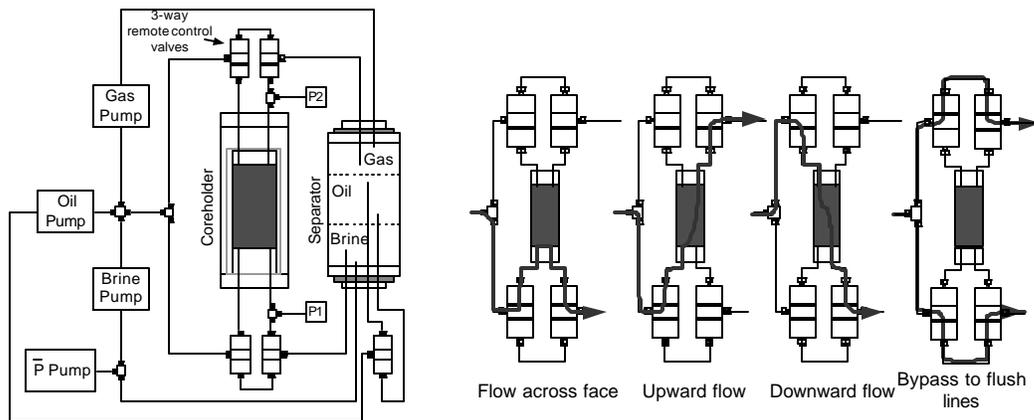
Figure 1. Simple schematic of flow system and valve operations.
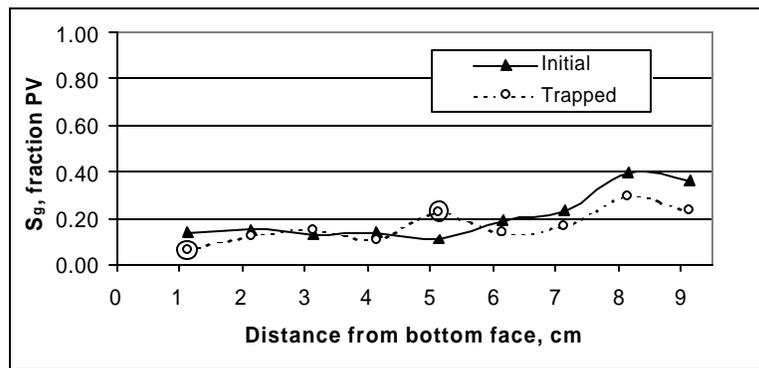
Figure 2. Initial gas saturation following depressurization and trapped gas saturation after subsequent oil and brine floods. Circles show questionable data.
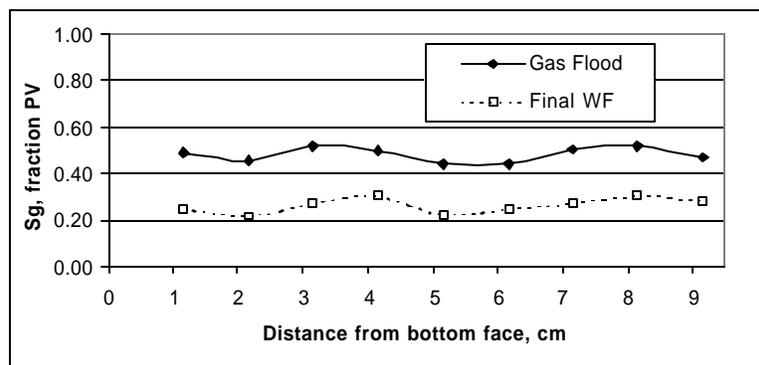
Figure 3. Maximum and minimum gas saturation profiles during steady-state gas-brine relative permeability test.
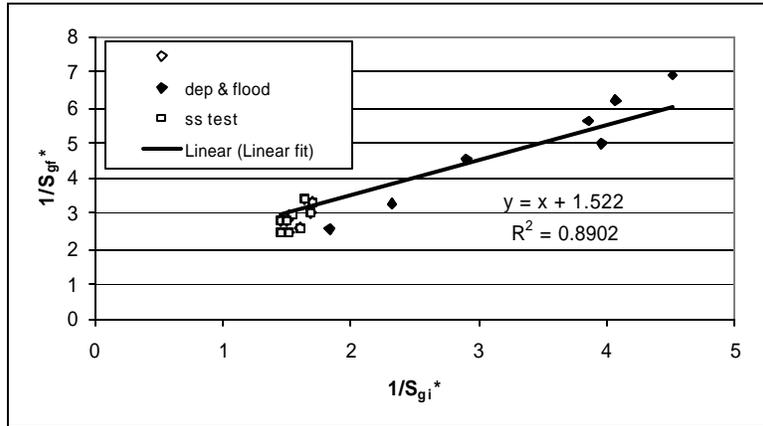
Figure 4. "C" determined using data from figures 2 and 3.
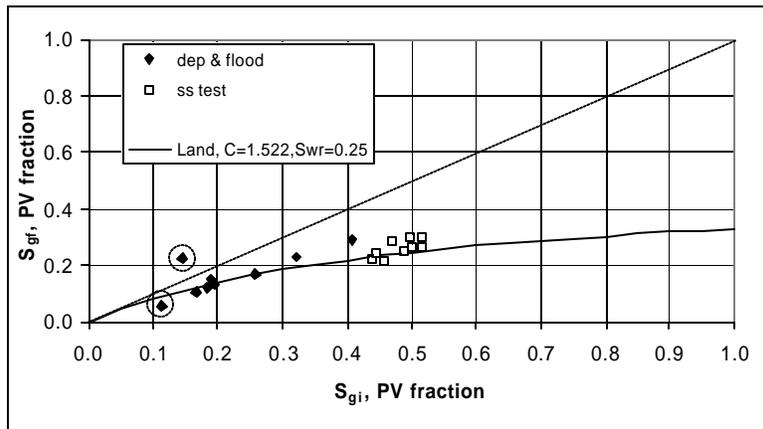
Figure 5. Comparison of Land Correlation with in situ saturation data from test 4.
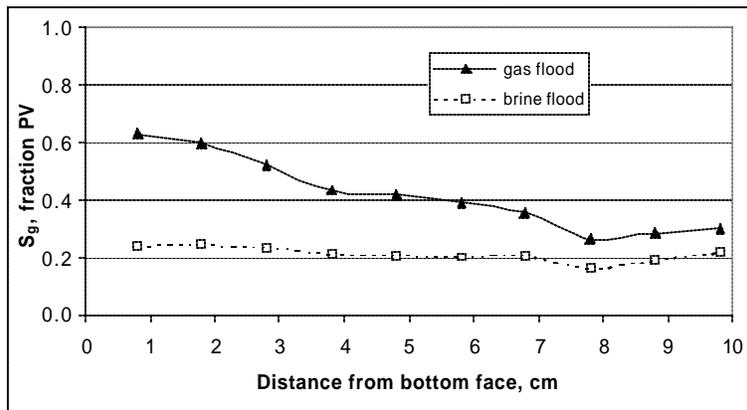
Figure 6. Saturation profiles during simple gas-brine trapped gas test.
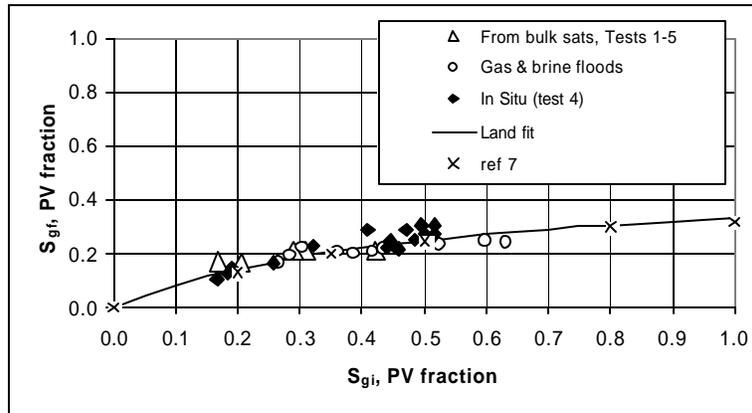
Figure 7. Final (trapped) versus initial gas saturation from average saturation and in situ saturation measurements. Data from reference 7 is for chalk-like rocks.