MOVEMENT OF CONNATE WATER DURING WATER INJECTION IN FRACTURED CHALK

By
E. A. Spinler and D. R. Maloney
Phillips Petroleum Co.

Abstract

The movement of connate water can be important in enabling or blocking contact between chemicals in injected water and the moveable oil. Likewise, the complete displacement of connate water is normally assumed for the flushed zone in well log interpretation. Unexpectedly, our investigation showed that most of the connate water in fractured low permeable rock was not viscously displaced by injected water. Flow tests were conducted with a highly water-wet Kansas outcrop chalk plug fractured along its axis. X-ray was used to monitor the movement of only connate water in the chalk matrix. Injected water in the fracture was observed to not outrun the imbibition front in the matrix. Water production at the outlet face of the plug did not occur until oil displacement was near completion. Most of the connate water was not banked by the imbibition process although some banking was observed. Continued water injection indicated that diffusion of the connate water salt from the fluids in the chalk matrix into the fluids flowing in the fracture appeared to be the most significant contributor to the movement of connate brine.

Introduction

The replacement of connate water by injection water in a reservoir is a miscible displacement process that can become important for many reasons. Two of the more common include: 1) using the injection water as a carrier for chemicals to contact the mobile oil phase for improving oil recovery, or 2) assuming that complete displacement of the connate water by drilling fluids or injection water to determine the resistivity for conventional well log interpretation. Classical displacement studies indicate that the connate water is readily displaced by injection water. Russel, et al[1] concluded that more than 80% of the water content in a core was displaced with one pore volume of injected water. Brown[2] concluded that the connate water forms a zone that displaces oil and separates the invading floodwater from the continuous oil phase. Their work was done in relatively homogenous sand packs or sandstone. The experiments reported herein show that neither one of those conclusions may be true when sufficient heterogeneity exists parallel to the direction of displacement.

Two tests were conducted with fractured chalk rock. The chalk itself is very homogeneous material and an extreme in heterogeneity occurs when the chalk is fractured. An initial test identified the flow characteristics of a fracture parallel to the flow direction using magnetic resonance imaging (MRI). A second test was used to confirm the results of the initial test and provide X-ray images of the connate water displacement. Since fractures and other heterogeneities exist in many carbonate reservoirs, these experimental results suggest assumptions of complete and rapid displacement of connate water by injected water may have to be reexamined for such reservoirs.

Results and Discussion

Equipment, Materials, Methods Kansas outcrop chalk was selected as the porous medium. Its physical properties are listed in Table 1 and are typical for some chalk reservoirs having low permeability and high porosity. Since the rock was outcrop material and had not been exposed to crude oil, it was believed to be highly water-wet. The fracture in the chalk was created by breaking the plug parallel to its axis and offsetting the broken pieces (under light applied pressure) approximately 0.16 mm (1/16 inch) to create a flow path for fluids. An epoxy coat was then applied to hold the broken pieces in place. When saturated with brine, MRI was used to characterize the fracture. The rough appearance of the fracture can be seen in Figures 1 to 3. The fracture properties are also described in Table 1 and are similar to those described for typical tectonic fractures in some chalk reservoirs[3]. The permeability enhancement from the fracture when scaled up to a highly fractured reservoir (by assuming a 0.0283 m^3 (1 ft^3) block was a representative fracture to matrix density) was 13.7 times greater than the matrix permeability.

In the initial test, the fractured plug was saturated with 45,000 ppm potassium chloride (KCl) brine and desaturated with n-decane via centrifuge to an initial water saturation of 16 %. End pieces were then attached to the plug allowing for an open fracture at the inlet and outlet ends. North Sea water (containing no potassium, K+) was injected from one end at a rate of 5 ml per hour (which was equivalent to a displacement rate of 1-2 feet/day) at a pressure gradient of 0.9 psi per foot. Samples were collected via an automatic sample collector and analyzed for their K+ content to determine the production of the connate water. Following the test, the end pieces were milled off and the remaining fluids and salts extracted. The plug was dried for further testing.

For X-ray imaging during test 2, the connate water was doped with 15% by weight potassium iodide (KI) to provide brine with high X-ray absorbing properties. The rock sample was placed horizontally on the X-ray scanning rack and rotated so that the fracture plane was slightly tilted with respect to the direction of X-ray exposure. This was done to make the fracture easy to see in X-ray images while maintaining intensities of X-rays that passed through the fracture region at reasonable levels. An image intensifier was used to gain 2-D images of the rock. The image intensifier provides 'shadow' images from X-rays that pass through the entire sample rather than through a slice. Calibration scans were conducted by scanning the sample through plastic cells filled with KI brine, deionized water, and n-decane. These scans provided guidance on how to optimize X-ray settings.

For the X-ray tube settings employed, deionized water (to be used as the injection water) and n-decane have similar X-ray absorption characteristics. Thus, for this experiment, changes in the brightness of X-ray images (gray scale intensities) are related to changes in connate water saturation. Images range from dark to light as the concentration of the doped connate water in the rock decreases. Good images were obtained with the following X-ray settings:

Tube: 80 kV, 0.8 mA, 0.4 mm focus
Distance X-ray tube from sample: 50 cm
Distance Image Intensifier from sample: 50 cm
Image Intensifier mode: 22 cm mode (1.5 x electronic magnification)

A baseline image was obtained when the rock was 100% saturated with 15% KI brine. The core was centrifuged in n-decane to 18% brine saturation. After achieving this saturation condition, flow end-pieces were attached to the ends of the rock. The core was placed back on the X-ray rack in the same previous position for imaging the displacement test. Deionized water was injected in one end at a rate of 5 ml per hour to duplicate the first test. Samples were collected with an automatic sampler and analyzed for their iodide (I-) content to determine the production of the connate water.

Results Waterflood Test 1 Fluid production from the waterflood of the plug was only n-decane until water breakthrough and essentially only water thereafter (Figure 4). Based on the previously referenced laboratory studies, it might be expected that most of the connate water would be banked to the end of the plug and subsequently readily displaced. However, after 10 PV of injection, the analysis for K+ as the tracer for connate water indicated that production of the connate water was only about 50% complete (Figure 5). The potassium salt from the connate water showed up with the first water samples and was found in all later water samples. The test was stopped, unknowingly, without producing more of the connate water since analytical results were not available for several weeks.

Results Waterflood Test 2 The fluid production results from the 2nd waterflood of the fractured plug were like the first test. Only n-decane was produced until water breakthrough and essentially only water thereafter (Figure 6) with I- showing up in all samples with water. I- was used as the tracer in test 2 because it was less susceptible to possible ion exchange than K+, a possible cause of the delayed connate water production. The production of connate water as measured in the effluent water peaks at 1.7% after about 80 ml of produced fluids and declines thereafter (Figure 8). The test was stopped after 16 PV of injected water for practical reasons with 80% of the connate water produced. To obtain an estimate of the production of the remaining connate water, the decline trend was matched with an exponential equation. Summing the measured data and using the extrapolated trend, the cumulative production of the connate water showed an excellent material balance with the original material balance estimate of the quantity of connate water in the plug. The cumulative production of the connate water salt based on analysis for I- and the extrapolated curve fit is shown in Figure 9 as a function of the produced fluid volume.

X-ray images were also analyzed to quantify changes in connate water saturation. Average gray scale intensities at each horizontal pixel position were computed for each X-ray image to obtain changes in bulk connate water saturation with pore volumes of waterflood water injected. Note that the X-ray images along the upper and lower edges were trimmed because they were too bright. The thickness of the chalk sampled thinned along these edges due to its cylindrical shape**.**

X-ray scans were recorded at various times over a 4-day period, as the plug was waterflooded with de-ionized water. Although a 5-psi differential pressure transducer was plumbed into the flow system to measure the pressure drop across the sample, the pressure transducer range was exceeded immediately upon starting the waterflood test. It was later determined that the flow ports in the inlet and outlet end-pieces were centered slightly above the plane of the fracture and, unintentionally, the end pieces had been bonded across each core face instead at positions along the outer edges of the core faces (Figure 7). Consequently, fluid entry and exit locations were more like a point source and point sink rather than large areas of coverage. This was true for the upper portion of the plug, but the lower portion was separated by the fracture, so that water had to cross the fracture to displace n-decane or connate water in the lower portion. Despite conditions that caused a large entry pressure on the upstream side of the sample, the pressure drop across the length of the fractured rock was believed similar to the initial test.

Figures 10 through 14 show changes in bulk connate water saturation as a function of pore volumes of waterflood water injected. The movement of connate water during the waterflood is seen by comparing the progression of images. Only selected images are included. The saturation profile as shown at the top of each figure represents the average 1-dimensional connate water saturation at that pixel position. A change in image color from dark toward light in a particular image region corresponds to a decrease in connate water saturation or concentration in that region. Likewise, darkening in a particular image region corresponds to an increase in the concentration of doped connate water.

Observations The initial image was normalized at 18% water saturation (Figure 10). The following image at 0.01 PV injected (Figure 11) shows the noise level and/or the initial perturbation from injection. Some banking of the connate water was observed in the following images during imbibition with the bulk of the connate water being disturbed but not significantly displaced. The front of the observed bank represents the imbibition front and the rear represents injection water and relatively immobile connate water. Images at 0.09 and 0.23 PV injected (Figures 12, 13) show that the development of a radial front with an elliptical shape and then a more piston-like shape when the outer edges of the pattern reach the outer edges of the core. Note that the connate water moved both above and below the fracture, even though the point of injection was slightly above the fracture plane. Water did not race through the fracture ahead of oil production. The first show of produced water occurred after 0.63 PV of water had been injected (Figure 13). Little if any additional oil was produced after water breakthrough. When the test was stopped after 16.56 PV of water injection (Figure 14), the connate water had been completely removed from only the first half of the plug.

Although the connate water moved within the rock, the bulk volume or average saturation of connate water within the plug did not change appreciably until after water breakthrough. Figure 15 summarizes the change in connate water saturation within the plug for test 2 for both the X-ray images and the produced fluids. The comparison is very good considering that the X-ray images are trimmed along the upper and lower edges to obtain high quality images. The slight increase in bulk connate water saturation after 1 pore volume of waterflood water had been injected probably represents movement of connate water into the imaged region of the core from edges of the core that were not imaged.

An interpretation of the decrease in connate water saturation in the plug following the end of imbibition is that the primary mechanism for displacement of the dissolved connate salt may be diffusion. Displacement in the lower half of the fractured plug was limited to spontaneous imbibition, a small viscous gradient and diffusion. This was a consequence of the inlet and outlet ports for injection and production being positioned slightly above the fracture, effectively isolating the portion of the matrix below the fracture from any possibility of significant viscous pressures. Since similar events were observed in the chalk matrix both above and below the fracture, the displacement of connate water in the matrix above the fracture was also dominated by the same mechanisms. Examination of the X-ray profiles shows evidence consistent with diffusion. Circled area 1 of Figure 16 near the inlet of the plug shows a decreasing concentration of connate water with additional injection. If viscous forces were operative, the profile would not only decline, but should displace to the right (the direction of flow). Circled area 2 at the outlet of the plug shows a bank of connate water at the end of imbibition as displaced by the imbibition process (0.63 PV). At a later time (0.94 PV), this bank decreases in peak concentration and spreads, requiring some of the connate water to be displaced opposite to the direction of flow. This appeared to be diffusion-like behavior.

Discussion Contacting the continuous oil phase can be critical to improving the displacement efficiency for some chemical enhanced oil recovery processes. The experiment shows that for fractured chalk reservoirs, the injected water and the chemicals it may contain could contact the continuous oil phase and consequently may be able to improve oil recovery.

The lack of movement of most of the connate water under spontaneous imbibition suggests that only a portion of the water was mobilized like a classical miscible displacement. This result was unexpected. Additional experimental work may be required to understand this phenomena.

The low permeability of the chalk and the low viscous gradient allowed diffusion to dominate the fluid movement in the chalk matrix. Consequently, the apparent production of connate water as opposed to injection water from a fractured reservoir may be due more to diffusion rather than viscous displacement.

The presence of significant connate water in the chalk matrix after multiple pore volumes of water injection has potential implications to well log interpretation of fractured waterflooded zones. The near-wellbore flushed zone measurements following drilling usually assume complete viscous displacement of the connate water by the mud filtrate. This test indicates that much of the connate water may still be near the wellbore and therefore affects the assumed water resistivity used for well log interpretation of water saturation. The consequence of a mixture of a less saline mud filtrate and connate water would be to calculate higher residual oil and vise versa for a more saline mud. Mixed water will also affect well log interpretation deep in the reservoir. Areas of the reservoir that do not see enough pore volumes of water for complete displacement of the connate water would continue to have a mixture of connate water and injected water. Well log interpretation for drilled wells encountering such water-flooded zones would be affected.

Conclusions

1) The injected water in the fracture did not outrun the imbibition front in the chalk matrix. Only oil production and no water production occurred from the fracture at the outlet of the plug until imbibition was near its endpoint.
2) Most of the connate water was not displaced by imbibition of injected water and remained dispersed within the chalk matrix. Some banking of the connate water was observed.
3) The primary displacement mechanism of connate water after imbibition appeared to be diffusion of the dissolved connate water salt from the chalk matrix fluid into the fracture fluid.

Acknowledgment

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Nomenclature

cm	Centimeter
ft	Foot
I-	Iodide
K	permeability
mA	Milliampere
md	Millidarcy
ml	Milliliter
mm	Millimeter
psi	Pounds per square inch
PV	Pore volume
Sw	Water saturation
%	Percent

KCl	Potassium chloride
K+	Potassium ion
KI	Potassium iodide
kV	Kilovolt
m	Meter

References

1) Russel, R. G., Morgan, F., Muskat, M., "Some Experiments on the Mobility of Interstitial Waters," *Trans AIME*, (1946) 170, 51-61.

2) Brown, W. O., "The Mobility of Connate Water During a Water Flood," *Trans AIME*, (1957) 210, 190-195.

3) Da Silva, F., "Primary and Enhanced Recovery of Ekofisk Field: A Single- and Double- Porosity Numerical Simulation Study", *SPE paper 19840*, (1989).

Table 1

Kansas Chalk Plug and Test Properties

Property	Value	Comments
Length (cm)	7.1	1
Diameter (cm)	3.8	1
Porosity	34%	1
Pore Volume (ml)	27.9	1
Initial Water Saturation	16%	1
Residual Oil Saturation	26%	1
Injected Flow Rate (ml/hr)	5	
Equivalent Reservoir Flow Rate (ft/day)	1	
Infractured Plug Pressure Gradient (psi/ft)	112	2
Fractured Plug Pressure Gradient (psi/ft)	0.9	2
Unfractured Plug Water K at Sor (md)	0.49	3
Fractured Plug Water K at Sor (md)	63.7	3
Plug Permeability Enhancement	130.7	
Reservoir Permeabilty Enhancement	13.7	4
Fracture Thickness (microns)	<300	5
Est. Fracture Volume to Pore Volume	<0.31%	6

1. Chalk matrix only
2. At 5 ml/hour injection rate
3. Based on measured pressure drop
4. Permeability enhancement for 1 cubic foot block
5. Estimated based on visual and MRI images
6. Calculated for 1 cubic foot matrix block

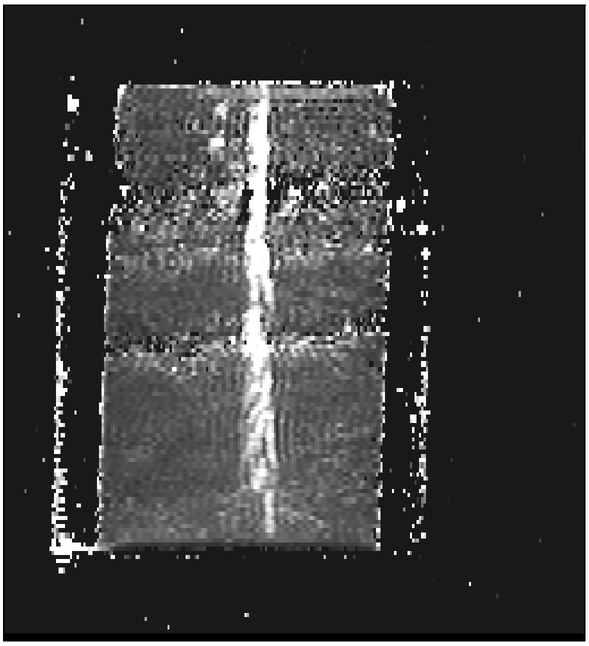

Figure 1 MRI image of the epoxy coated plug saturated with 100% KCl brine showing a side view of the fracture and internal heterogeneity.

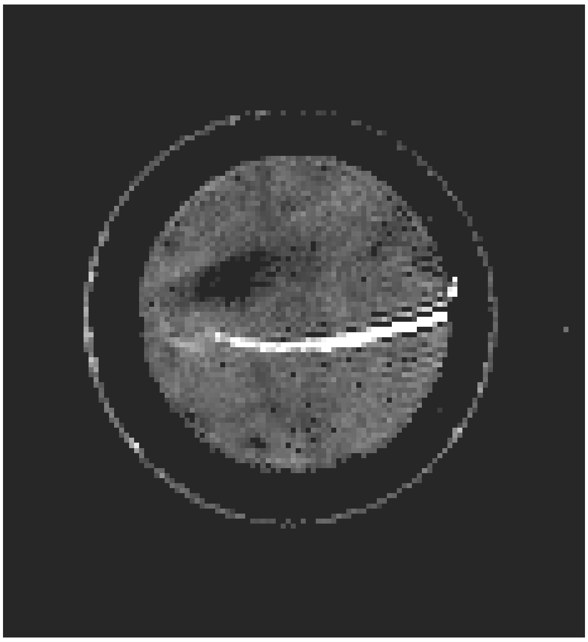

Figure 2 MRI image showing an end view of a slice through the fracture. The outside ring is the outside of the epoxy coating.

Figure 3 MRI image showing a top view of the fracture and providing an indication of fracture width with brighter areas indicating more fluid in the fracture.

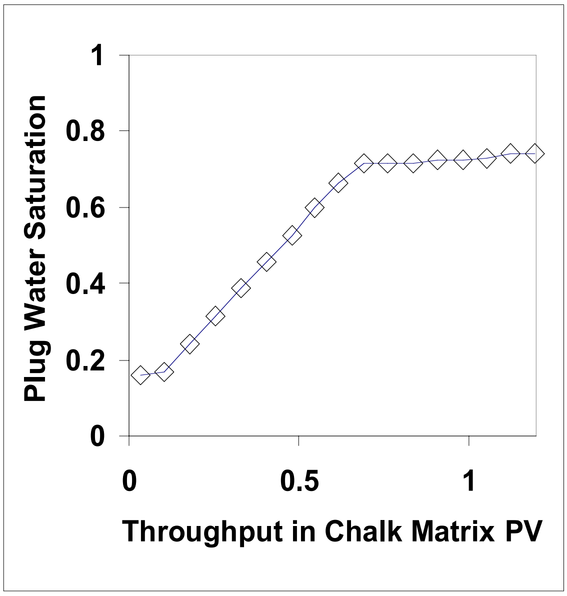

Figure 4 Saturation history for initial test in fractured chalk plug showing little water production after water breakthrough.

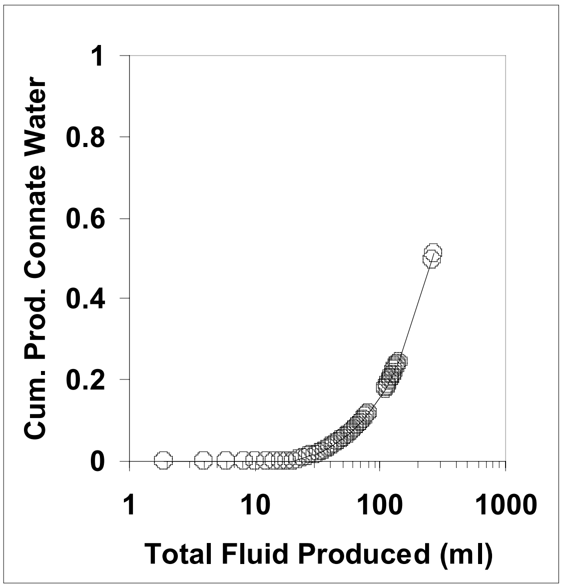

Figure 5 Cumulative fraction of the connate water produced based on sampling.

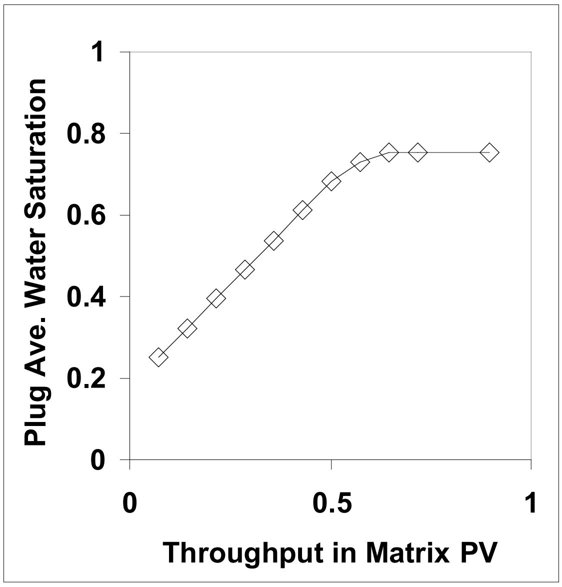

Figure 6 Saturation history for test 2 in fractured chalk plug showing similar behavior to the initial test.

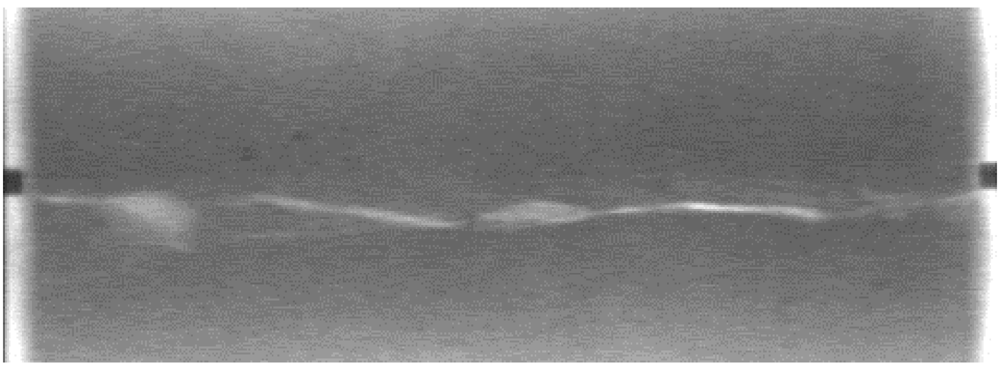

Figure 7 X-ray image of the fractured Kansas outcrop chalk plug showing position of the inlet and outlet ports (the dark spots at the ends of the plug).

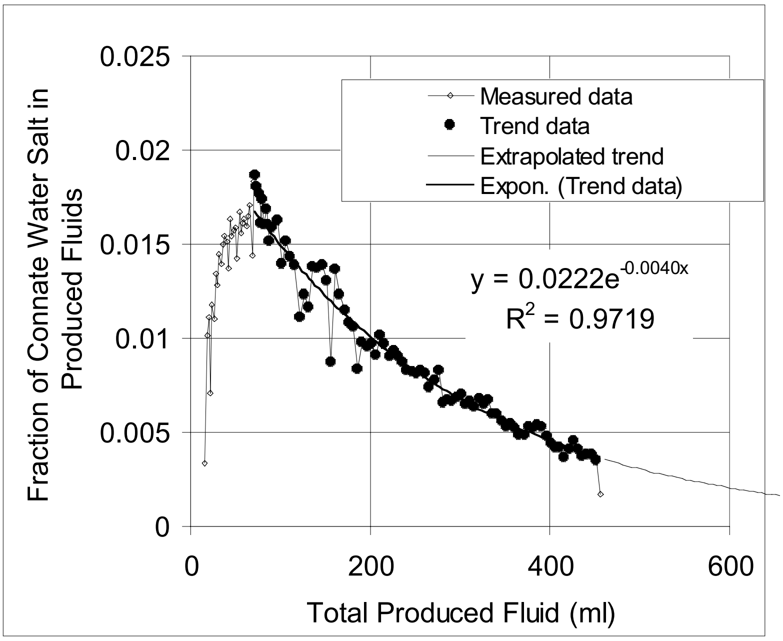

Figure 8 The measured fractional concentration of Iodide in the produced water. The equation is a best fit of the declining data trend.

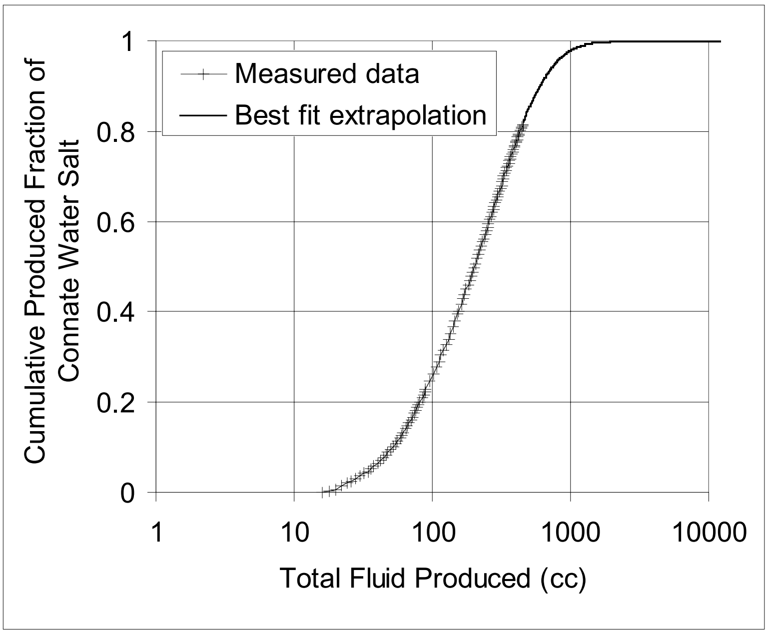

Figure 9 Cumulative produced connate water shows an excellent material balance with the original quantity of connate water in the fractured plug.

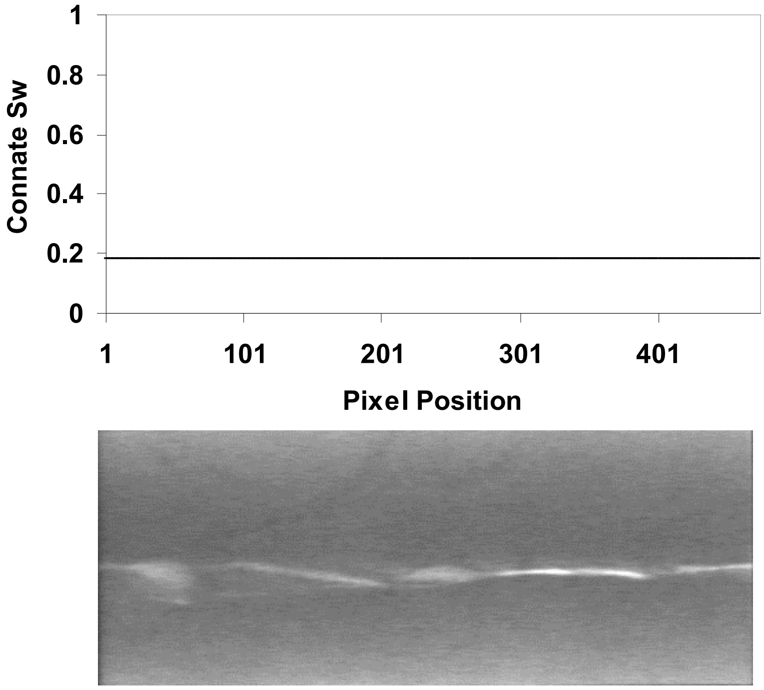

Figure 10 X-ray image at 18% initial water saturation and fractured filled with n-decane. The profile above image represents the average 1-dimensional Sw at a pixel position.

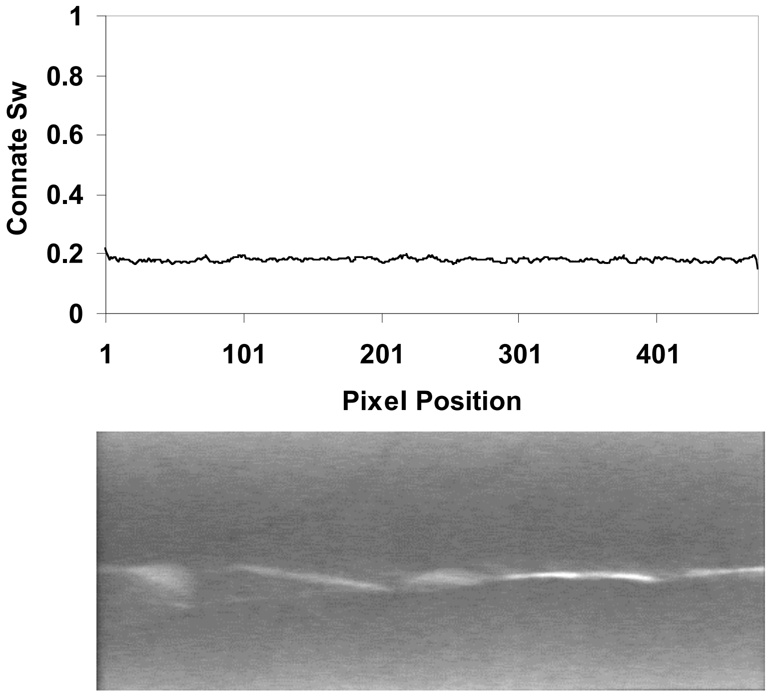

Figure 11 X-ray image at 0.01 PV of injected water.

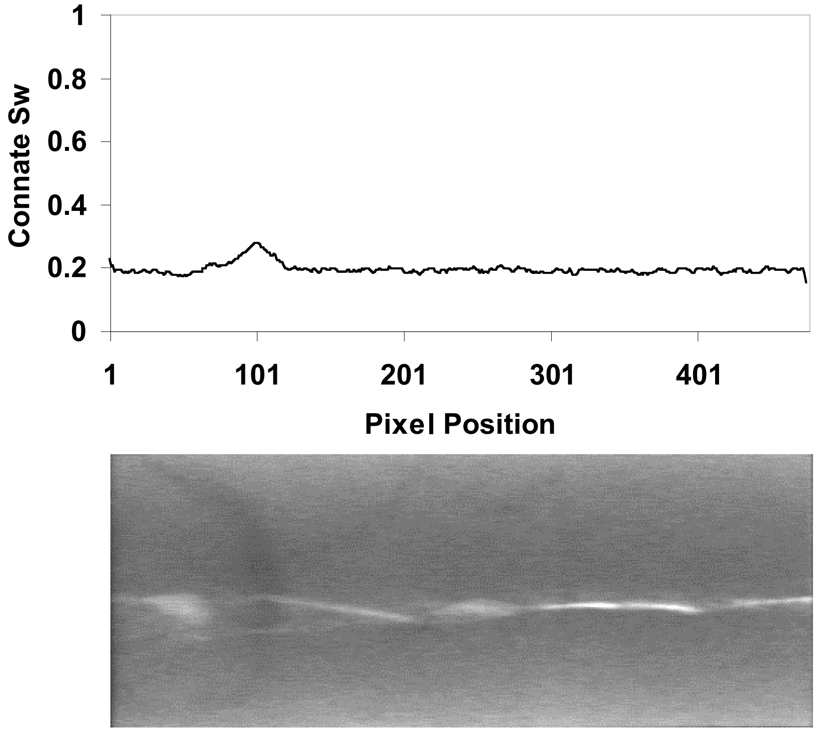

Figure 12 X-ray image at 0.09 PV of injected water showing the development of a connate water bank, but with the bulk of the connate water not displaced by imbibition.

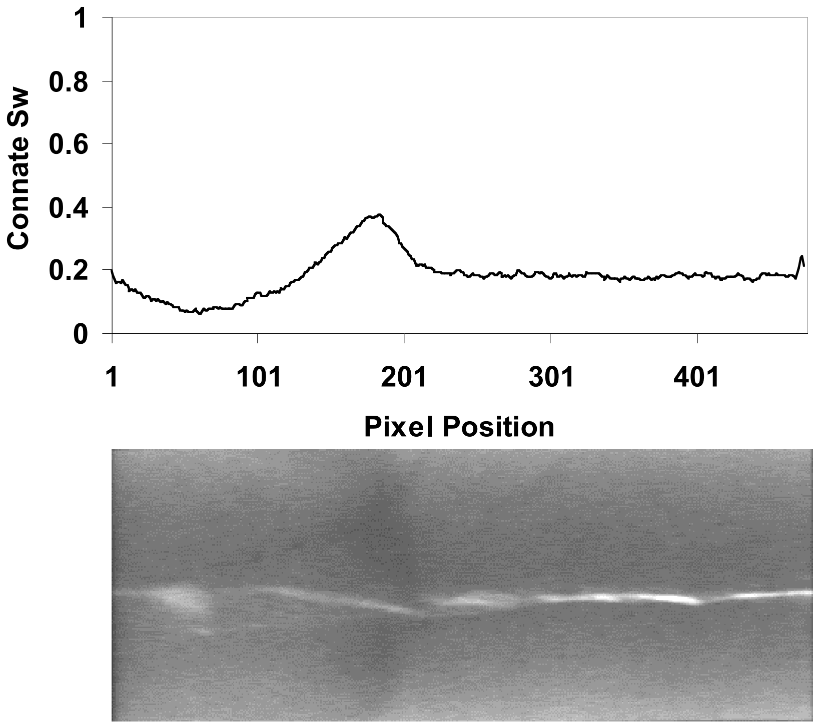

Figure 13 X-ray image at 0.23 PV of injected water showing further development of the connate water displacement.

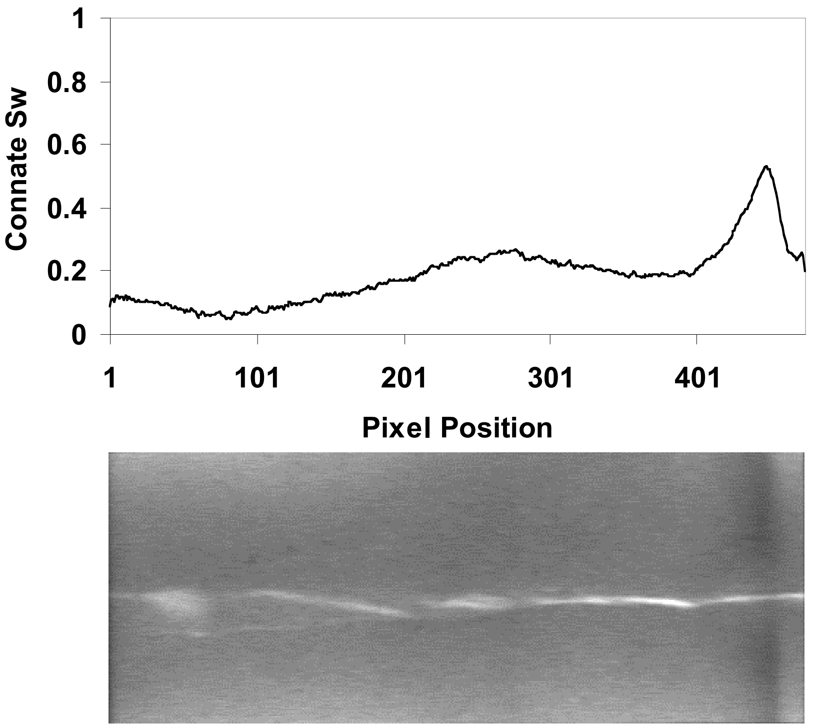

Figure 14 X-ray image at 0.63 PV of injected water showing the connate water distribution at the end of imbibition and the point of water production for this test.

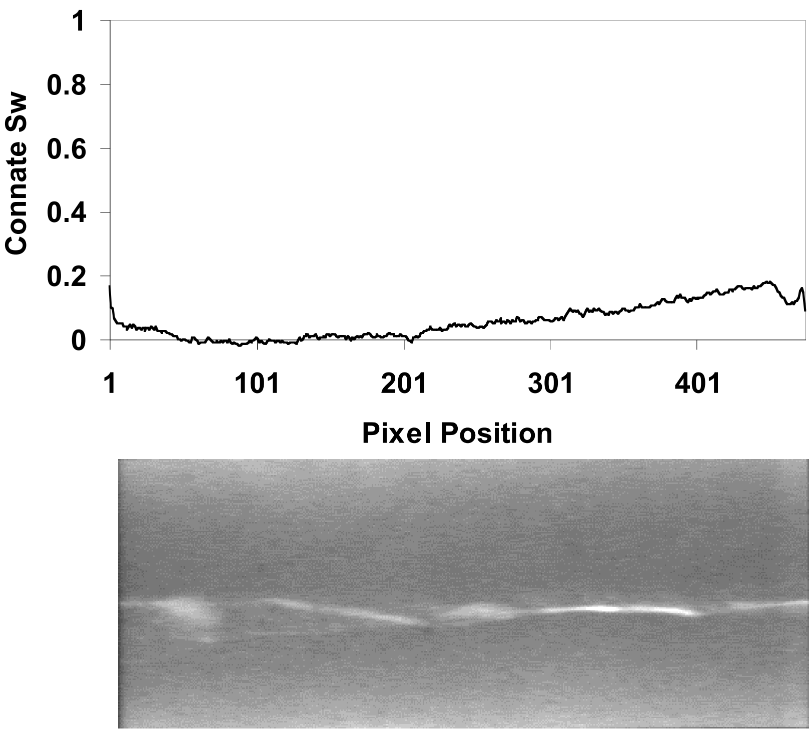

Figure 15 X-ray image at 16.56 PV of injected water showing the depletion of connate water.

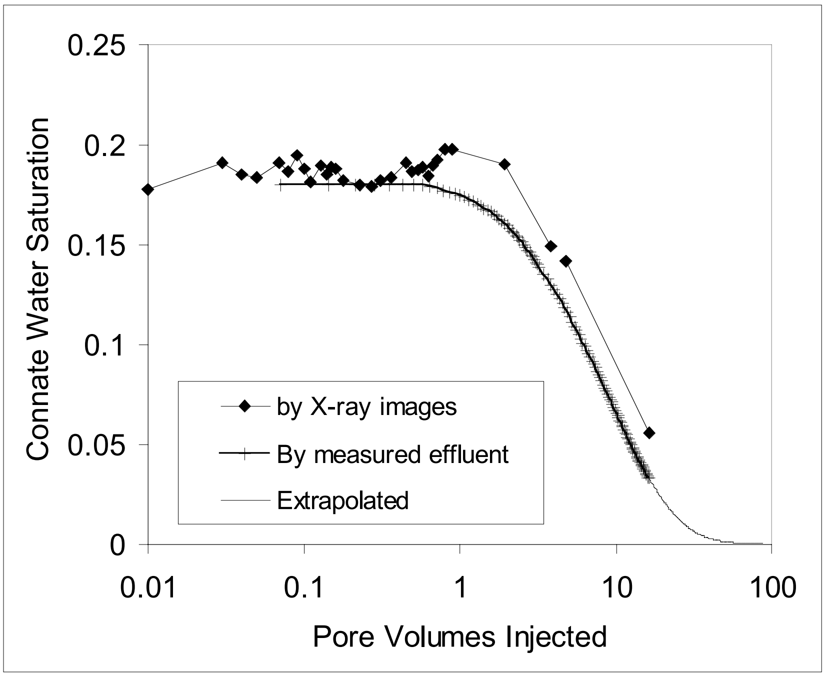

Figure 16 Comparison of calculated plug connate water saturation from X-ray and effluent measurements.

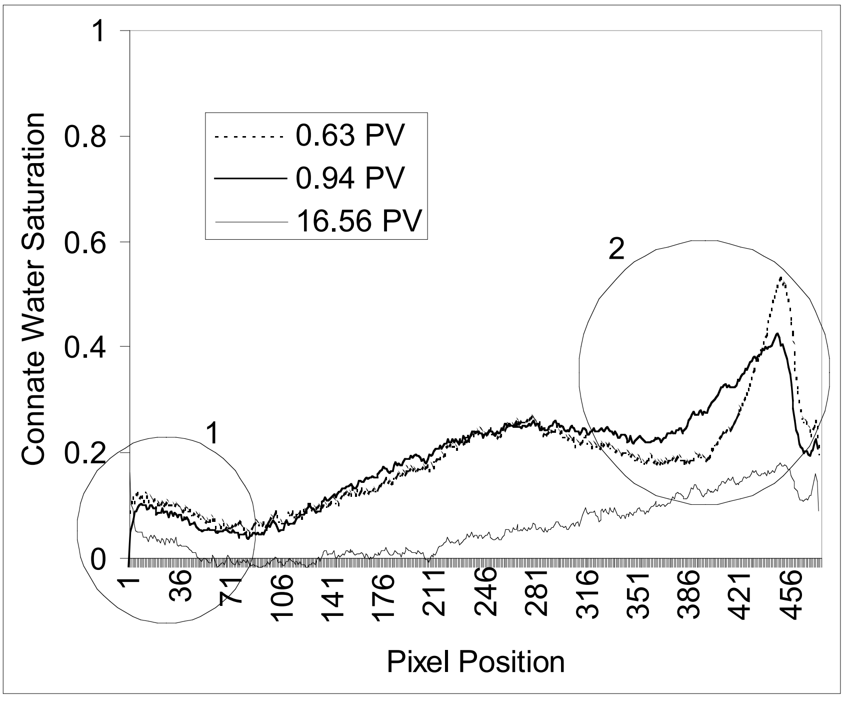

Figure 17 Saturation profiles along the length of the fractured Kansas outcrop chalk plug at different injected throughput volumes showing areas of connate water movement that are consistent with displacement by diffusion.