INTRODUCING THE MICROPILOT*: MOVING ROCK FLOODING EXPERIMENTS DOWNHOLE

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ABSTRACT

Using a combination of petrophysical log sensors to monitor the progress of a fluid flow experiment has long been recognized as a powerful integrator of petrophysics and reservoir engineering. Reservoir saturation monitoring is one such area of collaborative effort. Another recent technological innovation is the MicroPilot* single-well in situ enhanced oil recovery (EOR) evaluation, which combines advanced petrophysical logging sensors with a formation tester device to execute a flood of a desired secondary or tertiary recovery agent in situ in the reservoir and measure the parameters of the resulting flood in terms of the dimensions and the variation of fluid saturations away from the injection point.

In this paper, we describe initials trials of the technique to evaluate the performance of an EOR agent. The technique is executed under in-situ conditions downhole in a very short time. The method is described and we discuss the considerations in planning and executing the tests. In the first trial an alkaline-surfactant-polymer (ASP) was selected for a high-permeability sandstone formation containing medium-viscosity oil. In the second trial an alkaline-surfactant (AS) was selected for a low-permeability carbonate formation containing light oil. We demonstrate the value of the technique in confirming the performance of the EOR agent under downhole conditions.

This paper presents the results of the two trials and discusses the potential for the technique to characterize various types of secondary and EOR floods. Results of simulations are presented to support the feasibility of the technique.

INTRODUCTION

As fields mature there is an increasing need to resort to tertiary recovery techniques to extract the remaining hydrocarbon. The planning and execution of such projects require accurate knowledge of several key petrophysical properties such as residual oil saturation to water flood (S_{orw}) and to the enhanced oil recovery (EOR) fluid, relative permeability to oil and water under water displacement, and horizontal and vertical permeability for each layer.

Traditionally such data has been sourced from core measurements performed under controlled conditions. However, there are several difficulties in obtaining representative measurements on core. In high-porosity, unconsolidated sandstones or in vuggy carbonates, it may not be possible to recover representative core samples. If asphaltenes and resins are present in the crude oil, the wettability state of the core may be altered during the extraction of the sample to the surface. Without knowledge of the wettability state downhole, it is very difficult to restore the sample to its original wettability state. In heterogeneous carbonates, measurements on inch-sized core plugs may not be representative. It is preferable to perform the measurements on whole-core-diameter (10-cm) samples, but such measurements are very expensive, time-consuming, and difficult to perform accurately. As a consequence laboratory studies for screening EOR projects constitute the bulk of the time spent before pilot trials and full-field deployment. A method is needed that can acquire this valuable information in a representative manner and quickly.

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The objective of the new MicroPilot single-well in situ EOR evaluation is to perform a downhole rock flooding experiment. Saturation is measured before and after the flood, thus measuring the change in saturation due to the displacing agent. The displacing agent can be brine of any given salinity, or a hydrocarbon, or a chemical EOR fluid. Even crude oil can be considered as a displacing agent. In the two field tests discussed in this paper the displacement was conducted by alkaline-surfactant-polymer (ASP) in the first case and alkaline-surfactant (AS) in the second case.

Figure 1 describes the operational sequence (Al-Mjeni *et al.*, 2010). The formation tester device incorporates one or more sample chambers carrying the injection fluid, and a drill bit surrounded by a sealing packing element. The bit drills a pencil-width 6-in. (15-cm) hole into the formation. The operation is conducted underbalanced to ensure that no mudcake builds within the injection hole. Subsequently, the drill is withdrawn and a short production cycle flushes out the debris from the injection hole. Following this sequence, injection commences and the desired flood is executed.

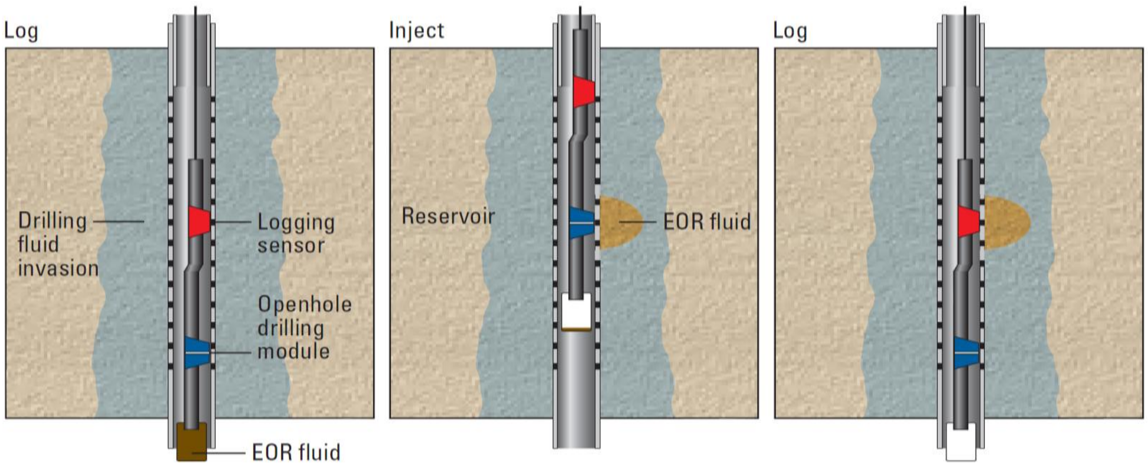

Figure 1: Schematic of the single-well in situ EOR evaluation procedure. In the first pass (left) the initial saturations are logged, then the EOR fluid is injected (center), and finally the logs are run again to assess the remaining saturation after injection (right). (From Al-Mjeni *et al.*, 2010)

Prior to and after the drill and inject operation, logging sensors are used to acquire saturation logs and borehole electrical images across the test zone. The logging sensors may be combined into the same tool-string or be run on separate descents in the hole depending on the maximum allowable time interval between the injection and the measurements. Comparison of the before and after data provides an accurate estimate of the saturation changes across the flood zone and the dimensions of the flood.

To make this a representative measurement, the small flood has to mimic the physical and chemical processes of the full field deployment. This requires very careful planning of all aspects of the experiment. Reservoir engineering considerations determine the geometry of the flood and rates at which fluid injection occurs. This, in turn, impacts the choice of hardware to be used. Petrophysical considerations determine the type of logging sensors needed to monitor the saturation change with the required accuracy. Because the dimensions of the flood are limited, special logging techniques are required to preserve the highest possible vertical resolution of the measurement.

Flow and log simulations and laboratory flood experiments are performed prior to the job to determine several experimental parameters (Arora *et al.*, 2010).

The planning also includes considerations of well trajectory and mud composition. The former determines the orientation of the logging sensors and injection device. A minimum deviation of 5° is needed to encourage the same orientation of the logging tools and injection probe. The mud composition is critical in preparing the near-wellbore region for the experiment. When performing surfactant floods, it is preferable to avoid the presence of surfactants in the mud system.

The saturation measurements before and after injection need to be independent of the changes in salinity and interfacial surface tension caused by the EOR agent such as alkaline surfactants. The saturation measurement volume also needs to be independent of the spatial changes in saturation. This means that low-frequency electromagnetic (EM) devices are unsuitable. Nuclear magnetic resonance (NMR) is the first choice because the magnetic field that defines the measurement volume is not affected by saturation, and for certain oils, the fluid saturations can be determined from the partitioning of the porosity map scaled in relaxation versus diffusion. The saturation accuracy of NMR has to be determined for the specific oil at reservoir conditions in a laboratory. A second choice for measuring the saturation change is a high-frequency EM device such as a dielectric measurement that has a reduced sensitivity to changes in salinity and conductive geometry. When injecting a miscible gas, a high-resolution density measurement (Eyl *et al.*, 1994) may provide an accurate gas saturation estimate.

The minimum volume of EOR fluid to be injected has to be enough to create a flood that fully covers the measurement volume of the saturation tool. The flood volume depends on the porosity, change in saturation, and the ratio of vertical to horizontal permeability (K_v/K_h) of the formation, so it has to be predetermined with modeling. The EOR fluid injection is made at a sufficiently slow rate to match the capillary number of the full-field EOR flood. The storage, conveyance, and pumping mechanisms must not alter the viscosity of the EOR fluid. The injection is made into a drilled hole that has depth and orientation matching the saturation tool's depth of investigation and relative bearing.

Three papers already presented at industry conferences (Arora *et al.*, 2010; Cherukupalli *et al.*, 2010; Edwards *et al.*, 2011) detail the planning, execution, and interpretation of tests of this new technique. This paper discusses results from two field tests and then explores the range of possible applications of this technology.

TEST # 1

The first test of the technique was performed in a 6-Darcy clean 33-pu sandstone formation with intermediate-viscosity oil. The EOR fluid injected was an ASP mixture with a viscosity close to 50 cP. Further details of the test are described by Arora *et al*. (2010).

Figure 2 shows a comparison of the borehole electrical image before and after the ASP injection. The depth of the injection hole is identified. We see a circular area around this point with increased conductivity. This is the zone where the oil has been swept by the ASP. Immediately surrounding this zone, there is a ring of decreased conductivity. This is the zone of the oil bank mobilized by the EOR fluid. The confirmed presence of this oil bank is an important finding of the test.

Both the images were carefully calibrated to the shallow laterolog conductivity. We also attempted to match the color scale of both images to improve the visual comparison.

Figure 3 compares the results from the NMR and dielectric logs recorded before and after the injection. Both logs confirm the nearly complete displacement of the oil within the swept zone and the presence of increased oil saturation in the oil bank. The vertical resolution of the dielectric log is clearly far superior to that of the NMR log.

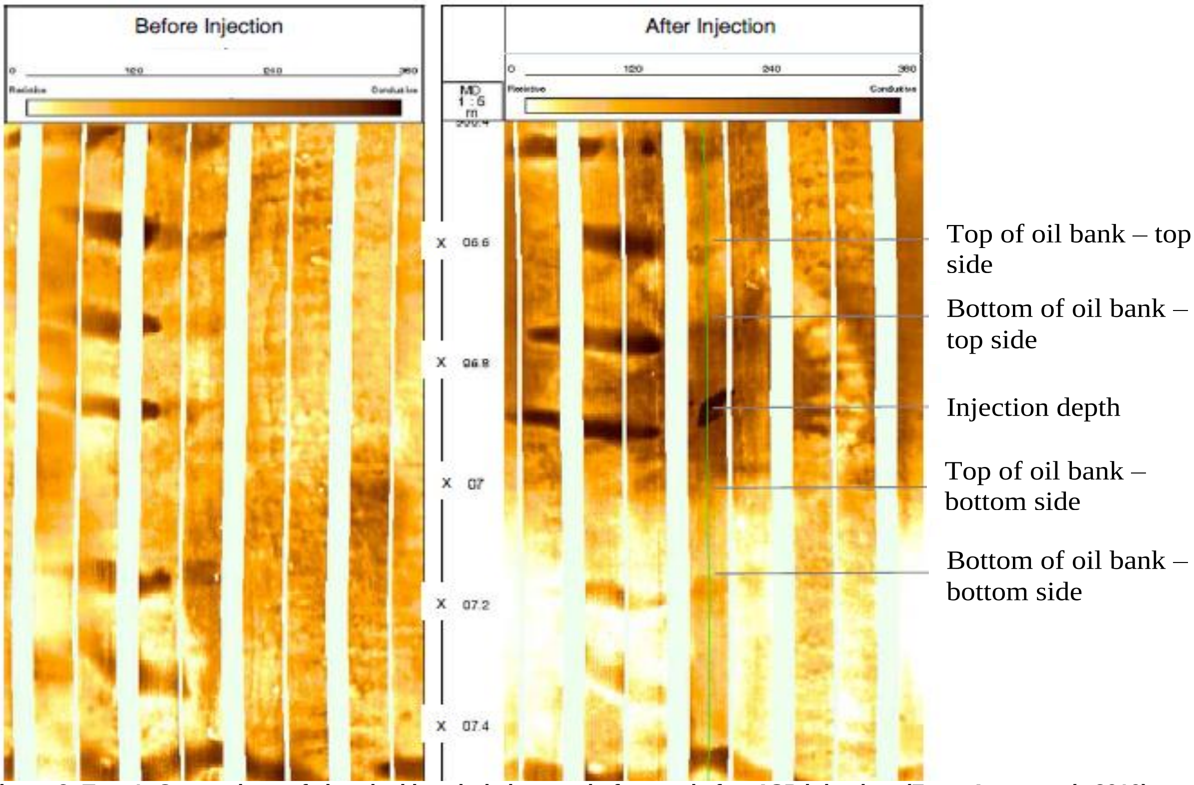

Figure 2: Test 1: Comparison of electrical borehole images before and after ASP injection. (From Arora *et al.*, 2010)

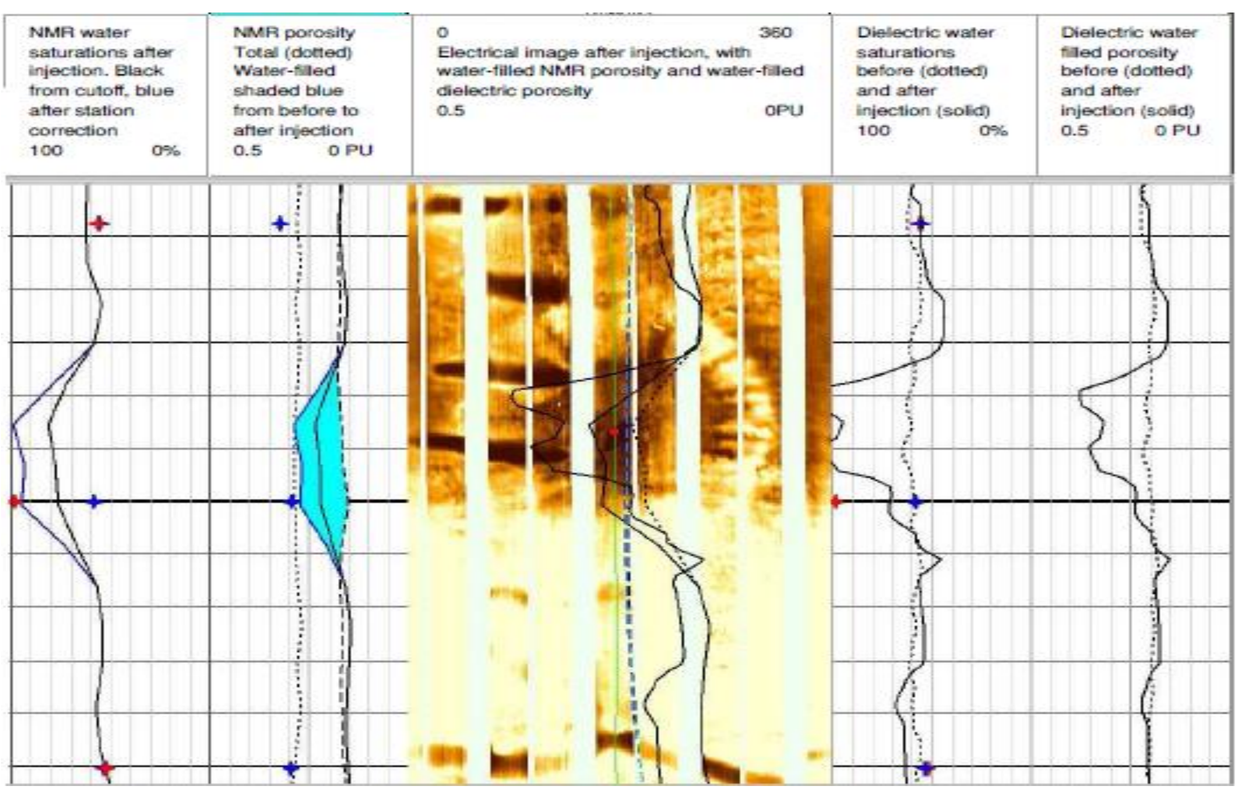

Figure 3: Test 1: Comparison of NMR and dielectric interpretation results before and after ASP injection. (From Arora *et al.*, 2010)

Figure 4 compares the magnetic resonance fluid characterization stations recorded at the swept zone before and after injection. The oil signal is clearly seen before the EOR flood and is almost completely absent after the flood. These results from several independent measurements clearly confirm the performance of the EOR agent and are a valuable addition to the EOR screening process.

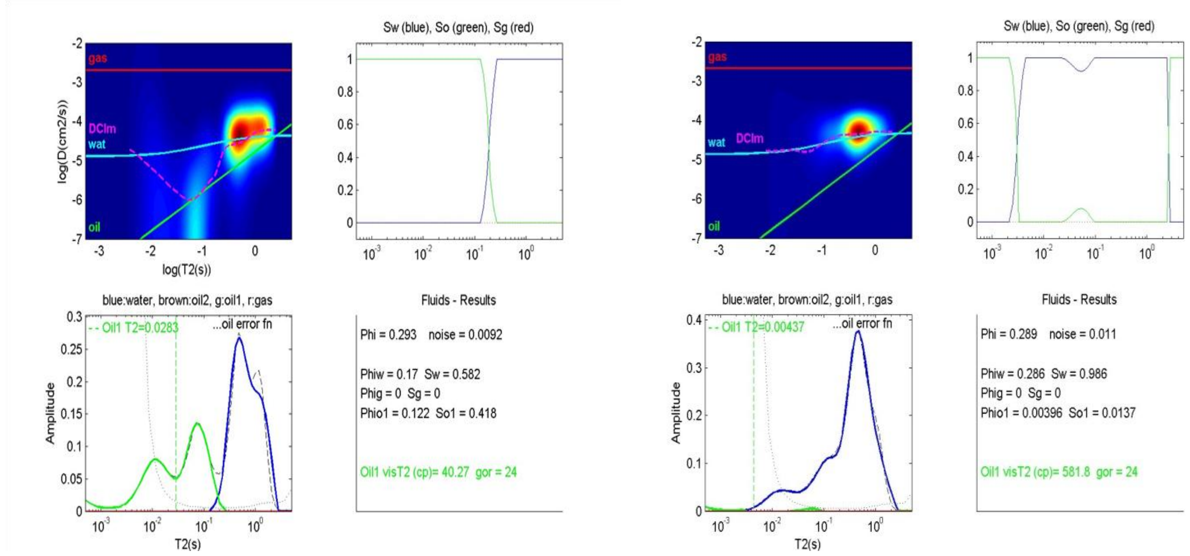

Figure 4: Test 1: Before-after magnetic resonance fluid characterization stations. (From Arora *et al.*, 2010)

Cherukupalli *et al.* (2010) have shown that it is possible to extract further petrophysical information from the data obtained from the technique. Analysis of the array laterolog data provides us with imbibition relative permeability to oil and water (K_{ro}, K_{rw}) that governs the water flood (Ramakrishnan and Wilkinson, 1996). The after-flood NMR data is dominated by the wetting phase and primary drainage capillary pressure curves can be derived from the T_2 distributions. Analysis of the after-drilling production period provides information on permeability and K_v/K_h. The latter is further corroborated by the flood dimensions on the electrical borehole image. History match of the ASP flood dimensions and saturation change provides verification of the surfactant properties that were determined in the laboratory. Figures 5 and 6 display the history match results.

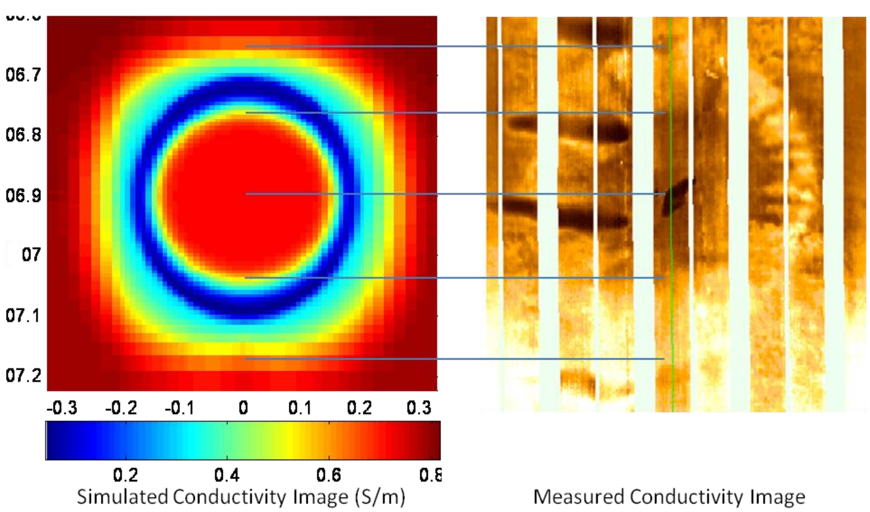

Figure 5: Test 1: History match of vertical dimensions of the ASP flood against the electrical borehole image log. (From Cherukupalli *et al.*, 2010)

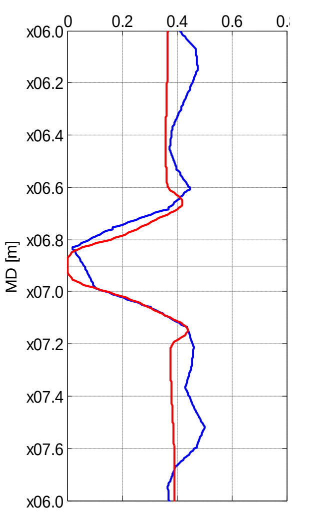

Figure 6: Test 1: History match of vertical saturation profile of ASP flood against the NMR saturation log. (From Cherukupalli *et al.*, 2010)

TEST # 2

The second test was performed in a 3-milliDarcy clean 30-pu limestone formation with light, low-viscosity oil. The EOR fluid injected was an AS mixture with a viscosity close to that of a low-salinity brine. Further details of the test are described by Edwards *et al.* (2011).

In this test, due to the low permeability of the formation, only 3 litres (0.003 m^3) of the EOR fluid could be injected into the formation. Anticipating the small dimensions of the consequent flood, the NMR log was not acquired after injection. The dielectric dispersion log, with a 1-in. (2.54-cm) vertical resolution, was recorded in three passes to confirm the repeatability and accuracy of the results.

Figure 7 shows the before- and after-injection borehole images and the after-injection interpreted dielectric dispersion log. All three passes of dielectric recorded after injection are shown, and we observe excellent repeatability. A 14% decrease in oil saturation is reported on the dielectric log due to the AS flood.

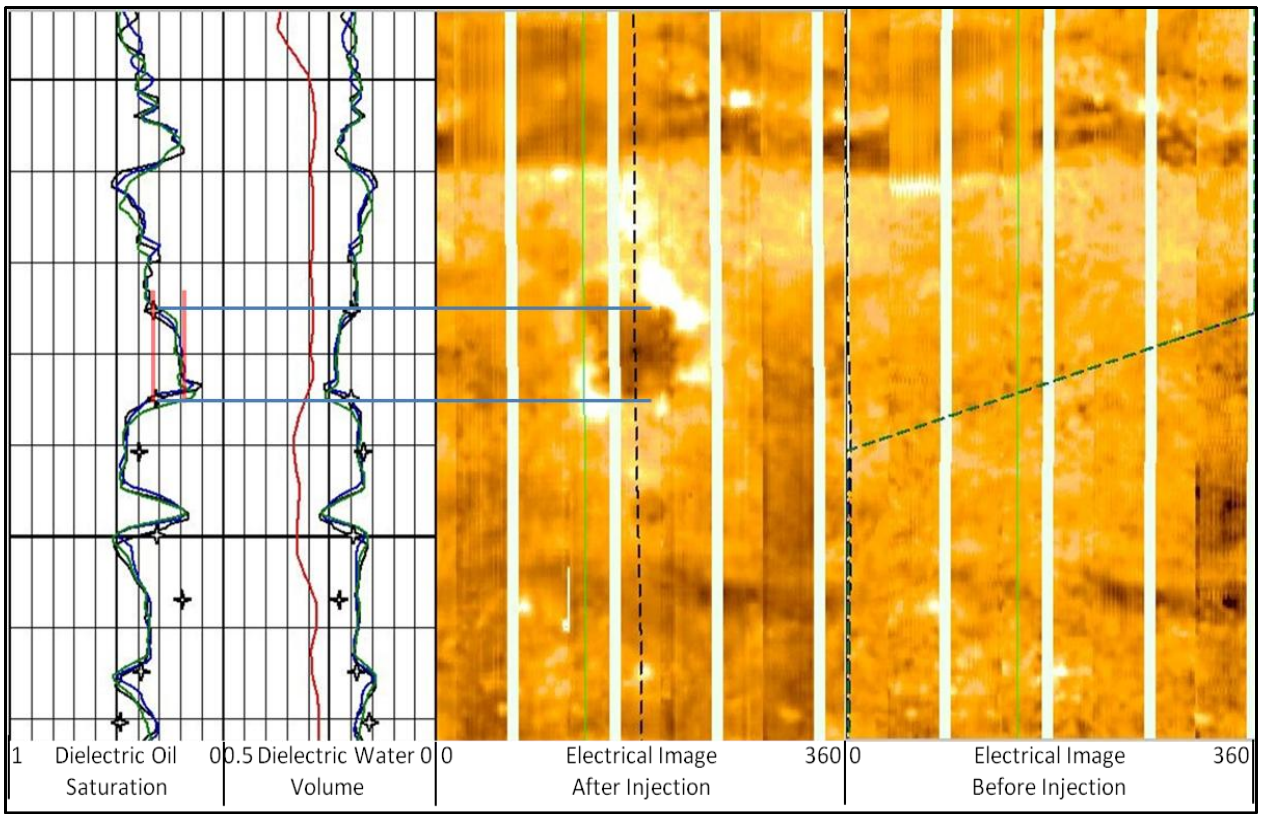

Figure 7: Test 2: Comparison of borehole image and dielectric logs recorded before and after injection of AS. NMR stations recorded before injection are overlaid on dielectric interpretation results. (From Edwards *et al.*, 2011)

DISCUSSION OF RESULTS

These results have demonstrated the feasibility of conducting rock flooding experiments downhole to derive several of the same properties heretofore available only through tedious laboratory measurements. Furthermore, by conducting the experiments in the reservoir, considerable time is saved by avoiding lengthy restoration of the rock to original conditions. Much uncertainty is avoided in achieving downhole conditions, because the rock is never altered in the first place provided the mud properties are properly controlled.

We have also seen that measurement volumes much larger than practical in a laboratory are accessed by employing this technique in the field. This helps to capture the effect of heterogeneity on a scale not achievable in a laboratory.

In the event that representative rock samples cannot be extracted from the reservoir and transported reliably to the laboratory, this technique provides an attractive alternative to test the EOR process on the real formation.

ESTIMATING S_{orw}

Having established the viability of conducting rock flooding experiments downhole, we consider possible additional applications of the MicroPilot technology.

One significant unknown in EOR project planning is the residual oil saturation to a water flood (S_{orw}). Each year, operators around the world spend considerable sums of money acquiring special core or advanced logs to determine this parameter for their reservoirs. Several methods are applied such as sponge core or liquid trapper core (Park and Devier, 1983), logging surveys in in-fill wells drilled behind the flood front or close to an injector, log-inject-log surveys employing pulsed neutron tools (Smith and Stieber, 1974) or NMR tools (Horkowitz *et al*., 1995), saturation monitoring surveys (pulsed neutron log or resistivity) in wells after the water flood has passed by, or core flood studies carried out in the laboratory. Each method has its advantages and drawbacks.

Of the methods mentioned above, the most accurate are the core floods in the laboratory. However, errors creep in when the sample is not sufficiently restored to the reservoir conditions. Furthermore, due to limited sample volumes, the results are of questionable representativeness in heterogeneous rocks such as carbonates.

S_{orw} from sponge cores or liquid trapper coring requires that the formation has already been brought to residual oil saturation by the passage of the water flood. Great care needs to be taken to ensure no fluids are lost from the sample during extraction to surface and transportation to the laboratory. The process of cutting the core also needs to minimize spurt loss invasion that can reduce the oil saturation below S_{orw}. Use of surfactants in the mud system must be avoided.

Log-based methods of determining S_{orw} are handicapped by the fact that the invasion process during drilling, the well is uncontrolled and there is no certainty that the capillary number has remained below the critical value. As shown by several researchers (Abrams, 1974; Chatzis *et al.*, 1988), at high flow velocity when the capillary number exceeds the critical value, the residual oil saturation to water flood decreases with increasing capillary number. In the far field, the capillary numbers remains well below critical value. Hence, it is S_{orw} at a low capillary number that is of interest. For wells where an objective of coring or logging is the determination of S_{orw}, the mud program should be carefully managed to ensure low-invasion conditions are achieved. Techniques using either resistivity or pulsed neutron capture logging are further plagued by uncertainty in the Archie parameters or in the salinity of the formation waters behind a flood front.

Given the above, the single-well in situ EOR evaluation technique provides an attractive alternative. By executing a controlled brine flood downhole, several of the drawbacks of conventional approaches are avoided. Injection rates as low as 0.2 cc/sec can be achieved, though in practice rates between 0.5 and 1.0 cc/sec are used. Given the very large surface area of the drilled injection hole, it is very easy to maintain the capillary number below the critical value. In the vicinity of the probe over the investigation volume of the NMR or dielectric sensor, several tens of pore volumes pass through the rock, thereby ensuring that the saturation reduces to the residual value. Measurements such as NMR or dielectric avoid many of the pitfalls of resistivity or capture sigma measurements.

Figure 8 shows the results of an ASP flood simulation. The plot on the top left shows the saturation cross-section at the injected depth. The swept zone, oil bank, and far field are clearly visible. The plot on the top right shows four co-axial volume regions centered on the injection hole. Region 1 is the innermost region (colored dark blue) and region 4 is the outermost region (colored orange). The plot below shows the predicted desaturation versus pore volumes (PV) of ASP injected. In the simulation, six PV was achieved for region 4 after 3.5 hours of injection. We observe that within six PV all 4 regions are reduced to the residual oil saturation to the ASP flood.

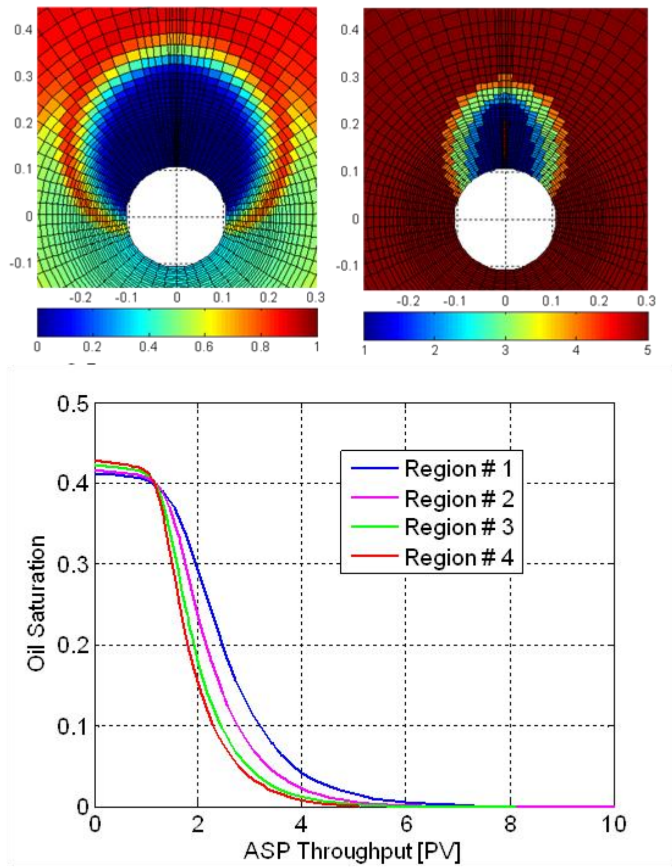

Figure 8: Simulated results of desaturation versus pore volumes injected for an ASP flood.

In the next section we explore the possibility of brine injection with the technique for the special case of low-salinity EOR.

LOW-SALINITY EOR

Although not tested in the field yet, the feasibility of using this evaluation technique with low-salinity brine as EOR fluid has been investigated. The EOR effect of low-salinity brine has been confirmed in numerous laboratory core floods as well as in both single-well and multi-well field pilots (e.g., Tang and Morrow, 1999; McGuire *et al.*, 2005). The governing physical and chemical mechanisms for the enhanced recovery are, however, not fully agreed upon. Experimentally it has been found that certain conditions are necessary to observe an effect from low-salinity injection, including the presence of clay minerals, crude oil containing polar components, initial formation water containing divalent cations, and injection salinity below approximately 5,000 ppm (Austad *et al.*, 2010). The uncertainty in the key recovery mechanisms highlights the importance of a staged screening and evaluation program in which the low-salinity process is trialed at successively larger scales before committing to full-field implementation.

A thorough simulation study was performed to assess whether the saturation changes expected during a low-salinity flood evaluation were quantifiable with available logging techniques. The low-salinity process was simulated using salinity-dependent relative permeability curves capturing the observed change in wettability towards more water wet with the decrease in brine salinity. Figure 9 shows simulated saturation and conductivity depth logs after injection of 10 liters of low-salinity brine (300 ppm). At each depth the saturation is derived from a cell located 1 inch into the formation in the direction of the injection probe. The selected depth into the formation best represents the volume investigated by the NMR and dielectric tools. Five scenarios are presented, corresponding to different levels of low-salinity effects, all representative of what has been experimentally observed for the low-salinity process. The plots on the right-hand-side show the relative permeability and fractional flow curves. The base high-salinity curves are shown in red. Each of the subsequent curves represents an increasing level of water wetness due to the low-salinity effect. The simulations were performed using the high-salinity curves in combination with the different low-salinity curves, thereby covering the range from no salinity effect to the most optimistic case represented by the blue curve.

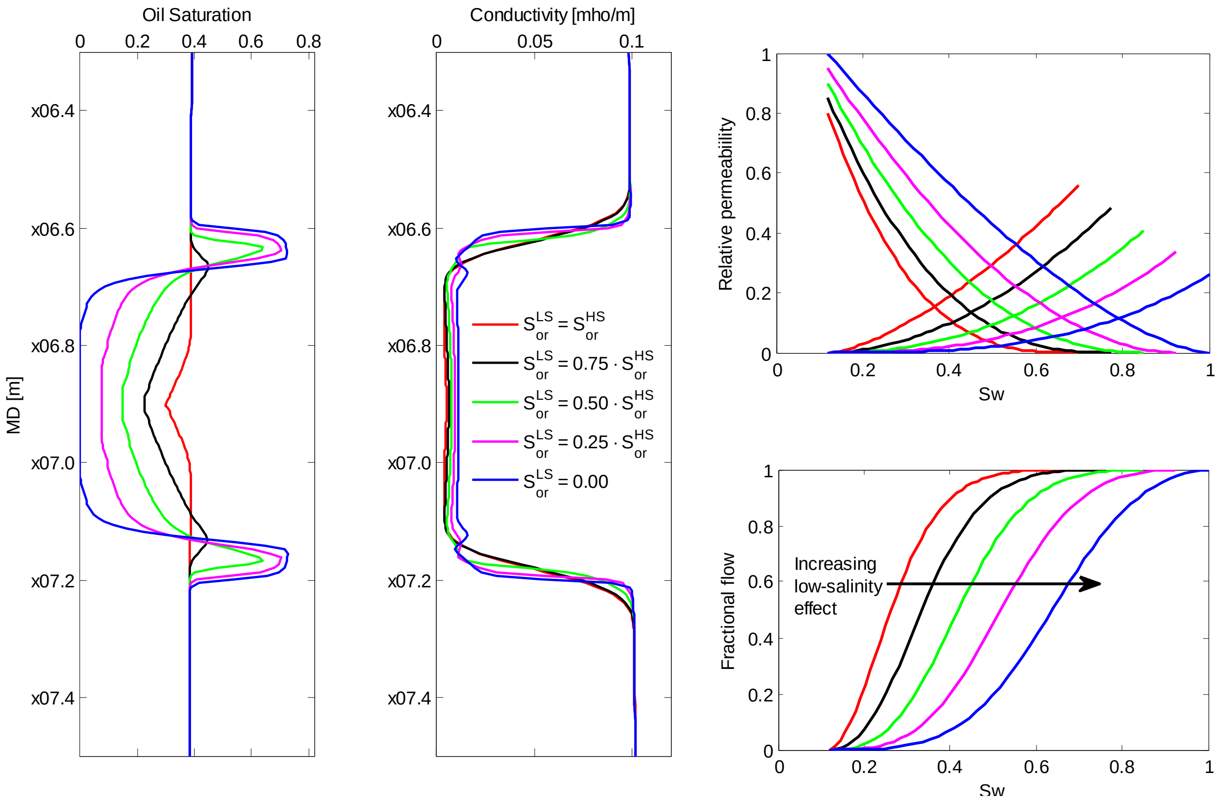

Figure 9: Simulated oil saturation and conductivity depth logs for low-salinity brine injection. Results are shown at varying degrees of low-salinity effect. The relative permeability and fractional curves are shown to the right. The base high-salinity curves are shown in red.

The maximum reduction in oil saturation due to low-salinity injection varies between 0.08 and 0.38 saturation units. Because the initial oil saturation after mud filtrate invasion is above the high-salinity residual saturation (S_{or}^{HS} = 0.30), injection of high-salinity water still reduces the saturation by approximately 0.08 saturation units.

The values measured by the logging tools represent a weighted average of the saturation in the formation over a vertical distance specified by the design characteristics of the tool. For instance, the saturation measured by an NMR tool such as the CMR* (Combinable Magnetic Resonance) has a vertical resolution of 6 in. (0.15 m) as a stationary measurement and 7.5 in. (0.19 m) when recorded as a depth log. The vertical resolution of the latest generation dielectric tool is 1 in. (0.025 m). The vertical response function for any tool determines its vertical resolution. The logs shown in Figure 5 must therefore be convolved with the vertical response function of the corresponding saturation tool before making an assessment whether a specific logging technology can monitor the saturation change achieved by a low-salinity EOR evaluation operation.

Figure 10 shows the saturation results convolved with the vertical response functions of a high-resolution NMR tool and the latest generation dielectric logging tool. The first track on the left shows the saturation depth logs as input from the simulation model. The second track shows the same convolved with the vertical response function of the NMR, and track 3 shows the results after convolving with the vertical response function of the dielectric tool. Observe that the 7.5-in. (0.19-m) vertical resolution of the NMR tool results in considerable smoothing of the saturation profiles. The oil banks become less apparent and are shifted farther away from the center of the flood. There is also an increase in the minimum oil saturation at the center of the flood for the two scenarios with the smallest low-salinity effect (red and black curves). Inspecting the results for the dielectric tool, we see that the excellent vertical resolution of 1 in. (0.025 m) has preserved the features as output from the simulation model.

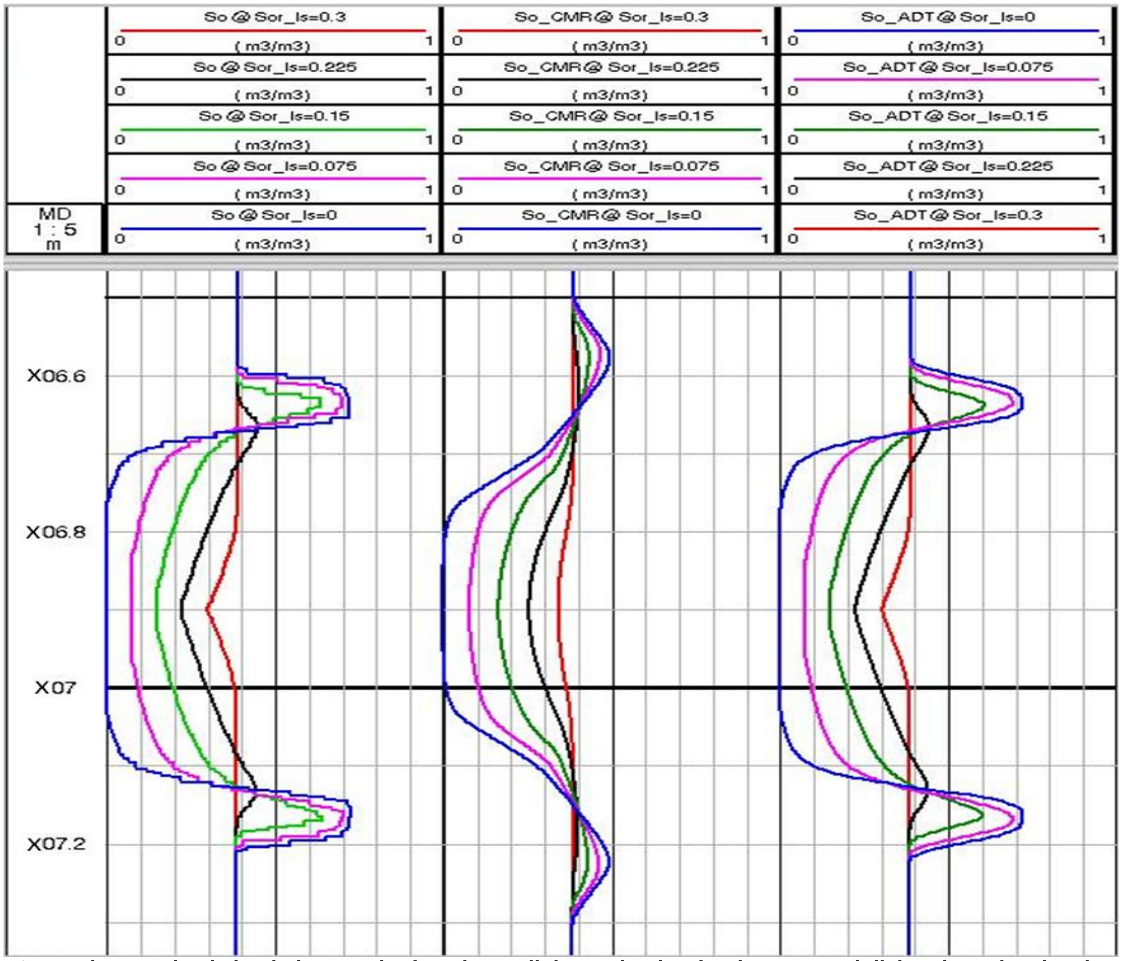

Figure 10: Depth-convolved simulation results for a low-salinity evaluation for the NMR and dielectric tools. The simulation results (left track) are shown together with the depth-convolved results for the NMR tool (center track) and the dielectric tool (right track).

This modeling demonstrates that the flood dimensions and saturation changes realistically attainable during a low-salinity EOR evaluation are well within the range quantifiable by existing logging methods, thereby making this an attractive pilot technology for low-salinity EOR. More details of the low-salinity modeling can be found in Kristensen *et al.* (2011).

CONCLUSIONS

We have presented a novel adaptation of existing technology and shown results from two field trials of chemical EOR agents. This adaptation of existing technology creates the opportunity for downhole rock flooding experiments. The two jobs performed covered two extremes of permeability at 6-D and 3-mD, clastics and carbonates, and heavy oil and light oil. Therefore over a wide range of formations, it is now possible to perform a quick validation of a particular reservoir's response to either brine or a more complex EOR fluid.

We expect that the MicroPilot technique will serve a long-standing need of the industry for reliable estimation of key petrophysical properties under reservoir conditions for various brine and chemical floods.

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