TESTING OF WETTABILITY EFFECTS ON CAPILLARY PRESSURE AND ELECTRICAL CONDUCTION IN FLUID-SATURATED ROCKS

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Testing of Wettability Effects on Capillary Pressure and Electrical Conduction in Fluid-Saturated Rocks

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Abstract – The main goal of core analysis is to reduce uncertainty in reservoir evaluation processes created by the uncertainty degree in the input parameters at the different levels from reserve estimate level to the enhancement of reservoir performance level. In order to reach these targets, the exact determination of certain petro physical properties are necessary such as rock porosity, relative permeability, water saturation, and capillary pressure at all stages of reservoir life and rock wettability. Predicting reservoir wettability and its effect on fluid distribution and hydrocarbon recovery remains one of the major challenges in reservoir evaluation and engineering. Current laboratory based techniques require the use of rock-fluid systems that are representative of in situ reservoir wettability. Several parameters like relative permeability's, residual saturations, and capillary depressurization curves change with the wettability state of the reservoir. In addition all these parameters, can greatly impact oil recovery. Thus, there is a need to relate all these parameter to wettability state of the reservoir [Anderson, 1986].

In this study, irreducible oil saturation and capillary pressures using rock centrifuge measurements for Berea Sandstone rock samples.

This paper summarizes and investigate the effects of wettability, pore geometry, and stress on electrical conduction in partially saturated porous media.

Experiments conducted on both glass-bead packs and Berea cores show that wettability has a profound effect on the saturation exponent, consistent with theoretical predictions based on a network representation of the porous medium. The effect of wettability is most pronounced when the pores are poorly connected. The influence of stress is substantially smaller than the effect of wettability in the relatively simple low-clay content intergranular-porosity systems considered here. Small increases in the formation factor were observed for the cores and the water-wet beads, whereas larger increases were observed with the compressible asphaltene-coated oil-wet beads.

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INTRODUCTION

Wettability is defined as the tendency of one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids. In other words wettability of reservoir rocks is the actual process by which a liquid spreads on (wets) a solid substrate or surface [Anderson, 1986].

The wettability of fluid/rock system can range from strongly water-wet to strongly oil-wet. When the rock has no strong preference for either oil or water, the system is said to be neutral (or intermediate) wettability. Besides strong and neutral wettability, there are two different types of wettability such as *fractional wettability*, and *mixed wettability* [Anderson,1986].

In partially saturated rocks, the situation is even more complicated. Here, not only pore geometry but also the relative locations of the oil/gas and water in the pore space become important. One of the least understood aspects of the resistivity response of fluid-saturated rocks is the influence of wettability. Donaldson and Bizerra (1984) reported n variations from 1.5 to 25.0 for different wettability conditions. The magnitude of this variation, if true, would make wettability a much more significant factor than either temperature, stress, or pore-space geometry.

Keller (1953), working with glass-bead packs made oil wet with Drifilm®, showed that values of ranged from 1.5 to 11.7 for the same packing of beads but under different wettability conditions. Moore (1958) observed n values from 1.6 to 2.7 for reservoir core samples and attributed the differences to changes in wettability. Sweeney and Jennings (1960) reported variations in n from 1.6 to 5.7 for carbonate rocks and higher values of n for glass beads made oil wet with Drifilm solution. Donald-son and Bizerra (1984) have reported values of n for cores ranging from 3.82 to 8.45. A linear relationship between the USBM wettability index and n was also observed.
Sanyal et al. (1973) found that the saturation exponent increased with temperature in the drainage cycle and decreased with temperature during imbibition. An excellent review of previous work is provided by Anderson (1986).

A major drawback with many of the above studies is the use of a two-electrode system for the measurement of resistivity. Dunlap et al. (1949) and Rust (1952) showed that significant errors can be caused by this method be- cause of electrode contact resistance at the interface be- tween the brine and the electrode. This problem is particularlyacutc for oil-wet systems at low water saturations. The four-electrode method described by these authors eliminates this problem and is used in our experiments. The effect of contact resistance for two-electrode systems is to increase the values of both m and n. The effect of contact resistance at the current electrodes is eliminated for four-electrode systems. Contact resistance at the volt- age electrodes must be very high relative to the imput impedance of the voltmeter used, which is typically 1- 10 Mohms, to affect m and n values. If significant contact resistance is present at the voltage electrodes, the effect is to reduce m or n, not increase it.

Swanson (1980) reported smaller values of n during water flooding than during drainage. Longeron ct al. (1989) reported increases in the measured value of n as the non- wetting fluid was changed from gas to mineral oil to crude oil. The increase in n was attributed to a continuous change in wettability toward oil wetness with time. They also reported some degree of hysteresis between drainage and imbibition cycles for both limestones and sandstones (Longeron et al., 1986, 1989).

There is a great deal of concern that the wettability conditions obtained in the lab may differ substantially from those existing in situ. These concerns relate to "native state" cores and "restored state" corcs and to "artificially treated" cores. The artificial oil-wet conditions created in the lab through asphaltene precipitation or Drifilm treatment will seldom be encountered in situ. These extreme oil-wetting conditions do, however, provide bounds on the variations in Rand n and clearly dem- onstrate the importance of wettability as a controlling factor in the resistivity of partially saturated rocks. These issues are discussed briefly in the section on Implications for Core Analysis.

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Many different methods have been proposed for measuring the wettability of a rock/fluid system. They include quantitative methods such as contact angles, imbibition and forced displacement (Amott), and USBM wettability method. The contact angle measures the wettability of a specific surface, while the Amott and USBM methods measure the average wettability of a core [Anderson, 1986].

Changes in the wettability of cores have been shown to affect electrical properties, capillary pressure, waterflood behavior, relative permeability, dispersion, simulated tertiary recovery, irreducible water saturation (IWS), and residual oil saturation (ROS) [Anderson, Oct. 1987].

WETTABILITY FUNDAMENTALS

Wetting forces are in play all around us. They have practical applications, such as making rain bead up on a freshly waxed car so it is protected from rust. And they provide whimsy: wetting forces bind sand grains to hold the shape of a child’s sand castle.

Forces of wetting influence hydrocarbon reservoir behavior in many ways, including saturation, multiphase flow and certain log interpretation parameters. However, before getting into these details, it is best to first establish what wettability is.

Wettability describes the preference of a solid to be in contact with one fluid rather than another. Although the term “preference” may seem odd when describing an inanimate object, it aptly describes the balance of surface and interfacial forces. A drop of a preferentially wetting fluid will displace another fluid; at the extreme it will spread over the entire surface.

Conversely, if a nonwetting fluid is dropped onto a surface already covered by the wetting fluid, it will bead up, minimizing its contact with the solid. If the condition is neither strongly waterwetting nor strongly oil-wetting, the balance of forces in the oil/water/solid system will result in a contact angle, , between the fluids at the solid surface (below).

In many oilfield applications, wettability is treated as a binary switch—the rock is either water-wet or oil-wet. This extreme simplification masks the complexity of wetting physics in reservoir rock. In a homogeneous, porous material saturated with oil and water, “strongly water-wetting” describes one end member of a continuum in which the surface strongly prefers contact with water. A strongly oil-wetting surface prefers contact with oil.1 Degrees of wetting apply along the continuum, and if the solid does not have a marked preference for one fluid over the other, its condition is termed intermediatewetting or neutral-wetting.

Reservoir rocks are complex structures, often comprising a variety of mineral types. Each mineral may have a different wettability, making the wetting character of the composite rock difficult to describe. Typically, the primary constituents of reservoirs—quartz, carbonate and dolomite—are water-wet prior to oil migration.

This brings up a further complexity: the saturation history of the material may influence surface wetting, such that pore surfaces that had been previously contacted by oil may be oil-wet, but those never contacted by oil may be waterwet.

Various terms have been used to describe both of these conditions, including mixed-, fractional- and dalmation-wetting. In this article, the general term “mixed-wetting” will be used for any material with inhomogeneous wetting. It is important to note the fundamental difference between intermediate-wetting (lacking a strong wetting preference) and mixed-wetting (having a variety of preferences, possibly including intermediate-wetting) conditions.

Another important distinction is that a preferentially water-wetting surface can be in contact with oil or gas. Wettability does not describe the saturation state: it describes the preference of the solid for wetting by a certain fluid, given the presence of that preferred wetting fluid. Thus, a water-wet rock can be cleaned, dried and fully saturated with an alkane, while the surfaces in the pores remain water-wet. This can be easily seen: drop such an oil-saturated but water-wet rock into a beaker of water and it will spontaneously imbibe a significant quantity of water and expel oil.

Strictly speaking, the term imbibition refers to an increase in the saturation of the wetting phase, whether this is a spontaneous imbibition process or a forced imbibition process such as a waterflood in a water-wet material. Conversely, drainage refers to an increase in saturation of the nonwetting phase. However, in practice, the term imbibition is used to describe a process with increasing water saturation, and drainage is used to describe a process with increasing oil saturation. Care should be taken when reading the literature to determine which sense is being used.

WETTABILITY MEASUREMENT

Several methods are available to measure a reservoir’s wetting preference. Core measure ments include imbibition and centrifuge capillarypressure measurements (below). An imbibition test compares the spontaneous imbibition of oil and water to the total saturation change obtained by flooding.

The Amott-Harvey imbibition test is commonly used.23 A sample at irreducible water saturation, *Swirr*, placed into a water-filled tube spontaneously imbibes water over a period of time—at least 10 days, and sometimes much longer. Then the sample is placed in a flow cell and water is forced through, with the additional oil recovery noted.

The sample is now at residual oil saturation, *Sor*, and the process is repeated with an oil-filled imbibition tube, and then an oil-flooding apparatus. Separate ratios of spontan eous imbibition to total saturation change for water, I_w, and oil, I_o, are termed the water and oil imbibition indices, respectively. The Amott-Harvey index is the difference between the water and oil ratios. The result is a number between +1 (strongly water-wetting) and –1 (strongly oil-wetting).

In a US Bureau of Mines (USBM) test, a centrifuge spins the core sample at stepwise increasing speeds.24 The sample starts at irreducible water saturation, S_{wirr}, in a waterfilled tube. After periods at several spin rates, the sample reaches residual oil saturation, S_{or}, and it is placed into an oil-filled tube for another series of measurements. The areas between each of the capillary-pressure curves and the zero capillary-pressure line are calculated, and the logarithm of the ratio of the water-increasing to oil-increasing areas gives the USBM wettability index.25 The measurement range extends from (strongly water wetting) to $-\infty$ (strongly oil wetting), although most measurement results are in a range of +1 to –1. The centrifuge method is fast, but the saturations must be corrected because the centrifuge induces a nonlinear capillary-pressure gradient in the sample.

It is possible to combine the Amott-Harvey and USBM measurements by using a centrifuge rather than flooding with water and oil to obtain the forced flooding states. The Amott-Harvey index is based on the relative change in saturation, while the USBM index gives a measure of Several methods are used for creating moving contact lines, from which the water-advancing and receding contact angles are measured. The assumption in this test is that the crude oil will change the model surface—under the conditions of the brine temperature, pH and salt concentrations—to that of the formation.

Wettability is often inferred from other measurements. Strongly water-wet and strongly oil-wet materials display certain characteristic relative-permeability curves, but intermediatewetting and mixed-wetting states are not a simple extrapolation between the wettability extremes.

No method for measuring wettability gives an absolutely accurate result, which drives ongoing research, as discussed later in "News from the Laboratory.

EFFECT OF WETTABILITY ON CAPILLARY PRESSURE

The capillary pressure/saturation relationship depends on the interaction of wettability, pore structure, initial saturation, and saturation history. No simple relationship exists that relates the capillary pressure determined at two different wettabilities. Therefore, the most accurate measurements are made with cores that have native reservoir wettability [Anderson, Oct. 1987].

In a uniformly wetted porous medium, pore geometry effects and the extremely rough surface of the porous medium make the capillary pressure curve insensitive to wettability for small contact angles (less than about 50є for drainage capillary pressure curves and less than about 20є for spontaneous-imbibition capillary pressure curves). When the porous medium has fractional or mixed wettability, both the amount and distribution of the oil-wet and water-wet surfaces are important in determining the capillary pressure curve, residual saturation, and imbibition behavior. Imbibition also depends on the interaction of wettability, pore structure, initial saturation, and saturation history. Because of these interactions, there is a large range of contact angles where neither oil nor water will imbibe freely into a uniform wetted reservoir core. In contrast, it is sometimes possible for both fluids to imbibe freely into a core with fractional or mixed Wettability [Anderson, Oct. 1987].

When oil and water are placed together on a surface, a curved interface between the oil and water is formed, with a contact angle at the surface that can range from 0 to 180 ^{0}. By convention, the contact angle, θ, is measured through the water. Generally, when is between 0 and 60 ^{0} to 75 ^{0}, the system is defined as water wet. When is between 180 ^{0} and 105 to 120 ^{0}, the system is defined as oil-wet. In the middle range of contact angle, a system is neutrally or intermediately wet [Anderson, Oct 1986].

EFFECT OF WETTABILITY ON RELATIVE PERMEABILITY

The wettability of a core will strongly affect its waterflood behavior and relative permeability. Wettability affects relative permeability because it is a major factor in the control of the location, flow, and distribution of fluid in a porous medium. In uniformly or fractionally wetted porous media, the water relative permeability increase and the oil relative permeability decrease as the system becomes more oil-wet. In a mixedwettability system, the continuous oil-wet paths in the larger pores alter the relative permeability curves and allow the system to be water flooded to very low residual oil saturation (ROS) after the injection of many PV's of water. The most accurate relative permeability measurements are made in native-state core, where the reservoir wettability is preserved [Anderson, Nov. 1986].

WETTABILITY ALTERATION BY SURFACTANTS

A surfactant is a polar compound, consisting of an amphiphilic molecule, with a hydrophilic part (anionic, cationic, amphoteric or nonionic) and a hydrophobic part. As a result, the addition of a surfactant to an oil-water mixture would lead to a reduction in the interfacial tension. In the past time, the surfactants were used to increase oil recovery by lowering IFT. Later on, due to the difficulty of initiating imbibition process in oil-wet carbonate rocks, many researchers have focused on how to alter the oil-wet carbonate to water-wet by using surfactants. The most successful method reported is the surfactant flooding in the presence of alkaline. There are a number of mechanisms for surfactant adsorption such as electrostatic attraction/repulsion, ion-exchange, chemisorption, chain-chain interactions, hydrogen bonding and hydrophobic bonding.

The nature of the surfactants, minerals and solution conditions as well as the mineralogical composition of reservoir rocks play a governing role in determining the interactions between the reservoir minerals and externally added reagents (surfactants/ polymers) and their effect on solid-liquid interfacial properties such as surface charge and wettability [Babadagli, 2003].

RESULTS AND DISCUSSION

The results of the drainage and imbibition process using rock centrifuge method for the test rock samples.

Due to the difference in oil compositions of the used crude oils (Arab-light, Arab-Medium, and Arab-heavy), there are marked changes in the capillary curves of the drainage cycles for the tested samples. Similarly, these marked changes between the capillary curves during the ambition cycles were occurred.

Practically, heavy oil has higher asphaltene concentrations than light oil. The presences of these asphaltene or polar components concentrations in crude oil can adsorb on mineral surfaces and alter their wetting properties. However, there are several distinct mechanisms by which a crude oil can alter rock wetting characteristic.

Therefore, oil compositional characteristics are needed that related directly to these mechanisms, such as acid and base numbers. Due to a complete analysis of used crude oil not available the judgment on the rock/oil wetting system was done by the variations on the irreducible water saturations during the drainage cycle of the capillary curve and on the residual oil saturation at the end of the imbibition cycle of the capillary pressure curve.

To draw a clear relationship between the capillary pressure, water saturation, and water saturation two stages should be investigated. These stages are Drainage and Imbibition. In the drainage stage the speeds of centrifuge ranged from 700 to 6000 RPM. Arab Light, Arab-Medium, and Arab-Heavy crude oils were used in samples A, B, and C respectively.

Whereas, drainage cycle means increasing the wetting-phase saturation from its maximum to the irreducible minimum by increasing the capillary pressure from zero to a large positive value, therefore, used fluid (Arab–heavy) in sample C change the wettability of this sample toward oil wet.

Wettability has a pronounced effect on the saturation exponent. Oil-wet cores show a large increase in the saturation exponent during both drainage and imbibition cycles.

As expected, the effect of the Quilon-C treatment on the cementation exponent was negligible; the cementation exponent increased by about 6% after the cores were treated with Quilon-C. This increase was probably related to the change in the size and shape of the pores caused by a thin layer of Quilon-C coating. The experiments were repeated several times to obtain some estimate of the standard deviation in the measurements. A comparison of the two-electrode and four-electrode methods shows how the results for the two-electrode method can be in- fluenced by contact resistance.

CONCLUSION

Distinct recovery mechanisms at different wettability conditions have been identified. At strongly water-wet conditions the matrix and the fractures plays two distinct roles in the recovery process. The fractures will be the transport path for the water and oil while the matrix will imbibe water from and expel oil to the surrounding fracture network.

However for the less water-wet cases, capillary continuity of the water phase caused the fractured system to act more as a uniform block with less significant boarders between the matrix and the fracture. In synthetic cases like these laboratory experiments, water crossed oil-filled fractures of 2-3mm aperture when the wettability index to water was in the range of 0.2-0.7. In fractured oil reservoirs the matrix blocks will be surrounded by fractures with various degree of contact with adjacent blocks. At lower wettability conditions the weak capillary forces will result in poor recovery by imbibition from the surrounding fracture network.

The stacked core experiments indicate that capillary contact across open fractures established by water bridges contributes significantly to oil recovery beyond the potential for spontaneous imbibition. The findings from the stacked core experiment are supported by the parallel work being performed on large block experiments.

Changing the wettability cause a change in capillary pressure curve. The irreducible water saturation reached at about 50 psi capillary pressure value equivalent to 6000 RPM rock centrifuge during the drainage cycle using syntheticSaudi formation brine and Saudi oil fluid pair.

Experiments with cores and with glass beads have dem- onstrated that wettability has a profound effect on the resistivity behavior of partially saturated rocks. Oil-wet conditions give substantially higher n values. This effect can be quantitatively studied through a theoretical three- dimensional network model. The influence of wettability is closely coupled with the pore-structure characteristics.

Better pore connectivity and narrower pore-size distri- butions tend to minimize wettability effects. The effect of saturation hysteresis is small in water-wet media but more pronounced in oil-wet media. Because of the slight curvature of the I-Sw curves, two-point n values show apparent hysteresis effects. Stress has a small, almost negligible, effect on the m and n values for the simple inter-granular porosity systems considered here. For compressible or deformable media, this may not be the case, as seen with the asphaltene-coated bead packs. The experiments and the experimental technique used here demonstrate the need for careful experimentation and repeat runs to ensure reproducibility and correctness in electrical measurements.

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