Effects of Petrophysical Properties on Array-Induction Measurements Acquired in the Presence of Oil-Base Mud-Filtrate Invasion

Mayank Malik, Jesús M. Salazar, Carlos Torres-Verdín, Gong Li Wang, Hee Jae Lee, and Kamy Sepehrnoori

ABSTRACT

We quantify the influence of petrophysical properties on array-induction resistivity measurements acquired in the presence of oil-base mud (OBM) filtrate invasion. To simulate OBM-filtrate invasion, we consider a simple two-component formulation for the oil phase (OBM and reservoir oil) wherein the components are first-contact miscible. Simulations also include the presence of irreducible, capillary-bound, and movable water. The dynamic process of OBM invasion causes the component concentrations to vary with space and time. In addition, the relative mobility of the oil phase varies during the process of invasion given that oil viscosity and oil density are both dependent on component concentrations. This behavior in turn conditions the spatial distribution of electrical resistivity and, consequently, the borehole array-induction measurements.

We use an implicit pressure, explicit concentration (IMPEC) reservoir simulator with a two-component formulation to reproduce the invasion process in axial-symmetric rock formations penetrated by a vertical well. Simulations of the process of OBM-filtrate invasion yield two-dimensional spatial distributions of water and oil saturation that are transformed into spatial distributions of electrical resistivity using Waxman-Smits’ saturation-resistivity equations. Subsequently, we simulate array-induction measurements with a numerical mode-matching method.

Simulation of induction measurements in the presence of OBM are compared against the corresponding measurements acquired in the presence of water-base mud (WBM) using field measurements from a deepwater Gulf-of-Mexico reservoir. Sensitivity analyses are conducted to quantify the effect of OBM-filtrate invasion on array-induction logs, including different values of formation porosity-permeability, movable water zone, capillary pressure, relative permeability, mud-filtrate invasion rates, and fluid viscosity. In addition, we quantify the effect of changes of rock wettability due to OBM invasion on field measurements. Our study indicates that relative permeability, capillary pressure, and flow rate of invasion control the radial length of invasion of OBM and, consequently, the values and relative separation of apparent resistivity curves. Porous rock formations saturated with movable water entail smooth radial distributions of water saturation which, in turn, result in deep (1.5 ft – 2 ft) radial invasion profiles and relatively large separation of apparent resistivity curves. By contrast, null or marginal separation of apparent resistivity curves occurs when the invaded rock is at irreducible water saturation.

Keywords: Invasion, mud filtrate, induction, oil-base mud, compositional flow, borehole resistivity measurements
INTRODUCTION

The array-induction imager tool (AIT) is widely used to measure formation resistivity in the presence of OBM. Resistivity measurements remain influenced by the process of mud-filtrate invasion that takes place under overbalanced drilling conditions. In the case of oil-base muds, invading mud-filtrate is miscible with formation oil. Such a fluid miscibility condition results in changes of bulk-fluid density and fluid viscosity, thereby altering the apparent oil-phase mobility in the near-wellbore region. Within a capillary transition zone, additional changes in the fluid-saturation front due to invasion arise because of the presence of movable water. The fluid-saturation front can also be altered because of variations of oil-phase mobility. Thus, it becomes imperative to accurately model the effect of OBM on the invasion process and, subsequently, on array-induction measurements acquired some time after the onset of invasion.

Oil-base muds contain oil, water, and surfactants necessary to maintain the oil-water mixture as an emulsion (Bourgoine Jr. et al., 1986; Lavigne et al., 1997), in which oil is the continuous phase and encapsulates water (Proett et al. 2002). The continuous phase dominates the process of invasion and mixes with formation fluids. Proett et al. (2002) simulated the process of OBM invasion using Todd and Longstaff’s (1972) miscible displacement algorithm in which the OBM was treated as a solvent. In this paper, we assume that oil is the main component of the OBM and neglect the effect of water and surfactants in the emulsion. Therefore, oil and water phases remain immiscible. This assumption is not restrictive in field applications, especially when the chemical activity of the OBM prevents separation of fluid phases within the mud as the latter invades the formation.

We are interested in quantifying the time-space variability of array-induction resistivity measurements in the presence of OBM-filtrate invasion. Lavigne et al (1997) studied several field cases where such variability was attributed not only to invasion, but also to shale fracturing. While performing experiments using OBM invasion on sandstone cores, Yan and Sharma (1989) observed considerable changes of wettability as well as a reduction of permeability. The latter laboratory evidence provides solid footing to analyze the effect of invasion observed on induction resistivity measurements acquired in wells drilled with OBM.

In this paper, we first analyze field measurements available to study the process of mud-filtrate invasion in a clastic rock formation. Subsequently, we explain the method adopted to simulate the process of OBM-filtrate invasion and array-induction resistivity measurements. Sensitivity analyses shed insight to the petrophysical and fluid properties affecting the radial length and shape of the fluid invasion front. In addition, they provide a quantitative framework to interpret resistivity measurements. Finally, we use the results of sensitivity analyses to reproduce induction resistivity measurements acquired in a deepwater turbidite reservoir.

GEOLOGICAL DESCRIPTION

The formation under analysis consists of unconsolidated shaly sands of a turbidite depositional system in the deepwater Gulf of Mexico formed mainly by channel levees. The sedimentary structures include ripple stratification, clay laminations, and massive intervals with moderate-to-good grain sorting. Based on thin-section interpretation, it is known that cements of clinoptilolite and smectite are present in this system. Quartz concentration is between 85% and 95%, with clay minerals being the remaining solid components of the rock. The latter minerals include mixed-layer illite/smectite, illite/mica, kaolinite and chlorite in small amounts. In rare cases, it is possible to observe electrically conductive minerals such as siderite and pyrite, as well as traces of calcite and dolomite in the rock matrix. Porosity ranges between 20% and 34% while permeability varies from 10 mD in low-porosity zones to 2,500 mD in high-porosity intervals. Figure 1 shows photographs of two core sections displaying both shale-laminated and massive sand intervals.

PETROPHYSICAL ASSESSMENT

We focus our attention to three depth intervals of the formation penetrated by a cored well. The first interval is at the lower section of the formation and is a 100% water-saturated rock unit that is assumed homogeneous (single layer). This interval is used to calibrate our synthetic base case where we perform sensitivity analyses of resistivity measurements to several petrophysical and fluid properties. The second and third intervals, located in the upper section of the formation, correspond to partially oil-saturated rock units containing movable water. These two intervals are subsequently used to simulate the process of mud-filtrate invasion and to reproduce field measurements with numerical simulations.

Water saturation

The formation is mainly composed of shaly sands and this prompts us to invoke the Waxman-Smits (Waxman and Smits, 1968) equations to calculate water saturation ($S_w$).

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However, since the salt concentration of connate water is very high (>200 kppm), Archie’s equation can also be applied to calculate Sw in cases of low values of hydrocarbon saturation (Archie, 1942). Waxman-Smits’ equation is given by

\[
\frac{1}{R_w(r, z)} = S_w^* (r, z) \frac{a \phi^{n*} (z)}{a} \left[ \frac{1}{R_w} + \frac{B Q_v}{S_w (r, z)} \right],
\]

where \(r\) is radial distance measured from the axis of the borehole, \(z\) is vertical distance with respect to the top of the formation, \(R_w\) is true formation resistivity, \(R_w\) is connate water resistivity, \(a\) is the tortuosity factor, \(m^*\) and \(n^*\) are clay-corrected Archie’s cementation and saturation exponents, respectively, \(Q_v\) is volumetric concentration of sodium exchange cations (CEC) associated with clay, and \(B\) designates the equivalent conductance of the counterions as a function of connate water resistivity. We use equation (19) of Waxman and Smits (Waxman and Smits, 1968) to calculate \(B\), whereas \(m^*\), \(n^*\), and \(Q_v\) are obtained from laboratory measurements. Equation (1) is solved iteratively for \(S_w\) starting with Archie’s \(S_w\) as the initial guess. Table 1 describes the input parameters used to calculate initial water saturation using Waxman-Smits’ model. Such parameters were obtained from laboratory measurements performed on cores and fluid samples withdrawn from the formation under consideration.

### Porosity and permeability

We followed the method described by Salazar et al. (2006) to calculate porosity and permeability. Porosity is calculated from density and neutron measurements by accounting for the presence of two fluids (oil and water) and two solid components (quartz and clay) in the porous medium. Permeability is calculated via a modified Timur-Tixier equation from porosity and irreducible water saturation. The specific equation for permeability was obtained with calibration of porosity-permeability measurements, and is given by

\[
k = 4.22 \times 10^6 \frac{\phi^{7.5}}{S^0.09},
\]

where \(k\) (mD) is permeability, \(\phi\) (fraction) is porosity, and \(S_{irw}\) (fraction) is irreducible water saturation. The coefficient and the exponents of the above equation were estimated with a multi-linear least-squares regression. Figure 2 shows the results obtained from the petrophysical analysis in the water interval. Figure 3 describes the results obtained from the petrophysical assessment in the two partially hydrocarbon-saturated zones.

### SIMULATION OF ARRAY-INDUCTION RESISTIVITY MEASUREMENTS

We describe the simulation of array-induction resistivity...
measurements in two stages. The first stage discusses our reservoir simulation method for OBM-filtrate invasion in the formation. The second stage describes our resistivity simulation technique that uses spatial distributions of water saturation, calculated in the presence of OBM invasion, and transforms them into spatial distributions of electrical resistivity via equation (1).

**Numerical simulation of the process of mud-filtrate invasion with a compositional simulator**

We use an IMPEC numerical formulation to calculate the spatial distribution of water saturation due to OBM-filtrate invasion. The formulation and the algorithm used in this simulation are similar to those described by Malik et al. (2007). We assume azimuthal symmetry in formation properties with respect to the axis of a vertical borehole. Our formulation enforces boundary- and source-flow-rate conditions on specific depth segments along the wellbore. The outer limits of the reservoir consist of impermeable zones with no-flow boundary conditions. The Peng and Robinson’s (1976) Equation of State is used to calculate the fluid compressibility factor and to solve for oil phase density. Since we assume that the OBM is water-free, salt concentration in the water phase is considered constant across the formation and equal to that of connate water.

Malik et al. (2007) simulated formation testing and pressure transient measurements using a multi-component formulation in the presence of OBM invasion. They described hydrocarbon phase components in the formation using four pseudo-components whereas mud filtrate was modeled with one pseudo-component. Increasing the number of pseudo-components can lead to longer computation times. In addition, due to the averaging of fluid-component properties, we may not observe a significant difference in the fluid saturation front (and, therefore, on apparent resistivity measurements) by increasing the number of pseudo-components. Thus, in order to keep computational time to a minimum, we use a simple binary formulation to describe both mud filtrate and formation oil. All components of OBM filtrate and formation oil are lumped into two pseudo-components.

![Fig. 2](image1.png)  
**Fig. 2** Petrophysical assessment within the water zone. Track 1 shows depth. Track 2 displays gamma-ray and caliper logs. Track 3 shows array-induction resistivity measurements (2-ft vertical resolution). Track 4 displays the estimated permeability. Track 5 describes the volumetric analysis with shale concentration, bulk volume water, and effective porosity. This depth interval is regarded as the base case of analysis.

![Fig. 3](image2.png)  
**Fig. 3** Petrophysical assessment of hydrocarbon zones. Track 1 shows depth. Track 2 displays gamma-ray and caliper logs. Track 3 shows array-induction resistivity measurements (2-foot vertical resolution). Track 4 displays log estimated and rock-core permeability. Track 5 describes the volumetric analysis with shale concentration, bulk volume water, and log estimated effective and rock-core porosity. The upper section is vertically heterogeneous while the lower depth interval is a fairly homogenous sand unit.
Table 2 summarizes the geometrical properties for the numerical grid used to simulate the base case. The wellbore radius is equal to 0.49 ft and the external radius is 1000 ft, with the grid consisting of 50 nodes in the radial direction and 60 nodes in the vertical direction. In keeping with the rapid space-time variations of pressure and component concentrations in the near-borehole region, radial nodes are logarithmically spaced from the wellbore toward the outer grid boundary (located 1000 ft away from the axis of the borehole). Along the vertical direction, grid nodes are spaced uniformly.

We simulate the process of OBM-filtrate invasion with flow rates of invasion calculated on the basis of specific formation and mud properties. The calculation of the invasion flow rate is based on the work by Wu et al. (2005) concerning WBM-filtrate invasion. At the onset of the mud-filtrate invasion process, the flow rate of filtrate is high due to the overbalance pressure in the wellbore. As the mudcake thickens, the filtrate flow rate gradually decreases with time. Although mudcake eventually becomes impermeable, invasion continues at a slow rate until the casing is set in the wellbore. Since OBM and formation oil are miscible, the invasion process in the presence of OBM differs from that involving WBM. In our work, we use a constant volume-averaged flow rate that was intended to simulate WBM-filtrate invasion as described by Wu et al., (2005). Rather than developing a new algorithm to quantify the mud-filtrate invasion process in the presence of OBM, we use the theoretical WBM algorithm of Wu et al. (2005) and adjust it as necessary to reproduce borehole resistivity measurements and to calculate flow rates of invasion.

We assume that the original formation hydrocarbons consist of components in the range from C_2 to C_{30}. These hydrocarbons are lumped into one component (FHC1) using their pseudo-properties summarized in Table 3. Oil-base mud filtrate is assumed to consist of components from C_{14} to C_{18} that are also lumped into one component (MC_{16}). Moreover, the binary-interaction parameter between the hydrocarbon components is assumed null.

We calculate oil viscosity of the hydrocarbon phase, \( \mu_o \), using a quarter-power mixing rule (Todd and Longstaff, 1972) that is widely used in the literature to describe well-mixed fluids (Koval, 1963). The mixing rule is applied to the sum of component concentrations of formation oil (\( x_{fo} \)) and OBM (\( x_{OBM} \)), given by

\[
\mu_o = \left[ x_{fo} \cdot \mu_{fo}^{1/4} + x_{OBM} \cdot \mu_{OBM}^{1/4} \right]^4.
\]

In the above expression, component viscosities (\( \mu_{fo}, \mu_{OBM} \)) are initialized to specific values of formation temperature and pressure. Under dynamic drilling conditions, drilling mud mixes with the solid particulate matter and formation fluids. This can modify the composition and viscosity of the mud. In addition, due to the high cost of OBM compared to WBM, OBM is often recycled in field operations, thereby altering its original composition. Such an adverse situation leads to uncertainty in knowing the exact composition, PVT properties, and viscosity of the OBM. In our simulation model, we take into account uncertainty of mud-filtrate composition by simulating cases of different mud viscosity and by simulating the corresponding impact on array-induction resistivity measurements.

Relative permeability and capillary pressure are two fundamental properties in the simulation of multiphase fluid flow. Figure 4 shows laboratory measurements of oil-water relative permeability and capillary pressure curves, respectively, used for the simulations considered in this paper. The same figure shows a least-squares fit to the Brooks-Corey (Corey, 1994) relation that is ultimately assumed in our analysis. Table 4 summarizes the specific parameters used in conjunction with Brooks-Corey’s saturation-dependent properties. For completeness, the Appendix describes in detail the Brooks-Corey relationships for capillary pressure and relative permeability. Oil-base mud and formation oil are first-contact miscible under reservoir pressure and temperature conditions, whereupon no capillary pressure or relative permeability effects exist within the hydrocarbon phase.
Table 4: Summary of relative permeability and capillary pressure parameters used in Brooks-Corey equations.

<table>
<thead>
<tr>
<th>Variable</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Empirical exponent for wetting phase, $e_w$</td>
<td>2.2</td>
</tr>
<tr>
<td>Empirical exponent for non-wetting phase, $e_{nw}$</td>
<td>(water base case and oil base case) 3.0 and 2.0</td>
</tr>
<tr>
<td>End point for wetting phase, $k_{rw}$</td>
<td>0.37</td>
</tr>
<tr>
<td>End point for non-wetting phase, $k_{r nw}$</td>
<td>0.99</td>
</tr>
<tr>
<td>Empirical exponent for pore size distribution, $e_p$</td>
<td>25</td>
</tr>
<tr>
<td>Capillary pressure coefficient, $P_c$, [psi·Darcy$^{1/2}$]</td>
<td>15</td>
</tr>
</tbody>
</table>

Resistivity modeling

We simulate array-induction resistivity measurements from the spatial distribution of electrical resistivity. The simulation assumes 2D axial-symmetry, where current loop sources are located at the center of the borehole. We use the Numerical-Mode Matching (NMM) to perform the simulation (Chew et al., 1984; Zhang et al., 1999).

In summary, the algorithm is initialized with the fluid-flow simulation of OBM invading porous and permeable media. Inputs for the simulation include rock properties and fluid PVT properties obtained from a priori information. Water saturation, obtained from fluid flow simulation, is converted into electrical resistivity using Waxman-Smits’ formulation. Subsequently, we use the spatial distribution of electrical resistivity to simulate the corresponding borehole array-induction resistivity measurements.

BASE CASE

We designate the rock formation shown in Figure 2 as our base case for the simulation of mud-filtrate invasion. The formation under analysis is 100% water saturated. Subsequently, we modify the initial water saturation of the same formation to carry out sensitivity analyses in a partially oil-saturated formation. Table 5 summarizes the assumed average petrophysical properties for the formation under consideration.

<table>
<thead>
<tr>
<th>Property</th>
<th>Units</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thickness</td>
<td>ft</td>
<td>30</td>
</tr>
<tr>
<td>Effective porosity</td>
<td>fraction</td>
<td>0.27</td>
</tr>
<tr>
<td>Water saturation</td>
<td>fraction</td>
<td>1.0</td>
</tr>
<tr>
<td>Shale concentration</td>
<td>fraction</td>
<td>0.12</td>
</tr>
<tr>
<td>Horizontal Permeability</td>
<td>mD</td>
<td>325</td>
</tr>
<tr>
<td>Vertical Permeability</td>
<td>mD</td>
<td>100</td>
</tr>
<tr>
<td>Formation compressibility</td>
<td>1/psi</td>
<td>1E-8</td>
</tr>
</tbody>
</table>

History matching of apparent resistivity measurements to estimate the flow rate of OBM

Because the simulation of OBM-filtrate invasion requires knowledge of the flow rate, we invoked the well-established concept of WBM-filtrate invasion to estimate the flow rate of invasion. To that end, we used the University of Texas’ Formation Evaluation Toolbox (UTFET), which allows one to calculate the flow rate of mud-filtrate invasion based on mudcake, rock, and fluid properties (Alpak et al., 2003; Wu et al., 2005). The process begins with a model that assumes standard mudcake properties for water-base mud (Dewan and Chenevert, 2001). After multiple simulations with varying mudcake properties (e.g. permeability, porosity, and maximum thickness), we secured a good match between measured and simulated apparent resistivity measurements. The average flow rate necessary to reproduce the apparent resistivity curves was approximately 0.027 ft$^{3}$/day/ft. Table 6 describes the mudcake properties used to calculate the initial flow rate of mud-filtrate invasion. The same table describes the formation and fluid properties used in the analysis of the base case.

Figure 5 describes the spatial distributions of water saturation and electrical resistivity calculated after three days of WBM-filtrate invasion. As expected, the low mudcake permeability causes shallow invasion similar to the case of OBM that is subsequently described in this paper. This procedure is performed to calculate an initial guess of the flow-rate of OBM-filtrate invasion. However, we note that

![Figure 4](image)

**FIG. 4** Water-oil relative permeability and capillary pressure curves assumed in the simulations of mud-filtrate invasion. Each panel compares the Brooks-Corey model to laboratory core measurements. The superscripts “Corey” and “Lab” designate relative permeability values calculated with the Brooks-Corey equation and measured in the laboratory, respectively.
such a low permeability value for mudcake is not common in practical applications.

Simulation of OBM-filtrate invasion

The calculated average flow rate for the WBM case is used as input to the simulation of OBM-filtrate invasion together with the properties described in the lower section of Table 6. Figure 6 shows spatial distributions of water saturation and electrical resistivity calculated after three days of invasion. We note the similarity of the spatial distributions of electrical resistivity with those shown in Figure 5. Figure 7 compares the simulated AIT measurements against field data for the cases of invasion with WBM and OBM.

Figure 8 shows the time evolution of the radial distribution of OBM-filtrate saturation into the wet formation. Given that the spatial distribution of formation fluids due to invasion varies with time, formation resistivity in the near-wellbore region also remains a function of time. Three days after the onset of invasion the radial length of invasion is approximately 0.3 ft. This observation is consistent with previous studies (Proett et al., 2002) about the simulation of OBM invasion, which suggested that the radial extent of OBM invasion was shallower than for the case of WBM invasion for the same rock-formation properties.

SENSITIVITY ANALYSIS

We performed sensitivity analysis to appraise the effects of several petrophysical and fluid properties on the simulated array-induction resistivity logs. To that end, we

<table>
<thead>
<tr>
<th>Variable</th>
<th>Units</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mudcake reference permeability</td>
<td>mD</td>
<td>5.0E-4</td>
</tr>
<tr>
<td>Mudcake reference porosity</td>
<td>fraction</td>
<td>0.50</td>
</tr>
<tr>
<td>Mud Solid Fraction</td>
<td>fraction</td>
<td>0.06</td>
</tr>
<tr>
<td>Mudcake maximum thickness</td>
<td>inches</td>
<td>0.4</td>
</tr>
<tr>
<td>Mudcake compressibility exponent</td>
<td>fraction</td>
<td>0.30</td>
</tr>
<tr>
<td>Mudcake exponent multiplier</td>
<td>fraction</td>
<td>0.10</td>
</tr>
<tr>
<td>Mud hydrostatic pressure</td>
<td>psi</td>
<td>8,000</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Formation and Fluid Properties for All Cases of Study</th>
</tr>
</thead>
<tbody>
<tr>
<td>Variable</td>
</tr>
<tr>
<td>Initial formation pressure</td>
</tr>
<tr>
<td>Mud-filtrate viscosity</td>
</tr>
<tr>
<td>Oil viscosity</td>
</tr>
<tr>
<td>OBM-filtrate density</td>
</tr>
<tr>
<td>Oil density</td>
</tr>
<tr>
<td>Wellbore radius</td>
</tr>
<tr>
<td>Maximum invasion time</td>
</tr>
<tr>
<td>Maximum invasion flow rate</td>
</tr>
<tr>
<td>Temperature</td>
</tr>
<tr>
<td>Formation outer boundary</td>
</tr>
<tr>
<td>Residual water saturation</td>
</tr>
<tr>
<td>Residual oil saturation</td>
</tr>
</tbody>
</table>

FIG. 5 Spatial distributions of water saturation (left-hand panel) and electrical resistivity (right-hand panel) calculated after three days of water-base mud-filtrate invasion.

FIG. 6 Spatial distributions of water saturation (left-hand panel) and electrical resistivity (right-hand panel) calculated after three days of oil-base mud-filtrate invasion into a water zone.

TABLE 6 Summary of mudcake, fluid, and formation properties assumed in the simulation of the process of mud-filtrate invasion.
slightly modified the base case to study the effect of OBM-filtrate invading a partially oil-saturated formation. In this case, initial water saturation was assumed equal to 42% (hereafter referred to as oil-base-case). Therefore, the formation under consideration is located within a capillary transition zone with presence of movable water together with gravity forces and vertical cross flow. With the intent of emphasizing the spatial variability of array-induction resistivity curves, the average flow rate was increased to 0.1667 ft³/day/ft, which is approximately six times greater than the one used for the WBM case.

Figure 9 shows the calculated spatial distributions of water saturation and electrical resistivity for this new case. We note low water saturation at the top of the formation and high water saturation toward the bottom of the formation due to gravity forces. Since the density of the water phase is greater than the density of the oil phase, water tends to flow toward the lower part of the formation.

Figure 10 shows the corresponding simulated AIT measurements. Mud filtrate displaces the movable water in the near-wellbore region thereby causing separation among the array-induction apparent resistivity curves. Figure 11 shows the time evolution of the radial distribution of oil saturation and oil viscosity that is miscible with formation oil. Mud filtrate reaches 0.9 ft into the formation due to the increased rate of invasion. Owing to the miscibility between OBM and formation oil, the concentration of OBM varies radially in the formation. The variation of OBM concentration in turn affects both oil-phase density and viscosity. As shown in Figure 11, oil-base mud viscosity is greater than formation oil viscosity. The mobility of the oil phase ($\lambda_o$) is defined as

$$\lambda_o (S_o, t) = \frac{k_o (S_o)}{\mu_o (t)}$$

\[ \text{Figure 7 \ Measured and simulated array-induction apparent resistivities after three days of oil-base (right-hand panel) and water-base (left-hand panel) mud-filtrate invasion into a water zone.} \]

\[ \text{Figure 8 \ Time evolution of the radial distribution of oil saturation in the invaded formation. Twenty five curves are plotted at time intervals of 0.12 days. At the end of three days of invasion, mud-filtrate extends to 0.3 ft into the formation.} \]

\[ \text{Figure 9 \ Spatial distributions of water saturation (left-hand panel) and electrical resistivity (right-hand panel) calculated after three days of oil-base mud-filtrate invasion into a partially oil-saturated formation.} \]
where \( k_{ro} \) is relative permeability of oil-phase as a function of oil saturation \( (S_o) \), and \( \mu_o \) is oil-phase viscosity that varies spatially with time \( (t) \) due to invasion. Therefore, oil-phase mobility also varies spatially in the presence of mud-filtrate invasion. This behavior in turn affects the fluid saturation front, which not only depends on the rate of mud-filtrate invasion, but also on the viscosity contrast between OBM and formation oil.

**Sensitivity to the relationship between porosity and permeability**

We consolidated this analysis by using equation (2). To that end, we honored the dependency of permeability on porosity when dealing with extreme perturbations of the two properties. Moreover, for this analysis we kept the ratio of vertical to horizontal permeability equal to 0.30. We remark that for each set of porosity and permeability values, capillary pressure was also modified via Brooks-Corey equations. Changes in capillary pressure entail changes in the radial distribution of fluid properties. Figure 12 shows the corresponding array-induction measurements simulated for three values of porosity and permeability. In high-porosity, high-permeability zones, the effect of gravity forces and cross-flow is remarkable as observed in the right-most track of Figure 12. Low-porosity low-permeability rocks entail marked radial variability of electrical resistivity, hence deep invasion profiles. The separation between apparent resistivity curves is largely governed by porosity. Accordingly, Figure 13 shows that invasion is relatively shallow for the case of high-porosity and high-permeability rocks.

**Sensitivity to capillary pressure**

For this analysis, we modified the parameters included in the Brooks-Corey equation for capillary pressure in two stages. The first stage consists of modifying the capillary pressure coefficient, \( P_c^0 \), to render extreme values of the maximum capillary pressure but keeping the same shape of the base-case capillary pressure curve. We perform the sensitivity for the case of no capillarity \( (P_c^0 = 0) \) and very high capillarity \( (P_c^0 = 150 \text{ psi-Darcy}^{1/2}) \). The effect of this parameter is almost negligible. However, for high values of capillary pressure the variability of resistivity curves is null. In the absence of capillary forces, it becomes easier to dis-
place the water phase, and hence oil saturation increases in the near-wellbore region.

The second stage consists of modifying the capillary pressure exponent ($e_p$) to produce different shapes of the curves but keeping the same value of capillary-pressure coefficient. This approach is equivalent to either changing the height of the capillary transition zone or changing the grain-size distribution of the rock under analysis. Figure 14 shows three capillary pressure curves for three different values of $e_p$. Figure 15 shows the corresponding apparent resistivity curves for each capillary pressure curve. The variation of capillary-pressure exponent leads to a large pressure differential between the oil and water phases and makes it more difficult to displace water from the pore space. Therefore, as the exponent decreases, capillary pressure increases, leading to a decrease in the separation among apparent resistivity curves. Figure 16 shows that for an exponent equal to 2, there is negligible displacement of the water phase by mud filtrate and, consequently, we do not observe separation among apparent resistivity curves.

**Sensitivity to residual water saturation**

We modified the residual saturation to change the amount of movable water in the transition zone. The base case with $S_{wr} = 0.07$ was taken as the lower-bound value, whereas $S_{wr} = 0.40$ was the upper bound, which resulted in only 2% of movable water. Figure 17 shows the Brooks-Corey relative permeability and capillary pressure curves for both cases. The two curves are affected by changes of residual water saturation. Figure 18 shows the corresponding simulated apparent resistivity curves for

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**Fig. 14** Water-oil capillary pressure curves for three different exponents of the Brooks-Corey equation. Changes in the shape of the curves can also be interpreted as rock-quality (pore size), being the lowest value of $e_p$ the one associated with the poorest rock quality. The blue curve ($e_p = 25$) corresponds to the oil-base case.

**Fig. 15** Sensitivity of the simulated array-induction resistivity measurements to the shape of capillary pressure curves after three days of oil-base mud-filtrate invasion into a partially oil-saturated formation. The left-most panel describes the oil base case.

**Fig. 13** Radial distribution of oil saturation at the end of three days of invasion for different cases of formation porosity and permeability. The base case corresponds to a rock with effective porosity ($\phi$) equal to 0.25 and horizontal permeability ($k_h$) equal to 325 mD.
three values of $S_{wr}$. From the plot, we observe that high movable water (low $S_{wr}$) causes a large variation of array-induction apparent resistivity curves compared to the small variation observed for the case of low movable water (high $S_{wr}$). Figure 19 displays the radial distribution of oil saturation at the end of three days of invasion. Increasing the residual water saturation makes it difficult to displace water from the pores and hence there is no significant separation between the simulated apparent resistivity curves.

**Sensitivity to relative permeability (wettability)**

In this analysis, we modified the critical water saturation ($S_{wcr}$: water saturation when the relative permeabilities of wetting and non-wetting phases are the same) by changing

**Fig. 16** Radial distribution of oil saturation at the end of three days of invasion for different values of capillary-pressure exponent.

**Fig. 17** Water-oil capillary pressure ($P_c$) and relative permeability ($k_rw$ and $k_rnw$) curves for two different values of residual water saturation. Changes of residual water saturation ($S_{wr}$) are equivalent to shifting the fluid transition zone toward conditions of irreducible water saturation.

**Fig. 18** Sensitivity to residual water saturation of array-induction resistivity measurements simulated after three days of oil-base mud-filtrate invasion into a partially oil-saturated formation. The left-most panel describes the oil-base case.

**Fig. 19** Radial distribution of oil saturation at the end of three days of invasion for different cases of residual water saturation.
the exponents of the Brooks-Corey equation for relative permeability. The critical water saturation of the oil-base case is equal to 59%, which is considered a mixed-wet condition. Figure 20 shows extreme cases of relative permeability with low-$S_wcr$ indicating a preferentially oil-wet rock, and high-$S_wcr$ indicating a preferentially water-wet rock. Figure 21 shows the simulated apparent resistivity curves for the three values of wettability, from left to right, oil-, mixed-, and water-wet, respectively. Preferentially oil-wet rocks cause the invading oil to penetrate deeper in the formation, thereby resulting in more variability of the array-induction apparent resistivity curves. Highly water-wet rocks cause water to adhere to the grains, thereby preventing the invading oil from moving freely into the formation and, consequently, the radial length of invasion becomes relatively shallow.

The latter situation is similar to the case of irreducible water saturation. A similar conclusion stems from the radial distribution of oil saturation shown in Figure 22. In that figure, the radial length of invasion extends to 1.9 ft into the formation for a value of critical water saturation equal to 0.32. If the wettability of the rock is altered during the process of OBM-filtrate invasion, the Archie saturation exponent is no longer constant in the radial direction. It effectively becomes a function of wettability (Donaldson and Siddiqui, 1989), and therefore variable with time depending on invasion rate. Such effect is difficult to quantify; it suffices to state that we have found that changes in the wettability state of the rock are the most dominant in controlling the variability of apparent resistivity curves.

Sensitivity to the rate of mud-filtrate invasion

We perform an additional sensitivity analysis by changing the rate of mud-filtrate invasion associated with the oil base case. Two cases of perturbations of flow rate are considered in which the rates are changed by 50%. Figure 23 shows the simulated apparent resistivity curves that result from this analysis. We note that as the flow rate increases the variability of the apparent resistivity curves also increases. Figure 24 indicates that high invasion rates lead to relatively deep radial invasion. Uncertainty in both the flow rate of invasion and the elapsed time from the onset of drilling can drastically influence apparent resistivity measurements.
measurements, as the latter are highly sensitive to the time evolution of fluid saturation. Therefore, this sensitivity analysis shows that it is important to quantify both the mud loss and the maximum time of invasion for a given formation in order to assess the impact of mud-filtrate invasion on borehole resistivity measurements.

**Sensitivity to OBM viscosity**

In order to quantify the uncertainty of mud-filtrate composition on borehole resistivity measurements, we perform a sensitivity analysis by modifying the value of mud viscosity. Two cases of OBM viscosity are analyzed (0.9 cp and 2.5 cp) and compared to the oil base case. Figure 25 shows the radial distribution of oil viscosity resulting from this analysis. Even though we decrease the OBM-filtrate viscosity by 24% and increase it by 40% with respect to the oil base case, there are negligible differences between the simulated apparent resistivity curves for each value of viscosity. Therefore, for the case of low uncertainty (±25%) in the viscosity of mud filtrate, the corresponding impact on simulated array-induction apparent resistivity measurements is low in oil-bearing formations. However, if the formation is gas-bearing or heavy oil-saturated, where the viscosity contrast between mud and formation fluids is much higher, uncertainty in OBM viscosity can considerably affect the resistivity measurements.

**REPRODUCING THE FIELD MEASUREMENTS**

For the purpose of resistivity matching, we performed multiple simulations of the process of two-phase flow of oil-base mud filtrate invading a partially oil-saturated formation and compared the results to field measurements. As previously explained, the rock is also saturated with movable water whereas both formation and invading oil are fully miscible. The objective is to perform multiple simulations of induction resistivity by modifying the most dominant petrophysical and fluid parameters (as elicited from
TABLE 7 Summary of average petrophysical properties assumed for the formation under analysis.

<table>
<thead>
<tr>
<th>Thickness, ft</th>
<th>$\phi$, fraction</th>
<th>$S_w$, fraction</th>
<th>$k$, md</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lower Interval</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1.5</td>
<td>0.260</td>
<td>0.470</td>
<td>198</td>
</tr>
<tr>
<td>2.0</td>
<td>0.250</td>
<td>0.220</td>
<td>782</td>
</tr>
<tr>
<td>2.0</td>
<td>0.305</td>
<td>0.245</td>
<td>527</td>
</tr>
<tr>
<td>2.0</td>
<td>0.273</td>
<td>0.338</td>
<td>250</td>
</tr>
<tr>
<td>Upper Interval</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5.5</td>
<td>0.230</td>
<td>0.230</td>
<td>409</td>
</tr>
<tr>
<td>3.5</td>
<td>0.240</td>
<td>0.210</td>
<td>928</td>
</tr>
<tr>
<td>4.0</td>
<td>0.275</td>
<td>0.210</td>
<td>628</td>
</tr>
<tr>
<td>2.0</td>
<td>0.250</td>
<td>0.215</td>
<td>928</td>
</tr>
<tr>
<td>4.5</td>
<td>0.310</td>
<td>0.202</td>
<td>923</td>
</tr>
<tr>
<td>5.5</td>
<td>0.310</td>
<td>0.202</td>
<td>923</td>
</tr>
</tbody>
</table>

the sensitivity analysis) on invasion of OBM-filtrate, namely, relative permeability and flow rate of mud filtrate.

Field data

Figure 3 shows the formation under analysis. The lower interval is a 7.5 ft-thick, fairly homogeneous sandstone, and the upper interval is a highly heterogeneous 48.5 ft-thick clastic sequence. Both intervals exhibit high values of porosity and permeability. Previously, we described the algorithm used to perform the petrophysical assessment of field measurements. The lower formation is subdivided into four petrophysical layers, whereas the upper formation is subdivided into twelve petrophysical layers. Layer selection is based on observed changes of porosity-permeability and resistivity (Salazar et al., 2006). By dividing the formation into several layers, we are honoring the vertical heterogeneities included in the flow units. Table 7 shows layer values of petrophysical properties for the two depth intervals. These properties are assumed constant in the radial direction, but distinct for each petrophysical layer. Based on equation (2), permeability is averaged within each layer and the ratio of vertical to horizontal permeability (anisotropy) is kept equal to that of the base case (0.3).

Additional fluid, formation, and simulation grid properties are described in Tables 2 through 7.

History matching

Once the layered model is defined, we simulate array-induction measurements from the spatial distribution of electrical resistivity. At the end of resistivity modeling, field apparent resistivities are compared to those obtained from the simulation. The initial stage consists of matching the deepest-sensing resistivity curve (R90). This is accomplished by adjusting both porosity and initial water saturation. In the second stage, we attempt to match both the shallow-sensing resistivity curve (R10) and the separation of the intermediate-sensing curves (R20, R30, and R60). In the sensitivity analysis, we found that increasing the flow rate of invasion increased the maximum radial length of invasion. A similar situation occurred when we modify the value of critical water saturation in the relative permeability curves. The variability of the apparent resistivity curves increases when we assume that the rock is preferentially oil wet ($S_{wcr} < 50\%$).

The simulation is initialized with the flow rate and relative permeability curves for the oil-base case, namely, $q_{mf} = 0.1667 \text{ ft}^3/\text{day}/\text{ft}$ and $S_{wcr} = 59\%$. Subsequently, we change the average flow rate until securing a good match with the R10 curve. For the lower depth interval, the rate varies between 0.4 and 0.9 $\text{ft}^3/\text{day}/\text{ft}$ whereas for the upper depth interval the value is between 0.3 and 0.9 $\text{ft}^3/\text{day}/\text{ft}$. Such values are 12 to 33 times higher than the ones calculated for the corresponding case of WBM-filtrate invasion. After multiple iterations, we are unable to reproduce the separation of the measured apparent resistivity curves. We realize that it is possible to secure a good match only if we modify the wettability of the rock. Because we do not have core flooding data to quantify the variation of rock wettability due to OBM-filtrate invasion, we implement the simple approach of modifying the critical water saturation. This modification is performed layer by layer to secure the desired separation of apparent resistivity curves. Such separation also depends on the amount of movable water saturation within each layer. Assuming constant residual water saturation ($S_{wr} = 7\%$), for high values of initial water saturation the invading fluid moves more freely into the formation, thereby causing larger variability of the apparent resistivity curves. In order to secure a good match between measurements and simulations, $S_{wcr}$ is varied between 33% and 40%, with the lower values associated with those layers that exhibit low values of initial water saturation.

Previous studies of alkaline/surfactant/polymer (ASP) flooding validate some simulation models with laboratory measurements and show that rock wettability depends on
both formation and emulsion properties. Under uncertainty on the exact composition of OBM in the dynamic drilling environment, it is difficult to resort to an ASP model to simulate the process of mud-filtrate invasion. By modifying the critical water saturation to honor changes of rock wettability, we introduce a simpler approach that can be used in conjunction with any reservoir simulator to match the measured apparent resistivities. Results from the simulation of mud-filtrate invasion consist of spatial distributions of water saturation and electrical resistivity, shown in Figures 26 and 27 for the lower and upper depth formation intervals, respectively. Such distributions are input to the simulation of array-induction resistivity curves. Figures 28 and 29 show the simulated apparent resistivities (2-ft vertical resolution) after manually changing both flow rate and critical water saturation. The same figures describe the field measurements, layer permeabilities, and average flow rate of mud filtrate. Figures 30 and 31 compare simulated to measured apparent resistivity curves. For the lower depth interval, the simulated deepest- and shallowest-sensing apparent resistivity curves agree well with field measurements. However, measured and simulated intermediate-sensing curves do not match across the two middle layers, probably due to the transformation of raw conductivity measurements into apparent resistivities. In the field measurements, the R10 curve exhibits higher apparent resistivity values than the R20 curve, which indicates an anomalous behavior. In this case, our simulations show a more realistic variation between R10 and R20 apparent resistivity curves with R10 > R20. As shown in Figure 31, for the upper depth interval, with the exception of a few layers, most of the simulated apparent resistivity curves agree well with field measurements.

**DISCUSSION AND CONCLUSIONS**

We studied the influence of OBM-filtrate invasion on array-induction resistivity measurements using a binary component formulation to describe the miscibility of the oil phase. Numerical simulations indicated that resistivity measurements are highly sensitive to porosity and permeability, rock wettability, and rate of mud-filtrate invasion. Alteration of rock wettability in the near-wellbore region increases the mobility of the water phase and influences the apparent resistivity measurements. Our simulations show that to properly quantify the influence of the process of OBM-filtrate invasion on borehole resistivity measurements it is important to quantify the mud loss in the invaded formation as well as the duration of the invasion process.

The well-documented physics of WBM-filtrate invasion can be used to estimate an initial value of flow rate of OBM-filtrate invasion. By performing multiple sensitivity analyses we were able to diagnose which petrophysical and fluid properties entailed the largest change on the spatial

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**FIG. 26** Lower depth interval of the oil-zone showing the spatial distributions of water saturation and electrical resistivity calculated after three days of oil-base mud-filtrate invasion. The spatial distributions were calculated after both flow rate of mud-filtrate invasion and relative permeability were adjusted multiple times to fit the available array-induction resistivity measurements.

**FIG. 27** Upper depth interval of the oil-zone showing the spatial distributions of water saturation and electrical resistivity calculated after three days of oil-base mud-filtrate invasion. The spatial distributions were calculated after both flow rate of mud-filtrate invasion and relative permeability were adjusted multiple times to fit the available array-induction resistivity measurements.
Effects of Petrophysical Properties on Array-Induction Measurements Acquired in the Presence of Oil-Base Mud-Filtrate Invasion

distribution of fluid properties resulting from OBM invasion. High rates of invasion caused deep radial invasion profiles. However, relative-permeability and capillary-pressure curves controlled the shape of the fluid invasion front. Thus, when simulating array-induction resistivity measurements, we found that the variability of apparent resistivity curves with various radial lengths of investigation remained controlled by the rock’s relative permeability and capillary pressure. The separation of these curves was relatively large when the rock was preferentially oil wet, whereas the separation was negligible when the rock was preferentially water wet.

We simulated array-induction resistivity measurements using a history-matching approach in a partially oil-saturated turbidite reservoir. The formation consisted of dead oil and was invaded with OBM-filtrate. Simulation results indicated that it was possible to secure a good match with field measurements by simultaneously modifying both critical water saturation and rate of mud-filtrate invasion. However, uncertainty on the value of critical water saturation rendered our history-matching method difficult to adapt for automatic inversion.

Dead oil and OBM-filtrate were fully miscible under reservoir pressure and temperature conditions. In addition, we assumed that OBM did not include a water phase as part of emulsion, thereby neglecting salt mixing between the emulsion and movable water in the formation. Our binary component formulation limited the modeling of partial miscibility between formation gas and OBM as we needed additional pseudo-components to accurately reproduce phase behavior effects. In this paper, we focused our analysis to a high-porosity, high-permeability formation and concluded that flow rate of invasion and relative permeability dominated the radial length of invasion and variability of apparent resistivity curves. However, this conclusion may not hold true in low-porosity, low-permeability formations. As emphasized by the sensitivity analysis, low-porosity rocks entail deep invasion and therefore resulted in significant variability of apparent resistivity curves. At irreducible water saturation conditions, we did not observe changes in the radial distribution of water saturation: the OBM-filtrate mixed with the native oil without entailing separation of apparent resistivity curves with various radial lengths of investigation. On the other hand, we showed that array-induction resistivity measurements can be highly affected by deep invasion (1.5 ft to 2ft) in zones with movable water. The larger the difference between irreducible and initial water saturation, the smoother the radial distribution of water saturation, and hence the larger the variability of apparent resistivity curves with different radial lengths of investigation.

Given the lack of laboratory measurements of wettability, we did not quantify the effect of wettability

**Fig. 28** Lower depth interval: field (Track 1) 2-ft vertical resolution array-induction resistivity measurements compared to their simulated values after (Track 2) resistivity matching by manually changing both flow rate and relative permeability. The right-most tracks show the matching values of flow rate of mud-filtrate along with the assumed permeability for each layer. Shaded rectangles identify the various layers assumed in the simulation, where green zones identify shales.

**Fig. 29** Upper depth interval: field (Track 1) 2-ft vertical resolution array-induction resistivity measurements compared to their simulated values after (Track 2) resistivity matching by manually changing both flow rate and relative permeability. The right-most tracks show the matching values of flow rate of mud-filtrate along with the assumed permeability for each layer. Shaded rectangles identify the various layers assumed in the simulation, where green zones identify shales.
variations on the saturation exponent. Donaldson and Siddiqui (1989) performed laboratory experiments by flooding crude oil into core samples and measured different values of the Archie saturation exponent, \( n \), for different values of oil saturation. As they injected oil, the rock became strongly oil-wet, thereby increasing the saturation exponent. Based on the comparisons between measurements and simulations, we found that resistivity measurements acquired in the lower-depth interval oil zone were difficult to match. One possible reason for the mismatch could be the processing of field raw conductivity measurements into apparent resistivities. Another reason may be an anomalous radial invasion profile due to the presence of surfactants on the emulsion forming the OBM, which was not studied in this paper. Including the presence of surfactants in the OBM is still work in progress. History matching with field measurements helped us to diagnose adverse field conditions and led to improved interpretation of apparent resistivity measurements in the presence of invasion.

**NOMENCLATURE**

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
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<tbody>
<tr>
<td>( a )</td>
<td>Archie’s tortuosity coefficient, [ ]</td>
</tr>
<tr>
<td>( B )</td>
<td>Equivalent conductance of counterions, [cm(^2)/(Ω·meq)]</td>
</tr>
<tr>
<td>( c_{nw} )</td>
<td>Empirical exponents for non-wetting-phase relative permeability, [ ]</td>
</tr>
<tr>
<td>( e_p )</td>
<td>Empirical exponents for capillary pressure, [ ]</td>
</tr>
<tr>
<td>( e_w )</td>
<td>Empirical exponents for wetting-phase relative permeability, [ ]</td>
</tr>
<tr>
<td>( k )</td>
<td>Absolute permeability, [mD]</td>
</tr>
<tr>
<td>( k_{nw} )</td>
<td>Non-wetting-phase (oil) relative permeability, [ ]</td>
</tr>
<tr>
<td>( k_{nw}^0 )</td>
<td>Non-wetting-phase relative permeability end point, [ ]</td>
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<tr>
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<td>Wetting-phase relative permeability, [ ]</td>
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<tr>
<td>( k_{w}^0 )</td>
<td>Wetting-phase relative permeability end point, [ ]</td>
</tr>
<tr>
<td>( m^* )</td>
<td>Clay-corrected Archie’s cementation exponent, [ ]</td>
</tr>
<tr>
<td>( n^* )</td>
<td>Clay-corrected Archie’s saturation exponent, [ ]</td>
</tr>
<tr>
<td>( P_c )</td>
<td>Capillary pressure, [psi]</td>
</tr>
<tr>
<td>( P_c^0 )</td>
<td>Coefficient for capillary pressure equation, [psi·Darcy(^{1/2})]</td>
</tr>
<tr>
<td>( Q_v )</td>
<td>Volumetric concentration of sodium exchange cations, [meq/ml]</td>
</tr>
<tr>
<td>( q_{mf} )</td>
<td>Flow rate of oil-base mud filtrate, [ft(^3)/d/ft]</td>
</tr>
<tr>
<td>( r )</td>
<td>Radial distance from the wellbore, [ft]</td>
</tr>
<tr>
<td>( R10 )</td>
<td>10 inches radial length of investigation apparent resistivity, [Ω·m]</td>
</tr>
<tr>
<td>( R20 )</td>
<td>20 inches radial length of investigation apparent resistivity, [Ω·m]</td>
</tr>
</tbody>
</table>

**FIG. 30** Lower depth interval: comparison of field and simulated array-induction resistivity curves after resistivity matching for five radial lengths of investigation. The left-most track shows the 1-ft resolution shallowest-sensing resistivity curves, the right-most-track displays the 4-ft resolution deepest-sensing curves and the three center tracks show the 2-ft resolution intermediate-depth-of-investigation curves. Continuous thick curves identify simulated values and thin dashed curves identify field data.

**FIG. 31** Upper depth interval: comparison of field and simulated array-induction resistivity curves after resistivity matching for five radial lengths of investigation. The left-most track shows the 1-ft resolution shallowest-sensing resistivity curves, the right-most-track displays the 4-ft resolution deepest-sensing curves and the three center tracks show the 2-ft resolution intermediate-depth-of-investigation curves. Continuous thick curves identify simulated values and thin dashed curves identify field data.
Effects of Petrophysical Properties on Array-Induction Measurements Acquired in the Presence of Oil-Base Mud-Filtrate Invasion

R30 30 inches radial length of investigation apparent resistivity, [Ω-m]
R60 60 inches radial length of investigation apparent resistivity, [Ω-m]
R90 90 inches radial length of investigation apparent resistivity, [Ω-m]

\( R_t \) True formation resistivity, [Ω-m]
\( R_w \) Conntate water resistivity, [Ω-m]
\( S_o \) Normalized wetting-phase saturation, [fraction]
\( S_w \) Oil saturation, [fraction]
\( S_{sw} \) Water saturation, [fraction]
\( S_{oir} \) Critical water saturation, [fraction]
\( S_{oir} \) Irreducible (residual) water saturation, [fraction]
\( x_{fo} \) Component concentration of formation oil, [fraction]
\( x_{OBM} \) Component concentration of oil-base mud, [fraction]
\( z \) Vertical distance with respect to the top of formation, [ft]
\( \phi \) Effective porosity, [fraction]
\( \lambda_o \) Oil mobility, [md/cp]
\( \mu_o \) Oil viscosity, [cp]
\( \mu_{fo} \) Formation oil viscosity, [cp]
\( \mu_{OBM} \) Oil-base mud-filtrate viscosity, [cp]

ACKNOWLEDGEMENTS

A note of special gratitude goes to Kerr-McGee (now Anadarko) for providing the data used in the field studies. We thank two anonymous reviewers for their constructive editorial and technical comments that improved the quality of the first manuscript. The work reported in this paper was funded by the University of Texas at Austin’s Research Consortium on Formation Evaluation, jointly sponsored by Anadarko, Aramco, Baker Atlas, BHP Billiton, BP, British Gas, ConocoPhillips, Chevron, ENI E&P, ExxonMobil, Halliburton Energy Services, Hydro, Marathon Oil Corporation, Mexican Institute for Petroleum, Occidental Petroleum Corporation, Petrobras, Schlumberger, Shell International E&P, Statoil, TOTAL, and Weatherford.

REFERENCES


APPENDIX

We assume a Brooks-Corey (Corey, 1994) relationship to compute the saturation-dependent relative permeability and capillary pressure. According to this model, wetting-phase relative permeability \( k_{nw} \) is given by

\[
k_{nw} = k_0 w S_{nw}^{e w}, \tag{A.1}
\]

where \( k_0 w \) is wetting-phase end-point relative permeability and \( e_w \) is an empirical exponent for wetting phase. In equation (A.1), \( S_n \) is the normalized wetting phase saturation, given by

\[
S_n = \frac{S_w - S_wr}{1 - S_m - S_{mr}}, \tag{A.2}
\]

where \( S_n \) is saturation and \( S_{mr} \) is irreducible saturation for the wetting phase, and \( S_{mr} \) is irreducible saturation for the non-wetting phase. The non-wetting phase relative permeability \( k_{nw} \) is given by

\[
k_{nw}^n = k_{nw}^0 (1 - S_n)^{e_r}, \tag{A.3}
\]

where \( k_{nw}^0 \) is non-wetting phase end-point relative permeability and \( e_r \) is an empirical exponent for non-wetting phase. Drainage capillary pressure is expressed by a relationship of the form

\[
P_c = P^0_c \left( \frac{\phi}{k} (1 - S_n)^{e_p} \right) \tag{A.4}
\]

where \( P_c \) is capillary pressure between oil and water phases, \( P^0_c \) is the coefficient for capillary pressure, \( e_p \) is the pore-size distribution exponent, \( \phi \) is porosity, and \( k \) is permeability expressed in Darcies.

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