SATURATION-HEIGHT AND INVASION CONSISTENT HYDRAULIC ROCK TYPING USING MULTI-WELL CONVENTIONAL LOGS

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ABSTRACT

Hydraulic rock typing is based on pore geometry, which relates to saturation-height modeling at a later stage in reservoir characterization. Additionally, pore geometry affects mud-filtrate invasion under over-balanced drilling conditions. Reliable hydraulic rock typing should simultaneously honor saturation behavior in the vertical direction and mud-filtrate invasion in the radial direction. Such a condition becomes critical when hydraulic rock typing is performed with well logs acquired in multiple wells penetrating the same or different capillary transition zones.

This paper considers three conventional core-based rock typing methods, namely Leverett’s $\sqrt{R/\phi}$, Winland $R_{35}$, and Amaefule’s flow zone index, to appraise whether rock classifications can be extrapolated from core-data to well-log domains. A new quantitative log attribute is derived from well logs to assist hydraulic rock typing, which integrates in-situ reservoir capillary pressure ($P_c$) and initial water saturation ($S_w$). The assumption is that the reservoir under study underwent hydrocarbon migration wherein vertical fluid distribution is still well represented by the primary-drainage capillary pressure curve. Petrophysical properties that are closely linked to pore geometry are quantified by invoking both Leverett’s J-function and Thomeer’s $G$-factor. The new log attribute is based on standard well-log analysis and only requires conventional well logs for its application. Thus, it can be generally applied to both clastic and carbonate reservoirs in multi-well contexts. It overcomes the limitation of the bulk volume water method which is only applicable to reservoir zones that are at nearly irreducible water saturation. Most importantly, it provides good initial estimates to constrain in-situ dynamic rock-fluid properties such as capillary pressure and relative permeability.

The method proceeds with initial estimates of dynamic properties to construct multi-layer petrophysical models with a common stratigraphic framework (CSF) for each rock type, and to simulate the process of mud-filtrate invasion. By honoring all the available well logs with the process of mud-filtrate invasion, pseudo dynamic rock-fluid petrophysical properties (capillary pressure and relative permeability) are calculated for each rock type that are amenable to reservoir modeling and simulation. Synthetic cases constructed from real reservoir analogues are used to test the method with predefined rock-type models. Two field cases of turbidite (submarine fan) siliciclastic reservoirs are used to verify the reliability of the new rock-typing method. In both cases, the agreement between log- and core-derived rock types is improved by 20% or more with the new method. One limitation of the new rock-typing method is that it is only applicable to reservoir zones above oil-water or gas-water contacts. Furthermore, the resolution of rock types is limited by the vertical resolution of the deep resistivity log.

INTRODUCTION

G.E. Archie (1950) defined petrophysical rock type based on the associated pore-size distribution, which acts as the hub linking the rock’s static and dynamic petrophysical properties (Fig. 1). In the same paper, Archie mentioned the possibility of using various types of well logs to probe the pore-size distribution and identify petrophysical rock types. Nowadays, rock typing is a key element necessary to construct reliable three-dimensional reservoir models. Hydraulic rock typing specifically refers to hydraulic properties of reservoir rocks, including storage and flow capacity, and provides a basis for many other reservoir characterization efforts such as saturation-height analysis and dynamic reservoir modeling (Rushing et al., 2008). Numerous hydraulic rock typing methods were advanced in the past; some of them invoke core measurements, such as Leverett’s reservoir quality index ($ROI = \sqrt{R/\phi}$) (Leverett, 1960), Winland’s $R_{35}$ (Pittman, 1992), and flow zone index ($FZI$) (Amaefule et al., 1993), while some others are mainly based on well logs, such as those defined with the concept of electrofacies (Serra and Abbot, 1981) and bulk volume water ($BVW = \phi S_w$, Buckles, 1965). Few papers have discussed the technical challenges remaining to accurately and reliably map hydraulic rock types from core to well logs. Common practice uses core-established rock types and their corresponding well-log responses to identify and classify rock types in a supervised-learning approach. Often, this method is not satisfactory because
well-log-defined facies may not be directly related to pore geometry. Indeed, most well logs are more sensitive to mineralogy and pore-filled fluids than to pore geometry. Resistivity logs are possibly the best indicators of rock texture. However, in many deepwater turbidite oil reservoirs, capillary transition effects render resistivity logs difficult to use in rock typing across multiple wells due to fluid saturation changes with height (Fig. 2). This paper introduces a new method to classify rocks based solely on well-log-derived properties; it probes the pore geometry, eliminates the effect of capillary transition on resistivity logs, and reconciles rock classes with core mercury injection capillary pressure (MICP) data. Additionally, it extracts important reservoir quality information from the reservoir’s saturation-height behavior and has practical applications in reservoir development such as horizontal well steering, facies interpretation, and reservoir connectivity analysis. The method also revisits Archie’s rock type definition and enables effective core-log integration.

Fig. 1: Archie’s original definition of rock type and its relation to petrophysical properties (Archie, 1950).

In the process of reservoir characterization, saturation-height modeling needs to be rock-type based, i.e., different rock types are associated with different saturation-height relations (Lucia, 1999). Core-derived rock types and their capillary pressure properties should be consistent with well-log-derived saturation-height distributions of water. At the same time, under relatively steady drilling conditions, mud-filtrate invasion is dominantly controlled by rock petrophysical properties. The radial invasion profile thus provides important information for hydraulic rock typing. A reliable hydraulic rock typing scheme must honor both saturation-height variations in the vertical direction and mud-filtrate invasion in the radial direction. Several authors documented cases in which petrophysical properties were inferred from the physics of mud-filtrate invasion (Salazar et al., 2006; Heidari et al., 2010). This paper extends the concept of mud-filtrate invasion to integrate saturation-height modeling and establish rock-type-based dynamic rock-fluid petrophysical properties.

In our study, we first compare three well-known core-based quantifying methods of hydraulic rock types and conclude that these methods are closely correlated due to similar mathematical formulæ and underlying petrophysical principles (pore-throat size or hydraulic radius). We then select Leverett’s $RQI$ (the simplest among the three methods) and derive its equivalent property from well logs using Leverett’s $J$-function to assist rock typing in multiple wells that penetrate the same capillary transition zone. For each identified rock type, we select a thick zone to simulate well logs under mud-filtrate invasion and calibrate the associated dynamic petrophysical properties. The workflow is referred to as “invasion facies” modeling. Final products from rock typing are not only a distribution of rock types along the well trajectory, but also the associated static and dynamic petrophysical properties, which are important for reservoir modeling and simulation. We use the calibrated capillary pressure curves to remodel saturation height based on the diagnosed rock types and compare them to the vertical distribution of resistivity-derived water saturation.

The new method for rock typing is verified with measurements acquired in two field cases of thick turbidite oil reservoirs. In case no. 1, we show how saturation-height and invasion consistent rock typing provides important information for horizontal well placement and steering. In case no. 2, we describe results of the application of the method in multiple wells to assist stratigraphic and sedimentary interpretation.

\textbf{$RQI$ vs. $R_{35}$ vs. $FZI$}

The three core-derived quantities have been widely used for hydraulic rock typing. Arguments regarding their strengths and weaknesses can be found in numerous publications on a case-by-case basis. Although these quantities originated from different authors using different approaches (empirical vs. experimental vs. analytical), they bear more similarities than differences owing to the common underlying petrophysical property that they intend to quantify - pore-throat size or hydraulic radius. The three quantities are functions of porosity and permeability measured with routine core
analysis. Let \( \Theta \) stand for any of the above quantities. Their common formulae can be expressed as:
\[
\log(\Theta) = x \log k + y \log \phi + z .
\] (1)
We compared the coefficients \( x, y, \) and \( z \) associated with these formulae in Table 1 and found that coefficients \( x \) are all close to 0.5, which has a well-established physical basis: permeability is proportional to the square of pore-throat radius. To emphasize their similarity, we repeat numerical testing of the correlation between these quantities using randomly generated synthetic core porosity-permeability points (Fig. 3). Correlations between each pair of quantities on a logarithmic scale are consistently higher than 0.9. This simple exercise indicates that the key to hydraulic rock typing for reservoir characterization does not rest on the selection of the three core-based quantities but on how to accurately map them into well-log domain.

**Table 1: Coefficients of mathematical expressions associated with three core-based properties.**

<table>
<thead>
<tr>
<th></th>
<th>( x )</th>
<th>( y )</th>
<th>( z )</th>
</tr>
</thead>
<tbody>
<tr>
<td>Leverett’s RQI</td>
<td>0.5</td>
<td>-0.5</td>
<td>0.0</td>
</tr>
<tr>
<td>Winland’s ( R_{35} )</td>
<td>0.588</td>
<td>-0.864</td>
<td>0.732</td>
</tr>
<tr>
<td>Amaefule’s FZI</td>
<td>0.5</td>
<td>-0.5</td>
<td>variable</td>
</tr>
</tbody>
</table>

**In-situ Reservoir Capillary Pressure**

In a hydraulically connected reservoir, in-situ reservoir capillary pressure (\( P_c \)) is calculated from the difference between true vertical depth (TVD) and the free water level (FWL), which can be derived from pressure measurements, resistivity logs, or core MICP data, namely,
\[
P_c = (\Delta \rho) gh = 0.433 \times \Delta \rho \times (TVD - FWL) ,
\] (2)
where \( \Delta \rho \) is density difference between connate water and hydrocarbon in g/cm\(^3\); TVD and FWL are depths in ft.

**Well-Log-Derived Leverett’s RQI**

Leverett’s RQI can be derived from \( P_c \) and initial connate-water saturation (\( S_w \)) using the empirical J-function model (Darling, 2005; Torres-Verdín, 2012)
\[
S_w = S_{wirr} + a J_b = J(S_c) = (S_c - S_{wirr}) \frac{1}{a},
\] (3)
together with Leverett’s capillary pressure model, given by
\[
\sqrt[3]{\frac{J(S_c)}{P_c}} = \frac{J(S_c) \times \sigma \cos \theta}{P_c} = \frac{(S_c - S_{wirr}) \frac{1}{a} \times \sigma \cos \theta}{P_c},
\] (4)
where \( S_w \) is initial water saturation, \( S_{wirr} \) is irreducible water saturation (which is set to 0.01 lower than the minimum water saturation in the entire reservoir column, Darling, 2005); \( a \) and \( b \) are constants derived from core-measured capillary pressure curves; \( \sigma \cos \theta \) is the product of interfacial tension and contact angle, which is assumed constant in the same reservoir; \( P_c \) is in-situ reservoir capillary pressure in psi. Equation (4) provides a link between saturation-height and reservoir quality index; it assumes that all reservoir rocks exhibit the same \( S_{wirr} \) and constants \( a \) and \( b \). This assumption is not always true but it does provide a first-pass quantification of reservoir quality based on a well-log-derived saturation-height relationship and remains reliable in many field cases.

**Leverett’s J vs. Thomeer’s G**

An alternative parameter to quantify pore geometry from well-log-derived saturation height is Thomeer’s G factor (1960). Thomeer proposed a model to define mercury/air capillary pressure curves given by
\[
\frac{S_h}{S_{w}} = e^{-G \log(P_c/P_c^*)},
\] (5)
where \( S_h \) is mercury saturation at capillary pressure \( P_c^* \); \( S_{w} \) is mercury saturation at infinite capillary pressure; \( G \) is pore geometrical factor reflecting the distribution of pore throats and their associated pore volume; \( P_c^* \) is the extrapolated displacement or entry pressure. Again, due to their similar mathematical expressions, Leverett’s J

**METHOD AND WORKFLOW**

**Conventional Well-Log Analysis**

Core-calibrated conventional well-log analysis is critical to provide relevant petrophysical properties, such as volumetric concentration of shale (\( C_{sh} \)), total porosity (\( \phi \)), and connate-water saturation (\( S_w \)). All these petrophysical properties relate more directly to hydraulic rock types than apparent logs. Therefore, it is here suggested that rock typing be based on these petrophysical properties whenever possible.
and Thomeer’s $G$ factors are highly correlated to each other. Numerical testing using randomly generated saturation-height points consistently gives rise to correlation coefficients higher than 0.9 (Fig. 4). For simplicity, we consistently use Leverett’s $J$ function and $RQI$ to quantify rock types in this paper.

**Fig. 4: Numerical testing of the correlation between log-derived Leverett’s $RQI$ and Thomeer’s $G$ factor.**

### Rock Classification and Validation

For each field case, we first perform core-based hydraulic rock typing with Leverett’s $RQI$. We then consider the well-log-data domain to classify rock types via cluster analysis on several relevant petrophysical attributes including volumetric concentration of shale, total porosity, water saturation in the irreducible zone, and well-log-derived $RQI$ (as in Eq. 4) in the capillary transition zone. Because both core- and well-log-based rock typing include the same quantity - $RQI$, the correlation between core-defined and well-log-derived rock types is significantly enhanced. Rock classification results can be validated by predicting permeability based on the well-log-derived rock types and compared to core measurements. In both cases, we show that a reliably-defined rock type distribution can help to accurately estimate permeability.

### Calibration of Dynamic Petrophysical Properties from Invasion Simulation - Invasion Facies Modeling

After rock typing, we calculate the porosity-permeability trend, the saturation-height relation, and capillary pressure curves for each rock type. We proceed to calibrate capillary pressure and relative permeability for each rock type by simulating the process of mud-filterate invasion at reservoir conditions. This simulation involves rock petrophysical properties such as porosity, permeability, capillary pressure, and relative permeability. It also considers drilling engineering parameters such as mud type, invasion duration, and overbalance pressure. Fluid properties such as density, viscosity, salt concentration, and temperature are also taken into consideration. With stable drilling conditions and constant fluid properties, rock petrophysical properties determine the radial distributions of water saturation which are used to calculate radial distributions of physical properties such as electrical resistivity, density, and migration length, to numerically simulate the corresponding apparent resistivity, density, and neutron logs (Gandhi et al., 2010). By matching all available well logs after mud-filtrate invasion, we obtain a set of estimated rock-fluid dynamic petrophysical properties, including both capillary pressure and relative permeability. We adopt Voss et al.’s (2009) and Heidari et al.’s (2010) procedure to iteratively estimate petrophysical properties using UTAPWeLS$^1$. The measured well logs must be corrected for borehole environmental effects to be compared to numerical simulations. Brooks-Corey’s parametric equations are adopted to describe saturation-dependent capillary pressure and relative permeability (Corey, 1994; Peters, 2012), namely

\[
P_c = P^0_c \frac{\phi^0}{k} (1 - S_w)^{1/2},
\]

where $P_c$ is capillary pressure in psi, $P^0_c$ is a constant coefficient in psi.darcy$^{1/2}$, $\phi$ is total porosity, $k$ is permeability in Darcy, $e_p$ is pore-size distribution exponent, and $S_N$ is normalized wetting-phase saturation, given by

\[
S_N = \frac{S_w - S_{wr}}{1 - S_{wr} - S_{nwr}},
\]

where $S_w$ is wetting-phase saturation, $S_{wr}$ is residual wetting-phase saturation, and $S_{nwr}$ is non-wetting phase residual saturation. Wetting and non-wetting saturation-dependent relative permeabilities, $k_{rw}$ and $k_{nwr}$, respectively, are given by

\[
k_{rw} = k_w^0 S_N^{e_p},
\]

and

\[
k_{nwr} = k_w^0 (1 - S_N)^{-e_p}.
\]

Note that $S_{nwr}$ must be set to zero in a primary drainage capillary pressure curve while it is non-zero in an imbibition capillary pressure curve (Fig. 5).

**Fig. 5: Example of saturation-dependent drainage and imbibition capillary pressure curves for the same rock.**

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$^1$ The University of Texas at Austin’s Petrophysics and Well Log Simulator
Saturation-Height Modeling with Brooks-Corey’s Drainage Capillary Pressure Model

After calibrating each rock type’s capillary pressure with invasion simulation, we perform saturation-height modeling on a rock-type basis. In a water-wet reservoir, saturation height modeling is performed by combining Eqs. (2), (6), and (7), i.e.

\[ S_w(\alpha) = S_{wirr} + (1 - S_{wirr})[1 - (\alpha H)^{e_p}], \]  
\[ \alpha = \frac{0.433 \Delta \rho}{P_\rho \phi} \sqrt{P}, \]

where \( S_{wirr} \) is irreducible water saturation and \( e_p \) is pore-size distribution exponent; \( H \) is height above the FWL in ft, \( \alpha \) is a scale coefficient that depends on rock type and density difference between water and hydrocarbon. It is necessary to estimate \( S_{wirr}, \alpha, \) and \( e_p \) for each rock type under a specific reservoir context to achieve satisfactory saturation-height modeling in formations without well penetration.

SYNTHETIC CASE

A synthetic reservoir model is constructed to gain understanding on how capillary transition affects rock typing via conventional methods such as E-facies and Buckle’s number. The reservoir model is an ideal cyclic turbidite sequence with a total thickness of 300 ft. Three hydraulic rock types of different grain sizes (therefore different pore-throat radii) are stacked to form fining-upward sequences (grain-size: RT4 > RT3 > RT2). Bed thickness is uniformly set to 3 ft to minimize thin-bed effects on well logs. Sequences are separated by pure-shale barriers. The reservoir has irreducible water saturation at the top and water saturation gradually increases toward the FWL at the bottom. Figure 6 shows the numerically simulated well logs (Tracks 1 - 4), conventional well-log analysis results (Tracks 5 - 6), and rock-typing results obtained with different methods (Tracks 7 - 11). Lithofacies (Track 7) can differentiate sand from shale, but cannot distinguish sands of different grain sizes because all sands are essentially clay free. E-facies from all logs and BVW (Tracks 8 and 9) are significantly biased when moving downward toward the FWL due to fluid effects. We observe that reservoir quality is overestimated in the upper zone while it is underestimated in the lower zone. Rock types diagnosed with the new method (Track 10) yield approximately the same vertical distribution as in the pre-defined (original) model (Track 11). This synthetic case indicates that variations of water saturation due to capillary transition and their effects on well logs must be corrected to enable reliable rock classification across the entire reservoir. Otherwise, resistivity logs, the most texture-sensitive logs among all conventional logs, cannot be included in the process of rock typing. Consequently, there is great uncertainty associated with rock typing when it is only based on nuclear logs due to their relatively low sensitivity to rock texture.
FIELD CASE NO. 1: DEEPWATER CENTRAL NORTH SEA

Reservoir Background

The first field example is a sandstone dome structure of Paleocene age which is located in the Central North Sea (Martin et al., 2005; Salazar et al., 2007). Near-continuous sandstone bodies were formed by overlapping submarine fans during the early Paleocene. Lithology in the preserved Paleocene strata mainly consists of siliciclastic sediments with minor presence of coal, tuff, volcaniclastic rocks, marls, and reworked carbonate sediments (Ahmadi et al., 2003). The reservoir has a typical vertically segregated fluid distribution with a gas cap (gas-oil-ratio = 871 scf/bbl) of average thickness of 192 ft and an oil column (gravity = 40° API) of average thickness of 184 ft supported by an active aquifer zone (BP, 2003).

The formation under analysis (B1/B2 sands) is predominantly composed of non-calcareous, blocky and sandy high-density gravity-flow deposits interbedded with grey mudstones. Reservoir units within the formation consist of alternations of sandstones of different grain sizes: fine- to medium-grained, or even coarse-grained. Total porosity ranges from 18 to 28 p.u., while horizontal permeability varies from 10 md in low-quality zones to more than 1,000 md in high-quality intervals.

Hydraulic connectivity in the reservoir section under analysis is confirmed by reservoir pressure measurements. The vertical reservoir fluid distribution agrees well with the saturation derived from the core-measured primary drainage capillary pressure curve. It is observed that the entire reservoir section under analysis (B1/B2 sands) is in a capillary transition zone with free water.

Well logs from three wells are available for rock typing. The three wells were drilled with OBM. Well No. 1 (key well) is a vertical well penetrating the FWL while wells nos. 2 and 3 are horizontal wells drilled 80 - 100 ft above the FWL.

Core-Based Rock Typing and Interpretation

Hydraulic rock types are first established from routine core porosity-permeability measurements (Fig. 7). Six hydraulic rock types are identified from the histogram of $RQI$. Table 2 describes the statistics of petrophysical properties for each rock type. We observe that rock types 1 - 4 have a largely overlapping porosity range which indicates that these rock types have similar grain-sorting. However, their average horizontal permeability exhibits a ratio around 2 - 2.5, which indicates that their average pore-throat radius ratio is approximately 1.5 (i.e., $1.5^2 = 2.25$). Because young-age sediments have not undergone significant diagenesis, the controlling factor for permeability variations is mean grain size. By inspecting the sand grain-size scale, mean grain size of these four rock types is interpreted (from fine to coarse) as lower fine (LF), upper fine (UF), low medium (LM), and upper medium (UM). For rock types 5 and 6, clay cementation plays an important role in reducing permeability. They are mostly composed of very fine (VF) and silty (ST) grains. There are several core samples with permeability higher than 1000 md which are found to contain lower coarse-grained sandstones (LC or RT0). Due to their relatively small population, it is difficult to separate them as one rock class via cluster analysis. The interpreted grain size information greatly contributes to the diagnosis of sedimentary facies in this reservoir.

![Fig. 7: Core-based hydraulic rock typing with Leverett’s RQI in North Sea field case.](image)

<table>
<thead>
<tr>
<th>Rock Type</th>
<th>Porosity (p.u.)</th>
<th>Permeability (md)</th>
<th>$RQI$ ($\mu m$)</th>
<th>MGS</th>
</tr>
</thead>
<tbody>
<tr>
<td>RRT0</td>
<td>24.0 ± 1.86</td>
<td>1058 ± 232</td>
<td>66.3 ± 8.5</td>
<td>LC</td>
</tr>
<tr>
<td>RRT1</td>
<td>24.1 ± 2.26</td>
<td>541 ± 184</td>
<td>46.9 ± 6.7</td>
<td>UM</td>
</tr>
<tr>
<td>RRT2</td>
<td>24.2 ± 1.95</td>
<td>255 ± 63</td>
<td>32.2 ± 3.6</td>
<td>LM</td>
</tr>
<tr>
<td>RRT3</td>
<td>22.7 ± 2.40</td>
<td>98.0 ± 34</td>
<td>20.3 ± 3.4</td>
<td>UF</td>
</tr>
<tr>
<td>RRT4</td>
<td>18.8 ± 2.91</td>
<td>16.0 ± 9.0</td>
<td>8.8 ± 2.3</td>
<td>LF</td>
</tr>
<tr>
<td>RRT5</td>
<td>14.2 ± 4.08</td>
<td>1.30 ± 0.9</td>
<td>2.8 ± 0.8</td>
<td>VF</td>
</tr>
<tr>
<td>RRT6</td>
<td>11.1 ± 2.45</td>
<td>0.20 ± 0.1</td>
<td>0.9 ± 0.3</td>
<td>ST</td>
</tr>
</tbody>
</table>
We perform core-calibrated, conventional well-log analysis in the key well (no. 1) to calculate volumetric concentration of shale, total porosity, and water saturation (Fig. 8, Tracks 5 - 6). From reservoir pressure measurements, we identify fluid types and their contacts as well as the FWL. Well-log-derived saturation-height and core-measured capillary pressure agree well (Fig. 9). From saturation-height, we derive Leverett’s RQI using Eq. (4) with constants $a = 0.33$, $b = -0.62$, and $S_{wirr} = 0.04$. We then classify rocks based on a combination of several petrophysical attributes, including volumetric concentration of shale, total porosity, and log-derived RQI in the capillary transition zone. Figure 8 shows the results of rock classification (Track 7) and the permeability estimated from rock types (Track 8). Estimated permeability agrees well with core-measured permeability (with Klinkenberg correction).

### Invasion Facies Modeling

After calculating the well-log-based saturation-height relation, we obtain an average capillary pressure curve for each rock type by curve-fitting with the same rock type. Core calibration is preferred but not required here.
We select thick zones of rock types 1 to 3 at different height to simulate the radial invasion profile under observed drilling and reservoir conditions to further calibrate capillary pressure and relative permeability curves. In this case, the top formation is saturated with light condensate with almost no free water. When invaded by OBM, the formation should not exhibit radial variations of water saturation in theory. However, we still observe a small separation between apparent resistivity logs with different depths of investigation, which has two possible explanations: The first explanation is that when overbalance pressure is very high (1,400 psi in this case), it can still displace a small amount of capillary-bound water deeper into the reservoir at this height above FWL (Fig. 9). The second explanation is that surfactants in OBM mud filtrate alter rock wettability which subsequently generates more free water (La Vigne et al., 1997; Salazar et al., 2007; Pour et al., 2011). In both cases, capillary pressure and relative permeability play important roles in determining how this relatively small volume of free water is distributed in the invaded zone regardless of mechanistic origin. Therefore, it is possible to calibrate rock dynamic petrophysical properties by honoring the effects of mud-filtrate invasion on various well logs.

Assuming that the rock is preferentially water-wet, OBM invasion becomes a drainage process. We numerically simulate gamma-ray, bulk density, and array-induction apparent resistivity logs in this example. Neutron and PEF logs are excluded due to environmental correction problems. Table 3 lists the simulation parameters and Figs. 10 - 11 show the radial invasion profiles and numerical well-log simulation for rock types 1 to 3 after 2 days of OBM invasion. It is observed that the best rock type gives rise to the highest resistivity due to the lowest connate water saturation. Table 4 and Fig. 12 summarize the final capillary pressure and relative permeability curves for the selected rock types. These properties simultaneously honor routine core measurements, the well-log-derived saturation-height relation, and mud-filtrate invasion. Therefore, they are suitable for upscaling in reservoir simulation grids. One key advantage of invasion-calibrated dynamic petrophysical properties is that these properties have been calculated at reservoir conditions.
Saturation-Height Modeling After Invasion Simulation

Using the capillary pressure curves calibrated from invasion simulation, we derive saturation-height relations for rock types 1 to 3 (Table 5). Saturation-height curves for each rock type are plotted together with the resistivity-derived water saturation (Fig. 8, track 6), indicating a good agreement. We fit 16 core MICP measurements with Brooks-Corey’s model and found that the parameters included in Brooks-Corey’s function were closely correlated to Leverett’s reservoir quality index. Better rock quality indicates higher $P_{c0}$ and $e_p$ together with lower $S_{wirr}$ and $P_e$ (Fig. 13). These values are also comparable to those calibrated with invasion simulation.

<table>
<thead>
<tr>
<th>Rock Type</th>
<th>$S_w(H)$ Function</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT1</td>
<td>$S_w(H) = 0.03 + 0.97[1-(0.0015H)^{0.087}]$</td>
</tr>
<tr>
<td>RT2</td>
<td>$S_w(H) = 0.05 + 0.95[1-(0.0014H)^{0.062}]$</td>
</tr>
<tr>
<td>RT3</td>
<td>$S_w(H) = 0.07 + 0.93[1-(0.0012H)^{0.091}]$</td>
</tr>
</tbody>
</table>

**Fig. 13:** Correlation between Leverett’s rock quality index and capillary pressure properties: $P_{c0}$, $e_p$, $S_{wirr}$, and $P_e$ from 16 core MICP data.

**Rock Typing and Horizontal Well Steering**

After reconciling rock types with their saturation-height relations in the key well, we examine the remaining two horizontal wells (nos. 2 and 3) drilled in the same formation to study lateral variability of reservoir quality. We perform conventional well-log analysis in well no. 2 and find that water saturation in sandstones is approximately 30% with a height above FWL of 100 ft. From the projection of the well-log-derived saturation-height data shown in Fig. 9 (red dots), we observe that major rock types in this horizontal section are RRT4 and RRT5 with an average porosity 12 p.u. and permeability ranging from 1 to 10 md. Decreasing reservoir quality indicates that well no. 2 was drilled toward the levee or distal fan facies and that the well productivity is relatively low (Fig. 14).
In well no. 3, predominant washouts render neutron and density logs useless. The only reliable logs are GR and deep resistivity. With an assumed constant porosity of 22 p.u., water saturation calculated with Archie’s equation is approximately 20% with a height above FWL of 80 ft. From the projection of well-log-derived saturation-height data shown in Fig. 9 (blue dots), we observe that the major rock type is RRT2 with permeability ranging from 100 to 300 md. Reservoir quality remains the same as that of the key well, thereby indicating that the well was drilled along the channel axis or fan lobe and that well productivity is much better than that of well no. 2 (Fig. 14), which is cross-validated by core data available in these two wells.

This example confirms that saturation-height-based rock typing in horizontal wells can reveal lateral reservoir-quality changes and provide critical real-time information for guiding the placement and steering of horizontal wells.

Fig. 14: Description of the possible drilling scenarios interpreted from rock typing in horizontal wells.

FIELD CASE NO. 2: DEEPWATER GULF OF MEXICO

Reservoir Background

The second field example is a Miocene turbidite oil field located in the deepwater Gulf of Mexico (Contreras et al., 2006). The depositional system is interpreted as a submarine fan complex developed in a mini-basin with stacked progradational lobes. Reservoirs primarily consist of sandy turbidite facies interbedded with muddy debris-flow facies. Reservoir rocks are mainly unconsolidated sandstones with very fine to fine- to medium-size grains. Thin-bed zones are present but are not addressed here. In this study, we evaluate only the two hydraulically connected, hydrocarbon-bearing sand units: M40 and M50 in three wells. These sands are buried at depths between 12,000 and 13,000 ft TVD and are dipping toward the West (Fig. 15). Core measurements indicate that the massive and planar stratified sands have porosities up to 35%, as well as 100 – 2000 md of nominal permeability. Well logs from three wells are used for rock typing. Well no. 1 was drilled with OBM and penetrated a capillary transition zone and the FWL. Wells nos. 2 and 3 were drilled with WBM where the M40-50 sands are located more than 500 ft above FWL (Fig. 15).

Fig. 15: Three well locations displayed on a seismic cross-section with litho-type well logs indicating the vertical interval of the Miocene M-series sands (Contreras et al., 2006).

Core-Based Rock Typing and Interpretation

Hydraulic rock types are first established using routine core porosity-permeability measurements. Six hydraulic rock types were identified from the histogram distribution of RQI (Fig. 16). Table 6 summarizes the statistics of petrophysical properties for each rock type. Similar to field case no. 1, we observe that rock types 1 - 3 exhibit a largely overlapping porosity range. Again, their average horizontal permeability exhibits a ratio around 2 - 2.5, which indicates that their average pore-throat radius ratio is close to 1.5. Laser grain size measurements for rock types confirmed that the controlling factor for permeability was mean grain size. Reservoir quality decreases with decreasing grain size.

Fig. 16: Core-based hydraulic rock typing from Leverett’s RQI in deepwater Gulf-of-Mexico field case.

Well-Log-Based Saturation-Height, Rock Typing, and Permeability Estimation

We perform core-calibrated, conventional well-log analysis in the three wells to calculate volumetric concentration of shale, total porosity, and water saturation. Normalization of gamma-ray logs is not performed in this study because we assume that the
gamma-ray log self-normalizes in each well when transforming gamma-ray logs to volumetric concentration of shale. From reservoir pressure measurements, we identify the fluid type, their contacts, and the FWL. Well-log-derived saturation-height and core-measured capillary pressure agree well (Fig. 17). From saturation-height results, we derive Leverett’s $RQI$ using Eq. (4) with constants $a = 0.63$, $b = -0.68$, and $Sw_{irr} = 0.05$. Subsequently, we classify rocks based on a combination of several petrophysical attributes including volumetric concentration of shale, total porosity, water saturation in the irreducible depth zone, and log-derived $RQI$ in the capillary transition zone. Figure 18 shows results obtained from rock classification (Track 7), as well as the permeability estimated from the rock types (Track 8). Estimated permeability agrees well with permeability (with Klinkenberg correction under stress) measured from whole core in the key well. In well no. 3, rock types agree well with the permeability measured from sidewall core samples. Rock typing results obtained in the three wells are displayed together to assist stratigraphic and sedimentary interpretations (Fig. 19) (Xu et al., 2012).

**Table 6: Statistics of porosity, permeability, and $RQI$ for each hydraulic rock type.**

<table>
<thead>
<tr>
<th>Rock Type</th>
<th>Porosity (p.u.)</th>
<th>Permeability (md)</th>
<th>$RQI$ ($\mu$m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>RRT1</td>
<td>33.6 ± 1.8</td>
<td>1099 ± 291</td>
<td>56.8 ± 7.2</td>
</tr>
<tr>
<td>RRT2</td>
<td>33.3 ± 2.1</td>
<td>549 ± 130</td>
<td>40.4 ± 4.9</td>
</tr>
<tr>
<td>RRT3</td>
<td>31.5 ± 4.4</td>
<td>179 ± 63.7</td>
<td>23.4 ± 3.4</td>
</tr>
<tr>
<td>RRT4</td>
<td>24.1 ± 6.1</td>
<td>42.9 ± 19.1</td>
<td>13.1 ± 2.1</td>
</tr>
<tr>
<td>RRT5</td>
<td>19.7 ± 3.9</td>
<td>11.3 ± 3.9</td>
<td>7.50 ± 1.1</td>
</tr>
<tr>
<td>RRT6</td>
<td>19.6 ± 3.7</td>
<td>4.00 ± 1.5</td>
<td>4.40 ± 0.9</td>
</tr>
</tbody>
</table>

**Invasion Facies Modeling**

We select thick zones of rock types 1 to 3 at irreducible water saturation to simulate invasion with WBM, which is an imbibition process in water-wet rocks. Rock types 1 and 2 are selected from well no. 2 and rock type 3 is selected from well no. 3. Both wells lack whole core samples and special core analysis. It is therefore important to extrapolate our understanding of rock types from the key well to uncored wells. We use gamma-ray, bulk density, neutron porosity, and AIT apparent resistivity logs for simulation. The PEF log is excluded due to presence of barite in the drilling mud. From well logs acquired across each rock type, we observe that they exhibit essentially the same nuclear responses, which confirms one previous conclusion, namely that apparent resistivity logs are irreplaceable for hydraulic rock typing.

Table 7 summarizes the simulation parameters. We iteratively match numerically simulated and measured well logs by adjusting the capillary pressure and relative permeability curves. Figure 21 shows the final simulations of radial invasion profiles and numerically simulated well logs for rock types 1 to 3 after 1.0 - 1.5 days of WBM invasion. Table 8 describes the final capillary pressure and relative permeability curves for the selected rock types using Brooks-Corey’s parametric model and plotted in Fig. 23.

**Table 7: Summary of mudcake, fluid, and formation properties assumed in the simulation of the process of mud filtrate invasion.**

<table>
<thead>
<tr>
<th>Variable</th>
<th>Units</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wellbore radius</td>
<td>inch</td>
<td>6.0</td>
</tr>
<tr>
<td>Maximum invasion time</td>
<td>days</td>
<td>1.0 - 1.5</td>
</tr>
<tr>
<td>Formation outer boundary</td>
<td>ft</td>
<td>2000</td>
</tr>
<tr>
<td>Reservoir temperature</td>
<td>°F</td>
<td>120</td>
</tr>
<tr>
<td>Initial reservoir pressure</td>
<td>psi</td>
<td>7800</td>
</tr>
<tr>
<td>Water viscosity (reservoir conditions)</td>
<td>cP</td>
<td>0.92</td>
</tr>
<tr>
<td>Oil viscosity</td>
<td>cP</td>
<td>0.8</td>
</tr>
<tr>
<td>Overbalance pressure</td>
<td>psi</td>
<td>500</td>
</tr>
<tr>
<td>Salt dispersivity</td>
<td>ft</td>
<td>0.1 - 0.5</td>
</tr>
<tr>
<td>Mud filtrate density (at STP)</td>
<td>g/cm³</td>
<td>1.02</td>
</tr>
<tr>
<td>Mud filtrate viscosity (at STP)</td>
<td>cP</td>
<td>0.92</td>
</tr>
<tr>
<td>Mud filtrate compressibility (at STP)</td>
<td>psi⁻¹</td>
<td>3.6 x 10⁶</td>
</tr>
<tr>
<td>Formation compressibility</td>
<td>psi⁻¹</td>
<td>4 x 10⁷</td>
</tr>
<tr>
<td>Mudcake reference permeability</td>
<td>md</td>
<td>0.01</td>
</tr>
<tr>
<td>Mudcake reference porosity</td>
<td>frac.</td>
<td>0.35</td>
</tr>
<tr>
<td>Mud solid fraction</td>
<td>frac.</td>
<td>0.06</td>
</tr>
<tr>
<td>Mudcake maximum thickness</td>
<td>inch</td>
<td>0.4</td>
</tr>
<tr>
<td>Mudcake compressibility exponent</td>
<td>frac.</td>
<td>0.40</td>
</tr>
<tr>
<td>Mudcake exponent multiplier</td>
<td>frac.</td>
<td>0.10</td>
</tr>
</tbody>
</table>
**Fig. 18:** Rock typing results in the key well of Gulf-of-Mexico case. Tracks 1-4: basic well logs; Tracks 5-6: standard well-log analysis, saturation-height for rock types 1 to 3; Tracks 7: distributions of rock types in M40-50 sands; Track 8: permeability prediction based on rock types and comparison to core permeability. Permeability is underestimated only in thin-bed zones.

**Fig. 19:** Use of rock-type distributions in multiple wells to assist sedimentological and stratigraphic interpretation.
Table 8: Rock-fluid properties calibrated with the simulation of mud-filtrate invasion for rock types 1 to 3 using Brooks-Corey’s model.

<table>
<thead>
<tr>
<th>RT</th>
<th>$\sqrt{RT}$</th>
<th>$S_{nis}$</th>
<th>$S_{irr}$</th>
<th>$k^h_{inw}$</th>
<th>$e_{irr}$</th>
<th>$k^h_{w}$</th>
<th>$e_{w}$</th>
<th>$P^0_c$</th>
<th>$e_p$</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>60.3</td>
<td>0.05</td>
<td>0.22</td>
<td>0.85</td>
<td>3.2</td>
<td>0.3</td>
<td>5.0</td>
<td>270</td>
<td>26</td>
</tr>
<tr>
<td>2</td>
<td>38.9</td>
<td>0.08</td>
<td>0.23</td>
<td>0.87</td>
<td>3.0</td>
<td>0.25</td>
<td>4.5</td>
<td>185</td>
<td>18.6</td>
</tr>
<tr>
<td>3</td>
<td>24.6</td>
<td>0.12</td>
<td>0.18</td>
<td>0.9</td>
<td>3.0</td>
<td>0.3</td>
<td>4</td>
<td>121</td>
<td>12.4</td>
</tr>
</tbody>
</table>

Saturation-Height Modeling After Invasion Simulation

Using the capillary pressure curves calibrated from invasion simulation, we derived saturation-height relations for rock types 1 to 3 (described in Table 9). To that end, we fit 14 core MICP measurements with Brooks-Corey’s parametric model and found that the parameters included in Brooks-Corey’s function were closely correlated to Leverett’s reservoir quality index. Better rock quality indicates higher $P^0_c$ and $e_p$ together with lower $S_{nis}$ and $P^e$ (Fig. 20), which enables a consistent petrophysical interpretation between well-log-derived saturation height and core MICP data.

Table 9: Saturation-height relations for rock types 1 to 3.

| RT1: | $S_w(H) = 0.05 + 0.95[1 - (0.0011H)^{0.109}]$ |
| RT2: | $S_w(H) = 0.08 + 0.92[1 - (0.0010H)^{0.164}]$ |
| RT3: | $S_w(H) = 0.12 + 0.88[1 - (0.0010H)^{0.181}]$ |

Figure 20: Correlation between Leverett’s rock quality index and capillary pressure properties: $P^0_c$, $e_p$, $S_{nis}$, and $P^e$ from 14 core MICP data.

Figure 22 shows the radial profiles of water saturation, salt concentration, and resistivity for each rock type after WBM invasion. In general, good-quality sands exhibit low irreducible water saturation but not necessarily more residual oil saturation due to wettability variations. The best quality sands exhibit the largest separation between deepest and shallowest apparent resistivity. Salt dispersivity plays an important role in the near-borehole process of salt exchange between mud filtrate and connate water. Low porosity-permeability rocks typically exhibit large salt dispersivity, which yields a smoother radial salt concentration front (Fig. 22, center panel).

Figure 21: Invasion simulation for rock types 1 to 3 (top to bottom) and corresponding numerical well-log simulation compared to field logs. Track 1: Depth; Track 2: GR log; Track 3: Bulk density and neutron logs; Track 4: Induction (AIT) resistivity logs; Track 5: Cross-section (vertical and radial directions) of water saturation. Three different rock types exhibit the same nuclear-log responses. Only resistivity logs can differentiate rock types.
Fig. 22: Radial distributions of water saturation (upper panel), salt concentration (center panel), and resistivity (lower panel) for rock types 1 to 3 after invasion with WBM for 1 - 1.5 days.

Fig. 23: Invasion-calibrated, saturation-dependent capillary pressure and relative permeability for each rock type.

SUMMARY AND CONCLUSIONS

Hydraulic rock typing must be based on pore geometry because it relates all petrophysical properties of reservoir rocks. While it is relatively simple to infer or quantify pore geometry from routine and special core analysis, it remains challenging to quantify it solely with conventional well logs. E-facies diagnosed from apparent well logs are not satisfactory because the latter are simultaneously sensitive to mineralogy and pore fluids. Buckle’s number relates to pore geometry in a direct manner but is only applicable to reservoir zones which are at irreducible water saturation conditions. We constructed a synthetic case with pre-defined rock types to illustrate how E-facies and Buckle’s number are biased toward capillary transition zones. New methods are necessary to perform hydraulic rock typing in thick oil reservoirs that exhibit long capillary transition zones.

We studied and appraised three conventional core-based hydraulic rock typing methods and performed numerical correlation testing to confirm their petrophysical similarity. Consequently, the three methods should perform equally well in detecting petrophysical rock types with different pore-throat radii. It was also pointed out that the key to reliable rock typing for reservoir characterization is to construct well-log-derived attributes that directly link rock types diagnosed from core measurements to well logs.

This paper introduced a new method for hydraulic rock typing in multiple wells penetrating a capillary transition zone that integrates vertical distributions of initial water saturation with reservoir capillary pressure. Conventional Leverett’s $J$-function and Thomeer’s $G$ factor were invoked to quantify reservoir quality in terms of pore geometry. The new method honors both vertical saturation-height behavior and mud filtrate invasion, both of which bear different expressions of hydraulic rock types. We successfully verified the new method with measurements acquired in two thick turbidite oil reservoirs from the Central North Sea and the deepwater Gulf of Mexico. In both cases, a good agreement was reached between core-derived and well-log-derived rock types, which were also validated with the estimation of permeability.

The petrophysical quality of young deepwater turbidite reservoirs is chiefly controlled by sedimentary grain sizes. Therefore, a link exists between petrofacies and depositional facies which can be effectively applied in reservoir development efforts. Reservoir capillary transition enables the estimation of grain sizes from saturation-height data. In the Central North Sea case examined in this paper, we showed how to implement saturation-height-derived rock types to quantify lateral variability of reservoir petrophysical quality and to guide well placement and steering with minimum LWD data in a submarine fan. In the deepwater Gulf-of-Mexico case, we showed that multi-well rock typing can assist in stratigraphic and sedimentary studies which are often used for exploration in frontier basins.
or in deepwater environments, where subsalt or pre-salt reservoirs cannot be clearly imaged with seismic data and well drilling is limited due to high rig cost. It was also found the two field cases could be approached with the same rock-type scheme when using the ratio of permeability between neighboring sandy rock types. This observation is not coincidental and has geological and petrophysical significance. Rock types associated with young-age turbidite reservoirs can still be differentiated by their median grain sizes, whereas neighboring rock types exhibit a grain size ratio close to 1.5 or $\sqrt{2}$. Well-log-derived rock types capture this property, which suggests that rock typing in similar cases may generally follow the same principle.

We suggest that rock typing should not only separate rocks into different groups. The more important task is to calculate static and dynamic petrophysical properties associated with each rock type based on core-log integration. The new interpretation method introduced in this paper provides a good initial estimation of rock-type-averaged capillary pressure and relative permeability. Both properties are further calibrated for each rock type by numerically simulating well logs based on the physics of mud-filtrate invasion. It was emphasized that each rock type is associated with a specific radial invasion profile due to differences in pore geometry. Therefore, it is possible to use invasion behavior to define dynamic petrophysical facies (or invasion facies) for reservoir simulation.

The method introduced in this paper assumes that the reservoir under analysis is hydraulically connected and underwent hydrocarbon migration similar to a primary drainage process. Complex hydrocarbon migration may give rise to saturation hysteresis which could deviate from the saturation-height relation defined by core MICP measurements. Reservoir pressure measurements should be used to confirm reservoir connectivity, whereas core-derived capillary pressure curves should be used to verify the well-log-derived saturation-height relation. One limitation of the method introduced in this paper is that it is only applicable to reservoir zones above oil-water or gas-water contacts. Moreover, the resolution of rock types is limited by the vertical resolution of the deep apparent resistivity log.

**NOMENCLATURE**

- $a$ : Linear coefficient in empirical $J$ function
- $b$ : Exponent in empirical $J$ function
- $C_{sh}$ : Volumetric concentration of shale
- $e_p$ : Pore-size distribution exponent
- $e_{nw}$ : Experimental exponent for $k_{nw}$ equation
- $e_w$ : Experimental exponent for $k_w$ equation
- $G$ : Thomeer’s pore geometrical factor
- $H$ : Height above the free-water level
- $J$ : Leverett’s $J$ function
- $k$ : Absolute permeability, (md)
- $k_{nw}$ : Wetting-phase relative permeability
- $k_{w}$ : Non-wetting phase relative permeability
- $P_c$ : Reservoir capillary pressure, (psi)
- $P_{c,0}$ : Entry capillary pressure, (psi)
- $R_{35}$ : Pore-throat radius at 35% non-wetting phase
- $S_w$ : Connate water saturation, (frac)
- $S_{sstr}$ : Irreducible water saturation, (frac)
- $S_{or}$ : Residual oil saturation, (frac)
- $x$ : Coefficient of permeability in rock quality
- $y$ : Coefficient of porosity in rock quality
- $z$ : Constant term in rock quality
- $\alpha$ : Scaling factor in saturation-height modeling
- $\phi$ : Total porosity, (frac)
- $\Delta \rho$ : Density difference between water and oil
- $\sigma$ : Interfacial tension, (dyne)
- $\cos \theta$ : Cosine of contact angle
- $\Theta$ : A symbol for quantifying pore-throat size

**ACRONYMS**

- AIT : Array Induction Tool
- BVW : Bulk Volume Water
- CSF : Common Stratigraphic Framework
- FWL : Free Water Level
- FZI : Flow Zone Index
- GR : Gamma Ray Log
- LWD : Logging While Drilling
- MICP : Mercury Injection Capillary Pressure
- OBM : Oil-Base Mud
- PEF : Photoelectric Factor Log
- RQI : Leverett’s reservoir quality index, $\sqrt{\Delta \rho / \phi}$
- RRT : Reservoir Rock Type
- TVD : True Vertical Depth
- WBM : Water-Base Mud

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