Interpretation of porosity and fluid constituents from well logs using an interactive neutron-density matrix scale

Olabode Ijasan¹, Carlos Torres-Verdín¹, and William E. Preeg²

Abstract

Neutron and density logs are important borehole measurements for estimating reservoir capacity and inferring saturating fluids. The neutron log, measuring the hydrogen index, is commonly expressed in apparent water-filled porosity units assuming a constant matrix lithology whereby it is not always representative of actual pore fluid. By contrast, a lithology-independent porosity calculation from nuclear magnetic resonance (NMR) and/or core measurements provides reliable evaluations of reservoir capacity. In practice, not all wells include core or NMR measurements. We discovered an interpretation workflow wherein formation porosity and hydrocarbon constituents can be estimated from density and neutron logs using an interactive, variable matrix scale specifically suited for the precalculated matrix density. First, we estimated matrix components from combinations of nuclear logs (photoelectric factor, spontaneous gamma ray, neutron, and density) using Schlumberger’s nuclear parameter calculator (SNUPAR) as a matrix compositional solver while assuming freshwater-filled formations. The combined effects of grain density, volumetric concentration of shale, matrix hydrogen, and neutron lithology units define an interactive matrix scale for correction of neutron porosity. Under updated matrix conditions, the resulting neutron-density crossover can only be attributed to pore volume and saturating fluid effects. Second, porosity, connate-water saturation, and hydrocarbon density are calculated from the discrepancy between corrected neutron and density logs using SNUPAR and Archie’s water saturation equation, thereby eliminating the assumption of freshwater saturation. With matrix effects eliminated from the neutron-density overlay, gas- or light-oil-saturated formations exhibiting the characteristic gas neutron-density crossover become representative of saturating hydrocarbons. This behavior gives a clear qualitative distinction between hydrocarbon-saturated and nonviable depth zones.

Introduction

Porosity calculated from neutron and density measurements is still the most commonly used estimate of pore volume in rock formations penetrated by wells. In complex lithologies, inadequate characterization of the matrix could yield inaccurate porosity and saturation estimates. The petrophysical effects of lithology, saturating fluid, and borehole conditions on nuclear logs are exhaustively discussed by Ellis and Singer (2007). Using departure curves from log interpretation charts (Schlumberger, 2009), corrections are applied such that interpreted properties are representative of the formation only. Extensive studies and publications on neutron and density logs, being ubiquitous for porosity and hydrocarbon estimation, can be found in the literature.

Historically, total porosity $\phi_t$ in gas-bearing formations is approximated with the following formula (Gaymard and Poupon, 1968):

$$\phi_t^2 \approx \frac{\phi_D^2 + \phi_N^2}{2}, \quad (1)$$

where $\phi_D$ and $\phi_N$ are the density- and neutron-apparent porosities, respectively. Mao (2001) studies the correlation characteristics of $\phi_D$ and $\phi_N$ for identification of oil- and gas-saturated zones. Spears (2006) applies lithofacies-based porosity corrections derived from neutron-density crossplots for $\phi_t$ calculations in geologic and reservoir models. Fertl and Timko (1971) extend Gaymard and Poupon’s (1968) formulations for calculation of hydrocarbon density $\rho_{hc}$ and detection of oil- and gas-bearing intervals in shaly sands.

The neutron-density overlay technique relies on the difference between apparent porosities, on a predefined matrix scale, for inferring hydrocarbon saturation ($S_{hc}$), $\phi_t$, and $\rho_{hc}$. Several petrophysical factors adversely affect the reliability of the overlay technique.

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For example, gas detection is challenging in shaly sands or shale gas reservoirs due to opposite effects of shale-hydroxyls and gas density in overlay characteristics. Similarly, in oil-saturated or invaded gas zones, the decreased difference between neutron and density-apparent porosities masks the characteristics of light-hydrocarbon crossovers (Mao, 2001). Consequently, application of the overlay technique requires implementation of a suitable matrix correction.

In this paper, we estimate \( S_{hc} \), \( \phi_t \), and \( \rho_{hc} \) using an interactive interpretation workflow based on the neutron-density overlay technique, with explicit consideration of neutron matrix scale and shale content. The interpretation workflow improves reliability of the overlay technique in the presence of arbitrary lithology and fluid effects. These effects and their influence on neutron and density-apparent porosities, along with conventional well-log interpretation methods, are described with a synthetic example of known lithology and fluid constituents. Additionally, the interactive matrix scale method is applied to field examples of varying geology and lithology, namely, carbonate, siliciclastic, and shale reservoirs, where porosity and fluid-saturation estimates are compared to laboratory core measurements. The calculated \( \rho_{hc} \) enables differentiation between gas- and oil-saturated intervals when \( \rho_{hc} < 0.25 \text{ g/cm}^3 \) and \( \rho_{hc} \geq 0.25 \text{ g/cm}^3 \), respectively, for simplified interpretation. Hence, the interactive analysis method is implemented for qualitative identification of fluid zones, fluid contacts, and reservoir compartments.

**Interpretation of apparent porosity**

The porosity value associated with neutron logs is inherently apparent for given matrix and fluid units. On the other hand, compensated bulk density measurements bear no apparentness until density porosity is calculated with constant values of matrix and fluid properties. This is a significant difference between density and neutron logs.

**Density-apparent porosity**

The bulk density measurement \( \rho_b \) principally responds to formation electron density such that

\[
\rho_b = \sum_{i=1}^{M} (1.0704 \rho_{e,i} - 0.188) V_i, \tag{2}
\]

where \( \rho_{e,i} \) and \( V_i \) are the electron density and volume fraction, respectively, of the \( i \)th fluid/matrix component up to \( M \) components. In hydrocarbon-bearing formations, \( \phi_t \) can be directly calculated from density logs if and only if matrix density \( \rho_m \) and fluid density \( \rho_f \) are known precisely. Otherwise, density-apparent porosity \( \phi_D \) is obtained using

\[
\phi_D = \frac{\rho_b - \rho_m}{\rho_f - \rho_m} = \phi_t + \Delta \phi_D, \tag{3}
\]

where \( \rho_m \) and \( \rho_f \) are assumed matrix and fluid densities, respectively, e.g., limestone matrix of 2.71 g/cm\(^3\) and freshwater of 1 g/cm\(^3\). The porosity departure \( \Delta \phi_D \) due to \( \rho_m \) and \( \rho_f \) assumptions (Ellis et al., 2007) is qualitatively and quantitatively intuitive such that

\[
\Delta \phi_D \approx \frac{\rho_b - \rho_m}{(\rho_f - \rho_m)^{3/2}} (\Delta \rho_m - \Delta \rho_f) - \frac{1}{\rho_f - \rho_m} \Delta \rho_m, \tag{4}
\]

where \( \Delta \rho_m \) and \( \Delta \rho_f \) are differences in matrix and fluid densities, respectively, between assumed and true properties.

**Neutron-apparent porosity**

The neutron log is an apparent porosity measurement, given that it refers to an equivalent hydrogen index (HI) response in water-filled lithology units, usually limestone. Limestone unit implies an equivalent response of water-filled limestone formation where the pore volume equals that of the neutron log. As shown by Gaynard and Poupon (1968), the environmentally corrected neutron-porosity log \( \phi_N \) across invaded formations can be expressed as

\[
\phi_N = \frac{1}{\text{HI}_{ml}} \sum_{i=1}^{M} \text{HI}_i V_i = \phi_t + \Delta \phi_N, \tag{5}
\]

where HI is the hydrogen index, subscript \( ml \) identifies mud filtrate, and \( \Delta \phi_N \) is porosity departure due to neutron-apparent porosity measurement. Equation 5 implies that the neutron response is a superposition of the volumetric contributions of component hydrogen concentrations. The apparentness in \( \Delta \phi_N \) is determined by the neutron-porosity unit (pu), usually water-filled limestone. For example, quartz, calcite, and dolomite blocks yield \( \Delta \phi_N \) of −2, 0, and 0.5 limestone pu, respectively. This matrix effect is qualitatively intuitive because quartz and dolomite have lower and higher matrix densities, respectively, than limestone. On the other hand, unlike \( \phi_D \), the matrix effect is quantitatively obscure and cannot be calculated directly from equations 3 or 4. This effect is exacerbated in complex mixtures of various lithologies. Similarly, a gas-saturated limestone formation yields negative \( \Delta \phi_N \) because the HI of gas is typically lower than that of water.

Hence, a physically intuitive parameter representation of neutron-porosity responses is necessary. Using neutron characteristic lengths, specifically migration length \( L_m \), a calibration of \( L_m \)-to-neutron porosity is used to quantify matrix and lithology effects (Ellis et al., 2007).

**Neutron parameter model**

The Schlumberger nuclear parameter calculator (SNUPAR, McKeon et al., 1989) calculates nuclear properties such as \( L_m \), HI, photoelectric factor (PEF), capture cross section, \( \Sigma \), etc., for any given mixture of rocks and fluids. In this paper, we implement \( L_m \) for
property characterization of wireline neutron porosity responses, typically with an americium-beryllium (AmBe) neutron source. It follows that equation 5 can be rewritten as

$$q_N = g_l \left(\frac{1}{L_m}\right),$$  \hspace{1cm} (6)

where $g_l$ represents the $L_m$-to-porosity calibration function in limestone water-filled units and $g_l$ is obtained by fitting a polynomial function to the inverse of SNU PAR-calculated $L_m$ and limestone pore volume. Figure 1 shows $g_b$, $g_c$, and $g_d$ water-filled calibration functions for sandstone, limestone, and dolomite units, respectively. Additionally, the SNU PAR-calculated compensated neutron tool (CNT) thermal porosity response, shown in dashed blue, agrees well with $g_c$. Unless otherwise stated, neutron-porosity logs in this paper are expressed in limestone matrix units, where $g_l^{-1}$ and $g_l$ are used to convert neutron porosity to $L_m$ logs, and vice versa, respectively.

Furthermore, we implement a SNU PAR-based compositional solver (Heidari et al., 2012) for estimation of mineral and fluid concentrations from nuclear logs. The solver uses nonlinear minimization of a constrained-error, quadratic cost function between SNU PAR-predicted properties and nuclear logs ($\rho_b$, $q_N$, PEF) for estimation of mineral and fluid volumetric fractions. Additionally, volumetric concentration of shale $V_{sh}$ and water saturation $S_w$ are calculated using linear scaling of the gamma ray (GR) log and Archie’s equation, respectively.

**Lithology effects**

**Matrix effect**

Equation 4 describes the sensitivity of $q_B$ such that the matrix effect in water zones, i.e., when $\Delta \rho_f = 0$ and $\rho_f = \rho_{cw}$ (connate-water density), is given by

$$\Delta q_D \approx \left(\frac{\rho_b - \rho_m}{(\rho_f - \rho_m)^2} - \frac{1}{\rho_f - \rho_m}\right) \Delta \rho_m.$$  \hspace{1cm} (7)

In the neutron-density overlay technique, water-saturated zones are expected to overlap only if the matrix scale for density and neutron corresponds to the precise formation lithology. Otherwise, the neutron-density matrix effect, $\Delta q_{\text{matrix}} = \Delta q_N - \Delta q_D$ (equations 3 and 5), depends on $\Delta \rho_m$ and the neutron response, $q_N$, of the matrix. Unlike $q_D$ in equation 3, $q_N$ of the matrix is not quantitatively intuitive, and it is only obtained from equation 6 by converting SNU PAR-calculated $L_m$ to neutron porosity. Qualitatively, with a limestone matrix scale in water zones, $\Delta q_{\text{matrix}} < 0$ across sandstone and $\Delta q_{\text{matrix}} > 0$ across dolomite.

**Shale-hydroxyl or matrix-hydrogen effect**

Typically, shales consist of clay minerals with high hydroxyl (OH⁻) content such that $q_N > q_D$. The shale-hydroxyl effect $\Delta q_{\text{Sh}}$ can be approximated from equation 6 using the expression

$$\Delta q_{\text{Sh}} = V_{\text{Sh}} g_l \left(\frac{1}{L_{\text{Sh}}}\right).$$  \hspace{1cm} (8)

where $L_{\text{Sh}}$ is the SNU PAR-calculated migration length in shale. For example, $L_{\text{Sh}}$ is approximately 15.35 cm for illite of density 2.78 g/cm³, whereby $\Delta q_{\text{Sh}}$ for pure illite (see Figure 1), i.e., $V_{\text{Sh}} = 1$, corresponds to 0.156. In unconventional reservoirs with an organic-rich kerogen matrix (Passey et al., 1990), the neutron porosity response increases due to high hydrogen content of organic matter. The SNU PAR-calculated HI of kerogen could be as high as 0.8, depending on the hydrogen-carbon ratio and kerogen density. Accordingly, equation 8 quantifies the matrix-hydrogen effect, where $V_{\text{Sh}}$ = 1 and $L_{\text{Sh}}$ become $V_{\text{ker}}$ (volume fraction of kerogen) and $L_{\text{mker}}$ (SNU PAR-calculated migration length of kerogen matrix), respectively.

It then follows that the total matrix effect on neutron-porosity logs is an addition of $\Delta q_{\text{matrix}}$ and $\Delta q_{\text{Sh}}$, i.e., interactive porosity departures due to apparent limestone matrix scale (calculated from SNU PAR in freshwater-filled assumptions, equations 6 and 7) and shale-hydroxyl or matrix-hydrogen effect (equation 8). The corrected or rescaled neutron-apparent porosity is given by

$$q_{\text{corr}} = q_N - (\Delta q_{\text{matrix}} + \Delta q_{\text{Sh}}).$$  \hspace{1cm} (9)

**Fluid and hydrocarbon saturation effects**

Given equations 3, 5, 6, and 9, fluid and saturation effects on rescaled neutron-apparent porosity can be written as

**Figure 1.** SNU PAR-calculated water-filled neutron porosity calibration functions $g_b$, $g_l$, and $g_d$ for sandstone, limestone, and dolomite units, respectively. The figure also shows neutron porosity responses across relevant formations.
\[ \varphi_{N,corr} = \varphi_t(1 + S_{hc} \delta_z), \]

where \( \delta_z \) is the difference in neutron response between hydrocarbon- and water-saturated formations. Several forms of equation 10 are given in Gaymard and Poupon (1968), Mao (2001), and Quintero and Bassiouni (1998). Gaymard and Poupon (1968) characterize \( \delta_z \) across invaded formations as the relative difference in HI between residual hydrocarbon and mud-filtrate; i.e.,

\[ \delta_z = (H_{hc} - H_{mf})/H_{mf}, \]

where the subscript \( hc \) identifies hydrocarbon. For gas-saturated formations at reservoir conditions, one has

\[ HI \approx 9\rho_g[0.15 + 0.2(0.9 - \rho_g)^2], \]

where the subscript \( g \) describes gas. Equation 12 is replicated in SNUPAR for \( \rho_{hc} = \rho_g < 0.25 \text{ g/cm}^3 \), while a SNUPAR-derived functional relationship is obtained for oil \((C_\nu H_{2\nu+2})\) when \( \rho_{hc} = \rho_g > 0.25 \text{ g/cm}^3 \). Estimation of \( S_{hc}, \varphi_t, \) and \( \rho_{hc} \) thus requires solving equations 2, 10, 11, 12, and inclusion of a water saturation model, e.g., Archie’s equation,

\[ R_t = \frac{a R_w}{\varphi_t^m (1 - S_{hc})^n}, \]

where \( R_t \) is the resistivity log, \( R_w \) is connate-water or mud-filtrate resistivity, \( a \) is Archie’s factor, \( m \) is the porosity exponent, and \( n \) is the saturation exponent. It follows that \( \delta_z = 0 \) corresponds to a water or deeply invaded zone. Consequently, the magnitudes of \( \delta_z \) and \( \rho_{hc} \) dictate the hydrocarbon type, i.e., oil or gas.

**Interactive analysis of matrix and fluid effects**

Well-log interpretation involves conceptual rock models when evaluating formation rock composition and saturating fluids. This paper introduces a new interpretation method, or interactive analysis workflow, that combines petrophysical effects due to apparent matrix scale and hydrocarbon saturation. Using a synthetic example of a layered earth model, where well logs are simulated with the University of Texas at Austin petrophysical and well-log simulator (UTAPWeLS, Voss et al., 2009), we describe the estimation of \( \varphi_t, \rho_{hc}, \) and \( S_{hc} \) using the interactive interpretation workflow.

**Interpretation workflow**

The first part of the interpretation involves rock/matrix compositional interpretation from \( \rho_b, \) PEF, and GR logs using the SNUPAR-based solver under the assumption of freshwater-filled saturation. We assume freshwater-filled formations for two reasons: (1) The environmentally corrected \( \varphi_N \) is typically referenced on freshwater-filled units and (2) we independently characterize matrix effects for estimation of \( \rho_m \) given that formation fluids have negligible or no effect on PEF and GR logs.

Using the estimated \( \rho_m \) from the matrix solver and equation 3, we calculate density-apparent porosity under the freshwater-filled assumption, \( \varphi_{N,wf} \). Accordingly, neutron-apparent porosity under the freshwater-filled assumption, \( \varphi_{N,corr} \), is obtained by converting the predicted \( L_w \) from the matrix solver to neutron porosity. It follows from equations 8 and 9 that \( \Delta \varphi_{matrix} + \Delta \varphi_{N,sh} = \varphi_{N,corr} - \varphi_{N,wf} \). i.e., the interactive neutron-density lithology effect in limestone porosity scale, where \( V_{sh} \) is calculated assuming linear scaling of the GR log. We then calculate the corrected neutron-apparent porosity \( \varphi_{N,corr} \) from equation 9 for rescaling with \( \varphi_D \). At this point, the overlay characteristics of \( \varphi_{N,wf} \) and \( \varphi_{N,corr} \) are solely due to porosity effects, and the overlay of \( \varphi_{N,corr} \) and \( \varphi_D \) is due to hydrocarbon pore volume.

The second part of the interpretation involves implementing the SNUPAR-based solver for hydrocarbon characterization. In this step, equations 2, 10, 11, 12, and 13 are solved such that a SNUPAR-defined inherent relationship between \( \delta_z \) and \( \rho_{hc} \) is implemented in the analysis for estimation of \( \rho_{hc}, S_{hc} \), and \( \varphi_t \). The functional relationship between HI and \( \rho_{hc} \) is derived from SNUPAR for oil \((\rho_{hc} > 0.25 \text{ g/cm}^3)\) and gas \((\rho_{hc} < 0.25 \text{ g/cm}^3)\).

Figure 2 summarizes the interpretation workflow where the “Matrix solver” loop is interactive as rock components (e.g., quartz, dolomite, pyrite, etc.) are chosen to quantify their effects on the calculated neutron-density matrix scale. Additionally, we compare estimated \( \rho_m \) to core measurements wherever available and appraise the solver’s numerical reproduction of PEF and GR measurements. Based on these comparisons, an interpretation decision is made concerning the most representative formation rock components. Consequent with the “Fluid solver” of Figure 2, final interpreted results include total porosity, hydrocarbon...
density, water saturation, matrix/grain density, and formation rock components.

**Synthetic example**

The interactive interpretation workflow is described for matrix and fluid effects on density and neutron-apparent porosities, using numerically simulated measurements across a synthetic and simplistic earth model. This model is designed to describe practical situations that present challenges to the interpretation of neutron and density logs.

Tables 1 and 2 describe the properties assumed for the synthetic earth model, while Figure 3 shows the simulated nuclear and resistivity logs. In Figure 4, we describe the interpretation results obtained with the interactive analysis workflow. Figure 4a and 4f–4h shows that estimated $\rho_{sw}$, $\varphi_t$, $S_w$, and $\rho_{hc}$, respectively, using the interactive interpretation, agree well with model properties in Table 1. It is particularly significant that the calculated $\rho_{hc}$ in Figure 4h distinguishes between gas- and oil-saturated layers.

Layers I and IV consist of gas-saturated shale of mixed orthoclase and illite clay, where $\Delta \varphi_{sh} = 0.155$ and shale density $\rho_{sh} = 2.738 \text{ g/cm}^3$. After correction for shale-hydroxyl effects, the actual matrix crossover effect, due to the shale density greater than limestone density, is shaded in brown in Figure 4b. On the other hand, layer V consists of gas-saturated shale with 20% water saturation (refer to Table 1), such that the gas crossover effect becomes accentuated after correction for shale-hydroxyl effect. In this layer because gas saturation and $V_{sh}$ impose opposite overlay characteristics, $\varphi_N - \varphi_D$ experiences a competition between gas and shale-hydroxyl effects. This behavior in neutron-density interpretation is especially common in logs acquired across shale gas formations.

Layers II and III consist of gas- and oil-saturated limestone formations, respectively. The matrix effect is irrelevant in these layers because limestone is the reference scale for neutron-density overlay. This behavior is corroborated by the overlap of $\varphi_{DWT}$ and $\varphi_{NWT}$ in panel c of Figure 4. Hydrocarbons, in comparison to fresh water, reduce the neutron porosity response because of lower HI (equation 5). From equations 11 and 12, the hydrocarbon effect is dependent on $\rho_{hc}$ and is accentuated in gas-saturated layers when compared to oil-saturated layers. In Figure 4d, layer III shows lower hydrocarbon effects and could be inadvertently interpreted as a water-filled layer. Consequently, the fluid solver incorporates the resistivity measurement, Archie’s model (equation 13), equations 2, 10, 11, and 12 for an inclusive calculation of $\rho_{hc}$, $S_{hc}$, and $\varphi_t$. Figure 4h shows that the estimated $\rho_{hc}$ reliably predicts gas and oil densities in gas- and oil-saturated layers II and III, respectively. In Figure 4f, the $\varphi_t$ approximation using Gaynard-Poupon’s formula (equation 1) is valid in layer II but inaccurate in shaly layers.

In layers VI and VII, for oil- and water-saturated dolomite, respectively, the overlay characteristics in Figure 4b indicate a matrix crossover. The matrix effect in panel d shows that $\Delta \varphi_{matrix} = 0.0072$ (i.e., 0.72 pu) for $\Delta \varphi_{sh} = 0$. By comparison, SNUPAR-calculated CNT response yields apparent thermal neutron porosity of 0.5 pu in dolomite of 0% pore volume.

**Table 1. Layer properties assumed in the synthetic example.**

<table>
<thead>
<tr>
<th>Layer</th>
<th>Matrix</th>
<th>Saturation fluid properties</th>
<th>Interpretation comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>I</td>
<td>Shale: 80% illite, 20% orthoclase, $\rho_{sh} = 2.738 \text{ g/cm}^3$</td>
<td>$\varphi_t = 0.10$, $S_w = 1$, $S_{hc} = 0$</td>
<td>Shale and matrix effects</td>
</tr>
<tr>
<td>II</td>
<td>Limestone</td>
<td>$\varphi_t = 0.28$, $S_w = 0.05$, $S_{hc} = 0.95$ (methane, CH$_4$, 0.182 g/cm$^3$)</td>
<td>Gas effect</td>
</tr>
<tr>
<td>III</td>
<td>Limestone</td>
<td>$\varphi_t = 0.28$, $S_w = 0.05$, $S_{hc} = 0.95$ (Liquid hydrocarbon, C$<em>{10}$H$</em>{22}$, 0.757 g/cm$^3$)</td>
<td>Hydrocarbon effects</td>
</tr>
<tr>
<td>IV</td>
<td>Shale: 80% illite, 20% orthoclase</td>
<td>$\varphi_t = 0.05$, $S_w = 1$, $S_{hc} = 0$</td>
<td>Shale and matrix effects</td>
</tr>
<tr>
<td>V</td>
<td>Shale, 80% Illite, 20% Orthoclase</td>
<td>$\varphi_t = 0.10$, $S_w = 0.20$, $S_{hc} = 0.80$ (Methane, CH$_4$, 0.182 g/cm$^3$)</td>
<td>Shale and gas effects</td>
</tr>
<tr>
<td>VI</td>
<td>Dolomite</td>
<td>$\varphi_t = 0.28$, $S_w = 0.05$, $S_{hc} = 0.95$ (liquid hydrocarbon, C$<em>{10}$H$</em>{22}$, 0.757 g/cm$^3$)</td>
<td>Matrix and hydrocarbon effects</td>
</tr>
<tr>
<td>VII</td>
<td>Dolomite</td>
<td>$\varphi_t = 0.10$, $S_w = 1$, $S_{hc} = 0$</td>
<td>Matrix effects</td>
</tr>
<tr>
<td>VIII</td>
<td>Limestone</td>
<td>$\varphi_t = 0$</td>
<td>Limestone reference</td>
</tr>
</tbody>
</table>

**Table 2. Summary of assumed Archie’s parameters and fluid properties for the synthetic example.**

<table>
<thead>
<tr>
<th>Variable</th>
<th>Value</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Connate water resistivity, $R_w$ at 200°F</td>
<td>0.0203</td>
<td>Ω m</td>
</tr>
<tr>
<td>Connate water density, $\rho_{cw}$</td>
<td>1.11</td>
<td>g/cm$^3$</td>
</tr>
<tr>
<td>Connate water HI, HI$_{cw}$</td>
<td>0.936</td>
<td>—</td>
</tr>
<tr>
<td>Connate water salt concentration</td>
<td>160,000 ppm NaCl</td>
<td></td>
</tr>
<tr>
<td>Archie’s factor, $a$</td>
<td>1</td>
<td>—</td>
</tr>
<tr>
<td>Archie’s porosity exponent, $m$</td>
<td>1.95</td>
<td>—</td>
</tr>
<tr>
<td>Archie’s saturation exponent, $n$</td>
<td>1.75</td>
<td>—</td>
</tr>
</tbody>
</table>
Field examples of application

In this section, the interactive interpretation workflow is implemented for estimation of \( \rho_m, \phi_t, S_w, \) and \( \rho_{hc} \) in two field examples: (I) gas-bearing carbonate field of dolomite lithology where \( \rho_m > 2.71 \text{ g/cm}^3 \), and (II) oil-bearing shale formation where \( \rho_m < 2.71 \text{ g/cm}^3 \).

Field example I, gas-bearing carbonate

This field example consists of conventional wireline nuclear and dual induction resistivity logs acquired across a gas-producing dolomite reservoir. Additionally, the well includes routine core measurements. Due to low reservoir pressure, deep mud-filtrate invasion affects the nuclear logs and even the deep resistivity log, such that log-derived \( S_{hc} \) is considerably lower than in situ \( S_{hc} \) for water-base mud (Xu et al., 2012). Table 3 summarizes the assumed Archie’s parameters and fluid properties for the gas-bearing carbonate field.

Figure 5 shows the field measurements together with core measurements, compared to results obtained with the interactive interpretation. The neutron-density overlay in Figure 5b emphasizes the matrix crossover because the reservoir is primarily of dolomite lithology. The gas flag in Figure 5j, proportional to hydrocarbon pore volume, is most pronounced across XX45–XX55 m despite the suppressed gas crossover in Figure 5b. Across the interval in Figure 5, the gas flag provides a qualitative and unequivocal indication of hydrocarbon saturation despite mud-filtrate invasion and matrix crossover.

The calculated \( \rho_{hc} \) in Figure 5h, with an average value of 0.176 g/cm³, confirms that the reservoir is largely saturated with gas. Conclusively, we implement combined matrix and fluid volumetric analysis with the SNUPAR-based solver, where methane gas of 0.176 g/cm³ is assumed as a component of the fluids, thus eliminating the water-filled assumption in the independent matrix analysis. Figure 5i shows cumulative plots of the volumetric fractions of shale, quartz, calcite, dolomite, water, and gas, obtained from the SNUPAR-based solver. The estimated \( \rho_m \) and \( \phi_t \) (Figure 5e and 5f, respectively), agree well with core measurements. On the other hand, log-derived \( S_w \) (Figure 5g) within interval XX08–XX32 m is considerably lower than core measurements. This behavior can be attributed to variations in Archie’s parameters for differing rock types along the well. Furthermore, \( S_w \) in core samples could increase due to quick spurt loss in low-porosity, low-pressure reservoirs (Xu et al., 2012).

Field example II, oil-bearing shale example

In this example, nuclear and array induction resistivity logs are acquired in a well drilled with oil-base mud across an oil-bearing shale formation from the Eagle Ford shale play. Table 4 describes the assumed fluid properties and Archie’s parameters for the oil-bearing shale reservoir. Figure 6 shows field measurements, core measurements, and interpreted petrophysical properties for the oil-bearing shale example. Here, the SNUPAR-based matrix analysis assumes kerogen \( (\text{C}_{100}\text{H}_{100}\text{O}_8) \) of density \( 1.4 \text{ g/cm}^3 \), calcite, kaolinite,
and illite as components of the matrix. Figure 6e compares \( \rho_m \) from the interactive analysis to core measurements and elemental capture spectroscopy (ECS) lithology analysis. The ECS-derived \( \rho_m \) (dashed blue curve) is significantly larger than the core \( \rho_m \) (blue circle points). This result is attributed to the exclusion of the low-density kerogen matrix from the ECS analysis. The matrix density \( \rho_m \) from SNUPAR-based matrix

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**Table 3. Summary of assumed fluid properties and Archie’s parameters for field example I, gas-bearing carbonate.**

<table>
<thead>
<tr>
<th>Variable</th>
<th>Value</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Connate water resistivity, ( R_w ) at 96°F</td>
<td>0.04</td>
<td>Ω m</td>
</tr>
<tr>
<td>Connate water density, ( \rho_{cw} )</td>
<td>1.12</td>
<td>g/cm³</td>
</tr>
<tr>
<td>Connate water HI, ( H_{Iw} )</td>
<td>0.932</td>
<td>—</td>
</tr>
<tr>
<td>Connate water salt concentration</td>
<td>170,000 ppm NaCl</td>
<td></td>
</tr>
<tr>
<td>Mud-filtrate water resistivity, ( R_{mf} ) at 96°F</td>
<td>0.84</td>
<td>Ω m</td>
</tr>
<tr>
<td>Mud-filtrate water density, ( \rho_{mf} )</td>
<td>1</td>
<td>g/cm³</td>
</tr>
<tr>
<td>Mud-filtrate HI, ( H_{Imf} )</td>
<td>1</td>
<td>—</td>
</tr>
<tr>
<td>Mud-filtrate water salt concentration</td>
<td>5147 ppm NaCl</td>
<td></td>
</tr>
<tr>
<td>Archie’s factor, ( a )</td>
<td>1</td>
<td>—</td>
</tr>
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<td>Archie’s porosity exponent, ( m )</td>
<td>1.96</td>
<td>—</td>
</tr>
<tr>
<td>Archie’s saturation exponent, ( n )</td>
<td>1.83</td>
<td>—</td>
</tr>
</tbody>
</table>

---

**Figure 4.** Interpretation results for the synthetic example using the interactive interpretation workflow. (a) Interpreted matrix density from SNUPAR-based matrix solver, (b) neutron-density overlay showing shale-corrected neutron log, matrix, and fluid crossover characteristics, (c) neutron and density-apparent water-filled logs from SNUPAR-based matrix solver, (d) interactive flag indicators showing matrix effect and gas flag, (e) corrected neutron-density overlay, (f) estimated total porosity, (g) estimated water saturation, and (h) estimated hydrocarbon and fluid densities. Refer to Table 1 for a description of layer properties.
analysis (red curve) agrees well with core measurements. The resulting fluid crossover, in Figure 6b, after matrix-hydrogen and shale-hydroxyl corrections, is due to the combined effects of $\rho_m$ (less than 2.71 g/cm$^3$ of limestone), fluid density, and fluid HI. It is found that the interactive analysis yields a relatively constant $\rho_{hc}$ of 0.747 g/cm$^3$ for the interval in Figure 6h. Furthermore, estimated $\phi_t$ and $S_w$ from the interactive analysis (Figure 6f and 6g respectively), agree well with core measurements.

**Fluid zone identification**

Conventional methods for fluid contact identification include interpretation of pressure gradients due to fluid density differences in the reservoir hydrostatic column. Additionally, impermeable sealing or geological barriers,

![Figure 5](image-url). Interpretation results for field example I, gas-bearing carbonate reservoir, using the interactive analysis workflow. (a) GR log, (b) neutron and density porosities on limestone scale, (c) dual-induction resistivity logs, and (d) PEF log. (e) Matrix density, (f) total porosity, and (g) water saturation from core measurements and interactive analysis. (h) Calculated fluid densities showing a gas cutoff of 0.25 g/cm$^3$. (i) Volumetric concentrations of rock and fluid components from the SNUPAR-based solver. (j) Gas flag from interactive analysis workflow.

*Table 4.* Summary of assumed fluid properties and Archie’s parameters for field example II, oil-bearing shale.

<table>
<thead>
<tr>
<th>Variable</th>
<th>Value</th>
<th>Units</th>
</tr>
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<tbody>
<tr>
<td>Connate water resistivity, $R_w$ at 215°F</td>
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<td>Ω m</td>
</tr>
<tr>
<td>Connate water density, $\rho_{cw}$</td>
<td>1.077</td>
<td>g/cm$^3$</td>
</tr>
<tr>
<td>Connate water HI, $\text{HI}_{cw}$</td>
<td>0.901</td>
<td>—</td>
</tr>
<tr>
<td>Connate water salt concentration</td>
<td>165,000</td>
<td>ppm NaCl</td>
</tr>
<tr>
<td>Archie’s factor, $a$</td>
<td>1</td>
<td>—</td>
</tr>
<tr>
<td>Archie’s porosity exponent, $m$</td>
<td>2.1</td>
<td>—</td>
</tr>
<tr>
<td>Archie’s saturation exponent, $n$</td>
<td>2</td>
<td>—</td>
</tr>
</tbody>
</table>
often at residual saturations, prevent hydraulic communication between fluid zones such that a higher density fluid resides above a lower density fluid in the hydrocarbon column.

Occasionally, when pressure measurements are unavailable or expensive to acquire, well logs are used to infer fluid zones. In this section, the estimated $\rho_{hc}$ log yielded by the interactive interpretation is used for a quick-look qualitative identification of hydrocarbon zones and fluid contacts along the reservoir column in two more field examples.

**Field example III, identification of hydrocarbon fluid contacts in a North Sea siliciclastic reservoir**

This example consists of a siliciclastic reservoir located in the central North Sea, where rock formations consist of noncalcareous mudstones interbedded with shaly sand deposits (Heidari et al., 2012). Figure 7a–7d shows nuclear and array induction resistivity measurements acquired in a vertical well drilled with oil-base mud, while Table 5 summarizes the assumed properties and Archie’s parameters for the siliciclastic reservoir. In addition, available pressure data in Figure 7f describe three distinct and approximately constant pressure gradients. Water saturation, $S_w$, shown in Figure 7e, estimated using the dual-water resistivity model, indicates that the hydrocarbon column exhibits a complete capillary transition with an aquifer below X660 m. Pressure gradients identify three fluid zones, i.e., gas of 0.263 g/cm$^3$ density, oil of 0.647 g/cm$^3$ density, and an aquifer at residual hydrocarbon saturation with connate water of 1.005 g/cm$^3$ density, distinguished by red, green, and black intervals, respectively. Figure 7g shows the fluid densities, fluid zones, and fluid contacts, where estimated fluid densities, $\rho_f$, from pressure gradients are juxtaposed with $\rho_f$ estimated with the interactive interpretation.

Qualitatively, $\rho_f$ (Figure 7g) and $\phi_t$ (Figure 7h) from the interactive interpretation agree well with pressure and core measurements, respectively, except across the interval between X550 and X600 m. This interval consists of highly interbedded sand-shale sequences; evident from the GR log in Figure 7a, whereby log-derived $\phi_t$ and $\rho_f$ are significantly influenced by shoulder-bed effects, and depth-by-depth analysis is inadequate. Note that the estimated $\rho_f$ from the interactive interpretation agrees well with $\rho_{hc}$ across the thick bed layers in the gas zone. Nonetheless, assuming no

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**Figure 6.** Interpretation results for field example II, oil-bearing shale reservoir, using the interactive analysis workflow. (a) GR log, (b) neutron and density porosities on limestone scale, (c) array induction resistivity logs, and (d) PEF log. (e) Matrix density, (f) total porosity, and (g) water saturation from core measurements and interactive analysis. (h) Calculated fluid densities showing a gas cutoff of 0.25 g/cm$^3$.
reservoir compartmentalization and good hydraulic communication, the gas-oil contact is located at X600 m, while the oil-water contact is located at X655 m where the water zone is at residual hydrocarbon saturation.

**Field example IV, identification of reservoir compartments in the deepwater Gulf of Mexico**

In this example, the reservoir consists of channel levees located in the deepwater Gulf of Mexico, where formations consist of unconsolidated shaly sand intervals and are primarily saturated with oil. Table 6 summarizes the assumed properties used in the interactive interpretation with a dual-water resistivity model. In Figure 8, the panels describe well logs and interpretation results across a hydrocarbon-saturated interval in the Gulf of Mexico reservoir. Figure 8e shows that average total porosities in the clean and shaly sand layers are 0.2721 and 0.1724, respectively. In Figure 8c and 8g, we observe a gas-saturated reservoir compartment between X817 and X819 m, where gas density is 0.144 g/cm$^3$ and the neutron-density overlay exhibits significant gas crossover. The primary oil-saturated zone, between X778 and X802 m, with an estimated oil density of 0.43 g/cm$^3$ is above the gas-saturated compartment at X817–X819 m. The compartmentalization of the gas layer is possible because hydraulic communication is severed between the oil and gas zones by the interleaving impermeable nonnet shale barriers. This example verifies the

<table>
<thead>
<tr>
<th>Variable</th>
<th>Value</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Connate water resistivity, $R_w$ at 254°F</td>
<td>0.025</td>
<td>Ω m</td>
</tr>
<tr>
<td>Connate water density, $\rho_{cw}$</td>
<td>1.005</td>
<td>g/cm$^3$</td>
</tr>
<tr>
<td>Connate water HI, $H_{Icw}$</td>
<td>0.997</td>
<td>—</td>
</tr>
<tr>
<td>Connate water salt concentration</td>
<td>77,600 ppm NaCl</td>
<td></td>
</tr>
<tr>
<td>Archie’s factor, $a$</td>
<td>1</td>
<td>—</td>
</tr>
<tr>
<td>Archie’s porosity exponent, $m$</td>
<td>1.89</td>
<td>—</td>
</tr>
<tr>
<td>Archie’s saturation exponent, $n$</td>
<td>1.92</td>
<td>—</td>
</tr>
<tr>
<td>Shale porosity, $\phi_{sh}$</td>
<td>0.10</td>
<td>v/v</td>
</tr>
<tr>
<td>Shale resistivity, $R_{sh}$</td>
<td>1.50</td>
<td>Ω m</td>
</tr>
</tbody>
</table>

Table 5. Summary of assumed properties and Archie’s parameters for field example III, North Sea siliciclastic reservoir.

Figure 7. Fluid zone interpretation results for field example III, North Sea siliciclastic reservoir. (a) GR log, (b) PEF log, (c) neutron and density porosities on limestone scale, and (d) array induction resistivity logs. (e) Estimated water saturation, (f) pressure measurements, and (g) fluid densities from interactive analysis and pressure gradients. (h) Total porosity from core measurements and interactive analysis.
capability of the interactive interpretation workflow to
distinguish between oil- and gas-saturated layers, irre-

ductive of formation lithology. The workflow also
provides an efficient qualitative method for identifica-
tion of reservoir compartments separated by sealing

The interactive interpretation workflow rescales the
neutron-density overlay with corrected neutron and
density-apparent porosities in a variable matrix scale,
for independent characterization of fluid effects. It
was found that the SNUPAR-based matrix analysis,
assuming freshwater-filled formations, renders accurate
estimations of matrix density even across hydrocar-
bon-saturated intervals. Such a result is due to the fact
that formation fluids have negligible or no effect on PEF
and GR logs. One limitation of the SNUPAR-based ma-
trix analysis is that a priori qualitative knowledge of
matrix components, i.e., lithology, clay mineral, etc.,
is essential for accurate estimation of matrix density.
This is achieved by preliminary lithology or matrix iden-
tification crossplots, e.g., PEF-$\rho_b$, thorium-potassium,
and PEF-potassium crossplots. Furthermore, the work-
flow assumes minimal shoulder-bed effects such that
depth-by-depth analysis is adequate for SNUPAR calcu-
lations. The uncertainty in estimated $\rho_{hc}$ increases in
thinly bedded intervals with pronounced shoulder-
bed effects.

The merits of the SNUPAR-based interactive inter-
pretation workflow and its contributions to the practice
of interpretation include the following:

Table 6. Summary of assumed properties and Archie’s
parameters for field example IV, deepwater Gulf of
Mexico reservoir.

<table>
<thead>
<tr>
<th>Variable</th>
<th>Value</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Connate water resistivity, $R_w$ at 150°F</td>
<td>0.030</td>
<td>$\Omega$ – m</td>
</tr>
<tr>
<td>Connate water density, $\rho_{cw}$</td>
<td>1.098</td>
<td>g/cm$^3$</td>
</tr>
<tr>
<td>Connate water HI, HI$_{cw}$</td>
<td>0.9441</td>
<td>—</td>
</tr>
<tr>
<td>Connate water salt concentration</td>
<td>140,000 ppm NaCl</td>
<td></td>
</tr>
<tr>
<td>Archie’s factor, $a$</td>
<td>1</td>
<td>—</td>
</tr>
<tr>
<td>Archie’s porosity exponent, $m$</td>
<td>1.92</td>
<td>—</td>
</tr>
<tr>
<td>Archie’s saturation exponent, $n$</td>
<td>2.00</td>
<td>—</td>
</tr>
<tr>
<td>Shale porosity, $\phi_{sh}$</td>
<td>0.15</td>
<td>v/v</td>
</tr>
<tr>
<td>Shale resistivity, $R_{sh}$</td>
<td>1.0</td>
<td>$\Omega$ – m</td>
</tr>
</tbody>
</table>

Figure 8. Fluid zone interpretation results for field example IV, deepwater Gulf of Mexico reservoir. (a) GR log, (b) PEF log,
(c) neutron and density porosities on sandstone scale, and (d) array induction resistivity logs. (e) Total porosity, (f) water satu-
rature, and (g) fluid density logs estimated using the interactive analysis.
• unequivocal identification of hydrocarbon-saturated zones,
• estimation of model-consistent/lithology-independent formation porosity, and
• calculation of hydrocarbon density for gas/oil-zone identification.

It was shown that the workflow incorporates interactive matrix corrections such that Gaymard-Poupon’s formulation for lithology-independent porosity and hydrocarbon identification can be implemented for any neutron-density matrix scale and lithology (clean and/or shaly), especially in wells with limited data.

Synthetic and field examples of application indicate that lithology-independent porosity and hydrocarbon density can be efficiently estimated from conventional nuclear and resistivity logs for reliable and quantitative detection and appraisal of hydrocarbon-saturated sweet spots and nonviable zones. Furthermore, identification of fluid types in the reservoir column provides a qualitative means for determining fluid contacts and reservoir compartments.

Symbols and nomenclature

\[ a = \text{Wimsauer factor in Archie’s equation ( )} \]
\[ \text{AmBe} = \text{Americium-beryllium} \]
\[ \text{AO10} = 25.4-\text{cm (10-in) array induction one-foot resistivity (}\Omega-\text{m}) \]
\[ \text{AO30} = 76.2-\text{cm (30-in) array induction one-foot resistivity (}\Omega-\text{m}) \]
\[ \text{AO90} = 228.6-\text{cm (90-in) ray induction one-foot resistivity (}\Omega-\text{m}) \]
\[ \text{CNT} = \text{Schlumberger-compensated neutron tool} \]
\[ g_d = \text{Neutron-porosity calibration function, in sandstone units} \]
\[ g_t = \text{Neutron-porosity calibration function, in limestone units} \]
\[ \text{GR} = \text{Gamma ray American Petroleum Institute} \]
\[ g_s = \text{Neutron-porosity calibration function, in sandstone units} \]
\[ \text{HI} = \text{Hydrogen index ( )} \]
\[ \text{ILD} = \text{Deep induction resistivity (}\Omega-\text{m}) \]
\[ \text{ILM} = \text{Medium induction resistivity (}\Omega-\text{m}) \]
\[ L_m = \text{Neutron migration length (cm)} \]
\[ m = \text{Archie’s porosity exponent} \]
\[ M = \text{Number of components} \]
\[ n = \text{Archie’s saturation exponent} \]
\[ \text{NMR} = \text{Nuclear magnetic resonance} \]
\[ \text{PEF} = \text{Photoelectric factor (b/e)} \]
\[ R_i = \text{True resistivity (}\Omega-\text{m}) \]
\[ R_w = \text{Water resistivity (}\Omega-\text{m}) \]
\[ \text{SFLU} = \text{Spherically focused resistivity (}\Omega-\text{m}) \]
\[ \text{SNUPAR} = \text{Schlumberger nuclear parameter calculator} \]
\[ S_w = \text{Water saturation (\%)} \]
\[ \text{UTAPWeLS} = \text{The University of Texas at Austin petrophysical and well-log simulator} \]
\[ V_i = \text{Volumetric concentration (v/v)} \]

\[ V_{sh} = \text{Volumetric concentration of shale (v/v)} \]
\[ \Sigma = \text{Capture cross section (cu)} \]
\[ \rho = \text{Density (g/cm}^3\text{)} \]
\[ \Delta = \text{Depature} \]
\[ \varphi = \text{Apparent porosity (v/v)} \]
\[ \rho_m = \text{Matrix density (g/cm}^3\text{)} \]
\[ \varphi_t = \text{Total porosity (v/v)} \]
\[ \delta_c = \text{Neutron fluid effect parameter ( )} \]

Subscripts

\[ b = \text{Bulk} \]
\[ \text{corr} = \text{Corrected} \]
\[ \text{cw} = \text{Connate water} \]
\[ e = \text{Electron} \]
\[ f = \text{Fluid} \]
\[ g = \text{Gas} \]
\[ \text{hc} = \text{Hydrocarbon} \]
\[ i = \text{Component index} \]
\[ \text{ker} = \text{Kerogen} \]
\[ \text{mf} = \text{Mud-filtrate} \]
\[ N = \text{Neutron} \]
\[ \text{nsh} = \text{Nonshale} \]
\[ \text{sh} = \text{Shale} \]
\[ t = \text{Total} \]
\[ \text{wf} = \text{Water-filled} \]

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References


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Biographies and photographs of the other authors are not available.