A Novel Approach to Numerical Integration of Conventional, Multi-Component Induction, and Magnetic Resonance Data in Thinely Bedded Sand-Shale Systems

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Summary

Exploration and development activities in deep water environments have increased during the last decade as a result of significant discoveries and excellent reservoir performances observed in some of those discoveries. Improved production facilities and the availability of new technologies for characterization of these reservoirs have made these successes possible. Many of these reservoirs are characterized by beds with thicknesses below the vertical resolution of most of the measurements used for interpretation. The advent of multicomponent induction instruments measuring the electrical anisotropy of the formation permits the evaluation these thinly bedded reservoirs at a scale smaller than that of the instruments resolution. However, the extraction of the information contained in the logging data represents a challenge log analysts and petrophysicists face in dealing with well log interpretation. The problem becomes especially difficult when data from conventional (e.g., density, neutron, gamma ray) and non-conventional (e.g., NMR, multi-component induction) instruments are available and need to be combined in a consistent interpretation.

We present a petrophysical model for use in the evaluation of low-resistivity laminated shaly-sand reservoirs. They allow for an effective and consistent combination of the various measurements leading to an accurate characterization of shale distribution, fluid distribution, and permeability of the sand lamina. The proposed petrophysical models, which are tailored to integrate conventional with NMR and multi-component induction data, comprise a volumetric description of the rock, representing the fractional volumes of each rock component, and a set of response equations relating rock volumetrics with rock physical properties; those provided by the log measurements. Simultaneous and sequential solutions of the petrophysical models are proposed that facilitate the estimation of the required analyst-provided formation parameters. Real field data examples are developed showing the ability of the proposed interpretation philosophy and methodology to reconcile formation lithology, porosity, fluid type, fluid distribution, and permeability.

Introduction

Numerous authors have described the challenges associated with the evaluation of low resistivity, low contrast laminated sand-shale reservoir. When the thickness of the laminations is significantly less than the vertical resolution of conventional logging instruments, the formation displays a macroscopic anisotropy with respect to properties such as conductivity and permeability. These properties will have different values dependent on the directionality of the measurements with maximum anisotropy occurring when measured parallel and perpendicular to the bedding planes, transverse anisotropy.

The petrophysical model for interpreting sand-shale reservoirs is based on the concepts of the volumetric shale distribution model (Thomas and Stieber, 1975), and a tensor resistivity model to determine laminar shale volume and laminar sand resistivity (Mollison et al., 2000). The resistivity tensor utilizes macroscopic electrical anisotropy defined by the combination of the horizontal parallel and vertical series resistivity equations (Hagiwara, 1994, 1997, 1998; Klein et al., 1997; Klein, 1996; and Herrick and Kennedy, 1996, Mezzatesta et al., 2002, Van Popta et al., 2004).

We propose a petrophysical model that simultaneously incorporates all volumes of distributed shale, laminar, structural, and dispersed, in the corresponding instrument response equations (total porosity, total volume of shale, density, neutron, etc.). A simultaneous solution of these equations allows us to account for the different combinations of shale distribution defined by the volumetric and tensor models to derive the laminar sand reservoir properties. The incorporation of NMR further results in the separation of estimated sand water saturation into its irreducible and moveable components and deriving a more accurate estimate of sand permeability using the Coates-Timur (Coates et al., 1991) permeability equation.

Data integration

By data integration we mean the process of deriving
a petrophysical model of the borehole surrounding consistent with the logging data used in the interpretation as well as with core and geological information. The data integration process requires the use of several elements or components that make the integration of data possible, that is,

- A mathematical model linking the desired petrophysical properties of the rock (e.g., mineralogy, rock porosity, shale distribution, fluid distribution, and permeability) with the actual geophysical rock properties measured in the field (e.g., density, travel time, neutron porosity, resistivity),
- A numerical technique to solve the system of equations derived from the application of the mathematical model,
- A software module to compute the solution to the mathematical model, and
- A strategy to help the analyst in the generation of petrophysical and geological sound interpretation results.

What follows provides a brief description of the data integration components listed above.

**The Petrophysical model**

The volumetric petrophysical model used in this work for a laminated shaly-sand formation is depicted in Figure 1, with the main rock components being the laminar shale (top) and sandstone (bottom) fractions.

![Fig. 1: Volumetric model of a laminated shaly-sand formation. The top portion represents the shale fraction of the rock and the bottom the sand fraction, forming the actual reservoir.](image)

The sand portion of the rock shows the volumes corresponding to sand matrix and structural shale (forming the actual structure of the sand fraction) and the poral space filled with dispersed shale and fluids, in the form of irreducible and movable. Assuming a unit volume of rock, the volumes of each of the components described above must add to one,

\[ V_{ma} + V_{shl} + V_{shs} + V_{shd} + V_{wi} + V_{wm} + V_{hc} = 1. \] (1)

Each of the terms in Equation (1) represents the volume associated with each of the components depicted in Figure 1. As in the Thomas-Stieber volumetric shale distribution, the model assumes a constant clean sand fraction porosity, which can be only filled with dispersed shale and fluids, i.e., water and hydrocarbon. Structural shale can only be present as a replacement of the sand grains. Laminar shale replaces the sandstone portion of the rock, including all its components, i.e. quartz, dispersed shale, structural shale, and fluids. To honor the shale-sand replacement law in the model, we need to introduce and additional equation, which considers the replacement of sandstone porosity with dispersed shale and can be written as

\[ \phi_{max}(1 - V_{shl}) = V_{shd} + V_{w} + V_{hc}. \] (2)

This establishes that the available rock pore volume can only be occupied with dispersed shale and fluids.

In addition to the volumetrics, the petrophysical model provides the relationships between the measured macroscopic properties of the rock (such as the total volume of shale, total porosity, density, and the bulk volume of irreducible water) with the macroscopic petrophysical rock properties (such as the volume of irreducible water, the volume of hydrocarbon, and the three shale volumes). This allows one to write a set of equations that can be simultaneously solved for rock petrophysical parameters once a given set of rock measurements is provided.

Two types of measurements are considered here: The scalar measurements that are characterized by a single scalar quantity and those of tensorial nature that are directionally dependent and need to be characterized by tensorial quantities. The two measurement types are depicted in Figure 2.

In order to relate the log measurements with the rock petrophysical parameters, we consider a model consisting of a volume-weighted average of the individual component properties. Also, to provide generality we use the letter \( P \) to indicate a generalized property, such as rock density, which can then be written as,

\[ P = P_{ma} V_{ma} + P_{shl} V_{shl} + P_{shs} V_{shs} + P_{shd} V_{shd} + P_{w} V_{w} + P_{hc} V_{hc}. \] (3)

Equation (3) allows for expressing a generic rock geophysical property, \( P \), as a volumetric-weighted average of the corresponding component properties. In this work,
we have used Equation (3) to represent responses such as those derived from Gamma Ray, Neutron, Density, Acoustic, and NMR instruments.

In particular, when NMR derived data is used, the basic response equations such as bulk volume irreducible, BVI, bulk volume moveable, BVM, and clay bound water, CBW, can be expressed as,

\[ CBW = \phi_{sh} V_{sh} \]  \hspace{1cm} (4a)

\[ BVI = V_{wi} \]  \hspace{1cm} (4b)

\[ BVM = V_{wm} + V_{hc} \]  \hspace{1cm} (4c)

The 3DEX\textsuperscript{SM} multi-component induction instrument allows for the derivation of a resistivity tensor at each logging depth. Specifically, it allows for estimating the resistivities in the directions parallel, \( R_h \), and perpendicular, \( R_v \), to the bedding plane (lamination). The combination of both resistivities improves the ability to characterize the actual reservoir by a more accurate estimation of the intrinsic sand properties (porosity and fluid saturations).

The tensor model resistivity response equations are,

\[ \frac{1}{R_h} = \frac{V_{shl}}{R_{shl,h}} + \frac{(1 - V_{shl})}{R_{sd}} \]  \hspace{1cm} (5a)

for the horizontal resistivity, and

\[ R_v = V_{shl} R_{shl,v} + (1 - V_{shl}) R_{sd} \]  \hspace{1cm} (5b)

for the vertical resistivity. \( R_{sd} \) represents the isotropic sand fraction resistivity which can be calculated using an appropriate saturation equation.

The incorporation of at BVI and/or BVM to the resistivity equations permits the separation of the total volume of water into its irreducible and movable components. In addition, knowledge about irreducible and movable fluids brings the possibility of estimating a formation permeability index by using the Coates-Timur equation.

**Solution of the system of equations**

The system of equations is simultaneously solved using a Nonlinear Weighted Regularized Least-Squares Method, i.e., we define the solution to the problem as the set of parameters that minimizes a weighted error function involving the data match, constraints, and a reference model, defined as,

\[ H(\hat{\rho}) = \| W_d (f(\hat{\rho}) - d) \|^2 + \| W_c (g(\hat{\rho}) - \hat{h}) \|^2, \]  \hspace{1cm} (6)

where \( W_d \) and \( W_c \) represent the weighting matrices associated data and constraints, respectively, and \( \hat{\rho} \) the solution parameter vector.

A Newton iterative process is used to obtain the solution of the nonlinear problem. The linearized system of equations is solved using the Marquard-Levenberg technique combined with the Singular Value Decomposition method (Mezzatesta et al., 1994, Mezzatesta, 1996).

**Integration strategy**

We propose a strategy for integration of the data consisting of the following steps, following the process of data QC and normalization:

- Estimation of log responses to shale and shale index (Step I),
- Estimation of the earth model volumetrics, i.e., matrix, shale, and porosity (Step II), and
- Estimation of shale and fluid distributions (Step III).

In Step I, the shale response to the logs is characterized via the use of single and dual shale indicators, using histograms for single indicators and cross plots for dual indicators. Results from this step produce a consistent set of shale parameters and an estimated shale volume that...
are subsequently used as input in the following steps. In Step 2, we carry out the calculation of volumetrics, consisting on matrix mineral volumes, a final shale volume, and formation effective porosity. At this level, a novel algorithm is executed to correct the volumetric results for the presence of light hydrocarbons, i.e., gas, previous to the estimation of fluid distribution in the pore space. Finally, Step III is used for estimating shale distribution (Vshl, Vshs, and Vshd) within the previously estimated total shale volume and fluid distribution (Vwi, Vwm, and Vhc) within the effective porosity.

Figure 3 shows a diagram of the proposed integration strategy.

The estimation of clean sand porosity required by Equation (2) is performed before entering Step III, by cross-plotting the effective porosity and volume of shale derived from Step II and using the Thomas-Stieber approach for shale distribution. Figure 4 shows a characteristic cross plot generated for this purpose.

Thus, when the two approaches are used independently, we may expect discrepancies in laminar shale estimates.

Our proposed petrophysical model and interpretation approach allows for simultaneously satisfying the two models in a consistent petrophysical solution.

Field example

To illustrate the proposed methodology we have processed a set of conventional and 3DEX SM data from a reservoir containing a section of shaly-sand laminations. Results are presented in Figure 5.

Interpretation results show in the first track the volumetrics from Step II consisting on volume of shale, volume of sand, and effective porosity. The second combined track shows NMR and resistivity data (Rh, Rv, and sand fraction estimated resistivity). The third combined track shows the estimated distribution of shale and fluids. The tracks on the right show an excellent fit between the actual and theoretical tensorial resistivity as well as a comparison of three laminar shale volumes derived from Thomas-Stieber, tensor resistivity, and the integrated approach (Step III).
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References


Fig. 5: Results of integration of conventional logs with multi component induction derived resistivity tensor.

It is important to observe that reservoir pay is characterized by the region in the well where the three derived volumes of laminar shale come to a good match. Outside that region, the estimated laminar shale volumes do not match as well, an indication of a reduction in the formation electrical anisotropy.

Conclusions

We proposed a methodology that allows for simultaneous integration of scalar and tensor logging data in an internally consistent interpretation process. A sequential approach facilitates the adjustment of model parameters and the quality control of interpreted results. The methodology has been successfully applied to various practical cases involved thin-bed environments.

Integration results lead to a petrophysical model consistent with available logging data.

The consistency of interpreted results with core and image data validates the quality and applicability of the proposed technology.