Title: Multi physics measurements integration for improving petrophysical interpretation

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This paper was prepared for presentation during the 16th International Congress of the Brazilian Geophysical Society held in Rio de Janeiro, Brazil, 19-22 August 2019.

Abstract

In this work we propose a fast method for obtaining improved porosity estimation, hydrocarbon quantification and calibrated rock physics models based on acoustics, bulk density, resistivity, and nuclear magnetic resonance (NMR) measurements, that has been successfully tested in complex carbonates of the Brazilian pre-salt oil wells, and siliciclastic gas wells.

This method honors the physics of each measurement in a fast-unidimensional approach capable of characterizing the formation properties in the presence of anisotropy, thin beds, gas bearing formation, mud invasion, complex mineralogy, and different porosity types.

Using mathematical and empirical models such as the effective medium theory fluid substitution model and the Archie and Waxman-Smits models, we estimate the desired petrophysical properties combining iterative methods and direct inversions and constraints given by the measurements and data analysis.

Introduction

The complexity and high operational cost of offshore wells motivates of the reservoir logging with multiple tools including nuclear magnetic resonance (NMR), dipole acoustics, resistivity, and bulk density to improve the confidence of the reservoir estimates. With the objective of improving the answers from these tools in complex scenarios containing anisotropy, high heterogeneity and complex mineralogy, we proposed an integrated method that can be applied to field data combined with mineralogy estimates.

We propose a fast method for obtaining improved porosity estimation, hydrocarbon quantification and calibrated rock physics models based on acoustics, bulk density, resistivity, and NMR, see Fig. 1. This method is different to Sushil et al. (2018) and Gao, Abubakar and Habashy (2012), although it has the same objectives. The first paper included acoustics, resistivity and density data. The current approach reconstructs the resistivity channels for far field and near field and the near- and far- field velocities. With this new and simplified inversion, we are able to integrate other measurements such as NMR and dielectric, and different rock physics methods. We are also able to test different input parameters because the computational time using a personal computer is around one minute for an interval containing 7000 samples.

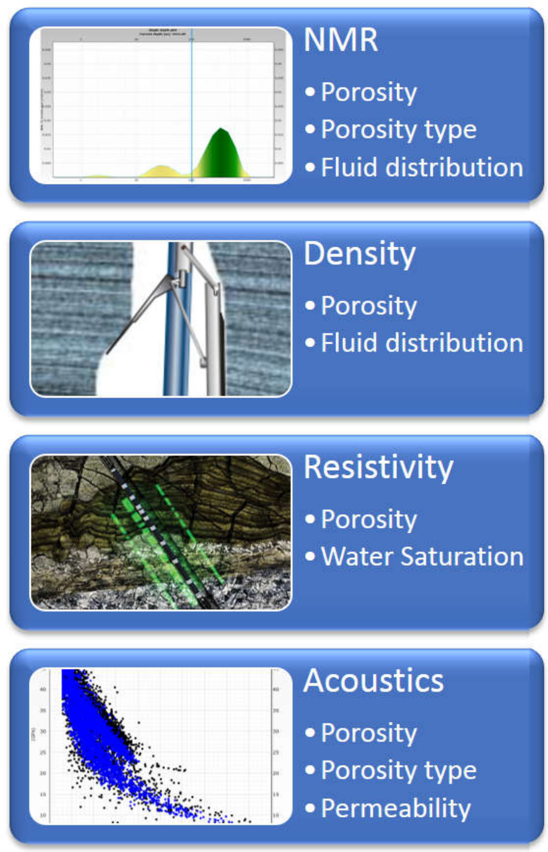

Figure 1: *Inputs and outputs for the multi sensor inversion.*

Method

The methodology proposed is being developed by specialists with a variety of backgrounds and experiences in Schlumberger and Shell and that combination allowed us to focus on a computer efficient, multi physics integration development for addressing field challenges.

The method has been successfully tested on a series of oil-bearing pre-salt carbonate wells and on gas-bearing clastic formation wells, each presenting different challenges.

The first main scenario of interest, which has been extensively used for developing and testing the methodology, is that of complex carbonates with different porosity types and high heterogeneity, typical of the pre-salt carbonate formation offshore Brazil. In these complex carbonates, the different porosity types and the high heterogeneity have a strong effect on permeability, fluid saturation and elastic properties, and represent a challenge for seismic interpretation, near wellbore characterization using logging data, reservoir modeling and production estimation.

The second main scenario of interest is that of siliciclastic formations with intrinsic anisotropy due to lamination thin beds and complex mineralogy. The assumption of an isotropic formation on the rock physics modeling used in seismic interpretation could lead to using an incorrect velocity model transform, and the simplification of anisotropy on the resistivity modeling could lead to a wrong water saturation estimate.

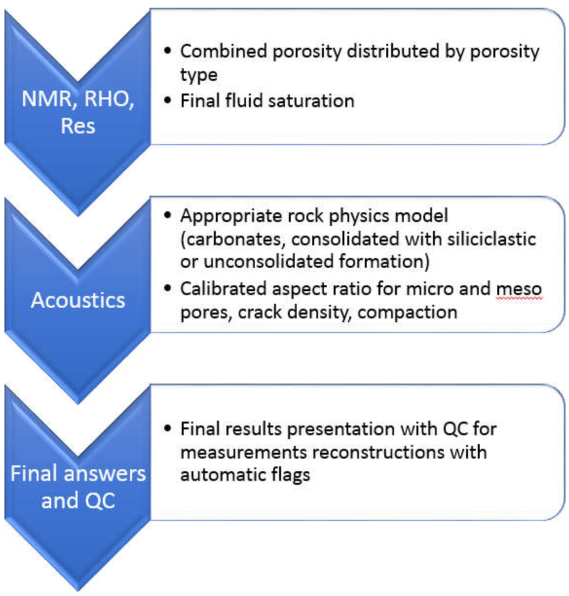

Figure 2: *The first part of the inversion includes the estimation of fluid distribution, porosity and porosity types distribution, together with the elastic properties of each mineral this information can be used to reconstruct the acoustic slownesses.*

Theory for integration

Our method aims to contribute to both wellbore characterization and rock physics model calibration. Fig.2 illustrates the steps followed in our modeling. First, we combine NMR, density and resistivity to obtain fluid distribution and fluid corrected porosity and permeability. Secondly, we reconstruct the elastic properties and finally we present the results for quality control and interpretation.

Regarding the rock physics modeling, we have used traditional methods based on Kuster Toksoz, Gassmann, Hudson´s cracks modeling, and Backus average as basic modeling pieces.

The element which is different in this methodology is estimating the input curves necessary for defining the inclusion properties internally, improving the method robustness and repeatability.

The different inclusion types are distributed considering micropores and vugs, which are associated with different aspect ratios, respectively. The porosity distribution is obtained using NMR or volume of clay.

In the presence of clay, the uncertainty associated with this mineral, for both bulk modulus, shear modulus and aspect ratio of micro pores, can be the first to be addressed, to reduce the difference between measured and estimated elastic properties.

When the measured and estimated elastic properties are similar, the rock physics model can be used for extrapolating formation elastic properties where the acoustic logs are not available, based on porosity distribution and mineralogy.

Based on NMR T_2 distribution, bulk density (ρ_b), and resistivity (R_t), we estimate a formation porosity (ϕ) and fluid distribution: water (S_w), gas (S_g) and oil (S_o). And these outputs are used to estimate formation elastic properties.

NMR T_2 distribution, formation bulk density and resistivity channels are used in the first part of the inversion to obtain formation properties influencing simultaneously those measurements. The physical modeling of the three measurements depends on parameters that can be calibrated using core measurements and fluid analysis. A consistent mismatch for the reconstructed measurements in a zonation is an indication that some of the parameters might not be valid for that interval.

The porosity estimation and fluid distribution are connected to the T_2 distribution according to Eq. 1:

$$\phi_{T_2} = \phi \times \left(\mathrm{HI_w} \times \mathrm{S_w} \times \mathrm{P_w} + \mathrm{HI_o} \times \mathrm{S_o} \times \mathrm{P_o} + \mathrm{HI_g} \times \mathrm{S_g} \times \mathrm{P_g}\right) \quad (1)$$

This equation depends on the following input parameters: hydrogen index (HI) of the fluids ($\mathrm{HI_w}, \mathrm{HI_o}, \mathrm{HI_g}$) and the fluids polarization functions ($\mathrm{P_w}, \mathrm{P_o}, \mathrm{P_g}$).

When one NMR measurement is available, the NMR porosity based on that T_2 distribution is combined with density porosity using the equation found on Freedman, et al. (1998). This approach is a simplification which assumes the NMR measurement and the density are reading the same formation.

In presence of more two or three T_2 distributions reading different depths of investigation, it is possible to consider the different depths of investigation of the density logs, NMR logs, and resistivity channels, using a methodology similar to that of Desport, et al. (2011). The methodology presented here aims at being applied to different datasets and it was adapted to be applied in cases where one or two T_2 distributions were available. Due to the contrast in HI and density between the liquid phase and gas, it is important to consider the different depth of investigations of the log measurements, which can be approximated with more certainty when there are measurements associated with different depths of invasions being affected by different amounts of drilling fluid invasion, one example of application is presented in Fig.4 and 5. The final bulk density depends on the matrix density (ρ_m) and the fluid densities $(\rho_w,\ \rho_o,$ and $\rho_g)$ according to the arithmetic average in Eq. 2:

$$\rho_b = (1-\phi) \times \rho_m + \phi \times (\rho_w \times S_w + \rho_o \times S_o + \rho_g \times S_g) \quad (2)$$

If we assume the matrix is non-conductive, the water saturation (S_w) can be estimated based on the measured formation resistivity using the empirical model derived by Archie, according to Eq. 3:

$$R_t = \frac{R_w}{{S_w}^n \times \phi^m} \quad (3)$$

The estimated water saturation based on measured formation resistivity (R_t) is strongly sensitive to formation Archie's parameters *m* and *n*, and mud and formation brine resistivity (R_w). Due to the conductivity of clay, Archie's model needs to be corrected for considering the presence of clay. In the methodology presented, we followed the Waxman Smits model as presented in Waxman, and Smits (1968). According to this model, the formation resistivity is also dependent on the clay properties, cation-exchange capacity (Q_v) and equivalent conductance per cation (*B*) as presented in Eq. 4.

$$\frac{1}{Rt} = \left({S_w}^{n^*} \times \phi^{m^*}\right) \times \left(\frac{S_w + BQ_v}{R_w \times Sw}\right) \quad (4)$$

In the presence of laminated shale, the final horizontal formation resistivity containing the isotropic medium and the laminated shale is obtained using a geometric average and the final vertical formation resistivity is obtained using an arithmetic average.

For modeling the elastic properties based on mineralogy, fluid saturation and porosity distribution in carbonates, we use the Effective Medium theory based on Kuster Toksoz and Gassmann, assuming three types of porosities associated with different aspect ratios, similar to the model presented in Xu and Payne (2009).

The three ranges of porosity, are defined as VMICRO, VMESO and VMACRO. It is assumed, in this case, that VMICRO contains the flatter pores with aspect ratio in the range between 0.02 and 0.08, VMESO contains the medium pores with aspect ratio between 0.08 and 0.2, and VMACRO contains vuggy porosity with rounder pores.

When the user does not provide a curve for VMICRO, the NMR T_2 distribution is used internally to estimate VMICRO based on the assumption that the part of the T_2 signal associated with a relaxation time smaller than a provided cut off corresponds to small pores. This simplification is not valid in the presence of fluids associated with low T_2 relaxation time, such as tar and heavy oils. The division between VMESO and VMACRO is obtained assuming the pores with relaxation time larger than a second cut off corresponding to macro porosity.

One interesting fact that can be considered when defining the model, is the strong sensitivity of the elastic properties to the aspect ratio of thin pores. Fig. 2 illustrates the effect of aspect ratio on final estimated elastic property of a calcite rock with 10% porosity filled with water. It can be observed that the sensitivity is higher for aspect ratios between 0.02 and 0.1, specially for the shear modulus.

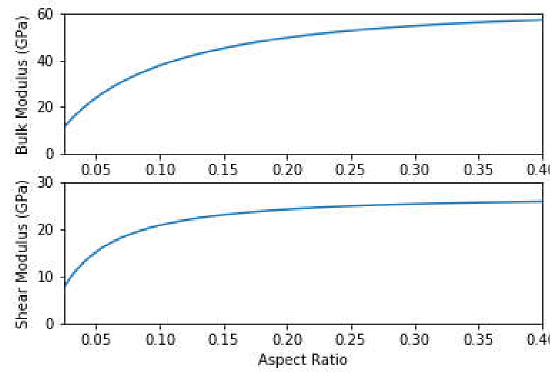

Figure 3: *Sensitivity of the final elastic properties to aspect ratio in the model*

For modeling the elastic properties based on mineralogy, fluid saturation and pore type in siliciclastic formations, we use the effective medium theory based on Kuster Toksoz and Gassmann assuming one type of pores associated with dispersed shale (VMICRO) and one type of pores associated with sands (free fluid) associated with different aspect ratios. For including the anisotropy found in laminated shale, Hudson's cracked model with one set of cracks was used.

Finally, after estimating the isotropic and transversely anisotropic layers elastic properties, the combined formation elastic coefficients are obtained using Backus Average. This formulation can be found in Backus (1962) and is a long wave approximation which assumes all materials are linear elastic.

Examples

The methodology was applied to oil-bearing complex carbonate wells and gas-bearing siliciclastic wells where the measurements from density, acoustics, resistivity and NMR were available.

In the gas-bearing siliciclastic formation well, there were two NMR relaxation times associated with two depths of investigation. This measurement proved to be of great importance to estimate the fluid distribution for two different depths of investigation showing different amounts of oil-based mud filtrate invasion. The near- and far-field are assumed to have the same porosity, which is a reasonable assumption for cemented formation, and the near and far field fluid distribution assumes the oil-based mud filtrate invades the near-field and displaces gas and free fluid. The resistivity is able to partition the fluids into hydrocarbon and water and the NMR and density combined can be used for estimating porosity and gas saturation.

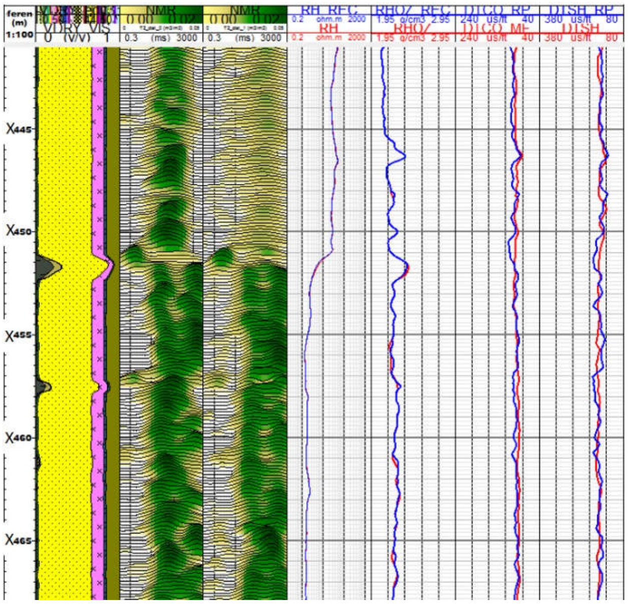

Figure 4: *Layout presenting input curves (black and red) versus reconstructed curves (blue) for quality control. This plot contains 7 tracks with the methodology inputs and outputs. Track 1: mineralogy, track 2: shallow T2 distribution, track 3: deep T2 distribution, track 4: deep resistivity (ohm.m), track 5: density (g/cm3), track 6 and 7: compressional and shear slownesses (us/ft).*

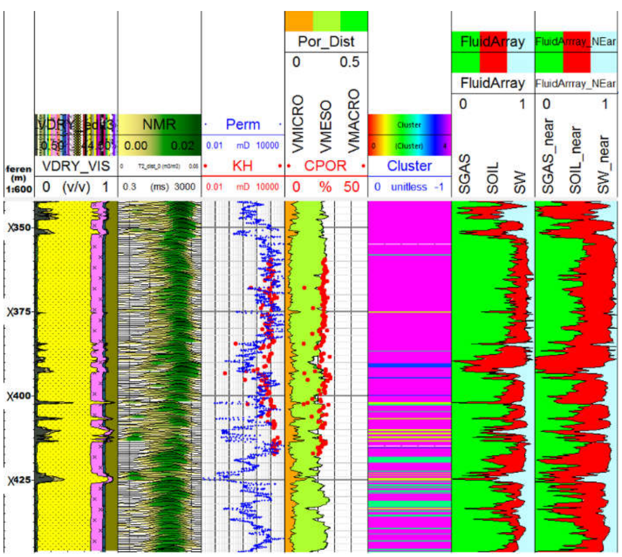

Figure 5: *General results on a siliciclastic well with gas and oil-based mud. Track 1: mineralogy, track 2: T2 distribution, track 3: core permeability (red) and estimated permeability (blue), track 4: core porosity (red) and estimated porosity distributed by pore size range, track 5: T2 based cluster, track 6 and 7: formation and shallow fluid distributions.*

Before interpreting the results, it is important to do a quality control comparing the reconstructed curves with the measured curves, which is done in tracks four to seven in Fig. 4. The measured curves are presented in red and the reconstructed curves are presented in blue. A mismatch between those logs is an indication that the model is not valid in the interval of interest or the parameters need to be optimized.

If the reconstructed curves are similar to the measured ones, it is an indication that the model might be correct, and evaluation can proceed, to give results as shown in Fig. 5. This plot presents estimated permeability (blue) versus core permeability (red) (track 3); porosity versus core porosity (track 4); and deep and shallow fluid distribution (tracks 6 and 7). Porosity track contains the porosity separation into micro porosity (orange), meso porosity (light green) and macro porosity (dark green), and core porosity (red). The fluid distribution is showing the water saturation in blue, oil saturation in red and the gas saturation in green, for the unflushed zone (track 6) and the shallow zone (track 7).

This well shows high permeability and high mud invasion displacing gas in the near-well region.

Regarding the combined porosity in Fig. 5 (track 4), we have compared the final estimation with core porosity and it showed a high degree of agreement with the exception of a few points which showed lower core porosity. This can be caused by thin layers that are not captured by the NMR due to its low vertical resolution compared to the thinness of the beds. This fluid-corrected porosity and free-fluid estimation has been used to calculate permeability using the Timur-Coates estimation and the result is compared to core permeability in Fig. 5 (track 3).

For this gas-bearing well, presenting intrinsic anisotropy regarding the elastic properties modeling we have used a Xu White rock physics model for the sand and dispersed shale portion, added cracks to the laminated shale portion using Hudson's model and combined the shale beds with the clean beds using Backus average.

In addition to porosity, permeability and fluid distribution we have used NMR for calculating a non-supervised clustering that can be used as a rock typing in petrophysical analysis where the porosity type is an important model input. The porosity type distribution may be important for calibrating parameters in permeability estimation, estimating fluid flow, wettability and water saturation. The cluster estimation is presented in Fig. 5 (track 6).

Results

Currently the methodology is fully integrated in the Techlog*- wellbore software platform with the calculations performed in C++ or Python, using vectorization and parallelization.

The method generates flags for density, resistivity, and NMR measurements with the objective of giving more user-certainty. It also generates automatic plots with organized inputs and outputs to help the interpretation using this methodology.

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* Mark of Schlumberger

Conclusions

We present the objective, methods, and examples for an integrated petrophysical inversion for improving reservoir characterization using NMR, density, resistivity and acoustics. This methodology can be applied in the presence of mud invasion, intrinsic anisotropy, complex mineralogy, and complex porosity. It has been tested in both siliciclastic and complex carbonates.

To date, the methodology has provided good reconstruction for density, resistivity, and acoustics logs together with porosity and permeability estimations similar to core measurements for oil-bearing complex carbonates and laminated siliciclastic formation. The method would benefit from improved rock physics models to account for compaction in highly unconsolidated formations.

For future research work, we plan to integrate the dielectric measurements in the inversion for estimating very shallow water saturation and mud resistivity, and to give a first estimation of Archie´s parameters. Under certain assumptions, this would reduce the uncertainty associated with water saturation given its great sensitivity to Archie's parameters, which would be of great importance specially in complex carbonates.

We also plan to improve results on unconsolidated formation, testing a different rock physics model.

Acknowledgments

This research was carried out in association with the ongoing R&D project registered as ANP 20024-6, "Multi Sensor Inversion Fase II" (Schlumberger / Shell Brasil / ANP) – Multi sensor inversion Phase II, sponsored by Shell Brasil under the ANP R&D levy as "Compromisso de Investimentos com Pesquisa e Desenvolvimento".

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