



## Using Sonic Log to Estimate Porosity and Permeability in Carbonates

Fernando Gomes de Mello e Silva (Petrobras)\*, Carlos Francisco Beneduzi (Petrobras), Gabriel Feres Nassau (Petrobras), Tiago de Bittencourt Rossi (Petrobras)

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### Abstract

The work proposal is testing, in carbonates, an empirical methodology to estimate porosity from measured S-wave slowness (already been successfully tested in sandstones, Silva and Beneduzi (2018)).

Oolitic carbonate reservoir sonic log data were used and results are in good agreement with lab data. Since the S-wave is practically insensitive to fluid effect, there must be no influence of the invaded zone on the results.

The method used to estimate porosity proposes a different way to calculate deviation log (Eberli et al., 2003), currently used to identify porosity type in carbonates. It was redefined in porosity terms as the difference between the S-wave porosity and the porosity estimated from the Wyllie equation (P-wave porosity). Results present good compatibility with porosity types and flow zones.

A significant linear correlation was observed between new deviation curve and the lab values, allowing calculate permeability for the entire well. The results are in good agreement with NMR log permeability.

New method brings up important reservoir petrophysical information. Moreover, the results can give a very important technical support in the early stages of well evaluation.

### Introduction

Sonic log is a measurement of mechanical wave slowness (the inverse of the velocity) throughout the formation, produced by a source located inside a tool immersed in a fluid filled borehole. The wave velocity in a formation will depend on the matrix and fluid composition, the porosity, the pore geometry and the rock stress.

The work adapts to carbonates a methodology to obtain porosity curve from shear slowness (S-wave slowness), measured by sonic logging tool.

Since the S-wave is practically insensitive to fluid effect, there must be no influence of the invaded zone and it wouldn't be necessary the knowledge of fluid parameters to calculate S-wave porosity.

The adopted rock physics model (Brie et al., 1995) had been already tested in sandstone reservoirs with different

fluids and degrees of compaction (Silva and Beneduzi, 2017), and the result indicates that correct estimate of the matrix composition is always necessary.

Log and lab petrophysical data from an Albian oolitic grainstone reservoir was analysed and results are in good agreement.

The deviation log results from an empirical method to identify porosity types in carbonates (Eberli et al., 2003). It is calculated by the difference between the measured P-velocity and the velocity estimated from the Wyllie equation, using porosity values from another log. High values indicates vuggy or moldic porosity type (Silva et al, 2013).

The work proposes a new way to calculate the deviation log. In the method the difference is between S-wave porosity and P-wave porosity (Wyllie equation).

Good compatibility was observed between deviation values, porosity types and flow zones. Besides, there was a significant linear correlation between deviation curve and the lab permeability, about two times the correlation value calculated with the original method.

Permeability values were calculated over the entire reservoir length and showed good agreement with NMR permeability values.

### Method

#### The sonic log measured curves

Slowness is the inverse of velocity, depending on the rock elastic modulus:

$$V_p = \sqrt{\frac{K + \frac{4}{3}G}{\rho}} \quad V_s = \sqrt{\frac{G}{\rho}} \quad (1)$$

Where  $K$  is the bulk modulus,  $G$  is the shear modulus and  $\rho$  is the rock density. A porous rock consists of a solid part, the matrix, and the fluid that fills its pores. As it passes through the formation, the wave interacts with these constituents in a more complex way than when it passes through a homogeneous medium without porosity. Its velocity and degree of attenuation depends on the matrix and fluid elastic modulus, the porosity (relative amount of fluid in the rock) and the pore space (pore shape and distribution in the matrix).

#### The S-wave porosity

Low viscosity fluids do not offer a significant shear resistance during wave movement. So, in this case,  $G$  is null, what allowed us to use the Gassmann assumption (2) that the total  $G$  rock modulus is similar to its  $G$  dry rock frame (with empty pores) (Gassmann, 1951).

$$G = G_{dry} \quad (2)$$

There are several models relating petrophysical parameters to P-slowness, but not so many with S-slowness. The model below (3) was used by Brie et al. (1995), to relate shear modulus to total rock porosity.

$$G_{dry} = G_m (1 - \phi)^c \quad (3)$$

The indexes  $m$  and  $dry$  relates rock matrix and dry rock elastic parameters;  $\phi$  is rock total porosity and  $c$  is a constant that depends on the formation ( $c=7.1$ , for the sandstones analyzed in Brie et al. (1995) and Chardac et al. (2003)). The dry rock modulus (frame rock modulus) differs from the matrix modulus by the inclusion and distribution of empty pores, expressing the acoustic and elastic rock dependence from the internal geometry and degree of compaction. It is important to note that there is no dependence of fluid parameters.

The model presents good correlation with rock physics dataset allowing to obtain reliable  $c$  values.

After the calibration with lab data, it is possible to extract a porosity log for the entire well (4), with equation 3.

$$\phi = 1 - \left( G_{dry} / G_m \right)^{\frac{1}{c}} \quad (4)$$

$G_{dry}$  may be calculated from the measured S-wave slowness and from density log, according to equations 1 and 2.

The rock matrix elastic modulus is calculated by the constituent mineral elastic modulus average (Mavko et al. (2009)). The Voigt-Reuss-Hill average (Mavko et al., 2009; Avseth et al, 2005) that considers a random distribution of minerals in the matrix was used:

$$M = \frac{1}{2} \left[ \sum_{i=1}^N f_i M_i + \left( \sum_{i=1}^N \frac{f_i}{M_i} \right)^{-1} \right] \quad (5)$$

Where  $f_i$  is the volumetric fraction and  $M_i$  is the elastic modulus ( $K$  or  $G$ ) of the  $i^{th}$  mineral.  $N$  is the total number of the different minerals present in the rock.

The matrix composition is estimated using DRX (X-ray Diffraction) analysis in fractions of rock samples or Petrographic thin sections analysis. The matrix density is obtained through laboratory petrophysical analysis.

The model assumes that matrix elastic modulus doesn't change along the reservoir.

#### The permeability estimates

In the 1950' s, Wyllie and other researchers proposed an empirical relationship (5) between the rock sedimentary total porosity and the compressional (P-wave) transit time value (Mavko et al., 2009).

$$\frac{1}{V_{P-rock}} = \frac{1 - \phi}{V_{P-matrix}} + \frac{\phi}{V_{P-fluid}} \quad (6)$$

Where  $V_p$  is the P-velocity (the inverse of P-slowness); the indexes  $rock$ ,  $m$  and  $f$  indicates the P-velocity for the entire rock, its matrix and the saturating fluid, respectively and  $\phi$  is the total porosity of the rock. The matrix and fluid velocity are calculated with their elastic parameters, using equation (1). Fluid parameters may be estimated by the Batzle and Wang expressions (Mavko et al. (2009)) which relate them directly to the properties that characterize the fluid in reservoir pressure and temperature. Saturating fluid elastic is calculated using the Wood's Law to find the equivalent mixture elastic modulus (6).

$$\frac{1}{K_{fluid}} = \frac{1 - S_w}{K_{oil}} + \frac{S_w}{K_{water}} \quad (7)$$

The difference between the velocity directly measured and calculated from the Wyllie equation is called Deviation log (Eberli et al., 2003).

$$DEVIATION_{ORIG} = V_{P-measured} - V_{P(Wyllie)} \quad (8)$$

Eberli et al. (2003), identified the porosity's type in carbonate rocks through the deviation values. High values indicate moldic or vugular porosity or intense cementation level while null deviation indicates interparticle or intercrystalline porosity.

The work proposes a new deviation log (9), obtained from the difference between the measured "S-wave porosity" and "P-wave porosity", obtained from Wyllie equation.

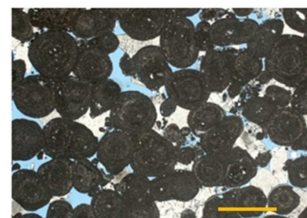
$$DEVIATION = \phi_{S-wave} - \phi_{Wyllie} \quad (9)$$

Deviation values have shown good compatibility with porosity types and flow zones.

A significant linear correlation was observed between this new deviation curve and the lab permeability, what allowed to calculate permeability values all over the well. The result is in good agreement with NMR log permeability.

#### **Results**

The analyzed oolitic grainstone reservoir shows low heterogeneity (Figure 1).



**Figure 1** – Albian oolitic grainstone carbonate reservoir (the orange bar corresponds to 1mm) – Brito (2013), Petrobras Internal Report

The reservoir has a mean porosity of 14,2 %, a mean

water saturation of 37%; hydrocarbon is oil. The well was drilled with WBM (water base mud).

DRX analysis identified calcite as the main matrix component (82%) with  $G_m=33,58$  Gpa and matrix density of  $2,73$  g/cm<sup>3</sup>. The model defined by equation 3 with  $c=3,38$  obtained from rock physics lab data (Figure 2), presented good correlation, however it's not adjusted with  $G_m$ .

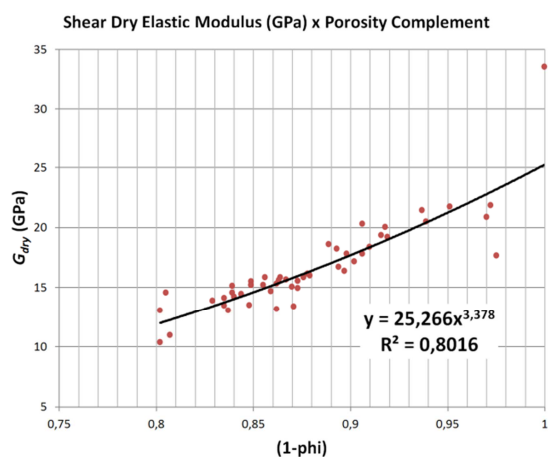


Figure 2 – Finding the “c” parameter using rock physics values

It seems that rigidity abruptly decays when porosity in the 0-3% porosity interval. However, there are no samples in this porosity range to justify this argument. So, we considered the model (3) valid only for porosities higher than 3%. Table 1 summarizes elastic parameters and the validity domain.

Table 1 – Elastic parameters: Matrix elastic shear modulus ( $G_m$ ), Matrix density ( $\rho_m$ ) and the “c” rock physical model constant (equation 3) after lab data calibration. The last column indicates a good calibration for porosities bigger than 3%, the validity domain of this approach.

$G_m$ (GPa)	$\rho_m$ (g/cm <sup>3</sup> )	c	$\phi$ (%)
33,58	2,73	3,38	> 3

Calculated S-wave porosity, using equation (4), shows a good agreement with lab data and well logs (Figure 3). Data indicates good correlation with effective NMR porosity. The correlation between S-wave porosity and data lab is higher than PhiDen (density porosity). (Figure 4).

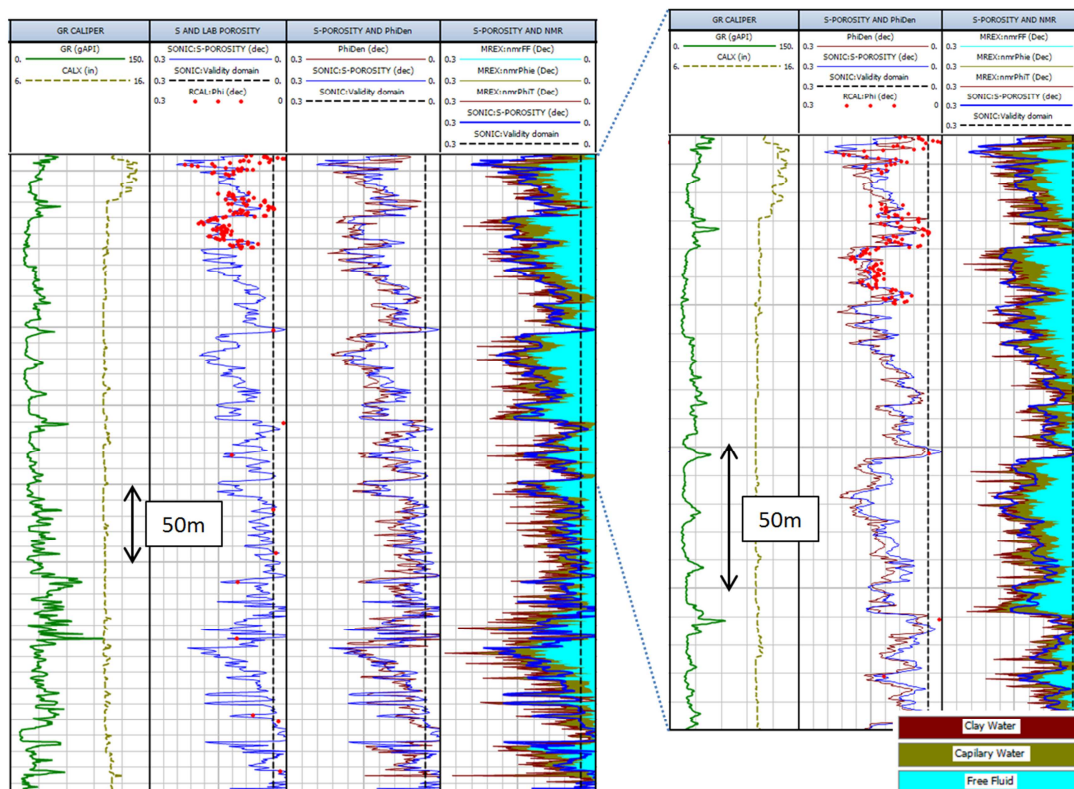
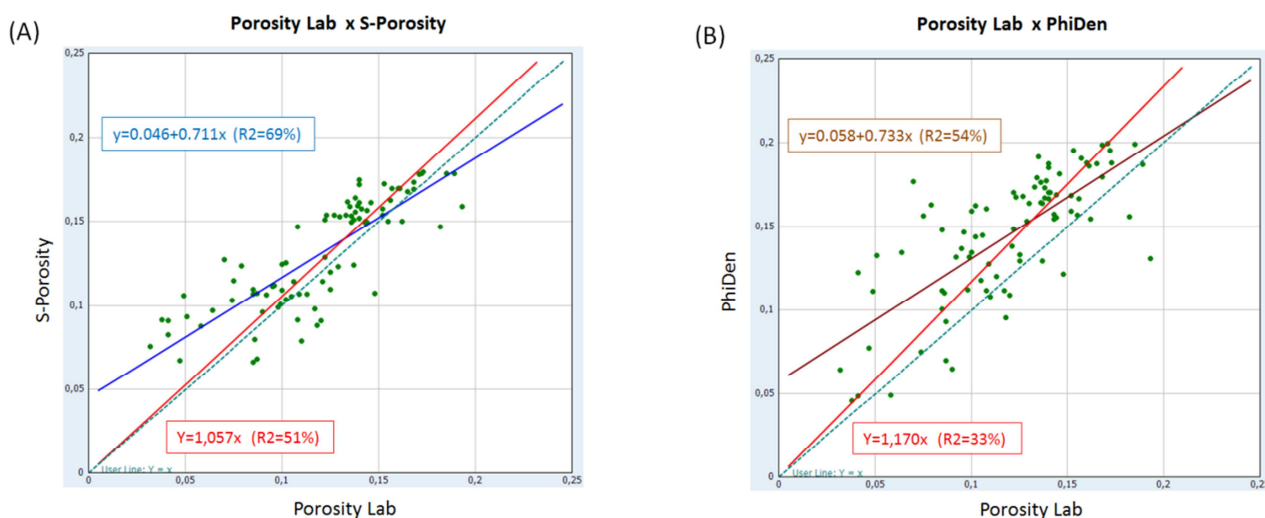
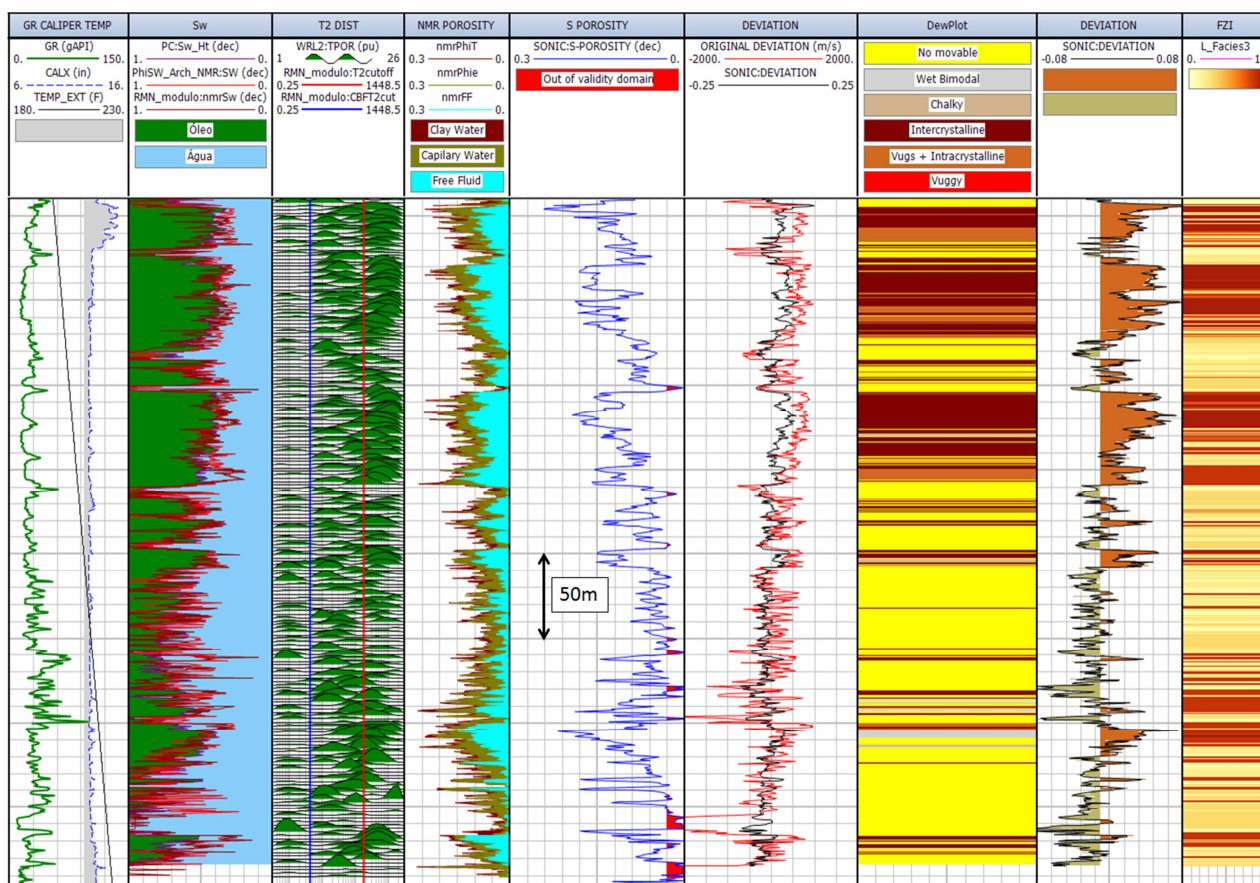


Figure 3 – Gamma ray and Caliper (track 1), S-wave porosity with porosity lab data (track 2), with PhiDen – density porosity (track 3) and with NMR porosities (track 4).





**Figure 4** – Correlation between lab porosity data and S-wave porosity (A) and between lab data and PhiDen – density porosity (B). Blue and brown lines are simple linear regression; red lines are forced to pass on the origin; green dotted lines are  $y=x$  lines.



**Figure 5** – Gamma ray and caliper logs (track 1); water saturation (track 2); T2 NMR distribution (track 3); NMR porosities (track 4); S-porosity (track 5); Deviation curves - equations 8 and 9 (track 6)- Original deviation curve calculated with PhiDen (density porosity); Porosity Type (Dewplot) (track 7); Deviation, equation 8, (track 8) as a qualitative indicator of FZI - flow zone indicators (track 9).

P-wave porosity was calculated with equation (6). Table 2 presents the calculated formation fluid parameters..

$S_w$  (Archie Equation saturation water), was used to obtain the fluid elastic modulus at each depth in Wood's Law (7). Deviation curve (9) is plotted in figure (5).

Qualitatively, both deviations curves (8 and 9 equations) are very similar. A qualitative correlation can be observed between intervals with fluid flow higher values, porosity type and deviation log.

**Table 2** – Fluids elastic parameters of Oil and Water Formation:elastic bulk modulus (K), density ( $\rho$ ) and P-wave velocity  $V_p$ .

	$K_m$ (GPa)	$\rho_m$ (g/cm <sup>3</sup> )	$V_p$ (m/s)
Water	3,32	1,09	1745,20
Oil	1,10	0,79	1178,57

Quantitatively, a linear correlation was set up between the new deviation log and the permeability lab data logarithm (10) (Figure 6-a). Original deviation method showed lower correlation value (Figure-6-b). The reasons for the difference will be an investigation subject at future works.

$$K = 10^{(-1,177 + 46,143 \times \text{DEVIATION})} \tag{10}$$

The result is in good agreement with NMR log permeability (Figure 7). It is important to emphasize that there is none NMR dependence in the method.

The method also leads to a linear relation between S-porosity and Sonic Permeability. This result may be exploited as a possible tool to look for seismic correlations or calibrations (Figure 7).

### Conclusions

The method was successfully tested in albian oolitic grainstone carbonates. S-porosity and permeability curve are in good agreement with data lab and another well logs. S-porosity is more similar to NMR effective porosity than NMR total porosity, suggesting that clay and its associate bound water acoustically behaves as if they were a matrix component. Coherent with Yan and Han (2016), that recommended the use of NMR effective porosity for fluid substitution.

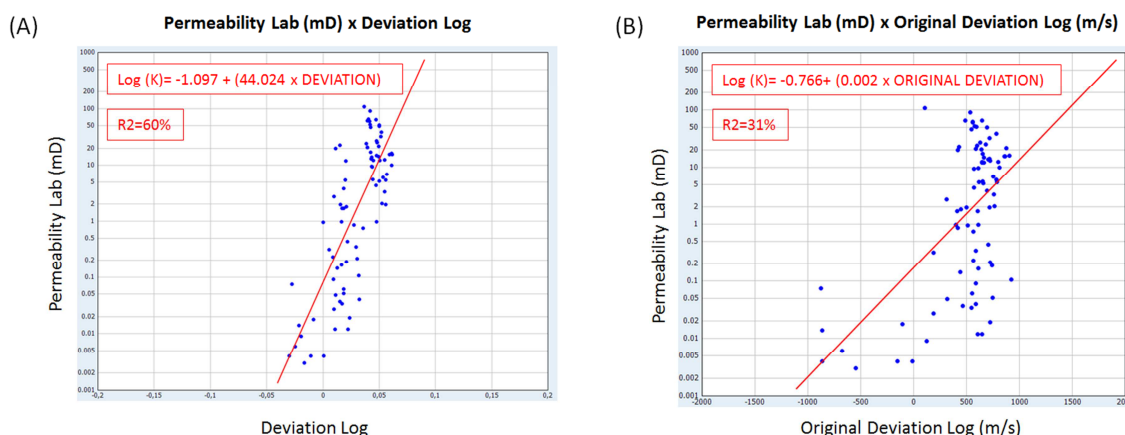
Eberli et. al. (2003) found an inverse relation between deviation log and permeability. They analyzed an oolitic carbonate where the high dissolution created moldic porosity, blocking pore throats. Deviation log values increased and permeability is reduced.

In this work, the new deviation log also describes qualitatively porosity types. Besides, describes intervals with a good flow capacity, showing a direct proportionality between the new deviation log and permeability. The analyzed carbonate porosity is interparticle and intercrystaline, more homogeneous than Eberli et al (2003) samples. Therefore, there is less secondary porosity, less dissolution and more connectivity in porous space.

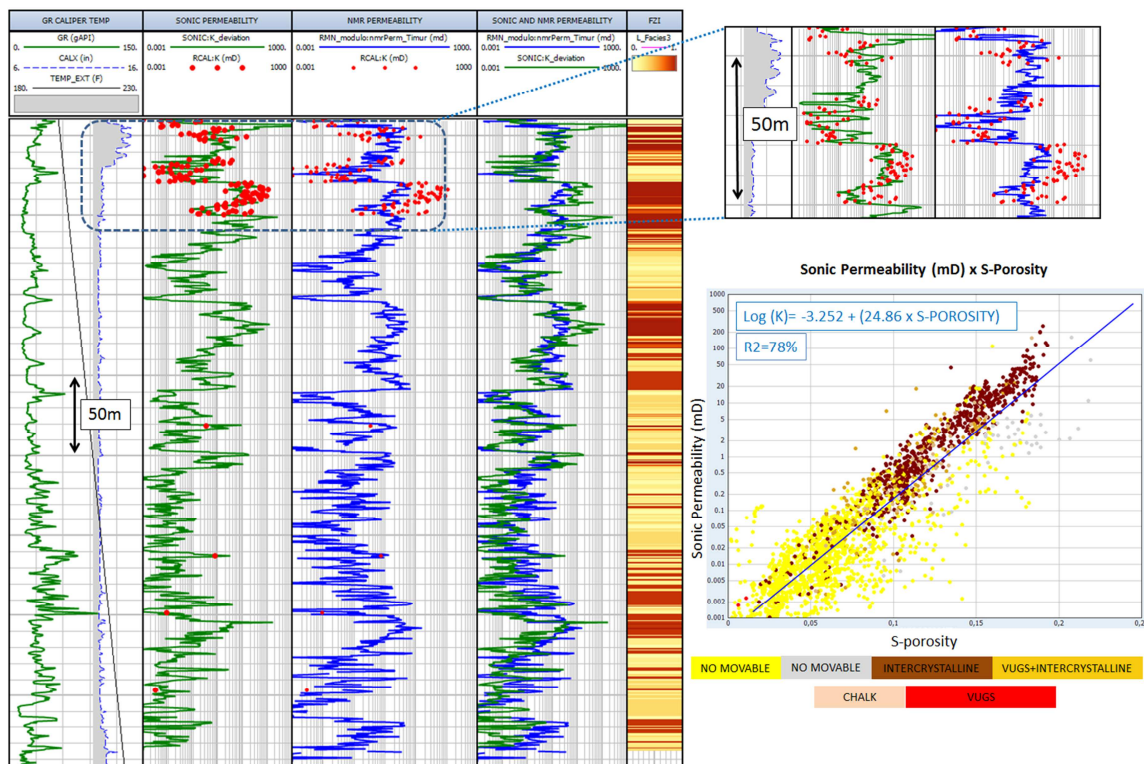
Future perspectives are calibrate permeability acoustic equation (10) for a reservoir as a whole and to extend these methodologies to more heterogeneous carbonates, with a higher porosity type variation.

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**Figure 6** – Correlation between the permeability lab data and the deviation log (equation 8) (A) and between permeability lab data and the original deviation log (used PhiDen, density porosity, in equation 7) (B).



**Figure 7** – Gamma ray and Caliper Logs (track 1); Sonic permeability curve and lab data (track 2); NMR permeability and lab data (track 3); Sonic (green curve) and NMR (blue curve) permeability (track 4); FZI (flow zone indicator) (track 5). On the right, a plot between Sonic permeability and S-porosity with a good linear correlation.

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