Using sonic log for fluid identification in siliciclastic reservoirs

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Abstract

The objective of this work was testing an empirical method (Chardac et al., 2003) for hydrocarbon identification in siliciclastic reservoirs saturated with fresh and salt water of Brazilian sedimentary basins. The method consists in comparing the compressional wave (P-wave) slowness, measured by the sonic well logging tool, with a synthetic compressional curve, modeled on the premise that the rock is saturated with water. The difference between the measured and the synthetic compressional log becomes an indicator of the presence of hydrocarbon in the formation.

This synthetic curve is obtained from the slowness of the shear wave (S-wave), measured along the same well, through a polynomial function. The methodology was tested in reservoir sandstones with different fluids and degrees of compaction. The results were satisfactory, indicating the importance and the potentiality of the sonic well logging tool in the formation evaluation.

Throughout this work it was also verified that, in addition to the acoustic contrast of the fluids, the results are also strongly influenced by the elastic properties of the rock matrix. In addition, it was also observed that the invasion of mud (drilling fluid) filtrate in the formation can affect the results, emphasizing the mud elastic parameters knowledge (WBM - water based mud, OBM - oil based mud).

Introduction

The motivation for this work was to adapt to Brazilian reservoirs a model that allows the hydrocarbon identification from sonic log data, making it a useful tool for the petrophysical evaluation of the reservoir.

The sonic log is a measurement of the 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 pressure which the rock is submitted.

The method proposes to identify a significant change in the speed of these waves considering only a change in the fluid type present into the rock (on reservoir pressure and temperature).

The main difficulty of any method with this purpose lies on the fact that the wave propagation is much faster in solids than in fluids. Consequently, the percentage difference, in total rock velocity, due to a change in its saturation would be very small.

The methodology adopted was proposed by Chardac et al. (2003) for siliciclastic reservoirs and consists of comparing the compressional wave (P-wave) slowness, measured by the sonic logging tool along a well, with a synthetic compressional curve obtained from the shear wave (S-wave) slowness, measured along the same well, through a function that assumes a water saturated rock.

Since the S-wave is practically insensitive to fluid effect, the synthetic curve is expected to be free from the influence of hydrocarbons if present. The difference between the measured compressional curve and the synthetic becomes an indicator of the hydrocarbon presence in the formation. The function that generates the synthetic curve depends directly on the rock matrix and formation water elastic parameters (on reservoir pressure and temperature).

The methodology was tested in sandstone reservoirs with different fluids and degrees of compaction. Tests were satisfactory.

There are strong indications that the process of rock invasion by the mud (drilling fluid) filtrate may influence the results, distorting them. So, it becomes necessary to know the filtrate elastic properties (WBM- water based mud, OBM - oil based mud) previously.

Method

The main problem is how to differentiate a hydrocarbon zone (oil or gas) from a water zone in a sandstone reservoir, considering the compressional slowness (inverse of the velocity) obtained with the sonic logging tool.

The methodology used proposes to simulate how the measured slowness would be if this same sandstone were totally saturated with the water formation (S_w=1), in all its extension. In this case, the measured and simulated curves would separate only at the hydrocarbon zone, since the P-wave velocity in the gas or oil is always lower than in the water.

The initial step to obtain this simulation is to model the P-wave (DTP) and the S-wave (DTS) slowness as a function of porosity with the use of rock physics models at the analyzed sandstone. Subsequently, when comparing the obtained curves, DTP is written as a polynomial function of DTS.

This is a function that allows us to build a synthetic DTP curve from a measured DTS curve along the well.

Since shear wave is not influenced by fluids in the rock (S-wave only propagates in solid media), the synthetic curve is free of the hydrocarbon influence and represents a water saturated DTP curve (S_w=1) along the entire well.

So is expected, in a correctly modeling, the measured and simulated DTP curve to coincide only at the water zone. At the hydrocarbon zone, the measured curve should present higher values than the simulated, identifying those regions in a qualitatively way (Chardac et al., 2003).

It is important to note that the method is limited to wells with a DTS shear wave log, and that there is no need for a porosity log (since the information of this property is implicit in the modeled slowness values).

Steps of modeling and adopted rock physic models

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

$$V_P = \sqrt{\frac{K + \frac{4}{3}G}{\rho}} \qquad V_S = \sqrt{\frac{G}{\rho}} \qquad (1)$$

Where *K* is the bulk modulus, *G* is the shear modulus and *ρ* is the density of the rock. A porous rock consists of a solid part, the matrix, and the fluid that fills its pores. As it passes through it, 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 depend 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). For the compressional wave modeling, the Gassmann equation (Gassmann, 1951) was used to calculate the rock bulk modulus from the elastic parameters of its constituents:

$$K = K_{dry} + \frac{\left(1 - \frac{K_{dry}}{K_m}\right)^2}{\frac{\phi}{K_f} + \frac{1-\phi}{K_m} - \frac{K_{dry}}{K_m^2}}; \quad G = G_{dry} \; ; (2)$$

$$\rho = \rho_m (1-\phi) + \rho_f \phi \qquad (3)$$

The indexes *m*, *f* and *dry* relates the elastic parameters to the rock matrix, to the fluid present in its pores, and to the dry rock (rock frame), respectively; ∅ is the total porosity of the rock.

The dry rock modulus (frame rock modulus) differs from the matrix modulus only by the inclusion and distribution of empty pores, expressing the acoustic and elastic rock dependence from its internal geometry and degree of compaction.

The dry shear rock modulus is identical to the rock shear modulus (2) because it is insensitive to the fluid presence.

The matrix elastic modulus

To solve the equation (2) it is necessary to know the rock matrix elastic modulus. The best way to estimate them, it is calculating an average over the elastic modulus of its constituent minerals (Mavko et al. (2009)). The Voigt-Reuss-Hill average is the most common (Mavko et al., 2009; Avseth et al, 2005). It considers a random distribution of minerals in the matrix:

$$M = \frac{1}{2}\left[\sum_{i=1}^{N} f_i M_i + \left(\sum_{i=1}^{N} \frac{f_i}{M_i}\right)^{-1}\right] \qquad (4)$$

Where f_i is the volumetric fraction and M_i is the elastic modulus (which may be *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 by the results of DRX (X-ray Diffraction) analysis in fractions of rock samples or by analysis of petrographic thin sections. The matrix density is obtained through laboratory petrophysical analysis.

Matrix elastic modulus and density doesn't change along the reservoir.

The frame elastic modulus

The K_{dry} and G_{dry} modulus depend, among other factors, of the rock total porosity (Avseth et al., 2005). Brie et al. (1995) presented two empirical results relating dry rock modulus to the matrix modulus and the porosity. One is the empirical relation for shear modulus:

$$G_{dry} = G_m (1-\phi)^C \qquad (5)$$

Where G_m is the shear modulus of the matrix and *c* is a constant with a value of 7.1, for the sandstones analyzed in Brie et al. (1995). The other empirical result is that the V_p/V_s ratio is practically constant and is independent of the sandstone porosity (Castagna et al., 1985), being equal to the respective matrix value. By conjugating both empirical evidences, it is possible to extend the expression (5) for the dry rock bulk modulus.

The fluid density and its elastic modulus

The fluid bulk modulus and its density may be estimated by the Batzle and Wang expressions (Mavko et al.

(2009)) which relate them directly to the properties that characterize the fluid on reservoir pressure and temperature.

As the objective is to simulate a water saturated reservoir, it is only necessary to know pressure, temperature and formation water salinity values, obtained from lab tests of formation water sampling.

The changes in the water bulk modulus along analyzed sandstones are negligible, so a mean value is adopted.

The polynomial function

With the simulated DTP(Ø) and DTS(Ø), it is possible to fit a 4th degree polynomial, as shown in DTP x DTS crossplot (Chardac et al. , 2003), building a DTP(DTS) function (Figure 1).

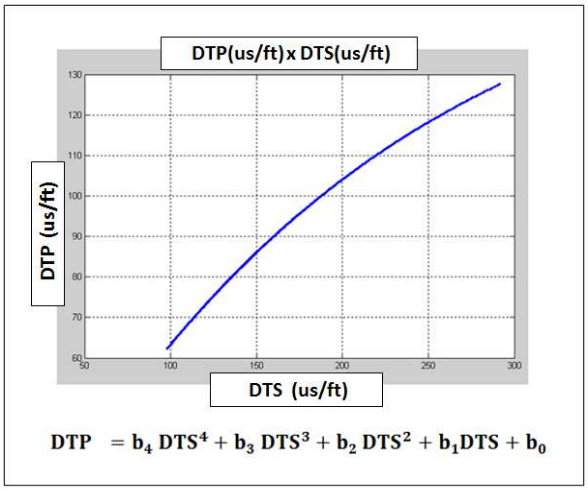

Figure 1 – *DTP x DTS modeled curves crossplot and the adjusted* 4th degree polynomial.

From this polynomial, characterized by its four coefficients, it is possible to generate a synthetic compressional curve for S_w=1 from the DTS curve measured along the well.

Results

Reservoirs with different fluids and degrees of compaction were used to test the method.

Table 1 presents relevant information needed for applying the method: formation fluid, borehole fluid, mean porosity and mean density reservoir overburden. Table 2 presents the elastic parameter values calculated as described in the previous section.

Chardac et al. (2003) used the quartz parameters to the matrix (K_m = 36.6 GPa, G_m = 45 GPa, ρ = 2.65 g / cm³), with c = 7.1 (Brie et al., 1995), and obtained good results. His suggestion is to use same polynomial coefficients for any other sandstones.

These considerations are not valid for the wells used in this work. The different ways to obtain the c value are described below, for each well.

Table 1 *– Fluid / Reservoir Attributes: Mean Porosity (Ø), Mean Matrix Density (ρ_m), Mean Overburden, (*) Unconsolidated Reservoir*

Wells	Fm. Fluids	Borehole Fluid	Ø (%)	Mean Overburden (m)
A	W/O	WBM	18	2420
B	W	OBM	12	4800
C	G	WBM	15	
D(*)	W/O	WBM	30	1860
E	W/O/G	WBM	11	1360
ρ_m = 2.64 g/cm^3				

Table 2 *–Reservoir Parameters Matrix elastic modulus (K_m, G_m), Formation Water Elastic Modulus and density (K_w, ρ_w) and Exponencial Index (c)*

Wells	K_m(GPa)	G_m(GPa)	K_w(GPa)	ρ_w(g/cm³)	c
A	47.65	34.08	3.29	1.09	5.2
B	39.64	24.64	3.36	1.09	3.9
C	48.02	36.55	3.36	1.09	3.9
D	37.61	43.83	2.92	1.05	8
E	47.45	34.38	2.53	1.00	8

Well A

The parameter c was obtained through the lab acoustic analysis from 20 sidewall cores. Laboratory velocity measurements are performed with dry samples, so it is possible to calculate their elastic modulus K_{dry} and G_{dry} by using expressions (1), (2) and (3).

Linearizing the expression (5) with the application of the logarithm function, it is possible to impose that the G_{dry} and K_{dry} modulus are equal to the values of the matrix modulus (found as described in the previous section) when porosity is zero. The linearized model crossplot (Figure 2) provides good linear adjustment of the modulus for a mean value of c = 5.2.

The method identified the oil and water zones (Figure 3, column 5 and column 6, where a percent error between the simulated and measured curve is used). There was no significant interference of invasion effects on the efficacy of the method.

It was also analyzed the case where matrix is composed only by quartz (Figure 3, columns 7 and 8). No hydrocarbon zone is identified, demonstrating the importance of matrix parameters definition.

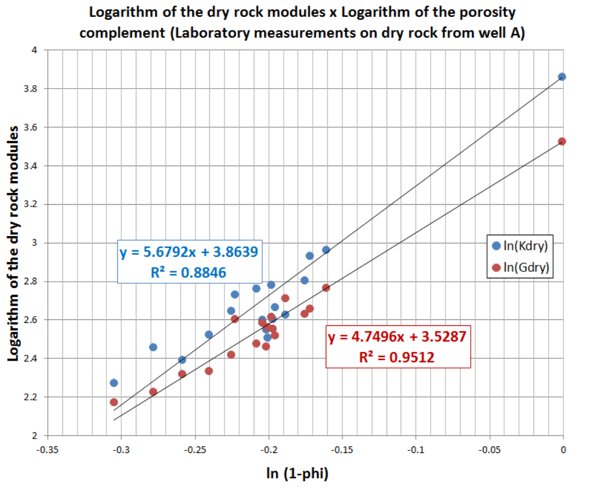

***Figure 2** – Finding the "c" parameter with the use of lab acoustic data*

Well B

Parameter *c* was obtained in the same way as well A (c = 3.85). Resistivity logs suggest water saturated reservoir, however the method indicates hydrocarbon saturated reservoir (Figure 4, column 5).

The well was drilled with OBM, resistivity logs suggests deep invasion (Figure 4, column 3) and there are evidence that sonic log is strongly affected by invasion shown by the fact that measured curve is very close to mud filtrate modeled curve (Figure 4, column 6). This curve almost matches the measured DTP curve.

The mud filtrate simulated curve is obtained with the same method used for water formation simulated curve.

Well C

The reservoir is the same of the well B and c=3.85. The interval is a gas zone and the method correctly identified it as a hydrocarbon zone (Figure 5).

The separation between simulated and measured curve is larger (Figure 5, column 5) than in the other wells because the water/gas acoustic contrast (the difference between the elastic parameters) is greater than the water/oil acoustic contrast.

Simulated curve with the formation gas parameters (Figure 5, column 6) is very close to the measured curve, confirming a gas zone.

The reservoir has a WBM deep invasion filtrate, as indicated by resistivity logs (Figure 5, column 3). In this case, the method was not influenced by the invasion. Probably because in a liquid-gas mixture, due to the high acoustic contrast and a non-linear mixing law (Brie et al., 1995), a small amount of gas is sufficient to decrease the fluid bulk modulus to gas bulk modulus values.

Well D

Well D reservoir is a high porosity unconsolidated sandstone (Table 1). The value of *c* = 8 was obtained from the best fit between the simulated and measured curve at water zone.

The high value of *c* is compatible with values found by Brie et al. (1995) for unconsolidated formations. With this value, the method works successfully (Figure 6) in this and other wells of the same reservoir.

In this well, the simulated curves for S_w=0%, S_w=50% and S_w=70% (Figure 6, column 6) were also calculated using Wood's Law (Mavko et al., 2009).

Comparing these curves, with the S_w simulated, and the sonic measured curve, we can see that water saturation is higher at the base, around 70%, and decreases to 50% at the top. According to the well report, the mean water saturation is 41%.

Resistivity logs (Figure 6, column 3) shows the existence of an invaded zone. Probably the sonic is strongly affected by invaded zone and gives high S_w values close to the O/W contact suggesting gravitational segregation. The correlation well had shown the same pattern.

Well E

The fresh water reservoir (15 kppm NaCl) is composed by conglomerates with a G/O contact defined by separation of neutron/density curves and O/W contact undefined by resistivity logs (Figure 7, column 3). The method proved to be efficient showing the water simulated curve starting its separation from measured curve in the contact (Figure 7, column 6). The parameter *c* was obtained in a similar way of Well D, and presents the same value.

The result is more evident applying a moving average filter over the results (Figure 7, column 6). As expected, the largest separation between the simulated and measured curve lies in the gas zone. The simulated curve for the oil formation is very close to the measured curve at the oil region. The same pattern is observed at the gas region with the respective gas simulated curve (Figure 7, column 7). By this method, each type of fluid was identified and elastic attributes had shown their efficiency over the resistivity method.

Conclusions

The method was successfully tested in siliciclastic reservoirs (clay<10%) with different degrees of compaction and saturating fluids (gas, oil, fresh and brine waters).

It's important to observe that the method cannot be used with a generic polynomial, or considering the matrix composed only by quartz. Therefore, a good estimate of the matrix composition is necessary.

The parameter *c* (Expression 5) can be estimated through laboratory acoustic data curve or through calibration of the simulated curve in the water zone.

The invasion of the drilling fluid filtrate may affect the results. This interference depends on the relation between the extension of invaded zone and the investigated depth of the sonic logging tool. Also depends of acoustic contrast between the filtrate and the formation fluid.

The method proved to be efficient identifying hydrocarbon zones from water zones in freshwater reservoirs, where there is no significant resistivity contrast between them.

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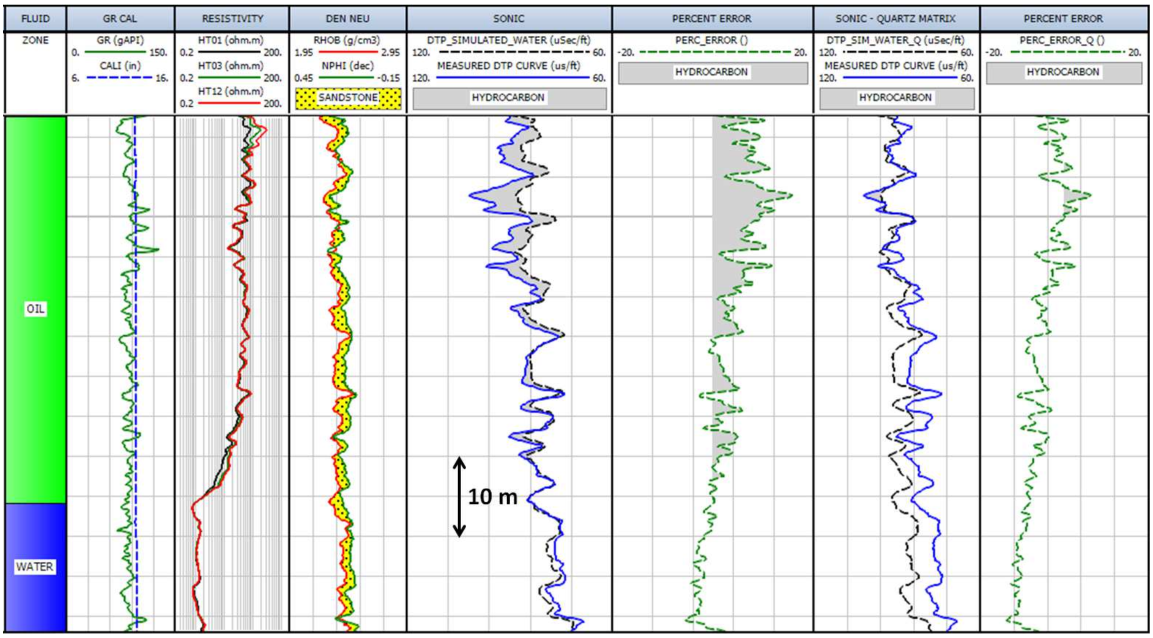

Figure 3 *– Well A*

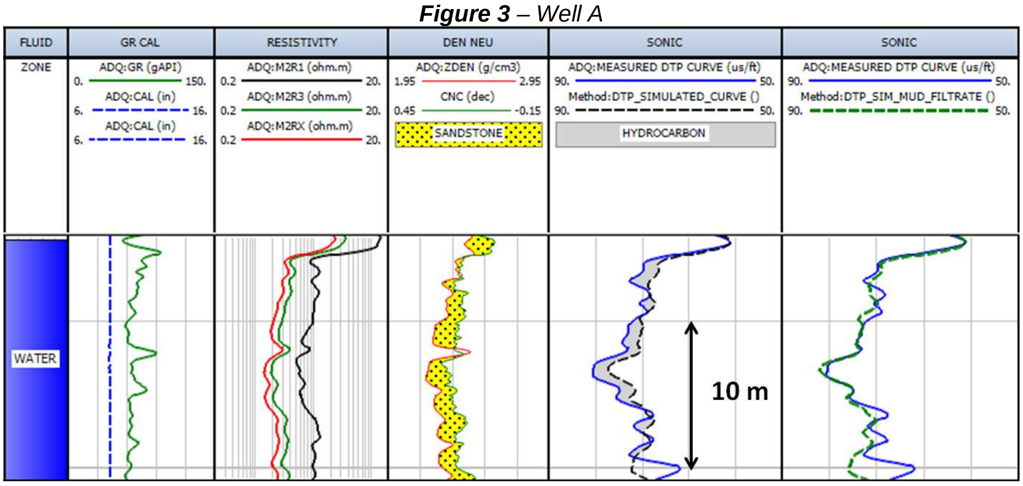

Figure 4 *– Well B*

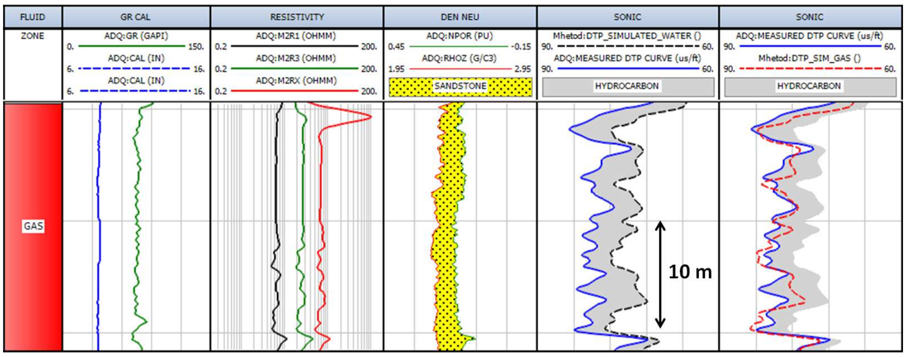

***Figure 5**– Well C*

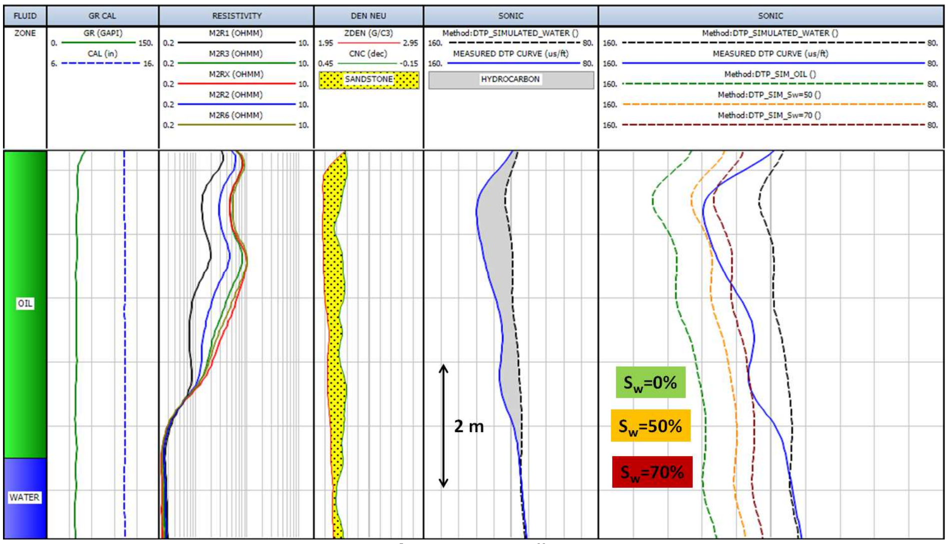

***Figure 6** – Well D*

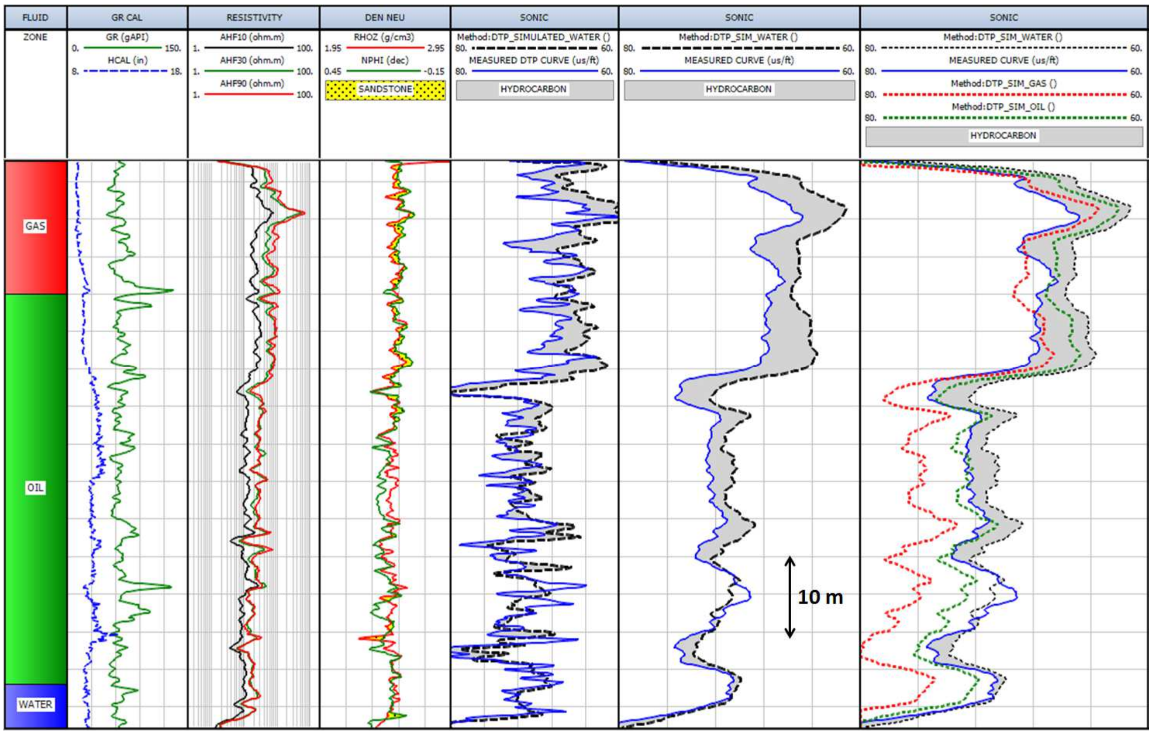

***Figure 7** – Well E*