A new approach for determining cementation exponent thereby reducing uncertainty in hydrocarbon saturation estimation

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Keywords

Petrophysics, Rock Physics, Cementation Exponent

Summary

Hydrocarbon saturation – one of the more important and challenging petrophysical calculations in the absence of core measurements – is usually estimated from its complement, water saturation (Sw). Complexities arise due to number of quasi-independent approaches based on Archie's relationship that can be used for this purpose, including Indonesian, Simandoux, Waxman-Smits and Dual Water formulas. Different models give different results, so the analyst needs to determine which of the models fit the available data and input logs based on known reservoir characteristics. The traditional Archie petrophysical parameters, cementation exponent (m), saturation exponent (n) and tortuosity factor (a) play an important role in saturation calculations. Generally, in the absence of core data, formation evaluation is carried out using constant values of a, m and n. In rocks with complex pore geometry, the assumtion of constant m (and other parameters) may not be valid, leading to uncertainity in saturation estimates. This paper outlines a methodology to determine cementation exponent by integrating petrophysical analysis and a rock physics modelling technique in a siliciclastic reservoir to reduce the uncertainity in hydrocarbon saturation.

Introduction

Various equations used to determine fluid saturations in different types of hydrocarbon reservoirs use common parameters, including porosity, saturation exponent, cementation factor, water salinity and formation resistivity. The uncertainity of estimated water saturation is dependent on the uncertainity of all petrophysical parameters used in these calculations. As saturation determination is of great importance in reservoir evaluation, a large number of studies have focused on the uncertainty of different parameters in saturation determination and finding new methods to decrease these uncertainties. Bagheri et al (2005) investigated the uncertainity and importance of saturation equation parameters and found that cementation exponent is the most important parameter in siliciclastic reservoirs. Cementation exponent is a physical quantity which is a rough indicator of degree of binding of the rock-forming sediments and is usually estimated from core data. Considering the fact that well log data are more accessible than core data, the method presented in this study appears to be more useful in determining cementation exponent. This paper discusses a method of determining cementation exponent by integrating rock physics and petrophysical analysis in siliciclastic reservoirs. The link of petrophysics with rock physics is pore aspect ratio, which, like m, is related to the texture of the rock.

Case Study

An example of determining cementation exponent by integrating petrophysics and rock physics modelling is given for a siliciclastic reservoir, resulting in an improved estimate of the cementation exponent, with implications for hydrocarbon saturation. The single well used in the study encountered both hydrocarbon and water-bearing intervals. Visual inspection of well logs was carried out to assess quality of the data (Figure:1).Quality assurance of log data is a very important step in formation evaluation, typically done by constructing curve overlays, histograms and cross plots. The process identifies depth mismatches and non-geologic responses due to bad hole, logging tool problems and calibration errors, which invalidate results if propagated to saturation calculations For the studied well, a complete set of high-quality, openhole wireline logs is available, including both P and S sonic logs. These logs have been vetted by quality assurance procedures.

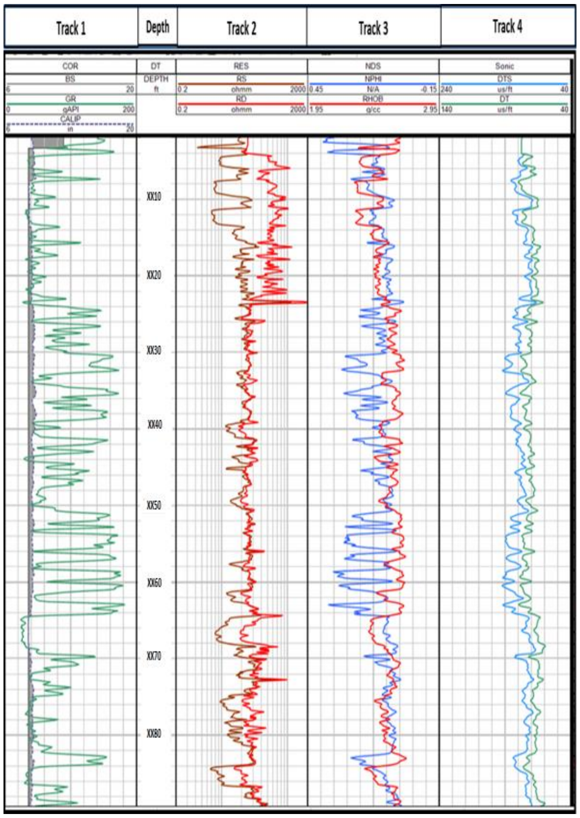

Figure 1: Log plot showing data used in the study

After quality control, clay volume, porosity and saturation are estimated by conventional petrophysical analysis. Parameterization of the sand-shale model chosen for this case begins with the estimation of clay volume, by picking clean and clay trends on gamma ray, neutron, and density logs. Calcareous streaks in the evaluation interval, indicated by the mud log, are ignored because the effect of this material is minor. Clay trends are picked using a combination of histogram and cross plots of log data (Figure:2). Porosity is calculated using hydrocarbon-corrected density and neutron data. Initially, water saturation is calculated using constant values for Archie parameters:tortuosity factor (a), cementation exponent (m) and saturation exponent (n). Saturation is computed from the Indonesian equation using Archie parameters a=1, m=2 and n=2 (Figure:3).

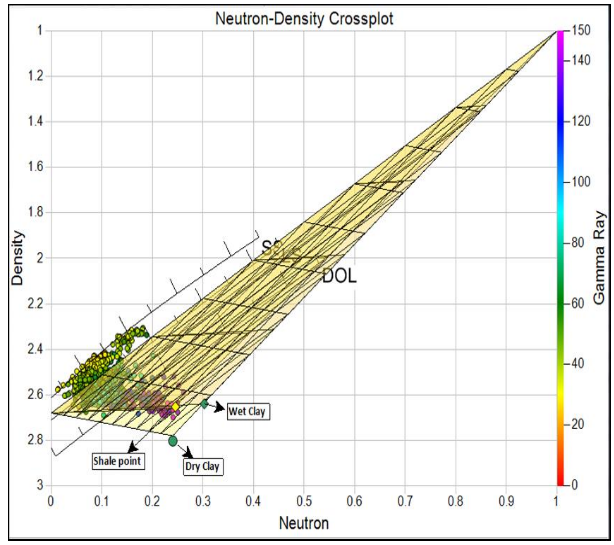

Figure 2: Density-Neutron crossplot showing wet and dry clay points.

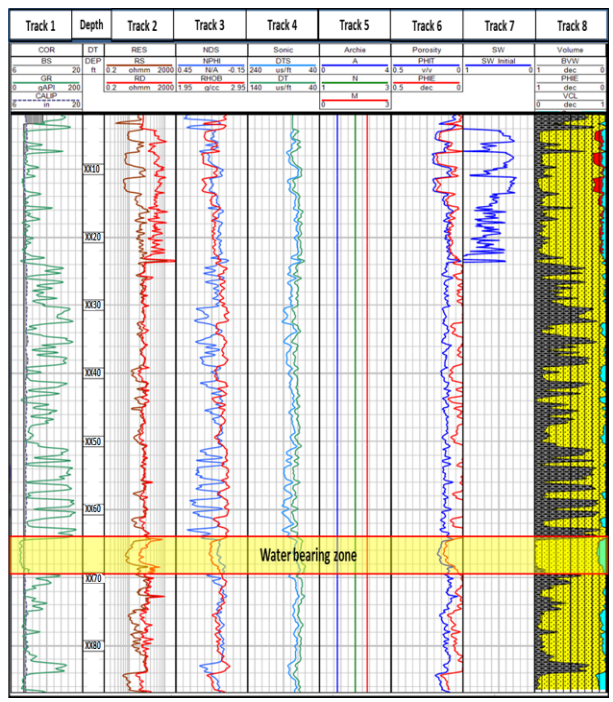

Figure 3: Log plot showing water saturation (Track 7 blue curve) estimated using constant cementation exponent (Track 5 red curve)

Once the reservoir properties (i.e. volume of clay, total porosity) have been estimated, a rock physics model is applied to provide a link between petrophysics and elastic properties. The model selected, Xu and White, (1995), is from a general class of models developed from differential effective media (Kuster-Toksoz, (1974); Cheng and Toksoz (1979) and Gassmann (1951) theories. Xu -White estimates velocities in rocks comprised of sand-clay mixtures. The inputs required by the model include densities and elastic moduli of the sand grains, clay particles and the pore fluids, the porosity and clay content of the rock frame and aspect ratios of pores. The aspect ratio cannot be measured directly, however, it is possible to invert the sonic data (P and S sonic) to provide an effective aspect ratio at each depth point applying the Xu-White model in wells having these logs.

Two factors affecting P and S wave velocity are cementation and pore pressure. Cementation tends to increase effective aspect ratio by filling small gaps between grains, creating a more linear relationship with aspect ratio. High pore pressure tends to limit compaction, keeping the small gaps between grains open. In the studied well, pore aspect ratio is estimated by inverting P and S-sonic data using Xu-White model. The effective aspect ratio used in this study is the average of apparent P and S sonic log aspect ratios.

Within the water-bearing zone (Figure:5, highlighted area in logplot), Archie's cementation factor (m) is computed by inverting the water saturation equation using water resistivity (Rw), true resistivity (Rt) and porosity. A cross-plot of effective aspect ratio and computed cementation exponent in water leg was created to investigate possible relationships between aspect ratio and cementation exponent (Figure:4). Figure 4 suggests this relationship is not random. Even though the coefficient of determination is not high (r-squared = 0.63), it is significant; effective pore aspect ratio explains over 60% of the total variance in cementation exponent, assuming a linear relationship between the two parameters. Considering the limited range of both variables in this example, the association could be stronger in data sets in which either cementation exponent or effective aspect ratio varies more widely. The fact that both parameters are proxies for pore geometry suggests a correlation should exist, even though the Xu-White model is limited to effective pore shapes ranging from penny-shaped cracks to spheres. In bimodal porosity, for example, m could take on values approaching 1.8 in flat pores (e.g. fractures), and much higher values in rounder pores, as suggested by Figure 4. Here, results indicate pore structure is homogeneous, implying constant cementation exponent is sufficient for estimating hydrocarbon saturation. When the relationship derived in Figure 4 is used to estimate cementation exponent (m) from aspect ratio in the evaluation interval, the result shows a good match with core-derived cementation exponent (Figure: 5, Track 5 green curve). The cementation exponent derived from the aspect ratio is used to revise water saturations and the result shows only small differences from calculations using constant m, as expected from homogeneous pore structure. (Figure: 5). Again, this may not be the case in other rocks, where failure to model larger variations in cementation exponent would have a more significant effect on estimated water saturation.

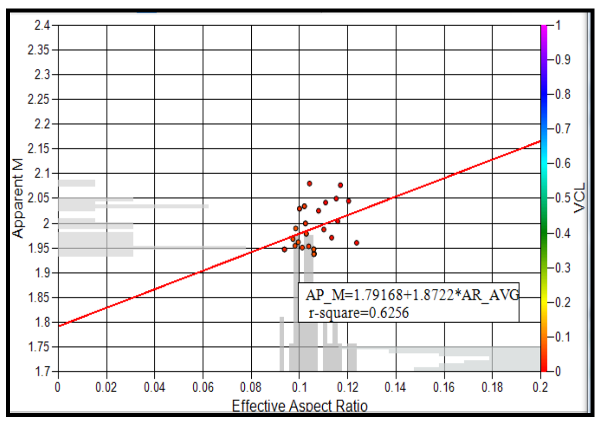

Figure 4: Cross-plot of effective aspect ratio and cementation exponent (apparent m) computed in water bearing zone

Broader implications for the significant relationship observed between effective aspect ratio and cementation exponent in this study include practical physical limits on m. One can argue that pore aspect ratio can never be smaller than zero or greater than one, independently of the model used to derive this parameter. In practical terms, effective pore aspect ratio generally has a more limited range, which has implications for the probable range of cementation exponent in any given set of data. In these data, for example, it is unlikely that m could ever be lower than about 1.8, because effective aspect ratio is approaching its limit of zero in Figure 4. If true, one could argue that any observation approaching m = 1.8 in Figure 4 (if it existed) is an outlier.

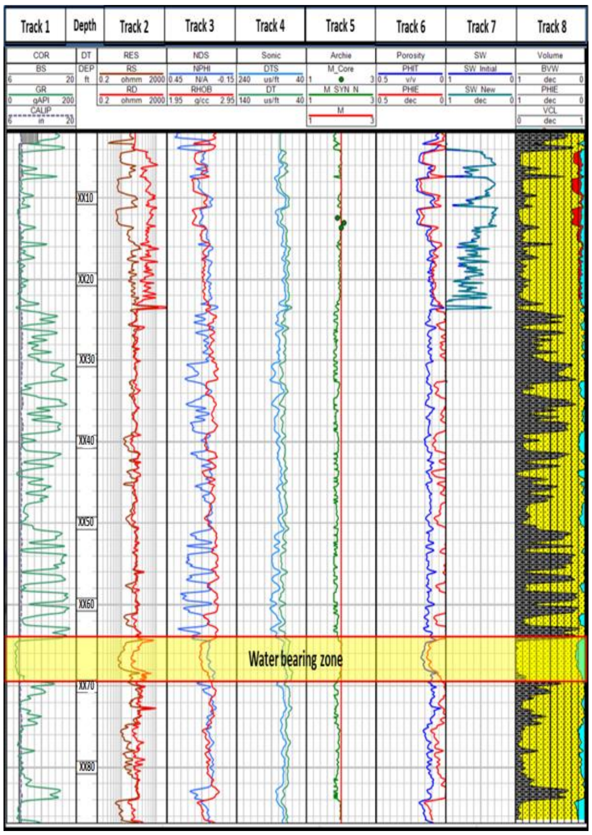

Figure 5: Log plot showing comparison of water saturation estimated using constant cementation exponent(Track 7 blue curve) and cementation exponent estimated from aspect ratio (Track 7 green curve)

Conclusions

Archie cementation factor, m, is one of the important "uncertain" parameters in reservoir studies in the absence of core data. Integration of rock physics and petrophysical analysis can be used to estimate cementation factor from well log data, thereby reducing the uncertainty in calculated hydrocarbon saturation, especially in rocks in which complex pore geometry is present. Calculation of effective pore aspect ratio is not completely decoupled from that of cementation exponent, but it is different enough that large variations in the former may signal equally large variations in the latter. Because rock physics modelling is often required in other phases of reservoir characterization studies, its application to the determination of cementation exponent is a bonus and creates a bridge between the underlying physical properties of rocks and parameters important to petrophysicists.

Acknowledgements

The author would like to thank Keven Chesser for critical review of content and CGG for permission to publish.

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Nomenclature

P Sonic = Compressional log

S Sonic = Shear log

a = Tortuosity factor

m = Cementation exponent

n = saturation exponent