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Using the Continuous NMR Fluid Properties Scan to Optimize Sampling with Wireline Formation Testers

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Abstract

One of the most important objectives of fluid sampling using wireline formation testers (WFT) is to ensure that representative samples of the different fluids encountered in the formation are obtained. Usually the wireline or LWD petrophysical logs will guide the sample acquisition program. This typically means that resistivity and nuclear logs are used to infer basic fluid types, caliper log is used to verify that the borehole is suitable for sampling, and NMR logs are used to gauge if permeability is sufficient for a sample to be taken. However these logs are not able to capture variations in the hydrocarbon column to allow the operator to ensure that all representative fluids are sampled. The most important information, a continuous fluids type and property log, is still not widely used in the industry.

Modern NMR logging tools can deliver – in addition to conventional porosity and permeability information – a continuous fluid log of oil, gas, water and OBM filtrate (OBMF) at multiple depths of investigation. The radial fluid profiling allows discrimination of OBMF versus native oil. Additionally, within the hydrocarbon column the NMR measurements can be used to provide continuous logs of oil viscosity and gas-oil ratio (GOR). With this information acquired before the sampling operation, it is easier to ensure that a full suite of representative samples are acquired and that we do not indulge in needless over sampling. When NMR data is acquired after the sampling operation, the continuous logs of viscosity and GOR can be calibrated with WFT data to provide fluid information in places where WFT did not sample.

Here, we show through several examples how continuous NMR fluid scan logs can help to:

- select and optimize pretest and sample points
- identify compositional oil gradients
- identify fluid differences that highlight potential reservoir compartmentalization
- confirm gas cap existence
- fill the gaps of missing fluid information in zones where sampling is difficult such as thin beds, poor borehole conditions, tight formations and heavy oils.

We conclude that the addition of the continuous NMR fluid properties log to existing methods is beneficial to formation tester sampling and pretesting operations in reservoirs with complex fluids distributions.

Introduction

Traditionally, resistivity and nuclear logs are used to estimate porosity, Φ and water saturation S_w prior to WFT operations. Castelijns *et al.* (1999) show the use of NMR continuous permeability, k , to select test points at the most permeable zones. However, what are missing are continuous hydrocarbon type and properties logs. For example, it is impossible to detect compositionally graded oils from Φ , S_w , and k logs and therefore insufficient sampling might result. On the other hand, excessive pretests and rig time might have been spent to acquire fluid information in difficult environments such as thin beds, washouts, near wellbore alterations, tight formations etc. where it may be more efficient to utilize NMR data.

Hydrocarbon type is usually inferred from well logs or from prior field knowledge. Sometimes, large density-neutron separation allows us to distinguish gas from oil but, in other cases, lithological effects could mask it. Hydrocarbon type can also be interpreted from pressure gradient plots. However, a reliable pressure gradient needs sufficient and well-spaced points that might be difficult in thinly laminated beds, or where there is a thin gas cap above the oil zone or a thin oil ring below the gas zone. Also, Jackson *et al.* (2007) have shown that the technique might not be reliable in case of a compositional gradient and or compartmentalized reservoirs.