Reserves quantification and thin beds rock characterization applying Nuclear Magnetic Resonance and Resistivity simulations.

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Abstract

This kind of research was done to characterize thin bed reservoir field. An experimental environment of thin beds rocks and measurements of NMR have been acquired in order to understand the response and spread this knowledge in a known scenario.

Introduction

During last ten years, the development of thin beds reservoir fields has been substantially increased and therefore the interest to characterize them properly has been a challenge for the majority of log analyst.

Nuclear Magnetic resonance (NMR) is rapidly gaining popularity in the petroleum industry as a means of overcoming the limitations of conventional logs. The primary advantages of NMR logging over conventional porosity measurements are that it uses no nuclear (radioactive) sources and it provides a lithology-independent measure of porosity. Much like the neutron tool, an NMR tool responds to the amount of hydrogen in the formation or hydrogen index.

NMR is closely related to medical Magnetic Resonance Imaging (MRI) in that is senses the fluids in the formation surrounding the borehole (like MRI senses the fluids in the body) while the solids are largely invisible. In the logging tool, a powerful permanent magnet in the tool causes the protons in the formation fluids (mostly in the hydrogen) to align. (McKeon, D, 1999)

NMR measurements are sensitive to porosity, fluids, wetability and pore size geometry. At the begggining of the experiment, measurements of pure sand and clay took place.

Theory and Method

An antenna in the tool sends a signal into the formation, causing the protons to tip away from that original alignment. When the antenna signal is turned off, the protons begin to realign in the strong magnetic field, producing a signal called the spin echo. Repeated application of the antenna´s signal leads to the measurement of many spin echoes, gathered as a spin echo train which is interpreted to estimate formation properties.

Mathematical modeling shows that the relaxation time (T2) of a given fluid within a single pore is proportional to the size of that pore.

The distribution of T2 data within a reservoir decipts the pore-size distribution. This may also be related to grain-size distribution of the reservoir.

Magnetic resonance fluid analysis also carried out on sandstones saturated with water and oil by measuring longitudinal, transverse relaxation times and fluid diffusibility obtaining classical maps T1/T2/Diffusion.

Then , a depositional model of thin beds of sandstones and shales 1 cm think fully embebed with brine and oil were constructed in a lab and NMR measurements were taken on model.

Examples

The figure 1 shows na example of T2 distribution in a clay fully embebed with brine and oil. This analyse shows that the oil is very defined in the sample and there is no water combined with oil.

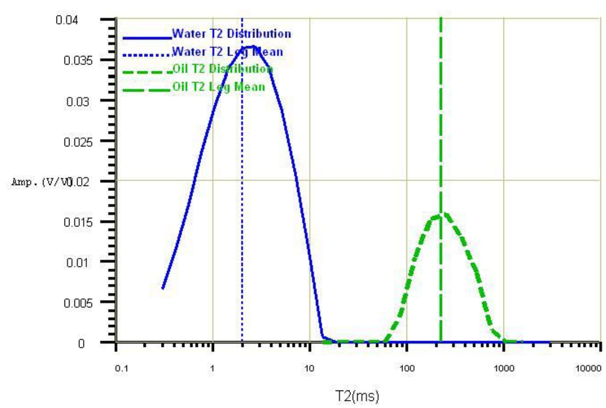

Figure1 - Clay embebed with brine and oil

The figure 2 shows na example of T2 distribution in a sand fully embebed with brine and oil. This analyse shows that the oil is mixed a litlle bit in the sample and there is water combined with oil and the sand.

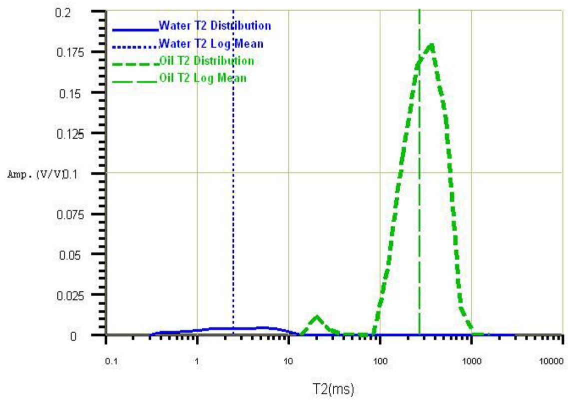

Figure2 - Sand embebed with brine and oil

Results

The results from pure sandstone showed a T2 log mean of 202 us clearly located on the free fluid space. On the other hand , the results for a pure clay showed a T2 log mean of 105us and located on the bound and capillary water area.
The magnetic resonance fluid analysis obtained a classical maps T1/T2/Diffusion. The results showed a clear peak of oil signal on 229 us (viscosity of 100 centipois).
The results showed a typical T2 bimodal distribution were free fluid represents the sandstone part and bound/capillary fluid representing the unmoveable fluids on clays. MRF stations were able to fully differenciate and quantify oil and bound water volumes as expected from previous independendant rock samples.
Then, resisistivity simulations were carry out to determine the hypotetical response of this laminated rock measure by inductions and laterolog measurements.
The results showed the strong impact of resistivity anisotropy on those measurements in a thin bed scenario and the consequences on the final oil in place calculations underestimated up to thirty percent if anisotropy is not considered.

Conclusions

Thin bed clays can present bi-modal T2 distribution and the oil in the sand can be measured when teh viscosity do not have a value bigger than 100 sintipos.

Bi-modal distribution could be representing thin beds rocks.
The measurements from induction resistivity and laterolog are influenced for the anisotropy and the anisotropy characterization is indispensible to the right estimation from the oil cointained in the rock.
The estimation hás got to be done with the right tools.

References

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