GeoNeurale

# NMR Rock Typing

by

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## Summary

NMR T2 distribution has been related to pore geometry. In this work we present an approach for rock quality determination using NMR measurements on core plug samples. We measured the NMR T2 relaxation in the laboratory for several core plug samples from clastic reservoirs in Eastern Venezuela. In addition, a standard petrofacies classification for the whole sample set was performed based on the main pore throat radius for 40% of mercury saturation also called $r_{35}$.

After analyzing the NMR results of samples of each petrofacies we found characteristic patterns in their T2 distribution curves. A detailed study reveals that the new classification can be defined on the basis of the ratio of free fluid index (FFI) over bound fluid volume (BFV), already explicit in the Timur-Coates permeability equation. Unlike the conventional method based on the determination of the main pore throat radius using Pittman equations, this novel approach does not require measurements of capillary pressure curves obtained from mercury injection nor the commonly tedious determination of the main pore throat radius dominating the fluid transport (e.g. $r_{35}$) The rock quality classification using NMR correlates very well with conventional rock quality definition in terms of mega-, macro-, meso-, micro-, and nanoporosity.

## 1 Introduction

The rock quality definition following Winland-Pittman provides a classification of rock quality based on the pore throat radius that dominates the fluid flow. For intergranular or intercrystalline porosity, the size of pore throat radius determines its class as megaporosity, macroporosity, mesoporosity, microporosity or nanoporosity. Specially for reservoir engineers and petrophysicists the distribution of porosity and permeability as a function of pore throat and pore size distributions are very important in the formation evaluation and definition of recovery strategies. Table 1 shows the porosity classes and the size of the pore throat dominating the fluid flow.

**Table 1.** Classification of rock types according to pore throat radius

| Rock type classes | Range of pore throat size/microns |
|---|---|
| Mega | > 10 |
| Macro | 2-10 |
| Meso | 0.5-2 |
| Micro | 0.1-0.5 |
| Nano | < 0.1 |

It is already known that relationships between lithology and NMR T2 distributions are present [3,4] in terms of the shape (patterns) of the T2 distribution curves that correspond to particular lithofacies for some reservoirs in Western and Southern Venezuela Basins. To build upon this knowledge, the NMR T2 distributions for the samples belonging to each rock quality class were analyzed. We have found that pore throat radius obtained from the Pittman equations are equivalent to the Timur-Coates equations, regarding the equivalence between the pore throat radius and the ratio Free Fluid Index over Bound Fluid Volume (FFI/BFV), obtained using suitable T2 cut-offs.

## 2 Permeability models

The parameters for the NMR permeability (K-NMR) following the Timur-Coates equation were determined based on the best correlation for the cross-plot of K-NMR vs. K-Klinkenberg as shown in Fig. 1. Equation (1) describes K in terms of other variables.

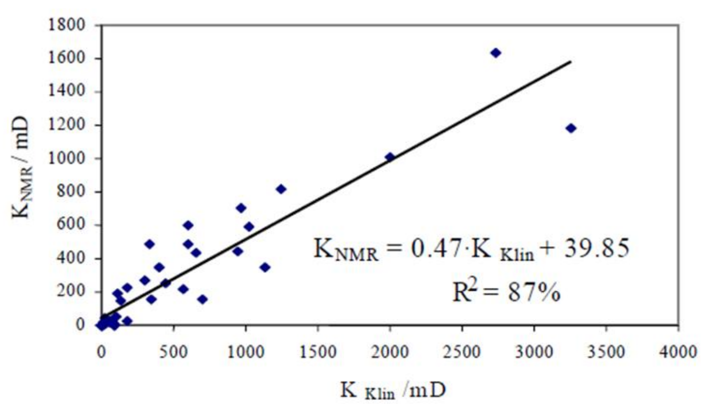


**Figure 1.** $K_{NMR}$ vs. $K_{Klinkenberg}$.

$$K = 0.1 \cdot \phi^{3.05} \left(\frac{FFI}{BFV}\right)^{1.74} \tag{1}$$

The Pittman equation that better fits the characteristics of the formation studied is:

$$r_{40 Pittman} = 0.360 + 0.528 \cdot \log K - 0.680 \cdot \log \phi \tag{2}$$

Using this equation and setting the radius of pore throat as a constant, several curves of permeability (K) as a function of the porosity (ϕ) can be plotted, defining the limits between the different rock types mentioned in table 1.

In order to find the correspondence between the Pittman and the Timur-Coates equations, it is necessary to solve both in terms of permeability as follows:

$$\log K = -0.682 + 1.288 \cdot \log \phi - 1.894 \cdot \log r_{40\,Pittman} \tag{3}$$

and

$$\log K = 0.1 + 3.05 \cdot \log \phi + 1.74 \log \frac{FFI}{BFV} \tag{4}$$

Comparing equations (3) and (4) follows that the logarithms of $r_{40}$ and the ratio FFI/BFV are equivalent.

**3 Results**

Following this hypothesis, the T2 distributions of the core plug samples for 100% water saturation and for irreducible water saturation Swi have been analyzed in terms of the variables FFI and BFV. The results show that the samples corresponding to the different rock types also show a characteristic pattern in the shape of the T2 distribution and that these rock types can also be characterized in terms of the FFI/BFV ratio. In Table 2, the corresponding values of each rock type in terms of pore throat radius, FFI/BFV ratio and T2 cut-off are given. Fig. 2 shows the permeability-porosity cross plot with the corresponding petrofacies delimitations and the typical T2 distribution curves of each facies following Table 2. The results show a very good agreement between both approaches.

**Table 2.** Classification of porosity according to pore throat radius

| Rock type classes | Range of pore throat size/microns | FFI/BFV | T2 cut-off/ms | Swi/% |
|---|---|---|---|---|
| Mega | > 10 | >12 | 0.62 | 6.74 |
| Macro | 2-10 | 4-12 | 4.44 | 9.41 |
| Meso | 0.5-2 | 1.5-4 | 7.61 | 13-73 |
| Micro | 0.1-0.5 | 0.1-1.5 | 10.55 | 28.87 |
| Nano | < 0.1 | <0.1 | --- | ---- |

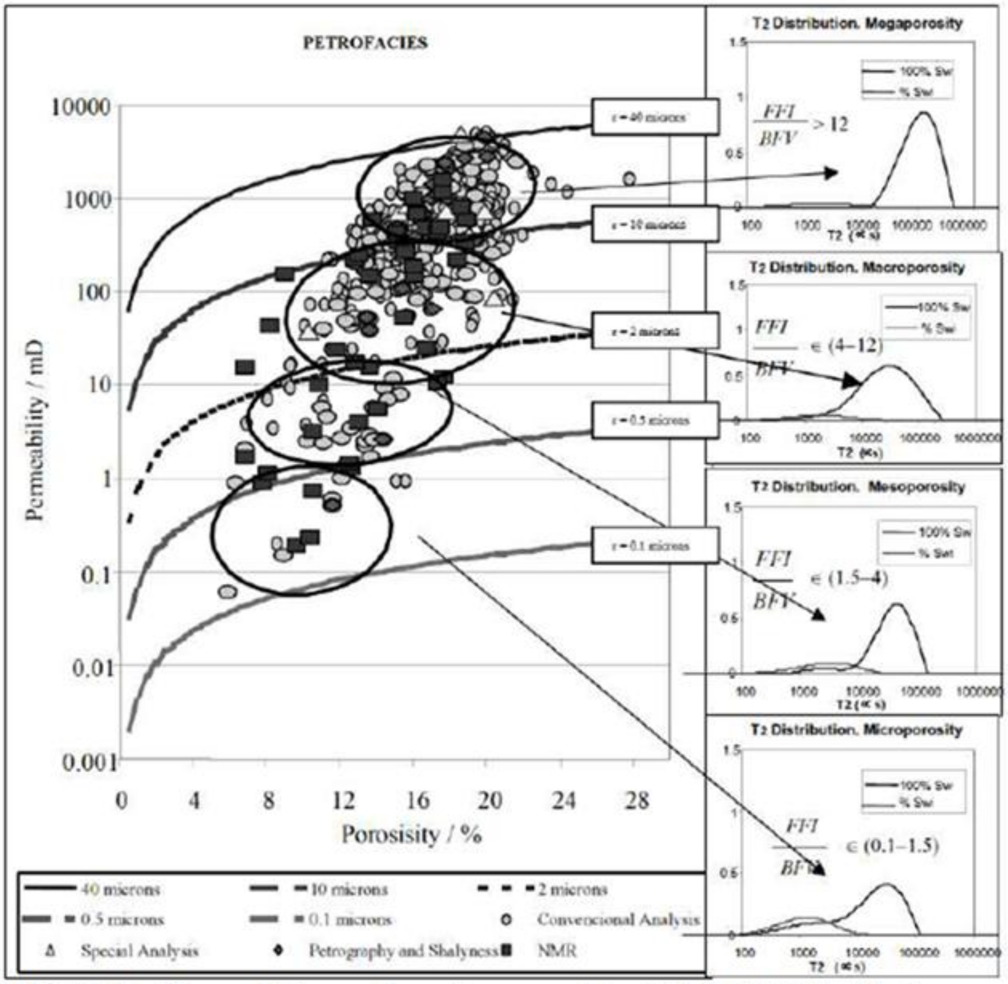


**Figure 2.** Permeability vs. Porosity cross-plot with NMR T2 distributions.

The advantage of a rock quality classification using NMR values lies in their direct determination, without going through the long way to find the pore throat radius dominating the fluid flow using the capillary pressure curves and the Laplace and Pittman equations. However, there is still a necessity of physical understanding of the correspondence between pore throat radius and the FFI/BFV ratio.

## 4 Conclusions

The low field NMR technique contributes in the classification of the rock quality. The correspondence between rock quality determination based on the definition of the pore throat radius dominating the fluid flow using Pittman equations and the FFI/BFV ratio has been shown. These results can contribute to an easy rock quality classification based on NMR T2 distributions.

This method applies not only for laboratory data but in general for logging data too, especially in case of light hydrocarbons in wells drilled either with water- or oil-based muds.

Further work at pore-scale level has to be done in order to find the physical interpretations of the relationship between pore throat radius and the FFI/BFV ratio.

## 5 References


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