MODELING RESIDUAL WATER SATURATION BY NMR, SEMIPERMEABLE MEMBRANE AND ULTRACENTRIFUGATION IN HYDROPHOBIC AND PARTIALLY HYDROPHOBIC PORE AND CAVERN CARBONATE RESERVOIRS

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ABSTRACT

To calculate oil bed saturation above the water-oil contact level, capillary pressure (Pc) versus saturation curves are considered the most reliable. These curves can be obtained by modeling displacement with the help of a semipermeable membrane. The authors estimated the residual water saturation on a Lower Permian core collection, Timan-Pechora province, with three independent methods. These methods are semipermeable membrane, NMR, and ultracentrifugation. Each of the three modeling methods has a different physical nature. Comparing the modeling suggests that NMR and ultracentrifugation give substantially lower Swr values compared to the semipermeable membrane. Pc values can be calculated for this pool thickness. Residual water in a naturally saturated core can exceed twice or greater than that in an extracted one. The hydrophobic carbonate reservoir experiments suggest that both the residual water and residual oil can occupy the same subcapillary pore system. The residual water saturation obtained by modeling cores after oil has been removed (extracted) there from gives substantially overestimated residual pool water in estimating initial oil reserves.

INTRODUCTION

When estimating reservoir saturation by well logging, a generally accepted technique has been formed, based on electric logs. Using the true bed resistivity, on the one hand, and core measurements, on the other hand, oil saturation factor So can be calculated. NMR Logging was attracted to verify the saturation evaluation reliability. Using Rt (true bed resistivity) values on the one hand, and core-measured Rt dependencies on oil saturations in the rocks having individual structural features, on the other hand, calculate oil saturations So.

NMR Logging, based on proton characteristics of fluids and their interactions with rock matrix surface, allows estimating the bed saturation. Taking into account the structural features of the rocks forming pay intervals in the regions under consideration, NMR feasibility study for such section types became necessary.

EXPERIMENTAL RESULTS

Figure 1 presents a comparison between the Swr values (represented as relationships Swr = f(∅)) obtained by different methods such as the direct one and theoretical modeling ones, for the section type discussed. The data presented suggest a low tightness of the relationship between the residual water saturation and porosity, no matter which Swr estimation method is used.

It is known that the total porosity estimated on core by a NMR method is always proportional to the area contoured by the T_2 distribution curve, always existing a boundary time T_{2b} that divides the porosity portion related to the free fluid and bound water. Early papers believed that T_2 can be assumed 30 ms and 90 ms for sandy/shaly rocks and carbonates respectively [1]. However, it turned out later that this value is variable for carbonate sections and – moreover – it can sometimes change substantially even within the same well.
Recently, the problem of the boundary value T_{2b} estimation in the carbonate rocks has been discussed quite actively. Two major trends can be seen. The first one matches NMR measurements (rock properties, T_2 distribution pattern, relaxation activity and boundary value T_{2b}) with the facial and structural peculiarities in different carbonate reservoirs [2,3]. The second one explains considerable T_{2b} variations in the carbonate section by interpore diffusion effect on T_2 distribution [4,5,6].

Comparing Swr values (obtained by modeling using the semipermeable membrane, ultracentrifuge) and Swr from NMR data calculated for a constant cutoff T_{2b} = 90 mc (see Figure 2). Discrepancies between NMR data and semipermeable membrane data are difficult to explain.

The carbonate section was silicificated in the Artinskoe time (moreover, the silification was irregular, with SiO_2 portion varying from 0% to 80% as a function of the bed. That silification changed substantially the pore space structure. The secondary mineral formation led to large pore throat narrowing (partial occlusion) as seen from SEM images (Figure 3). This is also illustrated by T_2 spectra in the same figure. The left-hand image demonstrates a pure, 100% calcite. The right-hand image shows a rock containing 50% SiO_2 , practically void of its cavernous component. The rocks are pure, clay-free. Clayey mineral content is 1-2% or even less, with the section total of 3% or less. Figure 4 shows T_{2b} distribution at the last step of the displacement pressure, using the semipermeable membrane. It is evident that T_{2b} varies in a very wide range. Such a wide T_{2b} spectrum can be explained by the fact written above.

We formed a core sample collection where NMR Swr and semipermeable membrane Swr are the same. In this collection, we transformed T_2 (ms) into pore size (μm) by normalizing on capillary pressure curves. Pore size distributions were constructed for the whole core collection, by the semipermeable membrane technique and the NMR method separately. The distribution comparisons confirm the above supposition that the semipermeable membrane gives throat sizes rather than pore ones. The pore distribution can be determined by processing the NMR measurements. Figure 3 (SEM images) shows clearly large pores. At the same time, they are not reflected in the pore size distribution determined with the help of the semipermeable membrane. The results obtained illustrate perfectly the fact that a simple mechanical attempt to calibrate NMR data by the semipermeable membrane data will cause great errors in S_{wr} estimation in the reservoir.

Besides, the results obtained confirm the conclusions done by many researchers concerning T_{2b} to depend mainly on lithologic, facial, and, which is the most important, on the structural features of the carbonate reservoirs. The problem of taking account of mineralogy when dealing with T_{2b} was solved by plotting a curve: SiO_2 content in the rock versus time T_{2b} (Figures 5). Using a lithodensity log, one can make corresponding corrections in the NMR logs and correct the T_2 cutoffs for SiO_2 content in the whole section. Figure 4 shows a T_2 distribution, which is supposed by the authors to be binormal (the left part: 40 ms to 90 ms, because of the mineral composition; the right part is 90 ms to 180 ms – due to a phobic rock).

The section examined is formed by rocks which are from partially to completely hydrophobic differences. The residual water determined by the semipermeable membrane on a sample with its natural (retained) wetting can be two or more times lower than that on a sample cleaned with a hot solvent. This fact can be well confirmed by experiments (Figure 6). Comparing core data about water saturation (obtained on wells drilled with a water-free drilling mud) with the modeling data (Figure 1) suggests that modeling Swr on a cleaned (extracted) core overestimates substantially, 2 to 4 times greater, the residual water saturation. In order to obtain compatible results, displacement pressure on the semipermeable membrane (when modeling on an extracted sample) should be 3-4 times greater than that calculated from the gravitation separation theory.

Figure 7 presents comparison between Swr values obtained by the semipermeable membrane technique at displacement pressures from 3 bar to 12 bar, on the one hand, and NMR data on cleaned samples. There is a clearly regular dependence shift observed. When the pressure reaches 12 bar, the results become compatible.

CONCLUSIONS

The boundary cutoff time T_{2b} on a relaxation curve in a carbonate section, first of all, depends on the complex structure of the pore space. In the section type under consideration these processes are represented by silicification (which leads to a partial filling of the caverns and large pores by secondary minerals such as SiO_2), and rock's mineral matrix surface hydrophobization. Both these factors can be taken into account when performing corresponding NMR calibration for core. In this section type, comparable direct method and semipermeable membrane technique data can be obtained at the displacement pressure of 12 bar.

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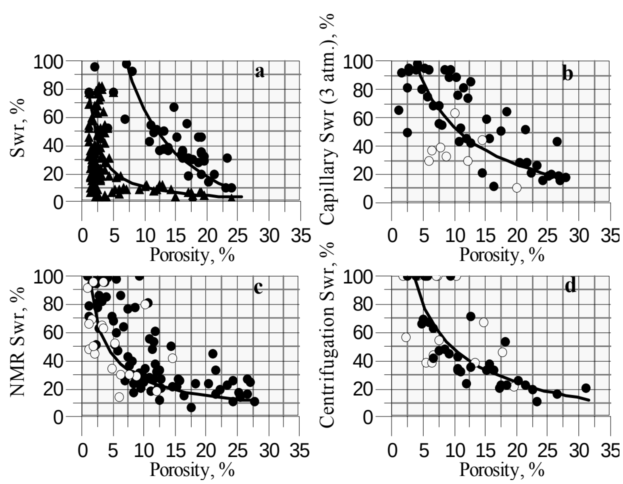
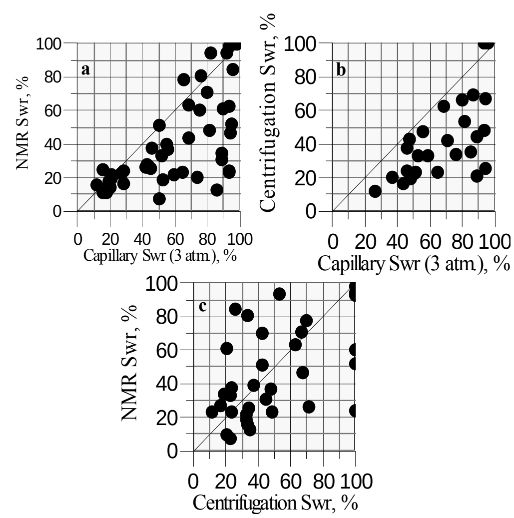


▲ - direct method data;
● - indirect method data (samples are extracted);
○ - indirect method data (samples with their natural wetting)

a - direct method data (water-free drilling mud well),
b - semipermeable membrane, c – NMR,
d - ultracentrifugation

Figure 1. Relationships Swr = f(∅) obtained by a direct and indirect methods for Low Permian carbonate sediments, Timan-Pechora province



a - comparison of Swr, obtained by NMR and semipermeable membrane methods,
b - comparison of Swr, obtained by semipermeable membrane and ultracentrifugation methods,
c - comparison of Swr, obtained by NMR and ultracentrifugation methods

Figure 2. Comparison of Swr obtained with different methods for Low Permian carbonate sediments, Timan- Pechora province

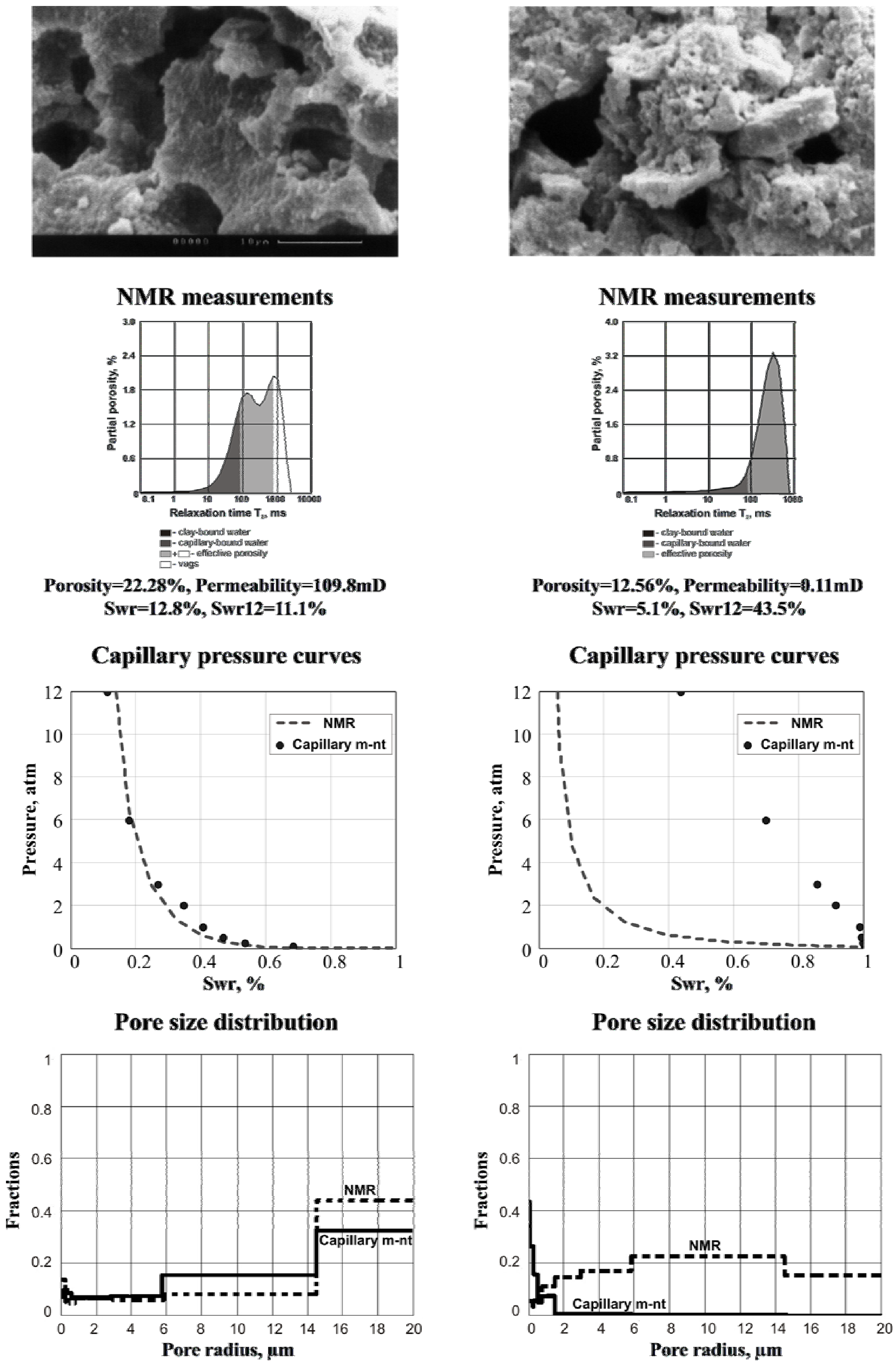


Figure 3. Porous reservoir structure on the NMR and capillary measurements data. Intregranular reservoir, Low Permian, Timan-Pechora province

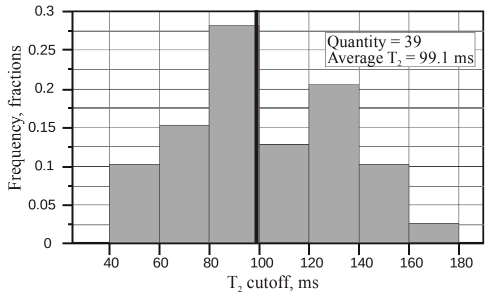


Figure 4. T_{2b} relaxation time distribution at the last displacement step (Pc = 3 bar)

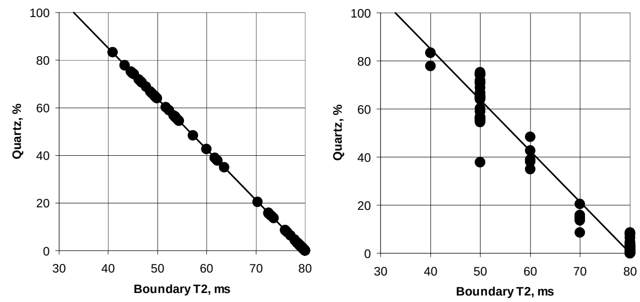


Figure 5. T_2 cutoff versus quartz content in the rock, Low Permian sediments (left - modeling, right - measurements)

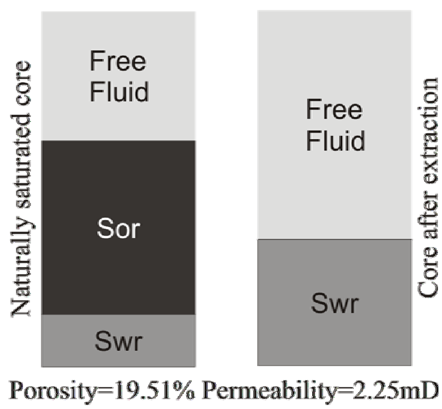
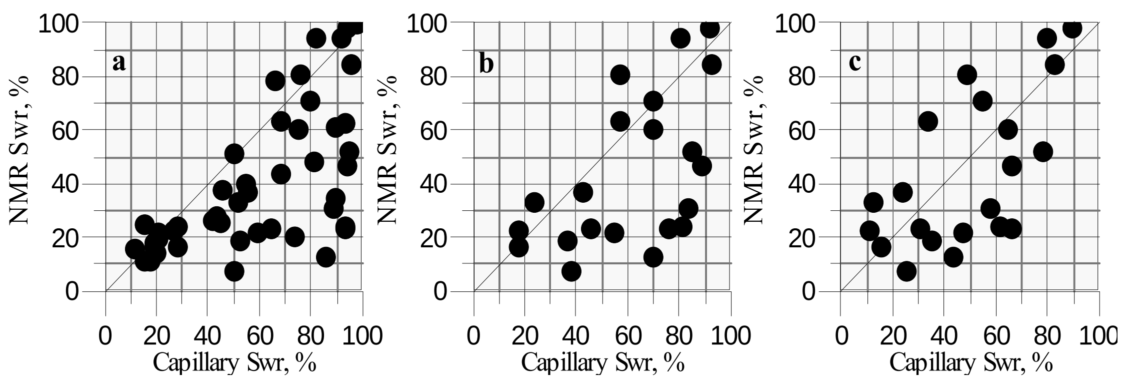


Figure 6. Comparison between Swr in a naturally saturated core sample and an extracted one



a - capillary pressure=0.3 MPa; b - capillary pressure=0.6 MPa;
c - capillary pressure=1.2 MPa

Figure 7. Comparison between Swr values obtained by NMR and semipermeable membrane methods for carbonate sediments