RESERVOIR ROCK TYPING USING NMR & CENTRIFUGE

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ABSTRACT

The work presented here discusses both static and dynamic properties and fluid flow behaviors, of nine carbonate plug samples, from three different depths within a carbonate transition zone. The samples were retrieved from a well completed in a heterogeneous cyclic carbonate reservoir from the Middle East. Core samples were characterized using Nuclear Magnetic Resonance (NMR) and Conventional Core Analysis (CCA) which aids for the Static Reservoir Rock Typing (SRRT). Capillary pressure measurements, using the ultra-centrifuge technique, were used to attain NMR T_2 cut-off values for Dynamic Reservoir Rock Typing (DRRT).

The study focuses on understanding the inter-relation in carbonate samples between rock fabric heterogeneity and pore-size distribution on fluid flow, with the presence of immobile water, using NMR and centrifuge measurements.

INTRODUCTION

A reservoir rock type (RRT) is defined as the unit of rock deposited under similar conditions that experience similar diagenetic processes having a unique porosity-permeability relationship, capillary pressure curve and water saturation for a certain distance above free water level (FWL) in the reservoir [1, 2].

Reservoir rock typing is a process by which geological facies are characterized by their dynamic behavior. The dynamic behavior of the facies is assessed by studying the rock texture, the diagenetic processes which overprinted the initial fabric, and the interaction between the rock itself and the fluids. Porosity, permeability and pore size distributions characterize the rock texture while capillary pressure, relative permeability and wettability describe the rock-fluid interaction [1-3]. Reservoir rock typing is a synergetic process between geology and petrophysics/special core analysis [SCAL]. It is therefore a process by which various petrophysical parameters and dynamic measurements obtained from SCAL are integrated in a consistent manner with geological facies (lithofacies) to estimate their flow (dynamic) behavior [3].

It should be noted that RRTs could be further subdivided and characterized as Static Reservoir Rock Types (SRRT's) also known as Petrophysical Groups (PG's) and Dynamic Reservoir Rock Types (DRRT's). For the classification of SRRT's the interpreter does not assign multi-phase flow characteristics, such as capillary pressure $[P_c]$ and relative permeability $[k_r]$ curves, which are required for the RRT assignment in the dynamic simulation models.

NUCLEAR MAGNETIC RESONANCE (NMR)

When performing NMR measurements on fully saturated porous rocks (carbonates in our case), the NMR relaxation of hydrogen nuclei can be used to determine the distribution of water within a porous medium in relation to pore size. Near the pore wall the transverse relaxation of the nuclei of the water is fast, in the order of microseconds. The relaxation of the hydrogen nuclei in bulk water, characterized by $T_{2,\,bulk}$, is much slower, in the order of seconds. Moreover, it has been shown that in the so-called fast diffusion limit the overall relaxation time, $T_{2,meas}$, is given by [4]:

$$\frac{1}{T_{2,meas}} = \frac{1}{T_{2,bulk}} + \frac{S}{V} P_{2,surf} \qquad (1)$$

$P_{2,surf}$ is the surface relaxivity. This fast diffusion limit generally holds for pore sizes in the nanometer and micrometer range [5]. Because the bulk relaxation time is much larger than the surface relaxation time, the first term at the right hand side of the equation can usually be neglected [6]. Therefore, the measured relaxation time is proportional to (V/S) which is a measure of the pore size.

In a sample saturated fully with brine, the magnetization decay from NMR source is proportional to the pore size where a single exponential decay reflects a single pore [7]. Smaller pores have faster magnetization decay times which correspond to shorter T_2 when compared to large pores. [5]

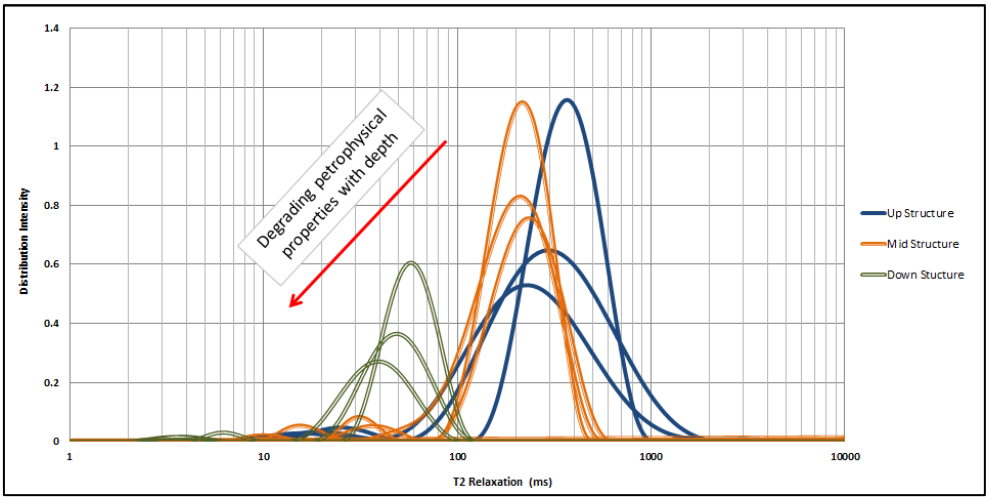

Figure 1: NMR T_2 Spectrum Pore Size Distribution along Oil Column

Figure 1 demonstrates the pore size distribution for all samples in this study from three different depth domains within an oil column. Highlighted in blue (bold line) are the samples taken from up-structure, orange from mid-structure and green (double line) from down-structure. Results show general pore size distribution for all samples to be fairly similar and unimodal however the range of T_2 shifts towards the left (faster transverse magnetization decay time) as the sample origin is deeper in the given reservoir. However, some samples exhibit higher distribution intensities which signify that they have a particular set of pore sizes which dominate its structure. It is also noticed that the petrophysical properties are degrading with respect to depth for this given carbonate reservoir and NMR is capturing this trend. This is due to the fact that up-structure samples are dominated by grain-supported limestone fabrics that were subject to early diagenetic dissolution which in turn allows for higher permeability. In down-structure, core plugs are dominated by mud-supported limestone which has lower permeability throughout.

NMR T_2 CUT-OFF METHODOLOGY

Identification of the mobile from the immobile fluids using a T_2 cut-off essentially defines the micro porosity from other types of porosity [5]. The following experimental procedure was conducted to evaluate the effect of various desaturation P_c points on measured pore size distribution using NMR.

Three cylindrical core samples at a time with individual dimensions of 1.5 X 2 inches were saturated 100% with synthetic formation brine. The samples were placed in an ultra-centrifuge apparatus for a multispeed air-brine drainage test until they reached S_{wirr}. Centrifugal speed can be converted to capillary pressure using the following equation [8].

$$(P_c)_i = (1.096 * 10^{-6})\Delta\rho N^2\left(r_b - {}^{L}/_{2}\right)L \quad (2)$$

$\Delta\rho$ is the density difference between the fluid phases, N the rotations per minute [RPM], r_b the length in cm from center of rotational axis of the centrifuge to the cup fluid receiver and L is the length of plug sample in cm.

In air-brine drainage test, air is continuously replacing the brine from the core at different speeds and a small amount of oil is used to distinguish between high and low interferences in the cup receivers. Before increasing the speed, the test is run for at least 24 hours until the production is ceased. The volume of brine replaced by air is collected in a calibrated glass vial, which is attached to the end of the cup. A stroboscope is used to capture current fluid location by the interfaces between different phases. At each pressure increment the initial interference value in terms of pixel height is measured. The value used to compute incremental volume produced is calculated using the difference between the average initialization value of that speed and that of production stability. The separation between heavy and light interfaces can then be converted to volume of brine produced.

NMR T_2 DESATURATION TIME-LAPSE

All nine samples were subjected from five to six capillary pressure desaturation increments and were subsequently removed from the ultra-centrifuge and placed in the NMR core holder. Multiple scans were measured to quantify the T_2 relaxation time. By doing so, this enables one to capture the desaturation effect, in a time lapse fashion, for a given sample on its pore size distribution, total porosity and equivalent volume (ml). The main aim is to reach S_{wirr} and discretize the amount of mobile from the immobile fluids by applying an NMR T_2 cut-off. One example of a time lapse desaturation from up-structure with the respective properties, centrifuge and NMR parameters as well as the NMR pore size distributions are shown below. Moreover, throughout the entire NMR acquisition, an inter-exponent delay time of 5,000 ms and 50,000 echoes were used.

Table 1: Up-Structure Sample Desaturation Parameters

Plug Sample	Sample Origin	Sample Bulk Volume (cc)	Centrifugal RPM (N)	Centrifugal Equivalent Pc (psi)	NMR Equivalent Water Volume (cc)	NMR Total Porosity %	Time to SNR 200 (minutes)
1_4	Up Structure	54.88	100 % Saturated	--	8.5	16.4	--
			1026	6	8.2	7.3	3:21 (24 scans)
			1325	10	7.8	6.9	6:09 (24 scans)
			2480	35	5.9	5.0	11:15 (44 scans)
			4192	100	4.0	5.4	17:20 (124 scans)
			4686	125	2.6	3.3	18:59 (440 scans)

Up-structure sample 1_4 experienced a large production during the first pressure increment. The production from meso pores is qualitatively assumed to have been around 10-35 psi respectively. The micro-porosity is noticeable at around 125 psi, once the level where production equilibrium at a given RPM/P_c ceased. The saturated volume of micro porosity (S_{wirr}) can then be computed [9]. Isolating the production from different pore types (e.g. meso and macro pores) is qualitative but through this method one can visualize (not shown in paper) how much desaturation occurred at each capillary pressure increment to further understand the semi-dynamic behavior of these carbonate rocks. In comparison to the semi-dynamic behavior of the samples up-structure, those originating from mid-structure and down-structure are respectively different but similar within their depth domains. As the petrophysical properties of the plug samples worsen with respect to depth, the capillary threshold pressure to initialize the fluid production during centrifugal replacement increases.

NMR T_2 CUT-OFF

Once successful results are obtained from the relaxation spectra of the fully saturated samples, the T_2 cut-off can be determined by dividing the bound and free liquid components from individual plug samples. This requires two relaxation spectra – one from a plug sample in a fully saturated state and other one from the same sample after it had been centrifuged to S_{wirr}. The value, in terms of transverse magnetization decay time, allows one to further understand the Free Fluid Index (FFI) of each sample.

Figure 2 is an example of a T_2 cut-off generated report using the Magritek© software from a mid-structure sample 8. It also demonstrates the incremental saturation (porosity) from the fully saturated sample and that of S_{wirr}.

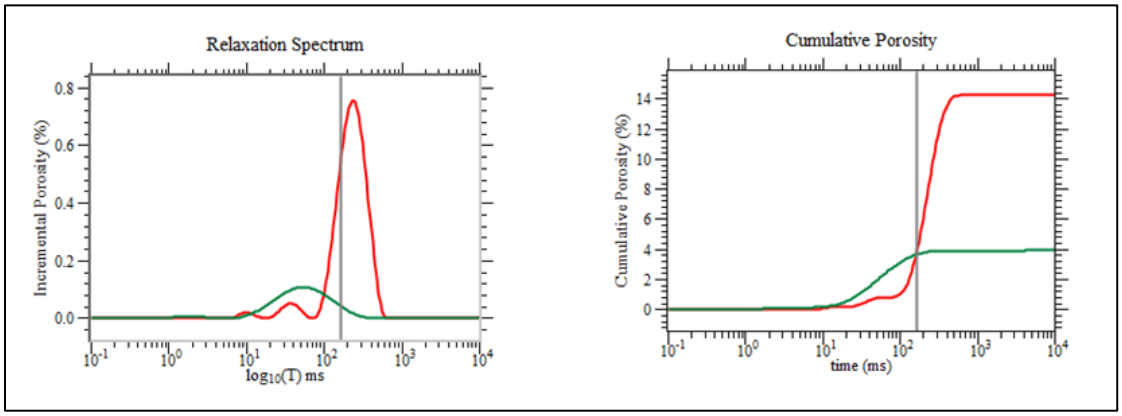

Figure 2: [LEFT] Fully saturated (red) and Swirr (green) spectrum overlain for T2 cut-off. Sample time is 164.5 milliseconds. [RIGHT] Cumulative porosity of both fully saturated and Swirr overlain. Volume between represents Free Fluid Index (FFI).

The S_{wirr} data is plotted in green on top of the fully saturated data plotted in red for the same sample. The computed S_{wirr} T_2 cutoff value for this sample is 164.5 milliseconds. The effective porosity, considering no clay content in these carbonate plug samples, is the same value as the FFI which is analogous to the NMR total porosity subtracted by the Bulk Volume Irreducible (BVI). The BVI corresponds to the volume of S_{wirr} hence; the FFI represents the porosity of the rock available to contribute to fluid flow. For all the samples used in this study the data is tabulated in **Error! Reference source not found.**2.

Table 2: NMR FFI from T_2 Cut-off

Plug Sample	Zone in Oil Column	Depth (ft.)	k air (mD)	Total NMR Porosity (%)	Bulk Volume Irreducible (%)	Free Fluid Index (%)	T_2 Cut-off (ms)	T_2 Mean (ms)
1	Up Structure	x511	12.66	19.9	4.6	15.2	174.3	292
1_4		x512	4.6	16.4	3.3	13.1	123.2	226
1_5		x514	1.5	21.1	3.1	18	219.6	331
1_25	Mid Structure	x577	7.836	17.1	4.7	12.4	138.3	174
1_26		x580	0.46	18.5	4.3	14.2	155.2	194
8		x581	1.7	14.3	3.9	10.3	164.5	200
2_15	Down Structure	x639	7.096	8.6	8.3	0.3	77.5	53
2_16		x642	0.04	6.4	6.1	0.3	73.2	45
12		x643	0.01	5.1	4.9	0.2	61.5	36

CONCLUSIONS

Error! Reference source not found. Results indicate that the petrophysical properties of the rocks within this cyclic carbonate reservoir are degrading with respect to depth. NMR transverse magnetization decay times are becoming faster and the capillary threshold pressures, from the air-brine centrifugal method, are increasing with respect to depth.

This signifies that the transition zone has been effectively captured using these samples from three depth domains.

Unlike sandstones, carbonate rocks have very complex pore systems due to the diagenetic overprint, causing individual samples to have different proportions of primary and secondary porosities. Because of this, the greater the porosity, the more complex is the pore size distribution and the wider the NMR T_2 spectrum. Furthermore, it is noticeable that the T_2 cut-off is not a standard value for all carbonate fabrics analyzed in this study, it varies according to the carbonate petrophysical properties such as the amount of micro-porosity. Table 2 indicates that the semi-dynamic behavior of carbonate rocks is very complex and depends strongly on the proportion and size of the pores [10]. However, by analyzing plug samples using this combined technique (NMR & Centrifuge) allows one to further understand the semi-dynamic complexities of these porous carbonate rocks. Nonetheless, the NMR T_2 mean is a reliable way to group plug samples into SRRT's. More research is required to attempt to standardize the value of NMR T_2 cut-off for carbonate rocks with different petrophysical properties.

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