ON THE MEASUREMENT OF PORE GEOMETRY: A COMPREHENSIVE PETROPHYSICAL STUDY OF CONVENTIONAL ROCKS

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ABSTRACT

Various techniques have been developed over the years for characterizing pore structure beyond a simple visual description. These tests provide qualitative data for both reservoir evaluations in the short run and reservoir simulation in the long run. In this study, mercury porosimetry (MP), low field (2MHz) nuclear magnetic resonance (NMR) relaxometry, centrifuge drainage tests and flow tests were run on 11 plugs of a mix of sandstones, limestones, dolomites and chalk. Initially, a representative elemental volume (REV) which uses pore size distribution (PSD) data and porosity to simulate the pore network is discussed. The model is later used to predict permeability and predictions were compared with gas flow measurements. NMR and centrifuge data are coupled to derive capillary pressure curves and the results are compared with MP derived capillary curves. The results indicate that there is significant difference between the two capillary curves based on the degree of heterogeneity of the samples. NMR and centrifuge data are also used to come up with a method to study the degree of heterogeneity of the plugs based on which it was decided which PSD (MP, NMR or centrifuge) would be the better representative of the pore network. This PSD is then used to make new permeability predictions using the REV model and the results show significant improvement over previous predictions. This study proves that MP, NMR and centrifuge tests provide complimentary information that is crucial to pore network simulation and analysis. This study also highlights the fact that rocks are complex and one test cannot represent the properties of the pore network, making it is necessary and beneficial to run complimentary tests to better understand the pore network. It also verifies the applicability of methods that combine results of these tests to assess the rock pore network.

INTRODUCTION

Pore network simulation and reservoir rock characterization have been of interest to researchers for almost a century. Initial approaches were mainly focused on permeability prediction. There is a vast literature that deals with permeability prediction; however most pioneering methods were based on experimental correlations [1]. Porosity-permeability cross plots are a good example of these approaches. Later researchers tried to predict permeability by simulating the pore network and applying fluid flow principles to the simulated network. Carman and Kozeny suggested that the porous network can be simulated using a bundle of non-interconnected tubes of varying radii [2]. This work has been the bedrock for future modeling by various researchers. Berg and Van Baaren used the same mentality and tried to correlate tube diameter with grain size distributions [3, 4]. Works of Leveret, Purcell, Thomeer and Swanson on the other hand dealt directly with pore entry pressures derived through Mercury Porosimetry (MP) [5, 6, 7, 8]. Following the work of Purcell, Ruth *et al.* suggested that the pore network can be simulated using a single REV,

correlating permeability with an average diameter and an average length of the conduit as follows [9]:

$$k = \frac{\emptyset\ \delta^2}{32\ \tau^2} \tag{1}$$

Here k is permeability, ∅ is porosity, δ is the representative diameter and τ is tortuosity. In their model they used Purcell's mean tube diameter as follows:

$$\delta^2 = (4\sigma\cos\theta)^2 \int_0^1 \frac{dS_v}{(P_c)^2} \tag{2}$$

Here, Sv is vacuum saturation, Pc is capillary pressure and σ and θ are surface tension and contact angle in the MP experiment respectively. They also incorporated electrical properties to account for the extended length of the mean flow path due to tortuosity. Archie's formation factor was used to define tortuosity as a function of porosity, cementation factor (m) and lithology factor (a) as follows:

$$\tau^2 = \frac{a}{\emptyset^{m-1}} \tag{3}$$

Eventually, they rewrite their model as:

$$k = \frac{\emptyset^m(\sigma\cos\theta)^2}{2\ a} \int_0^1 \frac{dS_v}{(P_c)^2} \tag{4}$$

PRELIMINARY WORK

This REV model was initially tested against a mix of 25 sandstone and carbonate samples from an offshore Ghana formation of Turonian age. Once provided with the mercury intrusion and formation factor data, the method was able to predict permeability with a mean error of less than 35%. Results of this study are presented in Figure 1. The two dashed lines represent the 50% and 100% error bars and the solid line is the one-to-one line where prediction matches measurement.

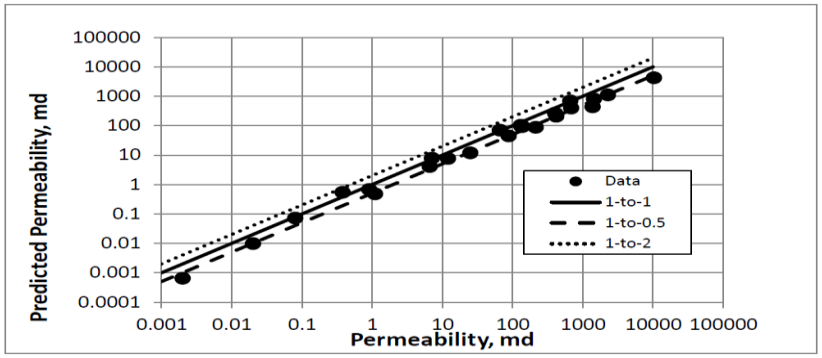

Figure 1 - Comparison between the calculated permeability and the measured permeability

In two other attempts, the REV model's predictions were compared with predictions of Carman-Kozeny, Swanson, Timur-Coates and Schlumberger-Doll-Research (SDR) methods [10, 11]. In

all cases except Swanson's, predictions made using the REV model outperforms predictions made using other methods. Swanson's however, makes better predictions than the REV method because it is optimized for the data set, thus making it less reliable when not optimized for the specific data set or formation.

After all, out of all the compared models, the REV model is the only one that solely relies on petrophysical properties of the rock and does not incorporate any fitting parameter. However, a claim cannot be made about the general applicability of this method particularly because the mean diameter of the conduit is calculated based on MP measurements done on small samples which are not always representative of the pore network. To start with, MP data is representative of the pore volumes accessible through specific pore throat sizes. In clean, homogenous sandstones where pore throats are supposed to be the main obstacles against fluid flow, and when pore throat to pore body ratios are not large, using throat size distribution (TSD) instead of pore size distribution (PSD) would not result in misinterpreting the pore network. However, in carbonates, where there is a wider variety of pore throat to pore body ratios using TSD would result in unreliable predictions.

Also, when it comes to field applications, MP is not the most applicable method because it's not easy to generate a continuous TSD profile for the entire height of the reservoir. However, logging techniques such as Nuclear Magnetic Resonance (NMR) can produce a continuous PSD profile for the entire height of the reservoir adjacent to the well bore.

RESULTS AND DISCUSSION

Techniques have been developed to derive capillary pressure from NMR data [12, 13]. Green [14] developed a model to produce capillary pressure data by coupling centrifuge tests with low field NMR measurements. In their method they calculated the capillary pressure distribution at each centrifuge spin by using Hassler-Brunner boundary conditions and applying it to Darcy's law to end up with the following formula:

$$P_c(r) = \frac{1}{2}\Delta\rho\omega^2(r_0^2 - r^2) \tag{5}$$

Here Pc(r) is the capillary pressure at each point along the sample, $\Delta\rho$ is the different in the densities of saturating and displacing fluids, ω is the spin velocity and r_0 is the distance from center of rotation. After each spin the sample is removed from the centrifuge and brine saturation along the sample is measured using low field NMR. Finally saturation at each r is coupled with capillary pressure at that point and a global capillary pressure curve is plotted for the sample. This test was run on the 11 samples used by Salimifard *et al.* [11] and results show that for the more homogeneous samples, MP capillary pressure curves match with the NMR capillary pressure curves. However, for the less homogeneous samples, i.e. samples E and J, the two capillary pressure curves differ. Figure 2 shows the results of the comparison. It should be mentioned that choosing the right contact angle for analyzing centrifuge capillary pressures is of utmost importance. In this study a fixed value of zero degrees was used for brine-air system which might not be the case for some rocks.

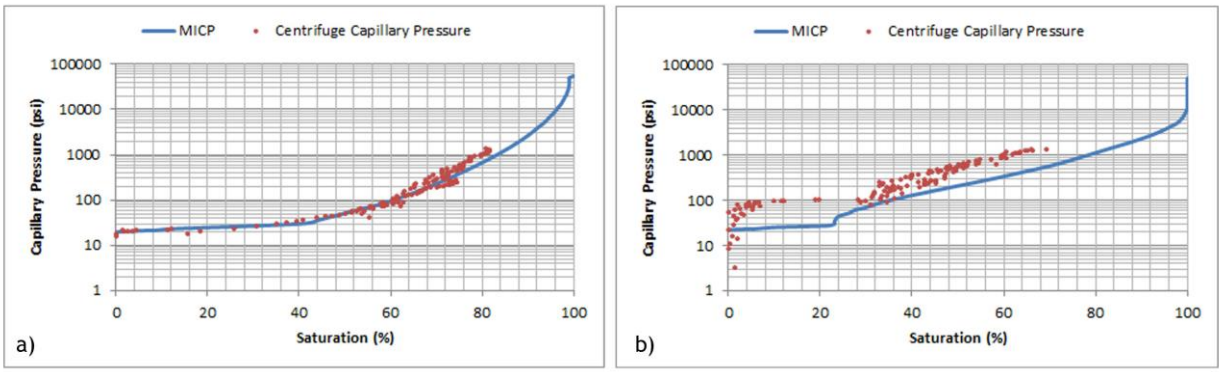

Figure 2 – a comparison between capillary pressures derived from MP and Centrifuge tests. Figure a (on the left) shows how MP and centrifuge capillary pressures match for a homogeneous sample while Figure b (on the right) highlights the fact that for less homogeneous samples, proper sampling can play an important role in capillary pressure determination.

Results of the same test are used to quantify the degree of inhomogeneity of the 11 samples. Each sample is divided in 4 segments and the total change in brine volume in each segment is monitored after each centrifuge spin. An average capillary pressure was calculated for each segment using Green's approach and the change in brine volume was coupled with that capillary pressure to construct the capillary pressure curve for each segment. The inhomogeneity of the sample then can be analyzed based on how well the capillary pressure curves for the four segments match. Obviously a good match means the sample is fairly homogenous and indicates that the end piece used for mercury porosimetry is a good representative of the core plug. As expected, capillary pressures for the four segments of samples E and J do not match which highlights the degree of inhomogeneity of the two samples.

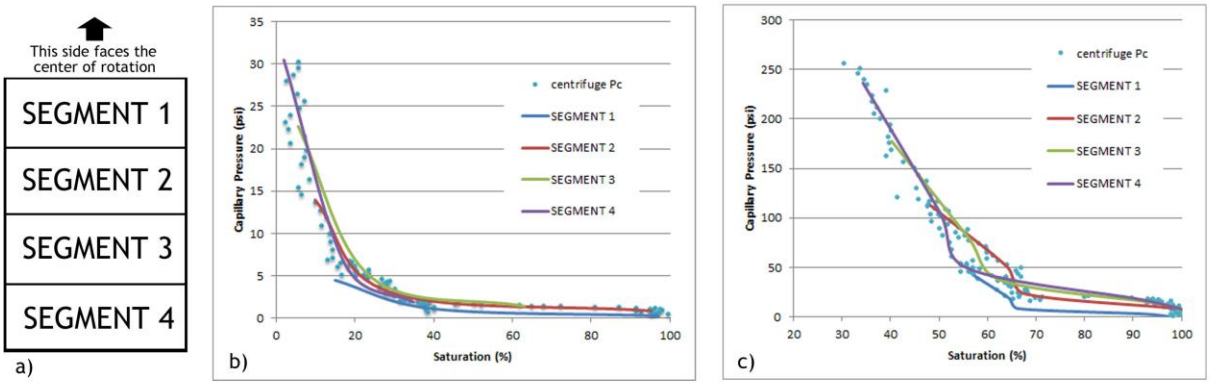

Figure 3 – a comparison between capillary pressures calculated for the four sections of a homogenous and a less homogenous sample. Figure a (far left) shows how the four segments are arranged on the core plug, segment 1 being the closest to the center of rotation and segment 4 being the farthest. Figure b (middle) shows capillary pressures of the four segments of a homogenous plug compared with centrifuge capillary pressure of the plug. Figure c (far right) shows the same results for a less homogenous sample.

In presence of heterogeneity, it is believed that the NMR derived PSD is a better representative of the pore network as it sees the entire plug, not just an end piece. Marschall's and Kleinberg's methods are used to convert NMR T2 distributions to capillary pressure data by matching the NMR T2 distribution curves with MP capillary pressure curves. As Marschall explained, NMR

data can be correlated with pore size when the plug is 100% brine saturated using the following equation:

$$\frac{1}{T_2} = \rho \frac{S}{V} \tag{6}$$

Here ρ is relaxivity and $\frac{S}{V}$ is the surface to volume ratio, which can be replaced by $\frac{2}{r}$ when a cylindrical pore network (a bundle of capillary tube) is assumed. Here ρ is calculated using

$$\rho = \frac{\sigma \cos\theta}{PT_2} \tag{7}$$

where ρ is defined as the effective relaxivity to account for the fact that NMR responds to pore bodies whereas MP responds to pore throats. An effective relaxivity is calculated for all 11 samples by finding the best match between the NMR T2 and MP capillary pressure distributions. These relaxivities match with the values reported by Marschall and Kleinberg and are tabulated in Table 1. Relaxivities are used to produce capillary pressure curves from NMR T2 distributions and permeability is recalculated using the REV method based on the new capillary pressure curves.

Table 1 – a compilation of sample properties and prediction results using different techniques

Sample Name	A	B	C	D	E	F	G	H	I	J	K
Porosity (%)	17.3	22.1	19.9	19.9	28.8	15.5	23.3	22.3	25.9	9.2	18.3
Measured Permeability (mD)	62.8	1060	7050	107	58.9	106	52.3	3810	1150	0.45	283
MP-Predicted Permeability (mD)	210	1090	2500	908	123	336	52	1220	892	6.13	302
Calculated Relaxivity (μm/s)	12.8	17.1	21.3	2.7	13.1	2.7	24.0	12.8	17.6	2.4	15.5
NMR-Corrected Permeability (mD)	180	1780	3960	184	590	250	86.9	3030	1030	4.38	295

CONCLUSION

Results shown in the table above clearly show that excluding sample E, using NMR derived capillary pressure curves improves the predictions for less homogeneous samples, namely for samples D and J. Even though the NMR T2 distributions are calibrated with MP capillary pressure curves, this approach improves the predictions by 113% (from 245% using MP data to 132% using NMR data, excluding sample E for both cases). Also, the T2 distribution curve was recalibrated with centrifuge capillary pressures for sample J and a new permeability prediction of 1.07 mD was achieved.

Sample E is a chalk sample which is highly compressible and sensitive to confining pressure. This is confirmed both by pressure-adjusted flow tests and by the NMR inhomogeneity test. As a result, because permeability tests are performed under confining pressure, NMR PSD might not be the best representative of the pore network when compared to confined flow tests, because NMR tests are done under no overburden pressure. Using NMR PSD would result in over estimating the pore sizes and over estimating the resultant permeability.

In conclusion NMR derived capillary pressures have proven to be properly representative of the pore network and are capable of making reliable permeability predictions. However, there's still a need for calibrating the T2 relaxation times with either centrifuge or MP capillary pressures. N2 adsorption techniques on the other hand can provide a direct measurement of surface to volume ratios, through which relaxivity values for each sample can be calculated [15]. In another approach, Fleury discussed a novel method to directly measure relaxivity values from NMR diffusion curves and concluded that the results compare with values derived through N2 adsorption measurements [16]. Unfortunately there wasn't sufficient data to apply these methods to the current set of samples. Once relaxivity is obtained for a formation, T2 relaxation times can directly be converted to PSD data and a continuous PSD profile can be generated for the entire height of the reservoir from NMR logs.

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