Developing a Model to Estimate Permeability from Other Petrophysical Data

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Abstract

Reservoir characterization has always been an important step in production planning and permeability is one of the most important transport properties of a rock to be determined. A new method to predict permeability of rocks, based on capillary pressure principles, has been published recently and proved to make reliable predictions. The method uses Mercury Injection Porosimetry (MIP) data as well as electrical data to find effective diameter and length for the REVs, which are used to simulate pore structure. Although mercury injection porosimetry has proven to be an effective means of determining pore structure, it only sees pore throats, missing pore bodies – pore bodies also contribute to fluid flow. On the other hand, NMR data is believed to give good estimates of pore size distribution, provided that proper relaxivity values are selected and proper experimental conditions are used. Methods exist to predict permeability from NMR data. A suite of 11 samples has been tested to further study permeability prediction methods using both NMR and MIP data. Samples were chosen in an attempt to cover a wide range of porosity, permeability and rock type. Having both NMR and MICP data helps the further understanding of pore structure, giving us information about both pore throat and pore body distributions. This paper will demonstrate that by combining NMR and MIP data, permeability predictions are improved over predictions using either method independently.

Introduction

Permeability is a key parameter in reservoir characterization and is often obtained through direct measurements done on rock cores drilled out of wells. Methods have been introduced to estimate permeability from different petrophysical data [1] [2] [3], some of which are methods based on Nuclear Magnetic Resonance (NMR) and Mercury Injection Porosimetry (MIP) measurements. These methods all revolve around the idea that by knowing the pore structure, one should be able to simulate fluid flow through the structure and calculate permeability. Both NMR and MIP measurements are well known for providing researchers with pore body and pore throat distributions which form the pore structure in a rock. However, neither of these measurements is capable of finding the configuration in which pore throats and pore bodies are constructed. NMR and MIP tests provide us with pore body and pore throat distributions respectively, which are later used by different models to estimate permeability. Two of the well-known models that use

NMR data to predict permeability are the Timur-Coates (TC) and the SDR models. Both of these models correlate permeability with porosity and pore sizes [4] [5] [6] [7]. The TC model correlates permeability (*KTIM*) with porosity and the ratio of free fluid index (*FFI*) to connate bound water (*CBW*) as follows:

$$KTIM = (\frac{\varphi}{C})^m \times (\frac{FFI}{CBW})^n \qquad (Eq.1)$$

Here φ is porosity in percent. Both *CBW* and *FFI* must be in the same units: percent or units of volume. To calculate *CBW* and *FFI* accurately, $T_{2cut\text{-}off}$ values should be determined for each sample. In the absence of such data, default values of 33 and 92 milliseconds can be used, respectively, for sandstones and carbonates [1]. These values comply with Marschall's observation that carbonates show lower relaxivity values than sandstones [8]. As a result, to end up with the same pore size as the cut-off size, a higher $T_{2cut\text{-}off}$ should be chosen for carbonates. The SDR method on the other hand, only correlates permeability (*KSDR*) with porosity and an average relaxation time as follows:

$$KSDR = C \times \varphi^m \times T_{2lm}^n \qquad (Eq.2)$$

Here φ is porosity in percent and T_{2lm} is the logarithmic mean value of the NMR T_2 distribution in milliseconds. *C, m, n* are all constants that can be determined from experimental data. In the absence of such data, these values can be set to 10, 4, 2 respectively [9].

There are also various models available for predicting permeability from MIP data. One of the pioneers to propose a model was Swanson. Swanson believed that not all the pore network in a rock contributes to permeability and therefore considered the apex of the S_b/P_c ratio on a capillary curve as the point where all the pores contributing to permeability are occupied by mercury [10]. He defined S_b as saturation of mercury and P_c as capillary pressure. Later he correlated permeability with this apex value as follows:

$$K = C(\frac{S_b}{P_c})^m \qquad (Eq.3)$$

Here *C* and *m* are constants derived from experimental data. Swanson reported values of 399 and 1.691 for air permeability and 431 and 2.39 for brine permeability for *C* and *m,* respectively. Swanson later showed, as one of the strengths of his method, that the difference in the apex in the capillarity between core plugs and drill cuttings is insignificant (see Comisky [2]).

Another method based on MIP data was later introduced by Ruth et al. who modified Purcell's capillary tube model by introducing electrical data and modeling flow through a series of Representative Elemental Volumes (REVs) containing a single tortuous tube [11]. Darcy's law was later applied to correlate permeability with porosity and tortuosity as follows:

$$K = \frac{\varphi^m (\sigma Cos\theta)^2}{2a} \int \frac{dS_v}{(P_c)^2} \qquad \text{(Eq. 4)}$$

Here m and a are the cementation factor and saturation exponent present in Archie's equation and are obtained from electrical data. σ and θ are interfacial tension of mercury and mercury-vacuum contact angle, respectively. Also, S_v is the saturation of vacuum and P_c is the capillary pressure obtained from the MIP experiment. Ruth et al.'s method has proven to make reasonable permeability predictions [3] [11]. In this study, the model, referred to as the REV method, is tested against the three other available methods discussed in the introduction.

Samples and Experimental Method

A total of 11 core plugs, 5 sandstones and 6 carbonates, were selected to run MIP, NMR and flow tests for the purpose of this study. The samples cover a wide range of permeability, from 0.45 mD to 7000 mD, and porosity, from 9.3 to 28.8 percent. Table 1 lists MIP, NMR and basic core analysis data for each sample. The samples were cleaned and dried prior to making any measurements.

For the NMR measurements, samples were vacuum saturated using 2% KCl solution. NMR measurements were done on all samples at 100% saturation using an Oxford Maran DRX-HF instrument at 30°C and 2MHz frequency. GITSystems software was used to make T_2 measurements with an interecho spacing of 0.1 msec and a minimum signal to noise ratio (SNR) of 100:1. Total and incremental brine volumes, porosity and T_2 distribution curves were obtained by the software. High pressure MIP tests were conducted on dry samples by Trican, a commercial service provider based in Calgary, Canada. Steady state flow measurements were also conducted on the samples using nitrogen gas at varying upstream pressures and 120 psi overburden pressure. Readings were corrected for Klinkenberg and Forchheimer effects to obtain air permeability.

To predict permeability from NMR and MIP reading, four methods were used: TC, SDR, Swanson and REV. For NMR models, cut-offs of 33 ms for sandstones and 92 ms for carbonates were used, however, having the permeability measured directly, most people calibrate these cut-off values to get better predictions out of the models. To calculate permeability using Swanson's method, values of 1.911 and 3.479 were used for C and m to get the best match with measured permeability. Values of 1 and 2 were used for a and m, respectively, in the REV method in the absence of electrical properties.

Discussion and Conclusion

The results of the tests and calculations are presented in Table 1. Figure 1 and Figure 2 show schematic comparisons of the four methods. A "trust region" of a factor of 2 is highlighted in Figure 1 by the dashed lines to make it easier to compare different methods' predictions. Swanson's method seems to make better predictions than the other three methods used in this study. However, it must be noted that Swanson's C and m parameters have been modified to match the measured permeabilities by fitting

Swanson's formula to get the best fit of *C* and *m* for all the data. Different researchers have reported different values for *C* and *m* for different data sets [2] which makes Swanson's method only reliable when optimized for a specific data set or formation. Among the four methods studied, the REV method is the only one that solely relies on rock properties and does not use any fitting parameter, yet still makes reliable predictions. Ruth et al. showed that using values of *m* and *a* obtained from formation factor tests could increase the prediction power of the method [11]. Using the REV method, there are a few samples that fall out of the "trust region"; notably samples 4 and 10, both highly vugular limestone samples. The REV method shows consistency in making the most accurate predictions, whereas other methods' predictions are more scattered (Figure 2). The heterogeneous nature of carbonates makes it difficult to make predictions based on small samples like the ones used for MIP measurements. On the other hand, NMR, while looking at a bigger image of the rock, might be a better candidate for permeability prediction in carbonate rocks. In this study, the TC method seems to make more reliable predictions than the SDR method, as shown on Figure 2. Overall, MIP based methods seem to make better predictions than NMR based methods; however NMR readings are much easier to obtain on well site. Both NMR based and MIP based methods provide valuable information about rock structure and there is significant opportunity for future research using these methods.

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Table 1 – A summary of sample properties, permeability measurements and permeability predictions. Here, Phi is porosity in percent, T_{2lm} is logarithmic mean of NMR T_2 distribution, CBW and FFI are calculated from NMR readings, S_v and P_c are vacuum saturation and capillary pressure at capillary pressure curve apex. Also shown in the table are measured permeability and calculated permeability using different methods discussed in the paper. Rock types mentioned are Sandstone (SS), Limestone (LS), Chalk (CH) and Dolomite (DS)

| Sample #	Petrophysical Properties						Measured Perm (mD)	REV Perm (mD)	SDR Perm (mD)	TC Perm (mD)	Swanson Perm (mD)	Rock type
	Phi (%)	T_{2lm} (ms)	CBW (%)	FFI (%)	S_v (%)	P_c (psi)						
1	17.3	105	16.0	84.0	50.2	18.0	62.8	210	98	244	68	SS
2	22.1	184	15.5	84.5	57.2	9.15	1060	1090	808	706	1130	SS
3	19.9	168	18.5	81.5	45.2	4.30	7050	2500	438	303	6870	SS
4	23.3	200	54.7	45.3	40.4	30.0	149	52	1170	20.2	5.38	SS
5	22.3	474	5.30	94.7	64.7	7.11	3810	1220	5520	7670	4160	SS
6	25.9	114	19.8	80.2	55.7	10.8	1150	892	592	741	568	SS
7	19.9	317	22.6	77.4	19.6	7.73	107	908	1570	183	48.7	LS
8	28.8	68.5	61.2	38.8	36.1	27.4	58.9	123	322	27.7	4.98	CH
9	15.5	679	11.4	88.6	45.3	12.8	106	336	2670	356	154	DS
10	9.20	110	44.3	55.7	21.6	27.4	0.45	6.13	8.96	1.18	0.83	LS
11	18.3	42.8	61.6	38.4	31.1	12.8	283	302	20.7	4.40	41.7	LS
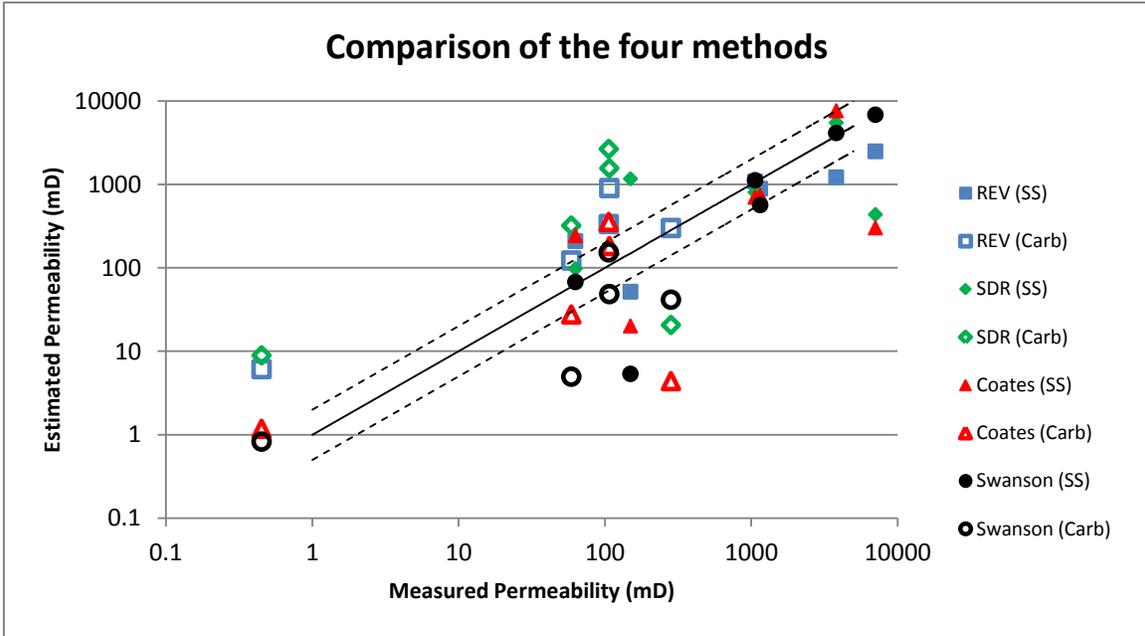
Figure 1 – Comparison of calculated permeability using four methods and measured permeability. Solid line is the 1-1 line and dashed lines are +100% and -50% errorlines. The region between the two dashed lines is referred to as a region of trust by Ruth *et al.* **[11]** ("SS" stands for Sandstone and "Carb" stands for Carbonate samples)

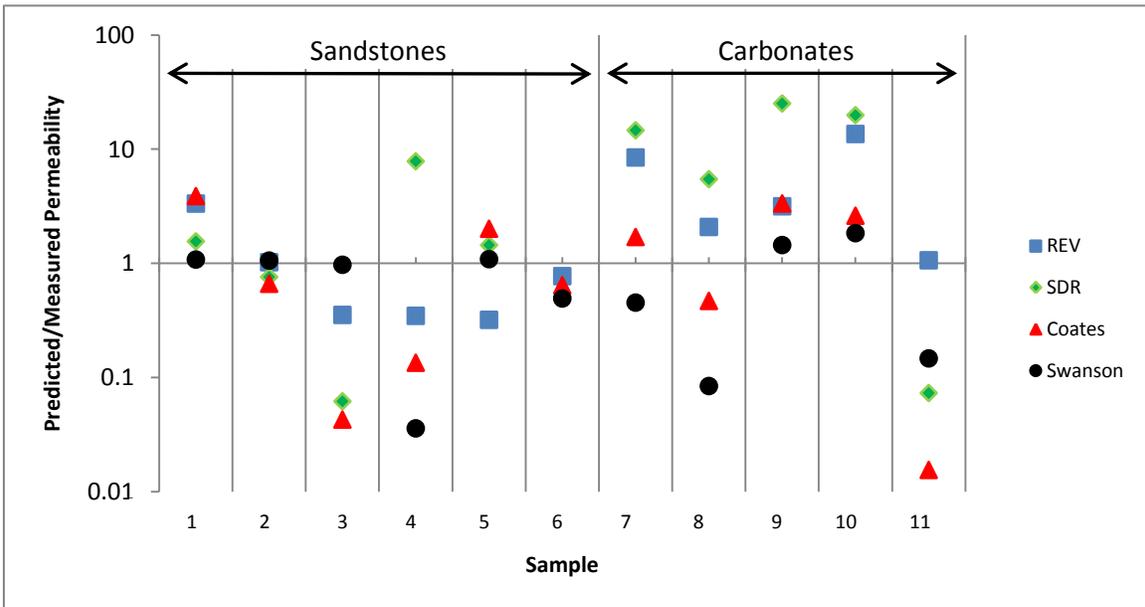**Figure 2** – Ratio of predicted to measured permebility comparison of the four methods