



Modelling of Relative Permeability from Fluid Substituted NMR T2 Distribution and Synthetic Capillary Pressure Data: An Innovative Technique in Carbonate

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Abstract

Understanding relative permeability in a hydrocarbon-bearing reservoir is a critical factor in production strategy planning and hydrocarbon recovery analysis. This is one of the crucial components for reservoir modelling studies and lifetime production assessments. Conventionally, research on relative permeability are performed in labs employing core samples. The true representation of reservoir characteristics through discrete sets of core data, on the other hand, is certainly debatable. Until now, predicting relative permeability at reservoir conditions has been a crucial problem that has proven to be challenging. In the last couple of decades, nuclear magnetic resonance (NMR) has been widely employed in the oil and gas exploration industry. However, it is often used mostly for evaluating porosity, permeability and water saturation. The NMR T2 distributions can be used to model the laboratory equivalent capillary pressure (P_c) curves, after the development of fluid substitution algorithm. This study presents a new methodology for constructing relative permeability curves from NMR T2 distribution using Fluid Substitution. The synthetic P_c derived from fluid-substituted NMR data appears to be comparable to capillary pressure curves derived from laboratory-based methods based on core data. Because the field is still in its early stages, validation using core data was not possible; once core data is accessible, additional validation will be required for model refinement. However, our results corroborate well with the results of exploratory well testing.

Introduction

In addition to reservoir permeability (derived from formation tester/NMR log), relative permeability is another dominating factor to describe the effective displacement or flow of different reservoir fluid phases in any reservoir. The information from the relative permeability curves are the major input in reservoir simulation. However, the determination of capillary pressure (P_c) data and relative permeability data are highly dependent on laboratory studies with cores. Till date core based relative permeability models have been used in the industry, which are expensive both in time and cost. Also, a small piece of core sample doesn't represent the entire reservoir heterogeneity, especially in heterogeneous reservoirs. On the other hand, in spite of having a worthy collection of NMR logs, its use is primarily confined for the evaluation of different kind of porosity distributions, permeability and water saturation in flushed zone. With the development of fluid substitution algorithms, core equivalent NMR logs can be generated. In our study we have done the statistical analysis of NMR data (Ilius and Singh, 2021) and then fluid substituted core equivalent T2 distributions and P_c curves have been generated. The P_c corresponding to identical facies have been used for the modeling of core independent relative permeability. The model of relative permeability helps us in understanding of flow behavior of wetting phase and non-wetting phase in exploratory wells of the carbonate reservoirs in Mumbai Offshore Basin (Figure 1). The first step is the identification of hydrocarbon components in NMR T2 distribution. The second step is NMR fluid substitution, which generates water substituted T2 distribution response, which can be compared with the laboratory NMR T2 data. Capillary curves has been generated from this new fluid-substituted NMR T2 distribution, corresponding to each poro-facies, which are equivalent to laboratory capillary data. After that, fluid substituted single phase capillary data has been used for the modelling of core equivalent relative permeability of wetting and non-wetting phases by numerical integration in MATLAB software. NMR derived water substituted P_c curves have been used for facies wise relative permeability modelling, which explains the flow



behaviors of the objects where testing results have been obtained in the exploratory wells. In current oil price scenario, to optimize the cost and time with promising accuracy the present model has been an extra aid in formation evaluation and reservoir characterization using only NMR data (Figure 2).

Geology of the study area

The area under our study is located in the southwestern part of Mumbai High (Figure 1). Deep Continental Shelf (DCS) is noticed towards further North of Diu fault whereas a carbonate platform is seen to its south. Prominent structural high trends/spurs radiating from Bombay High are seen in the study area. Wells drilled on these structures are commercially hydrocarbon bearing from multiple stratigraphic levels, dominantly carbonates of Early Miocene, Oligocene and Late to Middle Eocene age (Ratnagiri, Panvel, Heera, Mukta and Bassein) and to a lesser extent, in Eocene-Paleocene sands (Panna). The major hydrocarbon source rocks in the area west and NW of Bombay High are the Panna shales though some of the Oligocene shales also possess moderate to good source potential. Present study focuses on the accurate petrophysical evaluation of L-III in Ratnagiri formation.

Methodology

Fluid Substitution: The NMR T2 spectrum analysis on a water saturated rock sample is used in the lab to determine pore size distributions on core. The rock sample is drained to representative connate water saturation and the NMR T2 spectrum is re-measured to distinguish pores having free fluid from total porosity. There are no such controlled lab circumstances in the logging environment. To produce a pore size distribution of the logged formation, identify the free fluid section of the logged NMR T2 distribution and substitute reservoir fluid T2 values with water T2 values. Until date, working with log-derived data has been difficult due to the inclusion of numerous phases rather than just two. By substituting the hydrocarbon phase with a water phase, the fluid substitution algorithm (Ilius and Singh, 2021) enables for core-equivalent interpretations such as capillary pressures or grain-size characterization. With the developed fluid-substitution methodology, it is now possible to replace the hydrocarbon-phase with the water-phase and generate a synthetic NMR T2 distribution that is equivalent to the core-derived single-phase NMR T2 distribution (Figure 3a).

Capillary Pressure: Capillary pressure curve describes the capillary pressure required to obtain a given non-wetting phase saturation in a rock. T2 is related to specific surface area to pore volume ratio (S_{pv}) by the equation (Marschall, et al., 1995).

$$\frac{1}{T_2} = \rho * S_{pv} \quad (1)$$

By assuming the S_{pv} of a capillary tube as $S_{pv}=2/r$, equation can be written as the form of capillary pressure,

$$P_c = \frac{\sigma \cos \theta}{\rho_e * T_2} \quad (2)$$

In practical applications using NMR T2 depth log, the T2 and Pc can be correlated by a function known as scaling constant “ κ ” by the equation (Thungsuntonkhun and Engler, 2004),

$$T_2 * P_c = \kappa = \frac{\sigma \cos \theta}{\rho_e} \quad (3)$$

Where, P_c is the capillary pressure curve, σ is the surface tension, θ is the contact angle between the fluid interface and the pore wall, r is the radius of the tube (pore throat), ρ is the surface relaxivity, ρ_e is the effective surface relaxivity. The capillary pressure curves obtained for particular rock-type or facies should be free from hydrocarbon effects. With the application of fluid substitution, it is now possible to generate capillary pressure curves for each facies from NMR depth log, comparable to the results generated from core data (Figure 3b). Due to the absence of MICP data for the current study zone, the reference of “ κ ” has been taken from the comparable formation reported in the nearby area.

Relative Permeability: In this step, the capillary pressure curve (derived from the fluid substituted NMR log as described above) has been taken as the input for the computation of relative permeability. From the previous step it has been well explained that different poro-fluid facies will give different capillary pressure curve (P_c). So, according to the presence of the facies, the distinct P_c has been used for the generation of relative permeability curve. The correlation of estimating wetting phase relative permeability from capillary pressure data is expressed as the equation (Brooks & Corey, 1964):

$$K_{rw} = Se \frac{\int_0^{Se} \frac{dSe}{P_c^2}}{\int_0^1 \frac{dSe}{P_c^2}} \quad (4)$$

Similarly, for the non-wetting phase the equation modifies as:

$$K_{rnw} = (1 - Se)^2 \frac{\int_{Se}^1 \frac{dSe}{P_c^2}}{\int_0^1 \frac{dSe}{P_c^2}} \quad (5)$$

Where, $Se = \frac{(Sw - Sw_{ir})}{(1 - Sw_{ir})}$; Sw and Sw_{ir} are water saturation and irreducible water Saturation respectively (obtained from log evaluation and capillary curve, respectively).

After plotting the Se with P_c , it has been seen that different models showed that rational function and power function are associated with the lowest sum squared error (SSE). In our case study best correlation has been obtained with the rational function as,

$$P_c = \frac{a}{b + Se} \quad (6)$$

We have used the MATLAB2020 for the evaluation of a and b . Accordingly, the functional form of capillary pressure curve for each facie interval corresponding to hydrocarbon bearing zones have been integrated to generate water and hydrocarbon relative permeability curves (Figure 3c and 3d).

Results and Discussion

After generation of synthetic P_c curves from NMR data, water and hydrocarbon relative permeability curves have been synthesized by using Eq. (4, 5 & 6). While examining different fitting models, rational function has been most successfully fitted via the MATLAB curve fitting toolbox. However, we have tried other models such as exponential, power, hyperbolic, logistic or Harris functions to find the best fitting curve to P_c data. Finally, in MATLAB, the integration has been performed with the rational function to generate relative permeability data. The fitting function parameters ' a ' and ' b ' are different with respect to different facies i.e., for different depth intervals. For each depth point the integration has been performed by MATLAB codes to generate relative permeability. For example, few results are discussed as follows.

In Well-X, two objects were proposed for production testing by keeping conventional saturation and porosity cut offs. After performing the computation of ' a ' and ' b ' by curve fitting, integration has been performed for the objects in MATLAB to get the relative permeability curve. The point to be noted that the relative permeability curves have been generated for the entire interval of the reservoirs (including testing/ perforated interval). Hence, we have obtained the relative permeability curves for the entire range of water saturation (i.e., starting from lowest Sw to highest Sw). It has been assumed in our study that the reservoir rock as water wet and the migrated hydrocarbon displaced the initial formation water.

It has been observed that in object-I, the interpreted water saturation ranges from 0.4-0.8 in the entire perforated interval. From the computed output of the relative permeability (Figure 4a and 4b), it is clearly observed that the free fluid volume of non-wetting phase (i.e., hydrocarbon) and its flow ability is dominating over the wetting phase (i.e., water) in the mentioned range of water saturation. In other word we can say that, the relative permeability of water (K_{rw} , wetting phase) is less than the relative permeability of non-wetting (K_{rnw}) hydrocarbon phase in the perforated interval. During production testing of this zone, it was found that Object-I majorly flowed oil i.e., 330 BPD (bbl per day) with little water (40 BPD), as we indicated from the nature of relative permeability curves.



Similarly, in object-II, the interpreted water saturation ranges from 0.65-0.9 in the entire perforated interval. In the relative permeability curve for the interval, it is clearly indicating that the wetting phase (i.e., water) is showing major contribution in the relative permeability against the range of water saturation of the object (Figure 4c and 4d). During production testing, the object flowed 70 BPD of oil with nearly 300 BPD of water. Because for this, object the S_w 75% cut off would have been enough for optimised testing interval with reduced water cut. Which is well explained from the relative permeability curves.

Conclusions

The results of this study has shown that through performing the advance statistical analysis and some numerical modelling on the NMR log data, a lot of information can be achieved. In this paper, a novel workflow has been proposed to generate the synthetic capillary pressure curve and relative permeability curve corresponding to different poro-facies after the water substitution to the T2 distribution. After getting proper identification of poro-facies, the numerical integration has been performed with the saturation and capillary pressure data. The optimised best-fit functions and constants have been evaluated using MATLAB. According to the results and the outcome of the study, it has been concluded that the facies-wise P_c and relative permeability curve generation gives a promising framework in characterization of carbonate reservoir. The notable feature of the proposed methodology is the cost effectiveness, speed and the robust nature of the computation. The indication of relative permeability of different fluid phases at in situ conditions is definitely helpful not only for the exploratory wells but also for the planning of the field development. The workflow may be adopted for the optimization of testing intervals and petrophysical cut off (S_w) for less water cut during flow measurements in heterogeneous carbonate formation.

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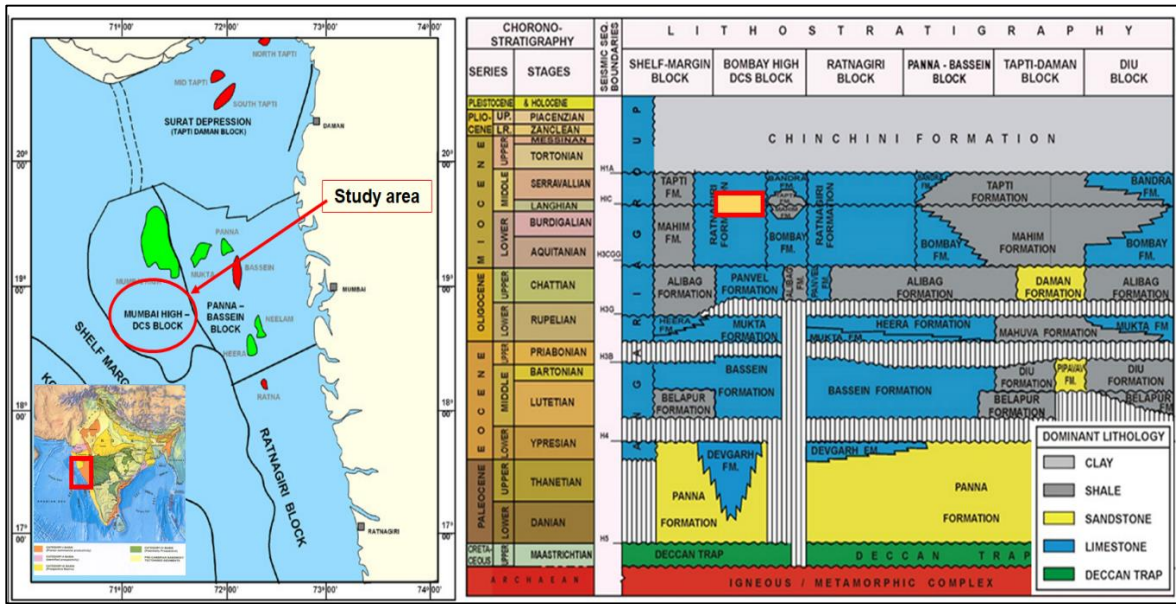


Figure 1: Location of study area and generalized stratigraphy of the Bombay-Cambay-Kutch area (adapted from National data repository, DGH, Government of India, open source, 2022). The yellow box mark highlights the stratigraphic zone of interest in this work.

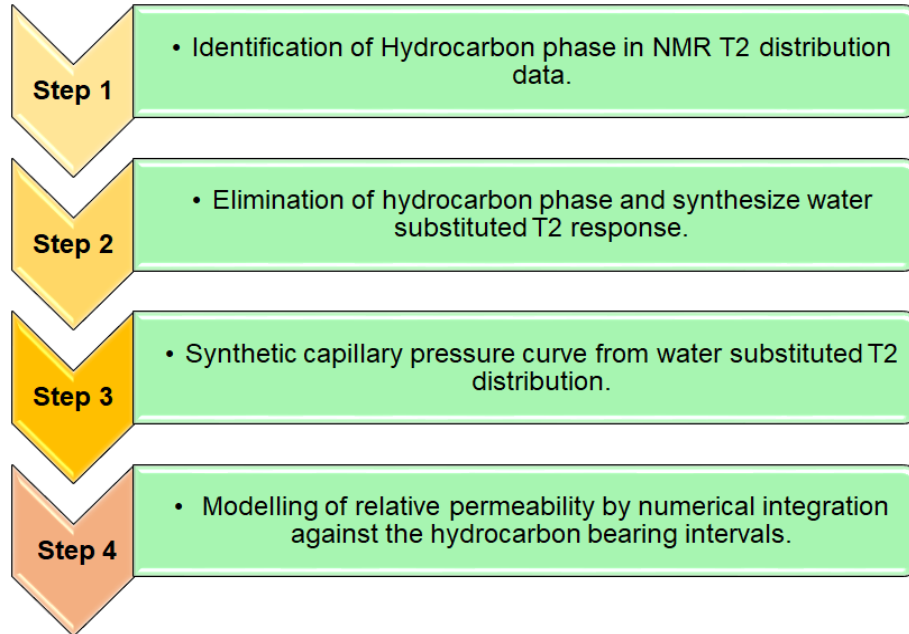


Figure 2: Flow chart of methodology developed for core independent relative permeability modelling.

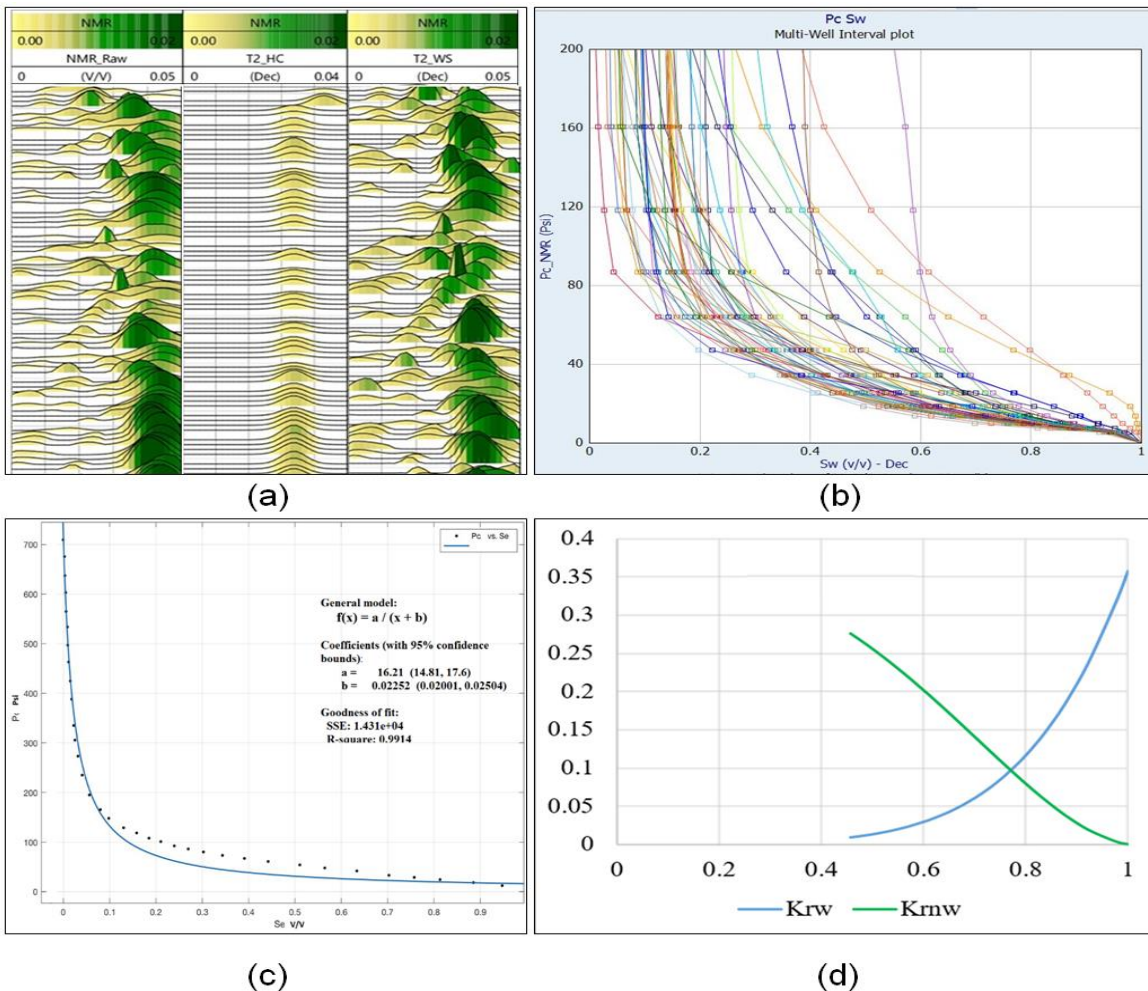


Figure 3: (a) Raw NMR T2 distribution (NMR Raw data: 1st track), T2 distribution corresponding to

Hydrocarbon (T2_HC: 2nd track) and water substituted T2 distribution (T2_WS: 3rd track); (b) Capillary pressure curve computed from water substituted T2 distribution; (c) Curve fitting in MATLAB with rational function and the computation of fitting parameters a and b against one Pc as an example (d) Modelled relative permeability curve corresponding to one interval with different Capillary curves (core data unavailable for validation).

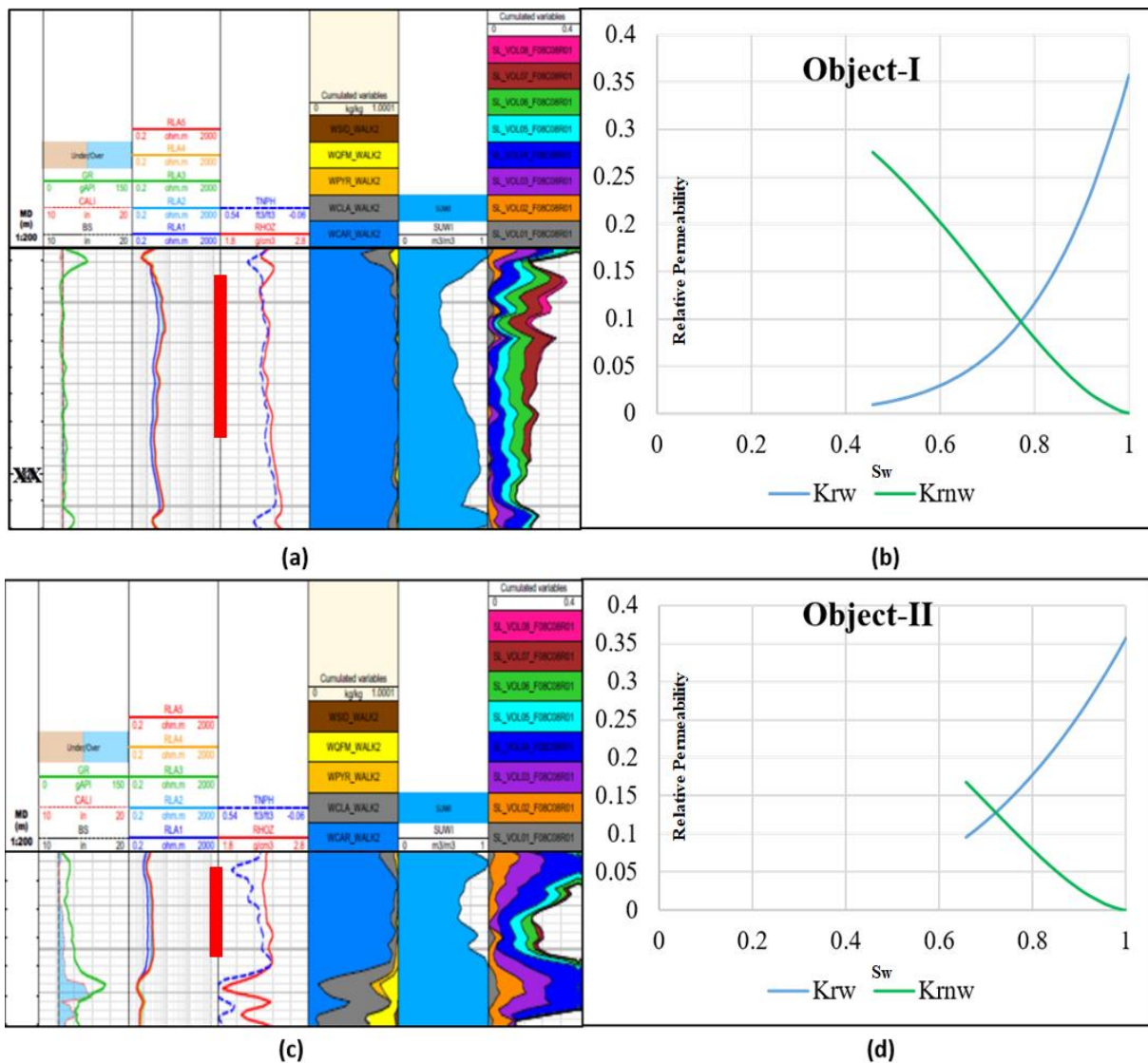


Figure 4: (a) Composite plot with NMR porosity bins and (b) Computed Relative Permeability against Object I; (c) Composite plot with NMR porosity bins and (d) Computed Relative Permeability against Object II of Well: X, (Perforated Objects are indicated as red boxes).