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Full Length Article

A novel estimation method for capillary pressure curves based on routine core analysis data using artificial neural networks optimized by Cuckoo algorithm – A case study

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ABSTRACT

Capillary pressure is one of the most important parameters affecting fluids distribution in a reservoir rock and is an essential input parameter for reservoir simulation. Measurement of capillary pressure data, in the context of special core analysis (SCAL) is a time and cost consuming process that does not often lead to accurate and reliable results. Routine core analysis (RCAL) data, on the other hand, can be obtained by simple, accurate, and cost-effective procedures. In this paper, the idea of using RCAL measurements to predict SCAL data (more specifically capillary pressure data) using Artificial Neural Network (ANN) approach is presented. An ANN with Multi-Linear Perceptron structure and feed-forward propagation was used to predict capillary pressure curves for a target reservoir under study. The ANN model was then optimized by Cuckoo optimization algorithm (COA). The ANN-COA model was used for 30 measurements, composed of both drainage and imbibition data points obtained from 15 core samples using centrifugation method. Out of this databank, 16 measurements were used for training and the remaining 14 measurements were used as the testing dataset. It was obtained that the optimized model shows a profound predicting performance based on the excellent value of coefficient of determination for predicted versus measured capillary pressure data.

1. Introduction

Proper characterization of reservoir rocks and demonstration of rock-fluid interaction needs accurate determination of reservoir rock properties. Porosity and permeability are the two most essential properties of reservoir rocks, and their measurement technique(s) could be considered as the simplest way of rock characterization [2,10]. However, capillary pressure and relative permeability govern fluid flow in porous media and are absolutely essential for predicting fluids distribution in a reservoir [20]. There are several methods to measure capillary pressure in lab such as centrifugation and mercury injection using core plug samples. There are also several models in the literature to predict capillary pressure data for a given rock-fluid system such as Leverett J-function [45] and the model proposed by Thomeer [46], Brooks and Corey [47], Bentsen and Anli [48] and Alpak et al. [49]. All these models were validated against experimental data. Capillary pressure measurement tests at the lab-scale are not very convenient tests to do: the tests are time consuming and expensive; the number of core plugs available for the SCAL tests are limited and even the available samples are not guaranteed to be extracted from the entire lithological and petrophysical spectrum of the formation. Therefore, the models developed for capillary pressure prediction could not be considered universal especially for heterogeneous formations in which their application could yield to erroneous predictions. Therefore, challenges toward modelling and prediction of capillary pressure data still exist [5,18,44].

Capillary pressure is a rock-fluid related property; therefore, a model for predicting capillary pressure data should contain both rock and fluid properties. Earlier models for capillary pressure prediction have been mainly developed for averaging, filling the data gaps, and proposing a universal formulation for a specified rock type [45–49]. J-function is known as the simplest function for capillary pressure

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Nomenclature

$P_{c,go}$	gas-oil capillary pressure
S_o^*	normalized oil saturation
S_o	oil saturation
S_{or}	residual oil saturation
$P_{d,go}$	threshold pressure
λ	pore size distribution index
$(V_b)_{P_c}$	fractional volumes occupied at P_c
$(V_b)_{P_\infty}$	volumes occupied at P_∞
F_g	pore geometrical factor
S_w^*	normalized water saturation
FZI	Flow Zone Index
P_c	Capillary pressure
P_d	displacement pressure
S_{wr}	irreducible water saturation
F_s	shape factor
τ	tortuosity factor
S_{gv}	surface area
$J(S_w)$	Leverett J-function for capillary pressure
J^*	Lithology index
ψ	Constant in Eq. (8)
σ	Interfacial tension
φ	Porosity
$Pc_{(r)}$	Capillary pressure at each step
r	Distance from the center of rotation
r_e	Distance from the core outlet face
$\Delta\rho$	Density difference
ω	Rate of rotation
var_{hi}	Upper limits for the variables
var_{low}	Lower limits for the variables
φ	deviation
k_{air}	Permeability to air
k_w	Permeability to water
k_o	Permeability to oil
ρ_{grain}	Grain Density
$S_{w,irr}$	irreducible water saturation

prediction, which correlates porosity, permeability, interfacial tension, and capillary pressure at any fixed level of water saturation. The idea behind proposing J-function was to generalize a function for correlating rock and fluid properties. In other words, it was intended to propose a model capable of predicting capillary pressure curves for any reservoir rock and fluid type. However, it is accepted that J-function is not generally applicable for all reservoir situations when reservoir rock and fluids properties vary [59].

Corey (1954) developed a model based on gas-oil capillary pressure data, using a straight-line relationship between squared inverse of the capillary pressure and normalized oil saturation [50]:

$$\frac{1}{P_{c,go}^2} = CS_o^* \tag{1}$$

Where $P_{c,go}$ is gas-oil capillary pressure, S_o^* is normalized oil saturation and is calculated by Eq. (2), and C is a constant;

$$S_o^* = \frac{S_o - S_{or}}{1 - S_{or}} \tag{2}$$

where S_o is oil saturation and S_{or} is residual oil saturation.

Brooks and Corey [47] modified the Corey's model [50] as follows:

$$P_{c,go} = P_{d,go}(S_o^*)^{1/\lambda} \tag{3}$$

where S_o^* is normalized oil saturation that can be calculated from Eq. (2), $P_{d,go}$ is threshold pressure, i.e. the pressure at which gas enters the pores and displaces the oil out, λ is the pore size distribution index independently measured through experimental tests with the typical value of 0.4–4 [17]. The Brooks-Corey model presented above is widely used in the literature for consolidated porous media.

Considering the above equations, the attempts toward further modifications were pointed toward factors that can affect the capillary pressure curves but were not included in the initial correlations such as pore size distribution of rock. Thomeer (1960) conducted several mercury injection tests and suggested the following form of equation for capillary pressure prediction with inclusion of a pore geometrical factor [46];

$$\log P_c = \frac{-F_g}{(\log(V_b)_{P_c} - \log(V_b)_{P_\infty})} + \log P_d \tag{4}$$

where $(V_b)_{P_c}$ and $(V_b)_{P_\infty}$ are the fractional volumes occupied by mercury at P_c and P_∞, respectively, and F_g is the pore geometrical factor representing the shape of capillary pressure curve. The parameter $(V_b)_{P_c}$ can be obtained by multiplying porosity by hydrocarbon saturation whereas $(V_b)_{P_\infty}$ is essentially equal to porosity.

In 1980, Van Genuchten proposed a capillary pressure model as follows [51]:

$$S_w^* = [1 + (aP_c)^n]^{-c} \tag{5}$$

where S_w^* is normalized water saturation, a, n and c are constants that should be determined for any specific rock type. For the case of unconsolidated rocks, Van Genuchten model have been repeatedly used in the literature.

A modification to the J-function relationship was proposed by Amaefule et al. (1993) in which the effect of surface area was considered. The general format of Amaefule's equation with introduction of the new concept of Flow Zone Index (FZI) is presented below [52]:

$$\ln\frac{P_c}{P_d} = \frac{\ln S_w^*}{S_{wr}(FZI_{min} - FZI)} \tag{6}$$

where P_d is displacement pressure, $S_w{}^*$ is normalized water saturation, S_{wr} is irreducible water saturation, and FZI is calculated as follows:

$$FZI = \left(\frac{1}{\sqrt{F_s}\,\tau S_{gv}}\right) \tag{7}$$

in which F_s is a shape factor, τ is tortuosity factor and S_{gv} is surface area per unit grain volume. There is an inverse relationship between FZI and water saturation in the pore structure. Experiencing a minimum value for FZI will direct the water saturation toward unity whereas a maximum value of FZI results in approaching water saturation to its irreducible value [52].

In 2003, the same approach of using Flow Zone Index was used by Desouky which resulted in a new form of equation for capillary pressure prediction [53]:

$$P_c = \psi\frac{S_w^{*-1/\lambda}}{\varnothing} \tag{8}$$

where:

$$J^*\cos\theta = \frac{\psi FZI}{\sigma} \tag{9}$$

$$J(S_w) = J^* S_w^{*-1/\lambda} \tag{10}$$

Other empirical, semi-empirical and theoretically-based predictive models for capillary pressure determination have also been developed over the years; however, their use is limited to specific rock types, and that some important factors have been ignored in developing these correlations which makes their application inaccurate when generalization of capillary pressure prediction is concerned. In some of these