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Fracture density estimation from core and conventional well logs data using artificial neural networks: The Cambro-Ordovician reservoir of Mesdar oil field, Algeria

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ABSTRACT

Fracture density estimation is an indisputable challenge in fractured reservoir characterization. Traditional techniques of fracture characterization from core data are costly, time consuming, and difficult to use for any extrapolation to non-cored wells. The aim of this paper is to construct a model able to predict fracture density from conventional well logs calibrated to core data by using artificial neural networks (ANNs). This technique was tested in the Cambro-Ordovician clastic reservoir from Mesdar oil field (Saharan platform, Algeria). For this purpose, 170 cores (2120.14 m) from 17 unoriented wells have been studied in detail. Seven training algorithms and eight neuronal network architectures were tested.

The best architecture is a four layered [6-16-3-1] network model with: a six-neuron input layer (Gamma ray, Sonic interval transit time, Caliper, Neutron porosity, Bulk density logs and core depth), two hidden layers; the first hidden layer has 16 neurons, the second one has three neurons. And a one-neuron output layer (fracture density). The results based on 8094 data points from 13 wells show the excellent prediction ability of the conjugate gradient descent (CGD) training algorithm (*R*-squared = 0.812).The cross plot of measured and predicted values of fracture density shows a very high coefficient of determination of 0.848. Our studies have demonstrated a good agreement between our neural network model prediction and core fracture measurements. The results are promising and can be easily extended in other similar neighboring naturally fractured reservoirs.

1. Introduction

Naturally fractured reservoirs (NFRs) represent a significant percentage of oil and gas reservoirs throughout the world and by definition they are very complex (Nelson, 1985; Ouenes, 2000; Kouider El Ouahed et al., 2003, 2005; Tran and Rahman, 2006; Jenkins et al., 2009; Darabi et al., 2010; Ja'fari et al., 2012). The challenges faced by geocientists and reservoir engineers when studying them are twofold. First, understanding the origin of the fracturing at a specific location; and secondly, to model the fracture network over an entire field (Zellou and Ouenes, 2001). According to Jenkins et al. (2009), fractured reservoir models used to generate field development plans and assist the field management need to accurately integrate the effects of natural fractures in the near-wellbore regions on the fluid flow and also to predict their distribution in the inter-well space. Initially, the naturally fractured reservoirs were initially homogeneous and became fractured under certain circumstances of rock deformation and/or physical diagenesis (Nelson, 1985; Kouider El Ouahed et al., 2003; Ja'fari et al., 2012). If related to brittle failure, fracture was probably initially open, but may have been subsequently altered or mineralized. If related to more ductile failure, it may exist as a band of highly deformed rock. As a result, natural reservoir fractures may have either a positive or negative effect on fluid flow within the rock (Nelson, 1985). The word "fracture" has been defined in various ways. Some definitions are purely descriptive, while others are mechanical. This term is used as a collective term representing any series of discontinuities features in rocks such as joints, faults, and fissures and/or bedding planes (Martinez-Torres, 2002). Natural fracture systems can be identified and evaluated by several techniques. The most common ones are the analysis of core data, petrophysical evaluation of the reservoir and pressure transient analysis. According to Martinez-Torres (2002), the disadvantage of core analysis is the difficulty in assessing the representativeness of the core plugs, the original geometry of the fractures which of practical significance is often lost in the process of recovery. And finally, core analysis is costly, intensive labor and subject to the availability of drilled rocks.

This paper presents an approach for fracture density estimation based on artificial neural networks (ANNs). The developed ANN model is able to predict fracture density estimation by using conventional well log data. The proposed fracture density estimation

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is simple to integrate 3D reservoir models and the results obtained from the model are accurate. The Cambro-Ordovician reservoir in Mesdar oil field in Algerian Saharan platform is used as an example (Fig. 1) and comparison between the results predicted by this method and those observed by the common core analysis are presented.

1.1. Literature review

The artificial neural networks (ANNs) were introduced in the late fifties by Rosenblatt (1962). The application of artificial intelligence (AI) tools such as fuzzy logic (FL) and artificial neural networks (ANNs) is evolving as an oil field technology. In the last few years, several studies have been conducted in the field of petroleum engineering by applying artificial intelligence (AI). From the 1990s, artificial neural networks were used to assist in solving some fundamental petroleum engineering problems, such as formation permeability prediction from geophysical well log responses with accuracy comparable to actual core analysis and well test interpretations (Mohaghegh and Ameri, 1995; Nivranesh, 2004). Methods relying on self-organizing maps (Baldwin et al., 1990) and back-propagation feed-forward neural networks were introduced for the estimation of lithology from logs (Rogers et al., 1992). These authors used Gamma Ray, Neutron, and Density logs as input variables to predict a four-mineral lithology proportion (shale, sandstone, limestone, and dolomite). Wiener (1991) used as input five logs (Shallow laterolog, Deep laterolog, Sonic interval transit time, Neutron porosity and Bulk density logs), plus computed porosity, water saturation and bulk volume of water to predict permeabilities logs. Al-Kaabi and Lee (1993) and Juniardi and Ershaghi (1993) have presented a new approach to identify a preliminary well test interpretation model from derivative plot data based on artificial neural networks technology. Ouenes et al. (1995), proposed a new approach using a neural network to find the relationship between, reservoir structure, bed thickness and the well performance which were used as an indicator of fracture intensity. Since, many studies by different authors have been carried out in several domains using the artificial intelligence tool, such as fractured reservoir characterization (Richardson and Weiss, 1995; Zellou et al., 1995; Basinski et al., 1997; Ouenes et al., 1998; Barman et al., 2000; Gauthier et al., 2000; Ouenes, 2000; Ouenes and Hartley, 2000; Sadiq and Nashawi, 2000; Eduardo et al., 2001; Zellou and Ouenes, 2001; Martinez-Torres, 2002; Malallah and Nashawi, 2005; Tran and Rahman, 2006; Jenkins et al., 2009; Sarkheil et al., 2009; Darabi et al., 2010; Tokhmchi et al., 2010; Gholizadeh Doonechaly and Rahman, 2012; Ja'fari et al., 2012; Jafari and Babadagli, 2012).

2. Geological background

2.1. Geological setting

The Mesdar field is located in the north central of the Saharan Platform, about 100 km southeast of the giant Hassi Messaoud

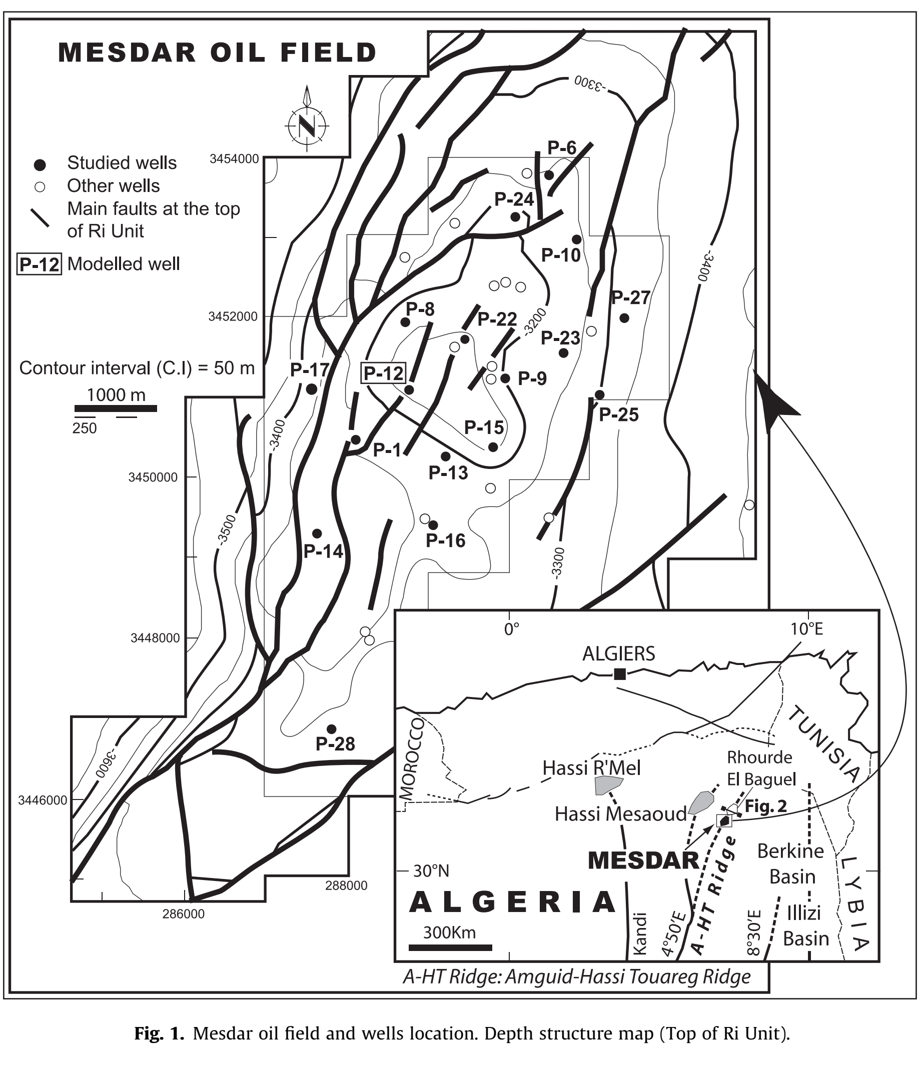

Fig. 1. Mesdar oil field and wells location. Depth structure map (Top of Ri Unit).