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The effect of heterogeneity on NMR derived capillary pressure curves, case study of Dariyan tight carbonate reservoir in the central Persian Gulf

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ABSTRACT

The porous network controls the behavior of fluids in the reservoir rocks. In carbonate reservoirs fluid flow characteristics do not certainly follow initial sedimentary fabrics. Therefore in these reservoirs, the properties of the porous network should be used in determining the facies. In this study, using a combination of petrographic, reservoir petrophysical and reservoir engineering data, porous network in Aptian-Albian Dariyan carbonates have been studied in one of the central Persian Gulf fields. Accordingly, four pore facies were determined by capillary pressure curves from mercury injection and nuclear magnetic resonance data in four different types of lithology with different microfacies. Also, 13 different petrophysical parameters of these curves derived from both methods and compared with each other. A clear trend was observed in reducing the reservoir quality from pore facies 1 to pore facies 4. The performance of the capillary pressure curves obtained from mercury injection and nuclear magnetic resonance and their derived parameters in 4 facies and the effect of lithology on these curves have been investigated. Results showed that the porosity of the NMR is completely independent of lithology and complexity of the porous system, while the permeability-dependent parameters are largely influenced by both lithology and pore system structure. It was also shown that the NMR curves are a suitable tool for determining the pore facies and their petrophysical parameters in homogeneous tight carbonate lithology with a simple porous system.

1. Introduction

In exploration studies of hydrocarbon reservoirs, petrophysical properties of the reservoir is of particular importance. Considering many studies in the field of carbonate reservoirs, there are still major challenges in identifying many parameters which their misunderstanding will have harmful and irreversible consequences for the oil industry. Since carbonate reservoirs are intrinsically heterogeneous and complex, their study requires careful attention (Mazzullo and Chilingrian, 1992; Shedid and Almehadiab, 2002; Asgari and Sobhi, 2006; Chenjei et al., 2015). Microporosity may account for a significant part of the total porosity of Cretaceous limestone reservoirs of the Middle East (Devile de Periere et al., 2011; Tavakoli and Jamalian, 2018). Different study methods are applied to dense reservoirs than conventional once. The determination of facies in reservoir studies is aimed at classifying the reservoir rocks into groups of different reservoir qualities (Archie, 1952; Coates et al., 1999; Rahimpour-Bonab and Aliakbardoust, 2014; Abdolmaleki et al., 2016; Tavakoli, 2018). The complex system of free space in carbonate rocks is the result of geological processes that can be the main reason for ambiguity in fluid behavior (Anselmetii and Eberli, 1999; Assefa et al., 2003; Eberli et al., 2003; Beachle et al., 2004). Pore facies are groups of reservoir rocks, each representing a different pore structure, and the difference in pore structure, the ability to store and direct the reservoir fluids, or in general, the quality of the reservoir rocks is different in these facies (Jensen et al., 2007; Chehrazi et al., 2011; Rahimpour-Bonab and Aliakbardoust, 2014). Pore facies analysis is a new generation of facies identification method in the reservoir rocks for better classification and evaluation, which is particularly useful in carbonate rocks where the porosity network is complex. Considering this fact, determining the pore facies and studying their distribution pattern to help identify the distribution of pore spaces, pore-throat radius, and reservoir zonation is one of the most important aspects of reservoir evaluation. Parameters such as pore-throat geometry, porosity network properties, porosity type and permeability can be used to determine the pore facies (Chehrazi et al., 2011; Aliakbardoust and Rahimpour-Bonab, 2013; Rahimpour-Bonab and Aliakbardoust, 2014; Xiao et al., 2016; Rabbiler, 2017). One of the most important, fast and convenient methods to examine the system of pore spaces and its distribution in reservoir rocks is mercury injection capillary pressure (MICP) tests. Evaluation of the

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MICP results is one of the most effective methods with high ability in measuring geometry of pore spaces, pore-throat size distribution (PTSD), pore-throat sorting (PTS) and connection of pore spaces (Purcell, 1949; Dullien and Dhawan, 1974; Wardlaw, 1976; Schowalter, 1979; van Brakel et al., 1981; Wardlaw and McKellar, 1981; Jennings, 1987; Krause et al., 1987; Kopaska-Merkel and Friedman, 1989; Melas and Friedman, 1992; Hollis et al., 2010; Skalinski and Kenter, 2013; Xu and Torres-Verdin, 2013; Rahimpour-Bonab and Aliakbardoust, 2014).

Another way to explore the pore spaces is to use nuclear magnetic resonance (NMR) as a powerful tool for providing valuable information on the system of pore spaces structure (Bowers et al., 1995; Coates et al., 2000; Dunn et al., 2002; Xiao et al., 2016). From the NMR spectrum, a lot of information including total porosity, effective porosity, permeability, irreducible water saturation, pore space and pore space distribution are predictable (Xiao et al., 2016). Another advantage of this method is the independence of NMR derived porosity from mineralogy, because it is only able to observe the fluids (Volokitin et al., 1999). In order to quantitatively measure the pore space from the NMR log, the distribution of transverse relaxation T_2 must first be converted to the PC curve, and then convert to the pore-throat radius by linear function. In recent years, several methods have been proposed for constructing PC curves from the NMR log (Altunbay et al., 2001; Glorioso et al., 2003; Green et al., 2008; Hamada, 2009; Shao et al., 2009; Kuang et al., 2010; Olubunmi and Chike, 2011; Xiao et al., 2016; Eslami et al., 2013; Xiao et al., 2016). Considering the high abilities of these two powerful tools, MICP and NMR which accurately determine the available pore space and its structure, they can provide very interesting results for determining the pore facies of the rocks. In this study, after constructing PC-SW (pseudo-capillary) curves from the NMR data, pore facies are determined in a drilled well in Dariyan Cretaceous carbonates reservoir in the Persian Gulf basin. The designated pore facies are compared with each other to classifying the facies in terms of reservoir quality.

2. Geological setting

During Paleozoic, the entire Arabian platform, Persian Gulf, southwestern Iran and central Iran were covered by shallow seas (Alsharhan and Nairn, 1997; Sharland et al., 2001; Alavi, 2004; Mehrabi et al., 2016; Tavakoli et al., 2018). Gray and organic-rich shales were dominate deposits during the Silurian period in almost the entire Persian Gulf basin which is considered as a source rock in this region (Aali et al., 2006). During the Mesozoic, climate change caused deposition of mixing sequences composed of source rock, reservoir rock and cap rock (Alsharhan and Nairn, 1997). In the Cretaceous of the Middle East, there were two distinct phases in the geological evolution that reflect the tectonic history of this region (Alsharhan and Nairn, 1997). During the Early Cretaceous, the NE margin of Arabian Plate (including the Persian Gulf and Zagros area of Iran) was located in the southern hemisphere and is considered as a continental passive margin along the eastern flank of the Afro-Arabian continent situated along the southern margin of the Neo-Tethys Ocean (Marschall et al., 1995; Sharland et al., 2001; Alavi, 2004). At this time, the general depositional setting of the Persian Gulf was a shallow carbonate platform surrounding the intra-shelf basins (Mehrabi et al., 2015). Such intra-shelf basins were formed by thermal differential subsidence (Alsharhan and Nairn, 1993). The carbonate successions of the Dariyan Formation (equivalent to Shuaiba in Arabian territories) have developed on these shallow platforms during the Aptian (Droste, 2010; Maurer et al., 2013; Mehrabi et al., 2015; Naderi-Khujin et al., 2016b a; b). Dariyan Formation is mainly composed of limestone and some dolomite and shale. Geographical location of the studied field is shown in Fig. 1. In the Persian Gulf, Dariyan is bounded, at the lower and upper parts, by two lithostratigraphic units known as the Gadvan (marl and marly limestone) and Kazhdumi (shale) formations (Fig. 2), respectively. Previous studies have shown that microporosity forms a major part of the pores in the Dariyan Formation (Maurer et al., 2013; Ehrenberg et al., 2007; Mehrabi et al., 2015; Tavakoli and Jamalian, 2018).

3. Materials and methods

A total of 270 thin sections, 123 core plug samples, 46 mercury injection tests, scanning electron microscope (SEM) and set of NMR log were studied from the reservoir zone of one well in the Persian Gulf. Oil in this field is hosted by the Cretaceous tight limestone of the Dariyan (Aptian) Formation. All of samples were collected from Lower Dariyan (LD) and Upper Dariyan (UD) units from 1245 m to 1330 m. Thin sections petrography was based on modified Devile de Periere et al. (2011) classification system for carbonate textures. Plug samples from the reservoir intervals in studied well were subject to special tests. These tests include (1) capillary pressure analysis with mercury injection (starting pressure from 0.068 MPa up to 411.93 MPa) (2) permeability test at ambient conditions and (3) porosity determination with helium using Boyle's law. Also, porosity and permeability were extracted from NMR data (based on Coates et al., 1999).

In this study, capillary pressure constructed at first from T_{2}- decay (NMR data) and called pseudo-capillary pressure curves (Altunbay et al., 2001; Xiao et al., 2016). Then, various petrophysical parameters extracted from both pseudo-capillary pressure and MICP curves such as pore-throat size (PTSi) in different saturations, PTSD, PTS and height above free water level. Also, reservoir quality index and flow zone indicator calculated using permeability and porosity from NMR data. Then, 4 microfacies determined in reservoir based on Dunham classification scheme on thin sections. Finally, average parameters of MICP and pseudo-capillary compared with each other to show the accuracy of determined pore facies and petrophysical parameters using pseudo-capillary pressure curves.

4. Background information

Petrophysical information such as porosity, pore size distribution and permeability can be extracted from NMR transverse relaxation time measurements. Understanding the nature of NMR mechanism of porous fluids is very important for the proper application of NMR in formation evaluation. In simple terms, we are measuring the relaxation behavior of hydrogen nuclei (Coates et al., 1999). In most porous rock systems, there will be a continuous range of pore sizes, rather than several discrete classes. In fully brine saturated rocks, each pore size has a distinctive T_2 value. The NMR response to one pore size will have a distinct T_2 value and signal amplitude proportional to the amount of fluid contained in pores of that size. In water-wet rocks, relaxation of hydrogen protons in the water occupying the smallest pores occurs, because of interaction with the pore surfaces. Part of the T_2 distribution relates to water in pores which is displaced by hydrocarbons and the other part relates to capillary bound water. The T_2 cut-off method is often used to define capillary bound water volumes, the defaults for carbonates is 100 ms. Therefore, to use NMR logs to accurately define water saturations it is beneficial to convert the NMR T_2 distributions to capillary pressure curves and calculate the saturation at each given height above the free water level. According to the Altunbay et al. (2001) T2-distribution is valid when there is no diffusion coupling, the T2 distribution is not shifted by the presence of hydrocarbons and the T2 of bulk fluid is large enough to drop the term 1/T2 bulk (Eq. (1)).

4.1. Relationship between capillary pressure and T_2

The equation for the T_2-decay phenomena for spin-spin relaxation can be written as follows: