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Research paper

Assessment of miscible light-hydrocarbon-injection recovery efficiency in Bakken shale formation using wireline-log-derived indices

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ABSTRACT

High original oil-in-place estimates accompanied by low primary recovery potential of organic-rich shale formations make them suitable candidates for enhanced oil recovery (EOR) projects. The organic-rich shale formation under investigation in this paper is the Bakken shale formation that exhibits significant variations in lithology, rock texture, clay content, porosity, and total organic carbon (TOC). Three wireline-log-derived EOR-efficiency indices are generated across the 200-feet-thick Upper, Middle, and Lower Bakken formations to identify flow units suitable for EOR using light, miscible hydrocarbon injection.

R-index is one of the three EOR-efficiency indices. R-index is calculated using kerogen content, water saturation, permeability, principal pore throat diameter, and porosity. Microscopic Displacement (MD) Index computes the microscopic displacement efficiency for the miscible gas injection. An important step in computing MD-index is to decompose NMR T2 distribution at each depth using factor analysis to compute the free oil, movable water, and bound fluid volumes. Moreover, the MD-index accounts for the effect of pore confinement on miscible oil volume and the effect kerogen content on the displacement efficiency. MD-index relies on a novel method to calculate the miscible free-oil volume from subsurface NMR T2-distribution logs. Lastly, k-means clustering method was used to generate the third index, referred as the KC-index, which is in the form of a step-wise curve. KC-index partitions the entire formation into four groups, representing miscible-gas-injection recovery potentials at discrete levels. The method uses water saturation, porosity, permeability, bound fluid volume, and principal pore throat diameter derived from various logs.

The proposed log-derived EOR-efficiency indices generate consistent predictions of miscible light-hydrocarbon injection performance in the Bakken shale formation at various resolutions. Indices indicate that several formation zones in the middle section of the formation will have much higher recovery potential in comparison to the upper and lower sections of the formation. At a resolution of 1-foot depth interval, several flow units were successfully identified in the middle section that exhibit high miscible-gas-injection recovery potential.

1. Introduction

1.1. Geology

The 200-feet-thick Bakken formation under investigation consists of three distinct members: upper, middle, and lower sections. Bakken shale formation is a three-member succession including an upper black shale, a middle sandy siltstone, and a lower black shale that underlies large areas of northwestern North Dakota, northeastern Montana, southern Saskatchewan and southwestern Manitoba (Han et al., 2017). Upper and Lower Bakken formations are hydrocarbon source rocks with the similar depositional condition. These two formations are organic-rich with total organic carbon ranging from 12 to 36 wt percent. The clay mineral content is dominated by illite and quartz. The Middle Bakken is the hydrocarbon-bearing reservoir and has a low TOC content ranging from 0.1 to 0.3 wt%. Three Forks formation is a dolostone interbedded with clay-rich conglomeratic dolo-mudstone. The formation is characterized by ultralow matrix permeability, which makes it difficult to mobilize oil in the matrix (Han and Misra, 2017). Current recovery factor in Bakken shale formation is around 3%–6% of the oil in place (Hawthorne et al., 2013). High oil-in-place estimates with low primary recovery mandates EOR projects based on light, miscible hydrocarbon injection.

1.2. Overview

Due to the ultra-low permeability and porosity, the mechanism of EOR in tight reservoirs is different from conventional reservoir. In tight

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oil formation, the EOR efficiency may be controlled by a combined mechanism of diffusion, sorption, dissolution etc., and diffusion is considered the primary mechanism (Sorensen et al., 2015). Large permeability contrast between matrix and fracture leads to fracture-dominated flow in the Bakken formation. A displacement process generally includes 4 processes in a tight formation: (1) injected gas flow through fractures, (2) injected gas goes into matrix by diffusion, (3) oil from matrix migrates to fractures via swelling and reduced viscosity, and (4) injected gas achieves equalization inside the matrix (Hawthorne et al., 2013). In this study, we describe the EOR efficiency in terms of processes 2 & 3. Many researchers have developed methods to rank/screen reservoirs for gas injections by setting criteria with corresponding weights (Taber et al., 1997; Thomas, 1998; Al-Adasani and Bai, 2010; Bourdarot and Ghedan, 2011). These methods give a reservoir higher score when a set of petrophysical/fluid properties reaches a threshold value. Rivas et al. (1994) developed a ranking characteristic parameter to overcome the 'binary characteristics' of conventional reservoir screening methods and applied the method to rank reservoirs for gas injection. Rivas et al. (1994) method has been subsequently used and modified by many researchers (Diaz et al., 1996; Shaw and Bachu, 2002; Zhang et al., 2015). Oil saturation index (OSI) is another important parameter that has been used to describe the potential producibility of shale formations. OSI is a simple geological normalization of oil content to TOC. In organic-rich source rock, kerogen has a strong affinity to oil. As much as 80 mg oil can be retained by 1 g of kerogen; thereby reducing the producibility of the formation (Jarvie, 2012). OSI requires laboratory measurements to compute the oil and TOC weight fractions. To overcome this requirement, carbon saturation index (CSI) and reservoir producibility index (RPI) were developed based entirely on the downhole logging tool measurements (Kausik et al., 2015). CSI is the weight ratio of carbon in light oil to TOC. The difference between OSI and CSI is that CSI relies only on light oil. RPI is formulated by multiplying the light oil content and CSI. Compared to CSI, RPI accounts for organic richness and can differentiate the reservoir qualities of organic-rich and organic-lean intervals (Kausik et al., 2015). Another approach to identify productive zones conducive to EOR was described by Li and Misra (2017a, 2017b).

1.3. Objectives

A wireline-log-based assessment of recovery potential of various flow units in the Bakken shale formation will facilitate efficient reservoir development plans and coring projects. To that end, we develop three log-based EOR indices, namely the Ranking (R) Index, Microscopic Displacement (MD) Index, and K-means Clustering (KC) Index. R-index is a modification of Rivas et al.'s (1994) reservoir ranking method and implements Jin et al.'s (2016a) findings from the laboratory investigation of miscible-gas injection. On the other hand, MD-index quantitatively compares negative and positive factors for miscible gas injection as a fraction. MD-index involves a novel method to calculate the volume of free miscible oil in presence of pore confinement effect. Factor analysis decomposes NMR T2 signal to factors representing different pore fluids. Pore fluid signatures obtained through factor analysis are then classified as free oil, movable water, and bound fluids. Finally, KC-index can be generated to further improve the assessment of EOR efficiency of various flow units. We applied the three indices to Upper, Middle, and Lower Bakken formation to identify the flow units suitable for EOR projects using miscible light-hydrocarbon injection.

2. Parameters influencing EOR efficiency when using miscible gas injection

The displacement efficiency during miscible gas injection is affected by several parameters, such as minimum miscibility pressure (MMP), pore structure, oil composition, gas composition, fractures, and formation dip. MMP is an important parameter governing the proposed EOR efficiency. MMP is the lowest pressure required for connate oil and injected light hydrocarbon to achieve miscibility. When reservoir pressure is higher than MMP, the injected gas can achieve miscibility with reservoir oil resulting in viscosity reduction, oil swelling, interfacial tension reduction, and single-phase flow (Ling et al., 2014). In this study, we are interested in the portion of oil that can achieve miscibility during light hydrocarbon injection. Miscible oil is the portion of hydrocarbon that can achieve miscibility with the injected light hydrocarbon. On the other hand, movable oil relates to the hydrocarbon residing in pores that do not bind the hydrocarbon due to high capillary pressure or due to pore isolation (Ojha et al., 2017a).

EOR efficiency of fluid injection in shale formations using CO_2, light hydrocarbon (C1-C2) mixture, and N_2 have been investigated using laboratory core flooding and numerical modeling by Alharthy et al. (2015). Recovery factor using light hydrocarbon mixture as an injected gas is comparable to that using CO_2. N_2 has a relatively high MMP compared to light hydrocarbon mixture and CO_2. To achieve high EOR efficiency using N_2 gas injection, a higher reservoir pressure is required to maintain the miscibility. Jin et al. (2016b) observed that the oil recovery factor using N_2 as an injecting gas is much smaller than that using CO_2 and light hydrocarbon mixture.

Nanoscale pore sizes in shale formations (Ojha et al., 2017b) lead to a few differences between the miscible displacement mechanism in shales and that in conventional reservoirs. There exist several published research works investigating the mechanisms of miscible gas injection in tight oil formation. Due to the drastic permeability contrast between fractures and matrix, the injected gas prefer to flow through open fractures leaving behind a large portion of oil in the matrix. Alharthy et al. (2015) conclude that miscible mixing and solvent extraction near the fracture-matrix region is the primary oil mobilization mechanism of miscible gas injection. The injected gas mix with the oil in the matrix by molecular diffusion and advection instead of direct displacement of oil in the matrix (Fai-Yengo et al., 2014; Alharthy et al., 2015) during the displacement process. Using CO_2 bathing core experiments, Jin et al. (2016a) investigated the effects of formation parameters on miscible oil displacement. The experiments showed that two flow regimes can exist in organic-rich shale formations similar to the one under investigation (Dadmohammadi et al., 2017). Viscous flow exists in fractures, while molecular flow exists in the matrix.

Pore confinement effect on MMP cannot be neglected because the dominant pore size is at the nanoscale. Several studies have shown that the flow behavior on the nanoscale is significantly different from that on a larger scale (Wu et al., 2016, 2017). Fluid properties on nanopores differ greatly from bulk fluid, which means conventional calculation may not accurately describe the miscibility. The critical temperature and pressure for injected gas and reservoir oil decrease in nanopores (Adekunle and Hoffman, 2014); therefore, leading to a decreased MMP in nanopores during gas injection. Several methods have been proposed to calculate the MMP in nanopores (Ahmadi and Johns, 2011; Teklu et al., 2014a). An alternation of MMP due to pore confinement effect may result in miscibility difference for oil in pores as a function of pore size. Another factor is the volume content of bitumen, which is a non-producible soluble organic matter. Due to the large molecular size of bitumen and small pore throat size in the formation, the existence of bitumen may clog pores and inhibit oil flow. Furthermore, bitumen swells the kerogen and has smaller and more complicated pore structure (Reeder et al., 2016). At high water saturation, oil is surrounded by water in the pore; therefore, the sweep efficiency of miscible displacement is reduced (Rampersad et al., 1995). In this paper, we take both bitumen and water contents as negative factors for EOR using light-hydrocarbon injection.

Natural or induced fractures may pose two contrasting effects on oil recovery during gas injection EOR. On one hand, the presence of fracture enhances the mobilization of oil in the matrix by molecular diffusion. On the other hand, connected fracture system may result in low