Journal of Petroleum Science and Engineering 143 (2016) 171–186

Contents lists available at ScienceDirect

Journal of Petroleum Science and Engineering

journal homepage: www.elsevier.com/locate/petrol

Fracture-matrix interactions during immiscible three-phase flow

Mohamed Ahmed Elfeel [1,*], Adnan Al-Dhahli [2], Sebastian Geiger, Marinus I.J van Dijke

Institute of Petroleum Engineering, Heriot-Watt University, Edinburgh EH14 4AS, United Kingdom

ARTICLE INFO

Article history:
Received 23 December 2013
Received in revised form
3 December 2015
Accepted 16 February 2016
Available online 17 February 2016

Keywords:
Fracture-matrix transfer
WAG injection
Dual porosity
Three-phase flow

ABSTRACT

Naturally Fractured Reservoirs (NFR) contain a significant amount of remaining petroleum reserves and are now considered for Enhanced Oil Recovery (EOR) schemes that involve three-phase flow such as water-alternating-gas (WAG) injection. Reservoir simulation of three phase flow is challenging because a proper set of flow functions, i.e. relative permeability and capillary pressure functions, that describe the underlying physics of fluid displacement is vitally important to obtain reliable production forecasts but associated with high uncertainty. For NFR, another challenge is the upscaling of recovery processes, particularly fracture-matrix transfer during three-phase flow, to the reservoir scale using dual porosity or dual permeability models.

In this work we approach a solution to these challenges by analysing three-phase flow during WAG injection at various scales, starting at the pore scale and then move on to an intermediate scale which is comparable to the scale of a single reservoir simulation grid block. At this scale, we represent fractures and matrix using a fine-grid model that employs empirical and pore-network modelling derived three-phase flow functions to study the effect of capillary and gravity forces on fracture-matrix transfer. We also consider different matrix wettabilities and permeabilities, as well as matrix block size distributions. We then perform an upscaling step that is typical for field-scale recovery simulations and use the dual porosity model to represent fracture-matrix transfer processes that were observed at the grid-block scale. This enables us to analyse and improve the accuracy of dual porosity models for three-phase displacement processes inherent to WAG in NFR.

We find that different three-phase saturation profiles develop inside matrix blocks, which are strongly dependent on wettability of the matrix. These profiles have a profound impact on recovery during WAG injection. The classical dual porosity model fails to capture these saturation profiles and hence miscalculates recovery during early WAG cycles. We present a double block dual porosity model, i.e. a simple multiple continua model, which better matches the fine grid simulation results.

1. Introduction

Fractures can occur naturally in carbonate and clastic formations. Naturally fractured reservoirs comprise complex heterogeneities because the fractures are typically highly conductive but have small storage. Vice-versa, the rock matrix has high storage but normally only a small contribution to flow. This renders the design of enhanced oil recovery (EOR) schemes difficult because of poor injection fluid sweep efficiency and early water and/or gas breakthrough. In petroleum reservoirs, the latter often renders overall hydrocarbon recovery very low in fractured reservoirs. This has been shown in numerous case studies (e.g. Davidson and Snowdon, 1978; Denoyelle et al., 1988; Panda et al., 2009).

Continuous water injection into petroleum reservoirs is a well-established secondary recovery method which aims primarily to displace the oil and maintain the reservoir pressure. Oil displacement from the rock matrix in fractured reservoirs by injected water is capillary dominated and hence strongly dependent on the wettability of the rock (e.g., Behbahani and Blunt, 2005; Fernø et al., 2011; Schmid and Geiger, 2013). For unfavourable, i.e. mixed- to oil-wet matrix wettability, water flooding can be ineffective. In such cases, secondary recovery plans can be changed from water to gas injection to increase recovery (O'Neill, 1988; van Dijkum and Walker, 1991). In particular, gas oil gravity drainage (GOGD) provides an important drive mechanism in such cases because it can increase recovery factors irrespective of the reservoir wettability (e.g., Hagoort, 1980). Fractures extend the exposure of the injected gas with oil in reservoir rock, which renders GOGD more effective compared to unfractured reservoirs. Hence gas injection has been applied in many NFR (e.g., O'Neill, 1988; van

* Corresponding author.
[1] Now at Schlumberger, Abingdon Technology Center, Oxfordshire, UK.
[2] Now at Petroleum Development Oman, Muscat, Oman.

http://dx.doi.org/10.1016/j.petrol.2016.02.012
0920-4105/

Dijkum and Walker, 1991; Jakobsson and Christian, 1994; Saidi, 1996). However, as the gas mobility is high compared to water and oil, so is the risk of by-passed oil and gravity override, which can lead to early gas breakthrough (e.g., Panda et al., 2009). This is particularly true for NFR. In addition, the lack of availability of gas may limit implementation of a recovery scheme that solely relies on gas injection.

Water-alternating-gas (WAG) injection, both at miscible and immiscible conditions, combines the merits of the two injection fluids described above on macroscopic and microscopic scales while stabilizing the injection front, delaying breakthroughs, and therefore leading to increased oil recovery compared to continuous water or gas injection. This has been demonstrated in micro-model experiments that mimic multi-phase flow in conventional (Sohrabi et al., 2004) and fractured porous media (Er et al., 2010; Dehghan et al., 2012). In almost all reported cases, WAG application on the field-scale was observed to improve recovery (Awan et al., 2008; Brodie et al., 2012; Christensen et al., 2001).

Gas (continuous or as part of WAG flooding) injection represents more than 80% of EOR projects in carbonate reservoirs in the United States (Manrique et al., 2007) where the majority of the world's WAG injections are applied (Christensen et al., 2001). In the North Sea, WAG is the most widely used EOR method (48%) and is typically applied in clastic reservoirs. In terms of incremental recovery, WAG has been regarded as the most successful EOR method in the North Sea (Awan et al., 2008). This is excluding other successful forms of WAG EOR methods, such as the Simultaneous WAG (SWAG) and Foam Assisted WAG (FAWAG). Elsewhere, preparations are underway to apply WAG to carbonate reservoirs in the Middle East (Arayni et al., 2013; Kalam et al., 2011; Rawahi et al., 2012) as well as the pre-salt carbonate reservoirs offshore Brazil (Pizarro and Branco, 2012).

Reservoir simulation of WAG injection includes additional complexities because all three phases, oil, gas and water, are mobile in parts of the reservoir. Hence representative three-phase relative permeability and capillary pressure functions, hereafter termed "flow functions", are required to characterise the corresponding three-phase displacement processes. Three-phase relative permeability and capillary pressure data are very difficult to measure experimentally and there are an infinite number of saturation paths that can occur. To overcome these challenges, empirical models are typically employed to predict three-phase flow functions from two-phase experiments (cf. Blunt, 2000). Empirical models are continuously improved to account for more processes that occur when three phases coexist (e.g., Fayers and Matthews 1984; Larsen and Skauge 1998; Blunt 2000). Although producing more accurate results, these improvements cannot easily overcome the major deficiency of the empirical models: They are mainly based on interpolating the much simpler physics of two-phase displacements, expressed in two-phase flow functions. They hence often fail to predict experimentally derived three-phase flow functions accurately, particularly when the rock is mixed or oil-wet (Delshad and Pope, 1989; Oak et al., 1990; Petersen et al., 2008; van Spronsen, 1982; Egermann et al., 2014).

Since most oil in a NFR is contained in the rock matrix, capillary and gravity forces can be more important in NFR in WAG compared to unfractured reservoirs. For example, capillary forces may either enhance or reduce recovery from matrix blocks depending on wettability (e.g., Gilman and Kazemi, 1988; Gang and Kelkar, 2008). Moreover, under some conditions, WAG may lead to water and gas displacing each other, while leaving the oil phase located in the rock matrix in place. Hence the choice of three-phase capillary pressure and relative permeability functions, which encapsulate how oil- or water-wet the rock is, will have a major impact on how fracture-matrix fluid transfer is predicted during reservoir simulation of WAG injection in NFRs.

At the field scale, the exchange between fractures and matrix is commonly modelled using dual porosity or dual permeability models. Both approaches employ transfer functions that simplify the exchange of fluids between fractures and matrix and resemble a fundamental upscaling process (e.g. Ramirez et al., 2009; Al-Kobaisi et al., 2009). This upscaling also neglects that the matrix properties are often heterogeneous, particularly in carbonate reservoirs. For example, Lichaa et al. (1993) found that that wettability indices in a Middle Eastern carbonate reservoir cover the full range from strongly water- to strongly oil-wet while the permeability varied over several orders of magnitude. These changes were observed in sections from two wells over a total length of less than 20 m, i.e. at a length that is typically at or below the scale of a common reservoir simulation grid block.

In addition to the heterogeneities in matrix wettability and permeability, there are further heterogeneities to consider related to the scales at which natural fractures occur. Often the distribution of the matrix block sizes in a reservoir simulation grid block does not follow Warren and Root's (1963) classical assumption that the matrix can be represented as uniform sugar-cube blocks. Instead, even at the scale below a single reservoir simulation grid block, individual blocks of the rock matrix often have multiple shapes and aspect ratios, which give rise to a distribution of fracture-matrix transfer rates (e.g., Haggerty et al., 2001; Di Donato et al., 2007; Geiger et al., 2013; Maier and Geiger, 2013). Since the classical dual porosity model assumes uniform matrix permeability, wettability, and uniform block sizes in each simulation grid-block, it is likely that some important recovery processes are misrepresented in the dual porosity upscaling process during WAG.

For two-phase flow processes in NFR, it has been demonstrated that lumping of capillary pressures can be used to account for heterogeneities in matrix permeability and wettability. Capillary pressure lumping involves the use of fine-grid simulations that represent matrix heterogeneities explicitly. The transfer function is then tuned to match the fine-grid results by readjusting the capillary pressure curve (Fung, 1993). To investigate fracture-matrix transfer during three-phase flow when WAG is applied to a NFR with a heterogeneous rock matrix, we follow a similar approach and use fine-grid simulations to analyse the complex three-phase flow displacement processes. We then use the results from the fine-grid simulations to test how the dual porosity model could be adapted to capture three-phase fracture-matrix fluid transfer more accurately.

Previous work has already investigated how the choice of hysteresis models impacts the predicted oil recovery during WAG in unfractured reservoirs (Spiteri and Juanes, 2006). Additionally, the impact of empirical and pore-network modelling derived three-phase flow functions on predicting recovery from a clastic reservoir during gas flooding after a prolonged waterflood was studied recently (Al-Dhahli et al., 2014). Here, we advance this research in that we compare three-phase relative permeability and capillary pressure curves derived from pore-network simulations with those from empirical models for predicting oil recovery from fractured reservoirs during WAG while considering different wettability states and other matrix heterogeneities.

Our work has three key objectives: First, we use a pore-network model to obtain physically consistent three-phase flow functions for immiscible displacements in realistic 3D pore geometries to estimate oil mobility at low oil saturations at different wettabilities. We then compare predicted recovery from a matrix block during WAG for the resulting flow functions and for empirical three-phase flow functions that interpolate two-phase relative permeability curves. Second, we use the three-phase flow functions derived from pore-network modelling in fine-grid simulations of WAG to analyse the emergent three-phase flow