Modelling Water Flooding Scheme in Dual Porosity Reservoirs: An Integrated Approach

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Abstract. Water flooding is one of the most widely used secondary recovery techniques in petroleum reservoirs to enhance oil recovery. However, its application in naturally fractured reservoirs (NFRs) presents significant challenges due to the complex dual-porosity and dual-permeability nature of such formations. In NFRs, the high-permeability fracture network provides rapid fluid flow paths, leading to early water breakthrough and bypassing a significant portion of the oil trapped in the low-permeability matrix; this results in inefficient sweep efficiency and poor overall recovery, making conventional water flooding strategies less effective. BOAST (Black Oil Applied Simulation Tool) is a well-established reservoir simulator used for modelling black oil. However, BOAST may require modifications or integration with empirical models to improve water flooding performance in NFRs. The research team modelled a naturally fractured reservoir as a single-layer formation using a 15×1×1 parallel Cartesian grid in MATLAB. They then integrated the developed model into BOAST. They performed a water-flooding simulation to predict pressure distributions within each grid block, as well as production data (oil, gas, and water volumes), and well pressure and shut-in pressure. The simulation results indicate that cumulative oil production reached 1.3 MMSTB after 2000 days, corresponding to a recovery factor of approximately 25%. The reservoir, however, experienced early water breakthrough in the fracture system, leading to increased water cut and reduced oil production after year four. The operators initially maintained pressure support through water injection, but its effectiveness declined as water saturation in the fractures increased. Gas-Oil Ratio (GOR) remained stable throughout, indicating no significant gas breakthrough or solution gas drive. The results of this study show that BOAST faces uncertainty in accurately simulating and predicting performance in fractured systems due to complex fracture–matrix interactions, early water breakthrough, and poor sweep efficiency. However, researchers can use BOAST as a rapid real-time screening tool for dual-porosity reservoirs when selecting candidates for a water-flooding program, provided the model fully captures fracture–matrix interactions.

Keywords: Dual Porosity (DP) reservoir; water flooding; cumulative production; breakthrough; fractured reservoir.

INTRODUCTION

A significant portion of the world's hydrocarbon reserves is located in naturally fractured reservoirs, yet these are also among the most challenging to manage. Analysing hydrocarbon recovery in naturally fractured reservoirs (NFRs) is challenging due to the complex connections between highly permeable fracture networks and low-permeability rock matrix. Although water flooding is an inexpensive secondary recovery technique, complex fracture systems that promote early water breakthrough often reduce its effectiveness in NFRs. Most commercial simulation tools, such as Schlumberger Eclipse, face limitations when modelling dual-porosity systems because they cannot fully capture fracture-matrix interactions [1]. Although dual-porosity simulation models are available, their predictive power varies depending on how they model transfer between the matrix and fractures.

Dual-porosity models are created to address this problem by capturing the interactions between the fracture and matrix systems [2]. These models treat the matrix and fractures as distinct but interdependent continua. The matrix mainly stores oil, while cracks control the flow channels. Transfer functions – usually based on capillary imbibition or pressure gradients – govern the fluid exchange between these two domains [3]. These formulations, implemented in BOAST (Black Oil Applied Simulation Tool), enable more accurate simulation of fluid behaviour during water flooding in fractured media. Developers created BOAST as a finite-difference reservoir simulator to model multiphase fluid flow in porous media under the black-oil assumption, and later expanded it to simulate fractured reservoirs [4].

Researchers can use BOAST NFR to analyse and assess the effectiveness of water injection in naturally fractured systems by modelling the matrix and fractures as distinct grid systems with interconnected fluid transport. The simulator contains techniques for defining capillary pressures, transfer coefficients, relative permeability functions, matrix properties, and fracture parameters [5]. A thorough examination of fluid flow and oil recovery over time is made possible by specifying well locations, injection rates, production limitations, and reservoir heterogeneity in relation to water flooding. BOAST NFR can observe key performance indicators, including water cut, oil recovery factor, saturation distribution, pressure variations, and fluid contact movement. The simulator can measure the amount of oil recovered through fractures relative to that retained in the matrix and track the onset of water breakthrough [6].

This comprehensive depiction is crucial for evaluating sweep efficiency and improving injection techniques. This research helps determine the optimal conditions for reducing water production and increasing oil recovery by eliminating the need for costly field tests and enabling reservoir experts to forecast reservoir performance under various assumptions. These simulations are crucial for effective reservoir management and informed decision-making [7].

In addition to enhancing technical comprehension of NFR behavior, the BOAST NFR water flooding simulation aids in economic assessments by estimating recovery potential and forecasting injection method efficiency this allows reservoir experts to prioritise development options and calculate the benefit of investment and the results of simulations are frequently used to inform reservoir management strategies, injection schedule adjustments and the location of new wells [8].

The key issue is that, to simulate water flooding in a naturally fractured reservoir using the BOAST NFR, specific tools or models that capture the complex nature of dual porosity systems are required first. BOAST NFR work by simulating the dynamics of a modelled fractured reservoir, but it cannot be used to create the model. The overall aim of this study is to:

a) Develop a 3-D synthetic fractured reservoir model using MATLAB;

b) Simulate a water flood scheme on the developed model using the BOAST NFR simulator, and,

c) Investigate the effect of the dual porosity on water injection performance.

METHODS

A three-dimensional synthetic dual porosity reservoir model was developed using MATLAB-MRST and used to simulate a water-flood scheme using a three-phase, three-dimensional black-oil numerical reservoir simulator, BOAST-NFR. The water flood scheme was simulated based on the steps illustrated in Figure 1. BOAST-NFR simulates isothermal, Darcy flow in three dimensions. It can simulate oil and/or gas recovery through fluid expansion, displacement, gravity drainage, and imbibition mechanisms, utilising constant shape factors to describe inter-porosity flow.

However, when time-dependent shape factors are used, only one-dimensional inter-porosity flow in water-oil systems is available. BOAST-NFR employs the implicit pressure-explicit saturation (IMPES) formulation to solve its system of finite-difference equations. The IMPES method first computes the pressure distribution for a given time step, then the saturation distribution for the same time step.

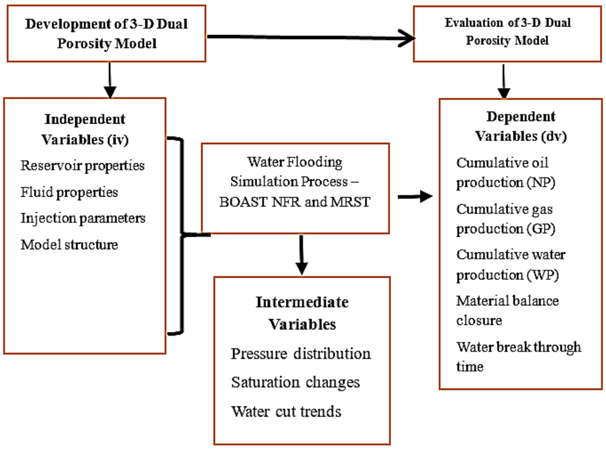

Figure 1 – Flow chart for modelling and simulating a water flooding scheme for the fractured reservoir

The IMPES formulation is straightforward, requires less arithmetic per time step, and hence is faster than other formulations.

Model Description. The dual-porosity, fractured reservoir was modelled as a single-layer formation using a 15×1×1 parallel Cartesian grid, with dimensions shown in Table 1. The reservoir is composed of a matrix system with φm = 29% and kx = ky = kz = 1 md. Assumptions for the model include: The fracture network consists of a single set of parallel fractures with φf = 1%, a diagonal permeability tensor with kf = 90 md and a fracture spacing of L = 5 ft. The reservoir model is initially assumed to contain only oil and water, with zero initial gas saturation.

Table 1 – Gridblock and Reservoir rock data for the synthetic fractured reservoir model

Parametres	Meaning
Number of gridblocks in x-direction, nx	40
Number of gridblocks in y-direction, ny	1
Number of gridblocks in z-direction, nz	1
Gridblock size in x-direction Δx, ft	50
Gridblock size in x-direction Δ, y, ft	1000
Gridblock size in x-direction Δz, ft	50
Matrix permeability, km, md	1
Matrix compressibility, cm, psi-1	3.5x10-6
Fracture permeability, kf, md	90
Fracture compressibility, cf, psi-1	3.5x10-6
Connate water saturation in the matrix, Swc,%	20
Initial pressure, pi, psig	5
Oil density, ρo, lb/ft3	51.14
Oil viscosity at pb, μo, cp,	0.21
Slope of μo above pb, dμo/dp, cp/psi	1.72 x 10-5
Oil formation volume factor at pb, Bo, RB/STB	1.8540
Slope of Bo above pb, Bo, dBo/dp, RB/STB/psi	-4.0 x 10-5

Simulation Runs. A simulation run was performed using a producer at gridlock (1, 1, 1) and an injector at (15, 1, 1). The researchers constrained fluid withdrawal to a total liquid production of 800 STB/D and initially controlled water injection at a constant rate of 1568 STB/D, limiting it to a maximum bottomhole pressure of 6100 psig. They considered the results from a 10-year simulation run. Using BOAST, they ran a water-flooding simulation. They extracted the following data: pressure distribution in each grid block, production data (oil, gas, and water volumes), and well pressure and shut-in pressure.

Cumulative production volumes – including oil, gas, and water – are crucial for evaluating reservoir performance, estimating reserves, and applying material balance equations. They can also be determined analytically using production rate data extracted from the simulation according to:

$$\mathrm{Np} = \int_0^t dt \qquad (1)$$

$$\mathrm{Gp} = \int_0^t gdt \qquad (2)$$

$$\mathrm{Wp} = \int_0^t qwdt \qquad (3)$$

where qo = oil production rate (STB/day); qg = gas production rate (MSCF/day); qw = water production rate (STB/day); t = time (days).

Since BOAST provides discrete production data, numerical summations were used instead of integration according to the following equations:

$$\mathrm{Np} = \sum_i^n qoi.\Delta ti \qquad (4)$$

$$\mathrm{Gp} = \sum_i^n qgi\Delta ti \qquad (5)$$

$$\mathrm{Wp} = \sum_i^n qwi\Delta ti \qquad (6)$$

where qoi, qgi, qwi = oil, gas, and water rate at time step i, respectively; Δti = time step duration (days); n = total number of time steps.

The data was populated using the trapezoidal rule to approximate integration as follows:

$$\mathrm{Np} = \frac{\sum(qoi+qoi+1.\Delta t)}{2} \quad (7)$$

$$\mathrm{Wp} = \frac{\sum(qwi+qwi+1.\Delta t)}{2} \quad (8)$$

$$\mathrm{Gp} = \frac{\sum(qgi+qgi+1.\Delta t)}{2} \quad (9)$$

For example, for a 10-day interval, assuming a linear rate decline:

$$\mathrm{Np} = \frac{500+450}{2}\,x10 + \frac{450+400}{2}x10 + \cdots \quad (10)$$

$$\mathrm{Gp} = \frac{1000+900}{2}\,x10 + \frac{450+400}{2}x10 + \cdots \quad (11)$$

$$\mathrm{Wp} = \frac{200+250}{2}\,x10 + \frac{250+300}{2}x10 + \cdots \quad (12)$$

Model Optimisation. The optimisation criteria used were the arrival times of the leading waterfronts at the producing well (grid blocks) and the injection rate. Sensitivity runs were conducted to determine the optimal perforation intervals, ensuring that all leading waterfronts reach the producing segments at approximately the same time while injecting water at the maximum injection rate. When the researchers determined that the criteria were not met, they adjusted the injection rate and injection points and reran the simulation. Once the requirements were satisfied, the results of the run were recorded and served as the basis for analysing recovery performance.

RESULTS AND DISCUSSIONS

A synthetic fractured 3-D reservoir was developed in MATLAB and initially simulated using the MATLAB Reservoir Simulation Tool (MRST) within MATLAB (Figure 2). The model assumed a single-layer grid with dimensions Δx = 200, Δy = 1500, Δz = 50; this defines the physical size of each grid block in the reservoir and defines and specifies grid blocks as: nx = number of gridblocks in the x-direction; ny = number of gridblocks in the y-direction; nz = number of gridblocks in the z-direction; NDT = interval of timesteps for which summary results were iterated.

The cap rock base depth to the top sand indicates the structural depth of the reservoir considered. The coordinate system used for this model assumes that z-directional elevation values increase with depth. Thus, users must read elevations as positive depths below the selected reference datum. Consequently, they interpret negative values as heights above the datum. In this work, the researchers assign a constant elevation of 2000 ft to the variable KEL, representing the distance from the datum to the top of the formation.

Porosity and permeability were assumed to be uniform across the grid, with a single porosity value used.

The researchers assign one permeability value to each of the x-, y-, and z-directions. In this work, they model fracture permeability using a diagonal permeability tensor. They determine fault location based on the gridblock number in the x- and y-directions and the fault's relative position within the block. This model seeks to accurately represent naturally fractured reservoirs by integrating the matrix and fracture domains within a dual-continuum framework, promptly addressing multiple weaknesses identified in previous studies. For example, while the studies by authors [9, 10] investigated cracked systems, they failed to include extensive 3D simulations that account for dynamic dual-porosity flow. Other researchers, such as [11–13], have utilised commercial simulators or simplified geometries, thereby limiting their ability to accurately replicate authentic fracture-matrix interactions.

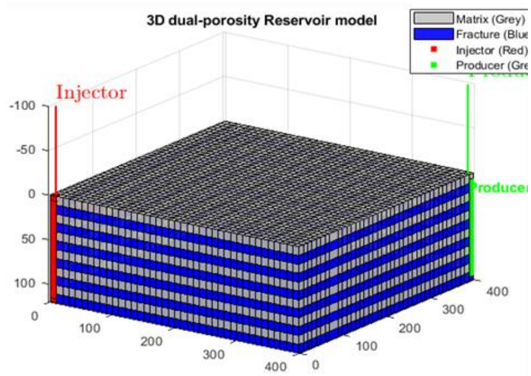

Figure 2 – Modelled 3-D fractured reservoir with one injector well, one producer well, and a water flooding scheme

Furthermore, studies by authors [13, 14] highlighted the lack of models capable of effectively simulating complex fluid displacement in fractured media. This study employs MRST to develop a detailed 3D dual-porosity model, providing a feasible alternative to current limitations and laying the groundwork for improved simulation of water-flooding dynamics in naturally fractured reservoirs.

The accumulated oil and water production from the simulated injection in the fractured reservoir is presented in Figures 3 and 4. The simulations have been conducted for a vertical injector well and one vertical producer with an OPENHOLE completion. The simulation results show that the OPENHOLE case initially produces more oil for the first five years of injection, before water breakthrough. As a result of the OPENHOLE breakthrough, oil production significantly decreased. As a result, after the 10th year, at approximately 3458 days of operation, the wells have produced less oil than in the first five years, at approximately 1,638 days of production. Additionally, the latter production period produces more water than the former throughout the operation.

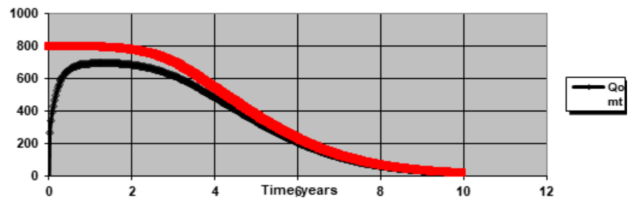

Figure 3 – Simulated cumulative oil and gas production for a period of 10 years

The simulation shows that the production rate decreases over time due to depletion. The simulation results show that the production team achieved the peak production rate at 2.5 years, observed a sharp increase in water cut around year 4, and recorded the peak at year 10, when the producer well no longer produced hydrocarbons.

Summary Report

Elapsed time [days]=	1638				
Time-step No =	16420				
Time-step [days]=	0.1				
P ave [psi]=	5939.069				
Qo [STB/D]=	460.5752	Np [STB]=	1171403	mbeo [%]=	0.000107
Qg [MSCF/D]=	704.6627	Gp [MSCF]=	1792954	mbeg [%]=	-8.54E-05
Qw [STB/D]=	339.4248	Wp [STB]=	138996.9	mbew [%]=	2.55E-14
Qgi [MSCF/D]=	0	Gi [MSCF]=	0		
Qwi [STB/D]=	-1127.892	Wi [STB]=	-2107761		
WOR [STB/STB]=	0.736958				
GOR [SCF/STB]=	1529.962				

Summary Report

Elapsed time [days]=	3458				
Time-step No =	34630				
Time-step [days]=	0.1				
P ave [psi]=	5980.798				
Qo [STB/D]=	25.02482	Np [STB]=	1480709	mbeo [%]=	0.000138
Qg [MSCF/D]=	38.28704	Gp [MSCF]=	2267784	mbeg [%]=	-0.00011
Qw [STB/D]=	774.9752	Wp [STB]=	1285691	mbew [%]=	1.13E-14
Qgi [MSCF/D]=	0	Gi [MSCF]=	0		
Qwi [STB/D]=	-818.8345	Wi [STB]=	-3786791		
WOR [STB/STB]=	30.96826				

Figure 4 – Simulated cumulative volumes at 5 and 10 years

Initial oil production was 800 STB/D, with a decline over time due to reservoir pressure depletion and increasing water cut. A typical exponential decline trend was noted. Cumulative oil production increased steadily over the simulation period. The simulation results indicate that operators can achieve optimum oil production during the first five years after water injection, when daily oil production remains above 300 STB/Day (Figure 3). Whenever the water saturation near the wellbore exceeds the irreducible water saturation, water enters the well, causing the reservoir to yield more water than oil; this is the water breakthrough. As a result, oil production drops significantly, and water production increases after the water breakthrough. Oil can be produced until the oil saturation near the well drops to residual oil saturation.

The reservoir initially had an average pressure of 6057 psi, which gradually declined over time due to production. Water injection, initiated to maintain reservoir pressure, was effective in stabilising pressure near the injection well while driving oil toward the production well. Pressure distribution showed a significant gradient between the matrix and the fracture system, with fractures dissipating pressure more rapidly due to their higher permeability. The Original Oil in Place (OOIP) was estimated at 5.28 MMSTB (Figure 5). Cumulative oil production reached 1.3 MMSTB after 2000 days, corresponding to a recovery factor of approximately 25%. Production rates declined over time, from an initial rate of 800 STB/D to approximately 300 STB/D at the end of the simulation period, indicating natural reservoir depletion despite the support of water-injection pressure.

Material Balance Report

Layer	1	
	OOIP [MMSTB]=	5.282302
	OWIP [MMSTB]=	2.139602
	S_OGIP [BSCF]=	8.081723
	F_OGIP [BSCF]=	0

Total initial fluid volumes in reservoir

OOIP [MMSTB]=	5.282302
OWIP [MMSTB]=	2.139602
S_OGIP [BSCF]=	8.081723
F_OGIP [BSCF]=	0

Well Report

	Time=	0.0001	
ID		Location	
	I	J	K
Ver Prod.	1	1	1
Ver Inj.	15	1	1

Figure 5 – Simulation results showing initial reservoir conditions and well locations

This observation addresses empirical limitations noted in the literature, particularly the lack of performance metrics in fractured reservoir simulations. For example, while studies by authors [9, 10, 15] explored methods for enhancing production, they did not evaluate cumulative oil and water yields over time or perform a quantitative material balance. Conversely, research by authors [16, 17] focused on gas or fracture mechanics, neglecting pressure dynamics and production assessment during waterflooding. Authors [11, 12] simulated flow dynamics; however, they did not examine the performance of Np, Gp, or Wp. This work provides quantitative insights into the effectiveness of waterflooding in naturally fractured reservoirs by simulating and evaluating key performance metrics using BOAST NFR.

Gas production followed a similar trend, reaching 2.0 BSCF by the end of the simulation period. The Gas-Oil Ratio (GOR) remained constant at approximately 1529 SCF/STB (Figure 4), suggesting that the reservoir did not experience significant free gas liberation or gas breakthrough. Water breakthrough occurred progressively over time, particularly in the fracture system due to its higher permeability and faster fluid flow. The Water-Oil Ratio (WOR) steadily increased, reaching 2.43 at 2184 days (Figures 3 & 4), indicating a significant rise in water production as the reservoir continued to be flooded. Water saturation in the fractured system changed more rapidly than in the matrix, with fractures exhibiting higher water saturation earlier due to the presence of preferential flow paths.

The fracture system demonstrated rapid pressure depletion and fluid movement, enabling faster water breakthrough and oil recovery near the production well. The matrix system retained higher oil saturation for a longer period due to slower displacement and improved fluid communication with the fracture system. The simulation results demonstrate that while water injection successfully provided pressure support and enhanced oil recovery, water breakthrough in the fracture system posed significant challenges, leading to increased water production and a decline in oil production rates.

CONCLUSIONS

This study employs MRST to develop a detailed 3D dual-porosity model, providing a feasible alternative to current limitations and laying the groundwork for improved simulation of waterflooding dynamics in naturally fractured reservoirs. The simulation modelled a single-layer fractured reservoir using BOAST, with vertical injector and producer wells placed at opposite ends of the reservoir. Cumulative oil production reached 1.3 MMSTB after 2000 days of simulation, translating to a recovery factor of approximately 25%.
The reservoir experienced early water breakthrough in the fracture system, leading to increased water cut and reduced oil production after year four. The operators initially maintained pressure support through water injection, but rising water saturation in the fractures reduced its effectiveness. The matrix system retained oil saturation for a longer period due to its low permeability, while fractures allowed for faster fluid flow. The Gas-Oil Ratio (GOR) remained stable throughout, indicating no significant gas breakthrough or solution gas drive. Advanced completions such as Flow Control Devices (FCDs) could reduce water production and improve long-term oil recovery.

The results of this study indicate that, although BOAST's capability to model and predict performance in fractured systems is compromised by uncertainty in fracture-matrix interactions, early water breakthrough, and poor sweep efficiency, it serves as a rapid, real-time screening tool for candidate selection in water-flooding programs for dual-porosity reservoirs.

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