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Original Article

Design of Dual-Porosity – Dual-Permeability Model of Ekofisk Field

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Abstract

Naturally fractured reservoirs contain a substantial portion of the world's hydrocarbon reserves. However, development of these fields poses a considerable challenge. The complex geological framework of fractured reservoirs requires proper fracture network characterization for a reliable simulation model. This work outlines a systematic methodology to construct a dual-porosity – dual-permeability model of Ekofisk field, with the aim to closely represent fluid flow behaviour in an actual fractured reservoir. Reservoir rock and fluid properties, as well as fracture characterization of the field is represented in this paper. Three variants of the model were developed, namely single-porosity, dual-porosity and dual-porosity – dual-permeability models. Fluid flow performances of the models were compared and evaluated through macroscopic observation of oil production rate, cumulative oil production as well as field and bottom-hole pressures. Significant differences in fluid flow were observed between single-porosity model and the other two models due to the existence of the fracture network. Smaller differences were observed between dual-porosity and dual-porosity – dual-permeability models due to the matrix – to – matrix and matrix – to – well fluid flow interactions.

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1 Introduction

Natural fractures exist practically in every reservoir, creating a system of interconnected fracture planes which divides the reservoir rock in pieces, termed as matrix blocks, distinguishing properties of the matrix and fracture system. If matrix has a reservoir quality with an interconnecting fracture creating an extended network, then the reservoir should be considered as multiple continua (dual-continua when matrix and fractures are present).

The concept of dual-porosity to simulate fluid flow behavior in a fractured porous medium was first implemented by Warren and Root in petroleum reservoir engineering to model the build-up well test responses in a fractured reservoir [1]. Their model considered an idealized condition of heterogeneous porous medium, in which set of fractures are highly interconnected and receives the fluids from the surrounding matrix blocks. Several authors have extended this earliest model by incorporating multi-phase flow [2,3] and important flow mechanisms such as gravity drainage or imbibition [2] in their flow equation and simulation models. One key challenge in the development of the model is the proper representation of flow mechanisms, specific for every reservoir. Unique individual approach should be taken in order to design a specific naturally fractured reservoir.

The field of interest in this project, Ekofisk field is located in the Norwegian Sector of the North Sea. Discovered in 1969, the field is considered as one of the largest fields in the Norwegian Continental Shelf with estimated initial oil in place of up to 7.1 billion STB of oil [4]. The reservoir is an elliptical

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elongated anticline covering an area of 13,625 acres [5]. The produced oils are extracted from two fractured chalk formations, Ekofisk (Danian Age) and Tor (Maastrichtian Age) formations, characterized by its highly porous fractures and low matrix permeability.

2 Model Development

Design of dual-porosity – dual-permeability simulation model of Ekofisk field is performed with Petrel (2015) and ECLIPSE (2014) software. The model development involves discretization of the reservoir into two continua, matrix and fracture. Each point in the reservoir would contain pressure and saturations for both of the systems. Fig. 1 outlines the overall procedures taken for the development of the dual-porosity – dual-permeability model.

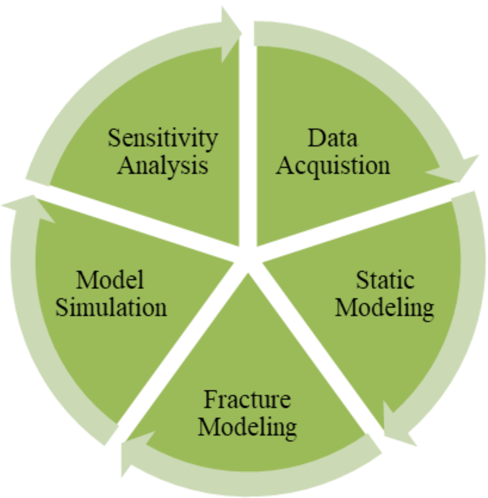

Fig. 1 Model development workflow.

2.1 Data Acquisition

Fluid, petrophysical properties and saturation – relative permeability curve of Ekofisk field used in the simulation models were based on published articles and researches [6-9], as summarized in Table 1, Table 2 and Fig. 2.

The bulk of the fractures in the Ekofisk formation were associated with the tectonic-induced fractures, creating a highly variable fracture intensity and spacing throughout the formation. The planar fractures formed a fully-developed parallel sets, with 65 – 80° dip angle. The second set of fractures are micro-fractures related to stylolite seams. Other minor classifications of fractures that exist in the reservoir are the healed fractures, a narrow zone of comminute chalk matrix that have been cemented, and lastly the non-planar, irregular fractures. All the different fracture systems form the primary conducive flow path for hydrocarbon and injected fluids.

In general, the Ekofisk field is cut by two generations of fractures. One set of fracture trends from North-North-East – South-South-West (NNE – SSW) throughout the field and a higher concentration could be identified in the northwest part of the field. Seismic stratigraphy studies indicated that normal and wrench faulting are present, with respective basin inversions. The process resulted in a complex distribution of shallow marine sediments and basinal shales within the graben. The second fracture set are related to doming process due to radial and tangential stress system [5].

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Table 1 Fluid & Petrophysical properties.

Fluid Properties		Petrophysical Properties	
Gas Oil Ratio (GOR)	1600 ft^3/bbl	Net Pay	479 ft.
Formation Volume Factor (FVF)	1.78	Gross Pay	617 ft.
Oil Gravity	36°	NTG	0.776
Bubble Point Pressure	5560 psia	Porosity (Matrix)	Avg. 30% (25 – 48%)
Water Salinity	56100 ppm	Effective Permeability (Matrix)	1 – 5 mD
		Effective Permeability (Fracture)	10 – 100 mD
		Interstitial Water	20%

Table 2 Ekofisk field properties.

Lithology		Limestone and Chalk (High porosity, Fine-grade)
Depth		Mid. Point 10400 ft. (3169.92 m)
Area		13625 acres (55.13 km^2)
Areal Extent		4.2 × 5.8 miles (6.8 × 9.3 km)
Thickness	Ekofisk Formation	330 – 500 ft. (100 – 150 m)
	Tight Zone	Avg. 50 ft. (15 m)
	Tor Formation	250 – 500 ft. (75 – 150 m)
Reservoir Pressure		7135 psia at 10400 ft.
Pressure Gradient		0.685 psi/ft.
Reservoir Temperature		265 °F at 10400 ft.
Temperature Gradient		2.02 °F/ft.
Type of Fractures		1. Tectonic Fractures (Main) 2. Stylolite-associated Fractures 3. Healed Fractures 4. Irregular Fractures
Major Fracture Trend		NNE – SSW direction
Dip Angle		Mean 70°

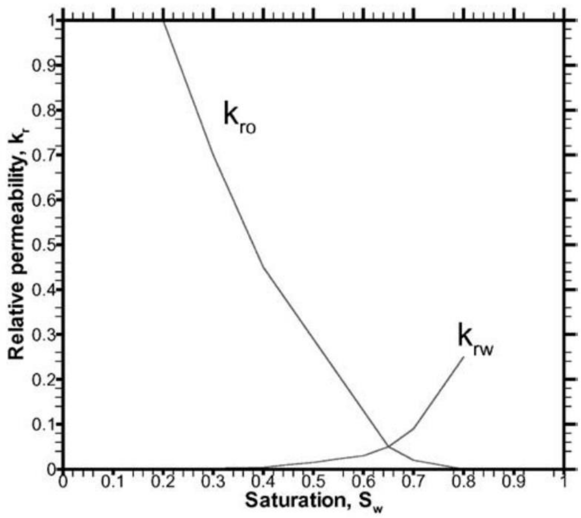

Fig. 2 Saturation - relative permeability curve of Ekofisk field [9].

2.2 Static Modelling

Static model was developed based on the acquired data, covering an area of 1 km^2 around wellbore of Well 2/4 – 2. Topographic map of Ekofisk field, as shown in Fig. 3, was digitized. Fluid contacts, facies distribution and their respective depth intervals were identified based on well logs data. Well tops (top depth of each facies) were determined. Both well tops and topographic map data were used to generate the surface map, taking into account depth interval of Ekofisk formation.

Simulation grid was created based on the generated surface map. Dimension of the grid model is 20 × 20 × 13, representing 100 m × 100 m of the area around the wellbore. In total, 5200 active grid cells were used. The model was populated with matrix properties of Ekofisk field as listed in Table 2. Properties distribution were generated by the software using normal distribution method according to the mean (average) and standard deviation of the properties.

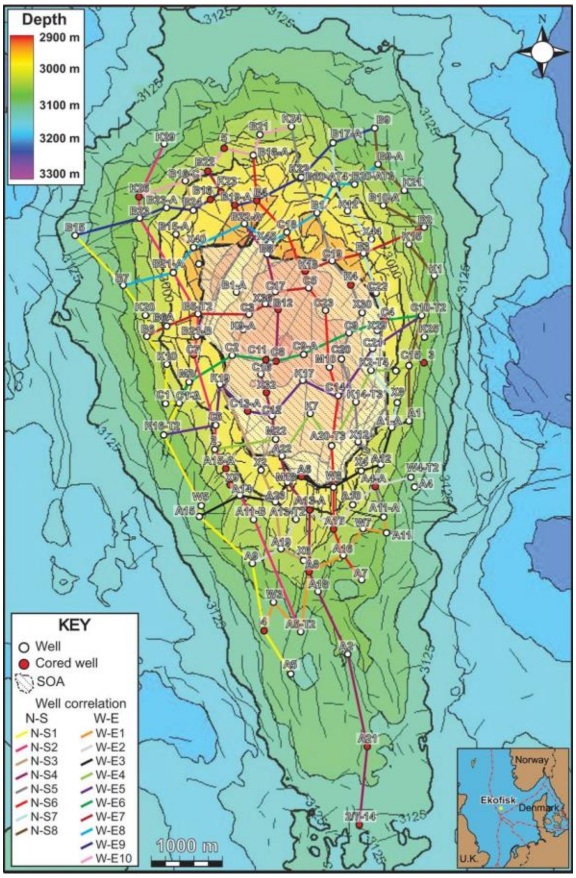

Fig. 3 Top Ekofisk formation surface map [10].

2.3 Fracture Modelling

Fracture modeling was done separately from static modeling, as static modeling only accounts for matrix system. Dual-porosity – dual-permeability models requires additional input of fracture network properties to represent the naturally fractured reservoir and the reservoir fluid behaviors on the system.

2.3.1 Fracture Interpretation

The initial step to generate a fracture model is to analyze interpretations of fractures from borehole images (Image log data). Data of interest in this matter is dip angle and dip azimuth angle and is obtainable from well logs such as FMI (Formation Micro Image) logs. For this project, fracture interpretation data were generated by Petrel software based on available Ekofisk reservoir and fracture properties input obtained from published articles and researches.

2.3.2 Fracture Network Modelling

Fracture network is a group of planes representing fractures. Since data from fracture interpretation such as fault patches or fault surfaces were not available, Stochastic Method was used to generate the network. This method describes fractures statistically using numerical input. The properties in the 3D grid were modeled using standard algorithms.

Fracture distribution extent was set throughout the entire grid to account for the heavily fractured Ekofisk Formation. Fracture density was defined as Frac area / volume (known as P32) with constant value of 0.5. This definition was used as the estimated values obtained along the wells were unbiased.

For this project, the shape of the planes was set at default at 4 to represent a rectangular plane. Fracture length were described using Power Law according to Pareto distribution law. Mean dip and azimuth values were based on the acquired data, following the major fracture trend at the location of Well 2/4 – 2 in the field.

2.3.3 Fracture Network Upscaling

Upscaling process converts the generated fracture network data into properties required to run the dual-porosity and dual-permeability simulation. Properties such as fracture porosity, fracture permeability and sigma factor were generated. Sigma factor was calculated using the relationship proposed by Kazemi et al. [2] as shown below. Statistical Calculation were used in this project. It is based on Oda Method to estimate permeability in accordance with the total area of fractures in each cell.

$$\sigma = 4\left(\frac{1}{L_x^{\,2}} + \frac{1}{L_y^{\,2}} + \frac{1}{L_z^{\,2}}\right) \tag{1}$$

2.4 Model Simulation

Three initial models were developed, namely single-porosity, dual-porosity and dual-porosity – dual-permeability model. Single-porosity model were established as a base of comparison on how fracture properties affects the fluid flow within the reservoir. The single-porosity model only accounts for the matrix properties. Dual-porosity model are more suitable to simulate systems that exhibit weak or negligible gravity effects. The next development is the dual-porosity – dual-permeability model, accounting for matrix-to-matrix interblock transfer between neighboring blocks. Fig. 4 shows the workflow for the simulation cases.

Fig. 4 Simulation case workflow.

2.4.1 Fluid Model

Fluid model defined the physical properties of the fluid and how it varies with pressure and temperature. It is also used to generate the initial conditions of the reservoir. Black oil model was selected as the fluid model. Due to the absence of free-gas component [9], a two-phase fluid model was considered. Known reservoir conditions and fluid properties were inserted. Unknown properties such as formation volume factor and viscosity were generated based on default correlation methods from the software.

2.4.2 Rock Physics Function

Saturation functions contains information on relative permeability and capillary pressure versus saturation. These information were used to calculate initial saturation for each phase in every cell, initial transition zone and fluid mobility used for flow equations. Rock compaction functions comprises of table for pore volume multipliers versus pressure. Transmissibility multiplier is generated based on the table.

Two separate functions are generated for Saturation functions, each representing independent matrix and fracture systems. Rock characteristics for the matrix system were initialized based on saturation and relative permeability function as given in Fig. 2**.** On the other hand, rock characteristics for fracture system were initialized as fracture (straight line) under the preset setting. Flow pattern in fractures is regarded to be similar to the flow in tubes. Thus, relative permeability function for fracture were represented as linear.

Rock types were initialized as consolidated limestone under the presets setting. Porosity property of the matrix were inserted to refine the Rock Compaction function.

2.4.3 Development Strategy, Simulation Cases, and Sensitivity Analysis

The models were run under the same development strategy: well pressure drawdown control with average pressure of 100 psi for the next 24 hours. The results were compared to evaluate the impact of fractures and matrices connectivity to the overall fluid flow in the model. Simulation cases were defined accordingly based on their types, SP: single-porosity, DP: dual-porosity and DPDP: dual-porosity – dual-permeability. Petrophysical data, fluid model and rock physics function generated were used as the inputs. Dual-porosity and dual-porosity – dual-permeability models require additional fracture properties input.

Sensitivity analysis was conducted on the simulation model to evaluate the effect of varying fracture properties on the fluid flow performance. Several key properties analyzed in the sensitivity analysis are fracture permeability, sigma factor, fracture distribution, orientation and aperture. Four (4) cases were run to analyze the effect of different inputs of fracture permeability, sigma factor, fracture distribution, orientation and aperture towards fluid flow in dual porosity run. The sensitivity analysis cases are presented in Table 3.

Table 3 Sensitivity analysis cases.

Properties	Permeability (mD)		Sigma Factor		Fracture Distribution		Fracture Orientation Concentration		Fracture Aperture	
Cases	**Model Name**	**Value**	**Model Name**	**Value**	**Model Name**	**Value**	**Model Name**	**Value**	**Model**	**Mean**
Base	DPDP	Base	DPDP	Base	DPDP	0.50	DPDP	40	DPDP	7.5×10^{-5}
1	KFrac _x05	x ½	Sigma_x0	x 0	Dist_025	0.25	Conc_0	0	Aperture _x0.5	3.75×10^{-5}
2	KFrac _x2	x 2	Sigma_x2	x 2	Dist_075	0.75	Conc_20	20	Aperture _x2.0	1.5×10^{-4}
3	KFrac _x5	x 5	Sigma_x5	x 5	Dist_1	1.00	Conc_80	80	Aperture _x5.0	3.75×10^{-4}
4	KFrac _x10	x 10	Sigma_x10	X 10	Dist_2	2.00	Conc_100	100	Aperture _x10.0	7.5×10^{-4}

3 Results and Discussion

3.1 Fracture Model

Initial fracture network distribution of Ekofisk field was successfully generated based on the Stochastic Method, as can be seen in Fig. 5 below.

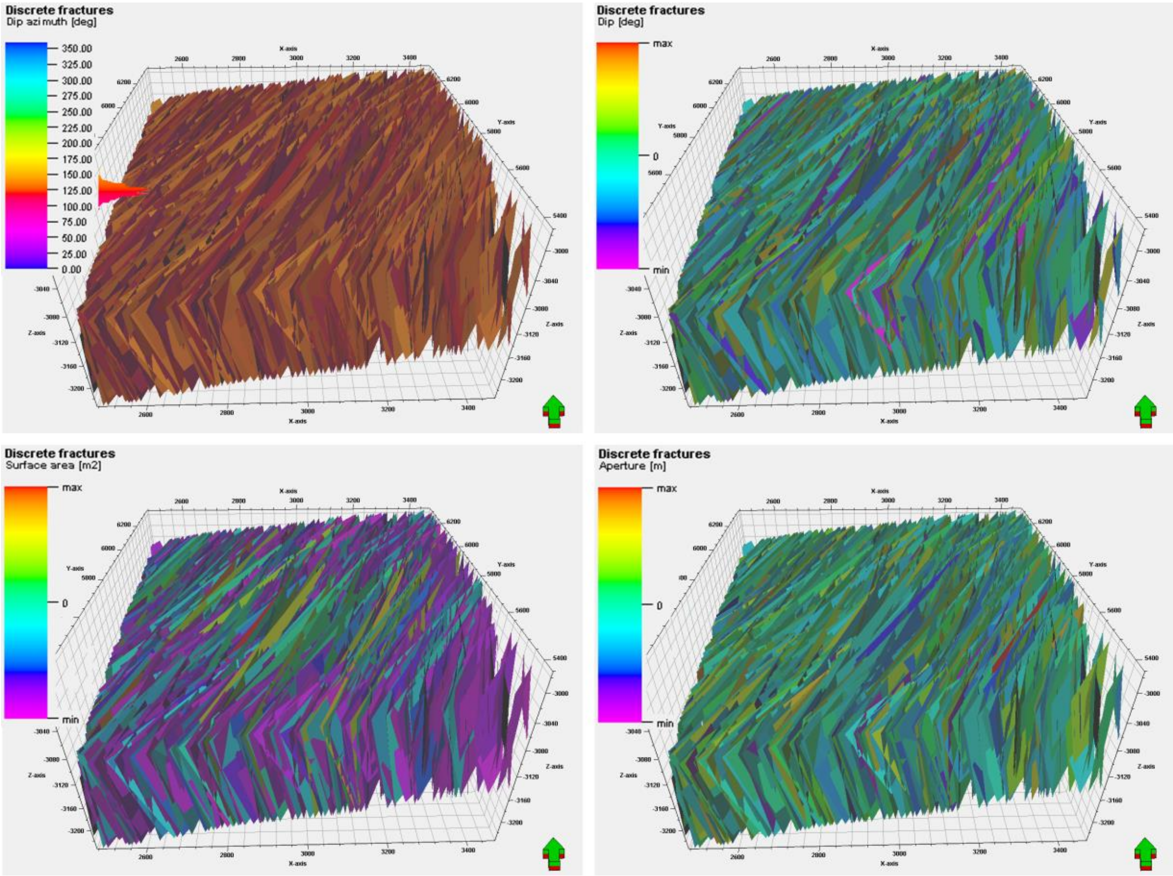

Fig. 5 Fracture network distribution results. From left to right: dip azimuth angle dip angle, fracture surface area and fracture aperture.

Fracture properties were generated as seen in Fig. 6 upon upscaling the fracture network of the Ekofisk field. These properties defined the fracture system of the field on the dual-porosity and dual-porosity – dual-permeability simulation runs.

3.2 Simulation Model Comparison

Properties distribution in DP and DPDP model were divided into two regions. Fluids exist in two interconnected systems, the rock matrix which provides the bulk of reservoir volume as well as highly permeable fracture network. Petrel software models the two systems by associating each block in the geometric grid with two simulation cells.

It was observed in Fig. 7 that the flow rate in both DP and DPDP models were higher compared to SP model. On top of that, bottom-hole pressure as represented in Fig. 8 depletes at a faster rate in the former two models. The results suggest that oil flow much more easily on dual porosity models due to the highly permeable fractures. Ultimately, cumulative oil production from DP and DPDP run is significantly higher compared to SP run for a 24-hours production period. Table 4 below summarizes the macroscopic evaluation of the models.

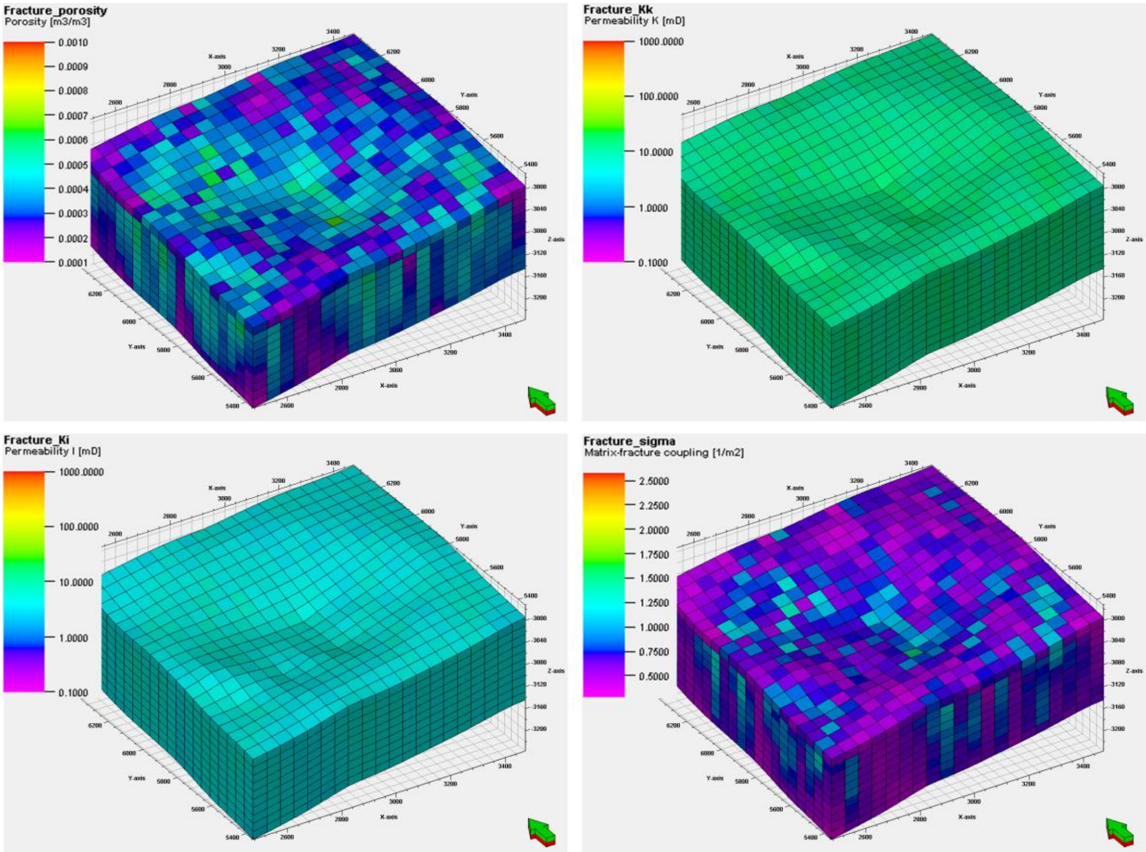

Fig. 6 Fracture properties distribution. From left to right: Fracture porosity, K-direction fracture permeability, I-direction fracture permeability and sigma factor.

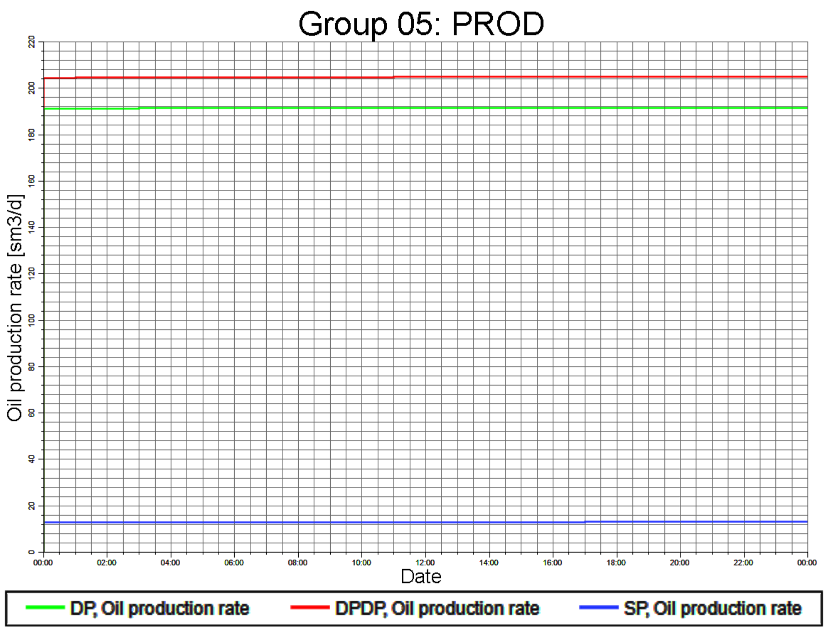

Fig. 7 Oil production rate comparison.

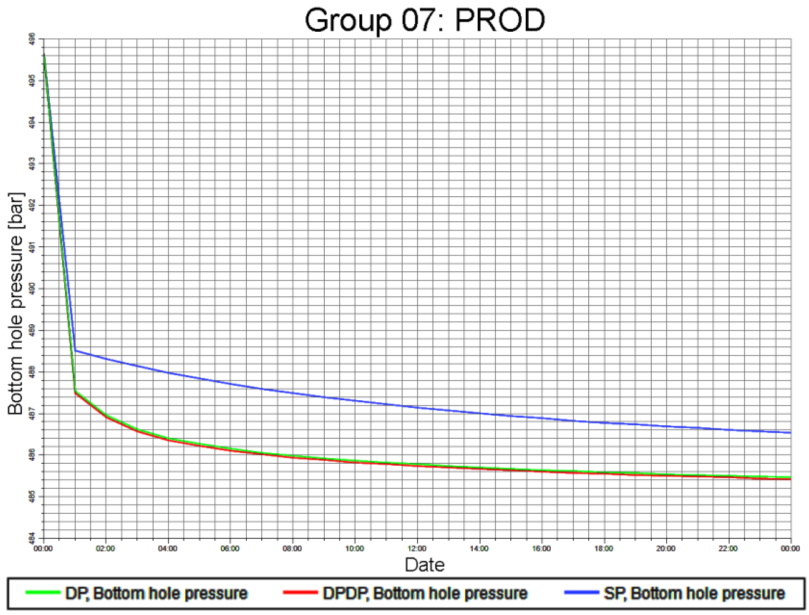

Fig. 8 Bottom hole pressure depletion comparison.

Table 4 Simulation results.

Parameters		Single-Porosity	Dual-Porosity	Dual-Porosity Dual-Permeability
		SP	DP	DPDP
Field Pressure (bar)	t = 0 hrs	497.60	497.61	497.61
	t = 24 hrs	497.58	497.47	497.46
Bottom Hole Pressure (bar)	t = 0 hrs	495.65	495.65	495.65
	t = 24 hrs	482.45	480.89	480.83
Cumulative Oil Production (sm3)		19.34	321.91	341.31

In a closer look, DPDP model yields higher flow rate and faster pressure depletion compared to DP model. The difference between these results is due to their fluid flow consideration. Dual porosity – single permeability system accounts fluid flow to take place only in the fracture network, while matrix blocks only act as a source. Dual porosity – dual permeability systems takes into account the possibility for fluid flow to occur between neighboring matrices. Matrix blocks have their normal transmissibility and contributes to the overall fluid flow.

This difference in flow consideration is represented through oil flow visualization as shown in Fig. 9. Oil flow is apparent in both fracture systems of DP and DPDP models. However, oil flow in matrix system can only be observed in DPDP model. Matrix-to-matrix flow and matrix-to-well flow are not taken into account in dual porosity – single permeability run.

4 Conclusion

A systematic methodology to construct an upscaled fracture model was established. Stochastic method was used to generate the fracture network based on the acquired fracture properties. The resulting fracture models were able to show the differences in a two-phase fluid flow between three systems in particular: single porosity, dual-porosity and dual-porosity – dual-permeability.

With additional fracture interpretation data from well logs and borehole images, a more precise deterministic mapping of fracture network may be generated. In addition, dynamic observations, such as data obtained from well tests and water breakthrough, will be able to assist in history matching of the model, allowing a proper evaluation of the model.

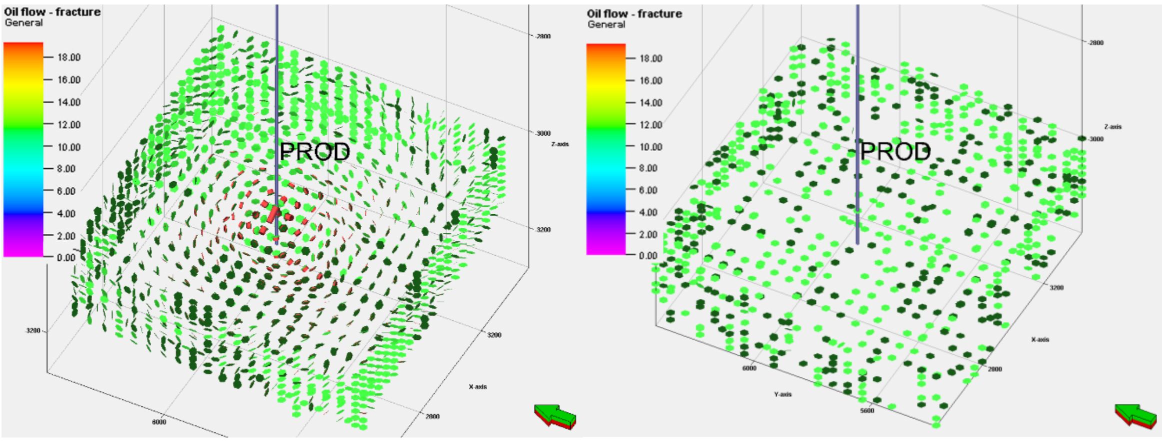

Fig. 9 Oil flow visualization of DP model at time t = 0 hours (left) and t = 24 hours (right). Flow direction is indicated by the green arrowhead and magnitude is indicated by the red arrow stem.

Nomenclature

Symbol	Description	Dimension / Unit
L_x, L_y, L_z	X, Y and Z-dimensions of material block making up the matrix volume	m
σ	Sigma factor	1/m^2

Declaration of Conflict of Interest

The authors declared that there is no conflict of interest with any other party on the publication of the current work.

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