MODELLING RECOVERY PROCESS IN DUAL POROSITY AND DUAL PERMEABILITY RESERVOIRS

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Abstract– *Determination of recovery of a reservoir is of great importance to oil companies for continuous monitoring of production and enhancement of recovery. In order to evaluate the recovery, there is need to use by measuring the production and oil-in-place (in volumetric units). In order to evaluate the recovery, there is a need to use correct oil in place and production values are very essential. For many decades, the volumetric method and material balance equation are used for the determination of oil-in-place and production using fluid and petro-physical properties. These evaluate oil-in-place and production for single porosity reservoirs successfully. Due to composite fluid flow behavior between fracture and matrix systems in dual porosity and dual permeability reservoirs, the determination of oil-in-place and production is simply made with software with consideration of both matrix and fracture parameters. This study determines the recovery of dual porosity and dual permeability reservoirs using eclipse 100 (black oil simulator). A base case of simulation model is developed with a typical reservoir fluid, and petro-physical properties using the black oil model. The recovery is impacted by the both matrix and fracture porosity and permeability-y. The black oil model serves to determine oil recovery in naturally fractured dual porosity and dual permeability reservoirs with the consideration that the composition of reservoir fluids does not change during the simulation.*

Key Words: *ECLIPSE, Recovery, Dual porosity reservoirs, Dual permeability reservoirs, Matrix porosity, Fracture porosity, Interporosity flow coefficient, Storativity ratio.*

1. INTRODUCTION

Proper understanding and representation of the complicated multiple media reservoir system is a key to successful field development and reservoir management to maximize the oil recovery. Unfortunately, the current single porosity and coarse simulation scale are unable to fully understand the geological features of the complicated reservoir system and over-simplified geological settings. In the absence of dual media in the simulation, many unsupported adjustments were consequently imposed on the matrix properties such as absolute permeability and three-phase relative permeability. To overcome the current single porosity model limitation, the robust simulation model is developed to properly establish a dual-porosity and dual permeability models that represent faults and fractures system. In this paper, we will present the system of production and recovery modeling using Dual porosity and dual permeability modeling simulation formulation.

1.1 Objectives of the study

The prime objective of this study is to model the production process and recovery efficiency for dual porosity and dual permeability reservoir using a black oil simulator (ECLIPSE 100) [1, 2]. Objectives of this study divided into multiple scopes.

Specific scopes of this study are as follows:

- The determination of recovery efficiency for dual porosity and dual permeability reservoirs

- To model the dual porosity and dual permeability reservoir production system in the grid form.

- Defining the parameters, that have an effect on oil production from reservoirs.

- To explain how the modification of fluid and petro-physical properties altering oil production.

1.2 Description of the physical system of a dual porosity and dual permeability reservoirs:

The porosity of a rock is a volumetric property measuring the storage capacity (pore volume) to hold the reservoir fluids. porosity is the ratio of void space (or) pore space in a rock to the total bulk volume of rock. Two main sorts of pore are often defined consistent with their time of formation:

- Primary porosity: Porosity that is formed at the time of deposition of sediments is called primary porosity. Fig -1 shows the primary porosities commonly available in the reservoirs [3].

- Secondary porosity: Porosity that is formed in a rock sometime after deposition is called secondary porosity. Example: Fracture porosity, Moldic porosity, Vuggy porosity. Fig. 1 shows the secondary porosities commonly seen in carbonate reservoirs and fractured reservoirs [3].

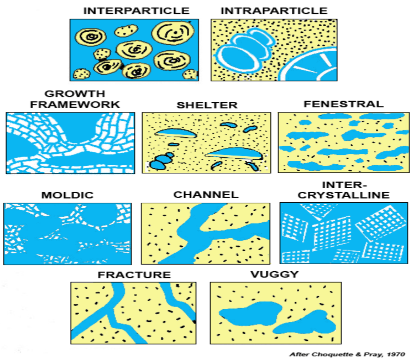

Fig. 1: Primary and secondary porosity systems

Rock characterized by primary porosity from original deposition and secondary porosity from different mechanisms like fracturing, recrystallization and dolomization, solution leaching, and in which flow to the well effectively occurs in one porosity system, and most of the fluid is stored with in the other. Such reservoirs are commonly termed as Dual porosity reservoirs. Naturally, fractured reservoirs, secondary porosity induced in carbonates, and vugular carbonates are classified as dual porosity reservoirs. Basement rocks serve as petroleum reservoirs because fracture porosity is sufficiently well endowed for them to flow. These reservoirs are commonly dual porosity systems wherever solution porosity has formed from the leach of unstable mineral grains. Fig -2 shows the methodology used for the grid formulation of naturally fractured reservoirs [5].

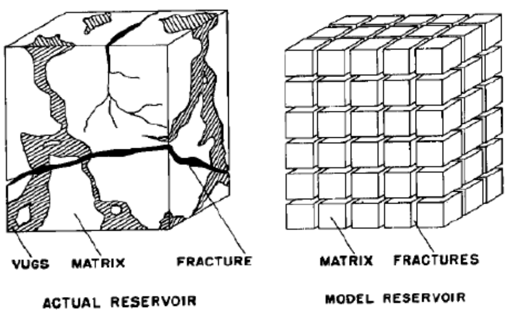

Fig. 2: Illustrating model for dual porosity reservoirs for fracture system

Initially, the reservoir is at high pressure with hydrocarbon fluids in both fracture and matrix pores. Since the fractures are well connected, the pressure will drop rapidly in them as the fluid is drained from the fractures while the lower permeability matrix will remain at high pressure. This leads to a pressure difference between fractures and matrix. There will be a flow of oil from the matrix to fracture as fluids expand. When the pressure drops below the bubble point, gas evolves from solution, and the expanding gas will lead to further recovery from the matrix [4]. This process is effective, but once the gas is connected in the system, principally only gas is produced, leaving significant quantities of oil in the matrix. Fig. 3(a) picturizes the flow process in dual porosity reservoirs [5].

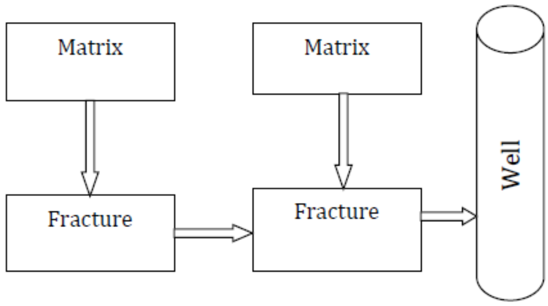

Fig. 3: (a). Dual porosity and single permeability system

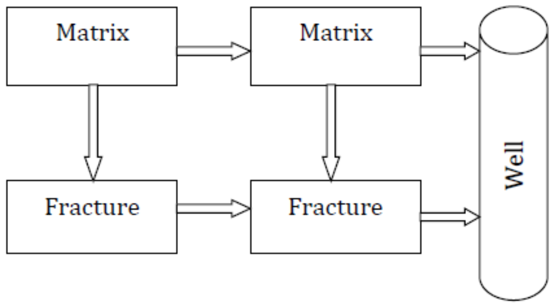

Fig. 3: (b) Dual porosity and dual permeability system

A dual porosity reservoir in which flow occurs to the well from both primary and secondary porosity systems is known as a dual permeability reservoir. In a dual porosity-dual permeability reservoir system, the fluid flow is from both matrix and fractures while in dual porosity-single permeability reservoirs, the fluid flow is from fractures only. Because of the unique conductivity and fluid storage feature of fractures and matrix, these reservoirs are usually called dual porosity-dual permeability reservoirs. The matrix provides the main storage while fractures provide the principal passage for the fluid flow [4]. Fig. 3(b) picturizes the flow process in dual permeability reservoirs. The important parameters in the dual porosity-dual permeability system are the interporosity flow coefficient, storativity ratio. The interporosity flow coefficient is defined as the ratio of permeability of the matrix to the permeability of fractures it indicates the flow of the reservoir and the storativity ratio is defined as the fraction of the total pore volume associated with fracture porosity that is indicates the storage volume in fracture porosity.

1.3 Recovery of oil production process

The Recovery Factor (RF) refers to the total cumulative volume of produced oil as a fraction of the initial total volume of oil in the reservoir [6]. Recovery with a time scale determines the efficiency of the production process. A high recovery factor is favorable whereas a low recovery factor implies the urge to apply secondary or tertiary recovery processes based on petro-physical and fluid properties.

$$Recovery\ factor\ (RF) = \frac{Volume\ of\ the\ total\ produced\ oil\ (N_p)}{Volume\ of\ the\ initial\ oil\ in\ reservoir\ (OOIP)}$$

Petro-physical and fluid properties affecting recovery [7]

Permeability variation: The relative permeability ratio of the reservoir rock is one of the factors controlling the recovery factor. The more permeable a reservoir rock is higher the ultimate recovery, thus the recovery factor. High relative permeability of hydrocarbon fluids aids in the increase of hydrocarbon mobility.

Porosity variation: Highly porous rocks (unconsolidated intergranular particles) affect the recovery most favorably, while low porous rocks tend to effect recoveries unfavorably. High-interconnected porosity gives a better permeability. High effective porosity is essential for high hydrocarbon storage and migration.

Connate water saturation: Connate water saturation is immobile water saturation adheres to the rock surface. Water occupies some pore space and leaves the remaining space for oil/gas. High water saturation implies water occupies larger space in the pores and low occupancy of oil/gas in the pores. In the case of three-phase fluid existence, gas saturation is also taken into consideration for oil occupancy in the pore. Hence low connate water saturation favors high occupancy of oil/gas in pore space. Hence, it favors an increase in the recovery of the process.

Oil gravity: The ultimate recovery increases with oil gravity. Lower API gravity implies high specific gravity. Thus, higher API or low specific gravity leads to a higher recovery factor. Oil recovery is higher in the reservoirs where gravity is the predominant drive mechanism.

Solution gas-oil ratio: A higher solution gas-oil ratio tends to lower ultimate recovery, and thus lower the recovery factor. Because of the liberation of free gas, the oil volume in the reservoir decreases.

Viscosity: A lower oil viscosity will lead to more improved recoveries, thus the recovery factor and higher water viscosity tend to high recovery. Low oil viscosity and high water viscosity also favor an increase in oil mobility.

Reservoir thickness: The reservoir pay thickness does not have much effect on the recovery factor.

Oil formation volume factor: A high formation volume factor results in high recovery because free gas liberation will be less at a high oil formation volume factor. A higher formation volume factor tends to have a high recovery factor.

2. MODELLING METHODOLOGY

2.1 SIMULATION MODEL DESCRIPTION FOR DUAL POROSITY RESERVOIR:

A three-phase, three-dimensional linear rectangular coordinate system, black oil simulator (Eclipse 100) [1, 2] is used for modeling and generating a recovery curve for the dual-porosity reservoir. Three vertical wells placed at three corners of the reservoir in which one is production well PX, one is water injection well IW, and the other one is gas injection well IG. Fig -4 shows the front view of the simulation model of the product grid with matrix properties having three wells in a linear coordinate system. Fig. 5 shows the front view of the simulation model of the product grid with fracture properties in a linear coordinate system. The color index depicts the oil-in-place values in different porosities four grids in Z-direction are used as two grids (1, 2) for matrix porosity in Z-direction and two grids (3, 4) for fracture porosity in Z-direction. Gravity drainage is considered in this model as the essential recovery mechanism [8].

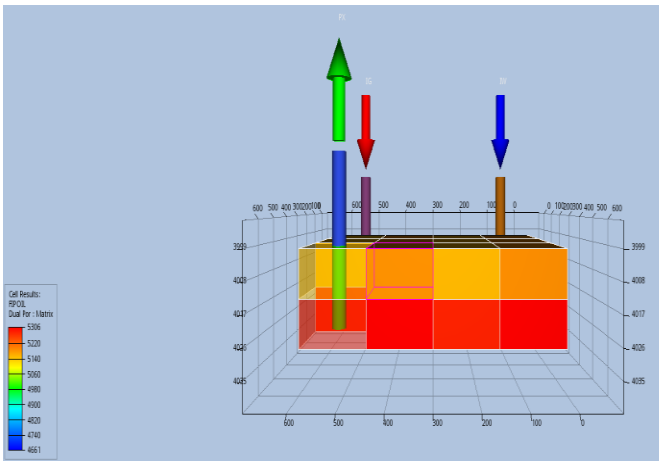

Fig. 4: Frontal view of dual porosity reservoir model in matrix porosity

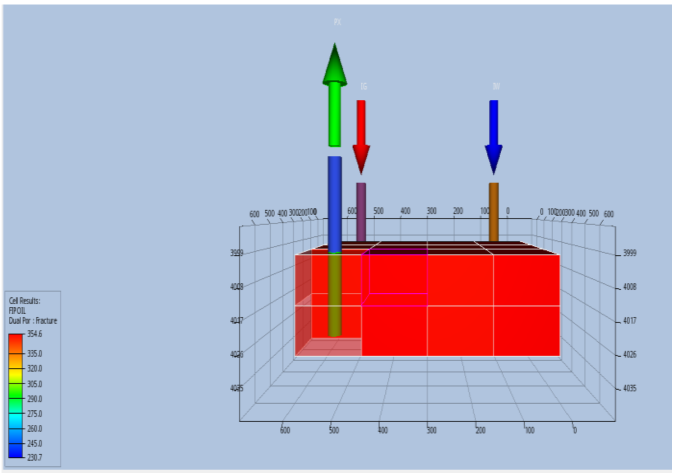

Fig. 5: Frontal view of dual porosity reservoir model in fracture porosity

A dual porosity model is built with matrix & fracture porosities and permeabilities. The bubble point pressure of the base case is about 4014 psia. Oil, gas, and water exist as three phases in the reservoir. Initial gas saturation and water saturation are about respectively. The base case data [8] used for dual porosity simulation is reported in table 1.

Table 1: Dual porosity simulation Model parameters

Reservoir parameters	Values	Units
Reservoir type	Dual porosity reservoir	
Grid system	Linear	
Reservoir Dimensions	4 x 4 x 4	ft
Grid size in X-direction	150	ft
Grid size in Y-direction	150	ft
Grid size in Z-direction	15	ft
Reservoir depth	4000	ft
Bubble point pressure	5014	psia
Matrix porosity	0.2	fraction
Matrix permeability	01	md
Fracture porosity	0.005	fraction
Fracture permeability	500	md
Density of oil	52	lb/ft^3
Density of water	64	lb/ft^3
Density of gas	0.044	lb/ft^3
Connate water saturation	25	%
Initial gas saturation	10	%
No. of production wells	01	
Oil production rate	209	STB/day
No. of injection wells	02 (water and gas injection wells)	
Gas injection rate	200	MSCF/day
Water injection rate	20	STB/day

2.2 SIMULATION MODEL DESCRIPTION FOR DUAL PERMEABILITY RESERVOIR:

A three-phase, three-dimensional linear model, a black oil simulator (Eclipse 100) [1, 2] is used for modeling and generating a recovery curve for a dual permeability reservoir. Four vertical production wells are placed at two corners of the reservoir. Fig -6 shows the front view of the simulation model of the product grid with matrix properties having four production wells in a linear coordinate system. Fig -7 shows the front view of the simulation model of the product grid with fracture properties in a linear coordinate system for a dual permeability reservoir. 6 grids in z-direction are used as 3 grids (1, 2, 3) for matrix porosity in z-direction and 3 grids (4, 5, 6) for fracture porosity in z-direction. Gravity drainage and imbibition are one of the majorly acting recovery mechanisms in this model [9].

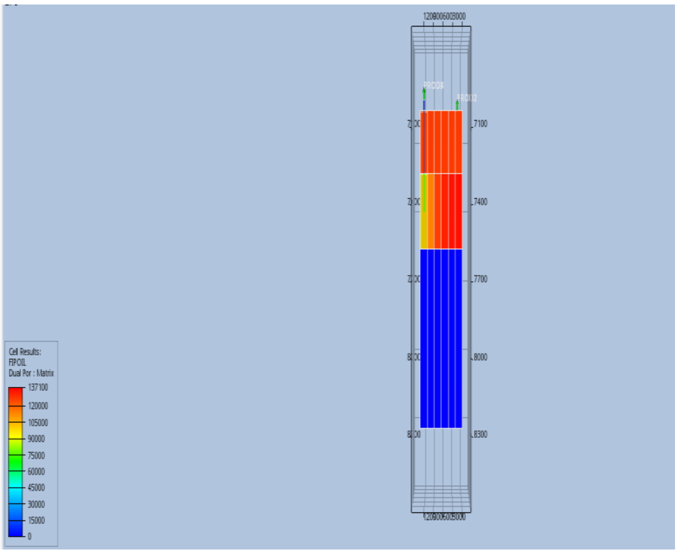

Fig. 6: Frontal view of dual permeability reservoir model in matrix porosity

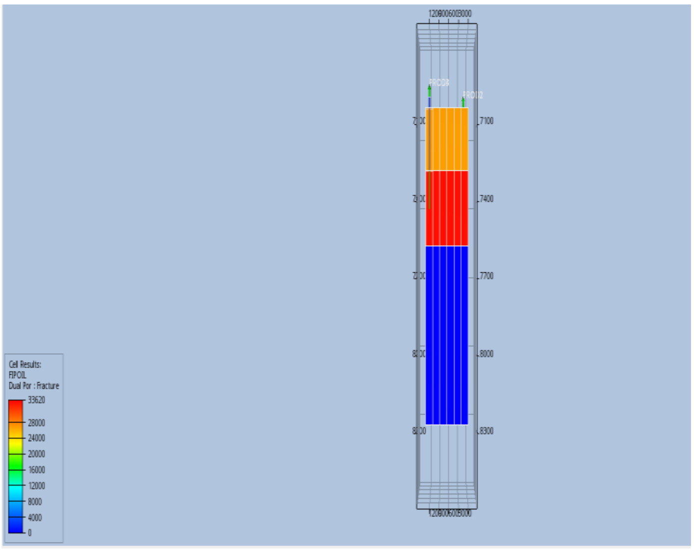

Fig. 7: Frontal view of dual permeability reservoir model in fracture porosity

The dual porosity-dual permeability model is built with different combinations of matrix & fracture porosities and permeabilities. The base case is modeled as four producing wells namely PROD 1, PROD 2, PROD 3, PROD 4 where PROD 1 and PROD 2 are situated at the same grid point and PROD 3, and PROD 4 are situated at the same grid point. Bubble point pressure of about 5014 psi is used in the base case. Connate water saturation of about 25% is assigned to all grid cells. The base case data [10] used for dual permeability reservoir simulation is reported in table 2.

Table 2: Dual permeability simulation Model parameters

Reservoir parameters	Values	Units
Reservoir type	Dual permeability reservoir	
Grid system	Linear	
Reservoir dimensions	6 x 6 x 6	ft
Grid size in X-direction	220	ft
Grid size in Y-direction	220	ft
Grid size in Z-direction	Varied	ft
Reservoir depth	7021	ft
Porosity	Varied	fraction
Permeability	Varied	md
Density of oil	55	lb/ft^3
Density of water	62.43	lb/ft^3
Density of gas	0.1	lb/ft^3
Connate water saturation	30	Percent
Initial gas saturation	10	Percent
Rock compressibility	4×10^{-6}	psi^{-1}
No. of production wells	04	

3. RESULTS OF SIMULATION RUNS

The production of dual porosity and dual permeability reservoir is monitored under the effect of a natural driving mechanism (Gravity drainage and Spontaneous imbibition). This mechanism depends on reservoir pressure. However, the recovery factor is not high under the natural driving mechanism because of less support for the reservoir pressure to maintain constant or higher value.

3.1 SIMULATION RESULTS OF DUAL POROSITY RESERVOIR

The developed dual-porosity reservoir model was run with the application of gas injection and a water injection well. It was noticed that average reservoir pressure declined to a pressure of 3874 PSIA as shown in Fig. 8 [11]. Cumulative oil production, Fig. 10 has reached 4200 STB out of the total original oil in the reservoir, Fig. 9, which is 178812 STB [11]. This shows that the recovery factor of produced oil, Fig. 11 was only 2.34% out of total oil in the reservoir [12]. The summary of the simulation results of the dual-porosity reservoir model as shown in table 3.0.

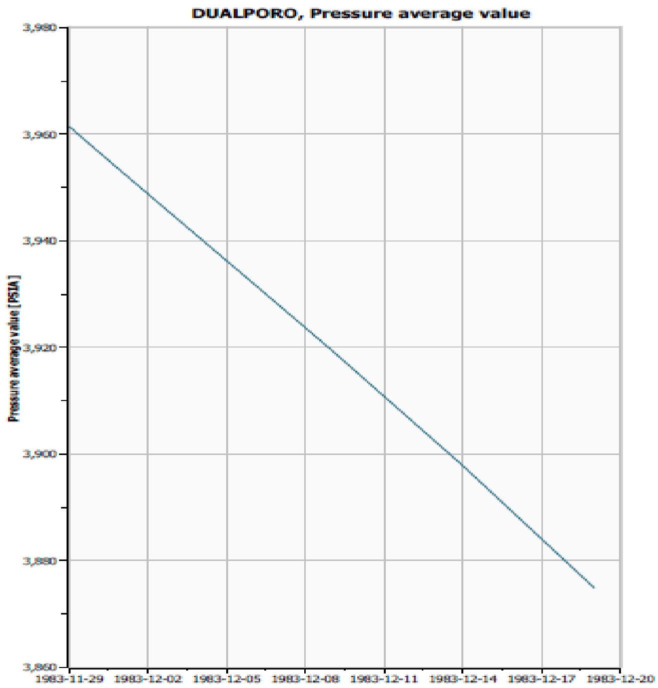

Fig. 8: Average reservoir pressure in dual porosity reservoir model

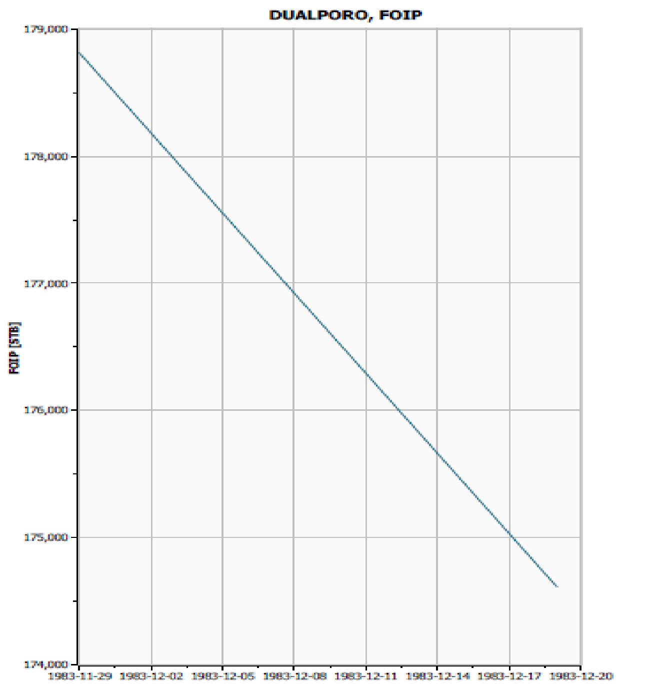

Fig. 9: Oil-in-place in dual porosity reservoir model

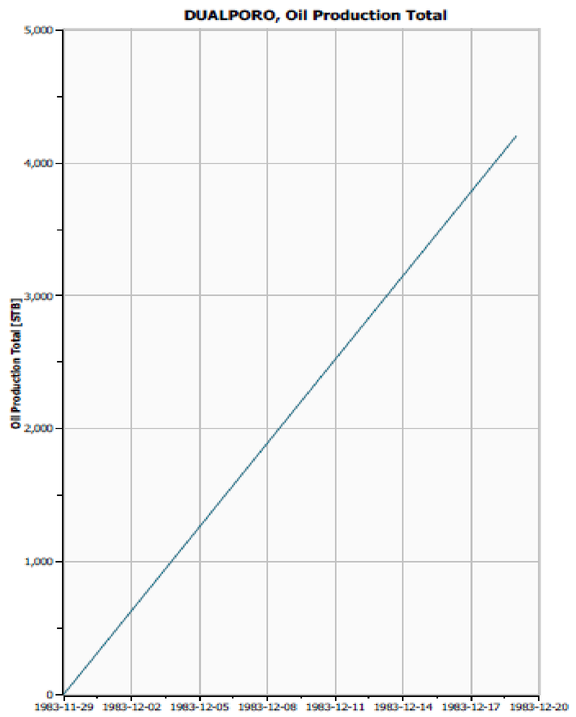

Fig -10: Cumulative oil production in dual porosity reservoir model

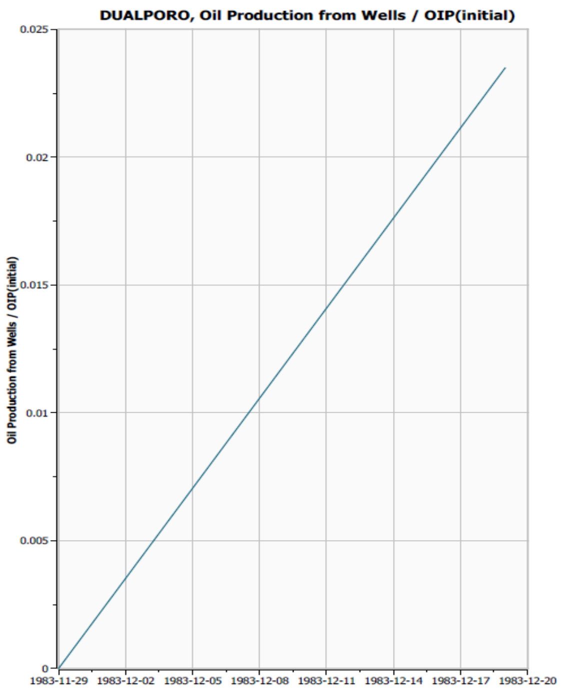

Fig -11: Oil recovery efficiency in dual porosity model

Table -3: Summary of Simulation results of dual porosity reservoir model

Parameters	Value	Units
Original oil in the reservoir	178812	STB
Cumulative oil production	4200	STB
Max. oil production rate	209	STB/day
Min. oil production rate	0	STB/day
Max. average reservoir pressure	3961	PSIA
Min. average reservoir pressure	3874	PSIA
Oil recovery factor	2.34	%
Cumulative gas production	6163	MSCF
Gas production rate	364	MSCF/day
Cumulative gas injection	4000	MSCF
Cumulative water production	0.055	STB
Cumulative production rate	0.009	STB/day
Cumulative water injection	400	STB

The gas production is equivalent to oil production volume. Equivalent production volume is established because of the high original gas in the reservoir. The gas injection also aided in the increase in gas volume. The pressure initially lowered below the bubble point pressure. Hence, the recovery of oil is too low in spite of using injection wells.

3.2 SIMULATION RESULTS OF DUAL PERMEABILITY RESERVOIR

The production of a dual permeability reservoir is monitored under the effect of a natural driving mechanism (Gravity drainage and Spontaneous imbibition). The developed dual permeability reservoir model was run. It was noticed that the average reservoir pressure is declined to 1013 PSIA as represented in Fig -12 [11]. Consequently, cumulative oil production, Fig -14 is about 1.8958 x 106 STB, and the total initial oil in the reservoir is 1.2606 x 107 STB, Fig -13 [11]. This shows that the oil recovery factor, Fig -15 is about 15% out of the total oil in the reservoir [12]. Summary of Simulation results of the dual-porosity reservoir model as presents in table 4.0.

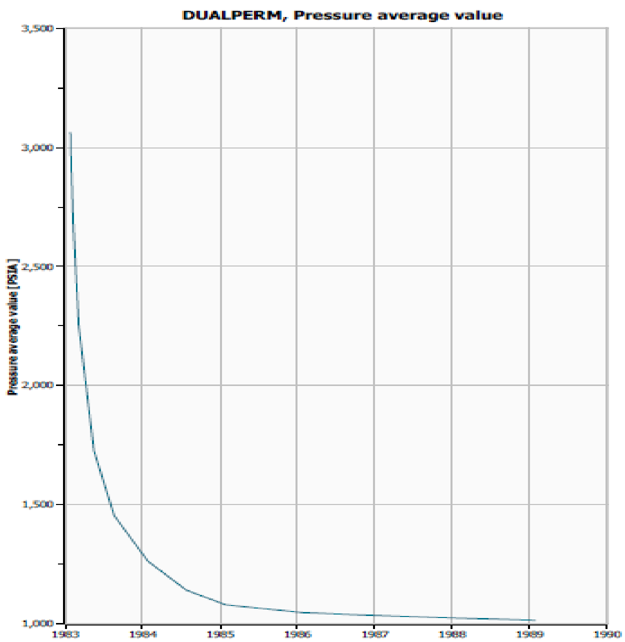

Fig. 12: Average reservoir pressure in dual permeability reservoir model

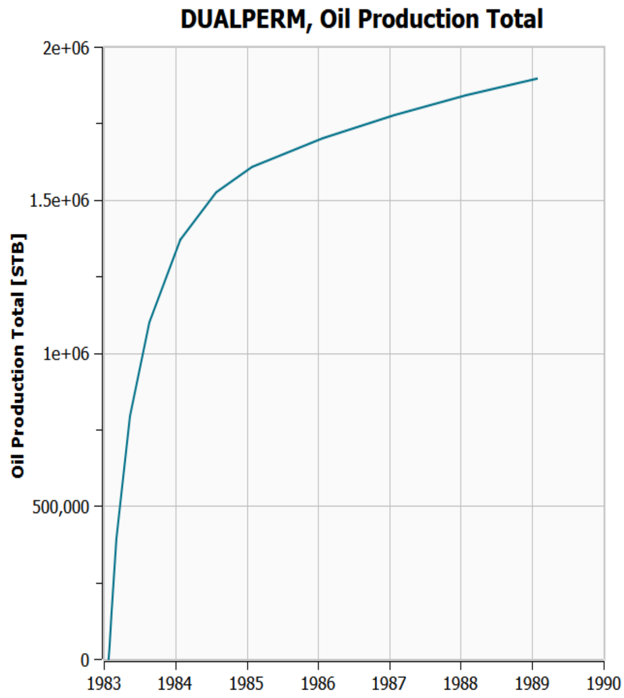

Fig. 14: Cumulative oil production in dual permeability reservoir model

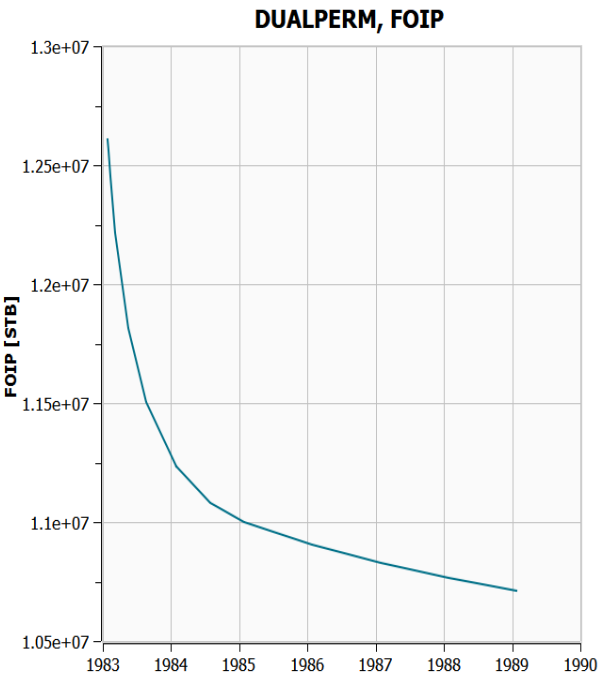

Fig. 13: Oil-in-place in dual permeability reservoir model

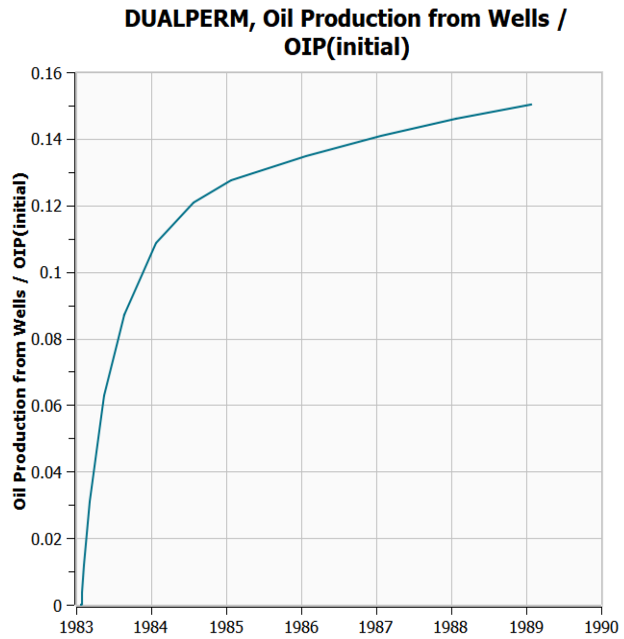

Fig. 15: Oil recovery efficiency in dual permeability model

Table 4: Summary of Simulation results of dual porosity reservoir model

Parameters	Value	Units
Original oil in the reservoir	1.2606×10^7	STB
Cumulative oil production	1.8958×10^6	STB
Max. average reservoir	3062	Psia

pressure		
Min. average reservoir pressure	1013	Psia
Oil recovery	15	%
Max. oil production rate	14687	STB/day
Min. oil production rate	150	STB/day
Cumulative gas production	1.13023 x 10^6	MSCF
Max. gas production rate	3605	MSCF/day
Min. gas production rate	26.245	MSCF/day
Cumulative water production	42652	STB
Max. water production rate	416	STB/day
Min. water production rate	2.05	STB/day

The recovery of the dual permeability reservoir is optimum without the application of secondary or tertiary recovery methods. The reservoir pressure is dropped below the saturation pressure. In spite of the variation in gas-oil ratio, oil is well produced. If a gas injection is introduced, it may lead to high gas production.

4. PETROPHYSICAL AND FLUID PROPERTY ANALYSIS

4.1 EFFECT OF OIL FORMATION VOLUME FACTOR

The oil formation volume factor relates the quantity of oil at reservoir conditions to the quantity of oil at stock tank conditions. The oil formation volume factor increases until the reservoir pressure decreases to bubble point pressure. After reaching bubble point pressure, the oil formation volume factor decreases because of the liberation of dissolved gas [1,2]. A higher oil formation volume factor tends to increase the ultimate recovery. Fig -16 & 17 shows the variation of oil formation volume factor with reservoir pressure during the production period for dual porosity and dual permeability reservoir models.

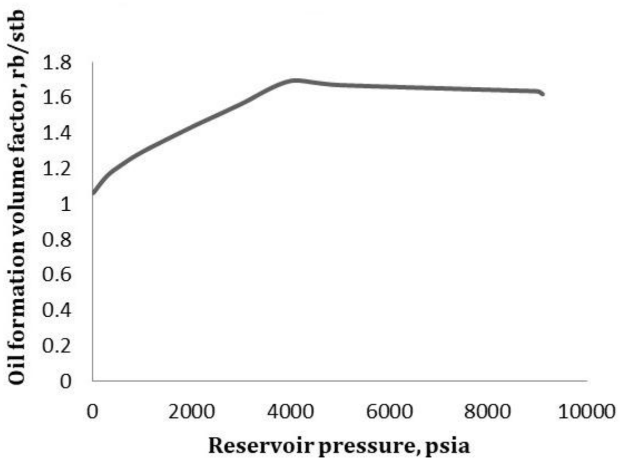

Fig. 16: Variation of Oil formation volume factor in dual porosity reservoir

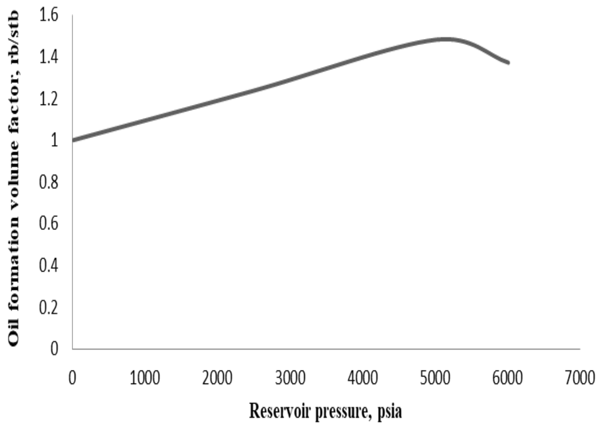

Fig. 17: Variation of Oil formation volume factor in dual permeability reservoir

4.2 EFFECT OF OIL VISCOSITY

Oil viscosity varies with reservoir pressure i.e., based on saturation pressure. Oil viscosity decreases until reservoir pressure reaches saturation pressure, oil viscosity increases from the saturation pressure point. This implies pressure maintenance at saturation pressure helps in a better flow of oil hence results in high recovery. Fig. 18 & 19 shows the variation of oil viscosity with reservoir pressure during the production period for dual porosity and dual permeability reservoir models [1, 2].

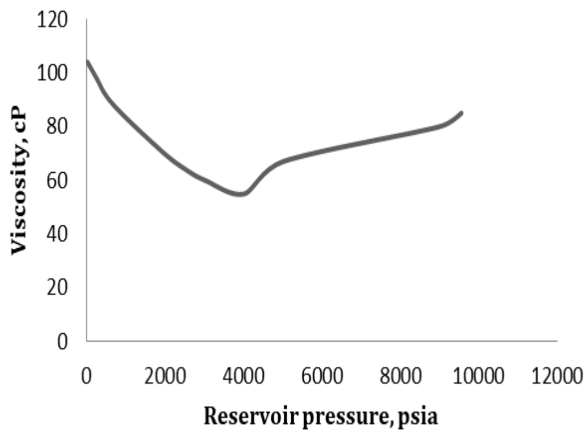

Fig. 18: Variation of oil viscosity in dual porosity reservoir model

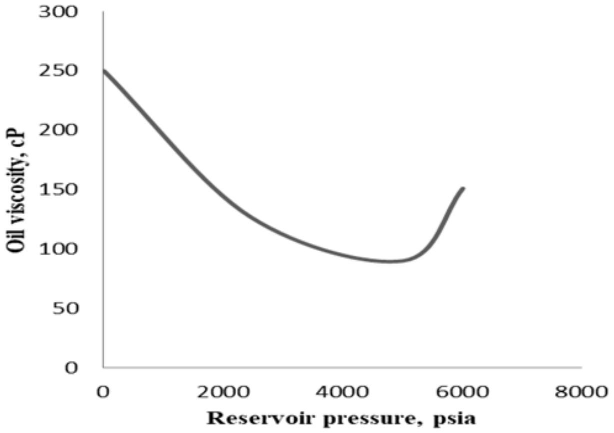

Fig. 19: Variation of oil viscosity in dual permeability reservoir model

4.3 EFFECT OF GAS OIL RATIO ON RECOVERY

Gas oil ratio is the ratio of production volume of gas at standard conditions to production volume of oil at standard conditions. Gas oil ratio increases when the free gas is evolved after reaching saturation pressure. High gas oil ratio favors high gas production. Gas flow faster oil and inhibits the flow of oil, which reduces the production of oil. Sometimes GOR may increase due to high gas injection [1, 2]. Fig. 20 & 21 shows the variation of Gas Oil ratio during the production period for dual porosity and dual permeability reservoir models.

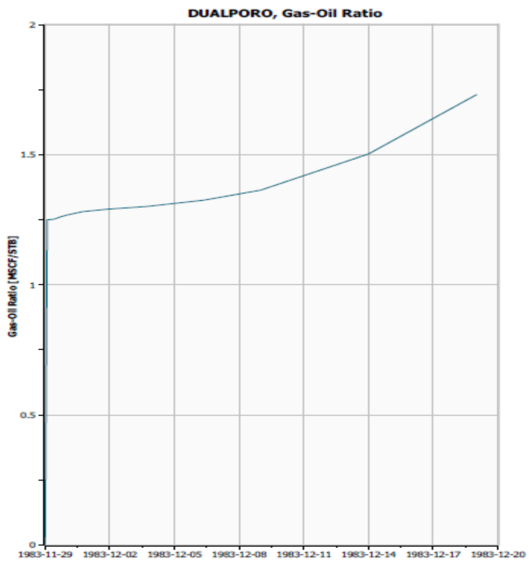

Fig. 20: Variation of Gas Oil Ratio in dual porosity reservoir model

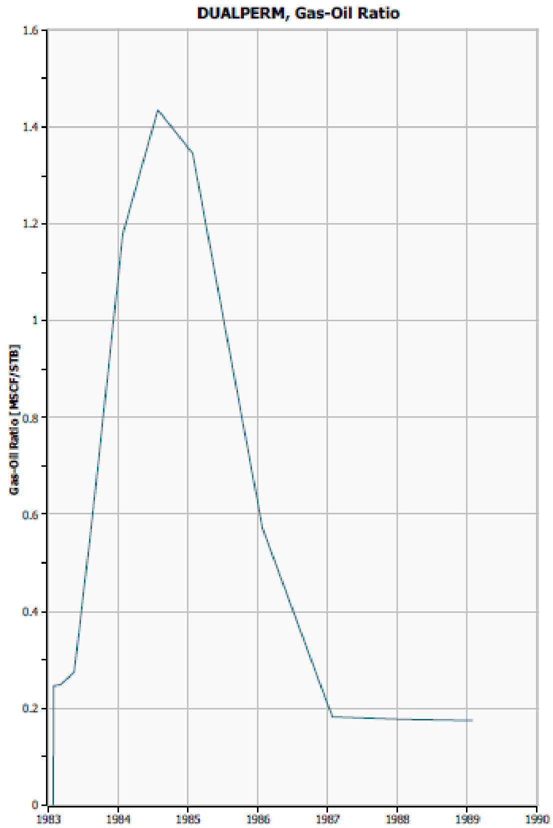

Fig. 21: Variation of Gas Oil Ratio in dual permeability reservoir model

5. CONCLUSIONS

In this study, recoveries of dual porosity and dual permeability reservoir are determined using a black oil simulator. Based on this work-study we conclude that

- The prime objective of this study i.e., to determine the recoveries of dual porosity and dual permeability reservoirs is achieved using a black oil simulator.
- The production grid modelling of dual porosity and dual permeability reservoirs are developed.
- Alteration of petro-physical and fluid properties (Oil formation volume factor, Oil viscosity, and Gas oil ratio) affecting the recovery are analyzed with the period of production or with reservoir pressure.

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