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Influence of low permeability barrier on hot water flooding performance – a numerical investigation

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Abstract

The existence of a low permeability barrier acts as a geological discontinuity in oil reservoirs. The presence of such discontinuities could alter the flow of injected hot water in the formation and would significantly influence the hot water flooding projects. The aim of the present work is to demonstrate the influence of a low permeability barrier on hot water flooding performance. For this purpose, we have formulated a numerical model by coupling energy transport and multiphase fluid flow models under non-isothermal conditions. The influence of the horizontal and vertical arrangement of the low permeability barriers in a reservoir formation is investigated. The low permeability barrier has a significant effect on the oil recovery when it is located closer to the injection well; subsequently, the production performance of oil recovery is improved by shifting the low permeability barrier towards a production well. The spatial (location) shift of the low permeability barrier towards the production well reduces its effect on the hot water flooding performance, and in turn, cumulative oil production improves. The cumulative oil produced is found to be 344.14 m^3 in 200 days when the low permeability barrier is situated near the production well during hot water flooding, which is improved by 2.23% and 6% with respect to low permeability located at the middle of the reservoir, and closer to the injection well, respectively. The pressure buildup decreases at the injection well with the presence of a low permeability barrier near the injection well. The low permeability barriers present at a slight offset location from the middle of the reservoir in the vertical direction provide a better cumulative oil production than the low permeability barrier arranged with no offset condition and fully offset condition in the reservoir. The cumulative oil produced is found to be 341 m^3 in 200 days when the low permeability barrier is present at a slightly offset condition in the middle of the reservoir, which is improved by 1.30% and 1.24% with respect to no offset condition and fully offset condition, respectively. The present study can provide the pathways for the future investigation of low permeability barriers for hot water flooding.

Keywords:

low permeability barrier; oil saturation distribution; injection pressure buildup; cumulative oil production; numerical investigation

1. Introduction

The increase in world population and the growth in industrialisation are increasing the world energy demand incessantly (**Samsol et al., 2023**). The total proven oil has been estimated at 126.7 billion tons in the world. More than 70% of the proven original oil in place remains to be heavy oil (**Zhang et al., 2023; Guo et al., 2016**). High energy demand and limited conventional oil reserves will not be able to meet the expected energy demand in the future owing to increasing population and industrial development (**Riazi and AlQaheem, 2010**). The exploitation of unconventional oil reserves such as heavy oil, oil sands, and bitumen could significantly satisfy the energy demand; hence, the exploitation of heavy oil is necessary to mitigate the energy crisis (**Huang et al., 2023; Ansari and Govindarajan, 2023**). A sound understanding of different types of enhanced oil recovery mechanisms associated with fluid flow through porous media is desirable towards characterizing the numerous subsurface applications such as production forecasting and reservoir management (**Vulin et al., 2018; Hanegaonkar et al., 2019; Arnaut et al., 2021**).

Thermal oil recovery methods such as steam injection, in-situ combustion, and hot water flooding are good candidates for the exploitation of heavy oil formations (**Santana et al., 2023; Anvari and Turzo, 2024; Pavan et al., 2022**). Heavy oil reservoirs can be explored by finding various means to decrease the oil viscosity. The aim of these processes is to transfer its heat energy to crude oil, subsequently reduce the oil viscosity, and

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eventually, to increase the oil mobility (**Hascakir and Noynaert, 2018**). The presence of high temperature effectively supports the displacement phenomenon of crude oil through the reservoir by reducing the viscous forces (**Algharaib et al., 2014**). On the other hand, the viscosity of oil can be reduced by increasing the flow capacity of heavy oil and heating the formation (**Chen et al., 2023; Srinivasa Reddy and Suresh Kumar, 2015**).

Hot water flooding is a thermal-enhanced oil recovery method that significantly improves the efficiency of heavy oil exploitation (**Han et al., 2017; Ansari and Govindarajan, 2023**). Hot water flooding is generally applied in unconventional oil reservoirs, possessing high viscosity and low API gravity. Hot water flooding is injected into the formation through the injection well. The heat introduced reduces the intermolecular force of attraction and the viscosity of the oil (**Banerjee et al., 2016**). However, the geology of the formation can influence the performance of the hot water flooding. Several factors, such as layer arrangement, permeability variation within the formation, the presence of shale in the interlayer, and the presence of low permeability faults or barriers, can impact the enhanced oil strategy (**Santana et al., 2023**).

Goodyear and Townsley (1996) studied the impact of reservoir heterogeneity on the improved oil recovery by applying hot water flooding. The uncorrelated small-scale heterogeneity has an insignificant effect on the hot water flooding, whereas correlated heterogeneity is observed to have a significant effect on the hot water flooding in two-dimensional horizontal flow**.** However, the inclusion of barriers or faults in the reservoir domain was not considered for the investigation.

Woods et al. (1996) studied the influence of the injection temperature of water on oil recovery in a reservoir possessing viscous oil. The effect of injection temperature on the low-temperature field possessing oil viscosity of 100 cP and 400 cP and moderate temperature possessing oil viscosity of 10 cP field in an anisotropic permeability environment were studied. Hot water flooding was observed to be detrimental in moderate temperature fields possessing oil viscosity of 10 cP. Hot water flooding was observed to have marginal benefits in low-temperature formations possessing 100 cP, whereas it was observed to be attractive in low-temperature formations possessing 400 cP.

Alajmi et al. (2009) explored the hot water injection performance in heterogeneous reservoirs using multilateral wells. The displacement performance of hot water flooding was significantly impacted by the combination of high variation in permeability and high correlation length. The oil recovery was observed to decrease with an increase in multilateral injection well length during hot water flooding, whereas the change in lateral well length in multilateral injection wells was observed not to be significant in the heterogeneous reservoir.

Alajmi et al. (2014) investigated the hot water injection performance in different heterogeneous reservoirs. The impact of well configuration on the hot water injection performance is also investigated. The investigated formation was a heterogeneous Middle Eastern reservoir possessing heavy oil and different fluid properties at different locations. The hot water injection performance is drastically impacted by the extent and geometry of reservoir heterogeneity. The vertical wells were observed to be highly suitable for developing the reservoir when applied using a five-spot pattern. The displacement performance of horizontal or multilateral wells was reduced significantly with the combination of large variations in permeability and strong correlation.

Zhao and Gates (2015) studied the impact of permeability heterogeneity on oil production and water breakthrough during hot water flooding. The permeability distribution was observed to play a significant role in the hot water injection performance. The overall heat utilisation efficiency is increased by the injection of lower temperatures at later stages of the recovery process due to heat recovery from the matrix. The larger permeability zone in the deeper part of the formation caused earlier production of oil and water breakthrough.

Wu and Liu (2019) studied the impact of the reservoir layer interchange effect on the hot water injection to improve oil recovery in thin formations after steam injection. Hot water flooding was observed to act effectively in reverse-rhythm and compound-rhythm reservoirs and was found to be poor in a positive-rhythm reservoir. Steam injection and hot water injection could yield extensive oil recovery when the heterogeneity is low, whereas the oil production obtained by steam and hot water injection degrades when the heterogeneity becomes serious.

Mortazavi et al. (2022) studied the impact of fracture orientation on the accomplishment of water flooding under isothermal and non-isothermal reservoir conditions. A computational technique was developed to investigate two-phase flow in the formation possessing micro- and macro-fractures. The naturally fractured reservoir was observed to block the oil during the water flooding process. The hot water injection caused significant oil viscosity reduction, facilitated the oil movement towards the production well and improved the oil recovery.

Based on the literature review, hot water flooding in different types of heterogeneous environments has been discussed in the previous study. The current work demonstrates the impact of geological discontinuities, such as shale, salt, and clay layers, which can act as a low-permeability barrier in sandstone reservoirs to hot water flooding. These discontinuities can alter the flow of fluids in the formation and impact the overall performance of the hot water flooding. The present study aims to understand the impact of low permeability barrier arrangement on the oil saturation distribution, injection pressure buildup, cumulative oil production, and temporal change

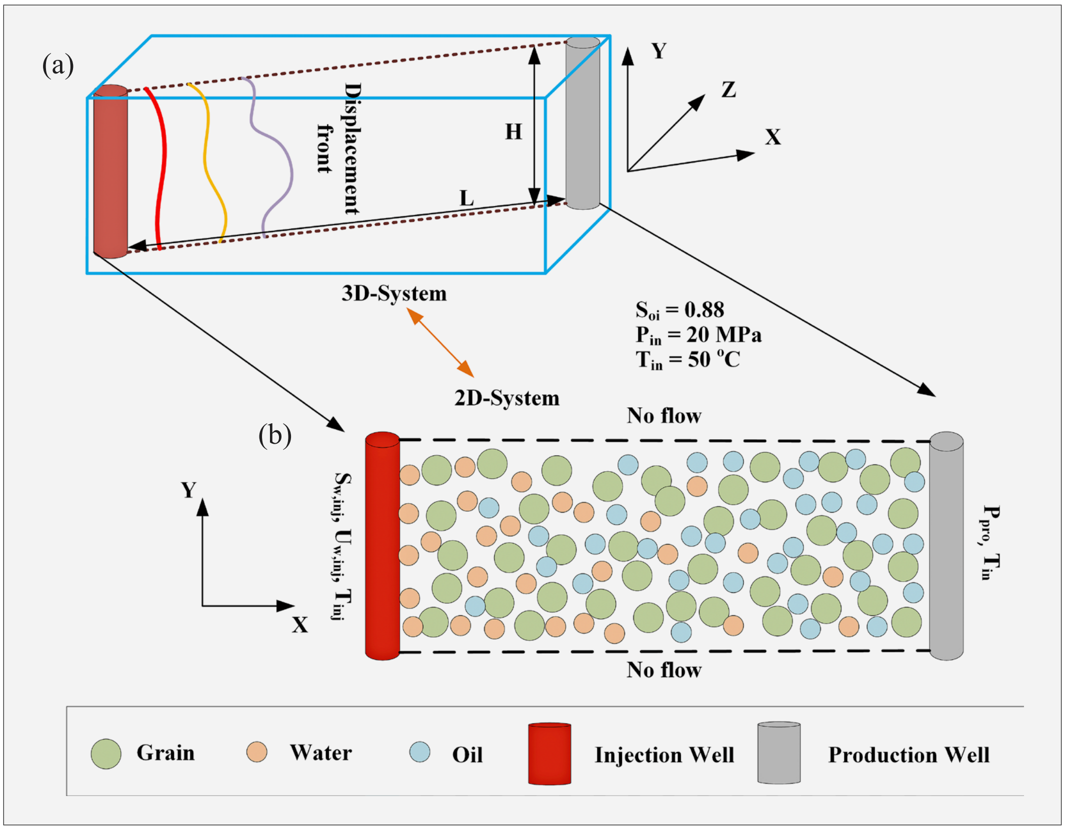

Figure 1: For the simulation of hot water flooding in a heterogenous reservoir: (a) three-dimensional pay zone, (b) two-dimensional cross-sectional plane view.

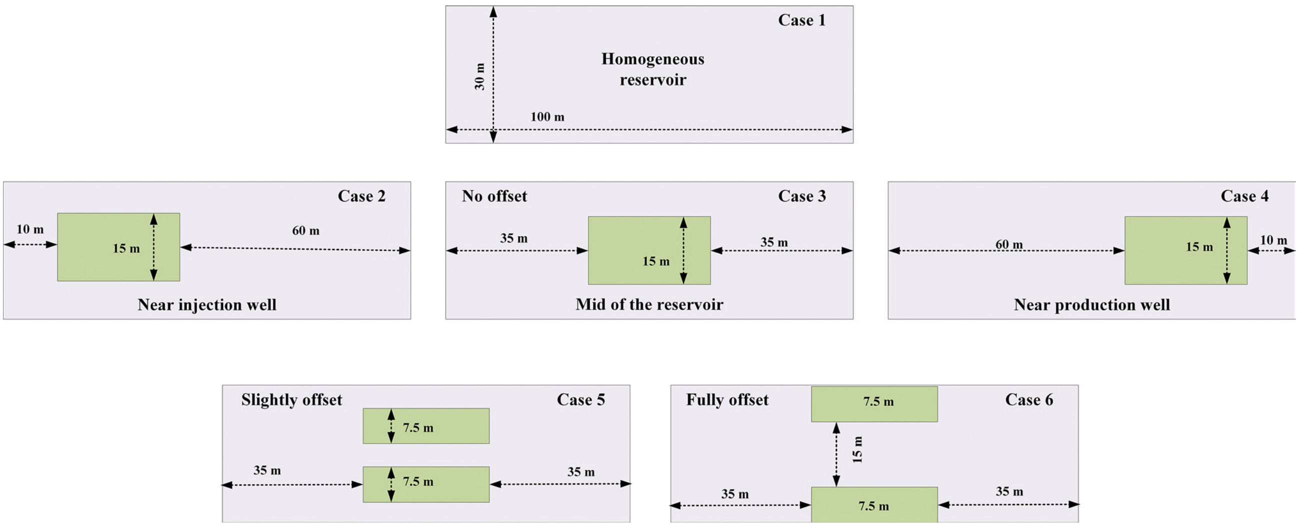

Figure 2: Reservoir model possessing low permeability barrier at different location in horizontal direction, and low permeability barrier breaking and shifting in vertical direction along with the equivalent homogeneous model.

in oil and water saturation at the production well during the hot water injection process. The understanding of the position of barriers and vertical arrangement of low permeability barriers at different offset positions in the hot water flooding performance can contribute to the oil and gas industries' future development of these types of reservoirs using hot water flooding.

2. Physical model

The reservoir model has been built in two dimensions considering the cross-sectional view. The model is considered to possess an injection and a production well. The injection and production well is maintained at 100 m in the 'x' direction (**Gudala and Govindarajan,**

2021). The thickness of the reservoir is maintained in the 'y' direction by 30 m (**Moradi et al., 2022**). The reservoir is considered to possess 88% oil saturation and 12% of water saturation. The schematic of the reservoir model is presented in **Figure 1**.

The presence of shale, salt layers, or clay layers can act as discontinuity to the formation. A formation possessing permeability lower than 50 mD is termed a low-permeability rock formation (**Li et al., 2021**). The barriers can be horizontal in nature, like shales, micaceous streaks or stylolites, and can be vertical, like faults or stratigraphic changes (**He et al., 2002**). For a better understanding of these discontinuities in the formation, several cases have been formulated in the present work. At first, the low permeability present near the injection well (Case 2), middle of the reservoir (Case 3), and near the production well (Case 4) are synthetically formulated and compared with the homogeneous reservoir (Case 1). Then, the low permeability present in the middle of the reservoir with no offset (Case 3), slightly offset (Case 5), and fully offset (Case 6) was formulated and compared with the homogeneous reservoir (Case 1). The word 'offset' means symmetrical vertical separation of the low permeability barrier from the centerline. The average permeability of all the systems is considered equal for the comparative analysis. The cases developed have a low permeability barrier of 14 mD in the reservoir formation of 200 mD in the heterogeneous reservoir, as shown in **Figure 2**.

3. Mathematical modelling

3.1. Assumptions

The reservoir is considered in local thermal equilibrium, meaning the grain and fluid temperature are considered constant. The two-phase is considered non-miscible and incompressible. The flow is constrained to a no flow condition through all boundaries except the injection and production well. The outflow condition is assumed at the production well, and no reenter of fluid to the formation is considered through the production well. The heavy oil is non-volatile. The capillary pressure is assumed to be equal in both the low permeability barrier and the reservoir formation.

3.2. Governing equations

The fully coupled equations have been developed using energy transport and multiphase flow equations, which have been presented in **Equations 1, 4, 5, 6** and **7** (**Mortazavi et al., 2022; COMSOL Multiphysics**).

The energy conservation equation is presented in **Equation 1**.

$$\left(\rho C_p\right)_d \frac{\partial T}{\partial t} + \left(\rho C_p\right)_{lf} \mathrm{u}.\nabla T + \nabla(-k_d \nabla T) = Q_s \quad (1)$$

$$\left(\rho C_P\right)_d = \Phi_u(\rho_{w'} S_{w''} C_{w'} + \rho_{o'} S_{o''} C_{o'}) + (1-\Phi_u)\rho_{r'} C_r \quad (2)$$

$$K_d = (1-\Phi_u)K_{s'} + \Phi_u(S_{w''} K_{w'} + S_{o''} K_{o'}) \quad (3)$$

Where 'Q_s' is the heat source or sink, 'ϕ_u' updated porosity, 'u' the darcy's phase velocity of the fluid, 'T' transient temperature, '$S_{w''}$' and '$S_{o''}$' water and oil saturation, '$(\rho C_p)_d$' effective heat capacity, and 'K_d' effective thermal conductivity.

Oil phase mass conservation and momentum equations are presented in **Equations 4** and **5.**

$$\frac{\partial}{\partial t}\left(\Phi_u \rho_{o'} S_{o''}\right) + \nabla.\{\rho_{o'} u_{o.}\} = Q_{o.} \quad (4)$$

$$u_o = -\frac{K_{ro} K_u \left(\nabla P_{o.} - \rho_{o'} g\right)}{\eta_o} \quad (5)$$

Where '$Q_{o.}$' is the mass flux of oil phase, 'K_{ro}' relative permeability of oil phase, 'K_u' updated permeability of the reservoir, 'g' the gravitational acceleration, '$u_{o.}$' velocity of oil phase and 'η_o' the dynamic viscosity of oil phase, '$P_{o.}$' oil phase pressure field respectively.

Water phase mass conservation and momentum equations are presented in **Equations 6** and **7**.

$$\frac{\partial}{\partial t}\left(\Phi_u \rho_{w'} S_{w''}\right) + \nabla.\{\rho_{w'} u_{w.}\} = Q_{w.} \quad (6)$$

$$u_{w.} = -\frac{K_{rw} K_u \left(\nabla P_{w.} - \rho_{w'} g\right)}{\eta_w} \quad (7)$$

Where '$Q_{w.}$' is the mass flux of water phase, 'K_{rw}' relative permeability of water phase, '$u_{w.}$' velocity of water phase and 'η_w' the dynamic viscosity of water phase, '$P_{w.}$' water phase pressure field respectively.

The total phases in the porous domain constitute the volume of the fluid fraction in the reservoir. The sum of oil and water phase saturation is written in **Equation 8**. The difference of the oil phase and water permeability is shown in the form of capillary pressure which is written in **Equation 9**.

$$S_{o''} + S_{w''} = 1 \quad (8)$$

$$P_{o.} - P_{w.} = P_{c'} \quad (9)$$

Where '$P_{c'}$' is capillary pressure.

The flow of fluid depends on the capillary pressure, and relative permeability of the fluids, which are presented in **Equations 12, 13** and **14** (**Brooks and Corey, 1964**).

$$S_{w1} = \frac{(S_{w''} - S_{rw'})}{(1 - S_{rw'} - S_{ro'})} \quad (10)$$

$$S_{o1} = \frac{(S_{o''} - S_{ro'})}{(1 - S_{rw'} - S_{ro'})} \quad (11)$$

$$P_{c'} = P_{ey}(S_{w1})^{\frac{-1}{\omega}} \quad (12)$$

$$K_{rw} = (S_{w1})^{(3+\frac{2}{\omega})} \quad (13)$$

$$K_{ro} = S_{o1}^{\ 2}(1-(1-S_{o1})^{\left(1+\frac{2}{\omega}\right)}) \quad (14)$$

Where 'S_{w1}' and 'S_{o1}' are the effective water and oil saturation.

The porosity, and permeability are varied in the present model in order to capture the transient fluid flow scenario in the presence of evolving petro-physical properties in the formation; and the respective mathematical model has been expressed in **Equations 15** and **16** (**Nabizadeh et al., 2022**). The variation in viscosity change of oil and water is considered as a function of transient temperature; and the respective details have been provided in **Table 1** (**Nakornthap and Evans, 1986**).

$$\Phi_u = \Phi_{,,} e^{Cr(P-P_{in})} \quad (15)$$

$$K_u = K_{,,} e^{C1(P-P_{in})} \quad (16)$$

Table 1: Oil and water phase viscosity

Temperature (°C)	Oil's viscosity (Pa.s)	Water's viscosity (Pa.s)
21.11	3.090×10^{-2}	0.8×10^{-3}
37.78	1.995×10^{-2}	0.62×10^{-3}
48.89	1.412×10^{-2}	0.50×10^{-3}
65.56	0.977×10^{-2}	0.38×10^{-3}
82.22	0.759×10^{-2}	0.32×10^{-3}
93.33	0.631×10^{-2}	0.28×10^{-3}
121.11	0.354×10^{-2}	0.21×10^{-3}

3.3. Numerical model

A finite element formulation-based numerical model has been employed to simulate the multiphase fluid flow in porous media in conjunction with the energy transport. The energy transport has been fully coupled to the multiphase flow under transient conditions. The coupled equations have been solved using COMSOL Multiphysics. The result was plotted using mapped mesh. The physical parameters and operational parameters used in the present study are written in **Table 2**.

The following initial and boundary conditions were utilized to solve the algebraic equations for hot water flooding (**Equations 17 - 24**).

$$P\,(t = 0) = P_{in} \quad (17)$$

Table 2: Thermophysical properties and model parameters

Parameter		Symbol	Value	References
Initial oil saturation		S_{oi}	0.88	**Kostina et al., 2019**
Initial formation porosity		$\phi_{,,}$	0.27	
Water phase density (kg/m³)		$\rho_{w'}$	1012	
Oil phase density (kg/m³)		$\rho_{o'}$	933	
Reservoir rock density (kg/m³)		$\rho_{r'}$	2100	
Heat capacity of the oil phase (J/KgK)		$C_{o'}$	2090	
Heat capacity of the rock (J/KgK)		$C_{r'}$	1050	
Heat capacity of the water phase (J/KgK)		$C_{w'}$	4200	
Rock thermal conductivity (W/mK)		$K_{s'}$	2.325	
Oil's thermal conductivity (W/mK)		$K_{o'}$	0.14	
Water's thermal conductivity (W/mK)		$K_{w'}$	0.58	
Initial reservoir pressure (MPa)		P_{in}	20	**Gudala and Govindarajan, 2021**
Production pressure (MPa)		P_{pro}	15	
Residual oil saturation		$S_{ro'}$	0.15	**Liu et al., 2020**
Formation compressibility (Pa⁻¹)		Cr	1.45×10^{-9}	**Nabizadeh et al., 2022**
Entry capillary Pressure (Pa)		P_{ey}	10000	**Helland and Skjaeveland, 2006**
Injection temperature (°C)		T_{inj}	120	**Wu and Liu, 2019**
Initial reservoir temperature (°C)		T_{in}	50	**Pang et al., 2021**
Pore-size distribution index		ω	2	**Pavan and Govindarajan, 2023**
Permeability (mD)	Formation permeability	$K_{,,}$	200	**Kareem et al., 2017**
	Low permeability barrier		14	**Iyi et al., 2022**
Homogenous reservoir average permeability (mD)		$K_{,,}$	158.64	**Kareem et al., 2017**
Inlet velocity (m/s)		U_{inj}	1.25×10^{-6}	**Present study**

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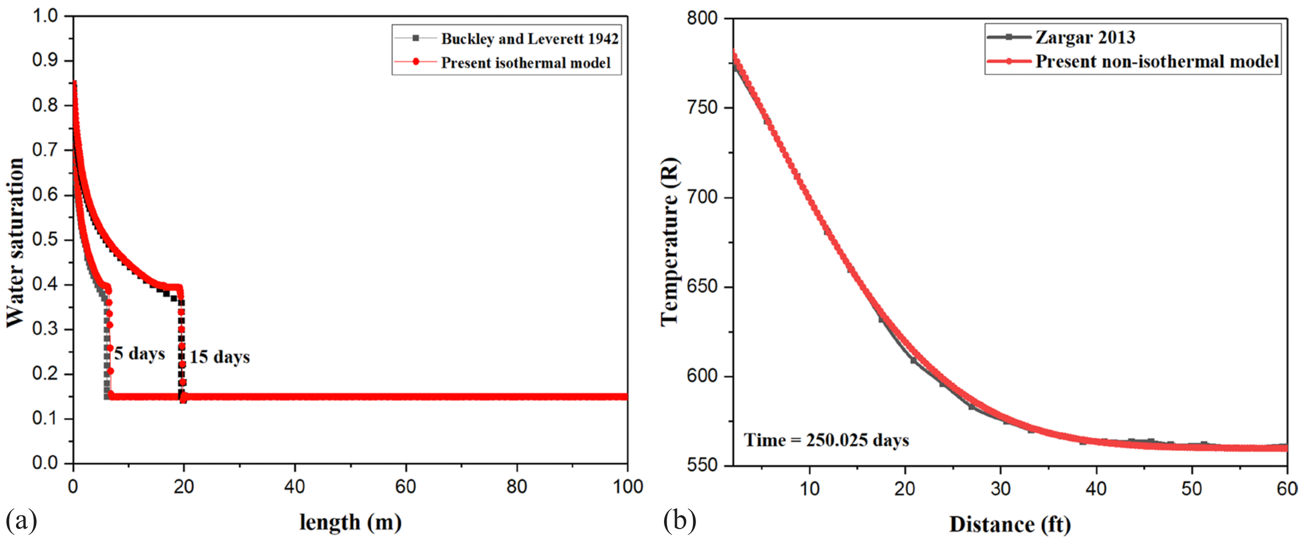

Figure 3: Verification of water saturation front, and temperature propagation with (a) Buckley and Leverett, 1942, and (b) Zargar, 2013.

$$T(t = 0) = T_{in} \tag{18}$$

$$S_o (t = 0) = S_{oi} \tag{19}$$

$$U_w (0, t) = U_{inj} \tag{20}$$

$$P (x = L) = P_{pro} \tag{21}$$

$$S_w (0, t) = 1 - S_{ro} \tag{22}$$

$$T (x=0) = T_{inj} \tag{23}$$

$$T (x=L) = T_{in} \tag{24}$$

4. Results and discussion

4.1. Verification of the present model

The verification of the present isothermal model has been performed utilizing the work of **Buckley and Leverett (1942)**. The water saturation is estimated along the length of the reservoir using a one-dimensional model for 5 days, and 15 days. The input parameters used in the present numerical model and analytical solution are constant. The numerical results and the analytical solution by Buckley and Leverett seem to be a great match, as represented in **Figure 3a**.

The temperature field distribution along the depth of the reservoir has been verified for 250.025 days using the coupled energy and momentum model of **Zargar (2013)**. The graphical representation of temperature field distribution has been represented in **Figure 3b** (**Ansari and Govindarajan, 2025**). The present model has been found to be a great match with Zargar's work.

4.2. Oil saturation distribution and injection pressure buildup

The spatial distribution of oil saturation at different interval has been represented in **Figures 4** and **5**.

Figure 4 shows the impact of locational change of the low permeability barrier such as near the injection well, in the middle of the reservoir, and near the production well in the horizontal direction on the spatial distribution of the oil saturation. Initially, the oil saturation has been observed to be degraded effectively near the hot water injection zone except in Case 2 up to 25 days. The ineffective sweeping of the region is due to the low permeability zone presence near the injection well in Case 2. During the later stage of continuous hot water flooding, the oil saturation has been found to decrease effectively in the lower part of the reservoir owing to the gravity segregation effect. The gravity effect causes hot water to sweep the lower part of the formation effectively because of higher water density compared to oil. The phenomena like splitting, ineffective oil displacement, and gravity effect were observed to take part significantly during hot water flooding. In Case 1, it can be observed that the split or irregular displacement is highly significant close to the production well at the end of 100 days (see **Figure 4**). On the other hand, the oil displacement seems to be ineffective due to the presence of a low permeability barrier. The presence of a low permeability barrier near the injection well has developed a larger ineffective displacement zone in Case 2. The low permeability zone is shifted symmetrically towards the production well, and has been observed to decrease in the size of the thief formation zone or observed to have effective displacement, which is shown in Case 3 and Case 4. Case 1 has been found to have the largest decrease in the reservoir oil saturation at 200 days of hot water injection. The low permeability barrier presence has reduced

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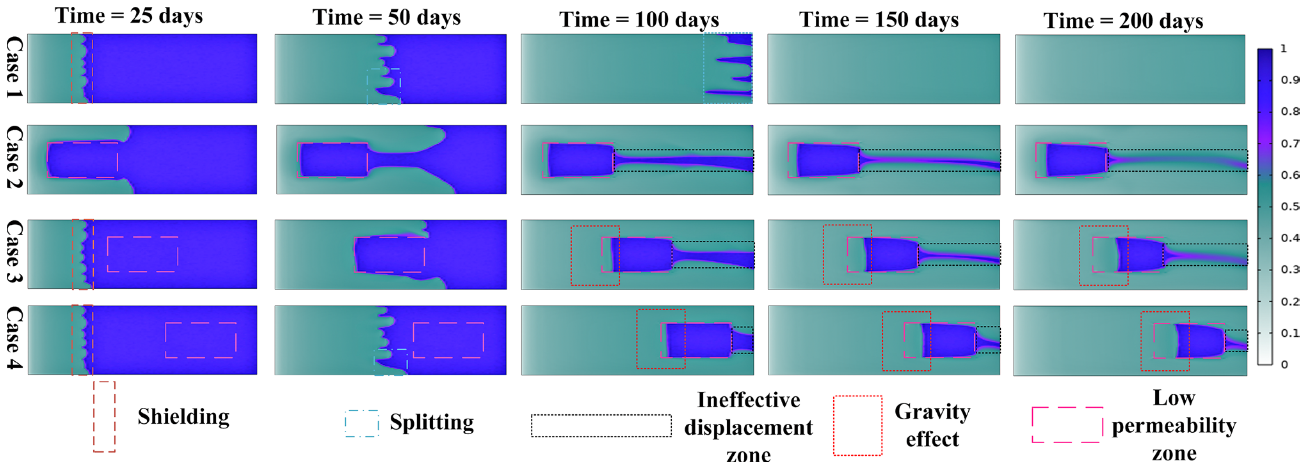

Figure 4: The schematic represents the spatial changes in oil saturation with time enhancement with the horizontal change in the location of the low permeability barrier at 10 m, 35 m, and 60 m from the injection well.

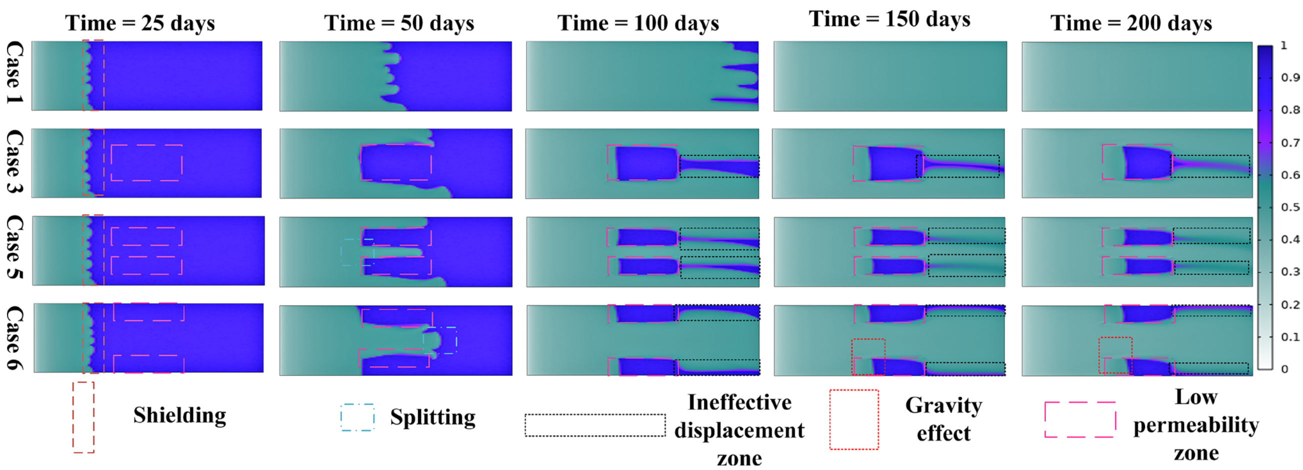

Figure 5: The schematic represents the spatial changes in oil saturation with time enhancement with the low permeability barrier present vertically.

the impact of hot water injection on the production of oil. However, the low permeability barrier presence near the production well (Case 4) has caused more reduction in the oil saturation in comparison to the presence of a low permeability barrier in the middle (Case3), and near the injection well (Case 2). The largest reduction in the oil saturation in Case 4 in comparison to Case 3 and Case 2 is due to the better development of injection pressure buildup and effective temperature distribution along the cross-section in Case 4 in comparison to Case 3 and Case 2, which are represented in **Figure 6a** and **Figure 7a** respectively. From **Figure 7a**, it can be interpreted that the temperature distribution profile at 25 m from the injection well is nearer to the homogeneous reservoir, which supports the effective oil displacement and avoids the water channeling problem.

Figure 5 shows the impact of the low permeability barrier present at no offset, slightly offset, and fully offset from the middle of the reservoir symmetrically on the spatial distribution of the oil saturation. Phenomena like splitting, ineffective oil displacement, and gravity effects were also observed to play a significant role in the vertically present low permeability barrier during hot water flooding. Initially, the oil saturation has been observed to be reduced effectively near the hot water injection zone in all cases. The oil saturation appears to have effective displacement by hot water flooding for 25 days in all cases. This is due to the large viscosity reduction in the hot water-invaded zone. During the later stage of continuous hot water flooding, the flow separation was observed around the low permeability region in Case 3, and the oil saturation reduction was found to be insignificant in the middle of the reservoir owing to a low permeability barrier presence. The low permeability barrier acts as a discontinuity to the hot water injection, causing the development of a thief zone or ineffective oil displacement. The injected hot water displaces the oil from the larger permeability region due to the minor effort needed to pass through the larger permeability region than the low permeability region. The zone possessing a low permeability region is not effectively being invaded by the hot water at the same injection rate.

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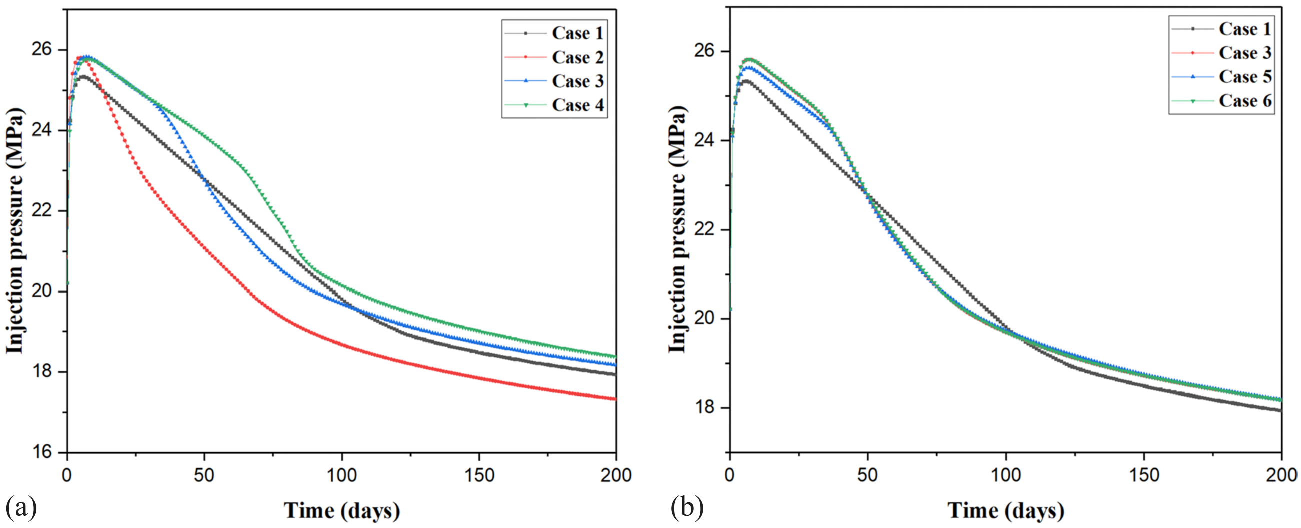

Figure 6: Impact of a low permeability barrier on injection pressure (a) with or without low permeability barrier horizontally starting at 10 m, 35 m, and 60 m from the injection well, and (b) with the division of the low permeability barrier vertically starting at 35 m from the injection well.

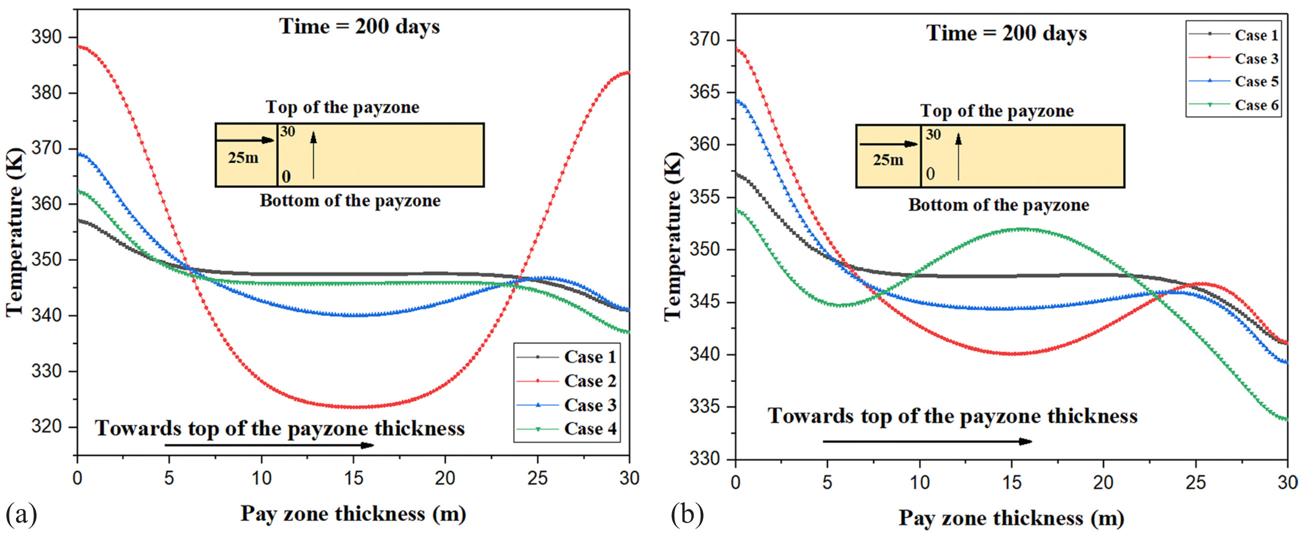

Figure 7: Impact of a low permeability barrier on temperature distribution at 25 m from the injection well (a) with or without low permeability barrier horizontally starting at 10 m, 35 m, and 60 m from the injection well, and (b) with the division of the low permeability barrier vertically starting at 35 m from the injection well.

The invasion can be increased by increasing the hot water injection rate, but the pressure buildup may cross the fracture limit. In Case 5 (low permeability is slightly offset from the mid-zone of the reservoir), the oil saturation reduction has been observed to be highly significant in the top, bottom, and mid regions of the reservoir, leaving the region of low permeability uninvaded, which is represented in **Figure 5**. On the other hand, the oil displacement seems to be highly insignificant in the reservoir when the low permeability barrier is present in the middle of the reservoir (Case 3). The low permeability barrier presence has reduced the impact of hot water injection on the production of oil. However, the presence of a slightly offset low permeability barrier (Case 5) experienced a larger reduction in the oil saturation in comparison to no offset low permeability barrier (Case 3) and fully offset low permeability barrier (Case 6). The pressure buildup is found to be slightly significant in the reservoir possessing low permeability at no offset (Case 3), slightly offset (Case 5), and fully offset condition (Case 6), which is represented in **Figure 6b**. The peak pressure attained at the injection well when the low permeability is present in the reservoir at no offset condition, slightly offset and fully offset condition at the middle of the reservoir has a light effect on the oil production rate. Gravity segregation plays a more significant role along with the temperature distribution in decreasing the oil saturation in the slightly offset low permeability present in the reservoir than the reservoir possessing a low permeability barrier at no offset or fully offset conditions, which are represented in **Figure 5** and **Figure 7b**. The presence of a continuous large low permeability

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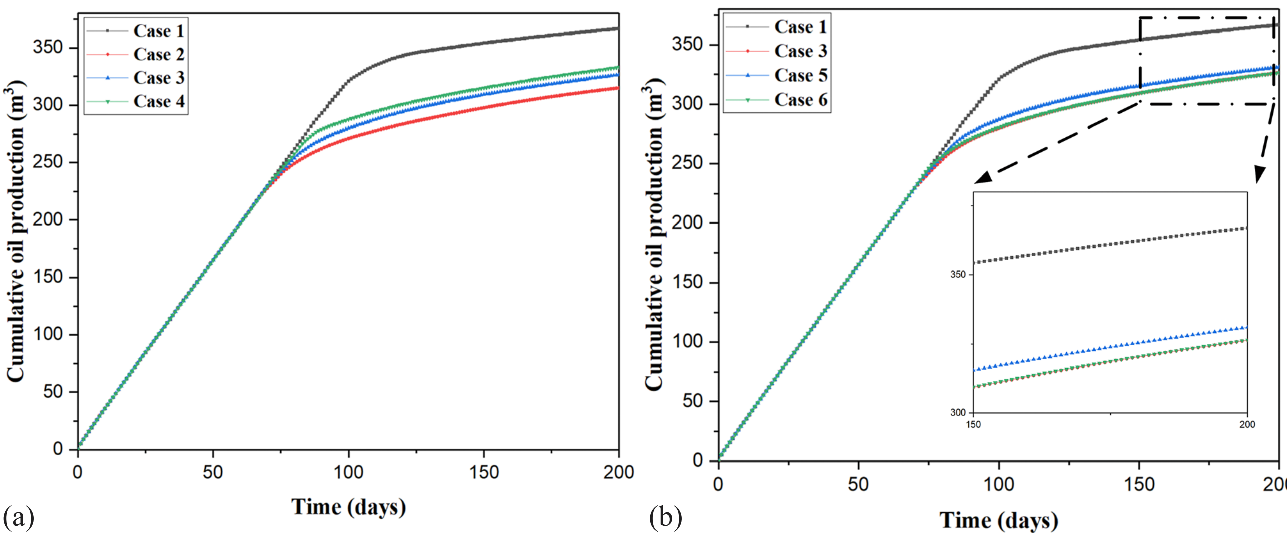

Figure 8: Impact of a low permeability barrier on cumulative oil production (a) with or without low permeability barrier horizontally starting at 10 m, 35 m, and 60 m from injection well, and (b) with the division of the low permeability barrier vertically starting at 35 m from injection well.

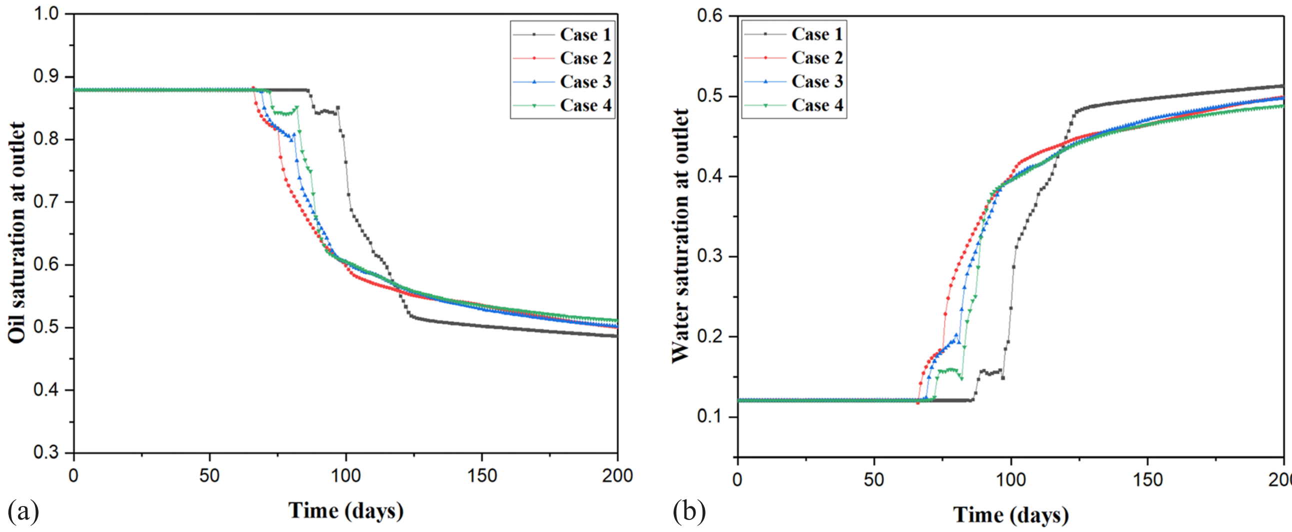

Figure 9: Impact of a low permeability barrier starting at 10 m, 35 m, and 60 m from the injection well on (a) oil saturation at outlet, (b) water saturation at outlet with the change on the location of the low permeability barrier horizontally.

region in Case 3 causes a large thief zone towards the production well, whereas the low permeability zone present at the top section in a fully offset case (Case 6) has insignificant sweeping towards the production well at the top section owing to the higher density of water in comparison to oil causing a gravity segregation effect.

4.3. Cumulative oil production

Figures 8a and **b** represent the cumulative oil production at different intervals. From **Figures 8a** and **b**, it can be inferred that the cumulative oil production is observed to increase with time enhancement. Homogeneous reservoir (Case 1) has been observed to possess the largest cumulative oil production in comparison to all cases.

The presence of a low permeability barrier reduces the performance of hot water flooding. From **Figure 8a**, it can be analysed that a low permeability barrier is present near the injection well (Case 2) which drastically reduces the efficiency of hot water flooding. The cumulative oil produced are 375.08 m^3, 324.65 m^3, 336.62 m^3, and 344.14 m^3 in Case 1, Case 2, Case 3 and Case 4 at the end of 200 days, respectively. The cumulative oil produced in Case 4 is 2.23%, and 6% higher than Case 3, and Case 2, respectively. The temporal change in the oil and water saturation at the outlet is plotted in **Figures 9a** and **b**. The oil saturation is observed to decrease early, resulting in a larger water saturation at the outlet in Case 2. The low permeability barrier presence near the injection well not only reduced the displacement of oil but also increased the early water production load, which

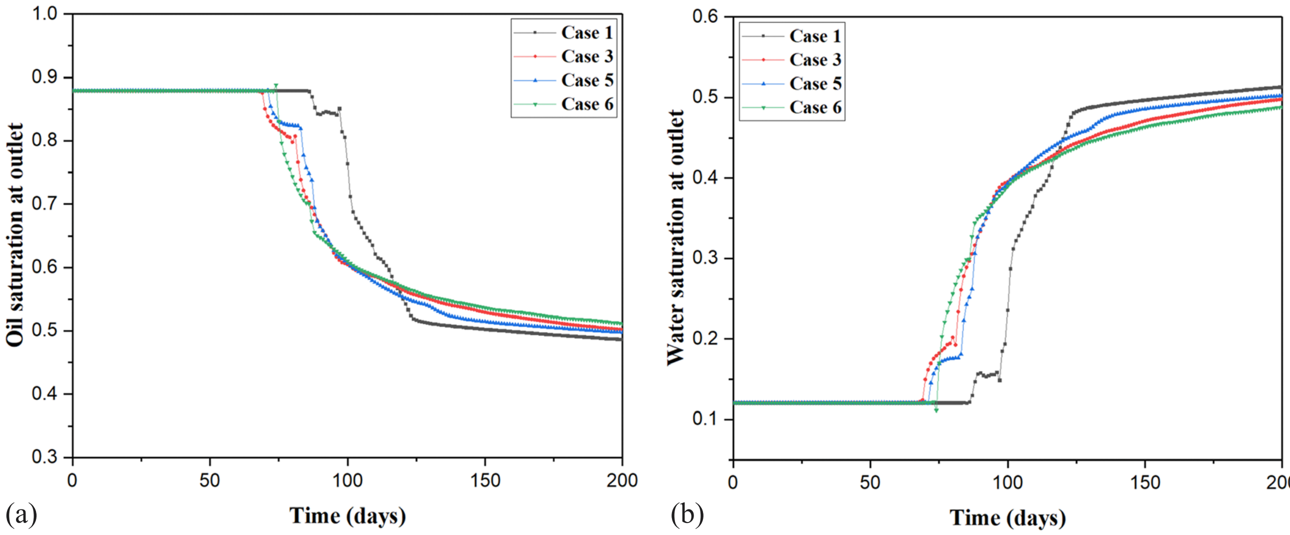

Figure 10: Impact of a low permeability barrier starting at 35 m from the injection well on (a) oil saturation at outlet, (b) water saturation at outlet with the division of the low permeability barrier vertically.

is presented in **Figure 9b**. The hot water injection performance is more significant when the low permeability barrier is situated far away from the injection well except in a homogeneous reservoir **Figure 8a**.

Figure 8b shows that the low permeability barriers present at slight offset conditions in the reservoir (Case 5) were found to have larger cumulative oil production compared to fully offset (Case 6) and no offset (Case 3) conditions. The cumulative oil produced are 375.08 m^3, 336.62 m^3, 341 m^3, and 336.81 m^3 in Case 1, Case 3, Case 5, and Case 6 at the end of 200 days, respectively. The cumulative oil produced in Case 5 is 1.30 %, and 1.24 % higher than Case 3, and Case 6, respectively. The temporal change in the oil and water saturation at the outlet is plotted in **Figures 10a** and **b**. The oil saturation is observed to decrease early, resulting in a larger water saturation at the outlet in Case 3. However, the presence of fully offset low permeability barriers symmetrically in the reservoir (Case 6) experiences larger cumulative oil production than Case 3. Case 5 is observed to have a larger oil displacement than Case 3 and Case 6. The presence of slight offset low permeability barriers (Case 5) not only increased the cumulative oil production but also increased the water production load at the outlet at the breakthrough (around 71 days), which is presented in **Figure 10b**. The hot water injection performance is more significant when the slightly offset low permeability barriers are present in the vertical direction except in a homogeneous reservoir **Figure 8b**.

5. Conclusions

A fully coupled numerical model is established on the basis of the hot water injection process. It has been attempted to investigate the impact of a low permeability barrier, which can act as a discontinuity to the fluid flow during hot water flooding. The results are obtained using the present numerical model after verification with Buckley and Leverett's analytical results and Zargar's works. The following observations have been obtained.

- The reservoir possessing a low permeability barrier has lower cumulative oil production in comparison to the homogeneous reservoir; however, a low permeability barrier present far away from the injection well can provide a larger cumulative oil production than the nearly present low permeability barrier. The cumulative oil produced are 375.08 m^3, 324.65 m^3, 336.62 m^3, and 344.14 m^3 in the homogeneous reservoir (Case 1), low permeability barrier near the injection well (Case 2), at the middle (Case 3) and near the production well (Case 4), respectively.
- The nearly present low permeability barrier reduces the injection pressure buildup, reduces the output oil saturation, and leads to the largest water production.
- The low permeability barrier present at a slight offset from the middle, top, and bottom location in the reservoir can lead to better cumulative oil production during hot water injection. The cumulative oil produced are 375.08 m^3, 336.62 m^3, 341 m^3, and 336.81 m^3 in the homogeneous reservoir (Case 1), low permeability barriers present at the middle with no offset (Case 3), with slight offset (Case 5), and with fully offset (Case 6), respectively.
- The low permeability barriers present at the top and bottom experience less of the gravity segregation effect, whereas the low permeability barrier presence exactly at the middle of the reservoir creates an ineffective oil displacement zone owing to reduced hot water invasion.
- The low permeability barriers present at no offset, slightly offset, and fully offset at the mid region of

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the reservoir has minimal effect on the injection pressure buildup.

- The low permeability barriers reduce oil recovery; however, the low permeability barrier presence near the production well and the slightly offset low permeability zone from the middle of the formation has a significant impact on the oil production rate.

The present work is limited to low permeability barriers symmetrically arranged in the reservoir. The scope of further investigation is to apply hot water flooding in an unsymmetrical low permeability barrier environment for performance analysis. A better understanding of the spatial (location) presence of a low permeability barrier in the petroleum reservoir can add value to the hot water flooding project effectively and economically. The sensitivity of various parameters of low permeability barrier, such as pore size distribution, permeability anisotropy, and porosity, should also be recommended for study in order to gain a better understanding of hot water flooding performance investigation.

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Conflict of interest

The authors declare that there is no financial or personal interest to research work associated with this paper.

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SAŽETAK

Utjecaj niskopropusne barijere na izvođenje zavodnjavanja vrućom vodom – numeričko istraživanje

Niskopropusne barijere u naftnim se ležištima pojavljuju kao geološki diskontinuitet. Postojanje takva diskontinuiteta može promijeniti tok utisnute vruće vode u formaciju te na taj način znatno utjecati na projekte povećanja iscrpka nafte zavodnjavanjem vrućom vodom (engl. *hot water flooding*). Cilj je ovoga rada prikazati utjecaj niskopropusne barijere na izvođenje zavodnjavanja vrućom vodom. U tu je svrhu napravljen numerički model koji objedinjuje model prijenosa energije i model višefaznoga protoka fluida u neizotermnim uvjetima. U radu je istraživan utjecaj horizontalnoga i vertikalnoga rasporeda niskopropusnih barijera u ležištu. Niskopropusna barijera ima znatan utjecaj na iscrpak nafte u slučaju kada se nalazi bliže utisnoj bušotini, dok se navedeni utjecaj na iscrpak nafte smanjuje pomicanjem niskopropusne barijere prema proizvodnoj bušotini. Pomak niskopropusne barijere prema proizvodnoj bušotini smanjuje njezin učinak na izvođenje zavodnjavanja vrućom vodom, što dovodi do povećanja ukupne proizvodnje nafte. Utvrđeno je da je u razdoblju od 200 dana ukupna proizvodnja nafte iznosila 344,14 m^3 u slučaju kada se tijekom zavodnjavanja vrućom vodom niskopropusna barijera nalazi blizu proizvodne bušotine, što čini povećanje za 2,23 % u odnosu na slučaj kada je niskopropusna barijera u središnjemu dijelu ležišta, odnosno povećanje za 6 % u odnosu na slučaj kada je niskopropusna barijera bliže utisnoj bušotini. Kada se niskopropusna barijera nalazi u blizini utisne bušotine, dolazi do smanjenja porasta tlaka na utisnoj bušotini. Niskopropusne barijere smještene u središnjemu dijelu ležišta uz blagi pomak u vertikalnome smjeru omogućuju veću kumulativnu proizvodnju nafte u odnosu na niskopropusne barijere postavljene bez uvjeta pomaka ili u uvjetima potpunoga pomaka u ležištu. Utvrđeno je da je u razdoblju od 200 dana kumulativna proizvodnja nafte iznosila 341 m^3 u slučaju prisutnosti niskopropusne barijere u središnjemu dijelu ležišta u uvjetima blagoga pomaka, što je za 1,30 % odnosno 1,24 % više u odnosu na niskopropusnu barijeru u uvjetima kad nema pomaka ili u uvjetima potpunoga pomaka. Provedeno istraživanje daje smjernice za buduća istraživanja utjecaja niskopropusnih barijera na zavodnjavanje vrućom vodom.

Ključne riječi:
niskopropusna barijera, raspodjela zasićenja naftom, porast tlaka utiskivanja, kumulativna proizvodnja nafte, numeričko istraživanje

Author's Contribution

Md Irshad Ansari (Research Scholar) - conceptualization, validation, formal analysis, and writing. **Suresh Kumar Govindarajan** (Full Professor) - conceptualization, formal analysis, and manuscript final correction.