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Article

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Research paper

A mathematical model to evaluate the polymer flooding performances

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ABSTRACT

Due to the enormous demand for crude oil, the selection of appropriate and economical techniques to enhance the oil recovery are always considered as the major concerns in reservoir developments. Polymer flooding is considered as one of the chemical enhanced oil recovery techniques especially for heavy oil reservoirs by the sweep efficiency improvement. The objective of this study is to perform a mathematical model to evaluate the polymer flooding performances in the presence of saturation profile and cross flow effect to validate the accuracy of the model with simulated field data. Thereby, the results of this developed model indicate that the model is approximately matched with the simulated field data rather than previous models. Furthermore, some geological problems such as high permeable channeling and semi-sealing issues are considered in the model to calculate the pressure integral and how each parameter would change regarding the cumulative pore volume alteration. Consequently, the proposed model would be an appropriate choice to verify the pressure integral which is compared with the simulated field data by the consideration of saturation distribution and cross flow effect.

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1. Introduction

Due to the increasing demand for the utilization of oil in petroleum industries and other industries, the preferable enhanced oil recovery (EOR) techniques would be operated as the significant scheme for providing the sufficient volume of hydrocarbons (Abidin et al., 2012; Al-Hajri et al., 2018; Davarpanah, 2018; Davarpanah and Mirshekari, 2019b,c). Polymer flooding is considered as one of the chemicals enhanced oil recovery techniques in many reservoirs, especially heavy oil reservoirs due to the low expenditures (Al-Shakry et al., 2018; Dann et al., 1982; Davarpanah and Mirshekari, 2019a,b; Jung et al., 2013; Kakoli et al., 2016). In respect to the way, polymer flooding is considered as the stabilized EOR processes to increase the water viscosity to reduce the fingering phenomenon which leads the oil to be more mobilized (Davarpanah and Mirshekari, 2019d; Wever et al., 2017; Yang et al., 2018; Yerramilli et al., 2013). The schematic of polymer flooding performances is depicted in Fig. 1.

The reduction of fingering viscosity has caused to enhance the sweep efficiency and provided more volume of oil and subsequently the required volume of injected water and produced water is dramatically decreased (Collins, 1976; Davarpanah and Mirshekari, 2019c; Jang and Chon, 2014; Sharma et al., 2014). Moreover, the polymer is administered to shut off the channeling which is made by water in the high-permeable layers and the

water coning phenomenon from the bottom hole aquifers. To avoid the problem of mobilizing the injected water or polymer to the high permeable zone, a weak gel which has the high resistance to the fluid flow is added to the polymer for the deep reservoirs and hence, the pathways of water flowing or the channeling issue would be controlled or blocked (Algharaib et al., 2014; Collins, 1976; Davarpanah et al., 2019a, 2018; Silva et al., 2007; Thomas et al., 2012). That is to say that, the phenomenon of disproportionate permeability reduction (DPR) mechanism is considered to the water permeability reduction. On the other hand, the viscoelastic behavior of polymers is another mechanism of using polymers instead of other chemical processes. The reason for this issue is related to the higher interfacial viscosity between oil and polymer rather than water-oil, and the value of shear stress is proportionally related to the interfacial viscosity, and subsequently, the polymer would exert a larger pulling force on the oil droplets which helps the oil push out of the dead-end pores (Amirian et al., 2018; Liang et al., 2017; Norouzi et al., 2017; Salehi et al., 2019; Song et al., 2015; Zampieri et al., 2019). Consequently, the oil recovery rate during polymer flooding is depended to the polymer injectivity rate and it should be taken into the consideration that the economic success of polymer flooding procedures has played a substantial role in the implementation of this technique. A successful economic aspect of polymer flooding performances is utterly depended to the polymer concentration, polymer additives, and reservoir characteristics (Delshad et al., 2008; Glasbergen et al., 2015; Jacobsen et al., 2019; Li and Delshad, 2014; Tie et al., 2019; Wang et al., 2015).

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Nomenclature

P_e	Formation pressure, Pa
P_{wf}	Wellbore injection pressure, Pa
k_{rw}	Water relative permeability, fraction
k	Absolute permeability, m^2
h	Thickness of the formation, m
B_w	Water formation volume factor, fraction
μ_w	Water viscosity, Pa s
r_e	External drainage radius, m
r_w	Wellbore radius, m
s	Skin factor, dimensionless
W_i	Cumulative injection, m^3
D	Reservoir depth, m
ρ	Density, kg/m^3
g	gravity acceleration, m/s^2
R_f	Permeability reduction factor, dimensionless
R_{rf}	Residual permeability reduction factor
r_b	Radius of the injected fluid solution
f_w	Water fractional flow
S_w	Water saturation, fraction
k_a	Value of permeability after polymer flooding, m^2
$\frac{\partial f_w}{\partial S_w}$	Estimated from the fractional flow curve
ΔV_p	Total pore volume of accumulated hydrocarbons
k_{row}	Oil relative permeability in the water–oil system
k_{rop}	Oil relative permeability in the polymer–oil system

Different types of rheology such as viscoelastic, power law and Newtonian rheology were analytically modeled by Liu et al. (2014) to consider the profound impact of rheology parameter on the polymer injectivity performances (Liu et al., 2014). In this study, it was assumed that polymer was a single aqueous phase by the consideration of no oil bank forming during the polymer flooding performances (Al-Shakry et al., 2019; Sun et al., 2019). To calculate saturation fronts by the assumption of segregation flow, AlSofi and Blunt (2010, 2013) proposed an analytical model to simulate the polymer flooding performances without the consideration of polymer concentrations (AlSofi and Blunt, 2010, 2013). Jain and Lake (2014) proposed an analytical model to calculate sweep efficiency in a layered reservoir which is based on the Koval's theory (Jain and Lake, 2014; Koval, 1963). In this theory, it was assumed that the flow is segregated in vertical equilibrium conditions. Seright (2017) proposed a case study model to determine the optimum viscosity volume of injected polymer in the layered reservoirs. Furthermore, the cross flow among layers with different characteristics regarding the injection of polymer solution was modeled analytically (Guo et al., 2019; Seright, 2017; Davarpanah et al., 2019b,c).

Hall plot is considered as a beneficial tool to analyze the performances of injection wells in the water flooding processes. Firstly, Hall (1963) stated the application of hall plot for the evaluation of steady state, a single phase of a radial flow for the Newtonian fluid. Since then, due to the widespread use of polymer flooding procedures in the operational performances, the Hall plot was applied to investigate its performances due to the similar operation of polymer to water in the reservoir (Hall, 1963). To verify the validity of this mathematical model, Buell et al. (1990) had proposed a numerical solution which is used these characteristics to be more adapted to the realistic situations; these assumptions are two-phase flow regarding

the presence of water and oil, slightly compressible flow, non-Newtonian rheological properties, retention/ adsorption with the reduction of permeability, and single permeability (Buell et al., 1990).

Although, there are numerous studies have been widely reported in the literature to consider the profound influence of polymer flooding performances, in this study, an mathematical model was proposed to evaluate the cross flow effect and saturation distribution in the pressure integral and provide a comparison with the simulated field data. According to the results of this study, it is clear that the developed model has a good agreement with the simulated field data rather than previous models. Furthermore, some of the geological problems such as high permeable channeling and the semi-sealing issue were taken into consideration in the model to calculate the pressure integral.

2. Governing equations

The proposed mathematical model of Hall plot which is developed by Hall (1963) with the constant assumptions that are mentioned in the introduction section like the following equation;

$$\int (p_{wf} - p_e) dt = \frac{141.2B_w\mu_w[\ln(r_e/r_w + s)]}{k_{rw}kh} W_i \quad (1)$$

where ; P_e is the formation pressure at the interface between the original reservoir fluid and the injected fluid, Pa; P_{wf} is the wellbore injection pressure, Pa; k_{rw} is the water relative permeability, fraction; k is the absolute permeability, m^2 ; h is the thickness of the formation, m; B_w is the water formation volume factor, fraction; μ_w is the water viscosity, Pa s; r_e is the external drainage radius, m; r_w is the wellbore radius, m; s is the skin factor, dimensionless; and W_i is the cumulative injection, m^3 . when the P_{wf} would not be measured, the wellbore pressure that is measured by the surficial equipment (P_{tf}) is utilized to propose the Hall plot model.

$$\int (p_{tf}) dt = \frac{141.2B_w\mu_w[\ln(r_e/r_w + s)]}{k_{rw}kh} W_i + \int [p_e + \Delta p_f - \rho gD] dt \quad (2)$$

where D is the reservoir depth, m; ρ is the density, kg/m^3 ; and g is the gravity acceleration, m/s^2 .

After plotting wellhead pressure differences versus injected volume, the pressure has dropped slightly, and subsequently, the slope of hall plot is measured according to the Eq. (3) which was derived from Eqs. (1) and (2);

$$m_H = \frac{141.2B_w\mu_w[\ln(r_e/r_w + s)]}{k_{rw}kh} \quad (3)$$

Therefore, the principle of using Hall plot is plotted by cumulative pressure versus cumulative water injection. As can be seen in Fig. 2, in the first stage of injectivity performances, the radius of the water zone would be increased with the time increase which indicates schematically in segment ab. Segment bA shows the stability injection pattern when the gas filled up, and it has invaded from the straight line, it would indicate formation is plugging or the poor quality of the water phase in segment bD. As it is shown in line B, this decrease would be caused by the injection processes performed above the parting pressure and negative skin. Injection performances out of the zone or possible channeling are indicated schematically in segment bC.

As Eq. (3) is a bit difficult for the evaluation of polymer injectivity performances due to the presence of three-phase banks in the reservoir, Buell et al. (1990) illustrated the new Hall plot

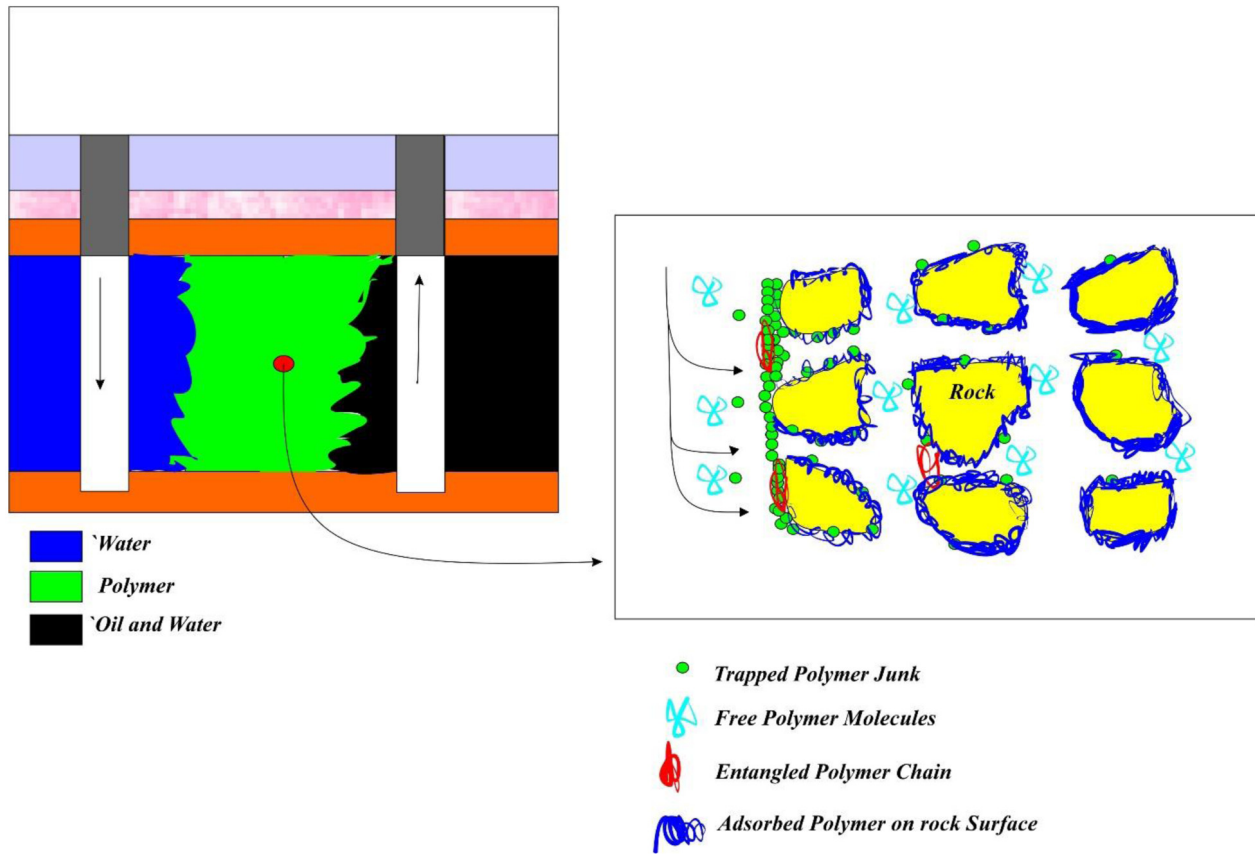


Fig. 1. Polymer flooding performances (Lotfollahi et al., 2016).

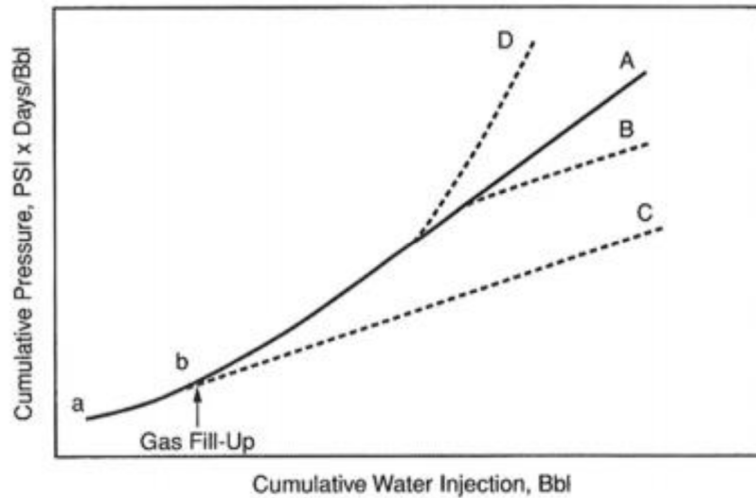


Fig. 2. Typical Hall plot for different circumstances (Thakur, 1991).

by the consideration of new assumptions of non-Newtonian fluids and occurrence of polymer, oil, and driving water. It is derived as Eq. (4) to be more matched to the polymer flooding circumstances;

$$m_H = 141.2 \left\{ \begin{array}{l} B_w \mu_w \left[\ln \left(\frac{r_{b2}}{r_w} \right) + s \right] / k_{rw} k_a h \quad (\text{Water Drive Bank}) \\ B_w \mu_p \left[\ln \left(\frac{r_{b1}}{r_{b2}} \right) \right] / k_{rw} k_a h \quad (\text{Polymer Bank}) \\ B_o \mu_o \left[\ln \left(\frac{r_e}{r_{b1}} \right) \right] / k_{ro} k h \quad (\text{Oil Bank}) \end{array} \right\} \quad (\text{RP40})$$

R_f is called as the ‘permeability reduction factor’, dimensionless; and R_{rf} is the residual permeability reduction factor. R_f is affected

by the adsorption of polymer which is caused to the reduction of rock permeability during the flow of polymer solution in the comparison of water flowing permeability. R_f is defined as the Eq. (5) as the water mobility before polymer flooding and the mobility of polymer solution;

$$R_f = \frac{(k k_{rw}) / \mu_w}{(k_a k_{rp}) / \mu_p} \quad (5)$$

Due to the reduction of polymer solution permeability in the case of post-polymer water flooding performances, the permeability reduction is defined as the residual permeability reduction factor

(R_{rf}). R_{rf} is defined as the Eq. (6) (Sheng, 2013).

$$R_{rf} = K/k_a \quad (6)$$

After the rewriting the Eq. (4) with the consideration of Eqs. (5) and (6), it is defined as Eq. (7).

$$m_H = 141.2 \left\{ \begin{array}{l} R_{rf} B_w \mu_w \left[\ln \left(\frac{r_{b2}}{r_w} \right) + s \right] / k_{rw} kh \quad (\text{WaterDriveBank}) \\ R_{rf} B_w \mu_w \left[\ln \left(\frac{r_{b1}}{r_{b2}} \right) \right] / k_{rw} kh \quad (\text{PolymerBank}) \\ B_o \mu_o \left[\ln \left(\frac{r_e}{r_{b1}} \right) \right] / k_{ro} kh \quad (\text{OilBank}) \end{array} \right\} \quad (\text{RP40})$$

where r_b is the radius of the injected fluid solution, m which was estimated from the Buckley–Leverett equation in radial coordinate (Collins, 1976).

$$r_b^2 = \frac{W_i}{\pi \Phi h} (\partial f_w / \partial S_w)_f + r_w^2 \quad (8)$$

where f_w is the water fractional flow, fraction; S_w is the water saturation, fraction; and k_a is the value of permeability after polymer flooding, m^2 ; and $\partial f_w / \partial S_w$ is estimated from the fractional flow curve.

2.1. Effect of cross flow

Permeability alteration in the vertical axis is one the substantial parameters on the recovery of polymer flooding performances. Polymer solutions would mobilize conveniently in the high permeable areas which caused the early breakthrough for the aqueous phase. To provide the Hall plot model for the cross flow section, the following assumptions are being used in the mathematical model; steady state flow according to Darcy's law, slightly compressible radial two-phase flow, heterogeneous reservoir, the residual oil remains in the displacement front, and the relative permeability remains constant through the whole layers. According to the El-Khatib (1985) model, the apparent permeability, apparent porosity, saturation differentiations, and total pore volume of accumulated hydrocarbons were estimated mathematically for different layers as Eqs. (9)–(12) respectively which should be calculated before the polymer flooding performances.

$$k_1^- = \frac{k_1 \Delta V_{p1} + \dots + k_n \Delta V_{pn}}{\Delta V_p} \quad (9)$$

where ΔV_p is the total pore volume of accumulated hydrocarbons which is defined as

$$\Delta V_{p1} = \Delta V_{p1} + \dots + \Delta V_{pn} \quad (10)$$

$$\Phi_1 = \frac{\Phi_1 \Delta V_{p1} + \dots + \Phi_n \Delta V_{pn}}{\Delta V_p} \quad (11)$$

$$\Delta S_1 = \frac{\Phi_1 \Delta S_1 \Delta V_{p1} + \dots + \Phi_n \Delta S_n \Delta V_{pn}}{\Phi_1 \Delta V_{p1} + \dots + \Phi_n \Delta V_{pn}} \quad (12)$$

So the permeability reduction was calculated as the flowing equation;

$$k_{d1}^- = \frac{k_1^-}{\Phi_1 \Delta S_1} \quad (13)$$

To define the performance of cross flow in the real time injectivity, k_{d1}^- is substituted with k in Eq. (7), it is changed to the following equation;

$$m_H = 141.2 / k_{d1}^- h_t \left\{ \begin{array}{l} R_{rf} B_w \mu_w \left[\ln \left(\frac{r_{b2}}{r_w} \right) + s \right] / k_{rw} \quad (\text{WaterDriveBank}) \\ R_{rf} B_w \mu_w \left[\ln \left(\frac{r_{b1}}{r_{b2}} \right) \right] / k_{rw} \quad (\text{PolymerBank}) \\ B_o \mu_o \left[\ln \left(\frac{r_e}{r_{b1}} \right) \right] / k_{ro} \quad (\text{OilBank}) \end{array} \right\} \quad (\text{RP40})$$

2.2. Effect of saturation alteration

However, fluid flow effective permeability in the single-phase reservoir would not change regarding the constant value of fluid saturation, in the multi-phase flow (especially polymer solution which was taken into consideration in this study), the effective permeability has changed due to the saturation alteration. To develop the saturation profile, Buckley–Leverett displacement theory in the immiscible flow condition is used, and according to the Buell et al. (1990) investigations, it was assumed that the saturation factor is constant for each injectivity bank. Thereby, saturation profile consisted of three different areas; immiscible two-phase flow (oil and water), immiscible two-phase flow between oil and polymer, displacement of oil by the water phase. The profile of saturation alteration for water and polymer solutions and the fractional flow curves for the polymer-oil and water–oil system are defined as the following equation;

$$(dx/dt)_{S=\text{constant}} = v \frac{df}{dS} \quad (15)$$

$$f_w = \frac{1}{1 + \frac{k_{row} \mu_w}{k_{rw} \mu_o}} \quad (16)$$

$$f_p = \frac{1}{1 + \frac{k_{rop} \mu_p}{k_{rp} \mu_o}} \quad (17)$$

where k_{row} is the oil relative permeability in the water–oil system and k_{rop} is the oil relative permeability in the polymer–oil system.

Regarding the polymer and water fractional flow curves, the velocity of the polymer saturation and water saturation in the polymer front are equal which is defined as the following relationship;

$$(df_w/dS_w)_{S_w=S_w=1-S_{or}} = (df_p/dS_p)_{S_p=S_{wp}} \quad (18)$$

Regarding the influence of oil flow in the resistance of polymer bank flow, in the polymer bank term, the oil flow displacement is considered in Eq. (14). As a result, polymer bank divided into oil and polymer solution. Eq. (19) was derived from considering both effects of saturation profile and cross flow effect in the heterogeneous reservoirs.

$$m_H = 141.2 / k_{d1}^- h_t \quad (19)$$

$$\times \left\{ \begin{array}{l} R_{rf} B_w \mu_w \left[\ln \left(\frac{r_{b2}}{r_w} \right) + s \right] / k_{rw} (1-S_{or}) + B_o \mu_o \left[\ln \left(\frac{r_{b2}}{r_w} \right) \right] / k_{ro} (1-S_{or}) \\ \quad (\text{WaterDriveBank}) \\ R_{rf} B_w \mu_w \left[\ln \left(\frac{r_{b1}}{r_{b2}} \right) \right] / k_{rw} (S_{wp}) + B_o \mu_o \left[\ln \left(\frac{r_{b1}}{r_{b2}} \right) \right] / k_{ro} (S_{wp}) \\ \quad (\text{PolymerBank}) \\ B_w \mu_w \left[\ln \left(\frac{r_e}{r_{b1}} \right) \right] / k_{rw} (\overline{S_w}) + B_o \mu_o \left[\ln \left(\frac{r_e}{r_{b1}} \right) \right] / k_{ro} (\overline{S_w}) \\ \quad (\text{OilBank}) \end{array} \right\} \quad (\text{RP40})$$

3. Results and discussion

3.1. The validity of the proposed model

To verify the accuracy of the proposed model, regarding the lack of insufficient data from the production oil fields, in this study, two sets of field data which was extracted from an evaluation of a reservoir in the Big Horn Basin, WY, for polymer flooding. Properties of studied field which was used in this simulation is statistically explained in Table 1.

As can be seen in Fig. 3, polymer injectivity performance by the utilization Hall plot model in cross-flow interlayer was schematically drawn, and it is compared with the models which were proposed with Hall (1963) and Buell et al. (1990). The proposed model indicates that it has a good agreement with simulated data for the studied field rather than other proposed

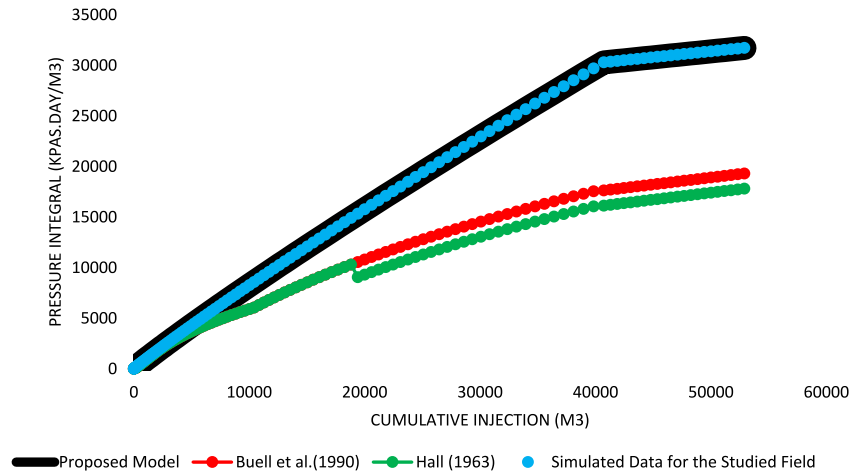


Fig. 3. Comparison of the proposed model with previous studies and simulated real field data.

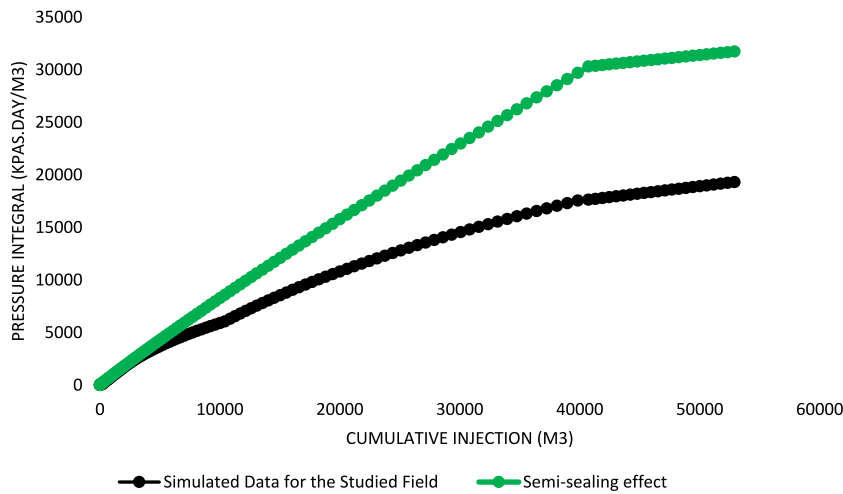


Fig. 4. The semi-sealing effect in the proposed model simulated real field data.

Table 1
Properties of the studied field.

Parameters	Value
Top depth, m	980
Total thickness, m	7.62
Area, m ²	5946.6
Porosity	0.2
Number of layers	4
Initial pressure, kPa	10000
Injection pressure, kPa	13000
Permeability, 10 ⁻¹³ m ²	3.95–5.43
Polymer viscosity, m Pa s	10
Oil viscosity, m Pa s	5

models. In the developed model which was proposed by Hall (1963) is just assumed the reservoir fluid is single phase and the effect of cross flow was not considered. Moreover, in the Buell et al. (1990), the saturation profile is missed in the developed model. Therefore, in this model, both of the cross flow effect and saturation profile is considered in the proposed model which indicated the more accuracy of the model in comparison with other models.

3.2. Semi-sealing properties

Reservoir plugging, fluid viscosity alterations, and permeability differentiations which was made by the different flow rates and pressures in theoretical features. Thereby, consideration of these issues in developing models should be explicitly provided to perform the more accurate results. To consider the influence of geological problems, the semi-sealing property should be mentioned in the cross-flow effect in the developed model. The semi-sealing was placed in the 30–36 m and 47–53 m from the injection well and its permeability was estimated about $9.8 \times 10^{-17} \text{m}^2$ for the plugging description of the formation. The effect of semi-sealing is schematically depicted in Fig. 4. Consequently, regarding the plugging property of the formation, pressure has increased accordingly.

3.3. High permeable channeling

To evaluate the considerable influence of permeability changes in the efficiency of injection performances, in this study, a high permeable cross flow interlayer is used. High permeable channels would provide a direct path flow with the right angle between the production and injection well. The results of high permeable

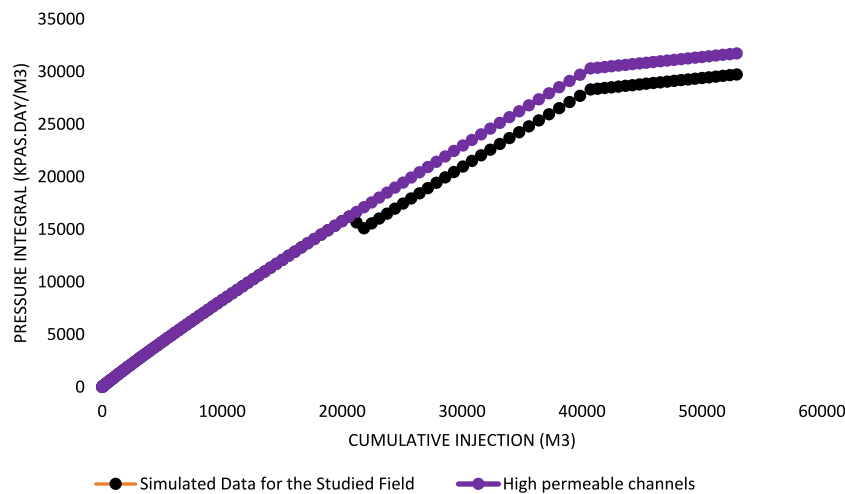


Fig. 5. The high permeable channeling effect in the proposed model simulated real field data.

channels are schematically drawn in Fig. 5 to provide a comparison with the stable polymer flooding performances. Therefore, the influence of high permeable zones would be diminished when the injection well distance was decreased.

4. Conclusion

Polymer flooding was considered as one of the most beneficial flooding performances to enhance the oil recovery factor, especially for heavy oil reservoirs. Polymer flooding would improve the sweep efficiency by increasing the water viscosity and subsequently leads to mobilize more oil volume in the reservoir. Therefore, the proper selection of this methodology in the reservoir would virtually eliminate the unnecessary expenditures. In this study, an mathematical model was proposed to analyze the considerable influence of cross-flow interlayers and saturation profile on the polymer flooding performances. The developed mathematical model was based on the profound impact of saturation profile and cross flow interlayer regarding the polymer solution in the heterogeneous reservoir. Moreover, the proposed model provides an accurate verification with the simulated field data from the studied field, and it indicates that it is approximately matched with the simulated field data more than the previous models due to the consideration of saturation profile and cross flow effect in a heterogeneous reservoir. Some of the geological problems such as high permeable channeling and semi-sealing issues were assumed to calculate the pressure integral and its comparison with the simulated field data. Therefore, the developed model was used to improve the efficiency of polymer flooding performances due to the accurate validation of the model.

Declaration of competing interest

The authors declare that they have no conflict of interest.

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