Investigating the Impact of Water and Polymer Flooding Techniques on Reservoir Performance in Heterogeneous Unconsolidated Formations

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Abstract

The global oil and gas industry increasingly leverages advanced enhanced oil recovery (EOR) methods to optimize hydrocarbon extraction from mature reservoirs. Among these, water flooding remains a widely adopted technique, typically achieving recovery rates ranging from 10% to 40% of the original oil in place (OOIP). Polymer flooding, a prominent EOR strategy, enhances recovery by introducing water-soluble polymers to increase the viscosity of the injected water, thereby improving the mobility ratio and vertical sweep efficiency compared to conventional waterflooding.

This study evaluates the comparative performance of water flooding and polymer flooding with respect to oil production rates, cumulative production, recovery factors, and the timing of water breakthrough. A three-dimensional, two-phase (oil and water) reservoir model was developed using a black-oil simulator. The investigation incorporated the injection of a flexible biopolymer, such as xanthan gum, into a heterogeneous and unconsolidated reservoir using a direct-line drive method. The study further conducted a sensitivity analysis of polymer flooding, focusing on various injection well configurations, with an emphasis on the five-spot pattern, to identify the optimal injection strategy.

The results demonstrate that polymer flooding using a direct-line drive achieves a recovery factor of approximately 44%. In contrast, employing a five-spot injection pattern significantly enhances recovery efficiency to 52% while substantially delaying water breakthrough. These findings underscore the effectiveness of integrating polymer flooding with a five-spot injection pattern to maximize oil recovery from heterogeneous reservoirs.

Introduction

As global energy demand continues to rise, oil remains a critical primary energy source. Currently, global daily oil consumption has increased by 0.8 million barrels, reaching approximately 101 million barrels per day, while daily oil production has grown by 2.1 million barrels, reflecting a growth rate of 2.3%. The recovery factor (RF) in oil fields is typically categorized into three phases: primary, secondary, and tertiary recovery (Ragab and Mansour 2021).

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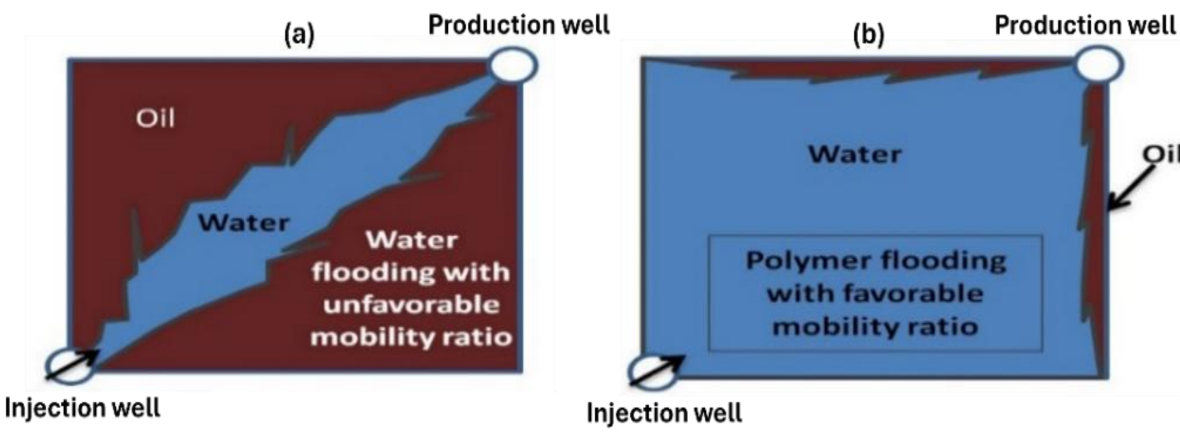
The primary recovery phase relies on natural reservoir energy, such as solution gas drive, gas cap drive, and aquifer influx, to extract oil, achieving recovery rates of 5% to 15% (Thomas 2016). As the natural energy depletes, secondary recovery methods, including water flooding and gas injection, are employed to maintain reservoir pressure and sustain production. The combined recovery factor from primary and secondary recovery methods typically reaches 32%. Tertiary recovery, commonly referred to as enhanced oil recovery (EOR), employs advanced techniques such as chemical flooding, gas injection, and thermal recovery to mobilize remaining oil. These methods significantly enhance recovery efficiency, achieving recovery factors of 30% to 60% of the original oil in place (OOIP), substantially exceeding the 20% to 40% recovery typically realized with primary and secondary recovery methods (Gbadamosi et al. 2019; Li et al. 2017).

Chemical flooding, a prominent EOR method, involves injecting water mixed with tailored chemicals, such as surfactants and polymers, to improve oil displacement efficiency. Even after secondary recovery methods like water or gas injection, significant volumes of oil remain trapped in the reservoir due to unfavorable mobility control, as depicted in **Figure 1(a)**. According to Glatz, an unfavorable mobility ratio is a major contributor to this inefficiency. The mobility ratio, defined as the ratio of the displacing fluid's mobility (permeability divided by viscosity) to that of the displaced fluid, directly influences the efficiency of the displacement process (Jang et al. 2015; Kossack 2012; Khan et al. 2021).

An inverse relationship exists between volumetric sweep efficiency and the mobility ratio. When the mobility ratio (M>1) exceeds unity, the displacement process becomes unstable, resulting in viscous fingering. Over time, this instability allows the displacing fluid to prematurely breakthrough to the production well, significantly reducing overall recovery efficiency. This phenomenon underscores the importance of achieving a favorable mobility ratio to optimize reservoir performance and enhance recovery outcomes.

$$M = \frac{\lambda_{water}}{\lambda_{oil}} = \frac{\kappa_{water} / \mu_{water}}{\kappa_{oil} / \mu_{oil}}, \quad (1)$$

To address the challenge of an unfavorable mobility ratio, polymer flooding is employed to reduce the mobility ratio and enhance displacement stability. By increasing the viscosity of the displacing fluid, this method mitigates the fingering effect, stabilizes water movement, and significantly improves oil recovery efficiency, as illustrated in **Figure 1(b)**. First introduced as a tertiary recovery method in the early 1960s, polymer flooding has since gained widespread recognition as a highly effective enhanced oil recovery (EOR) technique (Thomas 2016; Li et al. 2017).



(a) Fingering effect promoted by the unfavorable M (b) oil recovery facilitated using polymer flooding

Figure 1—Chemical flooding mechanism (Ragab and Mansour 2021).

Polymer flooding has been extensively studied over the past four decades, demonstrating its capability to recover up to 30% of the original oil in place (OOIP) across diverse reservoir conditions. This method is also cost-effective compared to conventional waterflooding, as it not only enhances oil production but also reduces excessive water production. Typically, the efficiency of polymer flooding requires the injection of 0.7 to 1.75 pounds of polymer per barrel of additional oil recovered.

The addition of polymers to water increases the viscosity of the displacing fluid, effectively reducing its relative permeability and improving the mobility ratio. The process begins with the injection of water containing surfactants, which lowers the interfacial tension between oil and water and alters the wettability of the reservoir rock. Following this preconditioning step, a polymer-water solution is injected continuously over a period of several years. Once approximately 30% to 50% of the reservoir's pore volume has been injected with the polymer solution, the injection is terminated, and drive water is subsequently used to push the polymer slug and the resulting oil bank toward production wells (**Figure 2**).

Ideal mobility control agents for polymer flooding should exhibit a combination of cost-effectiveness and high injectivity, while maintaining stability and performance under challenging reservoir conditions. These agents must resist mechanical and microbial degradation, tolerate high reservoir temperatures (up to 200°C), and perform effectively in the presence of reservoir brines and oilfield chemicals. Additionally, they should demonstrate low retention within porous media, ensuring minimal loss during injection. The agents must also be resilient to variations in acidity (pH) and remain unaffected by the presence of hydrocarbons to maximize their effectiveness in diverse reservoir environments (Ahmed 2006).

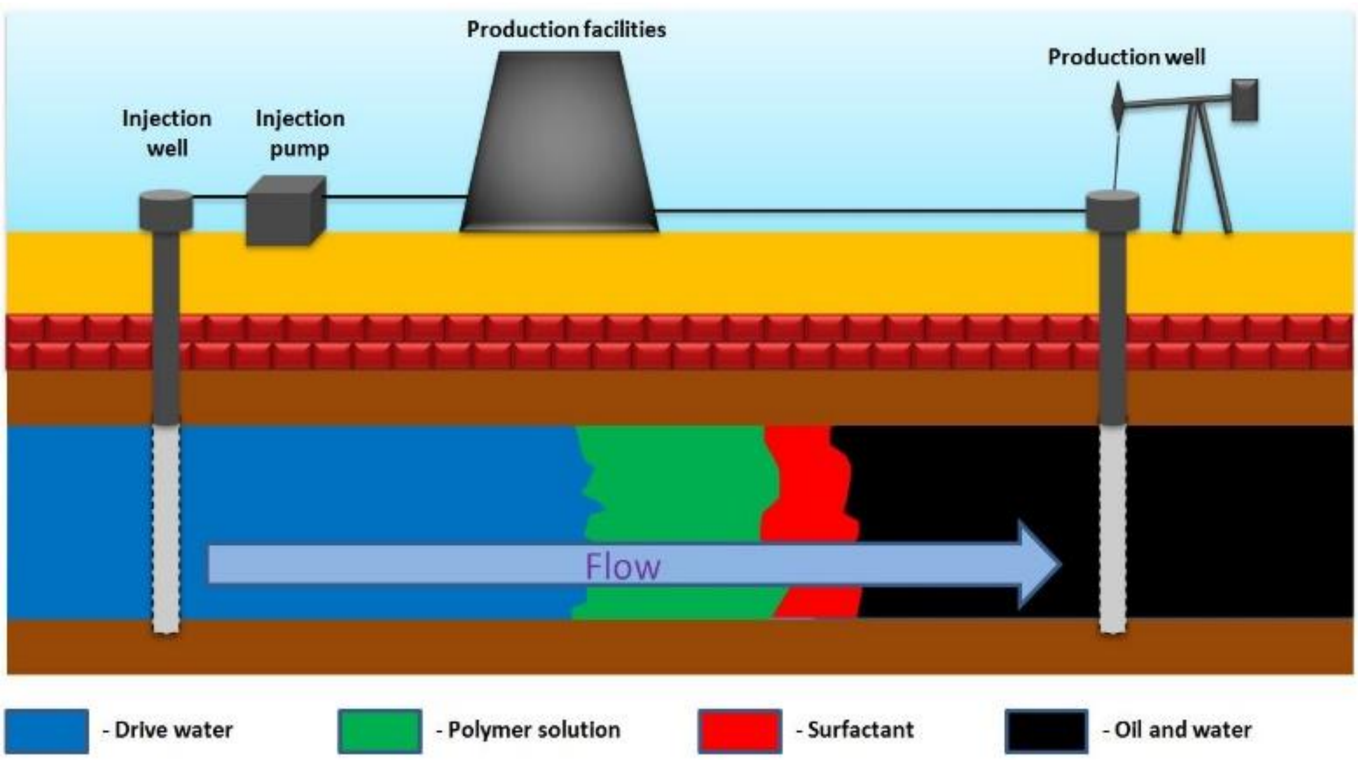


Figure 2—Schematic of polymer flooding (Ragab and Mansour 2021).

Polymer Types. Polymers employed in enhanced oil recovery (EOR) are broadly categorized into synthetic polymers and biopolymers. Commonly utilized synthetic polymers include polyacrylamide (PAM) and partially hydrolyzed polyacrylamide (HPAM), whereas biopolymers encompass xanthan gum and modified natural polymers such as hydroxyethyl cellulose (HEC), guar gum, sodium carboxymethyl cellulose, and carboxy ethoxy hydroxyethyl cellulose (Li et al. 2017). Each polymer type offers unique advantages and limitations, necessitating a selection process tailored to specific reservoir conditions.

PAM, characterized by a high molecular weight (>1.0×10^6 g/mol), was among the earliest thickening agents used in aqueous solutions for EOR. However, its application is constrained by its thermal stability, which is limited to temperatures of up to 90°C under normal salinity conditions and 62°C in seawater salinity. These temperature restrictions have primarily confined its usage to onshore operations. Additionally, high salinity environments can significantly reduce the viscosity of PAM solutions, further limiting its effectiveness (Khan et al. 2021).

HPAM, derived either through the partial hydrolysis of polyacrylamide (PAM) or the copolymerization of sodium acrylate with acrylamide, is one of the most widely utilized polymers in contemporary enhanced oil recovery (EOR) applications. It offers numerous advantages, including high mechanical stability during polymer flooding, resistance to bacterial degradation, and cost-effectiveness. HPAM exhibits thermal stability up to 99°C, with certain modifications extending its performance range to even higher temperatures-104°C for HPAM and up to 120°C for sulfonated polyacrylamide. Despite these benefits, its effectiveness diminishes in saline reservoirs due to its high sensitivity to brine salinity, water hardness, and interactions with surfactants or other chemicals, which can adversely impact its viscosity and performance (Khan et al. 2021; Ahmed 2016; Littmann 1988).

Xanthan gum, a polysaccharide produced by the bacterium Xanthomonas campestris through the fermentation of glucose or fructose, is notable for its exceptionally high molecular weight ($2\text{-}50\times10^6$ g/mol) and rigid polymer chains. This structural rigidity imparts xanthan gum with a remarkable tolerance to high salinity and water hardness, making it compatible with most surfactants and additives commonly used in tertiary oil recovery formulations. Its thermal stability ranges from 70°C to 90°C, although it is prone to bacterial degradation in lower-temperature regions of the reservoir. Furthermore, the presence of cellular debris in xanthan gum solutions may lead to plugging issues, potentially impacting injectivity and flow efficiency during application (Khan et al. 2021; Ahmed 2016; Thang 2005).

Recent research has highlighted the potential of xanthan gum in polymer flooding as an effective means of enhancing oil recovery. Biopolymers such as xanthan gum and guar gum are increasingly favored in polymer flooding applications due to their biodegradability, shear-thinning behavior, cost-effectiveness, low adsorption tendencies, and superior compatibility with brine. The selection of an appropriate polymer is primarily dictated by specific reservoir conditions and the desired recovery efficiency. While synthetic polymers and polysaccharides offer distinct advantages, their applicability is often constrained by reservoir-specific challenges, such as salinity, temperature, and chemical interactions, underscoring the need for tailored polymer solutions to optimize recovery performance.

Previous studies have often underestimated the potential of polymer flooding to enhance oil recovery in heavy oil reservoirs with unconsolidated formations. Xanthan gum, however, demonstrates significant promise for application in heterogeneous, unconsolidated sedimentary rock formations. Its use in polymer flooding offers notable advantages over conventional water flooding in addressing the challenges posed by these complex environments. In general, polymers outperform water flooding by effectively mitigating the impact of reservoir heterogeneity. Nonetheless, a comparative analysis of polymer flooding and conventional methods in such reservoirs remains critical.

This study aims to evaluate the synergistic effects of combining polymers with water flooding on the performance of heavy oil reservoirs, with a particular emphasis on improving water mobility. Furthermore, it investigates various injection well patterns, including the five-spot pattern, to identify the most efficient flooding strategy for optimizing polymer application in heterogeneous reservoirs.

Literature Review

Extensive research by scholars and industry professionals has focused on improving the recovery of hydrocarbons that are otherwise unrecoverable using conventional methods. Hydrocarbon production from oil and gas reservoirs progresses through distinct recovery phases. During the primary recovery phase, approximately 20-35% of the original oil in place (OOIP) is extracted, driven by the reservoir's natural energy mechanisms (Tunio et al. 2011). Secondary recovery techniques involve injecting fluids such as water or gas through injection wells to displace hydrocarbons toward production wells. The primary objective of secondary recovery is to maintain reservoir pressure; gas injection is typically applied in reservoirs with gas caps, while water injection is preferred in reservoirs with aquifers (Ramero-Zaron 2012).

The tertiary recovery phase, or enhanced oil recovery (EOR), employs advanced methods such as gas injection (miscible or immiscible), chemical injection, thermal recovery, and microbial processes (Samantha et al. 2012). EOR techniques have been shown to significantly enhance recovery efficiency, with Kamal et al. reporting recovery factors (RF) reaching up to 65%. In the context of polymer flooding, several factors, including polymer viscosity, mobility ratio, and polymer slug size, play a critical role in determining recovery efficiency (Kamal et al. 2015).

Recovery from heavy oil reservoirs is typically low when employing primary and secondary methods, primarily due to the high viscosity of heavy oil, which significantly impedes its flow toward production wells. Global reservoir data indicate that the recovery efficiency for low-permeability or heavy oil reservoirs using primary and secondary recovery techniques ranges between only 5% and 10%, highlighting the limitations of conventional approaches in such challenging environments (Tunio et al. 2011; Ramero-Zaron 2012; Standnes and Skjevrak 2014).

A simulation study conducted on a mature oil field demonstrated that polymer flooding can be economically viable by converting production wells into injection wells, resulting in an increase in recovery factor and net present value (NPV) by up to 46% (Lamas et al. 2021). The viscosity of the polymer plays a critical role in this process, as it modifies the mobility ratio and reduces the mobility of the displacing fluid during flooding. Another study highlighted those enhancements in polymer viscosity, sweep efficiency, and breakthrough time significantly contribute to higher recovery rates (Juarez et al. 2020). Polymer flooding is particularly effective in reservoirs with pronounced permeability variations across layers. Furthermore, as the molecular weight of the polymer increases, its viscosity also rises, directly influencing the efficiency of the flooding process (Li et al. 2021; Zhu et al. 2016).

A study analyzing the effects of polymer solutions with varying molecular weights across different reservoir layers concluded that utilizing polymers with tailored molecular weights can enhance the injection profile and improve overall reservoir development (Liang et al. 2010). Polymer retention is another critical factor, particularly in heavy oil reservoirs. Wang et al. (2000) conducted laboratory experiments to investigate polymer retention and effluent viscosity. Their findings emphasized that polymer retention may be overestimated if the relationship between polymer concentration and viscosity is not accurately accounted for.

Additionally, a separate study explored polymer retention by considering oil saturation in two-phase flow conditions. The results indicated that polymer retention increases with polymer concentration and that higher retention values are observed under oil-saturated conditions. These findings highlight the importance of understanding polymer retention dynamics in the presence of oil to optimize polymer flooding performance in heavy oil reservoirs (Yoo et al. 2020).

Injection rates play a significant role in recovery from viscous oil reservoirs. In polymer flooding, injection rates are generally lower than in water flooding due to the higher viscosity of polymer solutions. A numerical simulation study optimized polymer solution injection rates and viscosities, revealing that coarse grid simulations tend to overestimate injection pressures (Aitkulov et al. 2021). This technique has also been shown to be effective in sandstone and shale reservoirs with thin layers and low-permeability sequences, as polymers with tailored molecular weights and viscosities enhance oil recovery in these challenging formations. Notably, medium molecular weight polymers have demonstrated the ability to improve displacement profiles, resulting in increased oil production while reducing water production, all without causing pore throat blockage (Wang et al. 2000).

A simulation study on polymer flooding in multilayer heterogeneous reservoirs revealed that using polymers with varying molecular weights is more efficient than commingled or zonal polymer flooding approaches (Liu et al. 2018). Research into the effect of extensional viscosity found that extremely high extensional viscosity significantly enhances microscopic displacement efficiency and overall recovery (Zhu et al. 2016). Additionally, a study on hydrophobically modified polyacrylamide polymers demonstrated that incorporating sodium dodecyl sulfate increased the apparent viscosity of the polymer solution, leading to a 24.4% improvement in heavy oil recovery by optimizing the mobility ratio (Ji et al. 2016). Furthermore, functional polymers specifically designed for viscosity reduction in heavy oil reservoirs showed superior performance, effectively reducing viscosity and broadening the oil-water ratio, thereby improving recovery efficiency (Li et al. 2021).

Ultra-high molecular weight polymers are widely utilized in natural gas liquid (NGL) miscible enhanced oil recovery (EOR) processes. The low molecular weight and viscosity of NGLs, such as ethane, propane, and butane, often result in fingering through the reservoir oil, leading to early breakthrough and reduced oil recovery. Experimental studies have demonstrated that the addition of ultra-high molecular weight polymers to NGL mixtures enhances recovery by increasing the density and viscosity of the NGL phase. This adjustment improves the mobility ratio, thereby promoting a more stable displacement front and improving overall oil recovery efficiency (Dhuwe et al. 2016).

Methodology

This study investigates reservoir performance by comparing waterflooding and polymer flooding techniques. A comprehensive literature review provided the foundational data necessary to develop a three-dimensional (3D) reservoir model using a commercial simulation software. The base case scenario was established, employing a direct-line drive configuration for both water and polymer flooding to evaluate and compare the effectiveness of these injection methods. Furthermore, a sensitivity analysis was conducted to assess the impact of various injection well patterns, with a particular emphasis on the five-spot pattern, to determine its influence on reservoir behavior. The final phase of the study identified the optimal injection pattern based on key technical parameters, including oil production rates, cumulative oil recovery, water breakthrough timing, and overall recovery efficiency. A detailed visual representation of the methodology and workflow utilized in this study is provided in **Figure 3**.

Reservoir Characteristics. A three-dimensional (3D) reservoir model with dimensions of 500 feet in length, 500 feet in width, and 50 feet in thickness was constructed and simulated. The model is discretized into 7 grid blocks along the x-direction, 7 grid blocks along the y-direction, and 3 grid blocks along the z-direction, resulting in a total of 147 grid cells. The reservoir is characterized by two active phases—oil and water—and comprises three vertically stacked layers with permeabilities ranging from 20 to 1000 mD. The porosity is uniformly set at 20%. The simulation spans a 12-year period, with **Table 1** detailing the reservoir and fluid properties used in the base case model.

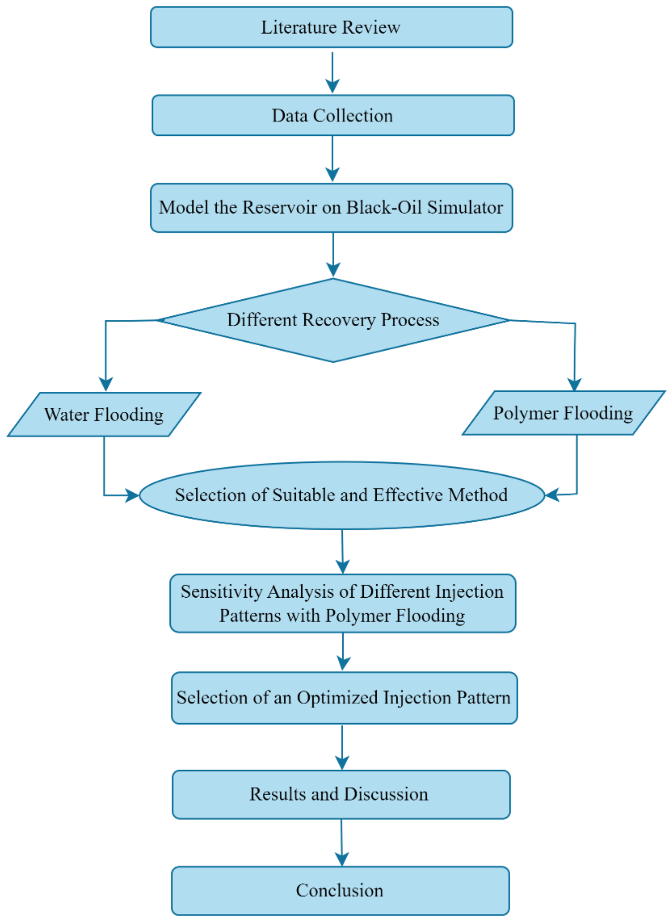


Figure 3—Methodology workflow diagram.

Table 1—Reservoir and fluid properties (Tunio et al. 2011).

Parameters	Values	Parameters	Values
Type of Simulator	Black oil	Datum depth	8,074 ft
Geometry Option	Block- Centered	Water FVF	1.02 rbbl/stb
Reservoir Length	500 ft	Density of water	63.0 lb/ft^3
Reservoir Width	500 ft	Density of oil	49.0 lb/ft^3
Reservoir Thickness	50 ft	Viscosity of water	0.5 cp
Porosity	20 %	Viscosity of oil	0.8 cp
Permeability Range	20-1000 md	Compressibility of rock	4.0×10^{-6} psi^{-1}
Reservoir Pressure	4500 psi	Compressibility of water	3.0×10^{-6} psi^{-1}

Two wells are positioned at opposite corners of the base model. The well labeled 'INJ1' functions as the injector, while the well designated 'PROD' is used for production, as depicted in **Figure 4**.

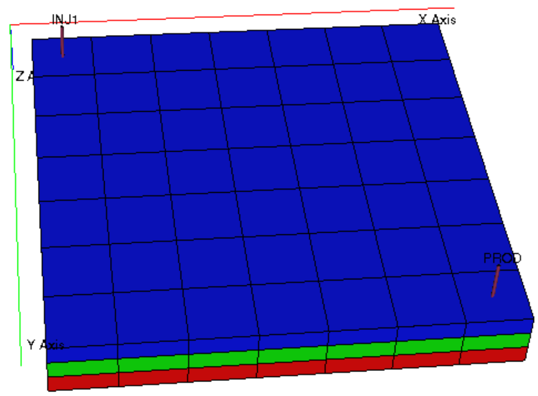


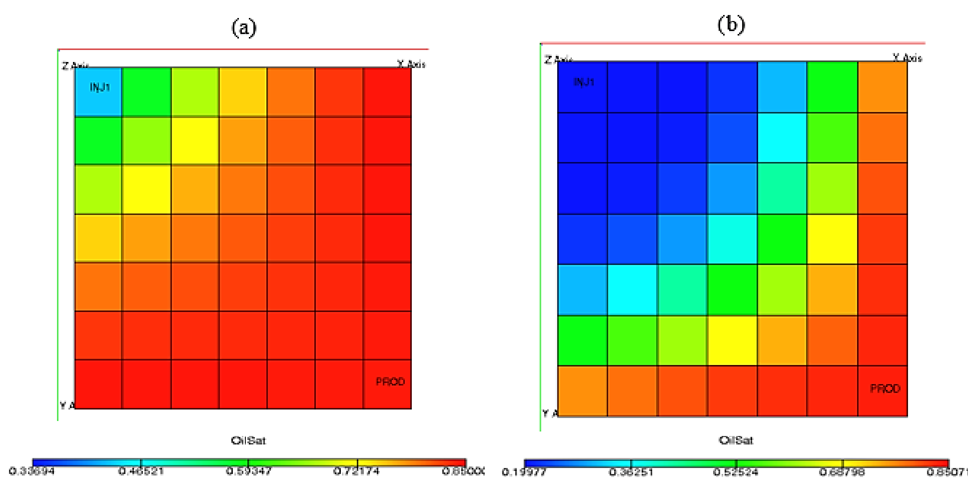
Figure 4—A three-dimensional reservoir model featuring INJ1 and PROD.

Results and Discussion

This section presents the results of the simulation and analyzes the performance of both water and polymer flooding techniques. The effect of different injection patterns on key performance indicators such as oil production rate, recovery efficiency, water cut, and reservoir pressure are discussed in detail.

Comparison of Water Flooding and Polymer Flooding Performance Using Direct Line Drive. The base model employs water flooding techniques with a single injector and producer well. A polymer solution with a concentration of 2.2 wt% is introduced into the water and injected into the reservoir. The results from the polymer flooding scenario are then compared to the base case model.

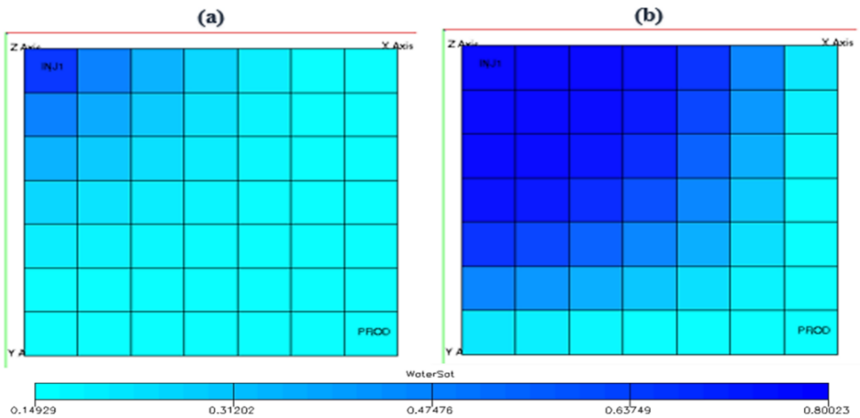
The reservoir models demonstrate variations in oil saturation within the reservoir grid block, showing the impacts of water flooding and polymer flooding techniques, as shown in **Figure 5**. Figure 5(a) shows the oil saturation distribution in the reservoir following water injection. High oil saturation remains in several areas, suggesting that waterflooding alone didn't fully sweep these zones. Figure 5(b) presents the oil saturation distribution after polymer flooding. The oil saturation decreases significantly in certain areas, highlighting improved displacement of oil by the polymer solution. Polymer flooding generally enhances the sweep efficiency by increasing water viscosity, thus reducing fingering and improving oil displacement.



(a) after waterflooding (b) followed by polymer flooding

Figure 5—Oil saturation distribution.

Figure 6 illustrates changes in water saturation within a reservoir grid, exhibiting the effects of water flooding and polymer flooding techniques. Figure 6(a) depicts water saturation after water flooding. The relatively uniform blue shades indicate higher water saturation, but some oil-rich areas might still be left upswept in the pores. Figure 6(b) shows water saturation following polymer flooding, where the water saturation is more uniformly distributed, reflecting the improved efficiency of polymer flooding. This technique leads to more effective oil displacement, reducing oil saturation and enhancing overall water sweep.



(a) after waterflooding (b) followed by polymer flooding

Figure 6—Water saturation distribution.

Figure 7 illustrates that polymer flooding achieves a higher oil production rate compared to water flooding. In the beginning, waterflooding reaches a peak oil production rate of 2,560 STB/D in the first year, but this rate declines throughout the simulation period. In contrast, the oil production rate for polymer flooding rises consistently during the first year, reaching a peak of around 5,000 STB/D. It then stabilizes around this level for the next 12 years of production. These results highlight that polymer flooding outperforms waterflooding in terms of sustained oil production rate.

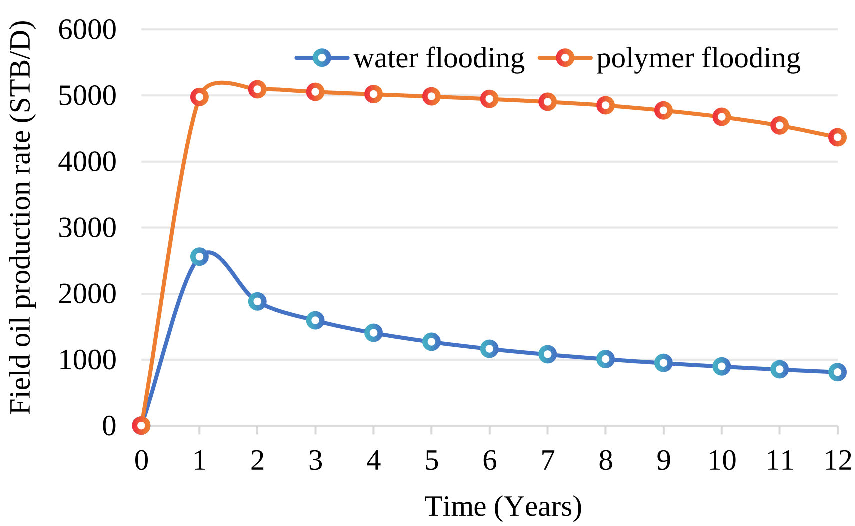


Figure 7—Oil production rate.

As shown in **Figure 8**, waterflooding exhibits a slight increase in total oil production, while polymer flooding demonstrates a steady and consistent rise throughout the production period. The higher mobility of water in waterflooding results in early water breakthrough, which leads to a decline in oil production over time. In contrast, the addition of polymers to the water in polymer flooding reduces its mobility, improving the displacement efficiency and enhancing oil recovery. By the end of the production period, total oil production reaches 6.2 MMSTB for waterflooding and 21 MMSTB for polymer flooding, highlighting the superior efficiency of polymer flooding. The increased viscosity of the water in polymer flooding delays the onset of water cut, which is directly correlated with a higher oil production rate and an overall increase in total oil production.

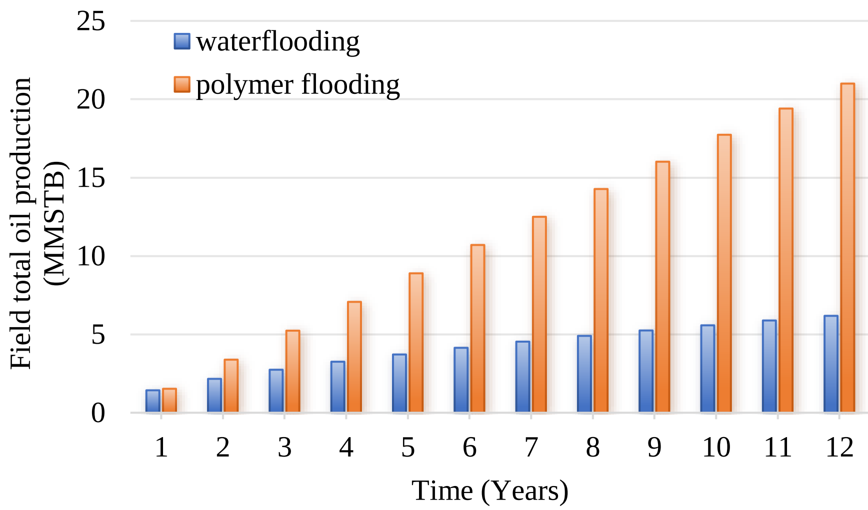


Figure 8—Total field oil production.

As shown in **Figure 9**, both water flooding and polymer flooding begin with an oil recovery efficiency of 3% in the first year. While waterflooding observes a gradual increase in recovery efficiency over time, polymer flooding demonstrates a more pronounced and rapid increase in recovery factors. By the end of the production period, waterflooding achieves a recovery efficiency of 13%, whereas polymer flooding attains a much higher recovery rate of 44%, indicating superior sweep efficiency over water flooding.

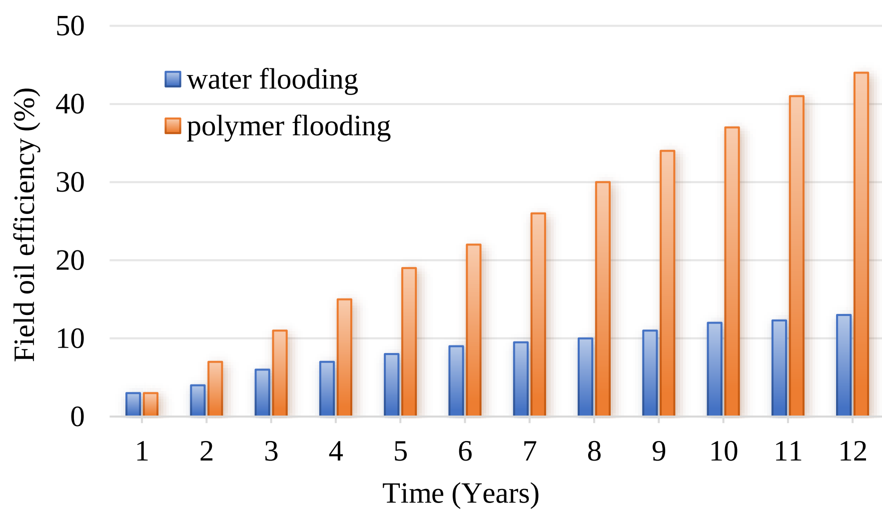


Figure 9—Field oil recovery.

Figure 10 depicts the initial reservoir pressure at 4500 psi. With water flooding, there is a sharp increase in pressure within the first year, reaching approximately 9930 psi. However, when the polymer is introduced along with water during polymer flooding, the initial pressure reaches a comparatively lower value of 5964 psi. In this case, waterflooding maintains higher reservoir pressure due to effective voidage replacement, while polymer flooding with its increased water viscosity, improves sweep efficiency. By the end of the simulation period, waterflooding results in an average reservoir pressure of 10,445 psi, whereas polymer flooding maintains a lower reservoir pressure of 6,143 psi, demonstrating improved pressure control with polymer flooding.

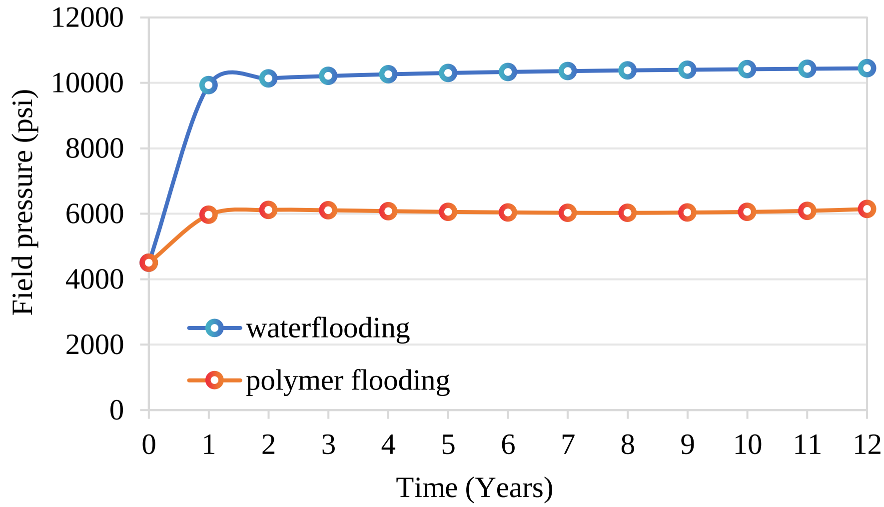


Figure 10—Field pressure.

As shown in **Figure 11**, waterflooding results in increased field water production, primarily due to water breakthrough in the first year. Polymer flooding, however, experiences its breakthrough in the second year, leading to lower overall water production. The delay is attributed to the enhanced water viscosity in polymer flooding, which helps maintain reduced water production rates. Over a 12-year simulation period, waterflooding generates a total water production of 37 MMSTB, while polymer flooding produces only 3.1 MMSTB.

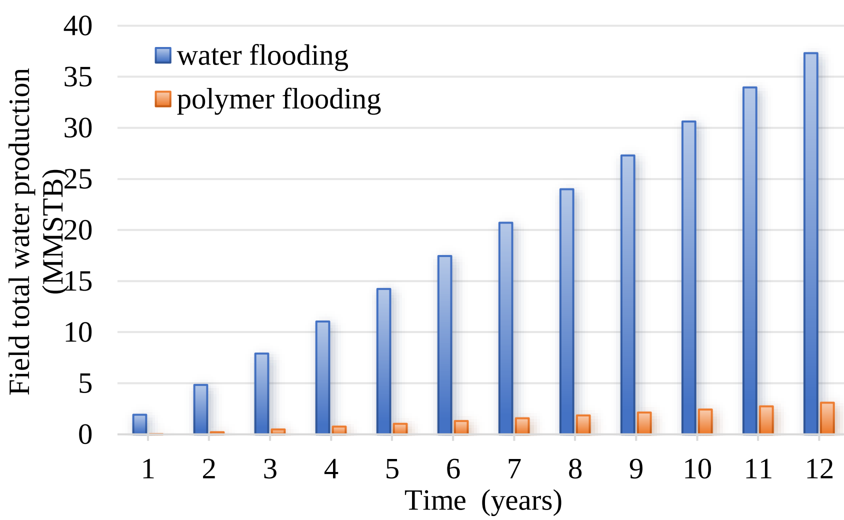
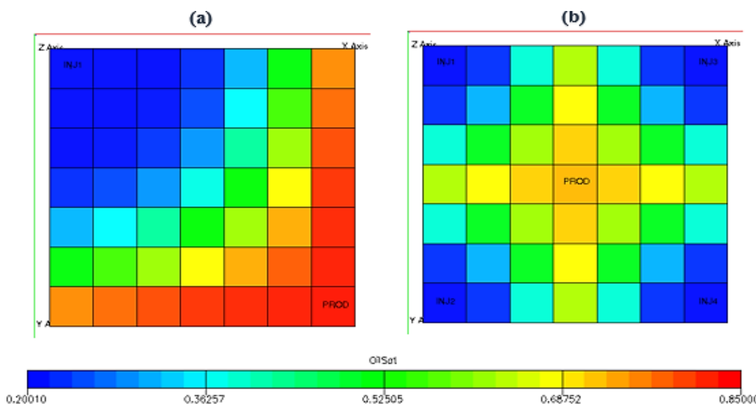


Figure 11—Field total water production.

The results suggest that polymer flooding is a more effective method than water flooding for improving oil recovery efficiency in unconsolidated heavy oil reservoirs. Polymer flooding enhances oil recovery and delays water breakthrough, significantly reducing water production. These findings indicate that polymer flooding is a more efficient and feasible approach for enhancing oil recovery in comparison to conventional methods.

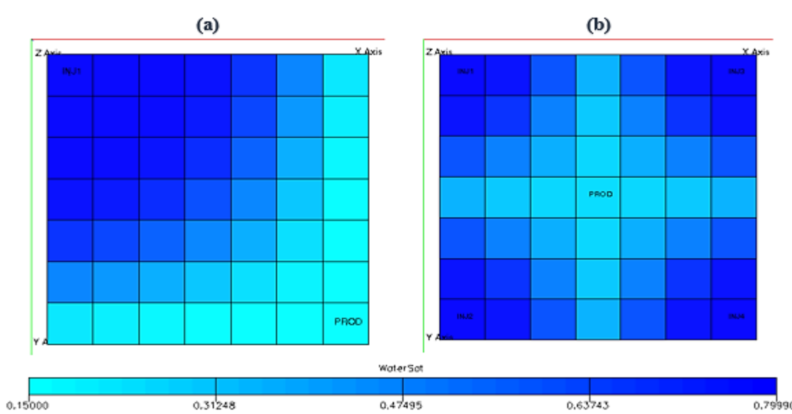
Performance Analysis. A sensitivity analysis was performed to compare oil saturation and water saturation under two different flooding configurations, such as direct line drive and five-spot injection pattern. **Figure 12(a)** shows oil saturation after applying a direct line drive pattern. High oil saturation is concentrated in certain regions, suggesting that this configuration might have left upswept zones with significant remaining oil. The line drive pattern can sometimes result in channeling, where injected water or polymer solution flows along high-permeability paths, leaving pockets of oil behind. **Figure 12(b)** illustrates the oil saturation distribution following polymer flooding in a five-spot pattern, where four injector wells are positioned at the corners with a producer well at the center. Compared to the direct line drive, the five-spot pattern shows lower oil saturation throughout the grid block, indicating more uniform oil displacement and less residual oil. This pattern typically enhances the sweep efficiency by providing multiple injection and production points, allowing for a more effective flood front.



(a) Direct line drive (b) Five-spot pattern after polymer flooding

Figure 12—Comparison of oil saturation.

Figure 13(a) shows water saturation using the direct line drive configuration. The overall water saturation appears uneven, and some areas might have relatively low water saturation, indicating an incomplete sweep. On the other hand, **Figure 13(b)** illustrates water saturation with the five-spot pattern after polymer flooding. There is a more uniform distribution of water saturation, suggesting that the five-spot pattern has a better areal sweep, distributing water more effectively and reducing bypassed oil zones. The comparison between the five-spot pattern and the direct-line-drive method offers valuable insights into the performance differences between these two injection techniques.



(a) direct line drive (b) Five-spot pattern after polymer flooding

Figure 13—Comparison of water saturation.

Figure 14 shows that both configurations experience an initial rise in oil production rates, with the five-spot pattern sustaining a higher rate throughout the first year. The direct-line drive achieves an initial rate of 4,973 STB/D, while the five-spot pattern reaches 7,068 STB/D. After the first year, however, the five-spot pattern's production rate gradually declines, whereas the direct-line drive maintains a stable rate for the entire simulation period. The five-spot pattern's high initial rates are achieved by injecting a large water-polymer mixture, which, however, also results in a higher water-to-oil ratio. By the end of the production period, the direct-line drive records a field oil production rate of 4,365 STB/D, compared to 3,638 STB/D for the five-spot pattern.

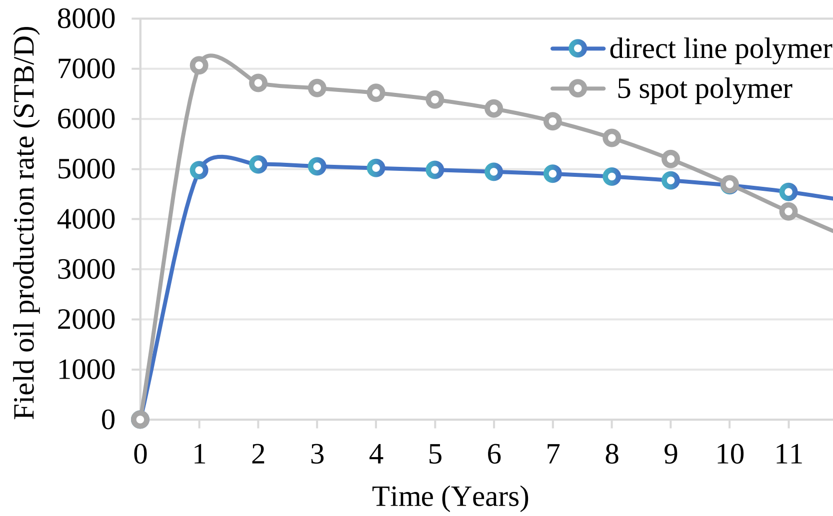


Figure14—Field oil production rate.

In **Figure 15**, both configurations exhibit increased total oil production, directly influenced by their production rates. The direct-line drive yields 2 MMSTB in the first year, while the five-spot pattern achieves 3 MMSTB, indicating the greater initial efficiency of the five-spot pattern. By the end of the production period, the direct-line drive produces a cumulative total of 21 MMSTB, whereas the five-spot pattern achieves 25 MMSTB, confirming the superior production capability of the five-spot pattern in polymer flooding applications.

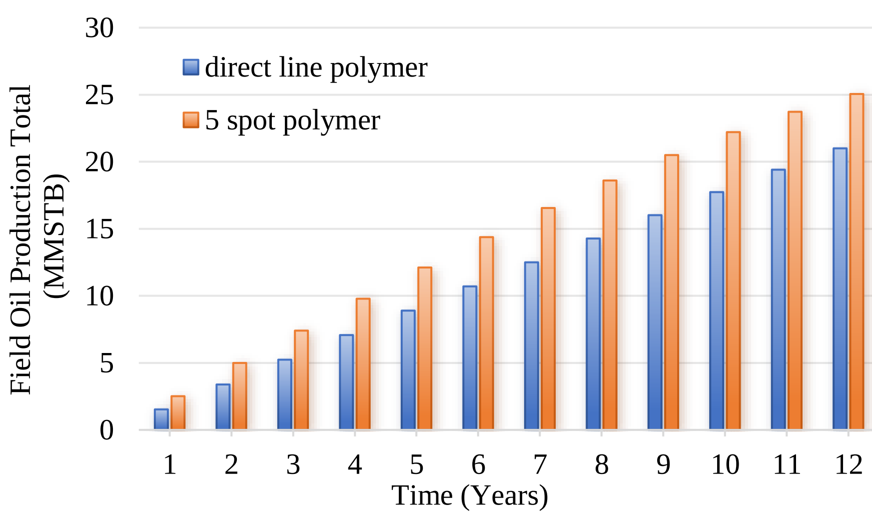


Figure 15—Total field oil production.

Figure 16 indicates that polymer flooding enhances oil recovery efficiency in both configurations. Higher cumulative oil production significantly improves the recovery factor, with initial recovery efficiency values of 3% for the direct-line drive and 5% for the five-spot pattern. Over the 12-year simulation, the direct-line drive's recovery efficiency rises to approximately 44%, while the five-spot pattern reaches 52%, showing the higher effectiveness of the five-spot pattern in enhancing the recovery factor.

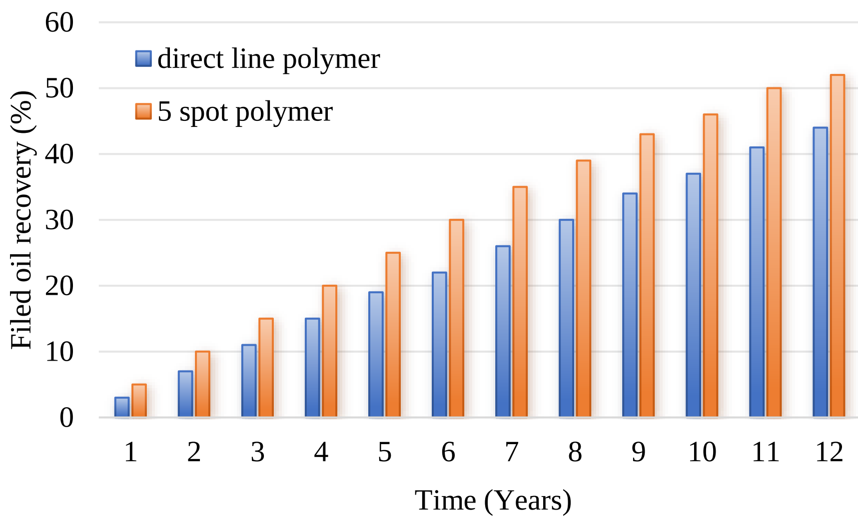


Figure 16—Field oil recovery.

As shown in **Figure 17**, both flooding patterns begin with an initial reservoir pressure of 4,500 psi, with pressure increases observed as production progresses. After eight months, both the five-spot pattern and direct-line drive reach an average reservoir pressure of around 5,717 psi. The five-spot pattern maintains a slightly higher average pressure due to its larger injected water volume, which provides better reservoir support. Over the 12 years, the five-spot pattern and direct-line drive configurations exhibit minimal differences in pressure maintenance, with average pressures of 6,143 psi for the five-spot pattern and 5881 psi for the direct-line drive, reflecting a minor (4.4%) difference.

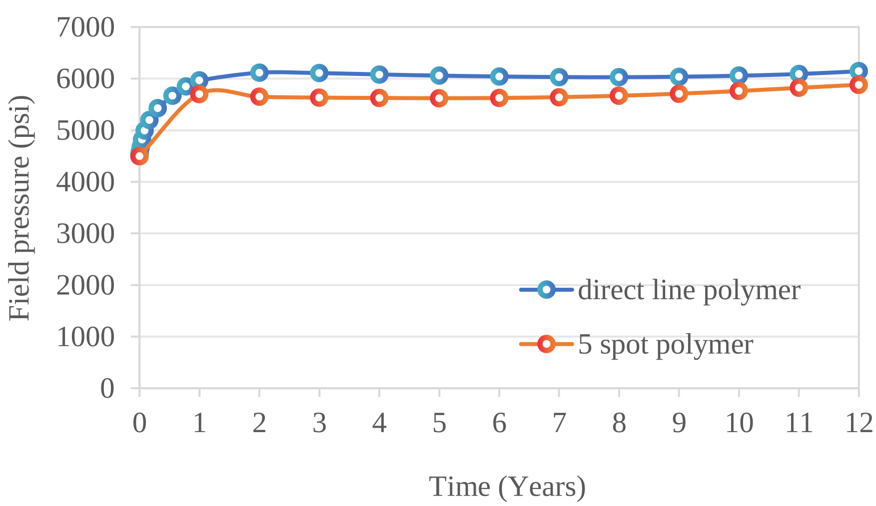


Figure 17—Field pressure over time.

Figure 18 indicates a steady increase in water production over time, which is directly correlated to cumulative water production levels. The five-spot pattern configuration shows higher water production from the start, reaching 0.1 MMSTB in the first year, as it relies on large volumes of water-polymer injection to sustain reservoir pressure. By the end of the simulation, the direct-line drive configuration produces 3 MMSTB of water, whereas the five-spot pattern generates a higher total of 5 MMSTB due to its enhanced injection scheme.

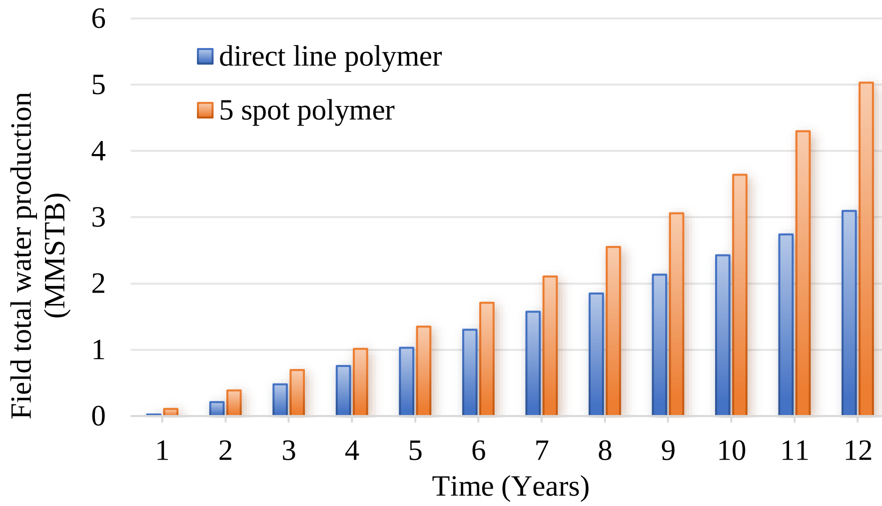


Figure 18—Field water production over time.

The simulation results highlight the critical role of waterflooding in maintaining reservoir pressure, while polymer flooding emerges as a highly effective method to enhance hydrocarbon recovery. The increased viscosity of water due to polymer injection mitigates the fingering effect, reducing water cuts and delaying water breakthrough, which ultimately leads to a significant increase in oil recovery efficiency. Addressing the fingering phenomenon, which is particularly pronounced in conventional waterflooding, is essential for optimizing oil production rates. The sensitivity analysis identified the five-spot pattern as the optimal injection strategy for this reservoir, demonstrating superior oil recovery efficiency and maximizing total oil production. This pattern thus represents the preferred choice for optimizing reservoir performance in heterogeneous, unconsolidated formations.

Conclusion

This study examines the impacts of waterflooding and polymer flooding on reservoir performance in heterogeneous, unconsolidated formations. Additionally, a sensitivity analysis was conducted to determine the optimal injection pattern, comparing direct-line drive and five-spot patterns. The key findings from the simulation are summarized as follows:

1. Polymer flooding proved to be significantly more effective than conventional water flooding, enhancing oil recovery efficiency to approximately 44%, compared to just 13% achieved by waterflooding.
2. Cumulative oil production was substantially higher with polymer flooding, reaching 21 MMSTB by the end of the simulation, compared to 6.2 MMSTB for waterflooding.
3. Water breakthrough occurred early during waterflooding, while the development of water cut was successfully delayed for a considerable period with polymer flooding, extending the production phase.
4. The sensitivity analysis identified the five-spot injection pattern as the most effective approach for this specific reservoir. However, its efficiency can vary depending on the characteristics of different reservoirs.
5. Furthermore, the five-spot pattern achieved a higher oil recovery efficiency of approximately 52%, with greater cumulative oil production, reaching 24 MMSTB, surpassing the 21 MMSTB produced using the direct-line drive technique.

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Nomenclature

CEOR	=	Chemical Enhanced Oil Recovery
MIOR	=	Microbial Improved Oil Recovery
OOIP	=	Original Oil in Place
S_{or}	=	Residual Oil Saturation

Conflicting of Interest

The author(s) declare that they have no conflicting interests.

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