The Application Effect of Polymer-Alternating-Gas in the Daqing X Block Reservoir

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Abstract

As global demand for oil continues to rise, conventional reservoir extraction methods have proven insufficient to meet current production needs. To enhance oil recovery rates, researchers have investigated more economically viable extraction techniques. Among these, polymer flooding and CO_2 injection have gained recognition as cost-effective methods. However, despite extensive research, the effectiveness of Polymer-Alternating-Gas (PAG) injection in field-scale applications remains ambiguous.

This study employs the commercial reservoir simulation software CMG-GEM to construct a three-dimensional geological model of the Daqing X Block, based on detailed geological data. Using an orthogonal experimental design approach, the injection parameters for the PAG process are optimized through numerical simulation to determine the optimal injection scheme for the Daqing X Block. Furthermore, the study conducts a comprehensive comparison of the development performance and oil displacement efficiency of Water flooding, Polymer flooding, Water-Alternating-Gas (WAG), and PAG injection methods. The results indicate that PAG injection can significantly enhance the recovery factor and demonstrates favorable application potential in the Daqing X Block reservoir.

This research provides critical theoretical insights and practical guidance for the implementation of Polymer-Alternating-Gas injection in oil field development.

Introduction

The global demand for oil continues to rise, particularly in developed and developing nations seeking to improve their standards of living. Conversely, the production of crude oil is gradually declining as reservoirs mature. This discrepancy has driven the oil industry to develop innovative technologies to extract oil from increasingly complex and less accessible reservoirs. After the primary and secondary recovery stages, nearly 70% of the original oil in place (OOIP) remains unrecovered and requires more efficient enhanced oil recovery (EOR) methods (Kumar and Mandal 2017).

Gas flooding has emerged as a preferred EOR technique for mature fields due to its superior microscopic sweep efficiency in fine reservoir pores, outperforming water flooding (WF). However, continuous gas injection presents challenges in heterogeneous reservoirs, including unfavorable mobility ratios, channelling, and early breakthrough. Additionally, gas flooding suffers from poor volumetric sweep efficiency, viscous fingering, and gravity segregation effects (Kumar and Mandal 2017).

To address these issues, Caudle and Dyes (1958) proposed the Water-Alternating-Gas (WAG) process, which alternates between water and gas injection. WAG has demonstrated better recovery compared to gas injection alone, and approximately 80% of commercial WAG projects in the U.S. have proven economically viable

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(Christensen et al. 2001). Nevertheless, recent studies have revealed that many fields fail to achieve the expected recovery factors using WAG, particularly in reservoirs with high-permeability zones or natural fractures (Enick et al. 2012). Despite the success of CO_2-WAG, incremental recovery from the field typically ranges between 5% and 15% OOIP, which is limited by gravity segregation, water blocking, and mobility control challenges (Alzayer and Sohrabi 2018). Additionally, WAG has encountered significant difficulties in improving sweep efficiency in highly permeable zones (Kamali et al. 2015).

In response to the limitations of traditional gas flooding and WAG, this study introduces a novel injection strategy known as Polymer-Alternating-Gas (PAG). By incorporating polymers into the water phase, this approach enhances water viscosity and improves the mobility ratio, integrating the benefits of CO_2 and polymer flooding (PF). PAG significantly increases sweep efficiency and enhances overall oil recovery (Yang et al. 2018). Several simulation studies have been conducted to evaluate PAG performance. Majidaie et al. (2012) were the first to simulate combined polymer and CO_2 injection in a homogeneous reservoir, demonstrating that PAG and WAG yield comparable recovery rates. Jeong et al. (2014) used numerical simulation in a synthetic heavy oil reservoir model, reporting that PAG achieved 45% higher recovery than WAG, and PAG performance was insensitive to cycle time. A 2:1 PAG ratio provided the highest recovery among the cases studied. Li et al. (2014) conducted a simulation study in a highly heterogeneous light oil reservoir (TR78, North Burbank Unit), showing that PAG delayed gas breakthrough, reduced the gas-oil ratio (GOR), and improved sweep efficiency, achieving an incremental recovery of 14.3%, which was 7.0% higher than WAG.

Li and Schechter (2014) extended this analysis, examining PAG performance across reservoirs with varying permeabilities, heterogeneities, and oil viscosities. For homogeneous reservoirs, PAG did not improve recovery for permeability below 500 mD but achieved 7% to 15% higher recovery than WAG at higher permeabilities. For heterogeneous reservoirs, formations with lower permeability and higher variability in permeability were ideal candidates for PAG, with lower oil viscosity further enhancing recovery. Their case study in the North Burbank Unit (TR59) showed that PAG increased recovery by 20%, 12% higher than WAG. Kong et al. (2015) applied simulation to a real field geological model of a light oil reservoir, concluding that PAG achieved a cumulative oil recovery of 74%, outperforming WAG (68%) and water flooding (59%). Jamal et al. (2016) optimized PAG operational parameters using Covariance Matrix Adaptation Evolution Strategy (CMA-ES) and Particle Swarm Optimization (PSO), incorporating factors such as well placement, cycle numbers, bottom-hole pressure (BHP), CO_2 injection rate, polymer concentration, and duration of injection. Yang et al. (2018) utilized a field model of a highly heterogeneous heavy oil reservoir (Liaohe Oil Field) and reported that PAG increased recovery by more than 10% compared to WAG, while reducing the water cut from 95% to 28% and lowering the GOR.

Additional experimental studies have also explored PAG performance. Zhang et al. (2009) conducted sandpack experiments of polymer injection followed by gas and water injection (PGAW) under immiscible conditions, demonstrating higher oil recovery than WAG or polymer flooding alone. Tovar et al. (2015) investigated PAG through core flood experiments in homogeneous and heterogeneous rocks, showing that while PAG did not outperform WAG under immiscible conditions, it did not hinder recovery. Pang and Mohanty (2022) conducted core displacement experiments comparing continuous gas injection (CG), WAG, and PAG, finding that PAG and WAG had similar recovery in homogeneous cores, while PAG reduced the fingering effect in heterogeneous cores, resulting in higher recovery than CG.

In a further study, Yegane et al. (2023) conducted X-ray CT-assisted core displacement experiments to compare the effects of CO_2, WAG, and Polymer-Assisted WAG (PA-WAG). Their results indicated that PA-WAG increased oil recovery by 10% over traditional WAG, reducing oil-gas segregation and enhancing displacement efficiency. Laochamroonvorapongse et al. (2023) utilized microfluidic models based on Thai oil fields to demonstrate that PAG achieved a 6% higher recovery than WAG. Chen et al. (2023) focused on optimizing polymers for low-permeability layers, finding that a temperature-resistant polymer surfactant (TRPS) significantly increased recovery by 8.21% over WAG, owing to its viscosifying properties and effective injectivity.

Modeling polymer flooding requires a simulator capable of simulating chemical floods, while CO_2 flooding necessitates proper compositional handling to account for CO_2 miscibility with oil (Kong et al. 2015). In this regard, CMG-GEM offers unique advantages. While previous studies predominantly used the CMG-STARS simulator, CMG-GEM is more suited for simulating the PAG process, as it can effectively model important mechanisms in miscible gas injection, such as vaporization, oil swelling, gas condensation, and miscible solvent bank formation through multiple contacts.

Despite extensive research, the effectiveness of Polymer-Alternating-Gas (PAG) injection in field applications remains unclear. This study focuses on the Daqing X Block reservoir, employing the CMG-GEM simulator to evaluate the effectiveness of PAG compared to water flooding, polymer flooding, and WAG. The contributions of this research are as follows: the evaluation of PAG's effectiveness in the Daqing X Block reservoir through simulation and comparison with other recovery methods.

This paper is structured as follows. Section 2 provides an in-depth explanation of the research workflow. Section 3 describes the reservoir characteristics of Block X, including model scale and well control conditions. Section 4 presents 16 orthogonal experiments designed to determine the optimal parameters for PAG. Section 5 compares the enhanced recovery effects of PAG, WF, PF, and WAG. Finally, Section 6 summarizes the main conclusions of the study.

Workflow

To evaluate the application of Polymer-Alternating-Gas (PAG) injection in the Daqing X Block reservoir, this study utilizes CMG-GEM software to simulate various recovery methods, including water flooding, Water-Alternating-Gas (WAG) flooding, polymer flooding, and PAG flooding. The research workflow, as illustrated in **Figure 1**, consists of several stages: starting with the construction of a detailed reservoir model, followed by the base case simulation of water flooding. Next, a PAG orthogonal experiment is conducted to optimize the injection parameters. Sensitivity analysis is then performed to identify the optimal parameterization, which is applied across all recovery methods. Subsequently, the different flooding processes (water flooding, WAG, polymer flooding, and PAG) are simulated and compared based on key performance indicators such as oil production rate, gas volume, recovery factor, water cut, and gas-oil ratio (GOR). The workflow ensures a thorough comparison without altering flow constraints across the simulations, allowing for a comprehensive evaluation of each recovery method. A consistent set of flow constraints is maintained across all simulations to ensure a valid comparison of the performance of each method.

Model Schematic Design

Reservoir and Fluid Characteristics. The study area is located in the northeastern region of the Daqing Oilfield, Heilongjiang Province, China. The block features a relatively gentle structural profile, spanning 1,472 meters from east to west and 1,485 meters from north to south, with a top reservoir depth of 2,430 meters and an effective reservoir thickness of 80 meters. The reservoir primarily consists of fine sandstone and siltstone, with an average porosity of 22.5%, average permeability of 162.7 mD, and a water saturation of 33.8%. The formation crude oil has a density of 0.857 g/cm^3 and a viscosity of 7.35 mPa • s. The formation water is of the $NaHCO_3$ type, with an original reservoir pressure of 21 MPa and a formation temperature of 55.6^{o}C. A summary of the reservoir characteristics and fluid properties is provided in **Table 1**.

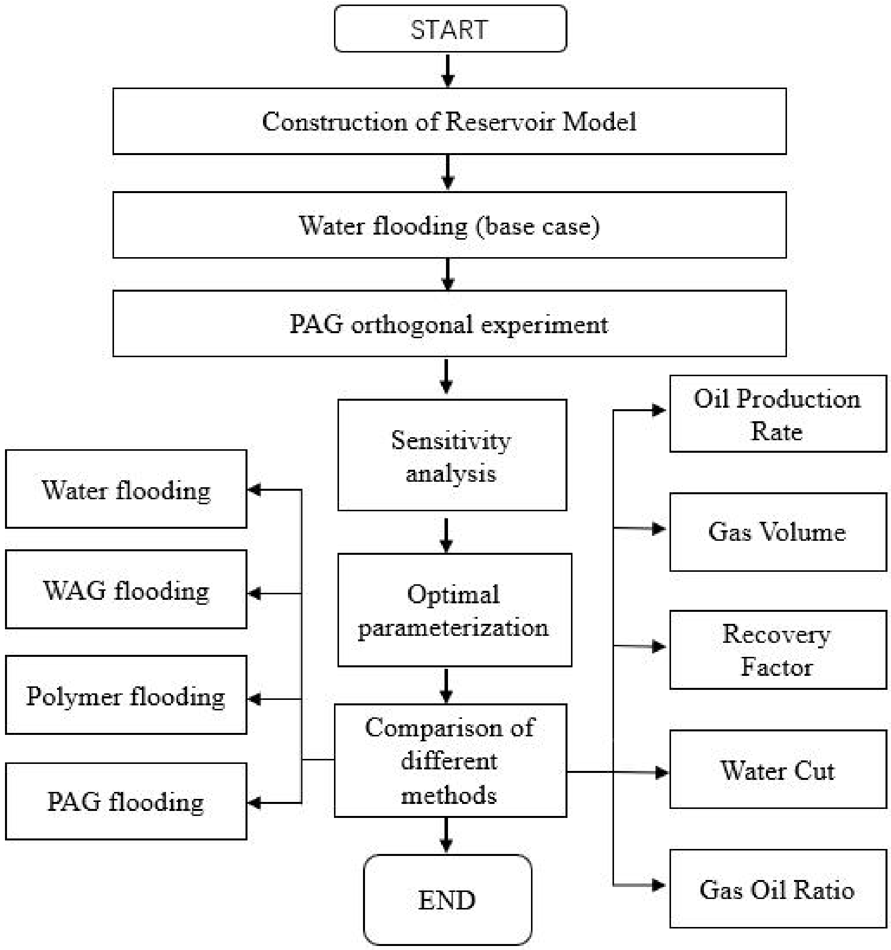


Figure 1—Simulation workflow of PAG application effects.

Table 1—Reservoir and fluid characteristics.

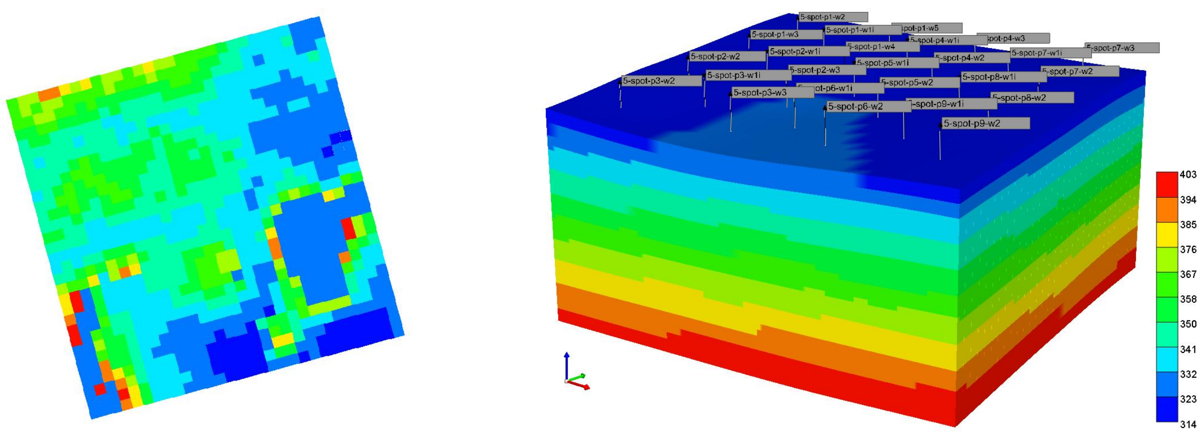
Information	Parameter	Value
Reservoir properties	Average porosity	22.5%
	Average permeability	162.7 mD
	Original reservoir pressure	21 MPa
	Temperature	55.6 ℃
Fluid properties	Water saturation	33.8%
	Crude oil density	0.857 g/cm^3
	Crude oil viscosity	7.35 mPa·s
	Formation water type	$NaHCO_3$

Model Overview. A detailed reservoir geological model was constructed based on formation data, consisting of 930,000 grid cells. Each grid cell measures 10 meters in both the x and y directions, with the reservoir vertically divided into 40 layers. The fundamental input parameters for the reservoir grids are summarized in **Table 2**.

Table 2—Basic Input Parameters of Reservoir Grids

Parameter	Value
Top reservoir depth, m	2340
Number of grids	150*155*40
Total blocks	930000
Active blocks	611750

The Polymer-Alternating-Gas (PAG) numerical simulation employs a five-spot well pattern, comprising 25 injection wells and 36 production wells, with an inter-well distance of 212 meters between injection and production wells. **Figure 2** illustrates the planar distribution of the block and the numerical model. **Figure 3** presents the permeability distribution range within the block. The histogram shows the percentage of grid cells falling within specific permeability ranges, measured in millidarcies (mD). The highest proportion of permeability values is concentrated below 50 mD, accounting for approximately 45.3% of the reservoir. Other significant ranges include 50-100 mD, representing 21.1%, and 100 – 150 mD, contributing 13.7%. Smaller percentages are observed as permeability increases, with the distribution tapering off toward values greater than 300 mD, which constitute less than 1% of the grid cells.



(a)Planar distribution (b)Grid model

Figure 2—Block numerical model.

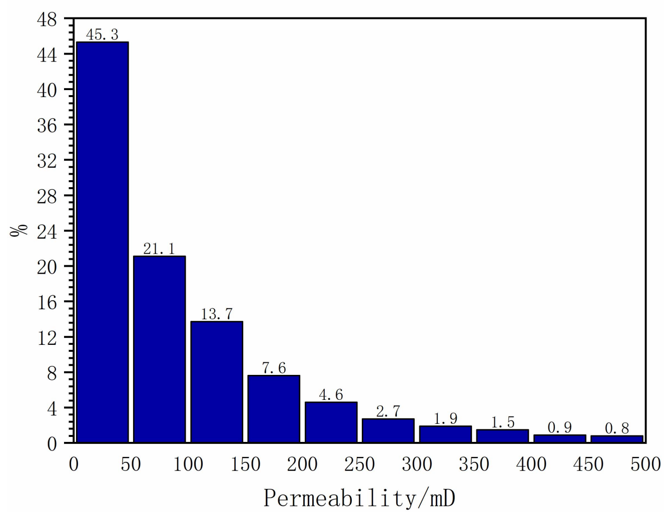


Figure 3—Histogram of permeability of X Block.

Table 3 presents the fluid constraint control conditions used in the simulation of the Daqing X Block reservoir. These control parameters include constraints on factors such as bottom-hole pressure (BHP), production rates, and gas-oil ratios (GOR) for both injection and production wells. These conditions are critical for ensuring the accuracy of the numerical simulation and for maintaining realistic operational limits during the Polymer-Alternating-Gas (PAG) flooding process. By defining these constraints, the simulation can more accurately replicate field conditions, leading to a more reliable evaluation of the different recovery methods tested.

Table 3—Well control parameters.

			WF	WAG	PF	PAG
Well control condition	Injection well	Max BHP, kPa	30000	30000	30000	30000
		Liquid injection rate, m^3/day	85	85	85	85
		Gas injection rate, m^3/day	-	40000	-	40000
	Production well	Min BHP, kPa	5000	5000	5000	5000
		Liquid production rate, m^3/day	115	115	115	115
Concentration of polymer, mg/L			-	-	2000	2000
Cycle index/time			-	12	-	12
Cycle number/month			-	12	-	12

Injection Scheme. Since sensitivity analysis evaluates changes in individual factors and is insufficient for optimizing production schemes, this study adopts an orthogonal experimental design to assess the interactions between multiple factors and optimize the injection scheme. Based on the sensitivity analysis of injection parameters, the orthogonal experiment is used to optimize key variables such as polymer concentration, polymer injection volume, alternating cycle ratio, cycle frequency, and the timing of water cut switching. An orthogonal experiment with 5 factors, each at 4 levels, was designed to explore the impact of these factors. The experimental setup follows the L16(4^5) design, resulting in 16 different production simulation injection schemes.

Table 4 outlines the orthogonal experiment design, while the specific injection schemes are presented in **Table 5**.

Table 4—Orthogonal Experimental Design Table

Number	Polymer Injecting Concentration (mg/L)	Polymer Injecting Volume (PV)	Alternating Cycle Ratio (Gas : Water)	Number of Alternating Cycle	Timing of Injection Conversion* (%)
1	1000	0.36	2:1	6	60
2	1500	0.48	1:1	9	70
3	2000	0.60	1:2	12	80
4	2500	0.72	1:3	15	90

* Note: The timing of injection conversion represents the point at which the injection method transitions to PAG when the water cut reaches a certain value during the injection cycle, serving as a critical factor for optimizing recovery.

Results

Table 5 also presents the results of the orthogonal experimental design for the PAG injection process, with a particular focus on recovery factor. It shows how variations in the each factor influence the overall recovery factor, which is the percentage of the original oil in place (OOIP) recovered under each specific injection scheme.

Table 5—Orthogonal experimental design injection schemes and results.

Number	Polymer Injecting Concentration （mg/L）	Polymer Injecting Volume （PV）	Alternating Cycle Ratio (Gas/Water)	Number of Alternating Cycle	Timing of Injection Conversion (%)	PAG Recovery (%)
1	1000	0.36	2:1	6	60	47.47
2	1000	0.48	1:1	9	70	48.76
3	1000	0.6	1:2	12	80	50.02
4	1000	0.72	1:3	15	90	50.40
5	1500	0.36	1:1	12	90	48.56
6	1500	0.48	2:1	15	80	47.75
7	1500	0.6	1:3	6	70	51.12
8	1500	0.72	1:2	9	60	52.24
9	2000	0.36	1:2	15	70	50.16
10	2000	0.48	1:3	12	60	51.15
11	2000	0.6	2:1	9	90	49.51
12	2000	0.72	1:1	6	80	51.84
13	2500	0.36	1:3	9	80	49.79
14	2500	0.48	1:2	6	90	51.49
15	2500	0.6	1:1	15	60	51.86
16	2500	0.72	2:1	12	70	50.42

Figure 4 illustrates the recovery factors for 16 different injection schemes in Table 5. A range analysis was performed on these results to quantify the impact of various injection parameters on the development effectiveness of the PAG numerical simulation. The plotted curves represent the recovery performance of the 16 PAG schemes alongside basic water flooding for comparison. Overall, the ultimate recovery factors of all 16 PAG schemes exceed that of water flooding (represented by the blue dotted curve). The recovery of each PAG scheme increases over time and eventually stabilizes, with Scheme 8 achieving the highest recovery factor at 52.24%. Generally, with a constant injection concentration, the recovery factor tends to increase with the injection volume. However, deviations are observed in some schemes, suggesting that the five influencing factors have varying impacts on the ultimate recovery rate across different schemes. Thus, it is essential to evaluate the contribution of specific parameters to enhancing recovery.

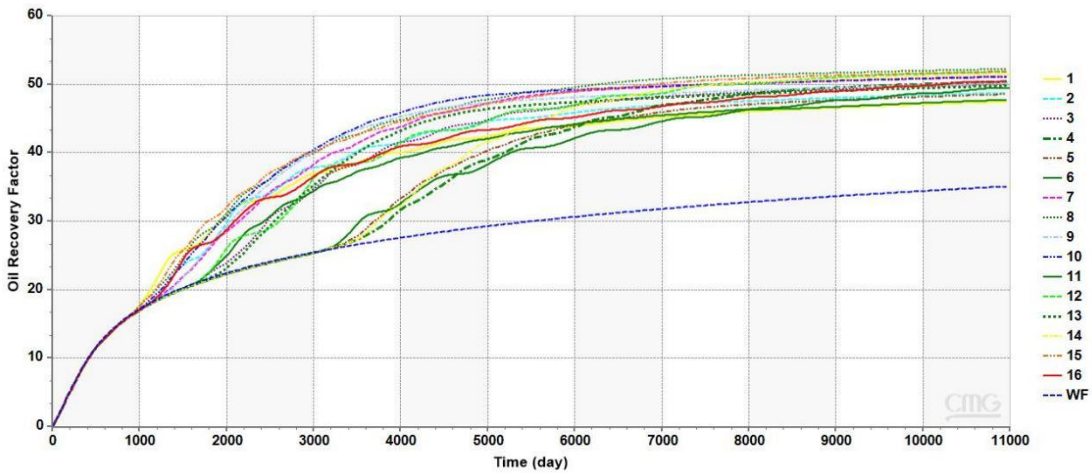


Figure 4—Comparison curve of final recovery rates for different injection schemes.

In **Table 6**, $\bar{K}i$ represents the average recovery factor for a specific injection parameter across various levels, which allows us to evaluate how well that particular parameter performs in terms of enhancing the recovery factor. R is the range of the recovery factor for each parameter, and it indicates the sensitivity or impact of the parameter on the overall oil recovery. A larger R value suggests that the parameter has a significant influence on the recovery factor, while a smaller R value implies a less impactful role. Specifically, parameters with higher R values should be prioritized for further fine-tuning in field applications to maximize oil recovery.

Table 6—Range analysis results for different injection parameters.

Number	Polymer Injecting Concentration (mg/L)	Polymer Injecting Volume (PV)	Alternating Cycle Ratio (Gas : Water)	Number of Alternating Cycle	Timing of Injection Conversion (%)
$\bar{K}1$	49.16	48.99	48.78	50.01	50.68
$\bar{K}2$	49.92	49.79	50.25	50.02	50.11
$\bar{K}3$	50.66	50.63	50.98	50.04	49.85
$\bar{K}4$	50.89	51.22	50.61	50.08	49.99
R	1.72	2.23	2.19	0.07	0.83

Based on the K_i and R values in Table 6, the most important factor is the polymer injecting volume, with an R value of 2.23. This indicates that variations in the volume of polymer injected have the greatest impact on the recovery factor in the PAG injection process. the alternating cycle ratio is also quite significant, with an R value of 2.19, closely following the polymer injecting volume. On the other hand, the number of alternating cycles has the least impact, as indicated by its very small R value of 0.07. In summary, the influence of various injection parameters on the recovery factor of the PAG process is ranked as follows: polymer injection volume > alternating cycle ratio > polymer injection concentration > timing of injection conversion > number of alternating cycles.

Figure 5 presents the relationship between the five influencing factors and the recovery performance of the 16 injection schemes. By evaluating the effect of different values for each factor on recovery, the optimal injection parameters for the PAG process are identified. This analysis provides insights into how variations in these factors contribute to optimizing the recovery.

Figure 5(a) illustrates the relationship between injecting volume (PV) and the oil recovery factor (%) in the PAG process. The curve shows a positive correlation between the injecting volume and the oil recovery factor, with a clear upward trend. As the injecting volume increases, the oil recovery factor steadily rises. At 0.36 PV, the recovery factor is around 48%, and it continues to improve, reaching approximately 51% when the injecting volume reaches 0.72 PV. This indicates that higher polymer injection volumes lead to enhanced oil recovery in the reservoir, with a notable increase in efficiency as the injection volume approaches 0.72 PV.

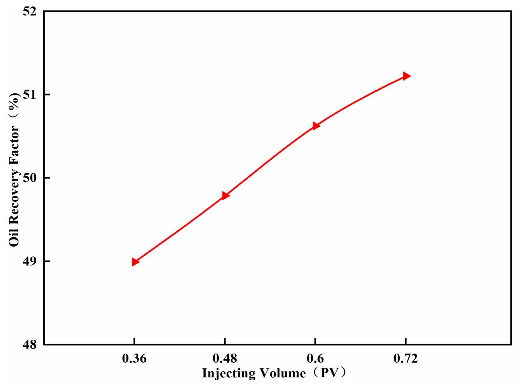
Figure 5(b) depicts the relationship between the alternating cycles ratio (gas to water) and the oil recovery factor (%) during the PAG process. The curve shows a non-linear relationship between the alternating cycles ratio and the oil recovery factor. As the ratio shifts from 2:1 to 1:1, the recovery factor increases, peaking at around 51% for the 1:1 ratio. However, as the ratio shifts further to 1:2, the recovery factor declines slightly, dropping to just above 50%. This suggests that a balanced alternating cycles ratio of 1:1 yields the highest recovery, while a higher or lower gas-to-water ratio (2:1 or 1:2) results in a reduced recovery factor.

Figure 5(c) illustrates the relationship between injecting concentration (mg/L) and the oil recovery factor (%) in the PAG process. The curve demonstrates a positive correlation between the polymer injecting concentration and the oil recovery factor. As the injecting concentration increases, the oil recovery factor also improves. At a concentration of 1000 mg/L, the recovery factor is around 48%, and it gradually increases with higher concentrations, reaching approximately 51% at 2500 mg/L. This indicates that increasing the polymer concentration leads to an improvement in oil recovery, with a significant rise in recovery as the injecting concentration approaches 2500 mg/L.

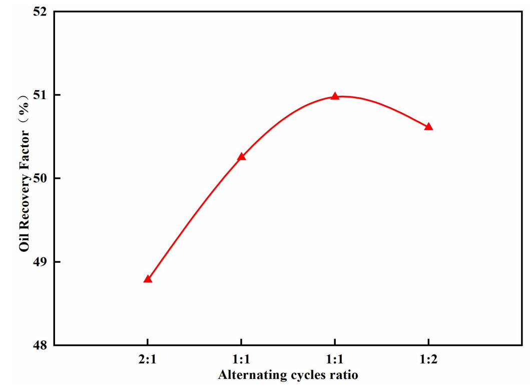
Figure 5(d) shows the relationship between timing of injection conversion (%) and the oil recovery factor (%) during the PAG process. The curve exhibits a non-linear relationship between the timing of injection conversion and the oil recovery factor. At 60% water cut switching, the recovery factor is at its highest, approximately 51%. As the switching timing increases from 60% to 80%, the recovery factor gradually declines, reaching around 50%. However, as the switching timing increases to 90%, the recovery factor shows a slight upward trend, stabilizing around 50%. This suggests that an earlier timing of injection conversion of 60% is most effective for maximizing oil recovery, while later switching timings lead to a reduction in recovery.

Figure 5(e) shows the relationship between the number of alternating cycles and the oil recovery factor (%) in the PAG process. The curve reveals a slight downward trend as the number of alternating cycles increases. At 6 alternating cycles, the recovery factor is approximately 50.5%, but as the number of cycles increases to 9 and 12, the recovery factor declines slightly, reaching around 50%. Beyond 12 cycles, the recovery factor stabilizes at around 50%, even as the number of alternating cycles increases to 15. This indicates that increasing the number of alternating cycles beyond a certain point (around 6 cycles) does not significantly enhance oil recovery and may lead to diminishing returns.

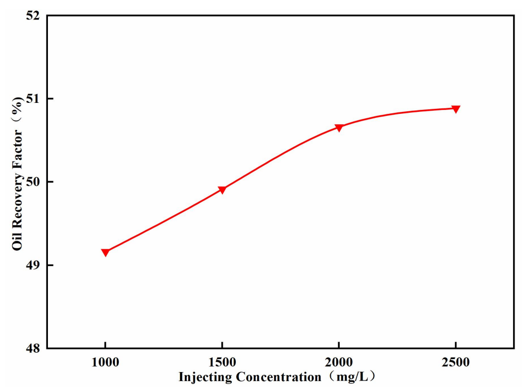
Through an evaluation of the average values at different levels of each factor, the optimal injection parameters for the PAG process have been determined as: (1) injection volume of 0.72 PV; (2) alternate cycling ratio of 1:2; (3) polymer injection concentration of 2500 mg/L; (4) timing of injection conversion of 60%; (5) number of alternating cycles of 15 times.



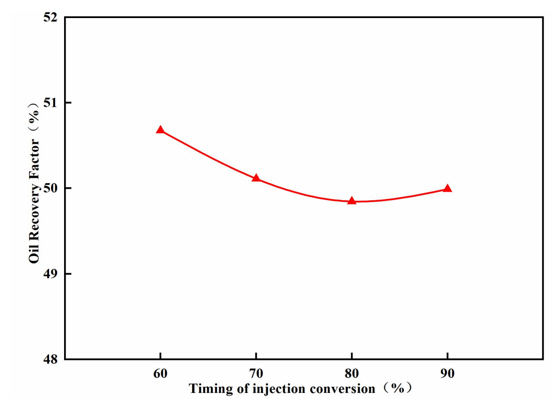
(a) Polymer injection volume



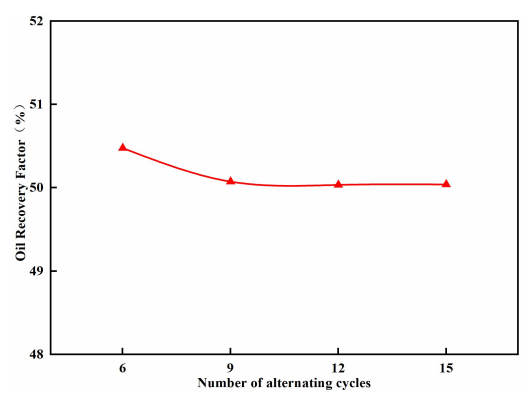
(b) Alternating cycles ratio



(c) Polymer injection concentration



(d) Timing of injection conversion



(e) Number of alternating cycles

Figure 5—Relationship between oil recovery factor and various influencing factors.

Discussion

Oil Recovery. In the numerical simulation process, polymer flooding (PF), water-alternating-gas (WAG), and polymer-alternating-gas (PAG) methods were evaluated in Block X to compare their oil recovery effects. The injection schemes were based on the optimal PAG plan. Simulations for PF, WAG, and PAG were initiated when the water cut reached 60%. During the PF process, a total of 0.72 pore volumes (PV) of polymer was injected continuously at a rate of 0.08 PV/year, with a polymer concentration of 2500 mg/L. For WAG and

PAG injections, 15 alternating cycles were implemented at a ratio of 1:2, with the same injection rate of 0.08 PV/year, resulting in a total of 0.72 PV of polymer injected.

Production development forecasts were conducted for each method using the numerical model of Block X. **Figure 6** presents the recovery rate comparison curves for water flooding, polymer flooding, WAG, and PAG. The results are also summarized in **Table 7**. The final recovery rate for water flooding was 30.6%, while polymer flooding increased it to 39.7%, WAG to 41.0%, and PAG to 50.9%. Compared to water flooding, polymer flooding improved the recovery by 9.1%, WAG by 10.4%, and PAG, which combines the advantages of polymer and CO_2 flooding, achieved the highest increase of 20.3%.

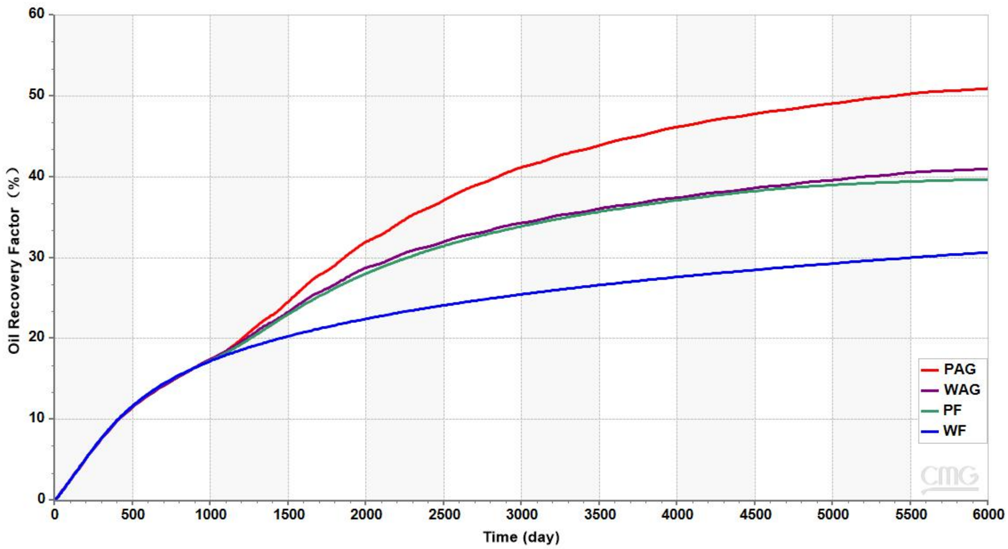


Figure 6—Comparison of recovery factor among different injection methods.

Daily Oil Production. Daily oil production is a key factor in evaluating the effectiveness of tertiary oil recovery methods. **Figure 7** presents the comparison curves of daily oil production for water flooding, polymer flooding (PF), water-alternating-gas (WAG), and polymer-alternating-gas (PAG). The analysis shows that during both PAG and WAG injection processes, daily oil production fluctuates. Specifically, during gas injection phases, daily oil production increases, while it tends to decrease during water injection phases. Among the methods studied, PAG consistently achieves higher daily oil production rates compared to WAG and polymer flooding, indicating its superior performance in sustaining oil output.

Table 7—Comparison of enhanced recovery factor among different injection methods.

Case	WF	PF	WAG	PAG
Recovery Factor (%)	30.6	39.7	41.0	50.9
Enhanced Recovery Factor (%)	/	9.1	10.4	20.3

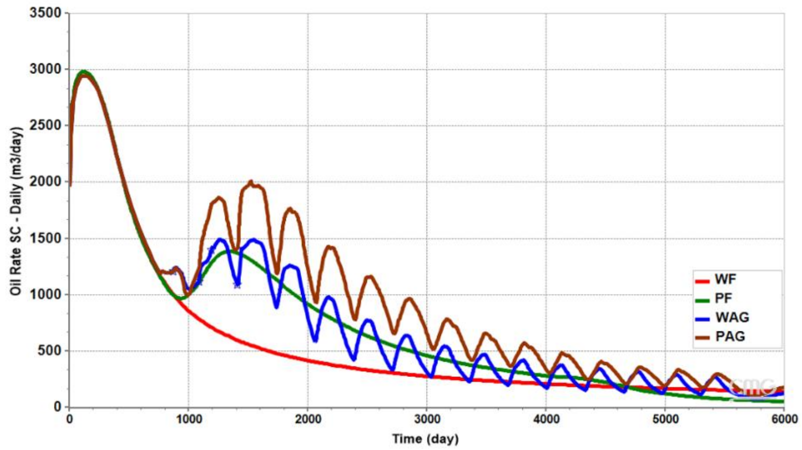


Figure 7—Comparison of daily oil production among different injection methods.

Water Cut. Water cut is another critical factor in determining the effectiveness of oil recovery techniques. **Figure 8** illustrates the water cut comparison curves for water flooding, PF, WAG, and PAG. During the injection processes of PAG and WAG, water cut shows fluctuations that mirror the trends observed in oil production. Gas injection phases result in a reduction in water cut, while water injection phases lead to an increase. PAG not only improves oil production but also exhibits a more substantial reduction in water cut compared to WAG and polymer flooding, further demonstrating its enhanced efficiency in tertiary recovery.

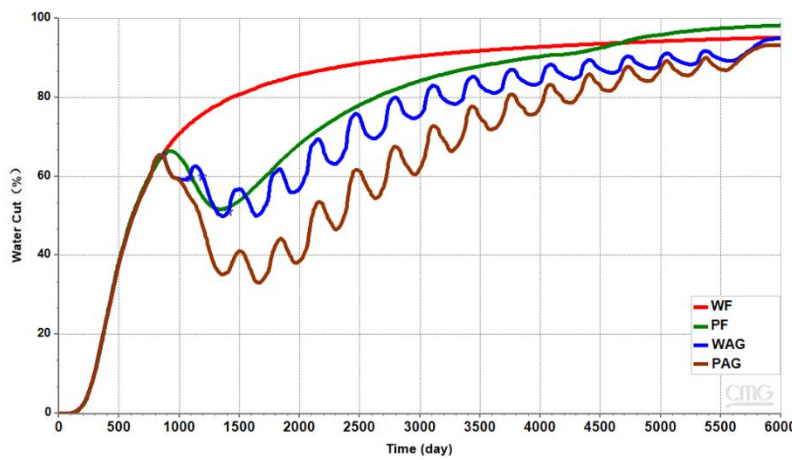


Figure 8—Comparison of water cut among different injection methods.

Gas-Oil Ratio. Figure 9 illustrates the gas-oil ratio (GOR) curves during the production processes of WAG and PAG in the X Block. It shows that PAG significantly reduces the gas-oil ratio compared to WAG throughout the injection period. The peak GOR for WAG reaches 2746 m^3/m^3, while PAG achieves a considerably lower peak of 1709 m^3/m^3. This indicates that PAG is more effective in retaining CO_2 within the reservoir, thereby mitigating early CO_2 breakthrough and improving CO_2 utilization efficiency.

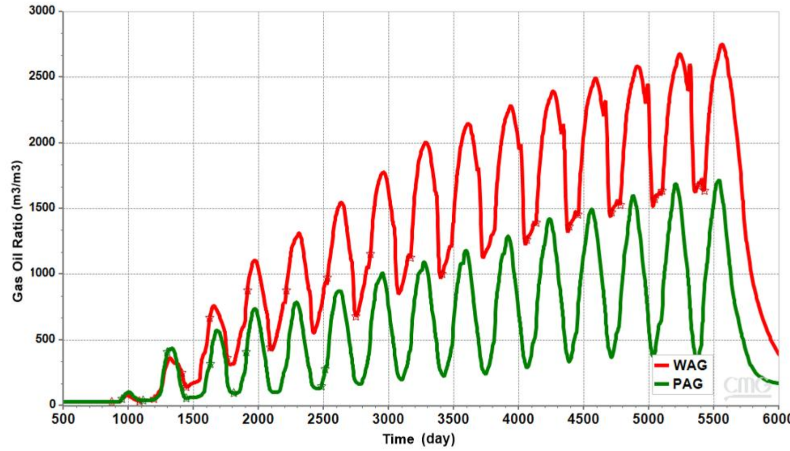


Figure 9—Comparison of gas-oil ratio among different injection methods.

Remaining Gas Volume in Oil. Figure 10 presents the cumulative mass curves of CO_2 remaining in crude oil during the WAG and PAG processes. Both WAG and PAG show fluctuations in the amount of CO_2 retained in the crude oil throughout the injection process. By the end of injection, the peak cumulative mass of CO_2 retained in WAG reaches 1.22×10^9 kg, while PAG retains 9.16×10^8 kg. Despite the lower cumulative mass for PAG, it demonstrates more efficient retention of CO_2 in the reservoir compared to WAG, resulting in better overall CO_2 utilization.

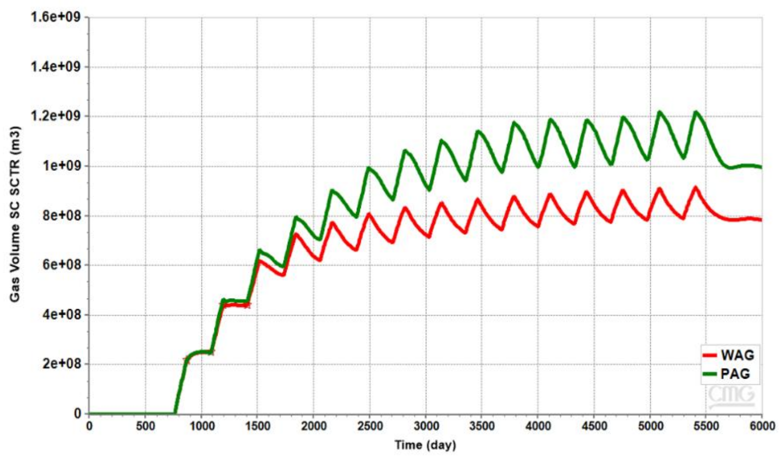


Figure 10—Comparison of gas retention in oil among different injection methods.

Residual Oil Saturation. The measurement of residual oil saturation is crucial for evaluating the recovery of an oil field. In this study, the 14th layer of the reservoir model, with an initial oil saturation of 0.8, was selected to assess the residual oil saturation for each recovery method.

Figure 11 illustrates the distribution of oil saturation in 14th layer at the end of injection for water flooding, polymer flooding, WAG, and PAG. The irregular driving patterns indicate non-homogeneity in the crude oil distribution, with the largest ripple areas observed near the injection wells. Upon comparison, PAG demonstrates the lowest residual oil saturation, a larger ripple area, and superior oil displacement efficiency compared to WAG, polymer flooding, and water flooding.

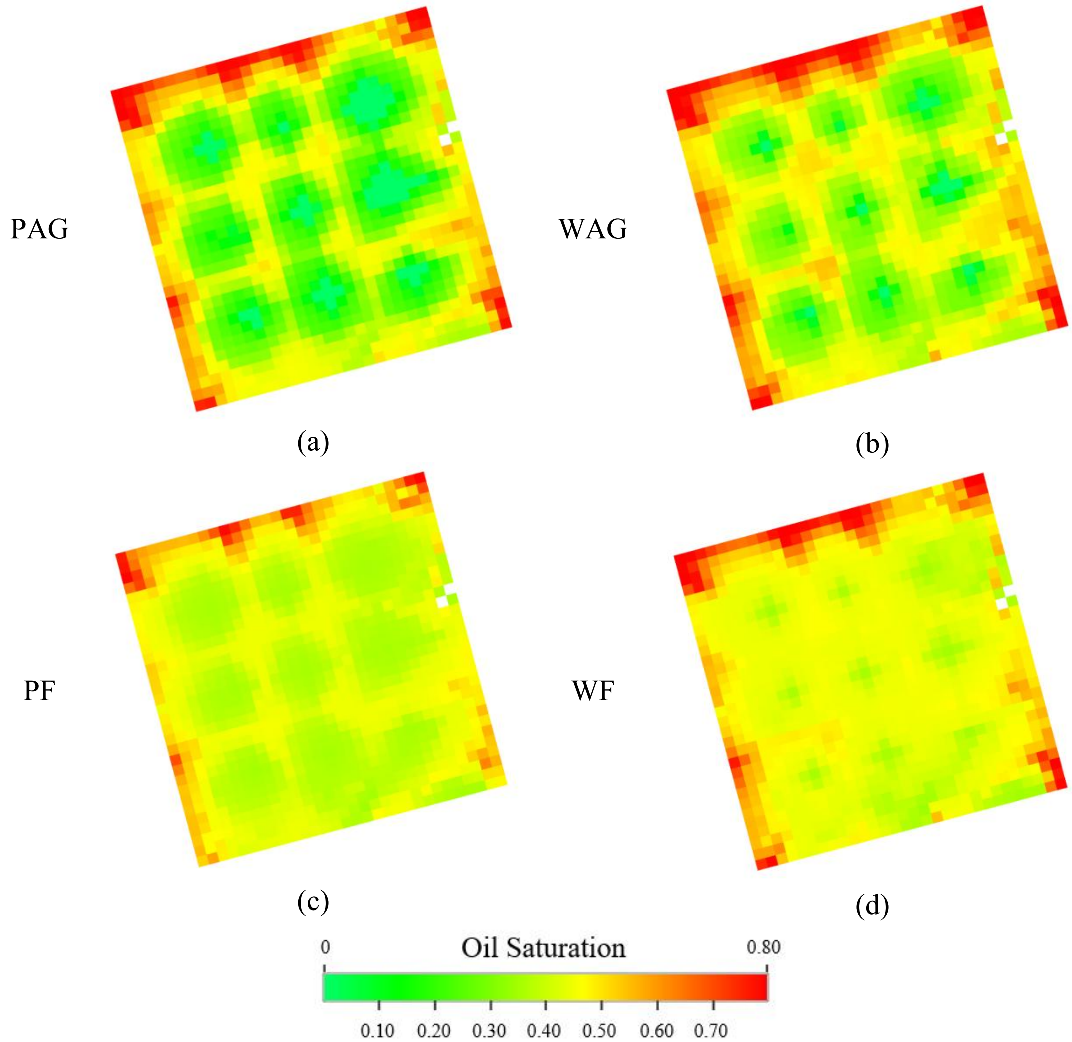


Figure 11—Comparison of oil saturation in layer 14 among different injection methods.

Recovery by Layer. To evaluate the differences between the various injection schemes, **Figure 12** compares the recovery rates for polymer flooding, WAG, and PAG across each layer of the reservoir during production. Excluding the ineffective grid layers, the results show that the upper layers of the reservoir exhibit greater mobilization. PAG enhances the recovery rate across all reservoir layers when compared to polymer flooding and WAG, with the most significant production increase observed in the upper layers.

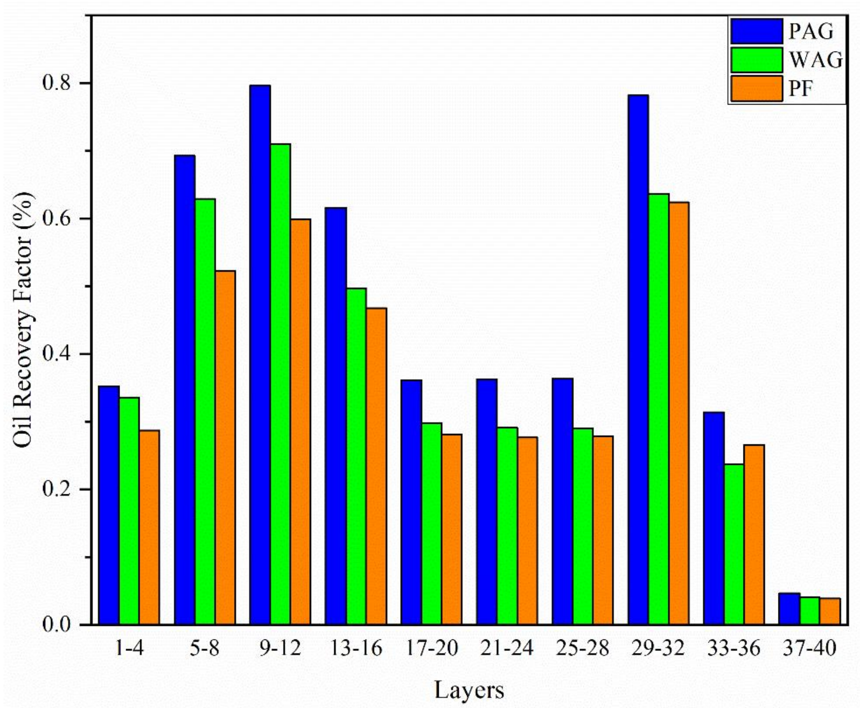


Figure 12—Comparison of the recovery of different injection methods at various layers.

Conclusions

This study evaluates the effectiveness of polymer-alternating-gas (PAG) injection in the Daqing X Block reservoir using numerical simulations and orthogonal experiments. The key conclusions are as follows:

1. Based on the analysis of average values, the optimal injection parameters for PAG are determined (Table 5).
2. Range analysis ranks the impact of each injection parameter on enhanced oil recovery for PAG as follows: polymer injection volume > alternating cycle ratio > polymer injection concentration > timing of injection conversion > number of alternating cycles. these findings provide critical insight into which parameters most influence the performance of PAG (Table 6).
3. Compared to water flooding (WF), polymer flooding (PF) increases ultimate recovery by 9.1%, while water-alternating-gas (WAG) increases it by 10.4%. PAG, which integrates the benefits of both PF and WAG, achieves the highest increase, with a 20.3% improvement in ultimate recovery over WF, demonstrating the effectiveness of PAG in the Daqing X Block (Table 7).
4. PAG leads to lower residual oil saturation, higher recovery across all reservoir layers, and greater mobilization of oil in the upper layers compared to WAG, PF, and WF. This results in a significant improvement in production, particularly in the upper reservoir layers.

In conclusion, this study highlights the substantial enhancement in oil recovery achieved by PAG injection, positioning it as a promising method for improving oil recovery in complex reservoirs like the Daqing X Block.

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Conflicting Interests

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

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