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Numerical Investigation on Alkaline-Surfactant-Polymer Alternating CO_2 Flooding

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Abstract: For over four decades, carbon dioxide (CO_2) has been instrumental in enhancing oil extraction through advanced recovery techniques. One such method, water alternating gas (WAG) injection, while effective, grapples with limitations like gas channeling and gravity segregation. To tackle the aforementioned issues, this paper proposes an upgrade coupling method named alkaline-surfactant-polymer alternating gas (ASPAG). ASP flooding and CO_2 are injected alternately into the reservoir to enhance the recovery of the WAG process. The uniqueness of this method lies in the fact that polymers could help profile modification, CO_2 would miscible mix with oil, and alkaline surfactant would reduce oil–water interfacial tension (IFT). To analyze the feasibility of ASPAG, a couples model considering both gas flooding and ASP flooding processes is established by using the CMG-STARS (Version 2021) to study the performance of ASPAG and compare the recovery among ASPAG, WAG, and ASP flooding. Our research delved into the ASPAG's adaptability across reservoirs varying in average permeability, interlayer heterogeneity, formation rhythmicity, and fluid properties. Key findings include that ASPAG surpasses the conventional WAG in sweep and displacement efficiency, elevating oil recovery by 12–17%, and in comparison to ASP, ASPAG bolsters displacement efficiency, leading to a 9–11% increase in oil recovery. The primary flooding mechanism of ASPAG stems from the ASP slug's ability to diminish the interfacial tension, enhancing the oil and water mobility ratio, which is particularly efficient in medium-high permeability layers. Through sensitivity analysis, ASPAG is best suited for mid-high-permeability reservoirs characterized by low crude oil viscosity and a composite reverse sedimentary rhythm. This study offers invaluable insights into the underlying mechanisms and critical parameters that influence the alkaline-surfactant-polymer alternating gas method's success for enhanced oil recovery. Furthermore, it unveils an innovative strategy to boost oil recovery in medium-to-high-permeability reservoirs.

Keywords: alkaline-surfactant-polymer alternating gas (ASPAG); ASP; chemical flooding; gas flooding; EOR

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1. Introduction

Enhanced oil recovery (EOR) is a tertiary oil recovery method that involves injecting chemicals (e.g., polymers and surfactants), gases (e.g., CO_2, N_2, and CH_4), or thermal energy into reservoirs to increase crude oil production [1]. In recent years, carbon dioxide (CO_2) flooding technology has experienced rapid global advancements. CO_2 flooding typically increases oil recovery by 7% to 25% [2–4]. CO_2-EOR is a highly promising and sustainable method for crude oil extraction, primarily due to its potential to increase crude oil recovery and reduce carbon emissions.

A generally employed CO_2-EOR technique for enhancing oil recovery involves CO_2 miscible flooding [5]. In the porous media of a reservoir, CO_2 undergoes component exchange with the oil and gas system within the pores. This interaction causes the reservoir crude oil to swell and its viscosity to decrease [6]. When the reservoir pressure reaches the minimum miscibility pressure of the CO_2–crude oil system, multiple contacts between carbon dioxide and crude oil lead to mixing [7]. Under miscible conditions, the interfacial tension between CO_2 and crude oil is greatly reduced, even approaching zero. Crude oil becomes completely soluble in CO_2, resulting in a solution with lower density, lower viscosity, improved fluidity, and increased ease of extraction [8]. In fact, previous research has demonstrated the significant potential of CO_2 flooding for enhancing oil recovery. For instance, Srivastava et al. [9] conducted experimental studies on the impact of CO_2 flooding in the Weyburn reservoir and found that oil recovery increased by 10.3%. In 2010, Wang et al. [10] introduced CO_2 flooding to the Bakken formation and estimated that this EOR method increased the oil recovery factor by 13% compared to water flooding. However, the sweep efficiency of CO_2 flooding remains relatively low [11]. In heterogeneous media, the presence of high-permeability zones, faults, and fractures exacerbates this challenge, leading to premature CO_2 breakthroughs. This prevents contact of CO_2 with the crude oil in low-permeability pores, significantly reducing the recovery factor [12]. And beyond that, the impact of gravity is also a notable factor. Due to the low viscosity and density of CO_2 gas, the gas concentrates predominantly in the upper regions of the reservoir, while the lower sections are less effectively swept, leading to a decreased recovery factor [13]. This contributes to the comparatively lower sweep efficiency of CO_2 flooding.

Caudle and Dye [14] proposed that the sweep efficiency of gas injection processes could be enhanced by reducing the mobility at the displacement front. This was achieved by injecting alternating slugs of water and gas. The water slug reduces the relative permeability of gas, thereby lowering the overall mobility of CO_2 gas and controlling its flow behavior. In their proposed method, water and gas were simultaneously injected in appropriate proportions. Subsequently, to address operational limitations and the challenge of simultaneous gas and water injection, this approach was modified into the water alternating gas (WAG) process, where gas and water are injected alternately. This method demonstrates improved recovery compared to separate gas or water injection, as water enhances gas sweep volume on a macroscopic level, while gas enhances oil displacement efficiency on a microscopic level. In 2001, Christensen et al. [15] found that the average incremental oil recovery from miscible WAG was around 9.7%, with a range of 6% to 20%, while non-miscible WAG resulted in an average increase of 6.4%. Subsequent research indicated that most oil fields were unable to achieve the expected recovery through the WAG process. Mobility control emerged as a key issue in WAG, particularly in high- or medium-viscosity reservoirs [16]. In cases of significant viscosity contrast between oil and water, resulting in a high mobility ratio, viscous fingering can arise when the mobility ratio is greater than 1.

In order to overcome the aforementioned challenges and enhance the efficiency of the traditional WAG process, a new method to improve oil recovery was introduced by Behzadi et al. [17]. This method involves a following sequence of injections: first a water injection, followed by an ASP (alkaline-surfactant-polymer) slug, then a miscible CO_2 slug, and finally a continuous miscible CO_2 injection. Studies suggest that this enhanced oil recovery approach could achieve a superior recovery factor compared to using only ternary compound flooding or miscible CO_2 flooding. Majidaie et al. [18] proposed a novel combined method called chemical water alternating gas (CWAG) and conducted numerical simulations. In this approach, an ASP slug is injected first, followed by three cycles of water-alternating CO_2 gas. Research indicates that CWAG can achieve a higher recovery factor compared to traditional WAG and gas flooding. In order to improve the recovery factor of heavy oil reservoirs in Saskatchewan, Canada, Luo et al. [19] conducted a laboratory study. They evaluated an improved WAG process that utilizes chemical substances (alkaline/surfactant/polymer) instead of water injection, known as the chemical-alternating gas (CAG) injection technique. This technique combines the mechanisms of reducing interfacial tension (IFT) and controlling mobility. The results demonstrated that the CAG process can increase oil recovery by 27.43% compared to water flooding. Continuing the research on CWAG injection, Majidaie et al. [20] further investigated the process. They implemented three cycles of WAG, followed by an ASP slug injection (0.6 PV). The enhanced oil recovery achieved with the CWAG method was 26.6%, more than twice the increase achieved by traditional WAG methods.

In previous CWAG research [17–20], the chemical agent was merely a pre-plugging phase and did not truly alternate with the gas. The present study introduces an upgraded WAG and ASP method, named ASPAG, which injects ASP to substitute water in the WAG for EOR. At present, the following problems with ASPAG still exist: (1) whether the ASPAG process could improve oil recovery; (2) what are the main mechanisms of this technique to increase oil; (3) which layers could benefit from this approach; and (4) which type of reservoirs are applicable to the method. This paper aims to utilize numerical simulations to solve and validate the aforementioned problems. The feature of this method lies in its multifaceted approach, i.e., polymers contribute to mobility control, crude oil can achieve miscibility with CO_2, while alkaline and surfactants synergistically reduce the interfacial tension between oil and water, collectively augmenting crude oil recovery. This study provides empirical evidence of the efficacy of the ASPAG (alkaline-surfactant-polymer alternating gas) process in enhancing crude oil recovery. Particularly noteworthy is its suitability for reservoirs characterized by medium to high permeability, especially those containing low-viscosity crude oils and composite reverse and positive rhythms. This finding not only introduces a novel strategy for enhancing crude oil recovery but also offers valuable insights for the development of diverse reservoir types.

The paper structure is as follows: In Section 2, we explore how alkaline and surfactant influence interfacial tension to affect the reservoir recovery factor, along with considerations for polymer rheological properties. Additionally, we outline the modeling approach for the ASPAG process to enhance our understanding of its operational mechanism. In Section 3, a comprehensive depiction of the numerical simulation process for ASPAG was provided, encompassing reservoir properties, the fluid model, key parameters of ASPAG, as well as the simulation's operating and constraint conditions. In Section 4, the oil recovery factor of the ASPAG is analyzed and compared with that of conventional WF, WAG, and ASP flooding. Subsequently, we delve into the primary oil displacement mechanisms of ASPAG. Notably, we also investigated which layers could benefit from this approach. This inquiry is unprecedented and is introduced for the first time in our study. Finally, to investigate the feasibility of the ASPAG method, we conducted a sensitivity analysis concerning average permeability, heterogeneity, rhythm, and fluid properties.

2. Materials and Methods

2.1. Mechanism of ASPAG

Based on the previous research on chemical alternating gas flooding, we found that these studies mainly focus on adding an ASP slug into the WAG process. The composition of the ASP slug primarily includes polymers, alkaline, and surfactants. Since the 1970s, surfactants have been considered effective enhanced oil recovery agents due to their ability to significantly reduce interfacial tension (IFT), change reservoir rock wettability, diminish capillary forces, enhance crude oil mobility, and increase recovery [21,22]. When surfactants dissolve in water, their amphiphilic structure causes molecules to align orderly at the oil–water interface, effectively reducing the interfacial tension (IFT) between oil and water [23]. Alkaline can react with long-chain carboxylic acids present in the crude oil to generate in situ surfactants or emulsifiers. When combined with surfactants, they can reduce interfacial tension (IFT) to extremely low levels [23], reaching values as low as 10^{-3} or 10^{-4} mN/m [24]. Moreover, alkaline can replace surfactants in adsorbing onto rocks, thereby reducing the adsorption of surfactants [25,26]. The objective of using polymers as mobility control agents is to enhance displacement efficiency and volumetric sweep efficiency [27]. It can modify the relative permeabilities between the oil and water phases, decrease the relative permeability of the water phase, reduce the oil–water mobility ratio, improve displacement effectiveness, and increase volumetric sweep efficiency [28–30].

The present study proposes a method, designated ASPAG, that injects ASP to substitute water in the WAG for EOR. Realize the alternation of ASP and CO_2 gas in the real sense. This technique combines the two following mechanisms: reducing oil–water interfacial tension and controlling mobility.

2.2. Alkaline and Surfactant Reduce Interfacial Tension

In ASP flooding, alkaline and surfactant are responsible for reducing IFT and, consequently, the residual oil saturation. Amaefule and Handy [31] develop a correlation between relative water and oil permeabilities and IFT. In developing this correlation, a relationship was established between the capillary number (N_c) and the residual oil saturations. The empirical expressions are established that relate IFT and residual oil saturations through the capillary number as follows:

$$S_{or_{\sigma}} = \begin{cases} S_{or_{(\sigma_o)}} & N_c < N_{co} \\ S_{or_{(\sigma_o)}}\left(\frac{N_{co}}{N_c}\right)^{0.5213} & N_c \geq N_{co} \end{cases} \tag{1}$$

where $S_{or(\sigma o)}$ is the initial residual oil saturation at the critical capillary number, N_{co}. $S_{or(\sigma)}$ is the residual oil saturation corresponding to any capillary number, N_c. σ and σ_o are the interfacial tension values that correspond to N_c and N_{co}, respectively.

The following expressions are the relative water and oil permeabilities as functions of saturation and IFT:

$$k_{rw}(S_w,\sigma) = \left(\frac{S_w - S_{wr_{(\sigma)}}}{1 - S_{wr_{(\sigma)}}}\right)\left\{2.5S_{wr_{(\sigma)}}\cdot\left[\left(\frac{S_w - S_{wr_{(\sigma)}}}{1 - S_{wr_{(\sigma)}}}\right)^2 - 1\right] + 1\right\} \tag{2}$$

$$k_{ro}(S_w,\sigma) = \left(\frac{1 - S_{or_{(\sigma)}} - S_w}{1 - S_{or_{(\sigma)}} - S_{wr_{(\sigma)}}}\right)\left\{5S_{or_{(\sigma)}}\cdot\left[\left(\frac{1 - S_{or_{(\sigma)}} - S_w}{1 - S_{or_{(\sigma)}} - S_{wr_{(\sigma)}}}\right)^2 - 1\right] + 1\right\} \tag{3}$$

where k_{rw} and k_{ro} are the water and oil relative permeabilities, and $S_{wr(\sigma)}$ is the initial residual water saturation at the critical capillary number.

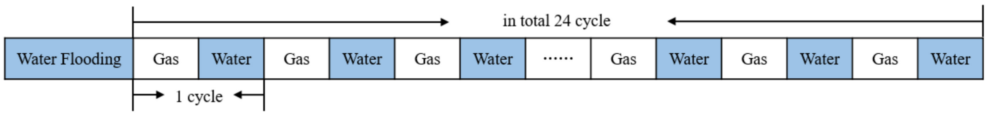
2.3. Polymer Rheological Properties

In this study, we consider the important rheological properties of polymer flooding for enhanced oil recovery, including [32–35]:

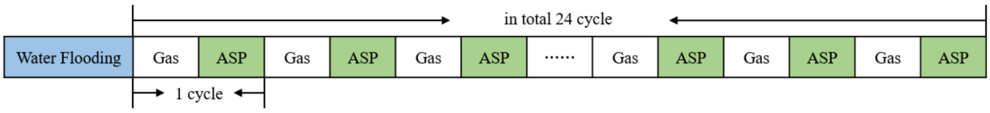
- Polymer viscosity using a non-linear model and the polymer viscosity up to concentration;
- Polymer inaccessible pore volumes;
- Permeability reduction due to polymer retention;
- Polymer adsorption.

2.4. The Modeling of ASPAG

The WAG and ASPAG processes are compared in Figure 1. In the WAG process, it is typically after water flooding that an alternating injection of CO_2 gas and water occurs (Figure 1a), while ASPAG involves the injection of gas and ASP during each cycle (Figure 1b). In the present study, this simulation was conducted using the STRAS software developed by the Computer Modelling Group (CMG Version 2021). The STARS module was primarily employed for simulating thermodynamics and advanced reservoir systems, offering comprehensive functionalities and tools to model and analyze complex thermal-fluid behavior, multiphase flow, and heat transfer processes. It is highly suitable for superior modeling of processes such as steam, chemical agents, and air injection in extraction processes. The fluid models were characterized using the WinProp software from CMG (Version 2021).



(**a**) WAG



(**b**) ASPAG

Figure 1. (**a**) A comparison of the WAG processes followed by water flooding. (**b**) A comparison of the ASPAG processes followed by water flooding (ASP = alkaline-surfactant-polymer). The blue part represents water injection, and the green part represents ASP injection.

3. Numerical Simulation Model Setup

3.1. The Reservoir Model

Table 1 summarizes reservoir properties, including reservoir size, grid, permeability, porosity, pressure, temperature, oil, and water saturation. All of these properties are established based on the sandstone reservoir. The reservoir model consisted of 1183 blocks in the 13 × 13 × 7 cartesian grid system, with each grid size of 20 m × 20 m × 3 m. The injection and production wells were fully perforated to maximize their effects on oil recovery. To analyze the sweep efficiencies clearly, the well pattern corresponded to the quarter-five-spot configuration. As shown in Figure 2, the injection and production wells were positioned at coordinates (1, 1, 1:7) and (13, 13, 1:7), respectively. It should be noted that this study built an interlayer heterogeneous reservoir model, and the reservoir thickness is sufficient to observe the effects of gravity segregation.

Table 1. The physical property of the ASPAG reservoir model.

Parameter	Values
Numbers of grids, (I, j, k)	(13, 13, 7)
Grid size, (m × m × m)	20 × 20 × 3
Reservoir depth, m	1814
Initial reservoir temperature, °C	85
Initial reservoir pressure, kPa	18,000
Mean permeability, mD	600
Porosity, %	22
Permeability variation coefficient	0.65
Initial water saturation, %	20
Initial oil saturation, %	80

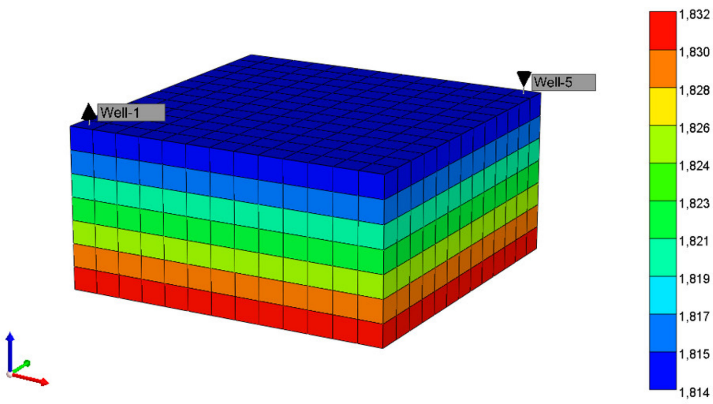


Figure 2. Geologic model.

3.2. The Fluid Model

In this study, we referred to the article titled "Experimental Study on Alternative Injection and Flooding of CO_2 and ASP Flooding" [36] and developed the fluid model using data collected from the Daqing oil reservoir. The composition and properties of the fluid obtained through the regression process are concisely presented in Table 2.

Table 2. Component fluid system and parameters.

Component	Specific Gravity	Mole Weight, g/mol	Pc, atm	Tc, K	Acentric Factor	Composition, %
N_2 to CH_4	0.3	16.04	45.4	190.60	0.01	18
C_2H_6 to C_4	0.50	46.46	41.43	379.64	0.15	5
C_5 to C_6	0.65	77.28	33.01	483.81	0.26	4
C_7 to C_9	0.75	88.46	25.67	613.02	0.42	8
C_{10} to C_{13}	0.79	123.03	25.37	707.5	0.58	26
C_{14} to C_{15+}	0.85	252.57	15.50	799.14	0.81	39
CO_2	0.81	44.01	72.80	304.2	0.22	0

The model utilizes the multiple mixing cell (MMC) [37,38] method to calculate the MMP of CO_2 as 16.6 MPa. Considering the initial reservoir pressure of 18 MPa and the maximum injection pressure of approximately 30 MPa, this light oil can achieve miscibility with CO_2. In STARS, the KVTABLE was used to realize the miscibility of CO_2 and crude oil.

3.3. The Parameters for ASPAG

The STARS module of CMG (Version 2021) can simulate the relationship between alkaline and surfactant interfacial tension (IFT). In this simulation, the synergistic effect of alkaline and surfactant is a key factor leading to IFT reduction [32]. Figure 3 depicts the curve illustrating the relationship between alkaline and surfactant IFT. The interaction of alkaline and surfactant reduces the IFT between oil and water, increases capillary number, modifies the relative permeabilities of oil and water, and reduces residual oil saturation [31]. STARS can interpolate the phase permeability curves based on the decreased IFT [17]. Different interpolations can illustrate changes in residual oil saturation for various displacement methods within the reservoir. When $\mathrm{Log}(N_C) = -6$, it corresponds to the phase permeability curve during water flooding, while $\mathrm{Log}(N_C) = -0.5$ corresponds to the phase permeability curve during ternary composite flooding. Figure 4 presents the phase permeability curves for water flooding and ternary composite flooding.

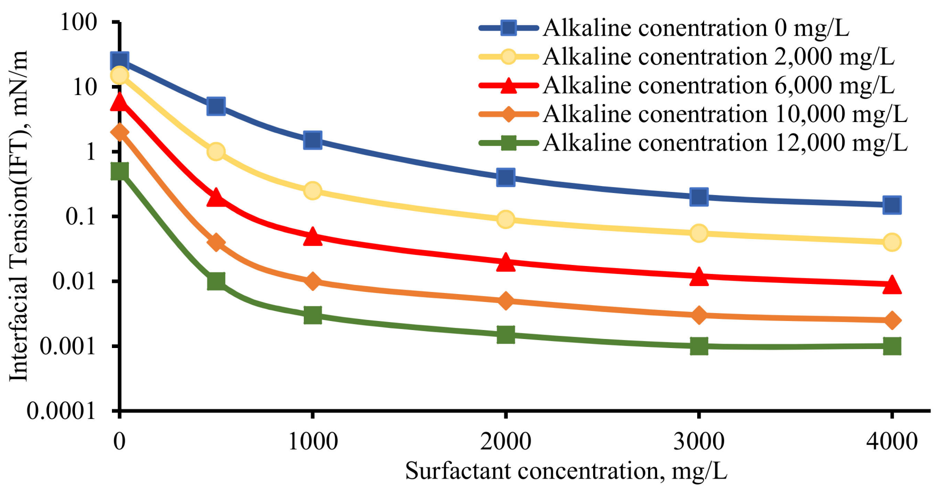


Figure 3. Interfacial tension diagram of a ternary composite system.

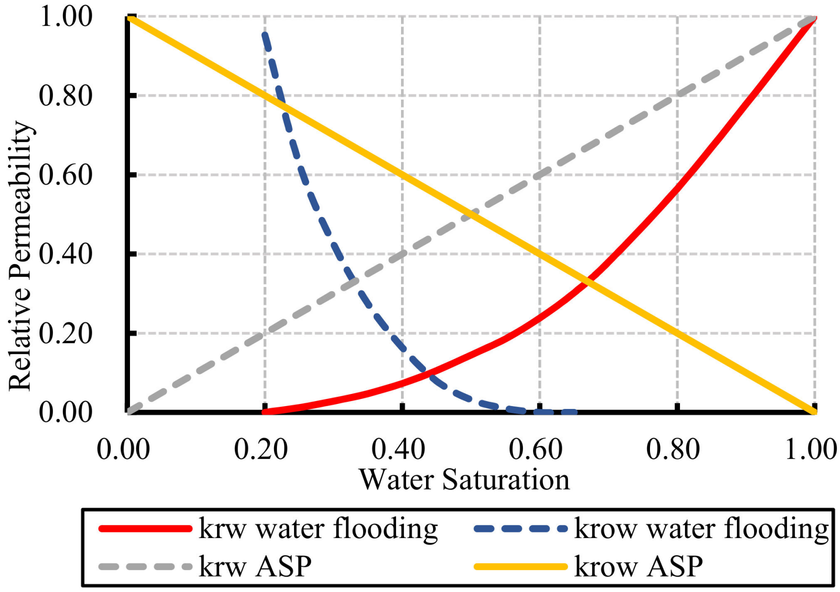


Figure 4. Relative permeability curve.

In STARS, the rheological properties of the aqueous phase are described by the concentration and viscosity functions of polymers [39,40]. Referring to the study conducted by Pandey and Kumar [39], experimentally determined adsorption values, polymer-accessible pore volume, and residual resistance factor (RRF) are employed in the simulation. The relationship between polymer viscosity and concentration is depicted in Figure 5.

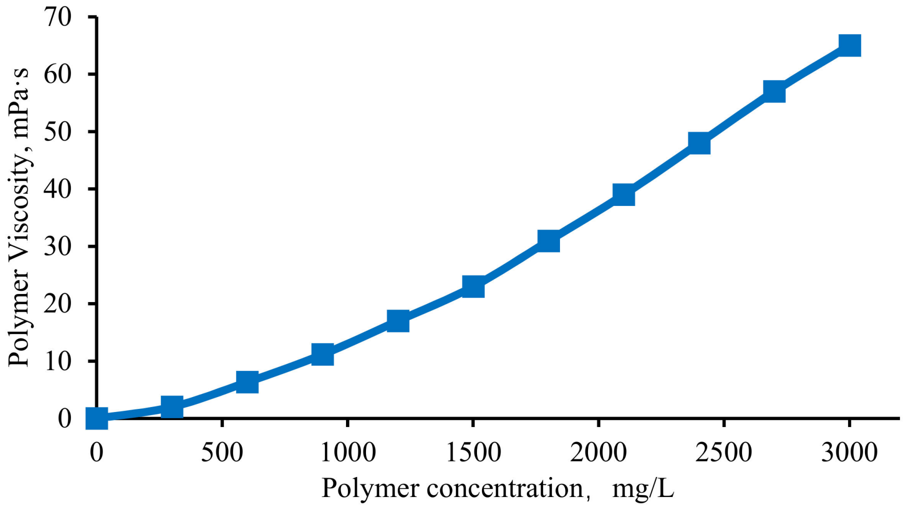


Figure 5. Polymer viscosity–concentration curve.

3.4. The Simulation Settings for the ASPAG

The simulated operating conditions and constraints for ASPAG and the other improved oil recovery methods (e.g., WF, ASP flooding, and WAG) are summarized in Table 3. In the entire production process, water flooding is initiated until reaching the water cut of 90%, followed by the implementation of the EOR process. The whole production stage was 17 years, i.e., 5 years of water flooding, followed by the EOR process. The number of ASPAG cycles was determined to be 24, with each cycle consisting of 3 months of gas injection followed by 3 months of ASP injection. Both water and gas injection rates were calibrated at 0.1 pore volume (PV) per year, corresponding to 115 m^3/day for water or 40,000 m^3/day for gas, respectively. Referring to previous studies by Caudle et al. [14] and Nasser et al. [41], the ASPAG cycle ratio was established at 1:1 under reservoir conditions, resulting in a total injection of 1.2 PV. During the initial 5-year water flooding, the injection and production wells exhibited varying bottom hole pressure (BHP) ranges, with a maximum of 30,000 kPa and a minimum of 6000 kPa. Simulations of water flooding, ASP, and WAG were conducted under identical pore volume (PV) injection conditions, as demonstrated in Table 3.

Table 3. Simulation scheme parameter table.

Parameter			WF	WAG	ASP	ASPAG
Well control condition	Injection well	Max BHP, kPa	30,000	30,000	30,000	30,000
		Liquid injection rate, m^3/day	115	115	115	115
		Gas injection rate, m^3/day	40,000	40,000	40,000	40,000
	Production well	Min BHP, kPa	6000	6000	6000	6000
		Liquid production rate, m^3/day	115	115	115	115
Cycle index/time			-	24	-	24
Cycle number/month			-	6	-	6
Total amount of chemical injection, PV			-	-	0.6	0.6
Total amount of gas injection, t			-	17.3×10^4		17.3×10^4
Concentration of chemical, mg/L		Polymer	-	-	2000	2000
		Alkaline	-	-	12,000	12,000
		Surfactant	-	-	3000	3000

Furthermore, sensitivity analysis was conducted to assess the impact of reservoir permeability, heterogeneity, rhythm, and crude oil viscosity on enhancing recovery during the ASPAG process. Table 4 summarizes the range of values for different influencing factors.

Table 4. The range of values for sensitivity analysis.

Influencing Factors	Range of Values					
Average reservoir permeability, mD	50		100	300	600	1000
Heterogeneity	0	0.5	0.6	0.7	0.8	0.9
Reservoir rhythm	positive rhythm		reverse rhythm	composite positive rhythm	composite reverse rhythm	composite reverse and positive rhythm
Crude oil viscosity, mPa·s	1		5	10	15	20

4. Results and Discussion

4.1. Performance Evaluation of ASPAG for Enhanced Oil Recovery

The oil recovery performance of ASPAG was compared with that of water flooding, ASP flooding, and WAG in Figure 6. Here, after the 5-year water flooding period, 31% of the initial oil has been recovered, and the final recovery of water flooding is 39.9%. At the end of the EOR process, the final oil recovery showed significant differences, i.e., 54.7% for WAG, 60.8% for ASP, and an impressive 71.4% for ASPAG. It is worth noting that both ASPAG and WAG exhibited a stepped increase in the recovery curve, with a substantial portion of the increase attributed to the timing of CO_2 injection. What sets ASPAG apart is its superior oil recovery performance compared to WAG and ASP flooding processes. This can be attributed to the injection of an ASP slug, which led to a more effective displacement of oil by CO_2.

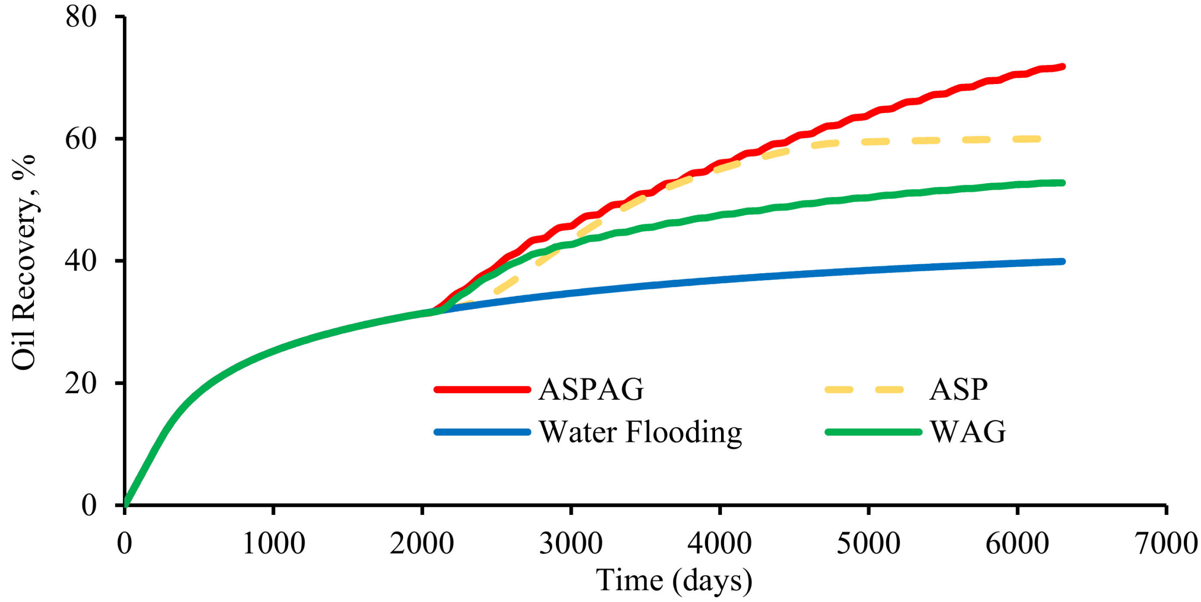


Figure 6. A comparison of the oil recovery of the water flooding, ASP, WAG, and ASPAG.

Both the oil production rate and water act for the four different EOR processes are predicted and shown in Figures 7 and 8, respectively. The oil production rate shows fluctuations during the ASPAG and WAG processes, increasing during gas injection and decreasing during liquid injection. In comparison to WAG and ASP, ASPAG demonstrates significantly higher oil production rates. This further supports the earlier statement that the injection of ASP enhances the oil displacement effectiveness of CO_2. Since the well-controlled conditions were set to constant liquid production during the simulation, the water cut curve exhibits an opposite trend to the oil production rate curve.

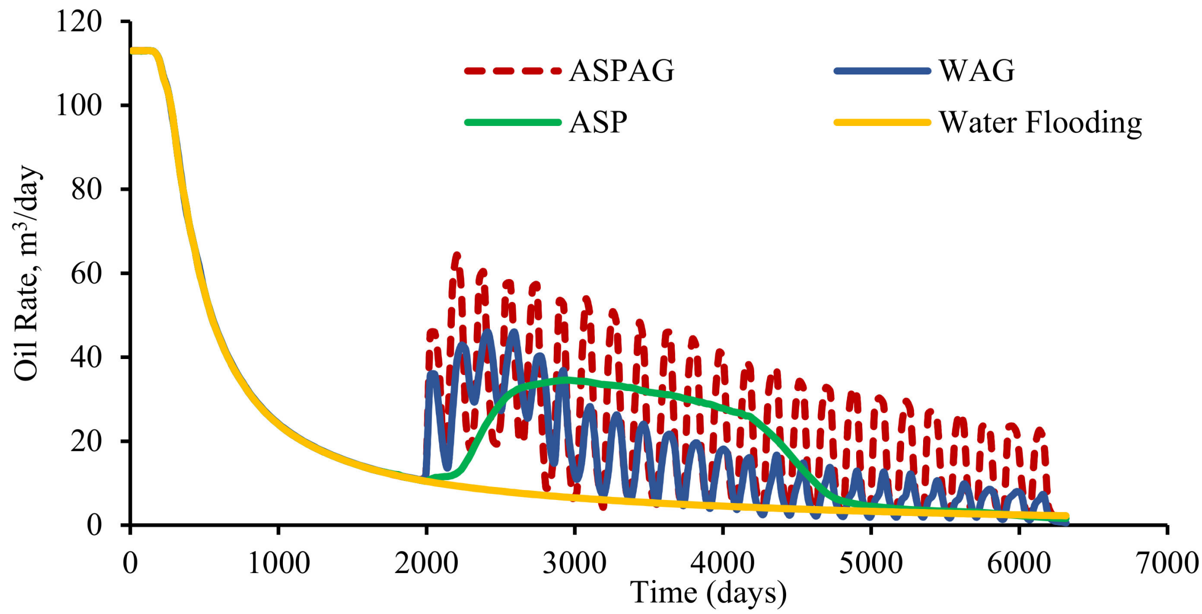


Figure 7. A comparison of the oil rates of water flooding, ASP, WAG, and ASPAG.

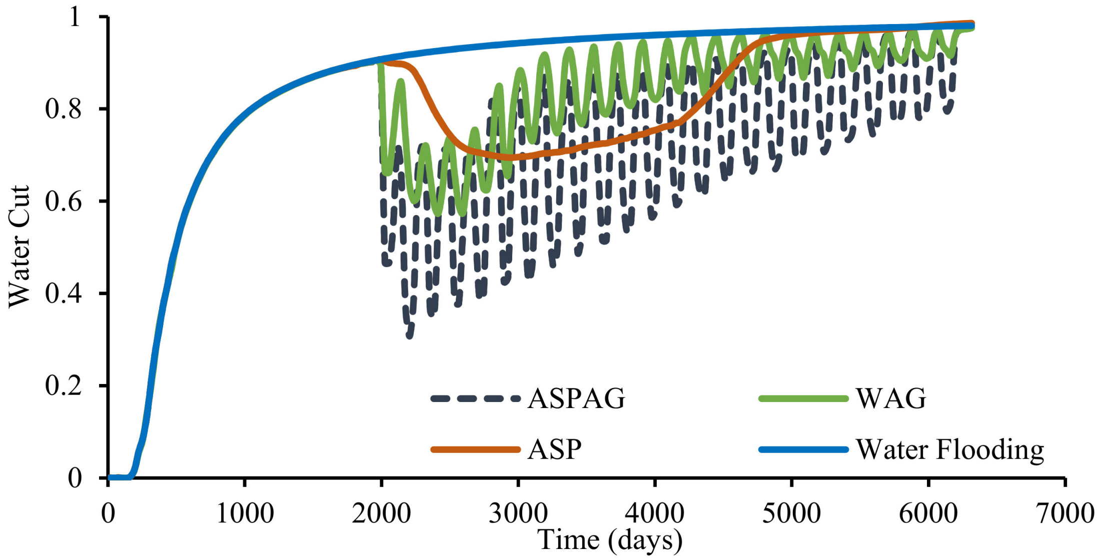


Figure 8. A comparison of the water cut of water flooding, ASP, WAG, and ASPAG.

The gas–oil ratio for the WAG and ASPAG processes is depicted in Figure 9. During the initial alternating phase, the gas–oil ratio increases significantly for both processes, with a relatively steady change observed for WAG. This increase is due to the rise in oil production, leading to a corresponding increase in gas production and, consequently, an elevated gas–oil ratio. However, after injecting CO_2 for two years, gas breakthrough occurs in the WAG process, resulting in a substantial rise in the gas–oil ratio. In contrast, the gas–oil ratio in the ASPAG process remains relatively stable, and no significant gas breakthrough is observed. This indicates that ASPAG can effectively delay gas breakthrough and retain more CO_2 in the reservoir.

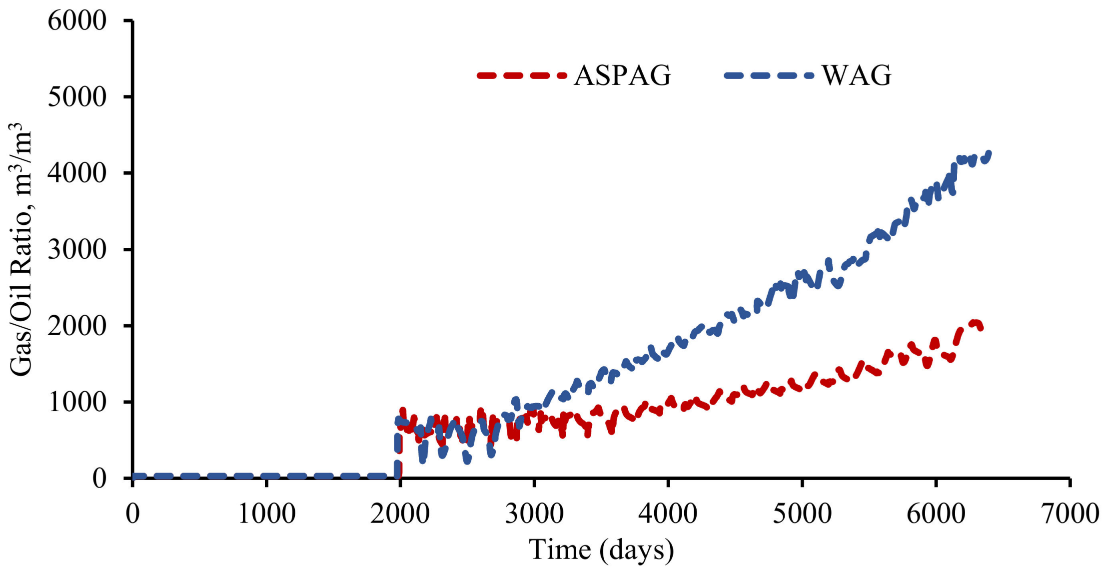


Figure 9. A comparison of the gas–oil ratio of WAG and ASPAG.

Figure 10a–c represent the distribution of oil–water interfacial tension (IFT) for ASPAG, ASP, and WAG, respectively, at the same time. In both the ASPAG and ASP processes, the interaction of alkaline and surfactant reduces the oil–water IFT to 0.001 mN/m. However, during the WAG process, despite the oil and CO_2 reaching a mixed phase, this does not affect the variation of oil–water interfacial tension.

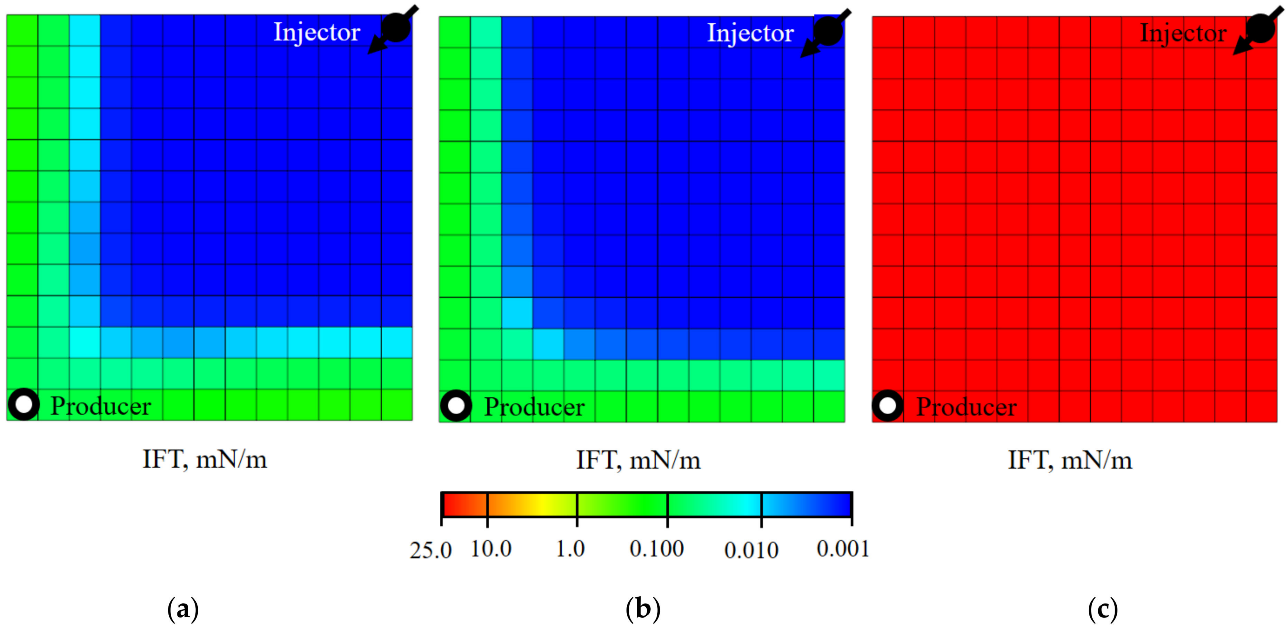


Figure 10. Oil–water IFT distribution after different EOR. (**a**) The Oil–water IFT distribution after ASPAG flooding. (**b**) The Oil–water IFT distribution after ASP flooding. (**c**) The Oil–water IFT distribution after WAG flooding.

Figure 11a–c represent the distribution of water viscosity for ASPAG, ASP, and WAG, respectively, at the same time. In both the ASPAG and ASP processes, the presence of polymers increases the viscosity of the formation water, with the maximum viscosity reaching up to 35 mPa·s. This increase in water viscosity reduces the mobility ratio and improves oil recovery. However, in the WAG process, the viscosity of the formation water remains relatively unchanged. Additionally, the alternating injection of chemicals and CO_2 gas does not significantly expand the sweep range of the chemicals.

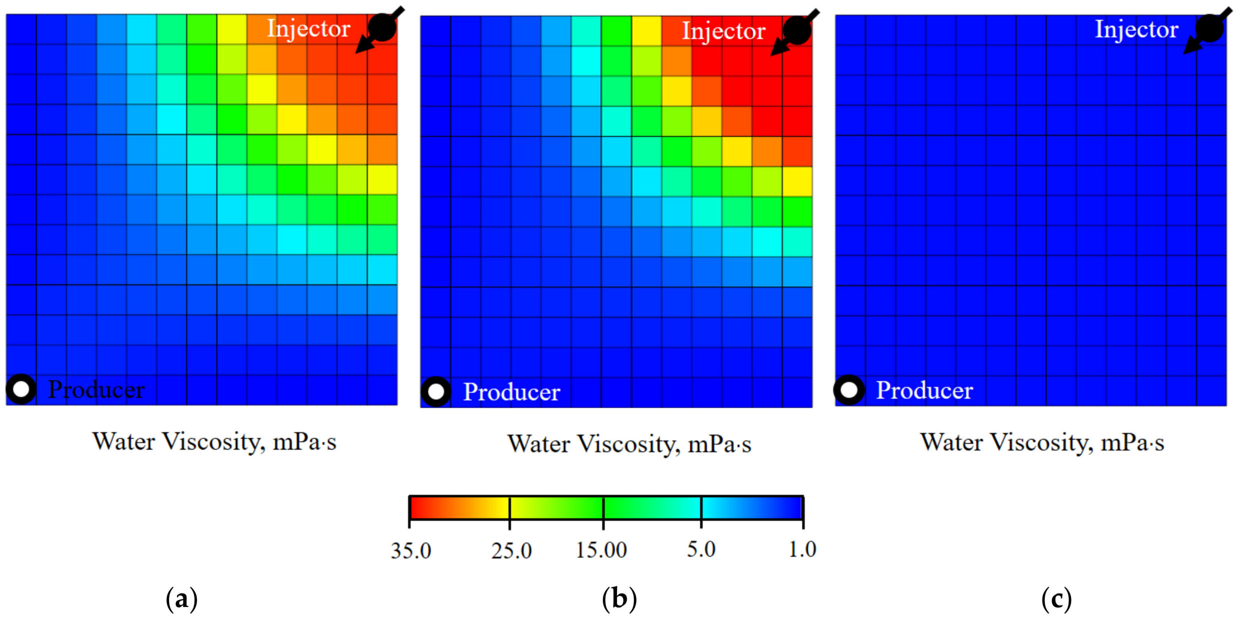


Figure 11. Water viscosity distribution after different EORs. (**a**) Water viscosity distribution after ASPAG flooding. (**b**) Water viscosity distribution after ASP flooding. (**c**) Water viscosity distribution after WAG flooding.

4.2. ASPAG for Enhanced Oil Recovery

To better elucidate the primary enhanced production layers in the ASPAG process, this study designed the reservoir rhythm of the model as a composite of reverse and positive rhythms, as shown in Figure 12. There is a significant variation in permeability, decreasing from bottom to top and then increasing. Figure 13a–c compare the cumulative oil production, cumulative gas injection, and cumulative water injection in each layer of the reservoir for the ASPAG, ASP, and WAG processes. ASPAG outperforms WAG and ASP in terms of oil production, especially in the high-permeability layers at the top. Layers 1 to 4 of the model exhibit a local reverse rhythm, influenced by gravity and local permeability, leading to increased entry of CO_2 gas and water into the high-permeability top layers. The higher the permeability, the greater the cumulative oil production. Layers 4 to 7 of the model demonstrate a local positive rhythm, influenced by gravity and local permeability, resulting in more CO_2 gas entering the sixth layer and more water entering the high-permeability bottom layers. ASPAG contributes to 83.4% of the total oil production in mid-to-high-permeability reservoirs. Hence, the primary layers for enhanced oil production through ASPAG are in the medium-to-high-permeability range.

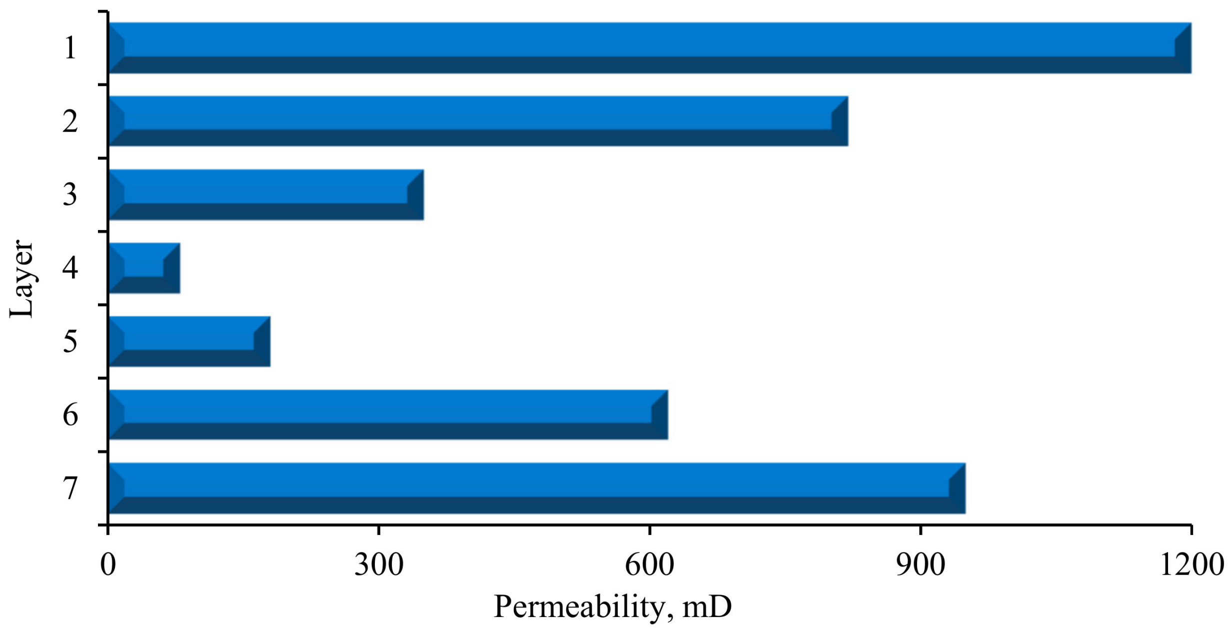


Figure 12. All-layer permeability distribution of composites' reverse and positive rhythms.

Table 5 compares the proportion of gas injection and water injection in all layers of the reservoir for the ASPAG, ASP, and WAG processes. The proportion of gas injection in each layer can visually demonstrate the gas sweep efficiency. Here, compared to WAG, ASPAG primarily increases the proportion of gas injection in high-permeability layers, indicating that injecting chemicals into the formation can effectively expand the gas sweep range in high-permeability layers (i.e., the first and seventh layers). The proportion of water injection in each layer can also show the water sweep efficiency. From the table, it can be seen that the overall water injection proportions for ASPAG, WAG, and ASP do not vary significantly. Compared to WAG, ASPAG and ASP increase the proportion of water injection in the middle-low permeability layers and bottom-high permeability layers, indicating that chemicals can also enhance water sweep efficiency. Through calculations, it is found that ASPAG can improve sweep efficiency by 21% in high-permeability layers compared to WAG, while ASPAG and ASP can improve sweep efficiency by 37–47% in low-permeability layers compared to WAG.

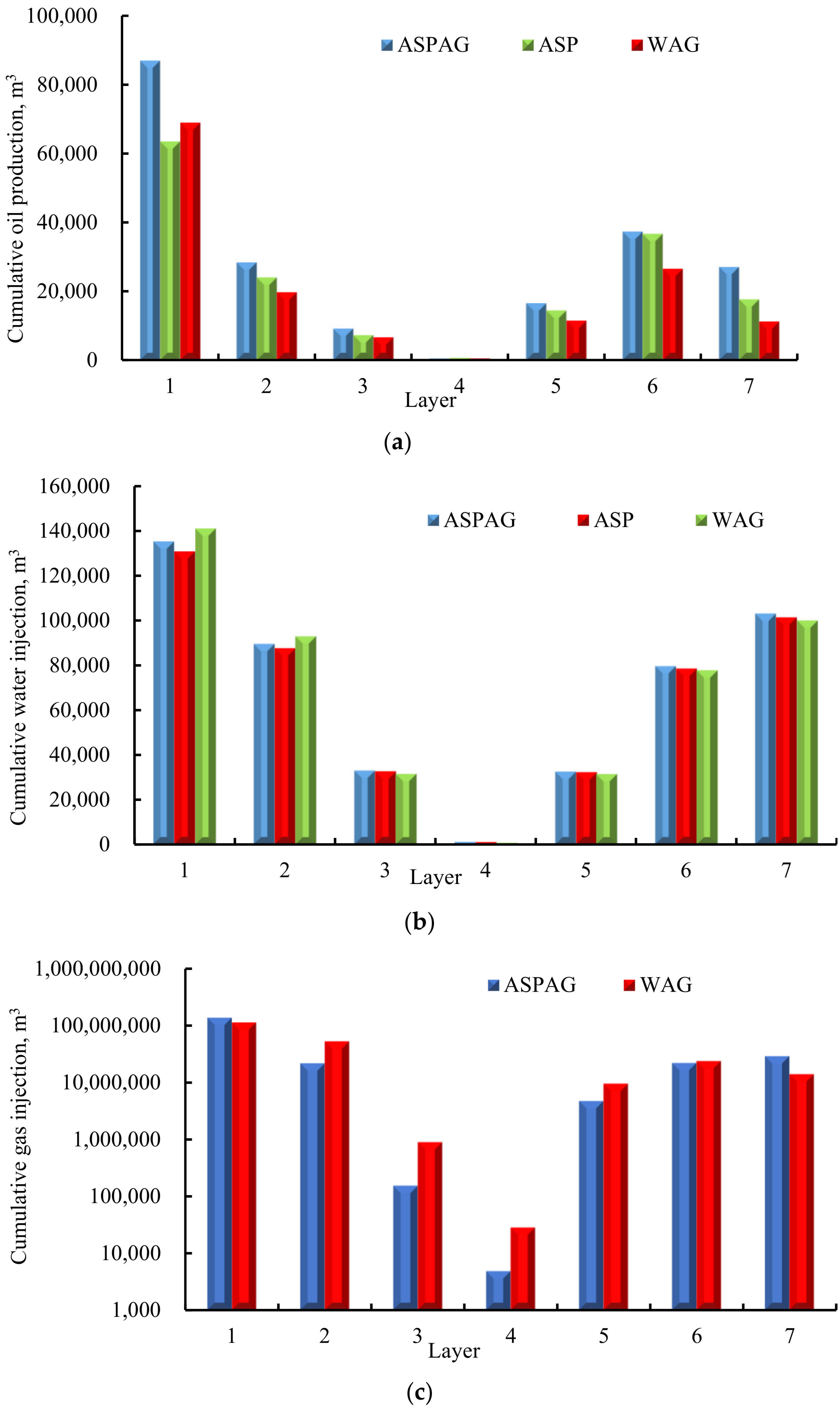


Figure 13. (**a**) All-layer cumulative oil production of WAG, ASP, and ASPAG flooding. (**b**) All-layer cumulative water injection of WAG, ASP, and ASPAG flooding. (**c**) All-layer cumulative gas injection of WAG, ASP, and ASPAG flooding.

Table 5. All-layer proportion of gas and water injection of WAG, ASP, and ASPAG.

Title 1	Layer	ASPAG	WAG	ASP
Proportion of CO_2 gas injection, %	1	64.01	53.03	-
	2	10.06	24.54	-
	3	0.07	0.41	-
	4	0.002	0.013	-
	5	2.19	4.43	-
	6	10.23	11.06	-
	7	13.42	6.49	-
Proportion of water injection, %	1	28.51	29.65	28.21
	2	18.89	19.54	18.87
	3	6.97	6.63	7.01
	4	0.23	0.16	0.22
	5	6.87	6.63	6.93
	6	16.79	16.37	16.91
	7	21.73	21.03	21.84

Figure 14 illustrates the distribution of oil saturation in different layers after the ASPAG, WAG, and ASP flooding, respectively. As shown in the figure, after the ASPAG process, the extent of oil saturation increases from the first to the fourth layer. From the fourth to the seventh layer, the extent of oil saturation decreases. Influenced by gravity and permeability, a larger amount of CO_2 gas enters the high-permeability layers at the top, while chemicals tend to penetrate the high-permeability layers at the bottom. Furthermore, the increased water viscosity due to the presence of polymers expands the gas sweep range in the high-permeability layers. After the WAG and ASP processes, the change in oil saturation in each layer is similar to that observed in the ASPAG process. Overall, compared to ASP and WAG, ASPAG exhibits a larger sweep range and higher oil displacement efficiency.

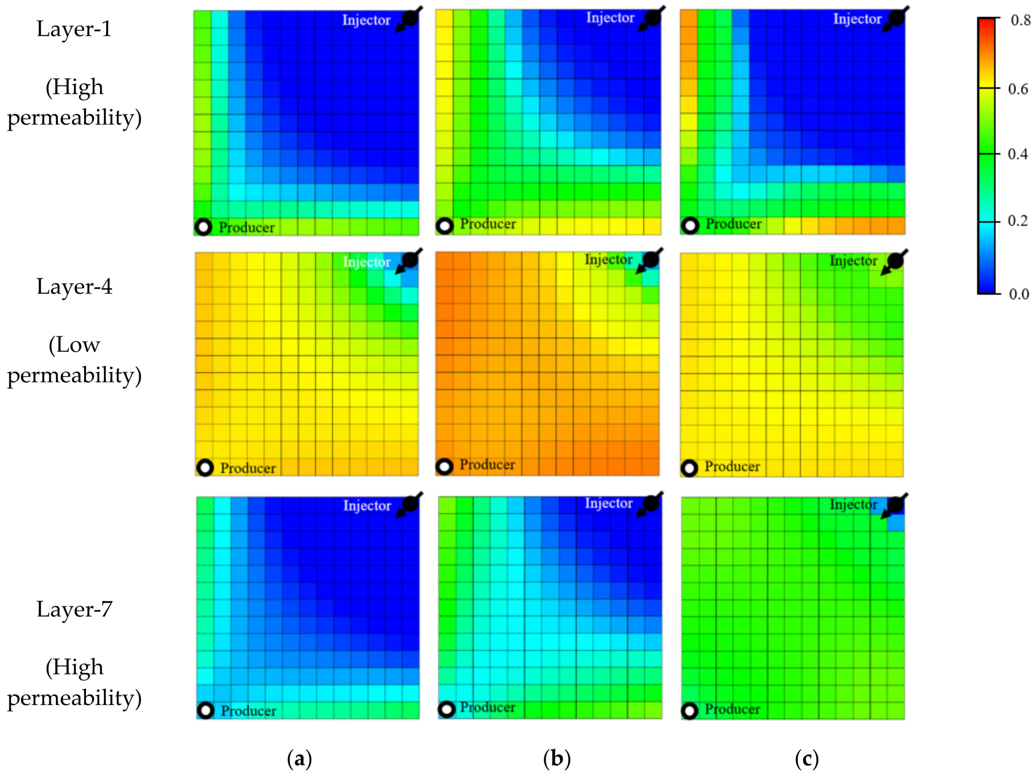


Figure 14. The oil saturation after different EOR. (**a**) The oil saturation after ASPAG flooding. (**b**) The oil saturation after ASP flooding. (**c**) The oil saturation after WAG flooding.

In summary, the principal mechanisms of the ASPAG process are as follows: (1) reduction of oil–water interfacial tension—alkaline and surfactant are used to lower the interfacial tension between oil and water, improving the displacement efficiency of water flooding in WAG; (2) increase in water viscosity—polymers are added to increase the viscosity of the water phase, which changes the volume of water injected into each layer, reduces the oil–water mobility ratio, and improves the sweep efficiency of water flooding; (3) miscibility of CO_2 gas with oil—CO_2 gas is injected to achieve miscibility with the oil, enhancing oil flow ability; and (4) alternating injection of CO_2 gas and chemicals—the alternating injection of CO_2 gas and chemicals helps to reduce the oil–water interfacial tension at the microscopic level, increasing the efficiency of oil displacement [9,42]. At the macroscopic level, it expands the gas propagation volume, reducing the oil–water mobility ratio and thereby improving the recovery efficiency [43]. Furthermore, research indicates that the ASPAG process primarily recovers oil from the medium-to-high-permeability reservoir layers.

4.3. Sensitivity Analysis of ASPAG

4.3.1. Average Permeability of Reservoir

The study encompasses a range of average permeabilities, from 50 to 1000 mD, with specific values at 50, 100, 300, 600, and 1000 mD. The reservoir's permeability exhibits a coefficient of variation of 0.65, indicating its heterogeneous nature. A consistent polymer concentration of 2000 mg/L was utilized in all cases. As depicted in Figure 15, an increase in reservoir permeability corresponds to an improved recovery factor for water flooding, WAG, and ASPAG. However, it is worth noting that when the permeability is 50 mD, ASPAG exhibits a lower recovery than WAG. When the permeability is 100 mD, ASP exhibits a lower recovery than WAG. This can be attributed to the relatively high concentration of injected polymers. According to the viscosity–concentration curve of the polymer (Figure 5), as the polymer concentration increases, the viscosity also increases correspondingly, which increases the injection difficulty of the polymer in low-permeability reservoirs. When permeability falls below 100 mD, challenges arise with polymer injection in low-permeability reservoirs, as illustrated in Figure 16.

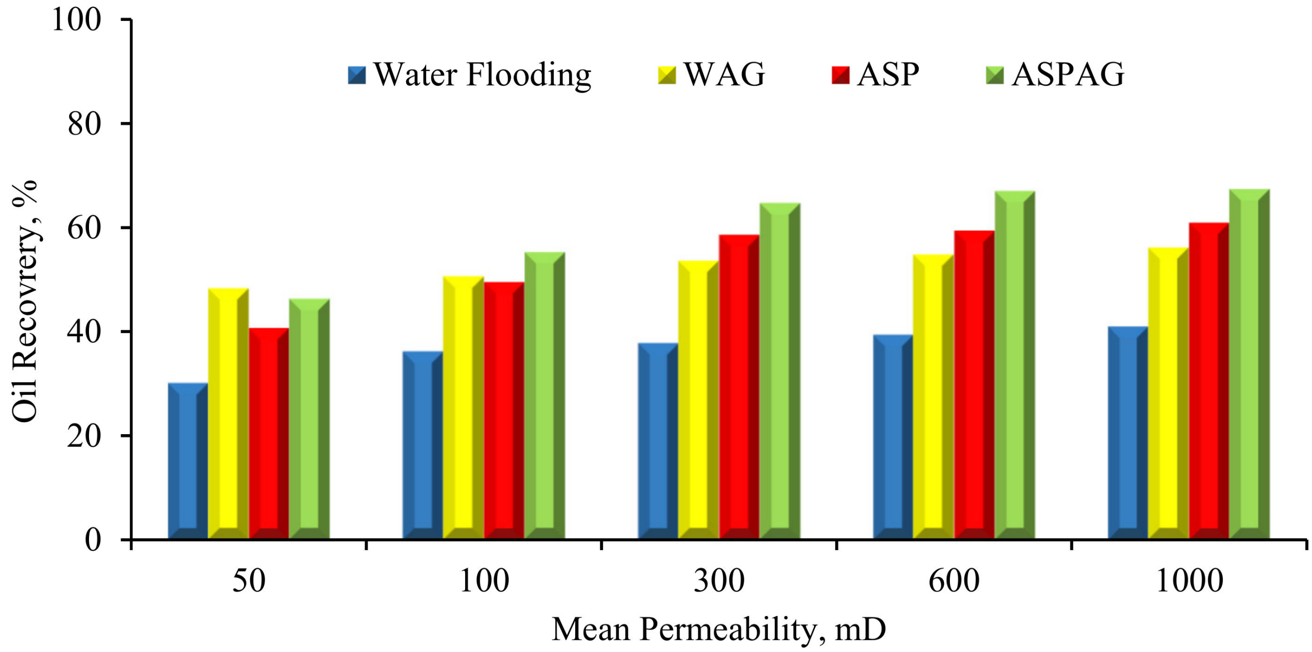


Figure 15. Comparison of oil recovery among water flooding, ASPAG, and WAG with different permeabilities.

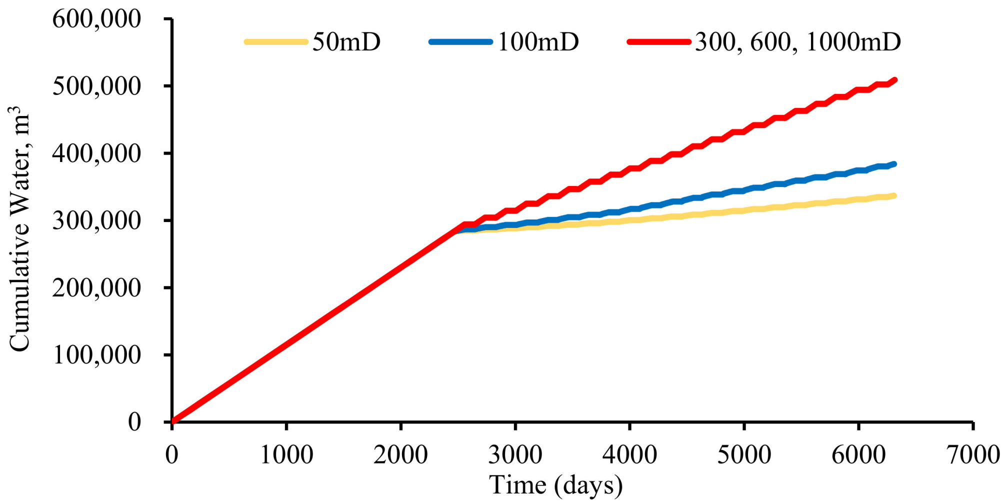


Figure 16. Cumulative water of ASPAG with different permeabilities.

Due to injection issues with higher polymer concentrations in low-permeability reservoirs, ASPAG exhibits lower recovery compared to WAG. Therefore, we employed different polymer concentrations for injection in reservoirs with varying permeability. Table 6 provides the corresponding polymer injection concentrations for different permeability reservoirs. As depicted in Figure 17, ASPAG consistently yields a higher recovery factor than WAG in reservoirs with varying permeability and polymer concentrations, and the recovery factor of ASP has also been improved. This is because lower-concentration polymers can effectively penetrate low-permeability reservoirs. When the reservoir permeability is low, the increase in recovery achieved by ASPAG is relatively small. However, for reservoirs with an average permeability greater than 300 mD, ASPAG outperforms WAG and ASP, with an increase in recovery factor ranging from 10% to 12.2%. Therefore, ASPAG is more suitable for application in medium-to-high-permeability reservoirs.

Table 6. Polymer injection concentration.

Permeability, mD	50	100	300	600	1000
Polymer concentration, mg/L	500	1000	2000	2000	3000

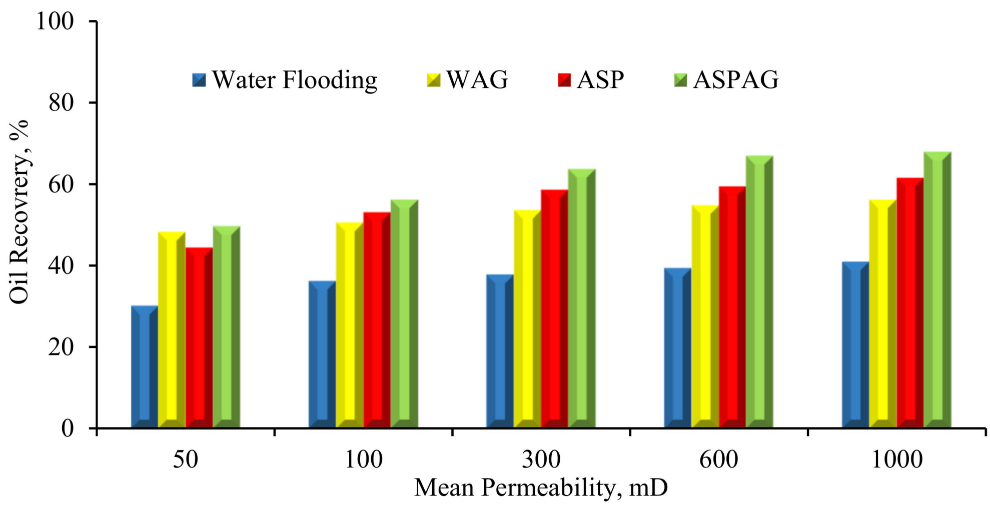


Figure 17. Comparison of oil recovery among water flooding, ASPAG, and WAG with different permeabilities after change polymer concentration.

4.3.2. Heterogeneity of the Reservoir

The vertical variation in interlayer permeability, which quantitatively describes the heterogeneity between layers, can be represented by the coefficient of variation of permeability. In this study, we considered the following six different sets of variation coefficients: 0, 0.5, 0.6, 0.7, 0.8, and 0.9, all with an average reservoir permeability of 600 mD. The polymer concentration for all cases was set at 2000 mg/L. Figure 18 shows the recovery factors of water flooding, WAG, and ASPAG under different heterogeneity conditions. It can be observed that the recovery factors of water flooding, WAG, ASP, and ASPAG decrease with increasing variation coefficients. The oil recovery increases as the heterogeneity decreases. The maximum value for homogeneous reservoirs in ASPAG that improve recovery is 30.1%. Compared to water flooding, ASPAG improves the recovery factor by 27–30%. Compared to WAG and ASP, ASPAG increases the recovery factor by 10–12.4%.

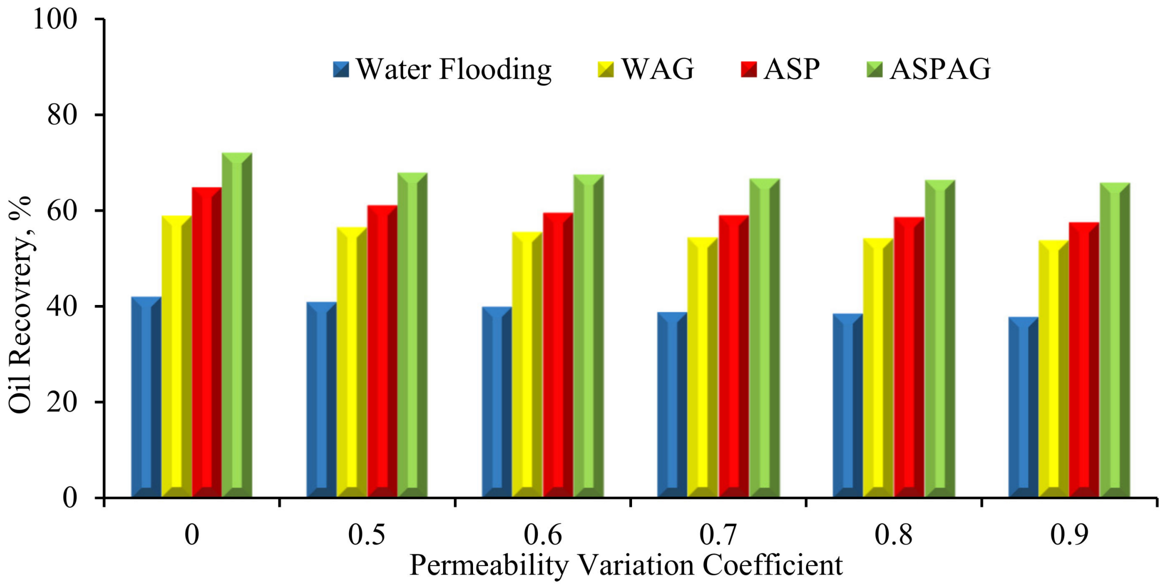


Figure 18. Comparison of oil recovery among water flooding, ASPAG, and WAG with different permeability variation coefficients.

4.3.3. Rhythmicity of Reservoir

The sedimentary rhythm of an oil reservoir directly reflects the variations of lithology and rock types in the vertical profile. When developing an oil reservoir through water injection, different sedimentary rhythms result in varying characteristics of water penetration and oil displacement efficiency [44]. This is due to the different movement patterns of oil and water in different rhythmical oil reservoirs. In this study, the recovery factors of ASPAG were predicted for positive rhythm, reverse rhythm, composite positive rhythm, composite reverse rhythm, and composite reverse and positive rhythm oil reservoirs, with an average reservoir permeability of 600 mD and a permeability variation coefficient of 0.65.

From Figure 19, it can be observed that the recovery factors for ASPAG are as follows: composite reverse rhythm < reverse rhythm < composite positive rhythm < positive rhythm < composite reverse and positive rhythm. When the reservoir follows a positive rhythm, water flooding has the lowest recovery factor as it easily breaches the high-permeability layers at the bottom due to the gravity effect. However, WAG and ASPAG can effectively develop the low-permeability layers at the top, resulting in the highest enhanced oil recovery of 30.4% and 38%, respectively. In the case of a composite reverse and positive rhythm reservoir, water flooding, ASP, and ASPAG achieve the highest recovery factor, while WAG shows the lowest improvement in recovery factor. In terms of increasing the recovery factor, the figure indicates that ASPAG is more suitable for positive rhythm reservoirs.

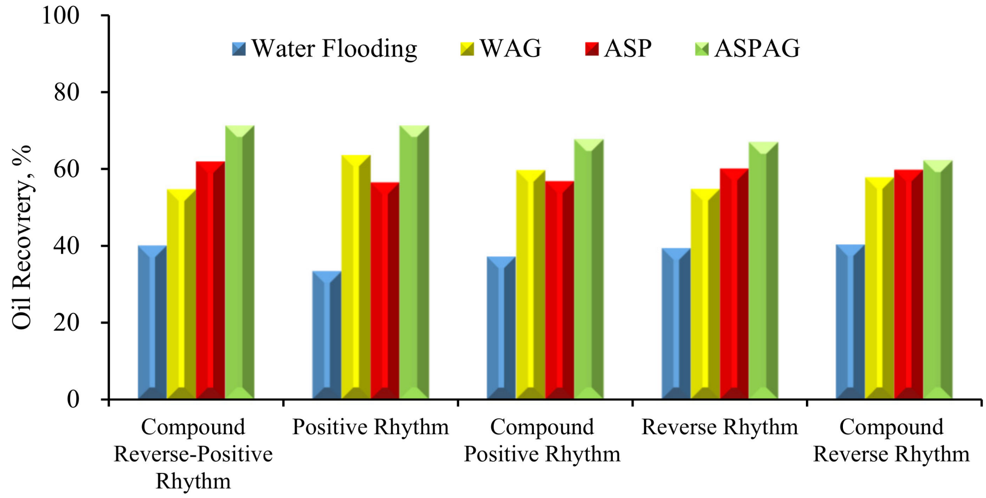


Figure 19. Comparison of oil recovery among water flooding, ASPAG, and WAG for models with different sedimentary rhythms.

4.3.4. Oil Viscosity

Viscosity is a measure of the resistance caused by internal friction during the flow of a fluid. The viscosity indicates the ease or difficulty of fluid flow, where a higher viscosity corresponds to greater flow resistance and more difficult flow [43]. In this study, the ASPAG process was predicted for different oil viscosities by using various oil samples. Five oil samples were tested with viscosity values ranging from 1 to 20 mPa·s, with an average reservoir permeability of 600 mD and a variation coefficient of 0.65. The minimum miscibility pressures of these five oil samples with CO_2 were lower than the reservoir average pressure, allowing for miscible displacement in the simulation process. From Figure 20, it can be observed that as the oil viscosity increases, the recovery factors of water flooding, WAG, ASP, and ASPAG decrease. At an oil viscosity of 1 mPa·s, ASPAG achieves the highest recovery factor with a 27% improvement, while WAG shows a 16% improvement. Across the range of oil viscosities from 1 to 20 mPa·s, ASPAG consistently outperforms WAG and ASP with a 9–12% increase in recovery factor. This indicates that the ASPAG process is suitable for reservoirs with lower oil viscosities. It can be noted that, as the crude oil viscosity increases, the recovery of ASP gradually falls below that of WAG.

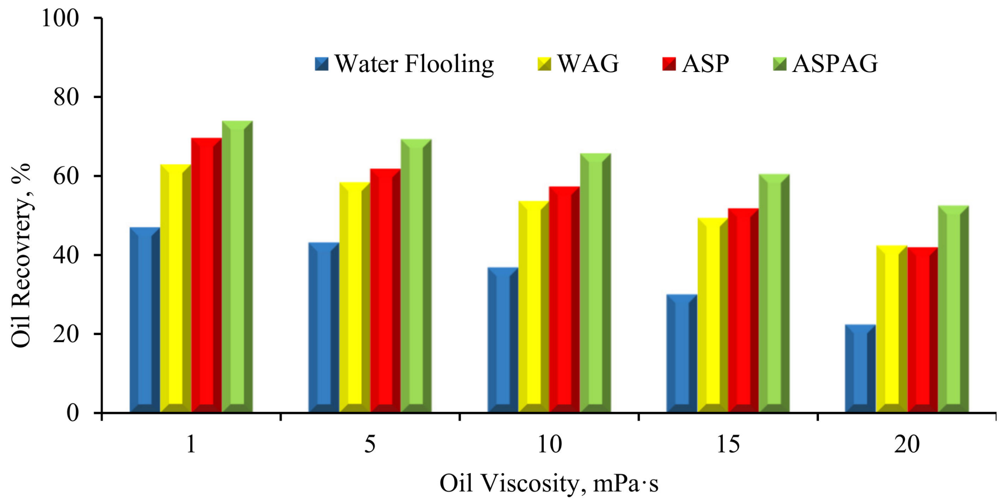


Figure 20. Comparison of oil recovery among water flooding, ASPAG, and WAG for models with different oil viscosities.

5. Conclusions

In this study, the effectiveness of a novel alkaline-surfactant-polymer alternating gas (ASPAG) injection method was investigated in terms of oil recovery, taking into account the contributions of the polymer rheological properties. Alkaline and surfactant reduce IFT and miscible CO_2 mechanisms. The main conclusions drawn from this research are as follows:

(1) The numerical simulation results indicated that ASPAG outperforms water flooding with a 22–30.3% increase in recovery factor. ASPAG improves the sweep efficiency and displacement efficiency compared to WAG, resulting in a 12–17% increase in recovery factor. Compared to ASP, ASPAG enhances the displacement efficiency and increases the recovery factor by 9–11%.

(2) Alternating injections of CO_2 gas and chemicals enhance the microscopic flow ability of the oil and macroscopically expand the gas sweep volume. ASPAG can improve sweep efficiency by 21% in high-permeability layers compared to WAG, while ASPAG and ASP can improve sweep efficiency by 37–47% in low-permeability layers compared to WAG.

(3) In the ASPAG process, the main layers contributing to oil production and increased recovery are the medium-to-high-permeability layers. The ASPAG method is more suitable for medium-to-high-permeability and positive rhythmic reservoirs with low oil viscosity.

It should be noted that all the information presented in this study is based on modeling and simulation work. This information will be continuously updated as our study progresses. Therefore, for future research, more experiments can be conducted, and additional field and laboratory experiences can be incorporated into the modeling and simulation process. Simultaneously, optimizing the key parameters of ASPAG and eventually applying numerical simulations to actual reservoir blocks will provide a deeper understanding of the comprehensive mechanisms behind the enhanced oil recovery process of ASPAG in medium-to-high-permeability reservoirs. These efforts may contribute to enhancing the operational design and optimization of future laboratory and simulation endeavors, as well as potential pilot projects.

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Data Availability Statement: The datasets used and/or analyzed during the current study are available from the corresponding author upon reasonable request.

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Conflicts of Interest: Authors Zhengbo Wang, Weidong Liu and Bing Dingwere employed by the company PetroChina. Author Hongliang Yi was employed by the company Petrochina Liaohe Oilfield. The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

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