Numerical Simulation of Alkali-Surfactant-Alternated-Gas(ASAG) Injection: Effects of Key Parameters

Qianqian Shi, **Weirong Li***, **Shihao Qian**,**Xin Wei**,**Tianyang Zhang**, and **Xu Pan**, Xi'an Shiyou University, Xi'an, China

Abstract

Alkali-surfactant-alternated-gas (ASAG) alternating injection is a method used to enhance oil recovery. In the water injection stage of the WAG process, chemicals (alkaline-surfactant) are added to the plug. This paper presents a numerical simulation study at the reservoir scale to analyze the influencing factors of ASAG process on improving recovery efficiency. The research results indicate that ASAG process can achieve an ultimate recovery efficiency of 67%, which is approximately 22% higher compared to water flooding. Among the various influencing factors, injection rate, plug volume, and chemical concentration have a significant impact on the recovery efficiency.

Introduction

Gas flooding is considered the most effective method to enhance the recovery factor in light to medium oil reservoirs. Water alternating gas (WAG) is one of the gas flooding techniques that improves the recovery factor by altering the fluid distribution in the reservoir through alternating injections of water and gas. WAG technology has been widely researched and applied over the past few decades, achieving successful outcomes in various types of reservoirs and geological environments. However, significant amounts of residual oil still remain in the reservoir after CO_2-WAG.

Alkali-surfactant-alternated-gas (ASAG) injection is a method used to enhance the recovery factor. Chemical agents (alkali-surfactant) are added to the water injection segment of the WAG process. Surfactants in this method primarily reduce interfacial tension, while alkalis assist in reducing interfacial tension with surfactants and can also minimize surfactant adsorption. Gas injection complements reservoir energy, lowers crude oil viscosity, and allows for miscibility with the crude oil.

The concept of ASAG injection was proposed by Lawson et al. in 1980. From 2012 to 2014, laboratory studies conducted by Guo et al. discovered that the alkali/surfactant/foam (ASF) process exhibited lower sensitivity to salinity and enhanced recovery of the majority of residual oil after water flooding when AS solution was introduced. Additionally, under high salinity (230,000 ppm) and temperature (83°C) conditions, successful recovery of residual oil from carbonate rock samples was achieved through ASAG injection. In 2013, Lou et al. found in their laboratory studies on ASAG injection that the process even yielded sufficient recovery of heavy oil.

DOI:10.14800/IOGR.1249

Received January 12, 2023; revised February 24, 2023; accepted April 11, 2023.

* Corresponding author: weirong.li@xsyu.com.cn

Numerous scholars have conducted research on ASAG injection under different conditions, as shown in **Table 1**. These studies have confirmed the enhanced oil recovery (EOR) potential of ASAG injection and demonstrated that it can improve reservoir recovery more effectively compared to WAG and SAG injection methods.

Table 1—Summary of some ASAG flooding studies

Author	Oilfield	Chemical slug	Gas	IFT(mN/m)
Srivastava et al.(2009)	Light to medium crude oil	AS、ASP coinjected with gas	CO_2	Ultra-low
Cottin et al.(2012)	Medium-light crude oil	AS、S coinjected with gas	N_2、methane	0.003
Guo et al.(2012)	Reservoir crude oil	AS coinjected with gas	N_2	0.008
Luo et al.(2013)	Heavy crude oil	ASPAG	CO_2、Flue gas	0.06
Majidaie et al. (2015)	Crude oil viscosity of 1.6 cP	ASPAG	CO_2	0.003

The field test data by Y. Zhu et al. in 2013 also demonstrated the effectiveness of this technique in extremely low permeability (0.3mD~3.5mD) tight reservoirs. The study conducted by S. Majidaie et al. in 2015 focused on the research of ASAG oil displacement using a specially developed AS formulation, which can reduce the oil-water interfacial tension to an ultra-low value, helping to minimize water blockage effects. The research by S. Jong et al. in 2016 also confirmed that the use of salinity gradient during ASAG oil displacement process can enhance foam stability, control mobility, and improve oil recovery.

The study by R. Phukan et al. in 2019 indicated that the performance of ASAG oil displacement is influenced by certain parameters, which need to be adjusted to improve oil recovery, including injection schemes, plunger size, plunger ratio, gas injection rate, total injected fluid volume, salinity gradient, etc.

The aforementioned studies demonstrate that under low permeability reservoir conditions, ASAG oil displacement can achieve higher oil recovery compared to WAG (Water Alternating Gas) method, but it is affected by various factors. However, the quantitative evaluation of the influence of different parameters on residual oil recovery in ASAG oil displacement has not been conducted. Although some scholars have attempted to study the factors affecting the improvement of oil recovery in ASAG, the discussions have been limited to certain aspects and are currently only at the laboratory core displacement experiment stage, lacking discussion at the reservoir scale.

This study aims to explore and adjust various factors influencing the potential of improving oil recovery in ASAG oil displacement at the reservoir scale. Numerical simulations will be conducted for water flooding, WAG, and ASAG oil displacement methods to compare the recovery results under the same reservoir conditions. Firstly, a geological model will be established using CMG·STARS commercial software to simulate the oil displacement processes of the three methods. In addition, detailed single-factor analyses will be performed to investigate the impacts of geological parameters, fluid parameters, and process parameters on oil recovery. The purpose is to gain a better understanding of the effectiveness of ASAG oil displacement and maximize petroleum recovery by adjusting parameter variations. The following sections of this paper will establish the geological model and then conduct single-factor analyses on nine important parameters to identify scientifically reasonable and economically viable parameter values as references for the application of ASAG in actual reservoirs.

Reservoir model and fluid characterization

Based on the geological data of a certain reservoir, establish a geological model with characteristic features. The model grid is 13×13×7, with 13×13 grids on the horizontal plane and seven layers vertically, each with a thickness of 3m. The model size is 260×260×21m, as shown in **Figure 1.** The permeability varies in each layer of the model, with an average permeability of 30 millidarcies (mD). The well pattern consists of a quarter of a five-spot well pattern. There is one injection well and one production well, with an injection-to-production ratio of 1:1. The injection rate is 0.1 pore volume per year (PV/a). **Table 2** shows the reservoir rock and fluid properties.

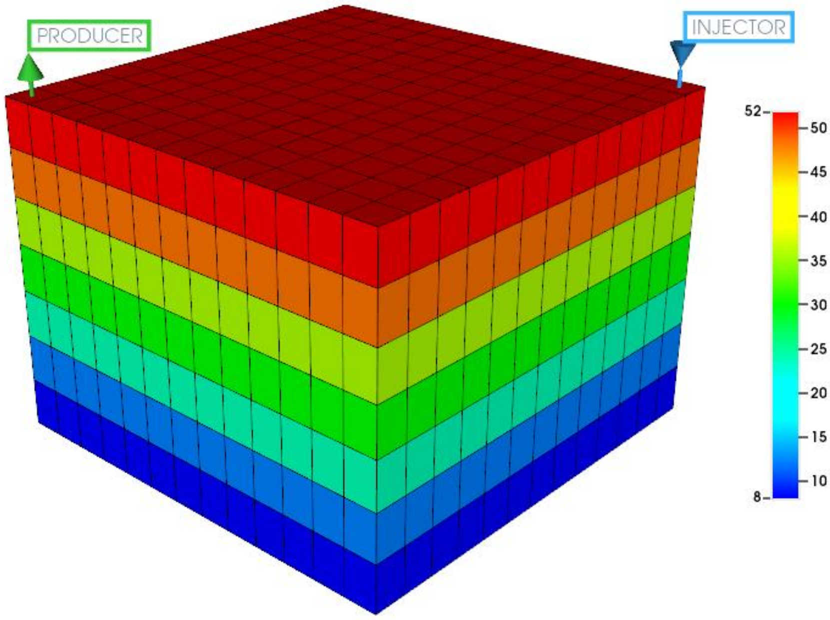


Figure 1—Geological model map.

Table 2—Reservoir rock properties and fluid properties

Reservoir rock properties		Fluid properties	
Porosity，%	22	Viscosity of water，mPa·s	1
Depth，m	1200	Viscosity of crude oil，mPa·s	1.25
Temperature，℃	85	density of the crude oil，g/m^3	817
Permeability，mD	30	Initial water saturation，%	20
Coefficient of permeability variation	0.65	Initial oil saturation，%	80

Results and discussions

Base Case.This article primarily conducts numerical simulations of three oil displacement processes: water flooding, WAG (Water-Alternating-Gas), and ASAG (Alkali-Surfactant-Alternating-Gas), as shown in **Figure 2**.

The WAG process includes an initial water flooding stage, followed by alternating gas injection, and subsequent water flooding. After reaching a 90% water cut in the reservoir during the initial water flooding, gas injection begins using the WAG oil displacement method. A total of 24 cycles of alternating injections are performed at an injection rate of 0.1 PV/a, with each cycle injecting water and CO_2, totaling 0.6 PV. Subsequent water flooding is then conducted until displacement is complete.

ASAG is based on the WAG process,after the initial water flooding stage, alkali and surfactant are added to the water to form an AS (Alkali-Surfactant) chemical slug, which replaces the water. The oil displacement is then carried out by alternating injections of the AS slug and gas, while maintaining the same number of cycles, injection rate, and total volume, throughout the entire simulation.

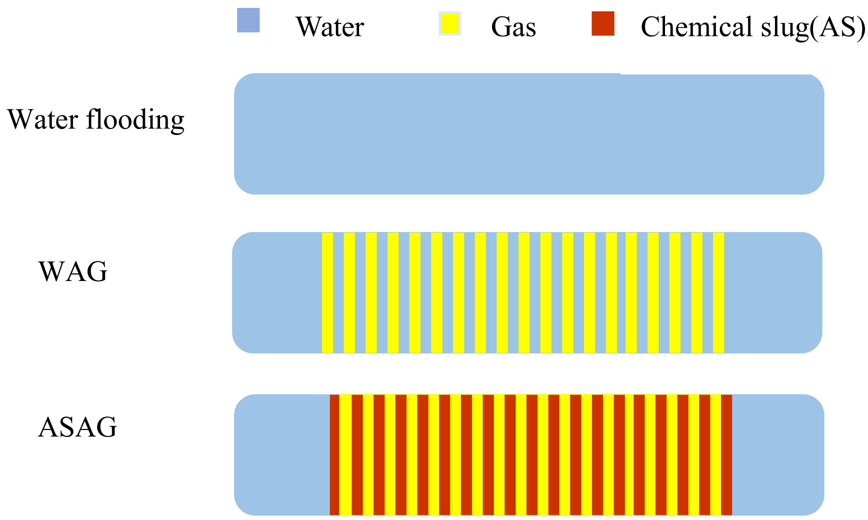


Figure 2—Diagram of different injection modes.

The recovery factors of water flooding, WAG, and ASAG were compared (**Figure 3**). As shown in the Figure, under the same reservoir conditions, ASAG has the highest recovery factor. After a certain period of water flooding, the increase in recovery rate slows down. To enhance the reservoir recovery factor, gas injection is introduced for WAG. From the recovery rate curve, it can be observed that WAG improves the recovery factor by approximately 10%. Building upon WAG, alkali-surfactant is added, resulting in ASAG. The addition of chemical agents enables the recovery factor to reach over 67%.

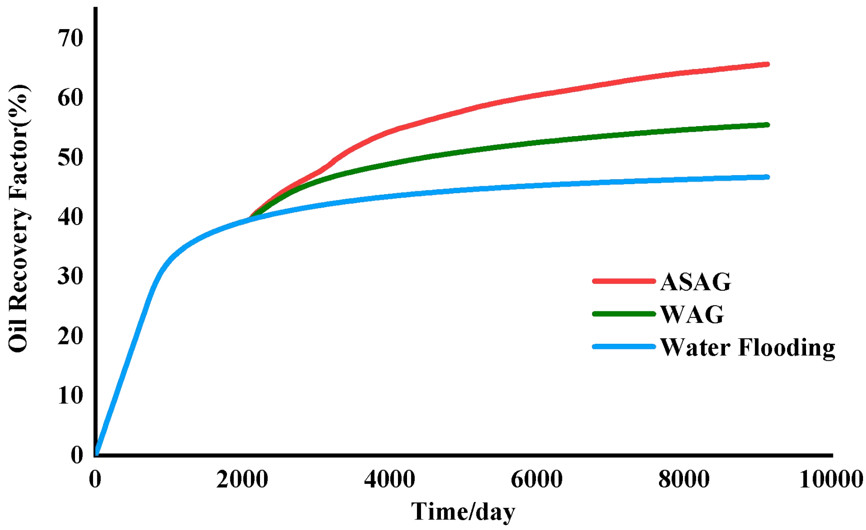


Figure 3—Comparison of oil recovery factor with and water flooding and WAG and ASAG.

Figure 4 compares the daily oil production for three different processes. From the graph, it can be observed that after a certain period of water flooding, the oil production declines rapidly. The introduction of chemicals results in higher daily oil production compared to water flooding and WAG injection, especially during the early stages of injection when the remaining oil saturation is high. ASAG demonstrates superior production enhancement effects.

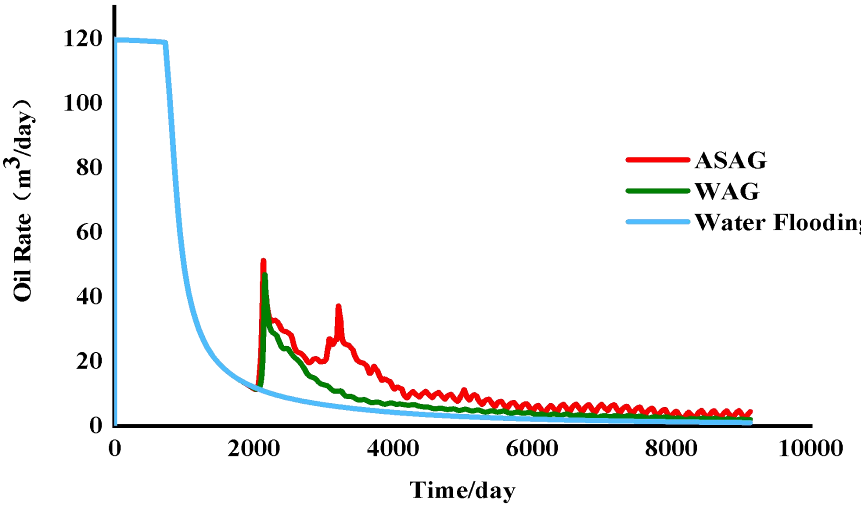


Figure 4—Comparison of oil rate with and water flooding and WAG and ASAG.

The gas-oil ratio of two production processes, WAG and ASAG, is illustrated in **Figure 5** from the perspective of petroleum engineers or reservoir specialists.

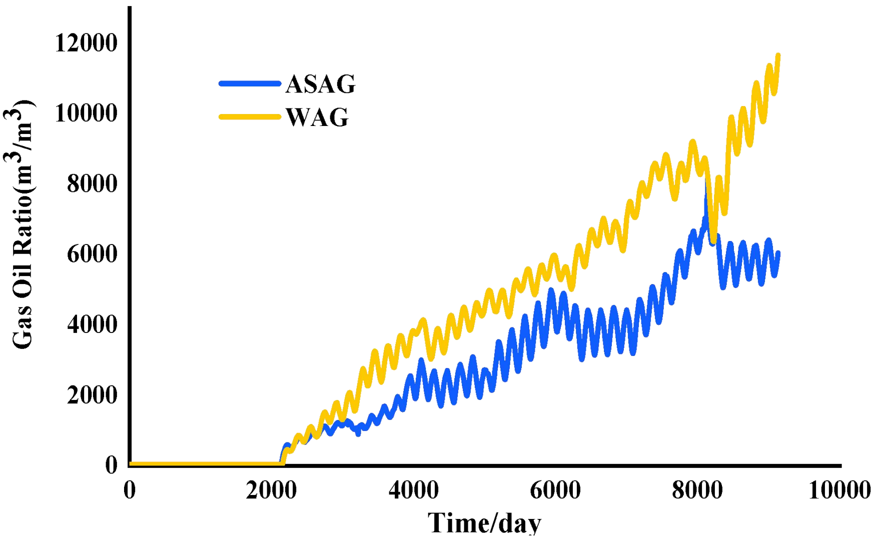


Figure 5—Comparison of gas oil ratio with and WAG and ASAG.

Based on the graph, it can be observed that the gas-oil ratio (GOR) increases more significantly in the WAG process compared to the ASAG process, and the GOR in WAG is much higher than in ASAG. This indicates that gas breakthrough is more likely to occur during the WAG oil displacement process, while the addition of alkali-surfactant can effectively delay gas breakthrough, reduce the GOR, enhance the thorough contact and mixing of gas and crude oil, lower the interfacial tension, and thereby increase the recovery factor.

Effect of Reservoir Rhythm. Based on the reservoir permeability, it can be determined that the reservoir is a stratified reservoir. A stratified reservoir refers to a formation where particle sizes change from fine to coarse from bottom to top. In such formations, there is significant variation in vertical permeability, with lower permeability in the lower section and higher permeability in the upper section. In this model, the maximum permeability of the first layer is 52 mD, decreasing progressively downwards, with the minimum permeability of the seventh layer being 8 mD.

To investigate the impact of reservoir stratification and varying permeability on recovery efficiency, this study examines the oil production and gas injection rates for each layer, quantitatively analyzing the primary producing layer positions under different vertical permeabilities. The cumulative oil production for each layer using ASAG and WAG alternating injections is shown in **Figure 6.**

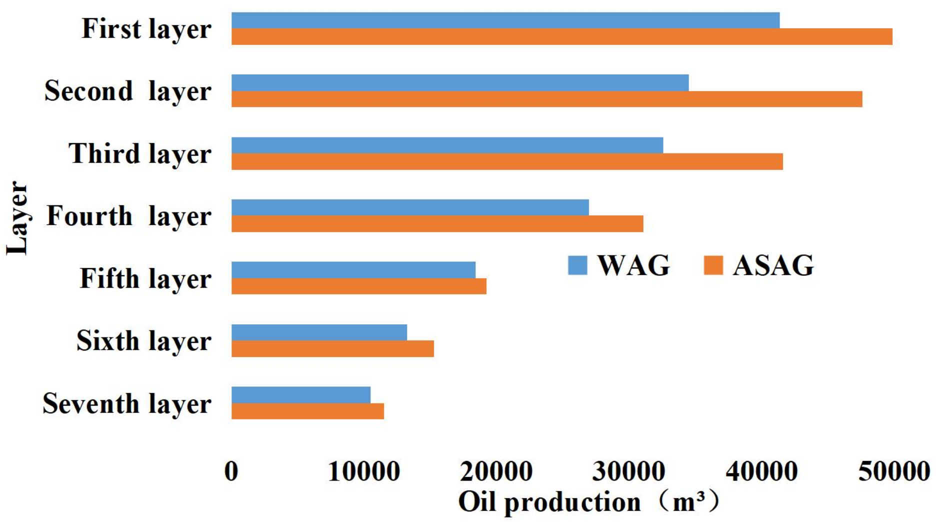


Figure 6—Comparison of oil production in each layer.

From Figure 6, it can be observed that both WAG and ASAG oil reservoirs are concentrated in the upper section with slightly higher permeability. In terms of oil production per layer, ASAG yields higher oil production than WAG, and the higher the permeability, the greater the difference in oil production. The oil production of the seventh layer is only 30% of the first layer. Therefore, compared to the WAG process, ASAG can improve the recovery factor across various permeability gradients, but it shows better results in higher permeability layers. This is because in the stratified reservoir, gas is influenced by lower density, and most of the CO_2 gas enters the high-permeability layers. The gas sweep range of ASAG is significantly larger than that of WAG. By injecting chemical solution plugs and alternating gas into the formation, the ASAG process reduces the mobility of the water phase in high-permeability layers and controls the gas mobility, allowing more gas to enter the high-permeability layers. Compared to WAG, ASAG only contributes 2% of the incremental oil production from low-permeability layers.

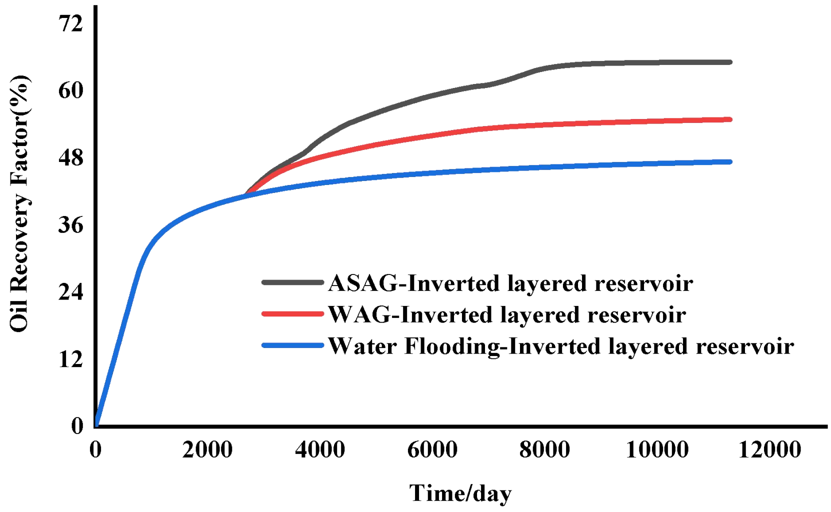


Figure 7—Correlation of cumulative oil production in antirhythmic reservoirs.

Figure 7 represents a comparison curve of cumulative oil production under different injection methods with the same reservoir conditions. From the graph, it can be observed that after a certain period of water flooding, the oil production rate slows down. However, by changing the oil displacement method, such as employing WAG or ASAG, the recovery factor can be significantly improved. In this particular reservoir, WAG can enhance the recovery factor by approximately 9%, and when ASAG, it can further increase the recovery factor by over 11% compared to WAG alone.

Effect of Injection Time. In this study, five injection timing schemes were set, namely, alternate injection of ASAG when the water cut of the reservoir reached 60%, 70%, 80%, 90% and 95% after water flooding. **Figure 8** compared the final recovery rate after ASAG under different water cuts of the reservoir.

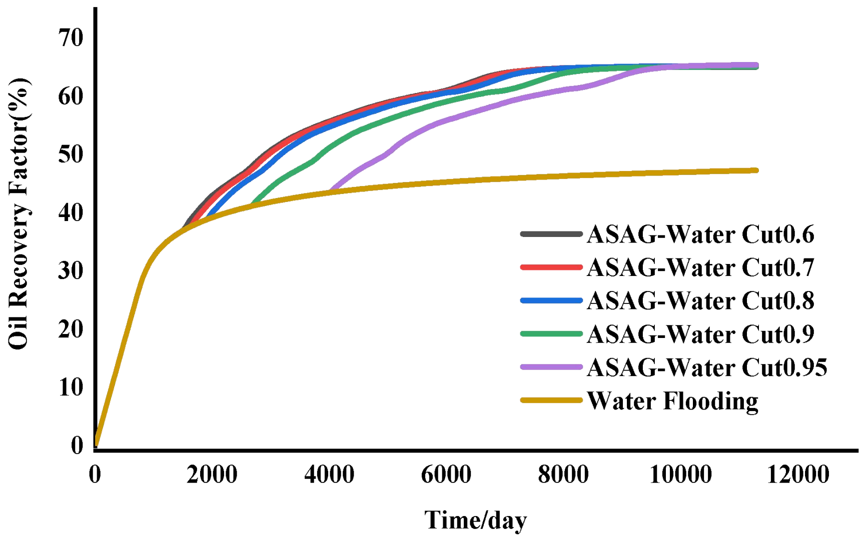


Figure 8—Comparison of recovery curves at different injection times.

According to Figure 8, it can be observed that when alternating injections of AS and CO_2 are started at different timings, the ultimate recovery slightly varies, primarily in terms of the time to reach the maximum recovery factor. However, the impact on the ultimate recovery factor after displacement is not significant. From the changes in the curve, it can be seen that the earlier the chemical agent is introduced, the earlier the maximum recovery factor is reached. However, the recovery trend for the five injection timings is the same. At a water saturation of 95%, the maximum recovery factor is achieved with ASAG injection, reaching 65.5%. Nevertheless, the differences in the final recovery factor among the various methods are not very distinct.

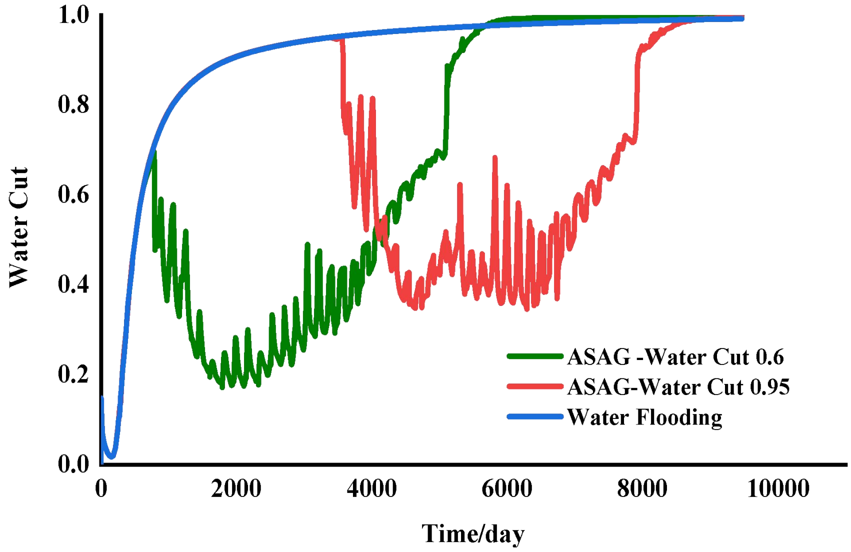


Figure 9—Comparison of water cut curves after ASAG when the water cut is 60% and 95%.

Figure 9 shows the water saturation curve of the reservoir after ASAG injection at different timing points when the water saturation reaches 60% and 95% respectively. During the water flooding stage, the water saturation increases sharply. With the injection of chemicals at different timing points, the water saturation is reduced to varying degrees. The injection of ASAG for oil displacement starts at different water saturation levels, leading to significant variations in water saturation. When the water saturation is at 60%, the chemical injection begins, resulting in a rapid decrease in water saturation, which is maintained at a low level for a certain period of time. However, when the chemical injection is stopped, the water saturation quickly rises to above 0.9. When the water saturation exceeds 0.9, the peak of water saturation reduction increases during chemical injection, as shown in **Table 3**. Nevertheless, it can still maintain a low water saturation level for a certain period of time until the ASAG injection for oil displacement is completed. The earlier the chemical injection, the earlier the decline in water saturation and the more pronounced the improvement in water saturation.

Table 3—Comparison of water cut content at different injection times

Injection times（Water cut），%	60	70	80	90	95
Minimum water cut，%	19.20	22.10	24.50	26.80	34.50

From Table 3, it can be observed that there are variations in the peak values of water cut changes after chemical injection. The earlier the injection takes place, the lower the peak value. Therefore, the earlier the chemical injection is performed, the better the effect.

Effect of Injection Rate. This study presents four different injection rate schemes, namely 0.1PV/a, 0.125PV/a, 0.15PV/a, and 0.2PV/a. The ultimate recovery factor of the ASAG method was compared for these four injection rates, and the results are shown in **Figure 10.**

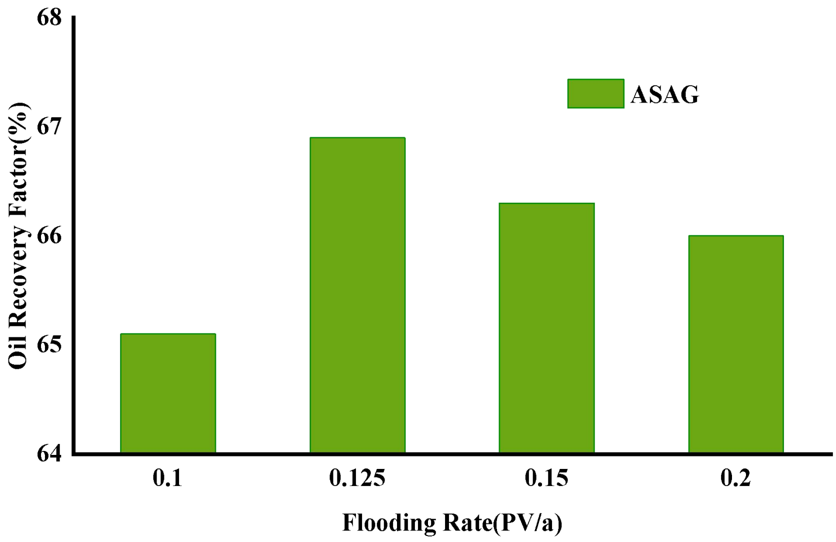


Figure 10—Comparison of ASAG recovery at different injection rates.

According to Figure 10, it can be observed that as the injection rate increases, the overall recovery factor of ASAG exhibits an initial increase followed by a decrease. When the injection rate increases from 0.1 PV/a to 0.125 PV/a, the recovery factor increases by approximately 2%. However, when the injection rate exceeds 0.125 PV/a, the recovery factor of ASAG gradually decreases. Therefore, faster injection is not necessarily better. At a higher injection rate, the injection time for the chemical agent decreases, resulting in a shorter contact time with the crude oil, which hinders the full effectiveness of the chemical agent. **Table 4** and **Figure 11** compare the variations in water content using the highest and lowest recovery factors as examples.

Table 4—Comparison of the lowest water cut when injection rate is 0.1PV/a and 0.125PV/a

Injection rate，PV/a	0.1	0.125
Minimum water cut，%	23.5	30.1

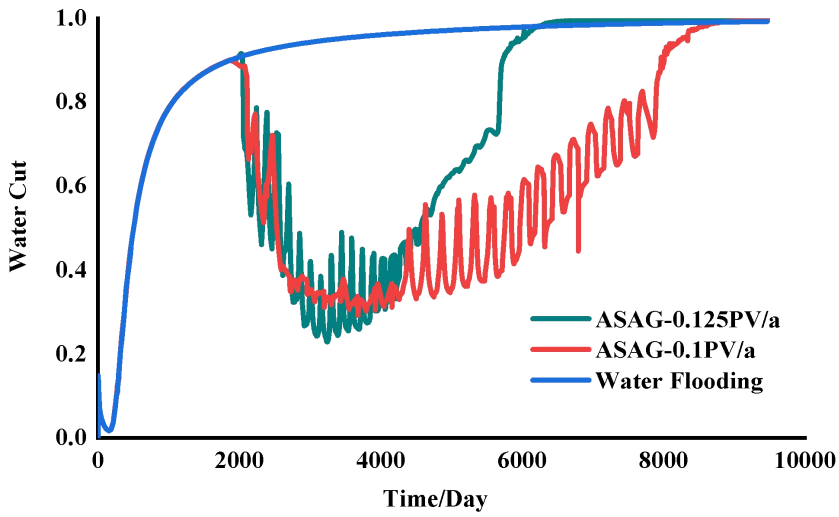


Figure 11—Different injection rates water cut curve.

Table 4 shows the minimum water cut values at injection rates of 0.1 PV/a and 0.125 PV/a. It can be observed that under different injection rates, the peak water cut varies, and overall, higher injection rates result in lower peak water cut. From Figure. 11, it can be inferred that during the initial water flooding stage, with the same injection rate, the water cut curves completely overlap, indicating a sharp increase. During the chemical injection stage, as the injection rate decreases, the water cut decreases to varying degrees and can be maintained at a lower level for a longer period. When the injection rate is less than 0.125 PV/a, under the same injection volume, a higher injection rate leads to greater injection intensity, shorter total injection time, more significant water cut reduction, but a faster rise. Considering the above results, the optimal injection rate for this reservoir condition is determined to be 0.125 PV/a.

Effect of Cycle Index. In the process of alternate injection, a higher viscosity AS slug is injected into relatively high-permeability layers to improve the macroscopic sweep efficiency. The alternating injection cycles have a certain influence on the oil displacement effect of AS and CO_2. When the alternating cycles are larger, the size of the slug is smaller, which may damage the chemical agent slug. When the alternating injection cycles are smaller, the size of the slug is larger, resulting in a longer displacement time and poorer flow control effectiveness.

In this study, five simulation scenarios with different numbers of cycles were conducted while keeping the total injected volume of AS constant. The scenarios included 6, 12, 18, 24, and 30 cycles. The ultimate recovery of ASAG was compared, and the results are shown in **Figure 12**.

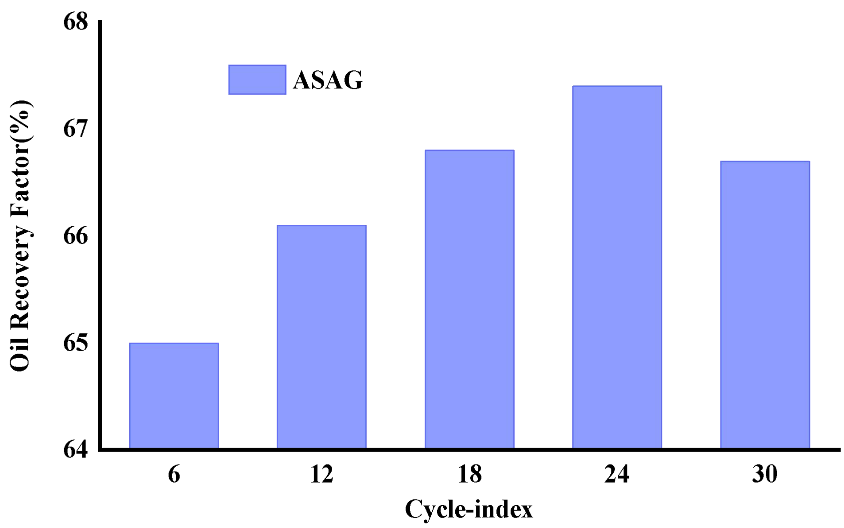


Figure 12—Comparison of recovery efficiency with different cycles

According to Figure 12, it can be seen that with a constant total injection volume of AS, the greater the number of cycles, the higher the recovery efficiency of ASAG. However, there is a maximum value, and the recovery efficiency of ASAG starts to decrease when the number of cycles reaches 30. Therefore, it is evident that the number of alternate cycles is not the more, the better; instead, there exists an optimum value. In this study, the optimal value is 24 cycles.

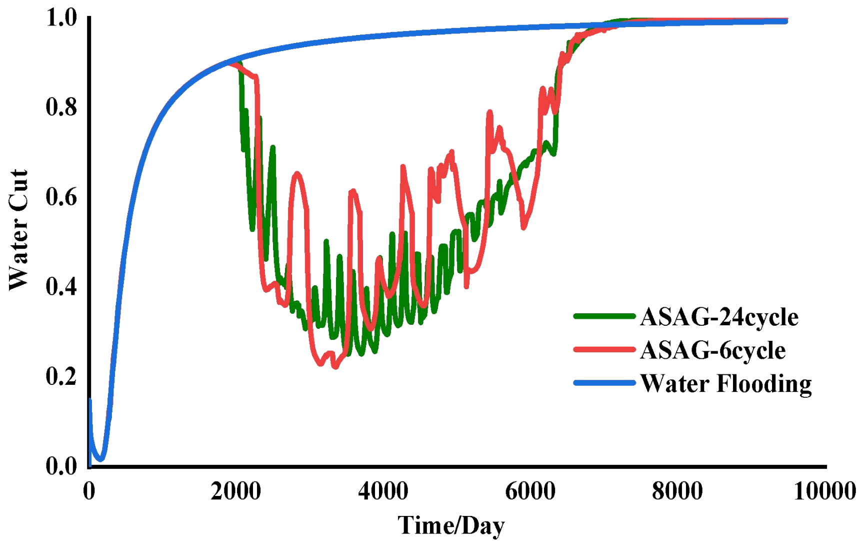
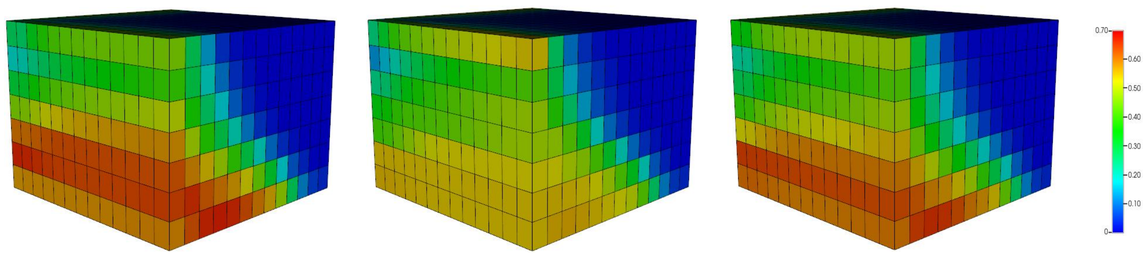


Figure 13—Comparison curve of water content when the number of cycles is 6 and 24.

The water cut curve from Figure 13 indicates that an increase in cycle frequency leads to a more stable maintenance of lower water cut levels. Consequently, at the 24th cycle, the recovery rate exceeds that of the 6th cycle. Additionally, the oil saturation plot reveals that employing a reasonable alternating cycle frequency allows for a higher extraction of crude oil.



（a）Perform 6 cycles （b）Perform 24 cycles （c）Perform 30 cycles

Figure 14—Oil saturation profile after ASAG for 6, 24 and 30 cycles.

According to **Figure 14**, during the ASAG process, when the cycling is performed 6 times, the fourth, fifth, sixth, and seventh layers of the reservoir exhibit high oil saturation. As the number of cycles increases to 24, the oil saturation in these layers notably decreases. However, when the number of cycles reaches 30, the oil saturation in the fourth, fifth, sixth, and seventh layers increases significantly. This is because with a smaller number of alternate injection cycles, the plugging effect is larger, resulting in a longer displacement time and poorer fluid control. On the other hand, with a larger number of alternate cycles, the plugging effect decreases, leading to noticeable viscosity losses. Therefore, considering the displacement effect, the best performance is achieved with 24 alternate injection cycles.

To achieve the optimum recovery and make full use of the injected fluid, it is necessary to inject chemical and gas plugs at the right time during the ASAG process. In fact, a higher number of cycles result in higher residual oil recovery. This may be attributed to the increased number of cycles, which improves the contact between the chemical solution and CO_2.

Effect of ASAG Ratio. In petroleum extraction, the alternating injection of chemical agents and gas aims to enhance the oil recovery factor by altering the pressure and temperature in the reservoir, as well as inducing chemical reactions. The alternating cycle ratio refers to the time ratio between the injection of chemical agents and gas. Modifying the alternating cycle ratio can have different impacts on the oil recovery factor, as outlined below:

Enhanced recovery factor: When chemical agents are injected into the reservoir, they react with the components in the crude oil, thereby altering its physical properties and making it more mobile. Gas, on the other hand, increases the reservoir pressure, promoting the movement of crude oil towards the wellbore. By immediately injecting gas after chemical agent injection, the chemical reactions can be accelerated, facilitating the flow of crude oil and thus enhancing the recovery factor.

Cost savings: By adjusting the alternating cycle ratio, it is possible to reduce the usage of chemical agents and gas without compromising the recovery factor, leading to cost savings.

It is important to note that different reservoirs and geological conditions require different alternating cycle ratios to achieve the optimal recovery factor and economic benefits. Therefore, experimental and simulation analyses are necessary to determine the best alternating cycle ratio.

The alternating cycle ratio refers to the proportion between the alkali-surfactant (AS) slug and the gas (CO_2) in each cycle. In this study, four sets of alternating cycle ratio schemes were employed, namely 1:2,1:1,2:1, and 3:1, while keeping other parameters constant. The injection volume of AS in each cycle was kept constant. A comparison was made with the water flooding and ASAG methods regarding the ultimate recovery factor, as shown in **Figure 15**.

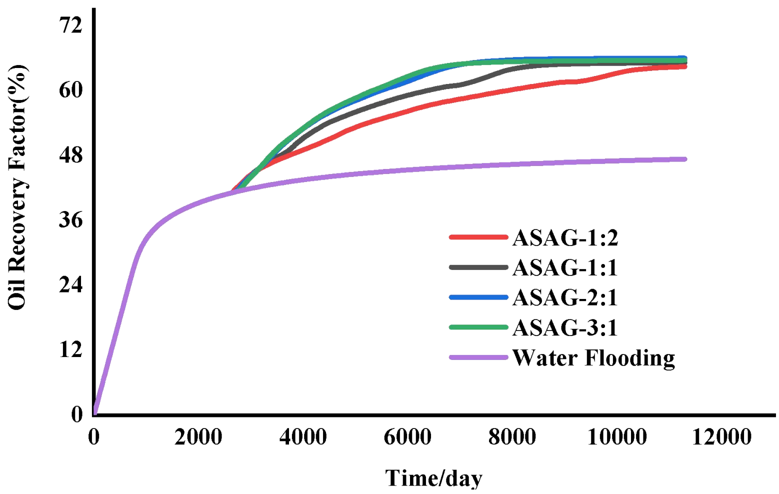


Figure 15—Comparison of recovery efficiency at different alternating cycle ratios.

From Figure 15, it can be seen that different alternating injection ratios have a certain influence on the recovery factor during the injection process. The lowest recovery factor is observed when the ratio of AS slug to gas is 1:2 during ASAG injection, and the increase in recovery rate is relatively slow. As the AS slug increases, the recovery factor gradually increases, and the rate of production enhancement also accelerates. However, after a certain value of AS slug increase, the recovery factor starts to decrease. The specific values of the recovery factor are shown in **Table 5**.

Table 5—Recovery of different alternating cycle ratios

Alternate cycling ratio	1:2	1:1	2:1	3:1
Recovery factor，%	64.3	65.1	66.2	65.8

From Table 5, it can be observed that maintaining a constant total volume of AS injection, the difference in the ratio between AS and CO_2 in the alternating cycles results in significant variations in the production cycle of the entire development process. An appropriate ratio for alternating cycles can increase the liquid absorption capacity of low-permeability layers and improve the oil displacement effect in these layers. In this model, the highest recovery efficiency of ASAG is achieved when the alternating ratio is 2:1, reaching 66.2%.

Effect of Slug Volume. This study established six different injection volume schemes for the AS segment plug, namely 0.2PV, 0.4PV, 0.6PV, 0.8PV, and 1.0PV, in order to compare their ultimate water flooding and ASAG recovery factors. **Figure 16** illustrates the variations in reservoir water saturation under the minimum and maximum segment plug volumes.

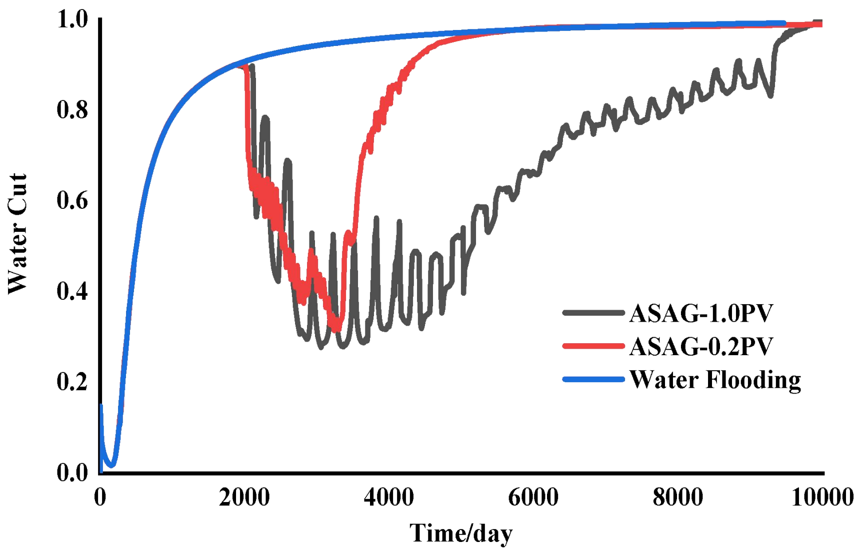


Figure 16—Comparison of water content curves when the volume of slug is 0.2PV and 1.0PV.

From Figure 16, it can be observed that under a constant injection rate, a larger volume of AS slug results in a longer injection time for the chemical agent, prolonging the production cycle and extending the period of low water content. Figure.17 compares the recovery efficiency of ASAG under different volumes of AS slug. When the AS slug volume injected is 0.2PV, the minimum recovery efficiency is 53.2%. On the other hand, when the AS slug volume injected is 1.0PV, the maximum recovery efficiency is 66.8%.

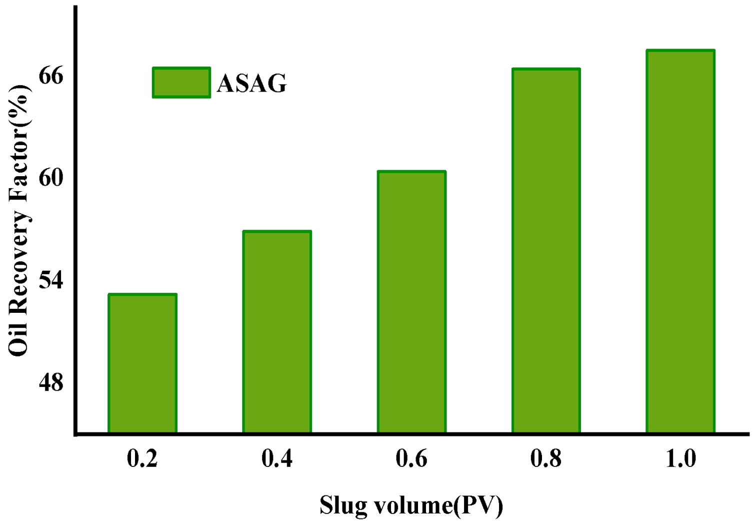


Figure 17—Comparison of recovery efficiency at different slug volumes.

From Figure 17, it can be observed that the volume of the chemical plug is positively correlated with the recovery factor. When the volume of the plug increases from 0.2PV to 1.0PV, the recovery factor increases by 13.5%. However, after the volume of the plug reaches 0.8PV, the increment in the recovery factor starts to decrease significantly, reaching a maximum increase of only 5.8% and eventually less than 1%. This indicates that a larger volume of the chemical plug is not necessarily better. Different reservoir conditions have an optimal volume for the chemical plug, and in this particular reservoir condition, the optimal volume for the AS plug is 0.8PV.

Effect of Surfactants Concentration. In alkali-surfactant (AS) flooding, surfactants play a crucial role. Surfactants can form micellar structures between crude oil and water, allowing the mixing of initially immiscible liquids. This increases the contact area between the oil and water, enhancing dispersion and interfacial activity between the two phases. Additionally, surfactants can reduce the viscosity of crude oil, making it more easily flowable. Moreover, surfactants can form a thin film within the rock pores, rendering the rock surface hydrophilic and reducing the adhesion forces. This, in turn, decreases the retention of oil in the rock pores and improves the oil recovery.

To analyze the effect of surfactant concentration on the oil recovery efficiency in ASAG flooding, this study employed three different surfactant concentration schemes: 1000 mg/L, 2000 mg/L, and 3000 mg/L. These concentrations were compared against the ultimate recovery efficiency achieved with water flooding and ASAG injection. **Figure 18** illustrates the variation in water saturation for the three surfactant concentrations.

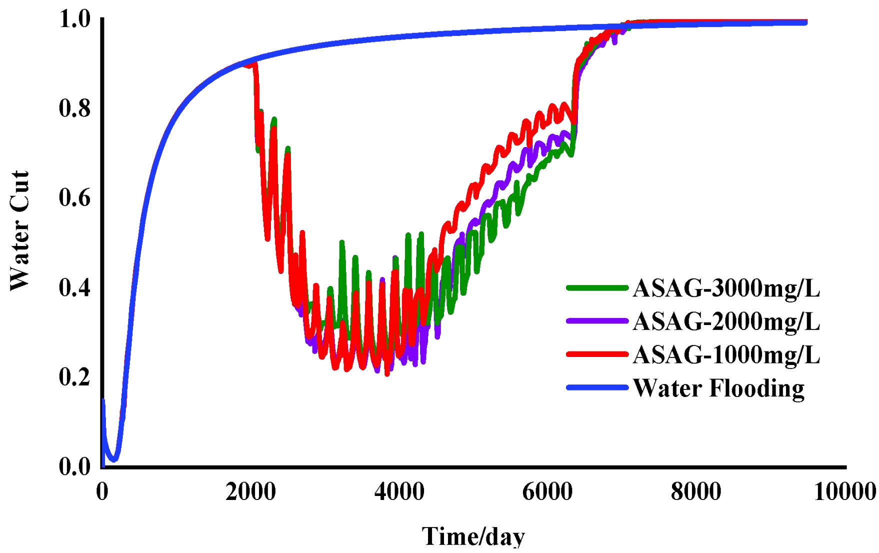


Figure 18—Comparison of water cut changes under different surfactant concentrations.

The change in the curve from the graph indicates that the addition of alkali-surfactant has significantly reduced the water content. Furthermore, different concentrations of surfactant result in varying changes in water content. As the concentration increases, the decrease in water content becomes even lower. Particularly, there is a more pronounced decrease in water content when the concentration increases from 1000 mg/L to 2000 mg/L. This is also reflected in the recovery factor, as shown in **Figure 19** for the recovery factor variation curve and summarized in **Table 6** for the recovery factor.

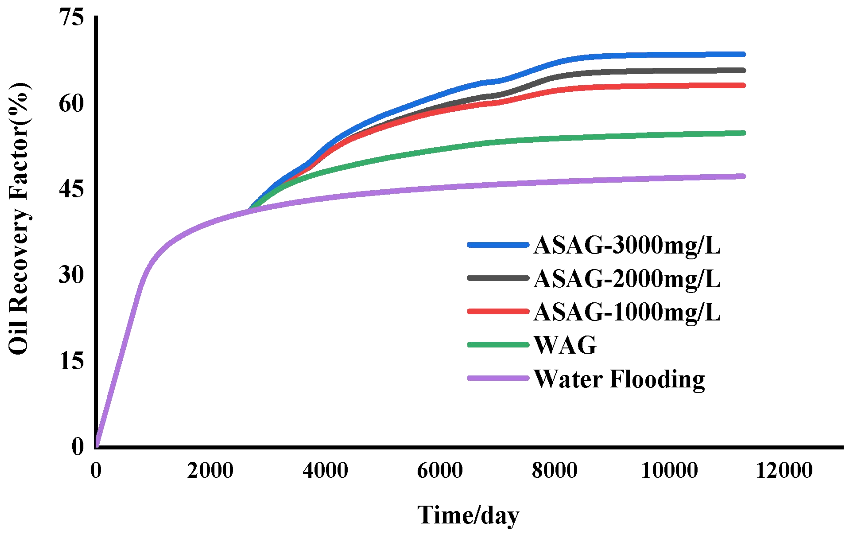


Figure 19—Comparison of recovery curve of different surfactant concentrations

Table 6—Recovery of ASAG at different surfactant concentrations

Surfactant concentrations，mg/L	1000	2000	3000
Recovery factor，%	63.1	65.9	68.6

According to Figure 19 and Table 6, it can be observed that higher concentrations of surfactants result in higher recovery rates, but the rate of increase diminishes. Increasing the surfactant concentration from 1000 mg/L to 3000 mg/L led to a 5.5% increase in recovery rate. This is because the surfactant concentration affects the interfacial tension between oil and water in the reservoir. The rate of increase in recovery rate decreases as the surfactant concentration increases, as the interfacial tension reaches an extremely low level (on the order of 10^{-3}), making further reduction difficult. When the surfactant concentration increased from 1000 mg/L to 2000 mg/L, the recovery rate increased by 2.8%; however, increasing the surfactant concentration from 2000 mg/L to 3000 mg/L only resulted in a 1.7% increase in recovery rate. This indicates that higher surfactant concentrations are not necessarily better, as they come with higher costs and can cause secondary contamination to the formation. Therefore, it is crucial to select the optimal surfactant concentration. In this reservoir's conditions, a surfactant concentration of 2000 mg/L is the most suitable choice.

Effect of Alkali Concentration. In the ASAG injection process, alkali plays a role in neutralizing acidic substances on the rock surface, thereby reducing the adhesion between the rock and the oil. In a combined flooding process, alkali serves two purposes: firstly, it neutralizes the acidic substances on the rock surface, reducing the adhesion between the rock and the oil, allowing the originally trapped oil in the rock pores to be released. Secondly, alkali enhances the effectiveness of surfactants, accelerating the flow of oil and thereby increasing oil recovery efficiency.

The synergistic effect between surfactants and alkali not only reduces the expensive usage of surfactants but also minimizes the adsorption loss of surfactants and polymers in the reservoir. Additionally, the introduction of alkali partially substitutes for surfactants, significantly lowering the cost of the combined flooding system. In summary, the substitution of alkali for surfactants can significantly improve the economic benefits and development efficiency of the combined flooding system.

In this study, four sets of alkali concentration schemes were employed, with alkali concentrations of 40,000 mg/L, 80,000 mg/L, 120,000 mg/L, and 160,000 mg/L, while keeping other parameters constant. These concentrations were compared for their ultimate oil recovery in both water flooding and ASAG injection processes. **Figure 20** shows the variation in water content at different alkali concentrations.

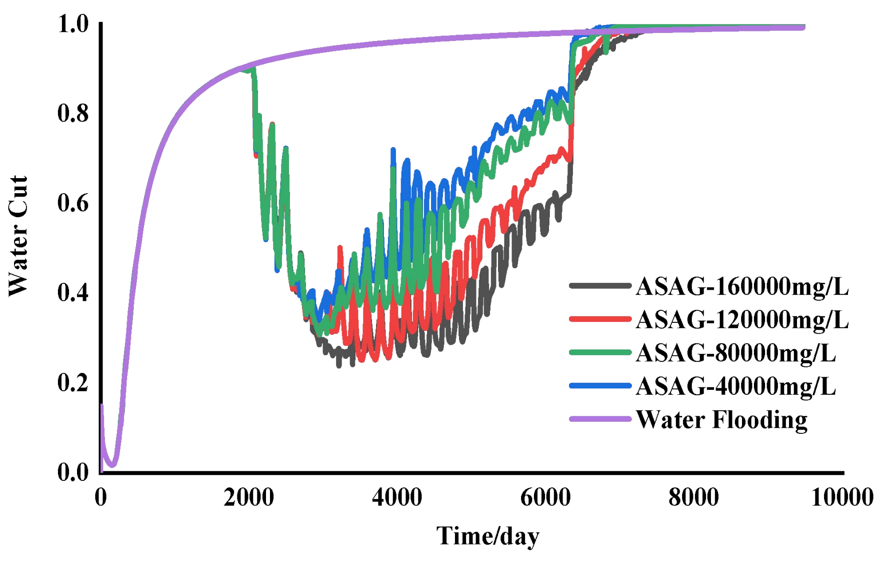


Figure 20—Comparison of water cut curves under different alkali concentrations.

The water cut curve reveals that the water cut decreases as the concentration of alkali increases. The most significant change in water cut occurs when the alkali concentration increases from 80,000 mg/L to 120,000 mg/L. As the alkali concentration continues to increase, the degree of change becomes less pronounced.

According to the recovery rate curve in **Figure 21**, it can be observed that the recovery rate continues to increase with the increase in alkali concentration. This is because alkali has two effects: on one hand, it can reduce the interfacial tension between oil and water caused by surfactants; on the other hand, it can adsorb onto the rock surface as sacrificial agent, replacing surfactants and polymers, thereby enhancing the performance of surfactants. However, as the alkali concentration continues to increase, the growth rate of the recovery rate gradually slows down. This is because it becomes increasingly difficult to further improve the recovery rate when the interfacial tension reaches an ultralow level (on the order of 10^{-3}).

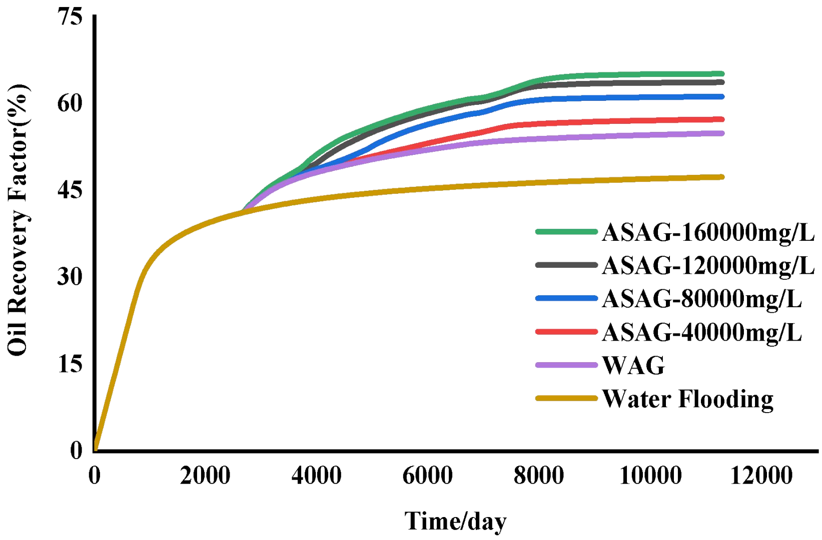


Figure 21—Comparison of recovery curves at different alkali concentrations.

Figure 22 shows the growth of the recovery rate for ASAG compared to water flooding at different alkali concentrations. At an alkali concentration of 160,000 mg/L, ASAG achieves the maximum increase in recovery rate of 17.2%; at an alkali concentration of 40,000 mg/L, the minimum increase in recovery rate is 10%. However, it can be seen from the graph that after increasing the alkali concentration to 120,000 mg/L, further increasing the alkali concentration results in a slower increase in the recovery rate. Therefore, a higher alkali concentration is not necessarily better, but there is an optimal value that maximizes the increase in recovery rate.

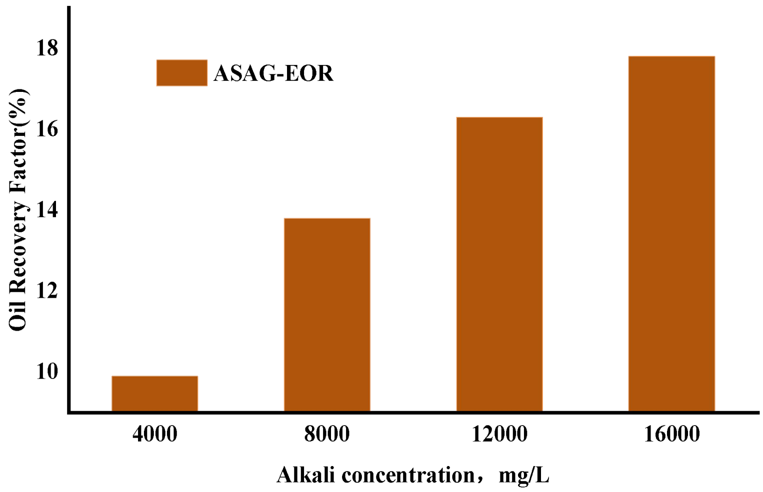


Figure 22—The increase in recovery efficiency at different alkali concentrations.

It should be noted that the use of alkali needs to be adjusted based on specific conditions, as high alkali concentration may have adverse effects on groundwater environments. Therefore, when using alkali-surfactant compound flooding in petroleum extraction, it is necessary to strictly control the dosage and concentration of alkali to ensure the safety and environmental protection of the oil extraction process.

Conclusions

This article presents a geological characterization model based on actual parameters of a low-permeability oilfield. It mainly analyzes the influencing parameters and their degrees of impact on the ASAG displacement process. The following conclusions are drawn:

1. In the ASAG process, surfactants can reduce interfacial tension and viscosity of crude oil. Surfactants can also form a thin film in the rock pores, making the rock surface hydrophilic and reducing rock surface adhesion. This leads to a decrease in the retention of crude oil in the rock pores and an increase in the recovery factor. Alkaline substances neutralize the acidic materials on the rock surface, reducing the adhesion between rock and oil, and enhancing the effectiveness of surfactants. This accelerates oil flow and increases oil recovery efficiency. The synergistic effect between surfactants and alkalis can reduce the expensive surfactant dosage and minimize surfactant adsorption losses.
2. In ASAG process, the water saturation curve rapidly declines after the addition of chemicals and can maintain a low water saturation level for a prolonged period. After ASAG is completed, the water saturation rate increases again. The daily oil production curve exhibits a peak shape, and the overall trend decreases with time. The cumulative oil production curve shows a sudden increase in production after water flooding and entering the ASAG stage. After displacement for a certain period, the oil production gradually decreases, and the cumulative oil production curve becomes flat.
3. Among the process parameters studied in this paper, the injection timing has almost no impact on the ultimate recovery factor but can change the time to reach the peak recovery factor. Injection rate, injection cycle ratio, and plunger volume all have some degree of influence on the recovery factor.
4. Chemical agent parameters are closely related to the improvement of recovery factor in ASAG. A larger chemical plunger leads to a higher recovery factor, but there is an optimal value that maximizes the recovery factor enhancement. The concentration of the chemical agent directly affects the degree of recovery, but a higher concentration is not necessarily better. There is an optimum value that maximizes the recovery factor while considering economic and environmental factors.

Conflicts of Interest

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

References

Cottin, C., Morel, D., Levitt, D.,et al. 2012. Alkali Surfactant Gas Injection: Attractive Laboratory Results under the Harsh Salinity and Temperature Conditions of Middle East Carbonates. Paper presented at the Abu Dhabi International Petroleum Exhibition & Conference Society of Petroleum Engineers, Abu Dhabi, UAE, November 11-13. SPE-161727-MS.

Cottin, C., Morel, D., Levitt, D., et al. 2013. Alkali Surfactant Gas Injection-Attractive Laboratory Results in Carbonates under Harsh Salinity And High Temperature. Paper presented IOR 2013-17th European Symposium on Improved Oil Recovery, April 11-13.

Gogoi, S.B. 2013. Carbon-dioxide for EOR in Upper Assam basin, in: M.Z. Hou, H. Xie,P. Were (Eds.), Clean Energy Systems in the Subsurface: Production, Storage and Conversion, Springer, p. 13.

Guo, H., Zitha, P.L.J., Faber, R., et al. 2012. A Novel Alkaline/Surfactant/Foam En-Hanced Oil Recovery Process, *SPE J* **17**(2):1186–1195.

Lawson, J.B. and Reisberg, J. 1980. Alternate Slug of Gas And Diute Surfactant for Mobility Control During Chemical Flooding. Paper presented at the SPE/DOE Symposium on Enhanced Oil Recovery Society of Petroleum Engineers, Tulsa, Oklahoma, April 1-4. SPE-8839-MS.

Luo, P., Zhang,Y., Huang, S. 2013. A Promising Chemical-Augmented (WAG) Process for Enhanced Heavy Oil Recovery. *Fuel* **104**:333–341.

Srivastava. M, Zhang. J, Nguyen, Q. P., et al. 2009. A Systematic Study of Alkaline-Surfactant-Gas Injection as an EOR Technique. Paper presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, October 9-12. SPE-124752-MS.

Majidaie, S., Onur, M., and Tan, I. M. 2015. An Experimental and Numerical Study of Chemically Enhanced Water Alternating Gas Injection. *Petrol. Sci.* **12**(2):470-482.

Zhu,Y., Hou, Q., Weng, R., et al. 2013. Recent Progress and Effects Analysis of Foam Flooding Field Tests in China. Paper presented at the SPE Enhanced Oil Recovery Conference, Kuala Lumpur, Malaysia, July 12-15. SPE-165211-MS.

Jong, S., Nguyen, N.M., Eberle,C.M., et al. 2016. Low Tension Gas Flooding as a Novel EOR Method: An Experimental and Theoretical Investigation. Paper presented at the SPE Improved Oil Recovery Conference. Tulsa,Oklahoma, USA, April 11-13. SPE-179559-MS.

Srivastava, M., Zhang, J., Nguyen, Q.P., et al. 2009. A Systematic Study of Alkaline-Surfactant-Gas Injection as An EOR Technique. Paper presented at the SPE Annual Technical Conference and Exhibition, October 4-7. SPE-124752-MS.

Phukan, R., Gogoi, S.B., Tiwari, P. 2019. Alkaline-surfactant-alternated-gas/CO_2 Flooding: Effects of Key Parameters. *J. Pet. Sci. Eng.* 173:547–557.

Phukan, R., Borgohain, S., Gogoi, P., et al. 2019. Optimization of Immiscible Alkaline-Surfactant-Alternated-Gas/Co Flooding in An Upper Assam Oilfield. Paper presented at the SPE Western Regional Meeting, San Jose,California, USA, April 23-26. SPE-195262-MS.

Wang, L. 2022. Production Technology of Low Permeability Oil Field. *Journal of Chemical Engineering and Equipment* **9**(1):23-35.

Qianqian Shi, is a master candidate in Petroleum Engineering department at Xi’an Shiyou University. She has focused her research in areas involving reservoir simulation, chemical flooding, and enhanced oil recovery.

Weirong Li, is a Professor in the Petroleum Engineering Department at Xi’an Shiyou University. His research interests include unconventional resources/reserves estimates, reservoir simulation, well testing, and production analysis. Li holds a bachelor’s degree in mathematics from Northeast Petroleum University, China; a master’s degree in petroleum engineering from Research Institute of Petroleum Exploration and Development, China; and a PhD degree in petroleum engineering from Texas A&M University.

Shihao Qian, is a master candidate in Petroleum Engineering department at Xi’an Shiyou University. He has focused his research in areas involving reservoir simulation, well testing, and production analysis. He holds a BS degree in Petroleum Engineering from Xi’an Shiyou University.

Xin Wei, is a master candidate in Petroleum Engineering department at Xi’an Shiyou University. He has focused her research in areas involving reservoir simulation, chemical flooding, and enhanced oil recovery.

Tianyang Zhang, is a master candidate in Petroleum Engineering department at Xi’an Shiyou University. He has focused his research in areas involving reservoir simulation, well testing, and production analysis.

Xu Pan, is a master candidate in Petroleum Engineering department at Xi’an Shiyou University. He has focused her research in areas involving reservoir simulation, chemical flooding, and enhanced oil recovery.