https://doi.org/10.29227/IM-2025-01-02-047 Received: 30 Oct 2024, Accepted: 01 May 2025, Published: 01 Sep 2025

Alkali-surfactant-polymer injection for enhanced oil recovery: from optimal chemical formulation experiments to coring simulation

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Abstract: *Chemical Enhanced Oil Recovery (CEOR) has gained significant attention, wherein the use of alkaline surfactant polymer (ASP) solutions has proven to be effective. The generation of a middle-phase microemulsion between the ASP solution and oil is key factor for the success of the flooding process in which exhibits ultralow interfacial tensions, thereby contribute increased the recovery efficiency. Prior research has emphasized the importance of the middle-phase microemulsion in the CEOR process. Additionally, experimental designs and response surface methodologies have been commonly employed to analyze multiple variables and their interactions, thereby facilitating the determination of the optimal concentration of components in an ASP solution for the highest quality microemulsion phase. These methodologies have proven to be effective in navigating the complexities of the ASP system and ensuring the attainment of favorable outcomes. In this article, an experimental design and response surface method employed to accurately determine the optimum concentration of surfactants in an ASP solution required to achieve the best quality of the microemulsion phase. Subsequently, the determined optimal ASP formulation was applied in core flooding tests to evaluate its efficiency in an actual reservoir condition such as salinity and temperature to ensure the reliability and comparability of the results. Ten sandstone cores were utilized to evaluate the impact of varying injection volumes on the recovery factor during ASP flooding. The study identified the optimal concentration of surfactants and the highest effective injection volume was determined. These findings underscore the significance of accurately determining the ASP formulation and injection volume for successful CEOR operations. The study's outcomes contribute implications for the optimization of ASP flooding processes in the enhanced oil recovery. Furthermore, the study opens avenues for future research aimed at refining ASP flooding techniques.*

Keywords: *ASP injection; optimal concentration; apropriate volume; coring simulation; reservoir condition; enhanced oil recovery.*

1. Introduction

In the context of the growing global demand for energy to support socio-economic development, as renewable and green energy sources are still in the early stages of development, the study and optimization of oil and gas extraction have driven advancements in enhanced oil recovery techniques. Among these techniques, chemical enhanced oil recovery, especially the use of Alkaline–Surfactant–Polymer (ASP) mixtures, stands out due to its strong advantages in altering the wetting characteristics of reservoir rocks and its sweeping efficiency. This approach promises continued extraction in fields where traditional methods have become less effective. However, the application of chemicals in general, and ASP in particular, still requires further research before widespread implementation.

In fact, while there have been many studies on ASP and its applications, most research accessed by the author focuses on individual aspects, such as the chemical properties in relation to rock or oil frameworks, simulation results, chemical interactions, or application results. However, a systematic approach to optimize chemical components for achieving ultra-low interfacial tension and high solubilization ratios is lacking. The complex interactions between surfactants and their combined effects on oil recovery have yet to be systematized and visualized. Moreover, the application of Design of Experiment (DOE), a useful tool for systematically assessing the effectiveness and interactions of chemicals to determine the optimal ASP formulation, remains under-researched in application studies.

Furthermore, research on ASP has often been conducted in isolation on specific topics, such as the mechanism of chemical interactions, impact on rock frameworks, core flooding experiments, simulation modeling, field trials, or data gathering from studies with inconsistent input parameters. A standardized procedure is lacking to ensure effective, reliable implementation.

Urgency Faced with the challenge of increasing energy demand, the oil industry continually strives to boost extraction output. Moreover, discovering new fields is becoming increasingly difficult, and most traditional oil fields are already in secondary recovery phases. However, many reservoirs still have high residual oil saturation, making the study and application of enhanced oil recovery methods, especially ASP chemical mixtures, a promising approach to increase recovery rates and save significantly on costs compared to exploring new fields.

Based on experimental research results, the study involves formulating an optimal chemical combination, conducting core flooding experiments, and using simulation models to evaluate the interactions of chemical components on core oil recovery factors.

2. Overview of Enhanced Oil Recovery (EOR) and Chemical EOR

Enhanced Oil Recovery (EOR):

In the oil and gas industry, EOR is applied to alter the physical and chemical properties of reservoir oil or rock or to improve the sweep efficiency of injected fluids. EOR methods are categorized based on various perspectives and developments in oil recovery technology and techniques. EOR can essentially be divided into the following groups: Immiscible Injection Methods, Miscible Injection, Thermal Methods, Chemical Injection, Other Methods.

Chemical Enhanced Oil Recovery

Since the 1960s, research on chemicals such as alkaline, surfactants, and polymers (ASP) has shown high efficacy in enhancing oil recovery. Then in the early 21st century, this method has been widely implemented, including in Vietnam, thanks to technological advances and rising oil prices. The development of artificial intelligence, bio-chemicals, and nanotechnology promises to further improve oil recovery in the future. Chemical EOR includes polymer injection, alkaline injection, surfactant injection, and ASP combination injections to enhance the effects of the injected chemical slug.

Literature review of Chemical EOR

Globally

The use of chemical injection combinations to improve oil recovery was studied early on, beginning in the 1960s. For example, Scott added an alkaline solution (sodium hydroxide - NaOH) to injection water [1]. Laboratory studies on alkaline injection by Campbell [2] and Johnson [3] aimed to better understand the effects of alkali on oil recovery rates. These studies demonstrated that in-situ soap formation in the oil reservoir environment, resulting from the interaction of alkali and acidic compounds in crude oil, increased oil recovery. Hill [4] proposed surfactant solutions as an auxiliary phase to enhance oil recovery. Later studies highlighted the role of in-situ saponification in reducing interfacial tension (IFT) and extending the range of optimal salinity for microemulsion formation [5, 6]. Polymer has been used to control the mobility of injected fluids since the 1970s, as pioneered by Chauveteau [7] and Norton [8]. These studies laid the foundation for ASP injection processes in enhanced oil recovery. A notable ASP field study was reported in 1993 on the West Kiehl Field by Clark [9], which showed a 15% increase in recovery factor over the total original oil in place (OOIP).

Today, ASP injections have successfully improved oil recovery rates in fields worldwide, achieving recovery improvements from 15% to 33% in West Kiehl Field [9], Daqing oil field [10],[11], Cambridge Minnelusa Field [12], Karamay oil field [13], Tanner Field [14], and West Salym [15], as well as in pilot tests in Bridgeport sandstones, Illinois [16]. When the microemulsion reaches equilibrium, the interfacial tension achieves low values around 10^{-3} mN/m, which can be estimated using the Huh equation [17]. Sahni [18] and Fortenberry [19] presented that the inclusion of organic cosolvents in ASP mixtures enhances microemulsion quality and provides phase equilibrium control. Stoll [20] experimented with salinity optimization by adjusting Na_2CO_3 concentration in the ASP mixture. Na_2CO_3 plays a role by interacting with crude oil acids to form surfactants under reservoir conditions. These in-situ surfactants are absorbed instead of the designed surfactants initially included in the ASP mixture [21].

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Domestically

Chemical EOR research is recognized as essential, with joint studies initiated by Vietsovpetro (VSP) and the Vietnam Petroleum Institute (VPI) on the Tê Giác Trắng (TGT) oil field since the early 2010s. A mid-term report in 2013 on EOR screening for the TGT field, with sandstone formations at a depth of 10,000 feet and reservoir temperature of 120°C, showed that chemical injection was the most effective method. In this project, VPI successfully designed and manufactured equipment to produce 100 tons of the VPI SP chemical to enhance oil recovery, with a capacity of 4 tons/day for industrial testing and evaluation [22], achieving an estimated recovery increase of 1.5%–2% OOIP. The project yielded 2,700 tons of oil over six months of application.

In 2022, Đinh Đức Huy applied a pilot project with a surfactant-polymer combination for enhanced recovery in the Lower Miocene of the White Tiger (Bạch Hổ) field [23]. After injecting 100 tons of ASP into the Lower Miocene over six months, the project increased oil production by 2,700 tons.

Although several studies suggest some chemical combinations effectively interact with oil to form microemulsions, they do not confirm these combinations as optimal formulations. Experimental studies also lack standard procedures. Additionally, the published injection volume values do not indicate how increased or decreased injection affects oil recovery. For these reasons, the author proposes a research procedure to determine the optimal chemical formulation and injection volume for each case.

As mentioned, chemical injection is much more effective than other enhanced recovery methods for medium-viscosity oils, so chemical EOR is increasingly widely applied (Figure 1). However, chemical screening must be carefully conducted to ensure compatibility with geological conditions and oil characteristics, avoiding issues such as precipitation, deposition, and minimizing chemical adsorption on the rock surface.

Application of Design of Experiments (DoE) to identify optimal chemical formulation

Design of Experiments (DoE) is a scientific method aimed at optimizing and understanding the relationship between input factors and outcomes. Through structured experimental planning, DoE identifies critical factors, optimizes processes, and improves efficiency.

Response Surface Methodology (RSM): Box and Wilson proposed using a second-order polynomial model [48] to explore component factors and locate optimal points through extreme values in the response surface. Box-Behnken Design: Each component is tested at three equidistant levels (low, medium, high), with systematic changes ensuring that experiments cover the concentration range of interest.

Application of experimental design in chemical formulation optimization The experimental design (DoE) is a scientific approach that helps optimize experimental processes by identifying and controlling influential factors. In enhanced oil recovery (EOR) using chemicals, DoE aids in determining the optimal formulation, improving extraction efficiency, and reducing trial-and-error costs and time.

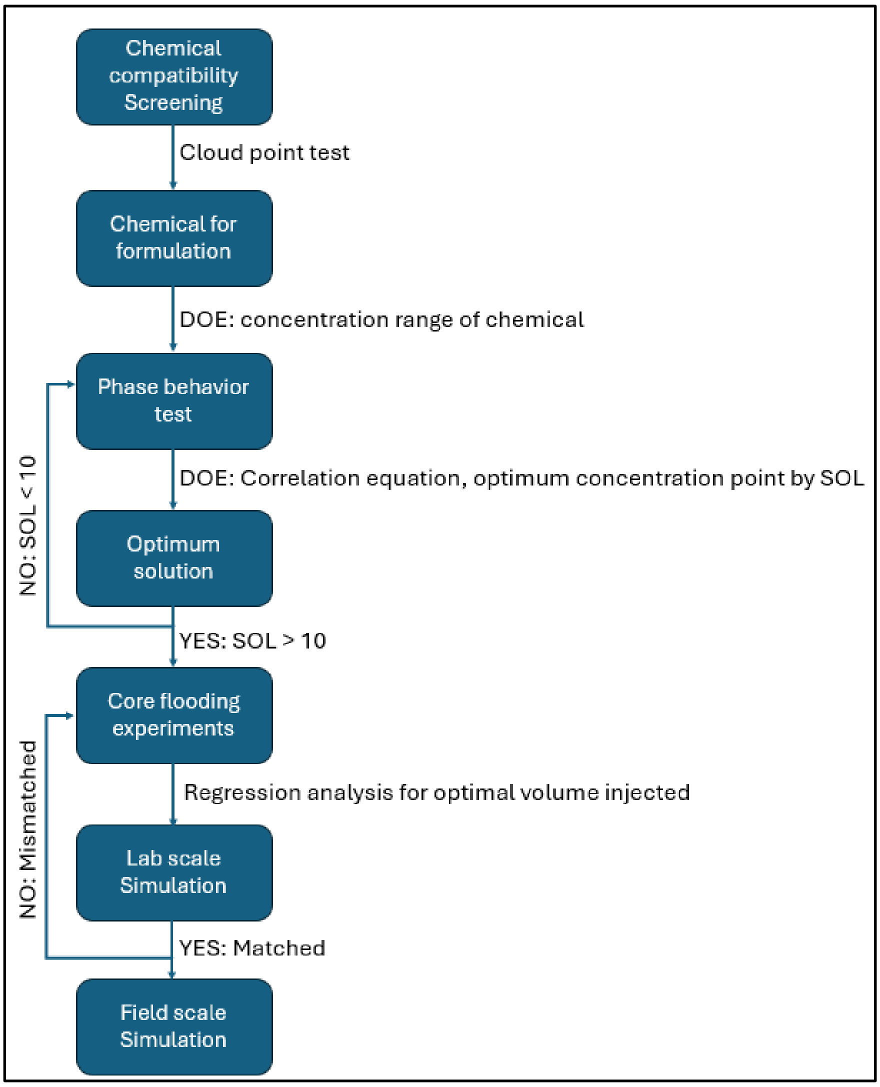

Fig. 1. Experimental-Simulation Process for Chemical Flooding

Chemicals used in formulation: Main surfactant, auxiliary surfactant, polymer, alkali solution, and solvent.

Determining effective injection volume: Injection volume plays a crucial role in the efficient and economical use of chemicals in oil recovery. Experiments on artificial Berea sandstone cores investigate the effects of the optimal chemical formulation and injection volume. Variables such as pressure, flow rate, breakthrough time, and oil recovery rate are analyzed. Simulation results align with laboratory core tests on Berea sandstone, validating larger-scale application potential.

3. Methodology

As previously discussed, an important method for optimizing the ASP chemical formula and injection volume is Response Surface Methodology (RSM), which allows identification of relationships between input factors and outcomes and also finds optimal values for variables like concentration, mix ratio, or component composition. Based on experimental injection results on Berea sandstone cores, determining the effective ASP injection volume contributes to optimizing the enhanced oil recovery process.

Steps in Effective Injection Research

1. **Literature Review:** Gathering existing studies on ASP chemical flooding EOR.
2. **Experimental Design:** Using statistical tools to establish correlations between chemicals and outcomes to determine the optimal values of each component.
3. **Chemical Stability Testing:** Ensuring the optimal formula retains properties and effectiveness in real-world conditions.
4. **Core Flooding Testing:** Conducting injection tests on Berea sandstone cores to evaluate the effectiveness of the optimal chemical formulation and injection volume.

5. **Simulation Modeling:** Developing a digital model to replicate core flooding processes, assessing the technical and economic performance of the optimal chemical formula and injection volume through simulation analysis.

The combined research methods allow the identification of optimal ASP formulations and injection volumes, ensuring stability and efficiency in enhanced oil recovery applications.

New findings of the study: Systematic Screening and Preliminary Chemical Selection, Phase Behavior Testing to Assess Chemical Interactions with Oil, Injection Testing and Core Simulation to Confirm Experimental Results.

In summary, the injection tests on Berea sandstone cores establish a detailed and comprehensive framework for evaluating, optimizing, and applying chemical flooding for enhanced oil recovery.

Characteristics of Berea sandstone cores

Berea sandstone core (Figure 2) is a sedimentary rock with highly uniform grain size, primarily composed of quartz sand cemented by silica. With porosity ranging from 18-22% and permeability between 100mD and 2500mD, Berea sandstone cores serve as ideal research samples in petroleum studies for evaluating reservoir properties, fluids, and enhanced oil recovery methods.

Fig. 2. Berea Sandstone™ petrleum cores

Similarity with M oilfield characteristics: The Berea sandstone core and reservoir rock in the M oilfield share similar lithological compositions, primarily sandstone. Petrophysics characteristics such as porosity and permeability of Berea sandstone closely match those of the reservoir of M oilfield, with approximately 18% porosity and 250 mD permeability. Oil used in the experiments is sourced from the M field with a density of approximately 42° API, closely reflecting the interaction of the chemical system with reservoir fluids.

4. Results and Discussion

Process of determining the optimal ASP chemical formulation

This study focuses on designing a process and identifying an optimal ASP (Alkaline-Surfactant-Polymer) chemical formulation for enhanced oil recovery (EOR). The research process includes a comprehensive literature review and investigation of previous studies to understand existing formulations and methods, identifying gaps, and proposing new improvements.

Identification of Optimal Chemical Formula and Injection Volume

Preliminary Screening of Chemicals Using the Box-Behnken Design

Surfactants: The preliminary screening experiment assessed the stability of each chemical component at varying salinity levels (Table 1). Only formulations achieving high solubilization ratios were considered for further testing. Results indicated that combinations of LAS and DOSS provided high solubilization ratios at elevated salinities (experiments 1, 7, 8, 13, 14). LAS outperformed DOSS in terms of solubilization ratio in individual tests.

Formulations containing LAS and DOSS achieved solubilization ratios greater than 10 over a broad range of salinities. The selected surfactants, C11-13 Linear-Alkyl-benzene-sulfonate and DiOctyl-Sulfosuccinate, exhibited high solubilization ratios (up to 16) under conditions compatible with reservoir water salinity (approximately 6,600 ppm). These formulations were chosen for further testing as input data for RSM calculations.

Tab. 1. Preliminary Screening Test for Chemical Stability Across Salinity Levels

https://doi.org/10.29227/IM-2025-01-02-047 Received: 30 Oct 2024, Accepted: 01 May 2025, Published: 01 Sep 2025

Experiment No.	Alkali (%)	Surfactants (%)	Solvent	TDS range	Solubilization Ratio
1	Na_2CO_3 1.0%	LAS (0.2%) $CE(EO_{20})SO_3$ (0.02%) DOSS (0.4%)	IBA 1.0%	0.2% - 1.2%	10.6 at 0.4%
6	Na_2CO_3 0.25%	LAS (0.5%) DOSS (0.32%)	DEGBE 1%	0.5 - 5%	12.5 at 2%
7	Na_2CO_3 0.5%	LAS (1.0%)	DEGBE 1%	0.5 -7%	> 13 at 4.5%
8	Na_2CO_3 2%	LAS (1.0%)	DEGBE 2%	0.5 -5%	> 13 at 3.5%
10	Na_2CO_3 1%	LAS (0.2%) DOSS (0.4%) TMN 6 (0.2%)	TEGBE 1.5%	0.2 – 1.6%	> 8.5 at 0.9%
13	Na_2CO_3 1.0%	LAS (0.2%) $CE(EO_{20})SO_3$ (0.02%) DOSS (0.4%)	TEGBE 1%	0.2 – 1.2%	> 11.3 at 0.6%
14	Na_2CO_3 4%	LAS (1.0%)	DEGBE 2%	0.5 - 5%	> 13 at 2.5%
15…	NaOH 0.05%	KORE FN-10 (0.15%) TMN 6 (0.04%) LAS (0.2%) DOSS (0.44%)	TEGBE 0.5%	0.2 – 2%	> 7.8 at 1.6%

The optimal ASP formulation with LAS and DOSS will proceed to further experimentation for response surface modeling (RSM) to refine concentration levels for enhanced oil recovery applications.

Polymer: Experimental results indicate that HPAM (hydrolyzed polyacrylamide), when evaluated under reservoir conditions and enhanced with heat-resistant additives to reduce rock adsorption, can be effectively applied for improving the recovery factor in the lower Miocene reservoir at field M. Viscosity measurements of the polymer at different temperatures, concentrations, and aging times are shown in Figures 3 and 4. Based on these results, HPAM was selected for further testing in the Box-Behnken design.

Alkaline/Alkali Solution: Based on previous studies, sodium carbonate (Na_2CO_3) was selected as the alkaline component for the ASP formulation.

Solvent: Three solvents were evaluated for compatibility with the target extraction conditions: **DEGBE**: Diethylene glycol butyl ether or 2-(2-Butoxyethoxy); **TEGBE**: Triethylene glycol monobutyl ether or 2-(2-(2-butoxyethoxy) ethoxy) ethanol; **IBA**: Indole-3-butyric acid.

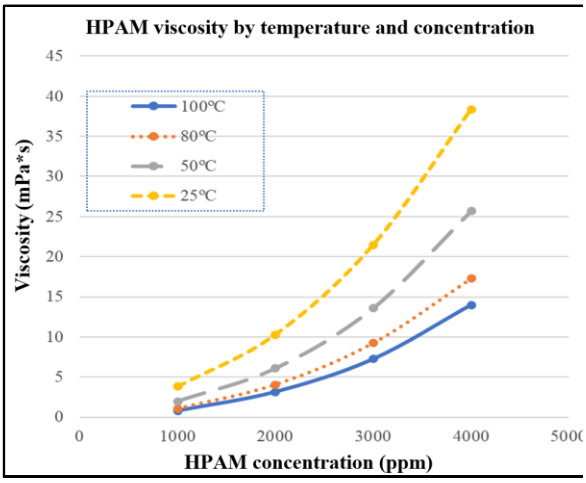

Fig. 3. HPAM viscosity as a function of temperature and concentration

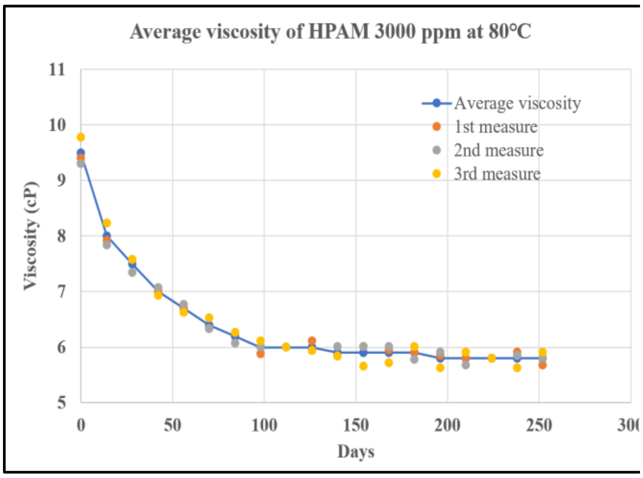

Fig. 4. Viscosity of 3000 ppm HPAM measured over aging time

The solvents were screened by testing their stability when mixed with 4% LAS (2% by weight). Screening results indicated that TEGBE was most compatible, achieving stability at the highest NaCl concentration (~4%), as shown in **Table 2**.

Tab. 2. Screening Results for Solvent Selection

Surfactant wt.%	Solvent wt.%	Stable System Limit (% NaCl)
LAS 2.0	IBA 4.0	~ 2.0
LAS 2.0	DGBE 4.0	~ 3.0
LAS 2.0	**TEGBE 4.0**	**~ 4.0**

Experimental design using the Box-Behnken model

With five components - surfactant 1 (LAS), surfactant 2 (DOSS), solvent (TEGBE), alkali (Na_2CO_3), and NaCl for salinity - each at three concentration levels, the Box-Behnken model proposed 46 experiments to analyze correlations between these chemicals and solubilization ratio (Table 3).

Tab. 3. Boundary Values of Factors in Box-Behnken Experimental Design

Elements	Concentration Boundaries		
	Low (wt.%)	Intermediate wt.%)	High (wt.%)
LAS	0	0.15	0.3
DOSS	0	0.15	0.3
TEGBE	0.5	2.75	5.0
Na_2CO_3	0.5	1.25	2
NaCl	0.2	1.1	2

The Box-Behnken design was implemented at three concentration levels for each of the five components, as specified in **Table 4**.

Tab. 4. Experimental Concentration Limits for Chemical Components

No.	Component	Concentration Range		
		Low	Intermediate	High
1	LAS	0	0.15	0.3
2	DOS	0	0.15	0.3
3	Na_2CO_3	0.5	1.25	2.0
4	TEGBE	0.5	2.75	5.0

5	NaCl	0.2	1.1	2.0

Determination of Effective Injection Volume for ASP Mixture

The first noteworthy point, cores with relatively uniform properties (k and ϕ) were used to establish a baseline for ASP flooding performance under controlled conditions, allowing focus on optimizing the ASP formulation and injection volumes. Ongoing research emphasizes the effects of mineral composition, shale type, and heterogeneity levels on injection efficiency and recovery factors.

The study also focused on determining the effective injection volume of the ASP mixture through experimental core flooding tests on Berea sandstone cores. Starting with core flooding experiments under similar conditions to the simulation model, the results were then used to establish the optimal injection volume of the chemical mixture.

Experiment on flooding Berea sandstone cores and verifying chemical formulations

Preparation of Core Samples: All core samples used in the injection experiment are Berea sandstone cores with general information presented in Table 5. All cores were treated uniformly through cutting, drying, water saturation, oil saturation, and water injection. The process for injecting the ASP chemical was followed according to the established procedure. Each sample was injected with a volume as per the design to evaluate the impact of the injection volume and recovery factor. A polymer plug was chosen to fix at 5% of the pore volume to minimize the influence of the polymer on the overall recovery factor. Synthetic seawater was injected following the polymer plug until no oil was observed.

Tab. 5. General information on core samples used in the injection experiment

Parameter	Value	Unit
Permeability	250	mD
Length	30.3	cm
Diameter	3.78	cm
Bulk volume	340	cm^3
Porosity	14.68÷16.1	%
Initial Oil Saturation	72÷78	%
Average oil saturation after water injection	55	%

Flooding procedure for core samples: The detailed procedure for the experiment on the core samples, with the petrophysics parameters (Table 6), is presented in Figure 5 to study the impact of chemical injection in a porous medium.

Tab. 6. Petrophysics parameters of the core samples

Parameter	Value
Average Pore Volume (cm^3)	49.89
Oil Volume (cm^3)	37
Cross-sectional Area (cm^2)	11.22

Simulation of flooding experiment conditions

Simulating initial water saturation: The Berea core was injected with synthetic seawater with the same salinity as the optimal salinity for the ASP formulation, which is approximately 0.66%. Simulating initial oil saturation: Crude oil was injected into the water-saturated core samples until stable pressure was achieved, and no more water was observed at the outlet. Simulating water injection phase: Water injection was performed using synthetic seawater with a salinity equivalent to that of the reservoir water. Synthetic seawater was injected at a rate of 10-15 ft/day, simulating actual water injection.

ASP Injection Procedure

Following the water injection phase was the ASP injection phase (Figure 5). The ASP combined formulation is one that has been optimized as stated. A total of 10 experiments were conducted with core samples, with ASP volumes varying from 0.025 PV to 1.75 PV. Following the ASP plug, a polymer plug with a volume of 0.05 PV was injected. The size of the polymer plug was chosen to be small enough to eliminate its influence on the final recovery factor. It is assumed that the recovered oil was solely produced by the water injection and ASP injection processes. The sample was positioned vertically, and the ASP and polymer plugs were injected from the bottom upward to minimize the effect of gravity.

All chemicals were injected at a flow rate of 0.24 cc/min (equivalent to 1 ft/day) until no oil was observed at the outlet. The times when oil appeared and the duration of the emulsion appearance at the outlet were carefully recorded. The emulsion breakthrough time at the outlet of the sample corresponds to the moment the first oil droplets appear. Once the designed volume of ASP was fully injected, the solution plug was injected immediately afterward.

After approximately 3-5 days of retention, the crude oil separated from the emulsion and water phase. The amount of oil obtained after this process is considered the total amount of oil recovered from the core sample.

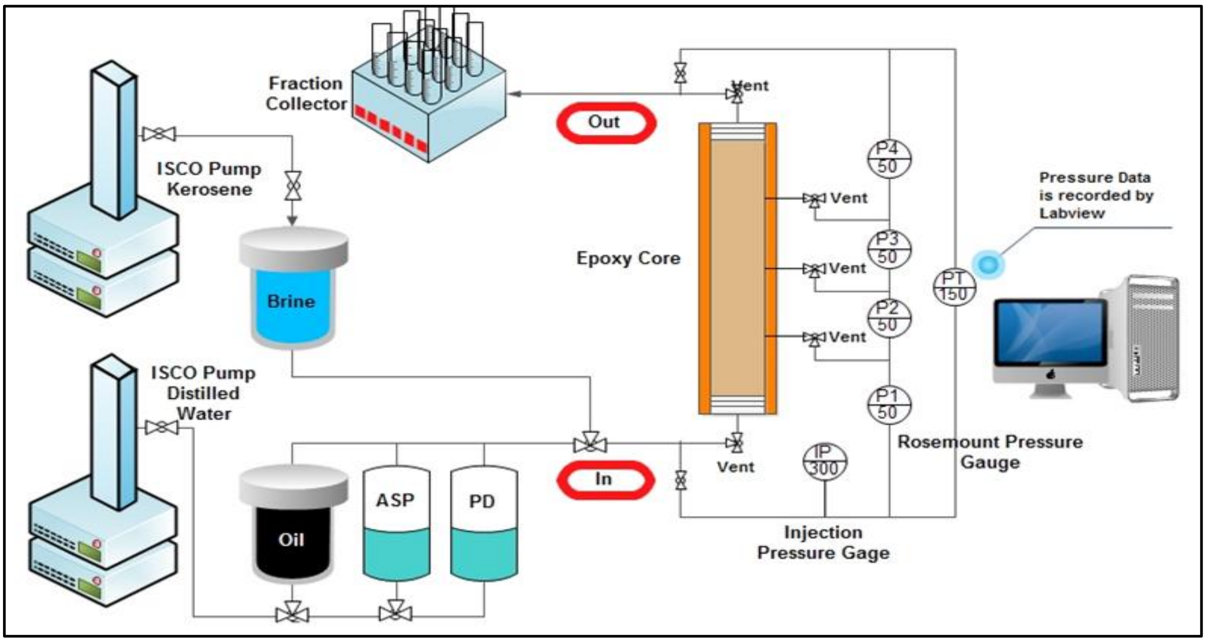

Fig. 5. Diagram of the ASP injection experiment on core samples

The optimized ASP solution was prepared and injected into all 10 core samples (Table 7). The total concentration of surfactants in the ASP plug is 0.57% (LAS: DOS ratio = 0.30: 0.27). The concentrations of the solvent, alkali, salinity, and polymer are 0.85% $Na2CO3$, 1% TEGBE, 0.82% NaCl, and 0.3% HPAM Alcoflood 995.

Tab. 7. Injection volumes of designed chemical plugs

Core Sample	%PV of ASP Plug	%PV of Polymer Plug	%PV of Displacing Water	Total % PV Injected
Core 1	4,3	5	190,7	200
Core 2	8,5	5	186,5	200
Core 3	17	5	178	200
Core 4	25	5	170	200
Core 5	34	5	161	200
Core 6	50	5	145	200
Core 7	85	5	110	200
Core 8	120	5	75	200
Core 9	154	5	41	200
Core 10	170	5	25	200

The percentage volume of the injected ASP plug (in red) shows increasing values for each core sample. The percentage volume of the polymer plug (in blue) remains constant across all core samples

https://doi.org/10.29227/IM-2025-01-02-047 *Received: 30 Oct 2024, Accepted: 01 May 2025, Published: 01 Sep 2025*

(Figure 6). Based on the injection results (Table 8), a trendline will be established to enhance the reliability of the experimental process.

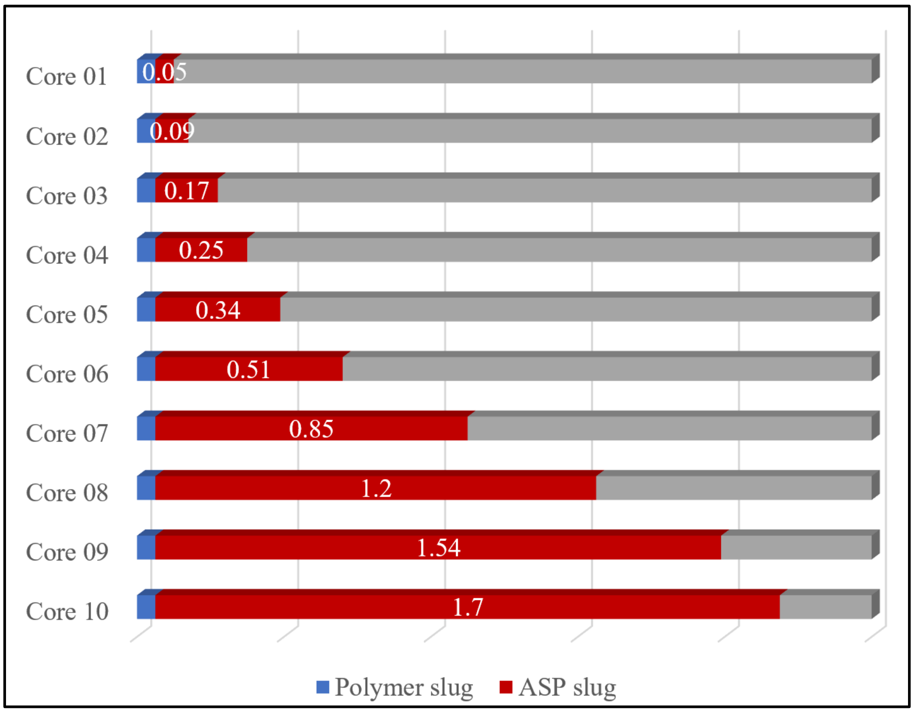

Fig. 6. Percentage volume of ASP and Polymer injection design

Tab. 8. ASP injection results

No	**Volume of ASP (%PV)**	**Overall Oil Recovery Factor (%OOIP)**	**Incremental Recovery Factor (%OOIP)**
Core 1	4,3	52.00	7.50
Core 2	8,5	64.86	20.36
Core 3	17	82.73	38.23
Core 4	25	87.01	42.51
Core 5	34	88.38	43.88
Core 6	50	88.73	44.23
Core 7	85	89.87	45.37
Core 8	120	90.79	46.29
Core 9	154	91.32	46.82
Core 10	170	91.67	47.17

Effective injection volume of ASP From the results of the core sample injection_ based on the type of curve in the form of a function of PV, the correlation between the recovery factor and the injected volume of ASP was identified (Figure 7). The curve was divided into linear regions to observe and assess the impact of the injected volume on the recovery factor. A linear regression method was used to establish trendlines for each section. The effective injection volume was determined by analyzing the intersection points of the trendlines.

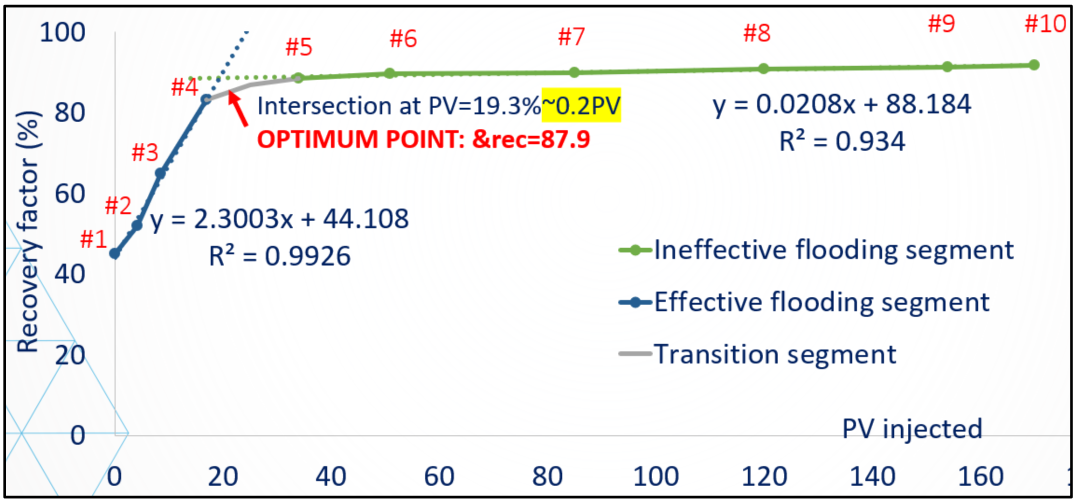

Fig. 7. Correlation between recovery factor and injected ASP volume

The recovery factor increases significantly up to about 85% as the volume of ASP injected rises from 4.3% PV to 17% PV. After that, even with an increase in ASP injection volume up to 175% PV, the increase in the recovery factor is negligible. The total additional recovery when increasing from 17% PV to 175% PV is approximately less than 5% of the total oil.

The recovery factor curve is divided into three segments. The first segment ranges from 0 PV to 17% PV, representing the effective injection phase. In this segment, the trendline was constructed using the least squares method to model the relationship between the recovery factor and the injected volume according to Equation 1, with a slope of 2.3. This result indicates that when the designed injection plugs from Table 8 are completed, the oil recovery factor increases by 2.3% for each additional 1% PV of chemical volume injected into the core sample.

$$Rf_1 = 2{,}3003PV + 44{,}108 \tag{1}$$

The second segment is selected from 17% PV to 34% PV, representing a transitional area.

The third segment starts from the ASP injection volume at 34% PV and above, indicating an ineffective injection phase, with a slope of 0.0208 (Equation 2). It is evident that during this phase, an additional 1% PV increase in the ASP plug results in an increase in the oil recovery factor of approximately 0.021%.

$$Rf_2 = 0{,}0208PV + 88{,}184 \tag{2}$$

The analysis results from the trendlines (Figure 7) show that the volume of ASP of interest will be quantified in the transitional phase by the intersection point of the two trendlines. From Equations (1) and (2), the calculated effective injection volume is:

$$PV_{eff} = 19.33$$

The additional recovery factor when injecting ASP at a volume of 19.33% PV reaches an optimal value of around 85%.

Segments 1 and 3 show significant differences in the correlation between additional injected ASP volume and the achieved oil recovery factor. The efficiency ratio of the ASP volume varies by approximately 100 times. This result confirms that injecting ASP into the core sample at volumes greater than 34% PV is unnecessary or yields negligible effects. Conversely, the value of the injection volume needed to balance with the oil recovery factor lies outside the range of 17% PV, within the transitional area -Segment 2.

The product of the injection volume and the total concentration of surfactants PV×CPV can be used to calculate the total surfactant used. The average injection volume in most pilot fields in China reaches 41.8% PV with a total surfactant concentration of approximately 0.28%. The results of this study yield PV×C=19.33×0.57=11.02PV, lower than the figures from ASP pilot projects in China, approximately 11.7%. This is also a noteworthy point in the study results. The total amount of chemicals in this study is about 7% lower than previously published results.

Verification of ASP injection results by simulation on a simple model

Characteristic parameters of the coring model

The simulation model was constructed based on the parameters of the core sample (Table 9). The sample was designed in 3D to observe changes in oil saturation during the injection process along and across the surface of the sample. Cheremisin and colleagues also demonstrated that conducting simulations on models with cross-sections of 1x1, 5x5, 15x15, and 30x30 did not show significant differences during the injection process and did not change the final oil recovery factor. Accordingly, a 3x3 cross-section model was chosen to observe the influence of gravitational differentiation on water/oil during the injection process as well as a preliminary view of oil/water displacement throughout the movement.

The input parameters of the numerical core model were derived from the values of the core sample used in the injection experiment. The numerical core model was established in a 3D format (24 blocks horizontally, 3 blocks vertically, and 3 blocks in width, Figure 8), allowing observation of the effects of the ASP solution and sweep efficiency at all injection positions. The permeability, porosity, and initial conditions were established similarly to the parameters of the core sample in the actual experiment.

Tab. 9. Parameters of the core sample in the simulation model

Parameter	**Value**
Number of grid cells	24×3×3
Grid cell size (cm)	x: 1.54, 22×1.24 × 1.54 y: 3×1.12 z: 3×1.12
Porosity (%)	0.18
Permeability (mD)	250
Bulk rock volume (cm^3)	340
Pore volume (cm^3)	49.89
Oil volume (cm^3)	37
Cross-sectional area (cm^2)	11.22
Sample length (cm)	30.3

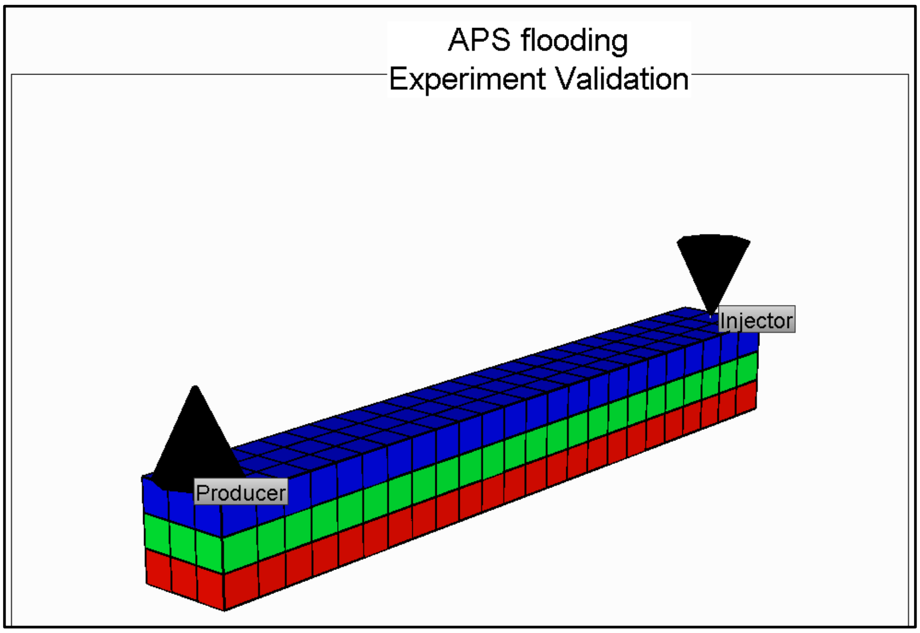

Fig. 8. 3D Simulation model of core according to experiment

Oil Simulation Parameters: The characteristic parameters of the oil used in the injection experiment are as follows: API gravity of 42, viscosity measured at 25°C is 1.4 cP at a shear rate of 10 s^{-1}, and oil saturation is 70% (Table 10).

Tab. 10. Oil Parameters and Initial Conditions

Parameter	Value	Note
API Density	42	
Viscosity (cP)	1.4	At $10s^{-1}$ and 25°C
Oil Saturation	70%	

Simulation of the injection solution on the coring model

The ASP solution was prepared with an alkali concentration of 0.84%. The viscosity of both the ASP solution and the polymer plug is 9.5 cP [92]. The chemical plug was injected at a flow rate of 0.24 cc/min, equivalent to a velocity of 1 ft/day [8]. The results of the ASP injection process show a significant change in oil saturation after each injection stage (Figure 9). In the initial state (Figure 9a), the model sample was oil-saturated, with the initial oil saturation set to the same value as in the core sample injection experiment, Soi = 70%. After water injection (Figure 9b), the oil saturation decreased to between 20% and 30% towards the injection well. However, at the production well, the oil saturation remained at around 60%. The oil distribution along the core model also became dispersed. Water moved further towards the production well in the lower layer, while oil remained in the upper grid cells near the injection well, possibly due to gravitational differentiation effects.

Following the water injection, 20% PV ASP and 5% PV polymer were injected. The difference between the two images is not substantial. A notable point here is the effectiveness of the sweeping process. The oil saturation in the chemically injected area dropped below 10%, and the color indicating oil saturation became uniform, unlike after the water injection process. Clearly, the effectiveness of the ASP solution and polymer injection, which has higher viscosity, demonstrated effective sweeping and oil replacement; the contact surface of the ASP plug and oil formed a vertical wall. At the end of the ASP injection process (Figure 9e), the oil saturation along the core model was around 10%. In comparison with the water injection (Figure 9f), the ASP injection process proved to have high efficiency in enhancing oil recovery.

Evaluation of the Effectiveness of Chemical Flooding

The effectiveness of the chemical flooding is illustrated by the difference between cumulative oil production and various volumes of ASP injected (Figure 10). In the case of water injection only, the cumulative oil recovery (original oil) is 18 cc out of 37 cc, corresponding to an increased recovery factor of 48%. This result aligns with the actual flooding experiments on the core sample, which ranged from approximately 44% to 47%.

The minimum designed injection volume is 0.05 PV for ASP and 0.05 PV for polymer. Oil appears at the outlet very early in the simulation; this early appearance can be explained by the influence of the water slug behind the polymer slug. Water is injected at a higher flow rate than the chemicals, allowing it to push the chemical slugs more quickly. The smaller volume of the chemical slug also means it requires less time to inject. The combined injection of chemicals and polymer at a ratio of 0.05 PV: 0.05 PV achieves a recovery factor of approximately 66% OOIP (a total of about 24.5 cc out of 37 cc).

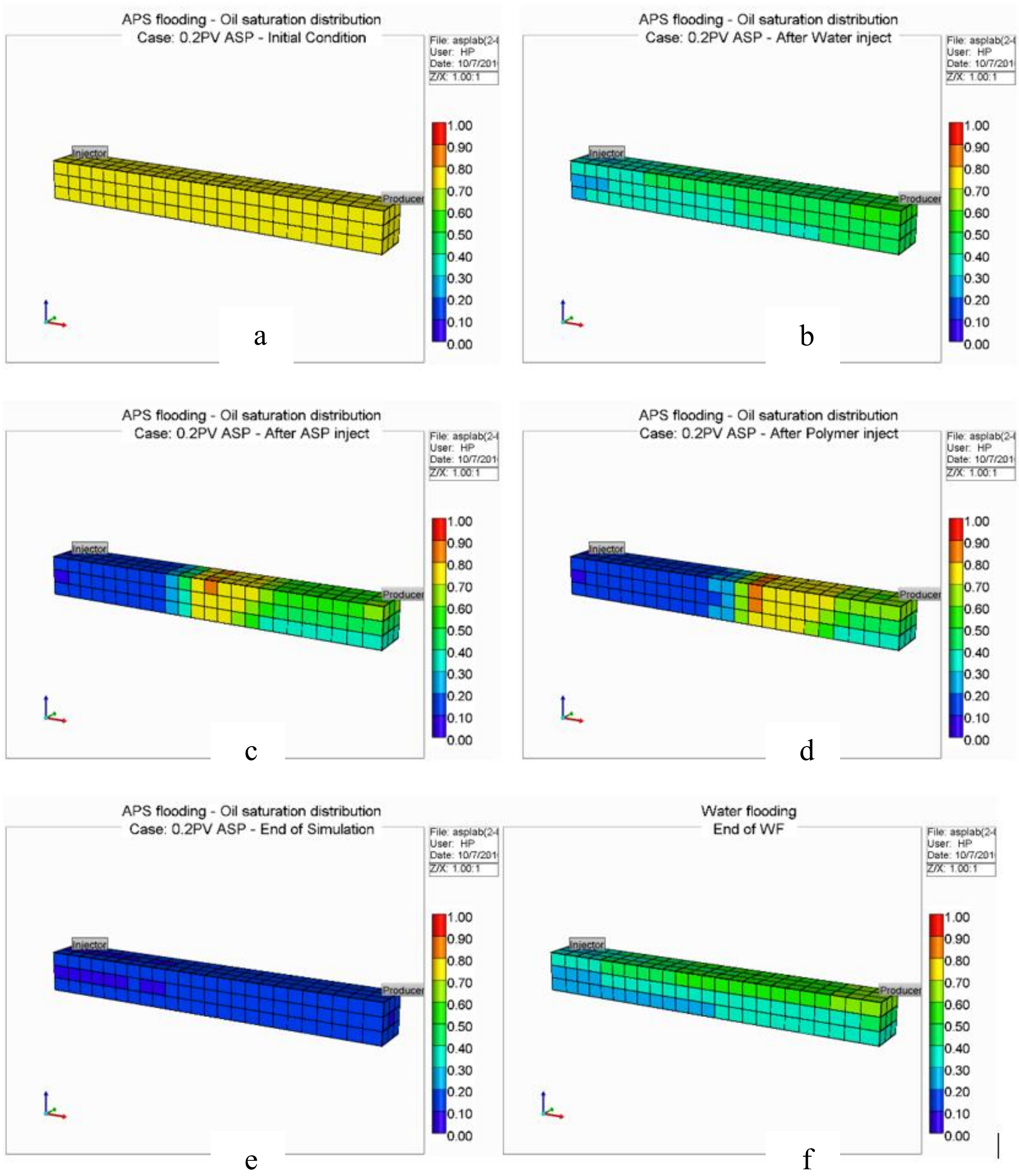

Fig. 9. Distribution of Oil Saturation with Various Injection Stages.

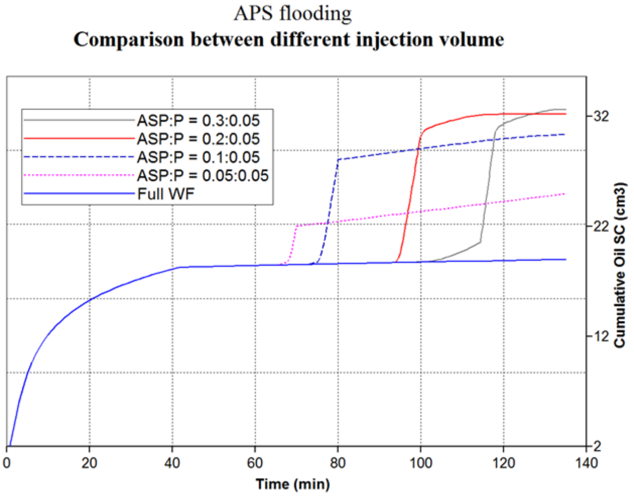

Fig. 10. Cumulative oil production with different ASP injection volumes.

The results of the flooding on the modified core sample also yielded similar recovery results, at 64.86% OOIP (Table 11).

Tab. 11. Cumulative Oil Recovery from Experiments and Simulation

Injection Experiment		**Injection Volume Ratio** (ASP:Pol)	**Simulation**	
Oil Recovered (cc)	Recovery Factor (%)		Oil Recovered (cc)	Recovery Factor (%)
(1)	*(2)*	*(3)*	*(4)*	*(5)*
16.5	44.60	0.00:0.00	18.0	48.65
24.0	64.86	0.05:0.05	24.5	66.21
30.7	82.73	0.10:0.05	29.8	80.70
32.7	88.38	0.20:0.05	31.7	85.67
33.2	89.73	0.30:0.05	32.5	87.84

The second injection scheme was conducted with 0.1 PV of ASP and 0.05 PV of polymer. Oil appeared approximately 9 minutes later than in the first case (equivalent to 2.16 cc of chemicals injected). The cumulative oil recovery from the simulation was about 30 cc, corresponding to a recovery factor of 81%. The results from the flooding experiment on the modified core sample were approximately 83%.

The third injection scheme used 0.2 PV of ASP and 0.05 PV of polymer. The detailed injection parameters including injection volume, flow rate, time, oil recovered, and recovery factor are shown in Table 12.

The final injection scheme with 0.3 PV of ASP and 0.05 PV of polymer also resulted in a total oil recovery similar to that of the third scheme.

Tab. 12. Injection Scheme of 0.2 PV ASP and 0.05 PV Polymer

Injection Sequence	**Flow Rate (cc/min)**	**Time (min)**	**Injected Volume (cc)**	**PV**	**Cumulative Oil Recovered (cc)**
1. Water Injection	2.4	0÷41.59	99.82	2	0÷17.8
2. ASP Mixture	0.24	41.59÷83.19	9.98	0.2	17.8÷18.16
3. Polymer Slug	0.24	83.19÷93.59	2.5	0.05	18.16÷18.23
4. Water flood	2.4	93.59÷135.18	99.82	2	18.23÷31.87

Matching on the prepared-core model

The results of the flooding experiments on the prepared-core sample and the simulation were compared to evaluate the degree of matching (Figure 11). Both datasets in the chart were conducted under the optimal injection volume scheme of 0.2 PV of ASP solution and 0.05 PV of polymer after performing a water flood with 2 PV. The matching results for cumulative oil production show that the experimental results and the modified core simulation are synchronized, indicating high reliability.

Received: 30 Oct 2024, Accepted: 01 May 2025, Published: 01 Sep 2025

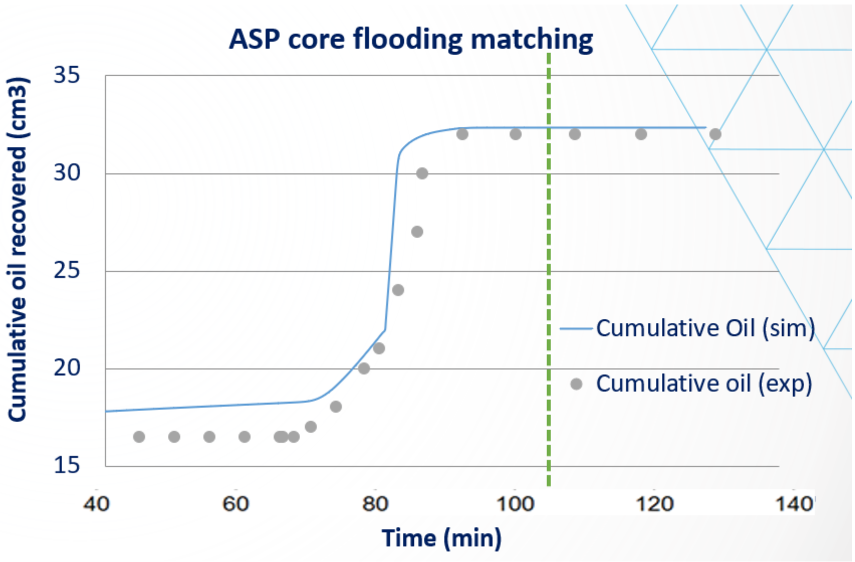

Fig. 11. Matching the results from the core flooding experiment and simulation.

Comparing the results of the modified core flooding experiment with the simulation model shows that the total amount of oil recovered reached approximately 32 cc (86.5% OOIP), confirming the similarity between the numerical model and the actual experiment.

Lastly, but not least, while ASP flooding demonstrates substantial potential for enhanced oil recovery, it is not without its limitations. Key challenges include scaling caused by alkali-ion interactions, emulsification that complicates oil-water separation, high operational costs, and environmental concerns related to the disposal of produced fluids. Addressing these issues is critical for the broader adoption of ASP in real-world applications.

5. Conclusion

The research results identify the optimal combination of alkaline, surfactant, and polymer flooding chemicals along with reservoir simulation, which not only establishes a feasible flooding process but also determines effective injection volumes, reduces residual oil saturation, and enhances the oil recovery factor for the research target. Specifically:

The ASP (Alkaline-Surfactant-Polymer) chemical combination has been optimized, and the experimental flooding process with core samples combined with simulation has been applied to evaluate oil recovery efficiency. The experimental results show that the optimized chemical combination meets the established goals, particularly the ability to form a microemulsion phase with extremely low surface tension, significantly increasing the oil recovery factor. Consequently, a tightly structured and efficient experimental process has been established, minimizing the number of experiments while ensuring the reliability of the results.

The experimental and simulation results document the effectiveness of the flooding process with 20% PV ASP compared to the water and polymer flooding methods.

The flooding process has been validated experimentally (on a modified Berea sandstone core sample). The results from the flooding experiments on the Berea sandstone core sample identified the advantage of increasing the oil recovery factor using the ASP chemical combination (an increase of 7.3%) compared to the water flooding method and 6.6% compared to the polymer and water method within the same timeframe.

Acknowledgements

This work is funded by PetroVietnam University under grant code GV1912.

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