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Evaluation of the Oil Recovery Potential and Cost Implication Analysis of Alternative ASP Formulations for Sandstone and Carbonate Reservoirs

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Cite This: ACS Omega 2024, 9, 20859−20875

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ABSTRACT: This study explores alternative chemical agents to enhance oil recovery in sandstone and carbonate reservoirs, aiming to address limitations in alkali−surfactant−polymer (ASP) flooding. Existing ASP methods face technical and environmental challenges, prompting research into alternative chemical agents. However, there are limited field deployments of these alternative chemical agents due to high costs, and ternary combinations of these agents remain unexplored. The study investigates a combination of organic alkali, amino acid-based surfactant/surface-active ionic liquid, and biopolymer. Comparative analysis with conventional ASP formulations reveals promising results. Organic alkali and biopolymer combination mitigates the adverse effects of inorganic alkalis on partially hydrolyzed polyacrylamide, enhancing the oil recovery potential. A unit technical cost (UTC) calculation showed that despite higher chemical costs per incremental barrel of oil, the alternative ASP formulations demonstrate comparable costs due to reduced facility cost. Cost-effectiveness will improve with incorporation of factors such as environmental friendliness and reduced preflush requirements. Mass production of these agents could further enhance the economic feasibility. Therefore, this study reveals that careful cost-benefit analysis, the development of low-concentration formulations, and mass production of these chemical agents could facilitate the implementation of these alternatives, ensuring compliance with environmental regulations and enabling ASP flooding in challenging reservoir conditions.
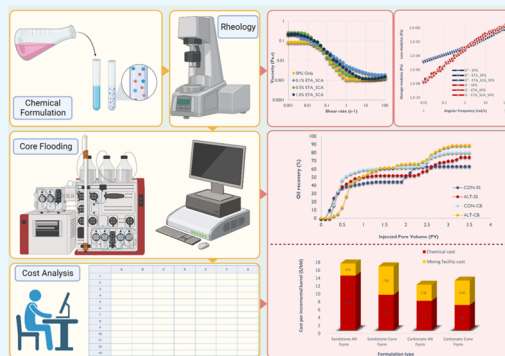
1. INTRODUCTION

In Chemical Enhanced Oil Recovery (cEOR) research, there have been numerous advances to improve the technical and economic feasibility of implementing these methods in the field. These advances include the investigation and evaluation of the oil recovery potential of new chemical agents as alternatives to the conventionally deployed ones. The conventionally deployed chemical agents in cEOR have various limitations that affect the technical feasibility and most importantly the economic feasibility of their application.

NaOH and Na_2CO_3 are the widely deployed alkalis that cause severe scale formation, subsequently impairing the reservoir and causing production loss.[1−4] These alkalis adversely affect polymer rheology. The surfactant used also has a detrimental environmental impact due to its high aquatic toxicity and low biodegradability. Some of the conventional surfactants have low salinity and hardness tolerance, hence less efficient in the presence of divalent cations.[5] Conventionally deployed polymers are also highly susceptible to temperature and salinity.[6,7] Therefore, the viscosity of displacing fluid required for mobility control deteriorates under harsh reservoir conditions.

Several scholars have investigated and suggested alternatives in the literature.[8] They proposed a switch to using organic alkalis as alternatives to inorganic alkalis. Monoethanolamine (ETA) proved to be one of the most promising organic alkalis which have undergone extensive studies.[1−4,9−11] Renewable resource-based surfactants have also been proposed as alternatives to petrochemical-based surfactants due to their high biodegradability and biocompatibility.[12−21] Surface-active ionic liquids (SAILs) have also been proposed for surfactant application in harsh reservoir conditions (high-temperature and high-salinity reservoirs).[22,23] Various biopolymers have been proposed as alternatives to partially hydrolyzed polyacrylamide (HPAM).[6,−31] Despite the promising EOR potential of these alternative chemical agents, their deployment in field application

is limited due to the high chemical cost. There are also limited reports on the potential of their ternary combination, which is believed to alleviate various technical limitations associated with conventional alkali−surfactant−polymer (ASP) flooding. Furthermore, most of the research investigations focus on achieving a high oil recovery in the development of cEOR formulations. Therefore, impractical formulations are developed due to high chemical concentrations.[32]

In view of this, this study focuses on evaluating the oil recovery potential of ternary combinations of alternative chemical agents for ASP flooding. A simplified cost analysis was included to evaluate the feasibility of deploying the proposed formulations in field applications. Though there are numerous investigations on these alternative chemical agents, there are no reported works on their economic feasibility, which is crucial for viable field implementations. The lack of such studies limits these investigations to the laboratory. However, this study is a step to bridge the gap between laboratory investigations of these alternative chemical agents and their possible field implementation. In this study, two ASP formulations are proposed and investigated for application in sandstone and carbonate formations. Both formulations for sandstone application are composed of monoethanolamine (ETA) as alkali and Schizophyllan (SPG) as polymer. The difference between the two formulations is the surfactants used. Sodium cocoyl alaninate (SCA), an anionic amino acid-based surfactant, is used for sandstone application. On the other hand, 1-hexadecyl-3-methyl imidazolium bromide (C_{16}mimBr), a cationic surface-active ionic liquid, is used for carbonate application. The performances of the proposed formulations are compared with conventional ASP formulations. These formulations include sodium carbonate (Na_2CO_3)/sodium dodecyl sulfate (SDS)/partially hydrolyzed polyacrylamide (HPAM) system for sandstone application and sodium metaborate ($NaBO_2$)/cetyltrimethylammonium bromide (CTAB)/HPAM system for carbonate application.

2. METHODOLOGY

2.1. Materials. The details of the various materials used in this study are summarized in Table 1. The study has utilized ETA, Na_2CO_3, and $NaBO_2$ as alkalis; SCA, SDS, C_{16}mimBr, and CTAB as surfactants; and SPG and HPAM as polymers. Synthetic brines were prepared using nine salts. The compositions and properties of brines are presented in Table 2. Brines 1 and 2 are intended for investigations in sandstone and carbonate, respectively. The composition of brine 1 is based on the composition of produced water from Malaysian oil field,[33] and that of brine 2 is based on Angsi seawater.[34] A light crude oil from a Malaysian oil field was deployed as the oleic phase. Its composition and properties are also summarized in Table 2. The chemicals were used as received, and deionized water was not purified further. Preparation and dilution of the various chemical agent solutions and brine were performed with deionized water.

Two sandstone and one carbonate rocks (1.5 in diameter by 12 in length) were procured from Polygon Synergy Ventures (Malaysia) for core flooding experiments. The sandstone cores are Boise Buff (BB) and Berea Sandstone (BS), and the carbonate rock sample is Desert Pink (DP). Each rock sample is cut into ∼3-in pieces. The core pieces' dry weight, length, and diameter are first measured. Then, the POROPERM equipment is used to determine their properties, including gas permeability, porosity, and pore volume. Prior to the core flood experiments, the cores are vacuum-saturated with brine. The wet weight is

Table 1. Details of Experimental Materials

materials	purity	supplier
sodium cocoyl alaninate	∼28−30%	Skyrun Industrial Company Ltd. (China)
sodium dodecyl sulfate	over 85%	Merck Chemicals
monoethanolamine	∼99.5−100%	R and M Chemicals (Malaysia)
sodium carbonate	AR, 99.5%	R and M Chemicals (Malaysia)
schizophyllan	(1% content)	Alfa Chemistry
partially hydrolyzed polyacrylamide		Revlogi Materials (Malaysia)
strontium chloride hexahydrate, $SrCl_2 \cdot 6H_2O$	AR, 99%	Merck Chemicals
calcium chloride dihydrate, $CaCl_2 \cdot 2H_2O$	AR, 99.5%	R and M Chemicals (Malaysia)
magnesium chloride hexahydrate, $MgCl_2 \cdot 6H_2O$	AR, 99.5%	R and M Chemicals (Malaysia)
potassium chloride, KCl	AR, 99.5%	R and M Chemicals (Malaysia)
sodium chloride, NaCl	AR, 99.5%	R and M Chemicals (Malaysia)
barium chloride dihydrate, $BaCl_2 \cdot 2H_2O$	AR, over 99%	R and M Chemicals (Malaysia)
sodium bicarbonate, $NaHCO_3$	AR, over 99%	R and M Chemicals (Malaysia)
sodium sulfate, Na_2SO_4	AR, over 99%	R and M Chemicals (Malaysia)
iron(III) chloride, $FeCl_3$	97%	R and M Chemicals (Malaysia)
crude oil		Portray (M) SDN BHD

Table 2. Brine and Crude Oil Composition and Properties

salt	salt concentration (ppm)		crude oil composition	% weight
	brine 1	brine 2		
NaCl	8452.6	23 966.7	saturates	55.6
KCl	404.8	715	aromatics	24.6
$MgCl_2 \cdot 6H_2O$	529.9	10 832.2	resins	16.3
$CaCl_2 \cdot 2H_2O$	171.3	1573.7	asphaltenes	3.5
$SrCl_2 \cdot 6H_2O$	1.1	20.1		
$BaCl_2 \cdot 2H_2O$	1.8	0		
$FeCl_3$	2.4	0		
Na_2SO_4	3635.8	4066.3		
$NaHCO_3$	802.8	218.9		
properties	brine 1	brine 2	crude oil	
density (g/mL) @ 25 °C	1.0069	1.0229	0.8404	
density (g/mL) @ 80 °C	0.98097	0.98281	0.809	
viscosity (mPa·s) @ 25 °C	0.75	1.041	13.6	
viscosity (mPa·s) @ 80 °C	0.4638	0.5334	6.3	
salinity (ppm)	1400.5	41 392.9		
total acid number (mg KOH/g)			0.01	

then measured to calculate porosity and pore volume. The properties of the various core samples are summarized in Table 3.

2.2. Rheological Measurements. The rheological measurements involved both rotational and oscillatory tests. The tests were conducted using the Couette bob geometry in a Discovery Hybrid Rheometer (DHR-1, TA Instruments). A detailed description of the rheometer can be found in ref 35. A Peltier plate effectively regulates the temperature, facilitating both heating and cooling at adjustable rates. For each run, approximately 17 mL of the chemical solution is added to the

Table 3. Summary of Core Dimensions and Properties

| core name | weight (g) | diameter (mm) | length (mm) | permeability (mD) | | PV (cc) | porosity (%) |
				K air	K_∞		
BB1	145.47	37.41	77.95	9248.75	9248.74	23.42	27.34
BB2	147.94	37.50	78.11	10913.55	10913.54	22.42	25.99
BB3	148.75	37.46	78.07	6961.24	6961.24	22.27	25.88
BB4	124.82	37.50	65.95	7666.83	7666.83	18.59	25.52
BS1	180.01	37.9	76.16	318.80	302.90	14.73	17.14
BS2	182.23	37.92	76.42	325.71	310.60	14.39	16.67
DP1	178.17	37.45	78.38	50.76	48.17	11.91	13.79
DP2	178.86	37.40	79.12	39.82	34.95	14.09	16.21
DP3	176.26	37.56	78.94	47.42	41.62	15.56	17.79
DP4	143.55	37.47	63.48	71.15	61.09	11.82	16.89
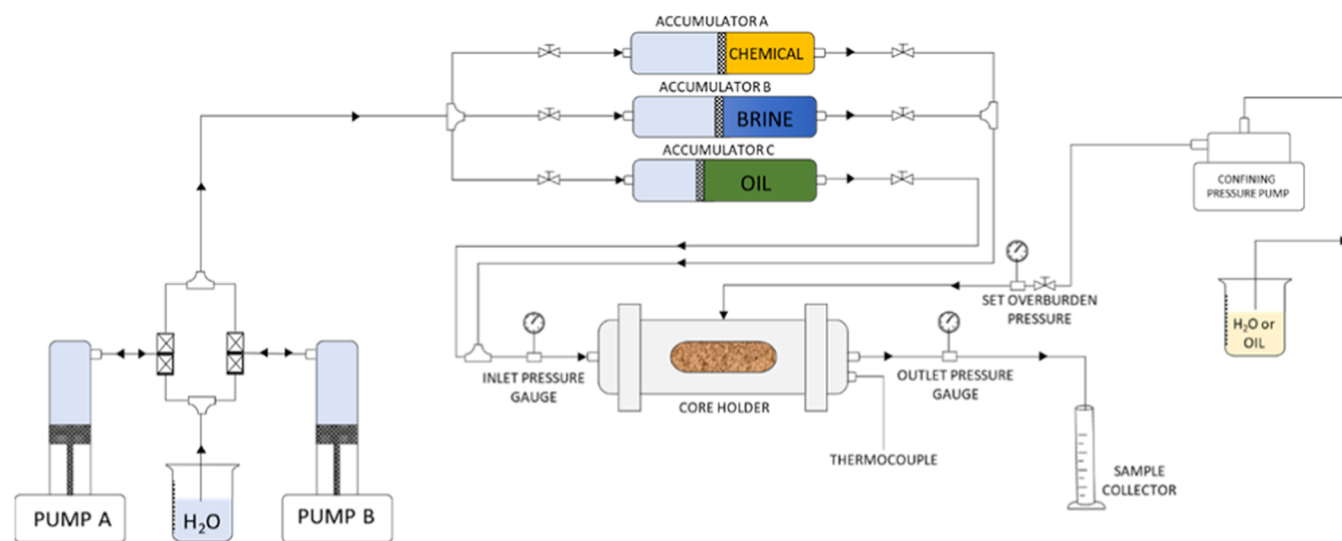
Figure 1. Diagram illustrating the relative permeability system. Reprinted with permission from ref 38 Copyright 2023 Elsevier.

test cell (cup). The experimental temperature is subsequently established at 25 °C for all experimental trials except during temperature ramping. Prior to commencing the run, the sample undergoes a 30 s soaking period followed by a 60 s equilibration to achieve thermal equilibrium.

2.2.1. Rotational Test. The flow curves are produced by conducting a steady flow sweep, gradually increasing the shear rate from 0.001 to 100 s^{-1}. The study involved investigating the flow behavior of ASP formulations at various alkali concentrations and then the effect of salinity. Temperature ramping (from 25 to 120 °C) was then conducted at a constant shear rate of 100 s^{-1} to study the effect of temperature on the rheological behavior of the ASP formulations. The viscosity data were analyzed using the Power Law model

$$\mu = k\gamma^{n-1} \tag{1}$$

where μ is the dynamic viscosity of the solution, γ is the shear rate, k is the consistency index, and n is the flow index.

2.2.2. Oscillatory Test. The viscoelastic properties of the ASP formulations were assessed at 25 °C. To explore the impact of alkali and surfactant, we evaluated combinations of alkali and polymer, as well as polymer solutions devoid of additional chemical agents, to ascertain their respective viscoelastic properties. Initially, an amplitude sweep test was performed to analyze the structural stability of the different formulations. The amplitude oscillation was gradually increased from 1 to 350%, with a constant frequency of 10 rad/s. This procedure identified

the range of strain where the storage (G') and loss (G'') moduli remained constant, commonly termed the linear viscoelastic range (LVER). G'' quantifies energy dissipation, reflecting the viscous component and hence is referred to as the viscous modulus. Similarly, G' represents the elastic energy stored within the system, known as the elastic modulus.[36] A frequency sweep test was carried out at a constant strain of 5%, varying angular frequencies from 100 to 0.01 rad/s, which is within the viscoelastic range of the tested polymer systems.

2.3. Core Flood Experiments. To investigate the injectivity of the various ASP formulations and assess their oil recovery potential, core flood experiments were conducted with a Relative Permeability System. The schematic of this system is shown in Figure 1. Detailed description of this system can be found in 37. The experiment is conducted at a temperature of 80 °C and a confining pressure of 2500 psi. The injection pressure was maintained at 1500 psi.

2.3.1. Injectivity Test. The rheological behaviors of the various ASP formulations in porous media are investigated through injectivity tests. The injectivity test involves evaluating the ability of the formulation to reduce the mobility as well as the permeability of the formation. The mobility reduction is quantified through the resistance factor (RF) and the permeability reduction is quantified through the residual resistance factor (RRF). The RF compares the brine mobility before polymer injection to the mobility of the polymer solution under identical conditions, as expressed by[30]

Table 4. Costs of Chemicals

chemical type	chemical name	price [US$/Ton]	reference
alkali	monoethanolamine	950−1800	Shandong Pulisi Chemical Co. Ltd.
			Shandong Near Chemical Co., Ltd.
			Qingdao Ever Century Chemical Co., Ltd.
			Yujiang Chemical (Shandong) Co., Ltd.
	sodium carbonate	200−700	Hebei Dechuang Chemical Equipment Co. Ltd.
			Changzhou Shanglian Chemical Co., Ltd.
			Qingdao Sincere Chemical Co., Ltd.
			Shandong Riyusheng International Trade Co., Ltd.
	sodium metaborate	600−1200	Qingdao Salus International Trade Co., Ltd.
			Hebei Ruisite Technology Co., Ltd.
			Lonwin Industry Group Ltd.
			Aqua Chem Industry Co., Ltd.
surfactant	sodium cocoyl alaninate	907−5443	Guangzhou Flower's Song Fine Chemical Co. Ltd.
			Henan Kingway Technology Co., Ltd.
			Hony (Guangdong) New Material Co., Ltd.
			Hangzhou TIM Chemicals Co., Ltd.
	sodium dodecyl sulfate	1000−4536	Henan Richvan Industry Co. Ltd.
			Yujiang Chemical (Shandong) Co., Ltd.
			Henan Yeedok Industry Co., Ltd.
			Shandong Zhishang New Materials Co., Ltd.
	1-hexadecyl-3-methyl imidazolium bromide	3478−9072	Career Henan Chemical Co. Ltd.
			Hebei Mojin Biotechnology Co., Ltd.
			Hebei Guanlang Biotechnology Co., Ltd.
			LY Global chemicals Co., Ltd.
	cetyltrimethylammonium bromide	4082−9072	Hefei Zhaohui New Material Technology Co Ltd.
			Tongren Decatur Mining Co., Ltd.
			Suzhou Greenway Biotech Co., Ltd.
			Shandong Boyu Chemical Co., Ltd.
polymer	schizophyllan	1550−7257	Tianjin Okay International Trading Co. Ltd.
			Wuhan Monad Medicine Tech Co., Ltd.
			M A M M Trading Enterprise
	partially hydrolyzed polyacrylamide	1000−3000	Shandong Chemichase Chemical Co., Ltd.
			Henan GO Biotech Co., Ltd.
			Hua Xing Shi Ji International Trading Co., Ltd.
			Yixing Cleanwater Chemicals Co., Ltd.

$$\mathrm{RF} = \frac{\lambda_{\mathrm{brine}}}{\lambda_{\mathrm{polymer}}} = \frac{(k/\mu)_{\mathrm{brine}}}{(k/\mu)_{\mathrm{polymer}}} = \frac{\Delta p_{\mathrm{polymer}}}{\Delta p_{\mathrm{brine}}} \qquad (2)$$

where λ_{brine} represents the mobility of brine before polymer injection and $\lambda_{\mathrm{polymer}}$ represents the mobility of the polymer system. Mobility is defined as the ratio of a fluid's relative permeability (k) to its viscosity (μ). Thus, the RF can be simplified as the ratio of pressure drop during polymer injection ($\Delta p_{\mathrm{polymer}}$) to the pressure drop during brine injection prior to the polymer system contact ($\Delta p_{\mathrm{brine}}$). The RRF, on the other hand, compares the mobility of brine before polymer system injection to the mobility of brine after polymer system injection ($\lambda_{\mathrm{brine\ PPF}}$) when all movable polymer systems have been displaced from the core (as per eq 3).

$$\mathrm{RRF} = \frac{\lambda_{\mathrm{brine}}}{\lambda_{\mathrm{brinePPF}}} = \frac{(k/\mu)_{\mathrm{brine}}}{(k/\mu)_{\mathrm{brinePPF}}} = \frac{\Delta p_{\mathrm{brinePPF}}}{\Delta p_{\mathrm{brine}}} \qquad (3)$$

The cores used in the injectivity tests are Boise Buff and Desert Pink for investigation in sandstone and carbonate, respectively. Detailed descriptions of the core samples are presented in Section 2.1, and their properties are summarized in Table 3. The injectivity test involves injecting brine consistently into the core at injection rates ranging from 0.5 to 9.5 mL/min. The stabilized

differential pressure at each injection rate is recorded. Subsequently, the brine is displaced by the polymer system. At this stage, different injection rates (same for brine injection) are used, and resultant stabilized pressure at each injection rate is recorded for RF estimation. The final stage involves the removal of the polymer system within the core with brine. After all of the movable polymers have been displaced, the injection rates are then varied, and the resultant stabilized pressure at each injection rate is recorded just as in the previous steps. These recorded pressures from this final step are used for the RRF estimation.

2.3.2. Oil Recovery Test. The proposed ASP formulations and their respective conventional counterparts were evaluated for the oil recovery potential through core flood experiments in Berea sandstone and Desert Pink, respectively. Core samples are described in Section 2.1, and their properties are summarized in Table 3. Prior to each oil recovery experiment, the brine permeability is determined through brine injection at constant injection rates from 0.5 to 4 mL/min. As done in the injectivity test, the stabilized differential pressure at each flow rate is recorded. The brine permeability is then determined via Darcy's equation. After the permeability determination, oil is injected at a constant rate of 0.5 mL/min until irreducible water saturation is achieved (i.e., all movable water is displaced). This step

mimics the drainage process. Subsequently, the oil is displaced with brine at 0.2 mL/min until residual oil saturation is attained (i.e., no oil is produced with further brine injection). This stage of the imbibition process mimics the waterflooding stage during oil recovery. 0.5 PV of the chemical formulation is then injected into the core at the same flow rate based on typical ASP injection scheme.[33,38] The final stage involves water injection, until no more oil is produced. This sequence is repeated for other chemical formulations in the various core samples.

2.4. Unit Technical Cost Estimation. In EOR projects, there are limited technical failures, usually in situations with no additional oil recovery. However, the predominant failure is economic failure where the additional recovery is insufficient or its production is too slow to offset the cost of the EOR project. The project could also be too costly to offset by the additional oil recovery.[39] Therefore, the economic implication of the proposed chemical formulations is vital to facilitate their application in the field. The economic evaluation performed is a simple cost-benefit analysis. It is very useful in determining the economic feasibility of a project through comparison of project cost against the benefits gained from the project.[40] This type of economic evaluation is essential since it only deals in monetary terms.[41]

The objective of this part of the study is to conduct a normalized economic evaluation of the various ASP formulations. By using the oil recovery from the laboratory analysis and the cost of the various chemicals, the cost implication of using alternative formulations over their conventional counterparts could be evaluated. This evaluation is focused on the unit technical cost (UTC): the cost per incremental barrel of oil. Cost estimates of chemicals are calculated based on the dosage used for the core flood experiments. The costs of the chemicals are presented in Table 4. The prices of these chemicals are mainly influenced by the volume discount. The conventional EOR chemical agents are available in large quantities, and therefore tend to be cheaper. On the other hand, the proposed chemical agents are mostly used in cosmetics and pharmaceutical industries. They are therefore not available in large quantities compared with the conventional EOR chemical agents.

Estimation of the chemical cost of injected barrel of solution is performed in three steps.[32,42] First, the chemical cost per barrel injected is calculated using eq 4

$$\frac{\$}{\text{bbl injected}} = \sum \text{concentration} \times \frac{\$}{\text{lb}} \times \frac{350 \text{ lb}}{\text{bbl}} \tag{4}$$

For injection of multiple solutions, the cost per barrel for each solution must be calculated. The cost per barrel of each solution must then be normalized to the volume of that specific solution injected in pore volume (PV) as shown by eq 5

$$\frac{\$}{\text{bbl of PV flooded}} = \sum \text{PV injected(fraction)} \times \frac{\$}{\text{bbl injected}} \tag{5}$$

The normalized cost per barrel for each solution is summed for all of the chemical solutions injected to obtain the total cost of chemical injected per barrel PV. Finally, the cost per incremental barrel of oil produced due to chemical injection is calculated as a ratio of the total cost of chemical injected per barrel PV of the incremental oil recovery due to chemical injection in PV (eq 3). The PV incremental oil recovery is calculated using eq 6

$$\frac{\$}{\text{bbl of oil}} = \frac{\frac{\$}{\text{bbl of PV flooded}}}{\text{PV(fraction)oil recovered}} \tag{6}$$

$$\text{PV} = \frac{\% \text{ OOIP} \times S_{oi}}{100} \tag{7}$$

where S_{oi} is the initial oil saturation. Another important component of the UTC is the chemical mixing plant facilities. This cost varies with the complexity of the plant and the volume of the fluid. According to ref 42, ASP plant costs vary from $400/1000 BIPD to $2000/1000 BIPD. The plant cost is assumed to be $2000/1000 BIPD. The water treatment can be up to half the mixing plant cost. Without the need for water softening, the plant cost could reduce to approximately a third to half the ASP plant cost.[42] Half of the original plant cost is assumed for the omission of water softening facilities.

3. RESULTS AND DISCUSSION

3.1. Bulk Phase Flow Behavior of ASP Formulations. The combination of different chemical agents holds potential synergies for enhancing oil recovery; yet, it can also introduce adverse effects that may compromise the performance of individual chemical agents. Hence, it is crucial to account for these potential drawbacks when formulating ASP slugs. Alkalis influence the viscosity of polymer solutions in two distinct ways. Their presence leads to an increase in the system's pH and ionic strength.[4] The pH elevation intensifies hydrolysis, resulting in a greater number of negative charges along the polymer chain. Consequently, the polymer molecules expand, augmenting the viscosity of the solution.

Conversely, the increase in ionic strength dwindles the polymer viscosity through the charge shield mechanism. The introduction of alkali leads to an increasing cationic concentration in the solution, which acts to shield the negative charges along the polymer chains. This phenomenon diminishes the repulsive forces between ionized carboxylic groups. Consequently, the polymer chains undergo coiling and compaction, resulting in reduced viscosity of the solution.[43] Table 5 illustrates the variation in pH and ionic strength at different alkali concentrations.

Table 5. Ionic Strength and pH Variation with Alkali Concentration

alkali concentration (wt %)	measured pH			calculated ionic strength		
	ETA	Na_2CO_3	$NaBO_2$	ETA	Na_2CO_3	$NaBO_2$
0.1	10.19	10.81	9.9	0.016	0.028	0.015
0.5	10.56	11.18	10.6	0.082	0.142	0.076
1.0	10.82	11.31	10.8	0.164	0.283	0.152

The effect of various alkalis on the rheological behavior of their respective polymers is shown in Figure 2. The concentration of polymer used in the various formulations is 0.1 wt %. As observed in Figure 2a, ETA has a minimal impact on the viscosity of SPG. The observation is seen in the lower-Newtonian and pseudoplastic shear range. At an ETA concentration of 0.1 wt %, the viscosity of SPG was reduced. However, increasing the alkali concentration to 0.5 and 1.0 wt % resulted in a viscosity increase. Nevertheless, it is imperative to mention that no discernible trend is observed regarding the impact of ETA on the viscosity of SPG. The observed
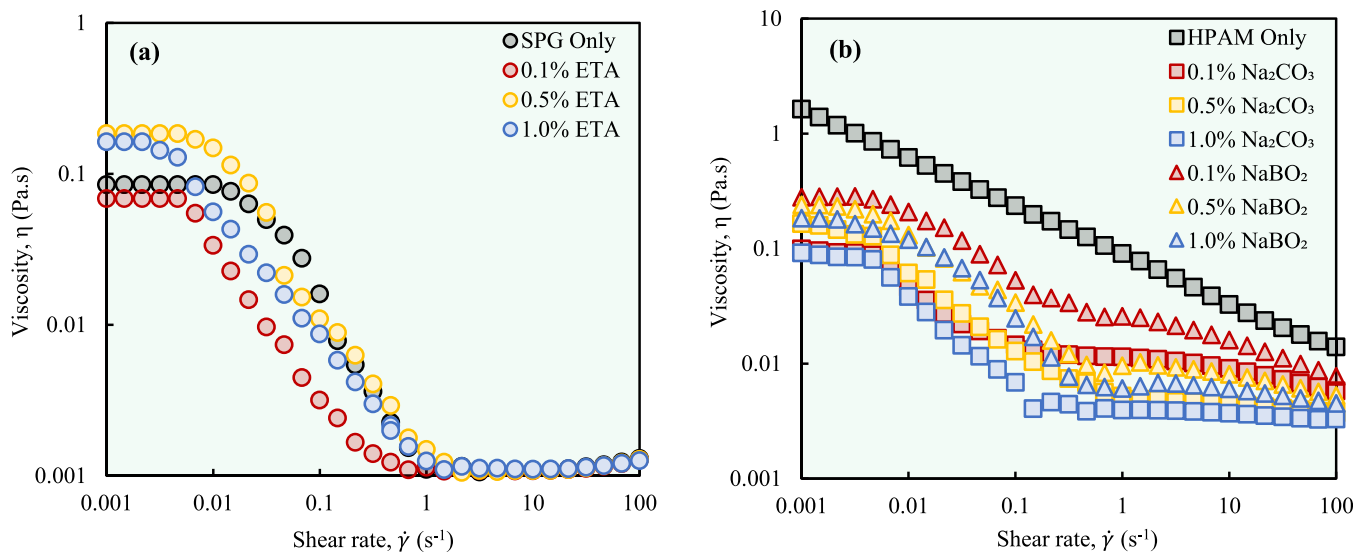
Figure 2. Effect of alkali on polymer rheology: (a) ETA−SPG system and (b) Na_2CO_3−HPAM and $NaBO_2$−HPAM system at 25 °C.

phenomenon can be mainly attributed to SPG's nonionic nature and ETA's characteristics as a weak base. Consequently, the increase in pH and ionic strength caused by increasing ETA concentration has a insignificant impact on SPG's viscosity.

Figure 2b also shows that the two inorganic alkalis, Na_2CO_3 and $NaBO_2$, have a significant impact on the rheological behavior of HPAM. First, increasing the concentrations of the inorganic alkalis monotonically reduced the HPAM viscosity. Furthermore, the flow curves of the alkali−polymer combinations did not exhibit pseudoplasticity over the entire shear rate range as observed in the flow curve of the HPAM solution. Another observation made in Figure 2b is that Na_2CO_3, being a stronger base, reduced the viscosity of HPAM more than $NaBO_2$. The rise in the Na_2CO_3 concentration results in a notable increase in ionic strength, as depicted in Table 5, leading to a considerable decrease in HPAM viscosity. Conversely, $NaBO_2$ exhibits an ionic strength even lower than that of ETA. However, owing to the ionic properties of HPAM, the charge shielding effect remains significant, resulting in a reduction in the viscosity of the HPAM solution.

For application in sandstone formation, SCA and SDS were added to the ETA−SPG and Na_2CO_3−HPAM systems at a concentration of 0.1 wt % to form the alternative and conventional ASP formulation, respectively. Similarly, $C_{16}mimBr$ and CTAB were added to the ETA−SPG and $NaBO_2$−HPAM systems at 0.02 wt % to form the alternative and conventional ASP formulation for carbonate formation. The rheological behavior of the ASP formulations at various alkali concentrations is shown by the flow curves presented in Figure 3. Based on Figure 3a,c, the alternative ASP formulations exhibited higher viscosities than SPG. The enhanced viscosity of the alternative ASP formulations may be attributed to the creation of surfactant−polymer complexes facilitated by a cooperative hydrophobic effect, which is influenced by the nonionic properties of SPG.[44,45] Conversely, the conventional ASP formulations demonstrated lower viscosity compared to HPAM as seen in Figure 3b,d. Due to the ionic nature of HPAM, the charge shield effect exerted by both surfactants and alkalis supersedes the impact of surfactant−polymer complex formation, thereby causing viscosity reduction in the respective ASP formulations.

3.1.1. Salinity Effect on ASP Formulation Rheology.
Electrolytes are encountered during ASP flooding in either the seawater used in ASP slug preparation or formation water present in the reservoir. The presence of an electrolyte can either increase or decrease the viscosity of polymers. For example, a homogeneous PAM solution experiences increased viscosity in the presence of electrolytes, whereas an HPAM solution sees a reduction in viscosity due to the charge shield mechanism as explained in the case of alkalis.[43,46] Based on our previous studies, the ASP formulations comprise 1 wt % alkali,[47,48] 0.1 wt % anionic surfactant[47] or 0.02 wt % cationic surfactant,[48] and 0.1 wt % polymer.[37] These compositions are used for both the salinity and temperature effect studies. As previously discussed, a combination of polymer and surfactant forms complexes. These complexes also have an influence on the viscosity of the formulations. Therefore, the impact of electrolytes would be more intricate than solely the charge shield effect. Figure 4 shows the impact of electrolytes (NaCl) on the viscosities of the ASP formulations.

As seen in Figure 4a,b, the presence of electrolytes reduced the viscosity of both ASP formulations for sandstone application. Nevertheless, no discernible trend is found with increasing salt concentration. The viscosity reduction is more apparent in the lower-Newtonian shear rate range. Furthermore, due to HPAM being ionic and SPG being nonionic, the viscosity reduction caused by the presence of electrolytes is more profound in the conventional ASP formulation. For the ETA−SCA−SPG formulation, the charge shield effect is ineffective on nonionic SPG; hence, the reduction in viscosity is subtle. The slight reduction in viscosity could be attributed to the complexes formed with SCA, which improves the viscosity of SPG yet introduces ionic character. This ionic character will be responsive to the charge shield effect, hence the observed reduction in viscosity.

Figure 4c shows that the ETA−$C_{16}mimBr$−SPG formulation exhibits substantial viscosity reduction in the lower-Newtonian shear rate range in the presence of electrolyte. However, viscosity increase is observed in the pseudoplastic and higher-Newtonian shear rate range. The viscosity rise at elevated salinity levels is a phenomenon documented in the literature, often referred to as the anti-polyelectrolyte effect.[46] On the other
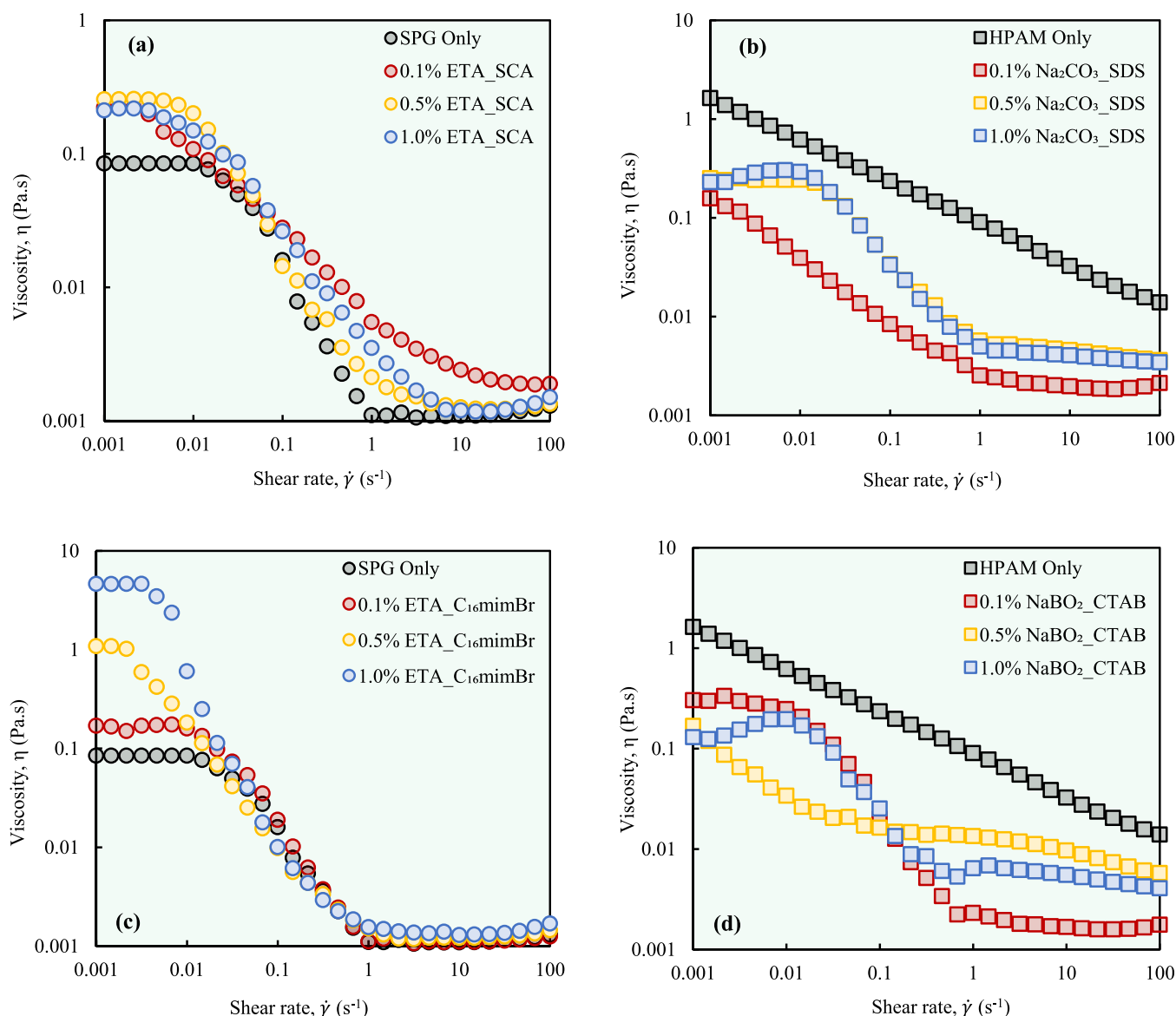
Figure 3. Viscosity vs shear rate at 25 °C for (a) ETA−SCA−SPG systems, (b) Na_2CO_3−SDS−HPAM systems, (c) ETA−C_{16}mimBr−SPG systems, and (d) $NaBO_2$−CTAB−HPAM systems at different alkali concentrations.

hand, the presence of electrolyte had an insignificant impact on the viscosity of $NaBO_2$−CTAB−HPAM formulation at the pseudoplastic and higher-Newtonian shear rate range. However, a viscosity reduction is observed in the high-Newtonian shear rate range (Figure 4d). In this case, the complexation between CTAB and HPAM could be responsible for countering the charge shield effect of the electrolyte. In general, all of the formulations exhibited high salt tolerance and hence would retain their viscosities at higher salinity conditions.

3.1.2. Effect of Temperature on ASP Formulation Rheology. Ensuring polymer stability under high-temperature conditions is crucial for their effective use in EOR applications, given that many reservoirs exist at elevated temperatures. The viscosity of polymers tends to decrease rapidly as the temperature increases. This phenomenon occurs because elevated temperatures enhance the activity of polymer chains and molecules, thereby reducing the intermolecular friction. Consequently, flow resistance decreases, leading to a drop in viscosity.[46] However, different polymers exhibit varying responses to temperature elevation due to differences in their

activation energy. SPG, with its triple helix structure, is known for its high-temperature stability, as illustrated in Figure 5a, while HPAM consists of a single long chain.[6]

Figure 5b depicts the viscosity change of the various ASP formulations in response to temperature change. It is noted that as the temperature rises, the viscosities of all formulations decrease, although each formulation exhibits a distinct degree of viscosity retention. Specifically, for formulations targeting applications in sandstone reservoirs, the ETA−SCA−SPG formulation experiences an initial rapid decline in viscosity followed by a moderated decline at higher temperatures. Conversely, the Na_2CO_3−SDS−HPAM formulation demonstrates a gradual viscosity decrease at lower temperatures, escalating to a rapid decline at higher temperatures. Thus, it is evident that the presence of surfactants modifies the heat resistance of the polymers. Nonetheless, both formulations retain over 50% of their viscosities at elevated temperatures.

In the case of formulations tailored for carbonate reservoirs, the ETA−C_{16}mimBr−SPG formulation displayed a notable viscosity retention. Even under high-temperature conditions,
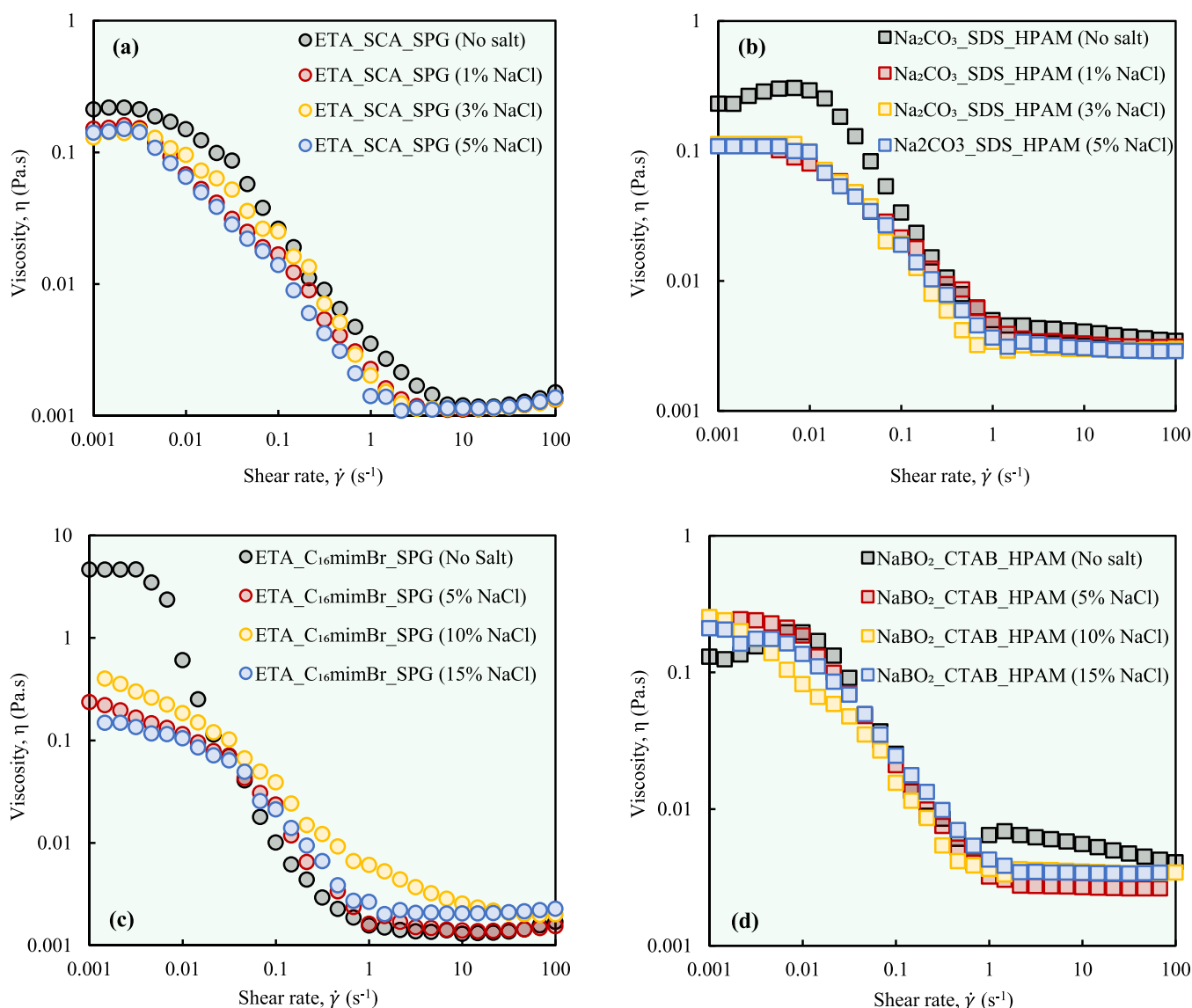
Figure 4. Viscosity vs shear rate for (a) ETA−SCA−SPG system, (b) Na$_2$CO$_3$−SDS−HPAM system, (c) ETA−C$_{16}$mimBr−SPG system, and (d) NaBO$_2$−CTAB−HPAM system in brine at different concentrations at 25 °C.

this formulation maintained over 70% of its initial viscosity. Conversely, the NaBO$_2$−CTAB−HPAM formulation exhibited a rapid decrease in viscosity as the temperature increased, yet it managed to preserve approximately 60% of its original viscosity. Therefore, the complexation between the polymers and the cationic surfactants did not notably impact the heat resistance characteristics of the polymers. Consequently, the ETA−C$_{16}$mimBr−SPG formulation demonstrates greater potential for high-temperature applications compared to that of the NaBO$_2$−CTAB−HPAM formulation.

3.2. Viscoelastic Properties of ASP Formulations. Throughout the years, researchers have substantiated the viscoelastic properties of polymers, aiming to facilitate the mobilization of residual oil and enhance oil recovery, particularly in heterogeneous reservoirs.[49−53] Mobilizing residual oil necessitates achieving a high capillary number (N_c). As delineated by eq 8, N_c compares viscous forces to capillary forces. Viscous forces are represented by the product of injected fluid's velocity and viscosity. Typically, the viscosity of polymer solution decreases with increasing (i.e., pseudoplastic fluid),

thus leaving the capillary number unaffected. However, in the case of viscoelastic polymers, an increase in velocity leads to a rise in viscosity, consequently elevating the capillary number and facilitating the mobilization of residual oil.[54,55]

$$N_c = \frac{\text{viscous forces}}{\text{capillary forces}} = \frac{v\mu_w}{\sigma_{ow} \cos\theta} \quad (8)$$

In the above expression, v represents the injected fluid's velocity (or Darcy's velocity), μ_w is the viscosity of the injected fluid, σ_{ow} is the interfacial tension between oil and water, and θ denotes the contact angle of the wetting phase on the rock. Polymers possessing viscoelastic properties have the potential to enhance both macroscopic and microscopic sweep efficiency. Alkaline and surfactant agents are recognized for their ability to mobilize residual oil by reducing the interfacial tension (IFT), thereby improving the microscopic sweep efficiency. However, incorporating polymer in any polymer-augmented flooding results in an elevation of IFT, consequently diminishing efficiency in mobilizing residual oil at a microscale. In ASP flooding, the
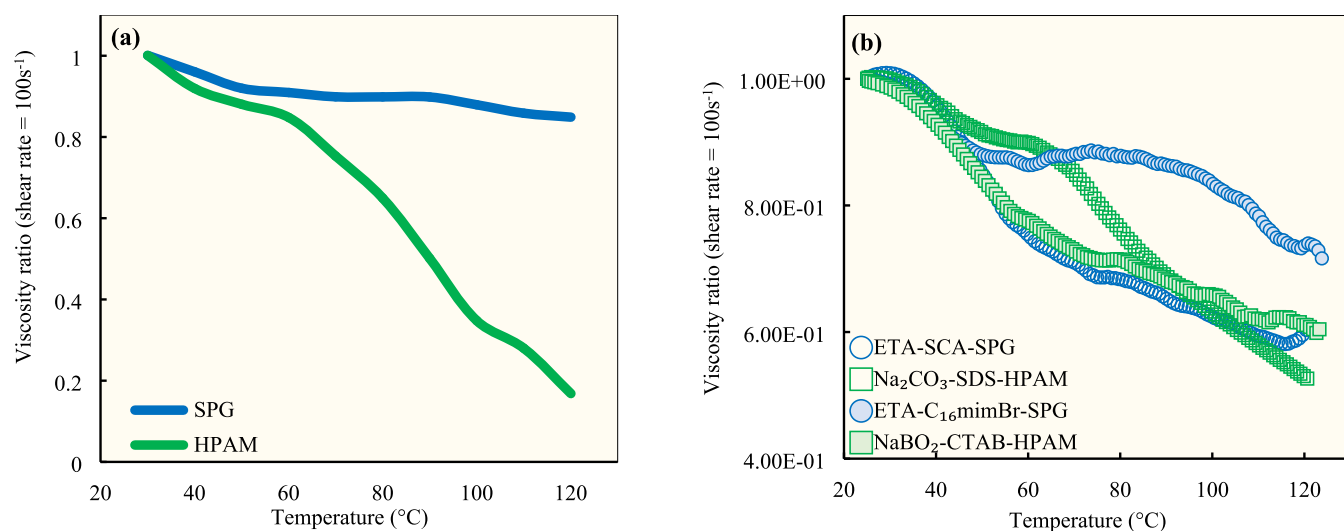
Figure 5. Temperature ramping of (a) polymers (reprinted in part with permission from ref 6 used under Creative Commons CC-BY license) and (b) ASP formulations at 100 s^{-1} shear rate.
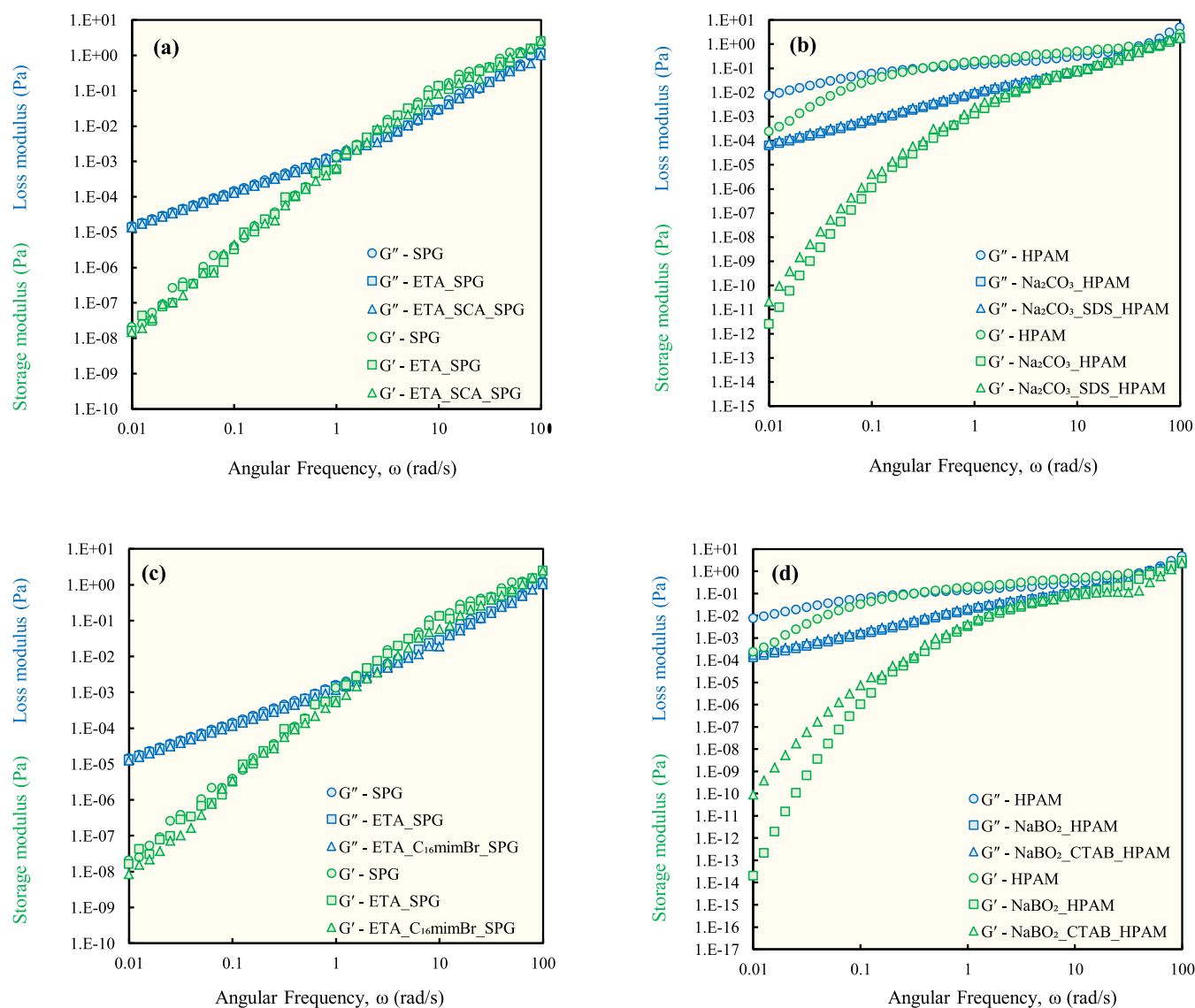

Figure 6. Angular frequency sweep of (a) ETA−SCA−SPG systems, (b) Na$_2$CO$_3$−SDS−HPAM systems, (c) ETA−C$_{16}$mimBr−SPG system, and (d) NaBO$_2$−CTAB−HPAM system at 25 °C.
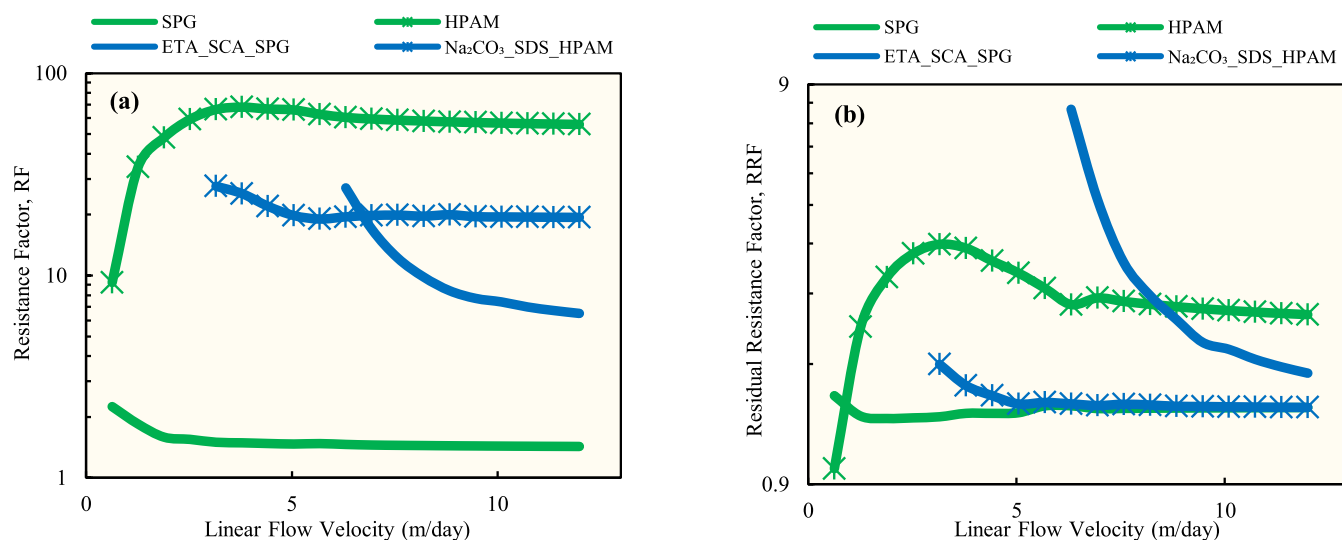
Figure 7. Polymers and ASP formulations' (a) resistance factors and (b) residual resistance factors in sandstone cores at 80 °C.

viscoelasticity of the formulation has been substantiated to hold greater significance than achieving ultralow IFT.[56]

A viscoelastic system exhibits both viscous and elastic properties when subjected to deformation or stress. This means that it can flow like a liquid under certain conditions yet also return to its original shape like a solid when the stress is removed. A system is characterized viscous when its G'' dominates the G'; the reverse indicates dominant elastic behavior.[36] The alternative ASP formulations proposed in this study use biopolymers for mobility control. These biopolymers have been reported in the literature to lack viscoelasticity owing to their low molecular weight and lack of hydrolyzed backbones[57] as evidenced by the findings of Needham and Doe[57] and Hincapie et al.[58] On the contrary, the biopolymer used in this study exhibited viscoelasticity just as the viscoelastic polymer (HPAM). As seen in Figure 6a,c, the variation of G'' and G' with angular frequency for SPG shows both viscous dominance (at low frequency) and elastic dominance (at high frequency beyond the crossover frequency). The crossover frequency is the frequency at which the G'' curve and G' curve intersect.[59]

Comparing the viscoelastic behavior of the ASP formulations to the pure polymer solutions, the effects of the other chemical agents are discerned. Figure 6a,c shows that ETA, SCA, and $C_{16}mimBr$ had no significant impact on the SPG's viscoelasticity. Conversely, the addition of Na_2CO_3 and $NaBO_2$, as shown in Figure 6b,d, notably affected the viscoelastic properties of HPAM. No crossover was observed, indicating the absence of elastic-dominant behavior. Although the addition of SDS and CTAB slightly enhanced the G', no crossover frequency was noted. Therefore, it is anticipated that the conventional ASP formulations will lack viscoelastic behavior owing to the effect of the inorganic alkalis and conventional surfactant. However, the alternative ASP formulations will exhibit viscoelastic behavior, potentially enhancing the microscopic sweep efficiency. The observed influence of alkalis and surfactants on the polymers' viscoelasticity could be attributed to the same phenomena elucidated in the flow behavior discussion.

3.3. Flow Behavior of ASP Formulations in Porous Media. To date, the examination of the flow characteristics of the different ASP formulations has primarily been conducted in the bulk phase. However, considering that these formulations

are designed for EOR applications, it is crucial to assess their flow performance in porous media. The injectivity test is therefore used to investigate the rheological properties of the formulations when injected into the reservoir. The variation of RF and RRF with linear flow velocity for the various formulations in Boise Buff cores is shown in Figure 7. In porous media, the shear rate resulting from a specific flow velocity is influenced by the permeability of the medium. The shearing is higher in low-permeability reservoirs compared to high-permeability reservoirs.[30] The Boise Buff used for the injectivity investigation is a very high-permeability core, as shown in Table 3. Therefore, the pressure differential for some formulations at low flow velocity could not be captured.

From Figure 7a, it is observed that SPG shows high RF at low flow velocity and that the RF decreases with increasing flow velocity. On the contrary, HPAM yielded an increase in RF with the increasing flow velocity. This observation means that SPG exhibits shear thinning behavior in porous media while HPAM exhibits shear thickening behavior. This observation agrees with the report of Quadri et al.[30] on SPG and of Chauveteau[60] on HPAM. This observation means that no injectivity problem will be observed at the injection point while SPG will exhibit good mobility control away from the injection point. The ETA−SCA−SPG and the Na_2CO_3−SDS−HPAM formulations exhibited shear thinning behavior, although the effect is more profound in the ETA−SCA−SPG formulation. In agreement with the bulk phase rheology, the addition of ETA and SCA improved the flow behavior of SPG. On the other hand, the addition of Na_2CO_3 and SDS reduced the viscosity yet improved the flow behavior of HPAM.

The significance of the RRF can be elucidated from two distinct perspectives. The decrease in permeability could be viewed as advantageous owing to the diversion of flow that facilitates enhanced sweep efficiency upon subsequent water injection. However, an excessively high RRF, indicative of significant permeability reduction, poses challenges to injectivity during subsequent water chase injections. Consequently, an optimal RRF should ideally be below 3.[30] Figure 7b shows that both polymers and their respective ASP formulations have favorable RRF in this formation, especially at high flow velocity. The favorable RRF at high flow velocity is due to low polymer retention at high flow velocity. Therefore, the ETA−SCA−SPG
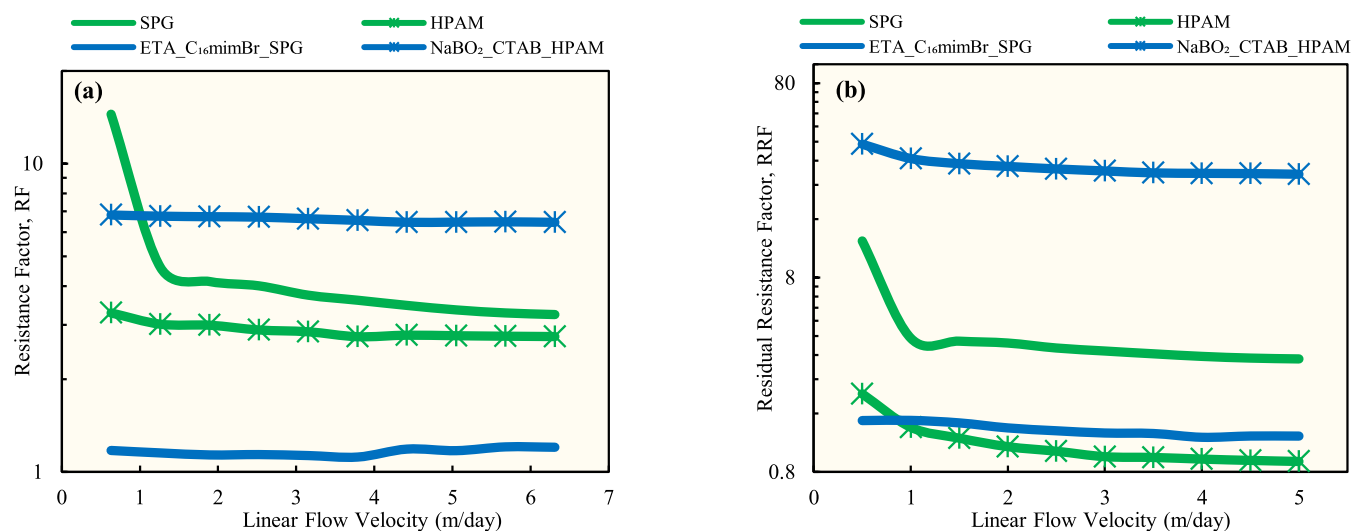
Figure 8. Polymers and ASP formulations' (a) resistance factors and (b) residual resistance factors in carbonate cores at 80 °C.

Table 6. Results of Core Flooding for the ASP Formulations in Sandstone Cores

core no.	brine permeability (mD)	chemical formulation	oil recovery (% OOIP)		saturation (% PV)		
			waterflood	additional	S_{wi}	S_{oi}	S_{or}
BS 1	82.64	1.0% Na_2CO_3 + 0.3% SDS + 0.1% HPAM	43.39	18.78	26	74	28
BS 2	82.84	1.0% ETA + 0.3% SCA + 0.1% SPG	52.04	22.44	27	73	19

formulation exhibits the potential to improve sweep efficiency through flow diversion while giving minimum injectivity problems.

The Desert Pink is a low-permeability carbonate core, resulting in a higher shear rate at a specific flow velocity. Figure 8 illustrates the variation of the RF and RRF with flow velocity for the polymers and their corresponding ASP formulations in the carbonate core. Both SPG and HPAM displayed a shear thinning behavior. This means that with increasing flow velocity (i.e., shear rate), the viscosity of the polymer solutions decreases resulting in reduced flow resistance (i.e., lower RF). Their corresponding ASP formulations, however, showed minimal variation in the RF. This phenomenon leads to injectivity problems, especially for $NaBO_2$−CTAB−HPAM formulation, which showed higher RF values compared to the pure HPAM solution. Therefore, ETA−C_{16}mimBr−SPG formulation though might have lower mobility control compared to the pure SPG solution, and the formulation does not impose any injectivity issues. $NaBO_2$−CTAB−HPAM formulation, however, will cause injectivity issues despite having better mobility control.

SPG and HPAM exhibit favorable RRF values in the carbonate cores, as shown in Figure 8b. Nonetheless, the comparatively higher RRF values of SPG suggest its effectiveness in enhancing sweep efficiency by diverting flow of subsequent water injection. With the incorporation of ETA and C_{16}mimBr, the RRF values of the ETA−C_{16}mimBr−SPG formulation decreased, indicating reduced retention or adsorption of SPG. Moreover, the $NaBO_2$−CTAB−HPAM formulation shows a significantly high RRF which is unfavorable as it signifies severe permeability reduction. Consequently, the ETA−C_{16}mimBr−SPG formulation offers an improvement in sweep efficiency while minimizing issues with postformulation water injection. Conversely, the $NaBO_2$−CTAB−HPAM formulation may enhance sweep efficiency but is likely to result in injectivity problems during chemical injection and chase water injection.

3.4. Oil Recovery Potential. Our previous studies have validated that combinations of alkalis and surfactants yield synergistic performance in enhancing oil recovery.[47,48] All optimized AS formulations displayed improved interfacial properties and wetting capabilities. The inclusion of alkali has been found to mitigate anionic surfactant adsorption while enhancing cationic surfactant adsorption. Nevertheless, with the low concentration of cationic surfactant required, this enhanced adsorption will have less economic significance. Subsequently, SPG and HPAM were introduced to create different alternative and conventional ASP formulations, respectively, intended for application in both sandstone and carbonate formations. The discussion so far has been on the rheological characteristics of the various ASP formulations. In this section, the oil recovery potentials of the ASP formulations confirmed through core flooding experiments are discussed. The effectiveness of the alternative ASP formulations is evaluated in comparison with their conventional counterparts.

3.4.1. Oil Displacement in Sandstone Cores. As outlined in the methodology, two core flood experiments were performed by using Berea sandstone cores. The compositions of the different ASP formulations are detailed in Table 6. The concentrations chosen for the alkalis and surfactants were higher than optimal concentrations to account for chemical loss due to adsorption.[16,61,62] Nevertheless, the optimum concentration for the polymers from the rheological studies was maintained for economic reason since they are the most expensive among the chemical agents.[63] Utilizing findings from the compatibility tests,[47] a softened brine was employed for the conventional ASP run to mitigate the impact of scale formation and surfactant precipitation. The outcomes of the core flooding experiments are presented in Table 6.

The dynamic curves for the various displacement processes are also presented in Figures 9 and 10. The oil recovery curves indicate that both ASP formulations achieved additional oil
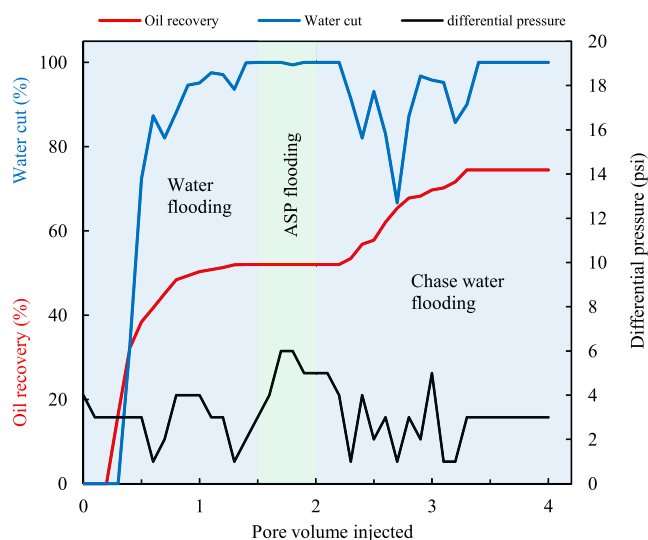
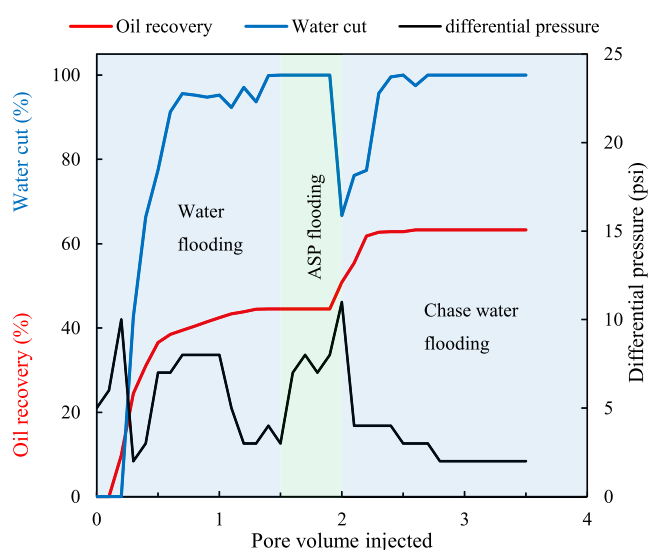**Figure 9.** Dynamic curves for the ETA-SCA-SPG formulation at 80 °C.

Figure 10. Dynamic curves for Na2CO3−SDS−HPAM formulation at 80 °C.

recovery following the waterflooding phase. In alkali and surfactant flooding, the primary mechanisms contributing to improved oil recovery involve reducing the IFT and altering rock surface wettability. Decreased IFT facilitates emulsification, aiding in the mobilization of crude oil droplets, while the modification of rock surface wettability ensures favorable relative permeabilities.[63] Further discussion on the oil recovery mechanisms of ETA and SCA can be found in.[47,64] However, while the addition of polymer is intended to stabilize emulsions, it also increases the IFT of the system, thereby impeding emulsification.

Nevertheless, viscoelastic polymers enable residual oil mobilization.[54,55] The mechanism behind the enhanced oil recovery can be elucidated by examining the dynamic curves of the water cut and the differential pressure. As depicted in Figure 9, there is a fluctuation in both the water cut and the differential pressure curve after the injection of the ETA−SCA−SPG slug. This fluctuation suggests intermittent production of oil and water, likely attributed to flow diversion within the heterogeneous core. The flow diversion is due to the favorable RRF of the ETA−SCA−SPG slug, as explained earlier in Section 3.3. The blockage of larger pores by chemical formulation through adsorption or mechanical trapping diverts subsequent water injection (chase water) to unswept pores.[46] Furthermore, the ETA−SCA−SPG slug also exhibits favorable RF as explained earlier, which yields good mobility control. However, this phenomenon is overshadowed by the flow diversion, as observed in the dynamic curves. From Figure 10, Na_2CO_3−SDS−HPAM slug injection was followed by a drop in water cut and a surge in differential pressure. This observation is attributed to mobility control by the ASP formulation, owing to favorable RF.

From the flooding results (Table 6), the ETA−SCA−SPG formulation improved the oil recovery better than the conventional ASP formulation. The ETA−SCA−SPG formulation achieved an additional oil recovery of ∼22%, while the Na_2CO_3−SDS−HPAM formulation achieved an additional oil recovery of ∼18%. The ETA−SCA system demonstrates superior performance in reducing IFT and altering wettability, as noted in.[47] Additionally, ETA has a minimal impact on the rheological properties of SPG, whereas SCA enhances the rheological behavior of SPG. Despite HPAM displaying superior rheological characteristics compared to SPG, the ETA−SCA−SPG formulation exhibits similar rheological behavior to the conventional ASP formulation.[57] Moreover, the ETA−SCA−SPG formulation demonstrates viscoelastic behavior, facilitating the mobilization of oil from small and dead-end pores.[57,65] These combined factors contribute to the enhanced oil recovery potential of the proposed alternative ASP formulation.

3.4.2. Oil Displacement in Carbonate Cores. To evaluate the oil recovery efficiency of the ETA−C_{16}mimBr−SPG formulation compared to that of the $NaBO_2$−CTAB−HPAM formulation, core flood experiments were conducted using carbonate cores. The specific compositions of the formulations utilized are outlined in Table 7. As previously mentioned, these formulations accounted for alkali and surfactant losses while maintaining optimal polymer concentrations. To prevent scale formation, softened brine was employed for both core flood runs. The outcomes of the oil displacement experiments are summarized in Table 7 as well. The data clearly indicate the significant potential of the ETA−C_{16}mimBr−SPG formulation in enhancing oil recovery, achieving an impressive additional oil recovery of approximately 27.05% postwaterflood. Conversely, the $NaBO_2$−CTAB−HPAM formulation also demonstrated a promising additional oil recovery, approximately 19.24%. This superior performance of the ETA−C_{16}mimBr−SPG formula-

Table 7. Results of Core Flooding for the ASP Formulations in Carbonate Cores

core no.	brine permeability (mD)	chemical formulation	oil recovery (% OOIP)		saturation (% PV)		
			waterflood	additional	S_{wi}	S_{oi}	S_{or}
DP 2	26.97	1.0% ETA + 0.04% C_{16}mimBr + 0.1% SPG	61.80	27.05	10	90	10
DP 3	24.78	1.0% $NaBO_2$ + 0.04% CTAB + 0.1% HPAM	61.12	19.24	16	84	17

tion is consistent with previously observed results in prior studies.[48]

Figures 11 and 12 depict the dynamic curves obtained from the various displacement experiments. Examination of the
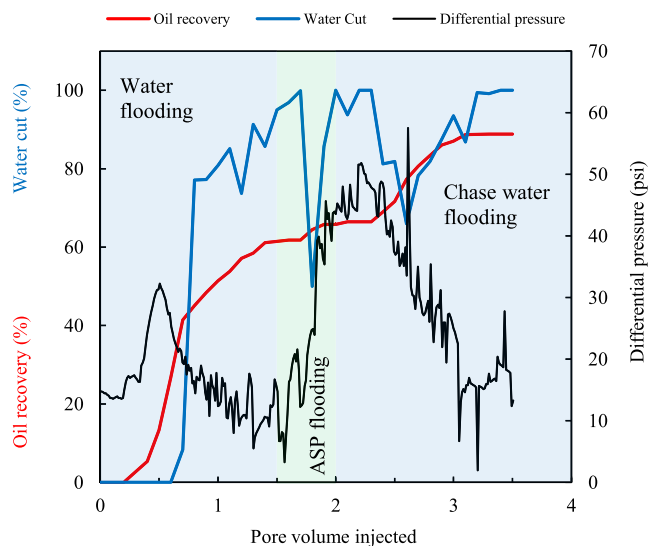

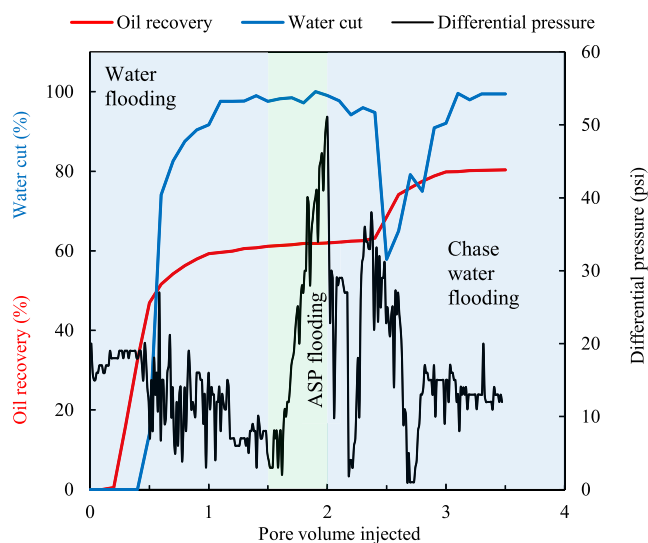**Figure 11.** Dynamic curves for ETA−C$_{16}$mimBr−SPG formulation at 80 °C.

Figure 12. Dynamic curves for NaBO$_2$−CTAB− HPAM formulation at 80 °C.

differential pressure curves reveals a significant pressure surge only during injection of the ETA−C$_{16}$mimBr−SPG formulation (Figure 11). In contrast, during the flooding process involving injection of the NaBO$_2$−CTAB−HPAM formulation, a secondary pressure surge occurs during the post-ASP water injection phase (Figure 12). The first pressure surge can be attributed to effective mobility control as both formulations exhibited favorable RF in the desert pink core (refer to Section 3.3). However, the subsequent surge is likely due to flow diversion and significant permeability damage. The absence of intermittent fluid production supports the indication of severe permeability reduction. As elucidated in Section 3.3, the NaBO$_2$−CTAB−HPAM formulation showed unfavorable RRF, possibly due to mechanical trapping of the formulation.

While both formulations demonstrate effective mobility control, the ETA−C$_{16}$mimBr−SPG formulation outperforms the NaBO$_2$−CTAB−HPAM formulation by achieving superior additional recovery, primarily attributed to minimal permeability damage.

The ETA−C$_{16}$mimBr system significantly enhances IFT reduction, achieving ultralow IFT levels, and facilitates wettability alteration, as reported in the literature.[48] Additionally, ETA has minimal impact on SPG's rheological behavior, while C$_{16}$mimBr enhances the rheological properties of SPG. Consequently, the ETA−C$_{16}$mimBr−SPG formulation demonstrates comparable rheological behavior to conventional ASP formulations.[37] Notably, the ETA−C$_{16}$mimBr−SPG formulation exhibits viscoelastic behavior, enabling the mobilization of oil from small and dead-end pores[57] in addition to its effective mobility control and favorable permeability reduction.[37] Given these characteristics, the ETA−C$_{16}$mimBr−SPG formulation exhibits outstanding potential as an alternative ASP formulation for applications in carbonate formations under high-temperature and high-salinity conditions.

3.5. Cost Implication Analysis. As mentioned earlier, the design of novel chemical formulations for EOR without consideration of the cost implications leads to the development of impractical formulations.[32] In view of this, a simple UTC estimation was made for the various ASP formulations to give insights into their practicability. The UTC does not incorporate the price of oil, but a comparison between the unit cost and price of oil could give a fair idea on the profitability of a project. According to Dean et al.,[32] for CEOR to be economically viable, the UTC should not exceed 40% of the price per barrel of oil. They explained that a chemical formulation whose UTC exceeds 40% of the oil price leaves little margin for all other EOR expenses.

Nevertheless, since the purpose of this estimation in this study is to compare the UTC of the various proposed ASP formulations to their conventional counterparts, no assumption is made for the oil price in this analysis. Furthermore, other cost elements that do not vary with the formulation types are excluded in this analysis. The estimated conceptual model cost per incremental barrel of oil produced is presented in Table 8. First, based on the chemical cost per incremental oil, it could be observed that the alternative ASP formulations are not better than the conventional ones in terms of practicability as shown in Figure 13. The chemical cost per incremental oil has been estimated using the range of chemical prices, and the average chemical price is used as the base case, on which subsequent analyses will be based. The ETA−SCA−SPG formulation has ∼$13.75/bbl compared to the ∼$8.45/bbl for the Na$_2CO_3$−SDS−HPAM formulation. For the carbonate application, ETA−C$_{16}$mimBr−SPG has ∼$7.19/bbl and the NaBO$_2$−CTAB−HPAM formulation has ∼$7.13/bbl.

Factors that have a significant impact on the chemical cost per incremental barrel include the cost of the chemicals, the incremental oil achieved, and the concentrations of the chemicals used. A formulation with a higher price per barrel of chemicals injected that outperforms a formulation with a lower injected barrel price could have a lower cost per incremental barrel of oil due to high recovery.[66] Nevertheless, although the alternative ASP formulations showed great potential in terms of incremental oil recovery, it did not warrant their practicability owing to the high cost of these chemicals. Efforts have been made to make these chemical agents economical through the use of cheaper source materials.[27,29,67] However, as mentioned

Table 8. Estimated Conceptual Model Unit Technical Cost

| ASP formulations	sandstone alt form	sandstone conv form	carbonate alt form	carbonate conv form
ETA, wt %	1		1	
Na$_2$CO$_3$, wt %		1		
NaBO$_2$, wt %				1
SCA, wt %	0.3			
SDS, wt %		0.3		
C$_{16}$mimBr, wt %			0.04	
CTAB, wt %				0.04
SPG, ppm	1000		1000	
HPAM, ppm		1000		1000
injected fluid cost, $/bbl	**4.51**	**2.35**	**3.50**	**2.30**
ASP injection PV	0.5	0.5	0.5	0.5
cost per bbl PV injected, $/bbl	**2.253**	**1.174**	**1.752**	**1.152**
incremental oil recovery (% OOIP)	22.44	18.78	27.05	19.24
initial oil saturation (S_{oi}) fraction	0.73	0.74	0.9	0.84
incremental oil recovery in PV	0.16	0.14	0.24	0.16
chem cost per incremental bbl oil, $	**13.75**	**8.45**	**7.19**	**7.13**
injected fluid bbl per incremental oil produced	3	4	2	3
cost per incremental barrel of mixing facilities, $	**3.05**	**7.20**	**4.11**	**6.19**
cost per incremental bbl oil, $	**16.80**	**15.65**	**11.30**	**13.32**
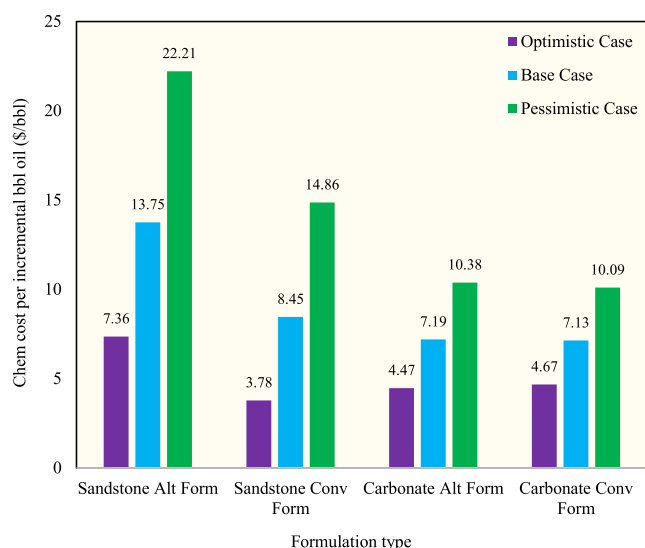
Figure 13. Chemical cost per incremental barrel for the various formulation types.

earlier, the major factor that influences the cost of chemicals is their availability. Irrespective of the superior attributes and performance of the chemicals, readily available chemicals will cost less. Based on the mass production of chemicals in China, where most chemical EOR projects are located,[68] these alternative formulations could become practicable in the foreseeable future.

The chemical cost could also be reduced by developing a low-concentration formulation.[42] This is the main advantage ASP flooding has over micellar-polymer flooding.[32] It is also observed

in Table 8 that due to the low concentration of the cationic surfactants, their formulations have lower injected fluid cost. An economic advantage of the alternative ASP formulations over the conventional ones is the nature of the polymers used. Due to the ionic nature of HPAM a higher concentration of the polymer is required to develop a fixed viscosity compared to the nonionic SPG in a high-salinity mixing water.[42] Therefore, in a situation where seawater is used to mix chemicals, the conventional formulations will have higher chemical costs compared to the alternative formulations.

Incorporating the cost of mixing facilities in UTC estimation improves the practicability of the alternative ASP formulations due to high incremental recovery, as seen in Figure 14. Since the
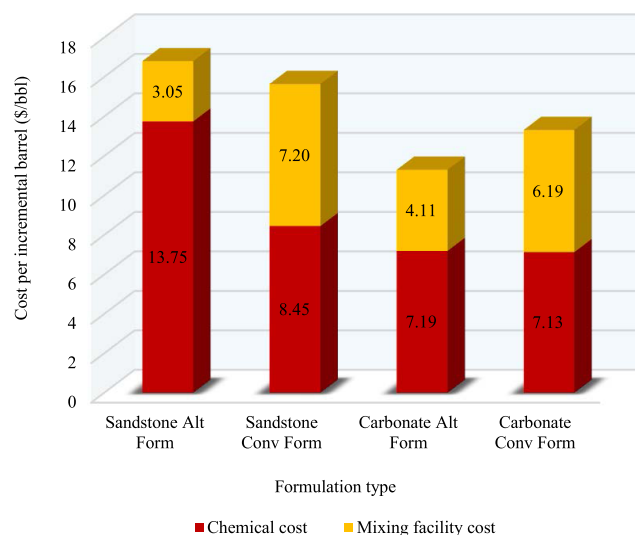
Figure 14. Cost per incremental barrel of oil for various formulation types.

same pore volume of chemical formulation is injected, a higher incremental recovery means less barrel of chemical injected per incremental oil. The mixing facility cost per incremental barrel of oil is estimated based on the volume of chemical injected. Therefore, the alternative ASP formulations have lower mixing facility cost per incremental barrel of oil. Furthermore, mixing facility cost increases with the addition of water treatment cost. The water treatment cost can be up to half the mixing plant cost as mentioned earlier. Therefore, the formulation with the need for water softening will have a higher mixing facility cost than the others. This explains the higher facility cost of the conventional formulation for sandstone application and the formulations for carbonate application.

Finally, there are other advantages of the proposed ASP formulations that have significant economic implications not considered in the UTC estimation. Compliance to various environmental regulations has cost implications that affect the overall economics of oil and gas projects.[69] The use of ecofriendly chemical agents will therefore help minimize the cost of compliance to environmental regulations. Furthermore, extensive preflush is required to prevent scale formation and surfactant precipitation. The use of surfactants with broad salinity tolerance, alkalis that have high hardness and salinity limit, and nonionic polymer reduces the cost of preflush. There is difficulty in controlling optimum salinity through preflush. As stated by Exxon in the Loudon II projects, preflushes are likely to be ineffective unless surfactant system has broad salinity

tolerance.[70] Therefore, this analysis could be made more robust by incorporating the economic values of these attributes of the alternative formulations.

4. CONCLUSIONS

In this study, alternative ASP formulations believed to alleviate various limitations associated with the application of their conventional counterparts have been proposed for applications in sandstone and carbonate reservoirs. The study first delves deep into the complex interplay of chemical agents in ASP formulations, shedding light on their bulk phase rheological behavior, as well as their performance in porous media. The potential of these formulations in enhancing oil recovery has been evaluated compared to their conventional counterparts through core flood experiment. The practicability of the proposed formulations is also evaluated through a simple UTC analysis. It can be concluded in this study that

- The alternative ASP formulations demonstrated pseudo-plasticity, enhancing macroscopic sweep efficiency, and viscoelasticity, improving microscopic sweep efficiency. Both ASP formulations effectively mitigated the adverse impact of inorganic alkalis on HPAM rheological properties. These formulations exhibit stability even under high salinity and elevated temperature conditions, with resilience observed in the ETA−C_{16}mimBr−SPG system.

- In porous media, the ETA−SCA−SPG formulation displays shear thinning behavior, indicating exceptional mobility control and favorable permeability reduction. Conversely, the ETA−C_{16}mimBr−SPG formulation exhibits limited mobility control but demonstrates a beneficial reduction in permeability.

- The ETA−SCA−SPG formulation showed promising EOR potential achieving an additional oil recovery of ~22%, while Na_2CO_3−SDS−HPAM formulation achieved an additional recovery of ~18%. The ETA−C_{16}mimBr−SPG formulation also exhibited excellent EOR potential by recovering ~27.05% additional oil, while the $NaBO_2$−CTAB−HPAM formulation also achieved an additional oil recovery of ~19.24%.

- By combining the chemical cost and mixing facility cost per incremental barrel, the alternative formulations had similar economic feasibility to the conventional formulations. The ETA−SCA−SPG formulation had a UTC of ~\$16.80/bbl, while the Na_2CO_3−SDS−HPAM formulation had ~\$15.65/bbl. On the other hand, the ETA−C_{16}mimBr−SPG formulation had a UTC of ~\$11.30/bbl while the $NaBO_2$−CTAB−HPAM formulation had ~\$13.32/bbl. The UTC for the alternative ASP formulations could be improved by incorporating the cost implication of other superior attributes of the alternative chemical agents.

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Notes

The authors declare no competing financial interest.

ACKNOWLEDGMENTS

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