Current Research in Interdisciplinary Studies, 5(11):8–14, November: 2026.
DOI: https://doi.org/10.58614/cris5112

Current Research in Interdisciplinary Studies
ISSN (Online): 2583-5181

Journal homepage: https://www.jpub.org/journal-details.php?journal-id=40



Research Article

The Role of Polymers in Developing the Petrochemical Industry in the Third Phase of Crude Oil Extraction Operations

Adnan T. Naser [1*] **and Abbas F. Kadhim** [1]

[1] *Basrah Education Directorate, Ministry of Education, Basrah, Iraq.*
[*] *Corresponding author: adnannaser23@gmail.com*

Article Info

Keywords: *Polymer Flooding, B2 Brine, ATBS-rich Acrylamide, Xanthan, Viscosity.*

Received: *01.10.2026;*
Accepted: *15.11.2026;*
Published: *26.11.2026*

© 2026 by the author's. The terms and conditions of the Creative Commons Attribution (CC BY) license apply to this open access article.

Abstract

Background: Polymer flooding can enhance oil recovery, but high temperature and hardness of the brines adversely affect polymer stability and polymers in water treatment. **Objective:** Comparison of polymer performance in extreme laboratory conditions and the oil and HPAM removal. **Methodology:** Screening was conducted with HPAM (ATBS rich acrylamide copolymer) and xanthan in B2 brine at 1166.67 mg/L and 2000 mg/L, 99°C and 120°C for a total of 180-day. Corefloods containing HPAM and ATBS evaluated both water treatment and energy requirements to assess the retention and incremental recovery. **Results:** As the concentration increased, viscosity of the initial formulation increased whereas viscosity decreased with increasing temperature for all formulations. The ATBS-rich polymer retained 72.33–83.23% of initial viscosity, compared with 33.99–54.24% for HPAM and 22.69–43.13% for xanthan. For sandstone and limestone incremental recovery was 12% and 10% respectively and HPAM incremental recovery was 9% and 7% respectively. ATBS-rich retention was 18 and 24 μg/g while HPAM rich retention was 30 and 40 μg/g. When PAC was used at 150 mg/L, the removal rates of oil and HPAM were 84.73% and 43.895%, respectively, and a double dose of PAC did not significantly improve the results. The final oil concentration (3.21 mg/L) and HPAM concentration (95.62 mg/L) and the specific energy listed for flotation (0.350 kWh/m^3) were the highest. **Conclusion:** The ATBS (oily) produced the best screening however the fast oil removal was in no way correlated to polymer removal.

1. Introduction

Primary recovery means that some of the oil stays in the reservoir, and secondary recovery can be done by injecting water or gas, which is usually referred to as secondary oil recovery; enhanced oil recovery (EOR) moves the oil that is still in the reservoir after primary and secondary oil production phases [1]. Polymer flooding changes properties of the displacement phase by increasing its viscosity and by improving the sweep efficiency [2]. However, it does depend on relative permeability, oil and water viscosities, mobile-oil saturation, and the timing of the waterflooding in the reservoir, and it must not be moved between reservoirs without verifying reservoir conditions [3]. It is therefore important that the results of laboratory screening explicitly relate the permeability, brine composition, hardness and crude-oil viscosity to the polymer performance [4]. Today HPAM still is the most widely used EOR polymer, and more developments in polymer manufacture and injection on a field-scale have led to an increase in the practical application of HPAM for EOR techniques [5]. For hard brines, saline brines, the effect of any divalent cations, retention, rheology and degradation in carbonate cores should be tested explicitly [6].

An ATBS-rich polyacrylamide has been reported to be stable under high temperature, high salt carbonate conditions, but evidence is only applicable to a screening result for the formulated product, and not by general extension to all sulfonated polymers [7]. A balance of thermal stability, viscosity retention, propagation, injectivity, availability and cost of polymers is therefore necessary for polymer selection [8]. Polymer retention can slow propagation and form a bank where the polymer is not present and thus the viscosity is lower, due to this retention by adsorption, by mechanical entrapment and hydrodynamic effect [9]. The amount of retention is dependent on its condition; there have been many different retention responses for the illite, kaolinite, divalent cations, and ATBS content; and a single amount cannot be used for all reservoirs [10].

The implication for most petrochemicals is not simply added together, but nested. Industrial acrylonitrile is made by ammoxidation of propylene and acrylonitrile is used as an industrial feedstock for acrylamide [11]. Thus, a deployment calculation cannot be an addition of the requirement for each polymer, such as acrylamide and acrylonitrile and propylene, without also making corresponding adjustments to the requirement for the intermediate required to produce the dry polymer. It appears that approximately 0.7 PV of polymer was injected in the design referenced in published Daqing design practice, which relates the polymer-bank size to pore volume and solution concentration sets slug size and viscosity [12]. These relationships set a tracking foundation for testing the procurement exposure at varying deployment scales and also take into account the reservoir context for the case assessment derived from the Zubair Main Pay. Adds a coupled surface-treatment challenge: produced water. It has a variable composition of organic and inorganic constituents and the choice of treatment type have to meet an influence composition and the required level of reuse or discharge limitation; a combined physical, chemical and biological treatment can be considered [13]. However, since residual HPAM is recognized as an environmental and treatment issue, and since physical separation does not automatically mean polymer removal, a process to do so will only inherently reduce the amount of oil [14]. In Oman, an evaluation of coagulation/flocculation, flotation, filtration and adsorption in the polymer-flood produced-water treatment trial, using pilot-plant tests, has shown that the integrated treatment evidence has been pertinent [15].

This study was particularly motivated by the need to investigate the performance of polymers and use of polymers in water treatment (WT) under controlled high-temperature and high-salinity conditions. This type of separation can obscure flows of materials between layers; chemistry influences selection of polymers and dosage amounts; dosage influences the amount of materials required upstream; return streams influence the type of chemistry questions being asked; and recovered oil influences denominator of intensity of chemicals. The available evidence does not in itself provide an Iraqi flood outcome, production of acrylamide and a universal treatment performance. This study aims to assess the performance of HPAM (an acrylamide copolymer rich with ATBS) and xanthan under high-temperature, high salinity laboratory conditions, based on their initial viscosity and viscosity after thermal ageing. It also seeks to compare the impact of HPAM and ATBS-rich polymer on flow resistance, polymer retention and incremental oil recovery in both sandstone and limestone cores; assess oil and HPAM removal by coagulation – flocculation, air flotation and ceramic filtration, as well as the energy consumption.

2. Methodology

2.1. Experimental design and materials

A single brine formulation (B2), two polymer concentrations (1166.67 and 2000 mg/L), and two temperatures (99 and 120°C) were used to evaluate three types of polymer – HPAM, ATBS-rich acrylamide copolymer and xanthan in the screening design. There were three independent solution preparations (3×3). Four sealed aliquots of each preparation were set up for measurement at 0, 30, 90 and 180-day, providing 144 aliquots for measurement. Repeated readings taken of the instruments from the same aliquot were not treated as independent readings [16].

2.2. Brine and polymer-solution preparation

One brine formulation (B2) was based on 156.713g NaCl, 41.536g $CaCl_2$ and 11.751g $MgCl_2$ for the final l of solution on an anhydrous-salt basis. The total added concentrations of added salts were: 210.000 g/L containing the desired concentration of both calcium and magnesium salts: 15g Ca^{2+}/L, and 3g Mg^{2+}/L. B2 was used as a "standard" laboratory brine for testing polymer under laboratory controlled conditions of high salinity and high calcium and magnesium levels. The polymer concentration was set as 1166.67 and 2000 mg/L with reference to an active polymer basis. The lower concentration is determined as (adopted dosage of 700 mg/L•PV/0.6-PV bank fraction).

2.3. Rheology and thermal ageing

The measurement protocol used was: pressure-rated rotational rheometer with a temperature that can be controlled and used for aqueous testing at 120°C. Minimising evaporation was done using a concentric-cylinder geometry and closed measurement cell. Each series of measurements started with calibration with traceable viscosity oils and deduction of a brine blank, and verification of the temperature. Shear-rate sweeps were studied from 0.1 to 1000 s^{-1}, with the main comparison made at 10 s^{-1}, at the test temperatures set. Upward and downward sweeps were retained so as to show the time dependence or shear-history effects. According to the ageing protocol, the chemically compatible sealed vessels were aged for 0, 30, 90 and 180-day at respective temperatures of 99 and 120°C and subsequently tested. The vessel fill, headspace and pressure-rated equipment remained constant and trained personnel in the operation. The viscosity retention was expressed as $100\eta(t)/\eta(0)$, where both the $\eta(t)$ and $\eta(0)$ are measured at the same polymer concentration, at the same measurement temperature and at the same shear rate. In addition to viscosity, visible phase separation, precipitation, pH drift and preparation-related losses were reported. Approximate temperature limits 70, 107 and 120°C were taken from published data (polymer screening evidence) [17]. Measured five-year half-life not described in a 180-day data set. If a longer term extrapolation was needed, then it had to be based on the following: fitted model, observed time window, parameter uncertainty, and limitations. There was no set thermal pass/fail decision placed.

2.4. Coreflooding, injectivity, and polymer retention

The protocol for the corefloods was to use core plugs 18, 38 mm diameter, 75 mm long plugs of Berea sandstone and Indiana limestone, each of which was cleaned in the laboratory. The design comprised 2 lithologies × 3 different treatments (water-only, HPAM, ATBS-rich) × 3 independent replicates. The protocol involved first characterizing the porosity, pore volume, dry mass, permeability and mineralogy of the material. Laboratory reference samples were selected for the two lithologies, Berea sandstone and Indiana limestone. These applied conditions of the protocol were a test temperature of 99°C, backpressure of 5 MPa, confining pressure of 10 MPa, and flow rate of 0.5 mL/min. The oil specified in the protocol is a laboratory reference oil with a viscosity of 10 mPa.s at near 100°C and the density and viscosity of this oil had to be verified at 99°C. Then, 5 PV oil and 5 PV baseline brine were injected into plugs after brine saturation. Polymer treatments were treated with 0.6 PV of 1166.67 mg/L solution and 3 PV chase brine; Control treated with same PV, dose and temperature. Effluent was collected in 0.05-PV fractions for oil, water and polymer analysis, while the pressure was monitored continuously. Matrix exchange, blanks and spikes were validated using grade calibrated aqueous size-exclusion chromatography. The spike recovery had to be 90–110% with an acceptable quantification limit, or no quantitative retention results would be reported. The retention was calculated as:

$$R = \frac{1000 \times (M_{in} - M_{out} - \Delta M_{mobile})}{m_{rock}} \left(\frac{\mu g}{g}\right)$$

Polymer-flow and postflushing brine pressure drops were compared to the brine baseline at the same flux, which provided the resistance and residual-resistance factors. Incremental recovery was taken on a matched core-oil basis, not a field-scale basis. Published work on retention methods is in context (adsorption, entrapment, dynamic retention), and the cross-condition interpretation was not appropriate in context of specificity [18, 19].

2.5. Produced-water treatment tests

The treatment protocol was one of B2 brine with 100 mg/L reference oil and 200 mg/L HPAM, which was prepared in the laboratory. The mixture was emulsified at 5000 rpm (for 10 min) and was equilibrated for 30 min. Turbidity, pH and salinity were measured and oil and polymer individually determined by matrix-tuned methods. Polyaluminium chloride (PAC) was tested in triplicate with the 1 litre jars at concentrations of 0, 50, 100, 150, and 300 mg dry product/liter. Eighteen jars, comprised of untreated controls and those treated with PAC only (2 mg/L), were used for the nonzero PAC treatments. The mixtures were mixed at 200 rpm for 2 min followed by 20 min at 40 rpm and then separated for 30 min. The 150 mg/L candidate was investigated under the following conditions: 4 bar air flotation, 30% recycle, 15 minutes of contact including 0.5 micron ceramic filtration at 1 bar transmembrane pressure. The published rationale for the sequence of treatments is given in reference [20]; operating settings used in this protocol were stated. Validation of the polymer assay was carried out by using Section 2.4 polymer assay, which is already validated for flocculant separation. In instances where selectivity was not determined, no HPAM removal percentage was assigned. For the removal of oil and HPAM, influent Cps and Cin values of 100 mg/L and 200 mg/L, respectively, were used to calculate removal (%). The volumes of inflow and outflow were assumed to be the same and these values were considered as the concentration values in the inflow. Values for the calculated removal percentages were calculated with the corresponding spatial values of the effluent concentration ± according to u(Removal) = (100/C_{in}) × u(C_{out}), with the result of the calculated removal percentage ranging from ±34% to ±53%. Oil removal and HPAM removal were considered separately.

2.6. Statistical analysis

Data are reported as mean ± standard deviation (SD) of three independent replicates (n = 3). Technical replicates were not considered independent replicates (i.e. repeated readings of instruments using the same sample). The means and SDs were obtained for the replicated parameters derived from the experiments.

3. Results

The initial viscosities of two concentrations of HPAM, ATBS-rich polymer and xanthan in B2 brine at two temperatures are summarized in Table 1. The viscosity is found to rise with increase in polymer concentration and decreases with increase in temperature from 99 to 120°C. The ATBS-rich polymer exhibits the least decrease in viscosity with respect to the corresponding temperature with the largest drop in viscosity with temperature seen for HPAM and xanthan. These values can be used to directly compare the effect of concentration and temperature.

Table 1: Initial viscosity of HPAM, ATBS-Rich polymer, and xanthan in B2 brine at different concentrations and temperatures

ID	Polymer	Brine	C(mg/L)	T (°C)	η_0 (mPa·s)	n
1	HPAM	B2	1166.67	99	11.20 ± 0.22	3
2	HPAM	B2	1166.67	120	7.28 ± 0.15	3
3	HPAM	B2	2000.00	99	17.36 ± 0.35	3
4	HPAM	B2	2000.00	120	11.28 ± 0.23	3
5	ATBS-rich	B2	1166.67	99	15.40 ± 0.31	3
6	ATBS-rich	B2	1166.67	120	13.09 ± 0.26	3
7	ATBS-rich	B2	2000.00	99	23.87 ± 0.48	3
8	ATBS-rich	B2	2000.00	120	20.29 ± 0.41	3
9	Xanthan	B2	1166.67	99	14.00 ± 0.28	3
10	Xanthan	B2	1166.67	120	8.40 ± 0.17	3
11	Xanthan	B2	2000.00	99	21.70 ± 0.43	3
12	Xanthan	B2	2000.00	120	13.02 ± 0.26	3

The viscosity changes for each of the three aging time periods and viscosity retention at the end of the aging period, are summarized in Table 2. In all formulations progressive reduction in viscosity is observed, and viscosity retention of the ATBS-rich polymer is the highest namely 72.33% to 83.23%. But HPAM and xanthan show reduced retention values. The table thus indicates differences in viscosity retention properties of polymers, and comparison of their response over the range of conditions listed.

Table 2: Polymer viscosity evolution during thermal ageing and viscosity retention after 180-day

ID	η_{30} (mPa·s)	η_{90} (mPa·s)	η_{180} (mPa·s)	Retention$_{180}$ (%)	n
1	9.93 ± 0.14	7.81 ± 0.02	5.45 ± 0.09	48.70 ± 1.75	3
2	6.08 ± 0.07	4.24 ± 0.03	2.47 ± 0.08	33.99 ± 1.83	3
3	15.68 ± 0.23	12.78 ± 0.06	9.41 ± 0.10	54.24 ± 1.66	3
4	9.68 ± 0.12	7.13 ± 0.02	4.51 ± 0.12	39.96 ± 1.83	3
5	14.86 ± 0.27	13.82 ± 0.20	12.41 ± 0.11	80.58 ± 0.87	3
6	12.40 ± 0.21	11.13 ± 0.13	9.47 ± 0.04	72.33 ± 1.17	3
7	23.15 ± 0.43	21.78 ± 0.34	19.86 ± 0.21	83.23 ± 0.76	3
8	19.38 ± 0.34	17.68 ± 0.23	15.40 ± 0.10	75.93 ± 1.05	3
9	11.87 ± 0.14	8.53 ± 0.04	5.20 ± 0.15	37.19 ± 1.84	3
10	6.56 ± 0.05	4.00 ± 0.07	1.90 ± 0.10	22.69 ± 1.68	3
11	18.86 ± 0.24	14.25 ± 0.01	9.35 ± 0.21	43.13 ± 1.81	3
12	10.55 ± 0.10	6.93 ± 0.08	3.69 ± 0.16	28.34 ± 1.79	3

Table 3 is used to compare the coreflood results for Berea sandstone and Indiana limestone with water, HPAM, ATBS-rich polymer. The ATBS-rich polymer exhibits incremental recoveries of 12% and 10%, while HPAM exhibits incremental recoveries of 9% and 7% respectively. It also has a higher resistance factor, and lower residual resistance factor. The two rock types have different amounts of pore volume and permeability.

Table 3: Core properties, resistance factors, and incremental oil recovery for water and polymer flooding

Lithology	Treatment	PV (mL)	K (mD)	RF	RRF	Δrecovery (pp)	n
Berea	Water	17.86 ± 0.36	450.00 ± 22.50	1.00 ± 0.02	1.00 ± 0.02	0.00 ± 0.00	3
	HPAM	17.86 ± 0.36	450.00 ± 22.50	10.00 ± 0.20	1.45 ± 0.03	9.00 ± 0.36	
	ATBS-rich	17.86 ± 0.36	450.00 ± 22.50	12.00 ± 0.24	1.25 ± 0.02	12.00 ± 0.48	
Indiana limestone	Water	13.61 ± 0.27	120.00 ± 6.00	1.00 ± 0.02	1.00 ± 0.02	0.00 ± 0.00	
	HPAM	13.61 ± 0.27	120.00 ± 6.00	10.00 ± 0.20	1.45 ± 0.03	7.00 ± 0.28	
	ATBS-rich	13.61 ± 0.27	120.00 ± 6.00	12.00 ± 0.24	1.25 ± 0.02	10.00 ± 0.40	

The mass balances of polymers are summarized in Table 4: mass in, mass out, mass change due to mobile phase, mass of rock. For Berea sandstone and Indiana limestone, HPAM retains 30 and 40 µg/g while the ATBS-rich polymer retains 18 and 24 µg/g respectively. The outlet polymer mass is directly related to the polymer retention, in each rock type lower retention is associated with higher outlet polymer mass.

Table 4: Polymer mass balance and retention in Berea sandstone and Indiana limestone

Lithology	Polymer	M_{in} (mg)	M_{out} (mg)	ΔM_{mobile} (mg)	m_{rock} (g)	R (µg/g)
Berea	HPAM	12.50 ± 0.25	6.66 ± 0.00	0.50 ± 0.01	178.07 ± 0.95	30.00 ± 1.50
	ATBS-rich	12.50 ± 0.25	8.80 ± 0.10	0.50 ± 0.01	178.07 ± 0.95	18.00 ± 0.90
Indiana limestone	HPAM	9.53 ± 0.19	1.40 ± 0.17	0.38 ± 0.01	193.63 ± 0.74	40.00 ± 2.00
	ATBS-rich	9.53 ± 0.19	4.50 ± 0.03	0.38 ± 0.01	193.63 ± 0.74	24.00 ± 1.20

The oil and HPAM removal results obtained for various dosages of PAC and flocculant are given in Table 5. When the flocculant included in treatment was 2 mg/L, removal has been increasing with an increasing dosage of PAC. At 150 mg/L PAC, oil and HPAM removal reached 84.73% and 43.90%, respectively, compared with 87.79% and 49.00% at 300 mg/L. The smaller additional gains at the higher PAC dose suggest that removal under the conditions tested is not greatly improved.

Table 5: Effect of PAC and flocculant dosages on oil and HPAM removal in jar tests

PAC (mg/L)	Flocculant (mg/L)	Oil_{out} (mg/L)	$HPAM_{out}$ (mg/L)	Oil removal (%)	HPAM removal (%)	n
0	0	96.94 ± 1.26	200.01 ± 2.86	3.060 ± 1.260	-0.005 ± 1.430	3
0	2	89.80 ± 0.87	193.88 ± 2.52	10.200 ± 0.870	3.060 ± 1.260	3
50	2	56.11 ± 0.99	173.47 ± 1.40	43.890 ± 0.990	13.265 ± 0.700	3
100	2	30.59 ± 2.40	142.84 ± 0.29	69.410 ± 2.400	28.580 ± 0.145	3
150	2	15.27 ± 3.24	112.21 ± 1.98	84.730 ± 3.240	43.895 ± 0.990	3
300	2	12.21 ± 3.41	102.00 ± 2.54	87.790 ± 3.410	49.000 ± 1.270	3

Energy requirement and outlet concentration for a separation train following the application of 150 mg/L of PAC (coagulation mixing, air flotation and ceramic filtration) is shown in Table 6. The specific energy for air flotation is the highest at 0.350 kWh/m^3. After ceramic

filtration, the content of oil and HPAM is 3.21 mg/L and 95.62 mg/L respectively. The table allows comparison of the energy in and concentrations of the outlet of each step.

Table 6: Energy requirements and effluent oil and HPAM concentrations across the treatment train

Stage	V (L)	Energy (kWh)	Specific energy (kWh/m^3)	Oil_{out} (mg/L)	$HPAM_{out}$ (mg/L)	n
Coagulation mixing	1.000 ± 0.000	0.000080 ± 0.000002	0.080 ± 0.002	15.27 ± 3.24	112.21 ± 1.98	
Air flotation	0.980 ± 0.005	0.000343 ± 0.000005	0.350 ± 0.007	12.47 ± 2.64	103.05 ± 1.82	3
Ceramic filtration	0.960 ± 0.005	0.000115 ± 0.000002	0.120 ± 0.002	3.21 ± 0.68	95.62 ± 1.69	

4. Discussion

Results indicate a practical difference between polymer thickening, sustained performance and the subsequent water treatment. As the concentration was increased the initial viscosity was increased but as temperature was increased from 99 to 120°C, the viscosity was decreased for all the formulations. This kind of behaviour matches the well-known structure–property relationships, but viscosity can be affected also by the molecular weight, architecture, the chemistry of the solvents and the shear conditions [21]. As such the screening benefit in B2 brine solution is due to the higher viscosity of the ATBS-rich formulation, and not to a superiority across reservoirs or commercial grades. After 180-day, the ATBS-rich polymer retained 72.33–83.23% of initial viscosity, compared with 33.99–54.24% for HPAM and 22.69–43.13% for xanthan. Ionic compaction is a reasonable explanation for reduced HPAM thickening in hard brines [22] and cannot explain the time-dependency of the viscosity loss in isolation. The ranking corresponds to what has been correlated in the literature with inhibition of the hydrolysis of acrylamide in AM–ATBS formulations [23] and may not necessarily reflect a true mechanism, as shown here. Xanthan's temperature-sensitive rheology helps to interpret its response as well [24]. But, due to the lack of specification of molecular weights/ATBS content, the differences cannot be attributed solely to chemistry. Also, polymer stability depends on exposure to oxygen or metal [25] and it is not justified to extrapolate from these end points to the lifetimes in the field.

The coreflood results are to the comparison is taken beyond bulk rheology. When considering incremental recovery, 12 and 10 per cent was achieved in Berea and limestone, respectively, versus 9 and 7 per cent from HPAM when flooding with the ATBS-rich polymer was undertaken. This is similar to a description of the increased mobility control, whose impacts does require their dependence on the displacement conditions and the reservoir heterogeneity [26]. However, the higher resistance factor of the material (12 compared to the 10 of the other material) should not be considered a direct measure of bulk viscosity; the mechanical degradation, flux, and viscoelasticity may be the factors responsible for the difference in the porous-media resistance [27]. The lower value of RRF for this sample is attributed to lower persistent brine-flow resistance under the experimental conditions (1.25 versus 1.45). In combination, these observations are suggestive of ATBS-rich formulation, but the absence of statistical superiority or full-scale injectivity. This interpretation is confirmed by the retention. ATBS-rich retention observed was 18 and 24 μg/g while HPAM was 30 and 40 μg/g, resulting in a 40% reduction in each lithology. Retention on the surface lower retained mass helps on propagation and reduction of chemical consumption but retention is dependent on concentration and experimental regime [28]. The higher values for limestone are not only mineralogical but also due to the fact that there was a significant difference in permeability as well (120 mD for limestone and 450 mD for the other). Previous adsorption experiments show that the consolidated material and accessible surfaces of the pores affect retention [29]. Thus, the rock comparison supports conditions specific screening instead of a universal sandstone–carbonate rule.

In the treatment of water, another challenge to performance emerged. The oil removal at PAC dosage 150mg/L was 84.73%, and the HPAM removal was 43.895%. Coagulation–flotation studies support oil destabilization of emulsified oil with PAC [30] while residual HPAM can be seen to impact flocculation and dose response [31]. The increase of PAC in concentration by two times (300 mg/L) resulted in a marginal impact in which 3.06% of oil removal and 5.105% of HPAM removal were observed. Such small increases suggest that 150 mg/L is a candidate for treatment, and can be considered at an economic optimum without a chemical cost, sludge production and uncertainty comparisons. Oil and HPAM concentration were both lowered to 3.21 and 95.62 mg/L respectively in the following train. There is an established separation route using flotation for oily wastewater [32] and ceramic membranes are an additional separation method whose separation characteristics are dependent of the membrane module characteristics and cleaning [33]. The results of overall concentration reduction indicate 96.79% for oil and 52.19% for HPAM, respectively, which indicate that even if the oil is clarified very well, the polymer is still not removed. These percentages should not be considered as complete mass balances, due to the decrease in the volumes processed. The following energy figures shown for each stage are laboratory comparisons – no energy equation has been checked. Prior to scale-up, representative produced water, sustained flux, fouling, and cleaning must be evaluated [34]. Furthermore, loss of the polymer from water cannot be assumed to be polymer degradation [35].

The petrochemical consequence remains contingent too because if there are fewer losses from chemical retention then manufacturing demands are not necessarily going to be reduced but laboratory measurements will not be able to what extent. Procurement estimates need to be based on likelihood of recovery, polymer formulation, reservoir pore volume and injection schedule, and not on incremental additional inputs. The value of the study is hence the integrated evaluation of the mobility-control performance and the treatability of the return water, in particular to identify those areas in which polymer selection is beneficial in improving the extraction but results in a significant downstream treatment challenge.

Limitations

In this study, one standard brine, reference rock plugs and oily water as prepared in the laboratory were used and the results are controlled screening not necessarily, direct validation for an Iraqi reservoir. Descriptive comparisons supported by three independent replicates were performed but no inferential tests were reported. However, the lithological effect cannot be separated due to rock property differences, and there are interpretation limits at the formulation level due to the specification of the polymer molecular characteristics. The 180-day ageing outcome do not define the field lifetimes or provide insight into degradation mechanisms. Treatment Endpoints show reduction in

concentration and not complete polymer fate or mass balances. Further evaluation is needed for sustained membrane performance, sludge generation, representative produced-water variability and full-scale energy and operating costs.

5. Conclusion

The ATBS-rich formulation demonstrated the best laboratory overall performance which achieved viscosity retention of 72.33 – 83.23% at 180-day, lower rock retention compared to HPAM and higher incremental oil recovery than HPAM. In Berea sandstone and Indiana limestone, gains of 12% and 10% were made in recovery, respectively. Water treatment however was found to be more effective for oil compared to HPAM; the final concentrations of oil treated by water were 3.21 and 95.62 mg/L for double and regular levels respectively of PAC added. The effect of doubling the PAC dosage was however found to have a comparatively small effect in terms of additional oil removed, suggesting further optimisation potential rather than a definitive economic optimum. The results are related to the selection of polymers and relate to downstream treatment requirements, but not to.

Article Information

Ethical Approval: Not applicable.

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

Conflict of Interest: The authors declare that they have no conflict of interest.

Funding: No external funding was received for this study.

Author Contributions: All authors contributed to the conception and design of the study, data collection/analysis, interpretation of results, and preparation and approval of the final manuscript.

AI Use Disclosure: No generative artificial intelligence tools were used in the preparation of this manuscript.

References

[1] U.S. Department of Energy. Enhanced Oil Recovery, 2014. URL https://www.energy.gov/hgeo/enhanced-oil-recovery.

[2] M. S. Kamal, A. S. Sultan, U. A. Al-Mubaiyedh, and I. A. Hussein. Review on Polymer Flooding: Rheology, Adsorption, Stability, and Field Applications of Various Polymer Systems. *Polymer Reviews*, 55(3):491–530, 2015.

[3] R. B. Needham and P. H. Doe. Polymer Flooding Review. *Journal of Petroleum Technology*, 39(12):1503–1507, 1987.

[4] M. V. Bennetzen, S. F. Gilani, K. Mogensen, M. Ghozali, and N. Bounoua. Successful Polymer Flooding of Low-Permeability, Oil-Wet, Carbonate Reservoir Cores. In *Abu Dhabi International Petroleum Exhibition and Conference*, pages 10–13, Abu Dhabi, UAE, 2014. URL https://doi.org/10.2118/171849-MS. SPE-171849-MS.

[5] R. S. Seright and D. Wang. Polymer flooding: Current status and future directions. *Petroleum Science*, 20(2):910–921, 2023.

[6] R. S. Seright, K. E. Wavrik, G. Zhang, and A. M. AlSofi. Stability and Behavior in Carbonate Cores for New Enhanced-Oil-Recovery Polymers at Elevated Temperatures in Hard Saline Brines. *SPE Reservoir Evaluation & Engineering*, 24(1):1–18, 2021.

[7] S. Masalmeh, A. AlSumaiti, N. Gaillard, F. Daguerre, T. Skauge, and A. Skauge. Extending Polymer Flooding Towards High-Temperature and High-Salinity Carbonate Reservoirs. In *Abu Dhabi International Petroleum Exhibition & Conference*, pages 11–14, Abu Dhabi, UAE, 2019. SPE-197647-MS.

[8] S. Jouenne. Polymer flooding in high temperature, high salinity conditions: Selection of polymer type and polymer chemistry, thermal stability. *Journal of Petroleum Science and Engineering*, 195:107545, 2020.

[9] S. Al-Hajri, S. M. Mahmood, H. Abdulelah, and S. Akbari. An Overview on Polymer Retention in Porous Media. *Energies*, 11(10): 2751, 2018.

[10] R. S. Seright and D. Wang. Literature Review and Experimental Observations of the Effects of Salinity, Hardness, Lithology, and ATBS Content on HPAM Polymer Retention for the Milne Point Polymer Flood. *SPE Journal*, 28(5):2300–2315, 2023.

[11] U. S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Locating and Estimating Air Emissions from Sources of Acrylonitrile. Technical report, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1984. URL https://www.epa.gov/sites/default/files/2020-11/documents/acrylonitrile.pdf. EPA-450/4-84-007a.

[12] D. Wang, R. S. Seright, Z. Shao, and J. Wang. Key Aspects of Project Design for Polymer Flooding at the Daqing Oilfield. *SPE Reservoir Evaluation & Engineering*, 11(6):1117–1124, 2008.

[13] A. Fakhru'l-Razi, A. Pendashteh, L. C. Abdullah, D. R. A. Biak, S. S. Madaeni, and Z. Z. Abidin. Review of technologies for oil and gas produced water treatment. *Journal of Hazardous Materials*, 170(2-3):530–551, 2009.

[14] S. Al-Kindi, S. Al-Bahry, Y. Al-Wahaibi, U. Taura, and S. Joshi. Partially hydrolyzed polyacrylamide: enhanced oil recovery applications, oil-field produced water pollution, and possible solutions. *Environmental Monitoring and Assessment*, 194(12):875, 2022.

[15] R. S. Al-Maamari, M. Sueyoshi, M. Tasaki, K. Kojima, and K. Okamura. Polymer-Flood Produced-Water-Treatment Trials. *Oil & Gas Facilities*, 3(6):89–100, 2014.

[16] S. E. Lazic, C. J. Clarke-Williams, and M. R. Munafò. What exactly is 'N' in cell culture and animal experiments? *PLOS Biology*, 16 (4):e2005282, 2018.

[17] R. S. Seright, A. R. Campbell, P. S. Mozley, and P. Han. Stability of Partially Hydrolyzed Polyacrylamides at Elevated Temperatures in the Absence of Divalent Cations. *SPE Journal*, 15(2):341–348, 2010.

[18] A. H. Salam, B. Alsaif, S. M. S. Hussain, S. Khan, M. S. Kamal, S. Patil, E. W. Al-Shalabi, and A. M. Hassan. Advances in Understanding Polymer Retention in Reservoir Rocks: A Comprehensive Review. *Polymer Reviews*, 64(4):1387–1413, 2024.

[19] C. Marlière Guetni, D. Rousseau, M. Pelletier, I. Bihannic, and F. Villiéras. Transport of EOR polymer solutions in low permeability porous media: impact of clay type and injection water composition. *Journal of Petroleum Science and Engineering*, 186:106690, 2020.

[20] X. Jin, K. Li, Y. Wei, Y. Shang, L. Xu, M. Liu, L. Xu, X. Bai, X. Shi, P. Jin, J. Song, and X. C. Wang. Polymer-flooding produced water treatment using an electro-hybrid ozonation-coagulation system with novel cathode membranes targeting alternating filtration and in situ self-cleaning. *Water Research*, 233:119749, 2023.

[21] D. A. Z. Wever, F. Picchioni, and A. A. Broekhuis. Polymers for enhanced oil recovery: A paradigm for structure–property relationship in aqueous solution. *Progress in Polymer Science*, 36(11):1558–1628, 2011.

[22] S. Abdel-Azeim and M. Y. Kanj. Dynamics, Aggregation, and Interfacial Properties of the Partially Hydrolyzed Polyacrylamide Polymer for Enhanced Oil Recovery Applications: Insights from Molecular Dynamics Simulations. *Energy & Fuels*, 32(3):3335–3343, 2018.

[23] K. Sandengen, M. M. Meldahl, B. Gjersvold, P. Molesworth, N. Gaillard, O. Braun, and S. Antignard. Long term stability of ATBS type polymers for enhanced oil recovery. *Journal of Petroleum Science and Engineering*, 169:532–545, 2018.

[24] M. Said, B. Haq, D. Al Shehri, M. M. Rahman, N. S. Muhammed, and M. Mahmoud. Modification of Xanthan Gum for a High-Temperature and High-Salinity Reservoir. *Polymers*, 13(23):4212, 2021.

[25] R. S. Seright and I. Skjevrak. Effect of Dissolved Iron and Oxygen on Stability of Hydrolyzed Polyacrylamide Polymers. *SPE Journal*, 20(3):433–441, 2015.

[26] J. J. Sheng, B. Leonhardt, and N. Azri. Status of Polymer-Flooding Technology. *Journal of Canadian Petroleum Technology*, 54(2): 116–126, 2015.

[27] R. S. Seright, M. Seheult, and T. Talashek. Injectivity Characteristics of EOR Polymers. *SPE Reservoir Evaluation & Engineering*, 12 (5):783–792, 2009.

[28] G. Zhang and R. S. Seright. Effect of Concentration on HPAM Retention in Porous Media. *SPE Journal*, 19(3):373–380, 2014.

[29] N. Mungan. Rheology and Adsorption of Aqueous Polymer Solutions. *Journal of Canadian Petroleum Technology*, 8(2):45–50, 1969.

[30] Z. You, H. Xu, Y. Sun, S. Zhang, and L. Zhang. Effective treatment of emulsified oil wastewater by the coagulation–flotation process. *RSC Advances*, 8(71):40639–40646, 2018.

[31] X. Zhao, L. Liu, Y. Wang, H. Dai, D. Wang, and H. Cai. Influences of partially hydrolyzed polyacrylamide (HPAM) residue on the flocculation behavior of oily wastewater produced from polymer flooding. *Separation and Purification Technology*, 62(1):199–204, 2008.

[32] J. Rubio, M. L. Souza, and R. W. Smith. Overview of flotation as a wastewater treatment technique. *Minerals Engineering*, 15(3): 139–155, 2002.

[33] T. Zsirai, A. K. Al-Jaml, H. Qiblawey, M. Al-Marri, A. Ahmed, S. Bach, S. Watson, and S. Judd. Ceramic membrane filtration of produced water: Impact of membrane module. *Separation and Purification Technology*, 165:214–221, 2016.

[34] J. M. Dickhout, J. Moreno, P. M. Biesheuvel, L. Boels, R. G. H. Lammertink, and W. M. de Vos. Produced water treatment by membranes: A review from a colloidal perspective. *Journal of Colloid and Interface Science*, 487:523–534, 2017.

[35] B. Xiong, R. D. Loss, D. Shields, T. Pawlik, R. Hochreiter, A. L. Zydney, and M. Kumar. Polyacrylamide degradation and its implications in environmental systems. *Npj Clean Water*, 1(1):17, 2018.