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Review of Important Aspects and Performances of Polymer Flooding versus ASP Flooding

Polymer flooding is a promising and effective chemical Enhanced Oil Recovery (cEOR) technology. Polymer flooding is especially cost-effective, whereas other chemical flooding methods, such as Alkaline Surfactant Polymer (ASP), are not profitable and cause serious on-site problems (scaling, uptime decrease, injectivity issue, hard-breaking emulsions). Recent papers in the literature mention ~30 field polymer floods. Most of them reported technical success. Although, polymer flooding has been applied ~60 years and it still requires further investigation to provide improvements. Thus, this paper describes important aspects and performances during polymer flooding based on a review of recent projects, combined with the Kalamkas field experience. A comprehensive literature review examines the applicability range in temperature, brine salinity, water source selection, oil properties, formation type, and permeability. Water source selection has an essential role during pilot/field project design and is one of the most responsible technical and economic success decisions. Polymer slug design has been extensively analyzed especially for the high viscosity oil fields; the selected oil/polymer viscosity ratio was usually much less than one. We placed significant emphasis on clarifying observed high polymer injectivities. We conducted feasibility studies of some reported ASP floods to clarify that this technology is not profitable at current oil prices. Also, we performed TAN analysis of three Kazakhstan oil fields for screening of ASP flood.

Keywords: polyacrylamide, polymer flood, chemical enhanced oil recovery (EOR), alkaline surfactant polymer (ASP), feasibility study.

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Content

List of abbreviations

ASP: alkaline surfactant polymer
ATBS: Acrylamide-Tertiary-Butyl Sulfonate
bbl: barrels of oil
Ca^{2+}: calcium
CO_2: carbon dioxide
cp: centiPoise
Da: Daltons
EOR: enhanced oil recovery
ESP: electrical submersible pumps
HEC: hydroxyethylcellulose
HPAM: hydrolyzed polyacrylamide
IFT: interfacial tension
kg: kilograms
km^2: kilometers square
m: meters
m^3/d: cubic meters per day
md: milliDarcy
mg KOH/g: milligrams of potassium hydroxide per gram of oil
Mg^{2+}: magnesium
MW: molecular weight
N_2: nitrogen
NVP: N-Vinyl-Pyrrolidone
OOIP: original oil in place
PCP: progressing-cavity pumps
PF: polymer flooding
ppb: parts per billion
ppm: parts per million
PV: pore volume
RF: recovery factor
SP: surfactant polymer
STOIIP: stock tank oil initially in place
TAN: total acid number
TDS: total dissolved salts

Review Plan

Inclusion and Exclusion Criteria: The present review is focused on polyacrylamides and biopolymers used in oil and gas industry as a displacement agent to enhance oil recovery from the reservoirs.

The review data mostly cover the technical papers and publications with the current polymer flooding experience. Thus, over the 50 papers were investigated to collect the main data from the polymer field projects. Most of them were taken from the leading oil and gas resource OnePetro. A lot of scientific journals from sources such as Scopus and Web of Science were also cited. The keywords used for the search were ‘chemical EOR’, ‘polymer flooding’, ‘polyacrylamides’, ‘polymer injectivity’, ‘chemical stability of polymers’, ‘thermal stability of polymers’, ‘polymer flooding field results’ etc. No statistical methods were used in this review.

Introduction

Only 3–5 % of global oil production can be attributed to enhanced oil recovery (EOR) [1]. This fraction is expected to grow, even for reservoirs with harsh conditions that do not allow for efficient oil production [2]. There are commonly several directions of EOR [3]: gas (CO_2, N_2, hydrocarbon, immiscible), thermal (steam, hot water, in-situ combustion, SAGD), chemical (polymer (P), surfactant polymer (SP), alkaline surfactant polymer (ASP) floods) and others (microbiological). Gas injection is used as an agent for a pressure maintenance system, and usually starts near the beginning of the field production (secondary recovery). Also, a central aspect is the availability of a gas source. For example, most EOR gas projects in the USA, Canada, and China are neighboring huge CO_2 reservoirs/fields [4, 5]. Some operators inject gas for utilization purposes and mask it as an EOR technique [6–8]. Thermal EOR is generally effectively applicable for heavy oil fields, where viscosity ranges from 100–10 000 cp or even higher. However, implementation of thermal methods is mainly limited by heat losses [9–11]. Heat losses can occur due to the initial reservoir condition (high thermal conductivity of the upper and/or lower impermeable layers, reservoir depth), development stage (high formation water saturation near injection wells), and infrastructure (well construction type, completion, tubing). Also another critical issue is the obtainability of the freshwater source. In contrast, chemical EOR does not have the limitations mentioned above. Hence it has been widely used in sandstone fields, especially at the late development stage. Furthermore, polymer flooding (PF) is often the most feasible chemical EOR technology. Especially, polymer flooding has prominence, where ASP/SP flooding is not profitable and causes serious on-site problems (scaling, uptime decrease, injectivity issue, hard-to-break emulsions) [12–15]. In addition, this paper describes the economic viability of ASP flooding based on some field case studies from the literature.

The principle of polymer flooding is to increase the viscosity of injected water and thereby develop a more favorable mobility ratio between displacing water and oil in place [16]. This approach reduces or avoids water fingering caused by geologic heterogeneities [17]. The favorable conditions for effective implementation of polymer flooding have been changed and improved by the augmented understanding of its mechanism over the last 60 years. The aim of this paper is to understand how the range of these conditions has changed and the current stage of development. The paper reviews some parameters such as oil viscosity, reservoir temperature, permeability, water ion composition, salinity, polymer concentrations, and injected volumes. Observations on required injection volumes have been described based on the Kalamkas oilfield experience. Water source selection has an essential role during pilot/field project design and is one of the most responsible technical and economic success decisions. Polymer slug design has been extensively analyzed, and it has been shown that achieving a unit oil-polymer viscosity ratio is not required, especially for high viscosity oil fields. Nevertheless, achieving a unit mobility ratio is desirable (to minimize viscous fingering), although it is not always practical because of injectivity constraints. Therefore, we placed significant emphasis on clarifying observed high polymer injectivities. Also, we performed a total acid number (TAN) analysis of three Kazakhstan oil fields for screening for ASP flood.

1 Polymer Flood Implemented Reservoir Conditions

Reservoir Depth, Temperature, and Salinity. Table 1 summarizes the main reservoir characteristics of many recent field projects. It can be seen that the majority of polymer flood projects are conducted in relatively shallow reservoirs with a depth of 1 600 m (except the Abu Dhabi case of 2 650 m). The reason is that shallow reservoirs have lower temperatures, which promotes polymer stability. Polymer degradation can be substantial at high temperatures (over 70 °C according to [18]). Thermal degradation of partially hydrolyzed polyacryl amides usually involves increased hydrolysis of HPAM amide groups, leading to precipitation with divalent cations (Ca^{2+}, Mg^{2+}). Incidentally, salinity and hardness often exhibit a linear relationship, which was obtained by analysis of several projects shown in Figure 1. Data were taken from fields such as West Koyot, Pelican Lake, Buracica, Bohai bay, Kalamkas, and others. Moreover, the interactions of hydrolyzed polymers with divalent cations lead to the reduction of polymer coil size. As a result, a decrease in solution viscosity or even polymer precipitation occurs [19, 20]. However, the inclusion of copolymers/monomers such as ATBS (Acrylamide-Tertiary-Butyl Sulfonate) and/or NVP (N-Vinyl-Pyrrolidone) enhances the thermal stability substantially [21–23] and allows polymers to be tolerant up to 120 °C. According to the table, many polymer flooding projects, especially in Kazakhstan, are conducted using monomer-modified polymers and show promising results even at high salinities [24–28].

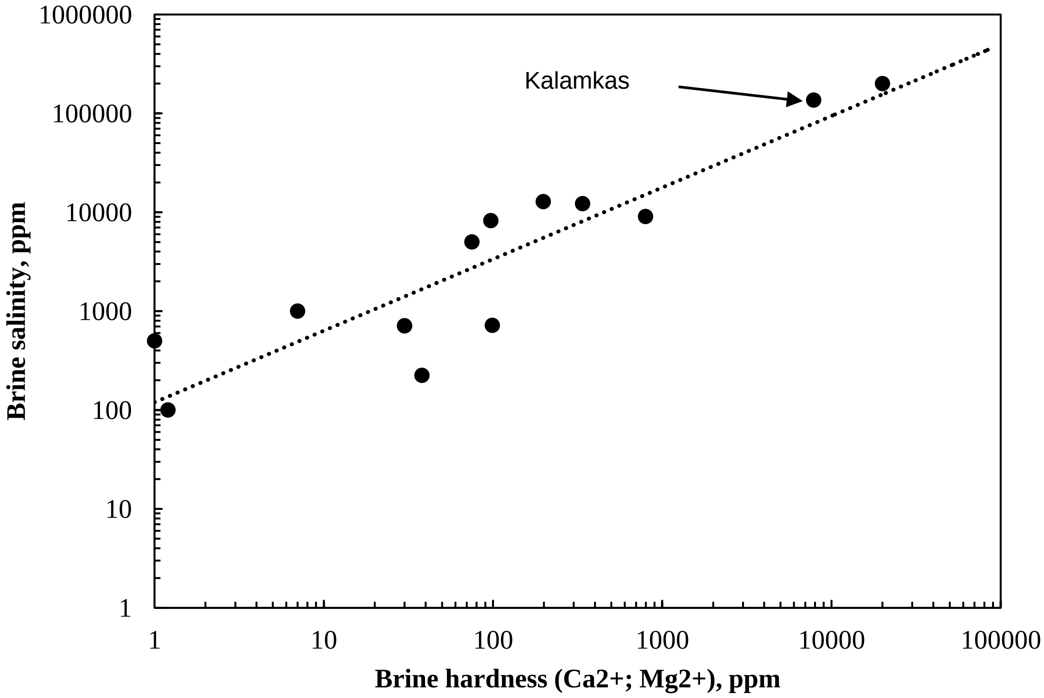

Figure 1. Relationship of water hardness to water salinity from different polymer flood projects

Formation Permeability. The permeability of reservoirs affects the molecular weight (MW) of polymers used. The weight and size of polymer molecules are critical since larger polymer molecules tend to plug in relatively small pore throats, reducing the permeability and solution concentration. This process is called mechanical entrapment, which negatively affects the propagation of polymer in the reservoir [2, 17, 29]. Theoretically, less retention is expected as permeability increases. Therefore, experience-supported recommendations for polymer selection depending on polymer weight have been made by Wang et al. [30]. The minimum permeability required for successful polymer flooding is in the range of 100–300 md, and MW should generally be not greater than 17–25 million Daltons. This statement is supported by Table 1, where the permeability is mostly greater than 100 md, while the average permeability is around 2 000 md.

Oil viscosity. Recent years in the history of polymer flooding (especially in Canada) have made it clear that achieving a favorable mobility ratio close to 1 or less is not always the primary goal, but to reduce it as much as possible. As many field experiences show, injecting the same or close viscosity to live oil may be unnecessary. The fact that end-point relative permeability to water is usually much less than that to oil is often used to justify why the injected polymer viscosity can be less than oil viscosity. This approach has been applied to Canadian fields, where oil viscosity reaches 15 000 cP, and a “favorable” mobility ratio cannot even be achieved. Nevertheless, the experience of oilfields such as Pelican Lake, Seal, Mooney, East Bodo, etc. shows that polymer flooding can effectively produce more oil even if the oil is heavy. Many of these fields experienced an unsuccessful thermal injection, which becomes non-profitable in deep and/or thin reservoirs and requires a lot of energy [31]. Besides that, the design of the injected polymer viscosity is commonly based on the optimum economic output (i.e., net present value) according to reservoir modeling and feasibility studies. Some of these concepts are presented in literature sources [28, 32, 33].

Table 1

Polymer flooding conditions in world projects

#	Field	Status	Depth, m	Formation thickness, m	Temperature, °C	Porosity, %	Permeability, md	Brine salinity, ppm	Live oil viscosity, cp
1	2	3	4	5	6	7	8	9	10
1	Marmul, Oman [34–36]	Field scale (Al Khalata)	550–675	–	46	25–30	100–2 000	4 600	90
2	Milne Point, Alaska, USA [37–39]	Pilot (J-Pad)	1 082	3–5.5	21.7	32	500–5 000	27 500	300

Continuation of Table 1

#	Field	Status	Depth, m	Formation thickness, m	Temper-ature, °C	Po-rosity, %	Permeabil-ity, md	Brine salinity, ppm	Live oil viscosity, cp
1	2	3	4	5	6	7	8	9	10
3	Captain (offshore), UK [40–42]	Pilot (SUCS)	914	<36.6	30.5	31	5 000	N/A	80
4	Dalia/Camelia (offshore), Angola [43, 44]	Pilot (DAL-710, 713, 729)	800–1 000	6–10	45–56	–	>1 000	117 700	1–11
5	Daqing, China [32, 45]	Field scale	1 000	6.1	45	25	1 100	3 000–7 000	9
6	Shengli, China [46]	Field scale	1 230	7.9–30.5	71	33.5	1 800	3 900	50–150
7	Shuanghe, China [47]	Pilot (Dong-Gudao)	1 460	25.2	72	20	422	4 356	7.8
8	Bohai bay, China [48]	Pilot (Layer II)	1 300–1 600	15–25	65	31	2 000	9 374	24–452
9	Tambaredjo, Suriname [49]	Pilot (Block-X)	375–425	13.7	36	33	3 000–10 000	10 000	300–1 100
10	East–Messoyakhskoe, Russia [50]	Pilot (T1-sand)	800	15–50	16	28–30	50–5 000	N/A	111
11	Matzen, Austria [51–53]	Pilot (PK1-3)	1 150	20	50	20–30	500	25 000	19
12	Carmopolis, Brazil [54, 55]	Pilot (8 TH)	700	50	50	12–22	100	20 000	70–120
13	Canto do Amaro, Brazil [54, 55]	Pilot	500	8	55	22	204	500	7
14	Buracica, Brazil [54, 55]	Pilot (Pilot-1)	305	20–40	60	20	150–400	33 000	11
15	Diadema, Argentina [56, 57]	Pilot (Pilot-1)	900	4–12	50	30	500	16 000	100
16	El Corcobo, Argentina [58, 59]	Pilot	650	0.5–18	38	27–33	500–4 000	46 000	160–300
17	Bockstedt, Germany [60]	Pilot	1 200	15	54	24–30	2 000	186 000	11–29
18	East Bodo, Canada [9]	Pilot	794	3.2	27	30	1 000	25 000–29 000	600–2 000
19	Mooney, Canada [61, 62]	Pilot (11-14 pattern)	875–925	3–5	29	26	1 500	N/A	300–600
20	Seal, Canada [10, 62]	Pilot	600–650	8.5	20	27–33	3 000–5 800	N/A	3 000–7 000
21	Caen, Canada [10, 63]	Pilot	930	2.9	21	26.5	500–2 000	13 509	69.5–99
22	Wainwright, Canada [64]	Pilot (Suffield area)	650	–	–	30	300	72 000	100–200
23	Pelican Lake, Canada [11,65]	Pilot (B pool)	300–450	1–9	12–17	28–32	300–5 000	N/A	1 650–15 000
24	Mangala, India [66–68]	Pilot (NE-5)	600	24–40	<62	21–28	5 000	7 140	9–22
25	Abu Dhabi [69]	Single well injection test	2 650	20	>93	20–30	10–1 000	>200 000	1
26	Nuraly	Pilot	1 550	10	81	19	368	57 000	0.91
27	East–Moldabek, Kazakhstan [25]	Pilot scale	250	10	25	35	1 500	140 000	400
28	Zaburunje, Kazakhstan [25]	Pilot (FM1)	875	10	38	30	230–1 000	145 000	20
29	Kalamkas, Kazakhstan [24, 27, 28]	Industrial pilot scale	746	10–20	39	28	946	136 211	16
Note – all 29 fields are sandstone reservoirs except the Abu Dhabi (carbonate-limestone) oil field.									

Figure 2 shows a radar diagram of the major screening parameters for polymer flooding, showing the polymer flooding applicablity range. Wide ranges are associated with most parameters, and the ranges have been expanded due to the growth in the understanding of the technology and its refinement during the past 60 years. However, temperature and depth of formation remain the weakest side of polymer flooding. Even if new monomer-modified co- and terpolymers are showing promising laboratory results [22, 23, 70–72], there are no real field implementations where the formation temperature is greater than 109 °C [73]. Nevertheless, the radar chart provides an excellent visual representation of observations made previously in this work.

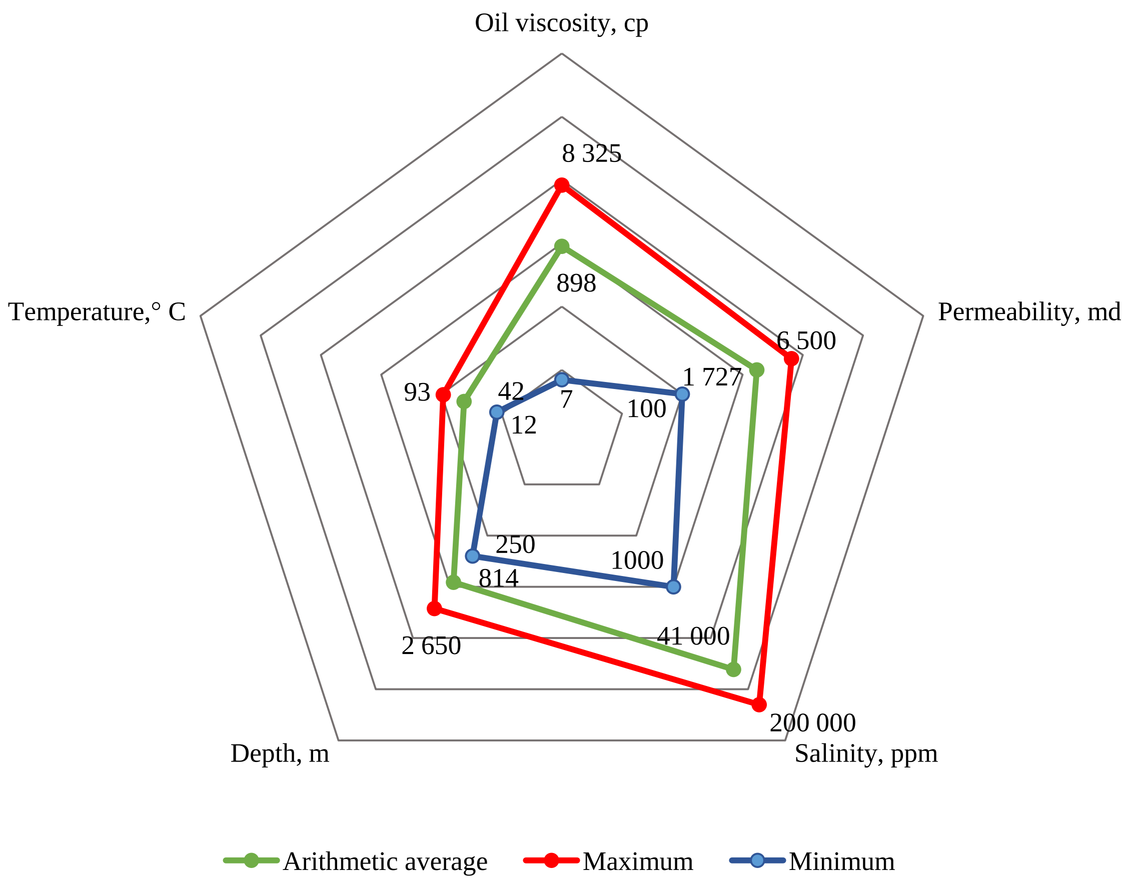

Figure 2. Main screening parameters for polymer flood according Table 1

2 Polymers and Injection Parameters

Polymers used in EOR. Table 2 summarizes the main injection parameters during the polymer flooding. According to many authors [2, 16, 17, 74], there are two main types of polymers in terms of their origin: synthetic polymers or polyacrylamides (PAM) used in paper production and biopolymers used in the food industry as a thickener. In early polymer flood applications, polyacrylamides were used much more frequently than biopolymers due to their efficient manufacturing environment and commercial availability. This tendency continues till these days because over 95 % of polymer floods are based on polyacrylamides. Also, it is essential to highlight that polyacrylamide is mainly used in its partially hydrolyzed form (HPAM). The main representative of biopolymers is xanthan gum (derivation of micro-organism *Xanthomonas campestris*) [75, 76], which is characterized by semi-rigid molecules, whereas the structure of polyacrylamide molecules is flexible long chains [77]. Understanding the structure of molecules and microscale studies reveals each polymer type's key features. Thus, the primary polymer parameters, such as stability to temperature, high water salinity, mechanical degradation, biodegradation, dissolvability, viscosifying characteristics, adsorption to the rock surface, etc., are noted.

There are many laboratory and simulation studies [78–81] that confirm HPAM benefits in viscosifying characteristics, biodegradation, and injectivity over biopolymers. Alagic et al. [80] states that biopolymers are often sensitive to biodegradation, and it is important to protect them against potential microbial degradation. On the other hand, Al-Murayri et al. [82] indicated that biopolymers are more stable in the presence of oxygen and H_2S in any concentration, while high concentrations limit stability for HPAM. Seright and Skjevrak [83] suggest that HPAM degradation can be mitigated by keeping dissolved oxygen at an undetectable or acceptable level (as close to zero as practical). For this reason, modern polymer injection units provide nitrogen blanketing in the polymer preparation system to prevent air contact with the solution [26]. Specialized equipment for HPAM solutions was also mentioned in many works [37, 44, 84]. For example, Abbas et al. [84] argue that specialized equipment is essential in the field conditions to overcome problems with dissolving HPAMs (e.g. fish-eyes and gels). In contrast, such dissolution problems are not observed for hydroxyethylcellulose (HEC) biopolymers. Seright et al. [85] confirmed that xanthan solution is more resistant to mechanical degradation showing pseudoplastic behaviour during coreflooding experiments. In addition, synthetic HPAMs lack thermal and brine hardness stability, as will be discussed below. However, the main conclusion for the polymer's limitations is made by Ryles [18] who observed that the main challenge lies with high temperature rather than high salinity. Despite these disadvantages, HPAM is still the most widely used polymer in the world. An internet search suggests that ~4×10^9 lbs of HPAM/PAM is produced each year, whereas only ~4×10^7 lbs of xanthan is produced. Thus, HPAM production (and availability) is roughly 100 times greater than xanthan (the most extensively produced biopolymer). The price of xanthan (per weight) is 3–6 times greater than that of HPAM. This information is from a combination of internet and confidential sources.

A major factor that aids the application of polymer flooding is the current price for large HPAM purchases (~\$2–2.5/kg) is actually less than that in 1980 (~\$4–5/kg). This fact is remarkable because the Consumer Price Index in the USA (the average cost of goods and services) has more than tripled since 1980. Much of the credit for keeping HPAM prices must go to the HPAM manufacturers. However, some credit must also be given to several large-scale polymer floods (Daqing, Mangala, Pelican Lake) that played a significant role in providing the market and promoting low-cost polymers. Interestingly, the primary justification (used by big oil companies) for eliminating EOR in 1986 was that the "cost of chemicals would always rise in direct proportion to the price of oil". The reality of HPAM price history emphasizes that technical and economic advances can upend conventional wisdom at a particular time.

Polymer Injection Design. A literature review reveals that polymer concentrations were in a wide range of 300–2 750 ppm and, on average, was 1 570 ppm, as shown in Fig. 3. Furthermore, the viscosity range was 3–300 cp and in average was 41 cp. Only a minority of field projects used polymer viscosity higher than 40 cp. On the other hand, some projects used relatively low polymer concentrations and achieved considerable viscosity because low-salinity (or fresh) water was used [86–88] (#26 line in Table 2). The selection of the process water source is paramount and should satisfy the following concepts: 1) compatibility with reservoir rock & fluids (no clay swelling/migration) should occur; 2) low cost and existing infrastructure; 3) high potential production capacity; 4) salinity (especially divalent cations) as lower as practical; 5) chemical stability; 6) dissolved iron, oxygen, TDS, oil contents as low as possible (absence is an ideal case); 7) if dissolved iron exists in the process water dissolved oxygen level should be controlled as low as possible (at a maximum <200 ppb based on [83] and <46 ppb based [89]).

Polymer Injectivity. Injectivity issues are important and of high current interest in polymer flooding technology. Besides creating a high-pressure displacement front *in-situ*, providing a sufficient injection rate is also essential. Moreover, in unfractured vertical injection wells, simple Darcy-law calculations reveal that polymer injectivity relative to water should be reduced by at least 80% [85]. In contrast, most field projects summarized in Table 2 reported relatively high polymer injectivity. Furthermore, the Kalamkas field case [24] demonstrated that polymer injectivity was roughly 4 times greater than water injectivity. Previous work has shown that the viscoelastic (or shear-thickening) behavior of HPAM polymers occurs at high fluxes, and as a consequence induces a fracture to form and extend in the well [90]. The presence of fractures during the polymer flood is consistent with the fact that most of the worldwide polymer flood projects inject into vertical wells above the formation parting pressure [33, 85, 87, 91–93]. In contrast, if fractures or fracture-like features are not present during polymer injection, achieving a favorable economical injection rate and acceptable voidage replacement ratio (e.g., the same as during a waterflood) are not practical. Also, Sagyndikov et al. [27] have demonstrated that these induced fractures reduce polymer mechanical degradation to a level that mitigates this degradation concern in a field setting.

Thomas et al. [94] have investigated injectivity prediction difficulties by reviewing some polymer field projects. The authors conclude that improving injectivity prediction is needed as pessimistic predictions are often obtained and can lead to the evaluation of polymer volumes that can be injected. The paper suggests further investigations using simulation processes, especially in reconsidering reservoir properties such as near-wellbore fractures and modeling polymer rheology and its features. Table 2 represents a modified summary of the polymer projects injectivity data presented by Thomas et al. [94].

Table 2

Polymer formulation and injectivity of PF projects

#	Field	Polymer type	Mw, million Da	Polymer concentration, ppm	Polymer viscosity, cP	Porcess water salinity, ppm	Injection rate, m^3/d	Injectivity issues
1	2	3	4	5	6	7	8	9
1	Marmul, Oman	HPAM	18–20	–	15	4 500	250–750*	No (fractures)
2	Milne Point, Alaska, USA	HPAM	N/A	1 600–1 800	45	2 500	350 and 95*	Initially no (decreased after 7 months)
3	Captain (offshore), UK	HPAM	18	~2 000	20	–	4 710 then 2 041*	No
4	Dalia/Camelia (offshore), Angola	HPAM	12–16	900	2.9	25 000–52 000	2 385*	No
5	Daqing, China	HPAM	N/A	2 000–2 500	40–300	700	0.14–0.2 PV/yr**	Mostly no (hydraulic fracturing applied if needed)
6	Shengli, China	HPAM	17	2 000	25–35	3 900	–	–
7	Shuanghe, China	HPAM (S625+S525)	N/A	1 090	93 at 3 rpm	fresh water	–	–
8	Bohai bay, China	Associative polymer	20	1 750	77.6–131	–	–	–
9	Tambaredjo, Suriname	HPAM Flopaam 3630S	N/A	<2 500	45 then 125	500	150–450*	No (fractures)
10	East-Messoyakhskoe, Russia	HPAM	20	1 830	30 at 7.34 s–1 80 at res. cond.	–	150*	No
11	Matzen, Austria	HPAM Flopaam 3630S	5–10	800	1.6–4.6 at res. cond.	23 000	400*	No (fractures)
12	Carmopolis, Brazil	HPAM	5–10	1 000	30	500	165*	No
13	Canto do Amaro, Brazil	HPAM	5–10	750	10	–	200–300**	No
14	Buracica, Brazil	HPAM	20	500	40	100	60–120**	No
15	Diadema, Argentina	HPAM Flopaam 3630S	N/A	1 500–3 000	70	16 000	1 000**	No
16	El Corcobo, Argentina	HPAM	N/A	500	20–25	1 044	1 000**	No
17	Bockstedt, Germany	Biopolymer Schizophyllan	18–20	300	25	–	135**	No (after reperforation and acidizing)
18	East Bodo, Canada	HPAM	20–25	1 500	50–60	–	200*	No (horizontal wells)
19	Mooney, Canada	HPAM	20	1 500	20–30	–	–	No (horizontal wells)
20	Seal, Canada	HPAM Flopaam 3630S	20	1 000–1 500	25–45	2 500–11 000	–	No (horizontal wells)
21	Caen, Canada	HPAM Flopaam 3630S	N/A	1 300	32	15 287	800*	No

Continuation of Table 2

#	Field	Polymer type	Mw, million Da	Polymer concentration, ppm	Polymer viscosity, cP	Porcess water salinity, ppm	Injection rate, m^3/d	Injectivity issues
1	2	3	4	5	6	7	8	9
22	Wainwright, Canada	HPAM	20	2 100–3 000	25	72 000	–	No (after installing booster pumps)
23	Pelican Lake, Canada (2006-...)	HPAM Flopaam 3630S	20	600–3 000	13–25	–	–	No
24	Mangala, India (2014-…)	HPAM Flopaam 3630S	18–20	2 500–3 000	15–20	5 400	~740*	No
25	Abu Dhabi	HPAM (ATBS)	N/A	500–2 400	1.2–5.5	>200 000	144*	No
26	Nuraly (2014-2019)	HPAM Flopaam 5115 VHM AL-777	14	500	6	1 300	80–220*	No
27	East-Moldabek, Kazakhstan (2019-…)	HPAM Flopaam 1630S	N/A	2 400	23	140 000	50*	No
28	Zaburunje, Kazakhstan (2014-…)	HPAM	N/A	1 950	15	135 000	740**	No
29	Kalamkas, Kazakhstan (2014-…)	HPAM R-1 and Superpusher K129	14	2 000	24	98 722–108 914	300*	No (fractures)

Note: * — injection rate for 1 well; ** — full field injection rate.

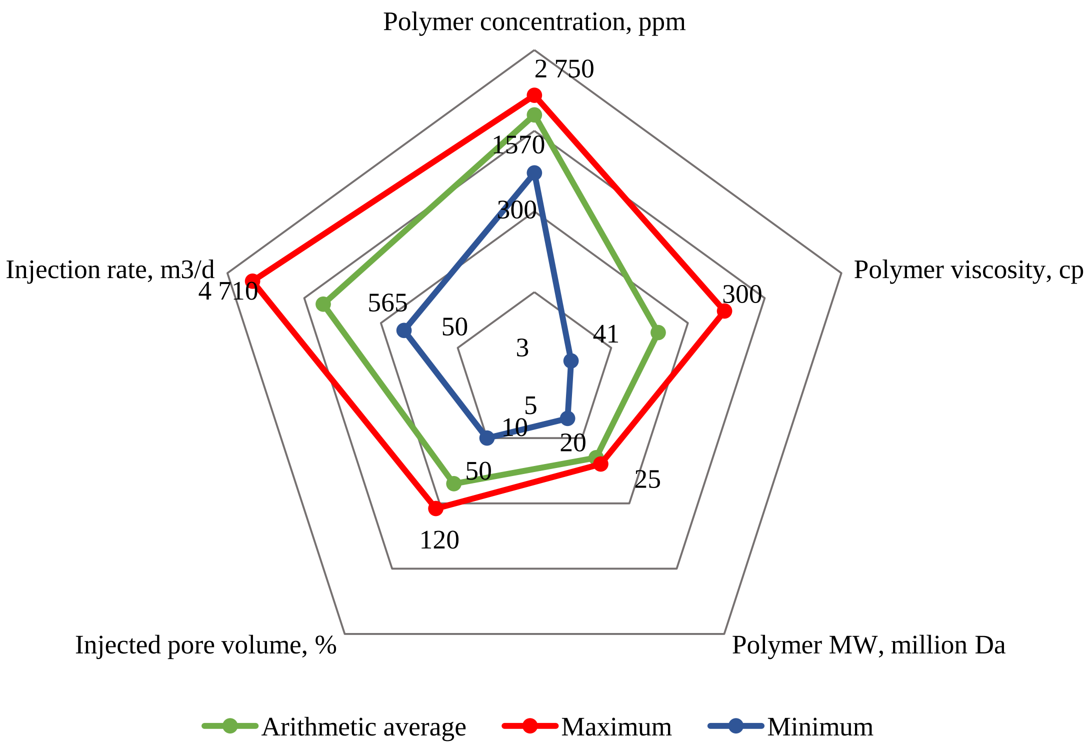

Figure 3. Polymer injection parameters for polymer flood according Table 2

Polymer viscosity and slug design. Determining the desired viscosity of the polymer solution is a key objective of designing the polymer flooding project since it strictly affects project feasibility. A simple method to estimate desired viscosity has been developed by Sorbie and Seright [95]. As the authors say, the base-case method helps to determine the target polymer viscosity by simply multiplying waterflood end-point mobility ratio times the permeability contrast (highest permeability divided by the lowest permeability. Thus, the measurement of water and oil relative permeabilities is a key for the polymer flood design.

Table 3 summarizes the main reservoir development parameters (mobility ratio & permeability contrast) in the comparison of PF design (viscosity, slug size), implemented conditions (number of injectors & producer, watercut) and an achieved result (incremental recovery factor — RF).

As the polymer solution is a shear-thinning (non-Newtonian) agent, it is strongly recommended to consider its apparent viscosity (dependent on the shear rate). Typically, polymer viscosities are evaluated at a shear rate of 7.34 s^{-1} which has been accepted as the industry standard (corresponds to 6 rpm of UL adapter on Brookfield viscosimeter). In fact, typical shear rates in reservoir conditions (deep from well perforations) can be lower (depending on permeability, well spacing, and injection rate), so the apparent viscosity could be higher. In addition, reservoir temperature should be considered while measuring the polymer solution viscosity since the higher the temperature, the lower the viscosity is expected.

Sheng [96] and Seright [33] show that over the 60-year history of polymer flooding, the concentration and volume of polymer injection have increased over time. Whereas the slug volume in the 1960–1980 period was around 5–17 % of the pore volume, in the last 20 years the volume has reached 120% (Daqing field, PRC). The increase in volume is due to the absence of a residual resistance factor effect, i.e., the absence of a post-effect when polymer wells are converted to water injection. Testing on physical reservoir models has shown that the viscous fingering of the polymer bank has occurred in the high permeable zone, thereby not involving the low-permeable zone. This phenomenon has been clearly demonstrated by a field example from the Kalamkas field [27].

Horizontal wells for polymer flooding. Up to the mid 1990s, before the widespread use of horizontal wells, accepted screening criteria [97] advocated that 150 cp was the upper limit of oil viscosity for polymer flooding applicability. The introduction of horizontal wells has allowed polymer flood applications with much higher oil viscosities [11, 33, 87, 98]. In particular, horizontal wells considerably increase injectivity, reservoir access, and sweep efficiency, relative to vertical wells.

Table 3

Reservoir development parameters accepted for polymer flooding projects

#	Field	End Mobility Ratio	Perm. Contrast	Polymer viscosity, cP	Injected Volume, PV	I/P*	Water Cut before PF, %	Incremental RF, %
1	2	3	4	5	6	7	8	9
1	Marmul, Oman (2010-…)	~40	10:1	15	–	27/–	~90	~10 expected
2	Milne Point, Alaska, USA (2018-…)	>20	10:1	45	–	2/2 (horizontal)	~65	~10 expected
3	Captain (offshore), UK (2011-2013)	31	–	20	–	1/1 (horizontal)	85	~16
4	Dalia/Camelia (offshore), Angola (2010-…)	–	10:1	2.9	0.5 expected	3/– (deviated)	>40	3–7 expected
5	Daqing, China (2008-…)	9,4	4:1	40–300	0.4–1.2	–	95	15–18
6	Shengli, China (2008-2013)	–	–	25–35	>0.4	55/84	95	3.7
7	Shuanghe, China (1994-1999)	–	4:1	93 at 3 rpm	0.4	–	91	10.4
8	Bohai bay, China (2005-…)	–	4:1	77.6–131	0.31	10/35	>80	7.1
9	Tambaredjo, Suriname (2008-2015)	–	12:1	45 then 125	0.65	3/9	80	11
10	East-Messoyakhskoe, Russia (2017-2019)	30	–	30 at 7.34 s^{-1} 80 at res. cond.	0.1	2/4 (horizontal)	>90	–
11	Matzen, Austria (2011-...)	–	–	1.6–4.6 at res. cond.	–	2/6	~90	~10 expected

Continuation of Table 3

#	Field	End Mobility Ratio	Perm. Contrast	Polymer viscosity, cP	Injected Volume, PV	I/P*	Water Cut before PF, %	Incremental RF, %
1	2	3	4	5	6	7	8	9
12	Carmopolis, Brazil (1997-2003)	12	–	30	0.1	4/21	10	–
13	Canto do Amaro, Brazil (2001-2008)	2–5	–	10	0.16	2/6	6	–
14	Buracica, Brazil (1999-2003)	3	–	40	0.73	2/7	8	–
15	Diadema, Argentina (2007-...)	80	9:1	70	0.8	5/19	96	6–8 expected
16	El Corcobo, Argentina (2012-…)	–	–	20–25	–	6/22	~85	6–10 expected
17	Bockstedt, Germany (2013-…)	–	3:1	25	–	–/4	>90	–
18	East Bodo, Canada (2006-…)	42	–	50–60	–	1/12	95	20 expected
19	Mooney, Canada (2008-2010)	–	–	20–30	–	2/3 (horizontal)	90	18
20	Seal, Canada (2010-…)	–	–	25–45	–	3/4 (horizontal)	~18	8.8
21	Caen, Canada (2010-…)	44–64	4:1	32	0.6	2/10 (horizontal)	96	7–12 expected
22	Wainwright, Canada (2009-…)	–	–	25	0.5	13/24	–	–
23	Pelican Lake, Canada (2006-...)	165	4:1	13–25	–	–	90	25 expected
24	Mangala, India (2014-…)	28	10:1	15–20	~0.7	86/–	77	23
25	Abu Dhabi (2021-2022)	1.8	10:1	5.5	N/A	1/–	N/A	N/A
26	Nuraly (2014-2019)	0.7	30	6	0,153	4/22	81	
27	East-Moldabek, Kazakhstan (2019-…)	–	–	30	0.035	2/17	~85	5.7–7.7
28	Zaburunje, Kazakhstan (2014-…)	–	–	19	0.17	4/63	~90	2.3
29	Kalamkas, Kazakhstan (2014-…)	7	4:1	24	0.075	2/23	~90	9 (expected)

3 Chemical (ASP) flood risks and feasibility assessment

The alkali/surfactant/polymer injection was first invented in 1983 by Krumrin and Falcone in the laboratory to achieve the synergetic effect of the chemicals. After 10 years, in 1993, the first field-scale implementation was conducted in the West Kiehl Field, Wyoming, USA, reported by Clark et al. [99]. The pilot test was successful, leading to the production of 26 % of original oil in place (OOIP) in 2.5 years. Later, other countries such as Canada, India, and Russia implemented field pilot tests. Finally, the largest field-scale implementations were started in China in 2014. According to Wang et al. [100], the widespread use of polymers in Chinese fields provided solid foundations for ASP flooding. This point of view was also supported by laboratory experiments conducted by Aitkulov et al. [101], which indicated more enhanced oil recovery of ASP after polymer flooding rather than after waterflooding.

The synergetic effect of ASP flooding is based on mechanisms induced by each of three chemicals: polymers, which create a stable piston-like displacement front; surfactants, which decrease interfacial tension (IFT) between oil and water; and alkalis, which mitigate surfactant adsorption and create in-situ soaps to decrease IFT. These three mechanisms improve the ability of the oil to flow in porous media involving untouched zones of reservoir.

To better understand the effect of ASP on oil production growth, especially the mechanism underlying the surfactant-oil interaction it is necessary to examine the main studies on microemulsion types [3, 102, 103]. There are three types of microemulsions formed when oil and surfactant come into contact in the reservoir, based on Windsor's [104] terminology. Thus, Type II (–), Type III, and Type II (+) have been detected depending on brine salinity level. These Windsor types can be well described by ternary diagrams. Type II (-) means a two-phase environment at low salinities where only water and oil are presented. Then, it moves to the Type III microemulsion at medium salinity where three phases exist in equilibrium: water, oil, and microemulsion (middle phase). Type III is the transitional stage from Type II (–) to Type II (+) or vice versa, where Type II (+) also has two phases, but at high salinity: water and microemulsion. Type II (–) and Type II (+) can coexist in the Type III environment since Nelson and Pope [103] did not observe type-to-type behaviour in EOR processes. In general, Type III is the most favorable condition for effective oil displacement in porous media since the pure oil phase and lowest IFT are achieved. Based on this theory and these processes, the evaluation of ASP formulation (phase behaviour tests) is conducted to reach successful ASP flooding projects. If the formulation fits reservoir conditions, over 20 % of incremental oil recovery can be accomplished, which is almost two times greater than polymer flooding.

Although ASP flooding seems promising in the laboratory as a tertiary recovery method, field experience has revealed several complicating features of the technology. Thus, it has been observed that the main problems while ASP flooding is related to operational arrays [12–15]. The scaling problem is the most common among ASP flood projects, and it creates the need to redesign surface facilities from ASP solution preparation units to production and processing units. Experience in China has shown that frequent pump failures have greatly shortened pump-checking time to tens of days [105]. Figure 4 represents some pictures of scaling accumulated on stators of progressing-cavity pumps (PCP) in the Daqing oilfield. ASP flooding in the Mangala field led to impairment of the artificial lifting system. As a result, jet pumps were accepted as suitable instead of electrical submersible pumps (ESP) [106]. The simple explanation for scale formation in the tubes is the significantly high pH level of the injected water, caused by the large amounts of alkali added [107]. Apart from reconsidering the artificial lift systems, it is also required to implement chemical techniques such as scale inhibitors and chemical-feeding systems [15], which certainly increase project operational costs.

Figure 4. Scaling PCP rotors in Daqing ASP flooding area [105]

Another complicating feature during production can be viscous hard-to-break emulsions, as was observed in several pilots in China. Guo et al. [15] reported that the maximum emulsion viscosity of the produced fluid reached 487 cp during strong alkali injection (NaOH). Some cases demonstrate great emulsion viscosities which are 10 times greater than injected ASP solution. The authors acknowledge that the phenomenon is not well understood, but the presence of emulsions and their problems remain a fact. The main associated problem is the loss of production. Therefore, potential emulsification issues should be envisaged preliminary as it was done in the Bhagyam field having additional demulsifier injection wells near producers [12]. Also, Finol et al. [13] have reported preliminary laboratory experiments on identifying cost-effective demulsifiers in the designing stage of the Al Khalata pilot test.

Feasibility study on ASP flooding projects. According to Dean et al. [108], the development of ASP formulations and their implementation in the field/pilot units has two main objectives: 1) academic applications aiming at a better understanding of the mechanism, and 2) practical applications pursuing economic benefits through the production of incremental oil. Based on a number of publications that are describing any ASP technology implementation at a pilot scale, it is observed that the authors refrain from providing the economic performance of any given project. This is the main reason for the difficulty in determining the real purpose of ASP projects. Moreover, some projects were evaluated without considering capital and/or operating expenditures, i.e., only the benefit from incremental oil was estimated, and the project's profitability was not adequately assessed. Such cases can misrepresent the understanding of the economic feasibility of ASP flooding, which is critical due to its complexity and use of expensive chemicals.

This section focuses on the economic evaluation of ASP flooding projects conducted on Daqing (China) and Mangala (India) oilfields. It is worth noting that the economics of the projects have been evaluated based only on the data presented in the scientific articles of Gao et al. [109] and Pandey et al. [106]. Both projects were successful, providing additive oil recovery. Nevertheless, the economics behind them were not properly assessed. Therefore, the main question to answer is: does the extra oil produced by ASP flooding pay for itself?

Gao et al. [109] presented an ASP flooding project, which involved 16 injection and 25 production wells. Injection of the main ASP slug started in 2014 and by 2019 the accumulated oil increment was 0.647 million barrels which refers to 7.89% of the incremental recovery. Considering the size of the pilot area and the number of wells involved, the complications of water treatment and production that are common in ASP projects, it can be assumed that the project does not achieve economic benefit. In evidence, the simplified feasibility study considering only the costs of chemicals as the main part of operational expenditures is presented in this section. The consumption of chemicals has been pre-compiled based on the given injected pore volumes and the slug formulations, and chemical prices have been taken as industry average prices. Thus, the following assumptions over prices were accepted (Table 4):

Table 4

Chemical prices according to industry averages

Chemicals	USD/kg
Alkaline	0.65
Surfactant	7
Polymer	3.5

ASP project was held on the N3D block with an area of 0.49 km^2 and a pore volume of 1 798 200 m^3, which is located on the East side of the Daqing oilfield. According to Guo et al. [15], the chemical formulations of ASP floods in China were analyzed. The authors presented data on 27 ASP flooding projects with slug concentrations. From the data, the average concentrations of each slug were identified and fitted to the injection volumes of the N3D block (Table 5). Combining all this available information and correct calculations makes it easy for us to imagine the costs of this project. It is estimated that around $41 million was spent on chemicals only to provide such slug volumes (Table 6). The author states that the economic benefit of performed ASP project is $32.35 million (calculated at $50/bbl), which is about $10 million more than the chemical cost. It is important to note that apart from the cost of chemicals, nothing else has been taken into account, i.e. the actual cost of the project could be times higher with capital and other operating costs caused by different challenges.

Table 5

Assumed design of Daqing ASP flooding [15; 109]

1st year		2nd–4th years		5th year		6th year		Total injected
Pre-Slug (polymer)		ASP Main Slug		ASP Vice Slug		Post-Slug (polymer)		
PV	Concentration, %	PV	Concentration, %	PV	Concentration, %	PV	Concentration, %	PV
0,2	0.14	0.505	0.3%S + 1%A + + 0.18%P	0.21	0.1%S + 1.2%A + + 0.16%P	0.18	0.12	1.0924

A similar approach was applied to evaluate an Indian ASP experience performed in the Mangala oilfield in 2014 [106]. The critical reason for evaluating its economic efficiency is the involved well locations. According to the authors, the ASP pilot project was carried out on a 5-spot pattern block with 4 injection wells and 1 production well, and an area of 10 000 m^2. The main reason to investigate this case is the well locations that lead to injected volume loss 3/4. It suggests that the crucial part of injected volume abandons outside of the well grid. Therefore, the economic effect is questionable, as the cost of chemicals for effective sweeping increases by a factor of 4.

Table 6

Cost of chemicals used in Daqing ASP pilot

Slug consequence	Chemi-cals	Injected weight, tonnes	Cost for chemicals, USD	Cost for chemicals over the pilot period, USD
Pre-Slug (polymer)	A	0	0	1 762 236
	S	0	0	
	P	503.50	1 762 236	
ASP Main Slug	A	9 080.91	5 902 592	30 693 476
	S	2 724.27	19 069 911	
	P	1 634.56	5 720 973	
ASP Vice Slug	A	4 479.68	2 911 789	7 615 449
	S	373.31	2 613 144	
	P	597.29	2 090 515	
Post-Slug (polymer)	A	0	0	1 357 929
	S	0	0	
	P	387.98	1 357 929	
Total				41 429 089

As reported by Pandey et al. [110] at the design stage of the ASP pilot, the thickness of the pilot formation is 70 m with a net-to-gross of 40 %. Considering the area of 10 000 m^2 and average porosity, the volume of pores is 70 000 m^3. Later, after a technically successful pilot, the slug formulations were presented in 2016 (Table 7).

Table 8 presents chemical cost estimation for each stage of ASP flooding at Mangala. Since the incremental oil reached 23 000 bbl, which the authors describe, the project will not be appropriate for returning investments spent even if the oil cost is 90 $/bbl. It should be noted that there was polymer flooding at the same pilot area for 3 years before the ASP flooding. The polymer slugs were graded, and the pilot performed well generating incremental oil, referring to 10–15% of STOIIP compared to waterflood [66]. Despite this fact, ASP flooding was technically justified, giving extra-incremental oil from the pilot area, but proved to be uneconomical.

Table 7

Chemical slug compositions prepared in Mangala ASP pilot [106]

ASP Main Slug		Polymer Drive-1		Polymer Drive-2		Chase Water Drive	
PV	Concentration, %	PV	Concentration, %	PV	Concentration, %	PV	Concentration, %
0.5	0.3%S+3%A+0.25%P	0.3	1.5%A+0.23%P	0.2	1%A+0.2%P	0.1	1%A

Table 8

Cost of chemicals used in Mangala ASP pilot

Slug consequence	Chemicals	Injected weight, tonnes	Cost for chemicals, USD	Cost for chemicals over the pilot period, USD
ASP Main Slug	A	1 050	682 500	1 638 000
	S	105	735 000	
	P	63	220 500	
Polymer Drive-1	A	315	204 750	373 800
	S	0	0	
	P	48.3	169 050	
Polymer Drive-2	A	140	91 000	189 000
	S	0	0	
	P	28	98 000	
Chase Water Drive	A	70	45 500	45 500
	S	0	0	
	P	0	0	
Total				2 246 300

ASP applicability studies on Kazakhstani fields. The previous section described the economic issues attributed to ASP flooding. Apart from this, the other critical property oil total acid number (TAN) for ASP applicability was studied. The high acidic constituents react with alkaline solutions to create in-situ surfactants [17]. Surfactants, for their part, obtain ultralow interfacial tension (IFT) between displacing agent and crude oil. Thus, several mechanisms are in place to enhance oil recovery. In the case of low TAN, alkalines may mitigate surfactant retention, which improves chemical consumption volumes.

In this regard, the TAN analysis of several Kazakhstan oilfields was carried out. The TAN analysis of the Mangistau (West Kazakhstan) oilfields, combined with actual ASP feasibility studies from other companies, argues that ASP is not a promising cEOR method for extending the life of brownfields (Table 9). According to Guo et al. [15], in 1987 the threshold value of the acid number for the effective reaction was considered 0.20 mg KOH/g, but then this number was reduced by several times, which can be noted in Table 9. Nevertheless, underestimating the importance of oil TAN, using highly reactive surfactants, is too risky because of production issues, such as scaling and hard-to-break emulsions. These problems, coupled with the expensive surfactant cost, only complicate and worsen the economics of projects.

Table 9

TAN analysis of Mangistau oilfields in comparison

Oilfields	Oil TAN, mg KOH/g	ASP flood conducted	Incremental RF, %	Complications
Bhagyam, India [12]	2.00	Yes	20	Emulsion, scaling, corrosion
Al Khalata, Oman [13]	0.78	Yes	–	Emulsion, scaling
Karazhanbas, Kazakhstan	0.251	No	–	–
Kalamkas, Kazakhstan	0.132	No	–	–
Uzen, Kazakhstan	0.048	No	–	–
West Salym, Russia [14]	0.040	Yes	16	Scaling
Daqing, China [15]	0.020	Yes	>20	Emulsion, scaling, repairment of surface equipment

Conclusions & Observations

The goal of this paper was to review important aspects and performances during polymer flooding. These aspects include reservoir conditions for effective implementation, polymer injection, and reservoir development parameters. The growing large-scale application polymer flooding demonstrates that it is the most feasible chemical EOR technology. In contrast, ASP/SP flood is not profitable and causes severe on-site problems. The primary novel finding from this review and analysis of field projects is to cast doubt on the economic feasibility of ASP flooding — especially in Kazakhstan. This work also provides a perspective on the TAN (total acid number) for Kazakhstan oilfields, especially for applicability to ASP flooding. Many insights into applicability of polymer flooding were also noted. In particular, the fact that HPAM prices are lower now than they were 40 years ago has greatly aided the ability for polymer flooding to be applied on a large scale today. The development of horizontal wells has greatly enhanced polymer injectivity and allowed the upper limit of oil viscosity for polymer flooding to be increased from ~150 cp to over 3000 cp. Controlled injection above the formation parting pressure has also played a major role in this regard. Until recently, commercially available EOR polymers were not sufficiently stable in reservoirs with temperatures exceeding ~70 °C. However, the recent availability of an ATBS polymer has the potential to allow feasible polymer flooding in reservoirs at temperatures up to 120 °C. A major difference from waterflooding is that the dissolved oxygen level as close to zero as practical—certainly less than 200 parts per billion. Above 60 °C, dissolved oxygen levels must be much closer to zero. In theory, polymer flooding can be applied in formations with any water salinity. However, practical considerations favor using the least saline water that is available. Field experience, as well as laboratory and theory, consistently reveal that the polymer bank size should be as large as practical (typically ~1 pore volume). Once injection is switched from polymer back to water injection, water cuts will quickly rise to high values. The vast majority of polymer floods have been applied in moderate-to-high permeability reservoirs (>100 md). This fact is due first to the need for high polymer injectivity and second because high-MW polymers exhibit difficulty in penetrating into less-permeability rock.

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М.С. Сагындиков, Р.М. Кушеков, Р.С. Серайт

ASP суландырумен салыстырғандағы полимерлерлі суландыруының маңызды аспектілері мен нәтижелеріне шолу

Полимерлі суландыру — бұл мұнай өндіруді арттырудың болашағы зор және тиімді химиялық әдіс. Полимерлі суландыру әсіресе сілтілі/беттік-белсенді зат/полимерлі суландыру (ASP) тиімсіз болған кезде және кен орнында күрделі проблемалар туындаған кезде тиімді (тұзды тұндыру, жөндеу кезеңінің төмендеуі, ұңғыманың қабылдау проблемалары, бұзылуы қиын эмульсиялар). Соңғы әдебиет дереккөздерінде полимерлі суландырудың 30-ға жуық далалық сынақтары туралы айтылады. Олардың көпшілігі техникалық жетістіктер туралы мәлімет береді. Полимерлі суландыру 60 жыл бойы қолданылғанымен, оны жақсарту үшін әлі де қосымша зерттеулер қажет. Мақалада Қаламқас кен орнының тәжірибесімен біріктірілген соңғы жобаларды шолу негізінде полимерлік суландырудың маңызды аспектілері мен сипаттамалары берілген. Әдебиеттердің кең шолуында температура, су қабатының минералдануы, су көзін таңдау, мұнай қасиеттері, қабат типі және өткізгіштігі тұрғысынан қолдану диапазоны қарастырылған. Су көзін таңдау пилоттық/өндірістік жобаны әзірлеу кезінде маңызды рөл атқарады және ең маңызды техникалық және экономикалық шешімдердің бірі болып табылады. Полимер қойыртпағының дизайны, әсіресе мұнай және полимердің тұтқырлықтарының арақатынасы бірден әлдеқайда аз болатын тұтқырлығы жоғары мұнай кен орындары үшін егжей-тегжейлі талданған. Полимерлердің жоғары қабылдағыштығын түсіндіруге ерекше көңіл бөлінген. Ағымдағы мұнай бағасы бойынша технологияның тиімсіздігін растау кезінде кейбір танымал ASP жобалары үшін техникалық-экономикалық негіздеме жүргізілген. Сонымен қатар, ASP суландыру скринингі үшін үш қазақстандық мұнай кен орындарындағы мұнайдың қышқыл мөлшеріне сандық талдау жасалған.

Кілт сөздер: полиакриламид, полимерлік суландыру, мұнай беруді ұлғайтудың химиялық әдістері, сілті/беттік белсенді зат/полимер (ASP) суландыру, техникалық-экономикалық негіздеме.

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Обзор важных аспектов и характеристик полимерного заводнения в сравнении с ASP заводнением

Полимерное заводнение является многообещающим и эффективным химическим методом увеличения нефтеотдачи (хМУН). Полимерное заводнение особенно эффективно, когда щелочь/ПАВ/полимерное заводнение (ASP) нерентабельно и вызывает серьезные проблемы на месторождении (солеотложения, снижение межремонтного периода, проблемы с приемистостью, трудноразрушаемые эмульсии). В последних литературных источниках упоминается о ~30 полевых испытаний полимерного заводнения. В большинстве из них сообщается о техническом успехе. Несмотря на то, что полимерное заводнение применяется уже ~60 лет, оно все еще требует дальнейших исследований для совершенствования. В данной статье описаны важные аспекты и характеристики полимерного заводнения на основе обзора последних проектов в сочетании с опытом месторождения «Каламкас». В обширном литературном обзоре рассмотрен диапазон применимости по температуре, минерализации пластовой воды, отбору источника воды, свойствам нефти, типу пласта и проницаемости. Выбор источника воды играет важную роль при разработке пилотного/коммерческого проекта и является одним из наиболее ответственных технико-экономических решений. Дизайн полимерных оторочек был подробно проанализирован, особенно для месторождений высоковязкой нефти, где выбранное соотношение вязкости нефти и полимера намного меньше единицы. Особое внимание уделено разъяснению наблюдаемой высокой приемистости полимеров. Проведена технико-экономическая оценка по некоторым известным ASP проектам для подтверждения нерентабельности технологии при текущих ценах на нефть. Кроме того, авторами статьи проведен анализ кислотного числа нефти трех казахстанских нефтяных месторождений для скрининга ASP заводнения.

Ключевые слова: полиакриламид, полимерное заводнение, химический метод увеличения нефтеотдачи, щелочь/ПАВ/полимерное заводнение, технико-экономическое обоснование.

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