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Assessing polyacrylamide solution chemical stability during a polymer flood in the Kalamkas field, Western Kazakhstan

During a polymer flood, the field operator must be convinced that significant chemical investment is not compromised at the early stages of polymer injection. Further, dissolved oxygen in the viscous polymer solution must be controlled at a safe level, where viscosity loss will be insignificant. Under anaerobic conditions, the hydrolyzed polyacrylamide (HPAM) solution is stable even if iron ions are present in the process water. Thus, in the field operation, introduced oxygen and existing iron ions will cause an enormous viscosity decline. The geochemical calculation reveals that dissolved oxygen can rapidly deplete after entering Kalamkas formation. This paper confirms this prediction through a combination of laboratory measurements and field observations. This study is based on rheology measurements of polymer solutions and produced fluid from the offset production well associated with the Kalamkas oilfield in Western Kazakhstan. Comprehensive analysis confirms no viscosity loss at the surface facilities during polymer preparation and injection at a Polymer Slicing Unit and significant viscosity loss at an Eductor-type unit caused by oxygen introduced during polymer solution preparation. However, even introduced high dissolved oxygen levels that degrade polymer at the surface can be rapidly depleted during contact with the formation, thereby promoting polymer chemical stability in the reservoir.

Keywords: polyacrylamide, polymer solution, chemical degradation, polymer flood, iron, oxygen, viscosity, injection.

Introduction

During a typical polymer flood, a high-molecular-weight partially-hydrolyzed polyacrylamide (HPAM) considerably increases viscosity for the injected water, thereby reducing the water-oil mobility ratio and improving reservoir sweep efficiency [1]. However, HPAM solutions can experience significant viscosity losses through mechanical and oxidative degradation [2–11]. Because chemical floods commonly involve a huge investment in polymers, it is critical to have confidence that the polymer is not degraded while being injected into the reservoir. Thus, any polymer degradation (and consequently reduced solution viscosity) can incur a substantial investment loss, and minimizing polymer degradation is a key to successful polymer flooding. Most Kazakhstan oil fields formation water (including the Kalamkas field) have high salinity and iron content. Commonly, those oil fields have no alternative fresh or low salinity (i.e., without iron content) water source similar to Daqing [12] or Milne Point [13]. The HPAM solution at sealed and anaerobic conditions is stable if iron ions exist in the process water [6]. Therefore, a sealing system for a polymer injection unit is crucial.

Nevertheless, in a field application, controlling dissolved oxygen content at the “zero” level is challenging. The study [6] suggested that 200 ppb oxygen is the highest value, where viscosity losses will be insignif-

icant. In contrast, [9] found that 46 ppb can lead to 10 % viscosity loss. Based on the geochemical calculation and laboratory experiment, [5] revealed that high dissolved oxygen content (which can be introduced during polymer solution preparation and injection) after entering the sandstone with 1 % pyrite (FeS_2) — as in the case of Kalamkas formation — can rapidly be depleted. On the other hand, lower dissolved oxygen content leads to higher polymer chemical stability, and the “zero” (undetectable) level is an ideal case. So how much-dissolved oxygen will be feasibly acceptable in a real field setting? A significant part of this paper is dedicated to testing and confirming those predictions in a field application at the Kalamkas polymer project. This confirmation required developing a special method to back-produce polymer solutions without further mechanical or oxidative degradation.

The Kalamkas Oilfield and Polymer Flood Review

The research in this paper is associated with the Kalamkas oilfield discovered in 1976. The field has been developed commercially since 1979 [14]. The brownfield Kalamkas oilfield has reached high water cut and non-uniform oil depletion, which is caused by a high difference in the mobility of water and oil [15]. The oil viscosity is over 16 cp at reservoir temperature (38–43 °C). Under these conditions, the application of polymer flooding is essential to increase oil recovery.

Pilot projects have been conducted in the West part since September 2014 and in the East part of the field since March 2015. These pilots use two types of polymer preparation and injection units having differences. Both units use polymer powder. The first unit uses the Polymer Slicing Unit (PSU) to dissolve polymer powder into water. This PSU reduces the polymer particle size to a uniform and allows for significantly higher polymer concentrations [16] up to 1.5 % or 15 000 ppm. In this unit, a polyacrylamide powder inlet is at the upper part to supply polymer by gravity force (positive pressure) to the screw pump and PSU. The unit is completely isolated from air by a nitrogen blanketing system (Fig. 1). The second one is the eductor-type unit. This conventional eductor works on the Venturi principle, and polymer powder is supplied by air injection. There is no action to isolate air from the unit (Fig. 2). After initial dissolution with these units, this polymer and water mixture flow to maturation tanks to achieve the mother solution's target viscosity. The time to fully dissolve the polymer in water for the PSU is ~45 minutes and for the eductor-type is ~3 hours. The next step is mixing the mother solution with brine to achieve the target viscosity, and then it is transferred by a low-shear pump to the injection well. An individual pump was used for each injection well. The PSU was used for the two West injectors and the seven injectors' East extension. The other four wells were supplied by the eductor-type polymer unit. Two types of commercially available HPAM were used for the West and East projects.

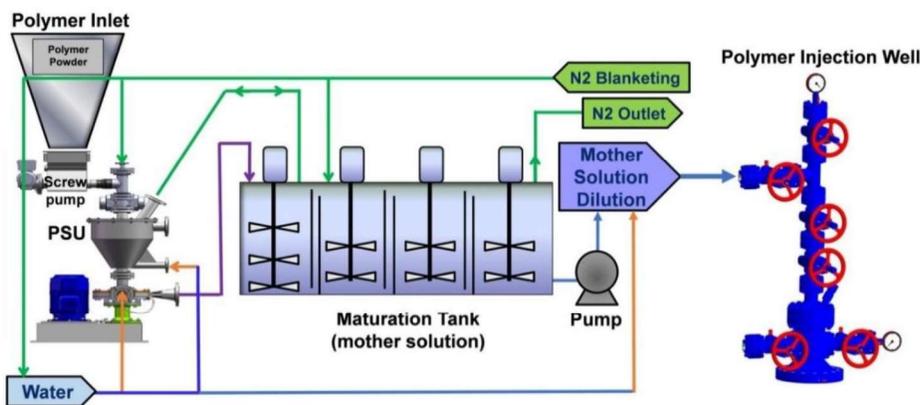


Figure 1. Main components of the polymer slicing unit (PSU)

The field oil pay zones are concentrated at Jurassic deposits, and Cretaceous deposits have massive gas and water reservoirs (Fig. 3). Cretaceous brine is used in the polymer-solution injection process (preparing the mother solution and diluting the target concentration). The brines' physical and chemical properties (salinity, density, viscosity, pH) of the Cretaceous and Jurassic formations are similar. The main reason for using Cretaceous brine is the absence of dissolved oxygen and lower total suspended solids (TSS) content. As mentioned previously in the Kalamkas field, there is no alternative to low salinity or freshwater sources (e.g., lakes and rivers) to reduce polymer consumption.

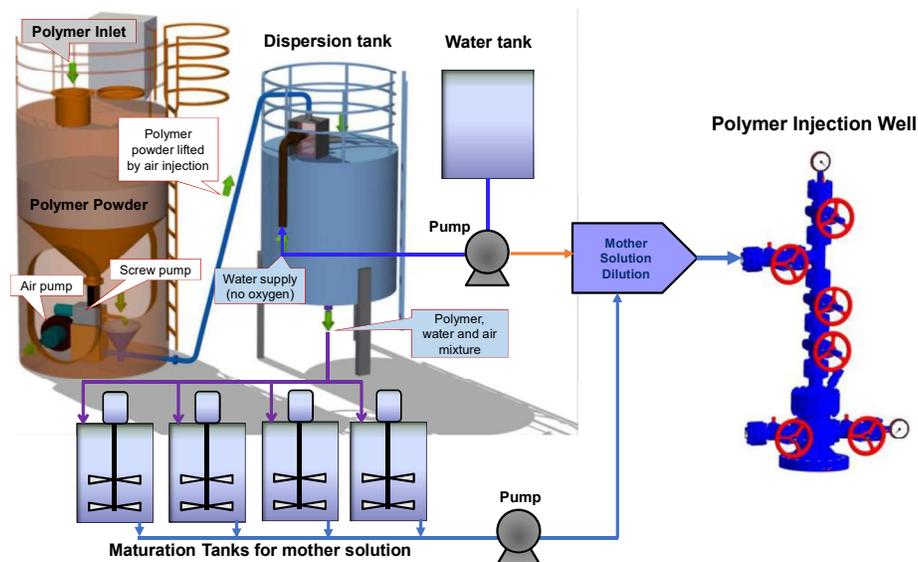


Figure 2. Main components of the eductor-type polymer unit

Cretaceous brine for polymer units is supplied from dedicated wells. The brine has high salinity (TDS 10–11.5 %) and high content of divalent cations (6 500–7 700 ppm). The field brine iron content varies between 20–40 ppm. Consistent with [6] experimental work, polymer solution viscosity losses at Kalamkas field conditions should be insignificant if the initial dissolved-oxygen concentration is 200 ppb or less. We recognize that the formation salinities are high and that HPAM provides much more cost-effective viscosity in low-salinity brine than in high-salinity brine. Nevertheless, polymer flooding with HPAM under the conditions at Kalamkas still provides a substantial economic benefit. Further, as in most current situations throughout the world, given the price and (lack of) availability of biopolymer, the use of HPAM is still more cost-effective than alternatives.

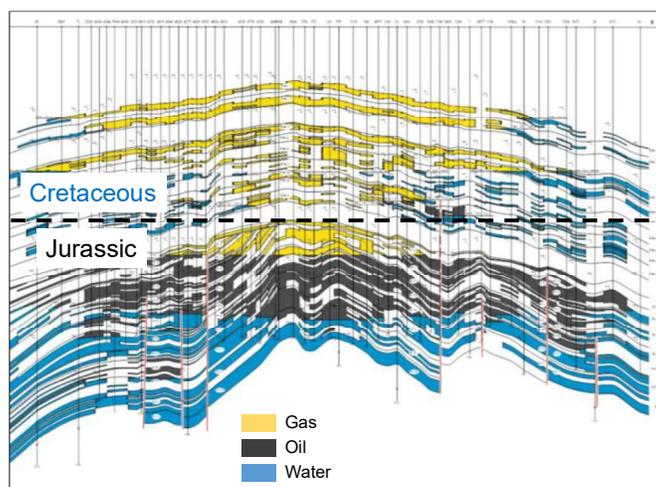


Figure 3. Geological profile of the Kalamkas field

The water's dissolved oxygen level was measured at the wellhead of production wells supplying West and East polymer projects. It was also measured in the water at storage tanks and in the mother solution from maturation tanks of the West PSU, the East PSU, and the East eductor-type polymer unit using CHEMets® express tests. The measurement results are shown in Table 1. Tests results reveal that, at the formation, brine (from the wellhead) dissolved oxygen level is undetectable (less than 0.025 ppm or 25 ppb). This finding is consistent with the fact that Kalamkas oil reservoirs have a reducing environment due to iron-containing minerals up to 2–4 % [5].

Table 1 represents that at the West polymer project, oxygen was introduced during water transportation from the production well to the storage tank, and its level was at 0.3–0.4 ppm. In contrast, this problem did not occur at the East polymer project, where the oxygen level at the storage tanks was undetectable. During the polymer dissolving process, the oxygen was introduced into the mother solution. The oxygen level was 0.3–0.4 ppm for the PSU-type system, and for the eductor-type unit was 2–3 ppm. For the PSU, the dissolved oxygen was close to the acceptable safe range, according to [6]. However, for the eductor-type, this value was over ten times higher than the acceptable level. As will be shown later, this unacceptable oxygen level resulted in 45 % viscosity loss and the equivalent of 25 % polymer concentration loss.

Table 1

The dissolved oxygen measurement results during polymer injection in the Kalamkas field

Polymer injection unit	Dissolved oxygen content, ppm			
	Water producer	Water storage tank	Polymer mother solution	Polymer Injector
West PSU	0	0.2–0.3	0.3–0.4	0–0.3
East PSU	0	0	0.3–0.4	0.3
East eductor	0	0	2–3	1–2

Experimental

A field sampling of polymer solutions

We compared laboratory prepared and sampled polymer solutions viscosities to assess chemical stability, where polymer concentrations were the same as at the field. Mother solutions were sampled from polymer dissolving units (PSU and eductor type) and polymer solution from injectors wellhead. We used fresh polymer solution viscosities as a baseline for comparison (the methodology will be shown later in this section). Viscosities were measured using a high-precision rheometer Anton Paar MCR 502 (Austria) at a shear rate of 7.34 s^{-1} , at room temperature ($25 \text{ }^\circ\text{C}$), and aerobic conditions. A shear rate of 7.34 s^{-1} is commonly used as a standard single-point for comparison of viscosities for non-Newtonian enhanced oil recovery fluids [7; 17–19]. Because most liquids (including polymer solution) are incompressible at low or medium pressures, a considerable change in pressure from 14.5 to 4350 psi causes no significant change in viscosity [20]. Therefore, the reservoir pressure condition for polymer solution viscosity measurement is not essential. The viscosity of each sample was usually measured twice and then averaged.

Polymer solution at the wellhead was collected in pressurized cylinders (Fig. 4). Pressurized cylinders and collection procedures were specially designed for the polymer flood project to protect the solution from oxidative degradation [7; 21]. These cylinders are made of stainless steel and coated with an inert material to prevent corrosion and any iron contamination. Oxygen can be effectively excluded by carefully flushing air from the cylinder with a polymer solution while collecting the sample.



Figure 4. Pressurized cylinders for a polymer solution sampling at the wellhead

The Brine, Polymers and Concentrations

During this study, brine was collected from the dedicated production wells of the Cretaceous water reservoir (which is used for polymer dilution, as shown in Table 2). Brines (West and East Producers) have high iron content. Consequently, Fe^{2+} reacts with oxygen after exposure to the air. Therefore, to eliminate the effect of oxidized products, both brines are pumped by air to oxidize all iron from the solution and then passed through paper filters before further use.

Table 2

Cretaceous formation brine physical and chemical properties

Parameter	Cretaceous formation brine (used for polymer dilution)	
	West Producer	East Producer
pH	5.8	6.0
Density, g/cm^3	1.071	1.082
Ca^{2+} content, ppm	4 809.6	5 611.2
Mg^{2+} content, ppm	1 702.4	2 067.2
K^+ and Na^+ content, ppm	32 722.5	35 890.9
Cl^- content, ppm	63 810	71 254.5
SO_4^{2-} content, ppm	118.5	21.4
CO_3^{2-} content, ppm	0	0
Total salinity, ppm	103 187.4	114 857.4
Water type by Sulin 1946*	Cl-Ca	Cl-Ca
Water hardness, mg-eq/l	410	470
Iron (Fe) content, ppm	40.6	18.2
Total suspended solids (TSS) content, ppm	14.0	12.0
Dissolved oxygen content, ppm	0 ²	0 ^{**}

Notes: * [22]; ** dissolved oxygen content measured with CHEMets® express tests shows the undetectable value (less than 0.025 ppm or 25 ppb).

Two powder-form partially hydrolyzed polyacrylamides (HPAM) (SNF products) were used, namely Superpusher K-129 and Polyacrylamide R-1. They had a molecular weight of 14 million Daltons and a hydrolysis degree of 16 %.

Polymer solutions were prepared by sprinkling the appropriate mass of polymer powder onto the brine vortex created by an overhead stirrer with a four-blade propeller. After mixing for several hours at a high rate, the stir rate was reduced for at least four hours, and the solution stood overnight. As in the field application, our target polymer concentrations for the three projects are in Table 3. For Superpusher K-129, we used brine from West producer (10.3 % TDS) and for Polyacrylamide R-1 — East Producer (11.5 % TDS).

Table 3

Polymer concentrations for the laboratory study

Polymer injection unit	Polymer type	Active polymer concentration, ppm	
		Mother solution	Injector wellhead
West PSU	Superpusher K-129	9 200	1 600
East PSU	Polyacrylamide R-1	15 000	1 700
East eductor	Polyacrylamide R-1	4 900	2 200

A sampling of producer fluid

Many polymer flood projects reported that production wells responded to polymer flooding by water cut decreases and increased produced polymer concentration [7; 23–26]. In some cases, the polymer channeled directly from an injector to a producer through a fracture, i.e., producing the same polymer concentration as injected. This circumstance occurred in Kalamkas field, where severe channeling and polymer breakthrough was observed from Injector XX37 to Producer XX87 in June 2019. Note that this polymer-channeling problem developed only once during over seven years of polymer injection (i.e., since 2014). The distance between the producer and injector was 400 m. After the breakthrough, polymer concentration in-

creased roughly from undetectable values (i.e., <1 ppm) to the injected values. Injector pressure fall-off tests (using the same method utilized later in this paper) after polymer injection revealed that injection occurred above the formation parting pressure and the fracture half-length was close to 400 m. This value is close to the well spacing (Fig. 10 and Table 7). Thus, the fracture was detrimental to sweep efficiency in this particular case because it extended from the injector to the producer. After several unsuccessful attempts to plug the fracture (both from the production and injection sides), the production well was shut down.

Figure 5 shows Injector XX37 and Producer XX87 operation history before and after polymer breakthrough. This history indicates a powerful hydrodynamic connection expressed by a quick change in producer dynamic fluid level during an injector workover and after injection. After the polymer breakthrough, the water cut increased from 87 % to 100 %. Tracer tests (Table 4 and Fig. 6) during water and polymer injection confirmed that the source of polymer breakthrough was Injector XX37.

This unusual case provided the opportunity to assess polymer solution chemical and mechanical stability that traveled from the injector to the producer through the reservoir.

Table 4

The interwell tracer tests results on Polymer Injector XX37 and surrounding producers

Date	Tracer type	Injected Mass, kg	Injected V, m ³	Prod-ed M, kg	Prod/Inj M, %	A tracer reached well number	Tracer max velocity, m/d	Tracer min velocity, m/d	Tracer average velocity, m/d
Nov. 2017	Urea	5000	18	147.8	2.96	25	1808	188	638
Nov. 2019	Fluorescein (Uranin)	60	9	0.6172	1.03	1 (XX87)	2781	2781	2781
Nov. 2020	Rhodamine C	60	18	0.1	0.11	6	1162	62	210

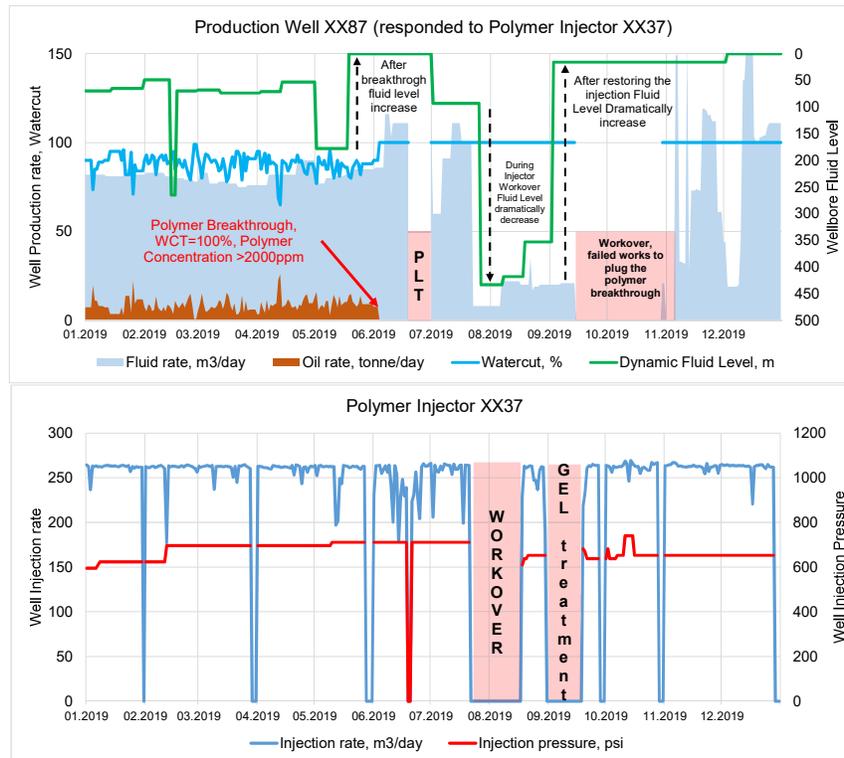


Figure 5. Well XX87 production and Well XX37 injection history, where polymer breakthrough was observed

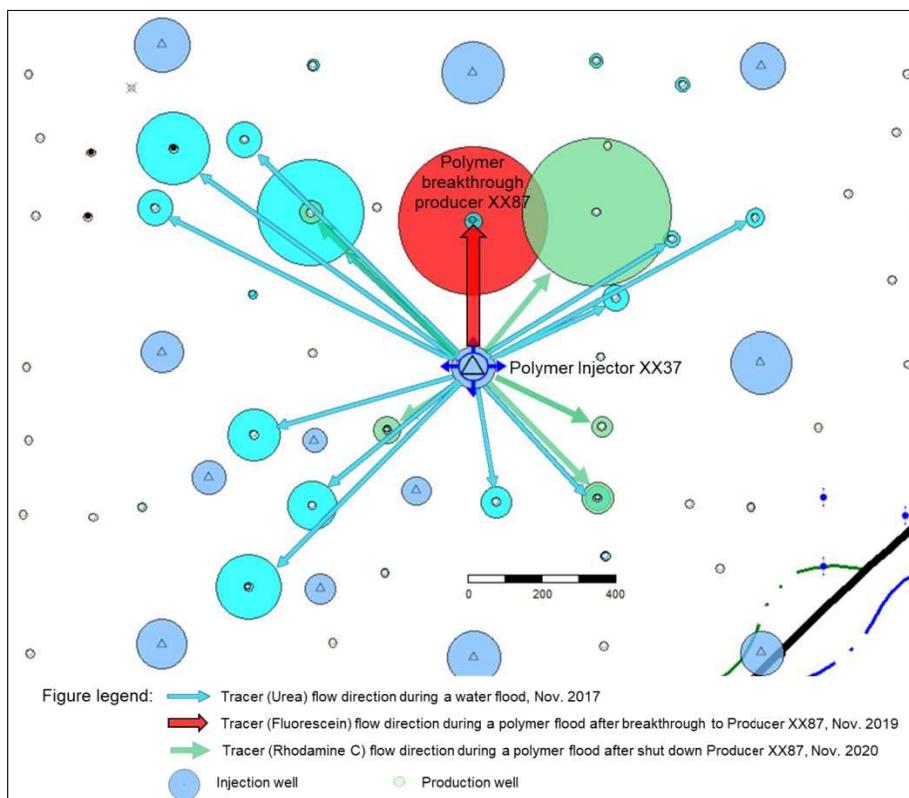


Figure 6. The interwell tracer tests results on Injection well XX37 and surrounding producers

A special scheme (Fig. 7) and procedure were developed to collect produced polymer solution samples from Producer XX87 and assess in situ polymer stability. The production well was equipped with a production line valve, check valve, annulus valve, wing valve, pressure gauge, sampler, and X-mas tree. The well downhole was equipped with tubing and a rod pump. The top of the perforation interval was at 806 m MD (measured depth), and the tubing end was at 590 m MD. A dedicated high-pressure hose was installed to connect the sampler to the pressurized cylinder to collect polymer solution samples at the wellhead. The special procedure was as follows as applied in Well XX87:

- Stop polymer solution injection unit (including Injector XX37) for planned repair work for >6 hours.
- Install pressure gauge flow meter, and connect the pressurized cylinder to collect samples before putting on production well XX87.
- Open wing and production line valve to put the well on the production and start to collect samples.
- Open the sampler valve and flush several-cylinder volumes with the produced polymer solution to prevent air from entering the sample.
- Collect six samples (total) at different cumulative production volumes with the same procedure described above and measure dissolved oxygen level.
- Collect injecting polymer solution at Well XX37 (source of the polymer breakthrough) and measure dissolved oxygen level.
- After collecting all samples, immediately transport pressurized cylinders to the field lab to measure viscosity.
- Viscosity measurements proceed as described above in the subsection “*A field sampling of polymer solutions*” and determine the rheological power-law index [21].

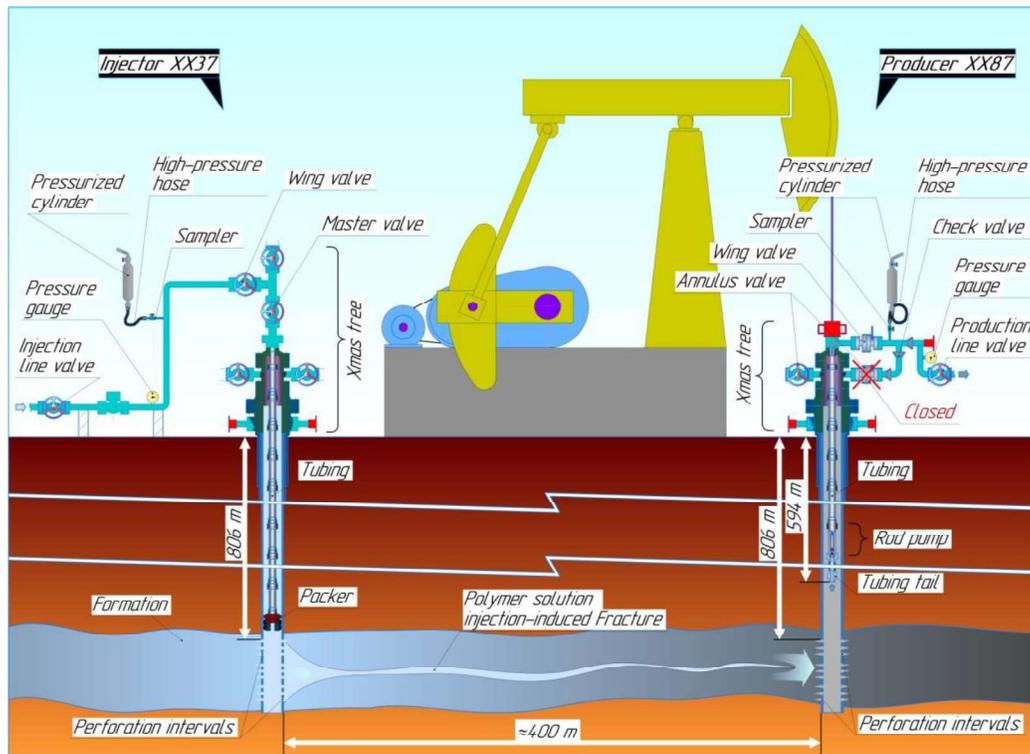


Figure 7. Scheme to collect polymer solutions from Producer XX87

Results and Discussion

Effect of Dissolved Oxygen

As shown in Table 2, process water has high dissolved iron content. Therefore, if dissolved oxygen is introduced to the polymer injection system, it will cause chemical degradation. The PSU is designed to keep dissolved oxygen low, and the eductor-type unit has no action to treat the oxygen or iron. Further, the effects of dissolved oxygen and Fe^{2+} on polymer viscosity for three polymer units are demonstrated in Table 5. Examination of this table first reveals that the PSU for both projects (West and East) has a good performance due to chemical stability. Chemical stability provided by nitrogen blanketing system and its efficiency is consistent with [6] work. The field viscosity of the PSU mother solution did not reach the lab viscosity. However, after subsequent dissolution processes (Fig. 1), the solution reached the required polymer viscosity and dissolving quality at the wellhead. Finally, viscosity losses were zero at the injector wellhead for the West and East PSUs, demonstrating high technical efficiency.

For the East eductor, both mother and polymer solutions showed a high level of viscosity losses. The viscosity loss for the mother solution and the injector wellhead were 36 and 45 %, respectively. These losses are unrelated to dissolving quality but are due to oxidative (chemical) degradation caused by dissolved oxygen and divalent iron reactions. As shown in Fig. 2, the dissolved oxygen was introduced by air injection associated with the polymer powder supply. At the first mixing step, the mother solution had 2–3 ppm dissolved oxygen. Due to the absence of oxygen in the process water and the polymer dilution process, the oxygen level at the wellhead decreased to 1.5 ppm (Table 1). This oxygen content was higher than the acceptable range — by roughly ten times. The final viscosity loss was about 45 % or equivalent to a 25 % loss of polymer concentration. The primary oxidative degradation location in the system is the dispersion tank. Subsequently, during transit from the injection unit to the wellhead, it loses about 10 % more viscosity. We assume this process continues in the tubing before entering the formation. As will be shown later, after the polymer solution enters the formation, all oxygen will be consumed by the surrounding rock quickly and provide subsequent chemical stability. Even so, severe degradation at the surface affects project economics and feasibility.

Table 5

The viscosity measurement results at different injection units

Polymer injection unit	Lab viscosity, cp		Field viscosity, cp		Viscosity loss, %		Polymer concentration loss, %
	Mother solution	Injector wellhead	Mother solution	Injector wellhead	Mother solution	Injector wellhead	
West PSU	680	20	652	20	4	0	0
East PSU	1 980	23	1 850	23	14	0	0
East eductor	240	38	154	21	36	45	25 %

Note: The viscosity of the polymer solution measured at 7.34 s^{-1} , $T = 25 \text{ }^\circ\text{C}$.

The polymer rheology and concentration loss

Figure 8 shows polymer concentration and viscosity relationship for two types of used polymers in the field. In our case, polymer viscosity roughly depended on the square of its concentration. This figure analysis reveals that 45 % viscosity loss for the East eductor polymer injection unit corresponds to 25 % equivalent polymer concentration loss.

Several views exist on how to solve this problem. They include: (1) chemical/mechanical treatment of the process water to remove all iron from the solution [27], (2) chemical additives such as free-radical scavengers or pH adjustment [28, 29], (3) keeping dissolved oxygen at an undetectable or acceptable level (close to zero) [5], and (4) no action [25] as in our example of the East eductor unit.

The viscosity measurement results at different injection units (Table 5) reveal that removing all oxygen from the system is the feasible and effective way to provide the chemical stability of the solution. Thus, we suggest modifying the East eductor injection unit to ensure an undetectable or acceptable oxygen level that will save 25 % cost of chemicals.

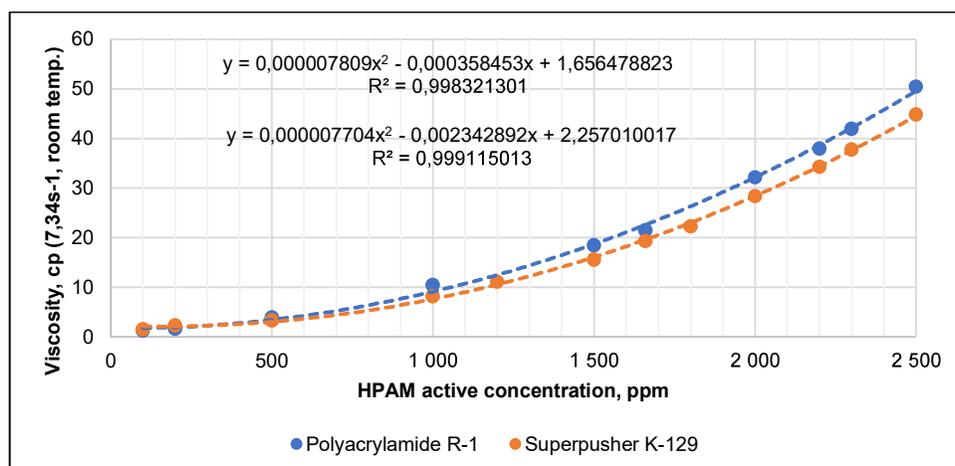


Figure 8. Polymer solution viscosities at different concentrations

Effect of the formation on the polymer stability

Fluid sampling for Producer XX87 and injection of polymer solution at the wellhead of Well XX37 occurred on 30th April 2021, as described above in the section “A sampling of producer fluid”. The typical surface temperature was +20 °C during the test. As shown in Fig. 7, samples from Producer XX87 were collected after polymer breakthrough and that polymer solution propagated over 400 m through the reservoir from Injector XX37. Additionally, the dissolved oxygen level was measured at the wellhead of Polymer Injection Well XX37 and the last four produced samples (# 3, 4, 5, 6) using CHEMets® colorimetric tests. The viscosity and oxygen measurement results are shown in Figure 9 and Table 6. Note in Table 6 that after the first listing (the original sample that was injected), the samples are listed in reverse chronological order of collection — i.e., Sample 6 was collected last from the formation, and Sample 1 was collected first in the tubing). Test results show that injected solution from Well XX37 had roughly 1.5 ppm (i.e., between 1 and 2 ppm) dissolved oxygen content and viscosity of 21.4 cp with a power-law index of 0.763. The first three produced samples (originating closest to the surface) contained 0.2 ppm dissolved oxygen and different degrees of vis-

cosity loss relative to the injected (25-50 %). The last three samples show undetectable dissolved oxygen levels (less than 0.025 ppm or 25 ppb) and minor viscosity loss, with a power-law index close to the injected solution. We presume that significant degradation was seen for the first collected samples because oxygen (air) was introduced into the production well during the well repair work. The gradual decrease in the level of degradation (i.e., increase in viscosity) with time reflected flushing this oxygen out of the system. These findings indicate that injected oxygen in the polymer solution (that transported 400 m through the Kalamkas reservoir) was consumed by the surrounding reservoir rock provided chemical (oxidative) stability of the solution (due to iron-containing minerals up to 2–4 %) [5].

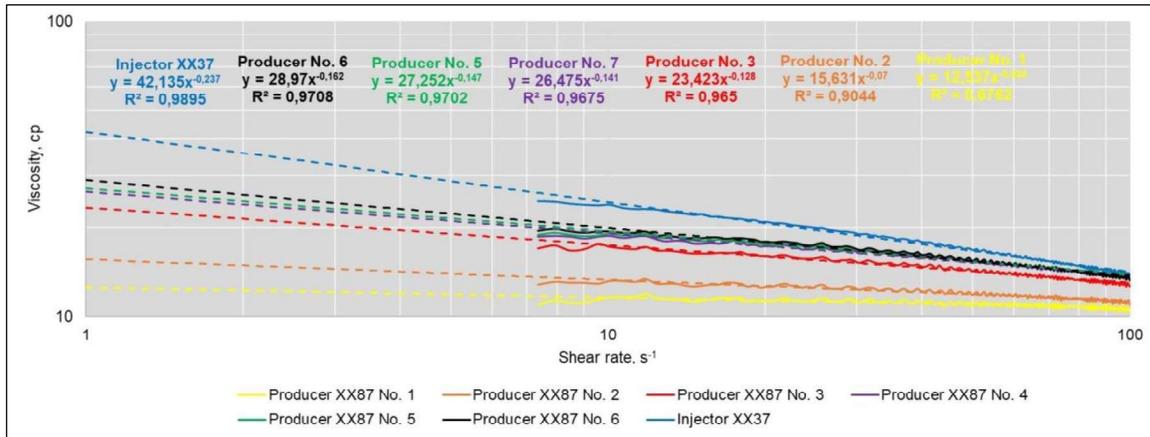


Figure 9. Rheological curve analysis of injected (Well XX37) and produced (Well XX87) polymer solutions

Table 6

Rheology measurements of the injected and produced polymer solution from Injector XX37 and Producer XX87

Well	Produced Volume, m³	Dissolved O ₂ concentration, ppm	The location of the collected sample	Viscosity at 7.34 s ⁻¹ , cp	The power law index (n), dimensionless*
Injector XX37		1.5	Injected	25.1	1-0.237 = 0.763
Producer XX87 No. 6	6.5	0	Formation	21.0	1-0.162 = 0.838
Producer XX87 No. 5	4.4	0	between tubing and perforation	21.3	1-0.147 = 0.853
Producer XX87 No. 4	3.6	0	between tubing and perforation	21.3	1-0.141 = 0.859
Producer XX87 No. 3	3.3	0.2	between tubing and perforation	19.2	1-0.128 = 0.872
Producer XX87 No. 2	2.9	N/A	between tubing and perforation	14.9	1-0.070 = 0.930
Producer XX87 No. 1	2.0	N/A	downhole tubing	13.1	1-0.035 = 0.965

Note: *API RP 63 1990.

Pressure fall-off test

We ran pressure fall-off tests in injection wells to obtain valuable well test data. The Well XX37 pressure fall-off test analysis during polymer flood is presented in Fig. 10 and Table 7. The transient pressure analysis plots pressure versus time and the Bourdet derivative on a log-log scale [30]. Comparing and analyzing two pressure curves (original and derivative) for each flood can display the signature of numerous well, reservoir, and boundary behaviors. In our case, the analyses of pressure fall-off tests showed that during polymer flood injection occurs over formation parting pressure. The absence of fractures during waterflood showed in other wells similar to Well XX37. The fracture half-length for Well XX37 where severe channeling and polymer breakthrough was observed, fracture half-length is close to the well spacing. We can

see that polymer injection leads to natural well stimulation. Consequently, the polymer solution flows through the perforations and near wellbore zone with an area high enough to ensure mechanical stability of the solution. If Well XX37 were not fractured, injection of viscous polymer solution would necessarily decrease injectivity, roughly in proportion to the polymer solution viscosity [4; 7]. In our case, the expected injectivity without open fractures would be 20 times lower than that for water. Our injectivity was enhanced by a factor of 1.6.

The presence of fractures during the polymer flood is consistent with most of the worldwide polymer flood projects injections in vertical wells occur above the formation parting pressure [4; 19; 31–32], where linear flow is expected. 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) is impossible. Additionally, according to the analytical calculations of [19] and the work of [33], fractures do not seriously affect a sweeping efficiency if the fracture half-length is less than 1/3 of the well spacing. These findings reveal that the advantages of fracture features during polymer flood (i.e., little or no injectivity loss, the mechanical stability of the polymer solution) outweigh its disadvantages (e.g., possible severe channeling, jeopardized sweep efficiency).

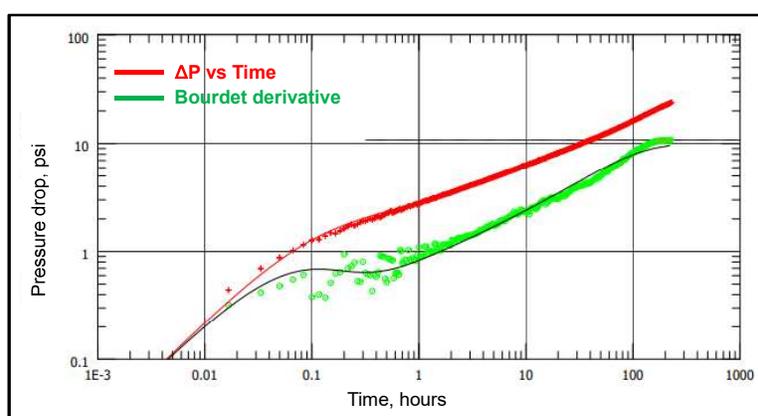


Figure 10. Analysis of pressure fall-off test during polymer injection into Well XX37 (2020)

Table 7

Analysis of pressure fall-off test during polymer injection into Well XX37

No.	Parameters	Value			
		During polymer flood (2021)	During polymer flood (2020)	During water flood (2018)	
1	Perforation interval, Top-Bottom	806–810, 812.5–820.5 m	806–810, 812.5–820.5 m	806–810, 812.5–820.5 m	
2	Test duration, hours	162.7	233.6	N/A	
3	Wellbore storage (WBS) model	Changing WBS	Changing WBS		
4	Well model	Vertical fractured finite conductivity	Vertical fractured finite conductivity		
5	Reservoir model	Homogenous	Homogenous		
6	Boundary model	Infinite	Infinite		
7	Reservoir pressure, bar	87.42	86.3		
8	Conductivity, mD·m	5670	5 630		
9	Average permeability, mD	506.5	503.1		
10	Total skin	–7.5	–7.13		
11	Geometrical skin	0	0.1		
12	Fracture half length, m	396	308		
13	Fracture conductivity, mD·m	6.13E+6	0.384E+6		
14	Fracture permeability, mD	7 740	623		
15	Injectivity index, m ³ /(day·bar)	6.7	5.7		4.3

Conclusions

The large investment associated with the polymer bank during a polymer flood necessitates a determination that the polymer is not substantially degraded during the process of preparation and injection. This paper provides a methodology for assessing chemical degradation in the field, and the methodology is demonstrated for an important field of application in Kazakhstan. This study indicates the possibility of optimizing operational expenditure and increasing the economic efficiency of the polymer flood project operated by the eductor-type unit. Modifying the East eductor injection unit, which ensures the acceptable oxygen level, will save 25 % cost of chemicals. Consistent with [6], 300–400 ppb oxygen in polymer preparation and injection process does not degrade polymer viscosity. Furthermore, polymer solutions that propagated over 400 m through a fracture from the injector to the producer were depleted of dissolved oxygen from 1.5 to 0 ppm, thereby providing field-based support that the Kalamkas formation provides further chemical stability. The injector pressure fall-off test indicated that fracture is open during polymer flood. In addition, field studies reveal that the advantages of fracture features during polymer flood are no injectivity loss and stability of the polymer solution.

Acknowledgments

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Батыс Қазақстандағы Қаламқас кен орнында полимерлік суландыру кезінде полиакриламид ерітіндісінің химиялық тұрақтылығын бағалау

Полимерлі суландыру кезінде кен орнының операторы полимерді айдаудың алғашқы кезеңдерінде химияға айтарлықтай салынған қаражаттың бос кетпеуіне сенімді болуы қажет. Сонымен қатар, тұтқыр полимер ерітіндісіндегі ерітілген оттегінің деңгейі қауіпсіз деңгейде бақылануы керек, бұл жағдайда тұтқырлықтың жоғалуы айтарлықтай болмайды. Гидролизденген полиакриламидтің (ГПАА) ерітіндісі анаэробты жағдайда, тіпті технологиялық суда темір иондары болған жағдайда да өте тұрақты болатыны белгілі. Осылайша, кен орнында енгізілген оттегі мен суда бар темір иондары тұтқырлықтың төмендеуіне әкеледі. Геохимиялық есептеу Қаламқас кен орнының қабатына енгеннен кейін еріген оттегі тез сіңірілетінін көрсетеді. Осы мақалада зертханалық зерттеулер мен далалық бақылаулардың көмегімен бұл болжамдар расталған. Жүргізілген зерттеулер Батыс Қазақстандағы Қаламқас мұнай кен орнымен байланысты полимер ерітінділері мен реактивті өндіруші ұңғымадан алынған сұйықтықтың реологиясын өлшеуге негізделген. Жан-жақты талдау PSU типті кондырғыда (polymer slicing unit) полимерді дайындау және айдау кезінде беткі жабдықта тұтқырлық жоғалмағанын және полимер ерітіндісін дайындау кезінде енгізілген оттегі туындаған Educator типті кондырғыда полимердің тұтқырлығының айтарлықтай жоғалуын растайды. Алайда, бетінде химиялық ыдырау туғызатын еріген оттегінің жоғары деңгейінің өзі тау жыныстарымен байланысу кезінде тез сіңеді, осылайша қабаттағы химиялық тұрақтылықты қамтамасыз етеді.

Кілт сөздер: полиакриламид, полимер ерітіндісі, химиялық бұзу, полимерлі суландыру, темір, оттегі, тұтқырлық, айдау.

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Оценка химической стабильности раствора полиакриламида при полимерном заводнении на месторождении Каламкас, Западный Казахстан

При полимерном заводнении оператор месторождения должна быть убежден, что значительные инвестиции в химию не теряются на ранней стадии закачки полимера. Кроме этого, уровень растворенного кислорода в вязком полимерном растворе должен контролироваться на безопасном уровне, при котором потеря вязкости будет несущественной. Известно, что раствор гидролизованного полиакриламида (ГПАА) в анаэробных условиях очень стабилен, даже при присутствии ионов железа в технологической воде. Таким образом в полевых условиях, введенный кислород и существующие ионы железа приведут к колоссальным потерям вязкости. Геохимический расчет показывает, что растворенный кислород после проникновения в пласт месторождения Каламкас будет быстро поглощен. Данная статья подтверждает эти предположения с помощью комбинации лабораторных исследований и полевых наблюдений. Проведенные исследования основаны на измерениях реологии полимерных растворов и жидкости из реагирующей добывающей скважины связанные с нефтяным месторождением Каламкас в Западном Казахстане. Всесторонний анализ подтверждает отсутствие потери вязкости на поверхностном оборудовании во время подготовки и закачки полимера в установке типа PSU (polymer slicing unit), и значительную потерю вязкости полимера в установке типа Eductor, который вызван введенным кислородом при приготовлении полимерного раствора. Однако даже введенный высокий уровень растворенного кислорода, вызывающий химическую деструкцию на поверхности, быстро поглощается при контакте с породой, тем самым обеспечивая химическую стабильность в пласте.

Ключевые слова: полиакриламид, полимерный раствор, химическая деструкция, полимерное заводнение, железо, кислород, вязкость, закачка.

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