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Experimental Study to Investigate the Effect of Polyacrylamide Gel to Reduce the Lost Circulation

Ali K. Al-Delfi [a, *], Faleh H. M. Al-Mahdawi [a], Yasir Mukhtar [b], and Yousif Eltahir Bagadi [c]

a Petroleum Engineering Department, College of Engineering, University of Baghdad, Iraq
b University of Petroleum, Beijing, China
c University of Science and Technology, Sudan

Abstract

One of the challenging issues encountered during drilling operations is the lost circulation. Numerous issues might arise because of losses, such as wasting of time and higher drilling cost. Several types of lost circulation materials have been developed and are being used to limit mud losses and avoid associated issues. Each solution has benefits and drawbacks.

In this study, a core flooding test was performed to study the effectiveness of polyacrylamide (PAM) granular gel on the reduction of the circulation lost. One common type of fracture characteristic is fractures with tips, commonly known as partially open fracture (POF). However, PAM gel therapy in POFs received little attention in prior research. Models of partly open fractures were built using a cylindrical core. A series of processes are performed on a core to get a POF model. Overall, the PAM gel can decrease plug permeability, making it a useful material for lost circulation. The results indicate that the Polyacrylamide granular gel can decrease the permeability up to 193 times.

Keywords: lost circulation, Lost Circulation Materials (LCM), Polyacrylamide, PAM.

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1- Introduction

Lost circulation is one of the most frequently discussed issues that has attracted industry-wide attention. It happens when drilling mud that is pumped through the drill string doesn't come back up to the surface. Instead, it goes into the formation that is being drilled. The cost of losses on well construction is estimated to be between two and four billion dollars per year in wasted drilling mud, missed productive time, and preventive lost materials [1].

When losses occur, non-productive time (NPT) rises. Due to a loss of circulation, NPT is wasted attempting to re-establish circulation. The expenditures of the lost drilling mud, as well as the treatment necessary to correct the problem, are included in the economic effect of losses. The yearly cost of lost circulation difficulties, including material costs and rig time, is estimated to be over one billion dollars [2]. It was reported based on a statistical survey over ten years period showed that the consequences of drilling losses in the Mexico Gulf were losing more than 12% of production time. Similarly, studies have shown that losses can rise drilling costs by $70 to $100 for a foot on average [3].

The formations where losses occur are classified as follows:

- Losses in high permeability formation

Lost circulation into a matrix porous takes place during the drilling of high-permeability zones. Majdi et al. explained that losses via pores begin slowly and steadily grow [4]. The filter cake on the wall of the wellbore activates progressively, which leads to a decline in the loss rate. Losses finish when the drill bit passes through the high-permeability formation. To access the pore space, the pore size of the matrix should be greater than 3 times the diameter of the drilling mud's solid particles, as explained by G.Beda et al. [5].

- Losses in vugular or cavernous zones

Vugular or cavernous formations are found in the rocks that have been dissolving throughout time. Limestone, dolomite, and rock salt are examples of such rocks. When the drilling bit strikes these zones, the losses begin quickly. In such structures, total losses are possible [6].

- Losses happen in natural fracture

The natural fractures, which occur prior drilling the well, may serve as conduits for drilling mud. Natural fractures accounted for 76 percent of losses at one large operator [7]. The fracture should be broad adequate and

*Corresponding Author: Name: Ali K. Al-Delfi, Email: ali.hashim2008m@coeng.uobaghdad.edu.iq

have sufficient permeability to let drilling mud to induce losses. When fractures are unlocked and linked, the ability of the fracture to soak up drilling mud might be nearly eternal, which result to occur severe or complete losses [8]. Majdi et al. explained that losses into fractures begin quickly and gradually drop over time [4].

- Losses caused by induced fracture

Even if there are no substantial natural fractures, fractures are produced during drilling, and this leads to fluid losses. Induced fracture occurs when the equivalent circulation density exceeds the fracture pressure of the formation. Losses into induced fractures account for more than 90% of a large operator's losses costs [9].

- Losses in depleted reservoir

Producing zones in the same field may result in subnormal formation pressure as a result of formation fluid extraction. The formation pore pressure drops happen in the depleted reservoir. Using the same mud density in these zones as in the remainder of the well will result in an increased overbalance. Lost circulation into the depleted reservoir will increase as the overbalance rises [10]. The circulation losses in some wells, which are drilled in depleted reservoirs, are about thousands of barrels [11].

Drilling fluid losses can be categorized based on the fluid volume lost in the drilled formation as follows:

- Seepage losses (when losses rate less than 1.6 m^3/h)
- Partial losses (when losses rate between 1.6 - 16 m^3/h)
- Severe losses (when losses more than 16 m^3/h)
- Total losses (when no fluid returns to well surface) [12]

To reduce mud losses and prevent related difficulties, many kinds of lost circulation materials (LCMs) have been created and are being employed. Each solution has advantages and disadvantages. As a result, no universal lost circulation material therapy has yet been developed which would be efficient in all zones and operational environments.

The idea of using LCM has been around since the beginning of drilling operations. MT Chapman's patent from 1890 described how to put a sealant substance into the drilling fluid. Since that time, LCM has been routinely employed to prevent or reduce drilling fluid loss into the formation [13].

The categorization of LCMs is a key aspect in making decisions about how to avoid and/or treat lost circulation situations. Conventional LCMs may be categorized as fibrous, flaky, granular, or a mix of these types [14]. Howard et al. divided LCMs into four categories regardless of physical properties: fibrous, granular, lamellated, and dehydratable [15]. Robert White replaced the dehydratable class with a blend of LCM categories in the previous classification. Because of the enormous number of existing accessible LCMs and their various implementations, it is important to reclassify LCMs into distinct groups [13]. A new classification was presented by Alsaba et al. based on physical, chemical, and applications of LCM. Granular, flaky, fibrous, LCM's combination, acid-soluble/water-soluble, and nanoparticles are the kinds of LCMs [16].

Savari et al assessed the effectiveness of LCM in sealing bigger gaps. An adapter with just a 31,700 micron hole was employed. When evaluated using a permeability plugging device (PPA), the mixture of high fluid loss squeeze (HFLS) with various reticulated foam effectively sealed the aperture [17]. Faleh Al-Mahdawi and Karrar Saad used the LTLP filter press to assess the effectiveness of silicon oxide nanoparticles. They discovered that increasing the concentration of nanoparticles causes the amount of filtrate to decrease [18].

Amanullah and Arfaj, used the waste of a deceased date tree as fibrous LCM. When compared to the commonly used commercial LCM product, the ARC Eco-Fiber apparatus displayed improved sealing and plugging performance with little or no loss of total drilling mud [19]. Noor Amory and Faleh Almahdawi added the powder of pomegranate peel and grape seed to drilling mud and investigated their ability to promote the mud properties. Their results indicated that the increased concentrations of the local materials powder reduced the fluid loss which it is good indicator to mitigate lost circulation [20].

Alsaba et al. performed lab tests and concluded that LCM’s with particle size distribution (PSD) implement preferable than particles of the same size. Small particulates fill the gaps between bigger particles, resulting in a tighter plug [7]. Savari et al. proved that, in most cases, combining LCMs is more beneficial than using just one kind [21]. Broussard et al. developed a unique engineered LCM chemically activated cross-linked pills (CACP). They used a mix of cross-linked polymer and fibrous cellulose to cure loss of circulation in deep water wells in the Gulf of Mexico. After the pill was set, circulation was entirely restored [22].

The main goal of this paper is to present the effect of polyacrylamide granular gel to reduce the lost circulation. Polyacrylamide polymer gel (PAM) systems have been frequently employed as plugging agents in heterogeneous reservoirs to regulate water output and increase sweep efficiency. Polyacrylamide polymer gel systems are classified into three classes depending on their composition and application conditions, which are in-situ monomer gel, in-situ polymer gel, and preformed particle gel (PPG).

2- Experimental Work

2.1. Core preparation

The utilised core in our experiments is a partially open fracture core. A partially open fracture mimics a natural fracture, which has an open fracture and ends in a porous formation. This core represents a natural core which is extracted from a well. A plug sample with a diameter of 1.5" and a length of 7 cm was extracted from a core by using a core driller. Then this plug was cleaned by utilisation of a Soxhlet extractor apparatus. Toluene and alcohol were used as cleaning agents [23]. After that, an oven and a desiccator vessel were used to dry the plug. Next, the plug sample is fully saturated with 1% NaCl brine by using a vacuum desiccator.

To generate a partially open fracture (POF), a plug was cut, by using a band saw, throughout the length of the cylinder core to a certain length, and the residual portion of the plug sample was left intact. The sliced part was divided into equal sized halves. By cutting through the designated region, one of the parts was extracted from the core. Following the cutting, the surface of the plug sample was softly cleaned with a brine to prevent rock grains from reducing permeability. To preserve fracture geometry, two rectangular stainless steel plates of varying diameters were attached to the taller sides of the created fracture with epoxy. The width of the fracture is the plate thickness. The fracture's shorter edge was left exposed as a fluid intake. Fig. 1 illustrates the manufacture of the POF model - fracture construction.

Next, the plates were covered with the cut part of the plug. The fractured sample was reassembled and epoxy was used to stabilise it. The fluid entry dimension was a rectangle. Fig. 2 shows the manufacture of the POF model - reassembling the fractured plug, while Fig. 3 shows the final front face of the plug sample.

After that, the plug was coated with tin paper to prevent leakage of fluid from the body of the fractured samples, as shown in Fig. 4 Then the plug is placed inside a rubber sleeve, as illustrated in Fig. 5 to ensure full control of fluid leakage before inserting it inside the core holder.

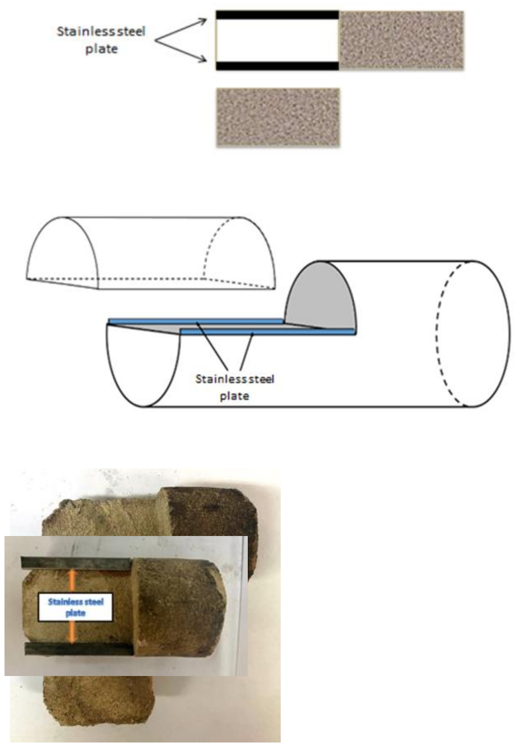


Fig. 1. Manufacture of POF Model - Fracture Construction

Fig. 2. Manufacture of POF Model - Reassemble Fractured Plug

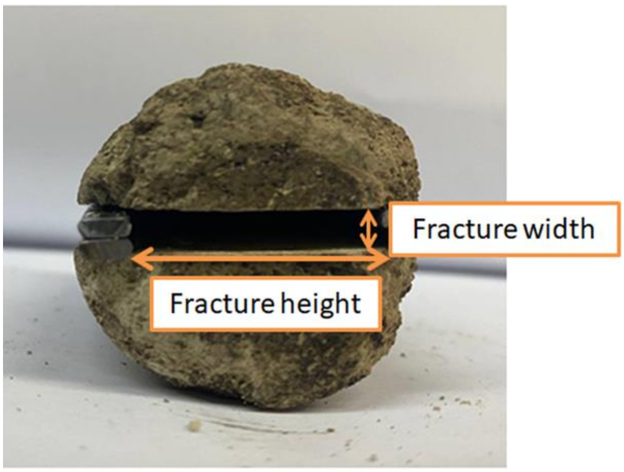


Fig. 3. Final Form of the Plug Sample

Fig. 4. Plug Sample Coated with Tin Paper

Fig. 5. Plug Sample Inside a Rubber Sleeve

2.2. Experimental materials

a. Polyacrylamide (PAM)

A commercial polyacrylamide polymer gel was chosen as the specimen for tests. This product has low cost. Acrylamide, or the mixture of acrylamide and acrylic acid, is the basis of polyacrylamide, which is water soluble. Polyacrylamide (shortened as PAM) is a polymer with the chemical formula (C_3H_5NO). It is a white granular product and it has a linear-chain structure. The average particle size of the used polyacrylamide in our experiments is a millimetre. PAM is extremely water-absorbent and, when hydrated, forms a soft gel. Fig. 6 illustrates a sample of polyacrylamide.

Fig. 6. Sample of Polyacrylamide

b. Sodium chloride (NaCl)

NaCl is frequently called salt. It has the chemical formulation NaCl and is an ionic substance. Salt is a natural Sodium Chloride (NaCl) and is used to formulate brines with specific gravity up to 1.20 and drilling muds.

c. Potassium chloride (KCl)

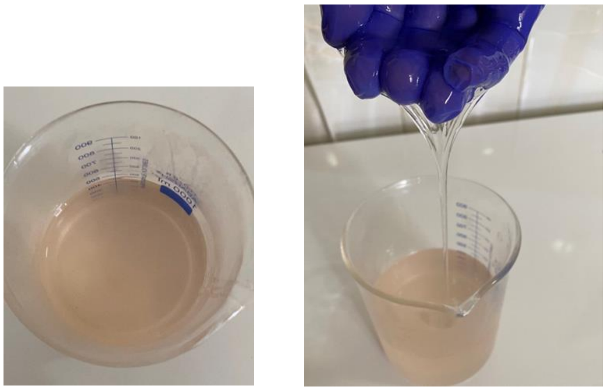
KCl is a soluble salt which is an extremely effective shale stabiliser during drilling in hydrosensitive clay zones and shale formations. Ion exchange provides inhibition; the potassium ion penetrates between the individual clay platelets in the shale to hold them together, preventing water from the drilling fluid from entering. KCl is used to make brines with a specific gravity of up to 1.15 and drilling muds.

d. Brine

Two types of brine are used in our experiments. The first one is a solution of 1% NaCl brine, which is used for both brine flooding tests, and the other one is a solution of 2% KCl brine, which was utilised as a base fluid for all PAM gel samples.

e. PAM gel solution

The samples were prepared using the subsequent methods: the brine, a solution of 2% KCl, was first put into a beaker and placed on the magnetic stirrer. To avoid flocculation, the PAM gel particulates were then gently introduced to the brine. After that, the mixture was left to blend until the PAM gel particles had absorbed all of the brine. Fig. 7 shows a PAM gel solution immediately after mixing and after 1 hour of mixing.



(a) (b)

Fig. 7. PAM Gel Solution (a) Immediately after Mixing, (b) after 1 Hour of Mixing

2.3. Core flooding system

A core flooding system is used in our experiments and the schematic system is shown in Fig. 8. To perform the tests, the brine and PAM gel are placed in the accumulators before being pumped over the specimens in the core holder; this is accomplished via the test technique and the specific conditions. A hydraulic hand pump confines the core sample inward to the core holder with a rubber sleeve. A data logger device is used to collect and transmit electrical signals from transducers and other sensor devices to a computer. After that, ORDEL software is used to monitor the transducer (pressure sensor), which records both analogue and digital pressure data, to determine the response curve by measuring the pressure differential across a rock sample at various points during this process [24].

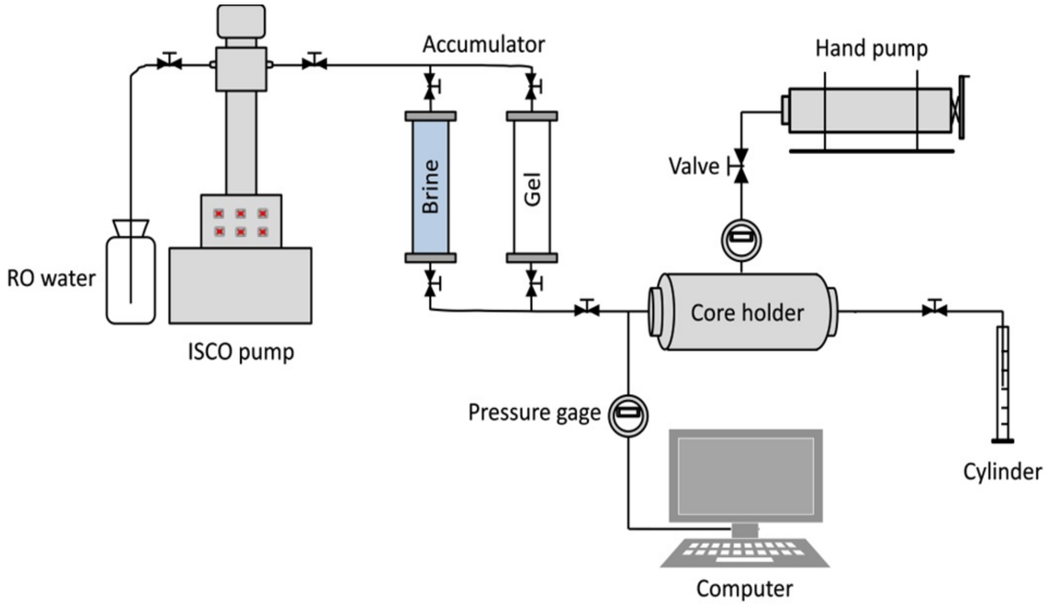


Fig. 8. Schematic of Core Flooding System

2.4. Experimental procedure

In our experiments, a core flooding system is used to evaluate the breakthrough pressure, which is the maximum pressure a material can withstand before cracking or forming internal channels, and plugging efficiency, which is calculated using the residual resistance factor (Frr). Frr represents the permeability reduction caused by using the PAM gel.

The plug sample was prepared as explained previously. Firstly, the plug samples are extracted from a homogenous core, and then the samples are cleaned by using a Soxhlet extractor apparatus. Next, an oven and a desiccator vessel are used to dry the plug samples. The plugs are then weighted to calculate the dry weight of the samples. After that, the plugs are saturated with 1% brine, and then the plugs' wet weight is calculated in order to measure the porosity of the samples. Finally, a partially open fracture is created and steel plates are put on to keep the opening of the fracture width. The plug was put into a core holder after being assembled once again as a whole cylinder.

After preparing all the materials and equipment that are required to perform the test, the core flooding system is connected as illustrated in Fig.8. The ISCO pump was filled with RO water and the hand pump was filled with hydraulic fluid. The brine and PAM gel solution were poured into the upper parts of both accumulators. The plug sample was placed into the core holder. And then a confining pressure of 1000 psi was immobilized. Finally, the test is performed and the data collected and analyzed.

Brine and PAM gel were injected under pressure into the core holder, which contains a plug sample inside it, from the accumulators using a syringe pump. At a steady pumping rate of 1.0 ml/min, all experimental injection operations were completed. The flooding process includes three phases as below:

a. First brine flooding

1% NaCl brine was pumped into the fracture entrance at a flow rate of 1 ml/min until the pressure became stable. This stable pressure is used to calculate the permeability of the plug sample by using the Darcy equation:

$$k = \frac{q\,\mu\,L}{A\,\Delta P} \quad (1)$$

Where: K is the plug permeability (md). q is the flow rate (cm^3/s). μ is the viscosity (cp). L is the plug sample length (cm). A is the cross section's area of plug (cm^2). ΔP is the differential pressure (stable pressure) (atm).

b. PAM gel placement

The fully swollen PAM gel was then pumped into the fracture using an accumulator from the opening inlet. The gel placement procedure was ended whenever the injection pressure stabilized or reached the desired value. The placement pressure, which was selected as the indication for PAM gel injection completion, is defined as the highest injection pressure of gel [25]. 500, 1000, and 2000 psi were selected as amounts for placing pressures in partly open fracture models based on the injection pressure behavior of numerous gel therapy applications [26]. The fractured plug, with the PAM gel sample inside it, remained in the core holder at room temperature for 1 hour to recrosslink the PAM gel.

c. Second brine flooding

Any PAM gel that remained in the connecting pipes was washed with water and air prior to the second brine flooding. The PAM gel filter cake was extracted from the plug's front surface. The first accumulator was refilled with 1% NaCl brine again prior to the next step starting. In the second brine flooding, 1% NaCl brine was pumped with a flow rate of 1 ml/min till a stabilized pressure was reached.

Pressure measurements were taken during each phase in order to study how the PAM gel spread and how the brine flowed. Utilizing the pump's injection time, the injection volume was computed. After finishing the test and collecting the data, the residual resistance factor, which is referred to as the permeability reduction, and plugging efficiency are calculated based on the following equations:

$$F_{rr} = \frac{K_b}{K_a} \tag{2}$$

Where: F_{rr} is the residual resistance factor. K_b is the permeability of brine before gel treatment. K_a is the permeability of brine after gel treatment.

The relationship between residual resistance factor and plugging efficiency is:

$$E = \left[1 - \frac{1}{F_{rr}}\right] * 100 \tag{3}$$

Where: E is the plugging efficiency %.

3- Discussion

A core flooding test including first brine flooding, PAM gel placement, and second brine flooding procedures was carried out in order to examine the overall behavior of PAM gel treatment in a partially open fractured core (POF). The POF measured length is 3.5 cm, approximately half the length of the entire plug sample, which equals 7 cm. The stainless steel plate thickness regulated the width of the fracture, which was set at 0.3 cm. Moreover, the height of the fracture is 2 cm. The fracture volume of the partially open fractured plug is calculated based on the volume of the rectangular equation.

$$FV = W_f * H_f * L_f \tag{4}$$

Where: FV is the volume of the fracture (POF) (cm^3). W_f is the width of the fracture (cm). H_f is the height of the fracture (cm). L_f is the length of the fracture (cm).

The plug sample with dimensions of 0.3 cm (W_f), 2 cm (H_f), and 3.5 cm (L_f) has a fracture volume of 2.1 cm^3.

After the plug sample is prepared as explained previously, it is put inside a rubber sleeve. A confining pressure of 1000 psi is applied to the rubber sleeve, which is inserted inside the core holder. 1% NaCl brine is poured inside the first accumulator. After that, the ISCO pump is operated at a 1 ml/min flow rate. After getting a fixed pressure, the pump is powered off and all data is recorded.

Fig. 9 illustrates the first brine flooding injection pressure. It is obvious that the injection pressure rose to around 3.5 psi at the beginning of the 18^{th} FV and dropped to approximately 1 psi at 50 FV. The two-phase flow in POF, which included both air, that was already present in the fracture, and brine, that was injected, was what created this pressure behavior. In the final phase of the first brine flooding, the pressure was fixed at around 1 psi. The partially open fracture had a remarkable permeability. As a result, the brine flow throughout the unbroken plug part behind the fracture section contributed the majority of the 1 psi, or pressure decrease, over the whole fractured core.

Eq. 1 is used to calculate the permeability prior to gel treatment and using a suitable convertor factor to be compatible with Darcy's equation units. Where: q = 1 ml/min, μ = 1 cp, L = 7 cm, A = 11.4 cm^2, ΔP = 1 psi.

The calculated permeability of the plug before gel treatment equals 150.38 md.

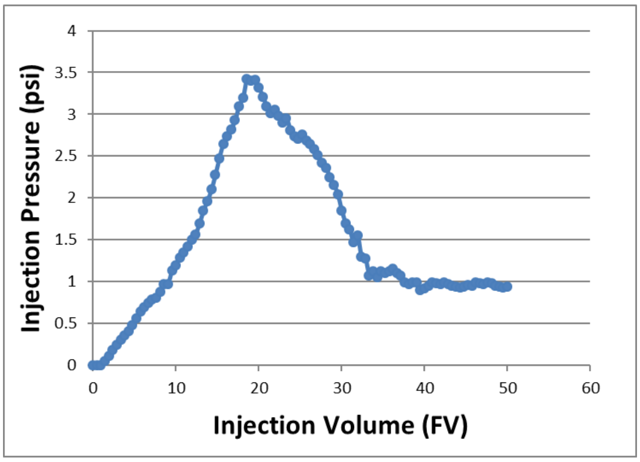


Fig. 9. Injection Pressure of the First Brine Flooding

After finishing the first brine injection and getting a stable pressure, a 3% PAM gel concentration is mixed with 2% KCl brine. Then the gel suspension is poured into the second accumulator. After that, the ISCO pump is operated at a 1 ml/min flow rate. Injection placement pressure for PAM gel in all experiments was 1000 psi. As illustrated in Fig. 10, the injection pressure gradually rose throughout the PAM gel injection at first, notably between 0 and 3 FV. After that, the pressure rose more quickly, finally reaching 1000 psi. Early on, particularly when PAM gel did not arrive at the fracture end, it was pushing the brine within the fracture. When the gel had completely filled the POF area, the fracture tip prevented the injection from pushing the PAM gel ahead. It is assumed that the PAM gel was dehydrated due to the difference in pressure between the injection pressure and the matrix pressure [27].

The process of PAM gel dehydration in the fracture is shown in Fig. 11. Depending on where the gel particle is, the direction of the pressure differential may change. Because of the very small pressure difference between the fracture and the plug matrix, the PAM gel suffered less from dehydration during the initial stages of injection. Due to its comparatively lower elastic modulus, the less dehydrated gel was more flexible when pressure was applied to it [28].

Consequently, the early gel injection pressure slope was low. Throughout the whole injection operation, the PAM gel was dehydrated progressively because of the pressure differential. Because gel elastic modulus increased and it produced a stiffer resistance to water flow when it was applied, the slope of flooding pressure rose quickly from 3 to 6 PV. It is thought that three factors contributed to the increased resistance: (1) more PAM gel being placed in the same volume, which could restrict the brine flow track; (2) a PAM gel filter cake forming on the fracture's surfaces; and (3) a decrease in permeability brought on by gel invasion into the matrix's core. No PAM gel particles were found in the effluent for the whole PPG injection, which lasted 6 FV.

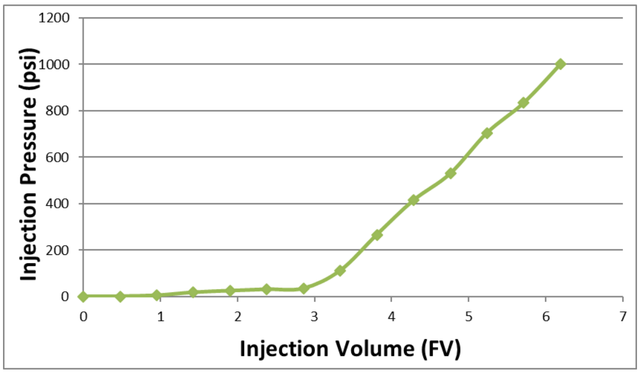


Fig. 10. Injection Pressure of the PAM Gel Flooding

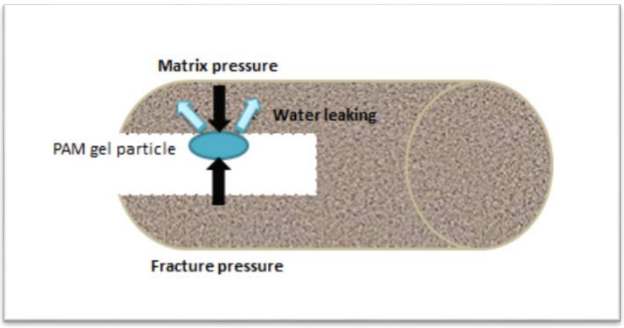


Fig. 11. PAM Gel Dehydrating under Pressure Difference

After finishing the gel injection, the fractured plug remained in the core holder at room temperature for 1 hour for recrosslinking the PAM gel.

Any PAM gel that remained in the connecting pipes was washed with water and air prior to the second brine flooding. The PAM gel filter cake was extracted from the plug's front surface. The first accumulator was refilled with 1% brine again prior to the next step starting. In the second brine flooding, 1% NaCl brine was pumped with a flow rate of 1 ml/min till a stabilised pressure was reached.

Fig. 12 explains the second brine flooding pressure. The injection pressure enhanced slowly from the start of flooding to 20 FV. During this time, no effluent was seen, indicating that the PAM gel in place completely prevented the flow of fluid through the fracture. After that, the pressure rose quickly and peaked at approximately 230 psi at 35 FV. This pressure is a breakthrough pressure. A considerable drop in pressure was then seen, going from 230 psi to 185 psi in 5 FV. The pressure drop showed that the packed gel was broken by the injected brine.

When the injection pressure exceeded the breakthrough pressure, the layed PAM gel particulates became capable of moving and moved aside by means of the pumped brine. The gel that had been put in moved, creating wormholes with extremely high permeabilities. The water injection pressure stabilised at roughly 193 psi from 42 to 50 FV. In comparison to the first brine flooding, the second brine flooding's steady pressure was significantly greater. The additional pressure drop created by the placement of gel, the cake of gel filter on the surface of the fracture, and the invasion of gel into the fracture surface area were the causes.

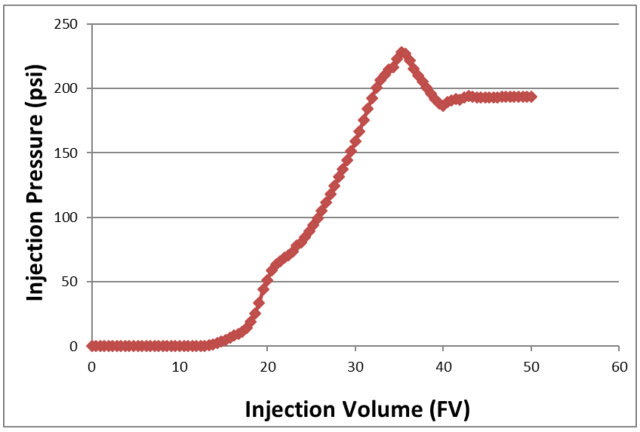


Fig. 12. Injection Pressure of the Second Brine Flooding

The plug sample permeability prior to gel treatment is calculated by utilizing the Darcy Eq. 1 by using the same variables used in the first brine flooding except using 193 psi as differential pressure. The calculated permeability equals 0.78 md.

The residual resistance factor Frr, which is referred to as the permeability reduction, of PAM gel was computed based on the permeability of both two brine flooding in order to more accurately describe the plugging performance of the used gel. Eq. 2 is used to compute the residual resistance factor. Where: K_b = 150.38 md and K_a = 0.78 md. The calculated residual resistance factor, Frr, equals 192.99. In other words, the permeability reduction after using PAM gel as treatment for lost circulation is approximately 193 times.

The plugging efficiency of gel treatment is calculated based on Eq. 3. The calculated plugging efficiency E of the used PAM gel is 99.48%.

Fig. 13 illustrates the plug sample before PAM gel treatment, while Fig. 14 shows the same plug sample after gel treatment.

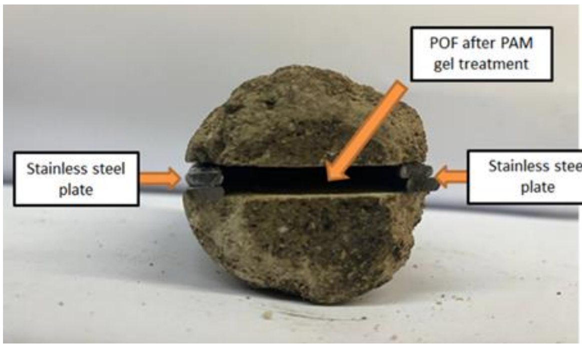


Fig. 13. Plug Sample before PAM Gel Treatment

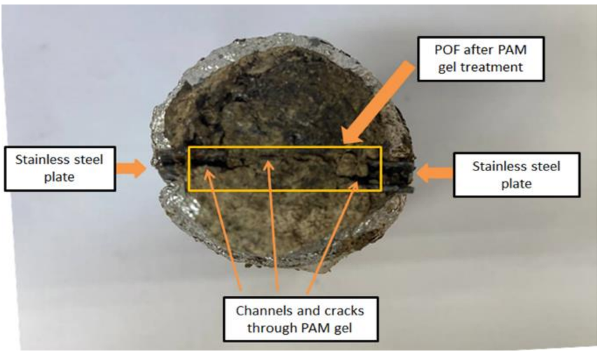


Fig. 14. Plug Sample after PAM Gel Treatment

4- Conclusions

- The PAM gel demonstrated encouraging results for fluid control losses while drilling.
- Overall, the PAM gel can reduce the plug permeability, which means it is an effective material to mitigate the losses.
- The permeability reduction caused by PAM gel treatment reaches to two hundred.
- The capacity of polyacrylamide granular gel to control lost circulation was investigated in great detail. According to this study, the polyacrylamide granular gel is a good option to be used as a lost circulation material (LCM) during drilling operations.

Nomenclature

A	Plug cross section area, cm^2
E	Plugging efficiency, %
F_{rr}	Residual resistance factor, Fraction
FV	Fracture volume, cm^3
H_f	Fracture height, cm
K	Absolute permeability, mD
K_a	Absolute permeability before treatment, mD
K_b	Absolute permeability after treatment, mD
L	Plug length, cm
L_f	Fracture length, cm
q	Flow rate, ml/min
W_f	Fracture width, cm
ΔP	Differential pressure, psi

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دراسة تجريبية لتقصي تأثير جل بولي أكريلاميد لتقليل فقدان دورة سائل الحفر

علي كريم الدلفي [١، *]، فالح حسن محمد المهداوي [١]، ياسر مختار [٢]، ويوسف الطاهر بغادي [٣]

١ قسم هندسة النفط، كلية الهندسة، جامعة بغداد، العراق
٢ جامعة النفط، بكين، الصين
٣ جامعة العلوم والتكنولوجيا، السودان

الخلاصة

إحدى المشكلات الصعبة التي تتم مواجهتها أثناء عمليات الحفر هي فقدان دورة سائل الحفر. قد تنشأ العديد من المشكلات بسبب هذه المشكلة، مثل المزيد من الوقت الضائع ونفقات الحفر المرتفعة. تم تطوير عدة أنواع مختلفة من المواد المانعة لفقدان السوائل ويتم استخدامها للحد من خسائر الطين وتجنب المشكلات المرتبطة بها. كل حل له فوائد و عيوب.

في هذه الدراسة، تم إجراء اختبار الغمر الأساسي لدراسة فعالية هلام حبيبات بولي أكريلاميد (PAM) لتقليل دورة سائل الحفر المفقودة. أحد الأنواع الشائعة لخصائص الكسر هو الكسور ذات الرؤوس، و المعروف باسم الكسر المفتوح جزئيًا (POF). ومع ذلك، تلقى العلاج الهلامي PAM في POFs القليل من الاهتمام في البحوث السابقة. تم بناء نماذج من الكسور المفتوحة جزئيًا باستخدام لباب صخري أسطواني. يتم تنفيذ سلسلة من العمليات على اللباب الصخري للحصول على نموذج POF. بشكل عام ، يمكن أن يقلل هلام PAM من نفاذية السدادة، مما يجعلها مادة مفيدة للحد من سائل الحفر المفقود. تشير النتائج إلى أن هلام البولي أكريلاميد الحبيبي يمكن أن يقلل من النفاذية حتى ١٩٣ مرة.

الكلمات الدالة: دورة سائل الحفر المفقودة، LCM، بولي أكريلاميد، PAM.