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Article

Experimental Investigation on the Impacts of Fracture Roughness and Fluid Composition on the Formation of Bubble Bridges through the Microbubble Fluid Flow

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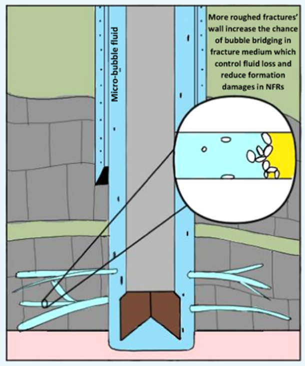
ABSTRACT: The colloidal gas Aphron (CGA) drilling fluids are an alternative to ordinary drilling mud to minimize formation damage by blocking rock pores with microbubbles in low-pressure or depleted reservoirs. Fractured formations usually have different characteristics and behavior in contrast to conventional ones and need to be investigated for Aphron applications. In this research, a series of core flood tests were conducted to understand the factors controlling the pore-blocking mechanisms of microbubbles in fractured formations. For the first time, a synthetic metal plug was used to simulate the fracture walls and eliminate the formation matrix effect. This study analyzed the effects of three fluid compositions, considering the polymer and surfactant concentrations at reservoir conditions, including temperature and overburden pressure. Additionally, fracture surface roughness as one of the parameters affecting the microbubble fluid penetration through the fracture path and bubble blockage were studied. The results indicated that microbubble fluid composition would not affect the bubble size or blockage probability. The different stable microbubble fluids resulted in the same pattern and conditions. Besides, fluid penetration would be more challenging if the fracture roughness decreased. Due to the accumulation of bubbles and the fact that some of them were trapped in the fracture's rough surface, the blockage possibility increased. According to the range of roughness for the steel core in previous studies and compared with the roughness of carbonate reservoir rocks, the roughness of fractured reservoir rocks is much higher than that of the steel surface. Accordingly, the observed trend in the experiments showed that when it is possible to form a bubble bridge in steel cores, then in carbonate rocks, we will definitely see blockage with any roughness, provided that other parameters are acceptable.



1. INTRODUCTION

Drilling operations in depleted oil and gas reservoirs can cause different problems during drilling, completion, and production.[1] Several fluid loss control materials (LCM) have been introduced, but these substances cause adverse skin effects and formation damage.[2] A special drilling fluid with suitable low density in accordance with the formation pore pressure can be a good option to prevent these challenges.[3] Colloidal gas Aphrons are a type of low-weighted drilling fluid that can be an alternative to ordinary drilling mud and their efficiency on formation damage has been proven.[4] Aphrons are the multilayered stable bubbles in the size range of 10−100 micrometers covered by the surfactant film;[5] their creation needs less facilities in contrast to the foam operation and they are easily made in a well-head mud-mixing equipment.[6]

He[7] detailed different aspects of Aphron, including creating Aphron's structure model, explanation of particular characteristics of the Aphron-based drilling fluid, agent selection approaches, and field applications. In addition, Ivan et al.[4a] explained the application of the microbubble drilling fluid experimentally and generated proper formulations for it. The applicability of this drilling fluid in real wells has been investigated by Ramirez et al.[4b] Furthermore, the physical features of this fluid and the effects of surfactant and polymer were assessed in micro models by Bjorndalen and Kuru.[3] The polymers and surfactants make it easier to create microbubbles with noncoalescing and low-density properties.[8] In another study, Spinelli et al.[9] showed the impacts of the surfactant of the microbubble drilling fluid on the drilling fluid surface tension.

Aphron fluid has been investigated in different aspects, such as microbubble fluid rheology and filtration in various polymer and surfactant concentrations.[10] Besides, the fluid stability, bubble size distribution, impacts of water-based or oil-based muds, flow rate, rheological models, rock wettability, permeability, temperature, and pressure effects, and drainage rate were scrutinized by Arabloo and Shahri[10b] and Mirabbasi et al.[11] In the latest research, Baseli Zadeh et al.[12] studied the effects of fracture width, mixing speed, and pressure difference

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on microbubble infiltration in a single-fracture medium. They observed that when the mixing speed (RPM[1]) and pressure difference increase, the diameter of the bubbles decreases, and consequently, the chances of blockage are reduced. In addition, they found that a smaller fracture width leads to more blockage.

The chemical composition of Aphron is one of the factors that affect its efficiency, and several studies have been done on it from different aspects.[13] Kim et al.[14] investigated the effect of pH on the stability of colloidal liquid Aphrons. They showed that the structure of CLA is stable in all of the pH ranges except for very low-pH conditions, and its stability is enhanced by increasing the pH in the aqueous phase. In another study, the fluid composition of Aphron in homogeneous sand-pack flood tests was investigated by Shi et al.[15] Their results showed that the bubble growth rate reduced with the increasing surfactant and polymer concentration, whereas it decreased and then increased with more salinity.

Bjorndalen et al.[16] focused on determining the effects of CGA composition on the resistance to the flow of micro-bubbles in pore space. In addition, they experimentally tested the effects of brine, water, crude oil, and mineral oil on the stability of microbubbles and the blocking ability. In another study, using the Taguchi design of experiment (DOE), the effect of polymer, salinity, and surfactant types and concentration on the CGA stability was investigated by Hosseini-Kaldozakh et al.[17] It was observed that the polymer fluid has the highest effect on CGA stability, whereas the surfactant has the lowest effect. However, increasing the salinity in both polymer and surfactant types of CGA fluid reduces its stability.

In addition to all of the above-mentioned studies of effective parameters in the microbubble fluid, one of the variables that play an effective role in changing the fracture media properties is roughness. It has been confirmed that fracture surface roughness affects the mechanical, hydraulic, and thermal behavior of fractures. Experimental studies have revealed that permeability and fracture rheology in such reactivation media are related to the roughness of the fracture surfaces.[18]

Luo et al.[19] assessed the influence of local surface roughness of fractures on fluid flow at the macroscopic scale of fracture nets. They considered two empirical models that related hydraulic apertures to mechanical apertures. They concluded that the effect of surface roughness in macroscopic scale on fractured rocks is critical when applying a model of mechanical-hydraulic apertures that forecasts significantly reduced hydraulic apertures. In another study, new stress-dependent mechanical and hydraulic aperture reduction assessments in fractured specimens were carried out. This research was used to rank the influence of in situ stress magnitude and orientation and fracture surface roughness on permeability response and network compressibility.[20] Niya and Selvadurai[21] used a novel modeling method to study fluid transport in an open fracture based on data derived from scanned surfaces of fractures by considering surface variations and velocity Laplacians in two orthogonal directions and the bulk flow rotation. This model examined the relationship between the permeability of a fracture and the joint roughness coefficient (JRC). Wang et al.[22] developed numerical models by utilizing the discrete element method (DEM) to study the effect of fracture surface roughness on the shear strength and permeability changes during such slip events. They concluded that samples with more significant asperity heights (rougher) show a higher peak strength, which quickly reaches a residual strength after a threshold shear displacement. In addition, rougher samples display a greater slip stability due to a high degree of asperity wear. Furthermore, in the long-term period, permeability reduces with rougher fractures, possibly because of asperities removal.

According to the latest articles from 2020 to 2022, there are no experimental tests yet of the chemical composition of Aphron fluid in a single fracture in the reservoir conditions with mud circulation simulation by considering the fracture wall roughness. In this research, a single metal plug fracture was used to consider only the fracture wall and eliminate the formation matrix effect for the first time. Therefore, three sets of experiments were designed in which the patterns of bubble bridge formation were different, and in each series, three different types of fluids were tested. In addition, to investigate the effect of roughness, three metal cores with different roughness (low, medium, and high) with the same fracture width and test conditions were experimentally studied. The results of this research can be used to create more accurate designs of Aphron fluid in a fractured reservoir to reduce formation damage during drilling or work-over operation.

2. METHODOLOGY

2.1. Experimental Materials. To accurately assess Aphron in fractures, two issues of fluid composition and roughness are investigated. Firstly, three metal plugs with different fracture widths, three fluid compositions, and three plugs with different roughness levels were prepared. Secondly, all test processes were performed in an experimental setup (FDS350) and each test was run for 30−60 min under the same conditions.

2.2. Core Sample Specification. In this research, metal plugs were utilized with a long fracture from one end to the other end of the plug and parallel to the axis of the cylinder. The plugs with a diameter and length of 1.5 in. and 10 cm, respectively, were prepared with three fracture widths of 0.1, 0.2, and 0.25 mm (Figure 1).

2.3. Fluid Properties. In this study, a water-based fluid was used as the microbubble fluid. Caustic soda was added to adjust the fluid pH, and xanthan gum (XG) was employed as a stabilizer and viscosifier. The last chemical used for preparing the microbubble fluid was sodium dodecyl benzene sulfonate (SDBS, CMC 1.5 mM). In this research, we have implemented the three most widely used types of microbubble fluid presented so far in literature.[17] The compositions of these fluids are presented in Table 1.

Figure 2 shows the microbubbles of fluids A, B, and C.

2.4. Experimental Procedures. *2.4.1. Microbubble Fluid Preparation.* For preparation of the microbubble fluid, firstly, caustic soda was added to water to set the pH in the range of 9.5−10. XG and SDBS were added afterward according to the concentrations in Table 1 in order to prepare the microbubble fluids A−C. For mixing the chemicals and preparing the final microbubble fluid, a mixing speed of 8000 RPM and a ΔP of 200 Psi were used. Table 2 illustrates the design of the experiments with different fluid compositions in three fracture sizes of 0.1, 0.2, and 0.25 mm.

2.4.2. Metal Core Roughness. To test the effect of the roughness, three metal cores with different levels of roughness (low, medium, and high) were used in this study. The different fracture surface roughness levels were done by smoothing the surface using wire-cut tools in two more levels. In these three

Figure 1. Metal core plug.

Table 1. Characteristics of Previously Studied Stable Microbubble Fluid Compositions[17]

fluid code	NaOH (caustic soda)	SDBS	XG (gr/L)
A	about 1 gr/L	0.9 gr/L	3
B	about 1 gr/L	1.2 gr/L	4.5
C	about 1 gr/L	1.5 gr/L	6

tests, the other parameters, including fracture width, fluid composition and mixing speed, and pressure differences of the circulation drilling fluid and fracture remained constant. The conditions considered for these tests were as follows: fracture size 0.2 mm, delta P 500 Psi, mixing speed 8000 rpm, fluid composition 1 gr/L NaOH (caustic soda), SDBS 1.2 gr/L, and xanthan gum 4.5 gr/L (fluid B).

2.4.3. Experimental Setup. In this study, a core flood system (FDS350) was used for the assessment of pressure in the middle of the plugs' fracture and the schematic of the system is given in Figure 3. To observe the pressure distribution in the core sample, four gauges are embedded along the core holder, two of them in the middle of the sleeve and two others at each end of the core holder. The pressure difference between these gauges is a sign bubble blockage in the fracture path. It also gives us the location of the blockage in the fracture. After inserting the plug in the sleeve, overburden pressure was applied to the core sleeve; afterward, the microbubble fluid was pushed to the circulation path. The pressure difference automatically was applied to the mud circulation point at the front end of the plug and the flow pressure was applied through the fracture of the plug. Indeed, these pressures represented the mud pressure in the well and the reservoir pressure, respectively.

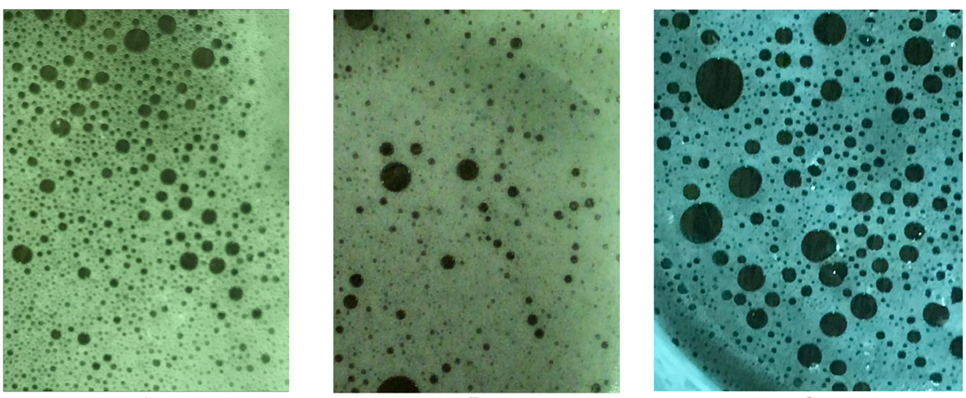
Table 2. Design of Experiments with Different Fluid Compositions in Three Fracture Sizes

test code	fracture fize (mm)	fluid code (Table 1)
CA-0.1	0.1	A
CA-0.2	0.2	A
CA-0.25	0.25	A
CB-0.1	0.1	B
CB-0.2	0.2	B
CB-0.25	0.25	B
CC-0.1	0.1	C
CC-0.2	0.2	C
CC-0.25	0.25	C

All experimental tests were conducted according to Table 2 for different conditions of fluid composition and fracture sizes. The pressure differences between the inlet pressure transmitter (PT) and Tab1, Tab2, and outlet PT were recorded as DPTs, which are illustrated in Figure 4. The system recorded the DPT every 5 s continuously. However, we changed the desired DPT position manually to gain enough favorable data for analyzing the trends of all three DPTs and looking for a sudden rise in them. Such rises reveal blockage in that position due to bubble accumulation.

3. RESULTS AND DISCUSSION

3.1. Fluid Composition. The fluid compositions listed in Table 1 were prepared from previous research works in three experimental series where the bubble bridge formation patterns were different (Figure 5). In the first case, due to the use of a core with a fracture width of 1 mm, it was observed that the pressure difference suddenly increases between Tables 1 and 2 (if we divide the length of the fracture into three hypothetical parts, the middle part) from a few minutes after the test and



A B C

Figure 2. Microbubbles of fluids A, B, and C.

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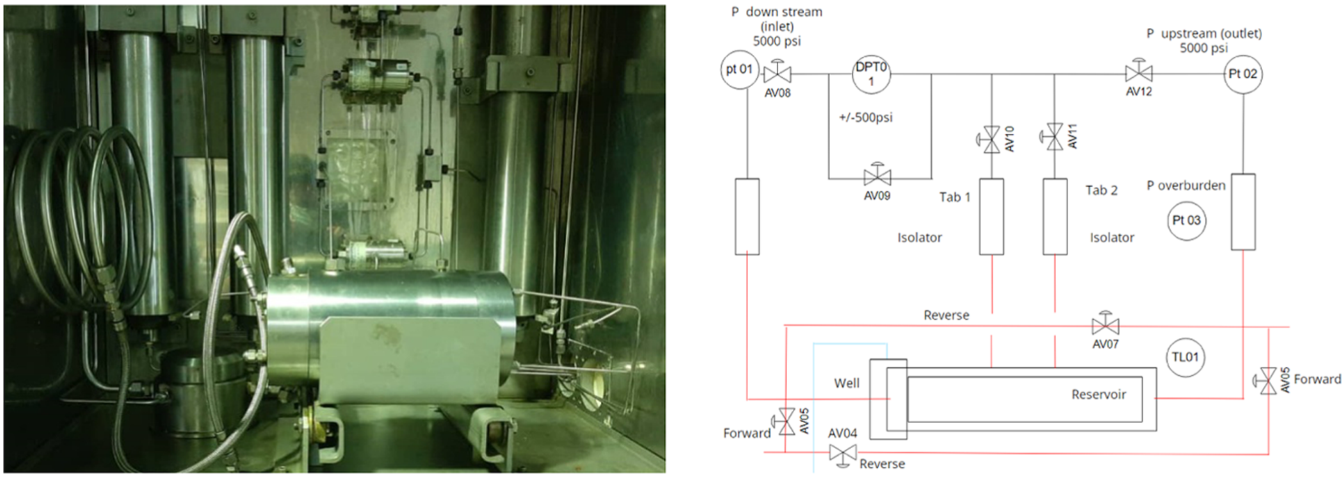

Figure 3. Core flood system (FDS350) apparatus, and piping and setup diagram of the locations of pressure gauges.

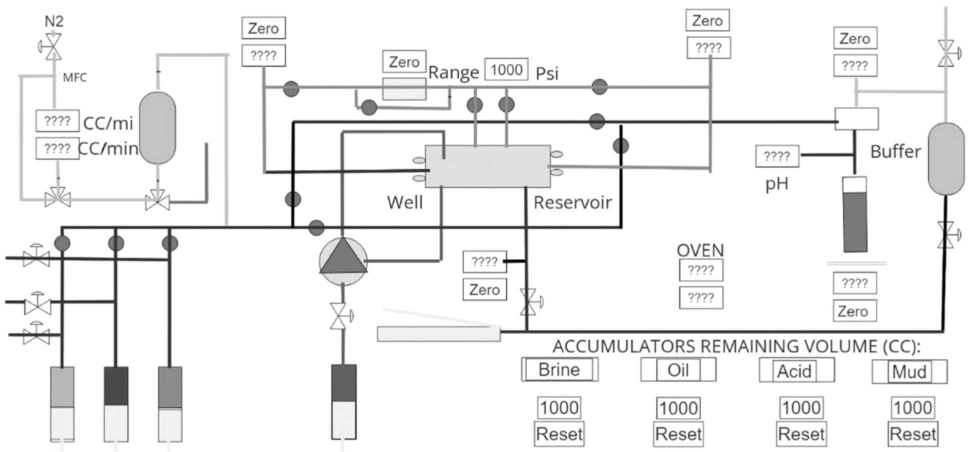

Figure 4. Schematic of formation damage and well treatment services (FDS350).

mud circulation. This trend is similar for all three fluids A, B, and C (in constant test conditions, stirring speed: 8000 RPM, Delta P: 200 PSI, and core number 1). For the second experiment series, a core with a fracture width of 0.2 mm was used; the results were similar to previous experiments, and at the end of the fracture length (between Table 2 and the output tab), a bubble bridge was formed and there was an intense pressure difference. As expected, as the width of the fracture increases in the last three experiment series to 0.25 mm, for the three types of stable fluid composition A, B, and C, we observed the same behavior and no bubble formation and blockage during fracture.

3.2. Fracture Roughness. The experiment was designed using three metal cores with a constant fracture width of 0.25 and three different roughness levels (low, medium, and high) to investigate the effect of roughness on fluid displacement in a single fracture. Due to operational limitations, it was practically impossible to measure the surface roughness of the core because, if the core was cut, the surface roughness of the crack wall would also be affected. For this reason, we qualitatively considered low, medium, and high levels for smoothness or roughness, and with one polishing round, high roughness was considered twice as medium and three times as low roughness. Figures 6−8 show 30−60 min of the test of mud circulation in one end of the core, which indicates the displacement and mud pressure in the well during drilling of the fractured reservoir zone. According to these results, it is clear that the higher the roughness, the more likely it is to form a bubble bridge and prevent drilling fluid loss. This is because when the roughness of the fracture increases, the probability of bubbles getting stuck at the surface of the fracture enhances. Therefore, a higher roughness of the fracture results in faster and more probable creation of the bubble bridge and leads to lower formation damage.

According to the above diagrams, fluid penetration will be more challenging when the fracture roughness increases. Besides, due to the accumulation of bubbles, and the fact that some of them are trapped in the fracture's rough surface, the blockage possibility increases in this situation.

In Figure 6, no blockage and no meaningful rises are observed in any part of the fracture paths. However, in the test with the core sample with medium roughness, more roughness of the surface causes bubble blockage in the last part of the fracture between the second pressure tab and the outlet one. The sudden rise in pressure differences of the inlet/ outlet pressure gauges in Figure 7 shows this phenomenon.

The last test result is presented in Figure 8. This test is run with the core sample with high roughness, which has the roughest fracture surface. Hence, the bubbles' trapping possibility increases, and bridging starts sooner and at the middle of the fracture path between the pressures in Tables 1 and 2. This phenomenon is the reason for the pressure

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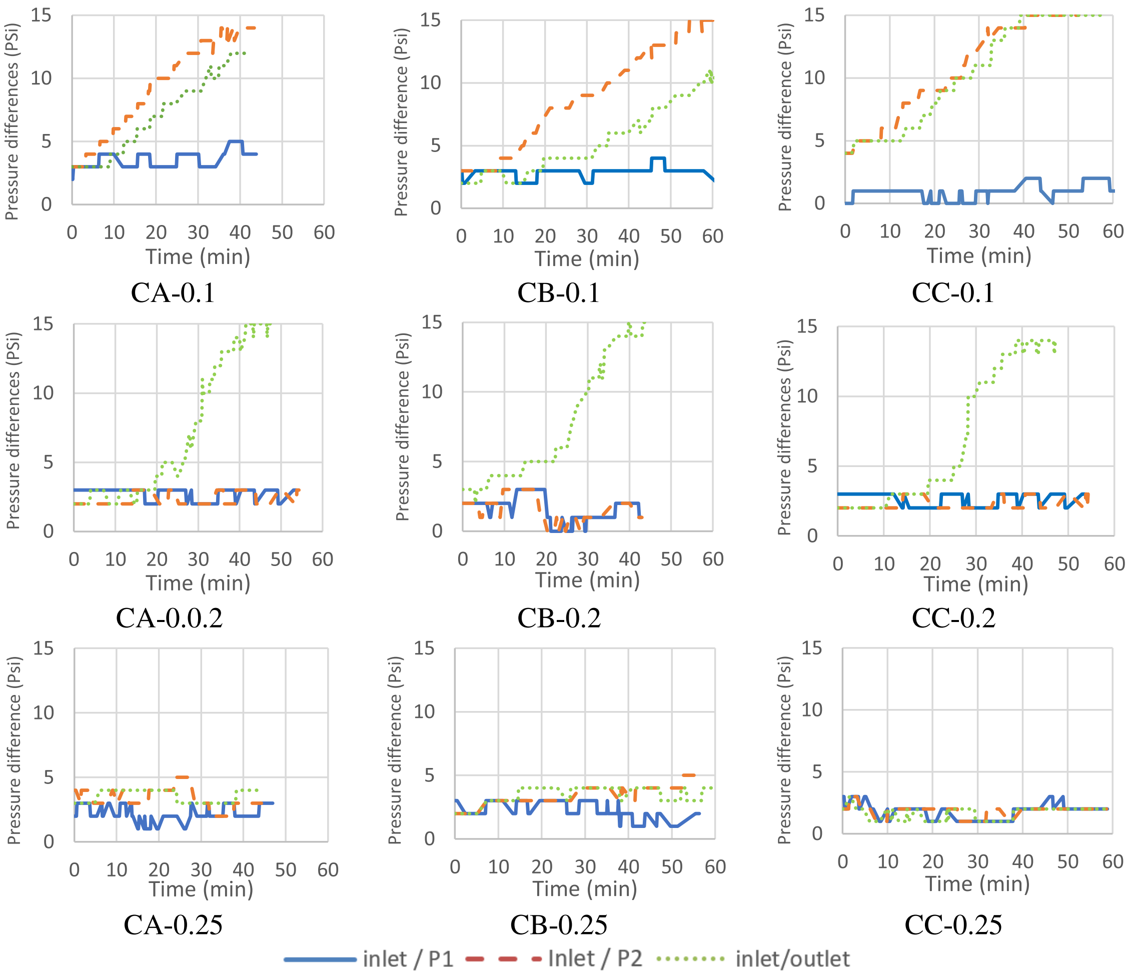

Figure 5. Pressure vs time results of sample tests of fluid composition with different fracture widths. (The inlet/outlet line indicates the pressure difference between the two ends of the plug in the core holder. The inlet/P1 line refers to the pressure difference between the inlet end and Tab1 thorough the core holder. The inlet/P2 line shows the pressure difference between the inlet end and Tab2 gauge in the middle of the plug in the core holder).

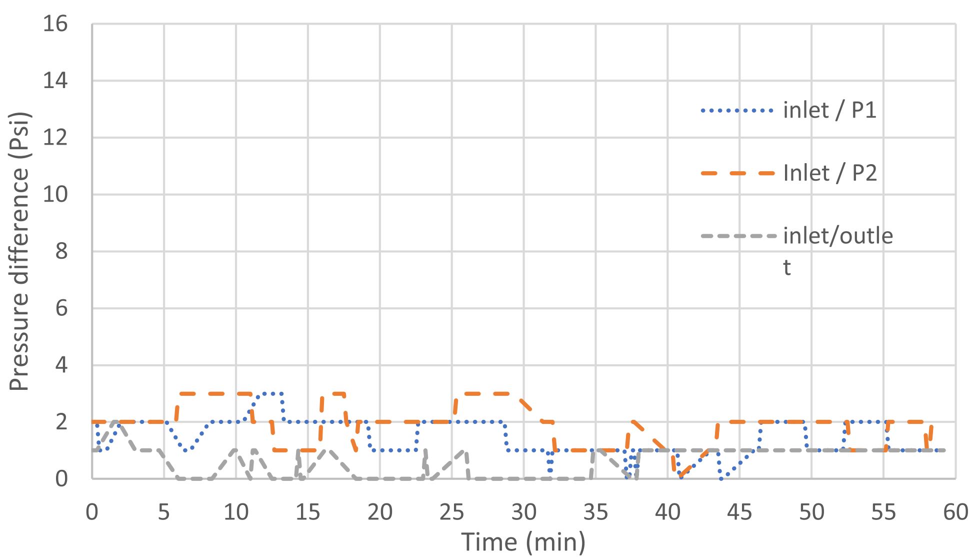

Figure 6. Pressure vs time results of the sample with low roughness. (The inlet/outlet line indicates the pressure difference between the two ends of the plug. The inlet/P1 line refers to the pressure difference between the inlet end and Tab1 through the core holder. The inlet/P2 line shows the pressure difference between the inlet end and Tab2 gauge in the middle of the plug in the core holder).

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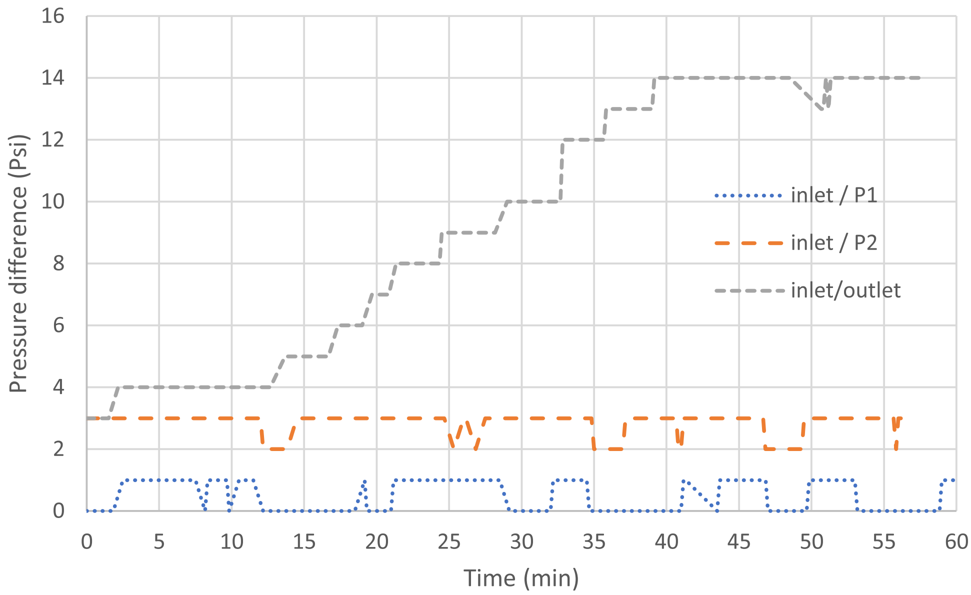

Figure 7. Pressure vs time results of the sample with medium roughness. (The inlet/outlet line indicates the pressure difference between the two ends of the plug. The inlet/P1 line refers to the pressure difference between the inlet end and Tab1 through the core holder. The inlet/P2 line shows the pressure difference between the inlet end and Tab2 gauge in the middle of the plug in the core holder).

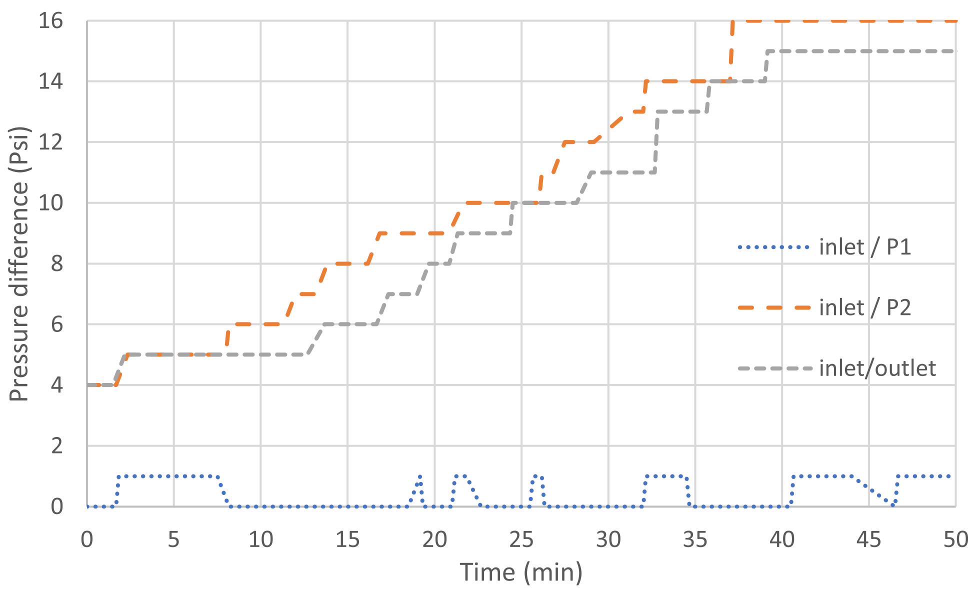

Figure 8. Pressure vs time results of the sample with high roughness. (The inlet/outlet line indicates the pressure difference between the two ends of the plug. The inlet/P1 line refers to the pressure difference between the inlet end and Tab1 through the core holder. The inlet/P2 line shows the pressure difference of the inlet end and Tab2 gauge in the middle of the plug in the core holder).

difference increase through the inlet/Table 2 gauges, and also through the inlet/outlet ones.

By comparing the roughness of the rocks of the fractured reservoirs and the roughness of the used steel cores, we can expect to reduce the formation damage caused by the penetration of the drilling fluid into the formation. It means that the higher the roughness, the lower the fluid penetration and, as a result, the lower the damage to the formation.[23] The reason for this is that the bubbles are more easily trapped in the scratches of the surfaces, and the higher the roughness, the more and deeper the scratches, and the accumulation of bubbles will be easier.

4. CONCLUSIONS

The objective of the current research was to investigate and highlight the penetration of a microbubble fluid in a single fracture using a synthetic metal plug. Firstly, a stable microbubble was able to reduce fluid loss and prevent formation damage near the production zone. However, different fluid compositions had no significant effect on improving the formation damage prevention. From the observations, it was concluded that due to the stability of the composition of the fluids used in this research, bubbles were formed, while the important parameter in creating and accelerating the creation of a bubble bridge and reducing formation damage is the size of the bubble, which is a function of other parameters and is not related to the composition of

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the fluid. As long as we use a stable microbubble fluid, if we keep the bubble size in an appropriate range, we can reduce the damage caused by the penetration of the drilling fluid into the formation. Secondly, fluid penetration was reduced by increasing the fracture roughness. In other words, the blockage possibility increased due to the accumulation of bubbles and the fact that some of them were trapped in the fracture's rough surface. By comparing the roughness of the rocks of the fractured reservoirs and the roughness of the used steel cores, we can expect to have a lower formation damage caused by the penetration of the drilling fluid into the formation by a higher surface roughness.

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Notes

The authors declare no competing financial interest.

ADDITIONAL NOTE

[1]Rotation Per Minute

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