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STUDY OF THE EFFECTIVENESS OF RESTORING THE PERMEABILITY OF NEAR-BOREHOLE ZONES

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Abstract: When drilling into a reservoir zone, the main goal is to reach the reservoir without damaging the pore space. Damage to the pores can happen because of the drilling mud. Drilling mud, especially when it has solid particles and clay, can block the pores near the wellbore, which is called formation damage. To avoid this, drilling fluids often contain bridging agents, usually finely ground carbonate rocks. These small particles move into the pore spaces of the reservoir zone. While drilling through the productive layer, they protect it from the further invasion of drilling mud and its filtrate. After the drilling is finished, the area where the bridging agents entered the formation is cleaned with hydrochloric acid (HCl). The acid reacts with the carbonate ($CaCO_3$), dissolving the blocking material. This process restores the permeability of the reservoir zone and allows hydrocarbons to flow freely into the well. The aim of this work is to explain the theoretical background of this topic and to perform laboratory tests that confirm the effectiveness of this process.

Keywords: drilling fluids, formation damage, bridging agents, reservoir zone, permeability

1. Introduction

Damage to the near-wellbore zone caused by drilling fluids is one of the most common factors reducing reservoir productivity. During drilling, solids present in the mud may invade the pore space, leading to pore throat plugging and permeability impairment [1]. To mitigate this risk, carbonate-based bridging agents are often added to drilling fluids in order to minimize filtrate invasion and protect the pore structure of the reservoir rock [2]. However, their presence requires an effective post-drilling cleanup treatment to restore the original permeability of the formation [3].

The aim of this study is to assess the efficiency of hydrochloric acid in restoring the permeability of the near-wellbore zone after exposure to drilling muds containing carbonate bridging agents. The novelty of this work lies in the direct experimental comparison of two scenarios: (i) rocks exposed to carbonate blockers, and (ii) rocks exposed to clay-based drilling mud, providing a more comprehensive understanding of acid cleanup performance.

In this study, laboratory experiments were conducted on sandstone core samples to evaluate changes in permeability at several stages of treatment, including exposure to drilling fluids and subsequent acid washing. The results demonstrate the extent to which the initial permeability of the rock can be restored after removing carbonate-based solids through acid treatment.

2. Method section

2.1. Materials used in the study

XCD Polymer 0.3%. A biodegradable polymer with a high molecular weight, designed to effectively increase the rheological parameters of drilling fluid, especially the yield point. Even low concentrations efficiently control the fluid properties, enabling its use in both freshwater and brine-based systems.

Mikhart 130. A bridging agent used in drilling fluids, whose main function is to reduce filtrate loss and prevent the liquid phase of the drilling fluid from penetrating into the formation. It is a fine-grained calcium carbonate ($CaCO_3$) with a controlled particle size distribution, allowing it to effectively seal the pore space of rocks with various permeabilities. During drilling, it forms a thin and tight filter cake on the wellbore walls, reduces fluid invasion, stabilizes the borehole, and protects the formation from contamination [4].

10% Hydrochloric Acid. Hydrochloric acid (HCl) is one of the most commonly used inorganic acids in the drilling industry. It is an aqueous solution of hydrogen chloride, colorless or slightly yellow, characterized by strong corrosive properties and high chemical reactivity, particularly when reacting with minerals containing carbonates, oxides, or metal hydroxides [5].

2.2. Equipment used in the study

Core sampling device. Used to prepare cylindrical rock samples of specified dimensions. The device operates on the principle of mechanical drilling with a diamond coring bit.

Permeameter. An instrument used to determine the permeability of porous rocks to gas (typically nitrogen) according to Darcy's law. Gas is injected into one side of the core under a known pressure, and the pressure difference recorded by sensors is used to calculate the permeability.

Core conditioning oven. Used for drying, heating, and conditioning core samples under elevated and stable temperature conditions.

Fann rotational viscometer. A device for measuring the rheological properties of drilling fluids. It has twelve rotational speeds (1–600 rpm). The measurement is based on observing the torsion of a spring in a two-cylinder system: the rotating outer cylinder (rotor) and the stationary inner cylinder (bob).

Mud balance. A beam balance consisting of a base, an arm with a scale and adjustable rider, and a sample cup with a lid and overflow opening. A level bubble above the pivot point provides accurate horizontal leveling.

Marsh funnel viscometer. A device used for quickly determining the viscosity of drilling fluid suspensions. The result depends primarily on the degree of gelation, and the density of the fluid. Routine checks with the funnel make it possible to detect rapid changes in fluid properties.

Filter press for filtration measurement. The method consists of measuring the volume of filtrate obtained from the filter press. A sieve and filter paper are placed at the bottom of the chamber, drilling fluid is poured in, and after securing the cover, pressure between 0.035 and 0.7 MPa is applied. After a defined time, the filtrate volume is measured with an accuracy of 0.1 ml.

Filter press for fluid flow through cores. A modified dynamic filter press used to conduct studies of fluid flow through rock cores under elevated pressure and temperature. Cores are placed in a rubber sleeve in such a way that the tested fluid is forced directly through the sample [6].

2.3. Preparation of drilling fluids

Since the drilling fluid containing bridging agents was to be filtered through the core during the experiment, its properties were first examined. To make comparison possible, two water-based drilling fluids were prepared: one containing only 0.3% XCD polymer (hereafter referred to as "XCD fluid"), and the other also containing the Mikhart 130 bridging agent (hereafter referred to as "Mikhart fluid").

The XCD polymer was necessary to create a viscous suspension capable of keeping the bridging agent dispersed in the fluid and preventing its migration into deeper parts of the formation. At the initial stage, it was assumed that two liters of water would be sufficient. Subsequently, the required amount of XCD polymer was calculated using the following formula:

$$M_{XCD} = M_w \cdot 0.003 \quad (1)$$

where:

M_{XCD} – mass of the XCD polymer [g],
M_w – mass of water [g].

After measuring the parameters of the XCD fluid, 1.75 liters of fluid remained. It was assumed that the second fluid should contain 200 g of bridging agents per liter of drilling fluid. Therefore, for 1.75 liters of fluid, 350 g of Mikhart 130 were added and thoroughly mixed. Subsequently, the same rheological parameters were measured as for the XCD fluid.

2.4. Rheology measurements of drilling fluids

2.4.1. Viscosity measured with the rotational viscometer

Viscosity is a material property observed in all states of matter that results from intermolecular interactions [7]. It describes the resistance, also known as internal friction, that occurs when one part (layer) of a medium moves relative to another. The measurements show an increase in viscosity after adding the bridging agents. Based on the viscometer readings, various types of viscosities as well as the yield point can be determined (Tab. 1).

Table 1. Viscosity of the drilling fluids measured using a Fann-type viscometer

Number of revolutions per minute [rpm]	XCD drilling fluid	Mikhart drilling fluid
	Bob deflection value	
600	29.75	42.05
300	21.50	30.40
200	17.90	22.80
100	13.75	17.30
60	11.75	14.15
30	9.30	11.70
20	8.60	10.35
10	7.00	8.65
6	6.25	7.20
3	5.25	6.70
2	4.95	5.85
1	3.95	4.85

2.4.2. Apparent viscosity

Apparent viscosity describes the overall "apparent" viscosity of the drilling fluid at a given shear rate. It reflects both the internal friction and the plastic behavior of the fluid. It was calculated using the formula (Tab. 2):

$$\eta_p = \frac{M_{600}}{2} \text{ [mPa} \cdot \text{s]} \quad (2)$$

where M_{600} – dial reading at 600 rpm.

Table 2. Apparent viscosity of the fluid

Number of revolutions per minute (rpm)	XCD drilling fluid	Mikhart drilling fluid
	Average value [mPa · s]	
600	14.88	21.03

2.4.3. Plastic viscosity

Plastic viscosity represents the component of viscosity responsible for the internal friction of the fluid during flow. It reflects the resistance of the fluid in laminar–turbulent motion, i.e., the degree of "thickness" during mixing or pumping. It was calculated using the formula (Tab. 3):

$$\eta = M_{600} - M_{300} \text{ [mPa} \cdot \text{s]} \quad (3)$$

where:

M_{600} – dial reading at 600 rpm,
M_{300} – dial reading at 300 rpm.

Table 3. Plastic viscosity of the fluid

Plastic viscosity	XCD drilling fluid	Mikhart drilling fluid
	Average value [mPa · s]	
η	8.25	11.65

2.4.4. Yield point

Along with plastic viscosity, the yield point is the second parameter determining the flow resistance of drilling fluids. It reflects the level of electrochemical attractive forces present in the fluid, resulting from positive and negative charges located on particles or in their immediate surroundings. It was calculated using the formula (Tab. 4):

$$\tau_y = M_{300} - \eta \cdot 0.48 \text{ [Pa]} \quad (4)$$

where η – plastic viscosity [mPa·s]

Table 4. Yield point

XCD drilling fluid	Mikhart drilling fluid
Average value [mPa · s]	
19.77	26.752

2.4.5. Density

Density is the ratio of mass to volume. It was measured using a Baroid mud balance. An increase in the density of the Mikhart fluid by 10.89% compared with the XCD fluid was observed. The difference results primarily from the presence of carbonate additives (bridging agents) in the Mikhart fluid, which increase the overall mass density of the system (Tab. 5).

Table 5. Density of the drilling fluids

Drilling fluid name	Density [g/m^3]
XCD drilling fluid	1.01
Mikhart drilling fluid	1.12

2.4.6. Viscosity measured with the marsh funnel

The viscosity measurement performed using the Marsh funnel is considered mainly an indicative method. Based on changes in outflow time, a shorter outflow time may indicate decomposition or thinning of the drilling fluid components, while a longer outflow time may indicate an increase in the solid phase content, particularly hydration-sensitive clays. The faster outflow time of the Mikhart fluid may result from its higher density compared with the XCD fluid (Tab. 6).

Table 6. Viscosity of the drilling fluids measured using a Marsh funnel viscometer

Drilling fluid name	Flow time of one liter [s]
XCD drilling fluid	52
Mikhart drilling fluid	45

2.4.7. Filtration

The volume of filtrate measured using the filter press provides information about the ability of the drilling fluid to allow liquid to pass through the filter and to form a filter cake on the borehole wall. In practice, this indicates how quickly and in what amount the fluid invades the formation [8]. At the same time, the filtrate volume indirectly indicates the quality of the filter cake: the lower the filtrate volume, the more compact and efficient the filter cake, protecting the borehole wall from excessive fluid loss (Tab. 7).

Table 7. Filtration time and filtrate volume of the drilling fluids

Drilling fluid name	Filtration time [min]	Filtrate volume [ml]
XCD drilling fluid	3.20	240
Mikhart drilling fluid	30	17

Filtration tests were conducted using a filter press. The results clearly show that the Mikhart fluid has significantly better filtration properties than the XCD fluid. The XCD fluid quickly broke through the filter and did not form a stable filter cake, whereas the Mikhart fluid effectively limited filtration, confirming its high efficiency in sealing the formation and stabilizing the borehole walls (Fig. 1).

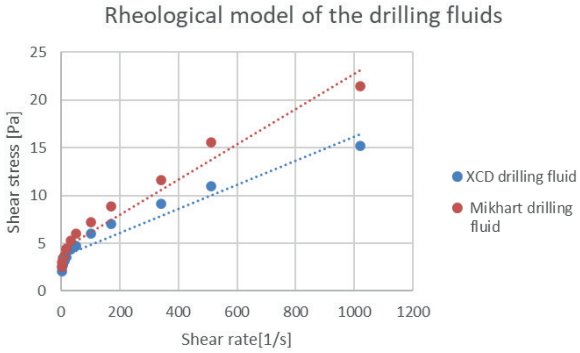

Fig. 1. Rheological model of the drilling fluids

2.5. Core drilling

Initially, ten sandstone core samples were drilled. Their dimensions were then measured, as these parameters are essential for the permeability calculations conducted later (Tab. 8).

Table 8. Core dimensions

Core number	L [mm]	D [mm]	V [mm^3]	A [mm^2]
1	47.8	25.4	24 220.59	506.451
2	51.5		26 095.40	
3	51.6		26 146.07	
4	50.0		25 355.35	
5	46.2		23 410.88	
6	51.3	25.4	25 994.09	506.451
7	47.8		24 220.61	
8	50.4		25 538.05	
9	50.3		25 487.38	
10	48.7		24 777.99	

The volume of each sample was determined using the formula:

$$V = \pi \cdot \left(\frac{D}{2}\right)^2 \cdot L \ \ [\text{mm}^3] \tag{5}$$

where:

π – mathematical constant equal to approximately 3.14,
D – core diameter [mm],
L – core length [mm].

In the further part of the study, it was necessary to determine the cross-sectional area of the cores, which is requires for permeability calculations:

$$A = \pi \cdot \left(\frac{D}{2}\right)^2 \ \ [\text{mm}^2] \tag{6}$$

where:

π – mathematical constant equal to approximately 3.14,
D – core diameter [mm].

2.6. Porosity measurement

As the first step, porosity measurements were performed on the core samples. Initially, the samples were weighed using a laboratory balance. Next, the samples were saturated with water in a special device called a saturator and then weighed again. This procedure made it possible to determine the mass of water absorbed by each sample. Knowing the volume of each core sample and the volume of water filling the pore space, the pore volume of each sample and the average porosity of the rock were calculated. The porosity was determined using the following formula (Tab. 9):

$$M_w = M_n - M_s \ [\text{g}] \tag{7}$$

where:

M_w – mass of water [g],
M_n – mass of the saturated core [g],
M_s – mass of the dry core [g].

2.7. Method of permeability measurement and calculation

The main measurements used to evaluate the effectiveness of acid washing were based on permeability measurements. The assessment of the treatment efficiency was therefore directly related to changes in permeability. The formula presented below shows how the permeability of the samples was calculated:

$$k = \frac{2 \cdot \mu \cdot L \cdot P_2 \cdot Q}{A \cdot (P_1^2 - P_2^2)} \ [\text{m}^2] \tag{8}$$

where:

Q – volumetric flow rate of the fluid [m^3/s],
L – core length [m],
A – cross-sectional area of the core [m^2],
μ – dynamic viscosity of the flowing fluid at the measurement temperature (for nitrogen at the measurement temperature [°C]: 0.0000199) [Pa·s],
P_1 – upstream pressure (atmospheric pressure plus applied pressure) [Pa],
P_2 – downstream pressure (atmospheric pressure) [Pa].

Nitrogen was used as the flowing medium for the permeability measurements. Before each measurement, the samples were dried. The dynamic viscosity coefficient of nitrogen was assumed to be 0.0000199 [Pa·s].

Table 9. Core porosity

Core number	Mass of dry core [g]	Mass of water-saturated core [g]	Mass of water [g]	Volume of pore space filled with water [mm^3]	Porosity [%]	Rock porosity [%]
1	40.66	45.66	5.00	5000	20.64	20.31
2	44.98	50.42	5.44	5440	20.85	
3	44.72	49.84	5.12	5120	19.58	
4	42.38	47.43	5.05	5050	19.92	
5	39.60	44.41	4.81	4810	20.55	

2.8. Permeability measurements

First, the newly drilled core samples were dried. Subsequently, their flow rates were measured in a permeameter under different pressure conditions (Tab. 10).

After drying the samples, and in order to improve the accuracy of the results, the dry cores were washed with hydrochloric acid, as they could have contained natural carbonate crystals that might later have influenced the experimental results (Tab. 11).

Table 10. Permeability of raw samples

Core number	P [psi]	Q [cm³/min]	P [Pa]	Q [m³/s]	P_1 [Pa]	P_2 [Pa]	μ [Pa·s]	D [m]	L [m]	A [m²]	k [m²]
1	0.010	21.80	69.40	3.633E−07	101 394.40				0.0478		9.8300E−12
	0.020	30.88	138.80	5.147E−07	101 463.80				0.0478		6.9600E−12
	0.030	38.68	208.20	6.447E−07	101 533.20				0.0478		5.8100E−12
	0.040	47.69	277.60	7.948E−07	101 602.60				0.0478		5.3700E−12
2	0.013	24.17	90.22	4.028E−07	101 415.22				0.0515		9.0313E−12
	0.020	29.48	138.80	4.913E−07	101 463.80				0.0515		7.1583E−12
	0.031	38.93	215.14	6.488E−07	101 540.14				0.0515		6.0964E−12
	0.040	46.63	277.60	7.772E−07	101 602.60				0.0515		5.6575E−12
3	0.008	18.33	55.52	3.055E−07	101 380.52				0.0516		1.1153E−11
	0.019	26.70	131.86	4.450E−07	101 456.86				0.0516		6.8380E−12
	0.031	35.20	215.14	5.867E−07	101 540.14	101 325	0.0000199	0.0254	0.0516	0.0005065	5.5230E−12
	0.039	41.00	270.66	6.833E−07	101 595.66				0.0516		5.1120E−12
	0.051	50.40	353.94	8.400E−07	101 678.94				0.0516		4.8035E−12
4	0.011	20.64	76.34	3.440E−07	101 401.34				0.0500		8.8495E−12
	0.021	30.00	145.74	5.000E−07	101 470.74				0.0500		6.7354E−12
	0.030	36.16	208.20	6.027E−07	101 533.20				0.0500		5.6817E−12
	0.040	44.75	277.60	7.459E−07	101 602.60				0.0500		5.2714E−12
5	0.010	21.07	69.40	3.511E−07	101 394.40				0.0462		9.1813E−12
	0.020	31.20	138.80	5.200E−07	101 463.80				0.0462		6.7963E−12
	0.029	39.20	201.26	6.533E−07	101 526.26				0.0462		5.8871E−12
	0.040	49.12	277.60	8.187E−07	101 602.60				0.0462		5.3463E−12

Table 11. Permeability of samples after removal of natural carbonate minerals

Core number	P [psi]	Q [cm³/min]	P [Pa]	Q [m³/s]	P_1 [Pa]	P_2 [Pa]	μ [Pa·s]	D [m]	L [m]	A [m²]	k [m²]
1	0.008	22.0	55.52	3.666E−07	101 380.52				0.0478		1.24E−11
	0.018	30.9	124.92	5.151E−07	101 449.92				0.0478		7.74E−12
	0.030	40.3	208.20	6.713E−07	101 533.20				0.0478		6.05E−12
	0.041	50.0	284.54	8.329E−07	101 609.54				0.0478		5.49E−12
2	0.011	24.6	76.34	4.102E−07	101 401.34				0.0515		1.08691E−11
	0.022	33.2	152.68	5.528E−07	101 477.68				0.0515		7.32058E−12
	0.029	39.1	201.26	6.516E−07	101 526.26	101 325	0.0000199	0.0254	0.0515	0.0005065	6.54531E−12
	0.039	47.2	270.66	7.861E−07	101 595.66				0.0515		5.86915E−12
3	0.010	22.0	69.40	3.666E−07	101 394.40				0.0516		1.07076E−11
	0.021	29.7	145.74	4.949E−07	101 470.74				0.0516		6.88024E−12
	0.029	38.2	201.26	6.365E−07	101 526.26				0.0516		6.40598E−12
	0.039	45.4	270.66	7.560E−07	101 595.66				0.0516		5.65543E−12
	0.050	50.8	347.00	8.467E−07	101 672.00				0.0516		4.93862E−12

Core number	P [psi]	Q [cm³/min]	P [Pa]	Q [m³/s]	P_1 [Pa]	P_2 [Pa]	μ [Pa·s]	D [m]	L [m]	A [m²]	k [m²]
4	0.009	21.7	62.46	3.619E−07	101 387.46	101 325	0.0000199	0.0254	0.0500	0.0005065	1.13795E−11
	0.020	30.8	138.80	5.131E−07	101 463.80				0.0500		7.25731E−12
	0.032	40.5	222.08	6.743E−07	101 547.08				0.0500		5.95873E−12
	0.040	47.0	277.60	7.833E−07	101 602.60				0.0500		5.53604E−12
5	0.012	24.8	83.28	4.132E−07	101 408.28				0.0462		9.00253E−12
	0.021	30.3	145.74	5.053E−07	101 470.74				0.0462		6.28996E−12
	0.031	43.3	215.14	7.222E−07	101 540.14				0.0462		6.08743E−12
	0.041	51.1	284.54	8.522E−07	101 609.54				0.0462		5.4295E−12

The cores were saturated with hydrochloric acid. As a result of chemical reactions between this hydrochloric acid (HCl) and carbonate minerals ($CaCO_3$ – calcium carbonate) present in the rock, carbon dioxide, water, and calcium chloride ($CaCl_2$) were formed [9]. Calcium chloride dissolves in water and is then easily removed during flushing (Fig. 2).

Fig. 2. Difference in color between the core sample treated with hydrochloric acid (left) and the untreated core sample (right)

The next step was flushing out the acid with water using a specially assembled filter press. For core sample No. 1, the amount of water required to completely remove the hydrochloric acid was determined. Water was passed through the sample, and the pH of every 100 ml of the discharged fluid was measured (Tab. 10). The discharged fluid was a mixture of water and acid, but with each measurement, the acid content decreased. An increase in pH indicated a lower acid concentration in the mixture (Fig. 3).

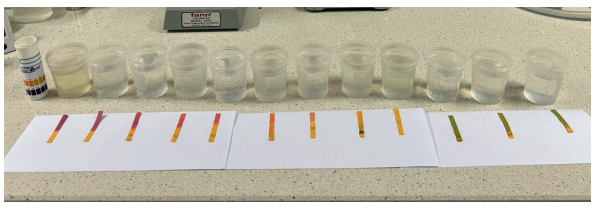

Fig. 3. Amount of water used to flush out the acid, together with pH indicator strips used for pH measurement

By calculating the mass of acid absorbed by the sample, it was determined that approximately 1.2 liters of water were required to completely remove the acid from a core of the given size. Based on this experiment, it can again be concluded that the sandstone sample is characterized by relatively high porosity and permeability, since as much as 1.2 liters of water was required to remove the acid from its interior, while the pore volume was only approximately 5 cm³. This experiment also makes it possible to calculate the amount of water required to flush the acid from the core:

$$4.41\ [\text{g}] = 1.2\ [\text{l}]$$

$$1\ [\text{g}] = x\ [\text{l}], \text{ therefore } x = \frac{1 \cdot 1.2}{4.41} = 0.27\ [\text{l}] \qquad (9)$$

It can therefore be concluded that approximately 0.27 liters of water are required to remove 1 gram of acid (Tab. 12).

Table 12. Amount of water required to flush the acid from each core

Mass of acid [g]	Amount of water [l]
4.41	1.20
5.42	1.46
5.33	1.44
5.39	1.46
5.21	1.41

Knowing the mass of the cores before the acid treatment, the content of natural carbonate fractions in the rock was calculated. After drying the cores, their masses were measured. By comparing the core masses before and after the acid treatment, the content of natural carbonate fractions in the rock was determined. Based on the obtained results, it was found that the tested sandstone samples contained small amounts of natural carbonate fractions, ranging from 0.14 g to 0.28 g. This indicates that the carbonate mineral content in the structure of these rocks is relatively low (Tab. 13).

Differences in mass loss between individual samples may result from rock heterogeneity, i.e., local variations in the content of carbonate cement. Subsequently, the permeability of the samples after the removal of natural carbonate fractions was measured.

The next very important step was the injection of the Mikhart drilling fluid into the cores. This was carried out using specially constructed equipment based on a filter press. Each sample remained in the press for 30 minutes to ensure complete filtration of the drilling fluid through the core (Tab. 14).

After drying the cores, their permeability was measured. Subsequently, the samples were again washed with hydrochloric acid, and their dry permeability was measured once more (Tab. 15).

Table 13. Mass of natural carbonate fractions contained in each core

Core number	Mass of the core before acidizing [g]	Mass of the core after acidizing [g]	Mass of natural carbonate fractions [g]	Content of natural carbonate fractions in the rock [%]
1	40.66	40.47	0.19	0.46
2	44.98	44.70	0.28	
3	44.72	44.58	0.14	
4	42.38	42.17	0.21	
5	39.60	39.44	0.16	

Table 14. Permeability of samples after injection of drilling fluid with blockers

Core number	P [psi]	Q [cm^3/min]	P [Pa]	Q [m^3/s]	P_1 [Pa]	P_2 [Pa]	μ [Pa·s]	D [m]	L [m]	A [m^2]	k [m^2]
1	0.0080	13.61	55.52	2.268E−07	101 380.52	101325	0.0000199	0.0254	0.04780	0.0005065	7.67E−12
	0.0200	20.59	138.80	3.431E−07	101 463.80				0.04780		4.64E−12
	0.0310	26.76	215.14	4.461E−07	101 540.14				0.04780		3.89E−12
	0.0410	33.13	284.54	5.522E−07	101 609.54				0.04780		3.64E−12
	0.0510	39.10	353.94	6.517E−07	101 678.94				0.04780		3.45209E−12
	0.0590	43.80	409.46	7.300E−07	101 734.46				0.04780		3.34179E−12
	0.0710	50.60	492.74	8.433E−07	101 817.74				0.04780		3.20679E−12
2	0.0090	17.30	62.46	2.883E−07	101 387.46				0.05150		9.33861E−12
	0.0210	25.70	145.74	4.283E−07	101 470.74				0.05150		5.94311E−12
	0.0290	31.55	201.26	5.258E−07	101 526.26				0.05150		5.28181E−12
	0.0400	39.74	277.60	6.623E−07	101 602.60				0.05150		4.82154E−12
	0.0500	47.10	347.00	7.850E−07	101 672.00				0.05150		4.57004E−12
	0.0580	52.25	402.52	8.708E−07	101 727.52				0.05150		4.36927E−12
3	0.0100	16.60	69.40	2.767E−07	101 394.40				0.05160		8.08006E−12
	0.0190	22.50	131.86	3.750E−07	101 456.86				0.05160		5.76237E−12
	0.0310	30.30	215.14	5.050E−07	101 540.14				0.05160		4.75417E−12
	0.0400	37.00	277.60	6.167E−07	101 602.60				0.05160		4.49782E−12
	0.0480	41.70	333.12	6.950E−07	101 658.12				0.05160		4.22315E−12
	0.0590	49.20	409.46	8.200E−07	101 734.46				0.05160		4.05221E−12
4	0.0080	19.80	55.52	3.300E−07	101 380.52				0.05000		1.16743E−11
	0.0220	24.00	152.68	4.000E−07	101 477.68				0.05000		5.14324E−12
	0.0300	29.01	208.20	4.835E−07	101 533.20				0.05000		4.55781E−12
	0.0400	35.10	277.60	5.850E−07	101 602.60				0.05000		4.13455E−12
	0.0510	42.30	353.94	7.050E−07	101 678.94				0.05000		3.9065E−12
	0.0600	48.50	416.40	8.083E−07	101 741.40				0.05000		3.80605E−12

Core number	P [psi]	Q [cm³/min]	P [Pa]	Q [m³/s]	P_1 [Pa]	P_2 [Pa]	μ [Pa·s]	D [m]	L [m]	A [m²]	k [m²]
5	0.0100	17.30	69.40	2.883E–07	101 394.40	101325	0.0000199	0.0254	0.04620	0.0005065	7.53954E–12
	0.0210	25.39	145.74	4.232E–07	101 470.74				0.04620		5.26718E–12
	0.0310	31.85	215.14	5.308E–07	101 540.14				0.04620		4.47439E–12
	0.0400	38.40	277.60	6.400E–07	101 602.60				0.04620		4.1795E–12
	0.0480	44.24	333.12	7.373E–07	101 658.12				0.04620		4.01151E–12
	0.0580	50.70	402.52	8.450E–07	101 727.52				0.04620		3.80334E–12

Table 15. Permeability of samples after removal of blockers by hydrochloric acid

Core number	P [psi]	Q [cm³/min]	P [Pa]	Q [m³/s]	P_1 [Pa]	P_2 [Pa]	μ [Pa·s]	D [m]	L [m]	A [m²]	k [m²]
1	0.011	21.40	76.34	3.567E–07	101 401.34	101 325	0.0000199	0.0254	0.0478	0.0005065	8.77184E–12
	0.021	28.40	145.74	4.733E–07	101 470.74				0.0478		6.09565E–12
	0.030	35.40	208.20	5.900E–07	101 533.20				0.0478		5.31703E–12
	0.041	44.70	284.54	7.450E–07	101 609.54				0.0478		4.91075E–12
	0.049	50.32	340.06	8.387E–07	101 665.06				0.0478		4.62434E–12
2	0.010	22.30	69.40	3.717E–07	101 394.40				0.0515		1.08335E–11
	0.020	29.90	138.80	4.983E–07	101 463.80				0.0515		7.26033E–12
	0.030	37.10	208.20	6.183E–07	101 533.20				0.0515		6.0037E–12
	0.041	44.90	284.54	7.483E–07	101 609.54				0.0515		5.31454E–12
	0.048	50.10	333.12	8.350E–07	101 658.12				0.0515		5.06402E–12
3	0.008	19.90	55.52	3.317E–07	101 380.52				0.0516		1.21087E–11
	0.019	28.90	131.86	4.817E–07	101 456.86				0.0516		7.40145E–12
	0.031	34.40	215.14	5.733E–07	101 540.14				0.0516		5.39748E–12
	0.040	41.10	277.60	6.850E–07	101 602.60				0.0516		4.99623E–12
	0.054	50.50	374.76	8.417E–07	101 699.76				0.0516		4.54517E–12
4	0.010	22.60	69.40	3.767E–07	101 394.40				0.0500		1.06595E–11
	0.018	27.70	124.92	4.617E–07	101 449.92				0.0500		7.25629E–12
	0.031	37.20	215.14	6.200E–07	101 540.14				0.0500		5.65582E–12
	0.040	44.00	277.60	7.333E–07	101 602.60				0.0500		5.18291E–12
	0.049	49.70	340.06	8.283E–07	101 665.06				0.0500		4.77757E–12
5	0.011	24.70	76.34	4.117E–07	101 401.34				0.0462		9.78561E–12
	0.022	32.70	152.68	5.450E–07	101 477.68				0.0462		6.47508E–12
	0.031	40.30	215.14	6.717E–07	101 540.14				0.0462		5.66148E–12
	0.039	46.10	270.66	7.683E–07	101 595.66				0.0462		5.1464E–12

3. Results

The following figures present the permeability values obtained for each of the tested core samples. Although the values are not identical for all samples, they are very similar. A common trend can be observed for all cores. The highest permeability values were recorded after the removal of their natural carbonate fractions by acid etching. Lower permeability was observed for the samples in their initial (untreated) state, followed by the permeability measured after the acid treatment aimed at removing the carbonate blockers. The lowest permeability values were obtained for the samples after the injection of drilling fluid containing carbonate blocking agents.

It should be noted that before pore plugging with the carbonate blocking material, water flowed freely through the cores during tests performed using the filtration press. After the pores were plugged with the blocking agent, the fluid flow ceased completely. Following the acid treatment, the flow was restored. Under real reservoir conditions, the blocking agent plays a protective role by preventing the migration of fluids, such as drilling mud, into the formation (Figs. 4–10).

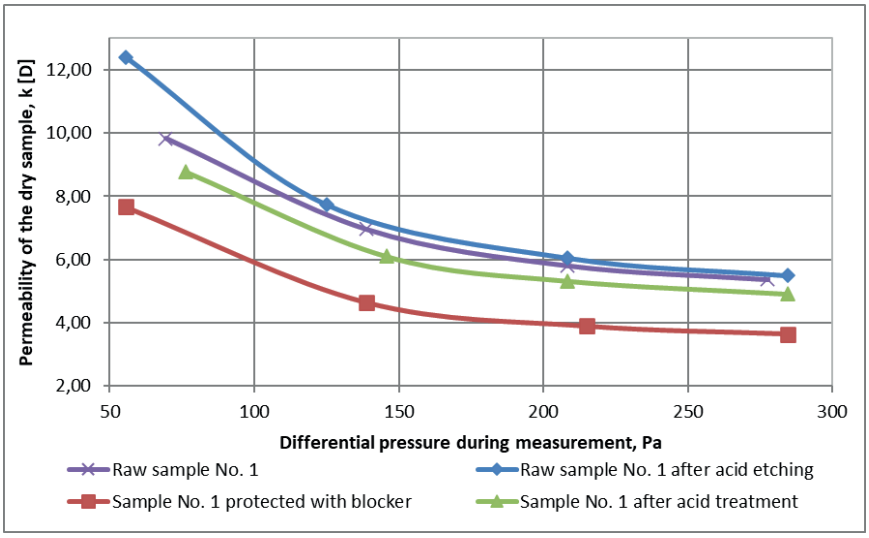

Fig. 4. Permeability test of sample: Core 1

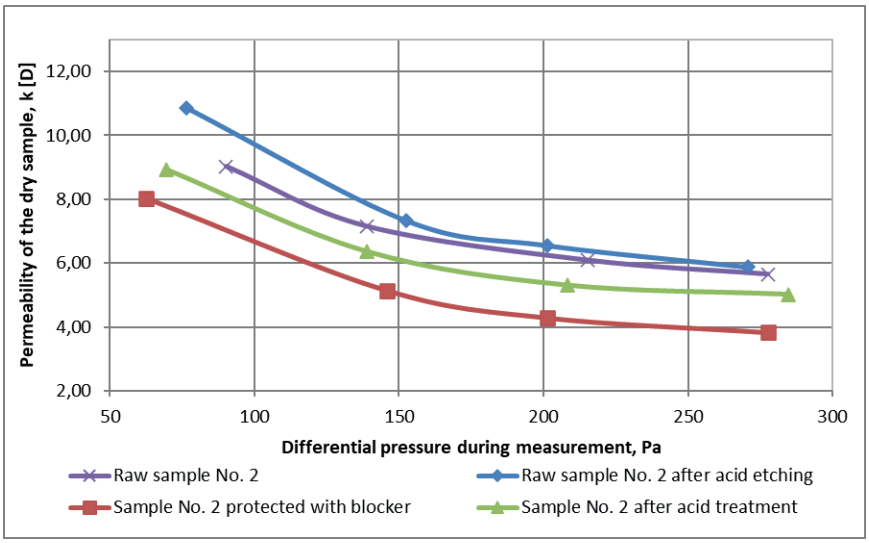

Fig. 5. Permeability test of sample: Core 2

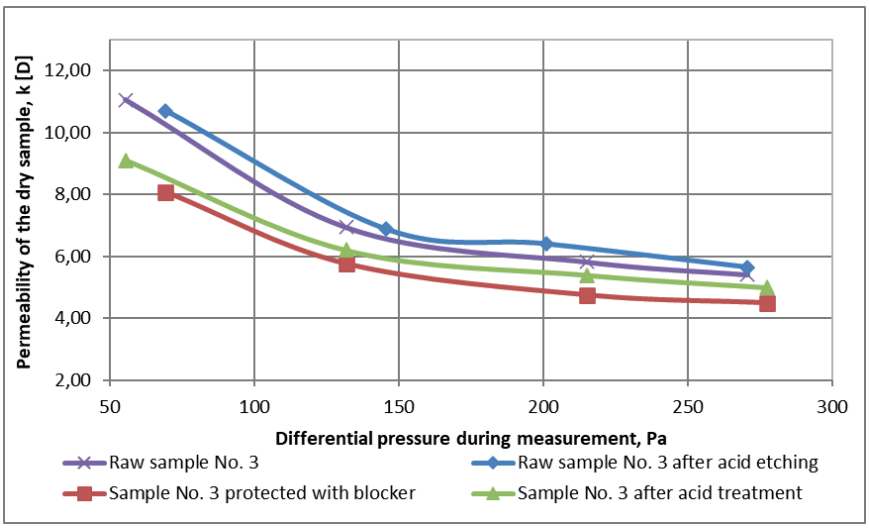

Fig. 6. Permeability test of sample: Core 3

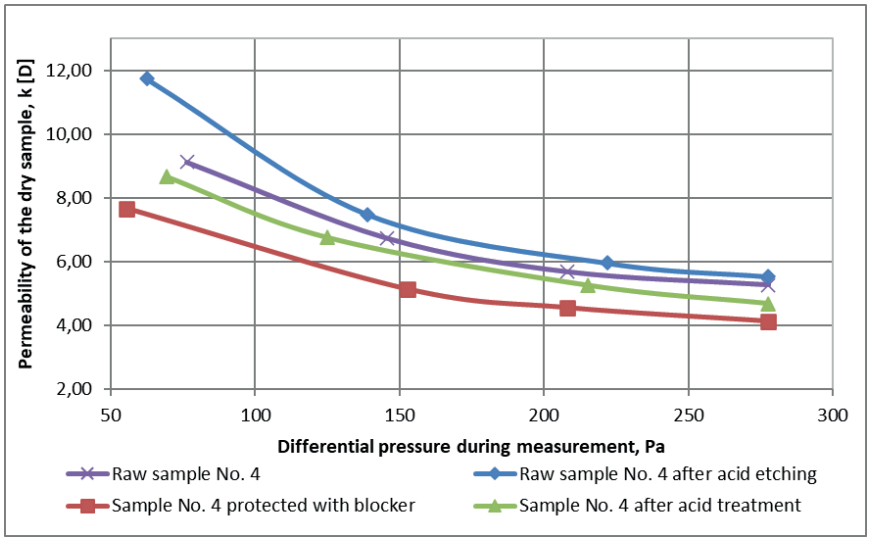

Fig. 7. Permeability test of sample: Core 4

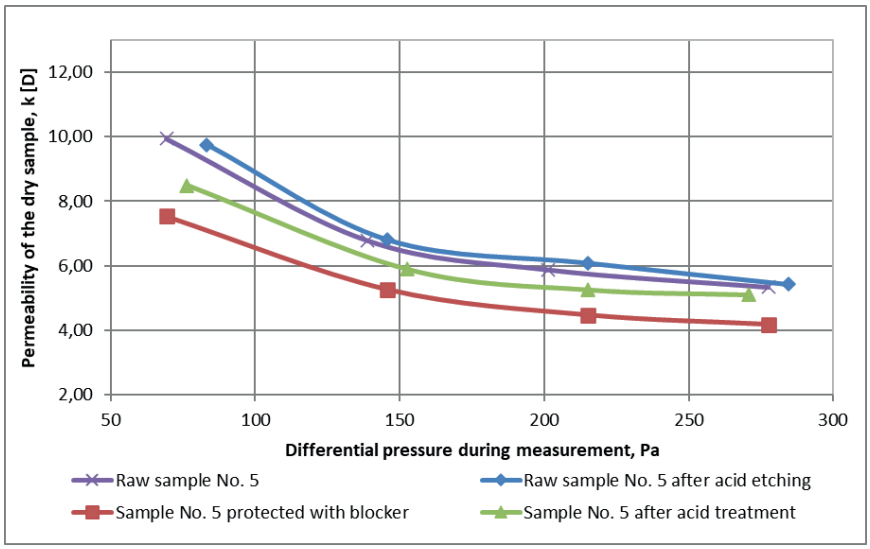

Fig. 8. Permeability test of sample: Core 5

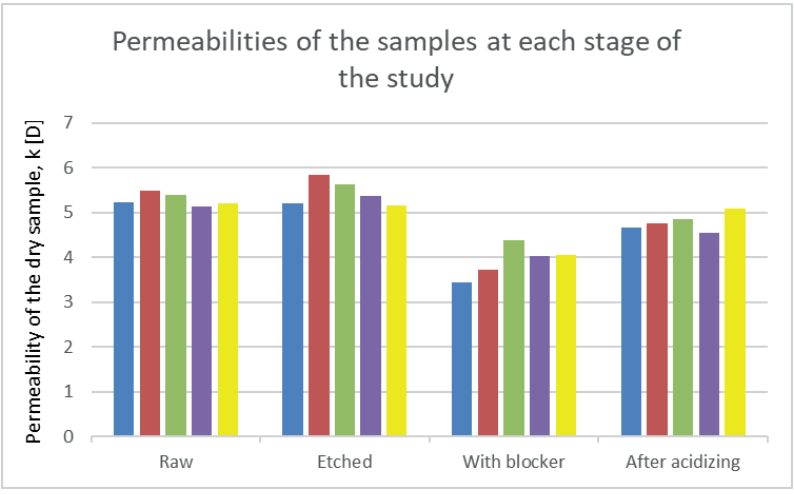

Fig. 9. Permeability of samples at each stage of the study

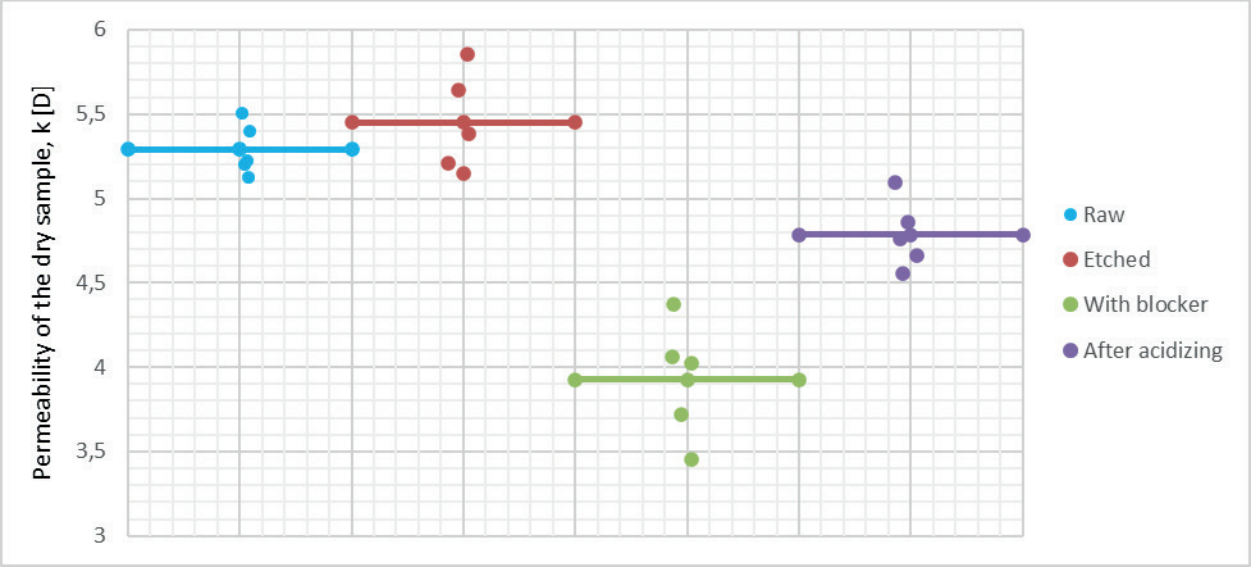

Fig. 10. Average permeability of samples at each stage of the study

4. Conclusions

The conducted experiment demonstrated that the permeability of the rock was restored by an average of 87% for the five tested samples. It can be clearly stated that the acidizing treatment is highly effective in restoring permeability. However, this process is effective only in the case of drilling fluids containing carbonate blocking agents, as a chemical reaction occurs between the acid and the carbonate material. In the case of clay-based drilling fluids, such reactions do not take place; therefore, permeability is not restored.

Consequently, drilling fluids without carbonate blockers and containing clay minerals are not suitable for reservoir drilling operations. Based on the obtained results, it can be concluded that the application of a carbonate blocking agent followed by acidizing constitutes a highly effective solution during the drilling of porous reservoir rocks.

1. The process of reservoir drilling is associated with the risk of pore space plugging caused by drilling fluids.
2. One of the solutions available on the market is the use of carbonate blocking agents in drilling fluids, which, when properly selected, protect the pore space from the invasion of drilling fluid.
3. In order to restore the permeability of the near-wellbore zone, hydrochloric acid is commonly used to remove the carbonate filter cake deposited on the borehole wall.
4. The conducted experiment confirmed the possibility of restoring the original permeability of reservoir rocks.
5. Quantitatively, the degree of permeability restoration was determined to be 87% of the original reservoir properties.

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Author contributions: Equations (1)–(9) were derived by the authors specifically for the conditions considered in this study.

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