ISSN 2720-3581

JOURNAL OF GEOTECHNOLOGY AND ENERGY

FORMERLY AGH DRILLING, OIL, GAS

2021, vol. 38, no. 4

WYDAWNICTWA AGH

KRAKOW 2021

The “Journal of Geotechnology and Energy” (formerly “AGH Drilling, Oil, Gas”) is a quarterly published by the Faculty of Drilling, Oil and Gas at the AGH University of Science and Technology, Krakow, Poland. Journal is an interdisciplinary, international, peer-reviewed, and open access. The articles published in JGE have been given a favorable opinion by the reviewers designated by the editorial board.

Publisher

AGH University of Science and Technology Press

Linguistic corrector: *Aeddan Shaw*
Technical editor: *Kamila Zimnicka*
Desktop publishing: *Munda*
Cover design: *Paweł Sepielak*

ISSN: 2720-3581
DOI: https://doi.org/10.7494/jge

Journal website: https://journals.agh.edu.pl/jge

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www.wydawnictwo.agh.edu.pl

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Journal of Geotechnology and Energy | vol. 38 | no. 4 | 2021 | pp. 5–10

https://doi.org/10.7494/jge.2021.38.4.5

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DISPLACEMENT EFFICIENCY IN TIGHT SANDSTONE BASED ON FRACTIONAL FLOW CURVE USING RELATIVE PERMEABILITY DATA

Date of submission:
5.10.2021

Date of acceptance:
25.01.2022

Date of publication:
31.01.2022

Abstract: In tight gas sandstone, relative permeability is an essential special core analysis dynamic test that can be used to estimate injectivity, secondary recovery, production rate, reservoir simulation, residual gas saturation, and effective water management. Having about 65% of hydraulic fracturing fluid not to flow back and stay in the reservoir results in having the tight sandstone gas reservoir to involve multi-phase flow, namely water and gas. During the hydraulic fracturing job both imbibition and forcibly imbibition processes take place while during fracturing fluid cleanup and gas production drainage flow becomes dominant.

The steady state flooding process was used to measure the relative permeability curves for a tight sandstone core sample collected from Travis Peak Formation at a depth of 8707 ft. The measurement process involved the performance of a series of steady state experiments with different gas-water injection ratios. The fractional flow curve has been plotted, based on the measured relative permeability, and used to calculate the displacement efficiency for flow through such tight porous media. The measurement showed relatively high irreducible water saturation (31%) and low residual gas saturation (6%). The measured gas relative permeability decreased slowly at a constant rate with increased wetting fluid saturation. The obtained fractional flow curve does not follow the s-shape behavior observed in a conventional reservoir. The results obtained showed that displacement efficiency can be enhanced by increasing water viscosity. Water viscosity can be increased by adding some polymer materials, however this is beyond the scope of this paper.

Keywords: tight sandstone, relative permeability, fractional flow curve, displacement efficiency

1. Introduction

Gas produced from tight sandstone reservoirs is growing in popularity because of advancements in horizontal drilling, multistage hydraulic fracturing and technology [1–6]. Gas produced from tight reservoirs and shale source rock in the USA increased from 5.7 tcf in 2000 to 27.4 tcf in 2020 and is expected to reach 38.7 tcf gas production in 2050 [7]. Tight and shale gas resource development leads to natural gas production increasing, not only in the USA but worldwide.

In order to exploit a tight gas reservoir, it has to be fracked and re-fracked as the production declines. Tight gas production declines by 70% during the first year of production. Fracking has a significant effect on tight gas development [8]. It is well known that a frack job requires 15–23 million liters of water [9], where about 65% of the injected fracturing fluid does not flow back. As a consequence, a large amount of the fluid used in hydraulic fracturing stays in the reservoir and constrains gas production from tight formations. As long as re-fracking is carried out continuously to restore/increase production, water production impacts gas production. The water effect on gas production from tight formations becomes more significant during the late stages of tight gas reservoir development.

Since the tight gas reservoir contains two fluids, water and gas, then effective/relative permeability has to be considered to evaluate this multiphase flow system. Gas flow in tight sandstone reservoirs, in the presence of water, is affected significantly by the following: pore size and pore size distribution, sandstone wetting characteristics and fluid saturation [1–3].

Reliable effective or relative permeability data are required input data in computerized reservoir simulation models as well as simple analytical models [10]. Numerous authors have conducted both experimental and theoretical work to estimate gas-absolute and relative permeability in tight sandstone [1–3, 10–12]. There are different lab methods available to measure core plug gas–water relative permeability. Some methods are based on steady and unsteady state flow processes [10, 12]. Variation in water saturation and overburden pressure values significantly affect absolute and relative gas permeability [1, 13]. It has been shown experimentally that increased confining pressure results in a significant reduction in gas absolute permeability for core plugs retrieved from the Travis Peak formation [1].

In this paper, the quantification of the displacement efficiency in tight sandstone is based on the measured relative permeability values of gas and brine. Gas and brine relative permeability were experimentally measured using the steady-state flow process. After measuring the relative permeability, a fractional flow curve was constructed and used to calculate displacement efficiency in tight sandstone. In addition, the sensitivity of the calculated displacement efficiency to water mobility has also been demonstrated.

2. Method section

2.1. Relative permeability measurement method

The studied core sample was collected from a tight gas reservoir in the Travis Peak formation. The core plug size was 8.7 cm long and 3.8 cm in diameter. The core porosity was 7% and absolute permeability is in the range of microdarcy [1]. The measured gas and water absolute permeability, for the same core plug but at different confining pressures, are shown in Table 1 [1]. Table 1 shows that absolute permeability for gas and water always decreases with increasing confining pressure. Table 1 shows that an increase in overburden pressure from 13.8 to 20.7 MPa resulted in gas permeability decrease of 20.98% and a water permeability decrease of 22.73%. The increase of overburden pressure from 20.7 to 27.6 MPa resulted in a decrease of 17.81% and 31.20% in gas and water permeabilities, respectively. There are many factors that affect both the porosity and permeability of the sandstone such as: particle size (sphericity and angularity); packing; sorting; cementing materials; vugs/dissolutions/fractures; and overburden stress (compaction). The above-mentioned decrease in permeability can be attributed mainly to the overburden pressure effect on permeability.

Table 1. Absolute gas and water measured permeability

Confining pressure [MPa]	Permeability [μd]	
	Gas	Water
13.8	31.58	5.06
20.7	24.93	3.91
27.6	20.49	2.69

In the displacement experiments, high purity nitrogen (99.99%) was used as a gas phase and 7.0 wt. % concentrated brine was used as a liquid phase. The brine used is potassium chloride based. Any possible reaction between the injected water and the slot and solution type core plug used is minimized by dissolving the salt in deionized water. Consequently permeability alteration is also minimized. Steady state flow experiments, utilizing a benchtop relative permeability system shown in Figure 1, were used to measure the brine-gas relative permeability.

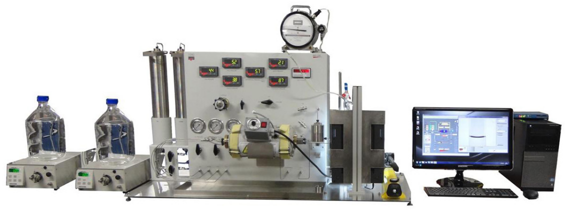

Fig. 1. Bench-top relative permeability system

The benchtop steady and unsteady state relative permeability system (Fig. 1) is used to determine liquid/liquid and liquid/gas relative permeability on core sample with a diameter of one inch or 1.5 inches and a length of one to three inches at an overburden pressure of up to 350 bar (5000 psi). The relative permeability was measured at an ambient temperature. The core saturation was determined by measuring the volume produced with a video separator. Liquid flow rate was controlled by a pump which was used to inject the liquid fluid into the core sample, while the gas flow rate was monitored using a gas mass flow controller.

The steady state flow process procedure used started with a core plug fully saturated with the prepared brine and continued as follows:

1. Brine was injected through the core plug to measure absolute permeability.
2. A mixture of brine and nitrogen was injected where the initial fraction of nitrogen was small.
3. After reaching a steady-state in terms of the flow rate of both fluids, inlet pressure, outlet pressure and flow rates were recorded.
4. Core fluid saturation was measured based on the volumes produced.
5. Effective permeability was calculated.
6. Relative permeability was calculated as a ratio between effective and absolute.
7. Steps 1 to 6 were repeated with a higher fraction of nitrogen than in step 2. The measurement process was continued until irreducible brine saturation was reached.

The effective permeability of the brine (k_w) and gas (k_g) phases was calculated using equations (1) and (2), respectively [14]:

$$k_w = \frac{q_w \mu_w L}{A(p_1 - p_2)} \cdot 10^3 \tag{1}$$

$$k_g = \frac{2 p_a \mu_g L}{A(p_1^2 - p_2^2)} \cdot 10^3 \tag{2}$$

where k_w is the effective permeability to brine, md; k_g is the effective permeability to gas, md; q_w and q_g are the brine and gas flow rate, mL/s; A is the core cross sectional area through which the flow takes place, cm^2; L is the length of the core plug, cm; μ_w and μ_g are the brine and gas viscosity, cP; p_1 and p_2 are the inlet and outlet pressure, MPa; and p_a is atmosphere pressure, MPa.

The relative permeability of brine (k_{rw}) and of gas (k_{rg}) phases are calculated as shown in equations (3) and (4), respectively:

$$k_{rw} = \frac{k_w}{k} \tag{3}$$

$$k_{rg} = \frac{k_g}{k} \tag{4}$$

3. Results and discussion

3.1. Relative permeability

The relative permeability values for gas–brine flow through a slot and solution core plug has been measured under lab room temperature, a confining pressure of 13.8 MPa and atmospheric outlet pressure. With the measured inlet pressure and gas and brine flow rates, the gas–brine relative permeability of the slot and solution core plug was calculated using equations (1)–(4) and plotted in Figure 2. The relative permeability of the Travis Peak sandstone core used does not resemble a permeability jail and behaves in a way similar to high permeability sandstone.

From Figure 2 one can notice that the irreducible water saturation value is S_{wi} = 31%, while the residual gas saturation value is S_{gr} = 6%.

3.2. Displacement efficiency analysis

To understand the fractional flow behavior in tight sandstone, the Buckley and Leverett theory is applied [15]. The relative permeability curves obtained were based on the steady state procedure of one dimensional flow through an incompressible tight sandstone with a valid

Darcy's law where the fluids were considered to be immiscible and incompressible. During the measurement of relative permeability, the core holder was placed horizontally, which means the flow dip angle is zero, gravity and capillary pressure are ignored. Thus, the fractional flow equation, based on these assumptions, can be written as follows [16, 17]:

$$f_w = \frac{1}{1 + \frac{\mu_w}{k_{rw}} \frac{k_{rg}}{\mu_g}} \quad (5)$$

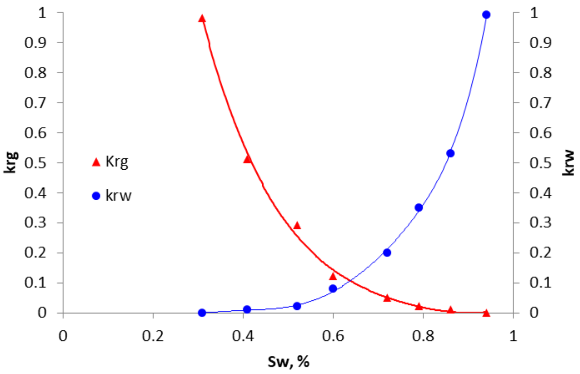

Fig. 2. Gas-water relative permeability curves

Due to the saturation dependence of the relative permeability curves, for constant gas and brine viscosities the fractional flow curve can only be expressed as a function of saturation. Water and gas fractional flow (f_w and f_g) can be determined as a function of total flow rate ($q_t = q_w + q_g$), using equations (6) and (7), respectively [18]:

$$f_w = \frac{q_w}{q_t} \quad (6)$$

$$f_g = \frac{q_g}{q_t} \quad (7)$$

It is clear from equations (6) and (7) that the fractional flow of both water and gas always add to unity. This means that with the knowledge of water and total flow rate, one can calculate both water and gas flow rates.

Water saturation can appear explicitly in equation (5) by applying the nonlinear regression analysis to relative permeability data (Fig. 2) to have relative permeability to water and gas calculated by equations (8) and (9), respectively:

$$k_{rw} = 164.15S_w^6 - 540.94\, S_w^5 + 722.09\, S_w^4 - + 495.06\, S_w^3 + 183.84\, S_w^2 - 35.08\, S_w + 2.69 \quad (8)$$

$$k_{rg} = 9.31\, S_w^4 - 29.50\, S_w^3 + 36.30\, S_w^2 - 20.83\, S_w + 4.74 \quad (9)$$

Using the measured relative permeability data, nitrogen viscosity of 0.0189 cP, brine viscosity of 0.89 cP and equation (5), the water fractional flow curve was calculated for the slot and solution core plug, as shown in Figure 3, while Figure 4 shows both water and gas fractional flow curves.

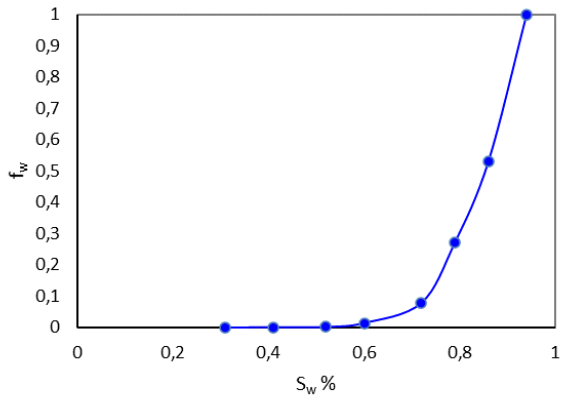

Fig. 3. Water fractional flow curve for the relative permeability data of Figure 2

It is clear from Figure 3 that the obtained curve is different from the fractional flow curve of conventional reservoirs, which is an S-shape. This is due to different reasons such as very low viscosity and density of gas compared to water that result in gravity override. The application of the Welge method [19] to compute the gas recovery from the water drive (where the outlet pressure is atmospheric at which the displaced gas is incompressible), using Figure 4, results in having no point of tangency for the line drawn from S_{wi}, instead the line will intersect with the flow curve at $f_w = 1$ which means that water saturation at the displacement front is equal to the average water saturation in the plug water bank ($\bar{S}_w$) and the average water saturation at the breakthrough ($\bar{S}_{wbt}$).

The gas displacement efficiency (E_d) can be calculated as follows [19]:

$$E_d = 1 - \frac{S_{gr}}{S_{gi}} \quad (10)$$

where, S_{gr} and S_{gi} are the residual and initial gas saturations, respectively. By definition, it is known that:

$$S_g + S_w = 1.0 \quad (11)$$

Accordingly, $S_{gi} + S_{wi} = 1.0$, that yields $S_{gi} = 1.0 - S_{wi}$. Also, $S_{gr} = 1 - S_{wbt}$, then equation (10) can be written as:

$$E_d = \frac{S_{gi} - S_{gr}}{S_{gi}} = \frac{S_{wbt} - S_{wi}}{1 - S_{wi}} \quad (12)$$

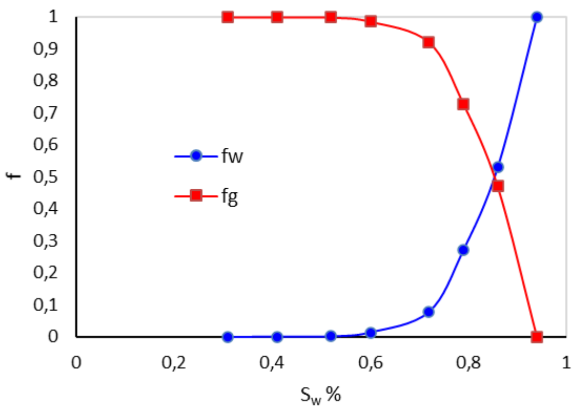

Fig. 4. The fractional flow curves for the relative permeability data of Figure 2

The calculated displacement efficiency is 0.913 which is the largest possible value for the kind of relative permeability curves measured. The minimization of the flowing water fraction at any core plug location results in enhancing displacement efficiency; this can be achieved by increasing the gas/water ratio. The highest displacement efficiency value is obtained at the lowest water saturation displacement efficiency as shown in Figure 5, therefore, f_w has to have the smallest possible value. Analyzing equation (5) results in determining how displacement efficiency is affected by the different reservoir properties and variables. Gas recovery is a strong function of fluid mobility (k_f/μ_f) and can be improved by decreasing (k_w/μ_w) and/or increasing (k_g/μ_g).

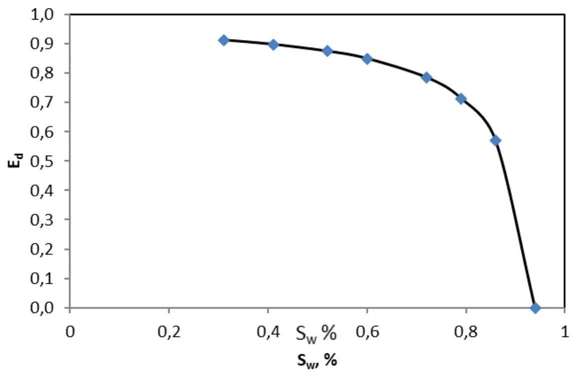

Fig. 5. Displacement efficiency changes

Displacement efficiency can be improved by decreasing the gas viscosity (temperature and pressure effects) or by increasing the water viscosity (by means of the addition of polymers). Gas viscosity will not change significantly; therefore, the displacement efficiency enhancement will be minimal. The water viscosity effect on f_w curve is shown in Figure 6 for different values of brine viscosity.

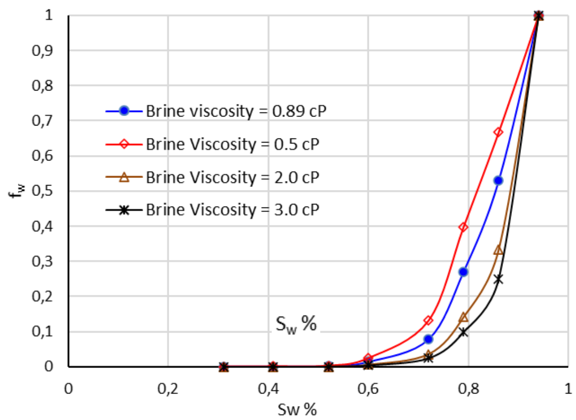

Fig. 6. The effect of brine viscosity on f_w behavior

Figure 6 shows that higher brine viscosity results in a better sweep efficiency and consequently better displacement efficiency.

4. Conclusions

The steady state flooding process was used to measure gas–brine relative permeability properties for slot and solution tight gas sandstone. The measurement showed high irreducible water saturation, indicating that the core sample used is of the water-wet rock type. The study showed that the relative permeability data did not yield the s-shape fractional flow curve for unconventional tight sandstone. The obtained value of irreducible water saturation indicated that the core rock used is water-wet where the wetting phase brine preferentially wets the solid rock surface and the brine is drawn into smaller pore space of the rock while gas flows in the larger pores.

The study showed that gas displacement efficiency in the considered tight sandstone can be increased by having better control over the mobility of the brine. Increasing the viscosity of the brine resulted in having a better control over wetting phase mobility and thus better displacement efficiency.

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Journal of Geotechnology and Energy | vol. 38 | no. 4 | 2021 | pp. 11–20

https://doi.org/10.7494/jge.2021.38.4.11

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THE IMPROVEMENT OF MUD DISPLACEMENT FROM THE ANNULAR SPACE OF THE BOREHOLE IN TERMS OF THE SELECTION OF WASHING FLUIDS AND PRE-FLUSHES

Date of submission:
9.11.2021

Date of acceptance:
25.11.2021

Date of publication:
31.12.2021

https://journals.agh.edu.pl/jge

Abstract: One of the most important steps in drilling a well is cementing the annular space between the casing and the rock formation. This process is significant because of the stabilization of the well and effectively separation of the consecutive rock horizons. It is essential that cementing ensures the durable and effective insulation of the rock mass. The complete displacement of the drilling fluid from the annular space is particularly important due to a number of negative phenomena related to its insufficient extrusion. The cement slurry pressed through the annular space displaces the mud but is unable to thoroughly remove the residue left behind sufficiently. The subject of the laboratory research was to check how selected washer affect the efficiency of displacing drilling fluid from the annular space of the borehole. In addition, the tests included the determination of the optimal washing time and optimal pumping rate of the washing fluid.

Keywords: washing fluids, pre-flushes, mud displacement, sealing the wellbore, washing time

1. Introduction

The most important technical and technological factors influencing the effective cementing of casing pipes are, among others, the technical condition of the borehole, the proper preparation of the borehole before the cementing operation and the cementing method, but also the proper removal of drilling fluid from the annular space. The complete displacement of the drilling fluid from the annular space is particularly important due to a number of negative phenomena related to its insufficient extrusion [1]. The cement slurry pressed through the annular space displaces the mud but is not able to sufficiently thoroughly remove the residue left behind. After injection, cement slurry may mix with the unremoved components of the drilling fluid. Due to harmful chemical reactions and physical phenomena in the contact zone between mud and slurry, it is possible to form liquids which will be difficult to pump. As a result, it will be necessary to increase the injection pressure of the slurry in the cement aggregates. In turn, this increases the risk of chemically active filtrates from the mud and slurry penetrating the well zone. This can lead to a deterioration of the permeability in the zones [2, 3]. Moreover, such contact of the chemical compounds of the mud and cement slurry may also adversely affect the setting time of the slurry and strength parameters of the hardened cement sheath. Additionally, it is possible to form pockets of mud not filled with sealing slurry which may cause uncontrolled flows of deposit media and thus problems in exploitation. Such a situation may occur when drilling into a gas-bearing zone [4]. A porous cement sheath can lead to gas accumulation in the inner-casing space which could result in an increase in pressure at the top of the borehole and the need to release the gas. When using drilling muds with the addition of high viscosity and structural strength weighting agents, it may be important to facilitate the displacement of the drilling fluid from the annular space of the borehole. Insufficient removal of the drilling fluid or its sediment from both the rock formation and the casing surface can also lead to complications during the cementation process by the formation of mud channels across the deposit zones and other permeable zones. This can lead to the so-called channeling of the mud through the sealing slurry and result in difficulties in the adhesion of the slurry to the rock layers and walls of casing pipes. For adequate displacement of the drilling fluid, it is desirable to achieve turbulent flow with a suitable washing fluid or light pre-slurry. Without them, achieving a flow velocity enabling its disturbance would require injecting the slurry with greater pressure, which could result in fracturing the rock layers.

2. Washes and pre-flushes

During the cementing process of casing pipes, when the cement slurry is injected into the borehole, it may mix with the remaining drilling mud, forming difficult to pump liquids. In addition, a number of chemical reactions and physical phenomena can occur in the contact zone between the mud and the slurry that negatively affect rheology and technological parameters of slurry, hindering or preventing the effective process of cementing.

Chemical and physical interactions between the slurry and mud force the use of higher injection pressures of the cement slurry, which in turn may adversely affect the injection of chemically active filtrate from the drilling fluid into the pores of the rocks and deterioration of the near-hole permeability. Moreover, higher injection pressure of slurry may result in hydraulic fracturing of low-strength layers, and in extreme cases, it may even make it impossible to pump the cement slurry. In order to eliminate the above phenomena and prevent contact between slurry and drilling mud, it is common to used advanced fluids, i.e. washes and pre-flushes.

3. Properties of washes and pre-flushes

When flushing drilling fluid residues from the borehole, it is important to select the appropriate washes or pre-flushes individually for each cementation procedure. The degree of displacement of the mud and the effectiveness of cementation depends primarily on their physical, chemical and technological properties.

Washing fluids are liquids with a density very close to that of water. They are usually designed to clean the annular and non-tubular space of the mudcake before the cementing procedure. The use of these fluids generally causes the dilution and dispersion of the mud. These liquids also have a relatively low viscosity, which positively affects the turbulent nature of the flow of this liquid in the annular space, which is desirable for efficient drilling fluid removal. Washing fluids usually contain surfactants or dispersants, which has a positive effect on the removal of mud cake [5].

Sometimes, we can define washes as pre-flushes, although they differ from one another in several respects, including their specially designed rheological and density properties. They are primarily used to separate individual drilling fluids. Pre-flushes contain much more solids than the washes to achieve a more efficient removal of the mudcake from the borehole wall. They are also more effective at separating drilling fluid and cement slurry. Washes and pre-flushes, due to their function, should be characterized by constant properties and negligible influence on the properties of the drilling fluids in the event of contact of both liquids. When exposed to high temperatures, they should maintain constant rheological properties and not affect the viscosity and setting time of the cement slurry. Depending on the drilling area, the washing fluids should be easily adjustable in terms of their physical, chemical and rheological properties, such as density, viscosity, and structural strength. It is also required that they show tolerance to the effects of chemical additives derived from the mud and slurry, such as liquefers, retarders, setting accelerators or dispersants. For pre-flushes, which are typically more dense and have a higher solids content than washes, it is desirable to be able to hold the drill cuttings and additional rock solids and mudcake in suspension. Both washes and pre-flushes must not react with steel, causing corrosion, and with the components of rocks and reservoir waters. Washes and pre-flushes should be easy to prepare with the use of fluids from the drilling rig, without the need for special liquids.

Advanced liquids can be divided due to two criteria. The first criterion is the division of those fluids according to the tasks during the cementation process of the casing column in the borehole. Classification is shown on the Figure 1.

The second one is the criterion of the type of fluid flow in the annular space of the wellbore when cementing the casing. A classification is presented in Figure 2.

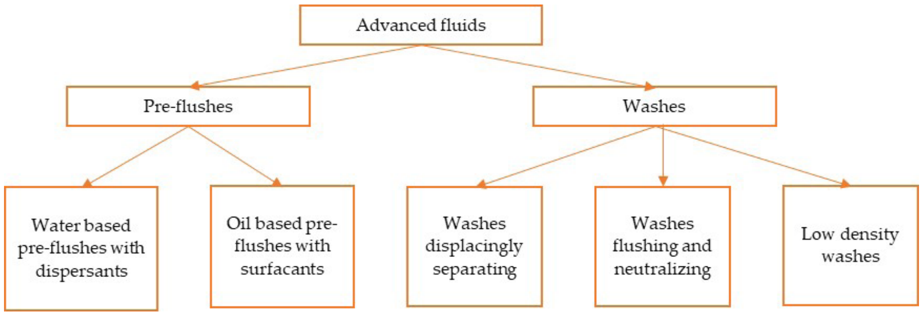


Fig. 1. Classification of advanced fluids due to their functions [5]

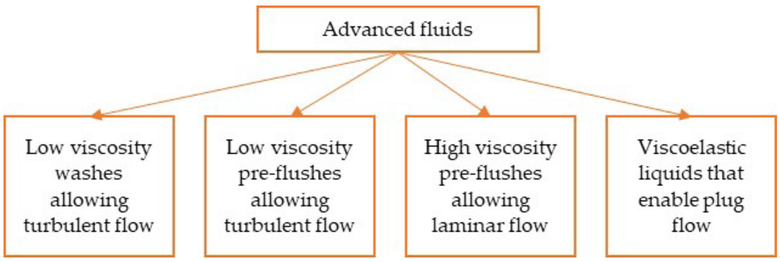


Fig. 2. Classification of advanced fluids due to the nature of the flow [5]

4. Flow through the wellbore

The method of pumping advanced liquids and sealing slurry in the borehole plays an important role in achieving the effective sealing of the casing column with a cement slurry. Basically, we can distinguish four stages of liquid flow in the borehole: laminar flow, transitional flow, turbulent flow and piston flow. We deal with laminar flow in wellbore conditions when Reynolds number (Re) < 2100, and with turbulent flow when Re > 3000. When Re is in the range from 2100 to 3000, then we can talk about a transitional (mixed) flow, showing the features of both laminar and turbulent flow [6]. A graphical representation of laminar and turbulent flow is presented in Figure 3.

In drilling practice, two types of flows are usually used: reciprocating and turbulent. They show the best effects of scrubbing sludge removal from the annular space. They are characterized by a flat velocity distribution profile [6, 7]. The plug flow profile is quite flat, the velocity of all fluid particles in such a flow is the same at all points. The technological properties of advanced fluids should be selected so as to enable obtaining plug flow at the highest possible flow velocities, and turbulent flow at the lowest possible velocities. The first condition is dictated by the maximum efficiency of scrubbing sludge removal from the borehole wall and casing, while the second condition is due to the pump capacity. In order to obtain plug flow at maximum flow rates, the leading fluids should have high structural strength and plastic viscosity [7]. It is also required that the advance fluids have a certain required density, which is lower than that of the sealing slurry but higher than that of the drilling fluid. Piston flow is used in annular spaces of medium and large diameter, in the order of 40–60 mm, as well as in directional drilling [1].

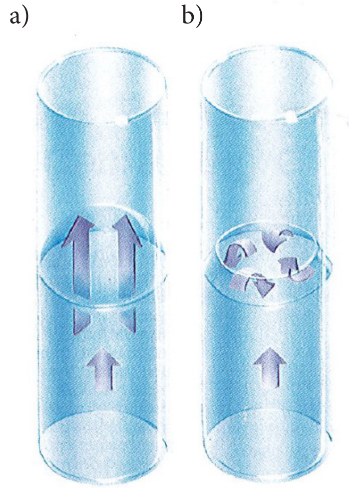


Fig. 3. Classification of advanced fluids due to the nature of the flow: a) laminar flow; b) turbulent flow

5. Factors and phenomena affecting the effective removal of the drilling fluid from the annular space

The perfect sealing of the annular space in the wellbore requires that all fluids previously present in the borehole (drilling mud with drill cuttings, formation fluids) are completely removed and replaced with cement slurry in the entire volume of the annular space. Excellent fluid displacement and a perfect seal are, however, rarely seen. The main factors and phenomena influencing the quality of effective cementation are [5, 7]:

- the shape of the borehole (caverns, washouts);
- eccentric placement of the casing column;
- rheological properties and density of drilling fluid, cement slurry and advanced fluids;
- the scheme of the injection of advanced fluids (washing time, volume flow);
- hole inclination (vertical, directional, horizontal);
- type of flow in the annular space (laminar, turbulent, transitional);
- escapes of mud in the rock mass.

6. Laboratory research

The subject of the laboratory research was to check how different types of washes and pre-flushes affect the efficiency of displacing drilling fluid from the annular space of the borehole. In addition to the selection of the best washing fluid, the tests included the determination of the optimal washing time and the optimal pumping rate of the washes and/or pre-flushes.

The research included determining the effectiveness of cleaning the internal surfaces of steel bushing by various types of washes. Apart from various types of advanced fluids, the influence of the flow rate and the washing time on the degree of cleaning the steel surface from the washing residue from the mud was also investigated. A washing device (Fig. 4) was built to simulate the flow of advanced fluids in the borehole.

Fig. 4. Washing device used for the laboratory research: 1 – a metal frame; 2 – hydraulic system consisting of PCV pipes; 3 – pipes with spacer nuts; 4 – steel bushing during washing; 5 – electrical device measuring the flow rate; 6 – submersible pump Viper 2850 WQD-10-8-0.55; 7 – pre-flush in plastic barrel

The bushing with the created reside on its inner surface is inserted between the sockets of PVC pipes and tightly tightened with distance nuts. Then the fluid pumped by the pump from the barrel goes to the pipes, flows through the bush and goes back to the barrel. The device works in a closed circuit. In order to prevent foaming of the washing liquids, the sockets of PVC pipes placed on the washed bushing were additionally equipped with rubber seal to prevent the ingress of air into the circulation. The flow rate was changed by turning the ball valve mounted under the flow meter. The washing time was measured with a stopwatch.

The density of washing fluid was 1000 kg/m^3, its filtration has value 6 s, structural strength was 0.4788 Pa for both 10 seconds and 10 minutes. Apparent viscosity was 3.25 mPa·s, plastic viscosity: 2.5 mPa·s and yield point 0.0893 Pa.

The washing of the steel bushing was carried out at specially defined washing pumping streams. The first three flow rates were determined based on the flow characteristics of the washing fluid. Delivery rates of 0.00024 m^3/s, 0.00035 m^3/s and 0.00047 m^3/s were calculated based on the Reynolds number limit values of 2000, 3000 and 4000, respectively. In order to determine these expenses, it was necessary to first calculate the velocity of the fluid flow in the bushing, transforming equation (1) into the Reynolds number as follows [7]:

$$R = \frac{\rho \cdot v \cdot D}{\eta} \tag{1}$$

where:
ρ – the density of the flowing fluid [kg/m^3],
v – fluid speed [m/s],
D – pipe diameter [m],
η – dynamic viscosity [Pa · s],
R – dimentionless Reynolds number [–].

After the necessary transformation, equation (1) was turned into:

$$v = \frac{R \cdot \eta}{\rho \cdot D} \tag{2}$$

In the above equation (2), parameters of an exemplary wash were taken as the dynamic viscosity and density. The bushing diameter was 0.05 m. After substitiotions, the equation has the form:

$$v = \frac{2000 \cdot 0.003}{1000 \cdot 0.05} = 0.12\ \frac{\text{m}}{\text{s}}$$

Flow rate was determined from formula [8]:

$$Q = v \cdot F \tag{3}$$

where:
Q – flow rate [m^3/s],
F – the cross-section area of the bushing [m^2].

Cross-secion area was determined from equation [8]:

$$F = \pi \cdot \frac{D^2}{4} \tag{4}$$

After the substitutions, the cross-section area and flow rate have the following values:

$$F = \pi \cdot \frac{0.05^2}{4} = 0.001963\ \text{m}^2$$

$$Q = 0.12 \cdot 0.001963 = 0.000236\ \frac{\text{m}^3}{\text{s}}$$

Another assumption for the flow rates was the fluid flow in the annular space of the borehole. Two holes with a diameter of 8 ½″ and 12 ¼″ were adopted, into which columns of casing pipes with an outer diameter of 7″ and 9 ⅝″ were inserted, respectively. For each of the holes, the pumping flow of the washing fluids were assumed to be 0.005 m^3/s and 0.010 m^3/s. Additionally, a fluid flow of 0.0125 m^3/s was assumed for the 8 ½″ hole. Then, the Reynolds numbers were determined for the fluid flow in the annular space of each holes at each of the pumping flows, and based on them, the fluid flows in laboratory tests were calculated. Parameters of laboratory assumptions are shown in Table 1.

Table 1. Laboratory assumptions concerning the diameters of borehole and casing, flow rate and Reynolds number

Diameter of the borehole [″] / diameter of the casing [″]	Flow rate [m^3/s]	Reynolds number [–]	Flow rate in the laboratory research [m^3/s]
8 ½ / 7	0.0050	5 390	0.00064
	0.0100	10 780	0.00127
	0.0125	13 479	0.00159
12 ¼ / 9 ⅝	0.0050	3 820	0.00045
	0.0100	7 639	0.00090

The first step before washing the bushing was to apply a layer of the mud to the inner wall with a brush. The bushing inside with an oil mud is shown in Figure 5.

Fig. 5. Bushing with layer of oil mud inside

The bushings were washed for 2, 5, 10 or 15 minutes. After washing, the bushings were paired with the stands, poured over with a sealing slurry and left in water at 20°C for 48 hours, or in a water bath at 80°C for 24 hours.

After the required time had elapsed and the cement slurry had hardened, the force needed to break the adhesion of the cement sheath with the wall of the steel bushing was checked. Extrusion of the hardened cement from the bushing was performed with a Matest model 183 PN 100 hydraulic press [8]. The bushing with the hardened cement slurry was placed in the press at the sample breaking station. The bushing rested on a steel ring that allowed the hardened cement slurry to slide down freely when pressure was applied to it.

At the top of the bushing, a special piston-shaped "squeezer" with a diameter equal to the internal diameter of the bushing was placed, which exerted pressure on the hardened cement slurry, breaking its adhesion with the steel bushing. The pressure force at which the adhesion of the hardened cement slurry with the bushing was broken determined the amount of adhesion of the hardened cement slurry to the bushing, which in turn determined its degree of washing from the filtercake [9, 10], e.g. when the hardened cement slurry slipped out of the bushing spontaneously without any force applied to it, it could be said that filtercake was not removed.

The research on washing steel bushings from the filtercake began with carrying out blank tests, i.e. checking the degree of adhesion of the hardened cement slurry to perfectly clean bushing and to the bushing with the filtercake applied. This was to create a comparative value to determine the degree of filter cake removal efficiency of individual fluids.

The force needed to break the adhesion of the hardened cement slurry with the bushing was taken as a measure of the adhesion of the hardened cement slurry to the steel bushing. As the minimum value of the stresses at the process of breaking the sample, above which it can be considered that there is sufficient adhesion of the hardened cement slurry to the bushing, the value of 0.1 MPa was adopted.

The minimum pressure force is determined from equation [8]:

$$F = P \cdot A \tag{5}$$

where:
F – pressure force [N],
P – tention [Pa],
A – the contact surface of the hardened cement slurrywith the bushing [m^2].

The contact surface of the hardened cement slurry with the bushing was determined from equation [8]:

$$A = \pi \cdot D \cdot H \tag{6}$$

where:
D – diameter of bushing [m],
H – hight of the bushing [m].

After the substitutions, contact surface of the hardened cement slurry with the bushing has value:

$$A = \pi \cdot 0.05 \cdot 0.054 = 0.00848\ m^2$$

$$F = 100\,000 \cdot 0.00848 = 848\ N = 0.848\ kN$$

The type of rinse was a 10% aqueous solution of the patent concentrated cleaner containing anionic compounds and surfactants. The chemical composition was very similar to popular cleaners, except that it did not contain fragrances [1, 11].

The washer was tested at the following flow rates: 0.0009 m^3/s, 0.001270 m^3/s and 0.00159 m^3/s. Visually noticeable effects of removing the filter cake from the bushing were obtained for 3 fluid rates: 0.001270 m^3/s during 15 minutes, 0.00159 m^3/s during 15 minutes and 10 minutes and 0.00197 m^3/s during 15 minutes, 10 minutes, 5 minutes and 2 min. The bushing washed with these rates were selected for cementing phase of the laboratory research. The flow rate of 0.00159 m^3/s corresponded to a Reynolds number of 13 479 obtained when injecting the fluid into the borehole at a rate of 0.001270 m^3/s, while flow rate of 0.00197 m^3/s was due to equipment limitations. The binding and hardening of the cement slurry took place at 80°C for 24 hours.

The average values of adhesion for different flow rates and for different flushing times with the washes used are presented in Figure 6.

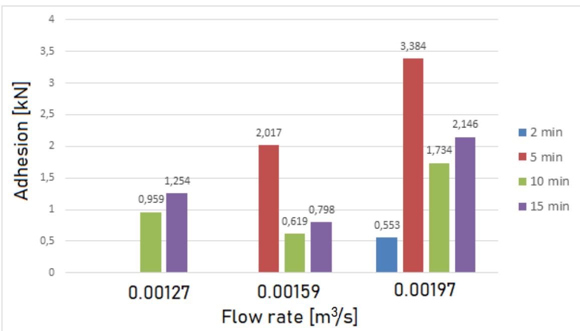


Fig. 6. Average values of adhesion for various pumping rates of the washing fluid and for various washing times

The washing efficiency can be seen in the Figure 7.

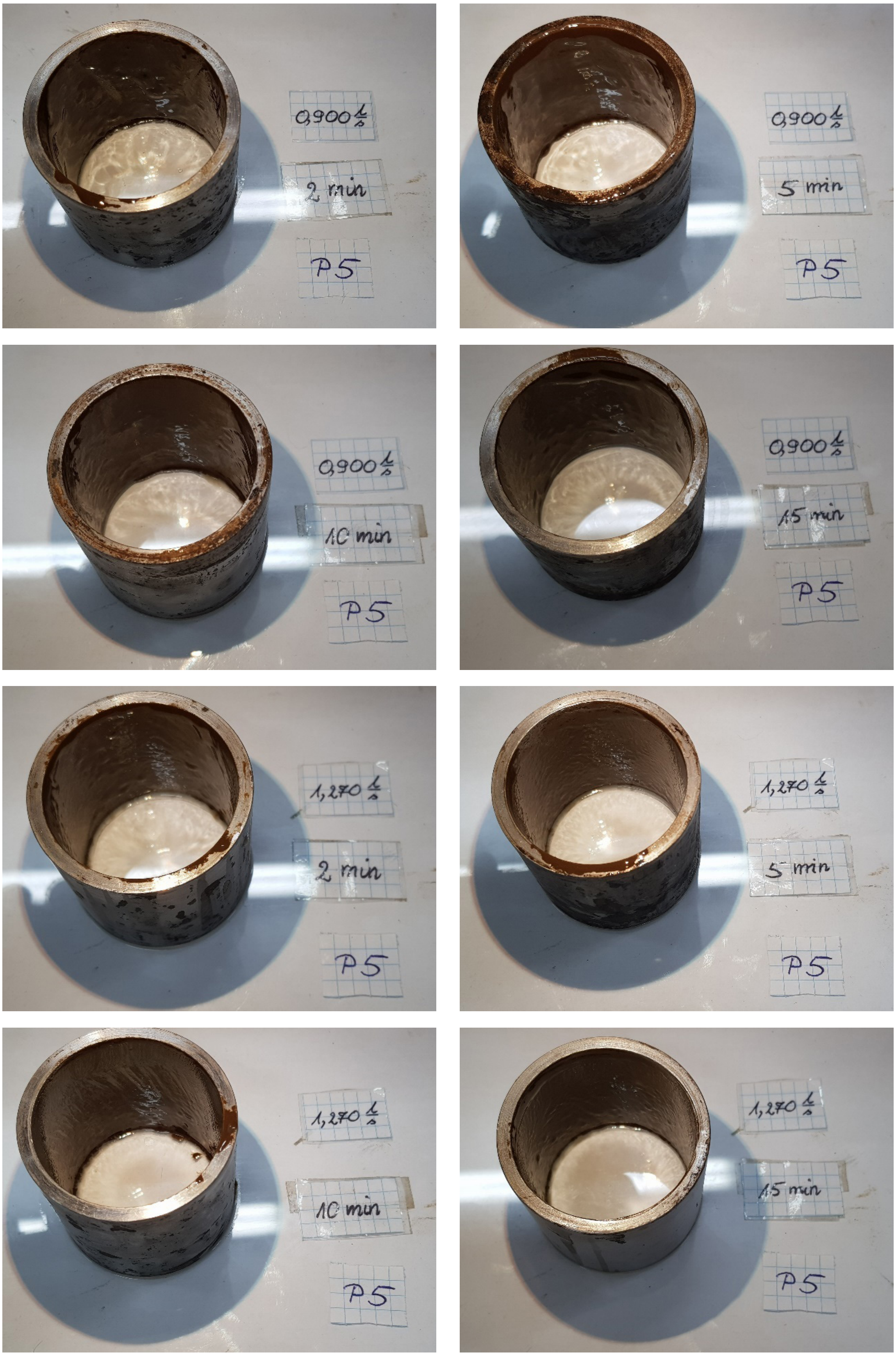
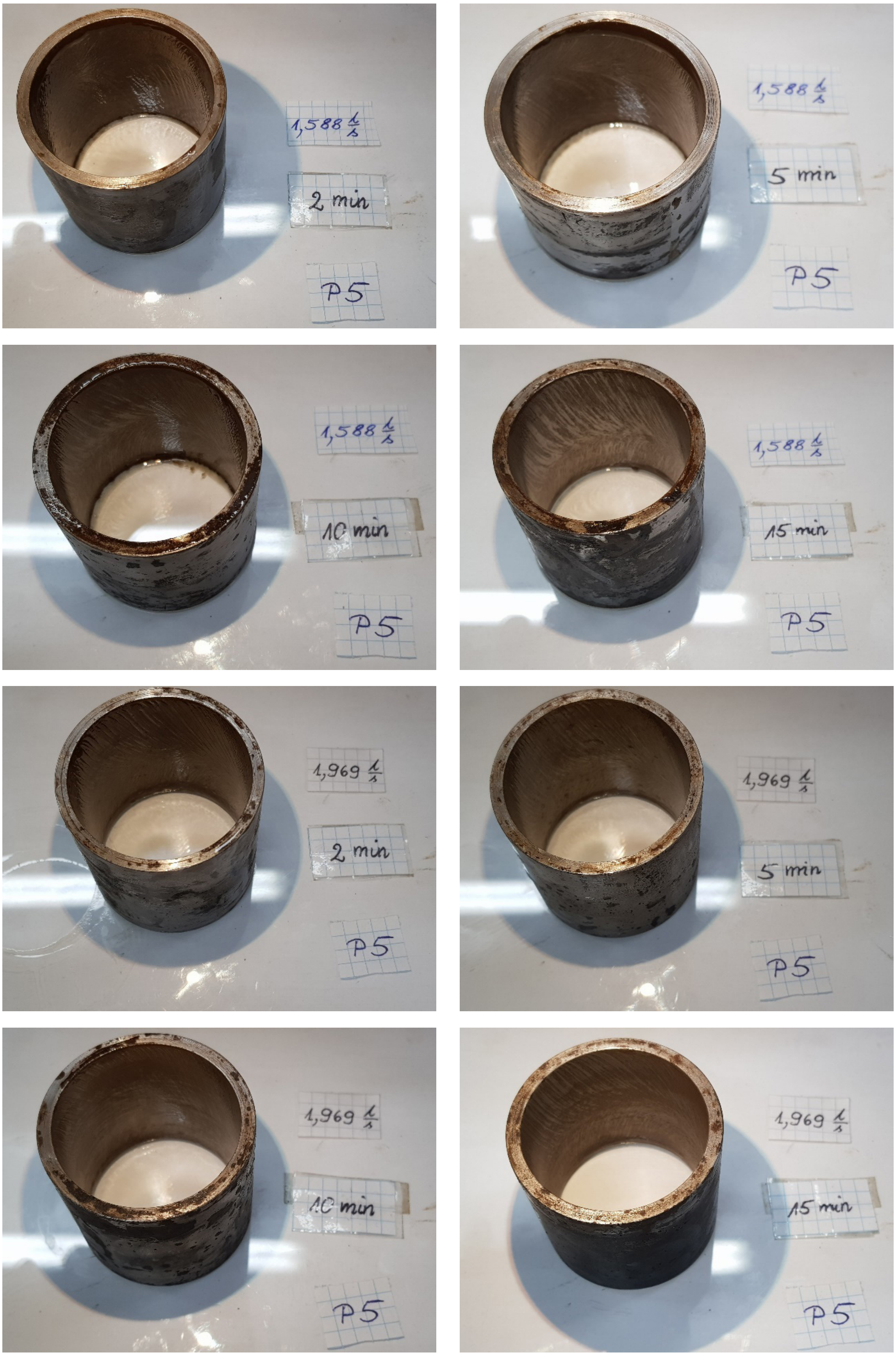


Fig. 7. Photos of the effects of washing steel bushing from the filtercake with a wash


1,588 l/s
2 min
P5
1,588 l/s
5 min
P5
1,588 l/s
10 min
P5
1,588 l/s
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1,969 l/s
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P5
1,969 l/s
5 min
P5
1,969 l/s
10 min
P5
1,969 l/s
15 min
P5

Fig. 7. cont.

7. Conclusions

Cleaning the annular space between the borehole and casing is critical during the process of cementing a well. The drilling fluid circulating in the well settles on the wall of the borehole and on the outer space of casing pipes and may cause insufficient connection between the hardened cement slurry and steel pipes. In order to minimize this risk, an appropriate washing fluid should be selected to clean the annular space of the borehole. After conducting laboratory tests, it can be concluded that both the flow rate and the flushing time play a large role in the process of cleaning the borehole from the residue. Moreover, it can be noticed that the increase in the flow rate of the washing fluid has a positive effect on the removal of the oil filter cake. On the other hand, the increase in the washing time of the steel bushing did not always increase the efficiency of this process. The pump used in the tests caused a gradual increase in the wash temperature due to its long-term operation. It was visually observed that as the wash temperature increased, the efficiency of the wash scale removal from the steel bushing increased. While testing the adhesion of the hardened cement slurry to the bushing, the results were sporadically divergent. This could be due to a corroded contact surface with the cement.

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