CORE ANALYSIS AS A KEY TO UNDERSTANDING FORMATION DAMAGE AFTER HYDRAULIC FRACTURING TREATMENT

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ABSTRACT

Hydraulic fracturing is the most effective stimulation method of hydrocarbon reservoirs. The main goal of this treatment is to increase production rate and recovery factor of oil and/or gas. Originally fracturing has been developed for conventional reservoirs and has been performed successfully in different oil and gas formations for decades. This technology has also become invaluable for completion of unconventional hydrocarbon deposits. It has been proved, that so far it is the only, effective method to allow hydrocarbons drainage and commercial production from gas shales and tight gas sandstones. Thanks to hydraulic fracturing it is possible to increase the recovery rate of hydrocarbons.

Just like any other technology along with benefits it also has drawbacks. One of the key drawbacks is the impact of technological fluids on reservoir rock. Any interference of technological fluids with stable reservoir system (rock – water - hydrocarbons) may result in undesirable effects. During the fracturing treatment, fracking fluids are injected also into pores and natural fractures of reservoir rock. In many cases the contact and interaction of these fluids with the formation may generate serious problems like clays swelling and precipitation of secondary minerals. Each of these phenomena may cause temporary or permanent formation damage and reduce its permeability.

There are several different field and laboratory methods designed to assess the degree and range of formation damage. In this area many possibilities is offered by comprehensive analysis of the core material. In our study, several techniques to evaluate the formation damage have been used. At first routine core analysis was applied and permeability and porosity coefficients were measured. Next, auxiliary analyses were performed, including fluorescence microscopy and Scanning Electron Microscopy in order to confirm the structural effect of formation damage by fracturing fluids. Presented results and conclusions of this research may be very useful to design more "clean" and efficient fluids for hydraulic fracturing.

INTRODUCTION

Hydraulic fracturing is now the most popular method of stimulating gas and oil reservoirs in non-conventional formations. Fracturing is necessary to enable production of hydrocarbons from formations of very low permeability, i.e. tight gas, coal and gas-bearing shales deposits that cannot be exploited without fracking [1]. When fracking fluids used are based on water, the so-called permeability damage is likely to occur caused by, among others, swelling of clay minerals, or by other physical and chemical mechanisms taking place in a formation being fractured. [2] The role of fracking fluid is to generate and propagate fractures. Any applied fracking fluid should transport the proppant in suspension, and then to leave it in the fracture made in the reservoir. It turns out, that in many Polish shale formations, swelling clay minerals occur, preventing the use of traditional water-based fracturing liquids due to the permeability damage hazard.

PERMEABILITY DAMAGE IN FRACTURING

In practice, fracking fluids based on water are most often used in hydraulic fracturing operations. They include water solutions of natural or synthetic linear and cross-linked polymers. Fracking fluid used for hydraulic fracking treatments in conventional deposits (cross-linked linear polymer technology) should have in surface conditions apparent viscosity in the range of thousands of mPa* s. And in formation conditions, apparent viscosity in the range of at least 100 mPa* s, at shear rate 40 s^{-1}, because it is assumed that such a shear rate occurs in a fracture [3]. In non-conventional deposits, in particular in shale formations, the role and types of fracking fluids are somehow different. From technological point of view, US onshore American experience shows that obtaining high number of fractures in the largest possible volume is achievable even when using low-viscosity fluids of several mPa* s at high pumping rate, however, its friction, when flowing in pipes, is high. As a result, small amount of synthetic polymer is added to water, usually polyacrylamide, which significantly, due to its low viscosity reduces the flow resistance. Shale fracturing in some cases also uses more "conventional" fracking fluids (linear and cross-linked polymer). Sometimes it is necessary to perform so-called hybrid fracturing. Fracturing of unconventional tight gas deposits also uses fluids based on gels, and foams [4,5].

During fracking, considerable amounts of technological fluid is injected (thousands of m^3), with a very high flow rate, even up to 25 m^3/min [2,6]. As a result, the fracturing pressure of the formation is exceeded, the fracture propagation is maintained, proppant in the fracking fluid of low viscosity is kept in the form of a suspension, in order to transport it to the fracture.

An important parameter that characterizes a fracturing fluid is its leak off into the rock matrix. Hydraulic fracking operations are always performed at high pressure. The difference of fracturing pressure and deposit pressure causes filtration of the fracking fluid into the matrix of formation. When using polymer fluids, the filtrate that infiltrates the matrix is water, and the filtration cake is formed on the fracture wall. Filter cake on a sandstone during laboratory filtration tests is shown on Figure 1

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Figure 1. Filter cake example

The degree of filtration significantly affects the efficiency of a fracking fluids and is one of the main parameter taken into consideration in the fracturing treatments design. Too high, uncontrolled filtration of fracturing fluid into the rock matrix during fracking can lead to screen out of proppant. Sandstone and carbonate reservoirs of low permeability have slightly different leak off nature of a fracking fluid. This difference stems mainly from the porosity and permeability. Sandstones have usually porous structure. Polymer on the surface of a porous rock creates filter cake and filtrate fills the pores. With low permeability of sandstone, the filtration range and the thickness of the filter cake are significantly limited. In reservoirs that have fracture porosity and permeability, frack fluid will rather fill fractures and micro-fractures, causing their further propagation. Classic filtration with filter cake shall be in this case marginal. In the process of filtration, the type of the reservoir fluid that fills the porous volume is also significant. Gas, as a compressible medium, will limit filtration to a very small extent, and oil, as less compressible, will limit it to much greater extent.

Another phenomenon that negatively affects the appropriate conductivity of a fracture is the insufficient cleaning of a fracture from polymers present in the fracking fluid. Also, insoluble residues included in the fracking fluid or formed during fluid breaking may remain in a fracture or in the porous space, thus reducing the primary conductivity of a fracture. It shows in particular during the flow of fracturing liquid filtrate into the reservoir rock (creating filter cake), and hence polymer thickening in a fracture filled with proppant [3].

PROCEDURES

When preparing the formulation for a fracturing fluid, its possible interaction with components of rock structure and the cement of the rock should be taken into account. The research was supposed to evaluate such interaction based on the results of experimental tests. In order to test formation damage with selected fluids, the following laboratory tests have been planned:

- how the prepared fracking fluids are damaging the rock formations (based on flow tests on natural cores)

- identification, analysis and assessment of rock formation damage

The tests have been conducted on natural rock cores from Rotliegend samples.
The impact of three fracking fluids on rock formation damage has been tested:

- fluid based on synthetic polymer - slick water
- fluid based on natural linear polymer
- fluid based on natural cross-linked polymer

Fig. 2 presents the core face after the flow tests with the use of cross-linked polymer, linear polymer, and slick water liquid. The core flow tests of the fracturing fluids have been conducted on AFS Core Flood System at ambient temperature using low backpressure (140 psi).

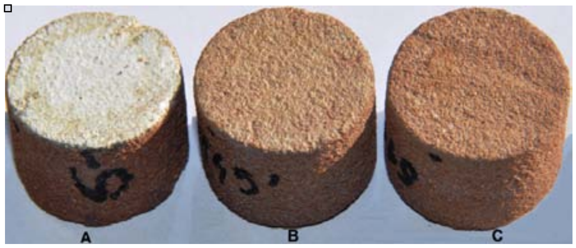

Figure 2. The Rotliegend Sandstone cores after the injection of A-cross-linked polymer, B-linear polymer, C-slick water.

RESULTS

The level of damage to rock pores after the flow tests has been defined using:

- permeability and porosity tests,
- SEM analysis
- fluorescence tests in UV light

According to our results –Table 1, the permeability of the cores significantly decreased after the application of the technological fluid with linear polymer and cross-linked polymer. The permeability has been reduced mainly by the filter cake, formed on the face surface of the cores. The permeability was reduced on the samples' surface, as visible in the microscopic photos. In the case of these cores, the porosity slightly increased as a result of solid particle elution. The sample core permeability increased after the injection of the slickwater-based fluid. Probable increase in permeability and porosity of the samples might be attributed to the washing out of solid particles from the cores, visible also in the received filtrate.

Table. 1 Porosity and permeability coefficient measured before and after the core flow tests.

Type of Fluid	k_0 initial core permeability [md]	k_k final core permeability [md]	ϕ_0 initial core porosity [%]	ϕ_k final core porosity [%]
slick water	78,09	99,39	24,77	26,28
linear polymer	146,64	15,47	26,88	27,01
cross-linked polymer	155,01	19,45	21,15	21,58

To identify the mineral phases in the samples, a FEI Quanta-650 FEG electron microscope (15 kV, 8–10 nA, 50 Pa) was used before and after the experimental tests. Below are the example images of the pore space after the linear polymer-based, and cross-linked polymer-based fluid injection into the core. The observation of fine clayey fractions, that were present in the intergranular space, and traces of the fracturing fluid, under the scanning electron microscope is important from the point of view of stimulation procedures.

A **B**

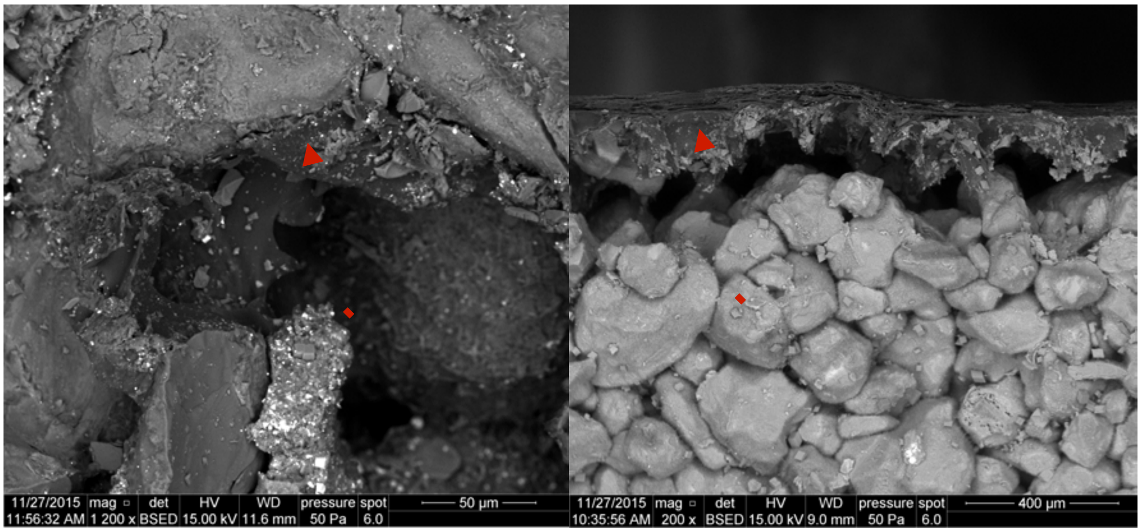

Figure 3. A-Polymer shreds (arrow) in the pore space visible even more than 3-4 mm from the front surface. B-The front surface of a core with visible polymer coating (arrow)

The level of the fracturing fluid impact on the permeability damage was confirmed by the UV tests. When using a slick water fluid, only a thin polymer coating was visible in the form of weak light blue fluorescence. Based on a linear scale visible on each image it was found that the thickness of the polymer coating is approximately 50 microns - Figure 3B. After inaction of linear polymer- based fluid, the traces of polymer were visible even at a distance of 6mm from the core surface. In the case of cross-linked polymer, the front surface of a core was covered with organic polymer layer with intensive, blue fluorescence.

A B C

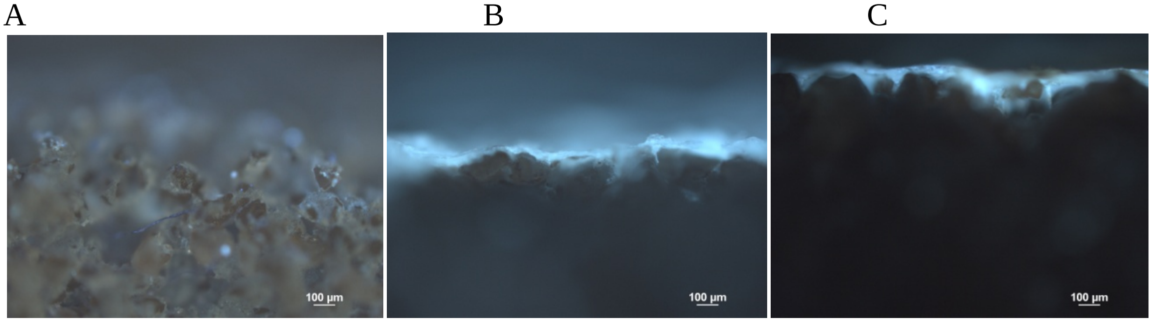

Figure 4. Core face surfaces: A-slick water, B-linear, C-cross-linked.

CONCLUSION

We defined the impact of the prepared fracking fluids on low permeability of rocks, based on experimental flow tests on natural cores. The presented fracturing fluids may damage a created fracture. The damage is caused by leak off into the rock matrix. As a result of filtrate escaping from a fracturing fluid into reservoir, the conductivity and permeability of a fracture, and the conductivity and permeability of the reservoir near the walls of the fracture can be decreased.

The tests show that this phenomenon is visible not only with cross-linked liquids, but also with linear polymer, and slick water. For this reason, when fracking low-permeability deposits, attention should be paid to fracking fluids prepared on the basis of surface-active agents, and to multi-phase fluids (the so-called energized fluids) [7].

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