

Formation Damage Due to Guar Gum and Its Derivative as Polymeric Fluid in Water Based Fracturing Fluid: A Literature Review

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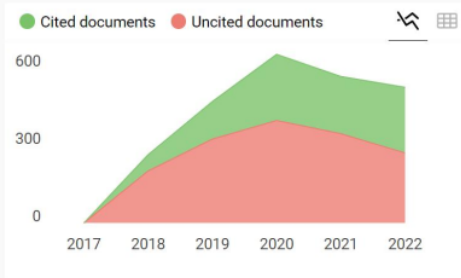
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1 Formation Damage Due to Guar Gum and Its Derivative as Polymeric Fluid in Water Based Fracturing Fluid: A Literature Review

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1

ABSTRACT

Hydraulic fracturing is a technique widely employed around the world to enhance the productivity of low-permeability wells. Hydraulic fracturing is performed by injecting a high-viscosity fluid capable of fracturing rocks and transporting proppant. A water-based fracturing fluid is the most commonly utilized fracturing fluid. This fluid is made up of water, polymeric minerals, crosslinks, breakers, and a variety of additional additives that are customized to the properties of the rock and fluid being penetrated. The existence of residues created by polymers that do not entirely break down after the fracture process is a common issue when using water-based fracturing fluids. In addition, the use of different water sources, such as the use of production water with complex ion content, affects both the residue and the rheology of the resulting gelling fluid. The fracturing fluid will also interact with the mineral reservoir rock, which contains clay minerals in varying amounts. This interaction can result in fines migration and clay swelling, which can increase the formation damage and impair permeability during hydraulic fracturing. The presence of residue, fines migration and clay swelling are a source of formation damage which can reduce permeability after hydraulic fracturing, better known as return permeability. This article reviews the formation damage in hydraulic fracturing caused by water based fracturing fluid comprises residues caused by interactions between polymeric materials and other additives, as well as clay issues such as fines migration and clay swelling. Comprehensive knowledge is needed regarding the factors that cause formation damage and return permeability caused by water based fracturing fluid, so that hydraulic fracturing will increase well productivity.



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1. INTRODUCTION

Hydraulic fracturing is stimulation method of ³ oil and gas industry as a way to increase hydrocarbon production especially in oil or gas reservoirs that have low permeability by inducing fractures in the formation to create conductive pathways for the flow of hydrocarbon [1- 5]. Formation damage due to water based fracturing fluids especially polymeric fluid is an important topic in petroleum engineering. The use of water-based fracturing fluids in hydraulic fracturing operations has become increasingly widespread, yet there is still much to be learned about the effects of these fluids on the formation. This paper will provide a literature review of the research conducted on formation damage due to water based fracturing fluids.

Many researchers have studied the polymeric fluid of fracturing fluids and their effect on the formation. It has been observed that the presence of certain chemicals, such as polymeric fluid, crosslinker, and breaker, can cause damage to the formation by produce residue from polymer break process contained in the thickening materials [5]. The type of polymer fluid that is widely used as a gluing fluid is Guar Gum and its derivatives. On the other hand, to reduce the level of residue and formation damage by polymers, a suitable type of breaker additive is needed both in type and composition.

Permeability and formation damage prediction in hydraulic fracturing after hydraulic fracturing plays an important role in the well productivity. Nowadays, permeability prediction after hydraulic fracturing can be done both laboratory test and numerical simulation. Laboratory test is time consuming due to experimental procedure, expensive because high cost to get chemicals and core sample, and also not applicable to damage core. In other hand, experimental method gives more experience visually. Compare to experiment method, computer modeling also has benefit to reduce the cost because of sample and chemicals needed, but this method requires a lot of data and it's still under development to be perfect. Other factor considering formation damage in hydraulic fracturing is clay minerals containing in reservoir rock. To minimize this effect, many clay stabilization has been developed including salt and polymer based.

2. Water Based Fracturing Fluid

Water, sand, and chemicals are the three most prevalent ingredients in water-based fracturing fluids [4], [6-8]. The fluid's basis is water, which also provides a way of moving and suspending the sand particles. After the pressure is released, sand, sometimes known as proppants, aids to sustain the fractures' open state. The compounds are included to improve viscosity, decrease friction, and stop bacterial development.

Using water-based fracturing fluids has various advantages. They are reasonably priced, environmentally friendly, and the sand particles aid in keeping the fractures open for a longer period of time. But they have flaws in the resultant residues and are sensitive to the clay mineral composition of reservoir rocks. The design of a water based fracturing fluid affects the performance of the fluid and the economics of the process. Designing fracturing fluid include polymeric fluid, additive and water source are important aspects. Many polymers were reported as thickener of the fracturing fluid, but it has consequences of polymer losses in the formation and became main problem after hydraulic fracturing job [9]. Once the design is complete, the fluid must be tested in the laboratory to ensure that it meets the job requirements [6].

There are 4 (four) types of water based fracturing fluid³ commonly used in oil and gas industry:

- a. Slick water, this fracturing fluid is mostly water with a very low proportion of linear polymer. Slick-water can efficiently reduce fracturing fluid flow drag [10].
- b. Guar- Based Fluids and its derivative, this fracturing fluid consists of high-molecular-weight polymer. The most popular is hydroxypropyl guar (HPG) the most stable in high temperature, other types are carboxymethyl hydroxypropyl guar (CMHPG) and cellulose derivatives like carboxymethyl

hydroxyethyl cellulose (CMHEC) [11].

c. Crosslinking of guar, this fracturing fluid is modified from guar-based fluid with add crosslink to increase the conductivity. The common crosslink used in Guar and its derivatives based fracturing fluid are Borate [12], Titanium (IV), Zirconium (IV), and Aluminum (III) ions [13].

d. Guar alternative. A synthetic associative acrylamide-based polymers modified with monomers such as sodium acrylate (AA), sodium acrylamido-tertiary-butyl sulfonate (ATBS), and other surfactant monomers with rheological properties comparable to crosslinked guar and favorable proppant carrying properties [14]. Because associative polymers have higher viscosity at lower shear rates, they are more suited for proppant movement within cracks. Carboxymethylcellulose (CMC) [15] and carboxymethyl hydroxyethyl cellulose (CMHEC)-based [16] replacements crosslinked with metal ions have been developed to replace guar products in extreme temperature and salinity environments.

Guar, a polymer with a long chain and a high molecular weight composed of mannose and galactose sugars, has been extensively used to viscosity water for hydraulic fracturing operations [1], [17], [18]. An insoluble polymannose helix can be formed by as little as six continuous unbranched mannose units as in Guar [19]. Guar is estimated to have up to 10% insoluble residue by weight [17], [18]. This early insoluble residue harms the proppant pack. In addition to the polymer, the use of crosslinks and breakers will also affect the residue produced. The use of the right breaker can reduce the residue produced. Some types of breakers that have been used include Bromate, Ammonium persulfate, Acid, and enzymes. The use of enzyme breakers is reported to be the most effective in reducing residues, but there are limitations in the length of reaction time as well as the optimum pressure and temperature [20]. These fracturing fluid generated residues diminish the proppant pack's conductivity and formation damage in the invaded zone. Precipitation takes anywhere from a few hours to a few days to form. Table 1 shows the relationship between the types of polymeric minerals, crosslinkers, breakers used and the tendency of the residues produced and the amount of return permeability.

Table 1. Comparison of polymeric fracturing fluid due to residue and return permeability

Author(s)	Type of Fracturing Fluid	Core Sample	Residue	Return Permeability
[20]	CMHPG based frac fluid with sensitivity: Breaker (acid, bromate, persulfate, enzyme)	N/A	The best breaker is enzyme, and the worst is acid	N/A
[21]	Crosslinking of guar	Tight carbonate	N/A	The longer the shut-in time will decrease the return permeability value
[22]	HPG and HECMC FAG-500	Tight gas reservoir	HECMC is less residue than HPG	N/A
[23]	Guar FF and polyacrylamide FF with Zr crosslinker	Low permeability Sandstone	355 mg/L for HPG 40 system, 719 mg/L for HPG 45 system, 113 mg/L for polyacrylamide FF	48% for HPG 40 system; 55% for HPG 45 system, and 11% for polyacrylamide FF
[24]	Type 1: crosslink gel (guar concentration of 0.45; type 2: like type 1 but lower guar concentration (0.35%); type 3: 0.55%; type 4: 0.5% Polyacrylamide.	Sandstone core sample. Clay has an average content of 20.4%, in which illite is about 30%, chlorite is about 21%, and smectite is less	Fluid type 4 produces the least amount of residue compared to other fluid types.	Fluid type 4 also produce the least return permeability compared to other fluid types.

than 0.2%				
[25]	CMHPG, CMC, and Surfactant FF	Proppant pack 20/40 mesh size	N/A	CMHPG produced the least return permeability compare to CMC and surfactant FF
[26]	Linear gel with 5 wt% KCl	Kentucky sandstone and Marcellus shale	N/A	Longer soaking time in the case sandstone cores showed increasing in the regain permeability due to reducing water saturation at the core inlet. The regain permeability in shale cores was found to be 0.15 of its original value without the soaking process, and continuously decreased as the soaking time increased

3. Water Source of Fracturing Fluid

Water-based fracturing fluid was initially developed using fresh water because it is compatible with additive addition and less damaging the formation [27]. However, considering the abundance of water sources originating from the oil or gas production process, various studies in recent years have focused on the use of produced water and flowback water as a material to make water-based fracturing fluids [28]. Also, the use of heavyweight brines as a basis for fracturing fluids is an efficient way for addressing the issue of excessive surface pressure during the deep well fracturing process [29]. Produced water has been investigated as one of the water sources used in the manufacture of fracturing fluids as a substitute for fresh water with a close-loop system (King, 2011). The use of this production water minimizes the construction of water tanks, and utilizes unused production water, making it more economical. Research conducted by (Ruyle & Fragachan, 2015) showed that the use of production water with polymers for recirculating fluid can minimize cost (L. Li et al., 2016).

Aside from that, there is research attempting to use high salinity sea water as a fracturing fluid. It is tough to optimize fracture fluid viscosity in a high-medium salinity (e.g., saltwater and produced water) [30], [31]. The usage of different types of water will have an impact on the rheology and formation damage induced. Some factors that need to be considered in designing a fracturing fluid using production water, flowback water, or seawater include total dissolved solid (TDS), hardness, monovalent and divalent ion content. The amount of monovalent and divalent ions must be considered when make used of produced water-based fracturing fluid [32], whereas sulfate especially Na_2SO_4 ions can alter the rheology of seawater-based fracturing fluids with the CMHPG polymer type [33], [34].

The high salinity and total dissolved solid (TDS) of seawater can cause problems with rheology and fluid stability at high temperatures as well as scale formation in the development of seawater-based-fracturing fluid [35], [36]. On other hand, based gel viscosity was not affected, but the crosslinking mechanism is less stable than fresh water whether HPG or CMHPG polymers are used to make seawater-based fracturing fluid [36]. The rheological instability of the gelling fluid in the use of HPG and CMHPG polymeric fluids with seawater can be improved by replacing the polymer used with a polysaccharide gelling agent (PGA) with zirconium added as a crosslinker [37]. This polymer is stable in the temperature range of 150-325 F. It also has excellent proppant transport characteristics and provides a low residue content when broken. In other studies, the viscosity stability of the gelling fluid with seawater can be improved by the use of scale inhibitors [38] or chelating agents [33].

When compared to fresh water, employing produced water directly as a fracturing fluid increases formation

damage [26]. This is due to the mineral deposition caused by the interaction of the produced water with the polymer utilized. In addition to polymers, the use of crosslinks affects the viscosity stability of the gelling fluid [39], [40]. Previous research has given several strategies to decrease the residue created, including diluting produced water [26], stabilizer additive [41], [42] and utilizing chelating chemicals [32].

4. Reservoir Rock Minerals – Clay Mineral

The key criteria that influence the level of clay formation damage are matrix grain size and clay content [43]. Clay minerals are formed through the disintegration of feldspar minerals in hard rocks such as granite as a result of rock weathering. They are often described as soil particles with sizes less than $2\ \mu\text{m}$, and are often referred to as nature's nanoparticles. Clays are chemically related to a group of minerals known as aluminosilicates. The basic components of aluminosilicates are silicon, aluminum, and oxygen, and they are made up of a complicated arrangement of atoms to produce varied structural configurations. Silicon tetrahedral sheets and aluminum octahedral sheets are formed when silicon and aluminum atoms link with oxygen. These sheets are then connected by sharing common oxygen atoms, albeit the oxygen atoms at the sheets' borders remain unpaired. These unpaired oxygen atoms at the sheet edges impose negative charges on clay mineral surfaces, making them water sensitive and cation reactive. Another process influencing large negative charges in clay minerals is isomorphic cationic substitution within sandwiched tetrahedral and octahedral sheets, which results in the imposition of excess negative charges on clay mineral surfaces. The technique outlined above adds to increased clay sensitivity to water-based synthetic fluids in subsurface environments.

Clay mineral classified based on their properties and mineralogy [44], [45]. Surface area and Cation Exchange Capacity (CEC) affect the tendency of clay swelling when interacting with water. Clay classification descriptions are captured below:

- a. Kaolinite is a clay mineral made of one silicate tetrahedral and one aluminum octahedral silicate. Because of its modest surface area and adsorption capacity, this structure renders kaolinite relatively stable.
- b. Smectites are a 2:1 clay mineral made of two silicate tetrahedrals coupled with one aluminum octahedral. Smectites are the most problematic clay minerals during drilling and production, especially with water-based engineered fluids. This behavior is due to smectites' huge surface area and strong cation exchange capabilities, which result in a high adsorption capacity.
- c. Illite, like smectites, is made up of tetrahedral and octahedral plates stacked in a 2:1 configuration. They have lower adsorption capacities than smectites but higher capacities than kaolinites.
- d. Chlorites are made up of Brucite layers that alternate with three-sheet pyrophyllite layers. Though chlorite can exist as a macroscopic or microscopic crystal, it is more commonly found in microscopic mixes with other minerals.

Ion sorption on the clay minerals influences the electrostatic double layer expansion via two apparent mechanisms: 1) ion exchange; and 2) surface complexation processes [46]. Smectite and illite contain large and small CECs around 100 and 20 meq/100g, respectively. The edge sites of SOH^{3-} in smectite and illite contribute in the total CEC by 5-10% and 20-50%, respectively. Smectite yields a specific surface area 5-6 times that of illite, which can cause more swelling in smectite.

These findings are consistent with [47] research, which stated that the change in shale porosity with different mineral compositions during hydraulic fracturing may be related to shale clay content; the higher the clay content, the greater the illite expansion, causing swelling of nanopores and a significant decrease in total pore volume (shale porosity decreased from 7.8% to 3.8%). Formation damage due to clay swelling

can be carried out in the laboratory using pressure transmission tests, by comparing changes in permeability due to clay swelling with the initial permeability [48].

Another problem associated with clay minerals is fines migration. There have been many studies on methods to reduce this effect, one of which is the addition of nanofluids [49- 52]. Clay problem also predicted by simulation. [53], investigate the impact of chemical additive present in fracturing fluids on the adsorption behavior and dynamics of water and ions at the clay interface using Molecular Dynamics simulations. The study results suggest that fracturing fluids with methanol and citric acid concentration of 5 wt% will not have a strong impact on wettability variation of illite. However, the presence of these chemical additives might affect the fluid flow inside clay nanopores, decreasing the mobility of water and sodium cations. Additionally, the authors also conclude that when fracturing fluids are in contact with high temperature reservoirs, the fluid flow is increased.

Injecting slick water as the fracturing fluid into shale rock samples with an average clay percentage of 34.46% resulting in reduction of the permeability of the rock at the start of immersion because the flowing channels were limited by the swelling of clay minerals and the cracks were not connected to one another. As the hydration process proceeds, the hydration stress and capillary force increase, causing induced fractures and the expansion, extension, and interconnection of microcracks, beddings, and hydration-induced fractures. As a result, the permeability of shale was regained and even increased over its previous value [54]. To control the clay problem in fracturing, the clay stabilizer was added. There are two kind of clay stabilizer in fracturing fluid are polymeric [20], [55] and salt [56] type. In the previous study, a phase inversion polymer coating potential to prevent clay swelling and fines generation in coal seam gas, or other petroleum, wellbores [57].

5. Formation Damage

Formation damage in hydraulic fracturing is a type of damage that can occur when a well is hydraulically fractured. Formation damage in hydraulic fracturing activities can occur from several factors (1) the size, property, shape and distribution of proppants [58- 60]; (2) changes in rock minerals, especially clay minerals [47] (3) the presence of residues caused by incompletely broken polymers [20], [61]; and (4) the flowback design and salinity of the fracturing fluid [62], [63].

Formation damage can have a major impact on well performance and production. Damage can result in a decrease in well productivity, an increase in water production, and slower oil recovery. Formation damage can also make it more difficult to identify productive targets in the formation and can even lead to well failure. Formation damage can be prevented by selecting fluids that are compatible with the formation, minimizing the amount of proppant used, and avoiding excessive pressure and flow rate [64], [65]. In addition, the design of the fracture dimensions, especially the fracture width, can increase permeability recovery after hydraulic fracturing [24]. Overall, formation damage in hydraulic fracturing can have a major impact on well performance and production. It is important for operators to take steps to prevent formation damage and to monitor the fracturing process to ensure that damage does not occur.

Formation damage caused by water based fracturing fluid in tight reservoir gas into tree types water sensitivity damage, water-locking damage, and solid-phase damage [66], [67]. The experiments conclude that water sensitivity damage had the biggest impact of formation damage about 12 %. Water sensitivity damage was a damage caused by interaction between water-based fracturing fluids and formation water. Calculation of formation damage is done by estimating the permeability before and after the invasion of the fracturing fluid, which is known as return permeability. On the other hands, residue was the main factor of

formation damage due to water based fracturing fluid in hydraulic fracturing, especially in tight sandstone gas reservoir [68].

In the other report, blockage in the production well after hydraulic fracturing caused by interaction between polymer as thickener and iron ion (Fe³⁺). It was reported that on polyacrylamide molecules, Fe³⁺ ions and carboxyl groups create stable -(COO)₃Fe bonds and increased the size of molecular clusters. But the use of ammonium persulfate as breaker can reduce formation damage by up to 39.5% [69].

6. Return Permeability

Return Permeability is the comparison between the permeability due to damage and the initial permeability [70] – [72]. Term return permeability mathematically can be defined as the ratio of the maximum injection pressure to the final (stable) pressure [73], which conducted research on return permeability that occurs as a result of the drilling process, which is caused by the invasion of the drilling fluid into the reservoir. Meanwhile [72] defines return permeability with a permeability approach. Return permeability in this study was calculated using the equation:

$$RP = \frac{k_d}{k_i} \tag{1}$$

Where, k_d = oil/gas/brine permeability after leak off test
 k_i = oil/gas/brine permeability before leak off test

Return permeability is identical to formation damage, so the formation damage ratio can be found using the following equation [23]:

$$\eta_d = \frac{K_1 - K_2}{K_1} \times 100\% \tag{2}$$

Where η_d = formation damage ratio, %
 K_1 = initial permeability before fracturing fluid invasion, μm^2
 K_2 = permeability after fracturing fluid invasion, μm^2

A developed method for measuring return permeability related to skin factor in the laboratory so that it is closer to field conditions [71]. Researchers recommend fluid loss dynamics in the return permeability test. Researchers use equation (3) to estimate return permeability in the laboratory,

$$RPs = 1 - ae^{-bx} \tag{3}$$

Where x is the dimensionless invasion depth, a reflects the damage at mud exposed surface, caused by fluid and solid invasion, while b reflects the distribution of damage in the invaded zone.

Other method to estimate return permeability by estimating initial pressure [73]. The equation of return permeability shown in equation (4) below,

$$\text{Return permeability ratio} = \Delta P_{\text{initial}} / \Delta P_{\text{final}} \tag{4}$$

where $\Delta P_{\text{initial}}$ is reading before filtration, and ΔP_{final} is reading during flowback (after filtration).

Return Permeability testing in the laboratory can be carried out by core-flooding [21], as is the case with core-flooding tests in Enhanced Oil Recovery (EOR) analysis but injection is carried out in two directions or backflow method. This method has limitation in imbibition process, so that a novel experimental method was carried out by combining the imbibition process into the flowback experiment [62], [74].

Apart from core-flooding with backflow, return permeability which indicates formation damage can also be tested using a CT scan to see the thickness of the invaded zone in core samples and computational fluid dynamics (CFD) simulations [75]. However, the use of CFD simulation still has problems in the length of running time. This obstacle was investigated by [75] by making a mathematical correlation with the sensitivity of the open radius of the core holder and the permeability of the core. By using the Sobol method, it is possible to estimate the parameters that are sensitive to the return permeability simulation using the CFD, so that later it can be simplified and shorten the simulation running time.

Fracturing permeability, also known as fracturing conductivity, can be predicted mathematically. [58] investigated the dynamic conductivity of generated fractures under closure stress during the hydraulic fracture-closing stage when the injecting viscous fluids are stopped. A three-dimensional (3D) volume-of-fluid-based (VOF-based) flow model is combined with a discrete element technique (DEM). The study concluded that closure stress and proppant size influenced fracture permeability.

7. Conclusion

In conclusion, the literature review presented in this paper has shown that there is a wealth of research on formation damage due to water based fracturing fluids. The research has shown that the presence of certain chemicals, such as polymeric material, crosslink, and breaker can cause damage to the formation. Another factor to consider is the source of the water used, because the source of the water will affect the characteristics of the water. Aside from the chemicals and water sources that must be considered while creating fracturing fluid, formation damage can also occur as a result of fracturing fluid contact with clay in rock minerals, which can induce fines migration or clay swelling. As a result, more research is needed to determine the impact of various sources of water as a fracturing fluid on the clay problems that develop.

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