



Review Paper

A review of reservoir damage during hydraulic fracturing of deep and ultra-deep reservoirs



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ABSTRACT

Deep and ultra-deep reservoirs have gradually become the primary focus of hydrocarbon exploration as a result of a series of significant discoveries in deep hydrocarbon exploration worldwide. These reservoirs present unique challenges due to their deep burial depth (4500–8882 m), low matrix permeability, complex crustal stress conditions, high temperature and pressure (HTHP, 150–200 °C, 105–155 MPa), coupled with high salinity of formation water. Consequently, the costs associated with their exploitation and development are exceptionally high. In deep and ultra-deep reservoirs, hydraulic fracturing is commonly used to achieve high and stable production. During hydraulic fracturing, a substantial volume of fluid is injected into the reservoir. However, statistical analysis reveals that the flowback rate is typically less than 30%, leaving the majority of the fluid trapped within the reservoir. Therefore, hydraulic fracturing in deep reservoirs not only enhances the reservoir permeability by creating artificial fractures but also damages reservoirs due to the fracturing fluids involved. The challenging “three-high” environment of a deep reservoir, characterized by high temperature, high pressure, and high salinity, exacerbates conventional forms of damage, including water sensitivity, retention of fracturing fluids, rock creep, and proppant breakage. In addition, specific damage mechanisms come into play, such as fracturing fluid decomposition at elevated temperatures and proppant diagenetic reactions at HTHP conditions. Presently, the foremost concern in deep oil and gas development lies in effectively assessing the damage inflicted on these reservoirs by hydraulic fracturing, comprehending the underlying mechanisms, and selecting appropriate solutions. It's noteworthy that the majority of existing studies on reservoir damage primarily focus on conventional reservoirs, with limited attention given to deep reservoirs and a lack of systematic summaries. In light of this, our approach entails initially summarizing the current knowledge pertaining to the types of fracturing fluids employed in deep and ultra-deep reservoirs. Subsequently, we delve into a systematic examination of the damage processes and mechanisms caused by fracturing fluids within the context of hydraulic fracturing in deep reservoirs, taking into account the unique reservoir characteristics of high temperature, high pressure, and high *in-situ* stress. In addition, we provide an overview of research progress related to high-temperature deep reservoir fracturing fluid and the damage of aqueous fracturing fluids to rock matrix, both artificial and natural fractures, and sand-packed fractures. We conclude by offering a summary of current research advancements and future directions, which hold significant potential for facilitating the efficient development of deep oil and gas reservoirs while effectively mitigating reservoir damage.

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1. Introduction

With the growth of the petroleum industry, the focus of reservoir exploration and development has progressively shifted from shallow and medium reservoirs to deep and ultra-deep ones (Zhu

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et al., 2017; Yao et al., 2018). Unconventional hydrocarbon resources, such as deep and ultra-deep reservoirs, now account for about 80% of the total global hydrocarbon resources. In recent decades, deep and ultra-deep reservoirs have become the main body of global reserves, since the drilling depths continue to reach unprecedented levels (Fu et al., 2020a). As shown in Fig. 1, between 2008 and 2018, the global hydrocarbon reserves experienced a remarkable increase of 2.34×10^{10} t of oil equivalent at a depth exceeding 4000 m, accounting for more than 60% of the world's new hydrocarbon reserves. The maximum drilling depth for hydrocarbons exceeds 12,000 m (Zhao, 2019). Worldwide, there are over a thousand oil and gas fields with depths ranging from 4500 to 8103 m, harboring substantial quantities of recoverable resources (Sun et al., 2013) (see Fig. 2).

Deep and ultra-deep reservoirs predominantly consist of carbonate, clastic, and volcanic rock types, with carbonate and clastic rocks being the most prevalent (Yao et al., 2017; Zhu et al., 2017; Che et al., 2018). Deep reservoirs, buried at depths ranging from 4500 to 8882 m (Jiang et al., 2016), are characterized by complex *in-situ* stress conditions and high salinity brines (Feng et al., 2016). Under the influence of the earth's internal heat and overlying rock pressure, the temperature increases with a geothermal gradient of $3\text{ }^{\circ}\text{C}/100\text{ m}$, while the pressure increment corresponds to a rate of $0.023\text{ MPa}/\text{m}$ with increasing burial depth. Consequently, they exhibit high temperature and high pressure (HTHP, 150–200 $^{\circ}\text{C}$, 105–155 MPa) characteristics (Zhao et al., 2015; Lei et al., 2021). The deep strata endure immense crustal stress due to the substantial weight of the rock and soil layers above, with stress levels rising as depth increases (Sibson, 1994). The overall geological structure is characterized by ultra-low permeability (Yao et al., 2017), constricted pore throats, and a formidable forces. These factors collectively render the development of deep reservoirs, an exceedingly challenging and costly endeavor (Zhu et al., 2015; Teng et al., 2016). Given the suboptimal reservoir quality, hydraulic fracturing often becomes imperative to stimulate production, especially through the application of hydraulic fracturing technology and horizontal well drilling (Li et al., 2019a; Wang D. et al., 2020a, 2020b, 2022). Hydraulic fracturing, in particular, has the capability to create highly conductive fractures within the deep formations, thereby significantly increasing the seepage area for fluid flow within deep and ultra-deep reservoirs (Hu et al., 2017; Song et al., 2018). This technology stands as the preferred method for enhancing production and optimizing the development of deep and ultra-deep reservoirs, having been successfully implemented

in both vertical and horizontal wells (Liang et al., 2018, 2022; Zhou et al., 2019). Following hydraulic fracturing, critical technical parameters such as fracture length and fracture conductivity have been significantly enhanced. The post-fracturing flowback rates can reach up to 59.9% (Mayerhofer et al., 2005), resulting in oil and gas production reaching $108 \times 10^4\text{ m}^3/\text{d}$ (Jiang et al., 2017).

While large-scale hydraulic fracturing can enhance hydrocarbon extraction, field experience often reveals that the expected production increase may not materialize as anticipated (Da et al., 2022). During the hydraulic fracturing process, as fracturing fluid permeates the reservoir formation, it can inadvertently inflict damage upon the reservoir. Under the influence of pressure differences and internal absorption mechanisms, the fracturing fluid can enter the deep reservoir formation through the rock matrix zone. If not returned in time, it would cause certain reservoir damage (Kang et al., 2016; Dai et al., 2018). According to incomplete statistics, more than 30% of low-permeability reservoirs suffer from water intrusion damage, resulting in oil phase permeability damage that can reach up to 80%, along with productivity losses exceeding 50% (Kang et al., 2016). Well tests conducted post-hydraulic fracturing reveal both positive and negative effects on the reservoir. To achieve effective production stimulation, it is imperative to minimize factors contributing to reservoir damage (Guan et al., 2007). Two widely acknowledged factors responsible for the negative impacts of fracturing fluid on flow conductivity are: 1) the interaction between fracturing fluid and rock matrix alters the physical and mechanical properties of the rock, ultimately increasing the degree of proppant embedment; 2) the conductivity of sand-packed fractures is diminished by the adsorption of the fracturing fluid on the fracture surfaces and proppants. Additionally, evaluating the harm caused by fracturing fluids is crucial, and two evaluation methodologies for fracturing fluid damage to the reservoir are prevalent: steady-state (Al-Ameri et al., 2018) and non-steady-state (Wang and Zhou, 2021) methods. The steady-state method is founded on Darcy's law, calculating permeability by maintaining a constant pressure difference and measuring the flow rate of samples. In contrast, the unsteady-state method, based on the one-dimensional unsteady flow theory, applies a pressure pulse to the upper container after achieving pressure equilibrium at both ends of the container (Zhang L. et al., 2019). It then monitors pressure changes at the upper and lower ends over time to obtain sample permeability. Unlike the steady-state method, the pulse decay method eliminates the need for recording flow rates at the core outlet, enabling the evaluation of permeability and core

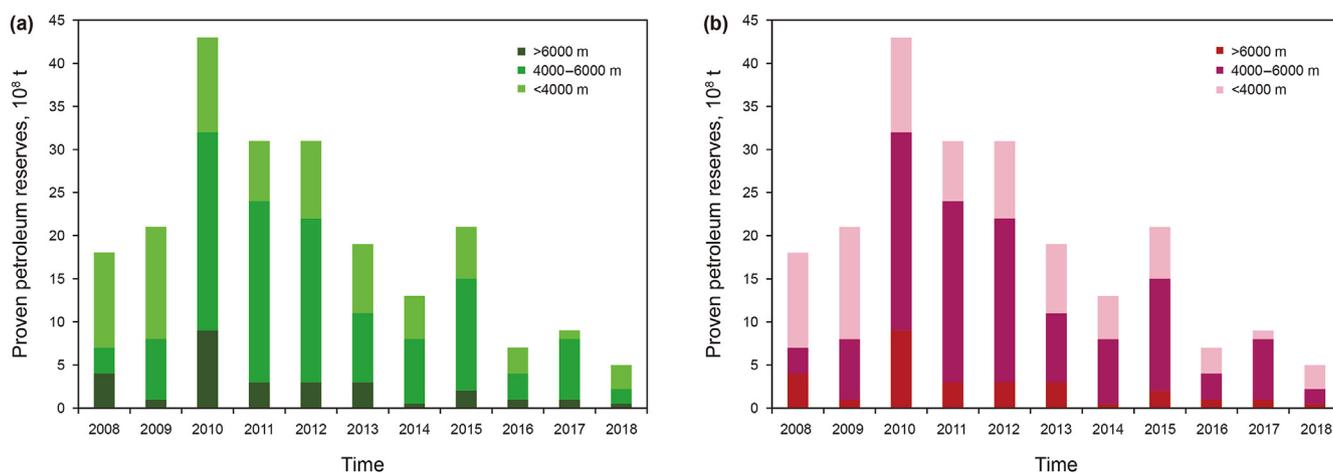


Fig. 1. Proven oil and gas reserves from 2008 to 2018. (a) Proven oil reserves; (b) Proven natural gas reserves (Zhao, 2019).

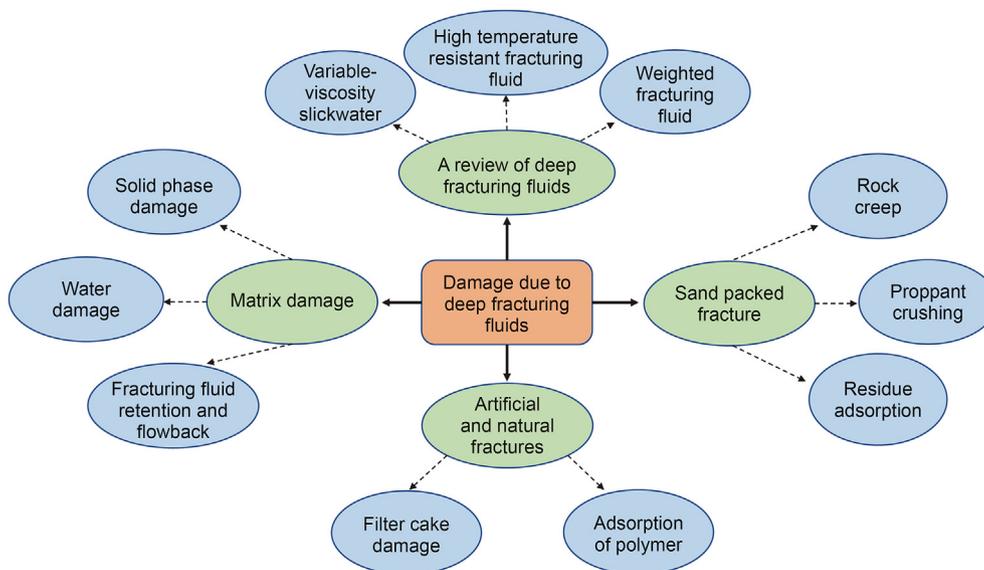


Fig. 2. Technical roadmap for this article.

damage. Instead, it records the change in downstream pressure over time as the fluid flows through the core in order to figure out its permeability and degree of damage. This method solves issues such as significant experimental errors and protracted flow monitoring times associated with low core permeability.

During hydraulic fracturing, various forms of reservoir damage predominate, including water sensitivity, water blocking, and fracturing fluid retention (Almubarak et al., 2020). The ultra-deep reservoir's "three-high" environment—marked by high temperature, high pressure, and high salinity—aggravates the severity of these damages. High temperatures accelerate the decomposition of fracture fluid (Xiong B. et al., 2018), while elevated pressure escalates proppant fracture rates (Bandara et al., 2021). Furthermore, hydraulic fracturing in ultra-deep reservoirs can induce specific forms of damage. For instance, high temperatures can trigger the growth of minute cracks within the rock, reducing the rock permeability and influencing the overall fracturing process (Peng et al., 2019). Additionally, rock experiences plastic deformation and creep reactions due to the high-pressure environment (Zhao et al., 2017). High-temperature reactions between the reservoir rock or proppants and subsurface fluids result in the formation of new minerals, sediment, or expansion products. These substances can fill the pores and fractures of the reservoir, altering permeability and fluid behavior (Tang et al., 2018). Due to the high geothermal and fluid pressure on the rocks or proppants in the reservoir, connecting caves or cracks becomes a straightforward process through liquid injection into the rock. Water breakthroughs may occur as a result of this phenomenon, potentially reducing the flow conductivity of the reservoir and impacting output. The mechanism through which fracturing fluid causes damage to different materials can vary. For example, deep shale typically possesses closed pores, microcracks, and a high clay content. Conventional fracturing fluid can result in water phase trapping and clay expansion, leading to the blockage of pore throats and low flowback efficiency, thereby diminishing the fracturing effect (Xu C. et al., 2016; Wanniarachchi et al., 2017). To minimize reservoir damage and optimize the effectiveness of fracturing fluids, it is essential to utilize clean fracturing fluids that exhibit low damage potential and high fluidity (Lu et al., 2015). The seepage of fracturing fluid into rock during the deep sandstone fracturing process leads to severe matrix damage due to the high salinity and high

ground stress characteristics (Zhu et al., 2017). Using weighted fracturing fluid is essential to ensure smooth flow and minimize osmotic pressure. The distribution of micro-fractures in deep carbonate rock is intricate, making it easy for fracturing fluid to extensively penetrate the fractures. This, in turn, hampers the flow of oil and gas, as well as weakens the reservoir (Li et al., 2009; Deng et al., 2019). Fracturing fluids with high solubility and water-based chemical reaction capacity are required to maximize the permeability of fracturing fluids into the rock. Deep granite reservoirs are typically more fragile. Micro-fractures arise from the combination of uneven particle expansion and thermal stress caused by a temperature gradient when cold fluid comes into contact with hot rock. Although this is beneficial for oil and gas seepage, it results in a significant loss of fracturing fluid (Zhang W. et al., 2019).

In recent years, our comprehension of the temperature and stress field characteristics within deep reservoirs has significantly advanced. While there exists a foundational understanding of hydraulic fracturing damage in conventional reservoirs, the intricate damage mechanisms in deep reservoirs subjected to high temperatures, high pressures, and high salinities remain enigmatic. This article focuses on fracturing fluid damage in deep reservoir development in the "three-high" environment (i.e., high temperature, high pressure, and high salinity), including rock matrix damage, artificial and natural fracture damage, and sand-packed fracture damage. Additionally, we delve into other pivotal frontier issues, such as fracturing fluid retention and flowback, high-temperature rock creep, and proppant diagenetic reactions. We provide a comprehensive overview of fracturing fluid characteristics specific to deep reservoirs, elucidate the diverse forms of damage incurred during hydraulic fracturing in high-temperature deep reservoirs, and scrutinize the underlying mechanisms. Furthermore, we outline corresponding solutions and chart the future research directions in this field. These insights hold significant guiding importance for advancing the efficient development of deep oil and gas reservoirs and effectively mitigating reservoir damage.

2. Water-based fracturing fluids in deep reservoirs

Hydraulic fracturing is a crucial technology for increasing hydrocarbon reservoir production. Within this technique, fracturing fluid emerges as a critical component. Deep reservoirs,

characterized by substantial burial depths and high temperature, demand hydraulic fracturing to improve conductivity and achieve high production (Yang et al., 2017; Li W. et al., 2020). However, the development of deep fracturing is accompanied by the “three-high” challenges posed by high temperature, high pressure, and high salinity. In addition to the ability to create fractures and transport proppant, fracturing fluids in this context must exhibit comprehensive properties, embodying the concept of “one dose with multiple effects and minimal damage.” Current issues with deep hydraulic fracturing fluid include the following: (1) Stability of fracturing fluid: Deep and ultra-deep reservoirs often experience high-temperature conditions. Fracturing fluids must exhibit robust stability, remaining intact under the duress of elevated temperatures and pressures. Ensuring that no excessive residue remains to harm the reservoir post-gel breaking is equally vital. (2) Chemical composition of fracturing fluids: Deep and ultra-deep hydraulic fracturing necessitates the use of fracturing fluids that can withstand high-pressure, high-temperature, high-salinity environment. These fluids can cause damage to the reservoir. (3) Performance of fracturing fluids: Deep and ultra-deep hydraulic fracturing requires the use of high-performance fracturing fluids, such as high-viscosity and high-strength fluids, to better transmit energy through rock fractures and accelerate the release of oil and gas. Therefore, strict control over the viscosity, density, and fluidity of fracturing fluids is imperative to minimize their impact on the reservoir during fracturing, retention, and flowback processes.

In view of these three points, we enumerate three types of fracturing fluids for deep reservoirs: high-temperature-resistant fracturing fluid, weighted fracturing fluid, and nanometer-viscosity-variable slickwater fracturing fluid. The description of various types of fracturing fluids facilitates the description and analysis of reservoir damage and corresponding solutions in later sections of this paper. The details can be found in Table 1.

2.1. High-temperature-resistant fracturing fluid

As drilling technology advances, the temperature of the reservoir also rises proportionally with the depth of drilling. When dealing with extremely high temperatures in deep and ultra-deep reservoirs, although it is possible to bring the fracturing fluid to a relatively lower temperature range, there are various limitations and detrimental effects imposed on the reservoir. Thus, the development of fracturing fluid technology that can bear higher reservoir temperatures has become a top priority.

Maintaining the sufficient sand-carrying capacity of high-temperature-resistant fracturing fluid in deep reservoirs has emerged as a challenge in current research. Fracturing fluid is a complicated system made up of additives, including thickening agents and cross-linking agents (Xu et al., 2022). Thickeners, typically high-molecular-weight water-soluble polymers, enhance both the viscosity and energy transfer effectiveness of fracturing fluids. Thickening agents are the most crucial area of research in a fracturing fluid. Generally, the nomenclature of a water-based fracturing fluid is based on the type of thickening agent employed. Currently, three types of fracturing fluids are commonly used in hydraulic fracturing: water-based fracturing fluid from natural plant gums, cellulose-based fracturing fluid, and synthetic polymer-based fracturing fluid (Barati and Liang, 2014). Natural plant gum and its derivatives offer significant advantages due to their powerful thickening capabilities and ease cross-linking ability, resulting in the formation of gels with ease. Guar gum and its derivatives currently reign as the predominant thickeners employed in fracturing operations, commanding approximately 90% of the total fraction of fracturing fluid thickeners. Within the realm of plant gum thickeners, guar gum and its derivatives stand unrivaled

as the most sought-after options in the industry (Xiong J. et al., 2018). In view of the acetal bond (glucoside bond) serving as the primary linkage connecting the main chain of natural polymers, it becomes evident that the susceptibility of said bond to rapid hydrolysis or thermal degradation at elevated temperatures necessitates a temperature tolerance limit of approximately 177 °C (Yang Z. et al., 2018). Under higher-temperature reservoirs, the sand carrying capacity experiences a notable decrease, consequently leading to a decline in fluid performance. In order to achieve enhanced resistance to higher temperature, the utilization of higher polymer loads becomes necessary for high-temperature conditions. However, this typically results in more residue and greater reservoir damage. Cellulose, a polysaccharide, exhibits a non-ionic nature. The hydrogen bond between numerous carboxyl groups along the macromolecular chain of the cellulose fracturing fluid imparts the fluid with robust thickening properties, a substantial sand-carrying capacity, minimal filtration loss, and negligible residue. However, due to its molecular structure, the hydration layer is susceptible to destruction with rising temperatures. This leads to the curling of the molecular chain and a substantial reduction in viscosity. Consequently, it is generally deemed unsuitable for high-temperature reservoirs (Liu K. et al., 2021). When encountering a high-temperature and deep reservoir, conventional polymer fracturing fluids can also cause reservoir damage due to breakage of molecular chains. However, unlike the previous two water-based fracturing fluids, these fluid thickeners are synthetic polymers. To meet the temperature and viscosity requirements of the fracturing fluid, measures are taken to minimize residue content after gel breaking and mitigate reservoir damage during hydraulic fracturing. In the context of deep reservoirs, conventional fracturing fluids confront inherent challenges. In the realm of deep fracturing, water-based fracturing fluids can be distinctively classified into three primary categories: modified guar gum fracturing fluid, synthetic polymer fracturing fluid, and viscoelastic surfactant fracturing fluid (VES). This will be reviewed in three sections.

2.1.1. Modified guar gum fracturing fluid

The modification of guar gum fracturing fluid primarily targets enhancing its temperature resistance by modifying the rigid groups along the grafted guar gum molecular chain. For example, Guo et al. (2011) employed a formulation comprising 0.55% ultra-high temperature modified guar gum, 1% temperature stabilizer (BA1-26), 0.5% discharge aiding agent (BA1-5), 0.5% clay stabilizer (BA1-13), 0.02% fungicide (BA2-3), 2% KCl, 0.6% crosslinker. The final gel-breaking solution has a residue concentration of 587 mg/L and a residue rate of 10.6%. The temperature tolerance limit is 180–200 °C. Nevertheless, owing to the inherent limitations of high molecular structure of guar gum, this method offers only a modest improvement in the temperature resistance of the fracturing liquid system. The reduction in insoluble residue content remains limited, thereby failing to significantly mitigate reservoir damage. In contrast, low-concentration guar gum systems, as exemplified by Li et al. (2019b), can effectively reduce residue content. They used 0.25%–0.30% hydroxypropyl melon gum for breaking, resulting in a glue residue content of less than 200 mg/L and a temperature tolerance limit of 120 °C. This approach simplifies flowback processes and minimizes reservoir damage while reducing guar gum usage by 44% compared to standard hydroxypropyl guar gum. However, due to the low concentration of guar gum, the quantity of cross-linking agent must be increased. The temperature resistance of standard borate cross-linking agent is insufficient, necessitating the use of a metal cross-linking agent. It's worth noting that heavy metal cross-linkers can cause serious reservoir damage and tend to be relatively expensive. To address these challenges, researchers have proposed modifying conventional polymer guar gum

Table 1
Common deep fracturing fluids: types, current problems, and improvement.

Fracturing fluid type	Performance	Application	Main type	Problem	Improvement direction	References
High-temperature-resistant fracturing fluid (Du et al., 2022)	The fracturing fluid can still maintain sufficient sand-carrying capacity in deep and ultra-high temperature reservoirs.	Deep and ultra-high temperature reservoir	Modified guar gum fracturing fluid	The temperature increase will result in the destruction of the hydration layer and the curling of the molecular chain. The level of insoluble residue rose.	Molecular chains are grafted to rigid radicals. Low concentration + well-matched crosslinker	Guo et al. (2011) Liu et al. (2015); Li et al. (2019a) Wang S.B. et al. (2014); Wang J. et al. (2017) Prakash et al. (2015); Li et al. (2018) Zhao et al. (2018b) Ozden et al. (2017) Sun et al. (2021); Zhou et al. (2021)
			Synthetic polymer fracturing fluid	Heat breaks the molecular chain of polymer. When the temperature is high, the quantity of polymer used and the amount of residue increase.	The multicomponent copolymer is formed by adding monomer to long chain.	
			Viscoelastic surfactant fracturing fluid (VES)	Poor temperature-resistance	Modified to synthesize new surfactant Nanoparticle temperature stabilizers are applied.	
Weighted fracturing fluid (Mao et al., 2022)	Increase the hydrostatic pressure of fracturing fluid in the wellbore, reduce wellbore friction resistance, and reduce the wellhead pressure.	Deep reservoir with high wellhead pressure	Weighted guar gum fracturing fluid Weighted polymer fracturing fluid Weighted slickwater fracturing fluid	The weighted fracturing fluid is characterized by high friction, strong corrosion, and easy to damage the reservoir.	The compatibility of the weighting agent and the thickening agent was studied to reduce reservoir damage.	
Viscosity-variable slickwater (Almeida et al., 2020)	It has the high resistance reduction performance of conventional smooth water and the good sand carrying capacity of high viscosity slickwater, nano oil flooding, and online mixing.	Deep and tight reservoir	Conventional variable viscosity slickwater	Poor temperature-resistance	Introducing salt-tolerant groups	Xiong et al. (2019) Liu P. et al. (2022) Liu H. et al. (2022)
			Nanometer viscosity-variable slickwater fracturing fluid	Poor capability to alter the viscosity	Add hydrophobic association monomer	
				Expensive	Proportional optimization	

fracturing fluids into small-molecule guar gum systems. This approach aims to reduce residue damage while maintaining temperature resistance. Wang J. et al. (2017) developed a small-molecule micro-damage guar gum fracturing liquid system using three key techniques: a low-dose guar gum multi-core crosslinking agent, a multifunctional anti-sludging agent, and a selective polymer fracture catalyst. This system has been successfully deployed in more than twenty fracturing operations in the Yanchang Oilfield, showcasing excellent temperature and shear resistance. It yields a gel-breaking residue of 72 mg/L and maintains a core damage rate of less than 10%, with temperature tolerance limit of 140 °C. Furthermore, Wang S.B. et al. (2014) obtained small molecular guar gum to meet the requirements of oilfield fracturing transformation via enzymatic degradation. As a result, the residue content of guar gum fracturing fluid decreased to 96 mg/L, with a temperature tolerance limit of 140 °C, representing a quarter of the typical residue amount.

2.1.2. Synthetic polymer fracturing fluid

Recent research efforts have pivoted towards addressing the limitations of guar gum fracturing fluid by focusing on the development of synthetic polymer fracturing fluids with superior

attributes. These attributes include ultra-high temperature resistance, suitability for low concentrations, robust thickening capabilities, excellent gel-breaking performance, remarkable temperature resistance, and minimal residue. Among synthetic polymer thickeners, the primary distinguishing factor is the monomer type, with polyacrylamide being the predominant choice. Li et al. (2018) synthesized a novel high-temperature-resistant zwitterionic polymer fracturing fluid using acrylic acid, acrylamide, and cationic monomers as raw materials. They successfully produced a cost-effective zwitterionic copolymer fracturing fluid thickening agent, denoted as PADA, which incorporates carboxyl groups. This was complemented with a specially formulated functional organotitanium crosslinking agent, TRGWY, at a ratio of 0.6% PADA + 1.5% TRGWY. The resulting fracturing fluid exhibited a residue content of 78 mg/L, with a temperature tolerance limit of 200 °C. This indicates that the fracturing fluid has a low residue content and has little potential for damage to the reservoir. Prakash et al. (2015) synthesized an acrylamide and acrylate terpolymer thickener. This synthetic crosslinked gel contained 15 mL/L of synthetic polymer and 0.2 mL/L of a delayed oxidation breaker. The temperature tolerance limit is 190–226 °C. During a 3-h shut-in period, 86% of the permeability was recovered,

and extending the shut-in period to 24 h resulting in 91% permeability recovery. These results indicate that fluid intrusion into rock causes minimal damage. Three acrylamide monomers were solution-polymerized to produce the FA-92 polymer. Using 0.6% FA-92 + 0.6% crosslinker + 0.2% drainage aid, the temperature tolerance limit is 200 °C, and the measurement of residue after gel breaking is only 41 mg/L (He, 2013).

2.1.3. Viscoelastic surfactant fracturing fluid (VES)

In 1997, Schlumberger invented clean fracturing fluids, also known as viscoelastic surfactant fracturing fluids, or VES. In contrast to polymer-based fracturing fluids, clean fracturing fluids do not contain polymers. Instead, they rely on surfactants as thickening agents, a formulation that does not harm the reservoir. The molecule of clean fracturing fluid possesses unique chemical properties, with a molecular weight merely 1/5000th that of conventional guar gum. Clean fracturing fluid, unlike conventional fracturing fluids, does not require a cross-linking agent. Due to the mutual repulsion between micelles, the micelles are spherical and the fluid has a very low viscosity. However, the viscosity can be increased by adding cations. Importantly, when washed by reservoir water or in contact with oil or gas, the wormlike micelles break down into smaller spherical micelles, significantly reducing fluid viscosity. This results in a fluid with a low viscosity that can be readily returned to the surface without the need of a gel breaker. However, conventional VES-clean fracturing fluids are suitable for operations at temperatures below 120 °C, rendering them inadequate for deep, high-temperature wells. However, scholars have demonstrated that by modifying the thickening agent and adding additives such as nanoparticles, the temperature resistance of these fluids can be substantially enhanced. For instance, Zhao et al. (2018b) devised a novel cationic trimer surfactant (VES-T) designed to enhance the temperature resistance of current clean fracturing fluids. VES-T, composed of three single chains and a spacer group, exhibited outstanding thermal stability, viscoelasticity, and proppant suspension at ultra-high temperatures ranging from 140 to 180 °C. Various concentrations (3–5 wt%) of VES-T fluids displayed remarkable rheological properties. Moreover, Ozden et al. (2017) added nanomaterials to the clean fracturing fluid to maintain the fluid viscosity at 110 Pa s for more than 2 h at 176 °C and a shear rate of 100 s⁻¹. This innovation effectively enhance the fluid's temperature resistance.

2.2. Weighted fracturing fluid

Deep and ultra-deep reservoirs are characterized by high pressure and salinity, leading to challenges such as excessive wellhead pressure and significant fracturing fluid seepage into the rock matrix. To mitigate these issues, weighted fracturing fluid is employed as the most effective method (Zhou et al., 2021). By elevating the density of the fracturing fluid, the osmotic pressure on both sides is reduced, thus preventing an excessive amount of fracturing fluid from permeating the reservoir and causing damage (Wu et al., 2011). Due to the inclusion of weighting agents in the fracturing fluid, weighted fracturing fluid is typically resistant to high temperatures. While commonly used aggravating agents like bromide salt and calcium salt substantially augment fluid density, their effectiveness comes at a considerable price. Conversely, economical weighting agents like potassium chloride exhibit limited efficacy in increasing density. The current weighted fracturing fluid systems mainly include the borate crosslinking system, carboxymethyl hydroxypropyl guar gum zirconium cross-linking system (Bose et al., 2014), viscoelastic surfactant system (Zhou et al., 2005), and guar gum organic boron cross-linking system. The weighted agent is mainly salt, the fluid density can reach up to

1.7 g/cm³ (Zhou et al., 2005), and the maximum temperature can reach up to 180 °C (Bartko et al., 2009). However, aggravating materials have some particularities compared with application conditions. However, compared to conventional fracturing fluids, weighted fracturing fluids have more technical difficulties. (1) Salinity impacts the dissolution (Beall et al., 2004) and cross-linking (Huang et al., 2005) of thickening agents, affecting fluid stability. (2) Breaking the gel in weighted fracturing fluid is more challenging and may result in residue (Bagal et al., 2006), causing potential damage to the reservoir and propped fractures. (3) Increased fluid density raises pipe string friction, which can jeopardize safe fracturing operations (Ke et al., 2006; Liu et al., 2020). Currently, a series of weighted fracturing fluids with high efficiency have been devised to address the issues. Such as high-temperature and low-friction cross-linked boron-weighted fracturing fluid (Sun et al., 2021). By employing modified organoboron crosslinking and potassium formate as the weighting agent, the difficulty of gel breaking caused by the weighting agent has been effectively reduced, while simultaneously boosting temperature resistance and reduction in resistance rate. With 55% potassium-formate weighted brine + 0.5% guar gum thickener HPG + 6 g/L cross-linker TOB-170, the resistance-reducing rate reached 68.44% and the residue concentration was 383.2 mg/L. Industrial calcium chloride weighted guar gum fracturing fluid (Zhou et al., 2021). CaCl₂ is used as a weighting agent to prevent formates from causing damage to the reservoir. The residue concentration after gel breaking is 275 mg/L using 35.00% CaCl₂ + 0.45% HPG. Low friction high-temperature resistant polymer-weighted fracturing fluid (Zhao, 2020). Even with the use of sodium nitrate as a weighting agent and a minimal concentration of polymer thickener, adequate sand-carrying capacity can be maintained. Using 41% NaNO₃ + 0.6% polymer thickener reduces drag by 55.34%. Weighted slippery water system (Wang L. et al., 2020). Combined with the benefits of the slickwater and the weighted fracturing fluid, it can not only assure small reservoir damage but also reduce drag effectively. Using 46% CaCl₂ + 0.15% resistance-reducing agent + 0.5% discharge aiding agent, the resistance-reducing rate is 62%, and the core damage rate is 11.2%.

2.3. Viscosity-variable slickwater

Traditional guar gum fracturing fluid, conventional slickwater, and high-viscosity slickwater each have distinct advantages and disadvantages. Traditional fracturing fluids offer high viscosity, strong prop-carrying capacity, low filtration, and excellent compatibility but suffer from poor stability and challenging friction control (Aften, 2018; Poppel, 2020). Polymer residues will cause serious damage to the reservoir. Unlike conventional slickwater, which mainly reduces friction, it is easily extends into fracture networks during fracturing. Hence, slickwater offers several advantages including minimal reservoir damage, rapid flowback rate, and cost-effective construction (Govier et al., 1973). Nonetheless, the inclusion of additives like active water and resistance-reducing agents reduces the proppant-carrying capability of these fracturing fluids. This can result in untimely proppant setting and sand plugging during fracturing. Even though it can increase pumping efficiency, it is simple to increase pipe string friction. Reservoir protection techniques should be completely considered during completion and fracturing treatment (Hu et al., 2018, 2019). High-viscosity slickwater has good prop-carrying capacity and drag-reduction effects but is often available as hard-to-handle powdered form. The powdered products are difficult to dissolve and cumbersome to combine on-site. At times, the polymer viscosity becomes excessively high and its structure becomes exceptionally stable, posing considerable harm to the reservoir (Brannon

and Bell, 2011).

In response to these limitations, some researchers have proposed a novel multifunctional variable viscosity slickwater. This innovation overcomes the limited prop-carrying capacity of conventional fracturing fluids while enhancing production stability and efficiency (Yao et al., 2021). The multifunctional variable viscosity slickwater combines the drag-reduction performance of conventional slickwater with the superior prop-carrying capacity of high-viscosity slickwater, facilitating the creation of extensive propped fracture networks and increased production. This slickwater, being in liquid form, is easy to dissolve and suitable for on-site mixing, simplifying construction processes, achieving fast-breaking gel, and minimizing residue content (Gupta et al., 2012; Almubarak et al., 2019).

Research in the field of multifunctional variable viscosity slickwater is relatively limited. Wang et al. (2019) developed a functional slickwater system comprised of drag-reduction and crosslinking agents. The low concentration drag-reducing agent solution can be swiftly thickened within 15 s, achieving a remarkable 74% drag reduction rate, rapid viscosity increase upon regulator addition, and high prop-carrying capacity. Wang W. et al. (2014) devised the HL-C3 slickwater formulation system based on the drag-reduction effects of surfactants. This approach eliminates reservoir damage like water blocking and water sensitivity during fracturing, alters rock wettability, replaces oil in micro-fractures or pores, and enhances oil production.

2.4. Future progresses

This section summarizes the current research status on deep fracturing fluids. At present, fracturing fluid damage is primarily associated with high reservoir temperatures and the high salinity of reservoir water, resulting in elevated osmotic pressure both inside and outside the rock matrix, coupled with damage from fracturing fluid intrusion into the matrix. Considering reservoir damage and temperature resistance, the following insights emerge.

- (1) Despite their high insoluble content and poor temperature resistance, natural polymer fracturing fluids remain widely used. Guar gum, as a natural macromolecular polymer, has the potential to generate detrimental residue when it breaks down within the reservoir. However, employing a low-concentration guar gum-based fracturing fluid or modifying it into smaller molecules offers a viable approach to significantly mitigate the formation of residue. This strategy aims to minimize reservoir damage while maintaining the essential temperature resistance of the guar gum-based fracturing fluid.
- (2) Synthetic polymer fracturing fluids exhibit superior temperature resistance and viscoelasticity, leave less residue after gel breaking, and cause less damage to the reservoir. Therefore, synthetic polymer fracturing fluid is the focus point for addressing fracturing challenges of deep, high-temperature reservoirs. Future research will concentrate on developing ultra-high temperature synthetic polymer fracturing liquid systems, assessing their temperature resistance and shear rheological resistance, modifying polymers to reduce its residue content after gel breaking, and elucidating the molecular structure-activity relationship of the high temperature fracturing liquid systems.
- (3) VES-clean fracturing fluid, with no residue and easy flowback characteristics, has a unique advantage in preventing reservoir damage during hydraulic fracturing and can offer a new method for the development of deep reservoir fracturing fluid. However, it is costly and lacks temperature resistance.

Future modifications must be made to the surfactant, optimizing the type and content of agents in the fracturing fluid to improve its temperature resistance.

- (4) Weighted fracturing fluid, which increases fluid density and viscosity, effectively solve the challenges posed by deep reservoirs, including high wellhead construction pressure and significant water seepage into the rock matrix due to high pressure and high salinity. However, the weighting agent will influence the dissolution and cross-linking of the thickener, resulting in an increase in residue after the gel breaks and the reservoir damage. By studying the compatibility between thickeners and adding a high-temperature stabilizers or corrosion inhibitors, it is possible to reduce reservoir damage without losing performance.
- (5) The variable-viscosity slickwater system represents an innovative water-based fracturing fluid. This system achieves controllable high-temperature and high-pressure rheological properties through the addition of temperature-resistant surfactants and viscosity modifiers to water. With its high permeability and low propensity for causing damage, this water-based fluid is capable of effectively executing hydraulic fracturing operations in deep reservoirs, consequently improving the efficiency of oil and gas exploration and development. Further research can delve into its viscosity-altering characteristics in high-temperature and high-salinity conditions.

3. Damage to the rock matrix

Polymer adsorption, filtrate infiltration, and backflow within the fracturing fluid can harm the reservoir matrix during hydraulic fracturing. However, the current research primarily concentrates on damage to reservoir fractures caused by fracturing fluid, disregarding matrix damage. Therefore, it is essential to assess these damages and adopt effective solutions. Section 3 provides an overview of the effects of hydraulic fracturing on rock matrix, focusing on three key aspects: solid phase damage, water damage, and fracturing fluid retention and flowback. It delves into the damage mechanisms, proposed remedies, and outlines future research directions.

3.1. Solid phase damage

3.1.1. Polymer retention and adsorption

Undissolved macromolecules in the fracturing fluid (e.g., guar gum in the traditional fracturing fluid (Liu J. et al., 2021), or anionic

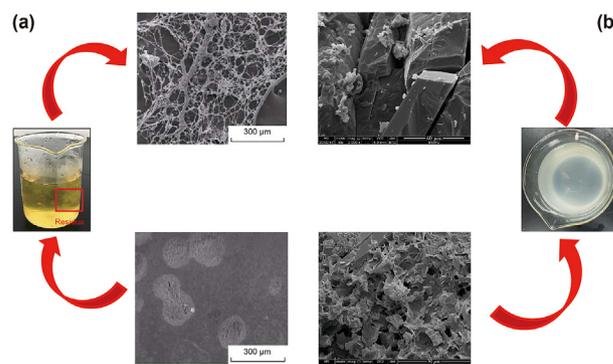


Fig. 3. Macromolecular material and its adsorption in the fracturing fluid. (a) Damage from guar gum in the fracturing fluid; (b) Damage from slickwater fracturing fluid (Guo J. et al., 2018; Liu J. et al., 2021).

polyacrylamide (APAM) in the slickwater fracturing fluid (Guo and He, 2012), as shown in Fig. 3), contribute to solid phase damage. The adsorption and retention in the pore throat of the reservoir block the seepage channel and cause a decrease in rock permeability (Sun et al., 2017; Zhang et al., 2022). Fig. 3(a) reveals that the original polymer solution characterized by a good three-dimensional network structure with a regular linear arrangement of molecular chains. This structure closely resembles that of anionic polyacrylamide, which is commonly used as a friction-reducing agent in slickwater. In contrast, the morphology of residual polymer solutions exhibit evident structural alterations. The three-dimensional polymer network becomes disrupted, causing molecular clustering and coiling. These aggregated polymer molecules reach the nanoscale molecules and block the pore throat radius, ultimately resulting in permeability damage. As shown in Fig. 3(b), the polymer is flocculent, intertwined with clay particles, adsorbed on both the rock and clay particle surfaces, obstructing the pore throat. This is primarily due to the incomplete degradation of melon gum solution and retention on the surface of rock particles, which causes adsorption plugging. Water-based fracturing fluids induce solid phase damage in two ways. First, when the diameter of solid residue exceeds the pore throat size of the rock, it physically obstructs the seepage channel. Second, when the diameter of solid residue is smaller, and the fluid passes through irregular throat, a portion of the solid is adsorbed, resulting in obstruction and reduced permeability (Cao et al., 2016b; Guo T. et al., 2018).

Both polymer-based and slickwater fracturing fluids have excellent suspension and elastic properties but may also cause solid-phase damage. Even though filtration experiments, a significant amount of residue remains. The higher the fracturing fluid residue content, the more serious the damage inflicted upon the reservoir (Lei et al., 2018). As shown in Fig. 4, the microstructural scanning electron microscope (SEM) observation reveals that the high-viscosity fracturing fluid enters pores, micro-fractures, and rock matrix instantly under high pressure and that the fracturing fluid residue exhibits flocculation and aggregation. When the fracturing fluid enters the matrix, the majority of the fracturing fluid residue and polymer block the pores and fractures at the inlet, and the residue is rich in an integrated film shape, resulting in a substantial decrease in matrix permeability. The matrix pores shear and filter the polymer present in the fracturing fluid. As the fracturing fluid penetrates deeper, the polymer molecules reduce in size, and the obstruction of matrix porosity decreases (see Fig. 4). The initial permeability has an impact on the penetration depth of solid particles, including residues and reservoir particles. Lower permeability results in smaller pore throats, intensifying the shear effect on the polymer and limiting the depth of solid particle penetration.

Retention and adsorption of polymers in the fracturing fluid are primarily due to macromolecular insoluble substances. The residue of fracturing fluid and residual gel will be mechanically captured in

the reservoir, intertwining and increasing in size, ultimately remaining in the reservoir to obstruct seepage channels and support pore throats within the fracture post-gel breaking. The retention and adsorption of polymers are attributed to van der Waals forces (VDW), electrostatic forces, and hydrogen bond forces. Incompletely hemolyzed guar gum or macromolecular polymers adhere to rock particle surfaces, resulting in adsorption plugging. The polymer adsorption and retention damage decrease progressively from the inlet to the outlet.

3.1.2. Particle migration

During the hydraulic fracturing process, particle migration and subsequent blocking can cause reservoir damage, particularly in reservoirs with rich clay minerals. As the fracturing fluid enters the core, the significant pressure differential between the matrix and fractures, coupled with high flow rates, inevitably leads to particle migration and blockage. The primary particle source in clay minerals is illite, which is easy to move and causes blockage (Yuan et al., 2018). The fracturing fluid blocks the remaining micropores post illite migration. The surface of matrix minerals is spotless (indicated by green arrows) before fracturing, as seen in Fig. 5(a). However, as a result of the breaking of tiny illite crystals during fracturing, the crystal faces near the borders of the mineral are now coated in short columns of distributed clay (indicated by red arrows). Because illite crystals disperse and migrate as a result of external forces, the microstructure of clay minerals changes from a dispersive and bridging shape to a thin film and dispersive shape. This is a characteristic of velocity sensitivity. In Fig. 5(b), external force disrupts the microstructure of hairy and bridging illite crystals, breaking the hairy crystals into short columns and crystal fragments. These fragments accumulate haphazardly between particles and on the surface, leading to the blockage of some intercrystalline pores (Han et al., 1999) (see Fig. 6).

Significant changes in flow rate and pressure, or flow rates reaching specific thresholds, can cause hydraulic forces to exceed the cumulative effect of van der Waals attraction and double electric layer repulsion between particles. This results in the migration of interstitial materials such as illite, along with particles like feldspar and quartz, which can lead to reservoir damage. In addition, the narrow throat and poor connectivity exacerbate velocity-sensitive damage, causing migrating particles to block deep reservoirs. This blockage hinders fracturing fluid from reaching deep reservoirs, thereby damaging the reservoir matrix and micro-fractures.

3.1.3. Salting-out crystallization blockage

During the development of deep reservoirs, the fracturing fluid and reservoir water undergo rapid pressure changes near the wellbore. As a consequence, when the salt concentration in the fluid reaches its solubility limit, the crystallized salt precipitates in the reservoir, resulting in reducing reservoir porosity and

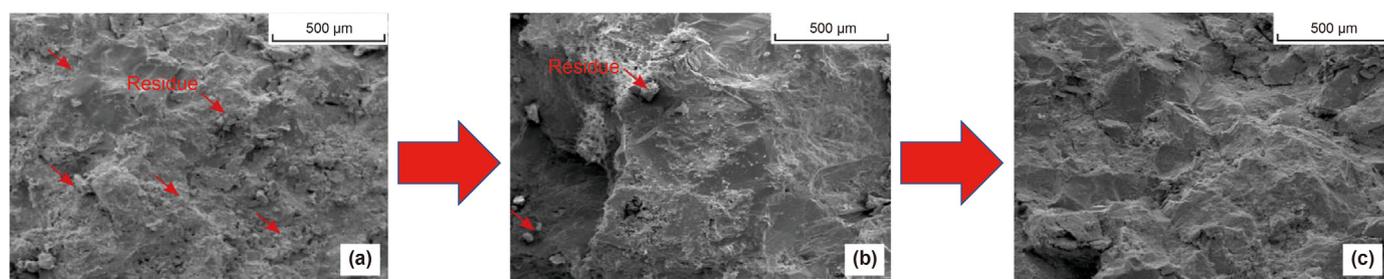


Fig. 4. SEM images of frac-fluid plugging types at different depths in matrix cores. (a) Injection end; (b) Middle part; (c) Exit end (Tang et al., 2021).

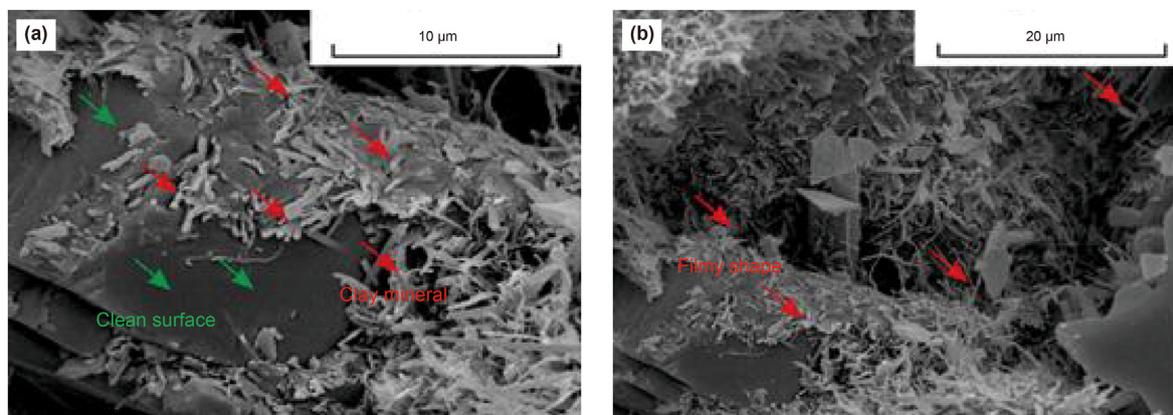


Fig. 5. SEM images of core matrix particle migration and blocking properties. (a) Clay covering; (b) Crystal broken (Tang et al., 2021).

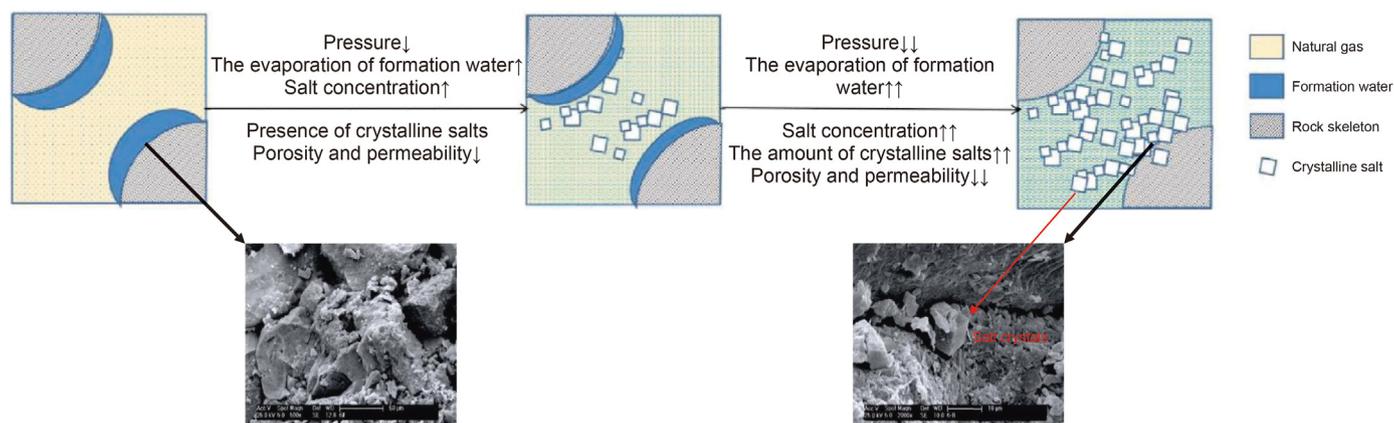


Fig. 6. Schematic diagram of salting out and SEM image (Jiang et al., 2022).

permeability. As the pore pressure further diminishes, intensified fluid evaporation leads to the release of more crystalline salt. The irregular accumulation of crystalline salt in the original reservoir channels narrows the flow channels and reduces overall porosity and permeability of the reservoir (Guo and He, 2012; Cao et al., 2016a; You et al., 2018). Compared to high-permeability reservoirs with large pore passages, deep reservoirs experience a sharper decrease in permeability due to their smaller pore throats, which are predominantly composed of small pores, or micropores. The influence of high temperatures on salting-out process is also very serious. The higher the temperature, the more serious the evaporative salting-out becomes, further reducing porosity and permeability. Excessive temperature levels can even lead to complete blockage of the near-well area, negatively impacting reservoir production.

Therefore, the blockage caused by salt-out crystallization is primarily attributed to the unstable pressure changes within the reservoir. Salting-out crystallization results from the evaporation of subsurface fluids and fracturing fluids, resulting in pore and throat plugging. This phenomenon is intensified by high temperatures, ultimately influencing production.

Intrusion of fracturing fluid into the reservoir can induce solid-phase damage through various mechanisms, including solid residue, particle migration, polymer adsorption or retention, and salting-out crystallization. Each type of damage is assessed in this section. Some forms of damage, such as polymer retention, are temporary and recoverable over time. These impairments do not alter the fundamental structure and composition of the reservoir but temporarily affect specific properties. For instance, polymer

residues can reduce the reservoir permeability, but some methods are applied to dissolve or filter these polymers, restoring the reservoir permeability to its original level. Conversely, some damage, such as particle migration and clay swelling, are permanent and alter the fundamental structure and composition of the reservoir, leading to irreversible changes in key parameters such as porosity and permeability. Particle migration, for instance, can reduce reservoir porosity and permeability, and once these particles move, returning them to their original position is challenging. Similarly, clay expansion decreases reservoir porosity and permeability, making it difficult for clay particles to revert to their previous state. These different types of damage have a superposition effect, with mutual influences and feedback mechanisms. For instance, polymer residues can adhere to rock surfaces and obstruct pores, preventing water from passing through and causing water blockage. Simultaneously, the polymer residues absorb salt, forming salt crystallization and increasing the degree of damage. In addition, water blockage can elevate salt concentrations, fostering the formation of salt crystals. Consequently, these various forms of damage compound one another, resulting in more severe effect on the reservoir.

3.2. Water damage

3.2.1. Water-sensitive damage

The ratio of bound water to free water determines the types of water-phase damage induced by fracturing fluid (Fu et al., 2020a). In the pore space of a reservoir characterized by limited permeability, two fluid states exist: bound flow and free flow. The causes

of water-sensitive damage are the expansion and migration of clay minerals. Nearly all reservoir rocks contain clay minerals, including montmorillonite and illite, in varying proportions (Wang and Rahman, 2015; Fu et al., 2020a). These clay minerals decrease matrix permeability and hinder the flow of hydrocarbons. This is mainly attributed to the presence of clay minerals, their compatibility with injected fluids, and their stabilizing properties. These clay minerals undergo physicochemical reactions with the infiltrating fluid, leading to disruption of the equilibrium among the original ions. As a result, the clay absorbs water, causing dispersion and migration that obstruct fluid flow channels and reduce permeability. This demonstrates the presence of water-sensitive damage (Bazin et al., 2010; Ali et al., 2011).

Currently, research techniques for conventional reservoir sensitivity are becoming more refined. In contrast to conventional reservoirs, deep reservoirs exhibit heightened sensitivity due to their elevated temperature and pressure characteristics. Montmorillonite will endure a number of physical and chemical transformations when subjected to high temperatures. This will lead to a change in montmorillonite's expansion characteristics, primarily seen as a shift in its crystal spacing. The swellability of montmorillonite is directly linked to its crystal spacing. The swelling property is strong when the crystal spacing is wide, and weak when it is narrow. Zhang et al. (2018) discovered through molecular dynamics simulation that as temperature and water content increased, so did the layer spacing of montmorillonite crystals. In essence, high temperatures promoted the diffusion of water molecules into crystal layers by fracturing fluid. Ma et al. (2020) discovered that under high temperatures and pressures, the activity of the illite-montmorillonite mixed layer increased, and clay minerals were more susceptible to hydration expansion and water-sensitive damage. As depicted in Fig. 7, pores under normal temperatures and pressures are substantially larger than those under high temperatures and pressures (red arrow in Fig. 7), which are more susceptible to blocking. The arrows indicate that hydration expansion occurs at high temperatures and pressures.

The filtrate and gel-breaking fluid generated by fracturing fluid entering the reservoir contains numerous chemical components. Under reservoir conditions, some of these components will decompose into filtrate and gel-breaking liquid containing electrolytes and a certain salinity. These electrolytes wedge into the lattice of the clay mineral, resulting in a reduction of permeability. However, at high temperatures, the activity of clay minerals increases, making it easier for them to hydrate and expand, resulting in damage. This issue can be alleviated by adding clay stabilizers.

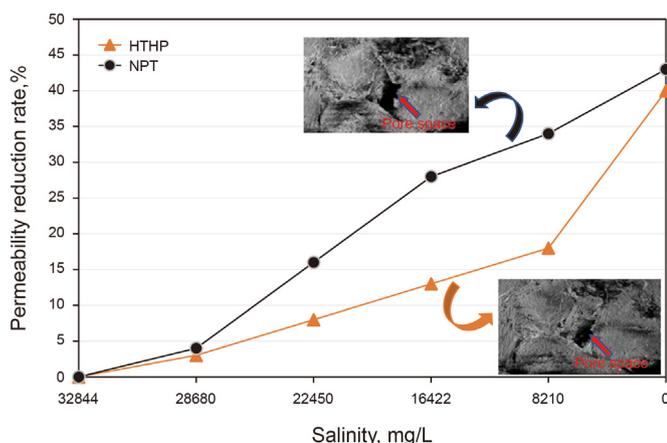


Fig. 7. Comparison of water-sensitive damage between high temperature and high pressure (HTHP) and normal temperature and pressure (NTP) (Ma et al., 2020).

3.2.2. Water-blocking damage

In addition to water-sensitive damage, water-blocking damage is a significant challenge (see Fig. 8). Deep reservoirs often feature intricate stress conditions, resulting in pore throats within the reservoir that are typically small, averaging at the micron scale. When the external fluid penetrates pores in the reservoir matrix, several factors come into play. During the flow of oil and gas, the capillary force, which is induced by the oil–water or gas–water contact surface, must be overcome. If the pore pressure is insufficient to overcome this force, the increase in the aqueous phase within the rock can cause adsorption damage to the water by the clay (Liu D. et al., 2022). Due to capillary force, the movable water phase will contribute to the resistance of the oil phase, hindering its flow (Fu et al., 2008; Jian et al., 2011). If the oil phase is unable to completely displace the increased water flow, the residual water will reduce the oil phase relative permeability and cause additional water-blocking damage (Bahrami et al., 2012; Zhang et al., 2016). In deep reservoirs, once the water-blocking effect occurs, particularly in a reservoir with low permeability, permeability damage can exceed 70%, thereby reducing production by one-third (An, 2019).

When an external fluid invades the core and causes water-blocking damage, the extent of the damage is primarily dependent on the quantity of flowing water retained. Furthermore, water-blocking damage is temporary, especially in highly permeable reservoirs, and can be swiftly reversed. However, in the case of deep and ultra-deep reservoirs, where the pore throat is narrow and permeability is low, the damage caused by water blocking cannot be swiftly eradicated (Bahrami et al., 2011). Due to the presence of small pores and cracks in the reservoir, when water infiltrates, water molecules adhere to the solid surfaces, creating a film that densifies the rock, originally abundant in pores and cracks, and consequently decreases the reservoir permeability. In high-permeability reservoirs, the impact of water-blocking is minimal due to the large size of pores and fractures in the rock. This is attributed to the relatively thin film created by water molecules, which is susceptible to breakage under surrounding pressure and flow shear forces. For deep and ultra-deep reservoirs, their micro-nano pore structure gives rise to ultra-high capillary forces, resulting in more stubborn pore and fracture plugging caused by the water blocking effect. These reservoirs also require more time to restore their reservoir permeability. The relationship between capillary pressure and water saturation in various permeability ranges is depicted in Fig. 9(a). The results indicate that the capillary pressure is higher when the reservoir permeability and water saturation are low, especially when the reservoir permeability is approximately 0.001 mD. Since capillaries absorb water, this elevated capillary pressure results in increased water phase retention. However, some researchers hold a contrary perspective. For instance, Fang et al. (2015) discovered that the phase permeability curve at high temperature and pressure exhibited a greater relative permeability in the two-phase zone (Fig. 9(b)), resulting in

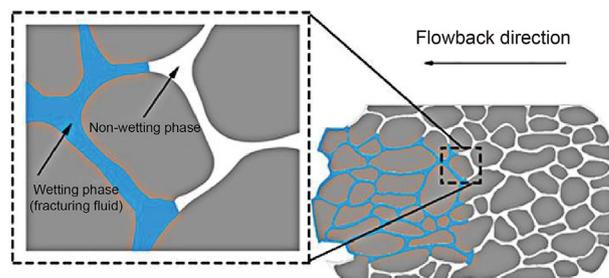


Fig. 8. Schematic diagram of water-blocking damage (Lin et al., 2021).

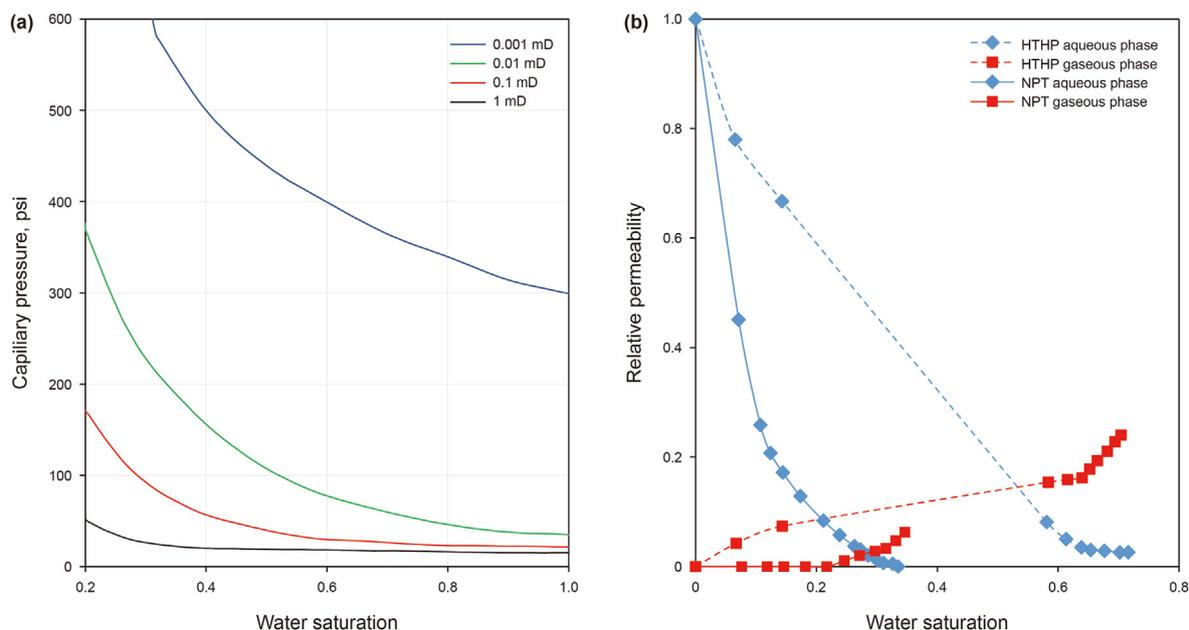


Fig. 9. (a) Relationship between capillary pressure and water phase saturation (Economides and Martin, 2007); (b) Comparison of gas–water relative permeability under the conditions of high temperature and high pressure (HTHP) and normal temperature and pressure (NPT) (Fang et al., 2015).

reduced bound water saturation. Under high temperatures and pressures, the relative permeability of the gas phase surpasses that at room temperature and pressure for the same gas saturation, indicating greater seepage capacity for gas and water phases in tight reservoirs. This suggests that the actual bound water content under reservoir conditions is lower at elevated temperatures and pressures. These high temperatures and pressures lead to reduced gas–water viscosity ratios, density ratios, and interfacial tension, while enhancing gas–water sweep efficiency (Fang et al., 2015). Consequently, the mechanism of water-blocking damage in deep reservoirs remains not fully understood and requires further investigation.

Tight reservoirs, characterized by small pore throats and poor connectivity, combined with the hydrophilicity nature of pore surfaces, experience water blocking when water saturation is very low. Fracturing fluid filtrate tends to accumulate in the narrow regions of the rock particle surfaces, along with edges and angles of the pores, while the oil and gas occupy the larger, more accessible network. This phenomenon exacerbates water blocking, making it challenging for fracturing fluid to flow back. The addition of discharge-aiding agents can reduce the reservoir damage caused by water blocking. The principal component of the drainage aid is a surfactant, which can reduce the surface tension between the oil and gas phases and the water phase, increase contact angles with rock surfaces, reduce the capillary forces within reservoir pores, and thus reduce the starting pressure necessary to overcome the water blocking during production.

3.3. Fracturing fluid retention and flowback

3.3.1. Fracturing fluid retention

Large volumes of fracturing fluid are injected into the reservoir during hydraulic fracturing to increase the fracture complexity (Sayed et al., 2017). However, poor physical properties result in low flowback rates (Cheng et al., 2018). A substantial amount of fracturing fluid remains near the rock matrix, microfractures, and hydraulic fracture walls at the end of flowback stage, resulting in substantially lower flowback rates compared to conventional

reservoirs (Singh, 2016) (Fig. 10). According to field data, approximately 10%–30% of the fluid injected during hydraulic fracturing can flow back to the surface. The majority of fluids continues to traverse through the reservoir (Makhanov et al., 2014).

Previous experimental studies have demonstrated that capillary pressure in nanopores is a crucial factor influencing oil recovery (Reinicke et al., 2012; Ghanbari and Dehghanpour, 2016; Zhang S. et al., 2019). Researchers have extensively investigated the impact of rock permeability, reservoir heterogeneity, clay minerals, fluid properties, wettability, and boundary conditions on spontaneous imbibition (SI) (Gu et al., 2017; Xu J. et al., 2019; Lin et al., 2021). As a function of pore structure, wettability, and interfacial tension, the capillary force plays a crucial role in the flowback process (Dutta et al., 2014; Xu et al., 2019a). The ultra-low permeability causes very high capillary pressure (King et al., 2015), causing fracturing fluid to penetrate deeply into the rock matrix, thereby impeding its flowback (Lin et al., 2021). Similarly, during the initial flowback phase, the fracture closure plays a crucial role in fluid retention. Some scholars believe that when the microfractures created by hydraulic fracturing are sealed, they block the connection of the fluid to the main seepage channel. Therefore, the fracturing fluid cannot flow smoothly out of the reservoir (Mahadevan et al., 2009; Song and Ehlig-Economides, 2011; Reinicke et al., 2012). Simultaneously, the retention of fracturing fluid results in a significant increase in water phase saturation, influencing early production behavior. Increased water phase saturation reduces gas productivity and reduces total gas volume (Cui et al., 2020), with an average decrease of 26.10% observed when water phase saturation reaches 0.3 (Miao et al., 2019; Li and Cai, 2023; Zhou et al., 2023).

Furthermore, the discrepancy in chemical potential between fracturing fluid and reservoir water significantly contributes to fracturing fluid flowback. In ultra-deep reservoirs, the original reservoir water exhibits an exceptionally high ion concentration (Feng et al., 2016). In contrast, the frequently employed fracturing fluids in hydraulic fracturing, known as slick water fracturing fluids, exhibit decreased ion concentrations (Teklu et al., 2018). When fracturing fluids come into contact with reservoir water, concentration disparities may arise between the two. During the backflow

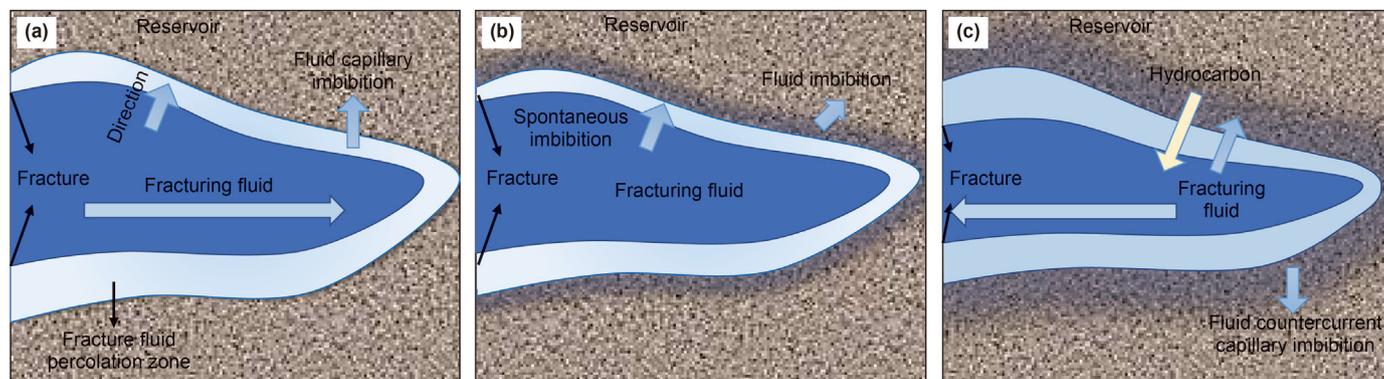


Fig. 10. Fracturing fluid retention and flowback. (a) During fracturing; (b) Closed well; (c) Fracturing fluid flowback.

process, the solute will naturally migrate from areas with high chemical potential to those with low chemical potential, aiming to achieve equilibrium. When the fracturing fluid enters the reservoir, there is a significant difference in the ion concentration of the two fluids, which becomes the driving force of fluid migration (Fakcharoenphol et al., 2014; Wang and Rahman, 2015). Nonetheless, this driving force can have a substantial effect on fluid retention, preventing fluid flowback and resulting in a very low flowback rate (Wang F. et al., 2016, 2017a; Wang J. et al., 2020; Wang L. et al., 2020).

Therefore, reservoir matrix damage caused by fracturing fluid retention is primarily due to two factors: Firstly, fracturing fluid progressively diffuses into the matrix via capillary force. Secondly, there is a significant difference in osmotic pressure between the fracturing fluid and the matrix, leading to substantial penetration of fracturing fluid filtrate into the reservoir matrix. This is influenced by the rock composition, mineral content, porosity, permeability, wettability, and liquid properties. Since the internal properties of the reservoir cannot be altered, reducing the capillary force and osmotic pressure between the fracturing fluid and the matrix are the first step in mitigating the harm caused by fracturing fluid retention.

3.3.2. Fracturing fluid flowback

Fig. 11 categorizes fracturing fluid damage during flowback into three phases: the liquid flow phase, gas–liquid flow phase, and gas flow phase. In the initial stage of flowback (liquid flow phase), the primary damage is caused by the blockage of microfractures by suspended particles in the flowback fluid and the water phase damage. As more fluids return during the middle stage of flowback, the reservoir pressure decreases, causing the desorption and diffusion of oil and gas from the pore walls of the matrix into microfractures. This continuous process reduces the water-phase permeability, and effectively reduces the water-phase damage (Du et al., 2017; Xu J. et al., 2019a; Xu Y. et al., 2019b). However, as the adhesion ability of the residual solids in the microfractures decreases, particle migration begins in the reservoir. In the third stage, oil and gas flow to the surface, and as the pressure decreases, the water within the retained fracturing fluid gradually evaporates, causing the precipitation of soluble salt crystals in the liquid phase, resulting in salt precipitation damage.

Field data show that flowback fluids are usually high in chemical substances (COD), dissolved solids (TDS), and suspended substances (Zolfaghari et al., 2016). The fraction of flowback volume is only 10%–30% of the total fluids, causing significant damage to the reservoir (Haluszczak et al., 2013). For example, increased the water-phase saturation near the fracture zone causes damage due to the water-phase trapping, making it difficult to desorb the gas

from the matrix (Kang et al., 2017). High concentrations of divalent ions, such as Ca^{2+} , Sr^{2+} , and Ba^{2+} , produce carbonate and sulfate deposits in the flowback fluid, which further affect the reservoir permeability (Nicot et al., 2014), clog the reservoir pores and fractures, and increase the flow resistance of oil and gas (Vankeuren et al., 2017). The fracturing fluid residue after gel rupture collects with other solids and blocks the fracture, resulting in permeability reduction. As a result, fracturing creates a complex network of fractures in which only a few fractures are effective (Xu et al., 2017). The overlapping of various post-fracture failures limits the efficient development of the reservoir (Zhang et al., 2015a; Wu X. et al., 2017). The behavior of gas production is closely related to the flowback of fracturing fluid. Water is the wetting phase, and gas is the non-wetting phase in this two-phase flow problem. The increase in maximum water relative permeability can raise the water flowback rate and gas production rate, but increasing non-wetting phase entry pressure will decrease the fluid flow rate.

Capillary force and viscosity of the fracturing fluid prevent a significant quantity of flowback fluid from returning to the reservoir during the flowback phase. The high concentration of insoluble matter in flowback fluid and unbroken gel will cause additional damage to the reservoir. The addition of surfactants or hydrophobic additives to remove the water film and increase fluid flowback can reduce the capillary force, thereby minimizing the damage. The gel breaker is applied to completely break the gel and reduce matrix damage resulting from incomplete breaking.

3.4. Solutions

This section summarizes the damage mechanism to the reservoir matrix caused by hydraulic fracturing in deep reservoirs, focusing on three perspectives: solid phase damage, water damage, and fracturing fluid retention and flowback. Moreover, the key problems in eliminating or reducing such damage are described in each section. Subsequently, solutions will be proposed from the aspects of optimizing the formula of the fracturing fluid and changing the type of the fracturing fluid. Specific application effects of various methods for addressing different matrix damages will be also discussed.

3.4.1. Optimization of the fracturing fluid formulation

To address the problem of polymer retention and adsorption, the key lines removing polymer residue with a strong oxidant facilitate polymer flow. Another method is to destroy the force of hydrogen bond adsorption between the polymer and rock. Strong oxidants like high concentrations of hydrogen peroxide, nitrate, and sodium peroxide are currently in use to achieve this. Desorption agents can increase the anti-adsorption rate to 70%. The

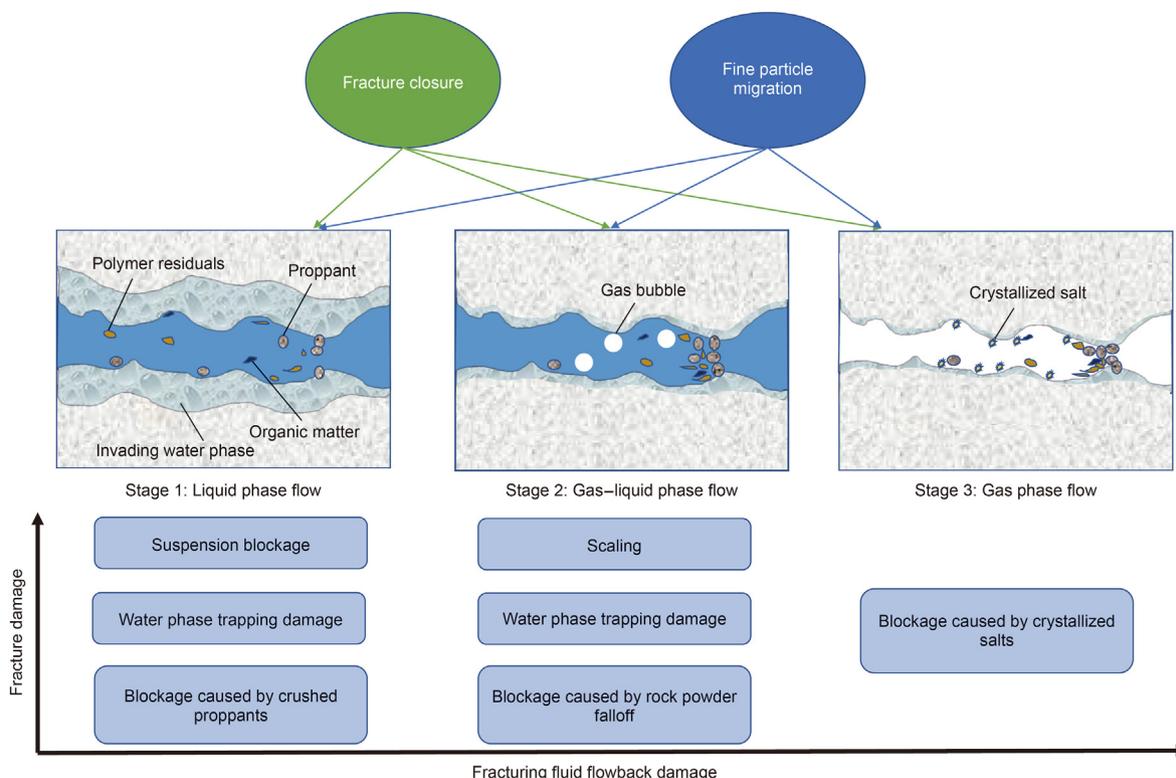


Fig. 11. Fracturing fluid flowback damage (You et al., 2019).

effective elimination of hydrogen bond adsorption between the polymer and rock can be accomplished by employing negatively charged small molecule adsorbents, reducing polymer adsorption capacity by 63.7% and achieving a permeability recovery rate of 73.3% (Fu et al., 2021).

Salt-proofing agents have proven effective in preventing salt crystallization damage during hydraulic fracturing. These agents control the activity of salt ions through adsorption and coordination, making it challenging for salt to precipitate and crystallize. Results indicate that these agents effectively prevent salt crystallization at 90 °C for 120 days, maintaining a salt inhibition rate between 85.27% and 96.73% throughout this period (Chen et al., 2023).

The optimization of clay stabilizers is key to addressing water-sensitive damage (Fu et al., 2020b). These stabilizers neutralize the charge on clay surfaces, forming a dense adsorption protective layer that reduces clay hydration expansion and inhibits particle dispersion and migration through multi-point adsorption (Li C. et al., 2020). Results have shown clay swelling inhibition rates exceeding 90%, a dissolve-loss ratio of only 0.68%, and a core damage rate of only 5.83% (Chen et al., 2023; Li et al., 2012). Clay stabilizers, a focal point of clay mineral science research, continue to evolve with novel and effective options introduced regularly (Jia et al., 2019; Xu J. et al., 2019; Xu Y. et al., 2019). Potassium chloride (KCl) is the most commonly used clay stabilizer in oilfield chemistry to prevent wellbore instability caused by rock expansion upon hydration (Horsrud et al., 1998). Currently, the main clay stabilizers include quaternary ammonium salt cationic surfactants (Tariq et al., 2021), organic amines (Fu et al., 2019), polyamines (Zhong et al., 2016), polyether amines (Vishkai and Gates, 2019), plant extracts (Murtaza et al., 2021) and polymers (Roshan et al., 2022). Furthermore, recent research has demonstrated that nanoparticles can act as clay inhibitors (Guzmán et al., 2017).

There is a correlation between capillary pressure, wettability, water blocking damage, fracture fluid retention, and flowback. Sandstone reservoirs primarily consist of negatively charged silicates. By introducing a cationic surfactant into the invading fluid, it can interact with the sandstone surface through its positive charge, forming a hydrophobic adsorption layer with the lipophilic chain facing outward. This allows the fracturing fluid, as it invades the pores, to accumulate and separate from the rock surface, consequently increasing the flowback rate (Xu et al., 2014). Based on this principle, Ren (2015) developed a surfactant system using alkyl carboxyl betaine with an interfacial tension of 0.046 mN/m. The contact angle with the rock surface increase from 55° to 83°, and the flowback rate increase from 9% to 16%. Similarly, Shan et al. (2017) developed a purification additive system using cetyl trimethyl ammonium chloride. This system reduced the interfacial tension to 0.024 mN/m and achieved a contact angle of 83.6°. In field applications, the flowback rate reached 37.7%, resulting in an increase of oil production by 0.9 tons per day. Furthermore, Xu Y. et al., (2019) prepared a purification additive based on a degradable Gemini fluorocarbon surfactant to reduce its surface tension to 16 mN/m. The flowback rate reached 84.34% in field applications after 52 days. Additionally, Fu et al. (2020b) also showed that when the interfacial tension decreased from 10 to 10⁻² mN/m, the flowback rate increased from 42% to 55%, resulting in a nearly 53% reduction in permeability damage.

3.4.2. Altering the type of fracturing fluid

Presently, to address solid-phase damage, using a low-damage fracturing fluid system such as carboxymethyl guar gum (CMG) fracturing fluid and microemulsion system is an effective method.

To address the limitations of hydroxypropyl guar gum (HPG) fracturing fluid residues and its subpar temperature resistance, carboxymethyl was incorporated into the main chain of guar gum,

resulting in the development of a carboxymethyl fracturing thickening agent. This carboxymethyl guar gum (CMG) fracturing fluid was formulated, which exhibits only 1/4 to 1/2 of the residue content compared to conventional hydroxypropyl guar gum fracturing fluid. Furthermore, the CMG fracturing fluid allows for a reduction of thickener concentration by approximately 0.1%–0.2% at similar temperatures, and it also enables a further reduction in glue breaker concentration (Hurnaas and Plank, 2015; Szopinski et al., 2015). These attributes make CMG fracturing fluid more suitable for application in deep and ultra-deep reservoirs (Jiang and Lu, 2009; Xu Z. et al., 2016).

In addition, the microemulsion is an important solution for preventing water blockage and fracturing fluid retention and flowback. Microemulsions effectively reduce surface tension and modify the rock wettability (Zelenev et al., 2011; Rostami and Nasr-El-Din, 2014). The development of microemulsions involves a combination of *n*-octane, *n*-butanol, and quaternary ammonium salt surfactant (GTN) Gemini surfactants, which are then diluted with water to create nanodroplets ranging from 20 to 300 nm (Qiu et al., 2015). By decreasing the capillary force, this new microemulsion temporarily obstructs the pore throat, and adsorb on the rock surface, altering its wettability. These actions can effectively protect the reservoir, promote the flowback, and alleviate the water blockage in the rock matrix. Microemulsion has a favorable protective effect due to their low surface tension and tiny droplets. It can inhibit the migration of water molecules into the pore space, temporarily blocking micropores and throats by reducing capillary pressure, thereby decrease the degree of spontaneous imbibition (Dong et al., 2015; Qiu et al., 2015) (as shown in Fig. 12). Furthermore, the nanodroplets within the microemulsion carry a positive charge, enabling them to be adsorbed on the rock surface through the electrostatic attraction, thus weakening the rock wettability. This effect further reduces capillary pressure, minimizes flowback resistance, and ultimately protects the reservoir.

3.5. Future progresses

Hydraulic fracturing in a deep, high-temperature reservoir is an essential stimulation technique but carries inherent risks, notably the possibility of rock matrix damage. Consequently, future

progresses will focus primarily on minimizing such damage to the rock matrix. The main envisioned paths forward are as follows.

- (1) Development of low-damage weighted fracturing fluid system: Current inorganic salt-weighted fracturing fluid is susceptible to salt blockage, which affects the thickener dissolution and crosslinking, and overall stability. Additionally, the residue from weighting agent may exacerbate damage to both the reservoir and supporting fractures. To reduce reservoir matrix damage, future efforts can explore alternatives to inorganic salts, such as low-ionic polymers or calcium carbonate, etc., which possess equivalent density but smaller ionic radius.
- (2) Advancements in high-temperature-resistant clean fracturing fluid system: clean fracturing fluid, characterized by its residue-free, easy flowback properties, and minimal reservoir damage, represent a promising avenue for reducing reservoir matrix. However, its temperature resistance has posed challenges for researchers. Addressing this issue can involve two approaches: (i) Research and development of new surfactants with high-temperature and high-salinity resistance, tailored for extreme conditions like high temperature and high salinity. (ii) Incorporation of nano-materials, such as nano-oxides, nano-silicon, etc., into the fracturing fluid to enhance its rheological properties, stability, and resistance to high temperatures and pressure.
- (3) Development of high-temperature-resistant, simplified microemulsion system: The microemulsion, as isotropic, thermodynamically stable systems formed spontaneously by two types of insoluble liquids (oil and water phases) under the influences of surfactant and cosurfactant, holds potential for minimal reservoir damage. Nevertheless, the oil–water interface within the microemulsion system is exceptionally narrow, rendering it highly susceptible to temperature fluctuations and prone to losing stability with changing temperatures. Moreover, the formulation is more intricate, requiring careful consideration of factors such as the oil phase-to-water phase ratio, surfactant type, and quantity. In the future, streamlining the preparation process will be

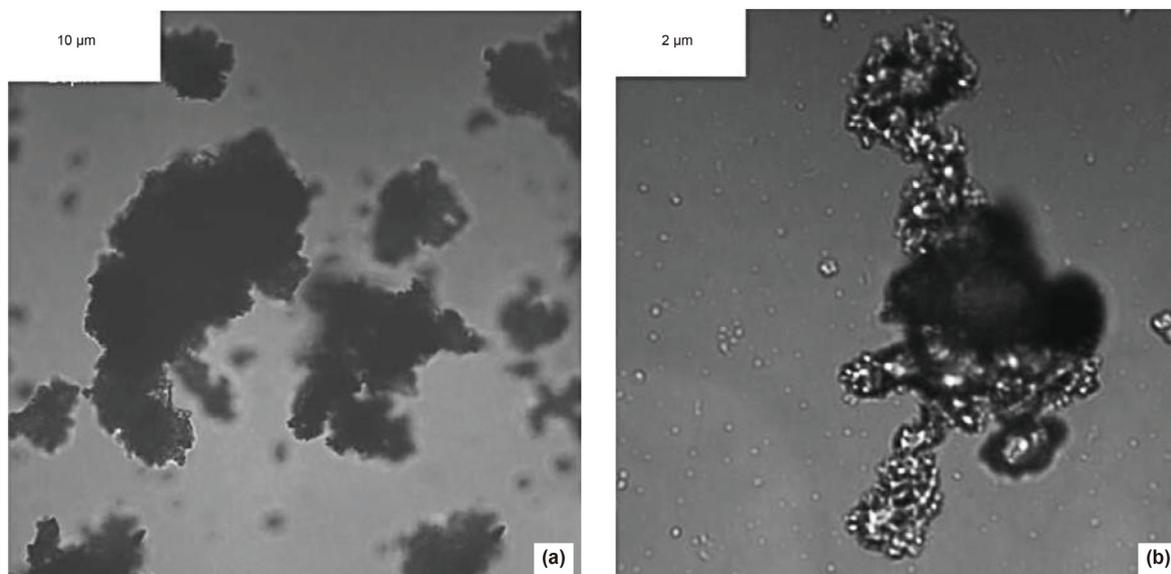


Fig. 12. Tight sandstone images with and without nanodroplets. (a) Before water absorption; (b) After absorbing water (Dong et al., 2019).

imperative, along with the addition of polymer stabilizers and colloidal silica to enhance temperature stability.

In conclusion, future efforts should focus on maximizing reservoir productivity while concurrently minimizing reservoir matrix damage.

4. Damage caused by hydraulic fracturing to natural and artificial fractures

4.1. Research progress

When hydraulic fracturing invades a reservoir, it can cause both internal and external damage. Internal damage primarily pertains to matrix damage, as discussed in Section 3. Meanwhile, external damage affects both natural and artificial fractures formed post-fracturing. This external damage is caused by the formation of a filtrate cake in the reservoir (Vitthal and McGowen, 1996). It is crucial to note that sand-packed fractures, artificial fractures, and natural fractures are distinct types of fractures with certain differences. Natural fracture refers to the rock fracture formed naturally in the geological process. Artificial fractures are created in rocks artificially. Typically, artificial fractures exhibit more regularity and limited distribution compared to natural fractures. Sand-packed fractures, on the other hand, result from the addition of proppant to artificial fractures post-hydraulic fracturing. These are essentially artificially supported cracks. On fracture surfaces, where polymers accumulate due to the percolation of fracturing fluid into reservoir pores, filtrate cakes are generated (Wang Z. et al., 2022). These filtrate cakes can adversely impact the conductivity of the proppant-packed fractures. This section predominantly addresses the damage inflicted on fractures by filtrate cakes resulting from fracturing fluid.

Current research and production practices have demonstrated that enhancing the conductivity of drilling-induced natural fractures is the most important factor affecting the high production of ultra-deep wells (Wang Z. et al., 2022). According to the statistics of the Keshen gas field in western China, Yang H. et al. (2018) found that the absolute open flow of gas wells with a developed fracture network reached $100 \times 10^4 \text{ m}^3/\text{d}$, while for gas wells without natural fracture, it was only about $(1-4) \times 10^4 \text{ m}^3/\text{d}$. The damage caused by the filtrate cake formed by the fracturing fluid is an important factor affecting fracture development. In deep reservoirs, fracture widths are frequently modest post-fracturing. In practical applications, fracture widths range from a few microns to a few millimeters on average (Zhu et al., 2017). When the thickness of the filtrate cake approaches the width of the fracture, it can entirely block the flow channel, leading to reduced conductivity. The extent of damage on the fracture surface is associated with the depth of fracturing fluid penetration and the skin factor effect (Volk et al., 1983).

The characteristics of high temperature and pressure have different effects on filtrate cakes formation in deep and ultra-deep reservoirs. Polymers typically employed to enhance viscosity in deep reservoirs at high temperatures (above $150 \text{ }^\circ\text{C}$) tend to disintegrate upon entering the reservoir. To keep the fracture open, high concentrations of proppant must be pumped. In order to prevent the proppant clogging due to high-viscosity fluids, fluid degradation must occur promptly after fracturing treatment. The use of gelatinized fracturing fluids has demonstrated effectiveness in deep and high-temperature reservoirs, where high temperatures can cause gel rupture, allowing for flowback. Gel stabilizers are frequently added to the reservoir to prevent premature gel rupture due to the high temperature. For instance, the use of guar-based fracturing fluids at high temperatures requires thiosulfate

stabilizers. During the fracturing treatment, the polymer becomes concentrated in the gel filtrate cake due to percolation, making it challenging to remove and resulting in significant yield stress that shortens the effective fracture length (Xu et al., 2011).

However, due to the percolation of the fracturing fluid, fracture closure, and small pore throat size, nearly all of the polymer in the fracturing fluid will eventually enter the fracture and form a filtrate cake. The polymer adheres to the proppant, which is a significant cause of flowback issues. In this process, some of the polymer molecules traverse the matrix and are fragmented into smaller polymer molecules. The remaining portion of the polymer molecules sustains the initial polymer concentration within the fracture pore space. This segment gradually adsorbs onto the fracture surface, forming a filtrate cake, as illustrated in Fig. 13. After the gel is broken, the residue is adsorbed onto the fracture wall or filtered with proppant. As the fracturing fluid is expelled, and oil and gas start flowing, this residue progressively obstructs some of the pore throats or supports the fracture, leading to a reduction in permeability.

Although the formation of filter cake can diminish the leak-off of fracturing fluid during hydraulic fracturing, it will significantly impact on the flow of oil and gas, consequently reduce the reservoir conductivity. Fig. 14(a) depicts the filter cake on the core sample face and its SEM experimental results. Unsteady pressure conduction experiments on deep and tight sandstone samples by Zhang L. et al. (2019) revealed that residues from various fracturing fluids primarily accumulate in or near the center of pore throats, obstructing them and forming filter cakes. This results in reduced rock permeability and affects oil production. Fracturing experiments conducted on deep sandstone samples by Tang et al. (2021) observed new fractures formed on the core surface via SEM, showing extensive contamination by polymer, residue, and clay minerals. These materials obstructed fracture planes and pores (Fig. 15), with local magnification highlighting that fracturing fluid residue and adsorbed polymers were the primary obstructions on fracture surfaces and within pores. The degree of blockage on fracture surfaces was significantly higher than within the rock matrix.

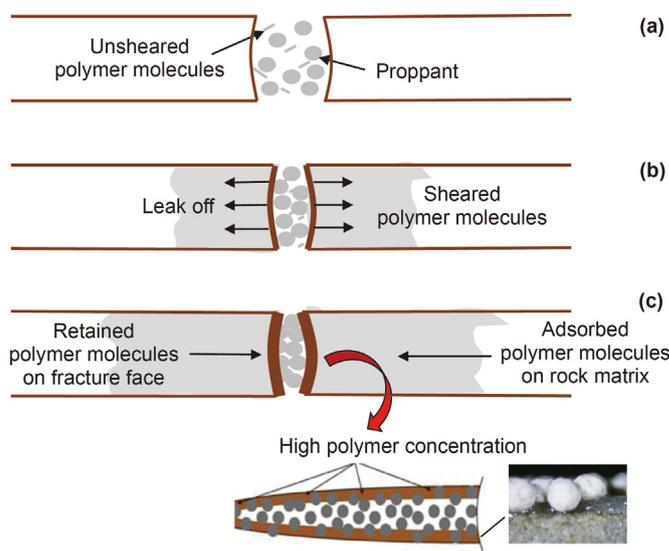


Fig. 13. Schematic diagram of polymer and gel damage during percolation. (a) Fracture opening during fracturing; (b) Fracturing fluid leak off, gel cake formation, and polymer adsorption; (c) Fracture closure and proppant partially filled with gel cake (Charoenwongsa et al. (2013) from Ayoub et al. (2009) modified).

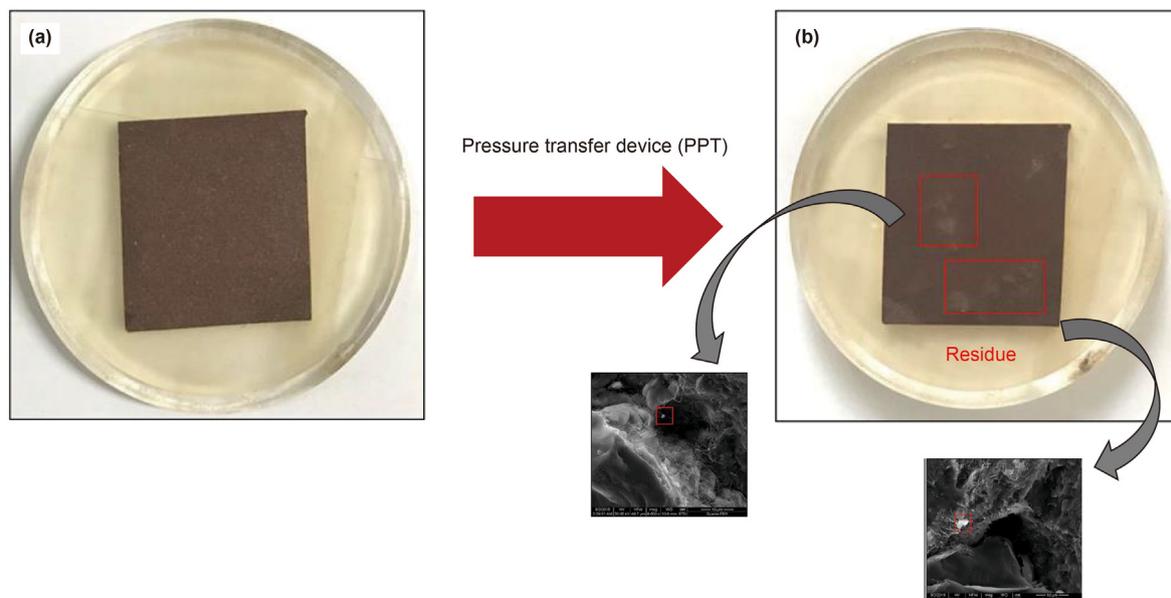


Fig. 14. Filter cake formed in the sample surface. (a) Before damage; (b) After damage (Zhang L. et al., 2019).

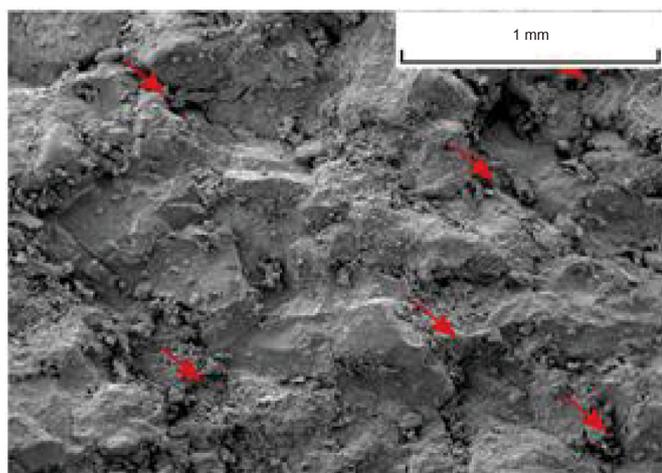


Fig. 15. SEM image of a fracture surface (Tang et al., 2021).

4.2. Solutions

Currently, three highly effective methods exist for reducing filter cake-induced damage: mechanical removal, chemical removal, and the utilization of VES clean fracturing fluid.

Mechanical removal is a common technique that can be directly removed by mechanical instruments (air guns, electric drills, etc.). However, it has the disadvantage of potentially damaging the well wall and bringing impurities, along with operational safety hazards.

Chemical removal is another prevalent approach for addressing filter cake blockages and primarily relies on filter cake cleaning agents. These agents operate through three main mechanisms: oxidation, biological enzymes, and acid treatments (Alotaibi et al., 2009). Oxidation-based agents utilize oxidizing agents to degrade macromolecular polymers within the filter cake, causing them to degrade into smaller molecular polymers and water. This degradation reduces the adhesion between filter cake particles, causing them to dislodge and loosen, ultimately achieving the objective of

cleansing the filter cake. Under specific temperature conditions, biological enzymes employ catalytic degradation to break the lengthy molecular chains of macromolecular polymers. This degradation transforms them into monosaccharides and disaccharides, thereby reducing the adhesion between filter cake particles. As a result, the filter cake becomes more porous and can be removed more easily (Siddiqui and Nasr-El-Din, 2005). Acid treatment primarily establishes an acidic environment in the reservoir, leading to the degradation of polymers. This degradation reduces the cohesion between filter cake particles and rapidly dissolves the skeleton material, effectively disassembling the filter cake and facilitating its removal.

The primary component of VES clean hydraulic fracturing fluid is a viscoelastic surfactant, known for its high efficiency and environmental friendliness. It is widely employed in the petroleum industry. Due to its molecular structure, incorporating both hydrophilic and hydrophobic groups that facilitate the formation of emulsifying particles between water and oil, VES surfactants exhibit a remarkable capacity for minimal damage. When utilizing high-temperature-resistant and clean fracturing fluids, the filtration rate remains constant throughout injection, preventing leakage into the reservoir and the formation of filter cakes. Leveraging its viscoelastic optimization, these fracturing fluids have limited penetration into pore throats. Surfactant-based VES fracking fluids induce minimal reservoir damage, thanks to the reversible aggregation of surfactants.

4.3. Future progresses

Serving as the intermediary contributor to both matrix damage and sand-packed fracture damage, the impact of fracturing fluid on natural and artificial fractures remains an underexplored area. This holds especially true for deep reservoirs experiencing elevated temperatures and pressures. Minimizing the harm inflicted by filtrate cakes on artificial and natural fractures in the context of hydraulic fracturing within high-temperature deep reservoirs represents a pivotal challenge. In the pursuit of solutions for this challenge, future research can be directed towards the following aspects.

- (1) To elucidate the mechanism of filtrate cake formation and its impact on fracture damage, a combination of experiments and numerical simulations will be employed. This research aims to explore the fundamental principles and behavior of filtrate cakes within the reservoir, as well as the mechanisms through which these cakes affect fractures during hydraulic fracturing. The insights gained from this study will furnish a scientific foundation for the development of subsequent control measures.
- (2) Investigating the interface properties of filtrate cake and rock within high-temperature reservoirs is paramount. The interaction between these two components significantly impacts filtrate cake damage. Subsequent research endeavors should delve into the interplay between various rock types and filtrate cakes, delineating the factors that influence the interface characteristics between these elements. This investigation will supply essential data for the enhancement and optimization of filtrate cake design.
- (3) Pioneering fracturing fluid systems and operational techniques are essential. The composition of fracturing fluids, as well as operational parameters such as flow rates and pressure, must be fine-tuned for minimizing filtrate cake within the reservoir. Modifying the fracturing approach and regulating flow rates in line with the particularities of high-temperature, deep reservoirs can mitigate fracture damage. Furthermore, the future development of fracturing fluids should consider the impact of elevated temperatures on reservoir filtrate cake and the influence of high polymer concentrations on filtrate cake reservoir yield stress.

5. Sand-packed fracture damage

In hydraulic fracturing, proppant is employed to bolster the fracture walls, thereby forming a sand-packed fracture. This ensures the effective conductivity of fractures during production (Fu et al., 2019). Unlike other stimulation methods like matrix acidization, the gelled fracturing fluid used in this approach does not interact with the reservoir, enabling it to penetrate deeper, especially in high-temperature conditions.

However, the high-stress levels in deep reservoirs lead to proppant embedding, which substantially reduces fracture width and can even cause fracture closure. Multiple phenomena, such as proppant embedding, particle reservoir effects, and migration, are the result of high temperatures and *in-situ* stress influencing proppant cementation (Fig. 16) (Mittal et al., 2018). The reduced conductivity of sand-packed fractures in deep reservoirs is primarily attributable to the embedding of the proppant. The primary function of the proppant is to maintain the openness of artificial fractures. Nonetheless, embedding adversely affects conductivity by triggering fracture contraction or closure, leading to a significant drop in oil production (Tang et al., 2018). In cases where confining pressures shifted from 7 to 70 MPa, fracture conductivity decreased by 78% in shale, 79% in siltstone, 82% in mudstone, and 92% in conglomerate reservoirs (Wen et al., 2007).

Many factors affect proppant embedding, including breaker and sand concentrations in the fracturing fluid, proppant size, placement mode, rock shear strength, closure pressure, and temperature. The damage of the fracturing fluid to sand-packed fracture is discussed in three aspects: rock creep and interaction, proppant breakage, and adsorption of fracturing fluid residue.

5.1. Fluid-rock interaction and rock creep

Between 15% and 35% of the hydraulic fracturing fluid is retrieved from the reservoir and returned to the surface.

Consequently, a significant portion of the fracturing fluid interacts with the subsurface reservoir, potentially leading to the softening of rock strength and influencing mechanical properties, including Young's modulus and Poisson's ratio. Zhang et al. (2022) noted that fluid–rock interactions may result in a substantial decrease in rock strength, thereby enhancing proppant embedment and decreasing sand-packed fracture conductivity. Temperature and pressure are key factors in proppant diagenesis, a process that generally occurs at temperatures exceeding 150 °C and can be expedited by elevated temperatures and stress conditions (LaFollette and Carman, 2010). With greater depth of proppant embedment, the fracture width diminishes, significantly impacting fracture conductivity and, consequently, production efficiency (Zhang et al., 2015b; Zhong et al., 2019). Bennion (2002) and Reinicke et al. (2012) discovered that stress-induced mechanical interactions between proppant and reservoir fracture surfaces can result in proppant embedment near the fracture surface. This leads to rock deformation, fragmentation of proppant and reservoir rock, disintegration, and the generation of fine particles, which subsequently result in pore plugging and compaction of the surfaces near the fracture. Studies have demonstrated that different fracturing fluids have varying effects on the conductivity of proppant flow in various forms (Liang et al., 2015). While it's true that overall flow conductivity in sand-packed fractures tends to decrease as pressure increases, the different types of proppants exhibit varying compressive strengths and sizes, leading to significant variations in their flow conductivity in sand-packed fractures (Liang et al., 2016). In a study by Zheng et al. (2018), the API conductivity of sand, coated proppant, and ceramic proppant was tested under identical pressure conditions. The results revealed that at 40 MPa, the ceramic proppant exhibited higher hardness and a lower fracture rate, with a conductivity of up to 10,000 mD ft. In contrast, the resin-coated proppant had a conductivity of 4583 mD ft, and the sand proppant exhibited a much lower conductivity of 390 mD ft.

As the stress on the fracture intensifies, the creep deformation of reservoir rocks can significantly expedite the proppant embedding process. The interplay between fracturing fluid and rock can induce rock creep, which is a critical factor in proppant embedding. Previous theoretical research has divided proppant embedment into two distinct phases: (1) elastic deformation, leading to proppant embedding; and (2) creep deformation, causing time-dependent proppant embedment (Guo and Liu, 2012). The substantial reduction in fracture surface strength during production is primarily attributed to the interaction of rocks with reservoir fluids and fracturing fluids (Rybacki et al., 2017; Tang and Ranjith, 2018).

The decrease in conductivity of sand-packed fractures can be attributed in part to rock creep. Creep is a progressive increase in soft or brittle rock deformation caused by long-term exposure to constant stress. Maranini and Brignoli (1999) proposed a classical three-peak creep curve by plotting the relationship between axial strain and time, delineating three distinct phases: (1) the primary stage, characterized by deceleration; (2) the second stage, maintaining a constant state; and (3) the third stage, marked by acceleration. Generally, the deformation is recoverable during discharge at the primary creep stage. However, the initiation of secondary creep effects can result in permanent deformation (Maranini and Brignoli, 1999). Numerous experiments have been conducted to examine the creep of strata rock. The researchers have also explored the influence of various *in-situ* reservoir conditions, including clay composition, rock mineralogy, temperature, and strain rate, on creep deformation (Liu et al., 2018). The time-dependent creep behavior of deep rock substantially promotes proppant embedment as the duration of fluid-rock interaction increases (Mighani et al., 2015).

In addition to the variables mentioned earlier, the placement

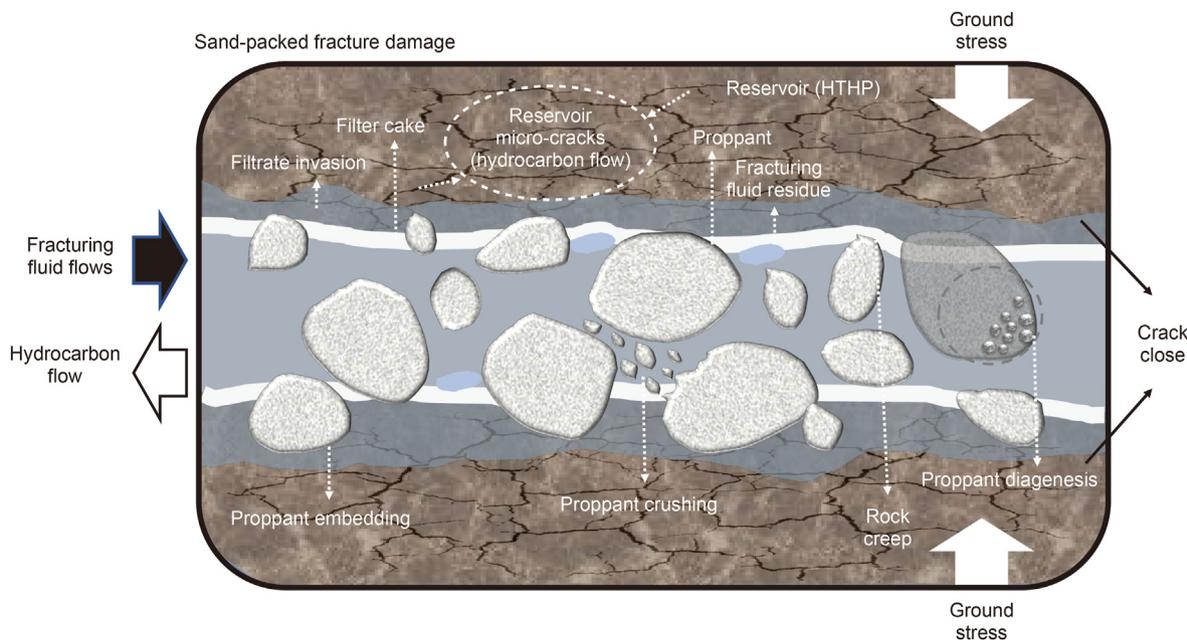


Fig. 16. Schematic diagram of sand-packed fracture damage (adapted from Katende et al., 2021).

and timing of proppants also significantly influence rock creep and subsequent proppant embedment. Through creep deformation experiments with various proppant arrangements within the fracture, it was observed that elastic deformation prevails in the embedding process for samples with both uniform and partial proppant distributions. In samples with a multilayer proppant distribution, however, the embedding process is predominantly controlled by creep deformation (Fig. 17) (Bandara et al., 2021). Changes in fracture width due to proppant embedding lead to a significant decrease in fracture conductivity over the course of production.

In summary, during hydraulic fracturing, the interaction between the fracturing fluid and the reservoir rock leads to a decrease in rock strength and an increase in proppant embedment. The environment of high temperature and pressure will cause a

diagenetic reaction, which will eventually result in a reduction of sand-packed fracture opening and a decrease in flow conductivity.

5.2. Proppant crush

The substantial interaction of fracturing fluid with reservoir rock results in rock softening, leading to changes in rock mechanical properties (Zhang and Mack, 2017; Zhong et al., 2019). However, the effect of proppant crushing has often been overlooked, and the crushing rate becomes more significant in deep reservoirs under high closure pressures. It is essential to account for and investigate the impact of fracturing fluid on the rate of proppant deformation.

Several studies have shown that the effective volume of fractures is reduced by approximately 30% due to fracture closure during the initial flowback period. The decrease in reservoir

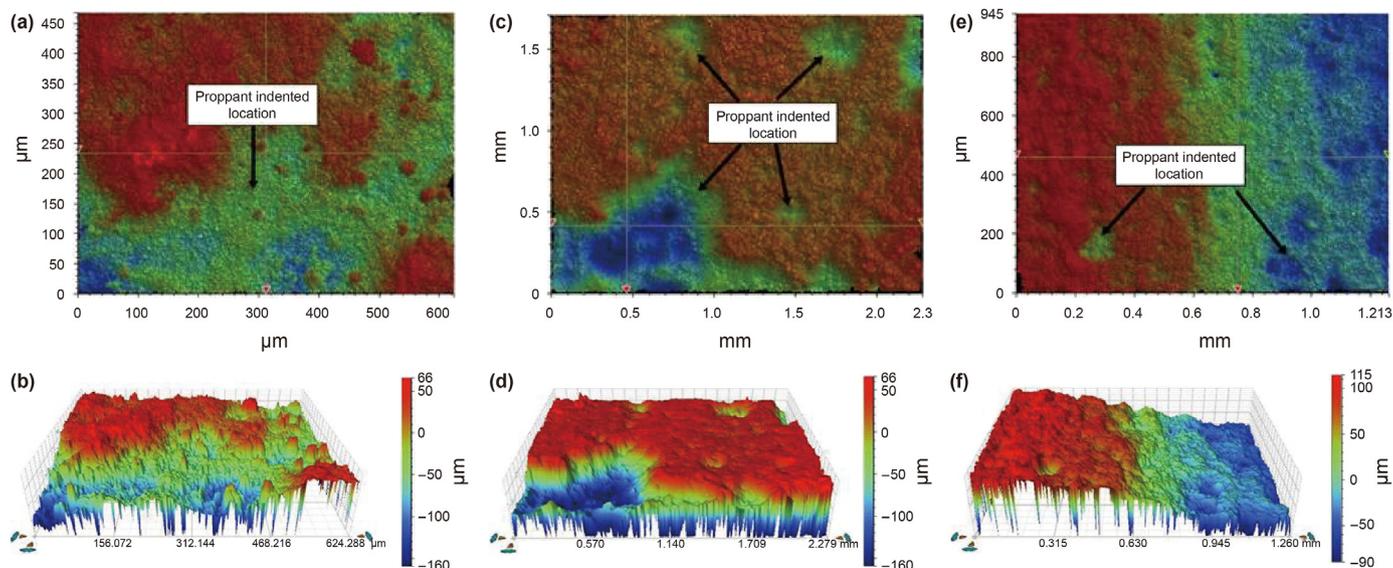


Fig. 17. Surface profilometry analysis of proppant-indented locations. (a, b) Sample with uniform proppant distribution, 2D and 3D; (c, d) Sample with partial proppant distribution, 2D and 3D; (e, f) Samples with multilayer proppant distribution, 2D and 3D (Bandara et al., 2021).

pressure can cause the proppant to become embedded in the fracture surface or be crushed and flow back to the surface with the fracturing fluid, resulting in sand production (Han et al., 2017). There are various factors that can impact fracture conductivity, and two types of damage may result from the high closure pressure applied to the proppant: (1) proppant breakage, and (2) proppant embedment (Barboza et al., 2021).

The detrimental impact of fracturing fluid on fracture conductivity is largely attributed to the performance of the residues within the fracturing fluid. The increased rate of proppant breakage, enhanced proppant embedment, and reduced pore size are the three primary ways in which the breaker and its residues adversely affect fracture conductivity (Raysoni and Weaver, 2013). In a fracture diversion experiment, conducted by Wang J. et al. (2020), the effects of temperature, pressure, and breaker concentration on the performance of gelled fracturing fluid were investigated. The observed effects of time, pressure, and temperature are as follows.

- (1) Submerging the fracturing fluid in the proppant significantly accelerates proppant breakage when the closing pressure exceeds 50 MPa. The damage increases with the duration of submersion due to proppant fragmentation, resulting in decreased fracture conductivity. When the closure pressure is less than 50 MPa, the proppant break rate is low, and the impact of submerging the broken solution is minimal, as indicated by Weaver and Rickman (2010).
- (2) The quantity of fracturing fluid residue progressively increases at different temperatures as the heating duration extends. Prolonging the soaking time in the fractured fluid exacerbates proppant fragmentation and embedment.
- (3) The higher the temperature, the faster the molecular chains of guar gum break, leading the more insoluble substances are produced. Therefore, under the same heating time duration, the residue content is higher in the high-temperature environment. From a molecular structure perspective, the disruption of the side-chain galactose bond during the initial

stage of gel rupture would lead to a significant decrease in the solubility of guar gum molecules (Burke et al., 2000; McDonald, 2005). Some guar gum molecules are separated from the solution to form a flocculent precipitate. This is mainly due to the proppant–fluid reaction of the proppant immersed in the high-temperature broken fluid, which destroys the proppant structure and strength, as shown in Fig. 18(a)–(c).

The damage to the fracture conductivity is mainly caused by the residue in the gel breaker. This residue leads to obstruction of the access path provided by the propped fracture and ultimately to a reduction in permeability, as shown in Fig. 18(d)–(f). In the context of deep reservoirs, the characteristics of high temperature and high pressure align with the findings mentioned above. The increase in temperature and pressure will accelerate proppant crush and embedment.

In addition to proppant fragmentation and embedment in the deep reservoir, diagenetic reactions occur and sediments become rocks. These reactions can affect proppant placement in sand-packed fractures under high pressure, stress, and temperature. This results in a significant reduction in proppant porosity and fracture conductivity (Weaver et al., 2005). Weaver et al. (2005) observed that chemical reactions occurring within fractures can rapidly and significantly harm the pores created by proppants under high stress and temperature conditions, resulting in a diminished fracture conductivity. Under higher pressures and temperatures, this mechanism may occur rapidly. So, proppant fracture and diagenetic reaction are significant causes of reduction in flow conductivity in high-temperature, deep reservoirs, and heightened temperature and pressure will accelerate this effect.

5.3. Residue adsorption damage

Numerous researchers have examined the macroscopic effects of different parameters on fracture conductivity (Liu et al., 2017;

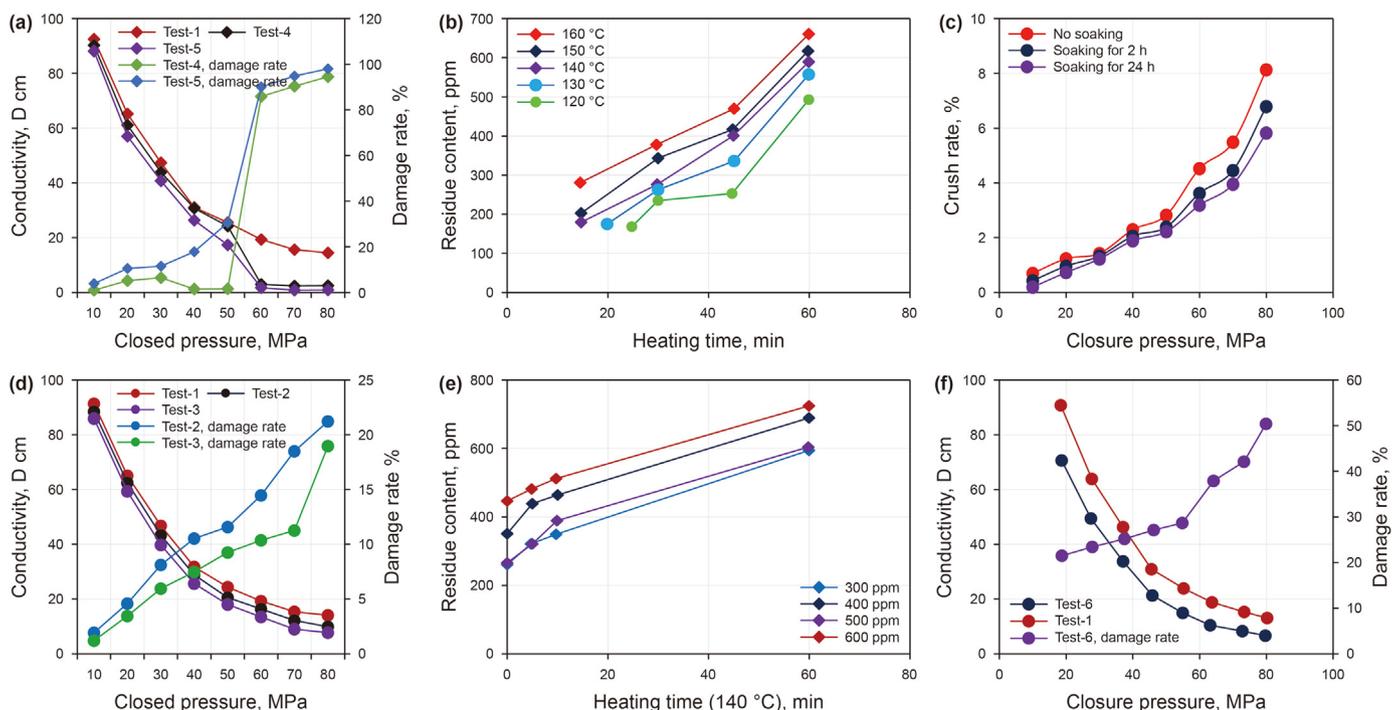


Fig. 18. Effect of the amount of broken glue on the residue content (Wang J. et al., 2020).

Wu W. et al., 2017; Zhao et al., 2018a), but the damage mechanism and cause have not been fully investigated. The microscopic process of fracturing fluid damage to supported fractures must therefore be studied.

Some scholars found that fracturing fluid residues were more harmful to sand-packed fractures than natural fractures (Wu et al., 2018; Huang and Liu, 2019). For a more detailed examination of the microscopic adsorption of residues on the proppant surface, Wang J. et al. (2020) conducted a flow diversion experiment on proppant fractures with gel residue at elevated temperatures. Subsequently, scanning electron microscopy (SEM) and energy-dispersive spectroscopy (EDS) elemental analyses were carried out on the proppant (see Fig. 19). It has been observed that as closure pressure increases, the residual solution can lead to significant damage to the propped fracture conductivity. This is primarily due to a 30%–40% reduction in pore volume between proppants resulting from the elevated closure pressure, consequently diminishing the pore size between proppants from 200 to 18 μm (Berg, 1970). With larger molecules more prone to entering the proppant pores, the extent of damage increases (Hakiki et al., 2015).

Under SEM observation, it's apparent that a substantial quantity of residue-like materials adheres to the proppant surface, leading to a decrease in proppant pack porosity and consequent damage to fracture conductivity. EDS analysis conducted on the proppant surface post-experiment reveals that the predominant elements are aluminum and oxygen, consistent with the primary constituents of ceramic proppant. EDS test results of proppant surface adsorbents show that the main elements are carbon and oxygen, which are the main components of a guar-based fracturing fluid. These experimental findings conclusively establish that the residue on the proppant surface originates from the remnants of the broken fluid. Consequently, it is the residue within the gel breaker that predominantly contributes to the reduction in flow conductivity. This residue is responsible for impeding the propped fracture, ultimately leading to diminished permeability.

5.4. Solutions

Research on fracturing fluid damage in deep reservoirs has primarily concentrated on the advancement of deep fracturing fluids and proppant selection, with limited studies addressing rock creep and proppant diagenesis in such deep reservoirs. Consequently, our analysis is predominantly centered on fracturing fluids and proppants:

First, let's address the fracturing fluid. To minimize rock-water reactions and residue adsorption, alterations can be made to the viscosity and fluidity of fracturing fluids. These modifications not only help control the movement and distribution of the fluid between the wellbore and reservoir but also regulate fluid penetration into the reservoir. Furthermore, adopting biodegradable systems with minimal residue can contribute to achieving these objectives. Using degradable, low-residue fracturing fluids can effectively diminish proppant residue adsorption and maintain fracture flow conductivity. The choice of a multi-functional slick-water fluid is particularly advantageous. It not only regulates the viscosity of fracturing fluid, minimizing water-rock reactions, but also boasts exceptional drag-reduction capabilities and a high capacity to transport proppant. The complete blend is readily emulsified and soluble, leaving behind minimal residue, and can be mixed seamlessly in real-time. Clean fracturing fluid offers distinct advantages in averting reservoir damage during hydraulic fracturing and serves as one of the methods to address the permeability issues arising from proppant residue adsorption in sand-packed fractures. Nano-emulsion is characterized by its minute particle size, robust stability, and notable biodegradability. In the course of hydraulic fracturing and subsequent flowback stages, the adsorption of fracturing fluid residue onto the proppant will be minimal, resulting in minimal harm to the sand-packed fracture. Consequently, the conductivity of the sand-packed fracture can be largely preserved.

The choice of proppant is the most important factor in resolving fracture damage induced by sand-packed reservoirs. Traditional proppants such as quartz sand, ceramic proppant, and coated proppant remain the primary choices for hydraulic fracturing. While quartz sand is a common proppant, it's susceptible to deformation and crystallization at high temperatures, which diminishes its conductivity. In contrast, ceramic proppant offers outstanding features, including high strength, resistance to high temperatures, and corrosion resistance, making it well-suited for fracturing deep reservoirs under high-temperature conditions. Ceramic proppants exhibit superior resistance to high-temperature environments compared to sand, thereby enhancing conductivity in high-temperature reservoirs.

In recent years, new proppants, such as low-density proppants, laminar proppants, nano-proppants, and micro-proppants, have been introduced. These proppants offer enhanced compressive strength and reduced fracture rates, providing improved performance. Low-density proppant involves the utilization of materials

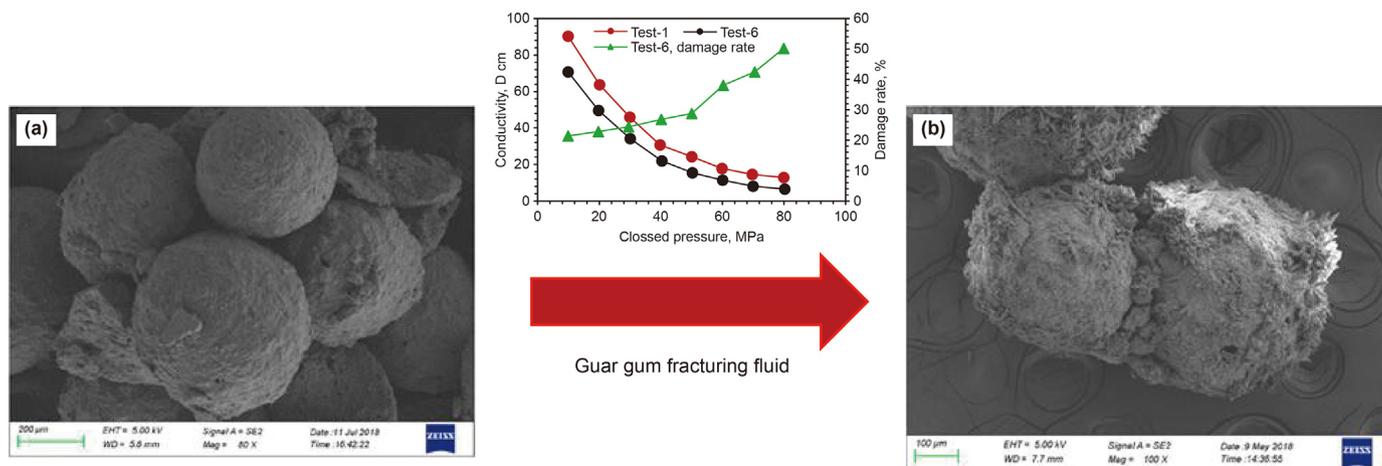


Fig. 19. SEM scan of proppant microstructure. (a) Micromorphology of proppants after reservoir water conductivity test; (b) Micromorphology of proppants after gel breaking liquid conductivity test (Wang J. et al., 2020).

with reduced density or hollow structures to achieve lower overall density. This approach is essential when working with low-viscosity sand-carrying fluids. By doing so, the need for excessive thickening agents in the fracturing fluid can be minimized, subsequently lowering residue content and mitigating reservoir damage. Lamellar proppant is an innovative proppant form comprising multi-layer sheets characterized by high strength and exceptional conductivity. In deep, high-temperature reservoirs, lamellar proppants provide effective fracture support and sustain excellent conductivity. In low-permeability reservoirs, there are typically natural micro-fractures, and the hydraulic fracturing process may create additional micro-fractures. However, the size of traditional proppants is often insufficient to prevent the closure of these micro-fractures. To address this challenge, micro-proppants, such as nano-proppants, have been developed. Nano-proppants have dimensions ranging from 100 nm to 1 μm . These nanoscale proppants are introduced into the reservoir to fill the micro-fractures on both sides of the main fracture before injecting conventional fracturing proppants. This strategy effectively supports the micro-fractures. Additionally, proppants can be coated with nanomaterials to enhance their compressive strength and temperature resistance.

5.5. Future progresses

The overall direction for future development revolves around high-temperature-resistant, low-damage fracturing fluids, and low-density, high-strength, cost-effective proppants. Given the growing complexity of reservoir conditions, the formulation of fracturing fluids and proppants should consider the following factors.

- (1) Enhance research on proppant mechanisms and preparation technology. The role of proppants during hydraulic fracturing is pivotal. The development of novel surface treatment technologies will enhance surface properties, increase proppant compressive strength, and mitigate conductivity loss resulting from breakage.
- (2) Clean fracturing fluid represents a highly promising fracturing system that charts the course for addressing the myriad challenges encountered in contemporary fracturing stimulation technology. Nonetheless, gaps exist in the understanding of rock creep, diagenetic reactions, and compatibility with clean fracturing fluid in reservoirs. Further investigation into the interplay between clean fracturing fluid and deep reservoir geology is essential to minimize reservoir damage and unlock the full potential of this fracturing fluid.
- (3) Nanomaterials offer tremendous potential in the realm of fracturing fluids. The incorporation of nanomaterials into fracturing fluids can significantly enhance temperature resistance and reduce the requisite thickening agents, consequently curtailing residue formation following gel breakage. With respect to proppants, nano-proppants and nano-coating technologies can be harnessed to bolster proppant strength, mitigate proppant breakage, and minimize reservoir damage.

6. Conclusions

During hydraulic fracturing, reservoir damage induced by fracturing fluid takes precedence, encompassing issues like water sensitivity, water blockage, fracturing fluid retention, and proppant residue adsorption. The ultra-deep reservoir's "three-high" environment (characterized by high temperature, high pressure, and

high salinity) amplifies conventional damage mechanisms. For instance, elevated temperatures accelerate fracturing fluid decomposition, and increased pressure raises the proppant breakage rate. Furthermore, hydraulic fracturing entails specific forms of damage in ultra-deep reservoirs. Examples include diagenetic reactions between rocks or proppants and subsurface fluids in high-temperature settings, plastic deformation of rocks, and the creep response of rocks in high-pressure conditions, all of which reduce rock permeability and subsequently impact the entire fracturing process. This paper delves into three types of reservoir damage mechanisms, encompassing damage inflicted on the rock matrix, artificial and natural fractures, and the conductivity of sand-packed fractures. It reviews the application and development of deep fracturing fluids, providing a summary of current challenges and future prospects. The key findings are as follows.

- (1) The judicious application of fracturing fluids plays a pivotal role in mitigating reservoir damage. In light of the challenges posed by reservoir damage and the imperative of temperature resistance, we conducted a comprehensive review of the prevailing deep fracturing fluids and explored strategies for their enhancement. To develop high-temperature-resistant fracturing fluids, it is imperative to establish a molecular structure-activity relationship and undertake polymer modifications aimed at curtailing residue content and adsorption following the fracturing process. This approach serves to minimize reservoir damage while upholding performance standards. VES clean fracturing fluids offer a residue-free, low-damage solution that can bolster temperature resistance through surfactant modifications and fluid additives optimization. Furthermore, by scrutinizing the compatibility between the weighting agent and the thickener and incorporating high-temperature stabilizers or corrosion inhibitors, weighted fracturing fluids can effectively reduce reservoir damage without compromising performance.
- (2) Matrix damage primarily stems from two distinct causes: first, the obstruction of residues, particles, and salts within the fracturing fluid during hydraulic fracturing and subsequent flowback; and second, the impairment arising from the penetration of fracturing fluid into the reservoir due to capillary forces and osmotic pressures. It's worth noting that deep reservoir environments characterized by elevated temperatures and pressures tend to exacerbate reservoir damage to a certain extent. To address these challenges and pave the way for future advancements, we should consider the development of low-damage weighted fracturing fluid systems, high-temperature-resistant clean fracturing fluid systems, and streamlined microemulsion preparation techniques.
- (3) Within the realm of fracture damage, hydraulic fracturing fluids can adversely affect both natural and artificial fractures, contributing to a combination of matrix and sand-packed fracture damage. A primary culprit behind this damage is the presence of filtrate cake, resulting from residual hydraulic fracturing fluid within the reservoir. Existing solutions primarily revolve around mechanical and chemical methods aimed at mitigating filtrate cake damage and altering the properties of fracturing fluid systems. Effectively reducing the impact of filtrate cake on both artificial and natural fractures remains a critical challenge in the context of hydraulic fracturing, particularly in high-temperature deep reservoirs. Unfortunately, there is a paucity of targeted studies in this regard, especially within the context of deep

fractures subjected to elevated temperature and pressure conditions. Moving forward, it is imperative to conduct comprehensive investigations into the mechanisms governing the formation of filtrate cake and its ramifications on fracture damage. Furthermore, exploring the interfacial properties between rock and filtrate cake in high-temperature deep reservoirs is of utmost importance. All of these efforts should contribute to the tailored development of fracturing fluid systems with the objective of minimizing reservoir damage.

- (4) Sand-packed fracture damage can be attributed to three primary factors: rock creep and fluid-rock interactions, proppant crushing and diagenetic reactions, and residue adsorption. Presently, there is a scarcity of research on rock creep and proppant diagenesis in deep reservoirs, as most efforts have been concentrated on the development of deep fracturing fluids and the selection of proppants. To mitigate the damage caused by sand-packed fractures, one strategy involves the application of variable-viscosity slickwater and nano-emulsions, effectively addressing concerns related to residue adsorption and water-rock reactions. A pivotal element in this endeavor is the judicious choice of proppant. By advancing novel surface treatment technologies, it is possible to enhance surface performance, bolster the proppant strength, and minimize damage stemming from the fracturing process in support fractures.

CRediT authorship contribution statement

Kun Zhang: Data curation, Formal analysis, Visualization, Writing – original draft, Writing – review & editing, Methodology. **Xiong-Fei Liu:** Project administration, Resources, Funding acquisition, Supervision. **Dao-Bing Wang:** Investigation, Methodology, Supervision. **Bo Zheng:** Project administration. **Tun-Hao Chen:** Data curation. **Qing Wang:** Writing – original draft. **Hao Bai:** Data curation, Methodology. **Er-Dong Yao:** Project administration, Supervision, Validation. **Fu-Jian Zhou:** Project administration, Supervision, Validation.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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