processes

MDPI

Article

The Development of an Alginate Drilling Fluid Treatment Agent for Shale and a Study on the Mechanism of Wellbore Stability Sealing

Cheng Huang [1], Liping Mu [2,*] and Xuefeng Gong [3,4]

[1] Shengli Oilfield Oil Development Center Co., Ltd., Dongying 257100, China; huangcheng503.slyt@sinopec.com
[2] School of Foreign Studies, China University of Petroleum (East China), Qingdao 266580, China
[3] Academy of Science and Technology, China University of Petroleum (East China), Qingdao 266580, China; 20080017@upc.edu.cn
[4] Shengli Oilfield Zhongsheng Industrial Co., Ltd., Dongying 257100, China
* Correspondence: muliping163163@163.com

Abstract: In order to prevent and control the problem of wellbore instability during the drilling process in shale formations, this study, based on the unique rheological properties, water solubility, and thermal stability of sodium alginate (SA), systematically investigated the rheological properties, filtration properties, and temperature resistance of sodium alginate-based drilling fluids before and after salt contamination. Additionally, it explored the wellbore stability and plugging mechanism of these drilling fluids in shale formations. The research shows that the BF + 0.4 wt% SA system significantly improves the rheological properties of the drilling fluid, effectively reduces the filtration loss, and exhibits good stability under the conditions of salt contamination and a high temperature of 100 °C. Sodium alginate binds to clay particles through hydrogen bonds and ionic bonds, enhancing the hydration and dispersion ability of the particles. The absolute value of its zeta potential reaches 39 mV and 37 mV before and after salt contamination, respectively, which is better than that of the control group, thus improving the colloidal stability of the drilling fluid. At the same time, through the moderate flocculation of clay particles, low-permeability filter cakes with filtration losses of 14 mL and 25 mL before and after salt contamination are formed, realizing a wellbore stability mechanism that combines physical plugging and chemical inhibition.

Keywords: sodium alginate; drilling fluid; wellbore stability; rheology; salt invasion stability

check for updates

Academic Editors: Lucian-Ionel Cioca and Elena Simina Lakatos

Received: 27 March 2025
Revised: 14 April 2025
Accepted: 16 April 2025
Published: 21 April 2025

Citation: Huang, C.; Mu, L.; Gong, X. The Development of an Alginate Drilling Fluid Treatment Agent for Shale and a Study on the Mechanism of Wellbore Stability Sealing. *Processes* **2025**, *13*, 1250. https://doi.org/10.3390/pr13041250

Copyright: © 2025 by the authors. Licensee MDPI, Basel, Switzerland. This article is an open access article distributed under the terms and conditions of the Creative Commons Attribution (CC BY) license (https://creativecommons.org/licenses/by/4.0/).

1. Introduction

Shale formations are prone to wellbore instability during drilling due to the presence of a large amount of clay minerals and abundant microcracks [1–3]. Due to its unique physical and chemical properties such as fluidity, viscosity, density, and thermal conductivity, drilling fluid can play multiple roles, for example, carrying rock debris, balancing formation pressure, stabilizing wellbore walls, and cooling and lubricating drill bits. Therefore, drilling fluid is also a key factor affecting wellbore stability performance [4–6]. Due to its environmentally friendly and low-cost characteristics, water-based drilling fluids are highly favored by the industry. However, their relatively poor rheological, salt leaching, and temperature stability also severely limit their use in the industry. Therefore, the targeted development of environmentally friendly drilling fluids with excellent rheological,

salt leaching, and temperature stability has become an urgent problem to be solved in the drilling industry.

Alginate is a high-molecular-weight polysaccharide composed of β-D-mannuronic acid (M) and α-L-guluronic acid (G). Its high molecular weight allows it to form high viscosity solutions in water, and its long-chain structure can form a network structure in water, further increasing the viscosity of the solution [7–9]. In addition, alginate molecular chains will undergo directional alignment under shear force, resulting in a decrease in viscosity. After the shear force disappears, the molecular chains re-entangle and the viscosity recovers. Alginate can react with divalent cations (such as calcium ion Ca^{2+}) to form a gel structure, giving it a certain gel strength. Therefore, alginate has good rheological properties. In addition, alginate also has excellent water solubility, thermal stability, environmental friendliness, and other characteristics, so these physical and chemical properties make alginate have a wide range of potential applications in drilling fluids [7,10]. Zhang [11] et al. successfully prepared double crosslinked high-performance gels (d_PPGs) with a storage modulus up to 86,445.0 Pa by two-step method to solve the problems of insufficient mechanical properties and a poor plugging effect of prefabricated particle gels (PPGs). The results of the core displacement experiment showed that the sealing efficiency of d_PPGs on fractures reached 99.83%. In 2022, Lalji et al. formulated saltwater drilling fluid by compounding sodium alginate, graphene oxide, and polymer pure bone (PB), and found that the synergistic effect of sodium alginate and graphene oxide can significantly reduce filtration loss [7]. In 2023, Lalji et al. further compared the effects of sodium alginate, polyanionic cellulose (PAC-LV), partially hydrolyzed polyacrylamide (PHPA), and PB on the properties of drilling fluid, and systematically evaluated the effects of four treatment agents on the rheological parameters of drilling fluid. The results showed that sodium alginate exhibited excellent performance in regulating flow and could significantly improve the rheological properties of the slurry, such as apparent viscosity (AV), plastic viscosity (PV), dynamic shear force (YP), dynamic plastic ratio (DPR), and static shear force [12]. Brahmi et al. [13] found that sodium alginate polysaccharide chains contain a large number of polar groups, which bind to montmorillonite through hydrogen bonding and adsorb on the surface of clay particles. In their study, they found that the interaction between sodium alginate and montmorillonite is significantly affected by the pH value, and the adsorption effect is more significant in acidic environments, mainly concentrated on the outer surface of montmorillonite. By adjusting the pH value of the drilling fluid system, its rheological properties can be effectively controlled to achieve specific rheological parameter goals (Figure 1).

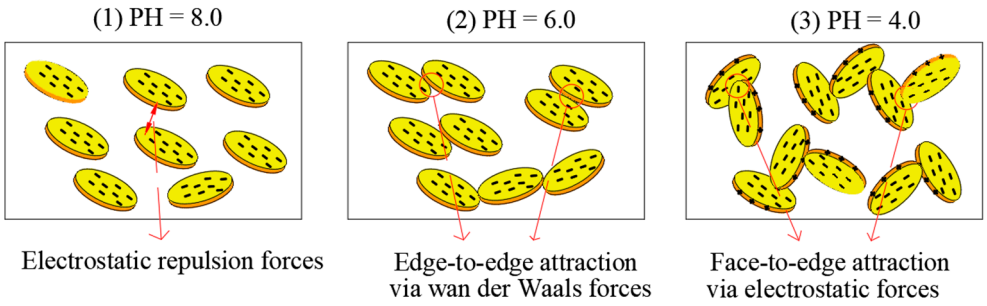


Figure 1. pH response characteristics of drilling fluid.

In summary, certain research has been conducted on sodium alginate water-based drilling fluids both domestically and internationally, and it has been found that sodium alginate, as a flow regulator, exhibits excellent performance in adjusting the rheological and water retention properties of drilling fluids. However, there is currently no systematic study on the viscosity increasing and filtration reducing mechanisms of sodium alginate drilling

fluids, especially their performance under salt immersion conditions. Therefore, this article conducts detailed research on the rheological properties, salt immersion stability, and temperature stability of sodium alginate drilling fluids, aiming to develop environmentally friendly drilling fluids with excellent rheological properties, salt immersion resistance, and temperature stability.

2. Experiments and Testing

Sodium-based bentonite (Na Bt) is the most widely used slurry material in water-based drilling fluids. After hydration, it has good slurry making ability, significant shear dilution, and suitable thixotropy. It can increase viscosity and shear, clean the wellbore, carry rock debris, reduce filtration, improve mechanical drilling speed, and maintain wellbore stability. However, under salt invasion conditions, it is easy to deteriorate the performance of the drilling fluid, greatly limiting its use in rock formations [14,15]. This article introduces an anti-salt treatment agent—sodium alginate (SA) based on bentonite water-based drilling fluid, and compares it with commonly used treatment agents Na-CMC [16,17] and PAC [18,19] to systematically evaluate the rheological properties, filtration reduction, and high-temperature resistance of sodium alginate-type drilling fluid.

2.1. Test Materials

Tables 1 and 2 show the materials and information of instruments.

Table 1. Materials required for the test.

Reagents Name	Manufacturer	Specifications
Bentonite	Industrial grade	Jianping Rongchang Mining Co., Ltd. (Chaoyang, China)
Sodium chloride	Analytical pure	Beijing Baiao Innovation Technology Co., Ltd. (Beijing, China)
Potassium chloride	Analytical pure	Beijing Baiao Innovation Technology Co., Ltd. (Beijing, China)
Sodium hydroxide	Analytical pure	Jinan Zhengkang Chemical Co., Ltd. (Jinan, China)
Anhydrous sodium carbonate	Analytical pure	Wuxi Jingke Chemical Co., Ltd. (Wuxi, China)
Sodium alginate	Analytical pure	Shandong Fengtai Biotechnology Co., Ltd. (Jinan, China)

Table 2. Information on instruments required for the experiment.

Equipment Name	Model	Manufacturer
Analytical balance	FA2004	Mettler Toledo Instruments Shanghai Company
High-speed centrifuge	GT10-2	Beijing New Era Beili Medical Equipment Co.
High-speed mixer	GJS-B12K	Tianjin Hengxing Chemical Reagent Manufacturing Co., Ltd.
High-temperature hot rolling furnace	XGRL-4	Qingdao Senxin Co., Ltd.
Six speed rotational viscometer	ZNN-D6B	Qingdao Shande Petroleum Instrument Co., Ltd.
High-temperature and high-pressure filtration instrument	STA-449F3	Germany Naichi Instrument Manufacturing Co., Ltd.
Rotational rheometer	DHR-2	Waters Corporation, Milford, MA, USA
SEM	S-4800	Hitachi, Ltd., Tokyo, Japan
Zeta potential meter	NS-90Z	Zhuhai Ouaike Instrument Co., Ltd.

Some of the experimental apparatuses are presented in Figure 2.

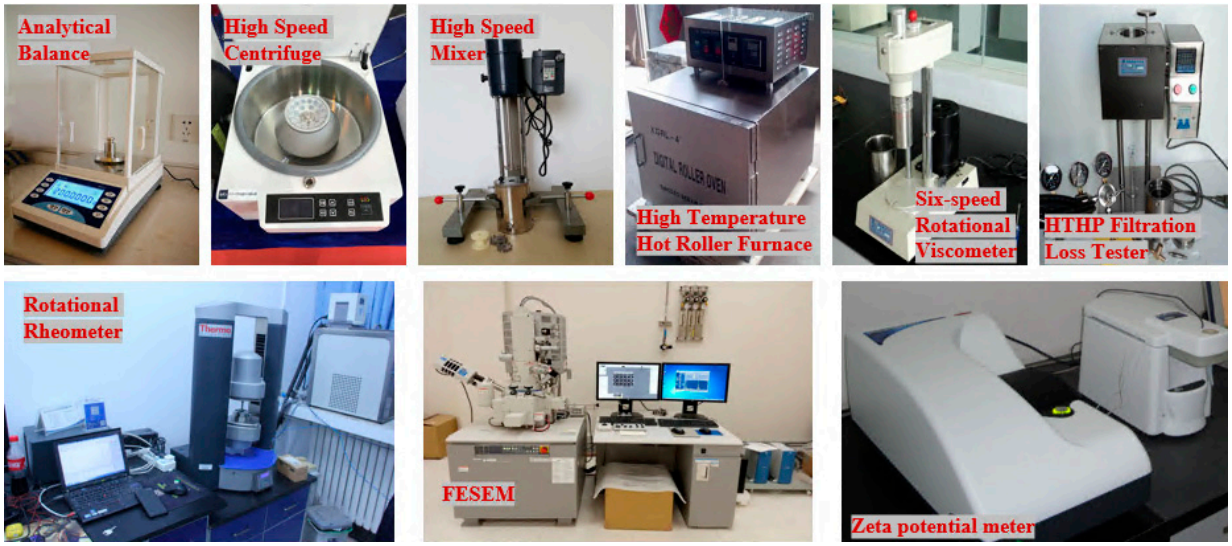


Figure 2. Experimental apparatus physical diagram.

2.2. Preparation of Drilling Fluid

The preparation process of drilling fluid is as follows (Figure 3):

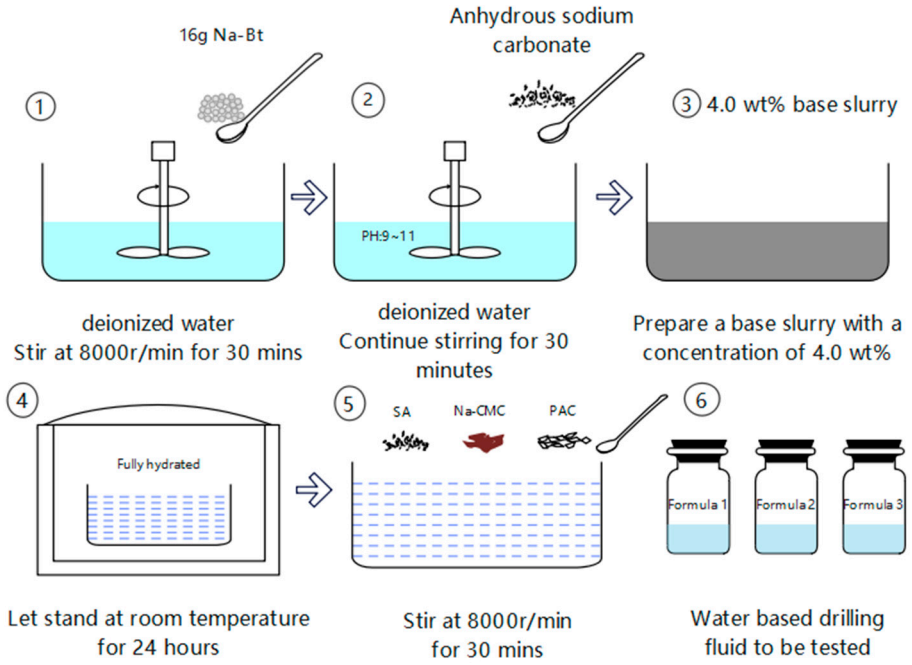


Figure 3. Preparation process diagram.

(1) Preparation of base slurry (BF):

Weigh 16 g of sodium-based bentonite (Na Bt) in 400 mL of deionized water and stir at 8000 rpm for 30 min. Then, add anhydrous sodium carbonate to adjust the pH to 9–11 and continue stirring for 30 min to prepare a base slurry (BF) with a concentration of 4.0 wt%.

(2) Static hydration:

Let the prepared base slurry (BF) stand at room temperature for 24 h to fully hydrate.

(3) Preparation of drilling fluid:

Slowly add SA, Na CMC, and PAC treatment agents of different concentrations to the above base slurry and stir at high speed for 30 min at 6000 rpm to prepare water-based drilling fluids of different formulations for testing.

2.3. Performance Testing

In order to comprehensively evaluate the performance of SA/BF under normal and salt invasion conditions, independent tests were conducted on the rheological properties, filtration characteristics, and temperature resistance of SA/BF drilling fluid before and after salt invasion. Different concentrations of NaCl and KCl were added to the SA/BF drilling fluid to indicate the salt invasion state.

2.3.1. Rheological Performance Testing

The rheological properties of drilling fluids were characterized using the apparent viscosity (AV), plastic viscosity (PV), yield point (YP), and yield-point-to-plastic-viscosity ratio (DPR) within the Bingham model [18,19]. Prior to the rheological property tests, the drilling fluids were aged for 16 h at 100 °C in an aging tank. The values of AV, PV, YP, and DPR can be calculated according to Equations (1)–(4), which are as follows:

$$AV = \varphi 600/2 \quad (1)$$

$$PV = \varphi 600 - \varphi 300 \quad (2)$$

$$YP = 0.511 \times (2 \times \varphi 300 - \varphi 600)\ (Pa) \quad (3)$$

$$DPR = YP/PV\ (Pa) \quad (4)$$

where φ 300 and φ 600 represent pouring 350 mL of drilling fluid to be tested into a measuring cup and fixing it on the tray of a high-speed centrifuge. Set the rotation speed to 300 r/min and 600 r/min, and record the readings.

2.3.2. Filtration Performance Test

The filtration loss of drilling fluid is mainly evaluated by the filtration loss and mud cake quality [20–22]. The principle is that the free water in the drilling fluid infiltrates the rock fractures under the pressure difference, while the solid particles form mud cakes on the wellbore wall, thereby reducing permeability and preventing further penetration of the drilling fluid into the formation. Firstly, the drilling fluid was aged for 16 h in an aging tank at a temperature of 100 °C. According to the American Petroleum Institute (API) standard [23,24], the measurement method for filtration loss is to use Waterman 50 filter paper (diameter 90 mm), apply a pressure of 100 ± 5 psi at room temperature, and measure the volume of the filtrate in mL after 30 min.

2.3.3. Temperature Resistance Performance Test

To evaluate the stability and filtration properties of the drilling fluid system under different thermal environments and salt invasion conditions, the drilling fluid samples were subjected to thermal rolling aging treatment for 16 h at 25 °C, 80 °C, 100 °C, and 120 °C, respectively. Subsequently, their filtration volumes were tested in three environments: salt free, 20% NaCl, and 20% KCl. This was carried out to investigate the impact of high-temperature and high-salt conditions on the filtration control ability of the drilling fluid.

3. Results and Discussion

3.1. Rheological Performance

By comparing the addition of different concentrations of SA, Na CMS, and PAC-LV in BF before and after salt invasion, the apparent viscosity (AV), plastic viscosity (PV), dynamic shear force (YP), and static shear force of the drilling fluid were tested. The apparent viscosity (AV) represents the internal friction between solid and liquid molecules. Plastic viscosity (PV) represents the frictional strength between the solid–liquid phase.

Dynamic shear force (YP) refers to the interaction force between polymer and viscous particles. Static shear force (SCF) reflects the gel strength of drilling fluid in static state.

According to the analysis of Figure 4, it can be seen that after adding different concentrations of SA, CMC, and PAC to BF, the apparent viscosity (AV), plastic viscosity (PV), and dynamic shear force (YP) of the drilling fluid will all increase. When the amount of treatment agent added exceeds 0.4 wt%, the growth rate effect of the apparent viscosity (AV), plastic viscosity (PV), and dynamic shear force (YP) of the drilling fluid will be weakened. Moreover, the study found that the apparent viscosity and plastic viscosity of SA are better than CMC and PAC, and the cutting effect is comparable to the two treatment agents. The addition of 0.1–0.5 wt% SA can maintain the yield–plastic viscosity ratio in the range of 0.5–0.6 Pa/mPa·s. This is beneficial for enhancing the rock fragmentation and cuttings suspension during the drilling process.

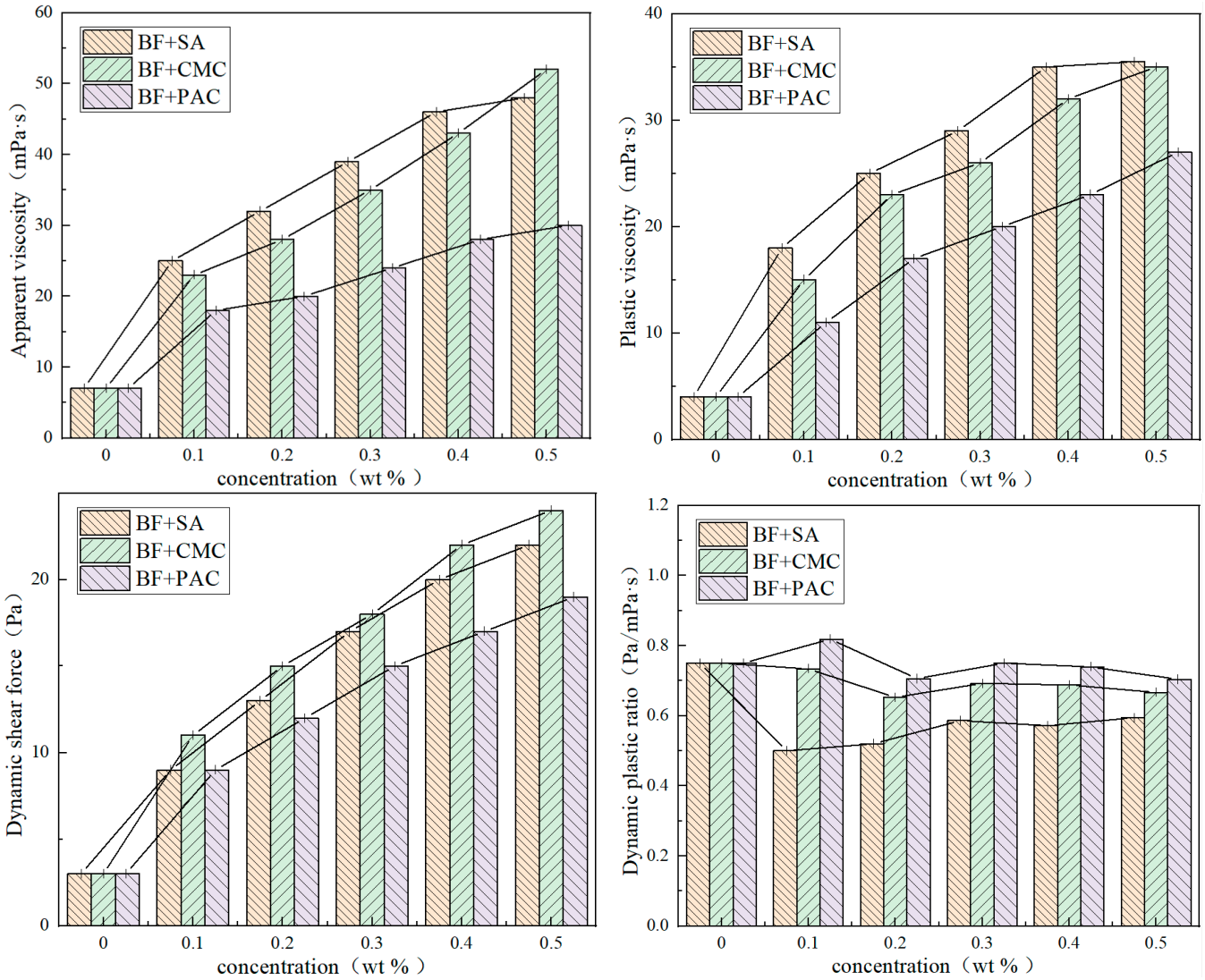


Figure 4. Effect of changes in rheological parameters.

In order to compare the rheological properties of drilling fluid under salt invasion, 0.4 wt% SA was added to BF, and different concentrations of NaCl and KCl were added to analyze the rheological properties of drilling fluid before and after salt invasion. The analysis results are shown in Figure 4.

According to the analysis in Figure 5, the apparent viscosity (AV), plastic viscosity (PV), and dynamic shear force (YP) of the drilling fluid after salt invasion all show an

upward trend. Under NaCl salt invasion conditions, the apparent viscosity (AV) and plastic viscosity (PV) of the BF + 0.4 wt% SA system first decrease and then increase with increasing NaCl concentration. When the NaCl concentration reaches 16 wt%, the apparent viscosity (AV) and plastic viscosity (PV) of the drilling fluid decrease to 32 mPa·s and 25 mPa·s, respectively, but are still significantly higher than the system without SA added. The dynamic shear force (YP) of BF + 0.4 wt% SA gradually increases with the increase of NaCl concentration, and the maximum dynamic shear force is 20 pa when the NaCl concentration is 20 wt%. In the state of KCl salt invasion, the apparent viscosity (AV) and plastic viscosity (PV) of BF + 0.4 wt% SA first increase and then decrease with the increase of KCl concentration. When the KCl concentration is 8 wt%, the apparent viscosity (AV) and plastic viscosity (PV) of the drilling fluid are the highest, at 45 mPa·s and 35 mPa·s, respectively. When the KCl concentration is 20 wt%, the apparent viscosity (AV) and plastic viscosity (PV) of the drilling fluid are the lowest, at 38 mPa·s and 25 mPa·s, respectively, which is much higher than that of the drilling fluid without SA addition. Under KCl salt invasion, the dynamic shear force of BF + 0.4 wt% SA is much greater than that without SA addition, indicating that salt invasion does not affect the rheological properties of BF + 0.4 wt% SA drilling fluid.

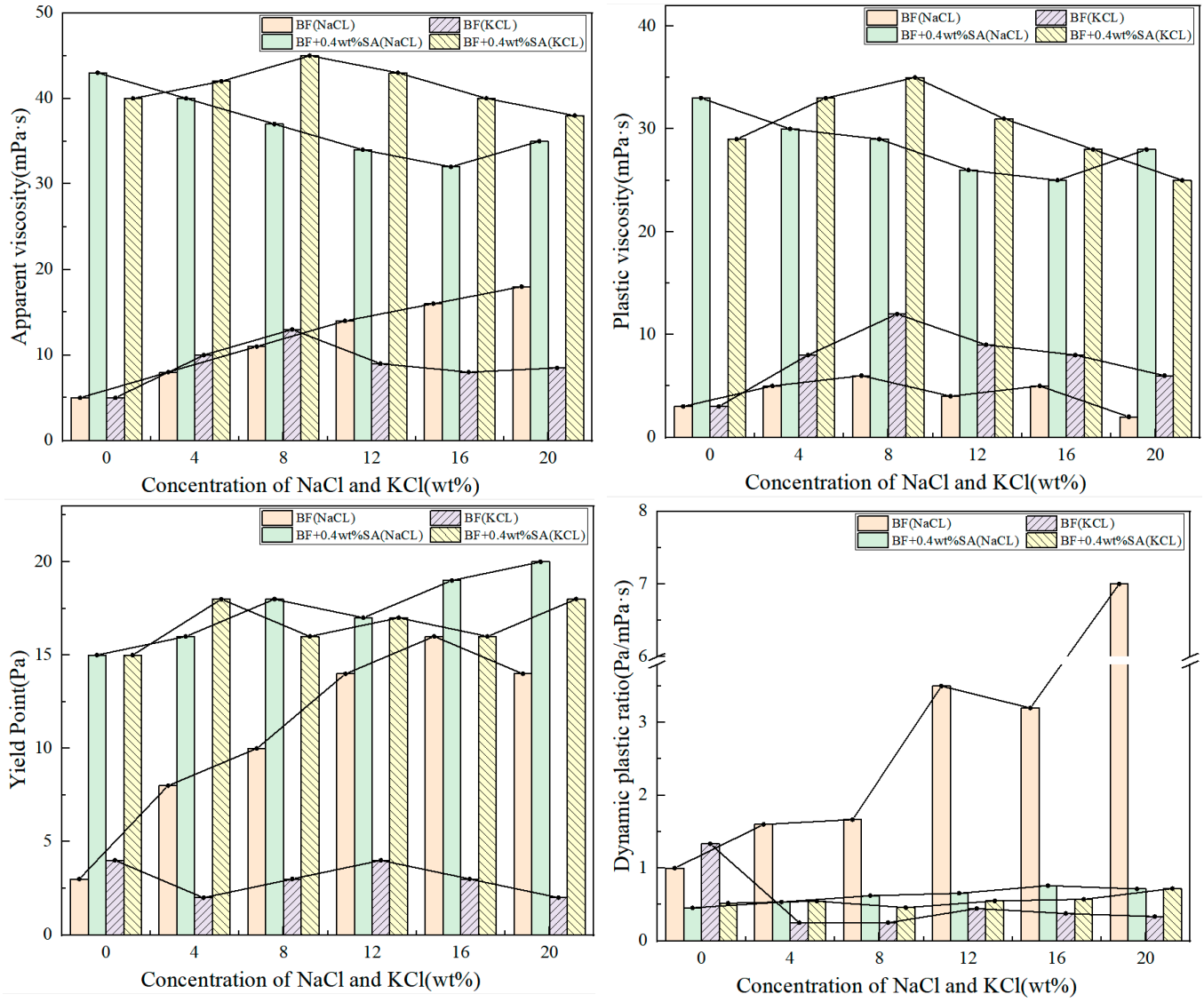


Figure 5. Rheological properties under salt invasion state.

Analysis shows that in the BF + 0.4 wt% SA drilling fluid system, the invasion of Na^+ particles and K^+ ions does not damage the spatial network structure between SA and clay particles, nor does it damage the stability of the drilling fluid system. In order to further study the stability under salt invasion, the zeta potential test was conducted to reflect the surface charge of clay particles in SA/BF to determine the stability of the drilling fluid. Generally speaking, when the absolute value of the zeta potential in a colloidal system is greater than 30 mV, the colloid is more stable, and the larger the absolute value, the more stable the colloid.

Figure 6 shows the zeta potential changes of four drilling fluid systems under different concentrations of NaCl and KCl salt invasion. Generally speaking, the larger the zeta potential value, the more stable the colloid. When the zeta value is greater than 30 mV, the colloid is more stable. Analysis shows that under NaCl and KCl salt invasion conditions, the potential values of the four drilling fluid systems gradually decrease with increasing concentration, and the potential value of the BF + 0.4 wt% SA drilling fluid system is the highest. This is because the uronic acid units in the SA molecular chain bind to the oxygen atoms on the surface of clay particles through hydrogen bonds, thereby firmly adsorbing around the particles. At the same time, the sodium carboxylate group in the SA molecular chain thickens the hydration film on the particle surface under hydration, resulting in an increase in the absolute value of the zeta potential. In addition, the hydroxyl groups in SA bind to the oxygen atoms on the surface of clay through hydrogen bonding and form coordination bonds with Al^{3+} at the edge of the broken bond, thereby firmly adsorbing onto clay particles. At the same time, the sodium carboxylate group in SA thickens the hydration film of clay particles under hydration, increases the absolute value of the zeta potential, enhances electrostatic repulsion, effectively prevents large-scale agglomeration of particles, and maintains the stability of the colloidal dispersion system [25].

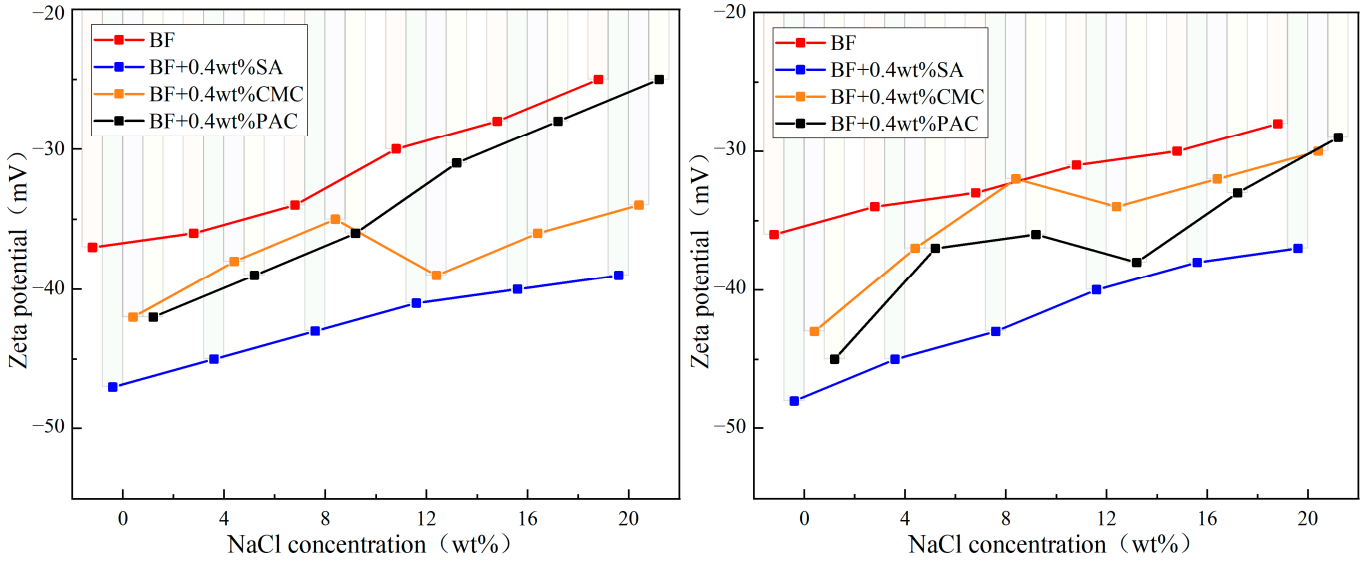


Figure 6. Potential values under salt invasion state.

3.2. Filtration Performance

In drilling operations, drilling fluid infiltrates into the pores of the wellbore rock formation due to pressure differences, a process known as drilling fluid filtration. The amount of filtration loss is directly related to the permeability of the formed mud cake. High-quality filtrate reducers can generate dense and low-permeability mud cakes, effectively reducing the loss of drilling fluid. The following figure shows the filtration loss when adding SA, CMC, and PAC to the testing drilling fluid.

According to the analysis in Figure 7, adding SA, CMC, and PAC to BF can all reduce the filtration loss of drilling fluid, and the filtration loss gradually decreases with the increase in additive dosage. Among them, SA has the most significant effect on reducing filtration loss. When PAC is used as an additive, the reduction effect of drilling fluid filtration loss is the worst. Therefore, adding SA to BF can effectively reduce the filtration loss of drilling fluid.

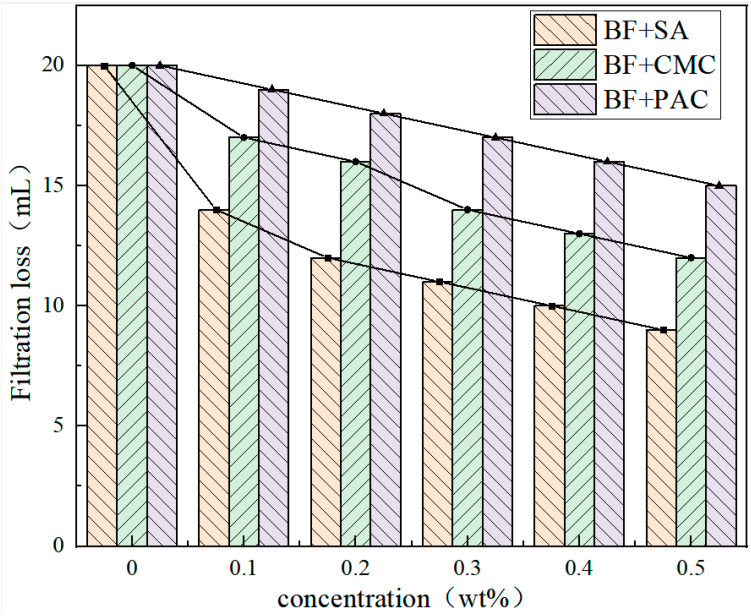


Figure 7. Filtration loss of drilling fluids with different concentrations to be tested.

In order to analyze the filtration effect of drilling fluid under salt invasion, 0.4 wt% SA, 0.4 wt% CMC, and 0.4 wt% PAC were added to BF, and different concentrations of NaCl and KCl solutions were added to test the effect of NaCl and KCl solution concentrations on the filtration loss of drilling fluids. The test results are shown in Figure 8.

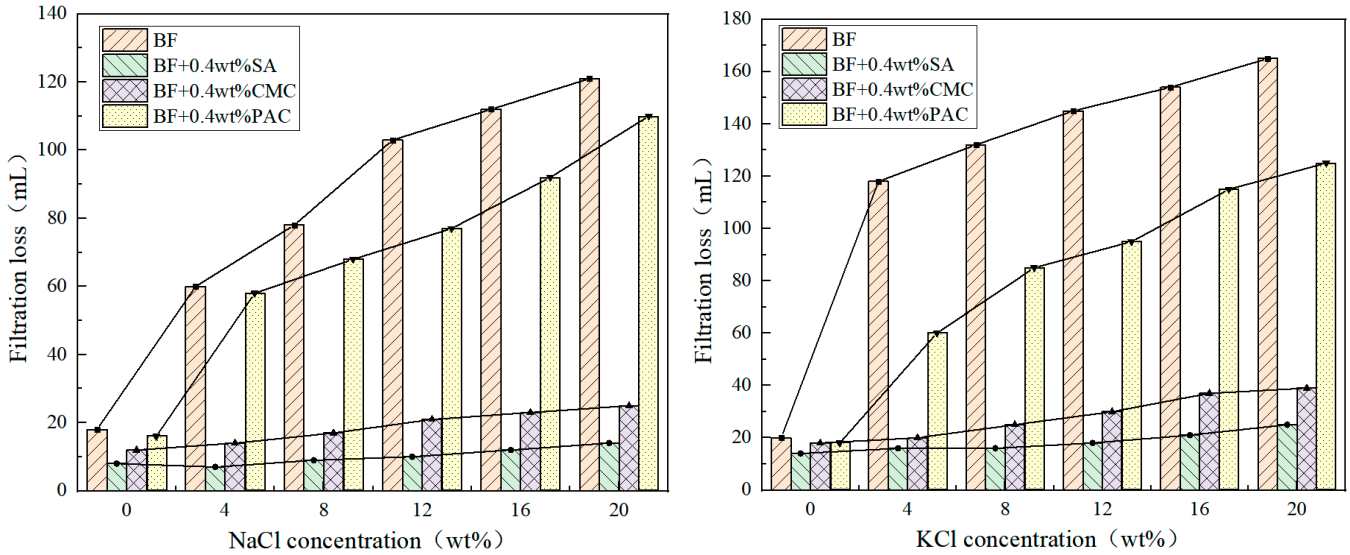


Figure 8. Filter losses under different concentrations of NaCl and KCl invasion states.

According to the analysis of Figure 8, with the increase of NaCl and KCl concentrations, the filtration loss of BF and BF + 0.4 wt% PAC increases significantly, while the filtration loss of BF + 0.4 wt% CMC slightly increases. The filtration loss of BF + 0.4 wt% SA does not

show significant changes, indicating that the anti-filtration effect of the BF + 0.4 wt% SA system is obvious.

After salt invasion in the BF + 0.4 wt% SA drilling fluid system, coarser clay particles can form supporting structures in the rock pores, reducing pore size, while finer particles fill the gaps between coarse particles, further reducing the permeability of the mud cake. The filtration performance analysis of the BF + SA drilling fluid system before and after salt invasion is shown in Figure 9.

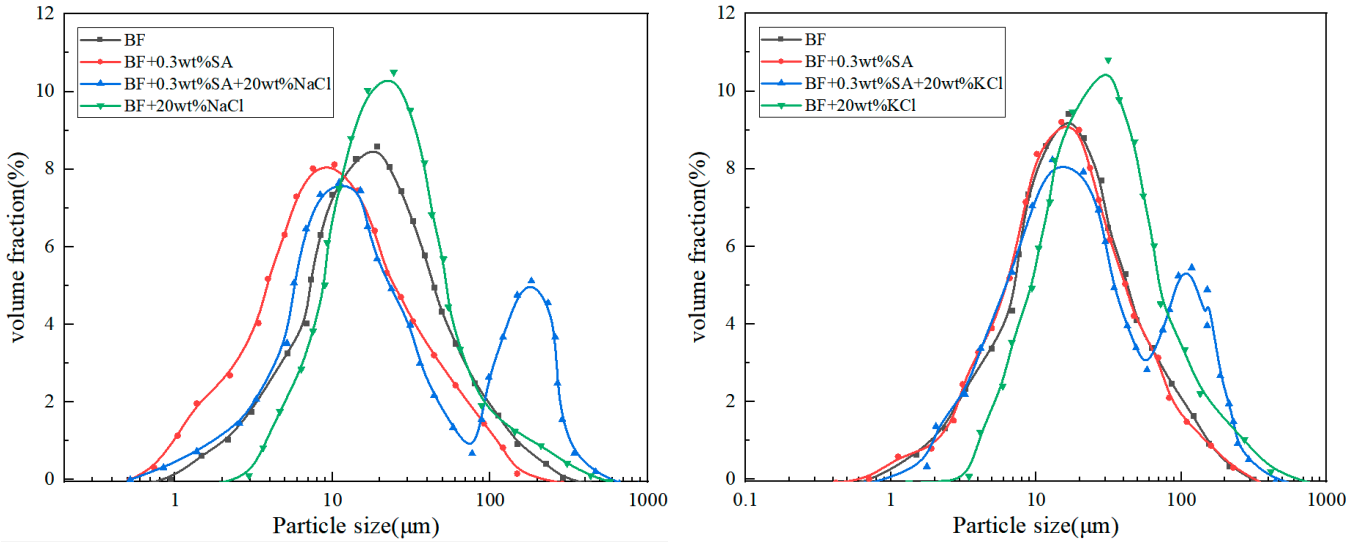


Figure 9. Particle size distribution under salt invasion state.

Figure 9 shows that the median particle size (D50) of clay particles significantly increases after salt invasion, and the particle size distribution tends to be concentrated. Electrolyte cations (such as Na^+, K^+) undergo ion exchange with water molecules between clay particle layers, weakening the electrostatic repulsion between crystal layers and causing particle flocculation and size increase. Among them, K^+, due to its smaller hydration radius, is more likely to enter the clay crystal layer, increase interlayer positive charges, and thus more significantly promote particle flocculation. The particle size distribution of SA/BF exhibits a "bimodal" characteristic, indicating slight flocculation of clay particles. A small amount of coarser particles can form bridging structures in the large pores of rock formations, while finer particles fill the pores, forming low-permeability mud cakes. This not only reduces filtration loss but also enhances the stability and sealing performance of the wellbore.

In addition, SA is a hydrophilic polyanionic electrolyte, and the uronic acid units on its molecular chain are tightly bound to the surface of clay particles through hydrogen and ionic bonds. The hydrated sodium carboxylate group significantly increases the hydration film thickness of clay particles, while also increasing the negative charge on the particle surface, thereby weakening the particle aggregation or flocculation phenomenon caused by the decrease in electrostatic repulsion. Moreover, multiple SA molecular chains can adsorb multiple clay particles, forming a composite spatial network structure, further promoting the hydration and dispersion of particles, and enhancing colloidal stability. This structure not only increases flow resistance and improves the rheological properties of drilling fluid but also helps to form a uniformly distributed and dense mud cake, effectively reducing filtration loss and enhancing wellbore stability and sealing performance (Figure 10).

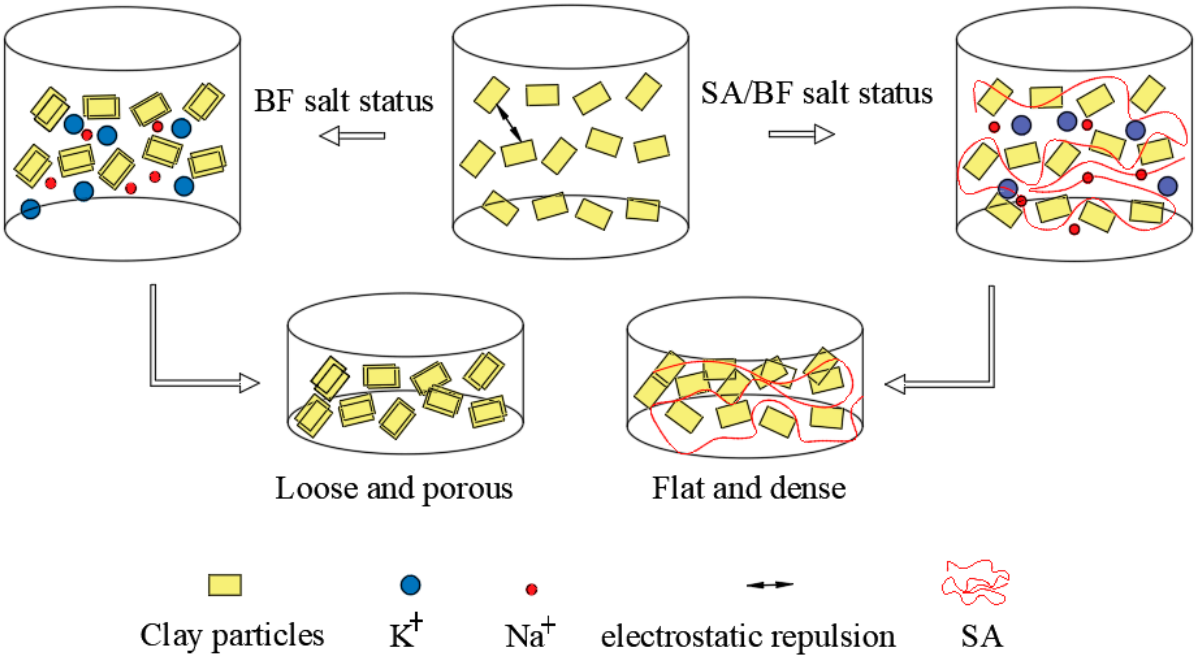


Figure 10. Schematic diagram of salt resistance mechanism.

3.3. Temperature Resistance Performance

Figure 11 shows the fluid loss of the drilling fluid after hot rolling for 16 h at different temperatures under the conditions of no salt invasion and when the concentrations of NaCl and KCl are 20 wt%.

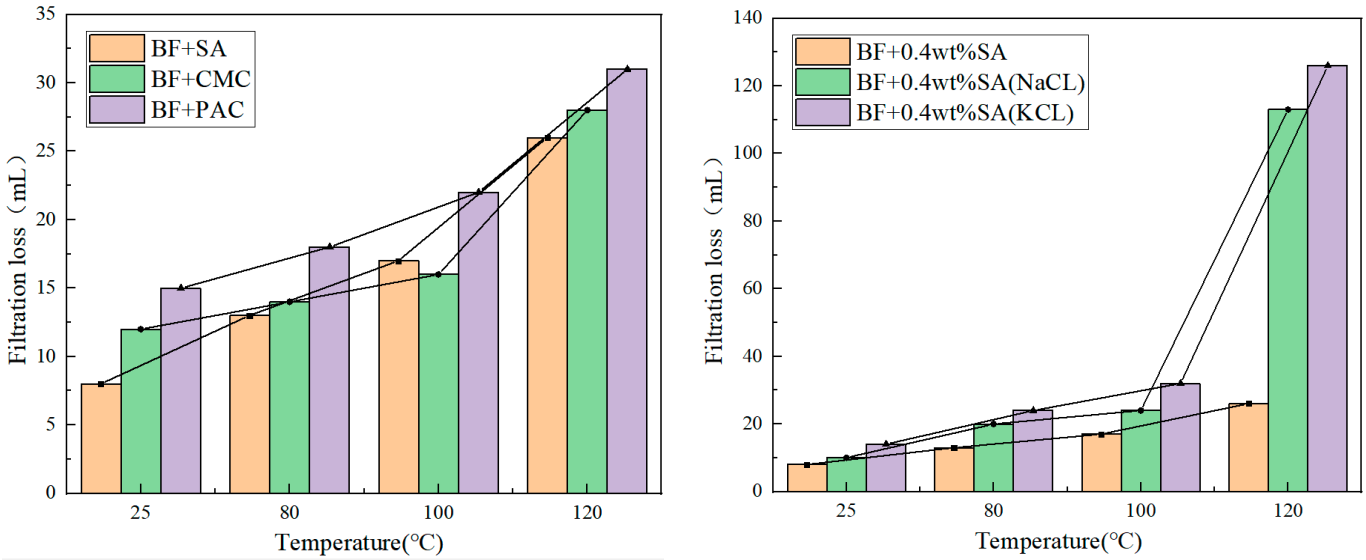


Figure 11. Comparison test of temperature resistance performance.

Figure 11 shows that the filtration loss of drilling fluid increases with temperature before and after salt invasion, and the filtration loss of drilling fluid is the smallest in the BF + 0.4 wt% SA system, indicating that the rheological properties of drilling fluid are the best under this condition. Before salt invasion, when the temperature was within 120 °C the filtration loss of the three drilling fluids increased slowly, indicating that all three drilling fluid systems were suitable for formations below 120 °C before salt invasion, with the BF + 0.4 wt% SA drilling fluid having the best filtration loss effect. After salt invasion, the filtration efficiency of the BF + 0.4 wt% SA drilling fluid system in NaCl and KCl systems was analyzed. When the temperature was ≤100 °C, the filtration rate of the BF + 0.4 wt%

SA drilling fluid increased slowly. When the temperature was >100 °C, the filtration rate of drilling fluid increased rapidly, indicating that the BF + 0.4 wt% SA drilling fluid system is suitable for formations below 100 °C after salt invasion.

When the temperature exceeds 100 °C, the deterioration of the BF + 0.4 wt% SA drilling fluid system is due to the high temperature damaging the molecular structure of the polymer, making it impossible to maintain the stretched state of the molecular chain, resulting in a decrease in the binding force between the polymer and clay [23]. Clay particles coagulate at high temperatures, and the pores of the mud cake further increase, leading to an increase in filtration loss (Figure 12).

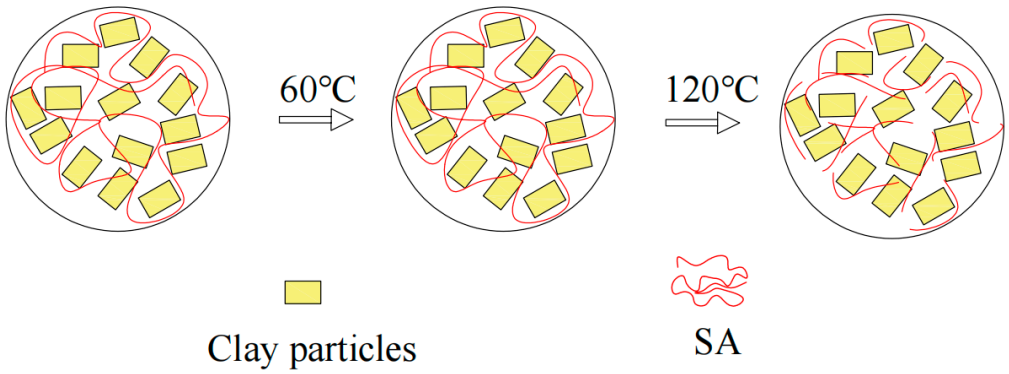


Figure 12. Schematic diagram of temperature deterioration.

4. Conclusions

(1) When 0.4 wt% SA was added to BF before salt invasion, the absolute value of the zeta potential was the highest, the colloidal stability was the best, AV, PV, and YP were significantly improved, and the effect of excessive addition was weakened.

(2) In the BF + 0.4 wt% SA drilling fluid system, NaCl (16 wt%) had the lowest AV and PV values after salt invasion, with values of 32 mPa·s and 25 mPa·s, respectively. After salt invasion with KCl (20 wt%), AV and PV were minimized, with values of 38 mPa·s and 25 mPa·s, respectively, both of which were much better than the system without SA. Because SA enhances the zeta potential, inhibits particle agglomeration, and maintains dispersion stability, it improves the rheological properties.

(3) Compared with CMC and PAC, SA has the best effect in reducing filtration loss before and after salt invasion, and the anti-filtration effect of the BF + 0.4 wt% SA system is the most obvious, because in this state the clay particles slightly coagulate to form a low-permeability mud cake with coarse particle bridging and fine particle filling, which not only reduces filtration loss but also enhances the stability and sealing performance of the wellbore.

(4) The BF + 0.4 wt% SA drilling fluid system before salt invasion is suitable for formations below 120 °C, and the BF + 0.4 wt% SA drilling fluid system after salt invasion is suitable for formations below 100 °C because temperatures exceeding 100 °C may damage the molecular structure of polymers, making it impossible to maintain the stretched state of molecular chains, resulting in a decrease in the binding force between polymers and clay and an increase in the filtration loss.

(5) After salt invasion, the sodium alginate drilling fluid system thickens the hydration film through uronic acid units and carboxyl groups, increasing the zeta potential. At the same time, the bimodal particle size distribution indicates that the clay undergoes slight flocculation, optimizing the sealing structure, reducing filtration loss, and enhancing wellbore stability.

Author Contributions: C.H., investigation, conceptualization, and writing—original draft. L.M., conceptualization, formal analysis, and writing—review and editing. X.G., investigation, formal analysis, and writing—review and editing. All authors have read and agreed to the published version of the manuscript.

Funding: This research received no external funding.

Data Availability Statement: The original contributions presented in this study are included in the article material. Further inquiries can be directed to the corresponding author.

Conflicts of Interest: Author Cheng Huang was employed by the company Shengli Oilfield Oil Development Center Co., Ltd. Author Xuefeng Gong was employed by the company Shengli Oilfield Zhongsheng Industrial Co., Ltd. The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

References

1. Chang, L.; Wang, H.; Zhuo, L.; Huang, H.; Zou, L.; Wang, Q.; Li, H.; Yu, J. Analysis of wellbore stability considering the interaction between fluid and shale. *Geofluids* **2023**, *2023*, 4488607. [CrossRef]
2. Zheng, D.; Ozbayoglu, E.; Miska, S.; Zhang, J. Experimental study of anisotropic strength properties of shale. In Proceedings of the 57th U.S. Rock Mechanics/Geomechanics Symposium, Atlanta, GA, USA, 25–28 June 2023; ARMA: Karaikal, India, 2023; p. ARMA–2023-0128.
3. Rafieepour, S.; Zheng, D.; Miska, S.; Ozbayoglu, E.; Takach, N.; Yu, M.; Zhang, J. Combined experimental and well log evaluation of anisotropic mechanical properties of shales: An application to wellbore stability in bakken formation. In Proceedings of the SPE Annual Technical Conference and Exhibition, Virtual, 26–29 October 2020; SPE: Richardson, TX, USA, 2020; p. D021S015R006.
4. Gautam, S.; Guria, C.; Rajak, V.K. A state of the art review on the performance of high-pressure and high-temperature drilling fluids: Towards understanding the structure-property relationship of drilling fluid additives. *J. Pet. Sci. Eng.* **2022**, *213*, 110318. [CrossRef]
5. Yang, J.; Sun, J.; Wang, R.; Qu, Y. Treatment of drilling fluid waste during oil and gas drilling: A review. *Environ. Sci. Pollut. Res.* **2023**, *30*, 19662–19682. [CrossRef] [PubMed]
6. Al-Shargabi, M.; Davoodi, S.; Wood, D.A.; Al-Musai, A.; Rukavishnikov, V.S.; Minaev, K.M. Nanoparticle applications as beneficial oil and gas drilling fluid additives: A review. *J. Mol. Liq.* **2022**, *352*, 118725. [CrossRef]
7. Lalji, S.M.; Ali, S.I.; Sohail, H.; Misbah, A.R.; Azam, K.; Navaid, N. Combine effect of graphene oxide, pure-bore and sodium alginate on rheological and filtration properties and cutting carrying capacity of water-based drilling fluid. *Chem. Pap.* **2022**, *76*, 6461–6473. [CrossRef]
8. Lalji, S.M.; Ali, S.I.; Yousufi, M.M.; Sultan, M.A.; Fatima, K.; Misbah, A.R. Factorial analysis for the impact on filtration properties of water-based drilling fluid after the addition of graphene oxide, pure-bore, and sodium alginate. *Arab. J. Geosci.* **2023**, *16*, 132. [CrossRef]
9. Wei, Z.; Wang, M.; Shan, W.; Guo, M.; Li, Y.; Qin, W.; Li, K.; An, Y.; Bo, K. Synergistic effects of potassium alginate and silicates co-inhibition performance in shale hydration. *J. Mol. Liq.* **2024**, *393*, 123538. [CrossRef]
10. Wei, Z.; Wang, M.; Li, Y.; An, Y.; Li, K.; Bo, K.; Guo, M. Sodium alginate as an eco-friendly rheology modifier and salt-tolerant fluid loss additive in water-based drilling fluids. *RSC Adv.* **2022**, *12*, 29852–29864. [CrossRef]
11. Zhang, X.; Deng, J.N.; Yang, K.; Li, Q.; Meng, S.Y.; Sun, X.X.; Song, Z.-Z.; Tian, Y.-D.; Zhang, S.-A.; Liu, X.-J.; et al. High-strength and self-degradable sodium alginate/polyacrylamide preformed particle gels for conformance control to enhance oil recovery. *Pet. Sci.* **2022**, *19*, 3149–3158. [CrossRef]
12. Lalji, S.M.; Ali, S.I.; Khan, M.A. Study of rheological characteristics of a water-based drilling fluid in presence of biopolymers, synthetic polymer, and modified natural polymer. *Pet. Chem.* **2023**, *63*, 906–916. [CrossRef]
13. Brahmi, M.; Essifi, K.; Elbachiri, A.; Tahani, A. Adsorption of sodium alginate onto sodium montmorillonite. *Mater. Today Proc.* **2021**, *45*, 7789–7793. [CrossRef]
14. Liu, J.; Zhang, T.; Sun, Y.; Lin, D.; Feng, X.; Wang, F. Insights into the high temperature-induced failure mechanism of bentonite in drilling fluid. *Chem. Eng. J.* **2022**, *445*, 136680. [CrossRef]
15. Pan, Y.; Zhang, X.; Ji, C.; Zhan, Q.; Li, Z.; Guan, J.; Huang, J. Modification method of high-efficiency organic bentonite for drilling fluids: A review. *Molecules* **2023**, *28*, 7866. [CrossRef]
16. Li, J.; Wen, M.; Jiang, Z.; Xian, L.; Liu, J.; Chen, J. Development and characterization of a surfactant responsive to redox conditions for gas recovery in foam drainage. *Sci. Rep.* **2025**, *15*, 511. [CrossRef]

17. El-Bana, A.A.; Barakat, N.M.; Abdelghany, A.M.; Meikhail, M.S. Effect of surfactants addition on physical, structure and antimicrobial activity of (Na-CMC/Na–Alg) biofilms. *Polym. Bull.* **2023**, *80*, 2883–2909. [CrossRef]
18. Li, J.; Wen, M.; Jiang, Z.; Gao, S.; Xiao, X.; Xiang, C.; Tao, J. Formulation and characterization of surfactants with antibacterial and corrosion-inhibiting properties for enhancing shale gas drainage and production. *Sci. Rep.* **2025**, *15*, 2376. [CrossRef]
19. Shi, F.J.; Feng, S.J.; Zheng, Q.T.; Zhang, X.L.; Chen, H.X. Effect of polyanionic cellulose modification on properties and microstructure of calcium bentonite. *Appl. Clay Sci.* **2022**, *228*, 106633. [CrossRef]
20. Li, J.; Wen, M.; Yang, J.; Liu, Y.; Jiang, Z.; Chen, J. Synthesis and analysis of magnetic nanoparticles within foam matrix for foam drainage gas production. *Geoenergy Sci. Eng.* **2024**, *238*, 212887. [CrossRef]
21. Liu, Y.; Zhou, L.; Wan, X.; Tang, Y.; Liu, Q.; Li, W.; Liao, J. Synthesis and Characterization of a Temperature-Sensitive Microcapsule Gelling Agent for High-Temperature Acid Release. *ACS Omega* **2024**, *9*, 20849–20858. [CrossRef]
22. Lei, M.; Sun, J.; Zhu, H.; Huang, W.; Cai, Z. Synthesis and characterization of natural rosin-modified silica nanocomposite and its green multifunctional applications for drilling fluid. *Colloids Surf. A Physicochem. Eng. Asp.* **2024**, *702*, 134994. [CrossRef]
23. Ibrahim, M.A.; Jaafar, M.Z.; Yusof, M.A.M.; Shye, C.A.; Suardi, H.; Hussin, M.F.M.; Razali, A.Z.; Idris, A.K. The influence of nanoparticle size, concentration, and functionalization on drilling fluid filtration properties. *Colloids Surf. A Physicochem. Eng. Asp.* **2024**, *693*, 134020. [CrossRef]
24. *ANSI/API SPEC 5L:2018*; Specification for Line Pipe. American Petroleum Institute (API): Washington, DC, USA, 2018.
25. Zha, H.; Fu, H.; Zeng, L.; Zhu, X.; Jia, C. Use of sodium alginate as a novel cementitious material to improve the engineering properties of disintegrated carbonaceous mudstone. *Bull. Eng. Geol. Environ.* **2022**, *81*, 431. [CrossRef]

Disclaimer/Publisher's Note: The statements, opinions and data contained in all publications are solely those of the individual author(s) and contributor(s) and not of MDPI and/or the editor(s). MDPI and/or the editor(s) disclaim responsibility for any injury to people or property resulting from any ideas, methods, instructions or products referred to in the content.