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DETERMINATION OF THE COMPOSITION AND STATIC CHARACTERISTICS OF A WATER SHUTOFF AGENT FOR THE KALAMKAS FIELD

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A B S T R A C T

This study focuses on developing and optimizing the formulation of a water shutoff agent and evaluating its static properties for application in Kalamkas field conditions. The proposed composition consists of modified starch (MS), unsaturated amides (UAM), a gelling agent (Y1), and a crosslinking agent (TN), which undergo polymerization to form a robust three-dimensional gel matrix. The research includes an assessment of the influence of reagent ratios and crosslinker concentration on the gel's rheological properties and water shutoff capacity. Experimental results demonstrate that the optimal concentration of the primary reagents – modified starch and unsaturated amides – lies in the 3.5-4.5 % range. The optimal UAM/MS ratio lies between 0.7 and 2.0, ensuring a balance between the mechanical strength and elasticity of the gel structure. The crosslinking agent concentration significantly affects gelation and structural integrity. It has been established that concentrations ranging from 0.08% to 0.10% provide an optimal crosslinking degree, preventing excessive rigidity while maintaining high-pressure resistance. The final formulation, SG-k (Strong Gel Kalamkas), was developed considering technical and economic factors. The optimized composition ensures a high-viscosity gel with a gelation time of approximately 20 hours, making it suitable for in-situ applications in the Kalamkas field. The presented results confirm that optimizing the composition of the water shutoff agent significantly improves its properties, which is critically important for reducing water inflow and leveling the profile leveling of injectivity. The findings contribute to advancing water inflow control technologies by providing a reliable and cost-effective water shutoff solution.

Keywords: profile leveling; water shutoff treatments; gelation; polymers; crosslinking.

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1. Introduction

Kazakhstan ranks among the world's leading countries in terms of mineral reserves, holding a prominent position in the global mining industry. Its territory is rich in diverse mineral resources, including oil, gas, coal, ferrous and non-ferrous metals, and rare earth elements.

Ore resources play a vital role in the country's economy. Kazakhstan holds leading positions in reserves of uranium, chromium, lead, and zinc while also being a significant producer of copper and gold [1, 2]. With its abundant mineral wealth and the active adoption of modern technologies, Kazakhstan continues to develop its mining sector, strengthening its presence in global markets.

The oil and gas industry is a cornerstone of Kazakhstan's economy, serving as the primary source of foreign currency inflows and defining the region's strategic importance on the international stage. Kazakhstan holds 12th place globally in proven oil reserves, which are concentrated mainly in the western areas of the country [3, 4]. Its substantial gas reserves also position Kazakhstan as a key player in the Central Asian hydrocarbon market [5].

Kazakhstan has expanded its hydrocarbon exports in recent years, utilizing modern transportation corridors such as the Caspian Pipeline Consortium and railway routes toward China. The oil fields of Western Kazakhstan [6], particularly in the Mangystau Region, play a critical role in these export efforts [7, 8].

The Kalamkas field, located in the Mangystau Region of the Republic of Kazakhstan, is one of the largest oil deposits in the area. Situated on the Buzachi Peninsula in the northeastern Caspian Sea, approximately 280 kilometers northeast of Aktau, Kalamkas was discovered in 1974. Exploratory drilling began on the site in 1976, and the field was put into industrial operation in 1979, with water injection commencing in 1980 [4, 9].

The Kalamkas field is characterized by a high water cut, with water content in the produced fluid reaching 86% [10].

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This issue is attributed to the extended period of field operation, challenging geological conditions, and reservoir heterogeneity both laterally and vertically [11]. Reservoir permeability varies significantly, leading to uneven distribution of injected water. Over years of profile leveling, large high-permeability channels have formed, far exceeding the initial pore space dimensions. Water injected through injection wells primarily flows through these channels, leaving low-permeability zones unrecovered.

The pronounced heterogeneity of the reservoirs and the resulting increase in water cut cause significant oil losses and a reduction in hydrocarbon recovery factors. This issue is particularly critical for fields in their late development stages, where the efficiency of the water drive system declines. Moreover, prolonged waterflooding weakens rock cementation, further complicating production stabilization.

To address these challenges, technologies involving the injection of specialized solutions containing wood chips, polyacrylamide, and ethyl resin are employed in the field [12]. Wood chips act as mechanical barriers within the reservoir, reducing the permeability of water-bearing zones and redirecting fluid flow to less permeable areas. This approach enables more uniform displacement of residual hydrocarbons [13]. Polyacrylamide, a water-soluble polymer, increases the viscosity of injected solutions, facilitating improved injection profile control and reducing water cut in produced fluids [14]. Ethyl resin hardens to form robust barriers that prevent water inflow from aquifers and enhance the reservoir's resistance to erosion [15, 16].

Despite the potential of injection technologies using wood chips, polyacrylamide, and ethyl resin, their application is associated with several drawbacks that limit their efficiency and economic feasibility under the conditions of the Kalamkas field [17, 18]. One of the primary challenges is the difficulty in accurately predicting the behavior of these solutions in reservoir conditions. Geological features such as permeability heterogeneity and high-permeability channels result in uneven distribution of the injected substances, reducing the effectiveness of water zone isolation and increasing material consumption.

While wood chips are accessible and cost-effective, their resilience in the aggressive environments typical of reservoir conditions is limited. Exposure to high temperatures and mineralized water leads to biodegradation and changes in their mechanical properties, diminishing the durability of the barriers formed and causing pore space clogging. Additionally, prolonged waterflooding and fluid redistribution exacerbate reservoir heterogeneity, leading to cross-flows and reduced water injection efficiency [19]. Wood chips may also form blockages in equipment or wellbore communications, necessitating additional cleaning and maintenance costs.

Polyacrylamide, although effective for increasing solution viscosity, is sensitive to the high salinity of formation water and the presence of divalent ions such as calcium and magnesium. Under such conditions, its properties degrade, reducing its efficiency in oil displacement and reservoir stabilization [20]. Moreover, its injection requires precise control of concentration and solution parameters, complicating the technological process and increasing operational costs.

Ethyl resin, while robust after curing, has limited permeability, which can hinder oil flow in the treated zone. Furthermore, there is a risk of premature hardening within the well or equipment, potentially causing significant complications during injection operations [21, 22].

These limitations underscore the importance of conducting preliminary laboratory and field tests before implementing the technology, as well as the necessity for further optimization of solution compositions and developing new approaches to enhance their efficiency under various reservoir conditions.

The Kalamkas field has already reached a stage of high reserve recovery, where declining oil displacement efficiency and increasing water cut remain critical challenges [9, 18]. Improving the oil recovery factor requires refining the hydrodynamic connectivity between injection and production wells and optimizing the composition of the solutions used.

Developing hard-to-recover resources has become a priority due to the depletion of easily recoverable oil reserves. Kazakhstan possesses substantial volumes of residual reserves in depleted fields, which remain attractive despite their high water content due to the presence of established infrastructure and skilled personnel. This makes fields like Kalamkas a focal point for implementing innovative technologies and fundamental research to increase oil recovery factors.

Water at the Kalamkas field originates from various sources, including formation water, runoff, artesian, and seawater. Water quality varies significantly, especially when water is injected from the block-cluster pumping station, which contains small amounts of bactericide and demulsifier [12, 18, 23]. The salinity of the water was replicated under laboratory conditions, and the corresponding data are presented in table 1.

The formation water of the Kalamkas field is characterized by high salinity and a complex ionic composition, which must be considered in the development of water shutoff agents. Analysis data indicate that the total salinity level is 79.6 g/L, and the total hardness is 5 g/L. The primary ions influencing the chemical activity of the environment are chlorides (48744 mg/L), calcium (4800 mg/L), and magnesium (960 mg/L). Additionally, bicarbonates (292.8 mg/L) and sulfates (307.4 mg/L) are present, which may interact with the chemical components of the reagents.

This water composition indicates a high concentration of multivalent ions, such as Ca^{2+} and Mg^{2+}, significantly impacting gelation processes. The elevated hardness and salinity reduce the efficiency of many reagents and may lead to premature degradation of gel structures.

Table 1

Salinity of formation water at the Kalamkas field

Injected water	HCO_3^-, mg/L	SO_4^{2-}, mg/L	Cl^-, mg/L	Ca^{2+}, mg/L	Mg^{2+}, mg/L	Na^+/K^+, mg/L	Total mineralization, g/L	pH
Mineralization	292.8	307.4	48744	4800	960	24523	79.6	5

Therefore, for the successful application of blocking reagents at the Kalamkas field, it is crucial to consider the impact of salinity and the chemical composition of the water on polymerization and gelation processes. In subsequent studies, these data were utilized to select reagents resistant to saline environments and to optimize their formulations, ensuring the stability and efficiency of gel systems under the specific conditions of this field.

This study aims to optimize the composition of a water shutoff agent and evaluate its static properties for use in Kalamkas field operations. This includes determining the appropriate concentration of key components such as modified starch (MS), unsaturated amides (UAM), and crosslinking agents to achieve a high-strength gel with optimal mechanical properties for water shutoff and adjusting the profile in reservoir conditions.

2. Literature review

The profile leveling of injectivity (PLI) is a key method for enhancing the efficiency of oil and gas development. This process aims to reduce the heterogeneity of filtration flows by decreasing the permeability of high-permeability zones and redirecting the working agent to less permeable areas. As a result, PLI improves reservoir coverage, contributing to increased recoverable hydrocarbon reserves [24].

One of the primary objectives of PLI is to create barriers in high-permeability zones that prevent the preferential movement of the displacing agent. This is achieved using specialized water shutoff systems, including gel-forming solutions, emulsions, and hardening compositions. These materials penetrate high-permeability zones, altering the structure of the pore space and reducing its conductivity. A critical criterion for selecting a water shutoff agent is its ability to function effectively under specific reservoir conditions, such as high temperatures, salinity of formation waters, and pressure [25].

The PLI process involves injecting slowly reacting compositions, such as crosslinked polymer systems or thermotropic gel-forming solutions, into the near-wellbore area of injection wells. These substances penetrate deep into the reservoir, redistributing filtration flows within its structure [26].

Such technologies are particularly effective in reservoirs with hydrodynamic connectivity between individual layers. The injected solutions fill the pores of these layers, forming a hydrophobic barrier that redirects water flow toward production wells. Ultimately, this results in increased oil recovery [25].

In [27], five main types of enhanced polymer gels developed to date are discussed: gel systems improved with nano-silica, gel systems enhanced with cellulose, gel systems reinforced with graphite, gel systems modified with oily sludge, and polymer gel systems augmented with foam. This study also examines several enhanced polymer systems' key properties, reinforcement and crosslinking mechanisms, application conditions, and field applications. It has been established that adding reinforcing materials can increase the bound water content in the gel network and significantly improve polymer gels' thermal and salt tolerance, enabling them to handle profile control and water-plugging applications in high-temperature and high-salinity reservoirs. Furthermore, future research directions for advanced polymer gel systems are outlined [27].

The application of PLI is efficient in heterogeneous reservoirs, where variations in permeability and saturation lead to the formation of low-productivity zones. Modern approaches to designing PLI operations are based on comprehensive geophysical data analysis, hydrodynamic modeling, and laboratory studies. This approach improves the reliability of predictions and enhances the efficiency of technology implementation in practice [28].

The primary drawback of profile leveling is the complexity of selecting and controlling the composition of gel-forming systems, which must account for geological conditions and reservoir properties. Additionally, the technology is limited in weak hydrodynamic connectivity between layers and heterogeneous reservoirs, where the compositions predominantly penetrate more permeable zones, leaving other areas unaffected. There is also a risk of reduced permeability in production wells due to possible penetration of the composition, which may lead to decreased well productivity. The high cost of the technology and the need for thorough monitoring further limit its widespread application [25].

Polymer gels have been effectively used as water management materials for profile control and water-shutoff treatments in low-to-moderate temperature and low-to-moderate salinity reservoirs. However, most polymer gel systems have limitations under high-temperature and high-salinity conditions, such as short gelation times, low strength, and long-term instability. Therefore, some researchers have developed enhanced polymer gels to meet the requirements of water control in high-temperature and high-salinity reservoirs.

Various methods for profile control and water shutoff have been developed for oil fields to address issues such as excessive water production and severe reservoir heterogeneity [29].

At the Gudong oilfield [30], a gel system enhanced with oily sludge was developed using polyacrylamide (PAM), a suspending agent, oily sludge, and a crosslinking agent, with the gelation time adjusted to 22-28 hours. The gel system maintains high strength and a viscosity retention rate of over 91% after aging for 180 days at 80 °C. Sandpack blockage experiments show that the blocking rate and breakdown pressure can reach 94% and 6.2 MPa, respectively. Experimental data demonstrate that the improved gel system offers high aging resistance, better cost control, and promising application prospects.

Foam-based gel systems generally consist of a polymer, a crosslinking agent, a foaming agent, and gas [31, 32]. When foam-based gel systems form within reservoir rock [33, 34], they reduce the oil-water interfacial tension [35, 36], while the foam significantly enhances stability [37, 38]. Foam-based gels exhibit higher temperature and salinity resistance compared to conventional gel systems. With an extended half-life and a larger blocking radius, foam-based gels can stably block highly permeable layers over the long term, achieving more effective profile control and water shutoff [26, 39, 40].

Modern research aimed at improving the efficiency of oilfield development focuses on using nanocomposite materials, such as polymer gels and nanogels. These studies explore the impact of nanoparticles on the mechanical and rheological properties of gel systems, as well as their effectivness in water shutoff, profile control, and enhanced oil recovery.

Laboratory evaluation results of a nanocomposite gel for water shutoff are presented in [41]. The NC-PPG-based

gel demonstrates high thermal stability, deformability, and salinity resistance, making it suitable for mature oilfields. A key advantage of this gel is its ability to significantly increase reservoir coverage by effectively sealing high-permeability zones.

Study [42] examines the synthesis of advanced preformed partially hydrogel particles (PPGs) based on AMPS, polyvinylpyrrolidone (PVP), and bentonite clay. Including clay in the polymer matrix and the interlayer intercalation of AMPS, along with hydrophilic interactions, improved the swelling degree, slowed the desorption process, and enhanced the gels' thermal stability and mechanical properties compared to pure PPGs.

Study [43] investigates colloidal dispersed nanogels for controlling reservoir fluid flows. The addition of TiO_2 nanoparticles improved the rheological stability of gels, increased their resistance, and reduced interfacial tension. It was demonstrated that nanoparticles act as «bridges» between polymer chains, enhancing the stability of the gel structure.

Work [44] discusses the advantages of nanogels as a diversion agent for enhanced oil recovery (EOR). Experimental studies showed that incorporating lightweight metal nanoparticles increased the gel systems' strength and raised the residual resistance factors to 22%. Using nanogels provides a prolonged effect, contributing to a 28% increase in oil recovery from the original oil in place.

Article [45] examines the application of nanogels for injectivity profile control. It was demonstrated that adding nanoparticles enhances oil recovery and improves reservoir fluid flow management. Experiments showed that optimal placement of the gel block near the production well resulted in oil recovery increases of 19% and 28% for conventional gels and nanogels, respectively.

Studies [46] and [47] focus on the impact of lightweight metal nanoparticles on the mechanical properties of polymer gels used in EOR. The authors demonstrated that adding nanoparticles increases gel systems' strength by 65%. It was found that nanoparticles facilitate uniform distribution within the gel, improving its mechanical properties and making the process cost-effective by reducing polymer consumption.

Study [48] presents a method for selective isolation of high-permeability intervals to prevent injected compositions from entering low-permeability oil- and gas-bearing zones. It involves sequential injection of a polyacrylamide solution, a flocculant with bentonite powder, and a viscoelastic sealing composition. The process forms a stable polymer-dispersed barrier, ensuring targeted placement in high-permeability zones while preserving the permeability of productive intervals.

Computer modeling of water shutoff technologies in the near-wellbore zone enables detailed analysis of methods for preventing water coning [49]. Studies aimed at reducing asphaltene deposits and increasing well production rates highlight the importance of improved approaches [50]. Furthermore, a review of chemical and mechanical water shutoff methods underscores their relevance in addressing challenges in oil and gas wells [51].

Numerical modeling allows the assessment of water shutoff efficiency in heterogeneous reservoirs [52] while developing new gel systems and colloidally dispersed gels contributes to modifying reservoir permeability and water shutoff [53, 54]. Special attention is given to thermosetting gels, which exhibit technological advantages in challenging operational conditions [55]. Using crosslinked polymer gels also demonstrates adaptability and reliability [56].

3. Objects and methods of research

The Kalamkas field is a typical example of a high-salinity reservoir. The mineralization of the reservoir water reaches 148640 mg/L, while the produced water has a mineralization of 79600 mg/L. The concentration of calcium and magnesium ions varies up to 5760 mg/L, and the reservoir temperature ranges from 39 to 42 °C [12, 18, 23]. These parameters present significant technological challenges during the field development.

Despite the success of profile leveling and water shutoff technologies, unresolved issues remain. In addition to concerns about the static properties of water shutoff compositions at high temperatures, such as rapid gel formation and thermal instability, discrepancies between laboratory tests and field trials have been observed. The main difficulties are outlined below:

1. Low Efficiency of Applied Systems: Wood pulp and polyacrylamide are insufficiently effective for profile leveling and water shutoff under high-temperature reservoir conditions. This is due to the degradation or dehydration of epoxy resins and polyacrylamides under high temperatures and the precipitation of salts, which limits their applicability.
2. Issues with Static Properties: Key reagent parameters include gel formation time and strength for high-temperature and high-salinity reservoirs. Temperature and mineralization lead to the breakdown of polymer chains and the precipitation of salts containing divalent iron, calcium, and magnesium ions. This reduces the strength of the compositions. Crosslinked gel systems are suitable for low-temperature conditions, but their application in high-temperature conditions is limited due to the rapid reduction in gel formation time.

Research into reagents with high thermal stability and strength is crucial for developing fields like Kalamkas, where mineralization and temperature impose strict limits on the technologies that can be applied [4, 9, 11]. The main goal is to increase the efficiency of injected water or other working agents using profile leveling and water shutoff methods. These methods help to involve areas with medium and low permeability, thereby increasing the coverage of the affected area.

Based on the results of screening tests, modified starch, and unsaturated amides were selected and subjected to polymerization using crosslinking technology. Starch molecules belonging to rigid nonionic groups exhibit good thermal stability and strength properties. After copolymerization with starch, the reagents retain these properties, making them promising for application in the Kalamkas field.

To choose the optimal crosslinked system, it is essential to assess the parameters that determine its suitability for the field conditions. The main static characteristics include:

1. Gel Formation Time. The gel formation process involves forming a network structure in the reagent due to the crosslinking reaction. Viscosity measurements or mechanical tests determine this time. Instruments such as a Brookfield viscometer, falling

ball viscometer, or rheometers (e.g., German Haake RS600 or British Bohlin CS-50) are used. The formation of strong gels can visually determine gel formation time.

2. Gel Strength. Key parameters include dynamic viscosity, viscoelastic modulus, and pressure changes.
3. Thermal Stability of the Gel. This parameter reflects the gel's resistance to degradation at high temperatures.

Studying these characteristics ensures the suitability of reagents for the conditions of high-salinity and high-temperature reservoirs.

To conduct experiments for evaluating the characteristics of water shutoff agents, specialized equipment is required, including a mixer with an electric drive for uniform component mixing, a reactor capable of operating under high temperatures and pressure, a Brookfield viscometer for viscosity measurement, a thermostated container for maintaining stable temperature, precision electronic scales, and standard glassware such as graduated cylinders, pipettes, and test tubes. Additionally, static characteristic evaluations involve a tubular model simulating reservoir conditions (fig. 1a); an advective pump (fig. 1b); an intermediate container for uniform reagent delivery (fig. 1c); and a pressure delivery system to control experimental parameters.

A Brookfield viscometer (fig. 1d) is used to measure the water shutoff agent's strength and determine the composition's viscosity. If the viscosity exceeds 200000 mPa·s, a HAKKE RS600 rheometer (fig. 1e) measures the viscoelastic properties. The viscosity and elasticity data obtained are used to assess the effectiveness of the water shutoff agent under high-temperature and high-salinity conditions. This approach completely characterizes the reagent and its compliance with operational requirements.

The experimental setup employs a 2PB00C advective pump (fig. 1b), which ensures controlled and uniform fluid

Fig. 1. Equipment for conducting experimental studies:
a) Tubular model, b) Advection pump, c) Intermediate tank, d) Brookfield viscometer, e) Haake RS600 rheometer

movement through the system. This is necessary to simulate reservoir flow conditions, accurately distribute reagents, and replicate dynamic characteristics that enable correct evaluation of the water shutoff agent's effectiveness. The advective pump operates by direct substance transfer without direct contact with the transferred material, which is especially important for delicate or aggressive media. These pumps are widely used in experimental studies to investigate gels' static and dynamic properties [57, 58].

The experiment begins with preparing the composition, where a specified volume of simulated reservoir water is placed in a container, and modified starch, unsaturated amides, an initiator, and a structural additive are sequentially added. Each additive is introduced only after the complete dissolution of the previous component, which is ensured by thorough mixing using a mixer. Afterward, the composition is placed in a thermostated container, where the temperature is maintained at the value corresponding to the reservoir conditions. The solution is visually inspected every hour to assess the gel formation process.

4. Research results and discussion

As a result of the research, the composition of the water shutoff agent was clarified, and its static evaluation was conducted. The base composition includes modified starch and an unsaturated amide, which undergoes polymerization to form a stable gel structure. The formulation was determined using a non-orthogonal experimental design method, and key parameters such as gelation time and gel strength were carefully studied.

The main reagents for creating the water shutoff agent were selected as modified starch and unsaturated amide, considering their cost-effectiveness and resistance to the influence of magnesium and calcium ions in the reservoir water. The reaction is carried out at 90 °C, promoting efficient copolymerization and forming a high-strength gel structure. The crosslinking agent type was determined based on the need to create a cellular structure through intermolecular crosslinking, ensuring reliable mechanical properties of the gel.

When selecting the gel-forming agent, the temperature range of the reservoir (38-41 °C) was considered. Reagent Y1 was chosen as it is optimally suited for low-temperature conditions and guarantees an adequate gelation time. Given the stability of this reagent under the specified conditions, further optimization of the composition for low-temperature conditions was not carried out.

Their concentrations were varied to determine the optimal dosage of the main components, and the gelation state was observed. Experiments were conducted with a standard volume of fluid (200 ml) using a HAAKE RS600 rheometer equipped with a PP-20 TI cone measuring tip with a diameter of 10 mm. The experimental parameters were set as follows: mechanical destruction with a force factor of 636600 Pa/N·m, destruction rate of 10 s^{-1}/rad·s^{-1}, pressure of 5 Pa, force application time of 120 seconds, and temperature of 40 °C. The rock breakdown pressure research results are presented in table 2 and in figure 2.

Table 2

Relationship between the dosage of the main reagent and gelation

Dosage, (%)	5.5	6	7	8	9	10	11	12
Gelling	incomplete	good	good	good	good	good	weak	weak

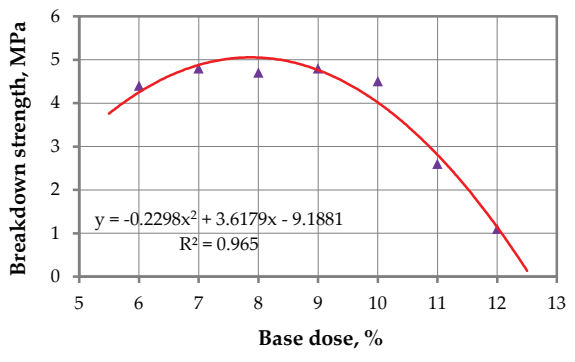

Fig. 2. Dependence of tensile stress on the volume of main reagents

The main reagent for water shutoff material includes modified starch and unsaturated amides. Polymerization of these components leads to the formation of a matrix with a macromolecular chain, which, due to crosslinking, forms a three-dimensional chemical structure. This material exhibits high strength and elasticity, making it suitable for reservoir conditions.

The dependence curve has a parabolic shape, which is described by an equation with a coefficient of determination R^2=0.965, indicating a good approximation of the experimental data by this model. The dosage of the main reagents plays a key role in determining the properties of the resulting water shutoff materials. According to the data presented in figure 2 and table 2, at low dosages, less than 5.5%, polymer compounds cannot form a solid gel structure, significantly deteriorating the material's properties. In the range from 6% to 8%, the breaking stress is observed as the volume of reagents increases. This indicates that increasing the concentration of components improves the gel structure. A pronounced maximum is observed, corresponding to the optimal concentration range of reagents around 7-9 %. In this range, the maximum breaking stress, approximately 5 MPa, is reached, indicating the highest gel strength. However, after reaching the optimal value, further increases in volume lead to a disruption of the system's equilibrium, negatively affecting the material's mechanical properties. With excessive reagent concentration, the polymerization process is hindered due to a lack of space for molecular chain growth, reducing the final strength characteristics of the gel. At dosages above 10%, a significant decrease in gel-breakdown strength is observed, making the material less suitable for use in reservoir conditions. This may be due to the deterioration of the gel structure with excess reagents, which decreases its mechanical strength. Furthermore, the cost increases, making this approach economically unfeasible.

The research also determined the optimal proportions of the main components. Based on laboratory experiments, it was found that for concentrations of the main reagents up to 7%, the mass ratio of modified starch (MS) and unsaturated amides (UAM) should be considered. The ratio of UAM/MS concentrations was selected in the range from 0.5 to 3.0. The

gelation efficiency was evaluated by the gel breakdown pressure, with results presented in table 3 and figure 3. The analysis showed that the correct choice of reagent proportions ensures optimal characteristics of the water shutoff material, which is critically important for use in actual reservoir conditions.

The analysis of figure 3 shows that the dependence curve has a parabolic shape, with a coefficient of determination R^2=0.9397, indicating a good approximation of the experimental data by this model. When the UAM/MS ratio exceeds 0.5, the system lacks sufficiently formed matrices of long chains of polymerized modified starch and unsaturated amides. In such conditions, a significant portion of the modified starch only physically fills the structure's cells without participating in chemical interaction. This results in insufficient strength of the chemical chains, negatively affecting the strength of the entire three-dimensional matrix structure and reducing the breakdown pressure.

As the UAM/MS ratio exceeds 2.0, most resulting chains consist of polymerized polyunsaturated monomers, less intensely than those formed when interacting with modified starch. This leads to a decrease in both the gel's elasticity and breakdown pressure. Given these limitations, a breakdown pressure of 4000 Pa is taken as the standard, and the optimal UAM/MS ratio is determined in the range from 0.7 to 2.0.

Economic considerations also play a significant role in choosing the proportions. Since unsaturated amides are relatively expensive and modified starch is more readily available, preference is given to a low UAM/MS ratio. Based on all factors, the concentration of the main reagents is proposed as follows: for a standard gel, w(UAM) – 3-3.7 % and w(MS) – 4-5.3 %, and for a high-strength gel – w(UAM) 3.5-4.5 % and w(MS) 3.5-4.5 %. If special conditions do not require otherwise, further evaluation of reagent characteristics will be based on this formulation.

An important parameter is the concentration of the crosslinking agent, which significantly influences the gelation process. At a concentration that is too low, insufficient crosslinking occurs, leading to incomplete gelation and the formation of a low-strength gel. On the other hand, excessive concentration of the crosslinking agent leads to overly rigid crosslinking, reducing the gel's elasticity, making it brittle, and decreasing the efficiency of water shutoff. The study's results on the effect of crosslinking agent concentration are presented in table 4 and figures 4 and 5.

The data in figure 4 demonstrate that increasing the concentration of the crosslinking agent leads to an increase in the system's viscosity. However, after reaching a concentration of 0.08%, further increases have little effect on viscosity, which stabilizes. This indicates the completion of the formation of a stable gel structure. Figure 5 presents the breakdown pressure's dependence on the crosslinking agent's concentration. In the concentration range of 0.04-0.08 %, the breakdown pressure increases, which is related to the gradual improvement of the gel structure. The structure is fully formed at concentrations of 0.08-0.10%, as the breakdown pressure remains unchanged. The concentration of 0.08% is characterized by nearly ideal crosslinking. If the concentration exceeds 0.10%, the density of crosslinks becomes excessive, which reduces elasticity, increases brittleness, and consequently lowers the breakdown pressure. Thus, to ensure optimal gel characteristics, it is recommended to use a crosslinking agent

Table 3

The effect of the ratio of the main reagents on gelation

Proportion UAM/MS(w/w)	0.5	1	1.5	2	2.5	3
Gelling	incomplete	good	good	good	weak	weak

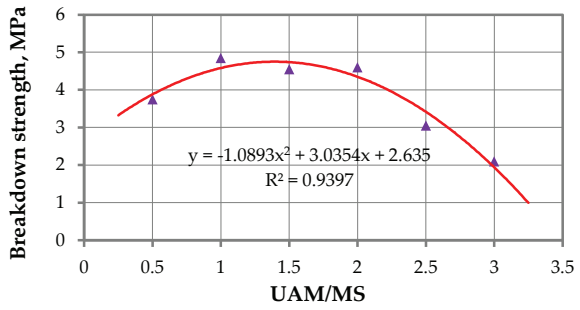

Fig. 3. Dependence of the breakdown strength on the proportion of the main reagents

Table 4

The relationship between the concentration of the crosslinking agent and gelation

Dosage of crosslinking agent (w, %)	0.04	0.06	0.08	0.10	0.12	0.14
Gelling	incomplete	incomplete	good	good	good	weak

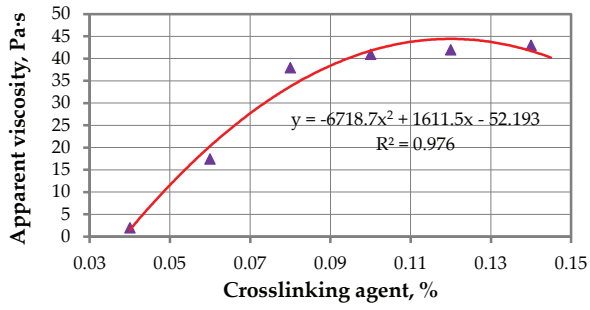

Fig. 4. Dependence of apparent viscosity on the concentration of crosslinking agent

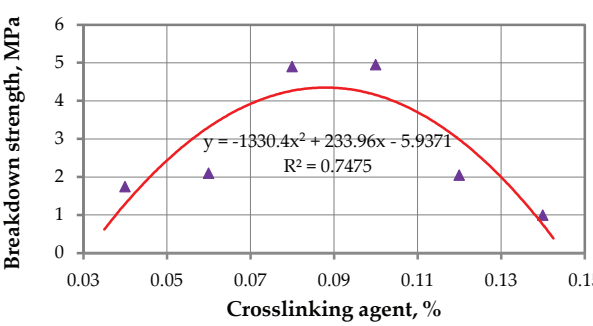

Fig. 5. Dependence of breakdown strength on the concentration of crosslinking agent

concentration in the range of 0.08-0.10 %.

At the stage of formulation optimization, the primary indicators chosen were gelation time and strength. Using a non-orthogonal methodology, the composition was adjusted by changing the concentrations of the main reagents, crosslinkers, and initiators.

The composition, selected based on the results of the studies for profile leveling and water shutoff at the Kalamkas field, represents a strong gel and was named SG-k (strong gel Kalamkas).

The results are presented in table 5, which contains data on temperature, component concentrations, viscosity, and gelation time.

The appearance of strong gel SG-k is shown in figure 6.

Optimal formulation and parameters of the strong gel SG-k — **Table 5**

Temperature, °C	Modified starch (MS), %	Unsaturated amides (UAM), %	Crosslinking agent (TN), %	Gelation agent (Y1), %	Initial viscosity, mPa·s	Gelation time, h	Viscosity, mPa·s
40	3.5-4.5	3.5-4.5	0.08-0.10%	0.001-0.01%	40-100	~20	>200000

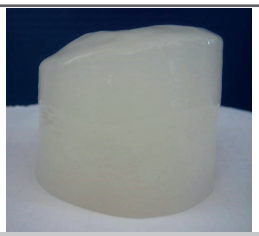

Fig. 6. Strong gel SG-k

Conclusions

The research findings can be summarized as follows:

1. The composition of the water shutoff agent, including modified starch and unsaturated amides, has been optimized to create a strong gel structure suitable for use under reservoir conditions. The polymerization of these components results in a stable three-dimensional matrix with high mechanical strength and elasticity.
2. The optimal concentration range for the main reagents, including modified starch (MS) and unsaturated amides (UAM), was identified to be 3.5-4.5 %. The ratio of UAM/MS was found to be most effective between 0.7 and 2.0, providing the best gel properties, including optimal gel strength and elasticity.
3. The optimal concentration of the crosslinking agent (TN) was determined to be between 0.08% and 0.10%, as this range ensures adequate gelation without over-crosslinking, which would compromise the gel's elasticity and increase brittleness.
4. The study also highlights the importance of the gelation agent (Y1) and the temperature during the gel formation process, with a gelation time of approximately 20 hours and a high viscosity (>200000 mPa·s) achieved under optimal conditions.
5. The developed strong gel formulation, named SG-k (strong gel Kalamkas), demonstrates high stability, making it suitable for water shutoff and profile leveling in oil reservoirs, specifically in the Kalamkas field.
6. The findings underscore the critical role of balancing reagent concentrations to optimize the water shutoff gel's mechanical properties and economic feasibility, which can be tailored to meet the specific conditions of different reservoir environments.

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