



## THERMOSENSITIVE GEL FOR WATER SHUT-OFF IN OIL WELLS

B. A. Suleimanov<sup>1</sup>, H. F. Abbasov<sup>\*2</sup>, V. J. Abdullayev<sup>1</sup>, Sh. Z. Tapdiqov<sup>1</sup>

<sup>1</sup>«OilGasScientificResearchProject» Institute, SOCAR, Baku, Azerbaijan

<sup>2</sup>Azerbaijan State Oil and Industry University, Baku, Azerbaijan

### ABSTRACT

A new approach to the creation of a cost-effective thermoactive composition based on readily available raw materials, including a gelation initiator and gelator solution, intended for use in water insulation systems, is presented in this study. The residual resistance factor and recovery factor of oil were determined in core samples with different permeability coefficients using the prepared gel-forming composition. Optimum concentrations of the mixture components were found to be 10-12 % for the gelation initiator and 9-10 % for the gelator. Increasing the temperature from 20 to 60 °C was found to lead to a significant 5- to 6-fold reduction in gelation time. Above 60 °C, gelation occurred within one to two hours. The results of field and experimental studies conducted in the Kruk and Shurchi fields in Uzbekistan using a thermosensitive, gel-forming composition are presented. The residual resistance coefficient of the samples ranges from 4.8 to 23.6. Oil sweeping tests showed the high efficiency of the proposed new method of water shut-off using a thermoactive gelling agent. The results of COMSOL Multiphysics modeling of the water filtration process in a porous medium with gel, taking into account the kinetics of gel formation, are also presented.

**Keywords:** acid based gel; residual resistance factor; oil displacement; water shut-off; COMSOL Multiphysics.

**Date submitted:** 05.12.2025

**Date accepted:** 21.04.2026

© 2026 «OilGasScientificResearchProject» Institute. All rights reserved.

### 1. Introduction

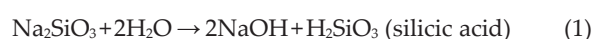
The majority (approximately 30 to 35%) of underground oil well treatment operations are performed to control produced water and sand formations [1-7]. Well production watering leads to corrosion of underground and surface equipment. Therefore, the development of chemical-technological processes to prevent well flooding is an urgent problem [8-11].

One commonly recognized water shut-off technology involves the injection of compositions containing sodium silicate, water, polyacrylamide (PAM) or partially hydrolyzed PAM (HPAM). However, a limitation of this technology is the lack of control over gelation time and the overall water shut-off process [12]. The authors [13] studied bulk gelation using a polymeric gelator prepared on the base PAM and hydroquinone-hexamethylenetetramine HQ/HMTA. Knowing the gelation time at different temperatures is crucial for determining how deep the gel can be placed in the tank at a given water temperature. The studies have shown that, first, the gelation time can be controlled by altering the gel composition and environmental conditions, and second, divalent ions promote faster gelation compared to monovalent ions. The authors concluded that the presented gel system is highly

effective for water shut-off in reservoirs. In other studies, the authors prepared an innovative and effective water barrier composition based on urea formaldehyde resin [14] and viscous plastic components [15]. It was shown that when regulating the rheological properties of polymer suspensions using chemical additives, it is necessary to determine the influence of thermobaric factors on the values of these properties. Studies to evaluate the influence of temperature on the rheological properties of gelling agents were carried out in the temperature range of 25-75 °C.

In general, new technologies based on foam systems [16], nanofluids [17-19], alkaline wastes [20], polymer-water-air mixture [21], and enzyme solutions [22] have been developed to enhance oil recovery by shutting off formation water. Among the chemical methods for targeted modification of wells, silica-based gels are cheaper and favorable from the point of view of environmental safety [23, 24]. It is also thermally stable and suitable for working in high temperature wells. In well-bore conditions, the gelation time of Na-silicate is more controllable [25].

Sodium silicate gelation is achieved through sol-gel technology, a process where silicate particles bond to form a three-dimensional network [26-28]. First, sodium silicate undergoes hydrolysis when it reacts with water:



\*E-mail: [abbasovhakim@gmail.com](mailto:abbasovhakim@gmail.com)

<http://dx.doi.org/10.5510/OGP20260301232>

Then, in an acidic environment, the resulting silicic acid molecules polymerize to form a hydrated silicon dioxide gel ( $\text{SiO}_2 \cdot x\text{H}_2\text{O}$ ) through a process called condensation: the silicic acid molecules undergo polycondensation, where they link together through the formation of silicon-oxygen-silicon bonds (Si-O-Si). Small oligomers are formed by this process, and they act as nucleation sites for the formation of larger, stable particles. These particles aggregate and spread throughout the system, forming a three-dimensional network – a gel.

The gelation is generally accelerated by lowering the pH (acidifying the solution), as the electrostatic repulsion between the silica particles is reduced and their aggregation is promoted: silica particles are generally negatively charged, and an increase in the amount of hydrogen ions in the medium leads to a decrease in the zeta potential of silica particles, which favors the aggregation of silica particles [29]. A comparative analysis of the results of silicate gel injection studies [30] shows that the use of Na-silicate and acid can create an effective gel plug to shut off formation water in the bottom-hole zone of the well. According to Van't Hoff's law, gel formation can also be accelerated by higher temperatures, as increased temperature intensifies hydrolysis and condensation reactions. Higher concentrations of sodium silicate result in decreased gelation times because more silicate molecules are involved in the reaction.

It has been shown that the presence of salts, particularly divalent ions such as calcium and magnesium, has a significant effect on the gelation process [27, 31]. This effect can manifest itself in various ways: from potentially accelerating the process to altering the properties of the resulting gel.

When pumping a sodium silicate solution containing additives into the well bottom zone, one of the key processes is the kinetics of gel formation upon contact with rock under well conditions [32, 33]. It is known that when Na-silicate solution comes into contact with formation water and rocks, its density and concentration changes. In other words, by determining the degree of dispersion and adsorption of Na-silicate, it is possible to develop an effective method for the reagent injection into the wellbore. Because the change in the concentrate and pH nature of the silicate solution has a direct effect on its gelation kinetics [34].

An alternative approach [35] to controlling water inflow into wells involves the sequential injection of an aqueous solution of sodium silicate, a separator, and a hardener. A drawback of this technique was the use of a 0.5-4 % hydrochloric acid solution as a hardener and a 7-9 % sodium silicate solution, which made it difficult to precisely control the gelation time. Furthermore, the effectiveness of this method was reduced due to incomplete mixing of the gel-forming solution components within the formation.

In deep well isolation treatments, Na-silicate is thermally stable and cost effective compared to other gel systems. Gel formation time of Na-silicate can be regulated by adding some inorganic and organic reagents [36]. This is because the viscosity, gelation time, and thermal stability of sodium silicate vary depending on the pH of the medium, salinity, and mechanical stress [31].

This study investigated the gel-forming ability of the acid-based, thermosensitive mixture proposed by us. The effect of this mixture on the oil displacement ratio was studied in laboratory conditions using models of carbonate and sandy

reservoirs. The residual resistance factor was determined using a prepared homogeneous gel-forming composition in artificial core samples. The field experiments were conducted with thermoactivatable composition in the fields of Kruk and Shurchi (Uzbekistan). COMSOL multiphysics simulations of filtration process for treated and untreated porous media with thermoactivated gel were also presented.

## 2. Experiment

Monobasic acid and dibasic acid residual alkali metal salt were used for preparation of gel-forming composition. The residual resistance factor was studied on artificial cores corresponding to the reservoir properties of the Kruk and Shurchi fields.

### *Preparation and investigation of gel-forming composition*

Two components were used in the preparation of the thermoactivatable mixture: gel-forming salt (GFS) and acid as a reaction initiator (RIA). First, 40% (wt.) GFS and 21% (wt.) RIA were diluted with technical water to form a 10% (wt.) solution, which is the optimum concentration to obtain a gel. The pH of GFS solutions with different concentrations was determined initially.

It was found that the GFS solution has a high buffering capacity and does not change the pH of the solution in the range of 8-10 % (wt./mass).

It should be noted that when mixed with solutions of weak acids and even alcohol, as well as with various resinous organic substances, GFS forms gels of varying composition and with different thermomechanical properties. Gels formed by organic substances with polymer-based acids are not very thermally stable, and the rate of gelation reaction strongly depends on the density of the second component. The composition of GFS consists of such a weak acidic residue that even when in atmospheric air it can turn into a gel after a long reaction with air moisture and  $\text{CO}_2$ . Technologically, when producing GFS-based gels, it is preferable for the gelation process to begin after 10–14 hours. Therefore, it is more convenient to carry out the process with 10-12 % solutions of initiators, which are inexpensive.

In the presence of more than an equivalent amount of acid in the medium, a reaction between GFS and RIA takes place and a thermally activated gel is formed. However, due to the excess of initiator in the medium, complete structuring or solidification does not occur immediately. Over time, after the acidity of the medium has been neutralized by an alkali, the gel is observed as a solid mass throughout the volume.

In the presence of solvent, the gel starts to swell. Basically, the degree of swelling of a confined gel ( $i = \frac{V_g - V_{g0}}{V_{g0}}$  where  $V_g$  and  $V_{g0}$  are the volumes of swollen and dry gel, respectively) grows in time proportionally to the difference between the limiting degree of swelling ( $i_\infty$ ) and the degree of swelling at a given moment ( $i$ ) [37]:

$$\frac{di}{dt} = -k'(i_\infty - i) \quad (2)$$

where  $k'$  is the coefficient of proportionality.

Integration of equation (4) gives:

$$i = i_\infty (1 - e^{-k't}) \quad (3)$$

When the gel is injected into a porous medium with porosity  $\varepsilon_0$ , the porosity of the medium decreases as the gel swells. An approximate relationship between porosity and the degree of gel swelling can be found. Before gel injection, the porosity of the medium is defined as:

$$\varepsilon_0 = \frac{V_t - V_m}{V_t} \quad (4)$$

where  $V_t$  is the total volume of the core,  $V_m$  is the volume of the core without voids.

After injection of gel into this medium, the porosity of the medium changes,

$$\varepsilon = \frac{V_t - V_m - V_g}{V_t} = \varepsilon_0 - \frac{V_g}{V_t} = \varepsilon_0 - \frac{V_{g0}}{V_t} (i + 1) \quad (5)$$

Considering Eq. (3) in Eq. (5) we obtain:

$$\varepsilon = \varepsilon_0 - c \left( 1 + i_{\infty} (1 - e^{-k't}) \right) \quad (6)$$

where,  $c = \frac{V_{g0}}{V_t}$  is the concentration of gel in the medium.

The Kozeny-Carman (KC) model [38, 39] establishes a connection between the characteristics of media and the flow resistance in pore channels. It is a frequently employed equation in various fields, such as soil physics, chemical engineering, and reservoir engineering, to calculate the permeability of porous materials. It relates permeability to porosity and specific surface area, showing how the structure of pores affects fluid flow.

$$k = \Phi_s^2 \frac{\varepsilon^3 d_p^2}{180(1 - \varepsilon)^2} \quad (7)$$

where  $\Phi_s$  is the sphericity of the particles in the packed bed ( $\Phi_s=1.0$  for spherical particles),  $d_p$  is the diameter of the volume equivalent spherical particle.

Prior to conducting petrophysical measurements, the samples were cleaned using organic solvents (toluene and methanol) to remove organic matter and salts trapped in the pores, and then dried in an oven at 65 °C until their weight stabilized. Measurements of air permeability, porosity, and grain density were conducted using Keyphi equipment (permeameter-porosimeter) at a pressure of 800 psi.

Displacement tests were carried out using porous media displacement equipment (see fig. 1a).

### 3. Results and discussion

The gelation times as a function of the mass ratio of the mixed reagents are shown in table 1 below.

Table 1

Gelation time for GFS and RIA mixtures at different acidity of the medium

Table 1 shows that when RIA is used at a concentration of less than 10% (w/w), gelation occurs rapidly. When using 10–20 % (by weight) of the initiator, a gel is formed that does not harden immediately, which satisfies the requirements. When more than 20% (by weight) of the initiator is used, the main properties of the resulting gel are not changed, and only an excess amount of acid remains in the system, which leads to additional costs. It was found that when 10% (by weight) of GFS was used, the volume of the resulting gel reached its maximum value, and a further increase in concentration did not result in significant changes. Experiments have shown that, in the presence of mineralized water, gel formation

| Concentration of mixed reagents, % (in the same volume) |     |     | Gelation time at 24 °C, hr | pH medium |
|---------------------------------------------------------|-----|-----|----------------------------|-----------|
| 1                                                       | GFS | RIA |                            |           |
| 1                                                       | 40  | 20  | Immediately                | pH>7      |
| 2                                                       | 20  | 10  | Immediately                | pH>7      |
| 3                                                       | 15  | 10  | Immediately                | pH>7      |
| 4                                                       | 10  | 10  | 9-12                       | pH=3      |
| 5                                                       | 10  | 15  | 16-18                      | pH<3      |
| 6                                                       | 10  | 20  | 27-31                      | pH=<3     |
| 8                                                       | 10  | 30  | >42                        | pH<2      |

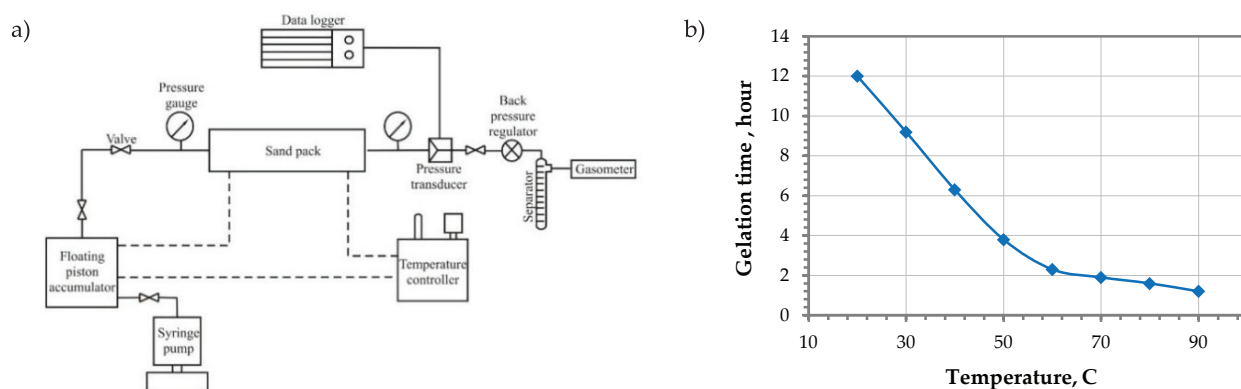
occurs immediately at a pH of 10, which creates technical difficulties in the bottomhole zone. At a pH of 3, gelation occurs after 16–18 hours, which is advantageous for injection [32].

We also examined the change in pH of a mixture obtained by adding RIA solutions in various ratios to a GFS solution of varying concentrations. To 20 and 30 % (w/w) GFS solutions, 0.5–10 % (w/w) RIA solutions were added; the mixtures were stirred, and the pH of the solution was measured immediately. It was shown that when RIA was added to a GFS solution, the salt was neutralized as a result of the reaction, a thermogel was formed, and the pH of the medium decreased to 1.5–2. When RIA is added to a 5% (by weight) GFS solution, the pH of the medium drops sharply, which is due to an excess of initiator in the medium. Since the optimal pH level for gel formation is 4–5, a mixture of a 10% (by weight) GFS solution and a 10% (by weight) RIA solution can be considered the optimal formulation [24]. When using an RIA solution at a concentration exceeding 20% (by weight), the pH of the medium drops sharply, which is undesirable. The use of RIA solutions with concentrations of 15 and 20 % (by weight) results in increased consumption and higher costs for the chemical mixture, as well as additional reactions between the rock and the initiator in the wellbore, which may cause operational difficulties. To summarize, we conclude that a solution prepared from a 10±2% (w/w) GFS solution and a 10–12 % (w/w) RIA solution in a 1:1 volume ratio is optimal for the formation of a thermosensitive gel.

The gelation process between GFS solution and RIA was carried out in two different ways:

1. Addition of the RIA solution to the GFS solution
2. Addition of GFS solution to RIA solution.

Experiments conducted using the first method—that is, by adding the RIA solution to the GFS solution—showed that the reaction did not proceed to completion. Specifically, gel formation occurred immediately upon adding the RIA solution, and a heterogeneous phase formed in the system—a solid mass was formed. This is because the density of the GFS solution used ( $\rho_{\text{GFS}} \approx 1.39 \text{ g/cm}^3$ ) is approximately 1.3 times higher than that of the RIA solution ( $\rho_{\text{RIA}} \approx 1.05 \text{ g/cm}^3$ ), and the pH of the medium was alkaline. As a result, the gel forms in the surface layer of the GFS where the GFS and the initiator come into contact; however, because of its low density, the initiator does not penetrate into the bulk of the GFS, and gel formation does not occur in the volume. In experiments conducted in accordance with the second rule—that is, by adding the GFS solution to the RIA solution—the two components mixed very well and



**Fig. 1. a) A schematic diagram of the experimental setup; b) the gelation time of mixtures as a function of formation temperature**

completely, and prolonged acidification of the medium slowed down the gel formation process [40, 41].

The results of a study conducted under laboratory conditions examining the relationship between gelation time and temperature are presented in figure 1b. It is well known that the temperature dependence of the rate of a chemical reaction is governed by Van't Hoff's law, according to which the rate of most chemical reactions increases by a factor of 2 to 4 for every 10 °C rise in temperature. Increase in temperature accelerates the gelation process between RIA and GFS (fig. 1b).

As shown in figure 1b, raising the temperature from 20 to 60 °C reduced the gelation time by a factor of 5–6. At temperatures above 60 °C, the gelation time is 1–2 hours, which is favorable for the injection time after mixing the solutions.

Formation water from the Shurchi field was used to assess the degree of permeability reduction in rock samples treated with a thermally activated gelling mixture in a porous medium. After passing the formation water through filter paper with a pore size of 0.45 μm, its dynamic viscosity and density were determined as a function of temperature (figs. 2 and 3).

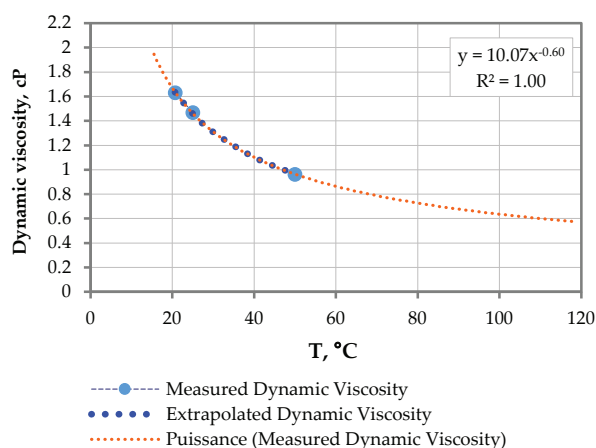
As can be seen from figures 2 and 3, the viscosity and density of formation water decrease with increasing temperature. This is due to a decrease in the intermolecular forces resulting from the thermal motion of the molecules as the temperature rises.

Displacement tests were conducted under conditions

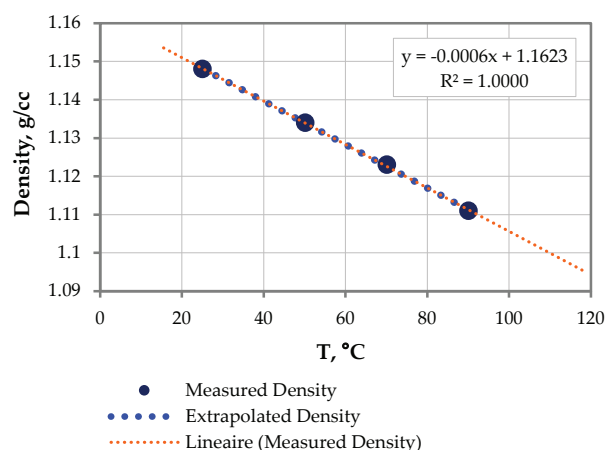
approximating those in the reservoir: a temperature of 51 °C, a reservoir pressure of 1442 psi, and a backpressure of 420 psi at a constant flow rate. The process was carried out in accordance with the following steps: complete saturation of the sample (100%) with formation water under high vacuum conditions, followed by the injection of formation water while recording the initial pressure drop values and permeability measurement results. Next, 0.5 PV (pore volume) of the first aqueous solution was injected, followed by 0.5 PV of the second aqueous solution. The pressure drop and residual resistance factor (RRF) were calculated during the injection phase, after which the reservoir was held for 24 hours under reservoir conditions. After 24 hours, formation water is reinjected at the same rate, the pressure drop is recorded, and the residual recovery factor (RRF) is calculated following conditioning. Once the first and second solutions have completely drained from the porous medium, formation water is injected until the pressure stabilizes and the flow rate at the outlet of the rock sample equals the flow rate at the inlet. At this stage, the value of the stabilized final pressure drop is recorded and divided by the initial pressure drop to determine the residual resistance factor (RRF):

$$PRF = \frac{\Delta P_f}{\Delta P_i} \quad (8)$$

The permeability is calculated from the Darcy's law:



**Fig. 2. Formation water dynamic viscosity versus temperature**



**Fig. 3. Formation water density versus temperature**

| Core sample | Porosity, % | K, mD | $\Delta P_i$ , psi | $\Delta P_f$ , psi | RRF  |
|-------------|-------------|-------|--------------------|--------------------|------|
| 1           | 14          | 456   | 0.44               | 10.4               | 23.6 |
| 2           | 18          | 29    | 6.2                | 9.7                | 4.8  |
| 3           | 18          | 287   | 0.57               | 2.8                | 4.9  |

$$K = C \frac{Q\mu L}{\Delta P \cdot S} \quad (9)$$

where,  $Q$  is the flow rate, cc/s;  $L$  is the sample length, cm;  $\mu$  is the dynamic viscosity, cP;  $S$  is the cross-sectional area of the sample, cm<sup>2</sup>;  $\Delta P_i$  is the initial differential pressure, psi;  $\Delta P_f$  is the final differential pressure, psi;  $K$  is the formation water permeability, mD;  $C$  is the unit conversion constant.

The values of the residual resistance factor and pressure drop for different injected pore volumes during formation water injection into rock samples using gel compositions are presented in table 2 and figures 4–6.

Tests of the effectiveness of the thermally activated gel-forming mixture to limit water breakthrough showed that the thermally activated gelling mixture used in this study was successful in reducing the permeability and hence the mobility ratio, resulting in better sweeping efficiency and braking for water inflow (water breakthrough).

#### Simulation in COMSOL Multiphysics

Finally, we present the results of COMSOL Multiphysics simulations of the water filtration process in a porous medium treated with the proposed thermosensitive gel composition.

Using equation (6), derived from the swelling kinetics of a confined gel, and equation (7), we visualized on COMSOL Multiphysics the water filtration process in a porous medium in which a thermoactivated gel was injected. The simulation results are presented in figures 7 (a-d). The governing equations in this simulation are the continuity equation, Navier–Stokes equations for laminar flow [42]. The inlet fluid velocity, and the outlet pressure was zero. Laminar flow (spf) model was used for the filtration of water in porous media. As can be seen, the filtration of water through treated with thermally activated gel porous medium is much weaker compared to untreated one and decreases with time. For simplicity of calculations the following parameters were chosen: gel concentration in porous medium  $c=1\%$ , limiting degree of swelling  $i_\infty \approx 10$ , porosity of untreated porous medium  $\varepsilon_1=0.2$ , permeability  $k_1=0.534 \cdot 10^{-6}$  m<sup>2</sup>, coefficient of proportionality  $k'=1$ . The porosity and permeability of the porous medium treated with thermoactivated gel change with time as  $\varepsilon_2=0.09-0.1 \cdot e^{-t}$  and  $k_2=k_1 \cdot \varepsilon_2^3 / (1-\varepsilon_2)^2$ , respectively.

As can be seen from figure 7, the rate of water filtration through the porous medium decreases sharply with time, which is due to the fact that the introduced thermally activated gel swells rapidly over time and blocks the pores of the medium.

#### Field implementation of the technology

In field conditions the method of water flow isolation is realized as follows. A calculated amount of reagents: gel-forming agent and gel initiator is supplied to the well-head. After the well is pressurized, light oil, gel-forming

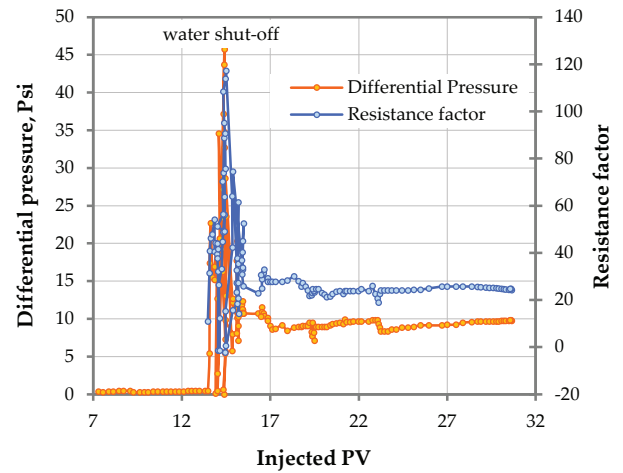


Fig. 4. The residual resistance factor and differential pressure versus the injected pore volume for the artificial core sample with the porosity 14% and permeability 456 mD

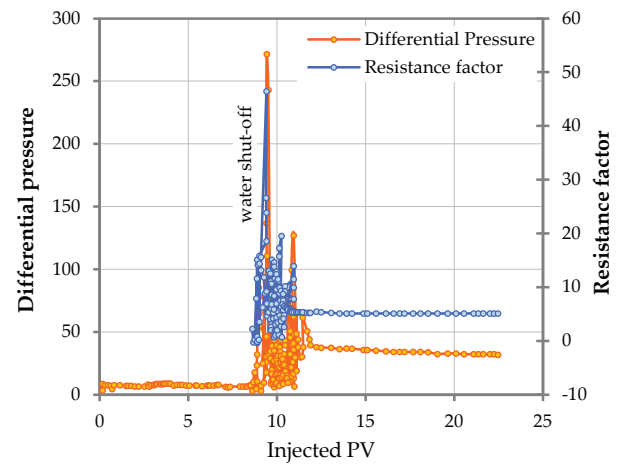


Fig. 5. The residual resistance factor and pressure difference versus the injected pore volume for the artificial core sample with the porosity 18% and permeability 29 mD

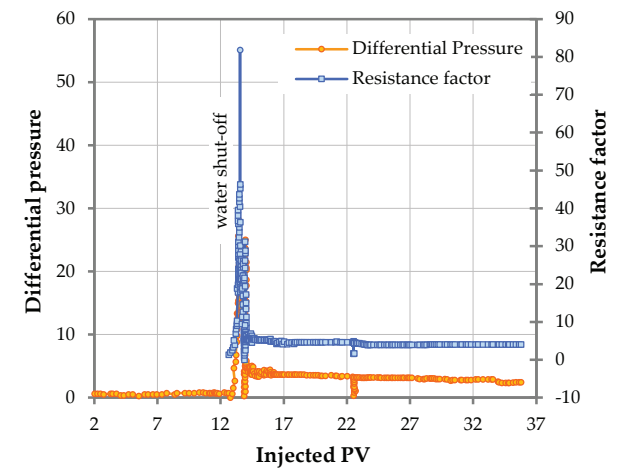


Fig. 6. The residual resistance factor and pressure difference versus the injected pore volume for the artificial core sample with the porosity 18% and permeability 287 mD

agent, light oil, gel initiator, light oil and technical water are sequentially injected into the well. After the event, the well is stopped and the well is held for 20 hours, after which the well is put into operation.

Implementation of the proposed method was carried out in the Kruk and Shurchi fields of Uzbekistan in 2024 and 2025. Below are the results of the technology application at five wells of the mentioned fields.

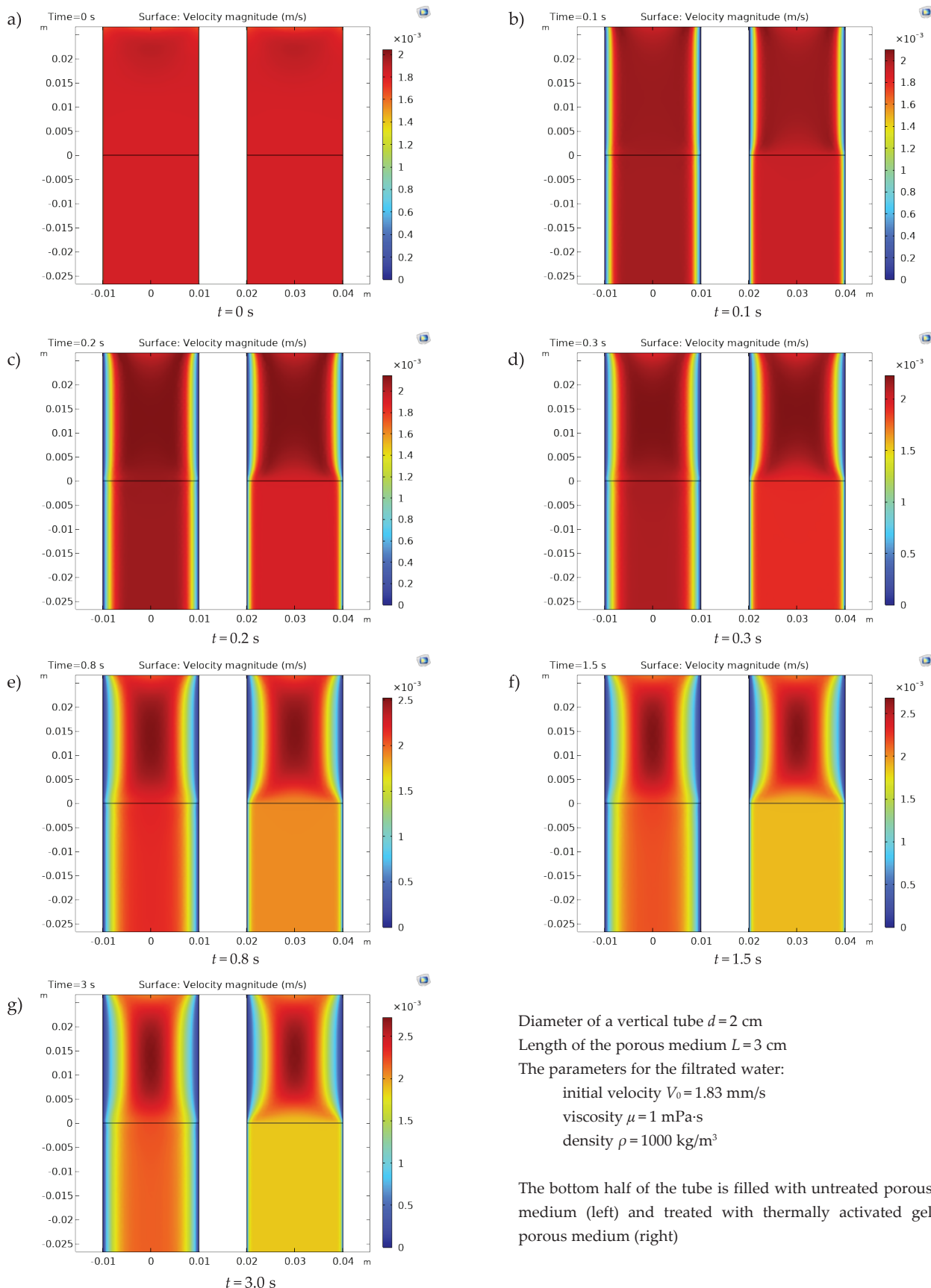
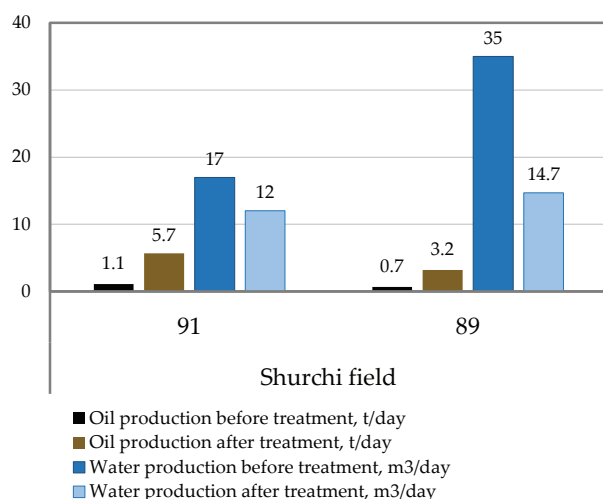
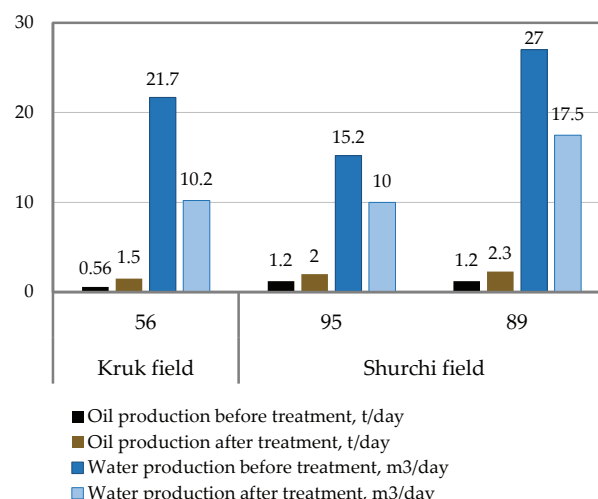


Fig. 7. Surface velocity plots of filtration processes for treated and untreated porous media with thermoactivated gel at successive times  $t = 0.0$  (a),  $0.1$  (b),  $0.2$  (c),  $0.3$  (d),  $0.8$  (e),  $1.5$  (f) and  $3.0$  (g) seconds



**Fig. 8. Results of field implementation of a method for limiting water inflow in the fields of Uzbekistan in February 2024**



**Fig. 9. Results of field implementation of a method for limiting water inflow in the fields of Uzbekistan in January-February 2025**

Results of field implementation of a method for limiting water inflow in the fields are shown in figures 8 and 9. As can be seen from the figures, in all five wells there is a decrease in water production and an increase in oil yield. At the same time, in several cases (see fig. 8), oil production

increased by 4-5 times. The results of activities carried out in February 2024 allow us to estimate the duration of the effect. At well 91 the effect lasted about three months, and at well 89 about a year. This can be seen when comparing data for well 89 in figures 8 and 9.

### Conclusion

1. A new method of water shut-off in wells using a thermoactivated mixture of solutions of gelation initiator and gelator with simultaneous acid treatment has been developed, which is effective in both terrigenous and carbonate formations.
2. Implementation of the method at the Kruk and Shurchi fields showed that it allows to precisely control the water shutoff process by regulating the gelation time achieved by temperature control and targeted delivery of the mixture to the required depth of the formation.
3. Thermally activated gel-forming mixture proposed in this study allowed to reduce permeability and, consequently, mobility ratio, which resulted in better sweeping efficiency and braking for water inflow (water breakthrough).
4. The water filtration process in a porous medium with thermally activated gel was simulated using COMSOL Multiphysics.

### References

1. Taha, A., Amani, M. (2019). Overview of water shutoff operations in oil and gas wells; Chemical and mechanical solutions. *ChemEngineering*, 3(2), 51.
2. Gasumov, R. A., Gasumov, E. R. (2023). Technical and technological solutions for limiting water inflow in gas wells with a horizontal bore end. *SOCAR Proceedings*, 3, 75-82.
3. Safaei, A., Asefi, M., Ahmadi, M., et al. (2023). Chemical treatment for sand production control: A review of materials, methods, and field operations. *Petroleum Science*, 20(3), 1640-1658.
4. Suleimanov, B. A., Abbasov, H. F. (2024). Microemulsion for stimulating wells with high gas and water cut. *Petroleum Science and Technology*, 44(1), 50-70.
5. Suleimanov, B. A., Abbasov, H. F., Ismailov, Sh. Z. (2024). A comprehensive review on sand control in oil and gas wells Part I. Mechanical techniques. *SOCAR Proceedings*, 3, 9-23.
6. Suleimanov, B. A., Abbasov, H. F., Ismailov, Sh. Z. (2024). A comprehensive review on sand control in oil and gas wells. Part II. Chemical treatment and sand management. *SOCAR Proceedings*, 4, 27-41.
7. Ibragimov, Kh. M., Kazimov, F. K., Akberova, A. F. (2022). Development and laboratory test of the gelling composition for the selective isolation of formation waters. *Scientific Petroleum*, 2, 40-46.
8. Bergmo, P. E. S., Grimstad, A. (2022). Water shut-off technologies for reduced energy consumption. SPE-209555-MS. In: *The SPE Norway Subsurface Conference, Bergen, Norway, April*.
9. Abdullayev, V. J., Veliyev, R. G., Ryabov, S. S., et al. (2023). Application of gel systems for water shut-off on Uzbekistan oil fields. *SOCAR Proceedings*, 1, 68-73.

10. Suleimanov, B. A., Abbasov, H. F. (2025). Optimizing acidizing design and effectiveness assessment for horizontal wells. *SOCAR Proceedings*, SI1, 19-22.
11. Suleimanov, B. A., Abbasov, H. F. (2025). Gasified acid solution in pre-transition state for well stimulation. *Journal of Dispersion Science and Technology*, 47(8), 1683-1691.
12. Sharma, P., Kudapa, V. K. (2022). Study on the effect of cross-linked gel polymer on water shutoff in oil wellbores. *Materials Today: Proceedings*, 48(5), 1103-1106.
13. Abdullayev, V. J., Huseynov, M. A. (2026). Assessment of enhanced oil recovery methods based on hydrodynamic model. *SOCAR Proceedings*, 1, 54-64.
14. Qayibova, A. Q., Abbasov, M. M. (2022). Study of innovative water-insulating composition based on urea-formaldehyde resin. *Scientific Petroleum*, 2, 35-39.
15. Ahmad, F. F., Gaibaliyev, G. G. (2022). Stimulation of oil inflow by isolating water inflows in the bottomhole zone. *Scientific Petroleum*, 2, 23-27.
16. Ahmadova, U. T. (2022). Review of oil recovery techniques using foam systems. *SOCAR Proceedings*, 3, 76-84.
17. Suleimanov, B. A., Abbasov, H. F., Ismayilov, R. H. (2022). Enhanced oil recovery with nanofluid injection. *Petroleum Science and Technology*, 41(18), 1734-1751.
18. Suleimanov, B. A., Ismayilov, R. H., Abbasov, H. F., et al. (2017). Thermophysical properties of nano- and microfluids with  $[\text{Ni}_5(\mu_5\text{-pppmda})_4\text{Cl}_2]$  metal string complex particles. *Colloids and Surfaces A: Physicochemical and Engineering Aspects*, 513, 41-50.
19. Suleimanov, B. A., Abbasov, H. F. (2022). Enhanced oil recovery mechanism with nanofluid injection. *SOCAR Proceedings*, 3, 28-37.
20. Kazimov, Sh. P. (2022). Enhanced oil recovery in water-flooded and hard to recover reservoirs. *SOCAR Proceedings*, 1, 89-93.
21. Mamalov, E. N., Dzhalalov, G. I., Gorshkova, E. V., Hadiyeva, A. S. (2022). Intensification of oil production using water-air mixture. *SOCAR Proceedings*, 2, 78-83.
22. Veliev, M. M., Shchetnikov, V. I., Mukhametshin, V. V., et al. (2022). Experimental studies of oil displacement ability using enzyme solutions based complexes on a reservoir model. *SOCAR Proceedings*, 2, 52-58.
23. Salem, R., Hannora, A. E. (2015). An experimental investigation of silica nano particles for enhanced oil recovery applications. SPE-175829-MS. In: *The SPE North Africa Technical Conference and Exhibition, Cairo, Egypt, September*.
24. Suleimanov, B. A., Abdullayev, V. D., Tapdigov, Sh. Z., et al. (2023). Method for isolation of water influx to well. *Eurasian Patent EA043725*.
25. Suleimanov, B. A., Gurbanov, A. Q., Tapdigov, Sh. Z. (2023). Gel system for water shut-off operations in oil wells. SPE-217559-MS. In: *The SPE Caspian Technical Conference and Exhibition, Baku, Azerbaijan, November*.
26. Matinfar, M. J., Nychka, A. (2023). A review of sodium silicate solutions: Structure, gelation, and syneresis. *Advances in Colloid and Interface Science*, 322, 103036-103047.
27. Hashemi, S. J., Hormozi, F., Mokhtari, R. (2023). Controlling the gelation time of sodium silicate gelants for fluid management in hydrocarbon reservoirs. *Fuel*, 341, 127645.
28. Hamouda, A. A., Amiri, H. A. A. (2014). Factors affecting alkaline sodium silicate gelation for in-depth reservoir profile modification. *Energies*, 7, 568-590.
29. Suleimanov, B. A., Abbasov, H. F. (2017). Chemical control of quartz suspensions aggregative stability. *Journal of Dispersion Science and Technology*, 38(8), 1103-1109.
30. Chi, M., Hu, J., Wang, X., et al. (2023). Preparation and application of pH-Responsive and high salt-tolerants silica-based amphiphilic Janus nanosheets for enhanced heavy oil recovery. *Geoenergy Science and Engineering*, 230, 212210.
31. Abbasov, H. F. (2022). A new model for the relative viscosity of aqueous electrolyte solutions. *Chemical Physics Letters*, 800, 139670.
32. Suleimanov, B. A., Gurbanov, A. Q., Tapdigov, Sh. Z. (2022). Isolation of water inflow into the well with a thermosetting gel-forming. *SOCAR Proceedings*, 4, 21-26.
33. Kudapa, V. K., Kumar, Sh. (2024). Applications of sodium silicate in oil and gas well operations. *Materials Today: Proceedings*, 102, 221-225.
34. Liu, S., Ott, W. K. (2020). Sodium silicate applications in oil, gas & geothermal well operations. *Journal of Petroleum Science and Engineering*, 195, 107693.
35. Chukwuemeka, A. O., Oluyemi, G., Mohammed, A. I., Njuguna, J. (2023). Plug and abandonment of oil and gas wells – A comprehensive review of regulations, practices, and related impact of materials selection. *Geoenergy Science and Engineering*, 226, 211718.
36. Sagala, F., Hethnawi, A., Nassar, N. N. (2020). Hydroxyl-functionalized silicate-based nanofluids for enhanced oil recovery. *Fuel*, 269, 117462.
37. <https://studfile.net/preview/2824550/page:26/>
38. Kozeny, J. (1927). Ueber kapillare leitung des wassers im boden. *Sitzungsberichte / Akademie der Wissenschaften in Wien*, 136(2a), 271-306.
39. Carman, P. C. (1937). Fluid flow through granular beds. *Chemical Engineering Research and Design*, 75, S32-S48.
40. Paprouski, A., Fatemi, M., Ghazanfari, M. H. (2021). Effect of silicate sodium and graphene nanoplatelets on morphology and rheology characteristics of new synthesized preformed particle gel (PPG) for water shut-off treatment. *Journal of Petroleum Science and Engineering*, 204, 108736.
41. Dijvejin, Z. A., Ghaffarkhah, A., Sadeghnejad, S., Sefti, M. V. (2019). Effect of silica nanoparticle size on the mechanical strength and wellbore plugging performance of SPAM/chromium (III) acetate nanocomposite gels. *Polymer Journal*, 51, 693-707.
42. Suleimanov, B. A., Abbasov, H. F. (2024). Wettability alteration of quartz sand using Z-type Langmuir-Blodgett hydrophobic films. *Physics of Fluids*, 36(3), 034118.