Heliyon 10 (2024) e26689

Contents lists available at ScienceDirect

Heliyon

journal homepage: www.cell.com/heliyon

Research article

Numerical study of the mechanisms of nano-assisted foam flooding in porous media as an alternative to gas flooding

Ayomikun Bello [a,*], Desmond Batsa Dorhjie [a], Anastasia Ivanova [a], Alexander Cheremisin [a], Ilnur Ilyasov [b,c], Alexey Cheremisin [a]

[a] *Center for Petroleum Science and Engineering, Skolkovo Institute of Science and Technology, Skolkovo Innovation Center, 11 Sikorski Street, Moscow 143026, Russia*

[b] *JSC «Messoyakhaneftegaz», Russia*

[c] *Tyumen Industrial University, Russia*

A R T I C L E I N F O

Keywords:
Foam
Nanoparticles
Gas
Surfactant
Hydrodynamic modeling

A B S T R A C T

Oil reservoirs are nearing maturation, necessitating novel enhanced oil recovery (EOR) techniques to meet escalating global energy demands. This demand has spurred interest in reservoir production analysis and forecasting tools to enhance economic and technical efficiency. Accurate validation of these tools, known as simulators, using laboratory or field data is pivotal for precise reservoir productivity estimation. This study delves into the application of nanoparticles in foam flooding for mobility control to improve sweep efficiency. Foam generation can occur in-situ by simultaneous injection of surfactants and gas or through pre-generated foam injection into the reservoir. In this work, a series of systematic simulations were run to investigate how much injected fluids can reduce gas breakthrough while also increasing oil recovery. Subsequently, we analyzed the most effective optimization strategies, considering their economic limits. Our primary objective is to numerically model nanofoam flooding as an innovative EOR approach, synergizing foam flooding mechanisms with nanotechnology benefits. In this work, modeling of nanoparticles in foam liquid was represented by the interfacial properties provided to the injection fluid. Additionally, we simulated Water-Alternating-Gas (WAG) injection schemes across various cycles, comparing their outcomes. Our results showed that nanofoam injection achieved a higher recovery factor of at least 38% and 95% more than WAG and gas injections, respectively. The superior efficiency and productivity of foam injection compared to WAG and gas injection suggest an optimal EOR approach within the scope of our model. These simulated optimization techniques contribute to the future development of processes in this field.

1. Introduction

Fuel price variations, greenhouse gas emissions, and technical improvements in renewable energy resources [1] have all contributed to the expectation that fossil fuels will soon be replaced in the energy mix. This notion has also contributed to the belief that there is no need for further development of new oil resources. However, the fact is that this argument is disputable since gas capture, usage, and storage may assist in reaching CO_2 emission reduction goals while fossil fuels remain in the energy balance [2].

* Principal corresponding author.
E-mail address: ayo.bello@skoltech.ru (A. Bello).

https://doi.org/10.1016/j.heliyon.2024.e26689
Received 18 October 2023; Received in revised form 15 February 2024; Accepted 18 February 2024

Available online 23 February 2024

Fossil fuels currently make up approximately 80% of the global energy supply [1,3]. In the next 50 years, global energy consumption will rise in lockstep with global population, which is predicted to reach 9 billion people. Indeed, the International Energy Agency (IEA) proposes that global energy consumption will continue to climb until 2050, with oil remaining the most important energy source. The IEA forecasts a 21% growth in global oil demand over the next 30 years, accounting for 35% of overall energy consumption [3,4]. This will necessitate higher oil and natural gas production. The objective of the oil and gas industry will be to deploy new technologies and enhance existing ones to maximize oil production efficiency. Modern EOR methods, which are guaranteed to improve oil production by boosting oil formation sweep efficiency, are expected to be mobilized to achieve that.

Foam injection is one of the EOR methods that is considered in this study. Foam is a non-wetting gas dispersion into a continuous liquid wetting phase [5,6]. Surfactant or polymer solutions are frequently used as the liquid wetting phase. Because injected gases are significantly less dense and viscous than formation oil and water, they tend to finger through or migrate to the top of the reservoir, leaving a significant amount of reservoir oil unaffected [7,8]. As a result, foams are employed in gas floods as mobility control agents [4,9]. They boost oil recovery by enhancing the effectiveness of the injection fluid in sweeping the bulk of the reservoir volume while also increasing oil displacement. The foam might be created in situ or pre-generated on the surface before being injected into the reservoir [10].

Despite the potential of foam as a gas mobility control agent, its metastability prevents it from being widely employed in pilot projects [11,12]. Foam stability is a crucial problem when designing foams for EOR processes; hence, laboratory tests should be conducted in conditions near the target reservoir as possible to understand how foam behaves. Nanotechnology has gotten much attention in the recent decade for its potential to enhance various processes in the petroleum industry [13–15]. Oil recovery is one of these processes. Nanoparticles have proven to be effective in injection fluids because of their ability to stay at the interface for extended periods [14,16,17]. They have unique chemical properties that allow them to adsorb to the surface of rocks and change their wettability. Also, due to their tiny size, they have little retention in the pores, allowing them to travel a considerable distance in the pore throats [18,19].

Nanoparticles have been shown to be important in several studies, notably for enhanced oil recovery. Moradi et al. (2015) [20] claimed that nanoparticle adsorption on the reservoir surface induced a change in wettability from oil-wet to extremely water-wet, resulting in an increase in oil recovery in a water-alternating-gas injection scheme. Maghzi et al. (2011) [21] investigated the effect of silica nanoparticles in polyacrylamide solution on oil wettability using a glass micromodel. When compared to tests without nanoparticles, injection experiments with nanoparticles resulted in a 10% improvement in oil recovery. Similar results were achieved by Yousefvand et al. (2015) [22], with an increase attributed to a change in fluid viscosity and wettability of the porous media.

Although they may be time-consuming, numerical simulation studies are essential to analyze the performance of injected fluids. They may be used to estimate oil recovery in various reservoirs under certain conditions [23]. However, experimental investigations in the laboratory are expected to demonstrate the technical viability of these processes before numerical simulations [23,24]. Furthermore, experimental research will provide additional input data for the simulator, allowing for more precise predictions. In recent years, reservoir engineering simulators have been widely employed in the industry for EOR operations.

Due to its ability to mimic flooding results and simulate complicated interaction processes of three-phase systems (i.e., oil, water, and injected fluid) in small and field-scale media, CMG was chosen as the simulator for this study. Pandey et al. (2008) [25] used a commercial simulator to conduct core-flooding simulation studies using the Mangala oilfield model to provide more information about the various mechanisms and generating chemical flooding parameters for projecting oil production. Their results described the complex dynamics involved in common EOR flooding processes and predicted the performance of the injected fluid with respect to the reservoir. This was clear in their findings since laboratory data was matched to the oilfield history data.

A numerical study was carried out in Tunnish et el. (2019) [26] to match alkaline flooding experimental results to a pseudo-sand pack model in a commercial simulator. A Cartesian grid structure was used to depict the sand pack model. The authors effectively history matched the oil production, water cut, oil cut, differential pressure, and liquid production rate profiles. They then investigated the effect of alkaline concentrations and oil viscosity on the recovery factor. Loaiza et al. (2020) [27] developed a numerical simulation model for polymer and nanoparticle co-injection. Although their findings validated previously published nanoparticle interaction processes, the conditions under which the simulator operated were not clearly explained.

To the best of our knowledge, there are no commercial reservoir simulators in the industry that can adequately simulate nanofoams to estimate oil recovery. This makes predicting the recovery performance of nanofoams difficult. To overcome this difficulty, in this paper, we report the development of a nanofoam simulation that includes the primary interaction mechanisms responsible for the efficiency of nanoparticles in displacing oil from formations. As reported in our previously published papers [28,29], the introduction of nanofoams has shown to be an effective approach to controlling gas mobility and improving volumetric sweep efficiency. In this work, we aimed to validate our experimental data.

This paper also includes a series of flooding experiments utilizing nanoparticle-enhanced foams to evaluate secondary and tertiary oil recoveries. We used numerical modeling to examine the potential of nanofoams for oil recovery in an unconsolidated heavy oil field in Western Siberia.

An extensive set of screening tests has been used to explore the physicochemical behavior of nanofoams in our previous work [28]. The information obtained was used as input for this investigation, and it was matched with the simulation model. A sensitivity analysis study was conducted after getting a satisfactory historical match to explore the influence of nanoparticle concentration on oil recovery. In terms of recovery factor and economic assessment profiles, the performance of the nanofoams was evaluated systematically.

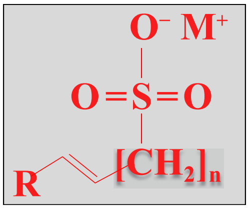


Fig. 1. Chemical structure of Alpha-Olefin Sulfonate (AOS) surfactant.

2. Experimental and simulation methods

2.1. Materials

The foaming agent used in this study was an anionic surfactant, alpha-olefin sulfonate (AOS) surfactant, and the stabilizing agents were silica nanoparticles. AOS (BIO-TERGE AS-40 KSB) was obtained from *Stepan, United States* as a dispersion with a 39% active content. The chemical structure is given below (Fig. 1):

LLC Khimuniverse, Russia, provided nanoparticle dispersion with a 30.4 wt.% silicon dioxide concentration. Brine was prepared with sodium chloride ($NaCl$, >99.0 wt.% pure, *Chimmed, Moscow*). Crude oil sample with density of 945 kg/m^3 was obtained from the oil field. All reagents were used as received.

2.2. Preparation of foaming suspensions

Surfactant solution was dispersed in brine to achieve the necessary surfactant concentration. Since the AOS surfactant was already in liquid phase, the following dilution formula (Equation (1)) was employed to calculate the required volume:

$$C_1 V_1 = C_2 V_2 \tag{1}$$

where: C_1 = initial concentration of solution; V_1 = initial volume of solution; C_2 = final concentration of solution; V_2 = final volume of solution.

The brine solution was prepared by weighing the required grams of NaCl into deionized water. The nanosolutions were homogenized for about 2 hours at 500 rpm using a magnetic stirrer. The silica nanoparticles used in this study was also obtained in a dispersed form, and so the same dilution formula used for AOS surfactant was applied. A precise and analytical balance was used to determine the masses of all reagents (Mettler-Toledo, Switzerland). During foam stability testing, mechanical vibrations were minimized as much as possible. In our experiments, the concentration of AOS used was above its CMC - 0.3 wt.%. The concentrations of silica nanoparticles in dispersions were 0.05 wt.% and 0.1 wt.%.

2.3. Determination of interfacial tension

A Spinning Drop Tensiometer *(KRUSS, Germany)* was used to measure the interfacial tension (IFT) between reservoir oil and foaming solutions at temperatures of 25 °C and 70 °C. Prior to the start of the experiment, the calibration of the spinning drop tensiometer was performed with a standard reference material (Water and n-Decane), and a value of 46 mN/m was obtained. This is in agreement with many literature [30–32] reporting IFT values of 45.7, 46.17, 46.5 mN/m respectively. The spinning drop capillary tube was filled with foaming solutions during the measurements. The dynamic interfacial tension was then determined by placing an oil drop at the meniscus of the tube and setting the capillary speed to about 8000 rpm for all tests. The temperature was set as 25 °C and 70 °C and the chamber was allowed to attain the desired temperature before tests were started.

Depending on the shape and form of the oil droplet in the foaming solution, either Vonnegut's equation or Young-Laplace formula was used to calculate the IFT. Vonnegut's equation is presented in equation (2) and Young-Laplace formula in equation (3).

$$\sigma = \frac{\Delta\rho\omega^2 r^3}{4} \tag{2}$$

$$\sigma = \frac{\Delta\rho\omega^2 D^3}{32} \tag{3}$$

where: ω, D, r, $\Delta\rho$ are the angular velocity, drop diameter, drop radius and density difference between foaming solutions and crude oil, respectively.

2.4. Simulation methodology

Prior to running the simulations, it was assumed that there were no chemical reactions in the reservoir and that the oil and water moving through the porous media complied with Darcy's law.

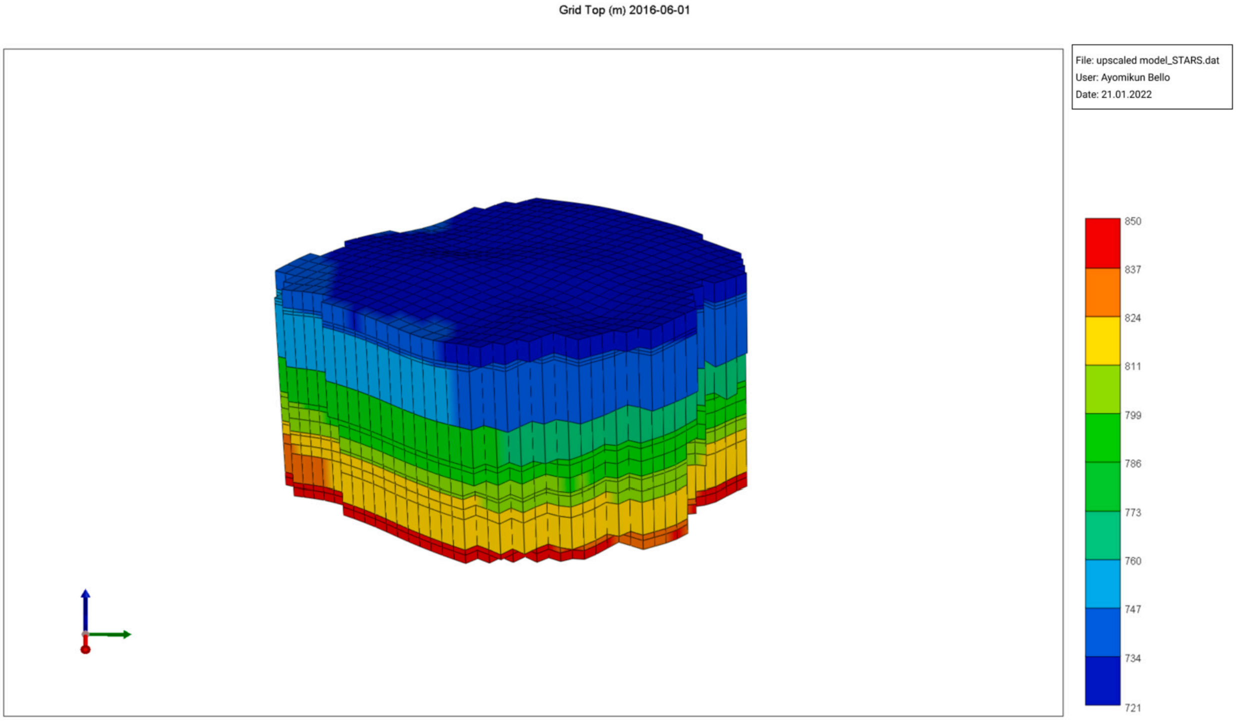


Fig. 2. Reservoir model.

Table 1
Simulation input of reservoir model.

Parameters	Values
Grid block size	28 x 24 x 14
Formation thickness	129 m
Reservoir top	721 m
Porosity	20% - 30%
Permeability	100 mD - 5000 mD
Reservoir pressure	7.9 MPa
Reservoir temperature	16.85^{o}C
Oil density	945 kg/m^3
Oil viscosity	100 cP
API gravity	17.45^{o}
Initial oil saturation	0.48

2.4.1. Reservoir model description

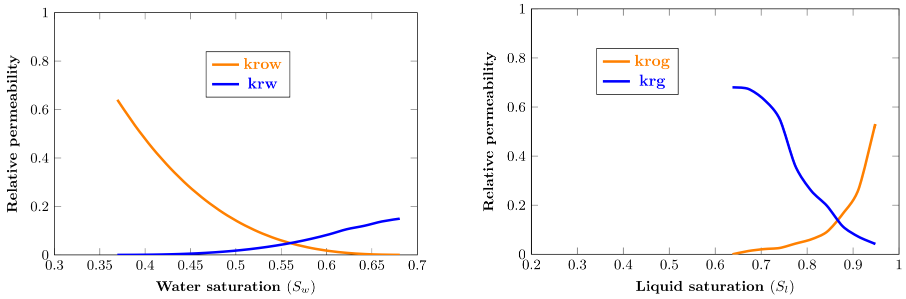
The model used in this study is from a section of an unconsolidated heavy oil field in West Siberia. The reservoir has a complex geological structure, a high degree of formation heterogeneity, and a large gas cap. The primary pay zones (productive layers) are found in terrigenous reservoirs with extreme vertical and horizontal discontinuity. Sands and thinly stratified sandstones make up the reservoir formation, which is highly heterogeneous. The porosity varies between 20% and 30%, while the permeability varies between 100 and 5000 mD. The reservoir model showing the grid top distribution is presented in the figure below (Fig. 2).

The characteristics of the formation are summarized in Table 1. The model has 14 layers with a total of 9408 blocks. This study takes into account the simulation of gas, water, and foam flooding with and without nanoparticles with eight horizontal wells comprising of two injectors and six producers. The relative permeability curves can be seen in Figs. 3a and 3b.

2.4.2. Grid refinement and upscaling

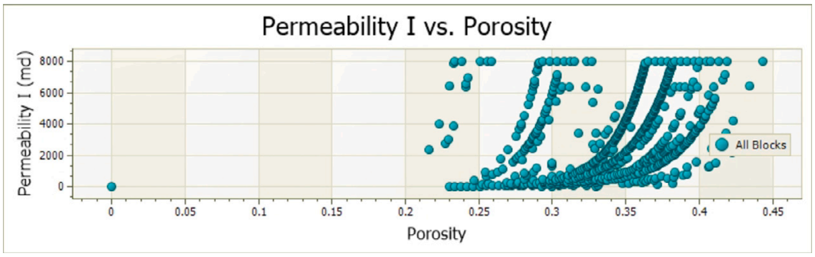
In order to reduce the computation time of the hydrodynamic model and the cost of computer RAM resources, grid refining and upscaling were employed to reduce the size of the grids and identify average geological properties [33]. During grid refinement, the layers of the geological model were combined into groups of smaller cells of the refined model. To make the upscaled simulation model as accurate as feasible, the grids were adjusted such that the blocks replicate the heterogeneities on the scale of the block.

Upscaling, on the other hand, includes computing the comparable properties of the large cells in the geological model and incorporating them into the upscaled model [33]. Since the list of these properties is very large and difficult to focus on all of them

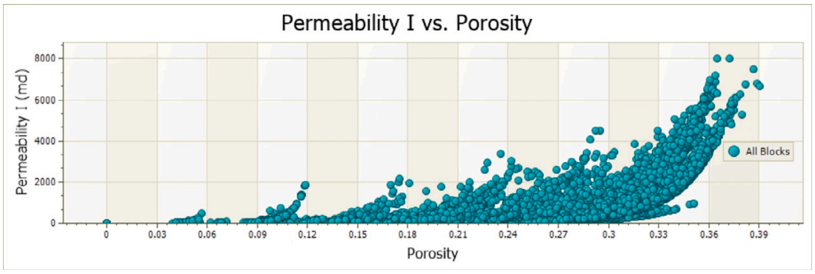


(a) (b)

Fig. 3. Relative permeability curves (a) Oil-Water relative permeability curve; (b) Liquid-Gas relative permeability curve.



(a)



(b)

Fig. 4. Porosity-Permeability distribution plots (a) before upscaling and grid refinement (b) after upscaling and grid refinement.

during upscaling, net-to-gross ratio was selected and at the same time porosity and permeability were controlled. This is due to the model's highly permeable interlayers, which are necessary for the grid formation of the model.

A simple volumetric average was used to upgrade porosity. The area to be averaged was selected and defined by A, and the average porosity in the upscaled model is calculated using the expression in Equations (4) and (5) below [34]:

$$\phi' = \frac{1}{A} \int_A \phi(x) dx \tag{4}$$

In the same way, net-to-gross ratio, N was upscaled by the formula below:

$$N' = \frac{1}{\int_A \phi(x) dx} \int_A \phi(x) N(x) dx \tag{5}$$

The distributions of porosity and permeability before and after grid refinement and upscaling are shown in Figs. 4a and 4b. Mean errors were calculated as 3.48% and 1.47% for permeability and porosity, respectively.

3. Results and discussion

In this work, firstly, the model was validated by matching the cumulative productions during water flooding to field production data at the same time intervals. Afterwards, water injection was simulated to be compared with CO_2 and N_2 gas injections were

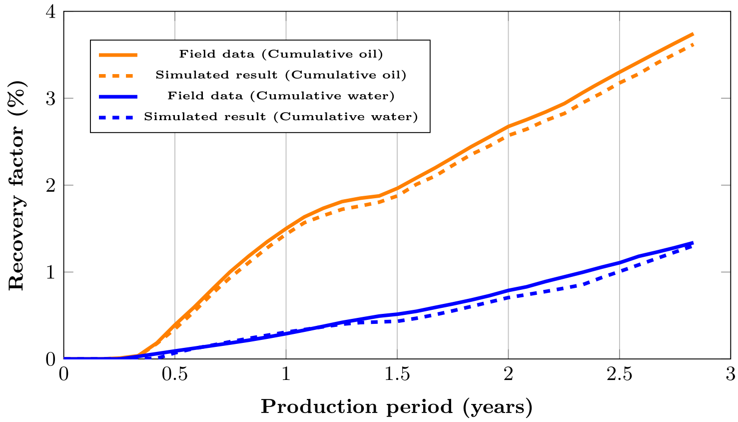


Fig. 5. History matching of simulated results to field production data.

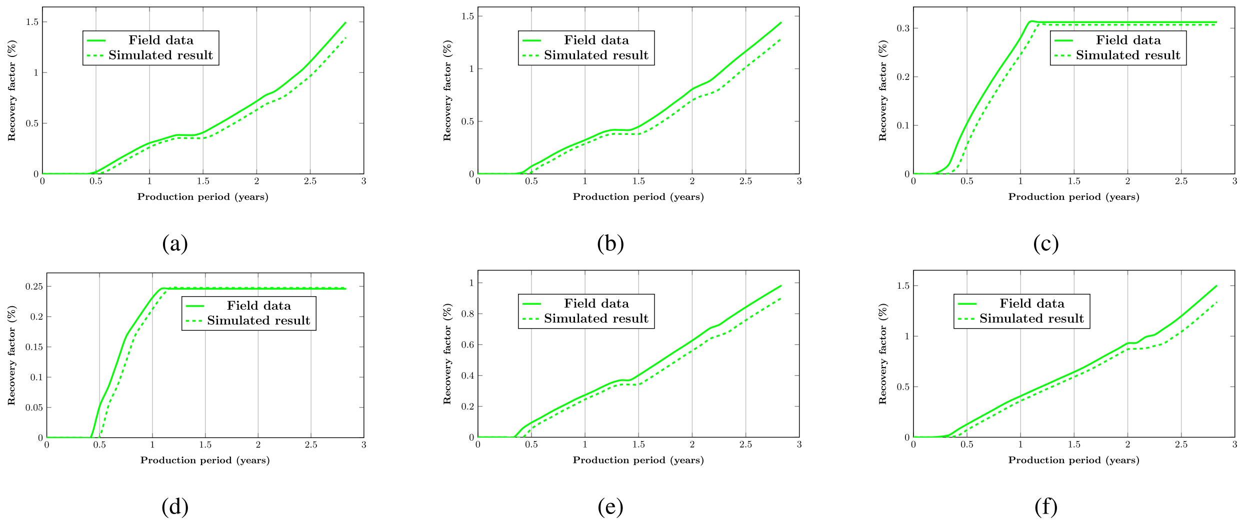


Fig. 6. History matching of cumulative liquid production (a) Producer 1 (b) Producer 2 (c) Producer 3 (d) Producer 4 (e) Producer 5 (f) Producer 6.

simulated. In order to mitigate the effects of gas breakthrough which was noticed during gas flooding, WAG and nanofoam flooding were implemented as optimization techniques.

3.1. *Validation of model through history matching*

Fig. 5 shows an appropriate history match results between modeling results and field production data. The results are consistent with standard rules-of-thumb, which state that the geological oil reserves of an upscaled model should not deviate by more than 5% from the original model [33]. It is also important to compare cumulative oil and water production and make sure that simulated results do not differ by more than 5% from field data. As it can be seen in our results (Fig. 5, deviations of our simulated results of oil and water recovery factors from field data are 1.32% and 2.05% respectively. Also, Figs. 6a - 6f show the adaptation of each producing well to the liquid production rates of the field data. Therefore, the bottom hole pressures were history matched.

3.2. *Interfacial tension of foaming solutions*

Nanoparticles have the ability to aid surfactant solutions in IFT reduction due to their adsorption at the interface and additional interactions with surfactant molecules. It was observed in this work that when nanoparticles were added to the foaming solutions, the interfacial tension (IFT) between oil and foaming solutions was reduced. As such, IFT was lowered from 0.77 mN/m in the absence of nanoparticles to 0.53 mN/m in the presence of nanoparticles, as shown in Fig. 7. Moreover, by increasing the concentration of silica nanoparticles in the solution from 0.05 wt.% to 0.1 wt.%, IFT was further reduced from 0.529 mN/m to 0.352 mN/m.

These findings suggest that nanoparticles can increase oil recovery by lowering IFT. Furthermore, as indicated in Fig. 7, increasing the temperature from 25 °C to 70 °C led to increase of interfacial tension. This is because temperature has a negative impact on AOS surfactant solubility in water [35–37]. According to Vatanparast et al. (2018) [38], the increasing trend of IFT with temperature

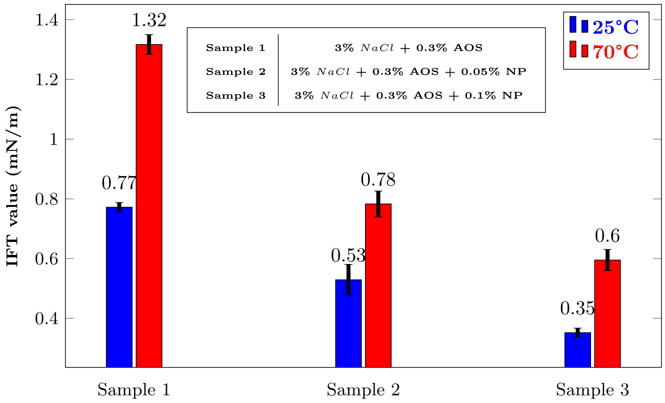


Fig. 7. Effect of nanoparticles on the interfacial tension between foaming solutions and reservoir oil at different temperatures.

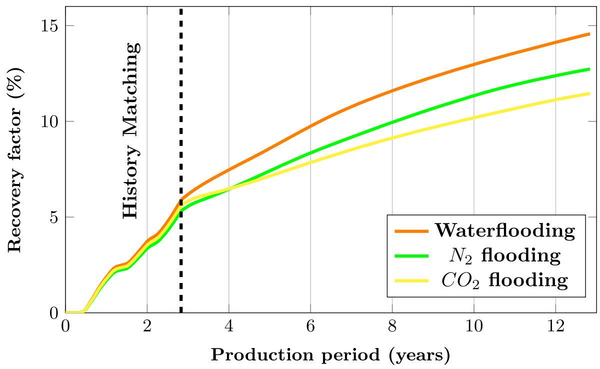


Fig. 8. Oil recovery efficiency during water and gas injection scenarios.

might be explained by a decrease in the number of hydrogen bonds between the surfactant and water molecules. These results were also supported by findings [35,36,38] where the hydrogen bonds number was found to reduce upon increasing temperature. This leads to a change in surfactant solubility and surfactant becomes less soluble in water and shows a stronger affinity to the oil phase, resulting in a higher IFT.

3.3. Flooding simulations

Prediction studies were performed using the history-matched model. A restart file was prepared in order to begin a fresh simulation run from the last simulation date of waterflooding (history matching). The new model loaded the previous simulation run obtained for the history-matched model and started the simulation run till our target date. Four injection methods were investigated in this study: water injection, gas injection, water-alternating-gas injection, and foam injection in the presence and absence of nanoparticles. All simulations were run under the same set of constraints, with 6 producers and 2 injectors. Production and injection rates were controlled by the last known bottom hole pressure during history matching.

3.3.1. Comparison of water injection with N_2 and CO_2 gas injection

Figs. 8 and 9a - 9c show the results of water, N_2 and CO_2 flooding simulations.

As it can be seen from Fig. 8, the comparative deviations of CO_2 and N_2 injections from water injection are 17.2% and 3.1% respectively. This means that within the same period and operational constraints, N_2 produced 3.1% less oil than water, while CO_2 produced 17.2% less oil. Thus, it is clear that water injection is better than both N_2 and CO_2 gas injections. This can be explained by breakthrough of gas, which can be inferred from Fig. 9.

The efficiency of water and gas injection processes were further assessed using their mobility ratios. Mobility ratio for both cases were calculated using the formula (Equation (6)) below:

$$M = \frac{K_{r1}\mu_2}{K_{r2}\mu_1} \tag{6}$$

where: K_{r1}, K_{r2}, μ_1 and μ_2 represent relative permeability of displacing fluid, relative permeability of displaced fluid, viscosity of displacing fluid and viscosity of displaced fluid, respectively.

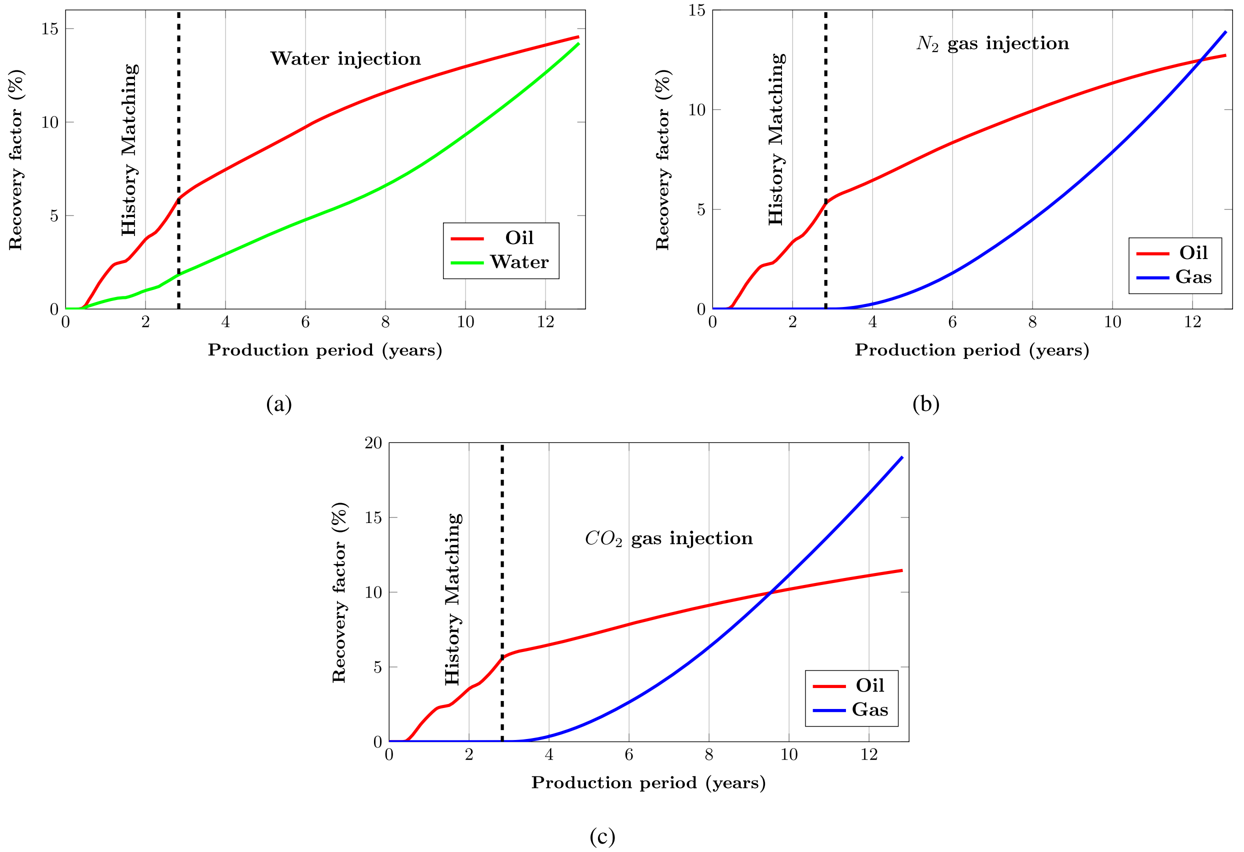


Fig. 9. Oil recovery efficiency during (a) water and gas injection scenarios (b) N_2 flooding and (c) CO_2 flooding.

Water, N_2 and CO_2 mobility ratios were calculated from Equation (6) as 15.7, 31.25 and 32.63, respectively. Although mobility ratios of fluids are generally high in this reservoir due to the high viscosity of reservoir oil, however mobility ratio during water injection is lower than during gas injection. This means that the gas viscosity is not high enough to withstand the flow of reservoir oil, and the gas does not have enough sweep efficiency as it should. As a result, injected gas separates after a while and, due to its lower density, rises to the reservoir top. This is known as a gravity override, and it causes the injected gas to break through early, which is why water injection produces more oil than both gas injections.

It is important to note at this point that N_2 injection performs better than CO_2 injection. However, in some studies, [39–43] it was reported that CO_2 gas injection has a better effect on oil displacement due to its favorable properties, which include miscibility with oil at low pressures, high density, oil swelling, and lowering of oil viscosity. Nevertheless, experiments conducted in [44–48] pointed out that because of its immiscible displacement process, N_2 gas injection is particularly successful in reservoirs with sufficient depth and high reservoir pressure.

CO_2 and heavy oil are immiscible due to the heavy components of the oil. Therefore, the immiscible displacement mechanism of N_2 injection proves to be the displacement mechanism, resulting in the production of more oil with N_2, because the gas does not fully contact the reservoir oil throughout the simulation. Similar results were observed in the study of Yuan et al. (2015) [49], which reported a considerable increase of 40% in oil recovery in a fractured-carbonate reservoir using N_2 gas flooding.

Depending on the level of heterogeneity in the reservoir, Joslin et al. (2017) [50] demonstrated the effectiveness of nitrogen gas injection over CO_2 gas via pressure maintenance when permeability value is low. The reservoir oil is heavy and so our prognosis is that the gases were injected at pressures far from the minimum miscibility pressure. Therefore, they were not able to mix with the reservoir oil and thus, miscible recovery mechanism was not possible. Several articles have demonstrated immiscible CO_2 and N_2 injection in heavy oil reservoirs and immiscible N_2 injection was a better oil recovery option.

In fact, in Vogel et al. (1980) [51] it was demonstrated that in comparison with immiscible CO_2, oil volume factor and solution gas-oil ratio decreased, and the oil density and viscosity increased when a black oil was contacted by immiscible nitrogen. The authors further mentioned that as an immiscible gas, nitrogen will lower oil viscosity more than CO_2 because of its lower density relative to carbon dioxide. So irrespective of the many importance of CO_2 to extract oil, it still needs to be injected at least near MMP in order to be miscible with reservoir oil. In this study, we believe that gas injection was injected at a pressure that could only enhance oil recovery through pressure maintenance and nitrogen injection does that better than CO_2.

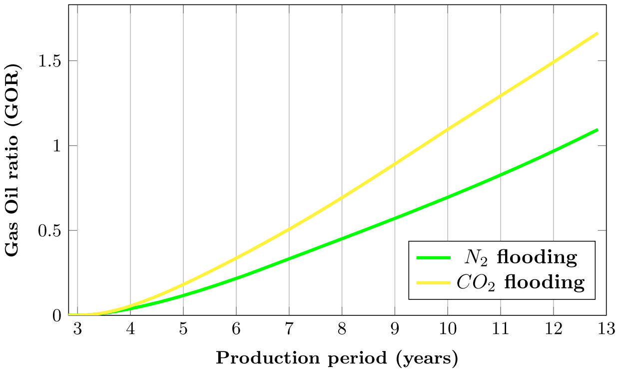


Fig. 10. Gas Oil ratio during N_2 and CO_2 injection.

Furthermore, a dead oil was used in this simulation study. Several works from James Sheng's Lab have presented immiscible gas displacement from cores with dead oil [52–54]. Their results demonstrated better recovery factor for nitrogen. This is in agreement with our work as well as in Rezaei et al. (2014) [55], where CO_2 and N_2 injections were considered in both miscible and immiscible displacement scenarios. The authors stated that in fact, when the injection rate of immiscible nitrogen injection was lowered, nitrogen breakthrough occurs later which gives rise to an increase in oil production. Additionally, the authors explained that even if miscible mechanism is used in CO_2 gas injection, it would only result in oil swelling and viscosity reduction which would ease oil mobilization. However, immiscible nitrogen injection is required to push the oil to the producers in order to improve oil recovery due to its better pressure maintenance mechanism.

Fig. 10 shows the gas-oil ratio (GOR) during gas injections. From the result shown, we can conclude that at the later stage of injection, the injection gas breaks through. To reiterate, we believe that the injected gas is unable to fully mix with the reservoir oil and just moves to the producing well. This is a typical challenge with gas injection operations due to their low viscosity and density. Moreover, we can conclude from Figs. 9 and 10 that CO_2 caused gas breakthrough earlier than N_2. As a result of this, the CO_2 gas sweep efficiency was lowered, resulting in a lower oil production.

3.3.2. *Influence of cycle period on oil recovery in WAG injection process*

Water-Alternating-Gas injection is a usual process in reservoirs with problems that are associated with viscous fingering and gravity drainage due to gas breakthrough during gas injection. WAG can be used to control the mobility of the fluids as the gas follows a different path through the reservoir to ensure that both areal and vertical sweep efficiencies are improved. In order to select the best WAG case for comparisons with other injection schemes, the WAG injection scheme was optimized using three scenarios – repeated water and gas cycles at intervals of 1 month, 3 months and 6 months (Figs. 11a and 11b).

As it can be seen in Fig. 11, 1-month and 3-month cycles produced higher recoveries in N_2 and CO_2 respectively. This is due to the improvement of the injection fluid mobility which caused a higher volumetric sweep. Another explanation for the enhanced recovery with shorter WAG cycles is an increase in gas injection displacement efficiency combined with the improved volumetric sweep by water flooding after gas injection. Although, WAG is not the best approach for early gas flooding breakthrough, it reduces the gas-to-oil ratio (GOR), as shown in Figs. 12a and 12b. The increased viscosity of the injected fluid (water) is helps to achieve a favorable mobility ratio, which stabilizes the displacement front and thus enhances the WAG displacement process.

Notably that the enhanced recovery can also be linked to gas trapping [56,57]. During the imbibition cycle, gas trapping might cause some residual oil to be mobilized, resulting in higher oil recovery in the reservoir. Since the gas is confined during imbibition, the flow is reduced, resulting in larger pore spaces for the oil to flow; hence more oil is produced.

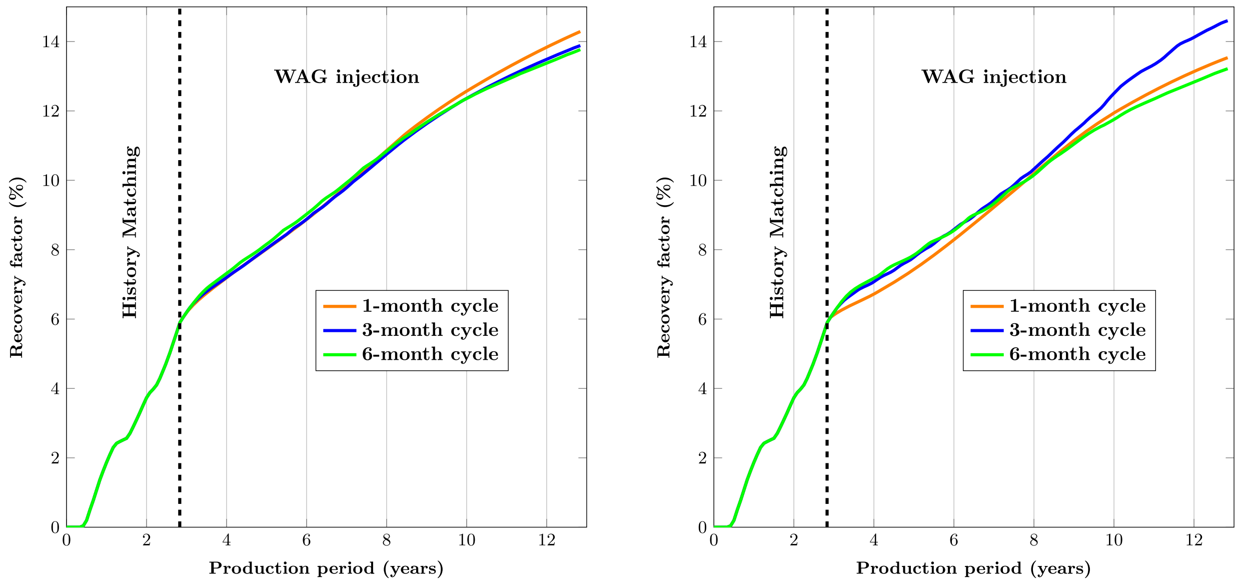
The higher oil recovery during WAG is due to the contact of unswept zones by water, as well as the improved displacement efficiency of gas after water injection. Due to the low interfacial tension between gas and oil, gas injection after water flooding can displace more oil from pore throats that have not been accessed by water. This considerably improves the effectiveness of microscopic sweep, resulting in better overall recovery.

Oil production is better enhanced when gas is injected intermittently for short periods i.e. 1 and 3 months. This is because these periods are ideal for the gases and cannot reach their breakthrough within those periods. In a longer period i.e. 6 months, gas already breaks through before water is injected and this defies the whole idea of optimization with water, hence less oil is recovered when compared with 1-month and 3-month cycles.

3.3.3. *Effect of nanoparticles on oil recovery during foam injection*

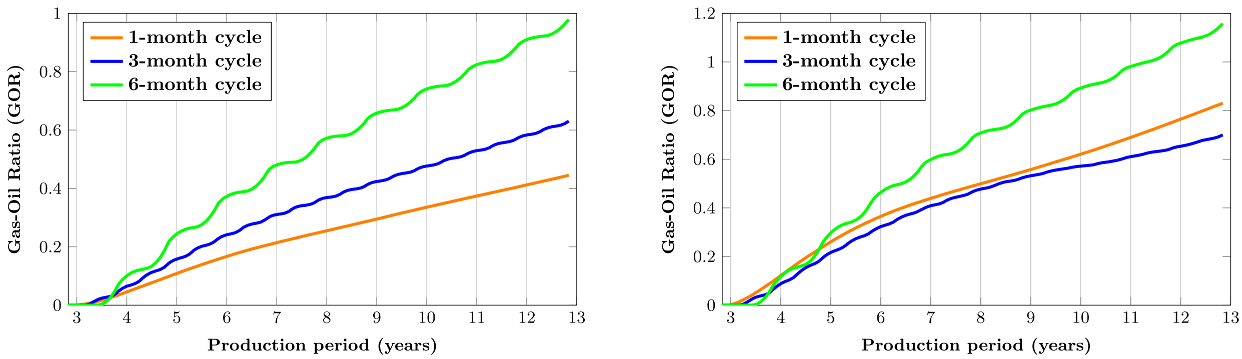
An empirical foam model in CMG STARS was employed in this investigation. When foam is available, this model simply rescales the gas relative permeability using a dimensionless scaling factor. Foam strength is represented by this scaling factor, with a maximum value of one indicating no foam present. It is a function of numerous factors that can be used to describe various effects on foam strength, including limiting foam strength, surfactant concentration, capillary number, oil saturation, and mobility reduction factor.

In order to simulate nanofoams, the effect of nanoparticles should be taken into account. Therefore, in this study, the effect of nanoparticles on foam was modeled by simply altering the IFT values from each case. The main oil recovery mechanism of



(a) (b)

Fig. 11. Oil recovery efficiency during WAG injection cycles: (a) N_2 WAG and (b) CO_2 WAG.



(a) (b)

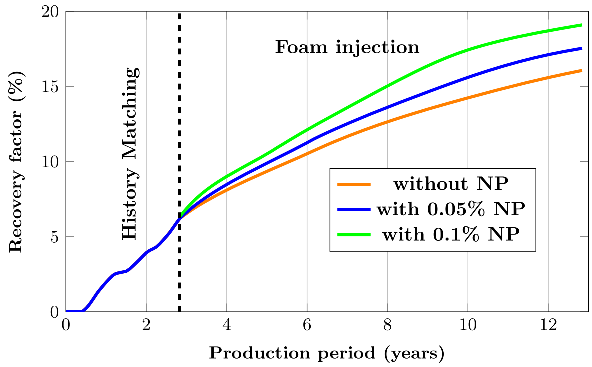
Fig. 12. Gas-to-Oil ratio during WAG injection cycles: (a) N_2 WAG and (b) CO_2 WAG.

nanoparticles is reduction of interfacial tension. This is also in line with previously published literatures [58–61]. The IFT values of foaming solutions without and with 0.05% and 0.1% nanoparticles were adjusted in the simulation model from experimental data and run with the same parameters and constraints as gas and WAG injections. Figs. 13a - 13d show cumulative oil and gas production when foam is injected with CO_2 and N_2 in the presence and absence of nanoparticles.

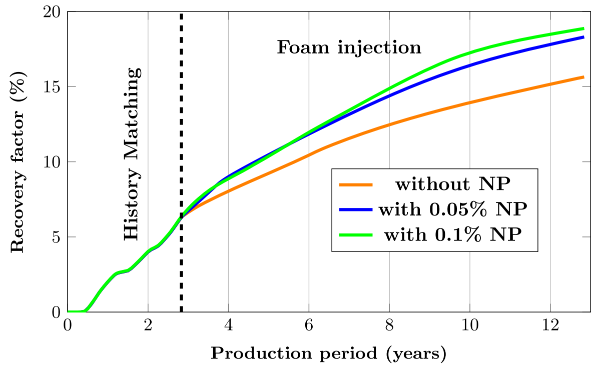
The difference between oil production during CO_2 foam and N_2 foam injection with the addition of 0.05% and 0.1% nanoparticles can also be seen in Figs. 13a and 13b. This is primarily due to a disparity in their levels of stability. We investigated foam stability with CO_2 and N_2 in our previous work [28]. The results showed that N_2 foams are more stable than CO_2 foams due to an increased solubility of CO_2 in water. As a result, CO_2 may easily transit within foam bubbles, thereby increasing gas diffusion and causing bubble disproportionation and foam instability.

In both cases, however, it is evident that the addition of nanoparticles to foam increased cumulative oil production. This can be explained by a couple of factors discussed in our previous work. Particularly in this study, an increase in oil production can be explained by a reduction in interfacial tension. Although, only the mechanism of IFT reduction was documented in this work. However, the effects of nanoparticles are, in fact, not only limited to that. Various articles [62,63] have reported that the addition of nanoparticles can enhance oil recovery by causing wettability alteration, effecting a decrease in capillary forces, creating a wedge film (structural disjoining pressure) as well as maintaining the very high specific surface area. Although, the effect of nanoparticles on wettability has not been studied in this work, it is considered as one of the explanations for increased oil recovery.

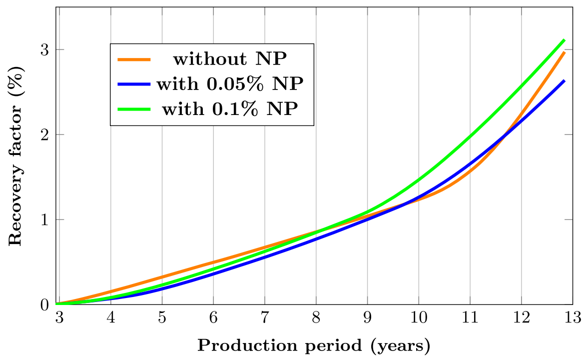
According to Wang et al. (2012) [64], increasing the concentration of nanoparticles up to their optimum value reduces the interfacial tension and zeta potential of oil drops, hence improving dilatational viscoelasticity. Nanoparticles in heavy oil reservoirs,



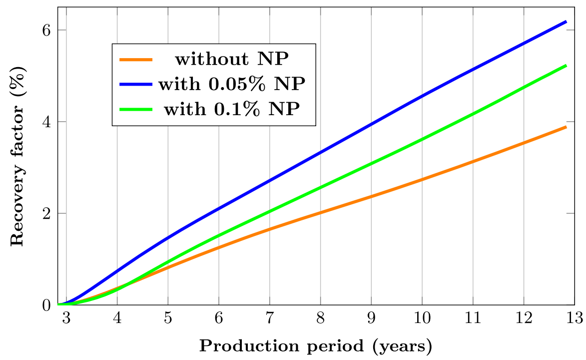
(a) Oil production during N_2 foam flooding



(b) Oil production during CO_2 foam flooding



(c) Gas production during N_2 foam flooding



(d) Gas production during CO_2 foam flooding

Fig. 13. Fluid production during foam injection: (a), (c) N_2 foam flooding; (b), (d) CO_2 foam flooding.

such as the one used in this study, can alter the pH of the reservoir and improve heavy oil recovery. Furthermore, we believe that the higher density and viscosity of the injected foam aided the blockage of gas and liquid phases hence, gas and water breakthroughs were minimized, as shown in Figs. 14a - 14d.

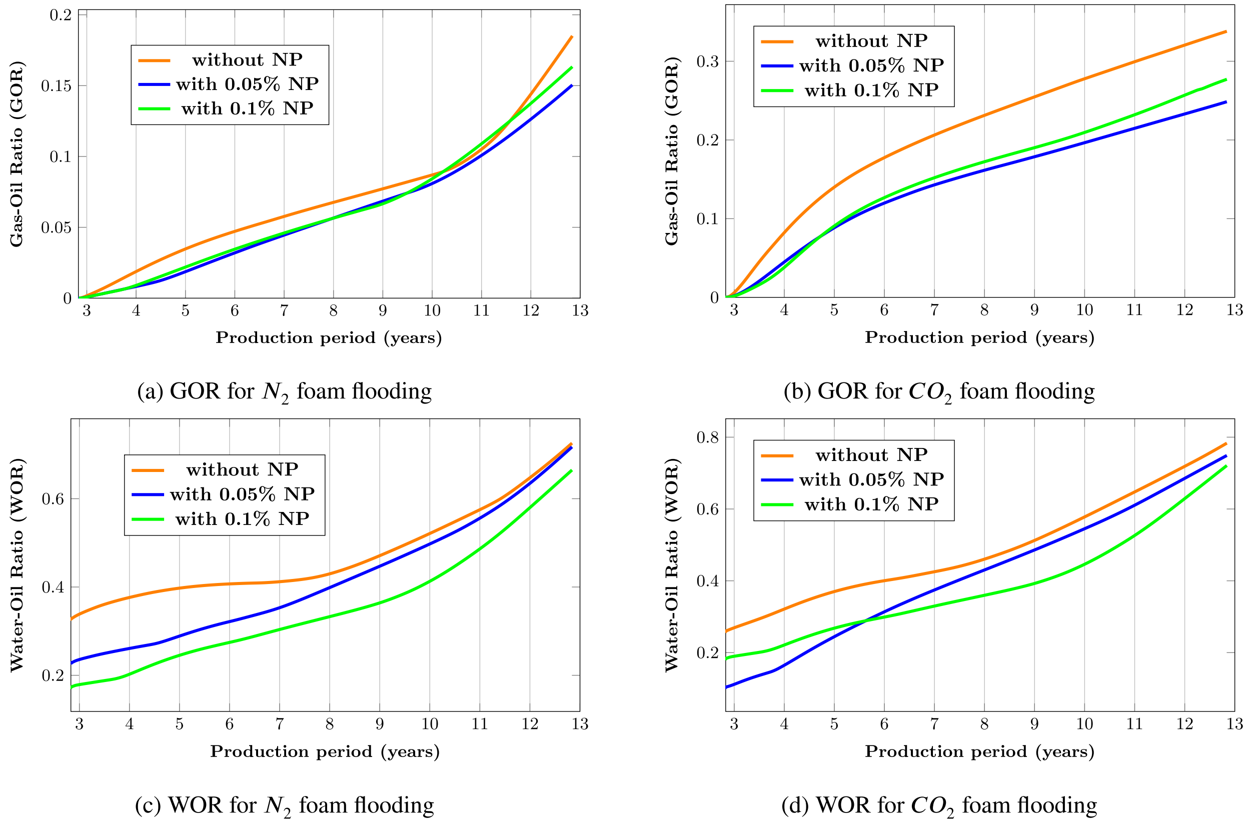
3.3.4. *Strengths of nanofoam over WAG as optimization techniques for gas injection*

The comparisons between the best cases of each optimization technique simulated in this study are shown in this subsection. As a case study, the result of the polymer injection which has already been implemented as a pilot project in this field is also included. The best oil production during the WAG injection process was obtained during the 1-month cycle and the 3-month cycle for N_2 and CO_2, respectively, as shown in previous subsections. Also, during foam injection, foam containing 0.1% nanoparticles performed better.

Figs. 15a and 15b present and compare the overview of these findings. The results indicate the influence of combining gas injection with a liquid phase to stabilize the displacing front by increasing its viscosity. This prevents the liquid and gas phases from breaking through, resulting in increased volumetric sweep efficiency. In this way, oil production is enhanced. Although the viscosity of the injected polymer is similar to that of the nanofoam, a significant difference can be seen in their oil recovery factors. This suggests that beyond viscosity, there are other superior underlying oil recovery mechanisms of nanofoams, which have been discussed in the previous section.

Although polymer flooding was out of the scope of this work. It is important to mention that the type and concentration of the polymer slug used in the flooding process might have contributed to its low recovery compared to foam flooding. Another major challenge with oil recovery during polymer flooding could be attributed to its high adsorption which is a common issue in carbonate rocks [65]. During conventional polymer flooding, high salinity is a big challenge [66]. In fact, Zhang et al. (2007) [67] noted that the recovery efficiency of polymer flooding is usually limited in the field when oil viscosity is more than 100 cp, salinity is more than 100000 ppm and permeability is higher than 20 mD. Also in this field, oil recovery by WAG is expected to be lower than waterflooding. However, it should not be lower than gas flooding. This is because WAG optimizes gas flooding and not waterflooding. These arguments are confirmed by the results obtained and presented in Fig. 15.

Alternating water and gas injections over a period of time by changing intervals is a common technological method aimed for improving volumetric sweep efficiency during gas injection. As a result, the improved microscopic sweep efficiency of gas injection is combined the with efficient macroscopic sweep efficiency of water injection. This is a well-established method of improving oil



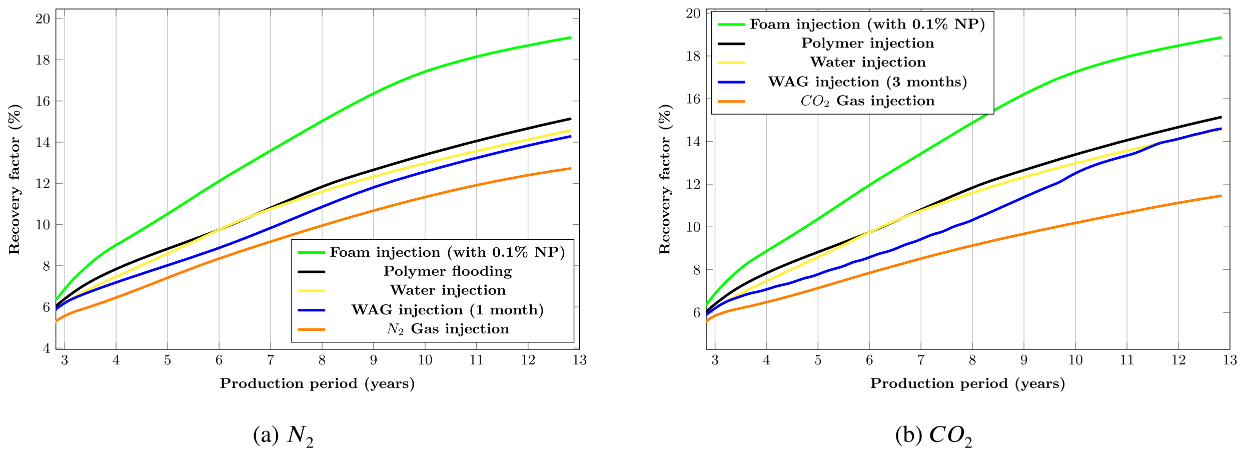
(a) GOR for N_2 foam flooding

(b) GOR for CO_2 foam flooding

(c) WOR for N_2 foam flooding

(d) WOR for CO_2 foam flooding

Fig. 14. Fluid ratios during foam injection: (a), (c) N_2 foam flooding; (b), (d) CO_2 foam flooding.



(a) N_2

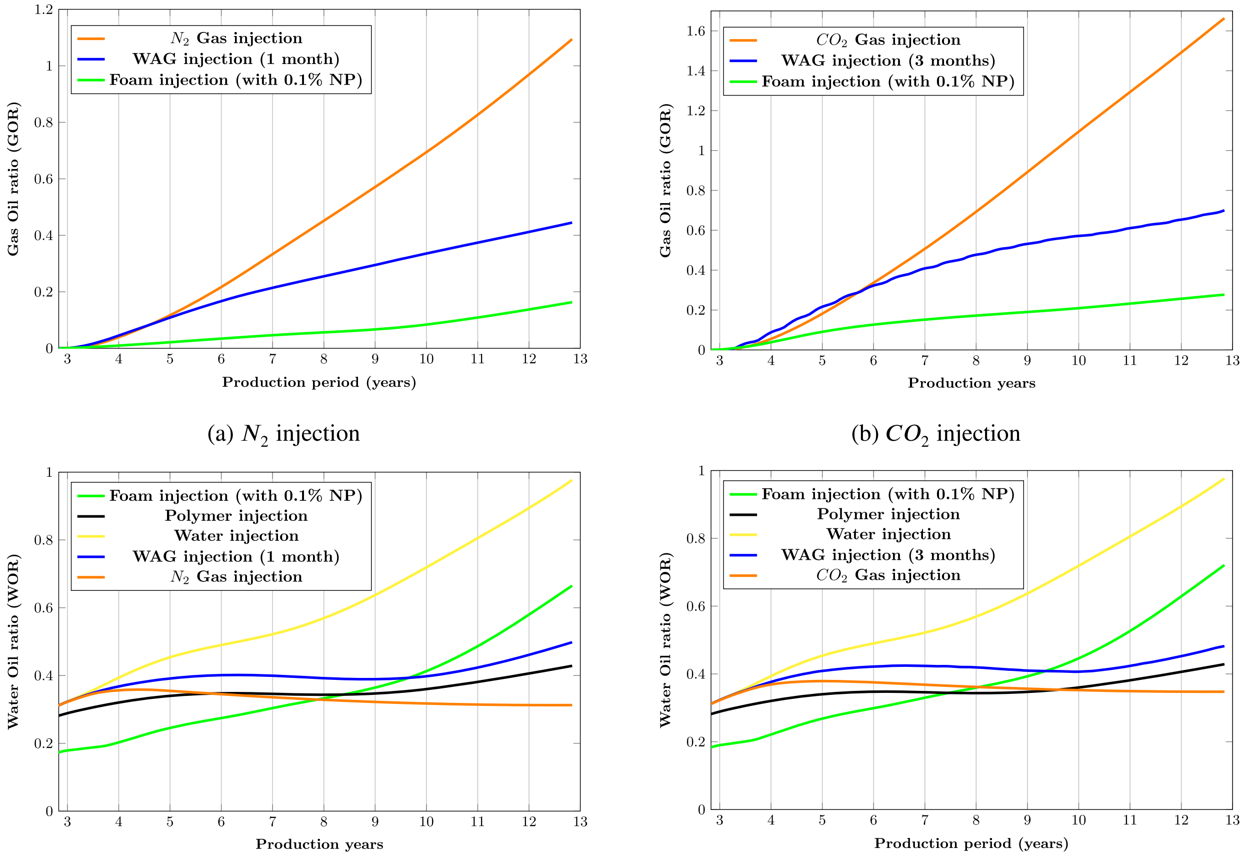
(b) CO_2

Fig. 15. Comparisons of injection processes: (a) N_2, (b) CO_2.

recovery in formations with a lot of heterogeneity or a low dip angle [68]. The mobility of gas is lowered by the presence of the water throughout the WAG injection process, resulting in a lower cumulative mobility ratio when compared to only gas injection.

Although water and gas are injected alternately to overcome fingering by increasing the viscosity and density of the resultant phase, the result is an upward movement of gas and downward movement of water due to their density difference. This results in an override, leaving a substantial volume of oil unswept. As a result, this does not appear to be the best solution because the injected phases move unevenly.

In fact, previous works [5,69–71] reported that similar to gas injection, gas breakthrough is a regular problem during most WAG operations. This occurs when the injectivity of the reservoir is lost or the pressure is not maintained properly. This will lead to a loss of miscibility and, as a result, a reduction in production rate. There have also been reports of pressure profile redistribution when injection is changed from gas to water and vertical permeability is limited. This is due to residual gas saturation following



(a) N_2 injection (b) CO_2 injection

(c) N_2 injection (d) CO_2 injection

Fig. 16. Comparisons of fluid ratios of each injection process: (a), (c) N_2 injection; (b), (d) CO_2 injection.

gas injection. Although, by optimizing the different parameters that come into play, such as WAG ratio, WAG cycle time, and well spacing, this can be optimized [70].

Foaming the injected gas is a better option for optimizing gas injection to overcome the difficulty with gas mobility, as validated by the results in this study with general comparisons presented in Figs. 16a - 16d, because the injected foam is homogeneous and moves uniformly within the reservoir in such a way that it encounters a high flow resistance [72,73]. This resistance is usually higher than the resistance of the individual foam phases. As a result, they are potential displacement fluids that can be used as gas or water blocking agents in production wells. Gases, particularly CO_2, generate unstable foams in typical reservoir conditions, hence they are not generally used in field operations. This is why nanoparticles are considered as additives to foam liquids in order to act as stabilizing agents.

Nanofoam flooding is a chemical upgrade of conventional foam flooding by introducing nanoparticles. Nanoparticles are added to a liquid phase that already contains surfactants. The liquid phase is co-injected with the gas phase into the reservoir to generate foam. As a result, the density and viscosity of the gas increase, thereby decreasing its mobility. Thus, the injected fluid takes advantage of the promising advantages of nanoparticles combined with the benefits of surfactants. The addition of nanoparticles in the foam ensures that enough particles are present at the gas-liquid interface to produce an impervious barrier that inhibits gas diffusion between the foam bubbles. Similarly, interfacial tension reduction is an essential process in this case. Low IFT reduces the amount of external force required to generate bubbles and facilitates the generation of fine foams, which improves mobility control [74].

3.3.5. Optimization of gas injection with nanofoams

Earlier results have shown that gas injection is not suitable in this field for a long period, due to gas breakthrough (Figs. 6 and 7). Hence, in order to optimize gas injection in this oil field, foaming the injected gas is an efficient method for optimization of gas injection in this oilfield

Moreover, it is important to understand the economic limit of each process. In this study, economic limit was determined as the point where the injection of a fluid can no longer recover oil significantly. In technological processes, it is much easier to separate water from oil than gas. Therefore, a high gas-oil ratio is not favorable for oil production. This is better presented in Figs. 9a and 9b, where the point, at which recovery factors meet, signifies the period at when equal volume of gas and oil are produced.

Table 2
Summary of simulation results.

Oil recovery method	Duration	Recovery factor (% of OOIP)
Water injection (HM)	2.83 years	3.62%
Water flooding	10 years	10.95%
N_2 gas flooding	10 years	9.11%
CO_2 gas flooding	10 years	7.84%
N_2 WAG (1 month)	10 years	9.87%
CO_2 WAG (3 months)	10 years	10.98%
N_2 foam flooding	10 years	12.44%
CO_2 foam flooding	10 years	12.02%
N_2 nanofoam flooding	10 years	15.47%
CO_2 nanofoam flooding	10 years	15.25%

Therefore, in order to reduce this to the minimum, that gas injection will not be economically viable in this field for a long period of time. This means that gas breakthrough is expected to set in after about five to six years and further injection of gas might not lead to significant oil production. Although there are still oil reserves in the formation, gas injection could no longer recover oil. As explained in previous sections, this is due to a lack of gas contact and miscibility with the reservoir oil, that result in a poor volumetric sweep efficiency. This can also be attributed to viscous fingering and gravity segregation, owing to low the viscosity of the injected gas compared to that of reservoir oil [10]. Furthermore, the injection fluid was no longer able to maintain the pressure needed to recover oil from the reservoir, and so another enhanced oil recovery technique is needed.

In sections 3.3.2 and 3.3.3, WAG and foam injection strategies were evaluated with the regard of optimizing gas injection to limit gas breakthrough, and foam injection recovered more oil by lowering GOR and WOR. During WAG injection, oil recovery is only maximal during the first WAG cycle. This is one of its limitations, because gas breakthrough is likely to occur in subsequent cycles due to the gas trapping. As a result, foaming the injected gas is a solution to address this issue. By blocking specific zones, the gas mobility factor can be lowered, resulting in a large delay in gas breakthrough.

Table 2 presents the recovery factors of the simulation schemes in this study:

From the table above, the comparison of the oil recovery methods simulated in this subsection can be seen. The results have shown that foam injection is a better enhanced oil recovery method. Higher recovery factor can be seen with foam flooding than in waterflooding and gas flooding. In fact, the recovery factor of nanofoam is almost twice more than that of gas injection for both N_2 and CO_2.

In this study, the aim of nanofoam flooding was achieved as the gas injection profile and sweep efficiency were improved. This brought about an increase in recovery factor. Furthermore, foam fluid contains surfactant and nanoparticles, which can greatly reduce the interfacial tension between oil and water and enhance oil displacement efficiency. Notably that, foam fluid has high viscosity, which can improve mobility ratio.

4. Conclusions

The existing limitations associated with gas injection which include early gas breakthrough, viscous fingering, gravity drainage and gas channeling have prompted the industry to seek the best and efficient methods of optimizing gas injection. This study further builds on the proposition to implement nanoparticles in foam flooding. The simulation of nanofoams was examined in this article as an optimization approach to prevent early breakthrough during gas injection. The following points can be highlighted based on the findings in this work:

- Validation of the model used in this study was accomplished by history matching of production data from an unconsolidated West Siberian oilfield;
- Oil production, gas production, reservoir pressure, and oil saturation were carefully assessed for each scenario based on experimental data using the simulator's foam model parameters, while the methods of grid refinement, upscaling, and optimizing transmissibility, skin factor, and well bottom hole pressure were used to match field production data;
- Foam injection provides important benefits by diverting gas channelling from preferential flow zones, otherwise known as thief zones. As such, it facilitates the access and mobilization of unswept oil towards the producers.
- Due to its advantage of blocking gas and liquid phases, foam can reduce early gas breakthrough thereby increasing cumulative production of oil;
- Through the mechanism of IFT reduction and increase in viscosity, nanoparticles can improve foam stability and hence increase oil productivity;
- The results from this study have demonstrated that nanofoams can potentially increase oil recovery by almost two times when compared to gas injection.

CRediT authorship contribution statement

Ayomikun Bello: Writing – review & editing, Writing – original draft, Visualization, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Desmond Batsa Dorhjie:** Writing – review & editing, Validation, Software, Conceptualization.

Anastasia Ivanova: Writing – review & editing, Supervision, Software, Resources, Project administration, Investigation, Formal analysis, Conceptualization. **Alexander Cheremisin:** Writing – review & editing, Visualization, Validation, Supervision, Resources. **Ilnur Ilyasov:** Writing – review & editing, Validation, Supervision, Software, Resources. **Alexey Cheremisin:** Writing – review & editing, Supervision, Software, Resources, Investigation, Funding acquisition.

Declaration of competing interest

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

Data availability

Data will be made available on request

Acknowledgements

This work was supported by the Ministry of Science and Higher Education of the Russian Federation under agreement No. 075-10-2022-011 within the framework of the development program for a world-class Research Center. The authors are grateful to the Center for Petroleum Science and Engineering at Skolkovo Institute of Science and Technology and JSC «Messoyakhaneftegaz» for providing suitable facilities and materials for this study.

References

[1] Hannah Ritchie, Max Roser, Energy. Our World in Data, https://ourworldindata.org/energy, 2020.
[2] IEA, Net zero by 2050: a roadmap for the global energy sector, IAEA-Tecdoc (2021) 224.
[3] IEA, World Energy Outlook - revised version October 2021, http://www.iea.org/weo, 2021.
[4] A. Bello, A. Ivanova, A. Cheremisin, Application of nanoparticles in foam flooding for enhanced oil recovery and foam stability in carbonate reservoirs, in: 83rd EAGE Annual Conference and Exhibition. European Association of Geoscientists and Engineers, 2022.
[5] Ahmed Farid Ibrahim, Hisham A. Nasr-El-Din, CO2 foam for enhanced oil recovery applications, in: Foams - Emerging Technologies, IntechOpen, September 2020.
[6] Ayomikun Bello, Anastasia Ivanova, Alexey Cheremisin, Foam eor as an optimization technique for gas eor: a comprehensive review of laboratory and field implementations, Energies (ISSN 1996-1073) 16 (2) (January 2023) 972, https://doi.org/10.3390/en16020972.
[7] M.J. Darvishnezhad, B. Moradi, G. Zargar, A. Jannatrostami, G.H. Montazeri, Study of various water alternating gas injection methods in 4- and 5-spot injection patterns in an Iranian fractured reservoir, in: Society of Petroleum Engineers - Trinidad and Tobago Energy Resources Conference 2010, SPE TT 2010, vol. 2, 2010, pp. 588–595.
[8] K. Akbari Aghdam, J.S. Moghaddas, B. Moradi, M. Dabiri, M. Hassanzadeh, Maximizing the oil recovery through miscible water alternating gas (WAG) injection in an Iranian oil reservoir, Pet. Sci. Technol. 31 (22) (2013) 2431–2440, https://doi.org/10.1080/10916466.2011.569822, https://www.tandfonline.com/doi/abs/10.1080/10916466.2011.569822.
[9] P.A. Gauglitz, F. Friedmann, S.I. Kam, W.R. Rossen, Foam generation in homogeneous porous media, Chem. Eng. Sci. 57 (19) (2002) 4037–4052, https://doi.org/10.1016/S0009-2509(02)00340-8, ISSN 00092509.
[10] A. Afsharpoor, G.S. Lee, S.I. Kam, Mechanistic simulation of continuous gas injection period during surfactant-alternating-gas (SAG) processes using foam catastrophe theory, Chem. Eng. Sci. 65 (11) (2010) 3615–3631, https://doi.org/10.1016/j.ces.2010.03.001, ISSN 00092509.
[11] Seung Ihi Kam, Quoc P. Nguyen, Qichong Li, William R. Rossen, Dynamic simulations with an improved model for foam generation, SPE J. 12 (1) (2007) 35–48, https://doi.org/10.2118/90938-PA, ISSN 1086055X.
[12] Ayomikun Bello, Anastasia Ivanova, Alexey Cheremisin, A comprehensive review of the role of co2 foam eor in the reduction of carbon footprint in the petroleum industry, Energies (ISSN 1996-1073) 16 (3) (January 2023) 1167, https://doi.org/10.3390/en16031167.
[13] M.F. El-Amin, Amagad Salama, Shuyu Sun, Numerical and dimensional analysis of nanoparticles transport with two-phase flow in porous media, J. Pet. Sci. Eng. 128 (2015) 53–64, https://doi.org/10.1016/j.petrol.2015.02.025, ISSN 09204105.
[14] Binshan Ju, Tailiang Fan, Experimental study and mathematical model of nanoparticle transport in porous media, Powder Technol. 192 (2) (2009) 195–202, https://doi.org/10.1016/j.powtec.2008.12.017, ISSN 00325910.
[15] Sebastián Llanos, Lady J. Giraldo, Oveimar Santamaria, Camilo A. Franco, Farid B. Cortés, Effect of sodium oleate surfactant concentration grafted onto SiO2 nanoparticles in polymer flooding processes, ACS Omega 3 (12) (2018) 18673–18684, https://doi.org/10.1021/acsomega.8b02944, ISSN 24701343.
[16] Sabber Khandoozi, Peyman Pourafshary, Saule Aidarova, Altynay Sharipova, A comparative analysis of the effect of nanoparticles/surfactant assisted foam injection on the gas mobility control at different heterogeneities, Fuel (ISSN 0016-2361) 350 (October 2023) 128810, https://doi.org/10.1016/j.fuel.2023.128810.
[17] A.A. Ivanova, A.N. Cheremisin, M.Y. Spasennykh, Application of nanoparticles in chemical EOR, in: Proceedings, EAGE Publications BV, April 2017.
[18] Abdelrahman Ibrahim El-Diasty, Ahmed M. Aly, Understanding the mechanism of nanoparticles applications in enhanced oil recovery, in: Society of Petroleum Engineers - SPE North Africa Technical Conference and Exhibition 2015, NATC 2015, vol. 000, 2015, pp. 944–962.
[19] Ayomikun Bello, Joy Ozoani, Adewale Adebayo, Dmitriy Kuriashov, Rheological study of nanoparticle-based cationic surfactant solutions, Petroleum (January 2022), https://doi.org/10.1016/j.petlm.2022.01.003.
[20] B. Moradi, P. Pourafshary, F. Jalali, M. Mohammadi, M.A. Emadi, Experimental study of water-based nanofluid alternating gas injection as a novel enhanced oil-recovery method in oil-wet carbonate reservoirs, J. Nat. Gas Sci. Eng. 27 (2015) 64–73, https://doi.org/10.1016/j.jngse.2015.07.009, ISSN 18755100.
[21] Ali Maghzi, Ali Mohebbi, Riyaz Kharrat, Mohammad Hossein Ghazanfari, Pore-scale monitoring of wettability alteration by silica nanoparticles during polymer flooding to heavy oil in a five-spot glass micromodel, Transp. Porous Media 87 (3) (2011) 653–664, https://doi.org/10.1007/s11242-010-9696-3, ISSN 01693913.
[22] H. Yousefvand, A. Jafari, Enhanced oil recovery using polymer/nanosilica, Proc. Mater. Sci. 11 (2010) (2015) 565–570, https://doi.org/10.1016/j.mspro.2015.11.068, ISSN 22118128.
[23] Ali Goudarzi, Mojdeh Delshad, Kamy Sepehrnoori, A chemical EOR benchmark study of different reservoir simulators, Comput. Geosci. 94 (2016) 96–109, https://doi.org/10.1016/j.cageo.2016.06.013, ISSN 00983004.

[24] Mahdi Kazempour, Vladimir Alvarado, Eduardo J. Manrique, Mehdi Izadi, Impact of alkaline-surfactant-polymer flooding model on upscaled recovery predictions: medium and heavy oils, in: Society of Petroleum Engineers - SPE Heavy and Extra Heavy Oil Conference - Latin America 2014, LAHO 2014, 2014, pp. 417–436.

[25] Amitabh Pandey, M. Suresh Kumar, Dennis Beliveau, Douglas W. Corbishley, Chemical flood simulation of laboratory corefloods for the mangala field: generating parameters for field-scale simulation, in: Proceedings - SPE Symposium on Improved Oil Recovery, vol. 2, 2008, pp. 540–550.

[26] Ahmed Tunnish, Ezeddin Shirif, Amr Henni, History matching of experimental and CMG-STARS results, J. Pet. Explor. Prod. Technol. 9 (1) (2019) 341–351, https://doi.org/10.1007/s13202-018-0455-2, ISSN 21900566.

[27] Cristian S. Loaiza, Juan F. Patiño, Juan M. Mejía, Numerical evaluation of a combined chemical enhanced oil recovery process with polymer and nanoparticles based on experimental observations, J. Pet. Sci. Eng. 191 (March 2020), https://doi.org/10.1016/j.petrol.2020.107166, ISSN 09204105.

[28] Ayomikun Bello, Anastasia Ivanova, Alexey Cheremisin, Enhancing N2 and CO2 foam stability by surfactants and nanoparticles at high temperature and various salinities, J. Pet. Sci. Eng. 215 (110720) (August 2022) 110720.

[29] Ayomikun Bello, Anastasia Ivanova, Alexander Rodionov, Timur Aminev, Alexander Mishin, Denis Bakulin, Pavel Grishin, Pavel Belovus, Artem Penigin, Konstantin Kyzyma, Alexey Cheremisin, An experimental study of high-pressure microscopy and enhanced oil recovery with nanoparticle-stabilised foams in carbonate oil reservoir, Energies (ISSN 1996-1073) 16 (13) (July 2023) 5120, https://doi.org/10.3390/en16135120.

[30] P. Than, L. Preziosi, D.D. Josephl, M. Arney, Measurement of interfacial tension between immiscible liquids with the spinning road tensiometer, J. Colloid Interface Sci. 124 (2) (August 1988) 552–559, https://doi.org/10.1016/0021-9797(88)90191-9.

[31] Ahmad A. Adewunmi, Muhammad Shahzad Kamal, Effect of water/decane ratios and salt on the stability, rheology, and interfacial tension of water/decane emulsions, Energy Fuels 33 (9) (August 2019) 8456–8462, https://doi.org/10.1021/acs.energyfuels.9b02011.

[32] E.A. Hauser, A.S. Michaels, Interfacial tension at elevated pressures and temperatures. i. a. new and improved apparatus for boundary- tension measurements by the pendent drop method, J. Phys. Colloid Chem. 52 (7) (July 1948) 1157–1165, https://doi.org/10.1021/j150463a008.

[33] V. Gholami, S.D. Mohaghegh, Intelligent upscaling of static and dynamic reservoir properties, in: Proceedings - SPE Annual Technical Conference and Exhibition, vol. 4, October 2009, pp. 2238–2252.

[34] Knut-Andreas Lie, An Introduction to Reservoir Simulation Using MATLAB/GNU Octave, Cambridge University Press, 2019.

[35] Wimpy Karnanda, M.S. Benzagouta, Abdulrahman AlQuraishi, M.M. Amro, Effect of temperature, pressure, salinity, and surfactant concentration on IFT for surfactant flooding optimization, Arab. J. Geosci. 6 (9) (2013) 3535–3544, https://doi.org/10.1007/s12517-012-0605-7, ISSN 18667538.

[36] A. Miquilena, V. Coll, A. Borges, J. Melendez, S. Zeppieri, Influence of drop growth rate and size on the interfacial tension of Triton X-100 solutions as a function of pressure and temperature, Int. J. Thermophys. 31 (11–12) (2010) 2416–2424, https://doi.org/10.1007/s10765-010-0825-6, ISSN 0195928X.

[37] Anastasia Ivanova, Denis Orlov, Nikolai Mitiurev, Alexey Cheremisin, Marsel Khayrullin, Alexey Zhirov, Igor Afanasiev, Georgy Sansiev, Microstructural imaging and characterization of organic matter presented in carbonate oil reservoirs, in: Day 4 Thu, June 06, 2019, SPE, June 2019.

[38] Hamid Vatanparast, Farshid Shahabi, Alireza Bahramian, Aliyar Javadi, Reinhard Miller, The role of electrostatic repulsion on increasing surface activity of anionic surfactants in the presence of hydrophilic silica nanoparticles, Sci. Rep. 8 (1) (2018) 1–11, https://doi.org/10.1038/s41598-018-25493-7, ISSN 20452322.

[39] Bao Jia, Jyun-Syung Tsau, Reza Barati, A review of the current progress of CO2 injection EOR and carbon storage in shale oil reservoirs, Fuel 236 (January 2019) 404–427, https://doi.org/10.1016/j.fuel.2018.08.103.

[40] Yongqiang Chen, Ahmad Sari, Quan Xie, Ali Saeedi, Insights into the wettability alteration of CO2-assisted EOR in carbonate reservoirs, J. Mol. Liq. 279 (April 2019) 420–426, https://doi.org/10.1016/j.molliq.2019.01.112.

[41] Huang Feng, Huang Haidong, Wang Yanqing, Ren Jianfeng, Zhang Liang, Ren Bo, Hassan Butt, Ren Shaoran, Chen Guoli, Assessment of miscibility effect for CO 2 flooding EOR in a low permeability reservoir, J. Pet. Sci. Eng. 145 (September 2016) 328–335, https://doi.org/10.1016/j.petrol.2016.05.040.

[42] Cheng Chen, Matthew Balhoff, Kishore K. Mohanty, Effect of reservoir heterogeneity on primary recovery and CO2 huff 'n' puff recovery in shale-oil reservoirs, SPE Reserv. Eval. Eng. 17 (03) (June 2014) 404–413, https://doi.org/10.2118/164553-pa.

[43] J. Shaw, S. Bachu, Screening, evaluation, and ranking of oil reservoirs suitable for CO2-flood EOR and carbon dioxide sequestration, J. Can. Pet. Technol. 41 (09) (September 2002), https://doi.org/10.2118/02-09-05.

[44] Mark H. Holtz, Immiscible water alternating gas (IWAG) EOR: current state of the art, in: SPE - DOE Improved Oil Recovery Symposium Proceedings, 2016-January, 2016.

[45] A.S. Bagci, Immiscible CO2 flooding through horizontal wells, Energy Sources, Part A: Recov. Utiliz. Environ. Effects 29 (1) (January 2007) 85–95, https://doi.org/10.1080/009083190934022.

[46] B. Sinanan, M. Budri, Nitrogen injection application for oil recovery in Trinidad, in: All Days, SPE, June 2012.

[47] T.A. Nguyen, S.M. Farouq Ali, Effect of nitrogen on the solubility and diffusivity of carbon dioxide into oil and oil recovery by the immiscible WAG process, J. Can. Pet. Technol. 37 (02) (February 1998), https://doi.org/10.2118/98-02-02.

[48] Haifeng Jiang, Lily Nuryaningsih, Hertanto Adidharma, The influence of o2 contamination on MMP and core flood performance in miscible and immiscible CO2 WAG, in: All Days, SPE, April 2012.

[49] Lin Yuan, Xiao Li Ping, Xiao Hua Tan, Lie Hui Zhang, Study on skin factor and productivity of horizontal well after acidizing with nonuniform damage, J. Chem. 2015 (2015), https://doi.org/10.1155/2015/706312, ISSN 20909071.

[50] K. Joslin, S.G. Ghedan, A.M. Abraham, V. Pathak, EOR in tight reservoirs, technical and economical feasibility, in: Day 1 Wed, February 15, 2017, SPE, February 2017.

[51] John L. Vogel, Lyman Yarborough, The effect of nitrogen on the phase behavior and physical properties of reservoir fluids, in: All Days, SPE, April 1980.

[52] Li Lei, James J. Sheng, Jinze Xu, Gas selection for huff-n-puff EOR in shale oil reservoirs based upon experimental and numerical study, in: Day 1 Wed, February 15 017, SPE, February 2017.

[53] Tao Wan, Yang Yu, James J. Sheng, Experimental and numerical study of the EOR potential in liquid-rich shales by cyclic gas injection, J. Unconv. Oil Gas Resour. 12 (December 2015) 56–67, https://doi.org/10.1016/j.juogr.2015.08.004.

[54] Yang Yu, Xingbang Meng, James J. Sheng, Experimental and numerical evaluation of the potential of improving oil recovery from shale plugs by nitrogen gas flooding, J. Unconv. Oil Gas Resour. 15 (September 2016) 56–65, https://doi.org/10.1016/j.juogr.2016.05.003.

[55] M. Rezaei, S.R. Shadizadeh, M. Vosoughi, R. Kharrat, An experimental investigation of sequential CO2and n2 gas injection as a new EOR method, Energy Sources, Part A: Recov. Utiliz. Environ. Effects 36 (17) (July 2014) 1938–1948, https://doi.org/10.1080/15567036.2011.557705.

[56] E. Fernández Righi, J. Royo, P. Gentil, R. Castelo, A. Del Monte, S. Bosco, Experimental study of tertiary immiscible WAG injection, in: Proceedings - SPE Symposium on Improved Oil Recovery, 2004-April, 2004.

[57] Ayomikun Bello, Desmond Batsa Dorhjie, Anastasia Ivanova, Alexey Cheremisin, Numerical sensitivity analysis of co2 mineralization trapping mechanisms in a deep saline aquifer, Chem. Eng. Sci. (ISSN 0009-2509) 283 (January 2024) 119335, https://doi.org/10.1016/j.ces.2023.119335.

[58] Chuncheng Li, Yinghui Li, Hui Pu, Molecular simulation study of interfacial tension reduction and oil detachment in nanochannels by surface-modified silica nanoparticles, Fuel 292 (May 2021) 120318, https://doi.org/10.1016/j.fuel.2021.120318.

[59] Xiaofei Sun, Yanyu Zhang, Guangpeng Chen, Zhiyong Gai, Application of nanoparticles in enhanced oil recovery: a critical review of recent progress, Energies 10 (3) (March 2017) 345, https://doi.org/10.3390/en10030345.

[60] Mohammad Zargartalebi, Riyaz Kharrat, Nasim Barati, Enhancement of surfactant flooding performance by the use of silica nanoparticles, Fuel 143 (March 2015) 21–27, https://doi.org/10.1016/j.fuel.2014.11.040.

[61] Abbas Roustaei, Jamshid Moghadasi, Abadan Iran, Hadi Bagherzadeh, Abbas Shahrabadi, An experimental investigation of polysilicon nanoparticles' recovery efficiencies through changes in interfacial tension and wettability alteration, in: All Days, SPE, June 2012.

[62] Jin Zhao, Dongsheng Wen, Pore-scale simulation of wettability and interfacial tension effects on flooding process for enhanced oil recovery, RSC Adv. 7 (66) (2017) 41391–41398, https://doi.org/10.1039/c7ra07325a.

[63] Himanshu Panchal, Hitarth Patel, Jash Patel, Manan Shah, A systematic review on nanotechnology in enhanced oil recovery, Petr. Res. 6 (3) (September 2021) 204–212, https://doi.org/10.1016/j.ptlrs.2021.03.003.

[64] Yan Wang, Fengjuan Lu, Yujiang Li, Tao Wu, Dejun Sun, Guochen Zhang, Xinghai Huang, Guopeng Wang, Effects of Na-montmorillonite particles on the emulsification stability of polymer flooding produced water, Colloids Surf. A, Physicochem. Eng. Asp. 410 (2012) 125–129, https://doi.org/10.1016/j.colsurfa.2012.06.030, ISSN 18734359.

[65] Ming Zhou, Chengwen Wang, Tingting Xing, Sisi Li, Zhe Zhang, Gang Luo, Studies on foam flooding for saline reservoirs after polymer flooding, J. Pet. Sci. Eng. 135 (November 2015) 410–420, https://doi.org/10.1016/j.petrol.2015.09.020.

[66] Wei Zhou, Cuiping Xin, Shengnan Chen, Qun Yu, Kai Wang, Polymer-enhanced foam flooding for improving heavy oil recovery in thin reservoirs, Energy Fuels 34 (4) (March 2020) 4116–4128, https://doi.org/10.1021/acs.energyfuels.9b04298.

[67] Guoyin Zhang, R.S. Seright, Conformance and mobility control: foams vs. polymers, in: All Days, SPE, February 2007.

[68] Mohammad Yunus Khan, Ajay Mandal, The impact of permeability heterogeneity on water-alternating-gas displacement in highly stratified heterogeneous reservoirs, J. Pet. Explor. Prod. Technol. 12 (3) (October 2021) 871–897, https://doi.org/10.1007/s13202-021-01347-3.

[69] O.A. Olabode, O.D. Orodu, S.O. Isehunwa, A. Mamudu, Tosin Rotimi, Effect of foam and WAG (water alternating gas) injection on performance of thin oil rim reservoirs, J. Pet. Sci. Eng. 171 (December 2018) 1443–1454, https://doi.org/10.1016/j.petrol.2018.07.043.

[70] J.R. Christensen, E.H. Stenby, A. Skauge, Review of WAG field experience, SPE Reserv. Eval. Eng. 4 (02) (April 2001) 97–106, https://doi.org/10.2118/71203-pa.

[71] N.C. Chithra Chakra, Deoki N. Saraf, History matching of petroleum reservoirs employing adaptive genetic algorithm, J. Pet. Explor. Prod. Technol. 6 (4) (2016) 653–674, https://doi.org/10.1007/s13202-015-0216-4, ISSN 21900566.

[72] Yan Wang, Xiang'an Yue, Kai Liu, Bo Zhang, Qing Ling, Effect of permeability on foam mobility and flow resistance distribution: an experimental study, Colloids Surf. A, Physicochem. Eng. Asp. 582 (December 2019) 123769, https://doi.org/10.1016/j.colsurfa.2019.123769.

[73] Martijn T.G. Janssen Abdulaziz, S. Mutawa, Rashidah M. Pilus, Pacelli L.J. Zitha, Foam-assisted chemical flooding for enhanced oil recovery: effects of slug salinity and drive foam strength, Energy Fuels 33 (6) (April 2019) 4951–4963, https://doi.org/10.1021/acs.energyfuels.9b00645.

[74] J. Wang, H. Liu, H. Zhang, G. Zhang, P. Liu, K. Sepehrnoori, A novel model of foam flooding considering multi-factors for enhancing oil recovery, Oil Gas Sci. Technol. – Rev. IFP Energies nouvelles 70 (6) (July 2014) 1007–1023, https://doi.org/10.2516/ogst/2014025.