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Displacement of Reservoir Oil by Nanoflooding: Physicochemical Mechanisms

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Abstract

This study explores the physicochemical mechanisms involved in oil displacement by aqueous solutions containing nanoagents. It delves into these critical issues and reveals the primary pathways for innovative solutions. The use of nanoparticles in oil recovery processes can significantly enhance the characteristics of the injected fluid. These enhancements include improvements in viscosity and density and reductions in surface tension. Additionally, nanoparticles can help optimise emulsification, leading to more effective oil recovery overall. During nanoflooding, the properties of the rock matrix change, particularly its wettability and heat transfer coefficient, both of which improve. The physicochemical mechanisms of oil displacement by nanoagents are discussed, along with the influence of the adsorption process on displacement efficiency.

Keywords: Nanoflooding, Nanoagents, Oil Displacement, Physicochemical Mechanisms, Oil Recovery

1. Introduction

A large number of geological processes occur at the nanoscale and microscale levels. In this regard, interest in nanoagents of oil displacement is growing [1-4]. Oil and gas nanotechnologies encompass nanoflooding, the application of nanocoatings, and the creation of functional systems at the atomic and molecular levels. Oil and gas nanotechnology combines elements of geology, porous media mechanics, physics, and chemistry with engineering developments to exploit the unique properties of nanoparticles that manifest themselves at the nanoscale [5-8]. One practical example of nanotechnology is the use of carbon nanotubes to transport nanoagents directly to the displacement front or residual oil deposits in developed fields. Carbon nanotubes have a stable structure and serve as a type of container for transporting nanoagents within the porous space of rocks to a specific location in the reservoir [9-12]. Sensor nanoagents within carbon nanotubes can be utilised both to monitor the position of the displacement front and to enhance the efficiency of oil recovery. Sensor nano-displacement agents can be controlled in the low-frequency range from the surface, in the so-called monitoring and displacement cycle [13-16]. The monitoring and displacement cycle involves controlling the activation of the nanoagent in a specific zone of the reservoir while recording the time of the nanoagent's injection into the reservoir. Physicochemical processes involved in the redistribution of substances within various parts of a heterogeneous reservoir system are referred to as sorption. Sorption (from Latin sorbio — to thicken) is a change, usually an increase in the concentration of a component either at the phase boundary, called adsorption, or in the volume of one of the phases, called absorption [17-20]. The solid body on whose surface adsorption occurs is called an adsorbent, and the adsorbed substance is called an adsorbate. Nanoscale sensors integrated directly into laboratory, underground, or surface oil and gas equipment enable the monitoring of displacement, production, and product preparation processes. Many oil and gas exploration companies, such as Saudi Aramco, use nanoagents to identify interphase contacts, locate displacement fronts, and delineate residual oil zones [21-24].

2. Materials and Methodology

The standard method for studying the efficiency of displacing compositions containing surfactants, polymers, and nanoparticles is the nanocore flood experiment (a laboratory study of oil displacement processes using nanoagents on core samples or artificial porous media). During this experiment, a displacing fluid is injected into a crude oil/rock mixture, and the amount of displaced oil is recorded based on the pressure and temperature of the medium [25-28] (Fig. 1).

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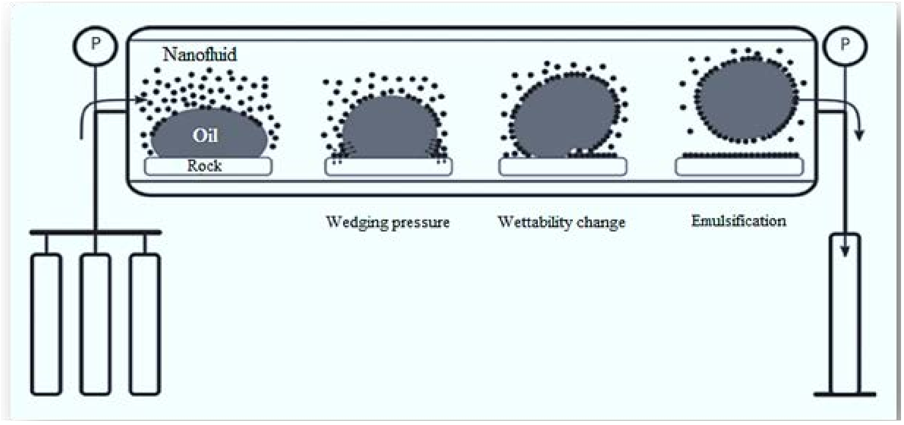

Figure 1: Schematic Diagram Illustrating the Experiment on Oil Displacement by Nanoparticles in Artificial Porous Media, Highlighting Nanocore Flooding and the Primary Mechanisms by Which Nano Agents Influence the Reservoir/Oil System

In the study, micromodels of transparent glass with a porosity of 44% and a permeability of 25 d were used [25]. It has been demonstrated that nanofluids at 0.1 wt. % can reduce residual oil saturation. When a nanofluid flows through a porous medium, certain mechanisms can lead to a decrease in the concentration of dispersed nanoparticles. The primary reason for the retention of nanoparticles in a porous medium is adhesion to the pore walls and clogging of the pore mouths. Clogging of pore channels with nanoagents has a beneficial effect on oil recovery [29-32]. In this study, a series of experiments was conducted to investigate the variations in interfacial tension values between oil and various types of nanofluids, aiming to achieve a significant enhancement in oil recovery.

3. Results and Discussions

A series of experiments have been conducted to study how the interfacial tension values change between oil and various nanofluids. The injection of nanoparticles, in the form of silicon dioxide, significantly affects the interfacial tension at the oil-water interface (Fig. 2A). To investigate the impact of various types of nanoparticles on surface tension, the studies were conducted using silicon oxide and aluminium oxide nanofluids at different temperatures and atmospheric pressure. The results showed that the SiO_2 nanofluid exhibited a lower interfacial tension value compared to the AI_2O_3 nanofluid (see Fig. 2 B).

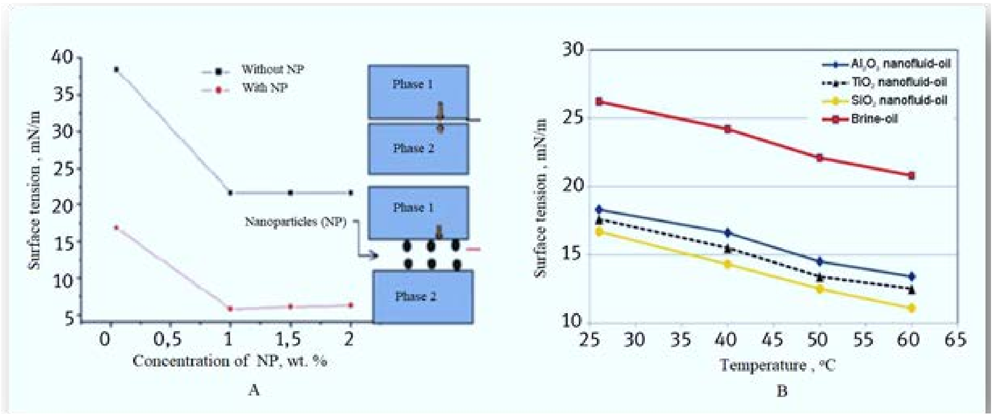

Figure 2: Formation Interfacial Tension. A - Interfacial Tension Between Two Liquid Phases, with and Without the Presence of Nanoparticles. B- At the Oil-Water Interface, Observed at Various Temperatures and at Atmospheric Pressure

Additionally, studies were conducted to examine the wetting characteristics of the rock using different types of nanofluids, as the sandstone rock sample was primarily oil-saturated. Wettability graphs for all samples are shown in Figure 3a.

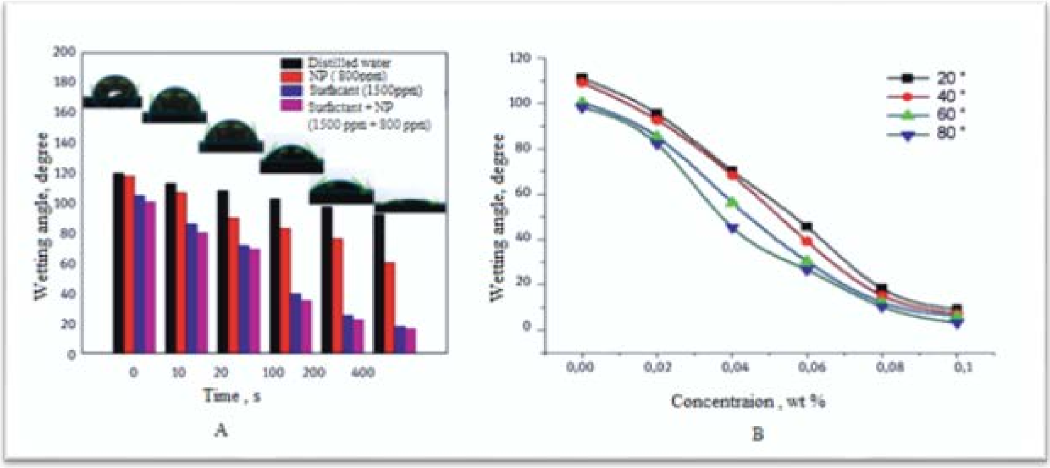

Figure 3: Wettability Graphs: A) Wetting Angles of Various Samples, Including Distilled Water, Nanoparticles (800 ppm), Surfactants (1,500 ppm), and a Combination of Surfactants and Nanoparticles (1,500 ppm + 800 ppm); B) The Influence of Silicon Dioxide Nanoparticle Concentration on the Wetting Angle.

Distilled water reduced the contact angle from 120º to 92°, indicating that the rock surface is moderately wettable. The SiO2 nanofluid reduced the contact angle to 60° from 118°, indicating that the rock surface is preferentially wetted by water. The surfactant solution changed the contact angle from 105 to 17°, indicating that the rock surface is predominantly water-wet. The contact angle value decreased from 100.2 to 16.2° for the surfactant-SiO_2 nanofluid (1,500 ppm + 800 ppm) suspension. The results indicate that the presence of SiO_2 nanoparticles in the surfactant solution provides better overall wettability properties. The presence of SiO_2 nanoparticles can influence the strong physicochemical interactions that occur at the liquid-solid interfaces, resulting in a favourable change in wettability for oil recovery. Many studies have focused on identifying the concentration ranges of nanoparticles and their effects on wettability modification [33-36]. Most studies have shown that with increasing nanoparticle concentration, rock wettability improves due to repulsive forces. Other studies, on the contrary, indicate that excessive concentrations can lead to pore blockage and increased operating costs [37-40]. Therefore, an ideal concentration is preferable to control wettability. The results indicate that increasing the concentration of nanoparticles results in a consistent decrease in the contact angle at all temperatures. The ideal concentration is 0.1 wt%, as shown in Figure 3b. Most of the measured contact angle values fall below 70°, which provides strong evidence that nanoparticles can effectively alter the wettability from hydrophobic to hydrophilic [41-44]. Polymers have been successfully used as viscosity-controlling agents to improve recovery efficiency [45-48]. In formations with high temperatures, pressures, and salinity, polymer fluids can decompose, which reduces their viscosity and displacement efficiency. The use of nanoparticles can increase the viscosity of the displacing fluid without reducing stability. The effect of silica nanoparticle dispersions on oil displacement by polymers with different fluid mineralisation is studied. Adding silica nanoparticles to the solution increased stability and showed greater efficiency compared to water and polymer (without nanoparticles) displacement. The study was conducted to investigate the dependence of the viscosity of the injected solutions on the concentration of nanoparticles (Fig. 4A).

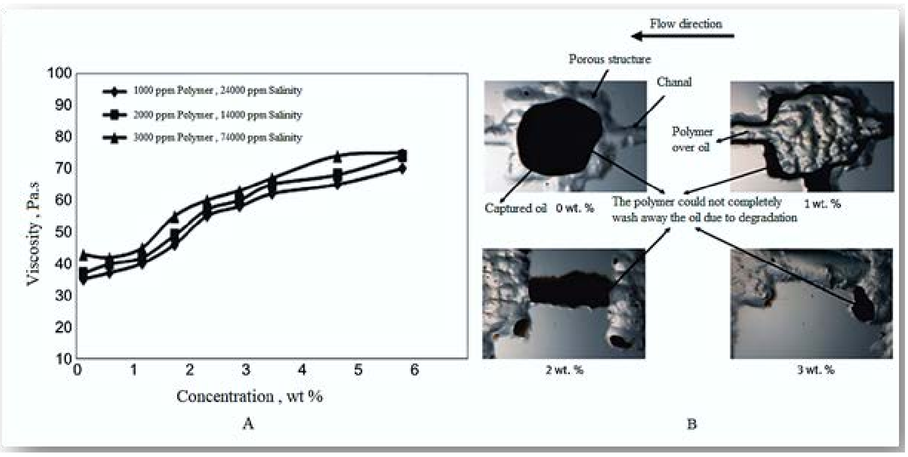

Figure 4: An Analysis of the Impact of Nanoparticles on Polymer Flooding: A — Silica Nanoparticle Concentration Influences the Viscosity of Polymer Solutions at Different Salinities and Polymer Concentrations, B — Residual Oil and Polymer Solution Distribution at the Pore Scale During Polymer Flooding with a 1,000ppm Polymer Solution (24,000 ppm Salinity) and Varying Silica Nanoparticle Concentrations

As shown in this figure, the results of viscosity measurements indicate that increasing the concentration of nanoparticles increases the viscosity of the polyacrylamide solution at all salinities and polymer concentrations. During each nanoflooding test, high-resolution micrographs were taken to visualise the distribution of fluid in the pores and channels. All of these micrographs demonstrate an increase in the efficiency of inter-porous transport resulting from the increase in nanoparticle concentration. Figure 4B shows that the entrapped oil is at its maximum by volume. The primary factors influencing the mechanism of oil recovery during nanoflooding are changes in the wettability of reservoir rocks, reduction of interfacial tension, and plugging of pore channels. Wettability is characterised by the wetting angle, which can change more than 2 times under the influence of nanodispersion. In this case, the main reason for the change in the wetting angle is the wedging pressure, which begins to increase when nanoparticles are introduced between the rock surface and the oil phase.

A decrease in surface tension reduces capillary pressure in pores. This mechanism, resulting from a significant change in the wetting angle, can be considered one of the primary parameters influencing the increase in oil recovery. A decrease in interfacial tension occurs due to a reduction in free surface energy, which depends on the integration area. This is accompanied by the division of large droplets into smaller ones, facilitating their migration through the porous medium. It should be noted that the decrease in interfacial tension compared to the surfactant is insignificant and does not have a major effect. The main mechanism is the clogging of pore channels. This process begins with the formation of nanoparticle conglomerates, which eventually form a "plug" that clogs the mouth of the pore channel. In this case, the fluid flow is redirected, thereby displacing oil from previously unaffected parts of the channels. The use of nanoparticles helps increase capillary pressure values and oil recovery by enhancing wettability in carbonate reservoirs. All the mechanisms described contribute to enhanced oil recovery. Consequently, altering the wettability of rocks, minimising the interfacial tension at the oil-water boundary, managing the mobility coefficient, and temporarily obstructing pore channels are the primary factors that enhance oil recovery when employing the combined polymer flooding method.

4. Conclusions

The use of nanoparticles can enhance capillary pressure and improve oil recovery in carbonate reservoirs by increasing wettability. It was confirmed that the use of these nanoparticles reduces surface tension, leading to a decrease in capillary pressure within the pores. This mechanism, caused by a significant change in the wetting angle, can be considered one of the main factors influencing increased oil recovery. Utilising nanoparticles provides a significant advantage by effectively blocking pore channels through the formation of nanoparticle conglomerates. This crucial process redirects fluid flow, ensuring that oil is displaced from areas of the channels that previously remained unaffected.

Generally, nanotechnology offers promising solutions for enhancing oil recovery. Although the complete impact of nanotechnology on the future of the oil industry is still being investigated, it has the potential to revolutionize the field.

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