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Nano-Emulsion for Control of Formation Damage During Drill-in and Completion Operations

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Abstract

Intensity of the hydrocarbons inflow into production well strongly depends on the three major formation characteristics: geology characteristics; fluids properties; and phase or effective permeability of rock for hydrocarbons or water. First two are bearing material impact on productivity of the formation and inflow intensity, then the third one is a key parameter for the inflow of hydrocarbons and duration of water-free production period. Hence, it is crucial for the subsurface engineers to keep the rock's phase permeability at the wetting state preferable for the flow of hydrocarbons from the moment of drilling into the productive formation. A nano-emulsion technology presented in this paper is an environmental chemical fluid that can be efficiently deployed for the formation damage control. Research results presented in this paper include core floods and wettability measurements on the low permeability carbonate rock cores. The nano-emulsion is an inverse emulsion with extremely low concentration of hydrocarbons augmented by surfactants with ultra-charged silicon dioxide nanoparticles. Unique physico-chemical properties of the nano-emulsion provide leverage to simultaneously prevent: (1) the flow of drilling or completion fluids into formation; and (2) alter the wettability of flow channels, allowing to functionally program subsurface formation.

Introduction

A goal for drilling an oil or gas well is to produce maximum volume of hydrocarbons. This means that any activities impacting the hydrocarbons flow quality are of highest importance. However, there are always trade-offs taking place at the drilling-in and completion operations because each square foot of the subsurface environment has its unique characteristics; hence, there are no similar wells. Drilling and completion engineers with the task to lower the risk of losing well control or to simply conduct essential operations must overbalance the formation pressure, inevitably inducing permeability impairment to the productive formation. Thus, drilling mud or completion fluids unavoidably flow into formation, materially lowering the rock's effective permeability for hydrocarbons and clogging rock matrix and fractures in the near-wellbore area. Induced formation damage during the drill-in and the completion operations may be caused by some or by all the following: mechanical particles in drilling and completion fluids; formation's loose fines moved by the fluids flow; swelling fines of minerals; and consequently, formed in-situ precipitates and other derivatives such as "gummy bears" of the polymer solutions (Rassenfoss 2020). Subsequently, these processes negatively affect the hydrocarbons production and accelerate water encroachment, deteriorating economics of the field development.

A nano-emulsion technology developed by the interdisciplinary team of petroleum engineers and researchers, who are striving to drive sustainable development of the global industry through nanotechnology integration. The technology background can be found in this work (Sergeev 2024). The nano-emulsion is an efficient, versatile and environmental tool to control formation damage. Its versatility and ease of customization bring a great potential for applications throughout the whole chain of subsurface fluids flow control tasks. Some grades of the nano-emulsion from light (1.0 g/cc) to heavy (2.0 g/cc) weights are presented in Fig. 1. Gained research results in applied nanotechnology for petroleum & geosystems engineering allowed to extend barriers of subsurface fluids flow control methods. In the papers (Zeigman et al. 2017a, 2017b; Sergeev et al. 2017) the authors discuss laboratory research results on basic physical properties of the nano-emulsions such as rheology and thermal stability. In the papers (Sergeev et al. 2018a, 2018b, 2019, 2020a, 2020b) the authors discuss technological properties of the nano-emulsions for improved oil recovery (IOR) applications in low pressure, low temperature (LPLT) carbonate oil formations and high temperature, high pressure (HTHP) sandstone oil formations. In the papers (Sergeev et al. 2020c, 2020 d, 2020e) the authors review the industrial deployments for IOR and wells workover in the said geo-physical conditions. In the papers (Abe et al. 2022; Yonebayashi et al. 2023; Carpenter 2023; Yamada et al. 2024; Sergeev and Abe 2024) the authors review the laboratory research results and the mathematical simulations for the commingled carbonate and sandstone oil formations at high temperatures. The applied research for the nano-emulsion application for enhanced gas recovery in HPHT gas-condensate sandstone formation is discussed in the paper (Sergeev and Abe 2023). Research results presented in this paper reveals a great potential for efficient deployment of the nano-emulsion in various operations within the upstream oil and gas with focus to improved formation damage control methods. Unique physico-chemical properties of the nano-emulsion provide leverage to simultaneously: 1- prevent flow of drilling and completion fluids into formation; 2 - alter wettability of the flow channels to the hydrophilic or hydrophobic or neutral wetting state, allowing a functional programming of the formation.

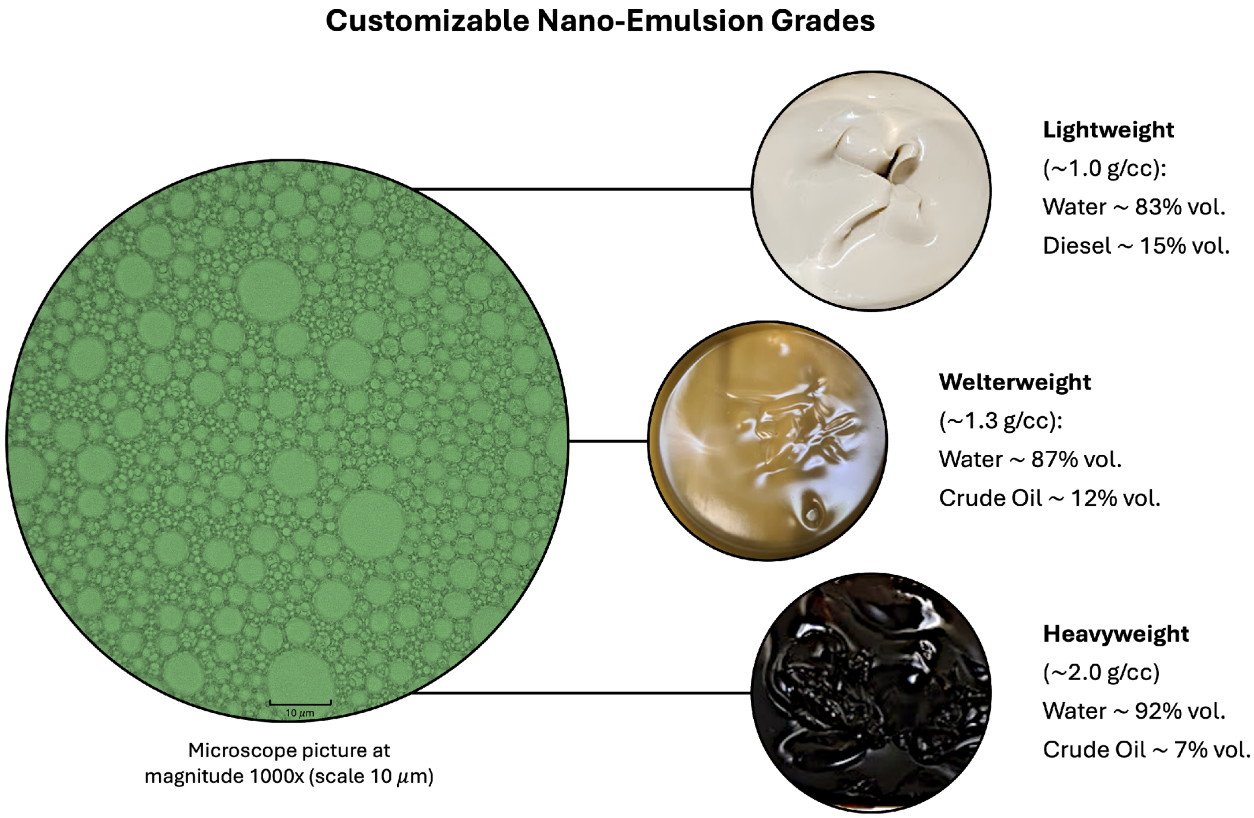

Figure 1 – Microscope picture of the nano-emulsion and the photographs of grades mixed at the well site (adjusted from Sergeev et al. 2024)

Formation Damage Control – A Century-Long Research

Formation damage control research origin derives from the studies dated by 1910s when Green and Ampt have documented the swelling properties of certain types of clays in water and offered a mathematical model for the forecasting of water infiltration in homogeneous soil using Darcy's law (Green, 1911). A few decades later, petroleum & subsurface engineers applied the concept to oil wells drilling, conducting research on a variety of clay minerals swelling properties in contact with various water solutions. For example, it was confirmed that the drilling mud composition drastically impacts the productivity of hydrocarbon formation. Incompatibility or prompt clays swelling drilling mud use resulted in lower oil rates of new wells (Wade, 1947). This concept application to petroleum engineering led to longer-than-century research on clays' ability to clog the pore channels of subsurface rock, resulting in impairment of fluid flow. This research topic is relevant even at present time (Hannun, 2022; Singh, 2023). This tells about a massive number of relevant areas for future research in petroleum & geosystems engineering even within just one topic of mineralogy – clays physical properties and impact on fluid flow in the porous medium of the subsurface formation. The subsurface environment is largely unknown and mysterious even for geologists and subsurface engineers. There are many reasons for it. One of the reasons is that, for example, in contrast to the cosmos scientists, the subsurface scientists cannot observe its research subject at scale in its original state.

Research in 1940s and 1950s

To fight the problem of formation damage with swelling clays, oil-based and inverse emulsion-based drilling muds were deployed in about 1940ss (Wade, 1947). These types of muds were more expensive than water-based mud, but the absence of some operational complications and higher oil rate of a well drilled on these muds resulted in much greater return on investment. In 1955, in the work "The Effect of Various Mud Filtrates on the Permeability of Sandstone Cores" by Kennedy it was reported that oil- and emulsion-based muds became common for use in drilling and had definite advantages over the water-based muds. This was supported by a conclusion, which was made in result of the core flooding research with four water-based mud filtrates on the natural cores from wells in Mississippi, Louisiana and Texas. Also, authors mentioned in conclusion that in all tested formations increase in water permeability led to decrease in air permeability (Kennedy, 1955), which confirms direct *interrelation between the saturation of rock with water and it's phase permeability*. Similar conclusions can be found in the results of studies published later in 1960s and 1970s when the topic of formation damage control during drilling-in and completions became a mainstream for drilling and completions engineers.

Research in 1960s

In the 1960s, a major number of studies were focused on elaboration towards the clays swelling effects and the water's compositional structures effects on the rock permeability. For example, in the work (Jones, 1960), the term "skin effect" appears, which the authors interpreted as a zone of reduced permeability around oil wells. In the same work the correlation between the length of formation exposure to drilling mud and the damage degree was studied. In the work (White, 1960), a susceptibility of the Powder River Basin (Wyoming) sandstones to water damage was studied. The authors listed several factors that could be responsible for water damage, such as swelling clays, particle transportation, low-permeability water block and water block in oil-wet sands. This study gets closer to the interfacial phenomena research and put a light on the significance of capillary effects in low permeability sandstones. In the work (Jones, 1964), the author studied the effect of water composition and salinity on the clay swelling and its impact on the rock permeability. The author highlighted the long-lasting negative effect of the permeability impairment caused by swelling clays filtered in the near-wellbore area during drill-in and completion operations to the wider field development processes such as production and water flooding. This research showed that rapid water salinity drop from high to fresh water can cause permeability impairment by clays which would not happen if salinity of water being introduced into sensitive formations is lowered gradually. Similarly to that, (Mungan, 1965) elaborated on formation permeability reduction through changes in pH and salinity. The author interpreted the term formation damage as a reduction in permeability, resulting from exposure of oil-producing formations to water substantially less saline than the connate water. This hints that the author directly related the formation damage to salinity inequalities between the artificially introduced water and the naturally occurring connate (formation) water.

Research in 1970s

In the 1970s, technological progress led to new research techniques, which helped to learn more about interfacial phenomena and micro-geology of subsurface formation. For instance, in 1971, Owens in the work "The Effect of Rock Wettability on Oil-Water Relative Permeability Relationships" reported that the degree to which the porous medium is wetted preferentially by oil or water significantly affects the measurement of flow properties. The author highlighted the importance of the wetting conditions of the rock for studies on cores. In the work (Abrams, 1977), the depth of mud invasion and related level of permeability impairment were studied on linear consolidated sand cores. It was concluded that these phenomena can be controlled, to some degree, through designing the mud to include bridging material. The effectiveness of the bridging material in reducing invasion is a function of the concentration and particle size of the material and of the pore sizes of the formation rock. In 1979, fundamental research on fines movement in porous media was reported by Muecke in the work "Formation Fines and Factors Controlling Their Movement in Porous Media". The author analyzed microscopic observations of fine-particle movement in micromodels of porous media with use of scanning electron microscope and X-Ray techniques. The results showed that transport of fines by fluids moving through pores is controlled by several factors. Besides mechanical bridging at pore restrictions, fines movement also is *influenced strongly by particle wettability* and the relative amounts of fluids flowing through the pores when two or more immiscible fluids are present. Particle *wettability and surface or interfacial forces* strongly influence particle mobility when multifluid phases are present. Particles will move only if the phase that wets them is moving (Muecke, 1979).

Research in 1980s

In the 1980s, further improvements in research techniques allowed better understanding of the rock wettability characteristics and the wettability impact on multiphase fluids flow in subsurface environments. In work (Sharma, 1985), the author evaluated an impact of water-based drilling fluid components on wettability and permeability of rock. In conclusion, the author highlighted a significant observation, the alteration of rock properties during drilling bears serious implications for both core analysis and formation damage. If core properties are altered relative to the reservoir, then predictions based on core analysis are of little value. This makes a lot of sense, especially nowadays, when all field development decisions are based on the mathematical model. Also, the author noted, if wettability is changed or permeability reduced in the near-wellbore area, then oil production may be restricted. *Wettability has a major impact on multi-phase flow in porous media. Wettability is also very sensitive to alteration.* Another fundamental study was conducted by Krueger in the work "An Overview of Formation Damage and Well Productivity in Oilfield Operations" in 1986. The author conducted a comprehensive analysis of the nature of formation damage problems, how they occur during various oilfield operations, and their effects on well productivity. The list of possible reasons for formation damage included 20 processes and associated phenomena. The analysis results led to the conclusion that formation damage is usually associated with either the movement and bridging of fine solids or chemical reactions and thermodynamic considerations. The fine solids may be introduced from wellbore fluids or generated in situ by the interaction of invading fluids with rock minerals or formation fluids. The author made an important note that *repair of formation damage is usually difficult and costly, the basic approach should be to prevent damage.* To achieve this goal, the entire process of drilling, completion, and production needs to be viewed as a whole, including extensive preplanning, execution, and follow-up. Failure to control treatment or operating procedures and chemicals properly at any stage may negate the effectiveness of all other well-designed and executed operations. Another point for subsurface engineers to keep in mind is the relative importance of the formation condition in the near-wellbore area for production rate and wider field development operations. Although the drainage radius may be several hundreds of feet, the effective permeability close to the wellbore has a disproportionate effect on well productivity. In the same year, another fundamental work was published (Morrow, 1986). The authors conducted research on the effect of crude-oil-induced wettability changes on oil flow intensity and recovery factor. In this paper, the authors reflected that there is no unity on the topic in the professional community, which is interesting because 40 years later the situation is the same. The authors concluded that the wettability alteration by crude oil occurs by forming of a film, probably a monolayer of asphaltenes. Adhesion of crude oil is a key feature of wettability alteration and film deposition at high-energy surfaces depending on the condition of the surface. In short, the authors concluded that for the conditions of the studies, oil-wet surface is preferable for the oil flow at predominantly oil-saturated core and the other way around water-wet surface is preferable for the oil flow at predominantly water-saturated core. In 1988, Krueger published an update to his earlier work (Krueger, 1988) where he listed the following possible mechanism of the formation damage:

- Physical nature of the path (pore conditions).
- Mineralogical composition permeability damage from freshwater invasion.
- Migration of water-wet fines.
- "Salinity shock" is a source of fine release in water-sensitive formations when there is a large difference in salinity between the invading and the formation water.
- Wellbore plugging from fine solids carried by wellbore fluids.

The author noted that mineralogical composition permeability damage from freshwater invasion was long assumed by specialists to be associated with swelling of montmorillonite. Now, it is well established that low- or non-swelling minerals can also cause formation damage, and freshwater contact is not a necessary condition. In 1988, the work (McKinney, 1988) was conducted to determine the extent of formation damage which may be caused by the synthetic oil-based or the mineral oil-based drilling fluids on Berea sandstone cores at elevated temperatures and pressures. The oil-based muds highlighted properties were low coefficient of friction, prevention of clays swelling since oil is the continuous phase of these muds, forming thin impermeable filter cake which allow minimal static fluid loss. The following interpretation of the wettability phenomenon was given by the authors: wettability refers to the tendency of a fluid to wet or spread over a rock in the presence of another fluid and is controlled by the compound absorbed on the rock surface. A change in the wettability of the reservoir rock causes a change in the relative permeability of the rock. The authors analysis results showed that wettability change is one of the most important parameters impacting the fluids flow subsurface. The synthetic oil-based drilling fluid showed higher permeability impairment than the mineral oil-based one because of differences in surfactant types and concentrations, which tells that surfactants play a crucial role in the wettability alteration mechanism. The next year, other work was published highlighting the similar topic (Menezes, 1989), where the authors investigated mechanism for the alteration of sandstone wettability due to interaction with oil-based mud components such as cationic and anionic surfactants. The authors highlighted that the wettability is a major factor in controlling the location, flow, and distribution of fluids in a reservoir. It was also noted that even "bland mud", which is supposed to be neutral (non-altering wettability), causes alteration of wettability. The disjoining pressure concept was used by the authors to describe the changes in the measured contact angles. The following three phenomena were highlighted as components of the disjoining pressure: molecular component, electrostatic component and structural component. Any attempt at predicting changes in wettability due to surfactants must account for structural forces. Neglecting these forces will result in theoretical estimations that may be both qualitatively and quantitatively incorrect. The results of the contact angle and capillary pressure measurements showed that oil-based mud components can in some cases drastically alter the original wettability conditions of both sandstone and carbonate rocks. The wettability alterations are caused mainly by surfactants in the drilling fluids, which aligns with conclusions made in the work by McKinney a year earlier.

Research in 1990s

In the 1990s the focus was on determining geo-physical conditions in which the water- or oil-based muds would perform best; and the other focus area was the investigation of the permeability reduction caused by the phase trapping phenomenon. In the (Yan, 1993), studied the wettability alteration caused by the multi-components oil-based mud (18 components) on Berea sandstone cores. It was learned that most of the oil-based mud components, especially surfactants, change the wettability of Berea sandstone samples greatly from a strong water-wet condition to various degrees of oil wetness. The combined Amott and USBM method was considered as an effective method to evaluate wettability alteration caused by oil-based mud components. The authors emphasised that the whole oil-based muds affect wettability less than do some of the strongly oil-wetting components. In the same year, the work (Jiao, 1993) investigated the dynamic filtration of invert-emulsion muds. The results showed that the *damage caused by oil-based muds is significantly less than that caused by water-based muds*, although mud-filtrate loss rates are comparable. This occurs because of the *effectiveness of the water droplets in bridging pore throats and forming an external filter cake that is removed easily* when the flow direction is reversed. In the fundamental work (Bennion, 1994), the permeability reduction due to aqueous phase trapping phenomenon in the low permeability gas sandstones was investigated. The authors emphasised the importance of understanding the concept of aqueous phase trapping. It is essential to differentiate between the concept of initial (connate) aqueous phase saturation and irreducible aqueous phase saturation:

- Initial aqueous phase saturation is the initial average fractional portion of the pore space which is occupied by water. The key point to differentiate in this area is that the initial aqueous phase saturation is not necessarily equal to the irreducible aqueous phase saturation and can be either higher or lower.
- Irreducible aqueous saturation represents that saturation which is forced to exist in the reservoir by capillary mechanics. We often obtain estimates of the irreducible aqueous saturation using air-brine or air-mercury capillary pressure tests.

The authors underlined that many hydrocarbon bearing reservoirs exhibit the potential for significant productivity reductions due to adverse relative permeability effects associated with the retention of invaded aqueous fluids. These fluids could include-water-based drilling mud filtrates, completion fluids, fracture fluids, workover fluids, kill fluids or stimulation fluids (including-spent acid). Conducted laboratory research confirmed the phenomenon of aqueous phase trapping in strongly oil-wet porous media. This theme was elaborated further in the work (Bennion, 1996), where the phenomena of water and hydrocarbon phase trapping in porous media during drilling, completion, workover and production operations were discussed. The introduction of an additional immiscible phase, or an increment in existing phase saturation within porous media can cause damaging relative permeability effects which can substantially impact the permeability of rock. The following four parameters were listed as the parameters affecting the severity of aqueous phase trapping:

- Difference between the initial water saturation and the irreducible water saturation – the larger the difference between the initial water saturation and the irreducible water saturation, the greater the potential damage associated with a potential aqueous phase trap.
- The configuration of the oil or gas phase relative permeability curves – strongly controls the apparent severity of damage associated with aqueous phase trapping.
- The physical depth of invasion – strongly controls the ability of the available reservoir pressure to mobilize and remove the entrained aqueous phase trap.
- Available reservoir pressure to mobilize the entrapped reservoir fluids – generally, the higher the available reservoir pressure, the higher the capillary gradient which can be applied and the lower the resulting irreducible liquid saturation which can ultimately be obtained.
- Wettability – low initial water saturations in water-wet formations (which most commonly exist in desiccated gas reservoir applications) exhibit significant problems with both spontaneous imbibition and phase trapping.

Overall, most water-wet formations in oil reservoir applications tend to exhibit in-situ initial water saturations with values close to the irreducible value (or exceeding the irreducible value if the formation produces free water). This means that these types of formations are not normally susceptible to severe, permanent aqueous phase trapping phenomena. Strongly oil-wet porous media often exhibit extremely low initial water saturations and can exhibit significant sensitivity to aqueous phase trapping. Typically, aqueous phase trapping tends to be more problematic in lower permeability formations (Bennion, 1996). On the contrary to this, an author of the work (Gruber, 1999) argued that the effects of fluid invasion on formation permeability in reservoirs with ultra-low water saturations has been over-dramatized, perhaps because the mechanisms of permeability reduction because of fluid invasion are not well understood. And, elaborating on it, the author reported that several permeability measurements performed on clastic, limestone and dolomite core samples with and without connate water saturation demonstrated negligible permeability reduction due to the presence of an irreducible water saturation. Even in low permeability cores (less than 0.5 mD), the effect of irreducible water saturation on gas permeability was only a 20% reduction. These results suggest that permeability damage is only slightly worse in desiccated gas reservoirs than in conventional gas reservoirs. Furthermore, the author concluded that permeability impairment because of fluid invasion is more a function of effects on macroporosity than microporosity (Gruber, 1999). In 1998, the work (Saponja 1998) described challenges associated with a relatively new technique called underbalanced drilling, which is less damaging to formation if executed properly. The author considered the formation damage theme is of particular concern with high-angle and horizontal wells because formations are exposed to an overbalance of drilling fluids and solids for a considerable period. It was reported that the underbalanced drilling increased operating costs twofold the conventional but is countered by the value of reduced formation damage, increased rate of penetration or avoidance of problems. It was highlighted that the underbalanced drilling technique was unsuccessful in some reservoirs because wells believed to be drilled underbalanced were found to have formation damage or positive skin. A review of operating procedures and circulating systems revealed that overbalance pressures occurred during drill string connections, and incompatible drilling fluids were used. Though underbalanced, wells were completely overbalanced, which caused formation damage. This brings to our attention the importance of the drill-in fluids even in an underbalanced drilling. In the same year this topic was elaborated in other work by Bennion in 1998. is not a solution for all formation damage problems. The author argued, the formation damage caused by poorly designed and/or executed underbalanced drilling programs can rival or even greatly exceed that which may occur with a well-designed conventional overbalanced drilling program (Bennion, 1998). In the same year, comprehensive laboratory work was reported (Longeron, 1998). The paper described results of a three-year program aiming at evaluating formation damage arising from overbalanced drilling and completion operations. Eight drilling fluid formulations, including water-based and inverted synthetic oil-based muds have been used in the static and dynamic filtration tests on outcrop sandstone core samples. The laboratory program included eight mud formulations (five water-based muds, one oil-based mud, and two pseudo-oil-based muds). The following results were reported:

- Fluid losses and permeability impairments obtained with water-based muds are significantly greater than those observed with invert oil-based muds. Dramatic near-wellbore permeability reduction due to the invasion of filtrate generated from water-based muds.
- Stimulating effect, i.e. oil return permeability greater than initial oil permeability, was observed after invasion of filtrate from inverted synthetic oil-based muds.
- The use of heavy brine as completion fluid may induce severe additional permeability impairment. The damaging effect was particularly important in cores either saturated with oil or gas in which the initial damage due to the mud was low.

The author highlighted that one of the reasons for this study was necessitated by the productivity losses due to formation damage, which are especially critical for horizontal wells which are often completed with open hole or slotted liner completions. The economic impact of poor productivity of open hole wells has pushed toward significant efforts to alleviate completion-induced formation damage issues. In the work (Bennion, 1999), the author considered the following four primary formation damage mechanisms:

- Mechanical. Related to a direct, non-chemical, interaction between the equipment or fluids used to drill, complete, kill or stimulate a well and the formation resulting in a reduction in the permeability of the formation
- Chemical. Related to adverse interactions between either the rock and introduced foreign fluids, or between introduced external fluids and in situ formation fluids
- Biological. Related to problems created by the introduction of viable bacteria and nutrient streams into a reservoir.
- Thermal. Related to those associated with high temperature injection operations (steam injection, in-situ combustion, etc.).

Separately, we would like to highlight the formation damage mechanism caused by the chemical adsorption. Nowadays, use of polymers and other high molecular weight materials in drill-in and completion fluids is common practice. Although every engineer is aware that the polymers are bound to adsorb on the surface of the formation matrix and clays and, by virtue of their large molecular size, resulting in restrictions for flow area and hence impaired permeability. This is especially a problem in lower permeability formations, which are under intense development nowadays. Also, Bennion highlighted the idea similar to the one expressed in the beginning of this paragraph – formation damage in oil and gas wells is difficult to quantify in many cases, due to the inability of the reservoir engineer to retrieve exact samples and conduct detailed measurements on the area of interest, which usually represents a volume of rock surrounding the wellbore, which is generally several thousand meters below the surface of the earth (Bennion, 1999).

Subsurface Rocks Wettability Alteration by the Nanotechnology

As we learned from the century-long research on formation damage control, the wettability is one of the most important parameters for assurance of the flow from the porous medium of subsurface rock. Depending on the wetting state of the rock surface only one phase out of three normally presented in the flow channel (gas, oil and water) will flow as a primary phase, while the rest will flow in drops or thin films within the primary phase. All authors referenced in the previous paragraphs agree on the fact that the wetting state of rock surface in porous medium significantly impacts the certain phase flow intensity. Also, they agree that the dominance of the wettability characteristics of the rock over the other factors rises in the low- and ultra-low permeability rock. This can be explained by the immense rise in capillary forces and interfacial phenomena in the lower permeability rock, especially for the sub-micron diameter of pore channels. This theme was thoroughly elaborated in multiple research and discussions in the 2000s. For instance, research results with focus on the low permeability gas sandstone formations reported in the works (Bennion 2000a, 2000b, 2000c; Bennion 2004; Coskuner 2004; You 2009) and on the oil and gas formations in the works (Bennion 2002; Davis 2004). Hence, the technologies that allow to control the wetting state of the rock surface make it possible to get closer to the ability to control the fluids flow in the subsurface environment.

Further developments in research led to many studies aimed at understanding of the loose formation fines migration and methods of controlling this phenomenon. In the 2010s, many research papers were published on the topic of nanoparticle-based fluids applications for preventing the formation's fines migration. For instance, the works (Ahmadi et al. 2011; Habibi et al. 2013) reveals laboratory research results on the fines migration reduction through deposition of MgO, SiO_2, and Al_2O_3 nanoparticles (NPs) on the rock surface. The authors stated that the fines migration governing forces are the electric double layer repulsion and the London-van der Waals attraction. The authors shared their hypothesis that it is possible to change these forces using NPs as surface coatings. Results showed that addition of 0.1 wt.% of MgO and SiO_2 NPs reduced fines migration by 15% compared with the reference state. MgO NPs were found to be more effective, even at high fluid rates, when used at a higher concentration, as noticed in the macroscopic and microscopic results. In 2014, another research work (Contreras et al. 2014) on NPs application as a filtration control additive to reduce formation damage showed that iron-based NPs and calcium-based NPs can be effectively applied for reduction of filtration losses in conventional formations at HPHT and LPLT geo-physical conditions. In 2016, the work (Yuan 2016) presented results on the evaluation of NPs efficiency for mitigation of the fines migration. A mathematical approach was used for evaluation – method of characteristics. The authors highlighted the positive contribution of NPs to mitigate fines migration, and the effect was characterized by increase of maximum retention concentration of fines particles on rock grains through two reactions: (1) adsorption of nanoparticles onto the fines/grain surface and (2) increased retention of fines attachment on the pore surface by means of reducing the surface potential between grains and fines. In 2018, the work (Fakoya and Shah 2018) described laboratory research results for effect of silica NPs on the rheological properties and filtration performance of surfactant-based and polymeric fracturing fluids and their blends. The authors concluded that the application of nanotechnology to impact the apparent viscosity, viscoelastic behaviour and filtration properties can deliver some benefits, if nanoparticle concentrations are selected carefully. In the work (Hoxha et al. 2019) the authors discussed the NPs effect to stabilize shale. They highlighted that the operational use of NPs in drilling and completion fluids is still limited at the present time, in part because of a lack of consistent evidence for and clarification of NP interactions with rock, formation fluids and other fluid additives. The authors found that for Mancos Shale, anionic SiO_2 NPs (20 nm) were effective in partially plugging the pore-throat system, depending on the pH of the nanofluid, which affects the surface potential and zeta potential of both NPs and shale. Furthermore, cationic SiO_2 NPs showed better results for pore-plugging capabilities than the anionic NPs. The authors highlighted that these findings lead to challenges for the practical field application of NP-based drilling fluids for borehole stability, given that efficacy depends on the specific type of shale; the specific type, size, and concentration of NP; the interaction between NPs and shale; and external factors, such as pH, salinity, and temperature.

The Wettability – A Delicate Phenomenon

In the work by (Sergeev et al. 2020), the authors highlighted that it is not an easy task to determine the wettability of the subsurface formation's pore channels surfaces because large number of factors affecting this parameter over the span of geological structuring on one hand and anthropogenic impact on the other. Considering this, the authors advised researchers to account for a complex geological and physico-chemical phenomena that take place at the macro- and micro-level, and changes in thermobaric conditions of reservoirs. The authors elaborated that initially during the geological structuring of the hydrocarbon formation, the wettability characteristics were dependent on: (1) formation's mineralogical composition; (2) formation's fluid composition. As a result of the formation's fluid molecules adsorption on the pore channels, the positively or negatively charged film is formed. This film defines the rock surface wettability in the balanced natural conditions of the formation. Then, at the stage of the drilling into the formation, the balanced natural conditions are not in balance anymore. Accordingly, the wettability is changed along with a change in the properties of reservoir fluids due to disruption of the thermobaric equilibrium. Adding to it an external foreign fluids inflow into the formation, the situation is totally messed up and there is no way back to the initial state. This is important to understand and keep in mind when working with the wettability related themes.

Translating the abovementioned in simple words, the subsurface hydrocarbon formation's rock is never naked. The flow channel is always covered with multiple films of fluids and fines that ever saturated and migrated into the channel during the natural process of geological structuring. Then, the anthropogenic impact comes to play, which adds up the new artificially created films of fluids and particles on the top of the naturally created films. Hence, wettability is a delicate topic. In the 21st century *the subsurface engineer who serves the interests of stakeholders in the oil and gas field development project should not ever agree to inject subsurface the synthetic polymers, silica gels, precipitate solutions because these "solutions" once reacted in-situ are:*

- *Non-degradable.*
- *Irreversible.*
- *Pollutants.*

A simple example, the macromolecules of synthetic polymers famous for their adsorption rate, which in simple language means that polymer macromolecules stick to and cover whatever surface they travel through. The polymer deposited on to the flow channel's surface enters in the molecules exchange reacting with the surrounding environment, and it's done. *The impacted zone is no more the productive formation you knew. It belongs to the polymer's derivatives now.* The engineer must take this into account when planning any subsequent activity in this zone, i.e., from the moment the polymer is pumped any plans to work with this zone should consider that the surface is represented by a film, which consists of the derivatives of the polymer reaction with the list of unknown fluid composition, fines and particles. In the laboratory, try to create the residual saturation of the core with this mess to reflect reality when you want to conduct some core floods.

Nano-Emulsion Applications for Formation Damage Control

In the 2020s, the research papers (Sergeev et al. 2020a, 2020b, 2020c, 2020d) on the nano-emulsion applications for petroleum and geosystems industry showcased effectiveness for: (1) fully reversible blockage of the flow channels; (2) ability to control the wetting state of the flow channels. The research results of the latter are discussed here in detail.

In the work by (Sergeev et al. 2020), an effect of the colloidal system with SiO_2 nanoparticles on wettability of carbonate rock surface was studied by the United States Bureau of Mines (USBM) method, which measures the rock's wettability index through assessment of a hysteresis loop of capillary pressure curves (Donaldson & Alam 2013). Below are results of altering the wetting state of the carbonate rock cores extracted from two oil and gas fields in the Volga-Ural oil and gas province.

The carbonate oil and gas formations' rock presented in this paper is characterized as low porosity and permeability rock with average porosity index of 14% and permeability for gas 18.6 10^{-3} μm^2. In Table 1 and Figure 2, the summary of the laboratory experiments is presented. In Figures 3 and 4, the recorded capillary pressure curves are shown. In Figures 5 and 6, the wettability indices USBM are presented.

Table 1 – Nano-emulsion's effect on the wettability indices of the carbonate formations rock cores measured by the USBM method (adapted from Sergeev 2020)

Rock core	**Wettability Index, I_{USBM}**	
	Before	**After**
1	0.76	0.19
2	0.67	-0.12
3	0.74	0.19
4	0.21	-0.02
5	0.60	-0.32
6	0.11	-0.17

The summary of the results is graphically represented in the Figure 2 below. It can be seen from these results that the nano-emulsion with ultra-charged SiO_2 nanoparticles can significantly alter the rock's wettability. The results showed that some formulations of the nano-emulsions can make a fully hydrophobic surface out of the fully hydrophilic one. In other cases, the rock became neutral or close to the neutral wetting state after the flow of the nano-emulsion.

The Figures 3-6 shown below reflect results of the capillary pressure curves recorded during the centrifugation of the core samples which were used to calculate the wettability indices by the USBM method. These research results displayed an ability of the nano-emulsion to alter the carbonate rock wettability to various degrees. Certain samples of the nano-emulsion (core samples No. 1, 3 and 4) made the rock surface close to neutral wettability. Other samples (core samples No. 2, 5 and 6) could change the rock surface wetting state from fully hydrophilic to fully hydrophobic. This gives us certainty that the nano-emulsions with ultra-charged SiO_2 can controllably alter wettability of the subsurface formation's flow channels. This effect can be used as a tool to control the flow of fluids subsurface, especially in the low- and ultra-low permeability rock, where the wetting state of the flow channels is a key parameter that controls the phase permeability, and, therefore, the fluids flow.

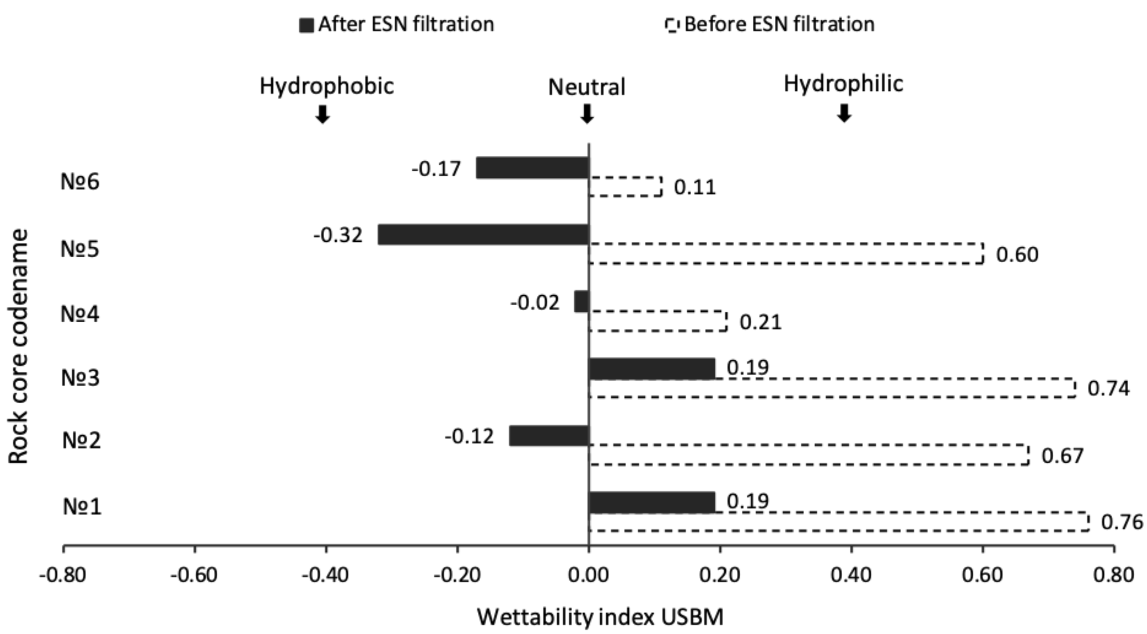

Figure 2 – The wettability index USBM for the carbonate rock cores before and after flow of the nano-emulsion (adapted from Sergeev 2020)

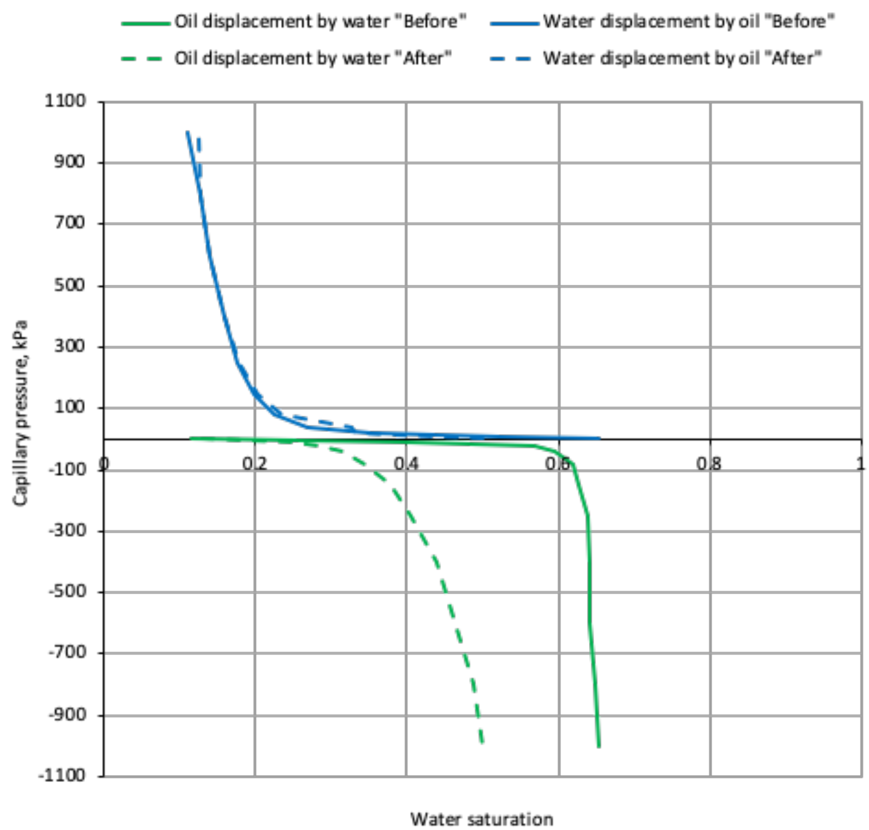

Figure 3 – The capillary pressure curves recorded for the carbonate rock core No. 2 before and after flow of the nano-emulsion (adapted from Sergeev 2020)

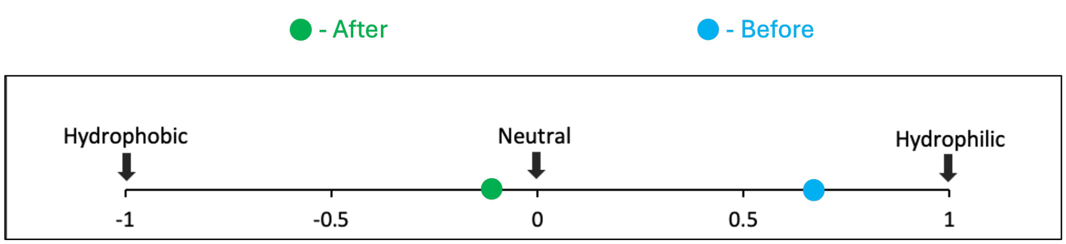

Figure 4 – The wettability index USBM for the carbonate rock core No. 2 before and after flow of the nano-emulsion (adapted from Sergeev 2020)

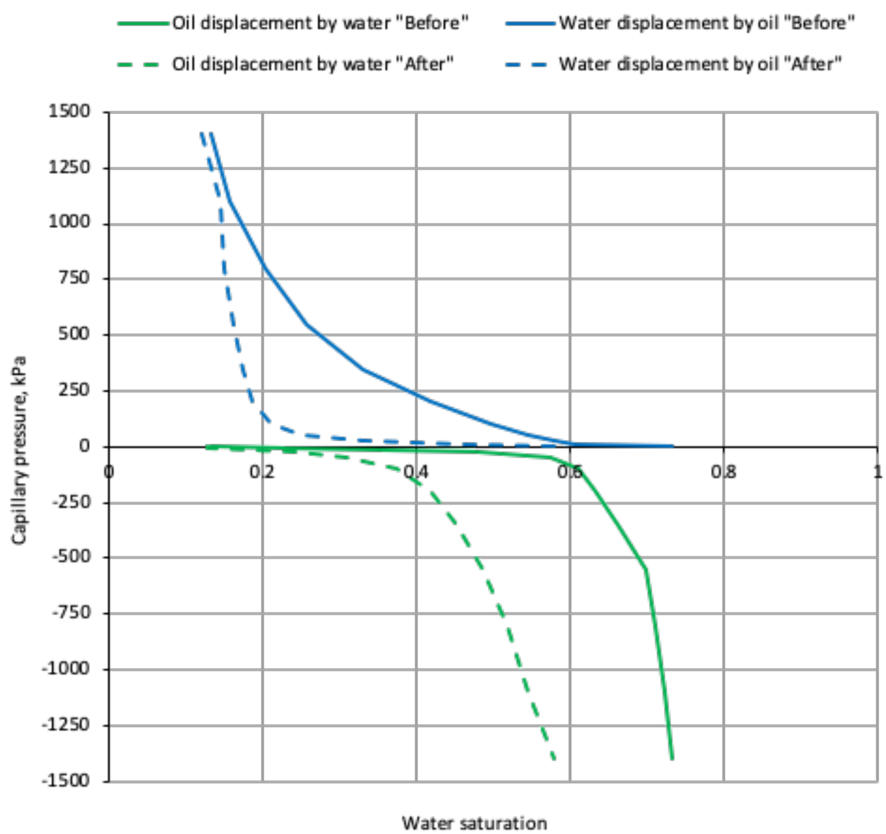

Figure 5 – The capillary pressure curves recorded for the carbonate rock core No. 5 before and after flow of the nano-emulsion (adapted from Sergeev 2020)

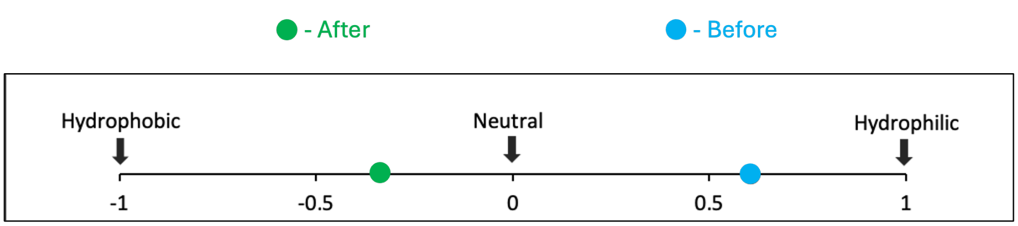

Figure 6 – The wettability index USBM for the carbonate rock core No. 5 before and after flow of the nano-emulsion (adapted from Sergeev 2020)

Conclusion

In the first chapter of this paper, we introduced to the reader the new generation functional fluid named the nano-emulsion. This fluid has already been proven in the field, and performed as an effective, versatile and environmental tool to control formation damage in various sub sectors of the oil and gas exploration and production industry. For instance, the nano-emulsions can be used for the drill-in and completion operations to preserve the formation's natural properties or functionally alter it to fit best to the purpose of the well. The nano-emulsion's versatility and ease of customization bring a great potential for applications throughout the whole chain of subsurface fluids flow control tasks.

In the second chapter, we covered the century-long evolution of the formation damage control science and technologies. The literature review is represented by the decades starting from the 1940s up to the present time. This review gives a clear picture on the topic development in the minds of specialists, who gave meaningful guidance to follow for mitigation of the formation damage risks. Also, the review showed how strongly intertwined the technology and the industrial progresses are. With the development in technology specialists learned more about the roots of the problem and its multicomponent nature and that the consequences of the formation damage go far beyond the bottom-hole zone, impacting all future activities in the drainage area of the well. This is why the assurance of formation damage control is crucial for effective development of the oil and gas fields.

In the third chapter, we discussed the importance of the wettability topic from the point of view of formation damage control. The drill-in operation leaves a significant imprint in life of the well, and the completion operation heavily affects the wider drainage area of the formation. Wettability is a fragile phenomenon, which gets affected by both operations. And the wettability is in the list of the most important parameters to account for to get hydrocarbons out of the formation. The relative importance of this parameter drastically grows when considered for low and ultra-low permeable formations. It is crucial for the efficient development of the field not to use any non-degradable, irreversible, polluting chemical compositions because their imprint costs too dearly to the environment and the stakeholders of the oil and gas field development project.

In the fourth chapter, we discussed research results on the ability of the nano-emulsion with ultra-charged SiO_2 nanoparticles to alter the rock wettability. The laboratory experiments conducted in accordance with the USBM method showed that the nano-emulsion can alter the wettability index of the natural carbonate rock cores from fully hydrophilic to neutral wetting state or to fully hydrophobic surface. This effect can be used by the subsurface engineers to functionally program the formation's wettability for conducting fluids of certain nature as a primary one.

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