Investigation of Hybrid Nanoparticle–Acid Fluids (HNAFs): Influence of Wettability and Interfacial Tension Mechanisms in Harsh Carbonate Reservoirs for Improved Oil Recovery

Mohamed Haroun, Md Motiur Rahman,* Mohammed Al Kobaisi, Minkyun Kim, Abhijith Suboyin, Bharat Somra, Jassim Abubacker Ponnambathayil, and Soham Punjabi

ABSTRACT: Over the past few years, there has been significant interest in the potential of hybrid nanoparticle–acid fluid (HNAFs) for improved oil recovery. This comprehensive study investigates the effects of nanoparticles and acid on interfacial tension (IFT) to establish a relationship between brine properties and the oil/brine IFT. This investigation is one of the first regional studies conducted utilizing candidate field data from the Middle East. Based on the literature review and screening studies conducted, a seawater (SW)-based HNAF was formulated with nanoparticles (SiO₂, Al₂O₃, and ZnO) and HCl to measure their effect on IFT. A total of 48 formulations of HNAFs, nanofluids with and without acid, were analyzed with crude oil from a candidate field. IFT measurements were subsequently conducted using the pendant drop method under ambient conditions and in a high-pressure, high-temperature reservoir environment. Results showcased that IFT reduction was observed by increasing the acid concentration with SiO₂ and Al₂O₃, although a reverse trend was observed with ZnO. Moreover, it was observed that IFT varied with increasing concentrations of nanoparticles, and at certain acid concentrations, IFT reduced significantly with higher nanoparticle concentrations. From the Amott studies, a clear signature was achieved, with ZnO exhibiting a total of 31.4% oil recovery, followed by SiO₂ (27.3%) and Al₂O₃ (23.7%). The results of this study may assist in defining a screening criterion for future displacement (oil recovery) studies involving the presented nanoparticles. The results also reveal further the mechanisms involved in IFT reduction by hybrid nano–acid fluids and their potential for significant applications in the Middle East.

1. INTRODUCTION

Recently, nanoparticles have gained considerable interest due to their potential to modify thermal, electrical, and interfacial properties of crude oil in reservoirs. Nanoparticles (NPs) can enrich fluid–fluid properties, such as viscosity, interfacial tension (IFT), thermal conductivity, and fluid–rock properties, such as wettability and the heat-transfer coefficient, thus enhancing oil recovery.

Polysilicon particles are a popular choice to alter the wettability and enhance oil recovery depending on the coating of the particle surface. Based on the wettability of the surface coating, polysilicons are classified into lipophobic and hydrophilic polysilicon (LHP), neutral wettable polysilicon (NWP), and hydrophobic and lipophilic polysilicon (HLP). Silicon dioxide, an LHP polysilicon, altered the wettability of sandstone surfaces from hydrophobic (oil-wet) to hydrophilic (water-wet) due to its adsorption/accumulation in pore throats. It was corroborated that the wettability alteration was relatively more influenced by the NWP type of nanoparticles than by HLP nanoparticles, as shown in Figure 1. Additional studies have also investigated the influence of wettability alteration by different concentrations of silica NPs, the variation in interfacial tension of solutions of surfactants and NPs, and the effect of the salinity of injected fluid on the contact angle, which result in a change in oil recovery. This included investigations on interactions of NPs with aqueous solutions in the pores of reservoirs and formation damage.

Received: June 10, 2022
Accepted: October 26, 2022
Published: November 4, 2022
nanofluid flooding and low-concentration acidizing ionic surfactant. Liquid systems if their surface is modified by the presence of an ionic surfactant. They can modify the interfacial properties of liquid/air or liquid/liquid systems.

Investigations how dispersed nanoparticles in an aqueous phase using representative materials (core plugs, crude oils, and synthetic brine, to showcase that interfacial tension reduction was observed in both nanofluids. The blend resulted in lower values, which might be due to the presence of the surfactant, and experiments indicated that wettability alteration can be achieved by both nanofluids. Afekare et al. also showed how aqueous dispersions of hydrophilic nanosilica may have a significant effect on the reduction (>70%) of the rock–oil adhesion force and work of adhesion (>95%), which leads to nanoscale wettability improvement and a potential increase in the recovery factor. Kaito et al. utilized a 0.5 wt% surface-modified nanosilica dispersion (SND), which contains 18% colloidal silica nanoparticles and some chemicals to enhance the stability of nanoparticles in synthetic brine, to show that nanoparticles increased oil recovery by 14 points in most core-flooding experiments.

Deng integrated nanoparticles with LCA and suggested the impact of hybrid nano–acid fluids (HNAF) on the fluid–fluid interaction by conducting IFT measurements. On the other hand, LCA combined with electrokinetics reduces interfacial tension, alters wettability, enhances the capillary number, and finally increases the displacement efficiency. CuO, NiO, SiO$_2$, and Al$_2$O$_3$ nanoparticles added to HCl solution were categorized into two groups depending on the existence and nonexistence of surface charge. It was observed in all tested fluids that an increase in acid concentration resulted in IFT reduction, while higher concentrations of nanoparticles had no effect on reducing the IFT. In addition, compared with acid solutions without nanoparticles and seawater, the presence of nanoparticles decreased the IFT by 16.8 and 56%, respectively. Hybrid nano–acid fluids with Al$_2$O$_3$ and SiO$_2$ showed a significant increase in oil recovery compared with seawater. Therefore, based on the literature and via IFT measurements, Al$_2$O$_3$ and SiO$_2$ acid fluids were selected for further studies due to their stability and higher surface area. Results from previous investigations, even with smart brines, have also been incorporated to comprehend and expand the impact of HNAFs.

2. MATERIALS AND METHODS

In this study, systematic experimental analyses were conducted using representative materials (core plugs, crude oils, and formation water/seawater solutions). A reservoir temperature of 90 °C was maintained where possible. Materials and methods used are defined in the following sections.

2.1. Reservoir Rock Sample. Core plugs retrieved from the Indiana limestones outcrop with 99% calcite, representing Abu Dhabi carbonate reservoirs, were used for the spontaneous imbibition test. Conventional core analysis was performed on the received plugs, and their petrophysical properties were measured. The results are listed in Table 1.

| core plug ID | diameter (cm) | length (cm) | pore volume (cm$^3$) | porosity (%) | $K_a$ (mD) | OOIP (cm$^3$) | $S_w$ (%) |
|--------------|---------------|-------------|---------------------|--------------|-----------|--------------|-----------|
| A-1          | 3.767         | 7.603       | 14.59               | 17.22        | 2.328     | 8.955        | 38.62     |
| A-2          | 3.778         | 7.598       | 12.661              | 14.86        | 1.542     | 7.994        | 36.86     |
| A-3          | 3.769         | 7.618       | 13.876              | 16.33        | 1.165     | 8.398        | 38.04     |
2.2. Crude Oil. Filtered crude oil retrieved from Abu Dhabi reservoirs was used to determine the IFT and aging of core plugs. The properties of crude oil are shown in Table 2. Each core plug was aged for 14 days.

| Table 2. Density and Viscosity of the Oil at Each Temperature of Brines |
|-----------------|---|---|---|---|
| temperature (°C) | 20 | 25 | 50 | 75 | 90 |
| density (g/cm³)  | 0.8232 | 0.8197 | 0.8023 | 0.7846 | 0.7753 |
| viscosity (cP)   | 3.8414 | 3.3288 | 1.9637 | 1.2603 | 1.0615 |

Synthetic formation brines were used to saturate reservoir rock samples based on the ionic composition of the formation water retrieved from Abu Dhabi reservoirs. Abu Dhabi representative seawater was used as a base for the HNAF study. The composition of the formation water and seawater tested are shown in Table 3. Temperature of Brines

2.3. Hybrid Nano–Acid Fluids (HNAFs). In this study, SiO₂, Al₂O₃, and ZnO nanoparticles, as mentioned in Table 4, were selected to prepare HNAFs with different concentrations (3–6 wt %) of hydrochloric acid to observe the best formulations. Forty-eight combinations of HNAFs, as indicated in Table 5, were prepared using the ultrasonicator equipment to form a nanoparticle suspension. Then, the dispersed nanoparticle solution was retrieved immediately out of the sonicator and used to measure the interfacial tension and Amott test. In addition, it was observed that the acid did aid in maintaining the uniform distribution of fluids. Acid solutions without nanoparticles and nanoparticle fluids without acid were tested as the baseline. Therefore, a total of 60 fluids were tested. Corrosion inhibitors were added to the HNAF solutions to preserve the equipment. The major criteria for the shortlisted brine include identifying an optimum concentration for the nanoparticles and acid while preventing corrosion.

2.4. Experimental Procedure. The following subsections detail the experimental procedure for measuring IFT and oil recovery through spontaneous imbibition.

2.4.1. Interfacial Tension. The pendant drop method was used to measure the interfacial tension (IFT) of HNAFs both under ambient conditions and under high-pressure and high-temperature (HPHT) conditions. Tracker software was used to capture and calculate the IFT based on the Young Laplace equation. The pendant drop system is shown in Figure 3.

The following steps were conducted:

1. A filling syringe was designed for the system with the oil sample and a cuvette with 25 mL of brine sample.
2. The density of oil and brine was input into the software before measuring IFT.
3. Measurement under ambient temperature and pressure conditions: the syringe was mounted tightly onto the device, and the cuvette was aligned with the camera. The dispenser needle was soaked into the cuvette and the tip of the needle was centered by adjusting the height and direction of the device.

4. Measurement at HPHT: the cuvette and syringe were placed into the chamber with a temperature probe and the cap was tightened. The prepared chamber was placed on the equipment under a pressure of 200 psi by connecting it to a nitrogen gas tank and the temperature was increased to 90 °C.

5. Measurements were performed on Tracker software, which captured the contour of the oil drop, calculated the interfacial tension value, and read the value every 1 min for 10 min until the reading stabilized. During drop formation, when the drop volume reaches a certain level, the speed of drop formation will decrease. The volume of the drop to be formed slowly reaches closer to the volume of the drop defined. The value of the initial drop-volume tolerance is defined as 1% in the system. Tracker uses the axisymmetric drop shape analysis technique to find the interfacial tension by fitting the Laplace equation.

IFTs between crude oil and various combinations of HNAFs were tested at ambient temperature. Three best brines from each

| Table 3. Ion Concentrations of Formation Water and Seawater |
|----------------|---|---|---|---|---|---|---|
|               | Na⁺ | Ca²⁺ | Mg²⁺ | K⁺  | Cl⁻ | SO₄²⁻ | HCO₃⁻ | TDS (ppm)  |
| FW            | 44.261 | 13.84 | 1.604 | 0.672 | 96.5659 | 0.885 | 0.332 | 157.488 |
| SW            | 19.054 | 0.69  | 2.132 | 3.944 | 30.924 | 1.2603 | 1.0615 | 57.539 |

| Table 4. Nanoparticle Properties |
|-------------------------------|
| products | SiO₂ | Al₂O₃ | ZnO |
| form | powders | powders | powders |
| particle size (nm) | 10−20 | 30−60 | ≤100 |
| molecular weight (g/mol) | 60.08 | 101.96 | 81.37 |
| density (g/cm³) | 2.2 | 3.27 | 5.61 |
| pH | 3.7−4.5 | 6−7 | 6−9 |
| surface area (m²/s) | 300 | 130 | 15−25 |
| surface charge | positive | positive | positive |

| Table 5. Hybrid Nano–Acid Fluid Formulations |
|-------------------------------|
| SiO₂ (wt %) | acid (wt %) | Al₂O₃ (wt %) | acid (wt %) | ZnO (wt %) | acid (wt %) |
| 0.1 | 3 | 0.01 | 3 | 0.4 | 3 |
| 0.2 | 4 | 0.04 | 4 | 0.6 | 4 |
| 0.3 | 5 | 0.07 | 5 | 0.8 | 5 |
| 0.4 | 6 | 0.1 | 6 | 1 | 6 |
| 4 × 4 = 16 | 4 × 4 = 16 | 4 × 4 = 16 |

the number of scenarios = 48
category of nanoparticles were selected for further studies under HPHT conditions.

2.4.2. Spontaneous Imbibition. Oil displacement by spontaneous imbibition was measured using Amott cells at 90 °C, as shown in Figure 4. Core plugs were first subjected to seawater. Once the oil production plateaued, the brine was switched with nanofluids (without acid) to determine the incremental recovery indicating a wettability alteration.

The following steps were conducted:

1. The core plugs were taken out from the aging cell, excess oil on the surface was removed by rolling on non-absorbent paper, and the weight was measured.
2. The core plugs were placed in Amott cells.
3. Degassed brines were siphoned into the Amott cell slowly to ensure that no air bubbles were introduced in the Amott cells and around the core.
4. The sequence of changing the brines was followed and the oil volume was recorded every 24 h.

3. RESULTS AND DISCUSSION

The results obtained based on the systematic experimental procedure are discussed in the following sections to define a screening criterion for future oil recovery studies.

3.1. Interfacial Tension under Ambient Conditions.

The IFTs of 60 HNAF formulations with crude oil were studied in this phase of the research. The fluids were divided into three categories depending on the nanoparticles used, as shown in Table 5. The IFT of seawater under ambient conditions was found to be 15.16 dynes/cm. The dispersed nanoparticles in an aqueous phase usually modify the interfacial properties of liquid–liquid systems. As observed in Figures 5−7, dispersed nanoparticles in the acidic phase decreased the IFT by more than 50%. It was also observed that increasing the acid concentration resulted in a higher reduction in the IFT.

As seen in Figure 5, IFTs with various concentrations of SiO₂ decreased with increasing acid concentration. However, the addition of nanoparticles had a lower effect on IFT reduction compared with acid.

Figure 6 shows the effect of Al₂O₃ with acid on the IFT between the HNAF fluid and crude oil. Compared with SiO₂,

Figure 4. Setup for spontaneous imbibition test.

Figure 5. Interfacial tension of SiO₂−acid fluids organized in terms of acid concentration.

Figure 6. Interfacial tension of Al₂O₃−acid fluids organized in terms of acid concentration.

the addition of Al₂O₃ showed a further reduction in IFT with respect to the acid concentration. Also, alumina acid fluids showed a lower IFT than SiO₂ acid fluids at much lower concentrations. With a higher concentration of Al₂O₃ (0.1 wt %), the rate of acid reaction may be less during an acid concentration increase of 3−4% than that during an acid concentration increase of 4−5%. Therefore, during a 3−4% increase, the in situ live acid is higher and IFT is decreased. Similarly, during a 4−5% increase, the in situ live acid may be less and IFT is increased at an acid concentration of 5% and then IFT decreased again, which may be because of the acid reaction kinetics. However, the in situ live acid available on the face of the pore space and nanoparticles depends on the rate of the acid reaction (kinetics and equilibria features).

Figure 7 shows the IFT measurement of a ZnO-based HNAF. Although the ZnO−acid fluid showed a decrease in IFT compared with seawater, the addition of ZnO at higher acid concentrations increased the IFT compared with fluids without nanoparticles. Therefore, ZnO nanoparticles do not affect the IFT in the acidic aqueous phase.

Figure 7. Interfacial tension of ZnO−acid fluids organized in terms of acid concentration.
3.2. Interfacial Tension under HTHP Conditions. Based on the IFT results under ambient conditions, three fluids from each category that achieved low IFT values were selected to measure the IFT under HPHT conditions. The selected fluid formulations, along with the IFT under ambient and HPHT conditions, are presented in Table 6. As can be observed in Figure 8, the IFT at HPHT was lesser than that under ambient conditions. Therefore, the acidic aqueous phase and temperature have a direct effect on IFT reduction while Abu Dhabi reservoirs are at about 90°C.

3.3. Spontaneous Imbibition. The impact of nanoparticles on wettability alteration was studied using spontaneous imbibition at 90°C without the addition of acid for this phase of the study. To prevent precipitation, the solutions were sonicated and heated to 90°C before being poured into the Amott cells. Seawater was used as the base brine for secondary recovery (without any acid) before subjecting the core plug to the nanofluid.

Figure 9 demonstrates the incremental oil recovery for the three tested hybrid nanofluids while using SiO₂ fluid (0.4% silica dioxide), Al₂O₃ fluid (0.1% aluminum oxide), and ZnO fluid (0.4% zinc oxide), respectively, without acid. These nanoparticle concentrations yielded the best results in the IFT test. This study confirmed the wettability alteration capabilities of the tested nanofluids. During the first phase of the Amott test, all three base fluids exhibited the same behavior on wettability alteration across the three tested core plugs. However, during the second phase of the test, a clear trend was observed as of the 12th day, with the SiO₂-based nanofluid outperforming the other two because the nature of SiO₂ is not vulnerable to high-temperature and high-salinity conditions but stable without deformation compared with other nanoparticles. ZnO negatively affected the permeability of the plugs by blocking the pores, and Al₂O₃ has the ability to reduce oil viscosity. The ZnO-based nanofluid response was delayed for about 10 additional days, after which it outperformed the other two nanofluids, indicating a longer residence time requirement for Zn to complete the ionic exchange. At the end of the test, a clear signature was achieved, with the ZnO nanofluid achieving a total of 31.4% oil recovery, followed by SiO₂ (27.3%) and Al₂O₃ (23.7%). The varying responses of each of the shortlisted nanoparticles is highly indicative of in situ reactions taking place that are a function of time, which need to be assessed in depth.

4. CONCLUSIONS

This investigation presents one of the first regional studies conducted utilizing candidate field data from the Middle East to analyze the influence of wettability and interfacial tension mechanisms in harsh carbonate reservoirs for improved oil recovery. Based on the nanoparticles (SiO₂, Al₂O₃, and ZnO) used, there is an indication of wettability alteration along with the potential for additional oil recovery.

The following are the key conclusions deduced from this study:

1. Pendant drop experiments performed at both ambient temperature and 90°C revealed that the IFT was reduced by around 2-fold with increased acid concentration compared with seawater with no acid. Under ambient conditions, it was revealed that the Al₂O₃-based hybrid fluid composition: 20°C(dyne/cm) 90°C(dyne/cm)

| fluid composition | 20 °C (dyne/cm) | 90 °C (dyne/cm) |
|-------------------|----------------|----------------|
| 0.1% SiO₂ + 6% acid | 5.5            | 4.7            |
| 0.3% SiO₂ + 6% acid | 5.6            | 3.2            |
| 0.4% SiO₂ + 6% acid | 5.6            | 3.1            |
| 0.01% Al₂O₃ + 6% acid | 5.1           | 3.2            |
| 0.07% Al₂O₃ + 6% acid | 5.0           | 3.8            |
| 0.1% Al₂O₃ + 6% acid | 5.1            | 2.9            |
| 0.4% ZnO + 3% acid | 6.4            | 4.1            |
| 0.6% ZnO + 3% acid | 6.4            | 5.0            |
| 0.8% ZnO + 3% acid | 6.3            | 6.3            |

Figure 7. Interfacial tension of ZnO–acid fluids organized in terms of acid concentration.

Figure 8. Comparison of nine IFT values obtained under ambient and HPHT conditions.
nano–acid fluid at its lowest concentration outperformed the other hybrid nano–acid fluids across the tested concentrations (0.01–0.1 wt %).

2. At 90 °C, SiO$_2$-based hybrid nano–acid fluids at their highest test concentrations resulted in an IFT reduction trend similar to that observed with the Al$_2$O$_3$-based hybrid nano–acid fluids.

3. In comparison, ZnO-based hybrid nano–acid fluids may have indicated in situ reactions consuming the acid, resulting in the weaker performance in IFT reduction.

4. All three nanoparticles (SiO$_2$, Al$_2$O$_3$, and ZnO) dispersed in seawater were tested in this study, which indicated a significant effect on wettability alteration. They demonstrated significant potential for additional oil recovery, with the highest incremental recovery recorded for ZnO at 31%, followed by SiO$_2$ at 27% and Al$_2$O$_3$ at 23%, as observed during the Amott tests.

5. The results of this study may assist in defining the screening criteria for future displacement studies involving the presented nanoparticles for the region. This may be further developed to result in low-acid-concentration hybrid nano–acid fluid deployment in the field.

**AUTHOR INFORMATION**

**Corresponding Author**

Md Motiur Rahman — Khalifa University of Science and Technology, Abu Dhabi 127788, UAE; orcid.org/0000-0002-4453-9230; Email: md.rahman@ku.ac.ae

**Authors**

Mohamed Haroun — Khalifa University of Science and Technology, Abu Dhabi 127788, UAE

Mohammed Al Kobaisi — Khalifa University of Science and Technology, Abu Dhabi 127788, UAE

Minkyun Kim — Khalifa University of Science and Technology, Abu Dhabi 127788, UAE

Abhijith Suboyin — Khalifa University of Science and Technology, Abu Dhabi 127788, UAE

Bharat Somra — Khalifa University of Science and Technology, Abu Dhabi 127788, UAE

Jassim Abubacker Ponnambathiyil — Khalifa University of Science and Technology, Abu Dhabi 127788, UAE; orcid.org/0000-0002-8368-3139

**Soham Punjabi — Khalifa University of Science and Technology, Abu Dhabi 127788, UAE**

Complete contact information is available at:
https://pubs.acs.org/10.1021/acsomega.2c03626

**Notes**

The authors declare no competing financial interest.

**ACKNOWLEDGMENTS**

The authors recognize and express their sincerest gratitude to the Khalifa University of Science and Technology for providing the valuable opportunity to conduct this study.

**NOMENCLATURE**

- $S_{\text{wi}}$: irreducible water saturation
- CuO: copper oxide
- DI: deionized water
- FW: formation water
- HNAF: hybrid nano–acid fluid
- HPHT: high-pressure high-temperature
- IFT: interfacial tension
- LCA: low-concentration acid
- NiO: nickel oxide
- NPs: nanoparticles
- OOIP: original oil in place
- SW: seawater
- TDS: total dissolved solid
- wt %: weight percent
- Al$_2$O$_3$: aluminum oxide or alumina
- SiO$_2$: silicon dioxide or silica
- ZnO: zinc oxide

**REFERENCES**

(1) El-Diasty, A. I.; Aly, A. M. In Understanding the Mechanism of Nanoparticles Applications in Enhanced Oil Recovery, SPE North Africa Technical Conference and Exhibition, Sep. 2015, 2015.

(2) Ju, B.; Dai, S.; Luan, Z.; Zhu, T.; Su, X.; Qiu, X. In A Study of Wettability and Permeability Change Caused by Adsorption of Nanometer Structured Polysilicon on the Surface of Porous Media, SPE Asia Pacific Oil and Gas Conference and Exhibition, Oct. 2002, 2002.

(3) Ju, B.; Fan, T.; Ma, M. Enhanced oil recovery by flooding with hydrophilic nanoparticles. *China Particul.* 2006, 4, 41–46.

(4) Roustaei, A.; Moghadasi, J.; Iran, A.; Bagherzadeh, H.; Shahrabadi, A. In An Experimental Investigation of Polysilicon Nanoparticles’ Recovery Efficiencies through Changes in Interfacial Tension and Wettability Alteration, SPE International Oilfield Nanotechnology Conference and Exhibition, June 2012, 2012.
(5) Olayiwola, S. O.; Dejam, M. A comprehensive review on interaction of nanoparticles with low salinity water and surfactant for enhanced oil recovery in sandstone and carbonate reservoirs. Fuel 2019, 241, 1045–1057.

(6) Olayiwola, S. O.; Dejam, M. Synergistic interaction of nanoparticles with low salinity water and surfactant during alternating injection into sandstone reservoirs to improve oil recovery and reduce formation damage. J. Mol. Liq. 2020, 317, No. 114228.

(7) Olayiwola, S. O.; Dejam, M. Comprehensive experimental study on the effect of silica nanoparticles on the oil recovery during alternating injection with low salinity water and surfactant into carbonate reservoirs. J. Mol. Liq. 2021, 325, No. 115178.

(8) Olayiwola, S. O.; Dejam, M. Interfacial energy for solutions of nanoparticles, surfactants, and electrolytes. AIChE J. 2020, 66, No. e16891.

(9) Suleimanov, B. A.; Ismailov, F. S.; Veliyev, E. F. Nanofluid for enhanced oil recovery. J. Pet. Sci. Eng. 2011, 78, 431–437.

(10) Zaid, H. M.; Latiff, N. R. A.; Yahya, N.; Soleimani, H.; Shafie, A. Application of Electromagnetic Waves and Dielectric Nanoparticle in Enhanced Oil Recovery. J. Nano Res. 2013, 26, 135–142.

(11) Alomair, O. A.; Matar, K. M.; Alsaheid, Y. H. In Nanofluids Application for Heavy Oil Recovery, SPE Asia Pacific Oil & Gas Conference and Exhibition, Oct. 2014, 2014.

(12) Ravera, F.; Santini, E.; Logljo, G.; Ferrari, M.; Liggieri, L. Effect of nanoparticles on the interfacial properties of liquid/liquid and liquid/air surface layers. J. Phys. Chem. B 2006, 110, 19543–19551.

(13) Sheng, J. J. Review of Surfactant Enhanced Oil Recovery in Carbonate Reservoirs. Adv. Pet. Explor. Dev. 2013, 6, 1–10.

(14) Kilybay, A.; Ghosh, B.; Thomas, N. C.; Aras, P. In Hybrid EOR Technology: Carbonated Water and Smart Water Improved Recovery in Oil Wet Carbonate Formation, SPE-182567-MS, SPE Annual Caspian Technical Conference and Exhibition, November 1–3, 2016, 2016.

(15) Kilybay, A.; Ghosh, B.; Thomas, N. C.; Sulemana, N. T. In Hybrid EOR Technology: Carbonated Water and Smart Water Improved Recovery in Oil Wet Carbonate Formation: Part-II, SPE-185321-MS, SPE Oil and Gas India Conference and Exhibition, April 4–6, 2017, 2017.

(16) Xu, Z. X.; Li, S. Y.; Li, B. F.; Chen, D. Q.; Liu, Z. Y.; Li, Z. M. A review of development methods and EOR technologies for carbonate reservoirs. Pet. Sci. 2020, 17, 990–1013.

(17) Haeri, F.; Rao, D. N. Precise Wettability Characterization of Carbonate Rocks To Evaluate Oil Recovery Using Surfactant-Based Nanofluids. Energy Fuels 2019, 33, 8289–8301.

(18) Dordzie, G.; Dejam, M. Enhanced oil recovery from fractured carbonate reservoirs using nanoparticles with low salinity water and surfactant: A review on experimental and simulation studies. Adv. Colloid Interface Sci. 2021, 293, No. 102449.

(19) Liu, J.; Sheng, J. J.; Wang, X.; Ge, H.; Yao, E. Experimental study of wettability alteration and spontaneous imbibition in Chinese shale oil reservoirs using anionic and nonionic surfactants. J. Pet. Sci. Eng. 2019, 175, 624–633.

(20) Yuan, S.; Liang, T.; Zhou, F.; Liang, X.; Yu, F.; Li, J. In A Microfluidic Study of Wettability Alteration Rate on Enhanced Oil Recovery in Oil-Wet Porous Media, SPE Abu Dhabi International Petroleum Exhibition and Conference November, 2019, 2019.

(21) Neubauer, E.; Hincapie, R. E.; Borovina, A.; Biernat, M.; Clemens, T.; Ahmad, Y. K. In Influence of Nanofluids on Wettability Changes and Interfacial Tension Reduction, SPE Europec, December, 2020, 2020.

(22) Afekare, D. In Enhancing Oil Recovery Using Aqueous Dispersions of Silicon Dioxide Nanoparticles: The Search for Nanoscale Wettability Alteration Mechanism, SPE Annual Technical Conference and Exhibition, October, 2020, 2020.

(23) Kaito, Y.; Goto, A.; Ito, D.; Murakami, S.; Kitagawa, H.; Ohori, T. In First Nanoparticle-Based EOR Nano-EOR Project in Japan: Laboratory Experiments for a Field Pilot Test, SPE Improved Oil Recovery Conference April, 2022, 2022.

(24) Deng, Y. Electrokinetics Assisted Hybrid Nanoacid Fluid for Improved Oil Recovery in Tight Formations. MSc Thesis, The Petroleum Institute Abu Dhabi, 2015.

(25) Ansari, A.; Haroun, M.; Rahman, M. M.; Chilingar, G. V. Electrokinetic Driven Lo-Concentration Acid Improved Oil Recovery in Abu Dhabi Tight Carbonate Reservoirs. Electrochim. Acta 2015, 181, 255–270.

(26) Meng, W.; Haroun, M.; Sarma, H. K.; Adeoye, T. J.; Aras, P.; Punjabi, S.; Rahman, M. M.; Al Kobaisi, M. In A Novel Approach of Using Phosphate-Spiked Smart Brines to Alter Wettability in Mixed Oil-Wet Carbonate Reservoirs, SPE 177551, Abu Dhabi International Petroleum Exhibition and Conference, Abu Dhabi, UAE, 9–12 November, 2015, 2015.

(27) Kim, M. Investigating Hybrid Nanoparticle Acid Application for EOR in Abu Dhabi Tight and Shale Reservoirs. MSc Thesis, The Petroleum Institute Abu Dhabi, 2016.