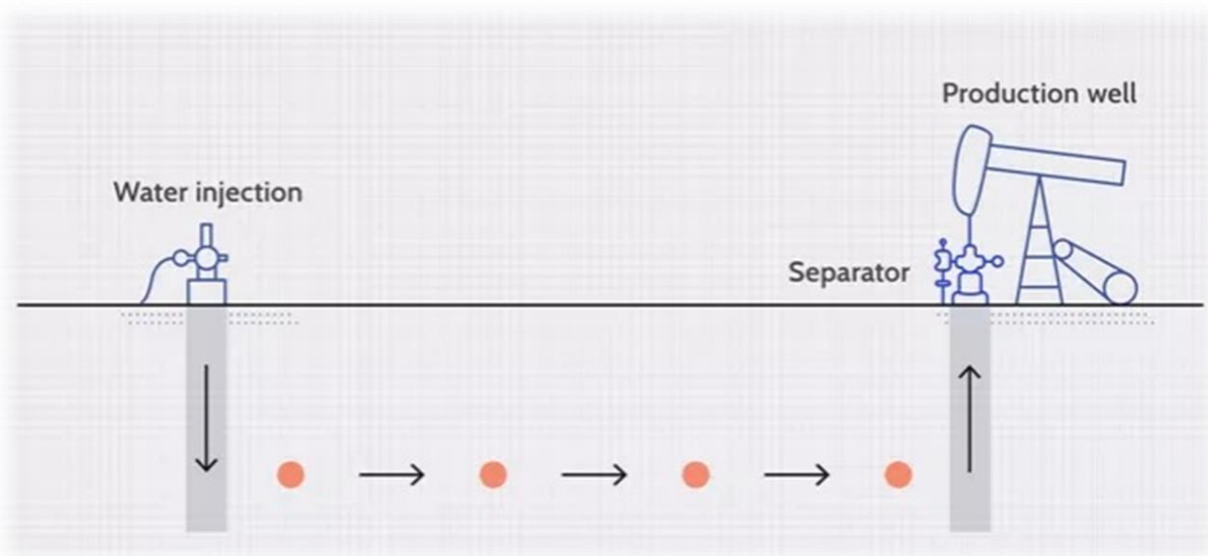
Enhanced Oil Recovery (EOR)

2017-2022

Bibliography



Prepared by:

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February 2022

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Introduction

Enhanced oil recovery (EOR), also known as "tertiary recovery," is a process for extracting oil that has not already been retrieved through the primary or secondary oil recovery techniques. Although the primary and secondary recovery techniques rely on the pressure differential between the surface and the underground well, enhanced oil recovery functions by altering the chemical composition of the oil itself in order to make it easier to extract.

Enhanced oil recovery techniques are complex and expensive and therefore are employed only when the primary and secondary recovery techniques have exhausted their usefulness. Indeed, depending on factors such as the cost of oil, it may not be economical to employ EOR at all. In those cases, oil and gas might be left in the reservoir because it is simply not profitable to extract the remaining amounts.

In the first type of technique, gases are forcefully injected into the well in a way that both forces the oil to the surface and reduces its viscosity. The less viscous the oil, the easier it flows and the more cheaply it can be extracted. Although various gases can be used in this process, carbon dioxide (CO_2) is used most often. Other common EOR techniques include pumping steam into the well in order to heat the oil and make it less viscous. Similar outcomes can be achieved through so-called "fire flooding," which involves lighting a fire around the periphery of the oil reservoir in order to drive the remaining oil close to the well. Finally, various polymers and other chemical structures can be injected into the reservoir to reduce viscosity and increase pressure, although these techniques are often prohibitively expensive[1].

Abstracts

Title: High-performance polymeric surfactant of sodium lignosulfonate-polyethylene glycol 4000 (SLS-PEG) for enhanced oil recovery (EOR) process.

Publication date: 2022

Authors: Priyanto S.,Sudrajat R.W.,Suherman S.Send mail to Suherman S.,Pramudono B.,Riyanto T.,Dasilva T.M.F.B.,Yuniar R.C.,Aviana H.

Journal: Periodica Polytechnica Chemical Engineering

Abstract: Recently, the increase in fuel oil demand was not supported by petroleum production due to the low productivity of old wells. Furthermore, an appropriate technology, such as Enhanced Oil Recovery (EOR) technology, is needed to maximize the productivity of the old well. Therefore, the purpose of this study was to synthesize a polymeric surfactant for the EOR process from sodium lignosulfonate (SLS) and polyethylene glycol (PEG) in various SLS to PEG ratios, namely 1:1 (PS1), 1:0.8 (PS2), and 1:0.5 (PS3). The surfactants were characterized using several methods, such as Fourier Transform-Infrared spectroscopy (FT-IR), compatibility, stability, viscosity, and phase behavior tests. The performance of the surfactants for the EOR process in different brine solution concentrations (16,000 ppm and 20,000 ppm) was also studied. The result showed that the introduction of the PEG molecule to the surfactant had been successfully conducted as FT-IR analysis confirmed. The surfactant's hydrophilicity increased with the introduction of PEG due to the increase of the ether group. A Winsor Type I or lower phase microemulsion was formed due to the high hydrophilicity. The highest oil yield (79 %) was obtained by PS1 surfactant, which has the highest PEG dosage, in a brine solution of 1,600 ppm. Therefore, it was concluded that the introduction of PEG could increase the hydrophilicity, viscosity, and EOR performance. © 2022, Budapest University of Technology and Economics.

Title: The effect of aluminosilicate in anionic–nonionic surfactant mixture on wetness and interfacial tension in its application for enhanced oil recovery

Publication date: 2022

Authors: Yahya Z.N.M.a,Puspaseruni N.P.a, b,Kurnia R.a,Wahyuningrum D.b,Mulyani I.b,Wijayanto T.c, d,Kurihara M.c,Waskito S.S.e,Aslam B.M.a,Marhaendrajana T

Journal: Energy Reports

Abstract: In particular, this study aims to investigate the effect of aluminosilicate nanoparticle in the mixture of anionic (Sulfonated Alkyl Ester) and nonionic (Fatty Ester Oleate) surfactants on the interfacial tension and wettability related to EOR processes. Various experiments were conducted such as measuring interfacial tension between oil and brine using spinning drop tensiometer, measuring contact angle between surfactant-NPs-brine solution and Buff Berea core using optical tensiometer, conducting spontaneous imbibition, and core flooding tests. It is observed that the more anionic surfactant in the mixture the more significant aluminosilicate reduces contact angle and increases interfacial tension (IFT), which promotes contradicting effect on oil recovery. In this study, the IFT prevails and eventually reduces ultimate oil recovery. At spontaneous imbibition tests the ultimate oil recovery is decreased from 58% to 47% and from 63% to 46% for SAE-01A and SAE-01B, respectively. The ultimate oil recovery is reduced from 54% to 35% and from 50% to 39% at core flooding tests (Figure 16) for SAE-01A and SAE-01B, respectively. The aluminosilicate nanoparticle contributes positively as the ratio of SAE and FEO becomes smaller. At surfactant formulation ratio of 1:2 (SAE-01C), the IFT is decreased slightly from 4.36×10^{-3} mN/m to 2.36×10^{-3} mN/m and contact angle is also slightly reduced from 41.9° to 40.3° by adding 250 ppm NPs. The results show that ultimate oil recovery is increased 52% to 61% and from 47% to 49% at spontaneous imbibition tests and core flooding tests, respectively.

Title: Application of microfluidics in chemical enhanced oil recovery: A review

Publication date: 2022

Authors: Fani M.a, Pourafshary P.b, Mostaghimi P.,Mosavat N.

Journal: Fuel

Abstract: In Chemical Enhanced Oil Recovery (CEOR), various chemicals such as polymer, surfactant, alkaline, and nanoparticles are injected solely or in combination to mobilize the remaining oil. Wettability alteration, interfacial tension reduction, modification of mobility ratio, stabilizing the injection fluid, degradation, swelling, adsorption, channel blockage, plugging, fluid diversion, and emulsification are the most important phenomena. Microfluidic chips are the best tools to mimic and visualize these microscale processes. Therefore, there are vast potentials for microfluidics to shed light on the micro-scale aspect of

CEOR. In this paper, the aim is to collect, analyze, and correlate the current knowledge and efforts and review them critically while discussing potential improvements for future research in the field of microfluidic for CEOR processes. There are certain limitations to the conventional CEOR experimentation, which can be addressed using microfluidic methods for fast, accurate, and reliable analyses. The versatility of the lab-on-a-chip devices and methods can assist users to simulate different heterogeneity and mineralogy patterns, apply automated image analysis through implementing machine learning algorithms, employing molecular tagging to locate and track the injection fluid front and various fluids or solids, and use multi-dimension chips to perform more realistic testing leading to better understating of fluid flow and the associated mechanisms in porous media.

Title: Oil shale in-situ upgrading with natural clay-based catalysts: Enhancement of oil yield and quality

Publication date: 2022

Authors: Song, R., Meng, X., Yu, C., Bian, J., and Su, J.

Journal: Fuel

Abstract: Abundant oil shale reserves in China provide great potential for solving the energy crisis and increasing the energy supply. Natural clay-based catalysts were prepared for oil shale in-situ upgrading, and the catalytic behavior was thoroughly investigated. Through the exploration of the hydrocarbon yield in the oil shale catalytic conversion products, the best catalyst was selected as SO3H-APG that was prepared by facile ball-milling of a natural clay, attapulgite, and 3-mercaptopropyltrimethoxysilane (MPTMS) and followed H2O2 oxidation. The highest oil generation ability of SO3H-APG was obtained when the –SO3H dosage was 4 mmol/g and the acid amount was 1.52 mmol/g. The oil yield reached 54.93%. The apparent activation energy Ea of oil shale pyrolysis on SO3H-APG catalyst was 61.43 kJ · mol−1, which was roughly 44 kJ · mol−1 lower than thermal cracking. In the catalytic conversion reaction of oil shale, this type of clay-based catalyst also showed good hydrocarbon generation ability and stability due to its abundant acid sites. The complexity of the catalytic conversion products was reduced, and the carbon number distribution was mainly concentrated between C6-C14. There was no compound of the boiling point above 300 °C detected in liquid products, mainly concentrated between 140 and 280 °C, and moved toward a lower boiling point. Compared with noncatalytic shale oil, the SO3H-APG catalyst enhanced the hydrocarbon yield in the product from 57.01% to 70.30%, reduced oxygen-containing compounds and nitrogen-containing substances to 22.16% and 5.54%, respectively. Meanwhile, under

the action of SO3H-APG catalytic decarboxylation, the H/C ratio of shale oil inclined to 1.78, the O/C ratio dropped to about 0.03, and the HHV value of shale oil generated by the catalytic conversion reached 45.24 MJ/kg. The development of SO3H-APG catalysts provided a promising approach to enhance the oil recovery and process feasibility for oil shale in-situ catalytic upgrading.

Title: Enhancing oil recovery by electric current impulses well treatment: A case of marginal field from Oman

Publication date: 2022

Authors: Rudyk, S., Taura, U., and Al-Jahwary, M.

Journal: Fuel

Abstract: Electro-enhanced oil recovery (EEOR) methods have the smallest carbon footprint, among which the electric current impulses method is the most economic. Its performance requires minimal surface facilities, no auxiliary equipment, downhole tools or hazardous materials. Stopping oil production or pulling the tubing out of the well for placing the downhole tools are not required either. The period of treatment session is short (12–24 h). The electricity consumption of 150–200 kW is lower than for any other methods. Prior to the abandonment of an oil field in Oman, treatment with the electric current impulses was applied to marginal wells to clean up the near borehole zone and improve well production characteristics. 7 wells were treated in pairs as cathode and anode in two successive electrical treatments, which were carried out with a difference of 4 months. In the period after the second electrical treatment, only five wells were in operation. Two of them, wells 5 and 12 were treated in both electrical treatments. The results of electrical treatments were thoroughly analysed due to the overlap of simultaneous operations that could mask the effect of electrical treatment. The incremental oil production compared to the forecast was evaluated using reservoir simulation and decline curve analysis. In wells after the second electrical treatment, the increase in oil production rate (OPR) by 36% was in Well 5 and by 25% in Well 1. There was no noticeable effect in Well 12, probably because it was located at the very edge of the reservoir structure. The effect of electrical treatment was also observed in untreated nearby wells. An increase of 11% in OPR was observed in Well 23 and 64% in Well 7. The effect of the electrical treatment was also observed in the form of heavy oil and wax flowing in slugs from three treated wells, which increased the total consumption of demulsifier from 12 to 20 L per day. It has been demonstrated that this method has great potential for cleaning the near wellbore space and increasing oil production.

Title: Microfluidics experimental investigation of the mechanisms of enhanced oil recovery by low salinity water flooding in fractured porous media.

Publication date: 2022

Authors: Mahmoudzadeh, A., Fatemi, M., and Masihi, M.

Journal: Fuel

Abstract: Spontaneous imbibition of water from fracture into the matrix is considered as one of the most important recovery mechanisms in the fractured porous media. However, water cannot spontaneously imbibe into the oil-wet rocks and as a result oil won't be produced, unless the capillary pressure barrier between fracture conduits and matrix is overcome. Wettability alteration is known as the main affecting mechanism for low salinity water flooding (LSWF), however, its effectiveness in fractured porous media has been less investigated, especially in the case of possible pore scale displacement mechanisms. In this study, the effectiveness of LSWF (diluted seawater) on oil recovery is compared to the formation water (FW) and seawater (SW) in four different fractured models. Each of these fractured models is representing a different sub scale of the NFR. In addition to the effect of fracture geometry, the effect of wetting conditions was studied. Contact angles, Interfacial Tension (IFT) and zeta potentials are measured to have more insight on the Crude-oil/Brine/Rock system under investigation. The results of micromodel experiments show a positive effect of LSWF in both water-wet and oil-wet states. Sessile drop and pendant drop tests show that contact angle alteration and IFT reduction cannot be the dominant mechanisms. Visual investigations on dynamic displacement tests, suggest that the formation of micro-emulsions and elastic oil/water interface are the main mechanisms of recovery in the case of LS and FW injections, respectively. Elastic FW/oil interface causes discontinuous water phase in the fracture, which in turn reduces the mobility of the FW in the fracture and facilitates the diversion of the flow from fracture towards the matrix. This mechanism results in better sweep efficiency for the case of FW compared to the case of SW. Nevertheless, the dominant formation of microemulsion in the case of LSW is more effective in the diversion of the flow from fracture into the matrix (compared to the effect of interface elasticity in the case of FW). This mechanism along with slightly better imbibition (less oil-wet state) in the case of LSWF enhances its recovery performance compared to the FW in both water-wet and oil-wet systems.

Title: Synergistic effects of AlOOH and sodium benzenesulfonate on the generation of Pickering emulsions and their application for enhanced oil recovery.

Publication date: 2022

Authors: Jia, H., He, J., Xu, Y., Wang, T., Zhang, L., Wang, B., Jiang, X., Li, X., Zhang, X., and Lv, K.

Journal: Colloids Surf. Physicochem. Eng. Aspects.

Abstract: The surfactant assisted nanoparticle stabilized emulsions exhibit the wide potential application and attract more and more attention. In the present study, the flake-like hydrophilic AlOOH nanoparticles were employed to stabilize Pickering emulsions with the assist of slightly amphiphilic sodium benzenesulfonate (SBS) molecules. The measurements of FTIR spectra, three-phase contact angle, zeta potential and Z-average diameter adequately testified the successful adsorption of SBS on AlOOH nanoparticles. Both slightly amphiphilic SBS and highly hydrophilic AlOOH nanoparticles could hardly stabilize emulsions, whereas the SBS modified AlOOH nanoparticles exhibited distinguished emulsifying capacity, which was reflected via the Turbiscan Stability Index and the reference values of backscattered light intensity. Batch adsorption experiments were conducted and the adsorption data was better fitted to the Langmuir model, suggesting that SBS could form monolayer adsorption on AlOOH nanoparticles. Confocal laser scanning microscopy and rheological measurements demonstrated that the functionalized AlOOH nanoparticles could spontaneously adsorb at the oil/water interface to form an interfacial film and generate a three-dimensional network structure in the continuous phase to effectively prevent droplet coalescence in normal and harsh conditions. Furthermore, SBS/AlOOH stabilized O/W emulsions presented significant displacement performance (tertiary oil recovery of 18.87%) in core flooding experiments. Microscopic visualization tests showed that the emulsions could block high permeability channels and enlarge the sweep area. This study opens up the possibility of adopting low surface-active molecules and hydrophilic nanoparticles to stabilize Pickering emulsions for enhanced oil recovery (EOR).

Title: Enhanced oil recovery and CO2 sequestration potential of Bi-polymer polyvinylpyrrolidone-polyvinyl alcohol.

Publication date: 2022

Authors: Sharma, T., Joshi, A., Jain, A., and Chaturvedi, K. R.

Journal: Journal of Petroleum Science and Engineering.

Abstract: In this study, the efficacy of blend, of polyvinyl alcohol (PVA) and polyvinylpyrrolidone (PVP), was explored for enhanced CO2 absorption and thereafter, used polymer enhanced carbonated fluid for flow behaviour and oil recovery from synthetic porous media of sand, prepared by wet-ramming of sand in sand-pack. Initially, PVA-PVP blends of varying wt% (2–5 wt% PVA and 1–3 wt% PVP) were formulated and their stability along with potential for CO2 absorption were investigated via viscosity measurements and thermogravimetric analysis over varying pressure, temperature, and saline conditions. Thermal stability results indicated that the performance of PVA-PVP solutions was better (than pure PVA solution) even at 150 °C. Comparative viscosity tests indicated that the impact of adverse conditions was least on PVA-PVP solutions consequently, these solutions proved to be excellent CO2 carrier fluid after CO2 solvation experiments in an equilibrium cell. Rheological results indicate strong interactions between PVA and PVP which was understood by the formation of new bonds in solution causing an increase in the viscosity and solid like nature of solution. Finally, these solutions were used as EOR agents for oil recovery from a porous media. The oil recovery tests were performed at a temperature of 40 °C and reservoir salinity of 4 wt% NaCl and these results indicated that PVA-PVP solutions displayed enhanced oil mobilization in these conditions. As a result, oil recovery improved by 12–18% original oil in place (OOIP). Thus, based on the results of this study, it can be anticipated that newer polymer composites of PVA-PVP exhibited better synergy with CO2 and act as CO2 carrier fluid for improved oil recovery and enhanced carbon storage. In addition, they are viable candidates for use in elevated temperature and saline conditions of oil reservoirs.

Title: Stable foam systems for improving oil recovery under high-temperature and high-salt reservoir conditions.

Publication date: 2022

Authors: He, G., Li, H., Guo, C., Liao, J., Deng, J., Liu, S., and Dong, H.

Journal: Journal of Petroleum Science and Engineering.

Abstract: Foams have high apparent viscosity when flowing in porous media, therefore foam flooding could significantly improve unfavorable mobility ratios, increase sweep efficiency, and enhance oil recovery. However, the applications of foam flooding in high-temperature and high-salt reservoirs are seriously restricted as foam systems often have inferior foamability and stability in these reservoirs. In this study, to improve foam flooding effectiveness in high-temperature and high-salt reservoirs, novel foam systems with excellent stability and plugging capacity are developed by combining surfactants, additives, and polymers. The performance of bulk foam, physical properties of the solutions, and properties of foam systems in core-flow experiments are investigated to determine the synergistic effects among the components of the foam systems and their foamability and plugging effect in cores. In foam systems with sodium alcohol ether sulfate (AES) and dodecylhydroxypropyl sulfobetaine (DHSB) as surfactants, and dodecanol as additive, the combination of the components makes surface tension decreased and surface dilatational modulus increased, therefore the foamability and stability of the systems are improved. The results of core-flow experiments under high-temperature and high-salt conditions show that these combined systems require low injection rate for foam generation in reservoirs, which is beneficial for foam regeneration in reservoirs. Moreover, to further improve the foam performance, a hydrophobically associating water-soluble polymer (HAWP) is employed. The interactions between HAWP and the surfactants reduce the critical association concentration of HAWP, and result in the increase of solution apparent viscosity and foam stability. The results of core-flow experiments under high-temperature and high-salt conditions show that polymer-enhanced foam systems could significantly increase the sealing pressure, widen the sealing permeability range, and deal with the gas-channeling problem of foam flooding. These foam systems could provide a potential technical pathway for improving the effectiveness of foam flooding in high-temperature and high-salt reservoirs.

Title: Sulfonated Graphene Oxide Nanofluid: Potential Applications for Enhanced Oil Recovery.

Publication date: 2021

Authors: Arenas-Blanco, B. A., Pérez-Rodríguez, E. M., Hernández, R. C., Santos-Santos, N., and Mejía-Ospino, E.

Journal: Energy and Fuels.

Abstract: Graphene oxide (GO)-based materials have been extensively evaluated in emulsification processes due to their amphiphilic properties, thermal stability, and high reactivity that allow for chemical functionalization with polymers, nanoparticles, and organic compounds, which can modify physicochemical properties and improve the recovery of crude oil. In this work, the effect of a sulfonated graphene oxide (SGO) nanofluid on interfacial properties in a light and medium crude oil–water system was evaluated. GO sulfonation was performed by amidation reactions with carboxyl groups present in GO flakes. GO and SGO were characterized by infrared spectroscopy (FTIR), Raman spectroscopy, X-ray photoelectronic spectrometry (XPS), and scanning electron microscopy (SEM). The thermal stability of GO and SGO was evaluated by thermogravimetry technique (TGA). The interfacial activity of SGO was evaluated by interfacial tension measurements performed by the pendant drop method, and the stability of emulsions was analyzed by ζ potential measurements. Results show that the sulfonation process

improves the surfactant effect of GO, decreases the IFT up to a 93% for the light-crude-oil/water system at low concentrations of nanofluid, and can improve the thermal stability with respect to GO in a wide range of temperatures, favoring the formation of stable emulsions.

Title: Oxidation of Heavy Oil Using Oil-Dispersed Transition Metal Acetylacetonate Catalysts for Enhanced Oil Recovery.

Publication date: 2021

Authors: Babapour Golafshani, M., Varfolomeev, M. A., Mehrabi-Kalajahi, S., Rodionov, N. O., Tahay, P., Zinnatullin, A. L., Emelianov, D. A., Vagizov, F. G., Sadikov, K. G., and Osin, Y. N.

Journal: Energy and Fuels.

Abstract: In this work, several transition metal-based acetylacetonates (Ni, Cu, and Fe) were prepared as oil-dispersed catalysts for heavy oil oxidation. X-ray diffraction (XRD), scanning electron microscopy (SEM), and Mössbauer spectroscopy were used for the characterization of catalysts. The effectivity of catalysts in the oxidation of heavy oil was investigated by a thermogravimetry method coupled with infrared spectroscopy (TG-FTIR) at four different heating rates (4, 6, 8, and 10 °C/min) and self-designed porous medium thermo-effect cell (PMTEC) techniques. The activation energy calculations using three isoconversional methods, Ozawa–Flynn–Wall (OFW), Kissinger–Akahira–Sunose (KAS), and Friedman, were performed based on thermal analysis data. The results showed that the bidentate ligand acetylacetonate (acac) provided good enough distribution of catalysts in heavy oil because in the presence of Cu(acac)2, Fe(acac)3, and Ni(acac)2, the oxidation temperature decreased in both fuel deposition (FD) and high-temperature oxidation (HTO). The activation energy of FD and HTO districts showed that Cu(acac)2 more efficiently catalyzed the oxidation of heavy oil than Fe(acac)3 and Ni(acac)2. The usage of Cu(acac)2 helped decrease the average activation energy of the in situ combustion process from 177 to 117 kJ/mol, from 187 to 127 kJ/mol, and from 198 to 128 kJ/mol based on OFW, KAS, and Friedman methods, respectively. The in situ transformation of the catalysts in the presence of heavy oil was studied under different isothermal conditions. Based on XRD and SEM data at 400 °C, Cu(acac)2 and Ni(acac)2 were transformed to CuO and NiO nanoparticles as the active form of catalysts. For Fe(acac)3, it was found that at 400 °C, it transformed to magnetite (Fe3O4) species; however, at 500 °C, hematite (α-Fe2O3) and maghemite (γ-Fe2O3) were the most predominant species. The heavy oil oxidation using these low-cost and easy to prepare catalysts could be the best route for improving the efficiency of in situ combustion in field applications.

Title: Insights into the Intimate Link between the Surfactant/Oil/Water Phase Behavior and the Successful Design of (Alkali)–Surfactant–Polymer Floods.

Publication date: 2021

Authors: Molinier, V., Klimenko, A., Passade-Boupat, N., and Bourrel, M.

Journal: Energy and Fuels.

Abstract: Formulating alkali-surfactant-polymer (ASP) solutions for chemical enhanced oil recovery (EOR) requires detailed phase behavior investigation, especially with some “difficult” crude oils of medium acidity, for which special attention must be paid to the surfactants and alkali selection. In this work, the efficiencies of eight corefloods performed on a real case study in (A)SP conditions have been related to the phase behavior of the surfactant/crude oil/water (SOW) systems investigated as a function of salinity, water-to-oil ratio (WOR), surfactant concentration, and alkali type. We show that the variation of the extent of the ultralow interfacial tension domain with WOR must be considered when designing the salinity gradient, especially when alkali is used. The precise salinity of the (A)SP slug is not a key parameter as far as the salinity of the water in place corresponds to type II systems and the salinity of the subsequent P slug corresponds to type I systems. The effect of the consumption of alkali during propagation in the coreflood is particularly sensitive for sodium carbonate, as compared to ammonia; therefore, this latter alkali should be preferred. Finally, the development of alkali-free surfactant formulations appears to be the most robust alternative and proved to be efficient on both sandstone and limestone, with a limited adsorption. The findings of this study are of practical interest for deploying chemical EOR on the field, particularly to overcome issues of salinity source availability.

Title: Molecular dynamics simulation of nanocellulose-oil-water interaction in enhanced oil recovery application.

Publication date: 2020

Authors: Ledyastuti, M., and Jason, J.

Journal: in: IOP Conference Series: Materials Science and Engineering.

Abstract: Enhanced Oil Recovery (EOR) is a way to obtain long hydrocarbon-structured oil by flooding oil reservoirs using water with certain materials. Hydrolyzed polyacrylamides (HPAM) and xanthan gum are commonly used in the EOR process. Both of these materials have several disadvantages, including

unstable at high salinity and leave debris in the environment. One alternative to substitute HPAM and xanthan gum is nanocellulose, which is an abundant amount of natural polymer. Molecular dynamics simulations investigate the potential of nanocellulose as an EOR agent. A mixture of decane and naphthalene is used as an oil model, while the SPC/E model is used as a water model. By analyzing the simulation trajectory, the interfacial tension and viscosity values were obtained. The simulation results showed the value of the water-oil interfacial tension increased with the addition of nanocellulose. This was caused by the position of nanocellulose that was always in the aqueous phase during the simulation. The water-oil interfacial tension also increased from 46.94 dyne/cm to 47.96 dyne/cm with the presence of two nanocellulose molecules at 353 K. Water viscosity increased from 3.10×10-4 kg/m.s to 3.80×10-4 kg/m.s after the addition of one cellulose molecule at 353 K. Nanocellulose can be an EOR agent by increasing the water viscosity but unfortunately the water-oil interfacial tension also increasing. Due to the change of these two opposing properties, nanocellulose cannot optimally improve oil recovery as shown by previous research.

Title: Utilization of Janus-silica/surfactant nanofluid without ultra-low interfacial tension for improving oil recovery.

Publication date: 2020

Authors: Liu, P., Yu, H., Niu, L., Ni, D., Zhao, Q., Li, X., and Zhang, Z.

Journal: Chemical Engineering Science.

Abstract: Janus nanoparticles with amphiphilic surfaces could be of particular significance for enhanced oil recovery (EOR) of reservoirs. However, currently available methods for preparing Janus nanoparticles are often complicated. Here we present a highly efficient and easily scalable one-step chemical etching method with NaOH as the etching agent for fabricating amphiphilic Janus-SiO2 nanoparticles. The structure, interfacial behavior and improved oil recovery (IOR) potential of the as-prepared Janus-SiO2 nanoparticles were systematically studied. Results show that Janus-SiO2 nanoparticles with size less than 10 nm exhibit good dispersibility in water and amphiphilicity as well. When combined with various surfactants, they can significantly improve the oil recovery upon simulated water flooding, due to their good abilities to increase the sweep efficiency of surfactants and reduce the interfacial tension of oil–water emulsion. Oil recoveries are improved by 7.4–9.8% with addition of Janus-SiO2 in surfactants compared to pure surfactant solutions, showing promising potential for EOR.

Title: Foam stability using silica coated nanoparticle for enhanced oil recovery.

Publication date: 2020

Authors: Zailan, M. A., Noor, M. Z. M., and Ganat, T. A. O.

Journal: in: IOP Conference Series: Materials Science and Engineering.

Abstract: A mixture of nanoparticles and water can be used in the nano-water alternating gas approach (NWAG) to enhance oil recovery from an oil field. Now, the wettability of rock, relative permeability curves, and the interfacial tension analyzed for improvement of the operation. With an approach application, nanoparticles became importance over the last decade but the activity of using nanoparticles is practically unknown. A major stumbling-block to the success of foam application in EOR is the adverse influence of oil on foam stability. The objectives were to evaluate the effects of various surfactant, nanoparticle concentration as well as hydrocarbons with well-defined properties on foam stability. Orderly, a comprehensive series of experiments at static state is conducted to investigate the foam stability of five different concentrations for surfactant and nanoparticle respectively in the absence and presence of mineral oil and synthetic brine suspension. The results suggested that there is a significant impact of the concentration of the surfactant and nanoparticle on foam stability. Besides, results suggested that less stable foam is shown in the presence of oil as compare to brine solution. The addition of half life method shows the promising result on the use of nanoparticles as foam stabilizer.

Title: Enhanced oil recovery by wettability alteration using iron oxide nanoparticles covered with PVP or SDS.

Publication date: 2020

Authors: Shalbafan, M., Esmaeilzadeh, F., and Vakili-Nezhaad, G. R.

Journal: Colloids Surf. Physicochem. Eng. Aspects.

Abstract: Wetting phenomena have been extensively investigated in treatment of rocks surface in oil reservoirs using nanofluids for enhanced oil recovery (EOR) purposes. Nanoparticles (NPs) have shown their potential in EOR through surface modification, which results in wettability alteration. In our previous study, the synthesized Fe_3O_4 NPs coated with Ethylenediaminetetraacetic (EDTA) or Sodium Lauryl Sulfate (SLS) showed good results for wettability alteration phenomenon resulting in EOR. In the present study, the same synthesized iron oxide NPs have been covered with new agents of Polyvinylpyrrilidone

(PVP) as a hydrophilic polymer or Sodium Dodecyl Sulfate (SDS) as an ionic surfactant using the same experimental technique as before. Full characterization of the modified NPs has been carried out using Field Emission Scanning Electron Microscope (FE-SEM), X-ray Diffraction device (XRD), Transmission Electron Microscopy (TEM), Fourier-Transform Infrared spectroscopy (FTIR), and the Vibrating-Sample Magnetometer (VSM) analysis. The Scanning Electron Microscope (SEM) micrographs and FTIR analysis and Zeta-potential measurements on the treated carbonate-rock surface decorated with the NPs showed strong wettability alteration from oil-wet to water-wet. The effect of various parameters including the concentration of the mentioned NPs in water-based nanofluid, exposure time, pH, salinity, temperature and pressure on wettability alteration of oil-wet carbonate-rock surface was comprehensively investigated by contact angle measurements. Additionally, the imbibition tests were conducted to determine the potential of the nanofluids in EOR at core-scale. Moreover, the stability of nanofluids in the absence and presence of salts was assessed with Zeta-potential measurements. Our final results showed that NPs covered with PVP and or SDS resulted in 16 % and 13 % increase in oil recovery compared to brine alone, respectively.

Title: Investigation on in Situ Foam Technology for Enhanced Oil Recovery in Offshore Oilfield.

Publication date: 2019

Authors: Chen, H., Li, Z., Wang, F., and Li, S.

Journal: Energy and Fuels.

Abstract: An in situ CO2 foams (ISCF) formula is presented to investigate its performance in enhancing oil recovery in homogeneous and heterogeneous formations. Surfactant evaluation, sandpack flooding, and microscopic visualization experiments were carried out to determine the biological surfactant for ISCF formula and confirm the feasibility and mechanism in oil recovery improvement. The results showed that biological surfactant A2 had a good foaming performance even in extremely saline solutions of greater than 2.5 × 105 ppm, acid solutions of concentration 20%, and high-temperature environment of 100 °C. The ISCF system had a good recovery efficiency in homogeneous and heterogeneous porous media. The SARA test confirmed the generated CO2 by chemical reaction could extract the heavy components which led to about 8% viscosity reduction, the inner pressure distribution indicated that ISCF had a better further blocking ability than conventional foam, the average diversion ratio curves demonstrated that ISCF system had a distinct effect on conformance control even in the presence of crude oil, the 2D micromodel experiment revealed that the generated foam was uniform and could occupy a wider pore space, and the

permeability variation of produced liquids analysis presented that the even distribution of acid in homogeneous and heterogeneous formations can also contribute to the blockage removal and oil recovery improvement.

Title: Surface-Functionalized Superparamagnetic Nanoparticles (SPNs) for Enhanced Oil Recovery: Effects of Surface Modifiers and Their Architectures.

Publication date: 2019

Authors: Khalil, M., Aulia, G., Budianto, E., Mohamed Jan, B., Habib, S. H., Amir, Z., and Abdul Patah, M.s

Journal: ACS Omega.

Abstract: Superparamagnetic nanoparticles (SPNs) have been considered as one of the most studied nanomaterials for subsurface applications, including in enhanced oil recovery (EOR), due to their unique physicochemical properties. However, a comprehensive understanding of the effect of surface functionalization on the ability of the nanoparticles to improve secondary and tertiary oil recoveries remains unclear. Therefore, investigations on the application of bare and surface-functionalized SPNs in EOR using a sand pack were carried out in this study. Here, the as-prepared SPNs were functionalized using oleic acid (OA) and polyacrylamide (PAM) to obtain several types of nanostructure architectures such as OA-SPN, core-shell SPN@PAM, and SPN-PAM. Based on the result, it is found that both the viscosity and mobility of the nanofluids were significantly affected by not only the concentration of the nanoparticles but also the type and architecture of the surface modifier, which dictated particle hydrophilicity. According to the sand pack tests, the nanofluid containing SPN-PAM was able to recover as much as 19.28% of additional oil in a relatively low concentration (0.9% w/v). The high oil recovery enhancement was presumably due to the ability of suspended SPN-PAM to act as a mobility control and wettability alteration agent and facilitate the formation of a Pickering emulsion and disjoining pressure.

Title: The effect of addition of polymer on viscosity as fluid of industrial oil and gas injection in EOR method.

Publication date: 2019

Authors: Pramadika, H., Samsol, S., and Satiyawira, B.

Journal: Journal of Physics: Conference Series.

Abstract: One EOR injection is polymer injection. In this study we will use FP3300S polymer with a concentration of 500ppm, 750ppm, 1,000ppm, 1,250ppm, 1,500ppm, 1,750ppm, 2,000ppm, 2,250ppm and 2,500ppm. The purpose and objective of this study was to determine the effect of polymer concentration on increasing viscosity, determine the effect of polymer concentration on polymer filtration (compatibility, filtration, screen factor, thermal stability), and to find out how the polymer injection results, the higher the research found. the polymer concentration the higher the viscosity where the highest at the polymer concentration 2,500ppm with 19,38cp, the viscosity required by the polymer as injection liquid is the viscosity of the polymer greater than 2X the viscosity of the oil to be injected, where the oil viscosity is 5,2pp. then while in polymer screening it was found that higher polymer concentrations were not always good for polymer filtration, and polymer injection has been shown to increase recovery factor, recovery factor was obtained at 51.5% water injection and polymer injection was 23.1%, before injection was correct really need to be screened first, to get the most optimal concentration to be injected.

Title: A novel high temperature tolerant and high salinity resistant gemini surfactant for enhanced oil recovery.

Publication date: 2019

Authors: Hou, B., Jia, R., Fu, M., Wang, Y., Ma, C., Jiang, C., and Yang, B.

Journal: Journal of Molecular Liquids.

Abstract: A novel high temperature tolerant, high salinity resistant gemini surfactant for enhanced oil recovery was synthesized and is described in this paper. The molecular structure of the synthesized gemini surfactant (named ANG) was first confirmed by infrared (IR) spectroscopy and nuclear magnetic resonance (NMR). Various experiments were then carried out to investigate both the basic properties and the capacity for enhanced oil recovery of ANG. The surfactant ANG showed excellent surface activity (31.7 mN/m). The product ANG also exhibited better interfacial activity (7.81 × 10− 3 mN/m) than sodium dodecyl benzene sulfonate (SDBS) at 120 °C. Furthermore, an ultralow interfacial tension (8.75 × 10− 3 mN/m) was still achieved for the surfactant ANG when used in a high-salinity environment (total salinity: 20 × 104 mg/L, Ca2+ concentration: 5000 mg/L). The emulsification ability of ANG was stronger than that of TX-100, and the median particle size (d50) of the emulsion droplets for ANG was only 5.05 μm. The surfactant ANG had a strong wetting reversal ability and could change the originally oil-wet surface (135°) into a water-wet surface (balanced contact angle: 62°). The oil recovery was improved by a reduction in the oil-water interfacial tension, wetting reversal of the core surface and the formation of an emulsion by

the synthesized gemini surfactant. Due to the above mechanisms, oil recovery increased by 17.3% of original oil in place (OOIP) for the surfactant ANG.

Title: Novel smart water-based titania nanofluid for enhanced oil recovery.

Publication date: 2019

Authors: Shirazi, M., Kord, S., and Tamsilian, Y.

Journal: Journal of Molecular Liquids.

Abstract: Smart water application in carbonate reservoirs has been recently gained a lot of attention by researchers as a low-cost enhanced oil recovery (EOR) method. In this study, for the first time, the behavior of different smart waters in the absence and presence of TiO_2 nanoparticles (NPs) has been investigated by analyzing their effect on wettability alteration, interfacial tension (IFT) reduction, and oil recovery improvement during the spontaneous imbibition process. The zeta potential analysis of TiO_2 NPs in seawater (SW) shows a detrimental and insufficient effects of divalent cations (Ca^{2+} and Mg^{2+}) and monovalent cations (Na^+ and K^+) on the nanofluid (NF) stability at a pH value higher than its point of zero charge (PZC), respectively, while the detrimental effect of divalent anions (SO_4^{2-}) is observed at pH values lower than PZC. The results of contact angle measurements show a little improvement in the wettability alteration changing from modified SWs (MSWs) to diluted MSWs (dMSWs) and a significant improvement changing from dMSWs to dMSWs-based NF that is observed a diverse behavior for the IFT reduction, emphasizing the significant role of NPs addition to smart waters and decreasing the salinity of smart waters. During the imbibition experiments, the performance of all types of smart waters is drastically increased in the presence of TiO_2 NPs confirming the results of contact angle experiments, occurred by their retention on the rock surface and movement through the porous media depending on the type of ions presented in the smart waters.

Title: Enhanced Oil Recovery by Heavy Oil Emulsified Viscosity System.

Publication date: 2018

Authors: Wang, G., Wang, Y., Li, Y., Shi, J., Rong, X., and Zhang, C.

Journal: Oilfield Chemistry.

Abstract: Aiming at the problem of large viscosity and mining difficulty in Chenjiazhuang heavy oil production in Shengli oilfield, the ability of emulsified viscosity reducer to reduce the interfacial tension between oil and water and the ability to emulsify heavy oil were investigated, including emulsified viscosity reducer SS(anionic olefin sulfonates), SD(Anionic alkane sulfonates), nonionic emulsification viscosity reducer SF, SS+SF(mass ratio 1: 1)and SD+SF(mass ratio 1: 1)compound system. The microscopic experiments were conducted using SS, SD, SF and SS+SF systems. the experimental results showed that under the condition of mass concentration of 0.4% and temperature of 25℃, the interfacial tension between the simulated heavy oil and the emulsification viscosity reducer SD or SS system was 1.87×10 -2 mN/m and 1.21×10 -2 mN/m, respectively, the viscosity of the emulsion formed with heavy oil, whose viscosity was 187 mPa•s, in mass ratio of 3: 7 was 42 mPa•s and 46 mPa•s, respectively. In the microscopic oil displacement process, the enhanced oil recovery rates of SD and SS anionic emulsification viscosity reducers system were 56.75% and 61.93%, respectively. Under the same conditions, the interfacial activity and ability to enhance oil recovery of SS+SF system was superior to that of the single component, the interfacial tension was reduced to 1×10 -4 mN/m or less, the viscosity of the emulsion with heavy oil was 30 mPa•s, and compared with the SF emulsifying viscosity reducing agent system, the recovery rate was enhanced by 14.9%. The emulsion viscosity reducing agent SS + SF was expected to be used as oil displacement agent in ordinary heavy oil field.

Title: Demulsification of Crude Oil in Water (O/W) Emulsions using Graphene Oxide.

Publication date: 2018

Authors: Othman, N. H., Jahari, A. F., Alias, N. H., Jarni, H. H., Shahruddin, M. Z., Irfan, M. F., Dollah, and Halim, N. H.

Journal: IOP Conference Series: Materials Science and Engineering.

Abstract: Implementation of nanotechnology in oil and gas industries, particularly for enhanced oil recovery (EOR) has recently gained interest. In this work, graphene oxide (GO) has been synthesized and used as nano-demulsifier for crude oil in water (O/W) emulsions. GO was synthesized by using modified Hummers' method and characterized using X-Ray diffractometer (XRD) and Fourier Transform Infrared (FTIR) spectroscopy. Subsequently, the nano-demulsifier's performances were tested to Field D crude oil-water emulsions by varying nano-demulsifier concentrations and contact time. The performances of GO for demulsication of crude oil-in-water emulsions were then determined by measuring the oil contents in water using a UV-Vis spectrophotometer. Demulsification tests indicated that the optimum GO concentration was around 20-40 ppm, while the optimum contact time was 30 min. The residual oil

content in the separated water was as low as 100 ppm. This might be due to the amphiphilic properties of GO. It indicates that the GO is a promising demulsifier and by further understanding the intrinsic interaction between GO and crude oil, the performances of GO can be easily tailored in the future.

Title: Development of the research on EOR for carbonate fractured-vuggy reservoirs in China. Zhongguo Shiyou Daxue Xuebao (Ziran Kexue Ban)

Publication date: 2018

Authors: Dai, C., Fang, J., Jiao, B., He, L., and He, X.

Journal: Journal of China University of Petroleum**.**

Abstract: Around the key problems of enhanced oil recovery (EOR) for carbonate fractured-vuggy reservoirs in China, this paper summarizes the research progress of four aspects of reservoir description, physical simulation, distribution of residual oil and EOR method, discusses and prospects the development of EOR technology for carbonate fractured-vuggy reservoirs in the future. The fine description of fractured-vuggy reservoir is the research basis of the EOR method, which is also the fundamental of the similarity physical simulation. The residual oil of fractured-vuggy reservoir is mainly distributed in the high part of the reservoir structure and the shielding area of the poor connectivity among fractured-vuggy reservoir structure. Currently the method of EOR is relatively simple, which mainly relies on gas injection to replace the crude oil at high position of reservoir structure. In the future, the development of EOR method for carbonate fractured-vuggy reservoir in China lies in the 2 aspects of the fine geological description, which is combined with reservoir exploration and 3D simulation, and the realization of equilibrium displacement in fractured-vuggy reservoir. The equidensity liquid and channel flow control technology are the two potential research directions.

Title: Enhanced Oil Recovery Potential of Alkyl Alcohol Polyoxyethylene Ether Sulfonate Surfactants in High-Temperature and High-Salinity Reservoirs.

Publication date: 2018

Authors: Liu, R., Du, D. -., Pu, W. -., Zhang, J., and Fan, X.

Journal: Energy and Fuels.

Abstract: Surfactant flooding has been widely applied in high-temperature and high-salinity reservoirs. In this paper, the enhanced oil recovery potential of alkyl alcohol polyoxyethylene ether sulfonate (CEOS)

was investigated in a combined study of surface activity, crude oil-water interfacial tension (IFT) reduction, emulsifying property, wettability improvement, and macroscopic oil displacement efficiency. The results illustrated that CEOS had high surface activity and IFT could be reduced to an ultralow level (10 -3 mN/m) at high-temperature and high-salinity conditions. When salinity ranged from 15 × 10 4 to 22.5 × 10 4 mg/L and reservoir permeability was ~10 mD, linear CEOS solution could effectively displace crude oil for its favorable IFT reduction ability. Linear CEOS or CEOS with a benzene ring was optimized for their favorable IFT reduction ability or emulsifying ability when reservoir permeability was ~50 mD or non-homogeneous. A 0.5 pore volume surfactant flooding and subsequent water flooding could remarkably enhance oil recovery to 16.19-19.38%. All of the results indicated that CEOS has great potential for improving oil recovery in high-temperature and high-salinity oil reservoirs.

Title: Insights into the Pore-Scale Mechanism for the Low-Salinity Effect: Implications for Enhanced Oil Recovery.

Publication date: 2018

Authors: Liu, Z. L., Rios-Carvajal, T., Andersson, M. P., Ceccato, M., Stipp, S. L. S., and Hassenkam, T.

Journal: Energy and Fuels.

Abstract: The properties and behavior of the interface between mineral surfaces, adsorbed organic compounds, and water are important for oil recovery. Low-salinity (LS) water flooding releases more oil from sandstone reservoirs than conventional flooding with seawater or formation water. However, the role of strongly adsorbed organic material, as an anchor for oil molecules, is not yet completely understood. Here, we mimic reservoir pore surfaces using graphene oxide sheets deposited on flat silicon wafers. The LS response was quantified using atomic force microscopy (AFM) in chemical force mapping mode to directly measure the adhesion force. AFM tips were functionalized to serve as models for hydrophobic and polar oil molecules, i.e., with alkyl, -CH 3 , and carboxyl, -COO(H). Adhesion force, measured with -CH 3 tips, was 18% lower in LS (~1500 ppm) than high-salinity (HS, ~35 600 ppm) solutions, while for -COO(H) tips, adhesion force was 13% lower in LS than HS solutions. The Dejarguin-Landau-Verwey-Overbeek theory predicts that the difference in response to the salinity-dependent force with the -CH 3 tips results from electric double layer (EDL) repulsion. The response to -COO(H) tips can be explained by combined EDL repulsion and cation bridging, which is consistent with density functional theory calculations. The absolute adhesion and the level of response agree with observations on sand grains from oil reservoirs, where other studies have demonstrated strongly bound organic compounds. Important implications of our study are that (i) oxidized graphene provides a convincing model for reservoir pore surfaces that is robust and reproducible and can be used for systematic testing for developing more effective enhanced oil recovery strategies and (ii) the new fundamental understanding about pore surfaces can also be applied over a range of disciplines, including improved remediation strategies for contaminated soil and groundwater.

Title: Effective Use of Technology Research and Application of Supercritical Steam on Deep Super-heavy Oil in Lukeqin Oilfield.

Publication date: 2017

Authors: Yin, Q., Huo, H., Huang, P., Wang, C., Wu, D., and Luo, Z.

Journal: Oilfield Chemistry.

Abstract: Due to the characteristics of great burial depth, high viscosity and high formation pressure with Wutong formation heavy oil reservoir in the east of Lukeqin oilfield, the conventional steam boiler had low efficiency because of difficult injection. In view of the outstanding production contradiction, supercritical steam soaking technology was put forward to increase production. The characteristics of supercritical steam were studied by physical simulation and numerical simulation, and the mechanism of enhanced recovery of crude oil by supercritical steam was analyzed. Through the establishment of supercritical steam injection parameter calculation model, the injection parameters were optimized and the parameters along flow was simulated. Finally, a pilot test in Lukeqin oilfield was carried out. The results showed that supercritical steam had the features of high solubility, high diffusivity and high reaction. The enhancement effect produced in the development of deep heavy oil was different from that of ordinary hot fluid. Under the condition of 35 MPa, 400℃ and 3.5 PV injection volume, the displacement efficiency of supercritical steam was above 90%. The optimum injection parameters of supercritical steam were obtained by calculation: >375℃ steam injection temperature, 5.4-9 t/h steam injection capacity, 3600t steam injection scale in the early three rounds, 27 MPa steam injection pressure at wellhead and 3-4 days soak time. By introducing a 35 MPa supercritical pressure steam boiler and wellhead equipment, 3 wells in 9 rounds of steam soaking tests were successfully implemented with 4000 tons cumulative oil, showing obvious oil increment. The supercritical steam soaking technology could be used for the development of deep ultra heavy oil in the east of Lukeqin oilfield.

Title: Pore Scale Visualization of Low Salinity Water Flooding as an Enhanced Oil Recovery Method.

Publication date: 2017

Authors: Amirian, T., Haghighi, M., and Mostaghimi, P.

Journal: Energy and Fuels.

Abstract: The controlling mechanisms behind low salinity water flooding (LSWF) as an Enhanced Oil Recovery (EOR) method are not well understood. So far, a limited number of researchers have tried to provide visual and direct evidence of the underlying mechanisms behind the LS effect. In this paper, to investigate the dynamics of displacement throughout LSWF, clean and clay-coated two-dimensional glass micromodels were used, with the wettability status set at both water-wet and oil-wet conditions. Hence, pore-scale displacement mechanisms in the presence and absence of clay, as well as in the drainage and imbibition-dominated two-phase flow, were studied. In water-wet systems, in the absence and presence of clays, LSW hindered "snap-off" perhaps due to the development of a viscoelastic water-oil interface. The wettability alteration toward more water wetness was observed for oil-wet systems. The observations are discussed in terms of the expansion of the Electrical Double Layer (EDL). Fines migration played an insignificant role in our observations.

Title: Development of in Situ CO2 Generation Formulations for Enhanced Oil Recovery.

Publication date: 2017

Authors: Wang, S., Kadhum, M. J., Chen, C., Shiau, B., and Harwell, J. H.

Journal: Energy and Fuels.

Abstract: The carbon dioxide flooding of oil reservoirs represents one of the most-proven tertiary oil recovery practices. However, there are significant challenges associated with applying CO2 flooding in certain onshore or offshore fields and applications. The common challenges include a limited supply of CO2, transportation, capital cost investment, and corrosion. For offshore flooding, the critical challenge could be more related to extreme remote and significant project cost increase. In this work, we investigated delivering CO2 indirectly to the subsurface formation by injecting the concentrated solution of ammonium carbamate (AC) as CO2 generated species. Ammonium carbamate, a highly water soluble solid (40 wt %) and commercially available, can be dissolved in aqueous solution and injected to the reservoir where it decomposes at reservoir condition, thus releasing products of CO2 and ammonia. The produced CO_2 results in lowering oil viscosity and oil swelling. Increase of ammonia concentration also lead to sand wettability reversal due to elevated alkalinity. Tertiary oil recovery performance of ammonium carbamate solution was evaluated by conducting multiple sand packs and core flooding test at various pressure and temperature conditions. Dodecane and several dead crude oils were used as oil phase. Injected AC concentrations tested were ranging from 5 to 35 wt %, with operational pressure, pressure (P) ranging from atmospheric to 4000 psi, and the preset temperature ranging from 96 to 133 °C. The average tertiary recovery observed from all the tests was found to be 29%. Results of laboratory experiments clearly demonstrated the potentials of this novel formulation for tertiary oil recovery. Mainly, it requires minimal capital investment up-front in comparison to CO_2 flooding and largely eliminates the occurrence of gravity segregation and reduces adverse fingering behaviors because there is no presence of a free-CO_2 phase involved. This endeavor serves as a successful proof of concept for the potential applications in tertiary oil recovery for both onshore and offshore fields.

Title: Application of Bacillus spp. in Pilot Test of Microbial Huff and Puff to Improve Heavy Oil Recovery.

Publication date: 2017

Authors: Sun, S., Luo, Y., Zhou, Y., Xiao, M., Zhang, Z., Hou, J., Wei, X., Xu, Q., Sha, T., Dong, H., Song, H., and Zhang, Z.

Journal: Energy and Fuels.

Abstract: Microbial metabolic products, such as biosurfactants, bioemulsifiers, acids, solvents, and biogases, are useful for reducing the viscosity of heavy oils and enhancing oil recovery. Two heavy oil viscosity-reducing microorganisms, namely, SH-2 and SH-3, were selected from produced water which were collected from high-temperature reservoirs by enrichment culture technique. The screened bacteria produce biosurfactants and biogases that can biodegrade heavy crude oil components. The screened bacteria combined with indigenous bacteria were applied in a pilot test of microbial huff and puff. Temperature, porosity, and permeability of the reservoir were 50 °C, 14.32%, and 22 mD, respectively. After microbial treatment, the 50 °C degassing for crude oil viscosity of the produced oil was decreased from 750 to 634 mPa·s. Moreover, wax and resin-asphaltene contents of produced oil were reduced by 12.3% and 16.9%, respectively. The average oil production was improved from 2.2 to 3.5 t/day after microbial treatment. The production remained stable without the chemical viscosity reducer for 54 days. The analysis of bacterial community structure indicated that the number of bacteria species increased and that the microbial diversity was highly abundant. However, harmful microorganisms for microbeenhanced oil recovery, such as sulfate-reducing bacteria, are inhibited during the progress of microbial huff and puff.

Title: Experimental Study on Low Interfacial Tension Foam for Enhanced Oil Recovery in High-Temperature and High-Salinity Reservoirs.

Publication date: 2017

Authors: Tao, J., Dai, C., Kang, W., Zhao, G., Liu, Y., Fang, J., Gao, M., and You, Q.

Journal: Energy and Fuels.

Abstract: Foam flooding is an important method to enhance oil recovery after water flooding. In this paper, a novel low interfacial tension (LIFT) nitrogen foam was successfully prepared by an amphoteric surfactant and sodium formate. It has good foaming ability and can reduce interfacial tension to a low interfacial tension level (10-1 mN/m order of magnitude) in high-temperature (90 °C) and high-salinity (183 g/L salinity) reservoirs. The influence of surfactant concentration, organic bases concentration, and aging on the performances of the LIFT foam system has been systematically studied through the modified Ross-Miles experiment. Furthermore, the foam displacement in flat-panel sand model and etched-glass micromodels were conducted to investigate the foam displacement mechanisms for enhanced oil recovery. The results of flat-panel sand model experiment showed that the LIFT foam could block high permeability channels and divert following injection fluid to adjacent low permeability areas efficiently. Meanwhile, with the injection of the LIFT foam, the injection pressure of the whole model continued to increase, and the pressure distribution was more uniform. The etched-glass micromodels experiment results showed that the LIFT foam could block the high permeability channels and improve sweep efficiency. Furthermore, comparing with the common foam, the LIFT foam could emulsify oil and strip oil film from model surfaces more easily. So it could enhance the oil recovery more efficiently.

Title: Chemical force microscopy study on the interactions of COOH functional groups with kaolinite surfaces: Implications for enhanced oil recovery.

Publication date: 2017

Authors: Santha, N., Cubillas, P., Saw, A., Brooksbank, H., and Greenwell, H. C.

Journal: Minerals.

Abstract: Clay–oil interactions play a critical role in determining the wettability of sandstone oil reservoirs, which, in turn, governs the effectiveness of enhanced oil recovery methods. In this study, we have measured the adhesion between –COOH functional groups and the siloxane and aluminol faces of kaolinite clay minerals by means of chemical force microscopy as a function of pH, salinity (from 0.001 M to 1 M) and cation identity (Na+ vs. Ca2+). Results from measurements on the siloxane face show that Ca2+ displays a reverse low-salinity effect (adhesion decreasing at higher concentrations) at pH 5.5, and a low salinity effect at pH 8. At a constant Ca2+ concentration of 0.001 M, however, an increase in pH leads to larger adhesion. In contrast, a variation in the Na+ concentration showed less effect in varying the adhesion of –COOH groups to the siloxane face. Measurements on the aluminol face showed a reverse low-salinity effect at pH 5.5 in the presence of Ca2+, whereas an increase in pH with constant ion concentration resulted in a decrease in adhesion for both Ca2+ and Na+. Results are explained by looking at the kaolinite's surface complexation and the protonation state of the functional group, and highlight a more important role of the multicomponent ion exchange mechanism in controlling adhesion than the double layer expansion mechanism.

Title: Advancing CO2 enhanced oil recovery and storage in unconventional oil play—Experimental studies on Bakken shales.

Publication date: 2017

Authors: Jin, L., Hawthorne, S., Sorensen, J., Pekot, L., Kurz, B., Smith, S., Heebink, L., Herdegen, V., Bosshart, N., Torres, J., Dalkhaa, C., Peterson, K., Gorecki, C., Steadman, E., and Harju, J.

Journal: Appl. Energy.

Abstract: Although well logs and core data show that there is significant oil content in Bakken shales, the oil transport behavior in these source rocks is still not well understood. This lack of understanding impedes the drilling and production operations in the shale members. A series of experiments were conducted to investigate the rock properties of the Bakken shales and how to extract oil from the shales using supercritical CO2. High-pressure mercury injection tests showed that pore throat radii are less than 10 nm for most pores in both the upper and lower Bakken samples. Such small pore sizes yield high capillary pressure in the rock and make fluid flow difficult. Total organic carbon content was measured using 180 shale samples, and kerogen was characterized by Rock-Eval pyrolysis, which indicated considerable organic carbon present (10–15 wt%) in the shales. However, oil and gas are difficult to mobilize from

organic matter using conventional methods. A systematic experimental procedure was carried out to reveal the potential for extracting hydrocarbons from the shale samples using supercritical CO_2 under typical Bakken reservoir conditions (e.g., 34.5 MPa and 110 °C). Results showed that supercritical CO_2 enables extraction of a considerable portion (15–65%) of hydrocarbons from the Bakken shales within 24 h. Measurement of CO_2 adsorption isotherm showed that Bakken shale has a considerable capability to trap CO_2 (up to 17 mg/g) under a wide range of pressures. The experimental results suggest the possibility of using supercritical CO_2 injection to increase the ultimate oil recovery and store a considerable quantity of CO_2 in the Bakken Formation.

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