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Editorial

Management of High-Water-Cut and Mature Petroleum Reservoirs

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An increasing number of oil and gas companies reach their economic limit after years of production, exhausting the support of natural-pressure drive mechanisms in the reservoir and the benefits of water or gas injection. Reservoir heterogeneity, fluid-mobility contrast and undesirable or unexpected dynamic processes may cause the displacement of hydrocarbons, rendering them less efficient over time. Large-scale fractures, thief zones and networks of natural fractures challenge displacement from the matrix during injection. Increasing water or injectant gas production and declining hydrocarbon production may be further limited by the separation and treatment capacity and economy of an asset. Good reservoir management requires that existing infrastructure and discovered resources are utilized to their fullest potential and that measures are taken to ensure that valuable natural resources are not needlessly abandoned. Decisions must be taken with regard to conformance/water diversion, implementing new recovery solutions, drilling new and smart wells, treatment capacity, etc. Under these conditions, it is essential to understand the drive mechanisms of recovery, displacement and rock–fluid interactions and make sure accurate information is collected and included in reservoir models used to make predictions and aid decisions. Collecting sufficient information about the reservoir for proper characterization is essential.

This Special Issue aims to contribute novel research that can extend and secure the petroleum energy supply and maximize the utilization of natural resources with a minimal environmental footprint. Eight papers are published covering a wide range of topics: the machine learning prediction of complex water-alternating-gas (WAG) injection [1], oil recovery experiments via water displacement performed and simulated under varied conditions [2], experimental investigations of chemically induced compaction in fractured chalk [3], an optimal control strategy for combined carbon storage and enhanced oil recovery [4], simulation of the hydraulic fracturing of tight reservoirs with n-heptane as a fracturing fluid [5], a review of recent advances in ultrasonic waves for enhanced oil recovery [6], a new surfactant to enable heavy oil recovery under high-temperature and high-salinity conditions in carbonates [7], and a guideline for combining specialized tools to properly characterize fine-grained chalk [8]. These studies cover fluid displacement processes at pore, core and reservoir scales and account for the complex interactions between heterogeneity, multiphase flow, reactions and geomechanics. A summary of each study is herein presented.

Andersen et al. [1] presented a machine learning study where a database of ~2500 reservoir simulations covering WAG, water injection and gas injection was investigated. The reservoir model was 2D with variations in layered heterogeneity, hysteresis, fluid mobilities, densities and injection conditions. Their previous work suggested that WAG could be interpreted using one effective mobility ratio, indicating the effectiveness of the injected fluids in displacing the mobile oil in place. However, there was great potential for reducing uncertainty in the predicted recovery. This was achieved using a machine learning algorithm

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called the Least Square Support Vector Machine, optimized using different approaches, which accurately predicted the recovery factor over the full dataset with $R^2 = 0.998$. Their model predicted recovery as function of dimensionless gravity numbers, mobility ratios, the heterogeneity factor, hysteresis parameters and the WAG water fraction.

A comprehensive combined experimental and simulation study was presented by Andersen et al. [2]. Strongly water-wet Berea and Bentheimer cores were saturated with oils with viscosity ranging from 0.4 to 32 cP at 90% initial oil saturation. The oil was displaced via spontaneous imbibition and forced imbibition, with the latter at low and high injection rates. In total, 22 experiments were performed (some identical). The vast amount of data under varied experimental conditions permitted the authors to characterize the multiphase flow functions (relative permeability and scaled capillary pressure) and determine the role of advection, the mobility ratio and capillary forces under the different conditions. Based on scaling analysis and numerical simulations, consistent interpretation was obtained. A favorable mobility ratio, even at high oil viscosity, resulted from very low water relative-permeability end points of ~0.01 and explained why spontaneous imbibition time scales varied by only a factor 5 when oil viscosity varied by a factor ~80; moreover, it explained why nearly all mobile oil was produced before water breakthrough in the forced imbibition tests. The results indicated that piston-like displacement models were useful for explaining forced and spontaneous imbibition in strongly water-wet systems. For spontaneous imbibition, this results in a recovery profile proportional to the square root of time.

The work by Bredal et al. [3] experimentally investigated how artificially fractured Obourg chalk responds to the injection of inert (NaCl) and reactive brines ($MgCl_2$ and synthetic seawater) under reservoir temperatures and stresses. The fractures were in the form of drilled cylindrical holes along the flow direction on three cores. Two cores without holes were tested as references. All the cores were first saturated and flooded with NaCl for six pore volumes in creep state (constant stress). The fractured cores deformed more than the unfractured cores in this stage. Following NaCl injection, $MgCl_2$ and seawater brine were injected in two fractured and two unfractured cores. Water weakening (enhanced compaction via interaction with injected brine) was observed in all cases but was delayed in the fractured cores as diffusion limited exposure of the matrix to reactive ions. The extrapolation of compaction trends indicated that long-term compaction would become more significant for the fractured cores and exceed the compaction in unfractured cores. Significant aperture reduction was observed in all three fractured cores and was attributed to both mechanical and reactive mechanisms.

Kuk et al. [4] considered the optimization of computationally expensive reservoir problems, focusing on the injection of carbon dioxide in a realistic complex reservoir for enhanced oil production (huff-and-puff) and long-term storage (continued injection) afterwards. A decision tree was used, whereby the tree nodes were defined by reservoir states and their limits, resulting in decisions (tree leaves) on the control variables (well rates) at each time step. Engineering experience and the specific problem investigated were used to design the tree, and artificial intelligence was used to optimize the node limits defining the decision-making in the control process. This approach can be considered an optimal reactive control strategy. Only twice as many simulations as unknowns were needed to determine the optimal decision tree, and hence, the optimal controls. The number of unknowns in the decision tree (node limits) was much lower than the number of decisions made during the full simulation. Their case determined the average pressure upper limit during injection and the oil rate lower limit during production. They demonstrated that carbon injection was beneficial and that the optimization of implementation could yield a higher net present value.

Mehmood et al. [5] presented mathematical simulations of the hydraulic stimulation of a tight gas field to investigate the use of a non-water-based fracturing fluid. The model accounted for thermal, multiphase and compositional flow; fracturing at higher pore pressures than the combined minimal horizontal stress and tensile strength; fracture closure if the pore pressure reduces, e.g., via leakoff to the matrix; the transport and settling of the proppant; and fractures being held open by the proppant. As a reference, a water-based gel carrying a proppant was shown to be ineffective as proppants settled at the bottom of the fracture, and the fracture closed around the top and the injection point. This was explained by the long fracture-closure time. A hybrid fluid fracturing concept was suggested whereby an injection of water-based fluid was followed by a non-water-based fluid. Using sensitivity analysis, injection at a higher rate, with a longer duration or with higher viscosity resulted in larger fracture volumes. Compared to water-based fluid, the hybrid method gave rapid fracture closure, flowback of injected fluids and the onset of gas production.

A review of recent research on ultrasonic waves for enhanced oil recovery was presented by Otumudia et al. [6]. This technique sends high-frequency waves from a tool in the well into the formation. Demonstrated impacts in the lab include reduced oil viscosity (as much as 86%); reduced interfacial tension; the clearing up of formation damage, asphaltene precipitation and condensate blockage; increased porosity and permeability; and the connection of pores or droplets, and thus, reduced residual oil saturation. Additionally, ultrasound could disintegrate heavier oil components and, accordingly, modify oil properties. Wettability was also sensitive to ultrasound, as indicated by contact angle measurements. The ultrasound effects were sensitive to the power and wave frequency used but appeared to have a lasting impact, likely related to permanent modifications in the oil phase, rock structure and fluid film configurations. Ultrasonic technology is considered environmentally friendly as no chemicals are required, but it appears to work better in synergy with other methods and may have limited reach from the well.

Yang et al. [7] developed a surfactant called SDY-1 for enhanced oil recovery application in high-salinity and high-temperature conditions in heavy oil carbonate reservoirs. Naturally fractured reservoirs rely on capillary forces for production, but carbonates saturated with heavy oil tend to be highly oil-wet, and wettability alteration towards a more water-wet state may be necessary. A heavy crude oil with high asphaltene content from Tahe oil field was investigated. The synthesized surfactant had a similar carbon number to the oil, which suggested a good ability to modify wettability and lower interfacial tension. The surfactant was able to disperse asphaltene aggregates, as seen in micro-images. It could lower the interfacial tension between oil and formation water by two orders of magnitude and maintained a similar value after high-temperature aging, indicating thermal stability. The surfactant was able to reduce the contact angle through water on carbonate from ~130 to ~65 degrees, i.e., it was more water-wet, supporting the capillary uptake of water. A flooding experiment in a micromodel mimicking Tahe reservoir rock showed greater oil recovery with the proposed surfactant compared to a standard surfactant. The surfactant also adsorbed less than the standard surfactant.

Zimmermann et al. [8] presented a toolbox of methods to investigate chalk (which is soft, brittle and composed of fossils at a micron scale), and other fine-grained rocks. The key challenges of these analyses were in simultaneously obtaining high-resolution images and compositional information from the same location, and performing sample preparation on brittle, soft material. For chalk, original features, such as fossils, and mineralogical alterations from chemical processes due to exposure to enhanced-oil-recovery fluids may occur at a submicron scale; thus, they must be characterized properly for upscaling and inclusion in reservoir models. The authors state that their workflow solves the mentioned issues while remaining economical and efficient, and if applied to coarser or harder rocks (than chalk), the workflow should be less challenging. Some of their suggested methods include scanning electron microscopy for microscale imaging, X-ray diffraction for mineral identification, isotope values for determining the temperature conditions of secondary minerals, specific surface area and density to indicate bulk mineralogical changes, and transmission electron microscopy for submicron imaging.

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