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Enhanced Hydrocarbon Recovery in Low-Permeability Reservoirs using Surfactants: An Integrated Rock and Fluid Study

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Introduction / Novelty

Commercial production of low-permeability liquid-rich gas reservoirs has become viable through the application of multi-fractured horizontal wells. However, hydrocarbon recoveries remain exceedingly low (<5-10%) using the primary recovery scheme. As a result, operators have investigated the use of 1) enhanced recovery techniques such as cyclic gas injection (e.g., Hoffman and Reichhardt, 2019) and/or 2) chemical additives such as surfactants (e.g., Druetta et al., 2019) and nanoparticles (e.g., Zhang et al., 2014) to improve hydrocarbon recovery. For testing chemical additives, spontaneous recovery experiments have been proposed as a simple, fast and cost-effective screening approach (though not fully representative) to allow the investigation of controlling mechanisms and factors. Experimental spontaneous recovery studies with surfactants are extensive, with seminal examples, providing insight into the fundamental mechanisms and controlling factors at pore (e.g., Zhang et al., 2020), core (e.g., Habibi et al., 2020) and field (e.g., Farajzadeh et al., 2021) scales. However, these studies are primarily focused on rock analysis, with much less attention given to fluid analysis. In particular, the dynamics of the surfactant-aided recovery processes over extended periods (i.e., months) has not been explored in the previous laboratory studies. The current work presents results from an integrated rock and fluid experimental study, investigating the dynamics of surfactant-aided recovery processes in low-permeability liquid-rich gas reservoirs. The primary objective is to evaluate the compositional evolution of the produced hydrocarbons, controlled by rock properties (e.g., organic/inorganic composition/content) and operational parameters (e.g., fluid salinity) over short (i.e., days) and long (i.e., months) periods.

Samples / Methods / Workflow

In total, nine core plugs with 2.5–3.8 cm (1, 1.5″) diameter and 2.8–5.3 cm (1.1–2.1″) length were analyzed in this study. These core plugs were drilled parallel to bedding from a 50m core interval obtained from a vertical well completed in low-permeability liquid-rich gas intervals of the Montney Formation in western Canada. The samples were subjected to a comprehensive suite of screening geochemical and petrophysical analyses, serving as important reference points for the current study. The selected samples have relatively similar organic/inorganic composition and content including TOC content: < 1 wt.%, clay content: 15-18%, quartz content: 37-42.0%, and carbonate content: 17-26%. The petrophysical properties represent a typical producing unit within the higher quality intervals of the Upper Montney Formation with the following ranges of key characteristics: helium porosity: 5.3-7.4%, mean pore throat size (10-35 nm), pressure-decay (N_2) permeability: 0.001-0.006 md, and profile (N_2) permeability: 0.004-0.012 md.

The experimental procedure for spontaneous recovery testing using surfactants included two primary stages: 1) spontaneous imbibition with dewaxed formation oil and 2) spontaneous recovery with tap water and synthetic brine (reproduced based on the produced water salinity) using three different commercial surfactants with similar concentration (1 cc/L). During stage 2), gas chromatography – mass spectrometry (GC-MS) of whole-oil was performed to determine the molecular composition of the produced hydrocarbons after 65 days and 6 months of recovery (both sub-sampled from the same recovered oil volume) to track the compositional evolution over short and long periods. The surfactant experiments were benchmarked against three blank experiments using tap water, field brine and synthetic brine with no surfactants.

Key Results / Observations

Experimental observations indicate that the ultimate imbibed oil volumes are controlled by micro/mesopore specific surface area, micro/mesopore volume and the pre-existing fractures. Regardless of the type of surfactants and fluid salinity, the application of surfactants results in enhanced oil recovery compared to blank solutions. The C_7-C_{13} components are the primary components produced at the early stage of the production (65 days) for all surfactants – these components are the primary components of the formation (dead) oil used in the tests. This is confirmed by the composition of hydrocarbon produced during the late-time production in which heavier components (C_{13}-C_{31}) are relatively enriched. Among blank solutions, oil is produced from synthetic brine solution only with a composition different from those produced from surfactant solution and formation oil (significantly lower concentrations of C_7-C_{13} and higher concentrations of C_{13}-C_{18}). The higher the recovered oil volume, the higher the concentrations of C_7-C_{13} components in early-term production (after 65 days). Comparing compositional data after short- and long-term production periods, it is evident that the commonly used compound ratios (i.e., saturate biomarkers) do not change over the recovery period, whereas some volatile aromatics are altered. Therefore, when performing EOR using surfactants, geochemical analysis based on aromatic hydrocarbons may not be reliable and only ratios of saturate compounds should be used. The findings of this study will be beneficial to operators developing the low-permeability reservoirs within the Montney Formation by allowing them to optimize the production and fluid testing programs over short and long recovery periods.

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