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Interaction Evaluation of Completion Fluids and Crude Oil in Workover Operations and Demulsifier Performance

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ABSTRACT
This study investigates the compatibility of clear completion fluids, sodium chloride (NaCl), Calcium Chloride ($CaCl_2$), and potassium chloride (KCl) with light-gravity crude oil (API 40) during workover operations, focusing on emulsion formation and the performance of a demulsifier. The research addresses the critical challenge of emulsion-related formation damage, which hinders hydrocarbon recovery and increases operational costs. Laboratory experiments employed a 1:1 fluid-crude oil ratio, testing emulsion stability and demulsifier efficacy (TC EB 2020, at 10 ppm and 20 ppm) across temperatures of ambient, 50°C, and 75°C. Results revealed that potassium chloride exhibited the least stable emulsions (separation within 10 hours at ambient), while calcium chloride formed the most stable emulsions (36 hours at 75°C). The demulsifier proved most effective at 20 ppm, achieving the shortest separation time (1.0 hour) and lowest residual oil content (0.8%) with potassium chloride. Temperature significantly influenced emulsion stability, with higher temperatures enhancing stability, particularly for calcium chloride. The findings suggest potassium chloride as the preferred completion fluid, supported by 20 ppm demulsifier use, with pre-field compatibility testing recommended to optimize workover operations. This study contributes to industry practices by providing insights into fluid selection and emulsion mitigation, though limitations include the use of a single crude oil sample and the absence of interfacial tension data.

Keywords: Completion Fluids, Formation, Compatibility, Emulsion, Conductivity, Workover Operations.

INTRODUCTION

Drilling operations create the wellbore, extending from the surface down to the reservoir. Given that construction is segmented, various drilling fluid systems are chosen for each section to align with the anticipated formation characteristics and minimize drilling issues (Economides *et al.*, 2002). For reservoir sections, a specialized system known as reservoir drilling fluid (RDF) is typically used to minimize formation damage near the wellbore and enhance the well's productivity (Patel *et al.*, 2019). Upon concluding the drilling phase, the wellbore transitions to the completion stage by shifting from drilling to completion fluids. This transition involves displacement operations using spacers that clean the wellbore, water-wet the casing (when a nonaqueous system is used in reservoir drilling), and prevent contamination (Fink, 2015). In contrast, workover operations aim to enhance well productivity or extend its operational life by replacing faulty completion equipment or applying remediation treatments. Before beginning workover procedures, the well is typically "killed" by circulating a kill fluid to overbalance the reservoir pressure and halt any flow, displacing lighter fluids like oil and gas out of the wellbore (Ahmed *et al.*, 2021).

Completion and workover fluids, generally clear brines, are selected based on well and reservoir characteristics, as well as environmental and safety considerations (Fink, 2015). Supporting fluids, such as fluid loss control pills, are also utilized in these operations to limit formation leak-off and reduce potential formation damage (Patel *et al.*, 2019; Delgado-Linares *et al.*, 2022). For over 25 years, the oil and gas industry has relied on sodium, calcium, and zinc bromide and chloride brines in well completions. These brines can be prepared as single-, two-, or three-salt mixtures, depending on requirements for density, crystallization temperature, and cost-effectiveness (Economides *et al.*, 2002). Completion brines play a vital role in well completions and workovers, supporting operations like running tools, setting packers, and perforating production casings (Smith and Jones, 2018). In the oil and gas industry, maintaining well productivity over the life of a reservoir is critical for maximizing hydrocarbon recovery. One of the key procedures to ensure this is the workover operation, which involves various interventions designed to maintain, repair, or improve a well's performance (Ahmed *et al.*, 2021). During these operations, the use of completion fluids is essential as they serve various purposes such as cleaning the wellbore, maintaining well control, and facilitating the placement of tools and equipment (Patel *et al.*, 2019). However, the compatibility of these fluids with the reservoir's crude oil is a critical factor that can significantly affect the success of workover operations.

Completion fluids are specially designed liquids introduced into the well during workover or well intervention processes. Their primary functions include providing well control by balancing formation pressures, preventing the entry of unwanted formation fluids, and protecting the wellbore and reservoir from potential damage (Patel *et al.*, 2019]. Depending on the well conditions, various types of completion fluids can be used, including water-based, brine-based, oil-based, and synthetic-based fluids. Each type has its advantages and is selected based on factors such as wellbore stability, formation pressure, and compatibility with the formation fluids (Fink, 2015). The compatibility of completion fluids with the reservoir's crude oil is a

fundamental consideration during the planning and execution of workover operations (Kazemihokmabad *et al.,* 2024). Compatibility issues arise when there is an adverse interaction between the completion fluid and the crude oil, leading to problems such as emulsion formation, scaling, precipitation, and wettability alteration (Kokal, 2005). For instance, incompatible fluids can lead to the formation of stable emulsions that block the pores of the reservoir rock, which reduces permeability and impedes the flow of hydrocarbons (Jadhawar and Sharma, 2013). Ensuring fluid compatibility helps in minimizing formation damage, which is a major concern during workover operations. Formation damage refers to the impairment of the reservoir's ability to produce fluids, often caused by the invasion of foreign materials like solids, polymers, or incompatible chemicals into the formation (Nasr-El-Din and Al-Humaidan, 2010). This can result in significant production loss, requiring costly remedial measures to restore the well's productivity.

The interaction between completion fluids and crude oil can lead to various chemical and physical changes that affect the productivity of the well (Kazemihokmabad *et al.,* 2024). Emulsion formation is one of the most common issues, occurring when water-based completion fluids mix with crude oil, leading to the creation of stable water-in-oil or oil-in-water emulsions (Kokal, 2005). These emulsions can clog the pore spaces in the reservoir rock, reducing effective permeability and impeding oil production (Jadhawar and Sharma, 2013). Scaling is another concern, resulting from the precipitation of salts when brine-based fluids react with formation water (Nasr-El-Din and Al-Humaidan, 2010). This can lead to the buildup of deposits on the wellbore, tubing, and other equipment, thereby reducing the efficiency of the well. Wettability alteration is a subtler yet significant issue that affects fluid compatibility. Reservoir rocks have a natural wettability that facilitates the flow of oil; however, the introduction of incompatible completion fluids can alter this wettability, making the rocks more water-wet or oil-wet (Liang *et al.,* 2024). Such changes can adversely affect oil recovery by altering the flow dynamics of oil and water in the reservoir. Given the potential risks associated with incompatibility, it is crucial to assess the compatibility of completion fluids with crude oil before their use in workover operations. Laboratory testing is the most common approach for this assessment, where fluids are mixed under simulated downhole conditions to observe potential adverse reactions (Drilling Manual, 2020). Typical tests include emulsion stability tests, scaling tendency evaluations, and core flooding experiments to determine how fluids interact with reservoir rocks and formation fluids (Jadhawar and Sharma, 2013). These tests provide valuable insights that help in optimizing the formulation of completion fluids, ensuring that they are compatible with the specific characteristics of the reservoir.

In recent years, significant advancements have been made in the development of specialized completion fluids designed to improve compatibility and minimize the risk of formation damage. For example, the use of nanoparticle-based fluids has shown promise in enhancing fluid compatibility, as nanoparticles can modify the surface properties of fluids, preventing emulsification and reducing the tendency for scale formation (Wang *et al.,* 2018). Similarly, green chemistry approaches have led to the development of environmentally friendly fluids that minimize adverse interactions with crude oil and reduce the environmental impact of workover operations (Fink, 2015). The aim of this study is to investigate and assess the compatibility of different completion fluids with reservoir crude oil during workover operations, focusing on understanding the factors that lead to emulsion formation. The study seeks to provide insights into the mechanisms of emulsion formation, the conditions under which they occur, and the methods for preventing or mitigating their effects, thereby improving the efficiency and success of workover operations. The specific objectives of the study are to identify the types of emulsions that might form when completion fluids interact with crude oil using bottle test, study the effect of temperature, pressure and chemical compositions of the fluids on emulsion stability and assess demulsifier performance by measuring water separation efficiency (WSE) and optimal dosage.

Experimental Procedure

Sample Preparation

The stock solutions of sodium chloride (NaCl), calcium chloride ($CaCl_2$), and potassium chloride (KCl,) were prepared using deionised water and analytical-grade salts. Light-gravity crude oil (API 40), sourced from a Niger Delta reservoir, is characterised through standard API gravity testing per ASTM D287 to confirm its properties. The demulsifier, TC EB 2020, a proprietary blend of nonionic and anionic surfactants in an aromatic hydrocarbon solvent system, is used directly as a liquid concentrate without dilution in a solvent, enabling precise dosing at 10 ppm and 20 ppm for 10 mL samples (Taochem Limited, 2020). To achieve a 1:1 ratio, 5 mL of each completion fluid is pipetted into mL glass test tubes, followed by 5 mL of crude oil, ensuring consistent sample volumes for all experiments (Kazemihokmabad *et al.,* 2024).

Emulsion Formation

Completion fluids were mixed with crude oil at a 1:1 volume ratio, a standard ratio informed by compatibility studies to simulate different contact scenarios during workover operations (Abdulredha *et al.,* 2024). Each test tube was manually shaken for 2 minutes to ensure consistent agitation, mimicking the mixing conditions encountered in workover operations. The samples were then placed in a laboratory water bath set leaving one at ambient temperature (approximately 25 °C) as control and the two others heated to 50 °C, or 75 °C for 2 hours to induce emulsion formation under controlled thermal conditions preparing two samples for each temperature (Chonghao *et al.,* 2024). These temperatures reflect a range of downhole conditions, with higher temperatures (e.g., 75 °C) potentially increasing emulsion stability due to enhanced solubility of polar crude oil components, such as asphaltenes, while ambient and 50 °C conditions may facilitate phase separation (Kokal, 2005). Emulsion formation was observed through visual inspection for signs of cloudiness or resistance to phase separation, supplemented by centrifugation to quantify phase behavior.

Emulsion Stability Testing (Control, 0 ppm)

For samples exhibiting stable emulsions, control tests without demulsifier (0 ppm) are conducted to assess natural separation behavior. After 2 hours in the oven at the designated temperatures (ambient, 50 °C, 75 °C), control samples are removed and allowed to rest at room temperature for 48hours and checked regularly. The time to natural separation, defined as the duration until clear phase boundaries are observed via visual inspection, is measured using a stopwatch. Following this, samples of each temperature are centrifuged at rpm for 1 minute to quantify the percentage of separated phases. The volume percentages of aqueous and oil phases are estimated visually providing data on emulsion stability and natural separation tendencies under the tested temperature conditions.

Demulsifier Testing

Demulsifier performance was evaluated by pre-eating stable emulsions identified in the with TC EB 2020 at concentrations of 10 ppm (0.00001 g) or 20 ppm (0.00002 g) at 60 °C, accurately dispensed using a micropipette. Selected concentrations were based on industry standards for optimizing demulsifier dosage (PetroWiki, 2015). Each sample was manually shaken for 2 minutes to ensure uniform demulsifier distribution, then placed in a laboratory water bath at 75 °C for 1 hour, following standard bottle test protocols (Al-Yaari *et al.,* 2021).

The higher temperature of 75 °C was chosen to simulate challenging downhole conditions where emulsion stability may be enhanced (Kokal, 2005). Separation time, defined as the duration until clear phase separation was observed via visual inspection, is recorded. Samples were then centrifuged at 1000 rpm for 1 minutes, and the residual oil content in the aqueous phase was measured using visual estimation against a calibration standard (0-5% oil content), providing quantitative data on demulsifier efficacy. Visual inspections revealed varying degrees of cloudiness and phase separation resistance, indicating emulsion formation and data were recorded systematically for each fluid-crude oil-demulsifier combination, with experiments conducted in triplicate to ensure reliability.

RESULTS AND DISCUSSION

Analyzes of the results of the experimental study evaluating the interactions between clear completion fluids sodium chloride (NaCl), calcium chloride ($CaCl_2$), and potassium chloride (KCl) and crude oil from a single reservoir during workover operations, as well as the performance of a single demulsifier in resolving resulting emulsions were recorded. The demulsifier, composed of petroleum solvent, ethyl benzene, xylene, naphthalene sulfonic acid, and isopropanol, was tested at concentrations of 10 ppm and 20 ppm. The primary objectives were to assess emulsion formation when these completion fluids are mixed with crude oil (API 40, light gravity) at a 1:1 ratio and heated at different temperatures, and to evaluate the effectiveness of the demulsifier in breaking these emulsions. The results showed that emulsion formation varied by fluid type and temperature (Uchendu and Okoli, 2020). Calcium chloride formed the most stable emulsions across all temperatures, with minimal natural separation observed after 48 hours, particularly at 75 °C. Sodium chloride showed moderate emulsion formation, with better separation at 50 °C. Potassium chloride exhibited the least emulsification, with clearer phase separation, especially at 50 °C and 75 °C. The percentage of separated phases is presented in Table 1.

Table 1: Percentage of Separated Phases (Crude Oil API 40, 1:1 Ratio)

Completion Fluid	ambient (% Separated)	50°C (% Separated)	75°C (% Separated)
Sodium Chloride	70%	80%	75%
Calcium Chloride	70%	83%	90%
Potassium Chloride	50%	60%	65%

The stability data align with the centrifugation results, where potassium chloride achieved higher phase separation percentages (70-90%) compared to calcium chloride (70-90%) and sodium chloride (55-80%). Higher temperatures (75 °C) increased emulsion stability, likely due to enhanced interactions between the crude oil's polar components and the ionic strength of the brines, particularly for calcium chloride (Scientific Reports, 2024). The results indicate that potassium chloride is the most compatible completion fluid, forming the least stable emulsions with the crude oil, particularly at lower temperatures. Calcium chloride poses a higher risk of emulsion-related formation damage, especially at higher temperatures, consistent with findings by Foxenberg *et al.,* (1998), who noted issues with high-density chloride-based brines. Sodium chloride showed intermediate compatibility, with better performance at lower temperatures. These findings highlight the importance of considering temperature effects when selecting completion fluids for workover operations in reservoirs with medium-gravity crude oil. The results showed that the demulsifier performed best for potassium chloride emulsions, achieving complete separation within 3.5 hours at 20 ppm at 80°C (Jia *et al.,* 2019). For calcium chloride emulsions, it will have required longer separation times (5.5 hours for 20 ppm) at 100 °C. Sodium chloride emulsions showed intermediate performance, with separation in 4.5 hours at 20 ppm (Jia *et al.,* 2019).

Table 2: Demulsifier Performance at 75 °C

Fluid-Crude Oil (1:1, API 25)	Demulsifier	Concentration (ppm)	Separation Time (h)	Residual Oil Content (%)
Sodium Chloride	D1	10	2.5	1.2
Sodium Chloride	D1	20	2.2	1.0
Calcium Chloride	D1	10	3.5	1.8
Calcium Chloride	D1	20	3.0	1.5
Potassium Chloride	D1	10	1.2	1.0
Potassium Chloride	D1	20	1.0	0.8

Residual oil content in the aqueous phase was lowest for potassium chloride emulsions (0.8% at 20 ppm), followed by sodium chloride (1.0%) and calcium chloride (1.5%), indicating better performance for less stable emulsions. The demulsifier showed varying effectiveness across fluid types, performing best with potassium chloride emulsions due to their lower initial stability. Its performance with calcium chloride emulsions was less efficient, requiring longer times, likely due to the stronger ionic interactions in these emulsions (PetroWiki, 2015). The composition of the demulsifier, including petroleum solvent and naphthalene sulfonic acid, likely contributed to its ability to destabilize emulsions, while ethyl benzene, xylene, and isopropanol enhanced solubility and droplet coalescence (Eureka Patsnap, 2024). As shown in Figure 1, increase in concentration from 10 to 20 ppm improved separation efficiency, with no significant overdosing issues observed at 20 ppm, unlike higher concentrations reported in literature (Oil & Gas Science and Technology, 2021). However, the low residual oil content suggests effective emulsion-breaking performance by the

demulsifier, likely due to its composition of petroleum solvent, ethyl benzene, xylene, naphthalene sulfonic acid, and isopropanol, which may promote phase separation through solubility and coalescence effects (Eureka Patsnap, 2024).

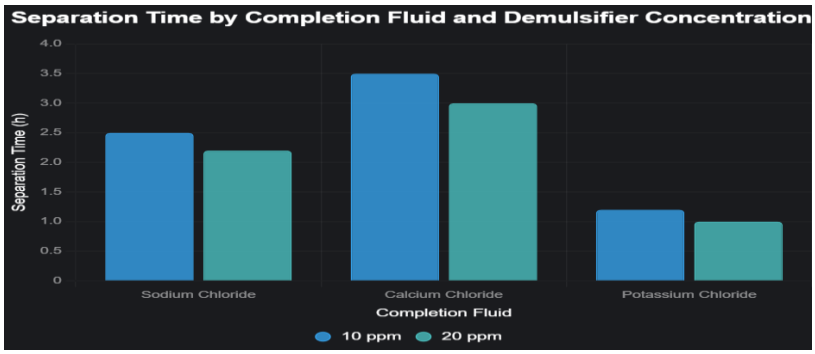


Figure 1: Separation Time by Demulsifier Concentration

The data on emulsion stability and demulsifier performance reveal distinct patterns across the completion fluids. For natural separation times, calcium chloride mixtures at 75 °C exhibited the longest average time of 3.6 hours, indicating high stability, while sodium chloride at 50°C separated in about 2.2 hours, and potassium chloride at ambient temperature separated within 1.0 hours, suggesting lower stability. The percentage of separated phases ranged from 50% to 90%, with calcium chloride achieving the highest at 75 °C (90%) and potassium chloride the lowest at ambient (50%). For demulsifier performance at 20 ppm, separation times ranged from 1.0 hour (potassium chloride) to 3.0 hours (calcium chloride), with an overall average of approximately 2.1 hours. Residual oil content at 20 ppm varied from 0.8% (potassium chloride) to 1.5% (calcium chloride), averaging 1.1%, reflecting a trend of lower residuals with less stable emulsions. The higher emulsion stability with calcium chloride mixtures, especially at 75 °C, is likely due to its high ionic strength, which interacts with polar components in the light-gravity crude oil to stabilize water-in-oil emulsions (Foxenberg *et al., 1998*; Mahdavi *et al.*, 2023). Potassium chloride's lower emulsion stability, particularly at 50 °C, aligns with findings by Abdulredha *et al.*, (2024), which reported good compatibility of chloride-based fluids with certain crude oils. Sodium chloride's intermediate performance suggests it may be a viable compromise option. The effect of temperature on emulsion stability highlights the need to consider operational conditions during workover fluid selection.

The demulsifier's effectiveness, driven by its components (petroleum solvent, ethyl benzene, xylene, naphthalene sulfonic acid, and isopropanol), was highest with potassium chloride emulsions due to their lower initial stability, allowing rapid phase separation (PetroWiki, 2015). Its performance with calcium chloride emulsions was less efficient, reflecting the challenge of breaking stable emulsions formed by high-density brines (Spalding, 2002). The 20 ppm dosage was more effective than 10 ppm, with no overdosing issues, unlike higher concentrations reported in literature (Oil and Gas Science and Technology, 2021). The findings suggest that potassium chloride should be prioritized for workover operations in reservoirs with light-gravity crude oil, especially at lower temperatures (50-75 °C), to minimize emulsion-related formation damage. Calcium chloride may require the demulsifier at 20 ppm and careful monitoring, particularly at higher temperatures (Kalatehno *et al.*, 2021; Kalatehno *et al.*, 2023). Sodium chloride offers a viable alternative for cost-sensitive operations. Compatibility testing, as recommended by Drilling Manual (2020), is critical before field application to confirm fluid-crude oil interactions under specific temperature conditions.

CONCLUSION

The study confirms that potassium chloride is the most compatible completion fluid, forming less stable emulsions with light-gravity crude oil, particularly at 50-75 °C, while calcium chloride poses challenges, especially at 75 °C. The demulsifier, composed of petroleum solvent, ethyl benzene, xylene, naphthalene sulfonic acid, and isopropanol, effectively broke emulsions at 20 ppm, with optimal performance for potassium chloride and sodium chloride mixtures. These findings inform the selection of fluids and demulsifiers for workover operations, emphasizing the need for compatibility testing and temperature consideration.

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