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Compatibility of Completion Fluids with Formation Water During Workover Operations

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ABSTRACT
Workover operations play a vital role in extending the productive life of oil and gas wells. Completion fluids play a critical role in maintaining wellbore stability, minimizing formation damage, and enhancing hydrocarbon recovery. This study evaluates the compatibility of common completion fluids (NaCl, KCl, and $CaCl_2$ brines) with synthetic formation water to optimize fluid selection and minimize formation damage during workover operations. Laboratory-grade salts were used to prepare the brines, which were mixed with synthetic formation water at volume ratios ranging from 1:9 to 1:1. The mixtures were conditioned at temperatures from room temperature (~25°C) to 95°C for 24 hours. Key fluid properties measured included pH, electrical conductivity, salinity, total dissolved solids (TDS), and resistivity, with visual observation for precipitation. NaCl and KCl mixtures exhibited linear trends in all measured properties, indicating good compatibility and stability. In contrast, $CaCl_2$ mixtures showed non-linear decreases in conductivity, salinity, and TDS at higher temperatures (70–95°C), accompanied by $CaCO_3$ precipitation. KCl is recommended as the preferred fluid for carbonate reservoirs to reduce scaling risk.

Keywords: Completion Fluids, Formation Water, Compatibility, Precipitation, Scaling, Workover Operations, Brines

INTRODUCTION

Hydrocarbon recovery from subsurface reservoirs involves complex interactions between drilling and completion fluids, reservoir rock, and formation water. Completion fluids play a critical role in maintaining wellbore stability, controlling pressure, minimizing formation damage, and enhancing hydrocarbon recovery (Caenn *et al.*, 2011; Civan, 2015; Darley, 1988). However, incompatibility between completion brines and formation water can lead to precipitation and scaling, which reduce well productivity and increase operational costs [Civan, 2015; Johnson and Lee, 2019; Smith, 2020). Formation water, a major component of the reservoir's geochemical system, interacts with completion fluids, sometimes leading to precipitate formation, which can obstruct hydrocarbon flow (Isah *et al.*, 2022; Oddo & Tomson, 1994). Therefore, compatibility between completion fluids and formation water is essential for preventing operational challenges and optimizing hydrocarbon recovery (Isah *et al.*, 2022; Oddo *et al.*, 1994). Given the increasing complexity of drilling and completion operations, selecting the appropriate completion fluid has become crucial. Poor fluid selection can result in:

1. Formation damage, leading to reduced well productivity.
2. Increased precipitation and scaling.
3. Lower hydrocarbon recovery rates.
4. Higher operational costs and environmental burdens.

Completion fluids, primarily composed of brines (chlorides, bromides, and formates), must be chemically compatible with reservoir fluids to ensure effective well control and production performance (Mackay and Jordan., 2013; Nasr-El-Din *et al.*, 2004). For instance, potassium acetate is preferred for clay-bearing formations due to its minimal clay swelling and stable pH, whereas calcium chloride is more likely to cause swelling, making it less suitable for siltstone and sandstone formations (Smith, 2020). Understanding these interactions is critical to optimizing workover operations, which help maintain and improve well productivity. The selection of appropriate completion fluids ensures wellbore stability, pressure control, and minimal fluid loss. Incompatibility issues, such as emulsification and solid precipitation, can significantly impact production rates (Johnson and Lee, 2019).

This research studies the compatibility of NaCl, KCl, and $CaCl_2$ completion brines with synthetic formation water, identify conditions leading to precipitation, and recommend optimized fluid selection strategies for workover operations.

Experimental Procedures.

This study adopted a quantitative, controlled laboratory experimental design. Reagent-grade NaCl, KCl, and $CaCl_2$ were used to prepare completion brines, while synthetic formation water was formulated using NaCl, $CaCl_2$, and $CaCO_3$ to simulate typical carbonate reservoir conditions. All brines were filtered to remove solids, and initial pH was measured.

Key equipment included glassware, magnetic stirrers, temperature-controlled ovens/water baths (25–95°C), a pH meter, Star A222 conductivity meter (for conductivity, salinity, TDS, and resistivity), and Inductively Coupled Plasma – Optical Emission Spectrometry (ICP-OES) for selected ion analysis.

Procedures involved initial fluid characterization, mixing brines with synthetic formation water at volume ratios of 1:9 to 1:1, static conditioning for 24 hours at target temperatures, measurement of fluid properties, and visual observation for precipitates. Data were recorded in laboratory notebooks and spreadsheets. All tests were performed under controlled conditions.

RESULTS AND DISCUSSION

Results

The pH of NaCl and KCl mixtures showed relatively linear trends with increasing temperature. In contrast, $CaCl_2$ mixtures exhibited non-linear pH increases at higher temperatures. Conductivity, salinity, and TDS of NaCl and KCl mixtures followed expected linear dilution patterns. However, $CaCl_2$ mixtures displayed significant non-linear decreases in these properties at 70–95°C, accompanied by visible white precipitates. Presented in Table 1 is the comprehensive report of the mixture properties that were measured.

Table 1: Properties of Pure Synthetic Formation Water and Brines at Selected Temperatures

Brine	Temp (°C)	pH	Conductivity (mS/cm)	Salinity (ppt)	TDS (g/L)	Restivity (Ω·cm)
Formation Water	25	7.44	10.51	5.91	5.08	96.32
Formation Water	95	7.01	10.37	5.81	4.10	97.69
NaCl Brine	25	6.44	31.06	19.41	15.21	32.21
NaCl Brine	95	6.24	29.92	18.64	14.69	33.12
KCl Brine	25	7.40	13.74	8.00	6.73	72.95
KCl Brine	95	7.11	13.27	7.70	6.60	74.29
$CaCl_2$ Brine	25	7.42	24.80	15.15	12.15	40.24
$CaCl_2$ Brine	95	6.99	23.77	14.24	11.03	41.08

Detailed results for mixtures at different volume ratios (1:9 to 5:5) and temperatures are summarized below. Only key representative data are presented in Table 2.

Table 2: Properties of 1:1 (Brine: Formation Water) Mixtures at 95°C

Brine	pH	Conductivity (mS/cm)	Salinity (ppt)	TDS (g/L)	Resistivity
NaCl	6.24	23.46	14.6	11.87	42.72
KCl	7.11	21.00	12.61	10.03	48.91
$CaCl_2$	6.99	28.00	16.04	13.00	38.31

Figure 1 shows the pH Trends. NaCl and KCl mixtures maintained relatively linear pH behavior. $CaCl_2$ mixtures showed non-linear pH increases at higher temperatures.

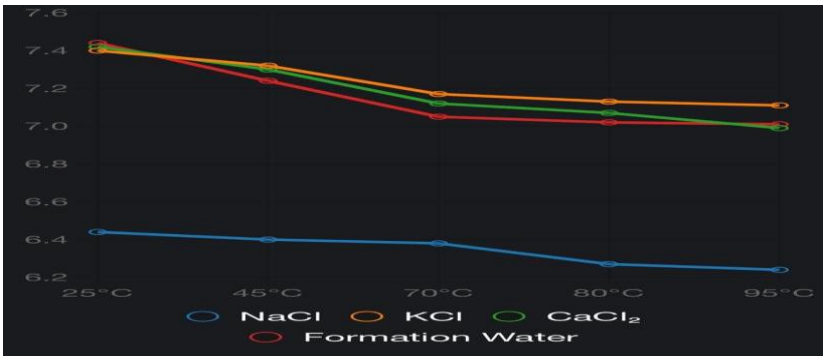


Figure 1: Ph Versus Temperature for Pure Brines and Selected Mixtures

Figure 2 shows the conductivity, Salinity, and TDS Trends. NaCl and KCl mixtures followed linear dilution patterns across all ratios and temperatures. $CaCl_2$ mixtures exhibited clear non-linear decreases in conductivity, salinity, and TDS at ≥70°C, with the effect becoming more pronounced at higher brine ratios.

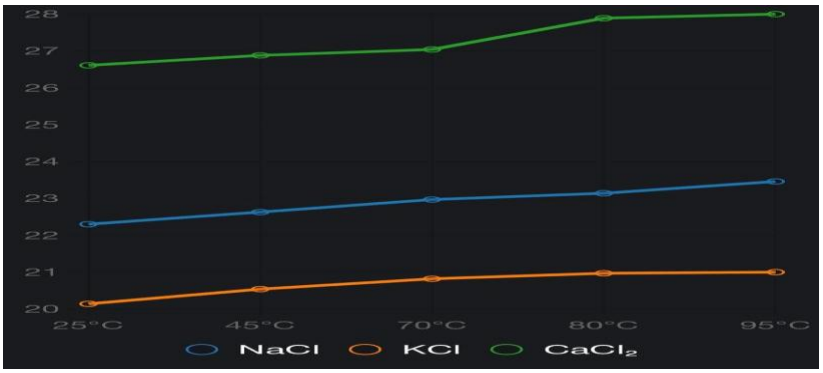


Figure 2: Conductivity Versus Temperature for 1:1 Mixtures

Discussion

The results reveal distinct compatibility behaviours among the tested completion brines. The linear trends observed in pH, conductivity, salinity, and TDS for NaCl and KCl mixtures across the temperature range (25–95°C) and mixing ratios (1:9 to 5:5) suggest simple physical dilution without significant chemical reactions. These monovalent brines (Na^+ and K^+) exhibit high stability when mixed with synthetic formation water, showing no visible precipitation or scaling. This stability is attributed to the lower reactivity of monovalent cations compared to divalent ions, consistent with the lower tendency to form insoluble salts with carbonate or bicarbonate species present in formation water (Nasr-El-Din *et al.*, 2004; Smith, 2020).

In sharp contrast, $CaCl_2$ mixtures demonstrated non-linear behaviour, particularly at elevated temperatures (70–95°C). The noticeable decrease in conductivity, salinity, and TDS, coupled with visible white precipitates, points to the removal of ions from the aqueous phase. This phenomenon is primarily driven by the inverse solubility of calcium carbonate ($CaCO_3$), where solubility decreases as temperature increases. The reaction can be summarized as:

Ca^{2+} (from $CaCl_2$) + CO_3^{2-} (from formation water) → $CaCO_3$ (s) ↓

This precipitation not only reduces the effective concentration of dissolved ions but also leads to a steeper increase in resistivity, as fewer charge carriers remain in solution. Such behavior aligns with thermodynamic principles of scale formation in oilfield systems and has been widely reported in high-temperature carbonate reservoirs (Mackay and Jordan, 2013; Zhang & Roberts, 2017). The findings corroborate earlier studies on divalent brine incompatibility. For instance, calcium-based fluids are known to react adversely with formation waters containing bicarbonate or carbonate ions, leading to scaling that can impair near-wellbore permeability and reduce well productivity (Johnson and Lee, 2019; Smith, 2020). In this study, the onset of significant precipitation above 70°C highlights a critical temperature threshold for $CaCl_2$ use, beyond which operational risks escalate. This temperature dependence underscores the importance of pre-job fluid compatibility testing, especially in reservoirs with bottomhole temperatures exceeding 70°C. From a field perspective, these results have important implications for workover operations in carbonate reservoirs. Using $CaCl_2$ in incompatible environments could result in formation damage, increased skin factor, and costly remediation (e.g., acidizing to remove scales). Conversely, KCl offers superior compatibility, better shale inhibition properties, and lower scaling potential, making it the preferred choice. NaCl remains a viable, cost-effective alternative in lower-temperature or less sensitive formations. Operators should integrate formation water characterization (via ICP-OES or similar) and apply temperature corrections to resistivity logs to avoid misinterpretation of reservoir properties (Civan, 2015).

Visual observations showed that NaCl and KCl mixtures remained clear with no precipitates at any temperature or ratio. In contrast, $CaCl_2$ mixtures produced visible white precipitates (identified as $CaCO_3$) that increased in intensity above 70°C and were most severe at the 1:1 ratio and 95°C. Resistivity of $CaCl_2$ mixtures also showed steeper increases than NaCl or KCl mixtures, consistent with ion removal due to precipitation.

CONCLUSION

This study successfully evaluated the compatibility of NaCl, KCl, and $CaCl_2$ completion brines with synthetic formation water. NaCl and KCl demonstrated excellent stability with linear property trends and no precipitation. $CaCl_2$ caused significant $CaCO_3$ scaling at high temperatures due to inverse solubility.Prefer KCl for workover operations in carbonate reservoirs, conduct compatibility testing prior to field application, exercise caution when using $CaCl_2$ in high-temperature environments, characterize formation water and apply temperature corrections to logging data. Future research should include dynamic flow tests, evaluation of scale inhibitors and additives, fluid-rock interactions, and testing with actual formation water from target reservoirs.

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