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AN EFFECTIVE ACID COMBINATION FOR IMPROVED ACIDIZING TREATMENT OF SANDSTONE FORMATION: A CASE STUDY IN BACH HO FIELD, VIETNAM

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Summary

The acidizing treatment of near-wellbore regions in oil and gas reservoirs is a critical technique for enhancing permeability and boosting hydrocarbon recovery. However, the conventional hydrochloric acid (HCl)-based solutions often face challenges such as the formation of stable emulsions, secondary precipitation, and incompatibility with reservoir fluids. This study focuses on evaluating the performance of modified acid systems (CKP^+ and GKP^+) for acidizing sandstone formations in the Bach Ho field. The experiments aimed at assessing the efficiency of these acid systems in enhancing permeability, mitigating clay swelling, and preventing the formation of secondary precipitates. Experimental results, including shale stability tests, dissolution experiments on formation rock, and permeability recovery evaluations, indicated that the proposed chemical systems effectively reduced the skin factor, enhancing oil permeability and sustaining recovery rates. The addition of anti-emulsifying agents and clay stabilizers improved the acid systems' compatibility with crude oil, reducing emulsion formation. Furthermore, the modified acid systems showed promising results in preventing iron-related precipitation, a common issue with conventional acid systems. Simulations conducted using Schlumberger's Kinetix Matrix software demonstrated that the proposed acid treatments could efficiently remove formation damage, especially in Miocene and Oligocene reservoirs, where traditional treatments had limitations. Overall, the study suggests that the CKP^+ and GKP^+ systems provide a cost-effective solution for improving well productivity and sustaining long-term hydrocarbon recovery.

Key words: Acid treatment, sandstone formation, Bach Ho field, formation damage, high clay content.

1. Introduction

Throughout the operations involved in oil and gas, including drilling, cementing, well completion, perforation, workover, and water injection, a series of events may occur near the wellbore formation, leading to changes in its natural physical and chemical properties. The impact of these events leads to a decline in permeability, resulting in reduced production efficiency in production wells and injection efficiency in injection wells. This decrease in permeability around the wellbore, as previously mentioned, is referred to as formation damage [1].

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The acidizing treatment of the near-wellbore region is a widely applied stimulation technique in the petroleum industry. It is particularly effective in restoring or enhancing the productivity of wells impaired by formation damage caused by factors such as drilling fluid invasion, scale deposition, or fines migration. The process involves injecting acid solutions - typically hydrochloric acid or blended organic/inorganic systems - into the near-wellbore formation to dissolve obstructive materials, clean pore spaces and natural fractures, thereby improving permeability and flow efficiency toward the wellbore. Compared to alternative methods such as hydraulic fracturing or mechanical wellbore cleaning, acidizing offers several advantages, including lower operational costs, shorter treatment durations, and broad applicability across various lithologies. Additionally, acidizing minimizes secondary formation damage and can be repeated multiple times throughout the well's production life, making it an efficient and cost-effective method for enhancing hydrocarbon recovery.

Recent advances in sandstone acidizing encompass the offshore application of GLDA chelating-acid systems, the development of aluminum-based retarded mud acids, and comprehensive reviews of acidizing mechanisms and workflows to optimize treatment design. Nars-El-Din et al. [2] presented the first offshore field application of a 25 wt% GLDA (glutamic acid N,N-diacetic) chelating-acid system in a sour (H_2S/CO_2) sandstone reservoir. After a xylene pre-flush, the GLDA solution - containing corrosion inhibitor and surfactant - was injected and allowed to soak for 6 hours before flowback. Field measurements showed exceptionally low casing corrosion (0.0023 lbm/ft^2), no formation of filter cake or fines migration, and ~88% chelant recovery. The GLDA treatment dissolved carbonate, oxide, and sulfide scales without secondary precipitation. Over the subsequent 60 days, oil production increased by 2,307 barrels, and the stimulation effect persisted for nearly 6 months - substantially longer than conventional mud-acid treatments. These results demonstrate that GLDA offers a low-corrosion, environmentally friendly alternative for sandstone acidizing in sour environments. Qin Ji et al. [3] evaluated the performance and mechanism of an aluminum-based retarded mud acid (15 wt% HCl, 1.5 wt% HF, 5 wt% $AlCl_3 \cdot 6H_2O$) for sandstone stimulation, compared to conventional mud acid (15 wt% HCl, 1.5 wt% HF). Batch solubility tests with kaolinite, bentonite, and illite at 75°F and 200°F, analyzed by ICP, SEM/EDS, and 19F NMR, demonstrate that $AlCl_3$ retards HF reaction (via AlF_4^- complexation) without forming AlF_3 precipitates, maintaining low free-F^- concentration and reducing secondary silica-gel formation. Core-flood experiments on Berea sandstone at 75, 200, and 300°F show deeper acid penetration (by CT imaging) and greater permeability enhancement (up to +212% at 75°F) with the retarded system, although the retardation efficacy diminishes at higher temperatures. These findings confirm that Al-based retarded mud acid offers controlled HF release, minimized formation damage, and improved stimulation depth. Shafiq and Mahmud [4] provided a comprehensive review of sandstone matrix acidizing, detailing the chemical mechanisms, treatment workflows, and performance of various acid systems under reservoir conditions. The review identifies critical future needs: development of economically viable, high-temperature-stable acids; expanded experimental data on heterogeneous sandstones; and deployment of pore-scale imaging to elucidate dissolution morphology and optimize stimulation design.

Based on numerous studies, the primary challenges commonly encountered during acid treatment of consolidated sandstone formations include limited penetration depth, secondary precipitation, elevated temperatures, and corrosion issues [5]. To identify factors that sustain treatment effectiveness in Miocene, Oligocene, and Upper Oligocene formations of Bach Ho field, this study will apply a synthesis and analysis approach, investigating the near-wellbore treatment data from 1988 to 2022.

Research has identified several challenges encountered during acid treatment of consolidated sandstone formations, including limited penetration depth, secondary precipitation, elevated temperatures, and corrosion issues [5]. This study aims to examine the factors that sustain treatment effectiveness in the Miocene, Oligocene, and Upper Oligocene formations of the Bach Ho field, analyzing near-wellbore treatment data from 1988 to 2022.

Between 1988 and 1999 [6], insufficient data for evaluating treatment effectiveness led to categorizing treatments into two groups: acid emulsion and acid solution. The acid emulsion method involves emulsifying acid solutions with oil phases such as diesel oil, crude oil, and acid microemulsions containing organic solvents and co-solvents [7]. The acid solution group includes hydrochloric acid, mud acid, polymer acid, and acid foam. Data from this period indicated that acidizing in clastic formations shows more significant challenges than in basement formations, emphasizing the need for further research to optimize acid systems [8].

From 2000 to 2022, the success of acid treatments was influenced by various factors, including reservoir geology, wellbore completion characteristics, acid composition, and the type of formation damage. Acid systems such as emulsified acid, hydrochloric acid (CKP), and mud acid (GKP) had notable impacts on clastic reservoirs in the Bach Ho field. Data analysis showed no significant difference in effectiveness between the conventional hydrochloric acid, mud acid, and acid emulsion systems between 2005 and 2007. However, after 2009, a decline in the efficiency of conventional hydrochloric acid and mud acid stimulation techniques was observed.

***Table 1.** Composition of acid systems used in the experiment*

No.	Solution	Composition (%)				
		HCl	HF	CH_3COOH	NTF	PAV
1	Hydrochloric acid	12	-	4	1.5	1.5
2	Mud acid	12	1.5	4	1.5	1.5

From 2000 to 2010, the acid emulsion system yielded positive results for clastic formations in the Lower Miocene, Upper Oligocene, and Lower Oligocene. Success rates remained high, typically ranging from 60% to 100%, with the lowest recorded rate being around 59% in 2004. The success rate was notably stable, remaining at approximately 80% for 6 consecutive years (2005 - 2010). However, after 2010, the use of acid emulsion was discontinued due to safety concerns [9 - 13].

Comparing the success rates of acid emulsion systems with hydrochloric acid and mud acid systems from 2005 to 2010, the emulsion systems were found to have a positive impact on clastic formations in the Bach Ho field. This suggests that organic contaminations (e.g., asphaltene, resin, oil/water emulsion, and water/oil emulsion) play a significant role, and addressing only inorganic contaminations is insufficient. Overall, the analysis indicates a decline in the effectiveness of hydrochloric and mud acid systems after 2011, primarily due to changes in the composition and concentration of acids and additives, which warrants further investigation to align with current field conditions.

2. Methodology

In this study, we initially conducted a series of experiments to evaluate the performance of the conventional acid solution used for acidizing treatment on sandstone formations, specifically focusing on the formation of emulsions, precipitation, and the potential for scaling. The results from these preliminary tests provided insights into the limitations and areas for improvement in the existing acid systems. The experiments focused on the acids that were currently being used at the Bach Ho field, including hydrochloric acid and mud acid, with the compositions provided in Table 1. This is the average composition of the acid systems as per the usage instructions for the Bach Ho field.

The crude oil used for the study was from Well 1 and Well 2. These two wells have experienced a decrease in production in recent years, following near-wellbore treatment, indicating poor treatment effectiveness. The incompatibility of reservoir oil with chemical systems is evident through two aspects and phenomena: (1) the formation of high-viscosity stable emulsions and (2) the formation of slugs, chemically composed of precipitates of asphaltene, resin, and high molecular weight paraffin [14 - 16].

Subsequently, based on the findings from the conventional acid experiments and widely accepted worldwide guidelines for acid selection in sandstone formations [1, 17], we developed a modified acid system. These guidelines are used by major companies such as Schlumberger, BJ, and Halliburton. The modified system was developed by adjusting the acid composition and the concentration of individual components. The authors analyzed the following criteria: permeability variation range, temperature range of the formation to be treated, mineral composition (quartz, feldspar, and clay mineral content), solubility of the formation rock in 15% HCl solution, and siltstone content. Based on analysis results, the authors proposed the optimal composition of the pre-flush acid and the main acid solution for the Lower Miocene, Upper Oligocene and Lower Oligocene formations in the Bach Ho field, as shown in Tables 2 and 3. This new formulation (CKP^+ and GKP^+) was designed to enhance compatibility with the formation fluids while minimizing undesired reactions such as precipitation or emulsion formation. The modified acid system underwent comprehensive testing, including shale stability evaluation, compatibility tests with formation fluids, thermal stability assessments, dissolution experiments on formation rock samples, permeability recovery tests, and corrosion evaluations. These tests aimed to ensure the stability and efficiency of the chemical system under the operational conditions of the Bach Ho field. The acid composition used in the corrosion test is shown in Table 4.

To improve compatibility, prevent secondary precipitation, and mitigate the formation of high-viscosity stable emulsions, the authors proposed using additional anti-sludge and anti-emulsion additives. In addition, the ability to inhibit swelling and stabilize clay was improved by using a clay stabilizer.

The emulsifier-breaking additives and clay stabilizers in the modified acid systems (CKP^+ and GKP^+) play a crucial role in enhancing the compatibility of the acid solutions with crude oil and preventing the formation of persistent emulsions. Specifically, the non-emulsifying agents help to reduce the crude oil and acid to emulsify, thereby inhibiting the stable emulsion creation that could otherwise cause flow restrictions. Mechanistically, these additives alter the surface properties of the acid, oil, clay interactions and the interfacial tension, thereby preventing both emulsion formation and secondary precipitation.

Finally, a Kinetix Matrix simulation was performed to model the acid injection process and its effect on skin factor changes throughout the acidizing treatment. Reservoir parameters used in simulation are shown in Table 5.

3. Result and discussion

3.1. Performance of the current acids

3.1.1. Stable emulsion capability

First, mixtures of Well 1 crude oil and acid solution were prepared to a total oil-acid volume of 25 ml and heated at 70°C for 2 hours to ensure homogenization. Each mixture was then blended with one of two acid formulations (hydrochloric "CKP" or mud-acid "GKP") at acid-to-oil volume ratios of 25:75, 50:50, and 75:25. The blends were vigorously shaken to form uniform emulsions and subsequently placed to a thermostatted bath maintained at 80°C. At defined intervals, and again after 2 hours or upon complete phase separation, the volumes of oil, water and emulsion layers were recorded. Thereafter, each sample was passed through a 100-mesh screen; any retentate was rinsed with 80°C water until completely passed. An acid system was deemed compatible if, after thermal treatment, it exhibited fully separated oil-water layers with a sharp interface and left no residue on the screen. In contrast, incomplete separation after 2 hours at 80°C and persistent screen blockage (indicative of stable, large-droplet emulsions) signified acid-oil incompatibility, with attendant risks of pore plugging and permeability impairment. Tables 6 and 7 summarize the emulsification capacities observed for CKP and GKP, respectively.

The results indicate that both the hydrochloric acid

Table 2. *Composition of the pre-flush acid solution*

No.	Chemical	Concentration (%)	Function
1	HCl	6 - 10	Dissolves inorganic contamination
2	CH_3COOH	5	Creates a buffering effect to keep pH at low level
3	Clay stabilizer	2	Inhibits clay swelling
4	Anti-sludge agent	1 - 2	Prevents the sludge formation
5	Interactive solvents	2	Improves quickly flow back to the well after treatment.
6	Anti-emulsifying agent	2	Prevents emulsion formation during treatment
7	Surfactant	5	Increases the contact of chemicals with the formation rock
8	Corrosion inhibitors	3 - 5	Inhibits, reduces corrosion
9	Water	Remaining	Dispersion medium

Table 3. *Composition of GKP^+*

No.	Chemical	Concentration (%)	Function
1	HCl	6 - 10	Dissolves inorganic contamination
2	HF	0.5 - 1	Dissolves inorganic contamination
3	CH_3COOH	5	Creates buffering effect to keep pH at low level
4	Clay stabilizer	2	Inhibits clay swelling
5	Anti-sludge agent	1 - 2	Prevents the sludge formation
6	Interactive solvents	2	Improves quickly flow back to the well after treatment.
7	Anti-emulsifying agent	2	Prevents emulsion formation during treatment
8	Surfactant	5	Increases the contact of chemicals with the formation rock
9	Corrosion inhibitors	3 - 5	Inhibits, reduces corrosion
10	Water	Remaining	Dispersion medium

Table 4. Composition of acid in corrosion test

No.	Acid	Composition
1	CKP+	HCl 8% + CH_3COOH 5% + Non-emulsifier 5% + Surfactant 2% + CS-1/CS-2 (2%) + Mutual solvent + CI-31 + Non-sludge 2%
2	GKP+	HCl 8% + HF 0.5% + CH_3COOH 5% + Non-emulsifier 5% + Surfactant 2% + CS-1/CS-2 (2%) + Mutual solvent + CI-31 + Non-sludge 2%

Table 5. Reservoir parameters

No.	Parameter	Value	Unit
1	Reservoir pressure	148.898	atm
2	Productivity index	1.9	m^3/d/atm
3	Permeability	89.4	mD
4	Skin factor	+9.8	
5	Reservoir temperature	90	ºC
6	Water cut	2 - 5	%
7	Oil rate	95	m^3/d
8	GOR	60	m^3/m^3
9	Gas density	0.72	
10	Oil density	0.8519	
11	Water density	1.02	
12	Pipe diameter	73	mm
13	Wellhead pressure	26	atm
14	Gas lift pressure	88	atm
15	Gas lift rate	25000	m^3/d

Table 6. Results of emulsion and slug formation of CKP acid system with Well 1 crude oil

No.	Acid/oil ratio	Phase	Emulsion state during sample storage time (%)				Note
			0 min	5 min	15 min	120 min	
1	25/75	Water	0	0	0	0	Whole was emulsion
		Emulsion	25	25	25	25	
		Oil	0	0	0	0	
2	50/50	Water	0	14.5	14.5	14.5	Separation part was water and emulsion
		Emulsion	25	10.5	10.5	10.5	
		Oil	0	0	0	0	
3	75/25	Water	0	18,5	18,5	18.5	Separated into 3 layers
		Emulsion	25	2,5	2,5	2.5	
		Oil	0	4	4	4	
Other observations: The CKP acid system was generally incompatible with crude oil from Well 1. When the acid contacted the oil, it formed a stable emulsion (25:75 ratio) or an incomplete emulsion, with a portion remaining as emulsion. The emulsion had high viscosity and could not pass through a 100-mesh screen (Figure 1).							

and mud acid systems currently used at the Bach Ho field are incompatible with the crude oil from Well 1. Notably, with a water phase ratio of 50%, the formed emulsion remains stable without separation.

The crude oil from Well 2 was generally compatible with the hydrochloric acid system, except at an acid-to-oil ratio of 25:75. However, this oil was incompatible with the mud acid system, as it tended to form slugs.

3.1.2. Slug formation capability

To evaluate the slug-formation tendencies of the acid system, 1000 ppm Fe^{3+} was added to the test acid solution and then mixed with the crude oil sample at a 1:1 volumetric ratio. The mixture was shaken vigorously to form a uniform emulsion, then placed in a thermostated bath at 80°C for 2 hours. After equilibration, the emulsion was poured through a 100-mesh screen and inspected. If

Figure. 1. Images of samples (CKP acid and Well 1 crude oil mixture with different volume ratios) after passing through a 100-mesh screen.

Table 7. Results of emulsion and slug formation of GKP acid system with Well 1 crude oil

No.	Acid/oil ratio	Phase	Emulsion state during sample storage time (%)				Note
			0 min	5 min	15 min	120 min	
1	25/75	Water	0	0	0	0	Whole is emulsion
		Emulsion	25	25	25	25	
		Oil	0	0	0	0	
2	50/50	Water	0	1.5	1.5	1.5	Mainly in emulsion
		Emulsion	25	23.5	23.5	23.5	
		Oil	0	0	0	0	
3	75/25	Water	0	18.5	18.5	18.5	Partly water, oil in emulsion form
		Emulsion	25	3.5	3.5	3.5	
		Oil	0	3.0	3.0	3.0	
Other observations: The GKP acid system was generally incompatible with crude oil from Well 1. At a water phase ratio of 50%, the formed emulsion was stable and did not separate. However, with a water phase ratio greater than 50%, phase separation occurred but was incomplete. The emulsion exhibited high viscosity and could not pass through a 100-mesh screen (Figure 2).							

Figure 2. Images of samples (GKP acid and Well 1 crude oil mixture with different volume ratios) after passing through a 100-mesh screen.

the oil phase did not fully pass through, the residue was rinsed with 80°C hot water. The acid system was deemed non-depositing if, after thermal treatment, complete phase separation occurred, and no solids remained on the sieve.

During the slug-formation test with the Fe-containing acid and crude oils from Wells 1 and 2, phase separation occurred, but a significant precipitate formed. Consequently, the separated oil phase could not pass

Figure. 3. *Images of precipitation and slug formation when CKP and GKP acid mixed with crude oil.*

through the 100-mesh screen (Figure 3), indicating deposit formation under these conditions.

Therefore, the acid systems currently used at the Bach Ho field pose a risk of forming stable emulsions with high viscosity when interacting with crude oil from the existing wells. The acid system itself, when contaminated with Fe (from pipeline and wellbore equipment corrosion products exposed to the acid solution), forms precipitates and slugs upon interaction with crude oil. These issues must be addressed during the optimization of the acid system composition.

3.1.3. Precipitation capability

To evaluate the capability of hydrochloric acid (CKP) and mud acid (GKP) systems to prevent secondary iron gel precipitation, Fe^{3+} at concentrations of 50 - 5,000 ppm was added to the acid solutions. Immediately following Fe^{3+} addition, both hydrochloric acid and mud acid solutions became cloudy and precipitated a white substance (Figure 4). This is a concerning signal, as in actual treatments, during pumping from the surface to the near-bottomhole zone, acid solutions dissolve and absorb steel corrosion products, creating Fe ions. These Fe ions can precipitate rapidly in the acid solution, leading to increased secondary precipitate formation, which could lead to near-bottomhole plugging.

Additional investigations of precipitation capability were carried out using a porous core model composed of reservoir rock and a reservoir model apparatus. Tests on Miocene rock samples from Well 3 and Well 4 showed that the post-treatment solution turned turbid and formed precipitates after being left undisturbed for a certain period.

A similar experiment was conducted to examine the precipitation potential of hydrochloric and mud acid as they flowed through a core sample. A reservoir model apparatus was used to analyze the resultant solution, with a core sample from Well 5 chosen for evaluation. Hydrochloric acid and mud acid were injected into the sample, and the resulting solution was allowed to settle undisturbed to observe any precipitation. The results showed the formation of a white precipitate in the post-reaction solution. The permeability recovery factor outcomes are detailed in Table 8.

To demonstrate the plugging ability of the precipitate, an experiment was conducted using the mud acid system with an additional 1,000 ppm Fe (specific composition: HCl 12% + CH_3COOH 4% + HF 1.5% + NTF 2% + 1,000 ppm Fe). The solution and precipitate were poured through a 100-mesh screen, and a large amount of precipitate was observed on the screen. This indicates that the precipitate size is >100 μm, capable of plugging sandstone pores.

Images of the precipitates obtained from the mud acid mixture with different Fe concentrations (500, 1,000, and 2,000 ppm) after drying are shown in Figure 5. These precipitates are NTF-iron complexes. Our findings align with the research in [18], which confirmed that NTF-iron complexes are poorly soluble. To improve the effect of NTF

Table 8. *Result of permeability recovery factor determination*

No.	Sample information	
1	Sample	Sample 1
2	Reservoir	Miocene
3	Gas permeability, (mD)	40.9
4	Temperature,(^{0}C)	115
5	Pressure, (atm)	100
6	Initial oil permeability K_1, (mD)	6.102
7	Chemical solution	CKP*
8	Oil permeability after treatment K_2, (mD)	5.956
9	Permeability recovery factor $K_{re} = K_2/K_1 \times 100\%$	99%
*CKP: HCl 6% + CH_3COOH 5% + NTF 4% + HF 1.5% + WCI-1212 1.25% + WHT 8213 3.75% + 1% PAV 2% + OS-802 100 g/m^3		

in the presence of iron, Shuchart and Gdanski [18] investigated adding the compound GLDA (L-glutamic acid diacetic acid) to NTF.

In conclusion, the studies presented in this section demonstrate that the hydrochloric acid and mud acid systems currently used at the Bach Ho field have limited secondary precipitation prevention capacity. These systems require further examination and improvement to meet new operational conditions.

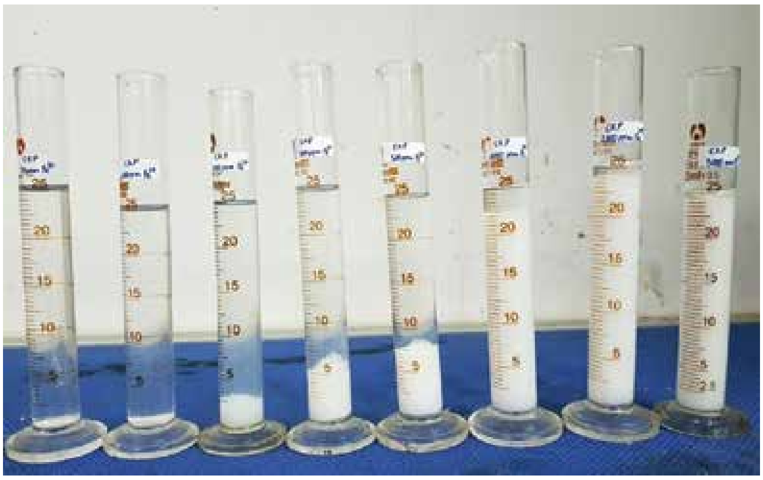

Figure. 4. *Images of precipitation when adding Fe^{3+} to CKP acid.*

Figure 5. *Images of the precipitates obtained from the mud acid mixture with different Fe contents.*

3.2. Performance of the modified acids

3.2.1. Shale stability

HCl-based acid systems lack the ability to prevent clay-swelling and may even induce clay-gel formation, thereby reducing permeability in formations containing HCl-sensitive clays, especially at lower temperatures. To overcome this limitation, two organic quaternary-amine stabilizers, CS-1 and CS-2, were evaluated. Both are colorless to pale-yellow viscous liquids, stable and low-toxicity in acidic environments, and effective from acidic to near-neutral pH [19, 20]. At 0.02 - 0.05 wt%, they outperform conventional NH_4Cl/KCl brines in enhancing shale stability, minimizing particle migration, and preventing pore blockage by fine clay fragments. These products are analogous to industry standards such as Halliburton's Cla-Sta FS, Schlumberger's L055, and Baker Hughes' Claytreat-3C and Claymaster-10.

CS-1 and CS-2 adsorb onto clay surfaces via electrostatic attraction: their positively charged functional groups bind to negatively charged clay platelets, forming a hydrophobic adsorption layer that impedes water ingress and suppresses clay swelling. Adsorption increases the clay's surface potential; this was confirmed by zeta-potential measurements on clay suspensions treated with CS-1 at 0.02% and 0.05%, which showed a marked rise in surface charge. Moreover, the polymeric nature of CS-1 provides interparticle bridging, as its cationic repeat

***Table 9.** Results of evaluating the compatibility of the proposed acid with crude oil from Well 1*

Time (min)	Emulsion separation	
	CKP^+	GKP^+
5	Completely soluble, no precipitation	Completely soluble, no precipitation
10	Completely soluble, no precipitation	Completely soluble, no precipitation
30	Completely soluble, no precipitation	Completely soluble, no precipitation

units link adjacent clay particles, preventing detachment and migration of fine grains that could otherwise plug pore throats.

The inhibitory effectiveness of CS-1 and CS-2 on shale from Formation X was quantified using laboratory swell-meter tests. Both stabilizers at 0.02 - 0.05% yielded superior suppression of shale expansion compared to brines containing 8% KCl or 5% NH_4Cl (Figure 6). In drilling practice, KCl is typically dosed at 80 - 120 kg/m^3 in formulations such as KCl/PHPA/Glycol or Ultradril® (MI Swaco) to protect shale, but protection often wanes after one day. In contrast, CS-1 and CS-2 deliver prolonged inhibition, effectively preventing shale swelling over extended periods at low concentrations.

3.2.2. Chemical system compatibility with formation fluid

Compatibility was assessed at 80°C using CKP^+ and GKP^+ acid formulations - each containing a non-emulsifier, clay stabilizer, surfactant and scale inhibitor - and formation fluids comprising crude oil from Wells 1 and 2 of the Bach Ho field, seawater, and completion brine (25.7% $CaCl_2$, 1.23 g/cm^3; 24% NaCl, 1.18 g/cm^3). Systems were deemed compatible if they either fully dissolved to yield a homogeneous single phase (in miscible cases) or completely separated without secondary precipitate formation (in immiscible cases). Results for Well 1 (Table 9, Figure 7) and Well 2 were equivalent, confirming that CKP^+ and GKP^+ are fully compatible with the tested formation fluids, with no precipitates or emulsions observed.

3.2.3. Thermal stability

Thermal stability was evaluated by heating CKP^+ and GKP^+ acid solutions in transparent, heat-resistant vials at 2 - 3°C/min in an oven. At every 10°C increment, up to a final temperature of 120°C, the samples were held for 10 - 15 min and visually inspected. After 120 min at 90°C, both formulations remained clear and homogeneous, with no phase separation or precipitation; identical behavior was observed at 125°C and 130°C. These results demonstrate that CKP^+ and GKP^+ retain thermal stability under the tested conditions.

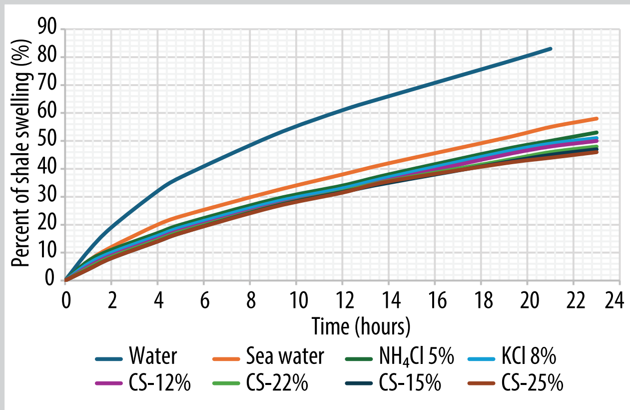

***Figure 6.** Effects of salt on clay swelling.*

***Figure 7.** Images of samples after passing through a 100-mesh screen.*

3.2.4. Dissolution experiment on formation rock

Consolidated sandstone from the Bach Ho field (18 g each from the Lower Miocene and Lower Oligocene) was characterized for composition and mineralogy, then exposed to the CKP^+/GKP^+ acid systems. Pre-experimental analyses established baseline chemical and mineralogical profiles. Table 10 reports that the mass percentage dissolved after drying. Dissolution tests showed that the acid blend attacked less than 6% of the rock, confirming minimal degradation of the cementing matrix and preserving the integrity of loosely consolidated Lower Miocene sands.

3.2.5. Permeability recovery experiments

Global service-provider guidelines correlate treatment efficacy with acid volume per meter of perforation. Optimal stimulation requires > 1.55 m^3/m (125 gal/ft), while near-wellbore cleanup typically uses 0.31 - 0.93 m^3/m (25 - 75 gal/ft).

Core-flood experiments to evaluate permeability recovery were conducted on Lower Miocene and Lower Oligocene cores using the following protocol. First, each core was oil-saturated by injecting five pore volumes (PV) of crude oil in the forward direction, and the initial permeability (K_1) was measured. Inorganic damage was then induced by sequentially injecting one PV of Solution A (5 g/l $CaCl_2$ + 5 g/l $FeCl_3 \cdot 6H_2O$) followed by one PV of Solution B (5 g/l Na_2CO_3 + 2.5 g/l Na_2SO_4 + 2.5 g/l NaOH) or until effluent precipitation occurred. After aging under reservoir conditions for 1 - 2 hours, three PV of viscous oil were forward-flooded to determine post-damage permeability (K_2). Acid treatment was performed in reverse flow by injecting one PV of NH_4Cl brine, one PV of pre-flush acid, and one PV of the main acid formulation. Finally, three PV of viscous oil were injected forward to measure the treated permeability (K_3). The permeability-recovery factor (K_3/K_1) was calculated to assess the effectiveness of the proposed chemical system (Table 11).

Based on the results obtained, it is evident that:

- All simulations of formation damage yielded reduced permeability, sometimes markedly, confirming that the experimental protocol successfully reproduced damage mechanisms such as $Fe(OH)_3$, $CaCO_3$, and $CaSO_3$ precipitation.

- Treatment efficacy was evaluated by comparing permeability before damage (K_1) and after acid remediation (K_3). A K_3/K_1 ratio ≥ 0.9 denotes effective removal of both primary and secondary damage.

Core-flood results demonstrate that the proposed acid systems not only restore permeability but also inhibit clay swelling, yielding high recovery factors and confirming their suitability for damage remediation.

3.2.6. Corrosion test

The authors investigated the corrosion performance of the chemical system, comparing it to the corrosion inhibitor CI-31 currently used in the acid treatment process at Field X, provided by Baker Hughes. To assess

***Table 10.** Results of sample dissolution experiments*

No.	Chemical system	Initial sample mass	Sample mass after reaction	Percent of sample dissolved	
		g	g	90°C	120°C
1	GKP^+ = 10:1	9.003	8.892	1.2	
2	GKP^+ = 10:1	9.001	8.516	5.4	
3	GKP^+ = 10:1	9.002	8.900		1.1
4	GKP^+ = 10:1	9.003	8.937		0.7

***Table 11.** Results of evaluating the permeability recovery*

No.	Sample information		
1	Sample	Sample 1	Sample 2
2	Reservoir	Oligocene	Miocene
3	Gas permeability (mD)	21.78	218.64
4	Temperature (°C)	100	100
5	Pressure, atm	100	100
6	Initial oil permeability, K_1 (mD)	3.22	40.22
7	Oil permeability after simulating contamination K_2 (mD)	2.19	29.14
8	Pump order	NH_4Cl 5%: $1V_0$	NH_4Cl 5%: $1V_0$
		Acid CKP^+: $1V_0$	Acid CKP^+: $1V_0$
		Acid GKP^+: $2V_0$	Acid GKP^+: $2V_0$
		NH_4Cl 5% - $1V_0$	NH_4Cl 5% - $1V_0$
9	Oil permeability after treatment K_3 (mD)	4.2	65.56
10	Permeability recovery factor K_{re}	**155.27**	**191.94**

corrosion characteristics under conditions resembling those of the formation, the "HP-HT Corrosion Cell" was used, maintaining conditions at 120°C and 100 atm for 4 hours, in accordance with ASTM standards (ASTM G1-03; ASTM G3-72) using the mass loss method. The evaluation results are displayed in Table 12.

The corrosion evaluation results demonstrate that the proposed chemical systems featuring corrosion inhibitor CI-31 show diminished corrosion rates compared to the present acid system utilized in Bach Ho field. Furthermore, these outcomes satisfy the criteria of maintaining a corrosion rate below 10 mm/year.

3.2.7. Simulation

Well X-1ST began production via gas lift in the Miocene reservoir on September 1, 2021, with an initial output of 89 tons per day from zones at depths ranging between 2,760 - 2,803 m and 2,848 - 2,920 m within the Bach Ho field.

The authors used Schlumberger - Techlog Kinetix Matrix software to formulate the treatment pumping schedule, simulate the treatment procedure for individual layers (Figure 8), evaluate each solution during treatment, and monitor real-time variation in the skin factor throughout the treatment (Figure 9).

Table 12. *Corrosion test results*

Sample	Mass - before (g)	Mass - after (g)	Mass loss (g)	Corrosion rate (mm/year)
		CKP^+		
1	353.005	352.695	0.3100	3.2738
2	343.923	343.611	0.3120	3.2918
3	347.543	347.031	0.5120	5.4044
		Average		**3.9900**
		GKP^+		
1	349.215	348.803	0.4120	4.3504
2	350.147	349.529	0.6180	6.5253
3	361.123	360.522	0.6012	6.3434
		Average		**5.7397**
		Acid being used for Bach Ho field		
1		GKP		**7.60**
2		CKP		**6.02**

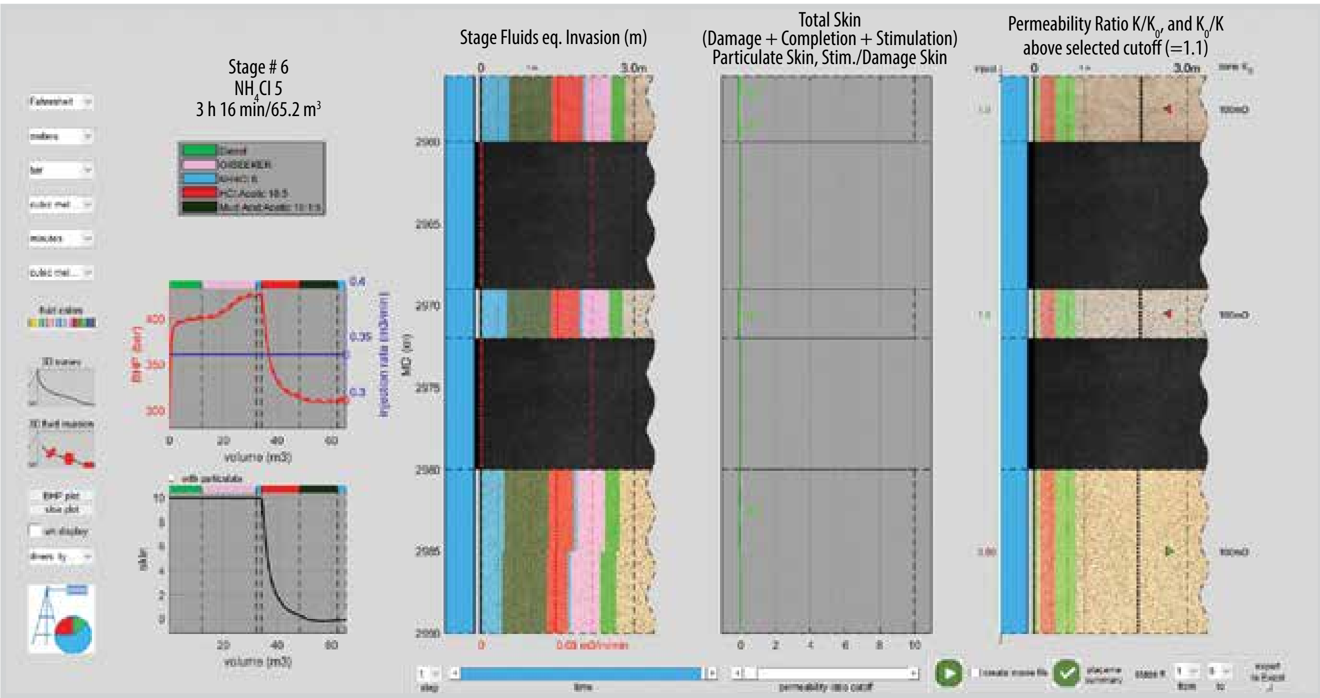

Figure 8. *Treatment process simulation for each layer.*

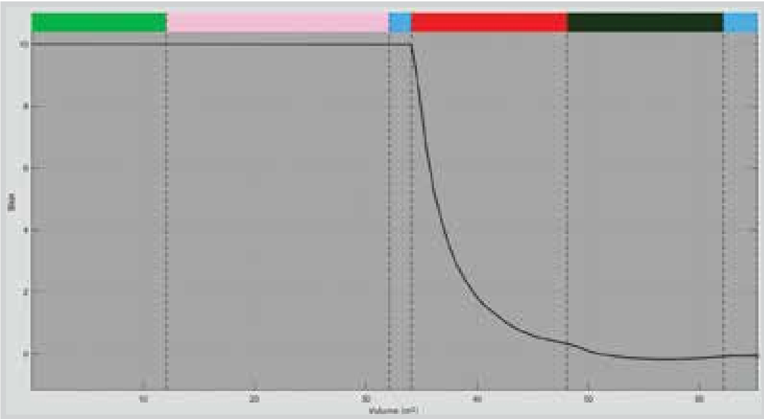

Figure 9. *Real-time variation in the skin factor throughout the treatment.*

The simulation results indicate that the acid system effectively dissolves inorganic scale and infiltrates fine particles from the formation into the near-wellbore area. Specifically, for Well X-1ST, the CKP^+ and GKP^+ acid systems proposed in this study, consisting of 8% HCl, 0.5% HF, and additional additives, show effective fouling dissolution within the well. As a result, the skin factor gradually decreased during the simulation, from 9.8 to 0, after treatment with the proposed acid system.

4. Conclusion

In conclusion, the modified acid systems, CKP^+ and GKP^+, exhibit significant advantages over conventional acidizing methods in the Bach Ho field. The results from the laboratory experiments and simulations confirm that these systems address common issues such as emulsion formation, clay swelling, and secondary precipitation. The introduction of clay stabilizers and anti-emulsifiers in the acid formulations has enhanced compatibility with crude oil and mitigated the formation of undesirable emulsions. Moreover, the dissolution experiments and permeability recovery tests have proven that these systems can effectively remove formation damage and restore permeability, especially in formations with high clay content. The simulation results highlight the promising potential of these acid systems in reducing the skin factor, improving hydrocarbon recovery, and ensuring stability under high-temperature and high-pressure conditions. These findings provide valuable insights into the design of more effective acid treatments for challenging reservoirs, offering both economic and operational benefits. Further optimization and field trials will be essential to fully understand the long-term performance of these systems in different geological settings.

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