Application of Thermochemical in Removing Condensate Banking in Gas Condensate Reservoirs

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Abstract

The accumulation of liquid near the wellbore, induced by condensate banking in gas condensate reservoirs, significantly impairs gas production rates, presenting a substantial challenge for hydrocarbon recovery. Conventional methods such as CO_2 injection and produced gas cycling offer only temporary mitigation, requiring frequent reapplication, which results in high operational costs and logistical complexities. This study explores the potential of thermochemical fluids (TCFs) as a more durable and cost-efficient alternative to address condensate banking. The exothermic reaction between sodium nitrite ($NaNO_2$) and ammonium chloride (NH_4Cl), catalyzed by acetic acid (CH_3COOH), produces heat, generating temperatures of up to 84°C, and achieving a maximum recovery of 52% from four core samples. TCFs induce in-situ heating, the release of nitrogen gas, and the generation of pressure, which together create microcracks that facilitate the vaporization and mobilization of the trapped condensate. This approach also helps maintain reservoir pressure above the dew point and reduces capillary pressure in the pore spaces. The study investigates the influence of varying reactant and catalyst concentrations on the reaction kinetics, emphasizing the critical role of optimal stoichiometry to maximize heat generation. Core flooding experiments were conducted using the huff-and-puff injection technique to compare the performance of TCFs injection with CO_2 injection. The results consistently showed superior condensate recovery with TCFs injection across all experiments.

Introduction

Retrograde gases represent a distinct category of gases that exhibit non-ideal behavior. Unlike typical gases, which expand when pressure decreases in accordance with Boyle's law, retrograde gases undergo condensation into a liquid phase. As pressure decreases and approaches a critical point, intermolecular forces, particularly van der Waals forces, become increasingly significant, leading to a reduction in volume and a phase transition from gas to liquid. This behavior deviates from the ideal gas law, where volume and pressure are inversely proportional at a constant temperature. Condensate gas reservoirs, which exhibit retrograde gas behavior, have garnered considerable attention due to their unique and complex nature. With the increasing global demand for energy, including oil and gas, the simultaneous production of gas and condensate holds substantial economic value (Izuwa et al. 2014; Li et al. 2023). In particular, Nigeria stands to benefit from condensate production, as it is not subject to OPEC production quotas (Nwabueze 2000). Furthermore, the pricing of condensates is comparable to that of naphtha, making it more profitable than crude oil on a per-volume basis. In alignment with this, on January 1st, 2024, the Nigerian Upstream Petroleum Regulatory Commission (NUPRC) set an

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Improved Oil and Gas Recovery
DOI: 10.14800/IOGR.1325
Received October 11, 2024; revised November 25, 2024; accepted December 20, 2024.

*Corresponding author: nkemakolam.izuwa@covenantuniversity.edu.ng ambitious target of producing 2.6 million barrels per day (bpd) of oil and condensates by 2026, a notable increase from the 1.6 million bpd achieved in 2023 (Mishra 2024). Nigeria's oil exports have been adversely affected by factors such as inadequate investment, crude theft, and pipeline vandalism, which have collectively diminished government revenues. Consequently, there is a strong incentive to enhance condensate production through innovative methods. However, the efficient exploitation of these reservoirs requires a comprehensive understanding of their phase behavior to prevent condensate banking, a phenomenon that has substantial implications for hydrocarbon recovery (Shariati et al. 2014).

The phase envelope diagram in Figure 1 depicts the reservoir's behavior, with the system operating between the critical temperature and cricondentherm, as described by Guo et al. (2020). The dashed lines within the envelope represent constant liquid volume fractions, ranging from 100% at the bubble point to 0% at the dew point. For the purpose of this experiment, assume the initial conditions are at pressure P_i and temperature T_i, where the reservoir temperature lies below the phase envelope's cricondentherm but remains above the critical temperature (C). As the reservoir pressure is reduced at constant temperature, following the pathway denoted by the solid line ABDE, the phase behavior of the system can be analyzed.

At point A along the dew point line, a liquid phase begins to form in the reservoir. As the pressure is reduced, additional liquid condenses, increasing the liquid phase volume until it accounts for 10% of the total reservoir volume at point B. With further pressure reduction, the liquid volume fraction rises to a maximum of approximately 12%. Beyond this point, the liquid phase volume decreases as the pressure continues to decline, returning to 10% at point D. The liquid volume continues to decrease from point D to point E. At point E, corresponding to the lower dew point, the liquid phase completely disappears (Ezekwe 2010). The liquid phase that has formed remains immobile until the condensate saturation exceeds the critical condensate saturation, at which point the oil phase becomes mobile and starts to flow (Izuwa et al. 2015).

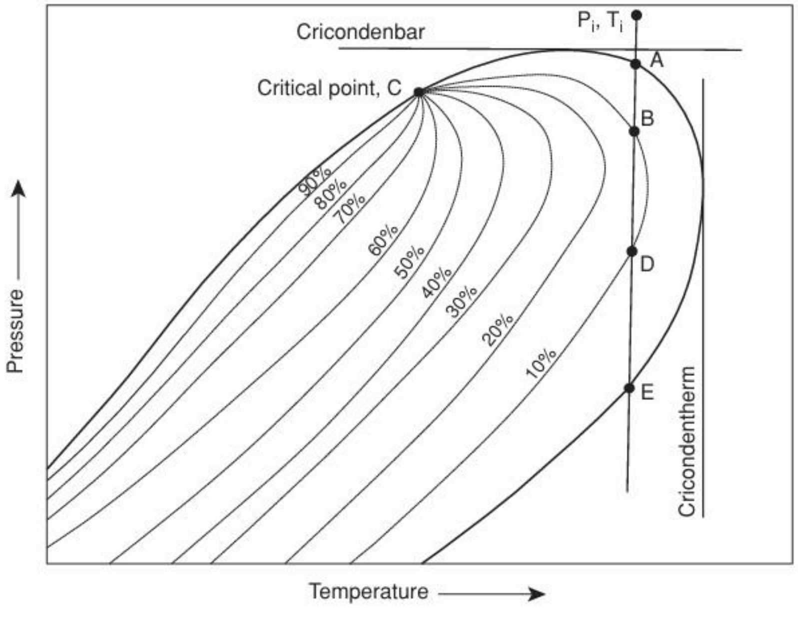


Figure 1—Phase Envelope of Retrograde Gas Condensate (Source: Ezekwe 2010).

The accumulation of condensate around the wellbore results in significant immobilization, leading to a marked reduction in effective gas permeability, which in turn decreases overall gas production (Hassan et al. 2019a). Asgari et al. (2014) demonstrated that condensate banking in carbonate reservoirs could reduce effective gas permeability by up to 80%. Additionally, in a core flooding experiment conducted by Kumar et al. (2006) on both reservoir and Berea sandstone cores, condensate banking caused the relative permeability to gas to decrease by 90% of its initial value during condensate accumulation. The impact of condensate banking on the gas relative permeability (K_{rg}) is illustrated in **Figure 2**.

As the distance from the borehole increases, condensate saturation (depicted by the green curve) decreases, while gas relative permeability (shown by the red curve) increases. This reduction in condensate saturation facilitates greater gas flow through the pore network. The issue is particularly pronounced in tight or low-permeability reservoirs, where the accumulated condensate remains largely immobile, acting as a barrier to the movement of gas, potentially leading to a complete cessation of gas productivity (Sayed and Al-Muntasheri, 2016). To address this challenge, various recovery techniques, such as chemical injection, horizontal well technology, gas cycling, and hydraulic fracturing, are commonly employed to mobilize the trapped condensate and enhance gas reservoir deliverability (Kumar et al. 2006; Evans et al. 2016; Su et al. 2017; Khan et al. 2010).

The Thermochemical Enhanced Oil Recovery (EOR) process introduces a novel approach by addressing both the fluid properties and the physical conditions required for pressure stabilization within gas condensate reservoirs, setting it apart from conventional methods that primarily focus on physical interventions. Hydraulic fracturing creates new fluid flow pathways within reservoir rock formations but does not alter the properties of the fluids, such as oil, condensate, or water. Gas cycling, which involves reinjecting gas to maintain reservoir pressure and mitigate condensate dropout, similarly does not modify interfacial tension or wettability. Horizontal well drilling increases the reservoir volume and enhances wellbore contact with the formation; however, like hydraulic fracturing, it does not directly impact the fluid properties.

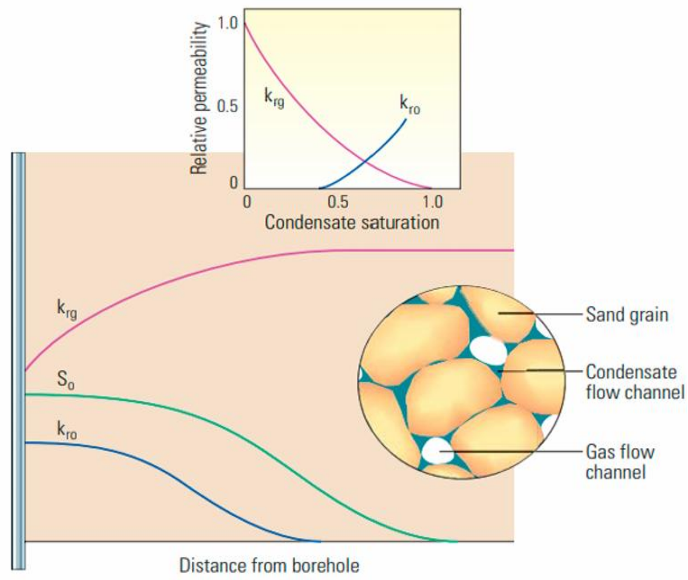


Figure 2—Condensate blockage schematic with reflection to relative permeability curves (Source: Sayed and Al-Muntasheri 2016).

A novel thermochemical treatment has been developed to enhance formation productivity and mitigate condensate banking (Sayed and Al-Muntasheri 2016). This approach utilizes reactive fluids to generate both pressure and heat, which not only creates multiple fractures but also modifies the behavior of the condensate (Hassan et al. 2018). According to Hassan et al. (2019a), the in-situ temperature and pressure generated during this process can exceed 500 ° F and 5000 psi, respectively. This treatment has demonstrated potential for reducing condensate-related damage and improving long-term formation deliverability (Hassan et al. 2019b). Hassan et al. (2018) further observed that the injection of thermochemical fluids can increase the reservoir pressure and temperature beyond the dew point curve, facilitating the transformation of liquid condensate into gas. Their findings revealed that the thermochemical reaction could generate a pressure of 1300 psi under typical reservoir conditions. The mechanisms driving this recovery include the reduction of capillary forces, immiscible displacement, modification of rock characteristics, and a decrease in viscosity (Hassan et al. 2019a). Under reservoir conditions, two chemicals that remain stable under surface conditions, ammonium chloride (NH_4Cl) and sodium nitrite ($NaNO_2$), can produce in-situ nitrogen gas, steam, heat, and pressure when their reaction is triggered. The reaction products are only generated once the thermochemical reaction begins. Thermochemical fluids (TCFs) are typically non-toxic, cost-effective, and environmentally friendly. The reaction can be initiated either by the natural reservoir temperature or by introducing a chemical activator. Specifically, the injection of an acidic fluid, acting as a catalyst, lowers the pH and triggers exothermic reactions within the reservoir formation (Hassan et al. 2019c; Hassan et al. 2020).

$$NH_4Cl + NaNO_2 \rightarrow NaCl + 2H_2O + N_2\,(\text{gas}) + \Delta H\,(\text{heat}), \quad (1)$$

In an experiment conducted by Hassan et al. (2019c), the huff-and-puff technique was applied to tight sandstone cores with a permeability of 0.9 mD, resulting in a 63% recovery of the initial condensate through the injection of thermochemical fluids. This process led to an increase in the inlet pressure, reaching 2300 psi, which significantly altered the behavior of the condensate. As depicted in Figure 3, the thermochemical treatment raised the temperature and partially restored the pressure within the system. The treatment moved the system to the point (3500 psi, 350 ° F), marked by the green triangle. This elevated temperature shifted the pressure-temperature (P-T) conditions back within the phase envelope, facilitating the redissolution of condensate liquid into the gas phase, thus enhancing flow efficiency and reducing liquid dropout. Furthermore, the treatment affected the rock's properties, such as permeability and capillary forces, through the pressure pulses. The removal of condensate banking resulted in an increase in the effective gas permeability, improving the relative permeability to gas by a factor of 1.98. The treatment also reduced capillary forces by 90%, with capillary pressure decreasing to 1.36 psi and 90.4 psi, respectively (Hassan et al. 2019c).

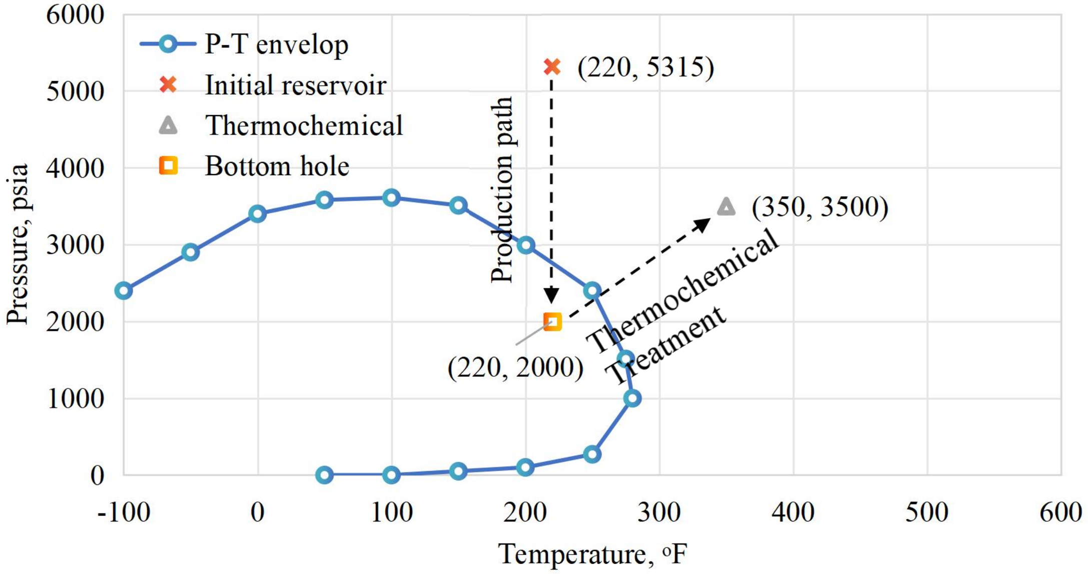


Figure 3 — Alterations of condensate behaviour due to thermochemical treatment (adapted from Hassan et al. 2019b).

In a separate study, Hassan et al. (2019a) demonstrated that thermochemical fluids can effectively mitigate condensate damage in sandstone formations when applied using the huff-and-puff injection method. The study showed that, on average, 67% of condensate could be removed without causing any formation damage. It was observed that more permeable rocks experienced greater condensate removal after treatment, while tight sandstones exhibited more moderate levels of liquid removal. The thermochemical treatment works through a chemical reaction between the fluid and the minerals in the formation, generating heat or gas to mobilize the condensate and remove it from the pore spaces. In permeable rocks, the larger pore throats facilitate easier penetration of the fluid, leading to more significant condensate removal. In contrast, tight sandstones, with their smaller pore throats, exhibited less pronounced condensate removal. The study concluded that, in general, three cycles of thermochemical treatment are sufficient to mitigate condensate damage in various sandstone formations.

Methodology

This section will present both qualitative and quantitative analyses, including thin section analysis of various tight sandstone cores, determination of porosity and permeability, chemical reactions of aqueous solutions, and core flooding experiments. For the thin section analysis, a Polarizing Microscope will be utilized due to its ability to provide detailed insights into the mineralogical composition and structural characteristics of the sandstone cores.

Thin Section Analysis. In this study, thin section analysis was conducted on five tight sandstone cores with varying porosities using a Polarizing Microscope in the laboratory. The Polarizing Microscope is a specialized tool equipped with polarizing filters that allows for the detailed examination of mineral compositions in core samples. The process involves slicing the rock into extremely thin sections and then illuminating them with polarized light. By observing how the light interacts with the minerals, I was able to identify and quantify the different minerals present, such as quartz, plagioclase, and muscovite. The percentages of these minerals are presented in **Table 1**.

Table 1—Diagnostic features of minerals from thin section.

Mineral Observed	Isotropic vs. Anisotropic	Interference Colours	Pleochroism
Quartz	Isotropic	No variation in colour	None (Remains colourless)
Plagioclase Feldspar	Anisotropic	Typically shows 1st order colours (low to moderate intensity): grey, white, yellow	Can exhibit weak pleochroism in some varieties (subtle colour changes)
Muscovite	Anisotropic	High order interference colours: bright yellows, greens, or reds	Strong pleochroism: colourless to pale yellow/green depending on orientation
Microcline	Anisotropic	Like plagioclase: 1st order colours (grey, white, yellow)	Can exhibit weak to moderate pleochroism in some varieties

Figure 4—Thin section of cores on glass slides.

Reaction Kinetics. Reaction kinetics refers to the study of the rates at which reactants are consumed and products are formed over time. It is typically quantified in units such as concentration change per unit time (e.g., M/s). The investigation of reaction kinetics involves understanding how different factors influence the rate of a chemical reaction. These factors include:

(i) Concentration of reactants
(ii) Temperature
(iii) Presence of a catalyst
(iv) Reaction mechanism (the step-by-step process of the reaction)

Experimental Design. A thermometer was placed within the vacuum tube of the compacted vacuum system to monitor any changes occurring during the experiment. The distinct thermochemical fluids were mixed in the vacuum jar after being dissolved in de-ionized water to create a soluble solution. The reaction was observed for five minutes before adding a catalyst (20 mL of acetic acid) to initiate the reaction. Throughout the experiment, the generated pressure and temperature were recorded at 5-minute intervals, along with their relationship to time. Key parameters such as the buildup, stability duration, and reaction rate were determined by observing the system's response. The experiment was conducted at various molar and catalyst concentrations, as outlined in **Tables 2** to **4**. By tracking the reaction temperature and pH after the catalyst (acetic acid, CH_3COOH) was introduced, the impact of different reactant concentrations on the reaction kinetics of the $NaNO_2/NH_4Cl$ system was evaluated. The results indicated that a molar concentration of 5M $NaNO_2$ and 5M NH_4Cl produced the highest temperature yield and pH reduction, indicating a more efficient reaction.

Table 2—Properties for 2M+2M solution + 20ml acetic acid.

Properties	$NaNO_2$	NH_4Cl	Product
Molar Concentration, mol (g)	2M (138g)	2M (107g)	-
pH	6	4	5
Temperature (°C)	22	24	65

Table 3—Properties for 2M+2M solution + 30ml acetic acid.

Properties	$NaNO_2$	NH_4Cl	Product
Molar Concentration, mol (g)	2M (138g)	2M (107g)	-
pH	6	4	5
Temperature (°C)	22	24	67

Table 4—Properties for 5M+5M solution + 60ml acetic acid.

Properties	$NaNO_2$	NH_4Cl	Product
Molar Concentration, mol (g)	5M (345g)	5M (267.5g)	-
pH	6	4	3
Temperature (°C)	18	20	84

Result

Modal Analysis of Core Samples. Modal analysis utilizes data from the thin section to quantify the relative abundance of each mineral present in the rock. It determines the modal mineralogy, which refers to the volume percentage of each mineral in the rock sample. **Table 5** presents the modal analysis of the Niger Delta core plugs used in the experiment.

The thin section analysis revealed a predominance of quartz in all five core samples, with concentrations ranging from 76.89% in Sample 3 to 96.8% in Sample 1. Other identified minerals included microcline (a type of feldspar), plagioclase feldspar (present in Samples 3 and 4), and muscovite (a clay mineral), which was only found in Sample 3. These findings provide insight into the mineral composition of the core samples, which can be important for understanding their petrophysical properties and behavior under various experimental conditions.

Table 5—Modal analysis of niger delta core samples.

Sample Number	Quartz (%)	Microcline (%)	Plagioclase (%)	Muscovite (%)
Sample 1	96.8	3.2	-	-
Sample 2	96	4	-	-
Sample 3	76.89	13.2	6.6	3.3
Sample 4	93.8	3.09	3.09	-
Sample 5	95.77	4.22	-	-

Potential Impact of Clay Minerals on Condensate Recovery. The presence of clay minerals, particularly muscovite in Sample 3, could potentially affect condensate recovery in the core flooding experiment through several mechanisms:

Reduced Pore Throat Size. Clay minerals often have a platy (plate-like) structure. These platy clays can coat pore surfaces and bridges between larger grains, effectively reducing the size of pore throats. This can hinder the flow of condensate through the rock, potentially impacting recovery during the production phase.

Wettability Alteration. Clay minerals can alter the wettability of the rock surface. In some cases, clays can promote a more water-wet condition. Condensate, being a hydrocarbon liquid, prefers a more oil-wet environment. A shift towards water-wetness might lead to increased residual condensate saturation within the core, further reducing recoverable volumes.

Effect of Reactant and Catalyst Concentration on the Temperature Generated. The reaction between sodium nitrite and ammonium chloride was evaluated by measuring the heat produced over time. Additionally, the influence of temperature and concentration on the reaction was explored to better understand its kinetics. **Figures 5** to **7** illustrate how the concentration of the thermochemical fluids affects the temperature during the reaction. These figures provide a visual representation of how varying concentrations of the reactants influence the thermal output, contributing to the overall understanding of the reaction dynamics and its potential for enhancing gas reservoir productivity.

The study investigated the effects of varying concentrations of Sodium Nitrite ($NaNO_2$) and Ammonium Chloride (NH4Cl), at 2M and 5M, on the temperature generated during the reaction. Additionally, the influence of catalyst concentration, specifically acetic acid (CH_3COOH), was explored. A series of reaction kinetics experiments were conducted to examine the interaction between reactant and catalyst concentrations, and the resulting temperature profiles.

In these experiments, identical initial concentrations of 2M Sodium Nitrite and 2M Ammonium Chloride were used, with varying volumes of acetic acid (Figures 5 and 6). In another set of experiments (Figure 7), the reactant concentrations were increased, and the catalyst volume was proportionally adjusted. Temperature changes were monitored over time, from 5 to 80 minutes. The results indicate a significant interplay between reactant concentration, catalyst volume, and the heat generated, providing deeper insights into the kinetics of the thermochemical reaction.

In Figures 5 and 6, a modest temperature increase is observed with a slight increase in catalyst volume (30 mL vs. 20 mL). Both scenarios show a peak temperature around the 10-minute mark, with Figure 6 exhibiting a marginally higher peak (67°C vs. 65°C). However, the increase in temperature is minimal, and considering the additional cost of the catalyst, this may not be economically advantageous for field-scale applications.

In contrast, Figure 7 demonstrates a more substantial temperature increase. In this case, both reactant concentrations were increased fivefold (to 5M), and the catalyst volume was adjusted proportionally to 60 mL. This resulted in a significantly higher peak temperature of 84 ºC compared to the previous scenarios. This finding highlights the critical role of reactant concentration in driving the heat evolution during the thermochemical reaction. A higher concentration of reactants provides more reacting molecules, amplifying the exothermic reaction and leading to a higher temperature rise, which is more favorable for optimizing reaction efficiency in larger-scale operations.

These findings indicate that while catalyst concentration does have some influence on temperature, the concentration of reactants plays a more critical role in optimizing heat generation during the thermochemical reaction for condensate bank remediation. Higher reactant concentrations lead to a greater number of reacting molecules, resulting in a more significant exothermic effect and a higher temperature increase. This insight is crucial for optimizing the thermochemical formulation for field applications, allowing for a balance between economic feasibility and the achievement of the desired temperature profile necessary for effective condensate recovery. By carefully adjusting reactant concentrations and catalyst volumes, it is possible to maximize the efficiency of the treatment while maintaining cost-effectiveness in field operations.

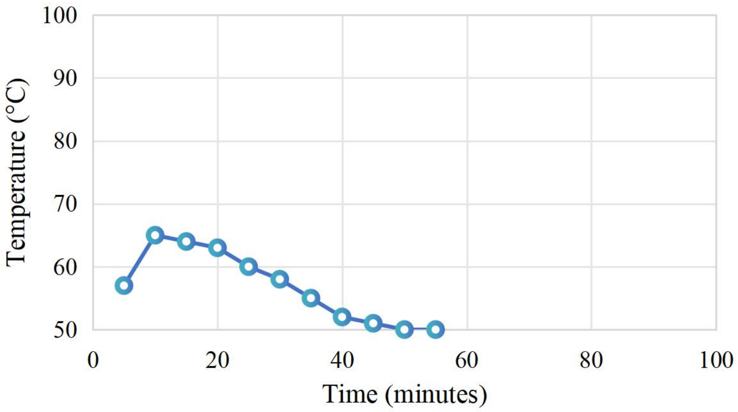


Figure 5—Temperature yield analysis–2M+2M (20ml acetic acid).

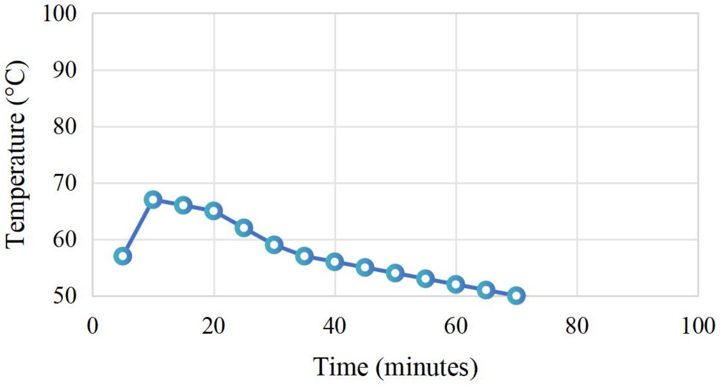


Figure 6—Temperature yield analysis–2M+2M (30 ml acetic acid).

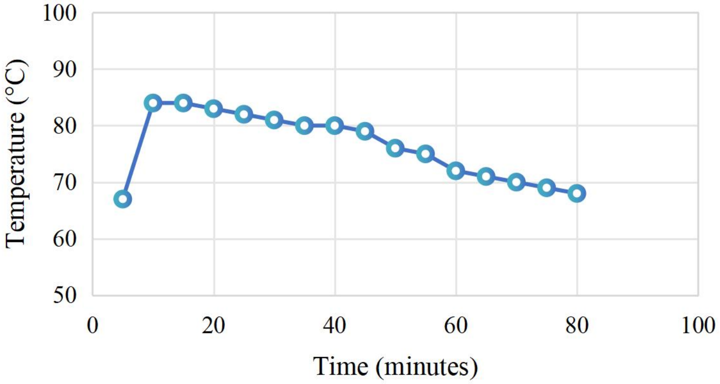


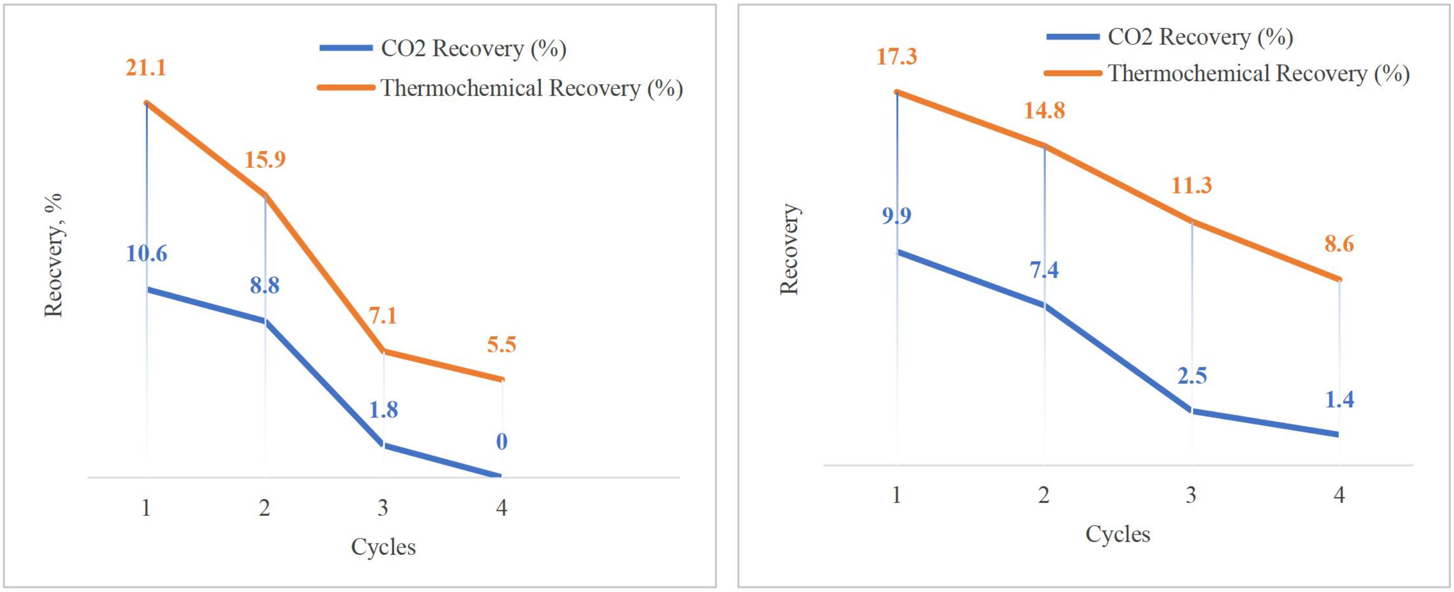
Figure 7—Temperature yield analysis–5M+5M (60ml acetic acid).

Analysis of Thermochemical Injection vs CO_2 Injection. Building upon the insights from the reaction kinetics experiments, we proceeded with core flooding experiments to evaluate the performance of the most effective thermochemical formulation (5M+5M reactants with 60 ml catalyst) in comparison to CO_2 injection, a commonly utilized enhanced oil recovery (EOR) technique. The huff-and-puff method was employed on four core samples (S4, S5, S6, S7), with their properties detailed in **Table 6**.

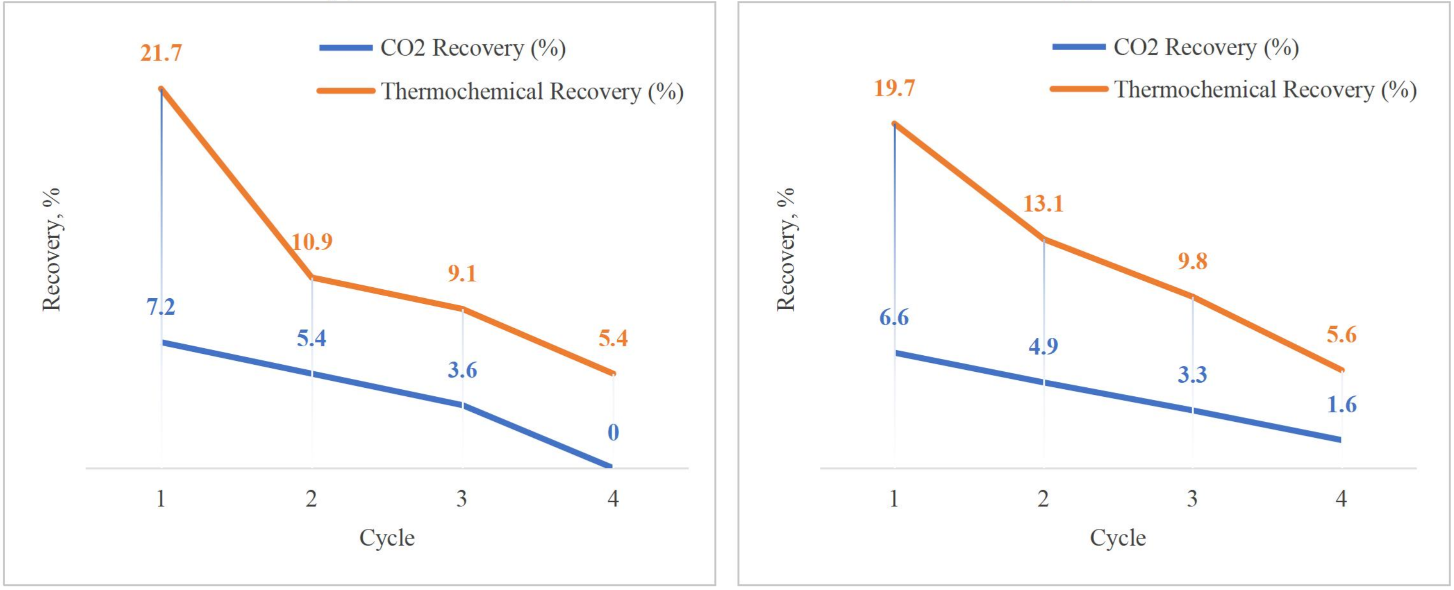
Table 6—Sandstone core properties.

Test No.	Diameter (cm)	Length (cm)	Dry weight (g)	Wet Weight (g)	Bulk volume (Vb) (cm^3)	Porosity (%)	Pore volume (Vp) (cm^3)	Permeability (mD)
S4	3.7	3.3	68	77	35.48	13.24	9.00	285
S5	3.65	4.2	86	97	43.95	12.79	11.0	372
S6	3.8	5.0	121	129	56.71	6.61	8.0	409
S7	3.8	5.0	121	129	56.71	6.61	8.0	409

Production data for each core sample are shown in **Figure 8**. A consistent trend emerged across all four core samples: the highest condensate recovery occurred during the first injection cycle. Specifically, Figure 8(c) highlights sample S6, which achieved the highest initial recovery of 21.7%. This result demonstrates the efficacy of the thermochemical treatment in improving condensate recovery during the initial stage of the process, with the potential for further optimization in subsequent cycles.



(a)S4 (b)S5



(c) S6 (d)S7

Figure 8—Production comparative analysis.

However, sample S6 also exhibited a significant decline in condensate recovery during the subsequent cycles, ultimately resulting in the lowest overall recovery of 47.1%. In contrast, sample S5, despite having the lowest initial recovery (Figure 8(b)), demonstrated a more stable recovery profile across all cycles, ultimately achieving the highest cumulative recovery among all the samples. These observations suggest that factors beyond initial recovery, likely related to the structural or petrophysical properties of the core samples, can significantly influence long-term performance.

The core flooding experiments also provided a valuable comparison between thermochemical fluid injection (TCFs) and CO_2 injection. While CO_2 injection typically stabilizes pressure and reduces condensate dropout, the thermochemical treatment showed superior performance in terms of both initial recovery and long-term condensate mobilization, especially in cores with favorable petrophysical characteristics. These findings highlight the potential for thermochemical treatments to enhance recovery efficiency, particularly in challenging reservoirs with complex phase behavior.

In all four core samples, the injection of thermochemical fluids (TCFs) consistently resulted in higher condensate recovery compared to CO_2 injection. These findings highlight the effectiveness of thermochemical fluids in mobilizing trapped condensate within the rock matrix. The enhanced recovery can likely be attributed to the synergistic effects of heat generation, gas evolution, and potential wettability alteration, which together facilitate the release and flow of condensate.

Overall, the core flooding experiments validated the potential of thermochemical fluids as a promising enhanced oil recovery (EOR) technique for condensate bank remediation. The consistent trend of superior recovery with TCFs injection, in comparison to CO_2 injection, underscores the potential of this approach for improving gas production in condensate gas reservoirs. This indicates that thermochemical treatments could offer a more efficient and cost-effective solution for addressing condensate accumulation and enhancing production in such reservoirs.

Conclusions

This study investigates the application of thermochemical fluids (TCFs) for enhanced oil recovery (EOR) in condensate gas reservoirs, with a specific focus on their ability to remediate condensate banks. The results reveal several key findings that underscore the effectiveness of thermochemical treatments in improving condensate recovery and enhancing gas production. The following are the main conclusions drawn from the study.

1. The concentration of reactants plays a more significant role in temperature increase than catalyst concentration. Higher reactant concentrations, particularly sodium nitrite and ammonium chloride, result in more pronounced heat generation, which is crucial for mobilizing trapped condensate.
2. Core flooding experiments demonstrated that the injection of thermochemical fluids consistently led to higher condensate recovery than CO_2 injection across all tested core samples. This finding highlights the effectiveness of TCFs in mobilizing and vaporizing condensate within tight formations, making it a promising alternative to traditional gas injection methods.
3. The huff-and-puff injection method used in the experiments showed no significant decrease in condensate recovery after four cycles compared to three cycles. This suggests that multiple cycles of thermochemical injection may offer sustained benefits, though further investigation is needed to optimize the number of cycles and evaluate their economic feasibility.
4. The thermochemical reaction generates nitrogen gas, which acts as an inert carrier gas to displace reservoir fluids. This gas production contributes to maintaining pressure within the reservoir, aiding in condensate vaporization and enhancing overall recovery.

Conflicting Interests

The author(s) declare that they have no conflicting interests.

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