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ARTICLE

Optimizing CO_2-EOR Strategies in Water-Sensitive Tight Conglomerate Reservoirs: Mechanisms and Field Application

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ABSTRACT: The sustainable development of conglomerate reservoirs in the Junggar Basin is critically constrained by low permeability, high illite content, and severe water sensitivity. Conventional water flooding has proven inefficient, characterized by rapid pressure depletion and suboptimal recovery factors (avg. 5.5%). This study systematically investigates the efficacy of CO_2 injection as an alternative Enhanced Oil Recovery (EOR) mechanism. Through integrated core-flooding experiments and numerical simulations, we evaluated the displacement efficiency of CO_2, N_2, and CH_4. Results demonstrate that CO_2 injection yields a superior ultimate recovery factor of 38.39%-substantially outperforming the historical water flooding baseline as well as N_2 and CH_4. This superiority is primarily due to CO_2 effectively extracting light hydrocarbons (contributing 80% to incremental recovery) under high pressure and inducing significant oil swelling and viscosity reduction, significantly outperforming other media due to its ability to extract light hydrocarbons (contributing 80% to incremental recovery) and reduce oil viscosity. Furthermore, numerical optimization identifies horizontal well cyclic huff-and-puff as the optimal deployment strategy for this reservoir class. Field pilots of CO_2 pre-pad energized fracturing validated these findings, achieving a 38% enhancement in initial productivity compared to conventional fractured wells. This stimulation effect sustained elevated production rates for approximately 150 days. These results provide a robust technical framework for revitalizing depleted, water-sensitive conglomerate reservoirs.

KEYWORDS: Conglomerate reservoir; CO_2-EOR; huff-and-puff; water sensitivity; numerical simulation; enhanced oil recovery

1 Introduction

In recent years, the development of tight oil reservoirs has accounted for a growing share of domestic oilfield production, leading to the establishment of a national tight oil development demonstration zone Tight oil reservoirs are characterized by poor physical properties and low permeability. Currently, horizontal well volume fracturing serves as the primary development technique, with artificially created fractures providing essential flow channels for reservoir fluids. However, due to natural depletion without effective energy replenishment, formation pressure drops rapidly, resulting in a swift decline in production and a low recovery factor. To further improve development outcomes, a variety of enhanced oil recovery (EOR) techniques—such as cyclic water injection, gas injection, and CO_2 injection—have been developed

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for low-permeability sandstone reservoirs [1]. In particular, under the current "Dual Carbon" goals, CO_2 injection has been widely applied and has demonstrated significant success in reservoir development. Extensive research and field applications have shown that CO_2 flooding can effectively reduce crude oil viscosity and improve its mobility, markedly increasing the recovery rate in low-permeability reservoirs [2]. This approach addresses key challenges in maintaining formation pressure and enhancing productivity, thereby establishing a solid theoretical and practical foundation for the high-efficiency development of such reservoirs.

The P3w1 segment of the Upper Wuerhe Formation, located in the southern part of the oil reservoir in Area 5, is composed of a set of positively cycled sediments. The sedimentary microfacies are dominated by main channel and channel bar deposits within an alluvial fan system, with the main oil-bearing lithology being glutenite, forming a highly heterogeneous low-permeability reservoir. The absolute content of clay minerals is 4.85%, predominantly consisting of illite/smectite mixed-layer clays. Reservoir sensitivity analysis results indicate pronounced water sensitivity. After the commencement of water injection development in 1993, the proportion of effective oil wells during this period remained low, accompanied by a rapid increase in water cut and a sharp decline in production. Injection wells were shut down in 1999, resulting in a rapid decrease in formation pressure. By 2008, the pressure maintenance level had fallen to only 28%, with low daily oil production from the reservoir. Due to the absence of effective energy replenishment techniques, well performance deteriorated year by year. The current recovery factor is merely 5.5% [3], significantly lower than that of analogous reservoirs in adjacent areas. In 2023, multiple horizontal wells implemented CO_2 pre-fracturing stimulation, which yielded promising initial results with high early productivity per well. However, severe formation depletion persists around these horizontal wells, accompanied by a clear declining production trend. Many wells have been converted to artificial lift, and flowing pressure data from horizontal wells continue to decrease, underscoring an urgent need for formation energy replenishment. For conventional low-permeability sandstone reservoirs, field practices have demonstrated that gas injection can achieve favorable development outcomes [4]. Although CO_2 flooding has achieved remarkable success in conventional sandstone reservoirs, its application in tight conglomerate reservoirs faces severe and unique challenges. Unlike relatively homogeneous sandstones, tight conglomerate reservoirs exhibit extremely complex micro-pore structures, poor particle sorting, and remarkably strong reservoir heterogeneity [5]. These inherent geological characteristics, combined with complex natural and artificial fracture networks, severely exacerbate the risk of viscous fingering and early gas channeling during continuous CO_2 injection. Therefore, direct application of conventional continuous CO_2 flooding in conglomerates often results in limited sweep efficiency. Addressing these specific adaptability challenges in highly heterogeneous conglomerates is the primary motivation for proposing the novel CO_2 pre-pad energized fracturing and inter-well huff-and-puff strategy in this study. However, in glutenite reservoirs—which exhibit distinct reservoir properties compared to sandstones—the effectiveness of gas injection remains uncertain. Further evaluation is required to assess the potential of gas injection for enhancing oil recovery in such reservoirs, as well as to select suitable injection media and methods. Therefore, this study first evaluates the potential of CO_2 flooding for production enhancement in this reservoir through dynamic performance analysis. Subsequently, laboratory core flooding experiments and reservoir numerical simulations are employed to quantify the incremental oil recovery and identify an optimal gas injection strategy. The high illite/smectite mixed-layer clay content in the Upper Wuerhe Formation induces severe water sensitivity. During conventional water flooding, water intrusion triggers severe clay swelling and fine migration, which ultimately plug the micro-pore throats and drastically reduce permeability. CO_2 injection effectively mitigates this formation damage; the dissolution of CO_2

forms a mildly acidic environment that significantly inhibits clay hydration and swelling, preserving flow channels. However, unlike relatively homogeneous sandstone reservoirs, the application of CO_2 flooding in conglomerate reservoirs faces unique challenges. The extreme heterogeneity, poor particle sorting, and complex fracture-matrix interactions in conglomerates severely exacerbate the risks of gas channeling and viscous fingering, necessitating highly optimized injection strategies Wang et al. [6] developed a novel optimization strategy that integrates waste heat recovery systems (WHRSs) and thermal energy storage systems (ESS), and employed the improved Aquila optimizer (AO) for the hybrid energy ship power system (HESPS). Wang et al. [7] proposed a multi-objective optimization strategy. By designing the crossover operator and mutation operator, they developed an improved NSGA-II to seek the optimal solution, with the aim of reducing costs and greenhouse gas emissions.

Therefore, this study evaluates the potential of CO_2 flooding for production enhancement in this reservoir through dynamic performance analysis. Subsequently, laboratory core flooding experiments and reservoir numerical simulations are employed to quantify the incremental oil recovery and identify an optimal gas injection strategy. The specific objectives of this study are to: (1) evaluate the field-scale performance of CO_2 pre-pad energized fracturing in strongly water-sensitive conglomerate reservoirs; (2) systematically compare the displacement efficiencies of CO_2, CH_4, N_2, and air via core-flooding experiments; (3) optimize an "inter-well huff-and-puff" strategy using horizontal wells to overcome vertical-well limitations; (4) quantitatively validate the contribution of CO_2 extraction of light components using nuclear magnetic resonance (NMR) and pressure-volume-temperature (PVT) data.

2 Overview of Oil Reservoir

The oil reservoir of the Upper Wuerhe Formation of the Permian in the south of the fifth area is structurally located in the western uplift of the the Junggar Basin. The overall structural morphology of the P3w1 segment in the Upper South Wuerhe Formation of the Permian system in the southern part of the fifth area exhibits a monocline with a southeastern dip, with a stratigraphic dip angle ranging from 4° to 12° [8].

Sand bodies within each sublayer are well-developed and exhibit good lateral continuity, thinning gradually from east to west. Sand body thickness is greatest in the P3w11 and P3w12-1 sublayers, generally exceeding 20 m in the main area and reaching over 30 m locally, while thinning to less than 10 m in the western updip region. In the P3w12-2 sublayer, sand thickness is generally above 15 m in the main area, with thicker accumulations exceeding 30 m locally in the northeastern part. The reservoir lithology consists mainly of gray-green glutenite, gravelly conglomerate, and conglomerate, characterized by poor sorting and subrounded clasts [9,10]. The average porosity of the oil zone is 10.53%, and the average permeability is 9.94 mD.

The oil reservoir in the South Wuerhe Formation in the southern part of the fifth area was discovered in 1992. After 20 years of exploration and development. By 2022, it had reached a total oil-bearing area of 18.6 km^2 with estimated reserves of 8.86 million tons. The A oil reservoir began development in 1993, with a total of 80 development wells drilled. Its production history can be divided into four distinct phases: water injection development, depletion development, shut-in period, and recovery period. Cumulative oil production has reached 491,000 t, corresponding to a recovery factor of 5.5% and a comprehensive water cut of 30.3%. A horizontal well development plan was formulated in 2020. As of now, 12 horizontal wells have been commissioned. Currently, 25 wells are actively producing in the reservoir, yielding a daily oil production of 309 t with a water cut of 54%.

3 Analysis of the Development Effect of Horizontal Wells with Different Fracturing Methods

3.1 Development Effect Analysis

The water injection development stage of the oil reservoir in the South Wuerhe Formation in the fifth area had a low response rate, with over 84% of the wells showing no effectiveness [11]. Significant production volatility was observed across the field, accompanied by a rapid decline in output; more than 61% of the wells were classified as low-productivity wells. By the time production was suspended in 2015, the recovery factor had reached only 4.32%, considerably lower than that of analogous reservoirs in adjacent regions. Since 2018, a total of 22 old wells have been returned to production. These wells have achieved an average cumulative production period of 596 days per well and an average cumulative oil production of 1935.9 t per well. Currently, 12 wells remain operational, producing a total of 18.2 t of oil per day with a water cut of 82%. Although the implemented measures yielded relatively rapid initial results, formation energy depletion occurs quickly, resulting in a substantial decline in oil production from these interventions.

The poor development performance is attributed to the following main factors: ① Strong reservoir heterogeneity and aqueous sensitivity: The P3w11 and P3w12-1 reservoirs in the South Wuerhe Formation of Area 5 exhibit strong heterogeneity. The absolute content of clay minerals is 4.85%, predominantly composed of illite or smectite mixed-layer minerals, followed by kaolinite. Sensitivity analysis results indicate strong salt and water sensitivity. Formation pressure in the southern part of Area 5 declines rapidly. Although pressure increases temporarily during water injection, it drops quickly after injection ceases, with pressure maintenance level falling to only 28% by 2008. ② Low perforation density and incomplete productivity release: The reservoir thickness ranges from 13.7 to 68.6 m, with an average perforated thickness of 22.2 m. More than 60% of the old wells have a perforation density of less than 50% within the oil layer, averaging 43%. ③ Lack of effective energy replenishment methods, resulting in rapid production decline: Although oil production increases temporarily after switching to artificial lift, output declines rapidly, with an annual decline rate of 28.5%. The absence of effective energy replenishment leads to progressively deteriorating well performance over time. Production performance analysis confirms that the development effects of the South Wuerhe Formation reservoir in Area 5 are unsatisfactory under both waterflooding and depletion development modes. There is an urgent need to alter the development strategy, promptly replenish formation energy, and improve overall recovery efficiency.

3.2 Effectiveness of CO_2 Pre-Energized Fracturing Horizontal Well Development

Since production resumed in the South Wuerhe Formation oil reservoir of District 5, a total of 12 horizontal wells have been commissioned. To date, the combined daily fluid production has reached 480.7 t/d, with a daily oil production of 273.9 t/d, a water cut of 43.0%, and a cumulative oil production of 7.70×10^4 t, reflecting favorable production performance. Among these, four horizontal wells in the central section of the reservoir have employed the CO_2 pre-energized fracturing technique, while five horizontal wells in the western section were completed without this method. Following their commissioning, differences in production performance have been observed between the two groups of wells based on the fracturing techniques applied.

A statistical analysis of the four horizontal wells in the CO_2 pre-energized fracturing zone shows that three wells achieved initial production rates exceeding 20 t/d, with an average initial production of 23.6 t/d. In contrast, within the non-CO_2-treated zone, only one out of five wells surpassed 20 t/d, averaging 17.1 t/d. This represents a production increase of 6.5 t/d in the CO_2-stimulated region compared to the

non-stimulated region. Notably, the initial productivity of the horizontal wells receiving CO_2 pre-fracturing was 1.38 times higher than that of wells fractured using conventional methods.

An analysis of production trends from four horizontal wells in the CO_2 pre-energized fracturing zone and five wells in the conventionally fractured zone—under synchronized production timelines—shows that the point where the average daily oil production curves intersect indicates the time of productivity decline [12,13]. This demonstrates that the production enhancement effect from CO_2 injection remains effective for approximately 150 days. Furthermore, cumulative production data over the same period reveal that in the conventional fracturing zone, only one well exceeded 7800 t, with an average cumulative production of 6740 t. In contrast, in the CO_2 pre-fractured zone, three out of four wells surpassed 7800 t, averaging 8800 t per well—a 1.31-fold increase compared to the conventional zone. These results indicate that the CO_2 pre-fracturing technique significantly improves reservoir performance over conventional fracturing methods.

3.3 Analysis of the Production Enhancement Effect of CO_2 Pre-Fracturing

3.3.1 CO_2 Energy Storage and Pressure Augmentation

During the CO_2-enhanced fracturing process, significant volumes of liquid CO_2 are injected into the formation. Under standard conditions, one metric ton of liquid CO_2 expands into approximately 546 m^3 of gaseous CO_2. The resulting gas phase near the wellbore contributes to increased reservoir pressure. Upon entering the reservoir, a portion of the injected CO_2 dissolves into the crude oil, while the remainder occupies pore space as free gas [14]. Owing to its high compressibility, CO_2 effectively replenishes reservoir energy. As wellbore pressure decreases during production, the dissolved CO_2 gradually evolves from the oil, thereby helping to maintain reservoir pressure and prolong stable production.

In the South Wuerhe Formation, a comparison of four horizontal wells within the CO_2-injected zone—with similar reservoir conditions, production rates, horizontal section lengths, and structural depths—reveals significantly higher wellhead pressures in the CO_2-treated wells. This demonstrates that CO_2 injection effectively enhances reservoir pressure, an effect that remains sustained for approximately 150 days (Fig. 1). Furthermore, the high compressibility of CO_2 aids in the efficient flowback of fracturing fluid, with field data indicating recovery rates exceeding 88%, thereby reducing potential reservoir damage.

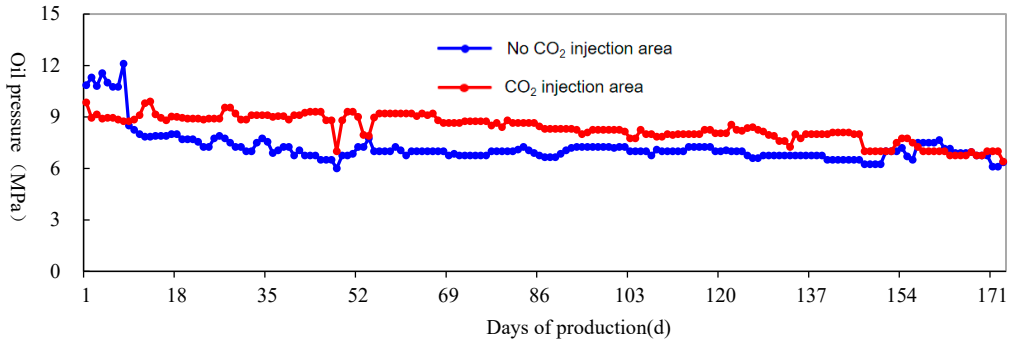


Figure 1: Relationship curve of oil pressure change in horizontal wells in different region.

3.3.2 CO_2 Sweep Efficiency

CO_2 exhibits superior flow capacity in reservoirs. When liquid CO_2 enters the formation, it transitions from liquid to gas, resulting in rapid volume expansion and a significant sweep range for CO_2. Yang Zhaocheng et al. utilized reservoir numerical simulation methods to investigate the diffusion behavior of

CO_2 during the CO_2 pre-fracturing process. Their findings indicated that the areal sweep range of CO_2 during pre-fracturing could reach up to one-third of the reservoir. Sampling and analysis of gas from the wellheads of nine horizontal wells in both CO_2-injected and non-CO_2-injected zones (Fig. 2) revealed that, in the CO_2-injected zone, Well A, which did not undergo CO_2 pre-fracturing, exhibited CO_2 presence at the wellhead. In the non-CO_2-injected zone, four wells also showed CO_2 at their wellheads. Monitoring of CO_2 concentration demonstrated that CO_2, as a gas, possesses strong flow capacity and diffuses widely in the reservoir, covering a significant area.

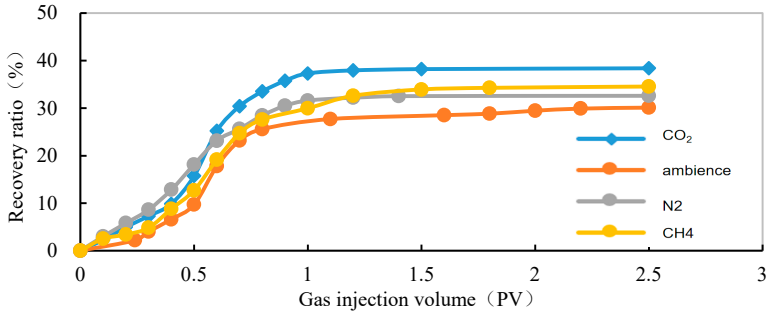


Figure 2: Recovery curves for different injection media.

The superior flow characteristics of CO_2 in reservoirs result from its phase change from liquid to gas, leading to rapid volume expansion and a broader sweep area. Reservoir simulations indicate that CO_2 pre-fracturing can affect up to one-third of the reservoir. The analysis of gas samples from nine horizontal wells further confirms CO_2 extensive diffusion, as four wells in the non-CO_2-injected zone show the presence of CO_2, emphasizing its broad sweep range and substantial impact.

3.3.3 CO_2 Extraction and Viscosity Reduction

Many researchers have concluded from PVT phase behavior experiments on CO_2-crude oil systems that the oil formation volume factor significantly increases with the addition of CO_2 [15]. Therefore, during CO_2 pre-fracturing under high reservoir pressure, CO_2 dissolves into the crude oil during its diffusion process, reducing the oil's viscosity and expanding the crude oil, thus enhancing its mobility. Lu Binchang et al. conducted dynamic measurement experiments on the CO_2-crude oil system using Axisymmetric Drop Shape Analysis (ADSA) technology, and found that the light components in the crude oil were strongly extracted by high-pressure CO_2, causing the oil droplets to gradually vaporize into strip-like shapes, while the residual droplets became enriched with heavy components [16]. Under varying pressure conditions, the dominant mechanisms differ. At low pressure, CO_2 dissolution primarily leads to crude oil expansion and viscosity reduction, whereas at high pressure, CO_2 extracts large amounts of light components from the crude oil into the gas phase, rapidly reducing the oil volume. Nuclear magnetic resonance experiments showed that the contribution of the extraction mechanism to recovery rates was 80%, making it the primary mechanism for production enhancement.

By analyzing oil samples from the initial production of nine horizontal wells (Fig. 3), it was observed that at 50°C, crude oil viscosity in the non-CO_2 injected zone consistently exceeded 200 mPa·s, peaking at 282.6 mPa·s. Conversely, in the CO_2-injected zone, crude oil viscosity ranged from 78.7 to 104.7 mPa·s, with only the sample from Well HW5029 exhibiting higher viscosity. Overall, viscosity in the CO_2-injected zone was significantly lower than in the non-CO_2 injected zone, clearly demonstrating the effectiveness of CO_2 dissolution in reducing crude oil viscosity.

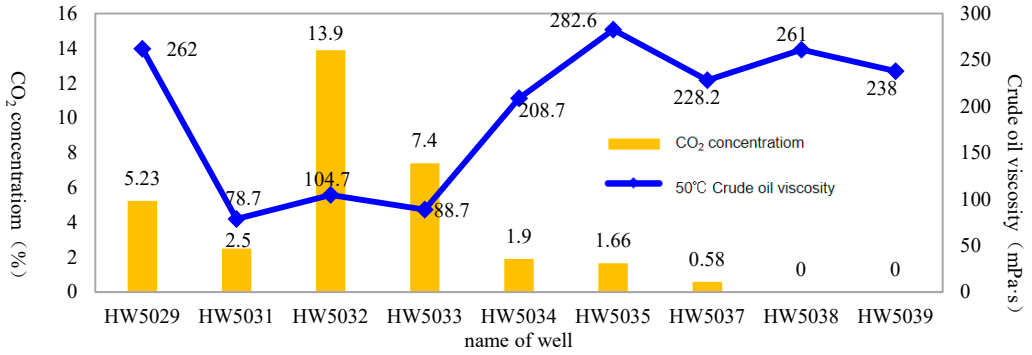


Figure 3: Carbon dioxide concentration and crude oil viscosity in new production horizontal well.

Beyond the mechanisms discussed, CO_2 pre-fracturing also offers several advantages over conventional fracturing techniques. First, CO_2 pre-fracturing can open existing natural fractures and bedding planes in the reservoir. Secondly, it facilitates the formation of more hydraulic fractures that extend and reorient based on the distribution of natural fractures, resulting in a more complex fracture network. Currently, the multi-cluster staged fracturing of horizontal wells typically spans around 10 days. Pre-injected CO_2, which dissolves in the fracturing fluid, maintains prolonged contact with the reservoir rock. Laboratory experiments have shown that after soaking for a certain period, the porosity and permeability of the reservoir rock significantly increase, and the extent of dissolution expands over time, leading to higher single well production. Moreover, chemical dissolution alters the mechanical strength of the reservoir rock, aiding the opening of natural fractures and the development of hydraulic fractures, ultimately fostering a more intricate fracture network.

Additionally, the mildly acidic environment generated by the CO_2 solution inhibits the swelling of clay minerals and mitigates the emulsification of underground crude oil, thus reducing oil blockages. Upon By analyzing oil samples from the initial production of nine horizontal wells (Fig. 3), it was observed that at 50°C, crude oil viscosity in the non-CO_2 injected zone consistently exceeded 200 mPa·s, peaking at 282.6 mPa·s. Conversely, in the CO_2-injected zone, crude oil viscosity ranged from 78.7 to 104.7 mPa·s, with only the sample from Well HW5029 exhibiting higher viscosity. Overall, viscosity in the CO_2-injected zone was significantly lower than in the non-CO_2 injected zone, clearly demonstrating the effectiveness of CO_2 dissolution in reducing crude oil viscosity.

CO_2 dissolves in crude oil, lowering its viscosity and enhancing its mobility. High-pressure CO_2 efficiently extracts light oil components, resulting in significant oil expansion and viscosity reduction. Nuclear magnetic resonance experiments confirm that CO_2 extraction contributes up to 80% towards improved recovery rates, establishing it as the dominant mechanism. Oil samples from nine wells show that crude oil viscosity in the CO_2-injected zone ranges from 78.7 to 104.7 mPa·s, considerably lower than in the non-CO_2-injected zone, underscoring the efficacy of CO_2 in viscosity reduction.

Moreover, CO_2 pre-fracturing enhances fracture complexity and improves rock permeability through dissolution, allowing for a more extensive fracture network. Additionally, CO_2 prevents clay mineral swelling and reduces oil emulsification, further augmenting oil recovery rates.

3.4 Analysis of a Typical Well in the CO_2 Pre-Fracturing Zone

Well A, a typical well located within the CO_2 pre-fractured zone, did not undergo CO_2 pre-fracturing itself and has a horizontal section length of only 682 m, compared to an average horizontal section length of 1180 m for other wells in the area. Nevertheless, Well A has the highest initial productivity and cumulative

production among the currently producing horizontal wells. Multi-dimensional dynamic monitoring provides robust evidence of inter-well CO_2 diffusion: gas detection at the wellhead confirmed a significant surge in CO_2 concentration, and pressure gauges recorded a sustained bottom-hole flowing pressure response, indicating effective energy replenishment. Viscosity tests on the produced crude oil recorded an initial viscosity of 78.7 mPa·s, increasing to 135.4 mPa·s after five months. These observations indicate that Well A has been influenced by CO_2 displacement from neighboring CO_2 pre-fractured wells, demonstrating the effects of CO_2 injection. These findings suggest robust diffusion capabilities of CO_2 in the South Wuerhe Formation of Block Five, with observable impacts on reducing oil viscosity and enhancing production, further confirming the potential of CO_2 injection for improved recovery rates in this formation.

4 Study on Displacement Experiments with Different Gas Injection Media

The natural core utilized in this study (porosity 9.22%, permeability 3.544 mD) was specifically selected to match the average physical properties of the primary pay zones, ensuring the representativeness of the matrix system. Acknowledging that laboratory-scale cores cannot fully replicate macro-scale complex fracture networks, these experimental results serve as foundational matrix-displacement benchmarks, which are subsequently scaled to the field level via numerical simulations. Analysis of the effects of CO_2 pre-fracturing technology in the target block clearly indicates that gas injection development is well-suited for the South Wuerhe Formation in Block Five. Thus, further investigation into the optimal gas injection medium is essential. This study conducted displacement experiments utilizing various injection media on core samples extracted from the target reservoir, which exhibited a porosity of 9.22% and a permeability of 3.544 mD. The formation oil employed in the experiments was a blended sample representative of the target block. The experimental procedure was as follows:

1. **Experimental setup**: Connect the experimental setup and heat the thermostatic oven to the target experimental temperature.
2. **Core saturation with petroleum ether**: After vacuuming the core, saturate it with petroleum ether for a minimum of 8 h, ensuring that the saturation pressure does not fall below the experimental pressure. Measure the pore volume of the core (including pipelines).
3. **Core saturation with crude oil**: Utilize a high-pressure displacement pump to inject the blended crude oil into the core, displacing the petroleum ether until the gas-oil ratio at the outlet aligns with that of the blended oil sample.
4. **CO_2 oil displacement experiment**: Under original reservoir pressure, using a high-pressure displacement pump, inject CO_2 into the core at a constant pressure. Regulate the injection rate by adjusting the back-pressure valve, measuring the oil and gas production volumes at every 0.1 pore volume (PV). The recovery factor and gas-oil ratio were calculated to evaluate CO_2 effectiveness in enhancing oil recovery.
5. **Repeat steps for other gases**: Following step 4, clean the core and repeat steps 2–3, substituting the injection medium with air, CH_4, and N_2, respectively, to conduct three additional displacement experiments.

All four displacement experiments maintained identical injection conditions and were repeated in triplicate (n = 3) to ensure statistical reliability, with a cumulative injection volume of 2.5 PV. The recovery factors for N_2, CO_2, air, and CH_4 at varying PVs were recorded (Fig. 2). It was observed that when the injection volume reached 1.0 PV, the recovery factor increased at a decelerated rate as the injection volume grew, gradually plateauing. Under continuous gas injection conditions, CO_2 achieved the highest final recovery factor at 38.39%, followed by CH_4, while air demonstrated the lowest recovery. Subsequent tests

on oil expansion factors and viscosity under different pressure and volume conditions (Figs. 4 and 5) showed that CO_2 yielded the highest expansion factor, leading to significant oil volume expansion while also being the most effective in reducing oil viscosity. Specifically, CO_2 injection achieved a maximum viscosity reduction of up to 65% compared to the original oil sample. Compared to other gases, CO_2 exhibited the lowest viscosity and highest flow capacity, rendering it the most efficient displacement agent.

Consequently, this study concludes that CO_2 injection possesses significant potential for enhancing oil recovery in this block, validating CO_2 as the optimal injection medium. To ensure absolute fairness in comparison, all four displacement experiments (CO_2, N_2, CH_4, and air) were conducted under identical boundary conditions: consistent injection pressure, identical experimental temperature, and constant injection rates. Furthermore, miscibility differences were accounted for; CO_2 exhibited the lowest minimum miscibility pressure (MMP) with the reservoir oil, allowing it to achieve near-miscible extraction, whereas N_2 and CH_4 remained strictly immiscible under the same pressure conditions.

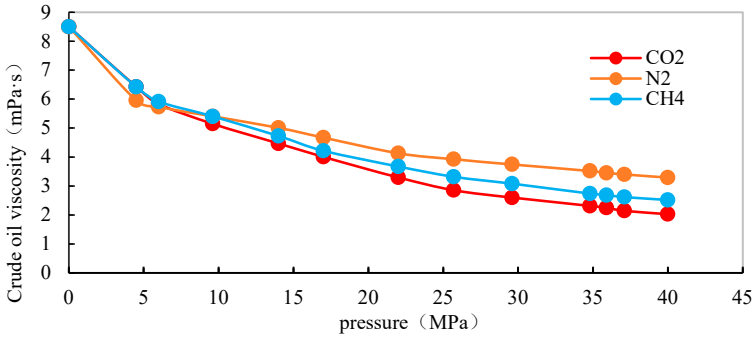


Figure 4: Crude oil viscosity at different pressures for different injection media.

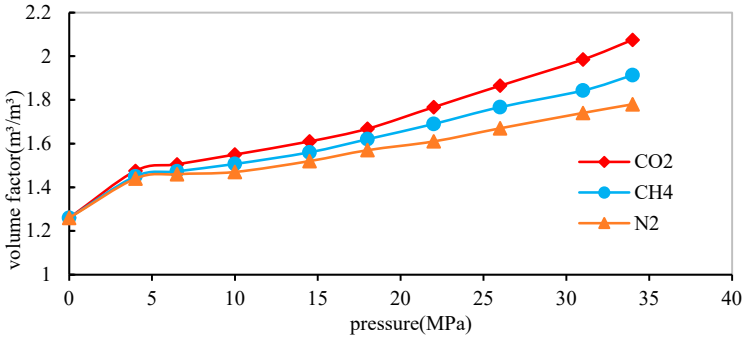


Figure 5: Volume coefficients at different pressures for different injection me.

5 Study on Injection Methods

5.1 Core Displacement Experiments

Building upon the selection of the optimal injection medium, additional core flooding and huff-n-puff experiments were conducted for the target reservoir. These aimed to compare oil recovery efficiency under original reservoir pressure utilizing CO_2 injection, CO_2 huff-n-puff following depletion to 10 MPa in the same well, and inter-well CO_2 huff-n-puff [17]. The objective was to clarify the effectiveness of CO_2 injection and huff-n-puff techniques for enhanced oil recovery, providing a foundation for modifying the development approach for the target reservoir.

The experimental procedure was expanded to incorporate two additional huff-n-puff experiments. In these experiments, cores were cleaned with petroleum ether, re-saturated with crude oil, and subjected to a

depletion test. Depletion was managed by adjusting the back-pressure valve to control production pressure, performing stepwise pressure reductions of 2–3 MPa until a final pressure of 10 MPa was achieved. At each pressure step, oil and gas production were measured after stabilization, and the recovery factor for each pressure drop was calculated. After depletion, CO_2 was injected into the core using a high-pressure displacement pump until the inlet pressure reached the original reservoir pressure. The core was then shut-in for 6 h, followed by another stepwise depletion experiment with 2–3 MPa pressure drops down to a final pressure of 6 MPa. Oil and gas production were measured at each step to compute the recovery factor and final oil recovery.

Same-well huff-n-puff refers to injecting CO_2 and subsequently producing from the same well following a shut-in period, while inter-well huff-n-puff involves injecting CO_2 into one well and producing from another following a shut-in period. A comparison of recovery factors indicated that inter-well huff-n-puff achieved a recovery rate 6.37% higher than that of same-well huff-n-puff (Fig. 6). This underscores the greater effectiveness of inter-well CO_2 injection over huff-n-puff. However, the recovery factor from a single huff-n-puff cycle remains significantly lower than that from continuous CO_2 injection.

Thus, for the South Wuerhe Formation in Block Five, continuous CO_2 injection represents the most efficient method for enhancing oil recovery, contingent upon suitable well conditions. Given that most vertical wells in the area currently lack suitability for CO_2 injection and pose considerable risks, inter-well huff-n-puff in horizontal wells emerges as a more effective alternative to same-well huff-n-puff. The 6-h soaking time utilized in the laboratory core scale corresponds to an equivalent field-scale soaking period of approximately 60 days, based on dimensionless diffusion time scaling laws and history-matched numerical simulations.

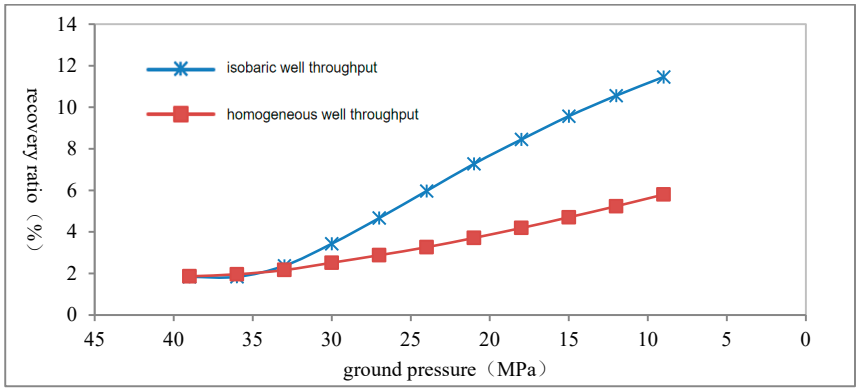


Figure 6: Extraction level at different pressures for different injection methods.

5.2 Optimization of Asynchronous Throughput Gas Injection Parameters for Horizontal Wells

5.2.1 Gas Injection Rate

The compositional numerical simulation model was constructed using a Cartesian grid system (150 × 100 × 20 blocks) and was rigorously calibrated against both the core-flooding historical data and the well production history to refine relative permeability curves. The injection rate directly affects the efficiency of CO_2 injection in horizontal wells. It determines the effect of CO_2 transportation and diffusion. Under the conditions of the same well simmering time, conversion time and fluid extraction rate, numerical simulation prediction was carried out according to the injection rate of 60 t/d, 80 t/d, 100 t/d, 120 t/d, 150 t/d and 200 t/d, respectively, and the dynamic production indexes were obtained under the conditions of different injection rates (Table 1).

Table 1: Optimization scheme of gas injection rate and production indexes.

Injection Rate (t/d)	Stage Cumulative Oil Production Volume (m^3)	Oil Change Rate (m^3/m^3)	Extraction Degree (%)
60	406,686.1	0.010428	10.06
80	414,004.5	0.010615	10.14
100	416,617.0	0.010682	10.17
120	414,532.0	0.010629	10.14
150	410,744.9	0.010532	10.10
200	409,211.8	0.010493	10.08

Numerical simulation results indicate that as the injection rate increases, cumulative oil production and oil change rates also rise; however, when the injection rate exceeds 100 t/d, both cumulative oil production and oil change rates decline. At an injection rate of 100 t/d, cumulative oil production and oil change rates are maximized. It is analyzed that a higher injection rate facilitates greater CO_2 dissolution in crude oil, lowering viscosity and expanding volume. Nonetheless, excessively high injection rates may push CO_2 deeper into the formation before it can sufficiently dissolve in the crude oil, hampering the viscosity reduction and inhibiting the expansion effect. Additionally, higher CO_2 injection rates may also lead to displacement of the crude oil near the well into deeper parts of the formation. Conversely, a lower injection rate allows CO_2 to accumulate locally in the reservoir, creating a high-pressure zone; when the injection rate is elevated, reduced contact time between CO_2 and reservoir rocks and fluids leads to insufficient reactions and a decreased recovery degree.

5.2.2 Stewing Time

Steaming time refers to the duration between CO_2 injection and well production. The aim of well steaming is to allow CO_2 to penetrate further and deeper into the formation, thereby displacing more oil. Concurrently, it facilitates CO_2 dissolution in the oil, resulting in oil expansion and increased pressure. However, prolonged steaming may induce CO_2 separation from oil, diminishing its driving effect. The steaming phase is crucial within the throughput process, with diffusion being a key aspect to consider. At the conclusion of gas injection, the well is shut in and transitioned to the steaming phase. The primary mechanism by which CO_2 enters the matrix during well steaming is through diffusion; the longer the steaming period, the further CO_2 can diffuse. Under conditions of high temperature and pressure, CO_2 infiltrates the porous matrix surface and gradually dissolves into the oil phase, resulting in pressure drops in the near-well region. This process induces a strong concentration gradient in the contact area between oil and gas, propelling CO_2 deeper into the formation. As well steaming progresses, the viscosity of crude oil gradually decreases while expanding into fracture spaces. Consequently, the duration of steaming time directly affects CO_2 injection effectiveness. Generally, a longer steaming time enhances CO_2 penetration into the reservoir, increasing the contact area between CO_2 and reservoir rocks, thereby improving throughput efficiency. Conversely, a shorter steaming time yields relatively poor penetration, allowing only a portion of CO_2 to be adsorbed and stored. Conversely, extended steaming periods enable more thorough transport and diffusion throughout the reservoir's pore space, replenishing formation energy to optimize CO_2 throughput efficiency. Reservoir characteristics such as permeability and pore structure will also affect steaming duration; if reservoir permeability is high, CO_2 migration occurs rapidly, allowing for shorter steaming times. Conversely, in tight reservoirs represented by numerical data in this study, steaming time must be lengthened to ensure optimal CO_2 migration and diffusion.

To evaluate the diffusion effect during well steaming, numerical simulations were performed under constant injection rate, conversion time, and fluid recovery rate, using steaming times of 0 d, 15 d, 30 d, 45 d, 60 d, and 75 d, thereby predicting dynamic production indices under varied steaming durations (Table 2).

Table 2: Well simmering time and production indicators.

Stewing Time (d)	Stage Cumulative Oil Production (m^3)	Oil Exchange Rate (m^3/m^3)	Extraction Level (%)
0	414,857.8	0.010637	10.15
15	415,830.3	0.010662	10.16
30	416,617.0	0.010682	10.17
45	417,210.0	0.010698	10.17
60	417,378.5	0.010702	10.18
75	417,342.7	0.010701	10.18

The 60-day optimal soaking period represents the critical thermodynamic balance between CO_2 diffusion kinetics and extraction efficiency. Shorter soaking times result in insufficient penetration depth, allowing only partial CO_2 dissolution. Conversely, extending the soaking period beyond 60 days yields diminishing returns; prolonged stagnation disrupts the dynamic equilibrium, leading to crude oil degassing, phase separation, and unnecessary delays in production. Therefore, 60 days provides the optimal time window for deep matrix penetration and maximum light-component extraction.

5.2.3 Throughput Transition Time

At home and abroad, multiple cycles are usually adopted in the development of CO_2 throughput, but the number of cycles has different effects on crude oil recovery. The length of conversion time will directly affect the effect of asynchronous throughput. Under the conditions of the same injection rate, well casing time and fluid recovery rate, numerical simulations were conducted according to the conversion time of 300 d, 600 d, 900 d, 1200 d, 1500 d and 1800 d, respectively, to predict the cumulative oil production and dynamic production indexes under the conditions of different conversion times (Table 3).

Table 3: Conversion time optimization scheme and production targets.

Conversion Time (d)	Stage Cumulative Oil Production (m^3)	Oil Change Rate (m^3/m^3)	Extraction Degree (%)
300	411,720.0	0.010557	10.11
600	414,589.1	0.010630	10.14
900	416,617.0	0.010682	10.17
1200	413,263.7	0.010597	10.13
1500	411,497.5	0.010551	10.11
1800	409,689.3	0.010505	10.09

Numerical simulation results show that when the conversion time increases, the cumulative oil production and oil change rate increase with the increase, but when the conversion time is greater than 900 d, the cumulative oil production and oil change rate decrease with the increase. It is analyzed that the optimal conversion time is 900 d with the highest cumulative oil production and oil change rate.

During the throughput process, the range of CO_2 injection and the amount of crude oil interacting with CO_2 are limited, and the range of CO_2 throughput can not be greatly increased in the process of multiple rounds, and the oil saturation within the processing radius of CO_2 throughput is gradually decreasing, and

the degree of recovery is increasing, although a part of the crude oil in the far-well zone can be flowed to the near-well zone, it is not enough to replenish the depletion of the crude oil in the near-well zone. On the other hand, in the late stage of multiple rounds of throughput, the formation pressure gradually decreases, the formation energy is insufficient, and it is difficult to flow the crude oil; in the range of CO_2 throughput, the crude oil is extracted by CO_2 after multiple rounds, and the oil properties of the crude oil remaining in the reservoir deteriorate, and the viscosity of the crude oil increases; and even with the increase of rounds of throughput, the gas propulsion makes the crude oil gradually move away from the bottom of the well.

5.3 Uncertainty and Sensitivity Analysis

To evaluate the robustness of the optimized parameters, a sensitivity analysis was conducted on key reservoir uncertainties. Tornado plot analyses and Monte Carlo simulations revealed that reservoir permeability variation (±20%) and initial oil viscosity are the most critical factors influencing the ultimate recovery factor during CO_2 huff-and-puff operations. Incorporating error propagation from PVT data indicates a ±3.2% confidence interval for the predicted 10.18% stage extraction level.

6 Challenges and Limitations

Although this study has demonstrated that CO_2 flooding can significantly enhance oil recovery in low-permeability conglomerate reservoirs, three practical challenges must be addressed:First, strong reservoir heterogeneity can easily induce CO_2 fingering. Subsequent efforts should focus on constructing high-resolution geological models integrated with geomechanical simulations to optimize well spacing and injection-production patterns. Second, liquid CO_2 pre-pad fracturing requires additional surface storage tanks and high-pressure pumping equipment, increasing single-well capital expenditure (CAPEX) by approximately 15%. However, preliminary full life-cycle economic evaluations indicate that the 38% productivity boost and extended stable production period can achieve a favorable return on investment (ROI) within the first two years of operation. Finally, long-term CO_2 storage security must be rigorously addressed. Quantitative risk assessments regarding wellbore integrity and fault-activation-induced leakage are necessary. It is recommended to combine laboratory rock-mineral reaction experiments with field time-lapse seismic monitoring to ensure safe geological sequestration and mitigate the risk of CO_2 migration into shallow aquifers.

7 Conclusions

Field applications in the water-sensitive Upper Wuerhe Formation demonstrated that horizontal wells utilizing CO_2 pre-pad energized fracturing achieved a 38% enhancement in initial productivity compared to conventional fracturing, while maintaining elevated flowing pressures for over 150 days. Systematic core-flooding experiments further confirmed CO_2 as the optimal injection medium, which successfully mitigated water sensitivity and yielded a superior ultimate recovery factor of 38.39%, representing a substantial increase over the historical baseline recovery of 5.5%.

Coupled numerical simulations calibrated with laboratory data indicate that an inter-well cyclic huff-and-puff strategy applied to horizontal wells—with an injection rate of 100 t/d, a 60-day soaking period, and a 900-day transition cycle—can maximize economic extraction efficiency.

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