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Using a well-to-well interplay during the CO_2 huff-n-puff process for enhanced oil recovery in an inclined oil reservoir: Experiments, simulations, and pilot tests

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A well-to-well interplay of CO_2 huff-n-puff is proposed as a novel gas injection strategy for displacing interwell-remaining oil in a well pair in an inclined oil reservoir. The well-to-well interplay mechanisms for enhanced oil recovery (EOR) are first studied in the laboratory using a three-dimensional (3D) physical model. Different CO_2 injection schemes are designed according to different well locations, and the production performance including oil, water, and gas rates is used for the EOR evaluation. A sensitivity analysis of the well-to-well interplay is then studied using a numerical model, and geological, developmental and fluidic factors are considered in the simulations. The experimental results show that, when CO_2 is injected into a lower well, a higher well always benefits with an oil increment. Under the effects of gravity segregation and edge-water driving, the injected CO_2 at the lower position can move upward to a higher position, where a large proportion of crude oil remains between wells after natural edge-water flooding. Oil recovery from the well-to-well interplay is 2.30% higher than conventional CO_2 huff-n-puff in the laboratory. Numerical results show that CO_2 injection mass, stratigraphic dip, horizontal permeability, and interwell spacing are the factors that most influence the well-to-well interplay; an application criterion for the well-to-well interplay is then proposed based on the simulations. Pilot tests using the well-to-well interplay of CO_2 huff-n-puff have been widely applied in C2-1 Block, Jidong Oilfield, China, since 2010. A total of 2.27×10^4 m^3 crude oil was recovered to the end of 2018, and the oil/CO_2 exchange ratio was as high as 3.92. The well-to-well interplay not only effectively extracted the interwell-remaining oil but also achieved higher CO_2 utilization efficiency. The findings of this study can lead to a better understanding of the EOR mechanisms used in the well-to-well interplay during the CO_2 huff-n-puff process in an inclined oil reservoir.

KEYWORDS

CO_2 huff-n-puff, well-to-well interplay, enhanced oil recovery, inclined reservoir, interwell remaining oil

1 Introduction

Given the continuous consumption of conventional reservoir reserves, unconventional resources have been of wide interest in recent years. Heavy oil reservoirs as one unconventional resource face challenges in oil production due to low oil mobility within the porous media (Babadagli, 2003; Huang et al., 2019; Shilov et al., 2019). Thermal methods, including steam injection and *in situ* combustion, are the most widely used techniques for enhanced heavy oil recovery; however, their applications are limited in thin or deep layers because of massive heat loss and the high investment necessary (Wang et al., 2018; Alajmi, 2021). Solvent-based non-thermal methods, including cyclic solvent injection and vapor extraction, are proving suitable for enhanced oil recovery (EOR) in these kinds of reservoirs (Jiang et al., 2014; Ma et al., 2017). Among such methods, the CO_2 huff-n-puff process is considered a promising technique for these complicated oil reserves (Ahadi & Torabi, 2018; Zhou et al., 2019). When CO_2 is injected into heavy oil reservoirs, the main EOR mechanisms include viscosity reduction, oil swelling, IFT reduction, and light/medium components extraction, greatly enhancing heavy oil production during the CO_2 huff-n-puff process (Kavousi et al., 2014; Cui et al., 2017; Li et al., 2018; Kashkooli et al., 2022; Zhou et al., 2022).

C2-1 Block in the Jidong Oilfield, China, is a heavy oil reservoir with a viscosity of 289 mPa·s under formation conditions (60, 16.24 MPa); it is an inclined reservoir with a stratigraphic dip of 15° (Figure 1). The block was initially developed by natural edge-water flooding from 2003, obtaining oil recovery of 4.79% by the end of 2010. During this operation, several wells faced severe water channeling problems, with water-cut values as high as 99%, and little oil was recovered. Several CO_2 huff-n-puff processes were conducted to enhance this oil recovery between 2008 and 2010. After CO_2 was injected into a single well, the oil production rate was enhanced from less than 2 t/d to more than 10 t/d, and the water cut also dropped to as low as 20–30%. Although the oil increases were obtained with a CO_2 injection, they sharply dropped to small values for the second cycle of CO_2 huff-n-puff—as observed by Ma et al. (2015). Furthermore, since CO_2 huff-n-puff is just a stimulation method for single wells with a limited range (Li et al., 2017), it can only extract the oil near the wellbore area: a quantity of crude oil still remained between the wells after CO_2 huff-n-puff in the C2-1 Block. Although a variety of chemicals including viscosity reducer, foaming agent, and gel have been proposed to further enhance CO_2 huff-n-puff oil recovery (Hao et al., 2021; Hao et al., 2022; Qu et al., 2022), they are still single-well stimulation methods, and novel techniques or gas injection strategies need to be studied to extract interwell-remaining oil during the CO_2 huff-n-puff process.

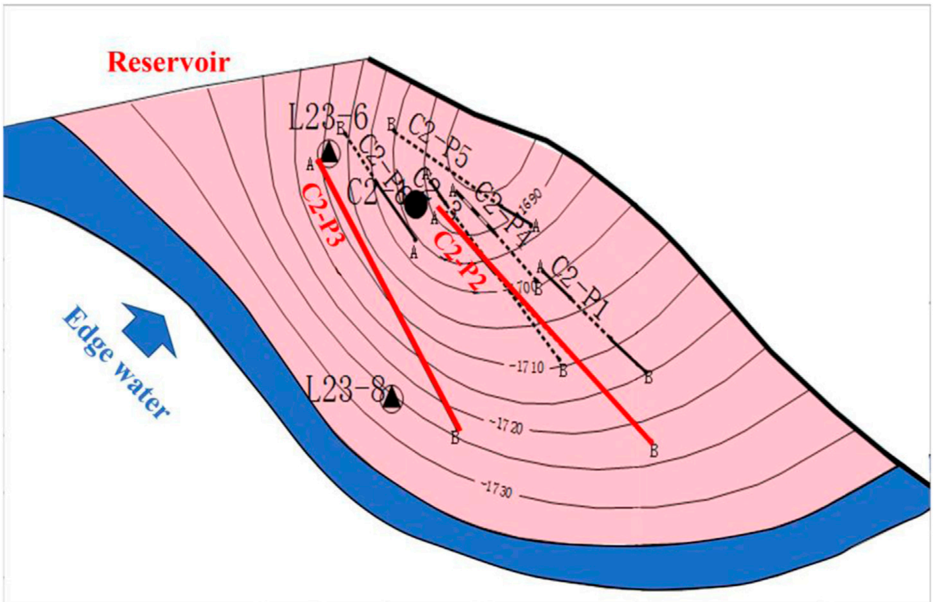

FIGURE 1
Top structure map of C2-1 Block, Jidong Oilfield, China.

When gas and water are injected into a formation, the gas will move to the top of the reservoir while the water will move to the bottom due to gravity—this is called "gravity segregation". In a horizontal reservoir, gravity segregation is usually a negative factor since the injected gas and water will override the oil (Fayers & Zhou, 1996). For example, the water-alternating-gas (WAG) technique is considered the most useful for EOR when CO_2 is mixed with oil; however, the gas–oil mixture will be separated by gravity as the mixture moves further away from the injector. As a result, the WAG process provides an unsatisfactory sweep efficiency with gravity segregation, leading to an early gas breakthrough in the producer (Afzali et al., 2018; Khan & Mandal, 2020). The gas-assisted gravity drainage (GAGD) technique has recently been proposed as an effective EOR method because it takes full advantage of gravity segregation, and a higher formation dip is favorable for its EOR (Chen et al., 2021). During a GAGD process, the oil is usually driven by CO_2 down-dip from the pores toward the wells. With a properly designed gas injection strategy, the gas breakthrough can be significantly delayed, with recovery of more than 30% in the laboratory (Rezk et al., 2019; Al-Obaidi et al., 2022).

Although, GAGD could achieve remarkable oil recovery in the inclined oil reservoirs, most GAGD processes are operated in a model without edge water. In the presence of an active aquifer, conditions could be completely different because the water coning could severely affect EOR. The treatment of edge water should be considered a primary task when applying an EOR method to this kind of reservoir. CO_2 has proven to be an effective method for water treatment (Wang et al., 2021; Tian et al., 2022); when it is injected into a lower location in an inclined oil reservoir, it will first delay the edge-water coning. Then, the CO_2 will move upward with the assistance of edge-water driving and gravity segregation, where the oil remaining between a well pair is just right at the higher position. As a result, a well-to-well interplay will occur with the interwell-remaining oil produced from the higher position. Gravity segregation is typically affected by developmental, geological, and fluidic factors. For example, Stone (1982) observed that the injection rate, vertical permeability, and density difference between water and gas are the main parameters that affect gravity segregation. The study conducted by Rogers & Grigg (2001) revealed that the increase in the vertical-to-horizontal permeability ratio (K_v/K_h) will reduce oil recovery during the WAG process, due to the dominant effect of gravity segregation. Al-Mudhafar et al. (2018) believe that reservoir heterogeneity is the most crucial factor that strongly affects hydrocarbon recovery during GAGD. Thus, as a CO_2–EOR method governed by gravity segregation, the influencing factors of well-to-well interplay during the CO_2 huff-n-puff process proposed in this paper should also be studied to achieve a better CO_2–EOR effect.

In order to study the mechanisms of interwell-remaining oil displacement using a well-to-well interplay of CO_2 huff-n-puff in an inclined oil reservoir, a well pair was established in a three dimensional (3D) inclined physical model. CO_2 was injected into the model through the lower well only, the higher well only, and the lower and higher wells simultaneously. The production performances, including oil, water, and gas rates, were used to evaluate the interplay mechanisms between the wells. A sensitivity analysis of the well-to-well interplay was then studied using a base reservoir model, and geological, developmental, and fluidic factors including CO_2 injection mass, interwell spacing, stratigraphic dip, horizontal and vertical permeability, and oil viscosity were considered in the simulations. EOR tests using the well-to-well interplay of CO_2 huff-n-puff were conducted in the pilot, and the oil recovered by the well-to-well interplay is also introduced in this paper.

2 Materials and methods

Theoretical analysis, physical experiments, numerical simulation, and field tests were utilized to study the EOR mechanisms, influencing factors, and its application to the well-to-well interplay of CO_2 huff-n-puff; the technical route of this study is shown in Figure 2.

2.1 Scaling groups for physical and numerical models

The inclined oil reservoir of C2-1 Block is in a geological reserve of 4.51×10^5 m^3. The average porosity and permeability of the reservoir is 25.9%, 667×10^{-3} μm^2, respectively, the depth of water/oil contact (WOC) is 1735 m, and the aquifer size is 100 times that of the oil reservoir. Since the purpose of this paper is mainly to discover the well-to-well interplay mechanisms and its influencing factors, the actual oil reservoir was simplified to an equivalent model with an effective radius of 316.23 m and an effective thickness of 26.8 m; Wells C2-P3 and C2-P2 were selected to form a typical well pair. The basic parameters of the equivalent model were the same as the actual oil reservoir (Table 1).

Scaling groups of the geometrical parameters derived by Shook et al. (1992) were then used to establish the 3D physical and numerical models, which were proven to be an effective method for CO_2–EOR by Li et al. (2015) and Zhao et al. (2018). An aspect ratio of the model (R_{model}) was used to ensure the similarity of the model; aspect ratios of well-length and spacing (R_{well} and R_{spacing}) and an aspect ratio of WOC (R_{WOC}) were used to ensure the similarity of the well pair. The permeability ratio (K_{mn}) was used to simulate a heterogeneity similar to the reservoir. Since the basic parameters of the equivalent model are given, the dimensionless group values were calculated (Table 2). Thence, the unknown parameters of the physical and numerical models were determined with the dimensionless values, with the final results listed in Table 1.

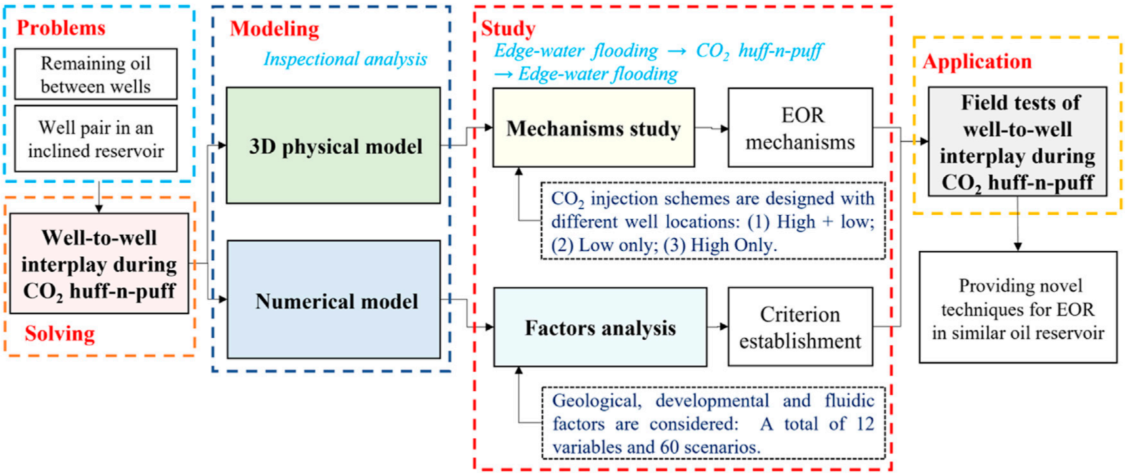

FIGURE 2
Technical route and major steps used in the study of well-to-well interplay of CO_2 huff-n-puff.

TABLE 1 Basic parameters for the equivalent reservoir, physical model, and numerical model.

Basic parameter	Equivalent model	3D physical model	Numerical model
Equivalent model radius (L)/m	316.23	0.400	316.23
Effective model height (H)/m	26.8	0.053	26.8
Stratigraphic dip (α)/°	15	15	15
Well length (L_{well})/m	102.72	0.130	100
Well spacing ($L_{spacing}$)/m	50	0.060	50
Distance between the lower well and WOC (L_{WOC})/m	96.60	0.17	100
Average horizontal permeability (K_h)/×10^{-3}μm^2	667	750	667
Average vertical permeability (K_v)/×10^{-3}μm^2	271.27	750	271.27
Highest permeability (K_{max})/×10^{-3}μm^2	1258.03	1200	1258.03
Lowest permeability (K_{min})/×10^{-3}μm^2	313.18	300	313.18
Average porosity/%	0.259	0.30	0.259

TABLE 2 Dimensionless group values calculated from the equivalent reservoir.

Dimensionless scaling group	
Aspect ratio of the model $R_{model} = (L/H)\sqrt{K_v/K_h}$	7.5246
Aspect ratio of the well length $R_{well} = (L_{well}/L)$	0.3248
Aspect ratio of the well spacing $R_{spacing} = (L_{spacing}/L)$	0.1581
Aspect ratio of WOC $R_{woc} = (L_{woc}/L)$	0.3055
Permeability ratio $K_{mn} = (K_{max}/K_{min})$	4.0170

According to the calculations, the 3D physical model used for well-to-well interplay during the CO_2 huff-n-puff process had a diameter of 400 mm, a thickness of 53 mm, and a stratigraphic dip of 15° (Figure 3A). The horizontal well pair including P1H and P2H was established in the middle of the core. The lengths of P1H and P2H were both 130 mm, the spacing between P1H and P2H is 65 mm, and the distance between P1H and WOC was 120 mm (Figure 3B). The model was a heterogeneous core with an average permeability of 750 × 10^{-3} μm^2, upper layer permeability of 300 × 10^{-3} μm^2, and bottom layer permeability of 1200 × 10^{-3} μm^2. In order to achieve the different

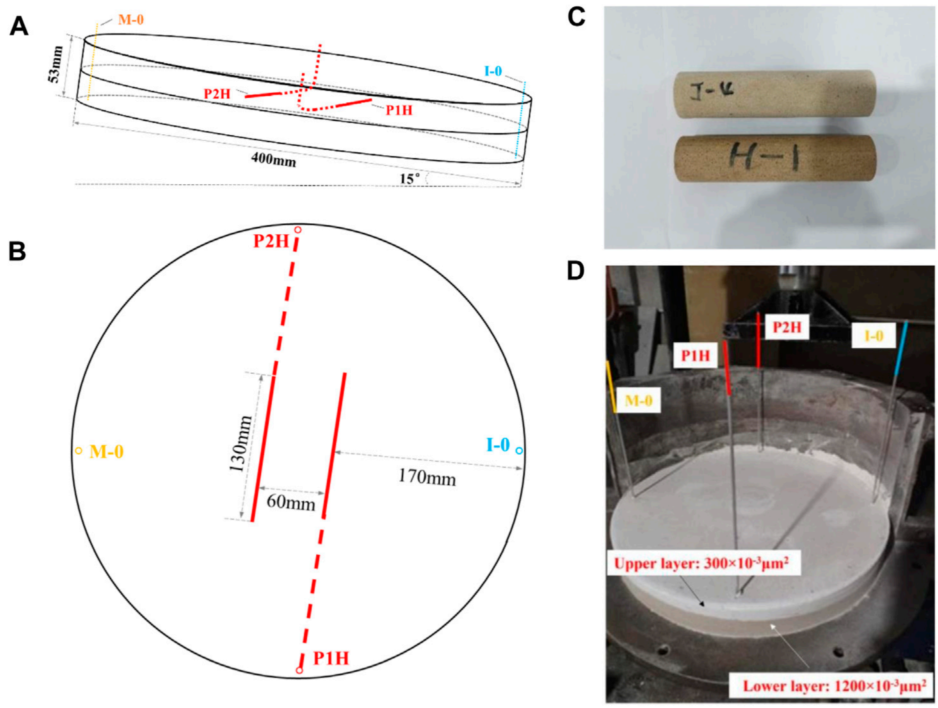

FIGURE 3
3D physical model used for the well-to-well interplay of CO2 huff-n-puff. **(A)** Side view and **(B)** top view of the designed model. **(C)** Picture of the 1D core. **(D)** Picture of the 3D core.

TABLE 3 Sand formula used to fabricate different permeabilities for 3D cores (measured from 1D cores).

Mesh range of sand	Core 1	Core 2
	Proportion/wt%	Proportion/wt%
40–80	28.9	6.2
80–100	66.4	62.3
100–150	3.7	24.9
200–300	1.0	6.6
Measured permeability/$\times 10^{-3}\mu m^2$	300	1200

permeabilities of the upper and lower layers, 1D homogenous cores were first fabricated with different mesh ranges of sand in the laboratory (Figure 3C). The proportions of different sands were determined after the permeability tests of 1D cores, with the results listed in Table 3. The sand formulas were then used to fabricate the 3D physical model (Figure 3D).

The numerical model was designed to be 500 m × 200 m × 30 m using a CMG-GEM simulator, and the value of the net gross ratio (NTG) was set at 0.9. With the same effective thickness of 26.8 m, the effective radius (L) was equal to 316.23 m in a circular equivalent model (Table 1). A Cartesian grid was used in the modeling—51 grids with a length of 9.8039 m were set in the x direction, 41 grids with a length of 4.8780 m were set in the y direction, and 15 grids with a length of 2 m were set in the z direction. The reservoir dip was set at 15°, and the depth of WOC was 1735 m. The sand body was normal rhythmic with an average permeability of 667 × 10^{-3} μm^2 and an average porosity of 25.9%. The initial oil saturation was set as 0.65, and the geological reserve was calculated to be same as the reserve in the real reservoir. An edge-water aquifer was connected to the bottom of the reservoir, which was 100-times the model size. P1H and P2H with the same horizontal length of 100 m were set as the lower and the higher wells, respectively. The spacing between P1H and P2H was set at 50 m, and the distance between P1H and

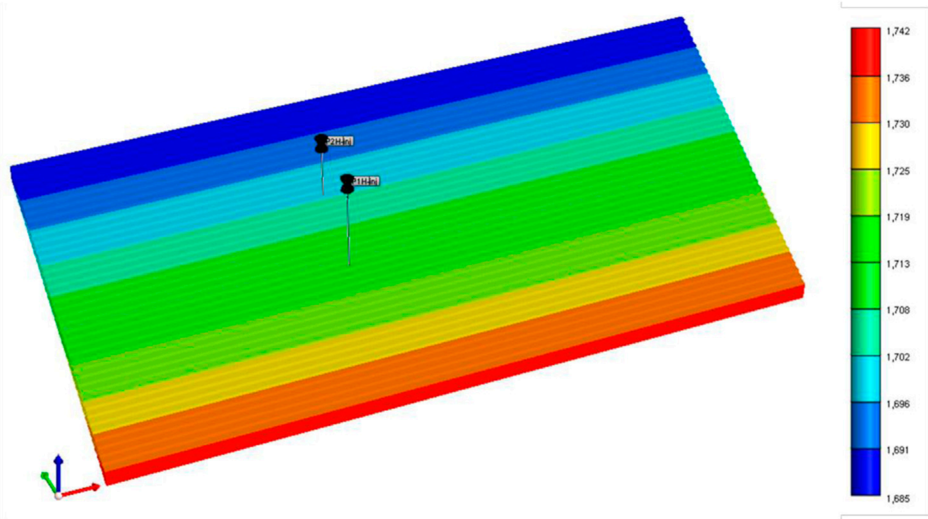

FIGURE 4
Numerical model used for the well-to-well interplay during CO2 huff-n-puff (grid top).

TABLE 4 Basic parameters of 3D physical models.

Scenario	Experimental scheme	Apparent volume/mL	Pore volume/mL	Porosity/%	Permeability/ $\times 10^{-3}\mu m^2$	Initial oil saturation/%
1	P1H_Lower Well 50 ml(RC) CO_2 + P2H_Higher Well 50 ml(RC) CO_2	6656.8	1755.2	26.37	300/1200	63.26
2	P1H_Lower Well 100 ml(RC) CO_2	6644.2	1700.9	25.60		66.32
3	P2H_Lower Well 100 ml(RC) CO_2	6669.4	1726.0	25.88		64.30

WOC was set at 100 m. The grid top of the numerical model is shown in Figure 4.

2.2 3D physical experiments for well-to-well interplay of CO_2 huff-n-puff

The oil and water samples used for the 3D physical experiments were collected from the block. The density of the formation oil was 0.97×10^3 kg/m^3, the viscosity was 289 mPa·s, and the gas/oil ratio was 18.9 m^3/m^3 under formation conditions (60°C, 16.24 MPa). The salinity of the formation water was 2.83×10^3 mg/L, and the injected CO_2 with a purity of 99.99 mol% was from Beijing, China. The basic parameters of the 3D physical models are listed in Table 4. The experimental setup consisted of six sub-systems: an injection system, an edge-water system, a displacement system, a production system, a temperature control system, and a data-acquisition system. In the injection system, the formation water, formation oil, and CO_2 were stored in cylinders and then injected into the model by a pump. In the edge-water system, formation water was stored in the cylinder and then injected into the model through Well I-0 (Figure 3). The 3D physical model was placed in the coreholder with a dip of 15°. In the production system, backpressure regulars (BPRs) were connected to the horizontal wells to control the production pressure. The produced oil and water were recorded by test tubes, while the gas was measured by using a gas flow meter. The thermostat was used to maintain the reservoir temperature, and the pressure monitored by M-0 was obtained by the data-acquisition system.

Several 3D experiments were designed in the laboratory to study the well-to-well interplay mechanisms of CO_2 huff-n-puff. The models were first displaced by the edge water and then by the CO_2 huff-n-puff process. Different injection schemes were designed with different injection wells and CO_2 volume allocations (Table 4). The bulk volume of the core was first measured before the 3D experiment. The core was then evacuated and saturated with formation water. The porosity was determined as the ratio of water saturation volume to bulk volume. The core was then displaced by formation oil to reach an initial oil saturation—calculated as the ratio of produced oil volume to the pore volume.

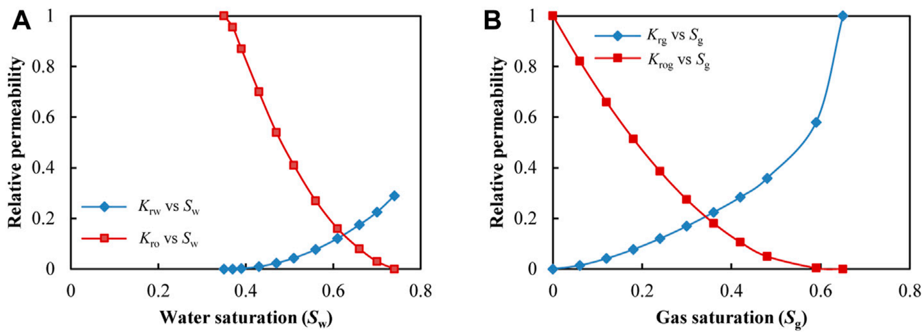

FIGURE 5
Relative permeability used for the numerical simulation. **(A)** Oil–water relative permeability. **(B)** Oil–gas relative permeability.

Edge-water driving was conducted first in the model according to these detailed procedures: 1) The formation temperature was set to 60°C, and the production pressures of the horizontal wells (P1H and P2H) were set to 16.40 MPa using BPRs. 2) Water was then injected through I-0 under a constant rate of 0.4 Ml/min to simulate the natural edge-water driving. 3) P1H and P2H were opened for production and then shut in simultaneously when the composite water cut of the well pair reached 98%.

CO_2 huff-n-puff was then conducted after edge-water driving. In Scenario 1, CO_2 was injected into the model through both the lower well P1H and the higher well P2H. The detailed procedures were 1) 50 Ml (reservoir conditions, RC) CO_2 and 50 Ml (RC) CO_2 were injected through P1H and P2H, individually, and then, these wells were shut in. 2) After a soaking time of 12 h, P1H and P2H were re-opened again for production. Simultaneously, the edge water was re-injected into the model through I-0. 3) The experiment was terminated when the composite water cut again reached 98%. The pressure, oil production, water production, and gas production were measured, and the oil recovery enhanced by CO_2 huff-n-puff was then calculated.

Scenarios 2 and 3 were designed with an equal total CO_2 volume of 100 Ml (RC) but different injection wells and gas allocations. In Scenario 2, 100 Ml of CO_2 was injected into the model only through the lower well P1H. In Scenario 3, 100 Ml of CO_2 was injected into the model only through the higher well P2H. Other procedures were the same as mentioned previously. After the experiments were finished, the production performances of the three scenarios were compared to study the interplay mechanisms during the CO_2 huff-n-puff process.

2.3 Numerical simulations for well-to-well interplay of CO_2 huff-n-puff

A sensitivity analysis of well-to-well interplay during CO_2 huff-n-puff was then conducted using the numerical model shown in Figure 4. Seven pseudo-components—CO_2, C_1+N_2, C_2~C_4, C_5~C_6, C_{7+}, C_{11+}, and C_{28+}—were set to simulate the formation oil, with proportions of 0%, 0%, 1.65%, 5.69%, 18.24%, 29.93%, and 44.49%, respectively. The viscosity of formation oil was tested at 289.25 mPa·s with a density of 0.974 × 10^3 kg/m^3—similar to the real oil sample under formation conditions. Figure 5 shows the oil–water and oil–gas relative permeabilities used for the numerical simulation.

As with the laboratory experiments, natural edge-water flooding was first conducted in the numerical model, and the liquid production rates of P1H and P2H were set equally at 18.42 m^3/d. Figure 6 gives the fitting curves of the daily production oil rates obtained from C2-P2 in the real reservoir and P2H in the numerical model. The daily oil rate was more than 16 m^3/d at the initial production stage (less than 18 days), dropping sharply to about 8 m^3/d within 50 days, and then gradually dropping to about 1 m^3/d. The average oil rate was 4.06 m^3/d within 500 days in the numerical model—similar to the average rate of 4.08 m^3/d obtained from C2-P2. Thus, the built model can be used to reflect the production performances of the real reservoir. The edge-water flooding process was conducted until the composite water-cut of the well pair reached 98%. Then, the CO_2 huff-n-puff process was conducted with CO_2 injected only through the lower well P1H. A total CO_2 mass of 400t was injected at a rate of 100 t/d. After 30 days of soaking time, P1H and P2H were reproduced until the composite water cut of the well pair again reached 98%. The oil production of the well pair enhanced by well-to-well interplay was obtained after the simulation.

Sensitivity analysis was then conducted, considering the developmental, geological, and fluidic factors used in the base model. A total of 12 variables and 60 scenarios were designed using the base model (as listed in Table 5). The oil production recovered by CO_2 puff-n-huff (ΔQ_o) was used to evaluate the well-to-well interplay for the well pair. Since five values were set for each variable, several values of ΔQ_o can be obtained after the simulations, and then, an average oil production ($\Delta \bar{Q}_o$) can be calculated as $\Delta \bar{Q}_o = \sum_{i=1}^{n} \Delta Q_{o-i}/n$, where ΔQ_{o-i} is the ith value of oil production (i = 1,2, . . . ,n.). The standard deviation of oil

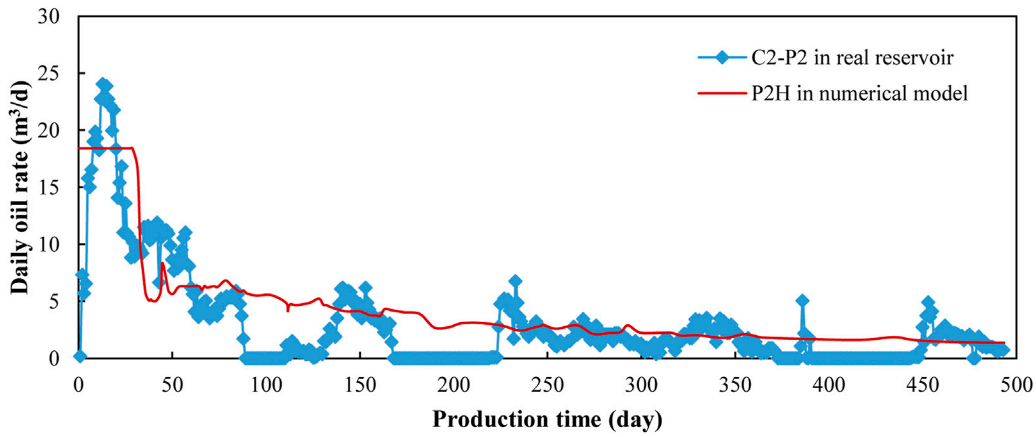

FIGURE 6
Fitting curves of daily oil rates obtained from the real reservoir and numerical model.

TABLE 5 Sensitivity analysis designed for the well-to-well interplay of CO_2 huff-n-puff.

Type	Influencing factor	Value	Default value
Developmental factors	CO_2 injection mass (t)	100, 200, 300, 400, and 500	400
	CO_2 injection rate (t/d)	25, 50, 100, 200, and 400	50
	Liquid production rate (m^3/d)	9.21, 13.82, 18.42, 27.63, and 36.85	18.42
	CO_2 soaking time (d)	15, 30, 60, 90, and 120	30
	Interwell spacing/m	40, 50, 60,70, and 80	50
	Height from WOC/m	6.31, 11.36, 16.41, 21.46, and 26.51	21.46
Geological factors	Horizontal permeability K_x/($\times10^{-3}\mu m^2$)	50, 100, 300, 667, and 1000	667
	Vertical permeability K_z/K_x	0.1, 0.2, 0.3, 0.4, and 0.5	0.4
	Lorentz coefficient of permeability (L_K)	0.1, 0.2, 0.3, 0.4, and 0.5	0.2
	Net gross ratio (NTG)	0.6, 0.7, 0.8, 0.9, and 1	0.9
	Stratigraphic dip (°)	0, 5, 10, 15, and 20	15
Fluidic factor	Oil viscosity (mPa·s)	10, 50, 100, 289.25, and 1000	289.25

production factor ($S_{\Delta Q_o}$) can also be calculated as $S_{\Delta Q_o} = \sqrt{\sum_{i=1}^{n}(\Delta Q_{o-i} - \Delta\bar{Q}_o)^2/n}$. Then, a coefficient of variation (C_v) was introduced as an evaluation index for the comparison of influencing factors for well-to-well interplay. The coefficient of variation (C_v) was defined as the ratio of the standard deviation to the average value of oil increase ($C_v = S_{\Delta Q_o}/\bar{Q}_o$). A higher value of C_v represented that the involved factor is more sensitive to the well-to-well interplay. After a comparison of C_v for each factor, the controlling factors for the well-to-well interplay during CO_2 huff-n-puff can be screened out.

3 Results and discussion

3.1 EOR mechanisms of the well-to-well interplay in 3D experiments

Before the CO_2 huff-n-puff operations, edge-water driving experiments were first conducted in the 3D physical models to form a similar remaining oil saturation; the results are compared in Table 6. Since the lower well P1H was closer to the edge water, the oil recovery of P1H was always the lowest with 6.84%–8.07%. The higher well P2H obtained a higher oil recovery of 11.21%–13.69%. When the composite water-cut of the well pair reached

TABLE 6 Experimental results of CO_2 huff-n-puff conducted in 3D physical models.

Scenario	Experimental scheme	Production well	Oil recovery/%		
			Edge-water driving	CO_2 huff-n-puff	Total
1	P1H_Lower Well 50 ml CO_2 + P2H_Higher Well 50 ml CO_2	P1H	7.48	2.18	9.66
		P2H	12.27	5.21	17.48
		Pair	19.75	7.39	27.14
2	P1H_Lower Well 100 ml CO_2	P1H	8.07	3.56	11.63
		P2H	13.69	6.13	19.82
		Pair	21.76	9.69	31.45
3	P2H_Higher Well 100 ml CO_2	P1H	6.84	2.27	9.11
		P2H	11.21	4.77	15.98
		Pair	18.05	7.04	25.09

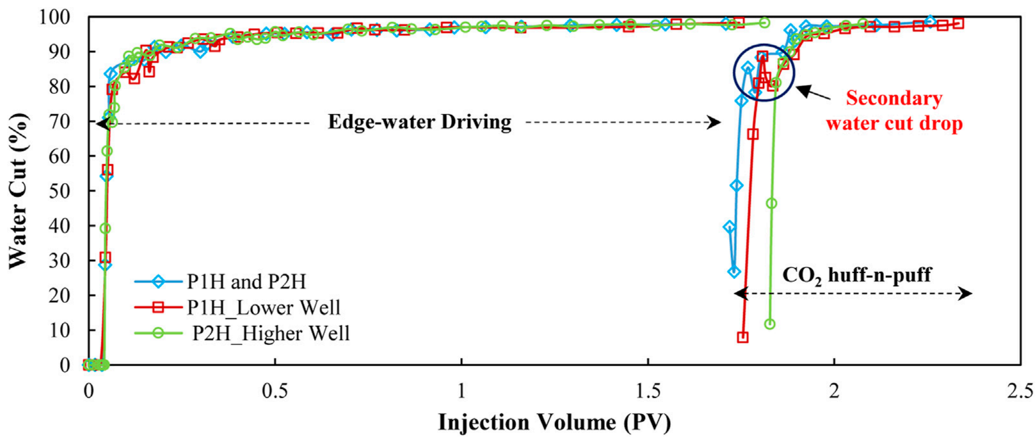

FIGURE 7
Comparison of composite water cuts for different CO_2 huff-n-puff scenarios.

98%, the total injection volume of edge water was around 1.70–1.80 PV, and the total oil recovery for the well pair was 18.05%–21.76%.

In order to study the mechanisms of well-to-well interplay during the CO_2 huff-n-puff process, different CO_2 injection schemes were designed according to the wells' locations. For the conventional CO_2 huff-n-puff conducted in Scenario 1, a total oil recovery of 7.39% was obtained for the well pair. The lower well P1H obtained an oil recovery of 2.18%, and the higher well P2H obtained an oil recovery of 5.21%. However, when CO_2 was injected only through the lower well P1H (Scenario 2), the highest oil recovery was achieved among the three scenarios. Not only did the operation well P1H obtain an oil recovery of 3.56%, but the higher well P2H also obtained an oil recovery of 6.13%., indicating an interplay between P1H and P2H during the CO_2 huff-n-puff process. When CO_2 was injected only through the higher well P2H (Scenario 3), the lowest oil recovery was obtained, with only 2.27% oil recovery obtained from P1H and 4.77% oil recovery from P2H.

Figure 7 compares the composite water cuts for different CO_2 huff-n-puff scenarios. At the initial production stage of CO_2 huff-n-puff, it can be observed that the lowest water-cut drop was obtained when CO_2 was injected only through lower well P1H (Scenario 2). CO_2 is soluble in the water phase, which is beneficial for treatment through water invasion. After comparing Scenarios 1 and 2, it is evident that a larger volume of CO_2 injected into the

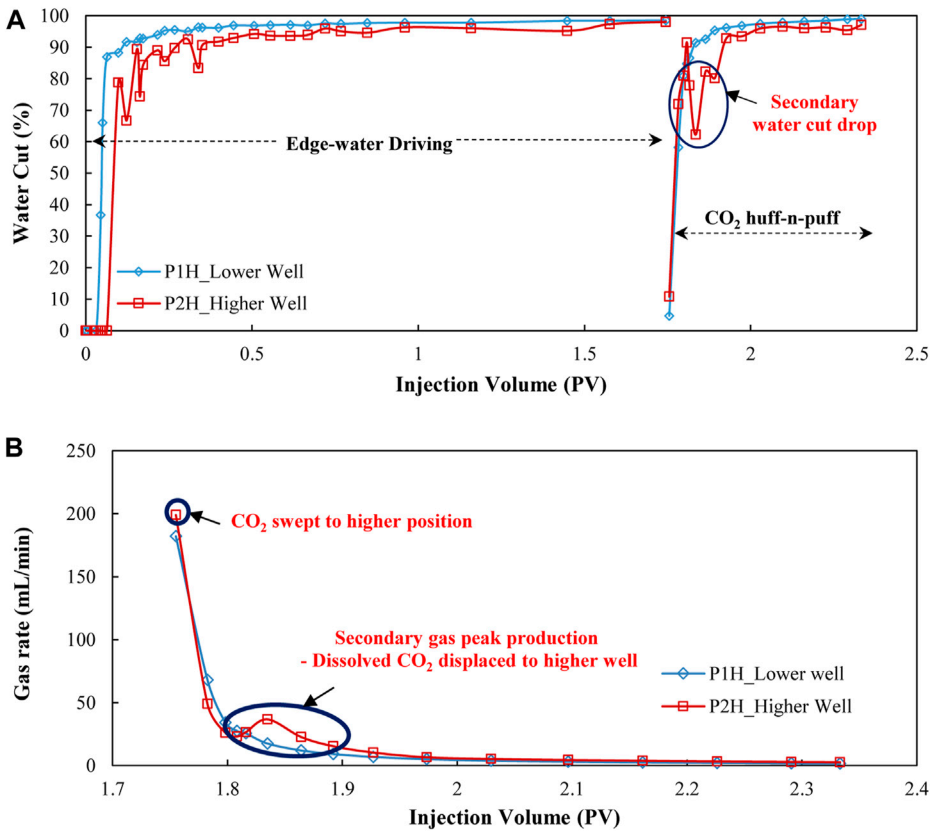

FIGURE 8
Production performance for single wells in Scenario 2 with CO_2 injected only through the lower well P2H. **(A)** Water cut curves. **(B)** Gas rate curves.

lower well allows better edge-water control. In addition to the lowest water-cut drop, production life can also be prolonged to 0.58 PV when the water cut again reaches 98% in Scenario 2. It can be observed that a secondary water cut drop formed in the successive production stage in Scenarios 1 and 2. Since CO_2 was injected though the lower well, it could be soluble in the remaining oil between P1H and P2H. With the assistance of edge-water driving, the dissolved CO_2 was displaced to a higher position, which then brought the amount of interwell-remaining oil to the higher well P2H. When CO_2 was injected only through the higher well P2H (Scenario 3), the water cut drop was mainly due to the oil recovered from P2H. Since no gas was injected through the lower well, the edge-water invasion was severe with the shortest production life of only 0.25 PV, and the water cut increased sharply with no period of secondary water-cut drops.

Figure 8A shows the water cut curves of individual wells in Scenario 2. When the composite water cut reached 98.27%, the water cut of P1H and P2H was 98.54% and 98.10%, respectively. After CO_2 was injected into the lower well P1H, the invasive edge water was treated first by CO_2, with the water cut of P1H and P2H dropping to as low as 4.73% and 10.80%, respectively. A large amount of crude oil was produced from P1H and P2H as long as CO_2 was produced—revealing it as the main contributor to the oil recovery increase. As the production process continued, the water cut of the lower well P1H increased gradually to around 90%; however, a secondary water cut drop was observed in the higher well P2H. The water cut of P2H again dropped from 91.55% to 62.26% during an injection volume of 1.81 PV to 1.83 PV, which can be attributed to the interwell-remaining oil displaced by the dissolved CO_2 and edge water. The injected CO_2 not only extracted the oil remaining around P1H and P2H but also displaced the oil remaining between P1H and P2H. Consequently, the oil recovery of the well pair can be maximized by injecting CO_2 into the lower position of the model.

Figure 8B provides the gas production rates for individual wells during the CO_2 huff-n-puff process in Scenario 2. Since CO_2 was injected only through the lower well P1H, an amount of CO_2 was produced from P1H immediately when the well was opened for production. However, it is interested to note that a larger amount of gas was also immediately produced from the higher well P2H. Since the model had a dip of 15°, part of the injected CO_2 in the lower position could migrate upward under gravitational differentiation, and then sweep the near-wellbore area of P2H. The remaining oil around P2H could be effectively extracted by the migrated CO_2, which then caused a remarkable water drop and oil increase for P2H. As the production process continued, the gas rate of the lower well P1H decreased gradually; however, another peak appeared on the gas rate of the higher well P2H. Since the edge water was being continuously injected into the model, part of the CO_2 in the lower position was displaced into the interwell area and then dissolved with the remaining oil. The remaining oil, dissolved CO_2, and invasive edge water were then produced successively from the higher well P2H. The duration of the secondary gas production peak for P2H was the same as that of the secondary water cut drop (as shown in Figure 8A), confirming that the oil increase in this period was due to the interwell remaining oil being displaced by CO_2 and edge water.

In summary, when CO_2 huff-n-puff is conducted in a well pair located in an inclined reservoir, an interplay can be formed between wells with a CO_2 injection into the lower position. Not only can water drop and oil increase be obtained from the lower well after the gas injection but also a more remarkable water drop and oil increase can also be obtained from the higher well. On one hand, the injected CO_2 in the lower position can migrate upward under gravitational differentiation in the inclined reservoir. On the other hand, dissolved CO_2 can be displaced into the interwell area with the assistance of edge-water flooding. Under the influence of migrated CO_2, dissolved CO_2, and edge water, the oil remaining between the wells can be effectively extracted through the higher well. The oil recovery of the well pair enhanced by CO_2 conducted in Scenario 2 is 2.3% better than the conventional CO_2 huff-n-huff, indicating that using the well-to-well interplay during a CO_2 huff-n-puff process for enhanced oil recovery is a promising gas injection strategy for the inclined oil reservoir.

3.2 Sensitivity analysis on the well-to-well interplay in simulations

Although the formation mechanisms of well-to-well interplay during the CO_2 huff-n-puff process were revealed using laboratory experiments, the influencing factors still need to be discussed before enlarging its application in field tests. A base reservoir model was built using a CMG-GEM simulator. As in the laboratory experiments, natural edge-water flooding was also first conducted in the base model, and CO_2 huff-n-puff was then conducted after the composite water cut reached 98%. For the default model, the liquid production rates of P1H and P2H were set at 18.42 m^3. CO_2 was injected through the lower well P1H at a rate of 100 t/d, a total CO_2 volume of 400t, and CO_2 soaking time of 30 days. After the composite water cut of the well pair reached 98%, 175.4t of crude oil was recovered from the lower well P1H, while a significant increase of 1197.24t of crude oil was obtained from the higher well P2H, accounting for 87.16% of the total oil increments for the well pair. Figure 9 shows the oil saturation before and after CO_2 huff-n-puff. The edge water mainly flowed through the higher permeable layers at the bottom of the reservoir, and an amount of crude oil remained between P1H and P2H. After the CO_2 huff-n-puff process was operated at the well pair, the oil saturation between P1H and P2H dropped notably due to the occurrence of well-to-well interplay. The injected CO_2 through the lower well P1H migrated upward with the displacement of edge water; the remaining oil between the wells was then effectively displaced from the higher well P2H. The simulation result was consistent with the experimental result, confirming that the well-to-well interplay of CO_2 huff-n-puff is an effective EOR method for the well pair in the inclined oil reservoir.

Sensitivity analysis was then conducted using the base model, with the simulation results shown in Table 7 and Figure 10. The calculated coefficient of variation (C_v) ranged from 0.0553 to 0.7287, with an average value of 0.2103. The C_v values of four factors— CO_2 injection mass, stratigraphic dip, horizontal permeability (K_x) and interwell spacing—were higher than its average. These four are considered the factors of most influence for the well-to-well interplay during CO_2 huff-n-puff. CO_2 injection mass is the primary factor in the well-to-well interplay, and Figure 11 shows the production performance of different CO_2 injection masses for the well pair. When the mass was less than or equal to 200t, the amount of CO_2 was mostly produced through the lower well P1H, with little CO_2 migrating up to the higher well P2H (Figure 11B). No interplay occurred between P1H and P2H; thus, the oil increment was less than 200t with the operation of CO_2 huff-n-puff. When the injected CO_2 mass exceeds 200t, the oil increase increased sharply to more than 1000t, a produced gas rate was observed from the higher well P2H, and the composite water cut also showed a secondary drop during the production stage. Thus, the injection mass of CO_2 should be more than 200t in order to enhance oil recovery using the well-to-well interplay.

The stratigraphic dip was the secondary influencing factor for the well-to-well interplay, and Figure 12 shows the production performance of different stratigraphic dips during CO_2 huff-n-puff. It can be observed that the oil increase is less than 850t when the dip is less than or equal to 5° and that little gas was produced from the higher well P2H. The dip was so small that the injected CO_2 could not migrate up to the higher position during one cycle of CO_2 huff-n-puff (Figure 12B). When the dip was higher than 5°, the oil increment increased to more than 1000t, a produced gas rate was observed from the higher well P2H, and the composite water cut also showed a secondary drop during the production stage. It can also be observed that a higher stratigraphic dip can recover more oil for the well pair, which is beneficial for the displacement of interwell-remaining oil achieved by CO_2 upward migration.

Horizontal permeability is the third influencing factor for well-to-well interplay, and Figure 13 shows the production performance of different horizontal permeabilities during CO_2 huff-n-puff. It can be observed that the oil increase was less than 500t when the

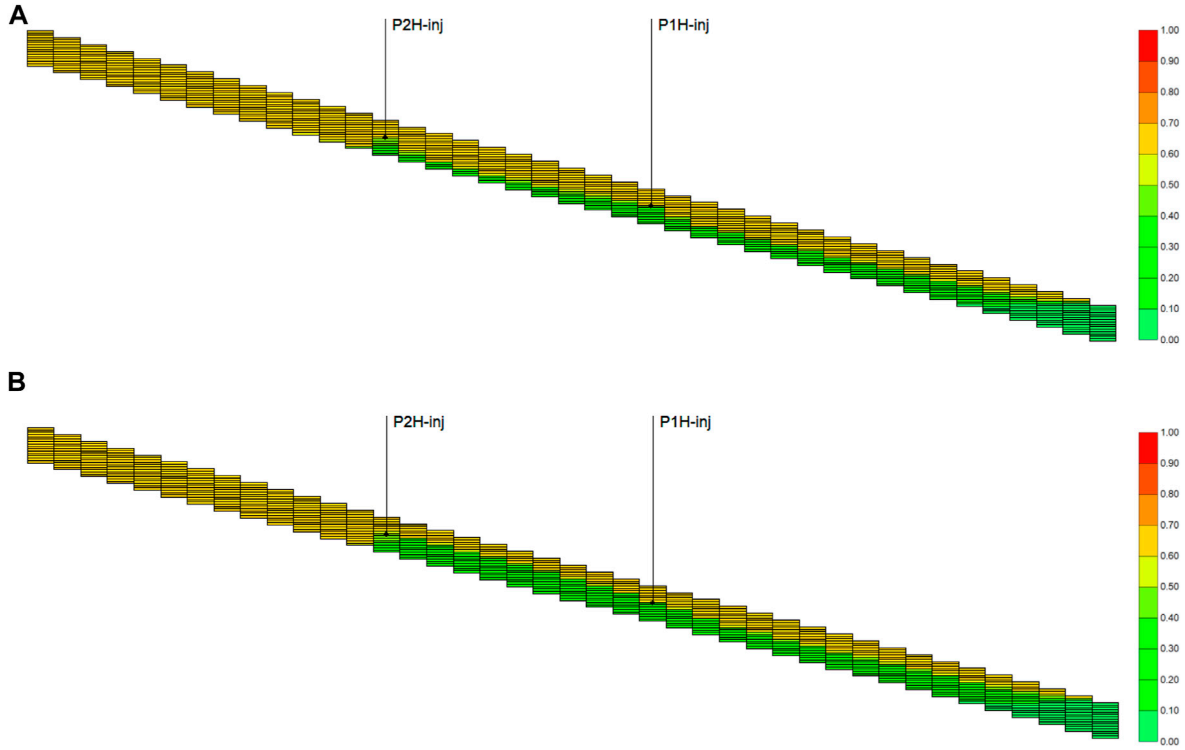

FIGURE 9
Oil saturation before and after the well-to-well interplay of CO_2 huff-n-puff. **(A)** Before and **(B)** after the well-to-well interplay of CO_2 huff-n-puff.

permeability was less than or equal to 100×10^{-3} μm^2, and that little gas was produced from the higher well P2H. The permeability was so small that the injected CO_2 could not migrate up to the higher position (Figure 13B). When the permeability was higher than 100×10^{-3} μm^2, the oil increase increased to more than 1000t, a produced gas rate was observed from the higher well P2H, and the composite water cut also showed a secondary drop during the production stage. Thus, the horizontal permeability should be more than 100×10^{-3} μm^2 when using well-to-well interplay for EOR.

The interwell spacing is the fourth influencing factor for well-to-well interplay, and Figure 14 shows the production performance of different interwell spacings during CO_2 huff-n-puff. It can be observed the oil increase increased as interwell spacing increased, which can be more than 2000t when the spacing exceeds 70 m. As the interwell spacing increased, more crude oil remained between P1H and P2H after edge-water driving. When CO_2 was injected into the lower well P1H, oil could be continuously produced from the higher well P2H under CO_2 gravitational differentiation and edge-water displacement (Figure 14B). As a result, the composite water cut remained at a level of less than 98% for more than 800 days, and considerable remaining oil was effectively recovered from the reservoir using the well-to-well interplay during CO_2 huff-n-puff.

In summary, a successful CO_2-EOR operation using well-to-well interplay mostly depends on both geological and developmental factors. The oil reservoir should be inclined with a stratigraphic dip of more than 5°, and horizontal permeability should be more than 100×10^{-3} μm^2. The CO_2 injection mass is the primary influencing factor; it should be more than 200t, and CO_2 should be injected through the lower position of the reservoir. A larger interwell spacing can allow the injected CO_2 to fully dissolve with the crude oil and then displace the remaining oil upward to a higher position. With an elaborate design of gas injection in this inclined oil reservoir, a considerable oil increase of more than 1000t can be recovered using the well-to-well interplay during the CO_2 huff-n-puff process.

3.3 Pilot tests using well-to-well interplay during the CO_2 huff-n-puff process

Pilot tests using well-to-well interplay of CO_2 huff-n-puff were widely applied after natural edge-water flooding in C2-1 Block, Jidong Oilfield, China, from 2010; a total of 2.27×10^4 m^3 of crude oil was recovered until the end of 2018. Figure 15 shows five typical well pairs using well-to-well

TABLE 7 **Simulation results and sensitivity analysis of well-to-well interplay during CO_2 huff-n-puff.**

Influence factors	Value of ΔQ_o (t)	Average value ($\Delta \bar{Q}_o$) (t)	Standard deviation ($S_{\Delta Q_o}$)	Coefficient of variation (C_v)
CO_2 injection mass	64.09, 133.66, 1154.27, 1373.58, and 1436.47	832.41	606.62	0.7287
CO_2 injection rate	1383.43, 1341.14, 1372.58, 1443.72, and 1626.54	1433.48	102.10	0.0712
Liquid production rate	1446.69, 1397.29, 1371.58, 1272.00, and 1176.97	1332.91	96.55	0.0724
CO_2 soaking time	1237.14, 1371.58, 1427.42, 1496.49, and 1510.72	1408.67	99.27	0.0705
Interwell spacing	1149.90, 1371.58, 1816.29, 2160.07, and 2391.64	1777.90	465.55	0.2619
Height from WOC	1561, 1507.56, 1423.63, 1371.58, and 1352.22	1443.20	79.76	0.0553
Horizontal permeability K_x	401.92, 424.41, 1420.17, 1371.58, and 1338.05	991.23	472.76	0.4769
Vertical permeability K_z/K_x	1030.79, 1254.71, 1334.89, 1371.58, and 1499.93	1298.38	155.45	0.1197
Lorentz coefficient of permeability (L_K)	1511.87, 1371.58, 1264.38, 1220.25, and 1167.27	1307.07	122.48	0.0937
Net gross ratio (NTG)	1155.73, 1170.87, 1302.01, 1371.58, and 1587.19	1317.48	157.21	0.1193
Stratigraphic dip	778.74, 827.62, 1205.74, 1371.58, and 1625.67	1161.87	322.34	0.2774
Oil viscosity	2063.50, 1773.80, 1563.30, 1371.58, and 1278.58	1610.15	283.32	0.1760

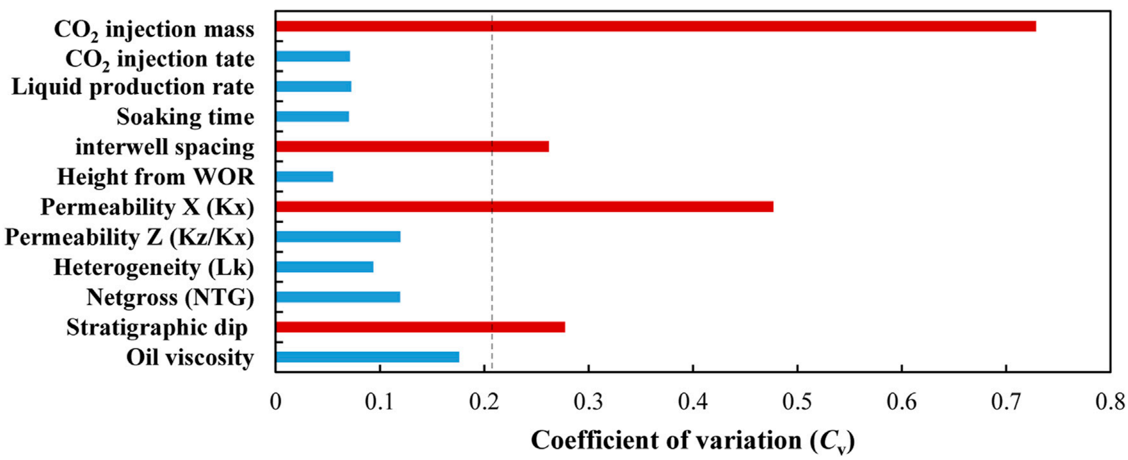

FIGURE 10
Sensitivity analysis results of the well-to-well interplay during the CO_2 huff-n-puff process.

interplay where CO_2 was injected into the reservoir through the lower wells. After the CO_2 injection, the same phenomena were observed with the oil recovered from both the lower and higher wells. Moreover, the oil increases of the higher wells were always higher than those of the lower wells, indicating that the interwell-remaining oil had been successfully displaced using the well-to-well interplay of CO_2 huff-n-puff.

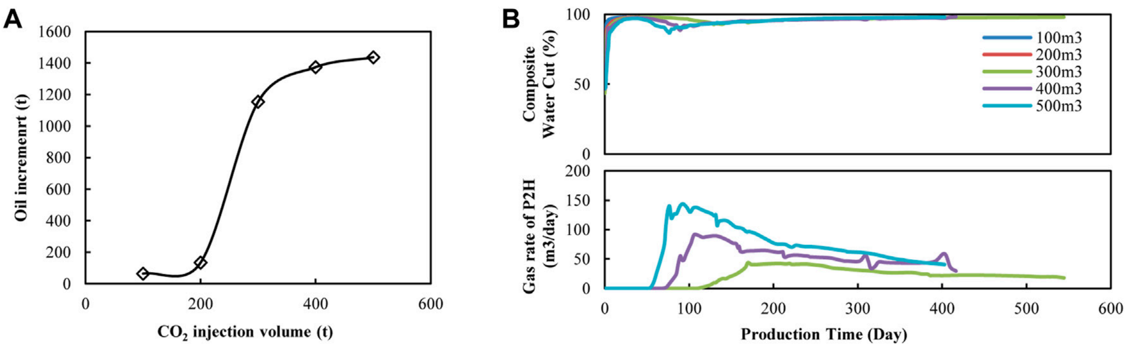

FIGURE 11
Production performance of different CO_2 injection volumes for the well-to-well interplay of CO_2 huff-n-puff. **(A)** Oil increment *vs*. CO_2 injection volume. **(B)** Composite water cut and production gas rate *vs*. time.

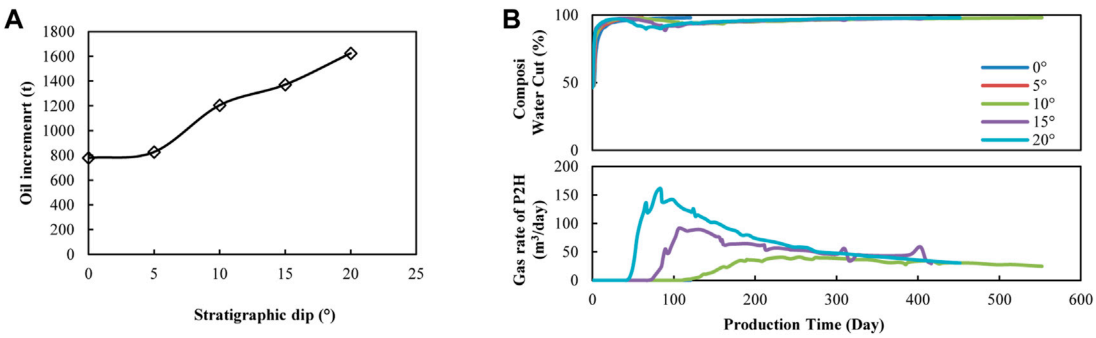

FIGURE 12
Production performance of different stratigraphic dips for well-to-well interplay of CO_2 huff-n-puff. **(A)** Oil increase vs. interwell spacing. **(B)** Composite water cut and production gas rate *vs*. time.

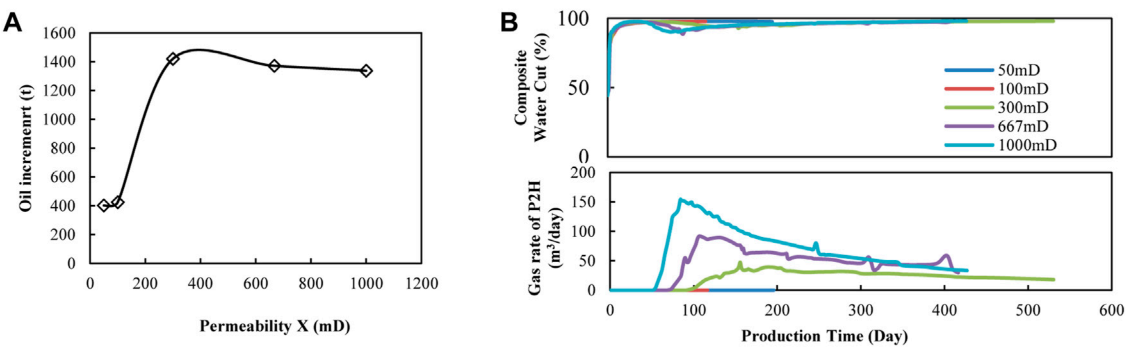

FIGURE 13
Production performance of different horizontal permeabilities for the well-to-well interplay of CO_2 huff-n-puff. **(A)** Oil increase *vs*. interwell spacing. **(B)** Composite water cut and production gas rate *vs*. time.

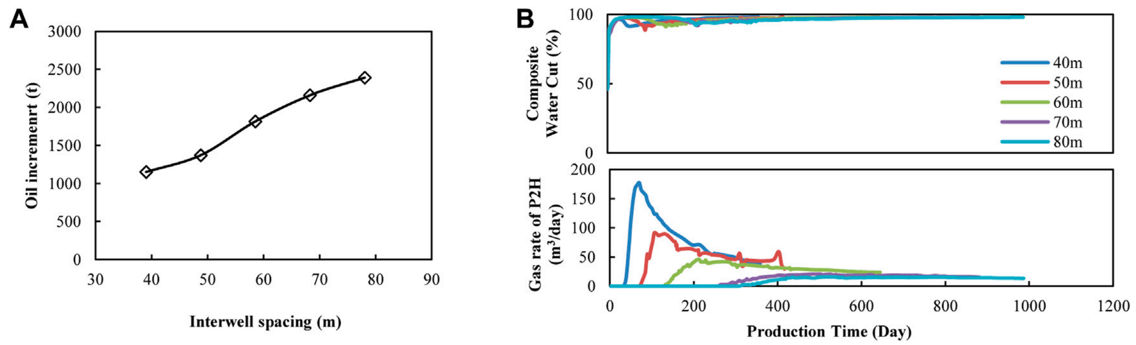

FIGURE 14
Production performance of different interwell spacings for the well-to-well interplay of CO_2 huff-n-puff. **(A)** Oil increase *vs*. interwell spacing. **(B)** Composite water cut and production gas rate *vs*. time.

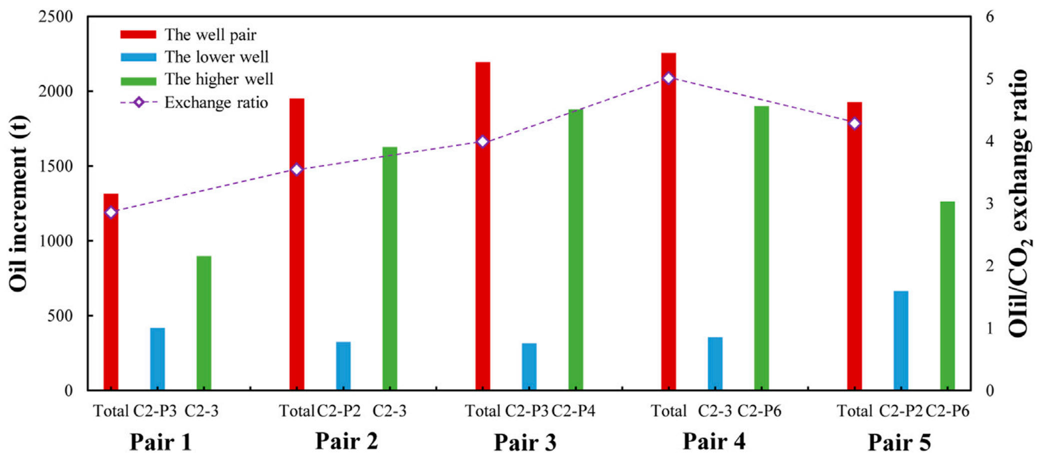

FIGURE 15
Oil increase and oil–CO_2 exchange ratio for five well pairs using the well-to-well interplay of CO_2 huff-n-puff in pilot tests.

The oil–CO_2 exchange ratio is defined as the oil increment enhanced by per unit CO_2, which can be used to reflect CO_2 utilization efficiency. The higher the value of the oil–CO_2 exchange ratio, the more efficient the CO_2 utilization is. Figure 15 also shows the total oil increases and the oil–CO_2 exchange ratio for these five well pairs. Using well-to-well interplay, the total oil increase for a well pair was more than 1300t during CO_2 puff-n-huff; the oil increases for pairs 4 and 5 in particular were more than 2000t. The oil–exchange ratio ranged from 2.85 to 5.01, which means that a small mass of CO_2 can recover plenty of crude oil from the reservoir. The total CO_2 mass operating in these five pairs was 2460t, the total oil increase was 9642.1t, and the average oil–CO_2 exchange ratio was 3.92. The well-to-well interplay not only achieved considerable EOR but also showed great potential for improving the CO_2 utilization efficiency during CO_2 huff-n-puff.

Although the successful utilization of well-to-well interplay during the CO_2 huff-n-puff process has brought great profits to the oil company, there are still some problems to be resolved during its operation. For example, several operations of the well-to-well interplay were failures because of the presence of fractures; however, some were much better than the EOR effects conducted in areas with no fractures. These may lead to completely different EOR mechanisms during the well-to-well interplay, which we will further investigate and report in a future study.

4 Conclusion

The well-to-well interplay of CO_2 huff-n-puff is proposed as a novel gas injection strategy for enhanced oil recovery (EOR) in an inclined oil reservoir. Laboratory experiments, numerical simulations, and pilot tests are reported in this paper, and these are some conclusions:

1) When CO_2 is injected into a lower well of a well pair in an inclined oil reservoir, not only can water drop and oil increase be obtained from the lower well, but a more remarkable water drop and oil increase can also be obtained from the higher well. The interplay between wells can dramatically enhance oil recovery for the well pair.
2) The displacement of interwell-remaining oil is the main contribution for EOR using well-to-well interplay. Under gravitational differentiation and edge-water flooding, CO_2 and edge water can migrate upward to displace the oil between wells. Physical experimental results show that oil recovery enhanced by a well-to-well interplay is 2.30% higher than recovery using conventional CO_2 huff-n-huff.
3) Sensitivity analysis results show that CO_2 injection mass, stratigraphic dip, horizontal permeability, and interwell spacing are the factors that most influence well-to-well interplay. To realize a better oil increment, the reservoir dip should be more than 5°, the permeability should be more than 100×10^{-3} μm^2, the CO_2 injection mass should be more than 300t, and greater interwell spacing is beneficial for achieving a better CO_2–EOR effect.
4) A total of 2.27×10^4 m^3 of crude oil was recovered using well-to-well interplay in the pilot between 2010 and 2018. The results of five typical well pairs show that the oil–CO_2 exchange ratio was as high as 3.92. The well-to-well interplay not only achieved a considerable EOR effect but also showed great potential for improving efficient CO_2 utilization during the CO_2 huff-n-puff process.

Data availability statement

The original contributions presented in the study are included in the article/Supplementary material; further inquiries can be directed to the corresponding authors.

Author contributions

HH contributed to the conception of the study. JH provided the funding for the study. MQ performed the experiment. WG performed the simulation. SD performed the data analyses obtained in the experiment and simulation. HL provided the data operated in the pilot test.

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Conflict of interest

HL was employed by PetroChina Jidong Oilfield Company.

The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

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