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Review article

A critical review of the CO_2 huff 'n' puff process for enhanced heavy oil recovery

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A B S T R A C T

Heavy oil resources have become increasingly important in recent years due to a reduction in light oil production and an increase in energy consumption. A large number of heavy oil reserves are found all over the world, and traditional production methods, such as solution gas drive, water flooding, etc., cannot gain a high heavy oil recovery factor, because of the high viscosity of the heavy oil. Although the thermal method has proven efficient and economical to produce heavy oil, it cannot be applied in deep reservoirs or reservoirs with thin pay zones due to the huge heat loss in these reservoirs. Thus, in order to enhance heavy oil production, several CO_2 injection processes are applied in heavy oil reservoirs. Among them, the CO_2 huff 'n' puff method has proven the most applicable.

In this research, the CO_2 huff 'n' puff process is reviewed in detail. Among the mechanisms of the CO_2 huff 'n' puff process in enhancing heavy oil production, the formation of foamy oil, viscosity reduction, and oil swelling are the most important ones, so that effect of foamy oil in the production stage is studied, and the viscosity reduction ratio with CO_2 injection and oil swelling factors at different temperatures and pressures are summarized. In addition, the diffusion coefficient, which indicates the mass transfer rate and amount of CO_2 dissolved into heavy oil through the two-phase interface of CO_2 and heavy oil, is analyzed in various heavy oil reservoirs at different temperatures and pressures.

Experimental studies on the CO_2 huff 'n' puff process indicate that the process applied in the heavy oil reservoir is successful and can be carried out with an oil viscosity up to 28,646 mPa·s and a reservoir permeability up to 24,200 mD. In pilot tests in the field, economical CO_2 huff 'n' puff processes have been applied in the heavy oil reservoirs with an oil gravity as low as 4 °API, a reservoir depth as high as 1985 m, and a pay zone as low as 12.2 m. Specifically, CO_2 utilization can be as low as 4.2 Mscf/Stb. Numerical simulation studies can gain very good simulation results on both experimental and pilot tests studies. However, mathematical models have seldom been published on CO_2 huff 'n' puff processes in heavy oil reservoirs.

1. Introduction

The heavy oil resource is defined as an asphaltic, dense, and viscous oil with an American Petroleum Institute (API) gravity less than 20 °API inclusive and a viscosity greater than 100 mPa·s [1–3]. Heavy oil resources are found all over the world, but they are mainly deposited in Canada and Venezuela. The total estimated volume of recoverable heavy oil (434 billion barrels) and bitumen (651 billion barrels) is almost the same as the remaining light oil reserves in the world. To meet the continuous increase in energy consumption, heavy oil production will be boosted in the future [1,4–9].

Two main difficulties for heavy oil production are high oil viscosity and thin oil pay zone. High oil viscosity leads to low mobility of the heavy oil in production process. To reduce high oil viscosity, two kinds of methods are mainly used:

(1) Thermal methods reduce oil viscosity significantly due to the high temperature of the injected fluids. These methods include processes such as Steam Assisted Gravity Drainage (SAGD) [10–12], Cyclic Steam Stimulation (CSS) [13,14], Steam Flooding [15,16], in-situ combustion [17–19], etc.
(2) Solvent based non-thermal methods reduce oil viscosity through the dilution of solvent into heavy oil. These methods include Cyclic Solvent Injection (CSI) [20,21], Vapour Extraction (VAPEX) [22,23], huff 'n' puff process [24,25], etc.

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Nomenclature

BC	boundary condition
B_o	heavy oil volume factor, rb/stb
B_{o-CO_2}	volume factor of heavy oil-CO_2 system, rb/stb
E	the efficiency of CO_2 the huff 'n' puff process, STB oil/Mcf CO_2
D	diffusion coefficient, 10^{-9} m^2/s
dp/dt	pressure depletion rate, kPa/min
GOR	gas oil ration, Sm^3/m^3
h_t	reservoir thickness, m
h_{net}	thickness of net pay zone, m
k	reservoir permeability, mD
K_o	oil relative permeability, mD
N_c	number of cycles
N_{well}	number of well
P_t	treatment pressure, kPa
$P_{(r,t)}$	pressure as a function of space and time, kPa
P_{wf}	wellbore flowing pressure, kPa
P_{Sat}	saturation pressure, kPa
P_{inj}	injection pressure, kPa
q_o	heavy oil production rate, bbl/day
$Q_{o/cycle}$	heavy oil production for each cycle, bbl
R	viscosity reduction ratio, fraction
RF	heavy oil recovery factor, %
r_L	limit radius, m
r_{md}	is maximum diffusion radius, m
r_w	well radius, m
S_f	swelling factor, m^3/m^3
S_{oi}	initial oil saturation, fraction
S_o	oil saturation, fraction
S_r	stimulation ratio
S_w	water saturation, fraction
T	temperature, °C
T_{Soak}	soaking time, day
U_{CO2}	CO_2 utilization, MScf/Stb
V_c	volume of injected CO_2 in each cycle per foot of sand, MMscf/ft
$V_{CO2/cycle}$	volume of injected CO_2 for each cycle, MMScf
μ_o	heavy oil viscosity, mPa·s
μ_{Lo}	live oil viscosity, mPa·s
μ_{oc}	viscosity of heavy oil-CO_2 system, mPa·s
$\varnothing$	porosity, fraction

Previous studies have determined that most heavy oil deposits in Canada are found in thin pay zones [26]. In Western Canada, up to 80% of the proven heavy oil reserves are in the oil pay zone, which is less than 5 m. Almost 97% of them are located in the pay zone, which is less than 30 m [27–29]. The thermal based production method could not be implemented in this type of heavy oil reservoir due to the extremely high heat loss to the over-/under-burdens [26,30]. Regarding deep heavy oil reservoirs, thermal methods cannot enhance heavy oil production significantly, because the steam quality will be decreased remarkably when the steam is injected into the deep reservoir: leading to a very slow heat expansion in the reservoir. To avoid the negative effects of thin or deep reservoir properties on thermal based methods, the solvent-based non-thermal recovery method can be applied to enhance heavy oil recovery in the thin or deep heavy oil reservoir. Regarding the solvent based non-thermal method, methane [31,32], ethane [33,34], propane [22,35], normal butane [22,36,37], toluene [38,39], CO_2 [31,40,41], and mixture solvents [20,24] etc., can be used as the injection solvent. Among the solvents, scholars have focused on CO_2 because (1) potential climate change will result in a rising temperature in the future and CO_2 emissions into the atmosphere (the latter, no doubt, is one of the key issues) [42–48]; (2) the laboratory tests indicate that CO_2 can be absorbed in heavy oil and thus boost heavy oil production in the industry [28,49]; and (3) CO_2 can gain a much higher saturation pressure and higher viscosity reduction ratio at high pressure than other solvents [50–52].

There are many approaches to enhance heavy oil recovery by using the CO_2 injection process, including continuous CO_2 injection, intermittent CO_2 injection, water-alternate-CO_2 injection, and CO_2 huff 'n' puff. Among them, the CO_2 huff 'n' puff process is the most efficient process, although the recovery factor is still low [24,53]. An ongoing CO_2 huff 'n' puff pilot test carried out in the Cold Heavy Oil Production with Sand (CHOPS) wells by Husky Energy in the Lloydminster area, Canada, indicates that the oil recovery has been increased about 8–20%, which is around 1.5 million barrels of heavy oil, and the recovery rate has been doubled [54,55]. Therefore, in this study, CO_2 huff 'n' puff process is reviewed to gain more details for future researches.

2. The CO_2 huff 'n' puff process

The CO_2 huff 'n' puff process is implemented in a single well. It is divided into three stages: (1) the injection stage, (2) the soaking stage, and (3) the production stage [24,56–57], as shown in Fig. 1. In the injection stage, CO_2 is injected into the target formation through the well, which acts as the injector in the injection stage. The injected CO_2 bypasses the unmovable heavy oil and pushes part of the mobile heavy oil and water into a further location in the reservoir: leading to water saturation reduction near the wellbore so that the relative permeability of the heavy oil increases. The other part of the movable heavy oil is prevented from pushing away near the wellbore, and it is exposed in the injected CO_2 phase. The CO_2 diffusion process is negligible in the injection stage, because (1) the diffusion coefficient of CO_2 in heavy oil is not very high, (2) the injection stage is brief, and (3) the CO_2 is injected at a high injection rate. At the end of the injection stage, the pressure in the reservoir will be much higher than the reservoir pressure when the injection process started.

In the soaking stage, the well is shut-in. CO_2 diffusion occurs, and the key mechanisms of the CO_2 huff 'n' puff process in terms of oil swelling and viscosity reduction are obtained. During the soaking period, the mass transfer of CO_2 into heavy oil occurs and light/medium components in heavy oil are extracted into CO_2 so that the volume of heavy oil increases and the viscosity decreases.

In the production stage, when the well is open, part of the injected CO_2, which does not dissolve into the heavy oil, is produced as the gas phase. Then the swelled heavy oil (indicated as a lighter color than the dead heavy oil in Fig. 1) that forms a large portion of the production fluids. Finally, heavy oil is produced with the water phase from a further location of the reservoir due to the drive force generated by the pressure drop. Part of the swelled oil is flushed by the movable water.

3. Mechanisms of the CO_2 huff 'n' puff in heavy oil reservoir

Regarding heavy oil reservoirs, the injected CO_2 is mainly under the immiscible condition for two reasons: (1) the Minimum Miscible Pressure (MMP) of the heavy oil is too high to be achieved in the heavy oil reservoir when the gravity of crude oil is lower than 30 °API [58]; and (2) the reduction of interfacial tension (IFT) between the injected CO_2 and heavy oil is not remarkable, so the miscible process cannot occur. The mechanisms of the immiscible CO_2 process are mainly reported as foamy oil, oil swelling, and viscosity reduction [51,56,59,60], so they are discussed in detail. However, the upper aspects are insufficient to enhance heavy oil recovery in the CO_2 huff 'n' puff process alone [61]. The extra concepts are (1) reduction of interfacial tension,

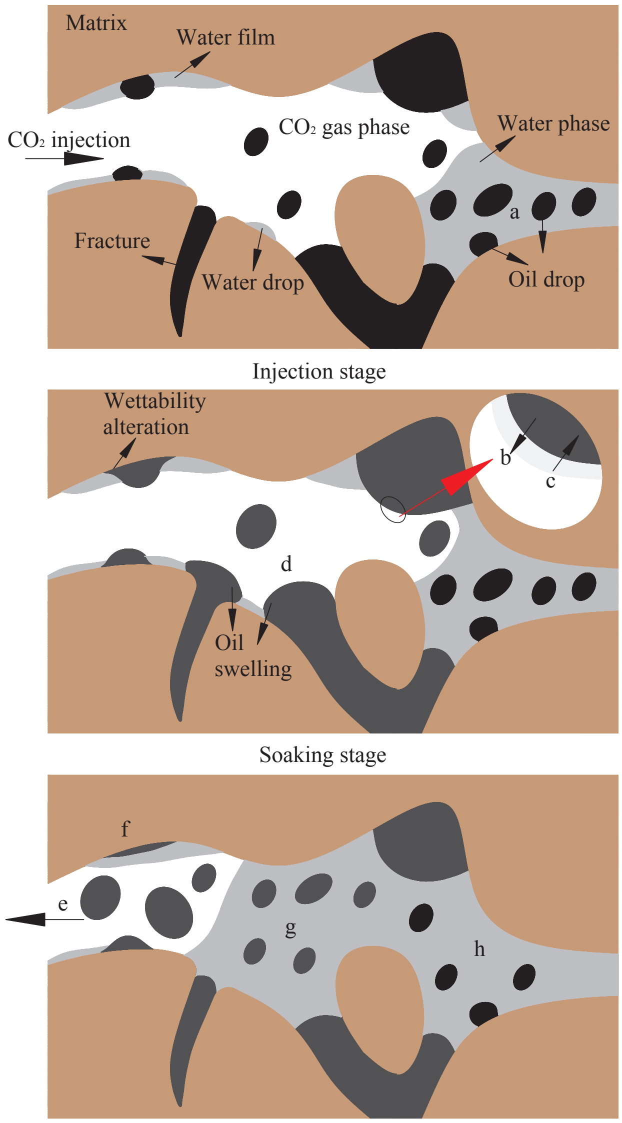

Fig. 1. Schematic of the CO_2 huff 'n' puff process in heavy oil reservoir. (a) oil drops are flushed to a further location in the reservoir by CO_2; (b) light/medium components are extracted by CO_2; (c) CO_2 dissolves into heavy oil; (d) oil drops connect together due to oil swelling; (e) the fluids flow direction; (f) residual oil due to wettability alteration; (g) oil drops generated from swelled oil in the soaking stage; and (h) oil drops in the water phase are driven from the further location.

(2) increased water wettability, (3) three-phase relative permeability effects, (4) CO_2 solubility in water, (5) light/medium hydrocarbons extraction, (6) solution gas drive, (7) CO_2 as a water shutoff agent, and (8) concomitant reactions with rock to increase the reservoir permeability near the wellbore, etc. [32,51,62–77].

3.1. Foamy oil

Compared with the CO_2 huff 'n' puff process in a heavy oil reservoir under water drive, the pressure depletion process that is conducted in the heavy oil reservoir can result in better oil production [78] mainly due to foamy oil occurring in the production stage. Solution gas drive has been proven as the main production mechanism in the CO_2 huff 'n' puff process applied in a heavy oil reservoir [79–82]. When CO_2 is injected into the heavy oil reservoir, it will dissolve into heavy oil through mass transfer, and the dissolved CO_2 gas will expand the volume of the heavy oil. Then the dissolved CO_2 will drive the heavy oil out of the pores to the production well when the pressure is declined in the production stage. Because of the high viscosity of heavy oil, the phase of the CO_2 appears as gas bubbles, which are dispersed in heavy oil and flow with the heavy oil when the reservoir pressure declines. The produced heavy oil is a mixture containing small bubbles, this kind of produced fluid is defined as foamy oil [83–85]. The foamy oil phenomenon has been observed in experimental studies on the CO_2 huff 'n' puff process in heavy oil reservoirs, and it enhances heavy oil production significantly [60,76,86].

In the production stage of the CO_2 huff 'n' puff process in heavy oil, the foamy oil phenomenon relates highly to the pressure decline rate, temperature, solvent solubility, etc. A higher pressure depletion rate results in a higher heavy oil recovery factor due to the higher pressure depletion rate producing more stable foamy oil in the production stage [7,87–89]. Considering the effect of temperature, researchers have found that the stability of the foamy oil decreases sharply and the volume of the dispersed gas increases with increasing temperature [90,91], but an optimized temperature can be obtained for a certain oil sample [92]. Among different solvents, foamy oil, which is generated by using CO_2 saturated in heavy oil, can achieve a higher quality than other solvents (CH_4 or N_2) due to the slow desorption of CO_2 in heavy oil [81]. The solubility of CO_2 in heavy oil relates to injection pressure, as the CO_2 solubility increases with the increasing of injection pressure. With higher CO_2 solubility, the foamy oil behavior will be more obvious in the production stage [76], and the heavy oil recovery factor will be higher.

3.2. Viscosity reduction

Viscosity reduction is another main mechanism of the CO_2 huff 'n' puff process. Previous studies have indicated that the effect of viscosity reduction is more significant in heavy oil with a lower API gravity [24,93]. When CO_2 is recombined into heavy oil, the viscosity of the heavy oil is extremely reduced, as shown in Table 1. The main reasons for viscosity reduction through CO_2 injection are: (1) the particulate matters in the heavy oil are washed out by the injected CO_2; (2) the viscous deposits are dissolved by the injected CO_2; (3) the viscous crude in heavy oil is diluted by the injected CO_2; and (4) the injected CO_2 is demulsified in heavy oil [94]. The viscosity reduction of heavy oil results in the fractional flow curve shifting to the right, so that the fractional flow of water is lower than that before CO_2 injection at the same water saturation and the oil mobility and oil connection are increased, which leads to a relative higher oil flow rate [56].

The viscosity reduction ratio of a heavy oil-CO_2 system changes with the temperature, pressure, and solubility of the dissolved CO_2 [95]. Fig. 2 shows the viscosity reduction ratio and CO_2 solubility of a heavy oil-CO_2 system at different temperatures and pressures. With temperature increases, the viscosity of the dead heavy oil decreases extremely and the viscosity reduction ratios for the dead oil at 60 °C and 93 °C are 86.8% and 97.3%, respectively. Therefore, the effect of temperature on heavy oil viscosity is remarkable.

With CO_2 injection, when the temperature is lower than the critical temperature, the viscosity reduction mainly occurs at a lower pressure due to the mass transfer of the liquid phase being much slower than the gas phase. This leads to the effect of pressure on CO_2 solubility being not significant. Regarding the heavy oil-CO_2 system, the efficiency of viscosity reduction decreases with temperature increases at the same pressure due to (1) lower CO_2 solubility with higher temperature in heavy oil; and (2) lower viscosity of heavy oil at higher temperature, which results in less viscosity reduction potential. The experimental study indicates that a higher percentage of viscosity can be reduced by CO_2 injection for heavy oil with a higher viscosity [95]. With an increase in CO_2 solubility, the viscosity reduction ratio increases, which means a higher percentage of the heavy oil viscosity is reduced by injecting CO_2. The viscosity reduction ratio can be as high as 97% for the studied heavy oil.

Table 1
Summary of the measured viscosity reduction ratios and oil swelling factors in different heavy oils.

Proposed by	Oil sample	Gravity (°API)	T (°C)	μ_o (mPa·s)	P_{Sat} (kPa)	GOR (Sm^3/m^3)	μ_{Lo} (mPa·s)	R (%)	S_f (m^3/m^3)
[97]	Athabasca	8.6	21	296660	/	/	640	99.8	/
[96]	Bartlett	16.9	23.9	1484.4	1341–4084	7.6–123	735.6–61.5	50.4–95.9	1.025–1.215
			60	195.6	214.4–4004.5	9.1–115.3	122.6–13.6	37.3–93.1	1.027–1.216
			93.3	39.66	396–4017	13.8–125.2	33–4.85	16.8–87.8	1.027–1.246
[98]	Burnt Lake	/	15.5	18000	3450	/	406	98	/
[99]	Heavy oil	11.3	28	12100	10342	/	717	94.1	1.07
[73]	Heavy oil	11.3	25	277000	4137	30.63	733	99.7	1.04
			50	1665	10342	/	219	86.8	1.053
[81]	Japan	13.1	50	172	9970	/	120	30.2	/
[93]	Kindersley	13.2	25.5	819	4580–7080	44.5–87	124.5–42	84.8–94.9	1.081–1.155
[100]	Lindbergh	14.7	21	12086	5880	/	500	96	/
[33]	Lloydminster	11.7	23.9	23000	2000–6000	/	/	/	1.033–1.131
[24]	Lloydminster	13.8	25.5	6822	6550	60.4	225.6	96.7	1.08
[101]	Lloydminster	15.8	28	1430	3280–7580	30.5–84.4	154–32	89.2–97.8	1.058–1.156
[102]	Orinoco Belt	7.8	54	14488	5800–8600	16–28	5570–4180	61.6–71.1	1.08–1.28
[82]	Saskatchewan	15.4	28	1423@22 °C	1724–7239	/	890	37.5–61.3	/
[103]	Saskatchewan	18.3	24	353	3530–7600	12.1–76.07	174.8–25.2	50.5–92.9	1.021–1.176
[26,104]	Senlac	15.4	/	1650	890–7580	6.76–84.4	859–32	47.9–98.1	1.012–1.156
[105]	Shengli	8.7	70	15889	1880–12210	5–70	12841–224	19.2–98.6	/
[106]	Shengli	17.4	60	7792–9890	8000–18000	69.8–126.6	906.4–447.2	88.4–95.5	1.148–1.28
			70	3462–4296	8000–18000	65.7–121.7	471.3–229.6	86.4–94.7	1.136–1.254
			80	1768–2159	8000–18000	59–117.9	265.9–157.1	85.0–92.7	1.116–1.236
			90	1092–1313	8000–18000	52.7–113.6	181.28–116.83	83.4–91.1	1.104–1.22
[107]	Wilmington	13.2	49	172	6101–22063	17.3–103.8	77.6–11	54.9–93.6	1.034–1.195

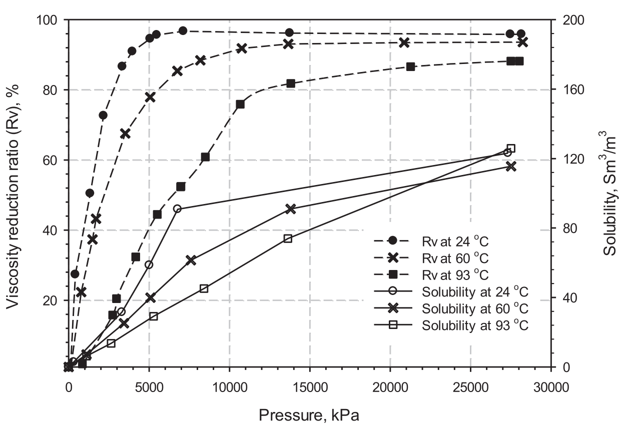

Fig. 2. The viscosity reduction ratio and CO_2 solubility of a heavy oil-CO_2 system at different pressures and temperatures [96].

A summary of viscosity reduction studies on a heavy oil-CO_2 system is tabulated in Table 1. Table 1 shows that the effect of CO_2 in heavy oil is significant, the viscosity reduction ratio can reach up to 99.8%, and the viscosity reduction of the heavy oil-CO_2 system relates to pressure and temperature. Among different heavy oil samples with a higher heavy oil viscosity, a greater viscosity reduction ratio can be obtained. Regarding the same heavy oil sample, the viscosity reduction ratio decreases with an increase in temperature.

3.3. Oil swelling

When CO_2 is injected into the heavy oil reservoir, an important phenomenon is observed in terms of oil swelling, because the injected CO_2 dissolves into the heavy oil and expands the volume [71,101,108,109]. The oil swelling is an important mechanism to enhance heavy oil recovery in the CO_2 huff 'n' puff process, because (1) oil swelling shows an advantage on the movable oil, and an inverse proportional relation is found between the oil swelling factor (which indicates the degree of oil swells and is defined as the volume of crude oil saturated with CO_2 at the reservoir pressure and temperature divided by the volume of crude oil at the atmospheric pressure and reservoir temperature [110]) and the residual oil saturation; (2) the mobility of the heavy oil is improved; (3) the dissolved heavy oil will generate a drainage force to push water out of the pore space; and (4) oil swelling can increase the oil saturation, resulting in an increase of oil relative permeability, which increases the oil phase fractional flow in the production stage [32,33,58,72,111].

The degree of oil swelling factor relates to pressure, temperature, and oil composition [58]. Figs. 2 and 3 indicate that the plots of the oil swelling factor have the same trends as the plots of CO_2 solubility, which means that, under the same conditions (temperature and pressure), the oil swelling factor is proportional to the CO_2 solubility. The effects of pressure on the oil swelling factor are different at different temperature, and a linear relationship is obtained between the oil swelling factor and pressure when the temperature is greater than the critical temperature. However, the phase of the CO_2 affects the oil swelling factor remarkably. In the low-pressure region (when the CO_2 is in the gas phase), the oil swelling factor increases with the pressure increases. At higher pressure, the phase of CO_2 changes from the gas phase to the liquid phase, leading to lower CO_2 solubility and a reduced effect of pressure on oil swelling factor. The effect of temperature shows

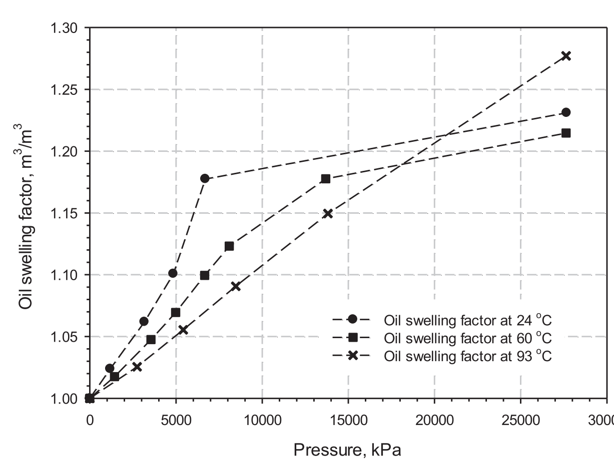

Fig. 3. Oil swelling factor of the heavy oil-CO_2 system at different pressures and temperatures [96].

that a higher temperature leads to a lower oil swelling factor in the low-pressure region due to CO_2 solubility decreasing with temperature increases. In a higher-pressure region, the oil swelling is greater than that at low temperature due to the phase change reducing the CO_2 solubility. Regarding oil composition, lighter oil can get a higher oil swelling factor than that of heaver oil, because more CO_2 can be dissolved into the lighter oil [24].

3.4. Diffusion coefficient

Another important parameter that impacts the properties of a heavy oil-CO_2 system is the diffusion coefficient, which indicates the diffusion rate and the amount of CO_2 dissolved into the heavy oil [112–118]. Previous studies indicate that heavy oil production in the vapour-extraction process is mainly from the transient zone, where heavy oil is saturated with an injected solvent and the area of the transient zone is controlled by the molecular diffusion rate of the injected solvent [119,120]. As a type of solvent, when CO_2 is injected into the heavy oil reservoir, it is gradually dissolved into the heavy oil by means of mass transfer (molecular diffusion), especially in the soaking stage [111,121]. This results in viscosity reduction and oil swelling so that heavy oil production can be enhanced.

The diffusion coefficient relates to pressure, temperature, and oil composition, as shown in Fig. 4 and Table 2. The effect of pressure on the diffusion coefficient is more sensitive at a higher temperature than at a lower temperature because (1) the lower surface tension of oil molecules can be obtained at a higher temperature, so that the mass transfer rate of CO_2 molecules into heavy oil is higher and (2) a lower heavy oil viscosity is obtained at a higher temperature and CO_2 molecules can pass through the interface easier. Kavousi et al. studied the CO_2 diffusion coefficient in heavy oil at different temperatures and pressures [122]. In their experimental researches, the CO_2 diffusion coefficient increases with pressure increases. However, if the pressure continues increasing at a very high level, the viscosity and density of the heavy oil-CO_2 system increases as well, which causes the diffusion coefficient decreases steadily [123].

Under a constant temperature, the diffusion coefficient increases with pressure increases in the relative lower pressure region, mainly because the higher pressure supports a greater drive force for the CO_2 transferring into heavy oil. The combined effects of pressure and temperature show that the diffusion coefficient of CO_2 in heavy oil increases with pressure and temperature increase.

The viscosity of heavy oil decreases with temperature increases, which can be concluded as the diffusion coefficient of CO_2 in heavy oil decreasing with heavy oil viscosity increases. Table 2 indicates that CO_2 diffusion coefficients are different for different oil samples. Even different diffusion coefficients can be achieved using the same experimental results [124,125], due to (1) different treatment of the pseudocomponents for the heavy oil in the calculation, and (2) a slight difference between the objective functions.

Regarding CO_2 solubility in heavy oil, the solubility of CO_2 increases with pressure increases and decreases with temperature increases, but no significant relationship can be found with the CO_2 diffusion coefficient.

To measure the diffusion coefficient of CO_2 in heavy oil, direct and indirect measurement methods have been applied in previous studies. In the direct method [126,127], oil samples are extracted out of the tested system during the test to involve compositional analysis. Then a mathematical model is required to calculate the diffusion coefficient. Experimental errors in the direct method are not easily avoided. In the indirect method, the properties of heavy oil and CO_2 are measured and the changes are monitored during the tests. The tested properties include pressure decay monitoring [32,112,126,127], volume changing measurement [128], volatilization rate of solvent testing [129], location of the gas-liquid interface determination [112,130], etc. Other indirect methods such as dynamic pendant drop volume analysis [33], Nuclear Magnetic Resonance (NMR) [131], and X-ray Computer Assisted Tomography (CAT) [132] are also used to determine the concentration of CO_2 at different locations of the test fluids.

The diffusion coefficients measured by previous scholars are summarized in Table 2. Table 2 indicates that the diffusion coefficient of CO_2 in heavy oil relates to oil components, viscosity, temperature, and pressure, and that most of the measured diffusion coefficients of CO_2 in heavy oil are in the order range $10^{-10}\,m^2/s$–$10^{-9}\,m^2/s$. For heavy oil with a higher API gravity, there are more light or medium components, which results in the CO_2 diffusion process occurring easily, so that the CO_2 diffusion coefficient is higher than that in heavy oil with a lower API gravity. Compared with different heavy oil samples, the heavy oil sample with a relative lower viscosity is beneficial to the diffusion coefficient, so that a greater diffusion coefficient can be obtained. Regarding the test methods, pressure decay is the most popular method in previous studies and the pressure profile is matched using the derived mathematical models. Then the diffusion coefficient of CO_2 is calculated. In the calculation process, the diffusion coefficient of CO_2 differs slightly according to different boundary conditions (equilibrium, quasi-equilibrium, and non-equilibrium) in the mathematic model even through the same tests are applied.

4. Experimental studies

Prior to the implementation of pilot tests of the CO_2 huff 'n' puff process in the heavy oil field, the applicability study on this process was carried out in the laboratory. The properties of the heavy oil-CO_2 system, in terms of viscosity, CO_2 solubility, swelling factor, etc., were studied in detail to investigate fluid properties in the process. The reservoir properties including porosity, permeability, oil saturation, and water saturation were researched to determine the reservoir properties that would be suitable for the CO_2 huff 'n' puff process. In addition, the operation parameters, such as number of cycles, injection pressure, soaking time, pressure depletion rate, etc., were optimized at the lab scale.

Table 3 indicates that the successful application of the CO_2 huff 'n' puff process at the lab scale can be carried out under high reservoir temperature as high as 90 °C, with an extra-high heavy oil viscosity that reaches to 28,646 mPa·s. The permeability of the tested models ranges from 30 mD, which is real core, to 24,200 mD, which is packed by using sands. The recovery factor did not change too much, so that the permeability is not a sensitive parameter that affects the production performance of the CO_2 huff 'n' puff process applied in a heavy oil reservoir. The oil saturation in the physical models shows that the process can be applied even in a low oil saturation reservoir, which can be as low as 40.6%, which means that this process can be conducted in the reservoir under higher water saturation [76].

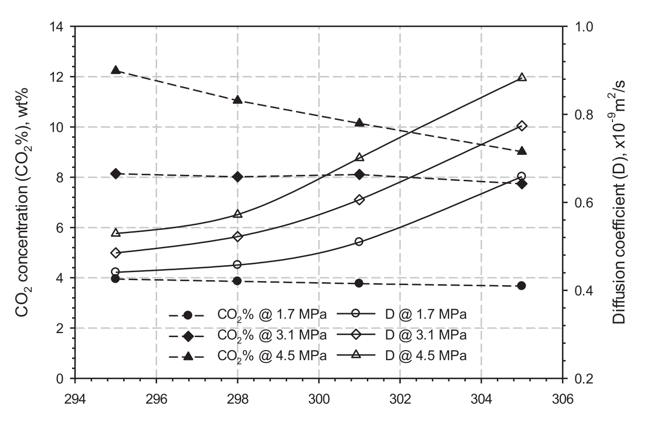

Fig. 4. CO_2 solubility and diffusion coefficient at different temperatures and pressures [122].

Table 2
Summary of the measured diffusion coefficients of CO_2 in different heavy oils.

Proposed by	Oil sample	Gravity (°API)	*T* (°C)	μ_o (mPa·s)	Test method	BC	P (kPa)	*D* ($\times 10^{-9}$ m^2/s)
[133]	Athabasca	6.4	21	2000000	Pressure decay	/	3100–5600	0.12–0.24
[126]	Athabasca	9.1	25–90	767@80 °C	Pressure decay	Quasi-equilibrium	4000	0.16–0.47
[34]	Athabasca	9.1	25–90	821000@ 25 °C	Pressure decay	Equilibrium	4000 8000	0.13–0.43 0.40–0.93
[134]	Athabasca	/	20–200	361700@ 20 °C	/	Quasi-equilibrium	/	0.279–1.75
[135]	Athabasca	11.7	50	10000@80 °C	Constant pressure	Equilibrium	3804.8	0.36
		14.0	75	100000@ 50 °C	Constant pressure	Equilibrium	3239.6	0.5
[136]	Cactus Lake	15.4	14.85–29.85	724.15@26 °C	/	Equilibrium	800–2000	0.171–0.641
[137]	Intevep	/	21	/	Pressure decay	Equilibrium	3510	4.8
[125]	Lloydminster	10.0	21.4	12854	Pressure decay	Quasi-equilibrium	3741	0.824
[124]	Lloydminster	10.0	21.4	12854	Pressure decay	Quasi-equilibrium	3741	0.43
[33]	Lloydminster	11.7	23.9	23000	Dynamic pendant drop volume	/	2000–6000	0.20–0.55
[32]	Lloydminster	11.7	23.9	20267	Pressure decay	Equilibrium, quasi-equilibrium, non-equilibrium	4200	0.56
[136]	Lloydminster	13	16.85–39.85	13443@17 °C	/	Equilibrium	800–2000	0.216–0.985
[50]	Lloydminster	14.4	23	4681	Constant pressure	/	5500	2.56
	Lloydminster	17.0	23	1032	Constant pressure	/	5500	3.59
[138]	Lloydminster	17.0	23	/	Constant pressure	/	1000	6
[132]	Heavy oil	7.6	25	15000@23 °C	Constant pressure	/	900–4140	0.11–1.19
[139]	Heavy oil	14.4	22	490000@ 30 °C	Pressure decay couple with rheometry	Equilibrium	2423–4794	0.493–1.162
[140]	Heavy oil	/	30–55	21285	Pressure decay	Non-equilibrium	2665.5	34–35.5
	Heavy oil	/	30–55	8154	/	Non-equilibrium	2415.3	58–68
[122]	Saskatchewan	12.9	24.85	20000	Pressure decay	/	1730.5–4487.1	0.413–0.532
	Saskatchewan	14.1	24.85	5000	Pressure decay	/	1725.8–4488.6	0.453–0.595

Also, the application of the CO_2 huff 'n' puff process in a heavy oil reservoir with an extremely high water cut (98%) was studied by using real core plugs [76,141]. The experimental results show that the CO_2 huff 'n' puff process can be applied in the heavy oil reservoir with a high water cut. Regarding the operation parameters, to optimize the number of cycles, a maximum of 10 cycles were conducted in the lab test, and it was found that the highest production rate occurred in the second cycle [68,82].

The injection pressure ranges from 1724 kPa to 25,000 kPa, which relates to the reservoir permeability. The soaking time is mainly around 2 days, but it can be as high as 18 days. In the production stage, the pressure depletion rate affects the heavy oil reservoir significantly. The trend shows that oil recovery increases with increasing pressure depletion rate.

The properties of heavy oil saturated with CO_2 were studied by using three different heavy oil samples with oil gravities of 10, 15, and 17 °API, respectively [69,96]. The experimental results indicate that, without CO_2 solution, the viscosity of the oil sample increases with pressure increases at a constant temperature. With CO_2 recombination, the CO_2 solubilities of the three heavy oil samples increase with increasing pressure at different temperatures. However, the trends of heavy oil properties change at different temperatures when CO_2 is recombined into heavy oil. At a lower temperature, CO_2 solubility increased until the critical pressure was reached, and then it kept almost stable. The same phenomena were observed for heavy oil viscosity and swelling factor. At higher temperatures, with increasing pressure, (1) CO_2 solubility in heavy oil increases, (2) the viscosities of the heavy oil-CO_2 system decreases significantly, and (3) the swelling factor increases up to as high as 1.28 of the tested oil samples.

The operation parameters, including injection pressure and soaking time, were researched by using a physical Berea core [68,82]. The experimental results indicate that, (1) the maximum oil production rate occurred at the second cycle; (2) higher oil recovery factor can be obtained when higher operation pressure was conducted, due to more CO_2 could be dissolved in the heavy oil to reduce the viscosity and increase the oil swelling factor at higher pressure; (3) even through the longer soaking time could not improve the oil recover factor remarkably, the oil production rate in the first several cycles could be increased significantly. Another important application of CO_2 huff 'n' puff process is conducted to enhance heavy oil production after solution gas drive process [25,31,41]. The results of these studies show that, higher recovery factor was obtained in the first cycle when longer primary production duration was carried out; the effect of surfactant in the test did not remarkable; and more than 30% of the total recovery factor can be improved because of the CO_2 huff 'n' puff process.

To obtain a better understanding, the same process was carried out on two kinds of heavy oil samples in Shi and Kantzas's research [31]. The effects of oil viscosity and pressure depletion rates were analyzed respectively. The tests indicate a high potential for heavy oil production using the CO_2 huff 'n' puff process, even in the low residual oil saturation (47.1% OOIP) after the primary production test.

In order to study the mechanisms of the CO_2 huff 'n' puff process applied after primary production in the heavy oil reservoir, Lu et al. conducted experiments in both a micromodel and a sandpack [25]. The micromodel tests show that the conversion pressure (at which the primary production process was changed into the huff 'n' puff process) affects oil production significantly, and the pseudo-bubble point pressure is the optimized conversion pressure. The results of the sandpack tests show that the highest recovery factor was obtained when the conversion pressure was applied, and the heavy oil recovery factor of the CO_2 huff 'n' puff process is proportional to injection pressure, soaking time, and pressure depletion rate. Therefore, CO_2 huff 'n' puff can be applied in the heavy oil reservoir after the primary production process due to the high potential of CO_2 huff 'n' puff as a follow-up process to primary recovery.

5. Pilot test studies

Pilot tests of the CO_2 huff 'n' puff process in the heavy oil reservoirs were carried out in several oil fields in the past several decades. Most of the published cases are successful. To analyze the production performance of heavy oil under the CO_2 huff 'n' puff process, the properties of

Table 3
Properties of the successful CO_2 huff 'n' puff lab tests in heavy oil.

Proposed by	T (°C)	μ_o (mPa·s)	Gravity (°API)	Model type	Model size (L × D, cm)	Sand/Core	S_o (%)	S_w (%)	K (mD)	Φ (%)	N_c	P_{inj} (kPa)	T_{soak} (Day)	dp/dt (kPa/min)	RF (%)
[141]	37.8	3000	13.9	Core plugs	49 × 5.08	Real core	51–54[1]	46–49	289	24	2	8618	–	–	9[2]
[142]	–	18100–28646	–	Sandpack	22.8 × 3.8	Sand: 0.6 mm	40.6–67[3]	5.5–7.0[4]	10500	36.5	1	7000	–	7.0–20.8	10.9–17.6
[60,68]	28	1423	15.4	Berea core	30.48 × 5.08	Artificial core	86.8–88.3	11.7–13.2	1800	24	7–10	1724–7239	1–2	–	47–74
[41,143]	23	–	–	Sandpack	200 × 5.35	30–50 mesh	92.7	7.3	24200	36.3	1–2	3557–3681	5	1.8–2.0	2.7–8.4
[144]	30	–	19	Core holder	15.8 × 3.81	Real core	–	–	47.2	15.3	3	10342	0.42	–	6.9
[40]	90	144	13	Core holder	20 × 6.5	Real core	68–100	0–32	30–40	19–20	8	25000	18	–	34.8–38
[25]	54	12041	8.2	Sandpack	60 × 2.54	Quartz sand	–	–	9854	37.5	–	6000–12000	0.5–2	5–20	2.1–19.5
Summary	23–90	144–28646	8.2–19	–	–	–	40.6–100	5.5–49	30–24200	15.3–37.5	1–10	1724–25000	0.42–18	1.8–20.8	2.1–74

[1] Oil saturation after water flooding process.
[2] Heavy oil recovery factor of the remaining oil in place (ROIP).
[3] Oil saturation after primary production process.
[4] Irreducible-water saturation.

the reservoirs and the production performance of the process are summarized in Tables 4 and 5, respectively.

Table 4 indicates that the properties of the heavy oil reservoirs in which successful CO_2 huff 'n' puff processes were carried out affect the production performance to some extent. The comparison of the heavy oil viscosity indicates that the successful application of the CO_2 huff 'n' puff process in a heavy oil reservoir can be carried out not only in a medium heavy oil reservoir with a viscosity as low as 118 mPa·s, but also in an extra-heavy oil reservoir with a viscosity as high as 17,200 mPa·s. In the studied reservoirs, the temperature, which affects the viscosity of heavy oil significantly, ranges from 33.3 °C to 65.5 °C. In this temperature range, different CO_2 phases (vapour phase and supercritical phase) were obtained in the pilot tests of the CO_2 huff 'n' puff process in the heavy oil reservoir. Because the reservoir temperatures in the pilot tests are higher than the critical temperature of CO_2 (31.1 °C), the phase of the injected CO_2 only relates to the initial reservoir pressure. As listed in Table 4, in most of the tested reservoirs, the initial reservoir pressure is higher than the critical pressure of CO_2 (7370 kPa), so that the phase of injected CO_2 is in a supercritical condition except that in the Halfmoon field [146]. Under the reservoir temperature, the highest saturation pressure in the pilot tests is 7102 kPa, which is much lower than the initial reservoir pressure. Thus, when CO_2 is injected into the reservoir, the heavy oil in the transition zone between the injected CO_2 and the heavy oil is saturated. This results in gas drive and foamy oil flow occurring in the production stage (with the pressure decline process).

The reservoir depth of the successful cases applied in the oil fields ranges from 350 m to 1985 m with a thickness of net pay zone ranging from 12.2 m to 60 m. When the CO_2 huff 'n' puff process is applied in the heavy oil reservoir, the water saturation can be as high as 42.7%, which means that this process can be applied in a reservoir with a high water saturation (as proven in the lab tests) or even in a reservoir which has undergone the steam stimulation process [148]. Furthermore, with CO_2 injection, the water cut of the produced fluids can be reduced significantly [78,146,150].

The reservoir properties and operation parameters, in terms of reservoir connections, reservoir homogeneity, amount of CO_2 injection, soaking time, etc., affect the production performance of the CO_2 huff 'n' puff process applied in the heavy oil reservoir, significantly. In regards to reservoir properties, the following aspects were mainly studied. The effect of the thickness of the net pay zone is sensitive to the production performance of the CO_2 huff 'n' puff process applied in a light oil reservoir [78,151,152]. However, in the heavy oil reservoir, the study indicated a different trend for the effect of the thickness of the net pay zone [65]. The evaluation of the Forest Reserve oilfield shows that the cumulative oil production does not increase with increases in the thickness of the net pay zone. In fact, it even decreases a little bit. The connections among the wells in the reservoir show a negative effect for the heavy oil production performance under the CO_2 huff 'n' puff process [146]. With well connection, the injected CO_2 will be pushed to the other wells nearby, which means that breakthrough will occur among different wells, leading to the injected CO_2 being pushed far away from the treated well. Thus, the pressure around the wellbore would not be maintained and the injected CO_2 would not be saturated in the heavy oil. Therefore, the oil production cannot be increased remarkably.

Another negative effect of the reservoir property is gas blockage near the wellbore, which forms another obstacle to the heavy oil production process [145,147]. In some wells, when CO_2 is injected into the reservoir, the injected CO_2 could not be pushed away from the vicinity of the wellbore due to unfavorable permeability around the wellbore. The injected CO_2 could not be dissolved into heavy oil in a further location. Consequently, in the production stage, the pressure in the reservoir declined rapidly and the production of heavy oil could not be improved too much.

For the operation parameters, the injection volume and injection rate were mainly focused on. The cumulative oil production increased

Table 4
Properties of the heavy oil reservoirs those performed CO_2 huff 'n' puff pilot tests.

Proposed by	Oil field	Country	T (°C)	P_i (kPa)	μ_o (mPa·s)	Gravity (°API)	P_{Sat} (kPa)	GOR (Sm^3/m^3)	h_t (m)	h_{net} (m)	S_w (%)	k (mD)	Φ (%)
[66]	Camurlu	Turkey	46.7	11969	475	10.8	7102	36.5	1300–1450	60	23	700	11–22
[65]	Forest Reserve	Trinidad and Tobago	33.3	–	3000	14	–	–	350	–	32	250	32
[145]	Bati Raman	Turkey	65.5	12411	450–1000	9–15	1103	3.2	1311	–	14	200–2000	14–20
[146]	Halfmoon	USA	57.2–60.6	3102–6205	118	17	–	–	1036–1097	12.2–29.8	7.6	95	15
[147]	Bati Raman	Turkey	53.9	12066	592	13	1069	3.2	1300	48.8	21	58	18
[148]	Liaohe	China	63.5	17330	16300–17200	13.85	–	–	1900–1985	38.2–49.8	42.7	448–897	20–25
[149]	Ikiztepe	Turkey	50	12693	2000–15000	4–13	6205	16.9	880	13.1–21.9	14–17	50–400	15–23
Summary	–	–	33.3–65.5	3102–17330	118–17200	4–17	1069–7102	3.2–36.5	350–1985	12.2–60	7.6–42.7	58–2000	11–25

Table 5
Production performance of heavy oil by using CO_2 huff 'n' puff process in the pilot tests.

Proposed by	Oil field	Country	N_{well}	N_c	$V_{CO2/cycle}$ (MMScf)	T_{Soak} (Day)	$Q_{O/cycle}$ (Stb)	U_{CO2} (MScf/)	S_r
[66]	Camurlu	Turkey	2	3	2.6–10.6	13	109–4998	18	–
[65]	Forest Reserve	Trinidad and Tobago	1	2	53.5–87	3–5	7781–10085	5	1
[145]	Bati Raman	Turkey	–	–	30–40 MMScf/d[1]	–	7000 b/d[1]	~4.3–5.7	–
[146]	Halfmoon	USA	3	3	9.3–11.0	–	–	4.2–15.5	1.7–2.4
[147]	Bati Raman	Turkey	9	–	2 MMScf/d/well[2]	≤21	100/50–60/25–30Stb/D[3]	–	–
[148]	Liaohe	China	3	1	–	–	6.79–12.97 t/d[2]	6.47 t/t	1.1–1.8
[149]	Ikiztepe	Turkey	1	3	6.86[4]	–	921[4]	7.45	–
Summary	–	–	1–9	1–3	–	3–21	–	4.2–18	1–2.4

The Number of wells is based on the details studied in the literature.
[1] The average injection and production data are based on all the tested wells.
[2] The average injection and production data are related to each tested well in the studied area.
[3] The average production rates are various: natural flow rate at 100 Stb/D; flow rate with pump at 50–60 Stb/D; then stabilized at 25–30 Stb/D.
[4] The injection and production data are based on all the three cycles of the studied well.

with greater CO_2 volume injected into the reservoir [65]. Because a larger volume of CO_2 was injected into the reservoir, a larger area of connections between CO_2 and heavy oil occurred, leading to more heavy oil being saturated with CO_2 and the production of more heavy oil during the production stage. Even under the same injection volume, the injection rate of CO_2 can affect the heavy oil production performance to some extent. With a higher injection rate, the heavy oil recovery is greater, because the higher CO_2 injection rate promotes more serious CO_2 fingering in the heavy oil reservoir than a lower injection rate [153,154]. Consequently, the injected CO_2 would be pushed into a further area in the reservoir and enlarge the connection area.

Table 5 shows that the stimulation ratio ranges from 4.2 to 18 MScf/Stb. The stimulation ratio is defined as the peak oil production rate after the CO_2 injection process divided by that before CO_2 injection [65,155]. Thus, the CO_2 huff 'n' puff process applied in the heavy oil reservoir is effective and economical. The reservoir properties and operation parameters for a successful CO_2 huff 'n' puff process applied in the heavy oil reservoir can be summarized as: a thick oil pay zone, deep reservoir, mild pressure support, an approximate 2–4 weeks soaking time, a high CO_2 injection rate and volume, and a maximum of 3 cycles [65].

6. Numerical and mathematical studies

The numerical and mathematical studies on the CO_2 huff 'n' puff process in heavy oil reservoirs in the published literature focus mainly on numerical simulation by using commercial simulators and mathematical study through the correlation method. Regarding the numerical simulation, different simulators were applied to conduct history match studies in terms of a single well simulator [156], dual-porosity simulator [157], thermal 3-D and 3-phase simulator [148], compositional simulator [40], and E300 [144]. The simulation results indicate that:

(1) The CO_2 huff 'n' puff process could be conducted to enhance oil production in heavy oil reservoir, successfully;
(2) The effect of the reservoir properties shows that the drainage area would affect the CO_2 huff 'n' puff process due to this process only impacting a certain area near the wellbore. If the drainage area is greater than the certain area, the incremental oil would not increase much;
(3) The recommended application of the CO_2 huff 'n' puff process differs according to the viscosity of the heavy oil. For the extra heavy oil (with an oil viscosity greater than 10,000 mPa·s), one or two cycles of the CSS process in the early stage will benefit CO_2 huff 'n' puff stimulation. For the regular heavy oil reservoir (with a viscosity ranging from 2000 to 10,000 mPa·s), even three to four cycles of the CSS process will benefit it. In addition, the CO_2 stimulation process can obtain oil production. For the heavy oil reservoir (with a viscosity lower than 500 mPa·s), the CO_2 huff 'n' puff process should be carried out directly [148];
(4) The effect of operation parameters indicate that (a) an optimized soaking time (24 h) exists in the liquid phase CO_2 huff 'n' puff process; (b) a lower oil recovery factor is obtained when a higher injection rate is applied (the higher injection rate will push the oil near the producer to a further area of the core. Moreover, the higher injection rate leads to a shorter duration for the connection of heavy oil and liquid CO_2); and (c) a higher oil recovery factor is gained when a larger volume of liquid phase CO_2 is injected due to the larger volume of heavy oil being connected with the injected CO_2.

For the correlation method, the effect of the key parameters including operation parameters (treatment pressure, treatment volume, backpressure, and the number of cycles) and reservoir properties (oil viscosity, reservoir depth, and current oil saturation) on the CO_2 huff 'n' puff process in heavy oil reservoirs were studied [158], and an analytical method was proposed to predict heavy oil production in the oil field [159]. The scholars studied the relationship among the reservoir properties, operation parameters, and production efficiency. Regarding the operation parameters, (1) a higher treatment pressure (the maximum reservoir pressure permitted during the injection process) can gain lower oil viscosity, because more CO_2 can be injected into the reservoir. The injection pressure can be as high as 15.8 kPa/m of depth, which was carried out in several fields with good heavy oil production performance; (2) backpressure may benefit the oil production, and the productivity increases with a declining bottom hole pressure. Regarding the reservoir properties, (1) commercial projects indicate that the heavy oil viscosity is usually less than 2000 mPa·s; (2) with a higher depth, the reservoir can obtain a higher injection pressure, which results in a higher CO_2 solubility and lower oil viscosity; (3) unexpectedly, high oil saturation tends to reduce the performance of the CO_2 huff 'n' puff process due to the incremental production being reduced. A correlation was developed for the efficiency of heavy oil production and the parameters [158]:

$$E = 0.33 - 0.035N_c - 4.5 \times 10^{-5}\mu_o + 1.6 \times 10^{-4}P_t + 1.3 \times 10^{-9}P_t^2 + 4.3 \times 10^{-5}k - 0.013S_{oi} - 0.69V_c$$

where, E is the efficiency of the CO_2 huff 'n' puff process, STB oil/MScf CO_2; N_c is the number of cycles; μ_o is the heavy oil viscosity, mPa·s; P_t is the treatment pressure, kPa; k is the reservoir permeability, mD; S_{oi} is the initial oil saturation, fraction; and V_c is the volume of injected CO_2 in each cycle per foot of sand, MMSc/ft.

The heavy oil production rate, which relates to the pressure distribution, heavy oil, and reservoir properties, was correlated according to the production data in the oil fields. To simplify the calculation, the velocities of CO_2 diffusion and heat transfer are assumed as constants. The pressure distribution was calculated using Spivey's model. An exact solution was obtained and the temperature distribution was calculated using Laplace's transformation based on Marx and Langenheim's model [160]. Carbon dioxide concentration in the transient zone is an important parameter to predict the location of CO_2 dissolved into heavy oil and how much heavy oil can be produced in each cycle, and Fick's law diffusion was applied to calculate CO_2 concentration in the transient zone. Then the oil production rate was predicted based on Boberg and Lantz's model [161], and the heavy oil production rate in the CO_2 huff 'n' puff process was presented as [159]:

$$q_o = \frac{0.536 \cdot h_t \cdot K_o \cdot (P_{(r,t)} - P_{wf})}{B_o \cdot \mu_{oc} \cdot \ln\left(\frac{r_L}{r_{md}}\right) + B_{o-CO_2} \cdot \mu_{oh} \cdot \ln\left(\frac{r_{md}}{r_w}\right)}$$

where, q_o is the heavy oil production rate, bbl/day; h_t is the reservoir thickness, m; K_o is the oil relative permeability, mD; $P_{(r,t)}$ is the pressure as a function of space and time, kPa; P_{wf} is the wellbore flowing pressure, kPa; B_o is the heavy oil volume factor, rb/stb; μ_{oc} is the viscosity of heavy oil-CO_2 system, mPa·s; r_L is the limit radius, m; r_{md} is the maximum diffusion radius, m; B_{o-CO_2} is the volume factor of heavy oil-CO_2 system, rb/stb; r_w is the well radius, m.

7. Challenges of CO_2 huff 'n' puff process

Through worldwide application in heavy oil reservoirs, CO_2 has been found to be an efficient candidate for recovering heavy oil in low pressure and thin pay zone reservoirs via the immiscible displacement process [162,163]. Although the CO_2 huff 'n' puff process has been carried out in the field for several decades, technic and economic challenges are still encountered when it is implemented in the field. Technically, asphaltene precipitation, corrosion, viscous fingering, etc., are the main serious problems. Economically, oil prices and the cost of CO_2 recourse are the key obstacles.

Asphaltene deposition in the CO_2 huff 'n' puff process causes serious issues such as formation damage, relative permeability reduction, and flow interruption in the reservoir and the surface facilities. It can lead to a low production rate and even no flow rate when the tubes or the wellbore are plugged [75,164–168]. Furthermore, when the asphaltene content is higher than 4.6%, the wettability of the reservoir will alternate from water wet to oil wet, which results in a reduction in heavy oil production [169,170]. To reduce asphaltene deposition in the CO_2 huff 'n' puff process, asphaltene inhibitors can be injected into the reservoir. The results of the tests show that the inhibitor can effectively reduce the asphaltene deposition in the gas lift production process in the heavy oil production [171]. Another way to reduce the asphaltene deposition in heavy oil is by adding a solvent mixture of polar protic hexane-1-ol and nonpolar toluene into the heavy oil along with the CO_2 injection process [172]. The tests indicate that the asphaltene deposition can be delayed or stopped when the solvents are injected.

In the production stage, the undissolved CO_2 evolves out of the reservoir through the penetrated holes on the well. The volume of the CO_2 expands extremely in a very short time, which results in heat extraction at the bottom of the wellbore. When the temperature decreases to the wax appearance temperature, wax precipitation occurs in the heavy oil at the bottom of the well, the wax sticks on the wellbore and the formation near the wellbore [148]: leading to the flow rate decreasing [173]. The efficient method to reduce wax precipitation in the reservoir is to optimize the pressure depletion rate, under which the temperature near the wellbore would not be decreased too much and the heavy oil production rate would not be affected too much. Another approach is to add a wax inhibitor into the reservoir. The polymeric inhibitor causes the formation of a hydrocarbon chain between the wax inhibitor and the wax. The chain is a polar segment which inhibits the aggregation stage of the wax, so the wax appearance time can be decreased [174].

The corrosion of equipment due to corrosive fluid is generated when the injected CO_2 encounters water. The chloride corrosion is serious in the CO_2 huff 'n' puff process implemented in the Bati Raman oilfield and Aminoil's North Bolsa Strip project, even though special steel and chemical protection is used [156,175]. The best way to avoid CO_2 acid corrosion is to add inhibitor chemicals into the reservoir and use a corrosion resistant element on the surface of the pipeline, metal components, etc. [176].

Because the viscosity of CO_2 is much lower than that of the reservoir fluids (heavy oil, formation water), viscous fingering occurs when CO_2 is injected into the reservoir. The injected CO_2 will pass through the higher permeability zone and bypass the lower permeability zone. In the oil field, injected CO_2 breakthrough occurs among nearby wells in a short time in the heterogeneous reservoirs [177–179]. For this type of reservoir, high permeability layer(s) exist and the injected CO_2 passes through these layers, except they will be maintained near the injector.

Different methods can be used to avoid the negative effect of high permeability layers among wells in different oil pay zones. First, a packer can be applied to isolate thin high permeability layers in the wellbore [146]. For a thick layer or a reservoir with natural fractures, which means there is a large amount of heavy oil reserves in this layer, the packer is not applicable. To solve this problem, a high viscosity gel solution or another type of solution can be injected into the reservoir to separate the high permeability layer prior to the implementation of the CO_2 huff 'n' puff process. By using this method, heavy oil production can be improved [145].

Other technical issues such as low injectivity, pump problems, ice plugs forming in the injection lines and tubes, and annular wellbore freezing occurring while the injection pressure is extremely low, etc., are also serious problems in the field [49,53].

In terms of the economic aspect, the costs of CO_2 capture, CO_2 transportation, facilities of CO_2 injection system, operation etc., are the main capital investments. Until now, successful field applications of the CO_2 huff 'n' puff process have been based on CO_2 reservoirs located close to the heavy oil reservoirs. For example, the CO_2 source for the CO_2 huff 'n' puff process applied in the Bati Raman field, Turkey, is a CO_2 reservoir (the Dodan field) located 88 km away from the heavy oil reservoir. However, regarding the application of the process without a CO_2 reservoir nearby, the benefits of the CO_2 huff 'n' puff process are not remarkable, because the costs of CO_2 capture and transportation without pipelines remain very high. Furthermore, the facilities used in the CO_2 huff 'n' puff process are specialized from common ones to avoid the corrosion of CO_2. In addition, the operations on the CO_2 huff 'n' puff field are much more complex than other common processes.

8. Conclusion

Five conclusions can be drawn from this study. First, the experimental, pilot tests and numerical studies show that the CO_2 huff 'n' puff process is efficient to enhance oil recovery in heavy oil reservoirs.

Second, the main challenges of the CO_2 huff 'n' puff process include asphaltene precipitation, wax deposition, equipment corrosion, viscous fingering, etc. were analyzed, and the solutions for the potential problems have been researched in detail.

Third, viscosity reduction is extremely remarkable in the heavy oil-CO_2 system, and the viscosity reduction ratio can reach up to 99.8%. Oil swelling is significant in the CO_2-based EOR process, and the oil swelling factor can be as high as 1.28 when CO_2 is recombined into heavy oil.

Fourth, the CO_2 huff 'n' puff process is one of the most successful EOR methods in heavy oil production from both experimental studies and field tests. The property range of the heavy oil in which the CO_2 huff 'n' puff process can be used to enhance heavy oil production is large. The oil viscosity can be as high as 28,646 mPa·s, the oil gravity can be as low as 4 °API, and the CO_2 utilization can be as low as 4.2 MScf/Stb.

Fifth, in terms of the reservoir properties of the heavy oil reservoir that can implement the CO_2 huff 'n' puff process successfully, this study indicates that the depth can be as high as 1985 m, the oil pay zone can be as low as 12.2 m, the permeability can range from 30 to 24,200 mD, and the porosity can range from 11% to 37.5%.

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