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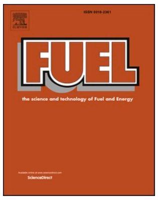

Full Length Article

Evaluation of EOR potential of energized fluid fracturing – From an energy perspective

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ABSTRACT

Energized fluid fracturing utilizes the high compressibility of fluids and their compatibility with the formation. After the fracturing, the energy stored in these fluids helps to facilitate flow back and to drive oil and gas out. Some papers and patents propose the ideas but with few field tests. Some papers predict the enhanced oil recovery (EOR) potential assuming a fracture network is enhanced from CO_2 fracturing. No quantitative analysis has been performed to analyze the EOR potential from an energy perspective in the literature. In this paper, a field test of CO_2 fracturing was analyzed to discuss the EOR potential. The test data are used to calibrate a simulation model to quantitatively analyze the potential to improve or enhance oil recovery. The EOR potential of energized fracturing fluids is discussed. It is observed that the volume from the CO_2 injection for fracturing is very limited so that the potential to enhance oil recovery is not significant. Such CO_2 fracturing process is analog to one cycle of huff-n-puff CO_2 injection for the EOR purpose after fracturing. If the injection time or injection volume during one cycle of huff-n-puff injection is like that for a typical fracturing process, the EOR potential from such one cycle huff-n-puff injection is very limited. Therefore, it can be derived that the EOR potential from energized fracturing fluids is limited.

1. Introduction

In a shale and tight reservoir, because of the low permeability, fracturing is needed to have a commercial production. Since gas is a highly compressible fluid, an energized fluid often refers to a liquid with some gas. If an energized fluid is used in fracturing, it is called energized fluid fracturing. When the fracturing fluid flows back, the gas will expand to provide drive energy to produce reservoir fluids – water, oil, and gas. Among other advantages, another advantage of an energized fluid is that formation damage will be less compared with water, for example, as water may cause clay swelling and it is easier for the energized fluid to flow back. Typically, energized fracturing fluids are CO_2 and foams. The gases used in foams can be CO_2, N_2, and natural gas. The liquids can be hydrocarbon-based and water-based. Another waterless fracturing option is to use liquid N_2 or CO_2 Linde Group [16,1], liquified petroleum gas (LPG), hydrocarbon, hydrocarbon gel [25], etc. For gas wells, Gruber and Anderson [12] explained that some CO_2 in the hydrocarbon phase releases as the pressure declines during leak-off, and a miscible bank is created between the fracturing fluid (hydrocarbon) and the gas. Because of the miscibility, virtually all the fracturing fluid may flow back, resulting in improved well productivity. Friehauf and Sharma [9] simulated the energized fluid effect on gas well productivity. The energized fluids are CO_2– or N_2– saturated water. They found that the gas in the energized fluids (e.g., CO_2, N_2) increases the gas saturation in the invaded zone so that high gas productivity is achieved during flowback and production. This mechanism is important when the drawdown saturation is low because the low drawdown cannot exceed the capillary constraint imposed by the invaded aqueous phase. However, when the drawdown pressure exceeds the capillary pressure, the gas productivity is similar for energized fluids and non-energized fluid. They did not study the effect on oil wells. The gas recovery from the Montney formation wells in the Western Canadian Sedimentary Basin showed that energized fluids improved gas recovery by 1.6 and 2.1 times compared to non-energized fluids [4]. However, the amount of proppant, the well lateral lengths, and the number of stages were higher for energized fluid cases. The energized fluids were nitrified slickwater and CO_2 foam. Although some articles propose the concepts, and rationale to improve oil and gas recovery, no quantitative analysis of the EOR potential has been seen in the literature. Yost et al. [26] reported a total of 5 liquefied CO_2 fracturing operations in the Devonian

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shale field, Perry and Pike Counties, Kentucky in 1993. They reported that in the Pike County study area, the initial monthly production rates stimulated with CO_2 are 50% better than nitrogen fractured wells. This study intends to provide a quantitative analysis of the EOR potential of the CO_2 fracturing process using numerical simulation and from the energy conservation principle. The simulation base model is described next. Because CO_2 fracturing to analog to one cycle of huff-n-puff CO_2 injection, the EOR potential of one short cycle CO_2 huff-n-puff injection is analyzed. The injection time or volume during the short huff period is similar to that in the CO_2 fracturing.

2. Base simulation model

For the purpose to build a calibrated simulation model, a single fractured well (Well A) is used. The well is a multi-staged fractured horizontal well. A half fracture and the production history data for the half fracture are used in building the base simulation model, assuming the symmetry of flow in each fracture. The stage spacing was 47 m. The average porosity was 11%, the average reservoir permeability was about 0.048 mD, the average original oil saturation was 76.5%, and the oil viscosity at the reservoir was 40 cP with gas-oil ratio (GOR) 17 m^3/m^3. The original reservoir pressure was 40.84 MPa, and the reservoir temperature was 92.63 °C. The bubble-point pressure was 7.58 MPa. The average reservoir thickness was about 44 m. Based on those reservoir data, combined with crude oil PVT experimental data, a compositional simulation model is built using Computer Modeling Group [6]GEM.

Fig. 1 shows the simulation model of an un-stimulated reservoir volume and a stimulated reservoir volume. The model sizes are 22.67 m by 520.7 m by 44 m in the I, J, and K directions, respectively. The fracture length is 280 m in the J direction, and the fracture height is assumed 44 m in the K direction.

A dual permeability model is used. The matrix permeability in the model used is 0.096 mD. Other matrix and fracture data for the stimulated reservoir volume (SRV) and the non-stimulated reservoir volume (Non-SRV) are presented in Table 1. Those data are from the history-matched model.

Based on the reported reservoir fluid compositions, 8 pseudo-

Table 1
Fracture and matrix properties.

	Non-SRV	SRV
Thickness, m	44	44
Matrix Permeability, mD	0.096	0.096
Matrix Porosity, fraction	0.11	0.11
Fracture Porosity, fraction	0.00011	0.0011
Fracture Permeability, mD	2.4	24
Fracture Spacing, m	8.2	2.3
Hydraulic fracture porosity, fraction		0.045
Hydraulic fracture permeability, mD		1000

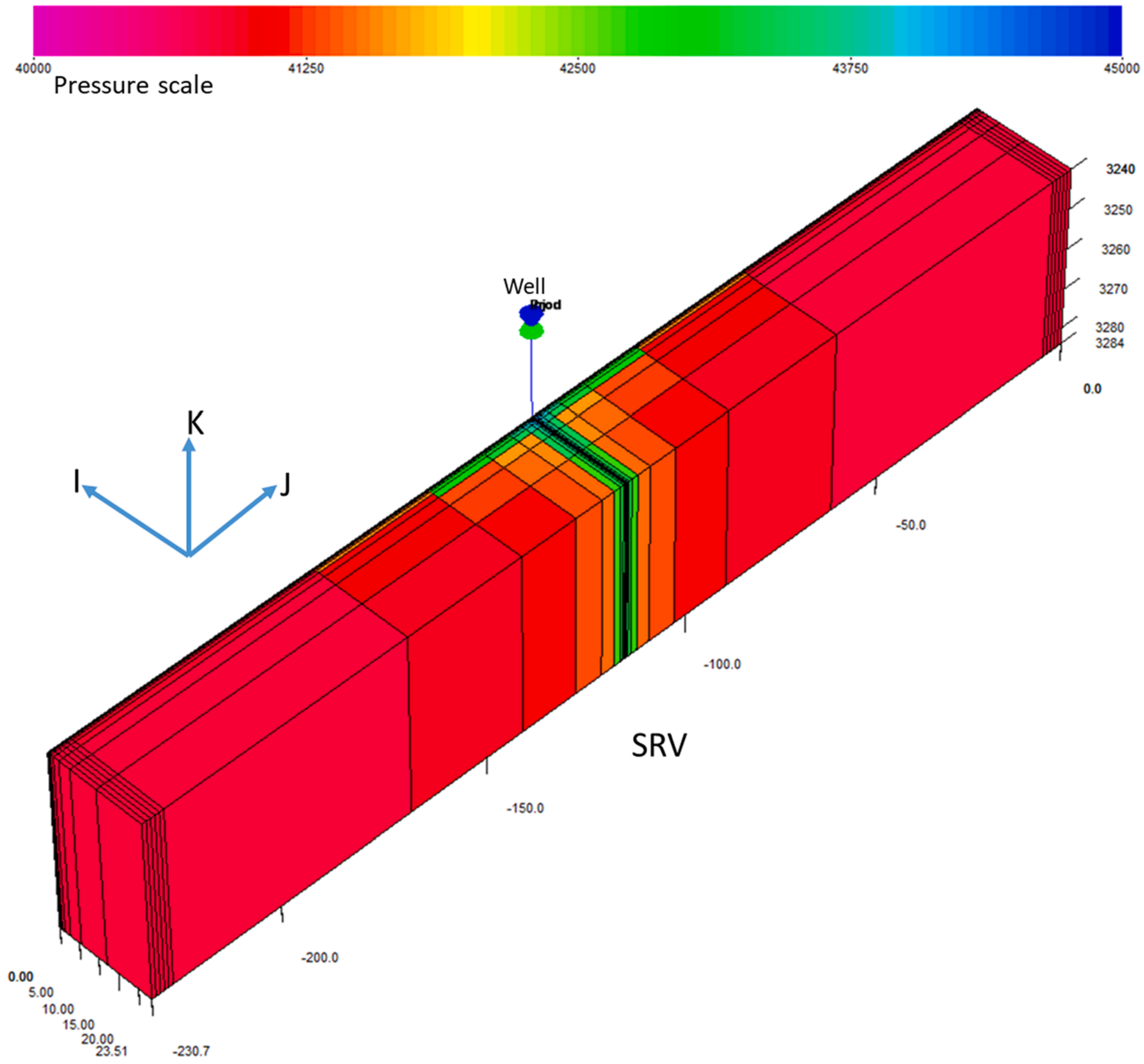

Fig. 1. Schematic of the base simulation model.

components are defined. The parameters for the Peng-Robinson EOS are presented in Table 2. They are tuned to match measured PVT data using CMG's WinProp[7]. In the table, T_c, P_c, and V_c are critical temperature, critical pressure, and critical volume, respectively, and MW is the molecular weight. The relative permeability curves are shown in Figs. 2 and 3. These relative permeability curves were obtained through a history matching process. For Fig. 3, the gas relative permeability k_{rg} is very low because we had to use such low $_{krg}$ to match the very low gas production rate. The reported gas rates are possibly lower than the actual ones. However, a very low krg curve was used by Kurtoglu [14] when she history match Bakken production data. During the history match, it was observed that the model oil rates were easily lower than the actual ones. To increase oil rates, a straight line k_{ro} was used. The model simulates water or CO2 injection during 3 h of fracturing by using actual injection rates and making sure the wellhead pressures are approximately matched.

Using the above data and fracturing fluid volumes, one year of production history (water, oil, and gas) are matched, as shown in Figs. 4 to 5. During the history match, the surface water, oil, and gas rates are imposed to match. Figs. 4 and 5 show that the oil and water rates are reasonably matched with the reported data. These matched data show the base model reasonably represents the well performance.

3. Discussion of the effect of fracturing fluids on EOR

By modifying the base history-matched model described in the preceding section, simulation data are used to discuss the effect of different fracturing fluids on oil recovery. The oil recovery factors (RF) from the two cases are compared in Table 3. In the case of WATER-BHP7, the earlier base model is changed to a prediction model in which the well produces at the bottom-hole pressure (BHP) 7 MPa for 1 year right after 3 h of water injection during fracturing. In the case of CO2-BHP7, the mass of injected water in the base case is replaced by the same mass of CO_2 (only CO_2 is injected), and the well produces at BHP of 7 MPa for 1 year.

The data in the table shows the oil recovery factors for the two cases at the end of one year are almost the same. Although the CO_2 injection case shows slightly higher oil recovery, that incremental is insignificant. Such a result is not expected. How is it explained?

First, a typical fracturing operation is reviewed. After the reservoir is fractured, there is an intended or unintended shut-in period followed by flow back. This process is equivalent to one cycle of huff-n-puff. Many studies have shown that huff-n-puff gas injection (e.g., [24,5,22,19,21,15]) or water injection can increase oil recovery (e.g., [27], and gas huff-n-puff injection generally overperforms water huff-n-puff injection[23,28]. Then why does the CO_2 injection (fracturing) not show a significant increase in oil recovery over water injection (fracturing)? To answer this question, the simulation cases by Sheng [22] are re-visited. In Sheng's [22] simulation models, the fracture is generated before gas or water huff-n-puff. The models use 200-day huff and 200-day puff without shut-in time between huff and puff for one cycle, and the cycle is repeated for 60 years. According to his modeling work, 22.77% more oil recovery is obtained for 60 years of production when gas is injected compared with water injection. Half of the days (30*365 = 10950 days) are used for injection. Then one-day injection results in 22.77%/10950 = 0.002% improvement in oil recovery for gas injection over water injection. In other words, although the improved oil recovery from CO_2 injection during the 60 years huff-n-puff is large, it is

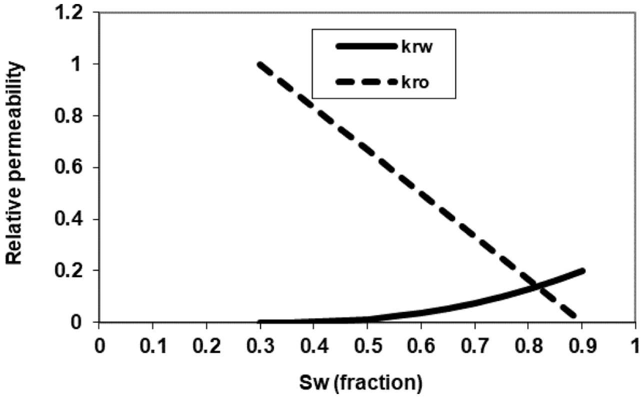

Fig. 2. Water and oil relative permeabilities.

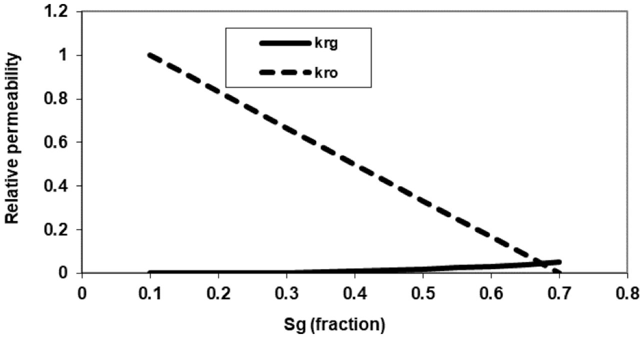

Fig. 3. Oil and gas relative permeabilities.

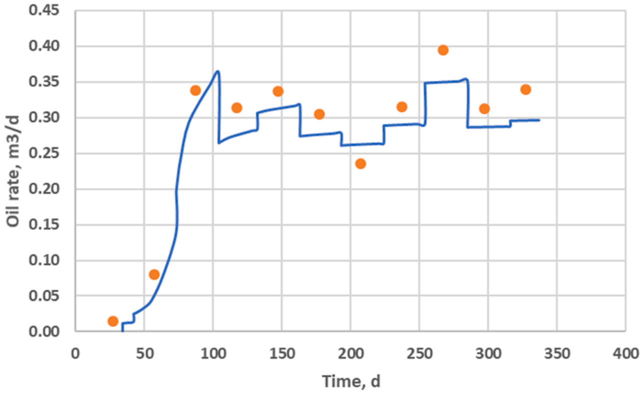

Fig. 4. Simulated oil rate (curve) compared with reported oil rate (dots).

Table 2
The parameters of the Peng-Robinson EOS.

Comp.	Initial mole fraction	P_c (atm.)	T_c (K)	V_c, L/mol)	Acentric Factor	MWg/mole	Parachor coeff.
CO_2	0.0012	72.80	304.2	0.0940	0.225	44.01	78.0
CH_4	0.1468	45.4	190.6	0.099	0.008	16.04	77.0
C_2-C_4	0.0721	43.67	352.4	0.1879	0.134	40.02	137.6
C_5-C_7	0.1389	32.29	505.8	0.343	0.274	84.61	252.1
C_8-C_{12}	0.1589	25.03	621.0	0.522	0.436	133.7	380.3
C_{13}-C_{20}	0.1926	17.40	713.5	0.825	0.679	219.4	589.1
C_{21}-C_{27}	0.0701	12.37	822.9	1.177	0.821	324.7	804.1
C_{28}-C_{36}	0.2194	9.15	1103.0	4.436	0.938	655.0	1088.3

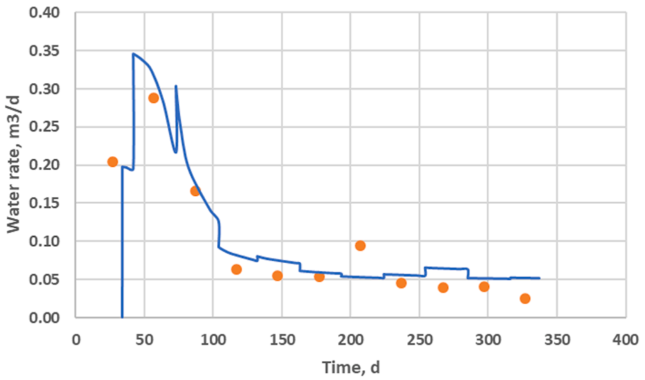

Fig. 5. Simulated water rate (curve) compared with reported water rate (dots).

Table 3
Oil recovery after one year of production for the cases of different fracturing fluid injection for 3 h.

Case	RF for 1 year, %	Injection pore volumes
WATER-BHP7	11	0.0087
CO2-BHP7	11.13	0.0087

insignificant for one day of huff-n-puff. In a fracturing operation, only a few hours are spent on injection at one fracturing stage. It can be understood that the energy injected during fracturing is far less significant to improve oil recovery.

To support the above argument, Sheng's [22] models are modified to simulate an operation of three hours of injection (injection pressure 7000 psia) followed by one year of production (production pressure 2500 psia). The models simulate the cases of one cycle of three hours of injection (huff) and one year of production (puff), which is similar to the cases reported above in that the fracturing operation was followed by one year of production. The recovery factors for water injection and gas injection are presented in Table 4. In the case of Gas-frac-1 year-puff, after the primary production for 3600 days (about 10 years), natural gas is injected for three hours followed by one year (365 days) of production. In the case of Water-frac-1 year-puff, after the primary production for 3600 days (about 10 years), water is injected for three hours followed by one year of production (365 days). In the case of Noinjection, no water or gas is injected. This table shows that the oil recovery factors from these two injection cases are almost the same. In other words, the effect of injected fluid during the three hours is insignificant. Strictly speaking, at the end of one year of puff, the oil recovery factor for the water injection case is higher than that for the CO_2 injection case. The difference is caused by the fact that the water injection pore volume is about twice that gas injection pore volume, as shown in the table. Yu and Sheng [27] experimental data showed that the oil recovery at the first cycle from nitrogen huff-n-puff and water huff-n-puff were similar, but the oil recovery from nitrogen injection became higher as more cycles were performed. The simulation models discussed here are run using CMG IMEX [8]. Such a result is also observed by Zheng et al. [30] who simulated the EOR potential of alternate injection of CO_2 and water. An Eagle Ford shale was developed 526 days before 167 barrels of water and 160 tons of CO_2 were injected within 11 cycles; the well was shut-in for 5 days and then put back on production. Their simulation results show that the oil recovery factors for the CO_2 and the water injection cases were very close during the subsequent 300 days of production.

Table 4
Oil recovery for one year of production for the cases of three hours of gas and water injection (3600 days of oil production by pressure depletion included).

Case	RF for one year, %	Injection pore volumes
Noinjection	5.874	0
Gas-frac-1 year-puff	5.888	0.0000882
Water-frac-1 year-puff	5.893	0.0001962

If more gas volume is injected, the mechanism of energized fluid (gas) will become dominant. To support this hypothesis, we reviewed the original models by Sheng [22], the oil recovery at the end of the first cycle (4200 days) from the gas injection is 6.4429%, higher than that (5.8936%) from the water injection. The 4200 days include 3600 days of primary depletion, 400 days of huff, and 200 days of puff. In those models, the injection (huff) pressures for the water and CO_2 injection cases are the same (7000 psia). Although less gas is injected (0.004875 reservoir pore volumes) than water (0.01639 pore volumes, 3.36 times the gas injection volume), the oil recovery from the gas injection is higher than that from the water injection. Note that the gas volume injected in 200 days is 55.27 times that volume injected in 3 h.

Based on the above discussion, we go back to the models in Table 3 and increase the injection time from three hours to 200 days. In the CO_2 fracturing case, CO_2 is injected for 200 days at the bottom-hole injection pressure (BHP) of 50 MPa followed by 365 days of production at the BHP of 7 MPa which is similar to the bubble point pressure. For the water fracturing case, water is injected for 200 days at the BHP of 50 MPa followed by 365 days of production at the BHP of 7 MPa. The recovery factors after one year of production are presented in Table 5. It shows that the oil recovery for one year from the CO_2-only injection is 5.219% higher than those from the water injection case. It can be understood that using the same injection pressure (50 MPa), more gas can be injected than water, about double as shown in Table 5. Compared with Table 3 for 3 h of injection, the gas volume injected for 200 days is about

4. Discussion of the effect of fracturing fluids on reservoir pressure (energy)

From the energy point of view, the volume change by fluid compressibility is equal to c*V*Δp. The average compressibility for CO_2 in 30–50 MPa is 0.02192 MPa^{-1}, while it is 0.000419 MPa^{-1} for water. If the pressure drop Δp and the injected volume V are the same, the ratio of volume changes for CO_2 and water is 0.02192/0.000419 = 51.32. The data does show that the CO_2 volume change (expansion) is higher than the water volume change if the injected volumes are the same. In Table 5, 0.5525 MMm^3F of CO_2 at the surface is injected; the amount is equivalent to 1090 tons. Compared with 542 m^3 of water injected, the gas injected volume in the reservoir condition is about 2 times the water volume injected. Therefore, as more gas is injected, more energy is injected, and more oil is recovered for the gas injection case.

However, in the earlier discussed fracturing cases in Table 4, the injected volumes in CO_2 fracturing and water fracturing are almost the same and the volumes injected are very small compared with the reservoir volume (in the base model the pore volume is about 126 times the injected volume). Thus, it results in an insignificant increase in energy or oil recovery, as shown in Table 4. To make sure the models reasonably represent the reservoir flow, pressure data are checked. The simulated BHP during water injection is 109 MPa (close to the actual average BHP 110 MPa) at 0.25 days. The base simulation model shows that the average reservoir pressure before production is 41.19 MPa when CO_2 is injected, and it is 41.21 MPa when water is injected. The average

Table 5
Oil recovery after one year of production for the cases of water and CO_2 injection for 200 days.

Case	RF, %	RF % increase by CO_2 injection over water injection	Injection pore volumes
WATER-BHP7-200d-frac	12.602	0	0.01998
CO2-BHP7-200d-frac	17.821	5.219	0.040285

pressures are almost the same for the same amount of fluid injected. After 3.5 months of production, the simulated average pressure is 41.11 MPa when CO_2 is injected, and it is 41.13 when water is injected. The average pressures are almost the same as well for the similar amount of oil produced. These data show that the model reasonably predicts the actual pressure during injection.

From the above discussion, we can see that an energized fluid can increase oil recovery, but the volume in the fracturing is not large enough so that the EOR potential is insignificant. This observation is based on the modeling results without including fluid-rock interactions which are to be discussed next.

5. Discussion of CO_2-rock interaction

When CO_2 is dissolved in water, a carbonic acid solution is formed. The acidic solution could dissolve calcite and dolomite fast, and quartz and clay slowly. The dissolution reactions may remove some particles. If precipitated particles are not aggregated to block flow channels, the rock permeability should be increased, as some experiments reported [10,18],Andreani et al. [2]. The rock porosity and permeability could be increased due to the dissolution [11]or decreased due to the pore plugging from the dissolved particles or the formation of new crystals [11,29]. During hydraulic fracturing, the acid solution may further dissolve some rock near the natural fracture surfaces, increasing the complexity of the fractures[17]. Supercritical CO_2 could change sandstone rock mechanical properties and increase rock fracturability [13]. Ribeiro et al. [20] modeled complex fracture propagation. Their modeling results showed that a larger fracture surface could be obtained from a CO_2 pad than a water pad due to the effect of lower CO_2 viscosity.

To test the CO_2 effect on fracture complexity, the preceding base model is modified in this way: (1) in the base model, the end of injection for fracturing or the beginning of production is at day 35; (2) in the modified base model, the actual production history from day 35 onwards is replaced by the predicted production at a BHP equal to 30 MPa; (3) the natural fracture density and permeability in the SRV zones in the modified base model are increased; (4) either water or CO_2 is injected in the modified base model so that different water and CO_2 injection cases are run. In the different case names, the ending "X5", for example, means the fracture density and permeability are increased by 5 times. Although Zhang et al. [31] reported that some experiments showed the fracture permeability of CO_2 fracturing was three orders of magnitude higher than that of water fracturing, such a high permeability effect was not evaluated for three reasons: (1) it is probably an unreasonably high increase; (2) the models are hardly convergent when such increase in permeability was used; (3) if the permeability is increased so much that the production increase would be unreasonably high. When the BHP is set at 7 MPa, the model does not converge because of too large pressure or saturation variation. Therefore, the BHP is changed to 30 MPa.

Table 6 shows the oil recovery is increased by 30.9% and 50.4%, respectively, when the natural fracture density and the SRV permeability are increased by 5 and 10 times. The incremental in oil recovery is significant. Combining the results about the insignificance of the EOR potential by the energized CO_2 fluid, we can conclude that the increase in fracture density or permeability by CO_2-rock interaction may be one of the dominant mechanisms by energized CO2 fracturing fluid. Note that 10-year oil recovery data are also added in Table 6. After one year of production, because of the pressure (energy) and the oil near fractures depleted, not much more oil can be produced after one year (10-years recovery factors are close to 1-year recovery factors). In other words, like a huff-n-puff gas injection process, the increase or effect of gas injection in a cycle cannot be extended for a long time. That is why we need a recycled huff-n-puff injection. This is another angle in which we can see that an energized fracturing fluid has limited EOR potential.

Table 6 also shows that the oil recovery from the CO_2 injection case (CO2-BHP30) is lower than that from the water injection case. This was initially not expected. In those models, the same mass of water or CO_2 is injected, the injection volumes are very close. The pressure increase Δp during an injection can be estimated from $\Delta V/(V_p c)$, where V_p is the pore volume, ΔV is the injected fluid volume, and c is the fracturing fluid compressibility. In the simulation models, the injected mass of water is the same ad that of CO_2. Because the CO_2 density is close to the water density at the reservoir pressure and temperature, the injected CO_2 volume (ΔV) is close to the water volume. Since the c for CO_2 is much higher than the c for water, the Δp (pressure increase) for the water injection is higher than that for the CO_2 injection, as shown in Figs. 6 and 7 by the pressures after 35 days that is the end of injection or the beginning of production. Those figures show the average pressure and the near fracture pressure for the two cases. Both figures show that the pressures from the water injection case are higher than those from the CO_2 injection. Because the pressure from the water injection case is higher, the drawdown for production is higher; therefore, the oil recovery is higher.

During the production, the oil, gas, and water production at 78 days are shown in Table 7. The oil volume produced in m^3 is converted to tons using the density of 0.843 tons/m^3. The water density is assumed to be 1 ton/m^3. The gas produced in m^3 is converted to tons by dividing it by 505 m^3/ton. It can be understood that more gas is produced back in the CO_2 injection case, while more water is produced back in the water injection case; the oil production from the CO_2 injection is higher as initially expected. The total fluid produced from the water injection case (440 tons) is lower than that (458 tons) from the CO_2 injection case. Therefore, the reservoir pressure in the water injection case is higher than that in the CO_2 injection case. The above discussions show that the reservoir pressure is closely related to the total fluid volume produced. At the beginning of production, more oil is produced in the CO_2 injection

Table 6
Oil recovery after one-year production including increased fracture. density and permeability.

Case	RF for 1 year, %	Incremental RF in 1 year, %	RF for 10 year, %	Incremental RF in 10 years, %
WATER-BHP30	3.9964		4.033	
CO2-BHP30 with fracture spacing 8.2 m in SRV	3.5297	0 (Reference)	3.5525	0 (Reference)
CO2-BHP30X5 with fracture density and k 5 times CO2-BHP30	4.6153	30.9	4.6171	30.0%
CO2-BHP30X10 with fracture density and k 10 times CO2-BHP30	5.3097	50.4	5.3119	49.5%

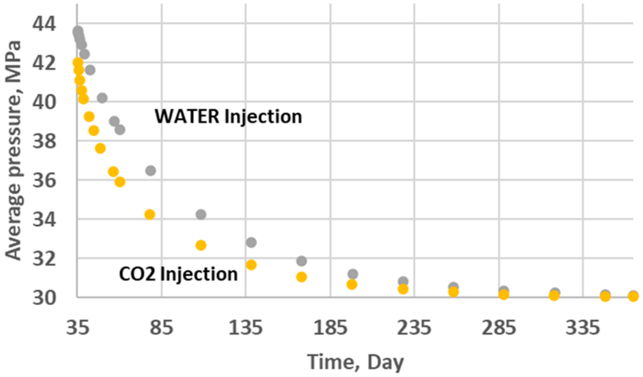

Fig. 6. Average model pressure for the water and CO_2 injection cases during the production period.

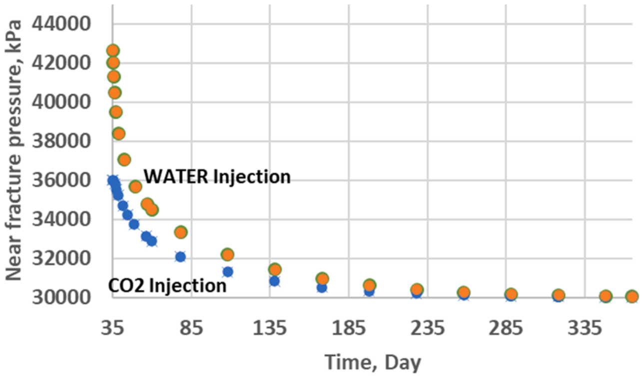

Fig. 7. Near fracture pressures for the water and CO_2 injection cases during the production period.

Table 7
Oil, water, and gas production at 78 days for the water and CO_2 fracturing cases.

Water injection				CO_2 injection			
Oil, tons	Water, tons	Gas, tons	Total, tons	Oil, tons	Water, tons	Gas, tons	Total, tons
352	75	13	**440**	403	41	14	**458**

case; however, as more CO_2 is produced, more reservoir energy is depleted, less oil can be produced later in the CO_2 injection case; finally, by the end of one year, slightly more oil is produced from the water injection case.

6. Further discussion

Simulation results have been discussed to analyze the EOR potential of energized fracturing fluids. The models are based on the history match of a CO_2 fracturing test. The model parameters in hydraulic fracturing and CO_2 fracturing are not changed except the fluid properties. Some parameters may be quite different in different fracturing fluids, for example, relative permeability curves in which aqueous phase trapping plays its role [3]. Some effects such as the wettability effect are not included in the models. This study focuses on the mechanism of drive energy, although the effect of CO_2-rock interaction on fracturing density and permeability is discussed.

Generally, the cost of non-aqueous fracturing fluids or energized fracturing fluids is more expensive than aqueous fracturing fluids; and the equipment costs are higher. If such extra costs are included, the energized fracturing would become less attractive to enhance oil recovery.

7. Conclusions

From the simulation analysis of the EOR potential of CO_2 fracturing and the quantitative analysis of the analogy of fracturing and the subsequent production to one cycle of huff-n-puff gas injection, the following conclusions may be reached.

1. The process of fracturing followed by the subsequent production is analogous to one cycle of huff-n-puff injection. The volume from energized fracturing like CO_2 fracturing is very small compared with the volume of a typical huff-n-puff injection for the EOR purpose. Therefore, the EOR potential from energized fracturing fluids may not be significant.
2. CO_2 as an energized fracturing fluid may increase the fracture density (fracture complexity) and the rock permeability. The EOR potential from such an increase is significant. Therefore, one of the dominant mechanisms of CO_2 fracturing is the increase in fracturing complexity and rock permeability.
3. The extra costs of using energized fracture fluids and equipment are not included. Including those may make energized fracturing less attractive to enhance oil recovery.

CRediT authorship contribution statement

James J. Sheng: Conceptualization, Methodology, Investigation, Writing – original draft, Writing – review & editing.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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