

Numerical Simulation of CO₂ Micro-Bubble Injection in Conventional Oil Reservoir

Abstract

Geological complexities make hydrocarbon recovery challenging, requiring EOR methods tailored to specific rock and fluid properties. However, CO₂ injection in low-permeability reservoirs often suffers from gas channeling and gravity segregation, while chemical and foam flooding face high costs and environmental concerns. On the other hand, CO₂ microbubble injection has been proposed as a gas-mobility-control approach with potential environmental and economic advantages. Laboratory studies have shown that the CO₂ microbubble method positively affects sweep efficiency and increases breakthrough time; however, no field studies have been reported yet. Numerical simulation, though limited by inherent model assumptions, is an economical and powerful tool for evaluating the performance of different production program scenarios and EOR methods. In this study, the CMG simulator was used to model production behavior in a sector of a conventional oil reservoir based on actual field data. CO₂ microbubble injection was represented by adapting CMG foam-model parameters, including rheology, base-fluid fraction, and rock adsorption. Performance was simulated over 700 days and compared against water and immiscible CO₂ injection scenarios, analyzing pressure profiles, recovery factor (RF), and oil saturation distribution. Results at day 480 show the CO₂ microbubble proxy achieving the highest recovery factor (54.88%), compared to water (49.90%) and immiscible CO₂ (43.62%). By day 700, however, water and microbubble recovery became nearly identical (58.13% and 58.10%), indicating faster intermediate recovery but no ultimate recovery gain over water.

Keywords: Enhanced Oil Recovery (EOR), CO₂ Micro-Bubble Injection, Micro-Bubble Viscosity, Field Sector Simulations, Commercial Simulators.

۲۵ ۱. Introduction

۲۶ The increasing global population and significant rise in industrial growth over the past three
۲۷ decades have led to a sharp increase in the demand for oil and its products. As a result, new
۲۸ methods for oil production must be proposed [۱]. Enhanced oil recovery (EOR) methods are the
۲۹ most effective approach for increasing the amount of hydrocarbons extracted from underground
۳۰ reservoirs [۲]. To boost oil production at an economic cost, various techniques can be applied,
۳۱ although new technologies may be required. It should be noted that these techniques are selected
۳۲ based on specific reservoir parameters, such as fluid properties, rock characteristics, and a wide
۳۳ range of tests [۳].

۳۴ CO_۲ injection is one of the EOR methods that has seen a significant increase recently [۴]. The
۳۵ reasons for this trend can be attributed to two main factors. Firstly, the source of the injected CO_۲
۳۶ is the atmosphere, which helps reduce and absorb this greenhouse gas, thereby alleviating public
۳۷ concern about global warming and its environmental impacts. Secondly, studies and experimental
۳۸ data have shown that CO_۲ injection, being readily accessible, significantly improves the Recovery
۳۹ Factor (RF) of oil reservoirs. In addition to these benefits, CO_۲ injection offers advantages to both
۴۰ the environment and oil production, with the results depending on several factors, such as oil and
۴۱ rock properties, including specific gravity and reservoir depth [۵].

۴۲ Many studies, including those by Mashayekhizadeh, Kord, and Dejam, have investigated CO_۲
۴۳ injection as a method for increasing the recovery factor of conventional reservoirs [۶]. In recent
۴۴ years, numerous successful output data have demonstrated the positive results of this method [۷–
۴۵ ۹]. One successful example is the Illinois Basin field in the United States, where a plan was
۴۶ developed based on data such as history matching, core analysis, well testing, well logging, and
۴۷ geological measurements. This project is an outstanding achievement that proves the effectiveness
۴۸ and advantages of CO_۲ injection [۱۰]. Similarly, the successful outcomes in the southern Iraqi oil
۴۹ fields have demonstrated the potential of this method [۱۱].

۵۰ In the realm of EOR methods, CO_۲ microbubble injection is an innovative technique that has been
۵۱ the subject of extensive research. This technique is employed in many industries; on the one hand,
۵۲ it demonstrates its capability in petroleum engineering, particularly as an EOR application [۱۲].
۵۳ CO_۲ microbubbles have been proposed to improve displacement in poorly contacted regions of

porous media [12–14]. Their lower buoyant force can increase residence time for interphase mass transfer and reduce effective gas mobility [13]. They may also mitigate preferential gas flow by improving sweep efficiency [14,15].

Previous work has examined CO₂ microbubble flow at pore, core, and laboratory scales. Xue et al. [12,13] reported improved dissolution in saline-aquifer and EOR systems. Patmonojai et al. [14] combined experiments with pore-scale simulation in a brine-saturated porous medium, while Jiang et al. [15] linked microbubble injection to better dissolution and sweep. Coreflood studies also provide useful evidence. Akai et al. [16] reported better sweep than with conventional CO₂ injection, and Hiramoto et al. [17] measured a 13% increase in recovery factor and less gravity segregation in Berea sandstone. Zhai et al. [18] followed migration and displacement with voxel-based X-ray CT. Using NMR, Wang et al. [19] found better pore-space use and up to 9.0% additional oil recovery. Le et al. [20] studied temporary plugging in homogeneous and heterogeneous media, whereas Telmadarreie et al. [21] examined rheology, stability, and porous-media flow under reservoir-relevant conditions. Jia et al. [22] later considered sequestration and gravity-induced ripening in low-permeability reservoirs, and Li et al. [23] reviewed micro- and nanobubble applications in CO₂-EOR. These studies are mainly experimental or pore-scale. Here, we use their reported behavior to parameterize a mobility proxy and compare it with water and immiscible CO₂ injection in one sector-scale reservoir model.

While the history of gas injection, particularly CO₂ injection, demonstrates improvements in the EOR field, there are still some imperfections [24]. An important issue is asphaltene deposition, which may occur during injection and cause several problems. As CO₂ is injected into a reservoir, it alters the composition of the reservoir fluid, which can lead to asphaltene precipitation and deposition during the injection process. This reaction might cause a chain of other problems, in particular pore plugging, which can have negative effects on reservoir parameters like permeability, porosity, and viscosity; additionally, it can alter wettability [25]. Furthermore, asphaltene deposition can damage pipelines and other vital facilities. In addition, asphaltene deposition during CO₂ injection may negatively impact the economic utilization of CO₂ and lead to unfavorable mobility ratios. As a result, this can reduce the recovery factor and increase production costs [26].

In this study, we focused on simulating CO₂ microbubble injection and found that its main difference lies in its rheological behavior, which improves recovery compared to CO₂ and water injection. We investigated CO₂ microbubbles as a potential EOR fluid that may provide an alternative to conventional CO₂ injection in selected reservoirs [15]. One of the biggest challenges in gas injection is the extremely short breakthrough time [27]. Microbubbles have been proposed to delay preferential gas movement through mobility reduction and modified rheological behavior [20,21]. CO₂ microbubbles exhibit transport behavior different from bulk CO₂ and may produce a more uniform displacement pattern [22].

The expected benefit of CO₂ microbubbles is mainly improved mobility control; the method does not remove every limitation of conventional CO₂ injection. Lower effective gas mobility and temporary resistance at pore throats can redirect the flow, and the larger gas-liquid interfacial area can promote dissolution [13,15,20,21]. Even so, gravity segregation, dissolution and ripening of the bubbles, pressure- and temperature-dependent behavior, injectivity, and possible asphaltene precipitation remain concerns. Our model does not include asphaltene deposition or changes in the bubble population. We therefore discuss these mechanisms as expected behavior from the literature, not as outcomes validated by the simulation.

Despite the potential benefits of CO₂ injection for enhanced oil recovery and reduced greenhouse gas emissions, it faces certain limitations, such as asphaltene deposition and unfavorable mobility ratios [28]. These factors might reduce recovery or damage the reservoir formation [29]. To address these challenges, we should use another EOR method without these challenges and with some benefits, we therefore simulated three injection-fluid scenarios to compare their performance [20,30]. We compared the injection of CO₂ microbubbles with both water and CO₂ injection in the same reservoir model. The same fluid and rock characteristics, as well as the same well pattern and maximum-rate control framework, are incorporated into these models. Based on the production rate, oil and water saturation, and oil recovery factor, each injection fluid's efficiency will be assessed. The purpose of this comparison study is to identify the injection technique that offers the most effective and long-term strategy for oil recovery.

2. Reservoir Model Description

2.1. Simulator software

In terms of modeling, we used the Computer Modeling Group (CMG) simulator, which helped us assess the desired changes. CMG is a widely used simulator for EOR studies. The modeling was carried out using the STAR module, with Winprop assisting in defining the fluid model.

2.2. Reservoir structure and well location

A simplified model was used to minimize heterogeneity effects and enable a clear comparison of the different scenarios. In the first step, we constructed a cubic model in the cartesian coordinate system (with axes I, J, and K), using 20 grid blocks in the I direction, 20 grid blocks in the J direction, and 8 grid blocks in the K direction (representing the number of layers). The size of the block in both the I and J directions is 50 ft, so the size of each square will be 5000 ft², and the grid thickness (K direction) is 10 ft, so the total size of our cubic will be 10000 × 10 ft³ as depicted in Fig. 1. The five-spot well pattern was employed to study oil displacement, with the locations of the injection and production wells shown in Fig. 1.

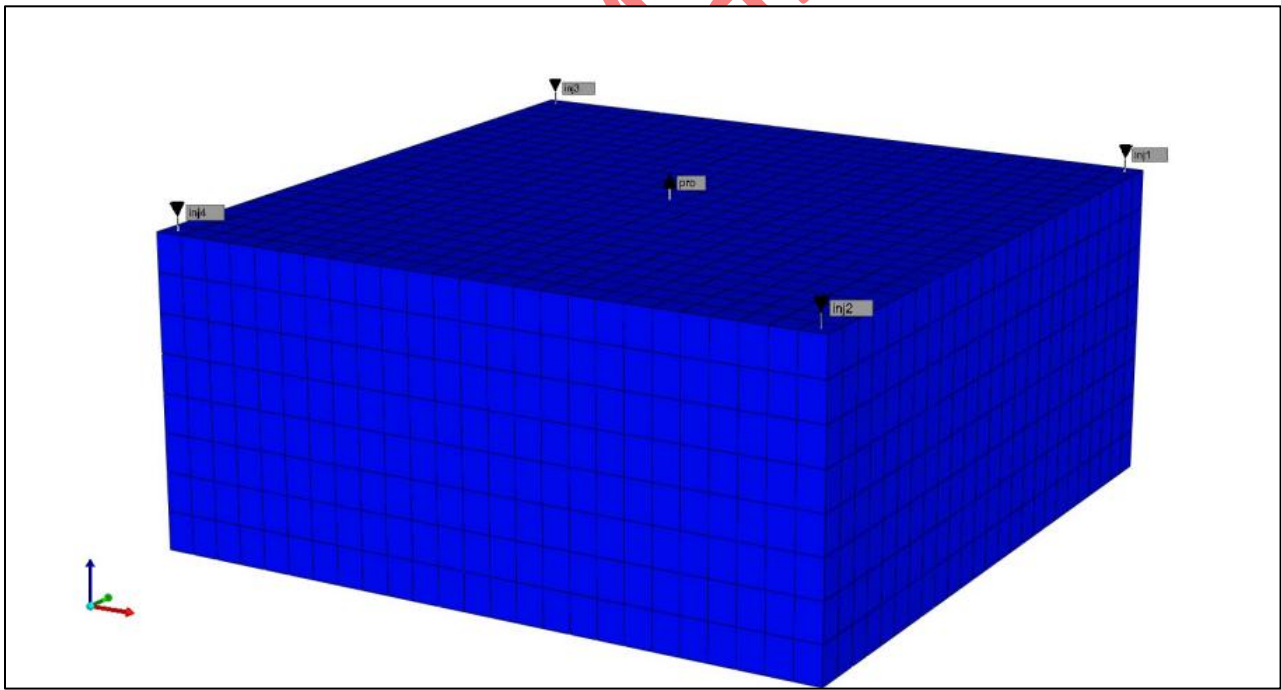


Fig. 1. cubic model and well pattern

Table 1 describes the initial volumes based on the dimensions, rock, and fluid properties used for the simulation.

Table 1. Initial volumes of the reservoir

Item	Unit	Value
Gross formation volume	ft ³	1.20×10^9
Formation pore volume	ft ³	2.4×10^8
Aqueous phase volume	ft ³	9.6×10^7
Oil phase volume	ft ³	1.44×10^8
Gaseous phase volume	ft ³	2.4×10^7

2.3. Rock properties

The rock properties were derived from the forest reserve field in Trinidad. In this section, average reservoir properties are considered for modeling, assuming a conventional reservoir. Therefore, the model does not include joints, faults, or other types of fractures. All properties were chosen from the forest reserve field in Trinidad and are listed in Table 2 [31].

Table 2. Reservoir rock characteristics

Reservoir characteristics	Unit	Values or type
Average permeability	mD	200
Rock compressibility	1/psi	0.00002962
Formation type	—	Sandstone
Average net pay	ft	64
Average depth	ft	—
Average porosity	—	0.3
Initial pressure	Psi	2200
Temperature	F	138
Grid thickness	ft	100

2.4. Fluid and well adopted parameters

Herein, we used fluid property data from the Trinidad oil field to construct the fluid model and implement it in the WinProp module. The lumping technique was applied to reduce the number of

components and accelerate simulation run time. The final fluid composition after applying the lumping technique is shown in Table 3 [31].

Table 3. Normalized composition of the reservoir fluid

Component	Normalized mole fraction (%)
CO ₂	2,4028
N ₂	0,0606
C ₁	36,4020
C ₂	3,4640
C ₃	4,0447
IC ₄	0,0807
NC ₄	1,3310
IC ₅	0,0738
NC ₅	0,8209
FC ₆	1,6119
C ₇ -C ₁₀	19,6727
C ₁₁ -C ₂₀	12,0640
C ₂₁ -C ₃₀	4,0046
C ₃₁ A ⁺	7,4332
C ₃₁ B ⁺	4,3201
Total	100,0000

Understanding the relationship between viscosity and temperature is essential for oil modeling before importing it into the simulation (STAR module). Therefore, we used WinProp to characterize oil viscosity as a function of temperature, as depicted in Fig. 2.

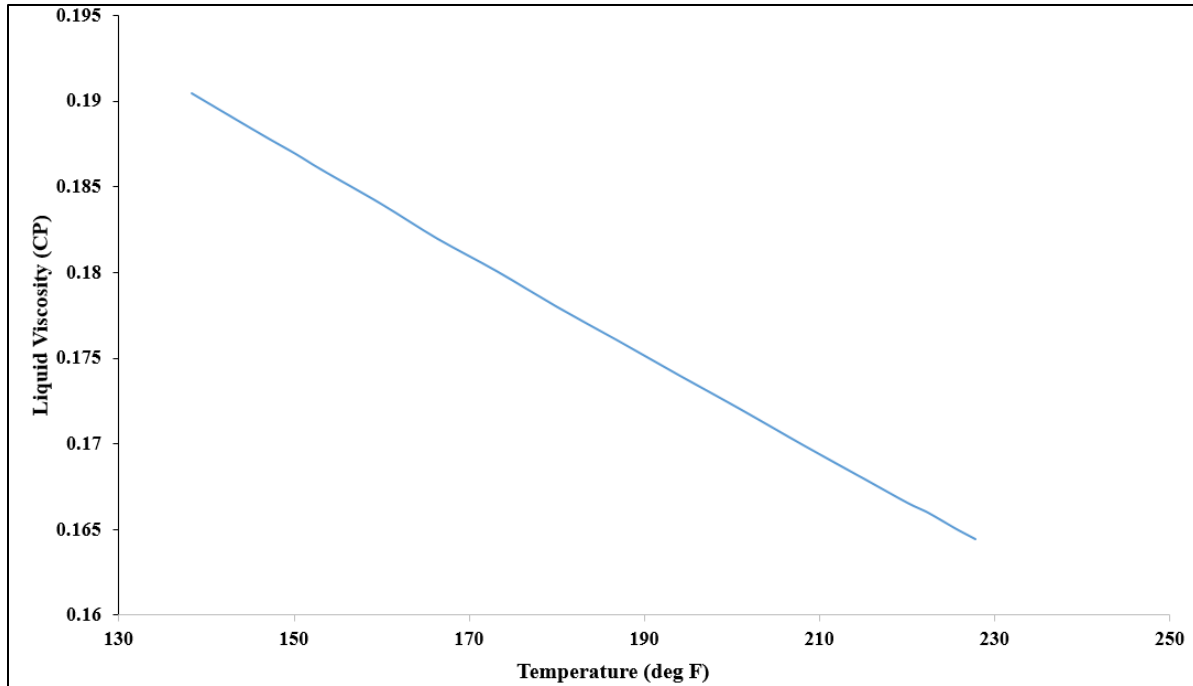


Fig. 2. Winprop output, viscosity and temperature relationship

One of the outstanding features of CMG is its ability to estimate various reservoir fluid properties based on fluid composition, although minor errors may occur. Nevertheless, this capability is utilized to achieve higher-quality estimations. Table 4 presents additional fluid properties from field data for the Trinidad reservoir [32]:

Table 4. Reservoir fluids characterization

Reservoir fluids characterization	Values
Critical temperature	70.3, 10.3 °F
Molecular weight	18.02 lb/lbmole
Molar density	3,467.02 lbmole/ft ³
Liquid compressibility	4.82633E-06 1/psi
Thermal expansion coefficient	0.000488889 1/oF

The relationship between water saturation and relative permeability for the sandstone reservoir is a key parameter for simulation. Based on the main reservoir parameters [32] and the study by Feng Xu et al., the required curves were obtained from CMG [33], as shown in Fig. 3.

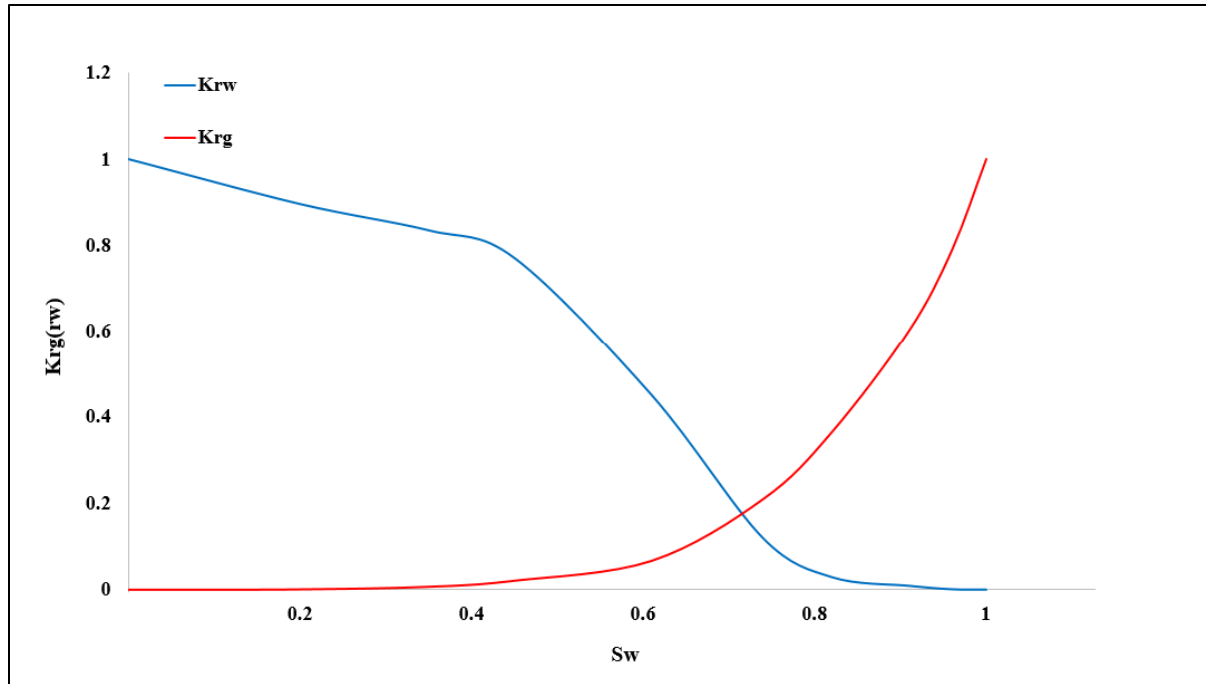


Fig. 3. Water saturation and relative permeability curves

Some parameters have a minor impact on the recovery factor (RF) and reservoir pressure behavior; however, they may still introduce errors. To enhance accuracy and reduce simulation run time, fractures and temperature gradients were neglected. Other important input parameters are presented in Tables 5 and 6 [32]:

For a direct comparison, the three cases were run in the same homogeneous and isotropic sector. Porosity, permeability, and fluid properties were kept uniform, and the model contained no faults, fractures, thermal gradient, geochemical reactions, or asphaltene deposition. Microbubble adsorption was set to zero. The simulator also did not track changes in bubble-size distribution, coalescence, dissolution, or ripening. This setup makes the effect of the imposed fluid mobility easier to compare, but it does not reproduce the heterogeneity of a field reservoir. Accordingly, the results are comparative rather than quantitative field predictions.

Table 5. Well characterization

Parameter	Value
Depth	2200 ft
Well length	2200 ft
Casing length	2200 ft
Insulation length	2200 ft
Tubing size	0.4 ft ID

Table 6. Initial condition of reservoir

Initial conditions	Value
Water-Oil-Contact (WOC)	3000 ft
Reference Pressure	974,20 psi
Reference Depth	2200 ft

The five-spot well pattern and the location of each well are shown in Fig. 1. In the injection scenarios, the mole fraction of CO₂ and water was set to 1. Notably, in the CO₂ microbubble case, this value was generated by CMG. The entries in Table 7 are upper rate constraints, rather than rates imposed at every time step. CMG determines the realized rate from these limits together with the other well and reservoir constraints. For water and microbubble injection, the liquid-rate limit is 0,000 bbl/day. The immiscible CO₂ case instead uses the simulator's gas-volume limit of 2,807,000 ft³/day. Realized rate histories and cumulative injected volumes were not retained in the exported data, so equal cumulative injection is not assumed.

Table 7. Maximum injection-rate constraints for each case

Case	Unit	Maximum-rate constraint
CO ₂ microbubble injection	bbl/day	0,000 × 10 ⁴
Water injection	bbl/day	0,000 × 10 ⁴
CO ₂ immiscible injection	ft ³ /day	2,8070 × 10 ⁶

3. CO₂-Microbubbles Modeling

3.1. Definition and Characteristics of CO₂-Microbubbles

CO₂ microbubbles are also discussed in the literature alongside colloidal gas aphron systems. Lower gas mobility and temporary resistance at pore throats can improve sweep during EOR [20,21,22]. In this study, we examined CO₂ microbubbles, which can be generated from a CO₂ stream using specialized porous filters. The details of this process can be found elsewhere. When the mixture is injected, it can reduce the mobility of CO₂ and impact the porous media through pore blockage. Bubble size matters because it affects stability, interfacial area, and passage through pore throats [20–22].

The size of microbubbles under various conditions has been analyzed by Ali Telmadarreir et al. in near-reservoir conditions. They demonstrated that microbubble size increases over time. However, in some cases, and over longer periods, larger diameters exhibited larger bubbles became more frequent than smaller ones. They found that the initial diameter of microbubbles ranged from 120 µm to 150 µm for all samples, and it increased over time during the test. This relationship between time and size is a crucial factor in the blocking process and enhanced oil recovery. Additionally, they found that microbubbles remain stable at temperatures below 104°F but become fully unstable above 149°F. Their studies on the effect of pressure indicated that the most influential factor is the pressurization rate; under gradual pressure changes, microbubbles exhibited greater stability [23].

The change in viscosity versus shear rate for CO₂ microbubbles and the base fluid is approximately similar. Tests have shown that the slight dissolution of CO₂ gas in the base fluid increases viscosity at low shear rates; however, it subsequently decreases at higher shear rates, as illustrated by the results of Khamsehchi et al. in Fig. 4 [24]. Initially, Aphrons exhibited slightly higher viscosity compared to the base fluid. The viscosity of Aphrons is significantly influenced by changes in temperature, shear rate, and pressure [25,26]. They demonstrated that at higher temperatures, the pressurization/depressurization rate has a greater impact on microbubble stability. Moreover, it has been reported that microbubbles can enhance oil recovery at lower pressures due to improvements in viscosity and sweep efficiency compared to the base fluid [23].

Using a foam formulation does not mean that CO₂ microbubbles and conventional CO₂ foam were assumed to be physically identical. Both systems can reduce mobility at the macroscopic scale, but their pore-scale structures differ. Conventional foam has a connected gas phase divided by

surfactant-stabilized lamellae; a microbubble dispersion contains separate gas bubbles in a liquid phase [23,27]. Foam stability depends strongly on surfactant concentration, salinity, oil, capillary number, and dry-out. For microbubbles, bubble size, dissolution, ripening, pressure history, and temperature are also important [21–23,27]. In the present model, the foam equations are used only to impose an effective mobility reduction. We did not perform separate foamability or stability tests, and the model cannot follow lamella behavior or changes in bubble size.

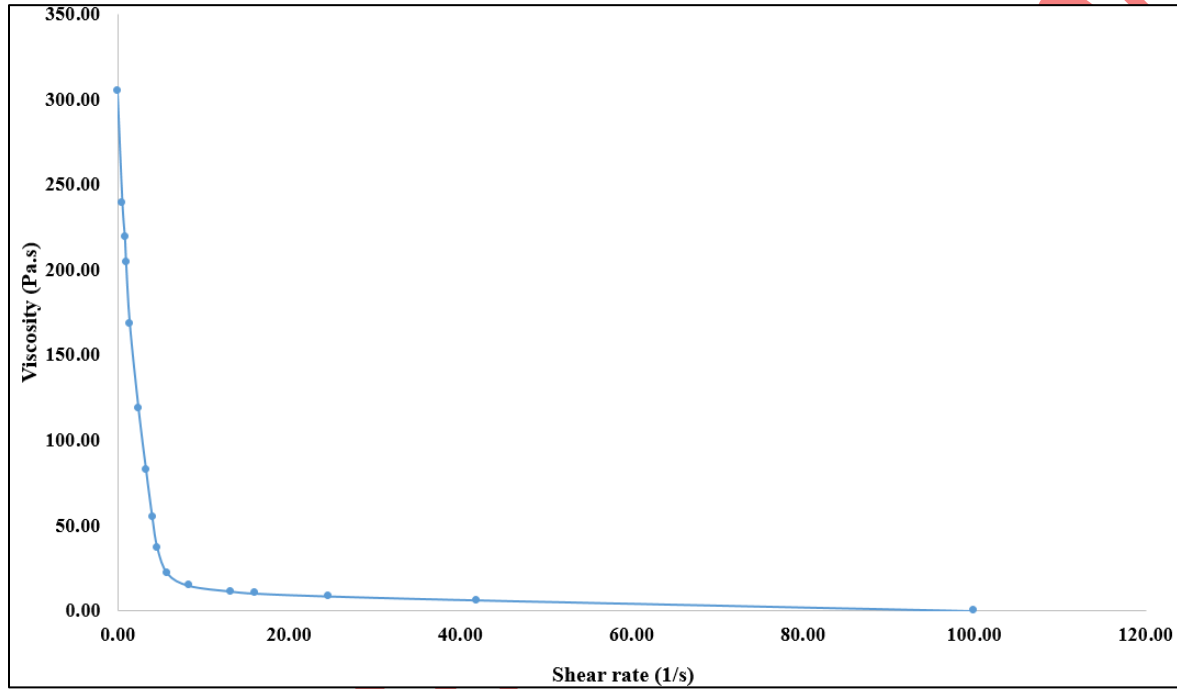


Fig. 4. viscosity versus shear rate for CO₂ microbubbles

3.2. Assumptions and Methodology for CO₂ microbubble Modeling

Since specialized simulators for CO₂ microbubble transport in reservoir porous media are currently unavailable, the mechanistic foam model within the CMG simulator was adapted for this study. The gas-foam model of the CMG Simulator is based on an accurate representation of the surfactant component's flow, and this adaptation is governed by the following assumptions and justifications:

- Microbubble adsorption onto the reservoir rock matrix is neglected

- The apparent viscosity of the aqueous phase containing microbubbles varies with gas quality.
- Relative permeability curves are modified to represent the microbubble flow

We therefore limit the foam–microbubble analogy to continuum-scale mobility. At this scale, both dispersions can lower effective gas mobility and divert flow, even though their pore-scale structures and stability mechanisms are different. The CMG parameters were adjusted to reproduce the apparent-viscosity and mobility trends reported for CO₂ microbubbles. This limitation is retained when the simulation results are interpreted. The model is based on an accurate representation of the surfactant component's flow, and the following details are required:

$$k_{r_{Co2}}^{s-f} = k_{rg} \cdot FM \quad (1)$$

$$FM = (1 + FMMOB \cdot DPHE)^{-1} \quad (2)$$

$$DPHE = PHMR_1 \cdot PHMR_2 \cdot \dots \cdot PHMR_n \cdot F_{dry_out} \quad (3)$$

$k_{r_{Co2}}^{s-f}$ is semi-foam relative permeability in the presence of CO₂ (we named it semi-foam because we had some limitations in CMG, and we just ran a model similar to CO₂ microbubble, and our model has some similarities to foam), FM is mobility-reduction factor which modifies gas relative permeability with foam, $PHMRs$ are effects of different physical factors on gas mobility reduction (capillary number, salinity, water saturation, oil saturation, foam generation, surfactant concentration, and permeability), fmmob is maximum-attainable gas-mobility reduction, and F_{dry_out} is foam dry-out.

The CMG foam model was used as the starting formulation for the present work [38]. In a separate study, Jia, Haowei et al. developed CMG formulas to describe the behavior of CO₂ microbubbles.

The mobility reduction was implemented by replacing the gas relative permeability in the foam formulation with an effective value for the microbubble case, following Jia et al. [39].

$$k_{r_{Microbubble}}^m = \frac{k_{rg}}{1 + DPHE \cdot fmmob} = k_{r_{Co2}}^{s-f} \quad (4)$$

240 If we look at Eq. 1, we can see the relationship between k_{rg} (gas relative permeability) and $k_{r_{CO_2}}^{s-f}$.
 241 Based on the aforementioned equations and modifications to the foam model in the CMG
 242 simulator, we assumed zero adsorption when exposed to rock, adjusted the foam weight, and
 243 reduced mobility. We calculated the relationship between apparent viscosity and gas fraction
 244 according to the work of Jia et al. [22]. Equation (6) defines the semi-foam quality [22]:

$$f_f = \frac{u_{MB}}{u_{MB} + u_w} \quad (6)$$

$$f_{s-f}^{MB} = \frac{1}{1 + \frac{\mu_g \times k_{rw}(S_w)}{\mu_w \cdot k_{r_{CO_2}}^{s-f}(S_w, FMMOB, DPHE)}} \quad (7)$$

245 Where f_{s-f} and f_{s-m}^{MB} are semi-foam quality in the absence and presence of microbubble, u_{MB} and
 246 u_w are microbubble and water Darcy velocity, μ_{MB} and μ_w are microbubble and water viscosity,
 247 k_{rw} is water relative permeability, and S_w is water saturation.

248 For the stimulated CO₂ microbubble apparent viscosity (μ_{app}^{MB}), we derived Eq. 8 from Jia, Haowei
 249 et al.'s work [22]:

$$\mu_{app}^{MB} = \frac{1}{\frac{k_{rw}(S_w)}{\mu_w} + \frac{k_{r_{CO_2}}^{s-f}(S_w, FMMOB, DPHE)}{\mu_g}} \quad (8)$$

250 Then, we employ equations for velocity [22]:

$$u_w = -\frac{k_{rw}}{\mu_w}(P_w + g\rho_g z) \quad (9)$$

$$u_{MB} = -\frac{k_{rg}}{\mu_g}(P_g + P_c + g\rho_g z) \quad (10)$$

251 Where P_c is the capillary pressure, P_g and P_w are the gas and water pressure in porous media, g is
 252 gravity, ρ_g is the gas phase density, and z is depth. We did not have reservoir-specific

measurements of FMMOB. The base value was therefore set to 0.311, as reported by Jia et al. [22], and its effect was checked with the sensitivity calculation described below. Table 8 presents the other necessary parameters, which were used to calculate the apparent viscosity-foam quality relationship.

Table 8. Inputs in apparent viscosity-foam quality relationship

Characteristics	Unit	Value
Water viscosity	$Pa \cdot s$	1
Gas viscosity	$Pa \cdot s$	0.0
CO ₂ density	kg/m^3	1980
Water density	kg/m^3	1000
Water Z factor	—	1
Gas Z factor	—	0.739
Water pressure	Pa	7894709
Gas pressure	Pa	7894709
Gravity (g)	m/s^2	9.8

Finally, based on these characteristics and equations, we establish the relationship between apparent viscosity and foam quality in Fig. 6 for our case using Eq. 6 and Eq. 7. In fact, a semi-microbubble injection model has been derived from the foam model by adjusting its key parameters to align with CO₂ microbubble properties.

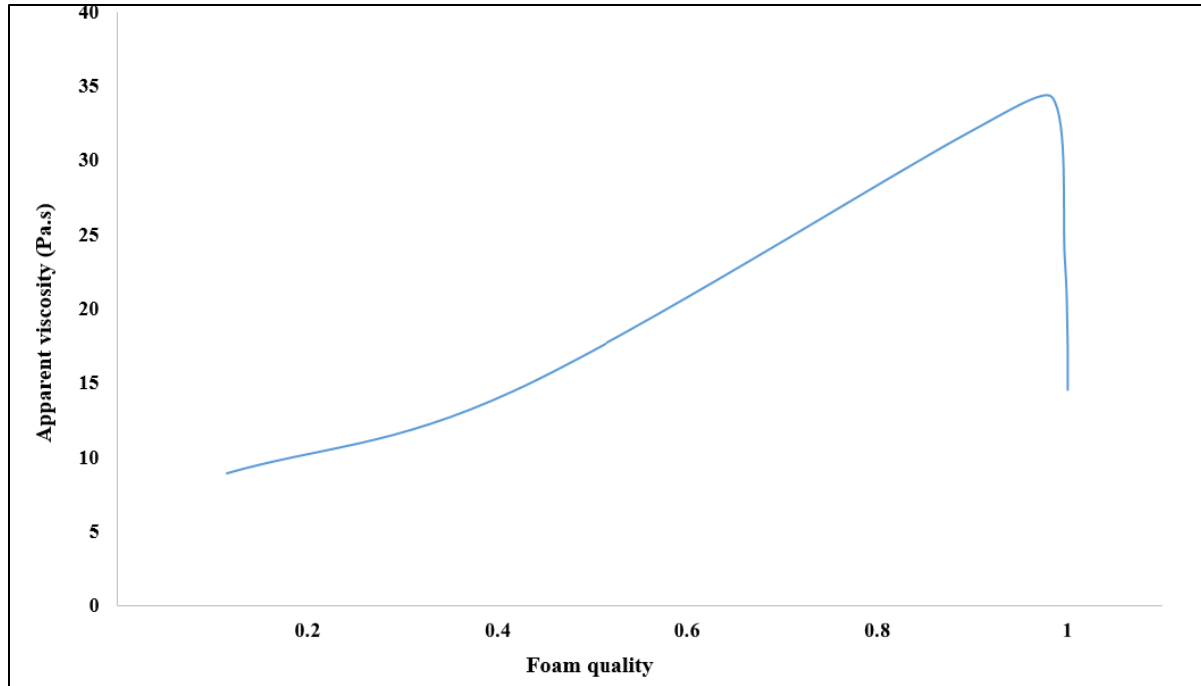


Fig. 5. Apparent viscosity and foam quality curve

As a first sensitivity check, FMMOB was changed by $\pm 20\%$ from the base value of 56,311 while DPHE was kept at 0. The relative-permeability, foam-quality, and phase-viscosity inputs were left unchanged. Peak apparent viscosity was 34,27 cP for the base case, 27,79 cP for the low case (-18.9%), and 41,13 cP for the high case ($+20.0\%$). FMMOB and DPHE occur as a product in Eq. (5); consequently, changing DPHE by $\pm 20\%$ gives the same algebraic response. This calculation checks the constitutive mobility-reduction equation only. We did not rerun the reservoir model, so no sensitivity of recovery factor or breakthrough time can be inferred. The three curves are plotted in Fig. 6. It should be noted that gas and water velocities were calculated using Eqs. (8) and (9), as depicted in Fig. 7.

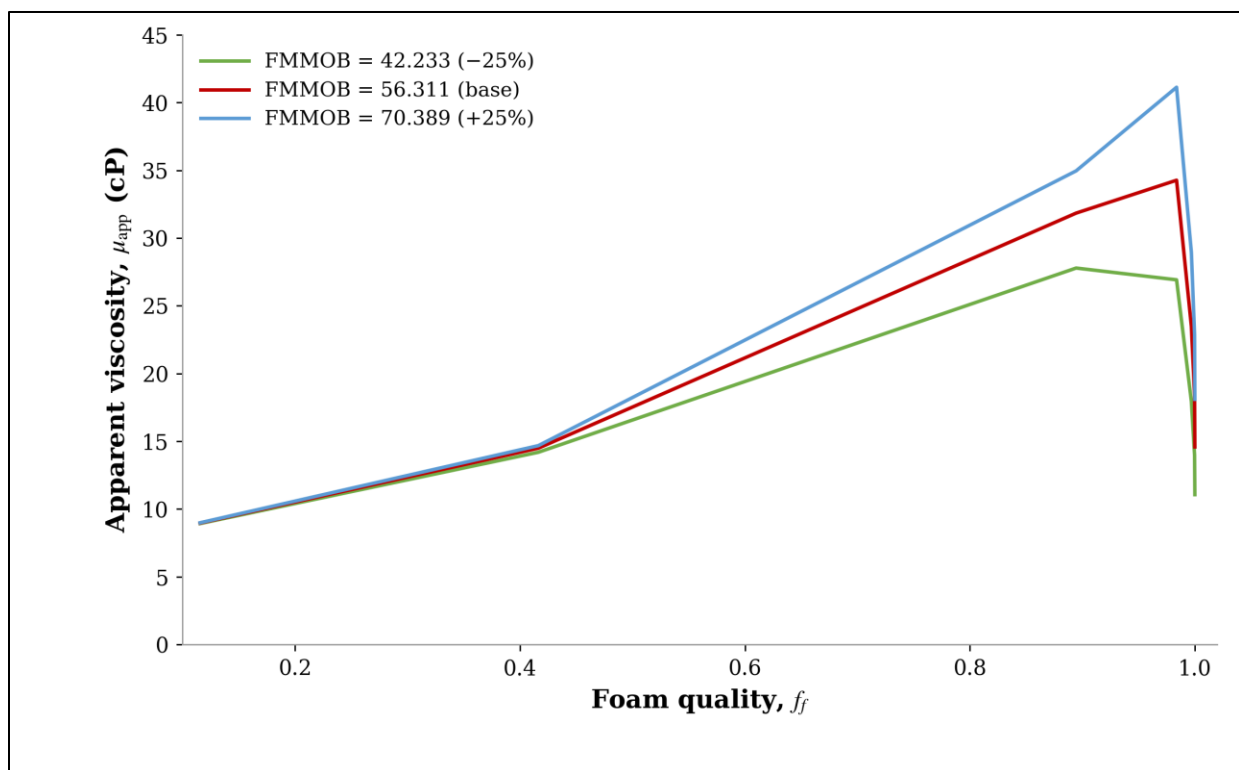


Fig. 6. Equation-level sensitivity of apparent viscosity to FMMOB

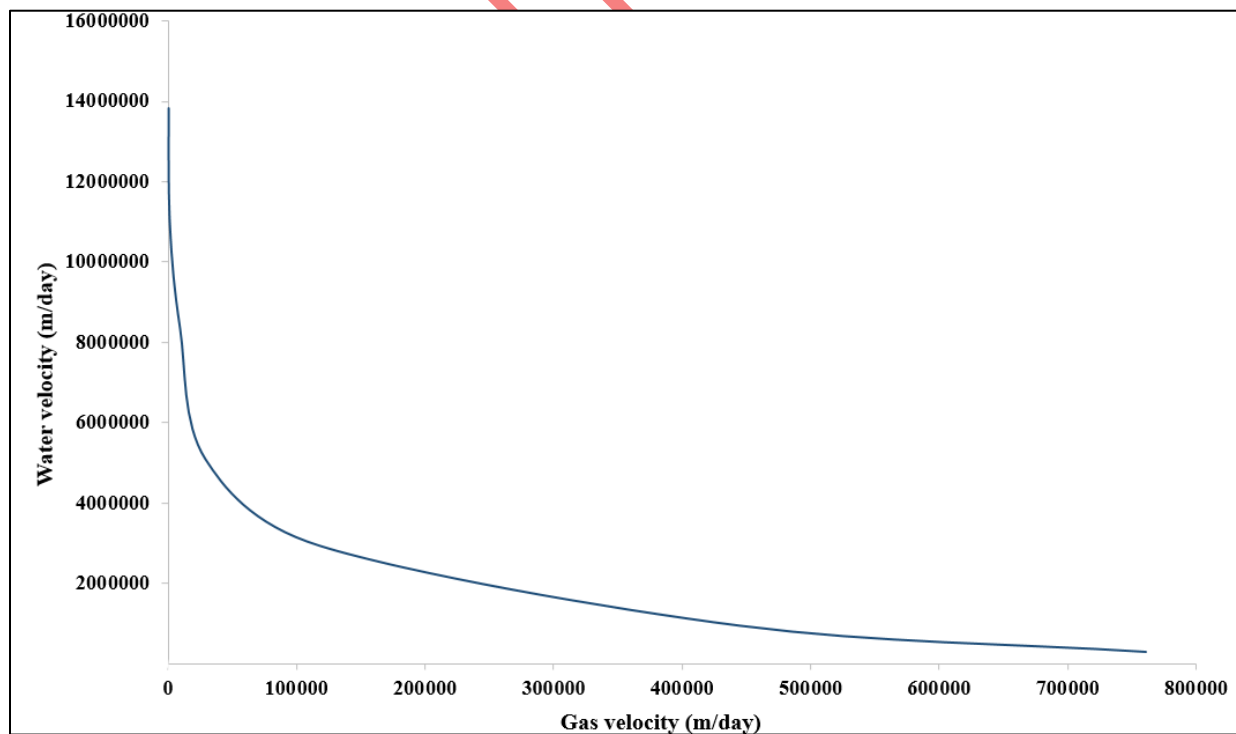


Fig. 7. Water and gas velocity curve

282 4. Results and Discussions

283 4.1. Visual description

284 The simulation for the described reservoir structure (as depicted in Fig. 1) was run for 500 days of
285 production and injection across three scenarios: water injection, immiscible CO₂ injection, and
286 CO₂ microbubble injection, using the rates specified in Table 1. Fig. 2 presents a 3D view of the
287 model, where two injection wells can be observed on the right and left sides of Figs. 2a and 2b. The
288 pressure distribution results for the microbubble injection (Fig. 2a & 2b), water injection (Fig. 2c
289 & 2d), and immiscible CO₂ injection (Fig. 2e & 2f) are shown at two time points: the middle of
290 the injection period (250th day) and the end of the injection period (500th day). Additionally, Fig.
291 2g illustrates the oil saturation distribution results for these three scenarios at both the midpoint and
292 the end of the injection process.

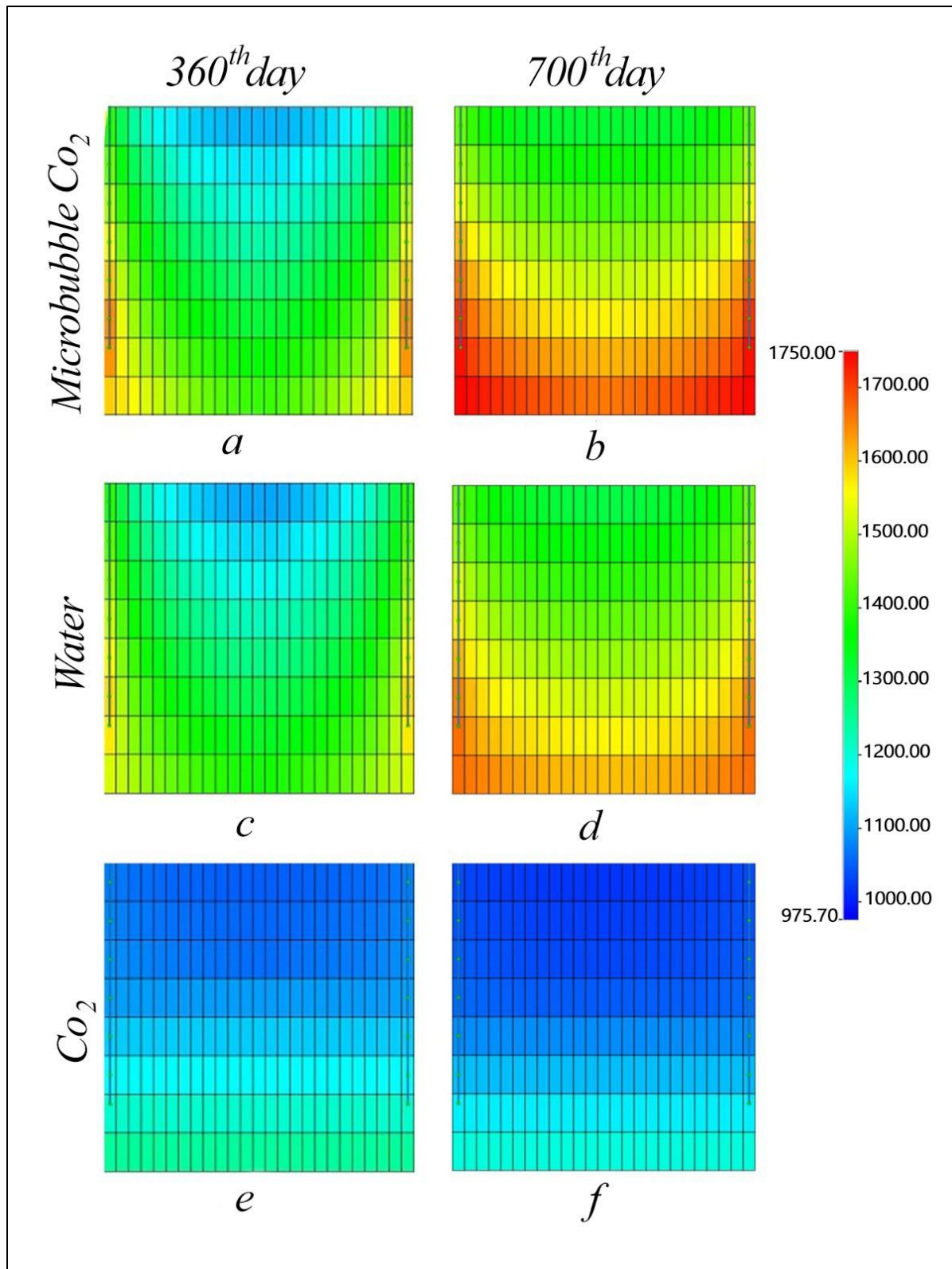


Fig. 8. Pressure profile in 360 and 700 days for all cases. Pressure is in psi.

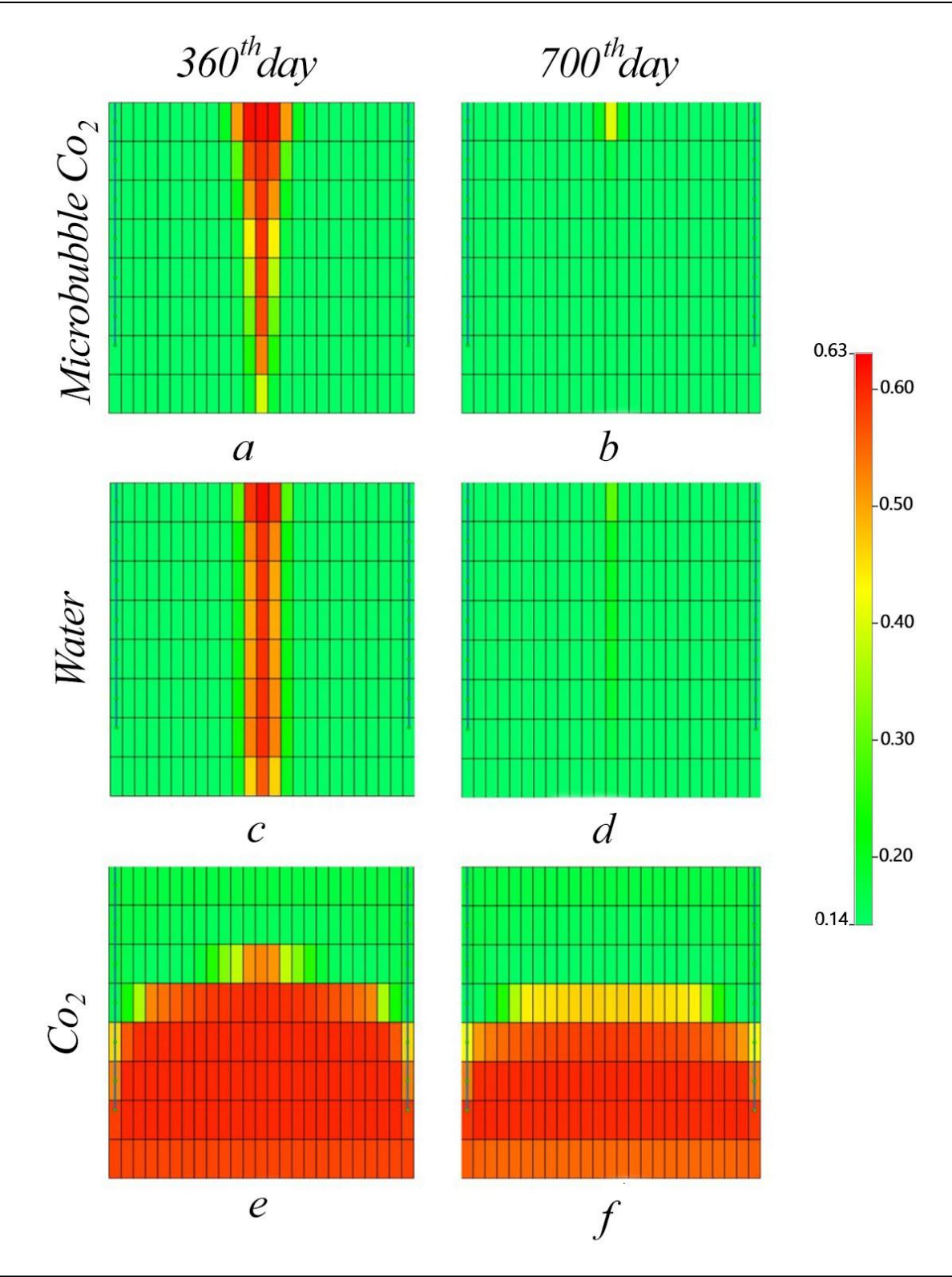


Fig. 9. Oil saturation distribution in 360 and 700 days for all cases. Saturation is expressed as a fraction.

As observed, CO₂ gas, due to its high mobility, moves more rapidly through pores with lower pressure, which decreases progressively from the reservoir edges toward the center, where the production well is located. The mobility ratio of the injection fluid is higher than that of the reservoir fluid, which is consistent with preferential gas flow and possible early breakthrough. In this case, the upper layers are effectively swept; however, despite increased gas injection, the lower layers remain unswept. This phenomenon, known as 'gas channeling,' is characterized by rapid breakthrough. To address this issue, techniques such as CO₂ WAG (Water Alternating Gas), foam treatment, or polymer gel methods are recommended, although these approaches fall outside the scope of this study.

Furthermore, since gas moves from high-pressure grids to low-pressure grids, the movement of CO₂ within the reservoir can be easily predicted (Fig. 8). The rapid migration of CO₂ leads to high oil saturation in the lower layers of the reservoir (Fig. 9). This pattern, including possible gas channeling, is compatible with the lower recovery factor, as will be discussed later in Fig. 13. Although the fluid contains heavy fractions (Table 3), asphaltene precipitation and deposition were not modeled. The results therefore say nothing quantitative about asphaltene-related permeability loss, pore plugging, or viscosity change.

In the immiscible CO₂ case, the local oil-saturation maps indicate preferential gas movement through some layers. We cannot attribute this pattern only to a higher injection rate: Table 4 contains maximum constraints, and the realized rate history was not available. For this reason, we describe the displacement as less uniform without assigning a single cause.

The pressure and saturation maps for the microbubble case differ from those for immiscible CO₂ and are compatible with lower effective gas mobility and a more even displacement front. This interpretation is limited to the continuum-scale output. Bubble bursting, pressure waves from individual bubbles, coalescence, and ripening are not represented, so they cannot be inferred from Figs. 8 and 9.

Both liquid-based injection cases exhibit a semi-linear displacement front, uniformly pushing oil through the reservoir. During the intermediate period, oil recovery was faster with the microbubble proxy. By day 700, however, water had a slightly higher recovery factor. The benefit seen in this model is therefore earlier mobility control, not a higher final recovery. Additionally, microbubble injection presents an environmentally friendly alternative to conventional methods.

4.2. Overall behavior from the start of injection

Fig. 10 presents a comparison of average reservoir pressure over time for the three injection scenarios. In the case of CO₂ injection, the average pressure initially surged dramatically, exceeding 1400 psi in the first few days. It then remained stable for several weeks before declining. Gas channeling is one possible explanation, but breakthrough time was not extracted directly. Over time, the reservoir pressure gradually declined to around 1100 psi. Preferential gas flow may also have contributed to this decline.

In contrast, both water and microbubble injection exhibited a more stable pressure trend before breakthrough. However, a noticeable shift in the slope of the pressure curves was observed. For microbubble injection, the pressure fluctuated between 1330 and 1530 psi from the 400th to the 570th day, demonstrating a prolonged period of pressure stability. In comparison, the water injection case exhibited a similar shift, but over a much shorter duration of approximately 40 days, with lower pressure stability.

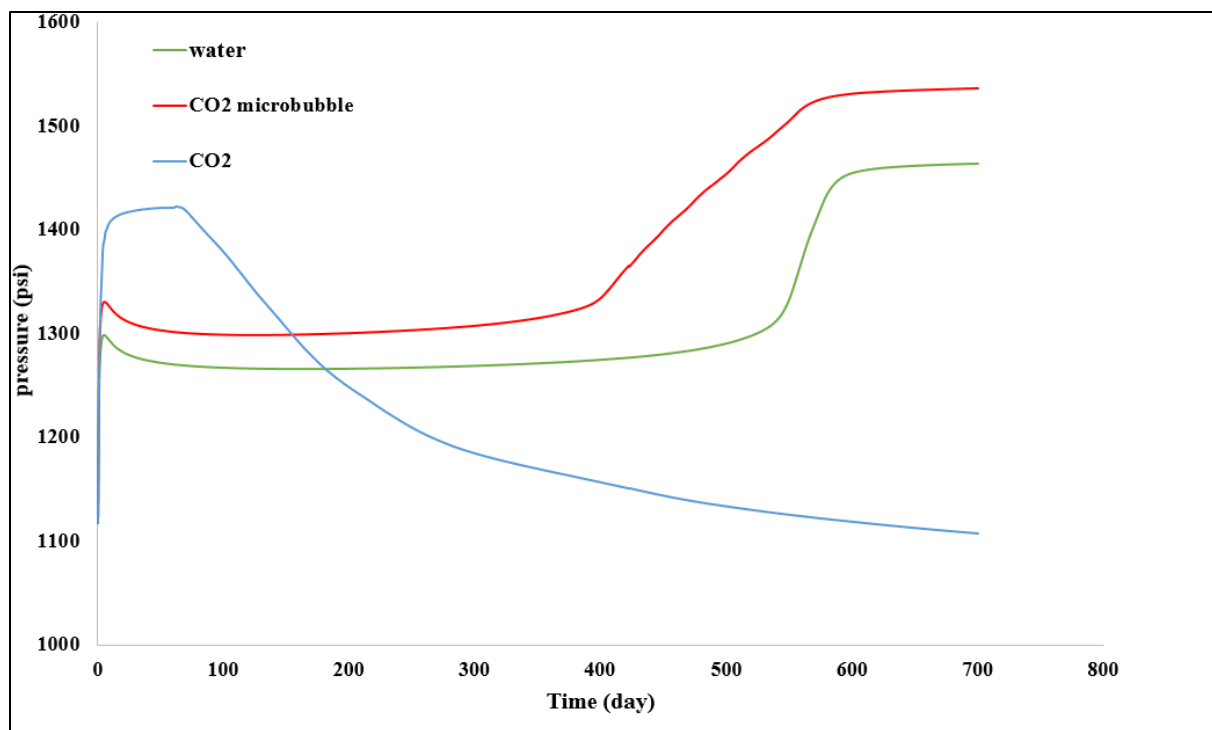


Fig. 10. Average pressure term versus time for three scenarios of injections

Fig. 11 shows the change in oil production rate over time. As observed, the microbubble injection curve declines moderately, similar to the pressure curve. The CO₂ injection curve, however, shows fluctuations, which could reflect preferential gas flow. The output does not contain a direct breakthrough-time diagnostic. We therefore do not assign the individual fluctuations to separate channel-arrival events.

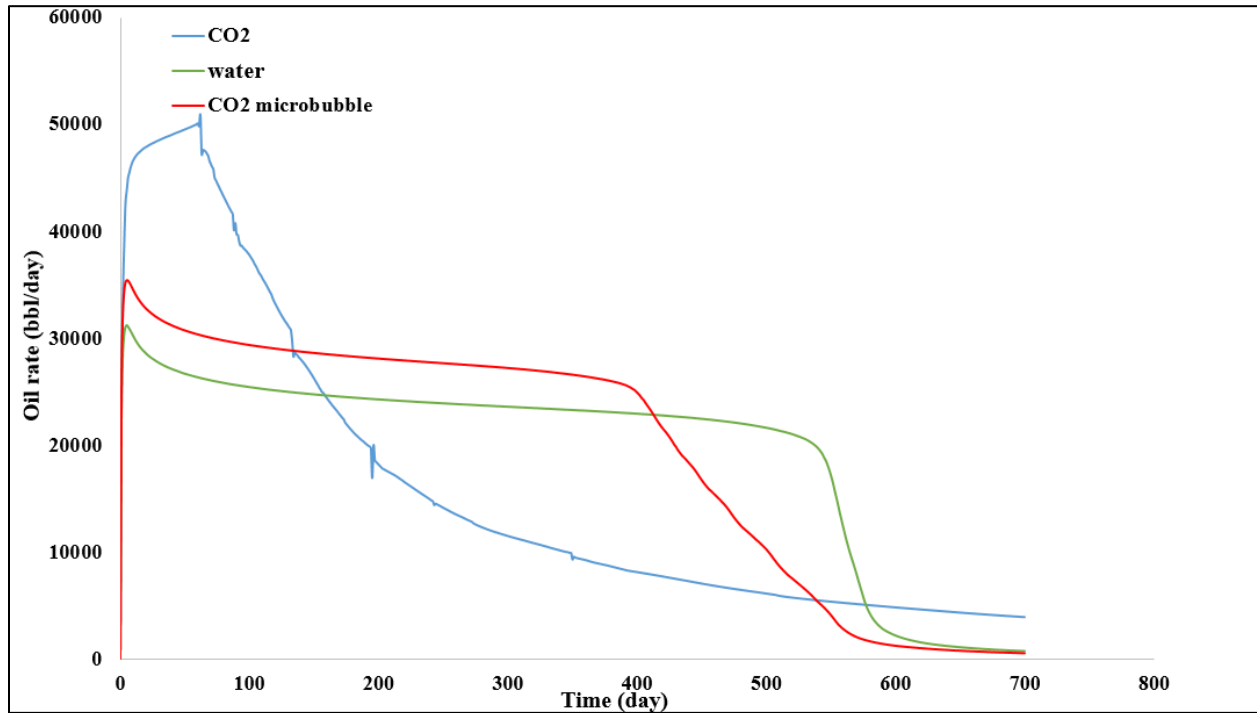


Fig. ۱۱. Oil production rate for each case during injection term

Fig. ۱۲ illustrates the average oil saturation in each injection scenario. Unlike the visual representation, at this stage, the CO₂ injection case shows higher oil saturation, which supports our observations in Figs. ۸ and ۹. The difference between the water and microbubble curves may be attributed to variations in injection pressure, as well as the weight difference between the fluids. At day ۷۰۰, average oil saturation was ۰,۲۵۰,۶ in the water case, ۰,۲۵۰,۸ in the microbubble case, and ۰,۲۹۹,۸ in the immiscible CO₂ case.

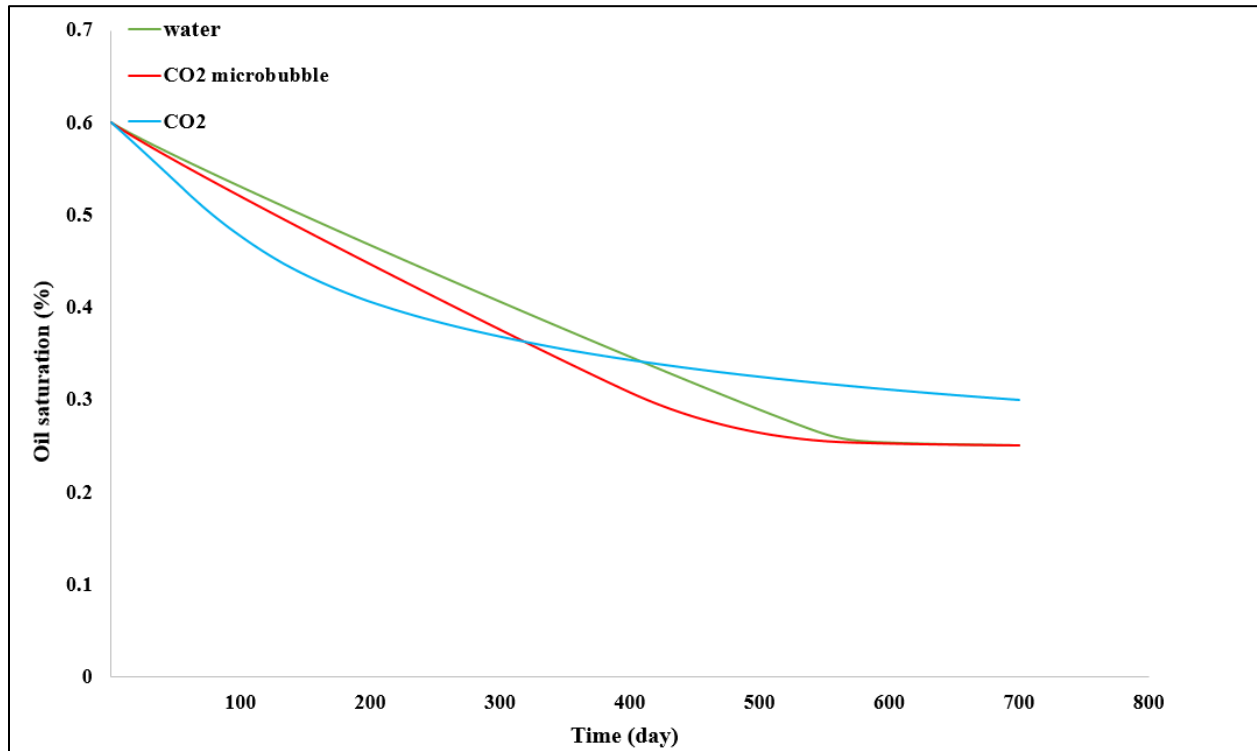


Fig. ۱۲. Average oil saturation for each case during injection term

The oil recovery factor is one of the most critical parameters in petroleum engineering. Fig. ۱۳ illustrates the recovery factor over time for microbubble, water, and CO₂ injection scenarios. As evident, the microbubble injection demonstrated superior performance, achieving a higher recovery factor compared to both water and CO₂ injection. The CO₂ scenario initially showed a recovery factor of ۳۱.۷۷% by the ۲۹۵th day, compared to ۳۱.۷۱% for the microbubble scenario and ۳۱.۷۸% for the water scenario. However, after the ۲۹۵th day, the recovery factor for the microbubble and water scenarios increased at a faster rate. At day ۴۸۰, recovery factor was ۴۹.۹۰% for water, ۵۴.۸۸% for the microbubble proxy, and ۴۳.۶۲% for immiscible CO₂. By day ۷۰۰, the values were ۵۸.۱۳%, ۵۸.۱۰%, and ۴۸.۲۷%, respectively. The microbubble case was ahead at the intermediate time, but it did not remain above water at the end of the simulation.

The microbubble case recovered more oil during the intermediate period, which is consistent with the mobility reduction imposed in the model and the more even displacement pattern. However, the realized injection histories were unavailable, and no laboratory or field data were used to

calibrate this reservoir model. The simulation alone therefore cannot show that breakthrough was delayed or identify a specific pore-scale cause for the recovery trend.

The simulated trend is qualitatively similar to published observations of temporary plugging, higher flow resistance, and flow diversion [20,21]. We treat this only as a consistency check. It is not independent validation because the same literature informed the model parameters. Predictive application would require matched high-pressure/high-temperature rheology and stability measurements, coreflood calibration, and complete time-dependent well histories.

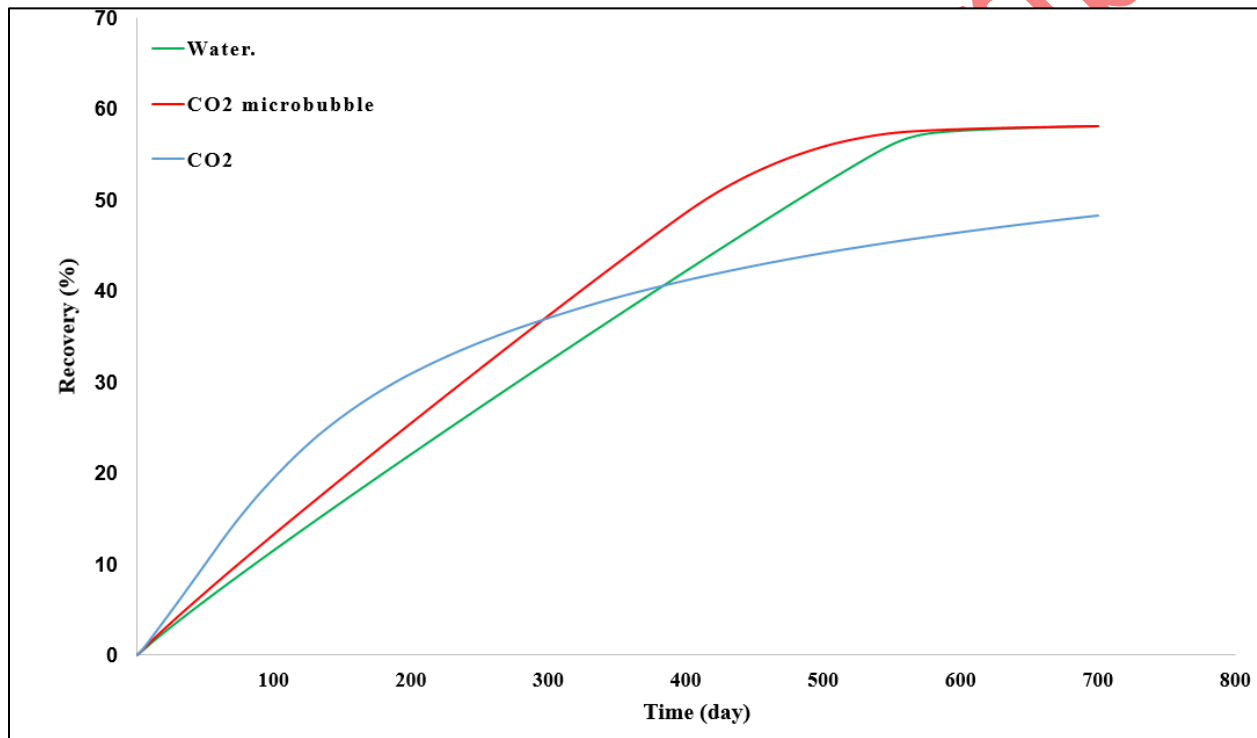


Fig. 13. Recovery Factor (RF) for each case during injection term

5. Conclusions

In this work, the CMG simulator was employed to model CO₂ microbubbles by modifying the foam model and incorporating CO₂ microbubble rheological characteristics. The model was compared with the CO₂ and water injection models over 700 days of simulation. At day 400, recovery factor was 54.88% for the microbubble proxy, 49.90% for water, and 43.62% for immiscible CO₂. The corresponding day-700 values were 58.10%, 58.13%, and 48.27%. In other

words, the microbubble proxy improved the rate of recovery at intermediate times but did not produce a higher final value than water. The model does not establish that early breakthrough was eliminated, and it cannot be used to assess asphaltene deposition because that process was not included.

Taken together, the results support further investigation of mobility-controlled CO₂ microbubble injection for EOR. The numerical values remain uncertain because the sector is homogeneous, the foam-proxy parameters come from the literature, the realized injection-rate histories were unavailable, and the model was not calibrated with laboratory or field data. Injectivity, stability, environmental performance, and asphaltene risk would need separate assessment before any field application.

Future studies

Further work needs to calibrate the mobility-reduction parameters with high-pressure/high-temperature rheology and coreflood data and to represent changes in bubble size explicitly. Microbubble and conventional CO₂-foam systems should also be tested under the same conditions. Finally, reservoir-scale sensitivity runs should use complete injection-rate and cumulative-injection histories.

Declaration of AI-Assisted Writing

During the preparation of this work, the authors used ChatGPT to improve the language, grammar, and clarity of the manuscript. After using this tool, the authors reviewed and edited the content as needed and take full responsibility for the content of the publication.

Nomenclature

$k_{r_{CO_2}}^{s-f}$	Semi-foam relative permeability in presence of microbubble	k_{rw}	Water relative permeability
k_{rg}	Gas relative permeability	k_{s-f}^{MB}	Semi-foam quality in the presence of microbubble
$k_{r_{microbubble}}^m$	Gas relative permeability in the presence of microbubble	μ_{app}^{MB}	Apparent viscosity (Pa·s)

DPHE	Effects of different physical factors	P_w	Water pressure in porous media (Pa)
$PHMR_\lambda$	Capillary number	P_g	Gas pressure in porous media (Pa)
$PHMR_\gamma$	Salinity	g	Gravity (m/s ²)
$PHMR_\tau$	Water saturation	ρ_g	Gas density (kg/m ³)
$PHMR_\varepsilon$	Oil saturation	z	Depth (m)
$PHMR_s$	Foam generation	P_c	Capillary pressure (Pa)
$PHMR_\gamma$	Surfactant concentration	μ_g	Gas viscosity (Pa·s)
$PHMR_\nu$	Permeability	μ_w	Water viscosity (Pa·s)
F_{dry_out}	Foam dry-out	S_w	Water saturation
f_{mob}	Maximum-attainable gas-mobility reduction	u_w	Water Darcy velocity (m/d)
f_{s-f}	Semi-foam quality in the absence of microbubble	u_f	Foam Darcy velocity (m/d)

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