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## Numerical Simulation of Immiscible CO<sub>2</sub>-Assisted Gravity Drainage Process to Enhance Oil Recovery

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### Abstract

The Gas Assisted Gravity Drainage (GAGD) process has become one of the most important processes to enhance oil recovery in both secondary and tertiary recovery stages and through immiscible and miscible modes. Its advantages came from the ability to provide gravity-stable oil displacement for improving oil recovery, when compared with conventional gas injection methods such as Continuous Gas Injection (CGI) and Water – Alternative Gas (WAG).

Vertical injectors for CO<sub>2</sub> gas were placed at the top of the reservoir to form a gas cap which drives the oil towards the horizontal oil producing wells which are located above the oil-water-contact. The GAGD process was developed and tested in vertical wells to increase oil recovery in reservoirs with bottom water drive and strong water coning tendencies. Many physical and simulation models of GAGD performance were studied at ambient and reservoir conditions to investigate the effects of this method to enhance the recovery of oil and to examine the most effective parameters that control the GAGD process.

A prototype 2D simulation model based on the scaled physical model was built for CO<sub>2</sub>-assisted gravity drainage in different statement scenarios. The effects of gas injection rate, gas injection pressure and oil production rate on the performance of immiscible CO<sub>2</sub>-assisted gravity drainage-enhanced oil recovery were investigated. The results revealed that the ultimate oil recovery increases considerably with increasing oil production rates. Increasing gas injection rate improves the performance of the process while high pressure gas injection leads to less effective gravity mediated recovery.

**Keywords:** Gravity Drainage, Enhanced Oil Recovery, CO<sub>2</sub> Injection, immiscible displacement.

بناء موديل عددي لمحاكاة عملية استخلاص النفط بواسطة تصريف الجاذبية ومساعدة غاز ثاني أكسيد الكربون (GAGD) بطريقة حقن غير قابلة للامتزاج لتعزيز استخلاص النفط

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الخلاصة

اصبحت عملية استخلاص النفط بواسطة تصريف الجاذبية وبمساعدة الغاز (GAGD) واحدة من أهم العمليات لتعزيز استخلاص النفط في كل من طرق الاستخلاص الثانوي والثالثي من خلال حقن غاز غير قابل للامتزاج. جاءت مزايا هذه الطريقة لقدرتها على توفير إزاحة مستقرة بواسطة الجاذبية لتحسين استخلاص

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النفط مقارنةً بطرق حقن الغاز التقليدية: الحقن المستمر للغاز (CGI) والحقن المتناوب بين الماء والغاز (WAG).

تم وضع حاقن عمودي لغاز ثاني أكسيد الكربون في أعلى الممكن لتشكيل غطاء غاز يدفع النفط نحو الآبار الأفقية المنتجة للنفط والتي تقع فوق سطح تلامس النفط مع الماء. لقد تم تطوير واختبار عملية GAGD في آبار عمودية لزيادة استخلاص النفط في المكامن بوجود دفع مائي فعال من قاع المكمن. تمت دراسة العديد من النماذج الفيزيائية والموديلات العددية والتي تحاكي GAGD في الظروف المحيطة والمكمنية لمعرفة تأثير هذه الطريقة لتعزيز استخلاص النفط وفحص معظم المتغيرات التي تتحكم في عملية GAGD.

في هذه الدراسة ، تم تصميم نموذج محاكاة ثنائي الأبعاد يعتمد على النموذج الفيزيائي المعد مسبقاً في المختبر لطريقة استخلاص النفط بواسطة تصريف الجاذبية وبمساعدة غاز ثاني أكسيد الكربون في سيناريوهات مختلفة. تم دراسة آثار معدل حقن الغاز ، وضغط الحقن للغاز ، ومعدل إنتاج النفط على أداء تصريف الجاذبية بمساعدة غاز ثاني أكسيد الكربون غير القابل للامتزاج لتعزيز استخلاص النفط . كشفت النتائج أن معامل الاستخلاص النهائي للنفط يزداد بشكل كبير مع زيادة معدلات إنتاج النفط كما ان زيادة معدل حقن الغاز يحسن أداء العملية في حين يؤدي حقن الغاز بضغط عالي إلى استخلاص أقل فعالية بواسطة الجاذبية.

## 1- Introduction

The environmental aspects of “sequestration of greenhouse gases” are playing a great role in the field development strategies. Also, the world’s current attention focuses on carbon dioxide (CO<sub>2</sub>) capturing and minimizing greenhouse gas emissions to control global warming. CO<sub>2</sub> can be obtained either from natural resources such as the associated gas produced from oil fields or it can be captured from the thermal power plants and refineries. For these reasons, CO<sub>2</sub> injection projects are recently expected to grow [1].

The concept of gas injection into reservoirs has been practiced widely to improve oil recovery. Laboratory researches and field applications have been initiated to perform a great interest in gas flooding, which has become an efficient injection agent to increase oil recovery, especially for miscible displacement. The effectiveness came from its ability to increase volumetric sweep efficiency and lower the interfacial tension to increase microscopic displacement efficiency, which leads to minimizing the trapping of oil in the rock pores [2]. Also, CO<sub>2</sub> assures delaying the breakthrough to the producer, due to its high volumetric sweep efficiency which leads to maintaining the injection pressure and increasing the gas injectivity [3].

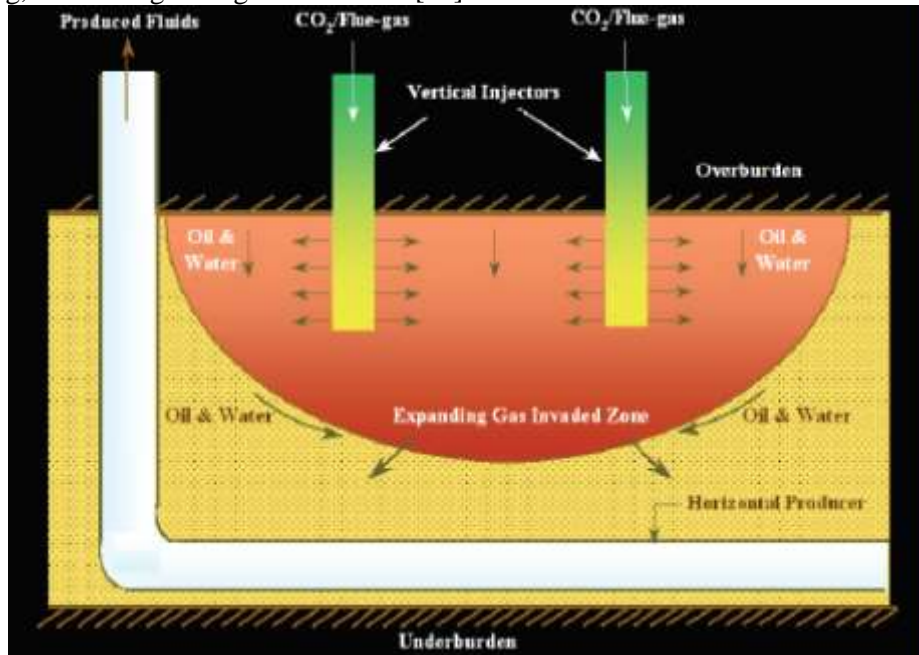
Gravity drainage is the gas/oil displacement process in which gravity forces act as a main driving force and where the gas replaces voidage volume. Thus, gravity drainage is a recovery process when gravity forces become dominating and may occur at every stage of the reservoir production, whether it is in primary depletion (segregation drive or gas cap drive), secondary gas injection stage, or tertiary oil recovery [4, 5]. In oil reservoirs, segregation of fluids is a strong proof for the presence of gravity. To take the advantage of the *in situ* segregation of fluids, gas is injected in the crest of the pay zone to create pressure maintenance, forcing oil downward the reservoir to get higher value of oil recovery [6, 7].

One of the efficient oil recovery methods in both secondary and tertiary modes is gas injection into dipping or reef reservoir in a gravity stable mode. GAGD technology is one of the applications of the gravity stable gas injection concept in different types of reservoirs. It was introduced by Rao [8] to improve oil recovery in secondary and tertiary modes for both immiscible and miscible processes. Large oil recoveries of around 85-95% of OOIP in field tests and nearly 100% in laboratory floods have been reported from core floods and field studies [9,10].

## 2- CO<sub>2</sub>- Oil Gravity Drainage EOR Process

CO<sub>2</sub>- assisted Gravity Drainage is an Enhanced Oil recovery (EOR) process in which CO<sub>2</sub> is injected in a gravity stable manner, i.e. the gas injection rate is below the critical rate. This process takes place either in miscible or immiscible modes through vertical wells from the top of the formation, while oil has been produced by placing horizontal producers at the bottom of the oil zone above the oil-water contact. The injected gas accumulates at the top of the formation to form a gas cap,

providing oil displacement drains towards the horizontal producer in a gravity stable mode. Due to the gravity segregation resulted from the distinct fluid densities at reservoir condition, better sweep efficiency and higher oil recovery have been achieved [11]. Figure- 1 shows the schematic drawing of GAGD process [9]. Due to horizontal wells, productivity has been increased because reservoir contact area has been increased and the coning in reservoir with bottom water drive and gas cap drive has been diminished due to the low pressure drawdown around the well sand- face [12]. Oil recovery by CO<sub>2</sub> injection through gravity drainage is a process wherein the pressure behind the CO<sub>2</sub> flood front in the gas zone remains constant [13]. Gravity forces play a major role at every stage of the producing life of the reservoir [5]. These forces contest with the viscous and capillary forces that are influential in the porous media. When gas is injected at rates higher than the critical rate, viscous forces are dominating and causing early gas breakthrough. CO<sub>2</sub> injection rate must be controlled to avoid viscous instability, gas fingering, and coning through the oil zone [14].



**Figure 1-** Schematic drawing of GAGD process [9].

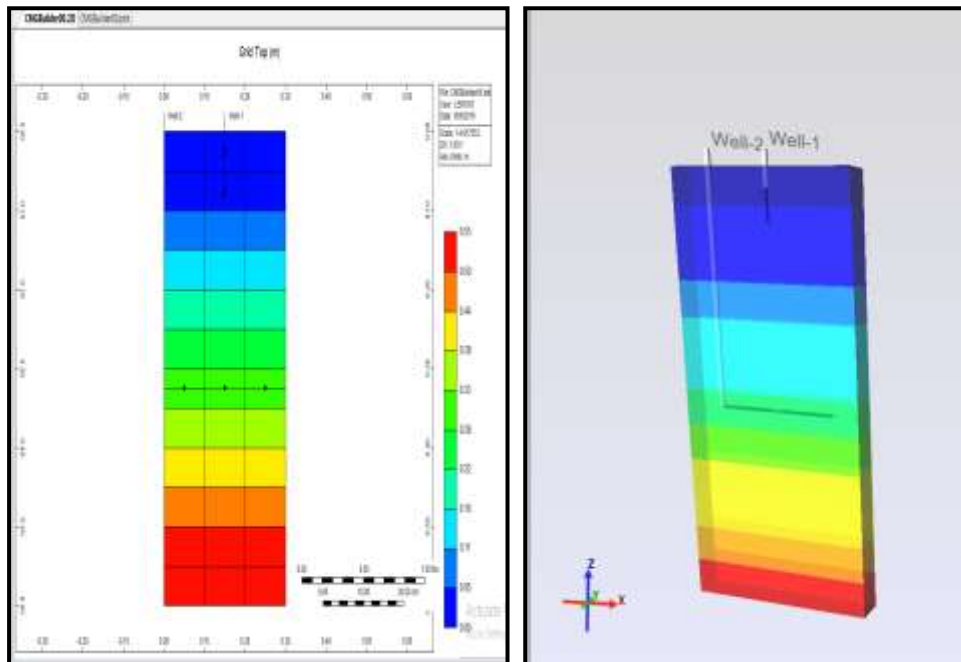
To keep the reservoir system in a gravity dominated mode, oil production rate must be controlled such that the oil production volumes plus the minor dissolved volumes are replaced with the equivalent gas injection volumes, implying constant pressure behind the CO<sub>2</sub> flood front. The gas oil interface (GOC) is moved downward slowly under the effect of gravity drainage from the high pressure zone to the low pressure oil production horizontal wells located at the lower part of the pay zone. [15]. Higher density difference between the reservoir oil and gas must be achieved to get more effective gravity segregation of the fluids, then gas- oil countercurrent flow occurs [16]. The accurate control of the operational parameters (gas injection rate and oil production rate) is necessary for the prosperity of the CO<sub>2</sub>-oil assisted gravity drainage-EOR process [15]. Heterogeneities, vertical permeability, gas and oil density, gas and oil viscosity, critical water saturation and many other reservoir and fluid parameters are also important [17]. Many studies were introduced to test the feasibility of GAGD process to enhance oil recovery on limited real oil fields. The GAGD process was applied for immiscible and miscible modes and the results showed that the oil recovery in the miscible mode is much better than that in the immiscible GAGD [3, 18]. Also, the CO<sub>2</sub>-assisted gravity drainage process was applied in North Louisiana field to find the optimal field prediction performance through an economic analysis [19]. Furthermore, the GAGD process was suggested for improving oil recovery in the main pay of South Rumaila Oil Field, which is located in south Iraq, through a compositional reservoir simulation study [20]. A higher recovery factor was obtained using CO<sub>2</sub>-assisted gravity drainage mechanism (recovery factor equal to 32.72%) as compared to continuous gas injection CGI and Water Alternating Gas (WAG) methods (12.35% and 11.37%, respectively) [21, 22,

23] . On the other hand, new studies presented and integrated downhole water sink with GAGD process to improve recovery in the reservoir with high water cut [24, 25].

In this study, a CO<sub>2</sub>-assisted gravity drainage mechanism was implemented on a non-dipping horizontal type reservoir using a prototype (laboratory-scaled) numerical simulation model to investigate the effects of various operational constraints (CO<sub>2</sub> injection pressure, CO<sub>2</sub> injection rate , and oil production rate) on this mechanism for a reservoir with an active bottom water drive.

### 3- Description of CO<sub>2</sub>-Assisted Gravity Drainage Simulation Model

The simulation model is a black oil model with a 2D Cartesian grid system which was scaled down from real reservoir geometry and developed using the CMG Implicit Explicit (IMEX) simulator. A total of 36 Cartesian grids were used (3 grids in the i-direction, 1 grid in the j-direction and 12 grids in the k-direction which represent 12 layers), as shown in Figure- 2. The geometry of the simulation model and the reservoir parameters were scaled down from a homogeneous isotropic reservoir with an active bottom water drive. The depth to Water Oil Contact (WOC) was equal to 35cm and the primary gas oil contact (GOC) was set to zero



**Figure 2-** Simulation model showing the grid top and the location of injection and production wells.

In this study, a water-wet system was considered with connate water saturation  $S_{wc} = 0.125$  and residual oil saturation  $S_{orw} = 0.13$  for oil–water system. For gas- oil system, the critical gas saturation  $S_{gc}$  was 0.02 and residual oil saturation  $S_{org}$  was 0.2. To construct the relative permeability curves for the gas-oil system, Corey [26] correlation with an exponent of 2 was constructed, while the relative permeability curves for the oil-water system were scaled down from the real reservoir data. The three-phase relative permeability curve was obtained using stones'II [27] model and the capillary pressure effects for the gas-oil and oil-water systems were neglected. The initial pressure for the model was 130 kPa while the saturation pressure was 101.3 kPa. N-decane with sp.gr. 0.76 was used as reservoir fluid and CO<sub>2</sub> with sp.gr. 1.5189 at s.c as injected fluid. Table-1 summarizes the aforementioned details. Carter Tracy infinite acting model [28] was selected to simulate the bottom aquifer. The porosity value was constant (homogeneous) from layer 1 to 7 with a value of 24.5%, while for the remaining layers it was 30%. Horizontal permeability in I directions was assumed to be 20000 md with a vertical to horizontal ratio ( $K_v/K_h$ ) equal to 0.1, while the rock compressibility was assumed to be  $5.8 \times 10^{-7}$  1/kpa, as listed in table 1 below. Initialization of these data yielded oil and water in place with values of 651cc and 768.29cc, respectively.

**Table 1-** Simulation model details

Property	Simulation Model
Number of grids	Cartesian 3*1*12
Grid size	10*3*5 cm
Grid thickness	5 cm
Pay thickness	35 cm
Reservoir temperature	25°C
Connate water saturation	12.5%
Vertical Permeability	2 D
$K_v/K_h$	0.1
Oil specific gravity	0.76
Gas specific gravity	1.518
Initial model pressure	130 kpa
Bubble point pressure $P_b$	101.3 kpa
Oil formation volume factor at $P_b$	1.02 m <sup>3</sup> /m <sup>3</sup>
Solution gas oil ratio $R_s$ at $P_b$	3.849 m <sup>3</sup> /m <sup>3</sup>

#### 4- Simulation of the Immiscible GAGD Process

The simulation model was conducted with setting up one horizontal production well above OWC in layer 7, which was perforated for the entire length to produce the gravity drained oil that was displaced by CO<sub>2</sub>. To formulate a gas cap and displace oil in a gravity drainage manner, CO<sub>2</sub> was injected in an immiscible mode through one vertical well which was perforated in layers 1 and 2. The last two layers represent the bottom infinite active water drive which was modeled using the Carter-Tracy infinite acting approach [28]. The bottom water drive aquifer was activated in the simulation model to support pressure maintenance. To represent the concept of the GAGD process, secondary mode immiscible CO<sub>2</sub> flooding was implemented to the under-saturated horizontal type reservoir for a number of simulation runs that extended to 24 hours. The immiscible GAGD process was conducted based on some constraints in the injection and production wells. The operating constraints for these wells were the oil production rate, gas injection rate and the bottom hole pressure for the injection and production wells. In this study, the well constraints for the GAGD process were the maximum oil production rate (MAXSTO) and minimum bottom hole pressure (MINBHP), each for the oil production well. For the gas injection well, the constraints were the maximum gas injection rate (MAXBHG) and maximum bottom hole injection pressure (MAXBHP). The immiscible GAGD process was simulated for nine different scenarios to demonstrate the feasibility of the process in enhancing oil recovery and minimizing water cut using CO<sub>2</sub> gas. Three operation parameters were selected to study their effects on the flow responses (oil recovery factor %) through the implementation of GAGD process for 24 hours prediction period. These parameters were oil production rate, gas injection rate and gas injection pressure. Table-2 summarizes these nine scenarios with their constraints.

**Table 2-** GAGD process constraints for nine cases

	GAGD Process Constraints			
	Injector		Producer	
	MAXBHG,(m <sup>3</sup> /d)	MAXBHP, Kpa	MAXSTO,(m <sup>3</sup> /d)	MINBHP, Kpa
1	0.00144	101.3	0.00144	101.3
2	0.00144	106.8	0.00144	101.3
3	0.00432	106.8	0.00144	101.3
4	0.00432	130	0.00144	101.3
5	0.00864	130	0.00144	101.3
6	0.00432	130	0.00216	101.3
7	0.0188	130	0.00144	101.3
8	0.00432	130	0.00432	101.3
9	0.00432	130	0.00864	101.3

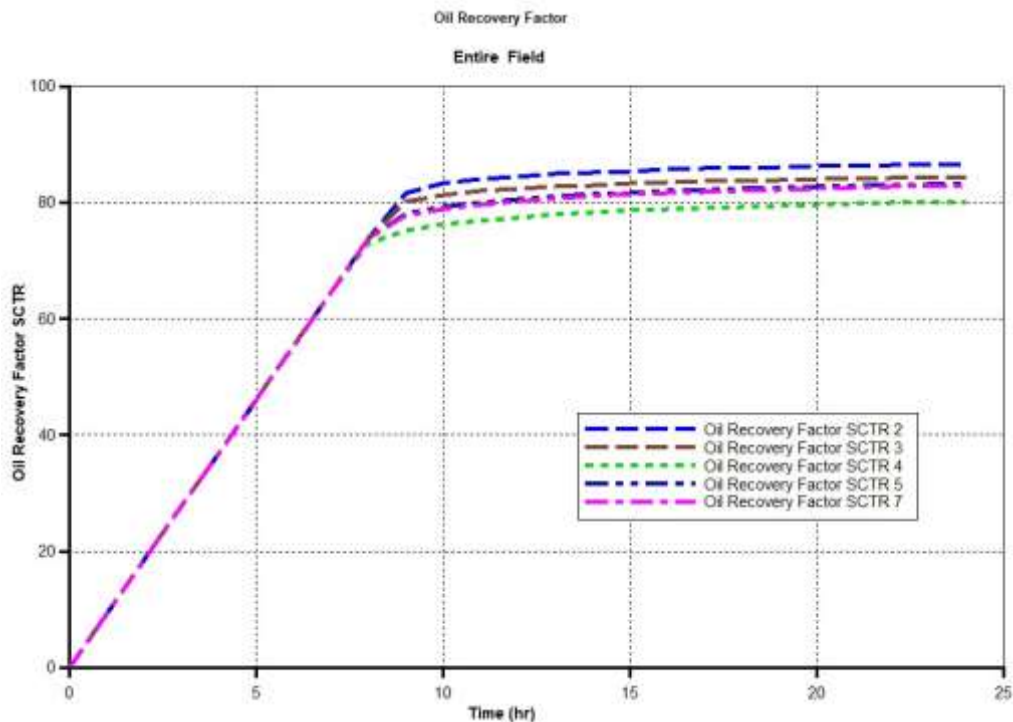
**5- An influence of Gas Injection Rate on Oil Recovery Factor**

Two sets of scenarios were implemented to evaluate the model response to gas injection rate variation. The first set was based on varying gas injection rate with a constant high injection pressure (cases 4, 5 and 7), while the second set depended on varying gas injection rate with a constant low injection pressure (cases 2 and 3).

At the beginning of the prediction period after the implementation of the CO<sub>2</sub>-AGD process, oil recovery factor showed the same increasing linear trend with time for the two sets. During this period, oil production rate was at the maximum rate constraint with a flat producing GOR profile, indicating that oil production occurs at the solution GOR. After that, oil recovery factor curves changed their trend from linear to near horizontal—straightening up after CO<sub>2</sub> breakthrough. Once CO<sub>2</sub> flood front reached the producing well, oil production rate dropped and continued to decline. After CO<sub>2</sub> breakthrough, GOR was increased rapidly while the oil production rate continued declining. Table 3 shows the oil recovery factor corresponding to breakthrough time and ultimate oil recovery for each case. Figures-(3, 4 and 5) present the oil recovery factor, oil production rate and GOR curves with time, respectively.

**Table 3-** Effects of oil recovery factor corresponding to breakthrough time and ultimate oil recovery for each case.

case	Time of breakthrough, hr.	Oil recovery factor at breakthrough, %	Ultimate oil recovery, %
4	8	73	80
5	8.2	73.7	83.2
7	7.8	73	82.9
2	8.6	81.6	86.5
3	8.4	80.3	84.3



**Figure 3-** Oil recovery factor for cases 2, 3, 4, 5 and 7.

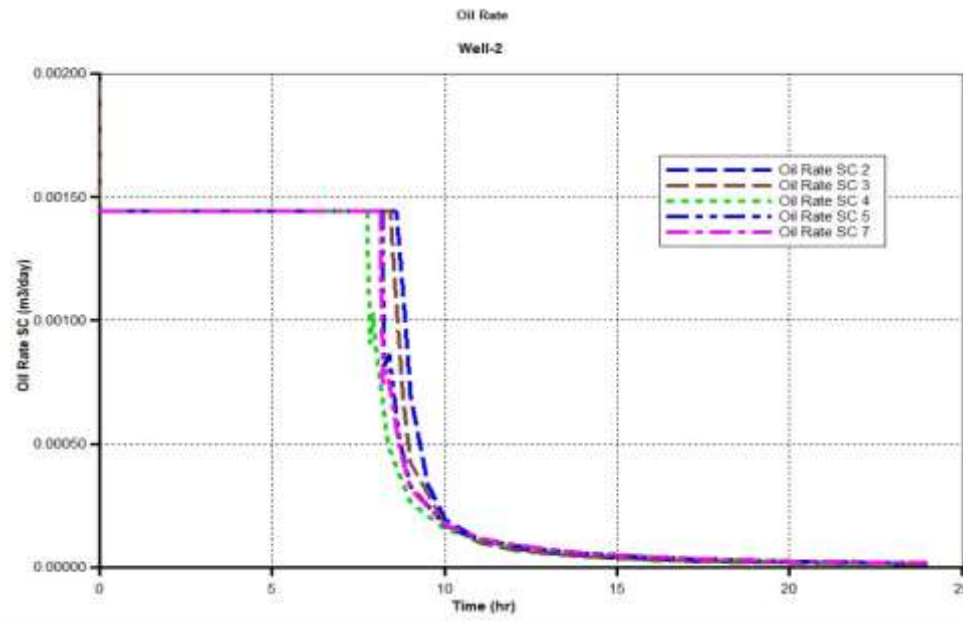


Figure 4 - Oil production rate for cases 2, 3, 4, 5 and 7.

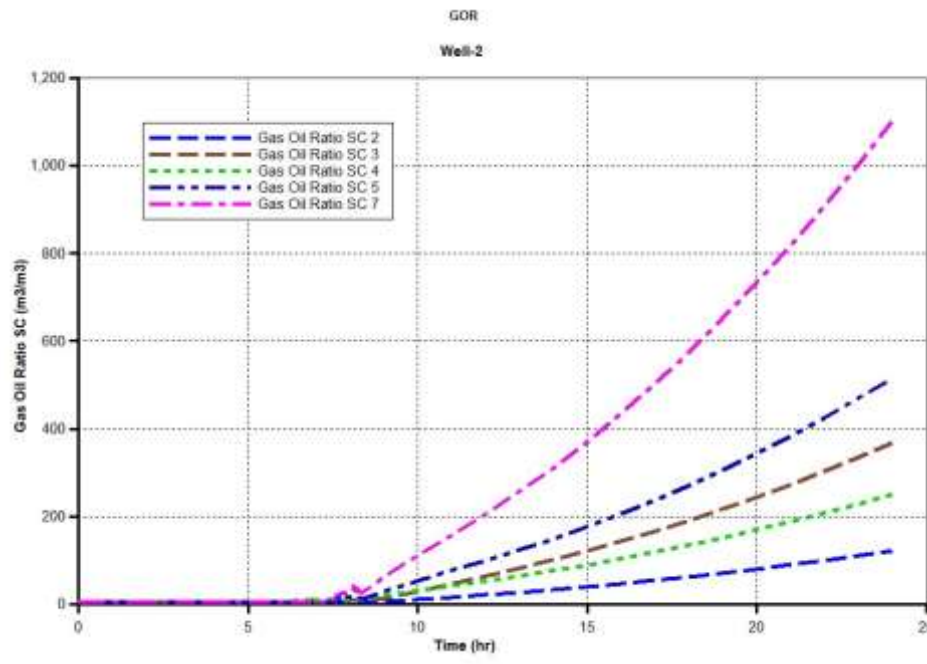


Figure 5- GOR for cases 2, 3, 4, 5 and 7.

From the above mentioned results, the following notes could be drawn; cases 4, 5, and 7 with high injection pressure equal to 130 kPa and injection rate equal to 0.00432, 0.00864 and 0.0188, respectively, showed an increase in oil recovery factor with increasing injection rate for case 4 and 5. The gain in oil recovery at cases 5 and 7 was higher than that for case 4 by 3%, which was due the efficient sweep out of the oil zone by CO<sub>2</sub> resulting from increasing gas injection rate which delays the arrival of CO<sub>2</sub> flood front. On the other hand, the different behavior in case 7 comes from the increasing in gas injection rate higher than the critical gas injection rate causing unfavorable displacement efficiency. Comparison between case 2 and 3 as related to oil recovery factor showed a decrease from 86.5% to 84.3% with increasing gas injection rate from 0.00144 m<sup>3</sup>/day to 0.00432 m<sup>3</sup>/day with low gas injection pressure (106.8 kPa). The reason behind the difference between the two sets is that the injection rates must be controlled with injection pressure to provide constant reservoir pressure behind the gas oil front to satisfy the Cardwell and Parsons criteria [13] of gravity drainage mechanism. This leads to better displacement efficiency and keeps the solution gas velocity in the oil

zone such that the oil becomes dispersed and falls freely under gravity. Figure- 6 shows the average pressure behavior for all cases. From this figure, one could imply that GAGD process could also maintain the reservoir pressure. Further increases in oil recovery since the beginning of CO<sub>2</sub> breakthrough give an evidence of the existence of gravity drainage oil recovery, which leads to form continuous thin oil films flowing between the gas and water phases and then draining towards the producer under gravity.

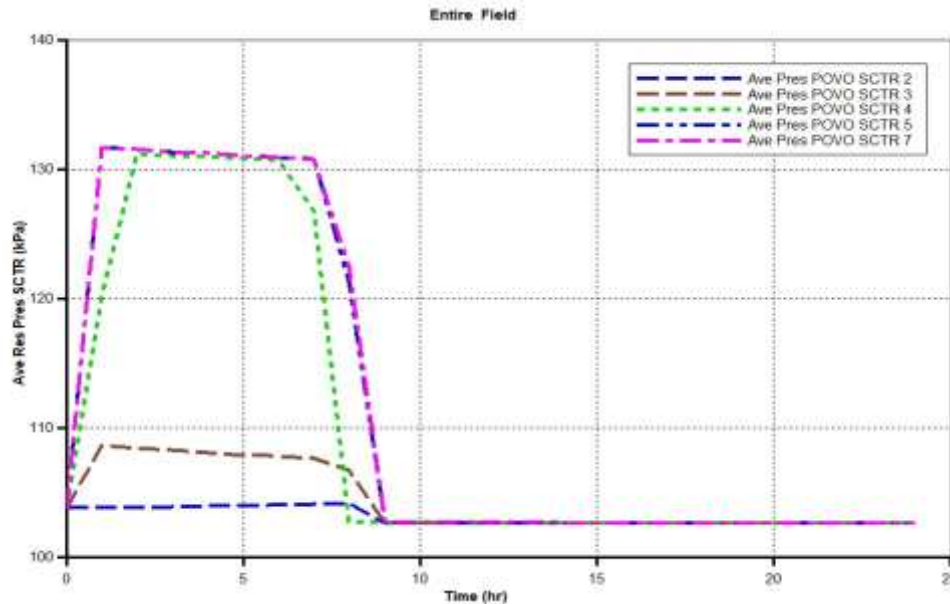


Figure 6- Average pressure for cases 2, 3, 4, 5 and 7.

**6- Effects of Oil Production Rate on Oil Recovery Factor**

In this study, four scenarios were selected to study the effects of oil production rate variation on oil recovery (cases 4, 6, 8 and 9), with a maximum production rate constraint equal to 0.00144, 0.00216, 0.00432 and 0.00864 m<sup>3</sup>/day, respectively. The values of injection pressure and rate were 130 kPa and 0.00432 m<sup>3</sup>/day, respectively. The comparison between these cases showed an increase in the ultimate oil recovery factor and a decrease in oil recovery at breakthrough time with an increase in oil production rate. Table 4 provides the values of oil recovery at time of breakthrough and ultimate oil recovery for each case. Figure- 7 shows the oil recovery factor with time for each case.

Table 4- Effects of injection pressure on oil recovery factor corresponding to breakthrough time and ultimate oil recovery for each case.

case	Time of breakthrough, hrs.	Oil recovery factor at breakthrough%	Ultimate oil recovery%
4	7.5	73	80
6	4.9	69	82
8	2.3	65	86
9	1.8	60.8	86.5

These results also show that case 9 provides higher ultimate oil recovery factor and an earlier time of breakthrough as compared to the other cases. At lower oil production rate, the well produces for a longer time at the consistent maximum production rate constraint, then the production drops very fast, indicating the vertical sweep out of the oil zone and the arrival of the CO<sub>2</sub> flood front. For higher oil production rate, such as that in cases 8 and 9, CO<sub>2</sub> flood front arrival was observed to occur earlier as compared to case 4, whereas GOR continued to rise significantly, as shown in Figure-9.



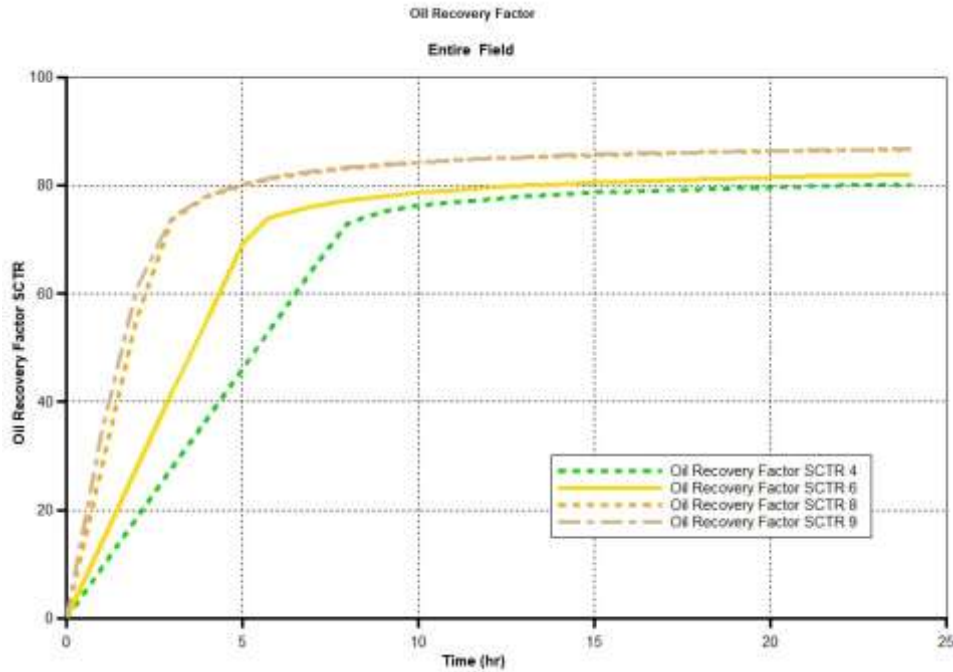


Figure 7- Oil recovery factor for cases 4, 6, 8 and 9.

Figure-8 shows the oil production rate with the production time for all cases. To keep the gravity drainage as the primary recovery mechanism, controlled oil production rate must be considered to allow domination of the gravity force over the viscous force. The gravity stable displacement occurring during the application of the GAGD process with increasing oil production rate leads to higher recoveries.

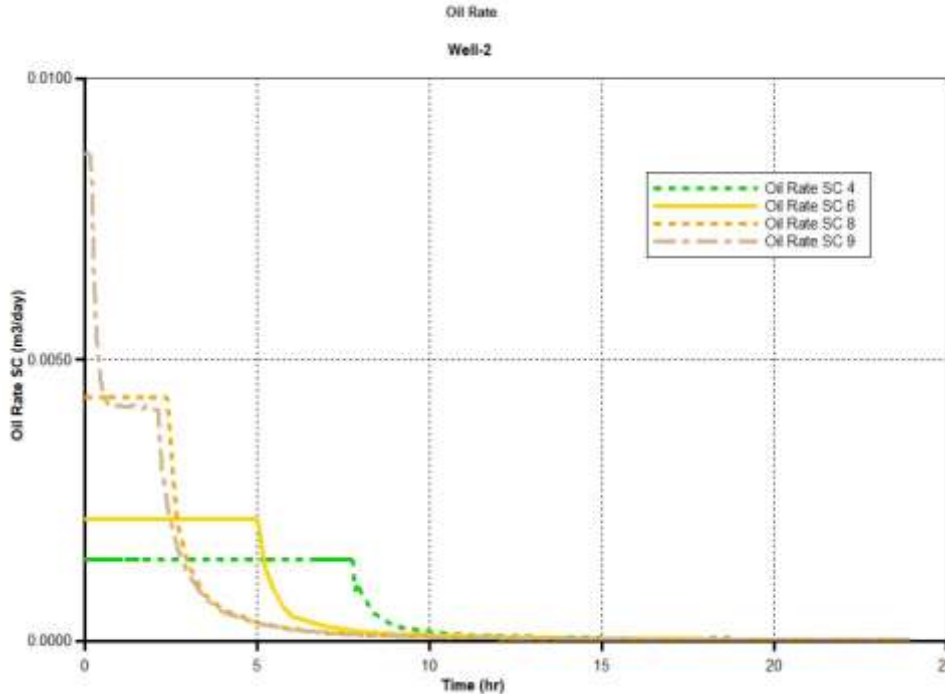


Figure 8- Oil production rate for cases 4, 6, 8 and 9.

Furthermore, with increasing oil production rate, high GORs and WORs were noticeable. From these results, we could suggest reducing the production rate after gas breakthrough to control higher GOR and WOR. Figure-9 shows the WOR and GOR curves.

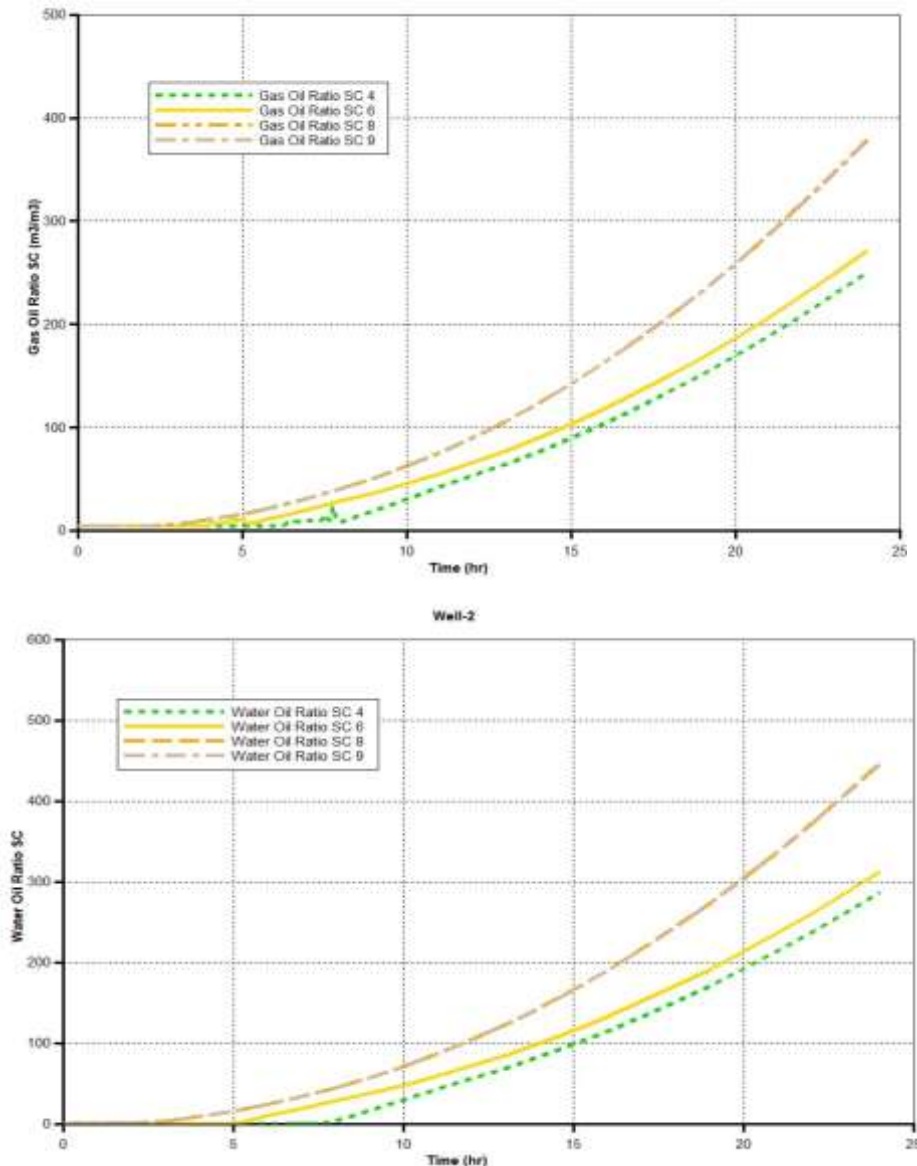


Figure 9- WOR and GOR curves for cases 4, 6, 8 and 9.

### 7- Effects of Gas Injection Pressure on Oil Recovery Factor

The effects of varying gas injection pressure at the same injection rate on oil recovery factor were observed through the implementation of two sets of scenarios. The first set was represented by case 1 and 2, with constant injection rate equal to  $0.00144 \text{ m}^3/\text{day}$  and injection pressure that varied from 101.3 kPa to 106.8 kPa for cases 1 and 2, respectively. The second set was through cases 3 and 4, with constant injection rate equal to  $0.00432 \text{ m}^3/\text{day}$  and injection pressure of 106.8 kPa and 130 kPa for cases 3 and 4, respectively. The comparison between cases 1 and 2 showed a slight decrease in the ultimate oil recovery factor with increasing injection pressure, with values of 87.53% for case 1 and 86.5% for case 2. A similar behavior was noticed when comparing the ultimate oil recovery factor values for cases 3 and 4, which showed a decrease in ultimate oil recovery with increasing injection pressure from 84.3% for case 3 to 80% for case 4. High pressure gas injection reduces the density difference between the gas and oil and leads to less recovery. Figures- 10, 11 and 12 represent the results of oil recovery factor, oil production rate and GOR, respectively, with different injection pressures. This further implies that increasing the injection pressure could help to maintain the reservoir pressure behind the gas oil front, as in cases 4, 5 and 7. It can be clearly seen that the controlled oil production rate, injection gas rate and gas injection pressure provided the nearly

constant average reservoir pressure. This keeps the velocity of gas solution in the oil zone such that oil becomes dispersed and drops freely under gravity.

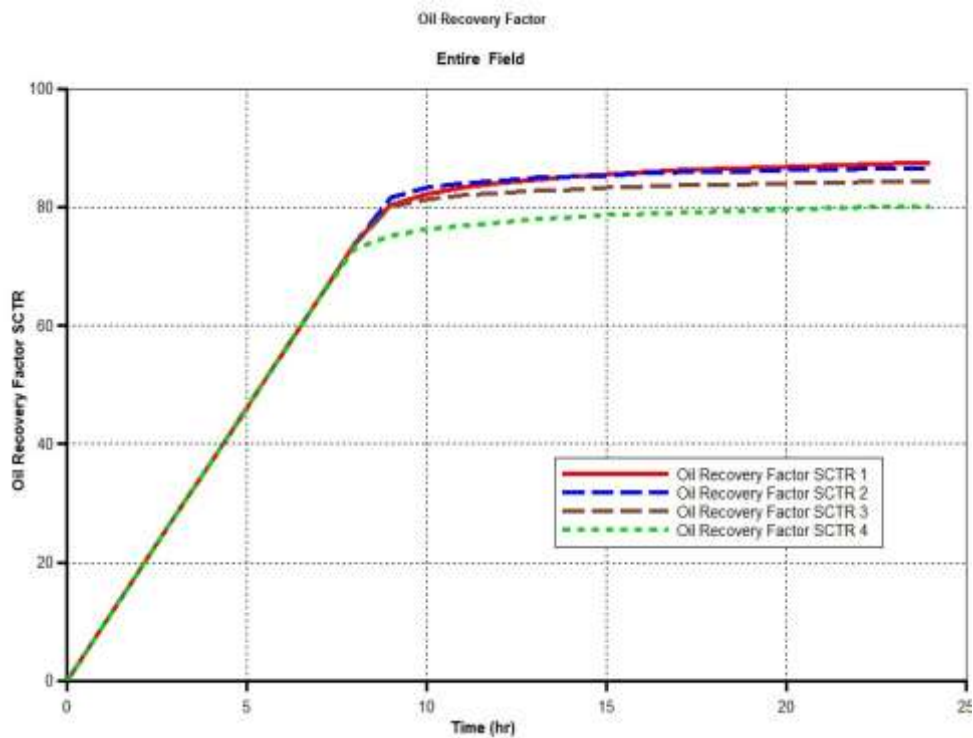


Figure 10- Oil recovery factor for cases 1, 2, 3 and 4.

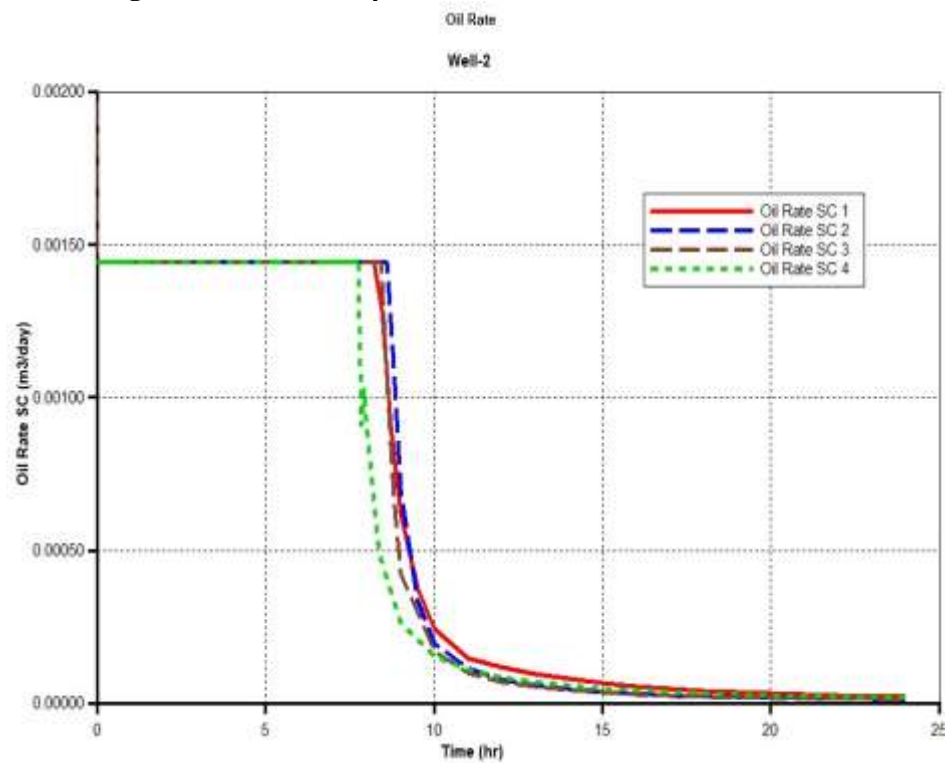


Figure 11- Oil rates for cases 1, 2, 3 and 4.

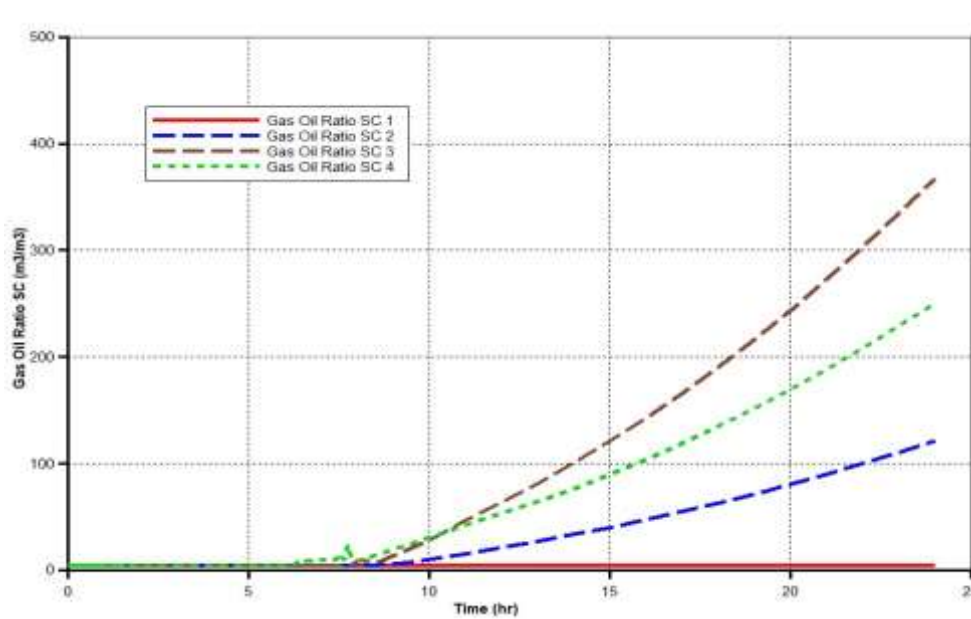


Figure 12- GOR for cases 1, 2, 3 and 4.

## 8- Conclusions

A simulation model based on the physical model is built to precisely evaluate the CO<sub>2</sub> flooding performance through the GAGD process and beyond the physical model limitation. The main conclusion can be introduced as follows:

1. Oil recovery through CO<sub>2</sub>-Assisted Gravity Drainage processes is sensitive to gas injection pressure, gas injection rate and oil production rate.
2. For a given high gas injection pressure and oil production rate, the higher the gas injection rate, the higher is the oil recovery factor.
3. For a given low gas injection pressure and oil production rate, the higher the gas injection rate, the lower is the oil recovery factor.
4. For constant injection parameters, increasing oil production rate leads to an increase in the ultimate oil recovery factor and to a decrease in oil recovery factor at the time of breakthrough.
5. Increasing oil production rate leads to early breakthrough.
6. For a given gas injection rate and oil production rate, increasing injection pressure causes oil recovery factor to decrease. After CO<sub>2</sub> breakthrough, a sharp decline in oil production rate occurs through the immiscible CO<sub>2</sub> -Assisted Gravity Drainage processes.
7. Increasing oil production rate leads to increased WOR and GOR after CO<sub>2</sub> breakthrough.

## 9-Acknowledgments:

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