NUMERICAL SIMULATION AND SENSITIVITY ANALYSIS OF GAS OIL GRAVITY DRAINAGE EOR

By

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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the

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Approved by,

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CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgement, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

AHMAD SHARIF BIN ABD RAHMAN

ABSTRACT

This study aims to shed some light on NUMERICAL SIMULATION AND SENSITIVITY ANALYSIS OF GAS-OIL GRAVITY DRAINAGE EOR. The purpose of this project is to investigate the effects of the parameters that control the process (for example; rate of the gas injection and oil production) and reservoir heterogeneities on the overall performance of immiscible gravity drainage enhanced oil recovery (EOR). Reservoir simulation studies will be conducted to map effective combinations of these parameters with respect to the oil recovery performance. Simulation runs yield several figures and plots, in which depicts the results of analysis. This document is a dissertation which encompasses a background of the study, a problem statement, the objective and scope of study, the relevancy and feasibility of study within the scope and time frame, the literature review, the outline of the research methodology, and project activities with key milestones.

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I am grateful to Allah, my Lord and Cherisher, for guiding me to conceptualize, develop and complete my final year project, Numerical Simulation and Sensitivity Analysis of Gas Oil Gravity Drainage EOR. Indeed, without His Help and Will, nothing is accomplished.

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Table of Contents

LIST OF FIGURES

CHAPTER 1

1 INTRODUCTION

1.1 Project Background

Gas injection either in the immiscible or miscible mode (largely CO2) is the key process amongst the major contending methods of enhancing oil recovery. It can be carried out either in secondary or tertiary stage of the producing life of the reservoir in continuous mode, alternating cycles of water and gas or in gravity drainage mode. Continuous gas injection methods are largely impaired by the viscous instabilities, the severe gas-oil gravity segregation and the poor volumetric sweep efficiency. Moreover, the larger difference of the density between the injected gas and the in-situ reservoir fluid leads to severe gravity segregation effects. The cumulative effect is an uncontrolled gas flood front leading to the premature gas breakthrough in the producing wells and the unfavorable mobility ratio culminating into the severe viscous fingering. Further modifications in the injection modes could not completely eliminate these recovery impeding factors. Therefore, a method that uses the natural density based gravity segregation of the fluids to recover the bypassed oil in the unswept regions looks to be a more promising option.

Gravity forces are recognized to play an important role at nearly every stage of the producing life of the reservoir, whether it is primary depletion, secondary water or gas injection scheme or tertiary enhanced or improved oil recovery methods. They always compete with the viscous (flow rate per unit area) forces and the capillary (ratio of the fluid/fluid forces to the grain size) forces occurring in porous media in addition to the vertical barriers in the form of heterogeneity. In presence of these impeding factors less dense fluid gets trapped in the producing zone, further diminishing the oil recovery performance. Conversely, gravity forces can be taken into advantage through the gravity drainage mechanism to maximize oil recovery from the oil bearing zone under investigation. A number of investigations carried out in the laboratories and in the field (Bangla et al., 1991; Chatzis et al., 1988; Da Sle and Guo, 1990; Kulkarni and Rao, 2006) suggest the significance of the gas-oil gravity drainage process in view of the higher oil recoveries obtained in contrast to the conventional gas injection EOR methods. Gravity drainage by gas injection is commonly implemented in either dipping or pinnacle reef type reservoirs.

1.2 Problem Statement

1.2.1 Problem Identification

The main difficulty in the gas-oil gravity drainage EOR process mechanism is to optimize the oil recovery in the reservoir. This is very closely related to the effects of the parameters that control the process; which are rates of the gas injection and oil production. Apart from that, reservoir heterogeneities play the big role in the mechanism. Since heterogeneity in porosity and permeability do influenced on vertical sweep efficiency, gas injectivity, vertical communication between layers, gravity crossflow, and fluid channeling, therefore the overall oil recovery performance of the reservoir will also be impacted.

1.2.2 Significant of the Project

A better understanding of Gas-Assisted Gravity Drainage (GAGD) will be achieved by simulating the effects of changes in injection and production rates based on mobility, heterogeneity in porosity and permeability, and physical arrangement of wells, on recovery performance.

1.3 Objective and Scope of Study

1.3.1 Objectives

a. To simulate the EOR-assisted gas-oil gravity drainage using simulation software within several parameters.

b. To determine the effective combinations of these parameters that will optimize the oil recovery, since the parameters are affecting sweep efficiency.

   i. Study the effects of well physical arrangement.

   ii. Study the effects of injection and production rate (mobility).

   iii. Study the effects of porosity heterogeneity.

   iv. Study the effects of connate water saturation.

1.3.2 Scope of Study

a. Familiarization of terms and theory related to the study.

b. Reading papers and journals that relevant to the study.

c. Familiarization of the simulation software that is going to be used in this study.

d. Conducting simulations of gas-oil gravity drainage EOR to see the effects of mobility, heterogeneity in porosity and permeability, and well physical arrangement on the sweep efficiency and recovery performance using simulation software from CMG.

1.4 Relevance of Project

At a time when the oil production using primary and secondary recovery become uneconomical, it is wise to start the enhanced oil recovery method. Enhanced oil recovery, EOR, has been the object intensive research for the past decades. Many EOR processes are aimed at recovering more oil from depleted reservoirs which still contain as much as 50% or more of the original oil in place.

This study will produce simulation models based on sensitivity analysis in which to observe effects of several parameters towards enhancing oil recovery for gas-oil gravity drainage. This will be investigated by learning the effects of injection and production rates, the effect of type of injection well, as well as permeability and porosity heterogeneity effect; in which all of them are with respect to the oil recovery performance.

1.5 Feasibility of the Project within Scope and Time Frame

a. Papers and journals for referencing purpose can be downloaded from the website, www.onepetro.org without any charge imposed to the student.
b. The simulation software (by CMG) required for the simulation work is available in computer laboratory at Academic Block 15 complete with how-to-use manual.
c. Since the study is on the simulation, no other materials other than the software and a computer are needed.

CHAPTER 2

2 LITERATURE REVIEW

2.1 Enhanced Oil Recovery

As production from oil-bearing reservoirs matures, the need for enhanced oil recovery becomes increasingly important; EOR then becomes the only alternative for revitalizing the matured reservoirs. The target oil for all the EOR processes is the residual oil that is left behind after primary and secondary production modes. EOR is the recovery of additional oil from an oil reservoir by injection of materials not normally present in the reservoir.

The oil recovery profile over the life of the reservoir is broadly classified as primary, secondary and tertiary recovery modes. Primary recovery is oil recovery by natural drive mechanisms inherently present in the reservoir. Natural drive oil recovery mechanisms include solution gas, water influx, and gas cap or gravity drainage (Muskat, 1949). Secondary recovery refers to techniques, such as gas cap injection or water injection, whose purpose, in part, is to maintain the reservoir pressure. Tertiary recovery techniques refer to any technique applied after secondary recovery, which includes chemical flooding, thermal processes (steam flooding, steam stimulation, etc.), miscible processes(CO_2 miscible flooding, hydrocarbon miscible flooding, etc.).

EOR encompasses the oil recovery techniques that could be applied in either secondary or tertiary stages. EOR results principally from the injection of gases or liquid chemicals and/or the use of thermal energy. The EOR processes primarily provide a supplementary mechanism to the depleting natural drive mechanism of the reservoir, such as pressure maintenance, wettability alteration, and mobility control.

2.2 Gravity Drainage Theory

Gravity drainage is defined as a recovery process in which gravity acts as the main driving force and where gas replaces the voidage volume (Hagoort, 1980). Gravity drainage has been found to occur in primary phases of oil production through gas cap expansion, as well as in the latter stages wherein gas is injected from an external source. Muskat (1949) provides a detailed review on the effects of gravity forces in controlling oil and gas segregation during the primary-production phase of gas drive reservoirs. It was suggested that the most efficient type of gravity-drainage production would be an idealized case wherein no free gas is allowed to evolve in the oil zone by maintaining the reservoir pressure above its bubble point, or by pressure maintenance at current GOR levels (Muskat, 1949).

The importance of gravity drainage as an important oil recovery mechanism has been well recognized. Gravity drainage has been observed to occur during gas injection (Muskat, 1949) as well as in the stripper stages of volumetric reservoirs (Matthews and Lefkovits, 1956). Field and laboratory experience has shown that that gravity drainage, under certain conditions, can result in very high oil recoveries and also, that gravity drainage is one of the most effective mechanisms of developing an oil field.

2.3 Factors Affecting Gravity Drainage

Gravity has long been recognized as one of the three important natural forces for expelling oil from the reservoir rock, along with edge water drive and solution gas drive. However, the quantification of oil recovery due to drainage has long been a concern.

Calhoun (1955) suggests that if drainage was occurring, those wells lowest in the structure should recover the highest amount of cumulative oil. During the early life of the reservoir, the reservoir tends to produce by solution gas drive, depending upon how much pressure drawdown is available. Although the primary mechanism is solution gas drive, some drainage is still evident in the reservoir during the production period at the lower part of the reservoir. However, when the reservoir pressure depletes, gravity drainage seems to be taking place at greater portions of the reservoir (Lewis, 1943).

2.3.1 Wettability

The wettability of a reservoir rock is a critical factor in determining the displacement effectiveness and ultimate oil recovery by displacing fluids, such as gas or water. Kovscek et al. (1993) suggest that since most wetting fluids tend to occupy the smallest and most hydrodynamically resistive pore channel, wettability is a prime factor in controlling multiphase flow and phase trapping.

Three broad classifications of homogeneous wettability are (i) water-wet, (ii) oil-wet, and (iii) intermediate-wet. The wetting characteristic of a reservoir rock is a critical factor in the determination of residual oil saturation after a given production scheme. A water-wet formation tends to expel more oil from the porous space in the early life of oil production. However, oil in the form of lenses tends to remain in the larger pore spaces because of capillary action. The need for EOR hence arises at these conditions in order to extract the otherwise lost oil. Gas injection EOR has been efficient in the recovery of this residual oil owing to reduction of interfacial tension and enhancement of film flow in the porous media. (Kulkarni, 2004)

2.3.2 Capillary Pressure

The distribution of oil, gas, and water in the reservoir pores is controlled by their capillary interaction and the wetting characteristics of the reservoir rock. Whenever immiscible phases coexist in the porous media, as in essentially all processes of interests, surface energy related to the fluid interfaces influences the distribution, saturations, and the displacement of the phases.

Most of the EOR processes tend to reduce the interfacial forces existing across the interface of the oil with injected fluid. However, in immiscible processes, characterized by high IFT, capillary force exists and traps the non-wetting fluid in the pore space.

Lewis et al. (1942) suggested that the self-propulsion of oil downward through sand under the impulse of its own weight occurs in two zones. At the top, where the liquid is in contact with free gas, the sand is only partially oil saturated and capillarity controls the flow. Below the base of this capillary zone, which corresponds to a free surface, the sand is saturated or nearly saturated with liquid and flow follows hydraulic laws. Therefore, the complete knowledge of the capillary action in the porous media is necessary to predict the saturations and displacement of the displaced phase.

Kantzas et al. (1988) presented equations to predict the saturations of each phase inside the capillaries of arbitrary pore sizes. Capillary pressure versus saturation plots for the three phase systems in capillaries of regular pore geometries were also developed. Li and Horne (2003) developed an analytical model based on capillary pressure curves to match and predict the oil production by free-fall gravity drainage. The model was able to match the experimental and numerical simulation data of oil recovery as well as the oil production data from Lakeview pool and Midway sunset field. These analytical models may find application in predicting recovery in the proposed GAGD process.

2.3.3 **Heterogeneity**

No reservoir is completely homogeneous; all reservoirs are geologically unique. Therefore, it is unreasonable to assume that if a production scheme is successful in one reservoir it will necessarily be successful in another. However, knowledge of the geological structure of the reservoir can help us predict weather or not a particular recovery scheme should be implemented in it.

Fayers and Lee (1992) suggest that severely adverse viscosity ratio may cause viscous fingering in heterogeneous reservoirs. The viscous fingering tendencies are dominated by channeling through the higher permeability pathways of a heterogeneous reservoir. Fractured systems provide examples of highly heterogeneous reservoirs.

The ratio of vertical to horizontal permeability (K_V/K_H) is a major factor that represents the reservoir heterogeneity effects. The magnitude of cross flow mechanisms involves interplay between viscous pressure difference, capillary pumping, and relative permeability modification. However, capillary pressure effects control the cross flow mechanism in a tertiary mode.

CHAPTER 3

3 RESEARCH METHODOLOGY

Below is the methodology and general flow of this project.

3.1 Project Activities

Develop a problem statement and objective of research based on the initial findings and review of journals and books which relates to the research title, also from the discussion with the supervisor.

↓

Understanding comprehensively the main concept of displacing mechanism for Enhanced Oil Recovery through intensive review of EOR reservoir engineering books

↓

Research on the theory and displacing mechanism behind the application of GAGD to improve the recovery of oil through books, journals, and research papers.

↓

Review of the main screening criteria and previous field application of GAGD in EOR.

↓

Develop an initial hypothesis to provide solutions to the problem statement.

↓

Develop a detailed methodology and procedures for conducting the required simulation to achieve the objectives

↓

Conduct simulation studies through sensitivity analysis of reservoir heterogeneities, injected and produced fluid properties, and displacement patterns in GAGD.

↓

Summarize all the findings and the analysis of the simulations results by preparing a written report and presentation.

Figure 1: Project Activities

3.2 Brief Explaination on Simulation Work

For the simulation work, it is going to be done using a set of software provided by CMG. The set of software are: [22]

a. IMEX – full featured Black Oil simulator, models the flow of three phase fluids in gas, gas-water, oil-water, and oil-water-gas reservoirs. It models in one, two, or three dimensions, including complex heterogeneous faulted structures.

b. WINPROP – is used for modeling the phase behavior and properties of reservoir fluids.

c. Builder – is an application used in the preparation of reservoir simulation models.

WINPROP will be used to characterize the fluids that will be used in the simulation. Tutorial for modeling the EOR mechanism can be found in the manual that comes with the software.
The reservoir input data needed for IMEX simulation software will be created using Builder. Then, data file from WINPROP (fluid characterization) and Builder will be imported to IMEX. IMEX is going to simulate the flow of fluids injected and displaced during GAGD process in the formations.

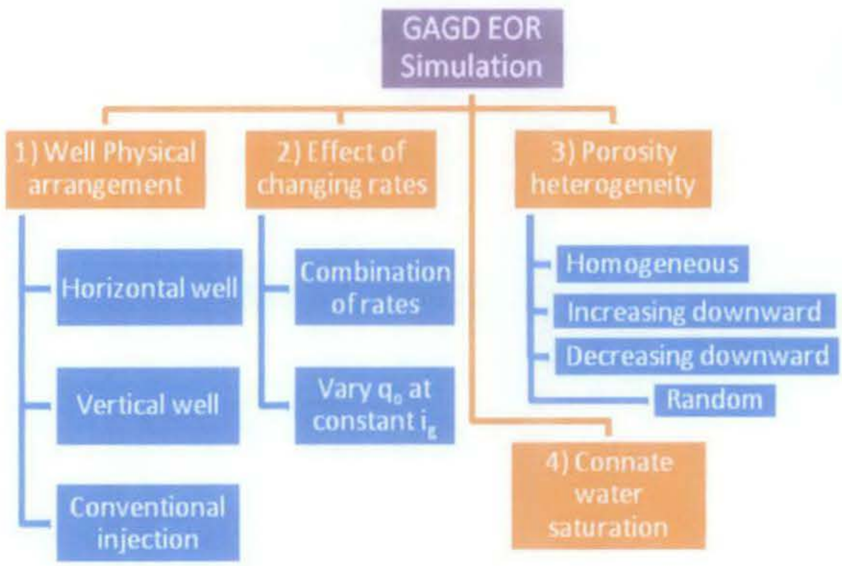

Figure 2: Simulation runs

3.3 Tools, Materials, and Equipments

The tool required for this study is simulation software provided by Computer Modelling Group Ltd. (CMG). The software will be use to simulate GAGD process mechanism.

3.4 Project's Gantt Chart and Key Milestones

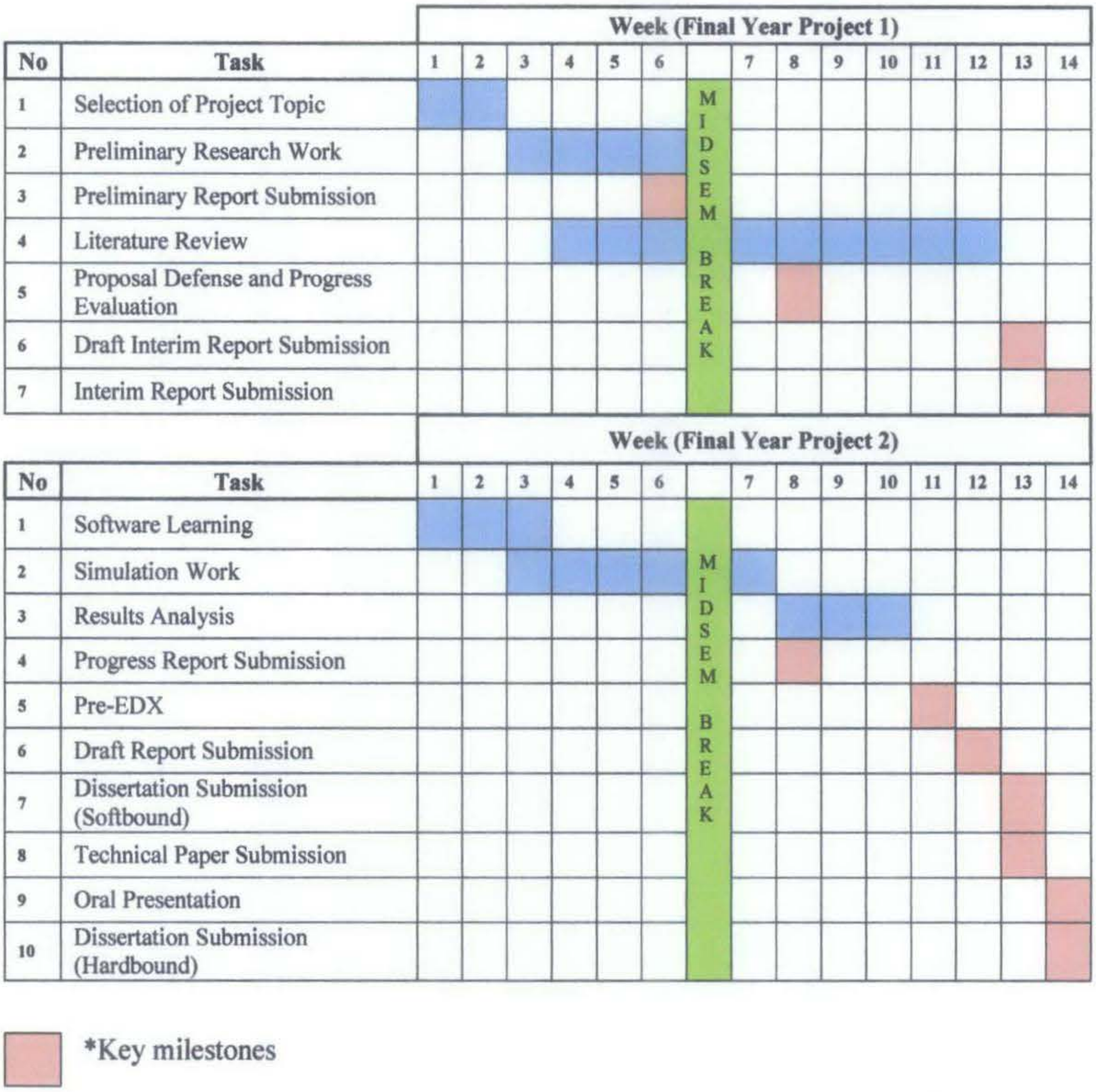

Figure 3: Gantt chart with key milestones

CHAPTER 4

4 RESULTS AND DISCUSSION

4.1 Reservoir Simulation Studies

Sensitivity analysis of operational parameters controlling GAGD process is investigated through reservoir simulation runs using CMG simulator: IMEX, an implicit explicit black oil simulator, and Builder.

4.2 Reservoir Model Description

Reservoir model is a hypothetical system with conventional Cartesian grids as indicated in Table 1. Other basic data listed in Table 1 are adopted from West Hackberry, USA field data.

Property	Reservoir model
Reservoir properties	Top depth, 5,000 ft Thickness, 1,500 ft
Pressure reference	3,200 psi at 6,200 ft
Grid properties	20 x 15 x 10 (100ft x 60ft x 150ft)
Gas oil contact, ft	5,450
Water oil contact, ft	6,200
Reservoir temperature, F	205
Porosity, %	27.6
Permeability	1000
Connate water Swc, %	19
Oil API gravity	33
Bubble point pressure, psi	3,295
Oil FVF at Pb	1.285
GOR, scf/STB	500

Table 1: Reservoir model details

Black oil was invoked to simulate three-phase flow of fluids. Reservoir fluid used is a 33° API black oil with a solution gas with a gravity of 0.65. Pressure, volume and temperature properties of reservoir fluid are generated using correlations incorporated in Builder. Connate water (0.19), critical gas (0.06) and end point saturations of oil, gas and water in a water-wet system are assigned in Builder to calculate relative permeability values. All Corey exponents are set as 2.0. Gas-oil contact (GOC) and WOC are at depths of 5,450 ft and 6,200 ft, respectively, with pay zone thickness of 750 ft. Model initialization yielded in-place volumes of oil, water and gas as 10.74 MMSTB, 11.33 MMSTB and 12.98 BCF, respectively.

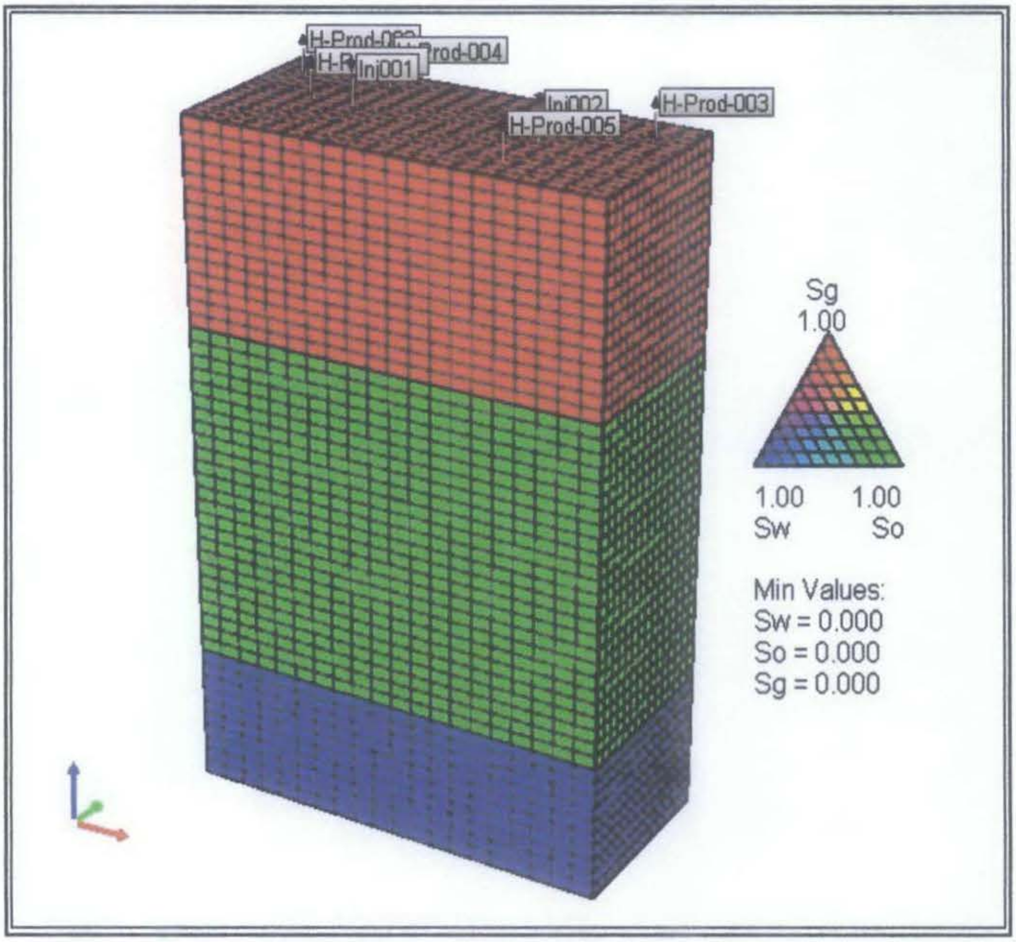

Figure 4: Reservoir model in 3D view

4.3 Field Development

Field development was undertaken with drilling of 5 horizontal production wells (perforated in Layer 8) and 2 vertical injection wells (perforated in Layer 2). The entire field was put on production [target of 500 BPD per well] and gas injection [target of 2,600 MSCF/d per well] in August 2011 until August 2031.

4.4 Effect of Well Physical Arrangement

To study the effect of well physical arrangement on oil recovery performance, three different methods were simulated:

I. Five vertical production wells (located at I-Layer 18) and two vertical injection wells (located at I-Layer 3) were drilled and perforated in each oil zone layer.

II. Five vertical production wells (perforated at K-Layer 6, 7 & 8) and two vertical injection wells (perforated at K-Layer 2) were drilled.

III. Five horizontal production wells (located at K-Layer 8) and two vertical injection wells (perforated at K-Layer 2) were drilled.

Gas injection and oil production rates used are 2,600 MSCF/D and 500 BPD, respectively, for each well.

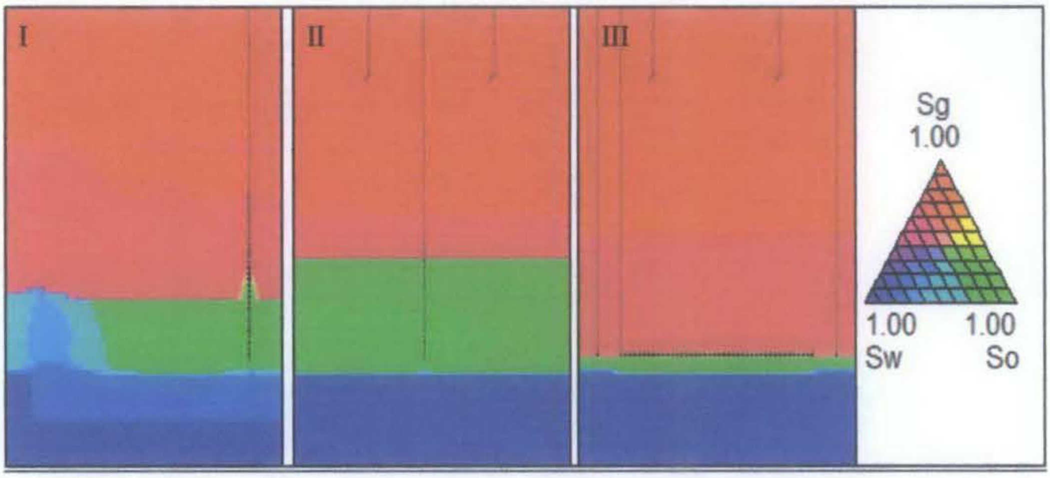

Figure 5: Ternary saturation after 15 years of production. (I) Conventional method (gas is injected at oil zone). (II) GAGD method with vertical production wells. (III) GAGD method with horizontal production wells.

Method III yielded better oil recovery and prolonged gas breakthrough period, as depicted in Figure 6, compared to Method I and II.

Method	I	II	III
Gas breakthrough (years)	3	7	11
Oil recovery after 15 yrs (%)	56.0	65.4	76.1

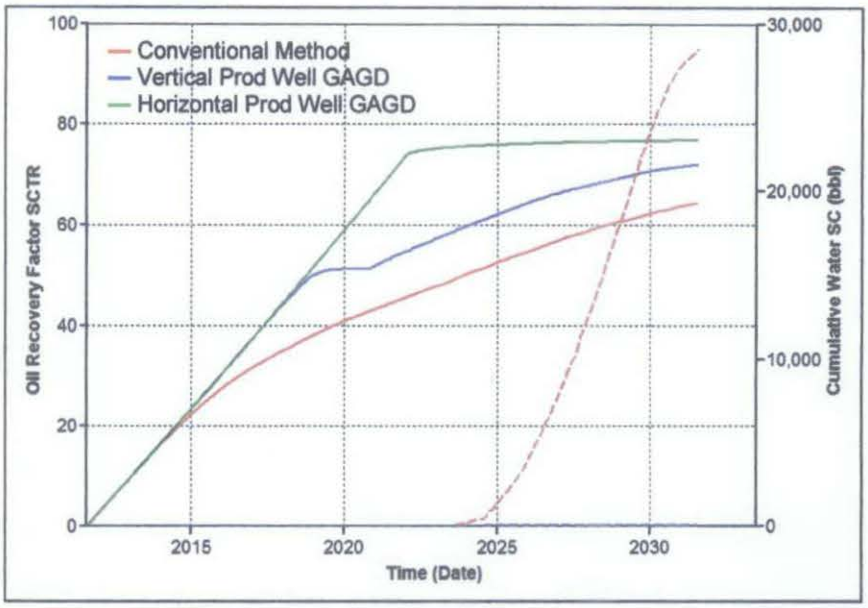

Figure 6: Recovery performance in three different production methods

4.5 Effect of Gas Injection and Oil Production Rates

Two approaches are adopted. In the first approach, reservoir response to gas injection and oil production rates is evaluated in 4 sets of values (Case I to IV). Second approach is based on varying oil production rates at a gas injection rate of 2,600 MSCFD (Table 2).

Rate Combinations		
Case	i_g (Mscf/d)	q_o (bpd)
I	900	245
II	2600	500
III	3400	670
IV	4200	800
Varying q_o at constant i_g		
A	2600	320
B	2600	600
C	2600	780

Table 2: Rate constraints for rate sensitivity analysis

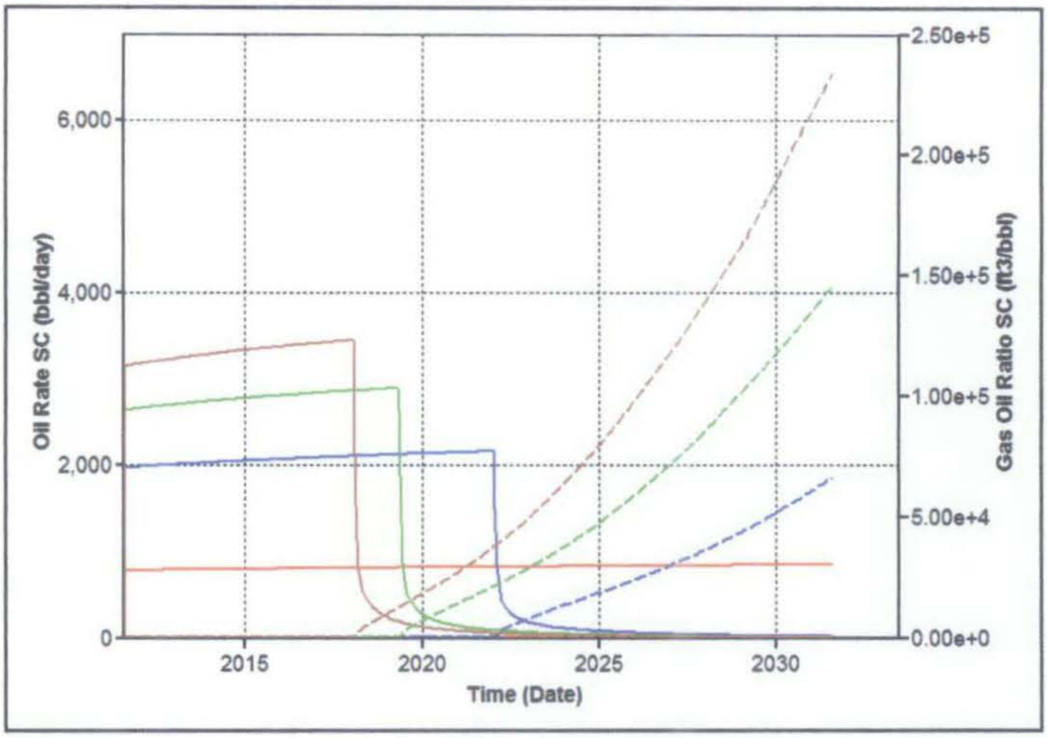

Figure 7: GAGD performance in four gas injection and oil production rate combinations.

In Case I rate combination, oil rate and GOR remained almost constant through as shown in Figure 7. For Case II, higher oil production is obtained compared to the previous case. Oil production rate remained almost constant until January 2022. During this period, producing GOR remained near its solution GOR values, stabilizing at 500 ft^3/bbl. Beyond this stage, oil production declined rapidly (see Figure 7). Corresponding GOR started to rise indicating that the gas floodfront reached in Layer 8. First gas breakthrough occurred at this stage. Gravity drainage after gas breaktrough could have come from oil flowing in the form of continuous thin films between the gas and water phases and then draining under gravity towards producer.

Higher rate combination (Case III) yield better oil recovery performance. Oil production rate is higher compared to Case II until gas breakthrough. Producing GOR did not change noticeably and remained at the solution GOR values because of the pressure maintenance at near constant values. Rise in producing GOR, containing the solution and injection gas, is observed when gas floodfront reached layer 8 in 2019 (3 years earlier than Case II). When gas breakthrough occurs, producing GOR abruptly increases to maximum of 150,000 ft^3/bbl.

At rate constraints of 4,200 MSCFD and 800 BPD (Case IV), higher oil production is obtained. It took only 7 years to reach Layer 8. GOR sharply increased in 2018 with the maximum value of 225,000 ft^3/bbl when GOC reached wells. Oil production mechanism before and after gas breakthrough is similar as obtained in Cases II and III.

Oil recoveries obtained include 76.0% (Case II), 76.4% (Case III) and 76.6% (Case IV) OOIP. Analysis of cumulative volumes of the reservoir oil produced show that a combination of higher gas injection and oil production rates (Case III and IV) yielded insignificant cumulative oil production over previous Case II. As Case II provided more stable oil recovery and lower GOR pattern, it was selected for the subsequent simulation runs.

Further studies of varying oil production rates at constant gas injection rates (2,600 MSCFD) were carried out in three settings (see Figure 8). At 320 BPD production rate, oil recovery by gravity drainage is prolonged therby delaying gas breakthrough by 6 years against base case of 500 BPD. Lower GOR and lower cumulative recoveries were the characteristics of Case A. For 600 BPD (Case B), gas breakthrough was shortened by 2 years and by 4 years when 780 BPD was used (Case C).

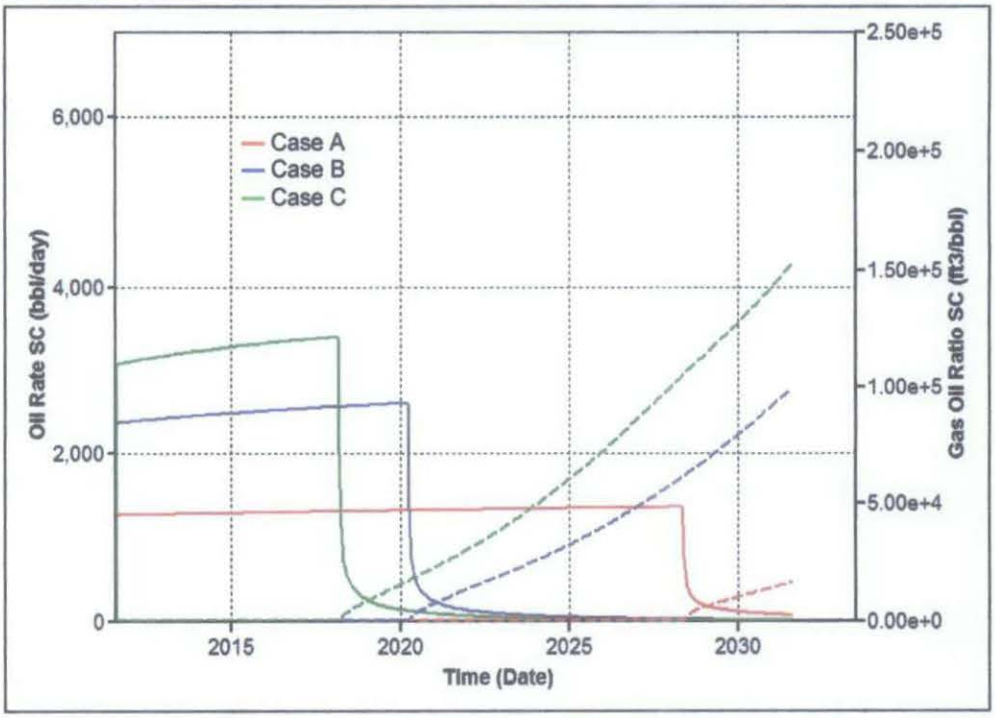

Figure 8: Effect of the varying oil production rates at constant gas injection rates on GAGD oil recovery.

Case	I	II	III	IV	A	B	C
Gas breakthrough (years)	15	11	8	7	17	9	7
Oil recovery after 15 yrs (%)	73.0	76.0	76.4	76.6	64.0	76.1	76.2

4.6 Effect of Porosity Heterogeneity

Heterogeneity delays breakthrough in vertical gravity stable floods because of physical dispersion and reduced gas channeling through high permeability layer. In horizontal floods, K_v/K_h (vertical to horizontal permeabilities) ratio is mainly influenced by viscous, capillary, and gravity forces. Therefore, heterogeneities in top-down gravity drainage EOR methods may help to improve injectivity and reservoir sweeps.

Three sets of porosity values were used in this study.

Porosity Heterogeneity Settings			
Layer	Set-I	Set-II	Set-III
1	0.18	0.15	0.42
2	0.2	0.17	0.38
3	0.22	0.19	0.34
4	0.24	0.27	0.33
5	0.28	0.27	0.28
6	0.28	0.28	0.27
7	0.28	0.28	0.24
8	0.22	0.33	0.2
9	0.22	0.38	0.16
10	0.22	0.44	0.14

Table 3: Porosity heterogeneity settings

In first set, uniform porosities are assigned in the oil zone (0.28) and the water zone (0.18) while it is assumed it is increasing downwards in gas zone. Water zone has a lower porosity than the upper oil zone. In second setting, porosity of the formation is increasing downwards from the top layer. In third setting, porosity of the formation is decreasing downwards from the top layer. Gas injection and oil production rates used are 2,600 MSCFD and 500 BPD, respectively. Results obtained in these settings are then compared to the results obtained in the homogeneous porosity (0.276) setting.

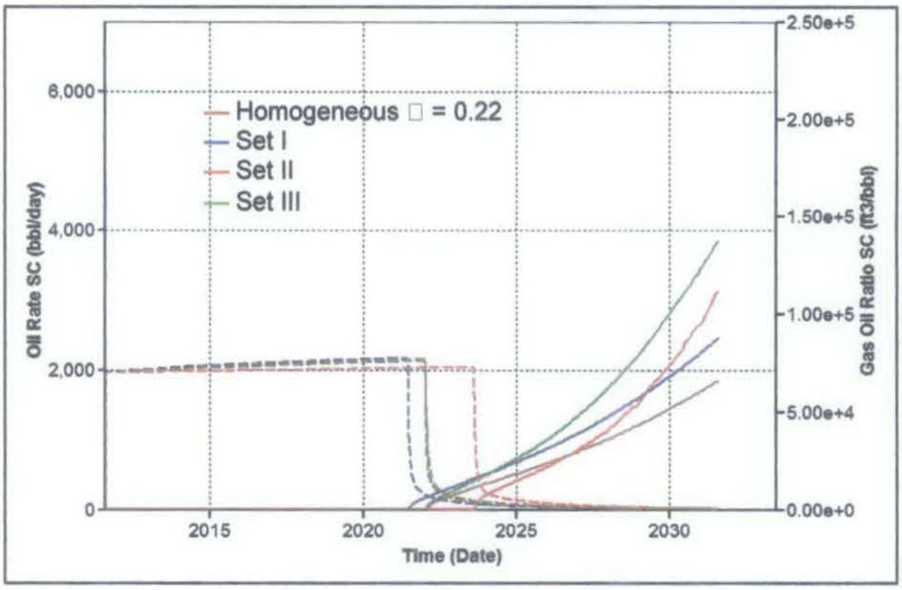

Figure 9: Effect of porosity heterogeneities on GAGD performance

Lowest oil production is obtained in Set I of three porosity settings. Gas breakthrough occurred 1 year earlier than homogeneous setting. In Set II, more stable and higher oil production is observed. Gas breakthrough occurred 1 year later than homogeneous setting. In Set III, gas breakthrough occurred at the same year as homogeneous setting. However, noticeably highest GOR value (140,000 MSCF/D) was obtained.

These results of porosity heterogeneity studies point out that the reservoir with porosity increasing downwards is favoured in GAGD process than the other porosity heterogeneity setting. This is due to the fact that the increasing pore volume downwardly improves the sweep efficiency under gravity effect.

Set	I	II	III	Homogeneous
Gas breakthrough (years)	10	12	11	11
Oil recovery after 15 yrs (%)	77.2	80.9	78.5	76.1

4.7 Effect of Connate Water Saturation

In this study, connate water saturation (S_{wc}) is varied as 0.25, 0.19 (base case) 0.15 and 0.08 in the rate constraints of 2,600 MSCF/D injection rate and 500 BPD production rate. Results are presented in Figure 12. S_{wc} of 0.25 resulted in the highest GOR (220,000 ft^3/day). Gas floodfront reached Layer 8 in May 2022, 1 year earlier compared to cases with S_{wc} of 0.19, 0.15 and 0.08. Considerably lower cumulative oil production was obtained.

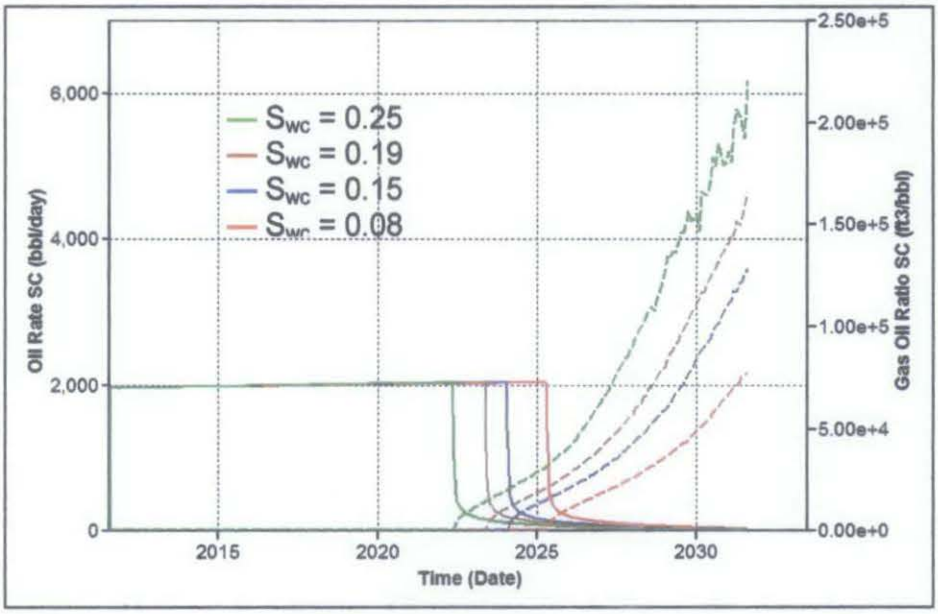

Figure 10: Comparison of GAGD performance at four S_{wc} values: 0.25, 0.19, 0.15 and 0.08.

At lower S_{wc}=0.08, lowest GOR (80,000 ft^3/day) and cumulative oil production is highest among four settings, especially after gas breakthrough.

Lower the fraction of water initially present in pores in the form of connate water, least will be the hindrance to oil drainage under gravity.

S_{wc}	0.25	0.19	0.15	0.08
Gas breakthorugh (years)	11	12	13	14
Oil recovery after 15 yrs (%)	81.1	82.0	82.4	83.2

CHAPTER 5

5 CONCLUSIONS & RECOMMENDATIONS

5.1 Conclusions

- GAGD method using horizontal producing wells yielded the highest oil recovery compared if using vertical producing wells and conventional method.
- Oil recovery through gravity drainage mechanism is sensitive to gas injection and oil withdrawal rates.
- For a given gas injection rate, increment of oil production rate will increase the GOR.
- Heterogeneity in porosity with their values increasing downwardly provides a better gravity drainage recovery. Porosity heterogeneity with increasing downwardly setting provides a better recovery compared to other heterogeneity settings and homogeneous case.
- By lowering the connate water saturation, will yield better sweep efficiency and oil recovery.

5.2 Recommendations

- Simulate using CO_2 injection instead of gas injection, in which more practical and economical.
- Emulate an actual reservoir and take into account the field development history (instead of injecting into a virgin reservoir). Therefore, the increment in oil recovery is more reliable.

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