Gas-Assisted Gravity Drainage in Naturally Fractured Reservoir

by

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Dissertation submitted in partial fulfillment of
the requirement for the
Bachelor of Engineering (Hons)
(Petroleum Engineering)

MAY 2011

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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the
Petroleum Engineering Programme
Universiti Teknologi PETRONAS
in partial fulfillment of the requirement for the
BACHELOR OF ENGINEERING (Hons)
(PETROLEUM ENGINEERING)

Approved by,

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UNIVERSITI TEKNOLOGI PETRONAS
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May 2011

CERTIFICATION OF ORGINALITY

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 acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

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ABSTRACT

The major issue in any successful EOR is to increase sweep and microscopic displacement efficiency. In naturally fractured reservoir, the high permeability contrast between fracture and matrix becomes the main issue on the low oil recovery. The injected gas in conventional gas injection method tends to flow through high permeability fracture channel, displaces some oil in the fractures and moves toward the producer which results in early gas breakthrough. Consequently, most of oil in the matrix is left behind. Therefore, the main objective of this project is to investigate productivity of gas-assisted gravity drainage (GAGD) in naturally fractured reservoir. Previous lab experiment proved the prospect of GAGD as the replacement for existing techniques. In this simulation, an injector and a producer are simulated in a gridblock model. The simulation focuses on three (3) parameters which are horizontal producing well depth; horizontal producing well length and injection rate. Based on simulation result, the author anticipated to see the optimum parameters which give the highest recovery. Besides, the old method which are continuous gas injection (CGI) and water alternating gas (WAG) will be compared against GAGD based on literature review. The scopes of study will be revolving around the crude oil, the use of horizontal well and carbonate reservoir type. For methodology part, PVT data from the selected SPE papers are exported into dual porosity model which originally from Msc. Thesis of University of Texas. The outcome are analyzed and discussed thoroughly.

ACKNOWLEDGEMENT

All praises are due to Allah, The Most Gracious and The Most Merciful. I have been bestowed with countless good things in this life. Therefore I thank Allah for the great opportunity to do this project. Then, I would like to express my sincere gratitude and appreciation to the following people for their continuous support and contribution towards the completion of this work.

First of all, I wish to express my appreciation to the management of Universiti Teknologi PETRONAS for the guidance and opportunity to use its facilities throughout my project completion.

Besides, I would like to extend my deepest gratitude to my supervisor, Mr. Iskandar Dzulkarnain, and Mr. Saeed from EOR Centre for their kind help, guidance and continuous support especially to find the way out when I came to a deadlock in doing this project. They had really helped me a lot from the beginning until the end of this project.

I am indebted to parents as well as all my fellow friends for their support and help especially at the time that I really need someone to be by my side. Lastly, my acknowledgement also goes to PETRONAS for giving me the opportunity to sponsor my 5-years study at Universiti Teknologi PETRONAS. May Allah reward all of you with His blessing. InsyaAllah.

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CHAPTER 1

INTRODUCTION

1.1 BACKGROUND OF STUDY

The major issue in any successful EOR is to increase sweep and microscopic displacement efficiency. Microscopic efficiency (E_D) is defined as the extent of mobilizing the trapped reservoir residual oil. It is a function of the capillary number (N_c), where N_c is the ratio of viscous to capillary forces. On the other hand, the volumetric sweep (E_V) is defined as the percent of reservoir rock contacted by the injected fluid. It is governed by the mobility ratio and reservoir heterogeneity.

To maximize the efficiency, the capillary number value should be maximized while the mobility ratio should be minimized. Gas injection EOR poses good prospects in field implementation because of excellent E_D which lower interfacial tension between injected gas and reservoir oil. However, the viscosity of commonly injected gases is about one-tenth of the reservoir fluids viscosities has resulted in unfavorable mobility ratios and severe gas-oil gravity segregation in the reservoir. This leads to large un-swept reservoir areas, which resulting in extremely poor E_V.[1]

The introduction of WAG is believed to improve E_V of gas injection but it did not meet the expectation as low recoveries observed in 59 field application reported in some literature review. This poor performance is due to imperfect mobility ratio improvement and increased mobile water saturation which forms water shielding that prevents miscibility condition.

Recently, Gas-Assisted Gravity Drainage (GAGD) has been proven to be efficient. Field tests showed recoveries up to 95% OOIP and laboratory floods showed 100% recovery efficiencies (Ren, 2002). This method employs drainage of oil under gravity forces by gas cap expansion or gas injection at the crest of reservoir which benefits the natural segregation of gas from liquid during injection. The GAGD consists

[1] Satter, A., Bushwalter, J.L., Lgbal, G.M., 2008. Practical Enhanced Reservoir Engineering: Assisted with Simulation Software, PennWell Corporation, Tulsa, Oklahoma, USA, 706 pp.

of horizontal producer placement near the bottom of oil column and vertical injector through the existing well. The injected gas forms a gas zone, while oil and water are pushed down and drained into the horizontal producer. It takes advantage of the density difference between injected gas and reservoir fluid that causing poor sweep efficiencies and gravity override in WAG.

CO_2 is a favorable alternative injection fluid for increasing oil recovery in conventional reservoir. Naturally fractured reservoirs do not meet classic CO_2 injection criteria due to excessive channeling of low viscosity CO_2 through natural fractures. However, with sufficient fracture vertical relief and significant density, CO_2 injection can give significant oil production by gravity drainage displacement. In the case of gas injection in a fractured reservoir, gravity drainage plays an important role especially when there is a high density difference between gas in fractures and oil in the matrix blocks. In high pressure reservoir, the CO_2 density is similar to the oil. This may reduce the gravity force and reduce final recovery compared to hydrocarbon gas. However, CO_2 is highly soluble in crude oil as pressure increases. The dissolved CO_2 swell the oil, reduce viscosity and make oil flow easily to compensate the lack of gravity force between oil and CO_2.

1.2 PROBLEM STATEMENT

1.2.1 Problem Identification

The main issue goal in EOR is to achieve high E_V and E_D which lead to high recovery efficiency. In naturally fractured reservoir, conventional methods is reported as inefficient to recover oil as injected fluid flows through the fracture by bypassing oil in the matrix. In contrast, drainage of oil under gravity force is believed to be the most efficient method to achieve high overall efficiency. The parameters used in GAGD should be identified, followed by deep investigation to achieve the optimum oil recovery.

1.2.2 Significant of the Project

The idea of this project is basically to see the effectiveness of the new gas injection technique, namely Gas-Assisted Gravity Drainage (GAGD) in naturally fractured reservoir. Conceptually, lab experiment results show that this technique has better oil recovery compared to the conventional Continuous Gas Injection (CGI) and Water Alternating Gas (WAG) in conventional reservoir. To investigate the effectiveness of GAGD in naturally fractured reservoir, a simulation is planned to be run in a fractured reservoir model (dual porosity model) to see its effectiveness to achieve high oil recovery.

1.3 OBJECTIVE

The main objective of this project is to investigate the conceptual oil recovery performance by using GAGD in naturally fractured reservoir. There are several parameters that had been focused in the previous research. However, this project is focusing on the following parameters to see their effect on oil recovery factor:

i. *Length of horizontal producer*

Different horizontal producers' lengths are used and effects on recovery are observed. Up to an optimum value, increasing the horizontal length will result in greater drainage area, less pressure gradient towards well, lower water cut, and more chances to cross the fracture network.

ii. *Depth of horizontal producer*

Different producers' depths are focused on and effects on recovery are observed. Theoretically, the deeper horizontal well in the reservoir, the higher oil recovery will be. In fact, there is better sweep efficiency of oil in the matrix above horizontal producers the injected gas pushes the oil downwards towards the well.

iii. *Injection rate*

Different injection rates are used and effects on recovery are observed. Injection rate controls flood front velocity and domination of gravity force. Beyond optimum injection rate, GAGD performance will be adversely affected with unfavorable mobility ratio and low oil recovery. Therefore, optimum injection rate is required to achieve optimum oil recovery.

1.4 THE RELEVENCY OF THE PROJECT

Most of oil producing fields around the world for naturally fractured reservoirs is carbonate formation.[2] The high permeability in the fracture network and its low equivalent porous medium has resulted in early breakthrough of the injected fluid. Therefore, an effective method to recover oil from such reservoir is important to cater this problem and to compensate today's increasing oil demand.

Conventional gas injection enhanced oil recovery (EOR) such as WAG and CGI as demonstrated in many field projects are moderately effective with only 5 to 10% additional recoveries. Other EOR methods such as chemical techniques are expensive and complex. Currently, many lab experimental results show the potential of GAGD to achieve high oil recovery. Thus, this project will further investigate GAGD potential to achieve high oil recovery as reported by previous lab experimental results. It is hoped that this simulation results will give more confidence to use GAGD as an alternative to the current method.

1.5 SCOPE OF THE STUDY

Learning on how to run simulation is very essential, as the model is quite complex with the inclusion of matrix and fracture. In overall, the scope of study is divided into two stages whereby the first stage is the study of background and theories related to this project. The next stage is focusing on the learning on the simulation. Therefore, the scopes of study are:

1. Crude Oil[3]

Reservoir fluids consist of wide variety of crude oil, from heavy to light crude oil. This study is intended for light crude oil which mainly consists of light component. The recovery of light oil will be investigated by using GAGD in naturally fractured reservoir.

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[2] Dr. Roberto Aguilera, "Naturally Fractured Reservoir (Second Edition)".

[3] William D. McCain, Jr. , Pennwell Publishing Company., 1990 The Properties of Petroleum Fluids, *Tulsa, USA, 149 pp.*

2. Horizontal Well

Horizontal well with 90° configuration is used as producing well. This well is located at the bottom of the reservoir. It water-oil contact exist, it should be slightly above the water-oil contact. Experimentally, oil production will increase with the increase of horizontal length up to an optimum value. With this well, greater drainage area, less pressure gradient toward well, lower water cut, and more chance to cross the fracture network are achieved.

3. Type of Reservoir

Naturally fractured reservoirs consist of sandstone and carbonate stone. But, the number of naturally fractured carbonate reservoir is much larger than sandstone. Generally, in fractured reservoir, matrix has high porosity but low permeability whereas fracture has low porosity but high permeability. For this study, real carbonate reservoir rock properties of Cantarell Oil Field are chosen as rock properties in the dual porosity model.

1.6 FEASIBILITY OF THE STUDY

The project is scheduled to be completed in two semesters. The approach that the author planned to use is by using simulation to examine the applicability of GAGD process in different operating modes in naturally fractured reservoir. The investigation will revolve around effect of length of horizontal well, depth of horizontal well in the reservoir and gas injection rate. Oil recovery comparison between GAGD, CGI and WAG at the same reservoir condition will also be made in literature review. Studies and researches have been started since the first semester, whereas simulation began in the second semester.

CHAPTER 2

LITERATURE REVIEW

Approximately 65% of the present world crude oil production comes from carbonate reservoir mostly located in the Middle East, Mexico and Canada. Based on literature review, there are several EOR techniques to recover oil in naturally fractured carbonate reservoirs. Among others are carbon dioxide injection (continuous or WAG), in-situ combustion, steam flooding and chemical flooding. However, gas injections are still the most common EOR method implemented in this lithology type. In the following discussion, the author is focusing on carbon dioxide injections which are Continuous Gas Injection (CGI) and Water Alternating Gas (WAG). Next, the author will discuss on the new Gas-Assisted Gravity Drainage (GAGD) and its potential to replace the current EOR techniques in naturally fractured reservoir based on evidence from literature review he made. On top of that, the author also discusses on the proposed parameters that having potential to optimize oil recovery in fractured reservoir.

2.1 GAS INJECTION TECHNIQUES

2.1.1 Continuous Gas Injection (CGI)

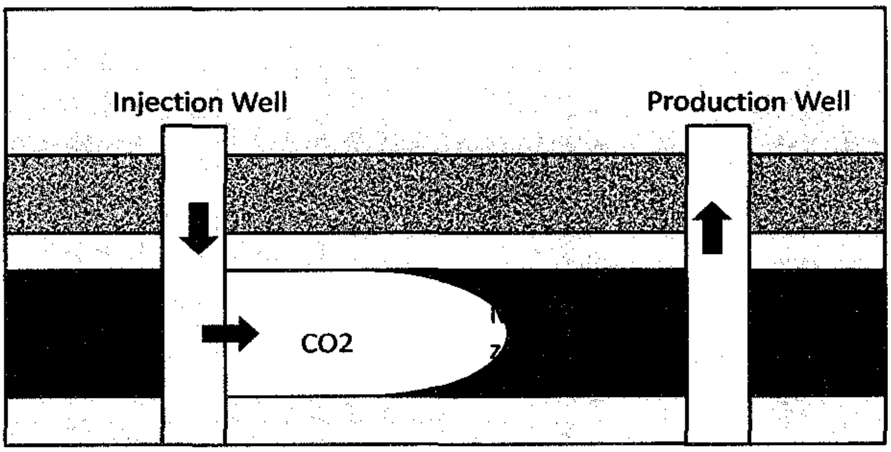

Figure 1: Theoretical Diagram of CO_2 Injection

Basically, during continuous gas injection, CO_2 is injected through vertical gas injection well, from surface down into the reservoir. The injected gas is then flooded horizontally to push the oil towards the producing well before it is recovered at surface. In general, CO_2 is very soluble in crude oil at reservoir pressures. Therefore, it swells the net volume of oil and reduces its viscosity by condensing and vaporizing gas mechanism. Both oil and CO_2 phases can flow together because of low interfacial tension and relative increase in the total volumes of CO_2 and oil phases compared to water phase.[4]

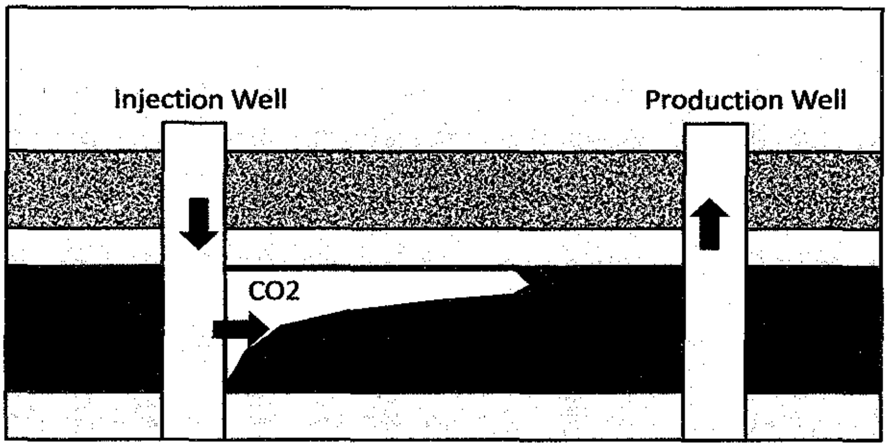

Figure 2: Injected gas bypass oil in reservoir

CGI is purposely carried out to obtain high oil recovery from waterflooded reservoirs using CO_2 gas. According to Shedid *et al.*,[5] CO_2 can improve microscopic displacement efficiency (E_D) by swelling and reducing the oil viscosity. However, CO_2 gas density (0.656 gm/cc @ 239 °F and 5000 psig) would always be less than the oil density (0.87 gm/cc for 30 API gravity oil) even in miscible injection. As shown in Figure 2, this results in low volumetric sweep efficiency (E_V) as the gas would rise to the top of the pay zone and bypass most of the oil in horizontal gas-oil displacement.

Additional to that, Chakravarthy *et al.*[6] reported, CO_2 is not likely to be economical unless significant recycling of gas is performed. In highly heterogeneous reservoirs, CO_2

[4] Lyons, William C.: "Standard Handbook of Petroleum and Natural Gas Engineering (2nd Edition)"

[5] Shedid, S.A., Almehaideb, R.A. and Zekri, A.Y.: "Microscopic Rock Characterization and Influnce of Slug Size on Oil Recovery by CO2 Miscible Flooding in Carbonate Oil Reservoir", *Paper SPE 97635 Presented at the 2005 SPE International Improved Oil Recovery Conference in Asia Pacific, Kuala Lumpur, Malaysia, December 5-6.*

[6] Chakravarthy, D., Muralidaharan, V., Putra, E. and Schechter, D. S.: "Mitigating Oil Bypassed in Fractured Cores During CO2 Flooding Using WAG and Polymer Gel Injections," *Paper SPE 97228 Presented at the 2006 SPE/DOE Symposium on Improved Oil Recovery, Tulsa, April 22-26*

gas has adverse mobility ratio and lose front conformance which cause premature breakthrough when CO_2 flow is horizontal between two vertical wells.

Other than that, Shedid *et. al.*[4] found that miscible CO_2 CGI has recovered up to 96% of IOIP in the laboratory at reservoir conditions by swelling the oil, lowering viscosity and increasing the pressure of the core. Although CO_2 CGI is widely used in conventional reservoirs, however it is not recommended for carbonate field application because it requires 1.5 hydrocarbon pore volume of CO_2 at miscible pressure to achieve high oil recovery which could be very costly.

Table 1 as shown below is the summary of conventional reservoir characteristics that employed continuous gas injection method.[4]

Table 1: Conventional reservoir characteristic in CGI

Crude oil properties	Gravity > 30 API Viscosity < 10 cp High percentage of intermediate hydrocarbon
Reservoir properties	Oil saturation > 30 % PV sandstone or carbonate with minimum fractures depth > 2000 ft
Limitations	Very low viscosity of CO_2 results in poor mobility control
Problems	Viscous fingering tends to occur which cause the CO_2 to bypass much of oil in the reservoir (early gas breakthrough)
Advantages	Possibility to achieve ultimate recovery proportional to the total CO_2 injected

[4] Shedid, S.A., Almehaideb, R.A. and Zekri, A.Y.: "Microscopic Rock Characterization and Influnce of Slug Size on Oil Recovery by CO2 Miscible Flooding in Carbonate Oil Reservoir", *Paper SPE 97635 Presented at the 2005 SPE International Improved Oil Recovery Conference in Asia Pacific, Kuala Lumpur, Malaysia, December 5-6.*

Case Study[7]

The 31,000 acre Midale field is part of a trend of Mississipian carbonate reservoirs in southeastern Saskatchewan. Since 1962, previous waterflood has recovered 20% of 500 million barrels of OOIP. In microscopic level, waterflood displacement efficiency is higher in more accessible Vuggy pore network than in the finer-pored Marly Dolomites. This left high residual oil concentrated in Marly zone high in the reservoir section. Table 2 as shown below summarizes the characteristic of the reservoir. Wax deposition also occurred shortly after the initial tertiary oil production which never occurred during primary and waterflood operation. Hence, deposits were routinely removed by solvent washes.

Table 2: Midale Field characteristic

Porosity	10-15% in Vuggy zone (fracture) 20-30% in Marly (matrix)
Permeability	Matrix 1-50 md Marly is twice of Vuggy
Oil Gravity	29 API
Reservoir Average Pressure	2600 psi
MMP	2250 psi
Observation	1. No CO_2 produced until a month after first injection (CO_2 penetrated large amount of matrix porosity) 2. CO_2 velocity is relatively low because it penetrated significant matrix porosity. 3. Halogen tracers showed that CO_2 flood behaved in a much less heterogeneous fashion (contacted matrix than just fracture porosity). 4. The image from tomography showed CO_2 rising in the reservoir some distance away from injection well. 5. Ultimate recovery is 27% OOIP at the end of injection calculated from saturation logs.

[7] D. Beliveau and D.A Payne, Shell Canada Ltd.: "Analysis of Tertiary CO_2 Flood Pilot in a Naturally Fractured Reservoir", *Paper SPE 22947 presented at the 1991 66th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers held in Dalias, TX, 6-9 April.*

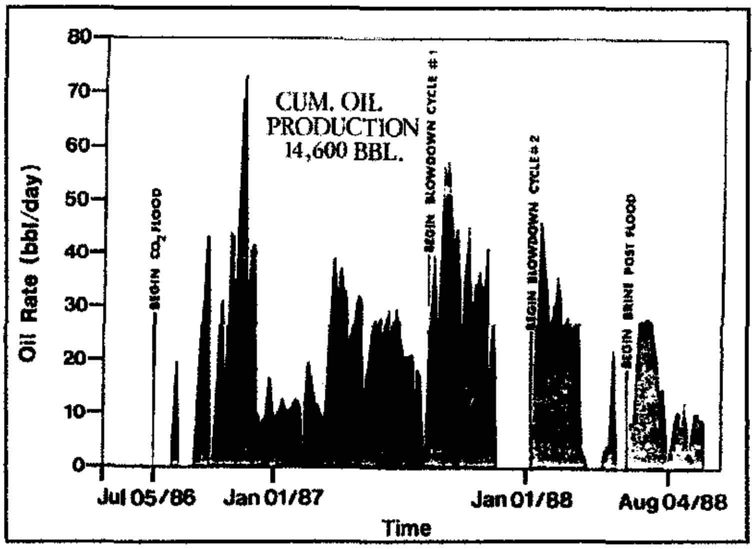

Figure 3: Tertiary oil produced

Figure 3 shows a total of 14,600 barrels (14% OOIP of nominal pilot area) of tertiary oil produced. The ragged of oil production was due to various operational changes during CO_2 flood.

Pilot logging and tomography results confirmed that gravity effects were critical in Midale. In fact, gravity effects are very important in any miscible flood, since solvents are much lighter than reservoir oil. Although CO_2 injection is primarily into more intensely fractured underlying Vuggy limestones, favorable gravity effects enhanced by the natural vertical fractures allow the CO_2 to contact and displace the large Marly EOR target.

Apart from that, diffusion was also an important force for fluid exchange because of very close fracture spacing. However, analyses showed that precipitated Midale asphaltenes dramatically slowed diffusion effect and affect fracture/matrix exchange in Midale.

2.1.2 Water Alternating Gas Injection (WAG)

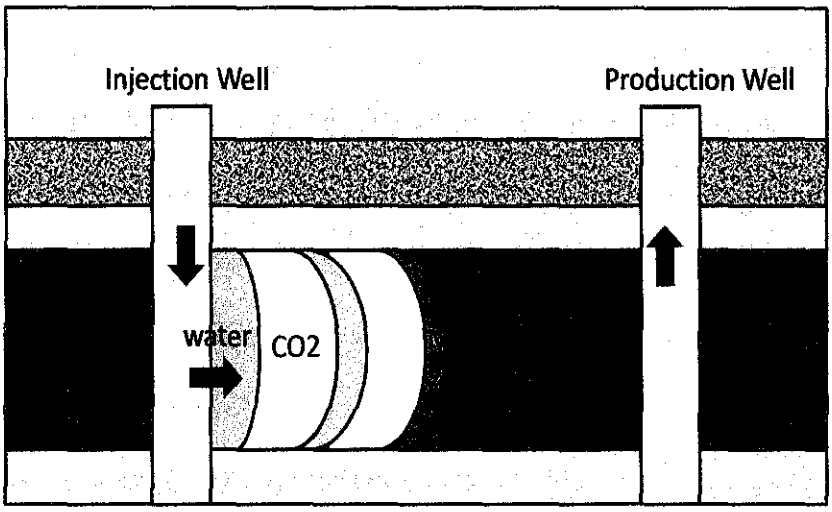

Figure 4: Theoretical diagram of WAG injection

In water alternating gas injection, water and gas are injected alternately from vertical injection well. These two phases are flooded horizontally towards the vertical producing well as shown this figure. Alternate slugs of gas and water are believed to homogenize the injected fluid in order to stabilize the flood front. Plus, if CGI is introduced to obtain high oil recovery from waterflooded reservoir, WAG injection is said to be able to improve both microscopic oil displacement and sweep efficiency of water flooding and continuous gas injection, thus improving overall oil recovery.[8]

This statement is agreed by Kulkarni *et al* who explained that if the injected water and water slugs flowed, excellent sweep efficiency would be obtained, which resulted in high oil recovery.[9]. Chakravarthy *et al,* added that WAG involves alternate injections of small pore volume (5% or less) of CO_2 and water until the desired volume of CO_2 has been injected from vertical well to flood horizontally.[6]

[8] L.M. Surguchev, Ragnhild Korbol, Sigurd Haugen, O.S Krakstad and Statoil A/S.: Screening of WAG Injection Strategies for Heterogeneous Reservoirs", *Paper SPE 25075-Presented at the 1992 European Petroleum Conference, France, November 16-18*

[9] Kulkarni, M.M., Rao, D.N.: "Experimental Investigation of Various Methods of Tertiary Gas Injection", *Paper SPE 90589 Presented at the 2004 SPE Annual Technical Conference and Exhibition, Houston, September 26-29.*

Both Novosel,[10] and Chakravarthy *et al.*[6] mentioned that water volumetric efficiency is better than CO_2 in horizontal flooding because of the relative density between the injected water and reservoir in place.

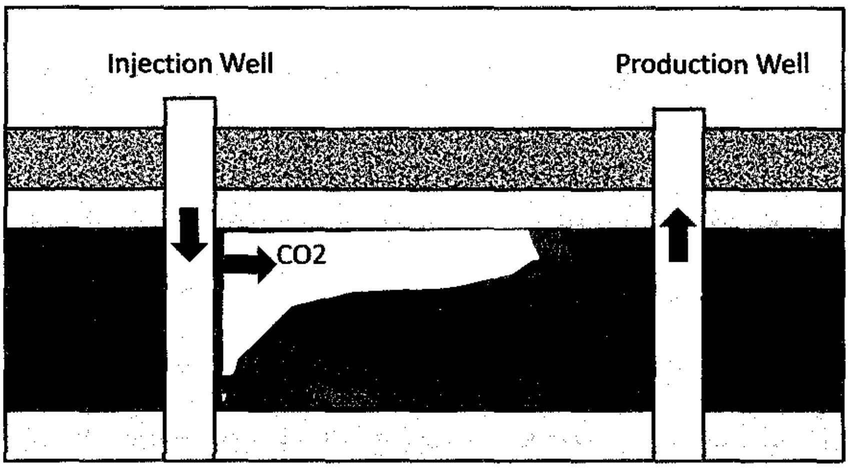

Figure 5 : Injected water and gas bypass oil reservoir

Nonetheless, experience from several field projects showed contradiction. This statement is supported by Mahmoud *et al.*[11] Such gas-water segregation is due to the natural tendency of the injected gas to override and the water to under-ride. The water would sink to the bottom of the reservoir and bypass a much of oil. This eventually resulted in low recoveries.[12]

Chakravarthy[6] also added, the phenomenon as mentioned above causes WAG as not very efficient choice in heterogeneous reservoirs. On top of that, WAG is very sensitive to heterogeneity and vertical segregation, which effects are not present in small diameter

[6] Chakravarthy, D., Muralidaharan, V., Putra, E. and Schechter, D. S.: "Mitigating Oil Bypassed in Fractured Cores During CO2 Flooding Using WAG and Polymer Gel Injections," *Paper SPE 97228 Presented at the 2006 SPE/DOE Symposium on Improved Oil Recovery, Tulsa, April 22-26.*

[10] Novosel, D.: "Initial Results of WAG CO2 IOR Pilot Project Implementation in Croatia", *Paper SPE 97639 Presented at the 2005 SPE International Improved Oil Recovery Conference in Asia Pacific, Kuala Lumpur, Malaysia, December 5-6.*

[11] Mahmoud T.N., and Rao, D.N.: "Mechanism and Performance Demonstration of the Gas-Assisted Gravity-Drainage Process Using Visual Models", *Paper SPE 110132 Presented at the 2007 SPE ATCE, Anaheim, CA, November 11-14*

[12] Rao, D.N., Ayirala, S.C., Kulkarni, M.M., Sharma, A.P.: "Development of Gas Assisted Gravity Drainage (GAGD) Process for Improved Light Oil Recovery", *Paper SPE 89357-MS Presented at the 2004 SPE/DOE Symposium on Improved Oil Recovery, Tulsa, April 17-21.*

core used in the lab.[10] WAG also has been stated to have many difficulties such as water, CO_2 cycling management, heterogeneity, viscous fingering, the need to operate under miscible conditions allowing viscous pressure to dominate the process in the reservoir.[13]

In the past decade, improvements have been made in WAG process by adding some polymers to create a gel like fluid in the reservoir to increase the viscosity of front flooding water and to stabilize the front by plugging high permeability streaks to prevent viscous fingering effects and premature CO_2 breakthrough.[6]

Measures are being taken to account vertical segregation effects in reservoir such as side tracking from horizontal flooding and essentially to perform a gravity stable CO_2 flooding to sweep the areas that have been bypassed by miscible CO_2 or water. It is proven that "Typical MIST (MI Sidetracks) patterns accumulate 3 to 4 times the EOR reserves of conventional vertical well WAG Pattern" from Pruhoe Bay field's experience.[14]

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[6] Chakravarthy, D., Muralidaharan, V., Putra, E. and Schechter, D. S.: "Mitigating Oil Bypassed in Fractured Cores During CO2 Flooding Using WAG and Polymer Gel Injections," *Paper SPE 97228 Presented at the 2006 SPE/DOE Symposium on Improved Oil Recovery, Tulsa, April 22-26.*

[10] Novosel, D.: "Initial Results of WAG CO2 IOR Pilot Project Implementation in Croatia", *Paper SPE 97639 Presented at the 2005 SPE International Improved Oil Recovery Conference in Asia Pacific, Kuala Lumpur, Malaysia, December 5-6.*

[13] Kelly, T.R.:" Utilizing Compositional Simulation for Material Balance and Bottomhole Pressure Calculations in CO2 WAG Floods", *Paper SPE 99714 Presented at the 2006 SPE/DOE Symposium on Improved Oil Recovery, Tulsa, April 22-26.*

[14] Rathman, M. P., McGuire, P.L. and Carlson, B. H.: "Unconventional EOR Program Increases Recovery in Mature WAG Patterns at Prudhoe Bay", *Paper SPE 100042 Presented at the 2006 SPE/DOE Symposium on Improved Oil Recovery, Tulsa, April 22- 26.*

Table below is an example of conventional reservoir characteristic as screening criteria in WAG selection.[15]

Table 3 : Conventional reservoir characteristic in WAG

Crude oil properties	Oil density > 38 API (light reservoir fluid) Oil viscosity < 2 cp
Reservoir properties	Depth > 4000 ft, Temperature 100-200 °F Average permeability < 100 md
Limitations	Optimum performance may occur for a short time with limited extend in reservoir because of heterogeneity
Problems	Water tends to sweep lower part of reservoir, gas tends to sweep upper part of reservoir
Advantages	Optimum conditions of oil displacement by WAG is achieved if gas and water are travelling the same speed

Case Study[16]

This carbonate Middle East Reservoir is located offshore and found at a depth of 8300 ft TVD subsea. It is a Middle Cretaceous carbonate rudist grainstone shoal that has been uplifted by salt to form a four-way dipping anticline. The top of the anticline provides stratigraphic seal on the trap. Structural dips are less than 10 degrees and moderately faulted.

The vertical well pilot operated from 1992 to 1996 with a total of 37 Bscf hydrocarbon gas was injected as WAG over 3 years in the three injectors surrounding the target producer. Regular saturation logging of the observation wells provided important insight into the in-situ characteristics of the gas-flood. Following the cessation of gas injection, the observation well was sidetracked and core taken to investigate residual oil saturation

[15] Manrique, Mayo. And Stirpe.: "Water Alternating Gas Flooding in Venezuela : Selection Candidates based on Screening Criteria of International Field Experiences", *Paper SPE 50645 Presented at the 1996 SPE European Petroleum Conference, The Hague, The Netherland, October 20-22*

[16] C. Schneider, SPE and W.Shi, SPE, ConocoPhilips.:"A Miscible WAG Project Using Horizontal Wells in a Mature, Offshore, Carbonate Middle East Reservoir", *Paper SPE 93606 Presented at the 2005 14th SPE Middle East oil & Gas Show and Conference held in Bahrain International Exhibition Centre, Bahrain, March 12-15*

after the miscible flood. The primary conclusions made were the injected gas was over-riding into the upper, more permeable section of reservoir leading to poor volumetric sweep and gas-flood not efficiently captured by the target producer.

Then, a horizontal well was designed by drilling a single horizontal well injector flanked by 2 horizontal producers. The wells are drilled and completed open-hole near base of reservoir. Gas gravity segregation and override is compensated by the producers' ability to draw the solvent down through the reservoir section. The strategy was 3 equal gas injection cycles of roughly 6 months during winter alternating with 6 month of water injection. The gas injection cycled slug sizes were 0.07 hydrocarbon pore volumes.

In total, gas injection of 21 BCF (0.15 HCPV) was completed in 3 injection cycles in 4 years. As shown in Figure 6, water injection continued following the last gas injection cycle in 2003. To promote the highest chance of reaching and maintaining miscibility pressure over largest reservoir volume possible, pilot reservoir pressure kept as high as possible, but below fracture pressure of injectors.

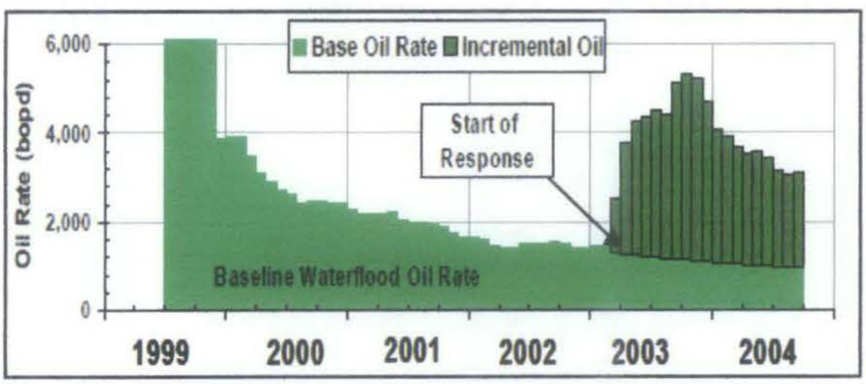

Figure 6 : Oil production rate of Middle East Reservoir

Oil production from pilot test demonstrated clear response to gas injection. The tertiary oil bank arrived was 3 years after the start of injection. The tracers used during injection arrived nearly coincidentally in both wells indicated the incremental gas flood oil banks generated by each injection cycles arrives at the same time. Table 4 as shown below summarizes the characteristic of the reservoir.

Table 4: Carbonate Middle East reservoir characteristic

Porosity	favorable and moderately uniform
Permeability	upper unit (50-200 md) lower unit (< 20 md) Diagenesis enhanced permeability beneath the unconfirmity
Oil Gravity	33 API
Solution Gas Ratio	< 500 scf/bo
Reservoir Pressure	Highly undersaturated
Observation	After history match, the incremental of gas flood is compared to the model case (assuming waterflooded only). The predicted incremental recovery from pilot after 20 years is 6% OOIP

2.1.3 Gas-Assisted Gravity Drainage (GAGD)

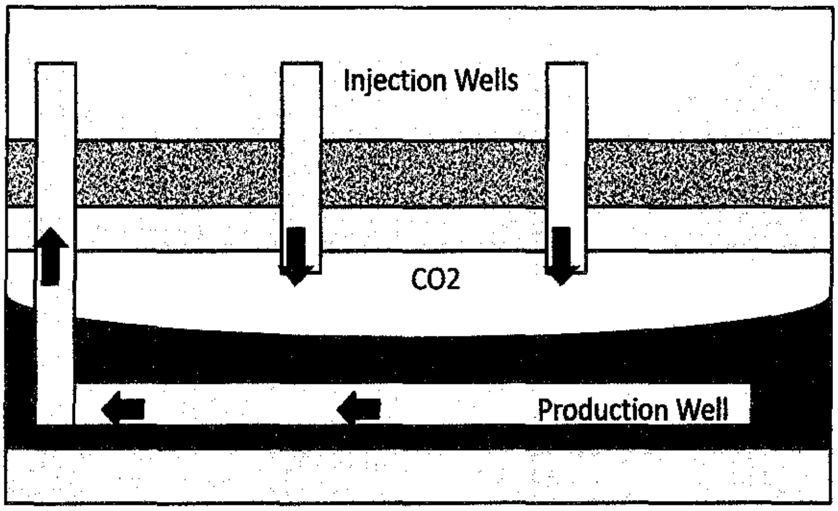

Figure 7: Theoretical diagram of GAGD

Norollah *et al.*,[17] described that GAGD process consists of a horizontal producer at the bottom of the pay zone and vertical gas injection wells at the top of gas cap to provide gravity stable displacement and uniform reservoir sweep. This process benefits the gravity segregation effects and horizontal well technology. Horizontal well is known for having high productivity index (due to large contact with reservoir).

[17] Kasiri, N. and A. Bashiri (2009). GAS-ASSISTED GRAVITY DRAINAGE (GAGD) PROCESS FOR IMPROVED OIL RECOVERY. *International Petroleum Technology Conference. Doha, Qatar*

Norollah agreed with the idea of Rao *et al.*,[12] who claimed that horizontal wells are ideal for the gravity drainage processes. When the natural drive of oil such as gas cap or solution drive has depleted, gravity forces will take over with continued oil production. Horizontal wells are also able to delay gas breakthrough and water encroachment.

Teletzke *et al*,[18] described that when the CO_2 is injected in miscible mode, microscopic sweep efficiency (E_D) will also be very high. Rao *et al.*,[12] among other claimed that injecting CO_2 in GAGD is beneficial as it combines both high volumetric sweep and high microscopic sweep, which has been rarely achieved in the past. CO_2 swells the oil and reduces the viscosity in the microscopic level, keeping the CO_2 gas chamber above the oil. This will lead to a very high volumetric sweep while holding a stable flood front and delay the CO_2 breakthrough.

E. Ghoodjani *et al.*,[19] had explained further on the importance of oil viscosity reduction and oil swelling. The overall viscosity reduction depends on the initial viscosity, where greater reduction for higher viscous crudes. Reducing oil viscosity increases oil relative permeability and reduces residual oil saturation. Swelling is important as residual oil saturation is inversely proportional to swelling factor. The residual oil saturation determines ultimate recovery. Furthermore, the swollen oil droplets will force fluids out of the pores, creating drainage process. This causes droplets that cannot move under present pressure gradient, to move towards production well. The oil swelling also increases oil saturation, therefore increases oil relative permeability, too. Table as below summarized the effect of CO_2 on viscosity and swelling factor from E.Ghoodjani's experiments.

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[12] Rao, D.N., Ayirala, S.C., Kulkarni, M.M., Sharma, A.P.: "Development of Gas Assisted Gravity Drainage (GAGD) Process for Improved Light Oil Recovery", *Paper SPE 89357-MS Presented at the 2004 SPE/DOE Symposium on Improved Oil Recovery, Tulsa, April 17-21.*

[18] Teletzke, G.F., Patel, P.D. and Chen, A.L.: "Methodology for Miscible Gas Injection EOR Screening", *Paper SPE 97650 Presented at the 2005 SPE International Improved Oil Recovery Conference in Asia Pacific, Kuala Lumpur, Malaysia, December 5-6.*

[19] Ghoodjani E, Bolouri SH (2011) Experimental Study of CO_2-EOR and N_2-EOR with Focus on Relative Permebility Effect. *J Pet Environ Biotechol 2:106. Doi: 10.4172/2157-7463.1000106*

Table 5: Effect of CO_2 on oil viscosity and swelling factor

	Oil Viscosity (CP)	Swelling Factor
Initial	11.868	1
CO_2	8.639	1.1022

Kurkarni *et al*,[9] found that in the case of viscous fingering, natural vertical segregation of reservoir fluid would take place provided the injection rate slowed down or stopped after certain period of time. Then, a stable flood can be resumed below the critical injection rate. Viscous fingering occurs when viscous force is dominant due to high injection rate. If injection rate below critical injection rate, viscous force will not present.

Wood *et al.*,[20] explained that heterogeneity can be neglected when using GAGD, provided that gas flooding is gravity stable manner. This is because; the flood will travel down the reservoir in uniform fashion, thus draining the oil out of permeable zones. The three phases of water, oil and gas co-exist in many reservoirs. Gas has the least density, followed by oil and water causing vertical segregation of the reservoir fluids. Therefore, the idea behind gravity drainage is to exploit the in-situ segregation of fluids by injecting gas in the crest of the zone thus to create pressure maintenance forcing the oil downward reservoir which leads to higher value of ultimate recovery. This is clearly explained in Mahmoud MS Thesis.[21]

The idea of GAGD mimics the steam-assisted gravity drainage (SAGD) and it is originated as a natural extension of the gravity-stable gas injection projects in pinnacle reefs of Alberta. The oil recoveries were in the range of 15 – 40% OOIP. Christensen *et*

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[9] Kulkarni, M.M., Rao, D.N.: "Experimental Investigation of Various Methods of Tertiary Gas Injection", *Paper SPE 90589 Presented at the 2004 SPE Annual Technical Conference and Exhibition, Houston, September 26-29.*

[20] Wood, D.J., Lake, L.W., Johns, R.T. and Nunez, V.: "A Screening Model for CO2 Flooding and Storage in Gulf Coast Reservoir Based on Dimensionless Groups", *Paper SPE 100021 Presented at the 2006 SPE/DOE Symposium on Improved Oil Recovery, Tulsa, April 22-26.*

[21] Mahmoud, T.N. : "DEMONSTRATION ABD PEFORMANCE CHARACTERIZATION OF THE GAS ASSISTED GRAVITY DRAINAGE (GAGD) PROCESS USING VISUAL MODEL" *MS Thesis, LSU, August 2006.*

al.,[22] have presented a review of 59 WAG field experiences. In spite of its predominance in field applications, the performance of WAG process has been disappointing with low incremental oil recovery in the range of 5 to 10%, which much lower than gravity-stable gas injection rate.

Since GAGD has similarity with gravity-stable gas injection process, the reservoir characteristic of the latter is taken to represent the former. Table as shown below is the general conventional reservoir characteristic for GAGD. [23]

Table 6: Conventional reservoir characteristic in GAGD

Crude oil properties	Oil density : 33 API Oil viscosity : 0.9 cp Oil FVF : 1.285 RB / STB GOR : 500 scf/STB
Reservoir properties	Porosity : 27.6% Permeability : 300 md Temperature : 205 F
Limitations	After gas breakthrough, displacement mechanism looses domination because hydrostatic pressure tends to decrease. Well need to shut in for a period of time, to allow segregation of fluid in reservoir before CO_2 injection resumed
Problems	Horizontal producing well cost might be high
Advantages	Suitable injection rate allow front flood conformance, which delay CO_2 breakthrough Employ gravity segregation effects and horizontal well technology (having high PI due to large contact area)

[22] Christensen J.R., Stenby, E.H. and Skauge, A.: "Review of WAG Field Experience", Paper SPE 39883, presented at SPE International Petroleum Conference and Exhibition, Villahermose, Mexico, March 3-5, 1998

[23] Ren and Cunha L.B.: "Numerical Simulation and Screening of Oil Reservoir for Gravity Assisted Tertiary Gas-Injection Processes", *Paper SPE 81006 Presented at the 2003 SPE Latin American and Caribbean Petroleum Engineering Conference in Port-of-Spain, Trinidad, West Indies, April 27-30*

Case Study[24]

Currently, lack of studies done in the literature especially in naturally fractured reservoir. Thus, it is hard to find GAGD field application as it is still a new technique. The idea of GAGD is conceptually similar to the gravity-stable vertical gas floods, which making use of buoyancy rise of injected gas to displace oil downwards. The difference is that it uses vertical producing well instead of horizontal producing well. Therefore, in this part, the author will discuss a case study on gravity-stable vertical gas flood in carbonate reservoir.

Among of the most successful EOR in Canada is the Wizard Lake D-3A vertical miscible flood. This kind of miscible flooding falls under gravity stabilization technique is applicable in pinnacle reefs, small area extent and significant vertical thickness. During the injection, solvent (CO_2 or hydrocarbon gas) can either be injected first, followed by chase gas (N_2 or methane) or they might be injected at the same time. They are injected in the gas cap zone before the oil is displaced downwards into vertical producing well as shown in Figure 8.

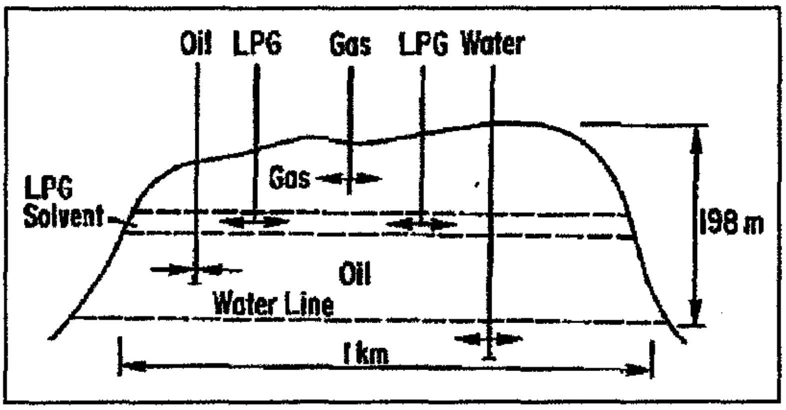

Figure 8: Vertical miscible flood

[24] Howes, B.J: "Enhanced oil recovery in Canada: Success in progress", JCPT, November – December 80-88, 1988

Table below shows the details of Wizard Lake D-3A.

Table 7: Wizard Lake D-3A characteristic

Areal extent	1075 hectares
Oil	Light to medium oil
Formation thickness	86.1 m (ideal for vertical miscible flood)
Cumulative production (December 31, 1986)	80% OOIP or $49.5x10^6 m^3$

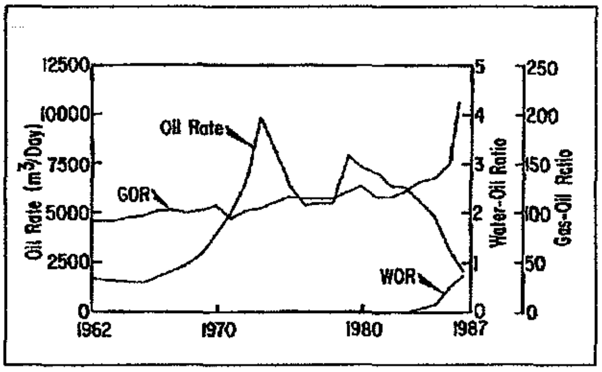

Figure 9: Production history for Wizard Lake D-3A Miscible Project

Based on Figure 9, it shows near stable GOR from 1962 until 1986. This indicates that gravity stable gas injection in Wizard Lake D-3A has successfully control mobility ratio and maintained front flood conformance. This prevents early gas breakthrough and results in high ultimate recovery.

2.2. COMPARISON BETWEEN CGI, WAG AND GAGD

To compare oil recovery using different gas injection methods in experimental lab, Mahmoud *et. al.,*[25] used a model that consisted of parallel glass plates separated by 1/4" space between them. Ottawa sand was used to represent as rock. A perforated tubing acted as horizontal producing well was put at the bottom of the reservoir model. The experimental results are summarized in Table 8.

Table 8: Experimental observation

	Free Gravity Drainage	CGI	WAG	GAGD
Ultimate Recovery	< 43% IOIP	10% IOIP	71.9% IOIP	74% IOIP
Observation	High residual oil saturation	Gas bypassed most of oil, only oil at the top of payzone recovered	Gas and water bypassed most of oil	Exploit in-situ segregation of fluid, forcing oil downwards to the producing well

Field application also exhibited the same results as in the experiments. In Table 9, GAGD's ultimate recovery is the highest among the three types of gas injection.

Table 9: Field Result Comparison

Type	**CGI**	**WAG**	**GAGD**
Formation	Carbonate	Carbonate	Carbonate
Oil Type Recovered	Light oil	Light oil	Light oil
Field	Midale (southeastern Saskatchewan)	carbonate Middle East Reservoir	Wizard Lake D-3A (Alberta, Canada)
Field Result	27% OOIP	60% OOIP	80% OOIP

Both experimental and field application results show ultimate recovery of GAGD is the highest compared to WAG and CGI. To investigate the factors that can optimize GAGD potential, the author will discuss those factors from his literature review in the following section.

[25] Mahmoud T.N., and Rao, D.N.:"Range of Operability of Gas-Assisted Gravity Drainage Process", *Paper SPE 1137474 Presented at the 2008 SPE/DOE Improved Oil Recovery Symposium held in Tulsa, Oklahoma U.S.A., April 19-23.*

2.3 PARAMETERS IN GAGD OPTIMIZATION

In previous papers, several parameters have been discussed in detail to see the effect on the GAGD performance. The parameters discussed so far are matrix block height, fracture/matrix properties, external displacing forces, capillary continuity, injection rate, miscibility condition, gas injection type and horizontal well length. However, only four of them are included here, those are injection rate, miscibility condition, gas injection type and horizontal well length.

2.3.1 Injection Rate

Gas injection rate is among of important factors that need to be optimized for the success in GAGD process. Injection rate control the flood front velocity and control the domination of gravity force. High injection rate could adversely affect the GAGD performance. The viscous force will 'combat' gravity force to gain domination because of the rapid pressure and CO_2 increase.

However, the high but optimum injection rate gives positive implication. It decreases the time required to complete the GAGD process and makes the process economically attractive. Furthermore, CO_2 solubility also becomes higher. Higher CO_2 gas in the solution lowers the interfacial tension, consequently improving microscopic displacement efficiency (E_D).

Figure 10 as presented below is the experiment result obtained by Mahmoud *et al.* The three injection rates represent low, intermediate and high injection rate. As shown, the higher the injection rate, the higher the ultimate GAGD oil recovery in the visual model.

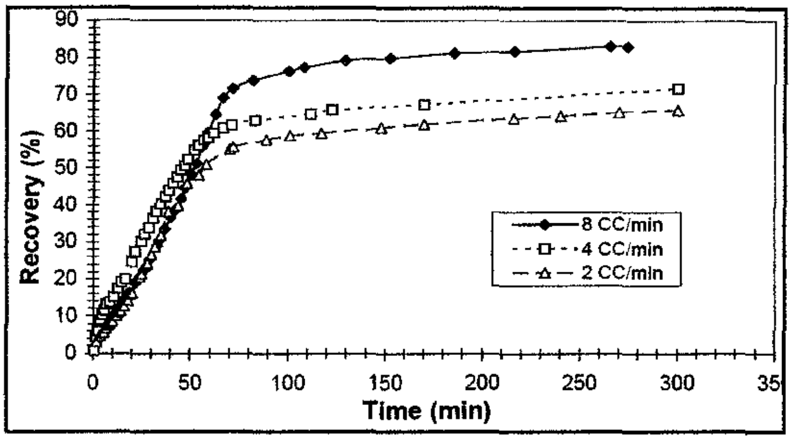

Figure 10: Effect of injection rate on GAGD oil recovery[25]

Apparently, Travedi *et. al.* found that higher injection rate only yields high production rate of oil in the initial period of project life. On the other hand, the low rate injection strategy is believed to be the best with most of the production contribution from matrix through the diffusion process.[26]

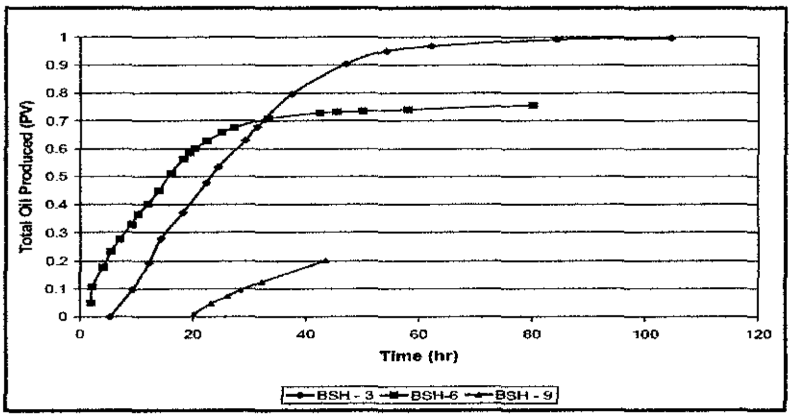

Figure 11: Cumulative production with time (Travedi *et al.*, 2006)

Figure 11 is the result of an experiment conducted by Travedi. The optimal rate seen is around 6 ml/hr (in blue). But, after 40 to 50 hours, the slower rate of 3 ml/hr (in pink) overpasses the production obtained from the 6 ml/hr case. This indicates the dominance of the diffusional flow (matrix-fracture interaction) compared to viscous flow (in

[25] Mahmoud T.N., and Rao, D.N.:"Range of Operability of Gas-Assisted Gravity Drainage Process", *Paper SPE 1137474 Presented at the 2008 SPE/DOE Improved Oil Recovery Symposium held in Tulsa, Oklahoma U.S.A., April 19-23.*

[26] J.J Travedi and T. Babadagli, SPE, U. of Alberta,: "Efficiency if Miscible Displacement in Fractured Porous Media", Paper SPE 100411 *Presented at the 2006 SPE Western Regional /AAPG Pacific Section/GSA Cordilleran Section Joint Meeting held in Anchorage, Alaska, U.S.A., May 8-10*

fracture). Thus, for faster and higher ultimate recovery, the process should be operated at 6ml/hr at the start before switched to 3 ml/hr.

Additionally, the author also proposed Fracture Diffusion Index (FDI)

$$FDI = \frac{\sqrt{k} * v * f(\theta) * \rho s}{k * D * \rho o}$$

Where, v is the volumetric injection rate of the diffusing phases, D is the diffusion coefficient between oil and solvent, and f (θ) is function of wettability.

High FDI indicates at high solvent injection rate, most of the recovery is from the fracture through viscous flow and recovery from matrix is low due to poor diffusion into matrix. Hence, it shows a faster recovery with more solvent injection and presumably less ultimate recovery from matrix. On the other hand, low FDI means at lower injection rate, the diffusion dominates the recovery. It is an indication of slow but more efficient recovery.

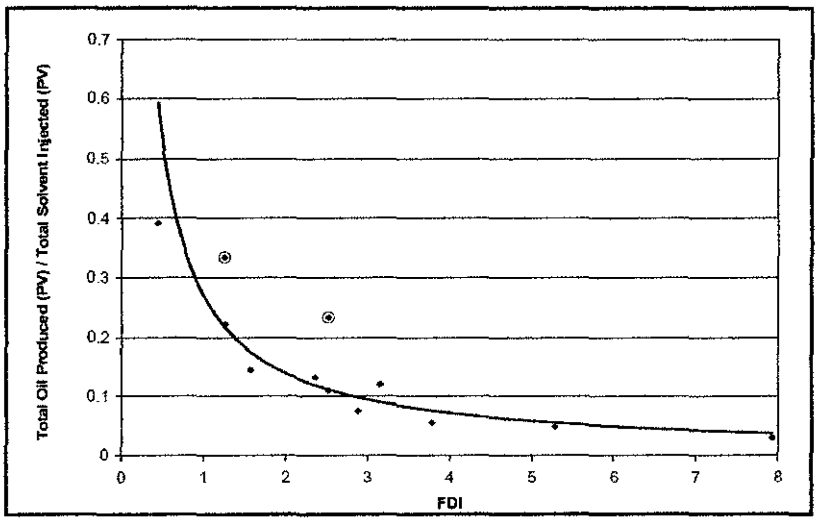

Figure 12 : FDI vs (total production/total injection) for all mineral oil experiments (Travedi *et al.*, 2006)

As shown in Figure 12, when injection rate reaches certain value (represented by progressing flat line parallel to x-axis with increasing FDI), flow is only through the fracture, and not enough residing time for diffusional matrix-fracture interaction to occur. Beyond the critical point (4 to 6), the diffusional recovery in fractured porous media considered as an inefficient process.

2.3.2 Miscibility Condition

The original objective of miscible displacement is to increase oil recovery by reducing the residual oil saturation to the lowest possible value. The interfacial tension (IFT) should be reduced to its lowest value by injecting slug of miscible solvent until miscibility is achieved.

$$.Nc = \frac{u\mu}{\sigma}$$

Equation above shows that by reducing IFT (represented by σ), capillary number (Nc) should increase. Meanwhile, residual oil saturation depends on the Nc, since the residual oil saturation decreases as the Nc increase.[27] This can be understood from Figure 13.

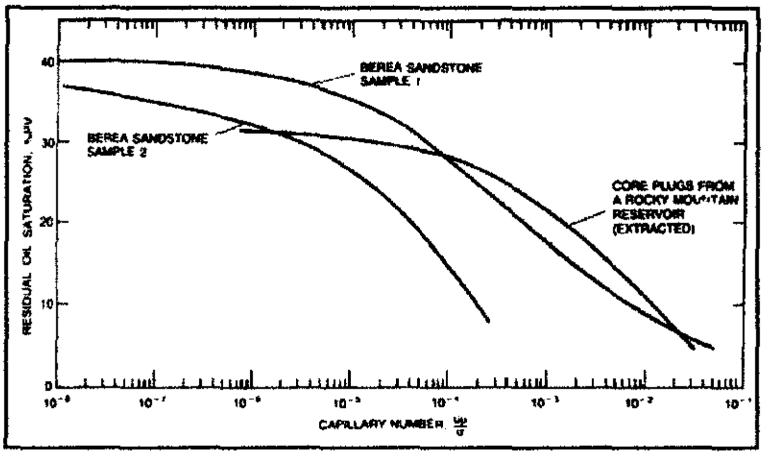

Figure 13: Dependence of residual oil saturation on capillary number[27]

Dynamic (multiple) miscibility of CO_2 with light- and medium- gravity crude oils is generated as a vaporizing gas drive mechanism. CO_2 at appropriate pressure vaporizes or extract heavier hydrocarbon (C_5 to C_{30}) from the oil and concentrates them at the displacement front where miscibility is achieved.[27]

[6] Kulkarni, M.M and Rao, D.N.: "Experimental Investigation of Miscible Secondary Gas Injection", *Paper SPE 95975 Presented at the 2005 SPE Annual Technical Conference and Exhibition, Dallas, TX, October 9-12.*

[27] Aurel Carcoana, *Applied Enhanced Oil Recovery*

Miscible GAGD process offered better recovery in compare to immiscible[17] but relative density of injection gas and reservoir fluid should be treated carefully. This statement was based on the gravity drainage definition and the two equations as below, where small interfacial tension developed between injected gas and reservoir fluid had boosted Capillary Number and Bond values.

$$R_{immiscible}(\%) = 5.49\ ln(N_{GD}) + 32.3$$

$$R_{miscible}(\%) = 5.47\ ln(N_{GD}) + 55.39$$

In the above equation, R represents recovery, N_{GD} represents gravity drainage number. It clearly shows that miscible recovery gives higher recovery compared to immiscible recovery. This has been proved through experiment. However, Mahmoud *et al.*, [11] claimed that it was impossible to simulate CO_2 miscibility condition in visual model as it this required high pressure. As replacement, red-dyed naptha was used as oil and clear decane as miscible gas in his experiment. The observed result was E_v less than 100% due to very low density difference between these two fluids. In contrast, gravity dominance would be easier to achieve in field due to larger density difference high pressured CO_2 and oil in reservoir.

Lawrence *et al.*, [28] stated that pressure is the key in determining the miscibility between the injected gas and the contacted fluid in the reservoir. Usually, oil recoveries for gas injection processes are greatest under the condition where the gas become miscible with the in-place oil. The gas and oil can be first contact miscible or develop multi-contact miscibility. Miscibility can be achieved by managing the reservoir pressure or changing the composition of injected gas by addition of either heavier hydrocarbon or acid gas components. On the other hand, immiscible gas injection is usually used for pressure maintenance.

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[11] Mahmoud T.N., and Rao, D.N.: "Mechanism and Performance Demonstration of the Gas-Assisted Gravity-Drainage Process Using Visual Models", *Paper SPE 110132 Presented at the 2007 SPE ATCE, Anaheim, CA, November 11-14*

[28] Lawrence, G.F. Teletze, J.R Wilkinson,: Reservoir Simulation of Gas Injection Processes, *Paper SPE 81459 Presented at the 2003 SPE 13th Middle East Oil Show & Conference in Bahrain, April 5-8.*

2.3.3 Type of Injected Gas

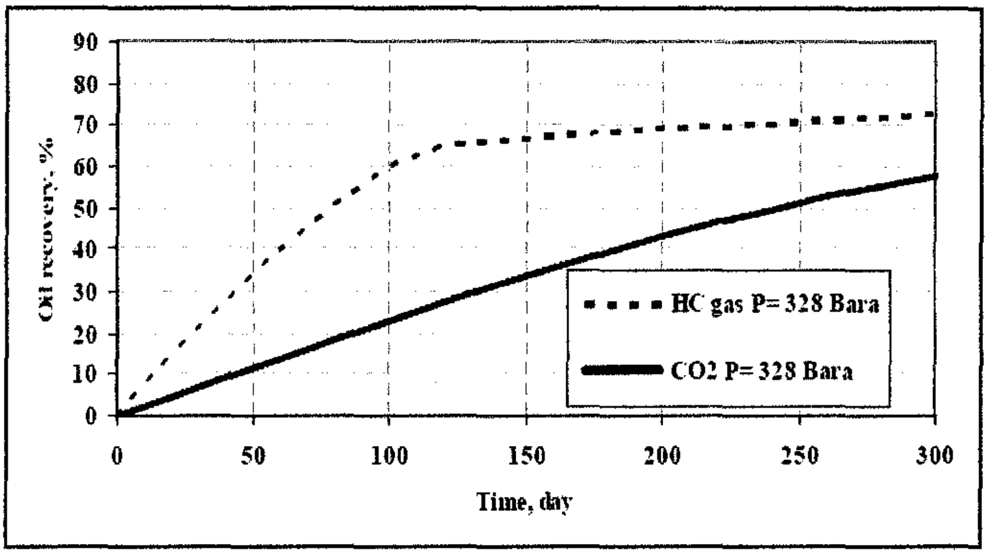

Figure 14: Simulation of the effect of two different injection gases[29]

The recovery performance for hydrocarbon case is compared with the CO_2 case as shown in the above figure. It clearly shows that the recovery for hydrocarbon gas at all stages is higher than in the CO_2 case. The high recovery for hydrocarbon is due to its lower density compared to CO_2 density. In this lab experiment, CO_2 density at P=328 bars is almost 1.2 times more than the hydrocarbon gas density. This has caused the density difference between CO_2 and oil become smaller.[29]

If the injection rate is high, then the pressure could increase rapidly causing the viscous force to gain domination along with the disadvantage of less density difference. This would lead to less gravity domination. As results, injected gas would bypass most of oil in reservoir and eventually lead to premature gas breakthrough and low overall efficiency.[25]

[25] Mahmoud T.N., and Rao, D.N.:"Range of Operability of Gas-Assisted Gravity Drainage Process", *Paper SPE 1137474 Presented at the 2008 SPE/DOE Improved Oil Recovery Symposium held in Tulsa, Oklahoma U.S.A., April 19-23*

[29] Gholam Reza Darvish, Erik Lindeberg, John Kleppe and Ole Torsaester, *Numerical Simulations for Designing Oil/CO_2 Gravity Drainage Laboratory Experiments of Naturally Fractured Reservoir*

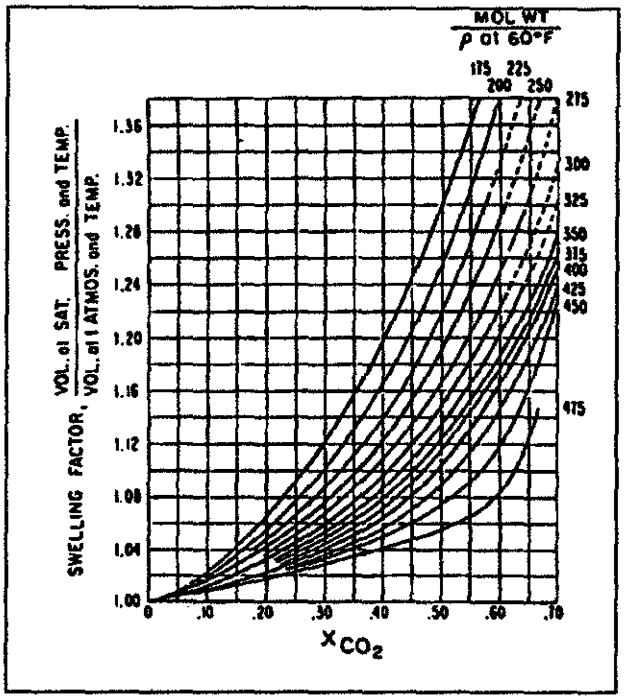

Figure 15: Swelling factor for oil (Simon and Grauge, 1965)

On top of that, the oil volume will increase more than 20% when CO_2 dissolved in it. Figure 15 shows the crude oil swelling factor (volume of CO_2 saturated crude at saturation pressure and temperature/volume of CO_2 free crude at the same temperature) as function of the mole fraction of CO_2 dissolved (XCO_2) and the molecular weight of oil. More CO_2 dissolve will cause the swelling factor to be larger. CO_2 in solution with water forms carbonic acid which in turn dissolves calcium and magnesium carbonates. This action increases the permeability of carbonate rock; improving well injectivity and generally the fluid flow through reservoir. It also has a stabilizing effect on shaley rocks, reducing pH and prevents the shales from swelling and causing blockage of the porous medium.[4]

2.3.4 Length of Horizontal Producing Well

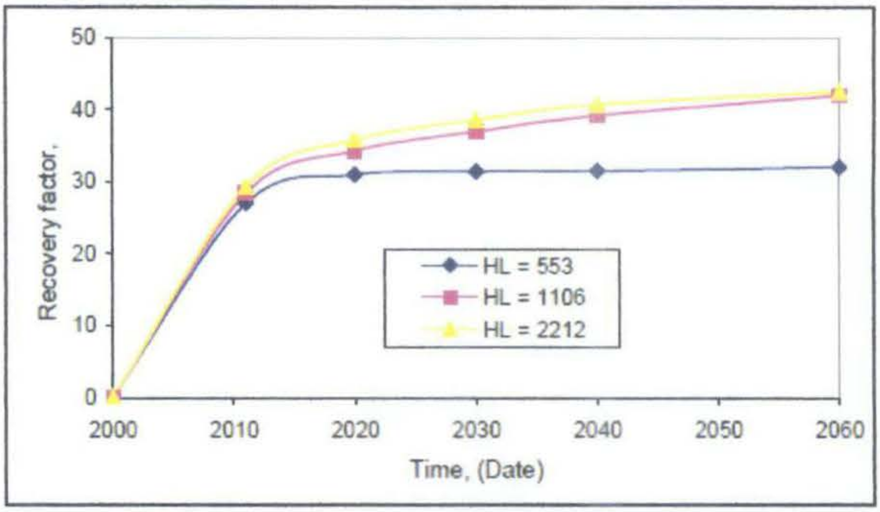

Figure 16: Oil recovery factor for different horizontal well lengths (Vali Ahmad *et al*)

Increasing the horizontal length will result in greater drainage area, less pressure gradient toward well, lower water cut, and more chance to cross the fracture network. Based on the results, up to some optimum value by increasing the horizontal length the oil production will increase. Figure 16 shows that in general horizontal wells have better performance than vertical wells especially in naturally fractured reservoir.[30]

Previous studies proved the benefit of using horizontal well including in fractured reservoir. With its length, a horizontal well can intercept more fissure than the vertical well, thus obtaining higher productivity. The included case study as below shows the high potential of this well.

[4] Lyons, William C.: "Standard Handbook of Petroleum and Natural Gas Engineering (2nd Edition)

[30] Vali Ahmad Sajjadian, Ali Mohammad Emadi and Elham Khaghani, "Simulation Study of Secondary Water and Gas Injection in a Typical Iranian Naturally Fractured Carbonate Oil Reservoir"

Case Study: Naturally Fractured Spraberry Trend Area[31]

The Spraberry reservoir that were discovered in 1949 has three distinct units which are a sandy stone, a zone of shales and limestone as well as a sandy stone respectively at the upper, middle and lower part of reservoir. However, the study was focusing on the upper part of reservoir, where the productive oil sands in this part are from two thin intervals, which are 1U and 5U. Both of them are characterized as low porosity and permeability interval. However, extensive sets of interconnected vertical fractures aid oil recovery from this low permeability sandstone. Basically, the study was purposely done to see the well productivity of using horizontal well through simulation in waterflood pilot project.

The varied average reservoir pressure was used from 1000 psia to 1500 psia with different length of well section. The results of simulation as below were performed using constant plateau rate of 100 BOPD, no water injection with 500 psi BHP for 10 years.

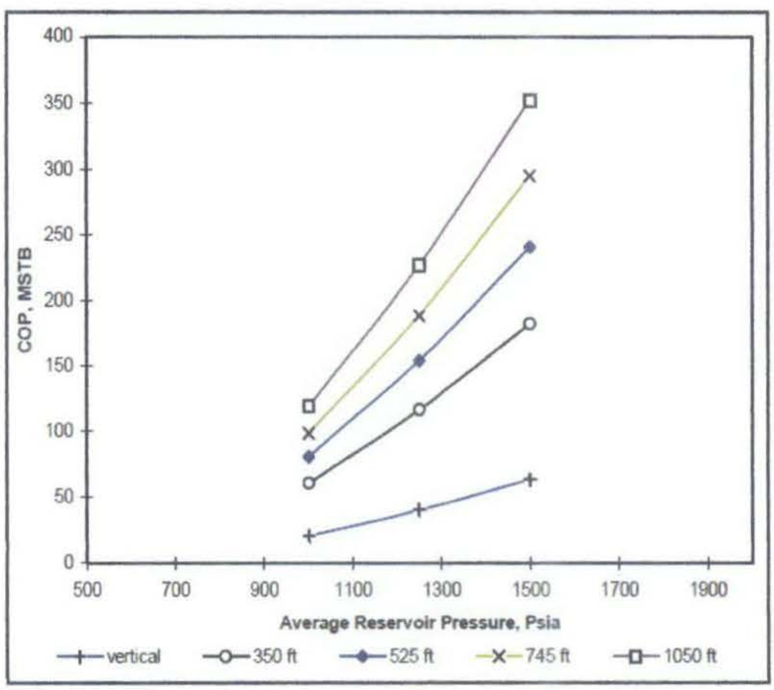

Figure 17: Horizontal length effect on cumulative oil recovery at different reservoir pressures

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[31] *"ADVANCED RESERVOIR CHARACTERIZATION AND EVALUATION OF CO_2 GRAVITY DRAINAGE IN THE NATURALLY FRACTURED SPRABERRY TREND AREA" 3rd Annual Technical Progress Report*

From Figure 17, the horizontal production well implies a significant improvement over the vertical production well. It could result in three to five times more in cumulative oil production. In addition, the number of wells could be further reduced by two. In terms of cost, the horizontal producing well is typically 1.2 to 1.5 times than the vertical production well per foot drilled.

Figure 17 also suggested maintaining or increasing the average reservoir pressure is critical. The production rate would almost double up with the increasing of the average reservoir pressure by 250 psia. In this study, the pressure could be maintained by water injection perpendicular to the fracture direction which was predicted to delay the water breakthrough in the producing wells

2.4 SUMMARY

GAGD is considered as the best option in comparison with CGI and WAG in naturally fractured reservoir application. Both experimental and field application done by previous researchers proved the effectiveness of GAGD. In this literature review, there are 4 parameters that have been discussed to improve oil recovery by using this method. The indentified parameters are injection rate, miscibility condition, gas injected type and length of horizontal producing well. As discussed, with optimum injection rate, miscibility condition, high density difference between in-situ oil and injected gas as well as at optimum length of horizontal well, large portion of oil can be recovered, which explicitly resulting high total oil recovery.

2.5 SIMULATION MODEL

2.5.1 Naturally Fractured Reservoir Description[32]

A naturally fractured reservoir is viewed as if a conventional reservoir with a fractured network which separate matrix blocks. Both matrix and fracture are characterized by their own permeability (k_m or k_f) and porosity (Φ_m or Φ_f). Thus, it is called a double porosity and double permeability reservoir.

Sometimes, reservoirs which contain solution channels or consist of interbedded layers of high permeability zones such as a permeable dolomite interbedded with less permeable silty, fine-grained sandstone behave as if they are naturally fractured reservoir. Their behaviors on well tests determine whether they are naturally fractured reservoir or not.

ORIGIN OF FRACTURE

The combination of stress and the specific elastic properties of the rock make the rock fracture. The position of the line of the fracture is influenced by the elastic properties. The differences in lithology could lead to major changes in the position of the line fracture. Sometimes, gross lithologic features are identical, but their elastic properties may be quite different. Consequently, the homogeneous pattern will not occur even when a rock mass is subjected to the same stress field.

In separate cases, percolating waters and hydrothermal fluids preferentially deposit minerals on the fractures surfaces, which reducing permeability. Consequently, this turns the originally homogeneous fractured into heterogeneous system.

In their book, the authors claimed that they are still working on fracture pattern characterization research. Figure 18 as shown below is the model derived on the basis of well testing that has no physical or geological connotation.

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[32] M.A. Sabet, *Well Test Analysis*

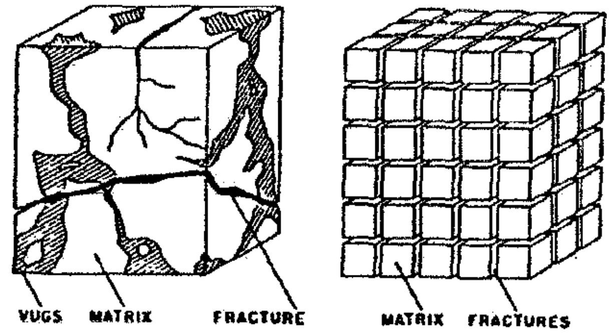


Figure 18: Idealization of the heterogeneous porous medium (Warren et. al, 1963)

Fracture porosity (Φ_f) is usually below 1%. Fracture storage, $S_f = \Phi_f C_f h_f$, is very small due to small Φ_f and extremely small fracture thickness, h_f. In contrast, it has high permeability. In comparison, matrix porosity is normally much higher than fractures with the total thickness, h_m equal to the net pay. Therefore, the matrix storage, $S_m = \Phi_m C_m h_m$ is much greater than fractures. However, its permeability is much lower than the permeability of the fractures. During well test analysis, all production move into the well through the fractures.

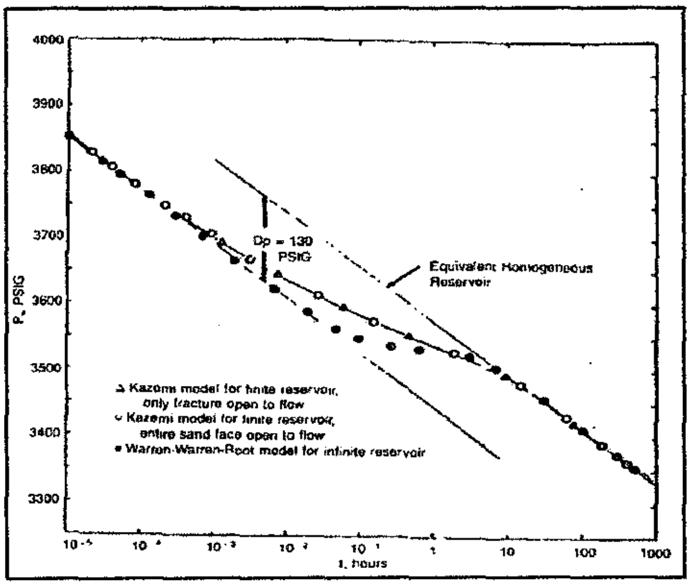


Figure 19: Pressure drawdown according to the model by Warren and Root (Kazemi, 1969)

Figure 19 shows a semi-log plot of drawdown test data, P_{wf} versus log t of naturally fractured reservoir based on Warren and Root (1963) model. The first segment is a straight line which indicates transient radial flow through the fractures. The available liquid here is quickly depleted in view of small fracture storage. Therefore, P_{wf} and fracture pressure drop rapidly.

The second and third segments represent transitional and transient radial flow stages respectively. In the second stage, the fracture pressure drop induces fluid influx from the matrix into the fractures. As such, there is a slowdown of the declining rate of P_{wf}. Finally, as the matrix pressure is approaching fracture pressure, the role is taken over by the fracture. Therefore, the third line segment shows the contribution from the fractures.

DUAL POROSITY, DUAL PERMEABILITY MODEL[33]

Fractured reservoirs simulation using dual porosity approach involves discretization of the solution domain into fracture and matrix. Warren and Root model assumes that matrix as source or sink to the fracture, which become a primary conduit for fluid flow. Capillary continuity between matrix blocks across fractures, highly affects the gravity segregation in a dual porosity medium. However, today's simulation models are not adequately modeling this mechanism. As such, research groups are still working on this.

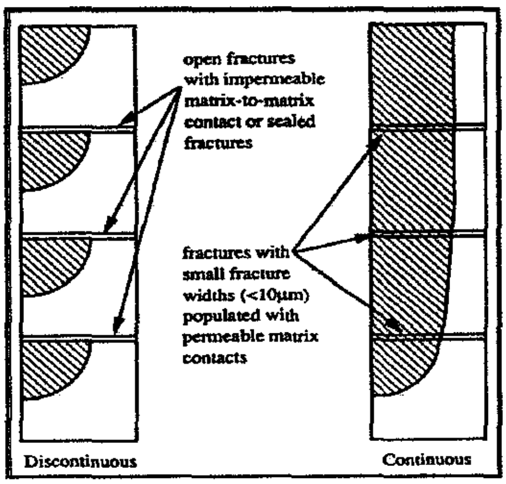


Figure 20: Effect of vertical capillary continuity on saturation distribution (Fung, 1991)

[33] K.Uleberg et. al, : " *Dual Porosity, Dual Permeability Formulation for Fractured Reservoir Simulation*", Trondheim RUTH Seminar, Stavanger 1996.

Figure 20 shows a schematic comparison of capillary-gravity dominated saturation distributions for a discontinuous system and a system with capillary contact between matrix blocks. The recovery for capillary continuous system is much higher compared to discontinuous system. This is proven from simulation results of previous researchers, whereby they suggested that the matrix is better described to be continuous.

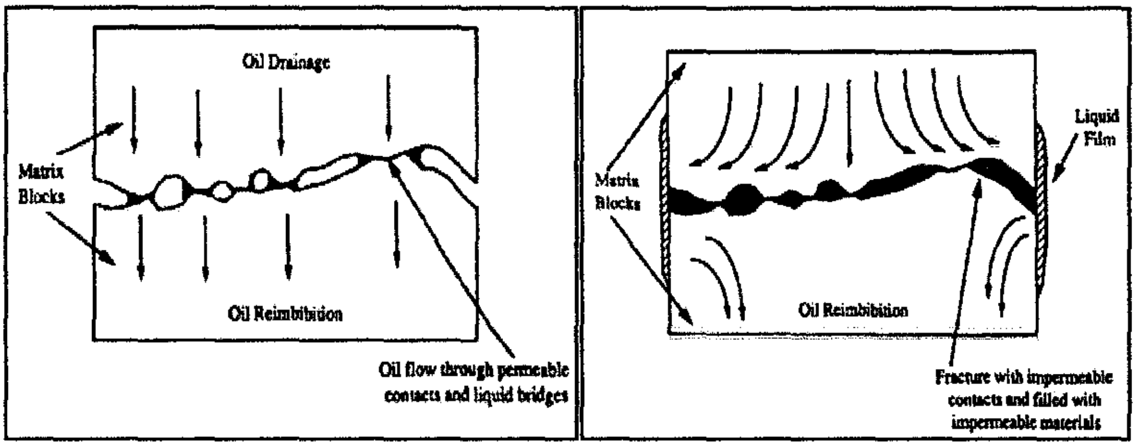


Figure 21: Reinfiltration of fluids from higher to lower matrix blocks (Fung, 1991)

In gas-oil gravity drainage, reinfiltration is defined as the drained oil from the upper matrix block enters into the underneath matrix block. It is a function of capillary forces and gravity. As shown in Figure 21, liquid bridging provides the main transmissibility during the initial stage of gravity drainage process. Gradually, when the oil saturation in the fractures becomes very low, the main liquid transmissibility from block to block is by the aid of film flow.

HIGH PRESSURE GAS INJECTION

The recovery mechanisms involved in high pressure gas injections in fractured reservoir include viscous displacement, gas gravity drainage, diffusion, swelling and vaporization/stripping of the oil. Viscous displacement plays a minor role, except in the near vicinity of the wells where pressure gradients are large. In fractured reservoir, the injection gas tends to flow in the fractured system, which resulting in relatively large composition gradients between fracture gas and matrix hydrocarbon fluids. This creates potential for transport by molecular diffusion, especially in reservoir with high degree of fracturing.

Whitson *et al* used cores which initially filled with Ekofisk oil, where methane gas was injected into the annulus system in their experiment. Their research results indicate that recovery can be roughly divided into three production stages, which are:

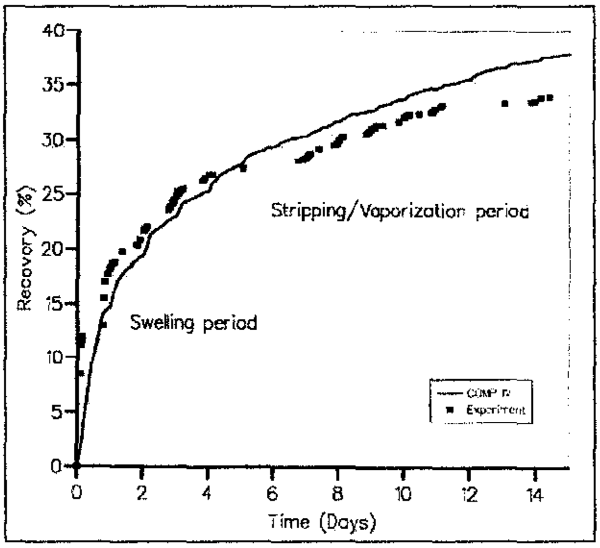


Figure 22: Experimental and modeled oil recovery vs. time (Whitson et al., 1993)

1. Primary swelling of oil

The initial stage is dominated by swelling of the oil inside the core, due to liquid-liquid diffusion. The light components of the oil diffuse into the core whereas the intermediate oil components from the core diffuse to the outer. Due to swelling of oil and interfacial gradients, there is some viscous from the center of the core to the fracture. This oil is then vaporized by the injection gas.

2. Secondary swelling and vaporization

The oil within the core becomes saturated. The free gas saturation advances towards the center of the core. The gas-gas diffusion will play a more dominant role on recovery process. During this stage, light and intermediate oil components are vaporized.

3. Final vaporization of oil

During this stage, heavy-intermediate and heavy components are vaporized. This stage is relatively slow compared to the previous stages, but large additional recovery may be achieved.

2.5.2 Gas-Oil Gravity Drainage Concept[34]

Gas-oil gravity drainage (GOGD) is one of the main recovery mechanisms in (non-water-wet) naturally fractured reservoir. After initial depletion, gas-oil and water-oil contacts are established in the fracture.

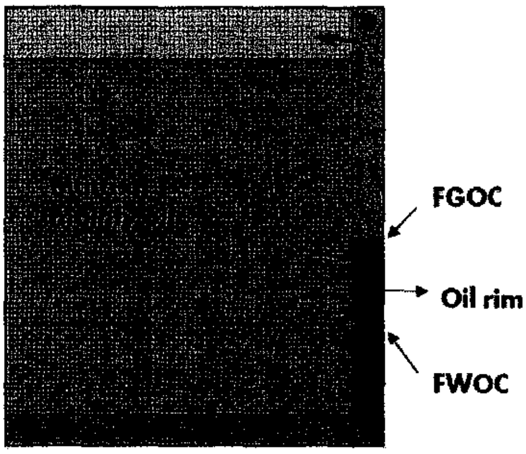


Figure 23: Fracture-matrix in equilibrium after primary depletion

At this stage, matrix oil can be produced by gravity forces. GOGD relies on the density difference between oil and gas (GOGD) and oil and water (WOGD) as driving force. Oil-rim in the fractures must be must be lowered through the production to maintain the production in GOGD. However, this has resulted in the early breakthrough and obvious reduction of the production. Under GOGD, the balance between oil rim and gas injection rate should be maintained. This is because overproduced wells will cause gas-out and rate reduction is required to allow the rim to build up again.

[34] R. farajzadeh et al., :" Foam Assisted Gas Oil Gravity Drainage in Naturally-Fractured Reservoirs", *Paper SPE 134203 Presented at the 2010 SPE Annual Technical Conference and Exhibition held in Florence, Italy, September 19-22*

CHAPTER 3

METHODOLOGY

3.1 GRID BLOCK PROPERTIES

Simulations were carried out by using Schlumberger ECLIPSE 100 Reservoir Simulation software. To ease the simulation process, the author uses gridblock model from Msc Thesis.[35] The fluid component properties were adapted from Middle East Reservoir fluid data[36]. The grid block size is summarized in Table 10.

Table 10: Grid block properties

Properties	**Dimension, ft^3**	**Number of cells in each direction**			**Permeability, md**			**Porosity**
		x	**y**	**z**	**x**	**y**	**z**	
Matrix	10x10x10	10	10	10	0.20	0.20	0.20	0.07
Fracture	10x10x10	10	10	10	5000	5000	5000	0.02

Initially, the injector is fixed at constant rate of 10 mscfd while the producer is fixed to produce under bottom hole pressure (BHP) of 950.0 psi. The location of injector and producer is shown in Figure 24. Visualization during gas injection is simulated using FloViz application in ECLIPSE 100.

[35] Gholamreza Garmeh, : *"Simulation of Interwell Gas Tracer Test in Naturally Fractured Reservoirs"*, MS Thesis, University of Texas, August 2005.

[36] Shahin Negahban, Karen Schou Pedersen, Mahmoud Ali, Pashupati Sah, and Jawad Azeem. : "An Eos Model for a Middle East Reservoir Fluid with an Extensive EOR PVT Data Material", *Paper SPE 136530 Presented at the 2010 Abu Dhabi International Petroleum Exhibition & Conference held in Abu Dhabi, UAE, November 1-.4.*

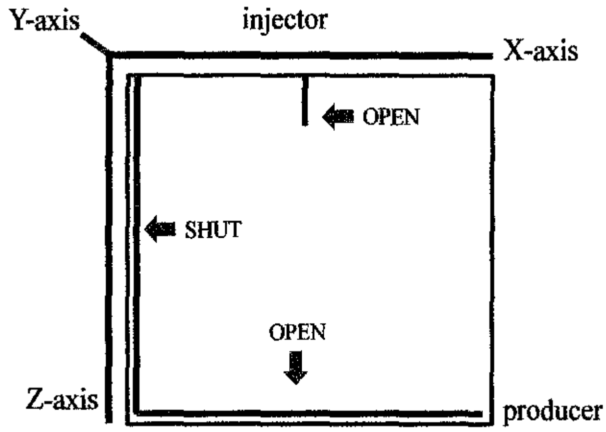


Figure 24: Location of Injector and Producer

The residual oil saturation distribution has an exponential relation with permeability distribution. The residual saturations of oil and gas in matrix and fracture are defined in Table 11.

Table 11: Residual oil and gas saturation

	Residual oil saturation	Residual gas saturation
Matrix	0.40	0.20
Fracture	0.30	0.15

The matrix shape factor is 0.12, assuming a fracture spacing of 5 ft in the horizontal direction and 10 ft in the vertical direction.

The driving forces here are gravity drainage and capillary pressure. Three-dimensional reservoir is used in this simulation study. Basically, this simulation is based on the Cantarell Oil Field reservoir, which is located in Mexico. Water-oil contact is out of simulation domain, so there is no mobile water seen in this simulation. Two main regions here are gas cap zone (set at 4040 ft under sea level) and oil zone. Time step of 6 years is used in this simulation. Dual porosity is used to handle naturally fractured reservoir performance. In this model, two sets of properties are specified, which are matrix porosity and permeability as well as fracture porosity and permeability. There is no flow between matrix-matrix in this model.

3.2 CANTARELL OIL FIELD

The Cantarell field is located around 80 kilometers offshore of the Yucatan Peninsula in the Bay of Compeche, Mexico. It is the largest oil field in Mexico and sixth largest oil field in the world. With 162 km^2 of surface area, Cantarell consists of four major fileds, which are Akal, Nohoch, Chac and Kutz. Akal field is the largest field, with average depth estimated at 2300 m below sea level, and pay zone thickness of 1200 m. It is described as a highly fractured carbonate reservoir with large volume of vugs from Jurassic, Cretacous and Paleocene geological ages (Rodriguez et al., 2001). The typical total porosity in the reservoir is 7% and 25% of it may correspond to secondary porosity (fractures, microfractures and vugs). On the other hand, typical total permeability in the matrix and fracture is 0.3 and 5000 md respectively.

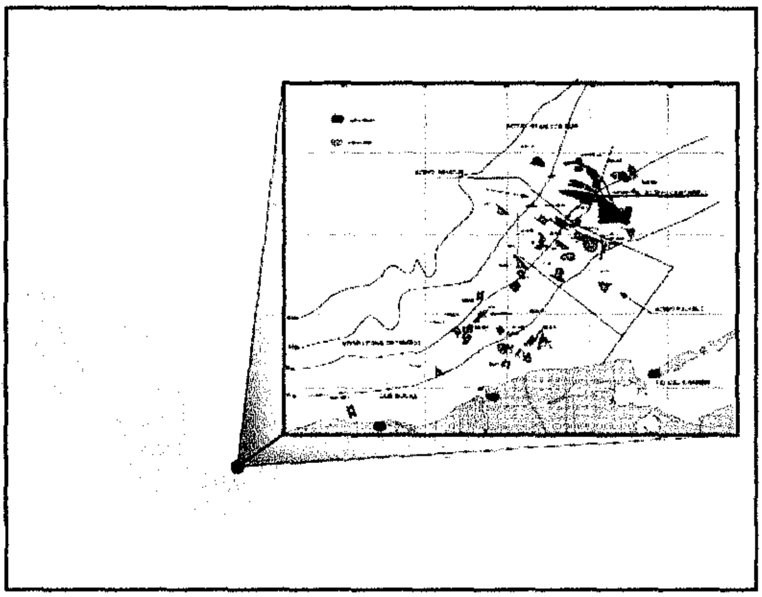
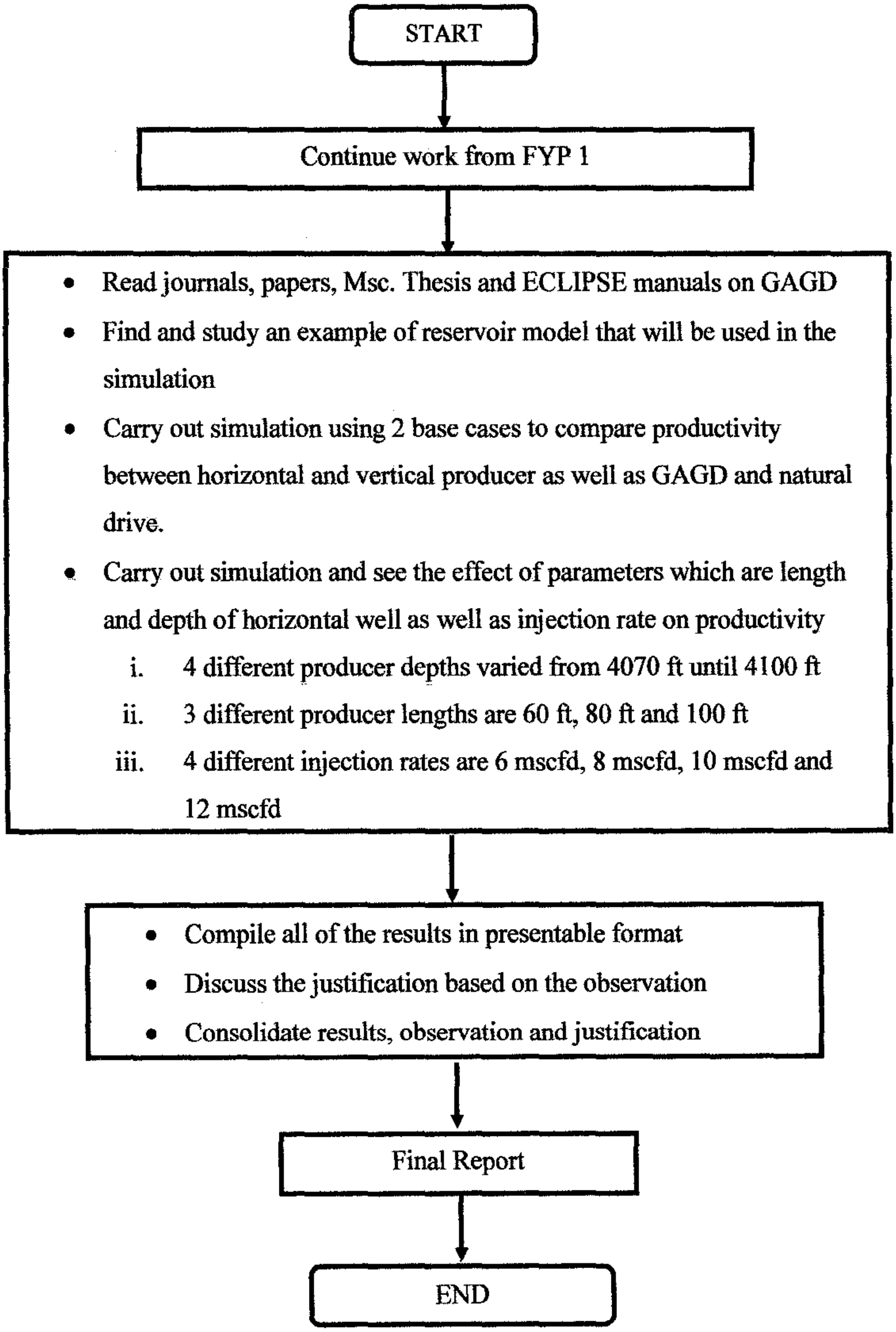


Figure 25: Cantarell oil field (Limon-Hernandez et al., 2005)

Akal Field produced under full gravity segregation condition and it is subject to thermal convection. The gas-oil contact has moved to its current thickness of 730 m. Water-oil contact has moved 480 m from the original position of 3200 m below its original below sea level. Initially, production rate from Akal field was about 29,000 STB/D per well but dropped to 7,000 STB/D in 1995. To optimize hydrocarbon recovery, pressure maintenance is required. Nitrogen was selected, considering gas injection technologies availability, cost, safety, environmental and reservoir issues.

3.3 PROJECT WORKFLOW



3.4 KEYMILESTONE AND FUTURE PLANNING

There are two semesters in the completion of this project. The research semester and the and the simulation work semester. There are two Gantt Charts below for each of the semesters:

i. FINAL YEAR 1st SEMESTER (JAN 2011)

Table 12: Final Year Project 1 Gantt chart

No	Project Activities	Week													
		1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**
1	Selection of FYP topics														
2	Study the theoretical part of GAGD														
3	Work on preliminary report														
4	Study on the parameters that influence recovery														
5	Reservoir modeling and simulation study														
6	Oral presentation														
7	Work on draft report														
8	Work on final report														

ii. FINAL YEAR 2nd SEMESTER (MAY 2011)

Table 13: Final Project 2 Gantt chart

No	Project Activities	Week													
		1	2	3	4	5	6	7	8	9	10	11	12	13	14
1	Study dual porosity model														
2	Work on simulation and analyze results														
3	Work on progress report								O						
4	Pre-SEDEX											O			
5	Final report submission (softbound)												O		
6	Technical paper submission													O	
7	Oral presentation														O
8	Final report submission (hardbound)														O

3.5 TOOLS AND EQUIPMENT REQUIRED

Throughout the Final Year Project period, PVTi was used to generate PVT data to be used in the simulation. Those PVT data are then exported to dual porosity model in Black Oil Simulator Schlumberger's Eclipse (E100). The blackoil model assumes that the reservoir fluids consist of two phases which are oil and gas, where no dissolved gas in oil and no vaporized oil in gas are set.

CHAPTER 4

RESULTS AND DISCUSSION

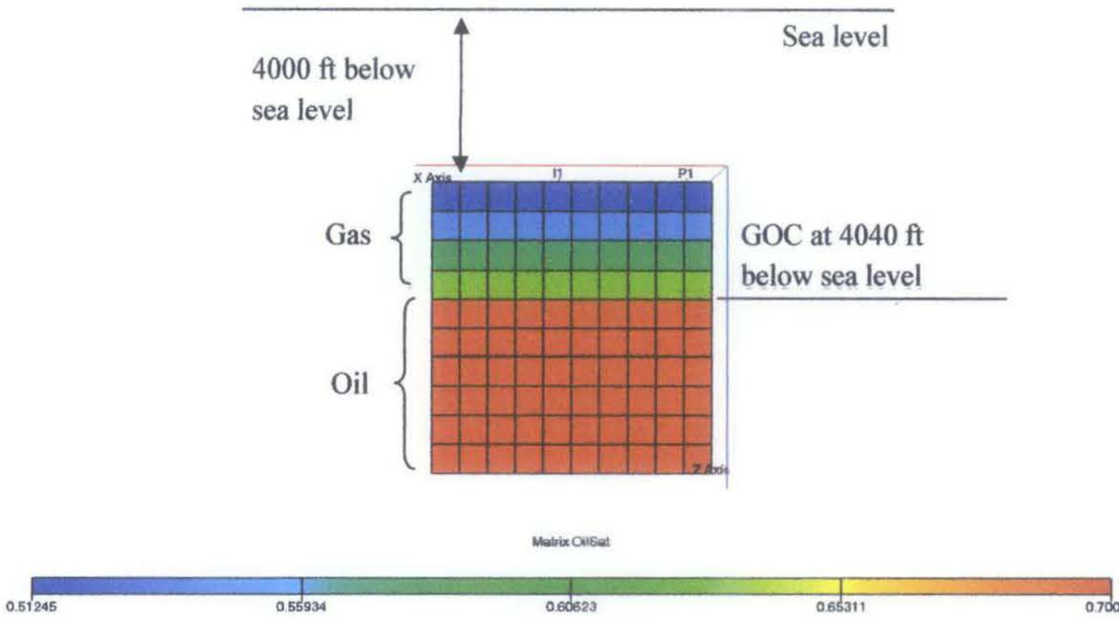


Figure 26 : Matrix oil saturation profile before gas injection in simulation case

Figure 26 is the initial matrix oil saturation profile. At this stage, both fractures and matrix contain oil with most of the oil are in matrix. In this simulation, there is no WOC shown as it is out of domain. The top most of gridblock is located 4000 ft below sea level with the GOC at 40 ft under it. Throughout the following discussion, FOE and FOPT terms will be used which represent oil recovery factor and oil production total respectively. Whereas, FOPR and FGPR represent field oil production rate and field gas production rate respectively which symbolizes cumulative production.

4.1 BASE CASE 1: HORIZONTAL (GAGD) VS VERTICAL PRODUCER (CONVENTIONAL GAS INJECTION)

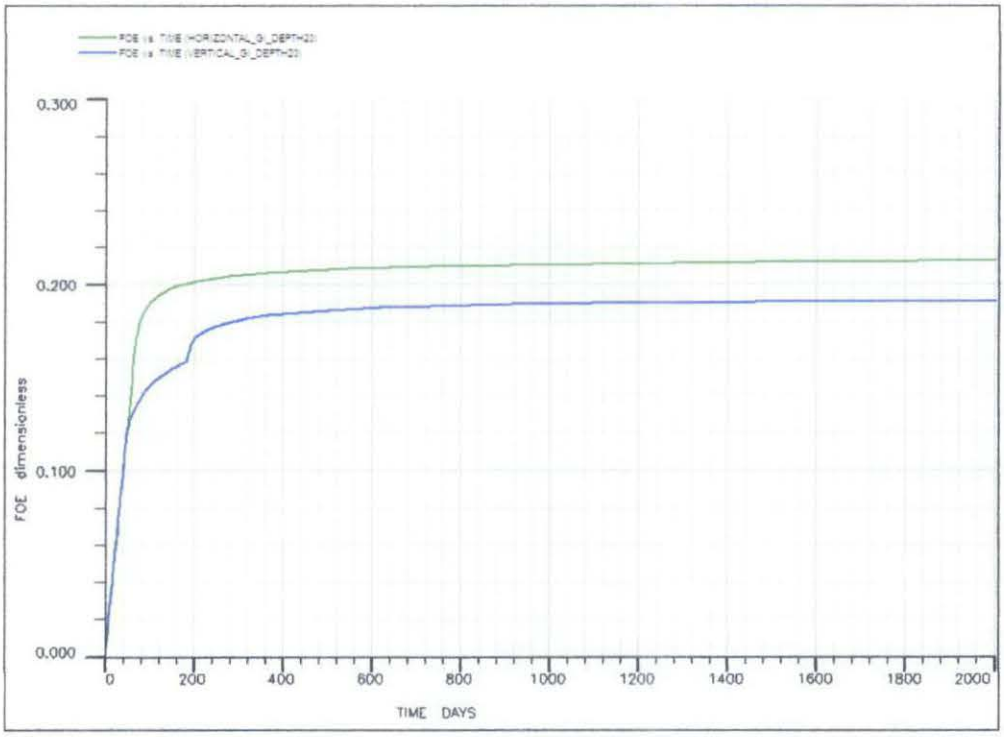


Figure 27: FOE of vertical and horizontal production well versus time

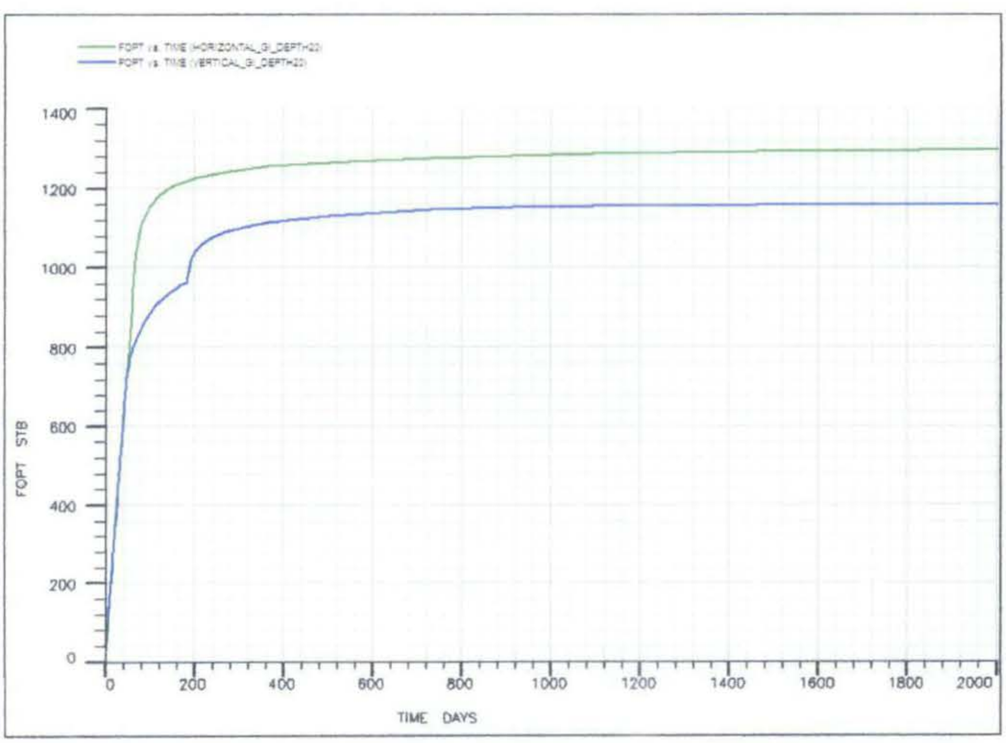


Figure 28: FOPT of vertical and horizontal production well versus time

BASE CASE 2: GAS INJECTION (GAGD) AND NO GAS INJECTION (NATURAL DRIVE)

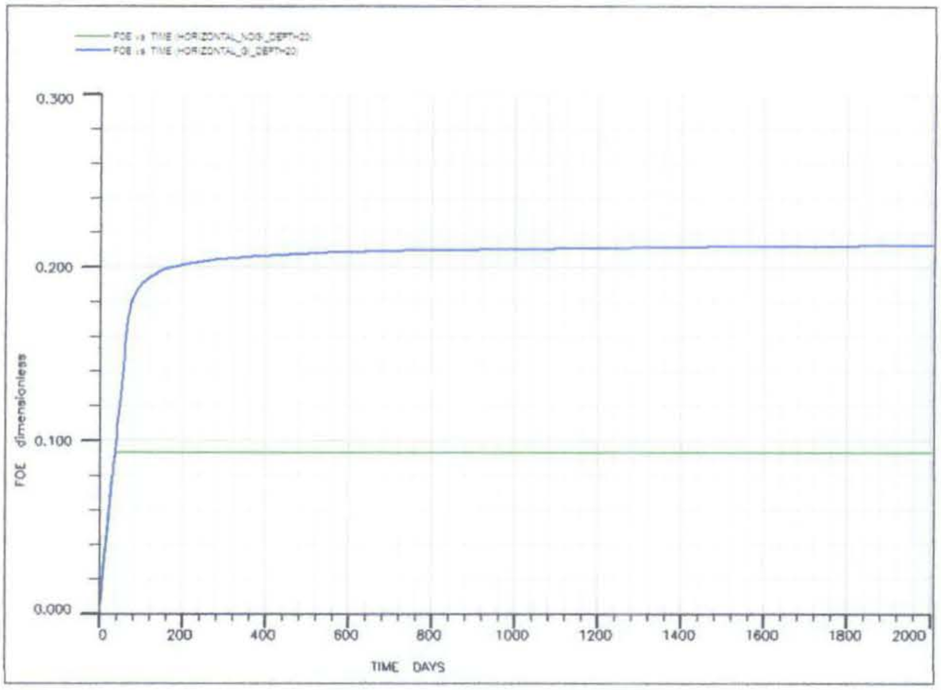


Figure 29: FOE for reservoir with gas injection (GAGD) and natural drive (no gas injection) using horizontal well versus time

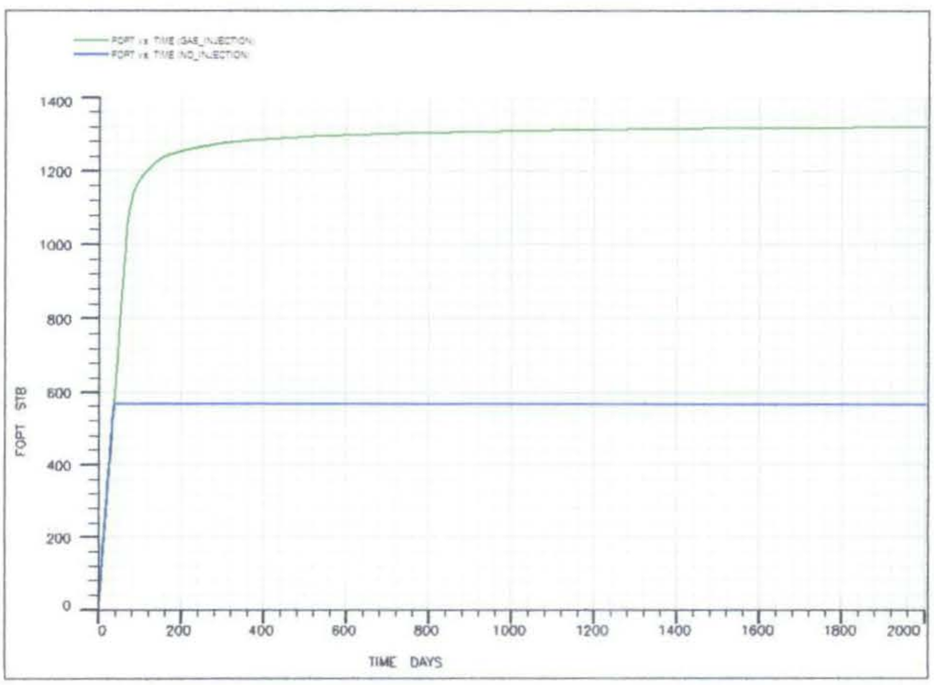


Figure 30: FOPT of reservoir with gas injection (GAGD) and natural drive (no gas injection) using horizontal well versus time

Table 14 : Base Cases

Well	FOE (%)	FOPT (stb)
Vertical	19.04	1156.97
Horizontal	21.29	1296.93
Gas Injection	21.29	1322.40
Natural Drive	9.28	565.78

Figure 27 and 28 shows horizontal well recovery is higher than that of vertical well with the oil recovery factor of 21.29 % and 19.04 % respectively (equivalent FOPT of 1156.97 stb and 1296.93 stb respectively). Theoretically, vertical well employs horizontal displacement. Due to severe gravity segregation effect, the injected gas simply flows through high permeable fracture and override much of oil in matrix. This has resulted in low oil recovery. On the contrary, horizontal producer employs vertical displacement. In this case, gas injection pushes oil downwards towards the producer, with the aid by gravity. Thus, it works well with gravity force to gain high oil recovery.

Figure 29 and 30 presents the advantage of gas injection (GAGD) over naturally producing reservoir. In Table 14, it shows that oil recovery factor for gas injection and natural drive are 21.29 % and 9.28 % respectively (equivalent to 1322.40 stb and 565.78 stb respectively). Basically, natural drive employs solely on the gravity force to produce oil. Gravity drainage is a slow process. Therefore, the amount oil recovered is very low. On the other hand, the use of gas injection has helped to replace the produced oil and avoid the rise of oil rim in the fracture. To maintain the oil production, oil rim in the fractures must be lowered. Otherwise, oil production rate will go back to natural gravity drainage. Furthermore, the gas injection case can also be described in terms of capillary forces of fractures. When fractures are full with gas while the rock is oil wet, it is easier for fracture to imbibe oil from matrix. Thus, more oil can be recovered with the aid of gas injection.

4.2 CASE 1: DIFFERENT HORIZONTAL WELL DEPTHS

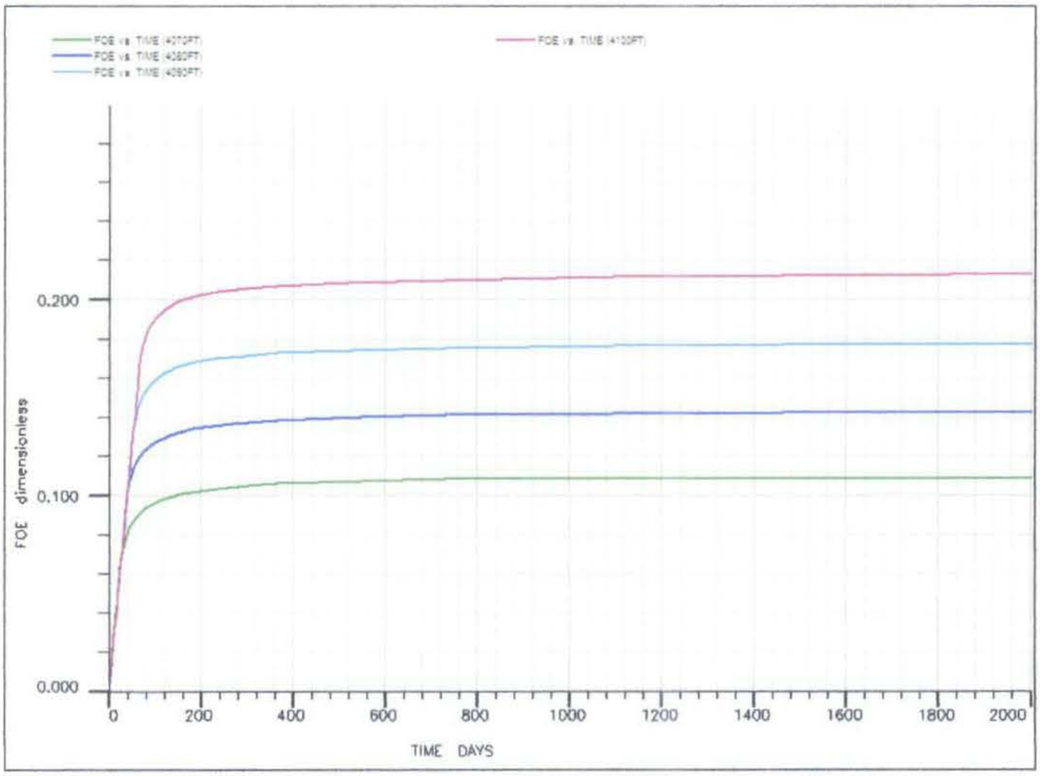


Figure 31: FOE for different horizontal well depths versus time

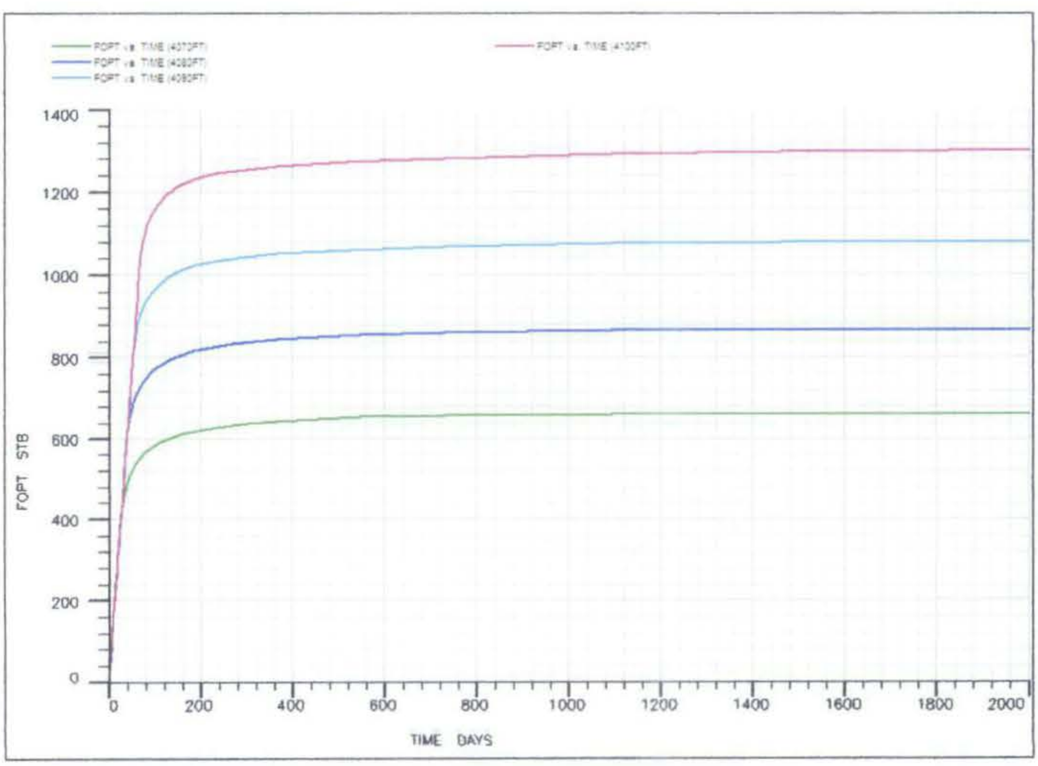


Figure 32: FOPT for different horizontal well depths versus time

Observation

Table 15: Oil recovery of different producer depths

Producer Depth (ft)	FOE (%)	FOPT (stb)
4070	10.87	661.87
4080	14.21	865.86
4090	17.71	1079.13
4100	21.30	1301.87

In Case 1, different horizontal well depths are used to see their effects on recovery factor. Figure 31 and 32 shows the increase depth of horizontal well will result in the increase of FOE and FOPT. As shown in Table 15, the deepest production well of 4100 ft recovers the highest oil which is 21.30% or equivalent to 1301 stb. The rest production wells of 4070 ft, 4080 ft and 4090 ft only recover less than 20% with FOPT of 661 stb, 866 stb and 1079 stb respectively.

Analysis

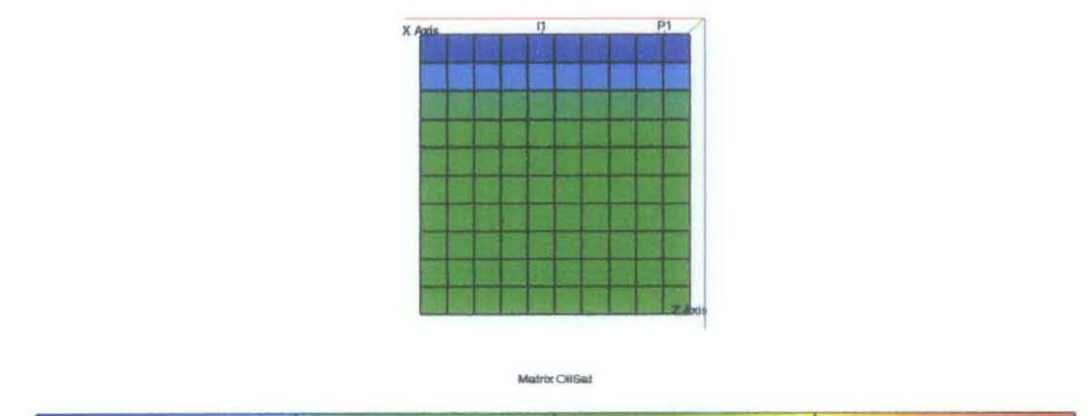


Figure 33: Matrix oil saturation profile after 2000 days of horizontal well at the deepest depth of 4100 ft

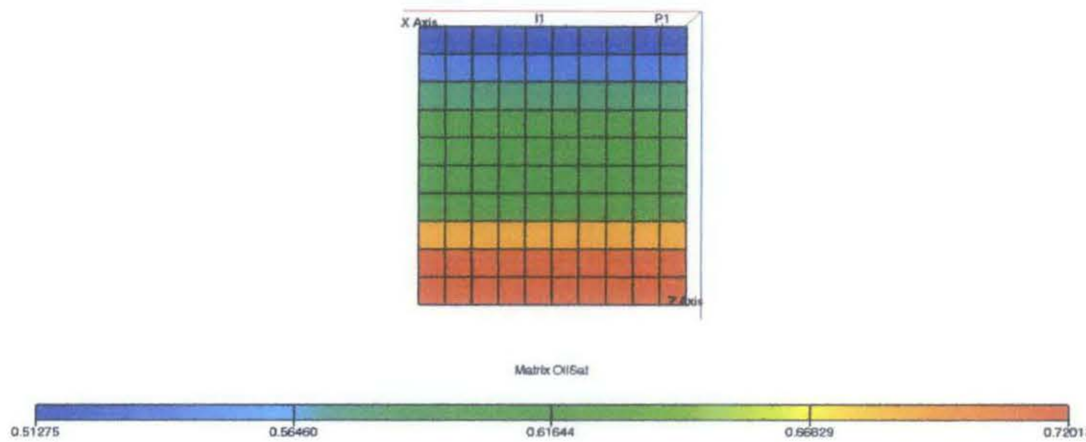


Figure 34: Matrix oil saturation profile after 2000 days of horizontal well at depth of 4070 ft

In Figure 33, producer is located at the bottom most of the reservoir which is at depth of 4100 ft (Z = 10). The green color which covers almost the whole reservoir shows good sweep efficiency of the injected gas. The location of the well has helped the recovery of oil from the most part of the reservoir above it and ultimately increases the oil recovery factor.

Meanwhile as shown in Figure 34, producer is located at the depth of 4070 ft which is at Z = 7. This case is also best representing the situation at the depth of 4080 and 4090 ft. In this case, oil production is mainly coming from the above part of the horizontal producer in the reservoir which is represented by the green color. The red portion at the bottom of reservoir is equivalent to the amount of unrecovered oil which becomes the cause of this lower recovery.

4.3 CASE 2: DIFFERENT HORIZONTAL WELL LENGTHS

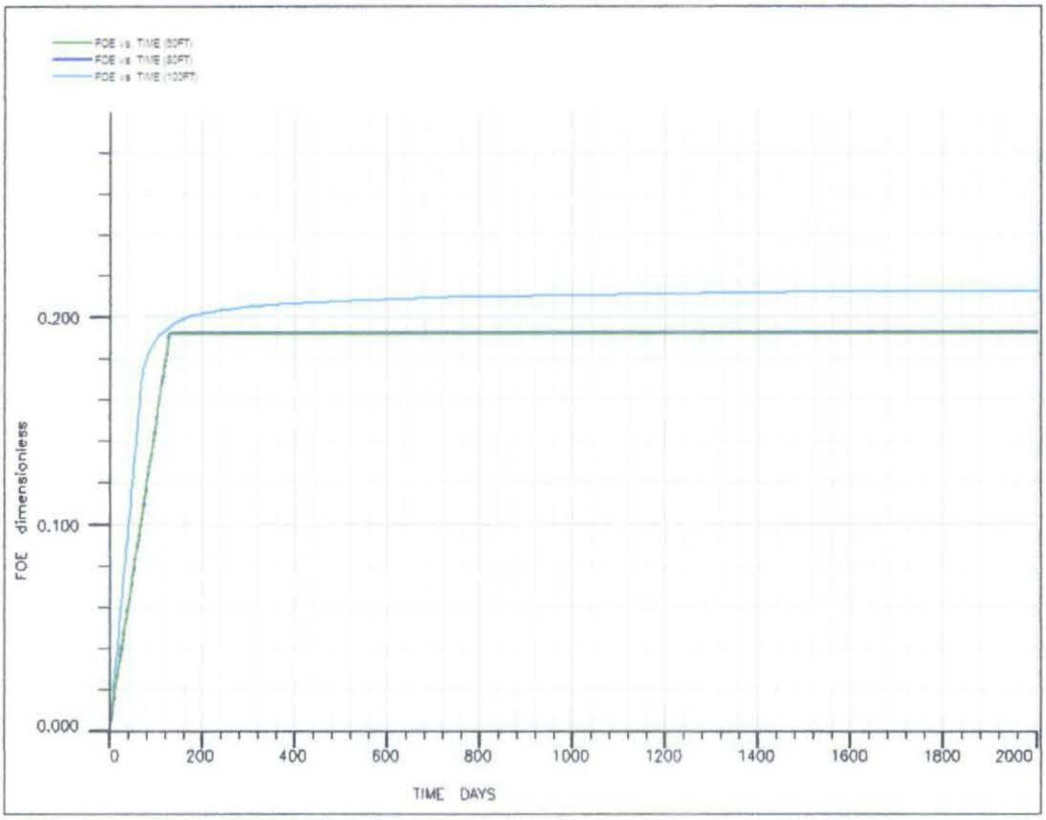


Figure 35: Different FOE vs. horizontal well lengths versus time

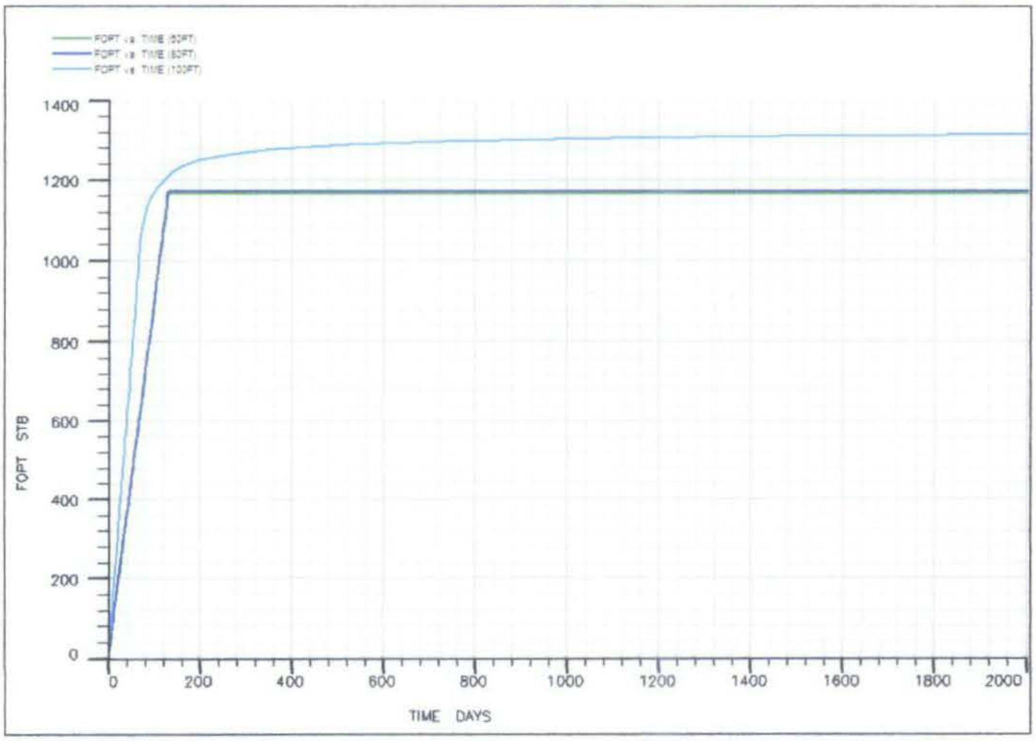


Figure 36: Different FOPT vs. horizontal well lengths versus time

Observation

Table 16: Oil recovery of different producer lengths

Well Length (ft)	FOE (%)	FOPT (stb)
60	19.16	1166.96
80	19.92	1170.87
100	21.26	1316.74

Both Figure 35 and 36 suggest that the longer horizontal producer, the higher oil is recovered. As presented in Table 16, the increase of horizontal well length has resulted in the increase of FOE and FOPT.

Analysis

As presented in Table 16, the longest well length which is 100 ft is able to gain oil recovery factor of 21.26 %. The two shorter wells only recover less than 20 %. It is because; the longer producer means more fractures are intercepted and larger drainage area is covered. Eventually, this will result in high oil recovery.

Figure 37 through 39 are the bottom view of reservoir model. As shown in Figure 37, the horizontal orange line represents the drainage area across the reservoir. On the other hand, Figure 38 and 39 suggest that the shorter producer provide smaller drainage area. Thus, it is concluded that, the longest producer has the highest possibility to achieve highest recovery factor.

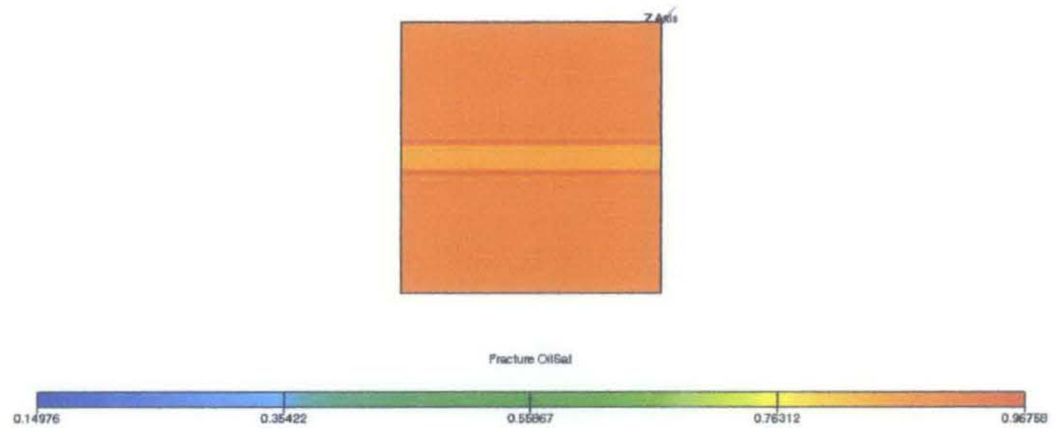


Figure 37: Fracture oil saturation profile from bottom view of reservoir for producer length of 100 ft.

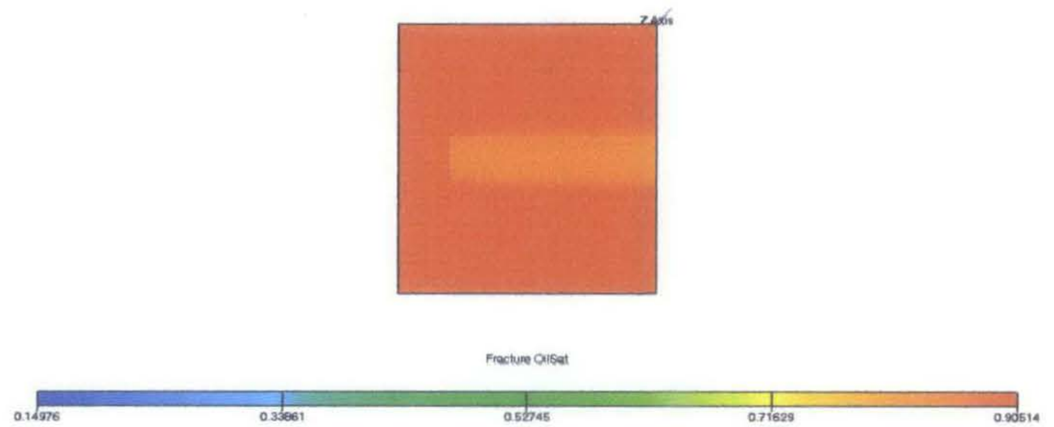


Figure 38: Fracture oil saturation profile from bottom view of reservoir for producer length of 80 ft.

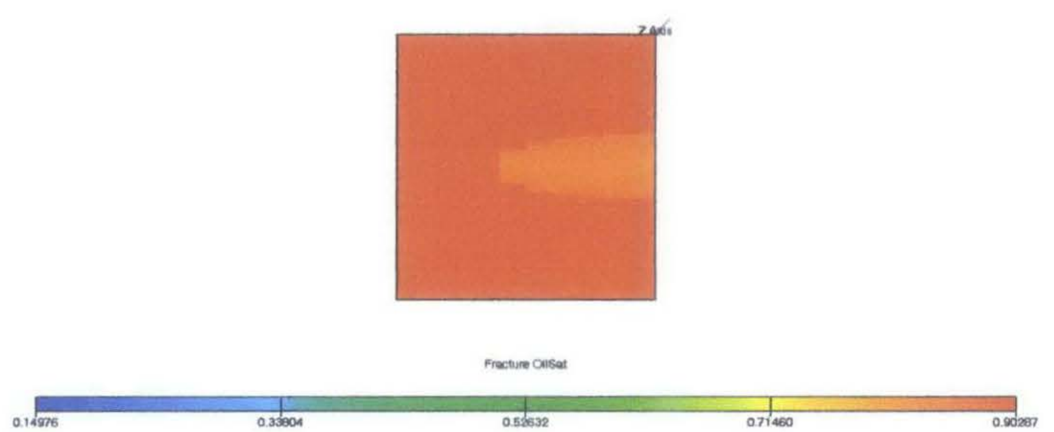


Figure 39: Fracture oil saturation profile from bottom view of reservoir for producer length of 60 ft.

4.4 CASE 3: DIFFERENT INJECTION RATES

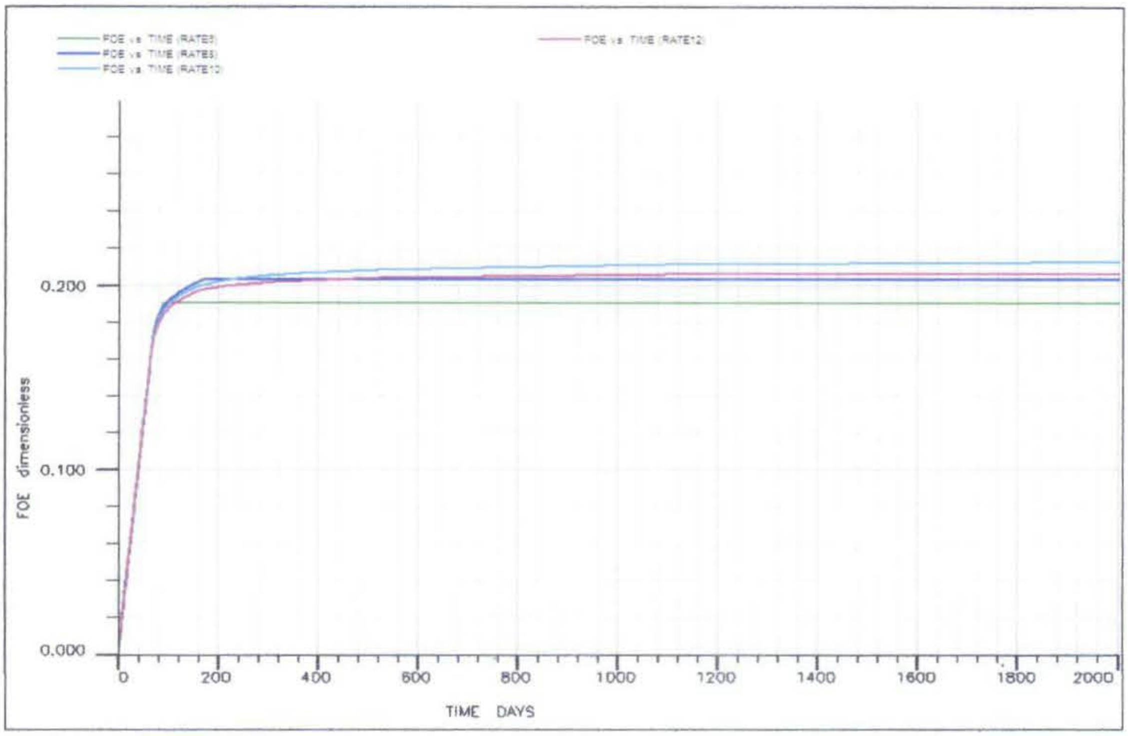


Figure 40: FOE of different injection rates versus time

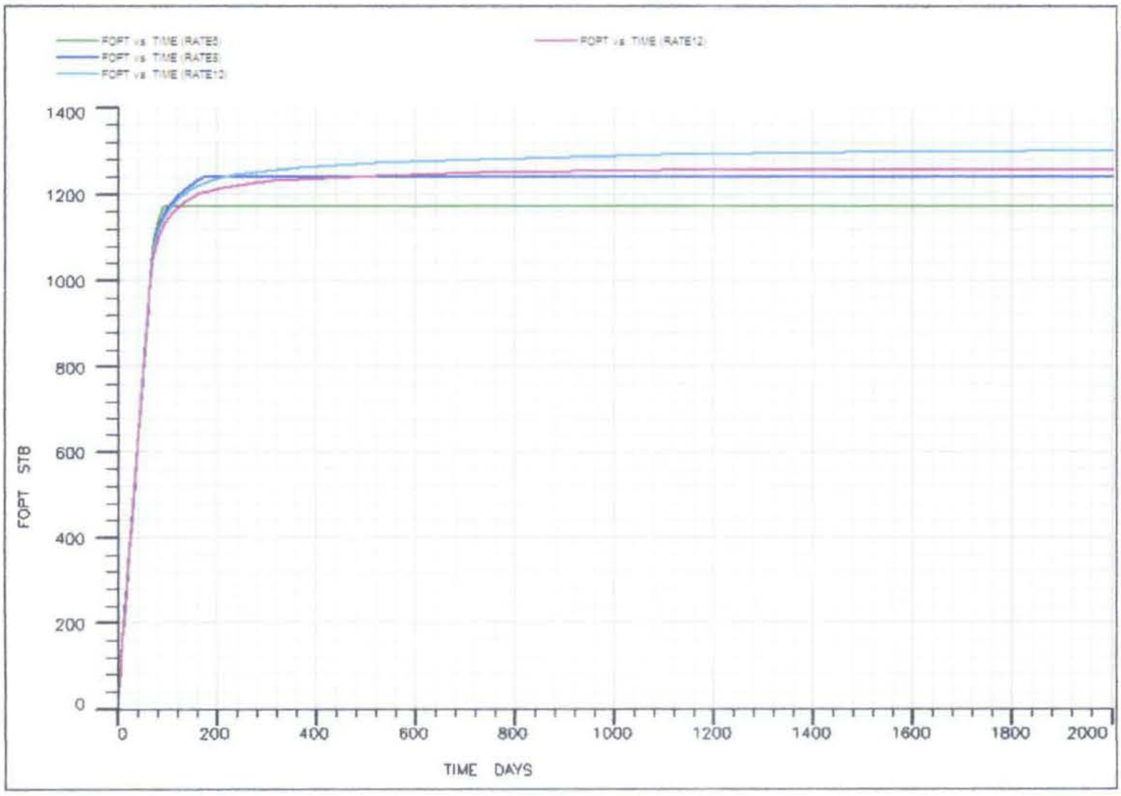


Figure 41: FOPT of different injection rates versus time

Observation

Table 17: Oil recovery of different injection rates

Injection Rate (mscfd)	FOE (%)	FOPT (stb)
6	11.70	1171.53
8	20.33	1239.16
10	21.99	1301.87
12	20.64	1257.44

In this case, 4 different injection rates are used which consist of 6 mscfd, 8 mscfd, 10 mscfd and 12 mscfd. In Table 17, it is clearly shown that FOE and FOPT are continuously increasing as injected gas rate is increased up to a certain limit. Beyond the limit, the increase of injection rate will only result in the decrease of both. In this simulation, FOE has improved when injection rates are increased from 6 mscfd up to 8 mscfd. The highest FOE is observed at 10 mscfd of injection rate. However, FOE becomes slightly lower than the previous one when the injection rate is increased to 12 mscfd. The following analysis is carried out to justify the observation.

Analysis

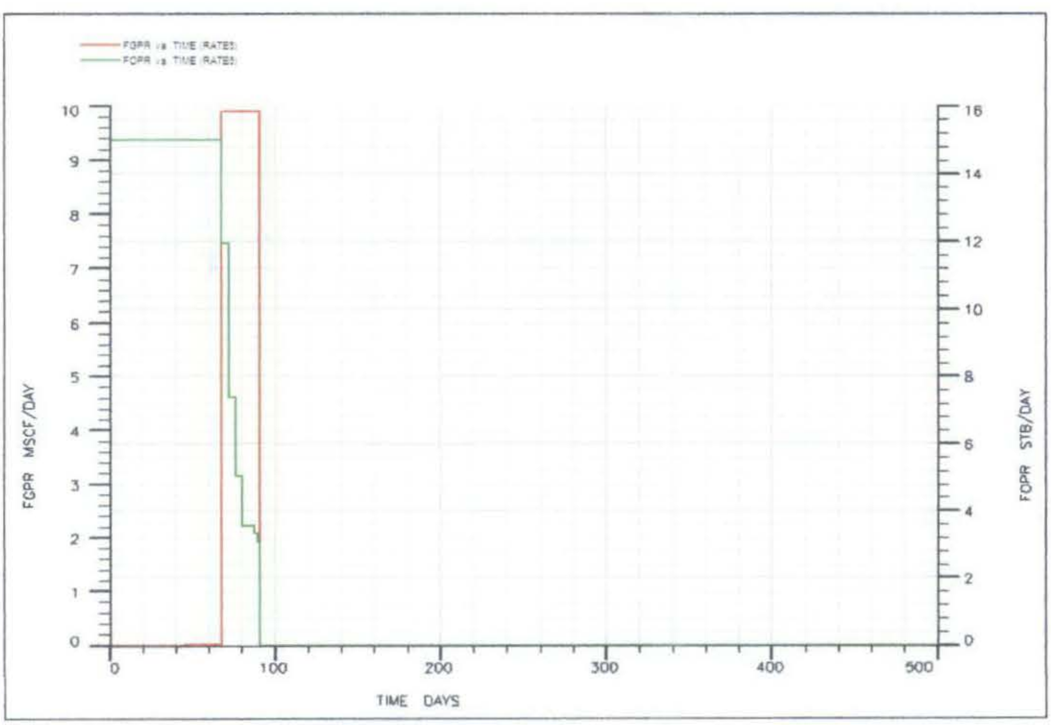


Figure 42: FOPR and FGPR at injection rate of 6 mscfd versus time

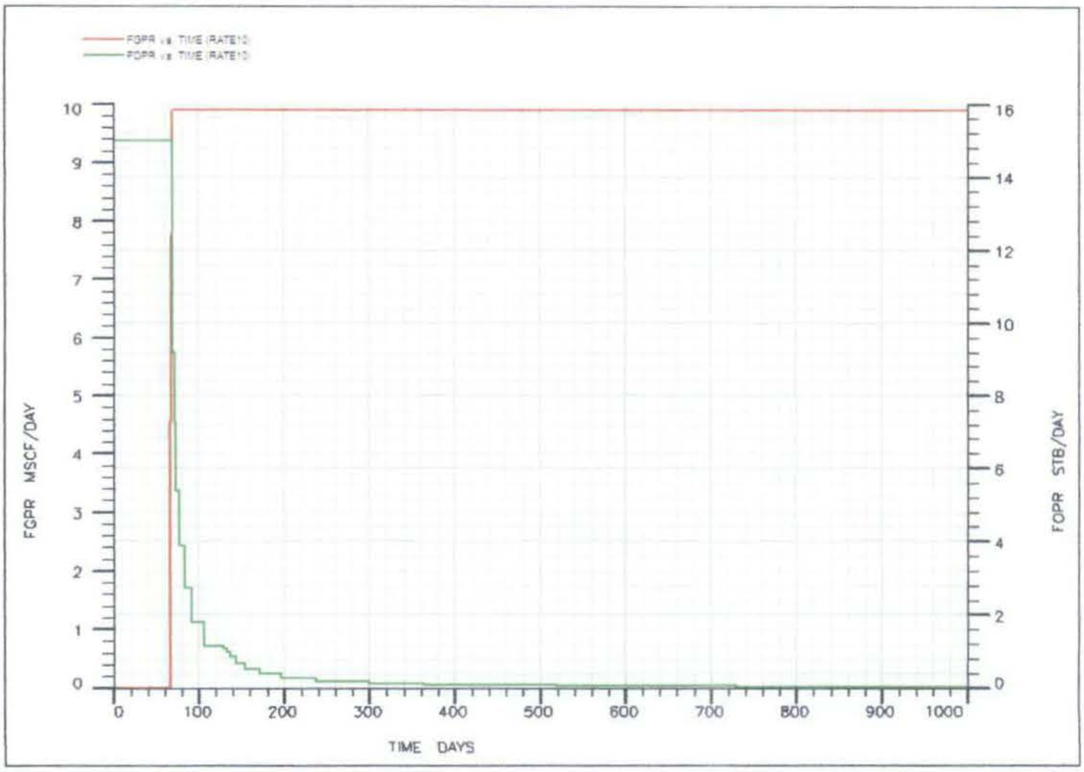


Figure 43: FOPR and FGPR at injection rate of 10 mscfd versus time

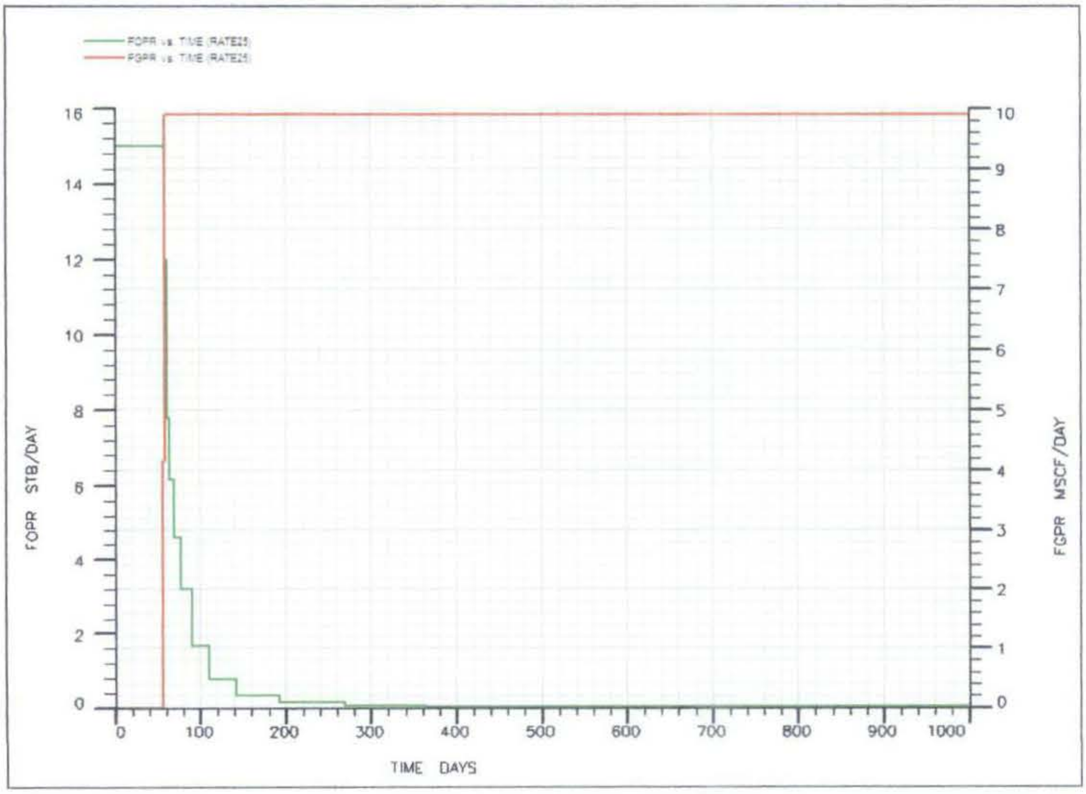


Figure 44: FOPR and FGPR of injection rate at 25 mscfd versus time

Table 18: Oil production period of different injection rate

Injection Rate (mscfd)	Oil production period from matrix and fracture before gas breakthrough (days)
6	73
8	70
10	68
12	67

In Figure 42 until 44, oil production which mainly from fracture is presented by the first green part with high production rate while production from matrix alone is indicated by the subsequent low and long tail production rate.

In Figure 42, at 6 mscfd, maximum oil production from matrix and fracture is until day 73. Subsequently, its oil production time period which mainly comes from matrix is much shorter which only around 20 days. As oil production rate starts to decrease, gas production rate increases significantly high, signifying the beginning of gas breakthrough into the producer. Subsequently, gas production rate suddenly drops to zero after 20 days. In this case, producer is set to produce 9.90 mscf as opposed to injection rate of 6 mscfd. This low injection rate fails to maintain reservoir pressure, thus causing the BHP pressure to fall below the set pressure of 950 psi in much short period of time. Eventually, producer is automatically closed and hence gaining low oil recovery. The same situation is observed at injection rate of 8 mscfd.

As presented in Table 18, gas injection rate at 10 mscfd is the optimum rate. As shown in Figure 43, oil production period before gas breakthrough is 68 days. After that, oil production begins to decrease with much slower rate compared to the previous case. It continues until day 2000. On the moment of gas breakthrough, sudden gas increase is observed and constantly prolonged until day 2000. This observation indicates at this rate, more gas is entering the matrix thus replacing the produced oil. This high amount of diverted gas into the matrix has increased oil recovery factor.

At 12 mscfd, the difference in terms of oil and gas production rate is not clearly observed. The injection rate is raised up to 25 mscfd as in Figure 44, the gas breakthrough is clearly observed as early as on day 60. This is indicated by sudden increment of gas production rate (red line). Meanwhile, oil production rate starts to decline and become completely zero on day 270. It is concluded that beyond optimum injection rate, more gas prefer to flow in high permeable fracture channels and simply leaving behind oil in the matrix. This has decreased the total oil recovery factor.

With the increase of injection rate, it is expected that viscous fingering phenomena will occur. It might be possible to clearly observe the phenomena at the rate of 25 mscfd. However, as shown in Figure 45, no trace of viscous fingering effect observed which suggests stable horizontal displacement. Most probably, this is due to the homogeneous permeability characteristic of both fractures and matrix. Viscous fingering will be clearly visible in heterogeneous permeability.

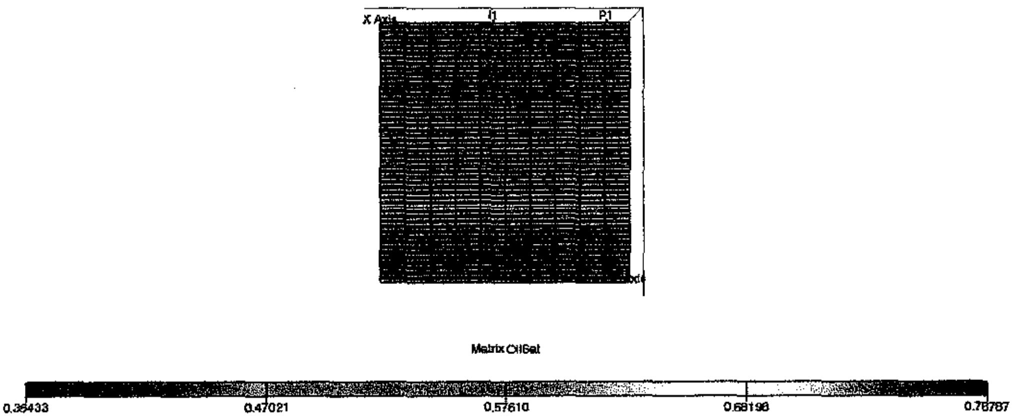


Figure 45: No viscous fingering observed at injection rate of 25 mscfd.

CHAPTER 5

CONCLUSION AND RECOMMENDATION

5.1 CONCLUSION

Based on the results and discussion, it is concluded that;

1. Horizontal well technology is beneficial as it benefits the gravity effect, whereas vertical well causes severe gravity effect. Horizontal producer recovery is 21.29%, whereas vertical producer recovery is 19.04%.

2. Recovery with gas injection (also known as GAGD) is much higher compared to natural drive (FOE of 21.29 % and 9.28 % respectively). Besides pushing oil from matrix and fractures towards producer, injected gas in fractures also aid the imbibitions oil from matrix.

3. Horizontal well depth should be kept as deep as possible, and possibly slightly above water-oil contact. The reason is that the well recovers most of oil on top of it while the injected gas keeps pushing the oil downwards. The deepest depth of 4100 ft gives the highest recovery which is 21.30%. All shallower producers depth only deliver less than 20% recovery factor.

4. Horizontal well length plays important role. The longer horizontal well length, the higher possibility of the well to intercept fractures and thus obtaining high productivity. The longest producer in this simulation gives the highest recovery factor of 21.26%. All shorter producers deliver less than 20% recovery factor.

5. Optimum injection rate is important for maximum recovery. Incorrect injection rate will lead to poor sweep efficiency, early gas breakthrough and less productivity. At optimum injection rate of 10 mscfd which close to the set production rate, the recorded recovery factor is 21.99%.

6. At this reservoir condition, the optimum condition to get the highest recovery are at the deepest depth of 4100 ft, at the longest horizontal producer of 100 ft and at the optimum injection rate of 10 mscfd.

5.2 RECOMMENDATION

The following are the suggestion to carry out in order to improve this project in the future:

1. Balance between oil rim in fracture and the gas injection rate is very important. Overproduced wells will result in gas-out which is indicated by the early gas breakthrough. Therefore, wells need to be closed-in or rate-reduced to allow the rim to build up again.
2. At optimum condition, the highest oil recovery factor is still low which less than 30%. One of the factors is the gas viscosity itself which is very low. If gas viscosity is further reduced, this will allow more injected gas being diverted into matrix thus obtaining higher productivity.
3. To see viscous fingering effect, reservoir permeability might need to be varied in x, y and z direction especially in different injection rates.

5.3 PROBLEM ENCOUNTERED AND SOLUTION

Throughout the project, the author faced a number of problems;

1. To find the most simulation model, as the existing model in ECLIPSE tutorial kept on giving errors when modification was made.
2. To understand phenomena and cause which affect productivity in each cases
3. To find root cause of errors for each simulation as some of simulation took up more than 1 hour to complete.
4. To modify the dual porosity model from Msc Thesis to fit the objective of FYP2.

The following are among of efforts to resolve the problems;

1. The author sought the assistance from his supervisor, Mr Iskandar Dzulkarnain, his lecturer, Mrs Mazuin Jasamai and post graduate student, Mr Saeed from EOR Centre when dealing with the model.
2. The simulation could be regarded as self-study as the author had to find root cause of each encountered problem and all possible solution on his own based on trial and error, papers and ECLIPSE manual.

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APPENDIX I : ECLIPSE Input File for dual porosity model

```
RUNSPEC
TITLE
    Gas Injection. DOUBLE POROSITY BLACKOIL 3D MODEL
DIMENS
    10    10    20/
DUALPORO
NSTACK
300/
--Phases
OIL
GAS
--Units
FIELD
FMTOUT
UNIFIN
UNIFOUT
--
--Dimension of Equilibration Tables
EQLDIMS
    2  300 /
--Full Implicit Solution
FULLIMP
--
TABDIMS
    2    1    50    50    1    50    50 /
WELLDIMS
    100   100    1    100/
--
REGDIMS
    3  3 /
--
START
   1 'JAN' 1991  /
--
--gravity drainage activated
GRAVDR
GRAVDRM
YES /
```

```
--Request information required by GRAF for the run-time
monitoring option
MONITOR
--
GRID    =======================================================
NODPPM
DPGRID
EQUALS
 'DX'      10      1  10  1  10  1   10/ MATRIX CELLS
 'DY'      10      1  10  1  10  1   10/
 'DZ'      10      1  10  1  10  1   10/
 'PORO'    0.07    1  10  1  10  1   10/
 'PERMX'   0.20    1  10  1  10  1   10/
 'PERMY'   0.20    1  10  1  10  1   10/
 'PERMZ'   0.20    1  10  1  10  1   10/
 'TOPS'    4000    1  10  1  10  1   1 /
 'PORO'    0.02    1  10  1  10  11   20/ FRACTURE CELLS
 'PERMX'   5000.0  1  10  1  10  11   20/
 'PERMY'   5000.0  1  10  1  10  11   20/
 'PERMZ'   5000.0  1  10  1  10  11   20/
 'TOPS'    4000    1  10  1  10  11   11/
--
/
SIGMA
0.12 /
DZMTRX
10.00/
--
--
INIT
--
PROPS   =======================================================
--STONE
--
--Sgas   Krg   Krog   PCo-g
SGOF
--For Matrix
    0.30  0.00  0.20  0.00
    0.35  0.02  0.14  0.52
    0.40  0.11  0.09  2.08
    0.45  0.25  0.05  4.68
    0.50  0.44  0.02  8.31
    0.55  0.69  0.01  12.99
    0.60  1.00  0.00  18.71/
```

```
--Sgas    Krg    Krog    PCo-g
--For Fracture
    0.10  0.00  1.00  0.00
    0.15  0.00  0.87  0.00
    0.20  0.02  0.75  0.02
    0.25  0.04  0.64  0.04
    0.30  0.07  0.54  0.06
    0.35  0.11  0.44  0.10
    0.40  0.16  0.36  0.14
    0.45  0.22  0.28  0.19
    0.50  0.28  0.22  0.25
    0.55  0.36  0.16  0.32
    0.60  0.44  0.11  0.40
    0.65  0.54  0.07  0.48
    0.70  0.64  0.04  0.57
    0.75  0.75  0.02  0.67
    0.80  0.87  0.00  0.78
    0.85  1.00  0.00  0.89/
/
-- Pref    Bw    Compress.    Visc    Viscosidad
--PVTW
--     4177.26515720938 1.04443331210154 3.38305207164555e-006
0.234206381222971 6.09495013140872e-006
/
--Rock Compressibility
ROCK
1532  4.5E-6/ MATRIX SYSTEM
1532  3.4E-5/ FRACTURE SYSTEM
--Surface density of reservoir fluids
-- oil    water    gas
DENSITY
   56.65   62.4   0.06150/
--request, flux limiting scheme to reduce numerical dispersion.
TRACTVD /
--PVT Props of dry gas (no vaporised oil)
--    Pgas    FVFG    VISCO
PVDG
         14.6959    239.8534      0.0105
         29.1996    119.4149      0.0106
        216.2977     15.0230      0.0119
        380.1898      8.5067      0.0127
        729.7296      4.3887      0.0137
```

```
       1130.0324      2.8049      0.0148
       1479.5722      2.1258      0.0159
       1829.1120      1.7092      0.0171
       2035.8160      1.5319      0.0179
       2074.2249      1.5021      0.0181
/
--Poil  FVFO  VISO /Data for undersaturated oil
PVDO
       2035.8160      1.6178      0.2533
       2074.2249      1.6157      0.2555/
/
PMAX
2074  2074 /

--Activated for SOF3, SWFN, SGFN, PVTW, PVDG, DENSITY and ROCK
keywords
RPTPROPS
 DENSITY  SWFN  SGFN  SOF3   /
--
REGIONS ================================================================
--To quantify the oil in place in the oil zone
FIPOWG
SATNUM
--Specify the saturation function to which it belongs
  1000*1   1000*2 /
--define equiblirationregion to each gridblock
--2 fracture region
--1 matrix region
EQLNUM
1000*1  1000*2 /

SOLUTION ===============================================================
--datum   datum   OWC  OWC    GOC  GOC   RSVD   RVVD   SOLN
--depth   press  depth Pcow  depth Pcog  table  table  meth
EQUIL
--for matrix
4000  1080  30000  0  4040   0   0   0   0  /
--
--for fracture
4000  1080  30000  0  4040   0   0   0   0  /
```

```
--output control (switch on output of initial gridblock
pressure)
RPTSOL
 POIL  SGAS  SOIL /
RPTRST
  'BASIC=3'
   /
SUMMARY
RUNSUM
EXCEL
--request run summary output
LOTUS
FOPR
FOPT
FOE
FGPR
FOPT
FGOR
/
FPR
WBHP
/
WOPR
/
WGPR
/
WWCT
PROD

SCHEDULE  =====================================================
RPTRST
'BASIC=1' 'TBLK' 'SGAS' /
--
RPTSCHED
 'CPU' 'FIP' 'POIL' 'SOIL' 'SGAS' 'WELLS' 'SUMMARY=2'
'WELSPECS'/
--
--gas re-solution rate
DRSDT
0 /

WELSPECS
--        i  j  ref depth
P1   G1  01 06  4100  'OIL' /
```

```
I1   G1  06 06  4042  'GAS' /
/
--
--wells must be completed in the fracture
--       i  j     k   k  Flag  sat.tab   ConnFactor   Skin
COMPDAT
P1       01  06  20  20  OPEN  0            1*         0.5/
P1       02  06  20  20  OPEN  0            1*         0.5/
P1       03  06  20  20  OPEN  0            1*         0.5/
P1       04  06  20  20  OPEN  0            1*         0.5/
P1       05  06  20  20  OPEN  0            1*         0.5/
P1       06  06  20  20  OPEN  0            1*         0.5/
P1       07  06  20  20  OPEN  0            1*         0.5/
P1       08  06  20  20  OPEN  0            1*         0.5/
P1       09  06  20  20  OPEN  0            1*         0.5/
P1       10  06  20  20  OPEN  0            1*         0.5/
I1       06  06  13  14  OPEN  0            1*         0.5/
/

--units (STB/d)
WCONPROD
P1 'OPEN' 'BHP' 15 1* 9.90 2* 950.01/
/
--units (Mscf/day)
WCONINJE
I1 GAS OPEN RATE 10 /
/
TUNING
0.001  5   0.05   0.15   3  0.3  0.1  1.25  0.75/
0.1  0.001  1E-7  0.0001
10  0.01  1E-6  0.001  0.001/
50   1   500   1   25   12  4*1E6/

TSTEP
6*365 /
END
```

3. Final vaporization of oil

During this stage, heavy-intermediate and heavy components are vaporized. This stage is relatively slow compared to the previous stages, but large additional recovery may be achieved.

2.5.2 Gas-Oil Gravity Drainage Concept[34]

Gas-oil gravity drainage (GOGD) is one of the main recovery mechanisms in (non-water-wet) naturally fractured reservoir. After initial depletion, gas-oil and water-oil contacts are established in the fracture.

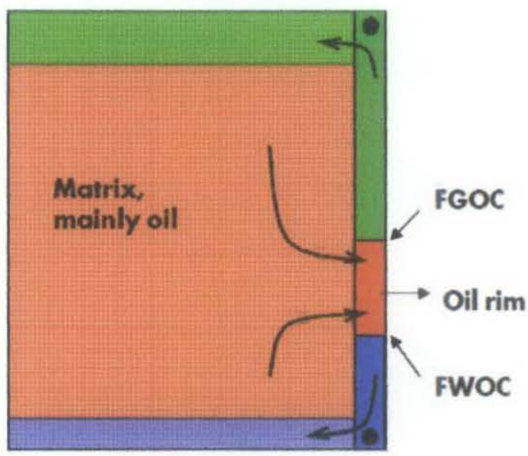

Figure 23: Fracture-matrix in equilibrium after primary depletion

At this stage, matrix oil can be produced by gravity forces. GOGD relies on the density difference between oil and gas (GOGD) and oil and water (WOGD) as driving force. Oil-rim in the fractures must be must be lowered through the production to maintain the production in GOGD. However, this has resulted in the early breakthrough and obvious reduction of the production. Under GOGD, the balance between oil rim and gas injection rate should be maintained. This is because overproduced wells will cause gas-out and rate reduction is required to allow the rim to build up again.

[34] R. farajzadeh et al., :" Foam Assisted Gas Oil Gravity Drainage in Naturally-Fractured Reservoirs", *Paper SPE 134203 Presented at the 2010 SPE Annual Technical Conference and Exhibition held in Florence, Italy, September 19-22*