Improved Oil Recovery for Oil Reservoirs with Gas Cap

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การเพิ่มการผลิตน้ำมันในแหล่งกักเก็บซึ่งขับดันด้วยชั้นก๊าซด้านบน

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วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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เมเลน ดโจมาทชัว ซีอานเจว : การเพิ่มการผลิตน้ำมันในแหล่งกักเก็บซึ่งขับดันด้วยชั้นก๊าซด้านบน (Improved Oil Recovery for Oil Reservoirs with Gas Cap) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: ผศ. ดร. จิรวัฒน์ ชีวรุ่งโรจน์ Ph.D, 181 หน้า.

ในปัจจุบันการผลิตน้ำมันจากแหล่งกักเก็บที่มีชั้นก๊าซด้านบนส่วนใหญ่อาศัยการฉีดอัดก๊าซ ซึ่งเป็นการเพิ่มพลังงานให้กับแหล่งกักเก็บและยังสามารถรักษาระดับการผลิตน้ำมันจากการกวาดน้ำมันเข้าสู่หลุมผลิต นอกจากนี้ยังเกิดกระบวนการแลกเปลี่ยนองค์ประกอบของก๊าซที่แดอัดกับน้ำมันในแหล่งกักเก็บ อย่างไรก็ตามการฉีดอัดก๊าซยังไม่ประกันได้ว่าประสิทธิภาพการผลิตน้ำมันจะสูงที่สุด เพราะยังมีปัจจัยที่เกี่ยวข้องอีกเช่นลักษณะของแหล่งกักเก็บที่หลากหลายและกลยุทธ์การผลิต

แบบจำลองแหล่งกักเก็บแบบองค์ประกอบถูกใช้เป็นเครื่องมือเพื่อศึกษาการเพิ่มการผลิตน้ำมันเบาจากแหล่งกักเก็บที่มีชั้นก๊าซด้านบนโดยอาศัยการฉีดอัดก๊าซ ซึ่งมีการเปลี่ยนแปลงของอัตราการผลิต ประเภทและตำแหน่งของหลุมผลิต การเริ่มและการยุติการฉีดอัดก๊าซ ผลการศึกษาแสดงให้เห็นว่าการผลิตน้ำมันด้วยอัตราการผลิตต่ำเช่น อัตราการผลิต 500 บาร์เรลต่อวันเมื่อเทียบกับ 200 บาร์เรลต่อวันจะให้ผลผลิตที่มากกว่า การฉีดอัดก๊าซให้ผลผลิตน้ำมันมากเป็นสองเท่าของการผลิตโดยใช้พลังงานจากแหล่งกักเก็บเพียงอย่างเดียว ในขณะที่การฉีดอัดก๊าซควบคุมแบบควบคุมในหลุมผลิตแนวนอนให้ผลผลิตน้ำมันมากกว่าหลุมผลิตมนแนวดิ่งที่มีการฉีดอัดก๊าซภายอัตราการผลิตและการฉีดอัดก๊าซเหมือนกัน การฉีดอัดก๊าซตั้งแต่เริ่มการผลิตและดำเนินการอย่างต่อเนื่องให้ประสิทธิภาพการผลิตสูงขึ้นกว่าการฉีดอีดก๊าซภายหลังและยุติกลางคัน การวางตำแหน่งหลุมผลิตให้ห่างจากหลุมอัดก๊าซทำให้ประสิทธิภาพการผลิตดีกว่าหลุมผลิตที่อยู่ใกล้กับหลุมอัดก๊าซ การฉีดอัดก๊าซช่วยกวาดน้ำมันในแหล่งกักเก็บละยังช่วยให้น้ำมันในแหล่งกักเก็บสามารถระเหยเป็นไอและถูกผ ลิตออกมาทำให้มีปริมาณน้ำมันหลงเหลือน้อยลง

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Current oil recovery method for a gas cap oil reservoir mostly involves gas reinjection. Gas reinjection is performed to supplement the reservoir energy, and to maintain oil production by sweeping oil towards the production well. The gas injection process also gives advantages of component exchange that occurs in the gas oil contact as the injected gas steam sweeps the oil in the reservoir. However, employing the strategy of gas reinjection does not necessarily guarantees high oil recovery efficiency, as the total amount of oil recovered depends on a wide range of reservoir characteristics as well as the production strategy.

In this work, a compositional reservoir simulator was used to investigate the improved recovery capabilities of a light oil reservoir with gas cap by concept of gas reinjection into the reservoir. The study comprised of changing operational parameters such as oil flow rate, type of production well, time to initiate/stop gas injection and changing well positions to see how each parameter affects the oil recovery efficiency. The results showed that producing the reservoir at different flow rates for example at 500 stb/d compared to 2000 stb/d, the lower flow rate gave slightly higher oil recovery efficiency compared to the higher flow rate. With gas reinjection into the reservoir, the recovery efficiency was more than double the recovery efficiency obtained from natural depletion, in addition, the horizontal wells under gas reinjection schedule gave much higher oil recovery than vertical wells under similar conditions of oil production rate and gas reinjection specifications. Initiating the gas reinjection process from the start of production resulted in higher oil recovery than starting the gas reinjection process later on during production. Also, performing the gas reinjection process from start of production till end of production gave higher oil recovery than terminating the gas reinjection process at some point during production. Finally, placing the production well a longer distance away from the injection well gave much higher oil recovery than placing the injection and production well closer apart. Gas reinjection helped in sweeping the oil and reducing the oil saturation in the swept area by vaporizing the oil into produced gas.

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LIST OF ABBREVIATIONS

rb	reservoir barrel
bbl/d	barrel per day
Mscf	thousand standard cubic feet
MMscf	million standard cubic feet
Bscf	billion standard cubic feet
Mscf/d	thousand standard cubic feet per day
stb	stock tank barrel
GOR	gas-oil ratio
mD	millidarcy
scf/stb	standard cubic feet per stock tank barrel
TVD	True Vertical Depth
IOR	Improved oil recovery
FRAC.S.G	fracturing pressure gradient
PVT	Pressure-volume-temperature
FOPR	field oil production rate
FOPT	field oil production total
FGPR	field gas production rate
FGPT	field gas production total
FPR	field pressure
FOE	field oil efficiency
FZMF	field total mole fraction

NOMENCLATURE

P_i	initial pressure
R_{si}	Initial gas oil ratio
^oAPI	American Petroleum Institute gravity
n_o	Corey oil exponent
n_w	Corey water exponent
n_g	Corey gas exponent
s_{wc}	connate water saturation
s_{orw}	residual oil saturation to water
$s_{w,max}$	maximum water saturation
s_{org}	residual oil saturation to gas
s_{gc}	critical gas saturation
s_{gi}	initial gas saturation
$s_{g,max}$	maximum gas saturation
k_{ro}	relative permeability to oil
k_{rg}	relative permeability to gas
k_{rw}	relative permeability to water

CHAPTER 1
INTRODUCTION

A gas cap reservoir is a reservoir which exists originally with two phases, an oil phase overlain by a gas phase, with both fluids at saturated conditions of temperature and pressure initially. Current oil recovery method for this kinds of reservoir mostly involves gas reinjection. Gas reinjection is performed to supplement the reservoir energy, and to maintain oil production by sweeping oil towards the production well. The gas injection process also gives advantages of component exchange that occurs in the gas oil contact as the injected gas steam sweeps the oil in the reservoir. With all of these benefits, gas reinjection process gives the possibility to recover a high percentage of the oil initially in place in the reservoir. However, employing the strategy of gas reinjection does not necessarily guarantees high oil efficiency, as the total amount of oil recovered will depend on a wide range of reservoir characteristics (for example rock permeability, fluid relative permeability) as well as the production strategy (including the well types, oil withdrawal rate and how well the reservoir drive mechanism is conserved in the reservoir.

In this work, a compositional reservoir simulator was used to investigate the improved recovery capabilities of a light oil reservoir by concept of gas reinjection into the reservoir. A saturated oil reservoir with a gas cap was selected for this study. The study comprised of changing operational parameters such as oil flow rate, type of production well, time to initiate/stop gas injection and changing well positions to see how each parameter will affect the oil recovery efficiency. In addition, compositional interactions that take place in the reservoir are analysed to have an understanding on how injected gas moves in the reservoir. In this light, oil and gas saturation in the reservoir at various time of production are analysed and a comparison is done on operational parameters as well as well completion types to arrive on conclusions of best parameters to use to produce the reservoir.

1.1 Objectives

1. To investigate improve recovery of light oil reservoir by concept of produced gas reinjection.
2. To study the effects of time to begin gas reinjection on level of improved oil recovery
3. To study the effects of producing gas-oil ratio during gas reinjection process on level of improved oil recovery
4. To study the effects of changing well position on level of improved oil recovery

1.2 Outline of methodology

1. Studying related work to understand life cycle of gas cap reservoirs
2. Data collection and building simulation model using Schlumberger ECLIPSE compositional simulator (ECLIPSE 300)
3. Study the performance of the reservoir based on oil recovery efficiency, by changind the operational parameters
4. Analyse oil and gas saturation profile of the reservoir at different time
5. Present results and discussion
6. Draw conclusions and make recommendations

1.3 Outline of thesis

This thesis is divided into six chapters. The outline of each chapter is described below.

Chapter 1 introduces the background of improved oil recovery process in gas cap oil reservoirs and states the objectives and outlines the methodology of the study.

Chapter 2 presents some review of literature studies on improved recovery process and oil well pressure maintenance via gas injection and fracturing.

Chapter 3 gives details of the theory and concepts related to the studies

Chapter 4 gives a description of the reservoir simulation model and fluid used in the study.

Chapter 5 presents the results obtained and discusses the effect of the operational parameters employed in the study

Chapter 6 gives concluding remarks of the study and also gives recommendations for future work.

CHAPTER 2
LITERATURE REVIEW

2.1 Gas cap reservoir

A gas cap reservoir is a reservoir which exists originally with two phases, an oil phase overlain by a gas phase, with both fluids at saturated conditions of temperature and pressure initially; the initial pressure equals the dew point of the gas cap fluid, and it also equals the bubble point of the underlying oil phase. However, there sometimes are gas cap reservoirs in which the initial pressure may be greater than the saturation pressure of all mixtures in the reservoir, with the reservoir originally in under saturated condition.

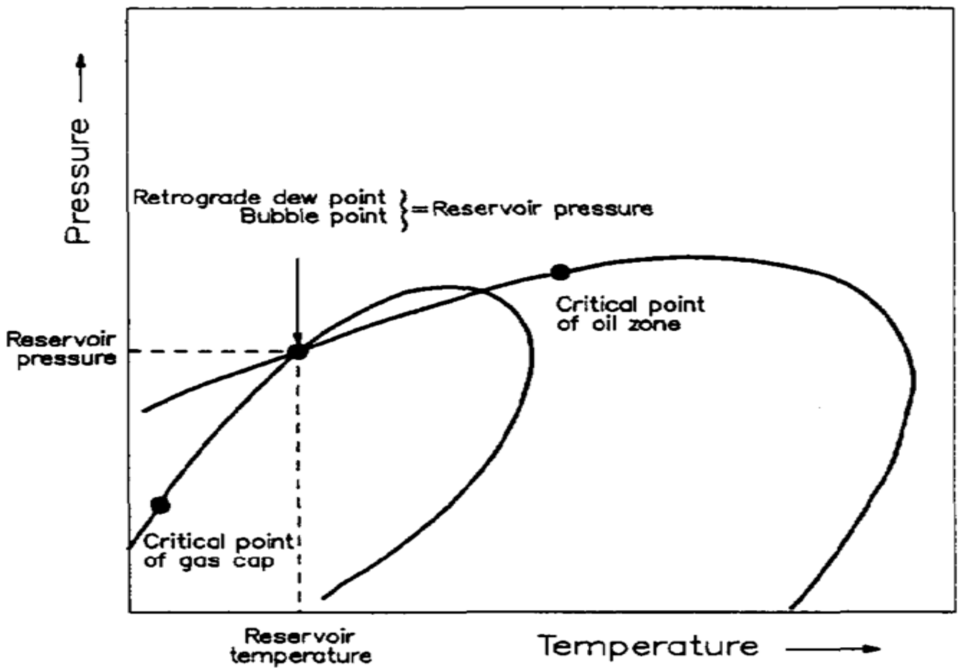

Figure 2.1 Pressure-temperature phase diagrams of gas cap and oil fluids in a reservoir that is initially at saturated conditions [1]

Craft et al [2] indicated that when there is an initial gas cap, there is negligible liquid expansion energy, however, the energy stored in the dissolved gas in the oil will be supplemented by the energy in the gas cap. In such gas cap drive, as production proceeds, the expansion of the gas displaces oil downward towards the producing well(s), this results in high increase in gas-oil ratio when the gas cap reaches the production well completion interval. Thus maintaining the gas cap movement at a uniform level is optimum for optimum recovery. If the gas cap shows definite expansion as indicated by a high level of reservoir pressure, and the producing wells remain at low gas-oil ratio, gravity is maintaining a uniform movement of the gas cap. The low produced gas-oil ratio continues until the gas cap reaches the wells, at which point a sizeable increase in the produced gas-oil ratio occurs. Recovery in such cases is greatly dependent on the completion intervals and well locations.

Muskat [3] showed that the presence of an active gas cap causes additional recovery in a gas cap reservoir, as well as maintaining higher pressure throughout the reservoir life. The produced gas-oil ratio is lower in the early production life and much higher in the late production life. This happens when the gas cap expands and reaches the perforated intervals in a producing well. When this happens, selective GOR Control is advisable which might include closing or recomplete the wells at a lower interval. Continued production without recompletion will not result in any appreciable additional oil from the wells, but will result in considerable loss of gas that should be kept in the reservoir to maintain the pressure. In some reservoirs, the gas may cusp into a producing well through a permeable zone. This also results in less recovery. Selective recompletion, or the shutting in of wells, should be considered to prevent unnecessary depletion of the reservoir energy.

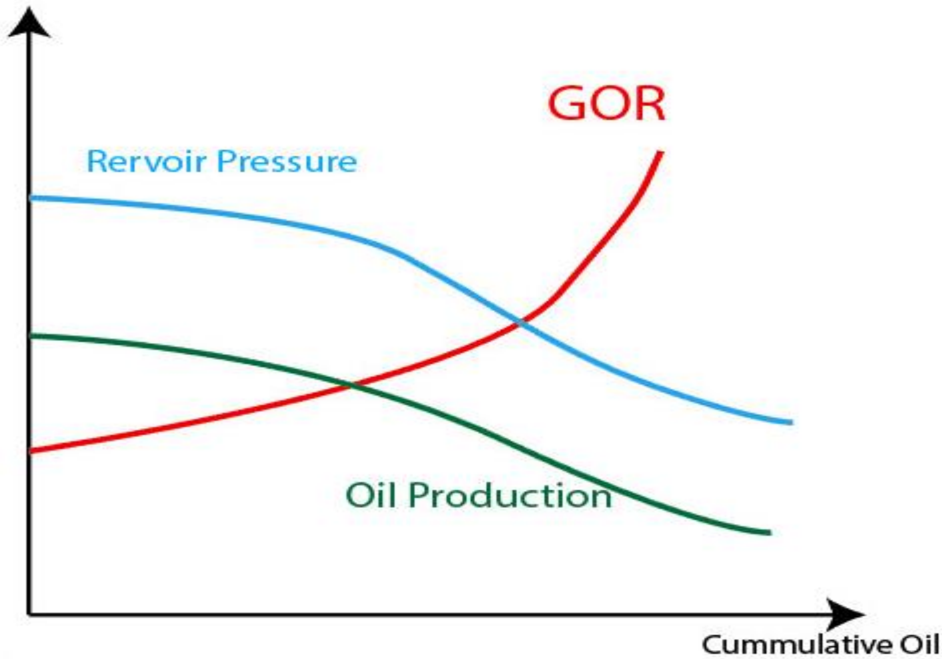

Figure 2.2 Typical production GOR, pressure and water cut profile for gas cap reservoirs [4]

As the natural energy of the reservoir declines, there is need to supplement the energy, to help improve productivity. A common method to provide external energy to a gas cap reservoir is via gas injection, in which the produced gas can be reinjected into the existing gas cap to help maintain reservoir pressure at high enough values, even if oil displacement is not required.

Wei et. al. [5] presented a field case performance history of the 26R reservoir under pressure maintenance by crestal gas injection. With a relatively inactive aquifer at the base of the 26R reservoir, pressure maintenance by crestal gas injection was initiated immediately after production began, this program led to an estimated reserve of 212 million barrel of the initial oil in place of 424 million barrel (50% OOIP), with reservoir pressure declining from 3155 psia to 2416 psia (this decline was attributed to migration of injected gas into the overlying shale reservoirs). They also performed a reservoir study using compositional simulation which indicated that more than 10% of oil and natural gas liquids produced resulted from oil vaporization process.

Murty et. al [6] performed gas injection in a saturated oil reservoir. The producing mechanism for the reservoir was by a combination of water drive, gas cap expansion and minor contribution from solution gas drive. The production performance was characterized by increase in water cut and GOR, causing decline in oil production. The increase in GOR, as well as water cut led to rapid pressure decline, which cause the gas cap to shrink, and oil migrated into the gas cap and lost as residual oil. To arrest the water invasion and stabilize the oil production they initiated gas injection in February 1986 at a rate equivalent to the produced gas from the gas cap, with objectives to stop the gas cap shrinkage, arrest the water invasion, increase the reservoir pressure and thus improve the reservoir performance. As a result, the reservoir pressure went up by 35 psia (241.3 kPa), the gas cap shrinkage was halted, the water cut in the affected wells decreased, and the daily oil production rate from the zone was stabilized.

2.2 Horizontal well

Horizontal wells are used mainly due to some unique character of the reservoirs and for the purpose of more surface area to flow and reduced pressure gradient in the reservoirs. Typically, horizontal wells are chosen to overcome the following key problems and limitations that often plague conventional IOR applications with vertical wells:

a. Insufficient well exposure in the formation
b. Poor injectivity and smaller drainage radius
c. Poor knowledge of the heterogeneity/lithology away from well
d. Higher pressure drawdown resulting in severe gas/water coning and sand egression
e. Inefficient displacement process because of well/reservoir constraints and radial flow
f. In thermal processes, less efficient use of thermal energy.

In addition, with horizontal wells gravity drive becomes the dominant drive mechanism. In fact, it can be envisaged that with horizontal wells which lead to much slower oil withdrawal rate, gravity force play an importance role for oil flowing down for oil reservoirs without strong water drive, for prevention of water coning for oil reservoirs with strong water drive, and for segregation of gas and oil for oil reservoir with gas cap.

Injection of produced gas for pressure maintenance purpose is a common practice in oil production when it is economical. Gangle et al [7] mentioned successful injection of dry gas into the large secondary gas cap region with production from horizontal wells for a reservoir which gravity drive is the dominant drive mechanism. Use of horizontal wells with fractures are now common for tight reservoir and shale reservoir [8] [9] [10]. The main purpose of using fractured horizontal wells is mainly for increase productivity of the well so that it can be produced economically. However, if it is argued that without these fractured horizontal wells, the reserves for shale gas or shale oil reservoirs will be zero, it can be said that these fractured horizontal wells not only increase productivity but also improve gas or oil recovery (from zero to some value).

CHAPTER 3
THEORY AND CONCEPT

3.1 Surface area to flow into wells

It is well-known that increase in surface area to flow into a well increases productivity of that well. This understanding is based on the concept of producing as much as possible from the reservoir probably mainly due to the economical reason. However, instead of producing from fractured horizontal wells at their full capacity, especially in a conventional oil reservoir, one can achieve slow movement of fluids in the reservoir due to pressure force by producing from fractured horizontal wells at their partial capacity. If this movement is sufficiently slow, the gravity force can become the dominant controlling force for movement of fluids in the reservoir. In addition, slow movement of fluids in the reservoir leads to low to very low pressure differences at various points in the reservoir. This allows near uniform phases distribution as opposed to non-uniform phase distribution in various regions of the reservoir as is the case with conventional vertical wells where there is higher pressure gradient. This high-pressure gradient causes gas to come out of oil and moving in the regions close to a well leading to less efficiency for oil production due to gas flow. In addition, accumulation of gas around a production well leads to obstruction to oil flow which may be one of the main reasons for low recovery factor. Near-uniform phase distribution will help alleviate all these problems. In addition, when pressure is under bubble point pressure, liberated gas occurring throughout the reservoir will help push oil from everywhere in the reservoir instead of only in the regions close to wells. For example, in the process of production from an oil reservoir with gas cap, if the movement due to pressure force is sufficiently slow, all liberated gas will move upward and join the existing gas cap due to domination of gravity force. This leads to the condition that only oil (with solution gas) is produced and all liberated gas is kept in the reservoir to further provide energy for pushing oil out. If the energy from gas in the gas cap and from the liberated gas is not enough to maintain optimal pressure in the reservoir, there is a need to inject produced gas into the gas cap.

If it can be controlled such that only oil (with solution gas) be produced and liberated gas be kept in the reservoir, finally all oil will be produced from the reservoir and only gas initially present in the gas cap and injected produce gas will be present in the reservoir. At this stage, it becomes a gas reservoir and can be produced further as a gas reservoir.

However, what is described in the previous paragraph seems to be idealized and occurs only if the reservoir can be deemed equivalent to a tank (no porous media). Usually, one expect that under reservoir condition with rock surface, heterogeneity (both in terms of permeability and porosity), and presence of various fluids, during production, some oil will be left in the reservoir due to capillary forces (with presence of gas, oil, and water) and heterogeneity. If this happens, it is expected that liberated gas in the oil section and initial gas and injected gas in the gas cap that invades into the oil section may cause oil to swell due to dissolution of gas in the oil (oil can flow easier) and may cause evaporation of the oil into the gas (no oil left). Hopefully, this can lead to the condition that all oil (phase) in the reservoir can be produced and gas can be produced later.

In order to create the condition and expectation mentioned in the previous paragraph, slow movement of fluids in the reservoir is not sufficient. It is also required that well configuration can reach various regions in the reservoir as much as possible (reaching-out). With this, distance of fluids flow in the reservoir (into a well) will be short or very short compared to conventional vertical well system. Reaching-out lead to benefits for improved oil recovery:

1. Influence of various factors that control flow behavior in porous media will be reduced and
2. Pressure in the reservoir at abandonment will be much lower than that of the conventional case.

Both of these results in better oil recovery. When a fractured horizontal well is included in the picture, one can envisage that fractures will be reaching most of the regions in the reservoir and these fractures are connected through the horizontal section of the fractured horizontal well. Hence, fluid will flow from the reservoir into fractures then from fractures into a horizontal section. Flow in fractures will be similar to flow in porous media with very high permeability while flow in a horizontal section is similar to flow in pipe. The main pressure drop will occur at the part of the horizontal section that is connected to the vertical section of the horizontal well under production condition. (That is, flow control system in the well will be installed in the part of the horizontal section close to the vertical section.) Pressure drop in fractures and in the majority part of the horizontal section will be minor due to very slow movement of the fluids. With this, all fractures and most part of the horizontal section can be considered as part of the reservoir but with very much higher permeability. Or to the extreme, space in all fractures and most part of the horizontal section can be considered as a tank.

With the tank concept for the fractures and the vertical section, one can optimally produce from the reservoir by only drawing oil in the oil section by adjusting flow under pressure force (due to expansion) and gravity force in the fractures and the vertical section. That is, letting movement of oil or gas due to gravity to be faster (than under pressure force) such that gas, oil, and water (if any) are situated in appropriate locations in fractures and horizontal section. This will allow only oil to be drawn out of the reservoir through the horizontal and vertical sections of the well.

After oil, gas, and water flow into fractures and horizontal section, it is hypothesized that the gas is expected to flow up in the fractures, while water and oil flow down in the fractures with water flowing down faster due to its relatively higher density. The location of the horizontal section must be designed such that it is in the oil section at all time. The best location is just above the water region at the final stage. After all oil is produced, gas will be finally produced. It is expected that the location of the horizontal section just above the water region will have no detrimental effect on gas production because gas production is mainly due to gas expansion. However, the horizontal section should be placed such that at the abandonment condition, water in the water region will still be below the horizontal section. To be able to maintain the horizontal section in the oil region, oil production from the horizontal section has to be controlled such that gas in the fractures flows up fast enough and not reaching (from above) the horizontal section and water in the fractures flows down fast enough and not reaching (from below) the horizontal section. That is, the gravity force dominates flow in fractures and pressure and viscous (resistance) forces play minor role. It is expected that at low withdrawal rate of oil compared to amount of oil, gas, and water flowing into the fractures, the gravity force should play dominant role.

The fractured horizontal well system will be used with compositional reservoir simulation. The main reason for using compositional reservoir simulation is that it is expected that with slow movement of fluid in the reservoir, there will be component exchange between oil and gas phases.

3.2 Gas reinjection for pressure maintenance

Natural gas reinjection is a petroleum enhanced recovery process which injects the gas produced with oil back into the producing reservoir to maintain reservoir pressure and increase the ultimate recovery of oil. Pressure maintenance is the practice of returning gas from flush production to the formation for the purpose of keeping reservoir pressure and energy as near initial conditions as possible. Unless there is a definite water drive associated with the oil in the formation, it is impossible for original reservoir fluids to compensate for the shrinkage due to oil and gas produced. In pools where oil is produced with inherently high gas-oil ratios, a volume in the formation equivalent to several barrels may be voided for each barrel of oil produced. If water does not move in to occupy the space voided, then both the gas above the oil and the solution gas in the oil will expand to occupy such space, with a resultant drop in reservoir pressure [8]. The best-known means of maintaining pressure in any reservoir is to produce the oil with as low a gas-oil ratio as possible, and to start in the very early life of the pool to return all gas produced. In this manner the pressure drop can be reduced to nearly that which would occur if only the net barrels of denuded oil were produced.

Gas injection projects are undertaken when and where there is a readily available supply of gas. This gas supply typically comes from produced solution gas or gas-cap gas, gas produced from a deeper gas-filled reservoir, or gas from a relatively close gas field. Such projects take a variety of forms, including the following:

a. Reinjection of produced gas into existing gas caps overlying producing oil columns.
b. Injection into oil reservoirs of separated produced gas for pressure maintenance, for gas storage, or as required by government regulations.
c. Gas injection to prevent migration of oil into a gas cap because of a natural water drive, down dip water injection, or both.
d. Gas injection to increase recoveries from reservoirs containing volatile, high-shrinkage oils and into gas-cap reservoirs containing retrograde gas condensate.
e. Gas injection into very under-saturated oil reservoirs for the purpose of swelling the oil and hence increasing oil recovery.

The primary physical mechanisms that occur as a result of gas injection are

a. Partial or complete maintenance of reservoir pressure,
b. Displacement of oil by gas both horizontally and vertically
c. Vaporization of the liquid hydrocarbon components from the oil column and possibly from the gas cap if retrograde condensation has occurred or if the original gas cap contains a relict oil saturation, and
d. Swelling of the oil if the oil at original reservoir conditions was very under-saturated with gas.

3.3 Fracture pressure

Injection of gas for pressure maintenance is mostly performed with gas injectors located at the gas cap overlying an oil layer. In such practices, if the gas injection is conducted at gravity-stable rates (less than the critical rate) it will result in greater volumetric sweep efficiency. Such injection projects should be performed at appropriate reservoir injection pressure as higher injection pressure above reservoir fracture pressure can create fracture to propagate into other reservoir. This fracture propagation can lead to the loss of injected gas as gas has the tendency to flow easily. Thus, initial injection pressure should be below formation fracture pressure to avoid fracturing condition.

A good number of researchers have published methods for fracturing pressure calculation. In this work, the fracturing pressure of the reservoir was calculated from correlation obtained from in the gulf of Thailand as published by Rangponsumrit [11]:

$$Fracturing\ pressure = \frac{FRAC.\mathrm{S.G} \times TVD}{10.2} \qquad \text{................(1}$$

Where

$$FRAC.S.G = 1.22 + (TVD \times 1.6 \times 10^{-4}) \qquad \text{..................(2)}$$

FRAC.S.G = fracturing pressure gradient (bars/meter)

TVD = true vertical depth (meter)

CHAPTER 4
RESERVOIR SIMULATION MODEL

In this section, the reservoir model is created using ECLIPSE 300. The model will be used to investigate various changes in the reservoir during the production period, and in level of recovery improvement. A compositional reservoir model is chosen for this study in other to facilitate the evaluation of the compositional changes that occurs in the reservoir especially during gas reinjection processes.

4.1 Reservoir model.

The reservoir model is constructed based on half the drainage area of one conventional vertical well. The investigation area is modeled with simple rectangular system with properties shown in Table 4.1.

Table 4.1 Reservoir properties.

Parameter	Value	Unit
Top depth	6000	ft
Reservoir porosity	20	%
Horizontal permeability	126	mD
Vertical permeability	12.6	mD
Connate water saturation	15	%
Initial reservoir pressure at GOC	3000	psia
Reservoir temperature	220	^{o}F
Thickness	100	ft
Length	1600	ft
Width	840	ft
GOC depth	20 ft below the top depth	

4.2 Reservoir model gridding.

The reservoir model was built on Cartesian grid and with a block centered geometry. The reservoir dimension is 1600 ft. x 840 ft. x 100 ft. in the x, y, and z directions respectively. To incorporate horizontal well, and fractures, the number of cells were varied as shown in Table 4.2.

Table 4.2 Reservoir grid block sizes

	Dimension	x-direction	y-direction	z-direction
Vertical well completion	No. of grid blocks	20	21	10
	Size (ft.)	80	40	10
	Total (ft.)	1600	840	100
Horizontal well completion	No. of grid blocks	20	21	10
	Size (ft.)	80	40	10
	Total (ft.)	1600	840	100

The vertical well is placed at coordinates I-10, J-11 (-x and –y direction respectively), and completed in the z-direction in blocks K-10, given 10 ft perforation interval. The horizontal well is placed at coordinate I-2, J-11 and K-10 (-x, –y and –z directions respectively), completed in the x-direction with a total length of 1360ft. Fracture creation was performed by locally refining grid blocks along the x-direction and specifying rock properties (porosity of 1, and permeability of 100 D.) for these grid block serving as fractures. 80 ft wide grid blocks were refined into 9 finer grid blocks, with a symmetrical increase in size on both sides of the fractures, as shown in Table 4.3

Table 4.3 Refined grid block sizes to accommodate fractures

Creation of fracture by refining grid blocks along the x-direction (x grid block sizes ft.)								
B1	B2	B3	B4	B5	B6	B7	B8	B9
30.745	8.3	0.833	0.0833	0.00833	0.0833	0.833	8.33	30.745
Plane B5 is the fracture plane, with fracture with of 0.00833 ft.								

Figure 4.1 shows the reservoir model in the case of a vertical well producer, Figure 4.2 shows the model for a horizontal producer and Figure 4.3 shows the model with horizontal well and fractures.

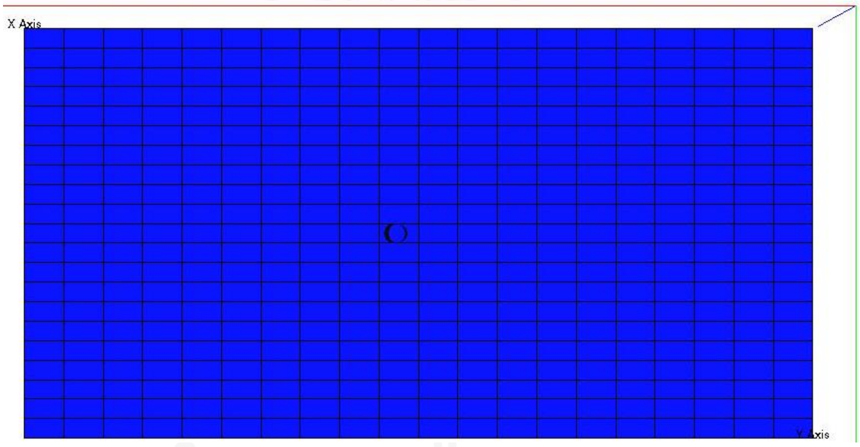

Figure 4.1 Oil Reservoir for Vertical Well (top view xy plane)

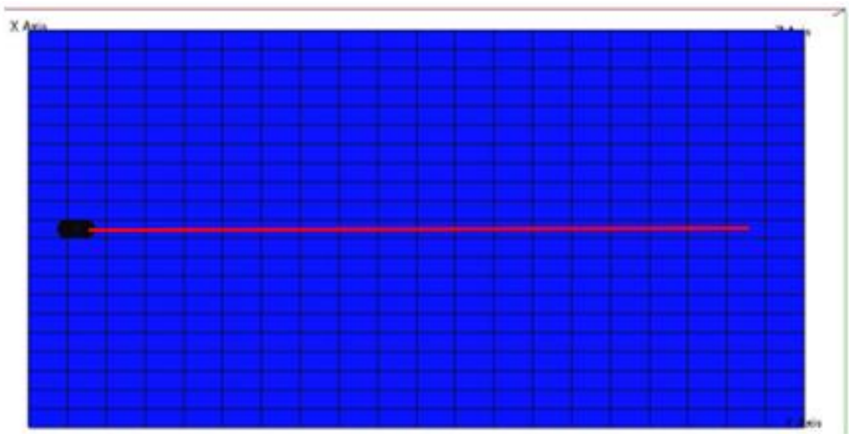

Figure 4.2 Oil Reservoir for Horizontal Well (top view xy plane)

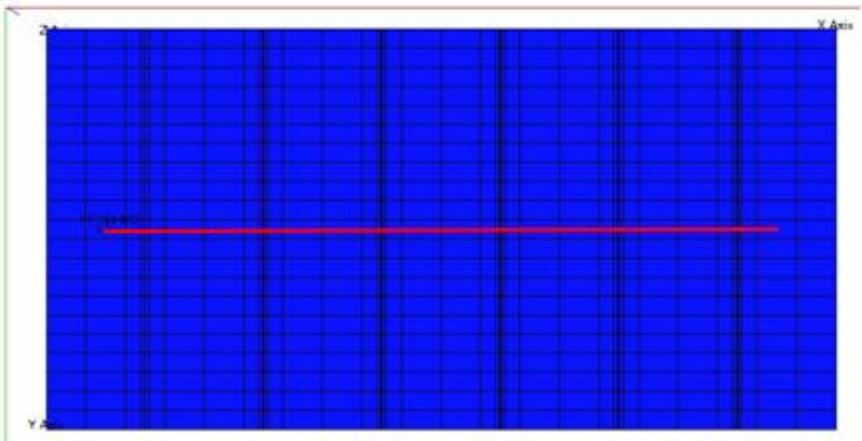

Figure 4.3 Oil Reservoir for Fractured Horizontal Well (top view xy plane)

4.3 Rock and fluid properties.

This section shows the rock and fluid properties used in this study. Table 4.4 shows the initial fluid composition, Table 4.5 shows the PVT properties of the reservoir fluid. The physical properties of the fluid, as well as the binary interaction coefficients are presented in Table 4.6 and Table 4.7 respectively.

Table 4.4 Initial composition of the reservoir fluid.

Component	Formula	Mole fraction
Carbon dioxide	CO2	0.0117
Methane	C1	0.3996
Ethane	C2	0.10595
Propane	C3	0.07615
Isobutane	i-C4	0.015778
Normal butane	n-C4	0.04306
Isopentane	i-C5	0.015778
Normal pentane	n-C5	0.015449
Hexane	C6	0.047443
Heptane plus	C7+	0.26907

Specific gravity of C7+ 0.86862

Molecular weight of C7+ 295.52

Table 4.5 PVT of the reservoir fluid.

N°	Parameter	Value	Unit
1	Reference pressure at gas-oil contact	3000	psi
2	H_2S content	0.00	percent
3	Bubble-point pressure of oil	3000	psia
4	Water formation volume factor at reference pressure	1.0217	rb/stb
5	Water viscosity at reference pressure	0.301	cp
6	Water compressibility at reference pressure	3.09E-6	psi^{-1}
7	Standard condition	60 14.7	F psi

The hypothetical reservoir fluid was simulated using the compositional PVT equation of state (EOS) software PVTi. This PVT characterization was based on 3-Parameter Peng-Robinson equation of state and the Figure 4.4 shows the phase diagram for the fluid.

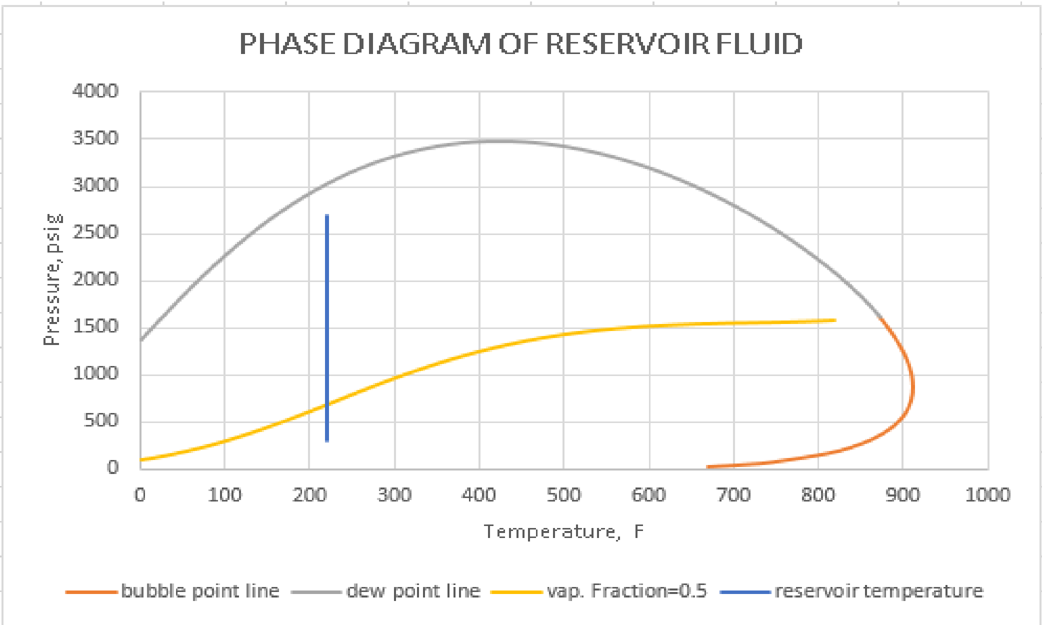

Figure 4.4 Phase diagram of the reservoir oil phase

Table 4.6 Physical properties of components in the reservoir

Component	Boiling point (^{0}R)	Critical pressure (psia)	Critical temperature (^{0}R)	Critical volume (ft3/lb-mol)	Molecular weight	Acentric factor	Critical z factor	Component parachor
CO2	350.46	1056.6	548.46	1.51	44.01	0.23	0.27	78
C1	200.88	653.09	343.08	1.57	16.04	0.01	0.28	77
C2	332.28	693.65	549.77	2.37	30.07	0.09	0.28	108
C3	415.98	601.06	665.64	3.2	44.09	0.15	0.28	150.3
i-C4	470.34	514.36	734.58	4.21	58.12	0.18	0.28	181.5
n-C4	490.86	535.96	765.36	4.08	58.12	0.2	0.27	189.9
i-C5	541.8	476.88	828.72	4.93	72.15	0.23	0.27	225
n-C5	556.56	474.09	845.28	4.98	72.15	0.25	0.27	231.5
C6	606.69	421.92	913.5	5.62	84	0.29	0.25	271
C7+	1182.89	157.01	1468.67	18.72	295.52	0.96	0.2	755.6

Table 4.7 Binary interaction coefficient between components

	CO2	C1	C2	C3	i-C4	n-C4	i-C5	n-C5	C6	C7+
CO2	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
C1	0.1								0.028	0.051
C2	0.1								0.01	0.01
C3	0.1								0.01	0.01
i-C4	0.1									
n-C4	0.1									
i-C5	0.1									
n-C5	0.1									
C6	0.1	0.028	0.01	0.01						
C7+	0.1	0.051	0.01	0.01						

4.4 Special core analysis.

Corey-type relative permeability are assumed. The parameters used in Corey relative permeability correlation for this study are shown in Table 4.8.

Table 4.8 Corey relative permeability

Parameter	Value
Oil Corey exponent, n_o	3
Water Corey exponent, n_w	2
Gas Corey exponent, n_g	3
Connate water saturation, S_{wc}	0.15
Water relative permeability at S_{orw}	0.3
Water relative permeability at $S_{w,max}$	1
Residual oil saturation to water, S_{orw}	0.2
Residual oil saturation to gas, S_{org}	0.2
Oil relative permeability at S_{wc}	0.6
Oil relative permeability at S_{gc}	0.6
Critical gas saturation, S_{gcr}	0.15
Initial gas saturation, S_{gi}	0.15
Gas relative permeability at S_{org}	0.8
Gas relative permeability at S_{gmax}	0.8

Table 4.9 shows the relationship between gas saturation, relative permeability to gas and relative permeability to oil. Also, Table 4.10 shows the relationship between water saturation, relative permeability to water and relative permeability to oil.

Table 4.9 Gas saturation, gas relative permeability, and oil relative permeability.

Sg	Krg	Kro
0	0	0.6
0.15	0	0.2731
0.2125	0.001563	0.182955
0.275	0.0125	0.115214
0.3375	0.042188	0.066675
0.4	0.1	0.034137
0.4625	0.195313	0.014402
0.525	0.3375	0.004267
0.5875	0.535937	0.000533
0.65	0.8	0
0.85	1	0

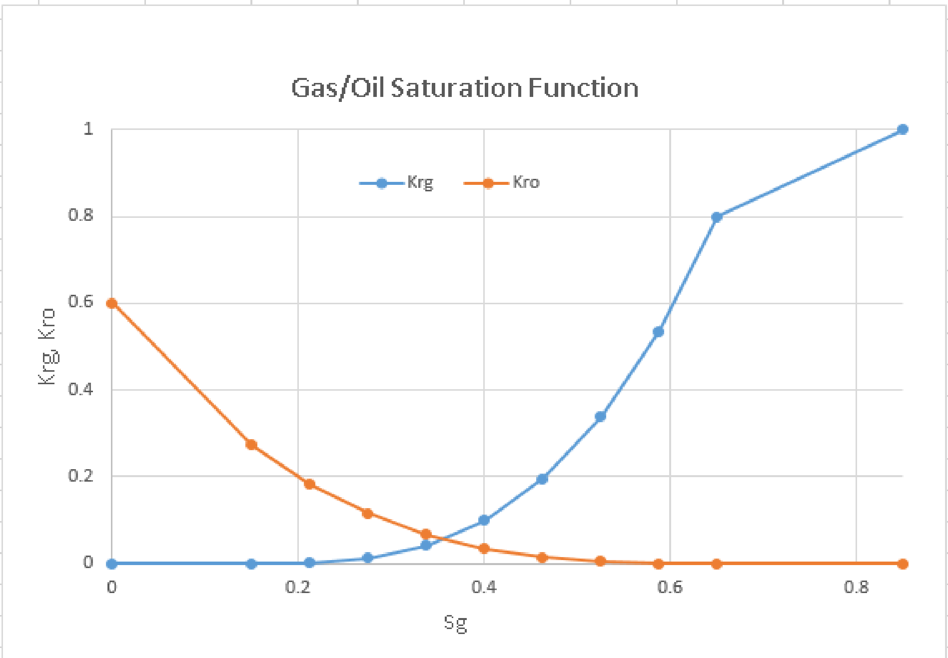

Figure 4.5 Gas/Oil Saturation function.

Table 4.10 Water saturation, relative permeability to water and relative permeability to oil

Sw	Krw	Kro
0.15	0	0.6
0.222222	0.003704	0.421399
0.294444	0.014815	0.282305
0.366667	0.033333	0.177778
0.438889	0.059259	0.102881
0.511111	0.092593	0.052675
0.583333	0.133333	0.022222
0.655556	0.181481	0.006584
0.727778	0.237037	0.000823
0.8	0.3	0
1	1	0

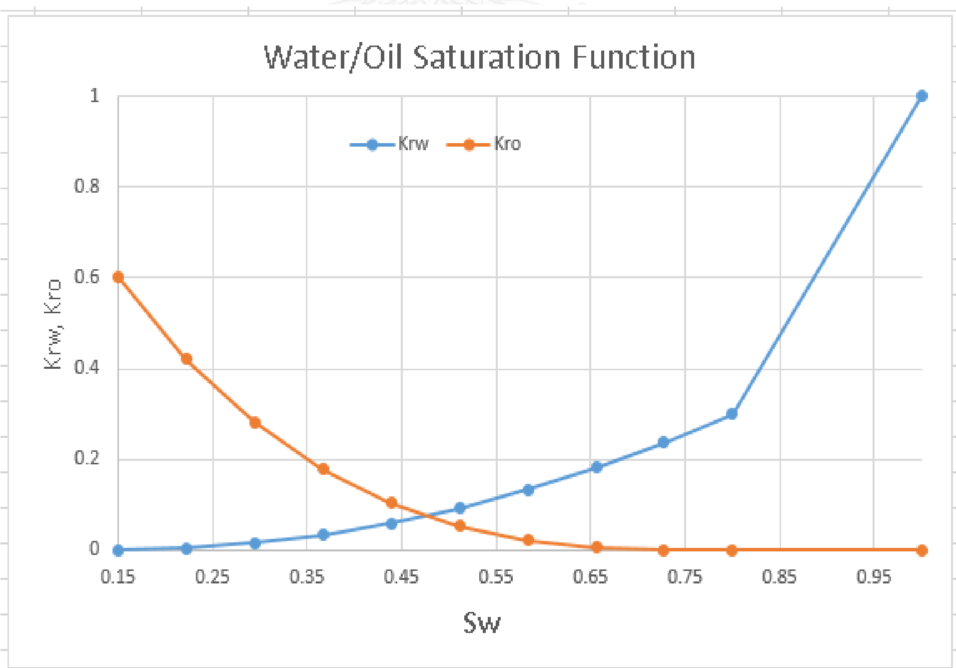

Figure 4.6 Water/Oil Saturation Function

4.5 Well model

There is one producing well and one gas injecting well in the model. The producing well is of three types: vertical well, horizontal well and fractured horizontal well, all with a wellbore diameter of 0.358 ft. As mentioned earlier, the vertical well is placed at coordinates i-10, j-10, and completed in the z-direction in blocks K-10, given 10 ft perforation interval. The horizontal well is placed at coordinate i-2, j-11 and k-10, completed in the x-direction with a total length of 1360 ft, and the fractured horizontal well, 1360 ft long has 6 fracture stages. Table 4.11 summarizes the characteristics of the different well type.

Table 4.11 Characteristics of well models

Well type	Parameter	Value
Vertical producers	Location	i-10, j-10
	Completion interval	10 ft. in k-10
Vertical injectors	Location	i-10, j-1
	Completion interval	10 ft. in k-1
Horizontal producer	Location	i-2 to i-19, j-10
	Length	1360 ft.
	Completion interval	1360 ft. along x-direction
Fractured horizontal producer	Location	i-2 to i-19, j-10
	Length	1360 ft.
	Completion interval	1360 ft. along x-direction
	Fracture spacing	200 ft.

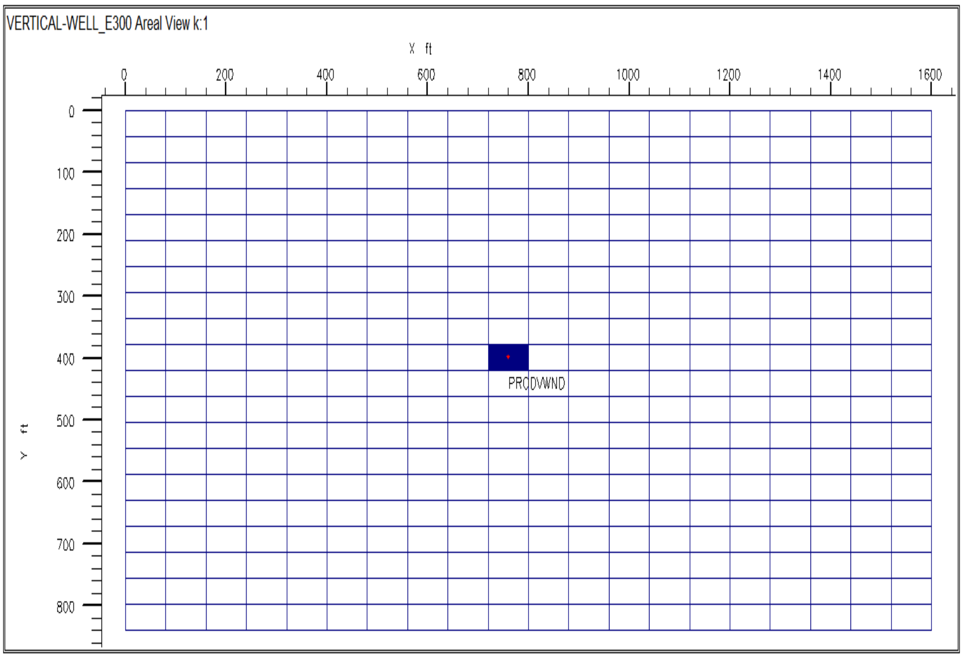

Figure 4.7 Top view (xy plane) for one vertical well in the model.

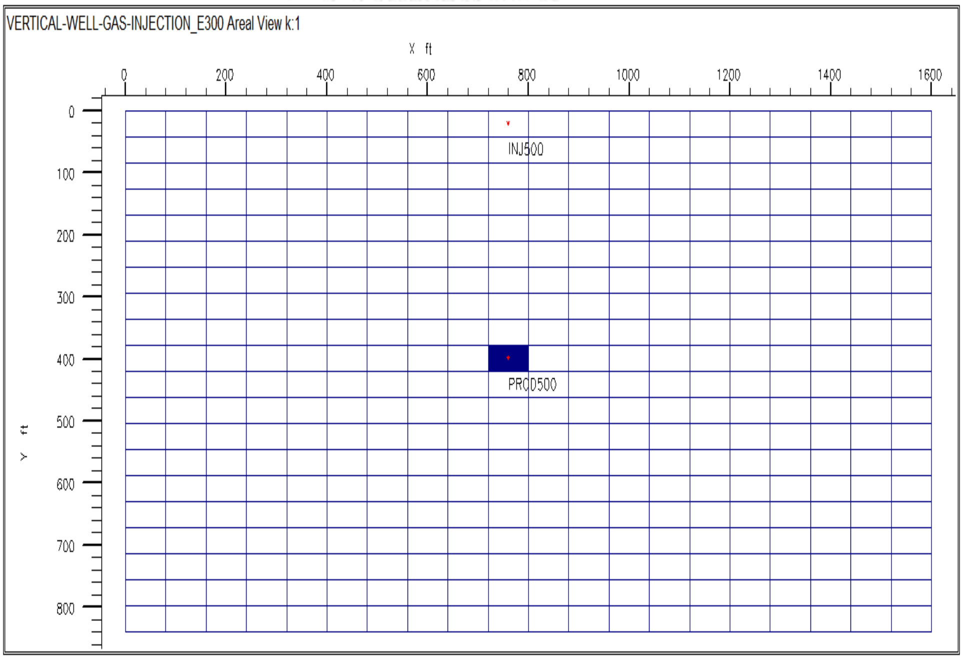

Figure 4.8 Top view (xy plane) for one vertical producing well (PROD500) and one vertical gas injection well (INJ500).

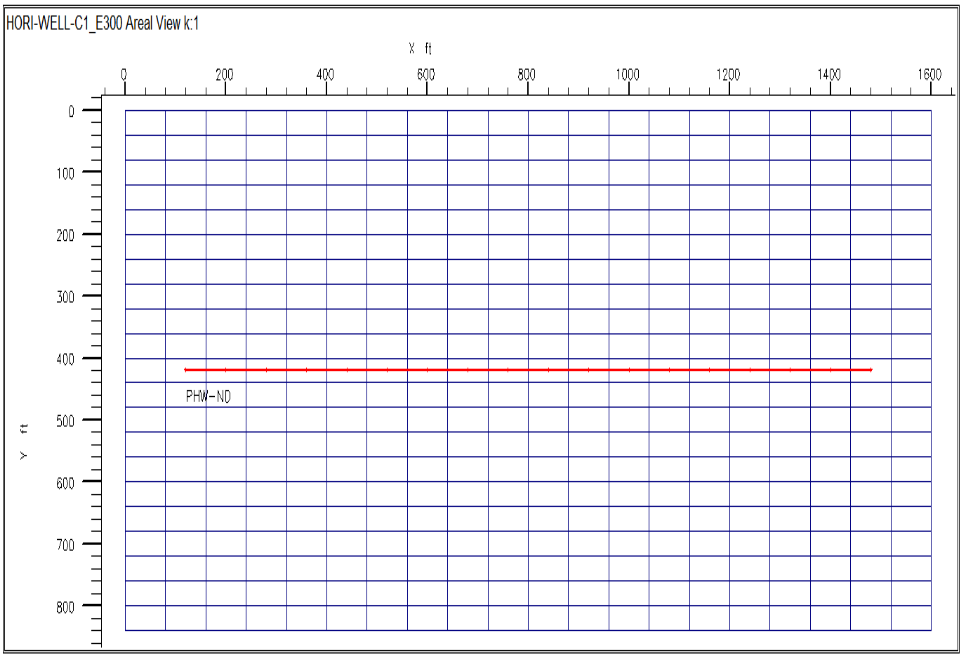

Figure 4.9 Top view (xy plane) for one horizontal well in the model.

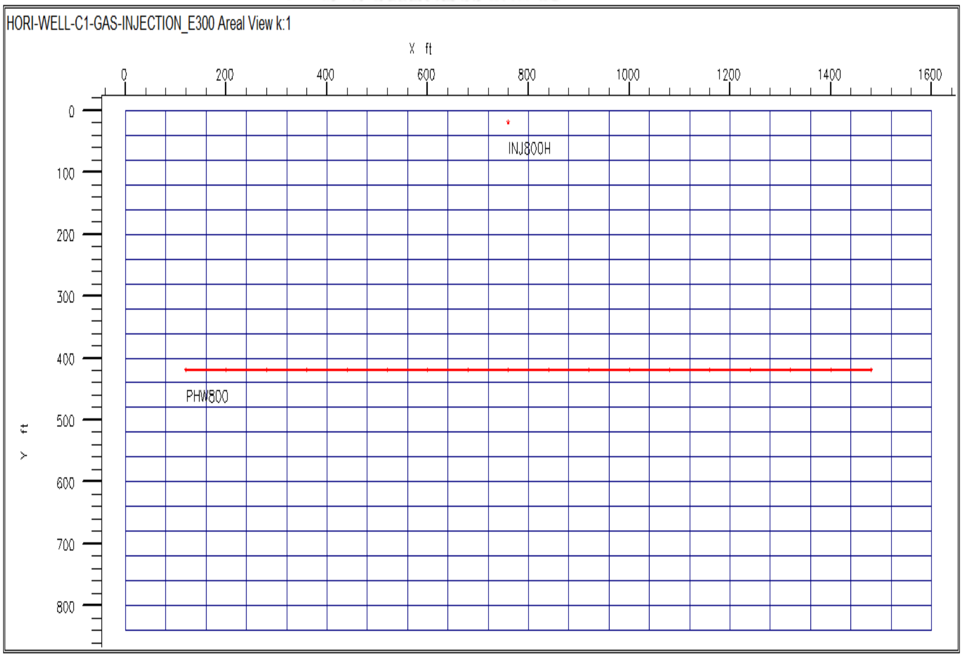

Figure 4.10 Top view (xy plane) for one horizontal producing well (PHW800) and one vertical gas injection well (INJ800H).

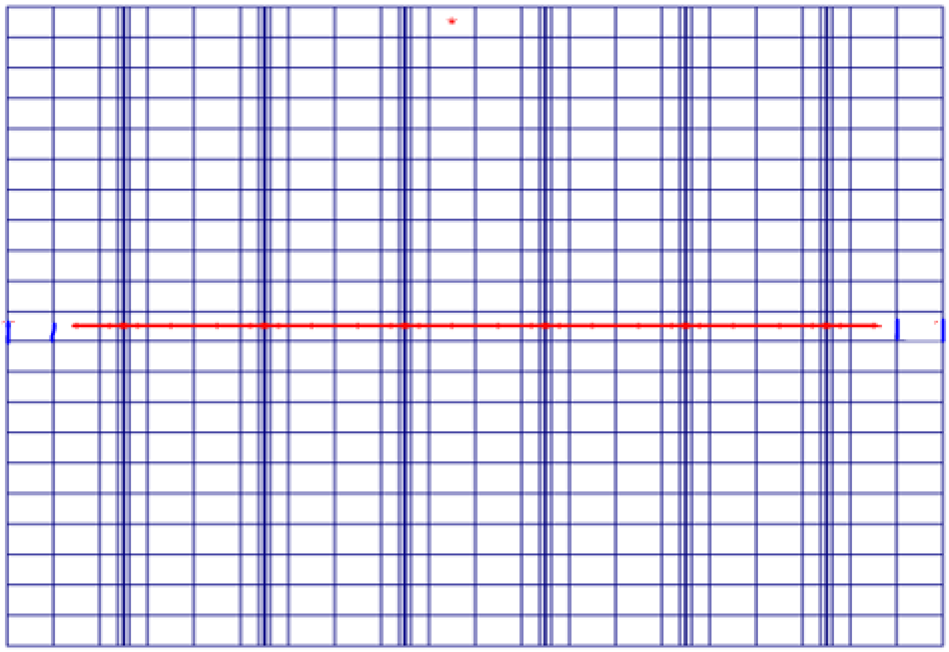

Figure 4.11 Top view (xy plane) one fractured horizontal producing well and one vertical gas injection well.

Well production constrains are set as bottom hole pressure of producing well, and oil economic limit as shown in Table 4.12. For the gas injection well, the maximum down hole injection pressure is set to 3700 psia, about 200 psi below the fracture limit.

Table 4.12 Production well economics limit

Parameter	Value	Unit
Oil economic limit	50	stb/day
BHP at production well	200	psia

CHAPTER 5
RESULTS AND DISCUSSION

The reservoir model and properties described in the previous chapter was used to study how oil recovery can be maximized in the modelled reservoir. The effect of operational parameters on recovery efficiency were evaluated. The operational parameters studied included

- Oil flow rate
- Gas reinjection
- Effect of well configuration

In view of varying oil production rate, performing gas reinjection and using different well types, the economic rate was set equal for all cases studied, at 50 stb/d of oil, and the well abandonment pressure was set a 200 psia.

5.1 Natural depletion of the reservoir

5.1.1 Vertical production well

From the data summarized in Table 5.1, we see that the oil production rate affects the oil production efficiency. Figure 5.1 clearly indicates that producing at lower oil withdrawal rates, we can maintain the plateau production much longer, whereas producing at higher withdrawal rates (say about 2000 stb/d), the plateau production rate is achieved for just about a quarter year compared to more than two years for withdrawal rate of 500 stb/d. Figure 5.1 also suggests that at higher withdrawal rates, the decline in flow rate is much steeper than for lower flowrates. This decline in oil production rate can partly be explained using Figure 5.2. Once production starts, there is a decline in gas production rate. This happens because as production goes on, the solution gas comes out of solution and migrate to the top of the reservoir leading to lower solution gas production with the oil. This solution gas joins together with the gas cap and at later stage of production when this gas cap expands until it reaches the production well, the gas production rate starts increasing as seen in Figure 5.2. When this liberated solution gas starts flowing into the perforation interval, there exists a competition to flow into the well between the oil and gas phase. With the gas phase having much higher mobility, it easily flows into the perforations, this is indicated as a sharp rise in gas production rate shown in Figure 5.2. This production of high amount of gas leads to a reduction in reservoir drive energy, which comes from the gas expansion and solution gas drive thus resulting in a decline in oil rate. More interestingly, Figure 5.3 shows that all the different cases of flow rates have almost similar values of abandonment pressure, but at different time periods, with the well in the case of flow rate of 2000 stb/d dying at a much earlier date. This indicates that a slow enough, and appropriate oil withdrawal rate gives additional benefits in terms of keeping the gas in the reservoir for a longer period of time, and hence better oil recovery efficiency, as confirmed in Table 5.1.

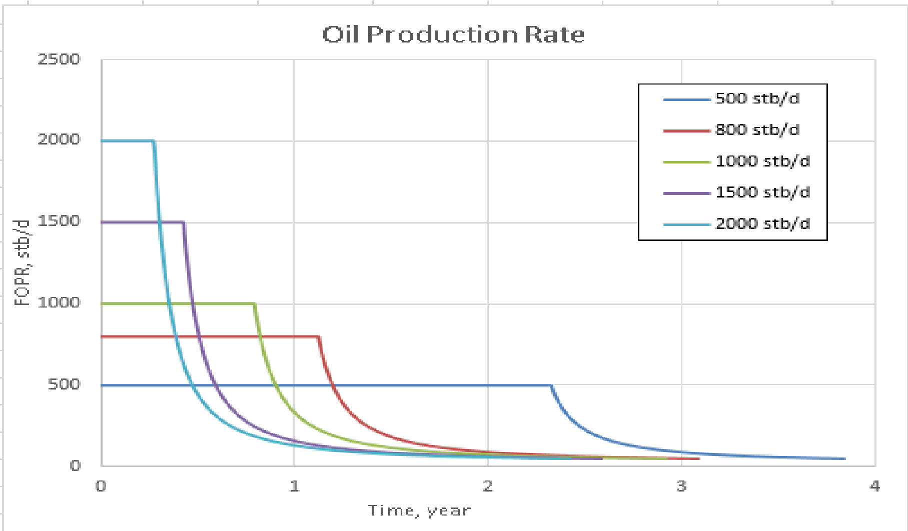

Figure 5.1 Oil production rates of vertical well under natural depletion.

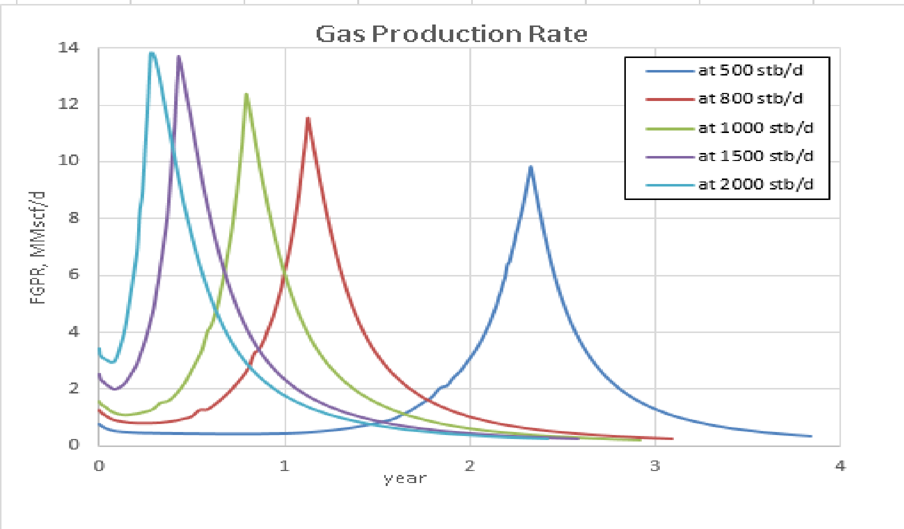

Figure 5.2 Gas production rate of vertical well under natural depletion at different oil rates.

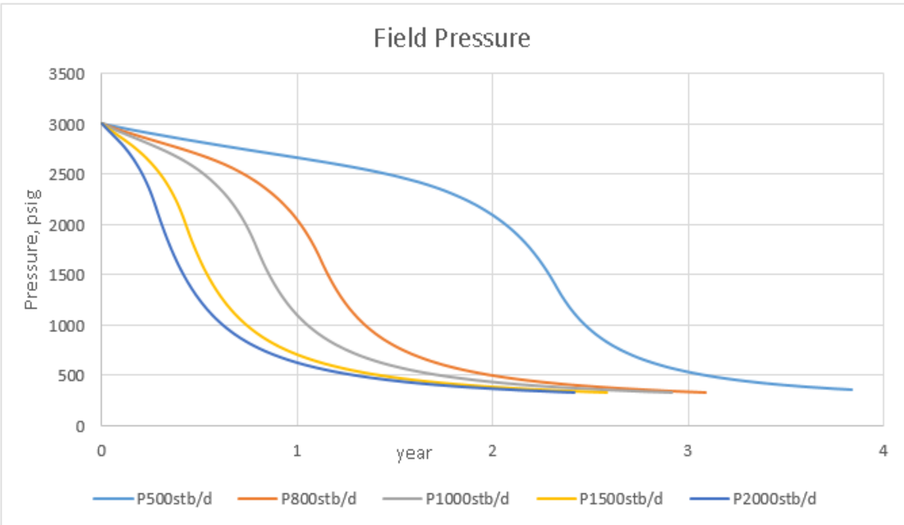

Figure 5.3 Field pressure of the vertical well under natural depletion at different oil rates.

The oil saturation profile presented in Figure 5.4 shows that gas channeling into the perforated interval of the vertical occurs, however, the extent of this gas channeling is minimal compared to cases with higher flow rates as seen in Appendix A (Figure A-1 to Figure A-3). Figure 5.5 shows a comparison in the trend of oil rate, gas rate and reservoir pressure. These trends shoews that once high amounts of gas production is seen, the resulting effect is a decline in flow rate due to the loose of reservoir drive mechanism that comes from gas expansion and solution gas drive, and also due to the gas production restricting the oil production since gas is more mobile and has higher relative permeability to oil in this reservoir. Table 5.1 presents a comparison of oil recovery efficiency for production using a vertical well at different flow rates, producing under natural depletion.

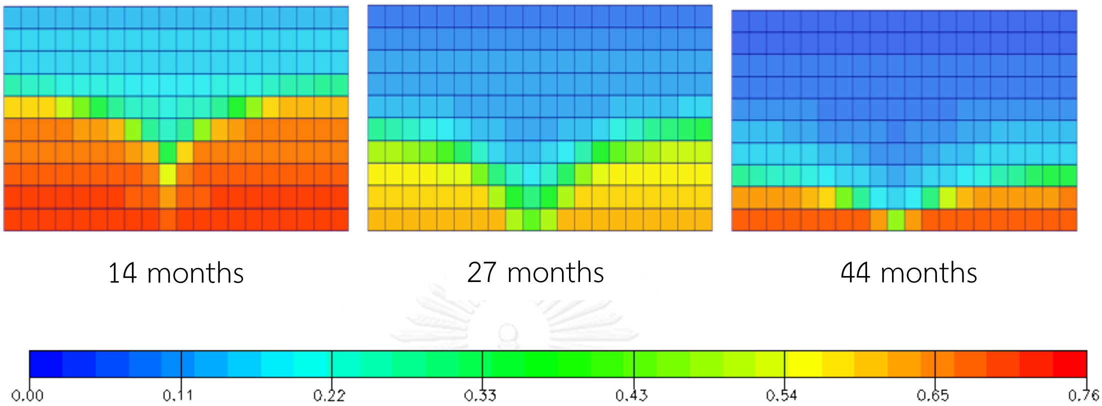

Figure 5.4 Oil saturation versus time for grid plane j = 11: vertical production well at 500 stb/d (xz plane view)

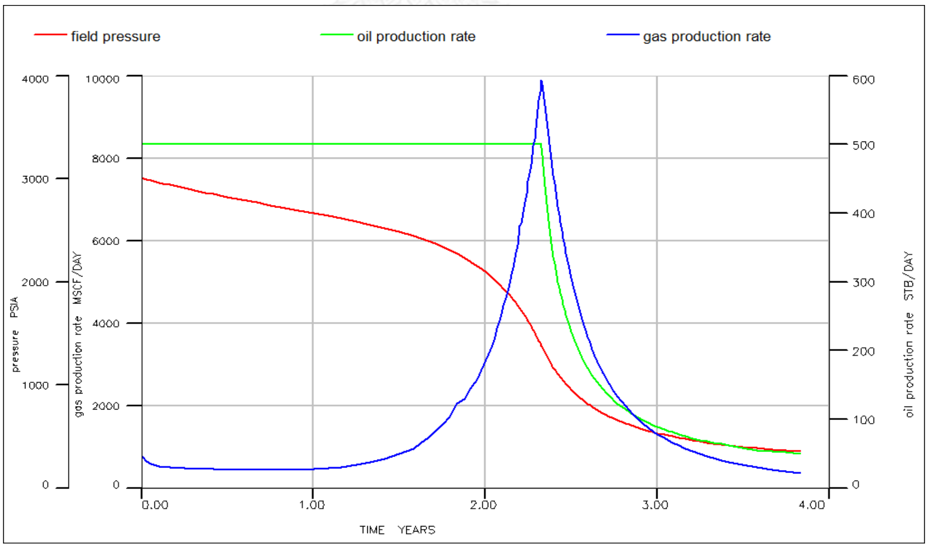

Figure 5.5 Trend of oil rate, gas rate and pressure of vertical well under natural depletion at 500 stb/d.

Table 5.1 Comparison of oil recovery factor for flow of vertical well under different flow rates.

Vertical well under natural depletion					
Oil rate (stb/d)	500	800	1000	1500	2000
Oil recovery efficiency %	28.4	24.7	23.3	21.6	20.7

5.1.2 Horizontal production well.

Similar to the case of using a vertical well, Table 5.2 shows that the oil withdrawal rate clearly affects the recovery efficiency. Producing the horizontal well at lower rates maintains the oil production plateau for a long time, than producing at higher rates, as seen in Figure 5.6. Figure 5.6 also shows that once oil production rate begins to decline, it declines very steeply until it reaches abandonment conditions. This decline in rate is attributed to the decline in reservoir pressure which occurs primarily due to large amount of gas production as seen in Figure 5.7, which depletes the reservoir drive energy that comes from gas expansion and solution gas drive. Figure 5.8 shows the reservoir pressure profile. We see from the trends of pressure that the pressure decline rate is rather slowly in the early production life of the reservoir, this is so because the gas production is minimal at early life of the reservoir, thus much of the reservoir drive energy is kept in the reservoir. However once gas production increases as seen by the sharp rise in gas production from Figure 5.7, the reservoir drive energy will be greatly diminished leading to the rapd decline in reservoir pressure as seen in Figure 5.8. We notice from Figure 5.10 that even when large amount of gas production begins, the oil rate does not drop, until at peak gas production. This can be attributed to the fact that gas is highly compressible and expands, occupying the available voidage in the reservoir and thus helps to push the oil towards the perforated section of the well. Also, this can be explained from the fact that using the horizontal well, we create much larger contact area between the well and the reservoir rock, causing fluid to flow for much shorter distances in the reservoir before reaching the well, this results in small pressure differences between different parts of the reservoir, and hence gives added advantage to produce more of the oil out. Figure 5.11 shows that when large amount of gas production occurs, the reservoir pressure begins to drop much rapidly due to the decline in the reservoir drive energy, thus irrespective of the fact that gas can expand to fill the reservoir void created from oil withdrawal, and that the horizontal well creates small pressure differences, it is very important to keep the gas cap in place as long as possible in order to get better recovery efficiency. The oil saturation profile shown in Figure 5.12 gives the saturation profile in the xz plane; for the plane containing the horizontal well. The saturation profile shows a more uniform expansion of the fluid contact, this is so due the the large contact area between the horizontal well and the formation, thus leading to more uniform fluid withdrawal across a large area of the reservoir and resulting in lower pressure differences between various regions of the reservoir.

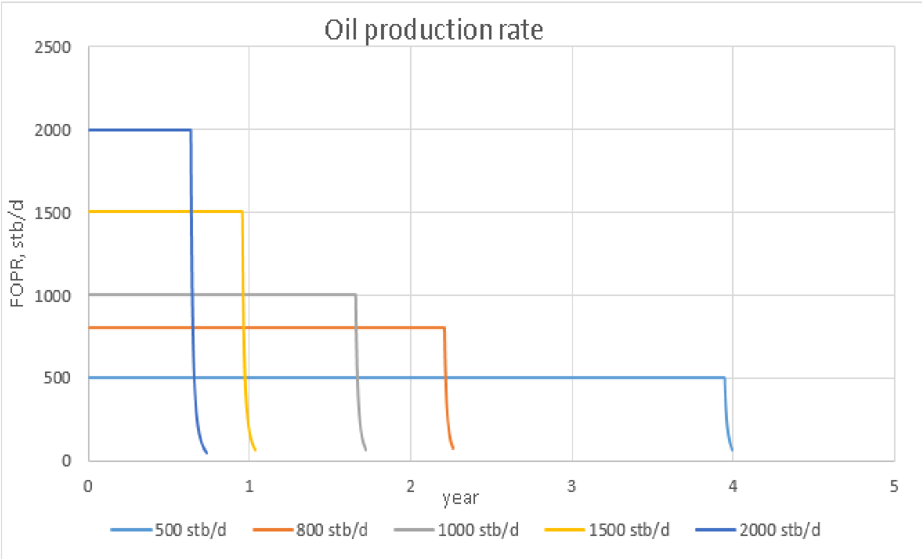

Figure 5.6 Oil production rate of horizontal well under natural depletion

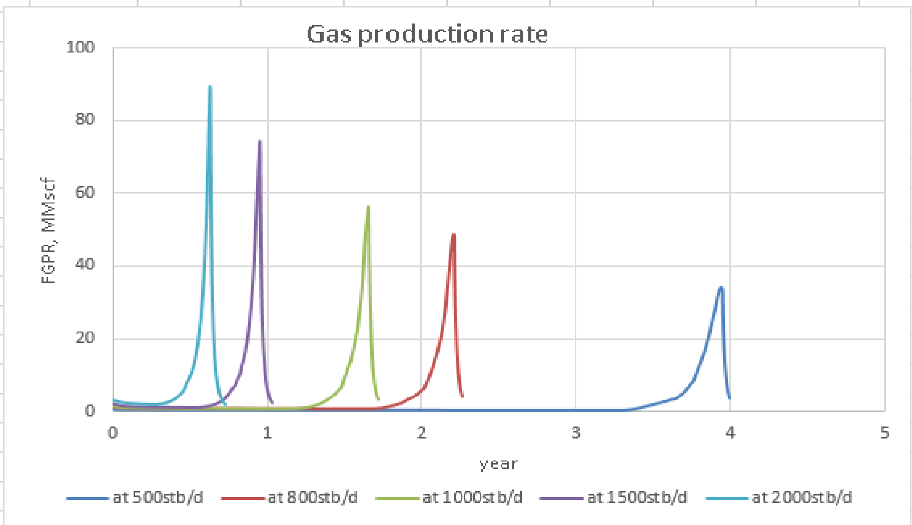

Figure 5.7 Gas production rate of horizontal well under natural depletion at different oil rates

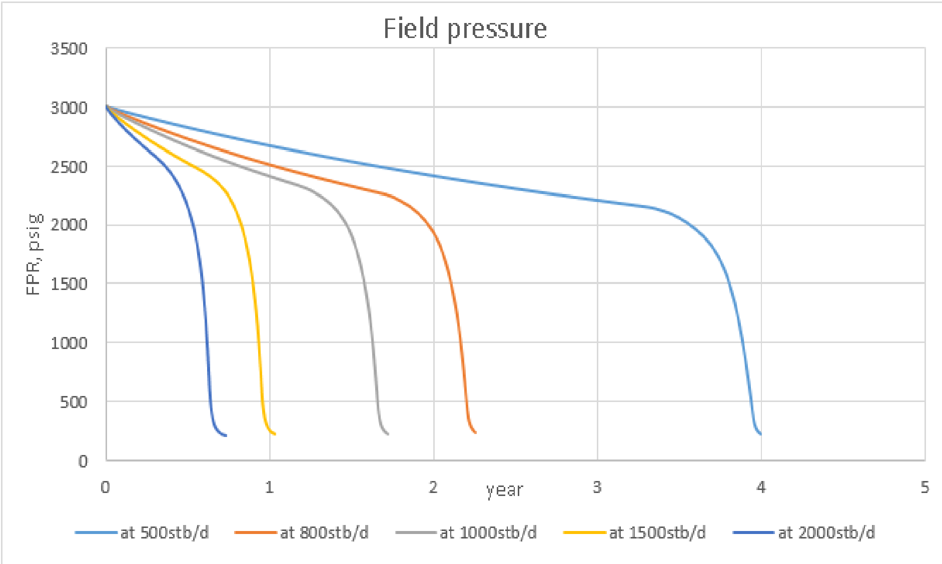

Figure 5.8 Field pressure of horizontal well under natural depletion at different oil rates

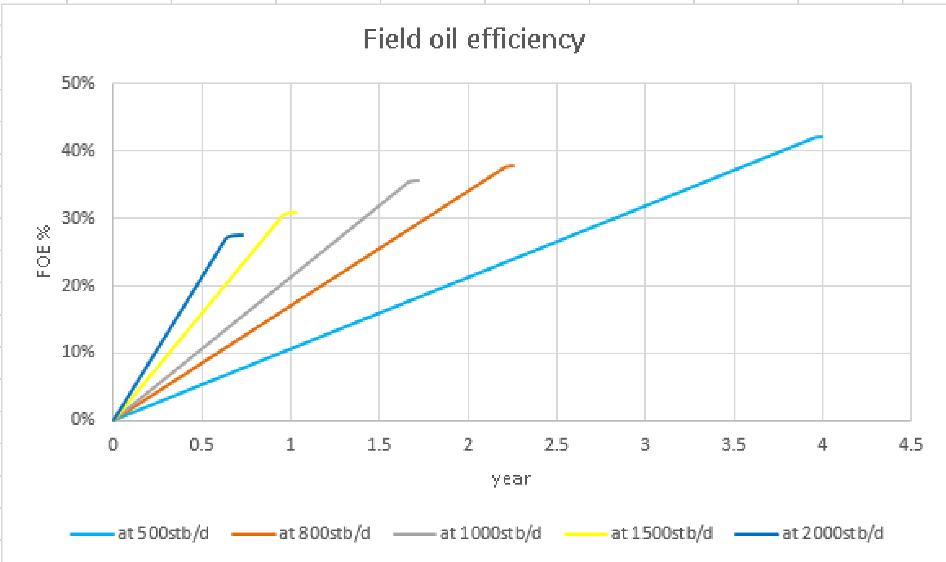

Figure 5.9 Field oil efficiency of horizontal well under natural depletion different oil rates

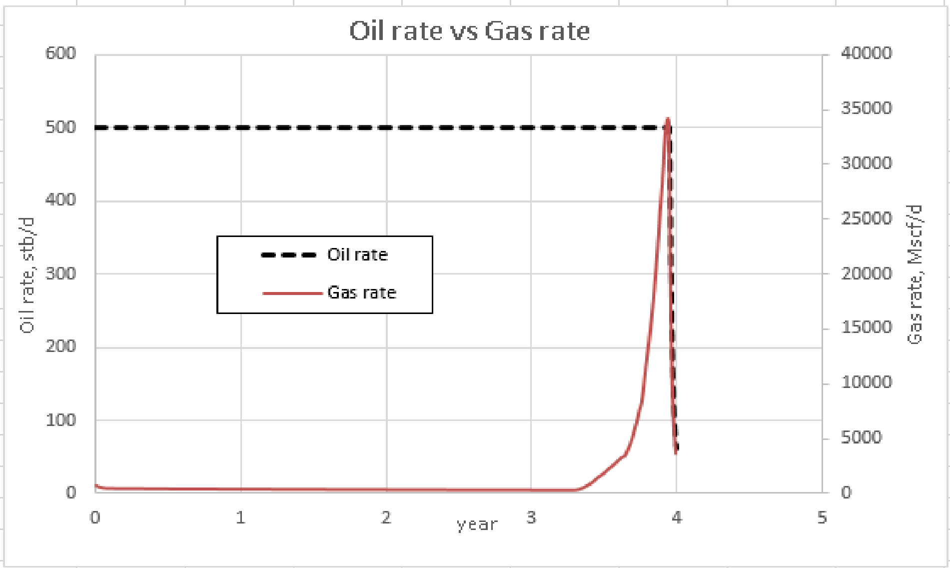

Figure 5.10 Oil rate profile, and gas rate profile of horizontal well producing at 500 stb/d

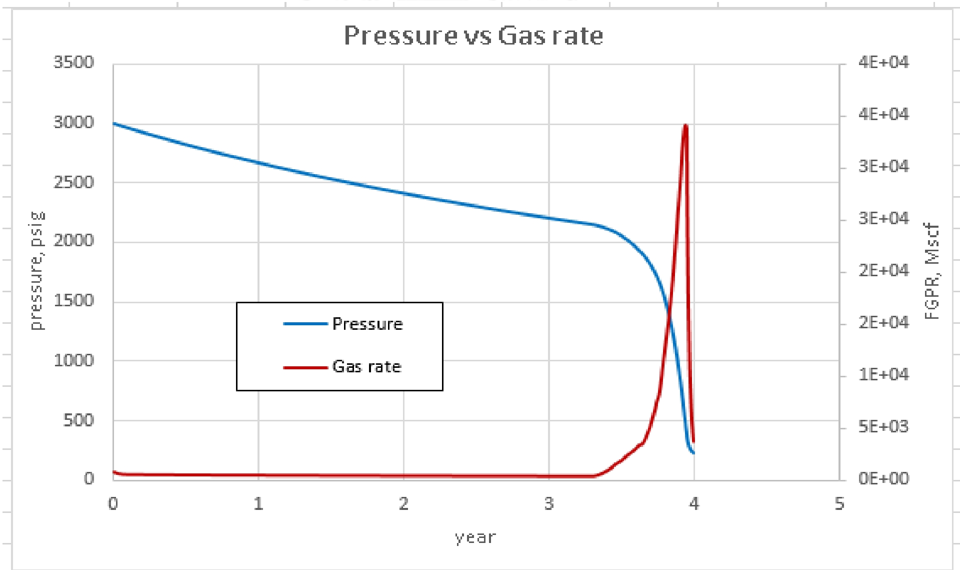

Figure 5.11 Field pressure profile, and gas rate profile of horizontal well producing at 500 stb/d

Table 5.2 Comparison of oil recovery factor for flow of horizontal well under different flow rates.

Horizontal well under natural depletion					
Oil rate (stb/d)	500	800	1000	1500	2000
Oil recovery efficiency %	42.2	37.8	35.7	30.9	27.6

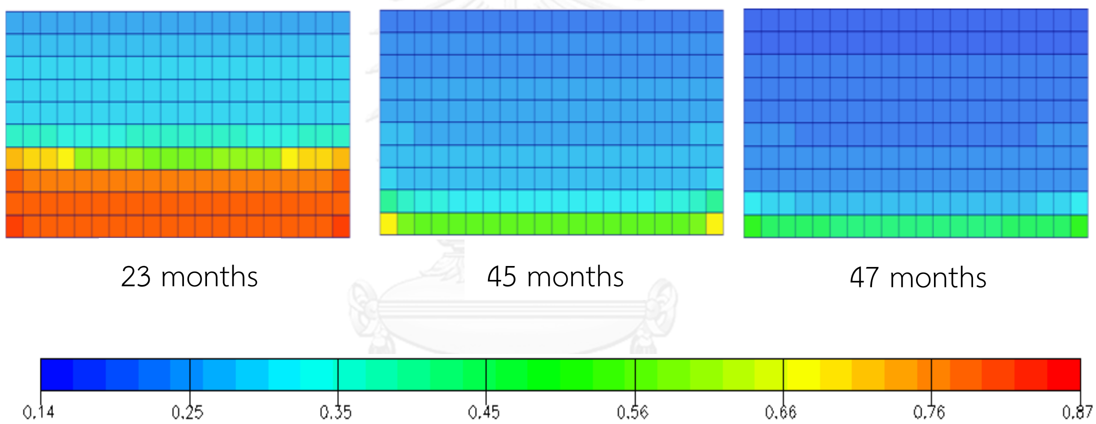

Figure 5.12 Oil saturation versus time for grid plane j = 11: Horizontal production well at 500 stb/d (xz plane view)

5.1.3 Fractured horizontal production well

Using the fractured horizontal well, the surface area created between the well and the reservoir formation is much larger. The fractured horizontal well thus reaches many part of the reservoir and with this, the distance of fluid flow from the formation into the well is much shorter and thus a near unoform phase distribution occurs. This leads to much uniform expansion of the gas cap, and with the horizontal section of the well being completion towards the bottomost part of the reservoir leads to the production of mostly oil with little solution gas. This enables the plateau production period to continue for a long period of time (Figure 5.13) with the flow rate only decling once large amount of gas is produce, at which point the gas cap have expanded into the production sedction of the well. As seen from Figure 5.14 that producing at higher oil rates results in faster gas breakthrough time. This gas breakthrough leads to gas production and thus reduction in reservoir drive energy which clearly leads to a faster decline in reservoir energy as indicated in Figure 5.15. This decline in reservoir energy leads to reduction in oil recovery efficiency as seen in Figure 5.16. Figure 5.14 also tells us that when gas breakthrough occurs, there is higher amount of gas produced in a very short period of time, with even much amount of gas produced for the cases with higher oil withdrawal rates, resulting the steeper pressure decline in the reservoir. It becomes clear from the result summarized that producing at lower oil rates permits sufficient time for the gas cap to expand uniformly and also permits sufficient time for solution gas to come out of the oil and forma secondary gas cap which also helps to supplement the drive energy needed to improve oil efficiency. The oil saturation profiles shown in Figure 5.18 tells us that the reservoir fluid preferably flows in high permeability fracture planes. With this in mind, the oil saturation profile shown in Figure A-13 indicates that production at higher oil rates causes the gas to move much faster in this high permeability fractures, thus resulting in faster breakthrough time and causing the rapid decline in reservoir energy.

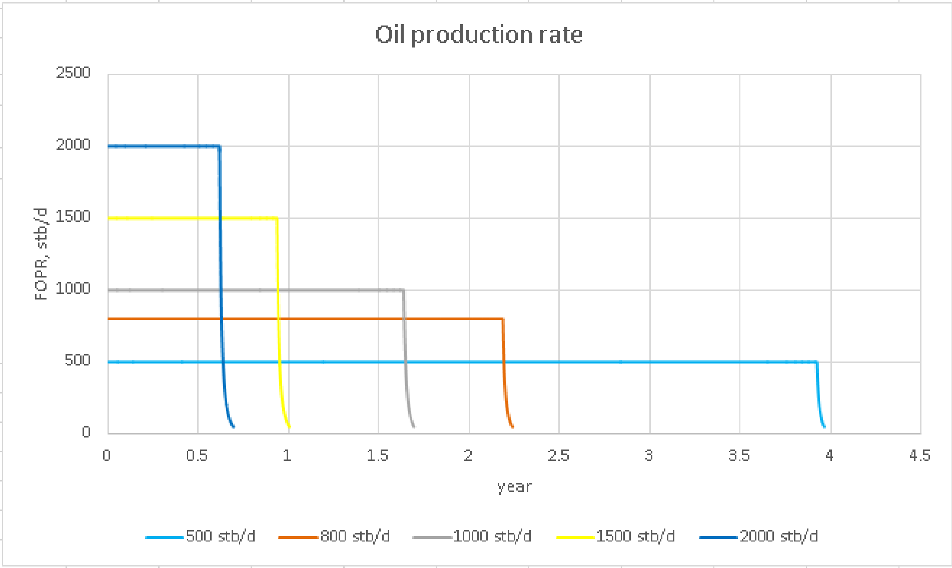

Figure 5.13 Oil production rate of fractured horizontal well under natural depletion

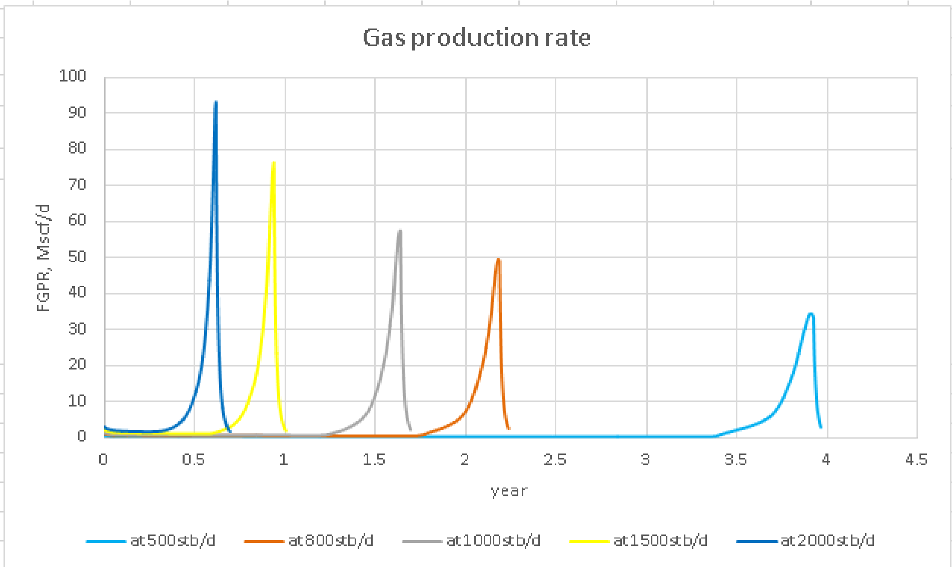

Figure 5.14 Gas production rate of fractured horizontal well under natural depletion at different oil rates

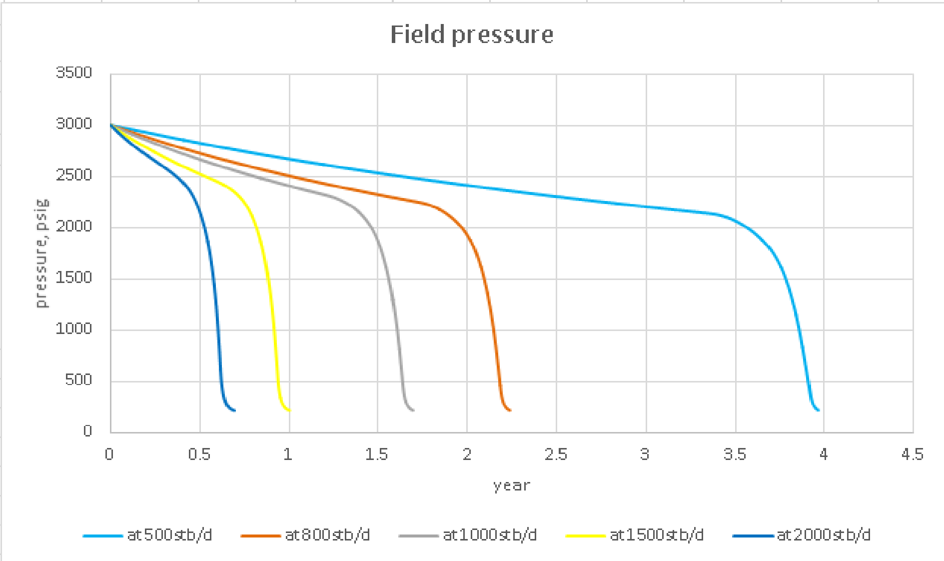

Figure 5.15 Field pressure of fractured horizontal well under natural depletion at different oil rates

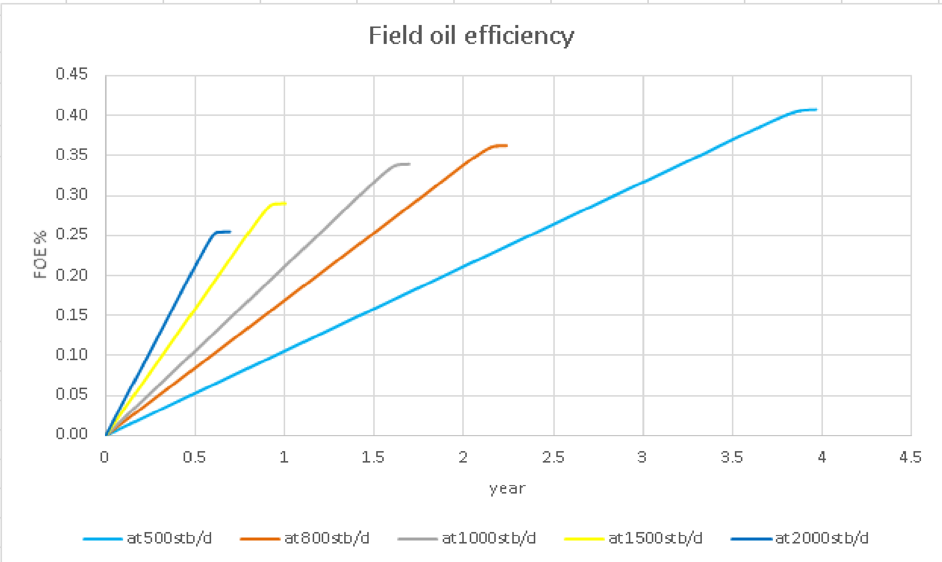

Figure 5.16 Field oil efficiency of fractured horizontal well under natural depletion at different oil rates

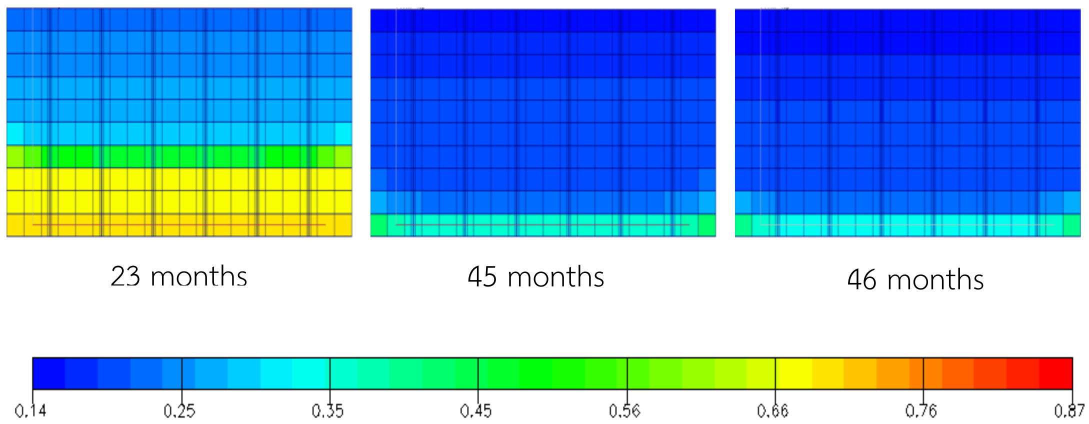

Figure 5.17 Oil saturation versus time for grid plane j = 11: Fracture horizontal production well at 500 stb/d (xz plane view)

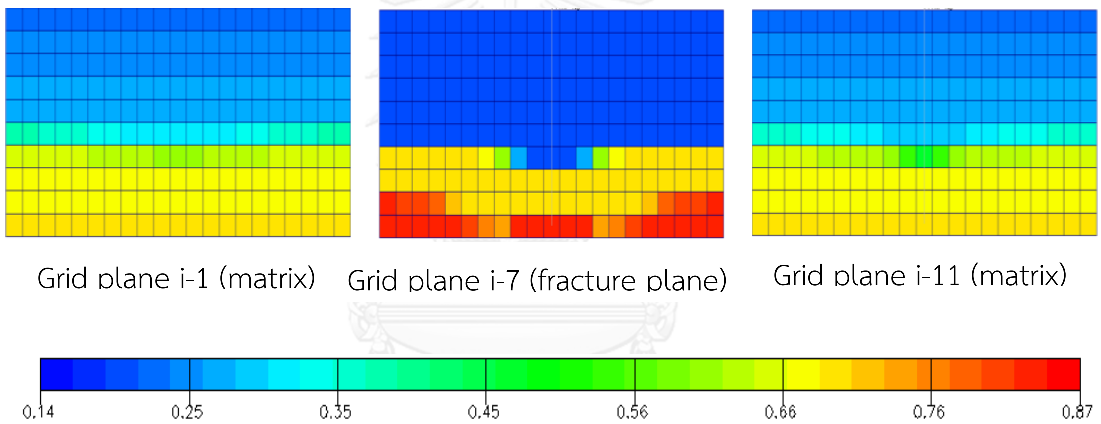

Figure 5.18 Comparison of oil saturation of a fractured plane and non-fractured plane at mid plateau of production for fractured horizontal well at 500 stb/d (yz plane view)

Table 5.3 shows that producing the reservoir at high rates results in lower oil production efficiency. As discussed earlier, this was due to the rapid loss of reservoir energy support from gas expansion once large amount of gas was being produced. The results of oil recovery efficiency for producing the reservoir under natural depletion on different oil flow rate is summarized in Table 5.4.

Table 5.3 Comparison of oil recovery factor for flow of fractured horizontal well under different flow rates.

Fractured horizontal well under natural depletion					
Oil rate (stb/d)	500	800	1000	1500	2000
Oil recovery efficiency %	41.9	37.5	35.2	30.3	26.9

Table 5.4 Summary of oil efficiency for different well types under natural depletion

Well type	Oil recovery efficiency %				
	500 stb/d	800 stb/d	1000 stb/d	1500 stb/d	2000 stb/d
Vertical well	28.4	24.7	23.3	21.6	20.7
Horizontal well	42.2	37.8	35.7	30.9	27.6
Fractured horizontal well	41.9	37.5	35.2	30.3	26.9

As hypothesized, the horizontal well with fractures is needed to increase the productivity of the reservoir by creating area of easy passage for the fluid into the well. However, Table 5.4 shows that the horizontal well alone gives higher recovery factor than horizontal well with fractures. This happens because the fractures allow gas channeling and creates faster path for the gas to flow into the well. As hypothesized the fluid (oil and gas) move into the fractures and as seen in Figure A-13, fluid segregation between the gas and oil occurs to a good extend, however, since the relative permeability to gas is higher than the relative permeability to oil, and given that the fracture causes the fluid to move faster into the well, the gas channels in the fractures much faster than it does in the matrix of the reservoir, and this causes lower oil recovery in the case of horizontal well with fractures than in the case of simple horizontal well as seen earlier.

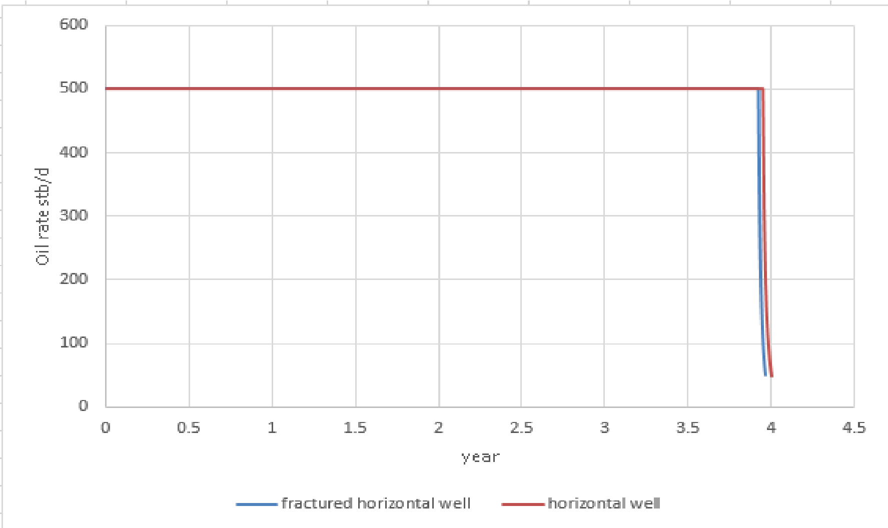

Figure 5.19 Comparison of oil rate for fractured horizontal well and horizontal well at 500 stb/d

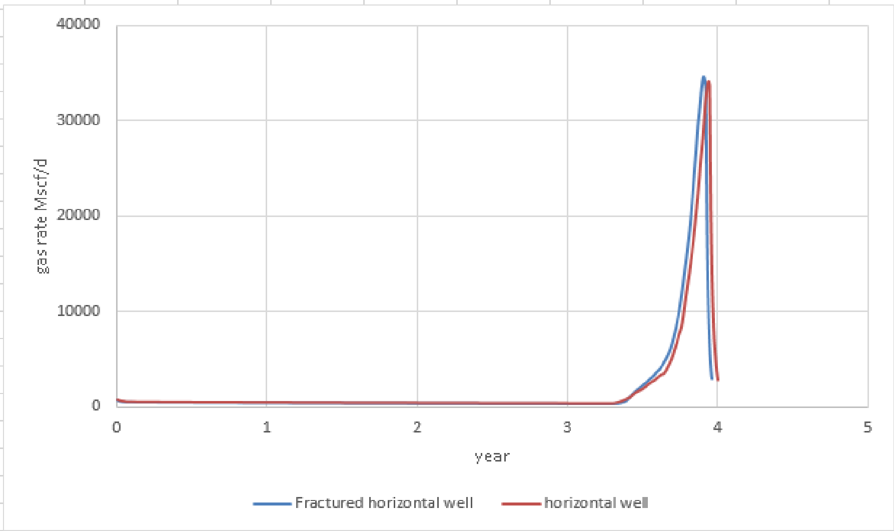

Figure 5.20 Comparison of gas rate for fractured horizontal well and horizontal well at 500 stb/d

From the results presented thus far it is noticed that for reservoir with relatively good permeability, the advantages and benefits of fractured horizontal wells could not come into play since the fluid can equally flow in the matrix of the reservoir and good production potential can be guaranteed based on the flow in the porous matrix alone. In other to arrive a definite conclusion as to whether the relatively good reservoir permeability prevents the manifestation of the benefits of a fractured horizontal well over a non-fractured horizontal well, the reservoir permeability of the current reservoir was decreased to make the reservoir a tight sandstone reservoir, with reservoir permeability of Kh = 1.26 md and Kv = 0.126 md. With the fluid properties unchanged, the reservoir rock permeability was altered as mention above, and the reservoir was put on production on natural depletion using a horizontal well and fractured horizontal at 500 stb/d oil rate. Figure 5.21 shows the result for oil production rate for the horizontal well and the fractured horizontal well. Figure 5.22 shows the result for gas production rate for the horizontal well and the fractured horizontal well while Figure 5.23 shows the result for field pressure for the horizontal well and the fractured horizontal well.

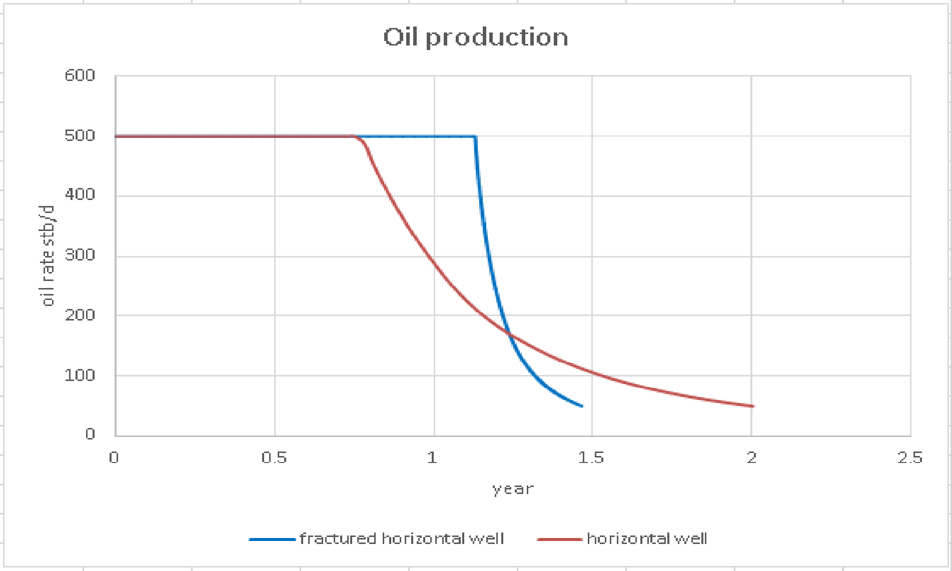

Figure 5.21 Oil production for different well types in a tight reservoir under natural depletion

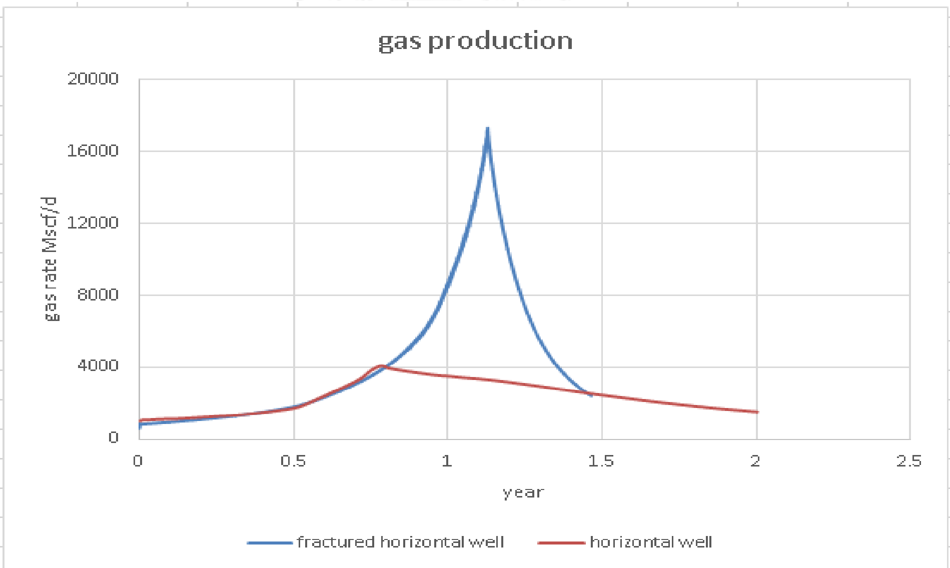

Figure 5.22 Gas production for different well types in a tight reservoir under natural depletion

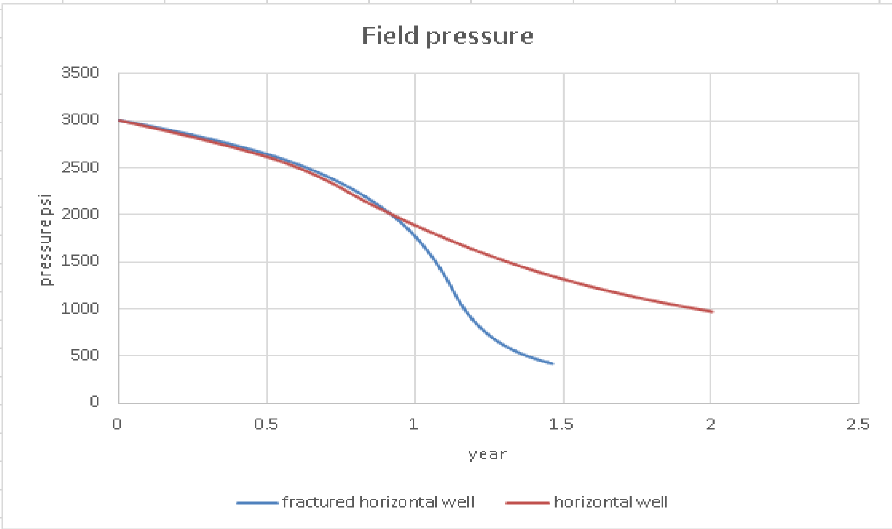

Figure 5.23 Field pressure for different well types in a tight reservoir under natural depletion

With a tight sandstone reservoir, the fractures creates high permeability planes for the fluid to flow into, then into the well. This, as seen in Figure 5.21 presents a higher potential for fluid production. However, since both oil and gas flows into the fractures, then eventually into the production section of the well, with gas having higher relative permeability than the oil, once gas breakthrough occurs, there is high amount of gas production as is seen in Figure 5.22, this presents a negative effect to the fractured horizontal well, and this high gas production leads to rapid decline in reservoir pressure, thus limiting the amount of oil recovered by the fractured well. The recovery efficiency of these two well types in the tight reservoir stands at 13.1% and 12.6% for the fractured horizontal well and non-fractured horizontal well respectively.

Based on the results presented in section 5.1, the further parts of this study assumes the following

- Since the trend in flow rate is consistent, with a decrease in recovery efficiency as the oil rate increases, further investigations assume the extremes of flow rate (lower end and the upper end being 500 stb/d and 2000 stb/d respectively)
- As seen, since the fractured horizontal well does not give any advantage over the non-fractured horizontal well in the conventional reservoir as earlier hypothesized, further investigations assume only vertical well and horizontal well.

5.1.4 Analysis of reservoir fluid composition; production using natural depletion

The analysis of the oil saturation in the reservoir with time is given by an average oil saturation of the reservoir fluid taken at some period of interest during the production life. The average fluid saturation was analyzed, with the reservoir temperature assumed to be constant during production and only production data from a designated flow rate (at 500 stb/d) was compared for different cases. As production starts, the oil saturation decreases equally in all cases until about two years were the reservoir in the case of vertical well sees a sharp decrease, then almost constant oil saturation due to more gas production. The oil saturation in the cases of the horizontal well and fractured horizontal well is lower thus indicating that the horizontal well give higher recovery potential than the vertical well at similar productin constrains. The oil saturation at the end of production is above 0.2 for all cases, with residual oil saturation being 0.2, we notice that the natural depletion process hardly can withdraw all movable oil in the reservoir. The saturation profile shown in Figure 5.25 for the vertical well case indicates more oil saturation left behind at end of production life, this happens because gas impedes flow of oil and lesser oil is recovered before economic limits. For the case of the horizontal well as seen in Figure 5.26 we realize lower oil saturation at end of production due to the advantage of the horizontal well to reach out to many parts of the reservoir and thus having the potential to produce more hydrocarbon. When fractures are created in the reservoir in combination with horizontal well, much lower oil saturation is seen near the wellbore. The fractures helps to reduce the pressure drawdown of the reservoir and thus higher potential of hydrocarbon recovery.

The average reservoir fluid composition as shown in Table 5.5 at the end of production shows that there is increase in mole percent of CO2, C1, C2, C3 and NC4, while other components decrease in mole percent. This change in fluid composition happens due to the distortion of equilibrium in the reservoir as production is initiated, and as pressure in the reservoir lowers during production, dissolved gas in the crude is released, and there exists a redistribution of components between the liquid phase and the gaseous phase in the reservoir.

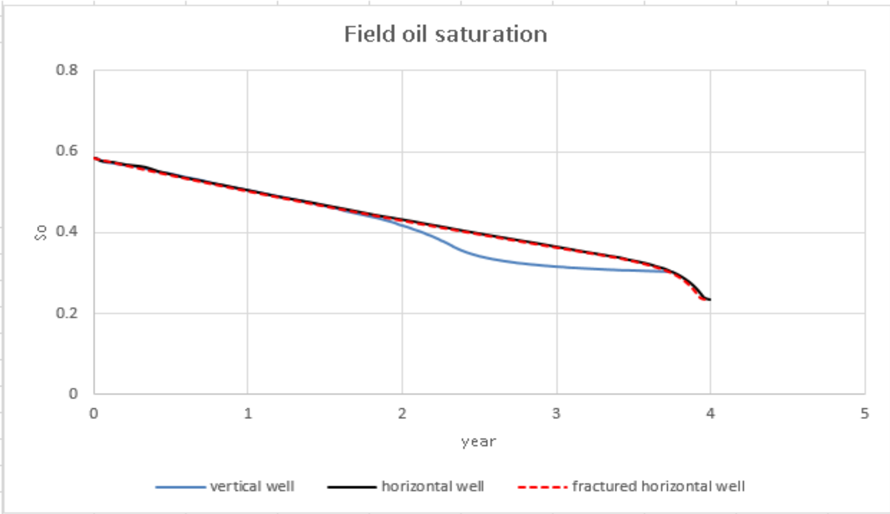

Figure 5.24 Average field oil saturation versus time for reservoir under natural depletion using different well types

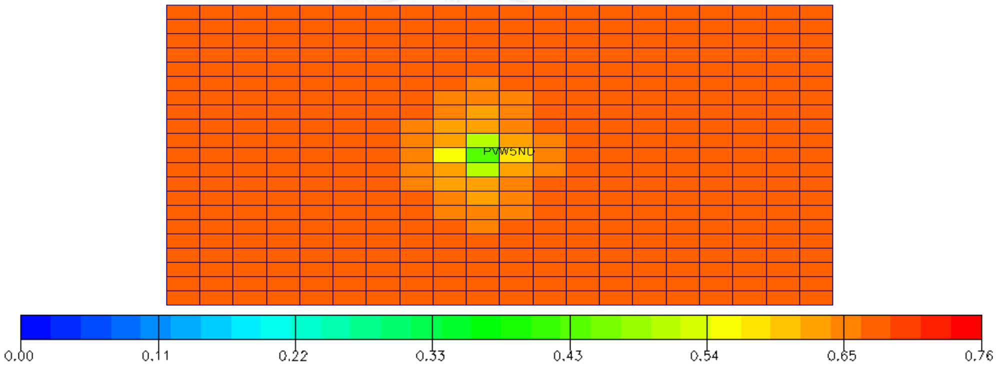

Figure 5.25 Oil saturation at abandonment for reservoir with a vertical well under natural depletion at 500 stb/d (xy plane view)

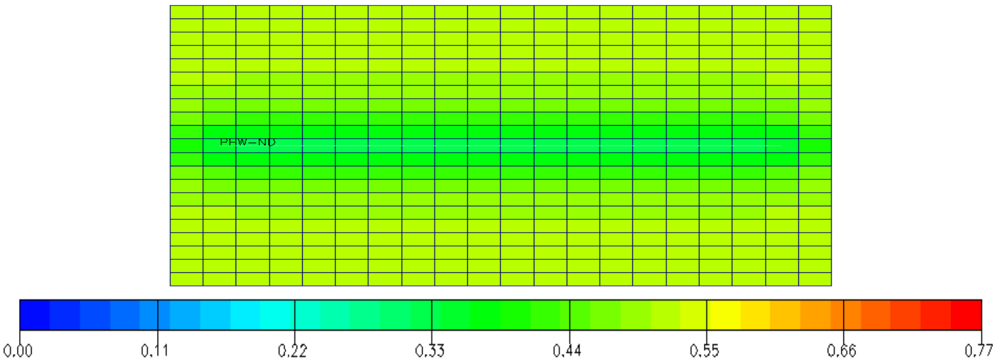

Figure 5.26 Oil saturation at abandonment for reservoir with a horizontal well under natural depletion at 500 stb/d (xy plane view)

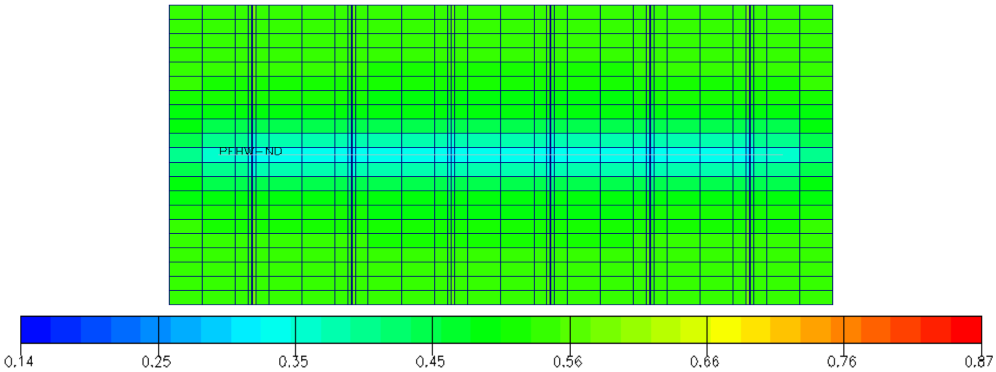

Figure 5.27 Oil saturation at abandonment for reservoir with a fractured horizontal well under natural depletion at 500 stb/d (xy plane view)

Table 5.5 Mole percent at different time for reservoir under natural depletion using different well types

component	Initial composition	Abandonment composition vertical well	Abandonment composition horizontal well	Abandonment composition fractured horizontal well
CO2	1.17	1.48	1.49	1.49
C1	39.96	51.94	53.55	52.67
C2	10.60	17.48	17.94	18.06
C3	7.62	13.68	15.10	15.44
IC4	1.58	0.70	0.81	0.83
NC4	4.31	7.20	8.50	8.80
IC5	1.58	0.25	0.30	0.32
NC5	1.54	0.34	0.40	0.42
C6	4.74	1.00	1.11	1.16
C7+	26.91	5.94	0.80	0.81
Reservoir conditions				
P_{res}	3000	354	220	219
T_{res}	220	220	220	220

The results presented thus for the cases of natural depletion of the reservoir for different oil production rate and for different well types can be summarized as follows;

- The vertical well gives the lowest value of oil recovery factor for all cases of flow rate compared to the horizontal well and the fractured horizontal well.
- The horizontal well gives the highest value of oil recovery factor for all cases of flow rate compared to the vertical well and fractured horizontal well, for example the horizontal well at oil rate of 500 stb/d gives 42.2% recovery factor, which is 0.3% more than the recovery factor of the fractured horizontal well.

5.2 Gas reinjection process: Effect of time to begin gas reinjection

The results from production via natural depletion reveals that the reservoir energy drops rapidly as gas breakthrough into the production well and that producing at low enough rates helps maintain a stable and uniform expansion of the gas-oil contact. In the quest to improve the recovery efficiency of this reservoir, produced gas reinjection was studied as an IOR method to help maintain the reservoir energy. In this evaluation, similar to the cases of natural depletion, the oil wells were set to produce at varying rates to evaluate the best scenario for gas injection. Due to the high mobility of gases, and their relatively high injectivity, a single gas injector was sufficient to replace the reservoir voidage and enable wide pressurization of the reservoir. The gas injection performed in this study is a pressure maintenance process, and the gas injection well was completed in the gas cap zone. The maximum injection pressure was evaluated and set at 3700 psia, 200 psi below the reservoir fracture pressure. The gas reinjection was performed at gas rates of 20000 Mscf/d using a single vertical gas injection well located at grid block i-10, j-1 and completed in the interval of k-1 (topmost z-layer). This part of the study seeks to find the best production schedule for gas reinjection in other to recover maximum oil recovery factor and is divided into three sections as outlined below.

- Effects of time to begin gas reinjection (Here, the time to initiate gas reinjection was varied with three options studied; performing gas reinjection from start of production, performing gas injection when reservoir pressure drops below 2500 psi, and performing gas injection when reservoir pressure drops below 1500 psi).
- Effect of time to stop the gas reinjection process (here, the time to terminate the gas reinjection process was varied based on the producing gas-oil ratoi recorded. The gas reinjection was initiated from the start of production and three options; performing gas injection till end of production, terminating gas reinjection process when GOR is greater than 80 Mscf/stb, and terminating the gas reinjection process when GOR is greater than 160 Mscf/stb).
- Effect of changing well positions.

5.2.1 Initiating gas reinjection from the start of production

The results presented here begins with the case of a vertical production well. Figure 5.28 shows the production rate of the reservoir at different flow rates. We notice that the higher the flow rate, the shorter the plateau production period. At oil rate of 500 stb/d, plateau production was maintained for about 43 months, while for the case of 2000 stb/d, it was maintained for just 4 months. As seen in Figure 5.29, everything being equal, the higher the production rate, the faster the gas breakthrough occurs. Producing the gas hinders the flow of oil (both in terms of reduction in reservoir energy and competition in two phase flow situation), this leads to lesser cumulative oil produced. The difference in recovery factor between all the cases ranging from oil rate of 500 stb/d to 2000 stb/d is about 2%, which is not a very significant difference as in the case of natural depletion. Figure 5.29 confirms that the longer the plateau period, the more gas is produced. Figure 5.29 also shows that in the early stage of production, we see a slight decrease in gas production rate; this happens because as production goes on, solution gas is liberated from the oil and migrates upwards joining to the gas cap. By the time large amount of gas was produced, oil rate dropped rapidly, coupled with rapid decline in reservoir pressure as indicated in Figure 5.30. The field pressure profile shown in Figure 5.31 shows a gradual decline in reservoir pressure with time, until at about 3 years where the pressure decline is almost halted, this happens when maximum gas was recycled in the reservoir. Looking at mass balance, the amount of fluid produced (gas plus oil production) is higher than the amount of fluid injected (produced gas reinjected), thus the pressure decline should continued. However for the case of 500 stb/d, the pressure decline appears to be arrested at about 4 years of production. This suggest that the injected gas vaporises some oil phases in the reservoir into gas phase, and the resulting volume created is almost equal to the volume of fluid withdrawed, thus giving constant pressure in the reservoir for that short period. The oil saturation profiles shown in Figure 5.33 to Figure 5.35 confirms that production at lower rates ensures a slightly uniform expansion of the gas region, delaying breakthrough of the gas and having higher oil displacement by the injected gas, since at lower oil withdrawal rates, the gas had sufficient time to spread out in the reservoir and expand uniformly sweeping the oil towards the production well. Figure 5.35 shows that the vertical well in each case dies due to excessive gas invasion, while leaving behind large amount of oil saturation in blocks further away from the gas injection well location. This suggest that the recovery efficiency could be further improved by locating the production well as far away on the opposite side of the injector well as possible. Figure 5.36, Figure 5.37, Table 5.6 and Table 5.7 give comparison between cumulative gas and cumulative oil production for vertical well at different production rates under natural depletion and gas injection. The results shows increases in recovery efficiency for all production rates under gas injection.

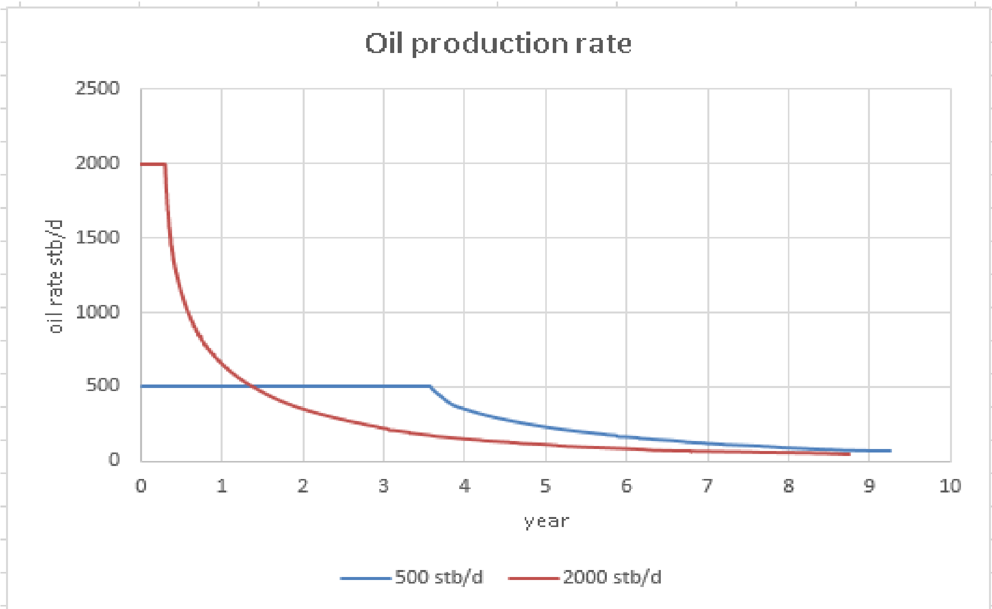

Figure 5.28 Oil production rate for vertical well under gas reinjection

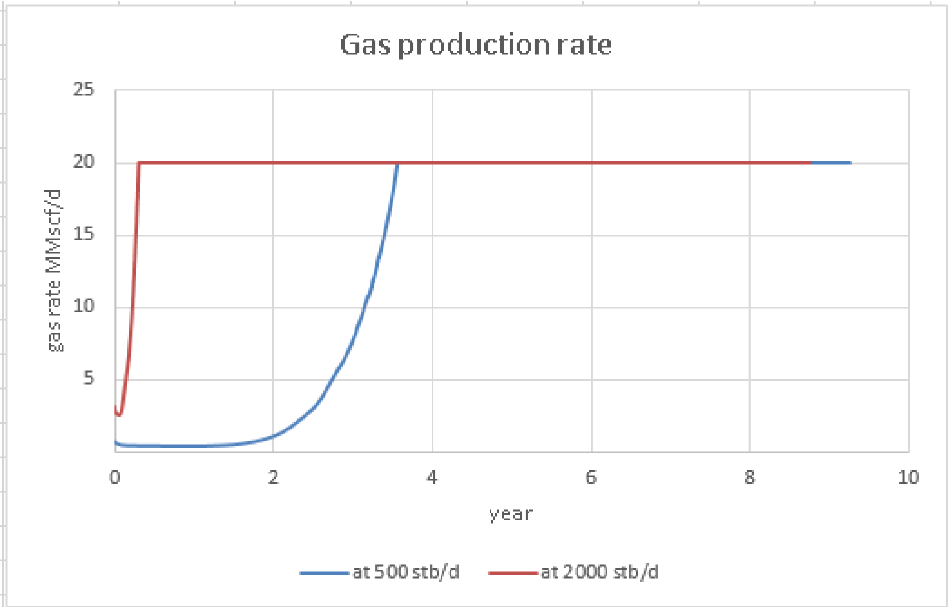

Figure 5.29 Gas production rate for vertical well under gas reinjection at different oil rates

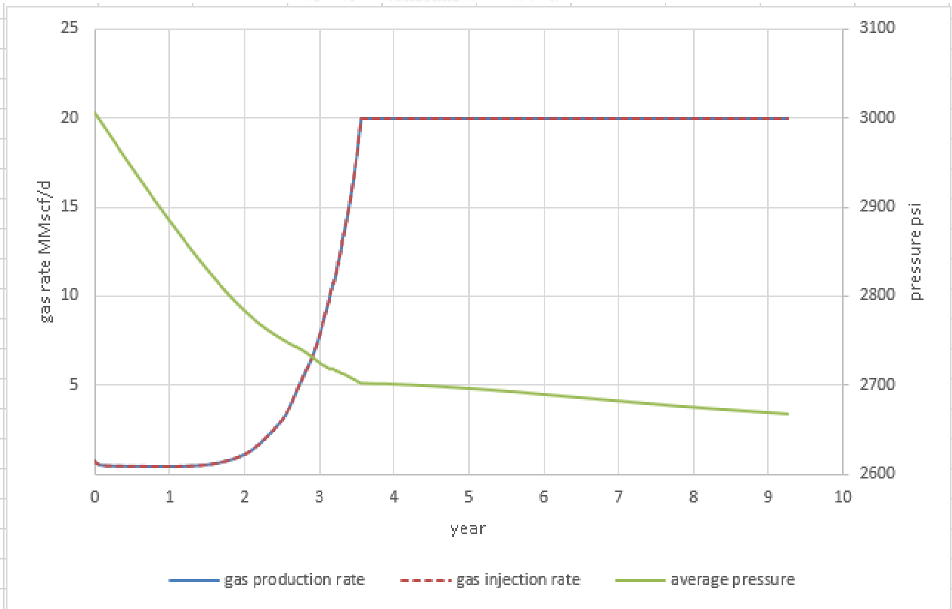

Figure 5.30 Trends of gas injection, gas production and average pressure for vertical well producer at 500 stb/d: gas injection scenario

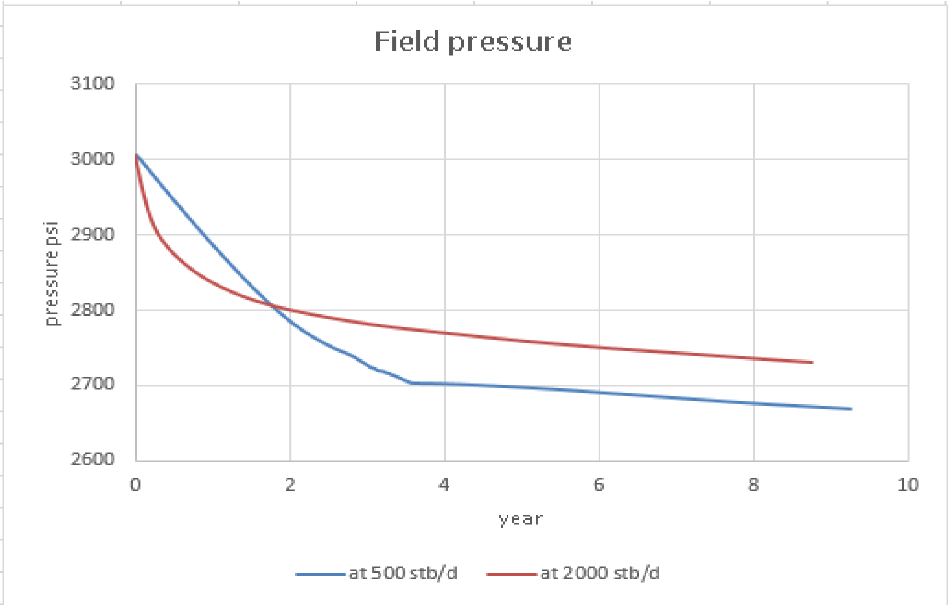

Figure 5.31 Field pressure for vertical well under gas reinjection at different oil rates

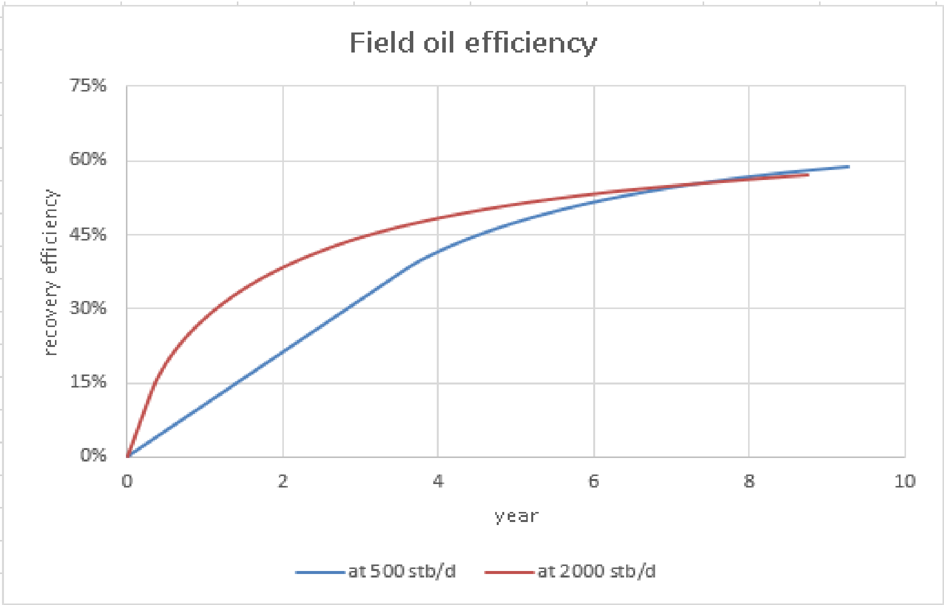

Figure 5.32 Field oil recovery efficiency for vertical well under gas reinjection at different oil flow rates

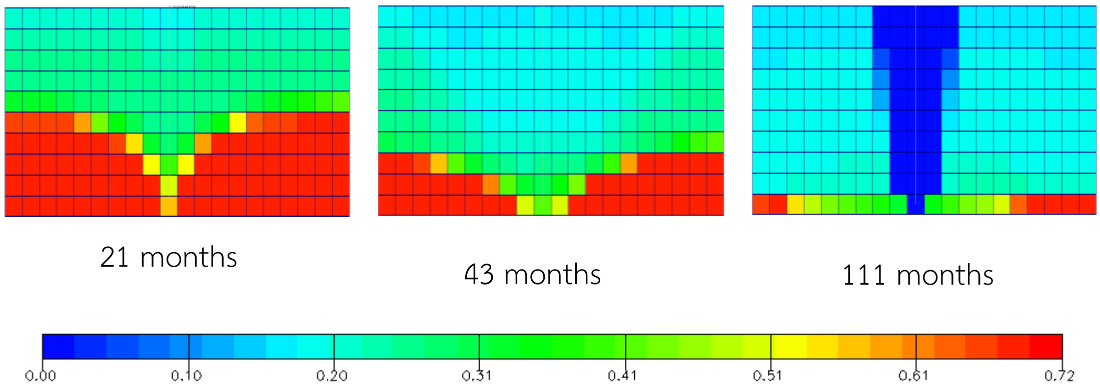

Figure 5.33 Oil saturation versus time for grid plane j = 11 gas injection with vertical production well at 500 stb/d (xz plane view)

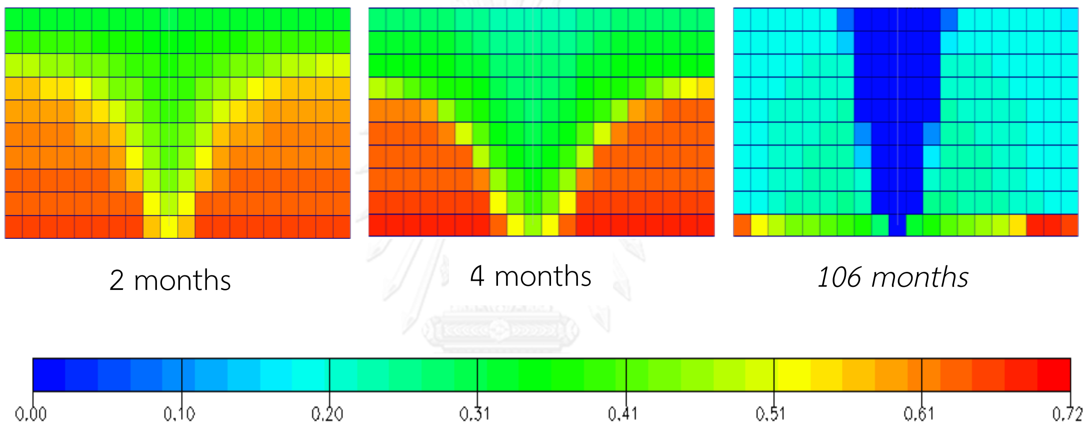

Figure 5.34 Oil saturation versus time for grid plane j = 11 gas injection with vertical production well at 2000 stb/d (xz plane view)

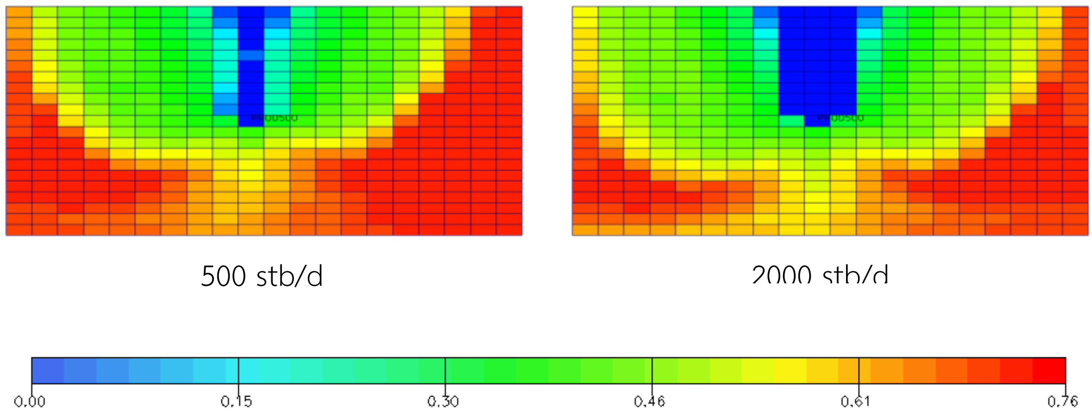

Figure 5.35 Oil saturation of plane k = 10 at abandonment for vertical well under gas injection at different oil rates (xy plane view)

Table 5.6 Comparing results for natural depletion with gas injection for vertical well – cumulative oil

Comparing cumulative oil produced					
Oil rate (stb/d)	500	800	1000	1500	2000
Natural depletion (MMstb)	0.487	0.423	0.340	0.368	0.355
Gas injection (MMstb)	1.01	-	-	-	0.978

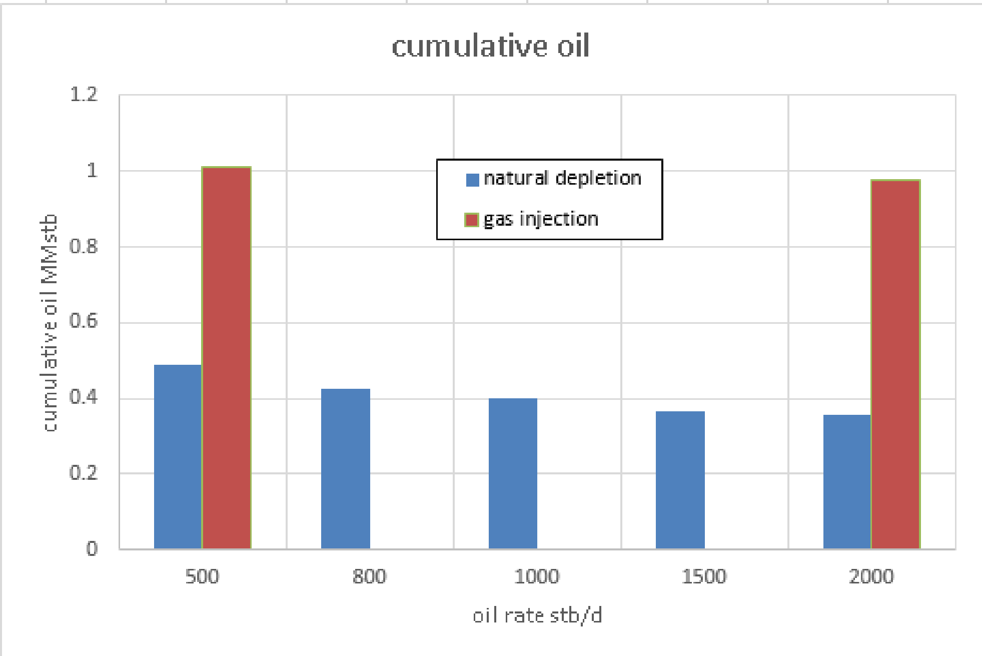

Figure 5.36 Cumulative oil for vertical well under natural depletion and gas injection

Table 5.7 Comparing result for natural depletion with gas injection for vertical well – cumulative gas

Comparing cumulative gas produced					
Oil rate (stb/d)	500	800	1000	1500	2000
Natural depletion (Bscf)	2.412	2.443	2.451	2.452	2.451
Gas injection (Bscf)	45.896	-	-	-	62.472

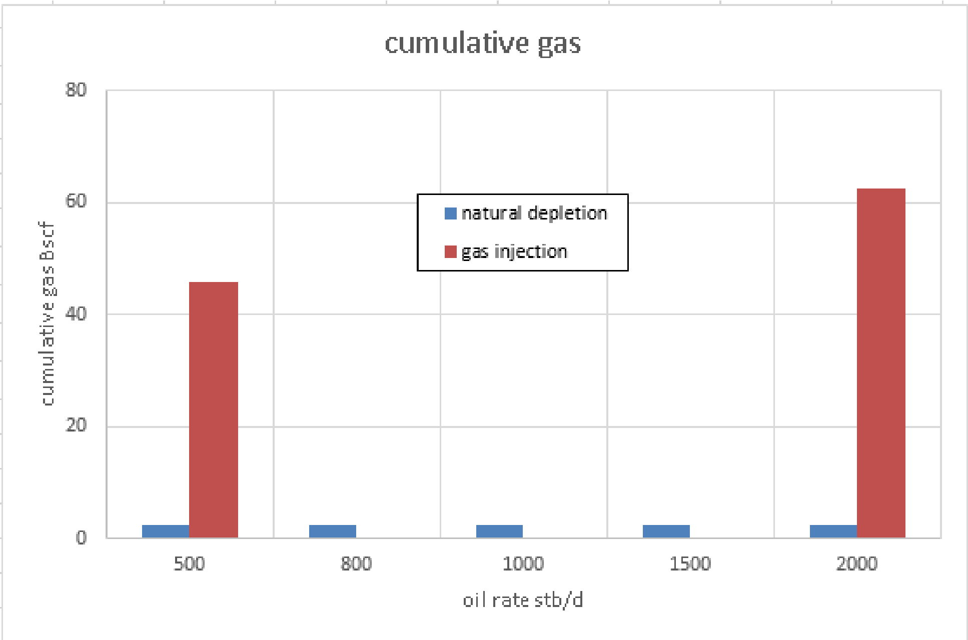

Figure 5.37 Cumulative gas for vertical well under natural depletion and gas injection

The results presented here is for the case of the horizontal production well. Figure 5.38 shows the oil production rate for the horizontal producers at 500 stb/d and 2000 stb/d. The production rate profiles shows an overlapping in trend from about 6 years onwards. This is because of the horizontal well's capibility to withdraw fluid from large area of the reservoir simultaneously, thus at late time, the reservoir uniformly depleted across a wide area. Figure 5.39 shows that once very high amount of gas production occurs, there exists competition to flow between the oil and gas, thus resulting in small amount of cumulative oil recovered over a long period of time, this thus led to very low recovery rates over a long period of time until abandonment. This is because as gas breakthrough occurs, there was high amount of gas produced, resulting in rapid drop in oil rates, since the more mobile gas flows faster and more. Since the gas injection in the case was schedule to continue till abandonment, this implies that the competition to flow continued as long as oil rate was greater than 50 stb/d. As seen in Figure 5.40 at about 4.6 years of production for the case of the horizontal well flowing at 500 stb/d, there is a slight increase in reservoir pressure. This happens due to the revaporization of intermediate hydrocarbons in the reservoir as indicated in Figure B-2. As seen in Figure B-2, as production starts, there is an increase in composition of components C7+, while composition of C1 increases, this is because the gas produced alongside the oil, leaving the reservoir fluid heavier. However, at about 4 years of production, composition of C7+ starts droping, indicating vaporization of this component into gas at the GOC thus the increase in gas components. The rapid increase in the volume of gas as seen by the sharp rise in both composition of C1, C2, while rapid decline in composition of C3, NC4, and C7+ creates a lot of gas volume in the reservoir which helps in pressurizing the reservoir, as seen by the slight increase in reservoir pressure at that period of production.

The results shown in Figure 5.41 show a similar trend as in the case of vertical wells, that producing at higher rates results in slightly lower recovery efficiency. This observed trend results due to time of gas breakthrough, which occurs much earlier with high oil rates than at low oil rates, and thus leads to higher gas production, and in turns pressure in the reservoir is higher. Figure 5.42 shows that when the gas production rate and gas injection rate stabled out, pressure drop was arrested and all of the injected gas was reproduced (gas cycling) with very little amount of oil. Thereafter the gas completely dominated a large section of the well open to flow, leading to very little oil production, thus abandonment of the well. Figure 5.43 shows the saturation profile in the xz plane for grid plane j=11 at different time of production for the horizontal well at 500 stb/d. Figure 5.44 shows the saturation profile in the xz plane for grid plane j=11 at different time of production for the horizontal well at 2000 stb/d. The oil saturation profiles show that the gas regions expand rather uniformly when producing at lower flow rates than at higher flow rates. The saturation profiles also show that the injected gas stream does move towards the horizontal section of the well, with the areas flooded by the gas having oil saturation close to zero.

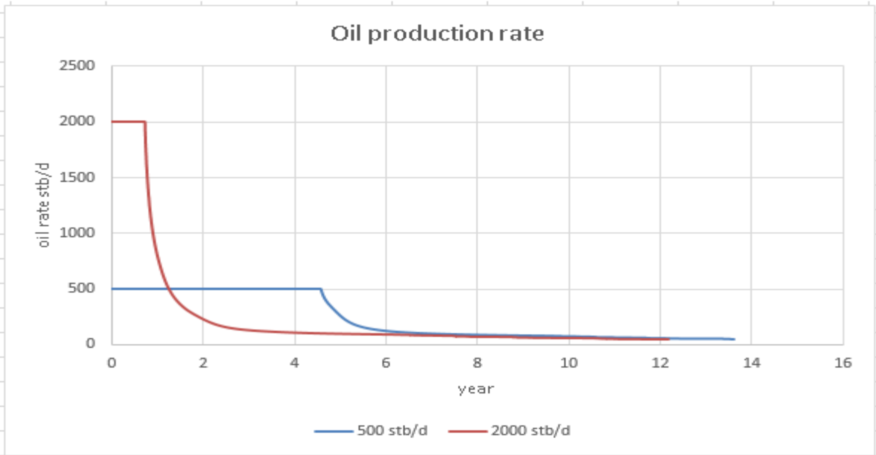

Figure 5.38 Oil production rate for horizontal well under gas reinjection

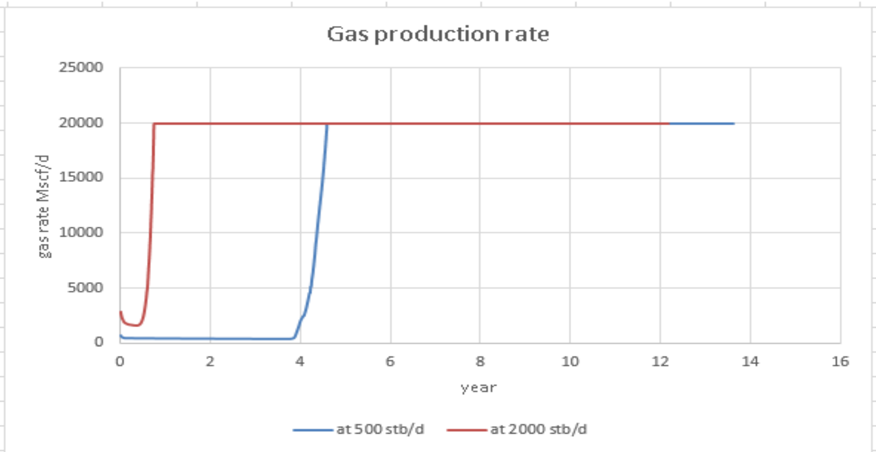

Figure 5.39 Gas production rate for horizontal well under gas reinjection at different oil rates

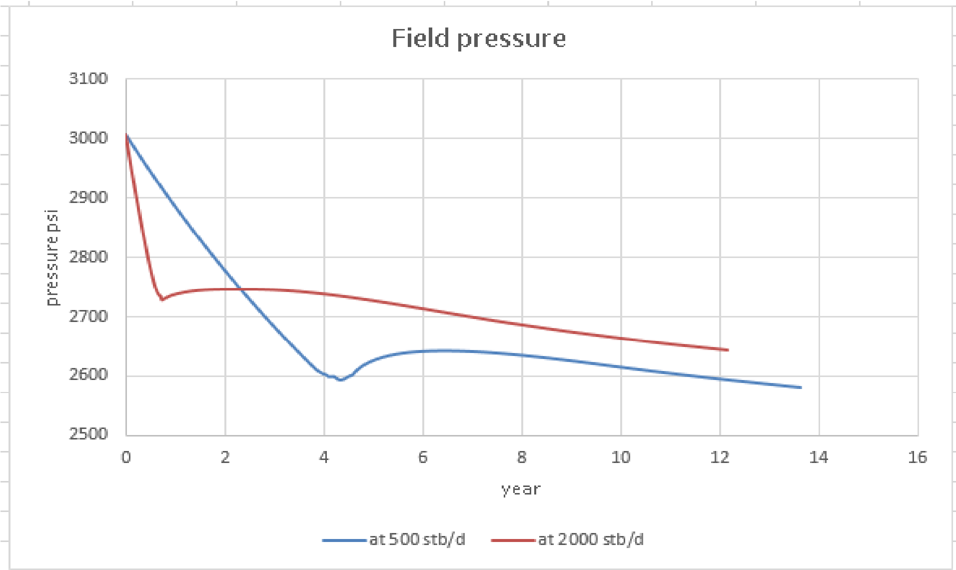

Figure 5.40 Field pressure for horizontal well under gas reinjection at different oil rates

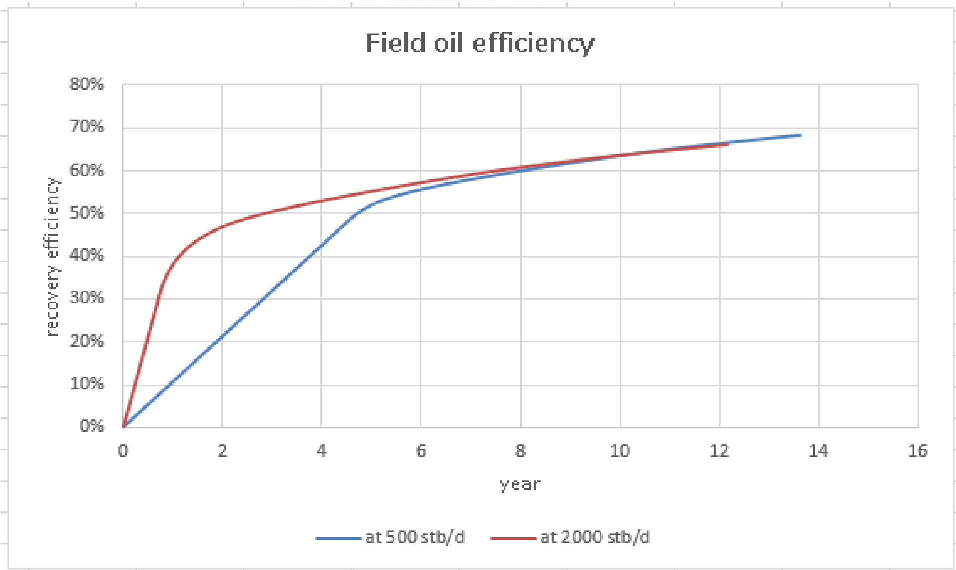

Figure 5.41 Field oil recovery efficiency for horizontal well under gas reinjection at different oil rates

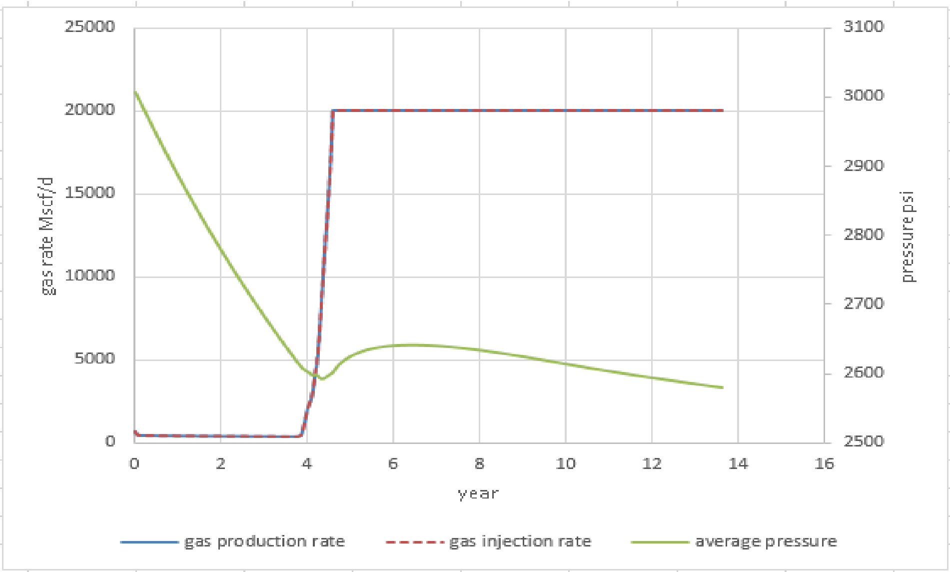

Figure 5.42 Trends of gas injection, gas production and average pressure for horizontal well producer at 500 stb/d: gas injection scenario

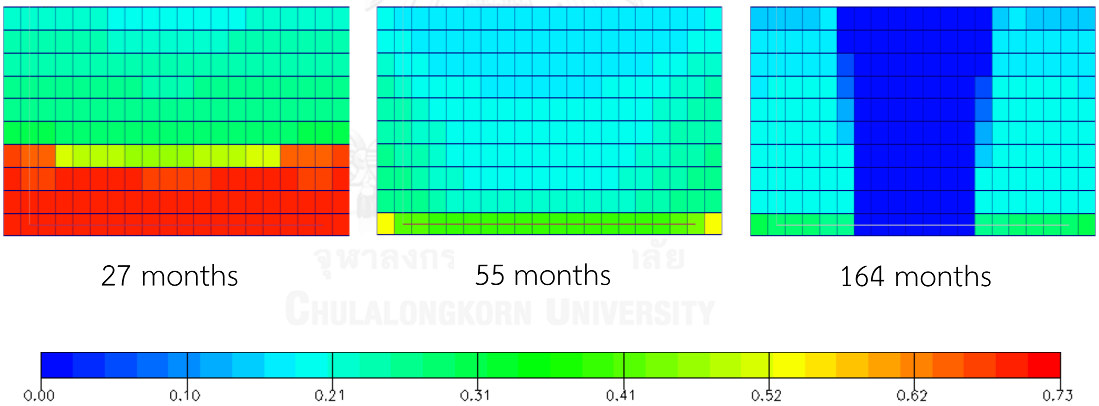

Figure 5.43 Oil saturation versus time for grid plane j = 11: gas injection with horizontal production well at 500 stb/d (xz plane view)

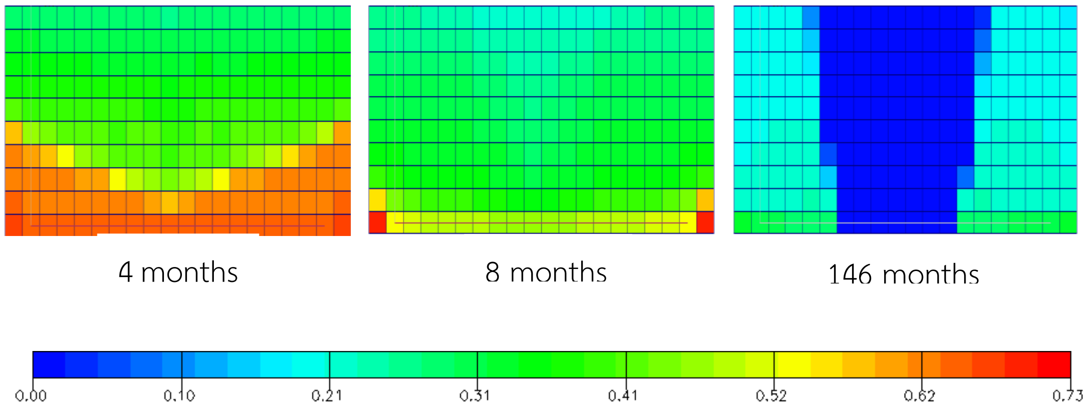

Figure 5.44 Oil saturation versus time for grid plane j = 11: gas injection with horizontal production well at 2000 stb/d (xz plane view)

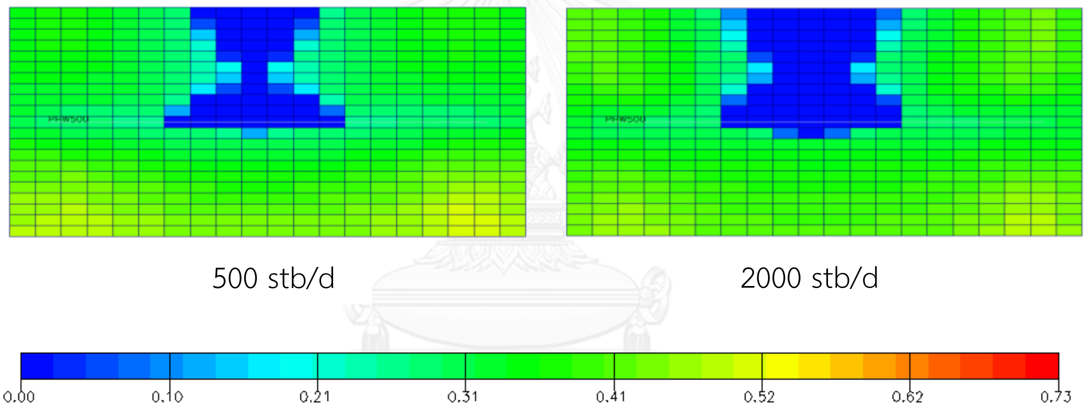

Figure 5.45 Oil saturation of plane k = 10 at abandonment for horizontal well under gas injection at different oil rates (xy plane view)

A comparison of cumulative oil and cumulative gas produced for different oil rates of the horizontal well under natural depletion and under gas reinjection is shown in Figure 5.46 to Figure 5.47 and Table 5.8 to Table 5.9.

Table 5.8 Comparison of cumulative oil produced by horizontal well under natural depletion and gas reinjection at different oil rates

Comparing cumulative oil produced					
Oil rate (stb/d)	500	800	1000	1500	2000
Natural depletion (MMstb)	0.724	0.649	0.612	0.5299	0.473
Gas reinjection (MMstb)	1.171	-	-	-	1.133

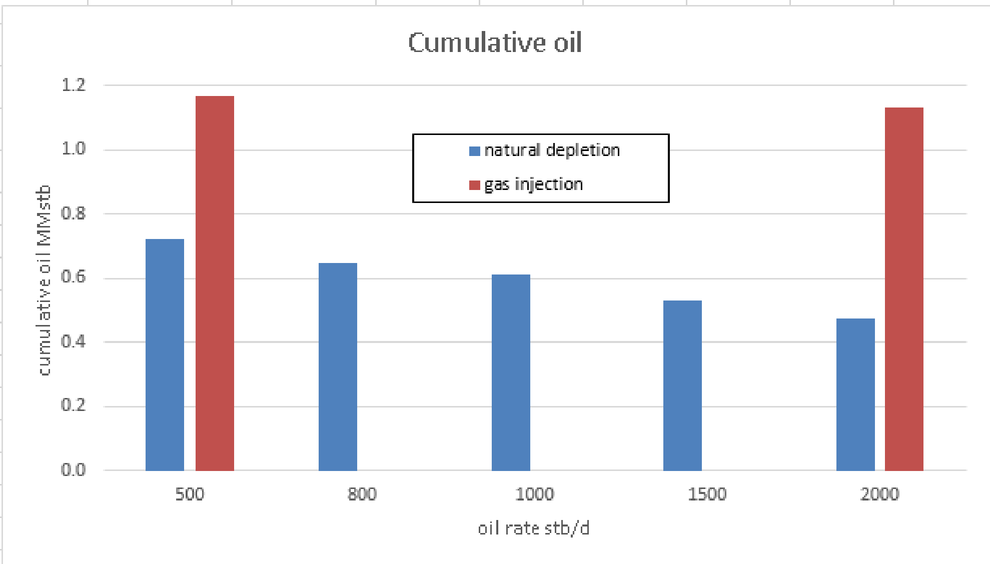

Figure 5.46 Cumulative oil produced by horizontal well under natural depletion and gas reinjection at different oil rates

Table 5.9 Comparison of cumulative gas produced by horizontal well under natural depletion and gas reinjection at different oil rates

Comparing cumulative gas produced					
Oil rate, (stb/d)	500	800	1000	1500	2000
Natural Depletion (Bscf)	2.596	2.592	2.591	2.598	2.603
Gas reinjection (Bscf)	68.462	-	-	-	84.531

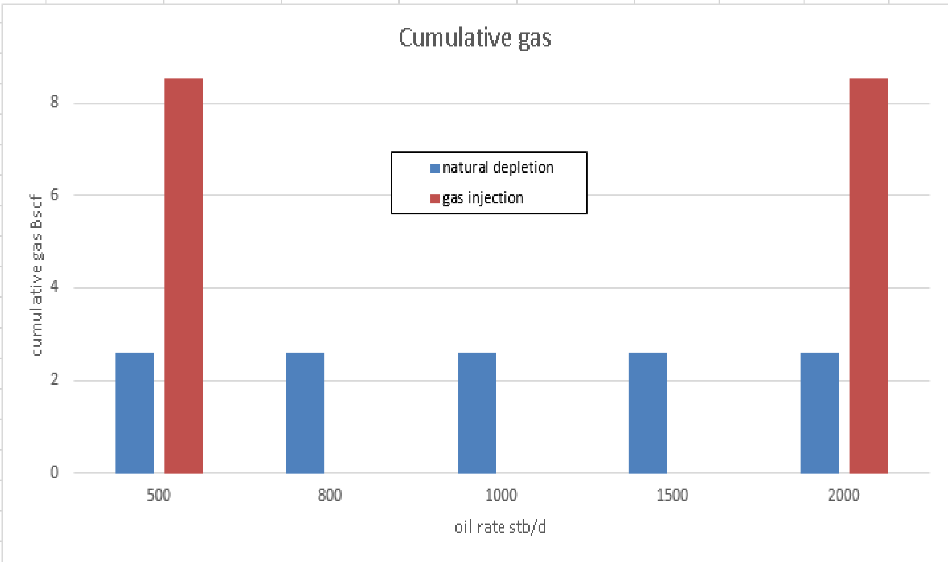

Figure 5.47 Cumulative gas produced by horizontal well under natural depletion and gas reinjection at different oil rates

The results of oil saturation analysis in this case of gas injection in the reservoir with production using the vertical well and horizontal well at 500 stb/d each is presented in Figure 5.48 to Figure 5.50. Figure 5.48 shows that the average field oil saturation can reduce down to about 0.15 for the horizontal well case. This low oil saturation is lower than residual oil saturation occurs at about 7 years of production, however, oil flow is still recorded. Technically once saturation is below residual oil saturation, oil cannot flow. Oil production continues occuring here because on an average, the areas in the reservoir not flooded by the injected gas still have high oil saturations. As this oil flow towards the well, it vaporises and is produced as condensate, thus this very low oil saturation (compared to the residual oil saturation initially of 0.2) suggests that there exists component exchanges between the fluid in the reservoir and the injected fluid (injected gas vaporizing the reservoir oil into the gas phase). With the reservoir fluid composition as shown in Table 5.10 where we see components C1 and C2 increase in composition compared to the initial composition and all other components being close to 0% in the reservoir. We can observe that the injected gas stream causes these components exchanges and thus helps in vaporizing the oil, leading to the high recovery potential and thus recovery of almost all liquid phase in the reservoir as seen.

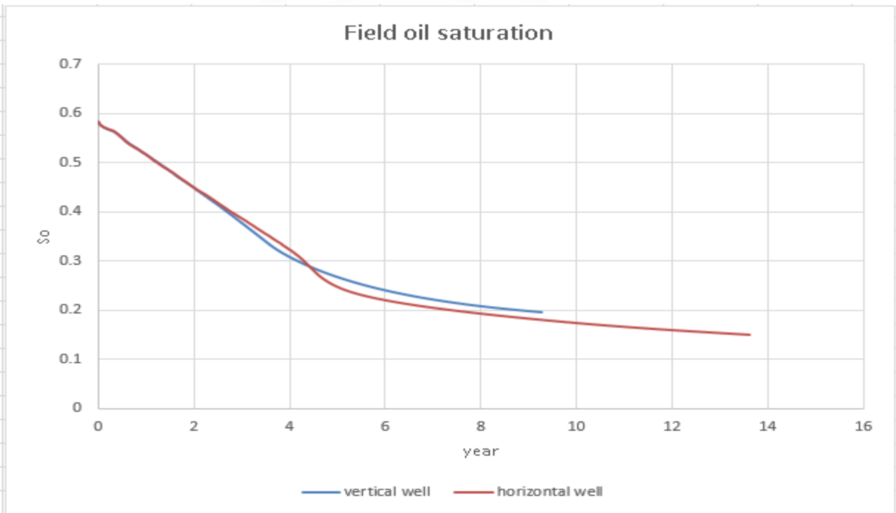

Figure 5.48 Average field oil saturation versus time for reservoir under gas injection using different well types

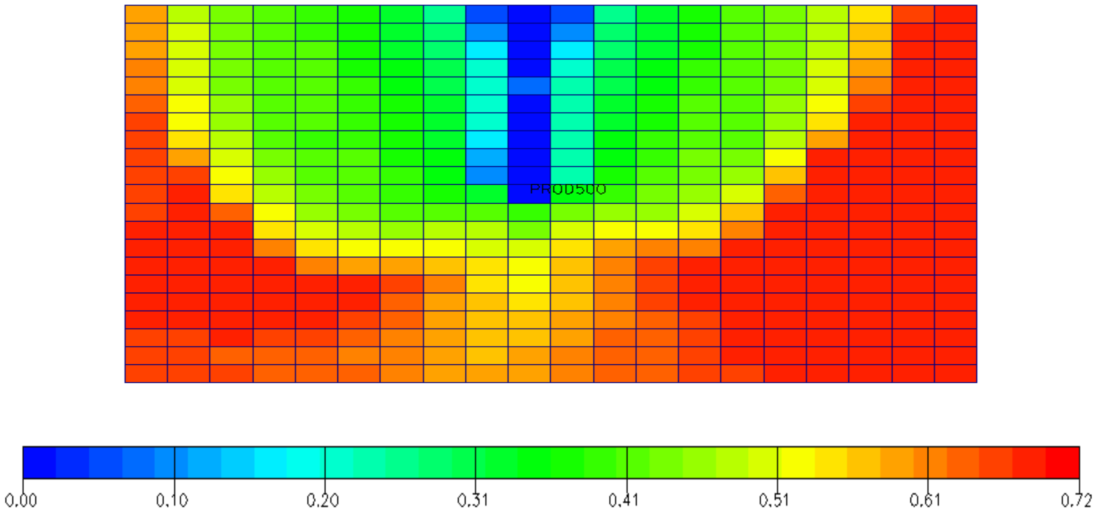

Figure 5.49 Oil saturation at abandonment for reservoir with a vertical well under gas injection at 500 stb/d (xy plane view)

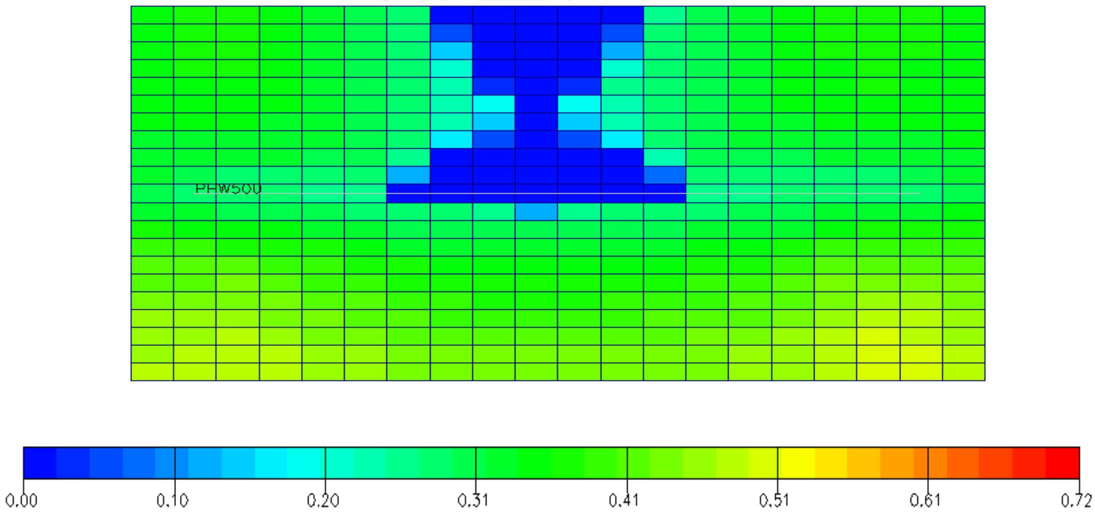

Figure 5.50 Oil saturation at abandonment for reservoir with a horizontal well under gas injection at 500 stb/d (xy plane view)

Table 5.10 Mole percent at different time for reservoir under gas injection using different well types

component	Initial composition	Abandonment composition vertical well	Abandonment composition horizontal well
CO_2	1.17	0.722	0.000998
C1	39.96	78.8	78.9
C2	10.6	20.9	20.9
C3	7.62	0.08	0.011
IC4	1.58	0.005	0.00069
NC4	4.31	0.06	0.0085
IC5	1.58	0.003	0.00045
NC5	1.54	0.004	0.00069
C6	4.74	0.017	0.0037
C7+	26.91	0.174	0.174
Reservoir conditions			
P_{res}	3000	2668	2578
T_{res}	220	220	220

5.2.2 Initiating gas reinjection when reservoir pressure is below 2500 psi

In these scenarios, the reservoir was produced first on natural depletion until when the pressure fell below 2500 psi, then gas reinjection was initiated.

For production using a vertical well at production rate of 500 stb/d and 2000 stb/d, the following results were obtained. Similar to the cases with injection from the start, Figure 5.51 shows the production rate of the reservoir at different flow rates. We notice that the higher the flow rate, the shorter the plateau oil production period. At oil rate of 500 stb/d, plateau production was maintained for about 40 months, while for the case of 2000 stb/d, it was maintained for just 4 months. Figure 5.52 shows that the higher the production rate, the faster the gas breakthrough occurs. Producing gas hinders the flow of oil (both in terms of reduction in reservoir drive energy and competition in two phase flow situation), this leads to lesser cumulative oil produced. The results from Figure 5.53 shows that once the gas reinjection begins at pressure lower than 2500 psi, the injection process re-pressurized the reservoir and slows down the pressure decline. At that stage, flowing at lower oil rates kept the pressure high in the reservoir for longer time than flowing at high rates. As seen in Figure 5.53 at about 3 years of production for the case of the vertical well flowing at 500 stb/d, and at about 0.4 years of production for the case of vertical well flowing at 2000 stb/d, the reservoir pressure decline was much slower. This happens due to the revaporization of intermediate hydrocarbons in the reservoir as indicated in Figure B-3 and Figure B-4 for 500 stb/d and 2000 stb/d respectively. As seen in Figure B-3, as production starts, there is an increase in composition of components C7+, while composition of C1 increases, this is due to the gas produced alongside the oil, leaving the reservoir fluid heavier. However, at about 1 years of production, composition of C7+ starts droping, indicating vaporization of this component into gas at the GOC thus the increase in gas components. The vaporization process is gradual as seen by the gradual increase in both composition of C1, C2, while also gradual decrease in composition of C3, NC4, and C7+ thus creating just enough gas volume in the reservoir which helps in pressurizing the reservoir, as seen by the complete arrest in reservoir pressure decline at that period of production.

The field oil recovery factor shown in Figure 5.54 indicates lower recovery rates towards the end of the production life. The vertical well draws fluid only in the area near it, thus once large gas production occurs and reduction in reservoir energy is seen, the vertical well performance greatly reduces. Figure 5.55 shows the trend of gas production rate, gas injection rate and reservoir pressure. It shows that before gas reinjection was initiated, the reservoir pressure was dropping rather steeply until about two years when the reinjection process was initiated and the pressure decline was significantly slowed down. This shows that the injected gas does help to support the reservoir pressure as production proceeds. The oil saturation profiles shown in Figure 5.56 to Figure 5.58, confirm that production at lower rates ensured a slightly uniform expansion of the gas region, though the gas coning was still significant.

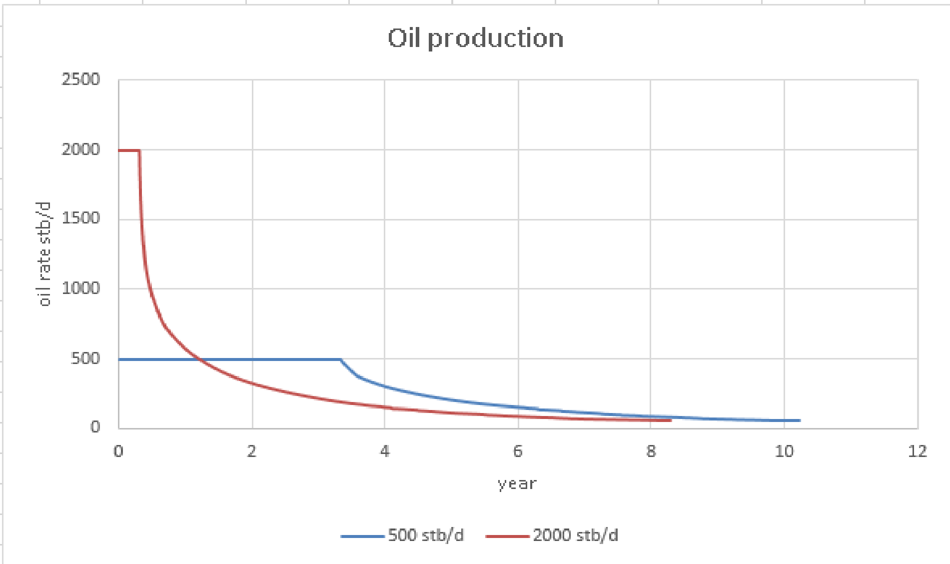

Figure 5.51 Oil production rate for vertical well under gas reinjection at pressure lower than 2500psi

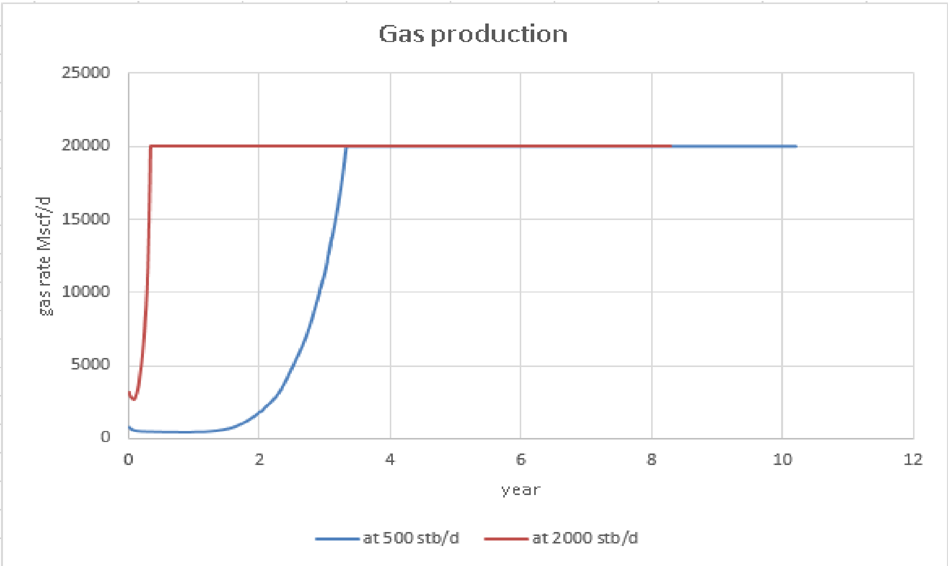

Figure 5.52 Gas production rate for vertical well under gas reinjection at pressure lower than 2500 psi

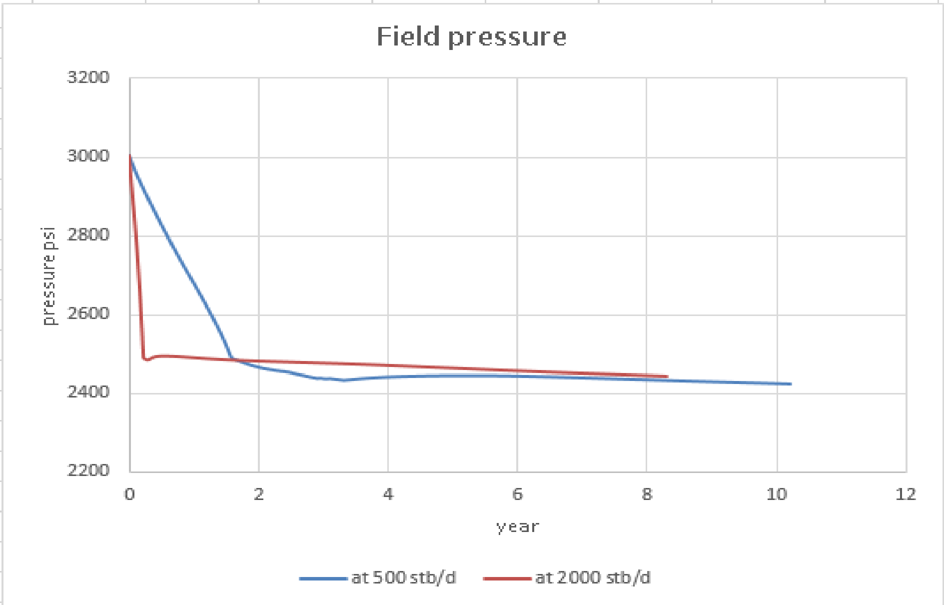

Figure 5.53 Field pressure for vertical well under gas reinjection at pressure lower than 2500 psi

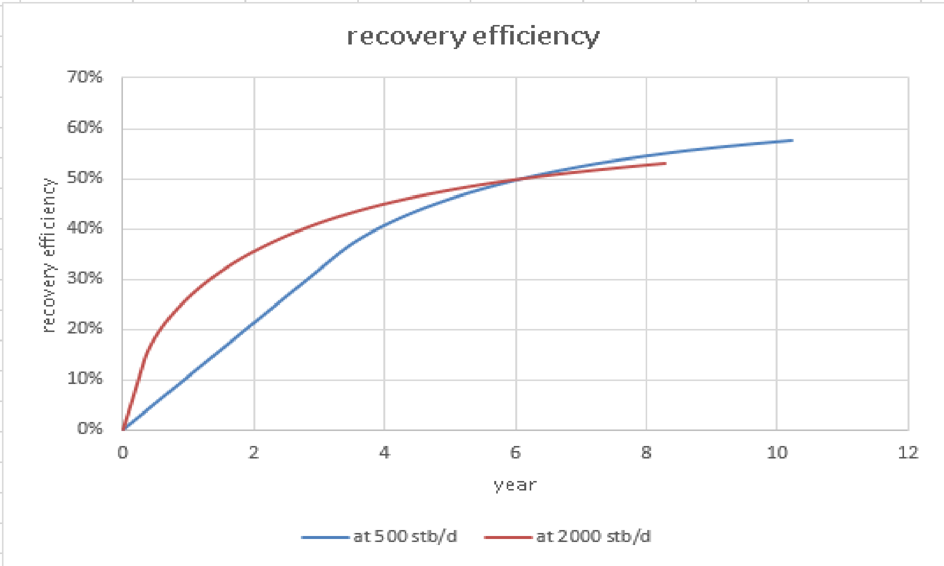

Figure 5.54 Field oil efficiency for vertical well under gas reinjection at pressure lower than 2500 psi

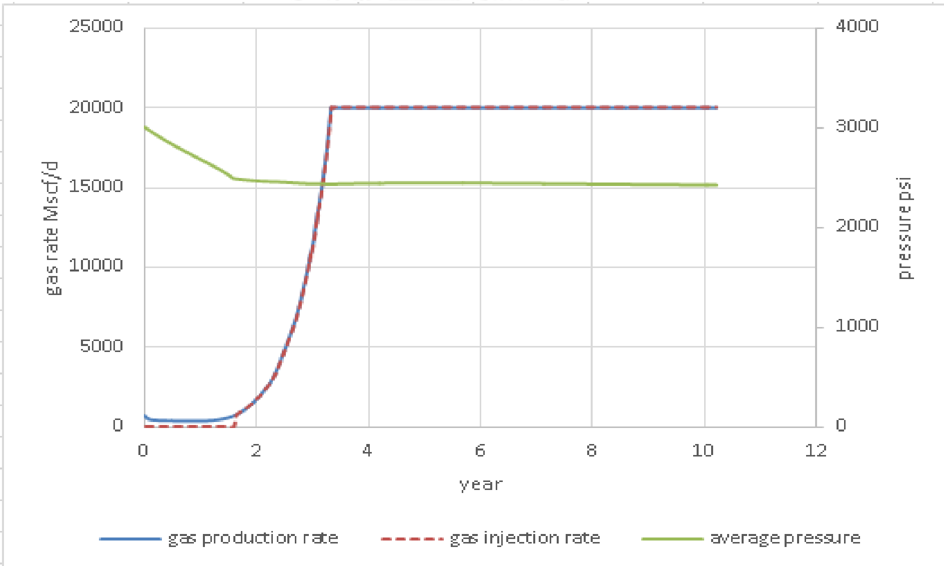

Figure 5.55 Trends of gas injection, gas production and average pressure for vertical well producer at 500 stb/d: gas injection when P<2500 psi scenario

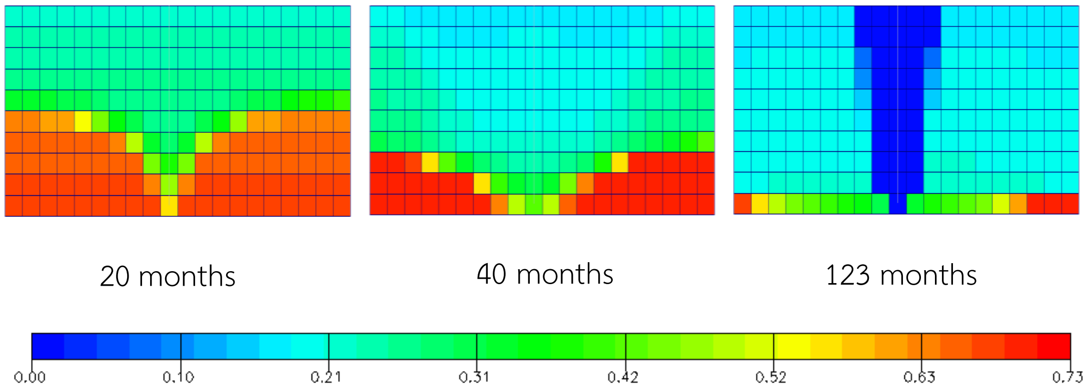

Figure 5.56 Oil saturation versus time for grid plane j = 11: gas injection when P<2500 psi with vertical production well at 500 stb/d (xz plane view)

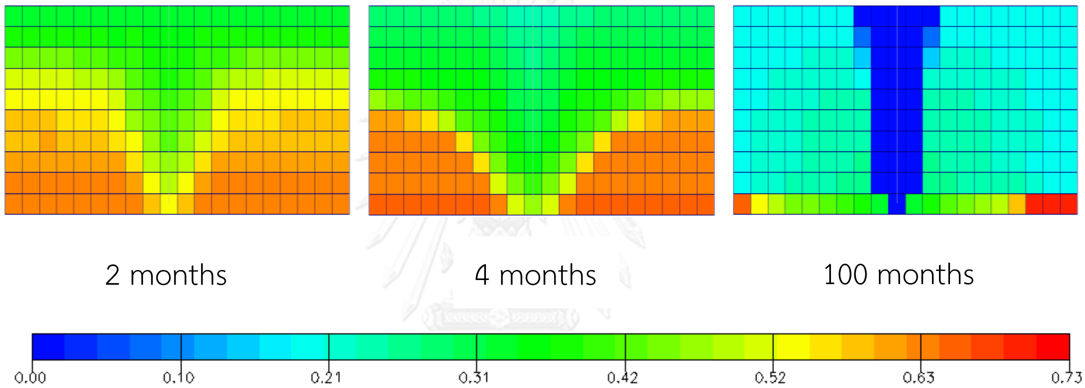

Figure 5.57 Oil saturation versus time for grid plane j = 11: gas injection when P<2500 psi with vertical production well at 2000 stb/d (xz plane view)

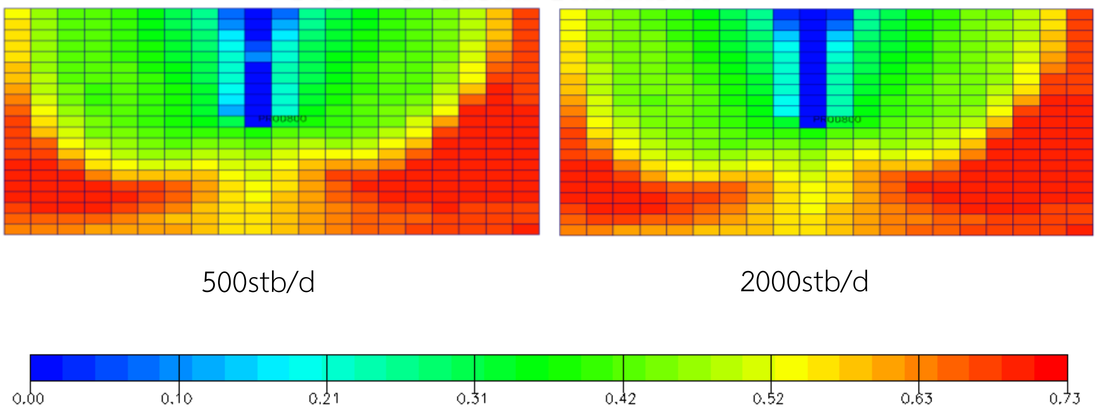

Figure 5.58 Oil saturation of plane k = 10 at abandonment for vertical well under gas injection when P<2500 psi at different oil rates (xy plane view)

Production using the horizontal well at oil production rates of 500 stb/d and 2000 stb/d are presented in this part. Figure 5.59 gives the oil production rate for the horizontal wells at 500 stb/d and 2000 stb/d. at about six years of production, the oil rate of both cases are quite similar. The plateau production period of the horizontal well at 500 stb/d is about 4.4 years while that of the horizontal well at 2000 stb/d is about 1 year. The higher flow rate case results in faster gas production as shown in Figure 5.60, thus this gas production hinders the potential of oil production. We also see from Figure 5.60 that as production begins, the gas rate drops slightly, this is due to the solution gas coming out of the oil and moving up in the reservoir, resulting in lesser amount of gas dissolved in the oil. Figure 5.61 indicates that prior to gas reinjection, the pressure of the reservoir declines rather steeply as the reservoir is produced on natural energy stored in the reservoir. As pressure drops below 2500 psi, the gas injection process was initiated, and the reservoir was re-pressurized and the pressure decline was arrested. In Figure 5.61 at about 1 year (for the case of 2000 stb/d) and at about 4 years (for the case of 500 stb/d) of production we see a slight increase in reservoir pressure even though the net amount of fluid produced (oil plus gas) is higher than the net amount of fluid reinjected (gas). This happes because the injected gas initiates component exchanges with the oil in the reservoir, thus vaporizing the oil and creating larger volume of gas which expands and supports the reservoir energy. As seen in Figure 5.61 at about 4 years of production for the case of the horizontal well flowing at 500 stb/d, and at about 0.9 years of production for the case of horizontal well flowing at 2000 stb/d, there is a slight increase in reservoir pressure. This happens due to the revaporization of intermediate hydrocarbons in the reservoir as indicated in Figure B-5 and Figure B-6. As seen in Figure B-5, as production starts, there is an increase in composition of components C7+, while composition of C1 increases, this is due to the gas produced alongside the oil, leaving the reservoir fluid heavier. However, at about 3.6 years of production, composition of C7+ starts droping, indicating vaporization of this component into gas at the GOC thus the increase in gas components. The rapid increase in the volume of gas as seen by the sharp rise in both composition of C1, C2, while rapid decline in composition of C3, NC4, and C7+ creates a lot of gas volume in the reservoir which helps in pressurizing the reservoir, as seen by the slight increase in reservoir pressure at that period of production.

Figure 5.62 show that once gas breakthrough occurs, there exists competition of flow between the oil and gas, thus resulting in low recovery rates over a long period of time until abandonment. The case of flowing at higher rate shows lower recovery rate than the case flowing at lower rate from about 6 years of production onwards, this results due to the much cumulative gas produced by this high rate wells which leads to decline in reservoir energy. The saturation profiles in Figure 5.64 to Figure 5.66 show that the gas-oil contact expands rather uniformly for lower oil rate cases, with the high rate cases showing very little gas layer coning into the well. This uniform gas contact expansion also helps in delaying gas breakthrough. Since the horizontal well draws fluid across the entire length of the reservoir, when gas finally breaks into the horizontal section, a large amount of gas was produced at a short period of time. Since the produced gas was recycled back to help maintain high reservoir pressure, Figure 5.63 shows that though this large amount of gas is produced at breakthrough, the reservoir pressure was still kept rather constant due to this gas recycling process performed.

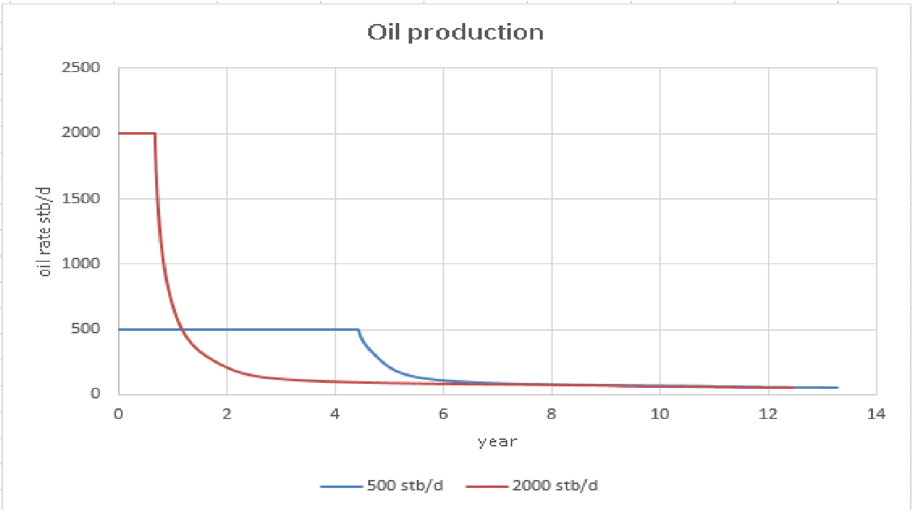

Figure 5.59 Oil production rate for horizontal well under gas reinjection at pressure lower than 2500 psi

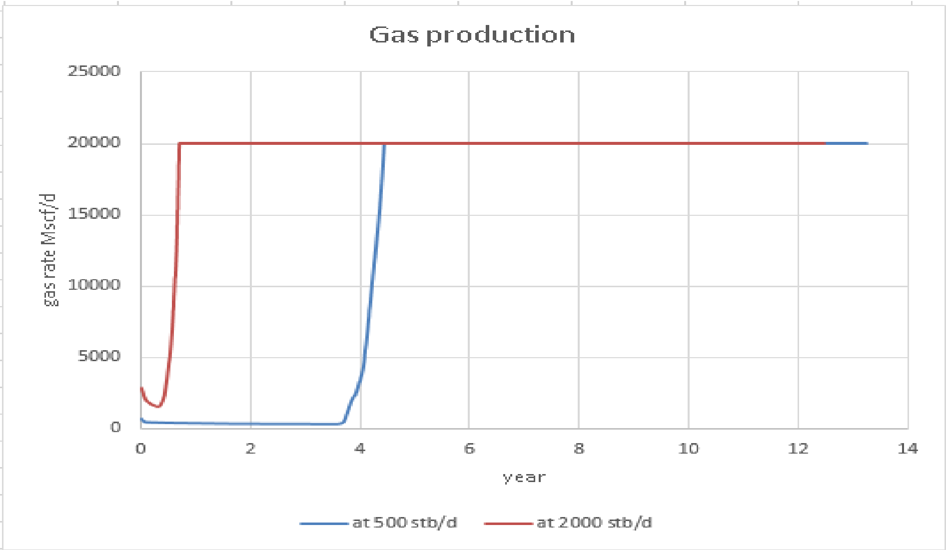

Figure 5.60 Gas production rate for horizontal well under gas reinjection at pressure lower than 2500 psi

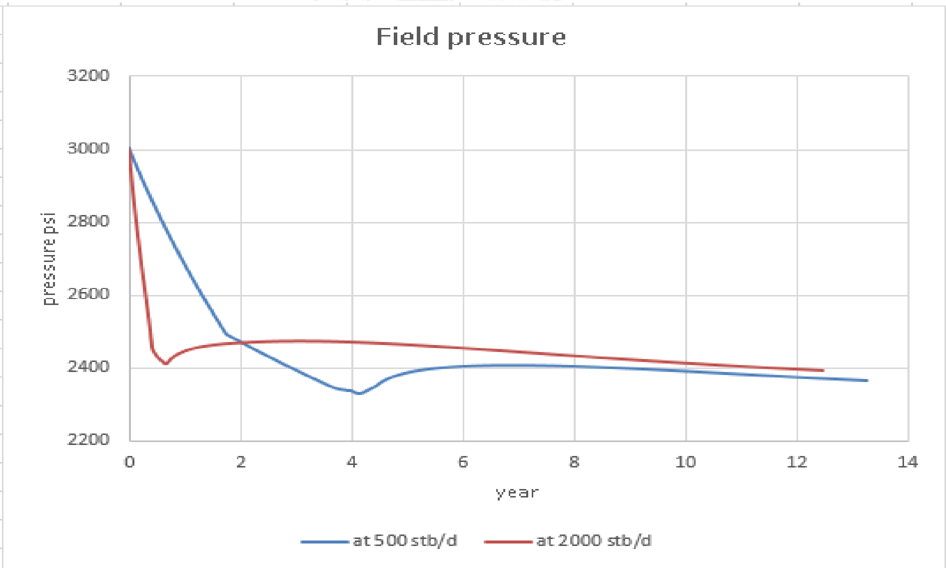

Figure 5.61 Field pressure for horizontal well under gas reinjection at pressure lower than 2500 psi

Figure 5.62 Field oil efficiency for horizontal well under gas reinjection at pressure lower than 2500 psi

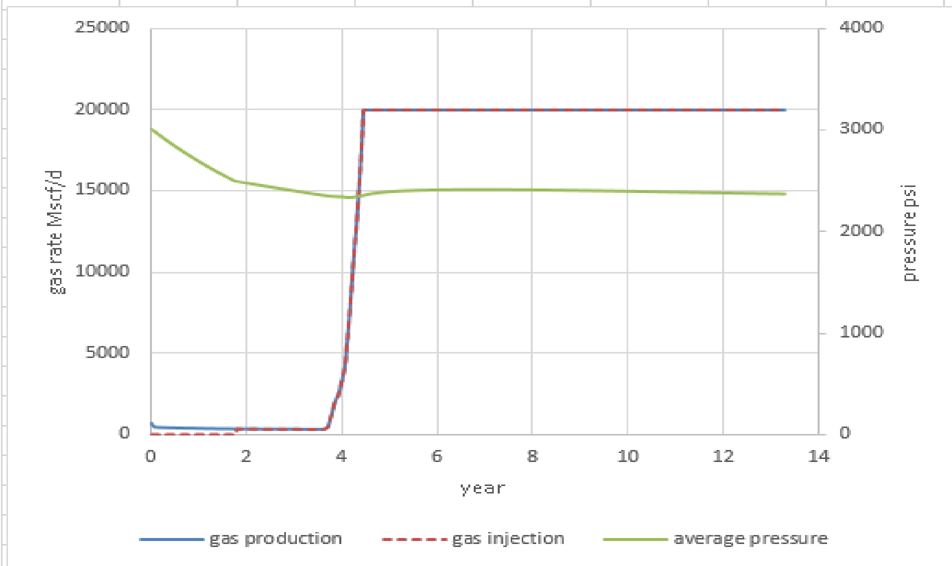

Figure 5.63 Trends of gas injection, gas production and average pressure for horizontal well producer at 500 stb/d: gas injection when P<2500 psi scenario

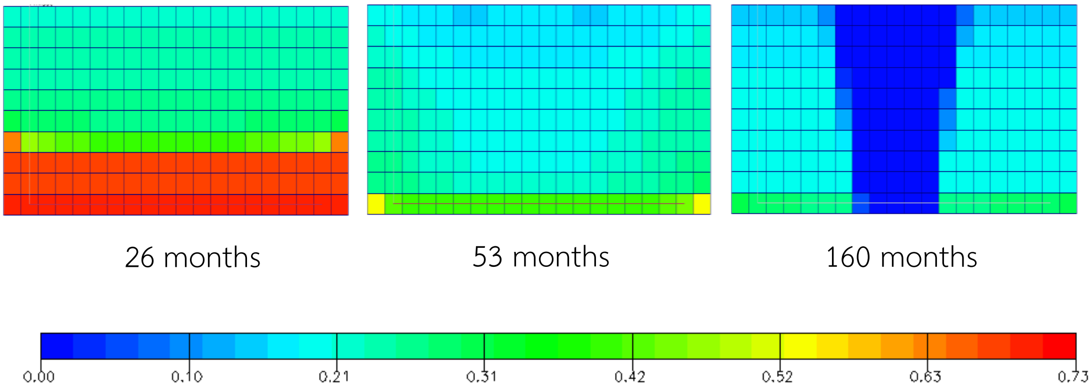

Figure 5.64 Oil saturation versus time for grid plane j = 11: gas injection when P<2500 psi with horizontal production well at 500 stb/d (xz plane view)

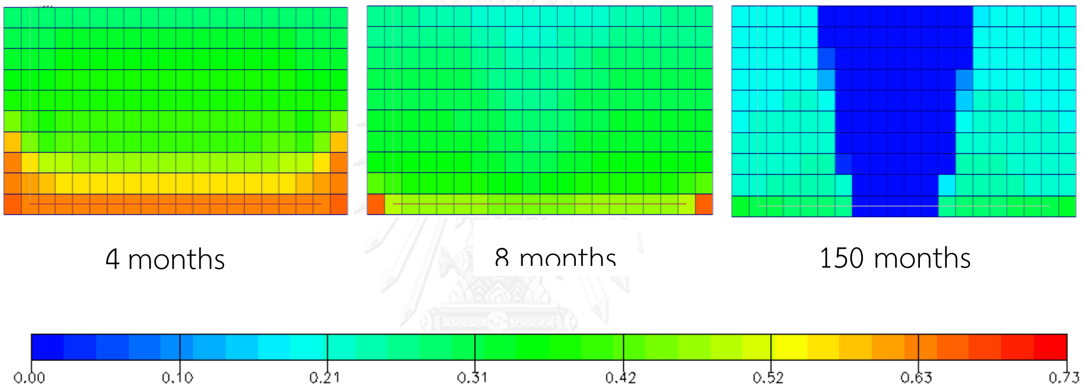

Figure 5.65 Oil saturation versus time for grid plane j = 11: gas injection when P<2500 psi with horizontal production well at 2000 stb/d (xz plane view)

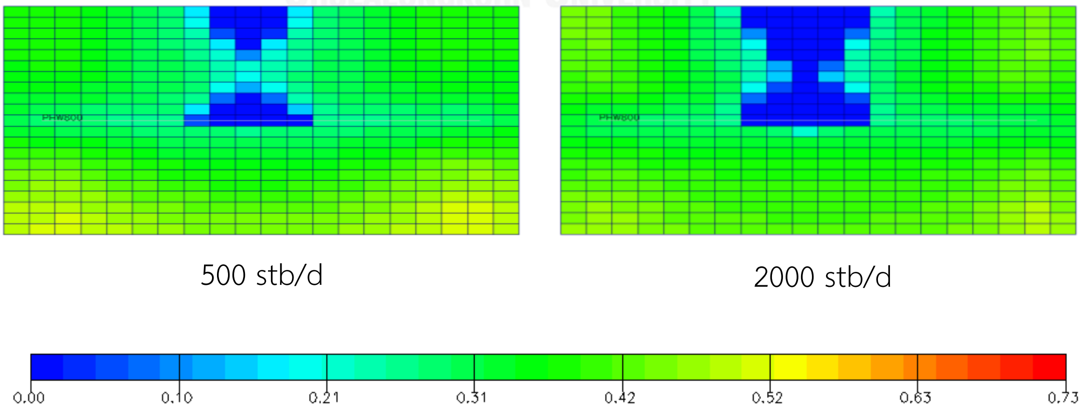

Figure 5.66 Oil saturation of plane k = 10 at abandonment for horizontal well under gas injection when P<2500 psi at different oil rates (xy plane view)

The reservoir fluid saturation analysis for this case of gas injection when P<2500 psi is presented below. The results of oil saturation analysis in this case of gas injection in the reservoir is presented in Figure 5.67. Figure 5.67 The average field oil saturation can reduce to down to about 0.17 for the horizontal well case. This low oil saturation lower than residual oil saturation occurs at about 8 years of production, however, oil flow is still recorded. Technically once saturation is below residual oil saturation, oil cannot flow. Oil production continues occuring here because on an average, the areas in the reservoir not flooded by the injected gas still have high oil saturations. As this oil flow towards the well, it vaporises and is produced as condensate, thus this very low oil saturation (compared to the residual oil saturation initially of 0.2) suggests that there exists component exchanges between the fluid in the reservoir and the injected fluid (injected gas vaporizing the reservoir oil into the gas phase). With the reservoir fluid composition as shown in Table 5.11 where we see components C1 and C2 increase in composition compared to the initial composition and all other components being close to 0% in the reservoir, we can confirm that the injected gas stream will cause these components exchanges and thus help in vaporizing the oil, leading to the high recovery potential and thus recovery of almost all liquid phase in the reservoir as seen.

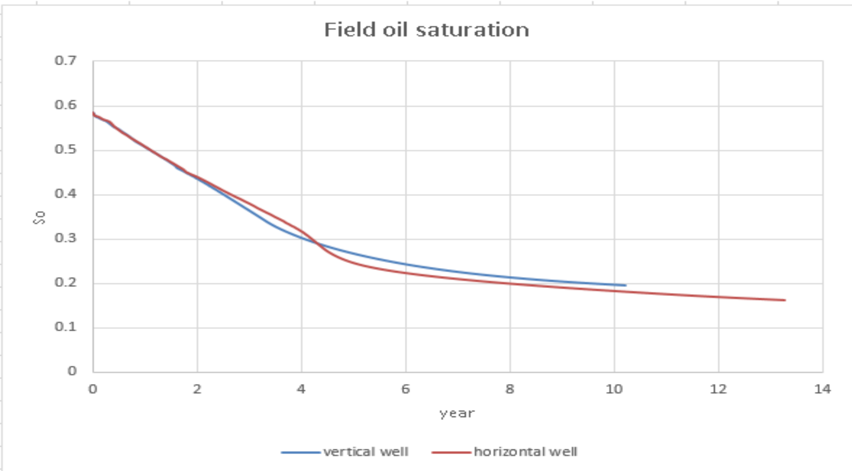

Figure 5.67 Average field oil saturation versus time for reservoir under gas injection when P<2500 psi using different well types

Table 5.11 Mole percent at different time for reservoir under gas injection when P<2500 psi

component	Initial composition	Abandonment composition vertical well	Abandonment composition horizontal well
CO2	1.17	0.00399	0.00096
C1	39.96	78.83	78.91
C2	10.6	20.92	20.91
C3	7.62	0.0466	0.0108
IC4	1.58	0.00296	0.00069
NC4	4.31	0.0359	0.0087
IC5	1.58	0.0018	0.00048
NC5	1.54	0.0026	0.00073
C6	4.74	0.0125	0.00378
C7+	26.91	0.14	0.126
Reservoir conditions			
P_{res}	3000	2425	2366
T_{res}	220	220	220

5.2.3 Initiating gas reinjection when pressure is below 1500 psi

The results for the case of production using the vertical production well at flow rates of 500 stb/d and 2000 stb/d is presented here. Figure 5.68 show a similar trend in rate, as the lower flow rate was maintained at plateau production for longer periods of time. Since the reservoir was first produced by natural depletion until when pressure is below 1500 psi before gas reinjection was initiated, the higher flow rate cases declined in production rate due to insufficient energy to support this high rates, and thus shorter plateau production time compared to the case in section 5.2.1. Figure 5.69 shows the gas production for the vertical wells at different constraints of oil rate. For the vertical producing at 500 stb/d, the trend in gas rate first declines slightly at early time of production due to solution gas coming out of solution, and at about two years of production, the gas rate starts increasing showing that the gas cap has expanded into the production section. For the vertical well flowing at 2000 stb/d, the gas rate is seen to increase, then a rapid decline in gas rate at about 5 months of production before increasing again. This happens because as the reservoir is produced under natural depletion, the reservoir energy decreases and cannot support this high rates, leading to rapid decline in both oil rate and gas rate. However, as seen in Figure 5.70 once gas reinjection is initiated (once pressure drops below 1500 psi), the gas rate picks up, with the reservoir pressure decline also arrested, this is evident that the injected gas supports reservoir pressure. Figure 5.71 shows that once gas injection was initiated, the pressure decline was arrested with the reservoir pressure later increasing due to gas expansion and voidage replacement. As seen in Figure 5.71 at about 2.6 years of production for the case of the vertical well flowing at 500 stb/d, and at 0.8 years of production for the case of vertical well flowing at 2000 stb/d, there is a slight increase in reservoir pressure. This happens due to the revaporization of intermediate hydrocarbons in the reservoir as indicated in Figure B-7 and Figure B-8. As seen in Figure B-7, as production starts, there is an increase in composition of components C7+, while composition of C1 increases, this is due to the gas produced alongside the oil, leaving the reservoir fluid heavier. However, at about 4 years of production, composition of C7+ starts droping, indicating vaporization of this component into gas at the GOC thus the increase in gas components. The rapid increase in the volume of gas as seen by the sharp rise in both composition of C1, C2, while rapid decline in composition of C3, NC4, and C7+ creates a lot of gas volume in the reservoir which helps in pressurizing the reservoir, as seen by the slight increase in reservoir pressure at that period of production.

The oil saturation profiles reveals that since gas injection begins much later in the production cycle, the injected gas did not have sufficient time to sweep much part of the reservoir as in the case seen in section 5.2.1, thus the anticipated component exchange and sweep efficiency of the injected gas was not be maximized, leaving larger area of the reservoir not swept and still very saturated with oil as shownin Figure 5.76. This resulted in much lower recovery efficiency as seen in Figure 5.72, with the vertical well flowing at 500 stb/d given just about 50.7% recovery.

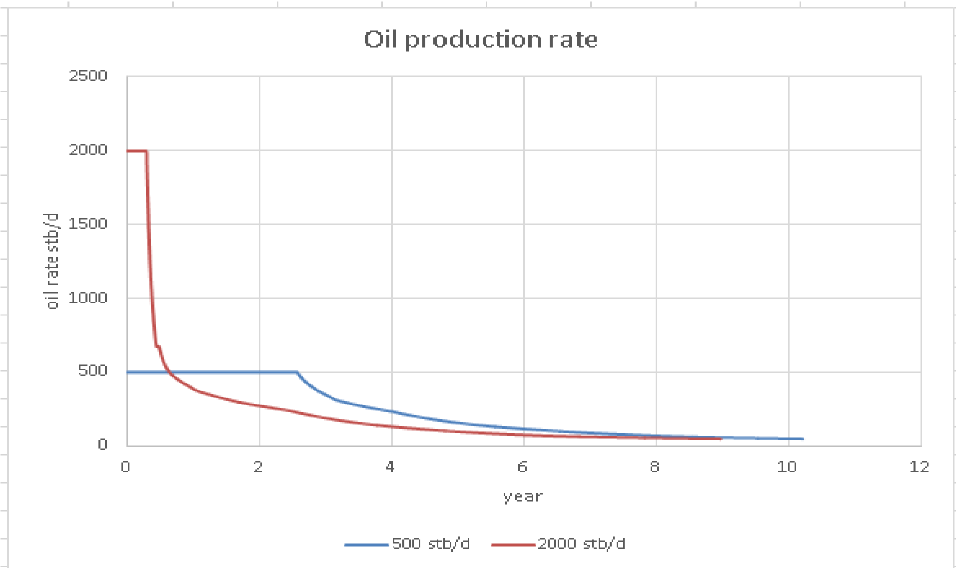

Figure 5.68 Oil production rate for vertical well under gas reinjection at pressure lower than 1500 psI

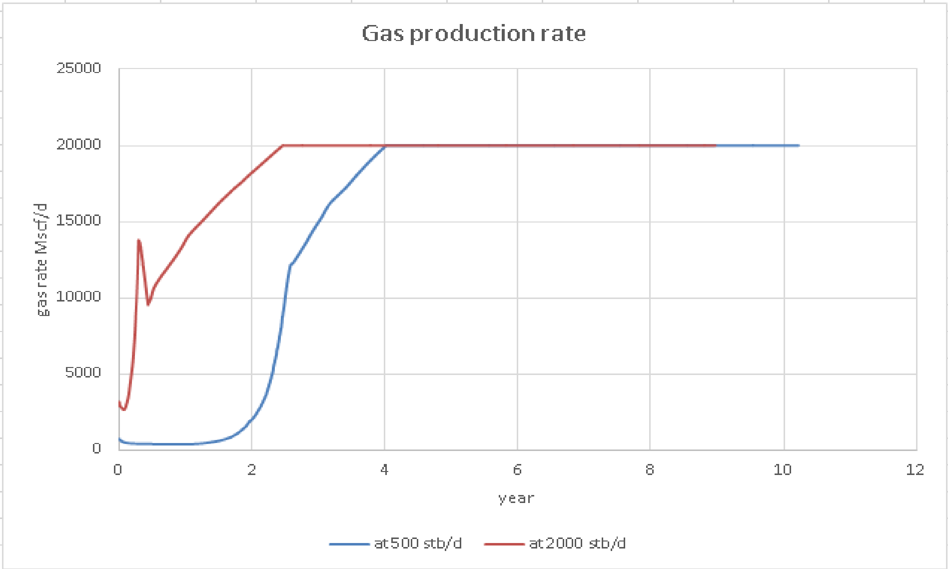

Figure 5.69 Gas production rate for vertical wells under gas reinjection at pressure lower than 1500 psi

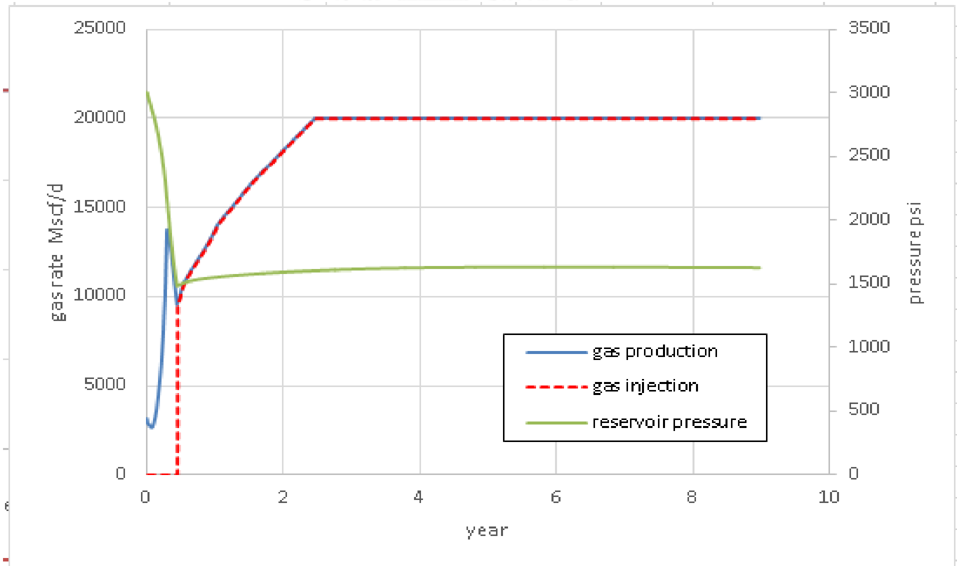

Figure 5.70 Trends of gas injection, gas production and average pressure for vertical well producer at 2000 stb/d: gas injection when P<1500 psi scenario

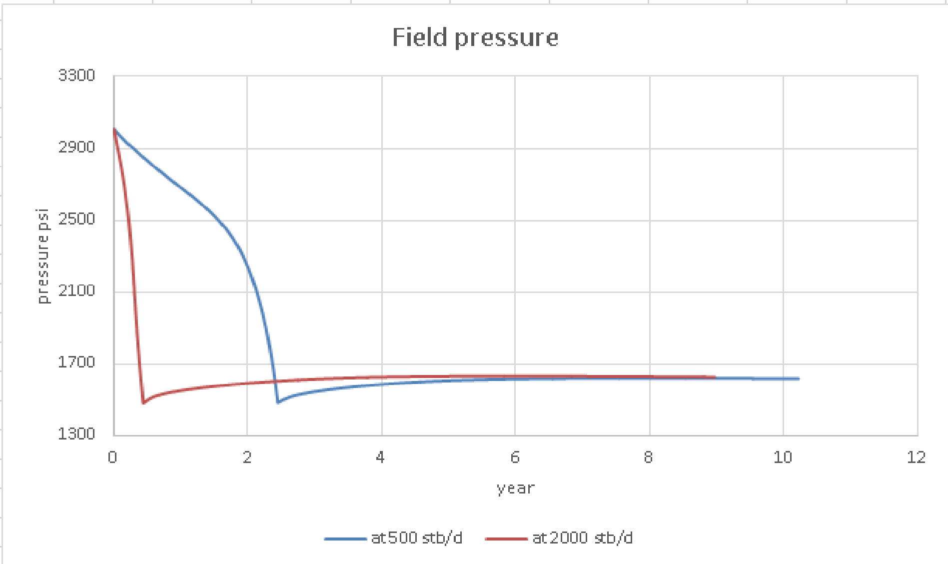

Figure 5.71 Field pressure for vertical wells under gas reinjection at pressure lower than 1500 psi

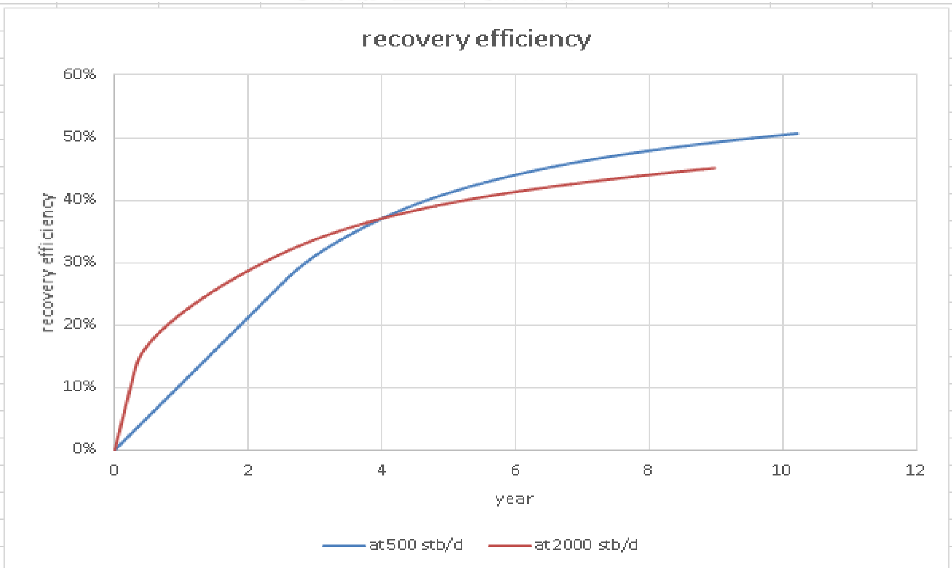

Figure 5.72 Field oil efficiency for vertical wells under gas reinjection at pressure lower than 1500 psi

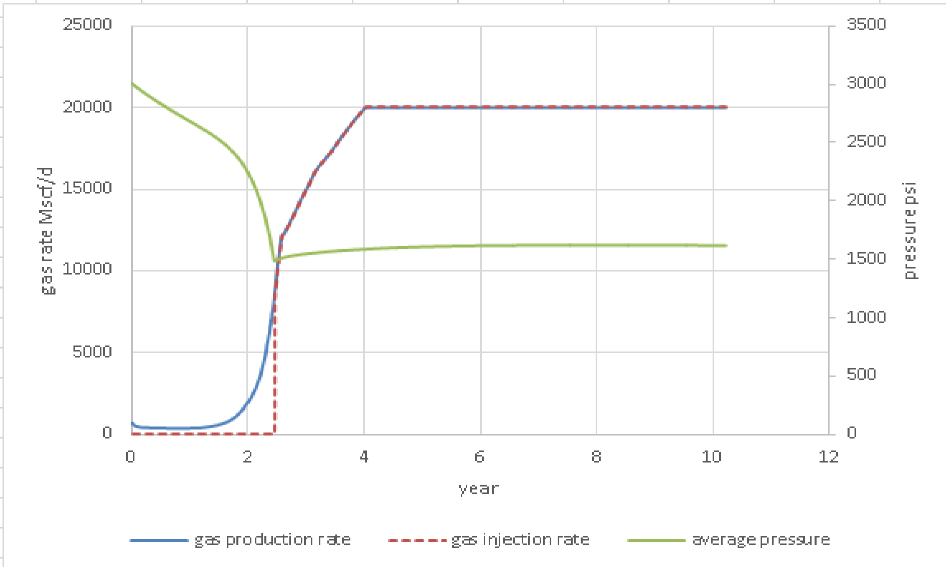

Figure 5.73 Trends of gas injection, gas production and average pressure for vertical well producer at 500 stb/d: gas injection when P<1500 psi scenario

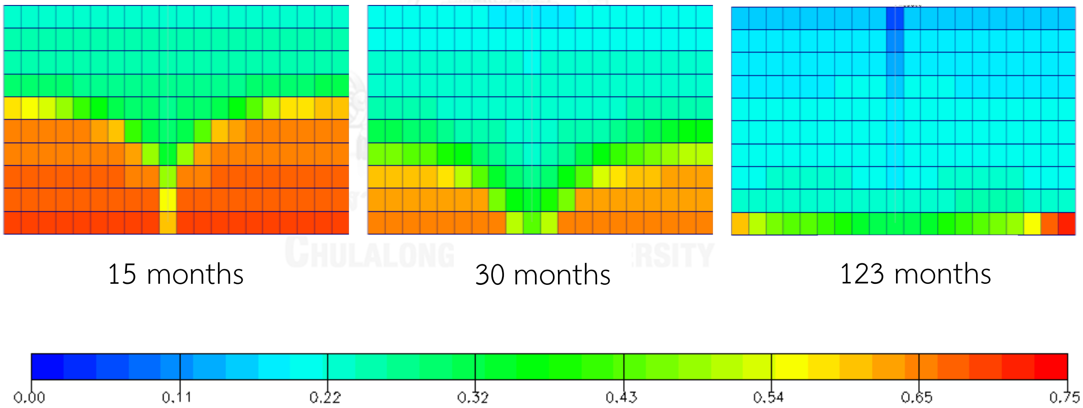

Figure 5.74 Oil saturation versus time for grid plane j = 11: gas injection when P<1500 psi with vertical production well at 500 stb/d (xz plane view)

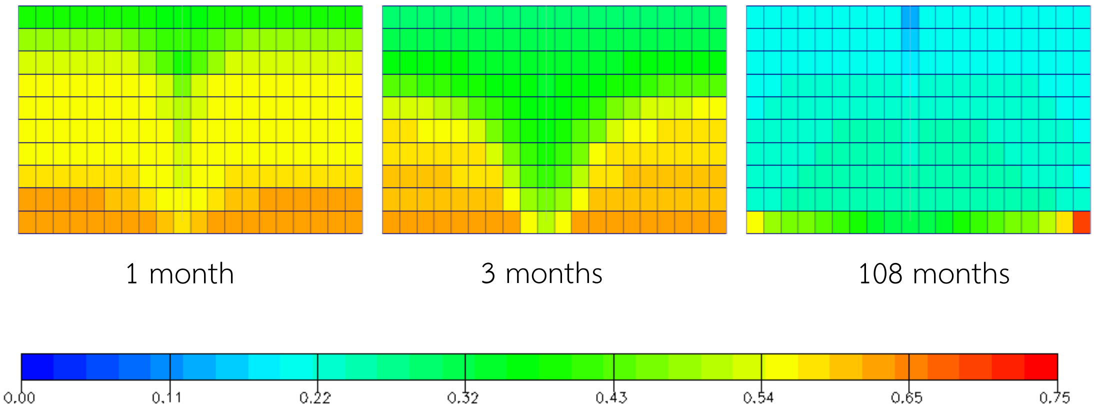

Figure 5.75 Oil saturation versus time for grid plane j = 11: gas injection when P<1500 psi with vertical production well at 2000 stb/d (xz plane view)

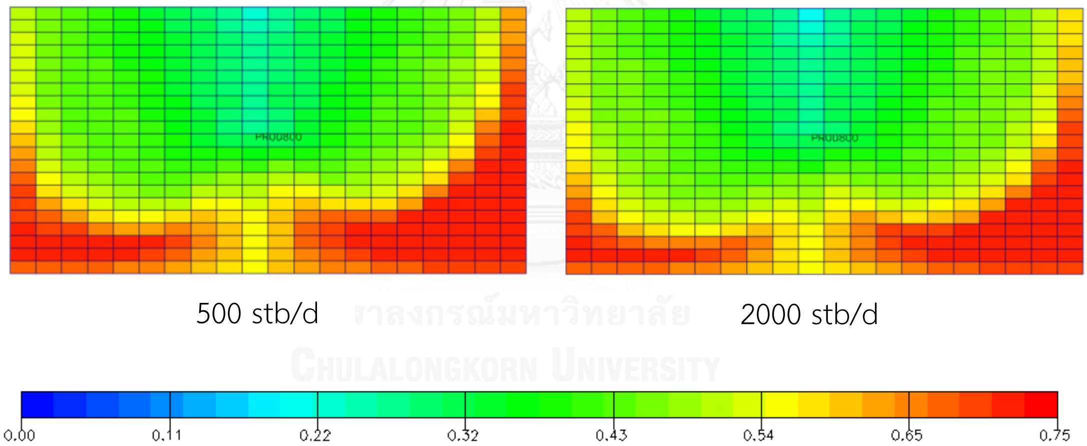

Figure 5.76 Oil saturation of plane k = 10 at abandonment for vertical well under gas injection when P<1500 psi at different oil rates (xy plane view)

For the case of using horizontal production well at 500 stb/d and 2000 stb/d, the following results were obtained. Figure 5.77 gives the oil production rate for the horizontal wells at 500 stb/d and 2000 stb/d. At about six years of production, the oil rate of both cases are quite similar. The plateau production period of the horizontal well at 500 stb/d is about 4.2 years while that of the horizontal well at 2000 stb/d is about 0.8 year. The higher flow rate case results in faster gas production as shown in Figure 5.78, thus this gas production hinders the potential of oil production. We also see from Figure 5.78 that as production begins, the gas rate drops slightly, this is due to the solution gas coming out of the oil and moving up in the reservoir, resulting in lesser amount of gas dissolved in the oil. Figure 5.79 indicates that prior to gas reinjection, the pressure of the reservoir declines fast as the reservoir is produced on natural energy stored in the reservoir. As pressure drops below 1500 psi, the gas injection process was initiated, and the reservoir was re-pressurized. Production at lower rates allowed this pressurized reservoir to keep this high pressure at longer period of time, with the pressure being kept constant as the gas cycling process continues till the end life of the reservoir. As seen in Figure 5.79 at about 4 years of production for the case of the horizontal well flowing at 500 stb/d, and at about 0.8 years of production for the case of the horizontal well flowing at 2000 stb/d, there is a slight increase in reservoir pressure. This happens due to the revaporization of intermediate hydrocarbons in the reservoir as indicated in Figure B-9 and Figure B-10. As seen in Figure B-2, as production starts, there is an increase in composition of components C7+, while composition of C1 increases, this is due to the gas produced alongside the oil, leaving the reservoir fluid heavier. However, at about 4 years of production, composition of C7+ starts droping, indicating vaporization of this component into gas at the GOC thus the increase in gas components. The rapid increase in the volume of gas as seen by the sharp rise in both composition of C1, C2, while rapid decline in composition of C3, NC4, and C7+ creates a lot of gas volume in the reservoir which helps in pressurizing the reservoir, as seen by the slight increase in reservoir pressure at that period of production.

Figure 5.80 shows that once gas breakthrough occurs, there exist competition of flow between the oil and gas, thus resulting in low recovery rates. Once gas production starts increasing, the recovery rate as shown in Figure 5.80 indicates that the well flowing at higher rate have a slightly lower recovery rate, due to the much larger amount of gas produced at breakthrough. The saturation profiles in Figure 5.81 to Figure 5.82 show that during the period of production by natural depletion prior to gas reinjection, the higher oil rate wells experienced faster gas breakthrough and faster pressure decline in the reservoir. The saturation profiles also suggest that a common cause of decline of oil rate is due to higher rates of gas produced and all wells die due to excessive gas production which impedes the flow of oil into the perforated section of the production well.

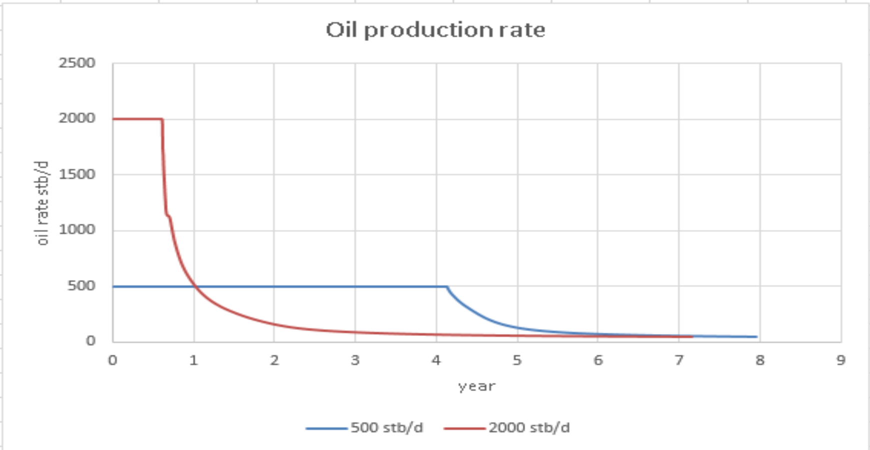

Figure 5.77 Oil production rate for horizontal well under gas reinjection at pressure lower than 1500 psi

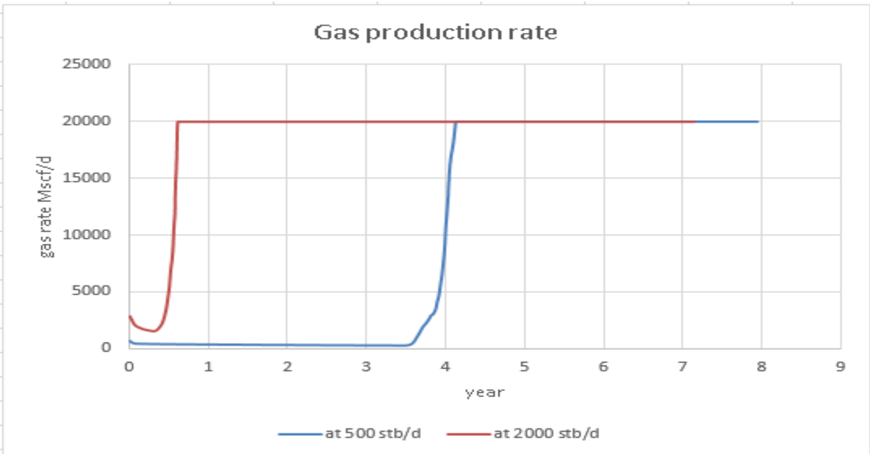

Figure 5.78 Gas production rate for horizontal well under gas reinjection at pressure lower than 1500 psi

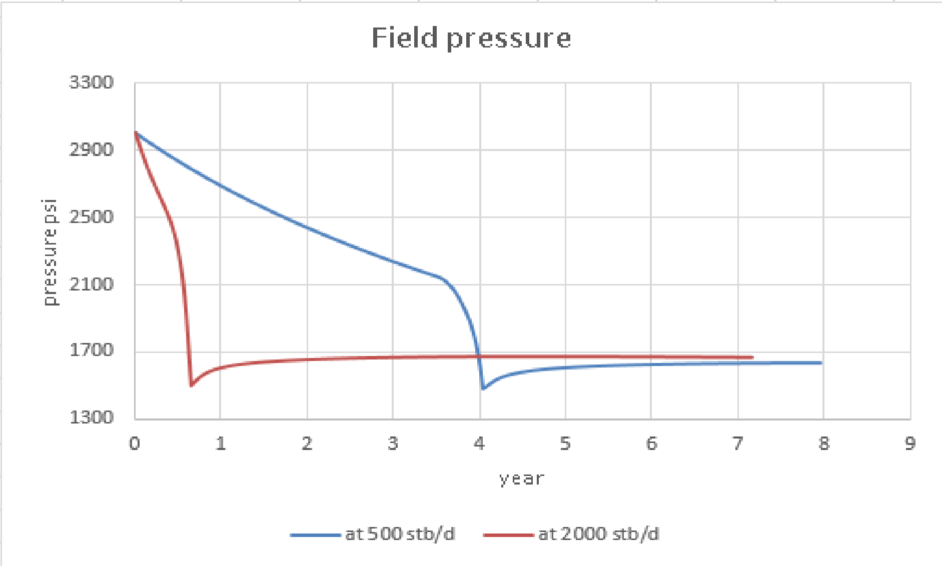

Figure 5.79 Field pressure for horizontal well under gas reinjection at pressure lower than 1500 psi

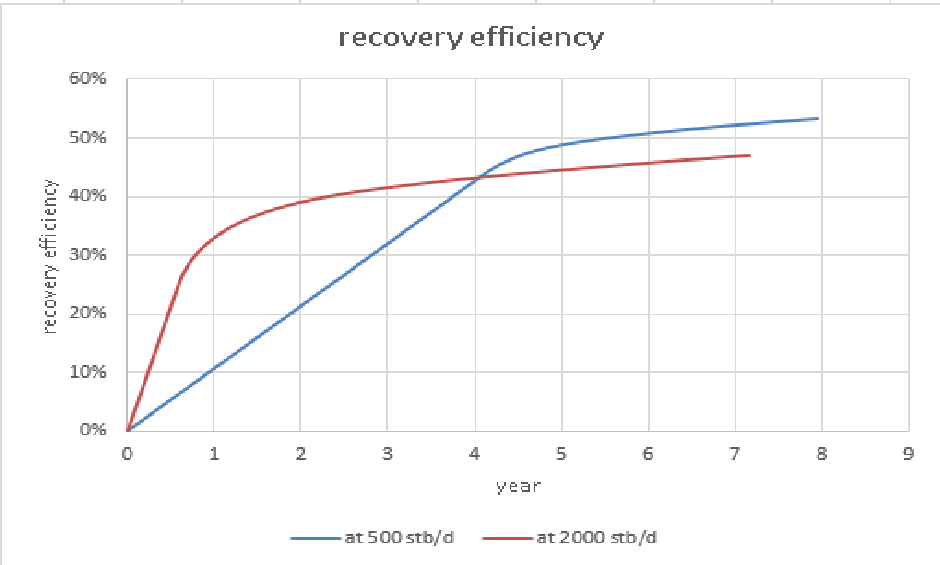

Figure 5.80 Field oil efficiency for horizontal well under gas reinjection at pressure lower than 1500 psi

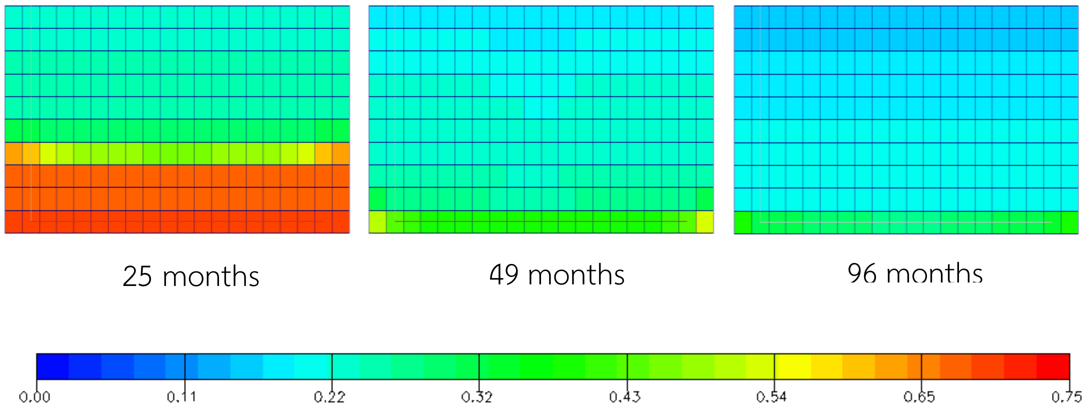

Figure 5.81 Oil saturation versus time for grid plane j = 11: gas injection when P<1500 psi with horizontal production well at 500 stb/d (xz plane view)

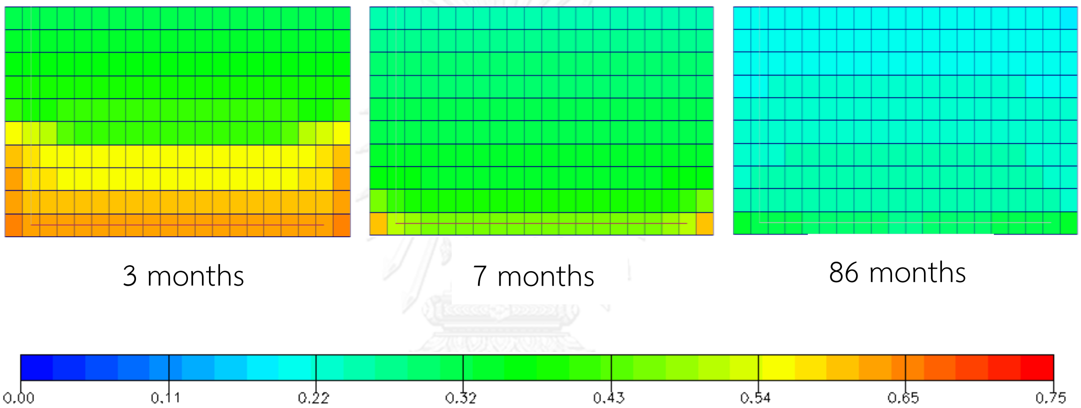

Figure 5.82 Oil saturation versus time for grid plane j = 11: gas injection when P<1500 psi with horizontal production well at 2000 stb/d (xz plane view)

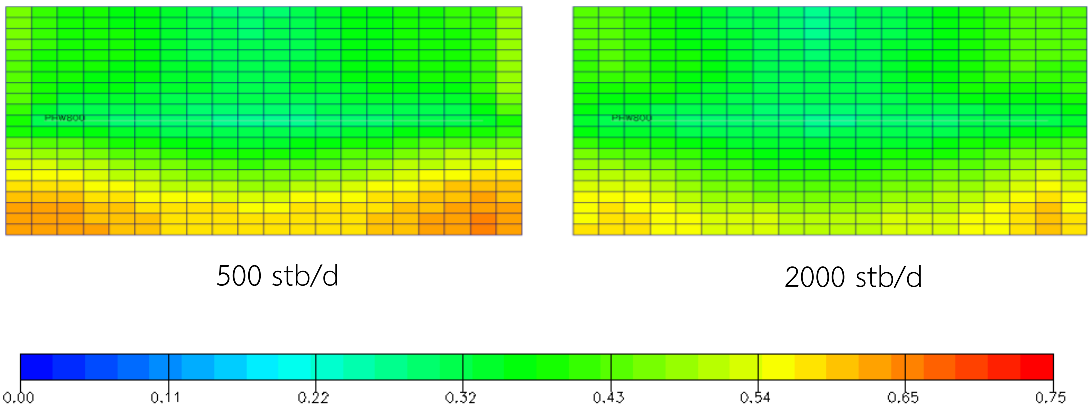

Figure 5.83 Oil saturation of plane k = 10 at abandonment for horizontal well under gas injection when P<1500 psi at different oil rates (xy plane view)

The analysis of reservoir fluid saturation for this case of gas injection when P<1500 psi for both vertical well and horizontal well each producing at flow rate of 500 stb/d is presented below. The results of oil saturation analysis in this case of gas injection in the reservoir is presented in Figure 5.84. The average field oil saturation can reduce to down to about 0.21 for both well cases. With the reservoir fluid composition as shown in Table 5.12 where we see components C1 and C2 increase in composition compared to the initial composition and all other components being close to 0% in the reservoir, we can observe that the injected gas stream causes these components exchanges and thus help in vaporizing the oil, leading to the high recovery potential and thus recovery of almost all liquid phase in the reservoir as seen.

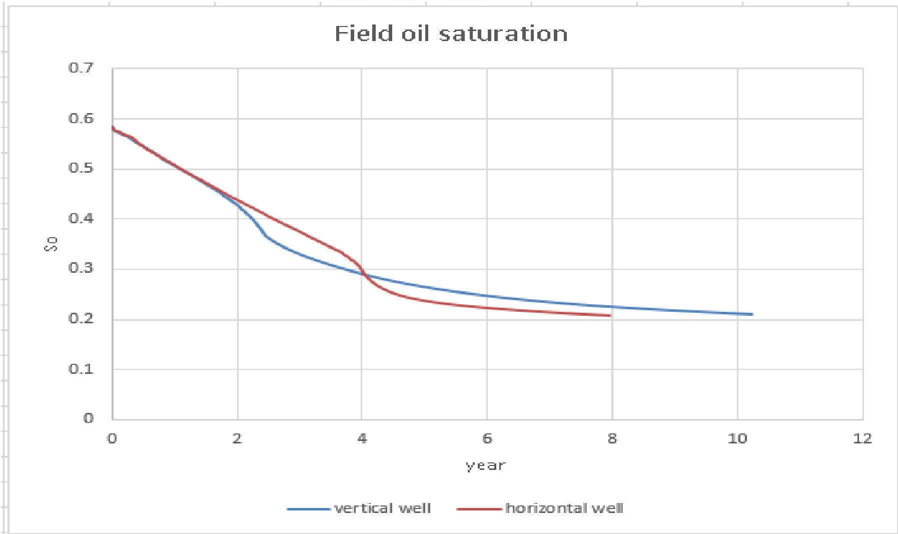

Figure 5.84 Average field oil saturation versus time for reservoir under gas injection when P<1500 psi using different well types

Table 5.12 Mole percent at different time for reservoir under gas injection when P<1500 psi

component	Initial composition	Abandonment composition vertical well	Abandonment composition horizontal well
CO2	1.17	0.00195	0.00499
C1	39.96	78.88	78.82
C2	10.6	20.93	20.9
C3	7.62	0.0263	0.0675
IC4	1.58	0.0018	0.0045
NC4	4.31	0.0222	0.0536
IC5	1.58	0.00123	0.0025
NC5	1.54	0.00189	0.0036
C6	4.74	0.0109	0.0154
C7+	26.91	0.127	0.127
Reservoir conditions			
P_{res}	3000	1616	1631
T_{res}	220	220	220

A comparison of the results obtained for varying the time to begin gas reinjection is presented here. The results obtained for varying time to begin reinjection as summarized in Table 5.13 indicates that there is very large difference in terms of recovery efficiency. Thus it can be argued that the best time to begin gas reinjection would be as soon as economic as well as gas source for injection is viable. In this case, since we have a gas cap reservoir, it is certain that a good quantity of solution gas then gas cap gas would be produced with the oil as time goes on, thus for further investigations, the scenario with gas reinjection from the start of production was adopted.

Table 5.13 Summary of results effect of varying time to start gas reinjection

Production schedule	Production well type	Cumulative oil MMstb		Cumulative gas Bscf		Recovery efficiency %	
		500 stb/d	2000 stb/d	500 stb/d	2000 stb/d	500 stb/d	2000 stb/d
Gas injection from start of production	Vert well	1.01	0.98	45.89	62.47	58.9	57.0
	Hori well	1.17	1.13	68.46	84.53	68.2	66.1
Gas injection when P<2500 psi	Vert well	0.99	0.91	54.53	58.94	57.6	53.0
	Hori well	1.12	1.07	66.85	87.02	65.2	62.4
Gas injection when P<1500 psi	Vert well	0.87	0.77	55.59	60.29	50.7	45.1
	Hori well	0.91	0.81	29.67	48.68	53.1	47.0

For the effect of time to start gas injection, we can draw the following conclusions

- Initiating gas reinjection from the start of production gives the highest value of cumulative oil produced for both cases of wells constrained at 500 stb/d and at 2000 stb/d.
- Initiating gas injection from the start of production also gives highest values of cumulative gas produced.

- The horizontal wells in all case give higher amount of cumulative oil produced, cumulative gas poduced as well as highest value of oil recovery factor.
- Initiating gas reinjection when pressure drops below 1500 psi gives the lowest values of cumulative oil production, cumulative gas production and oil recovery factor.
- Therefore, in other to achieve higher values of recovery factor, initiating the gas reinjection process from the start of production would be advantageouse than delaying the gas injection process.

5.3 Effect of time to stop gas reinjection (effect of GOR)

As seen in almost all cases analysed previously, the oil saturation profiles suggest that the wells produce lesser and lesser amount of oil once gas breakthrough occurs, and the wells finally die due to excessive gas production that impedes the flow of oil into the production sections of the well. Figure 5.85 also shows that once gas breakthrough occurs, the GOR continually rises until the end of life of the reservoir in the case where gas injection was performed. Thus, further investigation was performed in which the injection well was shut-in when excessively high GOR are recorded and then the reservoir was allowed to deplete with the available energy thus provided to see how this will affect the recovery efficiency of the reservoir. As seen in Figure 5.85 the GOR can go up to 300 Mscf/stb, for the case of gas reinjection using the single vertical well producer. With the initial GOR of the fluid being 0.8 Mscf/stb, time to stop gas reinjection was based on GOR recorded, and was taken when GOR is 100 times more than the initial fluid GOR (GOR of 80 Mscf/stb) and when GOR is 200 times more than the initial fluid GOR (GOR of 160 Mscf/stb). Gas reinjection was initiated from the start of production.

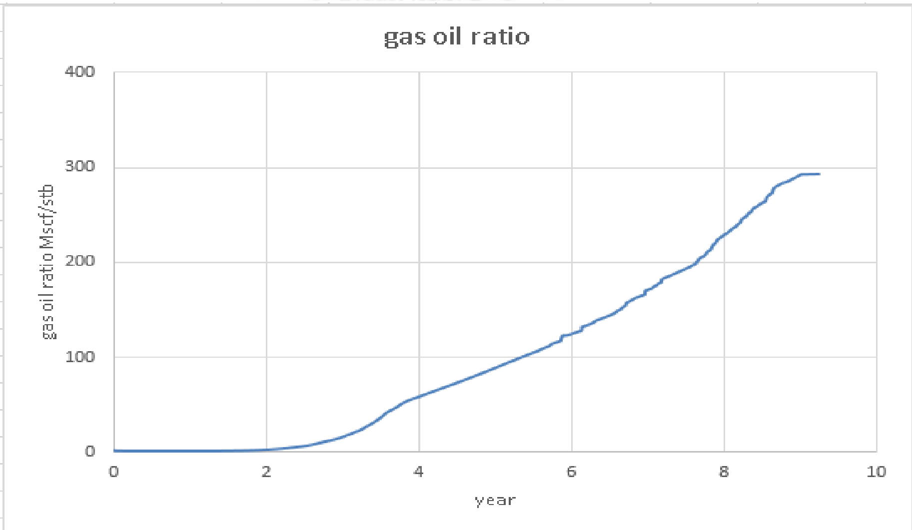

Figure 5.85 Gas-oil ratio for gas injection case with vertical well producing at 500 stb/d

5.3.1 Shut in injection well when GOR is above 80 Mscf/stb.

The results for production using the vertical well at flow rate of 500 stb/d and at 2000 stb/d is presented here. Producing a gas cap reservoir, it is inevitable that large amounts of GOR are recorded in the life of the reservoir during production. As seen in earlier cases, the amount of gas production keeps increasing, most especially as gas reinjection was performed. Constraining the production on GOR eliminates the source of pressure support which comes from the gas reinjection process; which helps to maintain oil production by sweeping oil towards the production well. As seen in Figure 5.86 once the GOR reaches 80 Mscf/stb and the injection well is shut-in, (which is at about 4.8 years for the case of 500 stb/d and about 2.8 years for the case of 2000 stb/d) the oil production rate starts dropping rapidly, this happens due to the lack of more injected gas to help sweep oil towards the well as well as lack of energy in the reservoir. Figure 5.87 shows that once the gas injection well is shut in, the gas production rate instantaneously drops to very low values in both case. This phenomenon reduces the reservoir drive energy thus leads to decrease oil recovery potential. As shown in Figure 5.88, once the GOR reaches the constrained value, the reservoir pressure rapidly declined due to the shutting-in of the injection well. Figure 5.89 shows that the amount of recovery obtained by trying to limit this gas oil ratio was much lower than in the case where the gas reinjection was left to continue till abandonment conditions. The oil saturation profiles in Figure 5.91 reveals that much oil saturation was left behind in most parts of the reservoir not flooded by the injected gas.

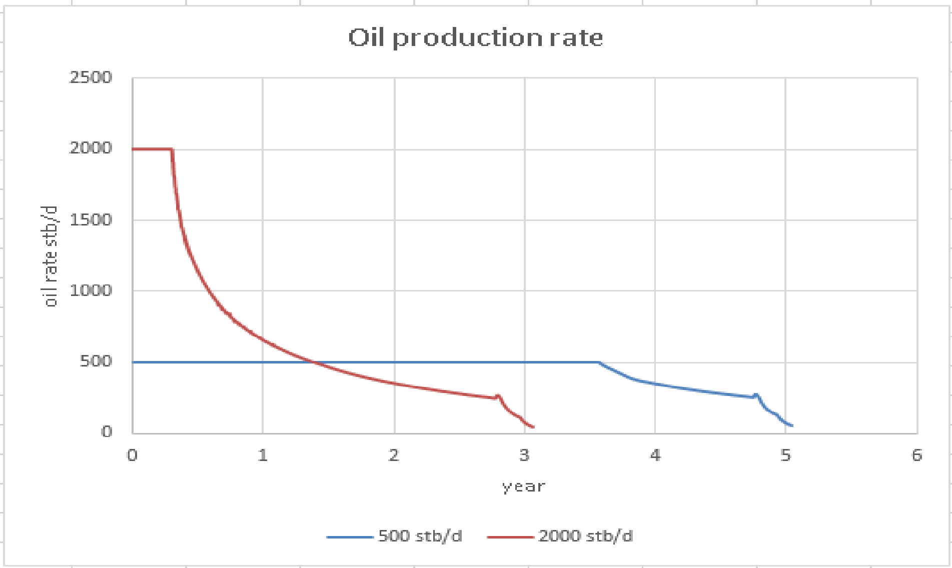

Figure 5.86 Oil production rate for vertical wells: production constrained at GOR<80 Mscf/stb

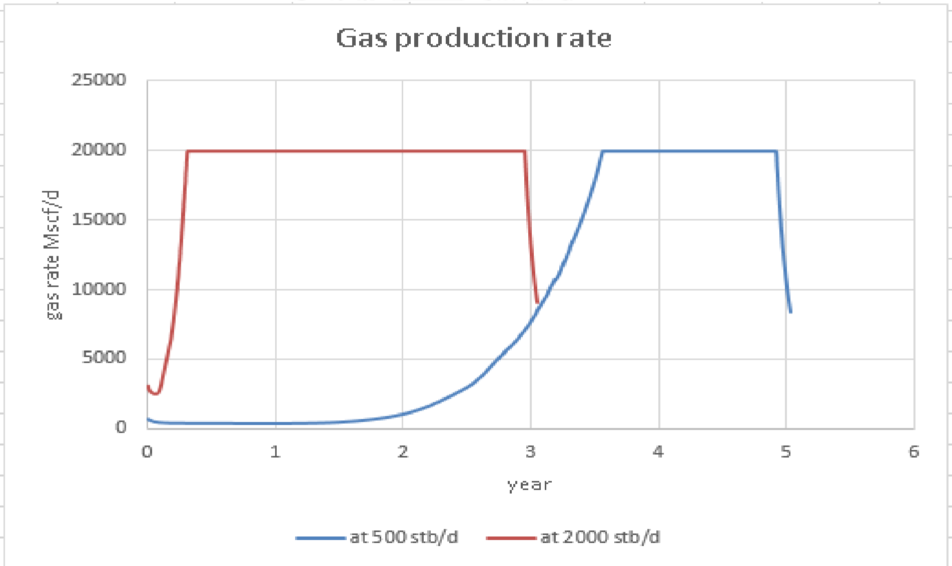

Figure 5.87 Gas production rate for vertical wells: production constrained at GOR<80 Mscf/stb

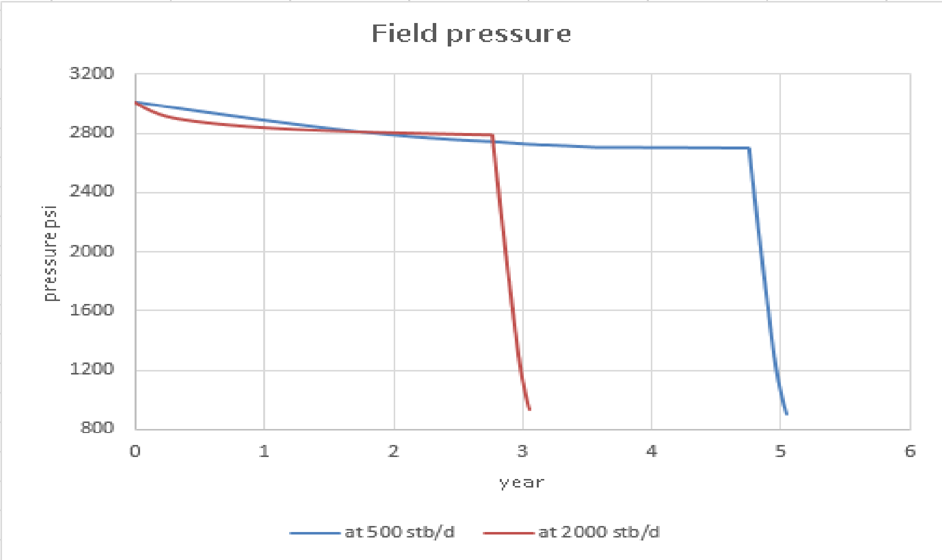

Figure 5.88 Field pressure for vertical wells: production constrained at GOR<80 Mscf/stb

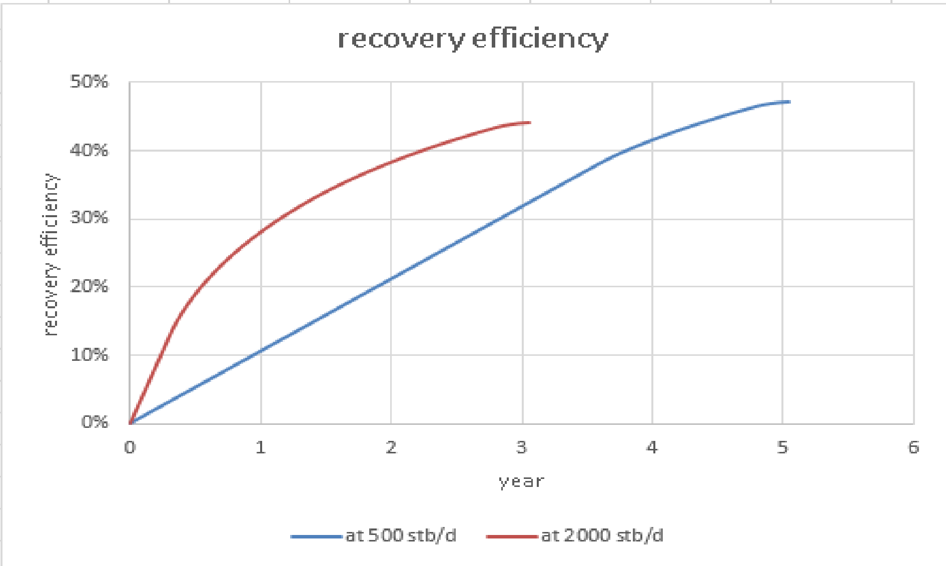

Figure 5.89 Field oil efficiency for vertical wells: production constrained at GOR<80 Mscf/stb

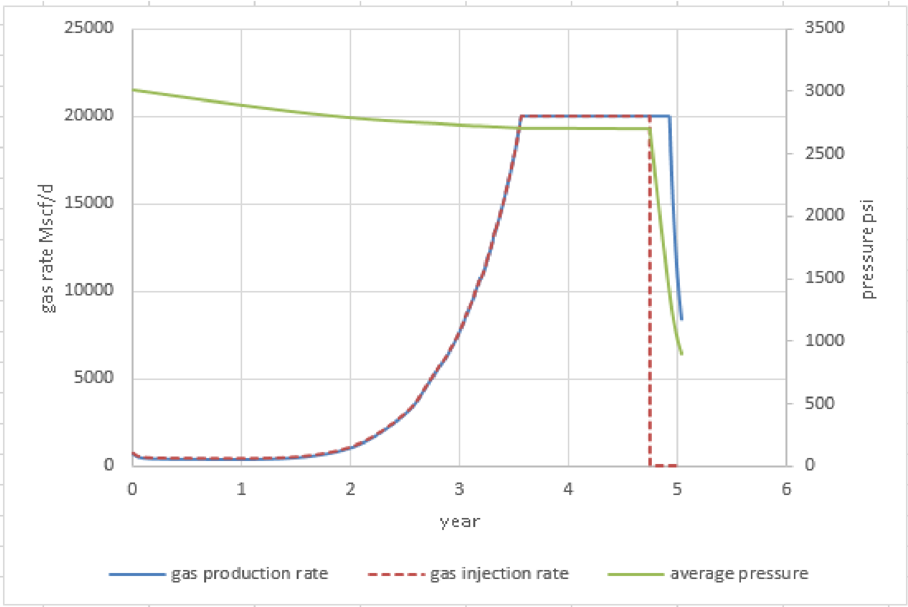

Figure 5.90 Trends of gas injection, gas production and average pressure for vertical well producer at 500 stb/d: gas injection constrained at GOR<80 Mscf/stb

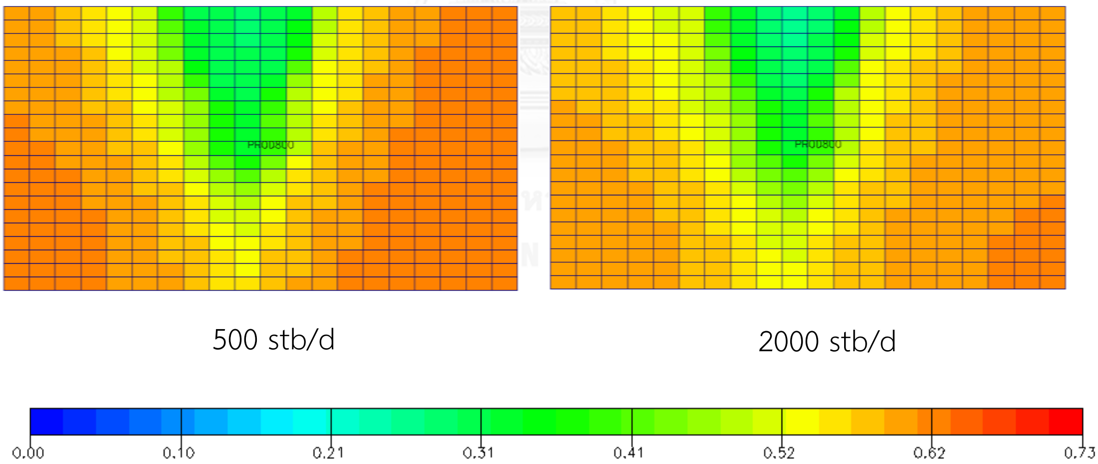

Figure 5.91 Oil saturation of plane k = 10 at abandonment for vertical well under gas injection constrained at GOR<80 Mscf/stb at different oil rates (xy plane view)

The results of production using the horizontal well at flow rates of 500 stb/d and 2000 stb/d is presented here. Producing with the horizontal well as discussed earlier leads to a more uniform expansion of the gas cap if production rates are not too high. Since the production well draws fluid from a larger area of the reservoir simultaneously, gas coning into the production section was less severe. As gas injection was performed, the reservoir energy was gradually declining for quite some time as shown in Figure 5.92. Once gas injection was stopped and this pressure support ceases, the reservoir pressure dropped rapidly. As seen in Figure 5.93 once the GOR reaches 80 Mscf/stb and the injection well is shut-in, (which is at about 5.1 years for the case of 500 stb/d and about 2 years for the case of 2000 stb/d) the oil production rate starts dropping rapidly, this happens due to the lack of injected gas to help sweep oil towards the well as well as lack of energy in the reservoir. Figure 5.94 shows that once the gas injection well is shut in, the gas production rate instantaneousely drops to very low values in both case. This phenomenon reduces the reservoir drive energy thus leads to decrease oil recovery potential. Figure 5.96 shows a slightly lower oil recovery factor for the case of 2000 stb/d compared to 500 stb/d. Thus limiting gas injection process on GOR constrain takes out the energy support that comes from gas injection as well as the sweepbenefits of the injected gas, with the horizontal well in both cases of flow rate having as low as about 300 psi reservoir pressure at abandonment.

The oil saturation profiles in Figure 5.97 reveals that much oil saturation in left behind in most parts of the reservoir not flooded by the injected gas, with the bottom most layer shown to be moderately saturated with oil. Similar to the case for the vertical well where the injected gas clearly does not reaches the perforated section of the production well, the saturation profiles in the case of the horizontal well shows that the injection gas has not reached the production horizontal section at the time the GOR reaches 80 Mscf/stb, however the production rapidly declines till the well dies, this suggests that since the gas cap gas was being produced, the drive energy was greatly declined and needed the continual gas injection to help sweeping the oil towards production well and help maintaining the production.

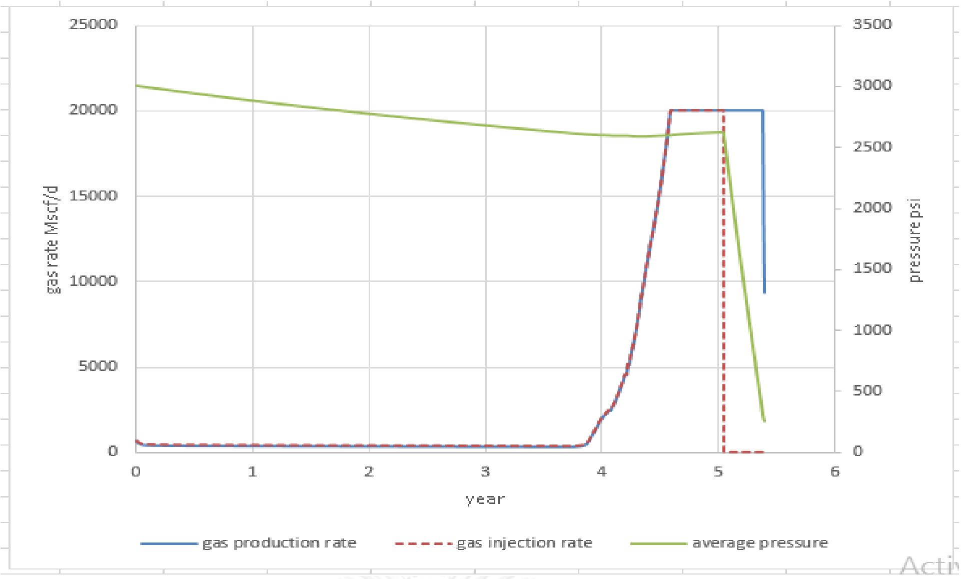

Figure 5.92 Trends of gas injection, gas production and average pressure for horizontal well producer at 500 stb/d for gas injection constrained at GOR<80 Mscf/stb

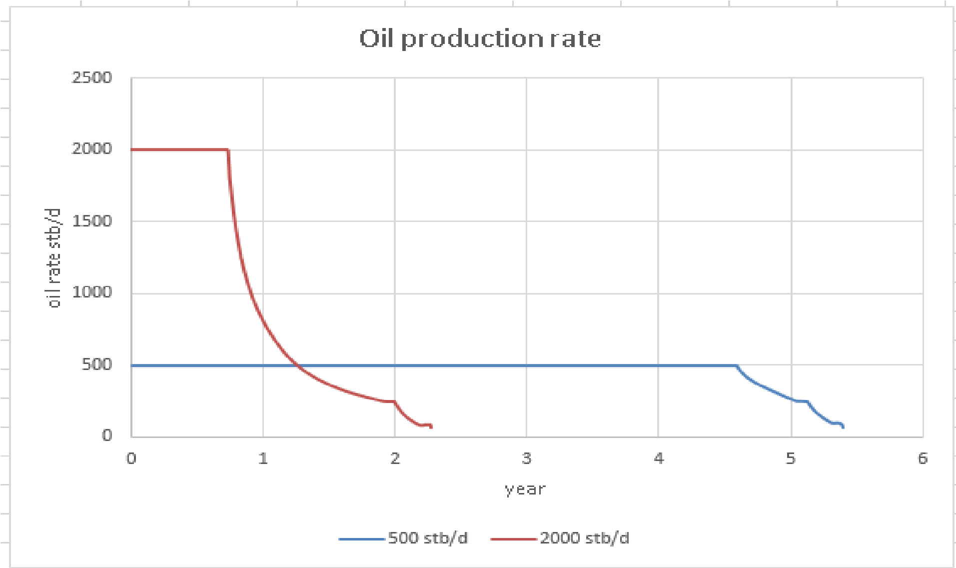

Figure 5.93 Oil production rate for horizontal wells for production constrained at GOR<80 Mscf/stb

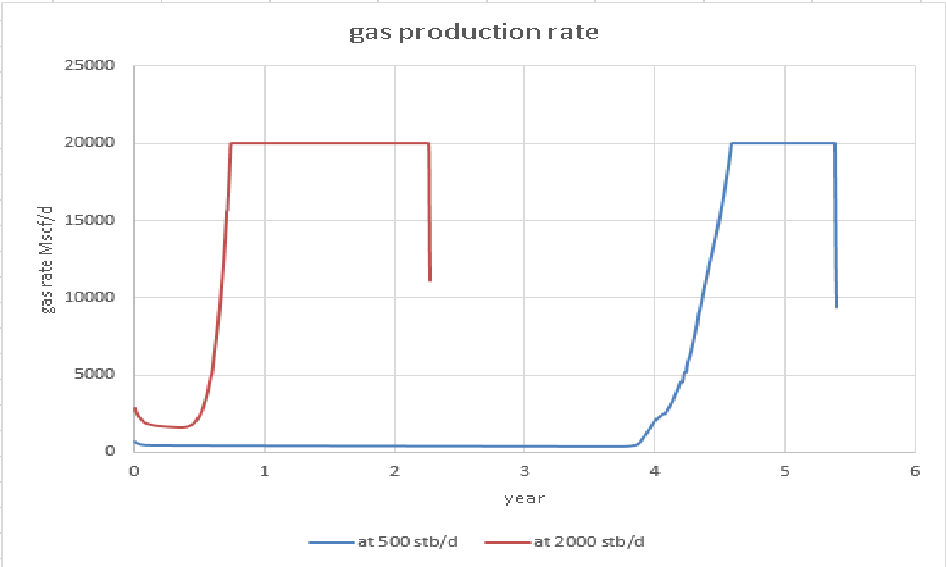

Figure 5.94 Gas production rate for horizontal wells for production constrained at GOR<80 Mscf/stb

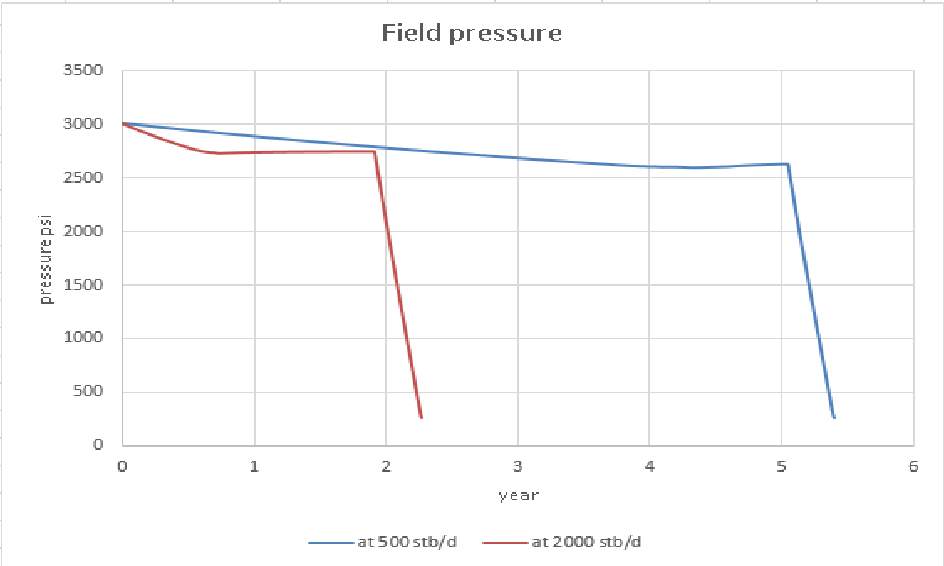

Figure 5.95 Field pressure for horizontal wells for production constrained at GOR<80 Mscf/stb

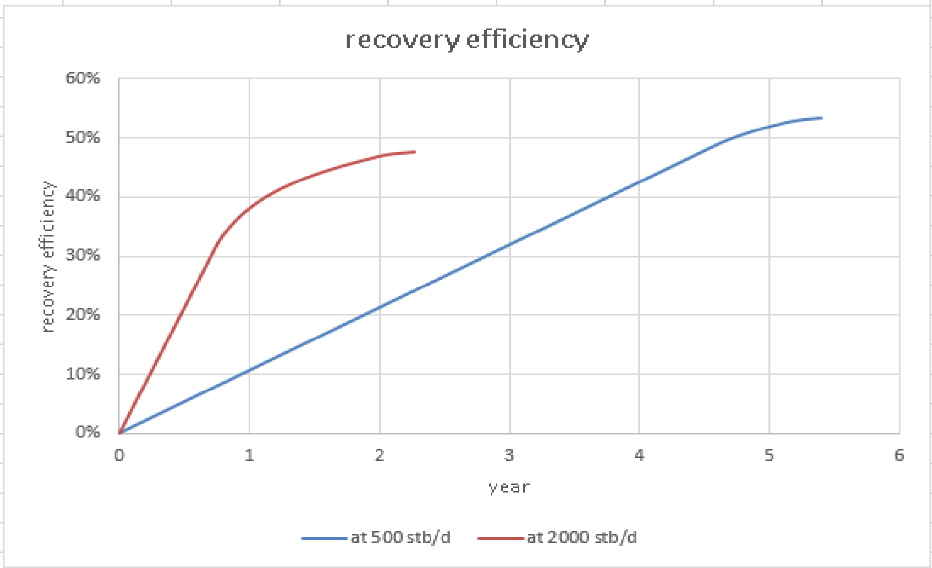

Figure 5.96 Field oil efficiency for horizontal wells for production constrained at GOR<80 Mscf/stb

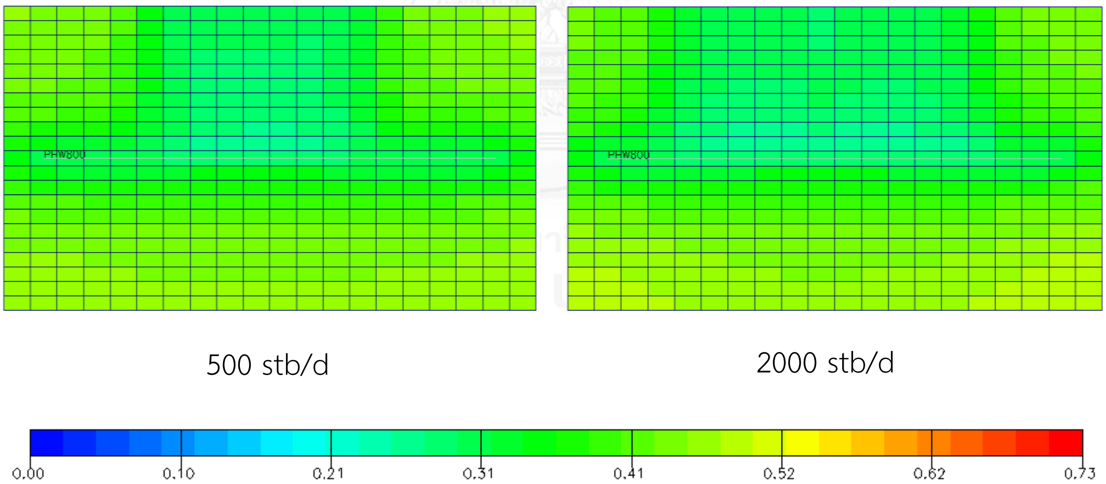

Figure 5.97 Oil saturation of plane k = 10 at abandonment for horizontal well under gas injection constrained at GOR<80 Mscf/stb at different oil rates (xy plane view)

The reserveoir fluid saturation analysis for the case of gas reinjection terminated when GOR > 80 Mscf/stb is presented here. The overall oil saturation as seen in Figure 5.98 shows that the average field oil saturation can reduce to down to about 0.24 and 0.19 for vertical well and horizontal wells respectively, this oil saturation (compared to the residual oil saturation initially of 0.2) suggests that there is component exchanges between the fluid in the reservoir and the injected gas, However, it is also noticed that the oil saturation here is much higher than in the case of gas injection with no constrains on GOR, this is due to limited gas injection once gas-oil ratio is used to constrain the production thus the benefits of sweep efficiency of the injected gas are not fully utilized in this case. With the reservoir fluid composition as shown in Table 5.14 where we see components C1 and C2 increase in composition compared to the initial composition and all other components decrease in composition in the reservoir, we can confirm that the injected gas stream will cause components exchanges and thus help in vaporizing the oil.

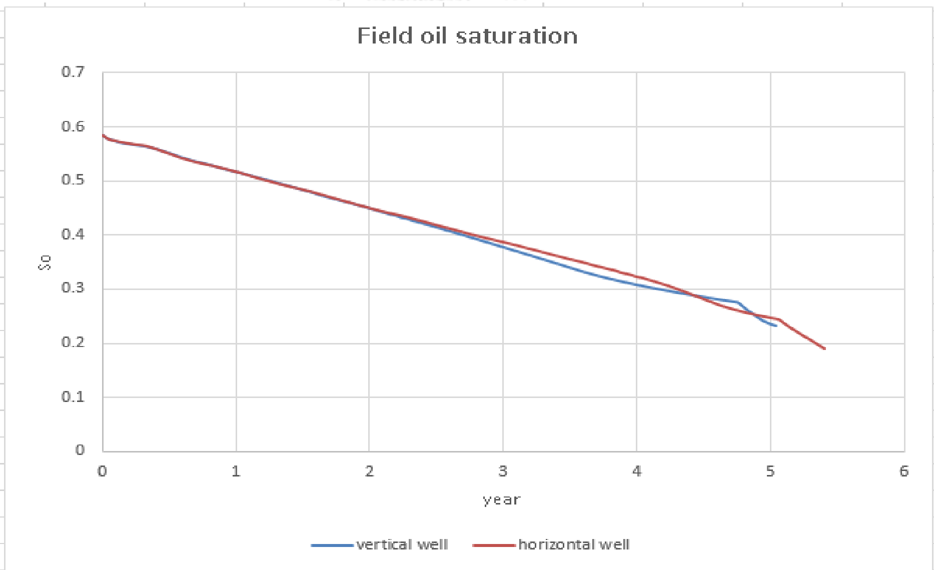

Figure 5.98 Average field oil saturation versus time for reservoir under gas injection constrained at GOR<80 Mscf/stb using different well types

Table 5.14 Mole percent at different time for reservoir under gas injection constrained at GOR<80 Mscf/stb

component	Initial composition	Abandonment composition vertical well	Abandonment composition horizontal well
CO2	1.17	0.439	0.625
C1	39.96	73.43	66.07
C2	10.6	20.54	22.31
C3	7.62	3.336	6.138
IC4	1.58	0.1545	0.324
NC4	4.31	1.519	3.428
IC5	1.58	0.049	0.124
NC5	1.54	0.0636	0.165
C6	4.74	0.1725	0.491
C7+	26.91	0.294	0.324
Reservoir conditions			
P_{res}	3000	902	254
T_{res}	220	220	220

5.3.2 Shut in injection well when GOR is above 160 Mscf/stb.

Producing the reservoir using vertical well at 500 stb/d and 2000 stb/d gave the following results. Similar to the case of shutting the injection well at GOR of 80 Mscf/stb, constraining the production on GOR<160 Mscf/stb eliminates the source of pressure support which comes from the gas reinjection process. Once the GOR reaches the constrained value, the reservoir pressure rapidly declined due to the shutting-in of the injection well. As the injection well was shut-in, oil production declines and gas production from the reservoir also declines as depicted in Figure 5.99 and Figure 5.100. Figure 5.101 shows gradual decline in the reservoir pressre as production went on until at about 4.8 years (for the well flowing at 2000 stb/d oil rate) and about 6.9 years (for the well flowing at 500 stb/d oil rate) where the reservoir pressure drops steeply to about 1000 psi. This happens when the injection well was shut in, and the reservoir drive energy cut off. The trend in reservoir pressure and gas rates shown in Figure 5.102 also confirms the driving factor behind this pressure behavior. The field oil recovery efficiency shown in Figure 5.103 presents higher oil recovery percentage than the cases seen in section 5.2.4. This suggest that shutting-in the injection well earlier will hinder the recovery efficiency potential, thus it can be infer that once gas reinjection is initiated, it should be allowed to continue until abandonment conditions of oil production are seen, as long as the gas reinjection process remains economically viable, because the injected gas stream sweeps the oil towards the producing well, as well as helps in initiating compositional interactions which all leads to improve recovery efficiency of the oil. The oil saturation profiles in Figure 5.104 reveals that much oil saturation in left behind in most parts of the reservoir not flooded by the injected gas, with the bottom most layer shown to be highly saturated with oil. The injected gas clearly reaches the perforated section of the production well and it hinders any further production of oil once the gas injection was stopped. Thus by the time the GOR reaches 160 Mscf/d and the gas injection is stopped, the reduction in pressure support as well as the production of gas greatly hindered the oil production leading to rapid decline in oil rate.

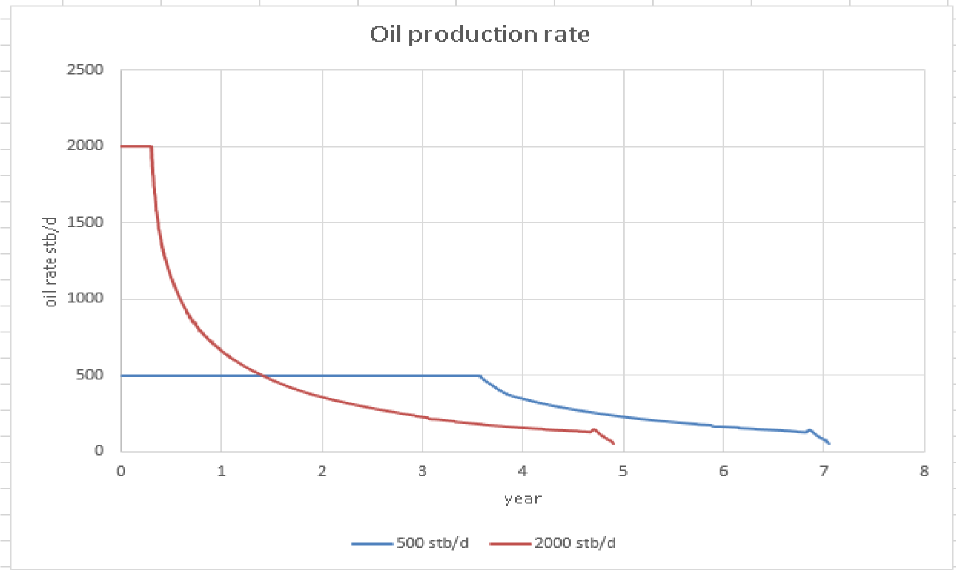

Figure 5.99 Oil production rate for vertical wells: production constrained at GOR<160 Mscf/stb

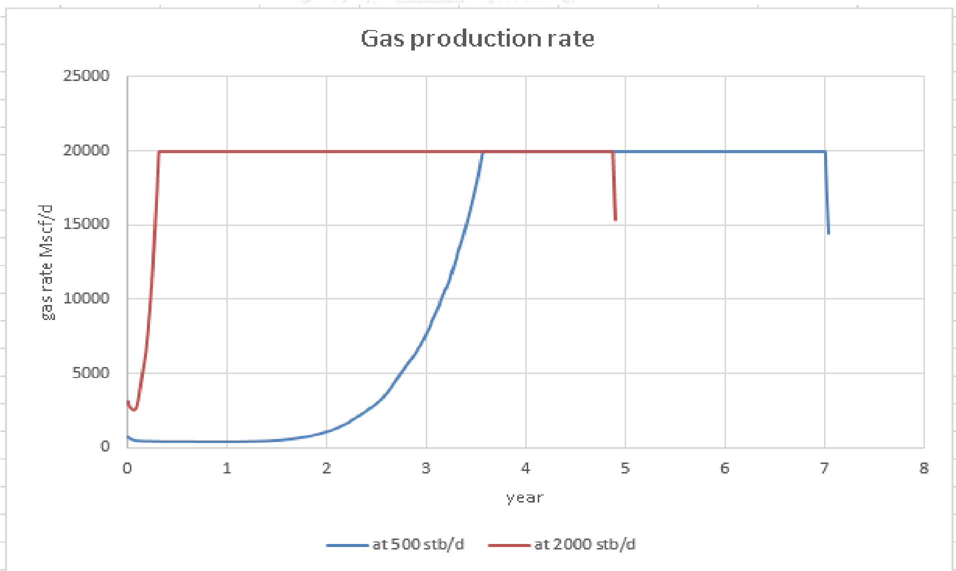

Figure 5.100 Gas production rate for vertical wells: production constrained at GOR<160 Mscf/stb

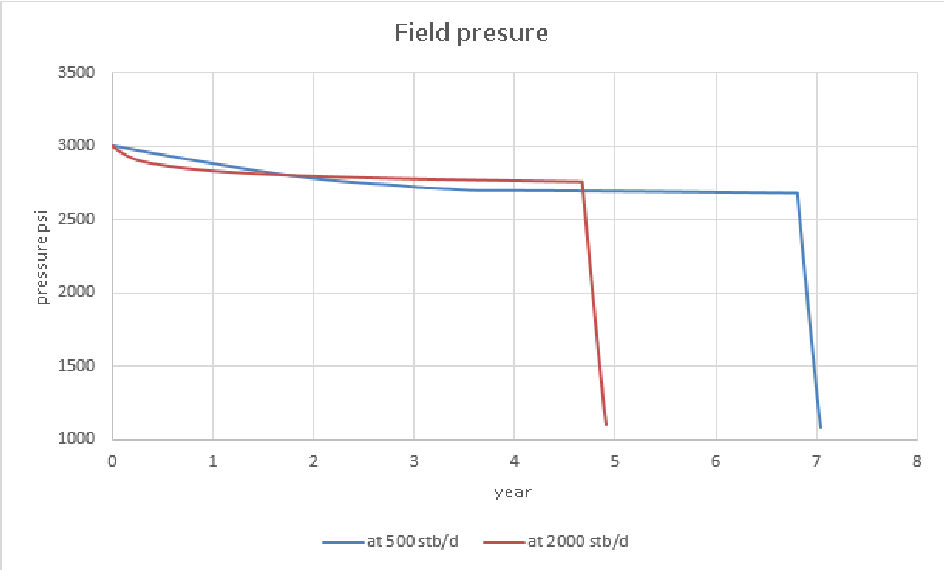

Figure 5.101 Field pressure for vertical wells: production constrained at GOR<160 Mscf/stb

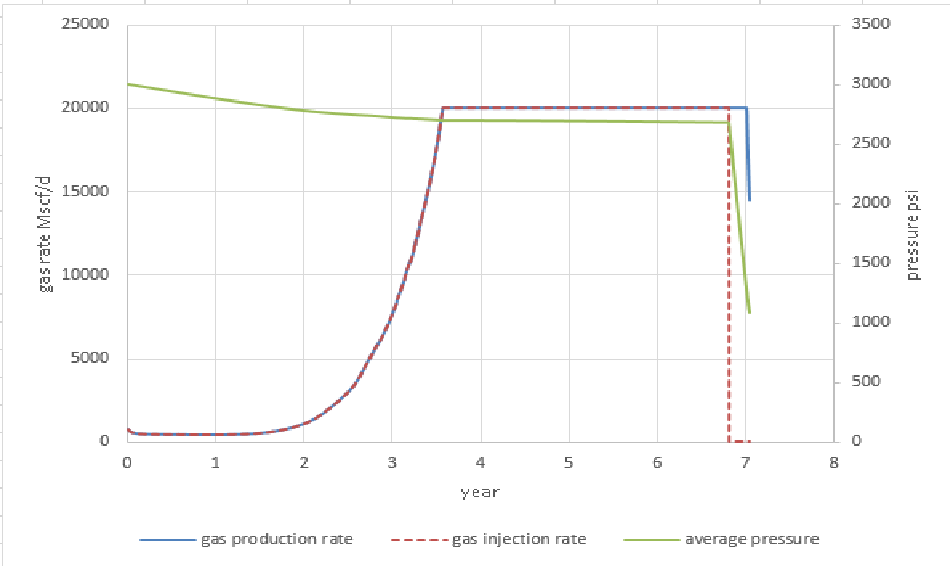

Figure 5.102 Trends of gas injection, gas production and average pressure for vertical well producer at 500 stb/d: gas injection constrained at GOR<160 Mscf/stb

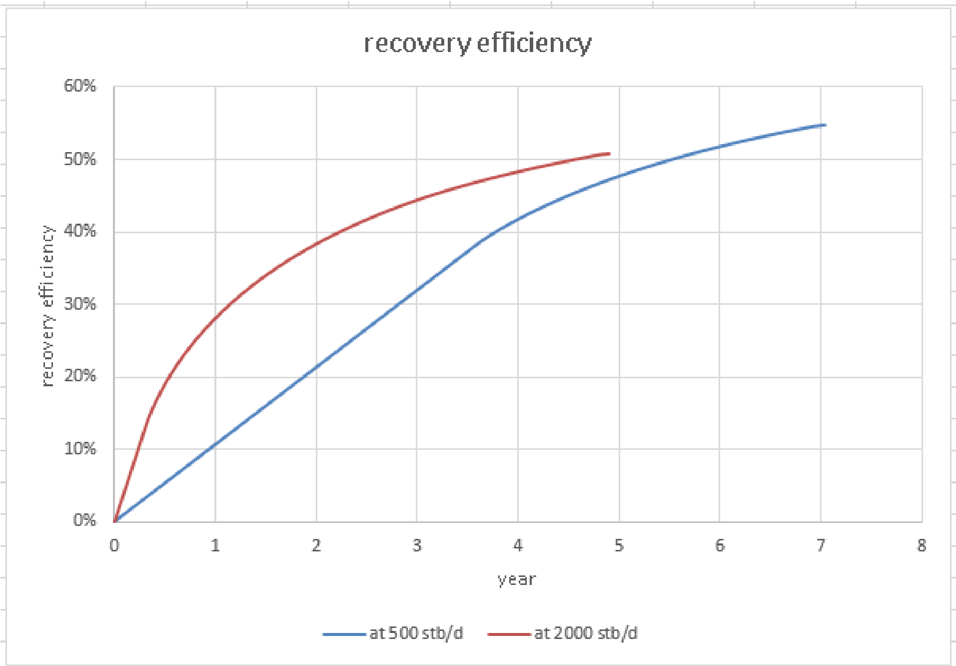

Figure 5.103 Field oil efficiency for vertical wells: production constrained at GOR<160 Mscf/stb

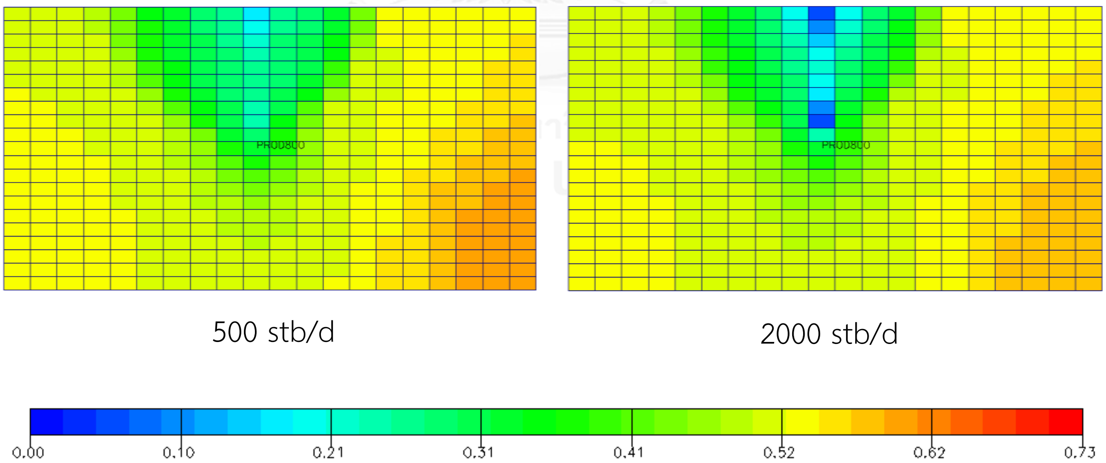

Figure 5.104 Oil saturation of plane k = 10 at abandonment for vertical well under gas injection constrained at GOR<160 Mscf/stb at different oil rates (xy plane view)

The results for producing with the horizontal well at flow rates of 500 stb/d and 2000 stb/d are summarized below. Producing with the horizontal well as discussed earlier leads to a more uniform expansion of the gas cap if production rates are not too high. Since the production well draws fluid from a larger area of the reservoir simultaneously, gas coning into the production section was less severe. As gas injection was performed, the reservoir energy was kept constant for quite some time as shown in Figure 5.105 with the pressure decline happening when gas production increases. Once gas injection was stopped and this pressure support ceases, the reservoir pressure dropped rapidly. As seen in Figure 5.106 once the GOR reaches 160 Mscf/stb and the injection well is shut-in, (which is at about 6 years for the case of 500 stb/d and about 3.4 years for the case of 2000 stb/d) the oil production rate starts dropping rapidly, this happens due to the lack of injected gas to help sweep oil towards the well and also provide energy to reservoir. Figure 5.107 shows that once the gas injection well is shut in, the gas production rate instantaneousely drops to very low values in both case. This phenomenon reduces the reservoir drive energy thus leads to decrease oil recovery potential. Figure 5.109 shows that the amount of recovery obtained by trying to limit this gas oil ratio is lower than in the case where the gas reinjection is left to continue till abandonment conditions, due to decline of reservoir drive energy from solution gas and injected gas stream. Unlike the case in section 5.2.1 where gas injection was performed from start of production till end of production, limiting the GOR during gas injection led to excess drawdown of reservoir pressure as indicated in Figure 5.108 where average field pressure at end of production is close to 250 psi. The oil saturation profiles in Figure 5.110 reveals that much oil saturation is left behing in most parts on the reservoir not flooded by the injected gas, with the bottom most layer shown to be partly saturated with oil. The injected gas reaches a good portion of the reservoir, however, the constrain on gas-oil ratio did not allow enoguh time for the injected gas stream to sweep the oil satisfactorily , thus leaving injection process to continue mucg longer leads to much higher recovery effiiciency

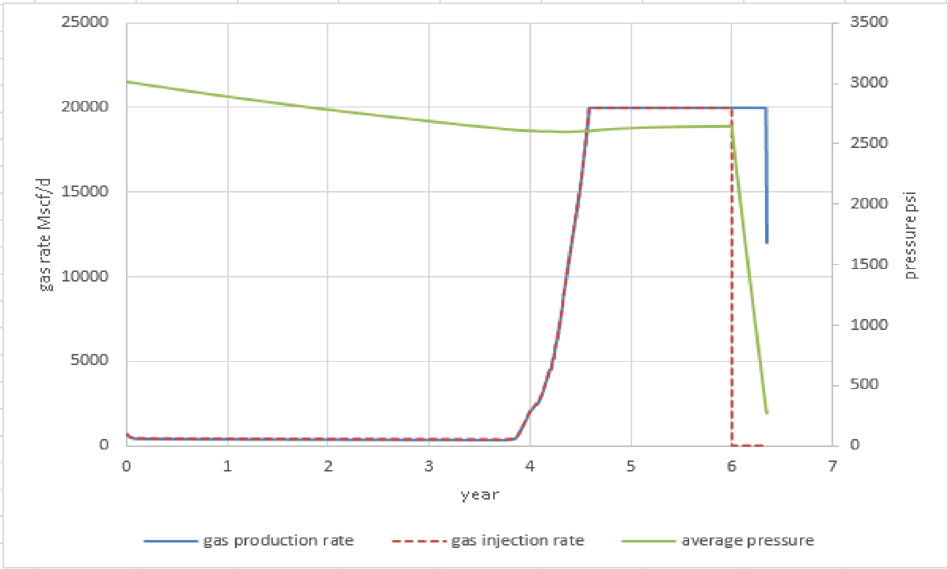

Figure 5.105 Trends of gas injection, gas production and average pressure for horizontal well producer at 500 stb/d: gas injection constrained at GOR<160 Mscf/stb

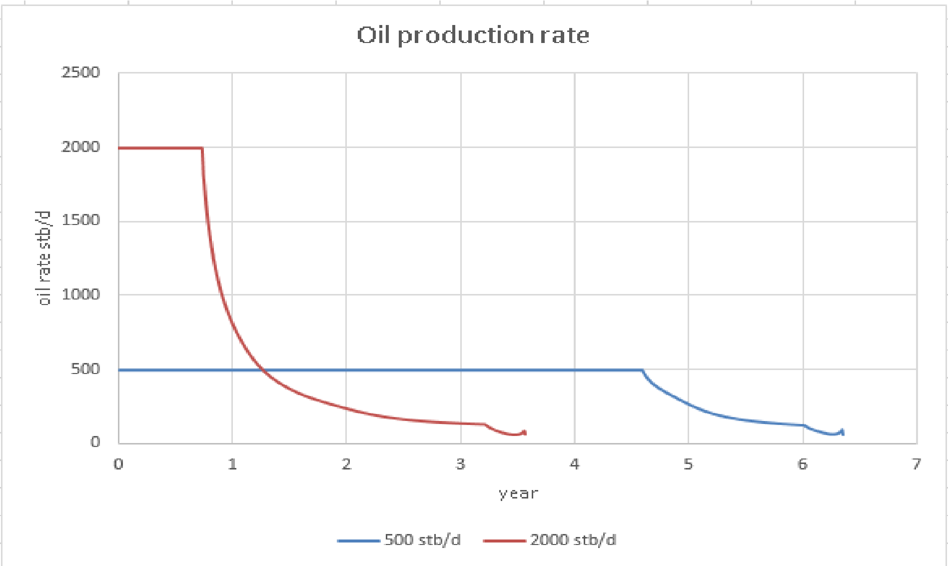

Figure 5.106 Oil production rate for horizontal wells: production constrained at GOR<160 Mscf/stb

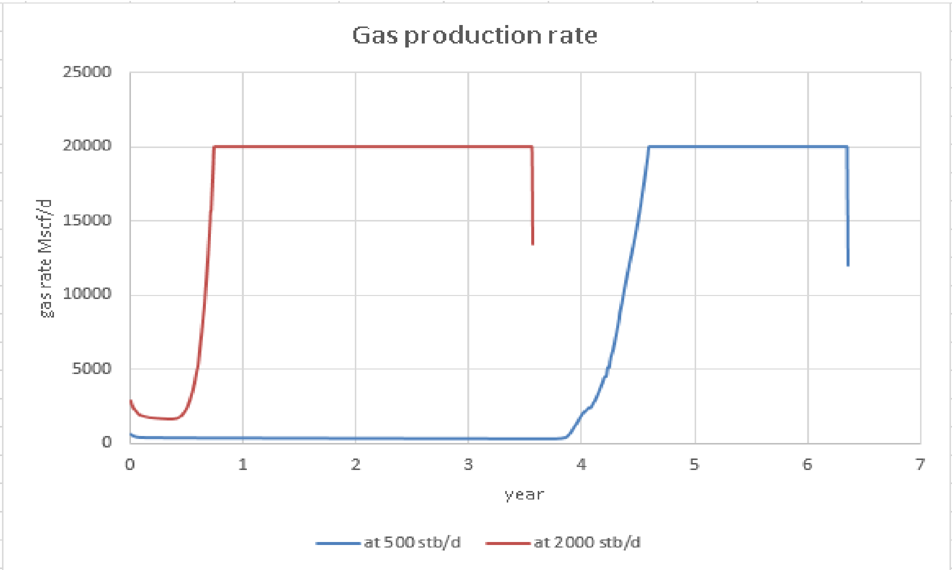

Figure 5.107 Gas production rate for horizontal wells: production constrained at GOR<160 Mscf/stb

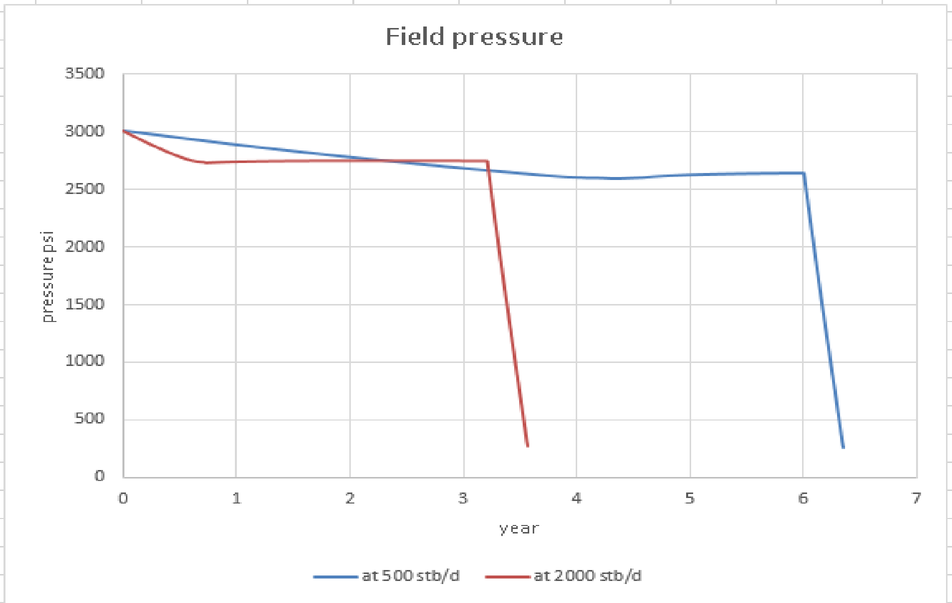

Figure 5.108 Field pressure for horizontal wells: production constrained at GOR<160 Mscf/stb

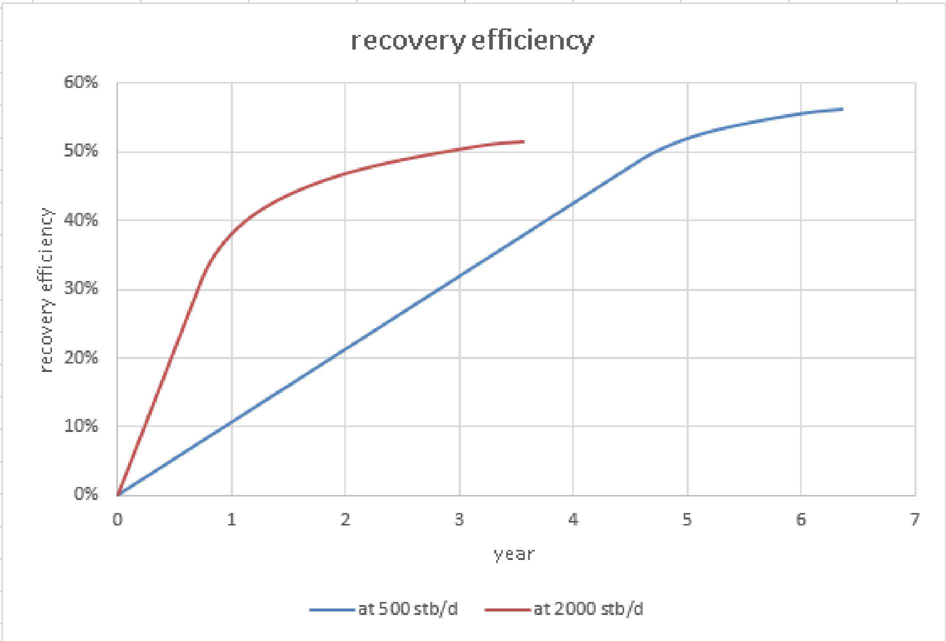

Figure 5.109 Field oil efficiency for horizontal wells: production constrained at GOR<160 Mscf/stb

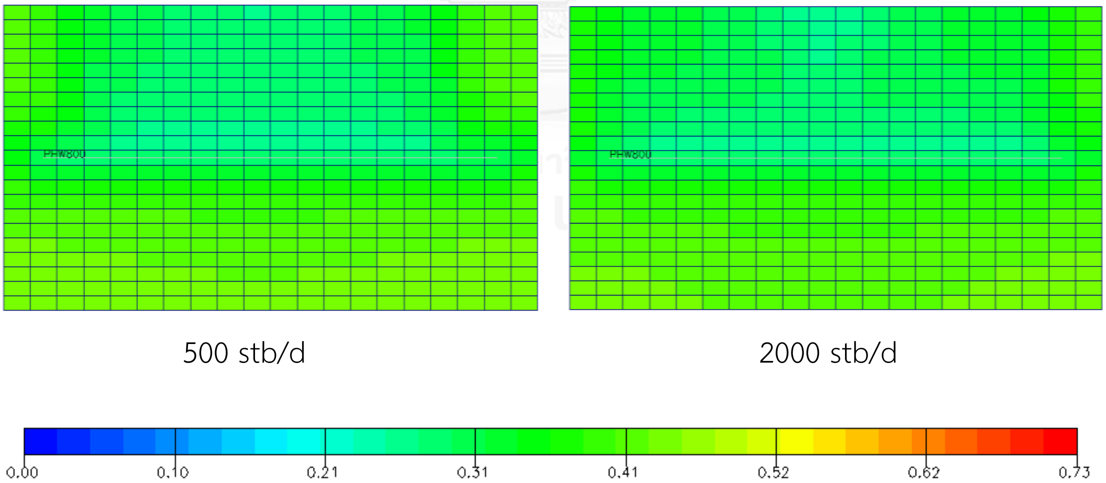

Figure 5.110 Oil saturation of plane k = 10 at abandonment for horizontal well under gas injection constrained at GOR<160 Mscf/stb at different oil rates (xy plane view)

The reservior fluid saturation analysis for the case of gas injection terminated when GOR>160 Mscf/stb is presented below. The overall oil saturation as seen in Figure 5.111 shows that the average field oil saturation can reduce to down to about 0.19 and 0.17 for vertical well and horizontal wells respectively, this very low oil saturation (compared to the residual oil saturation initially of 0.2) suggests that there exists component exchanges between the fluid in the reservoir and the injected fluid, which helps to vaporize reservoir oil. With the reservoir fluid composition as shown in Table 5.15 where we see components C1 and C2 increase in composition compared to the initial composition and all other components decrease in composition in the reservoir, we can observe that the injected gas stream causes component exchange, vaporizing the oil and leading to the high recovery potential. It is also noticed from Table 5.15 that the mole percent of components of the reservoir fluid do not get as low as is the case discussed above for complete gas injection in Table 5.10. This is due to the constrained placed on GOR during production which limits the amount of gas reinjected into the reservoir and thus limits the potential of gas sweep efficiency and also limits the benefits of component exchange in the reservoir between the injected gas and the reservoir fluid.

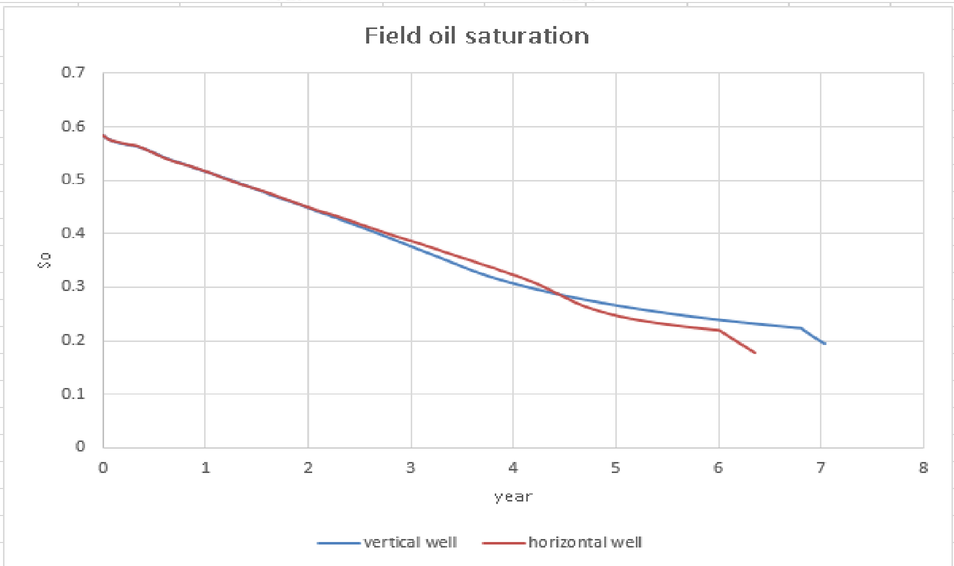

Figure 5.111 Average field oil saturation versus time for reservoir under gas injection constrained at GOR<160 Mscf/stb using different well types

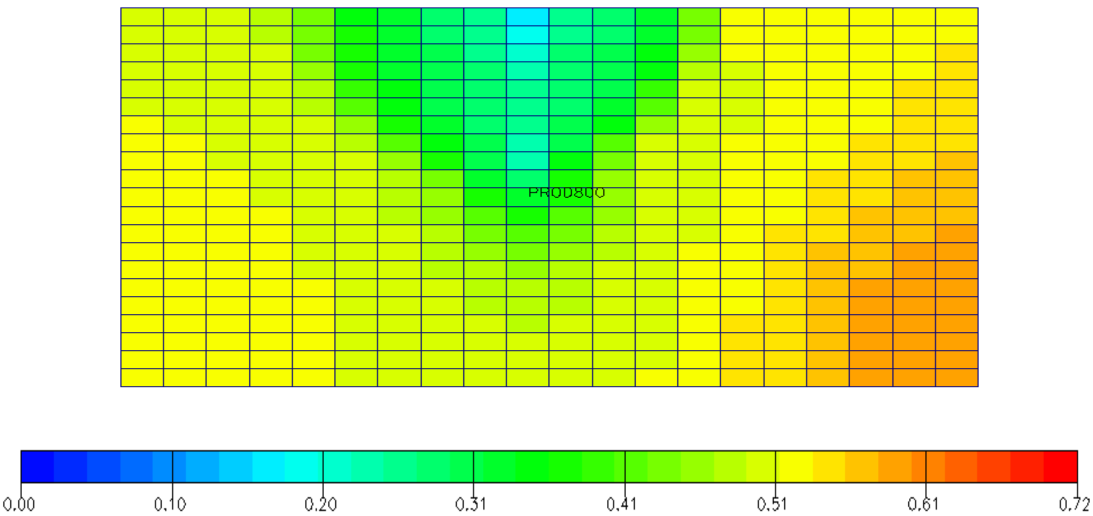

Figure 5.112 Oil saturation at abandonment for reservoir with a vertical well under gas injection constrained at GOR<160 Mscf/stb at 500 stb/d (xy plane view)

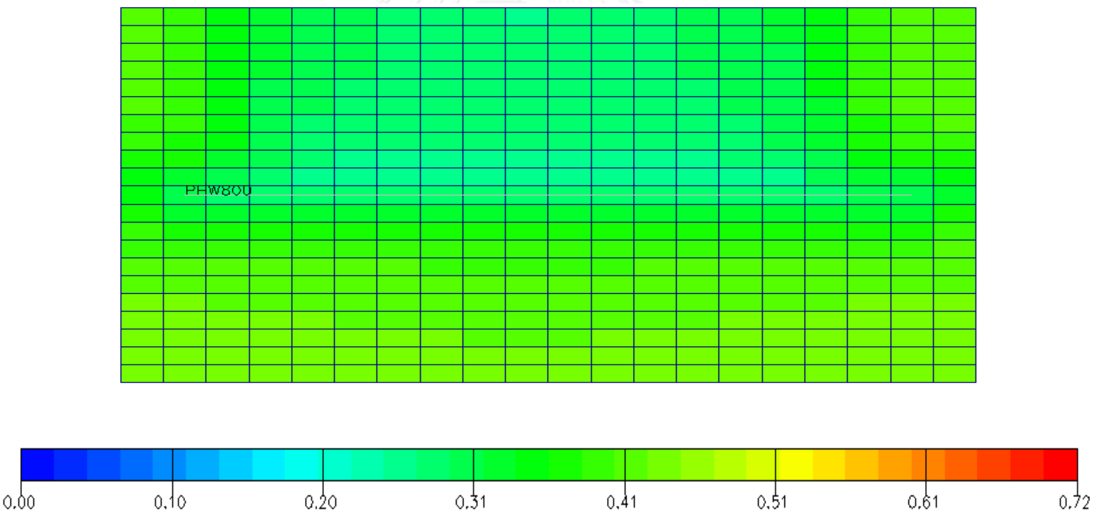

Figure 5.113 Oil saturation at abandonment for reservoir with a horizontal well under gas injection constrained at GOR<160 Mscf/stb at 500 stb/d (xy plane view)

Table 5.15 Mole percent at different time for reservoir under gas injection constrained at GOR<160 Mscf/stb using different well types

component	Initial composition	Abandonment composition vertical well	Abandonment composition horizontal well
CO2	1.17	0.139	0.33
C1	39.96	76.248	69.64
C2	10.6	21.51	23.698
C3	7.62	1.146	3.429
IC4	1.58	0.057	0.186
NC4	4.31	0.589	2.006
IC5	1.58	0.021	0.074
NC5	1.54	0.028	0.099
C6	4.74	0.085	0.293
C7+	26.91	0.175	0.245
Reservoir conditions			
Pres	3000	1085	265
Tres	220	220	220

A comparison of the results obtained for this case of terminating the gas injection when GOR>160 Mscf/stb is presented below. The results obtained for varying time to stop gas reinjection as summarized in Table 5.16 indicates that there is very large difference in terms of recovery efficiency. Thus it can be argued that performing gas reinjection until abandonment of the reservoir will be advantageouse than stopping the injection at some point during the production cycle.

Table 5.16 Summary of results effect of varying time to stop gas reinjection

Production schedule	Production well type	Cumulative oil MMstb		Cumulative gas Bscf		Recovery efficiency %	
		500 stb/d	2000 stb/d	500 stb/d	2000 stb/d	500 stb/d	2000 stb/d
Gas injection Throughout production period	Vert well	1.01	0.98	45.89	62.47	58.9	57.0
	Hori well	1.17	1.13	68.46	84.53	68.2	66.1
Gas injection terminated at GOR>160 Mscf/stb	Vert well	0.94	0.87	29.69	34.38	54.7	50.8
	Hori well	0.96	0.88	15.33	21.69	56.2	51.6
Gas injection terminated at GOR>80 Mscf/stb	Vert well	0.81	0.76	14.8	20.66	47.2	44.1
	Hori well	0.92	0.82	8.38	12.26	53.4	47.7

For the effect of time to stop gas injection, we can draw the following conclusions

- Performing gas reinjection throughout production period gives the highest value of cumulative oil produced for both cases of wells constrained at 500 stb/d and at 2000 stb/d.
- Performing gas reinjection until end of production life also gives highest values of cumulative gas produced

- The horizontal wells in all cases gives higher amount of cumulative oil produced, cumulative gas poduced as well as highest value of oil recovery factor
- Shutting-in the injection well when GOR>80 Mscf/stb gives the lowest values of cumulative oil production, cumulative gas production and oil recovery factor.
- Therefore, in other to achieve higher values of recovery factor, performing gas injection throoughout the production period results in higher recovery efficiency than terminating the gas injection process at some point during production.

5.4 Effect of well position

The results summarized thus far was simulated with the production wells located around the center of the reservoir. The results showed that all wells in the case of gas reinjection were abandoned due to excessive gas production even when high oil saturation still exists in the area opposite of the injection well. In this part of the study, the position of the injection and production wells were altered to see how much more recovery of oil can be obtained. There are two positions adopted for this part of the study (in addition to the original well position as shown in Figure 4.7 to Figure 4.11)

Position 1: the gas injection well is located in block i-10 j-1 k-1, while the production wells are located in block i-10 j-20 k-10 (for the vertical well) and i-2 j-20 k-10 (for the horizontal well)

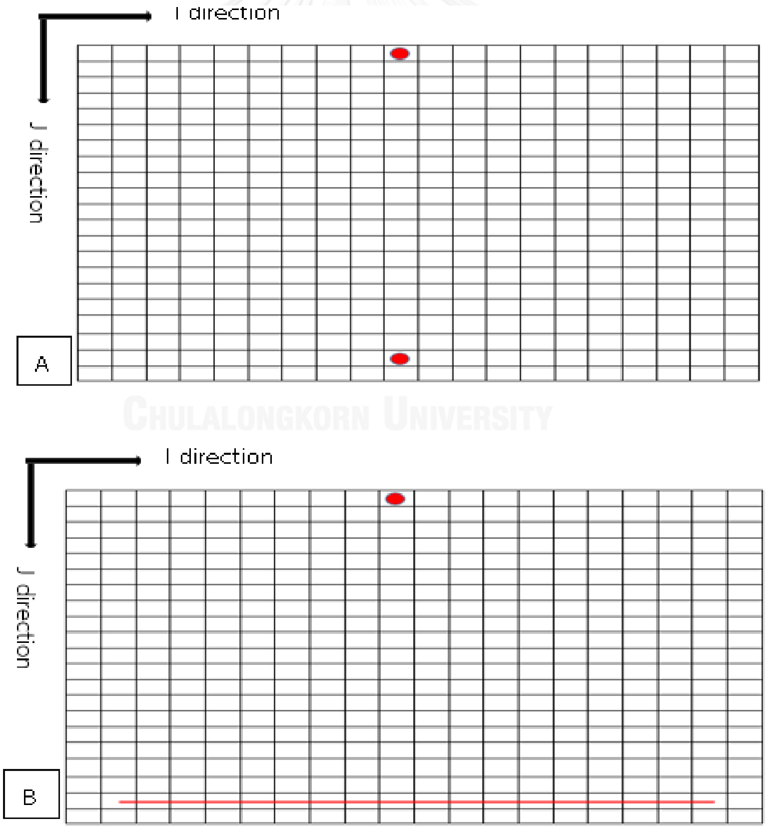

Figure 5.114 Top view for A) one vertical producer and one vertical injector and B) one horizontal producer and one vertical injector.

Position 2: the gas injection well is located in block i-11 j-11 k-1, while the production wells are located in block i-10 j-11 k-10 (for the vertical well) and i-2 j-11 k-10 (for the horizontal well)

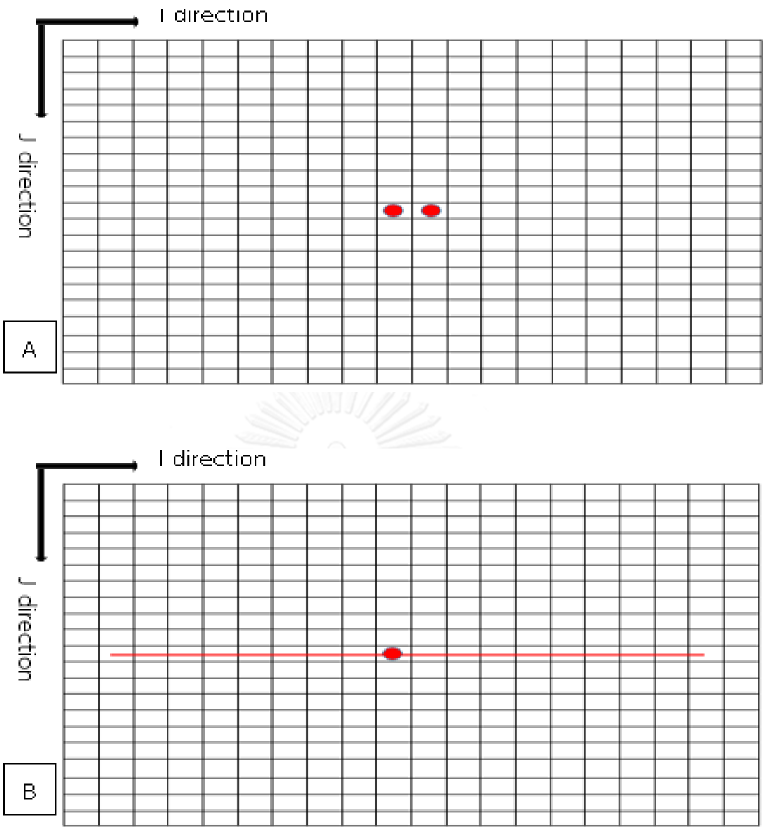

Figure 5.115 Top view for A) one vertical producer and one vertical injector and B) one horizontal producer and one vertical injector.

5.4.1 Vertical well producer: position 1 schedule

The results show that placing the producing well on the opposite side of the injector leads to higher recovery efficiency. This happens because the injected gas travels all through to the other side of the reservoir, thus sweeping a larger area of the reservoir fluid across to the producing well leading to higher oil recovered. Also, the injected gas travels a longer distance before reaching the perforated section of the producing well thus minimizing the tendency for the injected gas to impede the flow of oil into the producing well. The trend in flow rate as presented in Figure 5.116 is similar to other cases in which the lower flow rate plateaus for a longer period of time, and oil rate declines once large gas procduction occurs and reservoir drive energy declines. Figure 5.117 indicates that the gas breakthrough occurs slightly earlier in this case compared to the case presented in section 5.2.1, where the production well is located at the centre of the reservoir. This can be due to the fact that in the case of producing well at position 1, the well is closer to a reservoir boundary, and the reservoir fluid flow is restricted to move towards the boundary, thus a larger amount of fluid has the tendency to flow downwards once production is initiated, thus the gas cap expands downward a little quicker in this scenario. Figure 5.118 indicates that as production proceeds, the reservoir pressure declines gradually until about four years, at which time the gas production rate as well as gas injection rate is at maximum values, and the pressure declines less gradually until end of production life. This phenomenon occurs due to the pressure support from maximum gas injection in the reservoir. Figure 5.119 shows that the pressure profile for the vertical producing at 500 stb/d and at 2000 stb/d. In both cases, the reservoir pressure declines steeply in early production life of the reservoir, with the pressure decline gradually towards end life of the well when high amount of produced gas is cycled. The oil saturated profile shown in Figure 5.121 shows that though there is still a considerable amount of oil left in the area towards the corners on the reservoir, this amount is much lower than in the cases where the producer was placed at the centre of the reservoir, thus leading to the much higher oil recovery factor as seen in Figure 5.120.

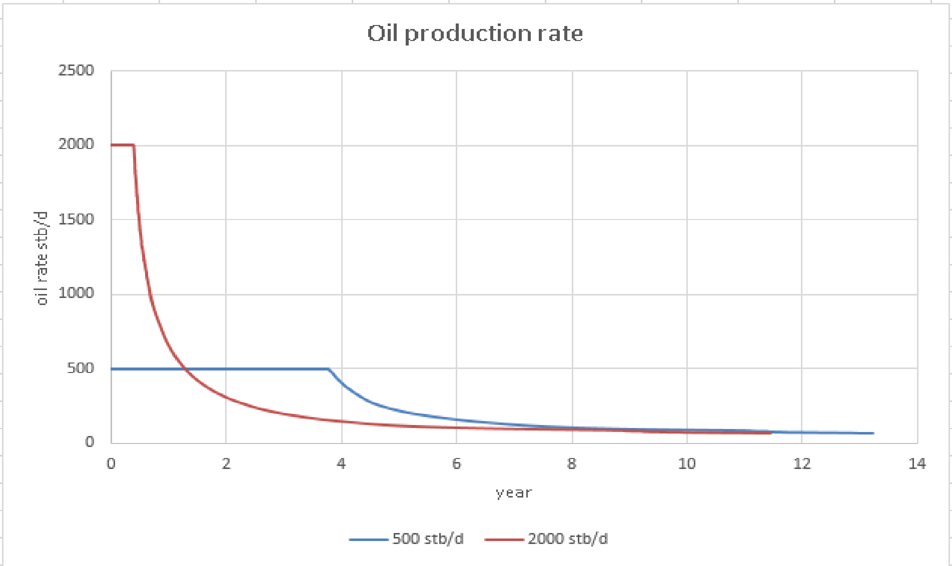

Figure 5.116 Oil production rate for vertical well at position 1 under produced gas reinjection

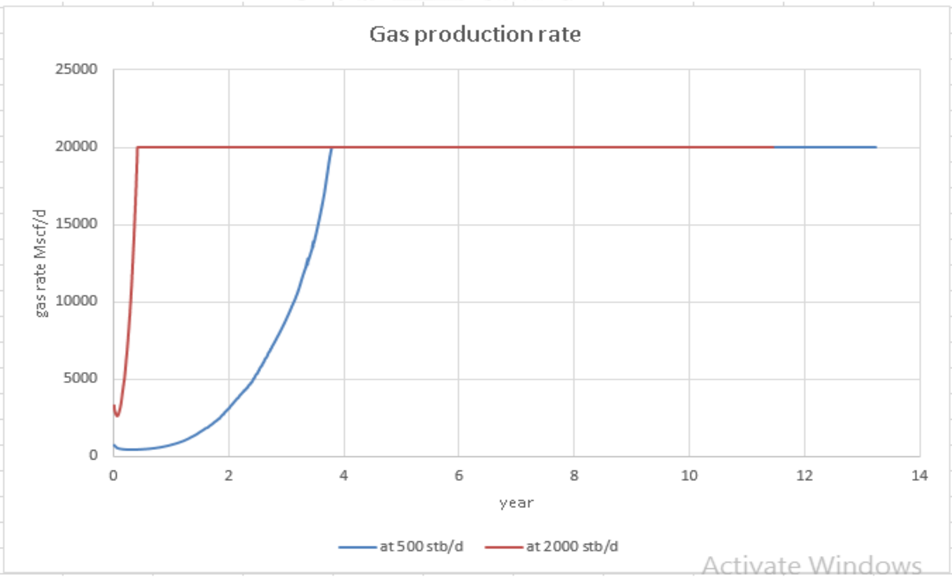

Figure 5.117 Gas production rate for vertical well at position 1 under produced gas reinjection

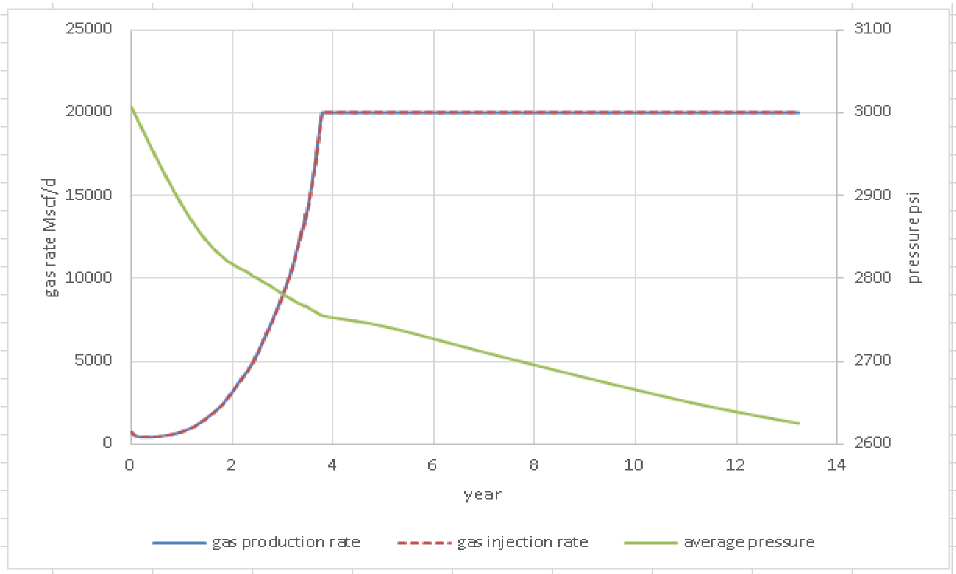

Figure 5.118 Trends of gas injection, gas production and average pressure for vertical well producer at 500 stb/d for production well on position 1

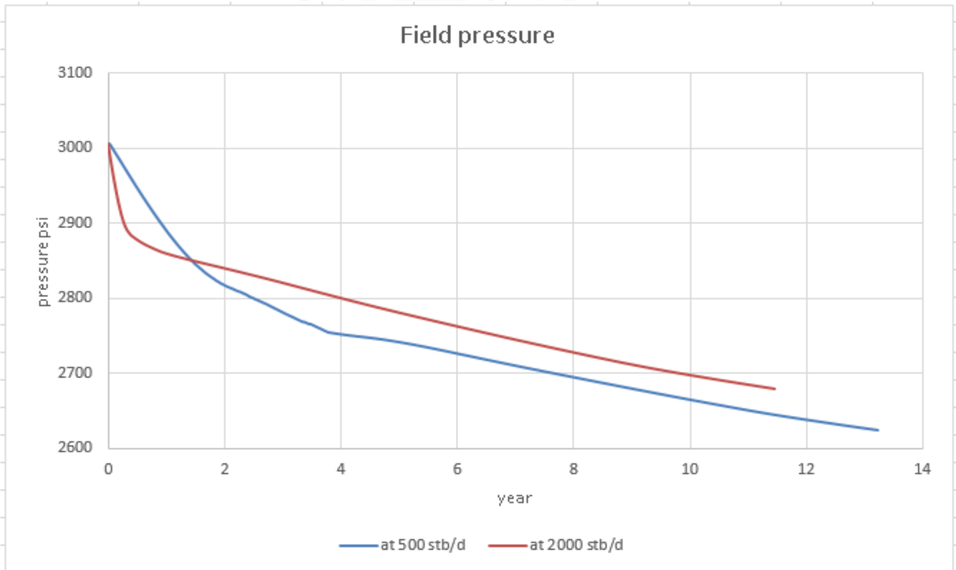

Figure 5.119 Field pressure for vertical well at position 1 under produced gas reinjection

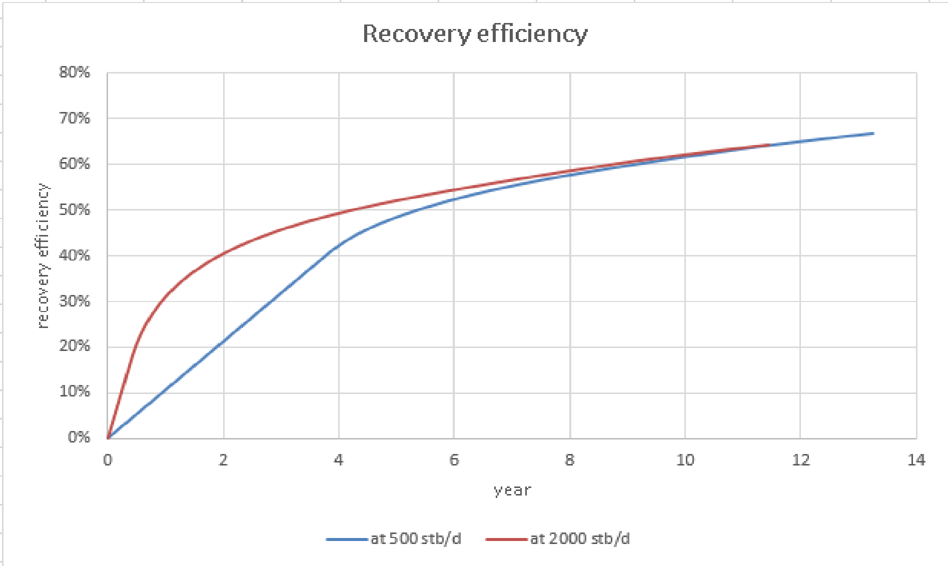

Figure 5.120 Field oil efficiency for vertical well at position 1 under produced gas reinjection

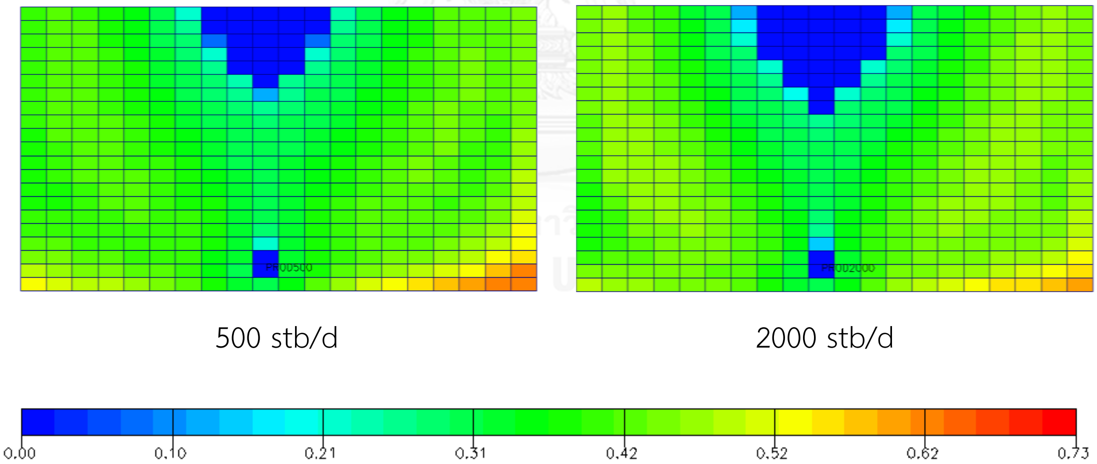

Figure 5.121 Oil saturation profile for grid plane k-10 at abandonment for vertical well at position 1 (xy plane view)

5.4.2 Horizontal well producer: position 1 schedule

Placing the producing horizontal well on the opposite side of the injector leads to higher recovery efficiency. The injected gas travels all the way through to the other side of the reservoir, thus sweeping larger reservoir area across to the producing well leading to higher oil recovered. Also, the injected gas travels a longer distance before reaching the perforated section of the producing well thus minimizing the tendency for he injected gas to impede the flow of oil into the producing well. The trend in flow rate as presented in Figure 5.122 is similar to other cases with the horizontal well in which the well plateaus for a shorter period of time, and once gas breakthrough occurs, the rate rapidly drops to very low oil rate due to pressure decline and increase in gas production. Similar to the case with the vertical well in section 5.4.1, Figure 5.123 indicates that the gas breakthrough occurs slightly earlier in this case compared to the case presented in section 5.2.1, where the production horizontal well was located at the centre of the reservoir. This is due to the fact that in the case of producing well at position 1, the well is closer to a reservoir boundary, and the reservoir fluid flow is restricted to move towards the boundary, thus a larger amount of fluid have the tendency to flow downwards once production is initiated, thus the gas cap expands downward a little quicker in this scenario. The horizontal well in position 1 has higher oil recovery than seen in the case in section 5.2.1, this is due to the fact that the position of the producer in this case is much further away from the injector than in the case in section 5.2.1, thus the injected gas sweeps large reservoir area and impedes oil flow into the well less serverely. Figure 5.124 shows the reservoir pressure for the horizontal well flowing at different flow rates. The reservoir pressure declines as production goes on, however in the period between 4 years to 6 years of production (for the case of the well flowing at 500 stb/d) there is an increase in reservoir pressure, even though the net fluid production (oil plus gas) is more than the net fluid injected (gas). This indicates that the injected gas causes revaporization of the reservoir fluid, thus resulting in an increse in gas vlume in the reservoir capable of causing this increase in reservoir pressure. As seen in Figure 5.124 at about 3.4 years of production for the case of the horizontal well flowing at 500 stb/d, and at about 0.6 years of production for the case of the horizontal well flowing at 2000 stb/d, there is a slight increase in reservoir pressure then rapid decline again. This increase in pressure happens due to the revaporization of intermediate hydrocarbons in the reservoir as indicated in Figure B-17 and Figure B-18. As seen in Figure B-17, as production starts, there is an increase in composition of components C7+, while composition of C1 increases, this is due to the gas produced alongside the oil, leaving the reservoir fluid heavier. However, at about 4 years of production, composition of C7+ starts droping, indicating vaporization of this component into gas at the GOC thus the increase in gas components. The rapid increase in the volume of gas as seen by the sharp rise in both composition of C1, C2, while rapid decline in composition of C3, NC4, and C7+ creates a lot of gas volume in the reservoir which helps in pressurizing the reservoir, as seen by the slight increase in reservoir pressure at that period of production. However, the pressure starts declining again even though the gas volume in the reservoir is still maintain at high, this is due to the large distance between the injection well and the producing well, thus the gas has a larger viodage to fill making the instanteneous increase in gas volume insignificant to keep keep pressure constant.

The oil recovery efficiency presented in Figure 5.125 shows that the recovery factor goes up to close to 80% for both oil rate cases. This very high recovery efficiency is due to the larger area swept by the injected gas in the reservoir. The oil saturated profile shown in Figure 5.126 shows that though there is still a considerable amount of oil left in the area towards the corners on the reservoir, this amount is much lower than in cases where the horizontal producer was placed at the centre on the reservoir, thus leading to the high oil recovery factor as seen in Figure 5.125.

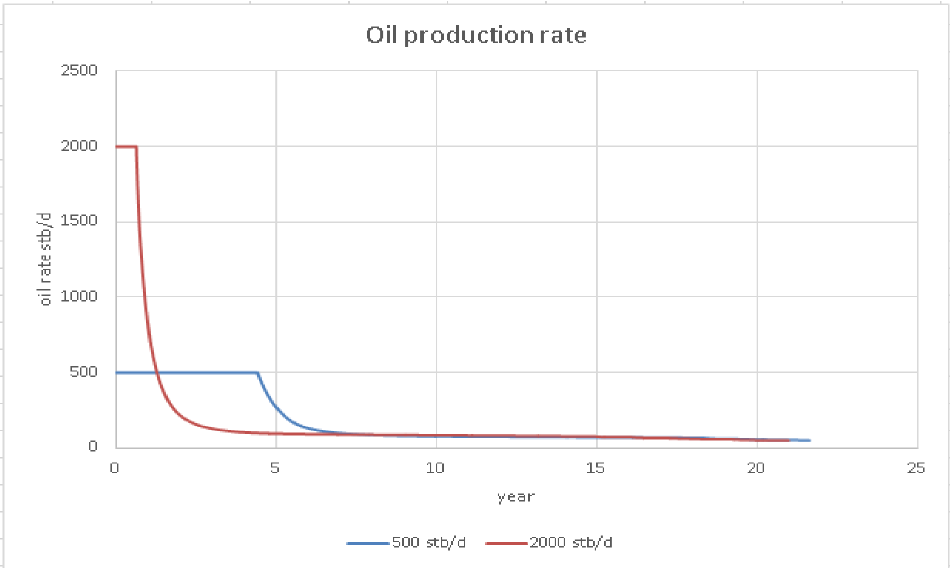

Figure 5.122 Oil production rate for horizontal well at position 1 under produced gas reinjection

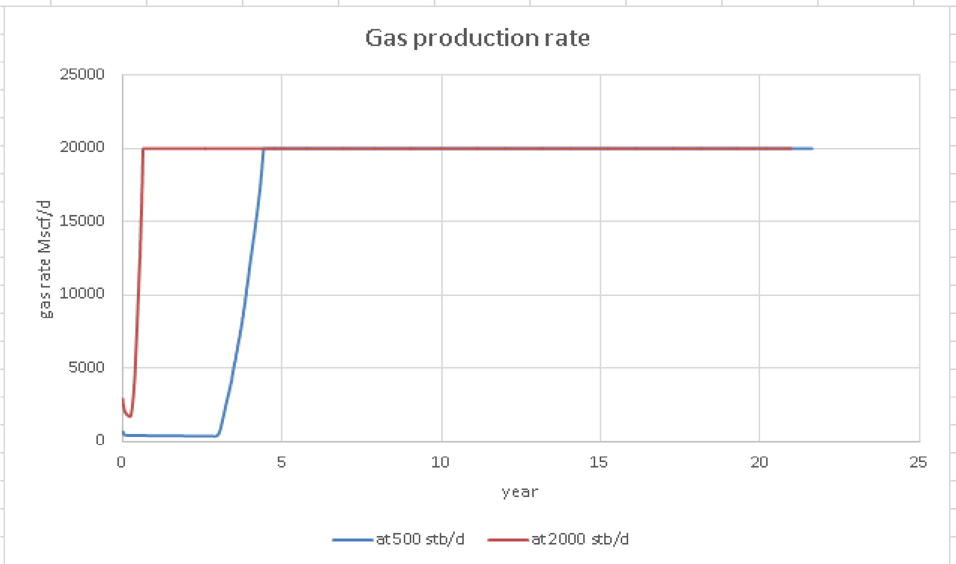

Figure 5.123 Gas production rate for horizontal well at position 1 under produced gas reinjection

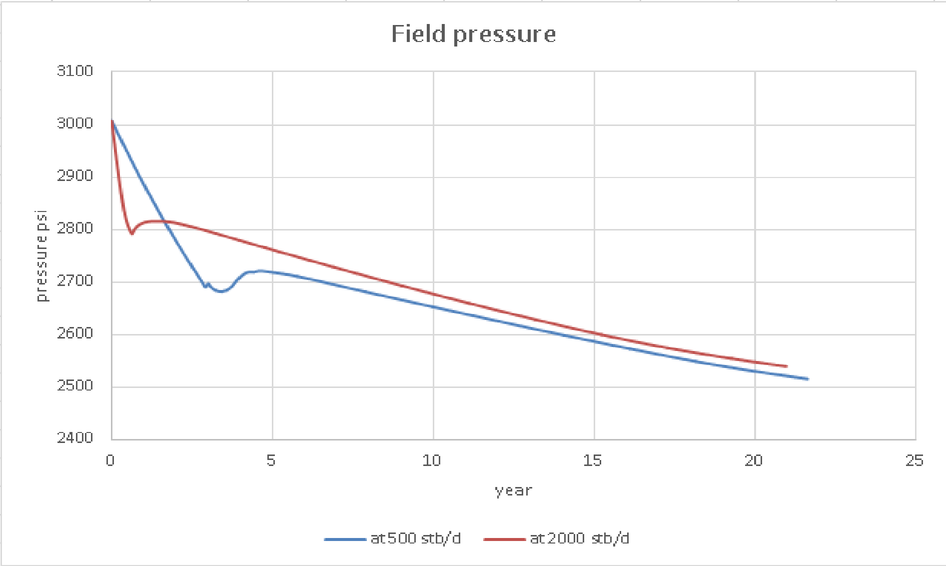

Figure 5.124 Field pressure for horizontal well at position 1 under produced gas reinjection

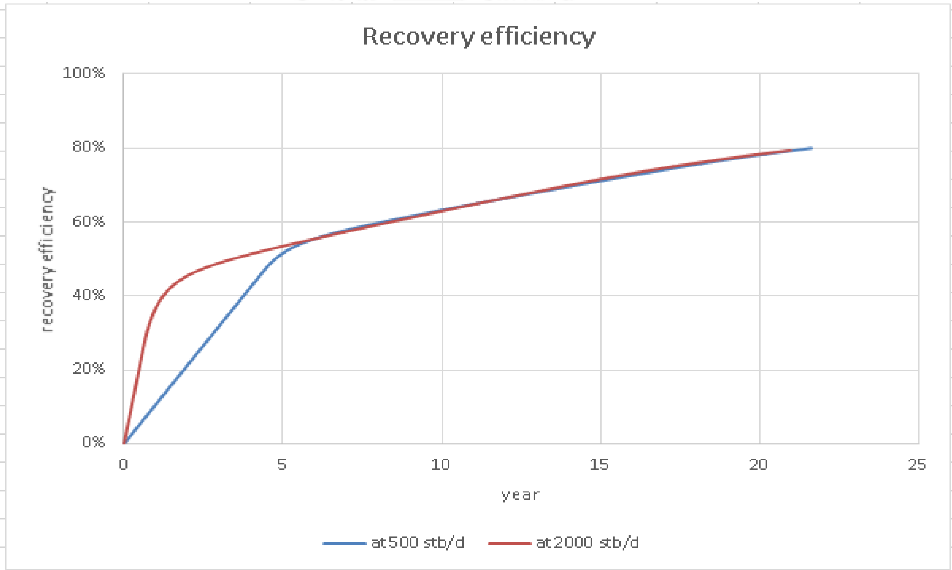

Figure 5.125 Field oil efficiency for horizontal well at position 1 under produced gas reinjection

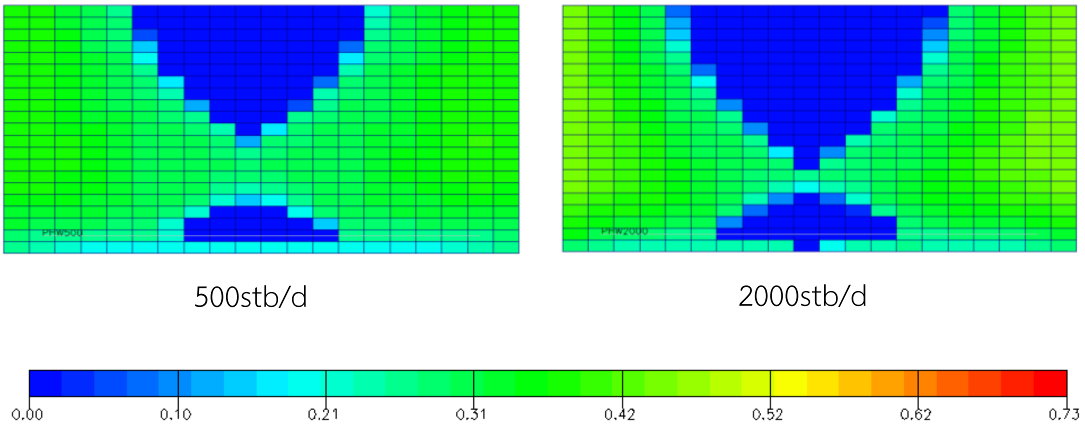

Figure 5.126 Oil saturation profile for grid plane k-10 at abandonment for horizontal well at position 1 (xy plane view)

The reservoir oil saturation analysis for the case of gas reinjection using well position 1 is presented here. The overall oil saturation as seen in Figure 5.127 shows that the average field oil saturation can reduce to down to about 0.09 for the horizontal well case. This low oil saturation is lower than residual oil saturation occurs at about 7 years of production, however, oil flow is still recorded. Technically once saturation is below residual oil saturation, oil cannot flow. Oil production continues occuring here because the areas in the reservoir not flooded by the injected gas still have high oil saturations. As this oil flow towards the well, it vaporises and is produced as condensate, thus this very low oil saturation (compared to the residual oil saturation initially of 0.2) suggests that the is component exchanges between the fluid in the reservoir and the injected fluid (injected gas vaporizing the reservoir oil into the gas phase). With the reservoir fluid composition as shown in Table 5.17 where we see components C1 and C2 increase in composition compared to the initial composition and all other components being close to 0% in the reservoir, we can observe that the injected gas stream causes these components exchanges and thus help in vaporizing the oil, leading to the high recovery potential and thus recovery of almost all liquid phase in the reservoir as seen.

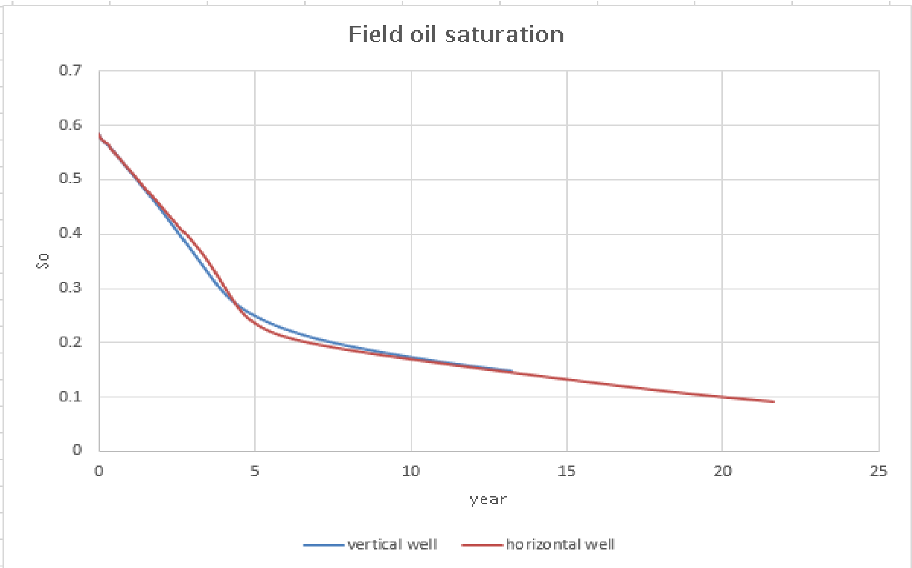

Figure 5.127 Average field oil saturation versus time for reservoir under gas injection: position 1 configuration

Table 5.17 Mole percent at different time for reservoir under gas injection: position 1 configuration

component	Initial composition	Abandonment composition vertical well	Abandonment composition horizontal well
CO_2	1.17	0.00082	$1.39*10^{8}$
C1	39.96	78.91	78.92
C2	10.6	20.94	20.95
C3	7.62	0.0096	$2.17*10^{6}$
IC4	1.58	0.00058	$5.27*10^{7}$
NC4	4.31	0.0067	$1.42*10^{5}$
IC5	1.58	0.00029	$2.21*10^{6}$
NC5	1.54	0.000414	$4.43*10^{6}$
C6	4.74	0.00168	$6.22*10^{5}$
C7+	26.91	0.128	0.127
Reservoir conditions			
P_{res}	3000	2625	2515
T_{res}	220	220	220

5.4.3 Vertical well producer: position 2 schedule

The results show that placing the producing well and the injecting well about the same location (with different region of completion) leads to lower recovery efficiency. This happens because the injected gas travels a shorter distance before reaching the completion interval of the producing well, thus sweeping less oil across to the producing well leading to lower oil recovered. Also, the injected gas travels a shorter distance before reaching the perforated section of the producing well thus giving a high tendency for he injected gas to impede the flow of oil into the producing well. The vertical permeability of 12.6 md as is the case of this reservoir is reasonably high enough to permit rapid downward flow of the gas, thus we notice that the injected gas invades the production well much earlier, leading to high oil saturation left behind in the reservoir. Figure 5.128 shows that as gas reinjection goes on until maximum injection rate of 20 MMscf/d, the reservoir pressure decline was not fully arrested, however, the abandonment reservoir pressure was about 2710 psi for the case flowing at 500 stb/d and 2640 psi for the case flowing at 2000 stb/d. The oil production rate profile shown in Figure 5.129 shows early decline from the plateau rate. The distance between the injector and producer is quite near in this scenario, thus the injected gas stream sweep a small area of the reservoir before reaching the production well. This resuted in rapid increase in gas production rate with the vertical well flowing at oil rate of 2000 stb/d producing large amount of gas less than one month from the start of production as seen in Figure 5.130. This effects the flow of oil thus reduction in oil recovery efficiency potential.

As shown in Figure 5.131, the pressure profile for the well flowing at 500 stb/d declines gradually till about 3 years, and the pressure decline is arrested slightly. The pressure profile for the well flowing at 2000 stb/d declines rapidly at early time of production, however at about 2 years of production, the decline in pressure arrested. This pressure behavior indicates that the gas recycling process helps to support reservoir pressure. The recovey efficiency as shown in Figure 5.132 is much lower than the recocery obtained in section 5.4.1, this is bcause the dstance between the injector and producer is shorter in this case, hence the injected gas does not sweep much area in the reservoir. The oil saturated profile shown in Figure 5.133 shows that there is still a considerable amount of oil left in the area towards the edge of the reservoir. This is due to the invasion of the perforated section of the well by the injected gas stream, thus leading to the much lower oil recovery factor as seen in Figure 5.132.

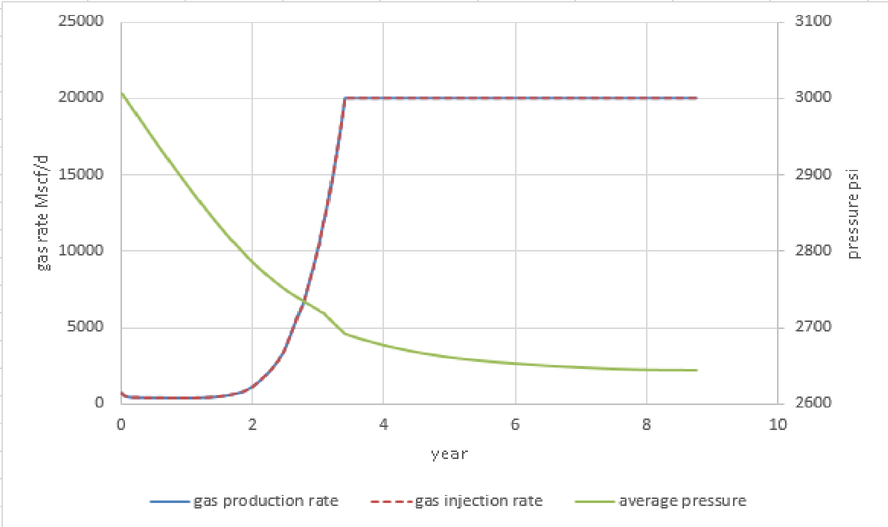

Figure 6.1 Trends of gas injection, gas production and average pressure for vertical well producer at 500 stb/d: production well on position 2

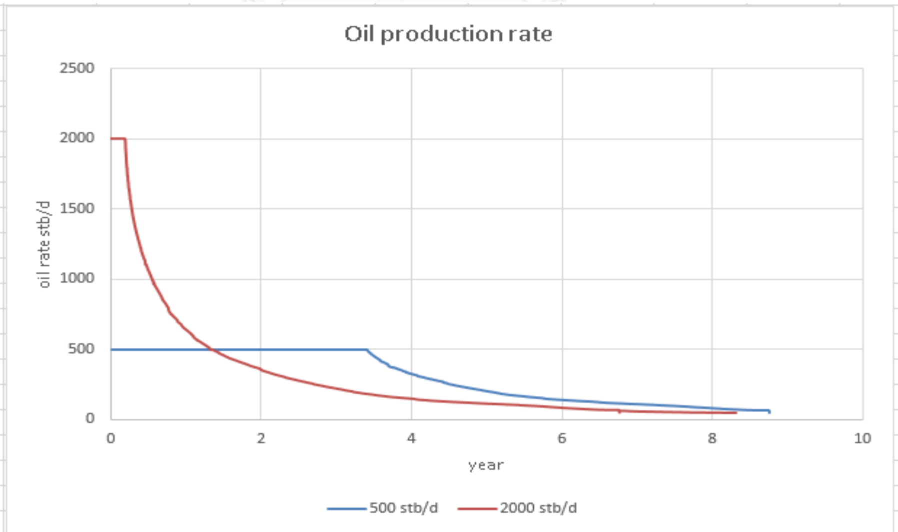

Figure 6.2 Oil production rate for vertical well at position 2 under produced gas reinjection

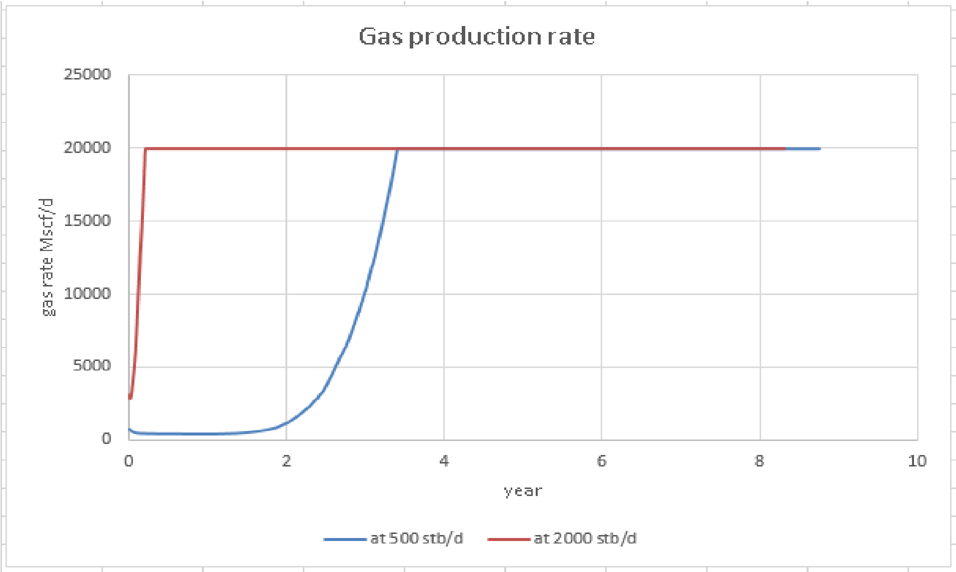

Figure 6.3 Gas production rate for vertical well at position 2 under produced gas reinjection

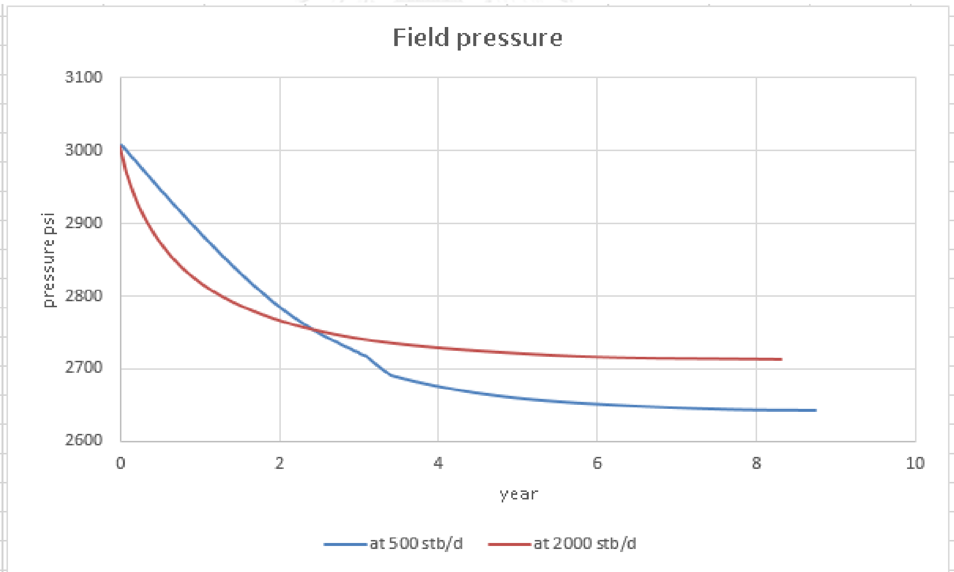

Figure 6.4 Field pressure for vertical well at position 2 under produced gas reinjection

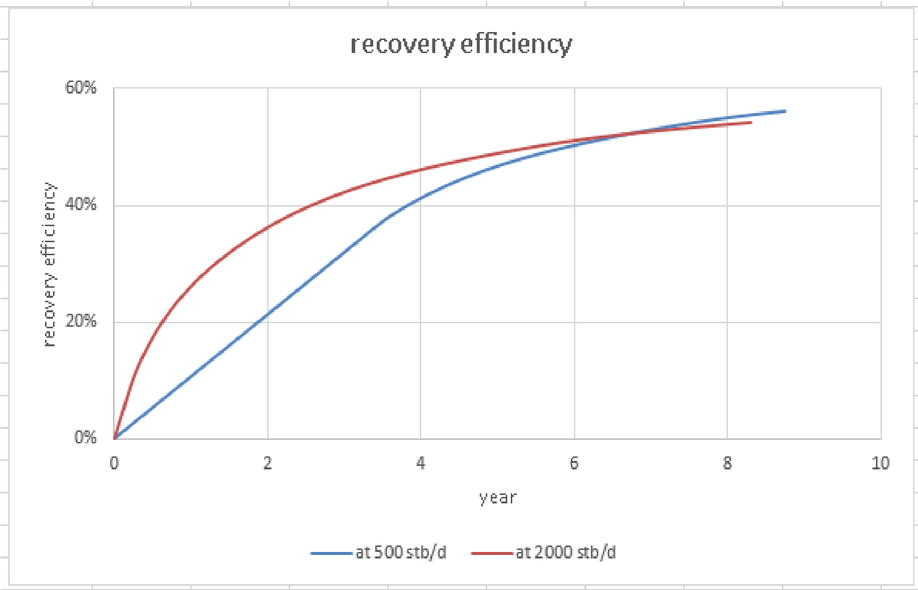

Figure 6.5 Field oil efficiency for vertical well at position 2 under produced gas reinjection

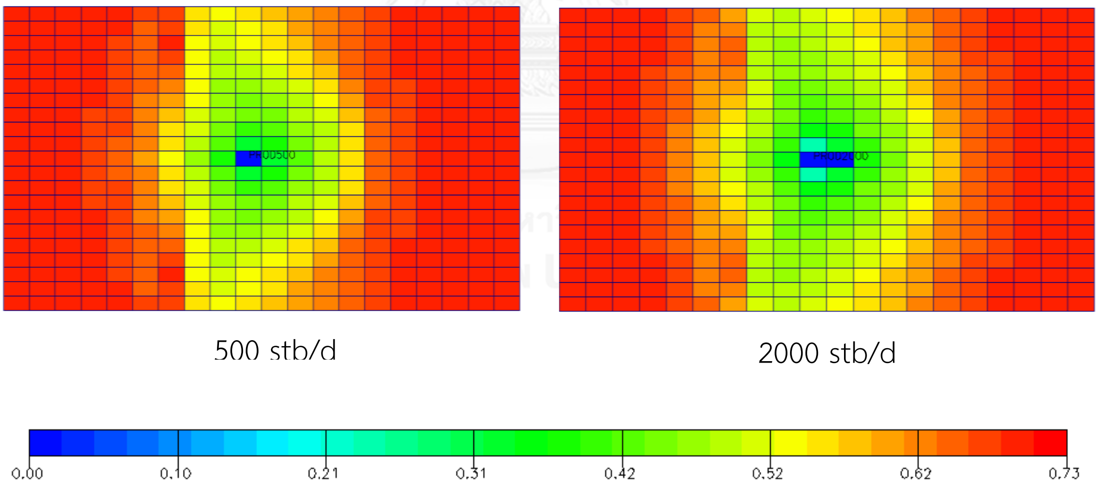

Figure 6.6 Oil saturation profile for grid plane k-10 at abandonment for vertical well at position 2 (xy plane view)

5.4.4 Horizontal well producer: position 2 schedule

Placing the producing horizontal well at the centre, just below the injector well leads to lower recovery compared to the case seen in section 5.4.2, however, for this same configuration (position 2) the horizontal well gives higher recovery efficiency than the vertical well as seen in section 5.4.3. Figure 5.134 suggests that the recovery rate at late time is lower for the well producing at high rate than for the well producing at lower rates. This is because the injected gas travels a short distance downward before reaching the production horizontal section, the higher withdrawal rates leads to higher gas coning and thus at late time gives more gas encroachment into the horizontal section, and impedes the flow of oil. The trend in flow rate as presented in Figure 5.134 is similar to other cases with the horizontal well in which the well plateaus for a period of time. Once gas breakthrough occurs, the rate rapidly drops to very low oil rate due to pressure decline and increase in gas production. Figure 5.138 indicates that once gas breakthrough occurs and large amount of gas is produced then recycled back into the reservoir, the average reservoir pressure decline was arrested, and the reservoir is also pressurized for about 60 psi more and the reservoir pressure was kept relatively high until end of production life of the reservoir. This slight increase in reservoir pressure as seen in the humps in Figure 5.136 occurs due to the gas vaporizing the reservoir oil and thus an increase in the reservoir gas volume. The oil saturated profile shown in Figure 5.139 shows that there is still a considerable amount of oil left in the area towards the corners on the reservoir. This amount is much lower than in cases where the producer is placed at the centre on the reservoir, but still considerable higher than the saturation profile seen in Figure 5.126 thus leading to the much lower oil recovery factor as seen in Figure 5.125.

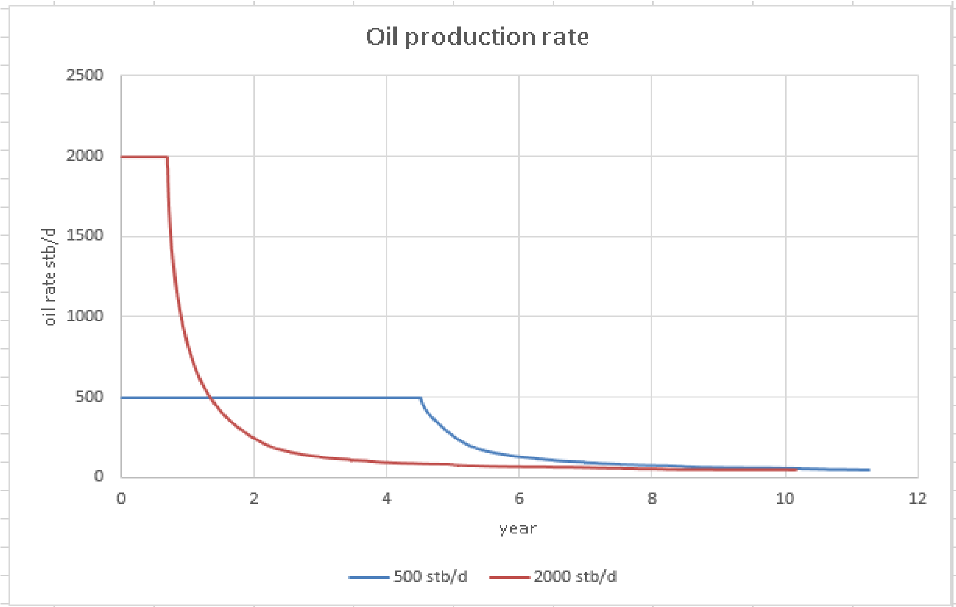

Figure 6.7 Oil production rate for horizontal well at position 2 under produced gas reinjection

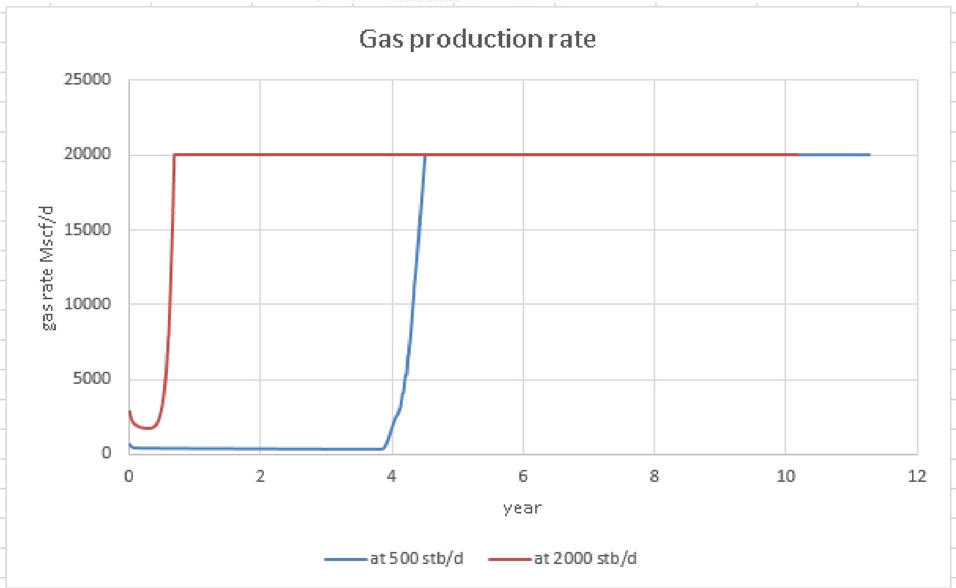

Figure 6.8 Gas production rate for horizontal well at position 2 under produced gas reinjection

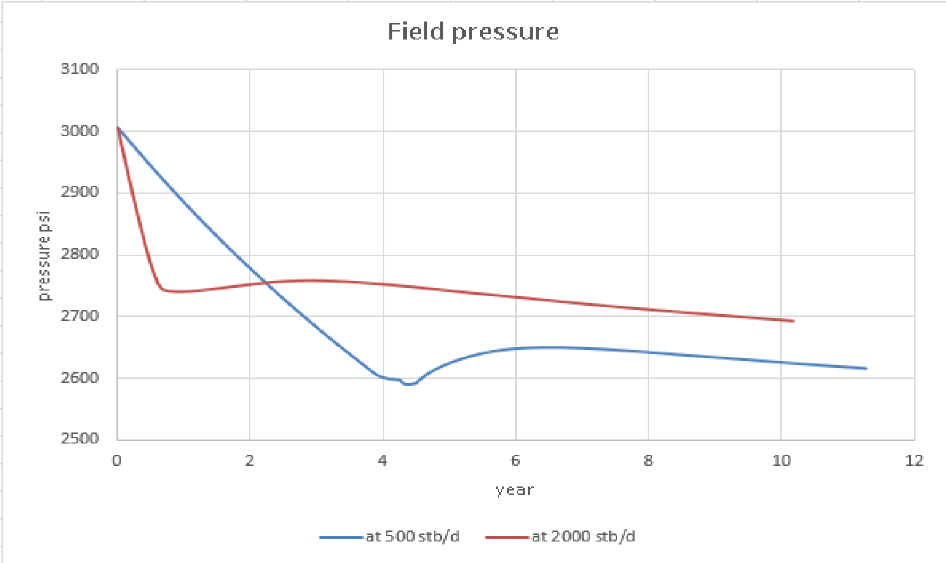

Figure 6.9 Field pressure for horizontal well at position 2 under produced gas reinjection

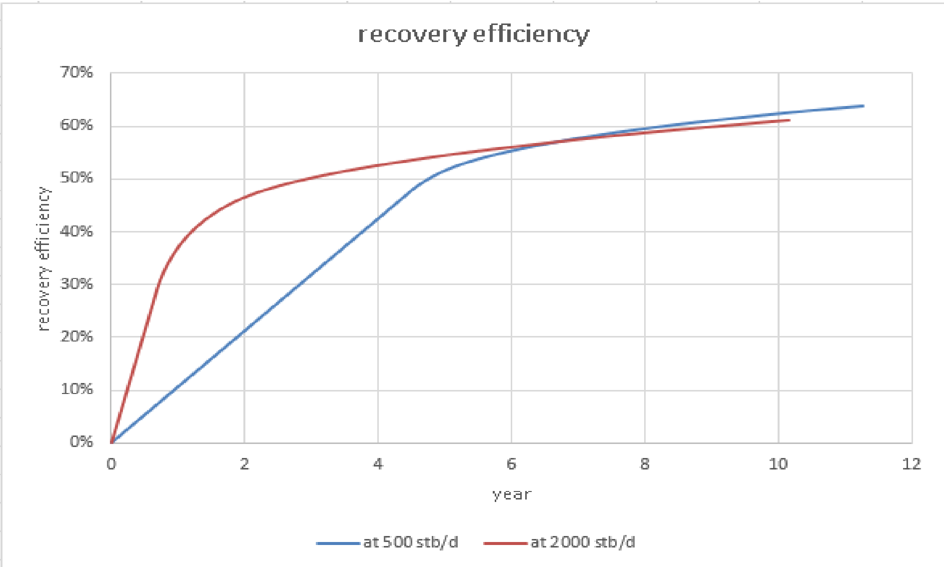

Figure 6.10 Field oil efficiency for horizontal well at position 2 under produced gas reinjection

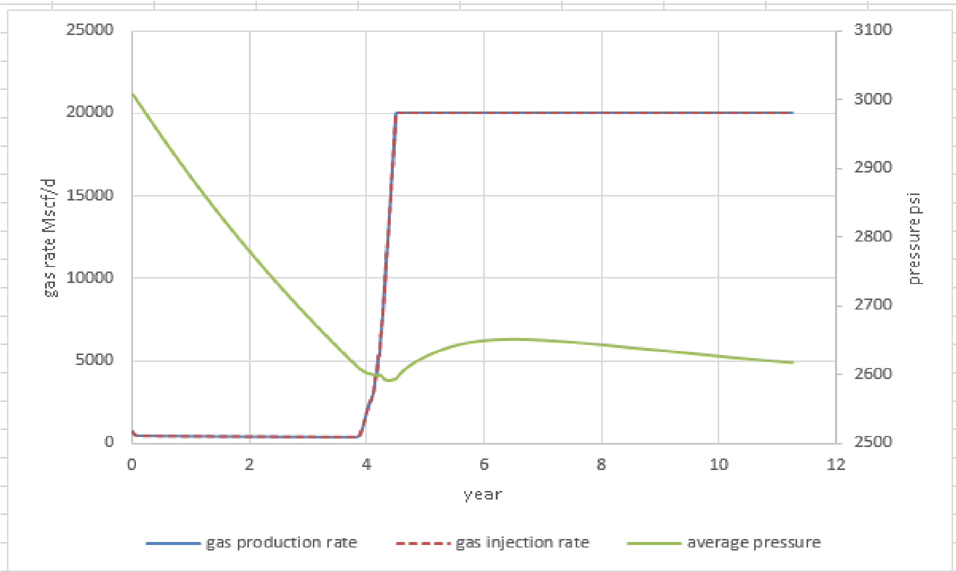

Figure 6.11 Trends of gas injection, gas production and average pressure for horizontal well producer at 500 stb/d: production well on position 2

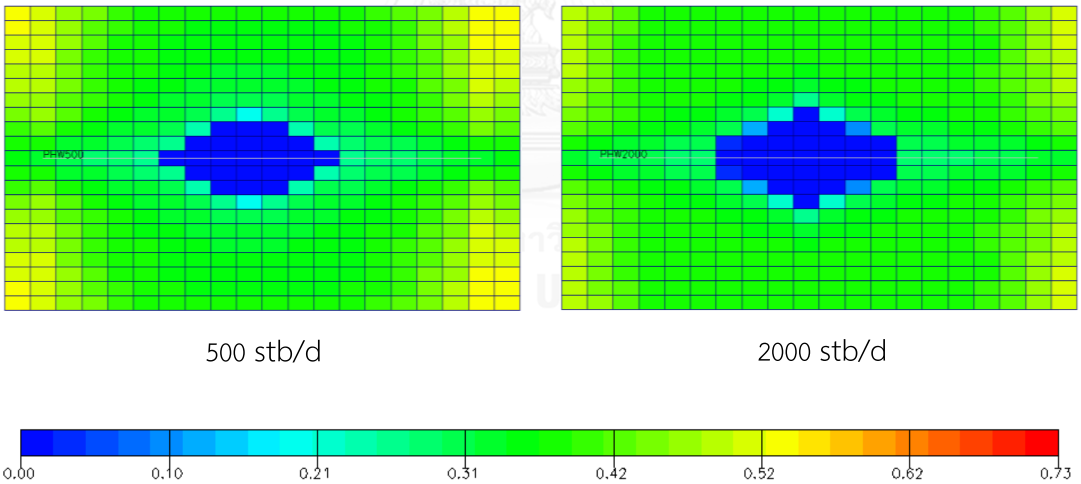

Figure 6.12 Oil saturation profile for grid plane k-10 at abandonment for horizontal well at position 2 (xy plane view)

The reservoir fluid saturation analysis for the case of production using well position 2 is presented here. The overall oil saturation as seen in Figure 5.140 shows that the average field oil saturation can reduce to down to about 0.18 for the horizontal well case. This low oil saturation lower than residual oil saturation occurs at about 7 years of production, however, oil flow is still recorded. Technically once saturation is below residual oil saturation, oil cannot flow. Oil production continues occuring here because the areas in the reservoir not flooded by the injected gas still have high oil saturations. As this oil flow towards the well, it vaporises and is produced as condensate, thus this very low oil saturation (compared to the residual oil saturation initially of 0.2) suggests that the is component exchanges between the fluid in the reservoir and the injected fluid (injected gas vaporizing the reservoir oil into the gas phase). With the reservoir fluid composition as shown in Table 5.18 where we see components C1 and C2 increase in composition compared to the initial composition and all other components being close to 0% in the reservoir, we can observe that the injected gas stream causes these components exchanges and thus help in vaporizing the oil, leading to the high recovery potential and thus recovery of almost all liquid phase in the reservoir as seen.

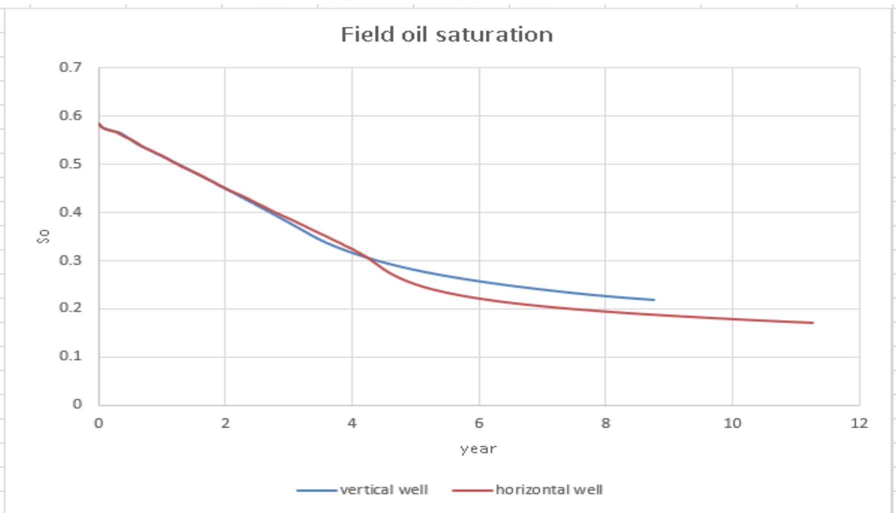

Figure 6.13 Average field oil saturation versus time for reservoir under gas injection: position 2 configuration

Table 6.1 Mole percent at different time for reservoir under gas injection: position 2 configuration

component	Initial composition	Abandonment composition vertical well	Abandonment composition horizontal well
CO_2	1.17	0.0176	0.0026
C1	39.96	78.75	78.88
C2	10.6	20.84	20.93
C3	7.62	0.15	0.0267
IC4	1.58	0.0078	0.0015
NC4	4.31	0.0813	0.0174
IC5	1.58	0.0031	0.000797
NC5	1.54	0.00428	0.00117
C6	4.74	0.0153	0.00615
C7+	26.91	0.127	0.127
Reservoir conditions			
P_{res}	3000	2643	2616
T_{res}	220	220	220

A comparison of results obtained for using well position 2 is presented here. The results obtained for changing the position of production well and injection well for gas reinjection is summarized in Table 5.19 indicates that there is very large difference in terms of recovery efficiency.

Table 6.2 Summary of results: effect of changing well position

Production schedule	Production well type	Cumulative oil MMstb		Cumulative gas Bscf		Recovery efficiency %	
		500 stb/d	2000 stb/d	500 stb/d	2000 stb/d	500 stb/d	2000 stb/d
Gas injection With production well at center of reservoir	Vert well	1.01	0.98	45.89	62.47	58.9	57.0
	Hori well	1.17	1.13	68.46	84.53	68.2	66.1
Gas injection with production well at position 1	Vert well	1.149	1.103	75.76	81.79	67.0	64.3
	Hori well	1.372	1.362	130.59	150.0	80.0	79.4
Gas injection with production well at position 2	Vert well	0.96	0.93	43.29	60.0	56.1	54.2
	Hori well	1.096	1.049	51.57	70.27	63.9	61.2

***Hori = horizontal. Vert = vertical.

For the effect of gas injection with changing well positions, we can draw the following conclusions

- Performing gas reinjection with well configuration of position 1 gives the highest value of cumulative oil produced for both cases of wells constrained at 500 stb/d and at 2000 stb/d.
- Performing gas reinjection with well configuration of position 1 also gives highest values of cumulative gas produced

- The horizontal wells in all cases gives higher amount of cumulative oil produced, cumulative gas poduced as well as highest value of oil recovery factor
- Producing the reservoir with well configuration of position 2 gives the lowest values of cumulative oil production, cumulative gas production and oil recovery factor.

Table 5.20 give the summary of production by natural depletion and production by gas reinjection for all cases studied at different oil flow rates and for different well types.

Table 6.3 Summary of cumulative oil, cumulative gas and recovery factor

Production schedule	Production well type	Cumulative oil MMstb		Cumulative gas Bscf		Recovery efficiency %	
		500 stb/d	2000 stb/d	500 stb/d	2000 stb/d	500 stb/d	2000 stb/d
Natural depletion	Vertical	0.49	0.35	2.42	2.45	28.5	20.7
	Horizontal	0.72	0.47	2.595	2.60	42.2	27.6
	Frac hori	0.72	0.46	2.595	2.60	41.9	26.9
Gas injection throughout prod.	Vertical	1.01	0.98	45.89	62.47	58.9	57.0
	Horizontal	1.17	1.13	68.46	84.53	68.2	66.1
Gas injection when P<2500 psi	Vertical	0.99	0.91	54.53	58.94	57.6	53.0
	Horizontal	1.12	1.07	66.85	87.02	65.2	62.4
Gas injection when P<1500 psi	Vertical	0.87	0.77	55.59	60.29	50.7	45.1
	Horizonal	0.91	0.81	29.67	48.68	53.1	47.0
Gas injection constrained at GOR<160 Mscf/stb	Vertical	0.94	0.87	29.69	34.38	54.7	50.8
	Horizontal	0.96	0.88	15.33	21.69	56.2	51.6
Gas injection constrained at GOR<80 Mscf/stb	Vertical	0.81	0.76	14.8	20.66	47.2	44.1
	Horizontal	0.92	0.82	8.38	12.26	53.4	47.7
Gas injection with production well at position 1	Vertical	1.149	1.103	75.76	81.79	67.0	64.3
	Horizontal	1.372	1.362	130.5 9	150.0	80.0	79.4
Gas injection with production well at position 2	Vertical	0.96	0.93	43.29	60.0	56.1	54.2
	Horizontal	1.096	1.049	51.57	70.27	63.9	61.2

***Frac hori = fractured horizontal, prod = production

CHAPTER 6
CONCLUSION AND RECOMMENDATION

This chapter presents the concluding remarks of this study as related to improve recovery strategy for this reservoir. The results of this study helped to foster the understanding of gas cap reservoir recovery mechanism and assist in designing production parameters to achieve optimum oil production. A reservoir simulator was used as the primary tool to investigate the improvement and changes in each set of different production parameters.

6.1 Conclusions

- Natural depletion of the reservoir gave reasonable recovery efficiency, with the lowest recovery factor being 20.7 % for the vertical well at 2000 stb/d. the horizontal well gave the highest recovery efficiency compared to the vertical well and fractured horizontal well at similar production conditions of flow rate.
- Gas injection gave considerably higher oil recovery factor compared to natural depletion at similar production conditions. Performing gas injection throughout the production period and producing the reservoir with a vertical well at 500 stb/d gave 58.9% oil recovery factor compared to 28.5% oil recovery factor for production via natural depletion using vertical well at 500 stb/d. Also, performing gas injection with a constrain (say terminating the injection process once GOR>80 Mscf/stb) gave higher oil recovery factor compared to production via natural depletion.
- Improvement in oil production was observed once gas reinjection was performed. For the vertical well contrained at flow rate of 500 stb/d under natural depletion gave a recovery factor of 28.4% whereas for the same vertical well flowing at 500 stb/d under gas injection from the start of production gave a recover factor of 58.9%
- Based on well types, the horizontal well resulted in more oil production than the vertical well. For the case of gas injection performed from the start of

production, the horizontal well flowing at 500 stb/d gave about 68.2% recovery factor, which is 9.3% greater than the vertical well flowing at 500 stb/d for this same scenario of gas injection from the start of production

- With reference to the appropriate time to start gas reinjection, reinjecting gas from the start of production resulted in more recovery efficiency than delaying gas injection process during the production. For the case of the horizontal well producer at 500 stb/d initiating gas injection from the start of production gave about 3% more recovery efficiency than reinjecting gas when reservoir pressure falls below 2500 psi and about 15.1% more recovery efficiency than reinjecting gas when reservoir pressure falls below 1500 psi.
- With respect to limiting the production gas-oil ratio, it was observed that once gas injection well is shut in and pressure maintenance source cut off from the production cycle, the reservoir pressure dropped rapidly, thus resulting in lower recovery efficiency. For example for the vertical well flowing at 500 stb/d, performing gas injection from start of production until the end of production gave 58.9% recovery, compared to 47.2% recovery when the gas injection is terminated when GOR>80 Mscf/stb, and 54.7% when the gas injection is terminated when GOR>160 Mscf/stb.
- With changing the production well and injection well position, it was observed that adopting the configuration of position 1 in which the production well was located on the opposite end of the field to the injection well resulted in much higher recovery efficiency compared to the case of placing the injection well next to the production well. This is due to the larger reservoir area swept by the injected gas.
- Performing gas reinjection resulted in vaporization of the intermediate hydrocarbon components of the reservoir fluid by the injected dry gas. This vaporization of the intermediates resulted in more gas phase in the reservoir. The rate at which the vaporization occurred dictated the pressure behavior of the reservoir.

6.2 Recommendations

Future related studies can be performed as recommended below;

- More realistic results can be achieved with appropriate reservoir data and complex heterogeneous fields
- In cases where the reservoir has no primary gas cap, but the field has nearby gas sources and/or multi-layered reservoir with available gas reservoir, a full study can be undertaken to understand how components exchange could improve recovery efficiency.
- Economics evaluation should be taken into consideration as gas injection requires lots of investment, thus reducing risk of investment.

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APPENDIX

Appendix A

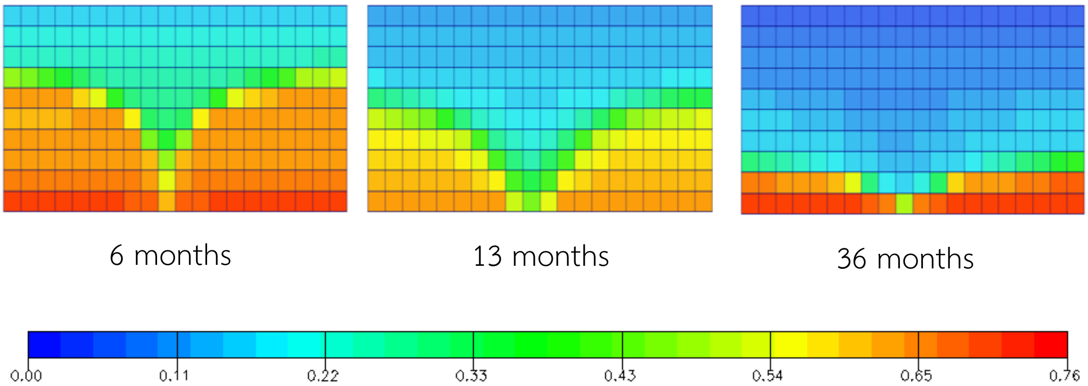


Figure A-1 Oil saturation versus time for grid plane j = 11: vertical production well under natural depletion at 800 stb/d (xz plane view)

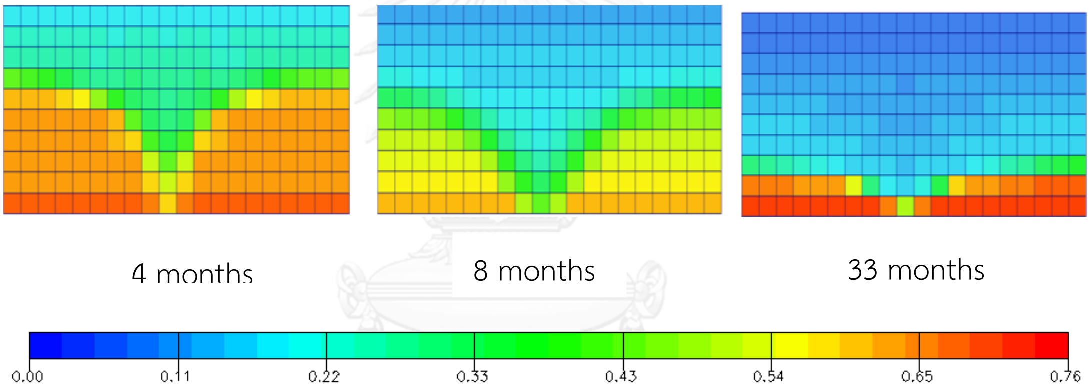


Figure A-2 Oil saturation versus time for grid plane j = 11: vertical production well under natural depletion at 1000 stb/d (xz plane view)

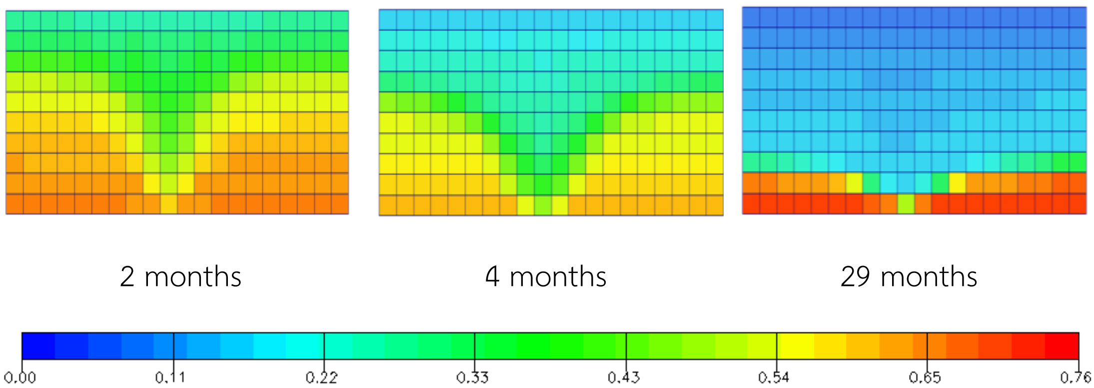


Figure A-3 Oil saturation versus time for grid plane j = 11: vertical production well under natural depletion at 1500 stb/d (xz plane view)

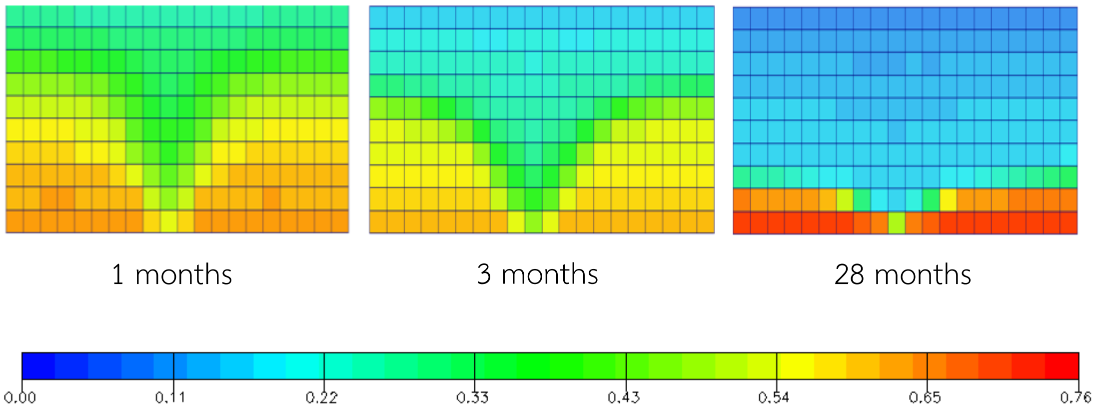


Figure A-4 Oil saturation versus time for grid plane j = 11: vertical production well under natural depletion at 2000 stb/d (xz plane view)

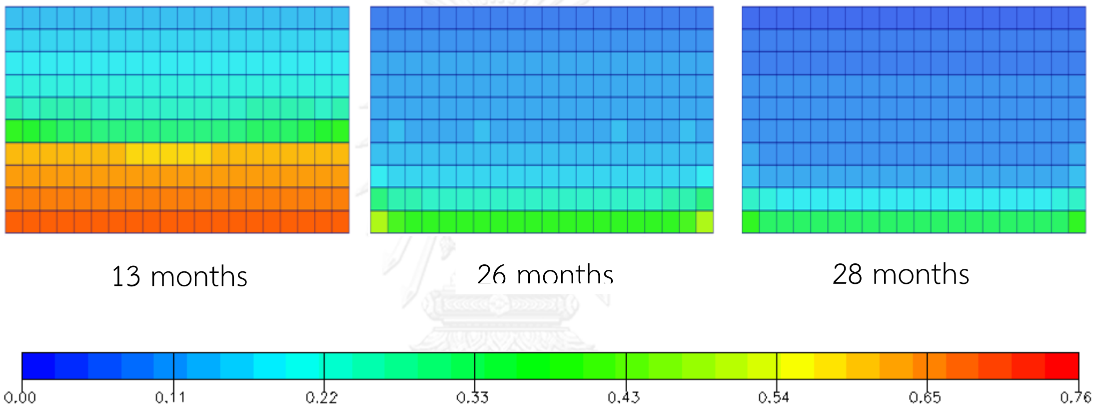


Figure A-5 Oil saturation versus time for grid plane j = 11: Horizontal production well under natural depletion at 800 stb/d (xz plane view)

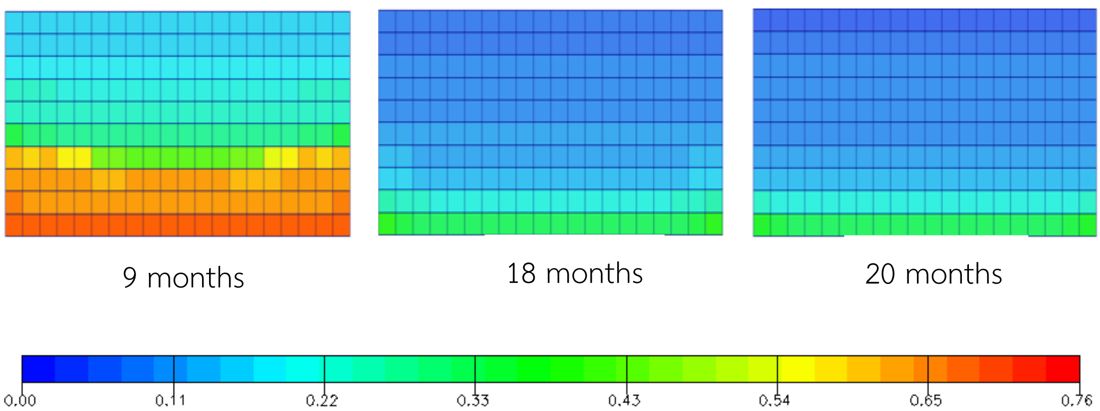


Figure A-6 Oil saturation versus time for grid plane j = 11: Horizontal production well under natural depletion at 1000 stb/d (xz plane view)

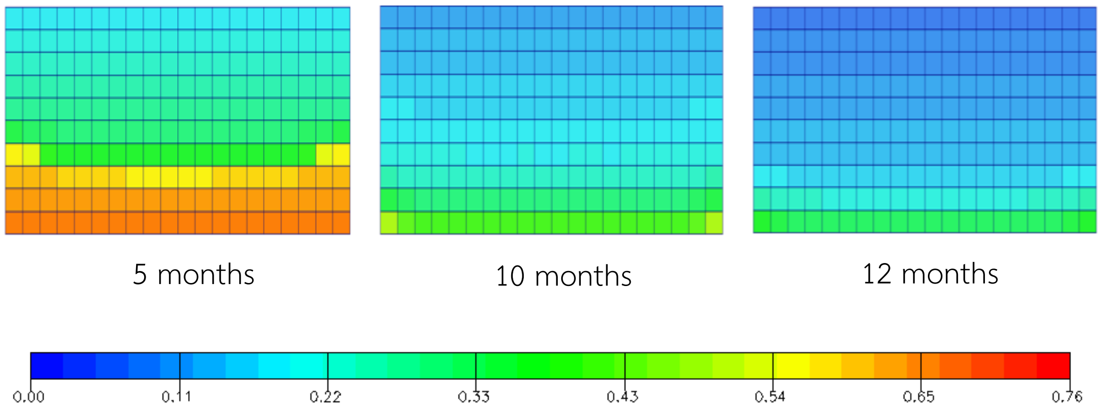


Figure A-7 Oil saturation versus time for grid plane j = 11: Horizontal production well under natural depletion at 1500 stb/d (xz plane view)

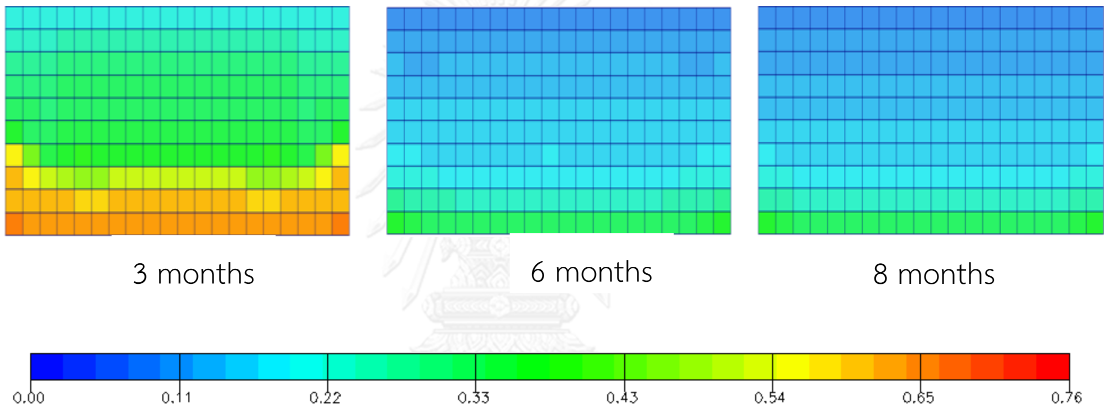


Figure A-8 Oil saturation versus time for grid plane j = 11: Horizontal production well under natural depletion at 2000 stb/d (xz plane view)

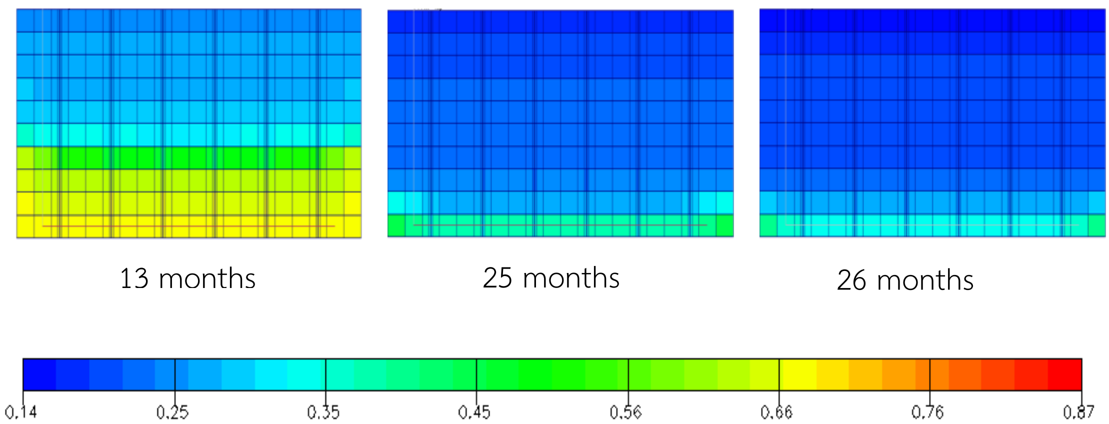


Figure A-9 Oil saturation versus time for grid plane j = 11: Fracture horizontal production well under natural depletion at 800 stb/d (xz plane view)

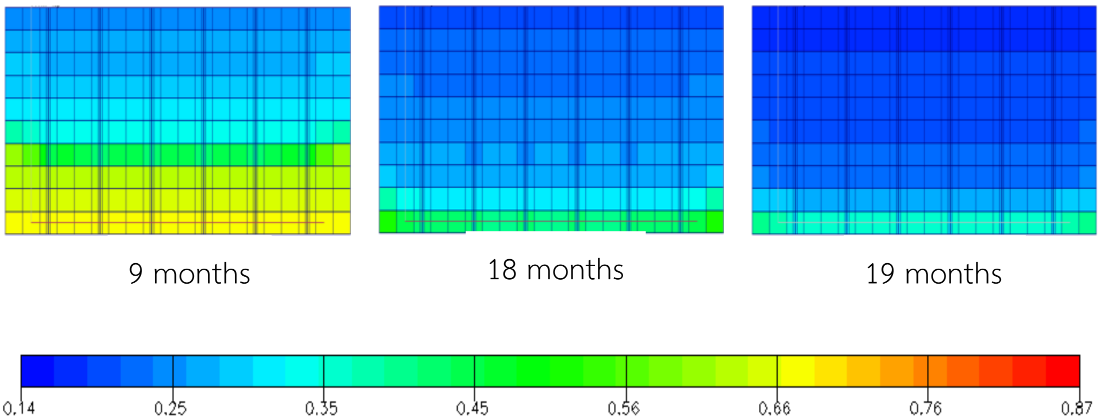


Figure A-10 Oil saturation versus time for grid plane j = 11: Fracture horizontal production well under natural depletion at 1000 stb/d (xz plane view)

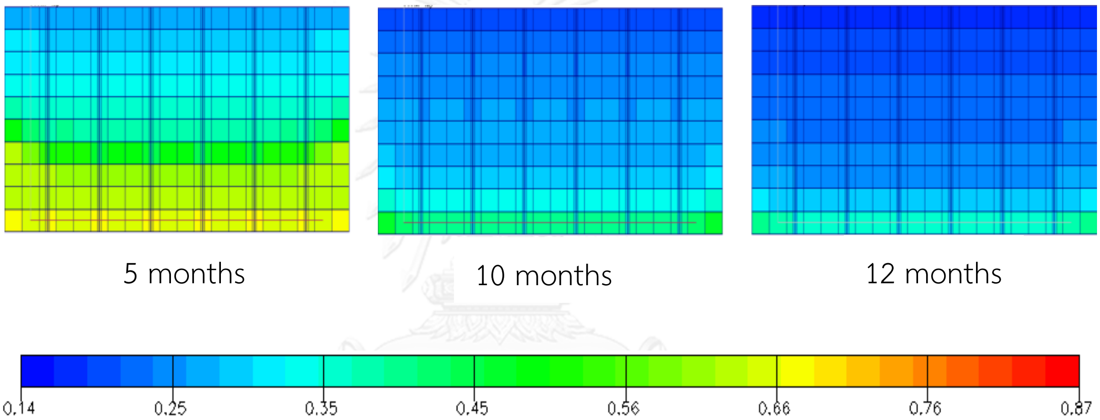


Figure A-11 Oil saturation versus time for grid plane j = 11: Fracture horizontal production well under natural depletion at 1500 stb/d (xz plane view)

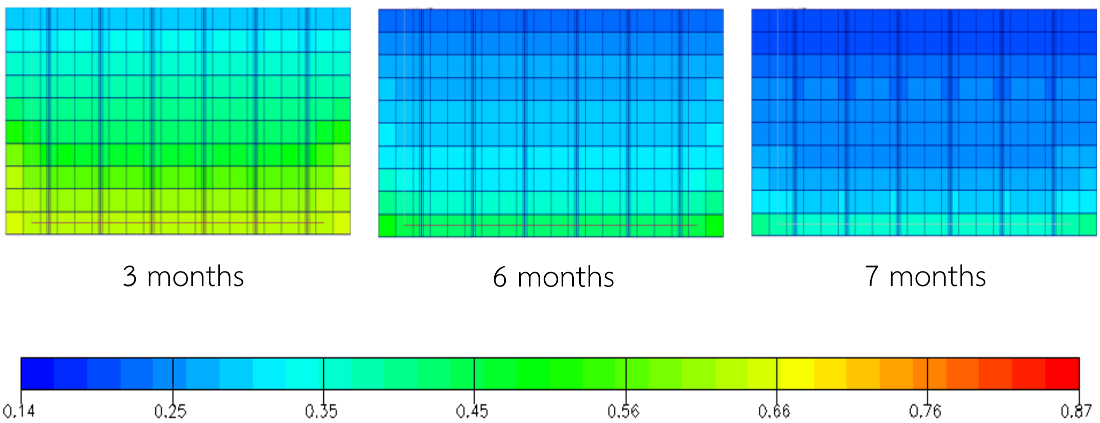


Figure A-12 Oil saturation versus time for grid plane j = 11: Fracture horizontal production well under natural depletion at 2000 stb/d (xz plane view)

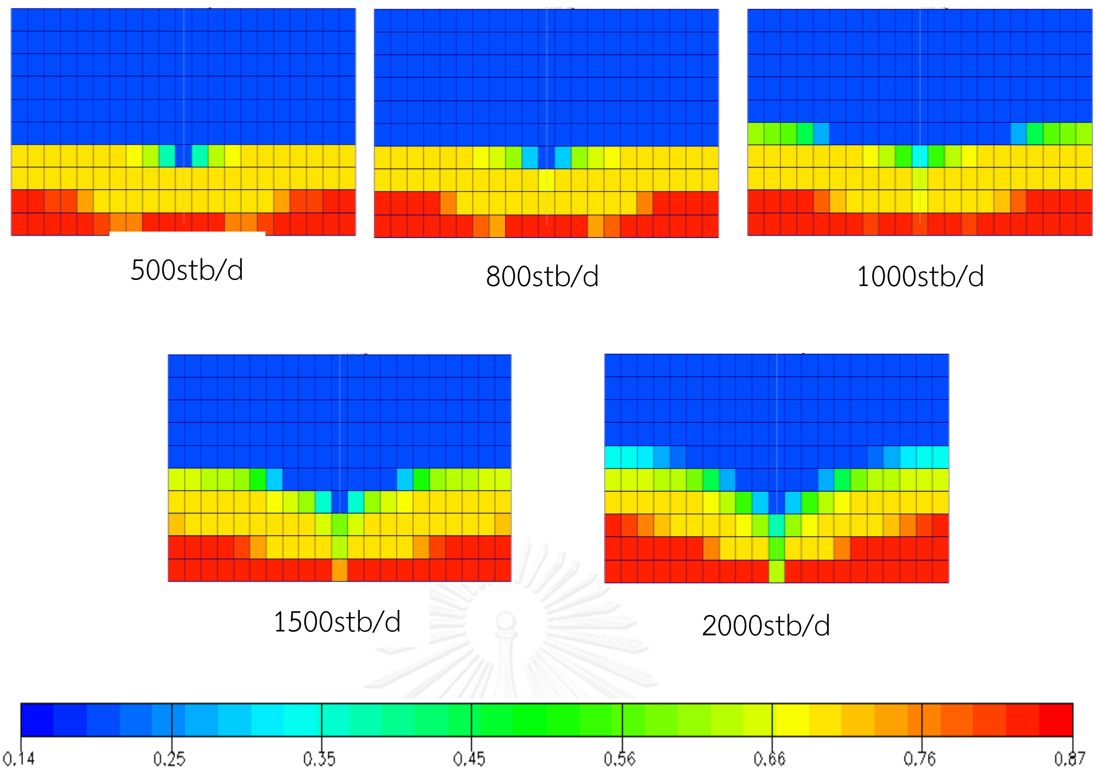


Figure A-13 Comparison of oil saturation profile for fractured plane (plane i = 7) at mid plateau production for different oil rates (yz plane view)

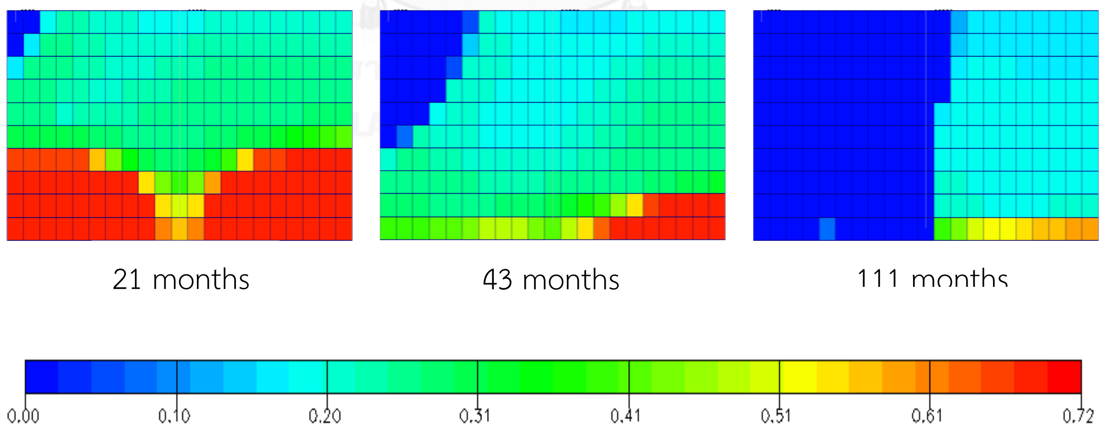


Figure A-14 Oil saturation versus time for grid plane i = 10: gas injection and vertical production well at 500 stb/d (yz plane view)

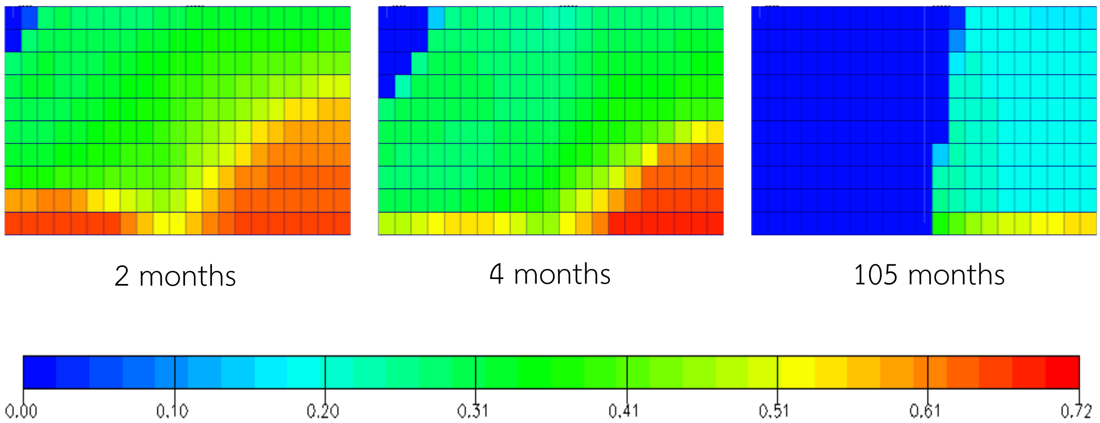


Figure A-15 Oil saturation versus time for grid plane i = 10: gas injection and vertical production well at 2000 stb/d (yz plane view)

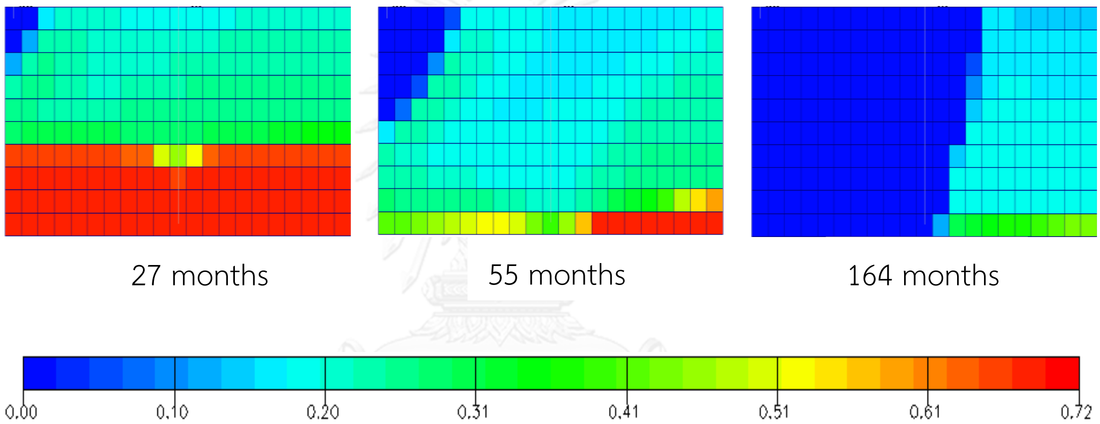


Figure A-16 Oil saturation versus time for grid plane i = 10: gas injection and horizontal production well at 500 stb/d (yz plane view)

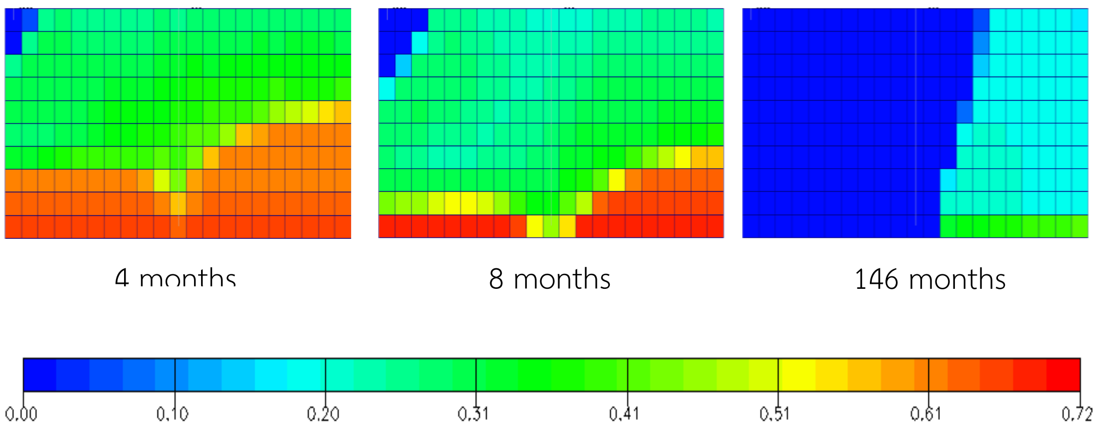


Figure A-17 Oil saturation versus time for grid plane i = 10: gas injection and horizontal production well at 2000 stb/d (yz plane view)

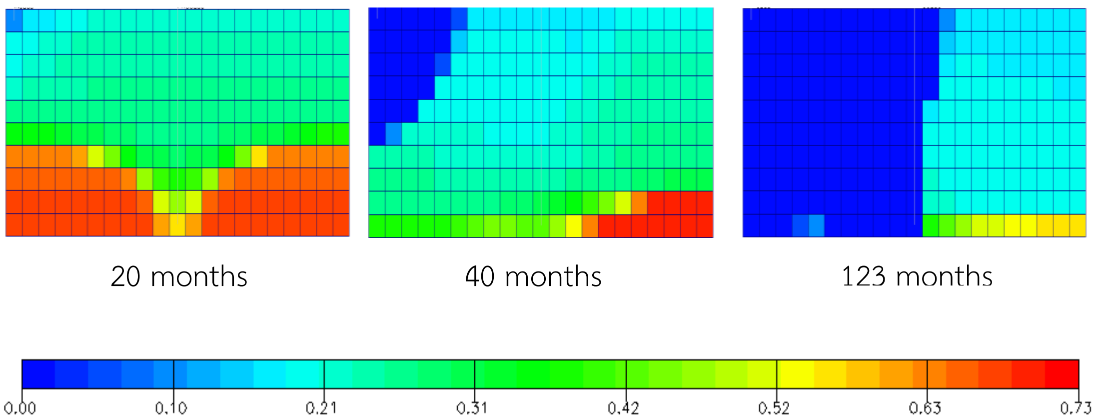


Figure A-18 Oil saturation versus time for grid plane i = 10: gas injection when P<2500 psi and vertical production well at 500 stb/d (yz plane view)

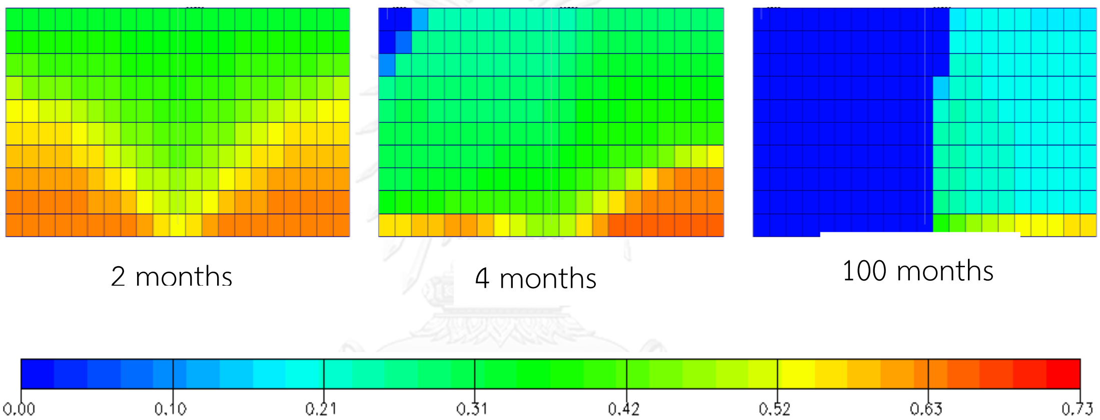


Figure A-19 Oil saturation versus time for grid plane i = 10: gas injection when P<2500 psi and vertical production well at 2000 stb/d (yz plane view)

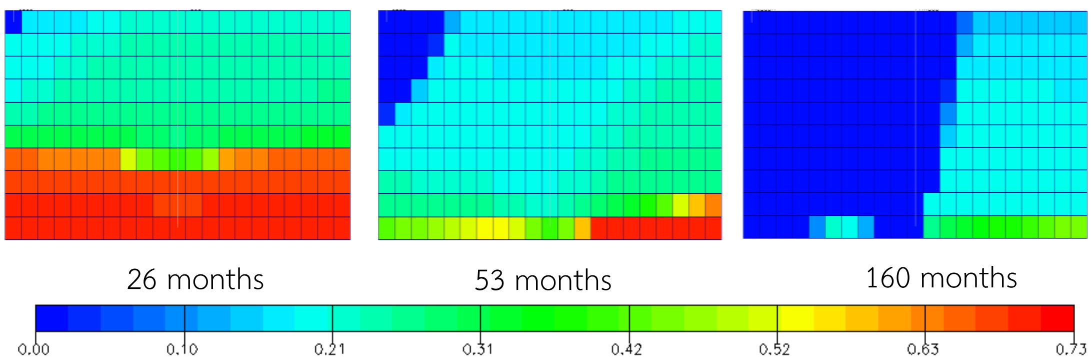


Figure A-20 Oil saturation versus time for grid plane i = 10: gas injection when P<2500 psi and horizontal production well at 500 stb/d (yz plane view)

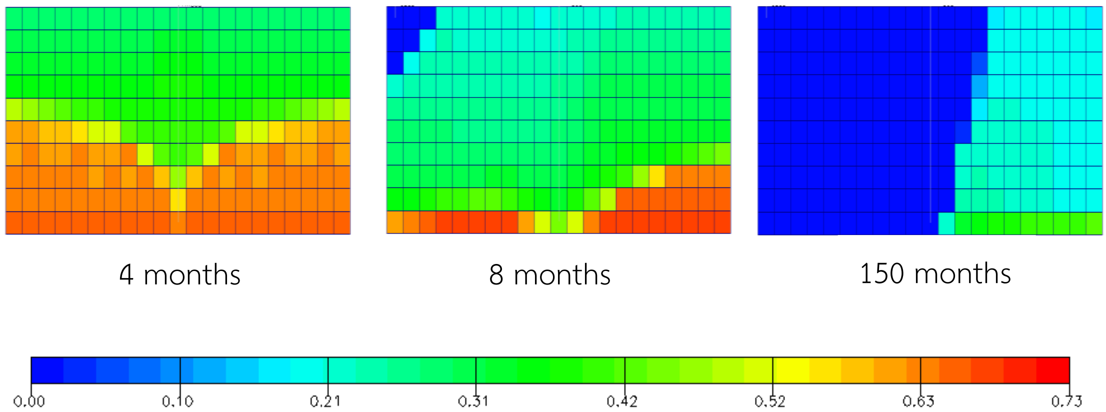


Figure A-21 Oil saturation versus time for grid plane i = 10: gas injection when P<2500 psi and horizontal production well at 2000 stb/d (yz plane view)

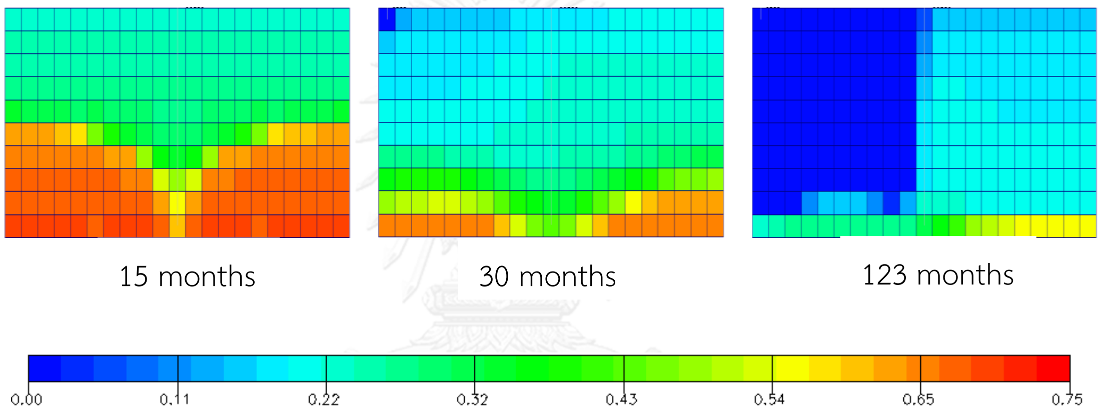


Figure A-22 Oil saturation versus time for grid plane i = 10: gas injection when P<1500 psi and vertical production well at 500 stb/d (yz plane view)

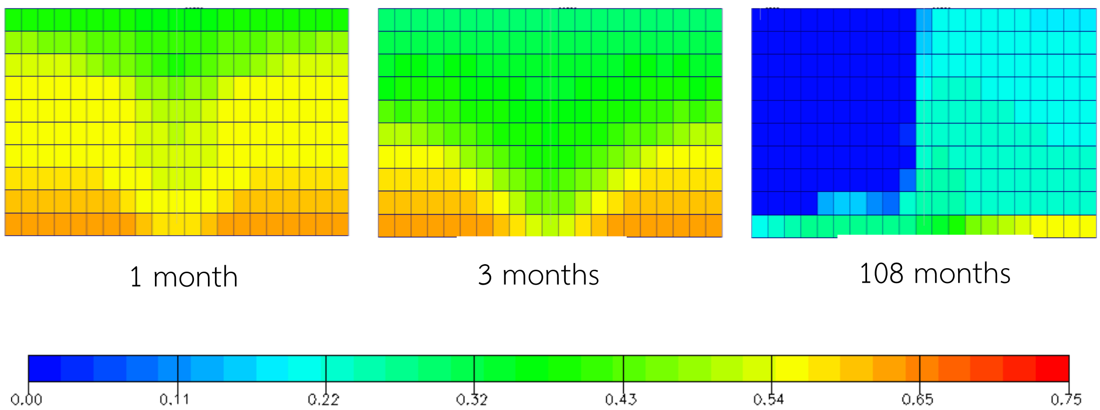


Figure A-23 Oil saturation versus time for grid plane i = 10: gas injection when P<1500 psi and vertical production well at 2000 stb/d (yz plane view)

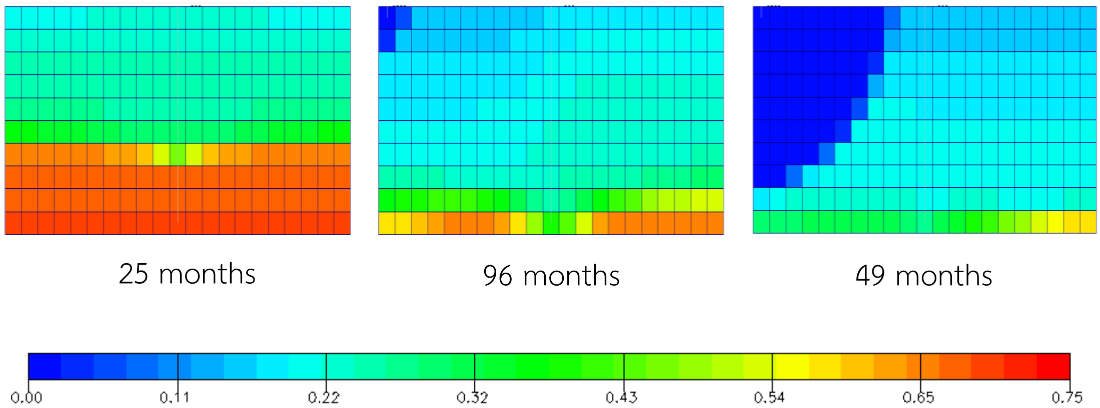


Figure A-24 Oil saturation versus time for grid plane i = 10: gas injection when P<1500 psi and horizontal production well at 500 stb/d (yz plane view)

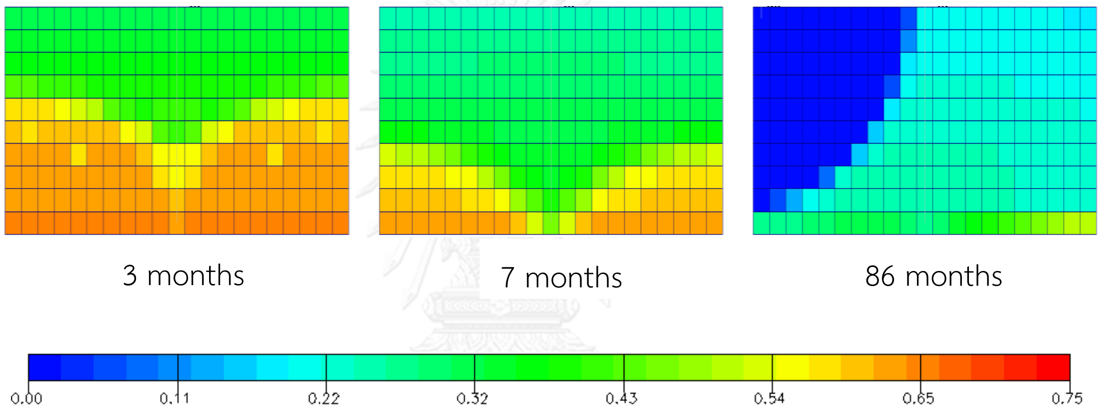


Figure A-25 Oil saturation versus time for grid plane i = 10: gas injection when P<1500 psi and horizontal production well at 2000 stb/d (yz plane view)

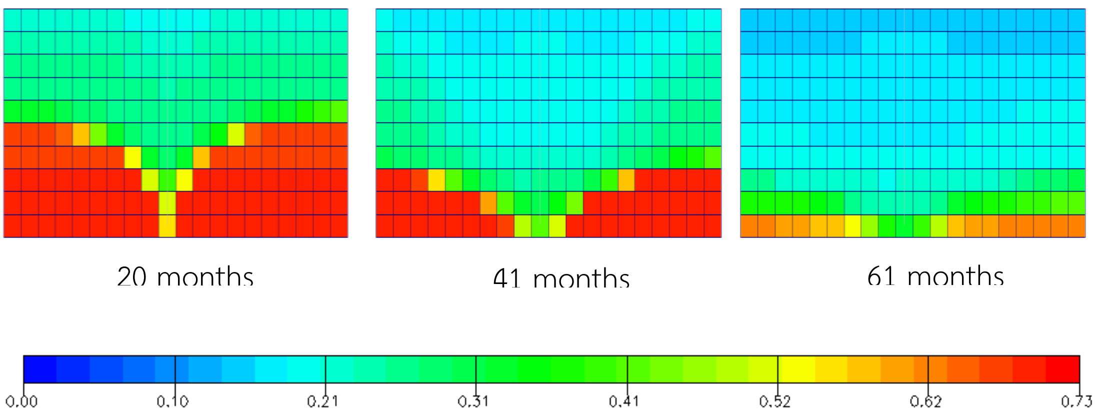


Figure A-26 Oil saturation versus time for grid plane j = 11: gas injection constrained at GOR<80 Mscf/stb and vertical production well at 500 stb/d (xz plane view)

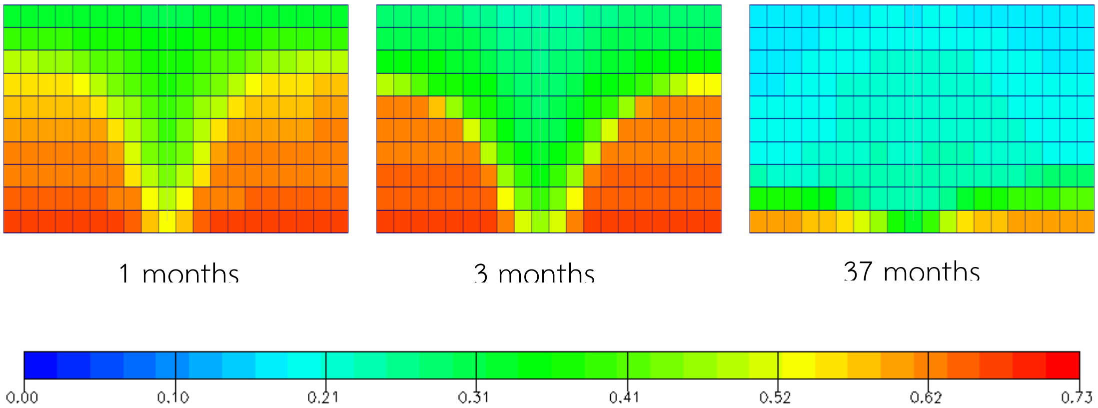


Figure A-27 Oil saturation versus time for grid plane j = 11: gas injection constrained at GOR<80 Mscf/stb and vertical production well at 2000 stb/d (xz plane view)

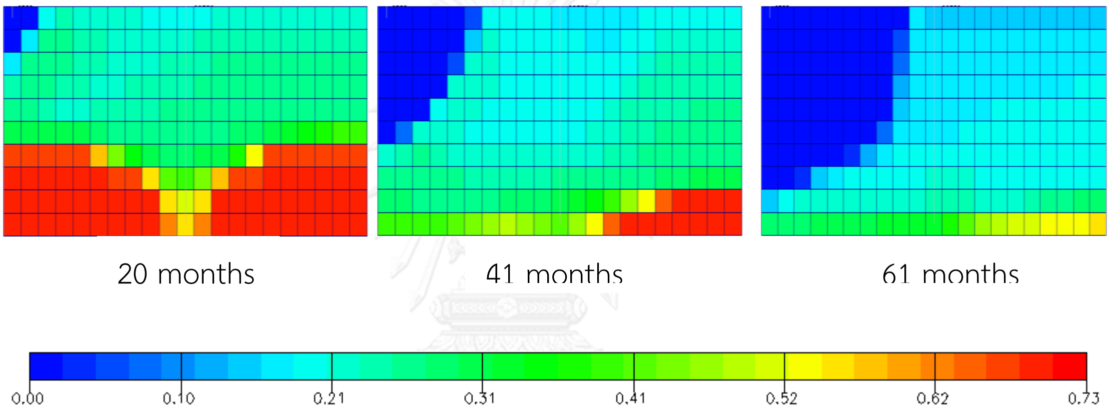


Figure A-28 Oil saturation versus time for grid plane i = 10: gas injection constrained at GOR<80 Mscf/stb and vertical production well at 500 stb/d (yz plane view)

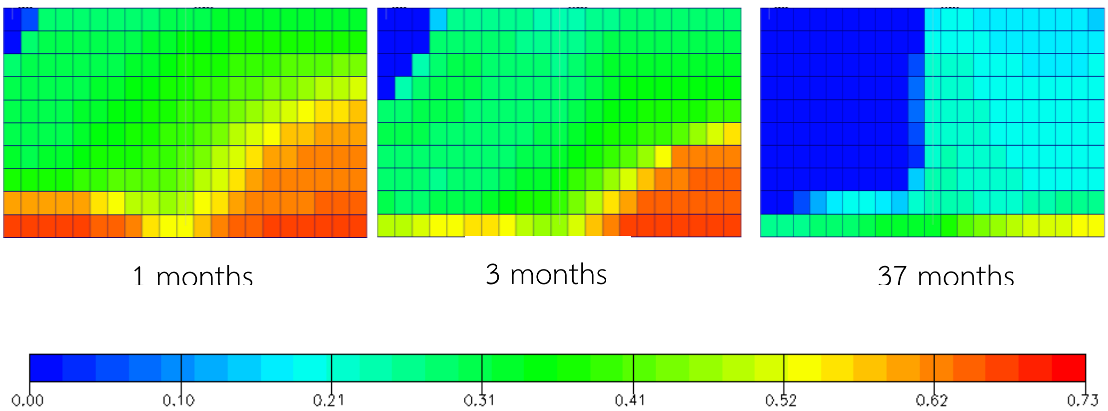


Figure A-29 Oil saturation versus time for grid plane i = 10: gas injection constrained at GOR<80 Mscf/stb and vertical production well at 2000 stb/d (yz plane view)

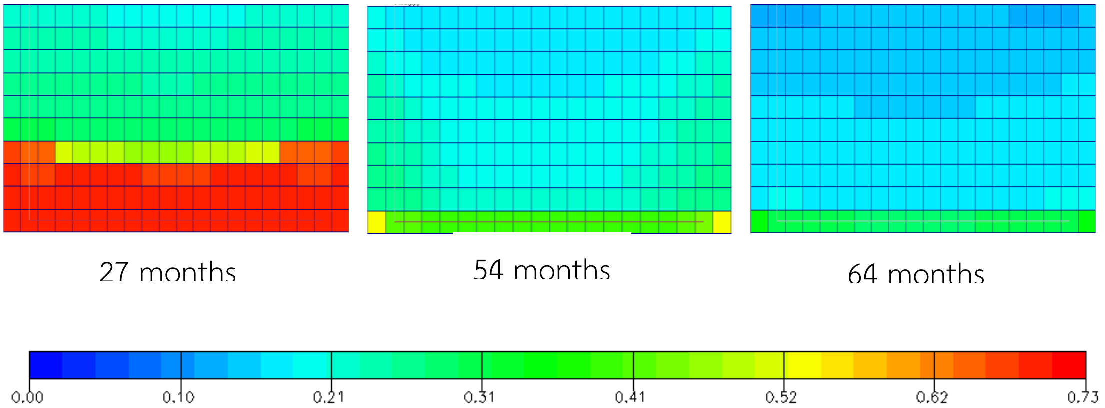


Figure A-30 Oil saturation versus time for grid plane j = 11: gas injection constrained at GOR<80 Mscf/stb and horizontal production well at 500 stb/d (xz plane view)

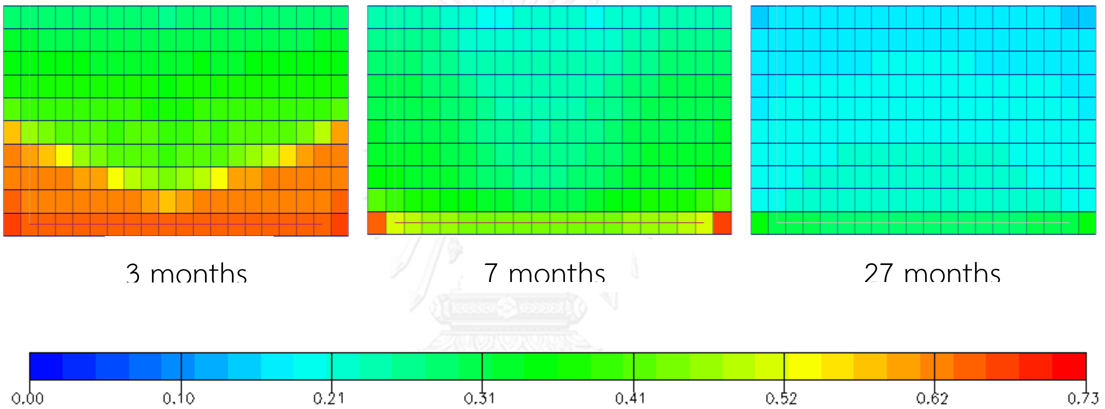


Figure A-31 Oil saturation versus time for grid plane j = 11: gas injection constrained at GOR<80 Mscf/stb and horizontal production well at 2000 stb/d (xz plane view)

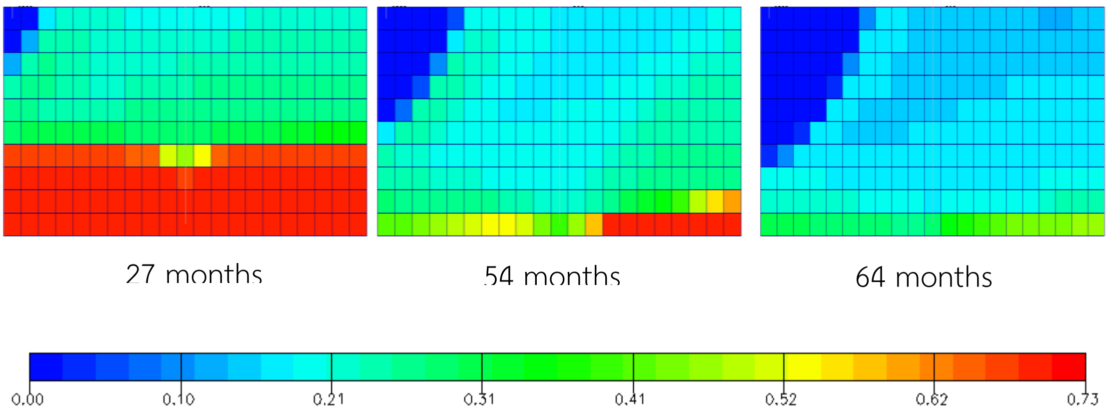


Figure A-32 Oil saturation versus time for grid plane i = 10: gas injection constrained at GOR<80 Mscf/stb and horizontal production well at 500 stb/d (yz plane view)

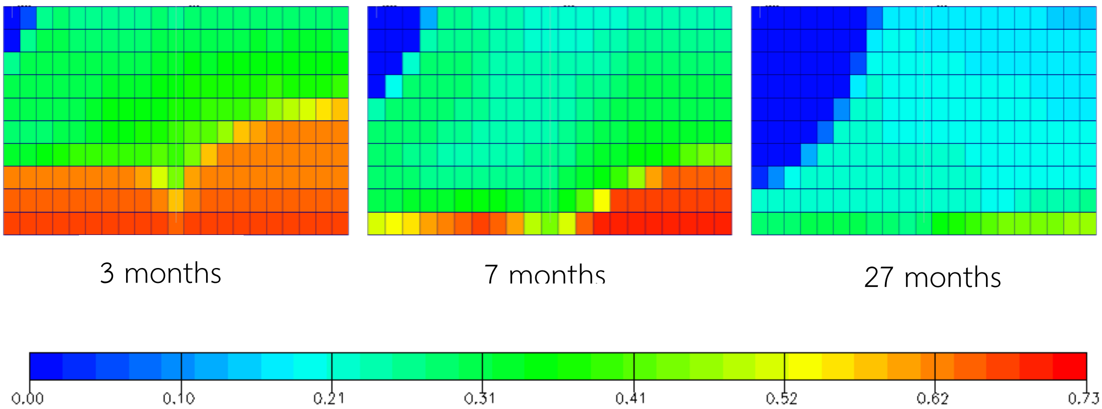


Figure A-33 Oil saturation versus time for grid plane i = 10: gas injection constrained at GOR<80 Mscf/stb and horizontal production well at 2000 stb/d (yz plane view)

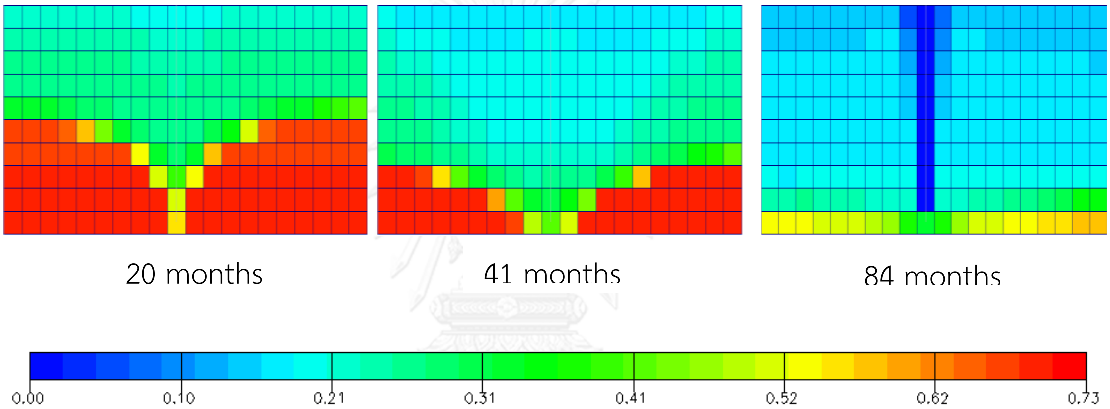


Figure A-34 Oil saturation versus time for grid plane j = 11: gas injection constrained at GOR<160 Mscf/stb and vertical production well at 500 stb/d (xz plane view)

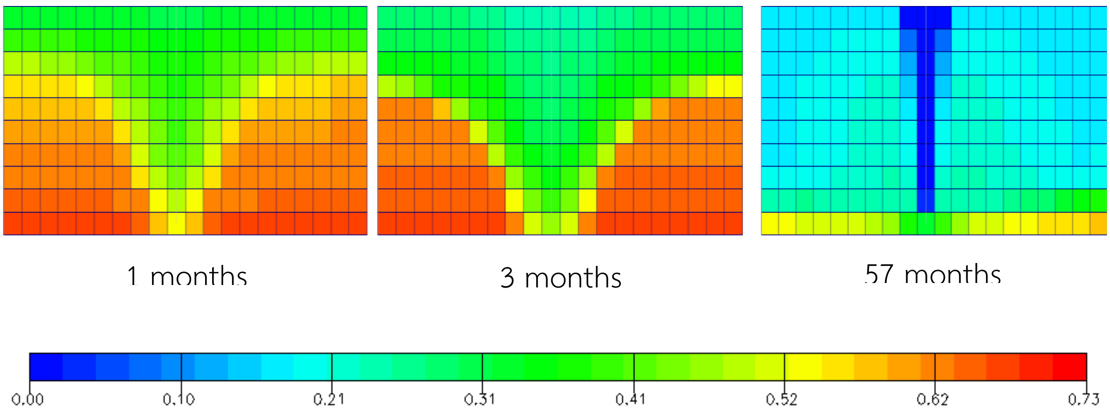


Figure A-35 Oil saturation versus time for grid plane j = 11: gas injection constrained at GOR<160 Mscf/stb and vertical production well at 2000 stb/d (xz plane view)

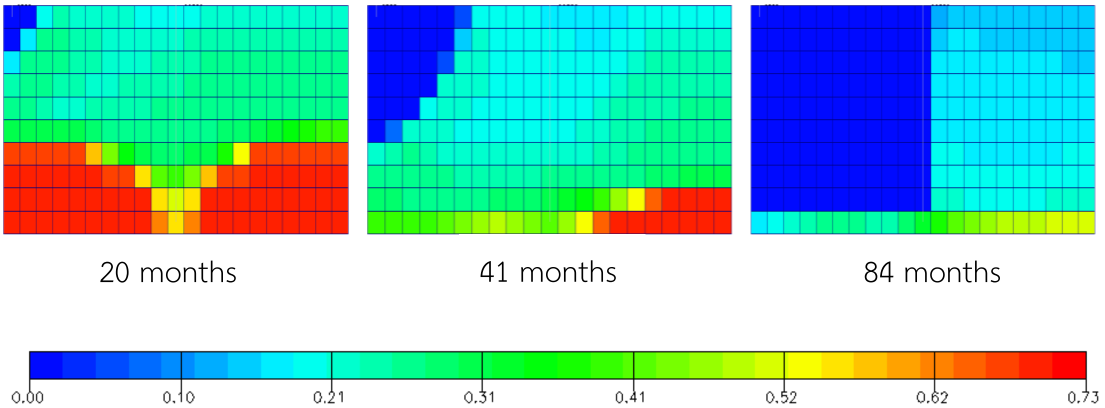


Figure A-36 Oil saturation versus time for grid plane i = 10: gas injection constrained at GOR<160 Mscf/stb and vertical production well at 500 stb/d (yz plane view)

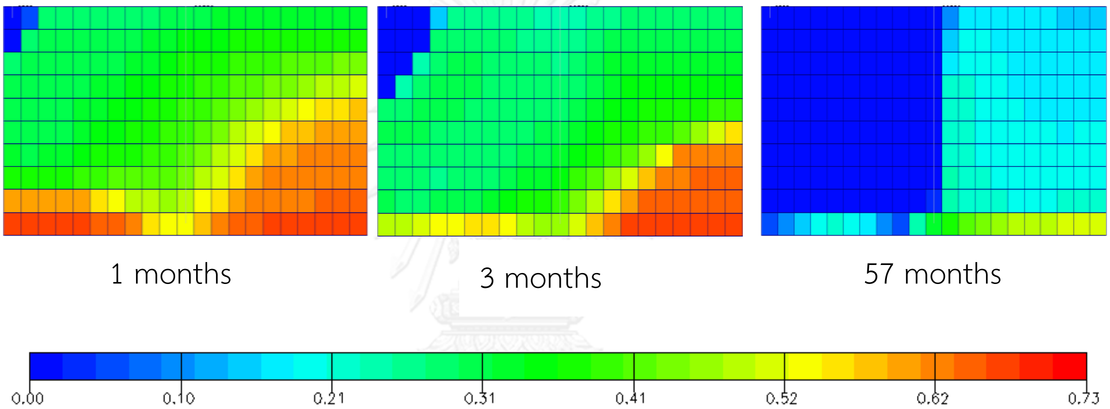


Figure A-37 Oil saturation versus time for grid plane i = 10: gas injection constrained at GOR<160 Mscf/stb and vertical production well at 2000 stb/d (yz plane view)

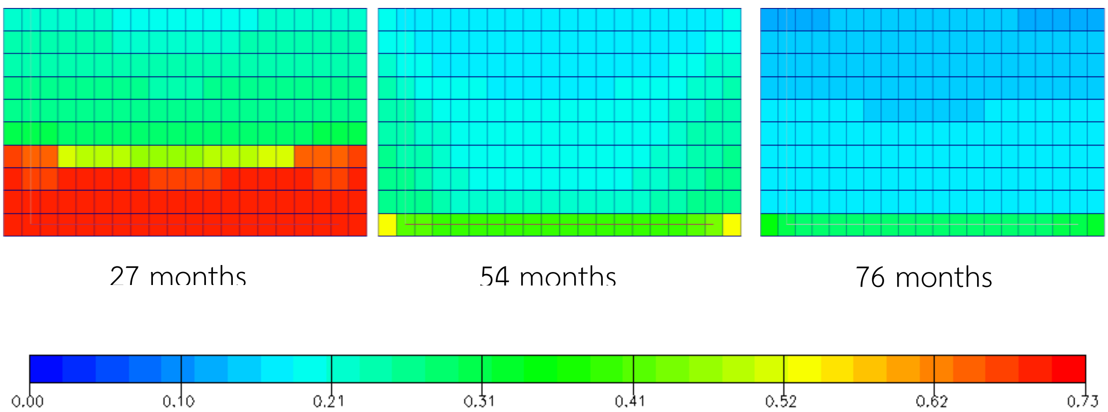


Figure A-38 Oil saturation versus time for grid plane j = 11: gas injection constrained at GOR<160 Mscf/stb and horizontal production well at 500 stb/d (xz plane view)

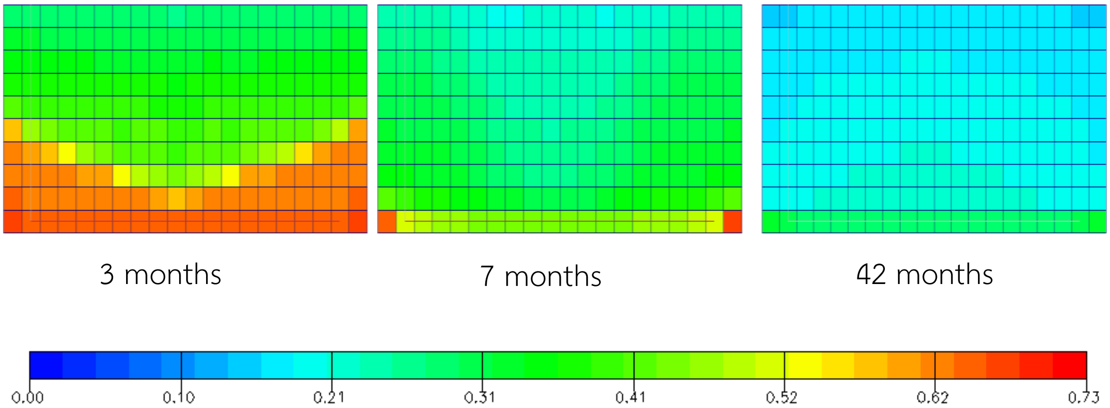


Figure A-39 Oil saturation versus time for grid plane j = 11: gas injection constrained at GOR<160 Mscf/stb and horizontal production well at 2000 stb/d (xz plane view)

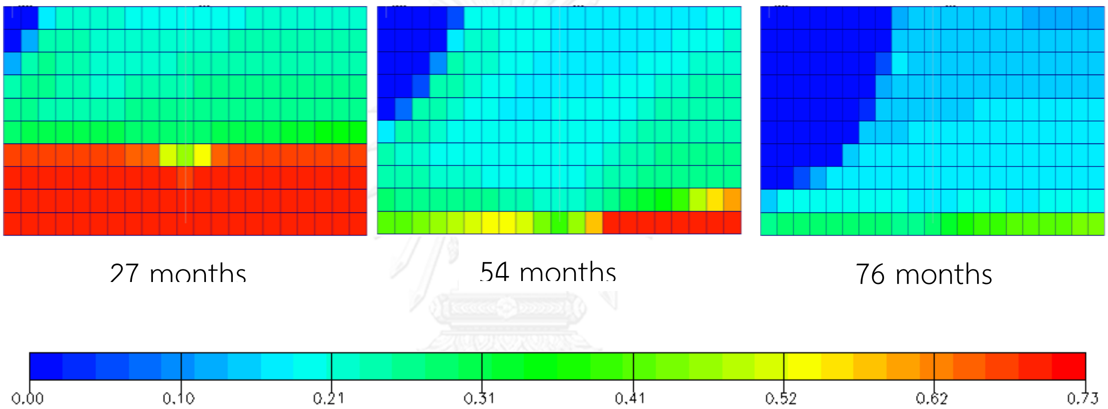


Figure A-40 Oil saturation versus time for grid plane i = 10: gas injection constrained at GOR<160 Mscf/stb and horizontal production well at 500 stb/d (yz plane view)

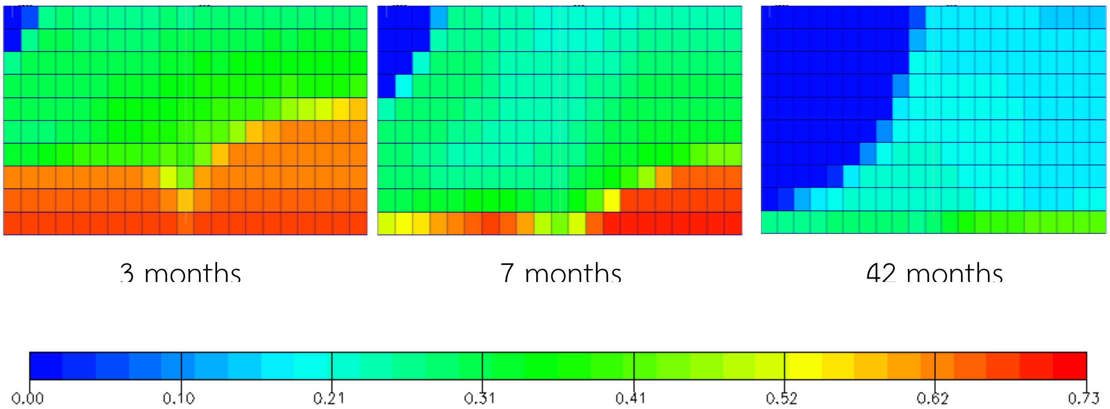
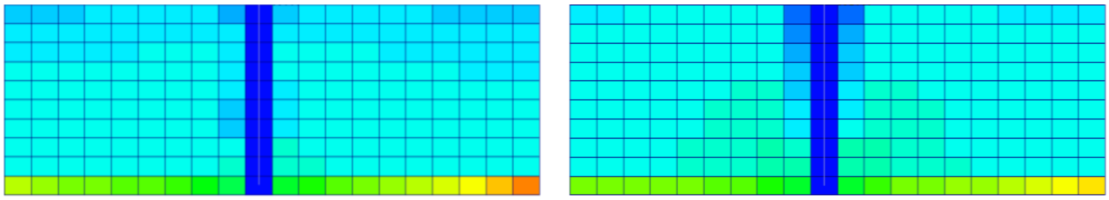
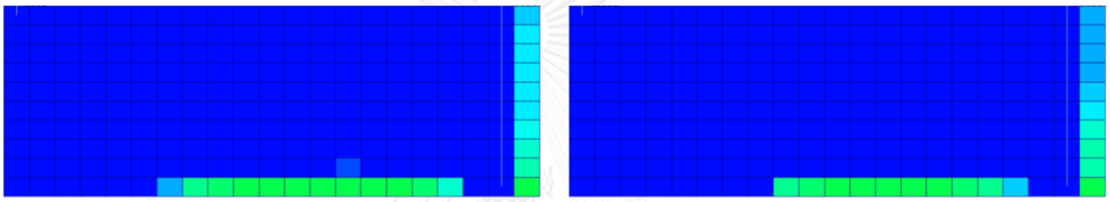


Figure A-41 Oil saturation versus time for grid plane i = 10: gas injection constrained at GOR<160 Mscf/stb and horizontal production well at 2000 stb/d (yz plane view)



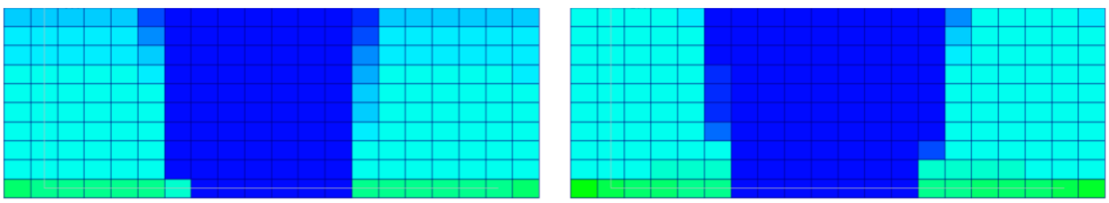
500 stb/d 2000 stb/d

Figure A-42 Oil saturation at end of production for plane j = 20: gas injection scenario and vertical production well in position 1 for different oil rates (xz plane view)



500 stb/d 2000 stb/d

Figure A-43 Oil saturation at end of production for plane i = 10: gas injection scenario and vertical production well in position 1 for different oil rates (yz plane view)



500 stb/d 2000 stb/d

Figure A-44 Oil saturation at end of production for plane j = 20: gas injection scenario and horizontal production well in position 1 for different oil rates (xz plane view)

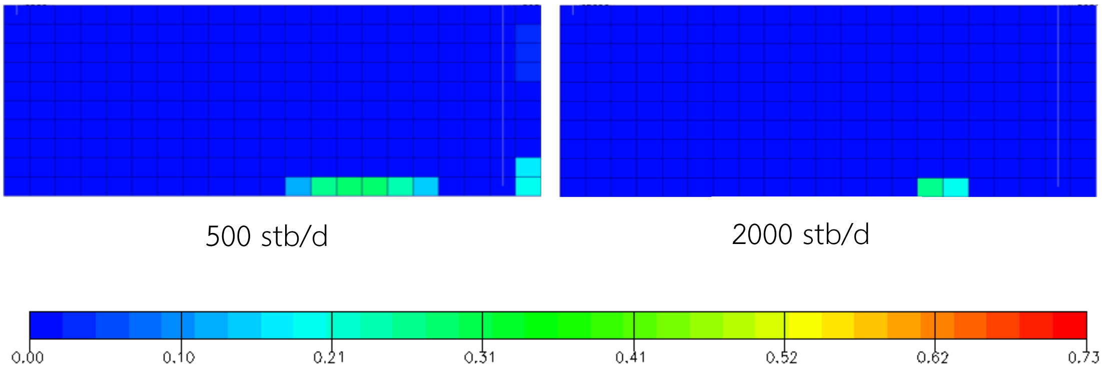


Figure A-45 Oil saturation at end of production for plane i = 10: gas injection scenario and horizontal production well in position 1 for different oil rates (yz plane view)

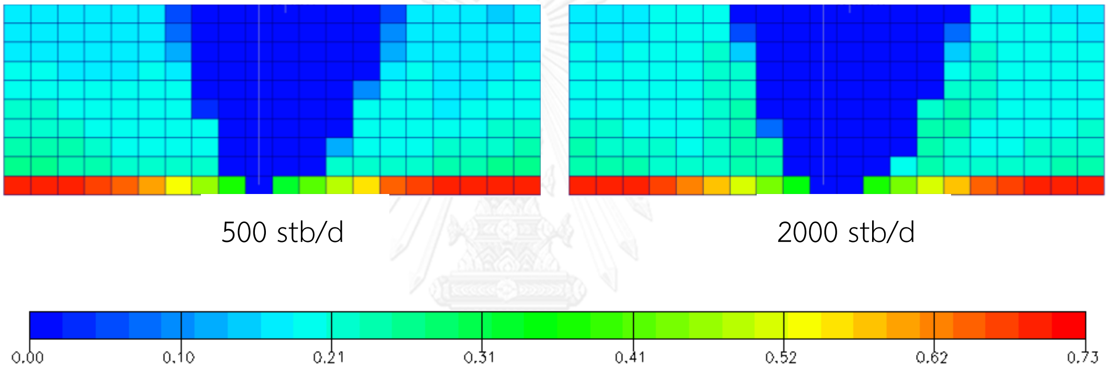


Figure A-46 Oil saturation at end of production for plane j = 11: gas injection scenario and vertical production well in position 2 for different oil rates (xz plane view)

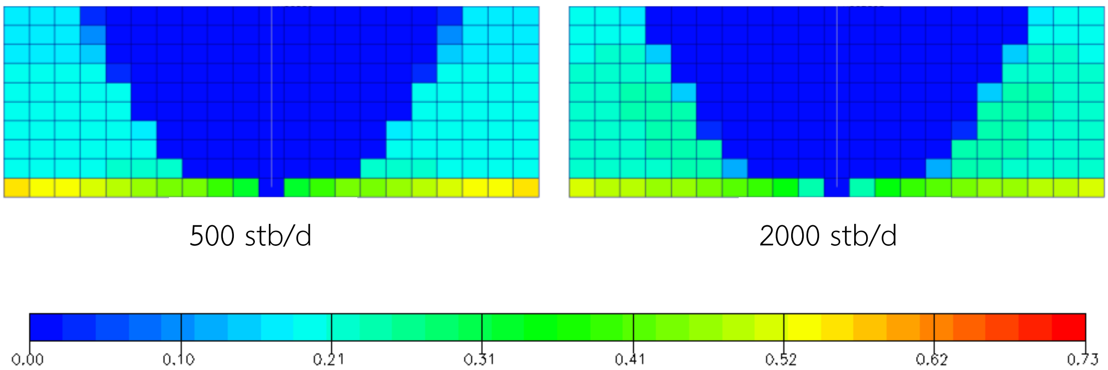


Figure A-47 Oil saturation at end of production for plane i = 10: gas injection scenario and vertical production well in position 2 for different oil rates (yz plane view)

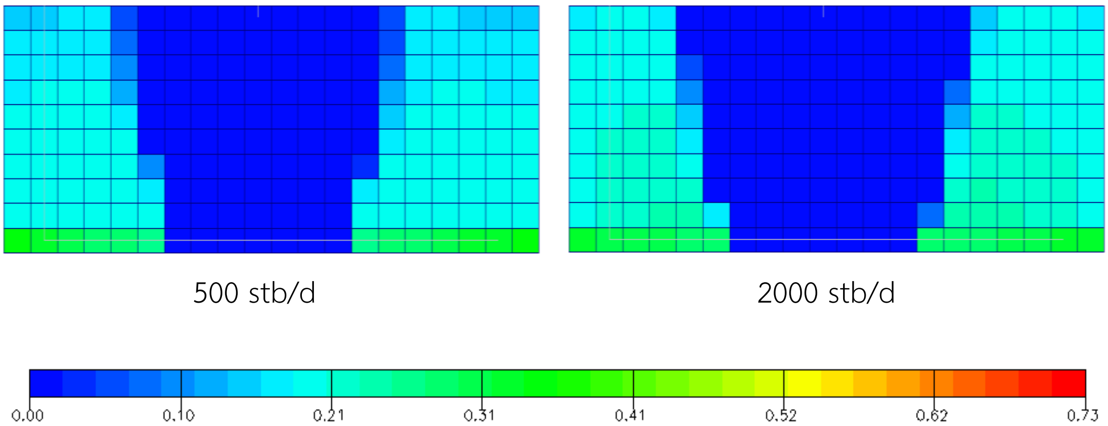


Figure A-48 Oil saturation at end of production for plane j = 11: gas injection scenario and horizontal production well in position 2 for different oil rates (xz plane view)

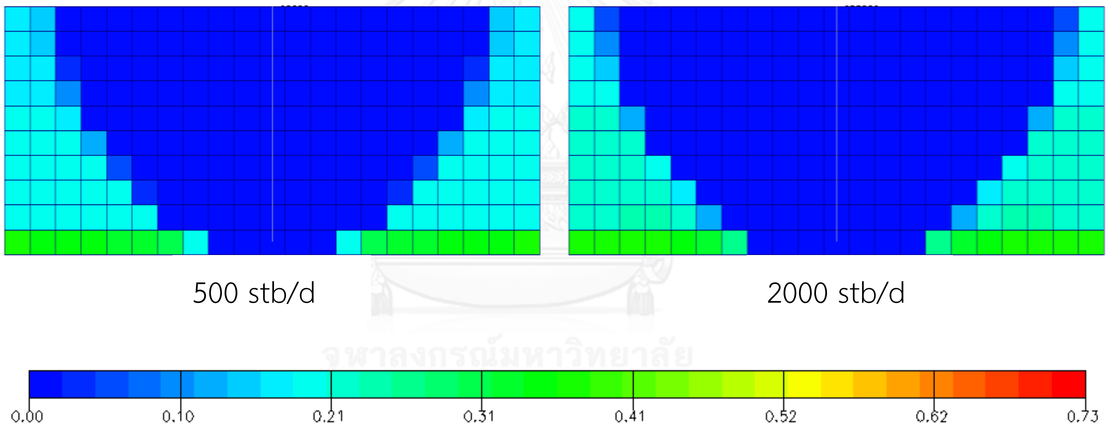


Figure A-49 Oil saturation at end of production for plane i = 10: gas injection scenario and horizontal production well in position 2 for different oil rates (yz plane view)

Appendix B

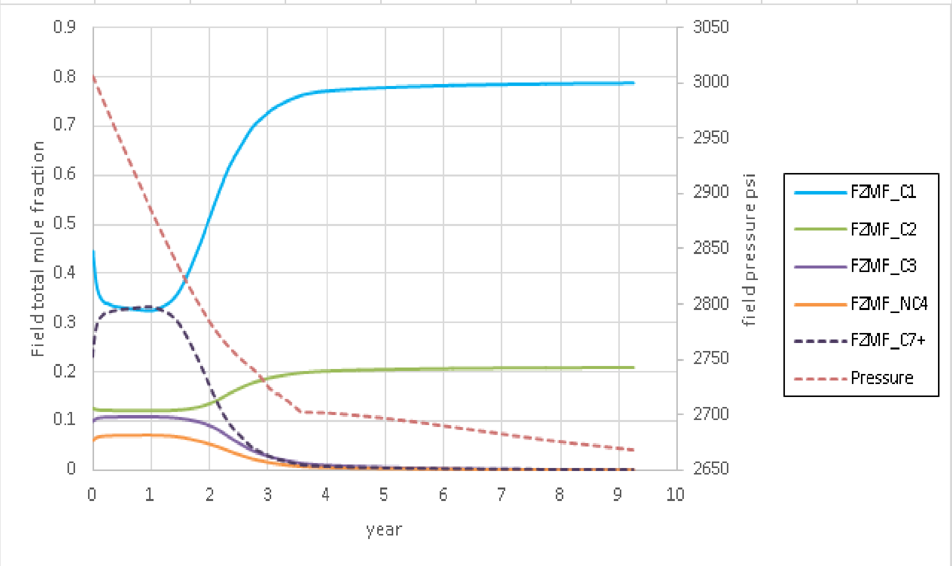


Figure B-1 Field total mole fraction and reservoir pressure vs time for the case of gas injection from the start of production using vertical well at 500 stb/d

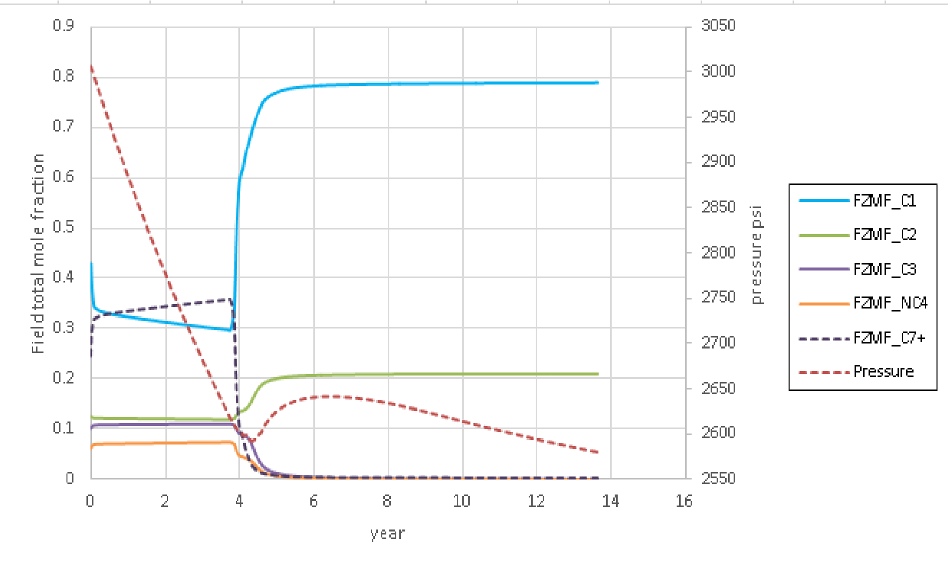


Figure B-2 Field total mole fraction and reservoir pressure vs time for the case of gas injection from the start of production using horizontal well at 500 stb/d

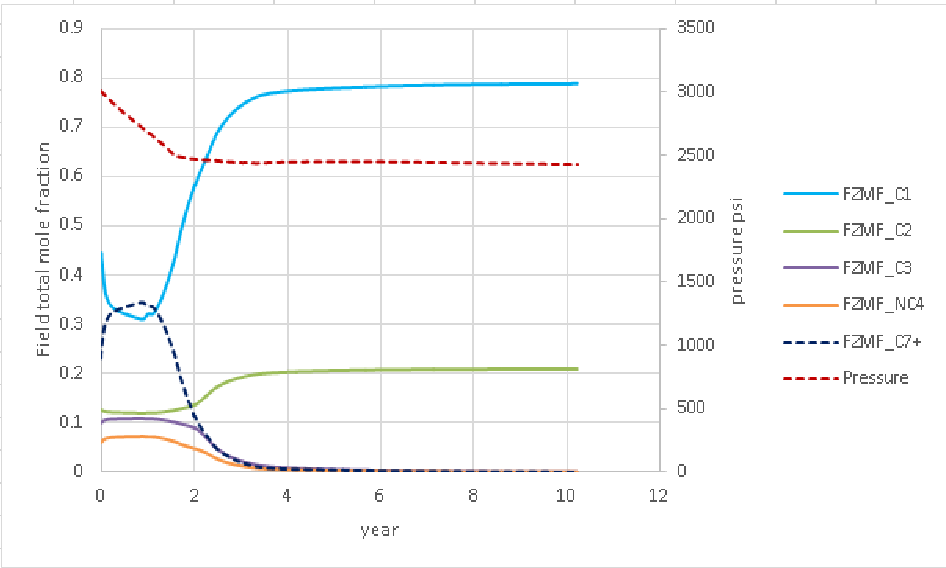


Figure B-3 Field total mole fraction and reservoir pressure vs time for the case of gas injection when pressure drops below 2500 psi using vertical well at 500 stb/d

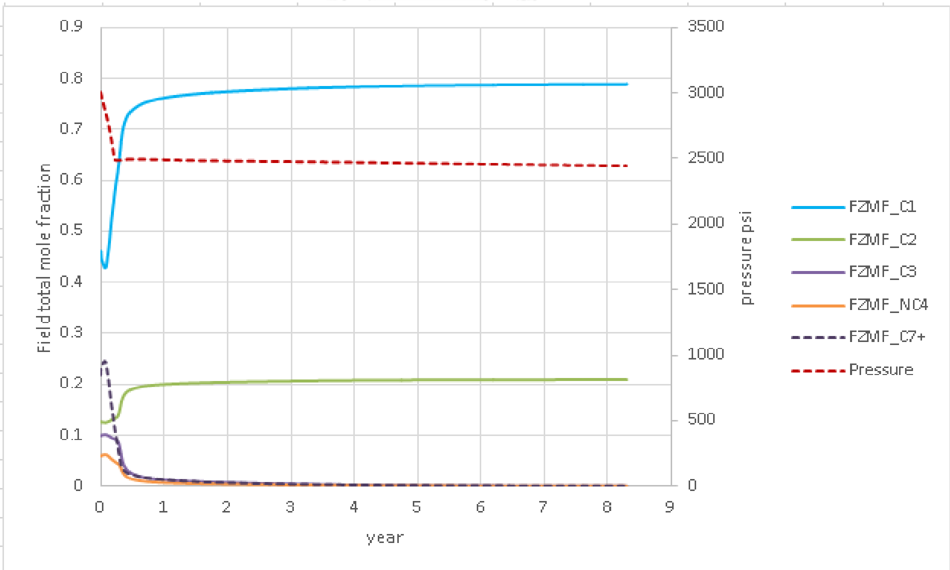


Figure B-4 Field total mole fraction and reservoir pressure vs time for the case of gas injection when pressure drops below 2500 psi using vertical well at 2000 stb/d

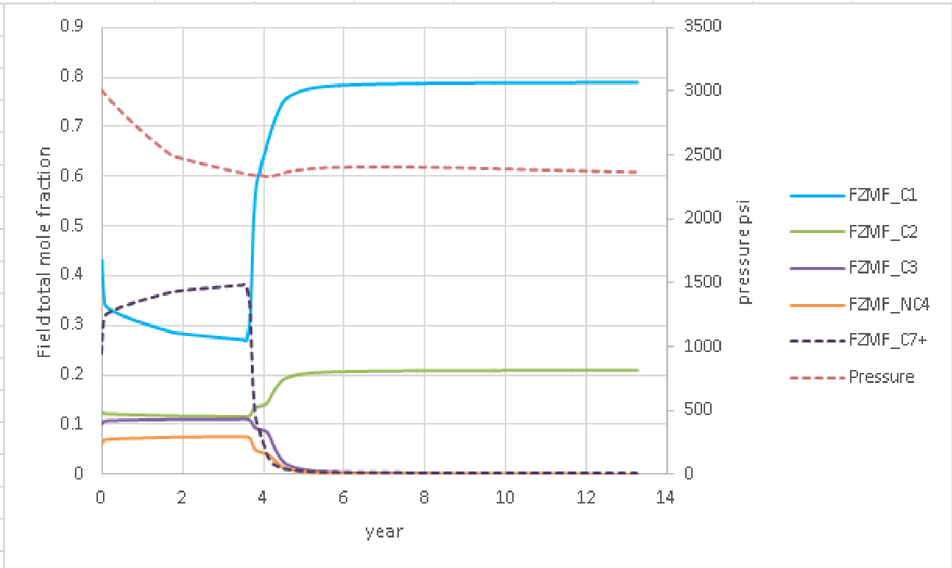


Figure B-5 Field total mole fraction and reservoir pressure vs time for the case of gas injection when pressure drops below 2500 psi using horizontal well at 500 stb/d

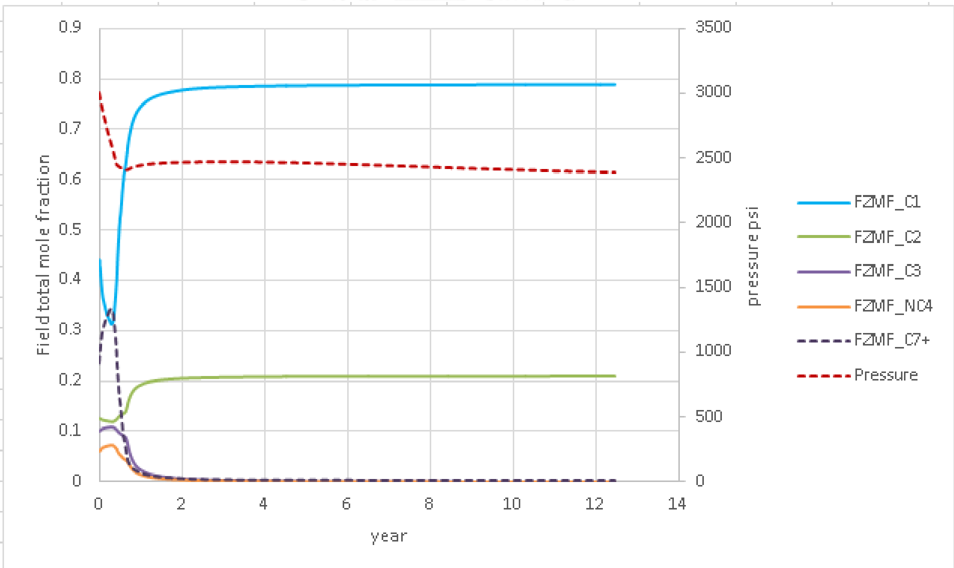


Figure B-6 Field total mole fraction and reservoir pressure vs time for the case of gas injection when pressure drops below 2500 psi using horizontal well at 2000 stb/d

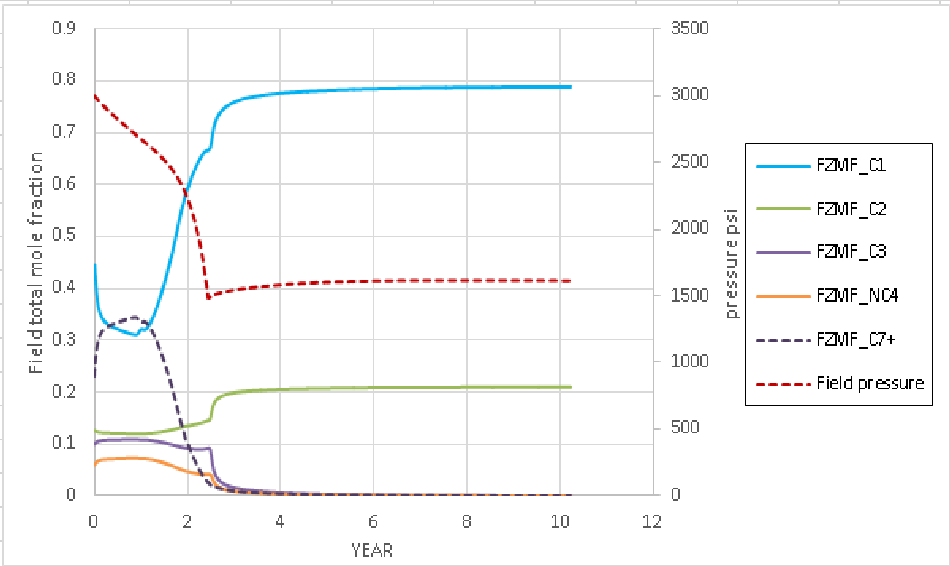


Figure B-7 Field total mole fraction and reservoir pressure vs time for the case of gas injection when pressure drops below 1500 psi using vertical well at 500 stb/d

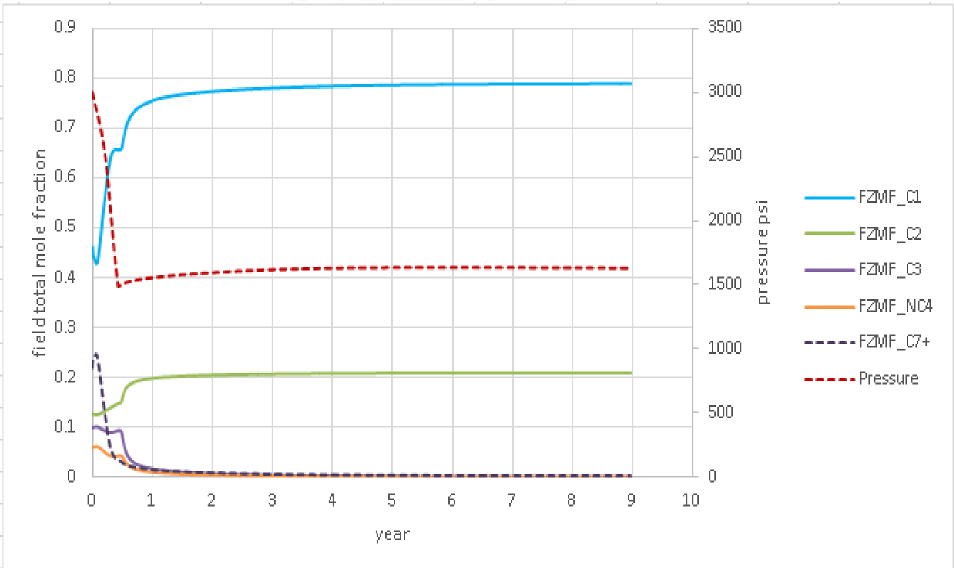


Figure B-8 Field total mole fraction and reservoir pressure vs time for the case of gas injection when pressure drops below 1500 psi using vertical well at 2000 stb/d

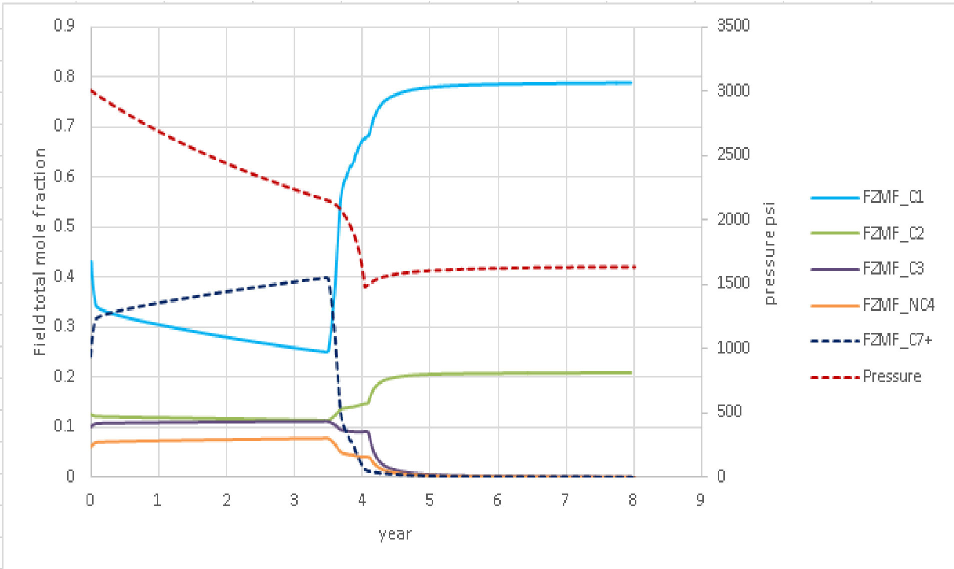


Figure B-9 Field total mole fraction and reservoir pressure vs time for the case of gas injection when pressure drops below 1500 psi using horizontal well at 500 stb/d

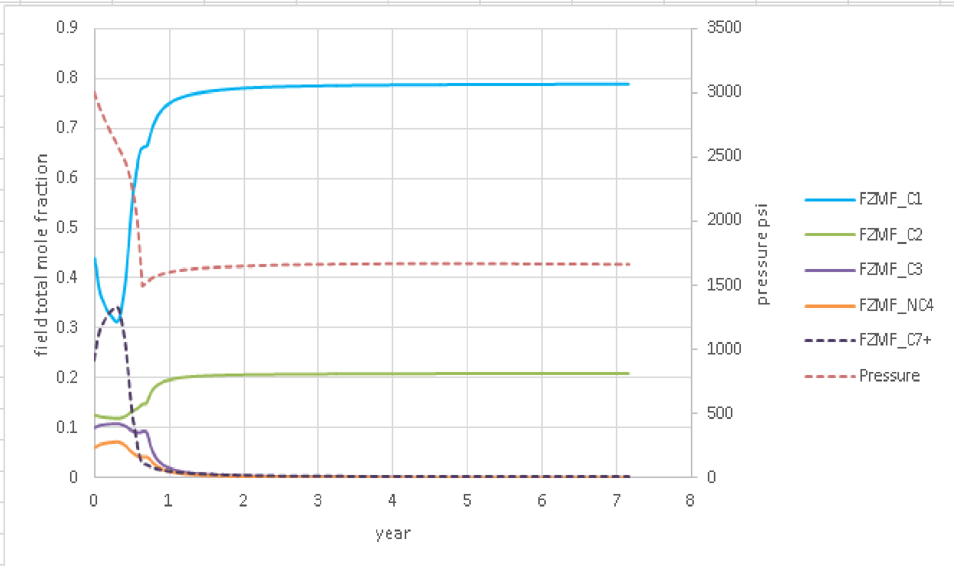


Figure B-10 Field total mole fraction and reservoir pressure vs time for the case of gas injection when pressure drops below 1500 psi using horizontal well at 2000 stb/d

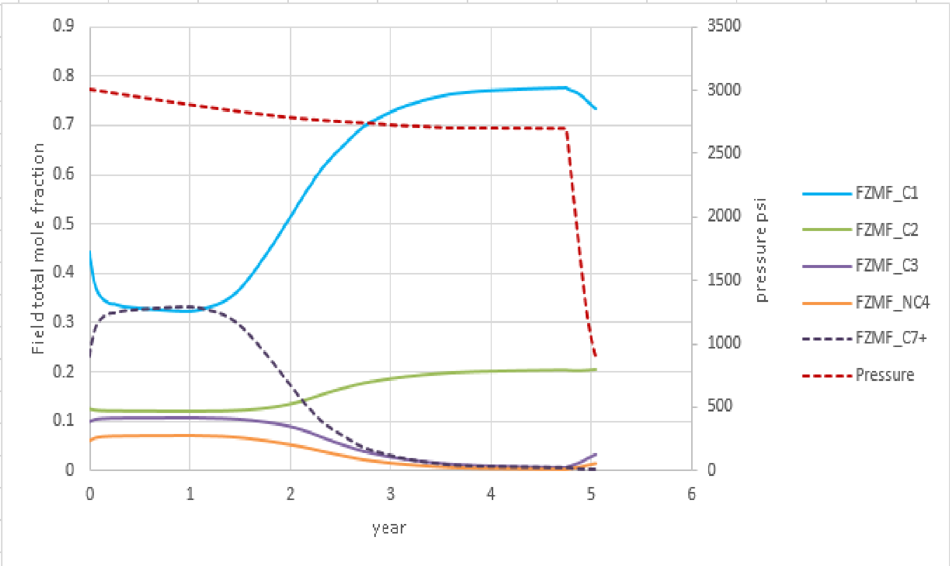


Figure B-11 Field total mole fraction and reservoir pressure vs time for the case of gas injection terminated when GOR>80 Mscf/stb using vertical well at 500 stb/d

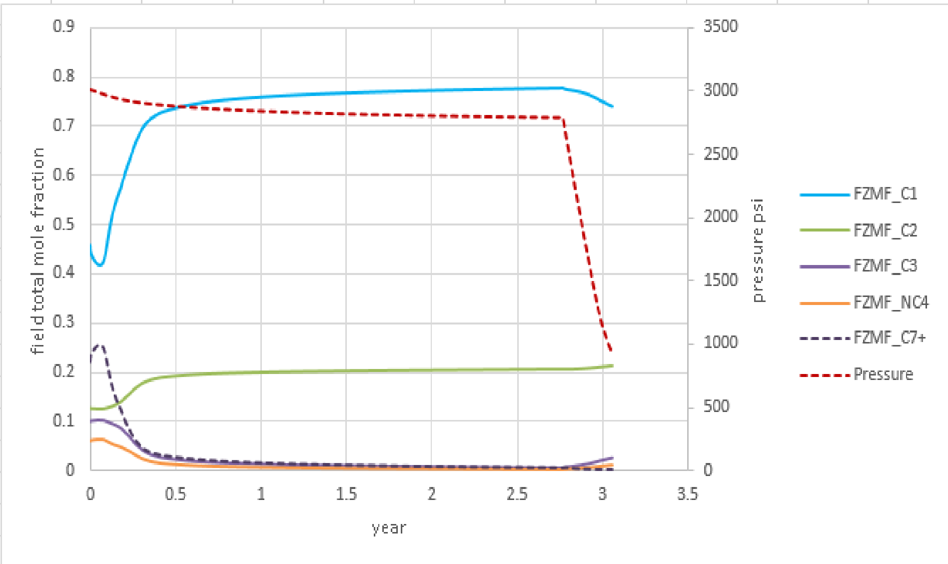


Figure B-12 Field total mole fraction and reservoir pressure vs time for the case of gas injection terminated when GOR>80 Mscf/stb using vertical well at 2000 stb/d

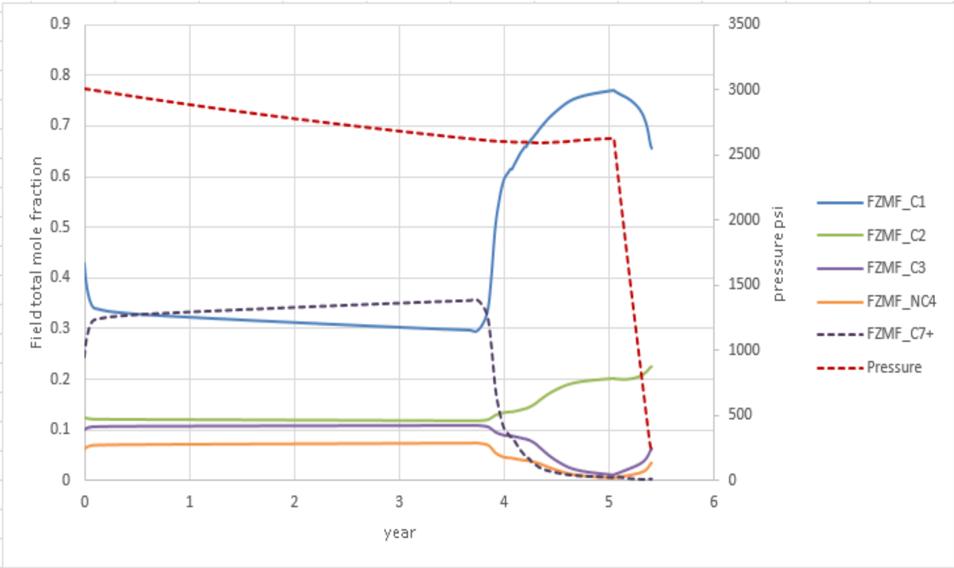


Figure B-13 Field total mole fraction and reservoir pressure vs time for the case of gas injection terminated when GOR>80 Mscf/stb using horizontal well at 500 stb/d

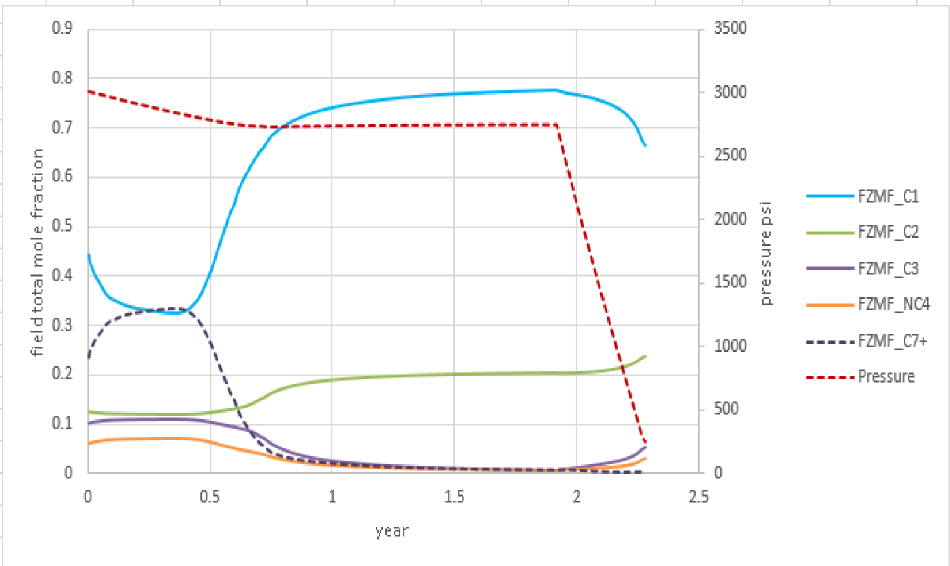


Figure B-14 Field total mole fraction and reservoir pressure vs time for the case of gas injection terminated when GOR>80 Mscf/stb using horizontal well at 2000 stb/d

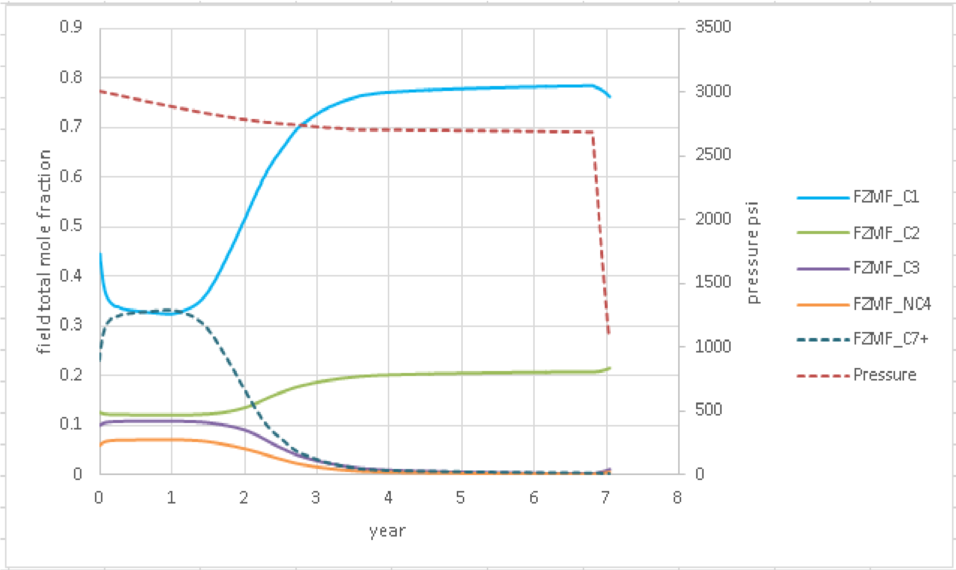


Figure B-15 Field total mole fraction and reservoir pressure vs time for the case of gas injection terminated when GOR>160 Mscf/stb using vertical well at 500 stb/d

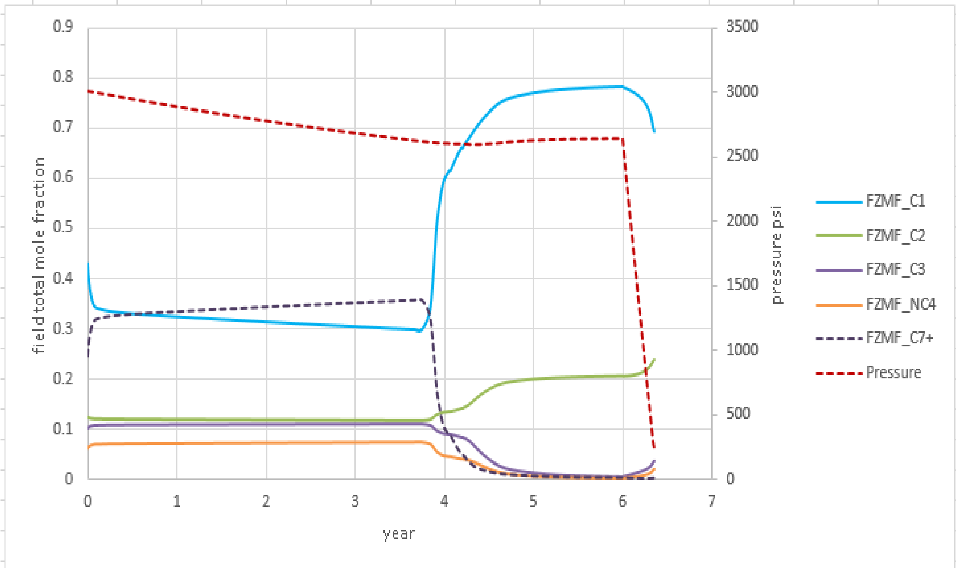


Figure B-16 Field total mole fraction and reservoir pressure vs time for the case of gas injection terminated when GOR>160 Mscf/stb using horizontal well at 500 stb/d

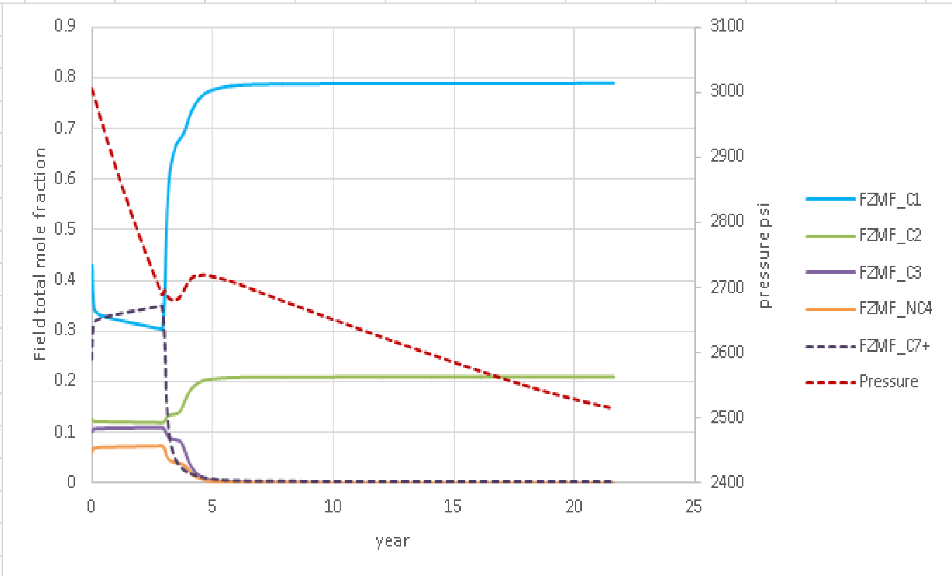


Figure B-17 Field total mole fraction and reservoir pressure vs time for the case of gas injection with production using well position 1 using horizontal well at 500 stb/d

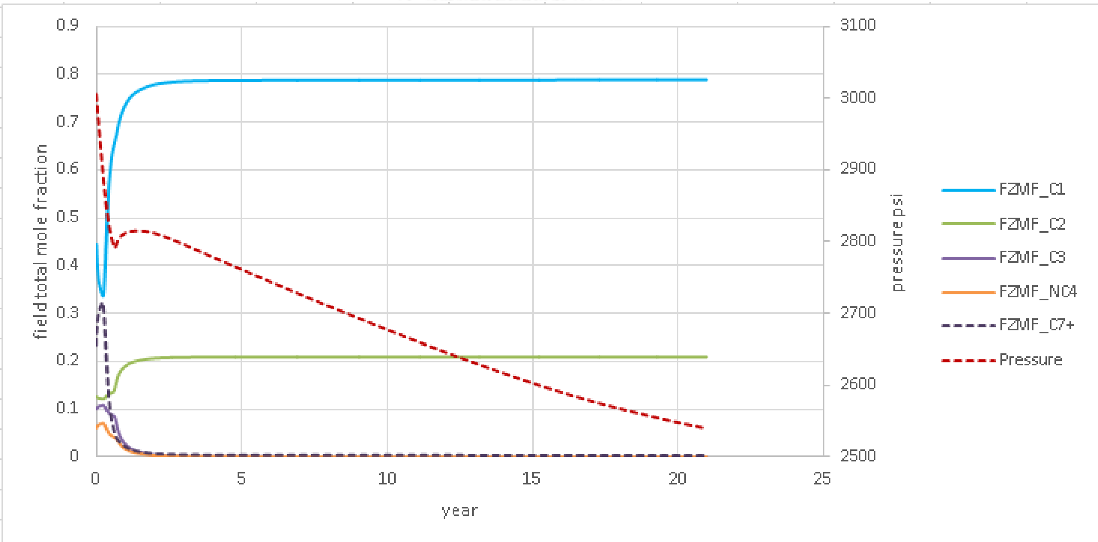


Figure B-18 Field total mole fraction and reservoir pressure vs time for the case of gas injection with production using well position 1 using horizontal well at 2000 stb/d

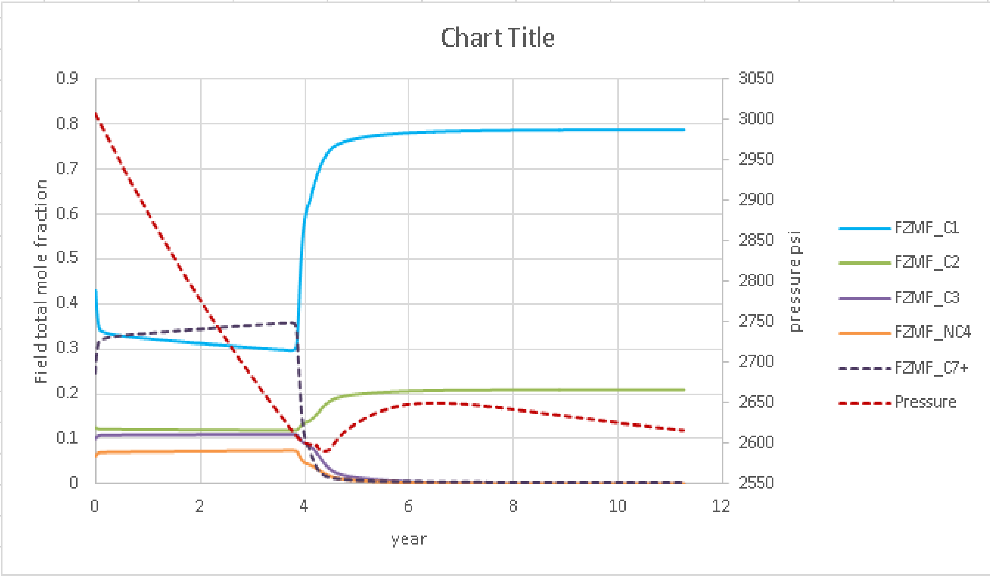


Figure B-19 Field total mole fraction and reservoir pressure vs time for the case of gas injection with production using well position 2 using horizontal well at 500 stb/d

VITA

Melaine Djomatchoua Ssianjeu was born on January 03rd, 1990 in Buba-I Tombel, Cameroon. He received his Bachelor of Science in Chemistry from the Faculty of Science, University of Buea in 2012. He worked as an English language teacher from 2013 until 2015 when he got admission to study Master of Engineering in Mining and Petroleum Engineering at the Department of Mining and Petroleum Engineering, Faculty of Engineering, Chulalongkorn University.