OPTIMAL HORIZONTAL WELL PLACEMENT IN COMBINATION DRIVE THIN OIL RIM

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การวางหลุมแนวนอนที่เหมาะสมที่สุดในชั้นน้ำมันที่บางและถูกขับเคลื่อนแบบผสม

นางสาวอิเมลดา เฟอร์นานโด มาร์เกซ

วิทยานิพนธ์นี้เป็นส่วนหนึ่งของการศึกษาตามหลักสูตรปริญญาวิศวกรรมศาสตรมหาบัณฑิต
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อิเมลดา เฟอร์นานโด มาร์เกซ : การวางหลุมแนวนอนที่เหมาะสมที่สุดในชั้นน้ำมันที่บางและถูกขับเคลื่อนแบบผสม (OPTIMAL HORIZONTAL WELL PLACEMENT IN COMBINATION DRIVE THIN OIL RIM) อ.ที่ปรึกษาวิทยานิพนธ์หลัก: สุวัฒน์ อธิชนากร, 144 หน้า.

การผลิตน้ำมันจากแหล่งกักเก็บที่มีชั้นน้ำมันที่บางเป็นสิ่งที่ท้าทายในอุตสาหกรรมน้ำมัน เนื่องจากมีปัญหาจากการเข้ามาของแก๊สและน้ำในหลุมผลิตอย่างรวดเร็วซึ่งส่งผลให้การผลิตน้ำมันได้ต่ำกว่าอัตราการผลิตที่คุ้มค่าในเชิงพาณิชย์ แหล่งกักเก็บที่มีชั้นน้ำมันที่บางโดยส่วนมากจะอยู่ระหว่างชั้นแก๊สด้านบนและชั้นน้ำด้านล่าง ที่ผ่านมาได้มีการศึกษาและประยุกต์ใช้วิธีการในการพัฒนาแหล่งกักเก็บที่มีชั้นน้ำมันที่บาง เช่น การผลิตน้ำมันและแก๊สพร้อมกันเช่นเดียวกับการระบายแก๊สหลังจากมีการผลิตน้ำมัน เนื่องจากแหล่งกักเก็บที่มีชั้นน้ำมันที่บางไวต่อการเข้ามาของแก๊สและน้ำ หลุมผลิตในแนวนอนจึงถูกนำมาใช้ในการเพิ่มประสิทธภาพในการผลิตน้ำมันและยังทำให้การเข้ามาของแก๊สและน้ำลดลง

เพื่อที่จะเพิ่มประสิทธภาพในการผลิตน้ำมันในแหล่งกักเก็บที่เป็นชั้นน้ำมันที่บาง การศึกษานี้ได้ศึกษาถึงตำแหน่งของหลุมผลิตในแนวนอนและอัตราการผลิตว่ามีผลอย่างไรต่อการผลิตน้ำมันในแหล่งกักเก็บที่มีชั้นน้ำมันที่บางซึ่งมีความหนา 70 ฟุตที่มีขนาดของชั้นแก๊สและชั้นน้ำแตกต่างกันโดยการใช้โปรแกรมจำลองเชิงตัวเลขของแหล่งกักเก็บ (โปรแกรม ECLIPSE 100) ผลการศึกษาแสดงให้เห็นว่าขนาดชั้นแก๊สและความแรงของชั้นน้ำมีความสำคัญต่อการเพิ่มการผลิตน้ำมัน โดยทั่วไปแล้วหลุมควรตั้งอยู่ที่ครึ่งล่างของชั้นน้ำมันที่บาง เมื่อชั้นแก๊สมีอิทธิพลมากกว่าน้ำ และควรตั้งหลุมที่ครึ่งบนของชั้นน้ำมันที่บาง เมื่อการพยุงของชั้นน้ำมีอิทธิพลมากกว่าการขยายตัวของชั้นแก๊ส สำหรับชั้นน้ำที่มีขนาดเล็กและขนาดปานกลาง (5 และ 50 เท่าของปริมาตรของรูพรุน) อัตราการผลิตที่ต่ำ ทำให้ได้ประสิทธิภาพการผลิตน้ำมันสูงที่สุด ในขณะที่ขนาดชั้นน้ำใหญ่ขึ้น (500 เท่าของปริมาตรของรูพรุน) ทำให้อัตราการผลิตสูงขึ้นส่งผลทำได้การผลิตน้ำมันสูงสุด

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Producing from thin oil rim reservoirs has always been a challenge in oil and gas industry, due to problems related with early gas and water coning that usually limit oil production below commercial rates. Most of the thin oil rim reservoirs are sandwiched between an overlain gas cap and an underlain aquifer. Strategies to develop thin oil rim have been studied and implemented such as the concurrent oil and gas production as well gas blowdown after oil recovery. As thin oil rim reservoirs are susceptible to coning or cresting of gas and water, horizontal wells are preferred with the objective of maximizing oil recovery while coning tendencies are minimized.

In order to maximize the oil recovery in these columns, this study investigates how horizontal well location and target liquid production rate affect oil recovery for different gas cap and aquifer sizes in a thin oil rim column with 70 ft thickness using a numerical reservoir simulator (ECLIPSE 100). Results show that the gas cap size and aquifer strengths play an important role on the increment of oil recovery. In general, the well should be located at the bottom half of the thin oil rim when the gas cap has stronger influence than water and at the upper half of the thin oil rim when the aquifer support is stronger than gas expansion. For small and moderate aquifer size (5 and 50 PV), small target liquid rates yields the highest oil recovery factor, while for larger aquifer size (500 PV) higher target liquid rate leads the highest oil recovery.

Department:	Mining and Petroleum Engineering	Student's Signature	....
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BSCF	Billion Standard cubic feet
cP	CentiPoise
FGPR	Field gas production rate
FOE	Field oil recovery factor
BOPD	Barrels of oil per day
FOPR	Field oil production rate
FVF	Formation volume factor
FWPR	Field water production rate
GOC	Gas-Oil Contact
GOR	Gas oil ratio
ID	Internal diameter
KOP	Kick Of Point
lb/ft^3	Pounds per cubic feet
OWC	Oil-Water Contact
ppm	Parts per million
psi	Pound per square inch
psi/m	Pounds square inch per meter
PV	Pore volume
PVT	Pressure-Volume Temperature
Rb	Reservoir barrel
RF	Recovery factor
SCAL	Special Core Analysis
SCF	Standard cubic feet
STB	Stock tank barrel
STB/D	Stock tank barrel per day
TVD	True vertical depth
WBHP	Well bottom hole pressure
$^{o}C/m$	Celsius degree per meter

NOMENCLATURE

B_o	Oil formation volume factor
k_h	Horizontal permeability
k_{rg}	Relative permeability to gas
k_{ro}	Relative permeability to oil
k_{rw}	Relative permeability to water
k_v	Vertical permeability
P_{bub}	Bubble pressure
q_o	Critical coning rate
R_s	Solution gas-oil ratio
s_{gcr}	Critical gas saturation
s_{gi}	Initial gas saturation
s_{gmin}	Minimum gas saturation
s_{org}	Residual oil saturation (relative to gas)
s_{orw}	Residual oil saturation (relative to water)
s_{wcr}	Critical water saturation
s_{wmax}	Maximum water saturation
s_{wmin}	Minimum water saturation
y_e	Half drainage length (perpendicular to horizontal well)
μ_o	Oil viscosity
ρ_g	Gas density
ρ_o	Oil density
ρ_w	Water density
$\Delta\rho$	Density difference between water-oil or oil-gas
F	Aquifer factor
i	Number of aquifer layer
L	Horizontal well length
M-Factor	Ratio between gas cap and oil volume

MSCF	Thousand Standard cubic feet
P_{ref}	Reference pressure

CHAPTER 1

INTRODUCTION

1.1 Background

Dealing with thin oil rim reservoirs that are prone to coning of gas and water has been a challenge to the field operators as most of the thin oil rim reservoirs are sandwiched between an overlain gas cap and an underlain aquifer. In this type of reservoirs, oil, the most valuable resource is produced first before gas from the gas cap. If gas is first produced, the reservoir pressure drops quickly, and gas from the solution in oil will come out reducing the volume of oil that can be produced.

In order to maximize the oil recovery in these columns, many factors have to be evaluated such as energy balance between the gas cap and the aquifer, well location and flow rate.

Many studies that were performed for developing thin oil zones proved that horizontal wells offer immense advantages over vertical wells by improving hydrocarbon recovery. This is achieved due to the large surface area of wellbore that is in contact with the formation.

As a methodology to study the reservoir performance, reservoir simulation has been adopted to evaluate, estimate and predict the performance of oil production.

This study investigates the effect of gas cap and aquifer strengths on oil recovery from a reservoir with a thin oil rim penetrated by one horizontal well using a numerical reservoir simulator model. It is conducted by varying well location and liquid production rate for different gas cap and aquifer sizes.

1.2 Objectives

The objectives of this study are:

1. To maximize oil recovery by determining suitable well location and liquid rate in thin oil rim reservoir with different combination drive mechanisms.
2. To compare the performance of the reservoir in terms of oil recovery and cumulative water among different gas cap and aquifer sizes.

1.3 Methodology outline

In this study, the following methodology was adopted:

1. Literature survey from diverse published literature related to thin oil rim reservoirs;
2. Collect necessary data in order to build reservoir model;
3. Run simulation for different cases in order to evaluate how the selected parameters affect the oil recovery factor. Such parameters are
   a) gas cap and aquifer sizes, where the term M-Factor is used to define the size of the gas cap relatively to oil volume and the aquifer is defined in terms of PV, which is the ratio between the aquifer volume and oil volume. The scenarios for the selected cases are summarized in Table 1.1.

Table 1.1 - Gas cap and aquifer sizes

M-Factor (gas cap volume/oil volume)	Aquifer size (PV)
0.5	5
	50
	500
1	5
	50
	500
2	5
	50
	500

b) well positioning along vertical direction in the thin oil rim reservoir with a fixed liquid rate of 5,000 STB/D in order to obtain the suitable well location for each gas cap size with a different aquifer size.

c) effect of liquid rate is performed at suitable well locations obtained on the study of well positioning along vertical direction with a fixed liquid rate. For each location 3 target liquid rates are selected based in oil recovery in which the middle target liquid rate leads the highest oil recovery while the first and the third are target liquid rates with a reduction and increment of 1,000 STB/D respectively.

4. Analysis and discussion of the results obtained from the simulator regarding to the suitable well location, optimal target liquid rate, performance of the reservoir in terms of oil and water production.
5. Summary of the most suitable criteria for development of the selected characteristics of thin oil rim.

1.4 Thesis outline

Chapter 1 gives a brief introduction about thin oil rim reservoirs, the objectives of the thesis and the methodology applied to conduct the study.

Chapter 2 is related with literature review where some published studies related to thin oil rim reservoirs are summarized.

Chapter 3 shows the theory and concepts of thin oil rim by describing the most important factors that have to be taken in consideration under the presence of a thin oil column.

Chapter 4 refers to the reservoir model where details about the reservoir data and fluid properties are presented. In addition, abandonment conditions are also presented.

Chapter 5 presents results and discussion of the studied parameters, optimal well location and effect of liquid rates under different combination drive mechanisms.

Chapter 6 presents the conclusions and recommendations of the present study.

CHAPTER 2

LITERATURE REVIEW

Lyare *et al*. [1] studied the effect of gas cap and aquifer strengths on optimal well location for thin oil rim reservoirs. In this study, a numerical reservoir simulator and a single horizontal well were used to evaluate the effect of completion location in the case of strong aquifer with a fixed aquifer-factor of 50 and the gas cap size was varied in terms of M-factor, the ratio between the gas cap and oil pore volume. M-factors of 0.05, 0.5, 1, 2.2, and 5 were used. It was found that the optimum completion location of horizontal well depends on the gas cap and aquifer sizes. For M-factor less than 1, the maximum volume of oil was produced when the well is completed above the GOC. For M-factor equal to 1, the maximum volume was obtained when the well was placed in the aquifer and the minimum when the well was placed above the GOC. For M-factor higher than 1, the maximum volume was obtained when the well was placed in the aquifer zone and the minimum when the well was placed above the GOC. The second conclusion was that the oil recovery in reservoir with a large gas cap can be improved if the horizontal well is completed close or below the oil-water contact.

Ali-Nandalal *et al*. [2] studied the optimal location and performance prediction of horizontal well in a thin oil rim at Mahogany field. This is 21-sand reservoir with an average thickness of 400 ft and an oil leg varying between 63 and 75 ft. A horizontal well was planned to develop the oil rim in order to reduce coning effect and initially was planned to be located at a depth of 10,058 ft. Because of the presence of shale bed, it was ultimately placed at a depth of 10,048 ft, 22 ft below the gas-oil contact. Various models were run in order to select well length. It was verified that a well longer than 1,500 ft could offer higher oil recovery. Thus, a well with 2,000 ft horizontal section was selected. When this the model was run in order to select the optimal flow rate, a rate 3,000 BOPD was expected to be produced during the first 2 years. As the horizontal wells in the neighboring field with thin oil rim were experiencing water coning prematurely, it was decided to reduce the flow rate to 2,000 BOPD. Local grid refinement was used in order to observe more closely the coning effect. As the well was located near the GOC, water was not expected to cone as fast as gas. The model predicted no water breakthrough for at least 5 years of production. However, when the well was put on production, a small amount of water was observed. In general, this well has performed as predicted by the model.

Zarafi [3] performed a study in Saih Rawl field with the aim of studying the performance of a horizontal well in a thin oil rim. The reservoir has undersaturated light oil (less than 25 m thickness) and is underlain by water. Vertical wells were drilled and rapidly induced water breakthrough, and an unattractive amount of oil had been produced. A horizontal well was drilled, and the initial flow rate of 120 m^3/d was used, 3 times of the initial flow rate of the vertical wells. And the reservoir was brought to the new lease of life.

Haynes *et al.* [4] studied the development of a thin oil rim reservoir in Amherstia/Immortelle fields, in offshore area of Trinidad. The reservoir with 22-sands has an oil leg varying between 31 and 46 ft gross pay. A full field model was developed in order to adequately address multiple well interference effects. The main depletion strategy was to develop oil reserves while utilizing produced gas to satisfy the market. Sensitivity analysis was performed to study well location and length. As the main objective was to produce oil and gas, the wells were placed in the model at varying depths and completed in the upper one third of the oil column, 20, 10 and 5 feet below the GOC. Comparing the wells that were located in the deeper zone with the wells located in the shallower depth, the last one was producing more gas, oil and condensate recovery and less water production. In addition, this study showed that longer lateral wells increase the recovery factor.

Razak *et al*. [5] proposed a correlation between IOR recovery factor and gas withdrawal volume for a thin oil rim reservoir in Malaysia. The reservoir has a large gas cap and large aquifer. The oil rim that was spread in thin layer had a column thickness varying between 10 to 70 meters. The strategy adopted to deplete this reservoir was to produce the oil rim first and the gas cap later. But the produced gas was re-injected to avoid the loss of energy in the gas cap. During this process, the oil rim thickness reduced, but remained slightly in the same place. The GOC moved downward, and the OWC moved slightly upward. This result was considered an effect of gas re-injection. Razak *et al*. [5] also studied another depletion method that was to produce first the gas from gas cap for sales and was found that this methodology can weaken the gas cap energy, and the oil rim could be lost by spreading and dispersing into the gas cap.

Cosmo *et al*. [6] studied concurrent development of Soku oil rims and gas caps. A box model was used to study parameters such as landing depth, well spacing, well length, permeability, producing GOR and the rate of gas offtake. This field has 10 oil rim reservoirs with a thickness of the oil rim varying from 8 to 123 ft and a ratio of gas pore volume to oil pore volume varying between 2 and 6. The challenge was to deliver a gas cap drainage plan which enables optimum drainage of the oil rims. The following parameters were studied:

Landing depth: The dimensionless elevation, defined as the ratio of the vertical distance between GOC and horizontal well to the oil column thickness, was defined for landing depth of the horizontal well. The values of 0.33, 0.5 and 0.66 were selected for the study. The result shows that the well near GOC could suppress water coning but caused a rapid increase in GOR, resulting in a lower oil recovery compared with the well landed at 0.5. The well near the OWC (with elevation of 0.66) gave a sharper rise in water cut but oil recovery improved relatively to the well at elevation of 0.33. The best result was found when the well that was located at elevation of 0.5 i.e., at the middle of thin oil rim.

Well spacing and horizontal well length: A second well was introduced with a well spacing of 500, 1,000 and 1,500 meters and a well length of 200, 500 and 800 meters. The simulator registered a well interference. In this study, it was verified that large well spacing created less interference and individual wells access larger volumes of oil. A good result was found for the large well length.

Permeability: A study with different permeability was perfomed (1,500 mD and 750 mD). The lower permeability (750 mD) affected the economic limit of the well. From this study, it was concluded that the permeability has a strong influence in the choice of well placement.

Producing GOR control: It was noticed that for high GOR a low pressure compressor would be necessary and the producing GOR was necessary to be controlled, in order to preserves reservoir energy.

Gas cap offtake: Under concurrent production of oil rim and gas cap, sensitivity for gas cap offtake rates of 100, 200 and 300 MMSCF/d was run. High pressure drop was registered for higher rate of 300 MMSCF/d, despite cumulative gas offtake and oil recovery (0.12 MMb) are similar in all cases. After this study for a box model, a full reservoir simulation was used to confirm the previous study.

CHAPTER 3

THEORY AND CONCEPTS

3.1 Thin oil rims

Reservoirs with oil columns between 30 and 90 ft which are overlain with gas cap and underlain by aquifer are considered thin oil rim reservoirs (see Figure 3.1). And reservoirs with less than 10 meters are considered ultrathin oil reservoirs. When put on production, these reservoirs lead to a relative low oil production due to early breakthrough of gas and water. Most oilfields with vertical wells experience similar problems as the reservoir approaches the end of its life [7].

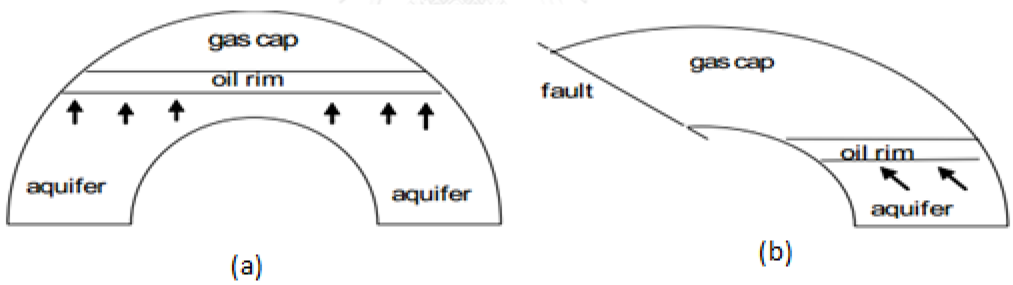

Figure 3.1 - Reservoirs with thin oil rim: (a) bottom and (b) edge water

Source: [8]

The performance of this kind of reservoir is strongly dependent on the following parameters: permeability, reservoir thickness, well length, well location and well orientation. Added to this, the development strategy will have influence on the oil production profile. For developing thin oil rims, horizontal wells offer a great advantage over vertical because they increase the area of formation exposed to the wellbore.

3.2 Horizontal wells

Carden and Grace [9] defined horizontal wells as wells designed with an inclination greater than 80° through the producing formation. This kind of well will enhance the productivity and profitability of the reservoir as it increases the surface area of a producing formation by intersecting horizontally a producing formation [9]. For example, if we drill into the same reservoir, a vertical well can give an exposure depth of 20 to 30 feet while a horizontal well can give an exposure of 2000 to 3000 feet. Horizontal wells have been applied in formations consisting of thin oil zones, where vertical wells are not economically viable [10].

3.2.1 Application of horizontal wells

Horizontal wells find their great importance on:

- Development of very thin oil rims with long reach horizontal wells selectively completed to avoid or minimize water and gas coning;
- Development of fractured reservoirs by intersection of natural fracture systems;
- Development of thick and multiple layered reservoirs by completing horizontal wells with large diameter sand-propped hydraulic fractures; and
- Water flooding.

3.2.2 Types of horizontal wells

There are three types of horizontal wells based on the turning radius:

1. **Long Radius** – This type is used to drill new wells. It has a build inclination of 2° to 6° per 100 feet, and is drilled with steerable motor systems. This type of horizontal well is good because it is easy to perform logging, and long horizontal sections and large hole sizes can be achieved, and it has unlimited alternatives to do completion. The disadvantage of this kind of well is the location of the Kick Of Point (which will now be referred to as “KOP”), is shallower than medium and short radius. This can increase the cost of drilling in harder formation where penetration rates are usually lower [10].

2. **Medium Radius** – This is used for recompletion of existing vertical wells and drilling of new wells. It has a build inclination of 6° to 20° per 100 ft. Higher build rates will be favourable to small horizontal wellbore length which is beneficial because they will reduce directional drilling costs. In troublesome formations near the target interval, a vertical hole can be drilled before the directional drilling starts, and as the KOP is near the target, the ability to hit the precise target is better [10].

3. **Short Radius** – This is used for recompletion of existing vertical wells and ultra-short radius is used for near wellbore gravity drainage and has been used mostly in heavy oil applications. Sometimes to vary the build rate, a motor is used with the short radius. This is an adjustable bend motor with single bend in the motor housing. With the single bend, the build rates are limited because the higher build rates can require two bends in the motor. Table 3.1 shows the characteristics of different types of wells [10].

Table 3.1 - Types of Horizontal Wells

Type	Hole Diameter (in)	Radius (ft)	Build angle	Recorded (ft)	Expected (ft)
Ultrashort		1 – 2	45^{o} – 60^{o}/ft		100 – 200
Short	$4\frac{1}{4}$	30	2^{o} – 5^{o}/ft	425	250 – 350
(Rotory)	6	35	2^{o} – 5^{o}/ft	889	350 – 450
Short	$4\frac{1}{4}$	40	2^{o} – 5^{o}/ft	-	-
(Mud motors)	$3\frac{1}{4}$	40	2^{o} – 5^{o}/ft	-	-
Medium	$4\frac{1}{2}$	300	6^{o} – 20^{o}/100 ft	1300	500 -1000
	6	300		2200	1000 – 2000
	$8\frac{1}{2}$	400 – 800		3350	1000 – 3000
	$9\frac{7}{8}$	300		-	-
Long	$8\frac{1}{2}$	1000	2^{o} – 6^{o}/100 ft	4000	1000 – 3000
	$12\frac{1}{4}$	1000 - 2500		1000	-

***Source**: [10]*

3.2.3 Undulation problems within the horizontal well

Although horizontal well improves the oil recovery in thin oil rim reservoirs, it presents some problems related with its shape, angle, path and fluids. An undulated horizontal well can create problems that result from the gas and liquid blockage (Figure 3.2).

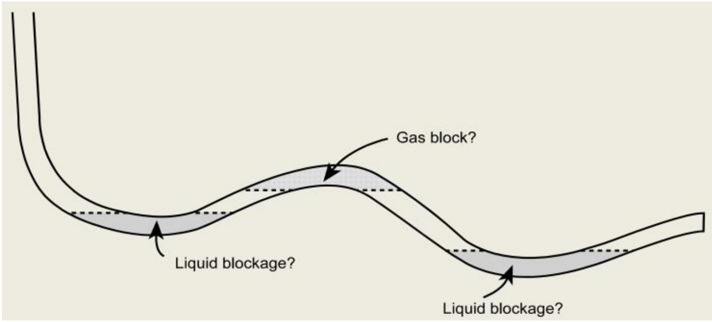

Figure 3.2 - Undulated horizontal well

Source: [11]

Unloading liquid blockage from horizontal wells is not well understood. Due to gravity effect, gas will tend to block the upper part of the undulated well and water will accumulate at low spots and may not be removed resulting in increased back pressure and water flow back (imbibition) into formation. In addition, produced sand and completion debris can also accumulate. In cases where scale and paraffin deposition occurs, flow assurance issues must be taken in consideration [11].

3.3 Coning

Coning results from the movement of reservoir fluids in the direction of least resistance, balanced by a tendency of the fluids to maintain gravity equilibrium. Coning can seriously impact the well productivity and influence the degree of depletion and the overall recovery efficiency of the oil reservoirs by:

- Adding costly water and gas facilities;
- Reducing average reservoir pressure if coning of gas occurs and consequently reducing oil recovery.

Gas coning and water coning must not be confused with free-gas production caused by a naturally expanding gas cap or water production caused by a rising OWC from water influx.

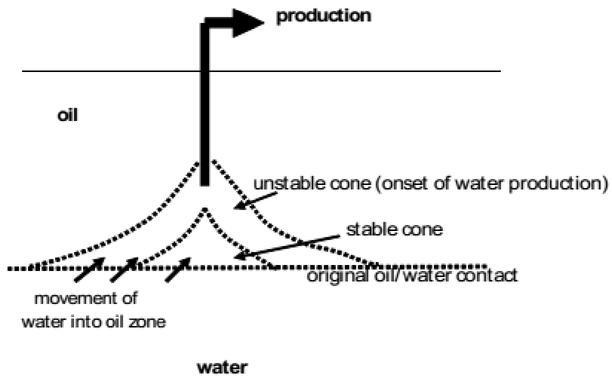

Figure 3.3 - Stable and unstable cone

Source:[12]

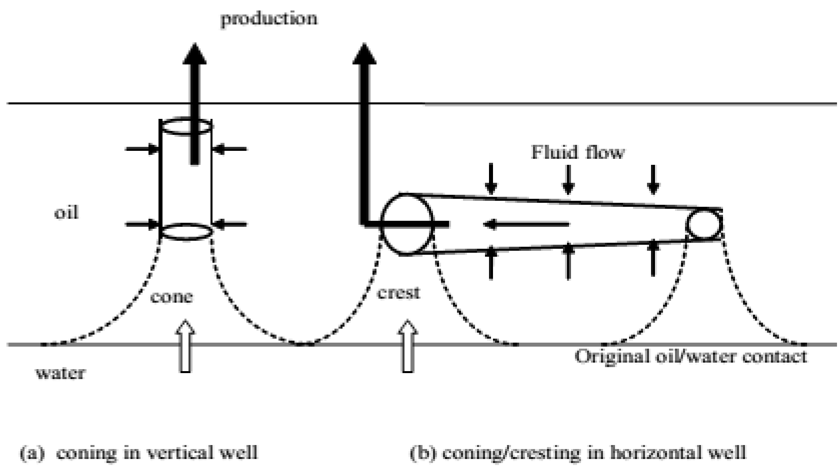

Figure 3.4- Coning in (a) vertical and (b) horizontal wells

Source: [12]

Coning is affected by three main forces:

- Gravity force
- Viscosity force
- Capillary force

Figure 3.3 and Figure 3.4 show schematics where water is underlying oil. Producing from the well can create pressure gradient that will elevate the water-oil contact in the immediate vicinity of the well originating coning effect.

From the three forces that affect coning, capillary force is considered to have negligible effect on coning while gravity force is related with fluid properties (density difference). Viscous force refers to the pressure gradients associated fluid flow through the reservoir. Coning occurs when viscous force at the wellbore is stronger than gravitational force [12].

In terms of rock and fluid properties, coning is affected by the following variables:

- Density differences between water and oil, gas and oil, or gas and water (gravitational forces);
- Fluid viscosities and relative permeabilities;
- Vertical and horizontal permeabilities; and
- Distances from contacts to perforations.

3.3.1 Impact of coning

Beyond reducing oil recovery, coning creates problems at the surface as the unwanted fluids must be handled. In addition, produced water must also be disposed of. Produced gas from coning in an oil well may or may not have a market. Another issue is related with pressure depletion as production of gas in an oil well after the cone breaks through can rapidly deplete reservoir pressure and may force shut in of the oil well.

3.3.2 Predicting coning

Different strategies have been applied in fields with a potential to cone. One is to predict the critical rate at which a well will cone and produce at a lower rate as long as possible. There are several equations that could be used to determine critical coning rate. The equation 3.3.1 refers to Efro's Method [10]:

$$q_o = \frac{4.888\times10^{-4} k_h \Delta\rho x^2 L}{\mu_o B_o \left[2y_e + \sqrt{\left(2y_e\right)^2 \left(\frac{x^2}{3}\right)}\right]} \tag{3.1}$$

where:

x = horizontal well distance from gas-oil or oil-water contact, *ft*

B_o = oil formation volume factor rb/STB

μ_o = oil viscosity, *cP*

k_h = horizontal permeability, *mD*

L = horizontal well length, *ft*

y_e = half drainage area (perpendicular to the horizontal well), *ft*

$\Delta\rho$ = difference between fluids densities (oil-gas or water-oil), *g/cc*

Another strategy is the optimal economics that may require the well to produce at higher liquid rate, causing the well to cone, but increasing the cumulative oil production. The use of horizontal wells instead of vertical well are preferred in thin oil rim reservoirs.

3.4 Pressure drop through a horizontal well

In horizontal wells, the pressure drop along the wellbore is considered negligible if the wellbore pressure drop is very small as compared to the pressure drawdown from reservoir to the wellbore. Figure 3.5 shows a schematic diagram of pressure drop along the well length. In horizontal wells, to maintain fluid flow from the well tip to the producing end, the pressure at the producing end must be lower than the pressure at the well tip. In cases were the wellbore pressure drop is significant compared with the reservoir drawdown, it will influence the production along the well length. This occurs in circumstances where there are high flow rates of light oil (greater than 10,000 RB/D) or heavy oil and tar sand are being produced [10].

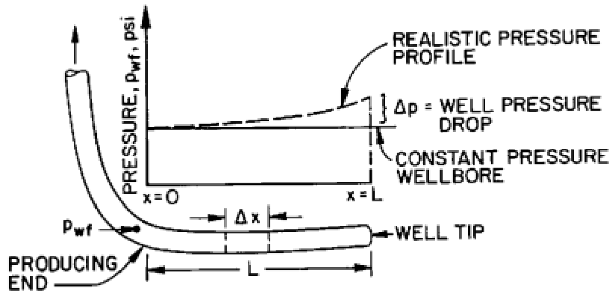

Figure 3.5 - Pressure loss along well length

Source: [10]

Joshi and Shah [13] studied the pressure drop along curved section, where the well turns from vertical to horizontal direction and the results show that if:

$$\frac{2R}{d} > 50 \tag{3.2}$$

Where

R =is radius of curvature; and

d =is diameter of the pipe,

the pressure drop along the well is almost the same as the pressure drop along the curved sections to the straight pipe (horizontal section), with pipe length equal to the distance along the curve.

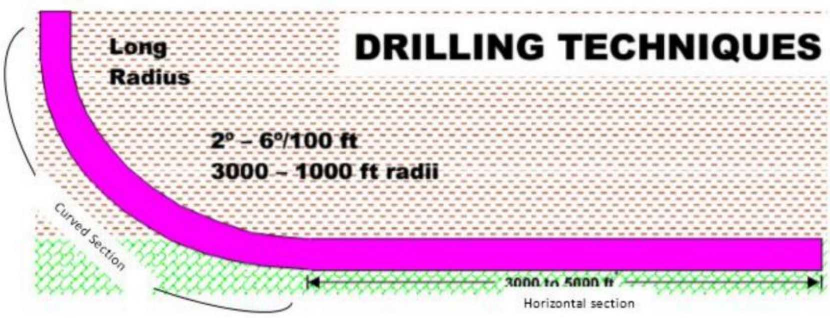

Figure 3.6 - Curved and horizontal sections

Source: [9]

3.5 Combination drive reservoirs

The oil production in saturated oil reservoirs with gas cap and aquifer can be supported by different drive mechanisms: gas-cap drive and water drive. Gas-cap drive mechanism is characterized by free gas above the gas-oil contact. As the reservoir pressure declines during oil production, gas will expand contributing for high gas oil ratio. The oil recovery factor for gas-cap drive is between 20 to 40%. For water drive reservoir, the recovery factor is between 35 to 75%. This high oil recovery factor of water drive is originated by the movement of water into the reservoir as oil and gas are produced. If the reservoir is undersaturated with a strong aquifer that the reservoir pressure is maintained above the bubble point, dissolved gas cannot form free gas inside the reservoir. However, if the aquifer is not strong enough to keep the reservoir pressure above the bubble pressure, free gas will form and two drive mechanisms will contribute to the energy for oil production [14].

3.6 Force balance in thin oil rim reservoirs

Many thin oil rims are sandwiched between an overlaying gas cap and an underlying aquifer, which means that the movement of the thin oil rim depends on two drive mechanisms: gas cap expansion drive and water drive. Before production, these forces are in equilibrium. In many situations, the oil production is first produced and followed by gas production. This strategy has shown good results.

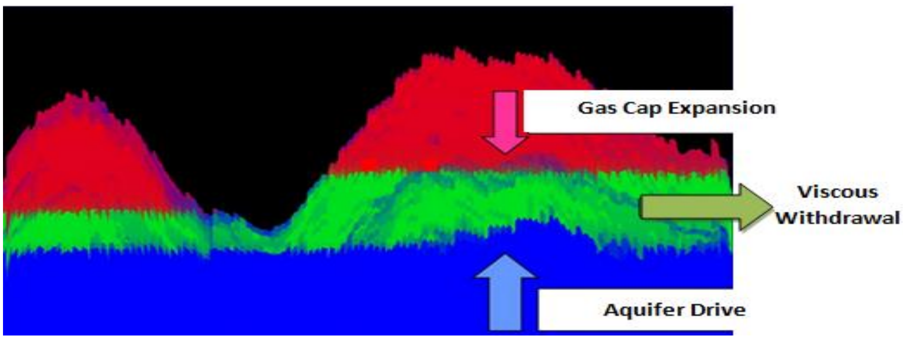

Figure 3.7 - Force Balance in Thin Oil Rim

Source: [15]

During production of oil, gas and water expand, affecting both GOC and OWC. The movement of GOC and OWC will depend on the strength of the gas cap and aquifer (if it is strong or weak). If water influx occurs and the connectivity of the aquifer is good, GOC will recede [16].

3.7 Permeability

Permeability is one of the most important factors that affects fluid migration, and is one of the parameters used to determine the reservoir quality (see Table 3.2). Permeability is affected by lamination, cementation, fracturing and solution, and by the shape and size of sand grains. If the grains are too small and characterized by irregular shape, permeability will be low [17].

Table 3.2 - Quality of reservoir determined by permeability

Permeability (mD)	Quality of reservoir
k<1	Poor
1<k<10	Fair
10<k<50	Moderate
50<k<250	good
k>250	Very good

Source: [17]

As many reservoirs have layers with different permeability due to rock type and grain size, permeability measured at the same point in horizontal and vertical directions (k_h and k_v) may be different. This directional dependency is called “anisotropy”.
Ayan *et al*. [18] showed the importance of knowing the permeability before drilling a horizontal well by stating that the production is affected by vertical and horizontal anisotropy. Higher vertical anisotropy will increase productivity index. And to have a good well producer, the well must be drilled normal to the larger horizontal

permeability. Figure 3.8 shows the drainage area of an ideal horizontal well is characterized by ellipsoidal pattern and dominated by permeability anisotropy.

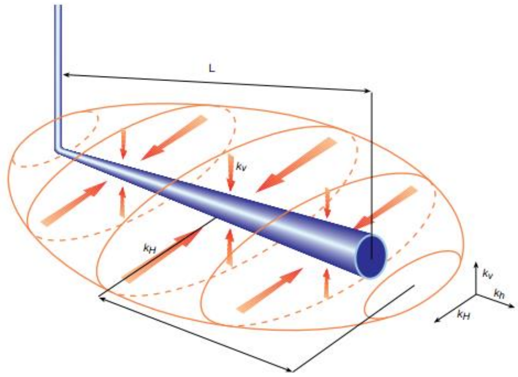

Figure 3.8 - Horizontal well drainage pattern

Source: [18]

3.8 Thin oil rim production techniques

The major challenge in producing from thin oil rim reservoirs is to avoid excessive production of free gas and water. Apart from reducing the total producing rate, which may often imply uneconomically low oil rates, several potentially useful techniques exist.

The critical rate to coning is very sensitive to the oil zone height. A technique sometimes referred to as **reverse coning** seeks to exploit this fact by completing the well above the GOC. The reverse coning in oil rim reservoirs is proposed to be used in reservoirs with small gas cap and strong aquifers. One of the successful field was the case of the Platong Field in the Gulf of Thailand, where one of the reservoirs consisting of a 30 ft oil column with a small gas cap and a large underlying aquifer [1]. A reservoir simulation study indicated that to maximise oil recovery, it would be better to locate the horizontal well in the gas cap. Upon drilling the well, gas was produced for the first two weeks after which the well started producing oil. The project was an economic success. Reverse coning has also been successfully applied in the D-2 Sand in the South Timbalier 37 field in the Gulf of Mexico and in Skua Field, located in the Timor Sea [1].

Other technique is the **inverse coning**, where the horizontal well is located below the OWC. This technique can be applied when the gas cap is strong and the aquifer strength is weak. When the well is placed on production, inverse coning occurs in which oil “down-cones’ through the water zone, into the completion. The net result is the production of water followed by oil. This phenomenon has been observed in a horizontal well drilled in the Troll field, offshore Norway [1].

CHAPTER 4

RESERVOIR SIMULATION MODEL

In order to optimize the oil production from thin oil rim under different gas cap and aquifer strengths, ECLIPSE100, a commercial simulator from Schlumberger was used to evaluate the effectiveness of well location and flow rates in oil recovery. Based on these cases, different scenarios will be created. This chapter describes the data used to construct the model which includes the grid model, PVT properties, relative permeability models, and well schedule used to conduct the study. Further details related with input parameters are illustrated in Appendix A.

4.1 Grid section

For this section, block-centred geometry was selected to perform the study. The reservoir is a box model with dimensions of 5,000x2,500 ft in the x-direction and y-direction respectively. As one of the objectives of the study is to evaluate the effect of gas cap size, the z-direction has a variable dimension of 525, 560 and 630 ft. The reservoir fluids are composed by gas cap zone with a variable thickness of 35, 70 and 140 ft, oil zone with a fixed thickness of 70 ft, and water zone with 70 ft thickness that is connected to an aquifer with variable pore volumes of 5, 50 and 500 PV. A schematic of the model is illustrated in Figure 4.1. Table 4.1 shows the reservoir data used in this study.

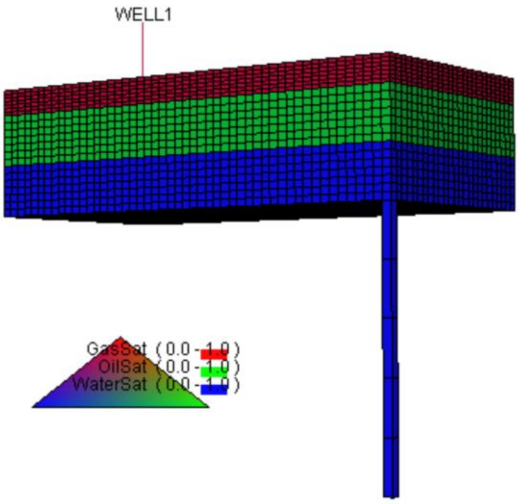

Figure 4.1 - Reservoir model

Table 4.1 - Reservoir data

Parameter	Value	Units
Number of grid blocks	50 x 25 x26	*blocks*
Reservoir size	5,000 x 2,500	*ft*
Effective porosity	0.296	*fraction*
Horizontal permeability	5,000	*mD*
Vertical permeability	500	*mD*
Depth of top face	5,035/5,000/4,930[1]	*ft*

4.1.1 Local grid refinement

Local grid refinement is applied to locate the well into the reservoir. It is applied only in the z-direction. When the well is placed right above OWC or right below GOC, the z-direction is subdivided into 10 grids with 1 foot each as the grid blocks in oil zone have 10 ft in size. If the well is placed in other locations, the z-direction is subdivided into 5 parts with 2 feet each grid block. Figure 4.2, Figure 4.3 and Figure

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[1] Represents the depth of top face for different gas cap thickness (35, 70 and 140) while the GOC is fixed for all cases.

4.4 illustrate the schematic of the LGR right below GOC, at the middle of oil column and right above OWC, respectively.

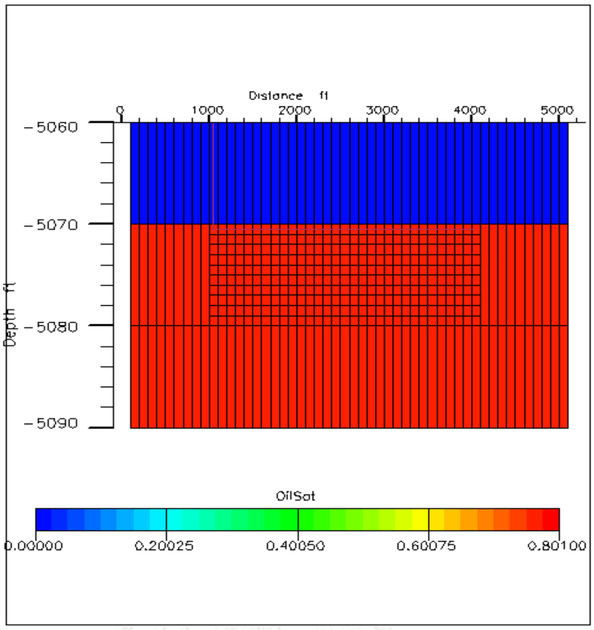

Figure 4.2 - LGR right below GOC

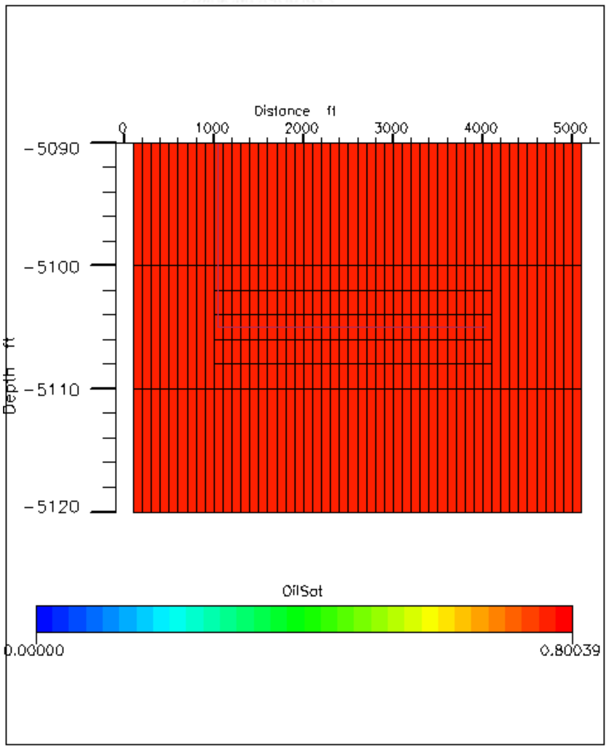

Figure 4.3 - LGR at the middle of oil column

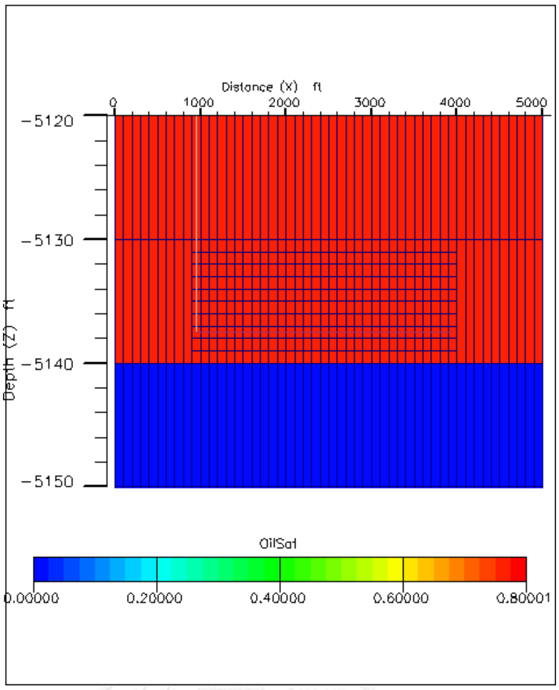

Figure 4.4 - LGR right above OWC

4.1.2 Aquifer modelling

A numerical aquifer was included in the simulation model. Table 4.2 to Table 4.4 show the data proposed to be used with different pore volume of aquifer. The thickness of each layer of aquifer was fixed in 70 ft to maintain the initial pressure of the aquifer in all cases. To vary aquifer strength, the area of aquifer has to differ in each layer by using an exponential factor:

$$(\text{Aquifer area})_I = \text{Reservoir area} \times F^{i-1} \tag{4.1}$$

where:

i = represents the first, second or subsequent aquifer layers (I = 1,2,3,4,and 5)

	PV=5	PV=50	PV=500
F	0.8882	2.30369	4.434485

Reservoir area= 100 x 50 x 100 x 25 = 12,500,000 ft^2

Table 4.2 - Data for 5 PV aquifer

PV	i	j	k	Area (ft^2)	Length (ft)	ϕ	k_v (mD)	Depth (ft)	Initial pressure ($psia$)
5	50	25	20	12,500,000	70	0.296	500	5,245	2,352
	50	25	21	11,102,500	70	0.296	500	5,315	2,383
	50	25	22	9,861,241	70	0.296	500	5,385	2,414
	50	25	23	8,758,754	70	0.296	500	5,455	2,446
	50	25	24	7,779,525	70	0.296	500	5,525	2,447

Table 4.3 - Data for 50 PV aquifer

PV	i	j	k	Area (ft^2)	Length (ft)	ϕ	k_v (mD)	Depth (ft)	Initial pressure ($psia$)
50	50	25	20	12,500,000	70	0.296	500	5245	2352
	50	25	21	28,796,125	70	0.296	500	5315	2383
	50	25	22	66,337,345	70	0.296	500	5385	2414
	50	25	23	152,820,679	70	0.296	500	5455	2446
	50	25	24	352,051,469	70	0.296	500	5525	2447

Table 4.4 - Data for 500 PV aquifer

PV	i	j	k	Area (ft^2)	Length (ft)	ϕ	k_v (mD)	Depth (ft)	Initial pressure ($psia$)
500	50	25	20	12,500,000	70	0.296	500	5,245	2,352
	50	25	21	55,431,063	70	0.296	500	5,315	2,383
	50	25	22	245,808,215	70	0.296	500	5,385	2,414
	50	25	23	1,090,032,843	70	0.296	500	5,455	2,446
	50	25	24	4,833,734,292	70	0.296	500	5,525	2,447

4.2 PVT properties section

Reservoir fluids properties are generated assuming consolidated sandstone. The surface oil is characterized by having 35° API oil gravity, an initial GOR of 507 SCF/STB and 0.8 gas specific gravity. Table 4.6 shows PVT properties for water, and Table 4.7 depicts fluid densities at surface.

Reference pressure and temperature (see Table 4.5) are determined based on following formulas [19]:

Reference pressure

$$\text{Pressure}=\text{TVD}(\text{ft})\times 0.3048\times 1.462\left(\frac{\text{psi}}{\text{m}}\right)+14.7 \qquad [\text{psi}] \tag{4.2}$$

Reference temperature

$$\text{Temperature}=1.8\left[0.059\left(\frac{^{o}\text{C}}{\text{m}}\right)\times \text{TVD}(\text{ft})\times 0.3048+21.38\right]+32 \qquad [^{o}\text{F}] \tag{4.3}$$

Table 4.5 - Reservoir pressure and temperature

Parameter	Value	units
Initial pressure at datum depth	2274	*psia*
Reservoir temperature	235	^{o}F

Table 4.6 – Water PVT properties

Parameter	Value	Units
Reference pressure	2274	*psia*
Water FVF at RP	1.034716	*rb/STB*
Water compressibility	3.367823×10^{-6}	*/psi*
Water viscosity at RP	0.2559402	*cP*
Water viscosibility	6.836929×10^{-6}	*/psi*

Table 4.7 - Fluid densities at surface condition

Parameter	Value	Units
Oil density	53.00209	lb/ft^3
Water density	62.42811	lb/ft^3
Gas density	0.04994	lb/ft^3

From PVT data, the following plots were obtained:

- Solution gas (R_s) versus bubble point pressure (P_{bub});
- Formation volume factor (FVF) versus bubble point pressure and versus pressure for gas.
- Viscosity versus bubble point pressure for oil and versus pressure for gas.

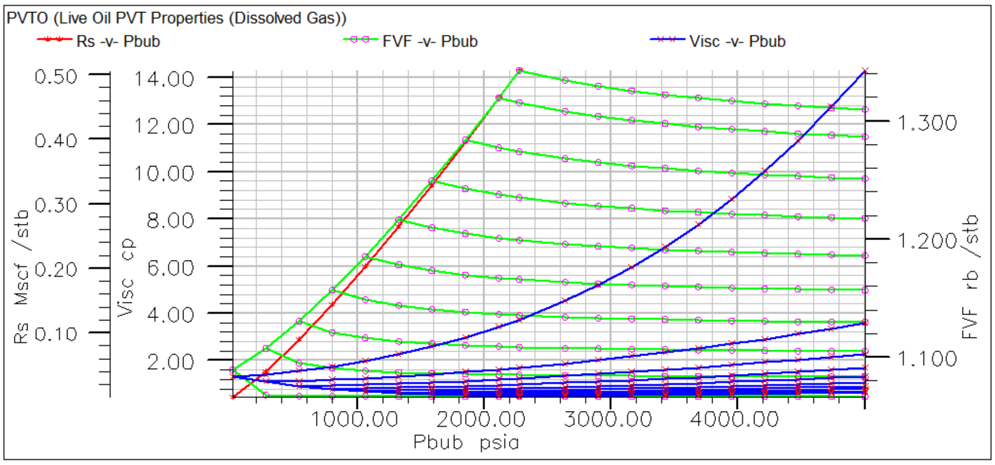

Figure 4.5 - Live oil PVT properties

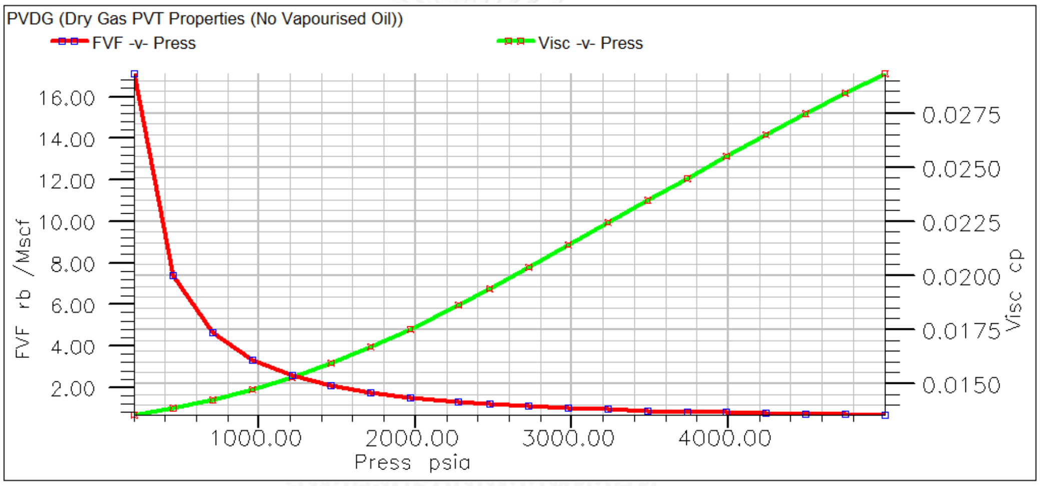

Figure 4.6 - Dry gas PVT properties

4.3 Special Core Analysis (SCAL) section

To obtain relative permeability curves for oil-water and gas-oil system, Corey's model was used with the following parameters:

Table 4.8 - Saturation parameters

Parameter	Value	Parameter	Value	Parameter	Value
Corey water	3	Corey gas	3	Corey oil/water	2
S_{wmin}	0.2	S_{gmin}	0	Corey oil/gas	2
S_{wcr}	0.2	S_{gcr}	0.1	S_{org}	0.1
S_{wi}	0.2	S_{gi}	0.1	S_{orw}	0.3
S_{wmax}	1	$K_{rg}(S_{org})$	0.4	$K_{ro}(S_{org})$	0.8
$K_{rw}(S_{orw})$	0.3	$K_{rg}(S_{gmax})$	1	$K_{ro}(S_{gmax})$	0.8
$K_{rw}(S_{wmax})$	1				

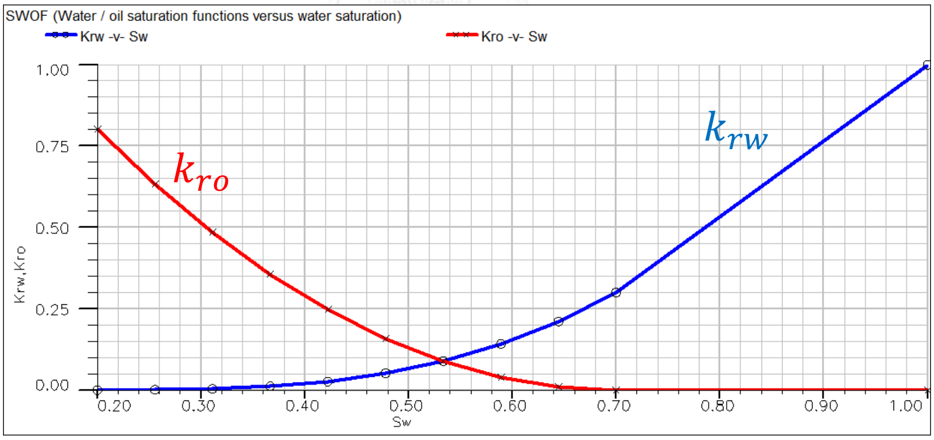

Figure 4.7 - Water-oil relative permeability

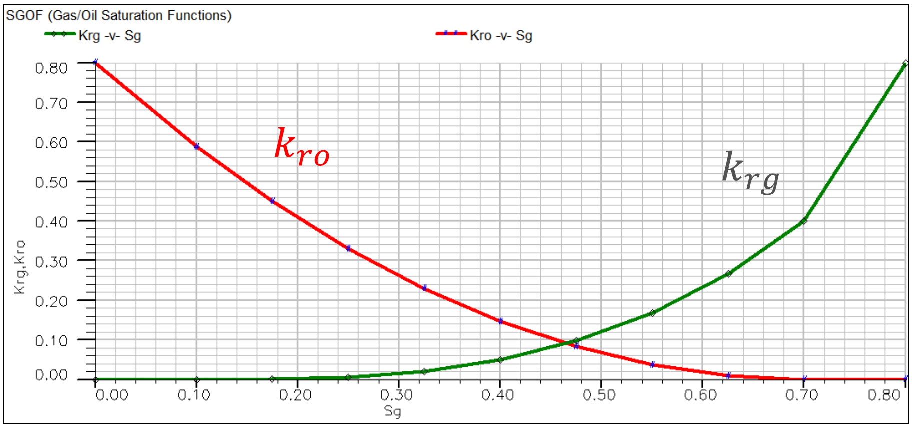

Figure 4.8 - Gas-oil relative permeability

4.4 Well schedule

The thin oil rim reservoir is developed by using a horizontal well as production well. It has a wellbore ID of 0.5104 ft and is perforated in all its extension. Well positioning under the vertical direction is variable as one of the objectives is to evaluate the effect of well location. The horizontal well has a fixed length of 3,000 ft. For the base case, the well is put on production at 5,000 STB/D liquid rate for a maximum period of 30 years with the constraints shown in Table 4.9.

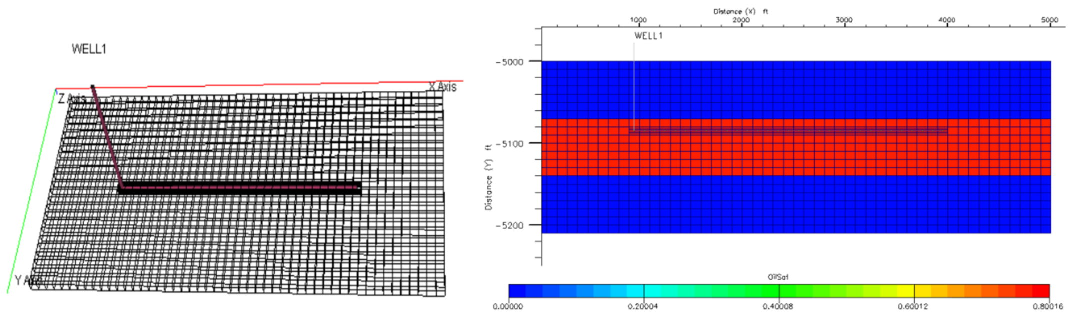

Figure 4.9 - Schematic of well positioning

Table 4.9 - Input parameters for well schedule in Eclipse 100

Parameter	Value	Units
Economic oil rate	50	STB/D
Maximum water cut	95	%
BHP target	200	*psia*
Concession period	30/10,956	*years/days*

No production constrain are used for gas production.

CHAPTER 5
RESULTS AND DISCUSSION

In this study, different scenarios were evaluated by varying the sizes of gas cap and aquifer. The effect of well positioning was studied by placing them at different depths. In addition to these, different target liquid production rates were evaluated for each case in order to maximize oil production. The present chapter first identifies possible locations along the vertical direction that will yield to higher oil recovery. The second step, consists in identifying the range of target liquid rate and the last part, the effect of aquifer and gas cap sizes are evaluated. In addition to this, the effect of target liquid rate is also studied.

5.1 Base case

5.1.1 M-Factor of 0.5 with 500 PV aquifer

For the base case, a target liquid rate of 5,000 STB/D is selected to produce through the thin oil rim. The horizontal well is located at the middle oil column, at a distance of 35 ft from GOC (thin oil rim column with a thickness of 70 ft). The results are summarized in Table 5.1.

The performance of the reservoir for the base case in terms of field oil production rate (FPOR), field water production rate (FWPR), field gas production rate (FGPR), well bottom hole pressure (WBHP), field average pressure (FPR) and gas-oil ratio (GOR) are shown in Figure 5.1 and Figure 5.2.

Table 5.1 - Summary results for the base case

Distance from GOC (ft)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
35	59.02	16.22	7.62	38.56	30.0

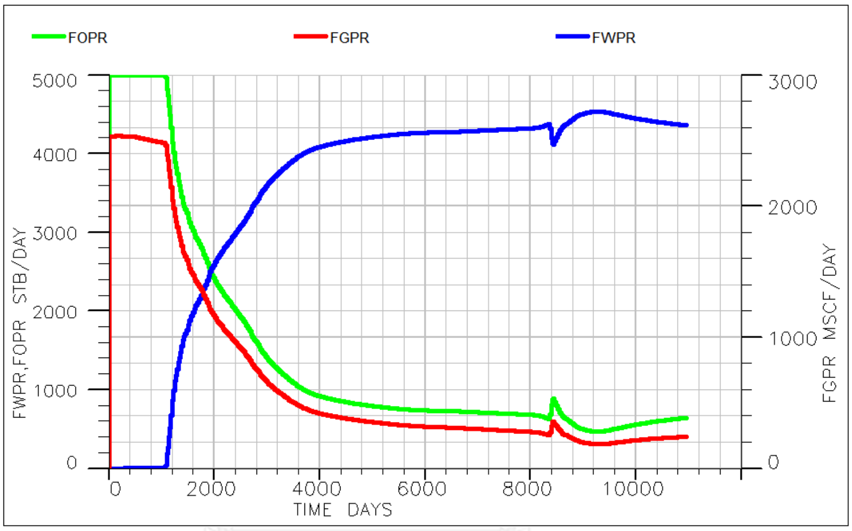

Figure 5.1 - Base case reservoir performance in terms of oil, gas and water production

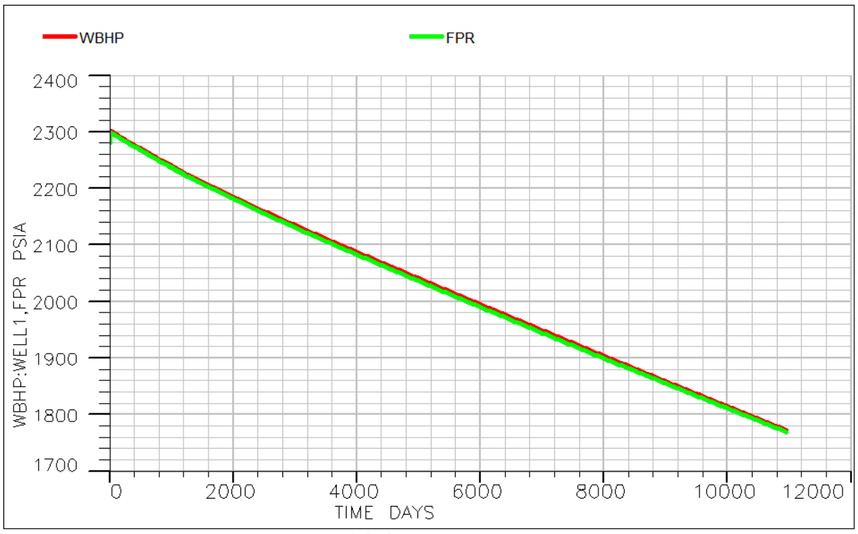

Figure 5.2 - Base case reservoir performance in terms of well bottom hole pressure and field average pressure

The reservoir starts producing oil on its target liquid rate of 5,000 STB/D. This plateau period persists for approximately 3 years. When water breaks through the well, the oil rate starts to reduce (Figure 5.1) until the time of 8,400 days when the oil and gas rate slightly increase and the water rate reduces. This slight increment in oil rate is caused by the downward movement of GOC (gas expansion). Figure 5.3 shows the saturation profile before oil production and after 8,400 days when gas expands, improving the oil recovery.

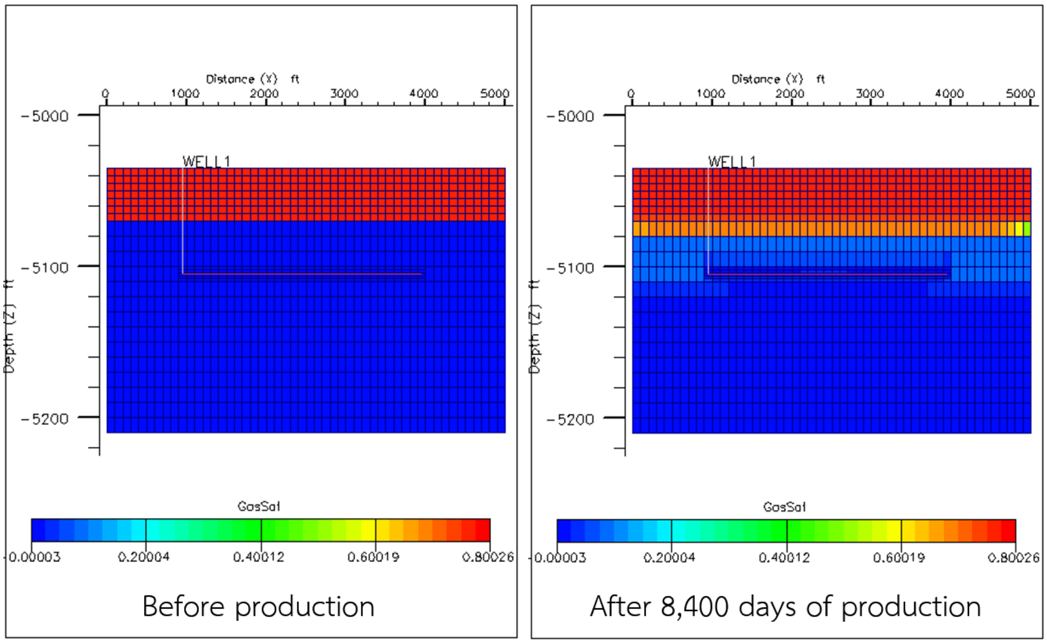

Figure 5.3 – Base case GOC expansion (Gas saturation profile)

The well bottom hole pressure and the field average pressure are both declining as oil is drawn from the reservoir (Figure 5.2). Before oil production, the field average pressure is 2,280 psia but as the well is put on production, the field average pressure registers an increment as shown in Figure 5.4. This increment is a result of water support from the aquifer. The reservoir pressure at the end of the concession period (30 years) is still high (1,770 psia). This is also a result of the strong aquifer that can support the reservoir pressure.

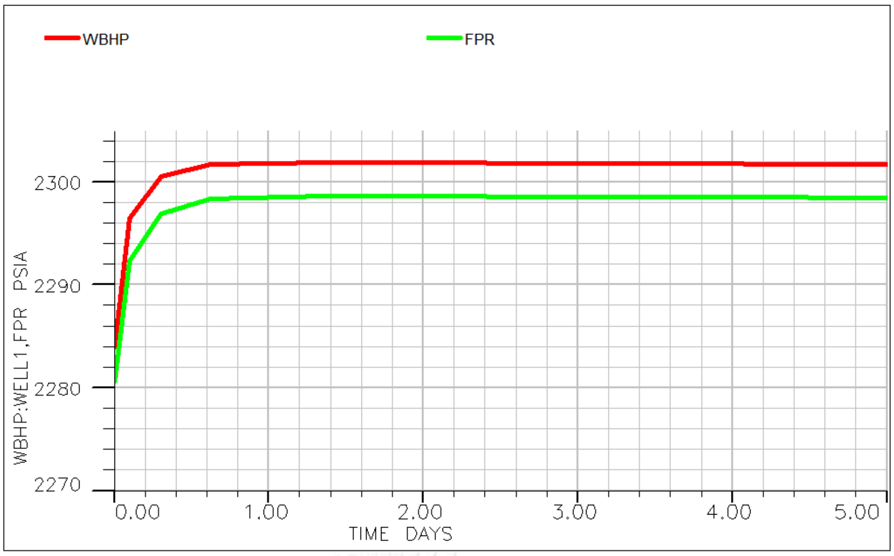

Figure 5.4 – Base case increment in well bottom hole pressure and field average pressure

Figure 5.5 to Figure 5.7 illustrate water and gas saturation profiles of the reservoir at different times during oil production. Figure 5.5 shows water and gas saturation profile after 60 days of oil production. Both water and gas start to move towards the well. As oil is produced, water tends to move faster to the wellbore while gas is expanding (Figure 5.6). At the end of concession period (Figure 5.7), just water reached the well while gas does not. The gas produced from the reservoir is dissolved gas. With the reservoir pressure reducing, the dissolved gas moves from the oil column to the gas cap zone. This results in a lower gas oil ratio as the reservoir pressure declines (Figure 5.8).

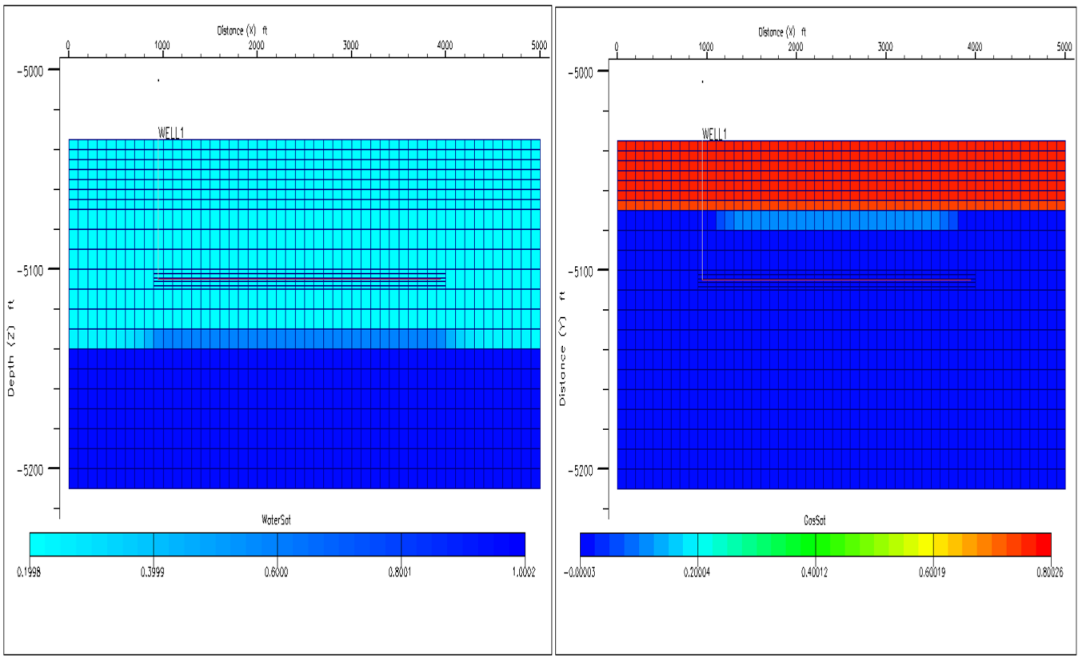

Figure 5.5 - Base case water and gas saturation profile after 60 days of production

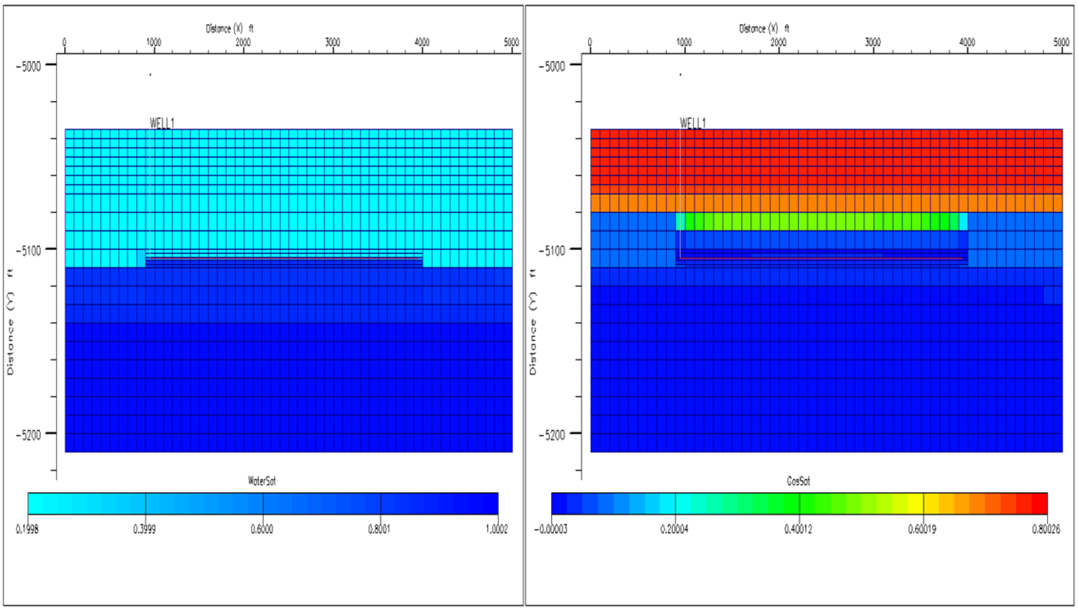

Figure 5.6 - Base case water and gas saturation profile after 23 years of oil production

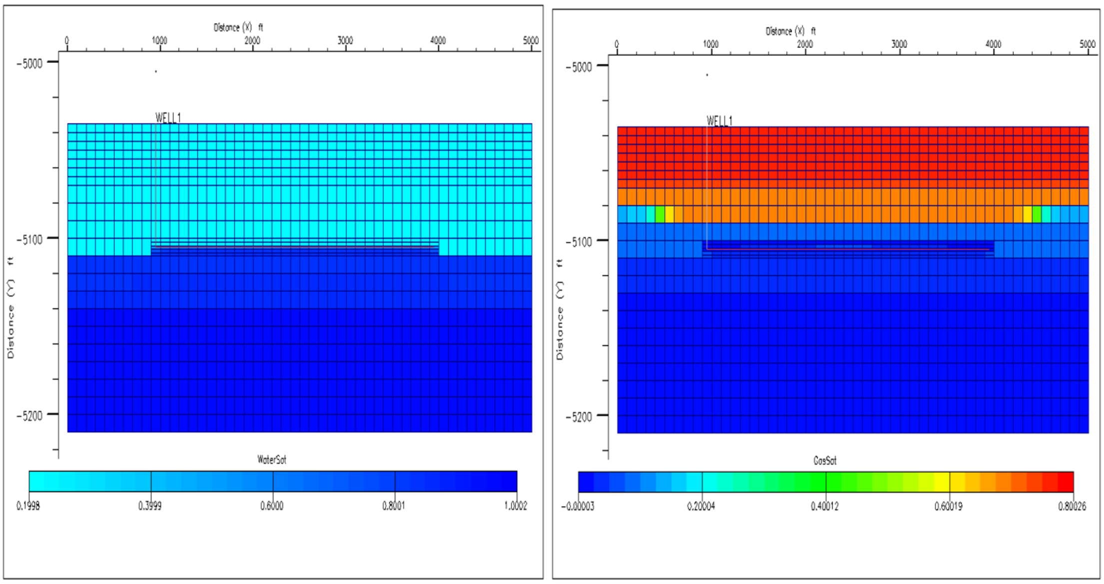

Figure 5.7 - Base case water and gas saturation profile at the end of concession period (30 years) of oil production

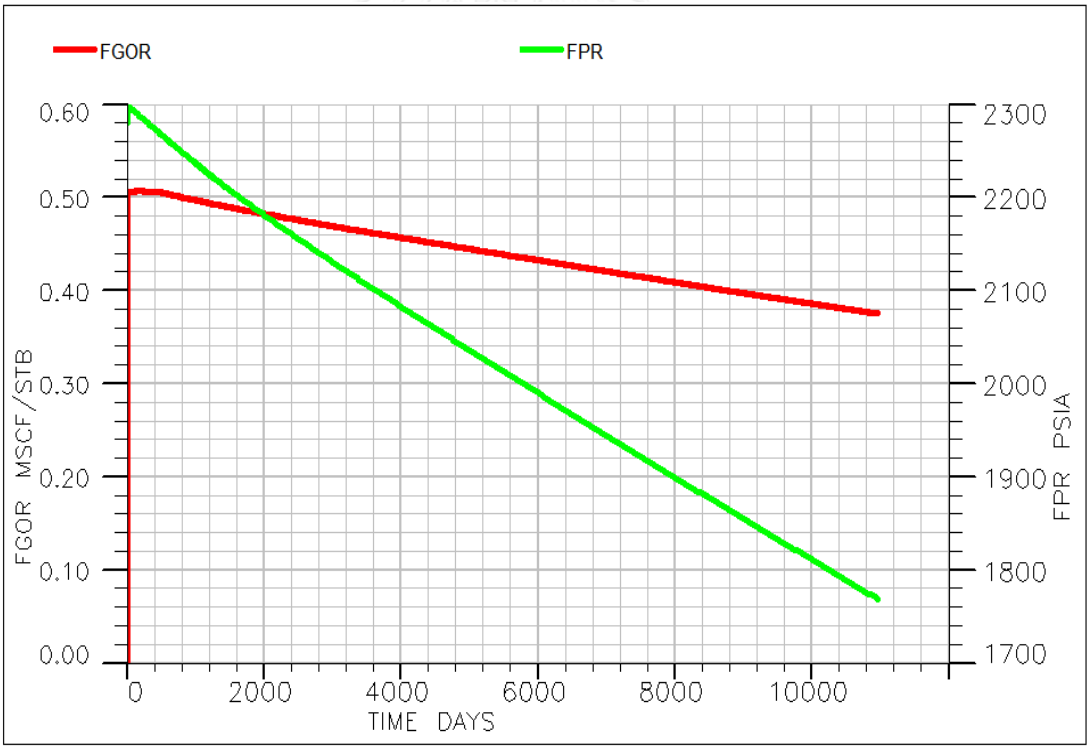

Figure 5.8 - Base case gas oil ratio

5.2 Effect of well location with fixed target liquid rate

In order to perform the study, the first step was to run the simulation to obtain possible optimal well locations in the thin oil rim. Simulation was performed along the thin oil rim zone at the grid blocks that are right above GOC and right below OWC (see Appendix B). As the oil recovery factor for the last zones (right above GOC and right below OWC) shows smaller oil recovery compared with the suitable well location found along the oil column, the results shown in this section are concerned with the oil column zone. To get these locations, a target liquid rate of 5,000 STB/D is used. The horizontal well is positioned at different depths, while the x-direction and y-direction are fixed coordinates. The thin oil rim has a thickness of 70 ft which is divided into grid cells of 10 ft along vertical direction. When the well is located right below GOC or right above OWC, the cells containing the well are subdivided with 10 divisions LGR along the vertical direction. When the well is located at other grid cells, those cells are subdivided with 5 divisions LGR along the vertical direction. For x-direction and y-direction, LGR is not applied. Table 5.2, Table 5.3 and Table 5.4 show the locations selected to produce from the thin oil rim reservoir for 5, 50 and 500 PV aquifer, respectively. These locations were selected based on the strength of the aquifer and gas cap. The landing depth is the ratio between the distance from GOC and the thickness of oil column.

Table 5.2 - Well locations for 5PV aquifer

Case	**Distance from GOC (ft)**	**Distance from OWC (ft)**	**Landing depth (ft/ft)**
1	35	35	0.50
2	45	25	0.64
3	55	15	0.79
4	62.5	7.5	0.89
5	67.5	2.5	0.96
6	69.5	0.5	0.99

Table 5.3 - Well locations for 50PV aquifer

Case	Distance from GOC (ft)	Distance from OWC (ft)	Landing depth (ft/ft)
1	25	45	0.36
2	35	35	0.50
3	45	25	0.64
4	55	15	0.79
5	62.5	7.5	0.89
6	67.5	2.5	0.96

Table 5.4 – Well locations for 500PV aquifer

Case	Distance from GOC (ft)	Distance from OWC (ft)	Landing depth (ft/ft)
1	0.5	69.5	0.01
2	2.5	67.5	0.04
3	7.5	62.5	0.11
4	15	55	0.21
5	25	45	0.36
6	35	35	0.50

5.2.1 Effect of well location for M-Factor of 0.5

For the case of 5 PV aquifer and M-factor of 0.5, both aquifer and gas cap are small.

Table 5.5 shows the results for this case. The results from simulation shown in this section are from the landing depth of 0.5 to 0.99 as this bottom half of the thin oil rim shows higher oil recovery factor than the oil recovery factor found at the landing depths smaller than 0.5. Simulation results indicate that the best landing depth is 0.79 as it gives the highest recovery factor of 52.94% (see Figure 5.9). A landing depth of 0.89 yields the second highest oil recovery (52.67%). Both locations are near the oil-water contact. This result shows that, as gas has better expandability than water (see gas saturation profile on Figure 5.12) and thus provides a good driving force for oil production, it should be kept inside the reservoir for as long as possible. Hence, locating the well further away from the gas cap helps increasing oil recovery. When the well is located at a landing depth of 0.89 (7.5 ft above the oil-water contact), the amount of produced water becomes higher but the gas production is slightly lower as shown in Figure 5.10 and Figure 5.11, respectively.

Table 5.5 – Effect of well position with a fixed target liquid rate for M-Factor of 0.5 and 5PV aquifer

Landing depth (ft/ft)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
0.50	42.42	11.66	25.38	1.24	7.1
0.64	49.69	13.66	25.20	3.11	9.2
0.79	**52.94**	14.55	24.95	6.65	11.6
0.89	52.67	14.48	24.71	10.22	13.5
0.96	50.73	13.94	24.60	12.72	14.7
0.99	50.03	13.75	24.53	14.00	15.2

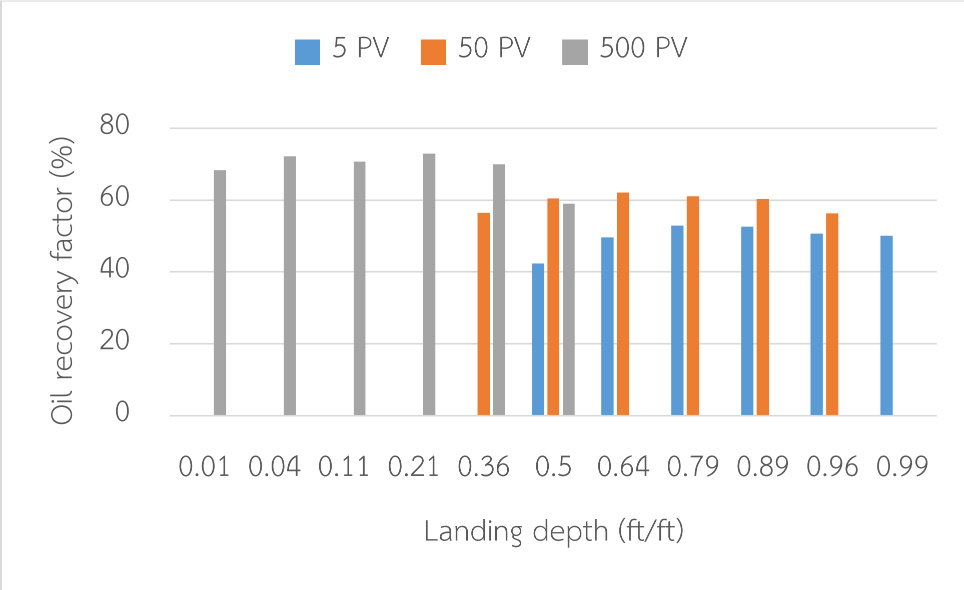

Figure 5.9 - Oil recovery factor for M-Factor of 0.5

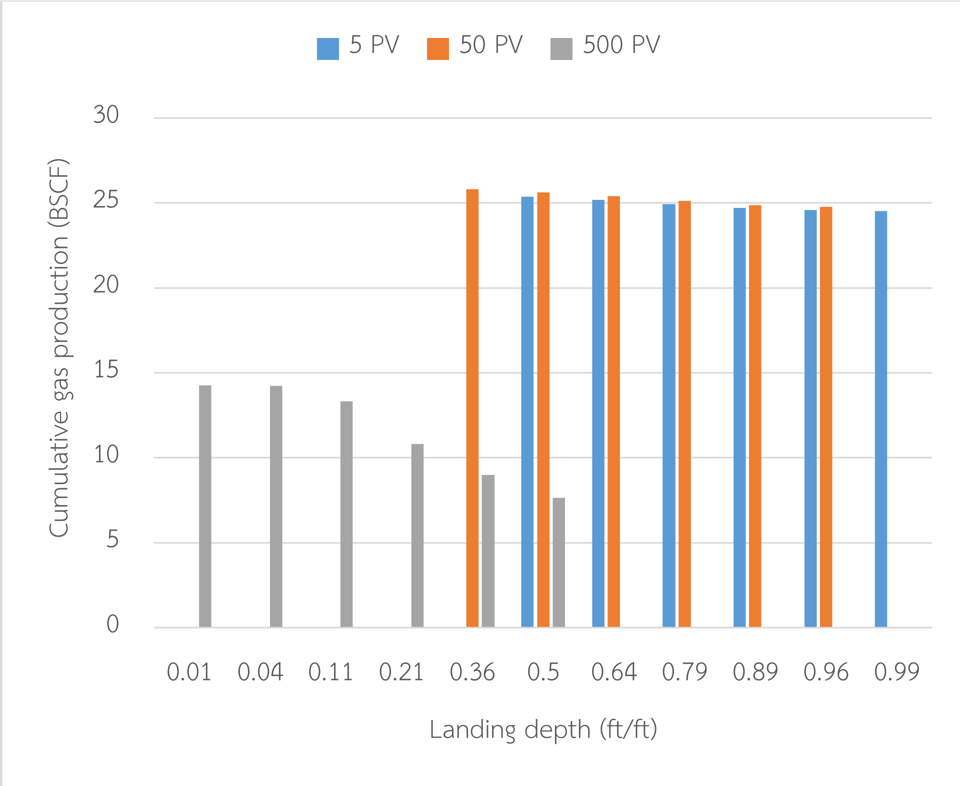

Figure 5.10 - Cumulative gas production for M-Factor of 0.5

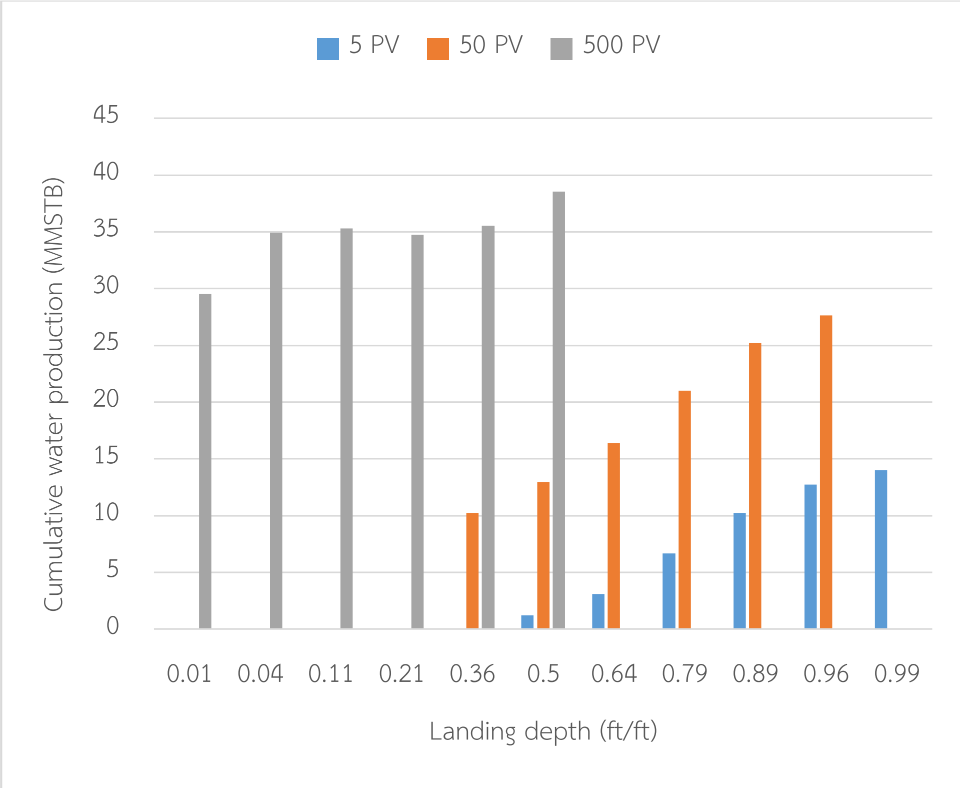

Figure 5.11 - Cumulative water production for M-Factor of 0.5

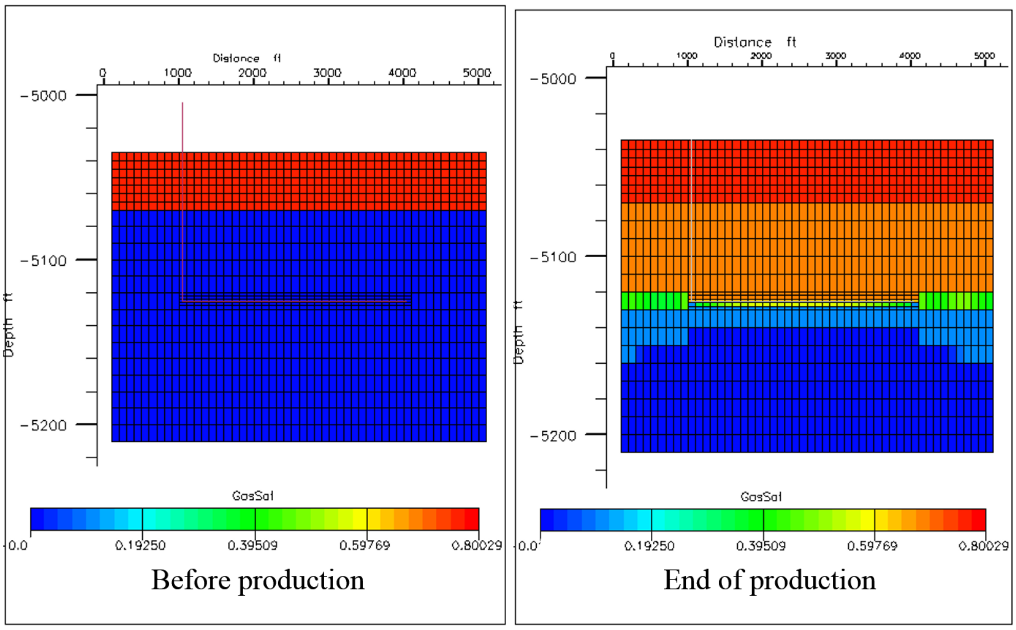

Figure 5.12 - Gas saturation profile for M-Factor of 0.5 with 5PV aquifer at a landing depth of 0.79 (5,000 STB/D) before and at the end of oil production

For the case of 50 PV aquifer and M-factor of 0.5, the optimal well location is at the landing depth of 0.64 as it gives the highest recovery factor of 62.10% (see Table 5.6) and moderate water production. Once again, the gas cap demonstrates its expandability, as the better horizontal well location is at the lower half of the thin oil rim column. Note that the gas production of the location that yields the highest oil recovery is higher than the gas production of the location that is located at a landing depth of 0.79, 0.89 and 0.96 and lower than the gas production of the well located at the middle of oil column (35 ft below gas-oil contact) as depicted in Figure 5.10.

Table 5.6 - Effect of well position with a fixed target liquid rate for M-Factor of 0.5 and 50PV aquifer

Landing depth (ft/ft)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
0.36	56.40	15.50	25.83	10.26	14.1
0.50	60.51	16.63	25.63	12.96	16.2
0.64	**62.10**	17.07	25.41	16.41	18.4
0.79	61.11	16.80	25.14	20.99	20.7
0.89	60.28	16.57	24.88	25.21	22.9
0.96	56.38	15.50	24.78	27.64	23.7

Differently from the first two cases (5 and 50 PV aquifer) where the gas cap is much strong than the aquifer, for the case of 500 PV aquifer and M-factor of 0.5, the highest oil recovery factor of 72.92% is obtained when the well is located at a landing depth of 0.21 (see Table 5.7). Due to the strong aquifer support, the well should be located far away from the water. The water production of the well increases as the well is moved to the middle oil column, while the gas production tends to reduce (see Figure 5.10 and Figure 5.11).

Table 5.7 - Effect of well position with a fixed target liquid rate for M-Factor of 0.5 and 500PV aquifer

Landing depth (ft/ft)	Oil Recovery Factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
0.01	68.35	18.79	14.26	29.51	26.5
0.04	72.19	19.84	14.23	34.94	30.0
0.11	70.80	19.46	13.33	35.32	30.0
0.21	**72.92**	20.04	10.81	34.74	30.0
0.36	69.93	19.22	8.99	35.56	30.0
0.50	59.02	16.22	7.62	38.56	30.0

Note that for the first location (landing depth of 0.01), the reservoir cannot produce during all the concession period of 30 years as the other locations. This location is the nearest the gas-oil contact. When oil is drawn from the reservoir, water is moving fast to the well (see Figure 5.13) reducing oil relative permeability and resulting in a high water cut of 95% (Figure 5.14) which is the production constraint used in this study.

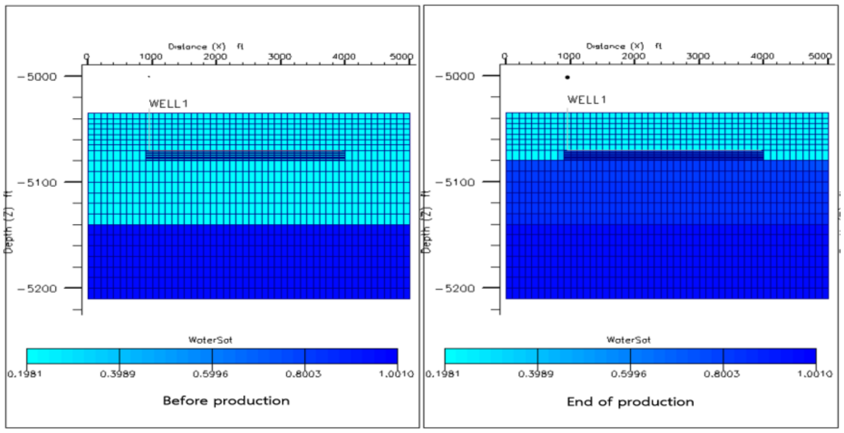

Figure 5.13 - Water saturation profile for M-Factor of 0.5 with 500PV at a landing depth of 0.01 (5,000 STB/D) before and at the end of oil production

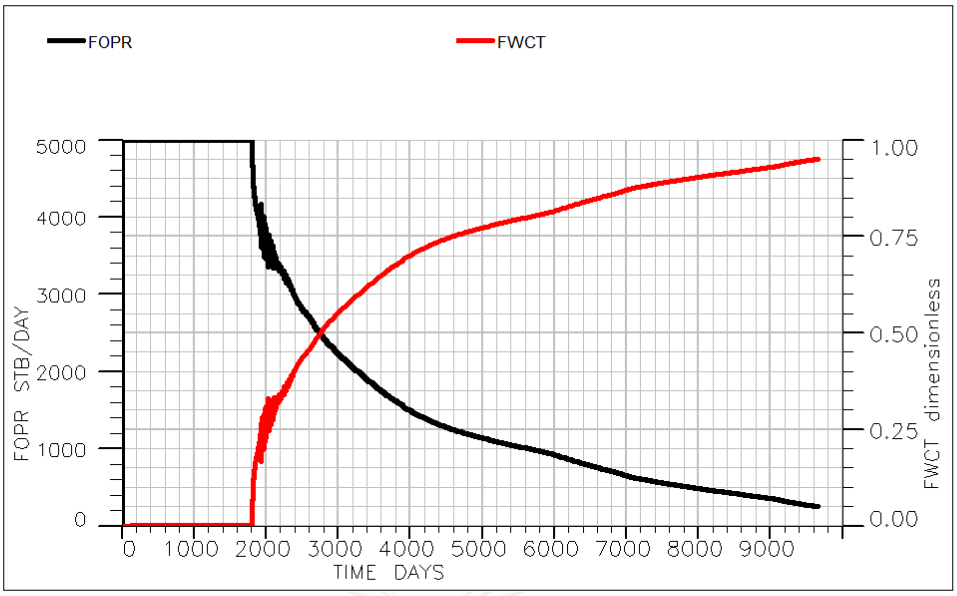

Figure 5.14 – Field oil and water cut for M-Factor of 0.5 with 500 PV aquifer at a landing depth of 0.01

Figure 5.15 to Figure 5.17 show the performance of oil, gas rate and field water cut for M-Factor of 0.5 with 500 PV aquifer. For the landing depths of 0.04, 0.11 and 0.21 where the oil recovery oscillates from 72.19 to 70.80 and then reaches the maximum of 72.79%, the oil production rate and water cut register oscillation on their curves which results in inconsistent results in this landing depths. For the landing depths of 0.36 and 0.50, the oil recovery registers a reduction although oil can be produced through the entire concession period without reaching the constraint of 95% for water cut. The cumulative oil production in these two locations is reduced due to its proximity to the OWC. Water breaks through the producer first when the well is located at the landing depth of 0.50 and then 0.36, contributing to the reduction in cumulative oil production. In terms of gas production Figure 5.16 shows that it is higher at the beginning of oil production when the well is near the GOC. Along the time it tends to reduce.

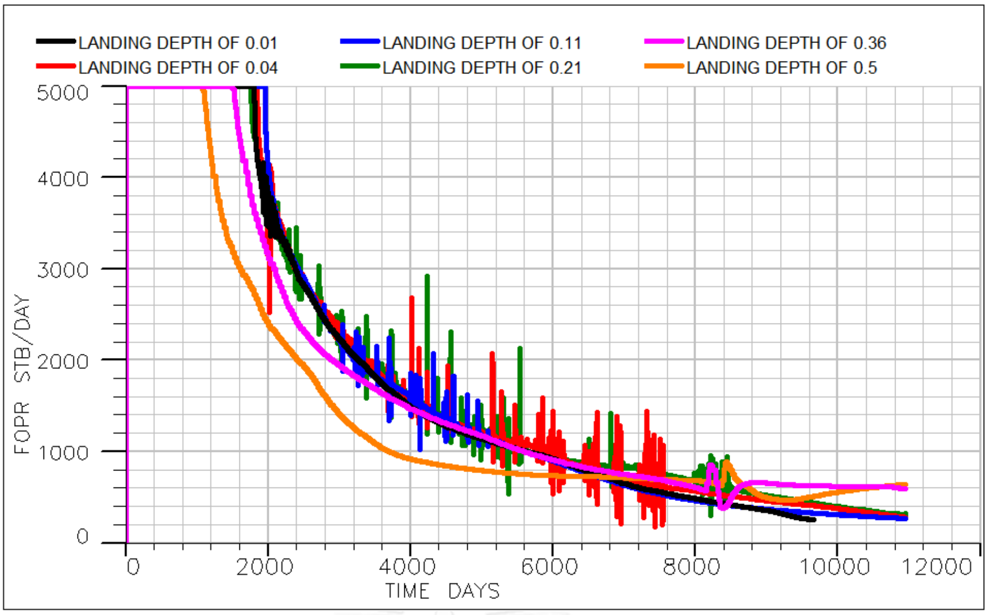

Figure 5.15 – Oil production rate performance for a fixed target liquid rate for M-Factor of 0.5 and 500PV aquifer at different landing depth

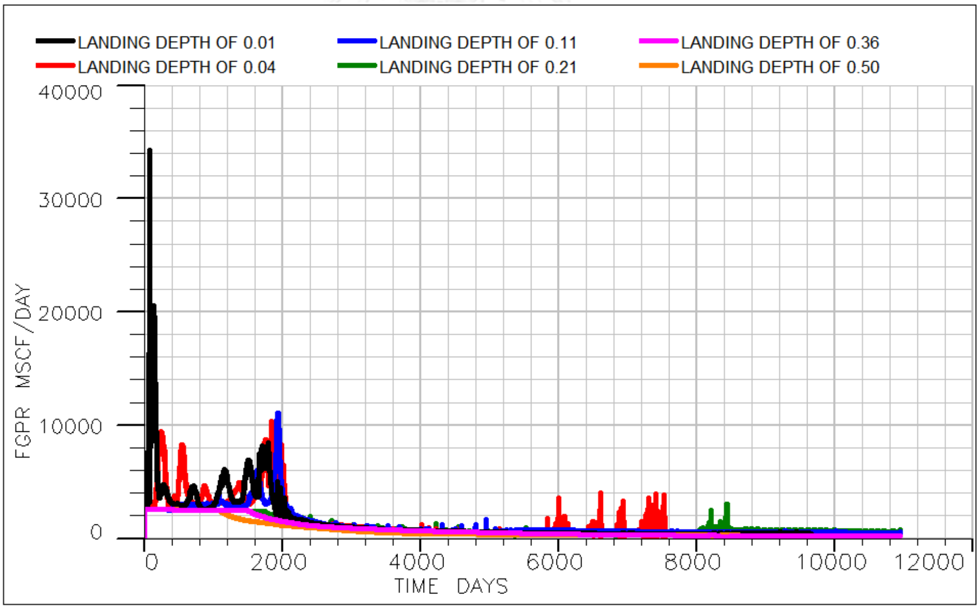

Figure 5.16 – Gas production rate performance for a fixed target liquid rate for M-Factor of 0.5 and 500PV aquifer at different landing depth

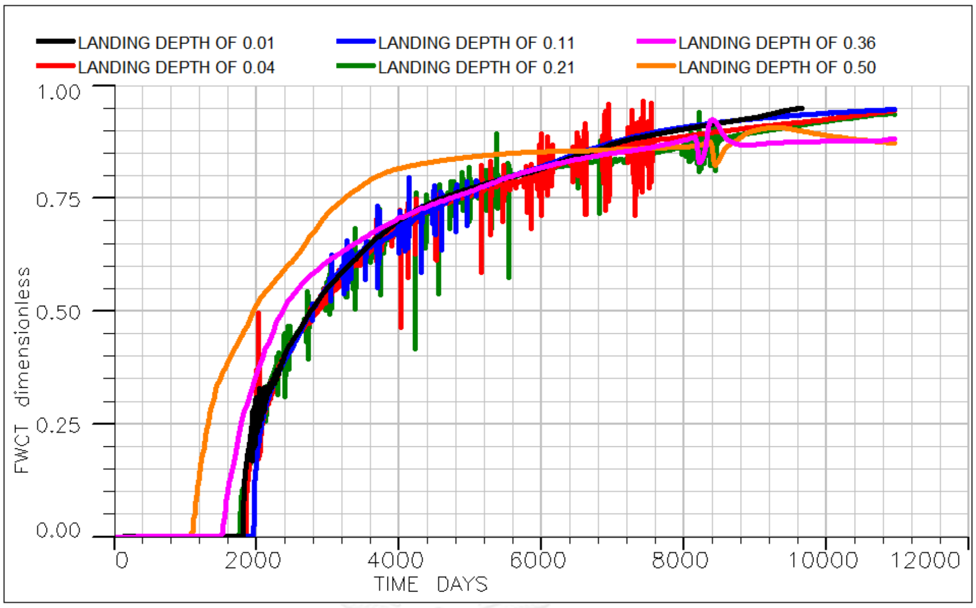

Figure 5.17 – Field water cut performance for a fixed target liquid rate for M-Factor of 0.5 and 500PV aquifer at different landing depth

In summary, when the aquifer strength is increased from 5 to 50, and 500 PV, the optimal well location changes from the landing depth of 0.79 to 0.64 and 0.21 (ft/ft), respectively, the recovery factor increases from 52.94 to 62.10, and 72.92%, respectively due to the downward movement of gas-oil contact in the case of weak aquifer and upward movement of the oil-water contact in the case of strong aquifer.

In addition, with increment in aquifer size, water influx acts to mitigate reservoir pressure decline and significantly increases the oil recovery factor (see Figure 5.18 and Figure 5.19).

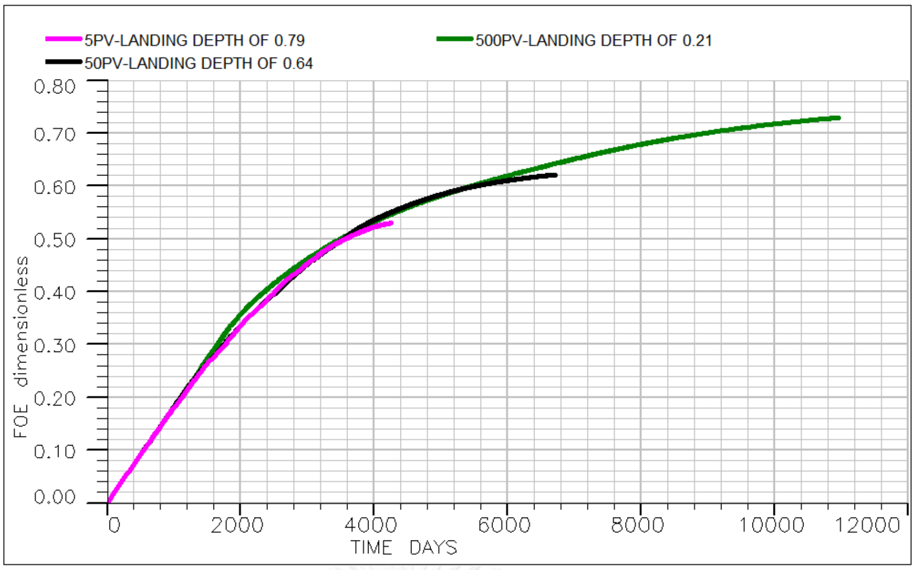

Figure 5.18 - Summary of oil recovery factor for optimal well location for M-Factor of 0.5

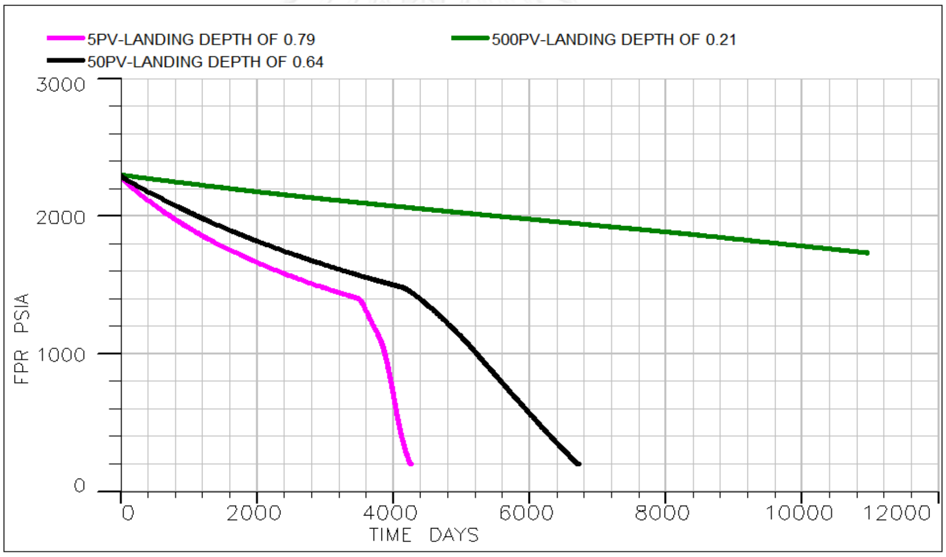

Figure 5.19 – Summary of field reservoir pressure for optimal well location for M-Factor of 0.5

5.2.2 Effect of well location for M-Factor of 1

For the case of 5 PV aquifer and M-factor of 1, the optimal well location is at a landing depth of 0.89, as it gives the highest recovery factor of 54.74% (see Table 5.8). The water production increases as the well is located towards the water-oil contact while the gas production slightly decreases as shown in Figure 5.21 and Figure 5.22, respectively.

Table 5.8 - Effect of well position with a fixed target liquid rate for M-Factor of 1 and 5PV aquifer

Landing depth (ft/ft)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
0.50	43.66	12.00	38.39	1.20	7.3
0.64	50.99	14.02	38.20	3.06	9.4
0.79	54.73	15.04	37.95	6.53	11.8
0.89	**54.74**	15.05	37.72	9.93	13.7
0.96	53.06	14.58	37.60	12.60	14.9
0.99	52.36	14.39	37.52	13.85	15.5

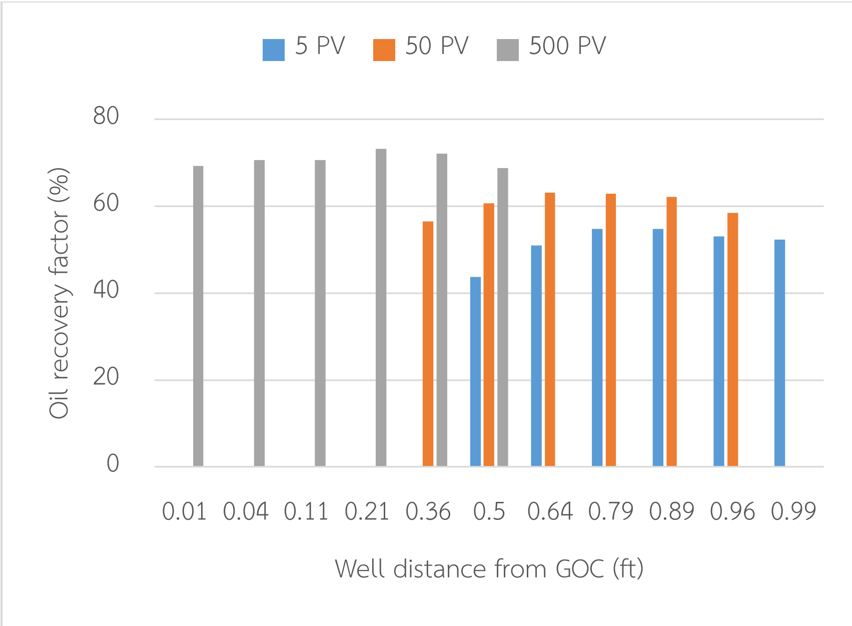

Figure 5.20 - Oil recovery factor for M-Factor of 1

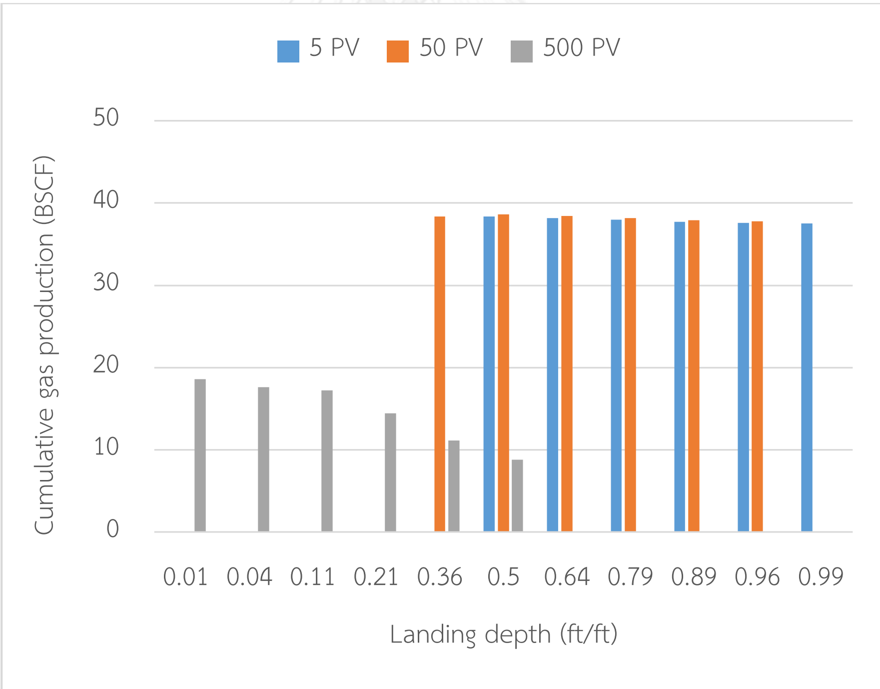

Figure 5.21 – Cumulative gas production for M-Factor of 1

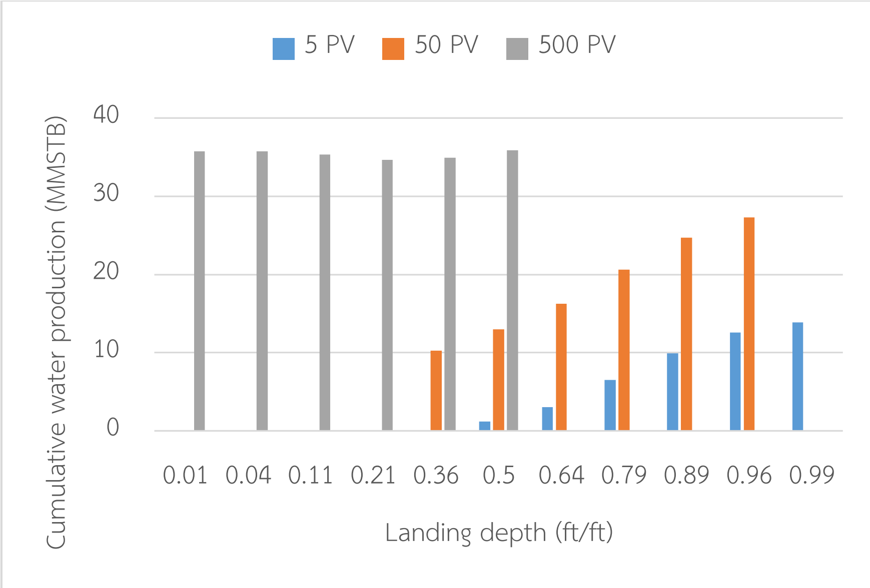

Figure 5.22 – Cumulative water production for M-Factor of 1

For the case of 50 PV aquifer and M-factor of 1, the optimal well location is at the landing depth of 0.64 as it gives the highest recovery factor of 63.08% (see Table 5.9). From this case, the water in the aquifer slightly dominates the forces of gas in the gas cap. As a result, the location right below the middle oil column at the landing depth of 0.64 yields the highest oil recovery factor. Furthermore, the water production increases as the well is located towards the water-oil contact while the gas production decreases (see Figure 5.21 and Figure 5.22).

Table 5.9 - Effect of well position with a fixed target liquid rate for M-Factor of 1 and 50PV aquifer

Landing depth (ft/ft)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
0.36	56.53	15.54	38.85	10.27	14.2
0.50	60.73	16.69	38.65	12.97	16.3
0.64	**63.08**	17.34	38.43	16.26	18.4
0.79	62.93	17.30	38.17	20.63	20.8
0.89	62.17	17.09	37.91	24.72	22.9
0.96	58.42	16.06	37.81	27.30	23.8

For the case of 500 PV aquifer and M-factor of 1, the aquifer is very large. The highest recovery factor of 73.20% is obtained when the well is located at the distance of 0.21 (see Table 5.10). Due to strong aquifer support, the highest recovery can be obtained when the well is located far away from water aquifer. The well has lower water production but higher gas production than the well in the middle as illustrated in Figure 5.21 and Figure 5.22.

Table 5.10 - Effect of well position with a fixed target liquid rate for M-Factor of 1 and 500PV aquifer

Landing depth (ft/ft)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
0.01	69.24	19.03	18.59	35.75	30.0
0.04	70.58	19.40	17.61	35.78	30.0
0.11	70.61	19.41	17.23	35.37	30.0
0.21	**73.20**	20.12	14.44	34.66	30.0
0.36	72.11	19.82	11.14	34.96	30.0
0.50	68.75	18.90	8.84	35.88	30.0

Figure 5.23 to Figure 5.25 show the performance of oil, gas rate and field water cut for M-Factor of 1 with 500 PV aquifer. The oil recovery increases from 69.24 at the landing depth of 0.01 to 70.58 at the landing depth of 0.04 to 70.61 at the landing depth of 0.11 and then reaching the maximum of 73.20% at the landing depth of 0.21. Although at these landing depths, there are fluctuations of oil, gas production rate and water cut, the recovery factor tends to increase with depth. For the subsequent landing depths of 0.36 and 0.50, the oil recovery registers a reduction although it can be produced through the entire concession period without reaching the constraint of 95% for water cut. The cumulative oil production in these two location is reduced due to its proximity to the OWC. Water breaks through the producer first when the well is located at the landing depth of 0.50 and then 0.36, contributing to the reduction in cumulative oil production. In terms of gas production Figure 5.24 shows an inconsistent curve when the well is placed at the landing depths of 0.01 and 0.04 as it presents fluctuations in its performance.

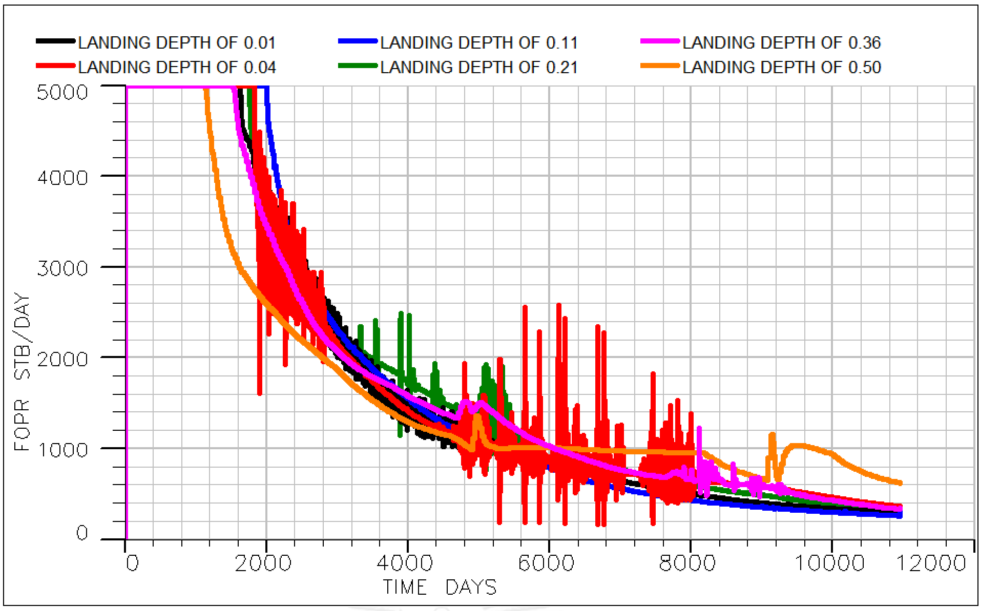

Figure 5.23 - Field oil rate performance for a fixed target liquid rate for M-Factor of 1 and 500PV aquifer at different landing depth

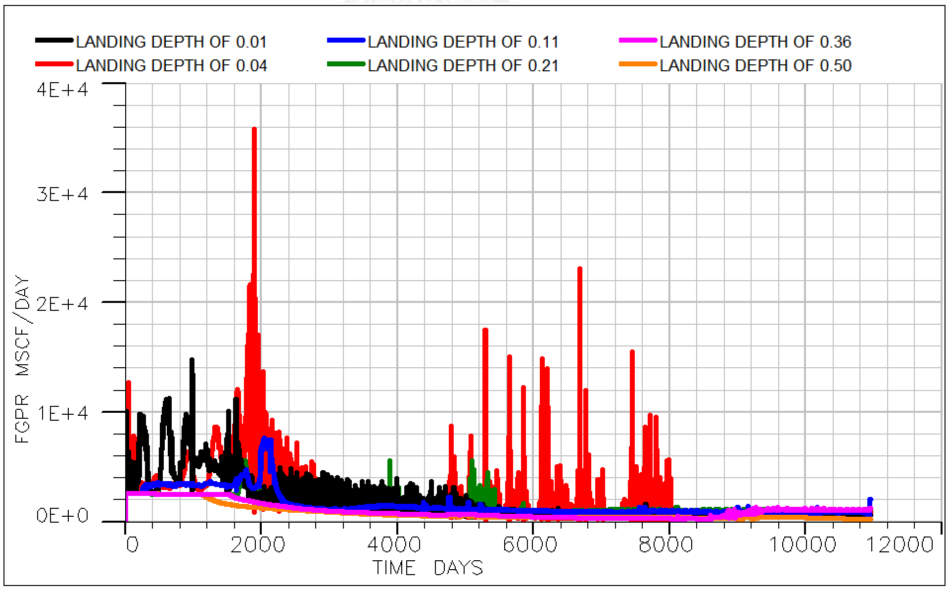

Figure 5.24 - Field gas rate performance for a fixed target liquid rate for M-Factor of 1 and 500PV aquifer at different landing depth

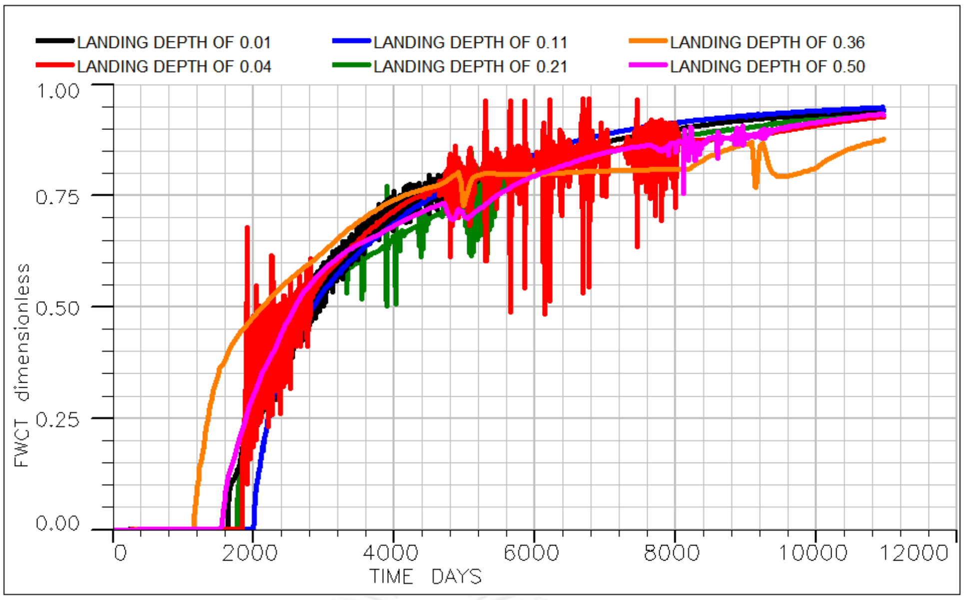

Figure 5.25 - Field water cut performance for a fixed target liquid rate for M-Factor of 1 and 500PV aquifer at different landing depth

In summary, when the aquifer strength is increased from 5 to 50, and 500 PV, the optimal well location changes from the landing depth of 0.89 in the first case to a landing depth of 0.64 in the second case to the landing depth of 0.21 in the last case with an increase in oil recovery factor from 54.74 to 63.08, and 73.20%, respectively due to relative movements of gas-oil and oil-water contacts for different aquifer strengths. As in the case with M-factor of 0.5, the increment in aquifer size significantly increases the recovery factor (Figure 5.26 and Figure 5.27).

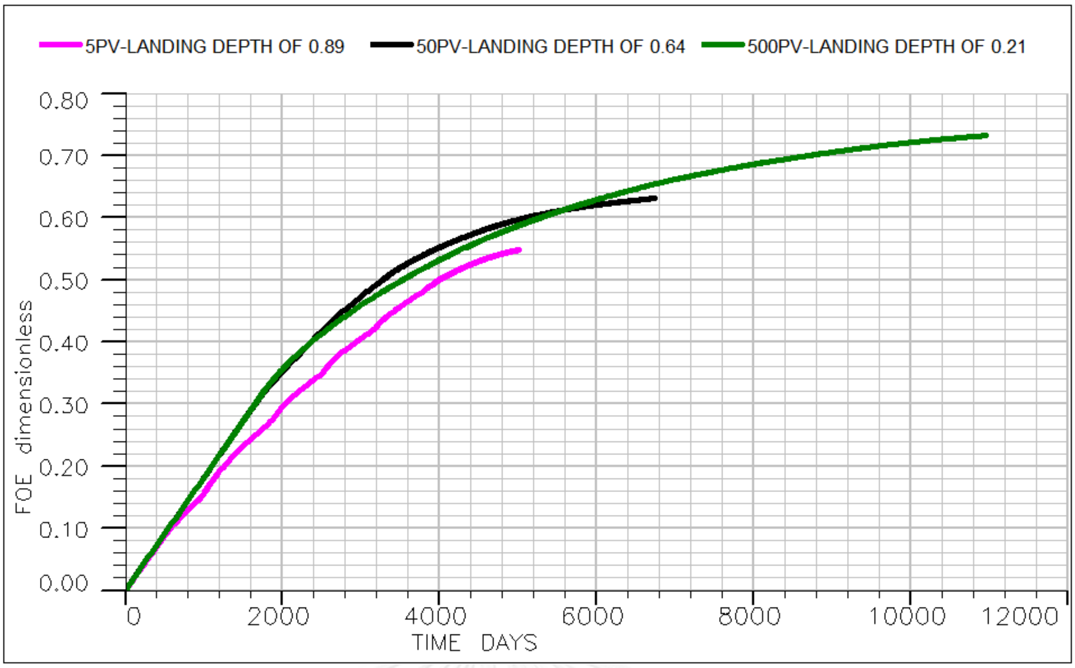

Figure 5.26 - Summary of oil recovery factor for optimal well location for M-Factor of 1

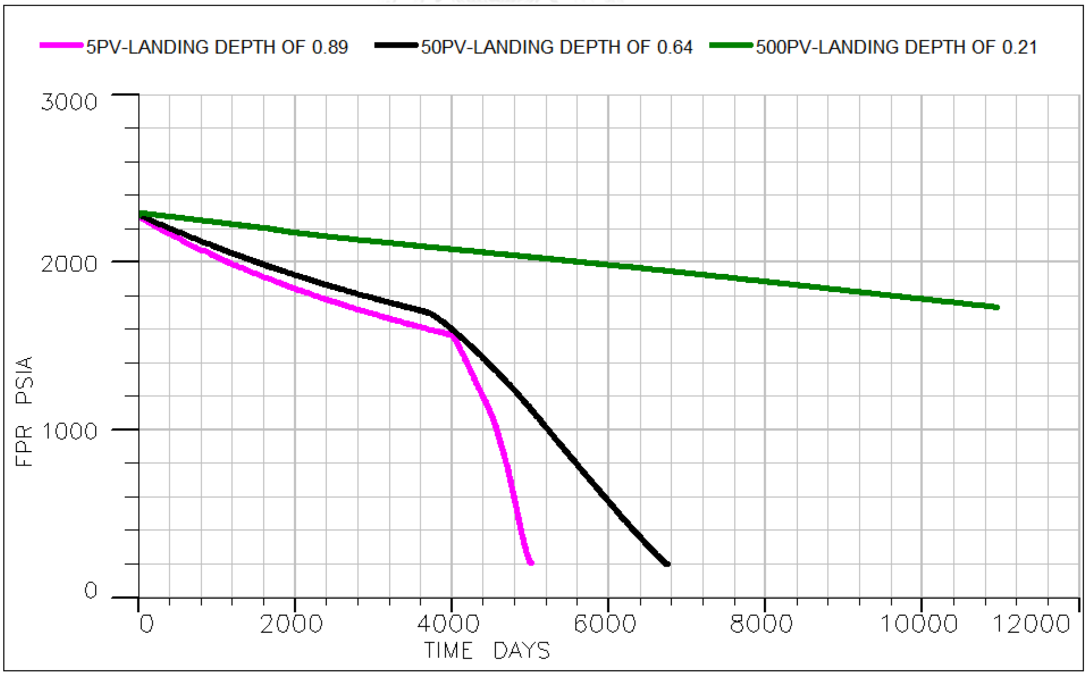

Figure 5.27 - Summary of field average pressure for optimal well location for M-Factor of 1

5.2.3 Effect of well location for M-Factor of 2

For the case of 5PV aquifer and M-factor of 2, the gas cap is large while the aquifer is small. The best well location is at the landing depth of 0.89 as it gives the highest recovery factor of 57.27% (see Table 5.11). In this case, gas provides a good driving force. The further away the well is located from the gas cap, the higher the oil recovery. As this location is the nearest to the oil-water contact, the amount of produced water become higher but the gas production is lower as shown in Figure 5.29 and Figure 5.30, respectively.

Table 5.11 - Effect of well position with a fixed target liquid rate for M-Factor of 2 and 5PV aquifer

Landing depth (ft/ft)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
0.50	45.78	12.58	64.37	1.43	7.7
0.64	52.89	14.54	64.19	3.39	9.9
0.79	57.12	15.70	63.93	6.84	12.4
0.89	**57.27**	15.74	63.68	10.16	14.2
0.96	55.69	15.31	63.53	12.83	15.5
0.99	55.06	15.14	63.47	13.99	16.0

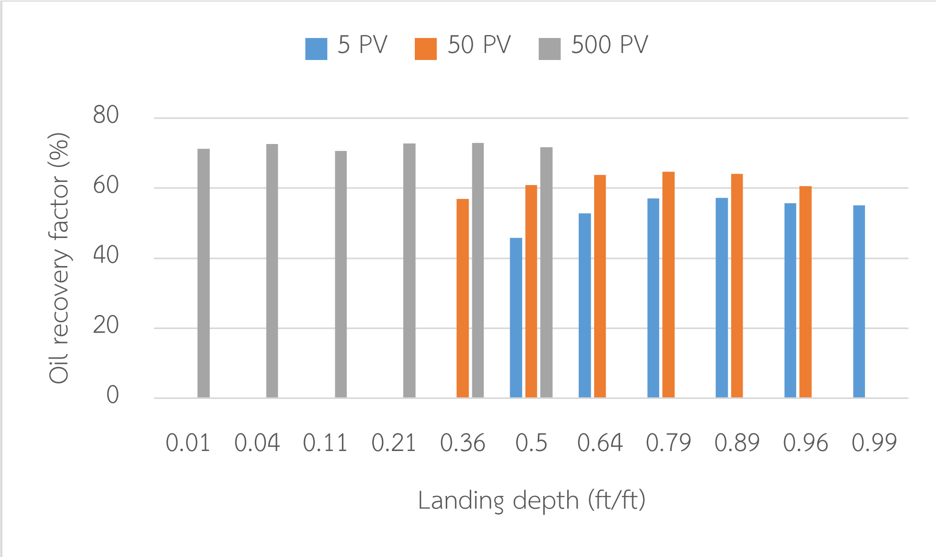

Figure 5.28 – Oil recovery factor for M-Factor of 2

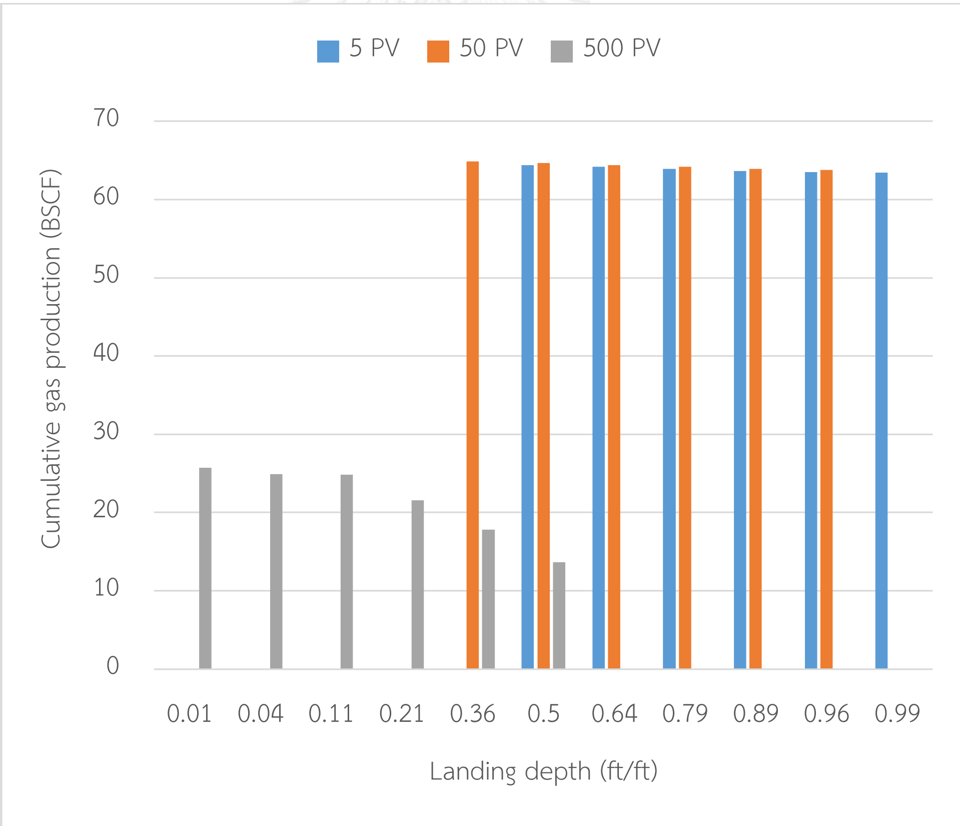

Figure 5.29 - Cumulative gas production for M-Factor of 2

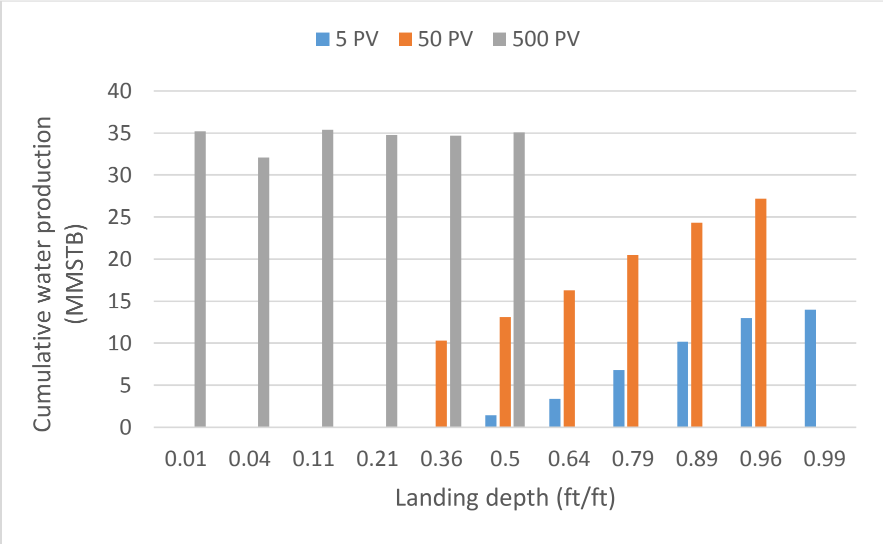

Figure 5.30 - Cumulative water production for M-Factor of 2

For the case of 50 PV aquifer and M-factor of 2, the optimal well location is at the landing depth of 0.79, with the highest recovery factor of 64.70% as depicted in Table 5.12 indicating that the gas cap is still a strong driving force even with this increment of aquifer size from 5 to 50 PV. Similar to previous cases with M-factor of 0.5 and 1 having 50 PV aquifer, the water production increases as the well is located towards the water-oil contact while the gas production decreases (see Figure 5.29 and Figure 5.30).

Table 5.12 - Effect of well position with a fixed target liquid rate for M-Factor of 2 and 50PV aquifer

Landing depth (ft/ft)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
0.36	56.88	15.63	64.85	10.33	14.3
0.50	60.90	16.74	64.65	13.12	16.4
0.64	63.86	17.56	64.43	16.28	18.6
0.79	**64.70**	17.78	64.17	20.44	21.0
0.89	64.08	17.62	63.92	24.32	23.0
0.96	60.61	16.66	63.81	27.22	24.1

For the case of 500 PV aquifer and M-factor of 2, the aquifer is very large. The highest recovery factor of 72.99% is obtained when the well is located at the landing depth of 0.36 (see Table 5.13). In the case of M-factor of 0.5 and 1 with 500PV aquifer, the optimal well location is located at the landing depth of 0.21. Comparing with the present case, it can be observed that the suitable well location moves 10 ft downward due to the increment of the gas cap size that boosts the gas cap strength. As the well is located deeper towards the aquifer, the water production slightly increases but gas production decreases as shown in Figure 5.29 and Figure 5.30.

Table 5.13 - Effect of well position with a fixed target liquid rate for M-Factor of 2 and 500PV aquifer

Landing depth (ft/ft)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
0.01	71.21	19.58	25.72	35.20	30.0
0.04	72.61	19.96	24.88	32.09	28.5
0.11	70.64	19.42	24.85	35.36	30.0
0.21	72.81	20.01	21.59	34.77	30.0
0.36	**72.99**	20.06	17.78	34.72	30.0
0.50	71.68	19.70	13.62	35.08	30.0

Figure 5.31 to Figure 5.33 show the performance of oil, gas rate and field water cut for M-Factor of 0.5 with 500 PV aquifer. For the landing depths of 0.01, 0.04, 0.11 and 0.21 where the oil recovery factor is 71.21, 72.61, 70.64 and 72.81%, cumulative oil production is limited by gas production. After reaching the maximum oil recovery of 72.79% at the landing depth of 0.36, oil recovery factor reduces to 71.68%. This reduction is due to the proximity of the well to the OWC. Water breaks through the producer first when the well is located at the landing depth of 0.50, contributing to the reduction in cumulative oil production. In terms of gas production Figure 5.32 shows that at the landing depth of 0.04 gas production has higher oscillation as for the cases of M-Factor of 0.5 and 1 with 500 PV.

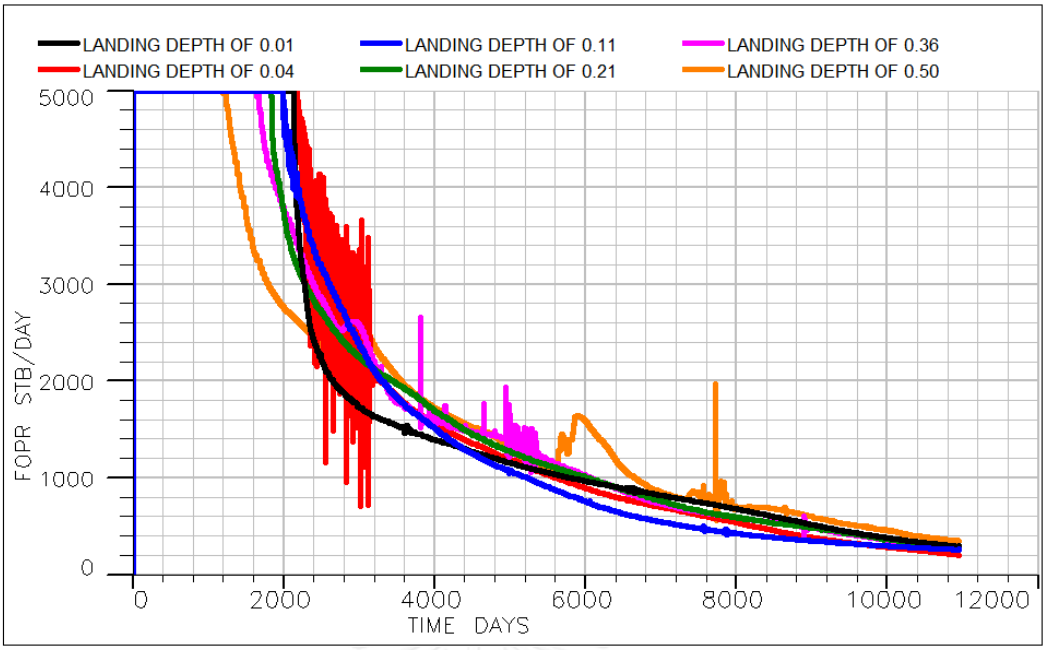

Figure 5.31 - Field oil rate performance for a fixed target liquid rate for M-Factor of 2 and 500PV aquifer at different landing depth

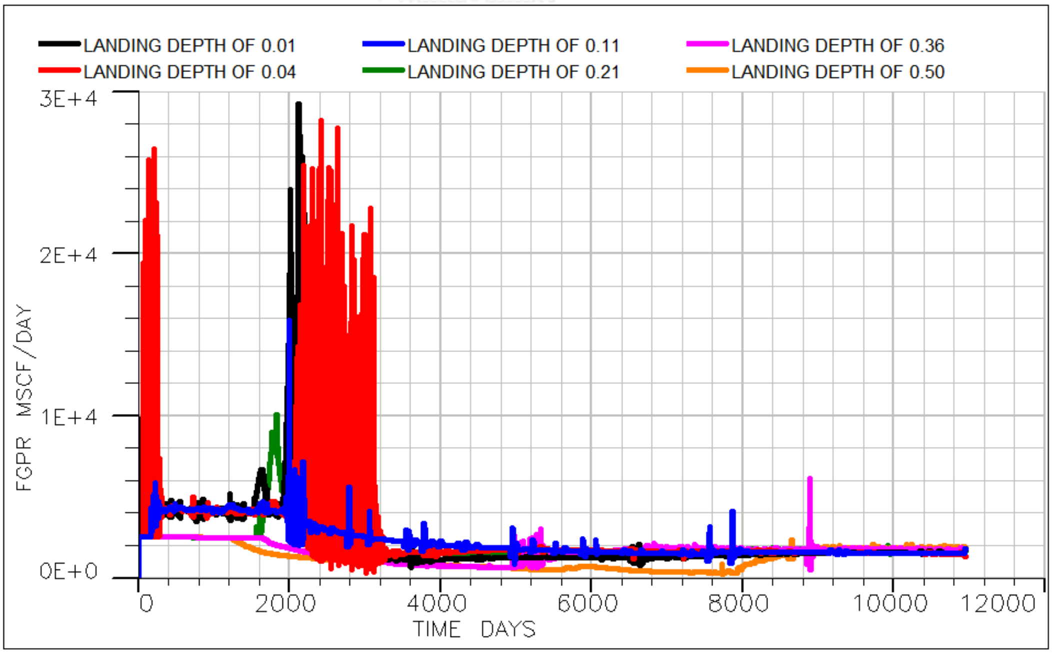

Figure 5.32 - Field gas rate performance for a fixed target liquid rate for M-Factor of 2 and 500PV aquifer at different landing depth

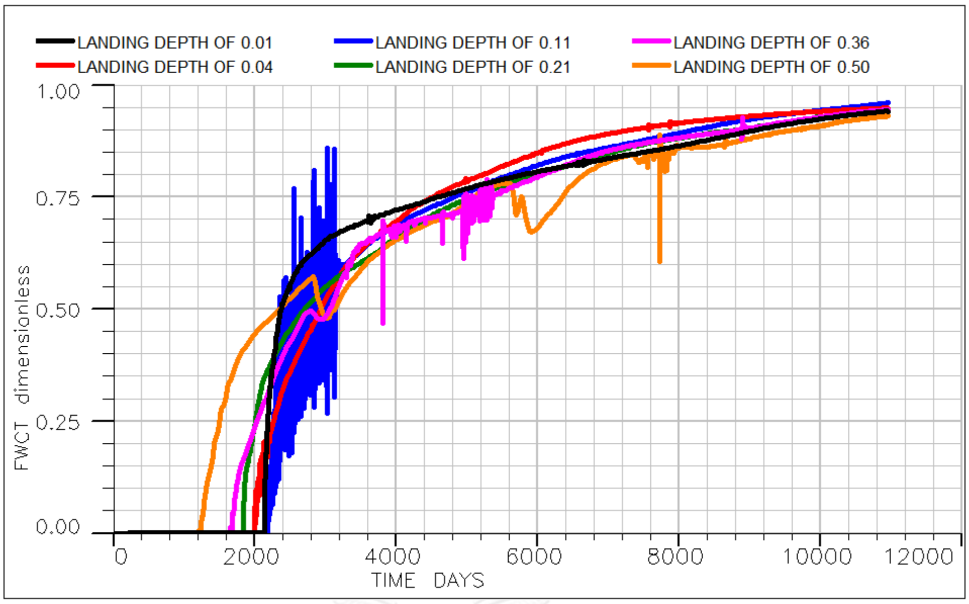

Figure 5.33 - Field water cut performance for a fixed target liquid rate for M-Factor of 2 and 500PV aquifer at different landing depth

In summary, when the aquifer strength is increased from 5 to 50, and 500 PV, the optimal well location changes from the landing depth of 0.89 in the first case to the landing depth of 0.79 for the second case and to the landing depth of 0.36 for the last case with a growth in oil recovery factor from 57.27 to 64.70 and 72.99%, respectively due to relative movements of gas-oil and oil-water contacts for different aquifer strengths. Similarly to the cases with M-factor of 0.5 and 1, the increment in aquifer size significantly increases the recovery factor.

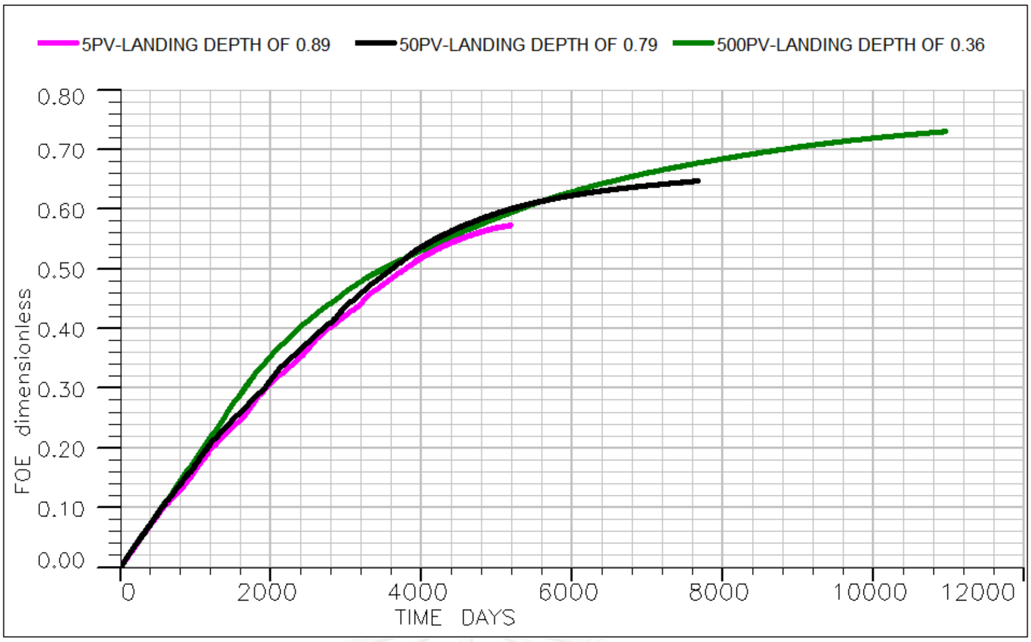

Figure 5.34 - Summary of oil recovery factor for optimal well location for M-Factor of 2

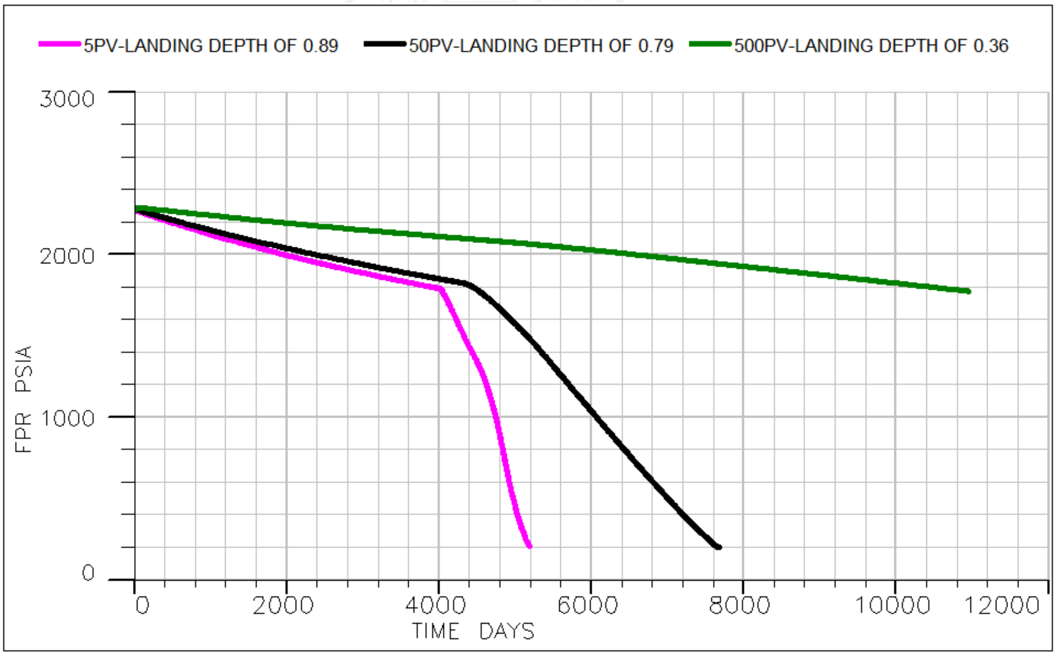

Figure 5.35 - Summary of field average pressure for optimal well location for M-Factor of 2

5.2.4 Summary for effect of well location with a fixed target liquid rate

From Table 5.5 to Table 5.13, it can be noticed that the well position that yields the highest oil recovery factor for each case is different. These positions are summarized in Table 5.14 , and they are used as basis for well locations when performing the study of effect of liquid rate in Section 5.3.

Table 5.14 - Summary table of optimal well location

PV	M-Factor		
	0.5	**1**	**2**
	Landing depth (ft/ft)		
5	0.79	0.89	0.89
50	0.64	0.64	0.79
500	0.21	0.21	0.36

From Table 5.14, the suitable well location depends on the strength of the gas cap and aquifer. For a fixed aquifer PV and varying the M-Factor, the suitable well location moves downward with the increment of the gas cap. For a fixed M-Factor and varying the aquifer PV, the suitable well location changes from near the OWC to a location close to the GOC.

When the well is located near the OWC, specifically at the distances between the landing depths of 0.79 and 0.99, the field oil and water production rates register a fluctuation (Figure 5.36).

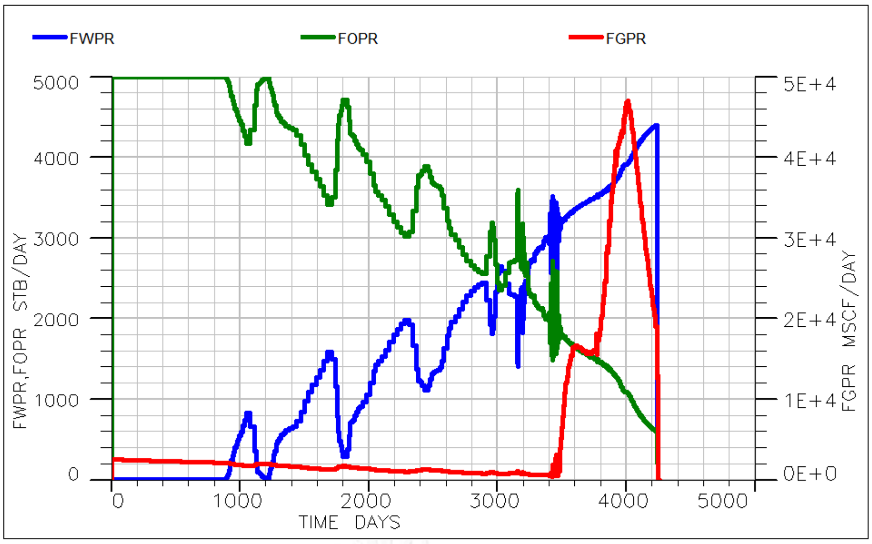

Figure 5.36 - Oil, gas and water production rates performance for a reservoir with vertical permeability of 500 mD when the well is located near OWC

As water rate increases, oil rate decreases (Figure 5.36). The fluctuations are caused by different strengths of gas cap and aquifer. Figure 5.37 shows the field water cut for the case of M-Factor of 0.5 with 5 PV aquifer. The well is at the landing depth of 0.79. The cycles are represented as 1, 2, 3 and 4 in Figure 5.37 in each cycle, water rate increases (oil rate reduces) until a certain point and then starts to reduce until the new cycle starts.

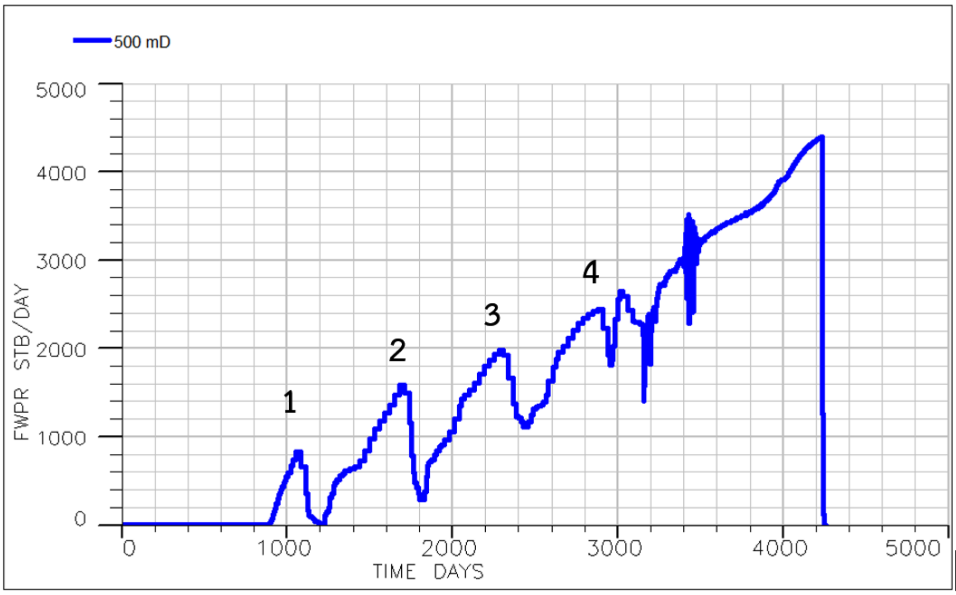

Figure 5.37 - Field water cut for the well near OWC with vertical permeability of 500 mD

Cycle 1 starts when water breaks through the horizontal well after 923 days of oil production. Gas and water saturation profiles are shown in Figure 5.38, where it can be noticed that water rate increases due to the fast movement of water towards the horizontal well. When the first cycle achieves its peak after 1,080 days, water rate stars to reduces due to the downward movement of GOC (gas expansion), resulting in an increment in oil rate (Figure 5.39).

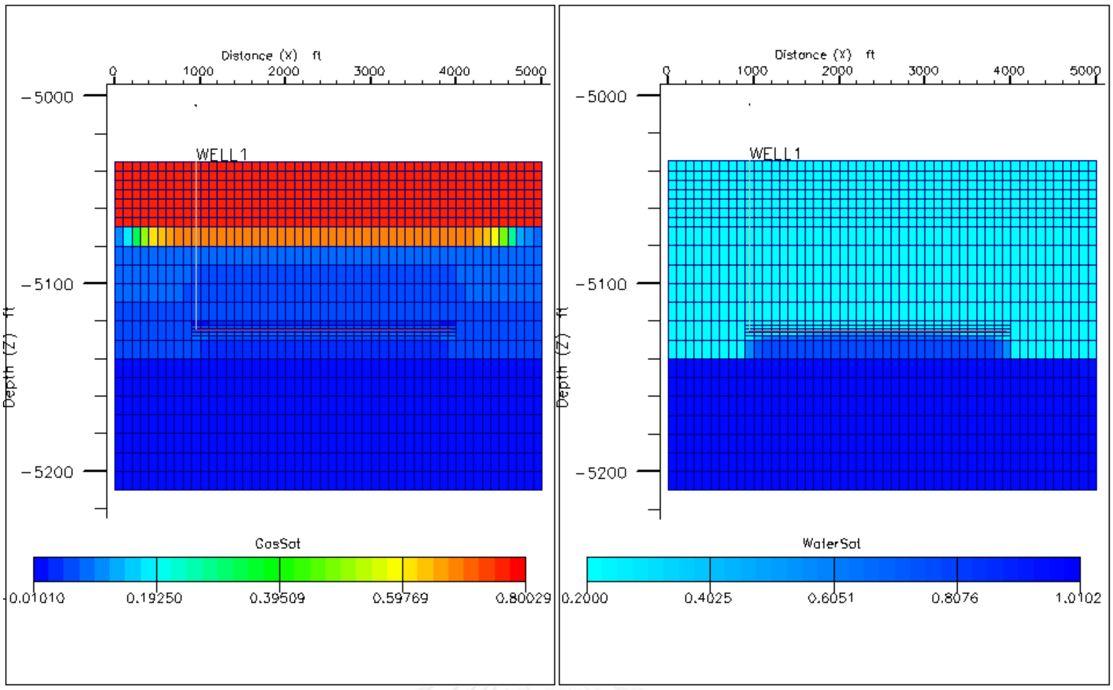

Figure 5.38 - Gas and water saturation after 923 days of oil production for cycle 1

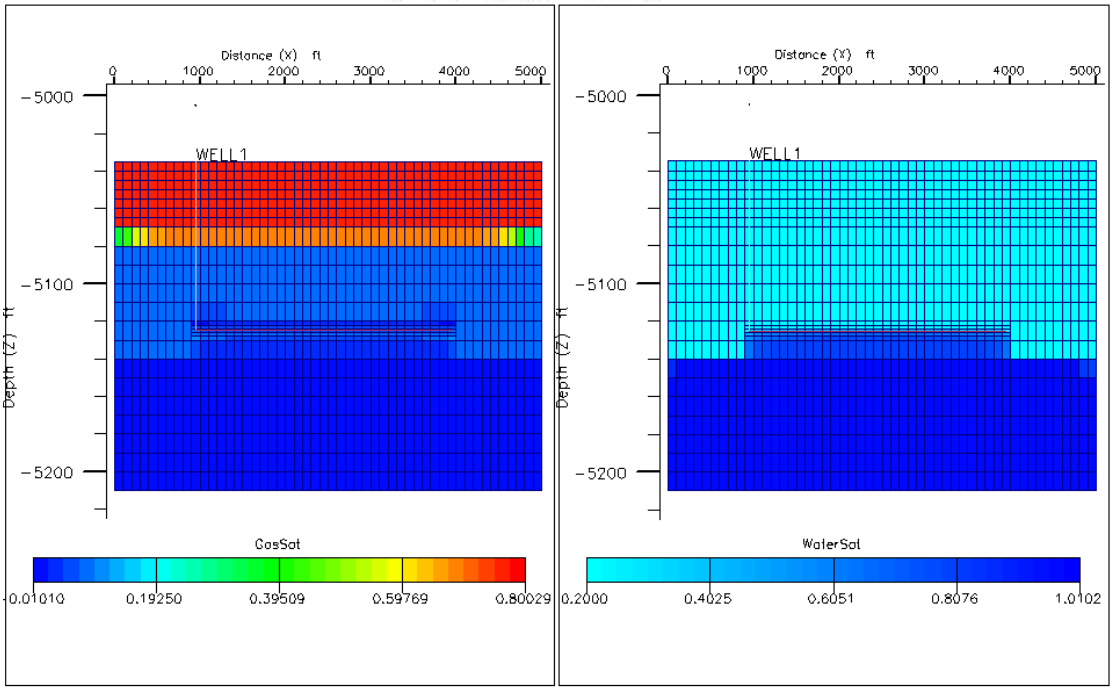

Figure 5.39 - Gas and water saturation after 1,080 days of oil production for cycle 1

For the second cycle, gas is expanding at the second layer of the grid blocks initially occupied by oil. During this phase which starts approximately after 1,225 days, gas expansion does not have enough strength to keep water far away from the well (Figure 5.40), resulting in an increment in water production and reduction in oil production. When the cycle reaches its peaks after 1,710 days, water production rate starts to reduce and oil production rate starts to increase due to expansion of the gas from gas cap (Figure 5.41).

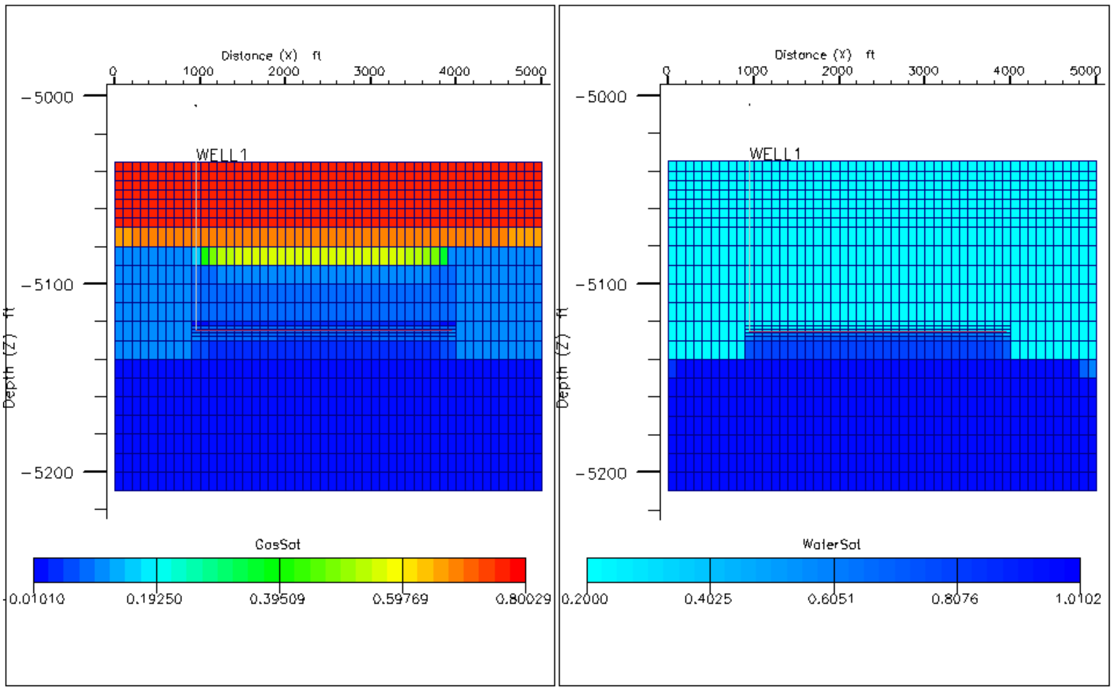

Figure 5.40 - Gas and water saturation after 1,225 days of oil production for cycle 2

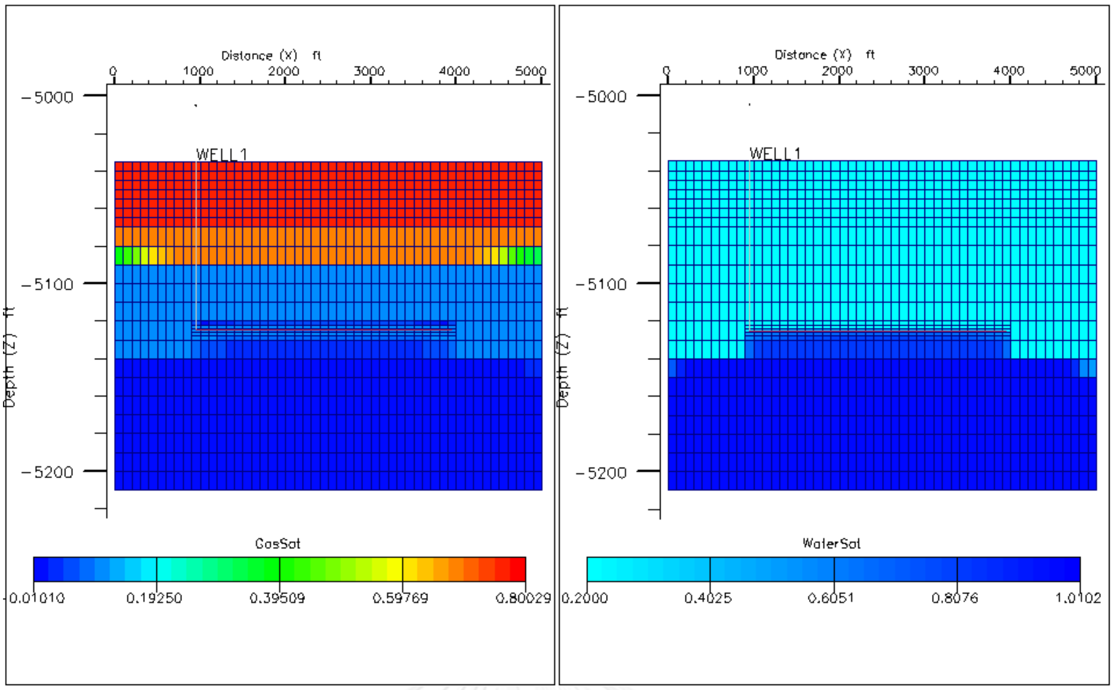

Figure 5.41 - Gas and water saturation after 1,710 days of oil production for cycle 2

For the third and fourth cycles, gas is expanding at the third and fourth layers respectively of the grid blocks initially occupied by oil. During these cycles which start approximately after 1,830 days for third phase and after 2,460 days for the fourth phase, gas expansion does not have enough strength to keep water far away from the well (Figure 5.42 and Figure 5.44), resulting in an increment in water production and reduction in oil production. When the cycle reaches its peaks after 2,310 days for the third phase and after 2,910 days for the fourth phase, water production rate starts to reduce and oil production rate starts to increase due to expansion of the gas from gas cap (Figure 5.43 and Figure 5.45).

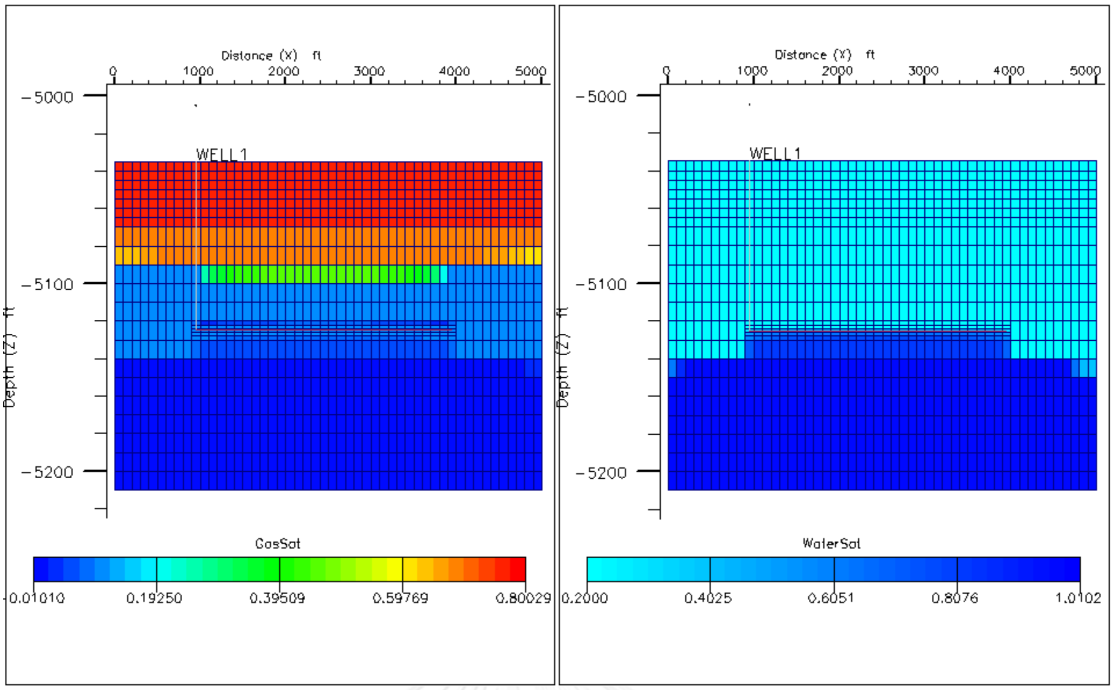

Figure 5.42 - Gas and water saturation after 1,830 days of oil production for cycle 3

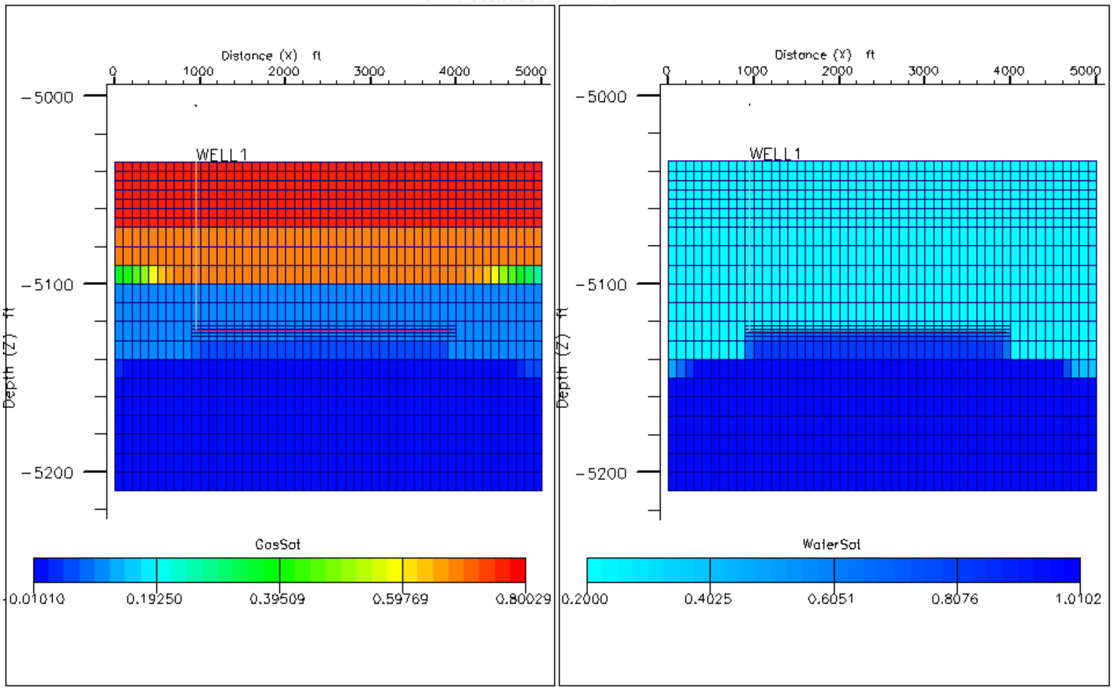

Figure 5.43 - Gas and water saturation after 2,310 days of oil production for cycle 3

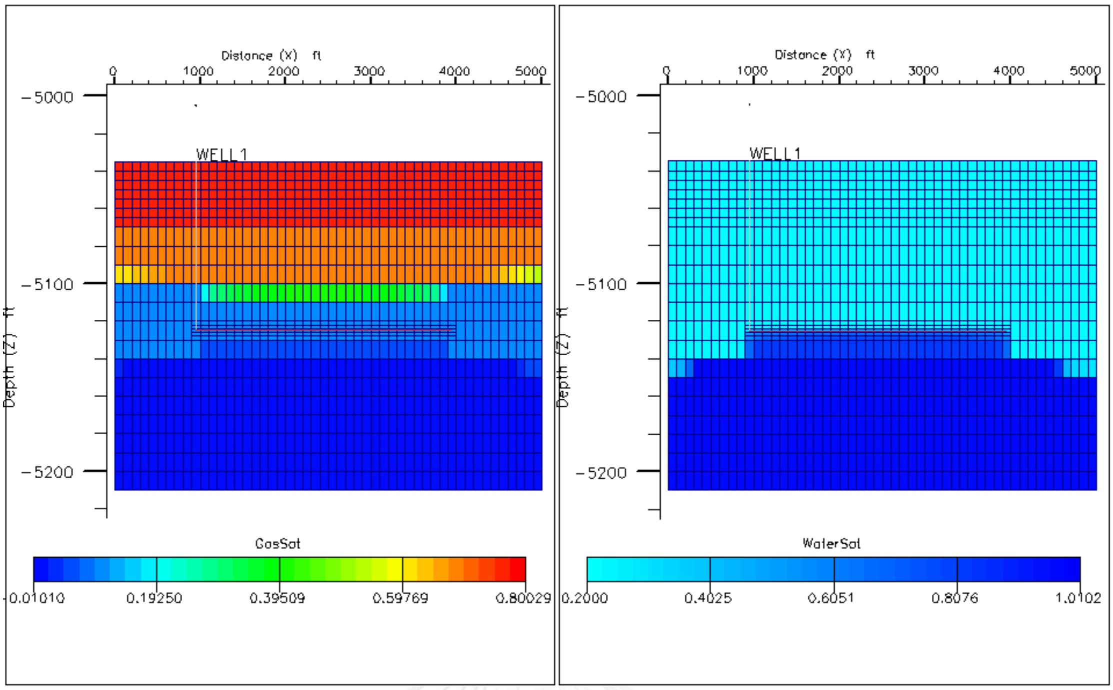

Figure 5.44 - Gas and water saturation after 2,460 days of oil production for cycle 4

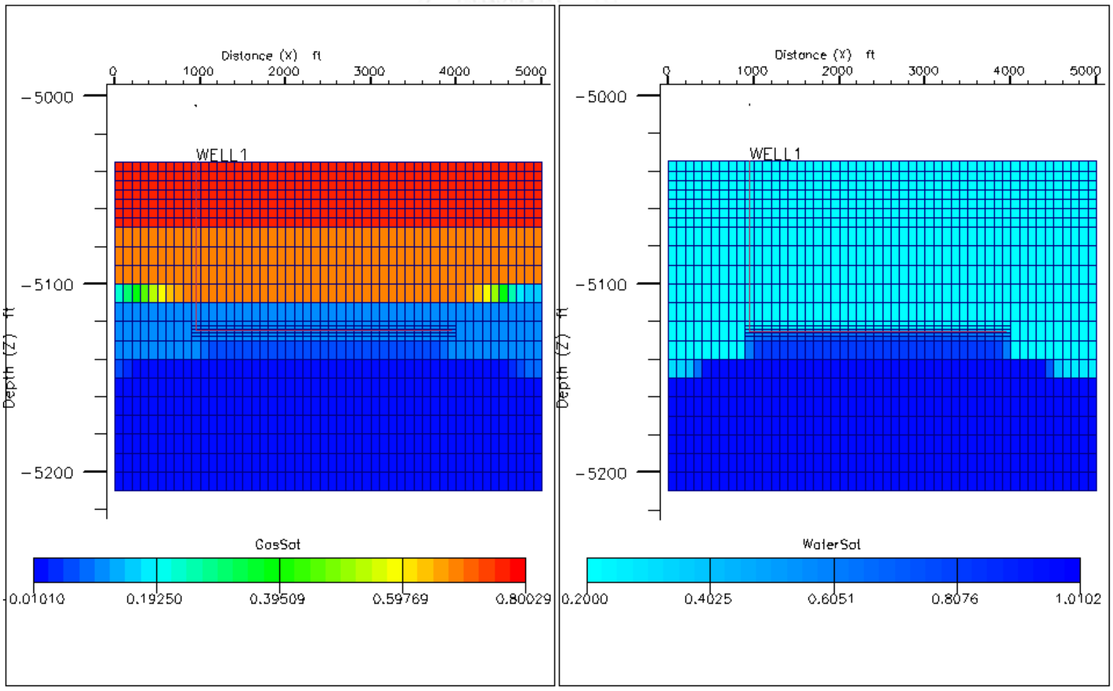

Figure 5.45 - Gas and water saturation after 2,910 days of oil production for cycle 4

Running simulation for different vertical permeability (5 and 50 mD), it was noticed that the fluctuation reduces with the reduction of vertical permeability. Figure 5.46 to Figure 5.50 show the effect of permeability in oil, gas and water production. When compared with the oil and water production rates demonstrated in Figure 5.36 (vertical permeability of 500 mD), the plots have less amplitude. When the vertical permeability is 5 mD, the oil and water curves become smooth as shown in Figure 5.47.

Figure 5.48 shows the performance of oil production for different permeability (5, 50 and 500 mD). As the reservoir contains higher permeability, the plateau period becomes longer for the cases with oil rate oscillations (50 and 500 mD). For gas production, Figure 5.49 shows that as the permeability becomes lower, gas expands fast and reaches the well. This quick gas breakthrough when the reservoir has lower permeability is caused by fast pressure decline in the reservoir. Figure 5.51 to Figure 5.53 illustrate oil and gas saturation profiles at the time of 2,400 days after oil production. At this time gas for the case of 5 mD reaches the horizontal well while for the cases of 50 and 500 mD gas did not reach the well. Figure 5.54 to Figure 5.56 illustrate oil and gas saturation profiles at the time of 3,030 days after oil production. At this time gas for the case of 5 and 50 mD reached the horizontal well while for the cases of 500 mD gas did not reach the well

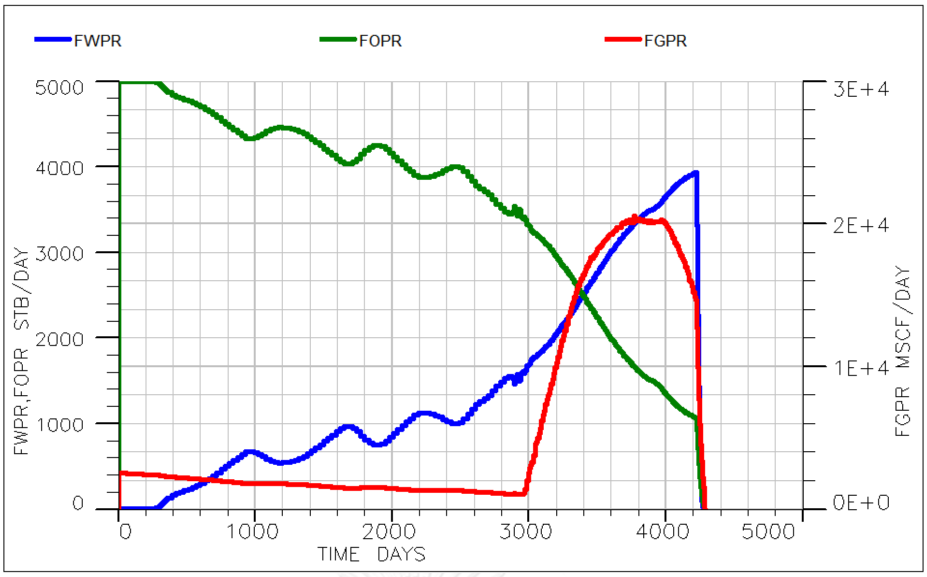

Figure 5.46 - Oil, gas and water production rates performance for a reservoir with vertical permeability of 50 mD when the well is located near OWC

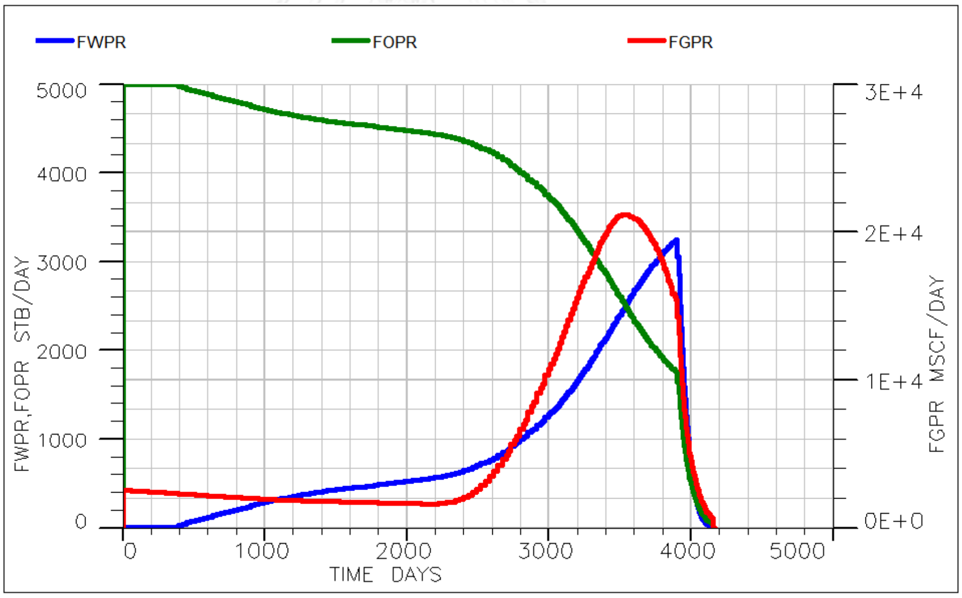

Figure 5.47 -Oil, gas and water production rates performance for a reservoir with vertical permeability of 5 mD when the well is located near OWC

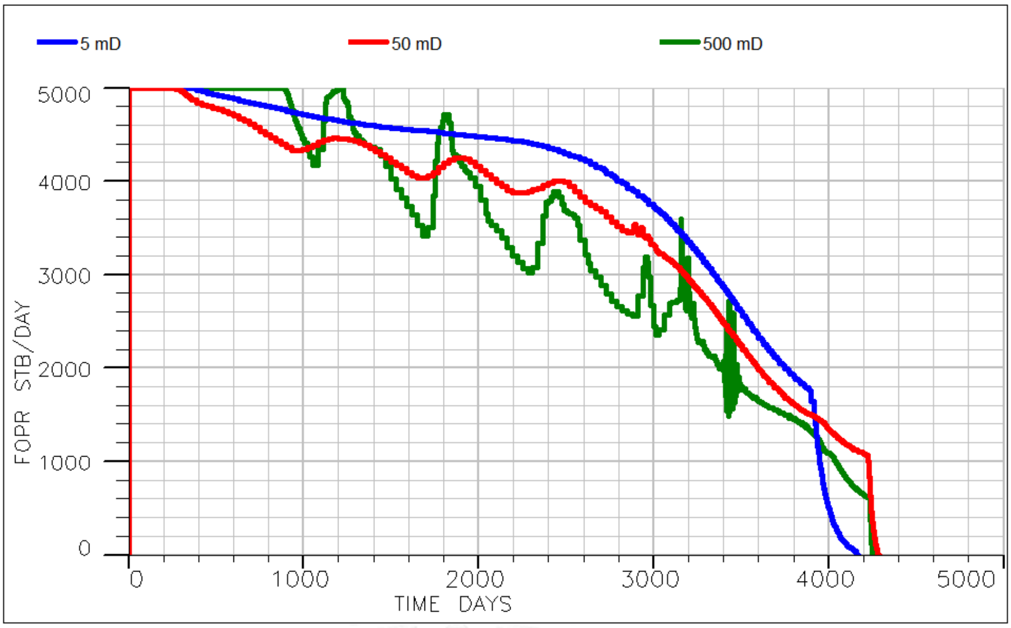

Figure 5.48 - Effect of permeability in oil production rate when the well is at the landing depth of 0.64

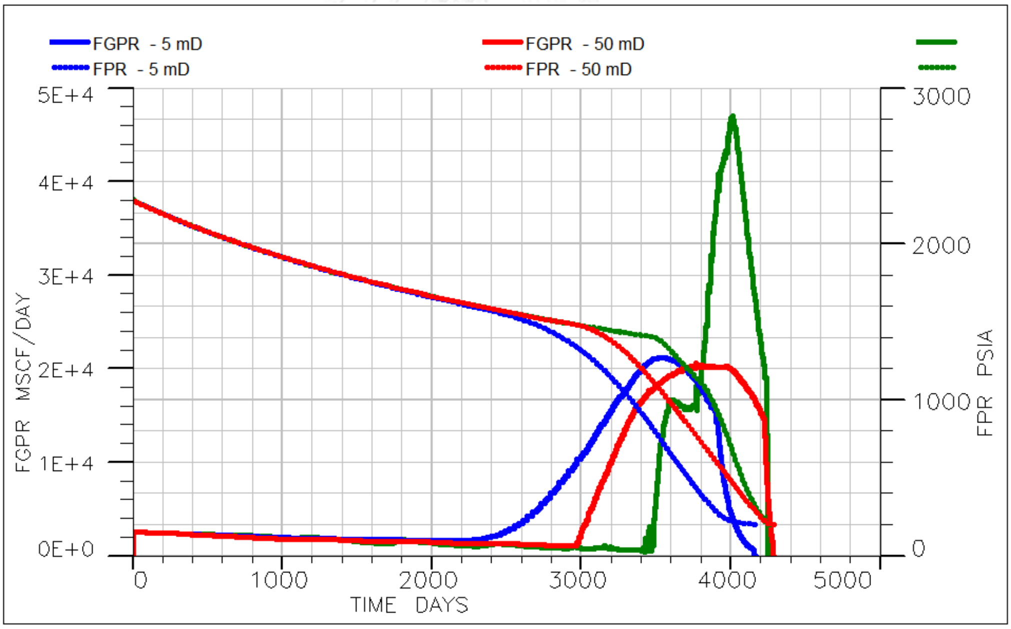

Figure 5.49 - Effect of permeability in gas production rate and field average pressure when the well is at the landing depth of 0.64

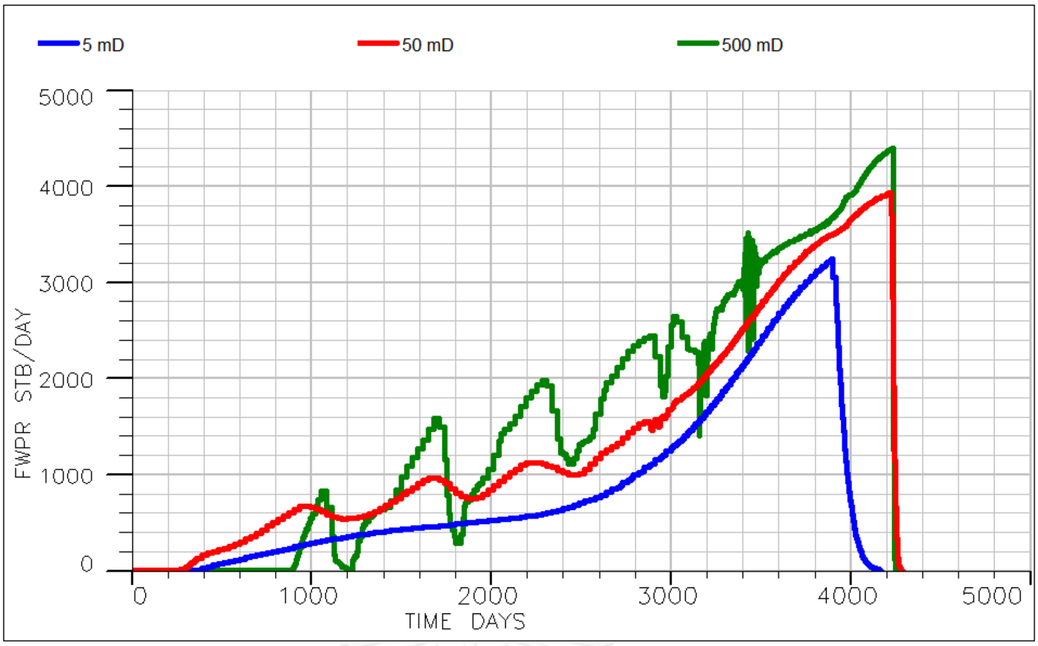

Figure 5.50 - Effect of permeability in water production rate when the well is at the landing depth of 0.64

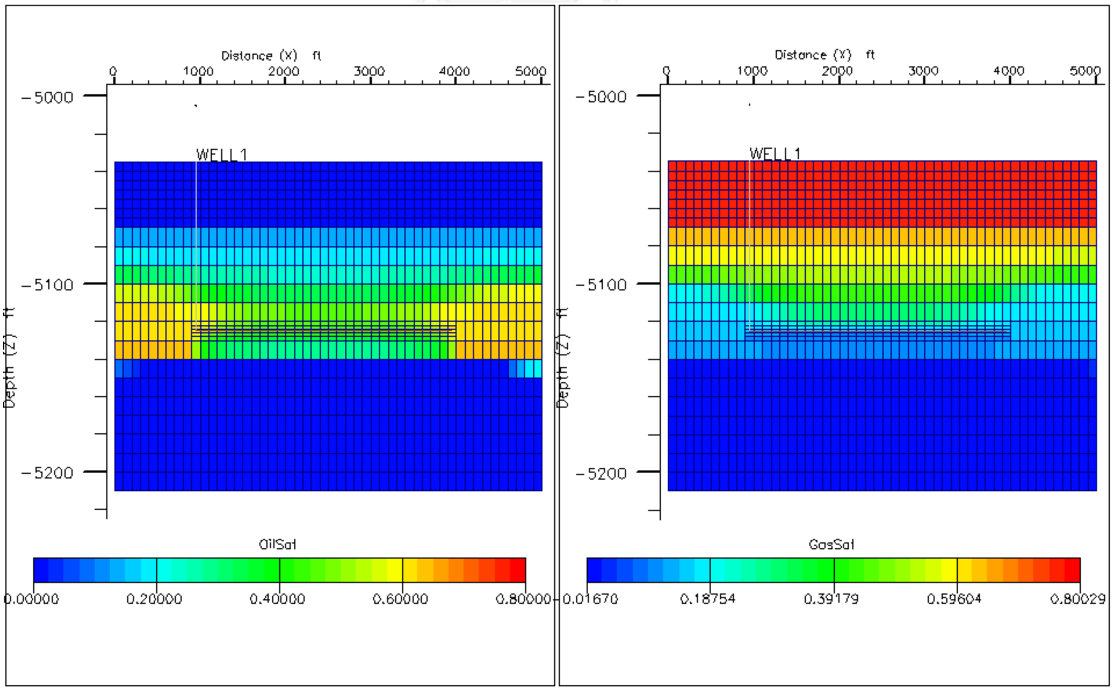

Figure 5.51 – Oil and gas saturation profiles after approximately 2,400 days of oil production for the case of 5 mD when the well is at the landing depth of 0.64

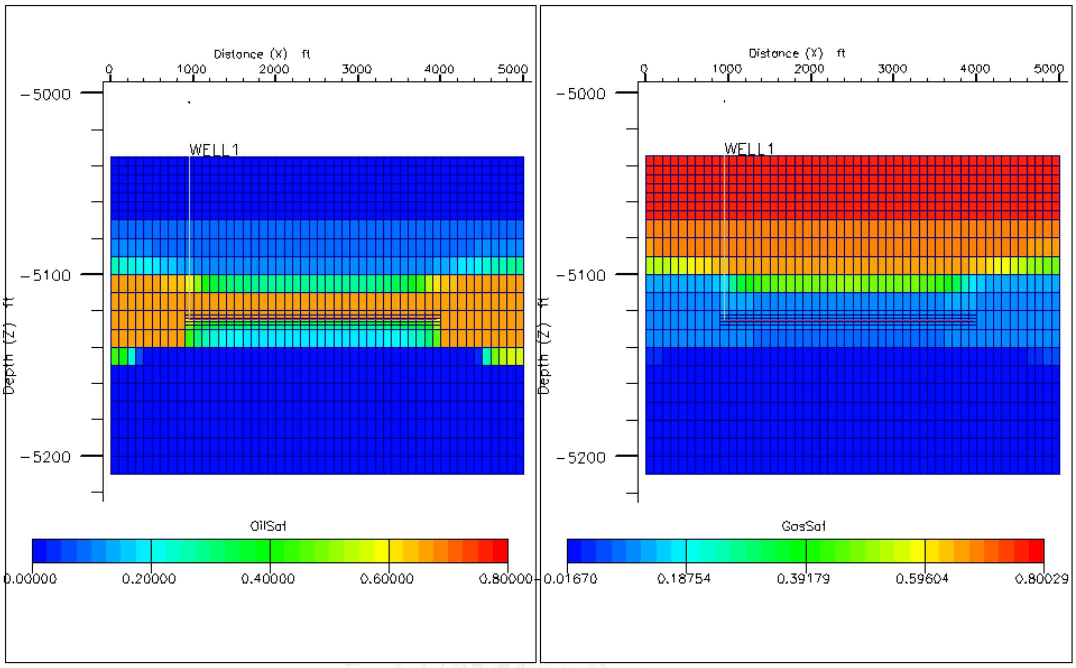

Figure 5.52 - Oil and gas saturation profiles after approximately 2,400 days of oil production for the case of 50 mD when the well is at the landing depth of 0.64

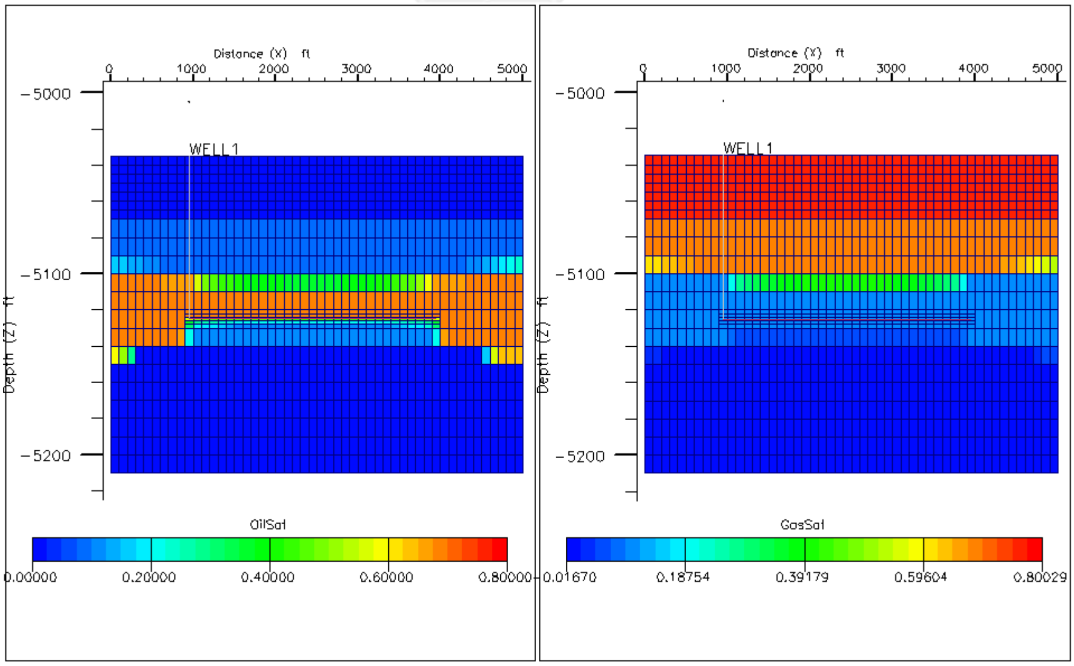

Figure 5.53 - Oil and gas saturation profiles after approximately 2,400 days of oil production for the case of 500 mD when the well is at the landing depth of 0.64

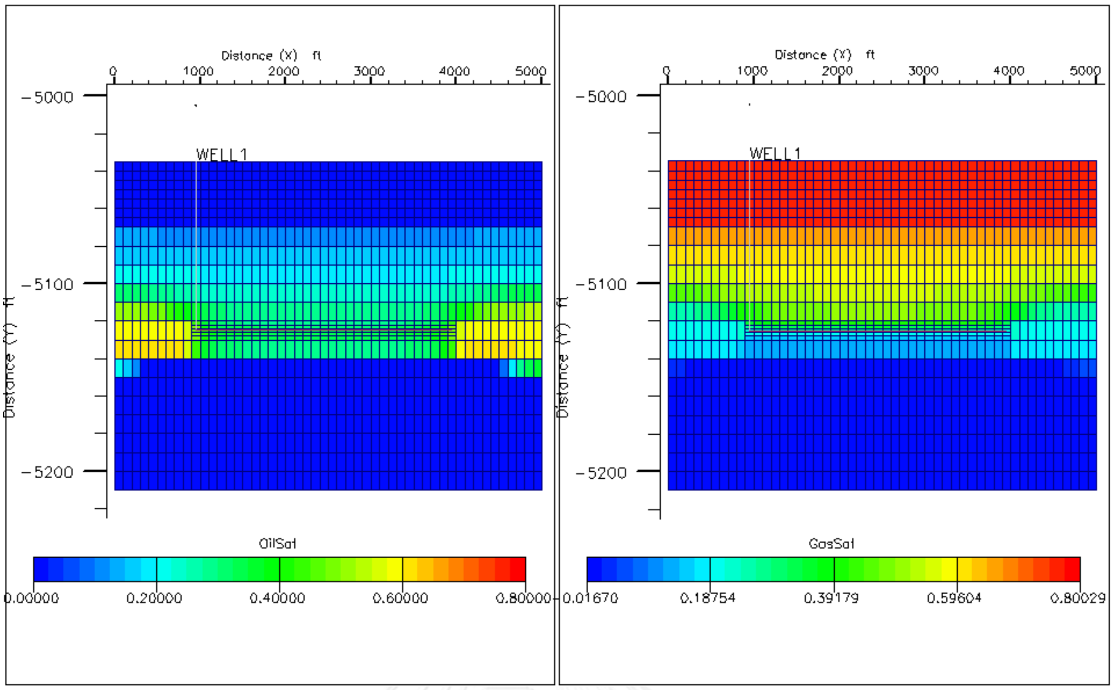

Figure 5.54 - Oil and gas saturation profiles after approximately 3,030 days of oil production for the case of 5 mD when the well is at the landing depth of 0.64

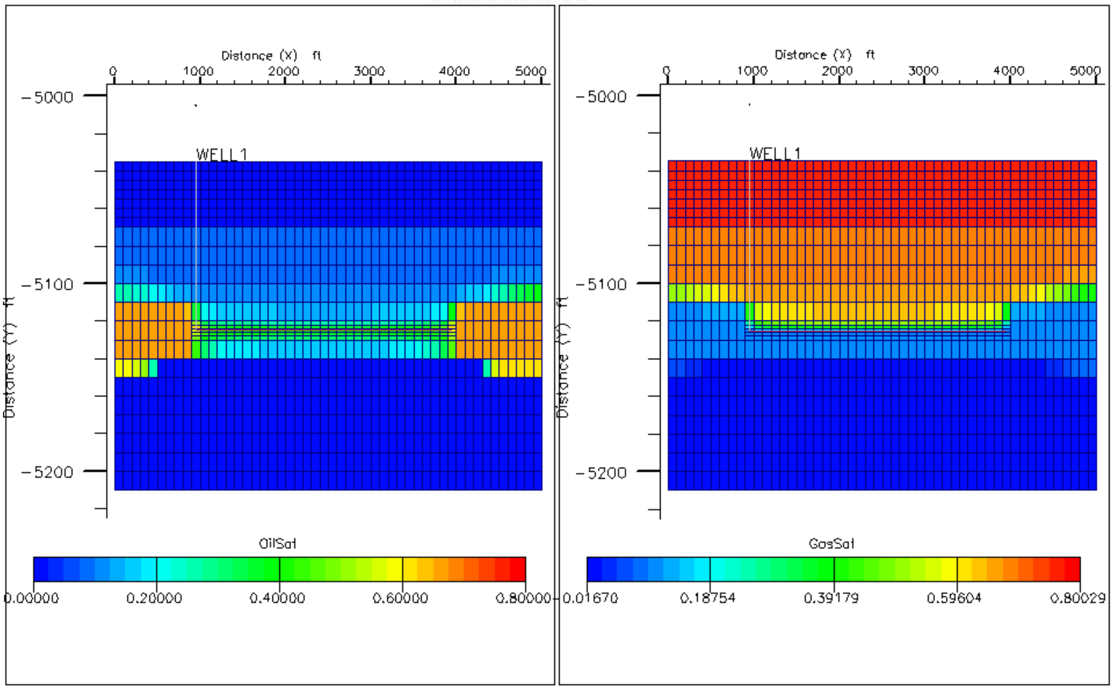

Figure 5.55 - Oil and gas saturation profiles after approximately 3,030 days of oil production for the case of 50 mD when the well is at the landing depth of 0.64

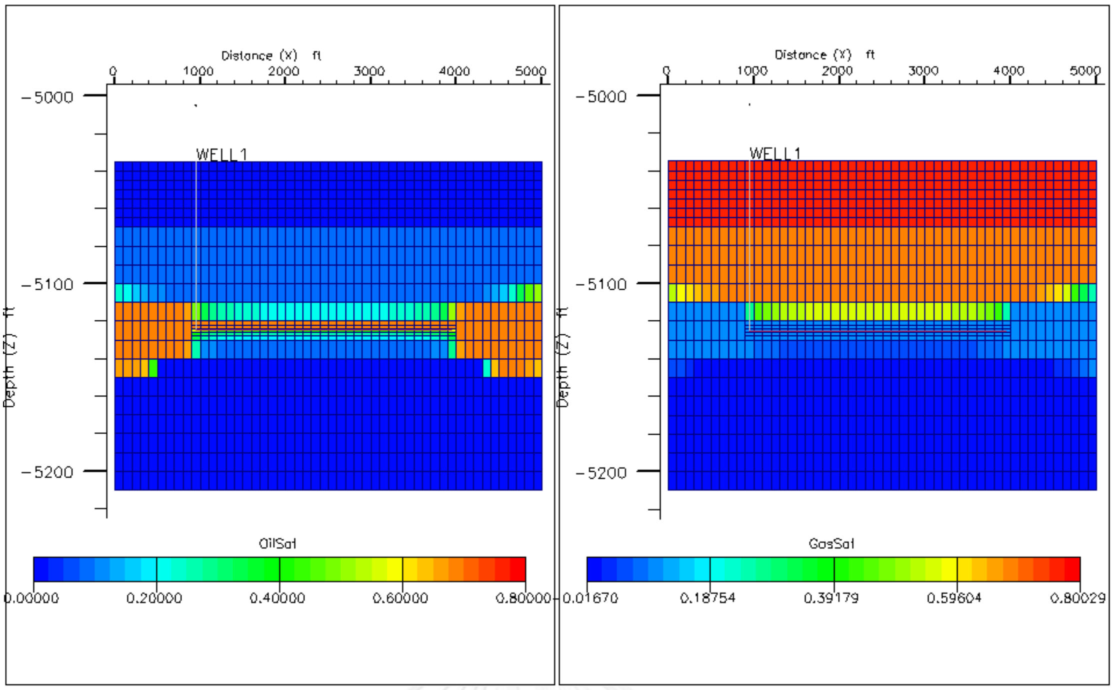

Figure 5.56 - Oil and gas saturation profiles after approximately 3,030 days of oil production for the case of 500 mD when the well is at the landing depth of 0.64

Table 5.15 demonstrates the results for the effect of permeability at the landing depth of 0.64, where the oil recovery increases with the reduction of vertical permeability. The total amount of water tends to increase with high permeability while produced gas reduces.

Table 5.15 – Summary of effect of permeability when the well is at the landing depth of 0.64

k_v (mD)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
5	59.36	16.32	25.07	3.53	11.4
50	55.96	15.38	24.97	5.83	11.7
500	52.94	14.55	24.95	6.65	11.6

For the cases where the well is located near the GOC, specifically between the landing depths of 0.01 to 0.21 where fluctuation occurs, the same behavior is justified by the reservoir vertical permeability that is high (500 mD). Figure 5.57 shows the performance of reservoir in terms of oil production and average pressure under different vertical permeability (5, 50 and 500 mD) when the horizontal well is at the landing depth of 0.04 for the case of M-Factor of 0.5 with 500 PV aquifer. With the reduction of vertical permeability from 500 to 5 mD, smooth curves are obtained (Figure 5.57). Figure 5.58 shows the field gas production for all three cases (5, 50 and 500 mD) where the amount of gas is high at the beginning of oil production due to the proximity of the horizontal well to the GOC. Figure 5.59 shows water production performance, where the case with 50 mD is the first starting to produce water, followed by the case with 5 mD and the last the case with 500 mD. This difference in water breakthrough time is related with the fluid movement in the reservoir. When the reservoir contains high vertical permeability (50 and 500 mD), the rise of the OWC starts in the middle of the x-direction and then spreads to the lateral parts of the reservoir (Figure 5.60 and Figure 5.61), causing the delay of water breakthrough which is more evident for the case with 500 mD. For the case with 5 mD, the OWC has a uniform rise along the vertical direction (see Figure 5.62). As water reaches the well, water rate keeps increasing and reaching a water cut of 95% which is the constraint for the study, forcing the well to shut in (Figure 5.63). This case results in lower oil recovery factor (Table 5.16).

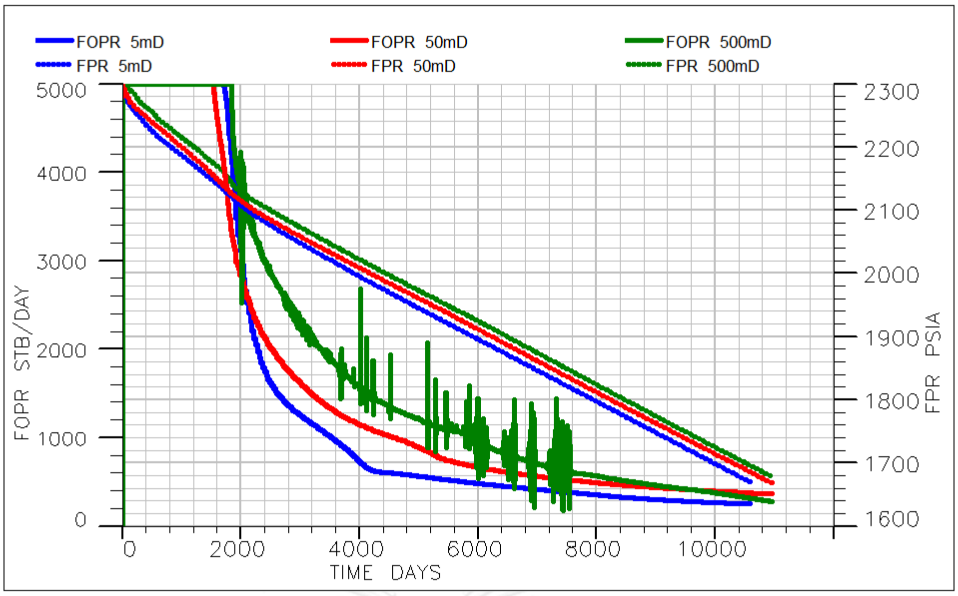

Figure 5.57 – Effect of permeability on field oil production and average pressure when the well is at the landing depth of 0.04

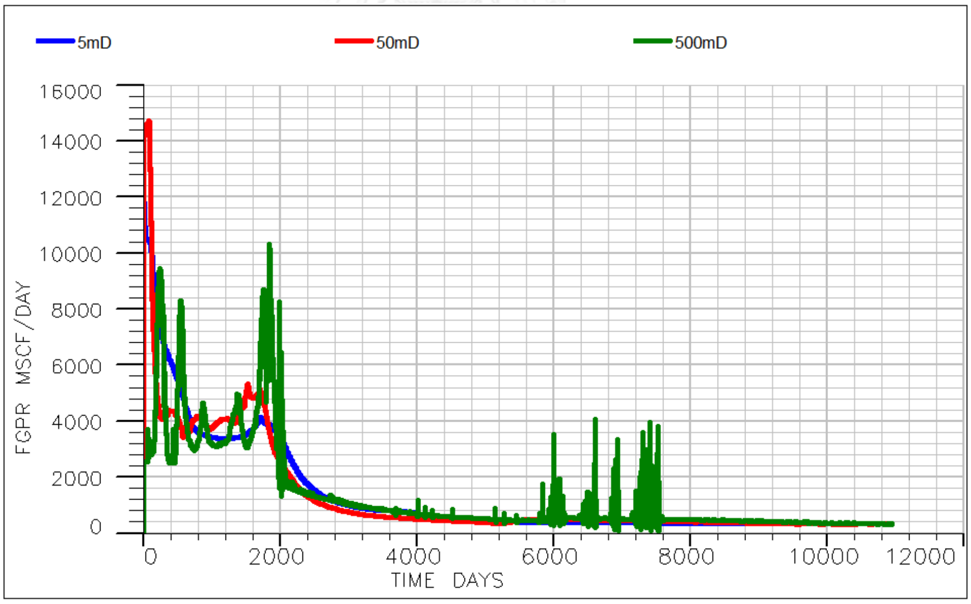

Figure 5.58 - Effect of permeability on field gas production when the well is at the landing depth of 0.04

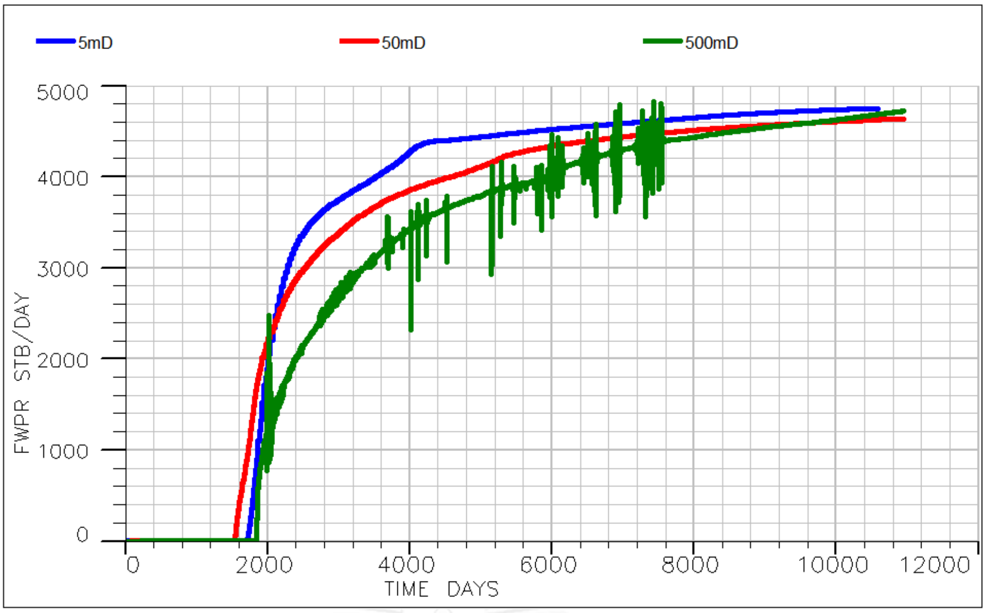

Figure 5.59 - Effect of permeability on field water production when the well is at the landing depth of 0.04

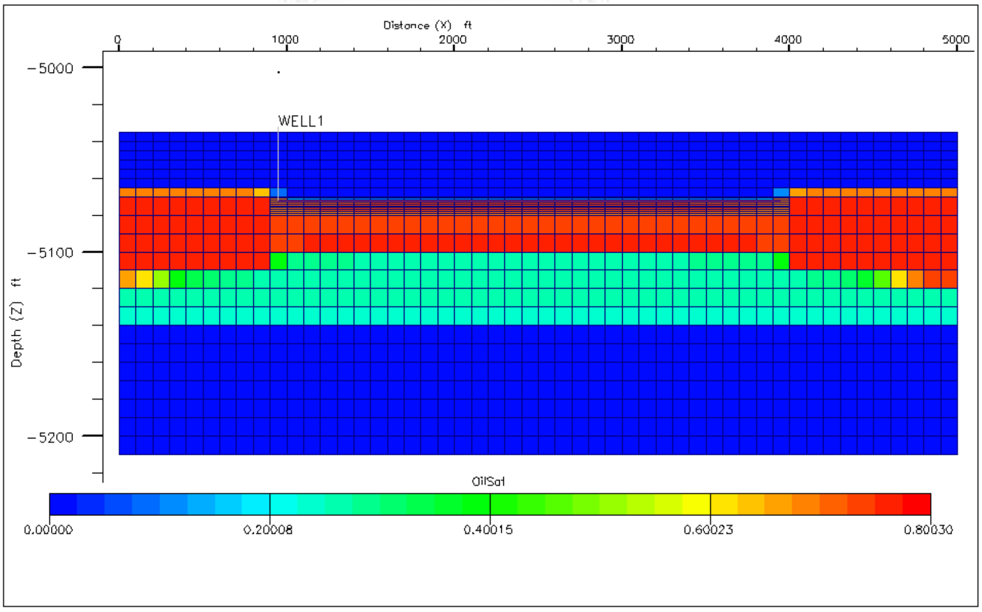

Figure 5.60 - Effect of permeability in oil saturation profile for M-Factor of 0.5 with 500 PV at the landing depth of 0.04 (500 mD)

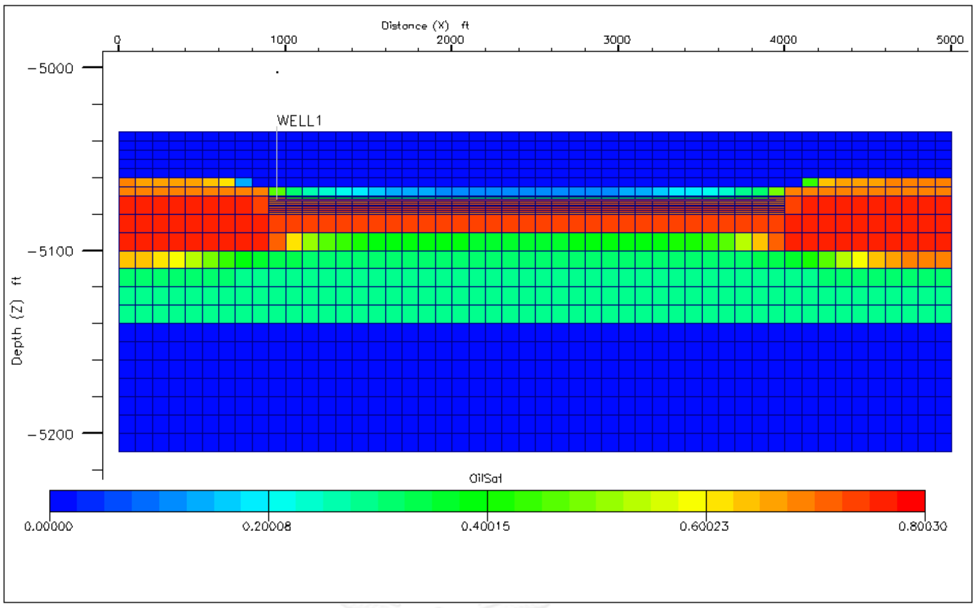

Figure 5.61 - Effect of permeability in oil saturation profile for M-Factor of 0.5 with 500 PV at the landing depth of 0.04 (50 mD)

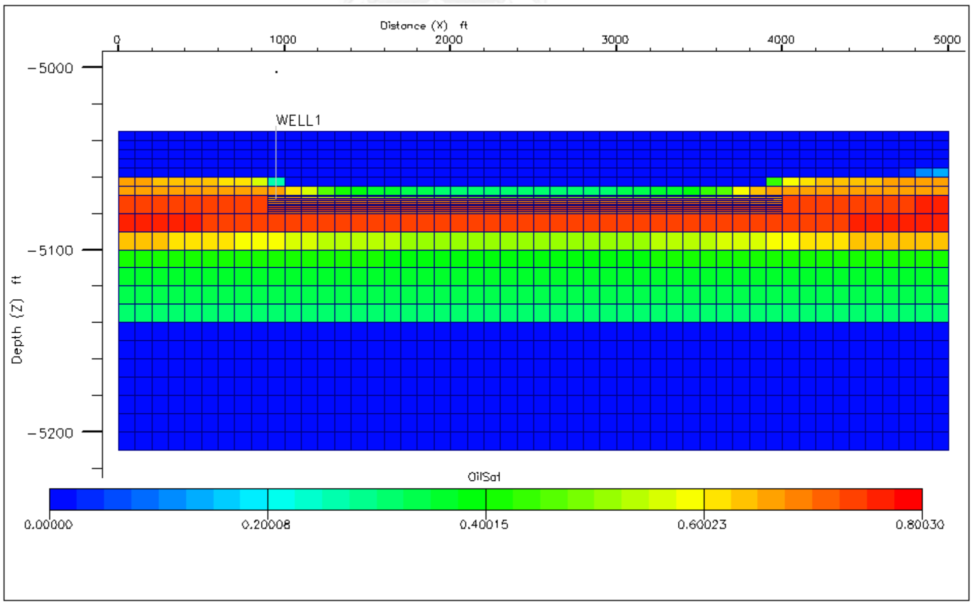

Figure 5.62 - Effect of permeability in oil saturation profile for M-Factor of 0.5 with 500 PV at the landing depth of 0.04 (5 mD)

Table 5.16 - Effect of permeability for the M-Factor of 0.5 with 500 PV at the landing depth of 0.04

k_v (mD)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
5	55.48	15.25	14.57	37.70	29.0
50	61.93	17.02	14.25	37.76	30.0
500	72.19	19.84	14.23	34.94	30.0

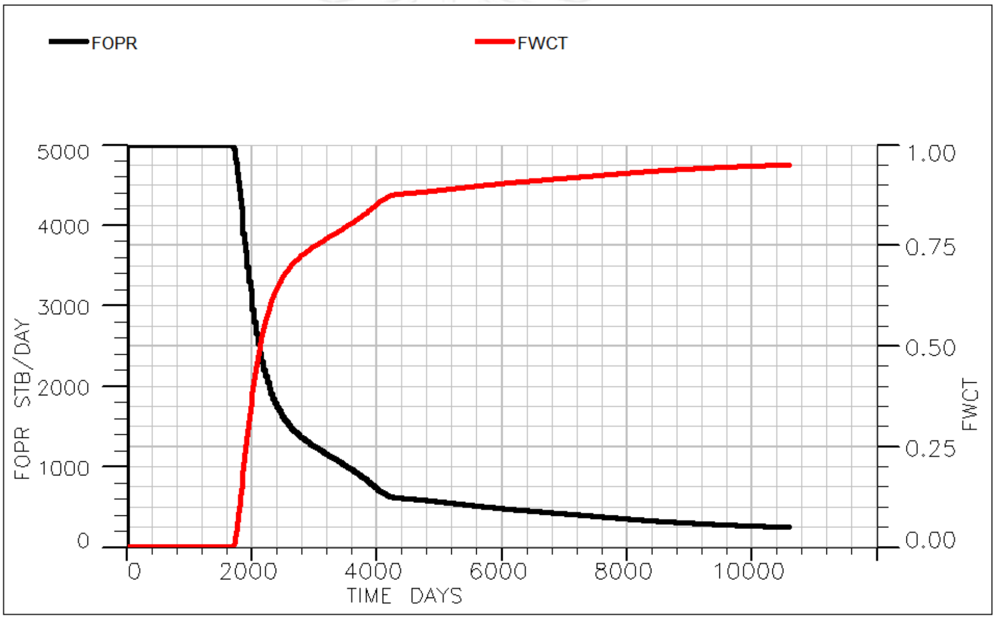

Figure 5.63 - Field water cut and oil rate for M-Factor of 0.5 with 500 PV at the landing depth of 0.04 (5 mD)

5.3 Effect of well position with different target liquid rates

To perform the comparative study among different target liquid rates, results for three different target liquid rates are analysed in this section. As the results in Table 5.14 shows that the well should be located towards the OWC for 5 and 50 PV aquifer but towards the GOC for 500 PV aquifer, the selected well locations for the study of target liquid rate for 5 and 50 PV aquifer are at landing depths of 0.5, 0.64, 0.79 and 0.89, while the locations for 500 PV aquifer are at landing depths of 0.21, 0.36 and 0.5. The results shown in this section are discussed in details in terms of oil recovery factor, cumulative oil, gas and water production.

5.3.1 Effect of well location and target liquid rate for M-Factor of 0.5 with 5 PV aquifer

From Table 5.17 to Table 5.20, results regarding to M-Factor of 0.5 with 5 PV aquifer are shown. For the case of M-Factor of 0.5 with 5 PV aquifer, target liquid rates varying between 1,000 and 3,000 STB/D are used for different well locations (landing depths of 0.5, 0.64, 0.79 and 0.89).

For all four selected locations, the maximum liquid rate of 2,000 STB/D results in the highest oil recovery (47.07% for the landing depth of 0.5, 55.85% for the landing depth of 0.64, 62.24% for the landing depth of 0.79 and 61.31% for the landing depth of 0.89). As the horizontal well location is varied from the middle oil column (landing depth of 0.5) to the landing depth of 0.64 and then to 0.79, the oil recovery for the target liquid rate of 2,000 STB/D increases from 47.07%, to 55.85% and then to 62.24%. When the well is placed deeper at the landing depth of 0.89, the production is negatively affected by water coning. As a result, the recovery factor decreases. The optimal well location that yields the highest oil recovery remains the same as the location found on the study of effect of well location for the same case (landing depth of 0.79).

The target liquid rate of 1,000 STB/D has the lowest oil recovery for all four locations. It produces at a plateau production during all the concession period of 30 years and at the end of this period most oil remains in the reservoir. Increasing the target liquid rate to 2,000 STB/D improves oil recovery as for all four location this target liquid rate yields the highest oil recovery. Increasing the target liquid rate to 3,000 STB/D results in a quick reservoir pressure depletion and consequently a reduction in oil recovery. The total amount of water tends to increase as the well is moved towards the oil-water contact. Meanwhile, the total amount of gas is slightly the same for all four locations (≈ 25 BSCF).

Table 5.17 - Effect of target liquid rate for M-Factor of 0.5 with 5PV aquifer at landing depth of 0.5

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
1,000	39.86	10.96	4.49	0.00	30.0
2,000	**47.07**	12.94	25.41	0.12	17.9
3,000	46.30	12.73	25.40	0.37	12.0

Table 5.18 - Effect of target liquid rate for M-Factor of 0.5 with 5PV aquifer at landing depth of 0.64

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
1,000	39.86	10.96	4.50	0.00	30.0
2,000	**55.85**	15.35	25.29	0.78	22.1
3,000	53.73	14.77	25.25	1.63	15.0

Table 5.19 - Effect of target liquid rate for M-Factor of 0.5 with 5PV aquifer at landing depth of 0.79

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
1,000	39.86	10.96	4.51	0.00	30.0
2,000	**62.24**	17.11	25.09	3.01	27.6
3,000	58.97	16.21	25.02	4.36	18.8

Table 5.20 - Effect of target liquid rate for M-Factor of 0.5 with 5PV aquifer at landing depth of 0.89

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
1,000	38.61	10.61	4.39	0.34	30.0
2,000	**61.31**	16.85	6.22	4.04	28.6
3,000	59.33	16.31	24.80	7.87	22.1

5.3.2 Effect of well location and target liquid rate for M-Factor of 0.5 with 50 PV aquifer

Increasing the aquifer size from 5 to 50 PV demonstrates that a large target liquid rate is necessary to obtain high oil recovery. For the case of M-Factor of 0.5 with 50 PV aquifer, target liquid rates varying between 2,000 and 5,000 STB/D are used for different well locations (landing depths of 0.5, 0.64, 0.79 and 0.89). For the first three locations at the landing depth of 0.5, 0.64 and 0.79, the target liquid rate of 3,000 STB/D leads to the highest oil recovery factor of 65.51, 67.13 and 65.03%, respectively.

For the last location at the landing depth of 0.89, the highest oil recovery of 62.89% is found when the target liquid rate of 4,000 STB/D is used (see Table 5.21 to Table 5.24). The target liquid rate (4,000 STB/D) that yields the highest oil recovery for landing depth of 0.89 is different from the other locations. At the landing depth of 0.89, the well starts producing water after 24 days of production. This location is characterized by oscillation of oil and water production as the well is near the oil-water contact. When the oil is drawn from the reservoir, the gas cap expands, providing a good drive mechanism for oil production (Figure 5.64).

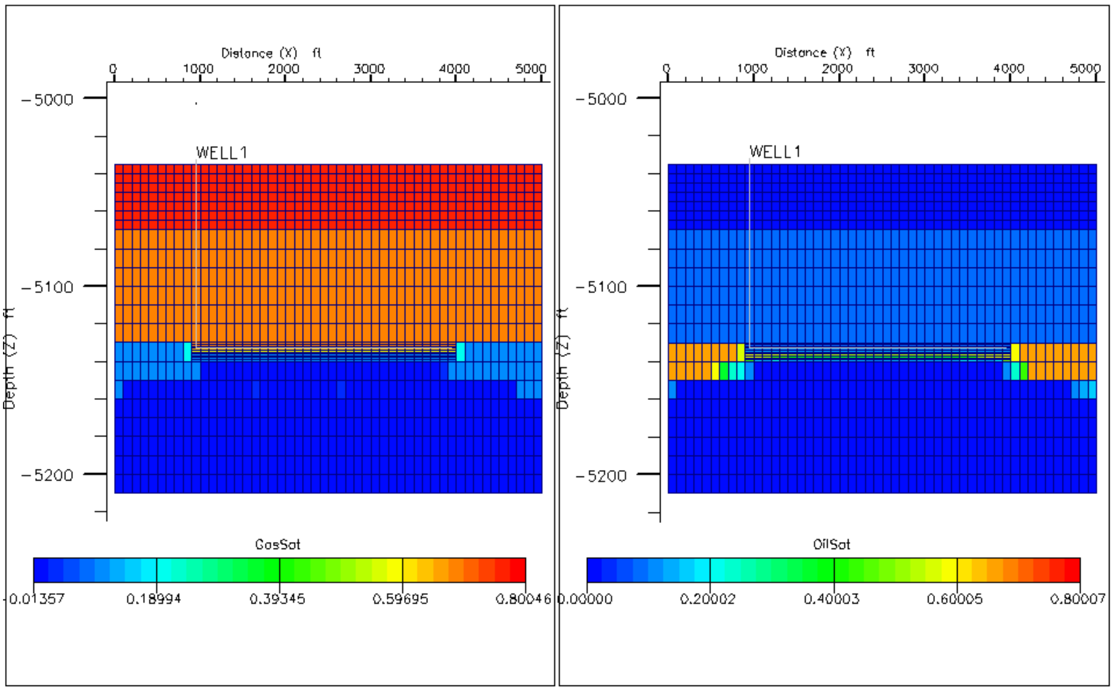

Figure 5.64 - Oil saturation profile for M-Factor of 0.5 and 50 PV aquifer with target liquid rate of 4,000 STB/D at a landing depth of 0.89 at the end of oil production

Combining both effects (well location and target liquid rate), the optimal location can be improved by locating the well at the landing depth of 0.64 and target liquid rate of 3,000 STB/D, which leads to an oil recovery factor of 67.13%. Note that this location is the same one that is found in Section 5.2.1 when the target liquid rate is fixed at 5,000 STB/D. However, the oil recovery factor in such case is only 62.10%. Cumulative water production tends to increase as the well is moved towards the oil-water contact in contrary to the cumulative gas production that reduces as the well is moved towards the oil-water contact.

Table 5.21 - Effect of target liquid rate for M-Factor of 0.5 with 50PV at aquifer at landing depth of 0.5

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
2,000	65.28	17.95	15.02	3.97	30.0
3,000	**65.51**	18.01	25.64	11.45	26.9
4,000	62.91	17.29	25.65	12.23	20.3

Table 5.22 - Effect of target liquid rate for M-Factor of 0.5 with 50PV aquifer at landing depth of 0.64

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
2,000	64.12	17.63	7.14	4.29	30.0
3,000	**67.13**	18.45	24.86	14.42	30.0
4,000	64.73	17.79	25.43	15.61	22.9

Table 5.23 - Effect of target liquid rate for M-Factor of 0.5 with 50PV aquifer at landing depth of 0.79

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
2,000	59.36	16.32	6.56	5.60	30.0
3,000	**65.03**	17.88	17.82	14.99	30.0
4,000	63.49	17.45	25.16	20.21	25.8

Table 5.24 - Effect of target liquid rate for M-Factor of 0.5 with 50PV aquifer at landing depth of 0.89

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
3,000	62.17	17.09	9.64	15.78	30.0
4,000	**62.89**	17.29	24.86	24.35	28.6
5,000	60.28	16.57	24.88	25.21	22.9

5.3.3 Effect of well location and target liquid rate for M-Factor of 0.5 with 500 PV aquifer

For M-Factor of 0.5 with 500 PV aquifer, target liquid rates varying between 5,000 and 9,000 STB/D are used to perform simulation studies as this range leads to the highest oil recovery for the present case. Results from three landing depths are shown in Table 5.25 to Table 5.27 , which are 0.21, 0.36 and 0.5. Varying the target liquid rate in each location affects the oil recovery factor. For the first two landing depths (0.21 and 0.36), the optimal liquid rate is 6,000 STB/D as it yields the highest oil recovery factor. Target liquid rate of 5,000 STB/D is too small to finish the production in 30 years. On the other hand, target liquid rate of 7,000 STB/D causes the well to have high water cut. For the middle oil column (landing depth of 0.5), the target liquid rate of 8,000 STB/D yields the highest oil recovery. As the well is located in the middle of oil column, the optimal target liquid rate becomes higher. However, this location does not achieve as high recovery factor as the wells located at the landing depth of 0.21 and 0.36 which achieve a recovery factor over 72% with target liquid rate of 6,000 STB/D. Both landing depths (0.21 and 0.36) achieve high recovery factors before the end of the concession period of 30 years (10,956 days) because they reach the water cut of 95% used as constraint for the field. In terms of water and gas production, it can be noticed that they increase as the target liquid rate increases.

Table 5.25 - Effect of target liquid rate for M-Factor of 0.5 with 500PV aquifer at landing depth of 0.21

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
5,000	72.92	20.04	10.81	34.74	30.0
6,000	**73.27**	20.14	11.65	42.86	28.8
7,000	72.75	20.00	11.93	46.57	26.1

Table 5.26 - Effect of target liquid rate for M-Factor of 0.5 with 500PV aquifer at landing depth of 0.36

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
5,000	69.93	19.22	8.99	35.56	30.0
6,000	**72.19**	19.84	9.17	45.04	29.6
7,000	70.60	19.41	9.03	46.26	25.7

Table 5.27 - Effect of target liquid rate for M-Factor of 0.5 with 500PV aquifer at landing depth of 0.5

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
7,000	68.52	18.84	8.51	57.86	30.0
8,000	**69.78**	19.18	8.60	63.92	28.5
9,000	68.88	18.94	8.50	63.21	25.1

In summary, the best production strategy for M-factor of 0.5 with 500 PV aquifer is to place the well at a landing depth of 0.21 and produce at 6,000 STB/D target liquid rate which yields the highest recovery factor of 73.27% and at the same time smallest water production. Note that this location is the same one that is found in Section 5.2.1 when the target liquid rate is fixed at 5,000 STB/D. However, the oil recovery factor in such case is 72.92%.

5.3.4 Summary for optimal cases for different aquifer sizes with M-Factor of 0.5

Figure 5.65 shows comparison of oil recovery factors among different aquifer sizes. Larger aquifer exhibits clearly higher oil recovery factor since the early time of production until the end of production. With the increment of aquifer size from 5 to 50 and 500 PV, the oil recovery factor increases from 62.24 to 67.13 and to 73.27%, respectively. Besides this increment in oil recovery, the disadvantage of larger aquifer is found on the amount of produced water. Water production for the case with 500 PV aquifer is approximately 14 times higher than the amount of water produced in the case with 5 PV aquifer and approximately 3 times higher than the amount of water produced in the case with 50 PV aquifer.

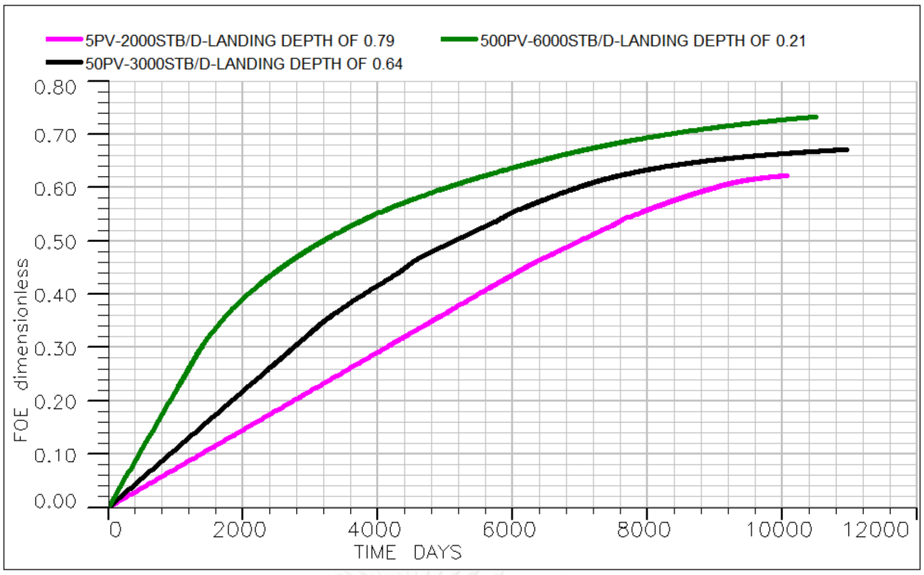

Figure 5.65 - Oil recovery factor for optimal target liquid rate for different aquifer sizes with M-Factor of 0.5

In terms of cumulative gas production, the case with 500 PV aquifer produces 2 times less gas than the amount produced from the cases with 5 and 50 PV aquifer. From this case, with small gas cap, the oil recovery is improved by 2 factors: aquifer size and liquid rate. Note that the same optimal well location found in the study of optimal well location is the one that yields the highest oil recovery in the study of effect of liquid rate.

5.3.5 Effect of well location and target liquid rate for M-Factor of 1 with 5 PV aquifer

Table 5.28 to Table 5.31 show the result for the effect of liquid rate for different well locations (landing depths of 0.5, 0.64, 0.79 and 0.89) in the thin oil rim column. The range of target liquid rates used in this section is between 1,000 to 3,000 STB/D. This range was selected after performing simulation for each case and resulted that the highest oil recovery is between this range. For all four selected locations, the target liquid rate of 2,000 STB/D results in the highest oil recovery: 47.98% for the landing depth of 0.5, 57.07% for the landing depth of 0.64, 63.85% for the landing depth of 0.79 and 63.10% for the landing depth of 0.89.

During the study of optimal well location, it was found that the best location would be at the landing depth of 0.89 with an oil recovery of 54.74%. This result is now improved with the change of target liquid rate to 2,000 STB/D and the well location to a landing depth of 0.79. This new combination gives the highest oil recovery factor of 63.85%.

As for the case of M-factor of 0.5 with 5 PV aquifer, the target liquid rate of 1,000 STB/D has the lowest oil recovery for all four locations. It produces at a plateau production during the entire concession period of 30 years and at the end of this period most oil remains in the reservoir. Increasing the target liquid rate to 2,000 STB/D improves oil recovery. Increasing the target liquid rate to 3,000 STB/D results in a quick reservoir pressure depletion and consequently a reduction in oil recovery.

Table 5.28 - Effect of target liquid rate for M-Factor of 1 with 5PV aquifer at landing depth of 0.5

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
1,000	39.86	10.96	4.81	0.00	30.0
2,000	**47.98**	13.19	38.41	0.18	18.3
3,000	47.36	13.02	38.40	0.42	12.3

Table 5.29 - Effect of target liquid rate for M-Factor of 1 with 5PV aquifer at landing depth of 0.64

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
1,000	39.86	10.96	4.81	0.00	30.0
2,000	**57.07**	15.69	38.29	0.78	22.6
3,000	54.71	15.04	38.26	1.60	15.2

Table 5.30 - Effect of target liquid rate for M-Factor of 1 with 5PV aquifer at landing depth of 0.79

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
1,000	39.86	10.96	4.82	0.00	30.0
2,000	**63.85**	17.55	38.10	2.82	27.9
3,000	60.64	16.67	37.96	4.21	19.1

Table 5.31 - Effect of target liquid rate for M-Factor of 1 with 5PV aquifer at landing depth of 0.89

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
1,000	39.34	10.81	4.77	0.14	30.0
2,000	**63.10**	17.34	7.03	3.54	28.7
3,000	61.12	16.80	37.81	7.57	22.3

5.3.6 Effect of well location and target liquid rate for M-Factor of 1 with 50 PV aquifer

For M-Factor of 1 with 50 PV aquifer, a range of target liquid rates varying from 1,000 to 4,000 are used to study the effect of target liquid rate for different well locations (landing depths of 0.5, 0.64, 0.79 and 0.89). Table 5.32 to Table 5.35 display the result for these cases. For the landing depth of 0.5, target liquid rates of 1,000 to 3,000 STB/D are used and the target liquid rate of 2,000 STB/D yields the highest oil recovery of 66.01%. The target liquid rate of 1,000 STB/D produces at its plateau for the entire concession period and provides the lowest oil recovery. The target liquid rate of 2,000 STB/D produces until the end of concession period with a plateau period of approximately 20 years. This target liquid rate produces a moderate amount gas and water. Increasing the target liquid rate to 3,000 STB/D depletes quickly the reservoir pressure and the well cannot produce at economical oil rate above 50 STB/D before the end of concession period of 30 years (Figure 5.66). For this landing depth, the total amount of produced water and gas increase with the increment of liquid rate.

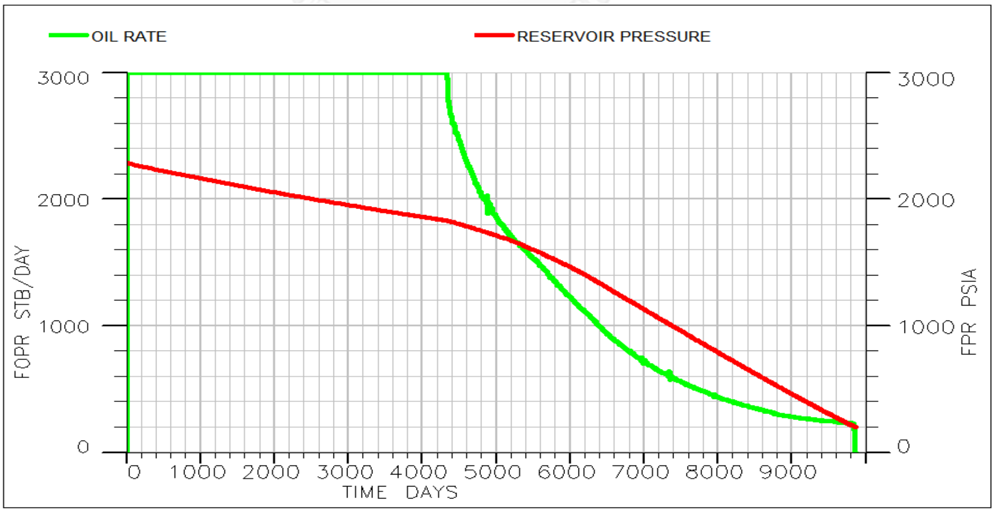

Figure 5.66 - Field oil rate and reservoir pressure for M-Factor of 1 and 50 PV aquifer at a landing depth of 0.5 (3,000 STB/D)

Comparing the range of target liquid rates used at the landing depths of 0.64, 0.79 and 0.89 with the case where the well is at landing depth of 0.5 (1,000 to 3,000 STB/D), the target liquid rate increased and it is varied from 2,000 to 4,000 STB/D. When the well is put in production at the landing depth of 0.5, gas expands fast limiting the use of high liquid rate. For all these three locations (landing depth of 0.64, 0.79 and 0.89), the target liquid rate of 3,000 STB/D leads to the highest oil recovery factor of 68.34, 66.75 and 64.83% respectively. The target liquid rate of 2,000 and 3,000 STB/D can produce for the entire concession period but the target liquid rate of 3,000 STB/D yields the highest oil recovery. Increasing the target liquid rate to 4,000 STB/D depletes quickly the reservoir pressure and the well cannot produce at economical oil rate above 50 STB/D before the end of 30 year period.

At the middle oil column (landing depth of 0.5), the best target liquid rate is different from the best target liquid rate in other locations (0.64, 0.79 and 0.89). This difference is caused by the movement of gas-oil contact that moves fast when the well is located at the middle oil column.

As the well is located near the oil-water contact, the cumulative water production increases and cumulative gas production have a tendency to reduce.

The maximum oil recovery for M-Factor of 1 with 50 PV aquifer is 68.34% (producing at a target rate of 3,000 STB/D) at the landing depth of 0.64. The same location found in the study of optimal well location in Section 5.2.2.

Table 5.32 - Effect of target liquid rate for M-Factor of 1 with 50PV aquifer at landing depth of 0.5

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
1,000	39.86	10.96	4.99	0.00	30.0
2,000	**66.01**	18.14	23.29	3.77	30.0
3,000	65.89	18.11	38.69	11.43	27.0

Table 5.33 - Effect of target liquid rate for M-Factor of 1 with 50PV aquifer at landing depth of 0.64

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
2,000	66.57	18.30	12.95	3.61	30.0
3,000	**68.34**	18.78	37.52	14.08	30.0
4,000	65.57	18.03	38.45	15.48	23.0

Table 5.34 - Effect of target liquid rate for M-Factor of 1 with 50PV aquifer at landing depth of 0.79

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
2,000	63.34	17.41	7.40	4.50	30.0
3,000	**66.75**	18.35	28.07	14.52	30.0
4,000	65.21	17.93	38.19	19.89	25.9

Table 5.35 - Effect of target liquid rate for M-Factor of 1 with 50PV aquifer at landing depth of 0.89

Target liquid rate (STB/D)	Oil Recovery Factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
2,000	55.10	15.15	6.36	6.77	30.0
3,000	**64.83**	17.82	16.44	15.05	30.0
4,000	64.76	17.80	37.93	23.85	28.6

5.3.7 Effect of well location and target liquid rate for M-Factor of 1 with 500 PV aquifer

Target flow rates with a range of 4,000 to 8,000 STB/D are used to produce the well at landing depths of 0.21, 0.36 and 0.5. For the first landing depth the target liquid rate is varied from 4,000 to 6,000 STB/D. For the second location, the target flow rate is changed from 5,000 to 7,000 STB/D. And for the last location, the target liquid rate is varied from 6,000 to 8,000 STB/D. The reason that higher target liquid rates are used when the landing depth gets deeper, is related with equilibrate force balance between gas cap expansion and water influx. Comparing with the other cases with the same M-Factor (5 and 50 PV aquifer), the target liquid rates as well oil recovery for 500 PV aquifer are higher (see Table 5.36 to Table 5.38) due to strong aquifer support. From the three locations, each one has its higher oil recovery factor with a specific optimal target liquid rate. At the landing depth of 0.21, the maximum oil recovery of 73.20% is found with a target liquid rate of 5,000 STB/D. The next position at the landing depth of 0.36 gives the maximum oil recovery of 72.90% when the target liquid rate is 6,000 STB/D. The last position at a landing depth of 0.5, the target liquid rate of 7,000 STB/D yields the highest oil recovery of 71.97%. The optimal target liquid rate that leads the highest oil recovery increases as the horizontal well is located further away from the gas-oil contact but results in the smallest oil recovery for M-Factor of 1 with 500 PV. As the well is further away from the GOC water from the water zone arrives early at the well and then the oil production is improved by expansion of gas from gas cap. This is different from the landing depth of 0.21 and 0.36 where the well is near the GOC. In these cases, gas arrives early but the movement of water provides a good drive mechanism for oil production resulting in higher recovery than at the middle oil column. As the wells are near the GOC, small target liquid rates compared with the middle depth are required to avoid water cut constraint.

The maximum oil recovery of the overall case of M-Factor of 1 with 500 PV aquifer is 73.20%, found at the landing depth of 0.21 with the target liquid rate of 5,000 STB/D. This location possesses the advantage of producing less water than other locations when producing at the same target liquid production rate with similar amount of gas, although, it is located near the gas-oil contact.

Table 5.36 - Effect of target liquid rate for M-Factor of 1 with 500PV aquifer at landing depth of 0.21

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
4,000	72.41	19,90	12,57	23,92	30.0
5,000	**73.20**	20,12	14,44	34,66	30.0
6,000	73.09	20,09	15,56	41,65	28.2

Table 5.37 - Effect of target liquid rate for M-Factor of 1 with 500PV aquifer at landing depth of 0.36

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
5,000	72.11	19.82	11.14	34.96	30.0
6,000	**72.90**	20.04	13.04	44.76	29.6
7,000	72.41	19.90	13.56	48.14	26.6

Table 5.38 - Effect of target liquid rate for M-Factor of 1 with 500PV aquifer at landing depth of 0.5

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
6,000	71.29	19.60	9.86	46.14	30.0
7,000	**71.97**	19.78	11.76	55.19	29.3
8,000	71.16	19.56	12.04	57.38	26.3

5.3.8 Summary for optimal cases for different aquifers sizes with M-Factor of 1

The plots of oil recovery factor for M-Factor of 1 with different aquifer sizes versus time are shown in Figure 5.67. In this figure, the oil recovery factor increases with the increment of aquifer size. M-Factor of 1 possesses higher oil recovery for 500 PV aquifer as for the case of M-Factor of 0.5 where the largest aquifer gives the highest oil recovery. This increment in oil recovery is a result of the aquifer support that prevents the reservoir from depleting fast its pressure (Figure 5.68) in the presence of larger aquifer (500 PV aquifer).

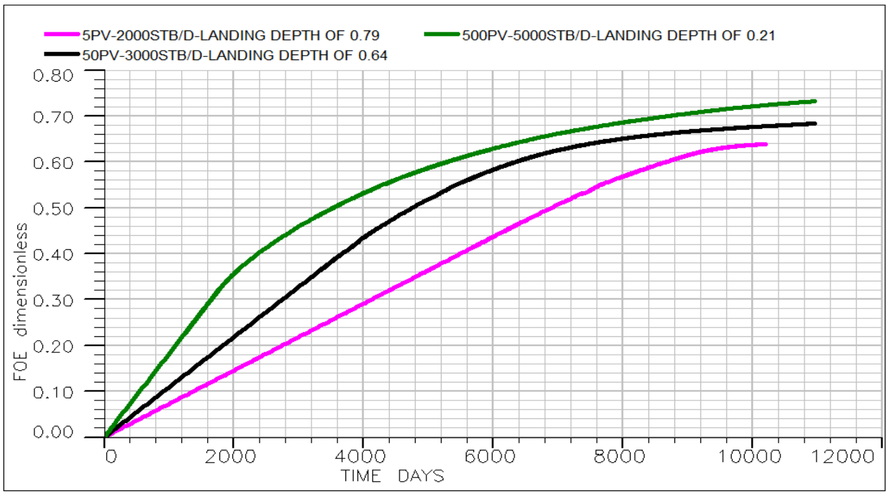

Figure 5.67 - Oil recovery factor for optimal target liquid rate for different aquifer sizes with M-Factor of 1

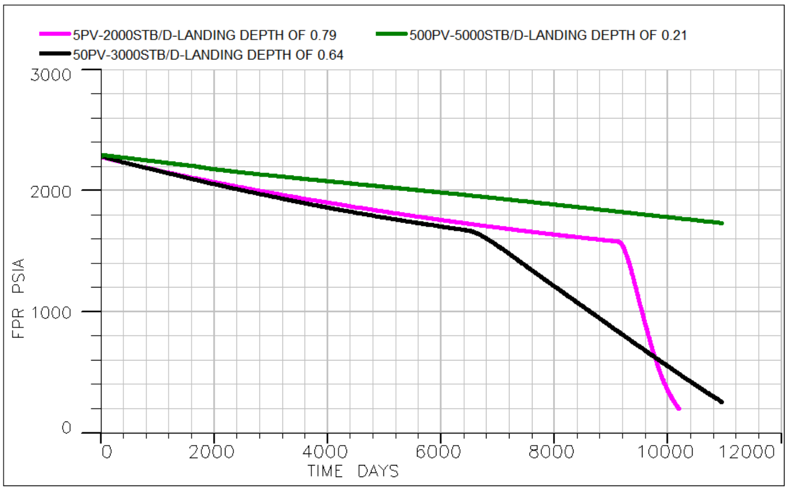

Figure 5.68 - Reservoir pressure for optimal target liquid for different aquifer sizes with M-Factor of 1

In summary, when aquifer strength increases from 5 to 50, and to 500 PV, the optimal target rate also increases, starting from 2,000 STB/D with an oil recovery factor of 63.85% for 5 PV aquifer and then 3,000 STB/D with an oil recovery factor of 68.34% for 50 PV aquifer and 5,000 STB/D with an oil recovery factor of 73.20% for 500 PV aquifer. In terms of water production, the case with 500 PV produces the highest amount of water approximately 12 and 2.5 times the amount of water produced for the case of 5 and 50 PV, respectively. But in terms of gas production, the case of 500 PV produces the least amount of gas, and the case of 5 PV produces the highest amount of gas.

5.3.9 Effect of well location and target liquid rate for M-Factor of 2 with 5 PV aquifer

For M-factor of 2 with 5 PV aquifer, target liquid rate varying from 1,000 to 3,000 STB/D are used. The well is landed at the landing depth of 0.5, 0.64, 0.79 and 0.89. In all four locations, the highest oil recovery factor is obtained when a target flow rate of 2,000 STB/D is used to produce from the field (see Table 5.39 to Table 5.42). The highest oil recovery for the case of M-Factor of 2 with 5 PV aquifer is found at 65.31% with the landing depth of 0.79. This location is different from the location found in the study of optimal well location in Section 5.2.3.

The field is able to keep its plateau target production at 1,000 STB/D during the entire 30 years of concession period for the first three locations (landing depth of 0.5, 0.64 and 0.79) resulting in the same oil recovery factor of 39.86%. Increasing the target rate to 2,000 STB/D speeds up the oil production to be the finished before 30 years, resulting in higher oil recovery.

Table 5.39 - Effect of target liquid rate for M-Factor of 2 with 5PV aquifer at landing depth of 0.5

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
1,000	39.86	10.96	5.09	0.00	30.0
2,000	**49.55**	13.62	64.41	0.31	19.1
3,000	49.04	13.48	64.39	0.65	12.9

Table 5.40 - Effect of target liquid rate for M-Factor of 2 with 5PV aquifer at landing depth of 0.64

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
1,000	39.86	10.96	5.10	0.00	30.0
2,000	**58.65**	16.12	64.29	1.08	23.6
3,000	56.45	15.52	64.26	1.87	15.9

Table 5.41 - Effect of target liquid rate for M-Factor of 2 with 5PV aquifer at landing depth of 0.79

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
1,000	39.86	10.96	5.10	0.00	30.0
2,000	**65.31**	17.95	64.07	3.22	29.0
3,000	62.43	17.16	64.02	4.64	19.9

Table 5.42 - Effect of target liquid rate for M-Factor of 2 with 5PV aquifer at landing depth of 0.89

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
1,000	39.82	10.95	5.10	0.01	30.0
2,000	**64.68**	17.78	7.83	3.00	28.5
3,000	63.40	17.43	63.78	7.65	22.9

5.3.10 Effect of well location and target liquid rate for M-Factor of 2 with 50 PV aquifer

For the case of M-Factor of 2 with 50 PV aquifer, target liquid rates varying between 1,000 and 5,000 STB/D are used for different well locations (landing depths of 0.5, 0.64, 0.79 and 0.89). For the first location at the landing depth of 0.5, target liquid rates of 1,000 to 3,000 STB/D are used and the highest oil recovery of 66.24% is found when the target liquid flow rate of 2,000 STB/D is applied. For the landing depth of 0.64 and 0.79, the target liquid rate of 3,000 STB/D leads to the highest oil recovery factor of 68.62 and 68.30% respectively. For the last location at the landing depth of

0.89, the highest oil recovery of 66.59% is found when the target liquid rate of 4,000 STB/D is used to produce through the reservoir. The difference in target liquid rate is justified by gas expansion limiting the use of high liquid rate when the well is located towards the GOC.

For the overall cases of M-Factor of 2 with 50 PV aquifer, the target liquid rate of 3,000 STB/D and well landing depth of 0.64 is the optimal case that yields the highest oil recovery factor of 68.62%. This case provides the highest amount of oil production (18.86 MMSTB) with high gas production (62.46 BCF) and moderate water production (14.01 MMSTB).

Table 5.43 - Effect of target liquid rate for M-Factor of 2 with 50PV aquifer at landing depth of 0.5

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
1,000	39.86	10.96	5.17	0.00	30.0
2,000	**66.24**	18.21	39.59	3.71	30.0
3,000	66.15	18.18	64.70	11.53	27.2

Table 5.44 - Effect of target liquid rate for M-Factor of 2 with 50PV aquifer at landing depth of 0.64

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
2,000	67.36	18.52	24.13	3.40	30.0
3,000	**68.62**	18.86	62.46	14.01	30.0
4,000	66.17	18.19	64.46	15.57	23.2

Table 5.45 - Effect of target liquid rate for M-Factor of 2 with 50PV aquifer at landing depth of 0.79

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
2,000	65.18	17.92	8.07	4.00	30.0
3,000	**68.30**	18.77	48.37	14.09	30.0
4,000	66.88	18.38	64.19	19.71	26.1

Table 5.46 - Effect of target liquid rate for M-Factor of 2 with 50PV aquifer at landing depth of 0.89

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
3,000	61.57	16.93	7.50	8.05	22.8
4,000	**66.59**	18.31	63.93	23.48	28.6
5,000	64.08	17.62	63.92	24.32	23.0

5.3.11 Effect of well location and target liquid rate for M-Factor of 2 with 500 PV aquifer

For M-Factor of 2 with 500 PV aquifer, 4,000 to 7,000 STB/D is the range of target liquid rates used to perform the study on effect of target liquid rate for well locations at a landing depth of 0.21, 0.36 and 0.5 (see Table 5.47 to Table 5.49). As the well is located towards the middle oil column, the target liquid rate tends to increase due to the distance from the GOC and OWC. For the first two locations, the target liquid rate is varied between 4,000 to 6,000 STB/D. The target liquid rate of 5,000 STB/D yields the highest oil recovery of 72.81 and 72.99% respectively. For the last location, the target liquid rate is varied from 5,000 to 7,000 STB/D. The target liquid rate of 6,000 STB/D gives the highest oil recovery factor of 72.64%. The optimal target rates in these cases can be sustained throughout the entire 30 year concession period. Producing at a larger target liquid rate results in earlier abandonment due to high water cut.

Overall, the target liquid rate of 5,000 STB/D at the landing depth of 0.36 leads to the highest oil recovery factor of 72.99%. This recovery is obtained at the end of concession period of 30 years. Comparing the amount of water produced for all three well locations, the amount of water is higher when the well is put on production at the landing depth of 0.5 and lower at the landing depth of 0.36. The amount of gas is higher at the landing depth of 0.21 and lower at the landing depth of 0.5.

Table 5.47 - Effect of target liquid rate for M-Factor of 2 with 500PV aquifer at landing depth of 0.21

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
4,000	72.01	19.80	18.25	24.03	30.0
5,000	**72.81**	20.01	21.59	34.77	30.0
6,000	72.69	19.98	23.63	41.76	28.2

Table 5.48 - Effect of target liquid rate for M-Factor of 2 with 500PV aquifer at landing depth of 0.36

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
4,000	71.76	19.73	14.24	24.10	30.0
5,000	**72.99**	20.06	17.78	34.72	30.0
6,000	72.81	20.02	19.53	40.46	27.6

Table 5.49 - Effect of target liquid rate for M-Factor of 2 with 500PV aquifer at landing depth of 0.5

Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
5,000	71.68	19.70	13.62	35.08	30.0
6,000	**72.64**	19.97	17.37	45.73	30.0
7,000	72.12	19.83	18.27	48.84	26.9

5.3.12 Summary for optimal cases for different aquifers sizes with M-Factor of 2

Figure 5.69 shows the plots of oil recovery factor among different aquifer sizes versus time. Once again, as for the M-Factors of 0.5 and 1, the oil recovery factor increases with the increment of aquifer size due to the pressure support from the aquifer (Figure 5.70). The largest aquifer (500 PV), at the end of concession period, registers a small pressure loss of approximately 500 psia, while the small and moderate aquifers (5 and 50 PV) register a high pressure loss as at the end of production the reservoir pressure is nearly 200 psia.

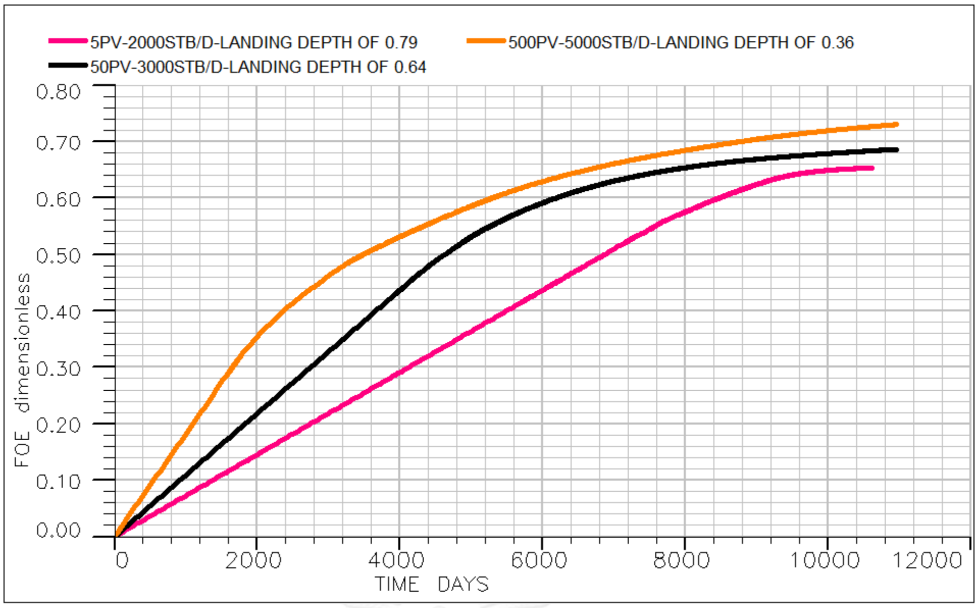

Figure 5.69 - Summary of oil recovery factor for cases with their best liquid rates with M-Factor of 2

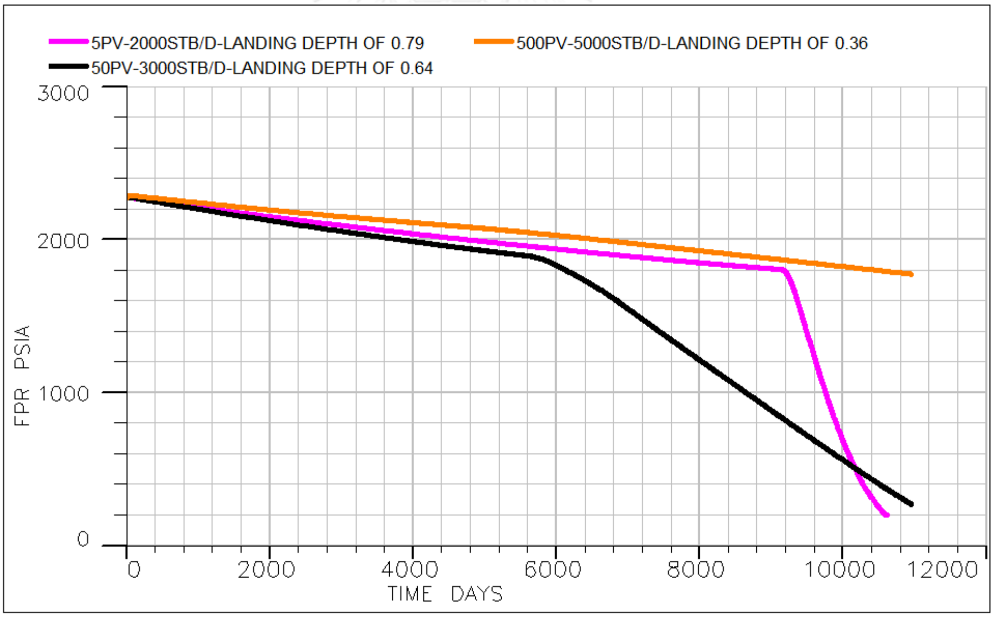

Figure 5.70 - Summary of reservoir pressure for cases with their best liquid rates with M-Factor of 2

In summary, when the aquifer strength is increased from 5 to 50, and 500 PV, the oil recovery increases from 65.31% with well location at the landing depth of 0.79 and target liquid rate of 2,000 STB/D for the first case, 68.62% with well location at the landing depth of 0.64 and target liquid rate of 3,000 STB/D for the second case and 72.99% with well location at the landing depth of 0.36 and target liquid rate of 5,000 STB/D for the last case. The cumulative amount of water is higher for the case of larger aquifer as it produces approximately 11 and 2.5 times the amount of water produced with 5 and 50 PV, respectively. The amount of produced gas is higher in the case of 5 PV (64.07 BSCF) and smaller in the case of 500 PV (17.78 BSCF).

5.4 Comparison of optimal cases among different M-Factors and aquifer PVs

Table 5.50 exhibits the values of target liquid rate and optimal well location that yield the highest oil recoveries for different aquifer and gas cap strengths. When the M-Factor increases from 0.5 to 1 and 2, the recovery factor changes from 62.24 to 63.85 and 65.31% for 5 PV aquifer (Figure 5.71), changes from 67.13 to 68.34 and 68.62% for 50 PV aquifer (Figure 5.72), and for 500 PV reduces from 73.27 to 73.20 and 72.99% (Figure 5.73).

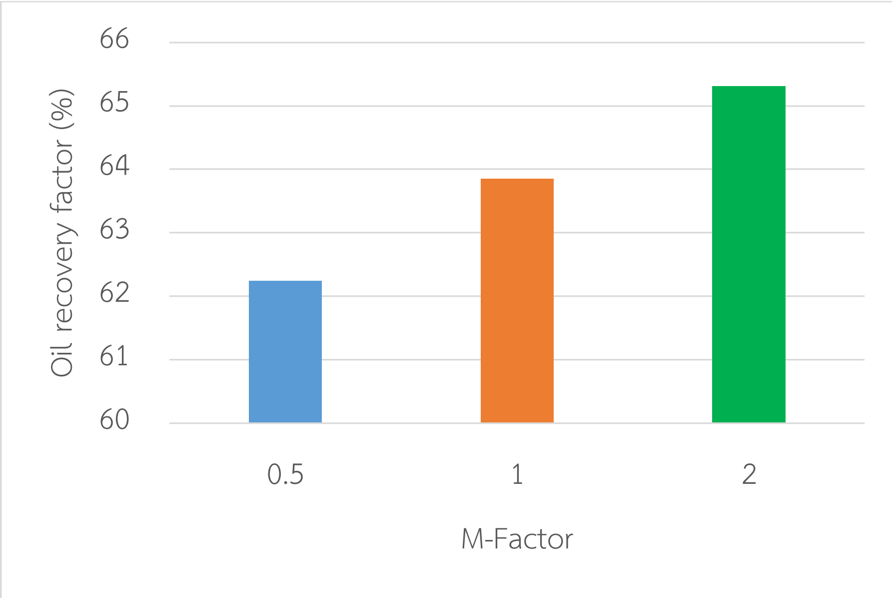

Figure 5.71 - Summary of the best cases for 5 PV aquifer

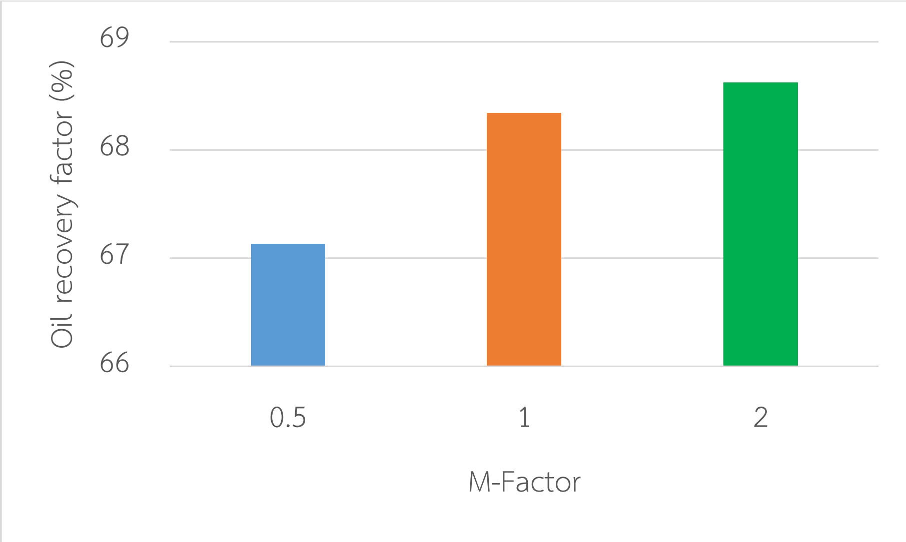

Figure 5.72 - Summary of the best cases for 50 PV aquifer

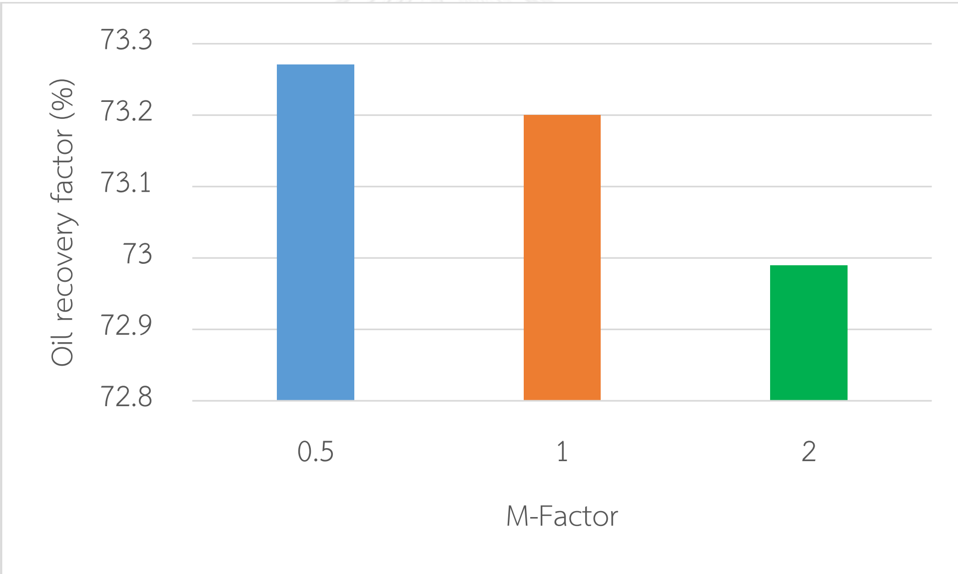

Figure 5.73 - Summary of the best cases for 500 PV aquifer

It is observed that for the case of 5 PV aquifer, the optimal target liquid rate and optimal well location among the different M-Factors of 0.5, 1 and 2 is the same (2,000 STB/D at the landing depth of 0.79). Gas production increases from 25.09 BSCF to 38.10 BSCF and 37.96 BSCF. When M-Factors is increased from 0.5 to 1 and 2, water production registers an oscillation for different M-Factors. M-Factor of 0.5 produces

3.01 MMSTB of water, M-Factor of 1 reduces to 2.82 MMSTB of water, and M-Factor of 2 increases to 3.22 MMSTB.

For the case with 50 PV aquifer, the optimal well location and target liquid rate is also the same among different M-Factors (landing depth of 0.64 and target liquid rate of 3,000 STB/D). Gas production increases from 24.86 MMSCF to 37.53 MMSCF and 62.45 MMSCF while water production decreases from 14.42 MMSTB to 14.08 MMSTB and then to 14.01 MMSTB with the increment of for M-Factor.

For 500 PV aquifer, the optimal liquid rates and optimal well locations that lead to the highest oil recovery are different for different drive combinations. For M-Factor of 0.5 and 1, the optimal well location is at the landing depth of 0.21, and the optimal target liquid rate is 6,000 STB/D for M-Factor of 0.5 and 5,000 STB/D for M-Factor of 1. This difference in target liquid rate is related with the movement of the oil-water contact. For M-Factor of 2, 5,000 STB/D is the optimal target liquid rate at the landing of 0.36. Gas production increases has M-Factor increases from 11.65 BSCF to 14.44 BSCF and 17.78 BSCF. When M-Factor is increased from 0.5 to 1 and 2, water production fluctuates. M-Factor of 0.5 produces 42.86 MMSTB of water, M-Factor of 1 reduces to 34.66 MMSTB and M-Factor of 2 increases to 34.72 MMSTB. This oscillation in water production results from the different liquid rates that yield the highest oil recovery.

Table 5.50 - Summary table for optimal well location and target liquid rate

PV	M-Factor														
	0.5					1					2				
	RF (%)	Landing depth (ft/ft)	Target liq. Rate (STB/D)	Total water production (MMSTB)	Total gas production (BSCF)	RF (%)	Landing depth (ft/ft)	Target liq. Rate (STB/D)	Total water production (MMSTB)	Total gas production (BSCF)	RF (%)	Landing depth (ft/ft)	Target liq. Rate (STB/D)	Total water production (MMSTB)	Total gas production (BSCF)
5	62.24	0.79	2,000	3.01	25.09	63.85	0.79	2,000	2.82	38.10	65.31	0.79	2,000	3.22	64.07
50	67.13	0.64	3,000	14.42	24.86	68.34	0.64	3,000	14.08	37.52	68.62	0.64	3,000	14.01	62.46
500	73.27	0.21	6,000	42.86	11.65	73.20	0.21	5,000	34.66	14.44	72.99	0.36	5,000	34.72	17.78

5.5 Comparison of the selected target liquid rates with critical coning rates

As the main problem in thin oil rim reservoirs is the coning of water and gas, critical coning rate for each location should be determined. In this study, Efro's equation described in Section 3.3.2 is used. Table 5.51 shows the determined values.

Table 5.51 - Critical coning rates for water and gas coning

Gas coning		Water coning	
Distance from GOC (ft)	Critical rate (STB/D)	Distance from OWC (ft)	Critical rate (STB/D)
0.5	0.5	69.5	1,691
2.5	12	67.5	1,595
7.5	111	62.5	1,368
15	443	55	1,059
25	1,230	45	709
35	2,410	35	429
45	3,984	25	219
55	5,951	15	79
62.5	7,684	7.5	20
67.5	8,963	2.5	2.2
69.5	9,502	0.5	0.1

These results show that in order to avoid coning problems of water and gas, the thin oil rim should produce below these flow rates. As can be noted in Table 5.51, if the well is far from the GOC the critical rate for gas coning is very high but very low flow rate for water coning is required.

To perform comparison study between optimal target liquid rates and target critical liquid rates, simulation was run using critical rates at optimal well locations summarized in Table 5.50. Table 5.52 to Table 5.54 show the results of the simulation when the reservoir produces at the critical rates and the results of the simulation when the reservoir produces with the optimal target liquid rates that yield the highest oil recovery for different M-Factors and different aquifer sizes. Producing through the thin oil column under critical rates to avoid water and gas coning results in a very low oil recovery compared with the results of the suitable optimal target liquid rates during the 30 years used as constraint for the study. For the case of 5 PV aquifer and M-Factor of 0.5, 1 and 2, the critical rate results in a recovery factor that is approximately 20 times smaller than the oil recovery offered by the suitable target liquid rate. For the case of 50 PV aquifer and M-Factor of 0.5, 1 and 2, the optimal target liquid rate offers an oil recovery that is approximately 8 times higher than the oil recovery offered by the critical rate while the case of 500 PV aquifer and M-Factor of 0.5 and 1, the landing depth of 0.21 and critical rate of 443 STB/D offers an oil recovery that is approximately 4 times higher than the oil recovery offered by the critical rate. For 500 PV aquifer and M-Factor of 2, the landing depth of 0.36 (critical rate of 709 STB/D) offers an oil recovery that is approximately 2.5 times higher than the oil recovery offered by the critical rate. In terms of water and gas production, producing at critical rates, no water is produced while the amount of produced gas tends to increase in the case of different aquifer sizes due to different target liquid rates used. The produced gas is gas that initially is dissolved in oil. Its amount tends to increase because different target critical liquid rates are applied for different landing depths. With the increment of the critical target liquid rate, more gas is produced.

Observing Figure 5.74 to Figure 5.76, which illustrate the field oil production performance at the optimal well location using critical rates, the reservoir can produce at plateau target liquid rate during the entire concession period for all four different landing depths of 0.21, 0.36, 0.64 and 0.79 with the target liquid rates of 443, 709, 219 and 79, respectively. The oil saturation profiles for 5 PV, 50 PV and 500 PV aquifer at the end of production are shown in Figure 5.77 to Figure 5.79. Neither gas nor water have reached the well.

Analyzing the results in terms of oil recovery factor indicates that flow rates higher than critical rates must be applied to improve the oil production through thin oil rims reservoirs.

Table 5.52 - Results comparison between critical rates and suitable target liquid rate for M-Factor 0f 0.5

Case	Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
5 PV at the landing depth of 0.79						
Critical rate	79	3.15	0.87	0.43	0	30
Optimal rate	**2,000**	**62.24**	17.11	25.09	3.01	27.6
50 PV at the landing depth of 0.64						
Critical rate	219	8.27	2.40	1.18	0	30
Optimal rate	**3,000**	**67.13**	18.45	24.86	14.42	30
500 PV at the landing depth of 0.21						
Critical rate	443	17.66	4.85	2.44	0	30
Optimal rate	**6,000**	**73.27**	20.14	11.65	42.86	28.8

Table 5.53 - Results comparison between critical rates and suitable target liquid rate for M-Factor of 1

Case	Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
5 PV at the landing depth of 0.79						
Critical rate	79	3.15	0.87	0.44	0	30
Optimal rate	**2,000**	**63.85**	17.55	38.10	2.82	30
50 PV at the landing depth of 0.64						
Critical rate	219	8.73	2.40	1.19	0	30
Optimal rate	**3,000**	**68.34**	18.78	37.52	14.08	30
500 PV at the landing depth of 0.21						
Critical rate	443	17.66	4.85	2.44	0	30
Optimal rate	**5,000**	**73.20**	20.12	14.44	34.66	30

Table 5.54 - Results comparison between critical rates and suitable target liquid rate for M-Factor of 2

Case	Target liquid rate (STB/D)	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (years)
5 PV at the landing depth of 0.79						
Critical rate	79	3.15	0.87	0.44	0	30
Optimal rate	**2,000**	**65.31**	17.95	64.07	3.22	29
50 PV at the landing depth of 0.64						
Critical rate	219	8.73	2.40	1.20	0	30
Optimal rate	**3,000**	**68.62**	18.82	62.46	14.01	30
500 PV at the landing depth of 0.36						
Critical rate	709	28.26	7.77	3.89	0	30
Optimal rate	**5,000**	**72.99**	20.06	17.78	34.72	30

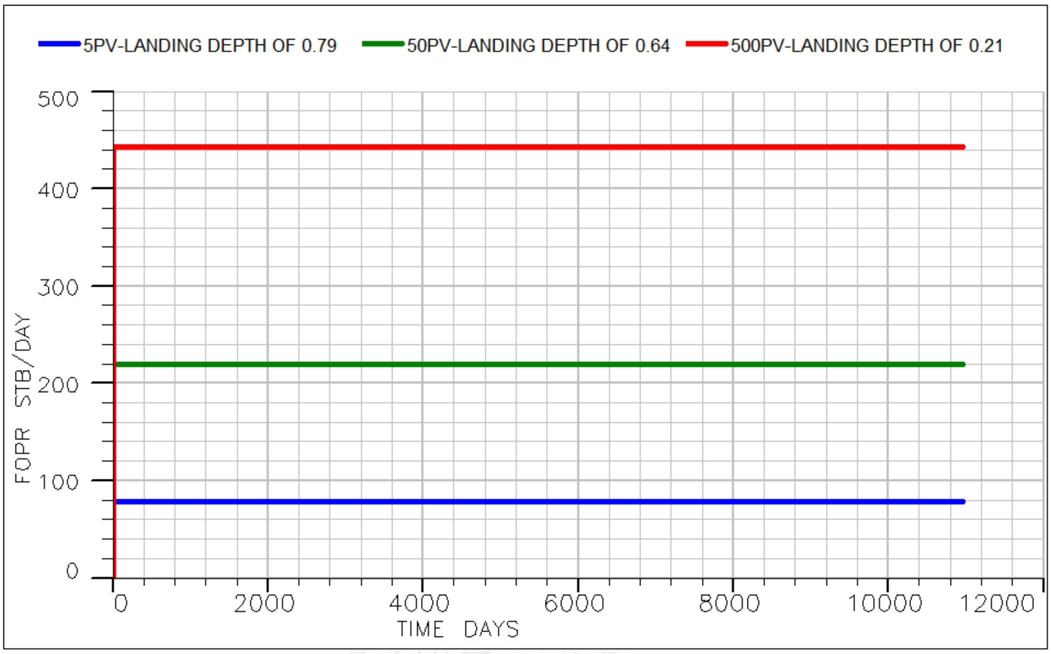

Figure 5.74 - Field oil production performance at optimal well locations using critical rates for M-Factor of 0.5

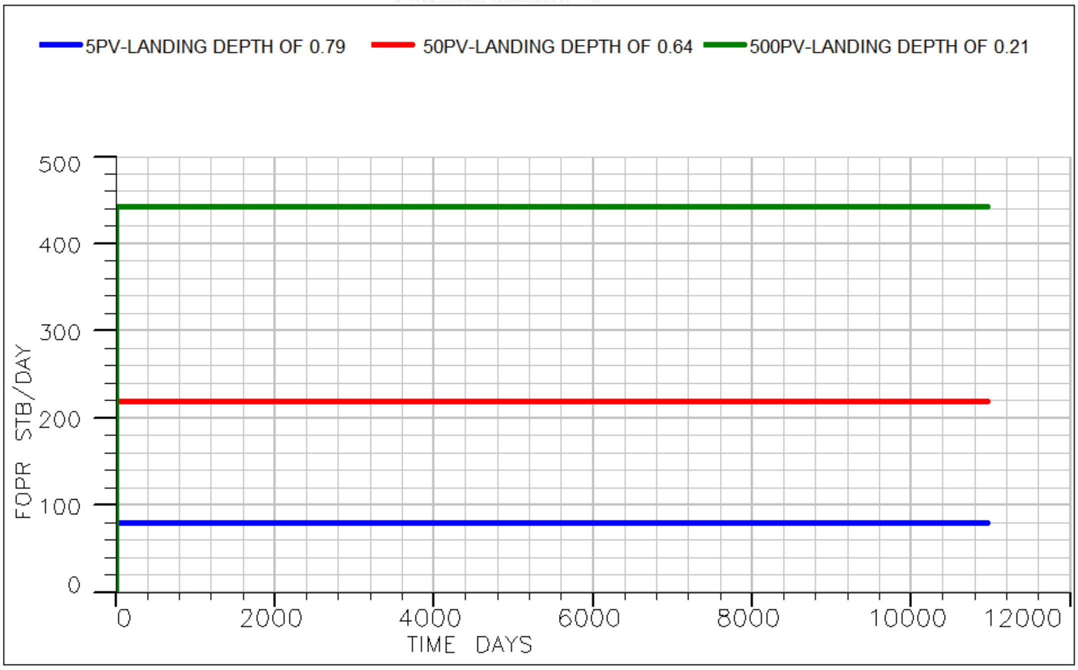

Figure 5.75 - Field oil production performance at optimal well locations using critical rates for M-Factor of 1

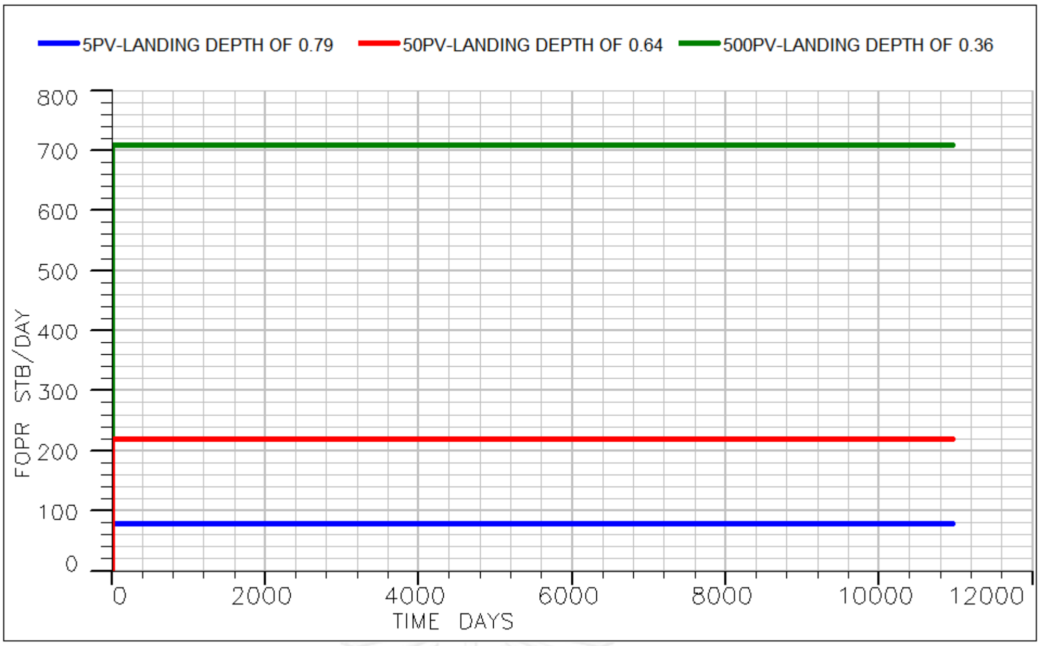

Figure 5.76 - Field oil production performance at optimal well locations using critical rates for M-Factor of 2

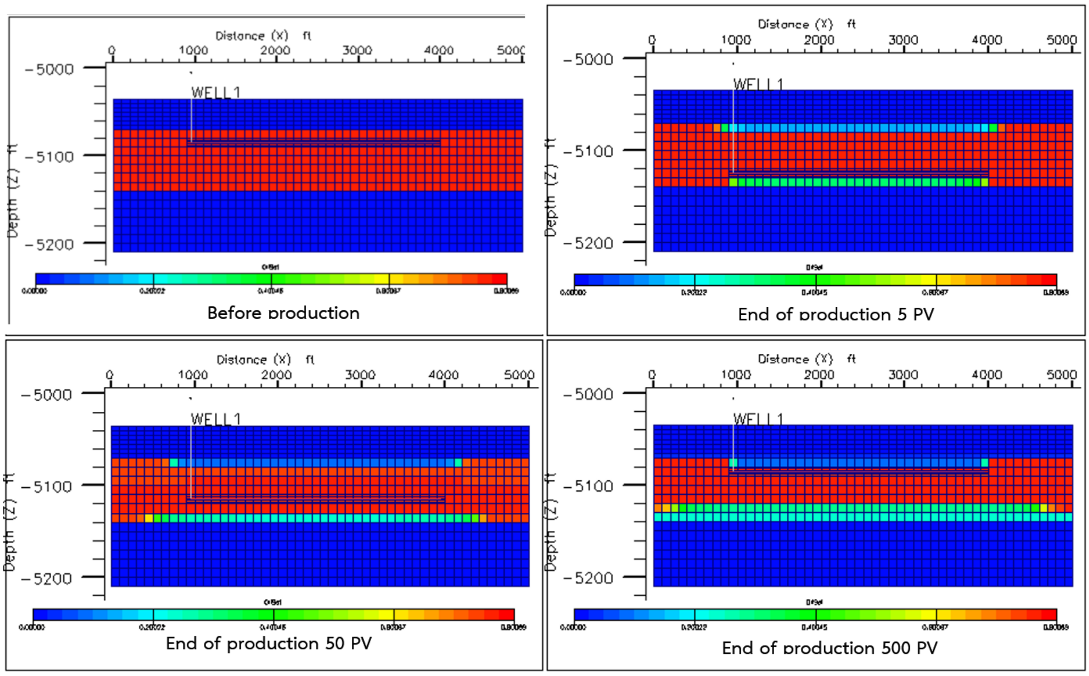

Figure 5.77 - Oil saturation profile before and at the end of production for M-Factor of 0.5 with 5, 50 and 500 PV aquifer using critical rates

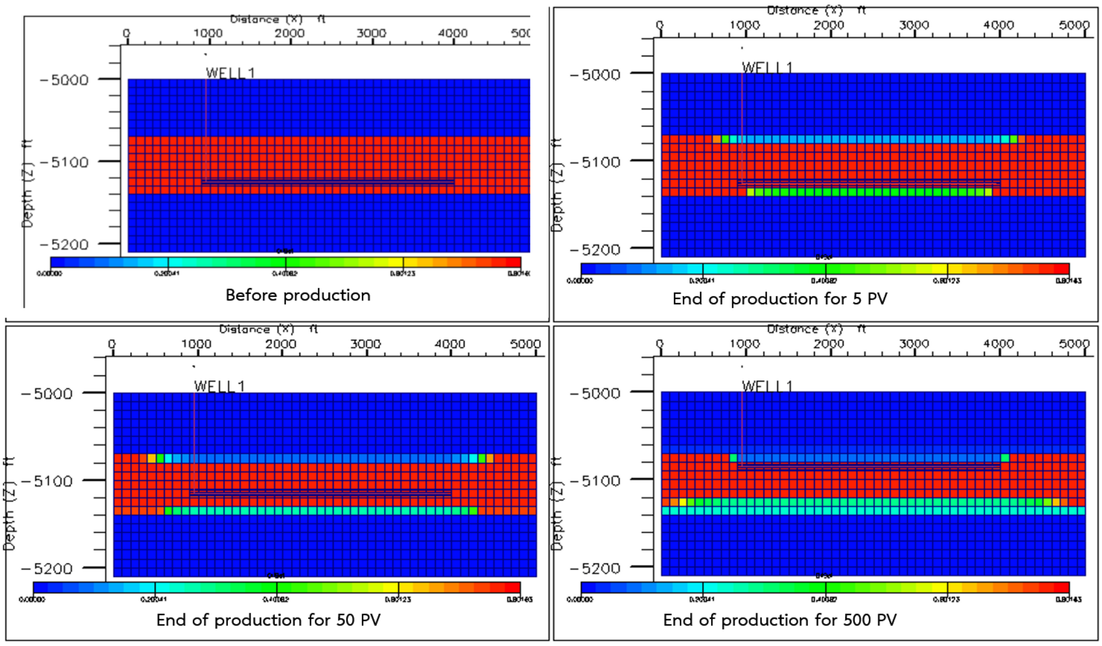

Figure 5.78 - Oil saturation profile before and at the end of production for M-Factor of 1 with 5, 50 and 500 PV aquifer using critical rates

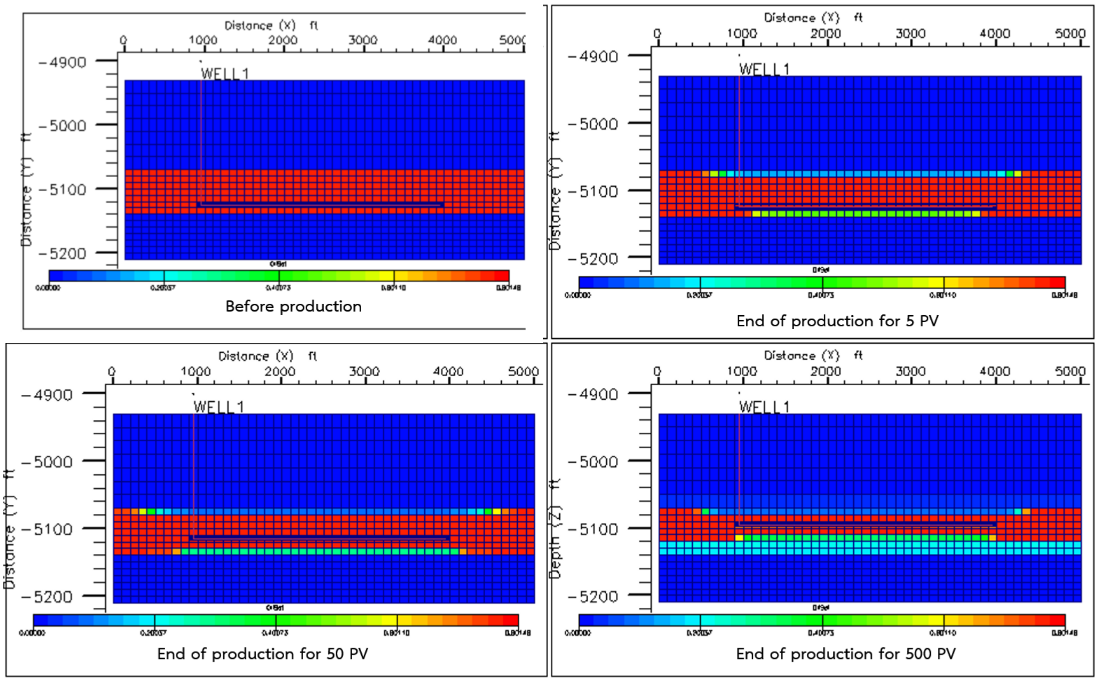

Figure 5.79 - Oil saturation profile before and at the end of production for M-Factor of 2 with 5, 50 and 500 PV aquifer using critical rates

CHAPTER 6
CONCLUSIONS AND RECOMENDATIONS

The study of optimal horizontal well placement in combination-drive thin oil rim provides useful information for the development of a thin oil rim reservoir under the presence of different gas cap and aquifer sizes. Based on the results obtained, the following conclusions can be made:

6.1 Conclusions

1. The optimal horizontal well location is determined by the strengths of gas cap and aquifer. For a fixed M-Factor and increasing the aquifer size, the optimal horizontal well location changes from the distance close to the oil-water contact at the landing depth of 0.79 for small aquifer and moderate aquifer (5 and 50 PV) to a distance close to gas-oil contact for larger aquifer (500 PV) at the landing depth of 0.21 for M-Factor of 0.5 and 1 and at the landing depth of 0.36 for M-Factor of 2. For fixed small and moderate aquifers, the increment of M-Factor does not affect the optimal well location which means that it remains the same, close to oil-water contact. For larger aquifer, the optimal well location is affected by the size of gas cap as it shows a tendency to move toward to the middle oil column with the increment of gas cap size.
2. The optimal target liquid rate is of a vital importance on the development of thin oil rim reservoirs. It is determined by the strengths of the gas cap and aquifer. For small and moderate aquifers (5 and 50 PV aquifers) where the expansion of gas cap provides energy for oil production, small target liquid rates of 2,000 and 3,000 STB/D yield the highest oil recovery. For large aquifer (500 PV) where water drive is the main mechanism, higher target liquid rates offer best oil recovery factor 6,000 STB/D for M-Factor of 0.5 and 5,000 STB/D for M-Factor of 1 and 2.

3. The recovery factor is affected by the size of gas cap and aquifer strength, as for a fixed small and moderate aquifer, the increment of M-Factor, results in increment of oil recovery factor. For large aquifer, the increment of gas cap size results in reduction on oil recovery factor.
4. The amount of produced water is affected by the drive mechanisms. The presence of strong aquifer results in higher cumulative water production which is associated with the upward movement of oil-water contact and higher target liquid rates while the presence of small aquifer results in lower cumulative water production as gas cap drive is the main drive mechanism.
5. Limiting the reservoir to produce below critical liquid rates, during the 30 years of concession period, will result in lower oil recovery compared with the oil recovery found with the optimal target liquid rates found for each case.

6.2 Recommendations

1. Perform study varying oil relative permeability, as some studies claim that locating the well right above GOC and right below OWC are favorable locations to produce through a thin oil rim reservoir.
2. Evaluate the effect of anisotropy ratio to understand how it affects oil recovery and at the same time how it affects the problems of water and gas coning.

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APPENDIX

APPENDIX A

Reservoir MODEL

1. Reservoir model

1.1 Case definition

Simulator	Black oil
Model dimension	Number of grid blocks in x-direction: 50
	Number of grid blocks in y-direction: 25
	Number of grid blocks in z-direction: 26
Grid type	Cartesian
Geometry type	Block centred
Oil-Gas-Water properties	Water, oil, gas and dissolved gas
Solution type	Fully implicit
Aquifer	Numerical

1.2 Grid

1.2.1 Properties

Active grid block	(1:50;1:25;1:21)=1
Inactive grid block	(1:50;1:25;22:26)=0
x permeability	5000 mD
y permeability	5000 mD
z permeability	500 mD
Porosity	0.296

1.2.2 Geometry

Parameter	M-Factor of 0.5	M-Factor of 1	M-Factor of 2
Grid block size	x grid block size: 100	x grid block size: 100	x grid block size: 100
	y grid block size: 100	y grid block size: 100	y grid block size: 100
	z grid block size: (1:7)=5 (8:21)=10 (22:26)=70	z grid block size: (1:7)=10 (8:21)=10 (22:26)=70	z grid block size: (1:7)=20 (8:21)=10 (22:26)=70
Depth of top face	5,035	5,000	4,930

1.2.3 Aquifer

Numerical aquifer assignments

I	J	K	Area (ft^2)	Length (ft)	Porosity (fraction)	k_v (mD)	Depth (ft)	Initial Press (psia)
50	25	22	12,500,000	70	0.296	500	5245	2352
50	25	23	11,102,500	70	0.296	500	5315	2383
50	25	24	9,861,241	70	0.296	500	5385	2414
50	25	25	8,758,754	70	0.296	500	5455	2446
50	25	26	7,779,525	70	0.296	500	5525	2477

Aquifer connections

Row	Aq ID	I-	I+	J-	J+	K-	K+	Face
1	1	1	50	1	25	1	21	K+

1.2.3 Local grid refinement

Cartesian Local Grid Refinement

LGR name	PROD_LGR
I1	10
I2	40
J1	13
J2	13
K1	11
K2	11
NX	31
NY	1
NZ	5

1.3 PVT

Fluid densities at surface conditions

Parameter	Value	units
Oil density	53.00209	lb/ft^3
Water density	62.42811	lb/ft^3
Gas density	0.04994	lb/ft^3

Water properties

Parameter	Value	Units
Reference pressure P_{ref}	2274	psi
Water FVF at P_{ref}	1.034716	rb/stb
Water compressibility	3.367823×10^{-6}	/psi
Water viscosity at P_{ref}	0.2559402	cP
Water viscosibility	6.836929×10^{-6}	/psi
Salinity	5,000	ppm

1.4 SCAL

Water/oil saturation functions versus water saturation

Sw	Krw	Kro
0.2000	0.0000	0.8000
0.2556	0.0004	0.6321
0.3111	0.0033	0.4840
0.3667	0.0111	0.3556
0.4222	0.0263	0.2469
0.4778	0.0514	0.1580
0.5333	0.0889	0.0889
0.5889	0.1412	0.0395
0.6444	0.2107	0.0099
0.7000	0.3000	0.0000
1.0000	1.0000	0.0000

Gas/oil saturation functions

Sg	Krg	Kro
0.0000	0.0000	0.8000
0.1000	0.0000	0.5878
0.1750	0.0008	0.4500
0.2500	0.0063	0.3306
0.3250	0.0211	0.2296
0.4000	0.0500	0.1469
0.4750	0.0977	0.0827
0.5500	0.1688	0.0367
0.6250	0.2680	0.0092
0.7000	0.4000	0.0000
0.8000	0.8000	0.0000

1.5 Initialization

Equilibration region

Equilibration data specification

Parameter	Value	Units
Datum depth	5,070	*ft*
Pressure at datum depth	2274	*psi*
OWC depth	5,140	*ft*
GOC depth	5,070	*ft*

1.6 Schedule

LGR Well Specification

Well name	WELL1
Group	1
LGR	PROD_LGR
I location	1
J location	1
Datum depth	5070
Preferred phase	OIL
Inflow equation	STD
Automatic shut-in instruction	SHUT
Crossflow	Yes
Density calculation	SEG

Well connection data in LGR

Well	WELL1
LGR	PROD_LGR
I	1
J	1
K upper	3
K lower	3
Open/shut flag	Open
Wellbore ID	0.5104 ft
Direction	X

As a horizontal well is used to produce from the reservoir, the well connection data in LGR was extended from grid 1 to the grid 40 in x direction. The last table is presented on the following table.

Well connection data in LGR

Well	WELL1
LGR	PROD_LGR
I	31
J	1
K upper	3
K lower	3
Open/shut flag	Open
Wellbore ID	0.5104 ft
Direction	X

Production well control

Well	WELL1
Open/shut flag	Open
Control	LRAT
Liquid rate	5000 STB/D
BHP target	200 psia

Production well economics limits

Well	WELL1
Minimum oil rate	50 STB/D
Maximum water cut	0.95 STB/STB
Workover procedure	NONE
Well End run	YES
Quantity for economic limit	RATE

Well Action Control

Action	1
Well Name	WELL1
Quantity	WWCT
Operator	>
Water cut	0.95

Production well control

Well	WELL1
Open/shut flag	SHUT

APPENDIX B

Results for well location right above GOC and right below OWC with a fixed target liquid rate of 5,000 STB/D

Results for right below OWC

Results for M-Factor of 0.5 with 5PV aquifer

Landing depth below OWC *(ft/ft)*	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (Years)
0.01	50.17	14.59	24.47	13.79	15.6
0.04	50.02	15.51	24.40	13.75	16.1
0.11	47.91	18.06	24.28	13.17	17.1

Results for M-Factor of 1 with 5PV aquifer

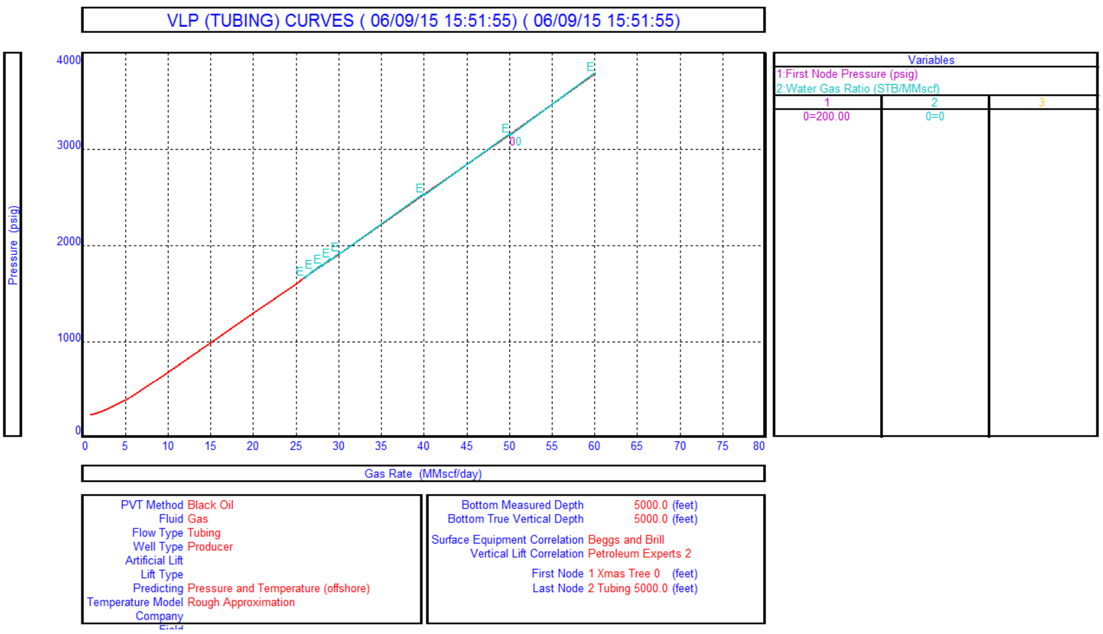
Landing depth below OWC *(ft/ft)*	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (Years)
0.01	52.40	14.42	37.47	14.31	15.7
0.04	52.22	14.35	37.41	15.23	16.2
0.11	50.38	13.85	37.29	17.94	17.4

Results for M-Factor of 2 with 5PV aquifer

Landing depth below OWC *(ft/ft)*	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (Years)
0.01	55.19	15.17	63.51	14.40	16.2
0.04	55.07	15.14	63.45	15.41	16.8
0.11	53.23	14.63	63.22	18.27	18.1

Results for right above GOC

For the present case, as the well is at the gas zone. The first step was to determine the amount of gas that can be sustained by the pipe. Prosper was used to determine the gas rate without causing erosional velocity. The gas rate of 25 MMSCF/D was selected.



Results for M-Factor of 0.5 with 500PV aquifer

Landing depth above GOC *(ft/ft)*	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (Years)
0.11	70.12	19.28	17.02	35.00	30.0
0.04	69.30	19.05	15.29	35.56	30.0
0.01	70.01	19.24	14.81	32.95	28.6

Results for M-Factor of 1 with 500PV aquifer

Landing depth above GOC *(ft/ft)*	Oil recovery factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (Years)
0.11	68.59	18.85	20.57	35.25	30.0
0.04	69.21	19.02	20.31	35.73	30.0
0.01	64.65*	17.42	17.80	26.26	24.1

* Note that this number does not follow the trend due to uncertainties in water cut. However, it does not affect the selection for the ranges of landing depth to maximize oil production.

Results for M-Factor of 2 with 500PV aquifer

Landing depth above GOC *(ft/ft)*	Oil Recovery Factor (%)	Cumulative oil production (MMSTB)	Cumulative gas production (BSCF)	Cumulative water production (MMSTB)	Time (Years)
0.11	61.27	16.84	26.98	22.12	21.5
0.04	60.38	16.60	28.02	38.12	30
0.01	66.07	18.16	25.94	36.59	30

VITA

Imelda Adelaide Fernando Marques, was born on March 22nd 1986 in Maputo, Mozambique. She obtained her bachelor degree in chemical engineering from Faculty Eduardo Mondlane University in 2012. In September of the same year, started working at INP (Instituto Nacional de Petróleo) in Project and Development Division. In 2013, she was endorsed in a Master Degree Program in Petroleum Engineering at Department of Mining and Petroleum Engineering Chulalongkorn University.