DEVELOPMENT STRATEGY FOR CONDENSATE RESERVOIRS WITH UNDERLYING MULTI-STACKED DRY GAS RESERVOIRS

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กลยุทธ์การผลิตแหล่งกักเก็บก๊าซธรรมชาติเหลวซึ่งมีแหล่งกักเก็บก๊าซแห้งข้างล่างหลายชั้น

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การผลิตจากแหล่งกักเก็บก๊าซธรรมชาติเหลวโดยปกติจะมีลักษณะที่ซับซ้อน เนื่องจากของเหลวจากก๊าซธรรมชาติกลั่นตัวตามที่ ความดันก้นหลุมตกลงต่ำกว่าจุดกลั่นตัว การสะสมของก๊าซธรรมชาติเหลวใกล้หลุมผลิตนั้นเรียกว่า “การสะสมของก๊าซธรรมชาติเหลว” ซึ่งนำไปสู่การสูญเสียความสามารถในการผลิตอย่างรุนแรงของหลุม ทำให้ก๊าซธรรมชาติถูกผลิตได้น้อยลงเช่นกัน หลากหลายวิธีการถูกเสนอและศึกษาเพื่อที่จะบรรเทาความเสียหายจากการสะสมของก๊าซธรรมชาติเหลว

การศึกษานี้สำรวจความแตกต่างของกลยุทธ์การผลิตซึ่งรวมถึง การผลิตแบบผสมผสาน การยิงท่อกรุหลายครั้ง และการแทนที่ก๊าซแบบถ่ายเท เพื่อที่จะปรับปรุงปริมาณการผลิตของเหลวสูงสุดสำหรับแหล่งกักเก็บก๊าซธรรมชาติเหลวที่มีแหล่งกักเก็บก๊าซธรรมชาติแห้งข้างใต้จำนวนหลายชั้น โดยใช้แบบจำลองแหล่งกักเก็บ เวลาของการแทนที่ก๊าซแบบถ่ายเทและหลายกลยุทธ์การยิงท่อกรุถูกศึกษา เพื่อเสาะหาสภาวะการปฏิบัติการที่เหมาะสมที่สุด ผลลัพธ์จากการจำลองแหล่งกักเก็บบ่งชี้ว่า การแทนที่แบบถ่ายเทให้ผลผลิตของก๊าซธรรมชาติเหลวปริมาณสูงที่สุด เมื่อเทียบกับวิธีการอื่นๆ ผลของการค้นหายังชี้ว่า เวลาที่ดีที่สุดสำหรับการแทนที่แบบถ่ายเทคือตอนเริ่มต้นการผลิต และกลยุทธ์การยิงท่อกรุที่ดีที่สุดคือการยิงท่อกรุชั้นก๊าซธรรมชาติแห้งทั้งหมดในเวลาเดียวกัน

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Production in gas condensate reservoirs usually exhibit complex behaviors due to condensate deposit as the bottom hole pressure drops below the dew point. The accumulation of condensate near the well, called “condensate bank”, can lead to a severe loss of well productivity and therefore lower gas recovery. Several methods have been proposed and investigated to treat damage caused by condensate blocking.

This study explores different production strategies, including commingled approach, batch perforations and gas dump-flood in order to improve the ultimate liquid recovery for gas condensate reservoirs with underlying multi-stacked gas reservoirs via compositional numerical simulation. The timing of gas dumpflood and various perforation strategies were investigated to see the most suitable operating conditions. Simulation results indicate that dumpflood shows the highest liquid recovery compared to other methods. The findings also suggest that the best timing for gas dumpflood is from the beginning and the best perforation strategy is to complete all gas layers at the same time.

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CHAPTER I
INTRODUCTION

Gas condensate reservoirs are an important source of hydrocarbon reserves and are often found as a single phase gas at the time of discovery. During production from the reservoir, the initial reservoir pressure drops as the fluid moves towards the well. When the pressure drops below the dew point of the gas condensate, liquid starts to drop out of the gas. This results in the formation of liquid hydrocarbons near the wellbore and in the reservoir, which is known as retrograde condensation. As the liquid hydrocarbon saturation in the near-wellbore region increases, the gas relative permeability is decreased, resulting in significant declines in well productivity. The condensate bank formed is partially unrecoverable due to critical oil saturation [1].

Several methods have been proposed and investigated to treat damage caused by condensate blocking. The most common approaches are either changing the phase behavior of reservoir fluids or reducing the pressure drawdown and thus maintaining the reservoir pressure above the dew point such as gas cycling, non-hydrocarbon gas injection, methanol treatments or hydraulic fracturing.

With a dominated fluvial deltaic depositional environment, geological model in the studied area is very complex including stacked thin reservoirs in the vertical direction, compartmentalized fault blocks and localized distribution in the lateral direction. In order to maximize resource recovery from such a kind of small individual accumulations, several production strategies are proposed. Additionally, reservoirs encountered in this study are multi-layered sandstone reservoirs with gas condensate in the upper layers and dry gas in the lower layers, which suggest a high possibility to apply gas dumpflood technique to improve the liquid recovery efficiency.

1.1 Objective

The objective of this study is to maximize the condensate production from gas condensate reservoirs with underlying dry gas reservoirs. Different production scenarios, including aggressive or commingled approach, batch perforations and gas dumpflood were simulated and compared using a simplified reservoir simulation model via ECLIPSE 300 compositional reservoir simulator. Several important factors such as plateau rate, timing of dumpflood and perforation strategies were investigated in order to find the most suitable operating conditions.

1.2 Outline of methodology

- ✓ Construct a homogeneous reservoir model in ECLIPSE 300 with the production well in the center of the reservoir
- ✓ Perform simulation for different production strategies
    - Scenario 1: Commingle production
    - Scenario 2: Bottom up with plug
    - Scenario 3: Bottom up without plug
    - Scenario 4: Top down without plug
    - Scenario 5: Gas dumpflood
- ✓ Optimize operating conditions for the five strategies by varying:
    - Plateau gas production rate
    - Timing of perforating the second batch
    - Timing of dumpflood
    - Perforation strategy for dry gas reservoirs in dumpflood

1.3 Outline of thesis

This thesis contains six chapters as outlined below:

Chapter I gives some overviews of study area, which is a multilayer gas condensate reservoirs and summarizes the objective and methodology of this study.

Chapter II introduces various published literatures relating to methods to increase condensate recovery.

Chapter III presents relevant theories and concepts relating to behavior of gas condensate systems and production mechanism in condensate recovery.

Chapter IV describes reservoir simulation model with all input data and constraints in details together with the case structure of simulation work.

Chapter V analyzes the simulation results and comparisons among different cases.

Chapter VI provides conclusions and recommendations of future work.

CHAPTER II

LITERATURE REVIEW

This chapter evaluates the information found in the literature related to methods to increase condensate recovery and gas dumpflood.

2.1 Methods to increase gas condensate recovery

Several techniques have been used to remediate productivity problems due to condensate banking in gas condensates wells over time with varying degrees of success.

Hydraulic fracturing [2] is the most common stimulation method that has been employed in siliciclastic reservoirs while acidizing is used in carbonate reservoirs. The benefits of hydraulic fracturing are particularly pronounced in reservoirs exhibiting low permeability, high skin and, in case of gas condensate reservoirs, near wellbore condensate banking. However, hydraulic fracturing is not always feasible or cost-effective and not easily achieved in very layered and heterogeneous, deep reservoirs.

Improving well productivity in gas condensate reservoirs via chemical treatment such as methanol, propane solvents or wettability alteration agents have been studied and have given very promising results. A methanol treatment [3] applied to a gas condensate well in the Hatter's Pond field in southwestern Alabama was found to increase both gas and condensate production by a factor of 2 over the first four months and 50% thereafter. A solution of a methanol-water solvent increased the steady state relative permeability by a factor of 2 to 3 over a temperature range of 145 to 275 °F [4]. The use of propane [5] as an injected vaporizer for a HPHT rich gas condensate is a potential option to improve productivity.

Gas cycling or re-injection has proven to be very effective in reducing the liquid accumulation to maintain the reservoir pressure above the dew-point. During gas cycling [6], produced lean gas is injected back in order to maintain the reservoir pressure and enhance the condensate production and ultimate condensate recovery. It has been reported that with higher volume of gas injection in the cycling process, more gas and condensate (oil) can be recovered at the end of the project. Although, such a high volume of gas injection could impede DCQ (and thus profits) but the total worth of the project towards the end would be higher. Above that, the injected gas will be produced back and will not be lost anyway.

Injection of non-hydrocarbon gases (CO2, N2) or methane (CH4) or mixture of CO2/N2 and CH4 combinations [7, 8] into a gas condensate reservoir has been suggested to enhance condensate recovery by revaporization. Water-alternating-gas injection (WAG) with CO2 [8] in partially depleted gas condensate reservoirs had higher ultimate condensate recovery than WAG with C1. The pure CO2 injection seems to reach the highest value of recovery compared to C1 and C1-CO2 injection combinations. In gas condensate reservoirs with active aquifer [9], injection of dry gas or CO2 is possible to return the water to the aquifer and achieve better control over the influx rate in certain areas of the reservoir.

Another method, cyclic injection [10] and production from one well, sometimes called huff and puff injection has been introduced in the oil field. Many different gases have been utilized as the injection gas in a huff and puff process to vaporize condensate around a well and then produce it. The laboratory tests reported by Shayegi et al. compared the use of pure carbon dioxide, pure methane and pure nitrogen, and concluded that that pure CO2 or pure methane are the most effective gases in reducing the liquid dropout compared to nitrogen when injected at the same pressure [11].

The selection of which solvent or method summarized above should be made with an economic analysis based on non-hydrocarbon cost, methane price and demand and final recovery. However, successful design and implementation of enhanced condensate recovery by gas injection schemes requires an accurate prediction of the compositional effects that control the local displacement efficiency.

2.2 Gas dumpflood

A "dumpflood" concept is implemented where a single well is used as a source of gas supply and inject domain. The in-situ gas dumpflood to allow cross flow within the tubing from a deeper gas sand into a partially depleted oil sand was implemented in North Arthit Field [12]. This technology makes use of energy from the deeper and high-pressure gas sand to increase reservoir pressure and sweep the oil to a nearby producer. It proved to be low cost and simple operation but can improve oil recovery significantly (up to 3000 stb/d). Basically, the in-situ gas dumpflood operation will stop when the gas sand stops to contribute. In term of operation, it is recommended to restrict the oil rate at the early stage of dumping process to avoid gas coning from deeper gas source.

There are many critical factors that need to be considered for the success of the in-situ gas dumpflood such as the timing to start the in-situ gas dump flood operation, reservoir permeability, the distance and flow connectivity between the dumper and the producer. For the case of North Arthit Field, the reservoir pressure in the oil sand was partially depleted (10%) when the operation was commenced. The highest permeability layer at the bottom and the lowest permeability layer at the top of oil reservoir contribute for the high recovery efficiency by the gravity segregation mechanism [12].

A simulation model was studied to evaluate the performance of CO2 dumpflood [13] to increase condensate recovery from a gas condensate reservoir. In the model, the high CO_2 gas is flowed from a deeper source reservoir to a shallow gas condensate reservoir. As a result, the reservoir pressure can be maintained to prevent the condensate dropout in the reservoir and the dew point of the reservoir fluid can be reduced as well. The results from reservoir simulation indicate that gas dumpflood will give the highest condensate recovery factor if it is implemented before the reservoir pressure drops below the dew point. The compositions of the source gas and the reservoir target depths have a slight effect on the recovery of condensate [13].

CHAPTER III
RELEVANT THEORY AND CONCEPT

3.1 Behavior of gas condensate systems

Hydrocarbon fluids are divided into five main types: dry gas, wet gas, gas condensate, volatile oil and black-oil. The phase behavior of a reservoir fluid at surface and reservoir conditions depends on the fluid composition, pressure and temperature. Gas condensate production is predominantly gas from which more or less liquid condense out of gas, hence the name gas condensate.

A typical gas condensate fluid [14] exhibist gas-oil ratios (GOR's) between 3000 and 150,000 scf/STB and oil-gas ratios (OGR's) from about 350 to 5 STB/MMscf, stock-tank liquid gravities between 40° and 60° API. Most known retrograde gas condensate reservoirs are in the range of 5000 to 10000 ft deep, at 3000 psi to 8000 psi and a temperature from 200^{o}F to 400^{o}F.

3.1.1 Phase behavior of gas condensate

For gas condensate systems [15], the reservoir temperature T lies between the critical temperature T_c and cricondentherm T_{ct} of the reservoir fluid. At the time of discovery, a typical gas condensate reservoir pressure might be above or close to the dew point pressure. At this time there exists only single-phase gas (point A) as shown in Figure 3.1. As pressure goes down to below the upper dew point pressure (point B) at constant temperature, liquid begins to condense out of the gas (vapor phase) to form a free liquid inside the reservoir. The reservoir enters two-phase region with the flowing gas becomes leaner as the heavier component drops into liquid.

However, the liquid will not flow until the accumulated liquid reaches the critical condensate saturation. This retrograde condensation process continues with decreasing pressure until the liquid dropout reaches its maximum at point C, where that liquid will start to vaporize. From this point to abandonment pressure D, liquid continues to revaporize and thus the amount of condensate dropout in the reservoir will decrease due to revaporization process. If the lower dew point is crossed then all the liquid will have revaporised.

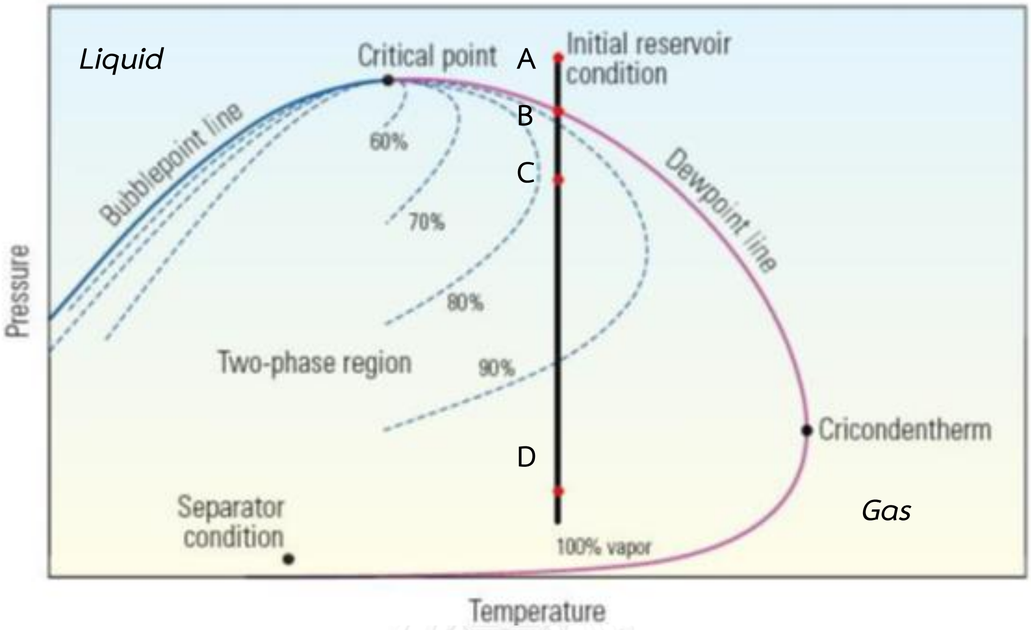

Figure 3.1 A typical phase diagram of gas condensate [16]

Figure 3.2 shows a typical curve for the variation of the liquid volume percentage with pressure. This curve can be also referred to as the liquid dropout curve.

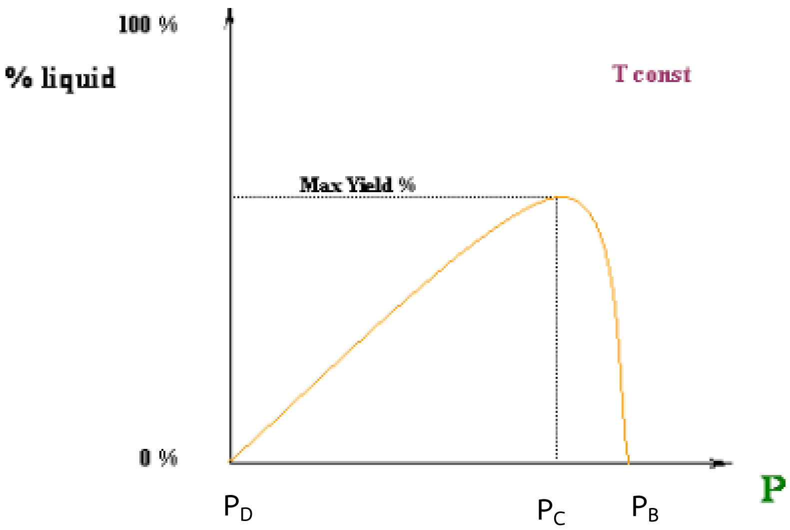

Figure 3. 2 Liquid dropout curve [17]

3.1.2 Fluid composition change

Figure 3.1 shows the phase diagram for fluid of a single constant composition. According to Roussennac [18], during the production period, the heavier components tend to drop out first and are concentrated in the condensate liquid, whilst the lighter components tend to concentrate in the vapor phase. The overall mixture close to the well becomes richer in heavy components as the liquids build up. Thus as the gas is produced, the composition of the gas and condensate remaining in the reservoir changes and the two-phase envelope will shift downwards and towards the right to a system with higher critical temperature as illustrated in Figure 3.2. The fluid behavior will change from the initial gas condensate reservoir to that of a volatile/black oil reservoir.

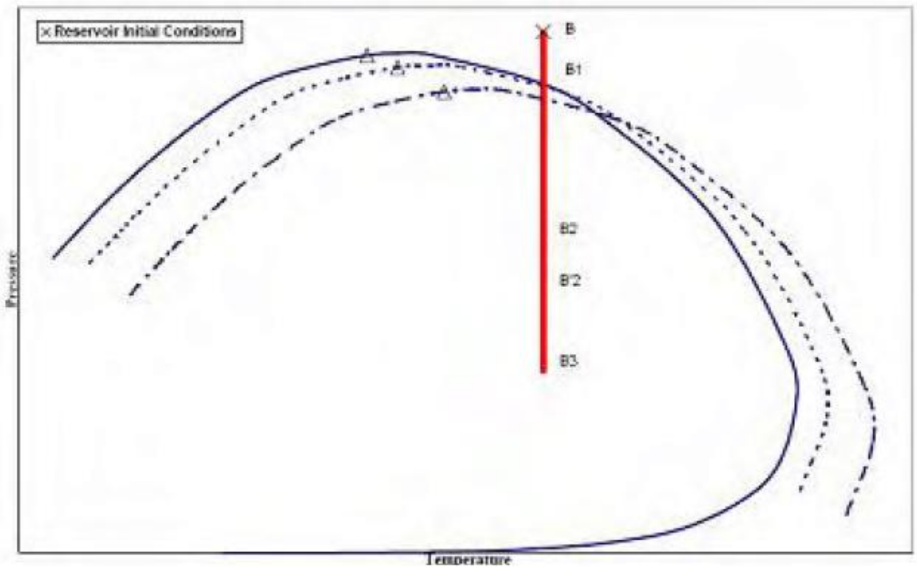

Figure 3.3 Shift of phase envelope with compositional change on depletion [18]

3.1.3 Behavior of gas condensate

Fevang and Whitson [19] identified three flow regions related to drawdown flow behavior in gas condensate reservoirs as shown in Figure 3.3.

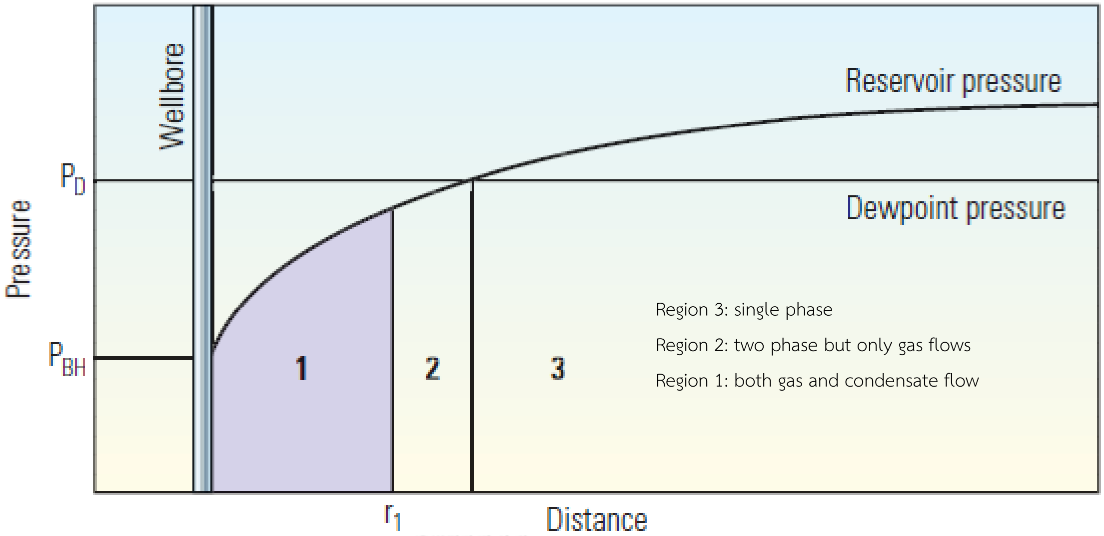

Figure 3.4 Pressure profile and flow regions in a gas condensate well [19]

- ✓ Region 1: This region is an inner near-wellbore region where both gas and condensate are flowing. This is because the reservoir pressure drops further below the dew-point, liquid saturation exceeds the critical saturation and part of the liquid starts to join the flowing gas phase and would be produced at the wellhead. However, the mobility of the gas phase is greatly reduced due to the liquid build-up around the well and in the reservoir.
- ✓ Region 2: This region is called an intermediate region where the reservoir pressure is lower than the dew-point, and thus condensate drops out in the reservoir. However, the accumulated condensate saturation in this region is not reached the critical saturation. Therefore, the flowing phase in this region still contains only the single gas phase, and the flowing gas becomes leaner as the heavier components are being released from the original gas.
- ✓ Region 3: This region is outer and far away from the well. Pressure here is higher than the dew-point, and hence only single phase gas (original reservoir gas) presents. However, if pressure decline below the dew point as production continues, region 3 will be shrunk and may be replaced by region 1 and 2.

According to Gringartenet e.t al. [20], besides three regions mentioned above, there is a fourth region in the immediate vicinity of the well where low IFT at high rate cause a decrease in the liquid saturation and an increase the gas relative permeability.

3.2 Commingled production

Commingling is a method to accelerate the total recoverable hydrocarbons from a well with minimized operation expenditure. Commingling provides an opportunity to produce zones that may be individually uneconomic to produce. In an aggressive approach, the so-called commingled approach, all pay sands are perforated at the initial completion stage. Minor exceptions include:

(i) sands which are at obvious risk of producing water,

(ii) shared pay which would result in downward cross flow if perforated, and

(iii) tight AZI (additional zone of interest) sand.

This approach minimizes the frequency of perforation jobs and minimizes downtime. This allows the entire well to benefit from booster compression (BC) at a later date in the WHP life without having to accelerate BC installation.

3.3 Gas cycling and gas dumpflood

Gas cycling or re-injection [21] of produced natural gas to maintain pressure in the reservoir above the dew point and therefore prevent the condensate dropout from the natural gas in the reservoir. In this method, gas is injected through an injection well at some distance away from a production well directly into the production reservoir as depicted in Figure 3.4. The high pressure near the injector essentially pushes oil or gas condensate towards the production well to sweep the formation for the remaining petroleum. Condensate is separated from the gas on the surface after it has been produced from the reservoir, and the produced gas is then re-injected into the reservoir through injection wells.

Although gas injection shows higher condensate recovery factors, this method of EOR may not be economical due to the high upfront investment costs for the requisite equipment and gas components, higher operating costs, and delay of gas sales. This high initial fixed cost was the barrier to entry into gas injection EOR for many smaller independent oil companies.

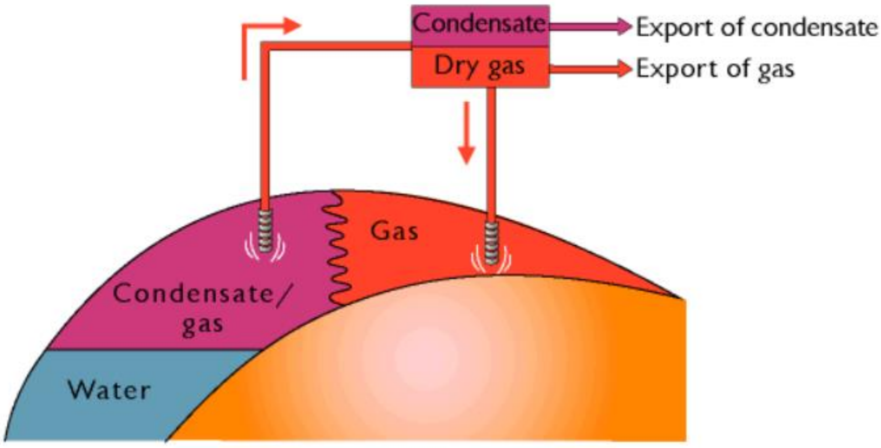

Figure 3.5 Gas cycling in gas condensate reservoir [22]

In contrast, the gas dumpflood method [12] allows gas to cross flow within the tubing instead of injecting gas from the surface. Gas is dumped from a deeper gas reservoir into the shallower gas condensate reservoir to increase reservoir pressure and sweep the gas condensate to a nearby producer as shown in Figure 3.5. This method may not provide higher recovery efficiency than flooding approach but it provides quicker return on oil well investments. The proposed gas dumpflood technology makes more efficient use of dry gas resources; it does not require drilling more wells. Finally, dry gas can be recovered at the surface anyway.

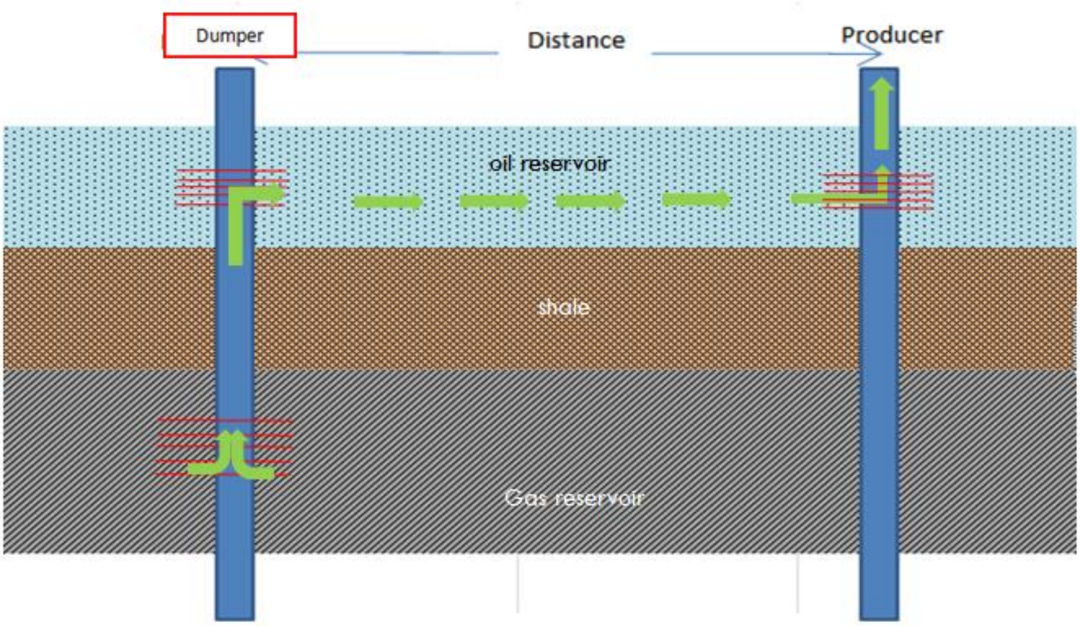

Figure 3.6 Gas dumpflood in gas condensate reservoirs [12]

3.4 Overall Recovery Efficiency

The overall efficiency [23] at breakthrough is defined as:

$E = E_V * E_D$

$E_V = E_A * E_i$

where:

E_V is the volumetric sweep efficiency

E_A is the areal sweep efficiency

E_i is the vertical sweep efficiency

E_D is the microscopic displacement efficiency.

All above efficiency factors (i.e E_D, E_i, E_A) are variables that increase during the flood and reach maximum values at the economic limit of the injection project.

3.4.1 Microscopic displacement efficiency (E_D)

The displacement efficiency is the fraction of movable oil that has been recovered from the swept zone at any given time. With constant oil density, the displacement efficiency can be expressed mathematically as:

$$E_D = \frac{Volume\ of\ oil\ at\ start\ of\ flood - Remaining\ oil\ volume}{Volume\ of\ oil\ at\ start\ of\ flood}$$

Because an immiscible gas injection or water-flood will always leave behind some residual oil, E_D will always be less than 1.0.

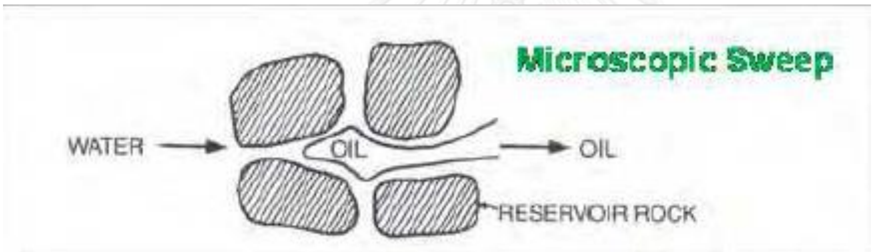

Figure 3.7 The schematic of microscopic displacement efficiency [23]

The microscopic displacemnt efficiency can be increased by reducing capillary forces or interfacial tension between the displacing fluid and oil or by decreasing the oil viscosity.

3.4.2 Macroscopic or volumetric displacement efficiency (E_V)

Macroscopic or Volumetric sweep efficiency [24, 25] at any time is the percentage of total reservoir volume contacted by the injected fluid during the recovery.

$$E_V = \frac{\text{Volume of oil contacted by displacing fluid}}{\text{Total amount of oil in place}}$$

Volumetric displacement efficiency indicates the effectiveness of the displacing fluid in sweeping out the volume of a reservoir, both areally and vertically.

$$E_V = E_A \bullet E_I$$

The areal sweep efficiency (E_A) is the fractional area of the pattern that is swept by the displacing fluid.

$$E_A = \frac{\text{Area contact by displacing phase}}{\text{Total area}}$$

The vertical sweep efficiency (E_I) is the fraction of the vertical section of the pay zone that is contacted by injected fluids:

$$E_I = \frac{Cross\_sectional\ area\ connected\ by\ displacing\ fluid}{Total\ cross\_sectional\ area}$$

The volumetric sweep efficiency is primarily a function of:

✓ Heterogeneity:

This includes reservoir vertical heterogeneity and areal heterogeneity.

Areal heterogeneity includes areal variation in formation properties (e.g., h, k, ϕ, S_{wc}), geometrical factors such as the position, any sealing faults, and boundary conditions due to the presence of an aquifer or gas cap. The movement of fluids through the reservoir will not be uniform if there are large variations in such properties as porosity, permeability, and clay content. This may lead to substantial by-passing of residual oil by injected fluids in many EOR projects.

In term of vertical heterogeneity, a reservoir may exhibit many stratified layers in the vertical section that have highly different properties. The injected fluid will preferentially enter the layers of highest permeability and will move at a higher velocity, resulting in earlier water or gas breakthrough.

✓ Fluid mobilities:

The mobility of a fluid is defined as its effective permeability divided by its viscosity. The mobility ratio is the mobility of the displacing phase divided by the mobility of the displaced phase. As the mobility ratio increases, the sweep efficiency decreases. The phenomenon called viscous fingering can occur if the mobility of the displacing phase is much greater than the mobility of the displaced phase. Once the channel of injected fluid exists between the injector and producer, then little additional oil would be recovered.

✓ Degree of gravity segregation:

Normally, gas is injected from high structure to displace oil downward toward the production wells that are completed low in the oil column, the force of gravity will work to keep gas on top of the oil or stabilize the flood front between the gas and oil (GOC). The gas/oil gravity drainage process is complicated if the oil column is overlain by a gas cap and underlain by an aquifer. In this case, the degree of gas cap expansion depends on the size of aquifer, and gas and water conning can both occur if the production rate is too high.

✓ Total volume injection:

Areal sweep efficiency increases with the volume injected and with a lower mobility ratio. The more gas injected, the faster the oil comes out. The greater the volume of reservoir contacted by the injected gas, the greater the oil recovery.

In general, reservoir heterogeneity [24, 25] probably has more influence than any other factors on the performance of a secondary or tertiary injection project. The most important two types of heterogeneity affecting sweep efficiencies, E_A and E_V, are the reservoir vertical heterogeneity and areal heterogeneity.

Figure 3.7 shows schematic of volumetric sweep efficiency [26] and illustrates some factors affecting the volumetric sweep efficiency such as viscous fingering and solvent channeling through high-permeability streaks heterogeneous reservoirs. The injected gas (solvent) sweeps only part of the reservoir and therefore only a portion of the oil in the solvent-swept regions is recovered. When vertical communication is high, solvent tends to segregate to the top of a reservoir unit and sweep only the upper part of that zone.

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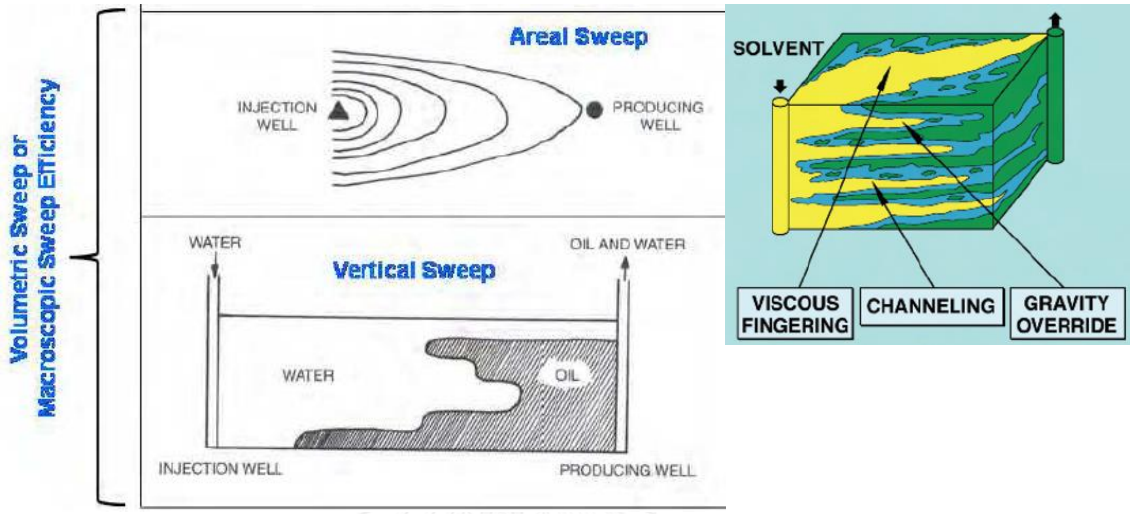


Figure 3.8 Schematic of volumetric sweep efficiency and some affected factors [24, 25]

3.5 Miscible fluid displacement

Miscibility [27] means that the gas that is injected will dissolve into the oil, thereby reducing oil viscosity and interfacial tension between the oil and rock and improve the oil flow rate. There are, in general, two types of miscible processes.

One is referred to as the single-contact miscible process (SCM) and involves such injection fluids as liquefied petroleum gases (LPGs) and alcohols. The injected fluids are miscible with residual oil immediately on contact. Reservoir pressures sufficient to achieve miscibility are required. This limits the application of LPG processes to reservoirs having pressures at least of the order of 1500 psia.

The second type is the multiple-contact, or dynamic, miscible process (MCM). The injected fluids in this case are usually methane, inert fluids, or an enriched methane gas supplemented with a C2–C6 fraction. The injected fluid and oil are usually not miscible on first contact but rely on a process of chemical exchange between phases to achieve miscibility.

A narrow transition zone (mixing zone) develops between the displacing fluid and the reservoir oil, inducing a piston-like displacement. The mixing zone and the solvent profile spread as the flood advances. The change in concentration profile of the displacing fluid with time is shown in Figure 3.8. Interfacial tension is reduced to zero in miscible flooding. Displacement efficiency approaches 1 if the mobility ratio is favorable (M < 1).

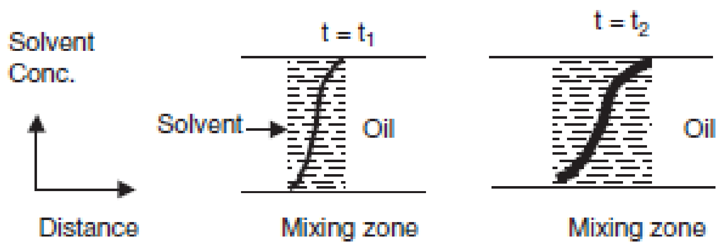


Figure 3.9 Transition zone and concentration profile of the solvent in miscible flooding [27]

3.6 Fracture pressure

Maximum injection pressure will increase with depth. Normally, critical pressure is approximately 1 psi/ft of depth. However, if it is exceeded, the injecting fluid will create fractures. This results in the channeling of the injected water or the bypassing of large portions of the reservoir matrix. Consequently, an operational pressure gradient of 0.75 psi/ft [25] normally is allowed to provide a sufficient margin of safety to prevent pressure parting.

The water-injection rate and pressure are roughly related by the following expression:

$$p_{inj} \propto \frac{i_w}{hk}$$

where:

P_{inj} = water-injection pressure, psi

i_w = water-injection rate, stb/d

h = net thickness, ft

k = absolute permeability, mD

3.7 Multiphase flow in pipe and vertical flow performance

Multiphase flow occurs in almost all producing oil and gas wells and surface pipes that transport the produced fluids. Multiphase flow is referred to the simultaneous flow of more than one fluid phase or component such as oil, gas and water in the production string of a well. Two-phase flow is a particular example of multiphase flow where any two of the three phases exist in a flow system.

3.7.1 Pressure gradient

The pressure drop in multiphase flow is more complicated than that of a single-phase flow because parameters such as velocity, friction factor, density and the fraction of vapor to liquid change as the fluids flow to the surface.

The total pressure gradient in the vertical direction [28], *dp/dz*, during multiphase flow (as in single-phase flow) is the sum of three major components including:

- ✓ the gravitational component or static head [$(dp/dz)_H$],
- ✓ the frictional component [$(dp/dz)_F$], and
- ✓ the acceleration component or kinetic head [$(dp/dz)_A$]

$$(dp/dz) = (dp/dz)_H + (dp/dz)_F + (dp/dz)_A$$

$$= (-1/g_c)[(\rho_M g) + (2 f_M v_M{}^2 \rho_M / d) + (\rho_M v_M dv_M/dz)].$$

This equation is used to account for the total pressure losses in wellbore fluid flow.

- The pressure drop due to elevation change depends on the density of the two-phase (liquid-gas) mixture. For vertical flow, except during annular flow, the static head is the major contributor to the total head loss, and in some cases (low gas fraction and low flow rates), it may account for more than 95% of the total gradient.
- The pressure drop due to acceleration is usually minor except in segments where there are changes in the diameter of the flow conduit.
- The pressure drop due to friction is most significant in high velocity gas wells, as well as in higher gravity oil flows.

3.7.2 Vertical flow regime

Multiphase flow is represented by the variation of flow regime (or flow pattern). Fluid distribution changes greatly in different flow regimes, which significantly affects pressure gradient in the tubing.

As shown in Figure 3.9, at least four flow regimes [29] have been identified in gas-liquid two-phase flow. They are bubble, slug, churn, and annular flow. These flow regimes occur as a progression with increasing gas flow rate for a given liquid flow rate in a vertical oil well. During the lifetime of a producing well, more than one flow regime may exist at the same time in the well.

In bubble flow, gas phase is dispersed in the form of small bubbles in a continuous liquid phase along the tubing. In slug flow, gas is found as larger bubbles that eventually fill the entire pipe cross-section. Between the large bubbles are slugs of liquid, which is still the continuous phase containing smaller bubbles of entrained gas. In churn (transition) flow, flow starts to change from slug to mist. The larger gas bubbles become unstable and collapse, resulting in a highly turbulent flow pattern with both phases dispersed. In annular (or mist) flow, gas phase becomes the continuous and dominant phase in the well. Liquid flows as a thin layer inside of the tubular with droplets entrained in the gas phase.

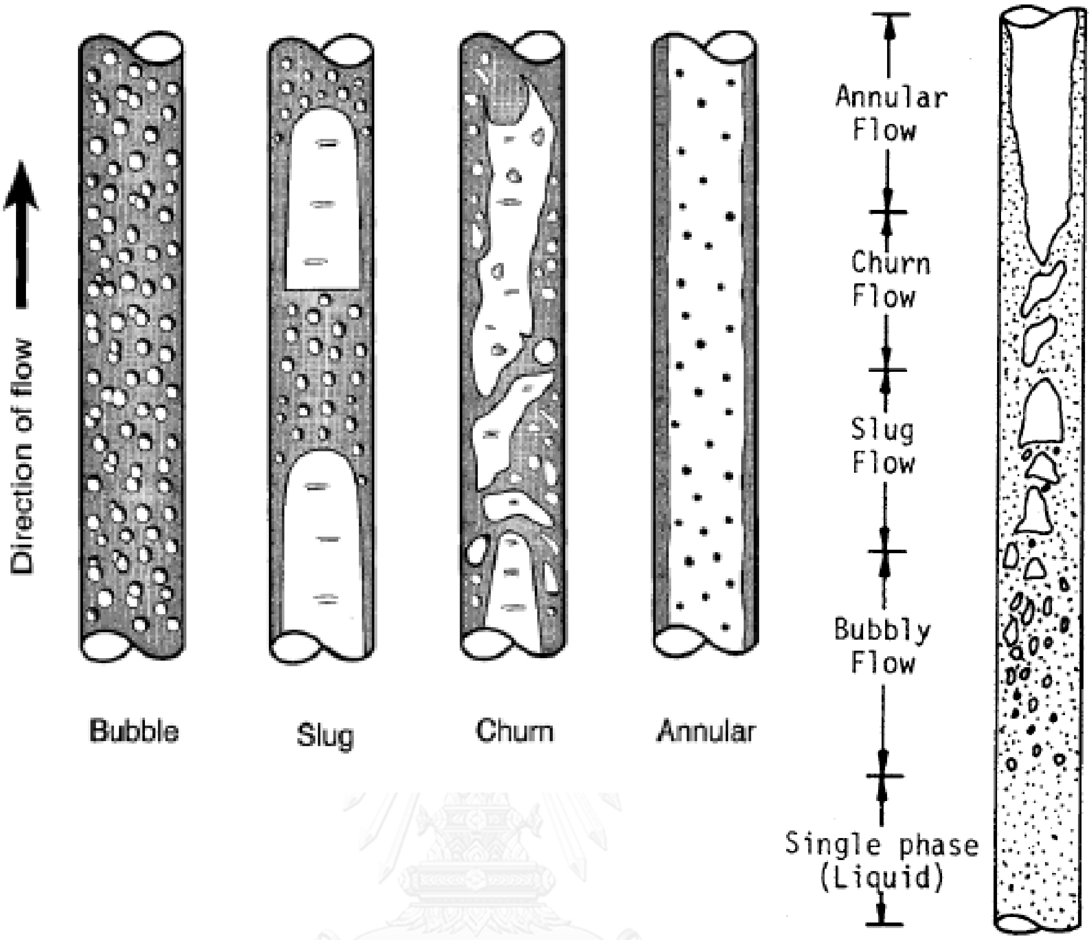


Figure 3.10 Vertical flow pattern in tubing [29]

CHAPTER IV
RESERVOIR SIMULATION MODEL

The geology of the discovered gas reservoirs in Gulf of Thailand (GoT) is very complex including stacked thin reservoirs in vertical direction, compartmentalized fault blocks and localized distribution in the lateral. With the above complex geological setting conditions, individual hydrocarbon accumulations are usually quite small and being limited by structural closure and fault block width. In this study, a fault block width of 1300 ft and length of 3300 ft is used. This is consistent with a geological model and well completion strategy in GoT.

The study was carried out with numerical reservoir simulation of fluid flow in gas/gas condensate reservoirs using ECLIPSE compositional simulator (E300).

4.1. Grid section

The reservoir system is the multi-stacked sandstone in the Gulf of Thailand, with layers of shale in between its various sand beds. The model is described as follows:

- ✓ The reservoir model contains 33x13x15 blocks in the x-, y-, and z-direction.
- ✓ Each grid block has a dimensions $\Delta x=\Delta y=100$ ft
- ✓ Eight reservoir layers with uniform reservoir properties, separated by shale layers. The thickness of sandstone and shale layers is 10 ft and 302 ft respectively as tabulated in Table 4.1.
- ✓ Cartesian coordinate with Block-Center (BC) Geometry.
- ✓ Monobore slimhole well design
- ✓ No bottom or edge water drive
- ✓ Drainage area is 98 acre
- ✓ Horizontal beds

Table 4.1 Thickness of reservoir layers in simulation model

Layer	Formation	Top sand ('TVDSS)	Net pay (ft)
1	sand	6021	10
2	shale	6031	302
3	sand	6333	10
4	shale	6343	302
5	sand	6645	10
6	shale	6655	302
7	sand	6957	10
8	shale	6967	302
9	sand	7269	10
10	shale	7279	302
11	sand	7581	10
12	shale	7591	302
13	sand	7893	10
14	shale	7903	302
15	sand	8205	10

The studied reservoirs are subdivided into discrete grids as shown in Figure 4.1. The 3D model is shown in Figure 4.2 with the distance between 2 producers of 2600 ft.

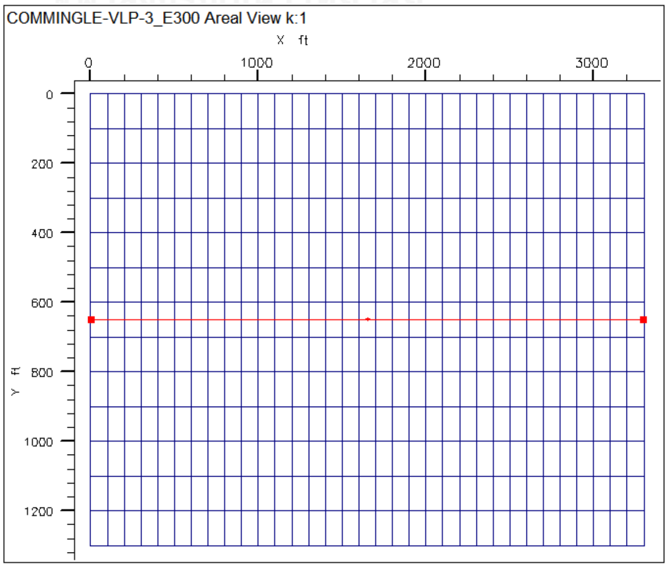


Figure 4.1 Top view of the reservoir model

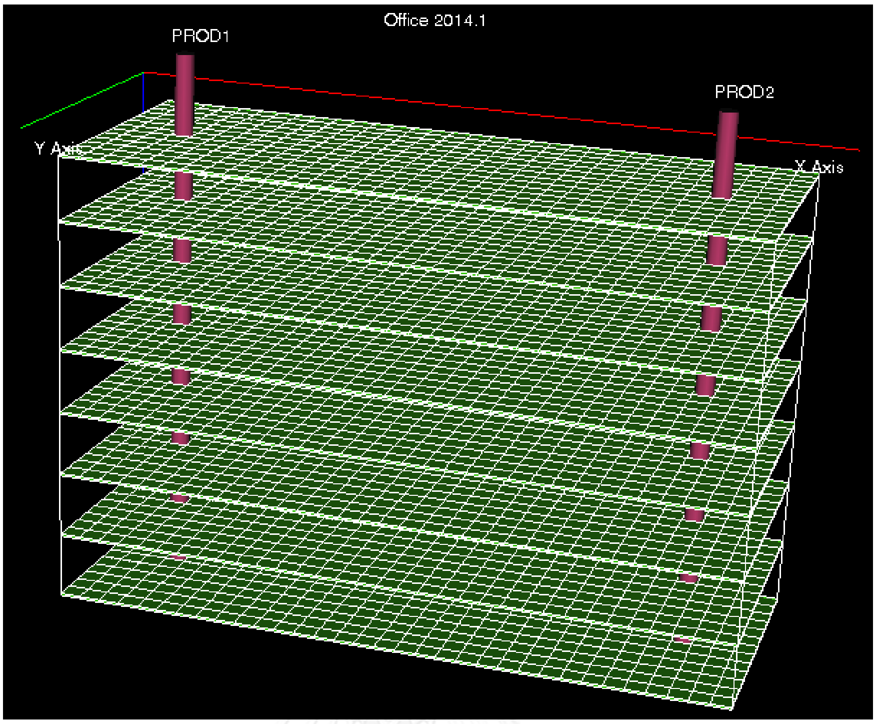


Figure 4.2 3D view of the reservoir model

4.2. Petrophysics data

The properties of the reservoirs under study are based on the average values of an exploration gas condensate well in the Gulf of Thailand.

The top depth of the reservoir is 6021 ft. The sandstone reservoir layers are homogenous with a uniform permeability and porosity of 41 md and 17 percent, respectively. Vertical-to-horizontal permeability ratio (kv/kh) is 0.1 as of typical assumption for sandstone reservoirs.

MDT/HSFT test data as depicted in Figure 4.3 was used to assign initial reservoir pressure and temperature in the model. The summary of reservoir properties is shown in Table 4.2.

Table 4.2 Reservoir properties of base case model

Layer	Formation	Top sand ('TVDSS)	Pressure (psia)	Temp (oF)	Porosity (%)	Water Saturation (%)	Horizontal permeability (mD)	Vertical permeability (mD)
1	sand	6021	2641	264	0.17	44	41	4.1
2	shale	6031						
3	sand	6333	2861	275	0.17	44	41	4.1
4	shale	6343						
5	sand	6645	3027	284	0.17	44	41	4.1
6	shale	6655						
7	sand	6957	3246	293	0.17	44	41	4.1
8	shale	6967						
9	sand	7269	3561	302	0.17	44	41	4.1
10	shale	7279						
11	sand	7581	3929	311	0.17	44	41	4.1
12	shale	7591						
13	sand	7893	4278	320	0.17	44	41	4.1
14	shale	7903						
15	sand	8205	4579	329	0.17	44	41	4.1

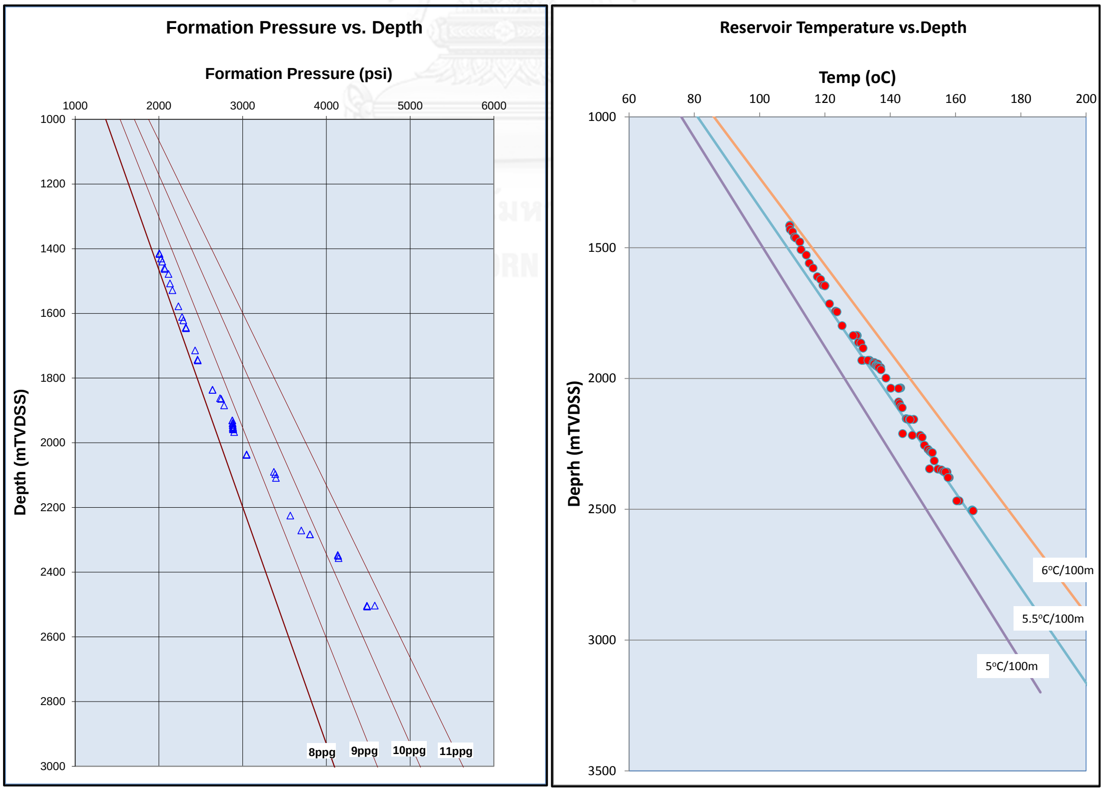


Figure 4.3 Reservoir pressure and temperature from MDT

4.3. PVT data

The PVTi program (Peng-Robinson Equation of State) was used to generate the phase behavior of the reservoir fluid and export all physical properties of each component such as critical pressure, critical temperature, critical volume, critical Z factors, reference density and acentric factors to ECLIPSE 300 simulation model. In this study, two sets of fluid compositions were used to set up the reservoir fluid model such that the "shallow" reservoir section, from reservoirs 1 to 4 contain gas condensate while the deeper reservoir section, from reservoirs 5 to 8, contain dry gas.

The composition for the gas condensate and dry gas reservoirs each consists of 10 components including inert CO2. The initial fluid composition of the gas-condensate reservoir and the physical properties of each condensate component are shown in Tables 4.2 and 4. 3. The phase diagram of gas condensate is shown in Figure 4.4.

Table 4.3 Composition and physical properties of the fluid in the four upper reservoirs

Comp.	Mole (%)	TCRIT (oR)	PCRIT (psi)	VCRIT	MW	ACF	ZCRIT
CO2	1.23	548.7900	1071.33111	1.505735	44.01	0.225000	0.274078
N2	0.00	227.4900	492.31265	1.441661	28.01	0.040000	0.291151
C1	59.99	343.4100	667.78170	1.569809	16.04	0.013000	0.284729
C2	8.43	550.1040	708.34238	2.370732	30.07	0.098600	0.284635
C3	6.40	665.9700	615.75821	3.203692	44.10	0.152400	0.276165
iC4	3.41	734.9100	529.05240	4.212855	58.12	0.184800	0.282737
nC4	3.90	765.6900	550.65537	4.084707	58.12	0.201000	0.273856
iC5	1.43	829.0500	491.57786	4.933686	72.15	0.227000	0.272711
nC5	1.40	845.6100	488.78563	4.981741	72.15	0.251000	0.268439
C6	7.27	913.8300	436.61519	5.622479	84.00	0.299000	0.250417
C7	6.54	1052.4845	415.68626	7.262027	115.00	0.368153	0.267356

Table 4.4 Binary interaction coefficients between components of the fluid in the four upper reservoirs

	CO2	C1	C2	C3	IC4	NC4	IC5	NC5	C6	C7+
CO2	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
C1	0.1	0	0	0	0	0	0	0	0.0279	0.0385
C2	0.1	0	0	0	0	0	0	0	0.01	0.01
C3	0.1	0	0	0	0	0	0	0	0.01	0.01
IC4	0.1	0	0	0	0	0	0	0	0	0
NC4	0.1	0	0	0	0	0	0	0	0	0
IC5	0.1	0	0	0	0	0	0	0	0	0
NC5	0.1	0	0	0	0	0	0	0	0	0
C6	0.1	0.0279	0.01	0.01	0	0	0	0	0	0
C7+	0.1	0.0385	0.01	0.01	0	0	0	0	0	0

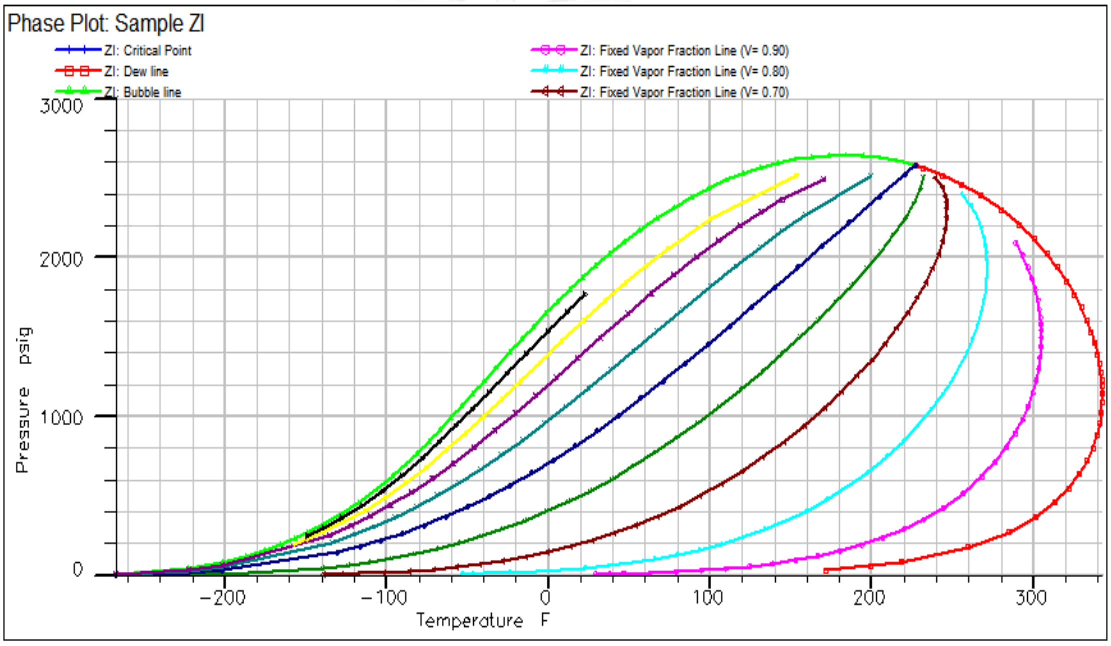


Figure 4.4 Phase diagram of the fluid in the four upper reservoirs

The initial fluid composition of the dry gas reservoir and the physical properties of each component are shown in Tables 4.4 and 4.5. The phase diagram of dry gas is shown in Figure 4.5.

Table 4. 5 Composition and physical properties of the fluid in the four lower reservoirs

Comp.	Mole (%)	TCRIT (oR)	PCRIT (psi)	VCRIT	MW	ACF	ZCRIT
CO2	5.93	548.79	1071.3	1.5057	44.01	0.225	0.27408
N2	0.00	227.49	492.31	1.4417	28.01	0.040	0.29115
C1	90.04	343.41	667.78	1.5698	16.04	0.013	0.28473
C2	3.14	550.10	708.34	2.3707	30.07	0.099	0.28463
C3	0.58	665.97	615.76	3.2037	44.10	0.152	0.27616
IC4	0.11	734.91	529.05	4.2129	58.12	0.185	0.28274
NC4	0.13	765.69	550.66	4.0847	58.12	0.201	0.27386
IC5	0.03	829.05	491.58	4.9337	72.15	0.227	0.27271
NC5	0.04	845.61	488.79	4.9817	72.15	0.251	0.26844
C6	0.00	913.83	436.62	5.6225	84.00	0.299	0.25042
C7	0.00	986.73	426.18	6.2792	96.00	0.300	0.25281

Table 4.6 Binary interaction coefficients between components of the fluid in the four lower reservoirs

	CO2	C1	C2	C3	IC4	NC4	IC5	NC5	C6	C7+
CO2	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
C1	0.1	0	0	0	0	0	0	0	0.0279	0.0331
C2	0.1	0	0	0	0	0	0	0	0.01	0.01
C3	0.1	0	0	0	0	0	0	0	0.01	0.01
IC4	0.1	0	0	0	0	0	0	0	0	0
NC4	0.1	0	0	0	0	0	0	0	0	0
IC5	0.1	0	0	0	0	0	0	0	0	0
NC5	0.1	0	0	0	0	0	0	0	0	0
C6	0.1	0.0279	0.01	0.01	0	0	0	0	0	0
C7+	0.1	0.0331	0.01	0.01	0	0	0	0	0	0

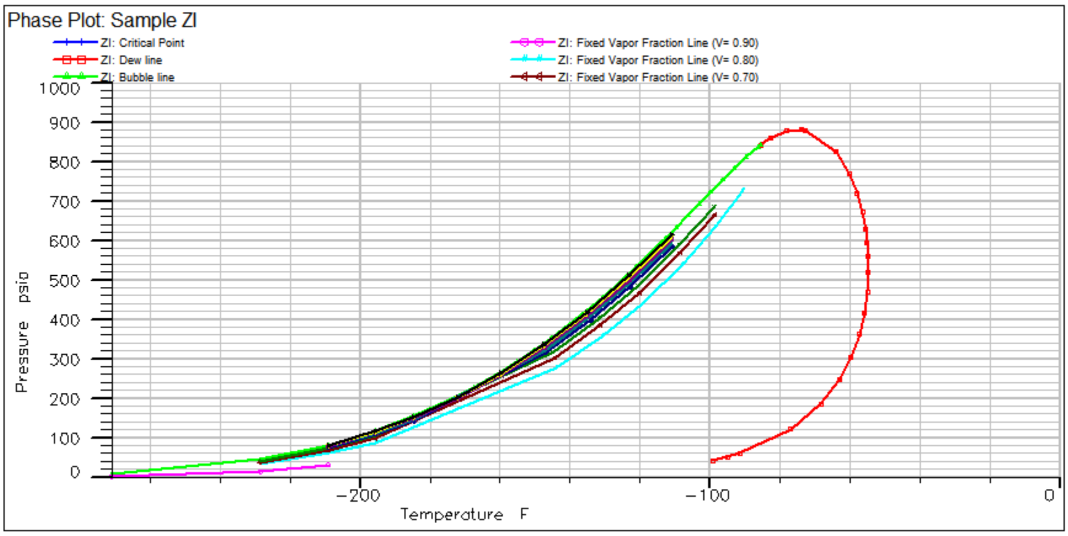


Figure 4.5 Phase diagram of the fluid in the four lower reservoirs

The same composition is used for the four upper layers while another composition is used for the remaining lower layers. PVTi is used to estimate the dew-point of condensate layers at different reservoir temperature. Initially, the reservoir pressure is above the dew point pressure as calculated in Table 4.6. Formation water properties correlated by ECLIPSE 300 as a function of pressure and temperature are shown in Table 4.6 as well.

Table 4.7 Dew point and water properties

Layer	Fluid	Top sand ('TVDSS)	Pressure (psia)	Temp (oF)	Water FVF (rb/stb)	Water Compressibility (psi^{-1})	Water viscosity (cp)	Water viscosibility (psi^{-1})	Dew-point (psia)
1	condensate	6021	2641	264	1.048	3.44E-06	0.227	7.90E-06	2355
2	condensate	6333	2861	275	1.052	3.48E-06	0.216	8.28E-06	2277
3	condensate	6645	3027	284	1.056	3.61E-06	0.209	8.57E-06	2200
4	condensate	6957	3246	293	1.060	3.70E-06	0.201	8.85E-06	2112
5	dry gas	7269	3561	302	1.064	3.78E-06	0.195	9.09E-06	
6	dry gas	7581	3929	311	1.068	3.86E-06	0.189	9.30E-06	
7	dry gas	7893	4278	320	1.072	3.95E-06	0.184	9.47E-06	
8	dry gas	8205	4579	329	1.076	4.05E-06	0.179	9.59E-06	

4.4. SCAL (Special Core Analysis) data

The normalized relative permeability curves from Special Core Analysis (SCAL) in GoT are used in this model. Several trials of Corey's exponents were tried in order to establish a good match with normalized relative permeability. Once Corey's exponents were selected, then are used together with initial water saturation of 44% to match with relative permeabilities in this case. The same relative permeability curves are used for all layers. The parameters in Corey model are summarized in Table 4.8, and the sets of relative permeability as a function of saturation are shown in Figures 4.6 and 4.7.

Table 4.8 Corey relative permeability correlation

Corey water exponent	2.7	Corey gas exponent	1.7	Corey Oil/water exponent	3
Swmin	0.44	Sgmin	0	Corey Oil/Gas exponent	3
Swcr	0.44	Sgcr	0.1	S_{org}	0.2
Swi	0.44	Sgi	0.1	S_{orw}	0.2
Krw(Sgrw)	0.175	krg(Sorg)	0.4	kro(Swmin)	0.7
Krw(100% sat.)	1	krg(Sgmax)	1	kro(Sgmin)	0.7

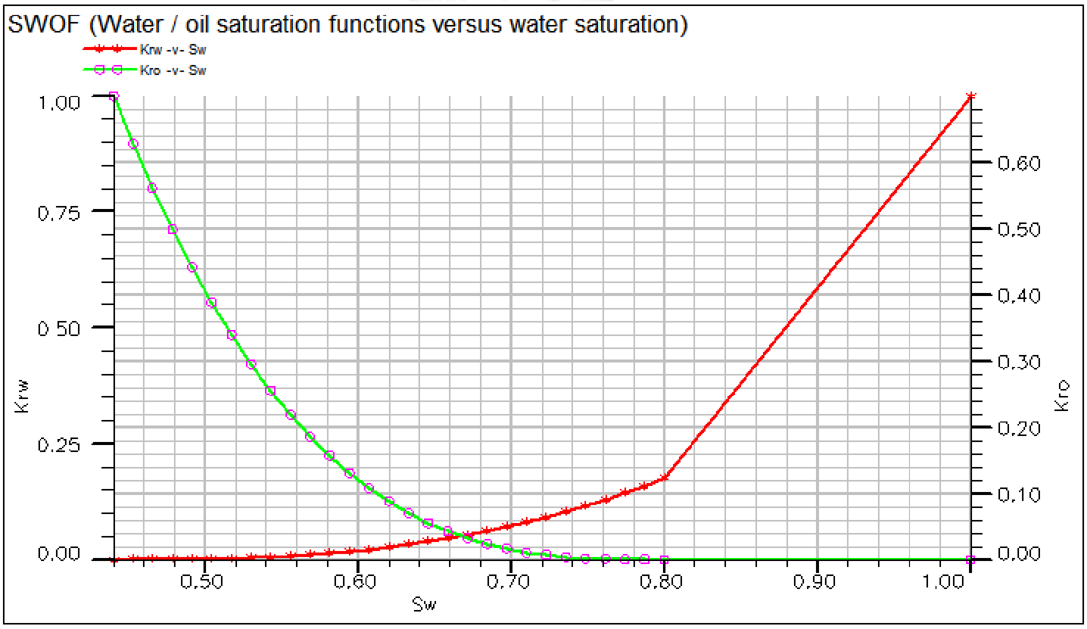


Figure 4.6 Two-phase relative permeability of water/oil system

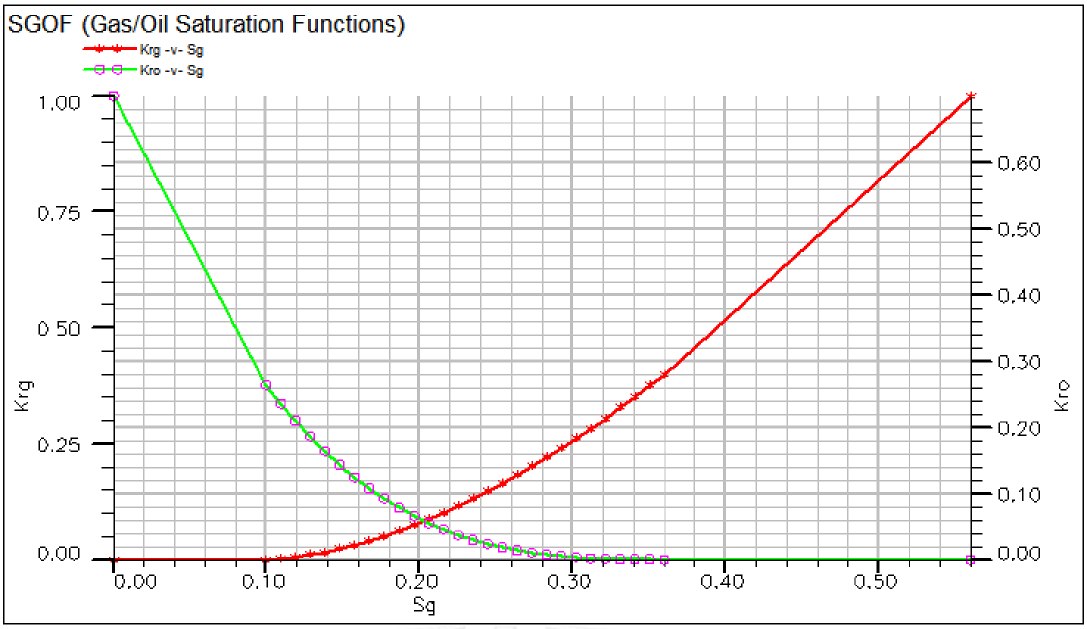


Figure 4.7 Two-phase relative permeability of gas/oil system

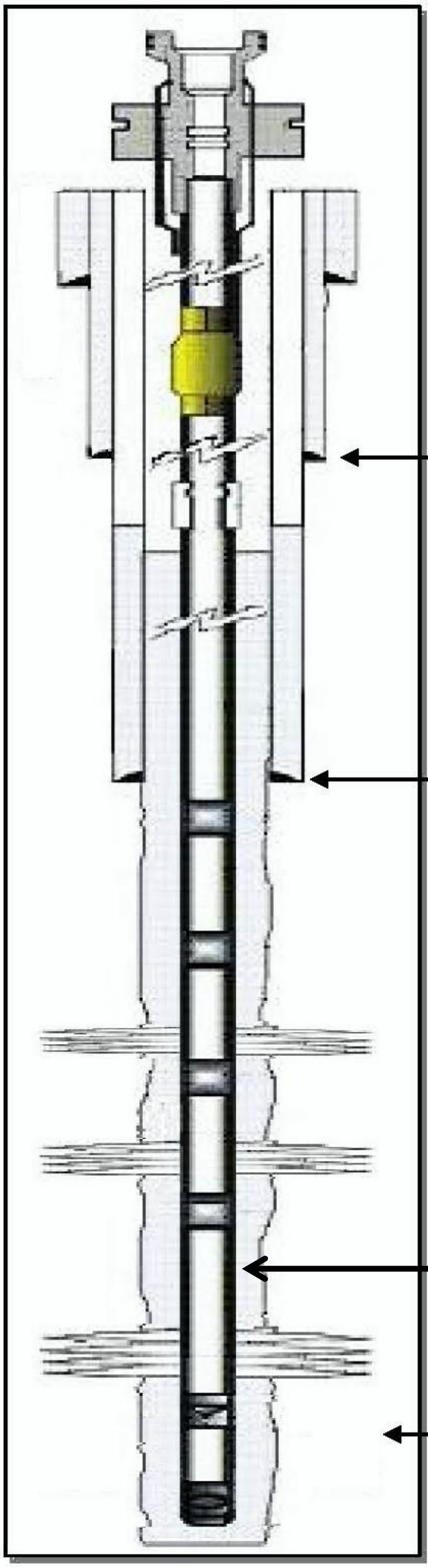
4.5. Well model

Slim hole well design, which is a practical application in Gulf of Thailand (GoT) is applied in this model. The development well will be vertical with 3 casing strings.

The first string of casing, referred to as the surface string, is 9-5/8” which is run into and cemented in a 12-1/4” hole. The intermediate casing string is 7” casing in a 8-1/2” hole. The final string is 2-7/8” production tubing in a 6-1/8” hole. Table 4.9 is a summary of the recommended casing and tubing specifications for development well design in this study. The schematic of wellbore configuration is shown in Figure 4.8.

Table 4.9 Well design

							Casing Pressure		
Casing	bit size (inch)	Casing size (OD,inch)	Shoe depth (ftTVD,BRT)	Grade	Weight (ppf)	Connection	Collapse (psi)	Burst (psi)	Tension (klbs)
surface	12 1/4	9 5/8	1038	N-80	40	BTC	3090	5750	737
Intermediate	8 1/2	7	4669	N-80	23	BTC	3830	6340	442
Tubing	6 1/8	2 7/8	9603	L-80	6.4	New Vam	11160	10570	105



Hole size	12-1/4	inch
Casing size	9-5/8	inch
Casing shoe	1038	ft

Hole size	8-1/2	inch
Casing size	7	inch
Casing shoe	4669	ft

Hole size	6-1/8	inch
Tubing size	2-7/8	inch
Well TD	9603	ft

Figure 4.8 Monobore completion schematic

The pressure drop in this study is derived from pre-calculated VFP tables. VFP tables can be constructed using PROSPER (Production and Systems Performance analysis software) to describe the pressure drop along a certain length of tubing. For a gas condensate well, the chosen vertical lift correlation is Gray. Because the wells in this model are completed in multi-layer reservoir, one VFP table at the top reservoir cannot represent the well deliverability from other reservoir layers. Therefore, the wellbore is divided into multiple tubing segments to provide a detailed description of fluid flow in the wellbore.

Each segment consists of a node at a specified depth and a flow path to its parent segment's node as shown in Figure 4.9. Each segment is specified with length, diameter, roughness, area and volume. The BHP is interpreted as the segment's nodal pressure (which is its inlet pressure), and the THP is interpreted as the pressure at the node of its neighboring segment towards the wellhead (that is the segment's outlet pressure).

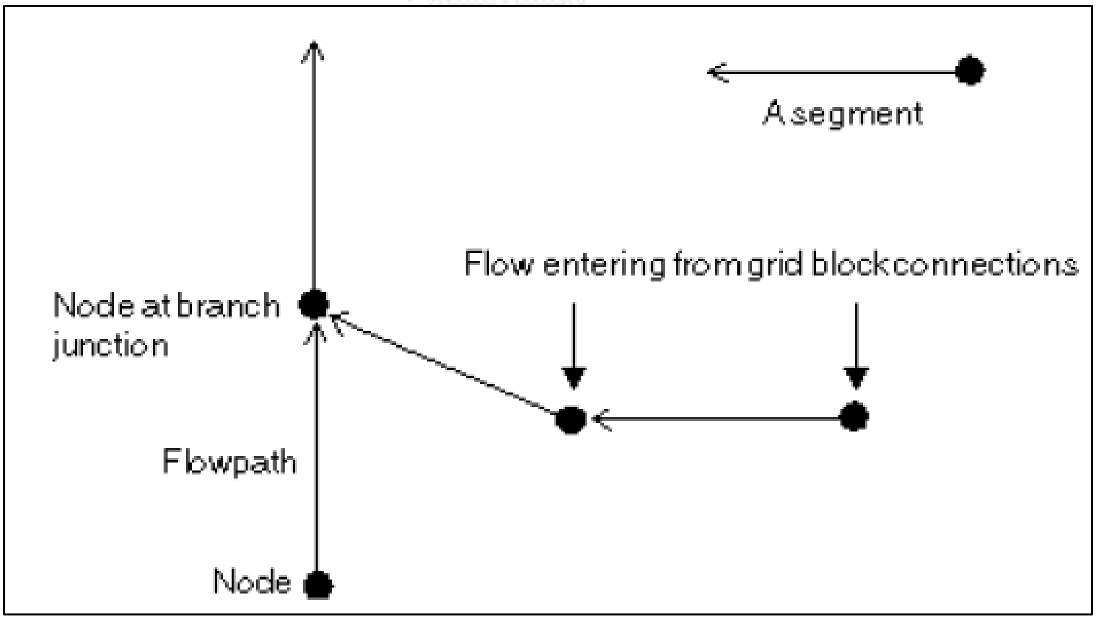


Figure 4.9 Well segments

Eight tubing performance curve (TPC) will be generated for eight tubing segment with some variables such as tubing head pressure (THP), condensate gas ratio (CGR) and water gas ratio (WGR) that affected total tubing pressure loss as shown in Figure 4.10.

- ✓ Tubing head pressure is varied from 200 to 2500 psig
- ✓ Condensate gas ratio (CGR) is varied from 0 to 70 (stb/MMscf)
- ✓ Water gas ratio (WGR) is varied from 0 to 70 (stb/MMscf)

In this study, two wells are used to produce fluid. Location of these wells are summarized in table 4.10 and illustrated in Figure 4.11.

Table 4.10 Well location

Location	Producer 1	Producer 2
X	4	30
Y	7	7

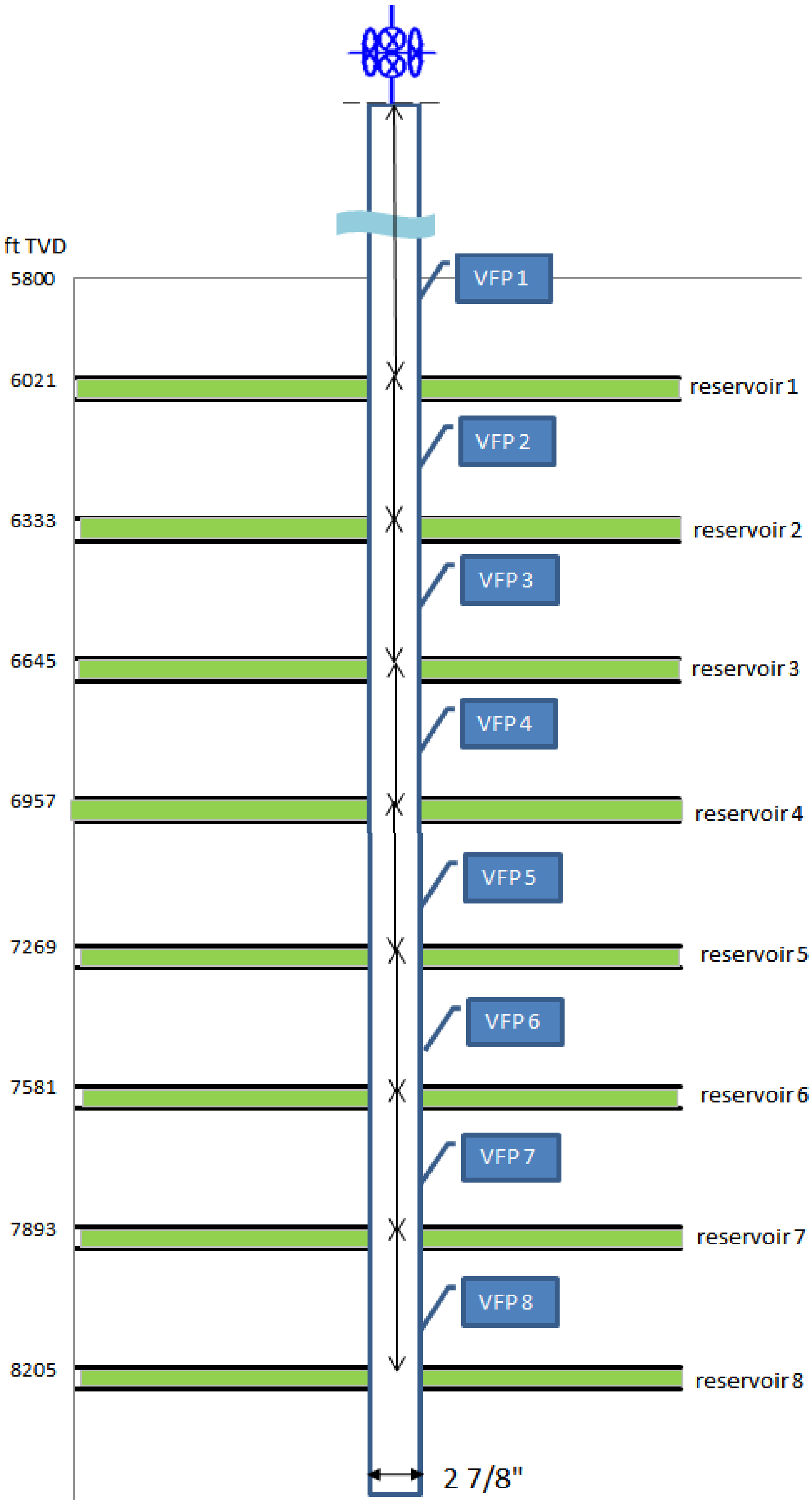


Figure 4.10 Multi-segment diagram

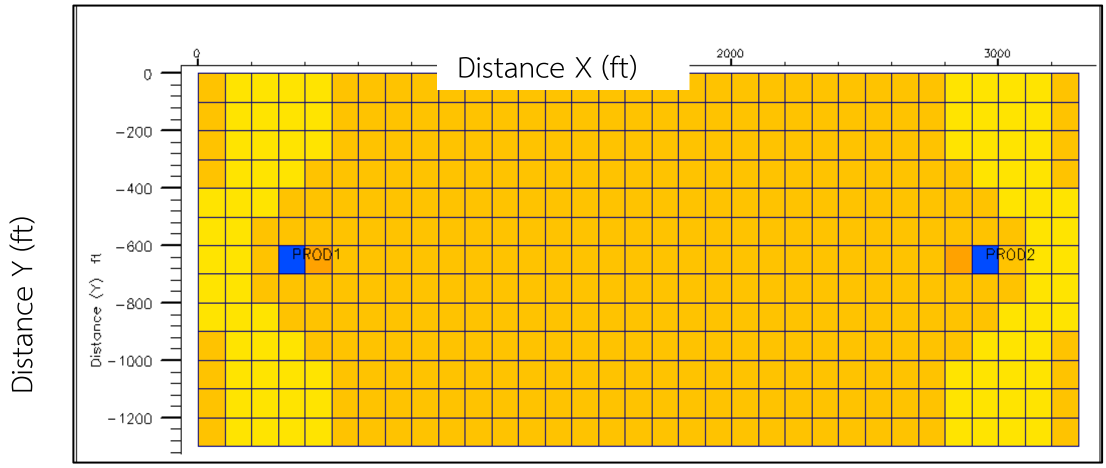


Figure 4.11 2D view of well locations

4.6. Production scenarios

Simulation for different production strategies were performed in this study as listed below:

- Scenario 1: Commingle production
- Scenario 2: Bottom up with plug (perforate all lower layers of dry-gas reservoirs in the first batch and all upper layers of condensate reservoirs in the second batch with isolation, i.e, plugging off the lower zones before perforating the upper zones)
- Scenario 3: Bottom up without plug (perforate all lower layers of dry-gas reservoirs in the first batch and all upper layers of condensate reservoirs in the second batch without isolation, i.e, no plugging of the lower zones before perforating the upper zones)
- Scenario 4: Top down perforation (perforate all condensate layers in the first batch and all gas layers in the second batch without isolation)
- Scenario 5: Gas dumpflood (Gas in the four lower layers is allowed to cross flow into the four upper gas condensate layers via a dumping well)

The following operating conditions and constraints were set up:

✓ Economic gas rate: 0.5 MMscf/d

- ✓ Production period: 10 years
- ✓ Minimum THP: 200 psi
- ✓ Different gas rate controls (3,6,9 MMscf/d) were explored in this simulation

4.7. Optimization of operating conditions

In order to obtain the maximum condensate recovery, each production scenario described in 4.6 will be investigated by various optimization factors such as plateau rate, timing of batch perforation and/or dumpflood or perforation strategy as shown in Figure 4.12. By doing so, the condensate recovery efficiency will be evaluated under all operating conditions and thus the operating conditions for optimum surface condensate recovery in the studying model will be concluded.

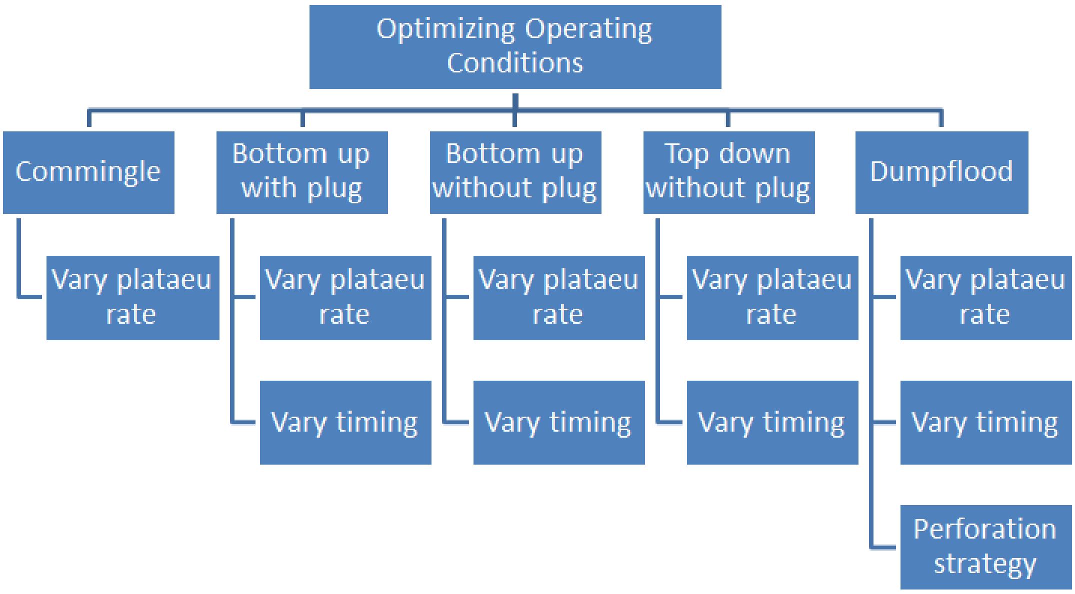


Figure 4.12 Optimizing the operating conditions in gas dumpflood

✓ For scenarios 1 (commingle production), vary

(i) plateau gas production rate

- maximum well gas production rate is 9 MMscf/d

- maximum well gas production rate is 6 MMscf/d
- maximum well gas production rate is 3 MMscf/d

✓ For scenarios 2-4, vary

(i) plateau gas production rate

- maximum well gas production rate is 9 MMscf/d
- maximum well gas production rate is 6 MMscf/d
- maximum well gas production rate is 3 MMscf/d

(ii) timing of second batch of perforation

- when well gas production rate is less than the plateau rate
- when well gas production rate is less than half of plateau rate
- when well gas production rate is less than the economic rate (0.5 MMscf/d)

✓ For scenarios 5 (gas dumpflood), vary

(i) plateau gas production rate

- maximum well gas production rate is 9 MMscf/d
- maximum well gas production rate is 6 MMscf/d
- maximum well gas production rate is 3 MMscf/d

(ii) timing of dumpflood

- from the begining
- when well gas production rate is less than the plateau rate
- when well gas production rate is less than half of plateau rate
- when well gas production rate is less than the economic rate (0.5 MMscf/d)

(iii) perforation strategy of dry gas reservoirs

- perforate all four layers at the same time
- sequential peroration (i.e perforate two lower source gas reservoirs first then the remaining two upper ones)
- perforate only two upper gas reservoirs
- perforate only two lower gas reservoirs

CHAPTER V
SIMULATION RESULTS

As mentioned in Chapter 4, five different production scenarios including commingled approach, bottom up with and without plug, top down without plug and gas dump-flood were investigated with a view to reduce the impact of condensate banking and to improve the ultimate liquid recovery for gas condensate reservoirs with underlying multi-stacked gas reservoirs. This chapter discusses the main results of 78 simulation cases in total, taking into consideration of the plateau rate, the timing of batch perforation or dumpflood and the perforation strategies in the dumpflood scenario as summarized in Figure 5.1.

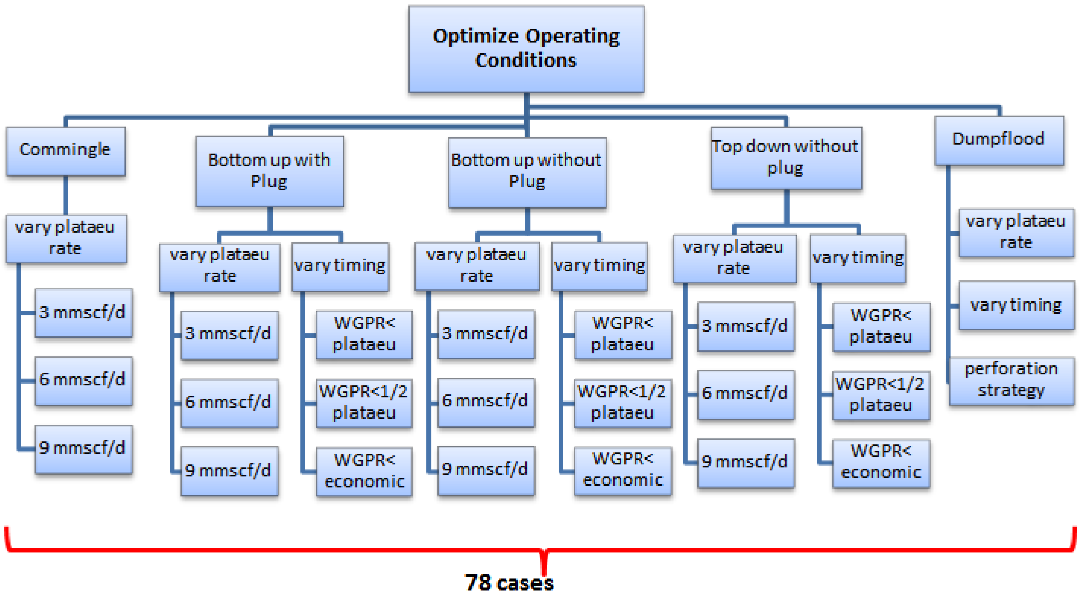


Figure 5.1 Case structure of simulation model

Because production time of all cases is quite short (less than five years) to establish an economic model, barrels oil of equivalent are thus used to provide guidance to economic evaluation instead. Basically, a gas volume is conversed to oil equivalents and sum of oil volume and oil equivalent is compared to select a favorable production scenario.

5.1 Commingle production

In this production scenario, all eight pay layers are perforated at the beginning in order to accelerate recovery from multi-zone reservoirs with a minimized expenditure. The maximum gas production rate is varied by 3, 6 and 9 mmscf/d.

Figure 5.2 shows the field gas production rate in the commingle cases. The higher the maximum gas production rate, the shorter the production life. The plateau rate can be observed from the first day of production and maintained longer with a lower maximum gas production rate. After the plateau period, gas production decreases with the same downward tendency in all three cases of plateau rate until the economic rate is reached.

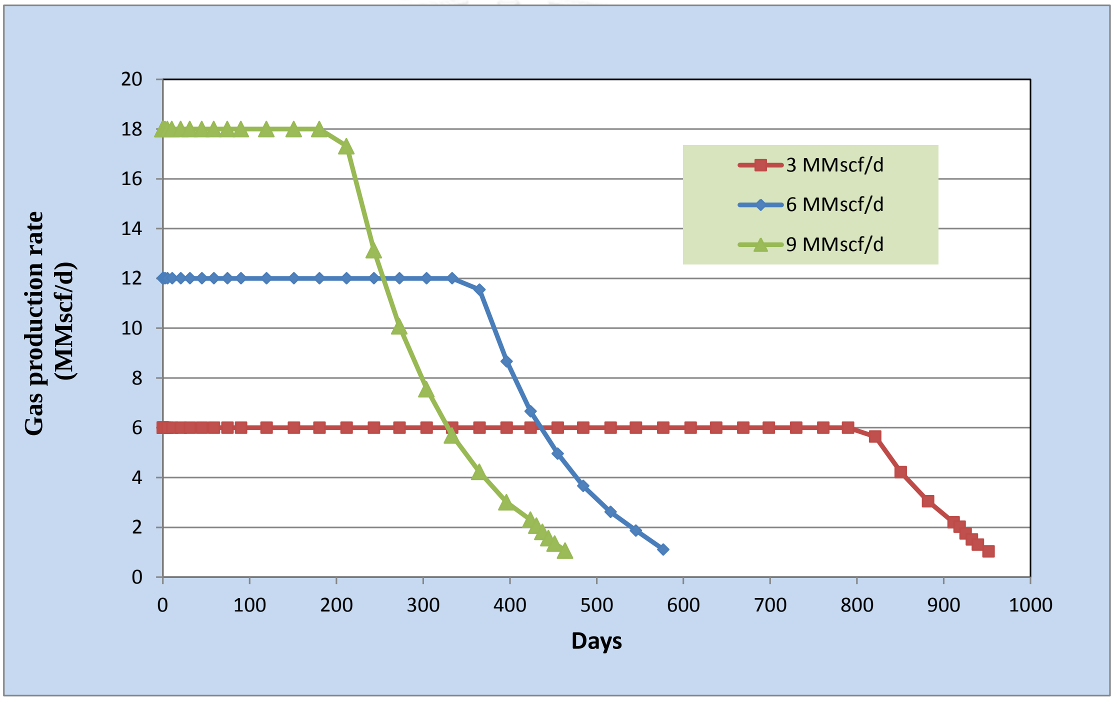


Figure 5.2 Field gas production rate in commingle cases

Figure 5.3 shows the field condensate production profiles. In contrast, no condensate production is produced during the first 20 to 45 days of production, depending on the maximum gas rate, due to cross flow phenomenon. While reaching the peak of condensate production, liquid starts to drop out from the gas phase inside the four upper reservoirs since pressures decline below the dew points (different layers have different dew points due to variation in reservoir temperature as shown in Table 4.7) , starting from the wellbores and expanding to the entire reservoirs with time. Condensate production declines quickly for the case with high gas production rates (9 MMscf/d). For the low and moderate gas rate cases (3 and 6 MMscf/d), condensate production declines after reaching its peak rate but later slightly increases again before a final decline. This slight increase in condensate production is due to revaporization of condensate dropout as confirmed by oil saturation at one of the producers shown in Figure 5.4.

Liquid drop-out curve for different plateau rates at the location of one of the producers is plotted in Figure 5.4. The maximum amount of oil saturation of all plateau cases is less than critical oil saturation (0.2), causing condensate to be immobile in the near wellbore region. Since this location has the smallest pressure in the reservoir, nowhere else in the reservoir has higher condensate saturation. This means that all condensate drop-out in the reservoir is immobile. When the liquid drop-out reaches the bottom hole flowing pressure of around 1500 psia as of maximum oil saturation, liquid starts to revaporize into the gas phase. As seen from the plot, the liquid fraction decreases with decreasing pressure and hence the amounts of condensate dropout near the wellbore decreases due to revaporization process. Therefore, such a slight increase in condensate production is because the condensate vaporizes back to the gas phase at lower flowing pressure evidenced by increasing the condensate to gas ratios on the surface as shown in Figure 5.5.

At the end of production, the bottom hole flowing pressure continues to decrease to 300 psia, which is close to the lower dew point of the phase diagram in Figure 4.4, and thus all condensate drop-out near the wellbore fully revaporizes into the gas phase, leaving zero oil saturation at this location.

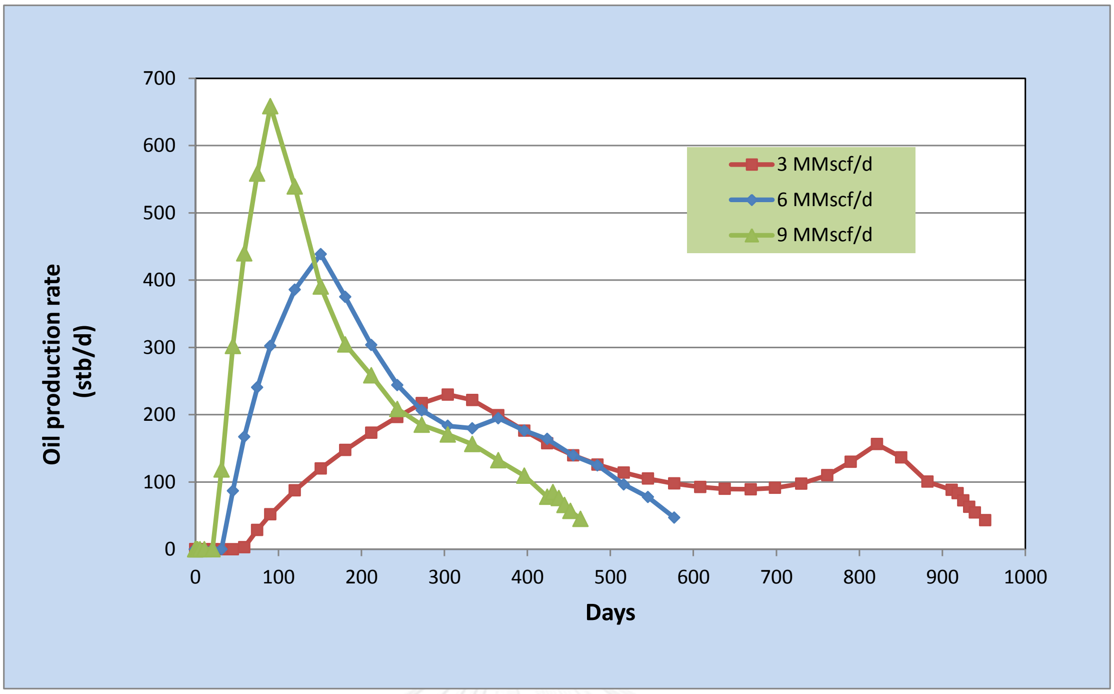


Figure 5.3 Field oil production rate in commingle cases

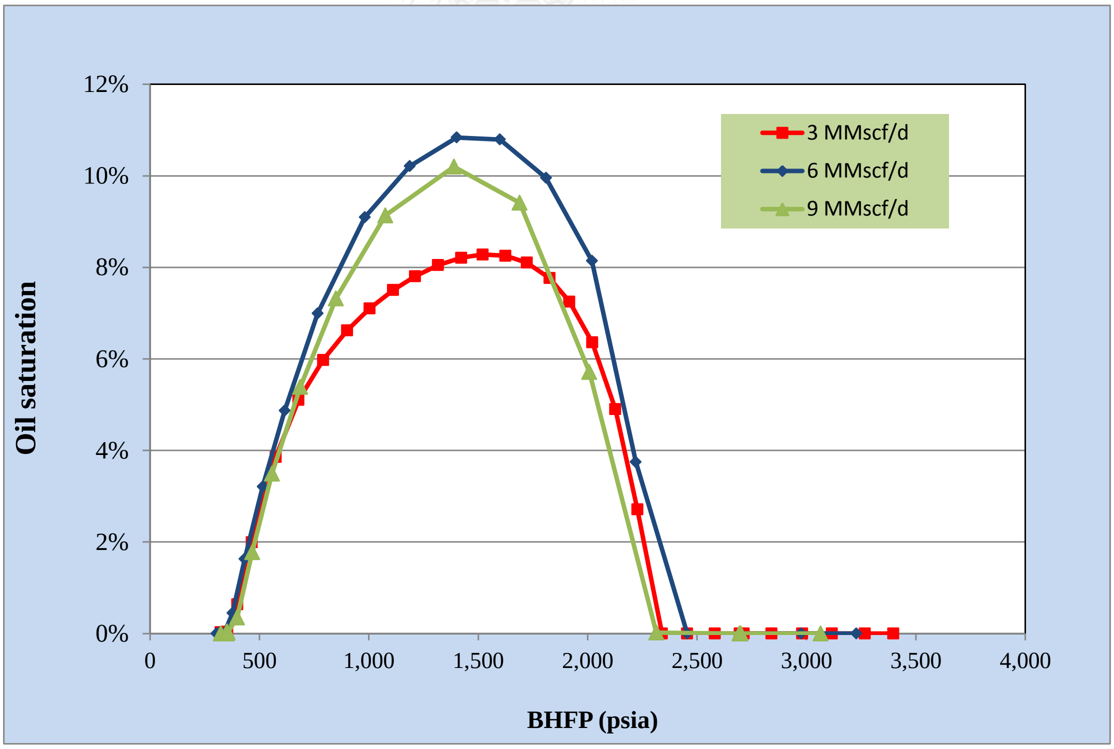


Figure 5. 4 Liquid drop-out curve of layer 1 at one of the producers in commingle cases

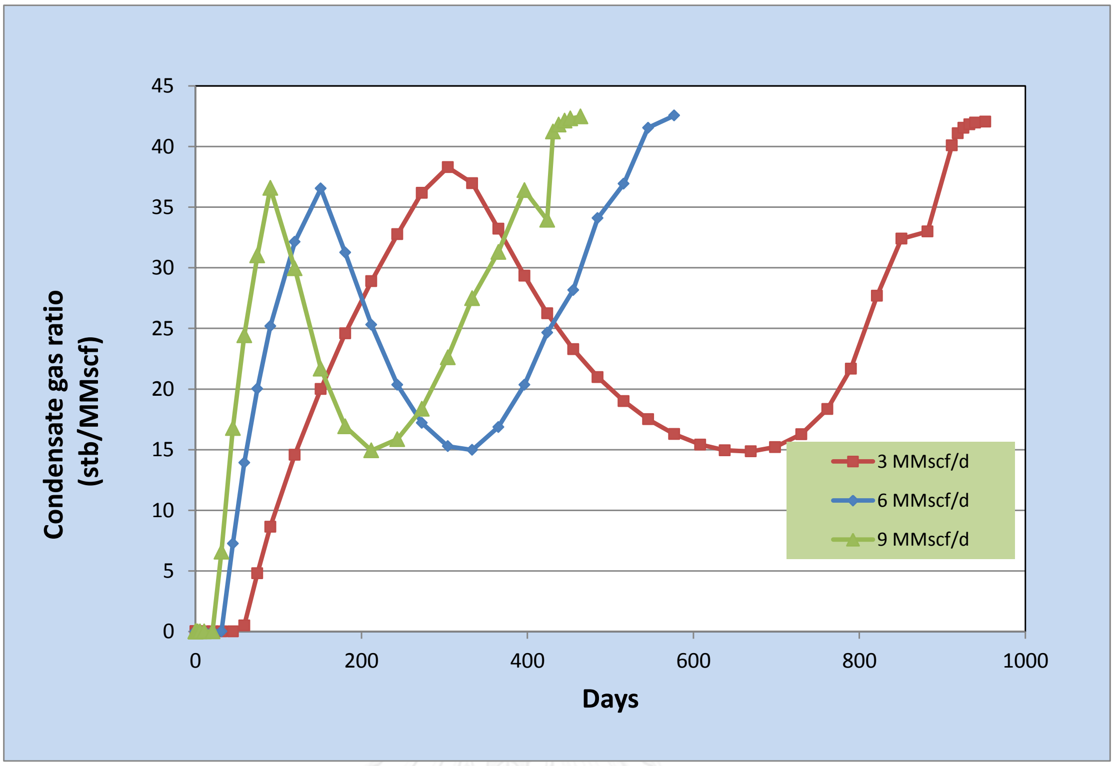


Figure 5. 5 Condensate gas ratios in commingle cases

The pressures of all layers are shown in Figure 5.6. Gas from the deeper layers having higher pressures flows to shallower condensate layers having lower pressures when all layers were perforated at the same time. It takes some days for pressures to get into hydrostatic equilibrium and thus gas from upper layers starts to flow and condense as liquid at the surface.

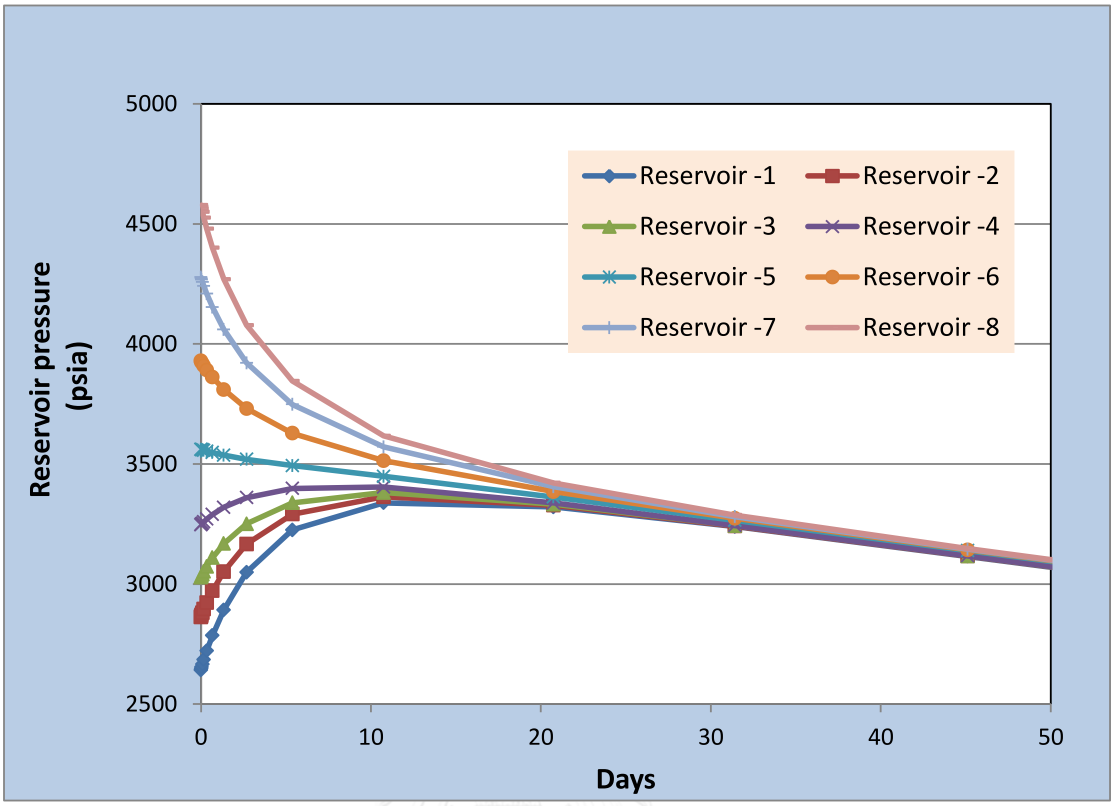


Figure 5.6 Reservoir pressure in a commingle case when the maximum gas rate is 6 mmscf/d

Table 5.1 shows the summary of results of commingle cases. The results of production time and recovery factor of gas and condensate are illustrated in Figure 5.7. The gas cumulative production at the end of field life is almost the same regardless of production rate, resulting in more than 90 % of gas recovery factor. In other words, gas recovery factor does not depend on production rate because all layers contribute to gas production as a whole.

In term of condensate, the phase diagram at the end of well life shown in Figure 5.8 is evidence of fluid compositions change due to production. It is observed that the higher gas flow rate results in a greater shift of the phase diagram to the right and hence higher condensate is being left into the reservoir at the abandonment pressure as illustrated in Figure 5.9. As a result, the condensate recovery factor of the case with 9 MMscf/d plateau rate is 2% lower than that of 3 and 6 MMscf/d plateau rate.

Table 5. 1 Commingle production with the different plateau rates

Plataeu rate (MMscf/d)	Production time (days)	Cumulative gas production (bscf)	Cumulative oil production (Mstb)	Gas RF (%)	Condensate RF (%)	MBOE (Mstb)
3	912	5.2	113.6	92	35	980
6	577	5.3	113.5	93	35	989
9	424	5.2	107.4	92	33	973

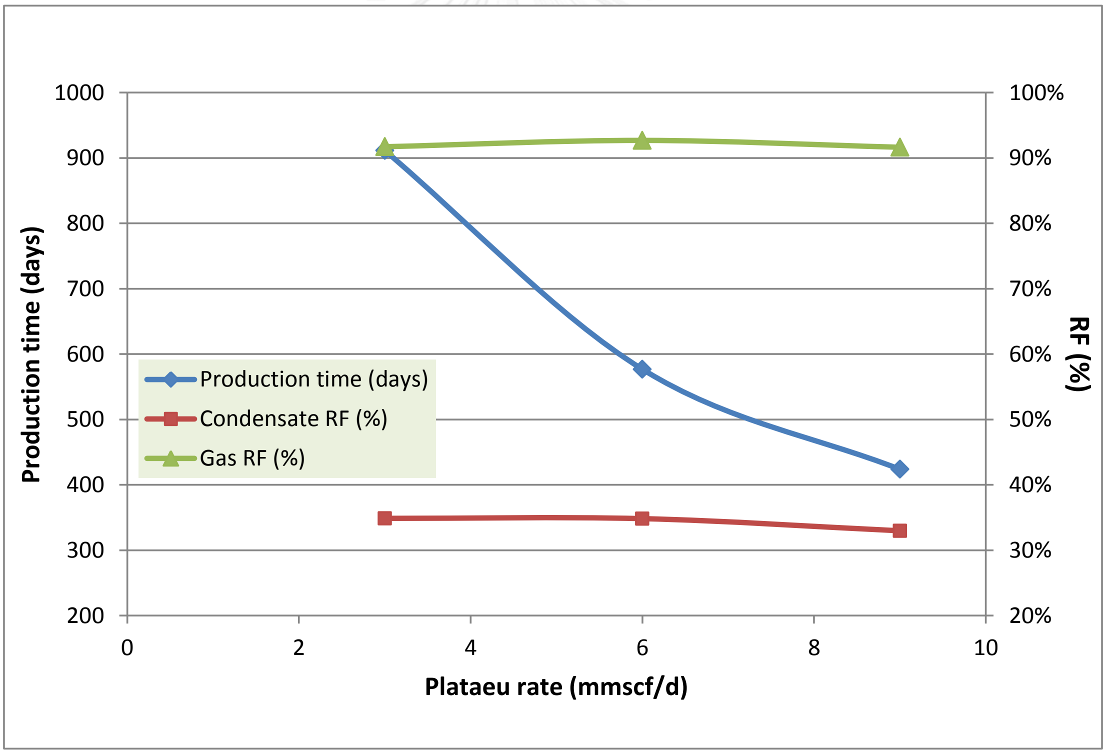


Figure 5.7 Production time and recovery factors for different plateau rates in commingle cases

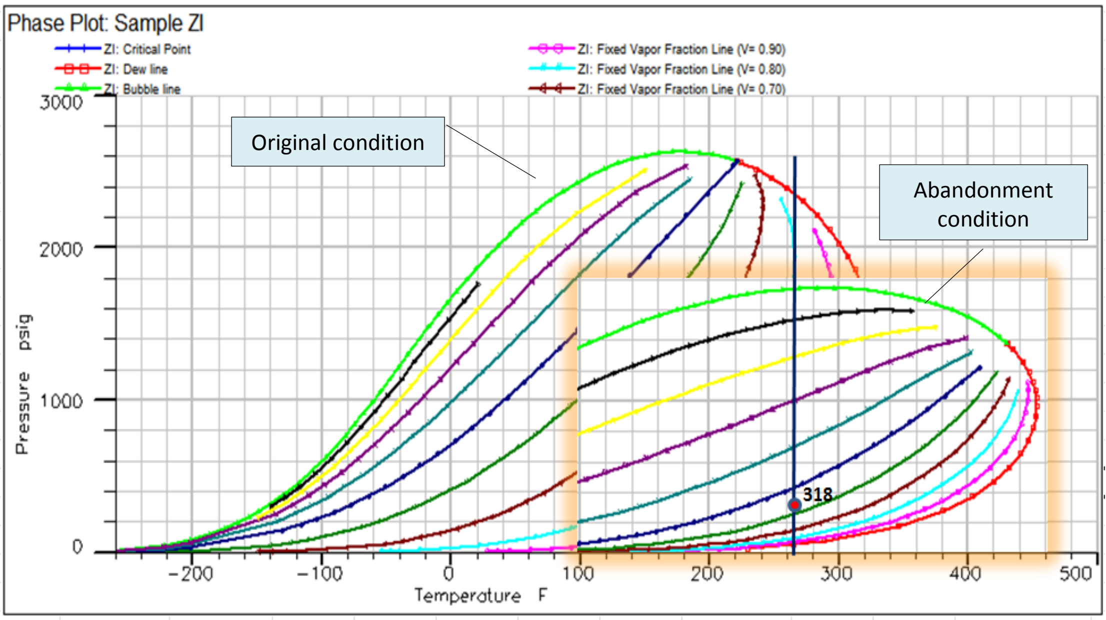


Figure 5. 8 Phase diagram when the maximum gas rate is 9 MMscf/d in a commingle case

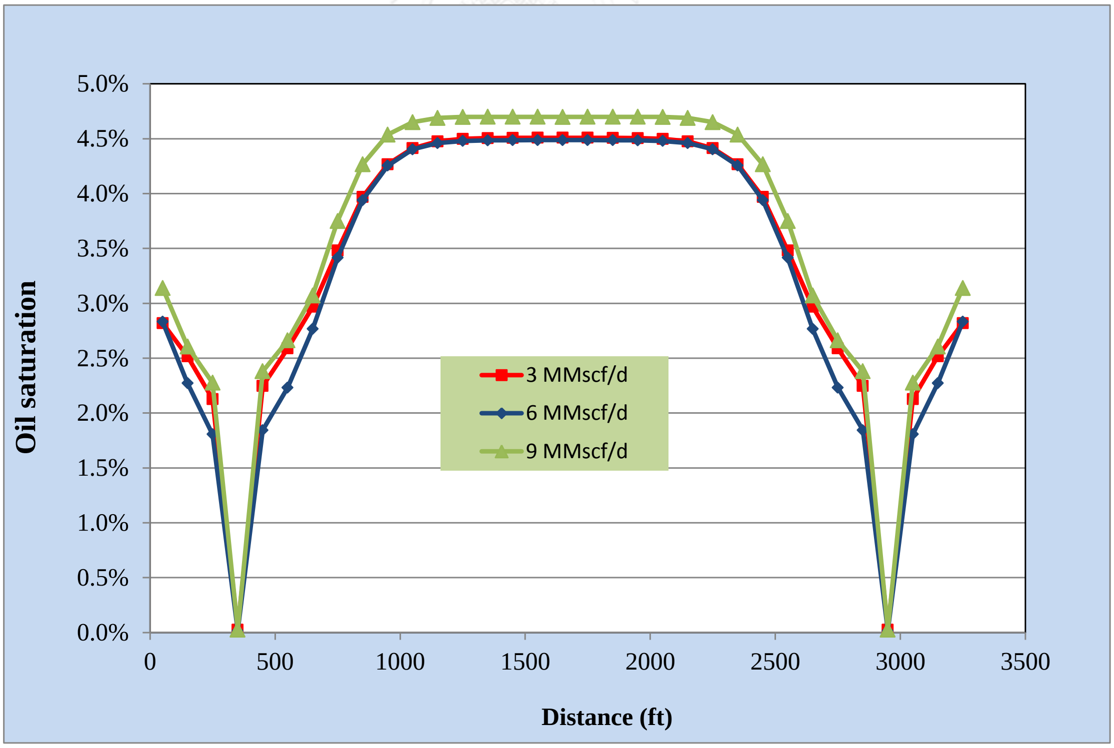


Figure 5. 9 Condensate saturation of layer 1 at the end of production time for different plateau rates in commingle cases

5.2 Bottom up with plug strategy

Bottom up perforation with plug is in fact a stand-alone production strategy, i.e., dry gas reservoirs and gas condensate reservoirs are produced separately and independently. In this scenario, all lower layers of dry-gas reservoirs are perforated in the first batch. At the right time, the lower layers are plugged off to proceed perforating all upper layers of condensate reservoirs in the second batch. The timing of perforating the second batch is varied as follows:

- ✓ Option 1: When the well gas production rate is less than the plateau rate
- ✓ Option 2: When the well gas production rate is less than half of the plateau rate
- ✓ Option 3: When the well gas production rate is less than the economic rate (0.5 MMscf/d)

In addition, the plateau rate is varied by 3, 6 and 9 MMscf/d to see the effects of maximum production rate on production performance of this production strategy. There are totally 9 simulation cases for this perforation strategy.

5.2.1 Effects of plateau rate

Figure 5.10 presents field gas production rate for the case that the second batch is perforated when the gas rate of the producer falls below the plateau rate (option 1). The gas plateau is split by two periods. In the first plateau period, gas is coming from only the four lower dry gas layers. In the second period, gas production is brought back to the plateau rate from the four upper layers while condensate is also produced. After the second plateau period, gas production decreases with the same downward tendency in all three cases of plateau rate until the economic rate is reached. In general, the higher the production rate, the shorter the plateau period and the production time. The gas production is delayed when the plateau rates decreases.

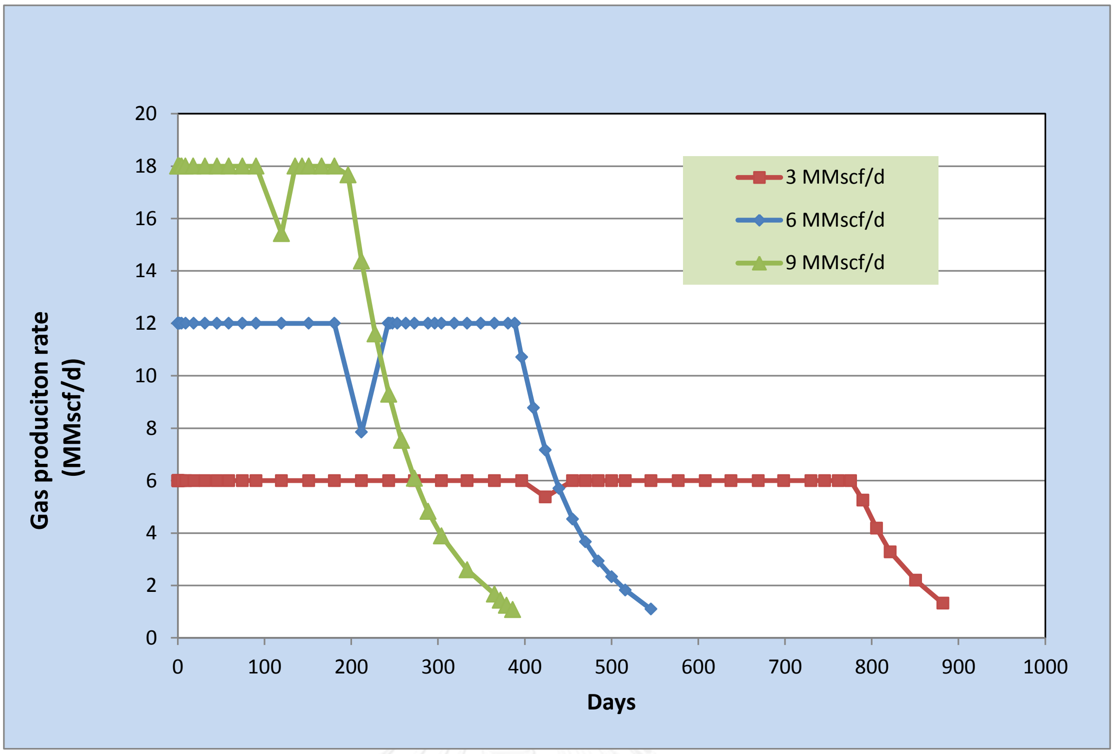


Figure 5.10 Field gas production rate for different plateau rates in bottom up with plug strategy when the timing of perforating the second batch is option 1

Figure 5.11 compares the field oil production profile for various plateau rates for the case that the second batch is perforated when the gas rate of the producer falls below the plateau rate (option 1). Condensate is produced from the upper reservoirs of the second batch only while gas is produced from both batches. Condensate profiles look very much similar despite of various plateau rates but the time that condensate starts to produce is different from case to case since it depends on the time that the four upper condensate reservoirs are perforated, which depends on the gas production rate. The duration of production time is longer when the maximum gas production is smaller.

Because no cross flow happens, condensate production increases immediately. For the case of low and moderate gas rate cases (3 and 6 MMscf/d), plateau rates can be observed for a while before liquid starts to build-up around the wellbores and in the reservoirs as pressures decline below the dew points. Condensate production declines after reaching its peak rate but later slightly increases again before a final decline. Such a slight increase in condensate production can be confirmed by increasing condensate to gas ratios with decreasing bottom hole flowing pressures shown in Figure 5.12.

Liquid drop-out curves shown in Figure 5.13 indicate that condensate accumulation around the wellbore is higher than the critical saturation in the case of moderate and high gas production rate (6 and 9 MMscf/d), leading to part of the condensate build-up around the wellbore resumes flow. In addition, the bottom hole flowing pressures reduce to less than 400 psia when production is continued, leading to the vaporization of condensates into the gas phase. This explains why condensate production increases slightly before continuing to decline to the end of well life as shown in Figure 5.11.

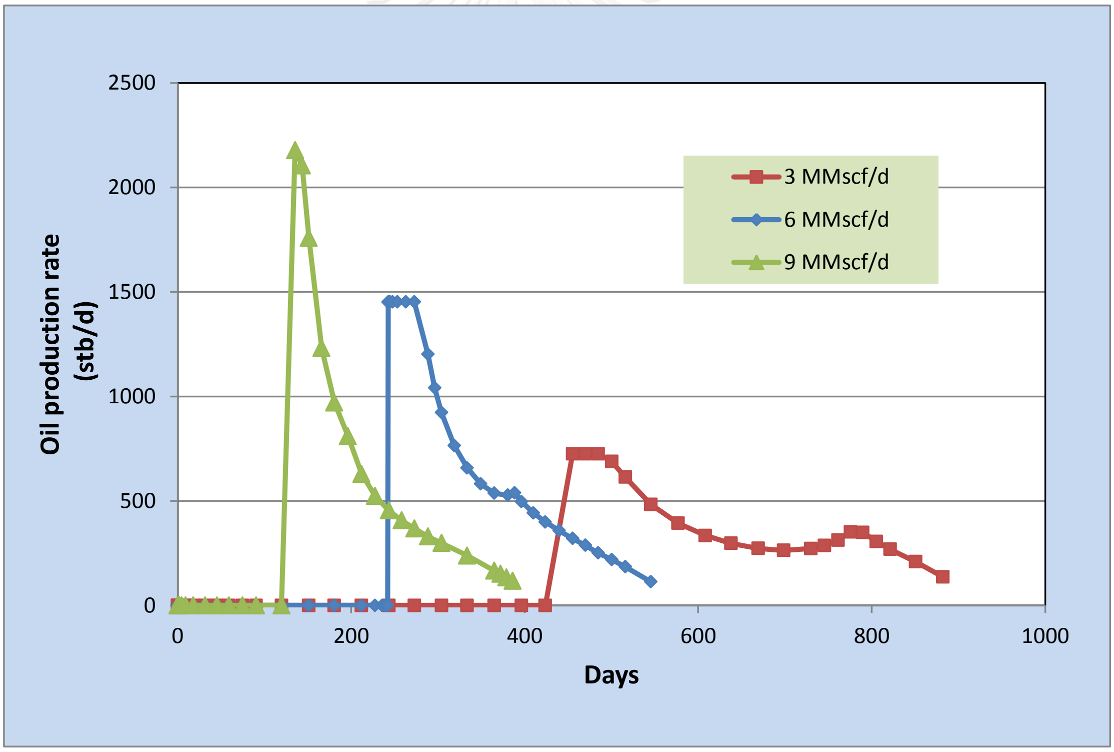


Figure 5.11 Field oil production rate for different plateau rates in bottom up with plug strategy when the timing of perforating the second batch is option 1

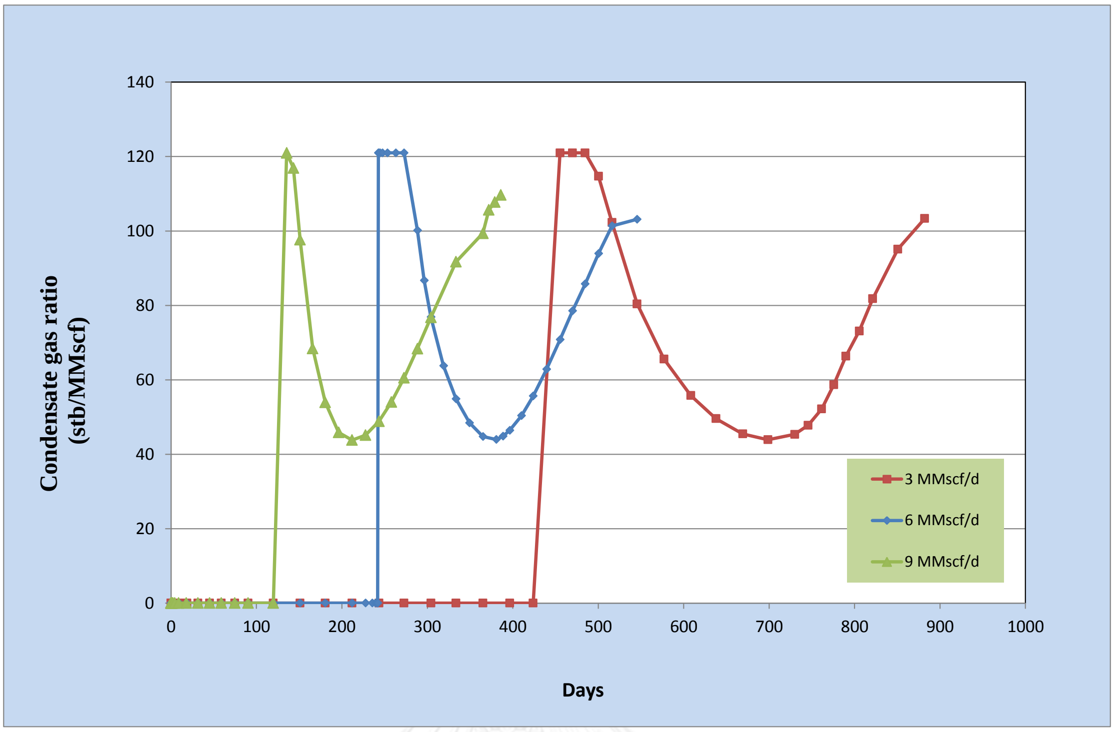


Figure 5. 12 Condensate gas ratios for different plateau rates in bottom up with plug strategy when the timing of perforating the second batch is option 1

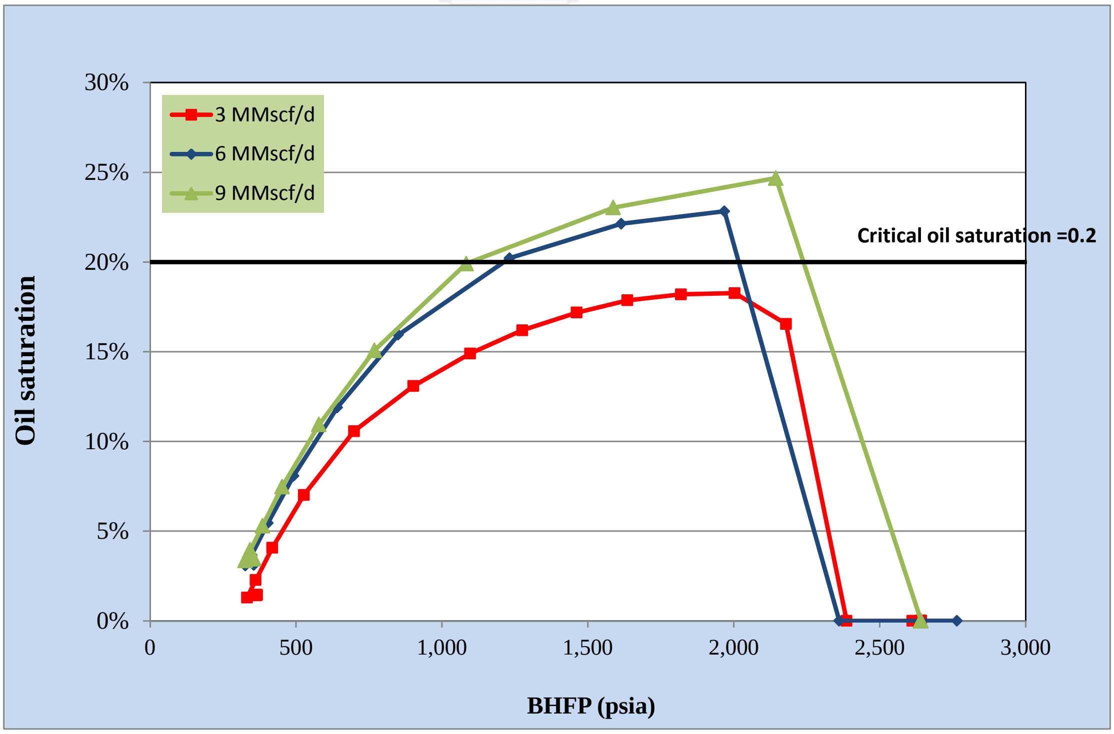


Figure 5. 13 Liquid drop-out curve of layer 1 for different plateau rates in bottom up with plug strategy when the timing of perforating the second batch is option 1

Table 5.2 calculates the gas recovery factor for each individual perforation batch. The data indicates that the gas volume produced from second batch stays nearly the same regardless of gas plateau rate because all upper reservoirs are produced until the economic level while the gas production from dry gas layers perforated in the first batch is decreased with higher maximum gas rate. It means that the difference in overall gas recovery factor results from the production of the first batch. If the timing of perforating the second batch is option 1 and 2, the gas recovery factor reduces slightly when plateau rate increases from 3 to 6 MMscf/d but it decreases by 8% in option 1 and 5% in option 2 when plateau rate increases to 9 MMscf/d. However, the gas recover factor is the same for various gas plateau rates when the timing of perforating the second batch is option 3. These can be explained by the plot of reservoir pressure versus plateau rate shown in Figure 5.14.

Figure 5.14 shows the energy of the reservoir by the time that the four lower layers are plugged off to proceed perforating the second batch. This can be seen clearly when perforation timing is option 1 and 2, the higher gas production rate has a higher reservoir pressure at the time to perforate the second batch, leading to more dry gas production left in the reservoir. In other words, the cumulative production is smaller when the maximum gas rate is higher. In the case of option 3, reservoir pressures are the same since the producer reach to the economic rate whatever the maximum production rate. Overall, the ultimate gas recovery reduces at very high gas production rate as shown in Table 5.3 and Figure 5.16.

Table 5. 2 Gas recovery factor of individual perforation batch for different plateau rates in bottom up with plug strategy

Perforation Timing	Plataeu rate (MMscf/d)	First batch: Cumulative gas production (bscf)	First batch: Gas RF (%)	Second batch: Cumulative gas production (bscf)	Second batch: Gas RF (%)	Overall gas RF (%)
Less than plataeu (option 1)	3	2.5	45	2.4	43	87
	6	2.4	43	2.6	45	88
	9	2.1	37	2.4	43	79
Less than 1/2 plataeu (option 2)	3	2.7	47	2.4	43	90
	6	2.5	44	2.6	45	89
	9	2.4	42	2.4	43	85
Less than economic rate (option 3)	3	2.8	49	2.4	43	91
	6	2.8	49	2.4	43	92
	9	2.8	49	2.4	43	91

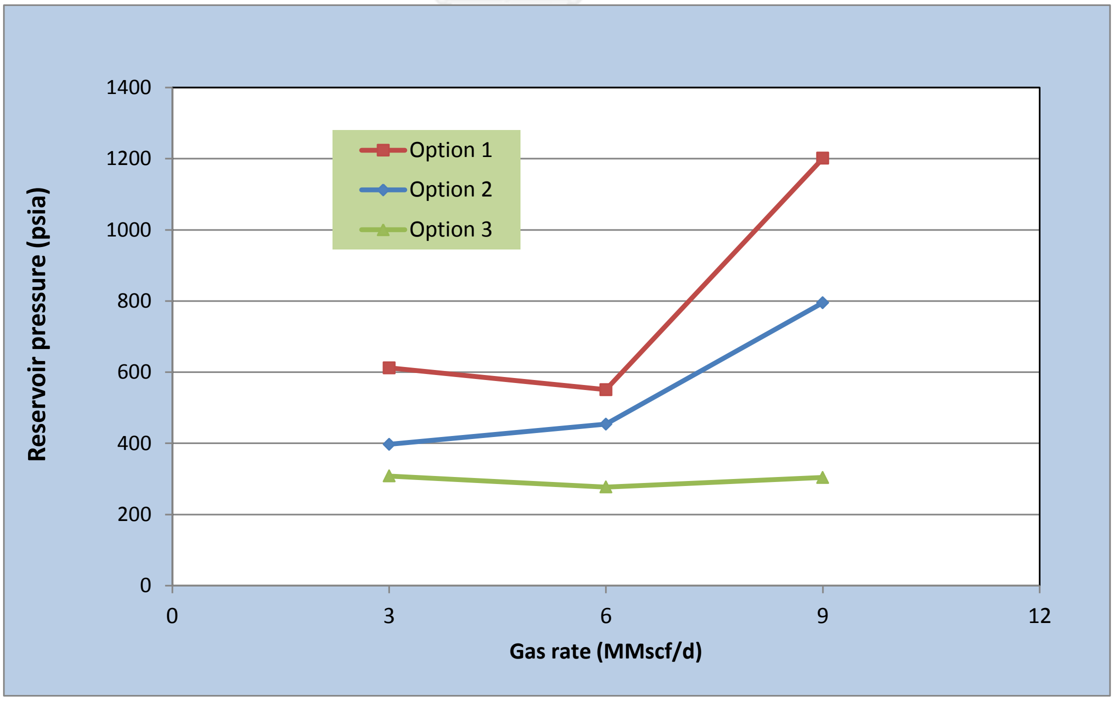


Figure 5.14 Reservoir pressure of the first batch layers at the time to perforate the second batch for different plateau rates in bottom up with plug

In term of condensate, the higher the maximum gas production rate, the lower the ultimate oil recovery though the difference is insignificant. This can be explained in the same ways as in Section 5.1 that the higher gas flow rate results in a greater shift of the phase diagram to the right and therefore the loss of heavier component in the near wellbore and in the reservoir becomes greater as illustrated in Figure 5.15. As a result, at the same perforation timing of the second batch, the oil recovery factor can be slightly reduced by 1 to 2 percent at higher plateau rate as shown in Table 5.3 and Figure 5.17.

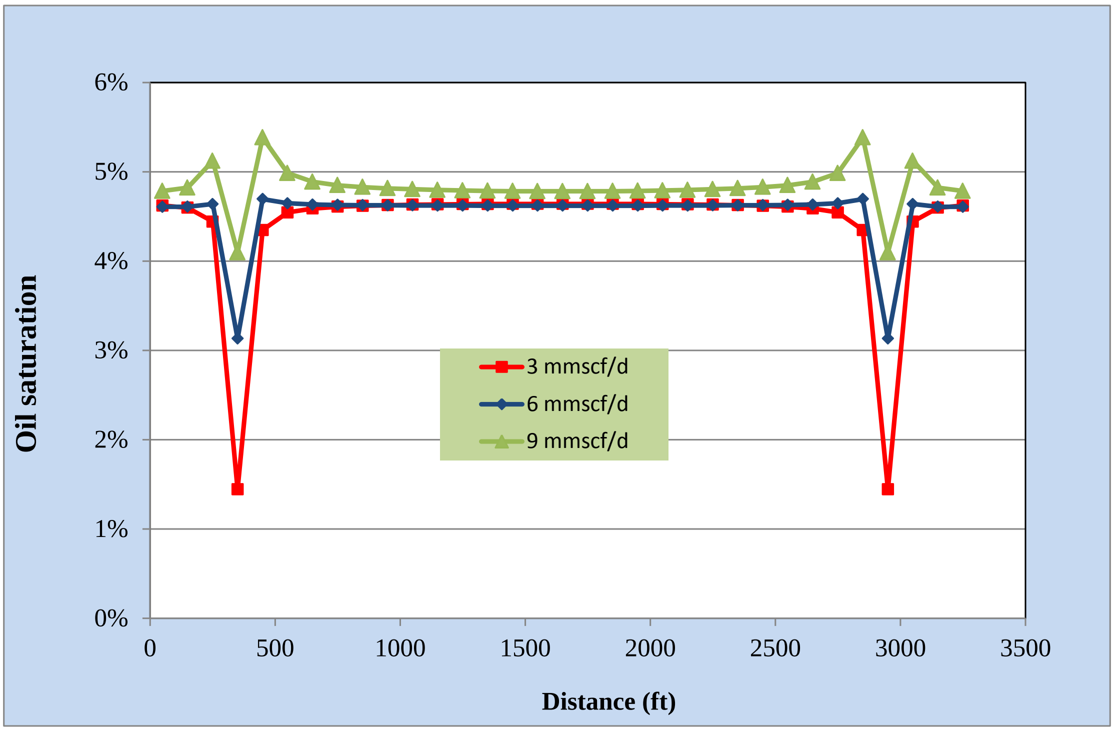


Figure 5. 15 Condensate saturation of layer 1 at one of the producers at the end of production time for different plateau rates in bottom up with plug strategy

Table 5.3 Comparisons of different plateau rates in bottom up with plug strategy

Perforation Timing	Plataeu rate (MMscf/d)	Production time (days)	Cumulative gas production (bscf)	Cumulative oil production (Mstb)	Gas RF (%)	Condensate RF (%)	MBOE (Mstb)
Less than plataeu (option 1)	3	882	4.9	174.1	87	53	997
	6	546	5.0	173.8	88	53	1005
	9	386	4.5	171.2	79	53	921
Less than 1/2 plataeu (option 2)	3	943	5.1	176.9	90	54	1027
	6	577	5.1	174.2	89	53	1017
	9	410	4.8	167.9	85	52	969
Less than economic rate (option 3)	3	1004	5.16	176.7	91	54	1038
	6	699	5.19	175.8	92	54	1042
	9	561	5.17	167.8	91	52	1029

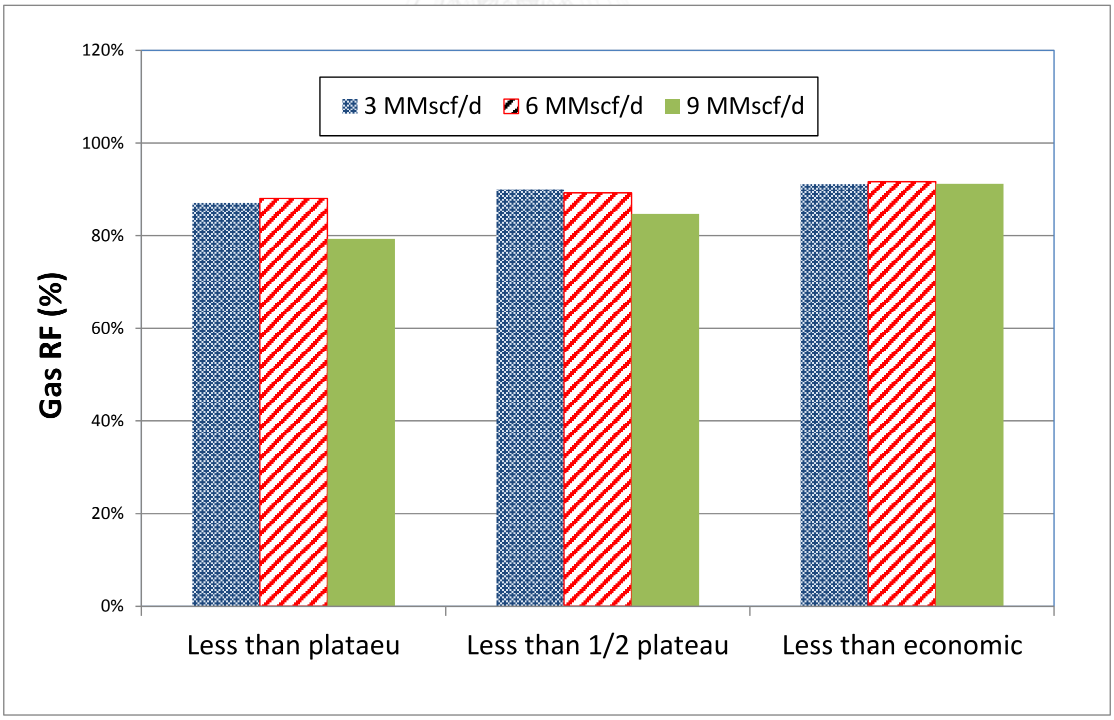


Figure 5.16 Gas recovery factor for different plateau rates in bottom up with plug strategy

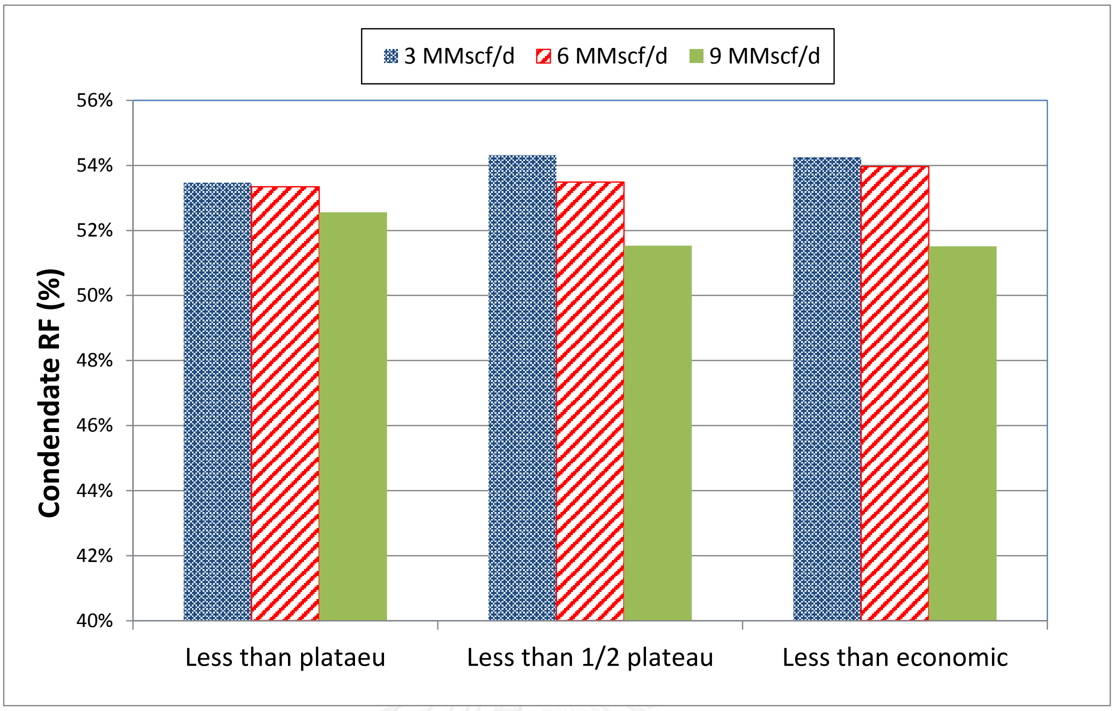


Figure 5.17 Condensate recovery factor for different plateau rates in bottom up with plug strategy

5.2.2 Effects of perforation timing

Figure 5.18 illustrates the field gas production performance for different perforation timings when the maximum gas rate is 6 MMscf/d. The results indicate that at the same plateau rate, the sooner the time to perforate the second batch, the shorter the production time. The gas plateau is divided into two periods. In the first plateau period, gas which is from only four dry gas layers can maintain plateau rate for six months before dropping steeply below the maximum production rate. In the second period, gas production is brought back to the plateau rate from the four upper layers for around five months then decline toward the end of production life.

In general, the same gas production behavior is observed for different perforation timings of the second batch. The duration of two plateau periods and the decline tendency are the same in all cases. The gas rate production curve is shifted to the right side when perforation timing of the second batch is delayed.

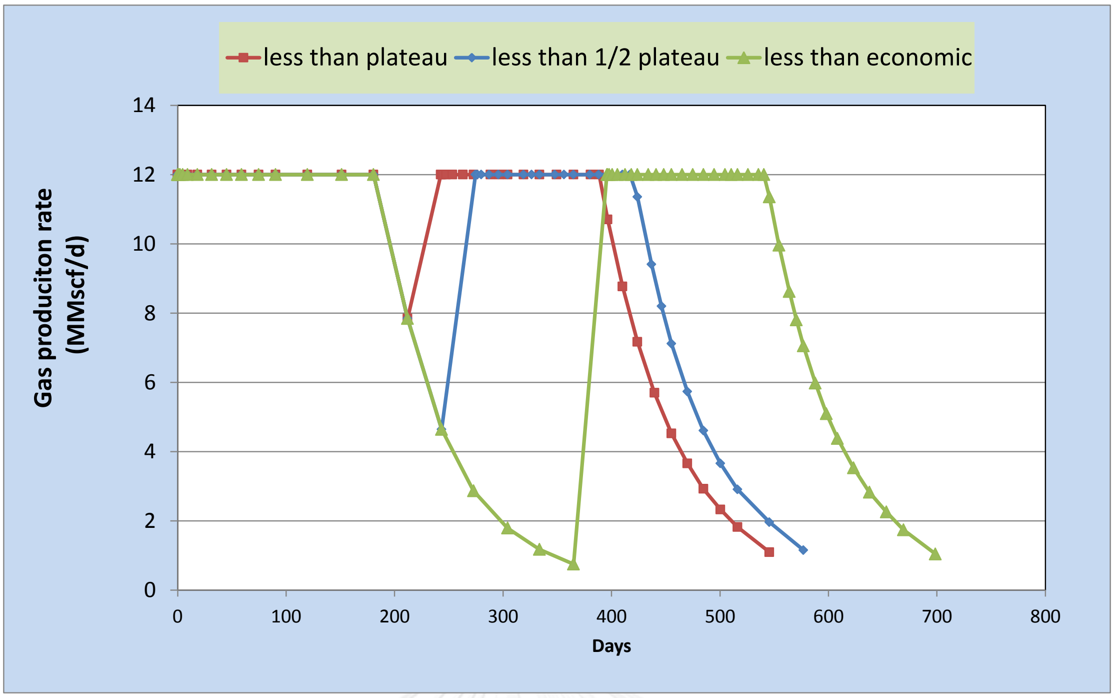


Figure 5.18 Field gas production rate for different perforation timings in bottom up with plug strategy when the maximum gas rate is 6 MMscf/d

Figure 5.19 shows the field oil production performance for different perforation timings when the maximum gas rate is 6 MMscf/d. Condensate starts to be produced when the second batch is perforated. In the case of low and moderate gas production rate, because of no cross flow, the condensate production can maintain the plateau rate for around one month before declining very fast as pressures decline below the dew points. Condensate continues to decline with the same downward tendency but later slightly increases again before a final decline. As explained in Section 5.2.1, this slight increase in condensate production is because a part of heavy components which condense in the reservoir will flow freely to the well bore due to higher oil saturation than critical one. In addition, a part of the condensate vaporizes back to the gas phase as pressures reach to the revaporization zone during production.

In general, condensate production displays the same behaviors for various perforation timings. The duration of plateau periods and the decline tendency are the same in all cases. The oil rate production curve is shifted to the right side when perforation timing of the second batch is delayed.

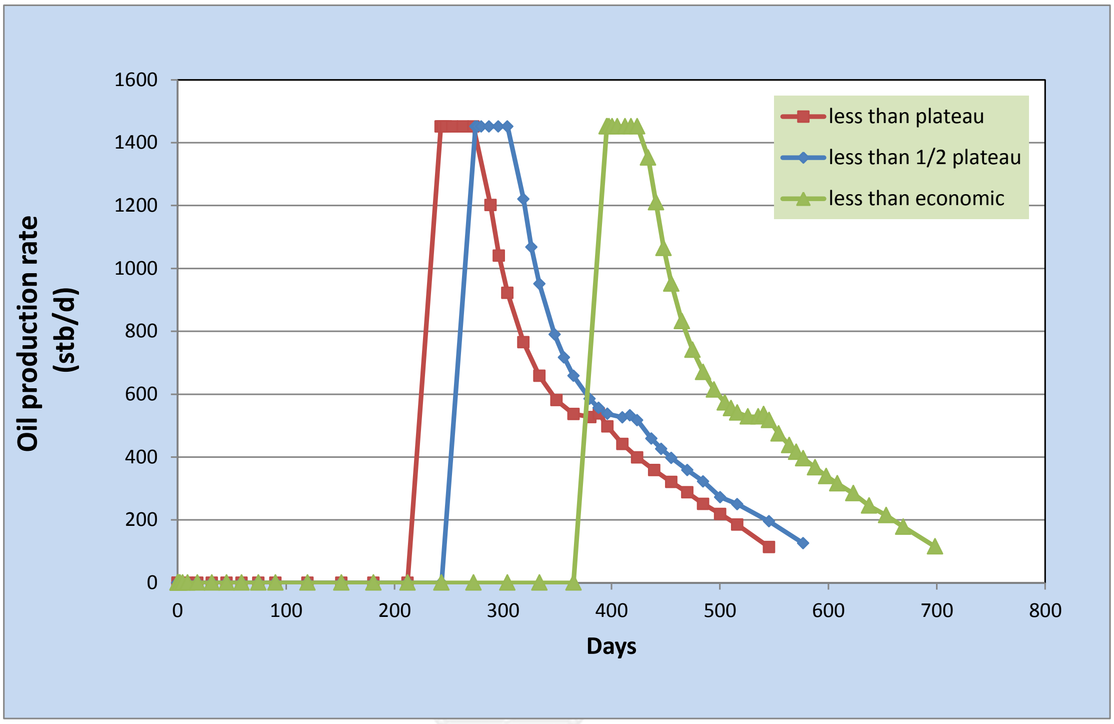


Figure 5.19 Field oil production rate for different perforation timings in bottom up with plug strategy when the maximum gas rate is 6 MMscf/d

In term of ultimate gas recovery, the sooner the perforating time of second batch, the lower the ultimate recovery of gas because gas is not produced until the economic rate and being lost in the lower layers before perforating the upper ones. As a result, the recovery factor of gas is increased by 4 to 8 percent when the second batch of perforation is delayed regardless of production rate shown in Table 5.4 and Figure 5.20.

In contrast, the recovery factor of condensate is independent on the perforating time of the second batch. This is because the four upper layers are produced separately from the four lower reservoirs until the economic rate is reached. In other words, at a specific gas plateau rate, the condensate recovery factors are the same regardless of timing selection as illustrated in Figure 5.21.

Table 5.4 Comparisons of different perforation timings in bottom up with plug strategy

Plataeu rate (MMscf/d)	Perforation Timing	Production time (days)	Cumulative gas production (bscf)	Cumulative oil production (Mstb)	Gas RF (%)	Condensate RF (%)	MBOE (Mstb)
3	Less than plataeu	882	4.9	174.1	87	53	997
	Less than 1/2 plateau	943	5.1	176.9	90	54	1027
	Less than economic	1004	5.2	176.7	91	54	1038
6	Less than plataeu	546	5.0	173.8	88	53	1005
	Less than 1/2 plateau	577	5.1	174.2	89	53	1017
	Less than economic	699	5.2	175.8	92	54	1042
9	Less than plataeu	386	4.5	171.2	79	53	921
	Less than 1/2 plateau	410	4.8	167.9	85	52	969
	Less than economic	561	5.2	167.8	91	52	1029

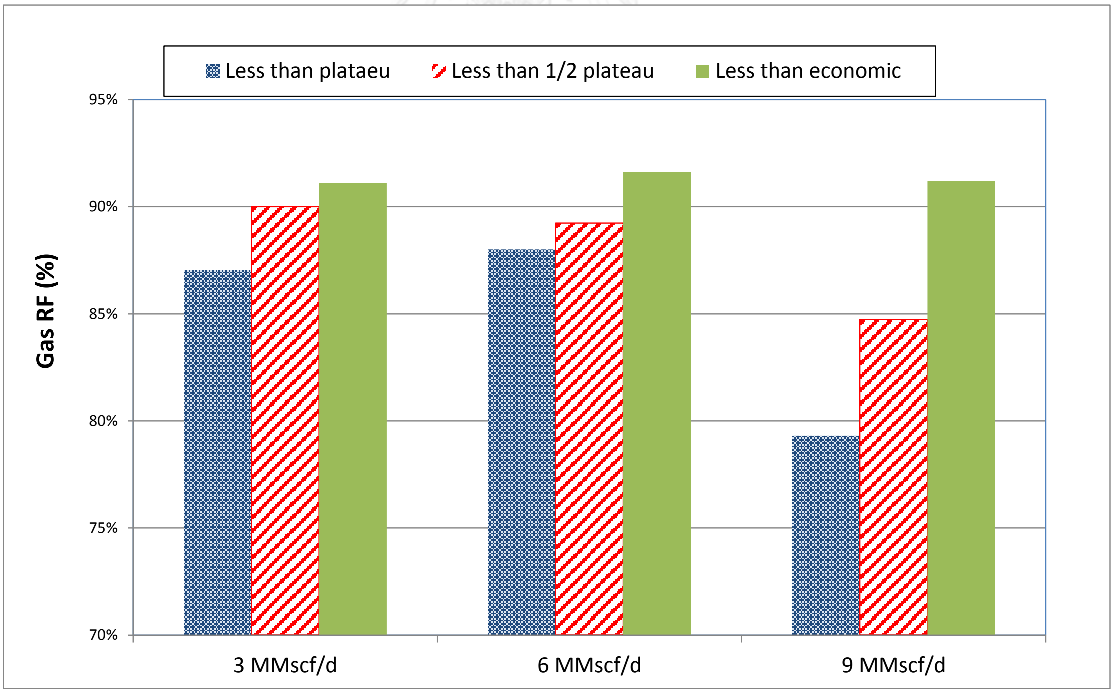


Figure 5.20 Gas recovery factor for different perforation timings in bottom up with plug strategy

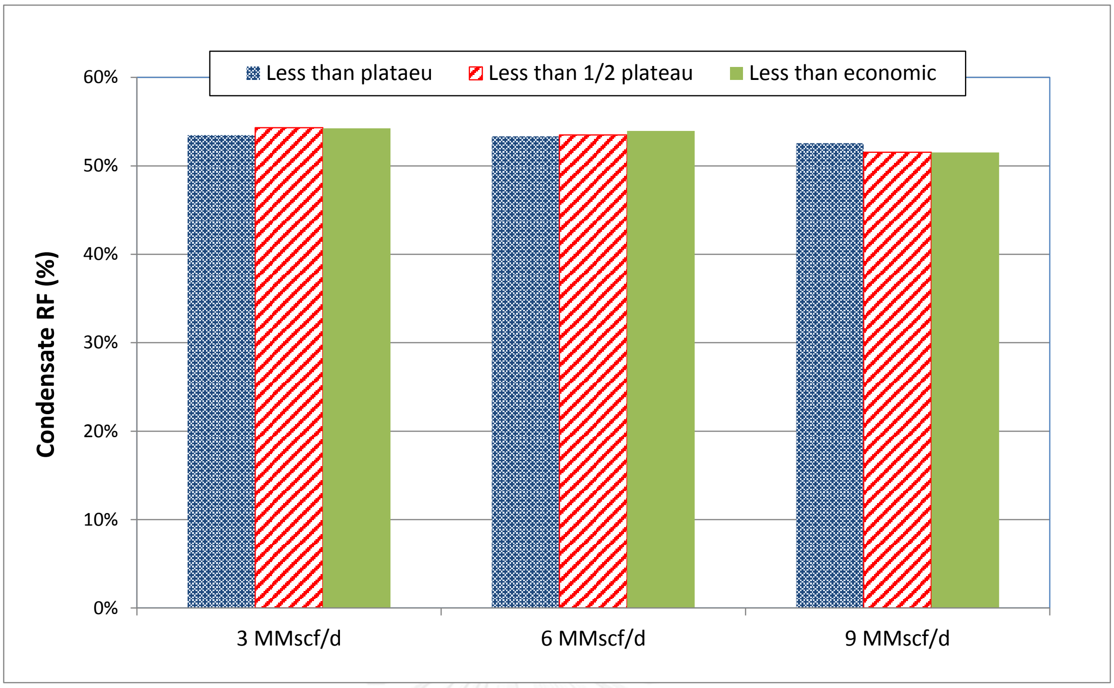


Figure 5.21 Condensate recovery factor for different perforation timings in bottom up with plug strategy

5.3 Bottom up without plug strategy

The bottom up perforation without plug means that all lower layers of dry-gas reservoirs are perforated in the first batch. At a selected timing, all upper layers of condensate reservoirs are perforated in the second batch without plugging the lower zones. The timing of perforating the second batch is varied as follows:

- ✓ Option 1: When the well gas production rate is less than the plateau rate
- ✓ Option 2: When the well gas production rate is less than half of the plateau rate
- ✓ Option 3: When the well gas production rate is less than the economic rate (0.5 MMscf/d)

In addition, the plateau rate is varied by 3, 6 and 9 MMscf/d to see the effects of maximum production rate on production performance of this production strategy. There are nine simulation cases in total for this perforation strategy.

5.3.1 Effects of plateau rate

Figure 5.22 shows the gas production performance for different plateau rates for the case that the second batch is perforated when the well gas rate falls below the plateau rate (option 1). The gas plateau production is divided into two periods. In the first plateau period, gas is coming from only the four dry gas layers. In the second period, the four lower layers combine with the four upper layers to produce gas as a whole. After the second plateau period, gas production decreases with the same downward tendency despite of various plateau rates until economic rate is reached.

In general, the higher the production rate, the shorter the plateau period and the production time. The gas production is delayed when the plateau rates decreases.

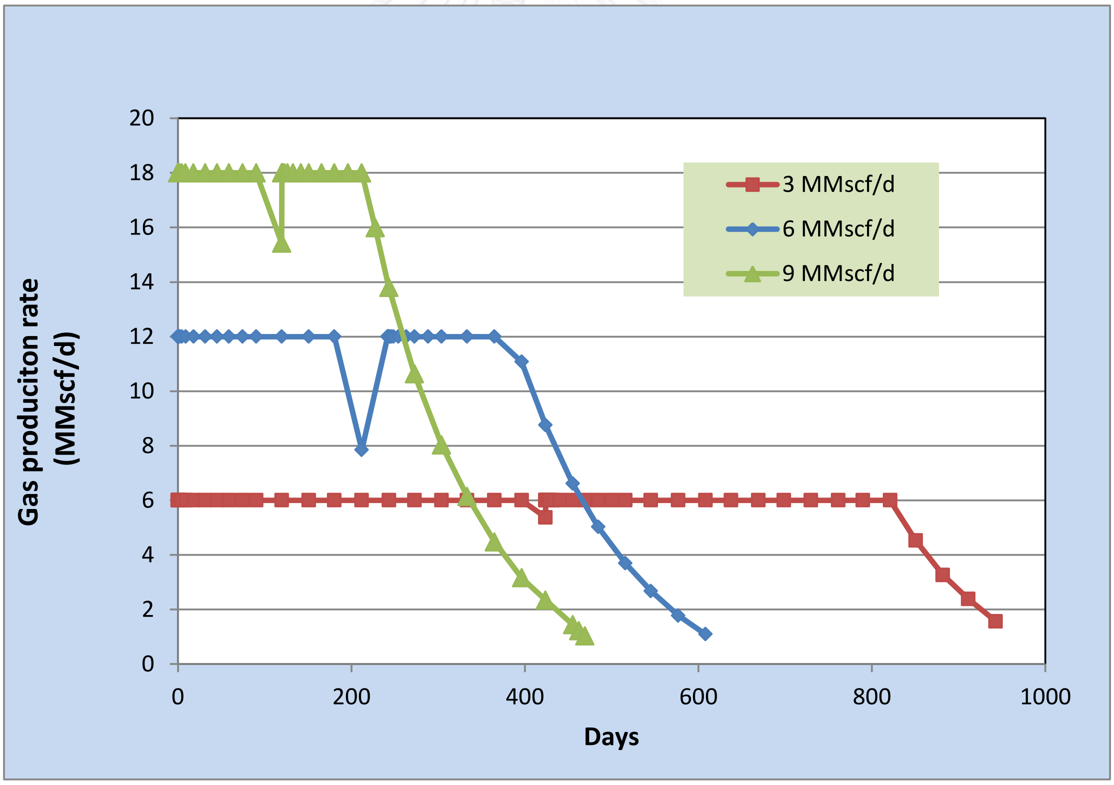


Figure 5.22 Field gas production rate for different plateau rates in bottom up without plug strategy when the timing of perforating the second batch is option 1

Figure 5.23 presents oil production performance for different plateau rates for the case that the second batch is perforated when the well gas rate falls below the plateau rate (option 1). Condensate starts to be produced when the upper layers of the second batch are perforated. Because of cross flow from the upper four layers into the lower four layers soon after the perforation of the second batch as confirmed by the increase in reservoir pressures of the four lower layers shown in Figure 5.24, oil production crashes suddenly at the surface. In addition, liquid starts to drop out from the gas phase since pressures decline below the dew points and hence no plateau of condensate production is observed. Before continuing to decline to the end of well life, oil production increases slightly. This is because gas condensate that has earlier cross flowed into the four lower layers gradually flows back into the wellbore and condenses at the surface. In addition, the flow of movable condensate from reservoir and the revaporization of condensate at low pressure help slow down the condensate decline till the abandonment condition.

Condensate production profile is similar despite of various plateau rates. In general, lower condensate production rate is obtained at the earlier time and production time is longer when the maximum gas production is smaller.

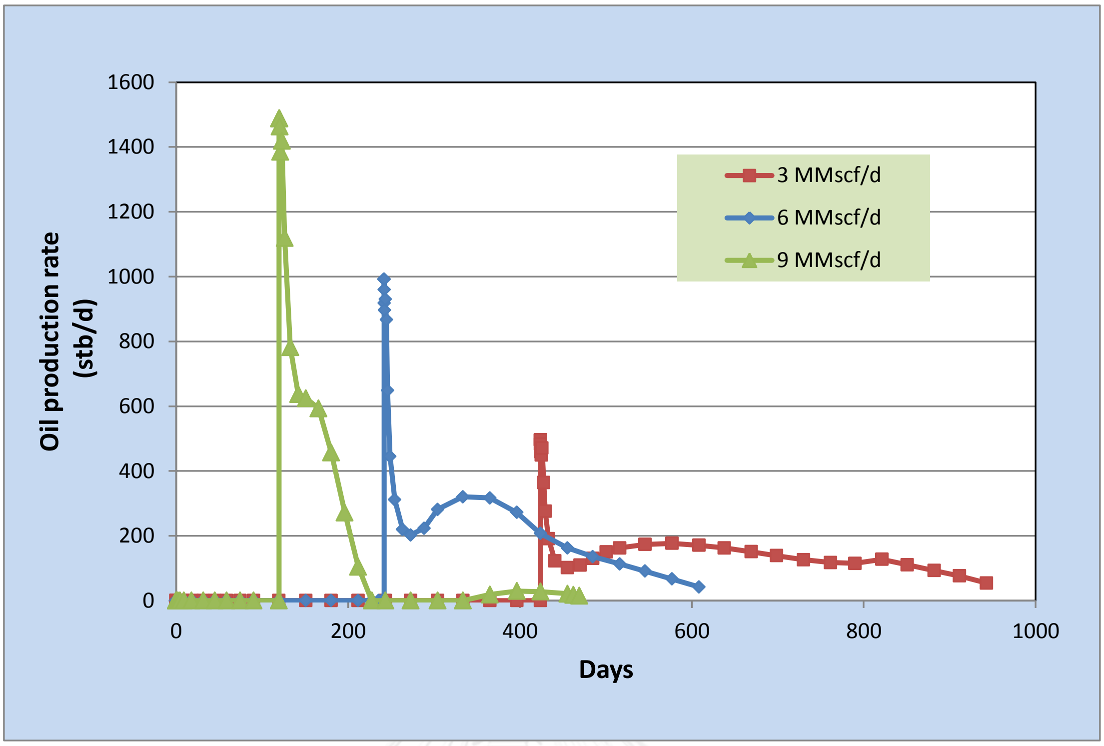


Figure 5.23 Field oil production rate for different plateau rates in bottom up without plug strategy when the timing of perforating the second batch is option 1

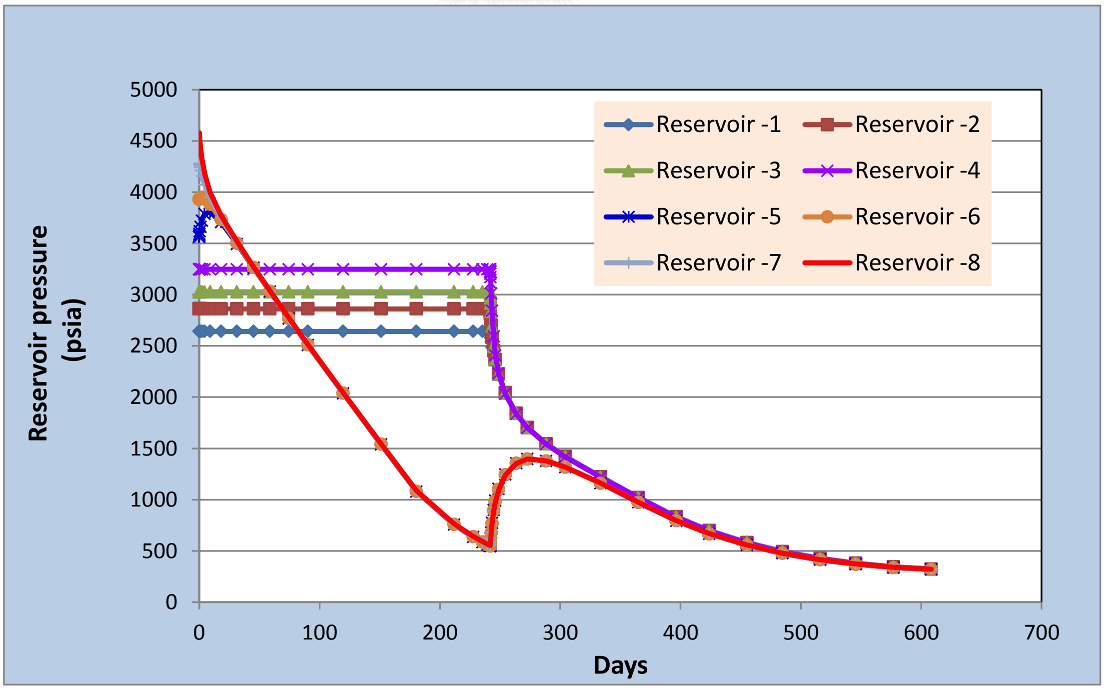


Figure 5.24 Reservoir pressure in bottom up without plug strategy when the maximum gas rate is 6 MMscf/d and the timing of perforating the second batch is option 1

In term of gas ultimate recovery, it does not depend on the maximum flow rate for each specific perforation timing because gas is contributed from all reservoirs anyway. The gas recovery factors are approximately the same at 93% for all cases as shown in Table 5.5 and Figure 5.31.

For condensate, it can be observed that if the timing of perforating the second batch is option 1 and 2, the condensate recovery factor is almost the same when plateau rate increases from 3 to 6 MMscf/d but it decreases by 7% and 3% for option 1 and 2, respectively when plateau rate increases to 9 MMscf/d. However, no difference in condensate ultimate recovery for various plateau rates when the timing of perforating the second batch is option 3. This can be explained by an increase in bottom hole flowing pressure due to crossflow and the change in phase diagram.

Figure 5.25 compares the cumulative condensate production for various gas plateau rates when the perforation timing of the second batch is option 1. As can be seen from the graph, higher gas production rate makes more condensate to be produced at the early time. However, condensate production in the case of 9 MMscf/d increases insignificantly after its peak, leading to rather flat cumulative curves while production curves of the other rates grow continuously toward the end of production life.

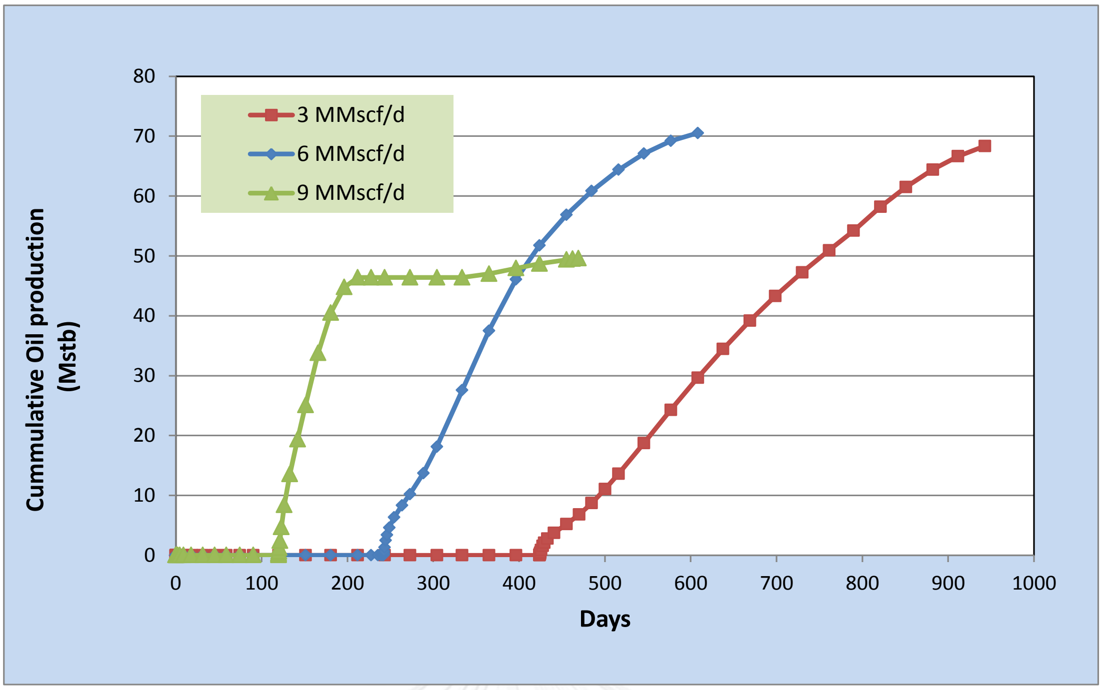


Figure 5. 25 Cumulative condensate production for different plateau rates in bottom up without plug strategy when the timing of perforating the second batch is option 1

As can be seen in Figure 5.26, when the perforation timing of the second batch is option 1, the bottom hole flowing pressure of the producer increases to a higher value in the case of 9 MMscf/d than that of the other plateau rates (2125 psi versus 1952 and 1984 psi). At that time, the amount of condensate flows downward into the lower dry gas layers in 9 MMscf/d case is actually lower than that of 3 and 6 MMSCFD cases (e.g. 7.0 Mstb compared with 9.0 and 8.5 MSTB, respectively). However, the amount of the condensate flows back into the well and can be recovered at the surface is higher for lower gas production rates and thus in the end the amount of condensate remains in lower dry gas reservoirs is higher for 9 MMscf/d case as illustrated in Figure 5.27.

Consequently, this cross flow of condensate into lower layers leads to lower condensate recovery and smaller percentage of condensate saturation in the upper reservoirs in the case of 9 MMscf/d than that of 3 and 6 MMscf/d at the end of production time as shown in Figure 5.28. Similar observation is seen for option 2.

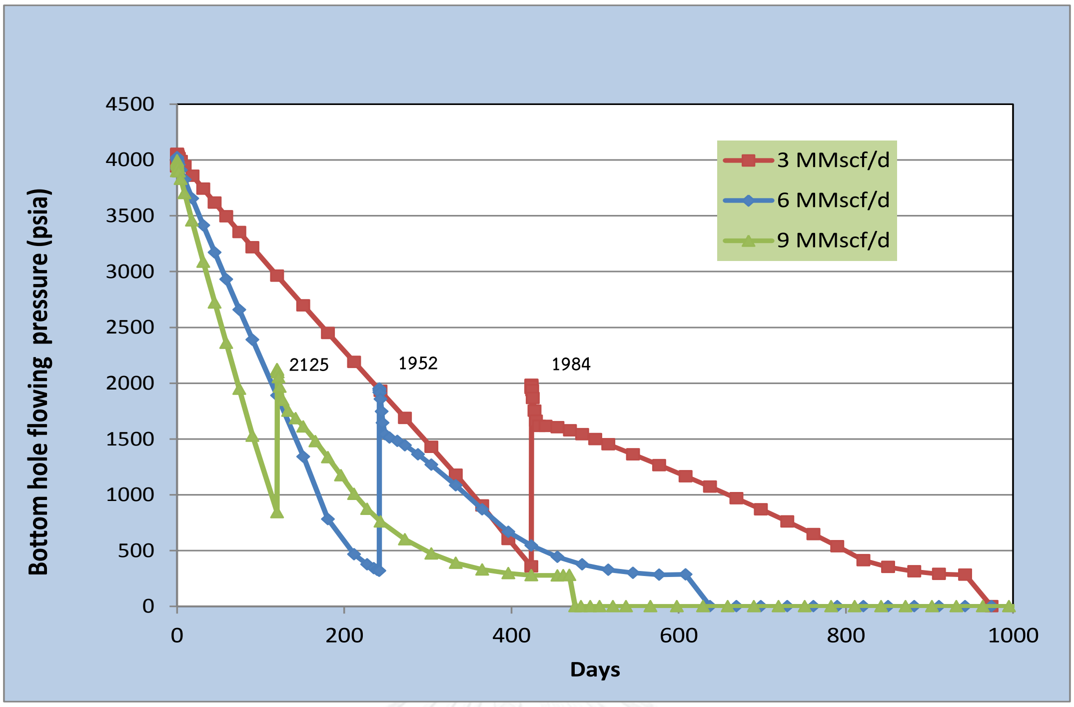


Figure 5. 26 Bottom hole flowing pressure at one of the producers for different plateau rates in bottom up without plug strategy when the timing of perforating the second batch is option 1

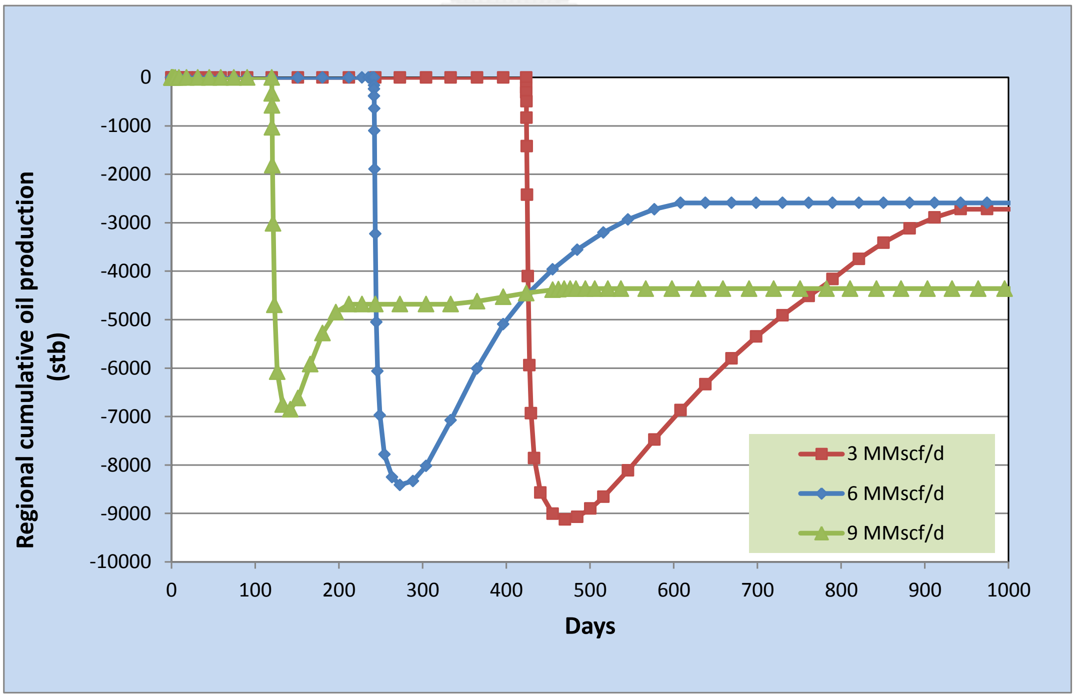


Figure 5. 27 Cumulative condensate production of layer 8 (bottommost layer) for different plateau rates in bottom up without plug strategy when the timing of perforating the second batch is option 1

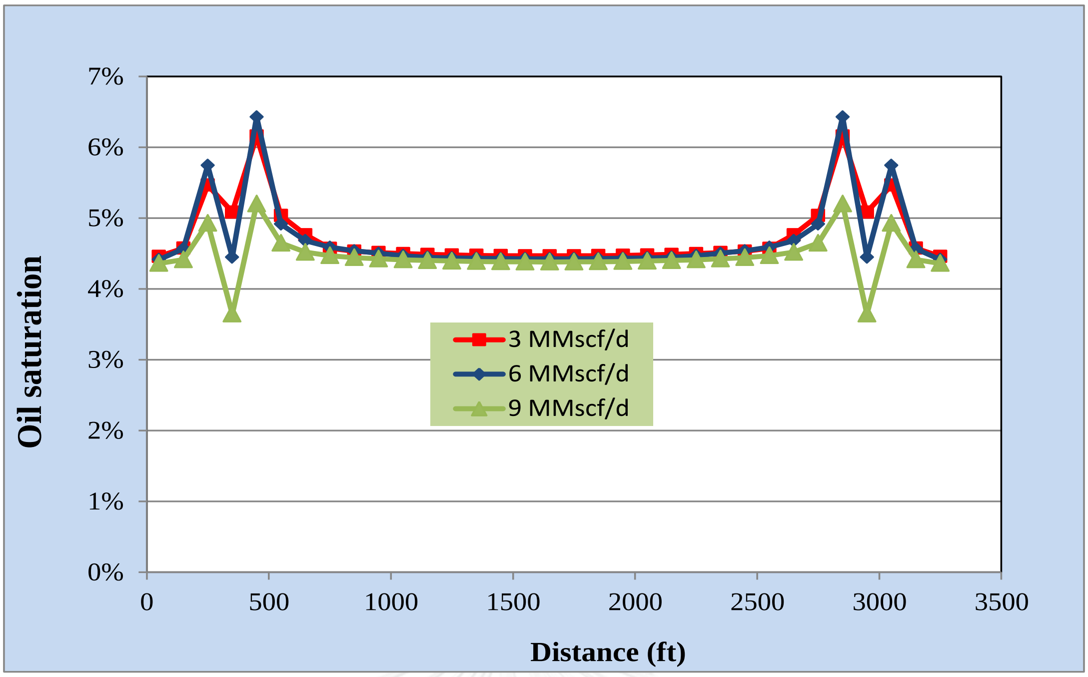


Figure 5. 28 Condensate saturation of layer 1 at one of the producers at the end of production time for different plateau rates in bottom up without plug strategy when the timing of perforating the second batch is option 1

Moving to perforation timing of the second batch is option 3, as the lower gas reservoirs are depleted until economic level before perforating the second batch, and hence the bottom hole flowing pressure of the producer varies insignificantly for various plateau rate as shown in Figure 5.29, leading to a same phase diagram and therefore same oil saturation left in the near wellbore as illustrated in Figure 5.30.

Overall, the ultimate condensate recovery reduces when gas production rate is very high. However the amount of decrease in condensate recovery factor depends on the perforation timing of the second batch as shown in Table 5.5 and Figure 5.32.

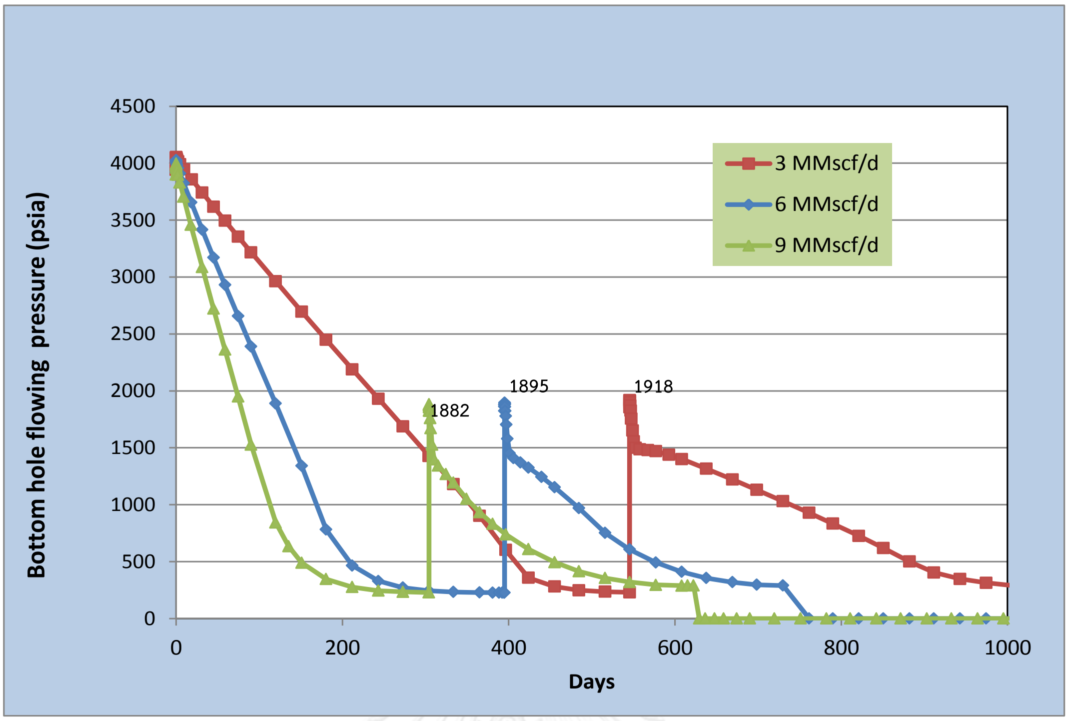


Figure 5. 29 Bottom hole flowing pressure at one of the producers for different plateau rates in bottom up without plug strategy when the timing of perforating the second batch is option 3

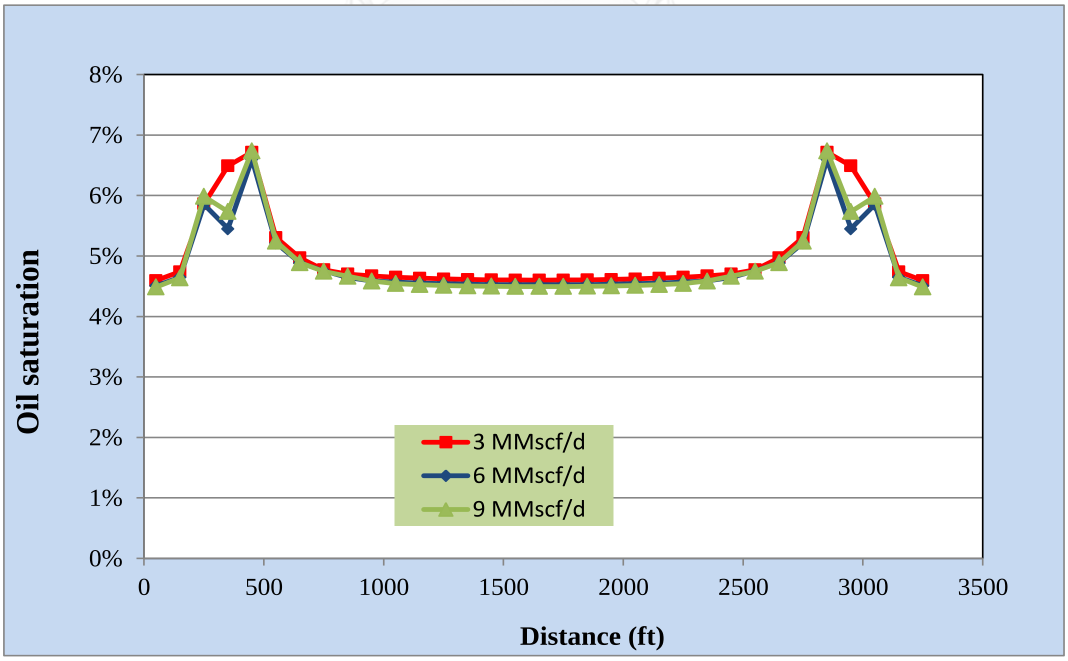


Figure 5. 30 Condensate saturation of layer 1 at one of the producers at the end of production time for different plateau rates in bottom up without plug strategy when the timing of perforating the second batch is option 3

Table 5.5 Comparisons of different plateau rates in bottom up without plug strategy

Perforation Timing	Plataeu rate (MMscf/d)	Production time (days)	Cumulative gas production (bscf)	Cumulative oil production (Mstb)	Gas RF (%)	Condensate RF (%)	MBOE (Mstb)
Less than plataeu (option 1)	3	943	5.3	68.4	93	21	946
	6	608	5.3	70.5	93	22	950
	9	469	5.3	49.6	94	15	936
Less than 1/2 plataeu (option 2)	3	974	5.2	72.4	93	22	947
	6	638	5.3	72.4	93	22	952
	9	483	5.3	60.9	93	19	944
Less than economic rate (option 3)	3	1004	5.21	72.3	92	22	941
	6	730	5.25	73.6	93	23	948
	9	622	5.26	73.6	93	23	951

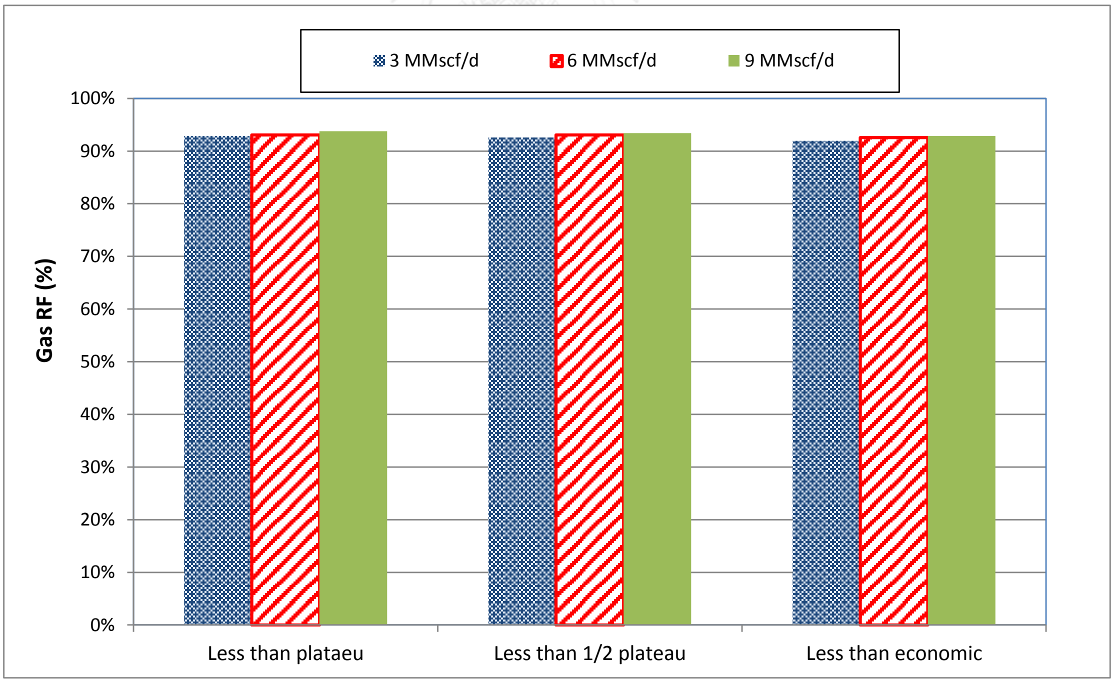


Figure 5.31 Gas recovery factor for different plateau rates in bottom up without plug strategy

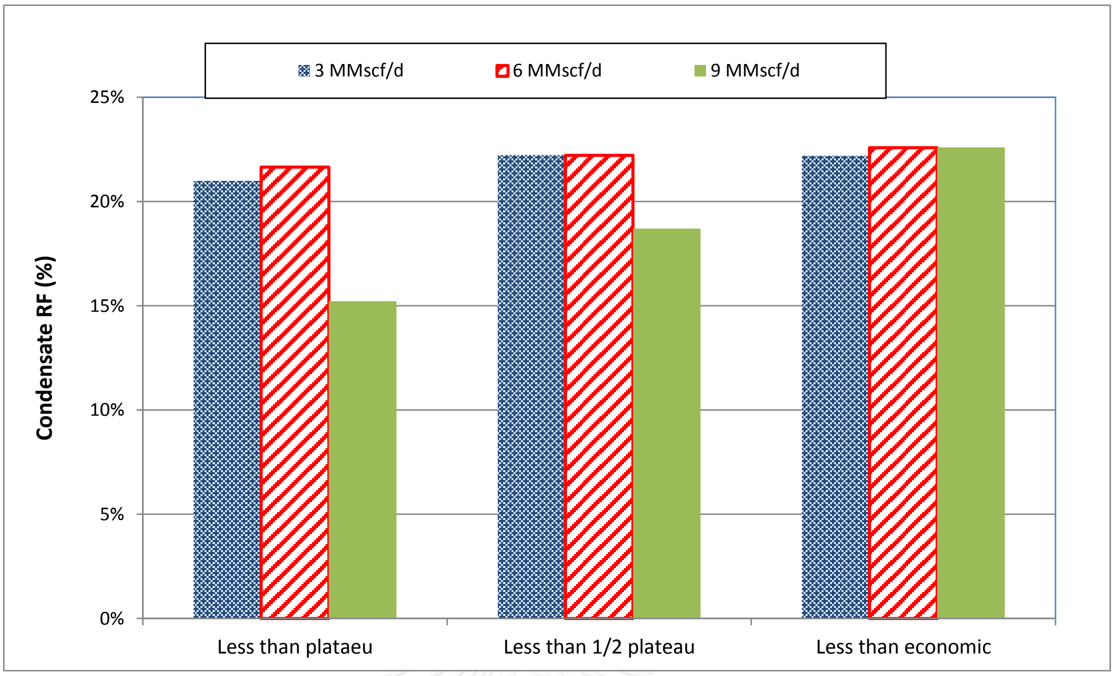


Figure 5.32 Condensate recovery factor for different plateau rates in bottom up without plug strategy

5.3.2 Effects of perforation timing

Figure 5.33 shows gas production profiles for different perforation timings when the maximum gas rate is 6 MMscf/d. The results indicate that at the same plateau rate, the sooner the time to perforate the second batch, the shorter the production time. The gas plateau production is divided into two periods. In the first plateau period, gas which is from only four dry gas layers can maintain the plateau rate for six months before decreasing abruptly. In the second period, the four lower layers combine with the four upper layers to produce gas as a whole and thus plateau rate can be maintained for around four months before continuing to decline toward the end of production life.

In general, the same gas production behavior is observed for different perforation timings of the second batch. The duration of two plateau periods and the decline tendency are the same in all cases. The gas rate production curve is shifted to the right side when perforation timing of the second batch is delayed.

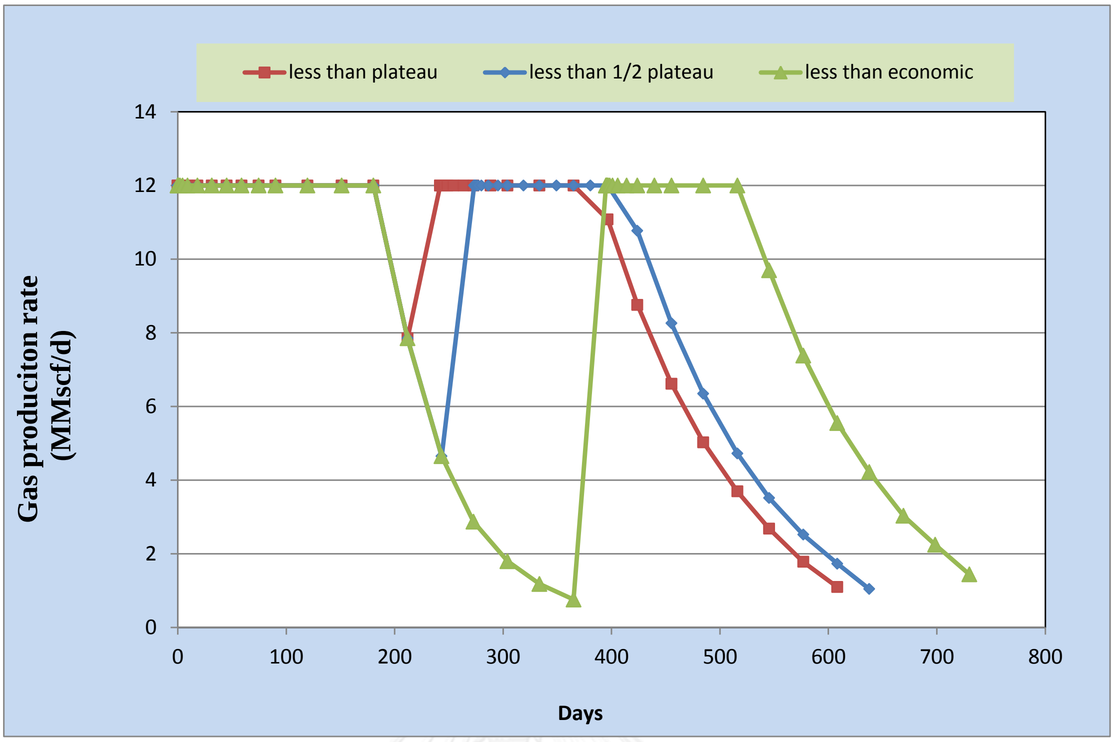


Figure 5.33 Field gas production rate for different perforation timings in bottom up without plug strategy when the maximum gas rate is 6 MMscf/d

Figure 5.34 compares the condensate production profiles for different perforation timings when the maximum gas rate is 6 MMscf/d. Condensate productions starts to be produced as soon as the second batch is perforated but cannot be maintained at the plateau rate. Condensate rate declines steeply due to cross flow from the upper layers to lower ones and condensate banking around and far from the wellbore as pressures decline below the dew points. As mentioned earlier, due to crossflow effect, oil flow rate increases once pressure from all layers get into hydrostatic equilibrium and fluid from the lower four layers flows back into the wellbore. This reason makes condensate performance improve before declining toward the end of well life.

In general, condensate production displays the same behavior for various perforation timings. The oil rate production curve is just shifted to the right side when perforation timing of the second batch is delayed.

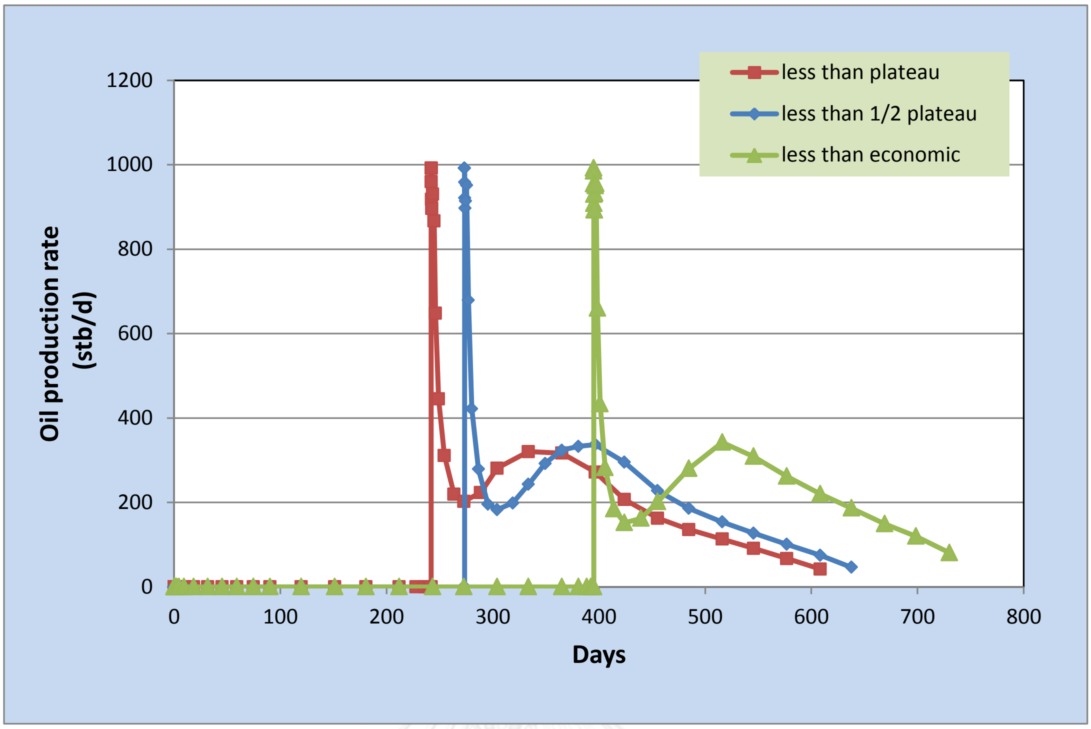


Figure 5.34 Field oil production rate for different perforation timings in bottom up without plug strategy when the maximum gas rate is 6 MMscf/d

In term of the ultimate recovery of gas, it does not depend on the perforation timing of the second batch because gas is contributed from all reservoirs anyway. The same gas recovery factor of 93% for all cases is observed in Table 5.6 and Figure 5.37.

For condensate, for each specific gas plateau rate, the sooner to perforate the second batch, the lower the ultimate recovery of condensate. However, the amount of reduction in condensate recovery factor due to the earlier perforation timing of the second batch is insignificant in the case of low (3 MMscf/d) and moderate (6 MMscf/d) gas production rate but up to 8 % in the case of high gas production rate (9 MMscf/d). It can be explained by Figure 5.35 and 5.36 below.

Figure 5.35 indicates that the sooner to perforate the second batch, the higher the bottom hole flowing pressure in the case of 9 MMscf/d, leading to a higher amount of condensate cross flowing to lower layers as explained in Section 5.31. However, the difference in bottomhole flowing pressure for various perforation timing is very minor when gas production rate reduces to smaller gas flow rate as shown in Figure 5.36. Therefore the ultimate recovery factors are not much different from three cases of perforation timing in the case of small and moderate gas production rate. Overall, ultimate condensate recovery reduces with earlier perforation timing. However, the amount of decrease in the condensate recovery factor depends on the plateau rate as shown in Table 5.6 and Figure 5.38.

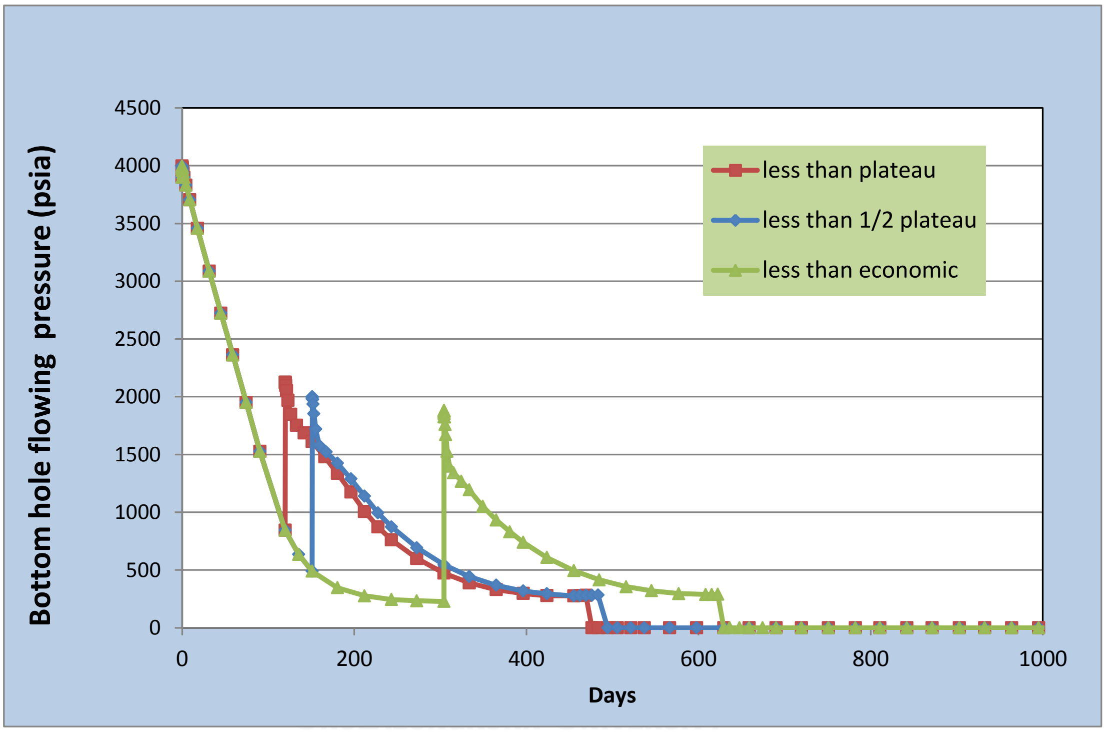


Figure 5. 35 Bottom hole flowing pressure for different plateau rates in bottom up without plug strategy when the maximum gas production rate is 9 MMscf/d

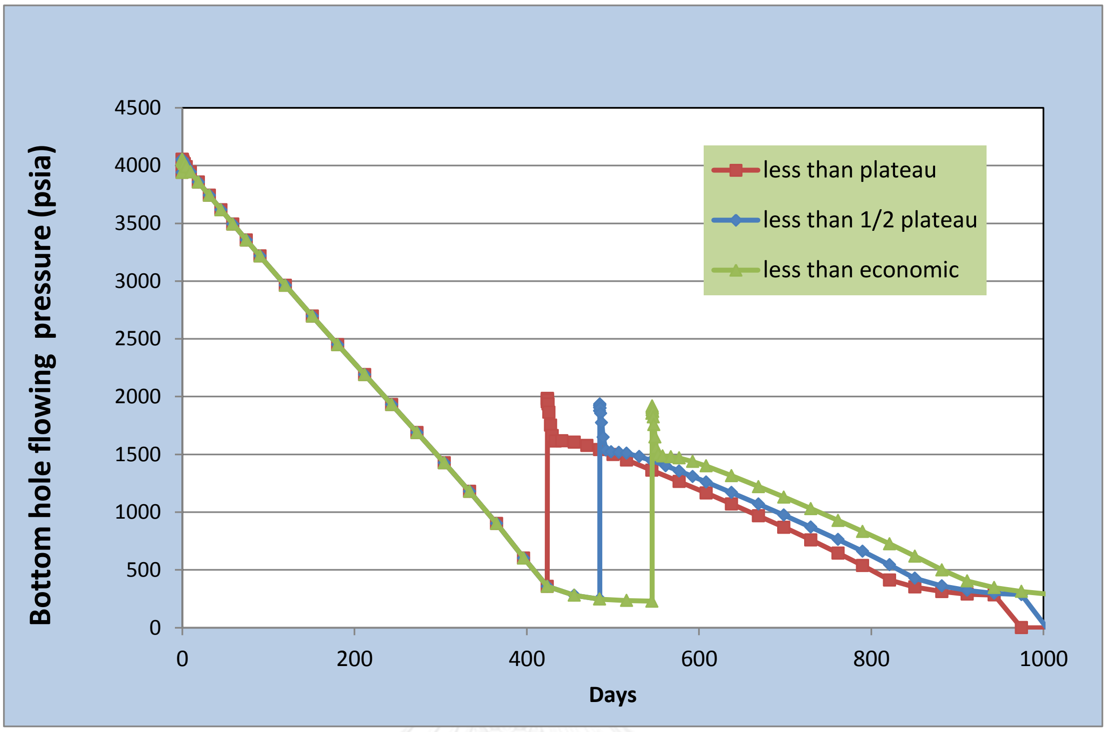


Figure 5. 36 Bottom hole flowing pressure for different plateau rates in bottom up without plug strategy when the maximum gas production rate is 3 MMscf/d

Table 5.6 Comparison of different perforation timings in bottom up without plug strategy

Plataeu rate (MMscf/d)	Perforation Timing	Production time (days)	Cumulative gas production (bscf)	Cumulative oil production (Mstb)	Gas RF (%)	Condensate RF (%)	MBOE (Mstb)
3	Less than plataeu	943	5.3	68.4	93	21	946
	Less than 1/2 plateau	974	5.2	72.4	93	22	947
	Less than economic	1004	5.2	72.3	92	22	941
6	Less than plataeu	608	5.3	70.5	93	22	950
	Less than 1/2 plateau	638	5.3	72.4	93	22	952
	Less than economic	730	5.2	73.6	93	23	948
9	Less than plataeu	469	5.32	49.6	94	15	936
	Less than 1/2 plateau	483	5.30	60.9	93	19	944
	Less than economic	622	5.26	73.6	93	23	951

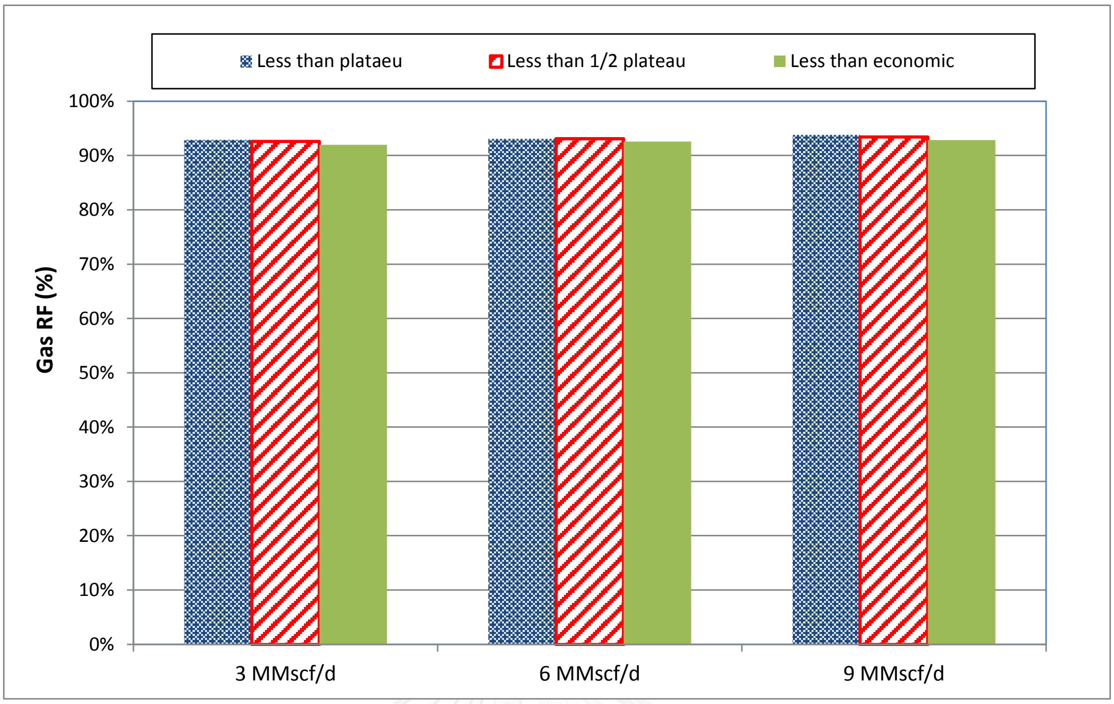


Figure 5.37 Gas recovery factor for different perforation timings in bottom up without plug strategy

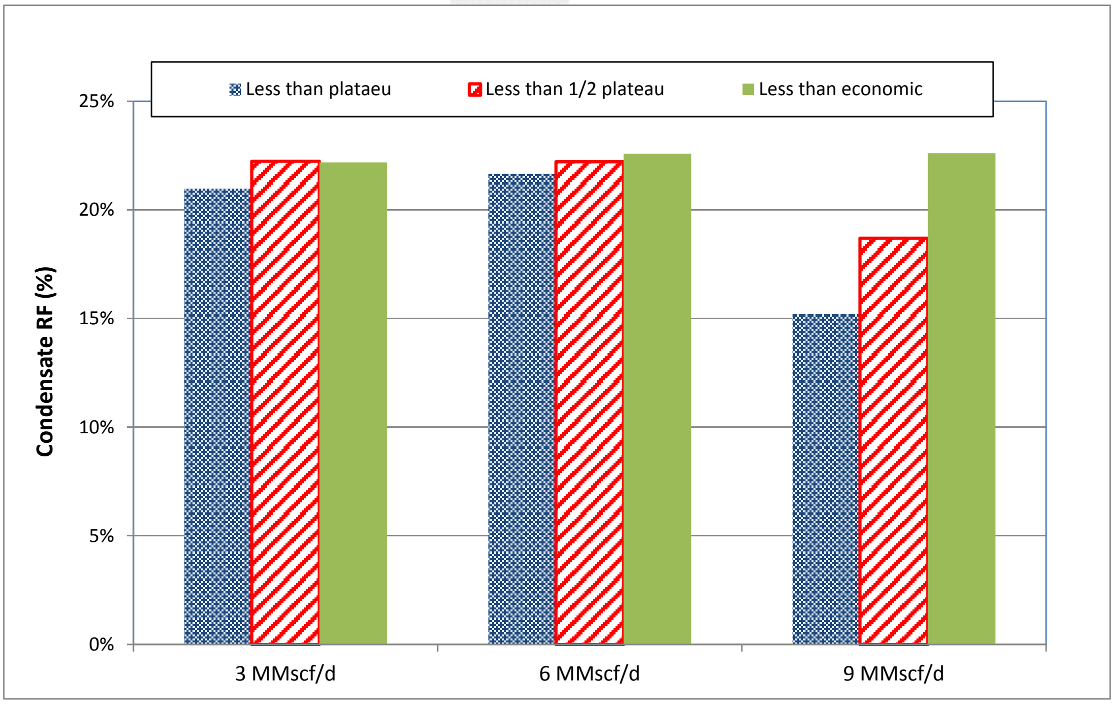


Figure 5.38 Condensate recovery factor for different perforation timings in bottom up without plug strategy

5.4 Top down without plug strategy

Top down perforation without plug strategy means that all shallower layers are perforated in the first batch. When the gas production rate drops below a certain condition, all deeper gas layers are perforated in the second batch without isolation. The timing of perforating the second batch is varied as follows:

- ✓ Option 1: When the well gas production rate is less than the plateau rate
- ✓ Option 2: When the well gas production rate is less than half of the plateau rate
- ✓ Option 3: When the well gas production rate is less than the economic rate (0.5 MMscf/d)

In addition, the plateau rate is varied by 3, 6 and 9 MMscf/d to see the effects of maximum production rate on production performance of this production strategy. There are nine simulation cases in total for this perforation strategy.

5.4.1 Effects of plateau rate

Figure 5.39 presents field gas production rate for the case that the second batch is perforated when the well gas rate falls below the plateau rate (option 1). The gas plateau is divided into two periods. In the first plateau period, gas is coming from shallower condensate layers. In the second period, gas production is added by deeper dry gas layers. After the second plateau period, gas production decreases with the same downward tendency despite of various plateau rates until the economic rate is reached.

In general, the higher the production rate, the shorter the production time and the shorter the plateau period. The gas production is delayed when the plateau rates decreases.

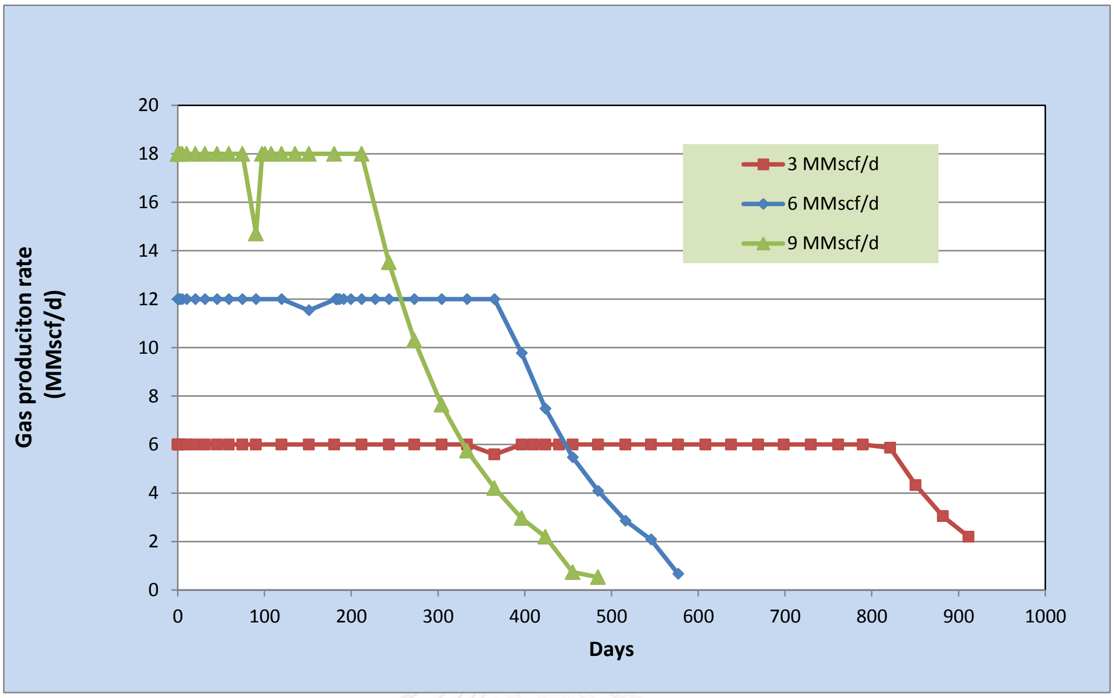


Figure 5.39 Field gas production rate for different plateau rates in top down without plug strategy when the timing of perforating the second batch is option 1

Figure 5.40 shows the production performance of condensate rate for the case that the second batch is perforated when the well gas rate falls below the plateau rate (option 1). Condensate is produced from the beginning and can be maintained at a constant rate for a while before liquid starts to drop out from the gas phase since pressures decline below the dew points. Condensate production stops for a while because dry gas from the four lower reservoir cross flows into the upper reservoirs.

Figure 5.41 plots the pressures of all layers. When the deeper four dry gas reservoirs are perforated, gas from these lower reservoirs having higher pressure pushes gas from the upper ones, which have a decline in pressure, back into the reservoirs. Cross flow effect finishes when pressures at upper section get into hydrostatic equilibrium with the pressures at lower section. After cross flow effect finishes, oil rate increases again as the fluids from the upper four layers gradually flow into the well bore again.

In general, lower condensate production is gained at the earlier time and production time is prolonged when the maximum gas production is reduced. It means that the plateau rate affects condensate in term of production time and earlier condensate production volume.

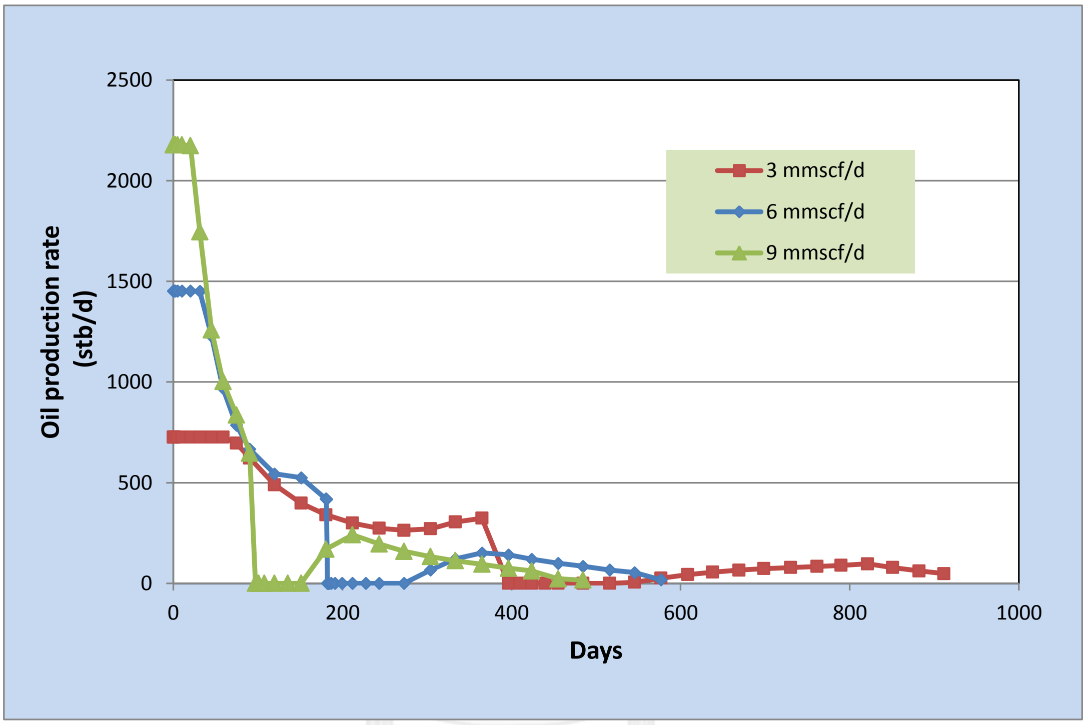


Figure 5.40 Field oil production for different plateau rates in top down without plug when the timing of perforating the second batch is option 1

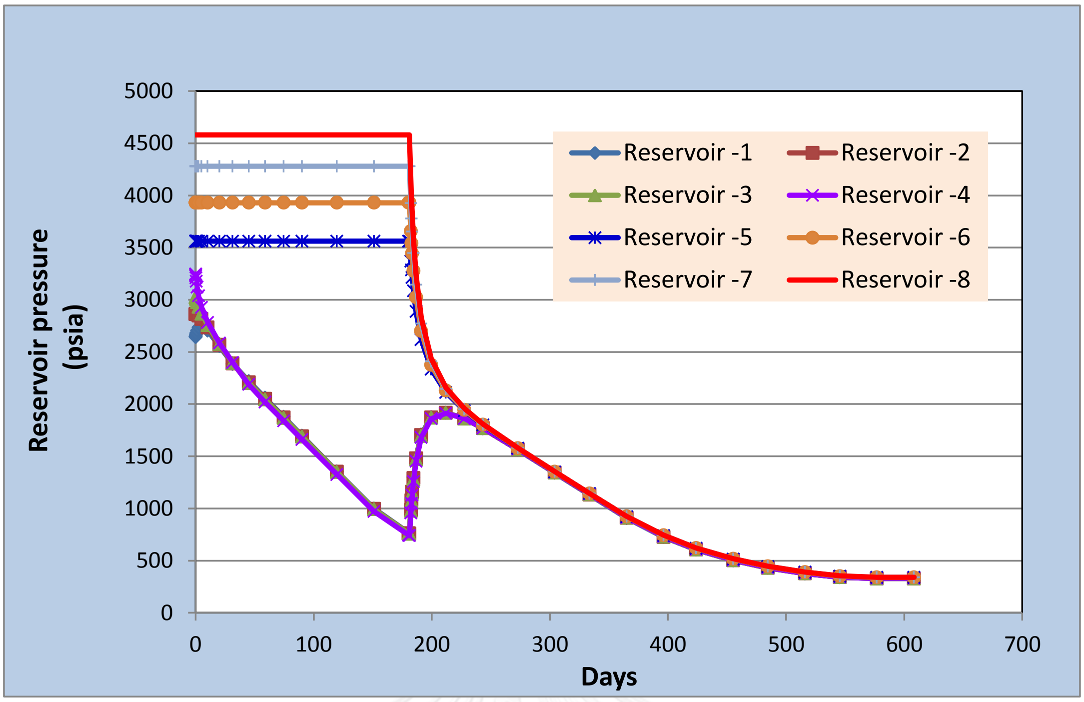


Figure 5.41 Reservoir pressure in top down without plug strategy when the timing of perforating the second batch is option 1

In term of the ultimate recovery of gas, the results indicate that gas flow rate does not affect the ultimate recovery of dry gas because all pay layers contribute to the production as a whole. In other words, the recovery factor of gas is independent on maximum flow rate as shown in Table 5.7 and Figure 5.44.

For condensate, too high gas rate results in lower ultimate condensate recovery. It is observed that very high gas rate induces more cross flow during the second batch of perforation due to lower bottom hole pressure. The higher gas flow rate results in a greater shift of the phase diagram to the right when dry gas mixes gas condensate and hence higher liquid drop-out into the reservoir at the abandonment pressure as illustrated in Figure 5.42. However, the amount of reduction in condensate recovery with higher gas production rate becomes less and less when perforation timings are delayed from Option 1 to Option 3. As explained in Section 5.3.1, the bottom hole flowing pressures by the time to perforate the second batch in option 3 are almost the same, leading to the similar liquid drop-out in the reservoir for various plateau rates as shown in Figure 5.43. Overall, recovery factor of condensate reduces when gas production rate is very high as shown in Table 5.7 and Figure 5.45.

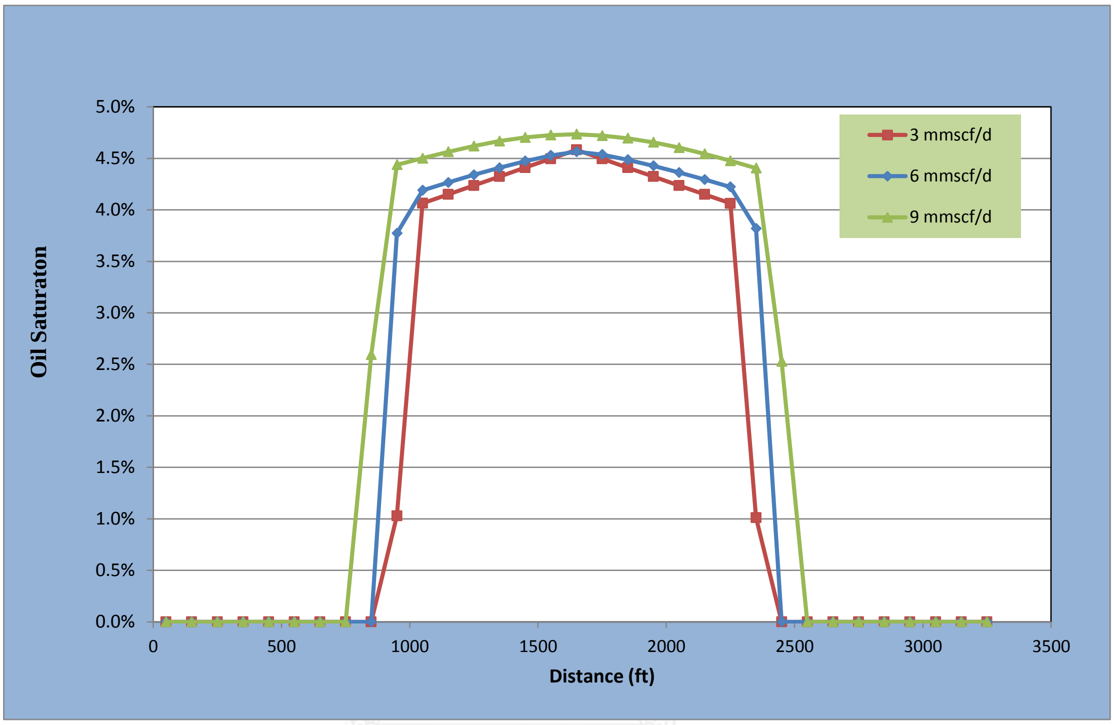


Figure 5. 42 Condensate saturation of layer 1 at the end of production time for different plateau rates in top down without plug when the timing of perforating the second batch is option 1

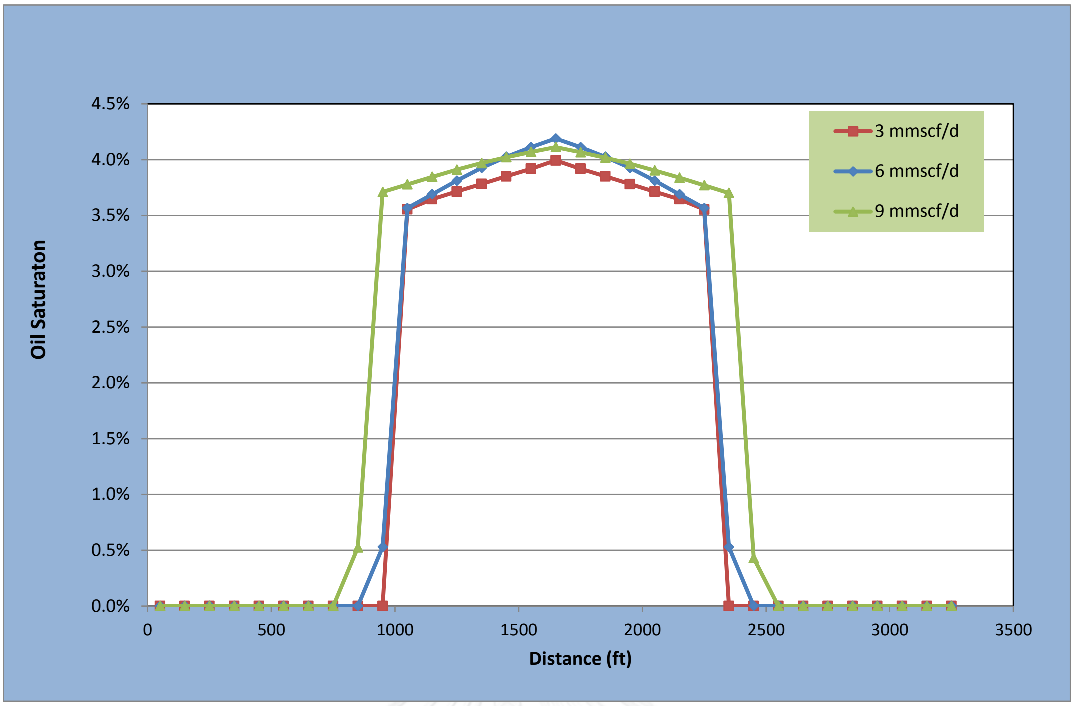


Figure 5. 43 Condensate saturation of layer 1 at the end of production time for different plateau rates in top down without plug when the timing of perforating the second batch is option 3

Table 5. 7 Comparisons of different plateau rates in top down without plug strategy

Perforation Timing	Plataeu rate (MMscf/d)	Production time (days)	Cumulative gas production (bscf)	Cumulative oil production (Mstb)	Gas RF (%)	Condensate RF (%)	MBOE (Mstb)
Less than plateau (option 1)	3	912	5.2	178.4	92	55	1045
	6	577	5.2	171.6	92	53	1041
	9	485	5.2	157.0	92	48	1028
Less than 1/2 plataeu (option 2)	3	943	5.2	188.5	92	58	1056
	6	598	5.2	178.8	92	55	1053
	9	455	5.2	169.5	91	52	1034
Less than economic rate (option 3)	3	1035	5.25	193.3	93	59	1068
	6	727	5.24	192.0	92	59	1065
	9	577	5.21	186.2	92	57	1055

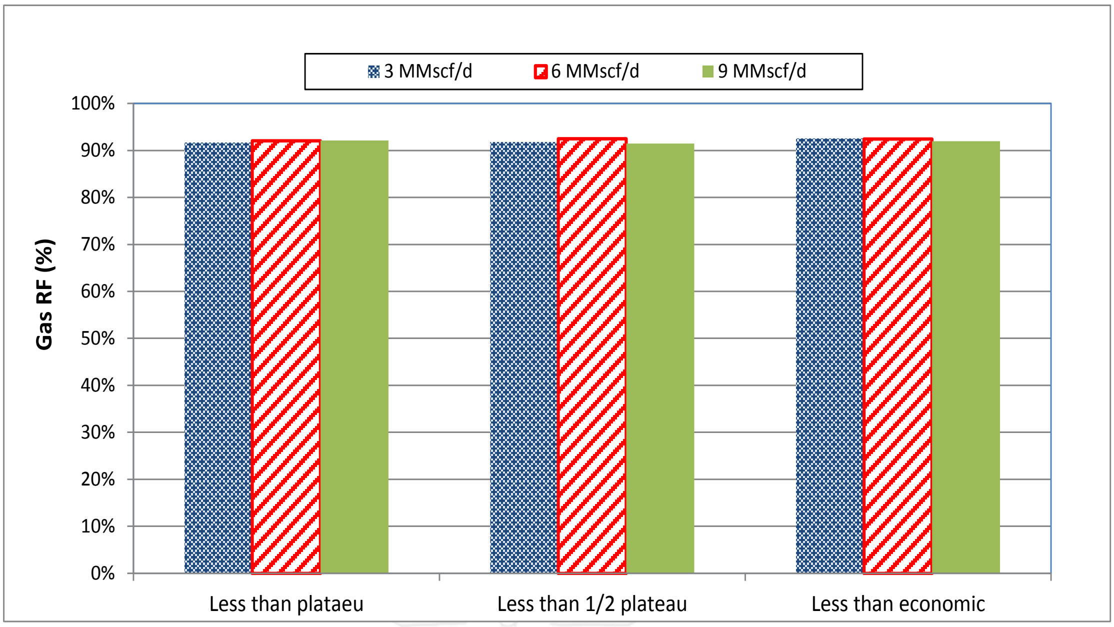


Figure 5.44 Gas recovery factor for different plateau rates in top down without plug strategy

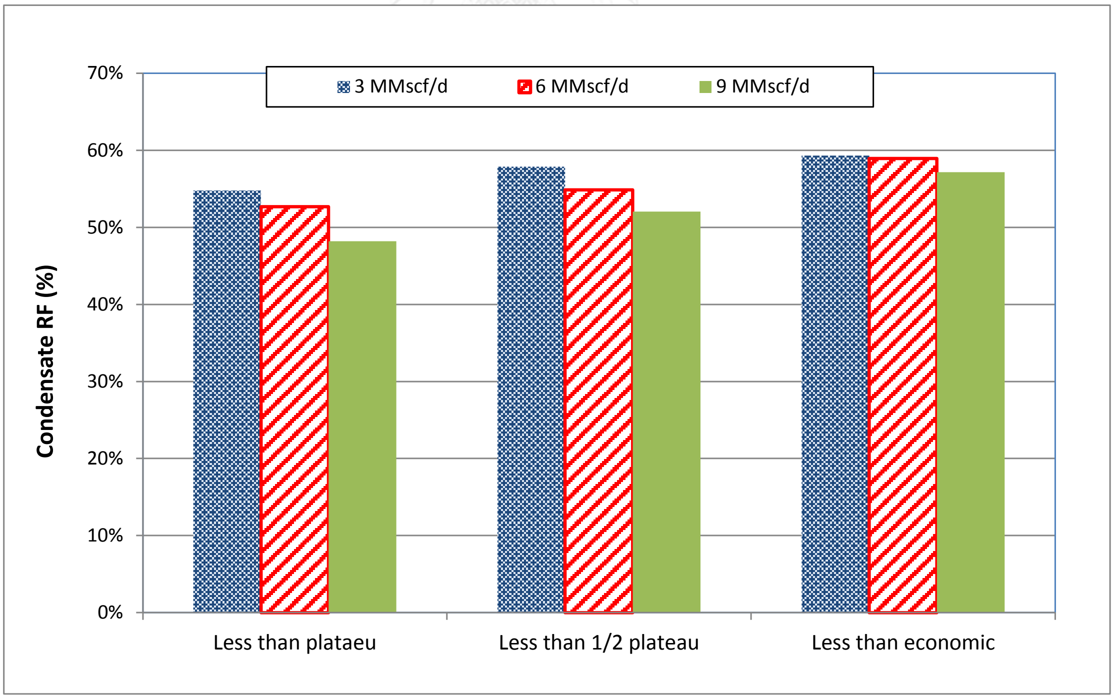


Figure 5. 45 Condensate recovery factor for different plateau rates in top down without plug strategy

5.4.2 Effects of perforation timing

Figure 5.46 illustrates the performance of gas production rate for different perforation timings when the maximum gas rate is 6 MMscf/d. The results indicate that at the same plateau rate, the sooner the time to perforate the second batch, the shorter the production time. The gas plateau is divided into two periods. In the first plateau period, gas is produced together with condensate at the surface from the upper four reservoirs. In the second period, the four lower gas layers are added to bring gas production back to plateau rate before declining rapidly toward the end of well life.

In general, the duration of two plateau periods and the decline tendency are the same in all cases. The gas rate production curve is shifted to the right side when the perforation timing of the second batch is delayed.

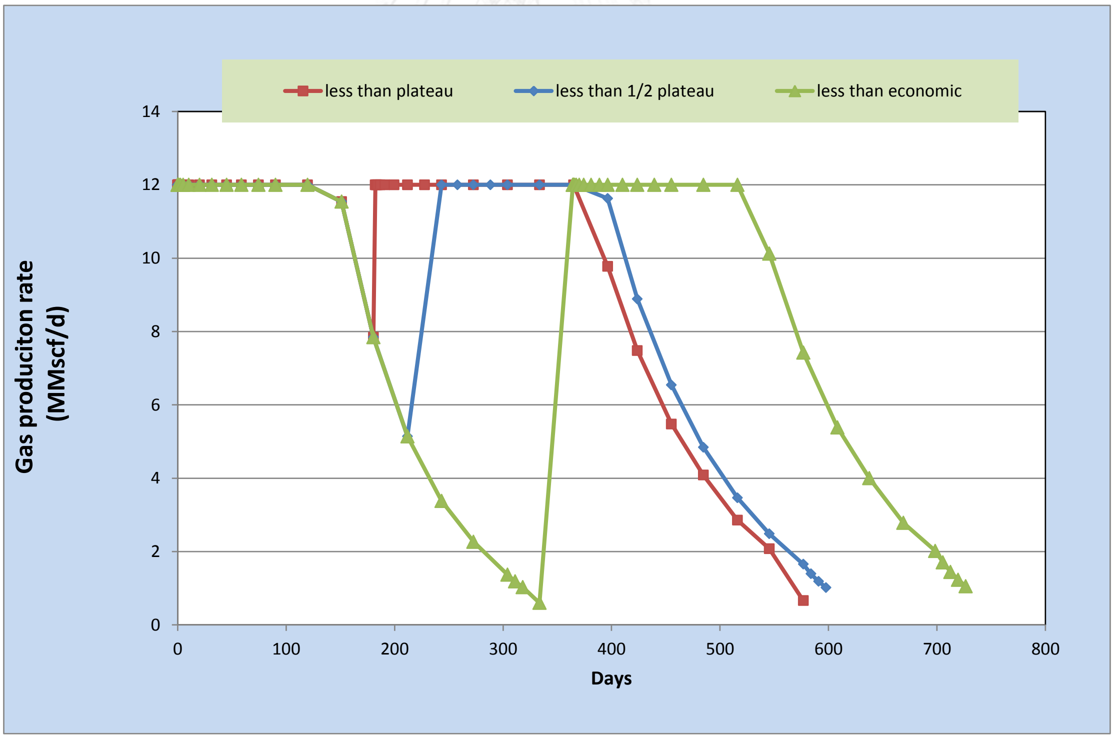


Figure 5. 46 Field gas production rate for different perforation timings in top down without plug strategy when the maximum gad rate is 6 MMscf/d

Figure 5.47 shows the production performance of condensate rate for different perforation timings when the maximum gas rate is 6 MMscf/d. Condensate is produced from the beginning and can reach to the plateau rate for a while before liquid starts to drop out from the gas phase since pressures decline below the dew points. As mentioned earlier, soon after the deeper four dry gas reservoirs are perforated, gas from these lower reservoirs having higher pressures pushes gas from the upper ones, which have a decline in pressure, back into the reservoirs due to cross flow effect. When pressures in upper reservoirs get into hydrostatic equilibrium with those of the lower reservoirs and hence cross flow effect finishes, oil flow rate increases again as the fluid from the lower four layers flows back into the wellbore. This reason makes condensate performance improve before declining toward the end of well life.

In general, the behavior of condensate production is the same for various perforation timings before the second batch is perforated. The tail of oil rate production curve is just shifted to the right side when perforation timing of the second batch is delayed.

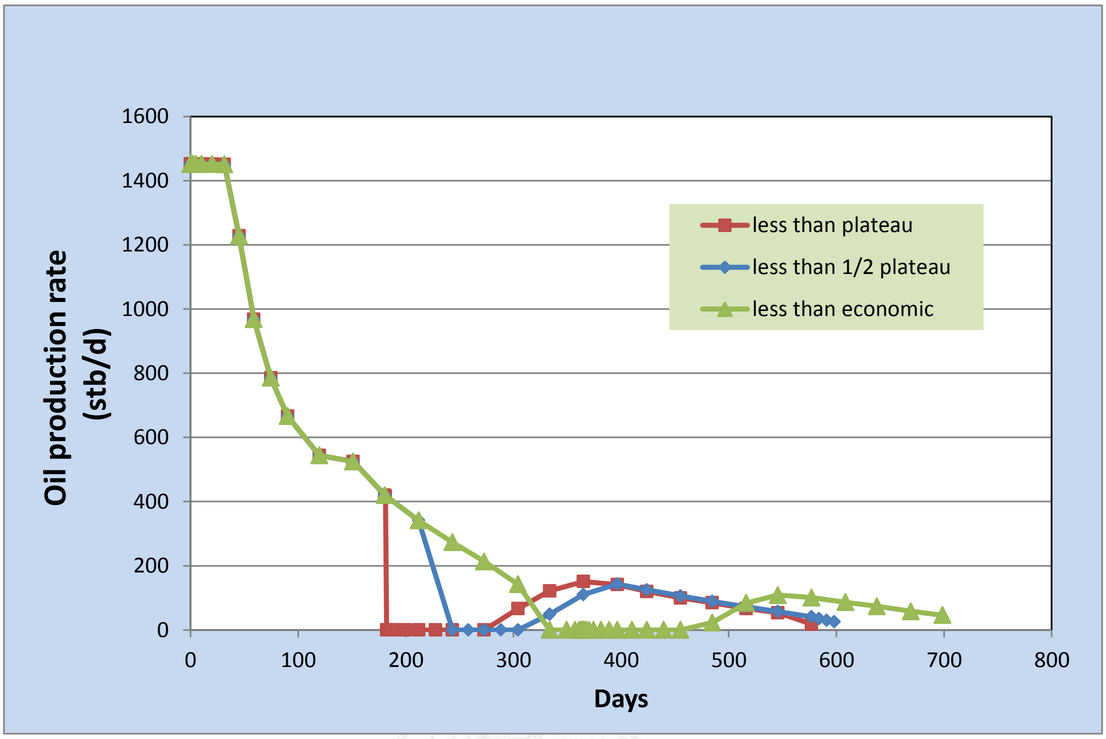


Figure 5. 47 Field oil production rate for different perforation timings in top down without plug strategy when the maximum gad rate is 6 MMscf/d

In term of gas recovery factor, the ultimate recovery of gas does not depend on the perforation timing of the second batch because gas is extracted from all reservoirs until economical limitation. The gas recovery factor of total field is around 92% as described in Table 5.8 and in Figure 5.48.

For condensate, it is shown that at specific gas plateau rate, the sooner to perforate the second batch, the lower the ultimate recovery of condensate because the upper section is not fully depleted before the lower section is added to well stream causing gas from upper layers to cross flowing into the lower layers. As a result, oil recovery factor is increased 4% to 9 % when the timing of the second batch is delayed from less than the plateau rate (Option 1) to less than the economic rate (Option 3) of perforation as shown in Table 5.8 and Figure 5.49.

Table 5. 8 Comparison of different perforation timings in top down without plug strategy

Plataeu rate (MMscf/d)	Perforation Timing	Production time (days)	Cumulative gas production (bscf)	Cumulative oil production (Mstb)	Gas RF (%)	Condensate RF (%)	MBOE (Mstb)
3	Less than plataeu	912	5.2	178.4	92	55	1045
	Less than 1/2 plateau	943	5.2	188.5	92	58	1056
	Less than economic	1035	5.2	193.3	93	59	1068
6	Less than plataeu	577	5.2	171.6	92	53	1041
	Less than 1/2 plateau	598	5.2	178.8	92	55	1053
	Less than economic	727	5.2	192.0	92	59	1065
9	Less than plataeu	485	5.2	157.0	92	48	1028
	Less than 1/2 plateau	455	5.2	169.5	91	52	1034
	Less than economic	577	5.2	186.2	92	57	1055

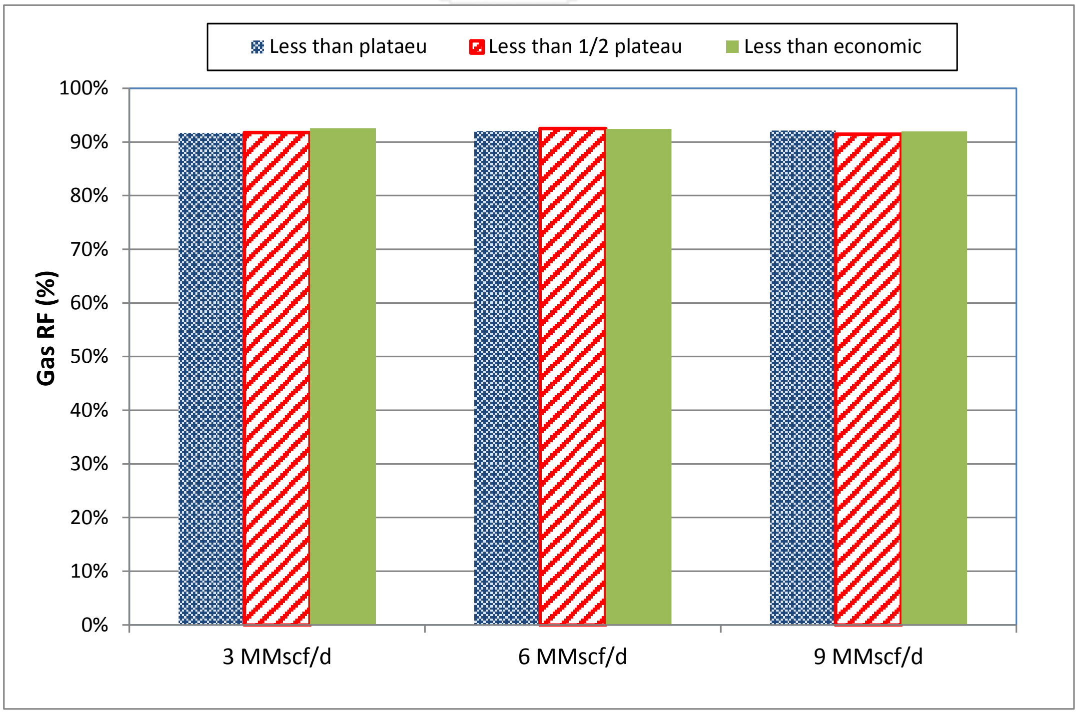


Figure 5.48 Gas recovery factor for different perforation timings in top down without plug

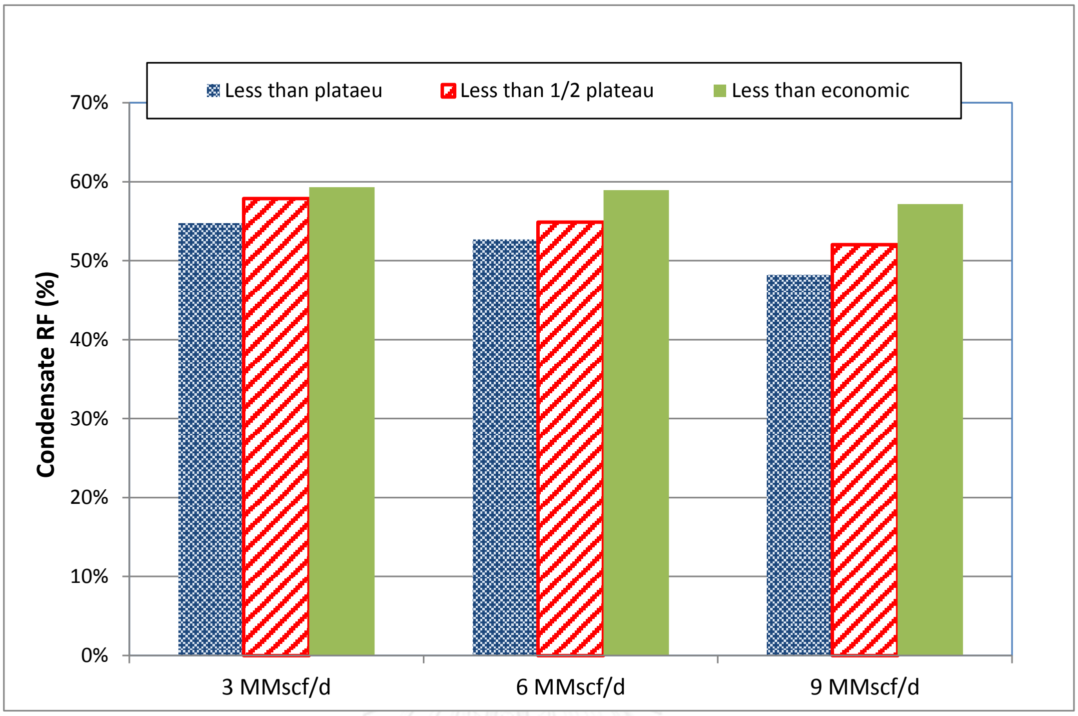


Figure 5.49 Condensate recovery factor for different perforation timings in top down without plug strategy

5.5 Gas dumpflood

In gas dumpflood, all the condensate layers are perforated in the first batch. When the gas production rate drops below a certain value, one of the production wells is shut in for 30 days in order to perforate some or all dry-gas layers in order to dump gas into the upper gas-condensate reservoirs while the other production well is still producing.

In order to optimize condensate recovery in the case of gas dumpflood, some operating conditions such as plateau rate, time of dumpflood and perforation option are explored. There are 48 simulation cases in total in this production strategy as shown in Figure 5.50. The results of such investigations are discussed in this section.

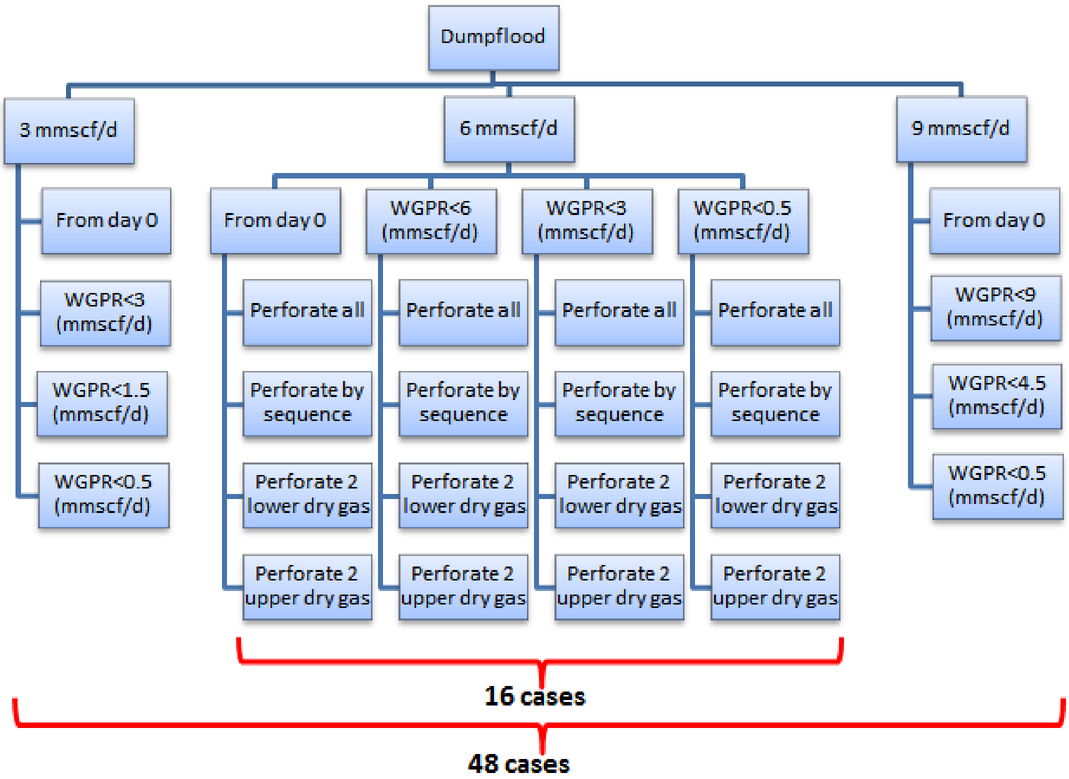


Figure 5.50 Flow chart of gas dumpflood strategy

5.5.1 Effects of plateau rate

The plateau rate is varied by 3, 6 and 9 MMscf/d to see the effects of maximum production rate on production performance of dumpflood.

Figure 5.51 illustrates field gas production rate for different plateau rates. At the beginning, gas is produced from two producers and maintained at a plateau rate for a while before decreasing steeply due to a fast decline in reservoir pressures. When well gas production drops to a certain level, the dumpflood is triggered. At that time, gas rate increases possibly up to the plateau rate due to gas cross flowing from the lower layers before declining. Such an increase in gas rate may happen once or twice time depending on the selected perforation strategy, i.e four lower dry gas layers are split or combined to perforate.

In general, the higher the production rate, the shorter the production time and the shorter the plateau period at the same timing of dumpflood and same perforation strategy. The gas production is delayed when the plateau rates is smaller.

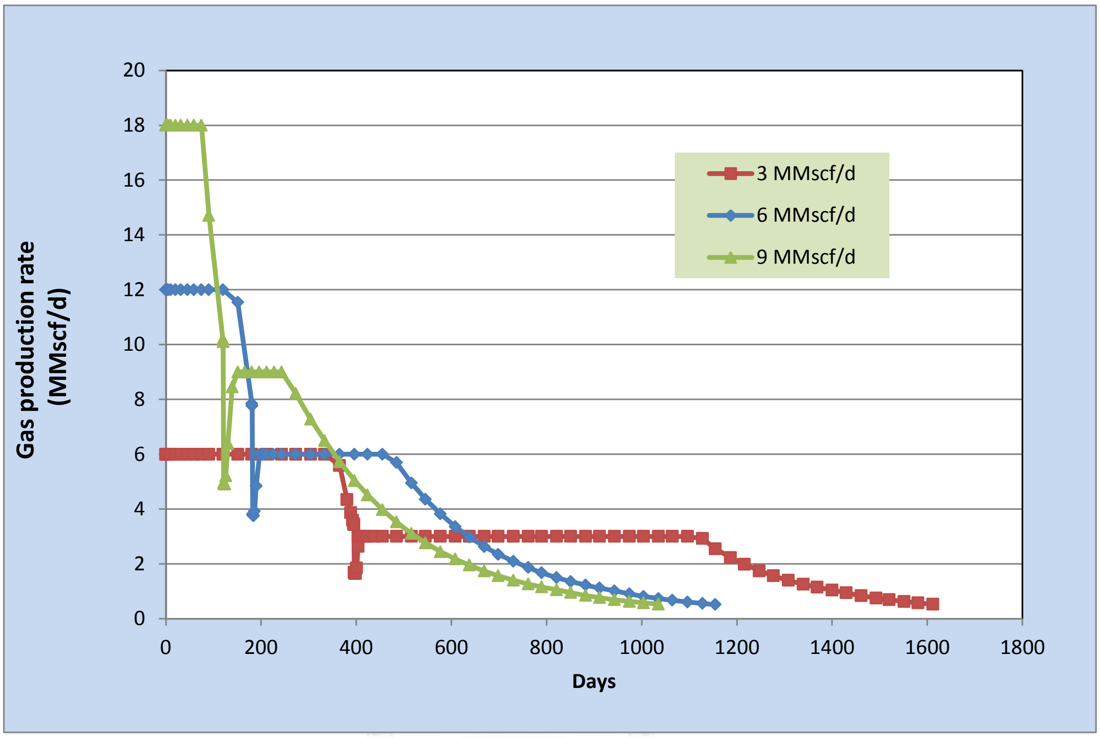


Figure 5.51 Field gas production rate for different plateau rates in dumpflood strategy and dumpflood is started when the well gas production rate is below the plateau rate

Figure 5.52 illustrates field oil production rate for different plateau rates. Condensate is produced from both producers from the first day. During the initial plateau production period, liquid starts to drop out from the gas phase since pressures decline below the dew points, starting from wellbore and expanding to the entire reservoirs with time. When the gas dumpflood is started, pressures in condensate layers increase due to the cross flow effect resulting in less liquid dropped-out in the reservoirs. As a result, oil production increases as a “hump” in the plot before decreasing. Such a “hump” may be observed again if other deeper gas layers are additionally perforated. In general, the plateau gas rate affects condensate production in term of production time and early condensate production rate. The condensate production is delayed when the gas plateau rate is smaller.

Figure 5.53 shows the pressure of all layers. Whenever the deeper dry gas reservoirs are perforated, gas from these lower reservoirs having higher pressures flows into the upper ones and increases the reservoir pressures of upper layers. Depending on the perforation strategy, the “hump” in pressure caused by cross flow can be observed once or twice.

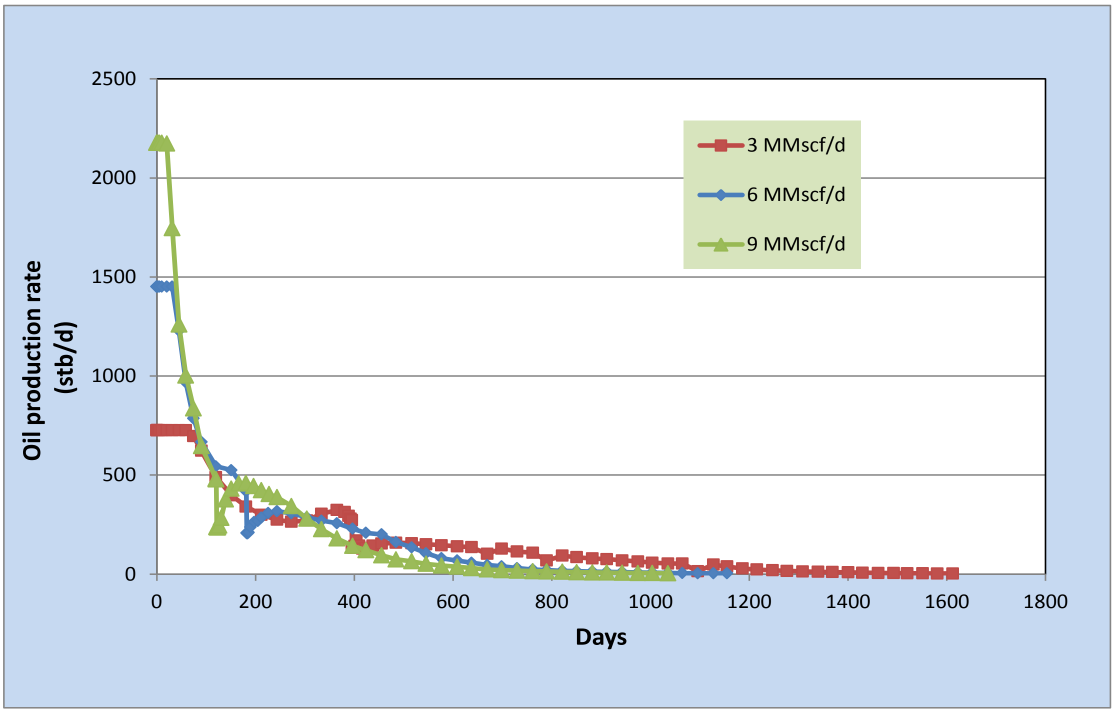


Figure 5.52 Field oil production rate for different plateau rates in dumpflood strategy and dumpflood is started when the well gas production rate is below the plataeu rate

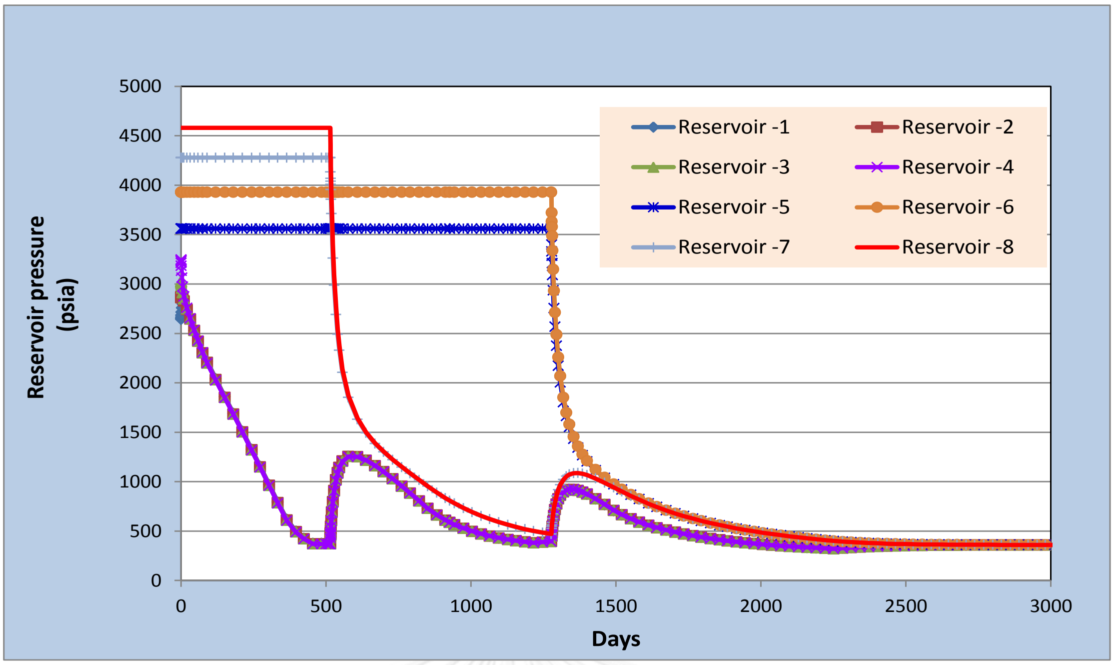


Figure 5.53 Reservoir pressure in dumpflood when the maximum gas rate is 3 MMscf/d and dumpflood is started when the well gas production rate is below the economic rate

In term of gas recovery factor, the results indicate that the maximum flow rate has no effect on ultimate recovery of gas because production is the summation of gas produced by all layers until the economic rate. In all cases, the recovery factors of gas are around 90% as shown in Table 5.9 and plotted in Figure 5.55.

For condensate, higher gas rate results in slightly lower condensate ultimate recovery. As explained earlier, the higher the gas rate results in a greater shift of the phase diagram to the right and hence more condensate is being left into the reservoir at the abandonment pressure as illustrated in Figure 5.54. In general, recovery factor of condensate reduces with higher gas production rate at the same perforation strategy. However, the amount of reduction become less and less when the dumpflood timing is delayed as shown in Table 5.9 and Figure 5.56.

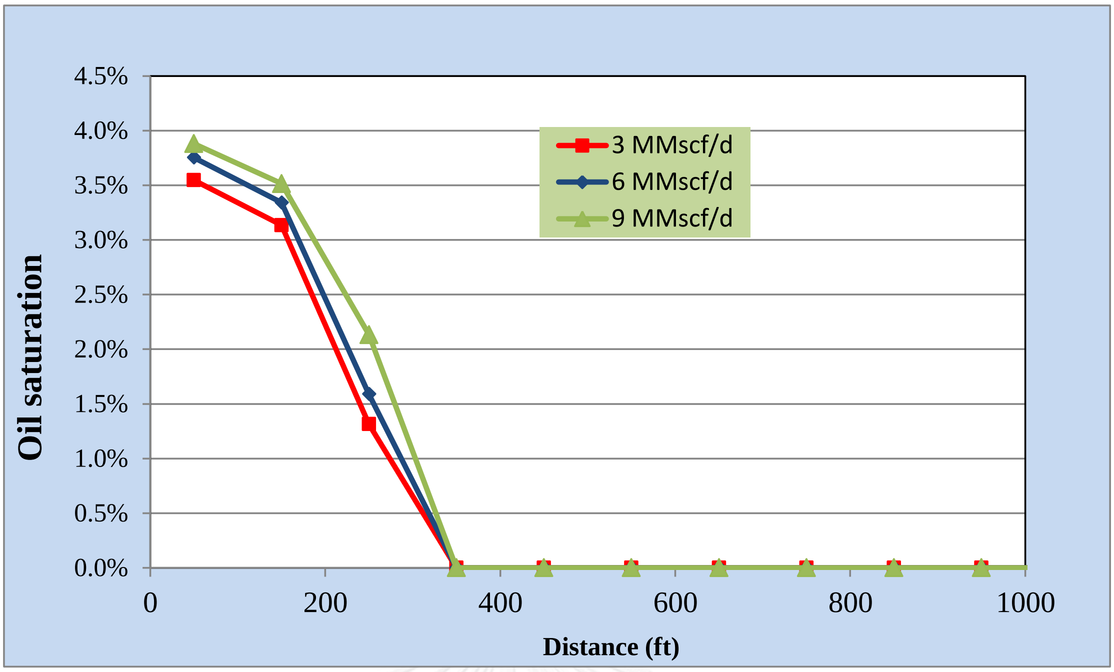


Figure 5. 54 Condensate saturation of layer 1 at one of the producers at the end of production in dumpflood strategy and dumpflood is started when the well gas production rate is below the plateau rate

Table 5.9 Comparison of different plateau rates in gas dumpflood strategy

Dumping time	Perforation	Plataeu rate (MMscf/d)	Production time (days)	Cumulative gas production (bscf)	Cumulative oil production (Mstb)	Gas RF (%)	Condensate RF (%)	MBOE (Mstb)
From the beginning	Perforate all	3	2069	5.1	270	91	83	1125
		6	1369	5.1	267	90	82	1121
		9	1155	5.1	265	90	81	1118
	sequence	3	2282	5.1	262	90	80	1114
		6	1734	5.1	261	90	80	1113
		9	1612	5.1	257	90	79	1111
	perf 2 lower gas layers	3	2130	5.2	261	91	80	1124
		6	1461	5.2	259	91	80	1121
		9	1308	5.2	256	91	78	1118
	perf 2 upper gas layers	3	2127	5.2	257	91	79	1118
		6	1472	5.16	252	91	77	1112
		9	1317	5.2	252	91	77	1112
Less than plataeu	Perforate all	3	1612	5.1	242	90	74	1089
		6	1155	5.1	241	90	74	1089
		9	1035	5.1	238	90	73	1086
	sequence	3	1946	5.1	248	90	76	1100
		6	1581	5.1	244	90	75	1095
		9	1520	5.1	243	90	75	1091
	perf 2 lower gas layers	3	1765	5.2	239	91	73	1102
		6	1317	5.2	230	91	71	1092
		9	1230	5.2	231	91	71	1092
	perf 2 upper gas layers	3	1765	5.2	238	91	73	1100
		6	1317	5.2	233	91	72	1093
		9	1225	5.2	229	91	70	1089
Less than 1/2 plataeu	Perforate all	3	1673	5.10	244	90	75	1094
		6	1155	5.07	241	90	74	1087
		9	1065	5.09	238	90	73	1086
	sequence	3	1977	5.12	250	90	77	1103
		6	1613	5.11	248	90	76	1100
		9	1581	5.11	246	90	76	1098
	perf 2 lower gas layers	3	1795	5.17	243	91	75	1105
		6	1348	5.17	240	91	74	1101
		9	1256	5.16	236	91	72	1096
	perf 2 upper gas layers	3	1795	5.17	243	91	74	1104
		6	1348	5.16	239	91	73	1099
		9	1256	5.16	235	91	72	1095
Less than economic rate	Perforate all	3	1734	5.10	244	90	75	1094
		6	1308	5.10	247	90	76	1096
		9	1186	5.09	245	90	75	1092
	sequence	3	2038	5.12	250	90	77	1103
		6	1734	5.11	252	90	77	1103
		9	1673	5.11	250	90	77	1101
	perf 2 lower gas layers	3	1857	5.17	243	91	75	1105
		6	1435	5.16	245	91	75	1105
		9	1348	5.16	241	91	74	1101
	perf 2 upper gas layers	3	1854	5.17	242	91	74	1104
		6	1470	5.16	243	91	75	1103
		9	1379	5.16	240	91	74	1101

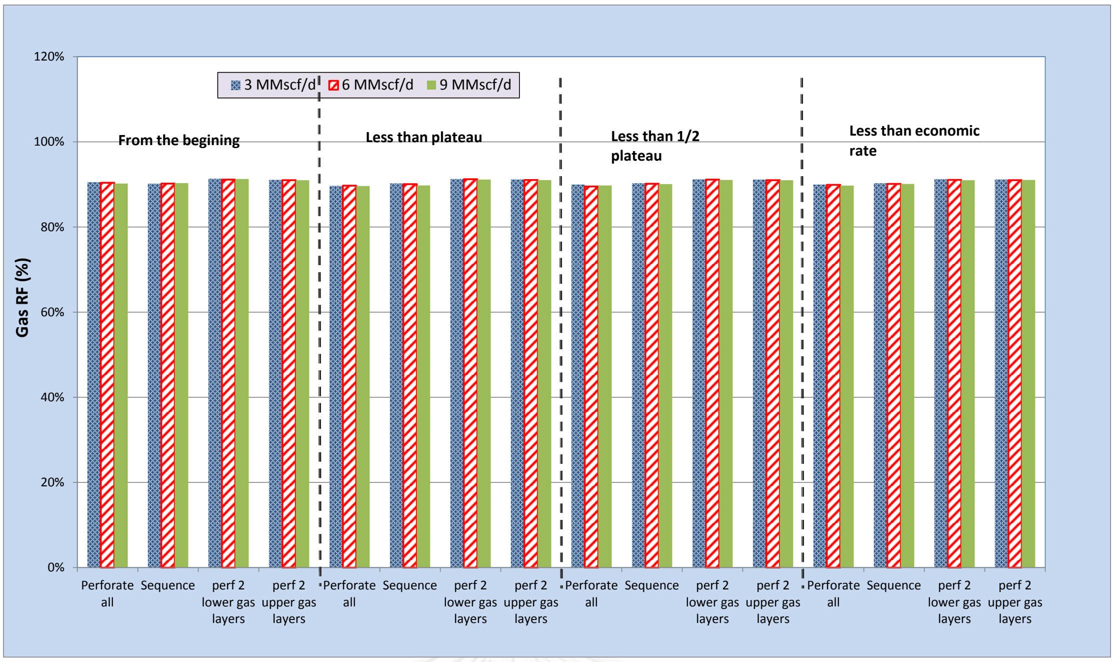


Figure 5.55 Gas recovery factor for different plateau rates in dumpflood strategy

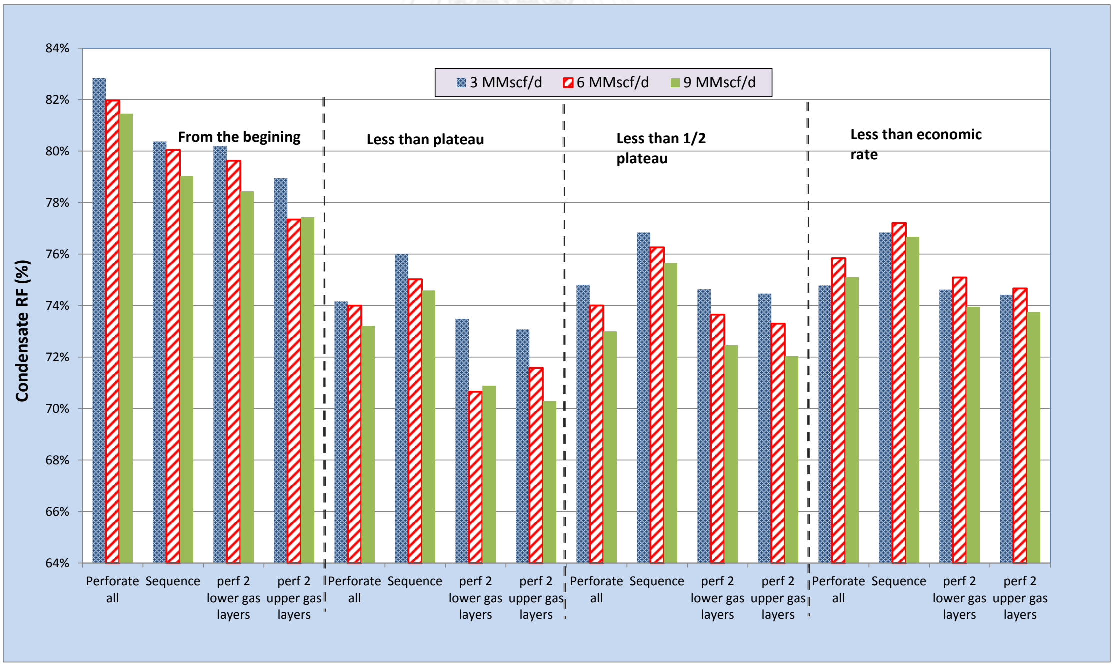


Figure 5.56 Condensate Recovery factor for different plateau rates in dumpflood strategy

5.5.2 Effects of timing of dumpflood

In general, oil is produced by two producers at the beginning until dumpflood is triggered by a certain value of well gas production except for the case that dumpflood is started at the beginning in which there is only one producer. There are four starting times to initiate gas dumpflood including:

- ✓ Option 1: From the first day of production
- ✓ Option 2: When the well gas production rate drops below the plateau rate
- ✓ Option 3: When the well gas production rate drops below half of the plateau rate
- ✓ Option 4: When the well gas production rate drops below the economic rate (0.5 MMscf/d)

Figure 5.57 compares field gas production rate for different dumpflood timings when the maximum gas rate is 9 MMscf/d. Gas is produced together with condensate from the beginning of production from the upper four reservoirs. In option 1, in which gas dumpflood is started from the beginning, the gas plateau rate is 9 MMscf/d (only one producer). This case can sustain the plateau period for the longest duration due to gas supply from dumpflooding. In options 2-4, in which gas dumpflood is started later, there are multiple plateau periods.

During the first plateau period, gas production drops quickly due to fast pressure decline. As soon as the dumpflood is triggered, gas rate increases again up to the plateau rate. In general, at the same plateau rate, the sooner the time to start dumpflood, the shorter the production time. However, in the case of dumpflood from the start-up, there is only one producer and one dumper for the whole production life making production time longer than that of the other cases.

Except for dumpflood from the beginning of production, the gas production displays the similar behavior for all timings of dumpflood. Specifically, the gas production performance is the same before dumpflood is started and the curve is shifted to the right side when dumpflood timing is delayed.

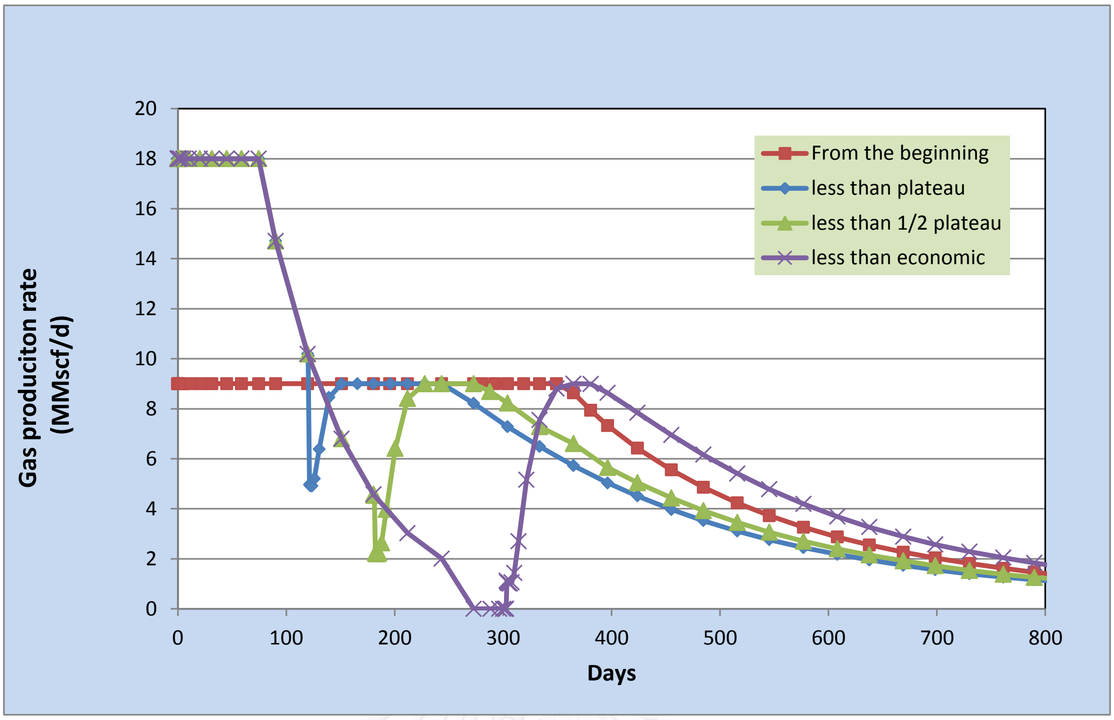


Figure 5.57 Field gas production rate for different timings in dumpflood strategy when the maximum gas rate is 9 MMscf/d and perforating all dry gas reservoirs

Figure 5.58 presents condensate production performance for different timings when the maximum gas rate is 9 MMscf/d. Condensate is produced from the beginning and can maintain a constant rate for a while before liquid starts to drop out from the gas phase since pressures decline below the dew points. As mentioned in Section 5.5.1, when dumpflood is started, high pressured gas that flows from lower dry gas sands causes reservoir pressures in upper condensate sands to increase and thus more gas containing heavier components flows from shallow condensate reservoirs to the producer. As a result, oil production increases during cross flow and declines toward the end of well life as pressure depleted.

Except for dumpflood from the beginning of production, the condensate production displays the similar behavior for all timings of dumpflood. The condensate production performance curve is just shifted to the right side when dumpflood timing is delayed.

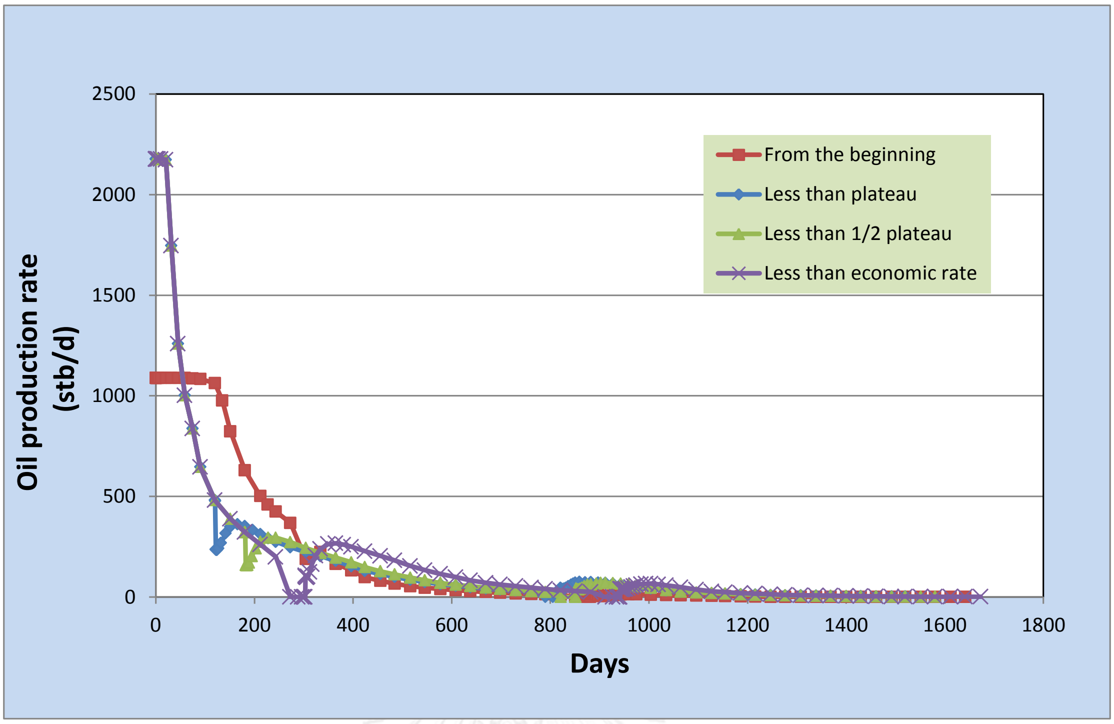


Figure 5.58 Field oil production rate for different timings in dumpflood strategy when the maximum gas rate is 9 MMscf/d and perforating all dry gas reservoirs

In term of gas recovery factor, sooner or later, gas from lower layers is recovered at the surface while sweeping the condensate during dumpflood process. Therefore, the timing of dumpflood has no effect on gas ultimate recovery because gas is extracted from all reservoirs until the economic rate. The gas recovery factors of total field are around 90% as shown in Table 5.10 and Figure 5.61.

For condensate, it is shown that at specific gas production rate, the sooner to start dumpflood, the slightly lower the ultimate recovery of condensate, except for dumpfood from the begining. It can be explained that if gas dumpflood is started at an early time when pressures of the condensate reservoirs are still high as shown in Figure 5.59, the dumped gas helps increase the condensate reservoir pressures to an unnecessary high value needed to keep everything in the gas phase. In this case, a small amount of gas is left for dumping at late times at which the condensate reservoirs are in need of dumped gas to increase their pressure. This is why dumping gas at an early time results in a slightly less condensate recovery. On the other hand, if gas dumpflood is started at a late time when the condensate reservoir pressures are low, the reservoirs are really in need of dumped gas to increase their pressures to revaporize condensate dropout. In this case, more condensate can be recovered.

However, in the case of dumpflood from the beginning, gas from the dumper helps to maintain the pressures and thus prevents the liquid to drop-out from the gas phase in the reservoir and around the near wellbores since the beginning as confirmed by oil saturation at one of the producers shown in Figure 5.60. As a result, the dumpflood from the beginning has the highest oil recovery factor compared to the other cases as shown in Table 5.10 and Figure 5.62.

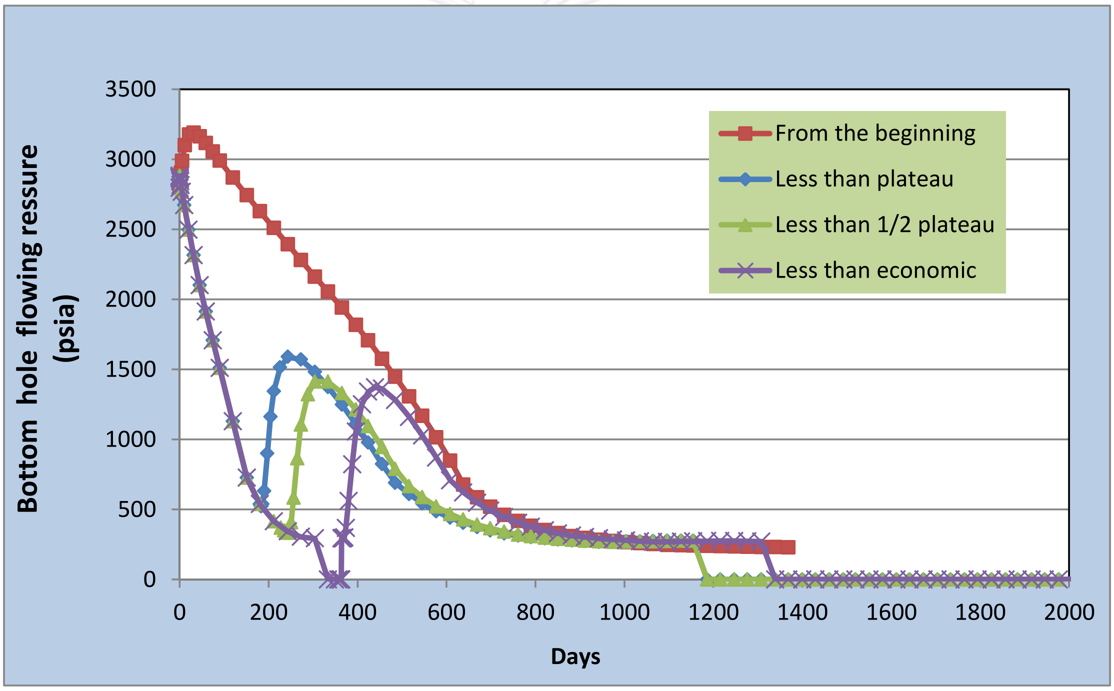


Figure 5. 59 Bottom hole flowing pressure at the producer when maximum gas production rate is 6 MMscf/d

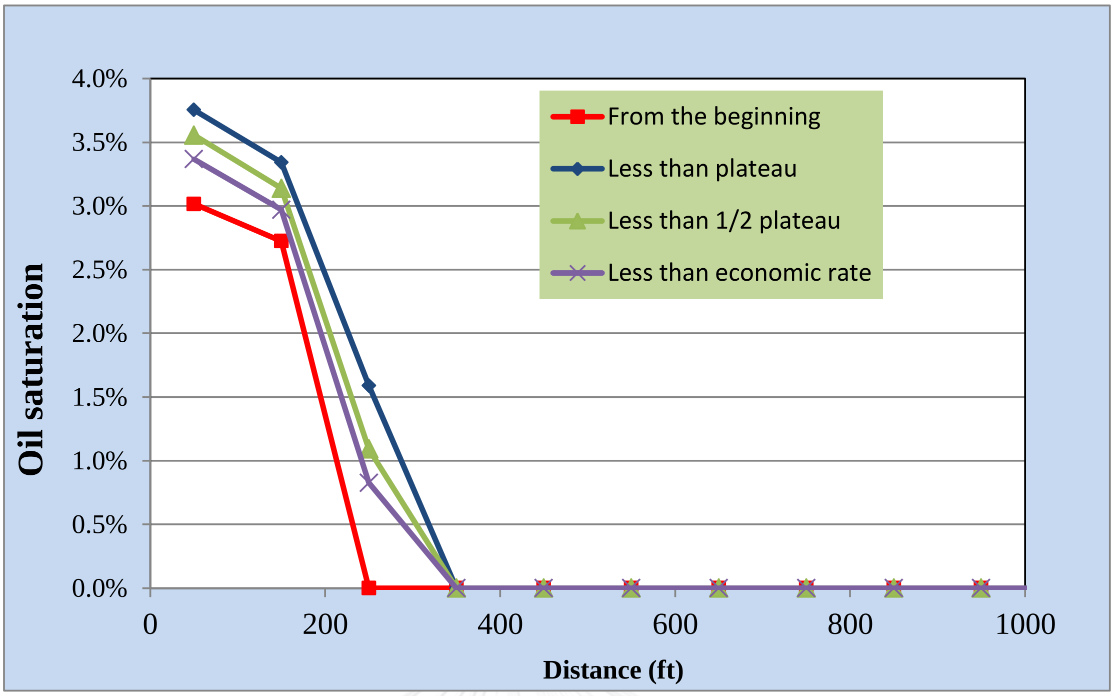


Figure 5. 60 Oil saturation of layer 1 at one of the producers at the end of production in dumpflood strategy and dumpflood is started when the maximum gas rate is 6 MMscf/d

Table 5.10 Comparison of different timings in gas dumpflood strategy

Perforation	Plataeu rate (MMscf/d)	DF Timing	Production time (days)	Cumulative gas production (bscf)	Cumulative oil production (Mstb)	Gas RF (%)	Condensate RF (%)	MBOE (Mstb)
Peforate all	3	From the beginning	2069	5.1	270	91	83	1125
		Less than plateau	1612	5.1	242	90	74	1089
		Less than 1/2 plateau	1673	5.1	244	90	75	1094
		Less than economic rate	1734	5.1	244	90	75	1094
	6	From the beginning	1369	5.1	267	90	82	1121
		Less than plateau	1155	5.1	241	90	74	1089
		Less than 1/2 plateau	1155	5.1	241	90	74	1087
		Less than economic rate	1308	5.1	247	90	76	1096
	9	From the beginning	1155	5.1	265	90	81	1118
		Less than plateau	1035	5.1	238	90	73	1086
		Less than 1/2 plateau	1065	5.1	238	90	73	1086
		Less than economic rate	1186	5.1	245	90	75	1092
Sequence	3	From the beginning	2282	5.1	262	90	80	1114
		Less than plateau	1946	5.1	248	90	76	1100
		Less than 1/2 plateau	1977	5.1	250	90	77	1103
		Less than economic rate	2038	5.1	250	90	77	1103
	6	From the beginning	1734	5.1	261	90	80	1113
		Less than plateau	1581	5.1	244	90	75	1095
		Less than 1/2 plateau	1613	5.1	248	90	76	1100
		Less than economic rate	1734	5.1	252	90	77	1103
	9	From the beginning	1612	5.1	257	90	79	1111
		Less than plateau	1520	5.1	243	90	75	1091
		Less than 1/2 plateau	1581	5.1	246	90	76	1098
		Less than economic rate	1673	5.1	250	90	77	1101
perf 2 lower gas layers	3	From the beginning	2130	5.2	261	91	80	1124
		Less than plateau	1765	5.2	239	91	73	1102
		Less than 1/2 plateau	1795	5.2	243	91	75	1105
		Less than economic rate	1857	5.2	243	91	75	1105
	6	From the beginning	1461	5.2	259	91	80	1121
		Less than plateau	1317	5.2	230	91	71	1092
		Less than 1/2 plateau	1348	5.2	240	91	74	1101
		Less than economic rate	1435	5.2	245	91	75	1105
	9	From the beginning	1308	5.2	256	91	78	1118
		Less than plateau	1230	5.2	231	91	71	1092
		Less than 1/2 plateau	1256	5.2	236	91	72	1096
		Less than economic rate	1348	5.2	241	91	74	1101
perf 2 upper gas layers	3	From the beginning	2127	5.2	257	91	79	1118
		Less than plateau	1765	5.2	238	91	73	1100
		Less than 1/2 plateau	1795	5.2	243	91	74	1104
		Less than economic rate	1854	5.2	242	91	74	1104
	6	From the beginning	1472	5.2	252	91	77	1112
		Less than plateau	1317	5.2	233	91	72	1093
		Less than 1/2 plateau	1348	5.2	239	91	73	1099
		Less than economic rate	1470	5.2	243	91	75	1103
	9	From the beginning	1317	5.2	252	91	77	1112
		Less than plateau	1225	5.2	229	91	70	1089
		Less than 1/2 plateau	1256	5.2	235	91	72	1095
		Less than economic rate	1379	5.2	240	91	74	1101

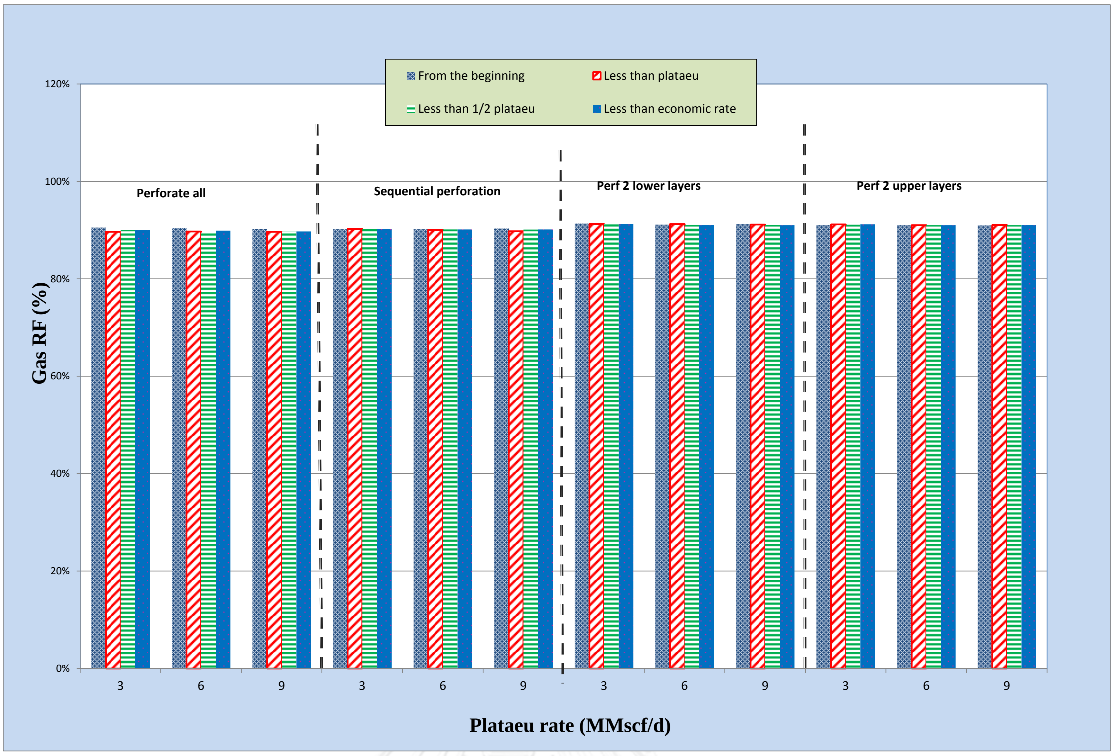


Figure 5.61 Gas recovery factor for different timings in gas dumpflood strategy

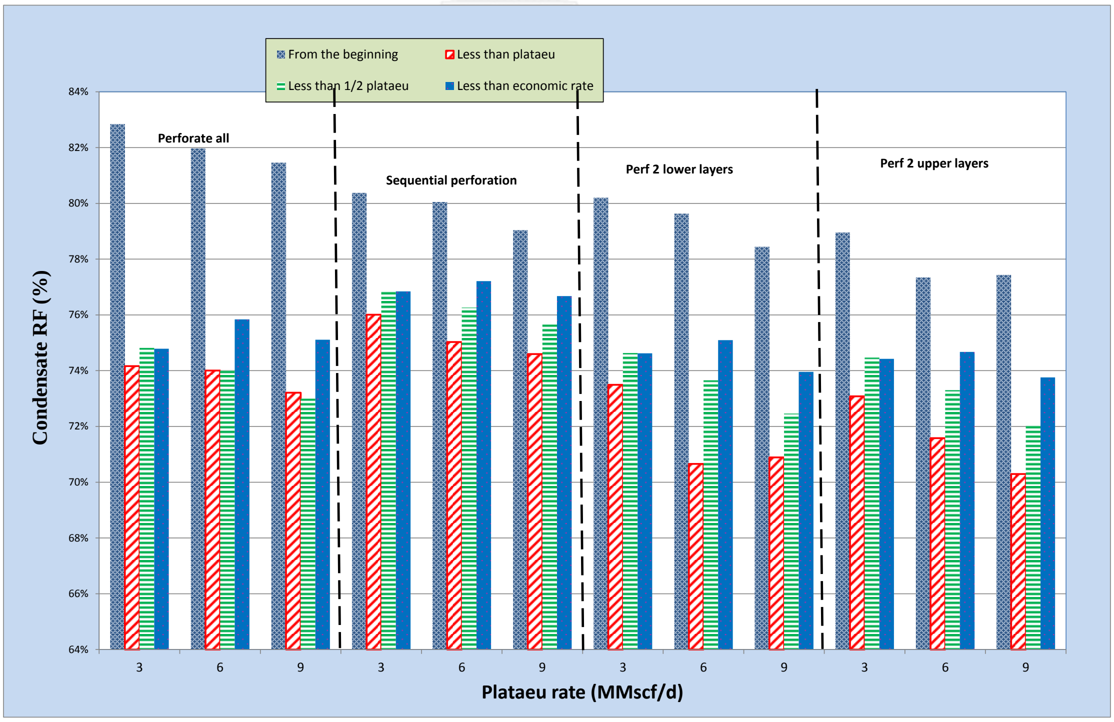


Figure 5.62 Condensate recovery factor for different timings in gas dumpflood strategy

5.5.3 Effects of perforation strategy

Well completion strategy is an important consideration in order to optimize condensate recovery via dumpflood. Various different completion philosophies are proposed as follows:

- ✓ Option 1: Perforate all four dry gas reservoirs at the same time at the dumping well
- ✓ Option 2: Sequential perforation. It means that at first, the bottom two among four dry gas layers are perforated at the dumping well when the dumping criteria is reached. After gas production rate of the producer is below the economic limit of 0.5 MMscf/d, the remaining two shallower layers are perforated at the dumper.
- ✓ Option 3: perforate only two deeper gas reservoirs. It means that only the bottom two among four dry gas layers are perforated at the dumping well when the dumping criteria is reached. After gas production rate of the producer is below the economic limit of 0.5 MMscf/d, all the perforated sands in the dumper including condensate sands in the upper section are patched so that production is continued by the top two remaining dry gas layers perforated at the producer.
- ✓ Option 4: perforate only two shallower gas reservoirs. It means that only the top two among four dry gas layers are perforated in the dumper well when the dumping criteria is reached. After gas production rate of the producer is below the economic limit of 0.5 MMscf/d, all the perforated sands in the dumper including condensate sands in the upper section are patched so that production is continued by the bottom two remaining dry gas layers perforated at the producer.

In general, at the same plateau rate, dumping gas from either two upper or lower layers of dry gas reservoirs delivers the same, higher production time than perforating all dry gas sands. However, sequential peroration gives the highest production time among four perforation strategies. It is because in sequential perforation, every two dry gas layers are added when gas production rate of the producer is less than 0.5 MMscf/d, causing the production time to be topped up.

Figure 5.63 compares the gas production rate for different perforation strategies. At first, gas is produced by two wells together with condensate from the beginning from the upper four reservoirs. During the first plateau period, gas rate declines due to pressure depletion. At the specific time, gas from the lower reservoirs is perforated to dump into the shallower condensate reservoirs and from this point, the difference in production performance for various perforation options is observed. Option 1 gives the longest plateau duration while the other options have two plateau periods leading to unsmooth and uncontinuous production before declining to the economic level. In general, the perforation strategy affects not only the production time but also the plateau durations and the total cumulative gas production accordingly.

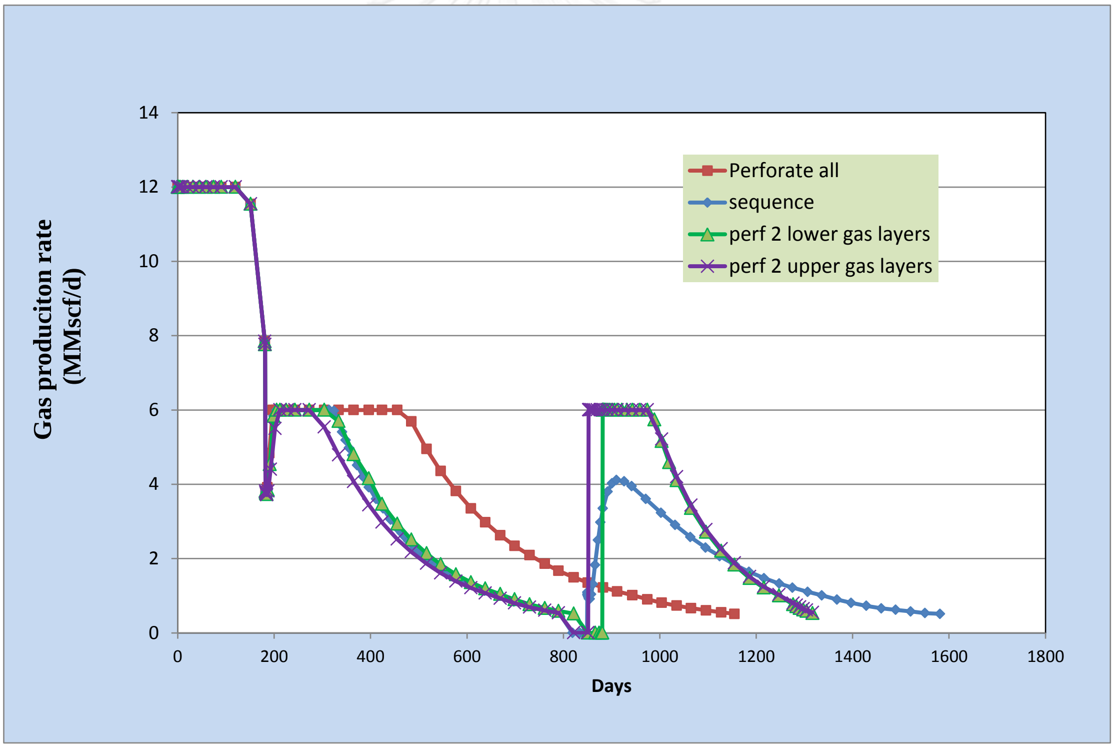


Figure 5.63 Field gas production rate for different perforation strategies in dumpflood cases when the maximum gas production is 6 MMscf/d and dumpflood is started when the well gas production rate is below the plateau rate

Figure 5.64 compares the oil production rate for different perforation strategies. Note that the perforation of each batch is done when the gas production rate of the producer is below the economic limit of 0.5 MMscf/d. The same condensate performance is observed until dumpflood is triggered. From this point onwards, the undulation performance of condensate production is observed for various perforation options. Almost the same response in term of production time, production tendency and cumulative production is noted in options 3 and 4. However, option 2 provides more time in production compared to the other options.

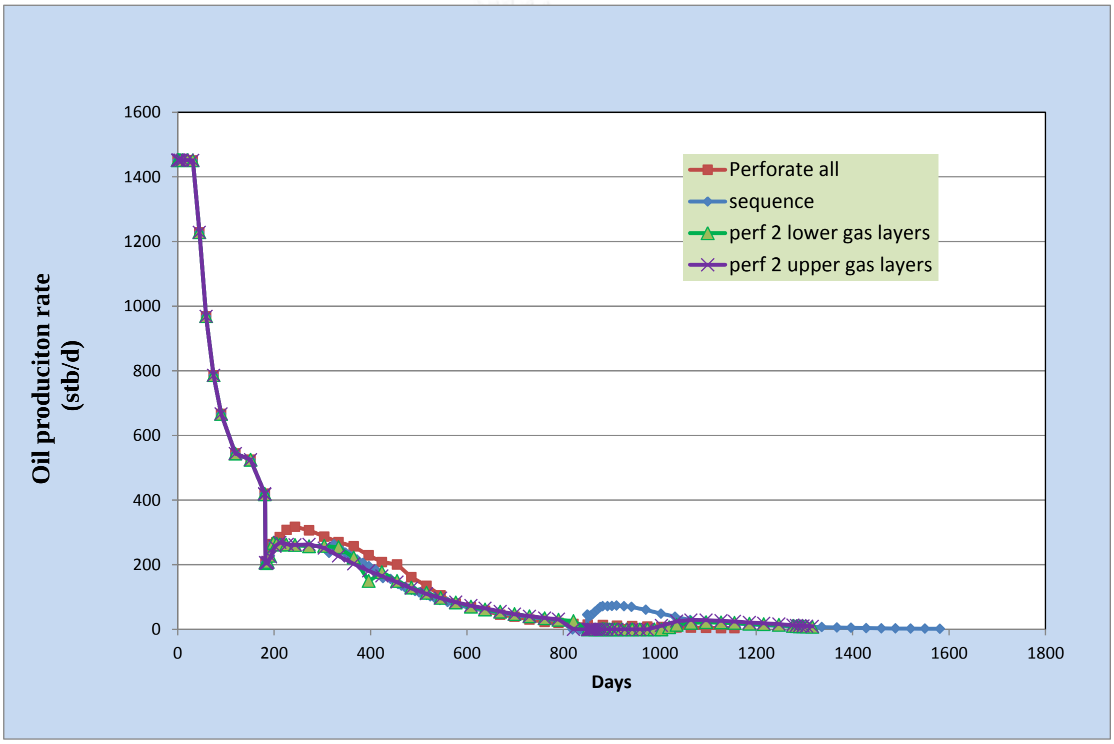


Figure 5.64 Condensate production rate for different perforation strategies in dumpflood cases when the maximum gas production is 6 MMscf/d and dumpflood is started when the well gas production rate is below the plateau rate

As the reservoirs are homogeneous, gas from the remaining layers is recovered via the producer later on. Therefore, perforation strategy has no effect on gas ultimate recovery because gas is produced from all reservoirs sooner or later.

The gas recovery factors of total field are 90% as shown in Table 5.10 and Figure 5.65.

In term of condensate, option 1 (Perforate all) produces the highest recovery factor compared to the other cases if dumpflood is triggered from the beginning. As explained earlier, gas from the lower reservoirs help maintain pressures and prevent liquid drop-out in the condensate reservoirs from the beginning. Option 2 (sequence) will be the second best option if dumpflood is performed at later time regardless of plateau rate. The other perforation strategies (options 3 and 4), i.e dumping gas from only two layers of dry gas reservoirs provides slightly less gas recovery by 2-4% compared to option 2 as shown in Table 5.11 and Figure 5.66.

Dumping gas from only two layers yields slightly less condensate recovery as there is a smaller amount of gas to repressurize condensate in the upper reservoirs. Comparing between concurrent perforation of all dry gas reservoirs (option 1) and sequential perforation of dry gas reservoirs (option 2), the second option gives slightly better gas and condensate recovery. This can be explained in the same fashion as in the case of appropriate timing for gas dumpflood. If gas is gradually dumped into the gas condensate reservoirs, it helps raise the reservoir pressures better than dumping a lot of gas all at once which helps increase the reservoir pressures to an unnecessary high value. As a result, pressures in the reservoir are maintained higher than those of the other cases.

Table 5.11 Comparison of different perforation strategies in dumpflood strategy

Plataeu rate (MMscf/d)	DF Timing	Perforation	Production time (days)	Cumulative gas production (bscf)	Cumulative oil production (Mstb)	Gas RF (%)	Condensate RF (%)	MBOE (Mstb)
3	From the beginning	Perforate all	2069	5.13	270	91	83	1125
		Sequence	2282	5.11	262	90	80	1114
		perf 2 lower gas layers	2130	5.18	261	91	80	1124
		perf 2 upper gas layers	2127	5.16	257	91	79	1118
	Less than Plataeu	Perforate all	1612	5.08	242	90	74	1089
		Sequence	1946	5.12	248	90	76	1100
		perf 2 lower gas layers	1765	5.17	239	91	73	1102
		perf 2 upper gas layers	1765	5.17	238	91	73	1100
	Less than 1/2 plataeu	Perforate all	1673	5.10	244	90	75	1094
		Sequence	1977	5.12	250	90	77	1103
		perf 2 lower gas layers	1795	5.17	243	91	75	1105
		perf 2 upper gas layers	1795	5.17	243	91	74	1104
	Less than economic rate	Perforate all	1734	5.10	244	90	75	1094
		Sequence	2038	5.12	250	90	77	1103
		perf 2 lower gas layers	1857	5.17	243	91	75	1105
		perf 2 upper gas layers	1854	5.17	242	91	74	1104
6	From the beginning	Perforate all	1369	5.12	267	90	82	1121
		Sequence	1734	5.11	261	90	80	1113
		perf 2 lower gas layers	1461	5.17	259	91	80	1121
		perf 2 upper gas layers	1472	5.16	252	91	77	1112
	Less than Plataeu	Perforate all	1155	5.09	241	90	74	1089
		Sequence	1581	5.11	244	90	75	1095
		perf 2 lower gas layers	1317	5.17	230	91	71	1092
		perf 2 upper gas layers	1317	5.16	233	91	72	1093
	Less than 1/2 plataeu	Perforate all	1155	5.07	241	90	74	1087
		Sequence	1613	5.11	248	90	76	1100
		perf 2 lower gas layers	1348	5.17	240	91	74	1101
		perf 2 upper gas layers	1348	5.16	239	91	73	1099
	Less than economic rate	Perforate all	1308	5.10	247	90	76	1096
		Sequence	1734	5.11	252	90	77	1103
		perf 2 lower gas layers	1435	5.16	245	91	75	1105
		perf 2 upper gas layers	1470	5.16	243	91	75	1103
9	From the beginning	Perforate all	1155	5.11	265	90	81	1118
		Sequence	1612	5.12	257	90	79	1111
		perf 2 lower gas layers	1308	5.17	256	91	78	1118
		perf 2 upper gas layers	1317	5.16	252	91	77	1112
	Less than Plataeu	Perforate all	1035	5.08	238	90	73	1086
		Sequence	1520	5.09	243	90	75	1091
		perf 2 lower gas layers	1230	5.17	231	91	71	1092
		perf 2 upper gas layers	1225	5.16	229	91	70	1089
	Less than 1/2 plataeu	Perforate all	1065	5.09	238	90	73	1086
		Sequence	1581	5.11	246	90	76	1098
		perf 2 lower gas layers	1256	5.16	236	91	72	1096
		perf 2 upper gas layers	1256	5.16	235	91	72	1095
	Less than economic rate	Perforate all	1186	5.09	245	90	75	1092
		Sequence	1673	5.11	250	90	77	1101
		perf 2 lower gas layers	1348	5.16	241	91	74	1101
		perf 2 upper gas layers	1379	5.16	240	91	74	1101

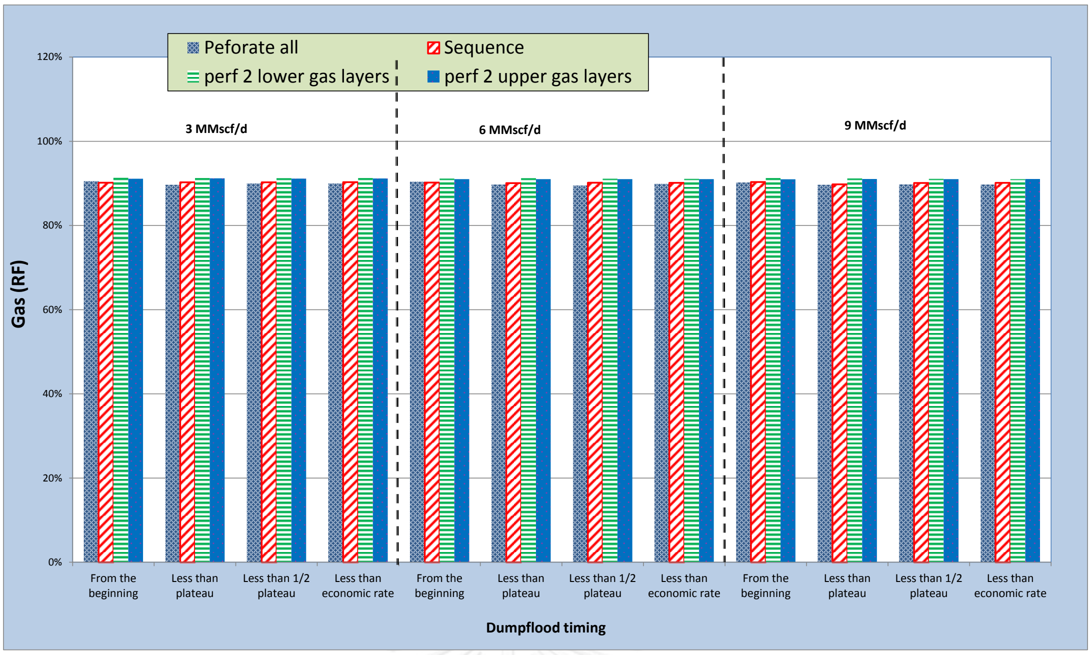


Figure 5.65 Gas recovery factor for different perforation strategies in dumpflood cases

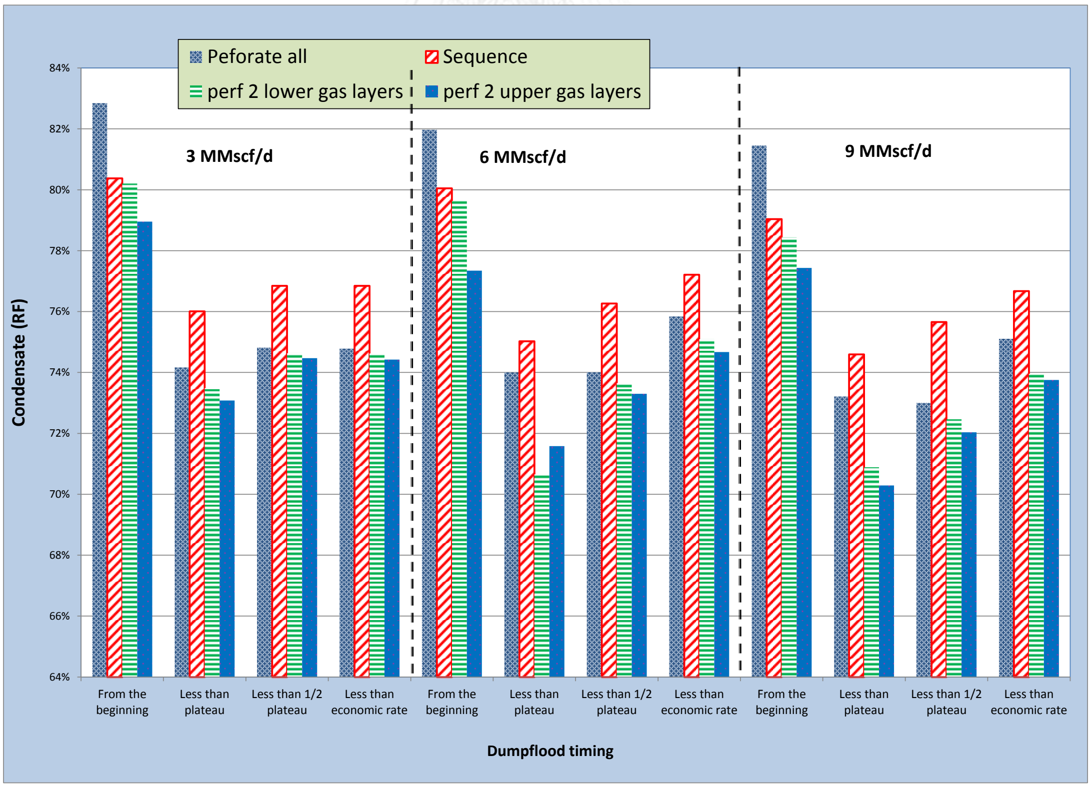


Figure 5.66 Condensate recovery factor rate for different perforation strategies in dumpflood cases

5.6 Best case comparisons

The study does not include the economic analysis. Nevertheless, comparison of ultimate oil and gas recoveries and field production time of different operations were made based on the barrel oil of equivalent criteria. Specifically, for each production scenario, the best case is selected based on the highest BOE. However, if there are two cases of similar BOE but the production times are much different, the one with lower production time is selected. As a result, the best case for each production scenario is summarized in the Table 5.12 and in Figure 5.67 while gas and condensate production profiles obtained from the best cases are illutrated in Figure 5.68 for each of the five production scenarios.

Table 5.12 Best cases comparisons from various production scenarios

Scenarios	Plataeu rate (MMscf/d)	Perforation timing	Production time (days)	Cumulative gas production (bscf)	Cumulative oil production (Mstb)	Gas RF (%)	Condensate RF (%)	MBOE (Mstb)
Commingle	6		577	5.3	113.5	93	35	989
Bottom up with plug	6	less than economic rate	699	5.2	175.8	92	54	1042
Bottom up without plug	6	less than 1/2 plateau rate	638	5.3	72.4	93	22	952
Top down without plug	6	less than economic rate	727	5.2	192.0	92	59	1065
Gas dumpflood from the beginning	6	perforate all	1369	5.1	267.0	90	82	1121

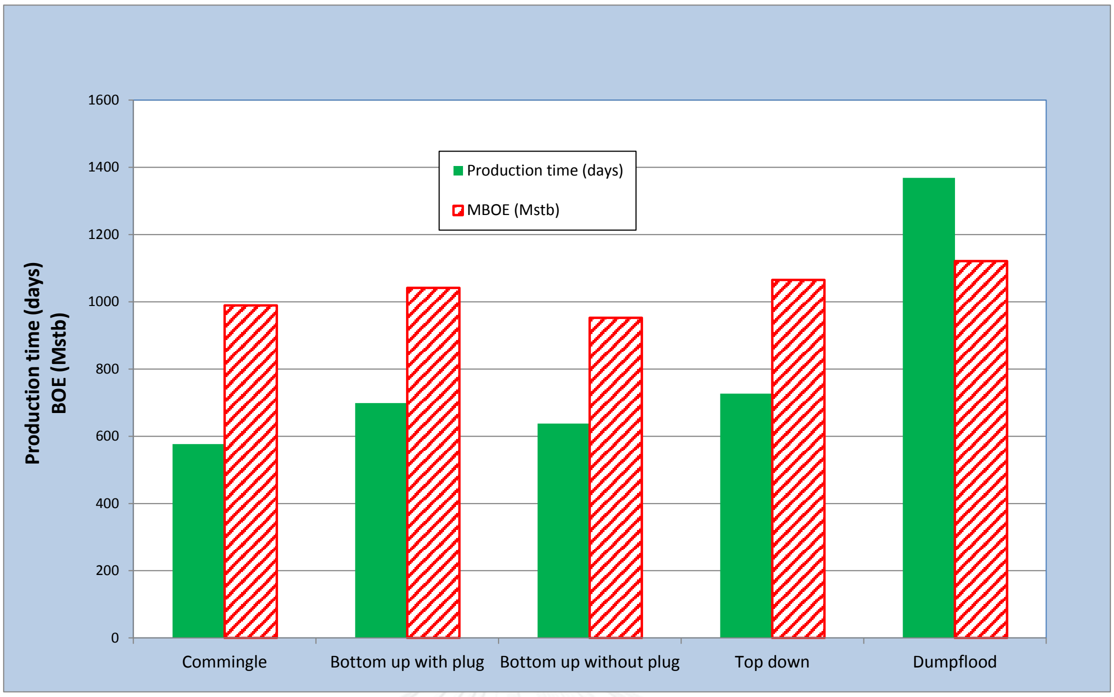


Figure 5.67 The best case comparisons in term of production time and BOE

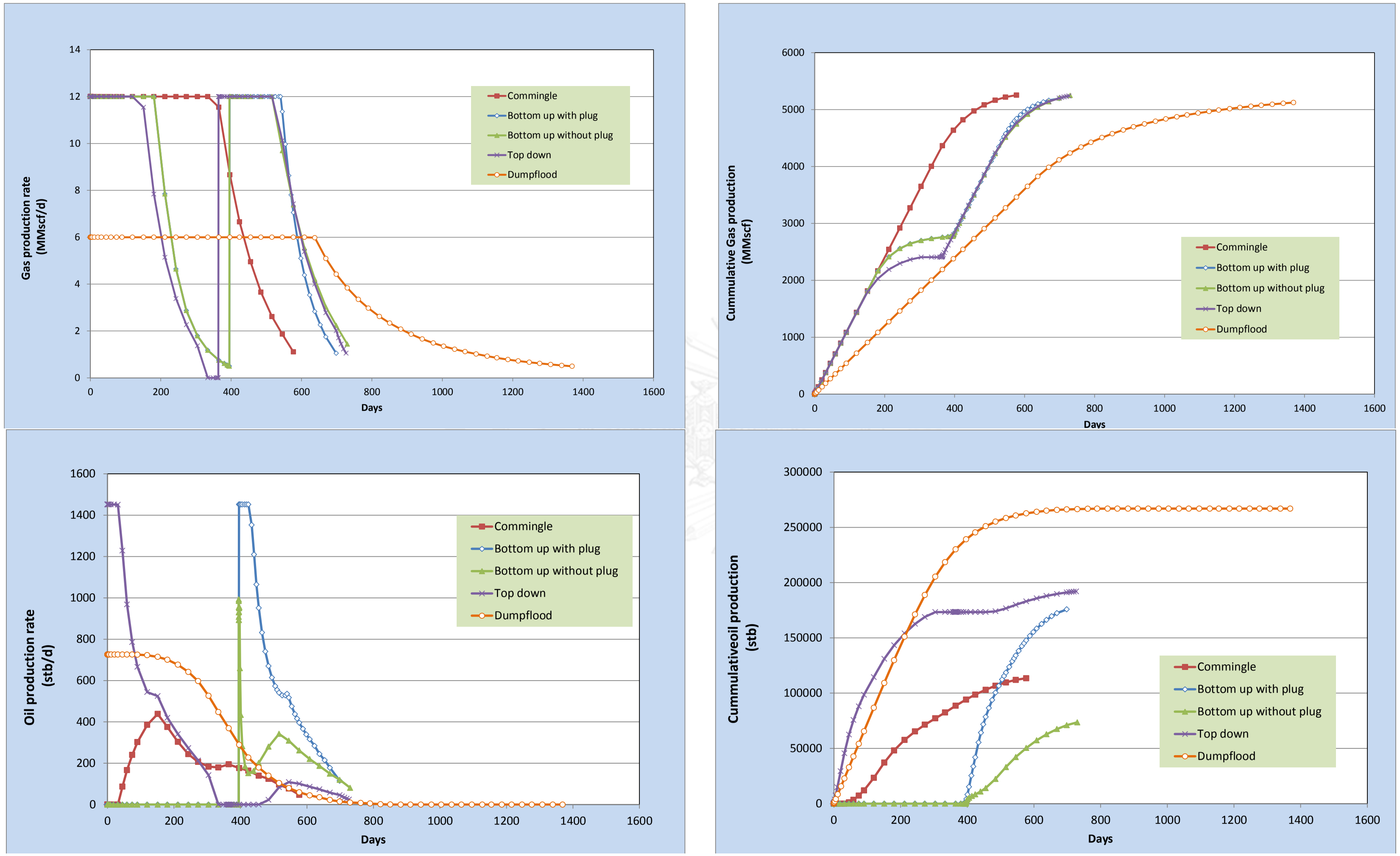


Figure 5.68 Gas and Oil production profiles for various production scenarios

CHAPTER VI
CONCLUSIONS AND RECOMMENDATIONS

The objective of this research work is to find the optimal operating conditions and production strategy for multilayer gas and condensate reservoir. This chapter presents the main technical conclusions and potential recommendations for future studies.

6.1. Conclusions

In order to maximize the condensate production in multi-stacked reservoirs, several operating scenarios including commingled and non-commingled production were investigated and compared with dumpflood. Based on the results obtained from the hypothetical reservoir model via ECLIPSE 300, there are some important findings summarized as follows:

- ✓ Commingle scenario produces the condensate recovery factor of 35%. Condensate recovery is quite low because it, being heavier than gas, crosses flow into the lower dry gas layers. Also, condensate recovery reduces with higher plateau rate.
- ✓ Bottom up perforation with plug is in fact stand-alone production strategy, i.e., dry gas reservoirs and gas condesate reservoirs are produced separately. In this scenario, gas is being lost in the lower layers by the time of perforating the uppers ones. It is found that the gas recovery factor varies from 79% to 92% as a function of perforating time and plateau rate. However, condesate production is higher than that of the commingle cases because there is no cross flow of condensate into the lower gas reservoirs. The ultimate condensate recovery obtained in this scenario is maximum 54% and can be reduced by 1 to 2 percent when plateau rate increases. However, the perforation timing does not affect the condensate recovery factors at a specific gas plateau rate.

- ✓ For bottom up without plug, the condensate recovery in this case is the lowest of 22% compared to the other scenarios because condenate crosses flow into depleted deeper dry gas reservoirs during in the second batch. The ultimate condensate recovery reduces with higher gas production rate and earlier perforation timing of the second batch. However, the amount of decrease in the condensate recovery factor depends on the relationship between these two operation factors.
- ✓ For Top down without plug, gas can be produced for a long time in the seond batch as all eight layers contribute to the production at late times, keeping the gas production above the economic limit. As a result, gas recovery factor is around 92% regardless of plateau rate and perforation timing of second batch. Consensate recovery in this scenario is up to maximum 59% because condensate cannot cross flow into the dry gas reservoirs. In fact, gas from the lower reservoirs flows into the condesate reservoir in the second batch. In other words, adding the dry gas reservoir to the condensate reservoir at late time already created so-called natural “gas lift” effect and thus enhances lift performance of oil production. The recovery factor of condensate reduces with higher gas production rate. In addition, at specific gas plateau rate, the sooner to perforate the second batch, the lower the ultimate recovery of condensate.
- ✓ Gas dumpflood are the best production scenario among five different strategies investigated in this study in term of the highest barrels oil of equivalent and the highest recovery factor of 83%. The main reason that gas dumpflood results in much higher condensate recovery than other strategies is because the dumped gas helps repressurize the condensate dropout inside the reservoir and increase the areal sweep efficiency as well. Though ultimate gas recovery factor is slightly lower than that of the other scenarios, the additional amount of condensate recovery obtained from gas dumpflood generally pays off for the delay in gas and condensate production.

  The time to start gas dumpflood does not affect the gas recovery but impacts condensate recovery. Starting dumpflood from the beginning gives the highest condensate recovery of 83%. The recovery factor of condensate reduces with higher gas production rate.

In term of perforation options, perforating all lower dry gas layers for dumpflooding produces the highest condensate recovery factor if dumpflood is triggered from the beginning. However, if dumpflood is performed at a later time then the sequential perforation (two at a time) gives a better condensate recovery than other perforation options. Dumping gas from only two layers of dry gas reservoirs (out of four layers) yields slightly less condensate recovery as there is a smaller amount of gas to repressurize the gas condensate reservoir.

6.2. Recommendations

In this study, the simulation model uses homogeneous reservoir properties with a number of assumptions and simplifications such as no dip angle and immobile reservoir water. Condensate recovery is significantly affected by fluid compositions, initial pressure, relative permeability and heterogeneities of the reservoir. Hence, it is suggested that in the future work, an inhomogeneous and anisotropic model that can include parameters mentioned above need to be considered to better characterize the condensate production in multi-stacked reservoirs.

The barrels oil of equivalent is used as a quick look to evaluate the likely profitability of gas dumpflood. The economic model is not described in this study due to the complexity and uncertainties of commercial inputs such as oil and gas price, inflation rate operating expenditure (OPEX), capital expenditure (CAPEX) and a type of field development contract. However, the specific economic evaluation can be checked to provide a better analysis of the actual profitability of gas dumpflood against the other production scenarios.

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APPENDIX

VITA

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