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Optimal Horizontal Well Placement in Combination-Drive thin Oil Rim

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Abstract: Producing from thin oil rim reservoirs has always been a challenge in the Oil and Gas Industry, due to problems related with early gas and water coning that usually limits oil production below commercial rates. Most of the thin oil rim reservoirs are sandwiched between an overlain gas cap and an underlain aquifer. Strategies to develop thin oil rim have been studied and implemented such as the concurrent oil and gas production as well gas blow down after oil recovery. In order to maximize the oil recovery in these columns, this study investigates the effect of gas cap and aquifer strengths on oil recovery from a reservoir with a thin oil rim using a numerical reservoir simulator model. Results shows that the gas cap size and aquifer strength play an important role on the improvement of oil recovery. In general, the well should be located close to the oil-water contact when the gas cap has stronger influence than water, at the middle of oil column when the two driving forces are more or less balanced, and near the gas-oil contact when the aquifer support is strong than gas expansion.

Keywords: *Thin oil rim, horizontal well, combination drive.*

1. Introduction

Thin oil rim reservoirs have oil columns between 30 and 90 ft which mostly are overlain with gas cap and underlain by aquifer [1] as depicted in Figure 1. Reservoirs with less than 10 meters are considered ultrathin oil reservoirs. Effective plan where the main concern is to improve oil recovery is essential to exploit thin oil rim reservoirs.

Studies that were performed for developing thin oil zones with horizontal wells proved to offer immense advantages over vertical wells by improving hydrocarbon recovery. This is achieved due to the large surface area of wellbore that is in contact with the formation. Other advantages of horizontal wells in thin oil rim are the improvement of productivity, oil recovery factor and higher critical rates for water and gas coning.

Many studies focused in locating the well along the thin oil rim [2]. Studies performed on effect of well standoffs to fluids contacts on oil recovery, resulted that wells have to be completed in the top half of the oil column [3].

The aim of this paper is to investigate the optimal horizontal well location under different gas cap and aquifer strengths. Reservoir simulation is the method adopted to evaluate, estimate and predict the performance of oil production.

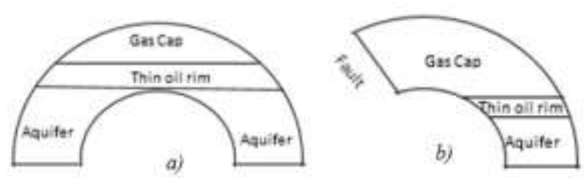

Figure 1 *Reservoirs with thin oil rim: (a) bottom and (b) edge water [4]*

2. Theoretical Background

Due to its small thickness (less than 90 ft), these reservoirs when put on production, lead to a relative low oil production due to early breakthrough of gas and water. Most oilfields with vertical wells experience similar problems as the reservoir approaches the end of its life [1].

Successful exploitation of thin oil rim is subjected to two drive mechanisms: gas cap expansion drive and water drive. Before production, these forces are in equilibrium. In many fields, the oil is produced first and gas later. This strategy has shown good results. During production of oil, gas expands, affecting both gas-oil contact (GOC) and oil-water contact (OWC). The movement of GOC and OWC will depend on the strengths of the gas cap and aquifer [5].

In order to develop and maximize oil recovery from thin oil rims many factors have to be evaluated, such as energy balance between the gas cap and the aquifer, type of well, reservoir geometry, well location, well length, oil viscosity, magnitude of bed dip, anisotropy, flow rate, rock permeability, thickness of the thin oil rim and other factors [3].

2.1. Coning

Coning results from the movement of reservoir fluids in the direction of least resistance, balanced by a tendency of the fluids to maintain gravity equilibrium. There are three forces that may affect fluid flow distributions around the wellbores: capillary forces; gravity forces; and viscous forces [6].

Coning is caused by the pressure drawdown within the oil column close to the wellbore being sufficiently large to overcome viscous and gravity forces and draw the water or gas into the well. As the flow rate increases, the cone height also increases until at a critical rate. Then, the cone becomes unstable and water is drawn into the wellbore above the oil-water contact or gas is drawn below the gas-oil contact. This premature water or gas breakthrough is often referred to as coning on vertical well, or cresting on horizontal well. Coning involves localized movement of gas or water towards the well while cresting involves the localised movement of gas or water along a significant, if not, the entire length of a horizontal well [6].

2.2. Production Strategy

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

2.2.1. Reverse coning

In this case, the well is completed above the GOC. The technique is proposed for reservoir with a small gas cap and strong aquifer. One of the successful fields was the case of Platong Field in the Gulf of Thailand, where one of the reservoirs consisting of a 30-ft oil column with a small gas cap and a large underlying aquifer [2]. A reservoir simulation study indicated that to maximize oil recovery it would be better to locate the horizontal well in the gas cap. Upon drilling the well, gas was produced for the first two weeks after which the well started producing oil. The project was an economic success.

The effect of gas cap and aquifer strength on optimal well location for thin oil rim reservoirs was performed using a numerical reservoir simulation [2]. A single horizontal well was used to evaluate the effect of completion location in the case of strong aquifer with a fixed aquifer-factor of 50. The gas cap size was varied in terms of M-factor, the ratio between the gas cap and oil pore volume. M-factors of 0.05, 0.5, 1, 2.2, and 5 were used. It was found that the optimum completion location of horizontal well depends on the gas cap and aquifer size. For M-factor less than 1, the maximum volume of oil was produced when the well is completed above the GOC.

2.3. Inverse Coning

This is the technique in which the horizontal well is located below the OWC. This technique can be applied when the gas cap is strong and the aquifer strength is weak. When the well is placed on production, inverse coning occurs in which oil "down-cones' through the water zone, into the completion. The net result is the production of water followed by oil. This phenomenon has been observed in a horizontal well drilled in the Troll field, offshore Norway [2].

3. Methodology

In this study, ECLIPSE100 reservoir simulator was used to construct a homogeneous water-drive saturated-oil reservoir model having drainage area of 5000x2500 ft^2 and variable thickness of 505, 540 and 610 ft. with a single horizontal well 3,000 feet long as shown in Figure 1. The model consists of 36,250 active cells and 6,250 inactive cells with the model dimensions of 50x25x34 in the x-, y- and z-directions, respectively. The thickness of the oil zone is fixed at 70 ft while the gas cap zone has variable thickness of 35, 70 and 140 ft representing the M-factor ratio (volumetric ratio of gas over oil) of 0.5, 1, and 2 respectively, and the thickness of the water zone is 50 ft. The water zone is connected to a numerical aquifer with variable sizes making the total aquifer size to be 5, 50, and 500 times the reservoir pore volume (5PV, 50PV, and 500 PV).

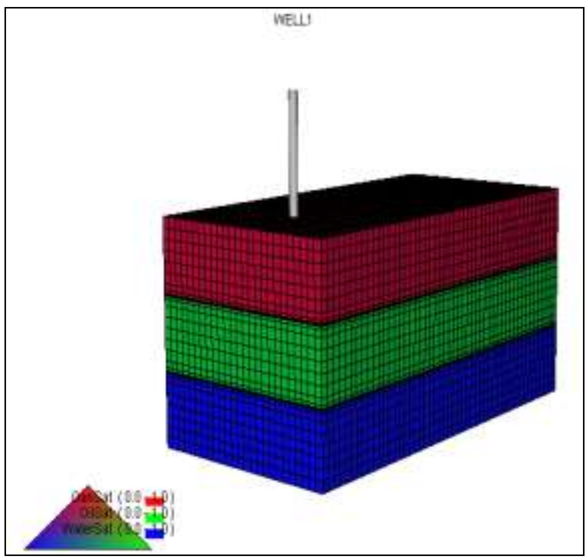

***Figure 2** Reservoir box model*

Reservoir and fluid properties used in the model are summarized in Table 1 and 2.

Table 1 *Reservoir properties*

Parameter	Value	Unit
Oil rim thickness	70	ft
Flow rate	5000	STB/D
Simulation time	30/10956	years/days
Porosity	29.6	%
Horizontal permeability	5000	mD
k_v/k_h	0.1	
GOC	5070	ft
OWC	5140	ft

Table 2 *Fluid properties*

Parameter	Value	Unit
Oil gravity	35	API
Gas gravity	0.8	
Water gravity	1	
GOR	507	*SCF/STB*

As the thickness of the gas and aquifer zones were varied while the thickness of the oil column was fixed, this created several combinations of scenarios as listed in Table 3.

Table 3 *Scenarios*

$M-Factor$	Aquifer size (PV)
0.5	5
	50
	500
1	5
	50
	500
2	5
	50
	500

Well location

In order to determine the optimal location for horizontal well placement, reservoir simulations were conducted for three candidate locations which are (1) right below the gas-oil contact, (2) at the middle of the oil column, and (3) right above the oil-water contact as tabulated in Table 4.

Table 4 *Position of horizontal well*

Case	Well position	Distance to GOC (ft)	Distance to OWC (ft)
1	Right below GOC	0.5	69.5
2	Middle of oil column	35	35
3	Right above OWC	63	7

For 5PV aquifer, only two scenarios of well locations were simulated (at the middle of oil column and right above the oil-water contact) because the aquifer strength is not strong enough for the best location to be near the gas-oil contact. Thus, the case was eliminated. On the other hand, only two well locations (right below the gas-oil contact and at the middle of oil column) were simulated for the case of 500PV since the gas cap is too weak for the optimal location to be near the oil-water contact. Such case was then eliminated from the run.

4. Results and Discussions

4.1. M-Factor of 0.5

For the case of 5PV aquifer and M-factor of 0.5, both aquifer and gas cap are small. Simulation results indicate that the best horizontal well location is right above the oil-water contact as it gives the highest recovery factor of 53.25% (see Figure 3). As gas has better expandability than water and thus provides a good driving force for oil production, it should be kept inside the reservoir for as long as possible. Hence, locating the well further away from the gas cap helps improves oil recovery. When the well is located near the oil-water contact, the amount of produced water became higher but the gas production is lower as shown in Figures 4 and 5, respectively.

For the case of 50PV aquifer and M-factor of 0.5, the optimal well location is at the middle of oil column as it gives the highest recovery factor of 62.10% (see Figure 3) and moderate water production (Figure 4). In this case, the driving force of gas in the gas cap is about the same as that of water in the aquifer. Thus, the middle location yields the highest oil recovery. Note that the gas production of the well at the middle of oil column is slightly lower than the gas production of the well located right above the oil-water contact but slightly higher than the gas production of the well located right above the gas-oil contact as depicted in Figure 5.

For the case of 500PV aquifer and M-factor of 0.5, the aquifer is very large while the gas cap is small. The highest recovery factor of 72.70% is obtained when the well is located right below the gas-oil contact (see Figure 3). Due strong aquifer support, the well should be located far away from water aquifer. The water production of the well right below the gas-oil contact is lower that of the well in the middle as illustrated in Figure 4 but gas production increases as the well location is close to the gas-oil contact (see Figure 5).

In summary, when the aquifer strength is increased from 5 to 50, and 500 PV, the optimal well location changes from right above the oil-water contact to the middle of oil column, and right below the gas-oil contact while the recovery factor increased from 53.25 to 62.10, and 72.70%, respectively due to the downward movement of gas-oil contact in the case of weak aquifer and upward movement of the oil-water contact in the case of strong aquifer. In addition, the increase in aquifer size significantly improves the recovery factor.

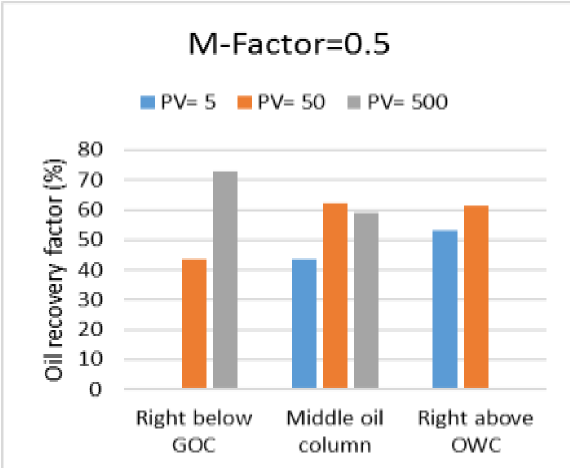

Figure 3 *Oil recovery factor for M-factor of 0.5*

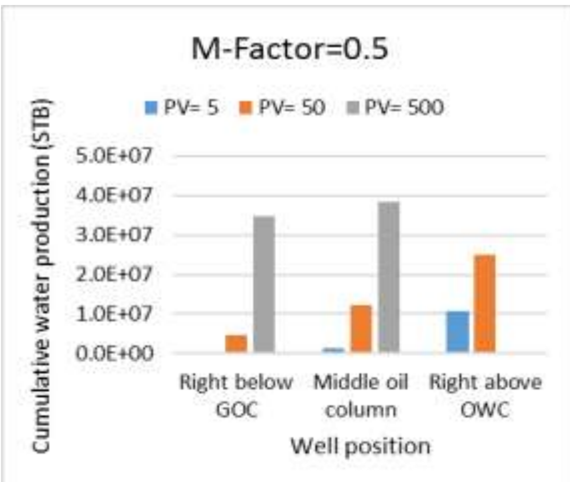

Figure 4 *Cumulative water production for M-factor of 0.5*

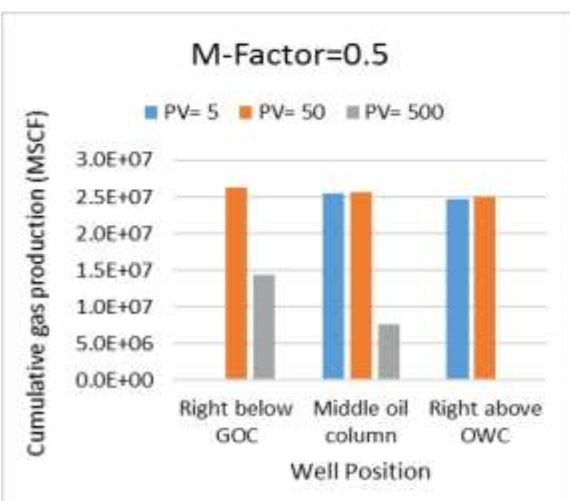

Figure 5 *Cumulative gas production for M-factor of 0.5*

4.2. M-Factor of 1

For the case of 5PV aquifer and M-factor of 1, the optimal well location is right above water-oil contact as it gives the highest recovery factor of 54.20% (see Figure 6). The water production increases as the well is located towards the water-oil contact while the gas production decreases as shown in Figures 7 and 8, respectively.

For the case of 50PV aquifer and M-factor of 1, the optimal well location is at the middle of oil column as it gives the highest recovery factor of 62.72% (see Figure 3). Neither the driving force of gas in the gas cap nor that of water in the aquifer dominates the response. As a result, the middle location yields the highest oil recovery factor. Furthermore, the water production increases as the well is located towards the water-oil contact while the gas production decreases (see Figures 7 and 8).

For the case of 500PV aquifer and M-factor of 1, the aquifer is very large. The highest recovery factor of 72.94% is obtained when the well is located right below the gas-oil contact (see Figure 6). Due to strong aquifer support, the highest recovery can be obtained when the well is located far away from water aquifer. The well located right below the gas-oil contact has lower water production but higher gas production than the well in the middle as illustrated in Figures 7 and 8.

In summary, when the aquifer strength is increased from 5 to 50, and 500 PV, the optimal well location changes from right above oil-water contact in the first case to the middle of oil column in the second case to right below the gas-oil contact in the last case with an increase in recovery factor from 54.20 to 62.72, and 72.94%, respectively due to relative movements of gas-oil and oil-water contacts for different aquifer strengths. As in the case with M-factor of 0.5, the increase in aquifer size significantly improves the recovery factor.

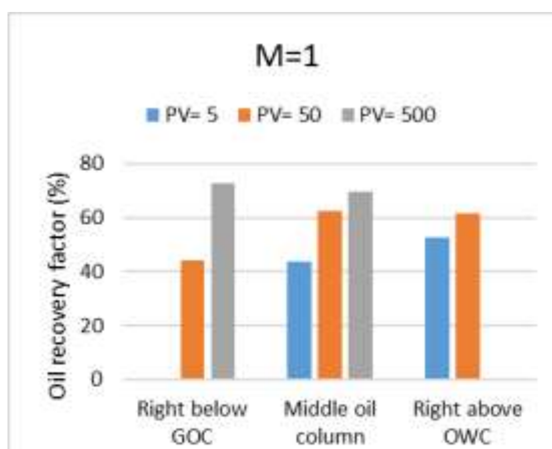

Figure 6 *Oil recovery factor for M-factor of 1*

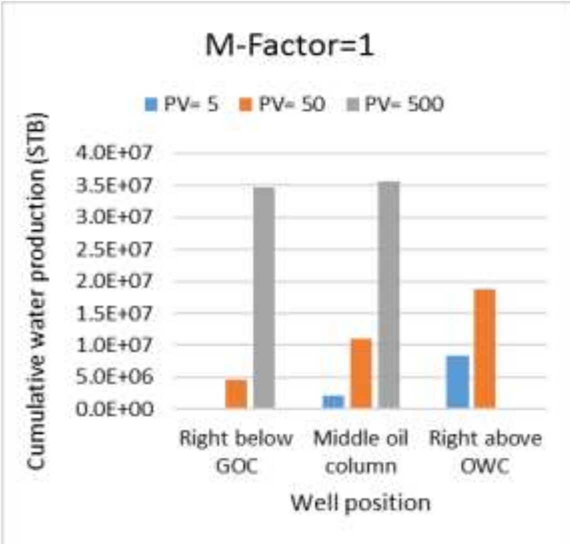

Figure 7 *Cumulative water production for M-factor of 1*

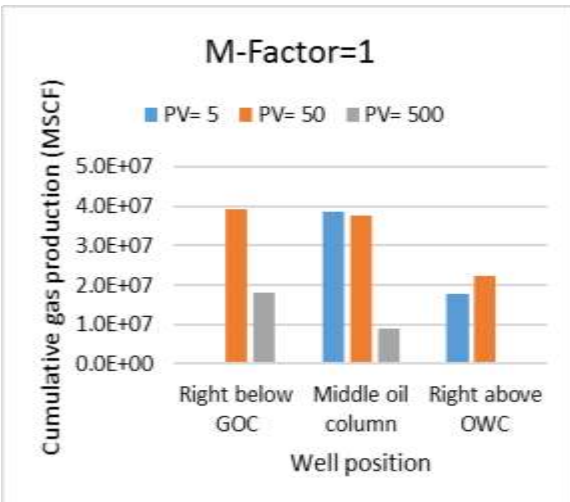

Figure 8 *Cumulative gas production for M-factor of 1*

4.3. M-Factor of 2

For the case of 5PV aquifer and M-factor of 2, the gas cap is large while the aquifer is small. The best well location is right above the oil-water contact as it gives the highest recovery factor of 57.82% (see Figure 9). As gas provides a good driving force in this case, the further away the well is located from the gas cap, the higher the oil recovery. When the well is located near the oil-water contact, the amount of produced water became higher but the gas production is lower as shown in Figures 10 and 11, respectively.

For the case of 50PV aquifer and M-factor of 2, the optimal well location is still right above the oil-water contact with the highest recovery factor of 65.31% as depicted in Figure 9 indicating that the gas cap is still a strong driving force even with this large aquifer size. Similar to previous cases with M-factor of 0.5 and 1 having 50PV aquifer, the water production increases as the well is located towards the water-oil contact while the gas production decreases (see Figures 10 and 11).

For the case of 500PV aquifer and M-factor of 2, the aquifer is very large. The highest recovery factor of 74.16% is obtained when the well is located in the middle of the oil column (see Figure 9) due strong driving forces from the gas cap and water aquifer. As the well is located deeper towards the aquifer, the water production increases but gas production decreases as shown in Figures 10 and 11.

In summary, when the aquifer strength is increased from 5 to 50, and 500 PV, the optimal well location changes from right above the oil-water contact in the first two cases to the middle of oil column in the last case with an increase in recovery factor from 57.82 to 65.31, and 74.16%, respectively due to relative movements of gas-oil and oil-water contacts for different aquifer strengths. Similar to M-factor of 0.5 and 1, the increase in aquifer size significantly improves the recovery factor.

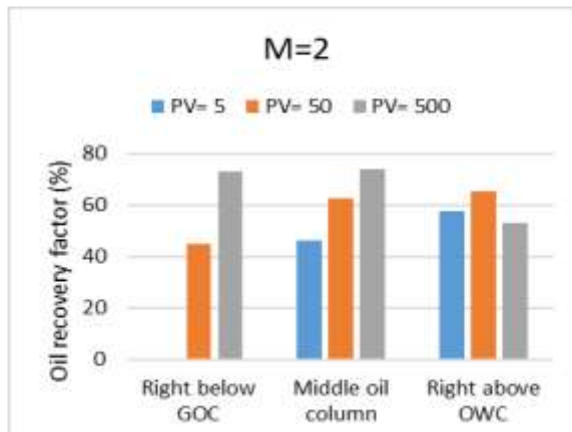

Figure 9 *Oil recovery factor for M-factor of 2*

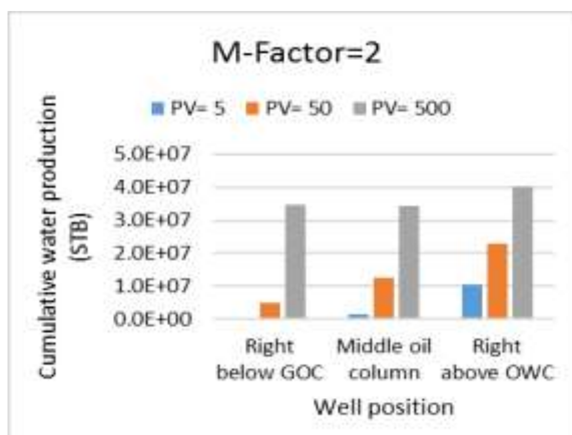

Figure 10 *Cumulative water production for M-factor of 2*

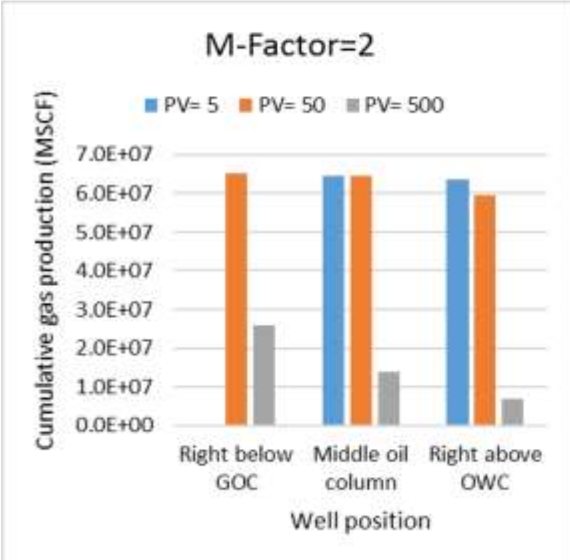

Figure 11 *Cumulative gas production for M-factor of 2*

4.4. Comparison among different M-factors

When the M-factor increases from 0.5 to 1 and 2 (gas cap size doubles and quadruples), the recovery factor increases from 53.25 to 54.20 and 57.82% for 5PV aquifer, changes from 62.10 to 62.72, and 65.31% for 50PV aquifer, and 72.70 to 72.94 and 74.16% for 500PV aquifer.

Conclusions

Based on results obtained, the following conclusions can be done:

(i) For small gas cap (M-factor of 0.5), when the aquifer strength is increased from 5 to 50, and 500 PV, the optimal well location changes from right above the oil-water contact to the middle of oil column, and right below the gas-oil contact respectively due to the downward movement of gas-oil contact in the case of weak aquifer and upward movement of the oil-water contact in the case of strong aquifer.

(ii) For medium-sized gas cap (M-factor of 1), when the aquifer strength is increased from 5 to 50, and 500 PV, the optimal well location changes from right above the oil-water contact in the first case to the middle of oil column in the second case to right below the gas-oil contact in the last case due to relative movements of gas-oil and oil-water contacts for different aquifer strengths.

(iii) For large gas cap (M-factor of 2), when the aquifer strength is increased from 5 to 50, and 500 PV, the optimal well location changes from right above the oil-water contact in the first two cases to the middle of oil column in the last case respectively.

Nomenclature

OWC-Oil Water Contact
GOC – Gas Oil Contact
PV – Pore Volume

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