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Experimental Study of Reasonable Drawdown Pressure of Horizontal Wells in Oil Reservoir with Bottom Water

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Abstract: The development effect of horizontal well in oil reservoir with bottom water is extremely sensitive to drawdown pressures. Since water coning is inevitable, it is significant to analyze the impact of drawdown pressures on post water breakthrough performance of horizontal wells. Based on a small-scale and discretized physical simulation system, the impact of different drawdown pressures, as well as the influence of changing drawdown pressures in different water cut stage, on the following indexes is discussed: increasing rates of water cut, oil recovery difference and displacing efficiency of bottom water. The results show that under different drawdown pressure, the variation curve between water cut and recovery degree tends to convex. For the thin oil with relatively high viscosity, it is reasonable to keep relatively large drawdown pressure to decrease water cut increase rate in medium and low water cut stage. But enlarging drawdown pressure in medium and high water cut stage is harmful to increase ultimate oil recovery. If the viscosity is further lower, it is beneficial to adopt small drawdown pressure to extend oil production period with low water cut content. While it is reasonable to increase drawdown pressure in medium and high water cut stage to improve the flooding efficiency of bottom water. For the heavy oil, it is acceptable to enlarge drawdown pressure under the condition of low water cut period.

Keywords: oil reservoir with bottom water, horizontal well, drawdown pressure, Gini coefficient, physical simulation.

1 Introduction

Reservoirs with bottom water are very common, especially for some offshore oil fields in areas of Bohai Bay in China. In order to develop such reservoirs efficiently and economically, the issue around how to control water coning should be

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addressed. In recent years, the wide use of horizontal well technology has led to better water coning management and enhanced oil production [Nutakk (2002); Azuhan and Ken (2006)].

In comparison to vertical wells, horizontal wells exhibit smaller pressure drawdown near the wellbore but possess a larger oil producing capacity. Besides their enlarged oil-well contact area and increased sweeping efficiency, horizontal wells also change water coning model by turning coning into cresting, thereby decreasing water cresting velocity and weakening water cresting tendency [Dikken (1990)] Furthermore, in high water-cut stage, under the same drawdown pressure and fluid producing intensity, the enhancement of oil production by horizontal wells is quite substantial [Li et al. (2010)]. However, with regards to oil reservoirs with bottom water, the disadvantages of horizontal wells cannot be overlooked. Once water breakthrough occurs, high mobility bottom water will invade cresting into high permeability overlying oil zone and move forward to the wellbore quickly, causing the rate of water-cut to increase rapidly [Chuok et al. (1959)].

In the past, we focused a lot of our attention on analyzing water coning mechanism, calculating critical rate, predicting water breakthrough time and lengthening water-free production period [Singhal (1996); Elkins (1958); Fortunati (1962); Outmans (1964)]. And in these few decades, some developments have been made. Giger (1986) obtained the critical flow rate of the horizontal well in bottom water drive reservoirs by establishing an analytic 2-D model of water cresting before breakthrough. Ozkan and Raghavan (1990) predicted the behavior of an evolving cone and the time for breakthrough by adopting an approximate analytical model which displayed all expected characteristics of cone movement. Guo and Lee (1992) determined the maximum water-free oil rate and location of the water crest under the critical condition by using both the conformal mapping theory and numerical simulation method. Luo et al. (2008) introduced a 3-D steady-state horizontal well model to obtain the critical rate and the breakthrough time by providing an analytical solution to the pressure distribution of the wellbore. In physical simulation aspects, based on sand pack physical model, Wibowo et al. (2004) investigated the impact of the interaction of forces (capillary force, viscous force and gravity force) on production performance of the horizontal well, which produces oil from bottom water driver reservoir. Based on a 2-D flat physical model, Wang et al. (2007) investigated the effect of horizontal length and drawdown pressure on water-free oil recovery and ultimate recovery of horizontal well. Based on a 3-D visualization model, Liu et al. (2011) studied the development of water coning and the characteristics of oil production and water cut under different horizontal lengths and drawdown pressures. But his physical model failed to take reservoir heterogeneity into consideration, and the method that was suggested to control water coning during high water cut condition was to simply close the well. In his advanced model [Liu et al. (2011)], although the heterogeneity of reservoirs was taken into account, the effect of different drawdown pressures was not discussed.

From all the numerical and analytical studies, we know that water breakthrough will occur if oil production rate is above the critical rate. But we also know that in most cases, the predicted critical rate is too low to be put into practice economically, especially regarding offshore oil fields. Taking together all research studies concerning physical models, we can conclude that pressure drop is one of the most significant causes of water cresting, and the variation of oil production and water cut of horizontal well is extremely sensitive to drawdown pressures.

Since drawdown pressure is so important and water coning is inevitable, the analysis of the impact of drawdown pressure on post water breakthrough performance of horizontal wells makes practical sense [Zhao et al. (2006)]. Based on the practical production data and dividing water cut into different stage, Zhou et al. (2004) used numerical simulation to analyze the relationship between the increasing rate of water cut and drawdown pressures, then the reasonable drawdown pressure after water breakthrough is obtained. While there are a limited number of experimental studies on evaluating the influence of different drawdown pressures on horizontal wells and analyzing the effect of changing drawdown pressures in different water cut stage. Furthermore, for nearly all previous experimental studies, segmentation measurement of different permeability strips of reservoirs could not be performed.

In this study, in order to take the on-way heterogeneity of horizontal well into consideration, we conducted researches on a small-scale and discretized physical simulation system. And based on this system, we investigated the impact of different drawdown pressures, especially the effect of changing drawdown pressures in different water cut stage on horizontal wells with various permeability ratio and oil viscosity.

2 Experimental apparatus and procedures

2.1 Apparatus and assumed condition

Suppose that the bottom water is big enough to provide sufficient energy and the horizontal well has infinite flow conductivity. If neglecting the influence of connectivity between sand packs and filling them with different glass beads, which represent various permeability strips with the same width, as shown in Fig. 1, this system can model the on-way anisotropy of horizontal well. The fluid flow in each strip can be treated as an one dimensional non-piston water-flooding model.

The apparatus diagram of the simulation system is shown in Fig. 2. The apparatus consists of three parts:

(1) Small-scale and discretized simulation system of horizontal well. This system consists of five sand packs which are in parallel. Each pack is 30-cm long with 3.8cm inner diameter. Glass beads of mesh numbers ranging from 20 to 160 are used as packing material.

(2) Bottom water driving system. This system consists of a constant pressure pump and a constant pressure control valve.

(3) Record system. This system consists of a high precision differential gauge, a stopwatch and five measuring cylinders.

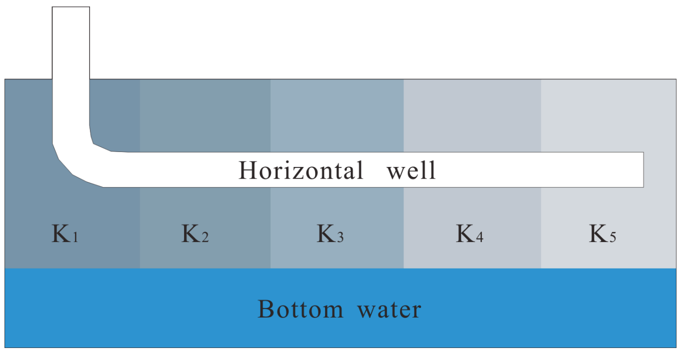


Figure 1: The schematic diagram of the simulation system.

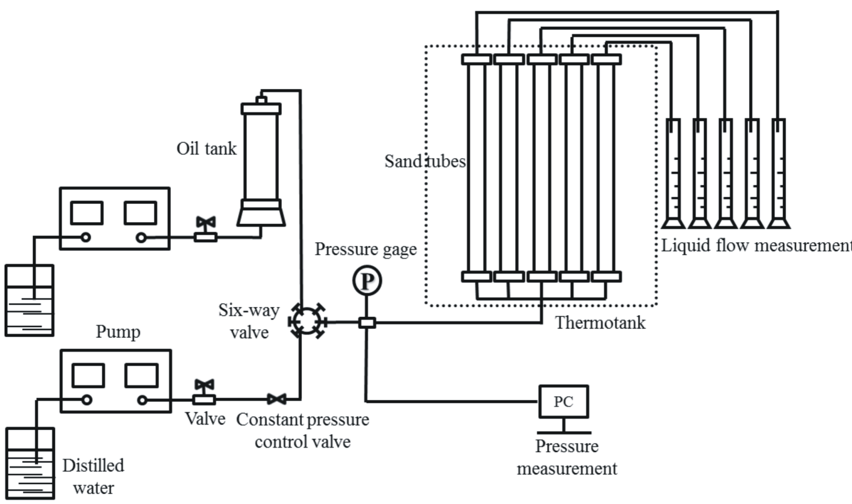


Figure 2: The apparatus diagram of the simulation system.

2.2 Experimental methods

Distilled water is used as displacing fluid and to simulate formation water. And there are three oil samples, of which viscosities at 60°C are 21.4 mPa.s, 87.8 mPa.s and 124.1 mPa.s, respectively. Based on the Darcy' law, the average absolute permeability of each sand pack is determined by the flow of water at a constant rate and by measuring the pressure drop between the two ends of the sand pack. In total, 15 sand packs are measured and the permeability values of all are summarized in Table 1. The oil sample is injected to displace the water to irreducible water saturation. After completion of water flooding with a drawdown pressure, the same pack is re-flooded with the same oil sample to displace the water to irreducible water saturation again and water flooding experiments are performed for other drawdown pressures. For subsequently experiments with different drawdown pressures, we substitute with different sand packs and with different oil samples. All water flooding experiments and oil saturating procedures are performed at a constant thermostat temperature of 60°C.

Table 1: Porosities of sand packs

Group number	Oil viscosity	Sand pack number	Absolute permeability (mD)	Permeability ratio	Porosity
I	87.8mPa.s	1	5200	—	117.2
		2	3300	1.58	111.7
		3	2020	2.60	115.4
		4	1570	3.47	110.8
		5	500	10.40	106.3
II	21.4mPa.s	6	512	—	119.2
		7	326	1.57	114.1
		8	238	2.15	99.7
		9	148	3.46	110.0
		10	122	4.20	97.5
III	124.1mPa.s	11	2380	—	118.4
		12	1730	1.38	110.7
		13	710	3.35	99.3
		14	490	4.86	107.6
		15	360	6.61	98.8

3 Experimental results and discussion

3.1 The variation of water cut of constant pressures

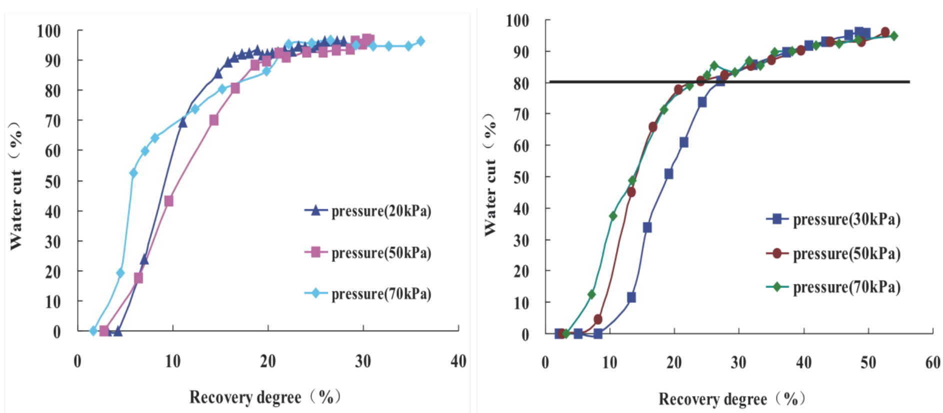
The relationship between water cut and recovery degree is the most basic rule of describing water cut rising [Han and Wan (1999)]. Drawdown pressure is one of the most sensitive and important factors influencing this law. Fig. 3 shows water-cut raise curves of two oil viscosities belonging to thin oil under different drawdown pressures. And water cut of permeability strips in different oil recovery condition with different drawdown pressures are given in Fig.4.

It is observed in Fig. 3(A) that for the oil sample of 87.8 mPa.s, all of these three curves tend to convex and under the same reservoir anisotropy condition (permeability ratio is 10.4), they show some similar characteristics, such as short water-free recovery period, rapid increase of water cut in medium-low water cut stage, and mild change in high water cut stage. But there are also some unique features. It is to be noted that although the water-free production period at drawdown pressure 20 kPa is longer than that at 50 kPa, the rising range of water cut at 50 kPa is smaller in the medium-low water cut stage and the final oil recovery is higher. Compared to the 27.95% recovery when water cut is 96.48% and the drawdown pressure is 20 kPa, the recovery at 50 kPa is 30.72% when water cut is 96.83%. It is also observed from Fig. 4(A) that at 20 kPa, the water cut of 5200μm^2 has already reached 80% when the recovery is only 7%. And the water doesn't break through strips between 3.6$\sim$10.4 permeability ratio even the recovery reaches 30%. Whereas the pressure is kept at 50 kPa and the recovery reaches 7%, the water cut of 5200μm^2 is only 38.46% and water breaks through another two relatively high permeability strips. This can be due to the relatively high drawdown pressure is beneficial to overcome viscous resistance and permeability ratio. The consequence is in medium-low water cut stage, water cut changes mildly with the recovery degree.

But if the drawdown pressure changes to 70 kPa, bottom water will accelerate into the high permeability strip, which aggravates the anisotropy among strips. It is to be noted in Fig. 4(A) that when the recovery is 7%, the water cut of 5200μm^2 is 81.25%, and the water cut of 3300μm^2 is even smaller than that at 20 kPa. That is to say the bottom water breaks through the highest permeability strip aggressively. Consequently during the initial stage, the water cut will rise significantly. The drawdown pressure is kept constant so the water cut expands along different permeability strips. During this period, medium and low permeability strips can overcome combined influences of two phase flow resistance, viscous resistance and permeability ratio and each strip can acquire a higher production degree. The result of this comprehensive function is that with the increase of oil recovery, water cut tends to change gradually and smoothly. Finally, the recovery at 70 kPa is 36.03%

when water cut is 96.40%. Thus for the oil sample of 87.8 mPa.s, increasing drawdown pressures appropriately has benefit for decreasing water cut increasing rate in medium and low water cut stage.

But for the oil sample of 21.4 mPa.s, the situation is different. It is to be noted in Fig. 3(B) that with the increase of drawdown pressure, the water-cut raise curves appear to have no intersection in medium-low water cut stage and the increased rate of water cut is higher. What's more, the water-cut raised curves under different drawdown pressures all appear apparent inflection point when water cut reaches 80%. After exceeding this value, the curves gradually reach plateau. As shown in Fig. 4(B), under the condition of relatively low oil-water viscosity ratio (21.4) and permeability ratio (3.46), advance speed of bottom water in different permeability strips is similar. While the larger drawdown pressure is, the faster watered out velocity is, which may change locally watered out pattern into punctiformly watered out pattern. So when it comes to the low oil viscosity reservoir, it is reasonable to adopt small drawdown pressures to extend the oil production period with low water cut content.

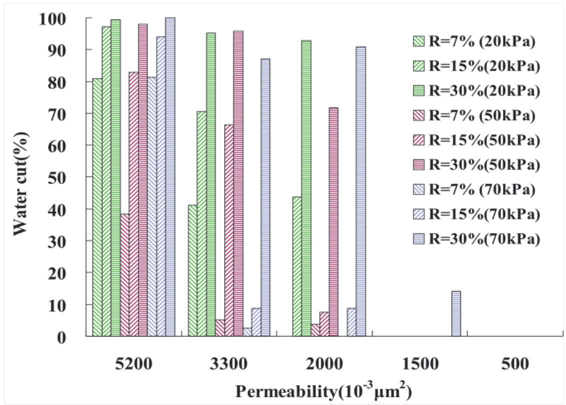


(A) Viscosity=87.8 mPa.s (B) Viscosity =21.4 mPa.s

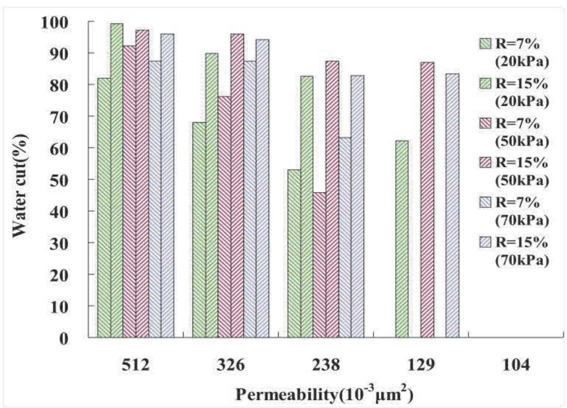
Figure 3: Water-cut raise curves of two oil viscosities under different drawdown pressures.

3.2 The variation of oil recovery of constant pressures

Gini coefficient is usually used to describe the uneven distribution phenomenon. So we use this index to quantitate the recovery difference between each permeability strip under various drawdown pressures. Fig. 5 shows the recovery degree and Gini coefficient curve of two oil viscosities under different drawdown pressures.



(A) Viscosity =87.8 mPa.s



(B) Viscosity =21.4 mPa.s

Figure 4: Water cut of permeability strips in different oil recovery condition with different drawdown pressures.

It is observed that with the increase of dimensionless time, Gini coefficient under different drawdown pressures are tending to decline. And with the Gini coefficient decreasing, the recovery difference among permeability strips is smaller, which leads to the improvement of comprehensive recovery. In other words, there is a negative correlation between Gini coefficient and comprehensive recovery. It is to be noted in Fig. 5(A) that for the oil viscosity of 87.8 mPa.s, when the drawdown pressure is 20 kPa, the final comprehensive recovery is 27.95% with Gini coefficient being always in a high level. If the drawdown pressure changes to 50 kPa, Gini coefficient reduces overall and the final recovery is 30.72%. When the drawdown pressure changes to 70kPa, the final recovery is 36.03% with the lowest Gini coefficient. This phenomenon can be attributed to the formation of multiple fingers [Jiang and Butler (1998)]. The oil with relatively high viscosity has large viscosity resistance. When the drawdown pressure is relatively low, the viscous fingering phenomenon happens within the highest permeability strip is serious. So "single finger" is always formed. Under this condition, the recovery difference among permeability strips is large. As drawdown pressure increases, although water still breaks through along high permeability strip, enlarging drawdown pressures is beneficial to overcome the negative influence of permeability ratio and viscous resistance. Consequently, those strips which have low producing degree under low drawdown pressures can be developed much more effectively. As a whole, "multiple fingers" are formed and the difference among permeability strips is becoming smaller. So it is reasonable to enlarge drawdown pressures properly to improve the producing degree of medium and low permeability strips in thin oil reservoirs with relatively high viscosity.

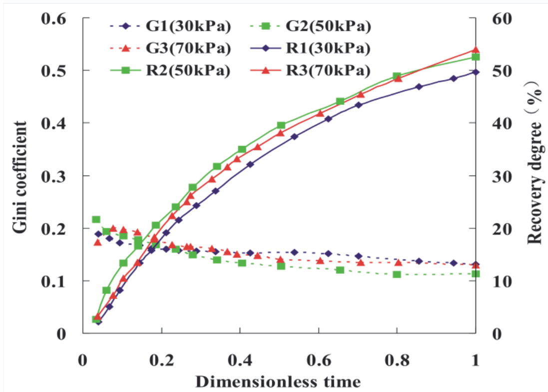
If the oil viscosity is further lower, as shown in Fig. 5(B) the viscosity is 21.4 mPa.s, the distinction of Gini coefficient with different drawdown pressures is small. What's more, the growth of final comprehensive oil recovery is limited with the increase of drawdown pressures. The final oil recovery is 49.63% at a pressure of 30 kPa. Compared to 53.19% at a pressure of 50 kPa, the final oil recovery is 53.96% at a pressure of 70 kPa. This can be attributed to the fact that thin oil has low viscous resistance and high flowability, and strips has relatively low permeability ratio (less than 4.2). So the recovery difference among permeability strips under different pressures is small. Moreover, larger drawdown pressures easily cause the crossflow much more serious. Under such condition, increasing drawdown pressures has limited effect on improving oil recovery.

3.3 Determination for the drawdown pressure in different water cut stage

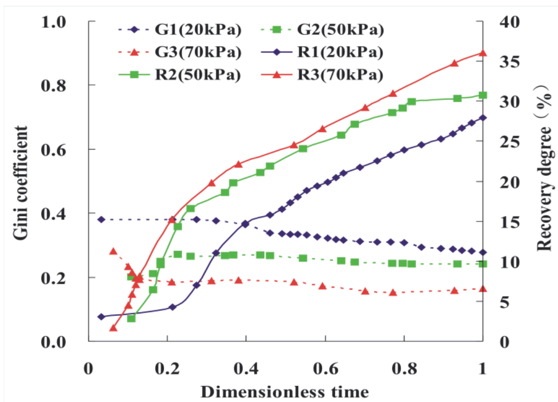
3.3.1 Effect of changing drawdown pressure on thin oil

From previous investigations we learn that in practice, the production rate of horizontal wells usually exceeds the critical rate. Correspondingly under such condition, oil production is always followed by a large amount of water. At the same time, with the influence of oil viscosity and reservoir anisotropy, most reserves will be recovered in medium and high water period. Therefore it is very important to study the effect of changing drawdown pressures in different water cut period on the increased rate of water cut and ultimate oil recovery.

The change in the relationship between cumulative water-oil ratio and recovery degree can not only reflect the incremental changes of water cut, but also directly



(A) Viscosity =87.8 mPa.s



(B) Viscosity =21.4 mPa.s

Figure 5: The difference of single sand-pack recovery degree under different drawdown pressures (G: Gini coefficient R: Recovery degree).

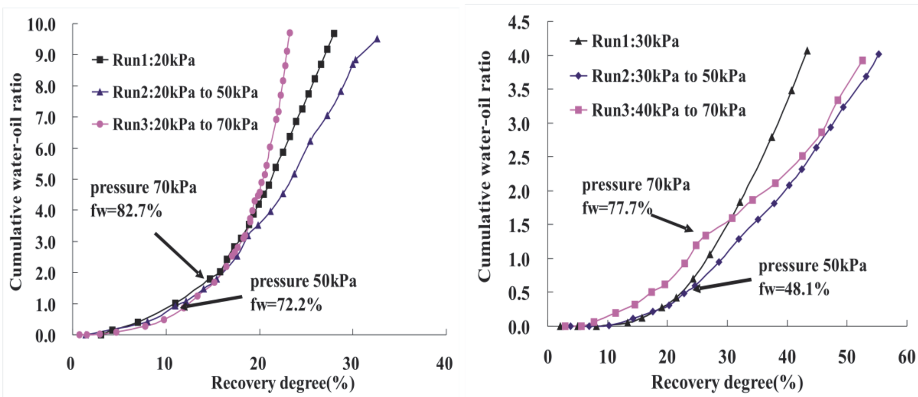
reveal the water consumption per unit oil production. Thus this index can further display the characteristics of bottom water displacement efficiency. Based on this, cumulative water-oil ratio curve can be used to evaluate the plausibility and predict the development effect when changing drawdown pressure under the condition of different water cut.

The variation curves between cumulative water-oil ratio and recovery degree of two thin oil viscosities under the condition of changing drawdown pressures are shown in Fig. 6. Fig. 7 illustrates the recovery difference among sand packs under the condition of changing drawdown pressures.

For the oil sample of 87.8mPa.s, it is observed from Run1 of Fig. 6(A) that if drawdown pressure is kept at 20 kPa, the recovery degree can reach 27.95% when the water cut is 96.48%. It can be also seen from Run1 of Fig. 7(A) that, under relatively small drawdown pressure, the highest permeability strip can achieve ideal production degree, whereas those of medium and low permeability can produce only a small amount or hardly any. If the pressure is changed from 20 kPa to 50 kPa when water cut is 72.2% (Run2 of Fig. 6(A)), it is to be noted that in the initial phase of the pressure change, the variation curve between cumulative water-oil ratio and recovery degree shows no significant difference compared with the curve at constant pressure 20 kPa. However, stepping into the later displacing stage, increasing pressure makes fluid injection rate of medium and high permeability strips increase, followed by an enhancement in the degree of extraction of the remaining oil in each permeability strip. Thus, with the increase of comprehensive recovery degree, the rising rate of change between cumulative water-oil ratio and recovery degree of Run2 (Fig. 6(A)) gradually decreases in comparison with Run1 (Fig. 6(A)). The result shows that when water cut is 95.04%, the oil recovery of Run2 (Fig. 6(A)) is 32.62%, which exceeds that of Run1 (Fig. 6(A)) by 4.67 percent points under the same water cut condition.

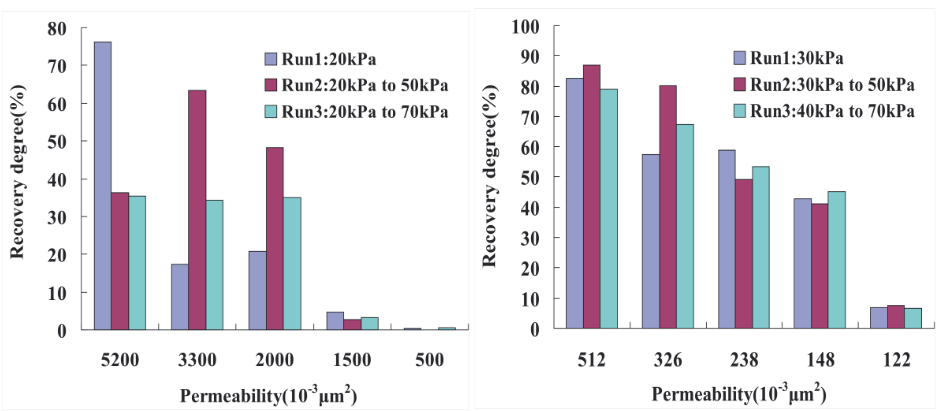
But if the drawdown pressure increases to 70 kPa when the water cut reaches 82.7% (Run3 of Fig. 6(A)), the opposite trend occurs. Because of relatively high water cut, breakthrough flow channel in high permeability strip has been formed. With further increases in drawdown pressure, although the recovery degree of high and medium permeability strip can increase with the help of high injection pressure, it still has no effect on the low permeability strip, as shown in Fig. 7(A). On the contrary, the increase in drawdown pressure can further exacerbate the water fingering to the high permeability strip. At this point, the cumulative oil-water ratio rises rapidly with the increase of oil recovery, as shown in Run3 of Fig. 6(A). When the water cut is 98.32%, the recovery degree is only 23.25%. So from the discussion above, for the thin oil with relatively high viscosity, increasing the drawdown pressure in high water cut stage will have negligible effect on the ultimate oil recovery.

With regards to the oil sample of 21.4mPa.s, the good effect of increasing drawdown pressure in medium or high water cut stage is shown in Fig. 6(B). It is to be noted that the rising rate of cumulative water-oil ratio of Run2 and Run3 decreases significantly once drawdown pressure is increased. It can be also seen from Fig. 7(B) that the recovery difference of each strip reduces as the drawdown pressure increases. Although the ultimate recovery of increasing pressure in high water cut stage is a little bit lower, enlarging drawdown pressures in medium or high water cut stage can both lead to the water consumption per unit oil production reducing substantially. So we can conclude that when adopting horizontal well to develop thin oil reservoir with relatively low oil viscosity, it is reasonable to increase drawdown pressures in medium and high water cut stage to improve the efficiency of bottom water flooding.



(A) Viscosity =87.8 mPa.s (B) Viscosity =21.4 mPa.s

Figure 6: The effort of changing drawdown pressures on the variation of cumulative water-oil and recovery at different water cut.



(A) Viscosity =87.8 mPa.s (B) Viscosity =21.4 mPa.s

Figure 7: The effort of changing drawdown pressures on single sand-pack oil recovery.

3.3.2 Effect of changing drawdown pressure on heavy oil

As mentioned earlier, the breakthrough of bottom water along high permeability strips is inevitable, especially for heavy oil reservoirs with bottom water, which have very short water-free oil production period.

Based on the theory of oil-water two-phase flow, Chen (1985) deduced the relational expression of cumulative water (W_p) and cumulative oil (N_p) under semilog coordination by using displacing front equation and average water saturation equation:

$$\log(W_p + C) = AN_p + B \tag{1}$$

As the water cut ratio and cumulative water increases continuously, the influence of constant C gradually reduces. When bottom water displaces to the medium and high water cut stage, under the condition where $W_p >> C$, the influence of constant C can be neglected. Under single semilog coordination and making the $\log W_p$ as abscissa and the N_p as vertical, we can see that $\log W_p$ vs N_p takes on a linear relationship, the equation (1) can be simplified as follows:

$$N_p = a \log W_p + b \tag{2}$$

In the relational expression, a is defined as water driving effective coefficient (WDEC). It signifies the cumulative oil production when the cumulative water rises 10 times. This value can be used to reflect bottom water displacing efficiency and development efficiency.

In order to study the influence of changing pressure on heavy oil reservoir with bottom water, the oil viscosity of 124.1 mPa.s is adopted. 20 kPa is used as an initial drawdown pressure, and 70 kPa is used as the subsequent drawdown pressure. Under different water cut condition, drawdown pressure is changed from 20 kPa to 70 kPa. Through analyzing the cumulative water and cumulative oil in high water cut stage based on equation (2), the WDEC is derived, as shown in Fig. 8.

The water ratios at altering drawdown pressure are 22.3%, 33.7%, 45.1%, 61.4%, 78.5% and 91.0%, respectively. It is to be noted that there exists a power function relation between the water cut at altering pressure points and WDEC. The higher the water cut is, the lower the WDEC becomes, thus indicating that the water flooding effect is worse. This is due to the fact that enlarging drawdown pressure in low water cut stage can overcome the influence of permeability ratio easily and make "multiple fingers" formed. But if drawdown pressures are enlarged in high water cut stage, due to high viscosity resistance and the complete breakthrough flow channel which strengthen the anisotropy among permeability strips, it is difficult to displace the remaining oil in medium and low permeability strips. What's more, the velocity of water production is extremely fast. So increasing drawdown pressures in this stage will have no use to increase oil production rate, even having negative effect. Using regression analysis, the relation of the water cut and the water driving effective coefficient a is shown as following:

$$WDEC = 268.89\,(f_w)^{-0.3297} \quad R^2 = 0.9803 \tag{3}$$

Thus, for the heavy oil, it is reasonable to increase drawdown pressures under low water cut condition.

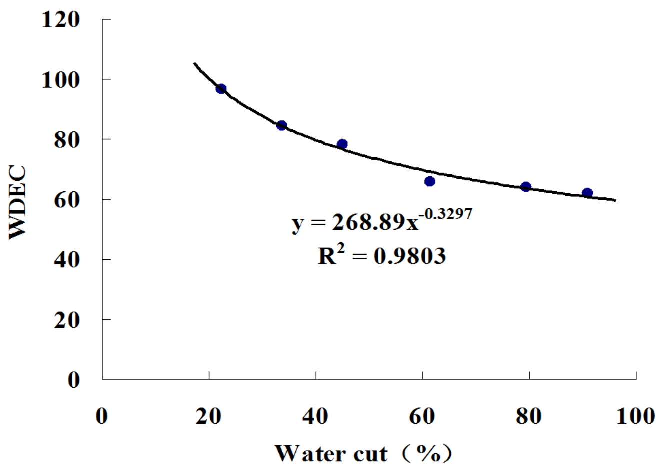


Figure 8: Water driving effective coefficient versus water cut at altering drawdown pressure.

4 Conclusions

(1) Experimental studies on the effect of different drawdown pressures and the impact of changing pressures under different water cut stage on the horizontal well with bottom water are carried out using a small-scale and discretized physical simulation system.

(2) For the thin oil reservoir with constant drawdown pressures, if the viscosity is relatively high, due to multiple fingers being formed and the difference among permeability strips being reduced, it is reasonable to keep relatively large drawdown pressure to decrease water cut increase rate in medium and low water cut stage and obtain high oil recovery. If the viscosity is further lower, keeping relatively large drawdown pressure has limited effect on oil production, so it is beneficial to adopt

small drawdown pressures to extend the oil production period with low water cut content.

(3) The water driving effective coefficient (WDEC) and the variation curve between cumulative water-oil ratio and oil recovery degree are used to evaluate the effect of changing drawdown pressures in different water cut period. For the thin oil reservoir, if the oil viscosity is relatively high, increasing the drawdown pressure in high water cut stage will have negligible effect on the ultimate oil recovery. While increasing the drawdown pressure in medium water cut stage is acceptable. For the oil with lower viscosity, it is reasonable to increase drawdown pressures in medium and high water cut stage to improve the flooding efficiency of bottom water. For the heavy oil reservoir, there exists a power function relation between the water cut at altering pressure point and WEC, so increasing drawdown pressures under low water cut condition is beneficial.

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