Proactive control of cresting in homogeneous oil reservoirs - an experimental study

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Abstract

This paper sets out to experimentally investigate the use of electromagnetic valve in controlling production of water during cresting from homogeneous non-fractured thick and thin-oil reservoirs, based on the principle of capillarity and breakthrough time. A time, half the initial breakthrough times were pre-set for the electromagnetic valve to close. The valve closed almost immediately at the set-time thereby shutting oil production temporarily, causing the water and gas height levels to recede by gravity and capillarity with receding reservoir pressure. The efficiency of this technique was compared with an uncontrolled simulation case, in terms of cumulative oil, oil recovery and water produced at the same overall production time.

From the results obtained, higher percentages in oil produced and water reduction were observed in the cases controlled proactively, with a 3.56% increase in oil produced and water reduction of 9.96% for thick-oil rim reservoirs whereas little increment in oil produced (0.7%) and lower water reduction of 1.03% were observed for the thin-oil rim reservoirs. Hence, the effectiveness of the cresting control procedure depends on the oil column height of the reservoir.

Keywords

Homogeneity, Capillarity, Cresting, Breakthrough time

1 Introduction

Prior to oil production, the reservoir fluid phases are separated by gravity, in order of their density differences (Beveridge et al. 1970; Mészáros et al. 2009; Singhal 1996). Due to the lower viscous nature of water and gas compared to oil, no restriction to flow is imposed by the reservoir rocks and thus a phenomenon called coning in vertical wells or cresting in horizontal wells may occur. When producing from a horizontal well, the gas- and water-oil interfaces deform into a crest-like shape or dip (Guo et al. 1992). At a certain rate of oil production (the volume of oil withdrawn to the surface with time) from the reservoir, the water or gas crest becomes unstable, resulting in the insurgence of water and/or gas into the wellbore through the perforations in the near wellbore region, thus the terms water and/or gas cresting occurs. The oil production rate is a parameter that affects cresting such that at oil production rates above the critical rate "effluent(s)-free oil rate" will result in cresting. Cresting can be detected when there is a substantial increase in water-oil-ratios and gas-oil-ratios after a period of low or no water or gas production (Singhal 1996). Cresting poses adverse effects in

terms of overall oil productivity, operating and handling cost of the water or gas produced and possibly the early shutting-in of wells, and in some cases results in increased water disposal and environmental effects such as in the Iranian oil fields (Shadizadeh and Ghorbani 2001). Furthermore, overcoming the buoyancy forces by the pressure drawdown at the fluid entry point in the well is very important for cresting behaviour (Singhal 1996). As a result of the increase in gas and water cut in oil reservoirs with strong water drive, production could be terminated, leaving behind high percentage of oil in the reservoir. If this occurs, more money could be spent to recover the oil left using improved techniques (Verga et al. 2005).

In conventional oil field practices, the objective of maximizing reserves and delaying cresting is achieved by placing wells adjacently in the pool such that their cones do not interfere with each other to help drain the pool more efficiently and thus increase the recovery factor. However, in modern industry practices, this impairment to production can be delayed by perforating wells as far above the water-oil contact (WOC) as possible in water-drive reservoirs, perforating in the lower part of the oil column or below the oil column in the oil column away from the gas-oil contact (GOC) in strong gas cap reservoirs, placing horizontal wells close to the water-oil contact in weak water drive reservoirs due to the higher mobility of gas compared to water as well as producing below the critical oil rate. There have been successes in reducing cresting with polymers and gels and other methods (Albonico et al. 1994; Brown 1984; Lakatos et al. 1998; Salavatov and Ghareeb 2009; Singhal 1993, 1996; Shirif 2000; Thakur and Tachuk 1974; White et al. 1973; Zaitoun and Pichery 2001). However, the use of chemicals would damage producing wells upon encroachment of these chemicals or polymers into wellbores. A more recent and novel approach, the Down Hole Water-Sink Technology (DWS) was proposed, in which water is produced separately from the oil using dual packers (Shirman and Wojtanowicz 2000). Inflow Control Devices (ICDs) have also been used but cannot completely stop the influx of water (Schevchenko 2013). In addition, the idea of injecting a "pancake" of cement just below the completion interval to prevent the vertical/upward flow of water into the wellbore was reported (Howard and Fast 1950; Makinde et al. 2011). The feasibility of downhole water loop (DWL) installation to produce water-free oil in reservoirs with bottom aquifer was investigated (Jin et al. 2010). Their investigation gave good results when a developed analytical model was compared to field data. However, using the installation is still expensive in use of energy pumping the water back to the aquifer zone and only solves the issue of lifting water to the surface experienced using the DWS technology. This study was motivated by the work of Beattie and Roberts (1996), who carried out a numerical parametric study to identify factors that contribute to water production into a vertical well in a naturally gas fractured reservoir. They stated that shutting-in the well for several days to allow the water level in the fractures to recede did not yield a sufficiently long period of low water production to be continued for a long term.

Despite the enormous advantages of proposed coning/cresting control mechanism from the literature, they are either expensive from high-energy consumption (pumping water to the surface or re-injecting water to the aquifer zone during oil production) and downhole installations or damage the producing well due to influx of materials used as barriers to control coning/cresting. Hence a safer, practical, inexpensive cresting control mechanism applicable in both thick and thin-oil rim reservoirs is essential for field operations. Therefore, this paper sets out to experimentally investigate the feasibility of using an electromagnetic valve to proactively control cresting in a homogeneous reservoir characterized by both strong bottom aquifer and considerable gas cap drive mechanisms. This was possible using a simplified physical reservoir model. The goal of this study is to reveal the mechanism of producing lower volumes of cumulative water at higher cumulative oil produced and possibly higher oil recovery ratios (ratio of volumes of oil recovered from an oil reservoir to the initial oil in place) in homogeneous oil reservoirs with considerable gas cap and strong bottom

aquifer. The mechanism of this novel procedure is principled on gravity segregation, capillarity and density difference (acting against existing viscous and gravitational forces during cresting) such that at a time, half the initial breakthrough times (half the time it takes for water and gas to encroach into the wellbore of an oil producing well) the electromagnetic valve is programmed to close almost immediately to shut oil production temporarily and after a set-time, enough for the distorted WOC and GOC levels to recede production is resume automatically.

2 Experimental

2.1 Experimental description

A water and gas-cresting rig (**Fig. 1**) used in this study consists of a reservoir, 0.45 m long, 0.10 m wide and 0.43 m high, similar to Akangbou et al. (2017) but in this case has an installed electromagnetic valve. The reservoir was assumed to have a free surface through which gas cresting can be modeled. The reservoir was filled with the same-sized polymer pellets with density > 1200 kg/m^3. Each pellet was 3 mm in length, 2 mm in width and 2 mm in height. The reservoir in this study was considered homogeneous due to the same-sized grains and fairly high-interconnected pore spaces indicated by a CT-scan visible in **Fig. 2**. **Fig. 2a** shows a CT-scan of unprocessed polymer pellets while **Fig. 2b** and **Fig. 2c** show CT-scans of reservoir grain sample reservoir grain sample showing interconnected pore spaces. Tomographic scans were done using the General Electric Phoenix V| Tome |X s high-resolution CT-Scanner. In **Fig. 2b**, the pore spaces are illustrated in green color. The reservoir was made of clear Plexiglas for good visualization of the cresting development. In addition, the oil (Silicone oil) with a viscosity of 50 cP and a density of 972 kg/m^3 respectively was dyed red whilst the water was also dyed using Fluorescein dye. Silicone oil was preferred in this experiment because of its non-sticky and no affinity to water at low and intermediate pressure ranges. The dimensions for the configuration of a horizontal well used in this investigation are illustrated in Table 1.

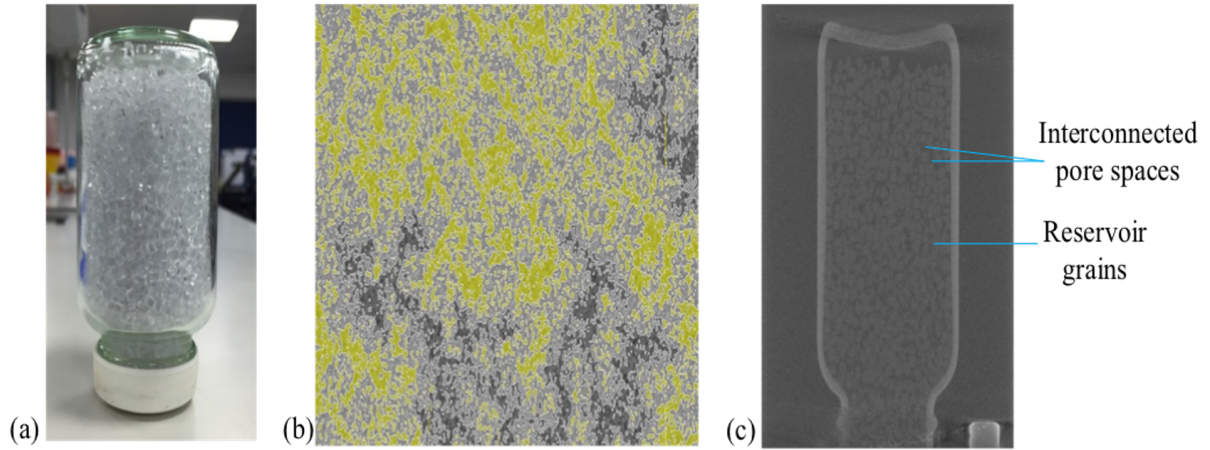**Fig. 1** Water and gas cresting rig (after Akangbou et al. 2017)

Fig. 2 a Unprocessed sample. **b** Processed CT-scan of reservoir grains showing fairly high interconnected pore spaces colored green. **c** CT-scan of reservoir grain sample showing interconnected pore spaces

Table 1 Sections and dimensions of the horizontal well

Sections of horizontal well	Dimension
Angle of inclination, degree	30
Measured depth, m	0.634
True vertical depth, m	0.167
Main-bore, m	0.140
Lateral length outside the reservoir, m	0.166
Length of lateral length inside the reservoir, m	0.305
Horizontal departure of the well, m	0.514
Length of the horizontal lateral section, m	0.473
Distance from the bridge block to the first perforation, m	0.040
Arc radius, m	0.400
Length of perforation section, m	0.050
Internal diameter of horizontal well, m	0.006
Perforation diameter, m	0.002

2.2 Procedure for the rig operation

The procedure for operating the water- and gas-cresting rig is as follows:

(1) Firstly, the dyed water was injected through the bottom water inlet points 1 and 2 to the required WOC. The WOC heights used in this study were 0.03 m and 0.10 m from the base of the reservoir for the thick-oil rim and thin-oil rim reservoirs, respectively.

(2) A rather uniform WOC was achieved by pouring the oil across the free surface of the reservoir in little volumes and at intervals. This procedure was continued until the desired GOC was observed. The modeled GOC was at 0.37 m and 0.28 m from the base of the reservoir for the thick-oil rim and thin-oil rim reservoirs, respectively.

(3) A vacuum at an initial constant pressure of -29.99 kPa provided the pressure differential enough to instigate cresting, while the pressure variation in the reservoir was measured using a digital manometer with probes placed at 0.18 m from the top left and right edges and depth of 0.22 m in the reservoir.

(4) A strong bottom aquifer was modeled at a constant flow rate of 41.68 cm^3/s (greater than the overall approximate liquid mass flow rate of 13.89 cm^3/s for all cases) while producing oil. Due to the strong nature of the bottom aquifer, the horizontal well was placed at 0.22 m from the base of the reservoir, closer to the GOC.

(5) Production was instigated by turning the ball valve at the outlet completely to the open position, while synchronically starting the digital timer and turning on completely the ball valve for constant water injection. Production in Cases 1 and 7 was controlled proactively by a ball valve whereas in Cases 2-6, 8, and 9 the ball valve was fully open and the programmable timer connected to an installed electromagnetic valve which proactively controlled production.

(6) Production times were 495 s and 210 s for thick- and thin-oil rim reservoirs, respectively. The simulation runs for each case was repeated three times and the average taken for higher accuracy.

2.3 Determination of total porosity and permeability

The total porosity is important in cresting problems such that at the higher total porosity, the more the tendency for cresting to occur and vice versa. Due to the small grain (pellets) used to model the porous media, a low total porosity was estimated using Eq. (1). Steady state permeability tests (**Fig. 3**) and Darcy's linear equation (Eq. (2)) were used to determine the permeability to water, oil, and gas. **Fig. 3** shows a set up for determining the permeability to water. The permeability to the oil (silicone oil) and dyed water were determined using a similar set up. The values of permeability and other reservoir data are summarized in Table 2 while the values obtained from the steady state permeability tests are summarized in Table 3.
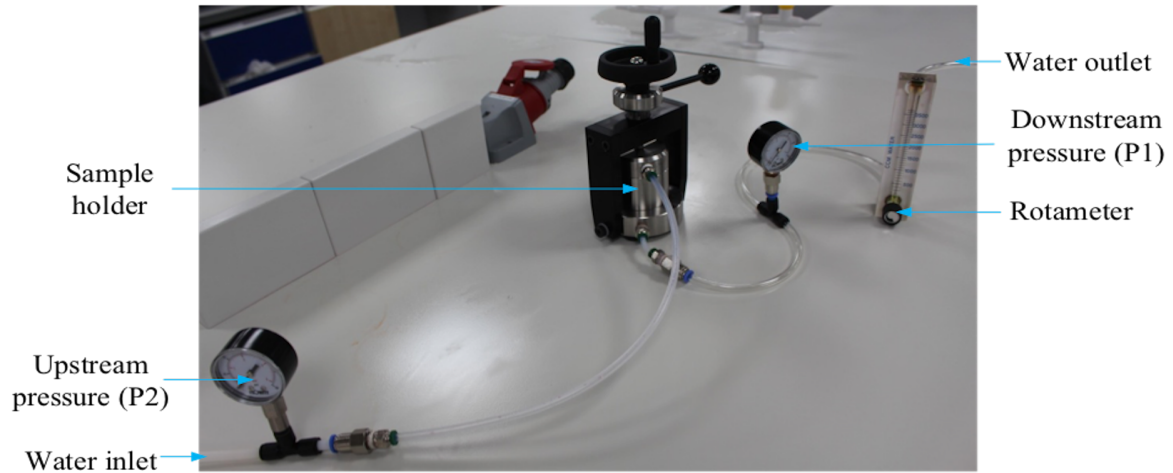

Fig. 3 Set-up for determination of water permeability

$$\emptyset = (V - V_s)/V = V_p/V \qquad (1)$$

where $\emptyset$ is the total porosity in fraction; V is the bulk volume of the reservoir in m^3; V_s is the total volume of the polymer pellet in m^3; and V_p is the volume of the pore space in m^3.

$$Q = kA(P_2 - P_1)/(\mu L) \qquad (2)$$

where Q is the flow rate in cm^3/s, μ is the viscosity of the fluid in cP, k is the permeability in D, P_2 is the upstream pressure in Pa, P_1 is the downstream pressure in Pa, L is the length of flow in cm and A is the cross-sectional area of flow in cm^2.

Table 2 Reservoir data

Parameter	Values
Total porosity	0.19
Permeability to silicone oil, D	1.06
Permeability to gas, D	4.41
Permeability to water, D	2.93
Viscosity of dyed water, cP	1.004
Viscosity of silicone oil, cP	50
Viscosity of gas, cP	0.018
Density of dyed water, kg/m^3	998
Bulk volume of reservoir, m^3	0.0198
Volume of pore space, m^3	0.00378642
Total volume of porous materials, m^3	0.01601358

Table 3 Values from permeability tests

Reservoir phases	Q (cm^3/s)	μ (cP)	A (cm^2)	L (cm)	P_2 (Pa)	P_1 (Pa)
Gas	87	0.018	39.67	3.8	68947.62	65500.24
Oil	0.12	50	39.67	3.8	137895.233	82737.14
Water	8.33	1.004	39.67	3.8	137895.23	110316.19

2.4 Wettability

Reservoir wettability is the tendency of a reservoir fluid in the presence of other immiscible fluid to spread on the reservoir rock or grains (Crocker and Marchin 1988; Galleguillos-Silva et al. 2017; Tarek 2001). Wettability is known to affect the production of hydrocarbons from pores and hence affects productivity and oil recovery during primary and enhanced oil recovery stages. A typical reservoir could be either oil or water-wet in nature characterized by the nature fluid displacement and the concave (water wet, $\theta < 90^o$) or convex shape (oil wet, $\theta > 90^o$) formed in a capillary tube during tests (Abdallah et al. 2007). Similar experimental procedure was demonstrated to determine the wettability of the reservoir modeled. After setting up the reservoir fluids in the porous media (**Fig. 4a**), a capillary tube was inserted close to one side of the beaker (**Fig. 4b)**. As shown in **Fig. 4b**, the convex shape observed with downward vertical displacement of water by oil in the capillary tube at $\theta > 90^o$ demonstrates that the reservoir grains has higher affinity to oil, hence an oil wet reservoir (Anderson 1986). Therefore, it is expected that during cresting, bottom water will move more rapidly through the Oil-wet regions leading to less oil recovery ratios from the oil-wet regions in the reservoir due to capillarity.
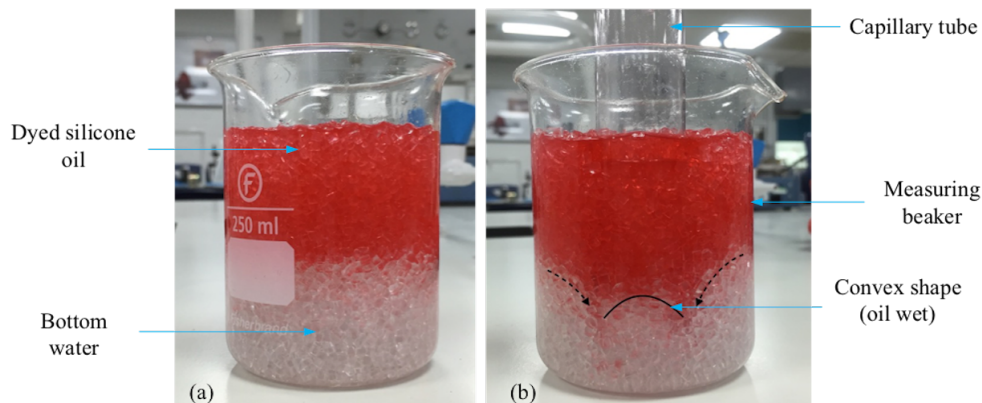
Fig. 4 a Before wettability test. **b** After wettability test

3 Results and discussion

This study involved two major cases: experiments controlled by an electromagnetic valve and the other controlled by a ball valve. The cases controlled electromagnetically were started and stopped at pre-programmed times, half the initial water and gas breakthrough time. After shutdown, the imbalanced gravitational force and hydrostatic pressure were reversed, thus allowing the water levels to recede. Oil production re-started automatically after an elapsed time also pre-set in the programmable timer; long enough for both gas and water to recede by capillarity.

Sets of experiments were performed to investigate the effect of gravity and capillarity on oil recovery, oil produced and cumulative water produced after temporary shutting-in a horizontal well in a homogeneous reservoir affected by cresting problems. In this study, an initial pressure loss prior to temporary shut-ins was considered negligible. Time was also assumed not to be a critical factor. The effluent breakthrough times for the thick- and thin-oil rim reservoirs were experimentally measured, approximately 140 and 63 s, respectively. The obtained breakthrough times are in good agreement with analytical, theoretical, and numerical simulations using field data, such that the closer the WOC and GOC to the well the faster the effluent(s) breakthrough time(s) at the same oil production rate (Peng and Yeh 1995; Schevchenko 2013; Papatzacos et al. 1991; Omeke et al. 2010).

In this study, Cases 1 and 7 had uninterrupted production for duration of 495 and 210 s, respectively whereas Cases 2-6, 8 and 9 had one shut-in each, half the water and gas breakthrough time (approximately 70 s for the thick-oil rim reservoirs (Cases 2-6) and 31 s for the thin-oil rim reservoirs (Case 7, 8)) (Table 4). The extra length provided by the solenoid valve was assumed to be negligible for the liquid produced. The production time for the thin-oil rim reservoirs was 210 s due to high volumes of water produced. Therefore, Case 7 had uninterrupted production for a period of 210 s controlled by a ball valve while Cases 8-9 were controlled by a pre-programmed electromagnetic valve. The results for these investigations were reported in terms of oil recovered, cumulative water and liquid produced at the same production times.

Table 4 Summary of simulated cases for thin- and thick-oil rim reservoirs

Case		Oil column thickness, m	Breakthrough time, s	Shut-in time, s	Production time, s
Case 1	Thick-oil rim reservoir	0.34	140	0 (uninterrupted)	495
Case 2				960	495
Case 3				2700	495
Case 4				5400	495
Case 5				7200	495
Case 6				9000	495
Case 7	Thin-oil rim reservoir	0.18	63	0 (uninterrupted)	210
Case 8				960	210
Case 9				2700	210

The reservoir types used in this investigation were thick- and thin-oil rim reservoirs; with the oil sandwiched between a strong bottom aquifer and considerable gas cap drive. **Fig. 5a** shows a thick-oil rim reservoir with fluids under static conditions ($T = 0$ s) while **Fig. 5b** shows a thick-oil rim reservoir at time $T > 0$ s.
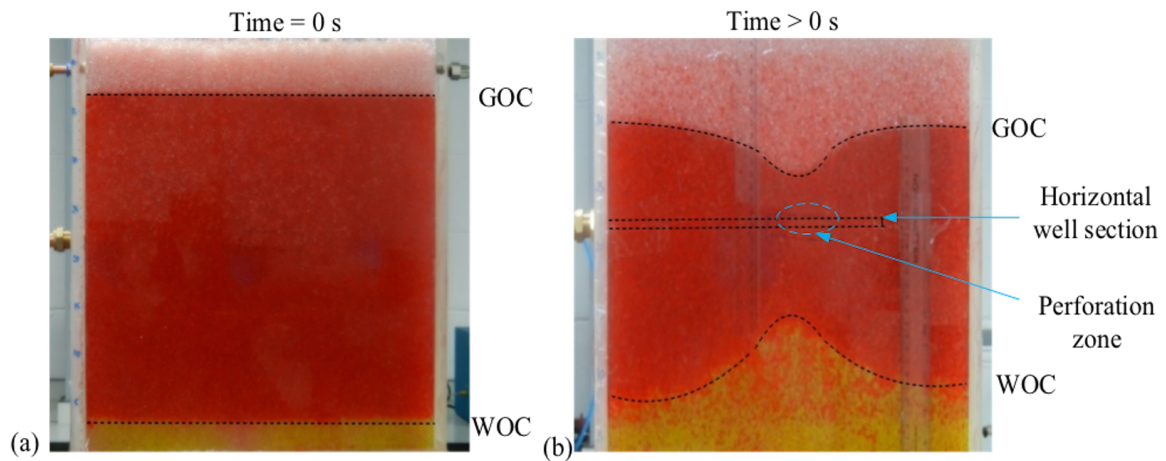
Fig. 5 a A thick-oil rim reservoir under static conditions. **b** A thick-oil rim at $T > 0$ s

3.1 Thick and thin-oil rim reservoirs

Thick-oil rim reservoirs are characterized by a thicker pay zone compared to water and gas cap zones, for the case of a three-phase reservoir. In this study, a thick-oil rim reservoir was modeled with WOC and GOC heights of 0.03 m and 0.37 m bottom-up the reservoir, respectively. On the contrary, thin-oil rim reservoirs are characterized by a thinner oil zone compared to water and gas cap zones. The case considered had WOC and GOC heights of 0.10 m and 0.28 m, respectively from the base of the reservoir.

3.2 Effect on oil recovery and oil produced

The oil produced in Litres (L) and oil recovery results for Cases 1-6 were listed in Table 5. Case 1 had the least oil recovery of 41.98%. This was due to the dominant drive mechanism in the modeled reservoir (water dive), hence the oil recovery ratio had a similar trend to a typical water drive mechanism with an oil recovery ratio of 35%-75% (Tarek 2001). For Case 2, an incremental oil recovery of 0.47% was achieved compared to the base case (Case 1) for a shut-in time of 960 s. At a shut-in time of 9000 s (Case 6), 1.55% increment in oil recovery was observed compared to Case 1. The relatively low oil recovery results obtained for Cases 1-6 could be due to the presence of some volumes of trapped water between pore spaces during shut-ins). However, Case 2 is seen to have 1.11% increment in produced oil compared to Case 1 for a shut-in time of 960 s. Similarly, Cases 3-6 are seen to have 2.35%, 3.22%, 3.52%, and 3.56% increments in oil produced at 2700, 5400, 7200 and 9000 shut-in times respectively over Case 1. Hence, a steady increase in both oil recovery and oil produced were observed from Case 2 to Case 6, with increase in shut-in time. This is as a result of fairly high-interconnected pore spaces and as such good tendency of oil displacement by water is possible. Due to the low total porosity, low permeability and limited size of the reservoir, a rather low increase in produced oil (3.56%) was observed between Cases 1 and 6. However, in actual field applications, an increment of 3.56% would mean high volumes of produced oil depending on the reservoir size and original oil in place.

Table 5 Oil recovery and cumulative oil produced results at production time of 495 s (thick-oil rim reservoir)

Case	Original oil in place, L	Shut-in time, s	Oil produced, L	Incremental oil produced, %	Oil recovery, %	Incremental oil recovery, %
Case 1	7.027	0	2.950		41.98	
Case 2	7.027	960	2.983	1.11	42.45	0.47
Case 3	7.027	2700	3.021	2.35	42.99	1.01
Case 4	7.027	5400	3.048	3.22	43.38	1.40
Case 5	7.027	7200	3.057	3.52	43.51	1.53
Case 6	7.027	9000	3.059	3.56	43.53	1.55

The oil produced and oil recovery results for Cases 7-9 are summarized in Table 6. Production in Case 7 was uncontrolled and is seen to have the lowest oil recovery and oil produced among all cases (26.80%). The low oil recovery compared to the thick-oil rim reservoir was due to the thin-oil column, thereby having lower effluents breakthrough times, where water production dominates production after breakthrough. Hence, for Cases 8 and 9, increments in oil recovery and oil produced were negligible (0.19% and 0.7% respectively). This is possibly due to the closeness of the new WOC to the perforation zone regardless of its fairly high-interconnected pore spaces. The closer the WOC is to the perforation, the faster the pressure drop will supersede the hydrostatic pressure at that contact. The size of the reservoir, low total porosity and the significantly short water crest height are contributing factors for the low performance in this type of reservoir.

Table 6 Oil recovery and cumulative oil produced results at production of 210 s (thin-oil rim reservoir)

Case	Original oil in place, L	Shut-in time, s	Oil produced, L	Incremental oil produced, %	Oil recovery, %	Incremental oil recovery, %
Case 7	3.672	0	0.984		26.80	
Case 8	3.672	960	0.991	0.7	26.99	0.19
Case 9	3.672	2700	0.991	0.7	26.99	0.19

3.3 Effect on cumulative water produced

Table 7 shows a summary of the cumulative water produced for thick-oil rim reservoir cases at a production time of 495 s. Highest volume of water (1.858 L) was produced in Case 1 and the least in Case 6 (1.674 L). The barrels of water decreased with the prolong of shut-in time. However, in between shut-ins the cumulative water reduced with time while attaining new WOC levels. Decrements of 4.90% (Cases 2 and1), 2.60% (Cases 3 and 2), 2.03% (Cases 4 and 3) and 0.65% (Cases 5 and 4) were observed in between shut-in times. The decrease in water produced was due to a reduction in available pore spaces over time for oil displacement. However, 9.96% reduction in the cumulative water produced was observed between Cases 1 and 6. The insufficiently low water production reported by Beattie and Roberts (1996) was possibly due to the available interconnected pore spaces in the fractured reservoir, shape and height of the water cone experienced in vertical wells. In horizontal wells, a crest-like shape was observed so a higher tendency to recede is possible in oil reservoirs with fairly high-interconnected pore spaces such as that used in this study.

Table 7 Cumulative water produced at production time of 495 s (thick-oil rim reservoir)

Cases	Cumulative water produced, L	Reduction in the cumulative water produced, %
Case 1	1.858	
Case 2	1.767	4.90
Case 3	1.721	7.37
Case 4	1.686	9.26
Case 5	1.675	9.85
Case 6	1.673	9.96

A summary of the cumulative water produced at production time of 210 s for thin-oil rim reservoir cases is shown in Table 8. It can be seen that Case 9, the uncontrolled production case had the highest produced water among all cases at 0.974 L of oil succeeded by Cases 8 and 9 at 0.965 L and 0.964 L respectively. Decrements in percentages of water produced (0.92% and 1.03%) were observed with increased shut-in times (0-2700 s) from Cases 7-9, possibly due to decreasing available pores for oil displacement by gravity and density. The low reduction in produced water between Cases 7 and 9 over increasing shut-in times was due to the closeness of the WOC to the perforation zone and hence a shorter water breakthrough time.

Table 8 Cumulative water produced at production time of 210 s (thin-oil rim reservoir)

Cases	Cumulative water produced, L	Reduction in the cumulative water produced, %
Case 7	0.974	
Case 8	0.965	0.92
Case 9	0.964	1.03

3.4 Effect on cumulative liquid produced

Table 9 summarizes the cumulative liquid in Litres produced at 495 s for thick-oil rim reservoir cases. The cumulative liquid produced decreased generally from Case 1 to Cases 5 and 6, with an increase in shut-in time. Despite the reduction in the cumulative liquid produced, higher volumes of oil were produced with reducing volumes of water produced. The percentage difference in the cumulative liquid produced between. The decline in the cumulative liquid produced was affected by gravity and density difference in the reservoir.

Table 9 Cumulative liquid produced at production time of 495 s (thick-oil rim reservoir)

Cases	Cumulative oil produced, L	Cumulative water produced, L	Cumulative liquid produced, L	Reduction in the cumulative liquid produced, %
Case 1	2.950	1.858	4.808	
Case 2	2.983	1.767	4.750	1.21
Case 3	3.021	1.721	4.742	1.37
Case 4	3.048	1.686	4.734	1.54
Case 5	3.057	1.675	4.732	1.58
Case 6	3.059	1.673	4.732	1.58

Table 10 presents a summary of the cumulative liquid produced at a production time of 210 s for thin-oil rim homogeneous reservoir cases. A similar trend to the thick-oil rim reservoir was observed. Therefore, with an increase in shut-in time, lower cumulative liquid was produced from Case 7 (1.958 L) to Case 9 (1.955 L). However, lower percentages in between shut-ins were realised. Case 7 and 8 had 0.10% reduction whereas Cases 8 and 9 was 0.05%. The percentage reduction between the base case (Case 7) and Case 9 was as low as 0.15%.

Table 10 Cumulative liquid produced at 210 s (thin-oil rim reservoir)

Cases	Cumulative oil produced, L	Cumulative water produced, L	Cumulative liquid produced, L	Reduction in the cumulative liquid produced, %
Case 7	0.984	0.974	1.958	
Case 8	0.991	0.965	1.956	0.10
Case 9	0.991	0.964	1.955	0.15

4 Conclusions

A novel procedure was presented for cresting control in horizontal wells in homogeneous reservoirs. This method involves the use of electromagnetically operated valve and effluents breakthrough time. The investigation was done for a homogeneous reservoir, characterized by fairly high-interconnected pores spaces for both thick and thin-oil rims. From the results presented, it can be concluded that:

1. The use of this procedure produced good results in terms of produced oil and water for thick-oil rim reservoir. Increment in percentage of 3.56% in oil recovered and reduction of 9.96% were observed in thick-oil rim homogeneous reservoir whereas a negligible increment in oil produced (0.7%) and 1.03% reduction in water produced were observed in thin-oil rim homogeneous reservoir.

2. The feasibility of this procedure depends on the thickness of the oil column. The longer the shut-in periods for thick-oil rim reservoir, the higher the oil recovery, cumulative oil produced and the lower the cumulative water produced. This is due to longer time required for the pressure drop to supersede the hydrostatic pressure at the Water-Oil-Contact.

3. The larger the oil column, the longer the time required for water and gas to recede after shut-in. The Gas-Oil-Contact level receded almost immediately when compared with Water-Oil-Contact due to its relatively low density and viscosity compared to that of water.

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