Optimization of frac imbibition process system in Lamadian oilfield

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Abstract. The most effective way to develop oil fields is hydraulic fracturing. During the development process, it is found that the shut-in time after fracturing has a great impact on crude oil production, and the analysis believes that imbibition is the main reason. Therefore, it is necessary to study the influence of hydraulic fracturing on the imbibition law of oil reservoir, give full play to the imbibition function, and improve the development effect of oil field. In this paper, the relationship between imbibition and post-fracturing shut-in time and imbibition rate and post-fracturing shut-in time is studied, and on this basis, the production system is optimized and the limit shut-in time is determined.

1. Introduction

At present, for the development of high water cut and low permeability oil and gas reservoirs, fracturing is one of the most effective measures to enhance oil and gas recovery and increase oil and gas production[1]. The main mechanism is to increase the fluid pressure of the pump group on the ground[2]. When the injection pressure greatly exceeds the formation fracture pressure, the pressure will be suppressed near the bottom of the well[3], and then the fracture along or perpendicular to the formation will be generated. Under normal circumstances, when fractures are formed after fracturing[4], due to the role of proppants, the fractures formed by fracturing have a high conductivity, generally between 10μm2 and 80μm2. Imbibition oil recovery is mainly through a way similar to molecular thermal motion or Brownian motion, relying on the surface and interfacial tension of oil[5], water and rock surface itself. The crude oil spontaneously enters the fracture, and then with the Darcy flow or multiphase pipe flow in the fracture, the produced crude oil flows into the bottom of the well. In combination with fracturing technology, it is a new idea for oilfield development to use the imbibition process of water-driven oil from hydrophilic rock for reservoir oil recovery. In this paper, based on the investigation of relevant literature on imbibition and fracturing, the spontaneous and dynamic imbibition rule of reservoir in fracturing fluid is analyzed and studied. By evaluating the effect of surfactant in fracturing fluid on improving the imbibition ability of matrix rock, the understanding of the formation system of improving reservoir imbibition is provided for the basis of capillary imbibition based reservoir development.

2. Relationship between imbibition recovery and shut-in time after fracturing

Referring to the article of Aronofsky J. S. et al., it is assumed that the amount of oil recovered from the rock matrix is a function of time. When the hydrophilic rock block is saturated with oil and completely immersed in water at t=0, the imbibition and oil discharge led by capillary force occurs, and the relationship between the amount of oil recovered from the rock matrix R and time t is as follows[6]:

$$R = R_{\infty}(1 - e^{-\lambda t}) \quad (1)$$

Where: λ: is an empirical constant and has no dimension;R: is the oil recovery rate, decimal;R_{∞}: represents the ultimate recovery rate of crude oil, decimal;

The Aronofsky J. S model is well adapted for short core samples with small diameters and cores placed vertically with water injected from the bottom. Babadagli found that the Aronofsky model has certain limitations in his experimental research, and proposed an extended model to address this limitation:

$$R = R_{\infty}(1 - e^{-\omega t^{n}}) \quad (2)$$

Where: n - is an empirical constant; ω - is a parameter related to fluid properties and reservoir rocks.

The model parameters are usually obtained by experimental methods. Due to the limitation of testing means and experimental equipment, experimental methods often have the disadvantages of expensive, long experiment period and large error. Therefore, the following methods are used to obtain the model parameters in this paper.

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Substituting $R=\frac{N_{\mathrm{P}}}{N}$ and $R_{\infty}=\frac{N_{\mathrm{r}}}{N}$ into $R=R_{\infty}(1-e^{-\omega t^{n}})$ yields:

$$\frac{N_r}{N_r-N_p}=e^{\omega t^n} \tag{3}$$

Finding the natural logarithm of both sides of formula (3) gives:

$$\mathrm{In}(\frac{N_{\mathrm{r}}}{N_{\mathrm{r}}\text{-}N_{\mathrm{p}}})=\omega t^{n} \tag{4}$$

To find the natural logarithm on both sides of formula (4), we get:

$$\mathrm{In}(\mathrm{In}(\frac{N_{\mathrm{r}}}{N_{\mathrm{r}}-N_{\mathrm{p}}}))=\mathrm{In}\omega+n\mathrm{In}t \tag{5}$$

Where: N_{p} : Cumulative oil production, m³; N_{t} : Recoverable geological reserves, m³; N : Geological reserves, m3.

From the above formula, we can see that $\mathrm{In}(\mathrm{In}(\frac{N_{\mathrm{r}}}{N_{\mathrm{r}}-N_{\mathrm{p}}}))$ and In*t* have a linear relationship. By using the least square method to linear regression the actual production data of the reservoir, we can get the values of n and In*ω*, so that the *ω* values can be obtained.

3. Relationship between imbibition rate and shut-in time after fracturing

In the process of reservoir fracturing development, the occurrence time of maximum imbibition velocity is closely related to the shut-in time after fracturing, which is an important parameter for reservoir imbibition effect evaluation and has great guiding significance for reservoir imbibition oil recovery. The occurrence time of the maximum imbibition velocity can be obtained by the following methods:

$$f=\frac{R}{R_{\infty}}=1-e^{-\omega t^{n}} \tag{6}$$

By differentiating both sides of equation (6) with respect to time t, we get:

$$\frac{\partial f}{\partial t}=n\omega t^{n-1}e^{-\omega t^{n}} \tag{7}$$

Formula (7) represents the imbibition rate. We can analyze and see that the imbibition rate is related to coefficient n and, and then take the second-order derivative of formula (7) to obtain:

$$\frac{\partial^2 f}{\partial t^2}=((n-1)-n\omega t^n)n\omega t^{n-2}e^{-\omega t^n} \tag{8}$$

Formula (8) represents the change rate of imbibition velocity. It can be seen from the formula that when the imbibition rate is the largest, that is $(n-1)-n\omega t^{n}=0$, the occurrence time of the maximum imbibition rate is as follows:

$$t=e^{\frac{In(\frac{n-1}{n\omega})}{n}} \tag{9}$$

Formula (9) represents the time when the maximum imbibition rate occurs.

4. Determination of limit shut-in time

To determine the limit shut-in time of oil reservoir after fracturing, the following three aspects should be considered: ① Combined with indoor dynamic and static spontaneous imbibition experiments; ② Consider the actual construction results and actual oil well parameters; ③ Judging the limit production by combining the oil well productivity formula.

4.1. Changes of dynamic and static spontaneous imbibition rates of oil Wells

According to the actual reservoir fracturing process, static imbibition experiment of fracturing fluid was carried out to determine the dynamic and static imbibition rates of formation core under indoor conditions, as shown in the figure, and the asymptotes of discharge and static imbibition and their related formulas were given in figure1.

For the selection of actual oil well parameters on site, horizontal Wells in tight oil reservoirs in Block X of Daqing Oilfield and their fracturing parameters were selected for analysis, as shown in the table.

Table 1 Horizontal Wells and fracturing parameters in Block X of Lamadian Oilfield

Item	parameter	Item	parameter
porosity	20%	Seam half length	80m
permeability	100×10⁻³μm²	Seam height	5m
Well spacing	300m	Fracture conductivity	40μm²
Horizontal well length	600m	Bottom hole pressure	MPa
Reservoir thickness	5m	Boundary pressure	30MPa
Wellbore radius	0.15m	Oil saturation	45%

In this paper, Joshi formula is used to calculate the productivity formula of the horizontal well in the layer. It is assumed that the horizontal well is open hole, equal thickness, homogeneous, infinite reservoir and single phase flow.

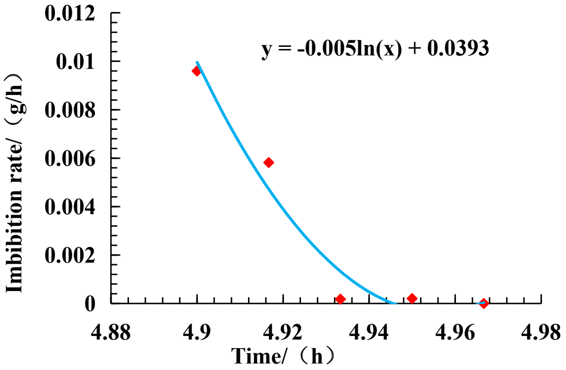
$$Q=\frac{0.5428K_h h\times\Delta P/(B_o\mu_o)}{\ln\left[\frac{a+\sqrt{a^2-(L/2)^2}}{L/2}\right]+(\beta h/L)\ln[\beta h/(2r_w)]} \tag{10}$$

Where,

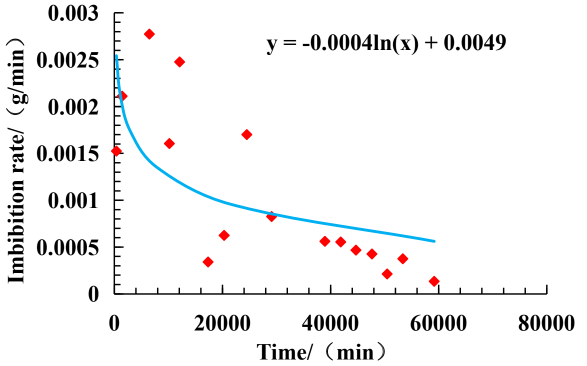
$a=(L/2)[0.5+\sqrt{0.25+(2r_e/L)^4}]^{0.5}$.

The physical meanings and units represented by each parameter in the above formula are as follows:

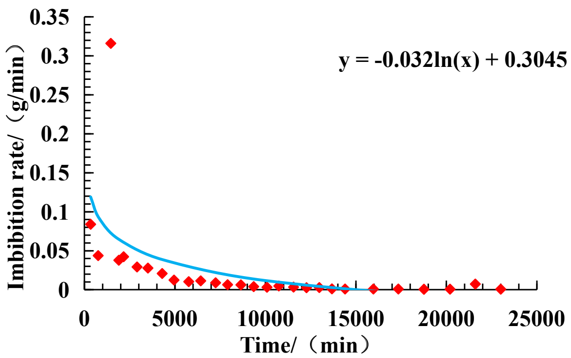
Q: Horizontal well oil production rate, m^3/d;K_h :horizontal permeability, $10^{-3}\mu m^2$;K_v: vertical permeability, $10^{-3}\mu m2$;H : reservoir thickness, m;B_o: crude oil volume factor;μ_o: crude oil viscosity mPa·s; L: Horizontal section length, m;r_e : drainage radius, m;rw: hole radius, m;β : reservoir anisotropy coefficient,;δ:eccentricity of horizontal Wells, m.



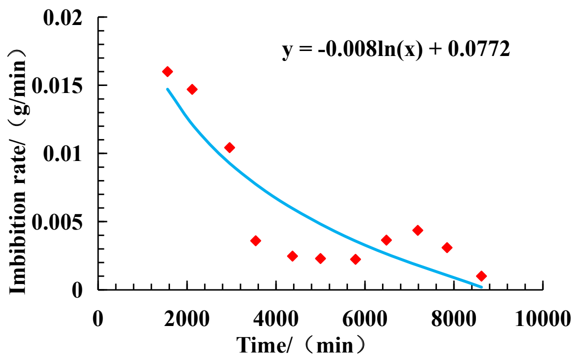
a. Core imbibition rate curve in formation water



b. Core imbibition rate in fracturing fluid (0.5%) filtrate



c. Core imbibition rate in fracturing fluid (0.9%) filtrate



d. Core imbibition rate in fracturing fluid (2%) filtrate

Figure 1 Static imbibition results at different fracturing fluid concentrations

4.2. Calculation of limit shut-in time

According to the productivity formula of horizontal Wells and the basic data in Table 1, the oil production of horizontal Wells is calculated as $12.15m^3/d$.

The formula of geological reserves of tight oil reservoir horizontal Wells in Block X of Lamadian Oilfield is as follows:

$$N = Ah\phi S_{oi} \tag{11}$$

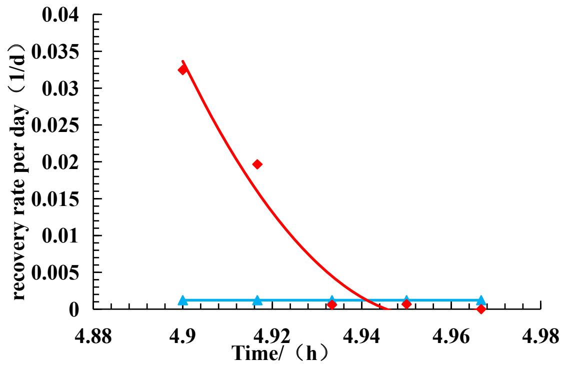
Combined with the data in Table 1 and formula (11), the geological reserves of horizontal Wells are calculated to be $28,350m^3$.

It can be obtained by calculating the specific gravity of the horizontal well production to the recovery factor.

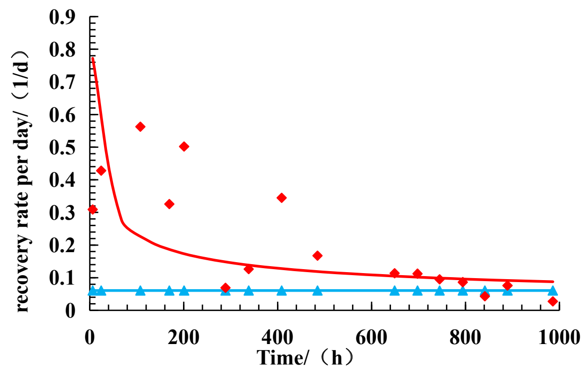
$$\frac{Q}{N} = \frac{12.15}{28350} = 4.2857 \times 10^{-4} \tag{12}$$

Meanwhile, the specific gravity of imbibition rate to the recovery factor can be calculated by combining the data in 3.1, as shown in figure 2: The limit shut-in time is determined to be when the increase in imbibition recovery rate is the proportion of production to recovery rate during normal production of horizontal well, that is, the intersection time of the two lines in the above drawings is the limit shut-in time. As can be seen from Figure 2, for the clear water fracturing fluid system without surfactant, the shut-in time after fracturing has a certain impact on the imbibition effect, but the impact is small. The limit shut-in time is about 4.94 hours. When the limit shut-in time is greater than the limit shut-in time, the recovery rate per unit time generated by imbibition gradually decreases to the normal production standard. However, when a certain amount of surfactant is added to the fracturing fluid system, the fracturing fluid system has a greater impact on the shut-in time after fracturing. Compared with formation water, the limit shut-in time is significantly extended. As can be seen from Figure 2.c, when the concentration of surfactant in the fracturing fluid reaches 0.5%, the limit shut-in time can be converted to about 600h. As shown in FIG. 2-c and FIG. 2-d, the concentration of surfactant in the fracturing fluid system increases, its imbibition effect is obvious, and the limit shut-in time is longer. In this case, the limit shut-in time cannot be determined by the above methods. It does not meet the site construction requirements, so the calculation of the limit shut-in time should be further studied.

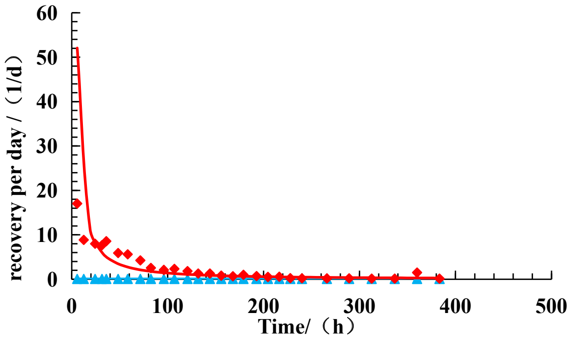
https://doi.org/10.1051/e3sconf/202457302011



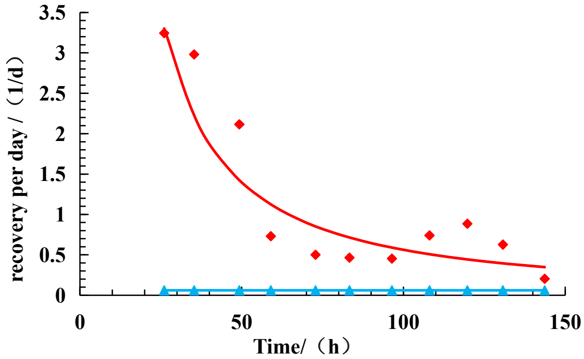
a. Core limit shut-in time in formation water



b. Limit shut-in time in frac fluid (0.5%) filtrate



c. Limit shut-in time in frac fluid (0.9%) filtrate



d. Limit shut-in time in frac fluid (2%) filtrate

Figure 2 Limit shut-in time of different fracturing fluid concentrations

5. Conclusion

Adding a certain amount of surfactant to the fracturing fluid system will have a great effect on the spontaneous imbibition in the reservoir. When 0.5% OP-10 surfactant is added to the fracturing fluid system, the limit shut-in time is about 600h (about 25d), and the impibition effect continues to increase as the surfactant concentration continues to increase. The above calculation method for the limit shut-in time is difficult to achieve and does not meet the on-site construction requirements. Therefore, the calculation of the limit shut-in time should be further studied.

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