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Research Article

Study on Reasonable Energy Supplement Time of Tight Sandstone Oil Reservoirs with Rock Compressibility Stress Sensitivity

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A-HBR field is a tight sandstone oil reservoir with a threshold pressure gradient and a rock compressibility stress sensitivity. However, no existing approach could predict reasonable energy supplement time considering both of them. Therefore, in this paper, rock compressibility stress sensitivity experiments are conducted. Then, a new approach is presented. This approach considers the correlation of rock compressibility and formation pressure. And the formation pressure is different from the development time and distance to oil well. The study suggests that the energy supplement time is later when the original rock compressibility is larger. The energy supplement time is earlier when the rock compressibility is more severe. A-HBR field's reasonable energy supplement time is 83 days when considering the effect of rock compressibility stress sensitivity. It is much earlier than that when not considering the effect of rock compressibility stress sensitivity.

1. Introduction

A-HBR field is an overpressured tight sandstone oil reservoir. The depth of the reservoir is 3760 m. The average porosity is 12%. The average permeability is 32 mD. The oil viscosity is 0.4 mPa·s. The original formation pressure is 50 MPa. Tight oil reservoirs have obvious threshold pressure gradient characters [1–3] and rock compressibility stress sensitivity characters [4–7]. The formation water is going to salt out and solution gas is going to get out from the oil if formation pressure decreases fast. As a result, oil production decreases [8–11]. Therefore, it is key to use natural energy as much as possible and replenish formation energy timely for A-HBR field.

Zhang [12] presented an approach to calculate energy supplement time considering the effect of threshold pressure gradient on drainage radius. However, this approach does not take the pressure distribution into account. Based on the Zhang's approach, Chen et al. presented an approach considering the effect of threshold pressure gradient on pressure distribution [13]. Numerical simulation also could consider both of threshold pressure gradient and rock compressibility stress sensitivity [14–16]. However, numerical simulation takes longer time and is harder to conduct.

However, no existing approach could predict reasonable energy supplement time considering both threshold pressure gradient and rock compressibility stress sensitivity [12, 13, 17–19]. Therefore, this paper comes up with a new approach considering the effect of threshold pressure gradient and rock compressibility stress sensitivity.

2. Rock Compressibility Stress Sensitivity Experiment of A-HBR Field

The rock compressibility stress sensitivity experiments were conducted. The cores comes from A-HBR field, and the basic parameters are shown in Table 1. Experimental process is shown in Figure 1. The experimental method refers to the standard SY/T 5815-2008. The effective stress is designed to be 2.76, 5.52, 8.27, 10.34, 13.79, 20.68, 27.58, 34.47, and 55.16 MPa, respectively. The experimental results are shown in Figure 2. It is found that the rock compressibility stress

Table 1: Basic parameters of cores in rock compressibility stress sensitivity experiments.

Number	Depth (m)	ϕ (%)	K (mD)	C_{ro} ($\times 10^{-3}$ MPa^{-1})
A	3773.72	12.6	37.6	7.8
B	3743.7	12.4	8.0	11
C	3727.36	11.5	35.2	7.6
D	3786.49	11.0	42.1	11
E	3775.76	10.6	40.3	7.4

sensitivity of A-HBR field is severe from Figure 2. The rock compressibility decreases by 90 percent when the effective stress increases from 2.76 MPa to 55.16 MPa. The correlation of rock compressibility and effective stress is obtained from the experimental results (1).

It is found that rock compressibility and effective stress show a good exponential relationship. Rock compressibility is the pore volume reduction per effective stress. When effective stress is small, pore volume is large and pore is easy to press. When effective stress increases, pore volume decreases and rock becomes tight. Thus, pore volume is harder to press and per effective stress results in less pore volume reduction. As a result, rock compressibility is less when effective stress increases [5, 20].

$$C_r = C_{ro} \cdot 4.3434\sigma_{eff}^{-1.097}, \tag{1}$$

where C_r is rock compressibility when the effective stress is σ_{eff}, MPa^{-1}; C_{ro} is original rock compressibility, MPa^{-1}; σ_{eff} is effective stress, $\sigma_{eff} = p_{over} - p$, MPa; p_{over} is overburden formation pressure, MPa; and p is formation pressure, MPa.

3. Reservoir Engineering Approach to Predict Reasonable Energy Supplement Time

The rock compressibility of A-HBR field is stress sensitive. As a result, the location with different distances to oil well has different rock compressibilities (Figure 3). The elastic cumulative oil production, where the distance is r from the oil well, is shown in (2) according to the matter balance principle.

$$dV_o = C_f(\sigma_{eff})(p_e - p(r))dV_f, \tag{2}$$

where V_o is the elastic cumulative oil production, m^3; C_f is the composite compressibility, $C_f = \phi(C_o + C_r(\sigma_{eff}))$, MPa^{-1}; φ is the porosity; C_o is the oil compressibility, MPa^{-1}; C_r is the rock compressibility, MPa^{-1}; V_f is the drainage volume of the oil well, $dV_f = 2\pi rh \cdot dr$, m^3; r is the distance to the oil well, m; h is the net pay, m; p_e is original formation pressure, MPa; and $p(r)$ is the formation pressure where the distance to the oil well is r, MPa.

The threshold pressure gradient greatly affects the pressure distribution in tight sandstone oil reservoirs. The elastic cumulative oil production is the max in tight sandstone oil reservoirs when formation pressure gradient equals the threshold pressure gradient. The formation pressure distribution is shown in

$$p(r) = p_{wf} + \frac{(p_e - p_{wf}) - G(r_e - r_w)}{\ln(r_e/r_w)} \ln\left(\frac{r}{r_w}\right) + G(r_e - r_w), \tag{3}$$

where p_{wf} is the bottom hole pressure, MPa; G is threshold pressure gradient, MPa/m; r_e is the drainage radius, m; and r_w is the well diameter, m.

At the same location, the formation pressure decreases in development. As a result, the rock compressibility decreases (Figure 3) because of the stress sensitivity. Integrating (2) with respect to formation pressure and distance yields the elastic cumulative oil production in drainage volume (4).

$$V_o = \int_{p_b}^{p_e}\int_{r_w}^{r_e} 2\pi rh \cdot C_f(r)(p_e - p(r))drdp, \tag{4}$$

where r_w is the well diameter, m, and r_e the is drainage radius, m.

The controlled reserves per well is shown in (5) if the well space is r_e.

$$N_o = \left(\frac{\pi r_e^2 \cdot h \cdot \phi \cdot S_{oi}}{B_{oi}}\right), \tag{5}$$

where N_o is the controlled reserves per well, m^3; ϕ is the porosity; S_{oi} is the original oil saturation; and B_{oi} is the formation volume factor.

The oil production per well is shown in (6) if the oil recovery rate equals a.

$$q = \frac{aN_o}{t}, \tag{6}$$

where q is the oil production rate, m^3/d; a is the oil recovery rate; and t is the production days per year, days.

Substituting (1) and (3) into (4) yields the elastic cumulative oil production. Substituting (5) into (6) yields the oil production rate. The reasonable energy supplement time is obtained when the elastic cumulative oil production divides the oil production rate:

$$t_b = \frac{V_o}{q}, \tag{7}$$

where t_b is the energy supplement time, days.

4. Verification

Numerical simulation could consider both threshold pressure gradient and rock compressibility stress sensitivity. Therefore, numerical simulation helps to verify the new approach, and commercial software Eclipse E100 is used. The numerical model is shown in Figure 4. The numerical model basic parameters are shown in Table 2. The threshold pressure gradient is shown in (8) [1]. Comparing to the

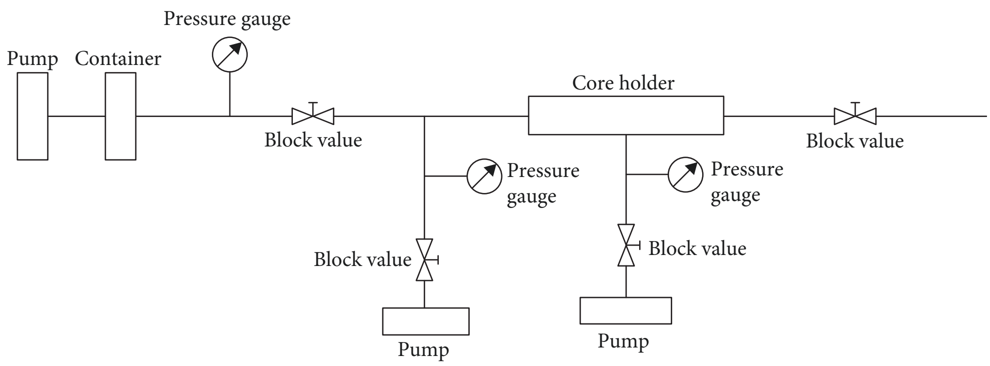

FIGURE 1: Rock compressibility stress sensitivity experimental process.

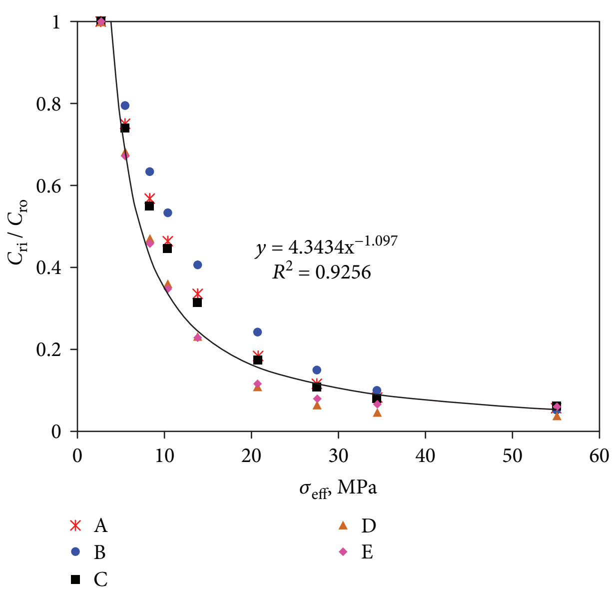

FIGURE 2: Rock compressibility stress sensitivity experimental results.

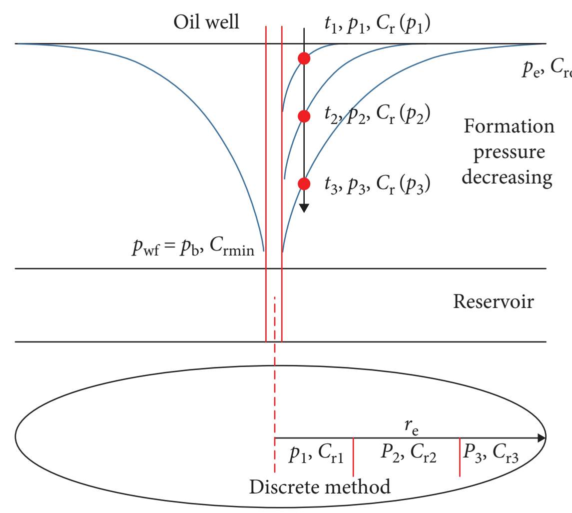

FIGURE 3: Rock compressibility distribution.

formation pressure distribution of numerical model and the new approach, the new approach results have a great agreement with numerical model results (Figure 5). And the error of elastic oil recovery is less than 1% (Table 3).

$$G = 0.075K^{-1.12}, \tag{8}$$

where G is the threshold pressure gradient, MPa/m, and K is the permeability, mD.

5. Sensitivity Analysis

5.1. Original Rock Compressibility. Original rock compressibility ranges from 0.0074 MPa^{-1} to approximately 0.011 MPa^{-1} (Table 1). Therefore, the effect of original rock compressibility on energy supplement time is studied. The basic parameters in the new approach is shown in Table 2. It is found that the original rock compressibility and energy supplement time have a good linear relationship (Figure 6). The average rock compressibility is larger in elastic development when the original rock compressibility is larger. As a result, formation pressure decreases slower and energy supplement time is later.

5.2. Rock Compressibility Reduction. The rock compressibility reduction is different, although the effective stress is the same (Figure 2). Therefore, the effect of rock compressibility reduction on energy supplement time is studied. The basic parameters in the new approach is shown in Table 2. It is found that rock compressibility reduction and energy supplement time have a good logarithmic relationship (Figure 7). The average rock compressibility is larger in elastic development when the rock compressibility reduction is less. As a result, formation pressure decreases slower and energy supplement time is later.

6. Application

Existing approach and this new approach are used to predict energy supplement time of A-HBR field. Basic data of the field is shown in Table 4. From Table 4, it is found that formation pressure decreases faster considering rock compressibility stress sensitivity (Figure 8). In order to avoid gas degassing from oil and oil rate decreasing, energy supplement time should be 86% earlier than not taking the effect of rock compressibility stress sensitivity into account.

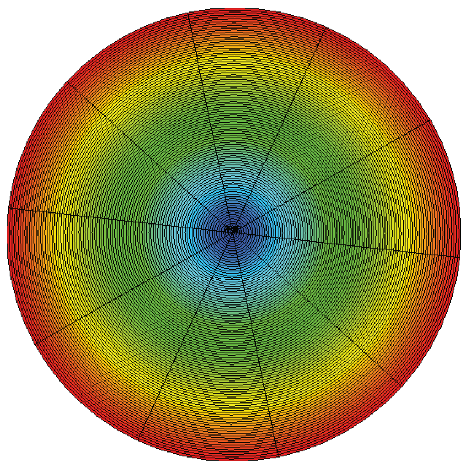

Figure 4: Numerical model.

Table 2: Basic parameters of numerical model.

Parameters	Value
Grid number	100 × 10 × 10
Grid size	1 m × 36° × 1 m
Porosity, %	10.6
Permeability, mD	20
Net pay, m	10
Original pressure, MPa	55
Drainage radius, m	1000
Fluid viscosity, mPa·s	0.4
Formation volume factor	1.6
Original rock compressibility, $\times 10^{-3}$ MPa^{-1}	8.9
Fluid compressibility, $\times 10^{-4}$ MPa^{-1}	4.5
Oil recovery rate, %	1

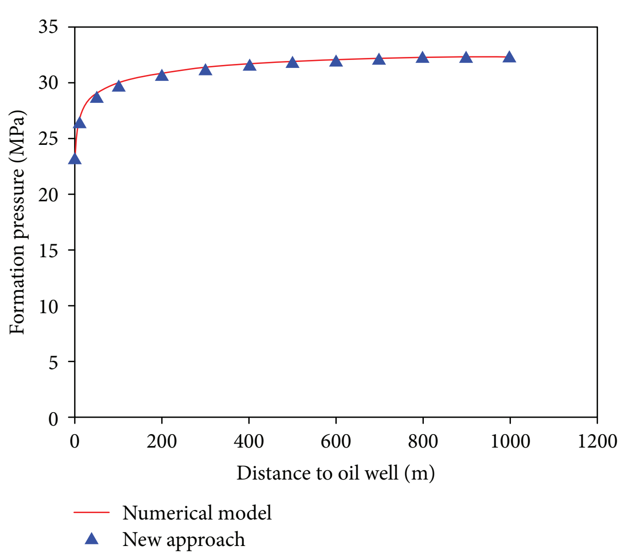

Figure 5: Verification of formation pressure distribution.

Table 3: Error of the new approach.

Method	Elastic cumulative oil production (m^3)	Elastic oil recovery (%)	Energy supplement time (d)	Average formation pressure (MPa)
Numerical model	5111	0.25	81	53.0
New approach	5136	0.25	81	53.3
Error (%)	0.48	0.43	0.39	0.59

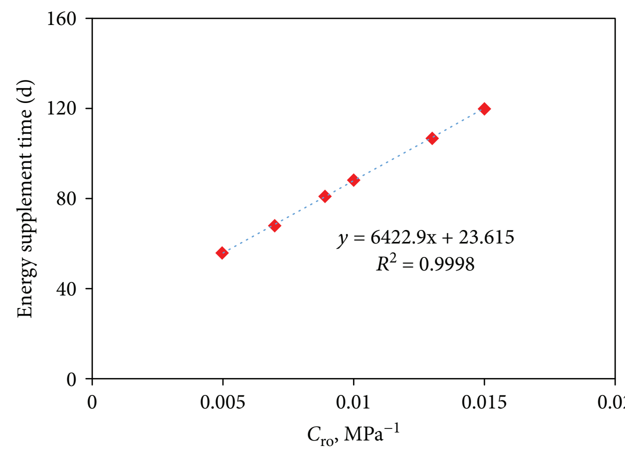

Figure 6: Energy supplement time vs original rock compressibility.

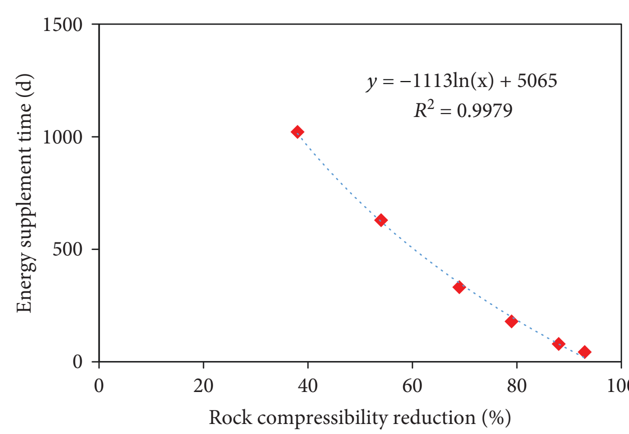

Figure 7: Energy supplement time vs rock compressibility reduction.

7. Conclusions

(1) From experimental results, it is found that A-HBR field has obvious rock compressibility stress sensitivity. The rock compressibility and effective stress have a good power relationship

(2) A new approach is presented to predict energy supplement time of tight sandstone oil reservoirs. This new approach takes threshold pressure gradient and rock compressibility stress sensitivity into account

Table 4: Basic data of A-HBR field.

Field	h (m)	φ (%)	K (mD)	μ_o (mPa·s)	B_o	p_b (MPa)	C_{ro} ($\times 10^{-3}$ MPa^{-1})	Energy supplement time (d) Existing approach (2)	The new approach
A-HBR	13	12	33	0.4	1.6	20	8.9	589	83

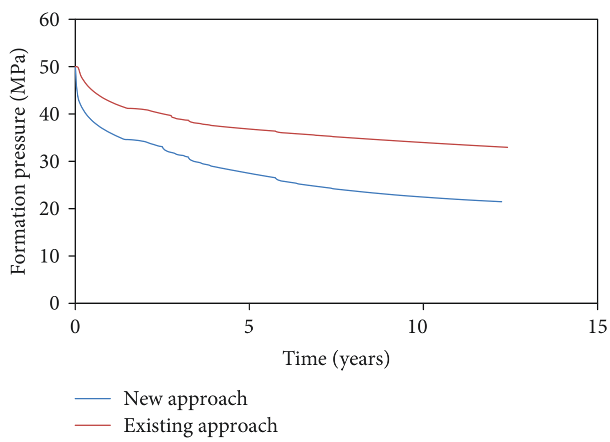

Figure 8: Formation pressure comparison of the existing approach and the new approach.

(3) The formation pressure decreases more slowly, and elastic recovery is larger if the original rock compressibility is larger. As a result, the energy supplement time is later. The formation pressure decreases faster and elastic recovery is smaller if the rock compressibility reduction is larger. As a result, the energy supplement time is earlier

(4) The energy supplement time of A-HBR is 83 days considering the effect of rock compressibility stress sensitivity. It is 86% earlier than the energy supplement time of not taking the effect of rock compressibility stress sensitivity into account

Data Availability

The data used to support the findings of this study are available from the corresponding author upon request.

Conflicts of Interest

The authors declare that they have no conflicts of interest.

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