Appropriate use of dissolved gas energy in fields at the final stage of development

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Abstract. In order to improve the development of fields at a later stage, this article considered the use of water-gas repression together with the dissolved gas energy. The theoretical basis of the study is based on the application of the method of physical modeling of oil displacement by water. As a result, it was found that waterflooding would be more effective when such an activity is carried out in the early stages of development. Waterflooding can also be effective in old, depleted fields with shallow depths of oil-bearing horizons. The article states that in flooded deposits, where the reservoir pressure did not drop below the bubble point pressure, it is advisable to reduce the reservoir pressure to the bubble point pressure (to carry out forced withdrawal). After that, water injection should be resumed with 30-50% compensation. It has been established that in order to increase the efficiency of the development of fields developed in the dissolved gas mode, waterflooding must be started at a reservoir pressure that is 30–70% less than the bubble point pressure. The best option for the development of such deposits is the presence of active edge waters. If they are absent, it is advisable to end water in the aquifer with compensation of withdrawals from 20 to 40% after the start of gas extraction from oil.

1. Introduction

Water-gas repression on a productive stratum is considered one of the most effective methods to enhance its oil recovery. Thus, the studies of Hnatiuk G. A. and Liskiewicz I. conducted in 70-80 years proved that water and gas injection is an effective method to increase the final oil recovery factor [1]. This method was thoroughly learned for the conditions of the Samotlor and Urengoi oil fields. Prior to the study of the early stage of field development, the introduction of this method at the Samotlo field showed its high efficiency. In this case, gas is by-passed from the gas reservoir under pressure higher than the reservoir pressure of the oil horizon.

Currently, many oil fields in the Volga-Ural province have entered a late stage of development, and since the main fields (Timan-Pechora, West Siberian, Volgo-Ural) have high gas factors and are developed with waterflooding [2-5], we considered the possibility application of water-gas repression using the energy of gas dissolved in oil.

2. Materials and methods

In order to identify a rational way of using the energy of gas dissolved in oil, based on the analysis of literature data of experimental studies carried out before, two possible options for the development of fields were modeled, which consisted of a combination of operating modes of water-driven and...
dissolved gas:
- development of the natural regime of dissolved gas to a drop in pressure in the reservoir followed by water injection (the conditions of the reservoir operation in the depletion mode with subsequent waterflooding were simulated;
- waterflooding regime with the maintenance of reservoir pressure higher than the saturation pressure to full waterflooding of the formation followed by oil recovery in the depletion mode and injection using water.

In both the first and second cases, the main driving force in the processes of oil displacement is the combination of gas energy, which is separated from oil after the pressure in the reservoir decreases, and water energy, injected following (or simultaneous) gas evolution [6]. Gas released from oil can fill part of the pores previously occupied by oil and contribute to its additional displacement from the formation during flooding (replacement effect). On the other hand, the presence of free gas causes a decrease in the phase permeability of the porous medium.

The dissolved gas mode is driven by the driving force - the energy of the gas that is released from the oil at a pressure below the bubble point pressure. In essence, this mode is similar to the elastic-water pressure mode, because the pressure in the reservoir does not decrease instantly, but gradually. The difference between this mode and the elastic-water-pressure mode is that gas is released from oil under the action of the gas expansion energy. Gas bubbles are elastic force carriers that induce carbonated oil to move. As in the elastic-water pressure, and in the dissolved gas mode, there are two phases distinguished.

During the development of the first phase, the pressure drop in the well is transmitted throughout the entire formation gradually: the radius of the conditional feed loop, on which the initial pressure is maintained, begins to increase. When the pressure starts to decrease at the natural boundary of the reservoir (oil-bearing contour), and the drainage area remains unchanged, the second phase begins [7]. A characteristic feature of the dissolved gas regime is the constancy of the oil-bearing contour, during the production of oil and gas, the reserves of the deposit are depleted (oil saturation decreases within the limits of a constant initial volume). The rate of saturation drop is much lower than the rate of pressure drop, and this is the second characteristic feature of the regime and the main reason for its low efficiency. The gas content of reservoir oil is constantly changing: first it increases, reaches its maximum value, and then, as the reservoir is developed, decreases.

Since, with a decrease in reservoir pressure below the bubble point pressure, the oil viscosity increases, and the phase permeability for oil changes, the oil recovery factor also decreases. At about 50% water saturation, water breaks through to the production wells very quickly. The oil displacement front practically does not arise, and is not formed from oil globules. Therefore, oil recovery does not increase until the displacement front breaks through. It is in this sense that the combination of the energy of dissolved gas and waterflooding is important, which can be both natural (active edge waters) and artificial, when water is forcibly injected into injection wells [8].

The second direction of research - the option of developing a field with a combination of modes of water pressure and dissolved gas, discusses the following. The field is developed by waterflooding and with the subsequent achievement of a higher saturation pressure, and ultimately leading to a complete flooding of production wells. After that, the reservoir pressure in the field is reduced to the bubble point pressure and below, by means of forced withdrawal and limiting the rate of water injection.

3. Results and discussion
The article discusses the results of experimental modeling of these development options in the geological and industrial conditions of the above fields. The study was carried out by physical modeling of fluid filtration processes in the pore space of the reservoirs of the indicated fields. Experiments were performed on reservoir models with natural sampling of coring material. Recombined samples of reservoir oils and waters were used as reservoir fluids.

The study modelled the corresponding values of reservoir pressure and temperature. To study the processes of filtration of inhomogeneous liquids in laboratory studies, it used methods of approximate
modeling and the similarity theory, which at one time was developed in detail by Efros D. A. and is a system of seven equations [9]. Subsequently, many researchers have comprehensively analyzed these equations and made conclusions regarding the filtration parameters of inhomogeneous fluids.

First of all, this concerns those parameters that are determined in advance, even before the start of development processes: physical properties of a porous medium, liquids and gases, surface tension at the liquid-gas interface, etc. In addition, some parameters can be determined not only by similarity conditions, but also by the very program of experience, when under given conditions it is possible to minimize a number of factors that affect the process of oil displacement. For example, in experiments in which gas dissolution should be avoided, the pressure drop should be small in relation to the total pressure level [10, 11]. Based on the conditions of similarity, performed in the experiments, we used models that consisted of natural core material, which ensured the geometric similarity of the pore space, also ensured the similarity of the capillary pressure and related ratios through equality of contact angles. For the processes of oil displacement, the external conditions of similarity are the criteria \( \Pi_1 \) and \( \Pi_2 \), which are calculated according to the following dependencies:

\[
\Pi_1 = \frac{\sigma \Delta P}{K_a \sqrt{m}} ;
\]

\[
\Pi_2 = \frac{\sigma \text{grad} P}{K_a} ;
\]

where \( \Pi_1 \) and \( \Pi_2 \) are similarity criteria; \( \sigma \) – interfacial tension at the fluid boundary, N/m; \( K_a \) – absolute permeability, \( m^2 \); \( m \) – porosity; \( \Delta P \) – pressure drop, Pa; \( \text{grad} P \) – pressure gradient, Pa/m.

A characteristic feature of these criteria is that, starting from some values of \( \Pi_1 \) and \( \Pi_2 \), they cease to affect the characteristics of filtration processes [12]. Due to this feature, the existence of a self-similarity region was established, when the fluid movement does not change when one or several parameters that determine this movement are changed, namely \( \Pi_1 < 0.5 \) and \( \Pi_2 > 0.3 \cdot 10^6 \). Based on these criteria, the minimum length \( L_{\text{min}} \) of the reservoir model will be determined by the formula:

\[
L_{\text{min}} = 6 \times 10^5 \sqrt{K_a} \cdot m
\]

If the porosity of the rock is 10-16\%, and the permeability is 40-170 \cdot 10^{-3} \mu m^2, then the length of the model should be at least 110-240 mm. Since in the experiments carried out the length of the models was 420–450 mm, the conditions of the laboratory studies performed with the proper completeness ensured the self-similarity of the processes according to the criteria \( \Pi_1 \) and \( \Pi_2 \).

For an experimental study of the processes of filtration and displacement of oil by water in accordance with similarity criteria, in relation to the parameters and conditions of occurrence of productive horizons of the Timan-Pechora, West Siberian, Volga-Ural fields, reservoir models were built as follows. Samples of sandstones were taken with a diameter of 28 mm, porosity from 0.10 to 0.16 and permeability from 1.0 \cdot 10^{-3} to 11.0 \cdot 10^{-3} \mu m^2. The compiled model from core material with approximately the same reservoir properties was placed in core holders, and thus its total absolute permeability was determined. After that, the samples were saturated with formation water, and the open porosity of the model was determined by weighing.

Residual water saturation was reproduced by the displacement method. First, from a water-saturated model, the water was mixed with transformer oil, after which the oil was replaced with kerosene. The model prepared in this way was injected with oil recombined in reservoir conditions [13]. At each stage of fluid injection, the phase permeability of the model was measured for each of them. To model the residual naphtha water saturation, reservoir water and oil from the above fields with the parameters shown in Table 1 were used.

For the recombination of oil samples, the study used the associated gas of the above fields, and for the displacement of oil it was fresh (river) water. The injection rate during the displacement process was \( \sim 0.17 \cdot 10^{-9} \text{ m}^3 / \text{sec} \). Experimental studies were carried out using the setup (Figure 1). Modeling of reservoir pressure and fluid injection was carried out using presses 1 and 2 of the installation, which are connected with containers 3, 4, 9, 13 using appropriate transmission channels. The working volumes of the containers were filled with fluids diverting for the experiments.
In the experiment, a core separator 5 was used, which makes it possible to create cylindrical models of a formation with a diameter of 28 mm and a length of 500 mm. The overburden pressure was modeled by lateral compression of the rock with an elastic cuff, the pressure on which was created using a hand press 6. Reservoir pressure was simulated using a pump 8 and a container with a piston separator 9 and was maintained by a pressure regulator 7. At the exit from the model, the fluids were separated in the separator 10, after which the liquid phase got to the measuring burette 11, and the gas volume was measured by the gas meter 12 or the so-called gas measuring burette.

Table 1. Geological and physical data for modeling

| Parameters                        | Deposits of the Timan-Pechora horizons | Deposits of the West Siberian horizons | Deposits of the Volga-Ural horizons |
|-----------------------------------|---------------------------------------|---------------------------------------|-----------------------------------|
| Depth of occurrence, m            | 2240                                  | 2575                                  | 2550                              |
| Porosity                          | 0.084                                 | 0.106                                 | 0.077                             |
| Permeability, 10-3 μm²             | 4.9                                   | 4.0                                   | 1.5                               |
| Oil saturation                    | 0.68                                  | 79                                    | 0.77                              |
| Reservoir temperature, °C          | 70                                    | 70                                    | 52                                |
| Initial reservoir pressure, MPa    | 30.7                                  | 34.3                                  | 20.0                              |
| Oil viscosity in reservoir conditions, mPa · s | 0.94                                  | 0.77                                  | 0.81                              |
| Volume factor                     | 1.475                                 | 1.67                                  | 1.315                             |
| Paraffin content,%                | 12.4                                  | 9.3                                   | 10.0                              |
| Saturation pressure, MPa          | 26.0                                  | 34.3                                  | 17.4                              |
| Density of oil, kg / m³           | 842                                   | 830                                   | 810                               |
| Gas content, m³ / t               | 165.0                                 | 611                                   | 115.6                             |
| Formation water salinity, g / dm³  | 180.0                                 | 118.0                                 | 115.2                             |
| Density of water, kg / m³         | 1120                                  | 1074                                  | 1035                              |

Figure 1. Schematic diagram of the installation: 1, 2 - installation presses; 3, 4, 9 - containers; 5 - reservoir model; 6 - press; 7 - reducer; 8 - pump; 10 - separator; 11 - measuring burette; 12 - gas meter; 13 - PVT bomb; 14 - valve

The results of the experimental work reproduced the development of the natural regime of dissolved gas followed by water injection (the conditions of reservoir operation in the depletion mode...
followed by waterflooding were simulated), shown in Figures 2 and 3. By using the obtained data for the conditions of the fields of the West Siberian horizons (Fig. 2) it established that in the case of a decrease in reservoir pressure to 0.75 \( P_{\text{sat}} \), about 45% of oil is squeezed out from the model; and when the reservoir pressure decreases to 0.5 \( P_{\text{sat}} \) and 0.25 \( P_{\text{sat}} \), 58% and 61% of oil is squeezed out, respectively.

**Figure 2.** Experimental dependences of oil recovery on reservoir pressure and injection volume, obtained on the model of menilite deposits of the Timan-Pechora horizons: 1 - curve of oil displacement beyond reservoir pressure \( P_{\text{dis}} \), higher oil saturation pressure \( P_{\text{sat}} \); 2 - curve of oil displacement beyond reservoir pressure \( P_{\text{dis}} = 0.75 \ P_{\text{sat}} \); 3 - curve of oil displacement at \( P_{\text{dis}} = 0.5 \ P_{\text{sat}} \); 4 – oil displacement curve at \( P_{\text{dis}} = 0.25 \ P_{\text{sat}} \)

Thus, with a decrease in reservoir pressure to 0.75 \( P_{\text{sat}} \) the oil displacement coefficient is slightly lower than the pressure above the bubble point pressure (0.46 versus 0.52). However, when the reservoir pressure is reduced to 0.50 \( P_{\text{sat}} \) and 0.25 \( P_{\text{sat}} \) (curves 3, 4, Figure 2), oil recovery is achieved at 0.58 and 0.61, respectively, i.e. more than in the “clean” water pressure mode (curve 1, Figure 2).
should also be noted that the oil recovery factor during the anhydrous period is lower than when exposed to gas. These results are shown in Fig. 3 in the form of the dependence of the change in the oil recovery factor on the magnitude of the decrease in reservoir pressure in the dissolved gas mode with subsequent gas injection [14].

Thus, our results indicate that waterflooding has the greatest effect at the early stage of field development, and in depleted formations, i.e. already at the final stage, as a result of natural development, where reservoir pressures are very low (much lower than the oil saturation pressure with water), further gas injection can be effective. Gas injection can be applied to old fields at a late stage of development and with already depleted reservoir pressure.

4. Conclusion

Thus, having conducted the analysis of the feasibility of using gas energy in fields at the final stage, we can highlight the following main points:

- waterflooding of deposits will be most effective if it is carried out at the initial stage of field development;
- in depleted reservoirs that were developed in the dissolved gas mode, when the reservoir pressure is low (close to atmospheric), so further waterflooding may be less effective. It is advisable to introduce such flooding in old depleted fields with a shallow depth of occurrence of oil and gas reservoirs;
- in flooded reservoirs, where the reservoir pressure does not decrease in relation to the bubble point pressure, it is advisable to reduce the reservoir pressure to a value low from the bubble point pressure. After that, water injection should be restored with 30–50% compensation;
- for the development of fields developed in the mode of dissolved gas, it is effective to start waterflooding at reservoir pressure below 30–70% of the oil saturation pressure. The best option for the development of such deposits is the presence of active marginal waters, and in the absence of them, it is advisable, after the start of gas extraction from oil, to pump water into the marginal area with compensation for withdrawals from 20 to 40%.

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