ORIGINAL PAPER - PRODUCTION ENGINEERING

Numerical simulation of air–foam flooding in Wuliwan District 1 of Jing'an Oilfield

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Abstract

Air–foam flooding is an important mean to reduce water cut, improve oil production rate, enhance oil displacement efficiency and oil recovery in old oilfield. Because of high cost of core displacement experiment, numerical simulation is an important method to get optimal injection-production parameters of air–foam flooding, which can improve displacement effect and direct field test in Wuliwan District 1 of Jing'an oilfield. Based on laboratory experiment of air–foam flooding, parameters including model component, low temperature oxidation reaction, physical/chemical phenomena, foam interpolation function were set, and then numerical simulation concept model of air–foam flooding was established, which realized accurate fitting for 1-D core flooding experiment. According to numerical simulation concept model of air–foam flooding, the injection-production parameters including injection volume, gas–liquid ratio, and injection time are optimized. Results indicated that optimum surfactant concentration was 0.5%, optimum injection volume of air–foam was 0.25PV, optimum gas–liquid ratio was 1.5:1, optimum injection time was 65% water cut when air–foam flooding began. The researches were applied in Wellbock ZJ53, Wuliwan District 1 of Jing'an Oilfield. There were 15 well groups with air–foam injection and 63 producers, with annual oil production rate scale of 50000 tons. The oil increase effect was very obvious and the application in Jing'an Oilfield was successful.

Keywords Air–foam flooding · Numerical simulation · Concept model · Injection-production parameter optimization · Field application

Introduction

Nowadays, due to the challenges presented in the oil and gas industry, new modern technologies have arisen to accomplish production goals and environmental requirements (Saleh 2016, 2017, 2018). Development of low permeability oil reservoir is a major task in China's oil industry. Many EOR methods including gas flooding, chemical flooding, profile modification and water shutoff with gel are used to improve development effect of low permeability oil reservoirs. However, it is very hard to get good results with a single method because of gas or water channeling in low permeability oil reservoir. Use of foam is one potential solution for reducing gas mobility (Memon et al. 2017) and promoting oil recovery in lower permeability reservoir by modifying the injection profile (Lu et al. 2013; Sun et al. 2016). Foam is widely used in polymer flooding (Sun et al. 2016), water-alternating gas injection (Memon et al. 2017), and steam flooding (Lu et al. 2013). Air–foam flooding technology combines gas injection flooding and foam flooding, which can act independently or interact with each other. Profile modification of foam and oil displacement of air is utilized simutaneously. The technology can greatly increase injection formation pressure, effectively avoid water channeling, gas channeling, low half-time of foam and loss of surfactant. Combined use of air and foam can also decrease cost, improve safety, increase oil production rate, enhance oil displacement efficiency and oil recovery (Kovscek et al. 1995; Rossen et al. 2010; Wang and Chen 2012). Air–foam flooding is one of the most potential technology in old oilfield, which has been widely used in low permeability oilfield, tight oil

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reservoir and heavy oil reservoir (Pang et al. 2015; Liu et al. 2016).

Change of foam size (Alvarez et al. 2001; Afsharpoor et al. 2010; Ashoori et al. 2012), shape and flow of liquid lamella (Rossen and Gauglitz 1990; Cox et al. 2002), gas diffusion (Nonekes et al. 2012), coalescence of liquid lamella (Weaire et al. 1997; Cohen-Addad and Hohler 2001) are important physical and chemical phenomena in the process of air–foam flooding. However, because it is very difficult to describe microscopic mechanism of air–foam flooding through fine mathematical method, empirical methods of numerical simulation are commonly used to research air–foam flooding (Kovscek et al. 1993; Rossen 2013).

In this paper, first, formulation evaluation, PVT physical property analysis and oil displacement experiment of air–foam flooding system were completed. Then parameters including model component, low temperature oxidation reaction, physical/chemical phenomena, and foam interpolation function were set. Furthermore, numerical simulation concept model of air–foam flooding was established, which realized accurate fitting for experiment data including water flooding and air–foam flooding. According to numerical simulation concept model of air–foam flooding, the injection-production parameters including injection volume, gas–liquid ratio, and injection time are optimized. The researches were applicable in low permeability reservoir of Wellbock ZJ53, Wuliwan District 1 of Jing'an Oilfield and the application effect was very good.

Built of numerical simulation concept model for air–foam flooding

The simulation is completed with the software STARS of CMG. The STARS is a software suitable for steam flooding, thermal recovery and other methods for enhancing oil recovery including air flooding, chemical flooding, polymer flooding, surfactant flooding, alkaline flooding, ASP flooding, and air–foam flooding. In the simulation with software STARS, following problems must be considered.

Set of model component

In the numerical simulation model (Table 1), there are three phases and eight components including WATER (water), SURF (surfactant), OIL (oil before low temperature oxidation reaction), OIL2 (oil after low temperature oxidation reaction), N_2 (nitrogen), O_2 (oxygen), CO_2 (carbon dioxide), and LAMELLA (liquid film or foam). Among them, surfactant only exists in the water phase. Because concentration of

surfactant is very small, the influences of surfactant on density and viscosity of water phase are ignored. There are four components including nitrogen, oxygen, carbon dioxide and foam (lamella) in the gas phase. Seepages of injection fluid and reservoir fluid accord with the generalized Darcy's law, which can realize combined displacement mechanism of difficult components including oil, water, surfactant and injection gas.

Low temperature oxidation reaction and parameter setting

The oxygen in the air will contact with the oil after air injecting into oil layer. When the temperature is lower than 300 °C, low temperature oxidation (LTO) will happen. As a result, the atom of oxygen will connect with the molecule of hydrocarbon, generated carboxylic acid, aldehyde, ketone, alcohol and hyperoxide will be further oxidized to large amount of oxidate and water. To ensure security of oxygen injection and avoid risk of explosion, the air with low concentration of oxygen is injected into the reservoir (Wu et al. 2018).

Through laboratory oxidation experiments between oil and air–foam, it was proved that low temperature oxidation reaction could occur between crude oil and air in the foam. Because of existence of liquid film in the air–foam, the contact between air in the foam and crude oil was delayed. According to chemical examination of crude oil, the molecular weight of crude oil before and after low temperature oxidation reaction was obtained. The coefficient of chemical reaction equation was obtained according to the molecular weight of each substance, and the low temperature oxidation reaction equation was as follows:

$$1OIL + 2O_2 \rightarrow 2WATER + 0.8263\ OIL2 + CO_2,$$

The activation energy E and Arrhenius constant k_0 of low temperature oxidation reaction of crude oil in Wuliwan District 1 of Jing'an Oilfield were obtained by experiments, which were 17.43KJ mol^{-1} and 1.81 min^{-1} separately. Simulation results indicated that in the process of air injection, the oxygen could be consumed quickly. Molar content of oxygen in producer wells was lower than 3%, without risk of explosure.

Description of physical/chemical phenomena and parameter setting

Foam is a dispersed system of gas (air, nitrogen, etc.) formed in liquid phase under the function of foaming agent, where gas is dispersed phase and liquid is continuous phase. Most bubbles require foaming agent to last a longer period of time.

Table 1 Set of model component (three phases, eight components)

Water phase		Oil phase		Gas phase			
WATER	SURF	OIL	OIL2	N_2	O_2	CO_2	LAMELLA

Foaming agents are usually surfactants, polymers or dispersed solids. Foam will break and regenerate continuously during migration in porous media, which is a dynamic equilibrium process. Following three chemical reactions should be considered for the foam.

1. Generation of foam

Under the function of surfactants, bubbles form when gas disperses into liquid. When the adsorption of orientated surfactant on the surface of bubbles reaches up to a certain concentration, the bubble wall will form a solid film. The following chemical reaction equation can be used to express generation of foam:

$$\text{WATER} + 2.15 \times 10^{-5}\ \text{SURF} + 1\text{N}_2$$
$$\longrightarrow 1\ \text{LAMELLA} + 1\text{N}_2.$$
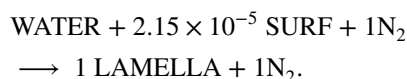
The formula indicates that water and surfactant form foam in the presence of gas phase. The reaction rate is relatively quick, which was 0.1 according to results of synthetic experimental estimation and numerical core fitting.

The main mechanism of surfactant flooding is decreasing IFT between water and oil, thus improving oil displacement efficiency. Pure surfactant flooding is not favorable to make water enter into low permeability layer and improve interlayer contradictions, especially in heterogeneous reservoir. The mechanism of air–foam flooding is that high viscosity foam blocks high permeability channels and the gas enters into low permeability layer, which can increase sweep efficiency of injection fluid.
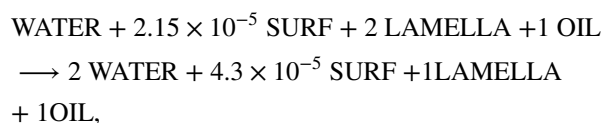
2. Decay of foam

Foam is a thermodynamically unstable system, which has a higher free energy than gas and liquid separately. Free energy tends to decrease spontaneously, which results in gradual break of foam and complete separation of gas and liquid. Foam decay can be expressed with following chemical reaction equation:

$$\text{WATER} + 2.15 \times 10^{-5}\ \text{SURF} + 2\ \text{LAMELLA}$$
$$\longrightarrow 2\ \text{WATER} + 4.3 \times 10^{-5}\ \text{SURF} + 1\text{LAMELLA},$$
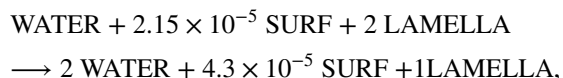
The formula represents the process of natural foam defoaming in liquid phase, where the reaction rate reflects the length of the foam half-life. According to total concentration (0.5%) of foaming liquid, measured half-life of foam system was 385 min, which was converted to reaction rate of 0.0018.

3. Foam defoamed by oil

Crude oil can inhibit and destroy foam. After air–foam system encounters crude oil, crude oil spreads on the surface of liquid film or enters into the liquid film in the form of oil droplet, which can lead to thinning and rupture of liquid film. Therefore, the phenomenon that foam defoamed by oil in the process of foam reaction, must be considered. The following chemical reaction equation can be used to express defoaming of foam when meeting oil:

$$\text{WATER} + 2.15 \times 10^{-5}\ \text{SURF} + 2\ \text{LAMELLA} + 1\ \text{OIL}$$
$$\longrightarrow 2\ \text{WATER} + 4.3 \times 10^{-5}\ \text{SURF} + 1\text{LAMELLA} + 1\text{OIL},$$

The formula represents the process of foam defoamed by oil. In the case of high oil saturation, foam system becomes unstable. The reaction rate measured by experiments and numerical core simulation was faster, which was five times as high as that without oil content.

When the foam decays or breaks, surfactant will generate again and the foam plays a role of surfactant flooding. Therefore, the effect of foam on IFT happens when the surfactant appears after decay or break of foam.

4. Jamin effect of gas bubble seepage

When air–foam system flows in rock pores, because of the influences of Jamin effect, foam is blocked at the narrow opening of the capillary channel. Therefore, foam needs to flow at a higher pressure gradient to overcome capillary force in the pores of rock and drive oil out of the throat. In the numerical simulation, LAMELLA is a liquid film of bubbles and exists as gas phase, similar to foam. By setting viscosity of the component LAMELLA, relative permeability curve of gas–liquid will change, and it can describe the influence of Jamin effect on oil displacement. In this study, viscosity (determined by foam flooding experiment) measured in laboratory is taken as equivalent liquid film viscosity in the bubble, which was 640 mPa.s.

Setting of foam interpolation parameter

In the process of foam flowing, because of changes of surfactant concentration, gas flow rate (or capillary number) and oil saturation, the viscosity and resistance coefficient of gas phase will change. Reducing relative permeability of gas phase is equivalent to increasing viscosity and resistance coefficient of gas phase, or two issues working together. It is the most flexible way to express these effects by modifying relative permeability curve of gas phase. In the empirical model

of foam flooding, foam mobility is expressed as a function of surfactant concentration, gas flow rate (or capillary number) and oil saturation. Reduction of foam mobility is determined by modifying relative permeability curve of gas phase (Fig. 1). The empirical model is expressed as follows:

$$K_{rg}^{f} = K_{rg}^{nf} \cdot F_{M}, \tag{1}$$

$$FM = \frac{1}{1 + MRF \cdot F1 \cdot F2 \cdot F3 \cdot F4 \cdot F5}. \tag{2}$$

Among them, K_{rg}^{f} is the gas phase relative permeability when foam exists; K_{rg}^{nf} is the gas phase relative permeability when foam does not exist. Dimensionless interpolation parameter FM depends on five equations F1–F5 and mobility reduction factor MRF,

$$F1 = \left(\frac{w_s}{w_{smax}}\right)^{es}, \quad F2 = \left(\frac{S_{omax} - S_o}{S_{omax}}\right)^{eo}, \quad F3 = \left(\frac{N_c^{ref}}{N_c}\right)^{ev}, \tag{3}$$

$$F4 = \left(\frac{N_c^{gcp} - N_c}{N_c^{gcp}}\right)^{egcp}, \quad F5 = \left(\frac{x_m^{cr} - x_m}{x_m^{cr}}\right)^{eomf}, \tag{4}$$

where w_s is the surfactant concentration (mole fraction),%; w_{smax} is the maximum surfactant concentration (mole fraction) maintaining strong foam,%; es is the foam concentration index, 1.0–2.0; S_o is the oil saturation; S_{omax} is the maximum oil saturation for foam generation, usually 0.1–0.3; eo is the oil saturation index, 1.0–2.0; N_c is the capillary number; N_c^{ref} is the capillary number of reference velocity; ev is the velocity index, 0.3~0.7; N_c^{gcp} is the critical capillary number, egcp is the index of critical capillary number; x_m is the mole fraction of oil component; x_m^{cr} is the mole fraction of critical oil component, and eomf is the index.
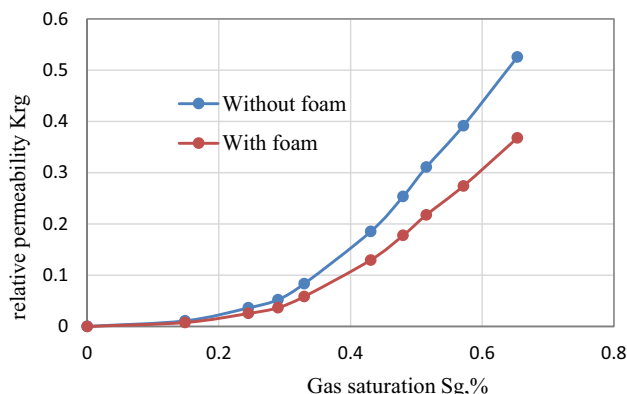

Fig. 1 The relationship between gas relative permeability and saturation under the condition of with or without foam

The MRF was obtained by flow experiment of foam water phase at the maximum surfactant concentration of wsmax:

$$MRF = \frac{(\Delta P)_{foam}}{(\Delta P)_{nofoam}}, \tag{5}$$

where $(\Delta P)_{foam}$ is the core pressure drop with foam flow; $(\Delta P)_{nofoam}$ is the core pressure drop without foam flow. MRF is used to adjust gas relative permeability curves, with a range of 5–100. When value of MRF is large, it is shown that surfactant can form strong foam; if the value is small, the foam is weak.

Usually, only F1, F2, and F3 are needed to be considered. F1 reflects the influence of surfactant concentration, F2 reflects the influence of oil saturation, and F3 reflects the influence of capillary number. According to experimental and fitting results of numerical core, the value of w_{smax} was 0.00003, S_{omax} was 0.3, N_c^{ref} was 0.001, es was 1.0, eo was 1.0, and ev was 0.5 in formula (3).

Optimization of injection-production parameters for air–foam flooding

Experiment fitting of air–foam flooding

There are many physical and chemical reactions in air–foam flooding, which need parameters to describe these phenomena. However, because of complexity of seepage mechanism of air–foam system, some parameters are very difficult to be determined. Based on core flow experiment, main flow rule and oil displacement effect of air–foam system can be reflected correctly; in addition, the parameters can be obtained through fitting between the experiment data and the model calculation data.

The conditions of air–foam displacement experiment are as follows. The size of one-dimensional sand pack is 60.0 cm × 3.0 cm × 3.0 cm. The experimental temperature is 56 °C and pressure is 12.2 MPa. Oil saturation is 58.5% and irreducible water saturation is 41.5%. Average permeability is 320 mD and porosity is 34.50%. Oil viscosity in formation is 2.0 mPa.s. The concentration of surfactant is 0.5% and water injection rate is 0.5 mL/min. First, water was injected into the sand pack until water cut reached up to 98%. Then air–foam was injected, with injection volume of 0.25PV and gas–liquid ratio of 1.5:1. After air–foam took effect, water cut gradually decreased. The final was subsequent water drive until water cut reached up to 98% again.

Experiment fitting is completed by the following steps. First, grid model is built according to actual one-dimensional sand pack. The grid number is 60 × 1 × 1 and grid size is 1.0 cm × 2.66 cm × 2.66 cm (equivalent diameter, $\sqrt{\pi \cdot 3^2/4} = 2.66$ cm). Porosity, permeability and oil saturation of the model are equal to the real sand pack. Then,
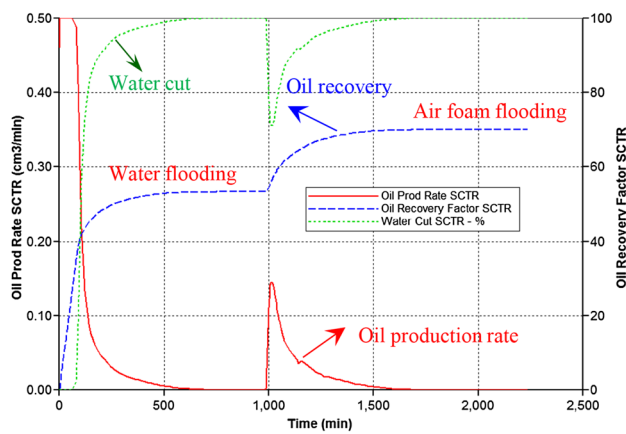
Fig. 2 Numerical simulation results of development indexes in one-dimensional sand pack model for water flooding and air–foam flooding
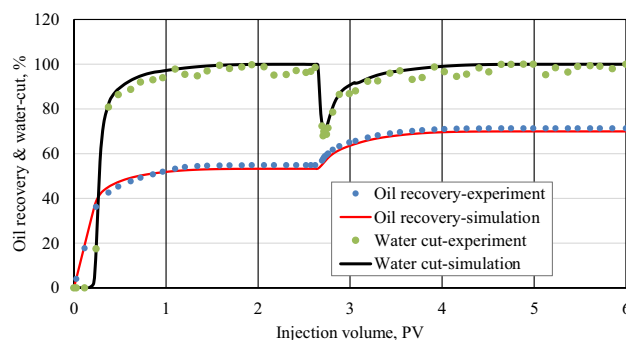

Fig. 3 Fitting of experiment data and model calculation data in one-dimensional sand pack model for water flooding and air–foam flooding

the corresponding parameters including model component, low temperature oxidation reaction, physical/chemical phenomena, and foam interpolation function were input into the model. Through calculation of the model, curves of oil production rate, oil recovery and water cut could be obtained. There might be some differences between experiment data and calculation data. In the process of history matching, water–oil relative permeability curve was adjusted according to water breakthrough time and increase velocity of water cut before injection of air–foam. The values of MRF and gas–liquid relative permeability were adjusted according to changing of water cut after injection of air–foam. Ultimately, a matching result was shown in Figs. 2 and 3. Results indicated that after reaching the limit of water cut, through injection of air–foam, water cut of core decreased, oil production rate and recovery was obviously improved. Simulation results of each stage were basically consistent with the experimental, and the accuracy of numerical simulation model could meet the requirements.
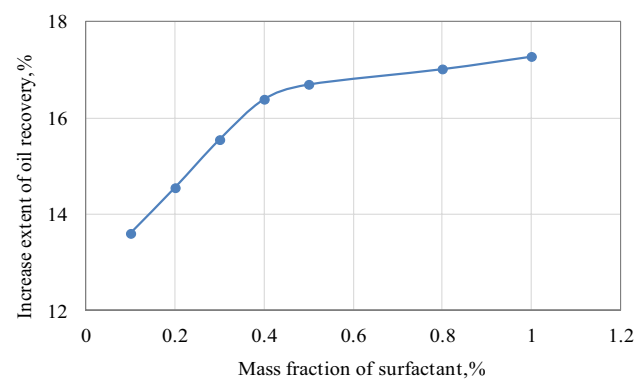

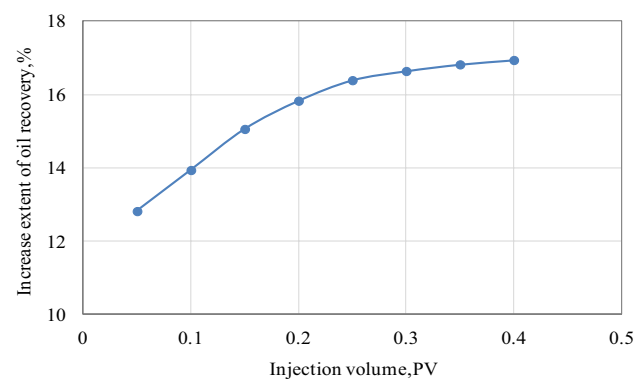**Fig. 4** Influence of surfactant concentration on increase extent of oil recovery

Fig. 5 Influence of injection volume of air–foam system on increase extent of oil recovery

Optimization of injection-production parameters

According to numerical simulation concept model of air–foam flooding, the oil displacement effect under different injection-production parameters was simulated. The relationships between increase extent of oil recovery after air–foam flooding and mass fraction of surfactant or injection volume are shown in Figs. 4 and 5. Results indicate that oil recovery rises with increase of surfactant mass fraction or injection volume, but the increase is getting smaller and smaller. When surfactant concentration or injection volume reaches up to 0.5% or 0.25PV, there is an "inflection point" in the oil recovery curve. Comprehensively considering, the optimum mass fraction of surfactant is recommended to be 0.5%, the optimum injection volume of air–foam is 0.25PV.

The relationships between increase extent of oil recovery after air–foam flooding and gas–liquid ratio or water cut are shown in Figs. 6 and 7. Results indicate that oil recovery first rises and then decreases with increase of gas–liquid ratio or water cut. This is because, too high
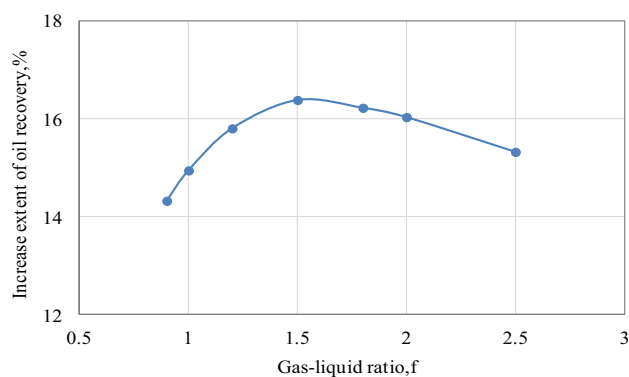
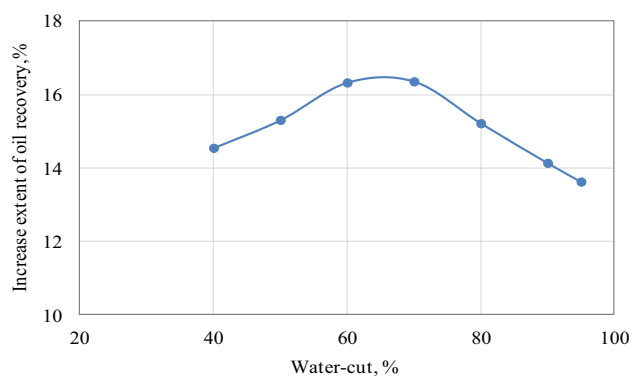**Fig. 6** Influence of gas–liquid ratio of air–foam system on increase extent of oil recovery

Fig. 7 Influence of injection time (water cut) of air–foam system on increase extent of oil recovery

Fig. 8 Apparent liquid (gas) absorption index curve of air–foam in test area
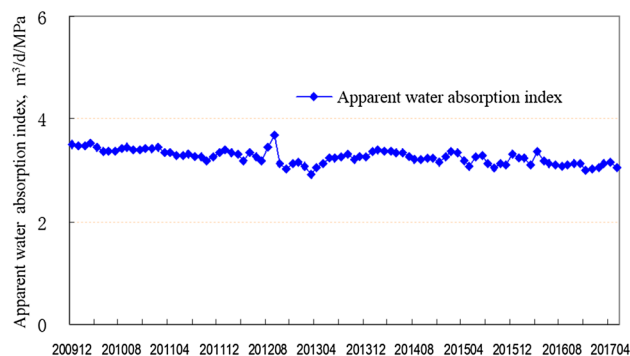
Fig. 9 Apparent water absorption index of nearby water injection wells in test area

gas–liquid ratio is unfavorable to control mobility ratio, and premature gas channeling can easily happen. High water cut makes air–foam unable to adequately modify the water absorption profile, with results of lower oil recovery. The optimal gas–liquid ratio for air–foam flooding is 1.5:1, and the optimal injection time of air–foam flooding is water cut of 65%.

Analysis of field application case

Pilot test of air–foam flooding in 4 well groups started in 2009 in ZJ53 well area of Wuliwan District 1 of jing'an oilfield. In 2012, the scale of test was expanded. Integral injection of 15 well groups was realized at the end of 2013. At present, there are 15 water injection wells and 63 producing wells, with annual oil production rate test scale of 50,000 tons. Up to 2017, cumulative injection volume of foam and air in test area is $47.4 \times 10^4 m^3$ and $49.0 \times 10^4 m^3$, with total of $96.4 \times 10^4 m^3$. Cumulative injected underground volume is 0.113PV and 45.15% of total design is completed. The dynamic characteristics of air–foam flooding in test area are as follows.
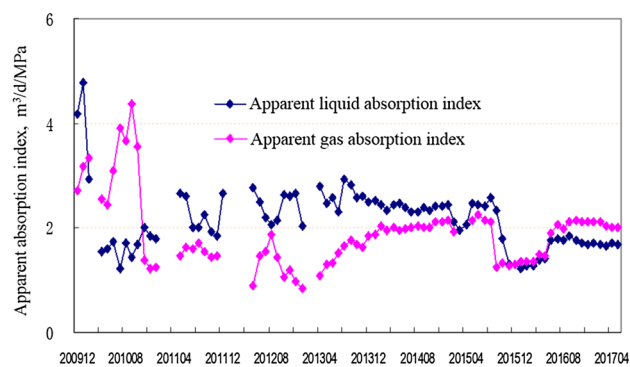
1. Injection pressure increased

   Since whole air–foam was injected, the pressure in the test area has been increased. Compared with injection wells near the test area, injection pressure increased by 1.6 MPa. In the same stage, apparent liquid absorption index was stable, and apparent gas absorption index increased slightly. Apparent water absorption index of nearby water injection wells decreased as a whole (Figs. 8, 9).

2. Water absorption profile and vertical utilization degree was improved

   The overall utilization degree of water drive in the test area arose from 60.0% before the test to 61.7% after the test. Among them, water absorption thickness of 6 wells increased compared to before, with average thickness increase of single well 2.55 m, whose utilization degree of water drive arose from 59.8% before the test to 77.1% after the test. Water absorption profile was better than before. Comparison test results of water absorption profile of well group showed that the overall utilization degree of water drive increased than before (Fig. 10).
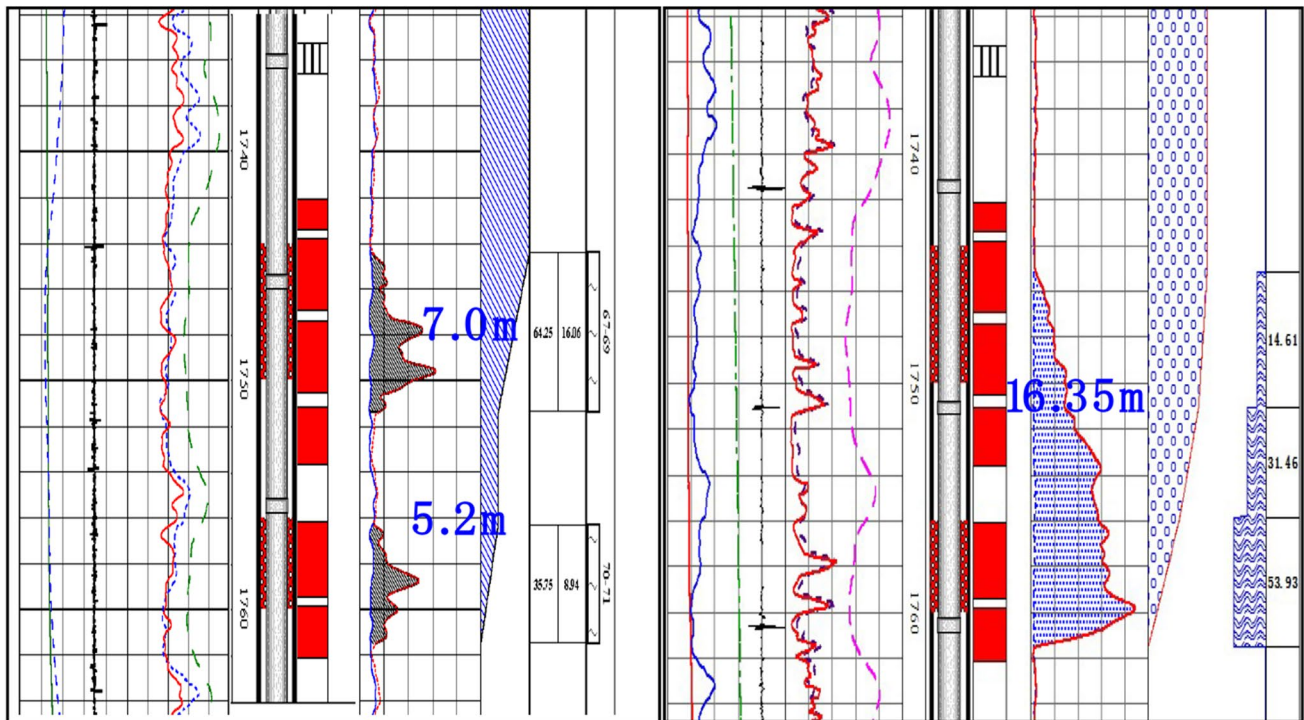
Fig. 10 Water absorption profile before and after air–foam injection for Well L76-60

3. **The level of formation energy in the test area was good**
    After the implementation of air–foam drive, formation pressure in test area increased from 13.2 to 14.7 MPa, and pressure maintenance level increased from 107.7 to 119.8%. Compared to the condition before injection, well pressure in the main direction decreased from 17.6 to 16.4 MPa, and the pressure in the lateral direction increased from 13.0 to 14.4 MPa. Pressure difference in the main and lateral direction obviously decreased. It was indicated that pressure distribution in the plane is more balanced, and sweep degree of injection water have been improved.

4. **Air–foam flooding could plug high permeability channel and increase plane sweep volume**
    According to special dynamic monitoring data and production performance of effective well, it was concluded that waterflooding channel was effectively plugged after air–foam flooding, oil wells in the weak direction gradually became effective. After total injection, integral water cut decreased from 62.9 to 54.7%. Water cut remained stable at 67.6% after restoration of gas injection.

5. **Development effect became worse after stopping gas injection, and remained stable after restoration of gas injection**

In the normal test period, effect of well groups was obvious, with effective wells of 60 and ratio of 95.2%. Average peak value of oil increase for single well was 0.35 tons. The current cumulative oil increase is 3.24×10^4 tons up to now. The increasing trend of water cut in test well group after stopping injection gas was obvious, and overall oil production showed a decreasing trend. After restoration of gas injection, oil production rate was stable, and rise trend of water cut was controlled effectively, which indicated the development situation was improved (Fig. 11).
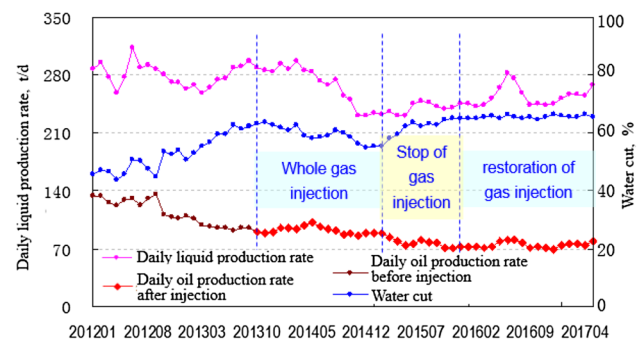

Fig. 11 Comparison of test wells before and after stopping gas injection in the process of air–foam flooding

Conclusions and suggestions

1. Based on laboratory experiment of air–foam flooding, parameters including model component, low temperature oxidation reaction, physical/chemical phenomena, foam interpolation function were set, and then numerical simulation concept model of air–foam flooding was established. The parameter fitting was completed by using various original data of air–foam displacement in the 1-D core experiment. Fitting of concept model was in good agreement with the experimental results.

2. According to numerical simulation concept model, oil displacement effect under different injection-production parameters were researched through simulation of water flooding, air–foam flooding and subsequent water flooding. Results indicated that optimum surfactant concentration was 0.5%, optimum injection amount of air–foam was 0.25PV, optimum gas–liquid ratio was 1.5:1, optimum injection time was 65%.

3. The researches were applied in low permeability reservoir of Wuliwan District 1 of Jing'an Oilfield, where 15 well groups were injected with air–foam. As a whole, injection pressure increased; water absorption profile and vertical utilization degree were improved; the level of formation energy in the test area was good; air–foam flooding could plug high permeability channel and increase plane sweep volume. The effect of air–foam flooding for the whole reservoir was obvious.

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