RESEARCH ARTICLE

Treatment technology of high water content wells in the super heavy oil reservoir of Pai 6 south block

Jingxuan Liu*

Xinjiang Xinchun Petroleum Development Co., Ltd, SINOPEC, Dongying, Shandong, China

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In response to the problems of reduced formation pressure, insufficient reservoir energy, and serious water flooding of oil wells in the southern part of Block 6 of Chunfeng Oilfield (Xinjiang, China) due to high cycles of steam stimulation, based on the geological conditions and reasons for high water cut in the block, nitrogen foam profile control and microbial oil recovery technology were proposed. A comprehensive treatment technology for high water content wells with microbial technology as the main focus and plugging and adjustment technology as the auxiliary was formed. The actual application effect of this technology was tested. The resistance factor and residual resistance factor of nitrogen foam were 540 and 270, respectively, which were higher than those of contrast foam. The core pressure value was greater than that of the contrast foam with good plugging property. By using this technology, the water content of the oil wells in the southern block of the rear row decreased and the oil production increased with a maximum oil increase of 847 ton. Microbial oil recovery experiments found that microbial strains could reduce the viscosity with the maximum decrease of 78.3%. The cumulative total oil production after expanding the experimental wells of microbial oil recovery technology was 3,286 ton. To sum up, the nitrogen foam profile control and microbial oil recovery technologies proposed in the study could effectively improve the recovery efficiency in super heavy oil reservoirs in southern Pai 6 block. The innovation of the research was the combination of nitrogen foam profile control and microbial oil recovery technology, which enriched the current research on the treatment of high water cut wells in super heavy oil reservoirs and provided new ideas and technical guidance for the treatment of high water cut wells in super heavy oil reservoirs. It had positive significance in improving the recovery of high water cut wells in super heavy oil reservoirs.

Keywords: heavy oil; high water content; nitrogen foam profile control; microbial oil recovery; petroleum; governance; foam gel.

***Corresponding author:** Jingxuan Liu, Xinjiang Xinchun Petroleum Development Co., Ltd, SINOPEC, Dongying 257000, Shandong, China. Email: may1314nick@163.com.

Introduction

With the continuous development of the social economy, the demand for oil is also increasing. To ensure the stable supply and demand relationship of oil, increasing oil recovery rate is crucial [1]. The steam stimulation development of commonly used heavy oil reservoirs belongs to depressurization depletion production, which can cause a decrease in formation pressure and insufficient energy in the reservoir after high cycles of stimulation. The invasion of edge and bottom water causes severe flooding of oil wells, thereby affecting oil recovery efficiency [2, 3]. For the treatment of high water cut wells in super heavy oil reservoirs, the commonly used technical means include nitrogen foam profile control and water plugging technology, mechanical water plugging, ash squeezing and water plugging, overhaul water plugging, pipe plug plugging composite cement plugging technology, temperature sensitive reversible gel water plugging technology, and gel composite particle plugging agent water plugging technology. Among them, nitrogen foam profile control and water plugging is the leading technology for water plugging in heavy oil horizontal wells. In order to address the high cost of treating produced water from offshore heavy oil reservoirs, researchers proposed a "green" deep profile control technology that integrated produced water reinjection and microsphere deep profile control technology, which could effectively improve sealing efficiency and recovery efficiency of offshore heavy oil reservoirs through adsorption, bridging, and aggregation methods [4]. To study the influence of interface properties on the stability of heavy oil emulsions in heavy oil reservoirs, Sun *et al*. simulated the content of asphaltene, resin, and wax in heavy oil, and observed the viscosity, interface viscosity, interface tension, and dehydration rate of heavy oil emulsions [5]. However, these technologies also had certain shortcomings such as high requirements for well conditions for mechanical water plugging, complex construction of ash squeezing water plugging, and high costs for major water plugging.

With the increasing demand for oil, the difficulty of extraction is also increasing. Many previous studies have focused on oil extraction technologies. Among them, nitrogen foam is widely used. Li *et al*. put forward an oil-based nitrogen foam to solve the gas channeling when nitrogen was sealed during oil exploitation. The results showed a good stability at 60 MPa and 80℃ and could better control the gas channeling problem during nitrogen flooding [6]. For the unsatisfactory water drive effect in the later stage of oil production water drive, Meng *et al*. proposed to use nitrogen foam for oil displacement. The results found that the recovery factor of nitrogen foam exceeded water injection [7]. The low permeability light reservoir in Tuha Oilfield had strong heterogeneity, which affected crude oil production. Wang *et al*. adopted nitrogen foam to enhance oil recovery. The results showed that it could block the main channel caused by heterogeneity with the recovery factor of small pores after nitrogen foam flooding as 28.43% [8]. For the uneven production, Lai *et al*. proposed a high strength nitrogen foam gel system. The results indicated that the system had good ability to control profile and improve oil recovery. The low permeability core had a conductivity of 38% and an enhanced oil recovery rate of 35.27% [9].

Microbial oil recovery, as a new technology for enhanced oil recovery, is a practical microbial method obtained by providing information on bacterial oil recovery. Many researchers have conducted in-depth research on it. However, there is limited research on microbial enhanced oil recovery technology for producing extracellular polymers. Lin *et al*. proposed an oil displacement method based on extracellular polymers and found that the sealing rate reached 60.1%, and the recovery rate increased by 261% [10]. Kanakdande *et al*. conducted research on the potential of a new strain of biosurfactant in rocks from earthquake prone areas. This separation material was applied in the oil recovery experiment of filling sand columns. The microorganisms of this biosurfactant had the potential to improve oil recovery, which was more effective than commercial biosurfactants [11]. The recovery efficiency of alkali free surfactant polymer flooding system is low. Therefore, Miao *et al*. proposed an alkali free surfactant polymer binary system based on a new heat and salt resistant biopolymer. The results showed good oil sand adsorption resistance, antidilution performance, and aging stability [12]. Sakthipriya *et al*. identified a biosurfactant based on *Pseudomonas aeruginosa* and *Bacillus subtilis* to address the low microbial recovery induced by non *in situ* biosurfactants. The results showed that, when the surface element concentration was 200 ppm, the recovery rate increased by 15.43%. When the rhamnolipid concentration was 200 ppm, the recovery rate increased by 15.47% [13].

Nitrogen foam and microbial oil recovery technology are used in various reservoir types with excellent usage effects. However, there are only a few studies that applied these two methods to the treatment of high water bearing wells in ultra heavy oil reservoirs. This research would develop a comprehensive treatment technology for high water bearing wells in super heavy oil reservoirs (SHOR) based on nitrogen foam profile control (NFPC) and microbial oil recovery technology with microbial technology as the main method and plugging and adjustment technology as the auxiliary to improve oil recovery and maintain the sustainable development of oil resources, and meanwhile, strengthening the research on efficient oil recovery engineering technology for high water content wells to enhance the quality of water drive development and reduce the impact of high water content on oil recovery [14, 15]. The results from this study was expected to enhance recovery efficiency and provide new ideas for the treatment of high water content wells.

Materials and Methods

Geological overview

The increasing heterogeneity of reservoirs during the high water cut period leads to poor quality of water drive development [16]. With the deepening progress of high water bearing oil fields, the contradiction of intensified reservoir heterogeneity has become more prominent, posing higher challenges to oil recovery engineering technology [17]. Chunfeng Oilfield Pai 6 South Block is located in Karamay City, Xinjiang Uygur Autonomous Region, China with part of it located in the general farmland and the rest in the Gobi Desert, which belongs to the secondary structural unit of western uplift of the Junggar Basin with an oil-bearing area of 3.8 km^2 and geological oil reserves of 355×10^4 tons. The top structure of the Pai 6 South Block in Chunfeng Oilfield is relatively simple and overall shows a southwest tilt with a structural dip angle of around 4°. The main oil bearing series is a section of the Neogene Shawan Formation with burial depths ranging from 470 m to 625 m. The thickness of the formation is about 40 m. The lithology is mainly composed of green, gray mudstone and sandy mudstone.

Nitrogen foam profile control treatment

Nitrogen foam profile control technology is a low cost and easy to operate process. Nitrogen is insoluble in both water and oil and has strong expansion energy characteristics. Adding nitrogen into foam can effectively supplement formation energy, control water cones, and adjust liquid production profile [18, 19]. When facing the super heavy oil and strong edge water reservoirs, this technology can be used to assist the steam stimulation process. Foaming agent is an important component of foam gel system, which is one of the core factors affecting profile control role. The anionic surfactants with sulfonic groups as polar groups has the best high-temperature foaming performance. In this study, refinery refined vacuum second line oil was used as raw material oil. Gaseous sulfur trioxide was sulfurized and then neutralized with alkali to generate anionic surfactants.

$$R-C_6H_5+SO_3\rightarrow R-C_6H_4SO_3H \tag{1}$$

$$R-C_6H_4SO_3H+NaOH\rightarrow R-C_6H_4SO_3Na+H_2O \tag{2}$$

Among the above equations, $R\text{-}C_6H_5$ is the mixture of C_{14}-C_{18}. SO_3 was gaseous sulfur trioxide. $R\text{-}C_6H_4SO_3H$ is dodecylbenzenesulfonic acid. $R\text{-}C_6H_4SO_3Na$ is the foaming agent of foam gel system. The plugging effect of foam agent in core was measured by the resistance coefficient of foam to fluid as follows.

$$R=\Delta P/\Delta P_0 \tag{3}$$

where R was the resistance factor. ΔP was the blocking pressure difference. ΔP_0 was the basic pressure difference. The core after the gel was broken to simulate the water permeability and the corresponding outflow viscosity.

$$R_r=\lambda_w/\lambda_{w_1} \tag{4}$$

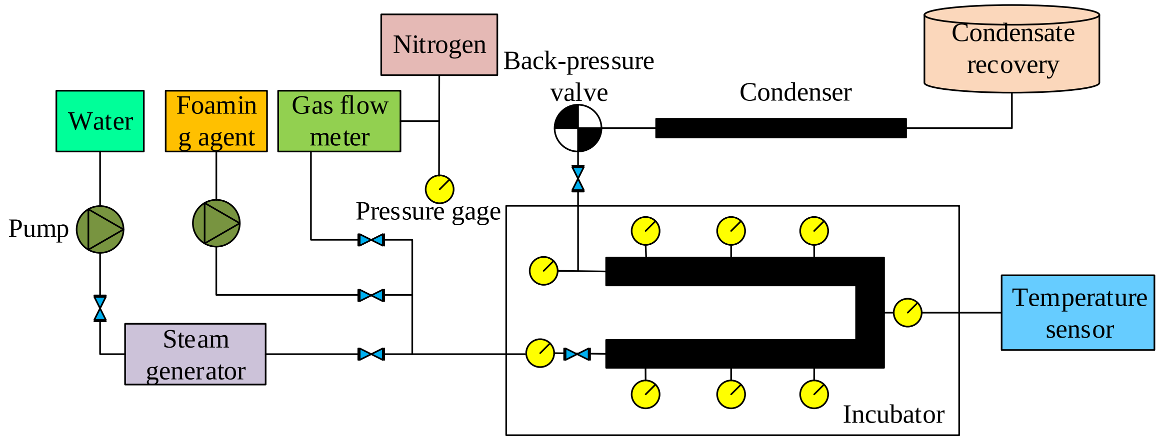


Figure 1. Flow chart of nitrogen foam replication steam throughput process.

where R_r was the residual resistance coefficient. λ_w was the fluidity of water. λ_{w1} was the flowrate of the expelled fluid after sealing. The quality of foam was expressed as:

$$\phi = 1/5[5 - \frac{m_T - m_d}{\rho}] \quad (5)$$

where m_T was the mass of foam gel sample at time T. m_d was the mass of foam gel sample at time d. ρ was the density of the base liquid. ϕ was the quality of foam. To improve the mixing degree of gas and polymer solution, a coupled internal and external vortex foam generator was used. The basic index of gas-liquid mixing performance was the diameter and particle size of foam, which was mainly determined by the rotating flow of gas and liquid along the swirl flow channel and could be calculated using equations (6)-(9).

$$\begin{cases} v_{in} = Q / A_{in} \\ v_{\theta w} = v_{in} \cdot \cos\alpha \end{cases} \quad (6)$$

where v_{in} was the gas flow rate at the inlet of the swirl tube. $v_{\theta w}$ was the tangential velocity on the wall of the swirl tube. Q was the inlet flow rate of the swirl tube. A_{in} was the inlet area of the swirl tube. α was the spiral angle of the guide vanes of the vortex tube.

$$v_{zw} = Q / [\pi(r^2 - r_m^2)] \quad (7)$$

where r_m was the geometric average radius of the swirl tube. r was the radius of the swirl tube. v_{zw} was the axial velocity on the wall of the swirl tube.

$$v_{\theta CS} = v_{\theta w} \frac{r / r_x}{1 + \frac{f A_r v_{\theta w} \sqrt{r / r_x}}{2Q}} \quad (8)$$

where $v_{\vartheta CS}$ was the tangential velocity at the radius of the inner vortex. r_x was the radius of foam outlet cone. f was the friction coefficient of the swirling flow channel. A_r was the total internal area of the swirl tube with frictional resistance.

$$d = 0.215 \frac{\mu^{0.375} \rho^{0.25} U_{t50}^{0.875}}{[\frac{(\rho_p - \rho) v_{\theta CS}^2}{r_x}]} \quad (9)$$

where d was the diameter and particle size of foam. ρ_p was particle density. Both μ and U were constants. The equipment consisted of a long tube sand filling model, a constant temperature box, a horizontal flow pump, an intermediate container, a steam generator, a precision pressure gauge, a temperature sensor, a data acquisition system, a condensing tube, a back pressure valve, and a data acquisition system (Figure 1). The long pipe sand filling model was erected with the bend facing downwards. A layer of stainless steel mesh was added below the end caps at both ends of the long pipe sand filling model to prevent fine sand from entering the pipeline and blocking the flow of oil.

Microbial oil recovery treatment

Microbial oil recovery is a low-cost, effective, and technically advanced technology for enhancing oil recovery. After the injection of nutrient solution into the formation, the growth and metabolic activity of microorganisms interact with oil and water in oil reservoirs to achieve increased crude oil production. The mechanism is that microorganisms degrade crude oil, transform large molecules into small molecules, emulsify and reduce viscosity, and dissolve biogas to improve the fluidity of crude oil. Microbial cells can automatically search for target crude oil, and even drive out crude oil from micro pore dead oil areas [20]. The optimal temperature for microbial survival is 30℃. However, microorganisms will not grow below 10℃ and will be killed over 45℃. According to the published standard of the Department of Energy (USA), recommended standards by domestic experts, and the conditions of the study area, Pai 6 south block in this study was suitable for implementing microbial cold mining, especially in the area south of Well Pai 6-Jian 1 in Block Pai 6 that is close to the edge water with the viscosity of underground crude oil from 8,000 to 20,000 mPa·s and the oil layer temperature of 32℃. The recovery rate of geological reserves in this area was only 2.1% before treatment and the remaining oil was enriched, providing a material basis for microbial oil recovery. It was noticeable that the surface wettability of reservoir rocks had an impact on oil recovery. The smaller the contact angle was, the stronger the hydrophilicity was. Otherwise, the lipophilicity would be stronger. When the contact angle (θ) was less than 90 degree, the rock surface was hydrophilic, and in a water wet state. When the contact angle was larger than 90 degree, the surface of the rock was hydrophobic and oil wet. However, when the contact angle equaled 90 degree, the rock was both oil and water friendly with the surface exhibiting moderate wettability. The rocks in the oil reservoir were composed of countless capillary pipes. During water flooding, capillary forces were generated between the oil-water interfaces.

$$\rho_c = 2\sigma_{wo} \cos\frac{\theta}{r_1} \tag{10}$$

where ρ_c was capillary force. σ_{wo} was the interfacial tension between oil and water. r_1 was the capillary radius. When $\theta < 90°$, the capillary force was consistent with the direction of water drive, which was the driving force for oil displacement. When $\theta = 90°$, the capillary force was opposite to the direction of water drive, indicating oil displacement resistance. When $\theta > 90°$, capillary force had no effect on oil displacement. The adhesion work of water was calculated as:

$$W_w = \sigma_{ow} + \sigma_{ro} - \sigma_{rw} \tag{11}$$

where W_w was the adhesion work of water. σ_{ow}, σ_{ro}, and σ_{rw} were the interfacial tension between oil and water, rock and oil, and rock and water, respectively. The balance relationships among the three factors were shown as follows.

$$\sigma_{ro} = \sigma_{rw} + \sigma_{ow} \cos\theta \tag{12}$$

By combining equation (12) with equation (11), the adhesion work of water was then as:

$$W_w = \sigma_{ow}(1 + \cos\theta) \tag{13}$$

The oil phase adhesion work was as:

$$W_o = \sigma_{ow}(1 - \cos\theta) \tag{14}$$

where W_o was the oil phase adhesion work. The smaller the contact angle θ of the water phase, the greater the adhesion work of the water phase, indicating that the adhesion work of the oil phase was smaller. The easier it was to peel off the injected water, the more oil droplets or oil films would remain on the rock surface, which was beneficial to improving reservoir recovery.

Results and discussion

The existing problems of the south block oil reservoir in Pai 6

The probability cumulative curve of the samples from the Neogene Shawan Formation in Well Pai 6-Ping 4 was shown in Figure 2 [21].

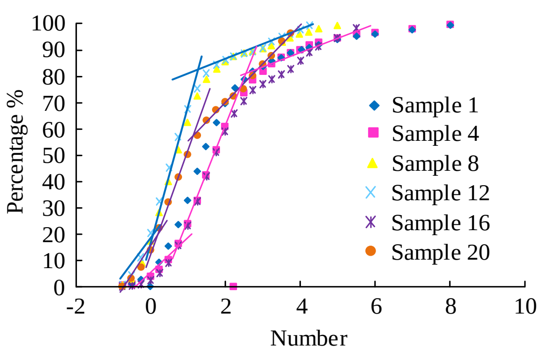


Figure 2. Cumulative plot of row 6-flat 4 wells.

The cumulative probability curve of all samples showed a clear three segment pattern, which reflected the relatively strong transport capacity of water bodies, indicating that sedimentation was mainly caused by traction flow sedimentation. The core section of Well Pai 6-Ping 4 was 552.0 - 565.3 m with the porosity of 32.8% to 41.0%, an average of 35.0%. The permeability was 232 mD to 22,200 mD with an average of 5,573.3 mD. According to the oil testing and production analysis of the near system Shawan Formation in Well Pai 6-Ping 4, the surface crude oil density of the near system Shawan Formation reservoir in this block was 0.9567 g/cm^3. The viscosity of degassed crude oil at formation temperature was 19,683 mPa. s. The freezing point was 4℃ and the wax content was 3.25%. The pressure was 5.71 MPa with the pressure coefficient of 1.07. The temperature was 32.97℃. The sand body was generally buried at a depth of 470 - 660 m. Taking the sand body pinch line from the east to the west as the boundary, an oil-water interface was found at 625 m. Based on comprehensive analysis, the oil reservoir type was a shallow thin layer and extra heavy oil reservoir. The southern district of Pai 6 was put into development in September 2010. By July 2020, the cumulative oil production was 70.6×10^4 ton and the cumulative steam injection was 96.3×10^4 ton. The cumulative oil gas ratio was 0.733 and the cumulative water recovery rate was 1.48, while the cumulative production injection ratio was 2.21 and the stage recovery rate was 16.69%. By the time of this study, there were a total of 46 wells and 42 wells were operated. The daily production of liquid was 776 ton/d, and the oil production was 162 t/d. The water content was 79.0%. The Pai 6 South Block has been under development since 2009, and crude oil has been continuously extracted. The depressurization mining has caused serious water intrusion. The water content in the southern region is increasing rapidly. Most oil wells have a water content increase of over 95.0% in the third cycle. The water recovery rate was above 2.0. Under the pressure difference, the southern waterline gradually advances northward. Currently, the waterline is basically stable. The water content equivalent was shown in Figure 3.

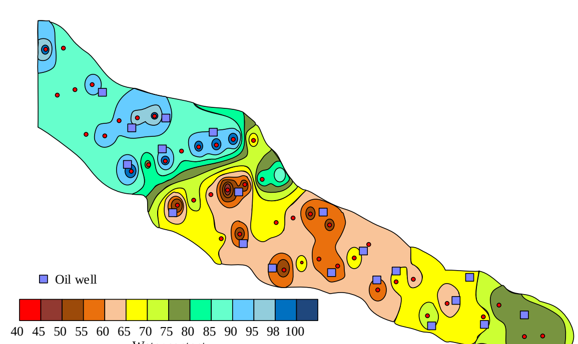
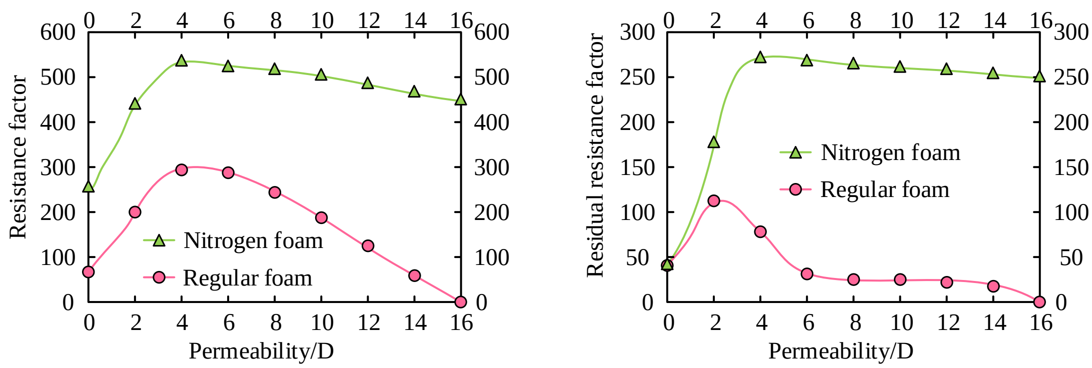


Figure 3. Distribution of water contour.



(a)Resistance factor (b)Residual resistance factor

Figure 4. Comparison of the sealing performance of nitrogen foam and ordinary foam.

The oil wells in the northern part of Block 6 were put into operation early, resulting in a large stratigraphic deficit. Under pressure difference, the southern edge and bottom water advance northward. The time for water to flow from south to north is prolonged, and the water recovery rate increases. The area north of Well Pai 6-Ping 40 experienced an average of 261 days of flooding after being put into operation. The average water recovery rate was 2.90. After being put into operation in the southern region, the average water recovery rate was 6.79, reflecting the relatively strong energy of the water body in the south and weak in the north. The average oil production of 20 wells in the flooded area was 0.29×10^4 tons with a geological reserve recovery rate of only 3.2%. Currently, 20 oil wells have been flooded, affecting geological reserves by 169×10^4 tons. The block is developed for horizontal wells. During the steam stimulation process, it is easy to accelerate water flooding, indicating that conventional steam stimulation technology has certain limitations in super heavy oil and strong edge water reservoirs.

Application of nitrogen foam profile control (NFPC) technology

The area south of Well Pai 6-6 was a strong edge and bottom water area. Low saturation oil layers were developed at the bottom of the sand body in the area north of Well Pai 6-6 and south of Well Pai 6-Ping 4, belonging to a weak bottom water zone. A pure oil layer was developed at the bottom of the sand body in the area north of Well Pai 6-Ping 4, belonging to a pure oil area. Because of the limitation of NFPC and water plugging intensity, the oil wells in weak bottom water area were selected for testing. To verify the plugging ability of nitrogen foam, the pressure changes of cores with different permeability during the injection of nitrogen foam and ordinary foam are recorded (Figure 4). The results showed that, when the permeability was 4, the resistance factors of nitrogen foam and ordinary foam were the highest of 540 and 300, respectively (Figure 4a). Under the different strip penetration conditions, the resistance factor of nitrogen foam exceeded the ordinary foam. The nitrogen bubble foam demonstrated better plugging performance. The residual resistance factor of nitrogen foam also reached the highest of 270. When the permeability was 2, the ordinary foam was the highest, reaching 110 (Figure 4b). Under different strip penetration conditions, the residual resistance factor of nitrogen foam exceeded the ordinary foam, i.e. nitrogen bubble foam had better plug performance. When different foam was injected, the results of pressure values on the core showed that, as the permeability of the core being added, the sealing pressure difference at the pressure measuring point in the front of the core continuously decreased (Figure 5). The highest values of front pressure were 2.50 MPa and 1.50 MPa, respectively. The highest values of middle pressure were 1.00 MPa and 0.75 MPa,

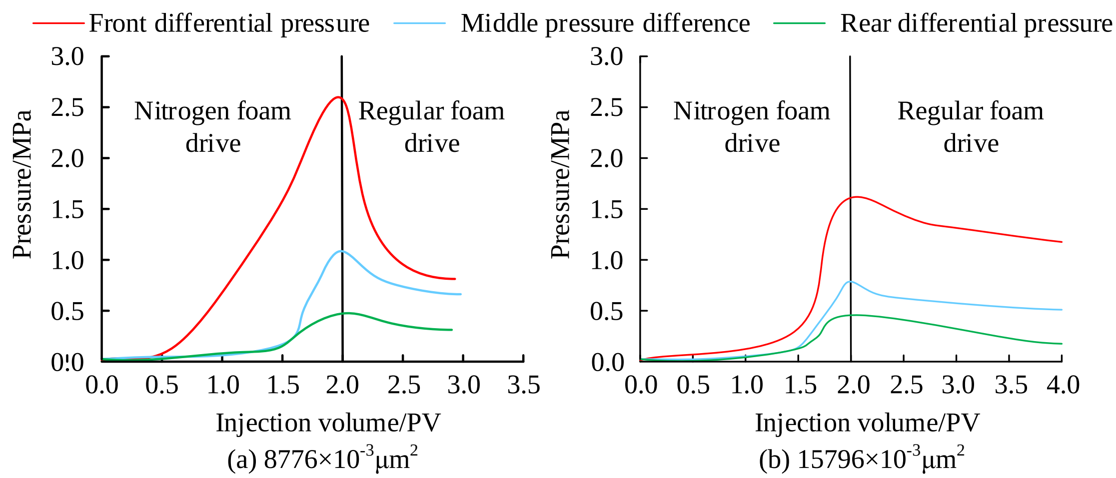


Figure 5. Change of foam injection pressure with different permeability.

Table 1. Nitrogen foam profile regulation effect in the south block of row 6.

Well No.	Before NFPC		After NFPC		Validity period (day)	Increase oil (ton)
	Daily oil (ton)	Water content (%)	Daily oil (ton)	Water content (%)		
Row 6- Flat 27	1.9	92.0	8.6	74.5	37	228
Row 6-flat 38	0.7	97.0	5.1	80.2	27	194
Row 6- Flat 37	1.0	90.5	6.8	78.5	95	607
Row 6-flat 36	1.4	90.6	7.4	75.0	102	532
Row 6-flat 42	0.3	97.1	0.5	88.5	27	287
Row 6-flat 40	2.6	92.1	4.1	72.5	68	464
Row 6- Flat 26	1.3	91.8	4.0	80.0	0	218
Row 6- Flat 27	1.6	96.5	3.1	94.0	10	119
Row 6- Flat 35	0.1	99.0	13.5	73.0	33	464
Row 6-flat 38	0.3	97.1	6.4	75.5	40	429
Row 6- Flat 27	0.7	96.9	0.9	98.0	0	208
Row 6- Flat 37	1.5	93.2	5.7	76.5	102	847
Row 6- Flat 35	0.6	98.0	4.9	90.5	15	178
Row 6- Flat 26	1.4	92.6	7.5	87.5	32	463
Row 6-flat 36	1.3	92.6	4.0	85.2	39	200

respectively. The highest values of rear pressure were 0.50 MPa and 0.45 MPa, respectively. When nitrogen foam was applied, the change rate of pressure value was large, indicating that nitrogen foam was better for permeability cores. After applying NFPC technology, the daily oil production of Pai 6-Ping Wells were increased, while the water content of the wells had declined (Table 1). The results confirmed that NFPC technology could effectively reduce the water content of the well, thus improving oil production.

Application of microbial oil recovery technology

Crude oil degrading bacteria were used to interact with crude oil. The changes in hydrocarbon composition of crude oil before and after the bacterial treatment were analyzed by using total hydrocarbon gas chromatography. The results showed that, as the amount of carbon increased, the trend of hydrocarbon content gradually increased first and then decreased. Before applying bacteria, the maximum and minimum hydrocarbon contents in crude oil were 8.4% and 0%, respectively, while, after applying bacteria, the maximum and minimum hydrocarbon contents in crude oil were 6.2% and 0%, respectively. After using microbial strains, the hydrocarbon content in the alkane combination with carbon 15 or higher in crude oil decreased (Figure 6), which indicated that hydrocarbons with higher carbon chains in crude oil were more easily utilized and metabolized by microbial strains.

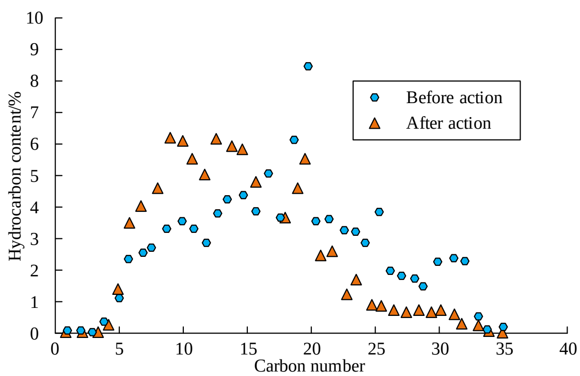


Figure 6. Distribution of hydrocarbon contents after applying microbial oil recovery technology to crude oil.

In addition, microbial oil recovery technology was applied to reduce the viscosity of crude oil in the super heavy oil reservoir of Pai 6 South Block. The results showed that, before applying microbial oil recovery technology, the maximum and minimum viscosities of crude oil were 34,872 mPa·s and 11,132 mPa·s, respectively, while, after using microbial oil recovery technology, the maximum and minimum viscosities of crude oil were 25,012 mPa·s and 5,083 mPa·s, respectively. After using microbial oil recovery technology in wells No. 43, 44, 48, 45, 47, 37, 50, 49, 46, 40, and 41, the crude oil viscosities decreased by 32.4%, 78.3%, 32.5%, 39.9%, 27.8%, 17.2%, 51.3%, 50.7%, 43.6%, 21.7%, and 36.1%, respectively (Figure 7), which confirmed that microbial oil recovery technology could reduce the crude oil viscosity.

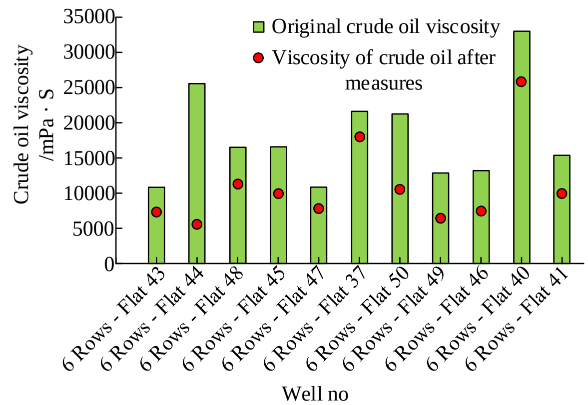


Figure 7. Comparison of the crude oil viscosity before and after applying microbial oil recovery technology.

The oil recovery effects of microbial oil recovery technology were analyzed. The results showed that the soaking time of wells was from 115 to 165 days with an average of 140 days. The average daily liquid was 139 tons, and the average daily oil was 23.5 tons with the average water content of 83.1%. The cumulative oil production of each tested well was listed in Table 2 with a total oil production of 3,286 tons. The results suggested that the proposed technology demonstrated good performance in the South Block of Pai 6, which could effectively increase oil recovery.

Conclusion

In order to improve the recovery efficiency of high water wells in the super heavy oil reservoir, nitrogen foam profile control and microbial oil recovery technologies were proposed in this study. The results showed that the resistance factor and residual resistance factor of nitrogen foam were higher than that of ordinary foam, while the change of core pressure was also higher than that of ordinary foam. After applying this technology, oil production was increased. After applying microbial oil recovery technology, the

Table 2. Effects of microbial oil recovery technology.

Well No.	Soaking time (day)	Average daily liquid (ton)	Average daily oil (ton)	Water content (%)	Oil accumulation (ton)
Row 6- Flat 37	115	9.5	2.0	78.1	268
Row 6-flat 38	119	23.7	0.9	98.2	8
Row 6-flat 40	125	7.9	1.4	81.1	77
Row 6- Flat 41	122	3.7	0.9	73.2	90
Row 6-flat 42	122	25.1	0.7	98.7	16
Row 6- Flat 43	153	11.5	0.8	93.0	276
Row 6- Flat 44	159	2.1	0.4	76.9	228
Row 6-flat 45	165	8.7	2.0	76.5	349
Row 6-flat 46	165	20.9	3.1	85.0	271
Row 6-flat 47	127	7.9	1.5	80.0	458
Row 6-flat 48	127	34.2	5.4	84.0	568
Row 6-flat 49	161	10.0	2.0	80.0	223
Row 6-flat 50	161	22.7	4.0	82.0	454
Total					3,286

hydrocarbon content in the alkane combination with carbon 15 or higher in the crude oil decreased, which could effectively reduce the viscosity. The cumulative oil production of each tested well was calculated with a total oil production volume of 3,286 tons. The results suggested that nitrogen foam profile control and microbial oil recovery technologies proposed in the study could effectively solve the problem of low oil recovery. However, as crude oil was extracted and the steam chamber expanded, the continuous implementation effect would gradually deteriorate. Subsequent studies are needed to further optimize the dosage of foam agent to improve plugging and profile control effect.

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