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ORIGINAL PAPER - EXPLORATION ENGINEERING

The study on classification methods for low production wells of thermal recovery and its applications

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Abstract
During the later period of steam injection, the oil production largely decreases to be a state of low production or low oil–steam ratio. In this article, a classification method of low production wells was established and some measures of improving oil production were researched for the low production wells during thermal recovery. Three visualization experiments were implemented to analyze the sweep efficiency and to measure the oil recovery factor during injecting different flooding agents. Then a novel diagram was introduced to guide us how to precisely choose the appropriate measures for the low production wells during thermal recovery in heavy oil reservoirs. According to the statistical results, the low production wells can be categorized into three types involving high degree of oil recovery, thermal disturbance (even steam channeling) among wells and dual factors. The results of visualization experiments showed that the injection of chemical agents can effectively increase the displacement efficiency in swept zone after steam injection. Temperature-resistant gel or foams can be used to decrease thermal disturbance and even steam channeling among wells during steam injection in heavy oil reservoir. The values of a new parameter can be employed to confirm the boundary of different improvement measures. Finally, a diagram was established to help choosing appropriate measures involving nitrogen injection, foam injection, gel injection and invalid measure.

Keywords Thermal recovery · Steam injection · Low production well · Classification method · Improvement measures

Introduction

The reserves of heavy oil around the world are about 9000×10^8 m^3, which is equivalent to 2.5 times of the reserves of light oil. In general, heavy oil can be considered an alternative energy source of light oil on earth (Yang and Han 1991; Thomas 2007). Thermal recovery is an important technology for developing heavy oil reservoirs (Jabbour et al. 1996; Fatemi and Jamaloei 2011). Steam stimulation is a key tool to achieve economic production of heavy oil. The primary object of the steam injection is to increase temperature and decrease oil viscosity near the wellbore. The initial oil rate is high because of enough oil saturation, large reservoir pressure and low oil viscosity. While, during the production stage, as oil saturation becomes lower, reservoir pressure decreases and oil viscosity increases resulting from heat losses to the formation rock and fluids, so oil rate declines again. At that moment, another cycle of steam injection is activated. Such cycle may be repeated many times. However, steam stimulation presents some problems involving serious heat losses, small heating area and even steam channeling (Fan et al. 2002; Cao et al. 2012; Brooks and Tavakol 2012). Steam channeling occurs when steam trends to a way from an injector into an adjacent producer. If it occurs prematurely during steam injection, it can lead to poorer sweep efficiency, which results in a lower oil recovery factor (Cao et al. 2012; Brooks and Tavakol 2012).

Gas injection has been recognized as an effective technique to increase oil production from reservoirs containing heavy oil. Some researchers found oil increases of 50% or more from gas–steam stimulation compared to steam alone in their studies (Zhou et al. 2013; Pang et al. 2017). The co-injection of non-condensate gas and steam becomes a new efficient method for heavy oil reservoirs. A lot of researchers also analyzed the development effect of steam and the gases injected into a high permeability path between injectors and producers (Stone and Malcolm 1985; Nasr et al.

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1987; Metwally 1990; Canbolat et al. 2004). Foam fluids often are used to inject with steam to solve the problems of steam channeling between wells (Zitha et al. 2006; Li et al. 2011; Pang et al. 2012; Lu et al. 2013). During gas and surfactant injection, foams are generated to decrease the mobility of steam in higher permeability formation and to divert steam to lower permeability formation. Foams can obviously increase flowing resistance in porous media, which has been demonstrated in several field tests (Green et al. 1991; Li et al. 2011; Pang et al. 2012, 2016). It is well known that foams increase the gas apparent viscosity and maintain reservoir pressure. Meanwhile, foaming agent is a kind of surfactant, which can improve the oil displacement efficiency (Dilgren and Owens 1982; Liu et al. 2007; Dai et al. 2011; Jamaloei et al. 2011). In addition, gel injection is an effective technology to block water channeling or steam channeling between injector and producer (Hunter et al. 1992; Wang et al. 2003; Wu et al. 2014). Some researchers also developed new temperature-resistant gels to plug water channeling or steam channeling (Eson and Cooke 1992; Moradi-Araghi et al. 1993; Zubkov and Fedorov 1995). Gel can effectively block the path of steam channeling, which can adjust steam injection profile and enhance oil recovery factor. But all the results were not used to explain how to choose appreciate measures to inhibit steam channeling or to improve sweep efficiency during steam injection.

This paper presented a quantitative standard to classify low production wells during steam injection in heavy oil reservoir. Some visualization experiments were employed to research the effective measures during steam injection in heavy oil reservoirs, and then a diagram of measure selection was established to help us how to choose appropriate measures for low production wells of thermal recovery.

Classification methods

Generally, low production wells are defined as the daily oil production is less than 0.5 m^3/day or the instantaneous oil–steam ratio is less than 0.1 m^3/m^3 during steam stimulation or steam flooding. According to the performance of low production wells in an actual Chinese oilfield, the low production wells are divided into four types: the edge water flooding, the higher degree of oil recovery, the steam channeling and the dual factors (both the higher degree of oil recovery and the steam channeling). This article focuses on the mentioned three cases, such as the higher degree of oil recovery, the steam channeling and the dual factors. The wells of higher recovery degree are mainly aiming at that the oil recovery factor is higher than 20% without steam channeling. The wells of steam channeling are mainly aiming at that there is serious channeling between two wells or even among multi wells. The wells of dual factors are mainly aiming there are double factors involving the higher oil recovery (> 17%) and the thermal disturbance between wells.

As shown in Fig. 1, a part of low production wells is mainly located in heterogeneous zones, where serious steam channeling exists among wells. The wells of higher recovery degree, which are mainly located in the middle of reservoir with homogeneous reservoir properties, have poorer steam

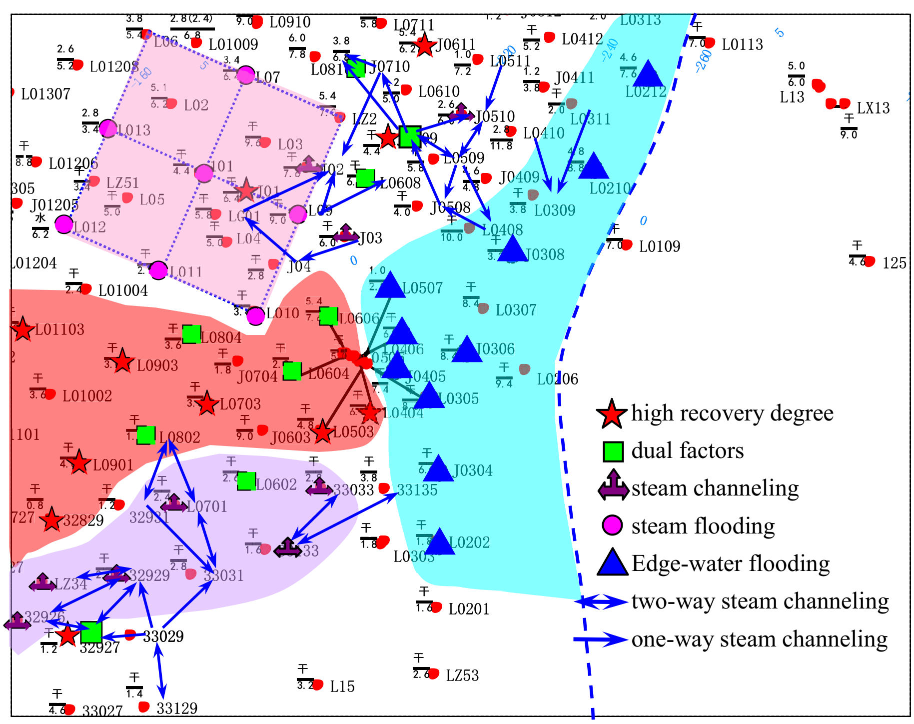


Fig. 1 The different types of low production wells in an actual Chinese oilfield

channeling but higher oil recovery. A part of low production wells which are controlled by the two factors has both severe steam channeling and the relatively higher degree of oil recovery.

Influencing factors

According to the geological characteristics of the oilfield, we chose nine parameters, such as top depth (D_t), permeability (K), net pay (H_e), net gross (NTG), oil viscosity (μ_o), formation dip (DIP), porosity (ϕ), sedimentary rhythm (R_s), and permeability contrast (V_k). Each parameter was assigned four characteristic values to research the influencing factors on the development effect of steam injection. The numerical simulation software, CMG-STARS, was used to determine the key factors through the orthogonal design-direct analysis and the orthogonal design-variance analysis. According to the orthogonal design, there are total 32 simulation projects if four values are assigned to the nine parameters. Therefore, aiming at the oil recovery factor ($\mathrm{ORF_i}$), the average values and the square of deviation are compared to give the range values and the F ratio, which can identify the key factors. The results are listed in Table 1. According to the direct analysis, the order is sorted as following: $\mu_o > K > V_k > H_e > \mathrm{NTG} > \phi > D_t > R_s > \mathrm{DIP}$. According to the results of variance analysis, the key factors include μ_o, K, V_k and H_e. Therefore, aiming at the key factors, we can establish a classification standard for the low production wells to choose the corresponding appropriate measures.

Classification standards

The parameter, $K{\cdot}H_e$, is called as formation capacity, which is directly relative to the reservoir productivity. Generally, the oil viscosity (μ_o) reflects viscous resistance during crude oil flowing in porous media; therefore, the oil production gradually decreases as oil viscosity increases (Jabbour et al. 1996). However, for heavy oil reservoirs, the porosity varies in a small range to result in a poorer influencing degree on the oil production. However, the sweep efficiency of steam will be expanded larger when porosity is smaller under the same steam injection intensity. Therefore, to quantitatively classify different types of low production wells, a new parameter, $[KH_e/(\phi \mathrm{Ln}\,\mu_o)]^{\frac{1}{V_k}}$, is introduced to comprehensively consider the key reservoir parameters including H_e, K, μ_o, V_k and ϕ. A scatter diagram is established according to the classification results and the values of the new parameter, as shown in Fig. 2. The results show that the different types of low production wells distribute in different zone. For the higher recovery degree, the value of $[KH_e/(\phi \mathrm{Ln}\,\mu_o)]^{\frac{1}{V_k}}$ is more than 400, which is corresponding to the $\mathrm{ORF_i}$ higher than 20%. Aiming at the type of steam channeling wells, the values are less than 400 and the $\mathrm{ORF_i}$ is less than 17%. Aiming at the low production wells of dual factors, the values are less than 400 and the $\mathrm{ORF_i}$ are more than 17%. There is a distinct boundary line between the type of steam channeling and the type of dual factors, which is a horizontal line corresponding the $\mathrm{ORF_i}$ of 17%. Above the line, the low production wells are affected by the dual factors. And below the line, the low production wells are mainly affected by the thermal disturbance or steam channeling among wells.

The adaptability experiments of measures

Experimental apparatus

Some visualization experiments were employed to analyze the different chemical agents [nitrogen (N_2), foams, viscosity reducer (VR), gel, etc.] to improve the development effect of steam injection in heavy oil reservoirs (Dovan et al. 1997; Shen et al. 2015; Gong et al. 2016). N_2 is a kind of non-condensate gas to enlarge heating area and to maintain pressure under reservoir conditions. Foams are generated by N_2 and foaming agent to decrease the mobility of gas phase and water phase under reservoir conditions. Viscosity reducer (VR) is a kind of chemical agent that can largely decrease oil viscosity under reservoir conditions. Gel is a kind of chemical agent with higher apparent viscosity to inhibit steam channeling from one well to another well. An appropriate measure can be chosen for the different type of low production wells according to the experimental results. The visualization experimental apparatus are shown in Fig. 3. They mainly consisted of five parts, including injection system, visualization model, production system, acquisition system and auxiliary system. The injection system includes two injection pumps, one steam generator, one nitrogen tank, one gas mass flowmeter, some electrical heating belts, three fluid tanks and so on, which are shown in Fig. 3a. The visualization model is shown in Fig. 3b, c. The main part of the model includes two pieces of quartz glass plate whose thickness is 3 cm, a stainless steel shell and a heating oven. Between the two glass plates, two layers of glass beads are pasted together to simulate porous media. The width of valid visualization is 20 cm. The mesh of glass beads is 40, that is, the diameter is 0.38 mm. Two wells, injector and producer, are located in the diagonal line of the visualization model to form injection–production system. The pipelines of injection well are wrapped up by the electrical heating belts whose temperature maintains at the same values with steam generator during experiments. In porous media, steam gradually becomes to condensate water due to heat transmission, which is similar to the steam–water migration under reservoir conditions. The production system includes some volume cylinders and several valves. The acquisition system includes one high-definition camera, a flat light source, a suit

Table 1 The results about orthogonal test of low production wells

Project	Factors									
	Top depth (D_t, m)	Permeability (K, 10^{-3} μm^2)	Net pay (H_e, m)	Net to gross (NTG, decimal)	Oil viscosity (μ_o, mPa s)	Formation dip (DIP, °)	Porosity (ϕ, decimal)	Sedimentary rhythm (R_s)	Permeability contrast (V_k, decimal)	The oil recovery factor (ORF$_i$, %)
1#	200	500	2	0.40	3000	0	0.20	Positive rhythm	0.10	11.33
2#	200	1000	4	0.60	10,000	5	0.25	Anti rhythm	0.30	15.46
3#	200	2000	6	0.80	20,000	10	0.30	Convex rhythm	0.60	18.54
4#	200	5000	8	1.00	50,000	15	0.35	Concave rhythm	0.90	19.19
5#	300	500	2	0.60	10,000	10	0.30	Concave rhythm	0.90	8.84
6#	300	1000	4	0.40	3000	15	0.35	Convex rhythm	0.60	24.85
7#	300	2000	6	1.00	50,000	0	0.20	Anti rhythm	0.30	15.31
8#	300	5000	8	0.80	20,000	5	0.25	positive rhythm	0.10	30.16
9#	400	500	4	0.80	50,000	0	0.25	Convex rhythm	0.90	2.32
10#	400	1000	2	1.00	20,000	5	0.20	Concave rhythm	0.60	17.71
11#	400	2000	8	0.40	10,000	10	0.35	positive rhythm	0.30	20.23
12#	400	5000	6	0.60	3000	15	0.30	Anti rhythm	0.10	38.46
13#	500	500	4	1.00	20,000	10	0.35	Anti rhythm	0.10	24.38
14#	500	1000	2	0.80	50,000	15	0.30	positive rhythm	0.30	6.26
15#	500	2000	8	0.60	3000	0	0.25	Concave rhythm	0.60	47.38
16#	500	5000	6	0.40	10,000	5	0.20	Convex rhythm	0.90	43.34
17#	200	500	8	0.40	50,000	5	0.30	Anti rhythm	0.60	0.58
18#	200	1000	6	0.60	20,000	0	0.35	positive rhythm	0.90	4.85
19#	200	2000	4	0.80	10,000	15	0.20	Concave rhythm	0.10	27.08
20#	200	5000	2	1.00	3000	10	0.25	Convex rhythm	0.30	33.43
21#	300	500	8	0.60	20,000	15	0.20	Convex rhythm	0.30	8.09
22#	300	1000	6	0.40	50,000	10	0.25	Concave rhythm	0.10	2.26
23#	300	2000	4	1.00	3000	5	0.30	positive rhythm	0.90	34.46
24#	300	5000	2	0.80	10,000	0	0.35	Anti rhythm	0.60	23.74
25#	400	500	6	0.80	3000	5	0.35	Concave rhythm	0.30	35.28
26#	400	1000	8	1.00	10,000	0	0.30	Convex rhythm	0.10	32.70
27#	400	2000	2	0.40	20,000	15	0.25	Anti rhythm	0.90	26.52
28#	400	5000	4	0.60	50,000	10	0.20	positive rhythm	0.60	26.30
29#	500	500	6	1.00	10,000	15	0.25	positive rhythm	0.60	32.10
30#	500	1000	8	0.80	3000	10	0.20	Anti rhythm	0.90	31.91
31#	500	2000	2	0.60	50,000	5	0.35	Convex rhythm	0.10	5.13
32#	500	5000	4	0.40	20,000	0	0.30	Concave rhythm	0.30	32.13
Average value 1	21.438	15.365	16.620	20.155	32.138	21.220	22.634	20.711	16.307	—

Table 1 (continued)

Project	Factors									
	Top depth (D_t, m)	Permeability (K, 10^{-3} μm^2)	Net pay (H_e, m)	Net to gross (NTG, decimal)	Oil viscosity (μ_o, mPa s)	Formation dip (DIP, °)	Porosity (ϕ, decimal)	Sedimentary rhythm (R_s)	Permeability contrast (V_k, decimal)	The oil recovery factor (ORF_i, %)
Average value 2	20.774	17.000	23.373	19.314	25.436	22.765	23.704	22.045	18.464	–
Average value 3	23.900	24.331	23.768	21.911	20.297	20.736	21.496	21.050	24.940	–
Average value 4	21.429	30.844	23.780	26.160	9.669	22.819	19.706	23.734	27.829	–
Range	3.126	15.479	7.160	6.846	22.469	2.083	3.998	3.023	11.522	–
Square of deviation	45.628	1220.936	296.542	223.044	2155.856	27.265	70.132	44.147	699.797	–
Freedom degree	3	3	3	3	3	3	3	3	3	–
F radio	1.674	44.78	10.876	8.181	79.07	1	2.572	1.619	25.666	–
F critical value	9.28	9.28	9.28	9.28	9.28	9.28	9.28	9.28	9.28	–
Significance		*	*		*				*	–

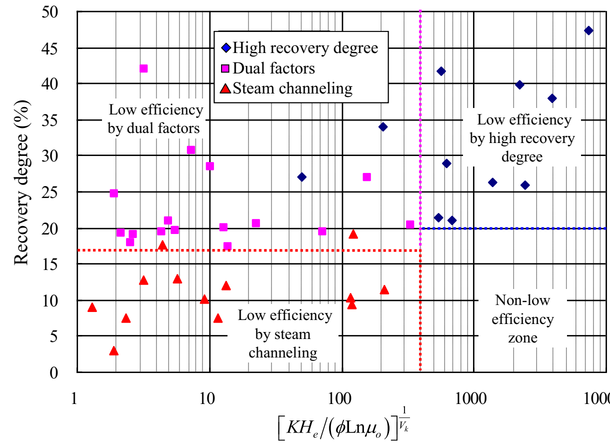


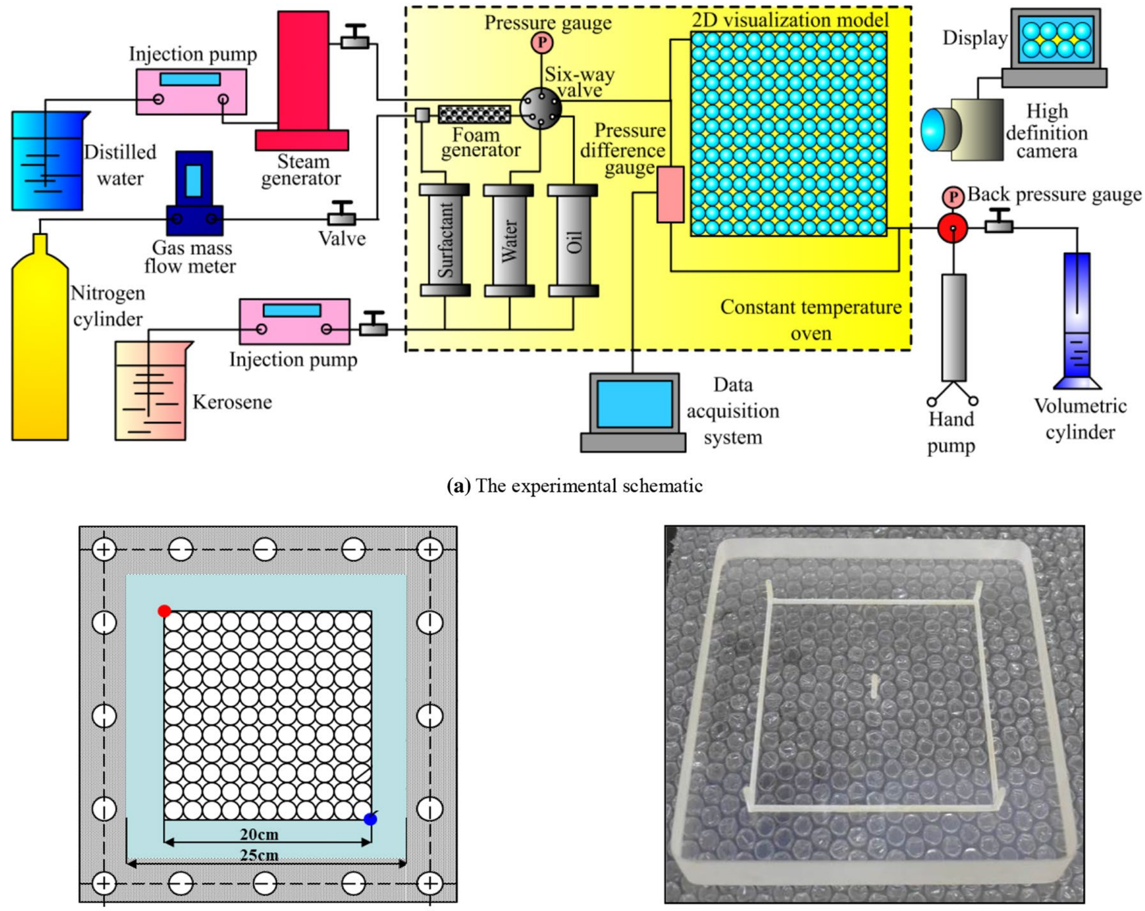
Fig. 2 The diagram of classification standard for low production wells

of pressure difference gauge, one data acquisition system and one computer. The auxiliary part includes one drying oven, a set of viscometer, one balance, etc.

Experimental procedures

Three suits of experiments were carried out, as listed in Table 2. During the processes of test 1, steam was first injected into the model until steam channeling between injector and producer, and then the different fluids were injected into the model from the injector. The injection order was nitrogen (N_2), viscosity reducer (VR), steam and N_2, steam and VR, steam with the mixture of N_2 and VR in turn. The injection rates were all about 0.2 ml/min under the experimental conditions. During the processes of test 2, steam was first injected into the model until steam channeling between injector and producer. Then foams were injected into the path of steam channeling until a large amount of steady bubbles existing in pores. Then subsequent steam was injected into the model following the foams. The flow rate was maintained at 0.2 ml/min. For the third test, steam was first injected into the model from injector. After steam channeling, 0.2 PV temperature-resistant gel was injected into the path of steam channeling. After 24 h (to form completer gelation), subsequent steam was injected into the model again. The flow rate was maintained at 0.2 ml/min. During those experiments, the injection temperature was controlled at 180 °C and the back pressure was maintained under 0.5 MPa to make injected steam keep saturation state. In these experiments, the viscosity of oil sample is 1502 mPa·s at 50 °C, but the viscosity is only 66.1 mPa s at 90 °C. The water sample used in experiments is distilled water.

The experimental procedures are as follows. First, the visualization model was maintained at 90 °C, then oil sample



(a) The experimental schematic

(b) The visualization model

(c) The quartz glass plate

Fig. 3 The schematic diagram of visualization physical simulation

Table 2 The experimental parameters of the visualization experiments

No.	Glass bead diameter (mm)	K (μm^2)	ϕ (decimal)	Oil volume (ml)	Injection fluids	Flux (ml/min)	Temperature (°C)	Back pressure (MPa)
Test 1	0.38	3.249	0.367	10.31	Steam	0.20	180	0.5
					N_2	1.25	180	0.5
					VR	0.20	180	0.5
					Steam/N_2	0.10/0.65	180	0.5
					Steam/VR	0.10/0.10	180	0.5
					Steam/N_2/VR	0.06/0.25/0.06	180	0.5
Test 2	0.38	3.336	0.372	10.60	Steam	0.20	180	0.5
					Foams	1.25	180	0.5
					Sub-steam	0.20	180	0.5
Test 3	0.38	3.197	0.363	10.32	Steam	0.20	180	0.5
					Gel	0.20	180	0.5
					Sub-steam	0.20	180	0.5

was injected from injector to saturate the model. After oil saturation, the visualization model was cooled to 50 °C (the original reservoir temperature) again. Then the steam of 180 °C was injected into the model at 0.2 ml/min. After steam channeling between injector and producer, the different fluids were injected into the visualization model to compare the variation of sweep efficiency and the oil recovery factor. Many small volume cylinders (generally 5 ml) were used to measure the liquid production, oil production and water content from the producer until no oil was produced. During the experimental processes, the high-definition camera can be used to record the swept area of real time in the visualization model, as shown from Figs. 4, 5 and 6. In these figures, the black zone is occupied by heavy oil, but the bright zone is scoured by injected fluids. Therefore, the areal sweep efficiency can be quantitatively analyzed through calculating the area ratio between the bright zone and the total valid visual zone during experimental processes.

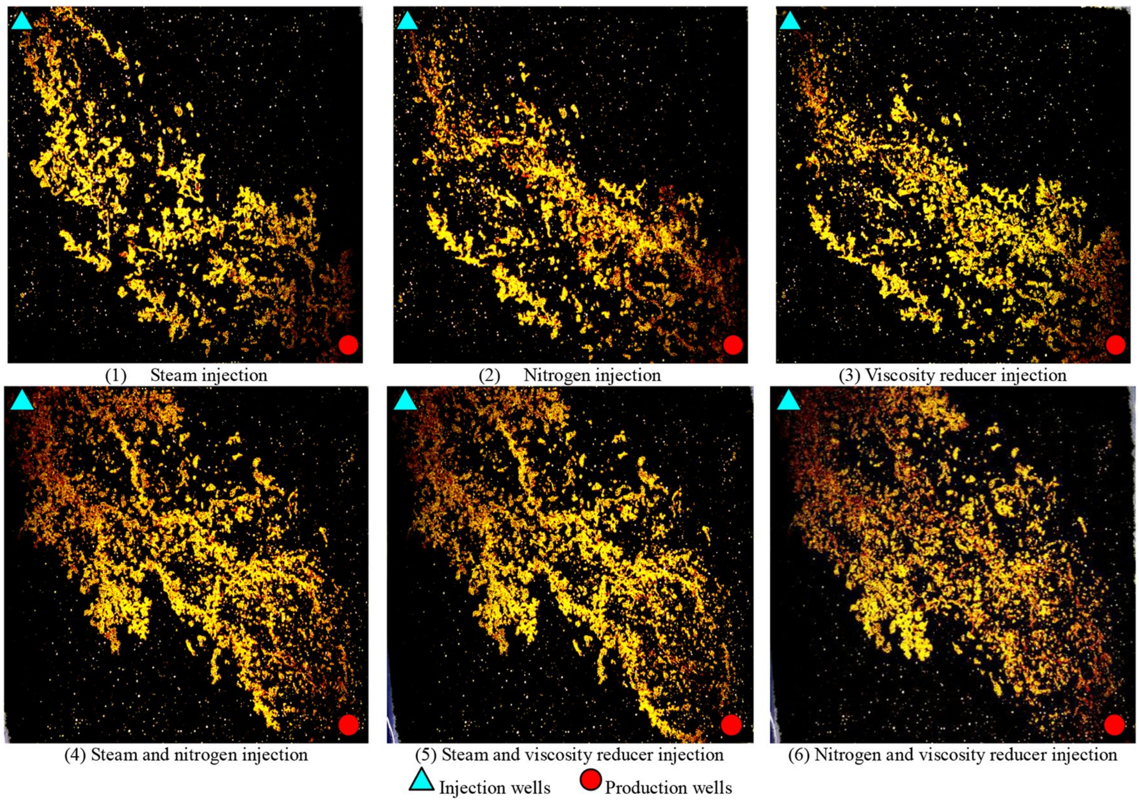


Fig. 4 The comparison diagram of areal swept zone of test 1

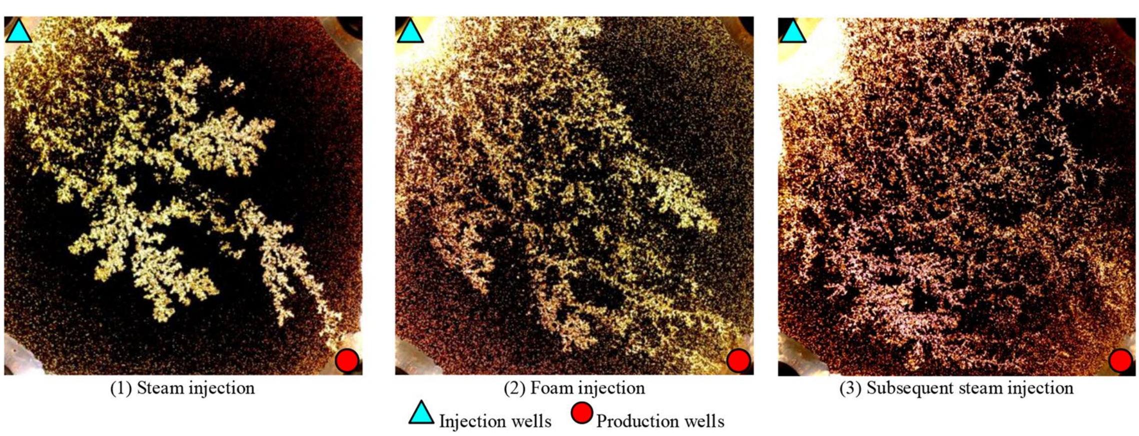


Fig. 5 The comparison diagram of areal swept zone of test 2

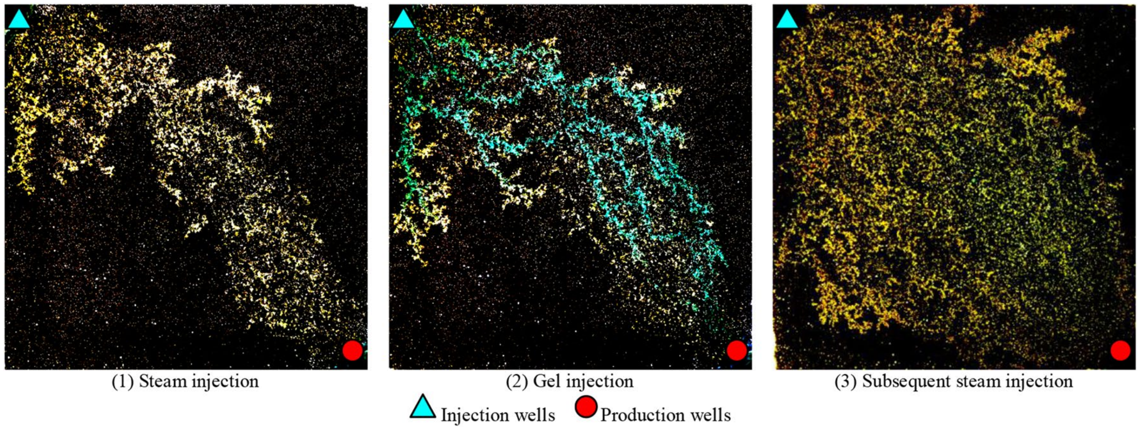


Fig. 6 The comparison diagram of areal swept zone of test 3

Experimental results and analysis

As shown in Fig. 4, after steam injection, a significantly bright zone is formed from injector to producer along the mainstream line in the visualization model. The ultimate areal sweep efficiency reaches 48.74%, however, a large amount of remaining oil are still detained inside the swept zone after steam injection. After the injection of nitrogen, the areal sweep efficiency presents a very small augment. But the swept zone becomes brighter and brighter due to the scouring effect of high speed from flowing nitrogen. After injecting a certain amount of viscosity reducer, the areal sweep efficiency increased to 49.05%, which is a small augment too, but the color of some zones is changed from dark red to bright yellow in swept zone. The results show that the viscosity reducer significantly increases the displacement efficiency, but the sweep efficiency hardly largely increases only through adding nitrogen or viscosity reducer after steam channeling (Green et al. 1991; Kam et al. 2007; Siddiqui et al. 2003). After the injection of steam and nitrogen together, the areal sweep efficiency reached 57.47%, which is 8.73% higher than steam injection. The results show that nitrogen-assisted steam can further expand the sweep efficiency of steam. The areal sweep efficiency has no obvious variation after the injection of steam and viscosity reducer together, but the displacement efficiency significantly improves near the injector. However, the areal sweep efficiency reached 70.35% after the simultaneous injection of steam, nitrogen and viscosity reducer, which is 12.88% higher than the injection of steam and N_2 together.

As shown in Fig. 5, after steam channeling, a bright swept zone is formed along the mainstream line and the sweep efficiency is only 49.13%. There is still amount of remaining oil inside the visualization model. After the injection of foams, the sweep efficiency gradually increases, as shown from Fig. 5b, c. When the total experimental processes terminate, the sweep efficiency reaches 84.49%, which is 35.36% higher than steam injection. As shown in Fig. 6, a channeling path is obviously presented between the injector and the producer at the end of steam injection. At the moment, the corresponding areal sweep efficiency is only 46.16%. Then the solution of temperature-resistant gel, 0.2 PV, was injected into the channeling path [the blue zone in Fig. 6(2)]. During this process, the areal sweep efficiency increases to 50.99% that is 4.83% higher than steam injection. As we know, gel can effectively increase the viscosity of flooding phase and thus decrease its mobility in channeling path, which can effectively improve the sweep efficiency (Eson and Cooke 1992; Hunter et al. 1992; Moradi-Araghi et al. 1993; Zubkov and Fedorov 1995). Therefore, the areal sweep efficiency of the subsequent steam injection reaches 77.44% that is 26.45% higher than steam injection.

The experimental results are listed in Table 3. When N_2 (or other non-condensate gas) is injected into reservoir along with steam, the swept zone can be obviously enlarged (Metwally 1990; Pang et al. 2012). When chemical agents, such as viscosity reducer and foaming agent (surfactant), are injected into reservoir along with steam, the displacement efficiency can be largely improved. In general, the displacement efficiencies of adding chemical agents are higher than 90%, as shown in Table 3. From the above analysis, the steam adding some fluids, such as nitrogen, viscosity reducer, can improve the development effect during steam injection; however, these injection modes only can be used to improve the displacement efficiency but not increase the sweep efficiency. For a poorer degree of steam channeling, foams can be used to enlarge swept zone and improve oil displacement efficiency (Lu et al. 2013; Li et al. 2011; Zitha et al. 2006). If there is a serious steam channeling among wells, a certain amount of temperature-resistant gel can be injected into the steam channeling path to plug it, and then subsequent steam is injected following with the gelation slug

Table 3 The development effect during different fluid injection

No.	Injection fluids	Sweep efficiency (%)	Displacement efficiency (%)	Oil recovery factor (%)	Sweep efficiency increment (%)	Recovery factor increment (%)
Test 1	Steam	48.74	83.34	40.62	–	–
	N_2	Little augment	85.85	41.88	–	1.26
	VR	49.05	93.25	45.74	0.27	3.86
	Steam–N_2	57.47	86.32	49.61	8.42	3.87
	Steam–VR	57.53	97.31	55.98	0.06	6.37
	Steam–N_2–VR	70.35	95.91	67.47	12.82	11.49
Test 2	Steam	49.13	83.68	41.11	–	–
	Foams	61.17	92.33	56.48	12.04	15.37
	Sub-steam	84.49	82.79	69.95	23.32	13.47
Test 3	Steam	46.16	84.66	39.08	–	–
	Gel	50.99	85.55	43.62	4.83	4.54
	Sub-steam	77.44	78.06	60.45	26.45	16.83

(Hunter et al. 1992; Eson and Cooke 1992). This injection mode can effectively expand the areal sweep area of steam and largely improve the development effect of heavy oil reservoirs.

The selection and application of measures

The selection method

To increase the oil production of low production wells, we consider the following measures: nitrogen-assisted steam; viscosity-reducer-assisted steam; nitrogen- and viscosity-reducer-assisted steam. For the low production wells from thermal disturbance or steam channeling, foams and even gel can be chosen during steam injection. Aiming at different types of low production wells, we choose improvement measures according to the reasons of low production. Some principles should be followed:

For low production wells with higher recovery degree, we should choose wells with poorer steam channeling and with a certain amount of remaining oil. We can consider nitrogen-assisted steam or foam-assisted steam. For super heavy oil, viscosity reducer should be simultaneously injected into reservoir.

For low production wells with the effect of dual factors, nitrogen-assisted steam or foam-assisted steam can be considered. For super heavy oil, viscosity reducer should be simultaneously injected into reservoir.

For low production wells with serious steam channeling, gel, foam-assisted steam or combined measures can be employed.

Aiming at the different low production wells, a new parameter, equivalent oil–steam ratio (EOSR), was employed to as a termination condition of numerical simulation. The EOSR is defined as the ratio between the cumulative oil volume and the cumulative equivalent steam injection (the total expense of chemical agents and steam is converted to the equivalent steam) during different improvement measures. The formula of EOSR is as follows:

$$\mathrm{EOSR} = \frac{V_{\mathrm{p}}}{\left(\frac{V_{\mathrm{N_2}} C_{\mathrm{N_2}} + V_{\mathrm{steam}} C_{\mathrm{steam}} + V_{\mathrm{VR}} C_{\mathrm{VR}} + V_{\mathrm{foam}} C_{\mathrm{foam}}}{C_{\mathrm{steam}}}\right)}$$

where EOSR is the equivalent oil–steam ratio, m^3/m^3; V_p is the cumulative oil production, m^3; V_{N_2} is the cumulative N_2 injection, m^3; V_{steam} is the cumulative steam injection, m^3; V_{VR} is the cumulative viscosity reducer (VR) injection, m^3; V_{foam} is the cumulative foaming agent injection, m^3; C_{N_2} is the unit price of N_2, CNY/m^3; C_{steam} is the unit price of steam, CNY/m^3; C_{VR} is the unit price of viscosity reducer (VR), CNY/m^3; C_{foam} is the unit price of foaming agent, CNY/m^3.

To find the optimum improvement measure, we introduced two new parameters, the volume of augment oil ($V_{p\text{-aug}}$) and the net gross income ($I_{p\text{-net}}$), to evaluate the effectiveness of different measures. The $V_{p\text{-aug}}$ is defined as the difference of cumulative oil production between the improvement measure and steam alone. The $I_{p\text{-net}}$ is defined as the difference between the augment income (the value of $V_{p\text{-aug}}$ timing oil price) and the augment cost (the total price of injected chemical agents). The two formulas are as follows:

$$V_{\mathrm{p\text{-}aug}} = V_{\mathrm{p\text{-}measure}} - V_{\mathrm{p\text{-}steam}}$$

$$I_{\mathrm{p\text{-}net}} = V_{\mathrm{p\text{-}aug}} \cdot C_{\mathrm{oil}} - \left(V_{\mathrm{N_2}} C_{\mathrm{N_2}} + V_{\mathrm{VR}} C_{\mathrm{VR}} + V_{\mathrm{foam}} C_{\mathrm{foam}}\right)$$

where $V_{p\text{-aug}}$ is the volume of augment oil production, m^3; $V_{p\text{-measure}}$ is the volume of oil production after improvement measures, m^3; $V_{p\text{-steam}}$ is the volume of oil production after steam injection, m^3; $I_{p\text{-net}}$ is the net gross income, CNY; C_{oil} is the unit price of heavy oil, CNY/m^3.

In China, the C_{N_2} is about 2 CNY/m^3; the C_{steam} is 236.76 CNY/m^3; the C_{VR} is about 2×10^4 CNY/m^3; the C_{foam} is about 2×10^4 CNY/m^3. In current, the oil price is 50 \$/bbl, that is, 2320 CNY/m^3. Generally, the EOSR must be higher than 0.15 during the improvement measurements. Therefore, numerical simulation can be used to find the limit conditions

Table 4 The limit conditions of different improvement measures

Parameters	Symbol	Nitrogen-assisted steam	Foam-assisted steam	Comments
Viscosity of crude oil (original temperature)	μ_o	< 23,000 mPa s	< 37,000 mPa s	Key parameter
Absolute permeability	K	$> 800\times10^{-3}$ μm^2	$> 1000\times10^{-3}$ μm^2	Key parameter
Permeability contrast	V_k	≈ 1.0	< 3.0	Key parameter
Net pay	H_e	> 3.0 m	> 5.0 m	Key parameter
Porosity	ϕ	> 0.26	> 0.22	Key parameter
Net gross	NTG	> 0.60	> 0.40	Key parameter

Table 5 The effectiveness of measures for different low production wells

No.	Well	H_e (m)	K (μm^2)	V_k	μ_o (mPa s)	ϕ (%)	ORF$_i$ (%)	ORF$_r$ (%)	Comments
1	L32829	1.4	0.987	1.0	9386.8	27.9	28.6	72.0	N_2 or foams is effective
2	L32725	3.0	1.031	2.8	3986.7	27.8	26.9	70.0	N_2 or foams is effective
3	L01406	4.8	1.380	1.0	7976.5	30.4	28.4	55.0	N_2 or foams is effective
4	L01505	3.4	2.810	1.3	8976.5	37.0	28.9	55.0	N_2 or foams is effective
5	L01208	2.4	1.788	1.0	8633.3	28.3	26.3	83.3	N_2 or foams is effective
6	L0903	3.4	1.487	1.0	7000.0	25.5	39.9	87.0	N_2 or foams is effective
7	L0404	2.8	0.704	3.7	8100.0	25.1	34.0	92.0	N_2 or foams is invalid
8	L32927	1.6	1.696	1.0	1268.2	27.7	57.5	90.0	N_2 or foams is invalid
9	L101	9.6	2.420	1.0	16,111.0	32.2	47.4	89.5	N_2 or foams is invalid
10	L0701	2.4	0.240	7.8	5475.0	19.4	7.6	32.7	N_2 is effective
11	L32926	5.0	0.930	5.1	7976.5	27.9	17.6	71.1	Gel injection is effective
12	L33033	3.8	0.950	3.3	4400.0	27.5	10.2	39.5	Gel injection is effective
13	L01004	1.6	1.130	1.4	7260.0	32.3	9.4	35.0	Gel injection is effective
14	L32929	5.2	1.190	1.7	1268.2	31.2	10.3	72.3	Foams or gel injection is effective
15	LJ02	7.6	1.460	32.9	7976.5	30.2	9.1	37.9	Foams or gel injection is effective
16	L0910	4.2	1.570	1.5	10,833.3	28.7	11.5	50.7	Foams or gel injection is effective
17	LZ34	5.0	3.730	5.0	4120.0	36.8	13.0	52.4	Foams or gel injection is effective
18	LJ03	7.6	5.220	3.7	7976.5	33.7	12.1	50.1	Foams are invalid
19	LJ0510	4.8	6.530	3.7	17,100.0	36.5	7.6	21.6	Foams are invalid
20	L0414	5.6	0.372	5.5	7976.47	32.2	24.8	52.7	N_2 is effective
21	L0602	4.6	1.130	5.3	3866.7	27.4	19.4	55.8	N_2 or foams is effective
22	L0604	7.2	2.130	11.1	5933.3	30.7	19.2	58.6	Gel injection is effective
23	L0608	6.8	1.420	2.6	10,125.0	27.6	20.5	60.2	Gel injection is effective
24	L0606	6.8	1.390	1.6	7240.0	27.7	26.9	69.4	Foams or gel injection is effective
25	L0804	8.3	1.140	1.5	8633.3	29.9	19.3	37.8	Foams or gel injection is effective
26	LJ0710	5.2	1.234	3.4	9443.0	27.0	32.6	72.8	Foams or gel injection is effective
27	LJ0512	8.2	1.380	4.1	7976.5	28.9	36.8	72.3	Foams or gel injection is effective
28	L32825	2.2	1.013	7.7	5705.9	28.9	26.7	55.6	N_2 is invalid
29	L32925	4.4	1.189	6.0	7976.47	29.8	24.6	47.5	N_2 is invalid
30	L0712	3.5	1.036	1.6	24,284.1	28.4	17.6	52.1	Foams are invalid

ORF$_i$ is the oil recovery factor of original oil reserves, ORF$_r$ is the oil recovery factor of single-well recoverable reserves of each geological parameter according to the former evaluation standard. The results are shown in Table 4. Based on the above analysis, based on key geological parameters such as μ_o, K, H_e and V_k, we used CMG-STARS to find the limit of geological parameters that can be used to implement nitrogen- or foam-assisted steam simulation in heavy oil reservoirs. First, for each improvement measure, the cumulative volume of oil production can be obtained when the EOSR is less than 0.15 through numerical simulation. Then, for pure steam stimulation, the cumulative volume of oil production can also be obtained under the same cumulative steam injection. Therefore, the effectiveness can be quantitatively elevated through the parameters including $\mathrm{ORF_i}$ and $\mathrm{ORF_r}$. The results are shown in Tables 4 and 5. We can find the limits for the following measures:

According to the values of geological parameters, we can calculate the limit of low production wells with high recovery degree. For nitrogen-assisted steam injection, it can be used only when the values of $[KH_e/(\phi \mathrm{Ln}\,\mu_o)]^{\frac{1}{V_k}}$ is higher than 919.1 (if oil viscosity is higher than 23,000 mPa s, viscosity reducer need be injected); for foam-assisted steam injection, it can be used only when the parameter, $[KH_e/(\phi \mathrm{Ln}\,\mu_o)]^{\frac{1}{V_k}}$, is from 400.0 to 919.1.

According to the values of geological parameters, we can calculate the limit of steam channeling or dual factors. For foam-assisted steam injection, it can be used only when the values of $[KH_e/(\phi \mathrm{Ln}\,\mu_o)]^{\frac{1}{V_k}}$ is from 12.9 to 400.0 (when oil viscosity is higher than 37,000 mPa s, viscosity reducer need be injected); if $[KH_e/(\phi \mathrm{Ln}\,\mu_o)]^{\frac{1}{V_k}}$ is less than 12.9, the gel must be used to inhibit steam channeling.

According to Tables 4 and 5, we used CMG-STARS to simulate the situations of low production wells and the effect of those measurements and to analyze its effectiveness. Finally, we got a diagram of measure selection, which was divided into four regions, as shown in Fig. 7. Nitrogen or foams can help to improve production when the parameter, $[KH_e/(\phi \mathrm{Ln}\,\mu_o)]^{\frac{1}{V_k}}$, is more than 919.1 and the $\mathrm{ORF_r}$ is less than 90%. Nitrogen injection is an effective method when the value of parameter is between 12.9 and 919.1. The $\mathrm{ORF_r}$ should be less than 90% for the low production wells of higher oil recovery whose parameter is between 400.0 and 919.1. For the regions which are from 12.9 to 400.0, that is, dual factors and steam channeling, the corresponding $\mathrm{ORF_r}$ should be less than 87%. When the values of parameters are less than 12.9, that is, serious steam channeling problem, gel injection or other compound measures can be used to block steam channeling to improve development effect.

Field applications

Based on the above standards, a series of measures, such as nitrogen, the mixture of nitrogen and viscosity reducer and foams, were utilized to improve the development effect of low production wells. The applications are listed in Table 6. For nitrogen-assisted steam, it is used 27 well-times. Among these 27 applications, 22 well-times show effective, that is, the effective percentage is 81.5%. Foams are used 28 well-times to inhibit steam channeling. Among these 28 applications, 22 well-times show effective, that is, the effective percentage is 78.6%. The total effective percentage of all applications is 80.0%. As shown in Table 7, aiming at

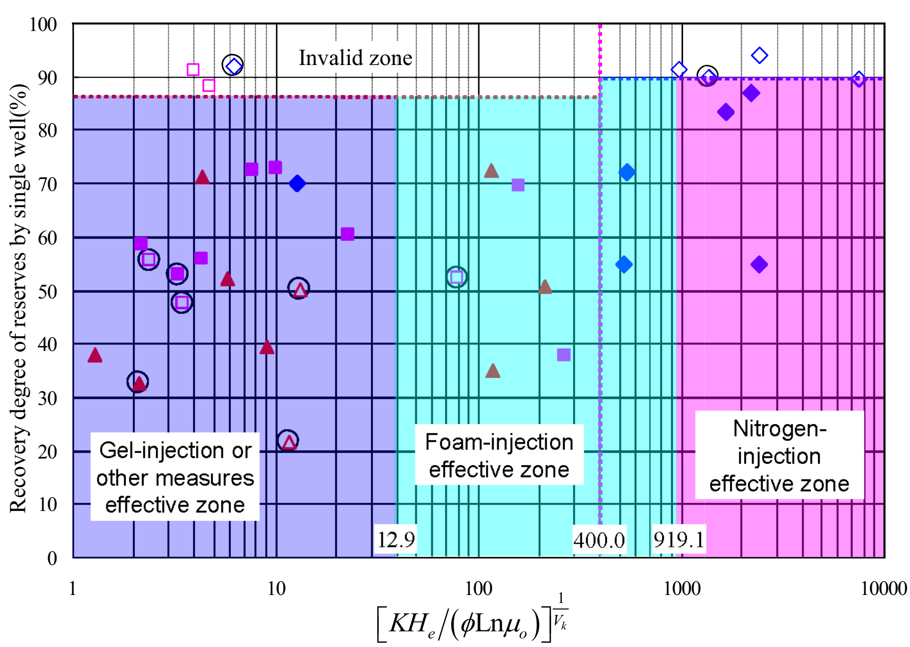


Fig. 7 A diagram of measure selection for different type of low production wells of thermal recovery

Table 6 The applications of improvement measure for low production wells

Fluid	Well-times			Effective percentage (%)
	Total	Effective	Ineffective	
Nitrogen	27	22	5	81.5
Foams	28	22	6	78.6
Total	55	44	11	80.0

nitrogen-assisted steam injection, the total incremental oil volume is 3130.2 m^3 and the average incremental oil volume per well is 142.3 m^3. The oil–steam ratio increases from 0.06 to 0.17. For foam-assisted steam injection, the total incremental oil volume is 3141.7 m^3, that is, the average incremental oil volume per well is 112.2 m^3. The oil–steam ratio increases from 0.07 to 0.21.

Conclusions

By introducing new parameters, $[KH_e/(\phi \mathrm{Ln}\,\mu_o)]^{\frac{1}{V_k}}$, we divided low production wells of thermal recovery into three types involving the higher degree of oil recovery, the steam channeling among wells and the dual factors. For the first type, the values of the parameter are more than 400 and the oil recovery is higher than 20%. For the second type, the values of the parameter are less than 400 and the oil recovery is less than 17%. However, for the third type, the values are less than 400 and the oil recovery is more than 17%.

A novel diagram for measure selection was established, which was divided into four parts to choose appropriate measures. For the type of higher degree of oil recovery, the chosen measures are effective only when the ORF_r is less than 90%. For the type of dual factors or steam channeling, the chosen measures are effective only when the ORF_r is less than 87%.

According to the selection method of improvement measures, nitrogen-assisted steam injection should be used when the parameter, $[KH_e/(\phi \mathrm{Ln}\,\mu_o)]^{\frac{1}{V_k}}$, is more than 919.1. Gel injection or compound measures can be used when the parameter is less than 12.9. Foam injection is an effective method when the value is from 12.9 to 919.1.

In a Chinese oilfield, many wells of steam injection are at a state of low production. The practical applications show that the efficiency reaches to 81.5% by injecting nitrogen. For foam injection, the increment production of average single well gets to 112.2 m^3 and the efficiency is 78.6%. The total efficiency is 80.0%.

Table 7 The effectiveness of different improvement measures

Type	Measures	Average cycles	Foaming agent consumption (ton)	Nitrogen consumption ($\times 10^4$ m^3)	Before measures					After measures				
					Steam (CCW) (m^3)	Production days (days)	Oil production (m^3)	Average daily oil production (m^3/day)	Oil–steam ratio	Steam (CCW) (m^3)	Production days (days)	Oil production (m^3)	Average daily oil production (m^3/day)	Oil–steam ratio
Higher recovery degree	Nitrogen	3	–	17.3	785	92.7	36.5	0.40	0.05	6207	957	920.8	0.96	0.15
	Foams	3.5	6.8	13.2	946	99.3	55.2	0.56	0.06	5077	731	956.3	1.31	0.19
Steam channeling	Nitrogen	3	–	79.0	727	98.6	47.9	0.49	0.07	25,246	4162	4249.0	1.02	0.17
	Foams	4	26.6	41.7	762	101.1	53.1	0.53	0.07	18,631	3007	4155.2	1.38	0.22

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Compliance with ethical standards

Conflict of interest The authors declare no competing financial interest.

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