Open Journal of Applied Sciences, 2023, 13, 2047-2054
https://www.scirp.org/journal/ojapps
ISSN Online: 2165-3925
ISSN Print: 2165-3917

Research on Optimization Design of Deep Profile Control Injection Scheme in Block S

Meinan Wang, Shaopeng Wang, Wei Zhang, Xiaoqi Chen, Junting Zhang

Bohai Oilfield Research Institute of CNOOC Ltd.-Tianjin Branch, Tianjin, China
Email: wangmn2@cnooc.com.cn

How to cite this paper: Wang, M.N., Wang, S.P., Zhang, W., Chen, X.Q. and Zhang, J.T. (2023) Research on Optimization Design of Deep Profile Control Injection Scheme in Block S. *Open Journal of Applied Sciences*, **13**, 2047-2054.
https://doi.org/10.4236/ojapps.2023.1311160

Received: October 22, 2023
Accepted: November 24, 2023
Published: November 27, 2023

Abstract

In view of the rapid decline rate of oil production and gradual increase of water cut in oil wells in Block S, based on the determination of the formula of foam profile control agent, the optimization study of foam profile control injection scheme was carried out. Petrel software is used to establish a facies controlled geological model based on stochastic modeling method in Block S, and CMG software is used for numerical simulation to design 7 sets of foam profile control prediction schemes. Dynamic data and numerical simulation methods are used to optimize foam injection mode and injection cycle. By simulating and calculating, the optimal injection method of alternating gas and liquid injection and the optimal plan with an injection period of 2 months were selected. Through the calculation results of various research plans, it can be seen that the water content of the optimal plan has decreased significantly, and the oil production rate has increased significantly, in order to slow down production decline, control water content rise, extend the economic recovery period of the oilfield, and achieve the goal of improving oil recovery.

Keywords

Foam Profile Control, Numerical Simulation, Injection Method, Injection Cycle

1. Introduction

The research on foam depth profile control technology has a history of more than 30 years [1] [2] [3] [4]. At present, as Block S enters the stage of high or ultra-high water cut development, the problem of water flooding is becoming increasingly complex, and the difficulty of stabilizing oil and controlling water technology is increasing. Traditional profile control can no longer meet the requirements [5] [6] [7] [8]. This requires continuous innovation and development in the field of technology, especially in the research and application of deep profile control fluid flow steering technology. In recent years, this technology has also achieved many research results, and has achieved significant results in improving the water injection development effect of high water cut oil fields.

The N oil layer in Block S selected in this article has good reservoir properties, but with well-developed faults and complex oil-water distribution, the water content increases rapidly after water breakthrough [9] [10] [11] [12]. Among them, there are locally developed sand bodies in contiguous blocks with a comprehensive water content of 60%, which increases the difficulty of development, reduces the efficiency of water injection and oil displacement, and increases the production cost. In this situation, using conventional adjustment techniques is often difficult to tap into the remaining oil potential of the block, and there is little room for improving oil recovery [13] [14] [15]. In this paper, foam profile control technology is adopted, and a reasonable injection scheme is proposed. By injecting profile control agent, the injection swept volume is increased, and the underground flow field is changed, so that the injection medium can reach the high oil saturation area, and the crude oil in it is driven out, so as to slow the decline of production, control the rise of water cut, and improve the oil recovery.

2. Research on Numerical Simulation of Block S

Block S mainly exploits N oil layers with a geological reserve of 193.54×10^4 t, with an average permeability of 0.0473 μm^2, porosity 22.7%, crude oil surface density 0.859 t/m^3, average effective thickness of single well in Block S is 11.6 m, and there are 45 oil wells and 15 water wells in this block. Using Petrel software combined with the actual geological data of Block S, a facies controlled geological model based on random modeling method was established for the study well area. At the same time, a numerical model was established using CMG software and historical fitting was performed to further achieve the prediction of the plan.

On the basis of establishing the fracture system, the S block is divided into 19,728 non-uniform corner grids on the plane. Combined with the dip angle data and geological understanding, the model is revised until it is reasonable. The edge of the construction model is determined as a closed boundary based on the location and strike of the three major faults, and ultimately combined with the fault system to form the construction model. In order to ensure the accuracy of the initial conditions of the prediction plan, it is first necessary to perform mining history fitting.

After the formation of the initialization parameter field, combined with geological, logging, and reservoir engineering analysis data, uncertain parameters such as porosity and effective thickness were corrected. After multiple repetitions of reserve fitting, the initial calculated reserves were compared with geological reserves. The fitted liquid production and water content are shown in **Figure 1** and **Figure 2**.

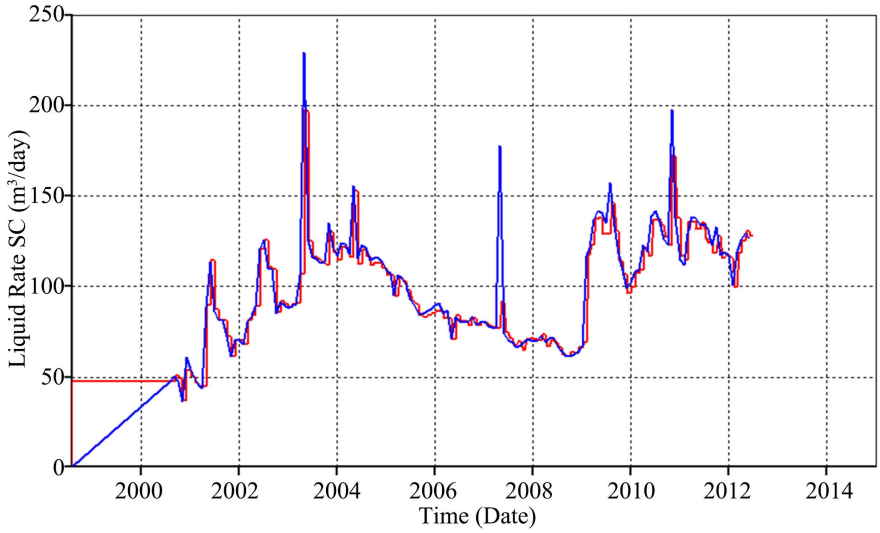

Figure 1. Fitting curve of liquid production volume in block S.

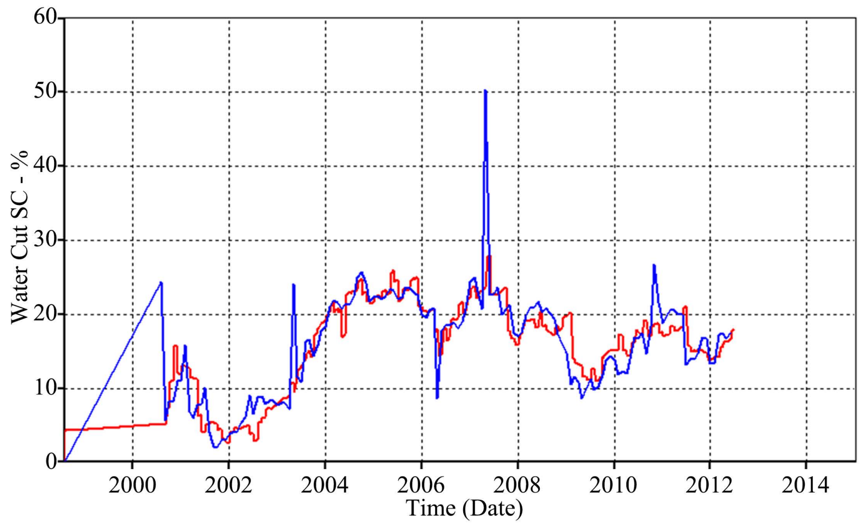

Figure 2. Fitting curve of comprehensive water content in block S.

3. Research on Injection Scheme of Profile Control Agent for N Reservoir in Block S

Before you begin to format your paper, first write and save the content as a separate text file. Keep your text and graphic files separate until after the text has been formatted and styled. Do not use hard tabs, and limit use of hard returns to only one return at the end of a paragraph. Do not add any kind of pagination anywhere in the paper. Do not number text heads—the template will do that for you.

Finally, complete content and organizational editing before formatting. Please take note of the following items when proofreading spelling and grammar:

3.1. Determination of Profile Control Well Group

The high water cut oil wells in this block are controlled by 7 water wells, namely

S-01, S-02, S-05, S-08, S-10, S-12, and S-15. This article selects the high water content well group centered around well S-15 as the research object for analysis, and the corresponding oil wells are S-28, S-34, S-32, S-43, S-44, S-35, S-30, S-45.

3.2. Optimization of Reasonable Injection Methods

According to the geological characteristics of oil layer N in Block S, the formula system of foam profile control agent adopted is: polymer molecular weight is 8 million, polymer concentration is 1000 mg/L, surfactant concentration is 0.25 wt%, and gas-liquid ratio is 1:1.

There are two injection modes of foam profile control agent: gas-liquid mixed injection and gas-liquid alternate injection. Optimize by designing the following three options:

Scheme 1: Water drive to a water content of 98%.

Scheme 2: Inject foam profile control agent in the form of mixed injection, the injection rate is 11 m^3/d, the profile control time is 3 years, and the subsequent water drive will reach 98% water cut.

Scheme 3: Inject foam profile control agent in an alternate way. Inject foam agent solution first, then inject CO_2. The injection cycle is 2 months, the injection rate is 11 m^3/d, the profile control time is 3 years, and the subsequent water drive is to 98% water cut.

Based on the simulation results, plot the curves of water content and daily oil production over time, as shown in Figure 3 and Figure 4.

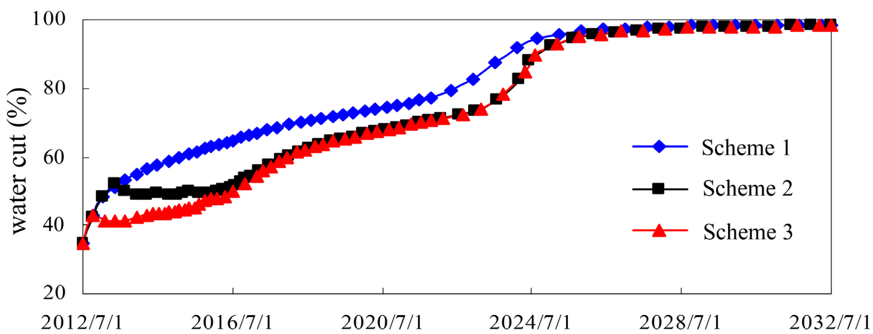

Figure 3. Comprehensive test well cluster under different injection methods.

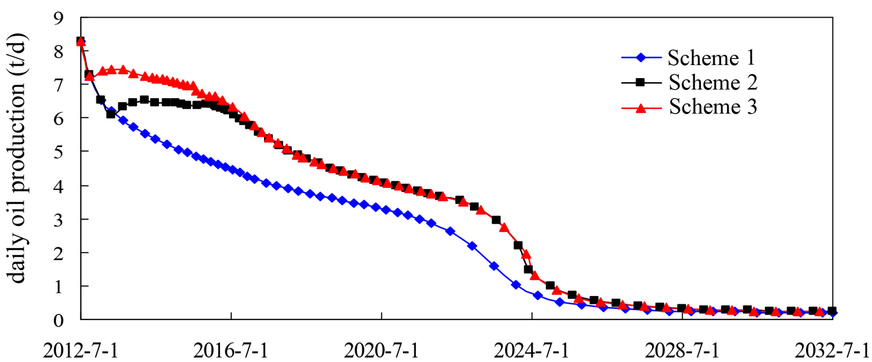

Figure 4. Time dependent curve of oil production under different injection methods.

From **Figure 3** and **Figure 4**, it can be seen that after adopting different injection methods for profile control, the water content will continue to increase and the oil production will continue to decrease for a period of time. During this period, the profile control measures have not yet been effective, and then there will be a decrease in water content and an increase in oil production, indicating that the profile control measures are effective. The mixed injection method showed true profile control effect after about 9 months, and the alternating injection method showed true profile control effect after about 3 months. The decrease in water content and the increase in oil production of alternating injection are both higher than those of mixed injection, indicating that the profile control effect of alternating injection is better than that of mixed injection.

The alternating injection method with the highest cumulative oil production of oil wells in the research well area is 13.750 × 10^4 t, 0.933 × 10^4 t higher than continuous water drive 0.167 × 10^4 t higher than mixed injection. The average daily oil increase and average daily water content decrease within three years of profile control measures are higher than those of mixed injection. The profile control effect of alternating injection is significantly better than that of mixed injection.

3.3. Reasonable Injection Cycle Optimization

The effect of foam profile control is different in different injection cycles. On the basis of determining that the injection mode is gas-liquid alternate injection, the following schemes are designed for the injection cycle (the injection sequence is foam agent injection before CO_2 injection):

Scheme 4: Inject foam profile control agent in an alternate manner. The injection cycle is 2 months, the injection rate is 11 m^3/d, the profile control time is 3 years, and the subsequent water flooding is 98% water cut.

Scheme 5: Inject foam profile control agent in an alternate manner. The injection cycle is 4 months, the injection rate is 11 m^3/d, the profile control time is 3 years, and the subsequent water flooding is 98% water cut.

Scheme 6: Inject foam profile control agent in an alternate manner. The injection cycle is 6 months, the injection rate is 11 m^3/d, the profile control time is 3 years, and the subsequent water flooding is 98% water cut.

Scheme 7: Inject foam profile control agent in an alternate manner. The injection cycle is 12 months, the injection rate is 11 m^3/d, the profile control time is 3 years, and the subsequent water flooding is 98% water cut.

Draw curves of water content and daily oil production over time based on simulation results (as shown in **Figure 5** and **Figure 6**).

From **Figure 5** and **Figure 6**, it can be seen that after adopting different injection cycles for profile control, the water content will continue to increase and the oil production will continue to decrease for a period of time. During this period, the profile control measures have not yet been effective, and then there will be a decrease in water content and an increase in oil production, indicating that the

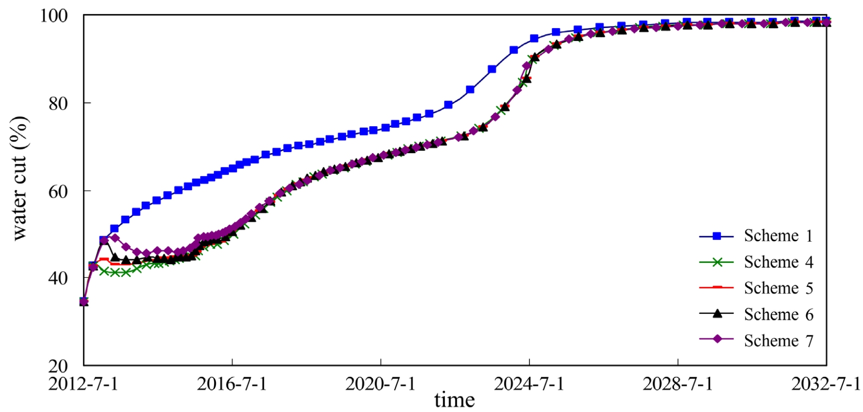

Figure 5. Time varying curve of comprehensive water content of test well group under different injection cycles.

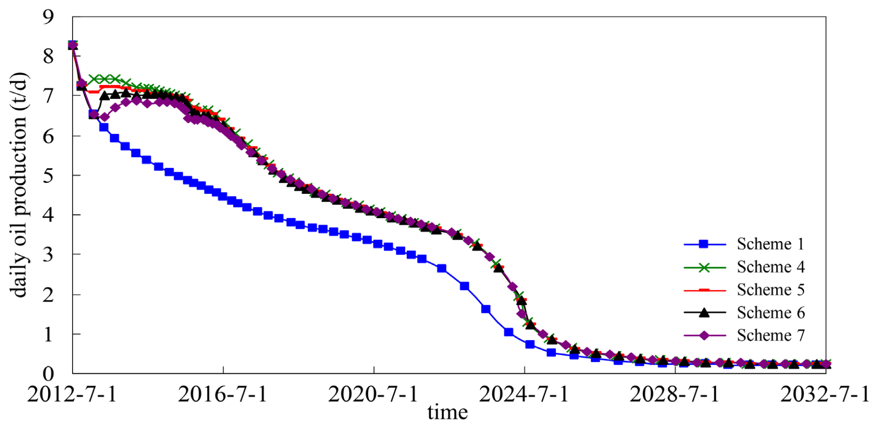

Figure 6. Daily oil production curve of test well group with time under different injection cycles.

profile control measures have been effective. The earliest effective injection period is 2 months, and the latest effective injection period is 1 year. The shorter the injection period, the more significant the decrease in water content and the greater the increase in oil production rate.

The shorter the injection period, the higher the cumulative oil production of the oil wells in the study well area. The average daily oil increase and average daily water content decrease within the profile control measures are greater, with the profile control effect being the most obvious after a 2-month injection period, with a cumulative oil production of 13.750 × 10^4 t, 0.933 × 10^4 t higher than continuous water drive, higher than other injection cycles. It shows that the reasonable injection period of foam profile control agent for N reservoir in Block S is 2 months.

4. Conclusions

1) Based on the production characteristics of oil wells in Block N of Block S, the high water cut oil wells and the water wells connected to them in the study block were determined, and the water well for profile control measures was de-

termined as S-15.

2) In terms of injection method selection, the profile control effect of alternating injection is 6 months earlier than that of mixed injection, and the cumulative oil production and average water content decrease is higher than that of mixed injection, indicating that the profile control effect of alternating injection is better than that of mixed injection.

3) In terms of injection cycle screening, the cumulative oil production and water cut decline values of the injection cycle of two months are higher than those of other schemes, so the reasonable injection cycle of foam profile control agent for oil layer N in Block S is two months.

Conflicts of Interest

The authors declare no conflicts of interest regarding the publication of this paper.

References

[1] Khatib, Z.L., Hirasaki, G.J. and Falls, A.H. (1988) Effects of Capillary Pressure on Coalescence and Phase Mobilities in Foams Flowing through Porous Media. *SPE Reservoir Engineering*, **3**, 919-926. https://doi.org/10.2118/15442-PA

[2] Fisher, A.W., Fouiser, R.W.S., Goodyear S.G., *et al.* (1990) Mathematical Modeling of Foam Flooding. *SPE/DOE Enhanced Oil Recovery Symposium*, Tulsa, Oklahoma, 22-25 April 1990, Paper Number: SPE 20195. https://doi.org/10.2118/20195-MS

[3] Du, Q.J., Hou, J., Li, Z.Q., Wang, Y.D. and Chen, Y.M. (2009) A Mathematical Model of Polymer Enhanced Foam Flooding. *Chinese Journal of Computational Physics*, **26**, 872-877.

[4] Pei, H., Zhang, G., Ge, J., Wang, J. and Ding, B. (2010) Investigation of Polymer-Enhanced Foam Flooding with Low Gas/Liquid Ration for Improving Heavy Oil Recovery. *Canadian Unconventional Resources and International Petroleum Conference*, Calgary, Alberta, 19-21 October 2010, Paper Number: SPE 2137171. https://doi.org/10.2118/137171-MS

[5] Gang, Q.L. (1999) New Technology for Improving Water Drive Effect in High Water Cut Oilfield. Petroleum Industry Press, Beijing, 87-93.

[6] Yao, X.T., Su, X.K., Zheng, X., Ma, J., Gai, L.P. and Cui, C.Z. (2023) 3D Physical Simulation Experiments of Development Effects after Well Pattern Adjustment in Extra-High Water Cut Reservoirs. *Petroleum Geology and Recovery Efficiency*, **30**, 139-145.

[7] Jia, X.F., Lei, G.L. and Jia, X.Y. (2009) Current Situation and Development Trend of In-Depth Profile Control. *Special Oil & Gas Reservoirs*, **16**, 6-12.

[8] Zhou, J.L., Sun, Y.L., Dong, C., Zhu, H.T., Song, L.J. and Niu, J. (2023) Study on Optimization Method of Reservoir Combination in DG Oil Field at Extra High Water Cut Stage. *Mathematics in Practice and Theory*, **53**, 182-189.

[9] Sun, H.Q., Yang, Y., Wang, H.T., Wang, J., Wu, G.H., Cui, Y.M. and Yu, Q. (2023) Distribution Characteristics of Remaining Oil in Extra-High Water Cut Reservoirs and New Technologies for Enhancing Oil Recovery. *Journal of China University of Petroleum* (*Edition of Natural*), **47**, 90-102.

[10] Li, X., Jin, L., Shen, Z.S. and Su, B.L. (2023) Discussion on Tapping Potential Tech-

nology of Highly Deviated Directional Well along Fault Edge in Ultra-High Water-Cut Old Oilfield. *Unconventional Oil & Gas*, **10**, 80-85.

[11] Shan, G.J., Wang, C.X., Wang, Z.G., Jiang, X.Y. and Guo, J.H. (2023) Water Injection Adjustment Methods Based on Dynamic Flow Resistance. *Xinjiang Petroleum Geology*, **44**, 435-441.

[12] Yang, B., Fu, Q., Guan, J.T., Li, L.X. and Pan, H.Y. (2023) Oil Displacement Efficiency Based on Different Well Pattern Adjustment Simulation in High Water cut Reservoirs. *Petroleum Reservoir Evaluation and Development*, **13**, 519-536.

[13] Wang, W.B., Xue, Y., Gao, Y.W., Kang, X.Y., Zhao, L., Jin, Z. and Wang, M. (2023) Research Progress in EOR Technology Based on Synergy of Microbial and Chemical Flooding/Gas Flooding. *Applied Chemical Industry*, **52**, 1587-1592.

[14] Wang, F.J., Xu, H., Liu, Y.K., Wang, Y.P., Wu, C.Y. and Li, G.Y. (2023) Study and Application of Polymer Flooding for Enhanced Oil Recovery in Shallow Ordinary Heavy Oil Reservoirs. *Special Oil & Gas Reservoirs*, **30**, 107-113.

[15] Li, X. (2023) Feasibility Study of EOR by Conversion to Steam Flooding in a Deep-Thin Offshore Heavy Oil Reservoir. *World Petroleum Industry*, **30**, 73-79.