Research on the Enhanced Oil Recovery Technique of Horizontal Well Volume Fracturing and CO₂ Huff-n-Puff in Tight Oil Reservoirs

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1. INTRODUCTION

With the fossil energy demand increasing all over the world and the conventional oil and gas resource reserves continuously declining, unconventional reservoir development such as tight oil and gas is being given more attention for reservoir engineering. According to statistics, tight oil and gas reserves are huge, and the world’s tight shale oil reserves are up to 716 trillion m³.¹ The tight oil resource is also rich in the Permian of Qaidam Basin, the Paleogene of Bohai Bay Basin, the Cretaceous of Songliao Basin, the Jurassic of Sichuan Basin, the Neogene of Qaidam Basin, and the Triassic of Ordos Basin, in China. Some scholars estimate that the original oil in place (OOIP) of tight oil is 53.7 billion ton.² The permeability of a tight oil reservoir is very low, which is below 2 × 10⁻³ μm², resulting in the low productivity of the oil well when the tight oil reservoir is put into development without fracturing technique application.³ Furthermore, the water injection capacity is also poor in tight oil reservoirs, leading to the reservoir energy in the elastic development stage dropping rapidly and the effective reservoir development time being short.⁴,⁵ Facing the development difficulty of tight oil reservoirs, a lot of tight oil enhanced recovery methods have been proposed, such as the water or gas flooding, surfactant flooding, gas huff-n-puff flooding, and so forth.⁶ However, in the process of water or gas flooding for tight reservoirs, too small well spacing often leads to earlier water or gas breaking into oil wells along the high-permeability channels of the reservoir.⁷ On the contrary, if the well spacing is too large, water injection will be difficult due to a high reservoir starting pressure gradient.⁸,⁹ Presently, the better stimulation way for tight oil reservoirs is to increase the effective drainage radius using horizontal well drilling and the hydraulic fracturing technique.¹⁰ Since 2007, volume fracturing as a large-scale reservoir stimulation method is first applied in tight oil reservoirs in North America to increase oil productivity, while a horizontal well with volume fracturing is applied to improve oil recovery in China from 2006 to 2010.¹¹ Compared with conventional fracturing methods, the injection volume of fracturing fluid and proppant is much more, where over 10,000 m³ of fracturing fluid and 1000 m³ of proppant are injected into the reservoir to form complex sand-filled fracture networks.¹² This reservoir stimulation method of volume fracturing of horizontal wells can effectively increase the drainage radius.¹³ However, in the process of tight reservoir development with horizontal well fracturing, an over-large or over-small fracturing scale of...
reservoir often results in low oil productivity and short effective oil increase life cycle. Hence, reservoir fracturing scale optimization of the horizontal well is important for tight oil reservoir EOR because a reasonable fracturing scale can communicate a large reservoir volume and increase the available reserves. After the effective oil production rate increase stage of the reservoir volume fracturing technique was over, the reservoir pressure and oil production rate of the horizontal well decline to the economic limit, and the timely energy supplement for tight reservoirs is the key technique in extending the effective oil production life. Currently, gas injection is thought to be the better energy supplement way for tight oil reservoirs, especially the use of CO2 as the injection fluids. Compared with other gas fluids such as N2 and CH4, CO2 has lower density, lower viscosity, better solubility, and diffusibility. When the reservoir pressure is between 6.7 and 26.7 Mpa and the reservoir temperature is 31.2 °C, the density of CO2 changes from 0.1 to 0.8 g/cm³. Moreover, the lower miscibility pressure of CO2 makes it easily miscible with crude oil to reduce interfacial tension, oil viscosity, and capillary pressure in the small pore throat. The extraction effect for heavy hydrocarbon components in crude oil is also better as the density increases of injected CO2 and the theoretical oil reservoir recovery factor at the CO2 miscible flooding can reach 100%. Therefore, this paper proposes to combine the advantage of horizontal well volume fracturing in the early development stage of tight oil reservoirs to improve oil productivity in the reservoir with the CO2 huff-n-puff technique to raise up the reservoir energy at the later low-reservoir pressure stage to recover the oil productivity to enhance the tight oil recovery rate. In order to optimize the stimulated volume of oil-bearing sand bodies in tight oil reservoirs, the fracturing scale of experiment well SP-1 is monitored through an inter-well micro-seismic technique during the whole fracturing process. When the fracturing scale is not suitable for the tight reservoir, the injection rate and volume of fracturing fluid are adjusted to induce a new fracture scale. After the oil productivity of the fractured horizontal well SP-1 declines to the economic limit, CO2 is used to inject into tight reservoirs timely to supplement the reservoir energy and extend the effective development cycle and ultimately increase the oil recovery rate of tight reservoirs.

2. RESERVOIR FEATURES OF BLOCK X

Tight oil Block X is in the periphery of the Daqing oilfield with an average reservoir porosity of 13% and permeability of 0.4 × 10⁻³ μm². The well location distribution is shown in Figure 1. Block X has been put into development since October 2004. In the initial development stage, seven vertical development oil wells were deployed in the elastic development mode with 300 m × 300 m well spacing. Due to the tight physical property of the reservoir and poor fluidity of crude oil, the average liquid production rate of every vertical well is 0.38 ton and the oil production rate is 0.33 ton. In order to improve the low oil productivity and increase economic benefits of Block X, six horizontal wells were deployed and fractured with large-scale fracture networks in 2016 and 2017, and the oil increase effect for six fractured horizontal wells is recorded for months. At the initial stage of the six horizontal wells being put into production, the average daily fluid production rate of every horizontal well is 10.5 ton and the daily oil production rate is 5 ton with 52.3% water cut. However, a poor development effect has appeared since March 2019 due to reservoir energy decline. At this low-oil production stage, the fluid production rate of every horizontal well decreases to 4.1 ton and oil production rate decreases to 1.9 ton. Hence, an enhanced oil recovery (EOR) technology is needed to extend the effective development time of tight oil Block X at the current development stage.

3. VOLUME FRACTURING TECHNIQUE APPLICATION IN TIGHT OIL RESERVOIRS

3.1. Precise Well Trajectory Placement. The oil production capacity of horizontal wells in tight oil reservoirs is related to the oil-bearing nature of the sand bodies drilled by the horizontal well’s trajectory. Oil wells have high oil production rates when the better oil-bearing sand bodies is drilled with the horizontal well but have low oil production rates with poor oil-bearing sand bodies. Thus, increasing the better oil-bearing sand body-drilling-across ratio of a horizontal well is the key factor for increasing oil productivity. Taking horizontal well SP-1 of tight oil Block X as a precise drilling example, the trajectory of SP-1 well is optimized with the reservoir sedimentary facies and sand body thickness distribution analysis, as shown in Figure 2a,b. The position relationship and oil-bearing nature of different sedimentary facies and sandstone are determined by the earlier developed vertical well logging. By analyzing the sandstone thickness and facies of Block X, the well trajectory of the horizontal well SP-1 is designed to drill through the river channel sand facies and extend along the thick-sandstone layer orientation. In order to control the drilling bit to drill along the good oil-bearing sand body precisely, the measurement while drilling (MWD) technique is also used to track the well oil-bearing sandstone. In addition to that, methods including rock fluorescence analysis, pyrolysis, and nuclear magnetic resonance are adopted to analyze the rock properties and oil-bearing characteristics. The analysis results are listed in Table 1. It can be observed that the sandstone well section with the better oil-bearing type (oil immersion and oil stains) encountered by the SP-1 well has achieved the purpose of precise drilling control. The well trajectory of the SP-1 well in the sand body profile is shown in Figure 3. As found in the well logging data of the SP-1 well, the reservoir permeability is 0.15−0.5 × 10⁻³ μm², porosity is 9–11%, average effective thickness of sandstone is 5 m, and reservoir mid-depth is 1600 m. The sandstone property type encountered by the horizontal well SP-1 is mainly fine and silt sandstone, the ratio of oil immersion and oil stains is as high as 82.3%, and the precise drilling well trajectory effect is good.
3.2. Precise Reservoir Stimulation Scale Controlling Technique. A reasonable volume fracturing scale of oil-bearing sandstone of tight oil reservoirs can effectively increase the oil or gas seepage capacity and the well’s productivity. Hence, precise fracturing scale controlling of tight oil reservoirs is particularly important after precise well trajectory placement. When optimizing the fracturing scale of Block X of tight oil reservoirs, the oil-bearing property of the reservoir and the sedimentary facies distribution have been comprehensively considered. The fracturing scale of the tight oil reservoir should be expanded as much as possible within effective oil-bearing sandstone, whose oil-bearing property is oil immersion and oil stains. Furthermore, the average fracture length is designed between 500 and 800 m with fracture spacing between 30 m and 50 by analysis of the oil-bearing sandstone width of river channel facies, which is between 550 and 950 m from Figure 2a. The volume fracturing design parameters of the SP-1 well are shown in Table 2, and a total of 1489 m³ of sand and 15,920.2 m³ of fracturing fluid are injected into the tight oil reservoir through fractured well SP-1, and the amount of fracturing fluid is five times more than that of

Table 1. Oil-Bearing Parameters of Reservoir Sandstone of the SP-1 Well Drilling through

| rock type                  | oil-bearing sandstone length (m) | porosity (%) | permeability (mD) | oil-bearing property     | oil saturation (%) |
|----------------------------|----------------------------------|--------------|-------------------|--------------------------|-------------------|
| fine sandstone             | 411                              | ≥11          | ≥0.5              | oil immersion, oil spots | 50                |
| siltstone                  | 263                              | 9–11         | 0.15–0.5          | oil spots, oil stains    | 40–65             |
| siltstone with mud, calcium| 145                              | ≤9           | ≤0.15             | oil spots, oil stains    | 55–80             |

Figure 2. Sedimentary facies and sandstone thickness distribution of Block X. (a) Sedimentary facies distribution. (b) Sandstone thickness distribution.

Figure 3. Vertical sand body profile for the well SP-1~well S4.
Table 2. Fracturing Parameters of Horizontal Well SP-1

| well section number | well section (m) | injection rate (m³/min) | proppant volume (m³) | fracturing liquid volume (m³) | proppant density (m³/m³) |
|---------------------|------------------|-------------------------|---------------------|-----------------------------|-------------------------|
| 1                   | 1701             | 12                      | 70                  | 1764.8                      | 0.09                    |
| 2                   | 1801–1753        | 12                      | 159                 | 1596.9                      | 0.1                     |
| 3                   | 1885–1846        | 12                      | 140                 | 1462                        | 0.1                     |
| 4                   | 1967–1927        | 12                      | 140                 | 1466.9                      | 0.1                     |
| 5                   | 2051–2011        | 11.8                    | 140                 | 1464.7                      | 0.1                     |
| 6                   | 2135–2090        | 11.8                    | 140                 | 1615.6                      | 0.09                    |
| 7                   | 2220–2180        | 12                      | 140                 | 1475.3                      | 0.09                    |
| 8                   | 2310–2265        | 12                      | 140                 | 1475.7                      | 0.09                    |
| 9                   | 2387–2348        | 11.2                    | 140                 | 1488.3                      | 0.09                    |
| 10                  | 2463–2427        | 11.3                    | 140                 | 1488.7                      | 0.09                    |
| 11                  | 2549–2504        | 11.3                    | 140                 | 1621.3                      | 0.09                    |
| Total               | 1701–2504        | 11.8                    | 1489                | 15,920.2                    | 0.09                    |

Figure 4. Fracture scale monitoring results of the SP-1 horizontal well with the micro-seismic technique.

conventional fracturing construction. In order to ensure the precise reservoir fracturing scale, the micro-seismic monitoring technology is used in real-time monitoring of the fracture’s propagation during the volume fracturing process. When the reservoir rock is fractured by the injected fracturing liquid, micro-seismic waves were generated and propagated along the bedrock, which is captured using the detector placed under the well bottom of another nearby monitoring well, and the seismic waves generated during the entire fracturing process are converted into the scale of underground fractures. By the real-time monitoring of the fracturing scale of horizontal wells, the injection volume and rate of fracturing fluid and proppant are adjusted to optimize the extended fracture length. The micro-seismic monitoring results of the horizontal well SP-1 are shown in Figure 4; the average fracture length from monitoring fracturing is 610 m, which reaches 80% of the maximum design fracture length—800 m. The fracture height exceeds the design requirement of 14 m and the actual fracture height of 22 m, which meets the design requirement of the precise horizontal volume fracturing scale.

4. RESERVOIR ENERGY SUPPLEMENT WITH CO2 Huff-n-Puff

4.1. Parameter Optimization of CO2 Huff-n-Puff. The oil production rate of six fractured horizontal wells of tight oil reservoir Block X is not economical after March 2019 with the average daily liquid production rate of every horizontal well being 4.1 ton and oil being 1.9 ton, compared with the liquid production rate of 10.5 ton and oil production rate of 5 ton at the primary reservoir fracturing stage. The oil production rate reduction of these fractured horizontal wells is mainly caused by the reservoir energy decline with the depressurization and solution gas drive development mode. Hence, tight reservoir energy supplement technology is urgently needed in this development stage. CO2 as a special energy supplement and viscosity-reducing fluid, is considered to be the most effective oil enhanced recovery substance with low density, low viscosity, good oil solubility, high oil swelling, and good crude oil extraction ability. Accordingly, a study about CO2 as tight oil reservoir energy supplement fluid is conducted by the pilot CO2 huff-n-puff experiment of the SP-1 horizontal well. In order to describe the phase change of reservoir fluid accurately during the CO2 huff-n-puff process of the horizontal well SP-1, the EOS of PR (1978) is fitted using the mode WinProp of CMG. The phase change fitting process is shown in Figure 5. According to the different physical properties of reservoir fluid components, the oil components are first regrouped in Table 3 with the purpose of shortening the numerical calculation time for the operation accuracy requirement. After the oil components are recombined, the composition expansion experiment (CCE), differential separation experiment (DL), and reservoir fluid expansion experiment with CO2 injection, which can model oil phase change during the CO2 huff-n-puff process, are selected to fit with the laboratory experimental data of reservoir fluid PVT. Moreover, considering the adjustable variables for fitting the EOS, the components C1–C6, H2S, CO2, and N2 in the oil phase are fixed, so that they cannot be adjustable variables. The composition of heavy components above C7+ in the oil phase is a mixture of many hydrocarbon polymers, and their properties change greatly, which can be used as adjustable regression variables, by adjusting the critical pressure \( P_c \), critical temperature \( T_c \), eccentric factor \( Ace \), molar mass \( Mol \), volume shift \( Vol \), and so on of regression variables of the C7+ components. Finally, the EOS that meets the fitting conditions is output for the CO2 huff-n-puff numerical model use.

By adjusting the regression variable parameters of the reservoir fluid equation of states, the fitting results of describing the reservoir fluid phase change as oil-phase relative volume, oil density, saturation pressure, fluid viscosity, and other parameters are shown in Figures 6–8. The fitting error is within 5%, which satisfies the accuracy requirements of the numerical simulation, and the EOS is output for the CO2 huff-n-puff model.

The CO2 huff-n-puff parameters of the horizontal well SP-1 are optimized by a numerical simulation method. The numerical model of depressurization is shown in Figure 13, which is from the in situ geological model of Block X. The model grid size of the \( x, y, \) and \( z \) direction is set to be 15, 15, and 5 m, respectively. The reservoir average permeability is \( 0.4 \times 10^{-3} \) \( \mu \)m, porosity is 13%, and water saturation is 54%. The PVT parameters of reservoir fluid are from the fitted EOS. Based on Darcy’s law with consideration of the capillary pressure and gravity effect, the relative permeability and capillary curves are measured by a steady-state CO2 core displacement experiment. The mixture of CO2 and live oil in a certain proportion is injected into the samples under a constant pressure, while keeping the inlet and outlet pressure constant and above the MMP as well.

When the inlet and outlet pressure of the rock sample is changed and the oil and gas flow rate at the outlet is stable, it is deemed that the distribution of water, oil, and CO2 in the sample is uniform and stable. At this time, the phase effective
permeability and relative permeability to oil and water and CO$_2$ and liquid can be directly calculated with Darcy's law using the recorded data. A series of CO$_2$/oil/water relative permeabilities under different oil saturations can be obtained by calculating the average oil/gas saturation with the material balance method and by changing the mixing ratio of oil and CO$_2$.

The capillary pressure of rock and fluid is measured mainly by a centrifugal method. With the help of the centrifugal pressure difference of the two-phase fluid, the capillary pressure of the rock sample is overcome, and the non-wetting-phase fluid enters the rock sample, and the wetting fluid is discharged. The volume of the wetting fluid discharged at a series of stable speeds to obtain the displacement capillary pressure curve of the rock sample was measured. By indoor experimental measurement, the relative permeability and capillary curves of Block X are shown in Figures 9−12. From the capillary pressure comparison between oil−water and CO$_2$−liquid phases, the capillary pressure between CO$_2$−liquid phases is lower because the CO$_2$ can easily dissolve into crude oil. This also explains the CO$_2$ EOR mechanism of tight oil reservoirs. The fractured horizontal well SP-1 is placed in the model for CO$_2$ injection and energy supplement. The optimization parameters of CO$_2$ injection rate, injection volume, and storage time are obtained by comparing the relationship between CO$_2$ injection parameters and cumulative oil production increase $N_o$ and gas and oil replacement ratio $I_{oj}$, as shown in eqs 1 and 2. Keeping the CO$_2$ injection rate of 150 ton/d and storage time of 30 d unchanged in the case model, the cumulative oil production $N_o$ and gas and oil replacement ratio $I_{oj}$ of SP-1 well are compared with different CO$_2$ injection volumes. Figure 14a presents the comparison results. Before CO$_2$ injection, the volume is 8000 ton, and $I_{oj}$ and $N_o$ increase with CO$_2$ injection volume increasing, but after CO$_2$ injection, the volume is 8000 ton, $N_o$ is
almost unchanged and the $I_{oij}$ declines; the optimal CO$_2$ injection volume is 8000 ton. Keeping the CO$_2$ injection volume of 8000 ton unchanged, the CO$_2$ injection rate and storage time are optimized, as shown in Figure 14b,c; the optimized CO$_2$ injection rate and storage time are 180 ton/d and 45 d, respectively, and reservoir pressure remains above the saturation pressure of 6 MPa before the horizontal well SP-1 is opened.

\[
I_{oij} = \frac{Q_{oil}}{Q_{gas}} 
\]

\[
N_0 = N_f - N_b
\]

where $Q_{oil}$ is the cumulative oil production, ton; $Q_{gas}$ is the cumulative CO$_2$ injection volume, ton; $N_f$ is the cumulative oil production at a CO$_2$ injection time, ton; and $N_b$ is the base oil production without CO$_2$ injection, ton.

Figure 7. Fitting results of the DL experiment. (a) Fitting result of oil density. (b) Fitting result of relative oil volume.

Figure 8. PVT parameter fitting of oil with CO$_2$ injection. (a) Saturation pressure fitting of oil with CO$_2$ injection. (b) Density fitting of oil with CO$_2$ injection. (c) Viscosity fitting of oil with CO$_2$ injection. (d) Relative volume fitting of oil with CO$_2$ injection.
4.2. CO₂ Huff-n-Puff Construction Process. Based on the optimized CO₂ energy supplement parameters, the in situ pilot experiment of CO₂ energy supplement of horizontal well SP-1 is carried out in March 2019. The CO₂ huff-n-puff process and its parameters are listed in Table 4 and Figure 15. After the liquid CO₂ stored in the storage tank is pressurized using a booster pump, a cumulative volume of 8000 ton of CO₂ is injected into the oil-bearing target layer with an injection rate of 160–200 ton/d. Besides the CO₂, a series of chemical additives such as antifreeze, tackifiers, and lubricant is also injected from the SP-1 well in the process of CO₂ injection, so as to relieve the well bore block and prevent the CO₂-hydrate formation and damage to tubing and other injection equipment.

4.3. Precautions for CO₂ Energy Supplement Construction. Both numerical simulation and oil field experiment prove that CO₂ can effectively supply reservoir energy due to its good solubility, crude oil swelling, and reducing oil viscosity. However, the CO₂ injection equipment must meet the requirements of withstanding high pressure and low-temperature liquid. Based on the in situ experience of CO₂ huff-n-puff construction operation, the following risk factors should be paid attention in the CO₂ injection and huff-n-puff construction.

(1) In order to ensure the safety of the wellhead and other equipment, withstanding pressure ability and gas sealing test of the CO₂ injection equipment must be carried out before CO₂ injection.

(2) During the CO₂ injection and huff-n-puff process, a series of chemical additives such as antifreeze and tackifiers should also be injected to relieve the well bore block and prevent the carbon dioxide hydrate formation and damage to tubing and other equipment.

(3) CO₂ can penetrate into the rubber and cause rubber swelling and deforming. Therefore, screw pumps and electric submersible pumps with rubber parts are not suitable for CO₂ huff-n-puff usage; as a replacement, the mechanical plunger pump is more suitable for CO₂ energy supplement operation.

(4) After the oil well is opened for oil production in the process of CO₂ huff-n-puff, the oil nozzle should be placed to control the bottom hole pressure (BHP) above the saturation pressure to slow the separation rate of CO₂ from crude oil, so as to prevent the bottom water rising up rate and oil viscosity decline.
5. RESULTS

5.1. Precise Fracturing Effect Analysis. The 4 mm nozzle is placed in the production tubing bottom to control the production rate after 4 h of volume fracturing operation in April 2016, and the production curve of fractured horizontal well SP-1 is shown in Figure 16. The daily oil production reached 11.5 ton during the peak period of crude oil production. In order to slow down the separation rate of gas from crude oil and prolong the effective reservoir development circle, the BHP of fracturing horizontal well SP-1 is kept above bubble point pressure. After the reservoir volume is fractured in a large scale, the effective oil production rate increase period lasts for 39 months with a cumulative crude oil output of 8097 ton with a recovery rate of 6.4%. Moreover, the average daily fluid production rate of six horizontal wells is 10.5 ton in the initial production stage, daily oil production rate is 5 ton, the average effective oil increase life cycle is 32 months, and the cumulative oil production increase of six horizontal wells is 28,712 ton.

5.2. Energy Supplement Effect Analysis with CO2. After CO2 injection operation is completed, the well BHP of the SP-1 well increases from 1.2 to 9.5 MPa compared with that before CO2 injection, and the CO2 storage time of 45 d is from August 1, 2019 to September 15, 2019 to promote the full miscibility of CO2 and oil. After the wellhead and drainage pipeline of horizontal well SP-1 have been inspected for safety, the drainage vale of well SP-1 is opened on September 19, 2019. The oil increase effect of the SP-1 well is shown in Figure 17. At the initial stage of horizontal well SP-1 opening, a large volume of CO2 gas is discharged. On October 1, 2019, the oil production rate increased and reached the oil production rate peak of 12.8 ton, and the daily oil production increase is 11.0 ton with a sectional oil increase of 1333.8 ton on April 1, 2020.

6. DISCUSSION

(1) When tight oil reservoirs are developed with vertical wells in depressurization and solution gas drive, a small wellbore drainage surface results in low liquid inflow capacity for wellbore storage and low oil productivity. However, when tight oil reservoirs are developed with horizontal wells and reservoir fracturing, the effective
drainage surface of the reservoir is increased, and liquid inflow capacity from the reservoir to the wellbore also increases a lot, and the oil production rate of the fractured horizontal well and oil recovery factor of the reservoir are all improved.

(2) When tight oil reservoirs are developed with fractured horizontal wells for the economic limit of oil production rate, CO₂ huff-n-puff can supplement the reservoir and enhance the recovery rate mainly due to the ability of CO₂ of reducing viscosity, dissolving, and swelling crude oil. Moreover, the pressure decline rate should be controlled to slow down the CO₂ separation rate from crude oil to prolong the effective development period of tight oil reservoirs.

(3) Presently, EOR technique research of tight oil reservoirs mainly focuses on the optimization of reservoir fracturing reconstruction parameters, CO₂ or other energy supplement gases flooding or huff-n-puff parameters, and the EOR mechanism analysis. However, tight oil reservoir development is systematic engineering; thus, engineering and geological factors should be fully considered when EOR technical parameters are optimized. In this paper, a systematic study of the tight reservoir EOR technique has been proposed considering the fine reservoir geological description, drilling engineering optimization, reservoir reconstruction parameter optimization, and later energy supplement parameter optimization. Furthermore, the concept of precise drilling, precise reservoir fracturing, and precise energy supplement is also proposed to
improve the development effect of tight oil reservoirs. Through on-site precise EOR pilot experiments of SP-1, a good oil-increasing effect has been achieved.

7. CONCLUSIONS
(1) In order to improve the development effect of tight oil reservoirs, precise horizontal well trajectory placement and large-scale reservoir volume fracturing are conducted, and the daily oil production of every horizontal well increased to 5 ton, and the effective development circle lasts for 32 months, achieving good development results.
(2) Reference to the deposit facies, sandstone thickness, oil-bearing nature, and other parameters, the drilling trajectory of horizontal wells is optimized, and more than 80% of the oil-bearing sandstone drilled by the SP-1 well is of oil immersion and oil stain types. The optimized fracture length of the horizontal well volume fracturing is between 500 and 800 m to obtain the largest reservoir reconstruction volume, and the fracture length of the horizontal well is monitored by micro-seismic monitoring. Ultimately, the precise reservoir fracturing scale of every horizontal well is sufficient for the reservoir EOR.
(3) After the oil production rate reduces to the economic limit, CO₂ energy supplement technology can effectively prolong the effective development period of tight oil reservoirs and increase the oil recovery rate. The pilot experiment of CO₂ injection and huff-n-puff of the SP-1 well shows that the reservoir pressure increases from 4.8 to 9.5 MPa, and the daily oil production increases from 1.9 to 10.3 ton after 8000 ton of CO₂ is injected into the tight oil reservoir with 45 d energy storage time waiting, and a good oil development effect is obtained.

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Notes
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