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Research and Application for Alternate Production Technology of Dual-Branch Horizontal Wells in an Offshore Oilfield

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Abstract: Old-well sidetracking is a key method for controlling low-productivity wells in the Bohai oilfield. This study employs reservoir engineering and numerical simulation techniques to investigate the maximum drainage radius and natural coning control mechanism in heavy-oil reservoirs with bottom water. Based on these findings, an alternate production technology was developed for dual-branch horizontal wells. The technology creates a new branch through sidetracking, connecting and isolating the old and new wellbores using a combination of wall hangers and branch guides. Initially, the old wellbore with an ultra-high water cut is temporarily sealed. When the new branch reaches a high water-cut stage, production is switched back to the old wellbore. This technology was successfully applied to three wells in the Bohai oilfield, resulting in the new branch achieving expected production levels, while reopening the old wellbore increased daily oil output by 27 m^3 and reduced water cut by 5.6%. Cumulative oil production from these wells reached 95,000 m^3. This technology improves well-slot resource utilization, enhances recovery rates, and has significant potential for broader application.

Keywords: horizontal well; old-well sidetracking; extra-high water-cut stage; dual-branch; alternate production

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1. Introduction

In the context of a tightening global energy supply, the development of offshore oil and gas resources has become essential [1]. However, this effort faces numerous challenges. A key issue in the Bohai Oilfield is the widespread high water cut in many wells, which greatly hinders sustained production [2]. With the deepening development of Bohai Oilfield, an increasing number of low-production and low-efficiency wells have emerged, and using old wellbore sidetracking is one of the effective ways to treat these wells. At present, the proportion of oil wells with a water cut greater than 90% in Bohai Oilfield is as high as 41%. However, a certain amount of remaining recoverable potential still exists specifically in horizontal wells during the extra-high water-cut stage. Direct sidetracking can cause waste of recoverable resources, while using the shutdown control method can reduce water cut, but it is time consuming, which greatly affects the wells' utilization rate in the oilfield [3–8]. The stability of wellbores during these operations is critical, particularly in challenging formations. A modified Mohr–Coulomb criterion has been shown to be more accurate in assessing wellbore stability, which is essential for avoiding issues during sidetracking operations in hydrate-bearing sediments [9]. Therefore, there is an urgent need for a production mode to effectively utilize these wells with high water cut. Furthermore, due to various factors such as the remaining recoverable reserves of the original well and the limitation of the number of platform slots, efficient utilization of platform slots, achieving multiple drills and oil recovery, is of great significance for achieving stable oilfield production and improving oil recovery [2,10–13].

C Oilfield is the largest bottom-water oilfield with a scale of billions of tons invested in the Bohai Oilfield so far. In terms of geological reservoir characteristics, the oilfield is located in the western sea area of the Bohai Sea, and its basic structural feature is a small buried-hill anticline structure, which is overlaid by the Paleogene and draped by the Neogene, forming a thin-top and thick-wing anticline structure. The distribution of C Oilfield structure is controlled by the ancient topography of the basement, mainly developing deep and shallow fault zones, with fewer deep faults and shallow faults developed, distributed on the north and south sides of the structure. Overall, the C Oilfield exhibits the characteristics of draped anticlines and semi-anticlines influenced by the ancient topography and fault systems of the basement. The deep structural traps have a smaller area and larger amplitude, while the shallow traps have a larger area and lower closure amplitude. The oil field has an oil well section of 760 m in length, mainly including three oil-bearing sections: the upper and lower Ming sections and the Guantao Formation, each divided into three oil formations. Furthermore, fracture reorientation during hydraulic fracturing in perforated horizontal wells presents another technical challenge in this context. Understanding how fractures reorient under varying stress conditions is crucial for optimizing well productivity in complex geological settings, such as those found in shale reservoirs [14]. In terms of sedimentary characteristics, the Minghuazhen Formation is a meandering river deposit, while the Guantao Formation is a braided river deposit. The reservoir has the characteristics of high porosity and high permeability. The average porosity of the Minghuazhen Formation reservoir is 32.7%, and the average permeability is 2600 mD; the average porosity of the Guantao Formation is 29.3%, and the average permeability is 1600 mD. The overall oil–water system is complex due to the dual constraints of structure and reservoir, mainly manifested as lithological structural oil reservoirs and block oil reservoirs under the structural background, followed by lithological oil reservoirs. From the perspective of edge- and bottom-water types, bottom-water reservoirs are mainly developed, followed by edge-water reservoirs dominated by bottom water. The main development method is to use horizontal wells to separate single sand bodies. In terms of oilfield production characteristics, the oilfield is mainly developed using horizontal wells and individual sand bodies. Oilfield clusters show characteristics like strong bottom-water energy, stable formation pressure, rapid bottom-water coning, a quick rise in water cut, and a short oil-free recovery period. After 20 years of development, the comprehensive water cut of the oilfield has reached 95.0%. The ultra-high water-cut oil wells in this oilfield account for 64% of the entire oilfield, and their liquid volume accounts for 90% of the entire oilfield. The problem caused by this situation is that the contradiction between the high liquid production demand of oil wells during the ultra-high water-cut period and the limited processing capacity of the oilfield is becoming increasingly prominent. At present, the oilfield is operating at full capacity, with no remaining well slots, and the bottom-water heavy-oil reservoir is difficult to utilize. The adjustment and potential tapping of the oil field are facing severe challenges.

To address low production and efficiency issues, and to maximize the oilfield's potential, C Oilfield employed reservoir engineering and numerical simulations to study the planar utilization radius of horizontal wells and the natural coning control mechanism in bottom-water reservoirs. As a result, dual-branch horizontal well technology was introduced. This approach efficiently uses the platform well slot and wellbore structure while retaining the original wellbores and adding sidetracking branch wells. In response to the unique wellbore structure, a supporting-branch-well rotary production process was designed. According to geological and mining requirements, the middle completion pipe column can be lowered to achieve "rotary production" between two wellbore wells, thereby expanding the oil drainage area, improving single-well production, delaying the increase in water cut caused by edge- and bottom-water advancement, and improving the oilfield recovery rate.

2. Research on the Drainage Radius of Horizontal Wells in Bottom-Water Reservoirs

2.1. The Drainage Radius Based on Reservoir Engineering Methods

For an infinite formation, the corresponding potential function for a vertical well located at the origin is [15]:

$$\Phi = \frac{q}{2\pi} \ln \sqrt{x^2 + y^2} + C \tag{1}$$

where q represents the crude oil production, measured in m^3/d; $\sqrt{x^2 + y^2}$ represents the radial distance from the origin (the well's location) to a point in the plane, measured in meters; and C is a constant, usually related to boundary conditions.

As shown in Figure 1, the horizontal well is divided into n infinitesimal elements with a length of dx, where the infinitesimal element with a length of dx can be regarded as a single vertical well. According to the theory of potential superimposition, the following integral expression is obtained:

$$\Phi = \int_{-L/2}^{L/2} \frac{q}{4\pi L} \ln\left[(x - x_0)^2 + {y_0}^2\right] dx + C \tag{2}$$

where $-L/2$, and $L/2$ are the starting and ending positions of the horizontal well, respectively, in meters; x_0 is the position of the point of interest in the horizontal direction, in meters; and y_0 is the position of the point of interest in the vertical direction, in meters.

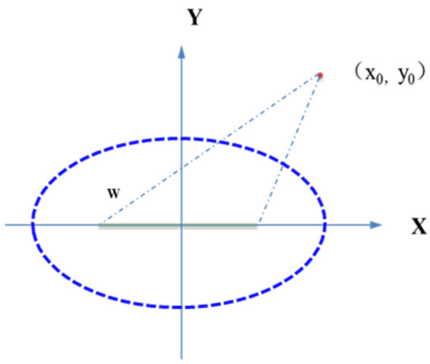

Figure 1. Schematic diagram of horizontal well-plane seepage field.

After integration, one can replace (x_0, y_0) with the potential at any point in the formation (x, y) to obtain the potential function of a horizontal well at any point in the XY plane:

$$\Phi(x,y) = \frac{q}{2\pi L}\left[\begin{array}{l} -L + y\cdot\arctan\frac{L/2-x}{y} + y\cdot\arctan\frac{L/2+x}{y} + \frac{(L/2+x)\cdot\ln((L/2+x)^2+y^2)}{2} + \\ \frac{(L/2-x)\cdot\ln((L/2-x)^2+y^2)}{2} \end{array}\right] + C \tag{3}$$

At present, many studies mention that based on pipe-flow models and rheological principles, the existence of pressure gradients in ordinary heavy oil has been macroscopically verified through laboratory experiments. Currently, for an oil sample from a certain block in the Bohai Oilfield, the crude oil has a viscosity of 10~450 mPa·s and a permeability of 186.4~6698 $\times 10^{-3}$ μm^2. According to the sand-filled tube experiment, the regression equation for the starting pressure gradient of the oil sample is as follows:

$$G = 0.1037 \times (K/\mu)^{-0.5753} \tag{4}$$

where K represents permeability and μ represents the viscosity of crude oil, measured in mPa·s.

If we take the partial derivative of Equation (3) and convert it into the expression of pressure gradient as:

$$\frac{\partial P}{\partial y}(x=0) = \frac{q\mu}{2\pi LK}\left[2\cdot\arctan\frac{L}{2y_e}\right] = G \tag{5}$$

$$\frac{\partial P}{\partial x}(y=0) = \frac{q\mu}{2\pi LK}\left[\ln\frac{L/2+x_e}{L/2-x_e}\right] = G \quad (6)$$

then, under the condition that the pressure gradient G is known, the maximum drainage radius x_e and y_e can be obtained. Based on Equations (1)–(6), the contour-distribution map of pressure (potential function) of a horizontal well in the reservoir plane can be obtained. The required calculation parameters are shown in Table 1.

Table 1. The calculation parameters for pressure and maximum oil drainage radius.

Oil Viscosity mPa·s	Layer Thickness m	Permeability 10^{-3} μm^2	Horizontal Section Length m	Pressure Difference MPa	Pressure Gradient MPa/m
142	10	3000	300	2~8	0.018

As shown in Figure 2, taking the production pressure difference of 2 MPa as an example, it can be seen that the pressure distribution around horizontal wells in the reservoir plane direction is significantly different from that of vertical wells. The dashed line in the figure indicates that the pressure gradient under producing conditions is exactly equal to the starting pressure. And the maximum drainage radius y_e is calculated as 90 m along the y-axis. Therefore, the starting pressure gradient can be used to calculate the maximum oil drainage radius of a single well in heavy-oil bottom-water reservoirs and thus determine the reasonable well spacing of $2 \cdot y_e$ for well network deployment.

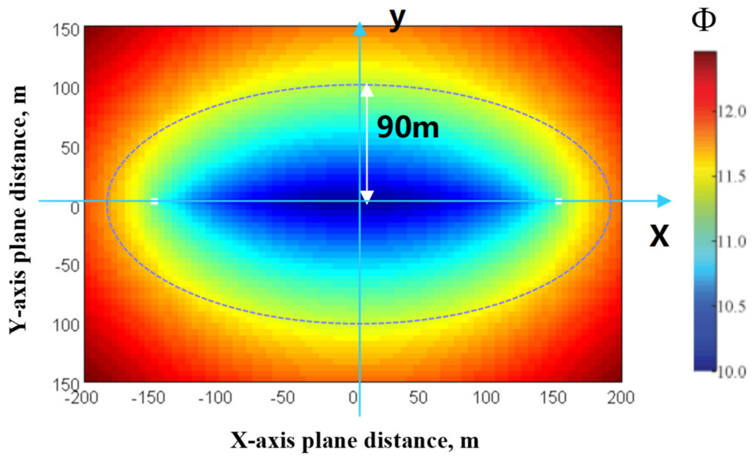

Figure 2. Distribution of pressure/potential function in the XY plane.

2.2. Establishment of the Maximum Drainage Radius Chart of Horizontal Wells

By using Equation (5), the pressure gradient distribution in the y-axis direction can be calculated. By initiating the starting pressure gradient and production pressure difference, the quantitative calculation of the maximum drainage radius can be achieved. The pressure distribution around horizontal wells is elliptical in the plane of the reservoir. By assigning different production pressure differences, the maximum drainage radius for this crude oil viscosity can be calculated. Taking a production pressure difference of 2.0 MPa as an example, the maximum drainage radius is calculated to be 90 m, as shown in Figure 3.

As shown in Figure 4, it can be seen that at a certain position in the reservoir, the pressure gradient in the oil drainage area will decrease to the starting pressure gradient, and at this point, the seepage velocity will decrease to zero. Under different driving pressure differences and starting pressure gradients, the distance at which effective driving can be formed varies significantly. The pressure distribution in the plane is elliptical. Under a given production pressure difference, the higher the viscosity, the smaller the extent of the plane pressure distribution. Under given oil-viscosity conditions, the larger the pressure difference and the greater the extent of the plane pressure distribution, but this trend slows down with increasing pressure difference.

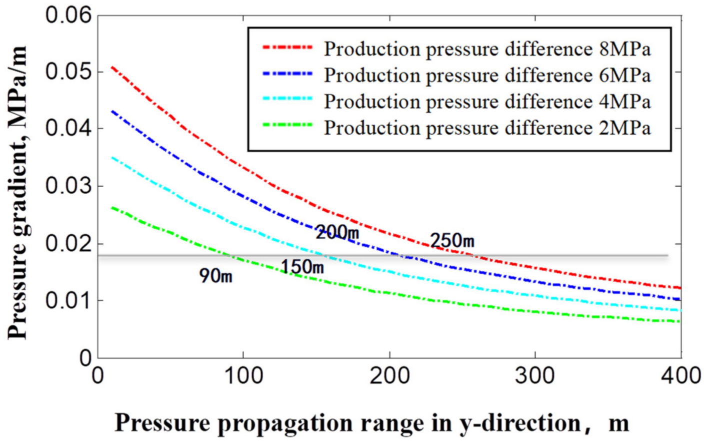

Figure 3. Example of calculating maximum drainage radius in y-axis direction.

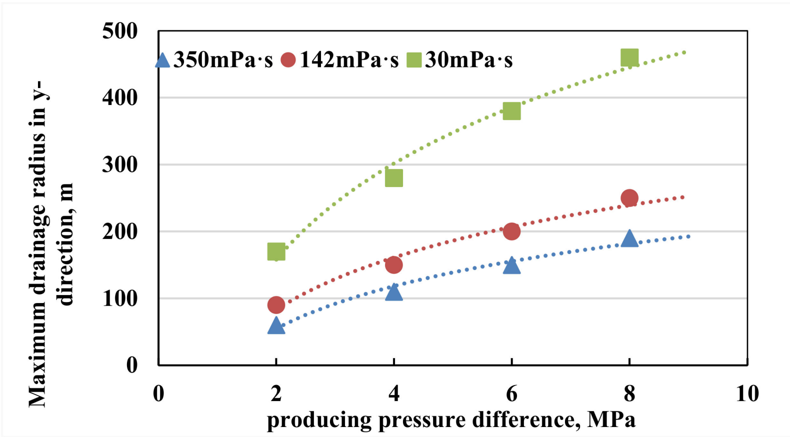

Figure 4. Calculation results of maximum drainage radius in y-direction.

3. Research on Natural Shut-In Coning Control Mechanism in Bottom-Water Reservoirs

3.1. The Natural Shut-In Coning Control Mechanism Research Based on Numerical Simulation Methods

At present, C Oilfield's water cut is as high as 95%. During the high water-cut stage, high production is generally achieved through liquid extraction [16,17]. However, offshore conditions have limited the oilfield's fluid processing capacity. To stabilize oil production and control water, it is essential to regulate liquid production from individual wells. This often requires shutting down wells to allow natural pressure cones to limit liquid output. At the same time, in order to meet the requirements of efficient development, some wells retain the original wellbore for sidetracking while there is still remaining oil. To determine when to reopen the original wellbore, it is necessary to accurately understand the behavior of the water-cone fall back after well shut-in [18–20].

The shut-in coning control method is one of the important measures to stabilize oil production and control water. The main reason is that after the oil well is shut in, the water cone naturally recedes due to the influence of gravity segregation. When the oil well is reopened for production, the water cut of the oil well will decrease [21], and the corresponding oil production will increase, as shown in Figure 5. The study of the extent of water-cone recession after well shut-in is crucial, as it determines the production performance of the oil well after reopening. Most research on well shut-in effects and water coning in bottom-water reservoirs focuses on vertical wells, with limited studies on the dynamic changes of water cones after horizontal wells are shut in.

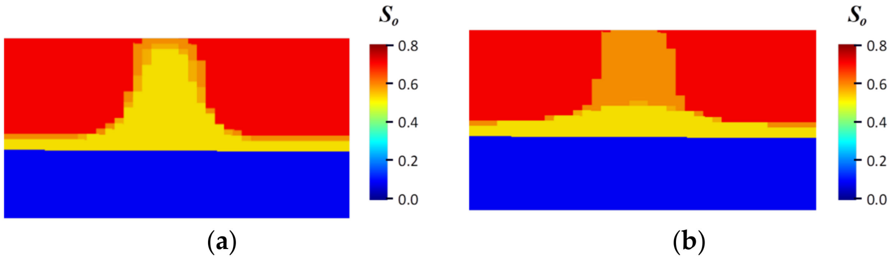

Figure 5. Schematic diagram of water cone falling back after shutting in the ultra-high water-cut well. (**a**) Pre shut-in state; (**b**) post shut-in state.

The shut-in coning law of horizontal wells was researched by using reservoir numerical simulation methods. Combining the actual reservoir parameters of the oilfield, a numerical simulation model was established, mainly referring to reservoirs' physical properties, reservoir thickness, PVT data, phase permeability curves, and other data. In numerical simulation, the characterization of bottom-water reservoirs is mainly achieved by setting a certain bottom-water thickness and water body, as shown in Figure 6.

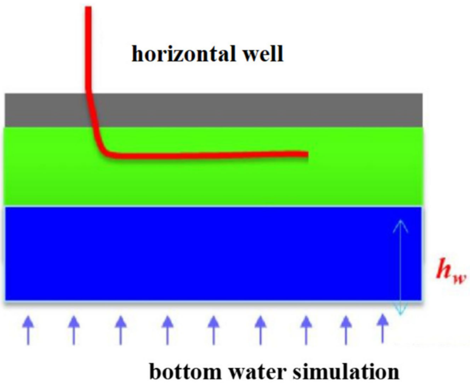

Figure 6. The diagram of bottom-water reservoir model.

The water type loaded in this numerical model is Carter–Tracy analytical water. The key parameters required for simplified modeling are shown in Table 2.

Table 2. Key parameters of reservoir model.

Oil Viscosity mPa·s	Layer Thickness m	Kv/Kh	Height of Water Avoidance m	Grid Size m	Daily Liquid Output m^3/d	Bottom-Water Types
3~325	5~20	0.1	18	25 × 25 × 1	1200	Carter–Tracey model
Horizontal section length m	Porosity %	Permeability 10^{-3} μm^2	Bottom-water thickness m	Model dimension	Control mode	Oil density Kg/m^3
400	30	1000~6000	2~60	80 × 40 × 40	Fixed liquid rate production	850~980

3.2. The Analysis of Natural Shut-In Coning Control of Horizontal Wells in Bottom-Water Reservoirs

Using the single factor analysis method, we simulate and calculate the impact of factors such as crude oil density, viscosity, reservoir thickness, and horizontal permeability.

When the water cone decreases by 5 m, and the well is reopened to produce a fixed liquid volume of 1000 m^3/d, we calculate the corresponding oil increase when the water cut reaches 98%.

According to the numerical simulation calculation results, the analysis of the main controlling factors for natural-pressure-cone water control in horizontal wells of bottom-water reservoirs shows that the better the fluid and physical properties of the reservoir, the better the cone-pressure effect, with the viscosity of crude oil being the main controlling factor, as shown in Figure 7.

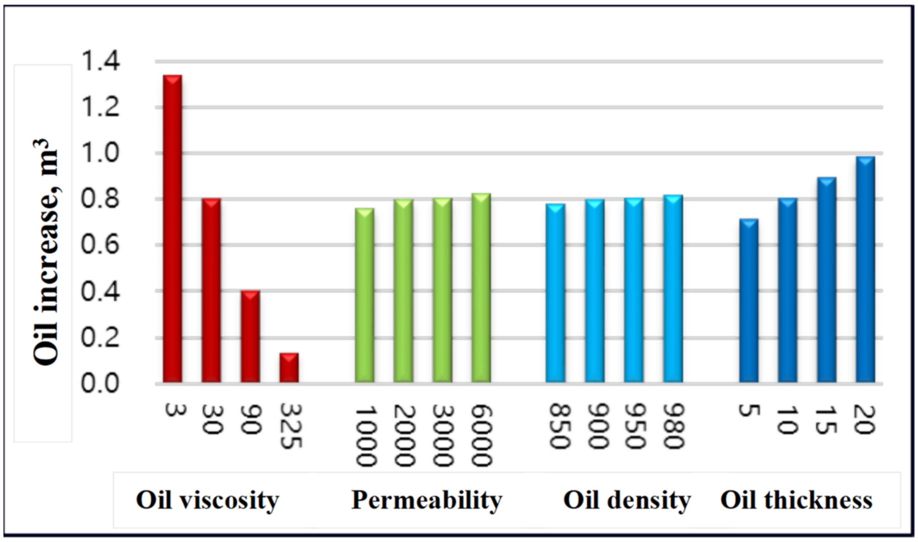

Figure 7. The shut-in coning effect under different single factors.

In terms of time required for shut-in coning, for oil with a viscosity of less than 100 mPa·s, the cone-pressure effect is better after 3~6 months of well closure. The oil viscosity is 150~425 mPa·s, and the cone-pressure effect is better after 12 months of well closure, as shown in Table 3.

Table 3. Conclusions recognizing shut-in coning.

Oil Viscosity mPa·s	100~425	50~100	<50
Typical representative	Ming Upper Formation	Ming Lower Formation	Guantao Formation
Shut-in coning effect	general	comparatively good	good
Recommended time for shut-in coning	12~36 months	3~6 months	about 3 months

4. Research and Application of the Alternate Production Technology with Dual-Branch Horizontal Well in Bottom-Water Reservoirs

4.1. A Brief Introduction of the Construction Process

In response to the current situation of high water cut, as well as limited liquid and electricity in oil fields, which are unable to significantly increase liquid production and have been in low production for a long time, adjustment and potential tapping of the oil fields are facing severe challenges [2,11–19]. Due to the difficulty of conventional water-control measures in high water-cut horizontal wells, accelerating underground exploration and rapid production increase are crucial in the limited platform well-slot resources. To enhance wellbore efficiency, research on alternate production technology using dual-branch horizontal wells has been conducted within the original wellbore. A brief introduction of the construction process is as follows [21]: Retrieve the branch wellbore guide and open the first barrier of the main wellbore. Retrieve drilling tools by running the directional device into the branch wellbore; then, conduct a pump test before the tool enters the well, and record in detail the corresponding displacement and pressure when the tool is released. When the pump is stopped, the tool is in a salvage state. The downward pressure pipe column can be directly inserted into the anchor groove of the directional device in the branch wellbore to achieve salvage locking, and the successful salvage can be confirmed through changes in the hanging weight.

Break through the rupture disc of the temporary blocking packer in the main wellbore and open the second barrier of the main wellbore. The lower part of the sealing device is equipped with a ceramic material rupture disc. When opening the main wellbore, the disc is broken through using a set of rupture disc-breaking tools, and then the well is drilled down to the position of the sealing device rupture disc. After confirming that the depth of the rupture disc is correct, the rupture disc is broken through by applying stress.

Run the middle completion string to isolate the main wellbore from the branch wellbore, achieving "re-entry" of the main wellbore. In the design of the middle completion string, the top packer is used to suspend and fix the middle completion string, and a specially processed large-sized positioning joint is used to position the tail pipe back to the top of the connecting barrel. Then, referring to the wellbore structure diagram, as shown in Figure 8, the 6″ insertion seal is placed inside the sealing cylinder of the temporary plugging packer through precise length matching. The fit between the sealing module unit and the sealing cylinder of the temporary plugging packer ensures effective isolation and sealing of the corresponding production layers above and below the temporary plugging packer.

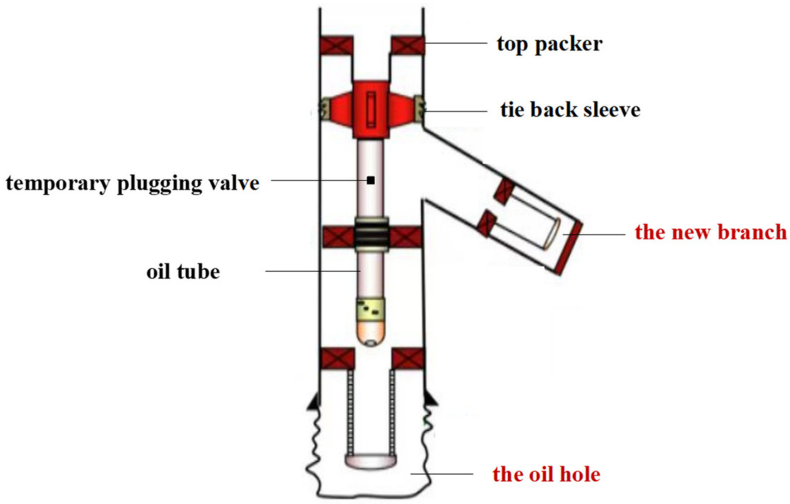

Figure 8. The schematic of alternate production technology of dual-branch horizontal well.

4.2. The Implementation Effect of Alternate Production Technology with Dual-Branch Horizontal Wells

By adopting the alternate production technology with dual-branch horizontal wells, "one slot for multiple uses" has been achieved, which not only retains the original wellbore and sidetracks a new wellbore for production but also achieves the closure of the new layer and the opening of the original layer production by opening the temporary blocking valve after the new wellbore has high water cut, ultimately achieving the shut-in coning rotary production of the new and old wellbores, as shown in Figure 9.

In terms of on-site practice, the first batch of multi-stage completion sidetracking and switching layers for three wells in Bohai Sea was completed in C Oilfield. After the old wellbore was reopened, a total daily oil increase of 80 m^3 was achieved in the initial stage, and the average single-well water cut decreased by 5.6%, as shown in Figure 10. The effect of water control and oil increase was significant.

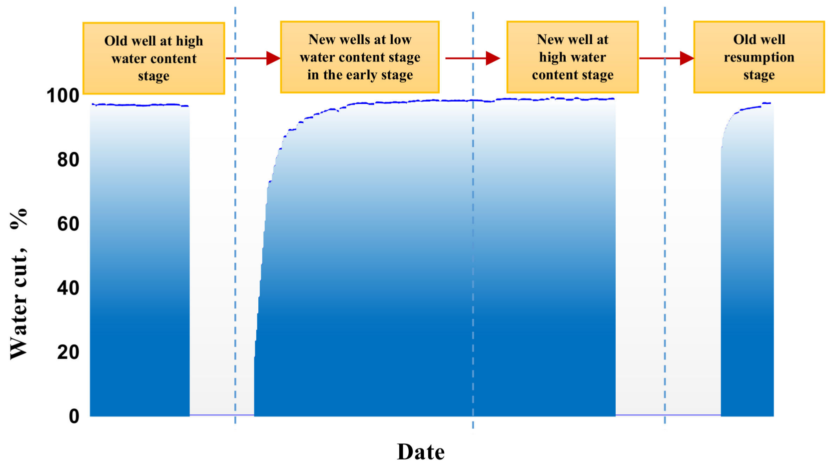

Figure 9. The sketch map of alternate production technology.

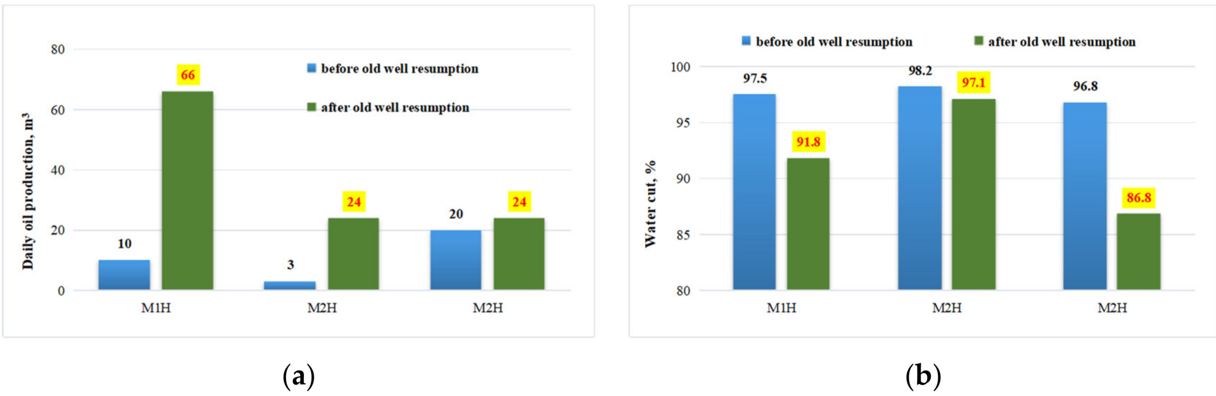

Figure 10. Comparison of production situation before and after old-well resumption. (**a**) Comparison of daily oil production before and after old-well resumption. (**b**) Comparison of water cut before and after old-well resumption.

Taking M3H/M3H1 as an example, the old horizontal wellbore M3H is located in the heavy-oil bottom-water reservoir in the Minghuazhen Formation, with a crude oil viscosity of 193 mPa·s. The M3H well was launched in 2013, and as the bottom-water ridge advanced, the water cut increased to 97.9%. The daily oil production gradually decreased to 6 m^3/d, and the historical highest production pressure difference was 0.57 MPa. According to the theoretical results shown in Figure 4, the radius of use was less than 90 m. Therefore, the new sidetracking M3H1 was implemented at a distance of 140 m from the M3H wellbore, with a daily oil production of 80 m^3/d and a water cut of 41.5% in the early stages, as shown in Figure 11.

With the increase in water cut in the new sidetracking M3H1 wellbore, the original horizontal section of the M3H well was successfully reopened and put back into production in March 2021 in Bohai Oilfield for the first time. After 3 years of shut-in coning control, M3H's initial daily oil production was 40 m^3, with a water cut of 91.8%. Compared to the production situation of the old wellbore after shut-in coning control, the initial water cut of the old wellbore M3H had decreased by 5.7% after resuming production, and the initial measures increased oil by 30 m^3/d, compared to the daily oil increase of 20 m^3/d in the new sidetracking wellbore M3H1. As of now, the daily oil production of the well is 53.5 m^3, with a water cut of 87.8%, which is still lower than the state before the old wellbore was closed for sidetracking, as shown in Figure 12.

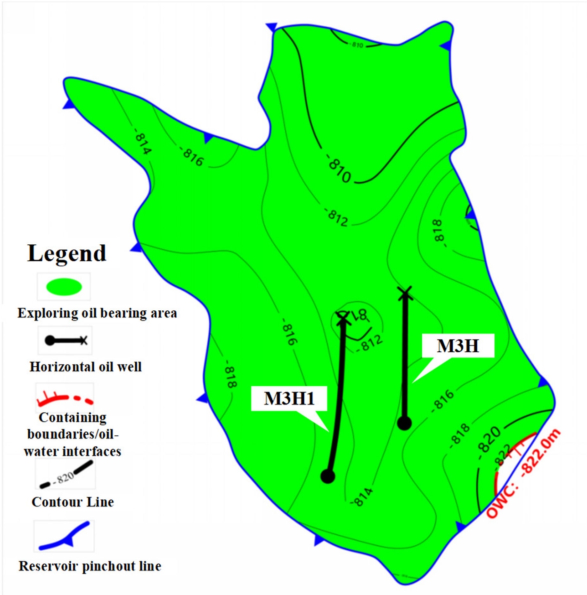

Figure 11. The well location map of M3H/M3H1.

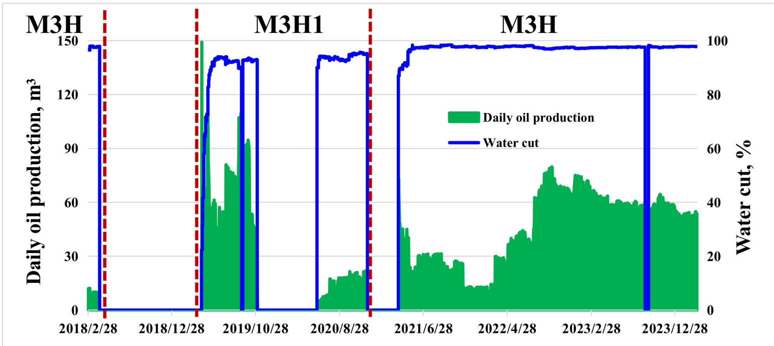

Figure 12. The comparison of production situation of M3H/M3H1.

This technology not only retains the old wellbore with significant remaining potential but also realizes the rolling tapping of the bottom-water heavy-oil reservoir plane. In the cases of the three wells that have been implemented, the wells were sidetracked due to high water cut, and the old wellbore had accumulated 15.80 $\times$ 10^4 m^3 of oil production. After sidetracking, the new sidetracking wellbore gradually entered the ultra-high water-cut period, and the old wellbore was reopened and resumed production. As of now, the cumulative production of the three wells after returning to the original horizontal sections has reached 4.76 $\times$ 10^4 m^3. The remaining oil in the original old areas of the old wellbores has achieved significant results in tapping potential, and the total cumulative production of the three wells is 28.95 $\times$ 10^4 m^3, as shown in Table 4.

Table 4. Summary of implementation results by alternate production technology.

Well No.	Old Horizontal Wellbore		New Sidetracking Horizontal Wellbore		Old Horizontal Wellbore Resumption		Subtotal $\times 10^4$ m^3
	Time	Accumulated Oil Production $\times 10^4$ m^3	Time	Accumulated Oil Production $\times 10^4$ m^3	Time	Accumulated Oil Production $\times 10^4$ m^3	
M1H/M1H1	7 July 2013	4.60	18 June 2019	1.71	1 November 2022	0.24	6.55
M2H/M2H1	3 August 2013	5.45	11 June 2019	2.19	14 August 2022	2.68	10.32
M3H/M3H1	7 September 2013	5.75	16 April 2019	1.56	28 March 2021	4.76	12.07
Subtotal		15.80		5.45		4.76	28.95

With the increase in water cut in the new wellbore, the original layer can be selectively opened for production, economically and effectively achieving cone-pressure rotary production of new and old wellbores. It has multiple advantages such as low overall investment, high economic benefits, solving the problem of restricted wellbores, and improving the utilization of low-edge thin and thick reserves. The successful application of this technology not only helps the ultra-high water-cut oil wells in C Oilfield regain their youthful vitality but also further verifies the applicability of the multi-stage completion technology in offshore bottom-water reservoirs. This technology successfully brings a new development mode for offshore oilfields with high water cut and limited well-slot resources, which provides valuable experiences for the treatment of low-production and -efficiency wells to enhance oil recovery, effectively saving platform slots and development costs. It also shows broad application prospects in large-scale adjustment for similar oilfields.

5. Conclusions

On the basis of in-depth research on the drainage radius of horizontal wells and the natural shut-in coning control mechanism in bottom-water reservoirs, an alternate production technology with dual-branch horizontal wells was carried out. This technology has multiple advantages, such as retaining the remaining potential of old wellbores, improving wellbore utilization, and tapping difficult potential reserves.

(1) By using reservoir engineering methods, the maximum oil discharge radius of a single well in heavy-oil bottom-water reservoirs was derived: under certain production pressure differences, the larger the viscosity, the smaller the range of plane waves; under certain crude oil-viscosity conditions, the larger the pressure difference, the larger the range of plane waves, but the trend slows down.

(2) According to the numerical simulation calculation results, the main controlling factors for natural shut-in coning control were analyzed in horizontal wells of bottom-water reservoirs, and the time required for shut-in coning was provided. The lower the viscosity of crude oil, the better the shut-in coning effect and the shorter the required time.

(3) The alternate production technology with dual-branch horizontal wells was innovated, and a brief introduction of the construction process and technical advantages was presented. Three wells were first applied in the Bohai Oilfield, and all of them successfully achieved the resumption of production in old wells, achieving alternate production in new and old wells, and achieving significant water control and oil stabilization effects. This technology has successfully opened up a new alternate production mode of dual-branch horizontal wells in bottom-water reservoirs and has better popularization and application prospects.

It is worth noting that the findings of this study are predicated on the assumption of accurate reservoir data. However, the inherent complexity of reservoirs often makes it difficult to obtain precise data, leading to significant uncertainties [22,23]. Given these uncertainties, the application of alternate production technology should be approached cautiously. It is essential to thoroughly assess data uncertainties to reduce decision-making risks and ensure the effective and reliable implementation of these technologies.

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Data Availability Statement: The data that support the findings of this study are available from the corresponding author upon reasonable request. The key data, such as those in Figures 10 and 12, are sourced from on-site measurement data. Currently, commercial flow meters are used in offshore oil fields, with a water content error of about 2% and a liquid volume flow rate error of about 5%. The error before and after the measures are consistent, so the data are detailed and reliable.

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