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Analysisof Causes of High Water Content in X Block Reservoirs and Treatment Strategies

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ABSTRACT

In response to the problem of high water content in the Chang 2 oil reservoir in Block The analysis results show that water breakthrough in oil wells includes edge and bottom water, injection water, and casing damage water breakthrough. The reason for the high water content in the Chang 2 reservoir oil wells in Block.

KEYWORDS

High Water Content, Water Breakthrough, Structure, Water Injection Intensity, Liquid Extraction Intensity.

1. INTRODUCTION

Water injection is a primary method for enhancing oil recovery. Currently, the low-permeability reservoirs in the Yanchang Formation of a specific region predominantly employ water injection technology. However, this approach is accompanied by water cut increase and ineffective injection issues. Block X in the study area, located within a regional basin, has undergone three development phases: natural energy extraction, water injection trials, and large-scale water injection. The main production layer is Chang 2, where 41.8% of oil wells were shut down due to high water cut. Statistical analysis of historical well closures in the study area reveals that water injection implementation has led to a rising trend in active water-injected wells, significantly impacting production capacity. Therefore, it is crucial to analyze the types and causes of high water cut in these wells and propose targeted remediation strategies [1].

2. ANALYSIS OF HIGH WATER CONTENT WELLS

2.1. High Water-Cut Distribution Characteristics

According to current water detection criteria, oil wells with water cut exceeding 80% and daily liquid production over 3m^3 are classified as high water-cut wells [2]. Statistical analysis of water cut levels in Block X reveals that long, high water-cut wells (with water cut between 80-100%) account for over 40% of the total. Other water-cut zones show smaller proportions but comparable well counts. A water cut distribution map can be created using 10% intervals to analyze the pattern. The distribution pattern indicates that high water-cut areas are primarily concentrated along reservoir margins, while central zones exhibit moderate to low water cut. Notably, exceptionally high water cut is observed in localized non-injected areas, suggesting that geological and engineering factors significantly influence water cut distribution in these wells.

2.2. Water analysis of high water content Wells

In oil wells, water detection typically manifests in three primary types: edge-bottom water, interbed water, and injected water. These water detection characteristics vary significantly in terms of production mechanisms, geological features, and production dynamics [3]. Moreover, changes in mineralization levels before and after water injection serve as a crucial indicator for identifying water detection types [4]. By applying these evaluation criteria, statistical analysis of mineralization changes can be conducted to determine water detection patterns in high-water-content wells.

3. CAUSE ANALYSIS OF HIGH WATER CONTENT

3.1. Construction factors

Edge-water reservoirs are significantly influenced by tectonic structures. The water cut in oil wells generally shows an inverse correlation with structural patterns, with high water cut being notably affected by tectonic factors. During reservoir development, the rising oil-water interface causes water to preferentially accumulate in tectonically low-lying areas [5]. Comparative analysis of water cut variations between the study area's early and late stages reveals that advancing edge-water flow has led to substantial increases in water cut at structural basins, with water-bearing zones gradually expanding. By comparing water cut distribution patterns and structural morphology between the initial production phase and current conditions, we can identify the primary causes of elevated water cut.

3.2. Liquid extraction intensity

The liquid production intensity significantly affects oil well water cut. In lithofacies-structural reservoirs with edge water, excessive production intensity may cause premature breakthrough of the edge water, leading to flooding. Conversely, insufficient intensity can control the advance rate of edge water but fails to ensure efficient reservoir development. Therefore, determining appropriate production intensity is crucial during operations [6]. Through calculations for two oil wells in the study area, we obtained individual production intensities and plotted convergence diagrams of production intensity versus water cut and production rate (Figures 1 and 2). Results demonstrate a positive correlation between production intensity and water cut. Excessive intensity accelerates water influx, with rapid water cut increase and sharp production decline when exceeding 0.7 $m^3/(m\cdot d)$. Comparative analysis of water cut and production intensity distribution reveals a correlation between high water cut zones and relatively higher production intensities.

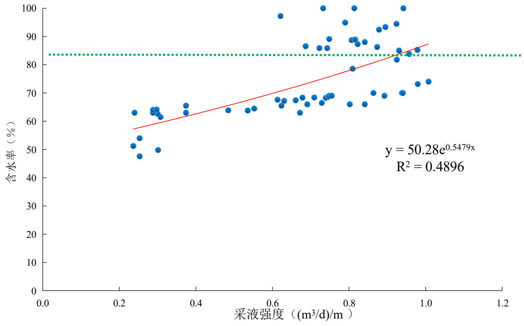

Figure 1. Intersection of liquid production intensity and water content in a single well

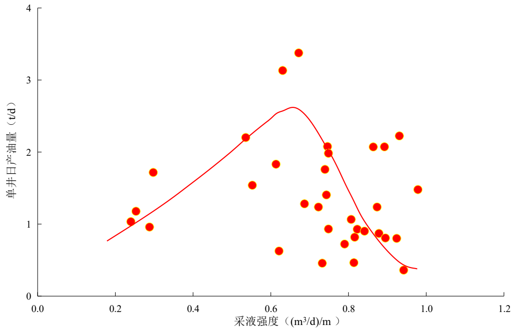

Figure 2. Intersection of liquid production intensity and production of a single well

3.3. 2.3 Water injection intensity

Reasonable water injection intensity is a crucial measure to ensure effective reservoir development. Insufficient injection intensity leads to inadequate formation energy and compromised production capacity, while excessive injection causes water to flow through dominant channels [7], resulting in premature water detection in production wells. To optimize reservoir development in the study area, calculated injection intensity data shows a distribution primarily concentrated between 1-2 $m^3/(d \cdot m)$, with an average of 2.51 $m^3/(d \cdot m)$. The highest injection intensity for high-water-content wells in the study area spans 7.58 $m^3/(d \cdot m)$ to 0.71 $m^3/(d \cdot m)$, averaging 2.77 $m^3/(d \cdot m)$ – significantly exceeding the regional average. Figure 3 presents the frequency distribution of injection intensity for these high-water-content wells, demonstrating that excessive injection intensity is a key factor contributing to high water detection in oil wells. Injection intensity also affects formation energy replenishment: higher intensities indicate sufficient formation energy, leading to significant liquid production and increasing the risk of high water content.

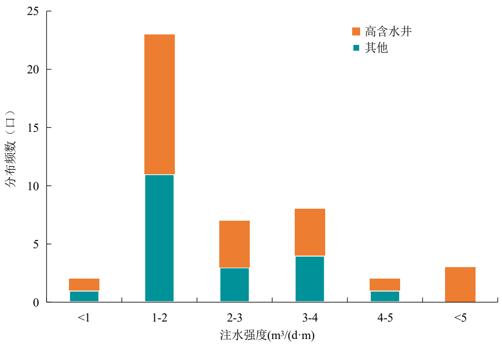

Figure 3. Frequency distribution of water injection intensity in the research area (Note 2)

3.4. Engineering factors

High water cut caused by engineering factors can be identified through the volume and composition of produced water. The engineering factors contributing to water detection in oil wells mainly consist of internal and external components. Internal factors include casing corrosion: Firstly, during production, crude oil in oil wells contains corrosive gases that cause varying degrees of corrosion inside the casing. Secondly, premature cementing leads to compromised cement rings, allowing direct contact between the casing and formation water. Corrosive gases in formation water then induce external corrosion on the casing. External factors involve casing damage caused by operations such as well repairs, fracturing acidizing, and recompressing, which shorten the casing's service life. These damages disrupt normal production processes, ultimately leading to water flooding in oil wells.

4. WELL TREATMENT MEASURES FOR HIGH WATER CONTENT IN BLOCK X RESERVOIR

4.1. Well Damage Treatment in Research Area

Engineering factors account for 17% of high-water-content casing damage wells in the study area. Current treatment methods primarily involve production suspension and cement injection, though some cases remain unresolved with no recovery of production capacity. This stems from insufficient analysis of root causes and inconsistent application of tailored solutions [8]. (1) For deformation or crushed casing, corrective measures include reshaping and reinforcement. (2) In cases of perforation, fractures, or damaged casing, precise leak localization should be followed by repeated cement injection, packer placement, small-diameter casing repairs, or metal corrugated pipe inserts, with methods selected based on specific well conditions. (3) When water quality fails to meet standards causing casing corrosion, analyze the composition of injected wastewater. Oilfield wastewater often deviates from recommended parameters. For formation reinjection, implement filtration, high-efficiency sterilization, enhanced monitoring of suspended solids and oil content, and selection of appropriate scale inhibitors, anti-expansion agents, and biocides. (4) For ineffective cement sealing, introduce new materials like thermosetting resin plugs. These composite materials combine unsaturated polyester glass fiber with epoxy-modified resin, combining glass fiber strength with resin toughness. They demonstrate high compressive and shear strength, excellent penetration through microcracks, superior water tightness, controllable reaction rates, high-temperature resistance, and cost-effectiveness. Storage duration is 2-3 months under summer heat conditions. These performances can be targeted to solve the problems of difficult and damaged Wells, and the field construction effect is also very good.

4.2. Profile adjustment and water blocking

Water influx in oil wells occurs when excessive water injection intensity opens high-permeability channels in water-rich reservoirs. For such wells, profile adjustment and water blocking measures can be implemented. By analyzing injection-production connectivity diagrams and dynamic injection-production data to determine water inflow direction, profile adjustment strategies such as sealing high-permeability zones or large pores can be applied. Within the same well group, profile adjustment is preferred for multiple high-water-content shut-in wells. For oil wells with multiple open reservoir zones where water layer positions cannot be effectively identified, water blocking is preferred, primarily targeting oil layers with substantial sand thickness, well-developed edge water and bottom water but underdeveloped interlayers. During fracturing operations, alternating injection of sand-carrying fluid and water-blocking oil displacement agents is performed. By controlling pressure, displacement rate, and sand ratio, the water-blocking oil displacement agents are precisely positioned in perforated sections to achieve effective water blocking and oil displacement.

4.3. Adjust Annotation

For injection wells within a well group that show water influx, some wells adopt water-blocking methods while others employ simpler, more practical approaches like water allocation adjustments. This strategy aims to reduce water injection in high-permeability layers, control water content, and improve water-flood efficiency. (1) Water Injection Volume There are multiple theoretical calculation methods for water injection well allocation, with the most commonly used currently being the injection-production ratio-based approach. The theoretical allocation is calculated using interconnected thickness, effective direction, daily liquid production, volumetric coefficient, water cut, and injection-production ratio. Drawing from practical experience in developed oil fields, the initial injection-production ratio is determined as 1.2 using the steady-rising well group method in water injection effectiveness analysis, with a 1:3 oil-water well ratio. This calculation yields a theoretical allocation per well of 16.0m3/d. Both theoretical studies and production practices confirm that when well spacing is less than 200 meters, inter-well interference increases, raising the risk of oil well flooding. For well groups with injection-production spacing under 200 meters, the single-layer allocation should be reduced by 5% to 15% compared to theoretical calculations. Enhanced monitoring is required after reinjection, with timely adjustments to water injection volume based on oil well production dynamics. At reservoir margins, intensified water injection increases single-layer allocation by 10% to 30%, while strengthened dynamic monitoring enables prompt workload adjustments. (2) Water Injection Intensity Analysis shows that high-water-cut zones in the study area require higher injection intensity than average levels. Therefore, reasonable injection intensity should be adopted to prevent premature oil well flooding. To maintain normal reservoir pressure in the study area, injection-production relationships across stratigraphic sections are analyzed based on well group production conditions, allowing determination of appropriate injection-production ratios and corresponding injection intensity. For low-permeability, low-pressure formations, the water injection-production ratio should be appropriately increased with enhanced injection intensity to boost formation pressure. Conversely, for high-permeability, high-pressure, high-water-bearing formations, the injection-production ratio should be reduced while controlling injection intensity to prevent water migration. Analysis of injection intensity across all wells in the study area suggests that the reasonable average injection intensity should not exceed 2.77 $m^3/(d·m)$. 3.4 Appropriate Liquid Production Intensity In the Chang 2 oil reservoir, structural factors causing high water cut can be managed by adjusting production intensity. The water body thickness in peripheral wells of the Chang 2 reservoir is greater than that in internal wells, allowing for lower theoretical liquid production intensity during initial development to slow the advance of edge water. During medium-high water cut periods, peripheral wells may adopt intensified drainage pressure to maintain average liquid production intensity below 0.7 $m^3/(m·d)$, achieving both oil recovery and water control. 3.5 Unstable Water Injection For wells encountering formation water, particularly those in structurally low-lying areas, water cut increases rapidly after injection. Conventional water control measures become increasingly ineffective under conventional injection development methods, while potential mitigation becomes more challenging. The industry has developed unstable water injection techniques for such scenarios, which have been successfully implemented in blocks of Changqing Oilfield, Henan Oilfield, and Shengli Oilfield, yielding positive results. The unstable water injection method can significantly achieve water control and oil stabilization. During implementation, well groups with high water content, sufficient formation energy, and relatively independent injection-production correlation at reservoir margins can be selected. As energy in the affected direction decreases, residual oil in the unaffected direction will be passively utilized, thereby improving the problem of edge and bottom water cone advancement.

5. CONCLUSION

In the late stage of water injection development, the prominent issue of water cut increase is influenced by four primary factors affecting oil well flooding in the study area: reservoir structure, water injection intensity, liquid production intensity, and engineering factors, with structural causes and water injection intensity being the dominant factors.

Different countermeasures can be proposed for various high water cut causes, including casing damage treatment, profile adjustment and water blocking, injection allocation adjustment, unstable water injection, and liquid production intensity formulation. For wells showing injected water due to interlayer contradictions, water blocking can be implemented for high water cut wells, or injection allocation adjustments can be made. The injection allocation per well should be 16.0m3/d; the reasonable average water injection intensity should not exceed 2.77$m^3/(d·m)$; liquid production intensity should be controlled below 0.7$m^3/(m·d)$. Unstable water injection methods can be adopted for marginal well groups in reservoirs to improve bottom water cone advancement issues.

Dynamic monitoring should be strengthened in the late stage of water injection, with timely adjustments to workload to mitigate rapid water cut increase.

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