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A Method for Predicting Formation Pressure during High Water Cut Stage

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Abstract: Formation pressure is a crucial evaluation index for the development of water-injected oil fields. In the process of oilfield development, the magnitude of formation pressure represents the level of energy in the formation. Excessive or insufficient formation energy can affect the development efficiency of oil fields. Therefore, how to quantitatively predict formation pressure is of great significance for oilfield development. Existing methods for determining formation pressure in water-injected oil fields consider only a single factor and neglect the changing patterns of oil field development. To more reasonably evaluate reservoir formation pressure, based on the principle of material balance and considering the changing patterns of oil field development, a prediction method for formation pressure is established. This method can provide formation pressure under different injection-production ratios and degrees of recovery. Research shows that: when the cumulative injection-production ratio remains constant and is always less than 1, as the degree of recovery increases, the formation pressure gradually decreases, and the smaller the cumulative injection-production ratio, the lower the formation pressure; when the cumulative injection-production ratio remains constant and is always greater than 1, as the degree of recovery increases, the formation pressure gradually increases; when the cumulative injection-production ratio is initially less than 1 but gradually increases later, the change pattern is related to the formation voidage. When the cumulative injection-production ratio is initially greater than 1 but gradually decreases later, the change pattern is related to the formation over-injection volume. This method has been applied in an offshore oil field, and the formation pressure at different development stages of the oil field has been calculated. Based on the current formation pressure, the development of the oil field has been guided, and good results have been achieved. This method has important guiding significance for the development of similar oil fields.

Keywords: High water cut; Water drive characteristic curve; Material balance; Formation pressure.

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1. Introduction

During the process of oilfield development, formation pressure is a crucial evaluation index for water-injected oil fields. If the formation pressure remains too high, it will lead to phenomena such as water flooding and increase the injection pressure, thereby increasing costs. Conversely, if the formation pressure is maintained at too low a level, it will be unable to form a sufficient production pressure differential to drive oil flow from the reservoir to the bottom of the production well, and may even result in three-phase flow, deteriorating the mobility of formation crude oil. Therefore, achieving accurate prediction of formation pressure is of great significance for improving oil recovery [1,2].

Many scholars have conducted research on the prediction of formation pressure or the determination of reasonable formation pressure. Liu Yinsong employed material balance methods, gas-oil ratio dynamic data analysis methods, and numerical simulation methods to study the changes in formation pressure with different crude oil viscosities, degrees of recovery, gas-oil ratios, and calculated the formation pressure in different blocks of the Daqing Oilfield [3]. C. Slider proposed a pressure recovery analysis method different from the conventional well testing analysis method of Horner. Based on the changes in oil pressure caused by the negative rate effect resulting from well shut-in, this method utilizes the changes in pressure over time before well shut-in to avoid independent evaluations of porosity and compressibility, and provides a simple mathematical expression for calculating pressure values. However, this method is only applicable to oil wells that have been producing for a sufficiently long time and are in a pseudosteady or steady flow state [4,5]. Luo Chengjian established a quantitative relationship formula among the maintenance level of formation pressure, liquid production rate, and water cut using the material balance equation and water drive characteristic curve method, combined with practical application results from oilfields, demonstrating the practical value of this method and providing numerical values for the maintenance level of formation pressure [6]. Guo Fenzhuan established a relationship between water cut, startup pressure impact factors, and reasonable formation pressure using the basic principles of oil recovery technology and oil-water phase permeability relationships, determining the reasonable maintenance level of formation pressure. However, this method is not applicable during the high water cut stage in low-permeability reservoirs [7]. Liu Wangdong proposed using the liquid production intensity method to predict reasonable formation pressure in the later stages of development based on a comparison of multiple methods, including the minimum flowing pressure method, hydrostatic pressure method, low-permeability reservoir characteristic method, crude oil viscosity method, minimum natural decline method, and the relationship between formation pressure and cumulative injection-production ratio [8]. Zhu Jie established a mathematical model based on the material balance principle and the comprehensive water drive law of reservoirs to describe the maintenance level of formation pressure under different injection-production ratios and degrees of geological reserve recovery. A sandstone reservoir in the Ordos Basin was used as an example to simplify the model [9]. Song Kaoping considered both recovery efficiency and economic benefits to establish a relationship formula for the optimal formation pressure under different oil prices and water injection costs [10]. Guo Xinjiang established a relationship between reasonable formation pressure and water cut, injection-production ratio, and startup pressure impact factors using the injection-production ratio principle, and conducted example calculations, achieving good results [11]. Zhang Xiuli calculated the relevant parameters for determining reasonable formation pressure in fault block reservoirs based on the injection-production balance principle, derived the relationship between different pressure maintenance levels and single-well production, and drew a pressure level optimization diagram [12].

Despite extensive research, existing methods for determining formation pressure in water-injected oil fields consider only a single factor and neglect the changing patterns of oil field development. To more reasonably evaluate reservoir formation pressure, a prediction method for formation pressure has been established based on the principle of material balance and considering the changing patterns of oil field development. This method can provide formation pressure under different injection-production ratios and degrees of recovery. This method has been applied in an offshore oil field, and the formation pressure at different development stages of the oil field has been calculated. Based on the current formation pressure, the development of the oil field has been guided, and good results have been achieved. This method has important guiding significance for the development of similar oil fields. This model provides a useful tool for engineers and analysts to predict and manage formation pressure during the development of waterflooded oilfields. By understanding how formation pressure changes with cumulative injection-production ratio and degree of recovery, they can make informed decisions about adjusting injection rates, production strategies, and other operational parameters to optimize oil recovery and maintain reservoir health.

2. Establishment of Method

The Material Balance Equation (MBE) is a central concept in reservoir engineering, aimed at describing the dynamic equilibrium state of subsurface fluids (including oil, gas, water, etc.) during the development of oil and gas reservoirs. Its principle is rooted in the Law of Conservation of Mass in physics, which states that in a closed system, regardless of the physical or chemical changes that occur, the total mass of the system remains constant. The MBE establishes a mathematical expression that quantifies the dynamic changes in the total fluid volume within an oil and gas reservoir by comprehensively considering the inflow of fluids (such as water injection for stimulation, natural gas reinjection, etc.) and outflow (such as oil production, natural gas production, formation water production, etc.), as well as the expansion or compression effects of fluids due to pressure changes. This equation not only reflects changes in the composition and state of fluids within the reservoir, but more importantly, it reveals how these changes impact the reserves and production performance of the reservoir. In reservoir engineering, the application of the MBE is extremely widespread. It serves as the foundation for reserve assessment, production optimization, and reservoir management, and is also a crucial tool for formulating development strategies and predicting long-term production performance of oil and gas reservoirs. Through the MBE, engineers can more accurately estimate the remaining reserves of oil and gas reservoirs, predict future production trends, and thereby develop more scientific and reasonable development plans to achieve the maximization of hydrocarbon resource utilization.

Given the assumptions: 1) The reservoir layer and fluid physical properties are uniform and isotropic; 2) The formation pressure at all points in the reservoir is in equilibrium and equal within the same time period; 3) The formation temperature remains constant throughout the entire development process; 4) Capillary force and gravity are not considered; 5) The production volume from all parts of the reservoir remains balanced, meaning that oil, gas, and water can instantly reach equilibrium at any given pressure [13,14].

For an artificially waterflooded oilfield without a gas cap and edge/bottom water [15,16], the material balance equation is:

$$\begin{aligned} N_{\mathrm{p}}\left[B_{\mathrm{o}}+B_{\mathrm{g}}\left(R_{\mathrm{p}}-R_{\mathrm{s}}\right)\right] &= N\left[\left(B_{\mathrm{o}}-B_{\mathrm{oi}}\right)+B_{\mathrm{g}}\left(R_{\mathrm{si}}-R_{\mathrm{s}}\right)\right]+mNB_{\mathrm{oi}}\left(\frac{B_{\mathrm{g}}}{B_{\mathrm{gi}}}-1\right) \\ &+\left(1+m\right)NB_{\mathrm{oi}}\frac{C_{\mathrm{w}}S_{\mathrm{wc}}+C_{\mathrm{f}}}{1-S_{\mathrm{wc}}}\left(p_{\mathrm{i}}-p\right)+\left(W_{\mathrm{i}}+W_{\mathrm{e}}-W_{\mathrm{p}}\right)B_{\mathrm{w}} \end{aligned} \tag{1}$$

When considering a scenario without a gas cap or edge/bottom water and where the formation pressure is above the bubble point pressure, we have:

$$m=0 \tag{2}$$

$$W_{\mathrm{e}}=0 \tag{3}$$

$$R_{\mathrm{p}}=R_{\mathrm{si}}=R_{\mathrm{s}} \tag{4}$$

$$B_{\mathrm{o}}-B_{\mathrm{oi}}=B_{\mathrm{oi}}C_{\mathrm{o}}\left(p_{\mathrm{i}}-p\right) \tag{5}$$

If

$$C_{\mathrm{t}}=C_{\mathrm{o}}+\frac{C_{\mathrm{w}}S_{\mathrm{wc}}+C_{\mathrm{f}}}{1-S_{\mathrm{wc}}} \tag{6}$$

Then, the material balance equation can be simplified to:

$$N_{\mathrm{p}}B_{\mathrm{o}}=NB_{\mathrm{oi}}C_{\mathrm{t}}\left(p_{\mathrm{i}}-p\right)+\left(W_{\mathrm{i}}-W_{\mathrm{p}}\right)B_{\mathrm{w}} \tag{7}$$

The generalized cumulative injection-production ratio is the ratio of cumulative water injection volume to cumulative liquid production volume, calculated as:

$$\mathrm{Z}=\frac{W_{\mathrm{i}}B_{\mathrm{w}}}{W_{\mathrm{p}}B_{\mathrm{w}}+N_{\mathrm{p}}B_{\mathrm{o}}} \tag{8}$$

Substituting (8) into (7) gives:

$$\left(1\text{-}Z\right)N_{\mathrm{p}}B_{\mathrm{o}}=NB_{\mathrm{oi}}C_{\mathrm{t}}\left(p_{\mathrm{i}}-p\right)+\left(\mathrm{Z}\text{-}1\right)W_{\mathrm{p}}B_{\mathrm{w}} \tag{9}$$

The Water Drive Characteristic Curve (WDCC) is a pivotal analytical tool in the fields of petroleum geology and petroleum engineering. It is specifically designed to describe the mathematical relationships among cumulative water production, cumulative oil production (or cumulative gas production), cumulative fluid production, recovery degree, oil-water ratio, and combinations of these variables during the process of water injection development or natural water drive in oil (or gas) reservoirs. These relationships often manifest as straight lines on different coordinate systems. Based on the principles of mass conservation and fluid dynamics, the WDCC visually demonstrates the dynamic changes of oil (or gas) being gradually displaced by water during the injection process, revealing the intrinsic connections among the aforementioned variables. Various types of WDCCs exist, such as Type A curves reflecting the semi-logarithmic relationship between cumulative oil production and cumulative water production, and Type B curves revealing the relationship between water-oil ratio and recovery degree through time derivatives. These types reflect the fluid dynamics under different reservoir conditions and development stages. In practical applications, the WDCC can not only be used to predict changes in water cut and estimate remaining recoverable reserves, providing important guidance for stable and increased oil production and development planning, but also to optimize water injection strategies and production schemes by analyzing its trends, thereby enhancing recovery efficiency and economic benefits. Furthermore, based on actual production data, the WDCC can be used to derive relative permeability curves, which are significant for reservoir performance prediction. Additionally, the WDCC is characterized by its intuitiveness, dynamism, and practicality, facilitating engineers' analysis and judgment through graphical representation. It serves as an indispensable tool for reservoir engineers in reserve assessment, production optimization, and reservoir performance prediction. Therefore, in-depth study and analysis of the WDCC play a crucial guiding role in oilfield development planning and production decision-making.

Currently, there are various types of Water Drive Characteristic Curves. This paper adopts the relationship formula between cumulative oil production and cumulative water production. When an oilfield has been developed to a certain stage, the cumulative oil-water ratio and cumulative oil production form a straight line, described by the formula:

$$\frac{W_{\mathrm{p}}}{N_{\mathrm{p}}}=a+bN_{\mathrm{p}} \tag{10}$$

Substituting (10) into (9) and rearranging gives:

$$\left(1\text{-}Z\right)\left(B_{\mathrm{o}}+aB_{\mathrm{w}}+bB_{\mathrm{w}}\frac{N_{\mathrm{p}}}{N}N\right)=\frac{1}{\frac{N_{\mathrm{p}}}{N}}B_{\mathrm{oi}}C_{\mathrm{t}}\left(p_{\mathrm{i}}-p\right) \tag{11}$$

Define:

$$R=\frac{N_{\mathrm{p}}}{N} \tag{12}$$

Substituting (12) into (11) gives:

$$\left(1\text{-}Z\right)\left(B_{\mathrm{o}}+aB_{\mathrm{w}}+bB_{\mathrm{w}}RN\right)=\frac{1}{R}B_{\mathrm{oi}}C_{\mathrm{t}}\left(p_{\mathrm{i}}-p\right) \tag{13}$$

These equations provide a comprehensive framework for analyzing the material balance of an artificially waterflooded oilfield without a gas cap and edge/bottom water, and where the formation pressure is above the bubble point pressure. By using these equations, one can better understand and predict the performance of such oilfields during development.

For a specific oil field, B_o does not vary with p_i. After statistical analysis, it was found that B_o and p approximately follow a quadratic equation. Taking a certain block as an example, as shown in the **Figure 1**, within a certain pressure difference range, B_o changes very little with the variation of p.

$$B_o = -0.0002p^2 + 0.0204p + 1.0373 \tag{14}$$

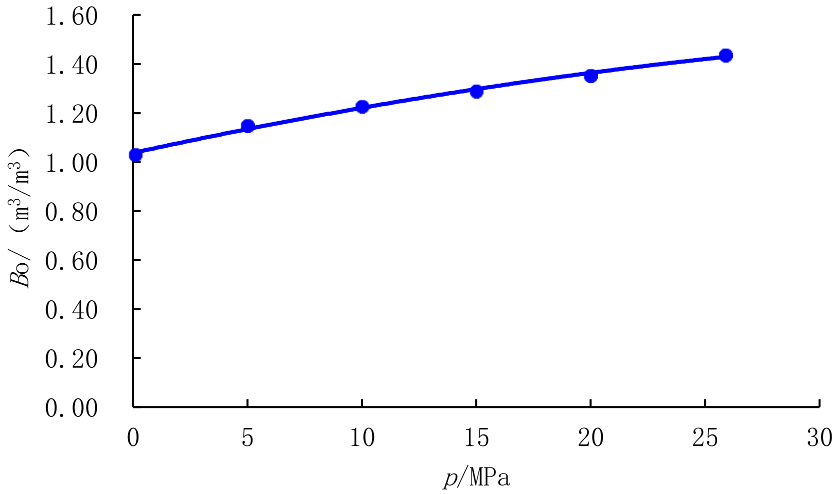

Figure 1. Curve showing the variation of oil formation volume factor with pressure

Therefore, when $p > p_b$ (where p_b represents the bubble point pressure), B_o can be approximated as B_{oi} (the initial oil formation volume factor) and B_w can be approximated as 1 (assuming water is incompressible at these conditions). Consequently, Equation (13) can be further simplified and rearranged to:

$$p = p_i - \frac{(1\text{-}Z)(B_{oi} + a + bRN)R}{B_{oi}C_t} \tag{15}$$

Equation (15) represents the established prediction model for formation pressure in a waterflooded oilfield. This model can be applied to the development stage of water-drive oilfields where the cumulative oil-water ratio and cumulative oil production satisfy a linear relationship. The model is expressed as a multi-factor function, with the formation pressure being related to the cumulative injection-production ratio and the degree of recovery. For a specific oilfield, the calculation using this model is straightforward. This model provides a useful tool for engineers and analysts to predict and manage formation pressure during the development of waterflooded oilfields. By understanding how formation pressure changes with cumulative injection-production ratio and degree of recovery, they can make informed decisions about adjusting injection rates, production strategies, and other operational parameters to optimize oil recovery and maintain reservoir health.

3. Analysis of Patterns

In order to gain a deeper understanding and grasp of the dynamic laws of formation pressure changes with cumulative injection production ratio and recovery degree, it is necessary to adopt more detailed and diversified analysis methods, and conduct detailed discussions and comparisons for various possible different working conditions and conditions.

Based on the development experience of oil fields, there are four potential scenarios regarding formation pressure in oil fields. The first scenario occurs when water injection conditions are limited, such that the injected water volume cannot meet the development needs, placing the oil field in a state of pressure deficiency. In this case, the cumulative injection-production ratio remains nearly constant but always less than 1. The second scenario arises when water injection conditions fully satisfy the development needs of the oil field, and to accelerate production, the formation pressure is maintained in an over-injected state. Here, the cumulative injection-production ratio remains constant but always greater than 1. The third scenario is influenced by drilling and completion progress as well as water injection conditions. In the early stages of oil field development, insufficient water injection leads to a loss of formation energy and pressure decline, with the cumulative injection-production ratio initially being less than 1. However, as the oil field continues to be developed, water injection conditions gradually meet the development needs, resulting in an increase in the instantaneous injection-production ratio and the gradual restoration of formation energy, with the cumulative injection-production ratio showing a trend of gradual increase. The fourth scenario involves the oil field adopting over-injection practices in the initial stages of development to maintain high formation energy levels, with the cumulative injection-production ratio initially greater than 1. However, as injected water continues to breakthrough, the water cut of the oil field rises continuously. To unleash the potential of the oil field and reduce ineffective circulation of injected water, production continues by lowering the cumulative injection-production ratio, which then gradually decreases. This paper analyzes the above four scenarios.

3.1. Constant Cumulative Injection-Production Ratio Less Than 1

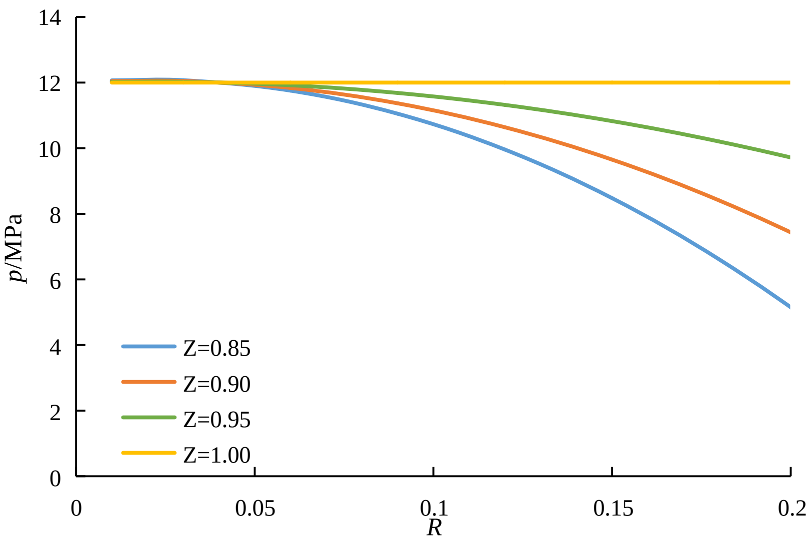

Figure 2. Variation Curve of Formation Pressure and Degree of Recovery at Different Cumulative Injection-Production Ratios (Z<1)

Figure 2 shows the variation curve of formation pressure and degree of recovery when the cumulative injection-production ratio remains constant and is always less than 1. From the figure, it can be seen that when the cumulative injection production ratio is 1, there is no deficit in the formation, and regardless of the degree of recovery, the formation pressure remains at the original formation pressure level. When the cumulative injection production ratio is less than 1, the formation experiences a deficit, and the formation pressure begins to decrease below the original formation pressure. Moreover, the larger the deficit, the lower the formation pressure. As the degree of recovery increases, the formation pressure gradually decreases. The smaller the cumulative injection-production ratio, the lower the formation pressure. This is because when the cumulative injection-production ratio is less than 1, it indicates that the cumulative production volume of the oilfield is always greater than the cumulative water injection volume. The formation energy is not replenished, resulting in a continuous depletion of formation energy. As the cumulative production volume continues to increase, the formation depletion also increases, ultimately leading to a continuous decrease in formation pressure. The greater the depletion, the lower the pressure. Low formation pressure can cause crude oil to degas, posing risks to electric submersible pump units and affecting stable development. Therefore, for oil fields with a cumulative injection production ratio less than 1, it is necessary to replenish the formation energy in a timely manner, otherwise the formation deficit will become larger and the formation energy will become smaller, and the formation pressure will become smaller and smaller.

3.2. Constant Cumulative Injection-Production Ratio Greater Than 1

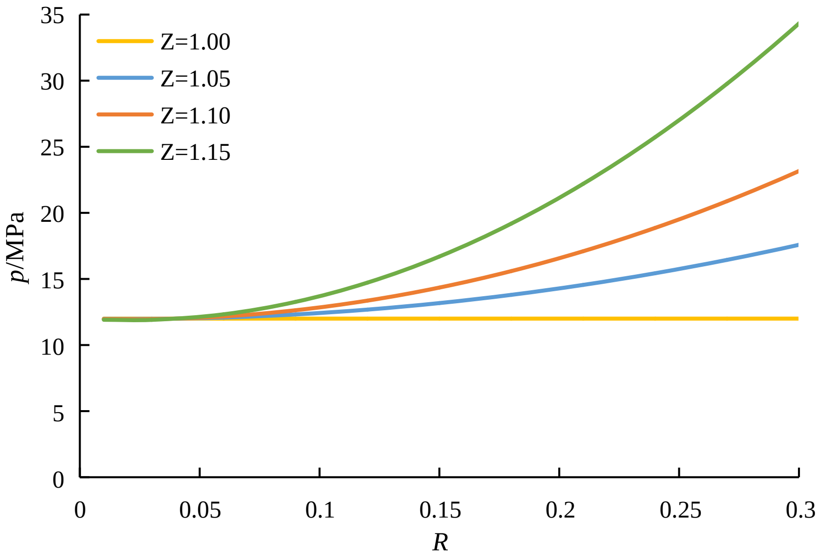

Figure 3. Variation Curve of Formation Pressure and Degree of Recovery at Different Cumulative Injection-Production Ratios (Z>1)

Figure 3 shows the variation curve of formation pressure and degree of recovery when the cumulative injection-production ratio remains constant and is always greater than 1. From the figure, it can be seen that when the cumulative injection production ratio is 1, there is no deficit in the formation, and regardless of the degree of extraction, the formation pressure remains at the original formation pressure level. When the cumulative injection production ratio is greater than 1, the formation experiences over injection, and the formation pressure begins to rise above the original formation pressure. Moreover, the more over injection, the higher the formation pressure. As the degree of recovery increases, the formation pressure gradually increases. The larger the cumulative injection-production ratio, the higher the formation pressure. This is because when the cumulative injection-production ratio is greater than 1, it indicates that the cumulative production volume of the oilfield is always less than the cumulative water injection volume. The formation energy is continuously replenished, resulting in a state of overpressure. As the cumulative production volume continues to increase, the excess replenishment of the formation also increases, ultimately leading to a continuous increase in formation pressure. Excessive formation pressure can pose development risks, therefore, such reservoirs should promptly reduce the instantaneous injection production ratio to achieve a decrease in cumulative injection production ratio, thereby restoring normal formation energy and reducing development risks.

3.3. Initial Cumulative Injection-Production Ratio Less Than 1, Gradually Increasing Later

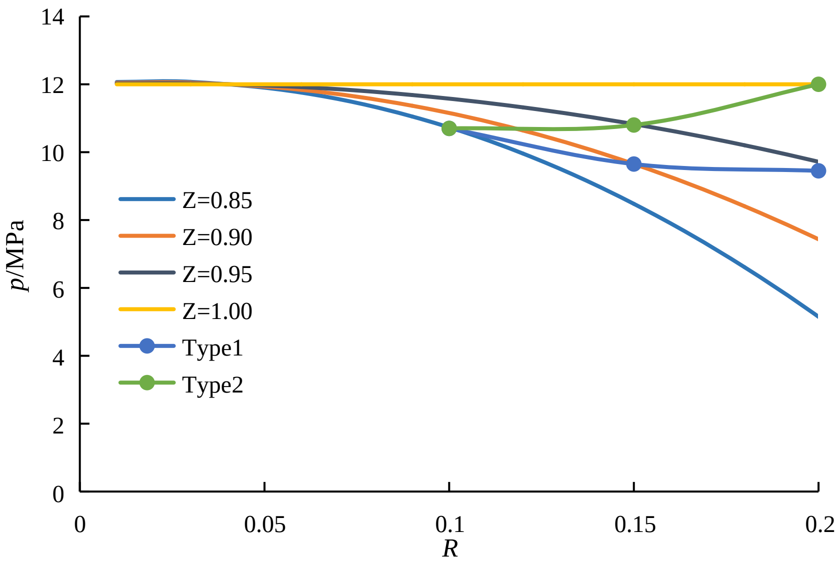

Figure 4. Variation Curve of Formation Pressure and Degree of Recovery

Figure 4 shows the variation curve of formation pressure and degree of recovery when the cumulative injection-production ratio is initially less than 1 but gradually increases later. This scenario is the most common in currently waterflooded oilfields, and there are two types. First, as the degree of recovery increases, the recovery of the cumulative injection-production ratio is slow, and the formation pressure first decreases and then gradually increases. This is because although the cumulative injection-production ratio is increasing, the oil production rate is faster, and the cumulative depletion gradually increases. Therefore, the formation pressure continues to decrease. When the cumulative depletion gradually decreases, the formation pressure gradually recovers. The other scenario is that as the degree of recovery increases, the cumulative injection-production ratio increases rapidly, and the formation pressure gradually increases. This is because compared to the oil production rate, the cumulative injection-production ratio increases faster, and the cumulative depletion gradually decreases. Therefore, the formation pressure continuously recovers. Therefore, from this perspective, simply increasing the water injection volume does not necessarily recover formation energy. Instead, changes in the oil production rate must also be considered.

3.4. Initial Cumulative Injection-Production Ratio Greater Than 1, Gradually Decreasing Later

Figure 5 shows the variation curve of formation pressure and degree of recovery when the cumulative injection-production ratio is initially greater than 1 but gradually decreases later. From the figure, it can be seen that there are two types of scenarios. As the degree of recovery increases, the decrease in the cumulative injection-production ratio is slow, and the formation pressure first increases and then decreases. This is because although the cumulative injection-production ratio decreases, the oil production rate is slower, and the cumulative over-injection volume of the formation still increases. Therefore, the formation pressure increases. When the cumulative over-injection volume gradually decreases, the formation pressure continuously decreases. The other scenario is that as the degree of recovery increases, the cumulative injection-production ratio decreases rapidly, and the formation pressure gradually decreases. This is because compared to the oil production rate, the cumulative injection-production ratio decreases faster, and the cumulative over-injection volume of the formation gradually decreases. Therefore, the formation pressure decreases.

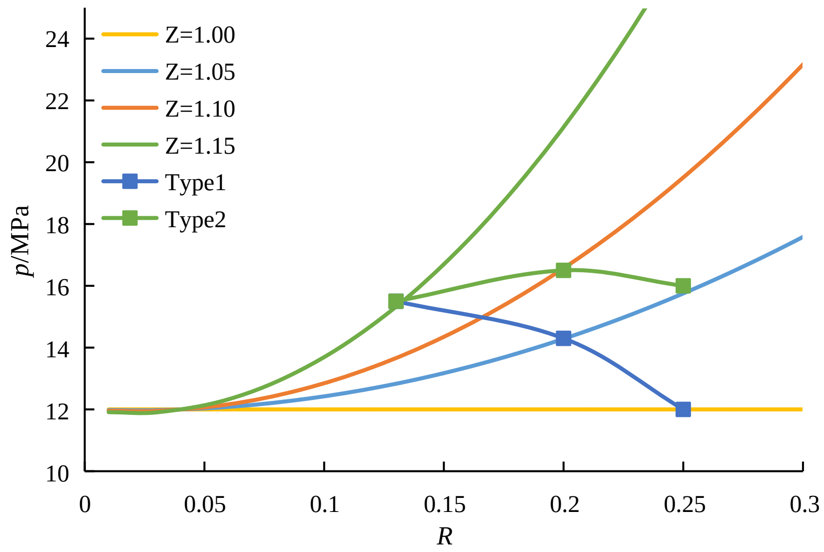

Figure 5. Variation Curve of Formation Pressure and Degree of Recovery

4. Oilfield Practice

The offshore P oilfield is a water-injection development oilfield. This oilfield is a complex fault block oilfield. The G Formation is a braided river delta deposit with continuous development of main layers and good connectivity. The M section is a meandering river deposit with poor connectivity and obvious channel migration. Crude oil belongs to medium to heavy oil, characterized by large changes in density, viscosity, and freezing point, high gum content, low wax and sulfur content. The oilfield has been in development since 2016. The cumulative water-oil ratio (W_P/N_P) and cumulative oil production (N_P) of this oilfield satisfy a linear relationship, as shown in **Figure 6**.

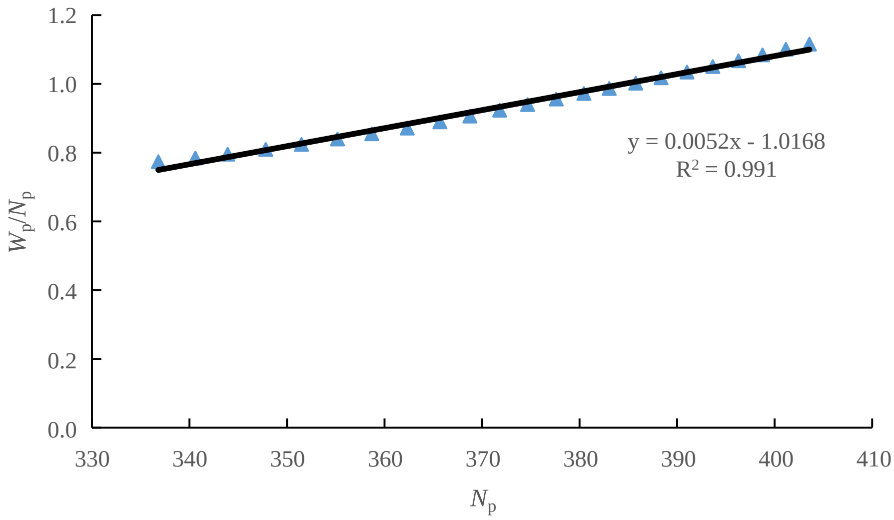

Figure 6. Relationship Curve of *Wp*/*Np* ~ *Np* for the P Oilfield

According to the method established in this paper, if the cumulative injection-production ratio remains unchanged, it is calculated that when the recovery degree of the oilfield reaches 18%, the formation pressure will drop to the bubble point pressure, at which point the formula is no longer applicable. If the formation pressure continues to drop, dissolved gas will be released from the crude oil. Although this may provide some dissolved gas driving force, it is more likely to reduce the oil recovery rate of the oilfield. To improve the development effect of the oilfield, while maintaining the oil production rate, the water injection volume of the oilfield should be increased. **Table 1** is a calculation table of the annual injection-production ratios required each year to restore the original formation pressure over different time periods, with a consistent annual recovery rate. Based on the injection capacity of the oilfield, a choice of restoring the original formation pressure over 2 or 3 years is made. In 2024, the predicted injection-production ratio is 1.13, with the formation pressure recovering to 0.97 of its original level.

Table 1. Annual Injection-Production Ratios Corresponding to Different Recovery Time Periods

recovery time	annual injection-production ratio			
	1 year	2 years	3 years	4 years
1	1.33	1.14	1.08	1.05
2	/	1.14	1.08	1.05
3	/	/	1.10	1.06
4	/	/	/	1.08

5. Conclusion

1) In order to evaluate the formation pressure of oil reservoirs more reasonably, based on the principle of material balance and considering the changes in oilfield development, a prediction method for formation pressure has been established. This method can provide formation pressure under different injection production ratios and different recovery degrees.

2) When the cumulative injection production ratio remains constant and always less than 1, as the degree of extraction increases, the formation pressure gradually decreases, and the smaller the cumulative injection production ratio, the lower the formation pressure. The cumulative injection production ratio remains constant and always greater than 1, as the degree of extraction increases, the formation pressure gradually increases. The situation where the cumulative injection production ratio is initially less than 1 but gradually increases in the later stage is related to the formation deficit. First, as the degree of recovery increases, the recovery of the cumulative injection-production ratio is slow, and the formation pressure first decreases and then gradually increases. This is because although the cumulative injection-production ratio is increasing, the oil production rate is faster, and the cumulative depletion gradually increases. Therefore, the formation pressure continues to decrease. When the cumulative depletion gradually decreases, the formation pressure gradually recovers. The other scenario is that as the degree of recovery increases, the cumulative injection-production ratio increases rapidly, and the formation pressure gradually increases. This is because compared to the oil production rate, the cumulative injection-production ratio increases faster, and the cumulative depletion gradually decreases. Therefore, the formation pressure continuously recovers. Therefore, from this perspective, simply increasing the water injection volume does not necessarily recover formation energy. Instead, changes in the oil production rate must also be considered. The situation where the cumulative injection production ratio is initially greater than 1 but gradually decreases in the later stage is related to the over injection amount in the formation. As the degree of recovery increases, the decrease in the cumulative injection-production ratio is slow, and the formation pressure first increases and then decreases. This is because although the cumulative injection-production ratio decreases, the oil production rate is slower, and the cumulative over-injection volume of the formation still increases. Therefore, the formation pressure increases. When the cumulative over-injection volume gradually decreases, the formation pressure continuously decreases. The other scenario is that as the degree of recovery increases, the cumulative injection-produc-

tion ratio decreases rapidly, and the formation pressure gradually decreases. This is because compared to the oil production rate, the cumulative injection-production ratio decreases faster, and the cumulative over-injection volume of the formation gradually decreases. Therefore, the formation pressure decreases.

3) This method has been applied in a certain offshore oil field, calculating the formation pressure at different stages of oil field development, and guiding the development of the oil field based on the current formation pressure, achieving good results. This method has important guiding significance for the development of similar oil fields.

Conflicts of Interest: This manuscript is the authors' original work and has not been published nor has it been submitted simultaneously elsewhere. All authors have checked the manuscript and have agreed to the submission.

Abbreviations

N_p	The cumulative oil production, in 10^4 m^3
N	the oilfield reserves, in 10^4 m^3
B_o	the oil formation volume factor
B_w	the water formation volume factor
B_g	the gas formation volume factor
R_p	the cumulative produced gas-oil ratio, in m^3/m^3
R_s	the solution gas-oil ratio, in m^3/m^3
B_{oi}	the initial oil formation volume factor
R_{si}	the initial solution gas-oil ratio, in m^3/m^3
m	the ratio of the original underground volume of gas cap gas to the original underground volume, also known as the gas cap index
B_{gi}	the initial gas formation volume factor
C_w	the compressibility of formation water, in MPa^{-1}
C_f	the compressibility of rock, in MPa^{-1}
S_{wc}	the irreducible water saturation
p_i	the initial formation pressure, in MPa
p	the current formation pressure, in MPa
W_i	the cumulative water injection volume, in 10^4 m^3
W_e	the cumulative natural water influx volume, in 10^4 m^3
W_p	the cumulative water production volume, in 10^4 m^3
C_t	the combined compressibility coefficient, in MPa^{-1}
C_o	the oil compressibility coefficient, in MPa^{-1}
Z	the cumulative injection-production ratio
R	The degree of recovery or the extent of production
a & b	calculation parameters

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