

Research Article

Development Favorable Area and Productivity Potential Evaluation Method of a Tight Oil Reservoir

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Tight oil resources have become the focus of unconventional oil and gas exploration and development. Well placement is an essential factor determining the development of a field. Oil wells should be located in the area with favorable criteria for development. These areas should be screened based upon oil and gas enrichment of the reservoir. The influencing factors and analysis theory of an enrichment area are summarized in this paper. Two types of methods evaluating areas favorable for tight oil and gas production are explained here as well, including model prediction and the combination of geological modeling and reservoir simulation. The area with favorable geological, engineering, and economic attributes has the best development potential. The productivity potential can be used as one basis for selecting areas favorable for production. Based on the previous concept of productivity potential, combined with the characteristics of a tight oil reservoir, this study modified the evaluation of productivity potential, and the calculated potential area was the priority for well placement. The modified equation of productivity potential comprehensively considers effective pore pressure, mobile oil saturation, porosity, permeability, effective thickness, distance from the boundary, and threshold pressure gradient. A tight reservoir was taken as an example for calculation, and the results of the modified method, original productivity potential method, and reserve abundance calculation method are discussed. Two new wells were arranged in the favorable areas obtained by different productivity potential evaluation methods, and the production was calculated under the same parameters for each method. The recovery of this area was 51.65%, which is 1.73% and 2.84% higher than that of the other two methods.

1. Introduction

The great success of the shale gas revolution in North America has led to the production of tight oil across the globe. At present, China's profitable exploration region of a tight oil reservoir is 18×10^4 km², and the geological resources are $74\text{--}80 \times 10^8$ t [1]. In 2016, tight oil production capacity in China was 1.553×10^6 t [2]. In 2020, the production of tight oil in the United States will reach 1071 MB. Many factors influence tight oil production, among which an area favorable for oil/gas enrichment, evaluation of productivity potential, and well location arrangement are the three key factors.

The determination of a favorable area for oil and gas enrichment and development is the premise of well place-

ment. The formation scale of tight oil in China is controlled by four geological factors: wide and gentle groove slope area, a high-quality and efficient source rock, large distribution extent of a tight reservoir, and effective source reservoir configuration. Yang et al. [3] explained three factors for tight oil enrichment in the Triassic Chang 7 member in the Ordos Basin: effective source reservoir configuration and continuous filling, dense microspores, and sustained strong oil filling. According to Wang et al. [4], the principal conditions of enrichment are (a) high-energy sedimentary environment, (b) strong dissolution, and (c) early oil and gas charging and overpressurization. A favorable development area includes geological, engineering, and economic attributes and a favorable area with all three will have the best potential

for high-yield development [5]. Yang et al. [6] and Han et al. [7] have performed several quantitative and qualitative studies on the evaluation and identification of profitable zones for the production of tight continental oil and have provided the systematic parameter evaluation criteria from the aspects of source rock, reservoir, and reservoir properties to the final recoverable yield of a single well.

As a critical decision in reservoir management, optimizing well placement remains a challenge in tight oil reservoirs. Yeten et al. [8] indicated that well placement is often posed as a discrete optimization problem. Zandvliet et al. [9] pointed out that well locations are typically determined manually. They also classified automated optimization methods of well placement into two categories. Optimization algorithms are mainly categorized into gradient-based and derivative-free algorithms [10]. Common examples of gradient-based algorithms are the adjoint algorithm and simultaneous perturbation stochastic approximation [9, 11, 12]. Evolutionary algorithms, evolution strategy, and swarm algorithms are among the three commonly used derivative-free algorithms [13–19]. Different approaches have been proposed to optimize well placement, including statistical methods, reservoir engineering methods, and proxy models [10, 20, 21].

The geological conditions of a tight reservoir are complex, and many geological parameters are uncertain, making it challenging to optimize the development of areas that are favorable for production. In the process of well location deployment, the diversity of parameters and the limitation of an optimization model can lead to significant errors. In engineering applications, engineers need to give the general scope of the development of a favorable area and determine the direction for the next step of well location placement. Based on the previous concept of productivity potential, combined with the characteristics of a tight oil reservoir, this paper modifies the evaluation of productivity potential; the calculated potential area is the priority well location area. This study is divided into three main sections. The first is to explain the screening method of the enrichment area and the favorable development area. The second is to revise the calculation for production potential. The last is to compare and discuss the calculation results.

2. Favorable Area of Tight Oil Development

In an oil and gas resource evaluation report released by the National Petroleum Commission of the United States in September 2011, tight oil is described as oil which is stored in sedimentary rocks that are not easily exploited due to low permeability. Some tight oil areas directly produce oil from shale, while many are tight sandstone or carbonates adjacent to their source rock. The National Energy Administration of China issued an industry standard in November 2013, which stipulates that tight oil is oil stored in tight sandstone, tight carbonate rock, and other reservoirs with overburden matrix permeability $\leq 0.2 \times 10^{-3} \mu\text{m}^2$ (air permeability $< 2 \times 10^{-3} \mu\text{m}^2$). Also, a single well generally has no natural production capacity or cannot reach industrial oil flow, but commercial production can be obtained under certain

economic conditions and technical measures, including hydraulic fracturing and horizontal drilling.

To determine the favorable areas of tight oil development, it is necessary to make clear the mechanisms of enrichment of oil and gas and then screen the areas that are favorable based upon these factors. In this section, firstly, oil, and gas enrichment is described, and then, two methods for determining favorable areas are discussed. After determining the favorable area for development, a well location can be determined.

2.1. Enrichment Area. The enrichment area of a tight reservoir refers to the area with a relatively high-quality reservoir that has relatively high porosity and permeability for a tight reservoir, and the oil and gas are mainly distributed in these relatively high-quality areas. A tight oil enrichment area is a fuzzy concept, and there is no absolute index to measure what is meant by “enrichment.” The enrichment area is often referred to as a “sweet spot” in oil and gas exploration, where most of the oil and gas resources in tight oil and gas reservoirs are enriched. The enrichment of oil and gas is affected by multiple factors. To determine the factors influencing the oil-bearing enrichment objectively and truly, the reservoir elements, reservoir formation types, and reservoir formation modes must be clear and then integrated into the geological research results to determine the oil-bearing enrichment controls.

The formation conditions of a tight oil enrichment area are mainly related to sedimentary, diagenetic, and structural conditions. The sedimentary environmental depositional conditions are mainly related to the sedimentation rate, source (single or multiple), distance from the source, parent lithology and degree weathering, geomorphic morphology of the sedimentary surface, lake expansion and sediment retrogradation, configuration and superposition of high-energy facies belts, continuous and intermittent accumulation, sedimentary water depth, and wave base surface. River behavior determines sand body configuration and several other factors. The diagenetic conditions can cause undercompaction and abnormally high-pressure zones, clay film on the surface of particles, and oil immersion. Structural conditions can have a variety of influences on the strata. There can be a period of structural stability during the middle stage of basin evolution. Tectonic influences can cause either inadequate or adequate accommodation space during basin formation, along with contemporaneous fault zones at the edge of a basin, two wings of synsedimentary anticlines, margin of subsidence centers, the late filling period of ancient river valleys, sedimentary discontinuities, uplift of the edges of the central belt of a basin, or overburden pinch-out zones. In general, the most crucial factor is the original material composition and structure, and the natural parent material is the source of the enrichment area. The tectonic, sedimentary, and diagenetic conditions are vital for the formation of an enrichment area.

Based on a comprehensive geological study of controlling factors of petroleum accumulation, comprehensive indexes such as oil generation conditions, preservation conditions, trap conditions, facies control conditions, reservoir conditions, migration conditions, oil-bearing property of oil layers,

oil test results, or the oil-bearing area can be used to predict enrichment areas.

2.2. Optimization Method of the Development Favorable Area. The selection of favorable areas needs to further clarify the development feasibility based upon enrichment areas. There are two methods to screen areas with favorable development. A geologic model can be used to comprehensively evaluate the influencing factors. The second is the combination of the geological model and numerical simulation, using the development indicators obtained from the simulation to screen for favorable development areas.

2.2.1. Model Prediction. This method first needs to evaluate the factors influencing the favorable development of an area, including geological and engineering factors. Jia et al. [22] selected 10 key indicators to evaluate the favorable development of an area, including porosity and permeability, matrix pore type, structural background, thickness, organic carbon content and maturity, formation pressure, fluidity, depth, fracturing ability, and surface conditions. Zou et al. [23, 24] suggested the “six characteristics” to evaluate source control, lithology, physical properties, brittleness, oil and gas properties, and stress anisotropy, comprehensively considering geological and engineering factors and finally evaluating areas favorable for tight oil development. Considering the geological “sweet spot” and engineering quality, Liang et al. [25] created an “eight properties” evaluation method, which included light source rock specialization, lithology, oil-bearing properties, physical properties, electrical properties, brittleness, in situ stress anisotropy, and sensitivity. Pang et al. [26] used four indicators to evaluate a favorable area, including source rock, porosity, profitable reservoir rock thickness, and fractures in the area.

Methods for determining favorable areas have evolved from being qualitative to quantitative. These methods mainly include multifactor superposition, fuzzy optimization, analytic hierarchy processing, and various fusion methods. The multifactor superposition method overlays the plane distribution map of the influencing factors of the favorable area and selects a favorable area according to a specific evaluation parameter set.

The analytic hierarchy process establishes a hierarchical structure model for optimizing favorable areas, calculates the weight of each influencing factor, and calculates a comprehensive score through a comprehensive evaluation using either constant weights or variable weights. The best development area will be scored the highest. Constant weights keep the value of a weight vector in the evaluation model constant with the change in the index state vector. The weight value of a constant weight can show the relative importance of each factor index throughout the whole decision system to a certain extent. It is easy to calculate and is widely used.

Fuzzy optimization applies fuzzy mathematics to deal with various factors and provide weights to establish a multi-level fuzzy mathematical evaluation model for screening development of favorable areas. Commonly used methods to determine weights mainly include expert scoring, principal

component analysis, grey correlation analysis, and neural network.

With the popularization and application of artificial intelligence and big data, this method can also be used to select favorable areas for tight reservoir development. The key is the number of samples and the evaluation model.

2.2.2. Geological Modeling and Numerical Simulation. Compared with model prediction, geological modeling and numerical simulation can grasp the development trend more comprehensively and further consider the influence of economic factors when determining an area suitable for development. It can integrate geological factors, engineering factors, and economic factors to screen for suitable areas. When the well pattern is infilled, this method can create a more accurate and comprehensive screening method. This method is limited in that a large number of geological static and production dynamic data are needed, which are often lacking in the screening stage for favorable areas.

Reservoir geological models are the core of reservoir evaluation. It is essential to quantitatively predict and interpolate reservoir parameters between wells from a three-dimensional perspective, mainly integrative, quantitative visual research. There are two types of 3D geological reservoir modeling methods: deterministic modeling and stochastic modeling. Deterministic modeling mainly includes seismic sedimentology, reservoir sedimentology, and Kriging interpolation. Stochastic modeling includes target-based and pixel-based methods. Based on geological, seismic, and logging data, the general idea and method of reservoir 3D geological modeling are to quantitatively characterize the spatial variation of macrogeometric shapes and internal characteristic parameters of a 3D reservoir using sedimentary petrology, reservoir geology, and geostatistics.

In reservoir research, the primary purpose of numerical simulation is to predict oil and gas production under different conditions. Reservoir simulation technology provides the flexibility to study oilfield production performance under specified production conditions. From a commercial point of view, the most important reason for using numerical simulation is its ability to forecast oil production and cash flow. It is easy to repeatedly calculate the development process of different favorable areas and different development methods so that the optimal favorable area and the best development method can be selected. A numerical simulation is based on the 3D geological model discussed in the previous paragraph. The uncertainty of the model and parameters needs to be noted in numerical simulation.

3. Evaluation of Productivity Potential

To achieve good development in a tight reservoir, well location layout is critical. For a new area, the wells should be arranged in a position with the best productivity potential. For infill wells, the wells should be arranged in the blank area with the best productivity potential. We have described the optimization method of an enrichment area and favorable area. It is not difficult to find that the existing methods need sufficient geological data and require engineers to have a

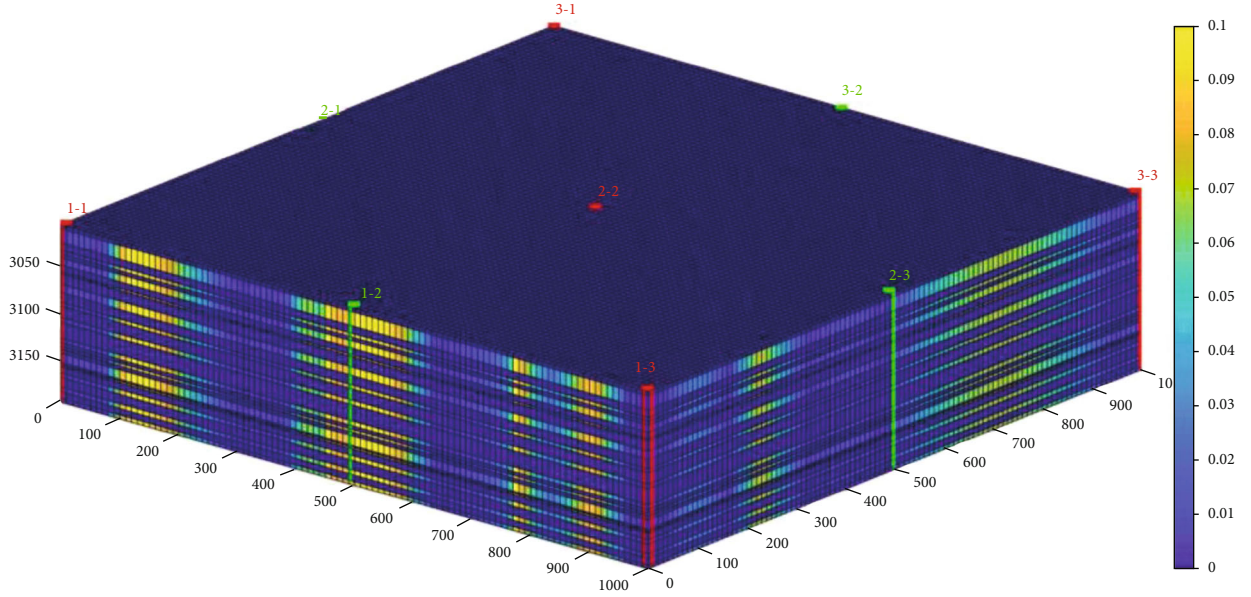
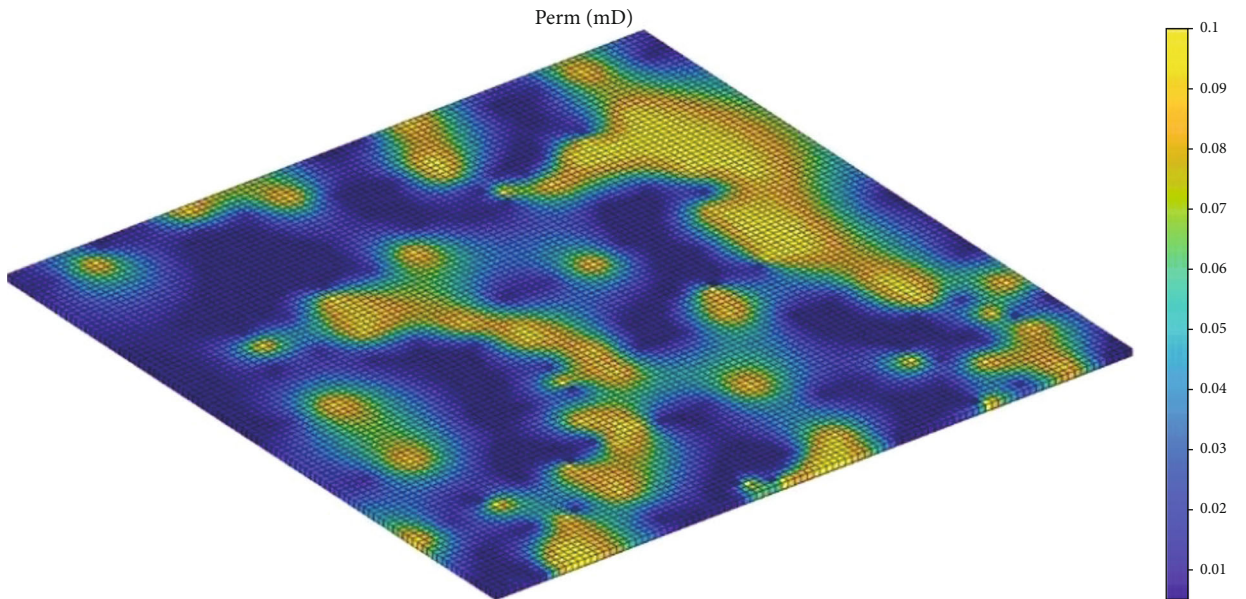


FIGURE 1: The model diagram of the reservoir.

FIGURE 2: Permeability distribution of the 14th layer.

geological background. In this study, we further improve and modify the method based on the previous concepts and equations of productivity potential.

Cruz et al. [27, 28] introduced the concept of a “quality map,” which is a two-dimensional representation of reservoir responses and their uncertainties. The “quality” for each position of a well is the cumulative oil production after an extended period of production. A well is placed in each cell of the reservoir, and then, the cumulative oil production over a certain period is calculated, or only the values of several cells are calculated. The total quality is the sum of the quality of all the wells, and the quality of the entire reservoir can be visualized spatially. In selecting well locations and well pat-

tern optimization, the quality of each cell is weighted to the nearest well according to the weight of distance from a well.

$$\begin{aligned}
 w_c &= \begin{cases} \frac{1}{a \cdot d_c^b}, & \text{for } d_c \geq 1, \\ 1, & \text{for } d_c = 0, \end{cases} \\
 Q_w &= \sum_{c=1}^{nc_w} Q_c \cdot w_c, \\
 Q_t &= \sum_{w=1}^{nw} Q_w,
 \end{aligned} \tag{1}$$

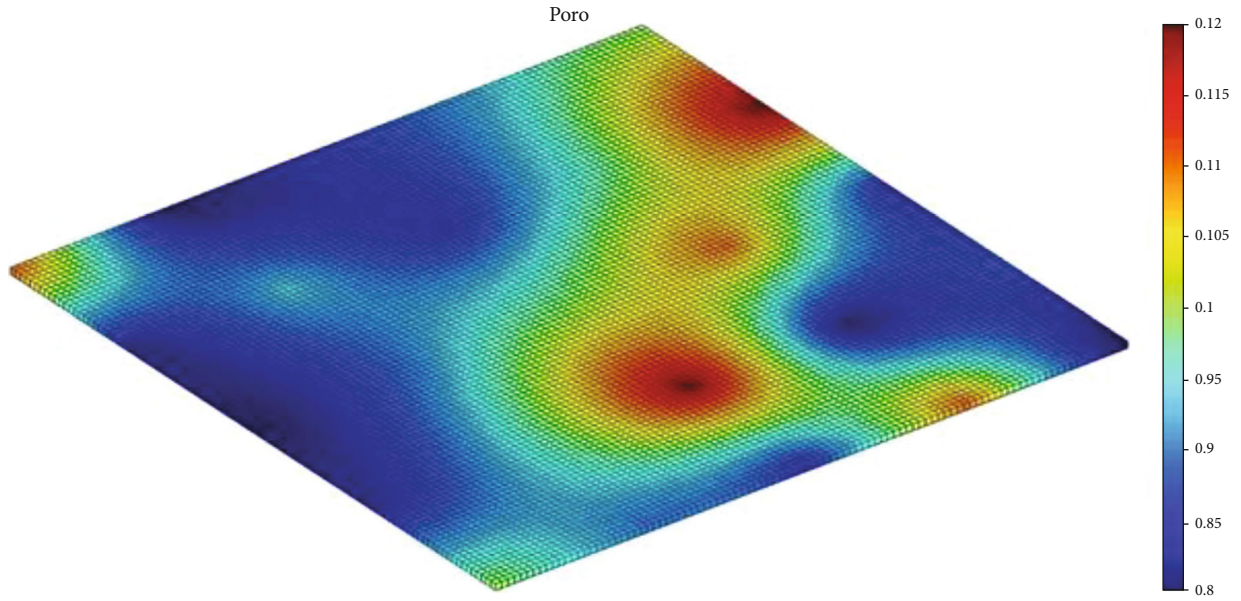


FIGURE 3: Porosity distribution of the 14th layer.

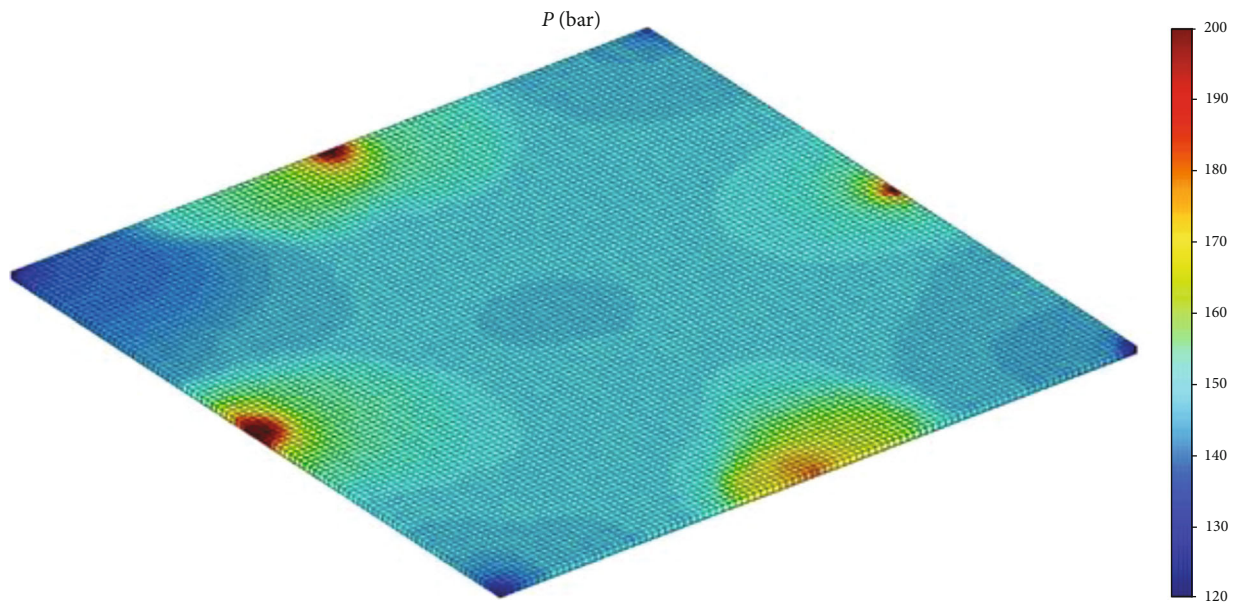


FIGURE 4: Pressure distribution of the 14th layer.

where Q_w is the quality of each well, Q_c is the quality of each cell, Q_t is the sum of all the well qualities, w_c is the quality of each cell based on the inverse distance weight, d_c is the distance from the cell c to the nearest well, nc_w is the number of cells allocated to a well w , and nw is the total number of wells.

Liu and Jalali [28] proposed an expression of productivity potential based on the material balance, the constraints of actual production conditions, and Darcy's law. Due to the substantial heterogeneity and the wide range of permeability values, the lognormal distribution is obeyed in a reservoir. Therefore, to prevent the permeability from dominating the

calculation results, the natural logarithm is typically taken. Similarly, to prevent the distance from the reservoir boundary from dominating the calculation result, the logarithm of the distance value should be taken.

$$J_{i,j,k}(t) = S_{o,i,j,k}(t) \cdot P_{o,i,j,k}(t) \cdot \ln K_{i,j,k} \cdot \ln r_{i,j,k}, \quad (2)$$

for $i = 1, n_x; j = 1, n_y; k = 1, n_z$.

where n_x , n_y , and n_z are the number of grid blocks in x -, y -, and z -direction. $J_{i,j,k}(t)$ is the productivity potential at grid block (i, j, k) at time t , $r_{i,j,k}(t)$ is the distance from the grid

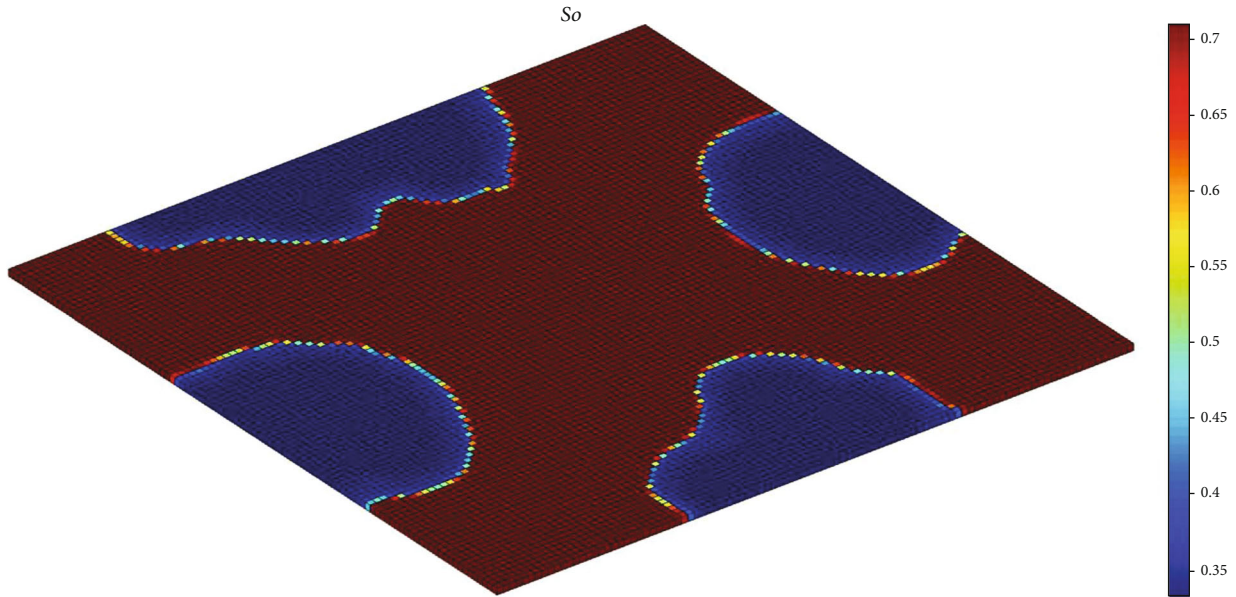


FIGURE 5: Oil saturation distribution of the 14th layer.

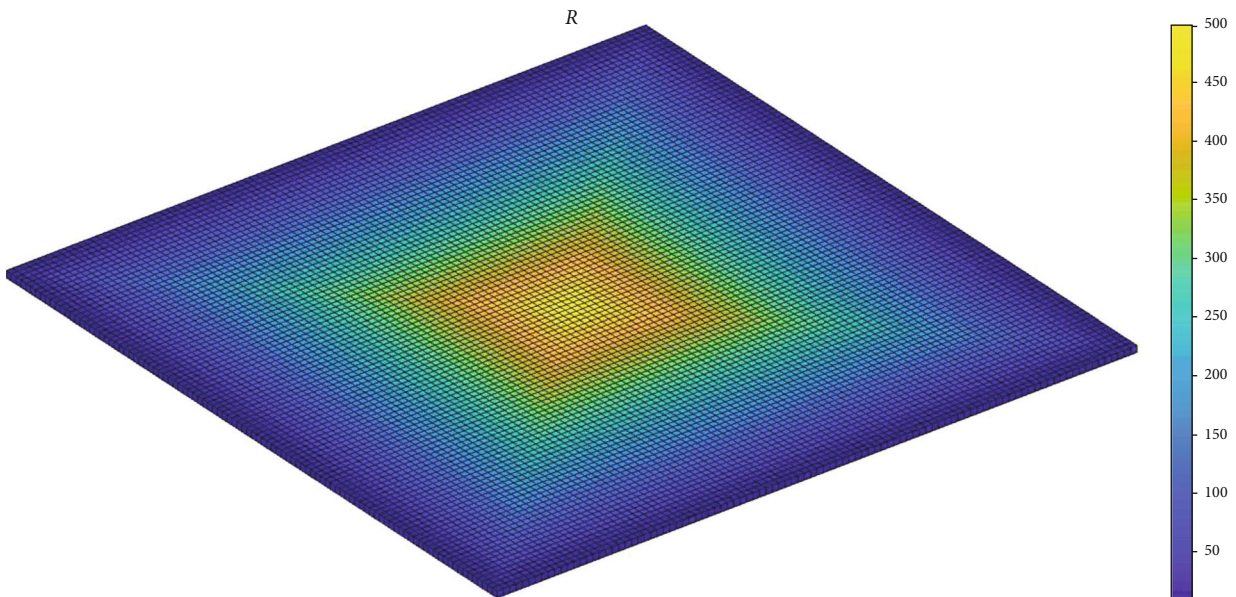


FIGURE 6: Distance data graph of the grid from the nearest boundary.

block (i, j, k) to the closest boundary. S_o is the oil saturation, P_o is the oil phase pressure, and K is the absolute permeability.

Well location optimization based on productivity potential refers to arranging wells at grid blocks with greater potential by continuously calculating the productivity potential of each grid block in the reservoir. The well location optimization process of productivity potential has the following steps: (1) The productivity potential of each grid block in a reservoir is calculated according to the productivity potential method. (2) The production wells are arranged according to the productivity potential from high to low, but the distance

between two wells cannot be too close; the initial well location optimization is completed. (3) After a period of production, the well density is increased according to the production history fitted by numerical simulation, and the productivity potential of each grid block in the reservoir is calculated again based on the numerical simulation results; wells are arranged according to the potential value. (4) This cycle continues until the number of production wells meets the production requirements, or the reservoir is abandoned.

Liu and Jalali [28] applied a well placement method based on productivity potential to two examples. The results showed that the high-permeability areas were still the priority area for

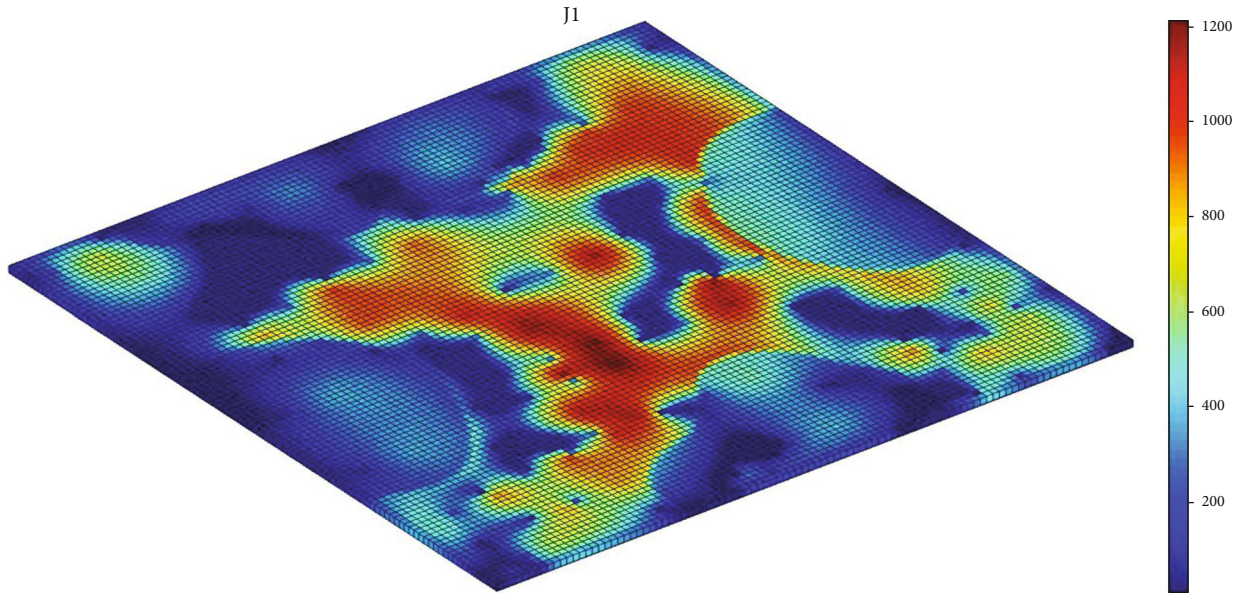


FIGURE 7: The productivity potential of the modified equation.

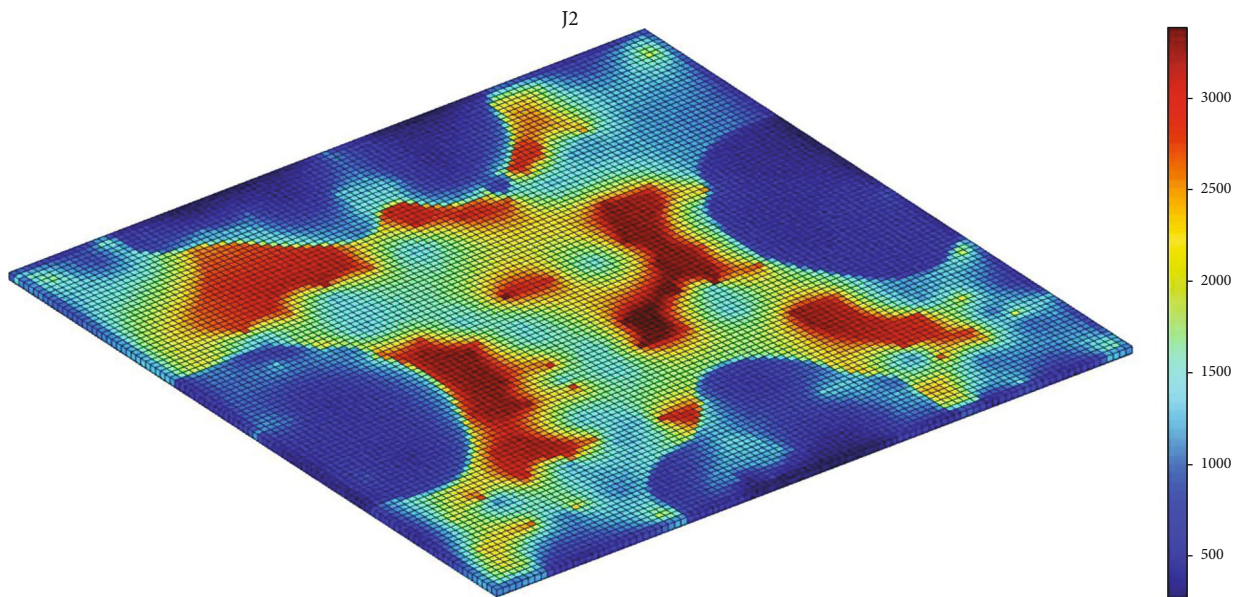


FIGURE 8: The productivity potential of the original equation.

well placement, even if the oil saturation of these areas was low. Based on the previous expression of productivity potential, two parameters, movable oil saturation and effective pore pressure, were considered. The productivity potential was obtained as follows:

$$J_{i,j,k}(t) = [S_{o,i,j,k}(t) - S_{or}] \cdot [P_{o,i,j,k}(t) - P_{min}] \cdot \ln K_{i,j,k} \cdot \ln r_{i,j,k}$$

for $i = 1, n_x; j = 1, n_y; k = 1, n_z$,

(3)

where S_{or} is the residual oil saturation and P_{min} is the minimum bottom hole pressure.

The porosity and effective thickness of a reservoir are critical factors affecting oil and gas enrichment, and these two parameters are also important for reserve abundance calculations. Therefore, they should also be an important part of reservoir productivity potential. However, previous research has not considered these two factors. Also, the threshold pressure gradient of a tight reservoir will also affect the ability of fluid to flow. In this study, the calculation of reservoir productivity potential has been modified.

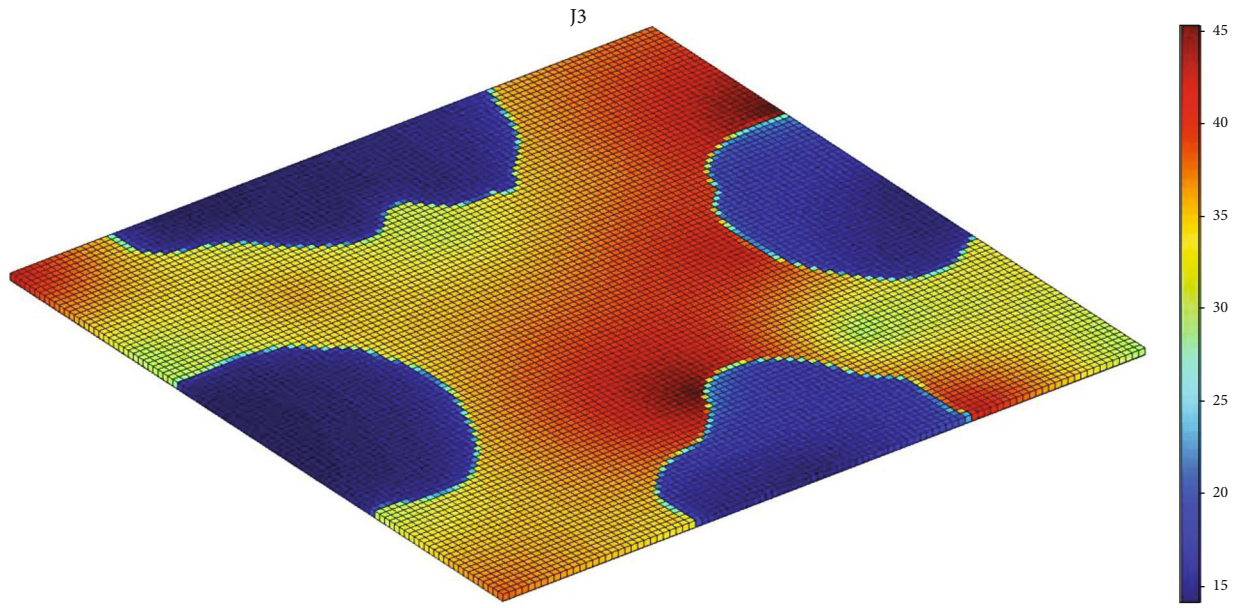


FIGURE 9: The reserve abundance of the 14th layer.

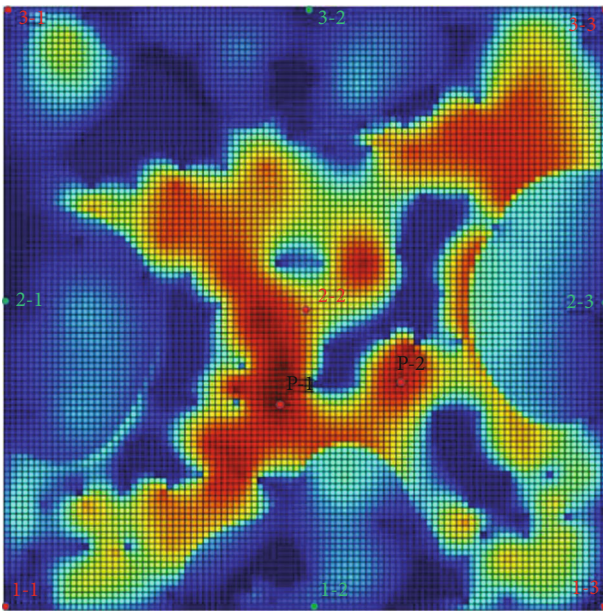


FIGURE 10: Schematic diagram of pattern infilling in scheme 1: red circle—production well; green circle—injection well.

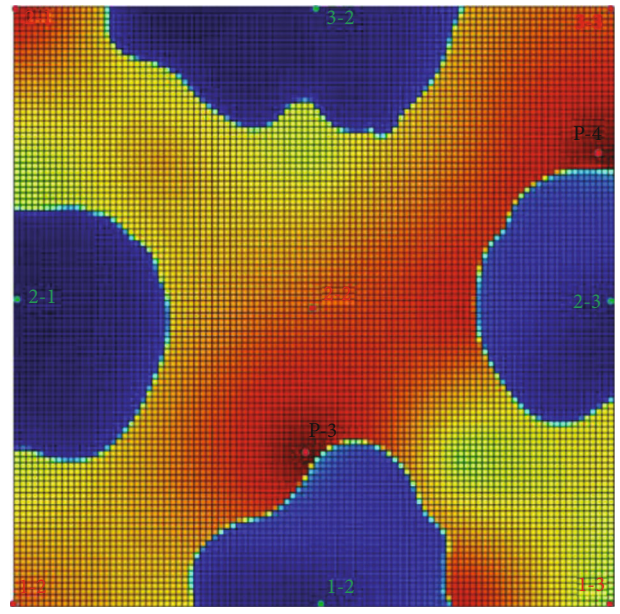


FIGURE 11: Schematic diagram of pattern infilling in scheme 2: red circle—production well; green circle—injection well.

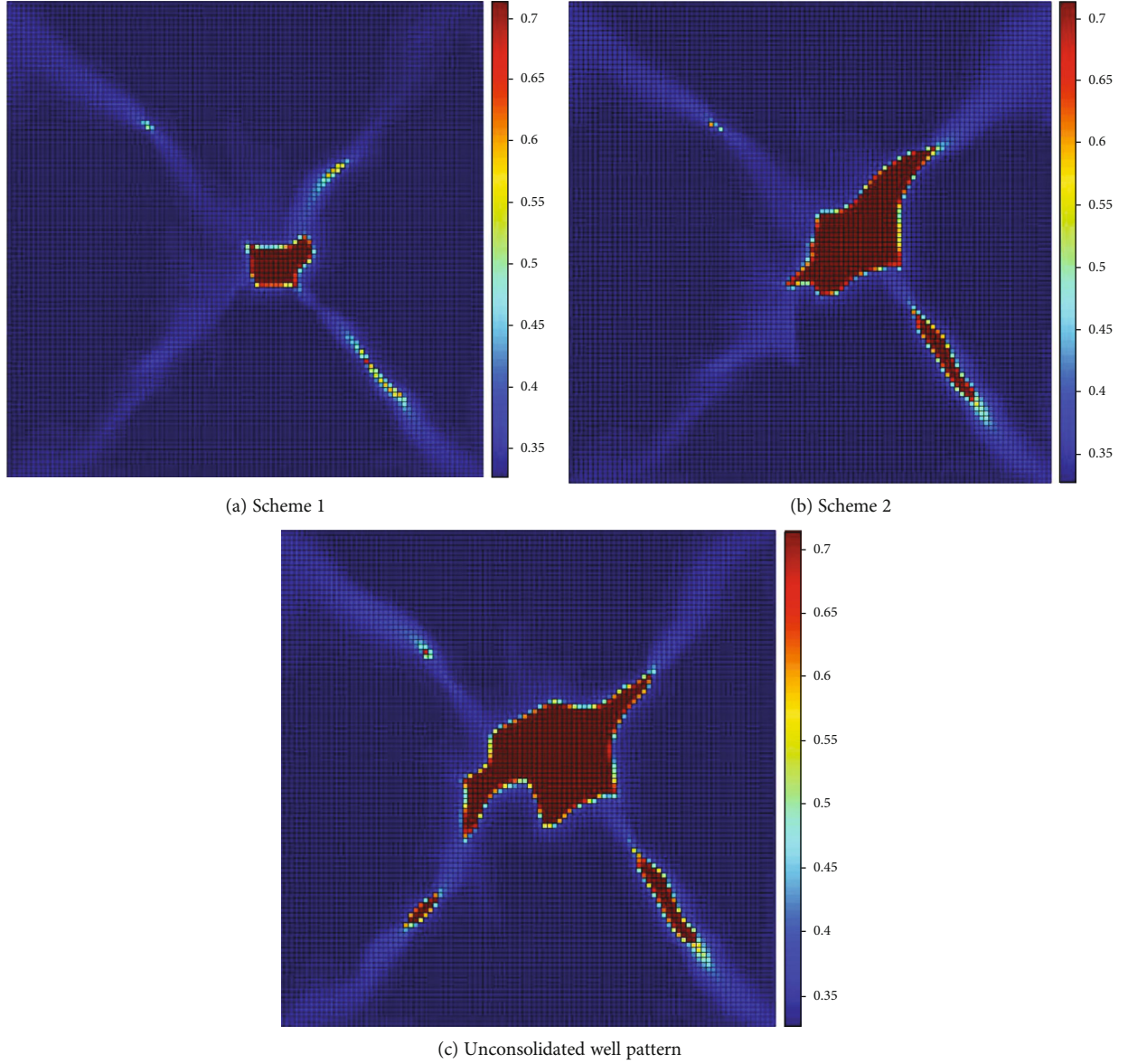


FIGURE 12: The remaining oil distribution after 20 years under different schemes.

Larger effective thickness and porosity can lead to increased oil and gas accumulation. The effective thickness and porosity are positively correlated with productivity potential, expressed as multipliers. The larger threshold pressure gradient results in a smaller corresponding fluid flow

capacity, negatively correlating with the productivity potential. The value distribution range of the threshold pressure gradient is variable. To avoid it becoming the dominant factor, the following calculation is obtained by taking the reciprocal of the threshold pressure gradient and natural logarithm.

$$J_{i,j,k}(t) = [S_{o,i,j,k}(t) - S_{or}] \cdot [P_{o,i,j,k}(t) - P_{min}] \cdot \ln r_{i,j,k} \cdot \varnothing_{i,j,k} \cdot h_{i,j,k} \cdot \ln \left(\frac{1}{G_{i,j,k}} \right),$$

$$G_{i,j,k} = 0.031 \left(\frac{K_{i,j,k}}{\mu} \right)^{-0.5592},$$

for $i = 1, n_x$; $j = 1, n_y$; $k = 1, n_z$,

(4)

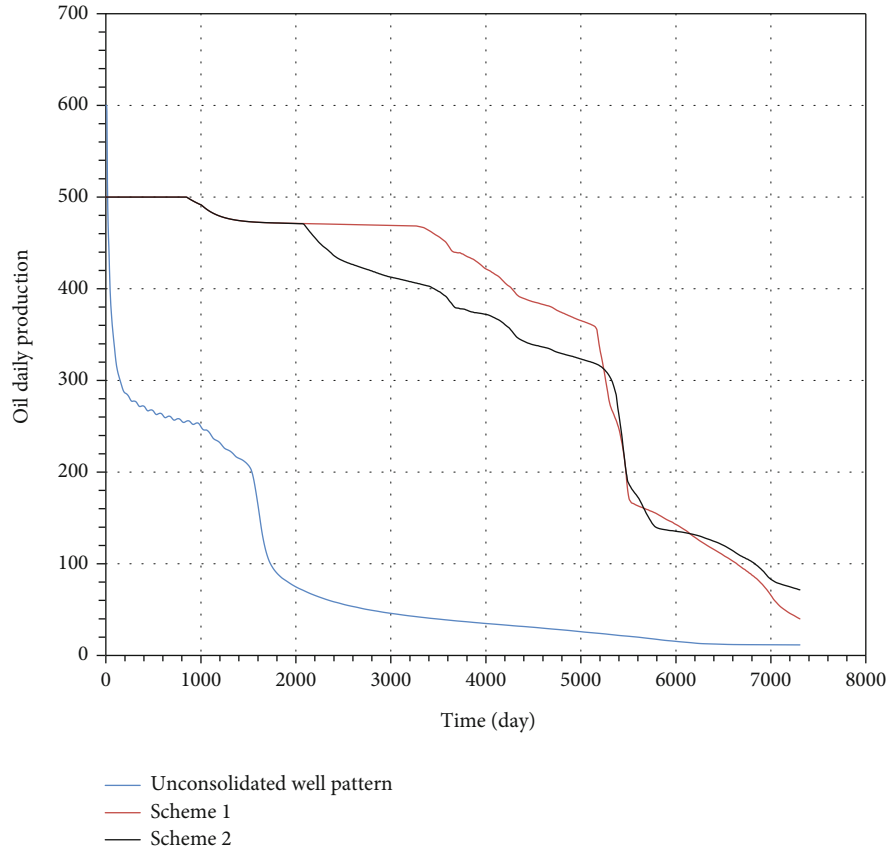


FIGURE 13: The relationship between production time and oil production.

where $\varnothing_{i,j,k}$ is the porosity at the grid block (i, j, k) , $h_{i,j,k}$ is the effective thickness at the grid block (i, j, k) , $G_{i,j,k}$ is the threshold pressure gradient at the grid block (i, j, k) , and μ is the fluid viscosity.

The modified equation comprehensively considers effective pore pressure, mobile oil saturation, porosity, permeability, effective thickness, threshold pressure gradient, and distance from a boundary on the productivity potential of a tight reservoir. It not only considers the dynamic seepage capacity of oil but also reflects the static reserve distribution of crude oil. In general, it can better reflect the development potential of different positions in a tight oil reservoir.

When the geological conditions are complex, the reservoir productivity potential method has a more guiding value for well location optimization and deployment in tight reservoirs. The reservoir productivity potential method can be applied to actual production and benefits from the development of stochastic reservoir modeling and numerical simulation software. Because of the development of multipoint geostatistics and the improvement of 3D seismic resolution technology, the reliability of fine geological modeling of a tight reservoir has greatly improved in recent years. Combined with geophysical logging, seismic inversion, drilling dynamic monitoring, and core analysis data, 3D fine geological models of tight reservoirs can be established based upon the sedimentary system and regional structure. Then, the

distribution of static parameters can be obtained. The 3D reservoir model is calibrated using various dynamic indexes such as water cut, oil production, bottom hole pressure, and production gas-oil ratio. Based on the geological model, the movable oil saturation and effective pore pressure of each grid block at different development periods can be obtained. In the process of well location deployment, the new modified equation can calculate the productivity potential of a tight reservoir, creating 3D distribution maps of the reservoir. The wells are arranged according to areas with high productivity potential. When the well pattern density needs to be increased after a period of production, the production history is fitted by numerical simulation software. The productivity potential of each grid block in the reservoir is calculated once again from the numerical simulation. The wells are arranged according to the productivity potential value. This cycle occurs until the amount of production wells meets the production requirements or the reservoir is abandoned.

4. Simulation and Discussion

To verify the feasibility of the modified productivity potential equation, a tight reservoir is taken as an example for calculation, and we also discuss the results with the original productivity potential method and reserve abundance calculation results. The reservoir is divided into 28 layers, where 14 are

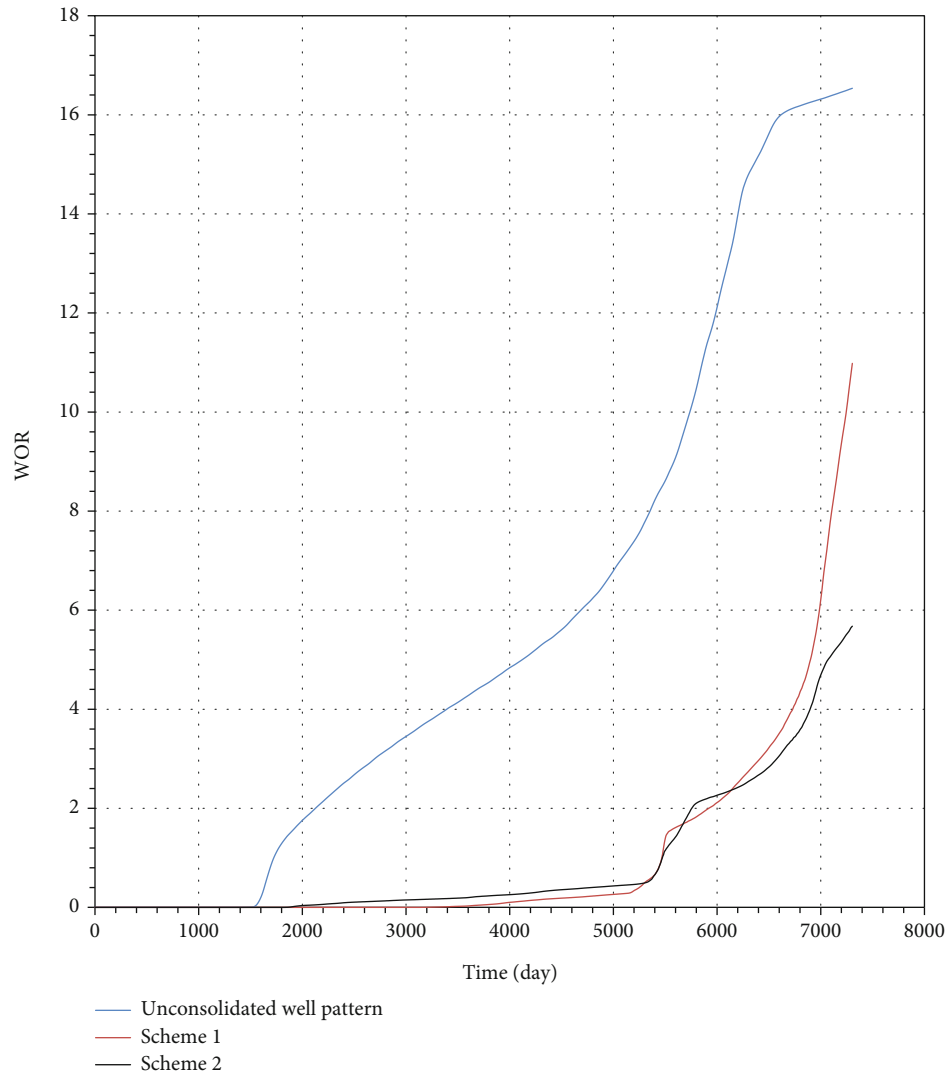


FIGURE 14: The relationship between production time and WOR.

production layers and the other 14 are interlayers. Each layer has 100×100 grids. The well pattern is a five-point vertical well pattern. Figure 1 is the diagram of the reservoir model.

The reservoir used for the simulation is the Shulu Depression in North China. The porosity of the main section is low, ranging from 0.20% to 3.40%, with an average of 1.34%. The distribution range is mainly between 0.5% and 2.5%. The permeability was $0.02 \times 10^{-3} \mu\text{m}^2$, the maximum was $3.80 \times 10^{-3} \mu\text{m}^2$, the average was $3.60 \times 10^{-3} \mu\text{m}^2$, and the distribution range was mainly between 0.04 and $3.28 \times 10^{-3} \mu\text{m}^2$.

Taking the 14th layer of the reservoir as an example, Figures 2 and 3 show the distribution of permeability and porosity. Figures 4 and 5 show the pressure and saturation map after 5 years of production, and Figure 6 shows the distance data map of each grid from the nearest boundary.

The minimum bottom hole pressure, crude oil density, residual oil saturation, and crude oil volume coefficient were input as 10 MPa, 0.85 t/m^3 , 0.3, and $1.2 \text{ m}^3/\text{m}^3$, respectively.

These data were used to calculate the productivity potential of the modified equation, the productivity potential of the original equation, and the reserve abundance of the reservoir. The calculation results are shown in Figures 7–9.

The permeability of a tight reservoir is usually less than $1 \times 10^{-3} \mu\text{m}^2$, and it becomes negative after the logarithmic permeability calculation. Also, permeability is negatively correlated with productivity potential, which is obviously inconsistent with conventional understanding. Consequently, applying the original productivity potential method to tight reservoir edges needs to be restricted. The reserve abundance calculation results are greatly affected by porosity. Because the influence of boundary factors and permeability is not considered, there are also locations with large productivity potential near the boundary and with low permeability values (Figure 9). The modified productivity potential method comprehensively considers more influencing factors. The calculation results show that the high-value locations satisfy the characteristics of high porosity, high mobile oil saturation, high effective pore pressure, low threshold

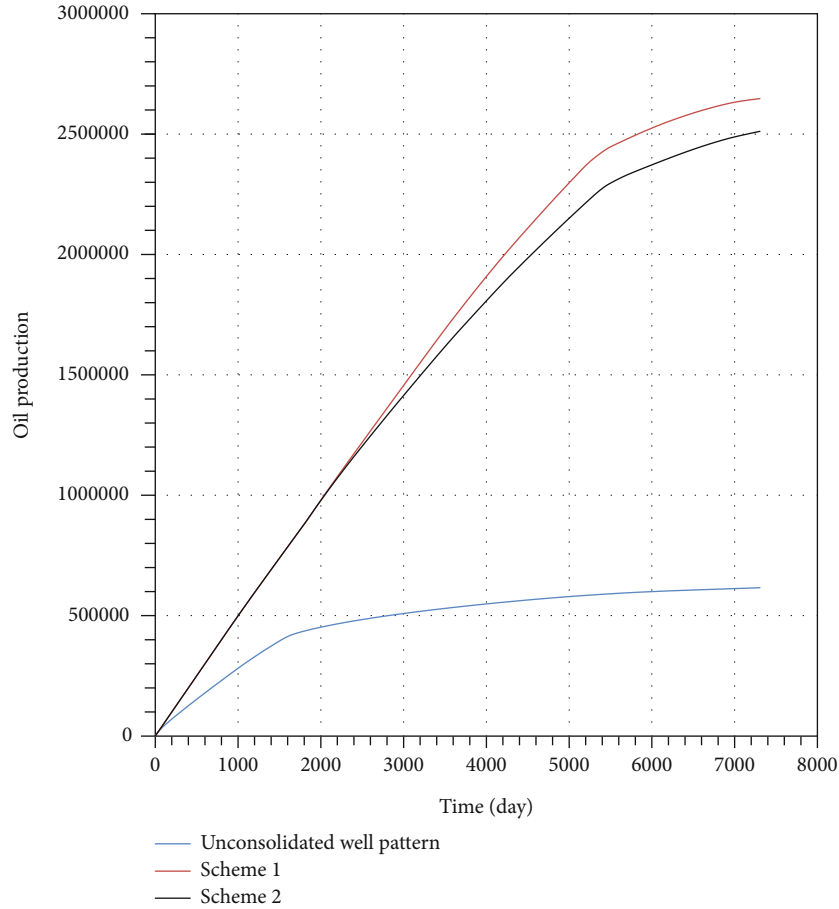


FIGURE 15: The relationship between production time and RF.

TABLE 1: Economic evaluation data.

Category	The total cost (million \$)	Gross price of crude oil (million \$)	Profits (million \$)	The profit margin
Unconsolidated well pattern	112.75	165.93	53.18	0.472
Scheme 1	246.92	699.01	452.08	1.831
Scheme 2	236.93	656.76	419.82	1.772

pressure gradient, and locations far from the reservoir boundary, which can reflect the development potential of different areas of a tight reservoir.

To verify the reliability of the modified productivity potential method, two schemes were used to encrypt the original well pattern, and the remaining oil distribution and the recovery rate are discussed.

Scheme 1. Select two grids with a high productivity potential value, add two production wells P-1 and P-2 (horizontal well), and maintain liquid production of $500 \text{ m}^3/\text{d}$ for 15 years (Figure 10), and the constant injection volume is $500 \text{ m}^3/\text{d}$.

Scheme 2. Select two grids with a high reserve abundance value, add two production wells P-3 and P-4 (horizontal well), and maintain liquid production of $500 \text{ m}^3/\text{d}$ for 15 years (Figure 11), and the constant injection volume is $500 \text{ m}^3/\text{d}$.

Figure 12 shows the remaining oil distribution of different schemes. The remaining oil distribution area is the smallest, and the dead oil area is the least in scheme 1. Figure 13 shows the relationship between production time and oil production. Figure 14 shows the relationship between production time and water-oil ratio (WOR), and Figure 15 shows the relationship between recovery factor (RF) and production time.

Tight oil development costs mainly include operating costs, depreciation costs of fixed assets, and period costs. The depreciation cost of the fixed assets is the highest, accounting for about half of the total cost, which is mainly caused by the higher development investment in the early stage. Second, the period cost accounted for nearly 30%. The lowest operating cost is 18%. In this paper, the fixed cost per well is \$27 million, the production cost per ton is \$73, and the oil price is set at \$307.86 per ton. The profit margins of

the three schemes are calculated as 1.831, 1.772, and 0.472 in the loose well network (Table 1).

5. Conclusions

- (1) Oil and gas enrichment areas and development of favorable areas should be optimized and screened before well location deployment. Determining areas that are favorable for development requires comprehensively considering geological, engineering, and economic factors
- (2) The favorable area optimization model prediction method involves analyzing influencing factors and model selection, while the combination of geological modeling and numerical simulation needs to consider the uncertainty of the input parameters
- (3) The modified productivity potential equation comprehensively considers the effects of effective pore pressure, mobile oil saturation, porosity, permeability, effective thickness, the distance from the boundary, and threshold pressure gradient. It can thus better reflect the development potential of different locations of tight oil reservoirs
- (4) Two new wells were arranged in favorable areas obtained by different productivity potential evaluation methods. The simulation results of these two wells showed that the profit margin of the two wells placed by the modified productivity potential method would be 1.831, which is higher than that of the original productivity potential method (1.772) and an unconsolidated well pattern (0.472).

Data Availability

The datasets used or analyzed during the current study are available from the corresponding author on reasonable request.

Additional Points

Highlights. (1) The influencing factors and analysis theory of the enrichment area were summarized, and two kinds of evaluation methods of the favorable area were explained. (2) This study modified the evaluation of productivity potential which comprehensively considers seven factors, and the calculated potential area was the priority area of well placement. (3) A tight reservoir was taken as an example for calculation, and the results among the three methods were discussed. *Code Availability.* The code used during the current study is available from the corresponding author on reasonable request.

Conflicts of Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper. We wish to draw the attention of the editor to the following facts

which may be considered potential conflicts of interest and to significant financial contributions to this work. We confirm that we have given due consideration to the protection of intellectual property associated with this work and that there are no impediments to publication, including the timing of publication, with respect to intellectual property. In so doing, we confirm that we have followed the regulations of our institutions concerning intellectual property. We understand that the corresponding author is the sole contact for the editorial process. He is responsible for communicating with the other authors about the progress, submissions of revisions, and final approval of proofs. We confirm that we have provided a current, correct email address which is accessible by the corresponding author and which has been configured to accept email from the journal.

Authors' Contributions

Fengpeng Lai contributed to the conceptualization, resources, methodology, and writing of the original draft. Li Zhiping was involved in the supervision and project administration. Kongjie Wang was responsible for the data curation. Hong Wang conducted the formal analysis, investigation, and validation. We confirm that the manuscript has been read and approved by all named authors and that there are no other persons who satisfied the criteria for authorship that are not listed. We further confirm that the order of authors listed in the manuscript has been approved by all of us.

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