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Three-Dimensional Geological Modeling Study of the Chang 6 Member in Block A Ordos Basin

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Abstract: Accurate characterization of three-dimensional heterogeneity in tight sandstone oil and gas reservoirs has become a critical research topic for enhancing recovery efficiency. Through core observations and thin-section identification techniques, the lithological characteristics, sedimentary facies distribution patterns, and physical property parameter distribution features of the Chang 6 member in Area A of the Ordos Basin were studied in detail. Utilizing prior research findings, a three-dimensional geological model of the reservoir in Area A was established. The results indicate that: the rock type of the Chang 6 member in Area A is feldspathic sandstone, and the sandbodies within the subaqueous distributary channels are well-developed, with large thickness, wide distribution, and relatively continuous sandbodies; the three-dimensional geological model of the Chang 6 member in Area A shows high consistency with the actual reservoir physical properties, accurately delineating the NE-SW-oriented continuous distribution pattern of subaqueous distributary channel sandbodies. The established three-dimensional geological model provides a robust foundation for reservoir numerical simulation.

Keywords: Reservoir characterization; 3D reservoir modeling; Numerical simulation.

1. Introduction

Tight Sandstone Oil Reservoir as globally widespread unconventional resources, have always faced severe technical challenges in efficient development. Under the global energy transition background, with the accelerated decline of recoverable conventional oil and gas reserves, such reservoirs have become a key area for alternative energy development [1]. Taking the Ordos Basin as an example, among the multiple oil-bearing series in this cratonic superimposed basin, the Triassic Yanchang Formation exhibits superior oil-bearing properties due to its unique continental clastic sedimentary system. This formation’s large-scale delta-front sedimentary body exhibits typical characteristics of "low porosity, low permeability, and strong heterogeneity," with its reservoir space controlled by complex diagenetic modification and microscopic pore structure evolution [2]. For such reservoirs, how to accurately characterize the three-dimensional heterogeneous patterns of reservoirs has become a critical research topic for enhancing recovery.

This study selects the Chang 6 member in Area A of the Ordos Basin as the research target. Through detailed core analysis and thin-section identification technology, and based on reservoir lithological characteristics, sedimentary facies distribution patterns, and physical property parameter distribution features, a three-dimensional geological model is constructed. It focuses on revealing the spatial distribution patterns of reservoir physical parameters and heterogeneous characteristics, providing high-precision geological model support for reservoir numerical simulation and development plan optimization, thereby establishing a reliable geological basis for the efficient development of low-permeability oil reservoirs in the Yanchang Formation of the Ordos Basin.

2. Geological Setting

The study area is located in the central-southern part of the Shaanbei Slope in the Ordos Basin, with a structural form of gentle west-dipping monocline, belonging to a typical lithologic reservoir[3]. The target layer, the Chang 6 member of the Yanchang Formation, serves as the main exploration and development layer series, exhibiting delta-front subfacies depositional characteristics, and develops microfacies such as subaqueous distributary channels, mouth bars, and sheet sands. The block has an oil-bearing area of 31.55 km², a reservoir burial depth of 1880 m, and an average effective thickness of 15.3 m. The reservoir physical properties demonstrate low porosity (11.2%) and low permeability (air permeability 1.08 mD), classifying it as an ultra-low permeability reservoir. Within this, the Chang 6_1^2 sub-member exhibits good sandbody continuity, with single-layer thickness reaching 8–12 m and a sand-to-shale ratio exceeding 75%. The current development well pattern adopts a 460×160 m diamond-shaped inverted nine-spot well pattern for deployment. All completed wells have undergone large-scale hydraulic fracturing, but during the natural energy development stage, the average daily oil production per well remains low, and the proportion of effective wells after waterflood development is also limited. There is an urgent need to conduct research on dynamic seepage mechanisms in the reservoir to improve development outcomes.

3. Reservoir Characteristics

3.1. Reservoir Petrological Characteristics

The clastic components are mainly quartz, feldspar, and rock debris, with average contents of 41.87%, 28.42%, and 11.57%, respectively. Additionally, they contain a certain amount of mica, with volume fractions ranging from 1% to 4% (average 2.68%). The rock debris is dominated by metamorphic and sedimentary rock fragments, with an average metamorphic rock fragment content of 5.0%. The matrix has an average content of 15.46% (Fig 1), primarily composed of clay minerals, carbonate cements, and siliceous material. The carbonate cements are mainly calcite and dolomite (Fig 2). According to X-ray diffraction analysis, the main clay minerals in the Chang 6 member reservoirs of the study area are chlorite, followed by kaolinite, illite, and illite-smectite mixed-layer minerals, with relative contents of 49.92%, 20.40%, 16.05%, and 13.63%, respectively. The grains are predominantly in point or point-line contact, with mainly pore-filling cementation and a grain-supported structure. The clastic particles are moderately sorted, and their roundness is primarily subangular to subrounded. Overall, these characteristics indicate that the target interval in the study area has medium structural maturity and low compositional maturity.

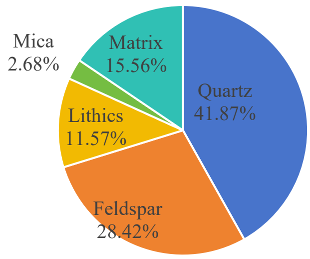

Figure 1. Proportion of detrital components of Chang 6 member in study area

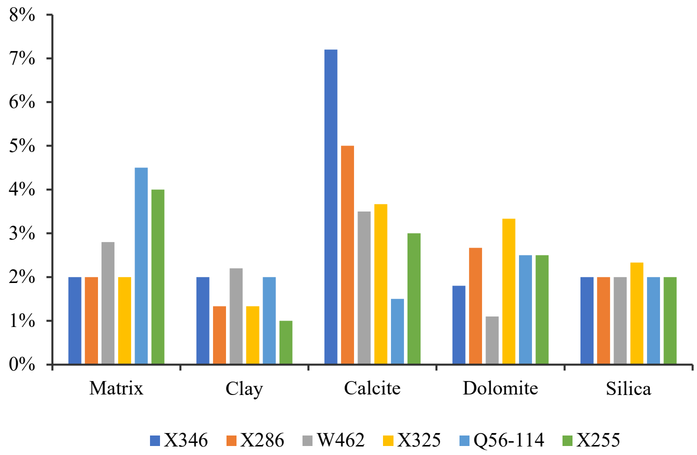

Figure 2. Histogram of Interstitial Material Composition of Chang 6 member in Study Area

3.2. Reservoir Sedimentary Microfacies and Sandbody Distribution Charact-eristics

Sedimentary microfacies have a certain controlling effect on the planar and spatial distribution characteristics of sandbodies. Based on an in-depth understanding of the regional sedimentary background and the geological characteristics of the study area, according to core observations, core facies and single-well facies analysis, combined with comprehensive information reflected by logging curves, it is considered that the sedimentary facies type of the Chang 6 member in the study area is the delta-front subfacies, with the subaqueous distributary channel microfacies being dominant; the sandbodies in the subaqueous distributary channels of the Chang 6 member are well-developed, with large thickness, wide distribution and relatively continuous sandbodies, and the average sandbody thickness is approximately 10 m (Fig 3).

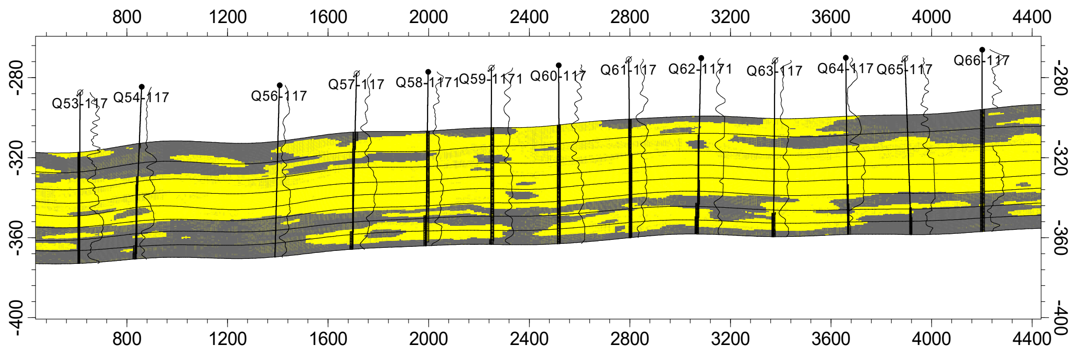

Figure 3. Modeled Cross-Section of Sandbody Thickness

3.3. Reservoir Physical Properties

Reservoir porosity and permeability are core parameters for evaluating hydrocarbon reservoir quality and development potential.[4] Porosity determines the storage capacity of the reservoir, while permeability controls fluid flow efficiency. Reservoir heterogeneity (e.g., sorting and connectivity of pore structures) and permeability anisotropy significantly impact development plan design and recovery factor prediction.The porosity of the Chang 6 member mainly ranges from 8% to 14%, with an average porosity of 10.7%, and permeability ranges from 0.05 to 1 mD, with an average permeability of 0.43 mD.

3.4. Reservoir Heterogeneity

Reservoir heterogeneity refers to the non-uniform spatial variations in lithology, physical properties, and oil-bearing characteristics of hydrocarbon reservoirs under the combined effects of sedimentation, diagenesis, and tectonic activity [5]. This heterogeneity, manifested through multi-scale differences (interlayer, planar, intralayer, and microscopic), directly constrains fluid flow patterns and displacement efficiency. Heterogeneity studies systematically reveal sandbody distribution patterns, flow barrier distributions, and dominant flow channel characteristics, thereby clarifying differences in oil-water migration pathways during waterflood development and providing critical geological basis for predicting remaining oil enrichment zones and optimizing development plans.

3.4.1. Intralayer Heterogeneity

The variation coefficient, breakthrough coefficient, and permeability contrast of reservoir permeability are used to characterize intralayer heterogeneity [6]. Based on formula calculations, the permeability variation coefficient of the Chang 6 member ranges from 0.5 to 1.1, and the breakthrough coefficient mainly ranges from 1.5 to 2. According to classification criteria, both indicate moderate heterogeneity. The permeability contrast of Chang 6 is generally less than 10, with some exceeding 10, indicating relatively weak heterogeneity in Chang 6 member. This conclusion aligns with the results from the permeability variation coefficient and breakthrough coefficient, both suggesting moderately weak heterogeneity.

3.4.2. Interlayer Heterogeneity

The Chang 6 member reservoirs in the study area exhibit typical tight sandstone characteristics, with lithology dominated by silt-fine-grained feldspathic sandstone and moderately to well-sorted clastic particles. Lithological assemblage differences control sedimentary microfacies differentiation, transitioning upward from coarse-grained feldspathic sandstone-dominated subaqueous distributary channel facies to mudstone-dominated interdistributary bay transitional facies. The overall interlayer lithological differences are reflected in variations of sedimentary microfacies, interlayer reservoir physical properties, and ultimately lead to differences in interlayer oil-bearing characteristics.

4. 3D Geological Modeling

The essence of 3D geological modeling is to use geostatistics and computer modeling techniques to construct a three-dimensional quantitative model reflecting the spatial heterogeneity of reservoir physical properties, with key parameters such as porosity, permeability, oil saturation, and reservoir thickness as objects, laying the foundation for subsequent reservoir numerical simulation and plan formulation[7][8]. This 3D geological modeling is based on Petrel software. On the basis of the structural model, the Sequential Indicator Simulation method was used to establish the sedimentary facies model. Variogram analysis was applied to determine the spatial correlation parameters of lithofacies, combined with sedimentary microfacies distribution patterns to constrain the simulation process. Under the principle of facies-controlled modeling, porosity and permeability log interpretation data and core analysis results were integrated, and the Sequential Gaussian Simulation algorithm was employed to construct the reservoir physical property parameter model. Geological research data were introduced as co-variables in the modeling process, and the Kriging interpolation technique combined with stochastic simulation was used to accurately characterize reservoir heterogeneity features.

4.1. 3D Structural Model

This study employs the planar contour constraint method and single-sandbody geological layering control method to establish a 3D structural model for the study area. The 3D structural modeling covers an area of 121.8 km², with the Triassic Yanchang Formation Chang 6 oil layer group as the main target interval, including eight sub-layers: Chang 6_1^{1-1}, Chang 6_1^{1-2}, Chang 6_1^{2-1-1}, Chang 6_1^{2-1-2}, Chang 6_1^{2-2-1}, Chang 6_1^{2-2-2}, Chang 6_1^{2-3-1}, and Chang 6_1^{2-3-2}.

First, based on stratigraphic layering data, the top and bottom surface models were established. The stacked surface models form the stratigraphic framework model, and the area between two adjacent surfaces constitutes the 3D simulation zone. A total of nine surfaces were built, spanning from the top of Chang 6_1^{1-1} to the bottom of Chang 612-3-2, corresponding to stratigraphic units Chang 6_1^{1-1}, Chang 6_1^{1-2}, Chang 6_1^{2-1-1}, Chang 6_1^{2-1-2}, Chang 6_1^{2-2-1}, Chang 6_1^{2-2-2}, Chang 6_1^{2-3-1}, and Chang 6_1^{2-3-2}. Subsequently, based on the surface models, the stratigraphic framework was discretized into 3D grids. The constructed structural model lays the foundation for subsequent sandbody distribution studies, reservoir property modeling, and numerical reservoir simulation.

The study area has minimal fault development, with gentle structural morphology characterized by higher elevations in the east and lower in the west. Under the combined effects of the Indosinian, Yanshanian, and Himalayan tectonic stress fields on the central Shaanbei Slope, near N-S oriented compression and compressional-shear stress effects dominate, resulting in a series of nearly E-W extending and regularly arranged nose-shaped folds in the sedimentary cover. Locally developed low-amplitude nose-shaped uplifts exhibit good vertical inheritance, with uplift amplitudes generally less than 10 m. The long-axis portions of these nose-shaped uplifts trend approximately E-W (Fig 4).

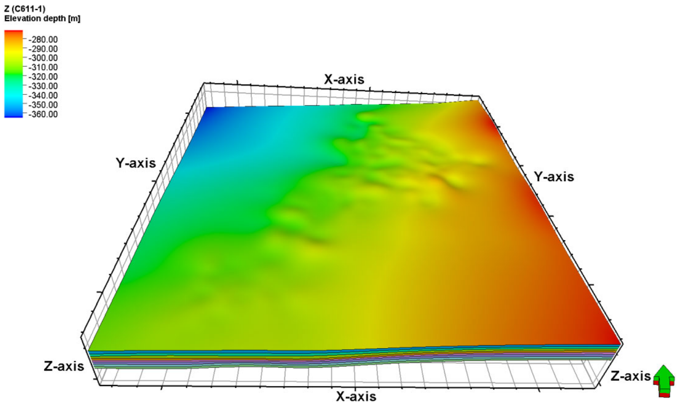

Figure 4. 3D Structural Model of the Chang 6 Member

4.2. Property Model

This study adopts the facies-controlled stochastic parameter field modeling method. Firstly, a lithofacies boundary constraint model is established based on the planar distribution map of sedimentary microfacies to reduce the uncertainty in predicting reservoir heterogeneity. On this basis, the sandbody distribution is realized through Sequential Indicator Simulation, which is suitable for discrete variables and can effectively characterize the geometric morphology and spatial stacking relationships of sandbodies. For reservoir physical property parameters, Sequential Gaussian Simulation is employed, utilizing variograms to represent the spatial correlation of continuous variables, and generating parameter fields that conform to geostatistical characteristics under facies-controlled conditions. Through a two-step modeling strategy, this method ensures spatial consistency between the lithofacies model and the physical property parameter model, significantly enhancing reservoir characterization accuracy.

4.2.1. Lithofacies Model

The lithofacies model was established using secondary log interpretation results and sand-to-shale ratio data, which not only conforms to geological principles but also controls the construction of the physical property model. For the study area, secondary log interpretation data and sand-to-shale ratio contour maps were loaded, the lithofacies data were upscaled, and the lithofacies model was constrained using the sand-to-shale ratio.

The vertical and lateral distribution of sandbodies and the determination of the variogram direction for sandstone layers were analyzed using variograms, thereby better aligning with geological principles. After calculating the aforementioned parameters, lithofacies models were established for the Chang 6_1^{1-1}, Chang 6_1^{1-2}, Chang 6_1^{2-1-1}, Chang 6_1^{2-1-2}, Chang 6_1^{2-2-1}, Chang 6_1^{2-2-2}, Chang 6_1^{2-3-1}, and Chang 6_1^{2-3-2} layers in the study area. In the study area, the Chang 6_1^{1-1} layer exhibits low sandstone content overall, trending NE-SW, while the Chang 6_1^{2-1} and Chang 6_1^{2-2} layers are extensively developed as the main reservoir intervals (Fig 5).

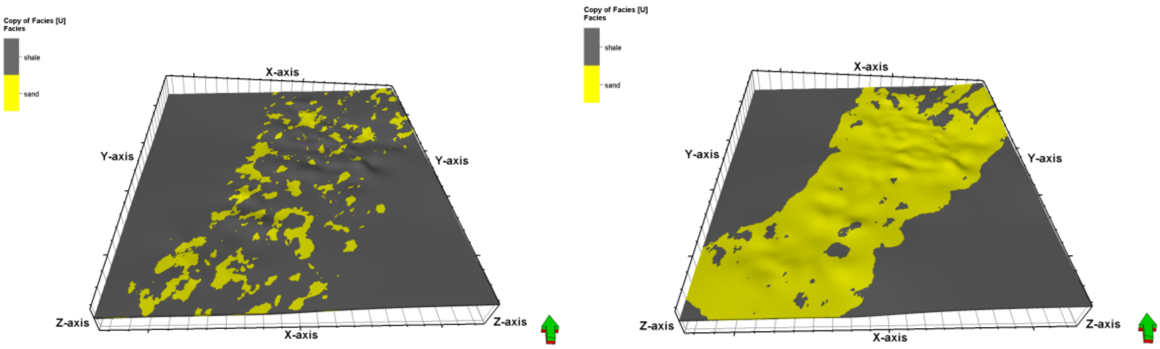

Figure 5. Chang 6_1^{1-1} and Chang 6_1^{2-1-2} Lithofacies model of target layers

4.2.2. Physical Property Model

Based on the reservoir spatial variability characteristics determined by variogram analysis, the Sequential Gaussian Simulation algorithm was employed to construct a 3D reservoir physical property model [9][10]. First, parameters such as porosity and permeability underwent normal score transformation to meet the Gaussian distribution assumption, with regionalized variable weights set under the constraints of the lithofacies model combined with planar sedimentary facies distribution trends. The spatial correlations of physical property parameters within each facies zone were characterized using variograms. The Kriging interpolation technique generated the initial field, followed by iterative optimization through sequential sampling to achieve conditional simulation. For the permeability model, the geometric averaging method was specifically introduced to upscale well data, enhancing the spatial continuity of high-permeability streaks in the main zones. The water saturation model, constrained by porosity, utilized probability field fusion technology to ensure spatial consistency between lithofacies boundaries and physical property fields in the 3D model.

The porosity model, using the lithofacies model as the facies-controlled basis, focused on sandstone intervals where the Sequential Gaussian Simulation algorithm generated the

3D porosity attribute model, while mudstone intervals were assigned fixed values. The median porosity of the model is 11.2% (Fig 6). The permeability model differentiated sandstone and mudstone facies, constrained by the porosity model, and used the Sequential Gaussian Simulation algorithm to generate the 3D permeability attribute model, with a median permeability of 0.84 mD (Fig 7). The water saturation model differentiated sandstone and mudstone facies, constrained by the initial oil saturation map and well testing results, and applied the Sequential Gaussian Simulation algorithm to generate the oil saturation model, with a median oil saturation of 52% (Fig 8).

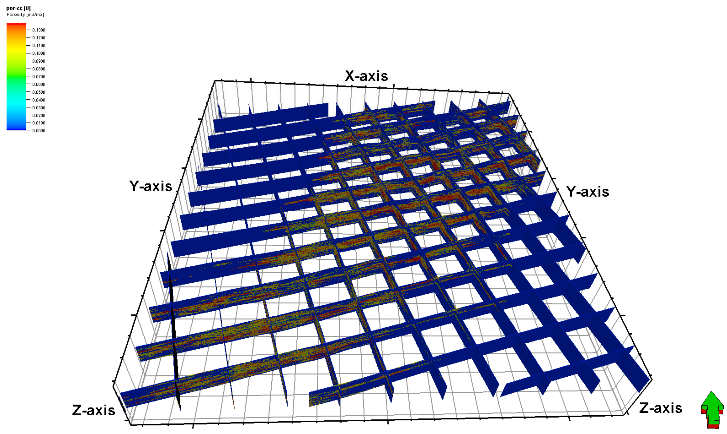

Figure 6. 3D Porosity Fence Diagram

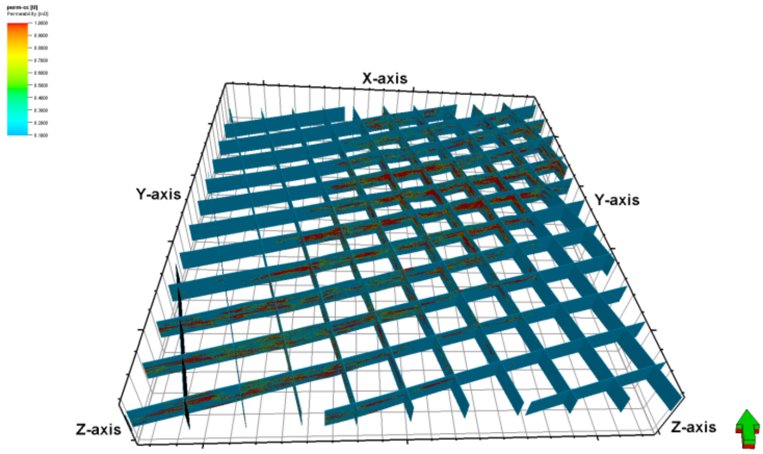

Figure 7. 3D Permeability Fence Diagram

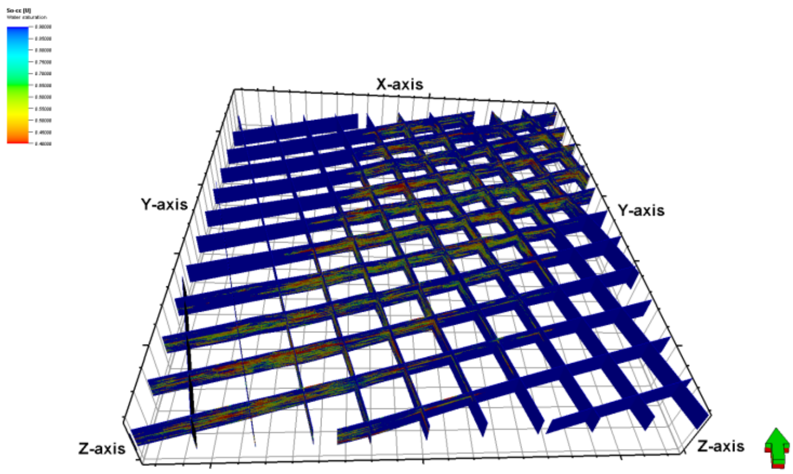

Figure 8. 3D Oil Saturation Fence Diagram

4.3. Model Validation

The 3D reservoir model was established using facies-controlled stochastic modeling methods based on stratigraphic depositional characteristics, sandbody distribution patterns, and spatial distribution features of reservoir physical properties. The Sequential Gaussian Simulation algorithm was applied to generate porosity and permeability parameter fields, with variograms introduced to characterize reservoir heterogeneity. During model iteration and optimization, sedimentary microfacies boundaries constrained the spatial configuration of sandbodies, and permeability anisotropy parameters were adjusted in combination with paleocurrent directions, ensuring simulation results aligned with geological understanding.

The simulation results were systematically compared with original well-log data from the study area. Statistical analysis shows that the average absolute error between simulated and measured porosity values is 3.2%, the root mean square error of log-transformed permeability is 0.23, and water saturation differences mainly fall within ±4%. Overall error levels are below 5%. Particularly in the main sandbody development intervals, simulated curves and well-log curves exhibit high consistency in vertical variation trends, cyclicity features, and thin-bed responses, with correlation coefficients exceeding 0.89 (Fig9). This agreement demonstrates that the model effectively integrates sandbody spatial configuration patterns constrained by sedimentary microfacies, heterogeneity characteristics represented by variograms, and lithology-physical property relationships, accurately reproducing the distribution patterns of high-porosity-permeability zones in delta-front subaqueous distributary channels. Errors primarily originate from vertical resolution limitations of thin interbeds (<0.5 m) and localized heterogeneity characterization of muddy interlayers. However, the prediction accuracy of key reservoir parameters already meets requirements for geology-engineering integration applications, validating the reliability of the facies-controlled modeling strategy.

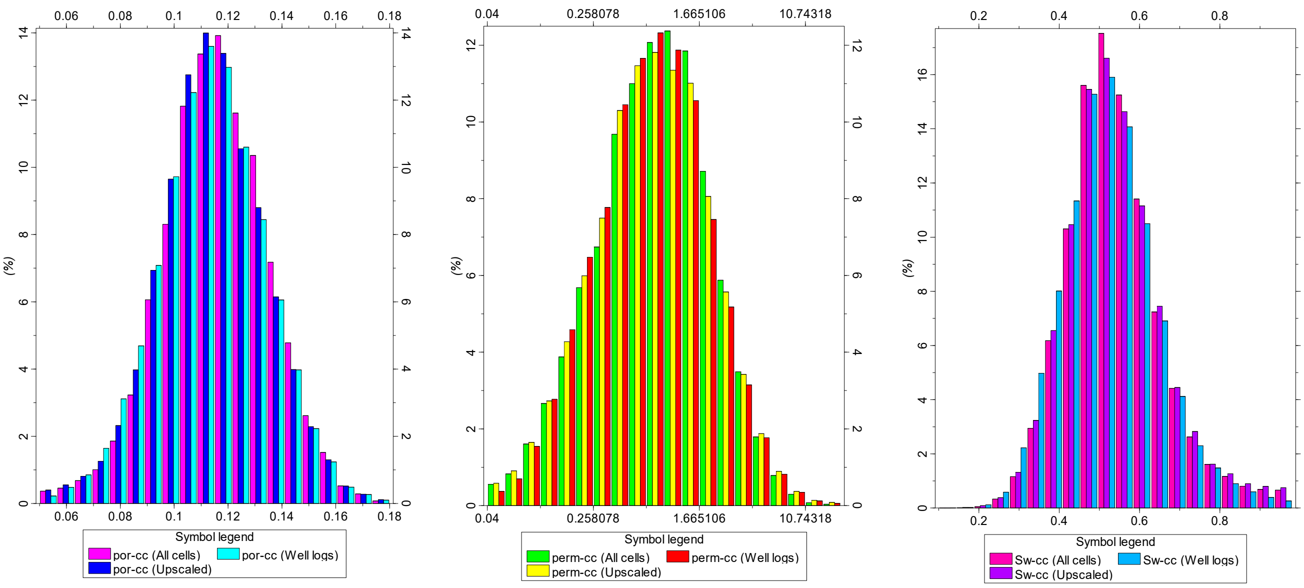

Figure 9. Comparison between simulation results and logginginterpretation results of physical property parameters in the target layer

5. Conclusion

(1) The rock type of the Chang 6 member in Area A is feldspathic sandstone, with grains predominantly in point or point-line contact. The cementation is mainly pore-filling type with a grain-supported structure. The sandstone exhibits moderate structural maturity and low compositional maturity. The sandbodies within the subaqueous distributary channels of the Chang 6 member are well-developed, characterized by large thickness (average approximately 10 meters), wide distribution, and relatively continuous sandbody geometry.

(2) The 3D geological model of the Chang 6 member in Area A, constructed using the facies-controlled stochastic modeling method based on comprehensive geological research, exhibits high consistency with the actual reservoir physical properties. The model precisely delineates the NE-SW-oriented continuous distribution pattern of subaqueous distributary channel sandbodies and reveals gradual variation patterns of porosity and permeability between vertical cyclicity and planar facies zones.

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