Three-dimensional in-situ stress modeling of tight conglomerate reservoirs: A case study of Triassic Baikouquan formation in the Mahu depression, Xinjiang Oilfield

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Abstract. As a tight conglomerate reservoir, the Baikouquan formation reservoir in the Mahu depression is vital heterogeneous. The development model of unconventional oil and gas fields such as shale gas is copied in the early development process. Advanced horizontal wells and volumetric fracturing technologies are adopted, with high development costs and low economic benefits. During the development of tight conglomerate reservoirs, there are typical problems such as underdeveloped natural fractures, complex fracture formation mechanisms during fracturing, and serious interlayer channeling in fractured wells. Practical results show that the adequate characterization of in-situ stress distribution plays a decisive role in the scientific and efficient development of tight conglomerate reservoirs. To accurately characterize the three-dimensional in-situ stress distribution law of conglomerate reservoirs, the paper selects the Mahu 131 demonstration well area. The mechanical parameters of the demonstration area are finely described through a series of core tests, well-drilled logging data, and seismic inversion data. As a result, the spatial distribution of essential parameters of the demonstration area has been established, such as the three-dimensional elastic modulus attribute volume and the three-dimensional Poisson's ratio attribute volume. Further, an advanced finite element simulator and large-scale parallel computing technology establish the test area's high-precision three-dimensional stress field model. Based on enormous fracturing data, microseismic data, and production data, quality control and correction of the three-dimensional stress field model are carried out. The results show that the established geomechanical model accurately reflects the direction, magnitude, and heterogeneity of the in-situ stress in the demonstration area. Through the three-dimensional minimum in-situ stress distribution, the three-dimensional horizontal stress difference distribution, the lithology characteristics of conglomerate, rock mechanical properties, and other factors in the test area, it
is believed that the difference in interlayer stress is the main reason for the interlayer channeling of fracturing. According to the established high-precision in-situ stress model and the rational fracturing construction process, it can actively strengthen or weaken the instantaneous and local stress field and pressure field, from near field to far-field, and promote the expansion of hydraulic fractures in the desired manner.

1. Introduction
The buried depth of the Triassic Baikouquan formation in the Mahu depression ranges from 2,500 m to 4,000 m; its deposition thickness is between 110 m and 140 m. The oil layer is divided into three sections vertically, including the Baisan section (T1b3), the Baier section (T1b2), and the Baiyi Section (T1b1). The performances of the reservoir show low-porosity, low-permeability, and ultra-low permeability. The reservoir in Mahu 131 well area is strongly heterogeneous, with undeveloped bedding fractures/natural fractures, few brittle minerals, and partial plasticity. The oil phase tracer is used to reflect the production of oil layers in different horizontal sections. Two horizontal wells in the demonstration area are selected to inject oily tracers, and then oily tracers are sampled and analyzed in adjacent wells. The analysis results of samples confirm that both the Baisan layer and Baier layer have extensive interlayer channeling. Fractured wells in the Mahu 131 well block are generally uneconomical, and the low development efficiency severely restricts the large-scale production of Mahu reservoirs.

The in-situ stress of the rocks and fluids of the reservoir is key to studying drilling and completion problems. Therefore, it is hoped that establishing a fair in-situ stress distribution of the Baikouquan formation in the Mahu depression. The traditional 3D in-situ stress modeling method calculates the in-situ stress data of a single well based on the logging data. It then uses the interpolation algorithm to form the entire oilfield stress field. However, this method cannot reflect the impact of formation heterogeneity and formation dip on in-situ stress distribution. Moreover, others have successfully used the finite element stress analysis method to simulate the three-dimensional stress field study area[1-4]. However, the finite element analysis software package alone cannot build a detailed 3D geological model that can reflect the heterogeneity of the reservoir. Liu et al. developed a series of algorithms to realize the two-way conversion between the Petrel software platform and the ANSYS software platform. Firstly, the Petrel software platform establishes the 3D heterogeneous geological model of the target area, and then the 3D geological model is imported into the ANSYS software platform. The finite element method simulates 3D in-situ stress in the target area[5]. At present, mainstream geological modeling software, such as Petrel and Jewel Suite, has been developed relatively maturely. In addition to completing traditional 3D geological modeling, new geomechanical modules are also embedded to complete the fine 3D geomechanical modeling.

The work uses the horizontal well fracturing microseismic waves in the demonstration area to determine the horizontal principal stress direction of the Baikouquan formation in the Mahu depression. The demonstration area is located southeast of the Ma 131 well fault block. It is a south-dip monoclinic with a dip angle of 4.0°. The burial depth ranges from 3010 m to 3130 m, and the top elevation of T1b3 ranges from 2550 m to 2670 m. Besides, hydraulic fracturing and fluid injection diagnostic tests are used to determine vertical changes of in-situ stress. Under the constraints of logging interpretation and mechanical experiments, the spatial distribution of mechanical
parameters is obtained. Based on the Mohr-Coulomb elastoplastic criterion, the three-dimensional principal stress distribution of the demonstration area is predicted by the finite element method. The horizontal stress difference distribution of the demonstration area is calculated. According to the established high-precision in-situ stress model, rationally fracturing techniques can scientifically guide the fracturing construction of tight conglomerate reservoirs in the demonstration area and promote the expansion of hydraulic fractures in the desired manner.

2. Mechanical characteristics of a tight conglomerate reservoir
Aiming at the reservoir core of drilled wells in the Ma131 well area, uniaxial, triaxial, and tensile strength tests are carried out. In this study, 39 cores are prepared for uniaxial and triaxial tests, and 13 cores are used for tensile strength tests, including glutenite and mudstone cores. The core depth is between 3062 m and 3070 m. Experimental results show that the uniaxial compressive strength of the core is between 20 MPa and 60 MPa, and most of them are between 30 MPa and 60 MPa. The compressive strength of the core increases under confining pressure. When the rock is subjected to confining pressure between 10 MPa and 30MPa its compressive strength is above 100MPa. Under uniaxial conditions, the modulus of elasticity ranges from 10 GPa to 15 GPa, and the Poisson's ratio is between 0.20 and 0.25. Under the condition of confining pressure, the Baikouquan formation has an average Young's modulus of 21 GPa and a Poisson's ratio of 0.21, belonging to a moderately soft formation. The tensile strength of glutenite is between 2.5MPa and 5 MPa, and the average tensile strength of mudstone is 3.4 MPa. Compared to the uniaxial compressive strength data, it is found that the uniaxial compressive strength is about 13 times the tensile strength. According to the Mohr-Coulomb criterion\[6]\, the cohesive force of glutenite ranges from 8 MPa to 11 MPa. The internal friction angle of glutenite is mostly around 45°. Therefore, the shear failure resistance of glutenite is insufficient. The cohesive force of brown mudstone is greater than 20 MPa, and its friction angle is between 31° and 36°.

3. The magnitude and direction of in-situ stress
This work uses various techniques to monitor the actual magnitude and direction of the in-situ stress in the demonstration area and obtain as much real data as possible to constrain the stress results of the model regression. The fluid injection diagnostic test (DFIT) data and hydraulic fracturing data are used to determine the vertical change of the in-situ stress. In addition, microseismic technology is used to determine the direction of in-situ stress in the demonstration area.

3.1. The fluid injection diagnostic test
The fluid injection diagnostic test (DFIT) injects a small amount of fracturing fluid and monitors the wellhead pressure. This is used to calculate the required parameters before the main fracturing and provide a sufficient basis for the construction and production process. Two wells, including well Ma1245 and well Ma1252, are tested.

3.2. Fracture closure pressure during fracturing
Fracture closure pressure is the minimum horizontal principal stress, equal to the minimum bottom hole pressure to keep an existing fracture open. The statistics of the multi-stage fracturing operation curves of 12 horizontal wells, including the well Ma1241 to well Ma1252 in the demonstration area,
204 credible minimum in-situ stress data are obtained.

3.3. Microseismic

Microseismic monitoring technology is often used in the fracturing engineering of low-permeability oil and gas reservoirs. This technology uses a demodulator in adjacent wells to monitor the microseismic waves induced by fractured wells. The microseismic waves can describe the geometry and spatial distribution of fracture growth during the fracturing process. By using microseismic technology, the occurrence and development of fractures during hydraulic fracturing of 12 horizontal wells, including well Ma1241 to well Ma1252 in the demonstration area, are evaluated. Based on the horizontal well fracture monitoring, the orientation of the major fractures in the demonstration area is between N90°E and N120°E.

4. 3D (Three-dimensional) in-situ stress modeling

4.1. Modeling flowchart

The entire modeling flowchart is shown in Fig 1. First, the structural plane of the study area is obtained based on seismic data and log data. A geological model that can truly reflect the structural changes is generated. Then, Three-dimensional elastic modulus, three-dimensional Poisson's ratio, and other three-dimensional heterogeneous material properties are established by a series of empirical formulae. Moreover, a three-dimensional pore pressure model is also established. Furthermore, the three-dimensional in-situ stress distribution is calculated by a heterogeneous-pore-elastoplastic geomechanical model. A small number of measured values are used to control the three-dimensional in-situ stress numerical simulation results.

Fig 1. Work flow chart of 3D in-situ stress modeling

4.2. Finite element mesh
The finite element method divides the solution space into finite elements, and the displacement on the element node represents the displacement within the element. The work is based on the Petrel software platform. It is easy to generate a high-quality hexahedral finite element grid for the reservoir by gridding the structural plane horizontally and vertically. The general finite element method requires the aspect ratio of the model to be as close as possible to 1. The upper, lower, and side lengths of the built reservoir model are supplemented. The basic principles are fine reservoir grids and coarse non-reservoir grids. The vertical grid of the reservoir is fine, the horizontal grid of the reservoir is coarse. The model uses 404×310×115 nodes and is subdivided into approximately 15 million grids.

4.3. 3D geomechanical model

4.3.1. 3D attribute volume model

Three-dimensional longitudinal wave velocity is obtained by interpolating the model's driven-wells longitudinal wave velocity (VP). First, the three-dimensional seismic layer velocity is used to constrain the interpolation results. Then, a series of empirical formulas establish three-dimensional elastic modulus, three-dimensional Poisson's ratio, and other three-dimensional heterogeneous material properties. 3D Young's modulus is between 7.17 GPa and 21.36 GPa, with a median value of 15.46 GPa. 3D Poisson's ratio is between 0.17 and 0.26, with a median value of 0.2. 3D friction angle is between 34.27° and 44.67°, with a median value of 39.36°. 3D cohesion is between 1.76 MPa and 22.78 MPa, with a median value of 12.49 MPa. 3D compressive strength is between 8.44 MPa and 86.15 MPa, with a median value of 52.54 MPa. 3D tensile strength is between 0.37 MPa and 7.25 MPa, with a median value of 3.55 MPa.

4.3.2. Three-dimensional pore pressure model

Pore pressure is an important reservoir and geomechanical parameter. It can be monitored in real-time using the DC index method during the drilling process. Moreover, it can also be measured on-site by the Drill Stem Test (DST) technology during the drilling process. However, the measurement data of the entire well is not continuous. Therefore, the pore pressure can be continuously estimated based on petrophysical data, such as compressional wave velocity. This article uses Eaton's formula[7] to estimate the reservoir's pore pressure.

The three-dimensional pore pressure is between 31.46 MPa and 38.4 MPa, with a median value of 34.30 MPa. The pore pressure equivalent density gradient is concentrated in the range of 1.25 g/cm³ to 1.40 g/cm³, where the pressure in the upper part (T1b3 section) of the reservoir is significantly higher than the pressure in the middle and lower part (T1b2 section and T1b1 section) of the reservoir.

5. Results and discussion

5.1. In-situ stress

Fig 2 shows the final calculation results of the three-dimensional maximum horizontal in-situ stress, the three-dimensional minimum horizontal in-situ stress, the three-dimensional vertical stress, and the horizontal stress difference. The Max horizontal stress ranges from 52.64 MPa to 72.73 MPa, with a median value of 64.36 MPa. The Min horizontal stress ranges from 42.21 MPa to 59.62 MPa, with a median value of 48.50 MPa. The overburden pressure ranges from 70.59 MPa to 76.32 MPa, with a
median value of 73.96 MPa. The Stress difference ranges from 8.56 MPa to 26.92 MPa, with a median value of 18.39 MPa. In general, Overburden pressure > Max horizontal stress > Min horizontal stress, the demonstration area belongs to the normal fault control range. The horizontal stress difference in the demonstration area is large, consistent with the value calculated by the previous multi-pole array acoustic wave logging. The numerically calculated maximum horizontal in-situ stress direction is N109°E, while the microseismic monitoring data show that the orientation of the major fractures in the demonstration area is between N90°E and N120°E.

The numerical calculation results of the in-situ stress in the demonstration area are calibrated using the existing measured values. Among them, the maximum horizontal in-situ stresses of two wells, including well ma1245 and well ma1252, are obtained by DFIT technology; its value is 68.25 MPa and 62.24 MPa, respectively. The measured maximum horizontal in-situ stress is within the range of numerical simulation results (from 52.64 MPa to 72.73 MPa). The statistics of multi-stage fracturing construction curves of 12 horizontal wells in the demonstration area, including well ma1241 to well ma1252, obtain 204 credible minimum in-situ stress data. The intersection of the measured point of the minimum stress and the numerical simulation results is established. As shown in Fig 3(a), the measured value and the numerical simulation results are very close. The expected results of Fig 3(a) are the ideal results. It is used to display the deviation between the measured value and the numerical calculation result. Simultaneously, Fig 3(b) shows the relative error between the calculated minimum stress and the measured value. The relative error is between 0.12% and 12.64%. And the average relative error is 3.95%.

There is a specific error between the numerical solution of the principal stress's magnitude and direction and the measured value. One of the reasons is that the calculation model still has a specific deviation in the details of the local structure and the actual situation. Also, the principal stress direction given by the actual measurement value is a range. The principal stress value is an average value, this shows that the measured value is also an average value and has an error. Secondly, it is considering that the primary purpose of the numerical results of the model is used for the later engineering sweet spot calculation. At the same time, the measured data points of the maximum horizontal ground stress are few, with only two measured data points. The model parameters mainly emphasize that the minimum horizontal stress result is close to the measured value. The direction of the maximum horizontal stress is consistent with the intermediate value of the measured value and ensures the rationality of the model.
Fig 2. Three-dimensional in-situ stress calculation results. (a) Max horizontal stress. (b) Min horizontal stress. (c) Overburden pressure. (d) Stress difference.

Fig 3. (a) Intersection diagram of the measured values and calculated values of the minimum horizontal stress. (b) The relative error of the minimum in-situ stress calculation value.

5.2. The analysis of three-dimensional minimum in-situ stress and three-dimensional horizontal stress difference

Fig 4 and Fig 5 show the vertical and transverse cross-sectional views of the minimum horizontal stress and the horizontal stress difference. The average minimum horizontal stress difference of the T1b3 layer is 49.29 MPa. And the average horizontal stress difference of the T1b3 layer is 16.92 MPa. The average minimum horizontal ground stress of the T1b2 layer is 44.96 MPa. And the average horizontal stress difference of the T1b2 layer is 19.32 MPa. The average minimum horizontal stress of the T1b1 layer is 45.50 MPa. And the average horizontal stress difference of the T1b1 layer is 18.95 MPa. The horizontal stress difference of the T1b3 layer is smaller than the T1b2 layer and the T1b1 layer, but all of them are greater than 10 MPa. Thus, the horizontal stress difference of the
demonstration area is large. Therefore, the area is not easy to be fractured to form a complex fracture network.

The minimum horizontal in-situ stress of the T1b3 layer is greater than the T1b2 and T1b1 layers. Since the cracks are easy to expand to areas with low minimum horizontal stress, the cracks are easy to be channeling to the T1b2 layer during the large-scale fracturing construction at the T1b3 layer. The channeling situation will reduce the efficiency of reservoir reconstruction within a single layer and affect the fracturing effect. The tracer monitoring results confirmed this phenomenon.

Based on the three-dimensional in-situ stress model, a new engineering sweet spot analysis method can be further developed to determine high-efficiency pressure zones, avoid low-economic zones in time, and increase single well production and recovery efficiency. It is helpful to guide the realization of scale efficiency and production.

**Fig 4.** The results of 3D minimum horizontal stress. (a) The vertical profile of minimum horizontal stress. (b) The T1b3 horizon profile of the minimum horizontal stress. (c) The T1b2 horizon profile of the minimum horizontal stress. (d) The T1b1 horizon profile of the minimum horizontal stress.

**Fig 5.** The results of 3D horizontal stress difference. (a) The vertical profile of horizontal stress difference. (b) The T1b3 horizon profile of horizontal stress difference. (c) The T1b2 horizon profile of horizontal stress difference. (d) The T1b1 horizon profile of horizontal stress difference.
6. Conclusion

- The mechanical parameters of the demonstration area are finely described using a series of core tests, well-drilled logging data, and seismic inversion data. In addition, the demonstration area's three-dimensional heterogeneous mechanical parameter distribution and three-dimensional pore pressure distribution are established. Finally, we get the three-dimensional in-situ stress distribution. In general, the demonstration area belongs to the normal fault control range, with overburden pressure > Max horizontal stress > Min horizontal stress. The numerical value of the maximum horizontal stress points in the direction of N109°E. The relative error between the calculated minimum horizontal stress and the measured value is between 0.12% and 12.64%. And the average relative error is 3.95%.

- The average minimum horizontal stress of the T1b3 layer is 49.29 MPa. And the average horizontal stress difference of the T1b3 layer is 16.92 MPa. The average minimum horizontal stress of the T1b2 layer is 44.96 MPa. And the average horizontal stress difference of the T1b2 layer is 19.32 MPa. The average minimum horizontal stress of the T1b1 layer is 45.50 MPa. And the average horizontal stress difference of the T1b1 layer is 18.95 MPa.

Acknowledgments

The work was financially supported by the China National Petroleum Corporation-China University of Petroleum (Beijing) Strategic Cooperation Science and Technology Project (No. ZLZX2020-XX).

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