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Original Paper

Quantitative prediction model for the depth limit of oil accumulation in the deep carbonate rocks: A case study of Lower Ordovician in Tazhong area of Tarim Basin

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A B S T R A C T

With continuous hydrocarbon exploration extending to deeper basins, the deepest industrial oil accumulation was discovered below 8,200 m, revealing a new exploration field. Hence, the extent to which oil exploration can be extended, and the prediction of the depth limit of oil accumulation (DLOA), are issues that have attracted significant attention in petroleum geology. Since it is difficult to characterize the evolution of the physical properties of the marine carbonate reservoir with burial depth, and the deepest drilling still cannot reach the DLOA. Hence, the DLOA cannot be predicted by directly establishing the relationship between the ratio of drilling to the dry layer and the depth. In this study, by establishing the relationships between the porosity and the depth and dry layer ratio of the carbonate reservoir, the relationships between the depth and dry layer ratio were obtained collectively. The depth corresponding to a dry layer ratio of 100% is the DLOA. Based on this, a quantitative prediction model for the DLOA was finally built. The results indicate that the porosity of the carbonate reservoir, Lower Ordovician in Tazhong area of Tarim Basin, tends to decrease with burial depth, and manifests as an overall low porosity reservoir in deep layer. The critical porosity of the DLOA was 1.8%, which is the critical geological condition corresponding to a 100% dry layer ratio encountered in the reservoir. The depth of the DLOA was 9,000 m. This study provides a new method for DLOA prediction that is beneficial for a deeper understanding of oil accumulation, and is of great importance for scientific guidance on deep oil drilling.

1. Introduction

It has become increasingly difficult to find new large-scale oil reservoirs in shallow buried strata (Guo et al., 2019; Li et al., 2021a). Owing to the renewed demand for hydrocarbon resources (Bradshaw et al., 2019; Liu et al., 2023) and improvements in exploratory drilling techniques (Aguilera and Ripple, 2012; Feng et al., 2020; Ma et al., 2021; Ramba et al., 2021; Liu et al., 2022), oil exploration worldwide has extended into deep and ultra-deep strata (Wang et al., 2019, 2022; Yang et al., 2022; Jin, 2023), where the petroleum potential is considered to be more than four times that of shallow strata (Pang et al., 2021a). Given the significant increase in drilling costs in deep hydrocarbon exploration (Xu et al., 2022), it is important to determine the depth limit of oil accumulation (DLOA), namely, the maximum burial depth of industrial oil accumulation. At this depth, geological conditions are not favorable for industrial oil accumulation, and there is a great risk in oil exploration; therefore, it is not suitable for oil exploration.

With increasing burial depth, crude oil cracking (Zhu et al., 2020), effective reservoir disappearance (Jiang et al., 2017), and a 100% dry layer ratio occurrence (Pang et al., 2021a) are signs of the

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DLOA. The prerequisite for oil accumulation is that the stratum temperature should not exceed the cracking temperature of the liquid-phase oil (Hill et al., 2003). There is an "oil window" (Tissot and Welte, 1978; Schenk et al., 1997; Hill et al., 2003) with a temperature corresponding to 65–149 °C (Pusey, 1973), and a "dead line" for oil gas exploration (Price, 1993) generally corresponding to 6,000 m (Bjorøy et al., 1988) and not exceeding 8,000 m (Tuo, 2002). Subsequently, liquid hydrocarbons were discovered at 8,406.4 m in the Tarim Basin (Zhu et al., 2012; Yang et al., 2020). Zhu et al. (2020) believed that the temperature limit of oil accumulation in Tarim Basin exceeds 210 °C, and the corresponding depth is 8,500 ± 500 m (Zhu et al., 2020). Nonetheless, there are more and more high-temperature oil formations above 210 °C discovered worldwide (Price, 1993; Quigley and Mackenzie, 1988; Teng and Yang, 2013). For example, oil layer over 210 °C in the Mississippi Depression in the Gulf of Mexico Basin (Xie et al., 2019), 230 °C in the Marun oil field in the Persian Gulf (Asadi et al., 2022), and 295 °C in the Caspian Basin in Russia (Li et al., 2021b), etc. This indicates that liquid petroleum has a wide temperature preservation range, which surpasses expectations. Hence, the DLOA based on the liquid crude oil preservation temperature prediction exhibits a long span, frequently resulting in greater uncertainty.

The storage space of the reservoir is the basis for oil accumulation, which depends on the existence of an effective reservoir (Zhou et al., 2015; Jiang et al., 2017). By performing studies on oil accumulation analysis (Wei et al., 2005; Zhou et al., 2015), statistical analysis (Zhou et al., 2015; Wang et al., 2020), nuclear magnetic resonance experiment (Jiao et al., 2009), Purcell method (Purcell, 1949), and core flooding (Guo, 2004), it indicates that, for the effective reservoir in the shallow layers, the lower limit of porosity is 6–7% and the DLOA is 3,000–6,000 m. However, with the increase in deep drilling, some scholars have found that the lower limit of porosity of effective reservoirs changes with depth (Wang et al., 2020). For the effective reservoir in the deep strata, the lower limit of porosity is about 2–3% and the DLOA is 6,000–8,000 m (Jiang et al., 2017; Wang et al., 2020; Pang et al., 2021a). When the burial depth further increases to an ultra-deep strata, the lower limit of the effective reservoir becomes much lower (Liu et al., 2014; Shen et al., 2015b). Because of the lower limit of the effective reservoir at different burial depths, there is no unified standard. The DLOA could not be determined based on a study of the effective reservoir.

Some scholars have directly determined the DLOA based on the dry layer ratio obtained during drilling. The dry layer, that is, the reservoir containing no movable fluids, refers to the reservoir that is essentially unstored in oil, natural gas, and water (Chen, 2013). A dry layer ratio of 100% is a sign of a DLOA (Pang et al., 2021a). The dry layer ratio refers to the ratio of the dry layer thickness to the total layer thickness drilled by wells at given depth intervals. Pang et al. (2021a) investigated the DLOA in the Songliao Basin. The dry layer ratio was 100% for the reservoir with depth exceeding 4,500 m, and the determined DLOA was 4,500 m. Presently, the discovered oil accumulations are mainly distributed at this depth, verifying the scientificity of predicting the DLOA using the dry layer ratio (Xiao et al., 2018; Pang et al., 2021b; Zhu et al., 2022). Nevertheless, it is challenging to predict the DLOA in the Tarim Basin using the dry layer ratio. The deepest drilling reached 8,882 m in the Tarim Basin, while the ratio of drilling to the dry layer could not achieve 100%. Thus, the DLOA in the Tarim Basin may not have been determined based on the dry layer ratio.

The Tarim Basin is one of the most complex petroliferous basins in the world and the largest petroliferous basin in China (Zhao et al., 2005; Zou et al., 2014; Zhu et al., 2020; Yang et al., 2020). In this study, the Lower Ordovician carbonate reservoir in Tazhong area of Tarim Basin was used as an example to study DLOA. By combining oil testing and logging data, and based on statistical analysis and numerical simulation, the critical porosity corresponding to the DLOA in a deep carbonate reservoir in the Tarim Basin was first determined. Second, the relationships between the carbonate reservoir porosity, depth, and dry layer ratio were determined. Finally, it collectively determines the relationship between the dry layer ratio and the depth of the reservoir; the depth corresponding to a 100% dry layer ratio is the DLOA in carbonate rocks. The study of DLOA in carbonate rocks is of great importance to reveal the prospects of deep marine oil exploration in the Tarim Basin and to scientifically guide deep oil drilling. In addition, it provides valuable insights for ultra-deep oil drilling in other marine basins worldwide.

2. Geological framework

The largest petroliferous basin in China, the Tarim Basin, located in Xinjiang province, covers an area of 56×10^4 km^2 and has a history of nearly 30 years of marine petroleum exploration. In the past 10 years, breakthroughs have been made in deep and ultra-deep marine petroleum exploration, with over 500 drilling wells below 4,500 m, the deepest drilling well exceeds 9,000 m, and deep hydrocarbon reserves accounting for 92%. The Tarim Basin is a typical superimposed basin that developed on the basement of the Ediacaran continental crust. It is also a large composite basin formed by the superposition of the Paleozoic marine craton basin and the Mesozoic-Cenozoic continental foreland basin. In the Tarim Basin, strata of different ages develop longitudinally, ranging from the oldest Neoproterozoic stratum to the latest Quaternary stratum (Zhu et al., 2019a). The strata from the Quaternary to the Silurian are mainly clastic, and those from the Ordovician to the Cambrian are primarily carbonate strata (Fig. 1). According to a survey, the hydrocarbon reserves of the marine strata in the Tarim Basin exceed 30×10^8 t, and the annual hydrocarbon production is greater than $1,000 \times 10^4$ t (Zhu, et al., 2019b). The main reservoir is the Ordovician stratum, with a thickness ranging from 700 to 3,000 m, a main burial depth beyond 4,500 m.

The Ordovician system can be divided into the lower, middle, and upper series. The lithology focuses on the limestone reservoir, possibly mixed with marl. In the lower Penglaiba Formation, dolomite developed with a total thickness of 683–3,018 m and exhibited multiple stages of discordant internal development. The upper Lianglitage and lower Yingshan formations are the main hydrocarbon reservoirs and production layers, respectively. The Lower Ordovician Yingshan Formation reservoir is limestone, with a micrite structure and a thickness of 0–500 m. In this set of carbonate strata, hydrocarbon exploration has achieved fruitful results, including the discovery of oil and gas accumulations. Currently, for the Lower Ordovician carbonate rocks in the Tazhong area of the basin, drilling has reached a burial depth ranging from 3,356 to 6,744 m; thus, there is abundant exploration well data. This stratum is also one of the hottest target layers of exploration in the Tarim Basin at present, as well as an important object of this study (Fig. 2).

3. Methodology and workflow

3.1. Model

According to the theory of hydrocarbon accumulation dynamics, hydrocarbon source rocks exhibit extremely low maturity in the shallow layer of a petroliferous basin, generating a small amount of oil that is stored in the hydrocarbon source rocks. Generally, reservoir storage space is occupied by free-flowing water. With a deeper burial depth of the stratum, the hydrocarbon source rocks

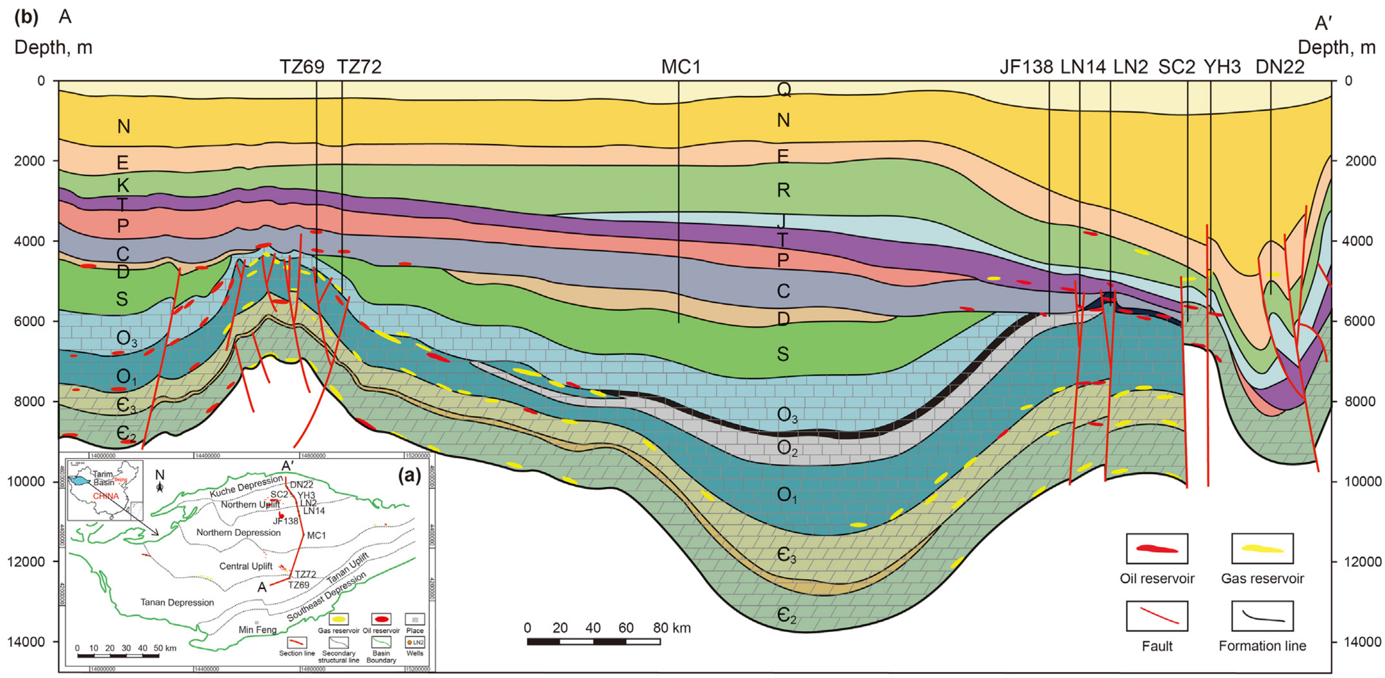

Fig. 1. Location of Tarim Basin and schematic diagram of north-south hydrocarbon reservoir profile in Tarim Basin (Zhang, 2022). The section's location is depicted in Fig. 1a.

mature and a large amount of oil is generated and expelled. For secondary migration, oil accumulates in the reservoir, and part of the free water is displaced by oil, with the reservoir storage space shared by oil and water. When the burial depth of the stratum is excessively large, the reservoir storage space is so small that oil cannot accumulate (Pang et al., 2021a). When the storage space is completely occupied by immobile-bound water, a dry layer is formed. According to the oil drilling results for the same set of reservoirs at different burial depths, the ratio of drilling to a certain stratum reflects the changing characteristics of the oil accumulation process (Fig. 3). Generally, it can drill to the water layer within the target reservoir with a shallow burial depth, followed by a water layer, oil layer, or oil-water layer along with downward drilling. With an increase in the burial depth, the ratio of drilling to the dry layer continuously increases until it reaches 100%. For the same reservoir, the ratio of the drilling to the dry layer increased with an increase in burial depth. When approaching 100%, the corresponding depth was determined as the threshold for oil accumulation (Xiao et al., 2018; Pang et al., 2021a; Zhu et al., 2022).

3.2. Data

In this study, Lower Ordovician carbonate reservoir porosity data and oil and dry layer interpretation data were collected (Shen, 2016). The logging physical properties and hydrocarbon interpretation results of reservoir segments of 56 drilling wells are presented, including 2,872 data points on porosity and oil-bearing properties. In addition, oil testing data and well logging data of 45 drilling wells were included, including 3,853 data on oil, water, and dry layers in the drilling-encounter target reservoir segments.

3.3. Workflow

First, the evolution of marine carbonate reservoir porosity with burial depth was characterized. The mathematical model proposed by Buryakovsky and Dzhevanshir in 1976 and used to calculate sediment compaction and diagenetic grade in petroliferous basins was employed in the following basic form:

$$U_t = U_0 \prod_{i=1}^{n} x_i \tag{1}$$

where U_t is the current compaction and diagenetic grade of the sediment. U_0 represents the initial compaction and diagenetic grade of the sediment. x_i is the model coefficient, which indicates the geological factors affecting the carbonate reservoir porosity, including geologic age, the number of tectonic cycles, depth of burial, and formation temperature, and the degree of homogeneity of carbonate rocks (Buryakovsky et al., 1990; Buryakovsky, 1993). For quantitative calculations, it is necessary to standardize the absolute values of the various geological factors. Through years of study, scholars have obtained the relationship between the absolute and standard values of various geological factors by utilizing fuzzy set theory, and the mathematical relationship has also been established (Table 1). Because each influencing factor has a different degree of influence on the porosity of the carbonate reservoir, the influencing coefficient (with three grades of strong, moderate, and weak) was determined through a large number of experimental studies, as shown in Table 2.

Based on the influencing coefficient corresponding to each geological factor and by combining the standard values of each geological factor, the modeling coefficient of the mathematical model for carbonate reservoir compaction and diagenetic grade was established, as shown in Eq. (2).

$$x_i = \exp\left(-a_j T\right) \tag{2}$$

where x_i represents the modeling coefficient. a_j indicates the coefficient of influence. As known from Table 2, T represents the standardized geological factor obtained from the formula in Table 1.

In combination with Eqs. (1) and (2), and by employing the mathematical model of sediment compaction and diagenetic grade in the petroliferous basin, the relative compaction and diagenesis of the carbonate reservoir (i.e., the relative change degree of carbonate reservoir rock) were calculated, as shown in Eq. (3).

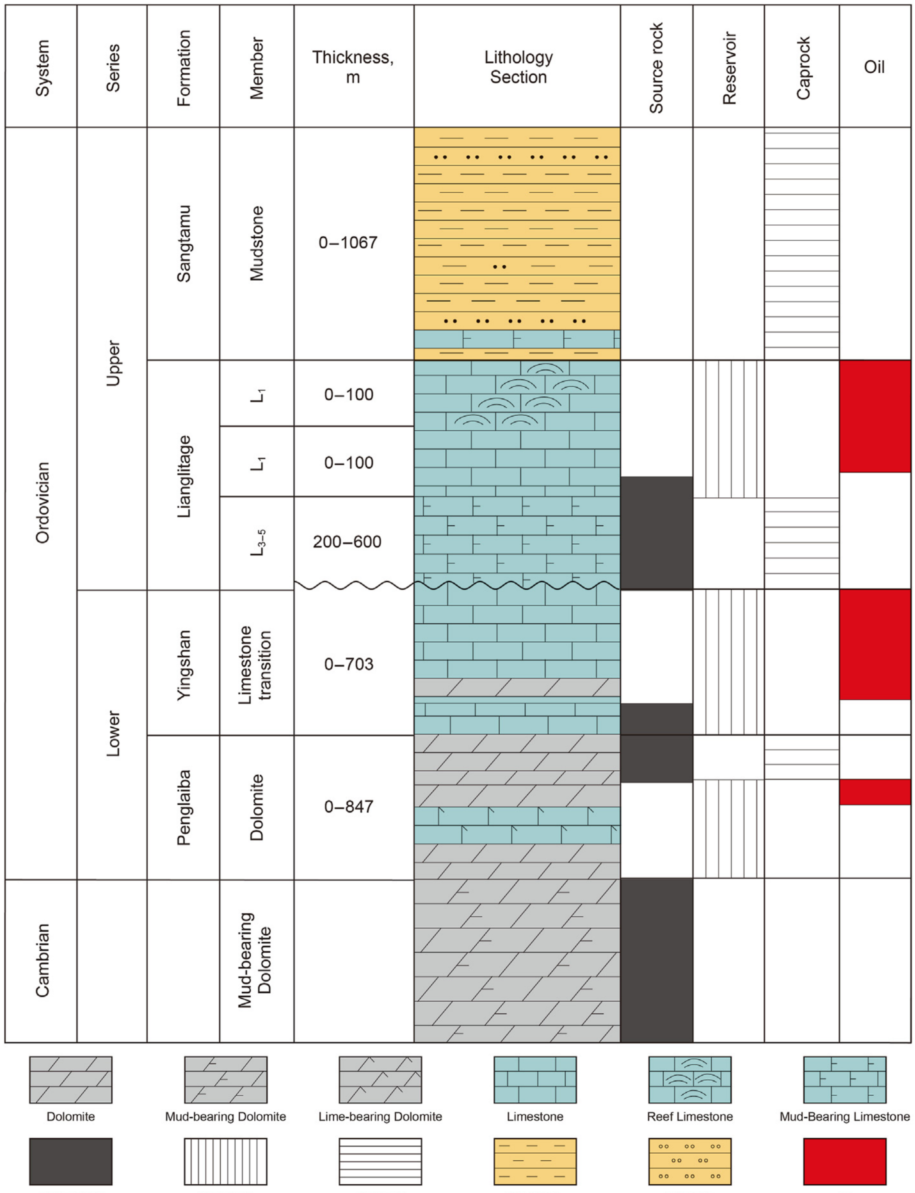

Fig. 2. Stratigraphy of Ordovician in Tazhong area of Tarim Basin (Shen et al., 2015a).

$$Z = U_t \Big/ U_0 = \prod\nolimits_{i=1}^{n} x_i \tag{3}$$

where, Z represents the relative compaction and diagenesis of the carbonate reservoir.

The formulae for carbonate reservoir porosity calculation are as below.

$$Z_1 = \prod\nolimits_{i=1}^{n} x_i / \left[1 - \varphi_0 \left(1 - \prod\nolimits_{i=1}^{n} x_i\right)\right] \tag{4}$$

$$\varphi = \varphi_0 Z_1 \tag{5}$$

where, φ indicates the current porosity of the carbonate reservoir, with unit %. φ_0 represents the initial porosity of carbonate rock before compaction and diagenesis, with unit %. Z_1 signifies the relative change in porosity without dimensions.

Second, the relationship between the porosity and dry-layer ratio of the marine carbonate reservoir was determined. In combination with the collected oil test data and well logging data and by analyzing the situation of oil, water, and dry layers in the drilling-encounter target reservoir segments, the ratio of oil, water, and dry layers in each segment with 0.5% porosity was obtained. The distribution relationship between the dry layer ratio and carbonate reservoir porosity was also determined.

Third, by combining the relationship between the dry layer ratio and porosity and that between the porosity and burial depth, the relationship between the dry layer ratio and burial depth was obtained. Based on this, the DLOA of the deep marine carbonate rocks was determined.

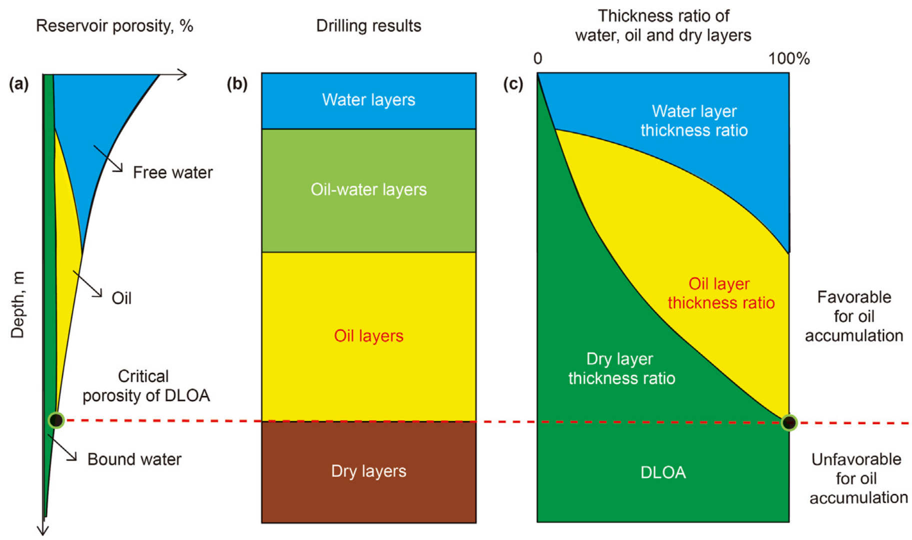

Fig. 3. Determination model for the depth limit of oil accumulation (DLOA) in the petroliferous basin (Jiang et al., 2010). (a) Change of porosity with burial depth and critical porosity of DLOA; (b) drilling results in reservoirs of different porosity; (c) thickness ration of water, oil and dry layers.

Table 1
Standardized formula for carbonate sediments (Buryakovsky et al., 1990; Buryakovsky, 1993).

Factor	Standardized formula
Geological age A, Ma	$T_A = 0.00125\ A$
Number of tectonic cycles N	$T_N = 0.2 + 1.46\lg N$
Burial depth H, km	$T_H = 0.1\ H$
Formation temperature t , °C	$T_t = 0.005t$
Homogeneity of carbonate rocks S	$S = 100\%\ r_a/r_{\max}$

4. Results

4.1. Change of porosity of carbonate reservoir with burial depth

The geological factors parameters affecting the physical properties of the carbonate reservoir are determined using data collected from the Tarim oil field or by referring to published literature. Determination of geological age. According to the stratigraphic and chronological representation of the oilfield in the Tarim Basin, the Lower Ordovician carbonate reservoir sediment in the Tazhong area of Tarim Basin has a geological age ranging from 510 to 468 Ma. Determination of the number of tectonic cycles based on the study results of Kuang et al. (2015) on the tectonic evolution process and stages of the paleo uplift in the Tarim Basin, the number of tectonic cycles experienced by the top and bottom of the Lower Ordovician reservoir in Tazhong area is determined to be 2.6–2.73. Determination of the simulated burial depth, when drilling the Lower Ordovician carbonate rock into this stratum in the Tazhong area, the burial depth was determined to be 3,356–6,744 m. For the reservoir in the simulated segment in this study, the burial depth ranged from 4,650 to 5,670 m, guaranteeing the universal representation of the top and bottom burial depths. Determination of the formation temperature, according to the temperature data obtained from the drilling data of the seven wells (ZG 43 well, ZG 431well, ZG 432 well, ZG 44C well, ZG 441 well, ZG 46 well, and ZG 462 well) drilled to the Lower Ordovician Yingshan Formation in Tarim Basin, the temperature gradient is 2.02 °C/100 m. This is consistent with the results reported by Lv et al. (2011). Based on this, the reservoir temperature in the simulated segment is determined to be 140–162 °C. Determination of the degree of homogeneity of carbonate rocks. The reservoir homogeneity can be described by the homogeneity coefficient, which reflects the degree of deviation between the average value and the maximum value, ranging from 0 to 1. A larger value indicates a more uniform medium distribution and stronger homogeneity. For a porous medium, rock homogeneity can be measured using fractal dimension (Mandelbrot, 1967; Katz and Thompson, 1985). Capillary pressure curve data can also reflect the degree of reservoir homogeneity (Tang and Tang, 2004; Zhang et al., 2010). In this study, based on the microscopic homogeneity coefficient of the core measured by conducting a mercury injection test after core sampling at depths of 4,650–5,670 m from five drilling wells (TZ 73 well, TZ 74 well, TZ 241 well, TZ 243 well, and TZ 824 well), the top and bottom homogeneity coefficients of the reservoir in the simulated segment were obtained as 0.07–0.09. Based on data from the Tarim oil field and the study results of Lv et al. (2011), the primary porosity of the Lower Ordovician limestone reservoir is 45–50%. The specific values of the five factors and the corresponding natural factors influencing the coefficients are listed in Table 3.

Based on these parameters, the change in porosity of the Lower Ordovician carbonate reservoir from the surface to a burial depth of 10,000 m in the Tazhong area was simulated, and the results are shown in Fig. 4. In the shallow layer of the basin, the reservoir maintained a large porosity of 20% before reaching a burial depth of 2,000 m. After entering the middle layer of the basin, the porosity significantly decreased to 8–12%. When continuously reaching the

Table 2
Influence coefficient of natural factors (Chilingar et al., 1979).

Degree of influence	Strong	Moderate	Weak
Influencing coefficient	0.968	0.714	0.511
Influencing factor	Geological age, number of tectonic cycles, burial depth, and formation temperature	Homogeneity of carbonate rocks	–

Table 3
Lower Ordovician carbonate reservoir parameters in Tazhong Area.

Factor	Influencing degree	Influencing coefficient	Value
Geological age *A*, Ma	Strong	0.968	468–510
Number of tectonic cycles			2.6–2.73
Burial depth *H*, km			4.65–5.67
Formation temperature, °C	Moderate	0.714	140–162
Homogeneity of carbonate rocks			0.07–0.09

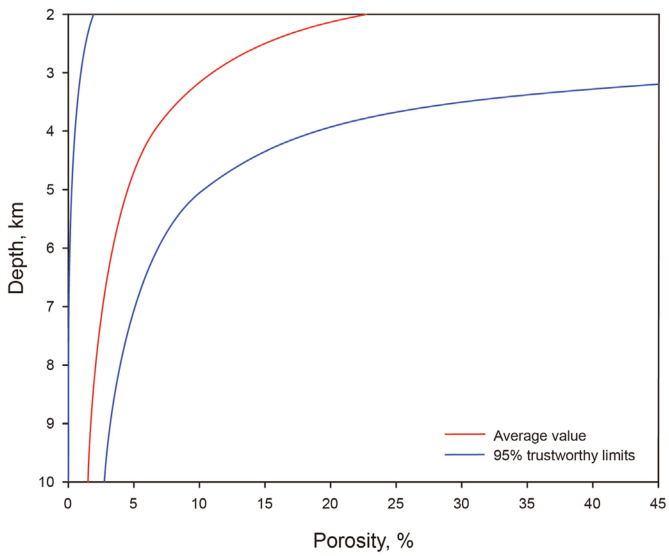

Fig. 4. Numerical simulation results of porosity variation with burial depth of the Lower Ordovician carbonate rocks in the Tazhong area, Tarim Basin. 95% trustworthy limits refer to that there're values consistent with the data at 95% confidence.

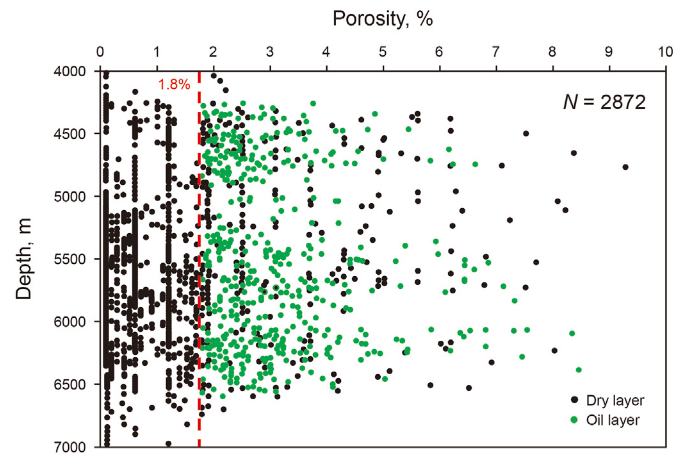

Fig. 5. Reservoir porosity and oil-bearing property of the Lower Ordovician in the Tazhong area.

deep layer of the basin, the porosity was reduced to 2–6%. In addition, the porosity decreased when entering the deep layers of the basin. With an increase in burial depth, the reservoir porosity tended to decrease, with a rapid decrease in the shallow burial stage and a slow decrease in the deep burial stage. After reaching 10,000 m, the porosity was very low with 1.2 %.

4.2. Critical conditions for DLOA of deep carbonate rocks

Statistical analyses were performed on the porosity data of the Lower Ordovician carbonate reservoir and the interpretation data of the oil and dry layers (Shen, 2016). As indicated by the results, when the reservoir porosity was less than 1.8%, dry layers were encountered in all drills. The oil layer was formed only when the porosity of the reservoir exceeded 1.8%. In the depth profile, and light of the relationship between the reservoir porosity and the interpretation results of the oil and dry layers, almost 100% of the oil layer was located to the right of the boundary (the line with a porosity of 1.8%), and 70% of the dry layer was situated to the left of this boundary (Fig. 5). Based on these results, the critical porosity of the DLOA in the carbonate reservoir of the Lower Ordovician Yingshan Formation in the Tazhong area was determined to be 1.8%. Under these critical conditions, the oil cannot enter the reservoir for accumulation.

4.3. Relationship between porosity and dry layer ratio of deep carbonate reservoir

Based on the collected oil testing and well logging data, and by providing statistical analysis of the 3,853 oil, water, and dry layers in the drilling-encounter target reservoir segments in the Tazhong area, the ratio of oil, water, and dry layers in each segment with 0.5% porosity was obtained. Fig. 6 presents the critical conditions of the DLOA. When the reservoir porosity exceeded 8%, oil and water layers were encountered in almost all the drillings. With a decrease in reservoir porosity, fewer oil and water layers were encountered during drilling, whereas more dry layers were encountered. After the reservoir porosity reduces to the range of 1.5–2% (the range closed the front and opened the back), the dry layer ratio increases to 92%. When the reservoir porosity further decreased from 1% to 1.5%, the dry layer ratio reached 100%. Hence, a relationship between the porosity and dry layer ratio of the carbonate reservoir was established.

5. Discussion

5.1. DLOA of carbonate rocks

The critical condition of the DLOA corresponds to the depth of the same target layer (where a dry layer can be encountered at 100% during drilling), as indicated in the hydrocarbon drilling results. In deep petroliferous basins, because the DLOA is not reached during drilling, it cannot be predicted by directly establishing a relationship between the ratio of drilling to the dry layer and depth. Thus, the DLOA can be predicted using the depth-porosity-dry layer ratio method. The evolution of the physical properties of the reservoir with depth was determined (Fig. 7a). Subsequently, by combining the relationship between the dry layer ratio and porosity and that between the porosity and burial depth, the relationship between the dry layer ratio and burial depth was obtained (Fig. 7b). The relationship among these three factors is shown in Fig. 7c. Fig. 7 shows the relationship between the critical condition of the DLOA and the depth limit of the Lower Middle Ordovician carbonate reservoirs in the Tazhong area. Therefore, the

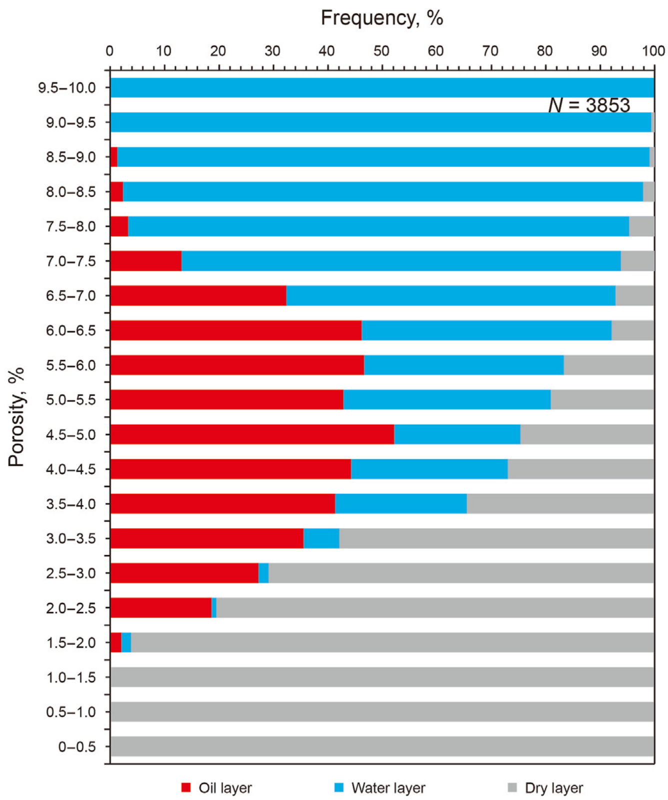

Fig. 6. Changes of ratio of water, oil and dry layer with different porosity of Lower Ordovician carbonate reservoir encountered of drilling well in Tazhong area.

DLOA of the Lower Ordovician carbonate rocks in the Tazhong area is predicted to reach 9,000 m. Currently, the maximum burial depth of the Lower Ordovician carbonate reservoir in the Tazhong area does not exceed this depth, which indicates the feasibility and prospect of deep carbonate oil exploration in this field.

5.2. Reliability

The published measured porosity data for the Lower Ordovician carbonate reservoir in the Tazhong area (Shen et al., 2015b) were compared with the numerical simulation results for porosity (Fig. 8). The two exhibited the same change trend, generally decreasing with burial depth. Although there are two belts with high porosity and permeability, as shown in the measured data, the final trend of the reservoir porosity decreasing with burial depth cannot be changed. Moreover, 97.6% of the measured porosity data points fall within the 95% trustworthy limits of the simulated trend line, indicating the high reliability of the numerical simulation results. 95% trustworthy limit refers to that there're values consistent with the data at 95% confidence (Pasman and Rogers, 2018).

5.3. Future work

The prerequisite for oil accumulation is having a sufficient liquid oil source. The termination of liquid oil production from source rocks serves as an indicator for the end of oil accumulation, establishing the DLOA. The “dead line” for liquid oil is also a crucial factor influencing the DLOA in carbonate rocks. However, the exact definition of this “dead line” has been a persistent concern among explorers. According to Yang et al. (2020), several factors contribute to the presence of liquid oil at a buried depth of 8,200 m in the

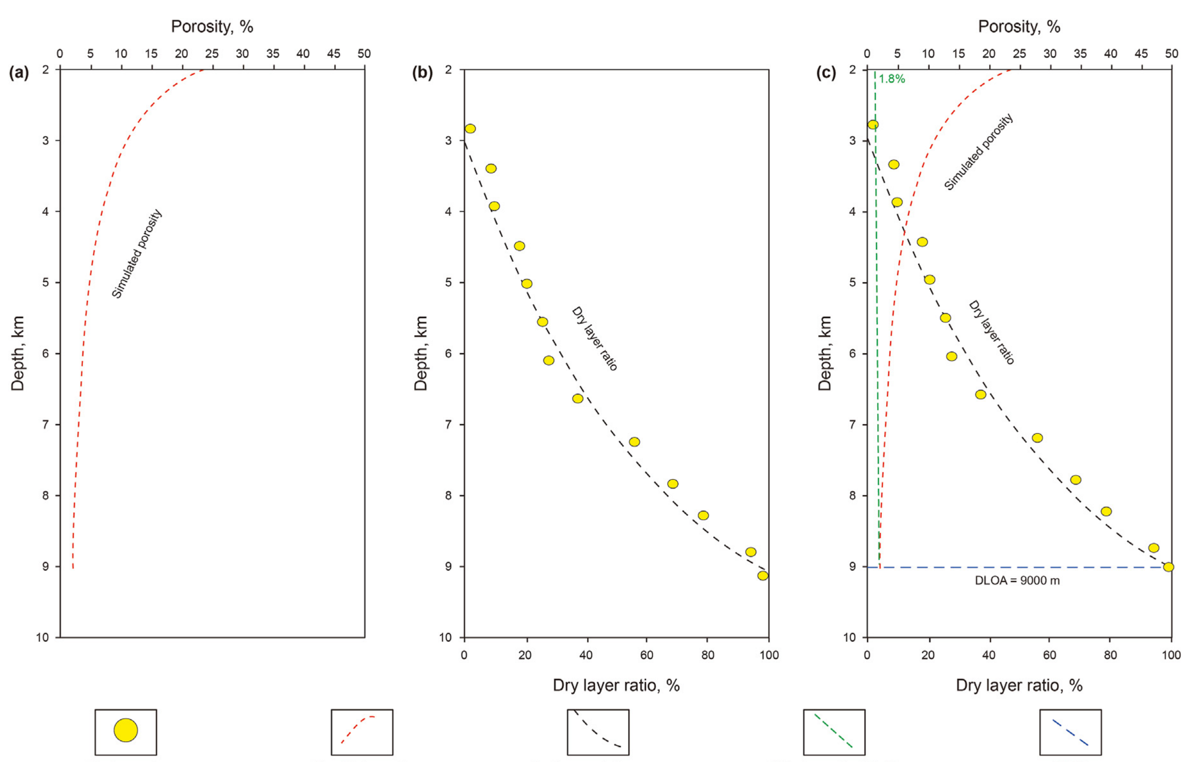

Fig. 7. The relationship between the layer ratio, critical condition of the depth limit of oil accumulation (DLOA) and DLOA of carbonate reservoirs in the Lower Middle Ordovician of Tazhong area.

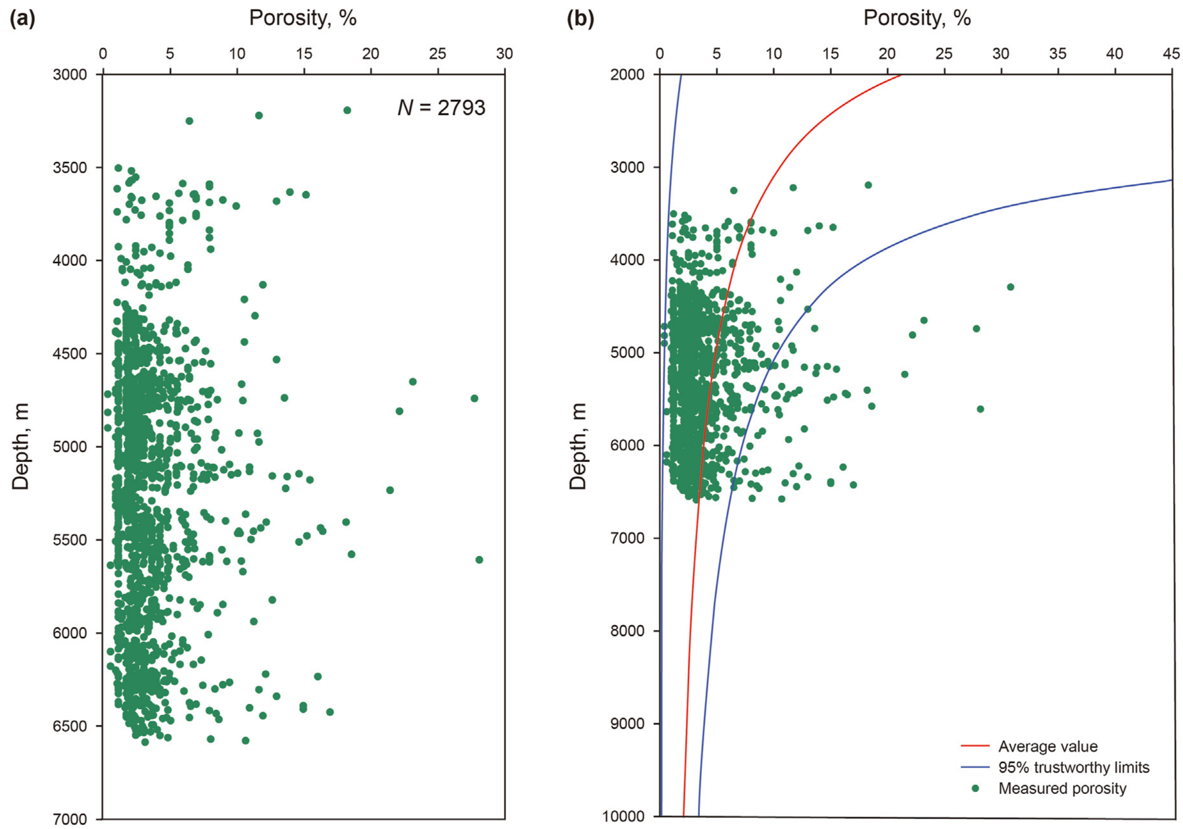

Fig. 8. Comparison of measured data and numerical simulation results of porosity variation with burial depth of Lower Ordovician carbonate rocks in Tazhong area, Tarim Basin. (a) Measured data (Shen et al., 2015b); (b) fitting degree between simulation results and measured data.

Tarim Basin. These factors include a relatively small temperature gradient in the Tarim Basin, rapid burial during the late Himalayan movement, and insufficient time for crude oil to undergo significant cracking. Huo (2014) conducted simulations of the hydrocarbon generation process in carbonate source rocks within the Tazhong area of the Tarim Basin. The results of the study indicated that liquid hydrocarbons are consistently generated during the thermal evolution of source rocks. The "dead line" for liquid oil distribution is predominantly influenced by temperature and pressure conditions. Further research is necessary to delineate the specific "dead line" for liquid oil in the Tazhong area of the Tarim Basin.

6. Conclusions

The porosity of the Lower Ordovician carbonate reservoir in the Tazhong area of the Tarim Basin tends to decrease with burial depth, exhibiting a rapid decrease in the shallow burial stage and a slow decrease in the deep burial stage. For the measured porosity data points, 97.6% fell within the 95% trustworthy limits of the simulated trend line, indicating high reliability of the numerical simulation results.

The critical porosity of the DLOA of the Lower Ordovician deep carbonate rocks in the Tazhong area of the Tarim Basin was 1.8%, and the DLOA was 9,000 m. The maximum burial depth of the Lower Ordovician carbonate reservoir in the Tazhong area does not exceed this depth, which indicates the feasibility and prospect of deep carbonate oil exploration in this field.

CRediT authorship contribution statement

Wen-Yang Wang: Writing – original draft, Conceptualization. **Xiong-Qi Pang:** Supervision. **Ya-Ping Wang:** Software. **Zhang-Xin Chen:** Writing – review & editing, Supervision. **Fu-Jie Jiang:** Methodology. **Ying Chen:** Formal analysis, Data curation.

Declaration of competing 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.

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Nomenclature

Symbols

U_t	Current compaction and diagenetic grade of sediment
U_o	Initial compaction and diagenetic grade of sediment

X_i	Model coefficient
A	Geological age, Ma
N	Dynamic deformation
H	Depth, km
t	Temperature, °C
S	Carbonate rock homogeneity
T	Standardized geological factor
a_j	Influencing coefficient
Z	Relative compaction and diagenesis of carbonate reservoir
φ	Porosity
Z_1	Relative change of porosity

Abbreviations

DLOA	Depth limit of oil accumulation

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