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Hydrocarbon generation, expulsion, and retention characteristics of the Permian Fengcheng shale and Lucaogou shale in the Junggar Basin: implications for the exploration of lacustrine shale oil

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Hydrocarbon generation patterns are crucial for defining favorable exploration maturity intervals and targets for shale oil. The Permian Fengcheng shale and Lucaogou shale in the Junggar Basin, as significant targets for shale oil exploration, study on their hydrocarbon generation, expulsion, and retention characteristics are insufficient. This study establishes hydrocarbon generation patterns for the Fengcheng shale and Lucaogou shale using a semi-open thermal simulation system, combined with rock pyrolysis, vitrinite reflectance (Ro), total organic carbon (TOC) analysis, carbon isotope analysis, gas chromatography-mass spectrometry (GC-MS), mercury porosimetry, and nitrogen adsorption. Additionally, a multivariate regression model was employed to systematically evaluate the primary controlling factors of hydrocarbon expulsion ratio. Based on these results, favorable exploration maturity intervals and targets for the Fengcheng shale and Lucaogou shale were identified. The results indicate that the hydrocarbon generation potential of Fengcheng shale was superior to that of Lucaogou shale, whether considering gas yield or oil yield. However, Lucaogou shale began the thermal degradation earlier than Fengcheng shale and has a broader degradation window. The corresponding (T_R) is slightly higher for Fengcheng shale. The Lucaogou shale exhibited significantly higher hydrocarbon expulsion ratios compared to Fengcheng shale, with a maximum hydrocarbon expulsion ratio 2.1 times that of Fengcheng shale. Mesopore volume and its connectivity were critical factors affecting the hydrocarbon expulsion ratio, whereas oil mobility and macropore volume have relatively limited effects. The optimal maturity interval for shale oil exploration as $Ro = 1.0\%–1.1\%$ for the Fengcheng shale and $Ro = 0.9\%–1.1\%$ for the Lucaogou shale. Exploration of the Fengcheng shale should focus on lithofacies assemblages, the dolomitic

mixed rock-shale assemblages in the shore-shallow lake facies represent the primary exploration target. Exploration of the Lucaogou shale should focus on source-reservoir assemblages, with a higher reservoir-to-shale thickness ratio being the primary exploration target. These findings provide support for the exploration and development decisions of shale oil in the Junggar Basin.

KEYWORDS

shale oil, Fengcheng shale, lucaogou shale, Junggar Basin, thermal simulation

1 Introduction

Shale oil have emerged as a global hotspot for unconventional hydrocarbon exploration and development, attracting widespread attention from petroleum geologists. China has made significant progress in shale oil exploration in several lacustrine sedimentary basins, including the Junggar Basin, Ordos Basin, Bohai Bay Basin, Songliao Basin, and Subei Basin (Hackley and Cardott, 2016; Zhao et al., 2020; Zou et al., 2019; Hu et al., 2024a; Feng et al., 2023). The Mahu Sag and Jimusar Sag, as important petroliferous sags in the Junggar Basin, have made significant breakthroughs in Permian shale oil exploration (Gong et al., 2024). Among them, the Lucaogou Formation shale oil in the Jimusar Sag has established the first national-level lacustrine shale oil demonstration zone in China, with estimated resources of 11.12×10^8 t (Tang et al., 2023). Multiple exploration wells in the Fengcheng Formation of the Mahu Sag have obtained industrial oil flow with a daily output exceeding 100 t, demonstrating its huge potential for shale oil exploration and development (Tang et al., 2021).

Previous research indicates that both the Mahu Sag and Jimsar Sag are saline sub-basins with hydrocarbon source rocks primarily composed of fungi and algae, with cyanobacteria development being distinctive compared to other saline lake basins (Cao et al., 2015). Although the source rocks of the Fengcheng shale and Lucaogou shale are similar, they exhibit marked differences in hydrocarbon generation characteristics and oil content (Zhang et al., 2019). The Fengcheng shale has a relatively low TOC content (approximately 1%) and a hydrocarbon generation potential of about 6 mg HC/g Rock (Dongming et al., 2021). In contrast, the Lucaogou shale has a higher TOC content (exceeding 3%) and a hydrocarbon generation potential greater than 20 mg HC/g TOC. Both shales show extensive lateral continuity in oil distribution (Zhi et al., 2019). However, the Fengcheng shale exhibits vertical continuity, whereas the Lucaogou shale contains two distinct “sweet spot” intervals vertically (Wang et al., 2014). Additionally, the reservoir characteristics of the Fengcheng shale and Lucaogou shale differ. The Fengcheng shale has a high carbonate mineral content, with pore throat radii primarily ranging from 0.01 to 10 μ m and an average porosity of approximately 3.3% (Tang et al., 2023). Conversely, the Lucaogou shale has a higher clay mineral content, with pore throat radii ranging from 10 to 100 μ m and an average porosity exceeding 9% (Ma et al., 2022). Overall, the differences in source-reservoir characteristics between the Fengcheng and Lucaogou shales are significant. As the source-reservoir assemblage is a critical factor affecting the generation, expulsion, and retention of shale oil (Jia et al., 2014; Schimmelmann et al., 2001; Shao et al., 2020), understanding the hydrocarbon generation and expulsion

characteristics of the two set shales is essential for elucidating the enrichment mechanisms and identifying favorable exploration targets in the Junggar Basin.

Thermal simulation experiment is a critical method for studying the generation, expulsion, and retention characteristics of shale oil and have been widely utilized (Zhang C et al., 2022). Combined with basin modeling, these experimental results can be applied to geological conditions to guide shale oil exploration. In this study, we employed a self-developed semi-open thermal simulation apparatus, integrated with various analytical techniques including rock pyrolysis, vitrinite reflectance, total organic carbon (TOC) analysis, carbon isotope analysis, gas chromatography-mass spectrometry (GC-MS), mercury porosimetry, and nitrogen adsorption. The objectives of this study are to (1) determine the T_R , product yields, composition, carbon isotopic characteristics, and variations in porosity and morphology for the Fengcheng shale and Lucaogou shale; (2) develop hydrocarbon generation patterns for the Fengcheng shale and Lucaogou shale; (3) identify the differences in hydrocarbon expulsion ratios and controlling factors between the Fengcheng shale and Lucaogou shale; (4) optimize favorable exploration maturity intervals and targets. These findings provide support for the exploration and development decisions of shale oil in the Junggar Basin.

2 Geological setting

During the Permian, the Junggar Basin developed a complex set of saline lacustrine deposits, which have been confirmed as the main source rocks of the basin (Zhang Y et al., 2022). The Mahu Depression, located in the northwest of the Junggar Basin, covers an area of approximately 5,000 km² (Jiang et al., 2023) and is classified as a sub-basin with high salinity lacustrine environments influenced by terrigenous freshwater inputs (Fang et al., 2006) (Figure 1A). The depression undergone five evolutionary stages: initial lake development, lake expansion, lake contraction, formation of alkaline lakes, and further lake expansion (Xiao et al., 2021). During the deposition of the Fengcheng Formation (P_1f), a fan delta-lacustrine depositional system developed and is further divided into three members (Zhang et al., 2018) (Figure 1B). During the deposition of the first member (P_{1f_1}), frequent volcanic activity provided a rich source of organic matter for hydrocarbon generation. During the deposition of the second member (P_{1f_2}), the paleoclimate changed to arid and hot, increasing lake salinity and resulting in the formation of dolomitic shales and alkaline minerals such as calcite and nahcolite. During the deposition of the third member (P_{1f_3}), the paleoclimate changed to more humid, leading

to the development of thick, high-quality shales interbedded with siltstone (Gong et al., 2024).

The Jimsar Depression, located in the eastern part of the Junggar Basin, covers an area of 1,278 km² (Hou et al., 2021) and was a relatively isolated sub-basin formed in the late Middle Permian with high water salinity (Liang et al., 2023). The Jimsar Depression undergone multiple tectonic movements, bounded by faults in the west and overlapping in the east (Figure 1C). The Lucaogou Formation (P₂l) primarily developed a lacustrine-delta depositional system and was the main source rock in the Jimsar Depression, with sediment thickness reaching up to 5,000 m in the depositional center (Tang et al., 2024). The P₂l was further divided into two members: the first member of Lucaogou Formation (P₂l₁) and the second member of Lucaogou Formation (P₂l₂), with sediments mainly comprising siltstone, shale, and carbonates (Figure 1D). Drilling results indicated that the Lucaogou Formation includes two shale oil-rich intervals (Lai et al., 2023). The upper sweet spot was characterized by dolomite with minor siltstone interlayers, while the lower sweet spot features interbedded dolomite and siltstone (Guo et al., 2019).

Despite the heterogeneity of shale, the type of organic matter within the same shale formation is relatively consistent. Selecting low-maturity shale samples for thermal simulation experiments is a widely utilized method to reveal the complete process of hydrocarbon generation from organic matter (Hu et al., 2024b). The shales in the northern margin of the Mahu Depression and the southeastern margin of the Jimusar Depression were relatively shallowly buried and exhibited low maturity. Drilling results indicate that the shales in well F5 and well J7 are well-developed with similar thermal evolution context, making them optimize choices for thermal simulation studies (Figure 1).

3 Sample and methods

3.1 Sample

The vitrinite reflectance (Ro) values for the Fengcheng shale and Lucaogou shale samples were 0.69% and 0.63%, respectively, indicating low maturity shale. Both Fengcheng shale and Lucaogou shale were high quality shale with type I kerogen (Du et al., 2023). The basic geochemical information of the samples is presented in Table 1. A total of ~700 g of samples was used in this study, with each pyrolysis experiment utilizing ~80 g of samples. To avoid the impact of heterogeneity caused by interbedded organic-rich and organic-poor layers on the hydrocarbon generation and expulsion characteristics of the shale, ~0.5 cm diameter particulate samples were used instead of powdered samples.

3.2 Thermal simulation experiment

To simulate the hydrocarbon generation, expulsion, and retention evolution of shale under geological conditions, semi-open system pyrolysis experiments were conducted using a formation pore thermopressurized hydrocarbon generation simulator IV, independently developed by the Wuxi Petroleum Geology Institute of the Sinopec

Exploration and Production Research Institute. The apparatus consists mainly of a high-temperature high-pressure reactor, a pressure-boosting system, and a product collection system (Figure 2). The specific operational procedure includes: (1) loading the shale sample (~80 g) into the reactor and injecting deionized water to pressurize to the target simulated formation pressure; (2) rapidly heating the system to the target simulated formation temperature and maintaining for 48 h; (3) quickly cooling the reaction system to room temperature and collecting the gas and oil. The mixed products pass through a liquid nitrogen-cooled separator, where the gas is collected in a gas metering tube and the expelled oil is frozen in a liquid collection tube. Subsequently, dichloromethane is used to extract the residual oil from the pyrolyzed shale sample. Finally, the pyrolyzed shale sample is dried, weighed, and sealed for subsequent experimental analysis.

Based on the basin modelling results from the Mahu Depression and Jimsar Depression, the burial history and thermal history of the typical MY1 well and J10025 well penetrated the Fengcheng Formation and Lucaogou Formation were selected to design 8 and 9 sets of pyrolysis experimental parameters for the Fengcheng shale and Lucaogou shale, respectively (Ref.). These parameters included temperature, fluid pressure, and Formation pressure (Table 2). This study systematically characterized the yield and composition of the products from each pyrolysis experiment, carbon isotope characteristics, shale reservoir morphology, and pore physical properties.

3.3 Experimental analysis

To avoid the loss of light hydrocarbons, the shale was crushed to 100 mesh under liquid nitrogen cooling and then analyzed using the Rock-Eval VI instrument, although some loss of light hydrocarbons during the waiting time in the analysis was unavoidable. Total organic carbon (TOC) of the shale was analyzed using the LECO CS230 carbon/sulfur analyzer. Inorganic carbon in the shale was removed with 5% HCl prior to analysis. Kerogen was separated using HCl and HF (Durand and Nicaise, 1980), and the Ro values were measured with a Leica DM4500P polarized microscope equipped with a photometer. The oil SARA (saturates, aromatics, resins, and asphaltenes) fractions were separated using column chromatography (Ogbonnaya et al., 2024) and quantified with an XP205 balance. Gas components were analyzed using an Agilent 7890-5975C gas chromatograph equipped with an HP-5MS fused silica capillary column (60 m × 0.25 mm × 0.25 μm) and helium as the carrier gas at a flow rate of 1 mL/min. Saturated and aromatic hydrocarbons in the shale oil were analyzed using a tandem TSQ8000 Evo mass spectrometer, with ion peaks identified and quantified using Agilent ChemStation® software. The carbon isotopes of gas and oil SARA fractions were analyzed using a Thermo Delta V Advantage stable carbon isotope ratio mass spectrometer, with m/z peak heights below 204 mV. The micropores, mesopores, and macropores of the shale was determined using a combination of an Autopro 9,520 high-pressure mercury intrusion porosimeter and an ASAP 2460 adsorption analyzer. The porosity of the shale was measured using a QK-98 gas porosimeter. After argon ion polishing, the surface morphology and pore characteristics of the shale samples were observed using a Helios 650 focused ion beam scanning electron microscope.

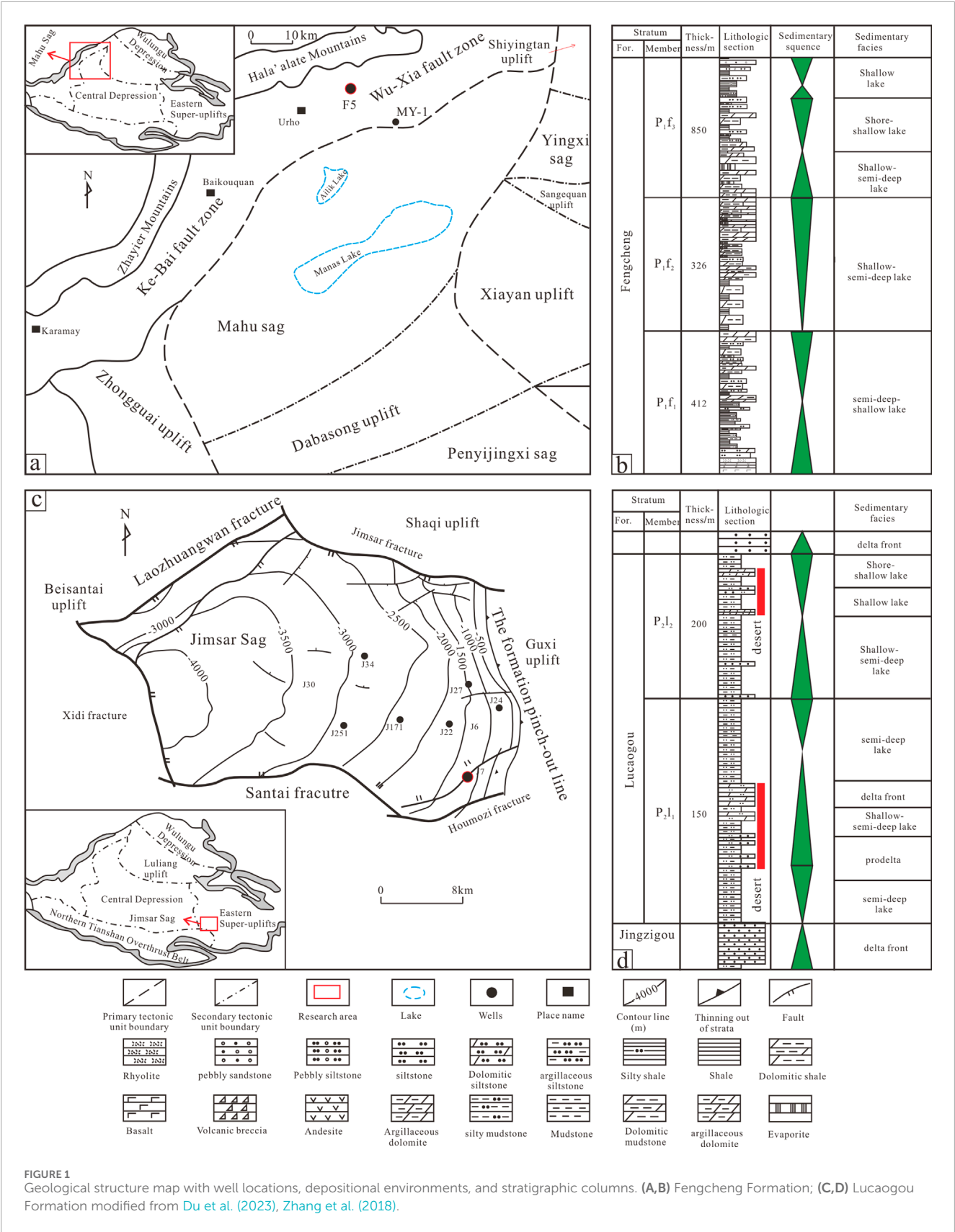
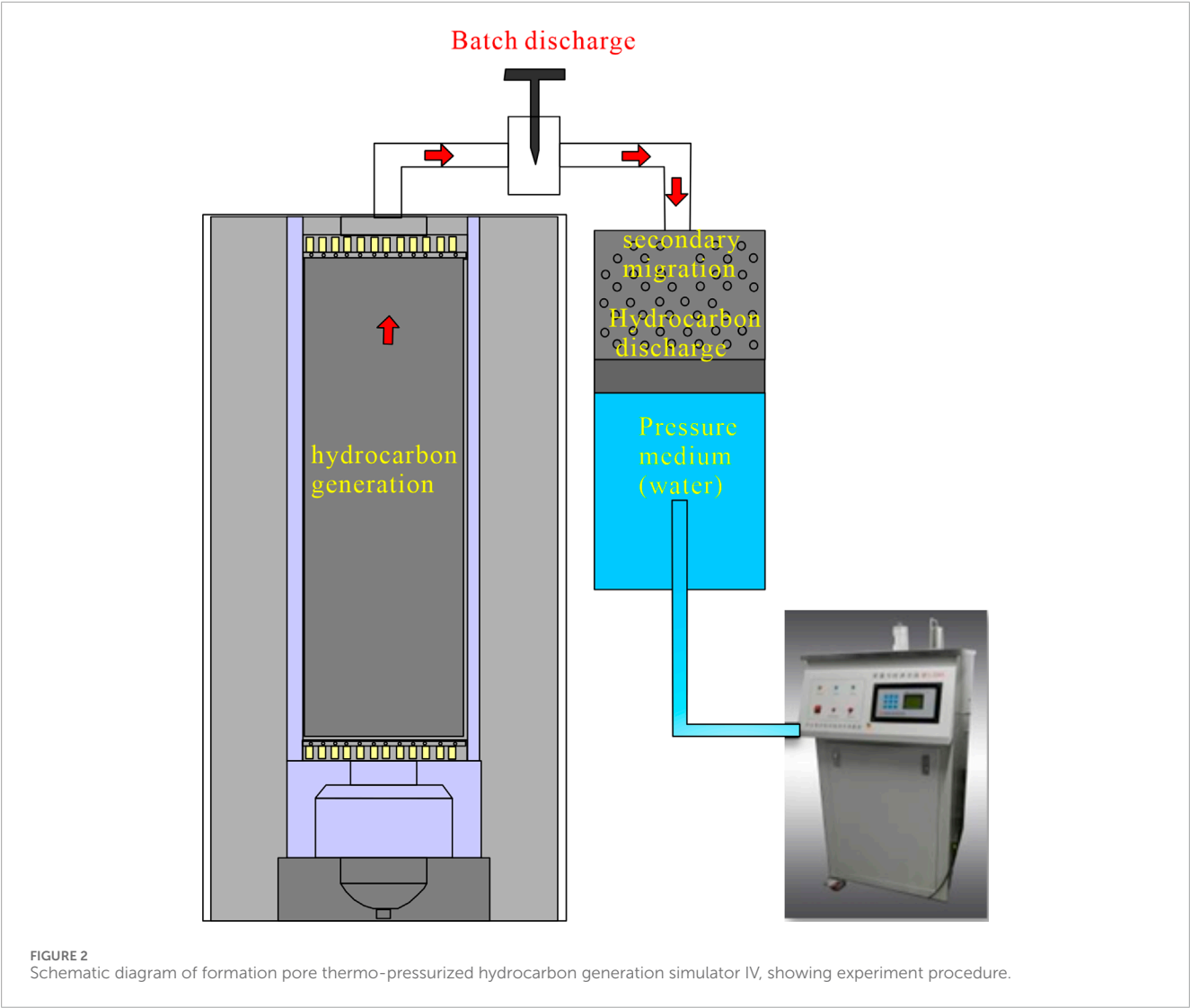


TABLE 1 Geochemical information of the Fengcheng and Lucaogou shale, including rock-eval pyrolysis, TOC, and Ro.

Sample	Formation	TOC (%)	S ₁ (mg HC/g Rock)	S ₂ (mg HC/g Rock)	HI (mg HC/g TOC)	Ro (%)
F5	Fengcheng	1.53	1.36	7.69	501.00	0.69
J7	Lucaogou	14.46	7.99	115.84	800.00	0.63



4 Results

4.1 Geological and geochemical features of shale samples

XRD analysis indicates that both Fengcheng shale and Lucaogou shale were the felsic lithofacies, with quartz and feldspar relative abundances exceeding 50%. However, Fengcheng shale is characterized by a high carbonate mineral content, predominantly dolomite (28.2%), whereas Lucaogou shale is characterized by a high clay mineral content, comprising 39.3% (Figure 3).

Organic petrology shows that the microscopic components of organic matter in both Fengcheng shale and Lucaogou shale were mainly composed of exinite and sapropelinite (Figure 4A). In comparison, Fengcheng shale featured telalginite and cutinize exhibiting yellow fluorescence (Figures 4B, C), while Lucaogou shale featured lamalginite and cutinize and spores with yellow fluorescence, as well as high contents of cutinite and funginite (Figures 4E, F). Additionally, the vitrinite group in both Fengcheng shale and Lucaogou shale is primarily composed of detrital vitrinite (Figures 4D, G). The TOC values of Fengcheng shale and Lucaogou shale are 1.53% and 14.46%, respectively, with HI values of 501.00 mg HC/g TOC and 800.00 mg HC/g TOC (Table 1),

TABLE 2 Thermal simulation experimental parameters of the Fengcheng and Lucaogou shale, including heating temperature, fluid pressure, and formation pressure.

Sample	Formation pressure (MPa)	Fluid pressure (MPa)	Heating time (h)	Heating temperature (°C)	Formation temperature (°C)	Ro (%)
F5	—	—	—	—	—	0.67
F5-300	81.6	47.6	48	300	90	0.7
F5-320	93.6	54.6	48	320	100	0.8
F5-330	104.4	60.9	48	330	105	0.9
F5-340	115.2	67.2	48	340	120	1.0
F5-350	124.8	72.8	48	350	140	1.1
F5-360	133.2	77.7	48	360	150	1.2
F5-370	139.2	81.2	48	370	160	1.3
F5-380	146.4	85.4	48	380	170	1.5
J7	—	—	—	—	—	0.63
J7-280	54.0	35.1	48	280	85	0.65
J7-300	58.8	38.2	48	300	95	0.7
J7-320	66.0	42.9	48	320	100	0.8
J7-330	74.4	48.4	48	330	110	0.9
J7-340	80.4	52.3	48	340	120	1.0
J7-350	86.4	56.1	48	350	135	1.1
J7-360	90.0	58.5	48	360	150	1.2
J7-370	93.6	60.8	48	370	160	1.3
J7-380	103.2	67.1	48	380	170	1.5

classified as high-quality shale (Welte and Tissot, 1984). Based on organic petrology and pyrolysis results, the organic matter in Fengcheng shale was type II₁, whereas that in Lucaogou Shale was type I (Chen et al., 2017).

The GC results indicate that although the main peak carbon for saturated hydrocarbons in Lucaogou shale was C₂₁, higher than the main peak carbon C₁₉ in Fengcheng shale, the relative content of saturated hydrocarbons with main peak carbons from C₁₆ to C₂₇ is higher in Lucaogou shale, whereas the relative content of saturated hydrocarbons with main peak carbons from C₂₉ to C₃₅ was higher in Fengcheng shale (Figure 5).

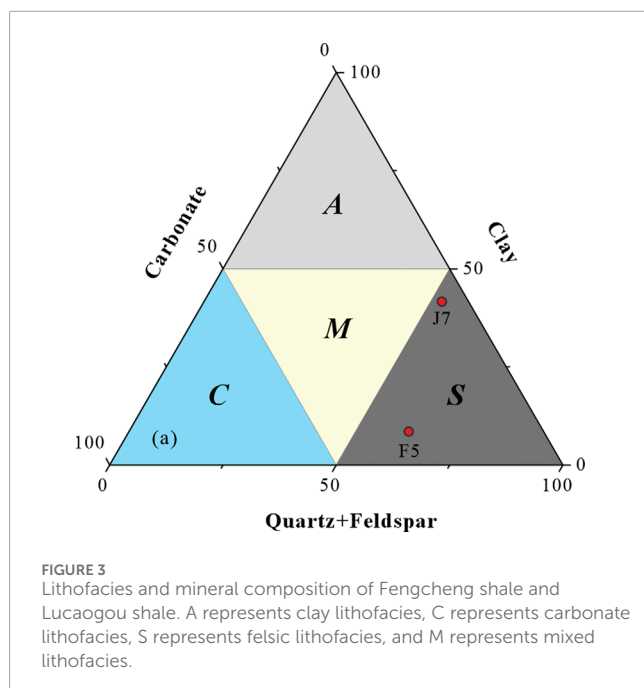
4.2 Relationship between temperature and Ro in thermal simulation experiment

To facilitate the guidance of shale oil exploration, it is necessary to establish a correlation between the simulation experiments timescale and geological timescales. Therefore, the Ro values of

Fengcheng shale and Lucaogou shale samples were measured before and after the simulation experiments and calibrated using the Vitrimat Easy Ro model (Sweeney and Burnham, 1990). As shown in the Figure 6, there is a positive linear correlation between the simulation experiment temperature and Ro, consistent with previous studies (Waples, 1980). This correlation provides a basis for applying the shale oil generation, expulsion, and retention models obtained from simulation experiments to actual geological conditions.

4.3 T_R of shale

HI is an important indicator for evaluating the hydrocarbon generation potential of shale. This study employs the statistical model proposed by Li E et al. (2020), which is very useful for the quantitative evaluation of shale oil and gas systems, to establish the relationship between HI and Ro for shale samples (Equation 1). Additionally, the T_R evaluation method based on the law of mass



conservation (Equation 2) is used to assess the degree of shale conversion (Chen and Jiang, 2015).

$$HI(Ro) = \frac{HI_0}{1 + \exp\left(\theta \cdot \ln\left(\frac{Ro}{\beta}\right)\right)} \quad (1)$$

$$T_R = \frac{1200(HI_0 - HI)}{HI_0(1200 - HI)} \quad (2)$$

where HI_0 initial hydrogen index, β represents the hydrocarbon generation peak, and θ represents hydrocarbon generation window.

The results indicate that both Fengcheng shale and Lucaogou shale began to degrade at a Ro of 0.65% and 0.6%, respectively. As maturity increases, the HI gradually decreases. The β values for Fengcheng shale and Lucaogou shale were 1.00 and 1.01, respectively, indicating that the degradation peak was reached at Ro values of 1.00% and 1.01%. The θ values were 12.5 and 11.5, respectively, suggesting that the hydrocarbon generation window for Lucaogou shale is wider than that for Fengcheng shale. Additionally, the model shows that, although the T_R at the degradation peak is higher for Fengcheng shale than for Lucaogou shale, the T_R values converge at 0.91 when the Ro reaches 1.1% (Figure 7).

4.4 Product yield and composition

4.4.1 Total product yield of shale

Thermal simulation experiment results indicate that the yield of Fengcheng shale can be divided into four stages (Figure 8A). In the first stage ($Ro = 0.75\%–0.88\%$), the products were mainly oil. Both the total yield and oil yield increase with temperature, from 158.88 mg/g TOC and 157.23 mg/g TOC to 447.38 mg/g TOC and 332.6 mg/g TOC, respectively. The gas yield was relatively low at this stage, increasing from 1.65 mg/g TOC to 114.78 mg/g TOC. In the second stage ($Ro = 0.88\%–0.97\%$), both oil and gas

products increase slowly, with oil and gas yields increasing by only 1.84 mg/g TOC and 0.6 mg/g TOC, respectively. In the third stage ($Ro = 0.97\%–1.06\%$), there was a rapid secondary increase in oil and gas products, reaching peak yields of 767.09 mg/g TOC and 504.31 mg/g TOC. In the fourth stage ($Ro = 1.06\%–1.14\%$), the total yield remained stable, with the secondary cracking oil yield decreasing to 365.44 mg/g TOC and the corresponding gas yield increasing to 376.08 mg/g TOC (Figure 8A).

The yield of Lucaogou shale can also be divided into four stages (Figure 8B). In the first stage ($Ro = 0.60\%–0.64\%$), the degradation rate of organic matter was slow, with low oil and gas yields of 84.95 mg/g TOC and 35.88 mg/g TOC, respectively. In the second stage ($Ro = 0.64\%–0.77\%$), the oil yield increases rapidly to 366.59 mg/g TOC, while the gas yield increases slowly to 111.21 mg/g TOC. In the third stage ($Ro = 0.77\%–1.05\%$), the oil and gas yields remain stable, reaching peak values of 402.28 mg/g TOC and 113.38 mg/g TOC at a Ro of 0.92%. In the fourth stage ($Ro = 1.05\%–1.12\%$), secondary cracking of oil leads to a decrease in oil yield to 318.87 mg/g TOC. Continued degradation of organic matter results in an increase in gas and total yields, reaching peak values of 163.25 mg/g TOC and 554.57 mg/g TOC, respectively (Figures 7, 8).

4.4.2 Expulsion and retention oil yields and composition

The expulsion and retention oil yields of Fengcheng shale can also be divided into four stages (Figure 9A). In the first stage ($Ro = 0.75\%–0.88\%$), the generated oil mainly accumulates within the shale, with the residual oil yield rapidly increasing to 328.67 mg/g TOC, while the expelled oil yield is relatively low at 3.93 mg/g TOC (Figure 9A). The retained oil was characterized by a relatively high abundance of stable C_{30} compounds and saturated hydrocarbons with a dominant carbon number of C_{21} , similar to the initial sample. In contrast, the discharged oil contained heavier saturated hydrocarbons with a predominant carbon number of C_{23} (Figure 10). In the second stage ($Ro = 0.88\%–0.97\%$), the residual oil yield remains stable, and the expelled oil yield increases to 28.3 mg/g TOC (Figure 9A). During this stage, the retained oil underwent a significant compositional change, with a decrease in large molecules like C_{30} hopanes and a corresponding increase in C_{21} saturated hydrocarbons. The discharged oil exhibited a shift in hydrocarbon distribution, with an enrichment of $C_{15}–C_{19}$ saturated hydrocarbons and a depletion of $C_{21}–C_{23}$ saturated hydrocarbons (Figure 10). In the third stage ($Ro = 0.97\%–1.06\%$), further degradation of organic matter leads to a rapid increase in residual oil yield to a peak of 430.97 mg/g TOC, and the expelled oil yield increases to 73.34 mg/g TOC (Figure 9A). The content of large molecules, such as C_{30} hopanes, in the retained oil continued to decrease during this stage, the content of $C_{20}–C_{24}$ saturated hydrocarbons continues to increase. Similarly, $C_{14}–C_{19}$ saturated hydrocarbons dominated the discharged oil (Figure 10). In the fourth stage ($Ro = 1.06\%–1.14\%$), secondary cracking causes the residual oil yield to decrease rapidly to 246.27 mg/g TOC, while the expelled oil yield continues to increase, reaching a maximum of 119.18 mg/g TOC (Figure 9A). The composition of the retention oil remained stable during this stage, The continued expulsion of retained oil results in an increase in the content of $C_{20}–C_{24}$ saturated hydrocarbons in the expelled oil (Figure 10).

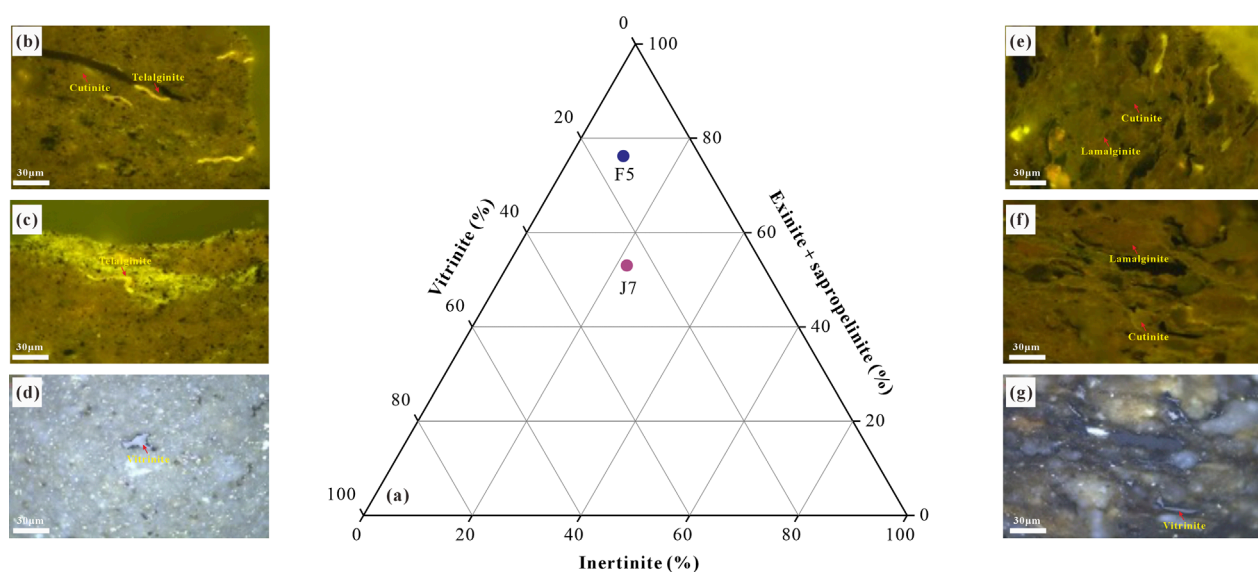


FIGURE 4
Organic petrology and microscopic components of Fengcheng shale and Lucaogou shale. (A) ternary diagram showing the relative abundance of microscopic components (B–D) show the organic petrology characteristics of Fengcheng shale, with telalginite and cutinite exhibiting yellow fluorescence, while vitrinite exhibiting gray under white reflected light; (E–G) show the organic petrology characteristics of Lucaogou shale, with lamalginite and cutinite exhibiting yellow fluorescence, while vitrinite exhibiting gray under white reflected light.

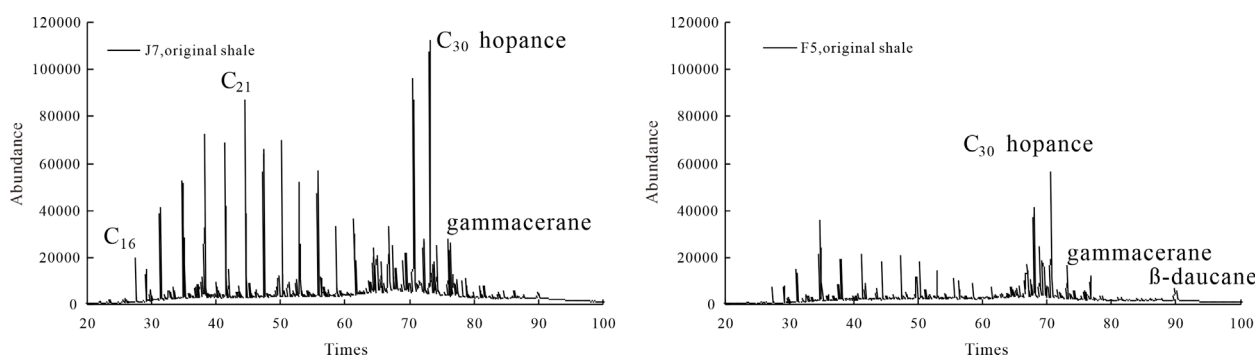
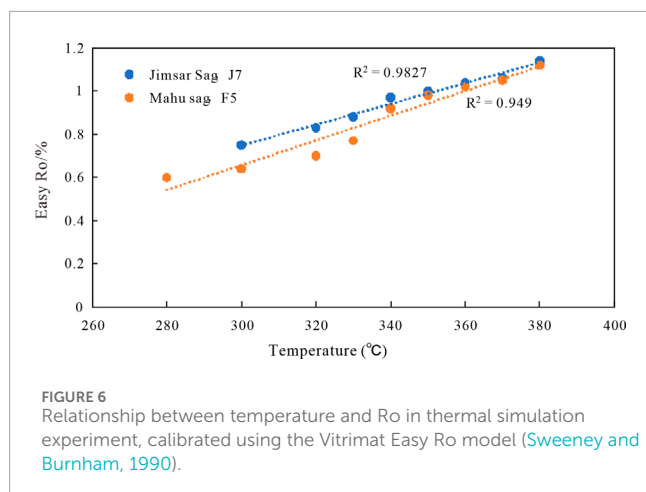


FIGURE 5
Total ion chromatograms (TIC) of saturated hydrocarbons from Fengcheng and Lucaogou shale samples.

The expulsion and retention oil yields of Lucaogou shale can be divided into five stages (Figure 9B). In the first stage ($R_o = 0.60\%–0.64\%$), the oil mainly accumulates within the shale, with the residual oil yield being low at 100.66 mg/g TOC, and the expelled oil yield at only 1.02 mg/g TOC (Figure 9B). The main peak carbon of saturated hydrocarbons in the retained oil was C₂₁, along with stable biomarker compounds at C₃₀, showing no significant difference from the initial samples. During this stage, the saturated hydrocarbons in the expelled oil were primarily light hydrocarbons, with the initial main peak carbon C₁₆. As maturity increased, hydrocarbons with main peak carbons of C₂₃–C₂₅ expelled (Figure 11). In the second stage ($R_o = 0.64\%–0.77\%$), the residual oil yield rapidly increases to 277.74 mg/g TOC, while the expelled oil yield also rapidly increases to 88.85 mg/g TOC (Figure 9B). During this stage, the content of large molecular

compounds such as C₃₀ hopanes in the retained oil decreases rapidly, while the saturated hydrocarbons with a main peak carbon of C₂₀ increase. Simultaneously, the content of saturated hydrocarbons with main peak carbons of C₂₃–C₂₅ in the expelled oil continues to increase (Figure 11). In the third stage ($R_o = 0.77\%–0.92\%$), the residual oil yield slowly increases to a peak of 295.94 mg/g TOC, while the expelled oil continues to increase to 106.34 mg/g TOC (Figure 9B). During this stage, large molecular compounds such as C₃₀ hopanes in the retention oil almost disappear, and the content of light hydrocarbons with main peak carbons below C₂₂ increased. The content of C₂₀–C₂₄ saturated hydrocarbons in the expelled oil increased (Figure 11). In the fourth stage ($R_o = 0.92\%–1.05\%$), secondary cracking causes the residual oil yield to decrease rapidly to 155.3 mg/g TOC, while the expelled oil continues to increase to a peak of 236.02 mg/g TOC (Figure 9B). The expelled oil was mainly



composed of saturated hydrocarbons ranging from C_{14} to C_{18} , with the main peak carbon decreasing to C_{16} (Figure 11). In the fifth stage ($Ro = 1.05\%$ – 1.12%), as the degree of cracking increases, both the residual oil and expelled oil yields decrease to 103.67 mg/g TOC and 215.2 mg/g TOC, respectively (Figure 9B). The composition of the retention oil remained stable during this stage, while the content of hydrocarbons with peak carbons more than C_{19} in the discharged oil increased slightly (Figure 11).

4.4.3 Gas yields and composition

Thermal simulation experiments revealed that the predominant gaseous products from Fengcheng and Lucaogou shales were CO_2 , H_2 , and hydrocarbon compounds (Figure 12). The gas composition from the Fengcheng shale at the early stage of organic matter degradation ($Ro = 0.75\%$) was characterized by extremely low yields and a dominance of H_2 (64%) and CO_2 (28%), with CH_4 representing only 7% (Figures 12A, B). As maturity increased ($Ro = 0.75\%$ – 0.83%), the H_2 yield exhibited a significant increase of 237.61 mL/g TOC. In contrast, the CO_2 and CH_4 yields increased at a slower rate, reaching 10.55 mL/g TOC and 37.75 mL/g TOC, respectively. Notably, heavier hydrocarbon gases (C_2 – C_5) began to form during this stage, with a yield of 13.32 mL/g TOC. H_2 dominated the gas product, accounting for a substantial 79%, followed by CH_4 at 13% (Figures 12A, B). As Ro increased to 0.83% – 1.0% , the H_2 yield decreased sharply to 90.85 mL/g TOC. In contrast, the yields of CH_4 and C_2 – C_5 heavy hydrocarbons increased significantly, with relative abundances increasing by 18% and 16%, respectively. The CO_2 yield increased slowly, with a relative abundance increase of only 3% (Figures 12A, B). As Ro increased to 1.0% – 1.14% , the H_2 yield plateaued at approximately 90.85 mL/g TOC. In contrast, the yields of CO_2 , CH_4 , and C_2 – C_5 heavy hydrocarbons continued to rise, reaching 30.39 mL/g TOC, 133.98 mL/g TOC, and 101.93 mL/g TOC, respectively. As a result, the relative abundance of H_2 decreased to 27% (Figures 12A, B).

The gas production rates of various components in the Lucaogou shale were relatively low. The CO_2 production rate was the highest, but only 60.33 mL/g TOC, and the H_2 production rate was the lowest, averaging only 0.84 mL/g TOC. In the early stage of organic matter degradation ($Ro = 0.6\%$ – 0.64%), CO_2 dominated, with a relative abundance of 86%–91% (Figures 12C, D). With

increasing maturity, the production rates of CH_4 and C_2 – C_5 heavy hydrocarbons gradually increased, and the relative abundance of CO_2 decreased accordingly. When Ro reached 1.12%, the relative abundances of CH_4 and C_2 – C_5 heavy hydrocarbons reached 24% and 19%, respectively, while the relative abundance of H_2 stabilized at about 1.44% (Figures 12C, D).

4.4.4 Carbon isotopes of product components

Carbon isotope analysis shows that with increasing maturity, the $\delta^{13}C$ values of CO_2 and light hydrocarbons (C_1 – C_4) in Fengcheng shale gas exhibit an initial increase followed by a decrease, reaching a minimum at a Ro value of 0.97%. In contrast, the $\delta^{13}C$ values of light hydrocarbons (C_5) show an opposite trend, reaching a maximum at a Ro value of 0.97%. Similarly, $\delta^{13}C$ values of saturates, aromatics, resins, and asphaltenes in the oil phase also show a decrease-increase trend, with a minimum at Ro value of 0.97% (Table 3). The $\delta^{13}C$ values of saturated hydrocarbons, aromatics, resins, and asphaltenes in the Lucaogou shale oil generally showed a negative shift. In contrast, the $\delta^{13}C$ values of light hydrocarbons (C_1 – C_5) exhibited a positive shift. The $\delta^{13}C$ values of CO_2 showed a more complex variation, with a relative enrichment of ^{13}C at a vitrinite reflectance (Ro) of 0.77%–1.02%, with an average $\delta^{13}C$ value of -1.2% , followed by a trend towards depletion (Table 3).

4.5 Reservoir characteristics of shale samples

SEM results indicate that the pores in shale primarily consist of inorganic matrix pores, organic pores, and fractures (Loucks et al., 2012). Organic matter in Fengcheng shale is uniformly distributed in both banded and massive forms. The shale is characterized by bitumen-filled fractures, well-developed intergranular inorganic pores, but a lack of organic pores (Figure 13A). At the low maturity stage ($Ro = 0.62\%$ – 0.73%), the preliminary degradation of organic matter and bitumen leads to the formation of fractures at the boundaries between organic matter and minerals in shale. A small number of pores develop within the bitumen, but overall, organic pores remain underdeveloped (Figures 13B, C). With further increases in maturity ($Ro = 0.83\%$ – 0.97%), intense thermal degradation of organic laminae and pore-filling bitumen led to a significant increase in the number of pores and fractures (Figures 13D, E). When the Ro value reached 1.12%, refractory plant fragments were observed coexisting with bitumen in the pores and fractures, although the increase in the number of fractures was not significant (Figure 13F). Overall, the pore evolution characteristics of Lucaogou shale were similar to those of Fengcheng shale. Intergranular pores in clay minerals and fractures were observed in the initial Lucaogou shale samples (Figure 13G). At the low maturity stage ($Ro = 0.60\%$ – 0.70%), intergranular pores and fractures increased (Figures 13H, I). At the moderate maturity stage ($Ro = 0.92\%$ – 1.12%), intense degradation of organic matter led to an increase in fractures, intergranular mineral pores, and organic pores in the shale, resulting in a loosening of the shale matrix and enhanced pore connectivity (Figures 13J–L).

This study classifies macropores, mesopores, and micropores according to IUPAC standards (Ougier-Simonin et al., 2016; Sing, 1985). High-pressure mercury intrusion and nitrogen adsorption

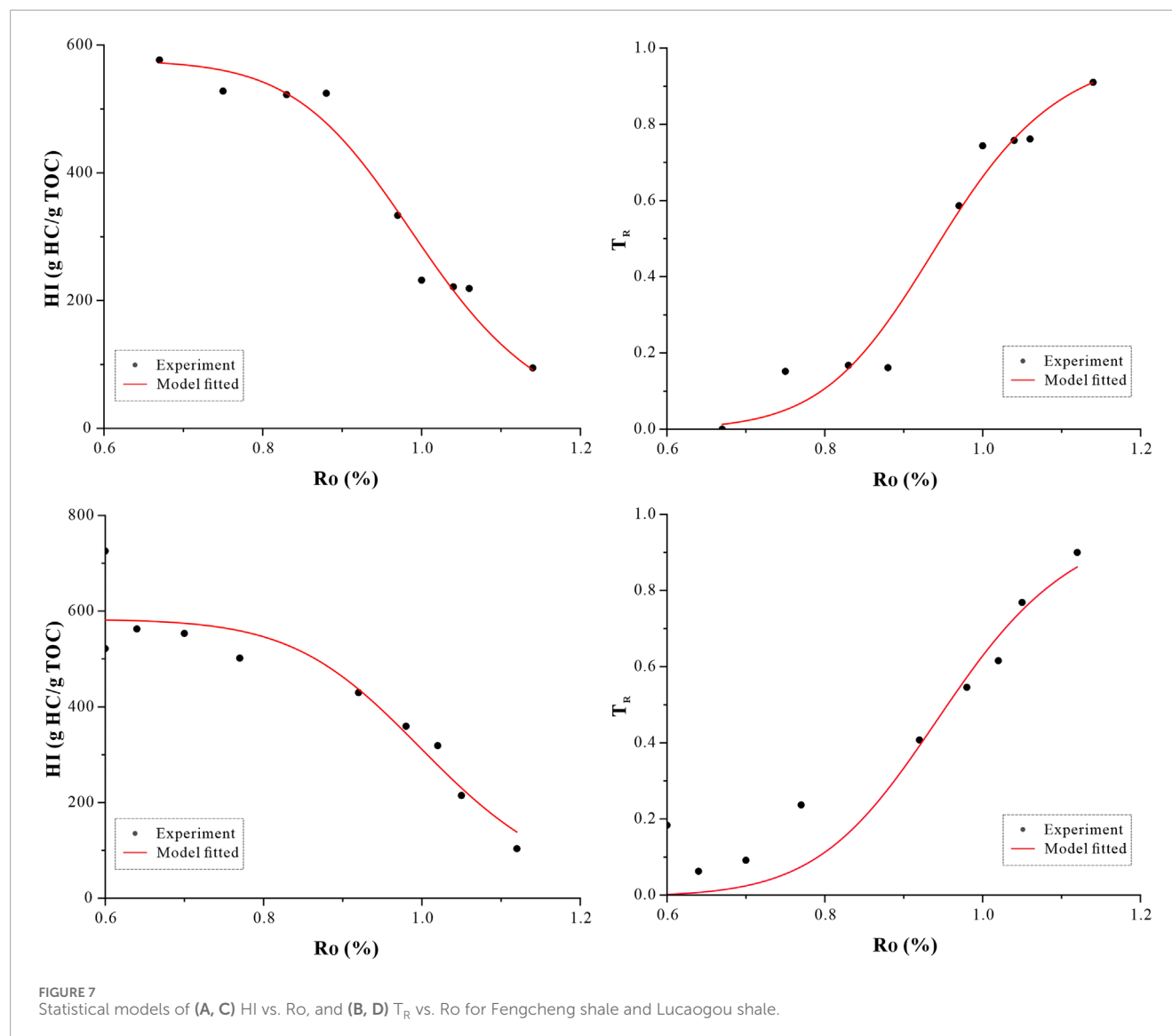


FIGURE 7
Statistical models of (A, C) HI vs. Ro, and (B, D) T_R vs. Ro for Fengcheng shale and Lucaogou shale.

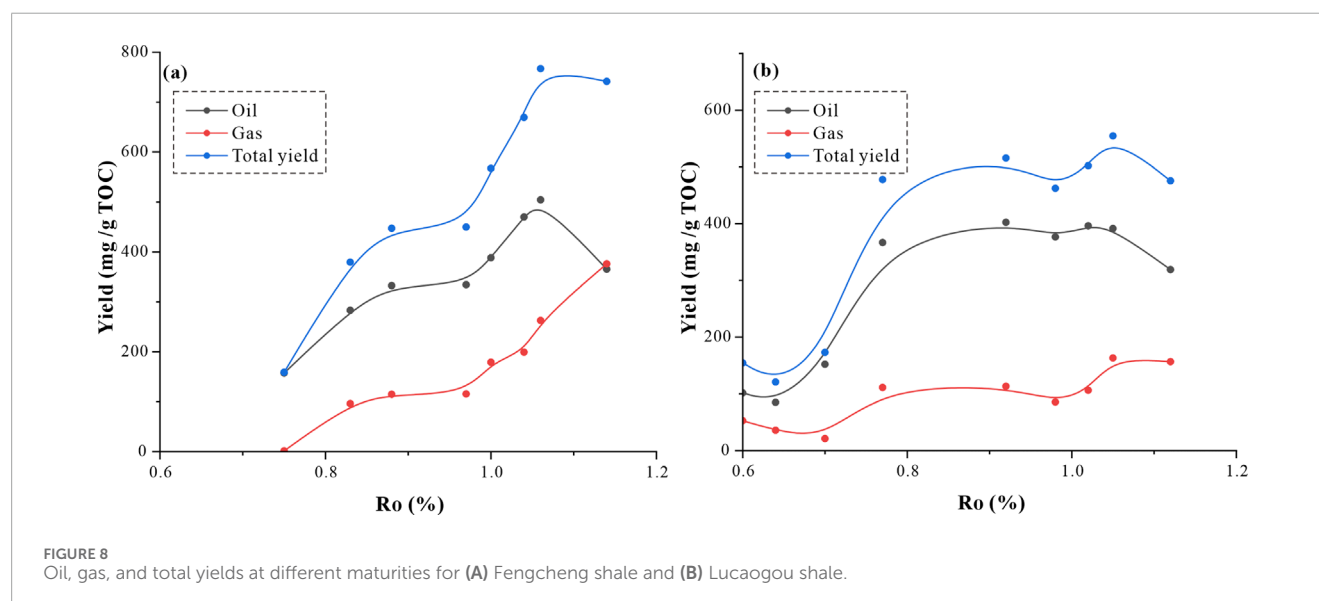


FIGURE 8
Oil, gas, and total yields at different maturities for (A) Fengcheng shale and (B) Lucaogou shale.

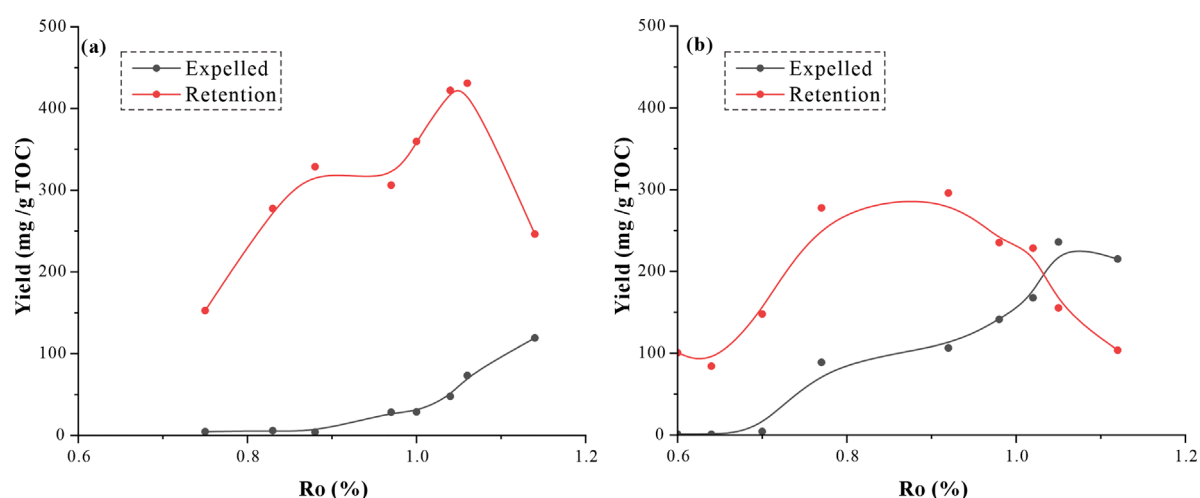


FIGURE 9
Expulsion and residual oil yields at different maturities for (A) Fengcheng shale and (B) Lucaogou shale.

results indicate that with increasing organic maturity, the pore volume of both Fengcheng and Lucaogou shales generally increases. Notably, macropores and mesopores contribute most significantly to the total pore volume (Figure 14). The maximum pore volume of Fengcheng shale is 0.026 mL/g, which is markedly lower than the 0.085 mL/g observed for Lucaogou shale. Interestingly, both Fengcheng and Lucaogou shales show a phase of decreased pore volume at Ro values of 1.04% and 0.98%, respectively, which may be related to pore closure caused by hydrocarbon expulsion (Figure 14).

5 Discussions

5.1 Hydrocarbon generation pattern

Previous studies have demonstrated that the degradation of organic matter in shale exhibits distinct stages (Tissot and Espitalie, 1975). Based on Ro, the degradation process can be divided into four stages: biogeochemical gas generation stage ($Ro < 0.6\%$), thermal cracking oil and gas generation stage ($Ro = 0.6\%–1.3\%$), thermal cracking wet gas generation stage ($Ro = 1.3\%–2.0\%$), and high-temperature cracking dry gas generation stage ($Ro > 2.0\%$) (Schmoker, 1996). However, the heterogeneity of lacustrine shale is significant, and the thermal degradation processes of organic matter in different basins or strata vary greatly (Chen and Jiang, 2015). Based on the results of the above simulation experiments, this study establishes the hydrocarbon generation patterns of the Fengcheng shale and the Lucaogou shale, respectively, aiming to provide more accurate guidance for shale oil exploration in these two areas of the Junggar Basin.

5.1.1 Fengcheng shale in the Mahu Sag

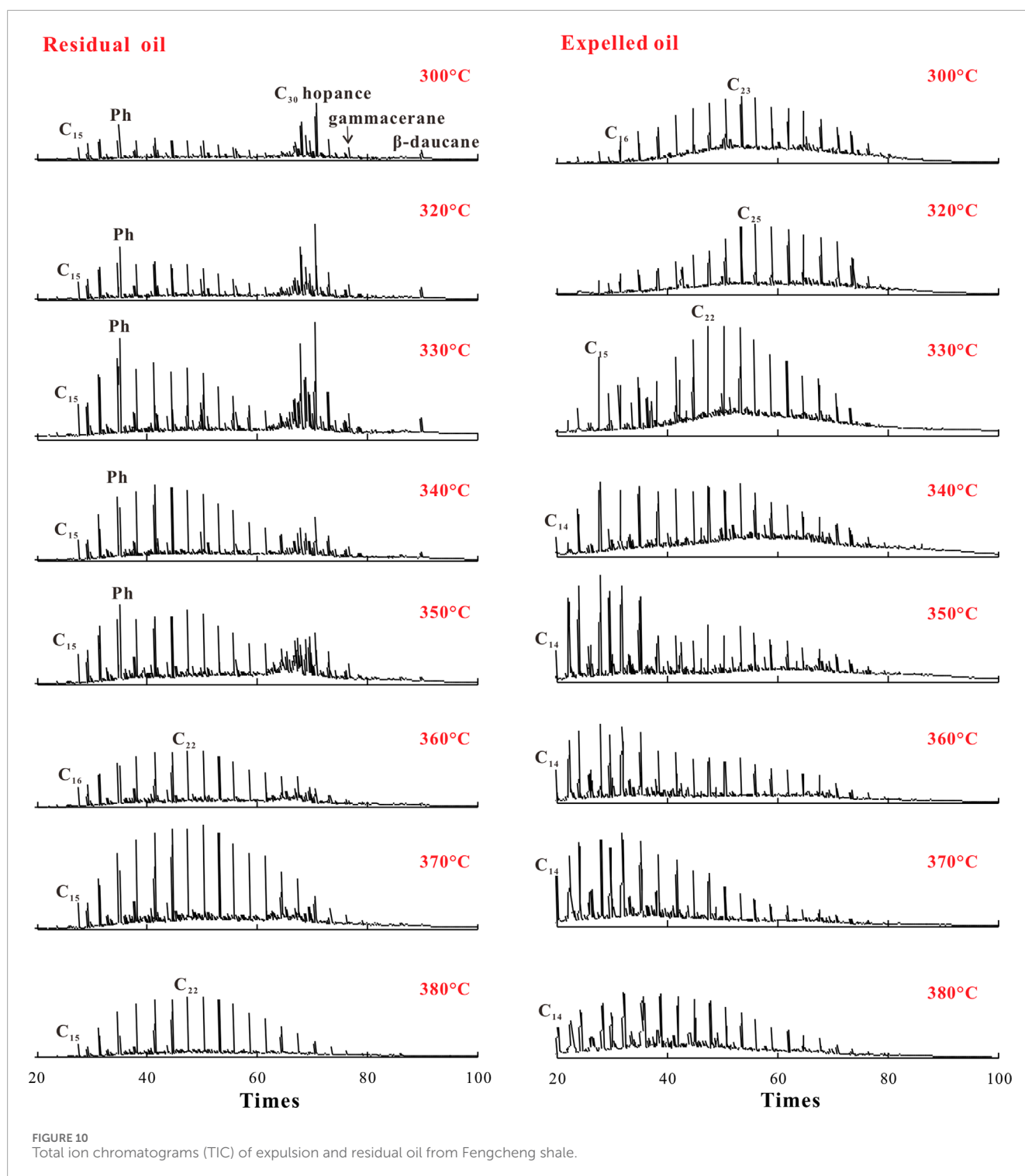
Previous studies have indicated that the Fengcheng shale in the Mahu Sag is rich in algal and bacterial organic matter, with a wide hydrocarbon generation window and a predominance of oil generation over gas generation (Cao et al., 2015). However,

the results of this simulation experiment indicate that at the low maturity stage, gas yield is relatively low. As maturity approaches the high maturity stage, gas becomes the dominant product. When the Ro value reaches 1.14%, gas yield surpasses oil yield (Figures 8A, 15A).

Combining the results of previous studies, this study divides the degradation process of organic matter in Fengcheng shale into three stages, as shown in Figure 15A. (1) Stage I ($Ro < 0.75\%$): due to the relatively low thermal degradation temperature ($<300^{\circ}\text{C}$), a small portion of organic matter initially degrades into macromolecular compounds, which remain trapped within the pores and fractures (Figures 13B, C). At this stage, the T_R value of Fengcheng shale reaches only 5%, with no gas generation or hydrocarbon expulsion (Figure 15A). (2) Stage II ($Ro = 0.75\%–1.04\%$): As the temperature increases, organic matter and macromolecular bitumen gradually degrade, producing gases such as H_2 and hydrocarbons, as well as a significant amount of light hydrocarbons with a predominant carbon peak around C_{24} (Figures 11A, 12A). Therefore, a negative shift of carbon isotopes in gas and oil components was observed (Bjørøy et al., 1991). Some of these products were expelled from the shale, leading to a gradual increase in hydrocarbon expulsion (Figure 15A). This stage shows two peaks in the oil generation rate, which may be attributed to the increased pore pressure in the shale, leading to pore compaction and closure after hydrocarbon expulsion (Zhang Y et al., 2022). (3) Stage III ($Ro = 1.04\%–1.14\%$): as the organic matter T_R increases from 80% to 91%, the yield of retained oil decreases (Figure 15A). This may relate to two factors: first, the further degradation of organic matter leads to an increased proportion of $\text{C}_{20}\text{--}\text{C}_{24}$ saturated hydrocarbons (Figure 11), which enhances the fluidity of the oil and results in greater hydrocarbon expulsion; second, some of the retained oil undergoes secondary cracking, converting into gas (Wang et al., 2022).

5.1.2 Lucaogou shale in the Jimsar sag

In contrast, Lucaogou shale contains lower amounts of exinite and sapropelinite groups, while it has higher amounts of vitrinite and inertinite groups (Figure 4A). The lower hydrocarbon potential



of the vitrinite and inertinite groups (Welte and Tissot, 1984) may contribute to the significantly lower yield in Lucaogou shale compared to Fengcheng shale (Figure 15A). In contrast to the Fengcheng shale, the gas product of the Lucaogou shale is primarily CO_2 (Figure 12D). This is likely due to the higher content of carboxylic and carbonyl functional groups in its organic matter (Li et al., 2024).

This study also divides the degradation process of organic matter in Lucaogou shale into three stages, as shown in Figure 15B.

(1) Stage I ($R_o < 0.7\%$): as temperatures below 300°C, only a small portion of organic matter in Fengcheng shale degrades into macromolecular bitumen, which remains trapped in the pores and fractures of the shale (Figures 13H, I). During this stage, the organic matter conversion ratio is low, with a T_R of only 2.5%. Despite this, the gas yield is relatively high, due to the lower energy required for the degradation of carbonyl and carboxyl groups, resulting in substantial CO_2 generation (Smirnov et al., 2024). (2) Stage II ($R_o = 0.7\%–1.05\%$): The hydrocarbon generation potential

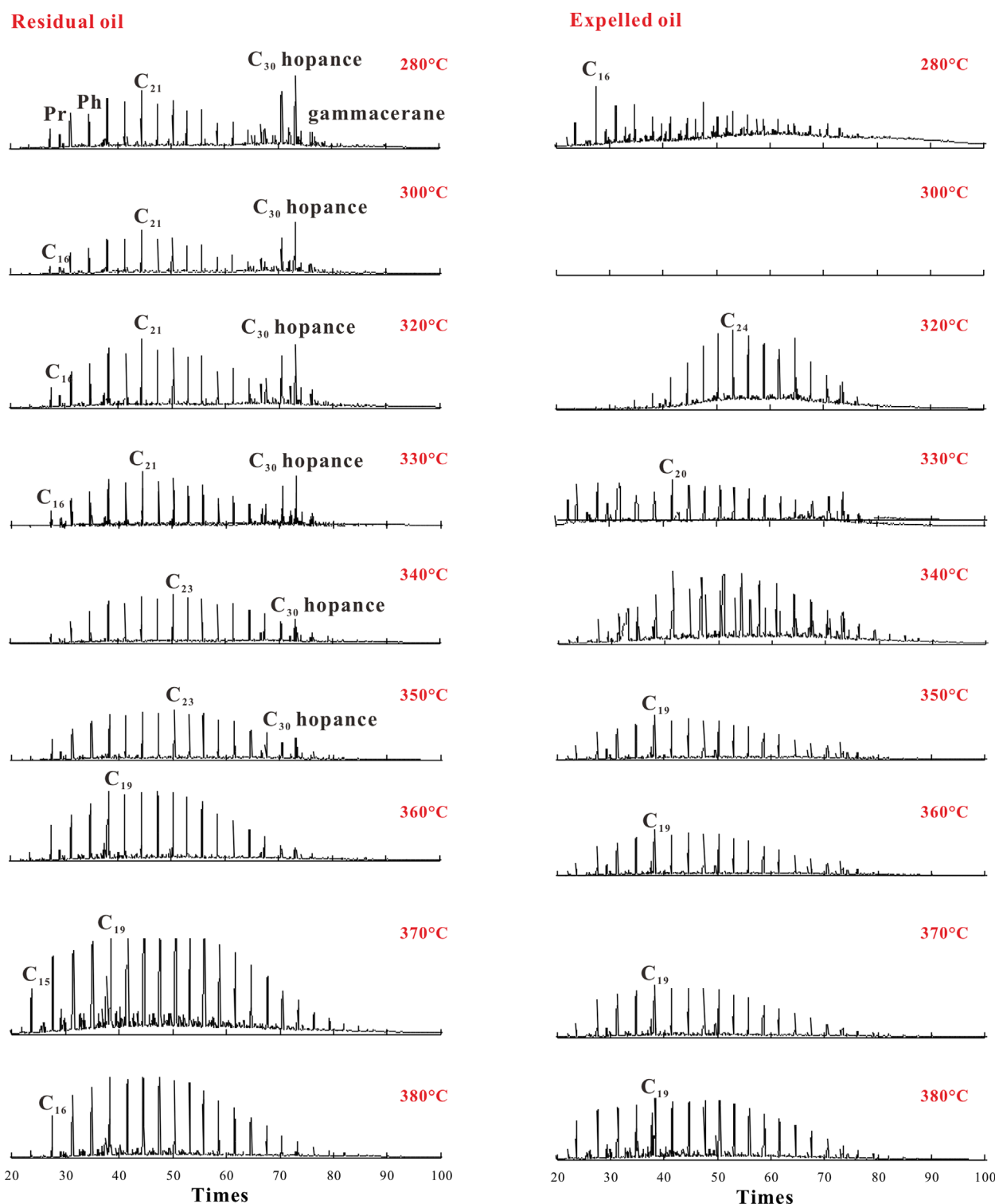


FIGURE 11
Total ion chromatograms (TIC) of expulsion and residual oil from Lucaogou shale.

of the organic matter rapidly decreases to 214.7 mg HC/g TOC, leading to the production of gas and light hydrocarbons with a peak carbon number below C_{24} (Figure 11B). This results in a negative migration of carbon isotopes in hydrocarbon gases and oil components (Bjørøy et al., 1991). The Lucaogou shale reached its oil

generation peak when Ro reached 0.92%. Subsequently, continued hydrocarbon expulsion leads to a decrease in retained oil yield and a corresponding increase in expelled oil yield. Additionally, gas yield slowly rises during this stage, predominantly as hydrocarbon gases (Figure 15B). (3) Stage III (Ro = 1.05%–1.12%): secondary cracking

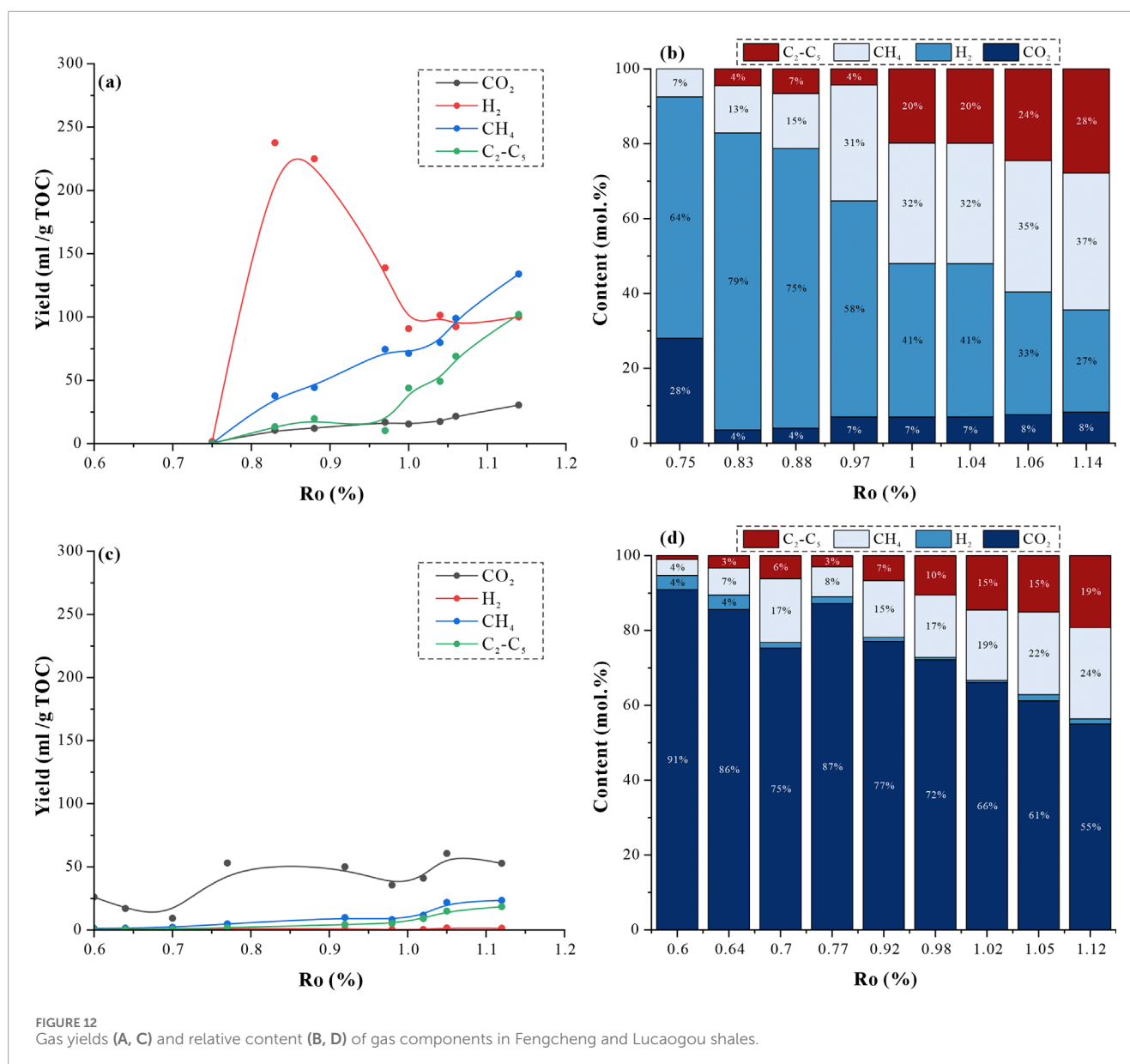


FIGURE 12 Gas yields (A, C) and relative content (B, D) of gas components in Fengcheng and Lucaogou shales.

led to a decrease in both expelled oil and residual oil yields, while the yield of hydrocarbon gases continued to increase. During this stage, the T_R of the Lucaogou shale reached a high of 82% (Figure 15B).

In summary, the hydrocarbon generation potential of Fengcheng shale is superior to that of Lucaogou shale, whether considering gas yield or oil yield. However, Lucaogou shale began the thermal degradation earlier than Fengcheng shale and has a broader pyrolysis degradation window. The corresponding T_R is slightly higher for Fengcheng shale. However, at the high maturity stage, their T_R converge. Additionally, the yield of expelled oil of Lucaogou shale is higher than that of Fengcheng shale.

5.2 Hydrocarbon expulsion efficiency of shale

Based on whether hydrocarbons were expelled from the shale, lacustrine shale oil was classified into two categories: layered shale

oil and shale-type shale oil (He et al., 2023; Jin et al., 2021). The characteristics of shale oil occurrence, evaluation parameters for the “sweet spot” intervals, and development methods differ between these two types (Zhao et al., 2018; Zou et al., 2019). Exploration results have shown that the Fengcheng shale is classified as shale-type shale oil, while the Lucaogou shale is classified as layered shale oil (Gong et al., 2024). Investigating the differences in hydrocarbon expulsion ratio and their controlling factors between these two shale layers is crucial for evaluating and selecting favorable development intervals for shale oil in the Junggar Basin.

Previous studies have indicated that the hydrocarbon expulsion efficiency of shale is related to factors such as organic matter type, maturity, mineral composition, pore characteristics, and oil properties (Esemeh et al., 2012; Liu et al., 2023; Zhao et al., 2023). Thermal simulation experiments demonstrated that Lucaogou shale commenced hydrocarbon expulsion at an earlier maturity stage, with a R_o value of 0.6% (Figures 15, 16A). This indicates that

TABLE 3 Carbon isotopes of gas and oil components from Fengcheng and Lucaogou shales.

Sample	Ro (%)	δ13CPDB(‰)											
		CO2	CH4	C2H6	C3H8	iC4H10	nC4H10	iC5H12	nC5H12	Sa	Ar	Re	As
F5	0.62	−13.2	—	—	—	—	—	—	—	−31.0	−30.4	−30.9	−30.4
	0.75	−4.9	−43.6	−34.5	−33.5	−34.3	−31	−31	−31.2	−31.5	−30.5	−30.6	−30.7
	0.83	−6	−42.8	−34.4	−33.6	−34.7	−31	−32.1	−32	−31.1	−30.2	−30.6	−29.6
	0.88	−17.3	−52.2	−51.1	−42.1	−42.6	−32.3	−29.3	−29.2	−31.3	−30.3	−30.6	−30.2
	0.97	−17.3	−52.2	−51.1	−42.1	−42.6	−32.3	−29.3	−17.3	−31.5	−32.6	−32.0	−32.2
	1.00	6.4	−44.7	−34.1	−34.8	35.5	−32.4	−33	−32.4	−31.4	−30.3	−30.3	−29.4
	1.04	6.3	−44.6	−34.5	−35.3	−35.9	−32.9	−33.6	−32.5	−30.7	−29.5	−29.5	−29.2
	1.16	6.1	−43.2	−34.1	−35.1	−35.4	−32.6	−33.1	−31.9	−30.5	−29.4	−29.1	−28.6
J7	0.60	−11.7	−43.2	−35.6	−34.9	−33.3	−30.4	−29	−29.3	−33.9	−32.0	−32.0	−32.5
	0.64	−9.7	−44.5	−36.2	−34.1	−33.4	−31.6	−30.4	−30.4	−33.5	−31.4	−31.3	−31.7
	0.7	−11	−44.5	−35.8	−34.3	−34.2	−32	−30.6	−30.5	−33.5	−31.2	−31.1	−31.3
	0.77	1.0	−44.5	−36.3	−35.1	−35.1	−32.9	−32.3	−31.6	−33.2	−30.8	−30.5	−29.7
	0.92	−1.1	−44.5	−35.9	−34.9	−34.7	−33.1	−32.4	−32.4	−32.0	−30.4	−30.1	−29.1
	0.98	−0.3	−45.4	−35.5	−34.9	−35.4	−33.3	−33	−32.9	−31.6	−30.1	−29.8	−29.1
	1.02	−4.4	−45.2	−35	−34.7	−35.3	−33.3	−32.9	−32.7	−32.1	−29.7	−29.4	−29.8
	1.05	−8.2	−44.5	−34.1	−34.1	−34.9	−32.9	−33.3	−32.4	−31.2	−29.5	−29.1	−28.9
	1.12	−9.1	−44.3	−34.3	−34.2	−34.9	−33.1	−33.7	−32.4	−31.1	−29.1	−28.4	−29.3

during stage I of organic matter degradation, the hydrocarbon expulsion ratio is primarily determined by the organic matter type, with shales rich in easily degradable organic material exhibiting higher hydrocarbon expulsion ratio. Although the hydrocarbon generation potential of the Lucaogou shale was lower than that of the Fengcheng shale, during stages II-III, where maturity and T_R were similar, Lucaogou shale exhibited significantly higher hydrocarbon expulsion ratios compared to Fengcheng shale, with a maximum hydrocarbon expulsion ratio 2.1 times that of Fengcheng shale (Figure 16A). This suggests that the characteristics of the shale reservoir and the mobility of the oil may be the most important factors influencing the hydrocarbon expulsion ratio. As shown in Figure 16B, the hydrocarbon expulsion ratio of both the Fengcheng shale and the Lucaogou shale exhibits a positive correlation with porosity. Due to higher porosity, the Lucaogou shale has a significantly higher hydrocarbon expulsion ratio compared to the Fengcheng shale.

Furthermore, this study developed a multiple regression model to quantitatively assess the influence of porosity, mesopore volume, specific surface area, and MI on the hydrocarbon expulsion ratio and to predict the hydrocarbon expulsion ratio. The model parameters are detailed in Table 4. To mitigate the impact of

multicollinearity, only macropore and mesopore volume was selected as the parameter for pore volume. The high R^2 value, normally distributed standardized residuals, and standardized predicted values distributed around zero in the regression model all confirm the reliability of the model (Table 4; Figure 17).

Model results indicate that both macropore volume and mesopore volume contribute positively to the hydrocarbon expulsion ratio. According to the standardized regression coefficients, mesopore volume is the primary factor affecting the hydrocarbon expulsion ratio in both the Fengcheng shale and the Lucaogou shale (Table 4). Specifically, a larger mesopore volume, which implies better connectivity, correlates with a higher hydrocarbon expulsion ratio (Figures 13, 14). In contrast, macropore volume has a significantly greater impact on the hydrocarbon expulsion ratio in the Lucaogou shale compared to the Fengcheng shale. This is primarily because macropores or fractures in the Fengcheng shale are often filled with large molecular asphalt, resulting in poor connectivity. Conversely, the micrometer-scale macropores or fractures formed by organic matter degradation in the Lucaogou shale provide excellent connectivity, facilitating hydrocarbon expulsion (Figure 13). Additionally, the standardized regression coefficient for the MI of the oil is negative, indicating

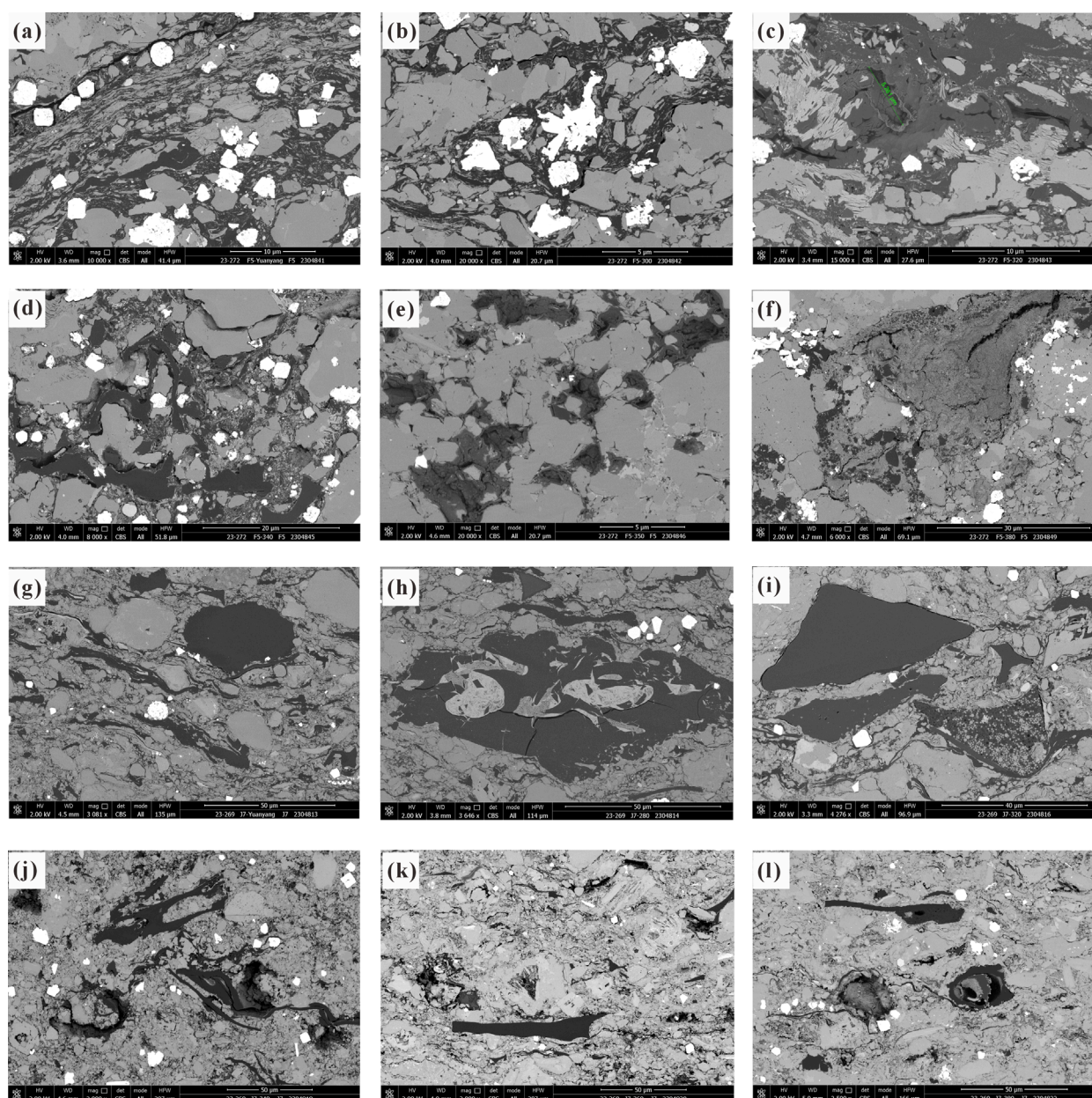


FIGURE 13

Scanning electron microscope (SEM) images of shale samples. (A) Initial Fengcheng shale; (B) Fengcheng shale, $R_o = 0.62\%$; (C) Fengcheng shale, $R_o = 0.73\%$; (D) Fengcheng shale, $R_o = 0.88\%$; (E) Fengcheng shale, $R_o = 0.97\%$; (F) Fengcheng shale, $R_o = 1.06\%$; (G) initial Lucaogou shale; (H) Lucaogou shale, $R_o = 0.60\%$; (I) Lucaogou shale, $R_o = 0.70\%$; (J) Lucaogou shale, $R_o = 0.92\%$; (K) Lucaogou shale, $R_o = 1.02\%$; (L) Lucaogou shale, $R_o = 1.12\%$.

that oil mobility has a limited or negative contribution to the hydrocarbon expulsion ratio in both the Fengcheng shale and the Lucaogou shale (Table 4). For instance, although the maximum MI in the Fengcheng shale is comparable to that in the Lucaogou shale, its hydrocarbon expulsion ratio is only 50% of that of the Lucaogou shale. During stage I, the Lucaogou shale has a high MI but the lowest hydrocarbon expulsion ratio, while during stage II, the hydrocarbon expulsion ratio increases despite the lowest MI (Figure 15). In summary, mesopore volume and its connectivity are critical factors affecting the hydrocarbon expulsion ratio, whereas oil mobility and macropore volume have relatively limited effects.

5.3 Implications for the exploration of lacustrine shale oil

Previous studies have shown that low to medium maturity and medium to high maturity continental shale oils exhibit significant differences in geological characteristics related to hydrocarbon generation, expulsion, and retention, as well as in exploration strategies, technologies, and evaluation criteria (Esemeh et al., 2012; Liu et al., 2023; Zhao et al., 2023). Therefore, selecting the optimal maturity interval is crucial for decision-making in the exploration and development of lacustrine shale oil (Hackley and Cardott,

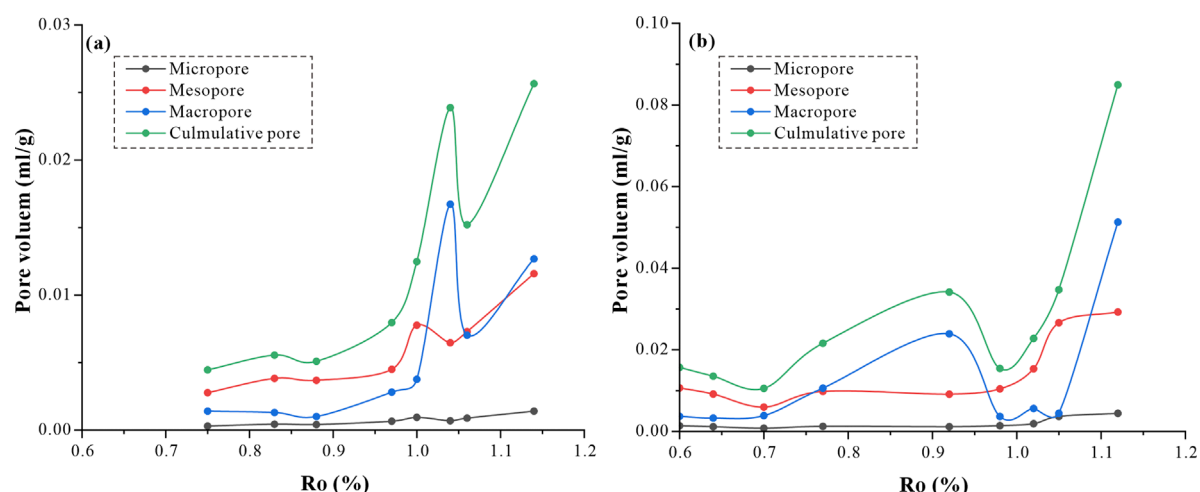


FIGURE 14
Total pore volume, macropore volume, mesopore volume, and micropore volume of (A) Fengcheng shale and (B) Lucaogou shale.

2016; Wang et al., 2022b; Hu et al., 2025). Currently, oil content and mobility are key factors in determining the favorable maturity interval for shale oil exploration (Donmoyer et al., 2023; Li et al., 2019). However, for layered shale oil, the yield of expelled oil or hydrocarbon expulsion ratio is the primary factor influencing its oil content (Jin et al., 2021). Therefore, this study aims to identify the favorable maturity interval for shale oil exploration in the Fengcheng shale and Lucaogou shale, based on the established hydrocarbon generation patterns, combined with assessments of oil content, oil mobility, and hydrocarbon expulsion ratio.

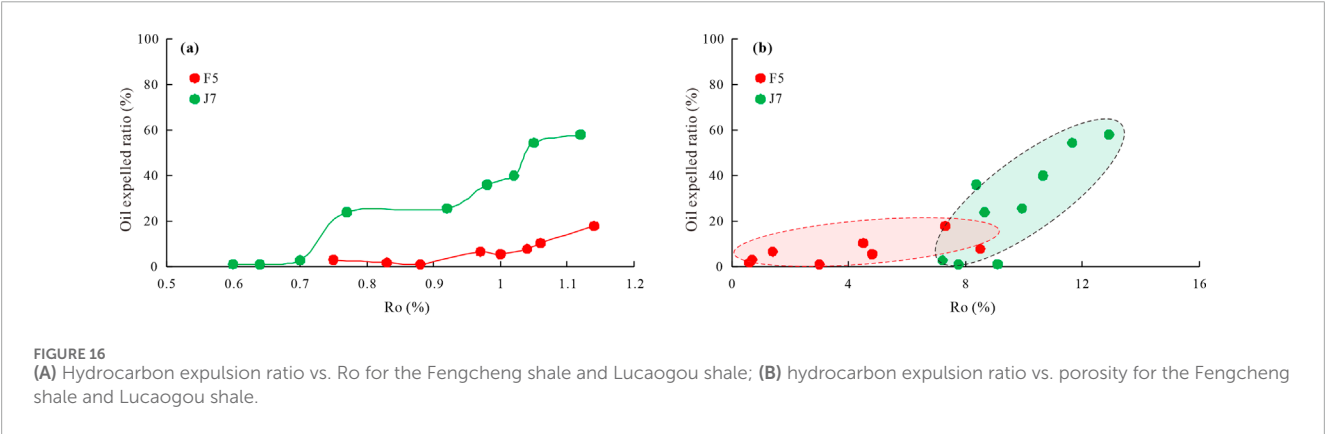
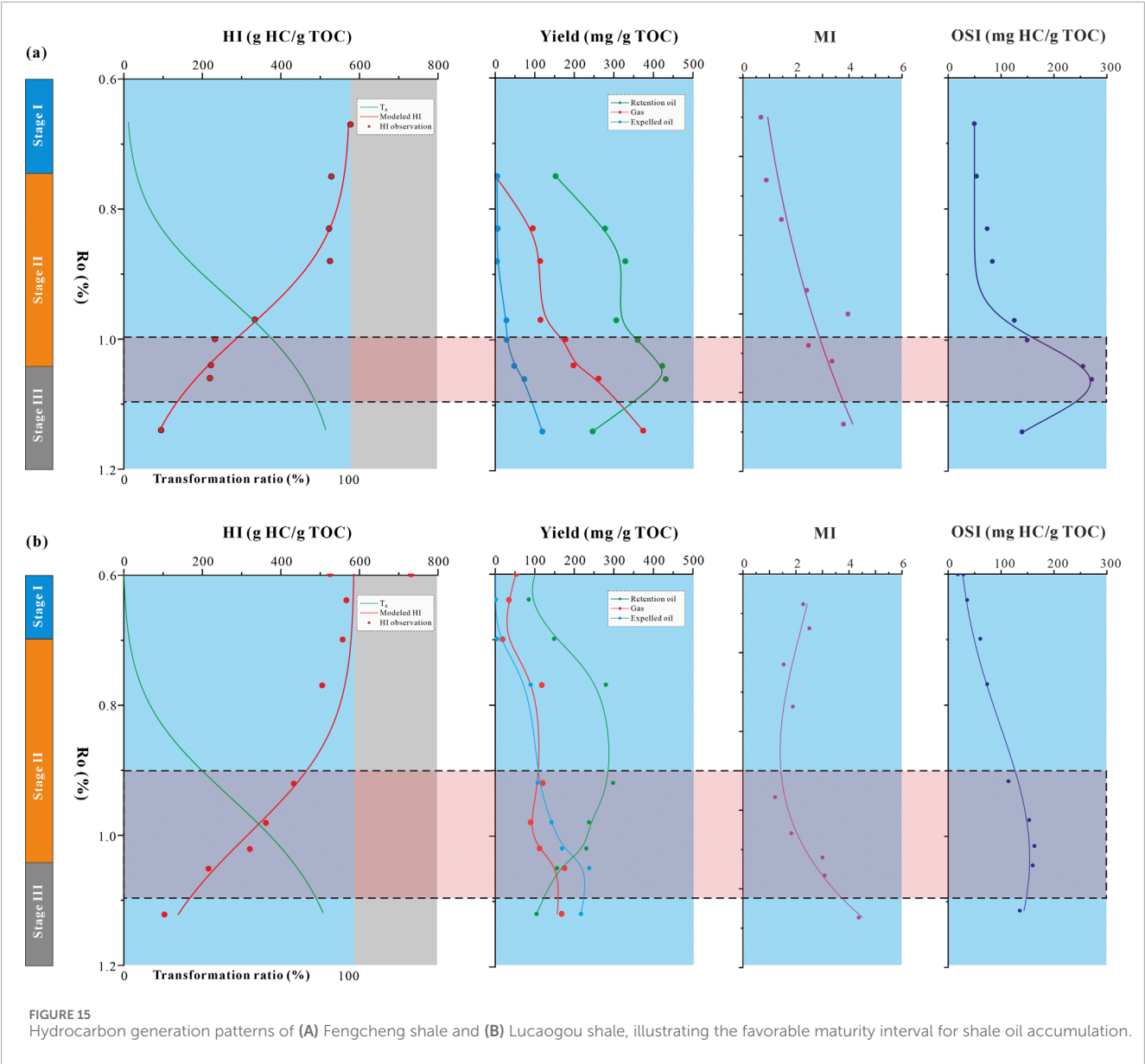
The pyrolysis parameter S_1 was used to characterize the oil content of shale, with S_1 values generally exceeding 2.0 mg HC/g Rock in the “sweet spot” intervals of lacustrine shales where exploration breakthroughs have been achieved in China (Javie, 2012; Li et al., 2023). Given that S_1 may be influenced by the micro-migration of shale oil, this study also employed the OSI to assess shale oil content (Wang et al., 2022a). Exploration results indicate that shales with OSI values greater than 100 mg HC/g TOC typically exhibit high oil content and high mobility (Javie, 2012; Wang et al., 2022a), findings consistent with the results of the thermal simulation experiments conducted in this study (Figure 15). Although the multiple regression model suggests that the MI has a limited impact on the hydrocarbon expulsion ratio (Table 4), MI is crucial for shale oil extraction. Generally, higher concentrations of saturated and aromatic hydrocarbons correlate with lower crude oil viscosity, facilitating the dispersion of asphaltenes and preventing their adsorption onto mineral surfaces due to their strong polarity (Brunauer et al., 1938). Consequently, a higher MI value indicates greater oil mobility, which is advantageous for shale oil extraction. Therefore, this study identifies the optimal maturity interval for shale oil exploration as $Ro = 1.0\%–1.1\%$ for the Fengcheng shale and $Ro = 0.9\%–1.1\%$ for the Lucaogou shale (Figure 15).

The Fengcheng Formation in the Mahu Sag was classified as shale-type shale oil. Despite its high T_R values and hydrocarbon yields, most of the oil residual within the shale. In the optimal maturity interval, the hydrocarbon expulsion ratio is below 20%

(Figures 15, 16). The depositional environment of the Mahu Sag was highly variable, resulting in centimeter-scale lithofacies assemblages, including combinations such as sandstone-shale, dolomitic mixed rock-shale, volcanic clastic-shale, and alkaline mineral mixed rock-shale (Tang et al., 2024). Among these, the dolomitic mixed rock-shale and volcanic clastic-shale assemblages in the shore-shallow lake facies, as well as combinations with a higher proportion of sandstone, are more favorable for hydraulic fracturing and represent the primary lithofacies assemblages for future exploration. The Lucaogou Formation in the Jimsar Sag was classified as interlayer-type shale oil. Although its hydrocarbon generation potential is lower than that of the Fengcheng shale, the Lucaogou shale exhibits a higher hydrocarbon expulsion ratio due to its high porosity and connectivity, with an hydrocarbon expulsion ratio exceeding 40% within the optimal maturity interval (Figures 13, 15, 16). However, the high clay content in the Lucaogou shale is unfavorable for hydraulic fracturing (Figure 3), necessitating a focus on source-reservoir assemblages during exploration. The confirmed “sweet spot” intervals typically have oil saturations exceeding 85%, predominantly composed of meter-scale sandstones (Zhi et al., 2019). Combinations with a higher reservoir-to-shale thickness ratio exhibit higher hydrocarbon expulsion ratios (Li C et al., 2020) and should be the primary targets for exploration.

6 Conclusion

- (1) The degradation process of the Fengcheng shale and Lucaogou shale can be divided into 3 stages: Stage I, the initial degradation of organic matter; Stage II, the rapid degradation of organic matter; and Stage III, the secondary cracking of organic matter. The hydrocarbon generation potential of Fengcheng shale is superior to that of Lucaogou shale, whether considering gas yield or oil yield. However, Lucaogou shale began the thermal degradation earlier than Fengcheng shale and has a broader pyrolysis degradation window. The corresponding T_R is slightly higher for Fengcheng shale.



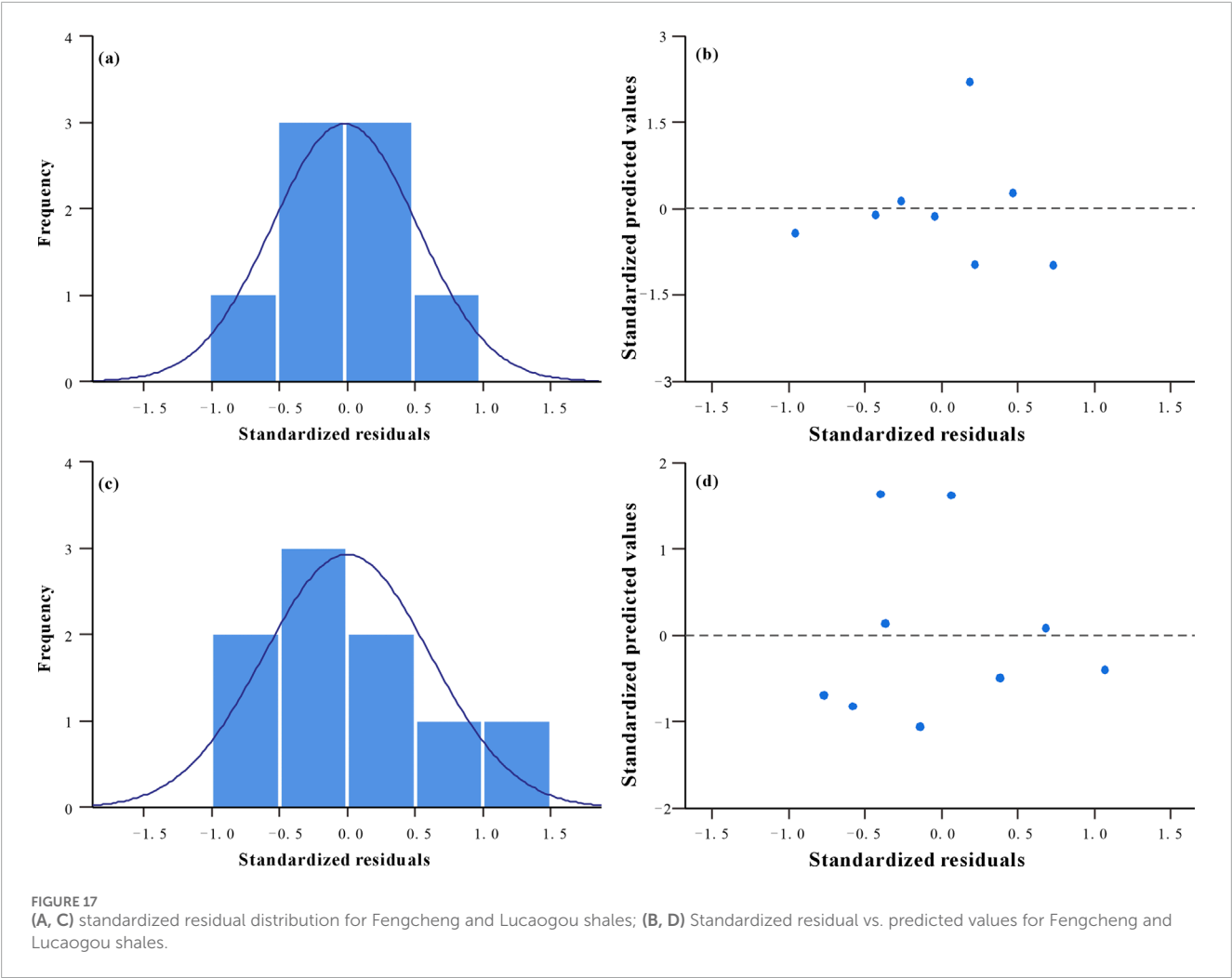


TABLE 4 Parameters of the multiple linear regression for the Fengcheng shale and Lucaogou shale.

Sample	Parameter	Unstandardized coefficients	Standardized coefficients	R ²
F5	Constant	−9.13	—	0.89
	Macropore volume (mL/g)	43.97	0.025	
	Mesopore volume (mL/g)	4,538.56	1.29	
	MI	−3.54	−0.44	
J7	Constant	4.24	—	0.81
	Macropore volume (mL/g)	168.15	0.11	
	Mesopore volume (mL/g)	3,675.39	1.22	
	MI	−35.78	−0.46	

Dependent variable: Hydrocarbon expulsion ratio (%).

However, at the high maturity stage, their T_R converge. Additionally, the yield of expelled oil of Lucaogou shale is higher than that of Fengcheng shale.

(2) During stage I, the hydrocarbon expulsion ratio is primarily determined by the organic matter type, with shales rich in easily degradable organic material exhibiting higher hydrocarbon expulsion ratio. During stages II–III, where maturity and T_R were similar, Lucaogou shale exhibited significantly higher hydrocarbon expulsion ratios compared to Fengcheng shale, with a maximum hydrocarbon expulsion

ratio 2.1 times that of Fengcheng shale. Mesopore volume and its connectivity are critical factors affecting the hydrocarbon expulsion ratio, whereas oil mobility and macropore volume have relatively limited effects.

- (3) The optimal maturity interval for shale oil exploration as $R_o = 1.0\%–1.1\%$ for the Fengcheng shale and $R_o = 0.9\%–1.1\%$ for the Lucaogou shale. Exploration of the Fengcheng shale should focus on lithofacies assemblages, the dolomitic mixed rock-shale assemblages in the shore-shallow lake facies represent the primary exploration target. Exploration of the Lucaogou shale should focus on source-reservoir assemblages, with a higher reservoir-to-shale thickness ratio being the primary exploration target.

Data availability statement

The original contributions presented in the study are included in the article/supplementary material, further inquiries can be directed to the corresponding author.

Author contributions

WH: Conceptualization, Supervision, Writing-original draft, Writing-review and editing. ZL: Conceptualization, Supervision, Writing-original draft, Writing-review and editing. CL: Conceptualization, Writing-original draft, Writing-review and editing. JH: Investigation, Writing-original draft, Writing-review and editing. JL: Investigation, Writing-original draft, Writing-review and editing. ZS: Investigation, Writing-original draft, Writing-review and editing. DL: Investigation, Writing-original draft, Writing-review and editing. SY: Investigation, Writing-original draft, Writing-review and editing.

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Conflict of interest

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The remaining author declares that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

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