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# Favourable exploration lithofacies of hybrid sedimentary shales in the Dongpu depression, Bohai Bay Basin

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Hybrid sedimentary shales (HSS) are key components of continental shale oil resources. The inherent heterogeneity of HSS lead to rapid variations in oil content and mobility, complicating sweet spot prediction. Previous studies have classified HSS lithofacies and assessed oil content. However, favourable lithofacies for oil content and mobility remains debated. This study classified the Shahejie Formation HSS from the Dongpu Depression, Bohai Bay Basin into massive argillaceous shale (Lithofacies I), bedded argillaceous shale (Lithofacies II), and laminated calcareous shale (Lithofacies III) based on sedimentary texture, mineral composition, and total organic carbon (TOC) content. The light hydrocarbon calibrated oil content ( $S_{1C}$ ), oil mobility (OSI), and micro-migration hydrocarbon content ( $\delta Q$ ) variations among these lithofacies were conducted to determine favourable oil content and mobility lithofacies. Results show that the Lithofacies III exhibited the highest average TOC (1.56 w. t. %), hydrogen index (HI) (264 mg/g TOC), oil content ( $S_{1C}$  = 1.81 mg/g), and oil mobility (OSI = 188 mg/g TOC). Geochemical data revealed that Lithofacies III also display the most pronounced micro-migration (average  $\delta Q$  = -138 mg/g TOC). TOC,  $T_{max}$ , and  $\delta Q$  influence the oil content of HSS, with TOC being the primary factor, suggesting that shales with high organic matter abundance possess better hydrocarbon generation potential and can produce more shale oil. Conversely,  $\delta Q$ , clay minerals, and carbonate minerals affect oil mobility, with  $\delta Q$  being the dominant factor, highlighting the role of micro-migration in pore connectivity, transport, and enrichment of shale oil within the extramicro-migration and intramicro-migration units. Global comparisons show that micro-migration drives HSS oil enrichment, while sedimentary environment and tectonic setting influence oil content and mobility. This study provides new insights into key factors controlling HSS oil micro-migration and enrichment, advancing global exploration and development of HSS resources.

## KEYWORDS

hybrid sedimentary shale, oil content and mobility, hydrocarbon generation potential, micro-migration, shale oil enrichment

# 1 Introduction

The successful shale oil exploration and development in the United States has established it as a global hotspot for unconventional oil and gas resources (Glikson-Simpson, 2021; Minna et al., 2021; Emmanuel et al., 2022; Xu et al., 2024). As shale oil and gas become increasingly viable, more companies are investing in shale oil exploration (Bernard et al., 2012a; 2012b; Milliken et al., 2012; Zou et al., 2013; Wang et al., 2021). Above them, hybrid sedimentary shales (HSS) are composed of clastic, clay, and biogenic components, formed in complex sedimentary environments (Zhou et al., 2023; Zhang et al., 2021; Hu et al., 2024a; Wei et al., 2024). Globally distributed, HSS are particularly prominent in the Delaware and Midland Basins in the United States, the Papua Basin in Australia, and the North Sea Basin in Europe (Haughton et al., 2009; Luo et al., 2012; Liu, 2022). HSS oil constitutes a significant composition of shale oil resources (Edgell, 1996; Hudec and Jackson, 2006; Jiang et al., 2022; Wang et al., 2022a). High organic-rich HSS formations include the Eagle Ford Shale (Altawati et al., 2021), Wolfcamp shale in the Permian Basin (Zumberge et al., 2017; Curtis and Zumberge, 2018), Vaca Muerta Formation in Argentina (Stinco and Barredo, 2014), Yanchang Formation in the Ordos Basin (Wang et al., 2024), and the Shahejie Formation in the Jiyang Depression (Teng et al., 2022). In contrast, medium-to low-organic-rich formations include the Fengcheng Formation of the Mahu Sag, Junggar Basin (Jiang et al., 2023a; Hu et al., 2024a), the Ganchaigou Formation in the Qaidam Basin (Li et al., 2022; Song et al., 2024), and the Shahejie Formation in the Dongying Depression, Bohai Bay Basin (Jiang et al., 2022; Wang et al., 2022b). The stratigraphy of HSS reflects complex sedimentary environments, resulting in considerable heterogeneity in shale reservoirs. The kerogen types and organic matter abundance in organic-rich laminae significantly control hydrocarbon generation potential (Gao et al., 2009; Eyong et al., 2018; Milkov et al., 2020; Yakubov et al., 2020), while inorganic mineral composition governs oil occurrence. Variations in sedimentary conditions impact density and thickness, thus controlling the distribution of sweet spots. Consequently, vertical variations in oil content and mobility are common in HSS (Gharib et al., 2024; He et al., 2024). Furthermore, the presence of salt minerals in lacustrine basins enhances the hydrocarbon generation and storage capacity compared to freshwater basins (Wu et al., 2023), further complicating sweet spot prediction and resource potential evaluation.

Early shale lithofacies classifications were qualitative, relying on core descriptions and thin-section observations (Loucks and Ruppel, 2007; Loucks et al., 2009; Liu et al., 2017; Williams et al., 2022). Contemporary classifications have evolved to quantitative proxies, such as mineral composition, sedimentary textures, and organic matter abundance (Potter and Longstaffe, 2007; Potter et al., 2020; Hamlin and Baumgardner, 2012; Shi et al., 2020; Pan et al., 2022). Previous studies have classified HSS lithofacies and characterized shale types (Ko et al., 2016; Jin et al., 2019; Kuang et al., 2021; Gao et al., 2022), yet the favourable lithofacies for oil content and mobility remains debated. Recent investigations have highlighted significant micro-migration phenomena in HSS (Hu et al., 2024a; Hu et al., 2024b; Hu et al., 2025; Rudra et al., 2024; Wu et al., 2024a), which play a critical role in hydrocarbon

generation capacity, storage capacity, and preservation conditions (Yurchenko et al., 2018; Liu et al., 2022; Liu et al., 2023; Zhang et al., 2024). Previous studies have identified micro-migration through geochemical anomalies, and quantitative models for evaluating micro-migrated hydrocarbons have been established (Liu et al., 2023; Hu et al., 2024a; Hu et al., 2024b). Applying this method to HSS can improve the accuracy of sweet spot predictions.

As a representative HSS formation, the third member of the Shahejie Formation in the Dongpu Depression (DD) is rich in oil and gas resources. This study systematically classified the lithofacies based on sedimentary textures, mineral composition, and total organic carbon (TOC) content. Geochemical analyses and micro-migration evaluations were conducted to reveal hydrocarbon generation potential, oil content, and mobility variations across lithofacies. The controlling factors for oil content and mobility were determined through microscopic observations and Pearson correlation analysis. Moreover, we compare favourable HSS lithofacies for oil content and mobility in the Dongpu Depression with the Mahu Depression in China and the Delaware and Midland Basins in the United States, highlighting the potential for global HSS oil resource exploration and development. This study provides theoretical foundations and new perspectives for the exploration of HSS oil resources.

## 2 Geological setting

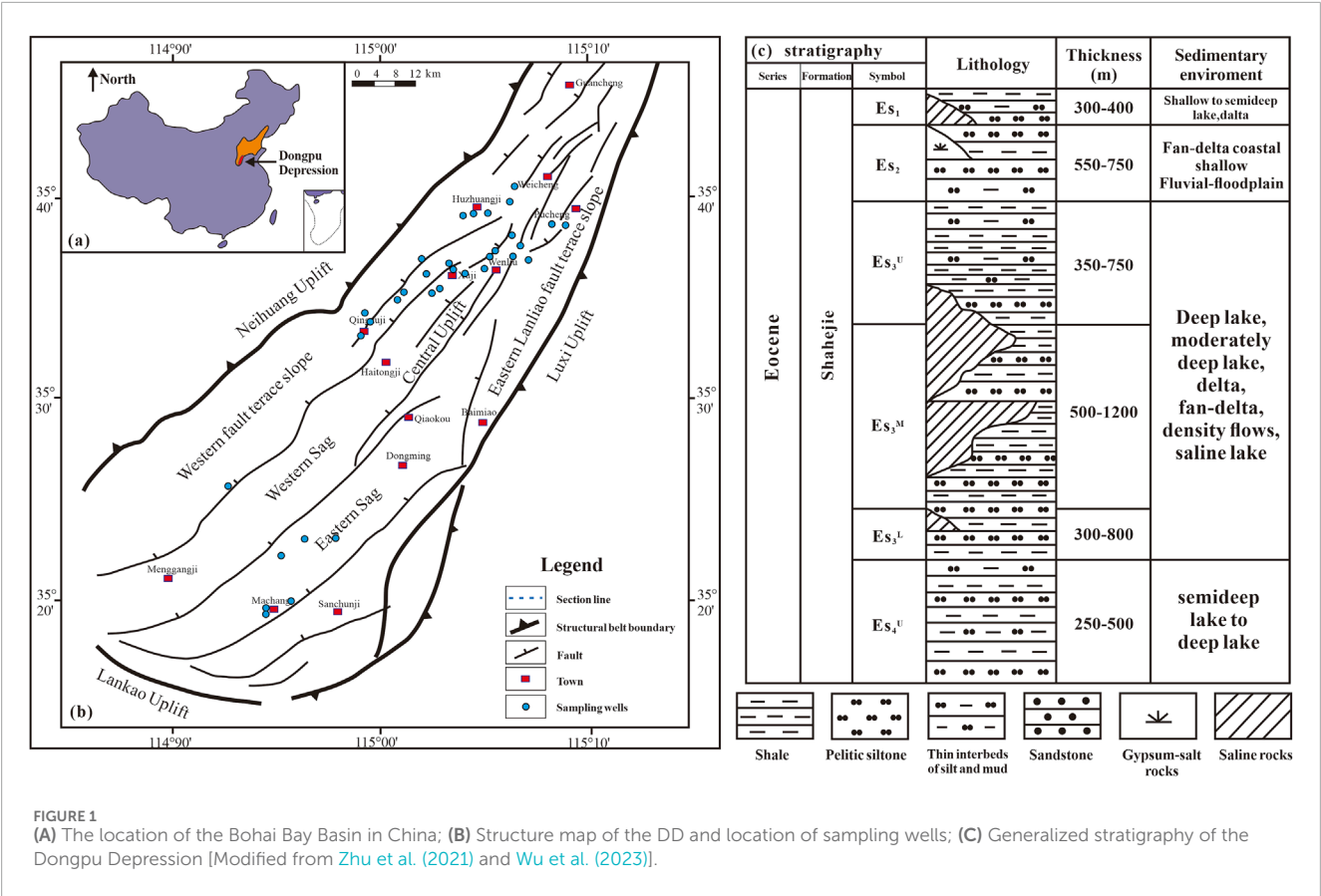
The DD in the Bohai Bay Basin, located in the southern part of the Bohai Bay Basin in China, is a part of the Linqing Depression, situated in the southeastern portion of the Linqing Depression (Su et al., 2006). It is bordered to the east by the Lanliao Fault and the Luxi Uplift, overlies the Neihuang Uplift to the west, faces the Lankao Uplift and Kaifeng Depression to the south across, and connects to the Shenxian Depression via the Malang Fault to the north (Jiang et al., 2022; Zhu et al., 2021; Wu et al., 2023). The depression trends north-northeast, narrower in the north and wider in the south, covering an area of approximately 5,300 km<sup>2</sup> (Figures 1A, B).

The DD includes sedimentary formations ranging from the Paleogene Shahejie Formation (consisting of 4th, 3rd, 2nd, and 1st members) to the Dongying Formation. These formations are angularly unconformably overlain by the younger Cenozoic Guantao and Minghuazhen formations. Following Paleogene sedimentation, there was regional uplift and erosion before subsequent subsidence and deposition of the Neogene formations. There is also an angular unconformity between the Paleogene and Neogene sequences. The study focuses on the strata of the Shahejie Formation (Wu et al., 2024b) (Figure 1C).

## 3 Methodology

This study analyzed 354 samples from 33 wells, employing a range of techniques including core observation, thin-section analysis, whole-rock X-ray diffraction (XRD), total organic carbon (TOC) analysis, pyrolysis, scanning electron microscopy (SEM), and elemental geochemical analysis. The experiments were conducted at the National Key Laboratory of Petroleum Resources and





Engineering at China University of Petroleum and the Zhongyuan Oilfield Branch of SINOPEC.

For the TOC analysis, inorganic carbon was removed from the samples before testing with a LECO CS-230 carbon-sulfur analyzer. The samples were subjected to heating at 300°C–600°C using a Rock-Eval II pyrolysis machine to obtain free hydrocarbons ( $S_1$ , measured in mg HC/g Rock) and pyrolytic hydrocarbons ( $S_2$ , also in mg HC/g Rock).

The analysis of major, trace, and rare earth elements required grinding the selected samples to a 200 mesh powder. The samples were dried for two hours in a constant temperature oven at 100°C, then cooled in a dryer. A 0.2,000 g sample was placed into a crucible, followed by the addition of 5 mL each of nitric acid, hydrofluoric acid, and perchloric acid. The sample was heated on an electric plate, gradually reaching over 200°C to remove impurities, then maintained at approximately 60°C for over three hours. After this, the sample was heated to 200°C, and aqua regia was added for extraction. The final extract was transferred to a 20 mL volumetric flask and diluted with water. Prepared samples were analyzed using ICP-MS and ICP-OES to determine the concentrations of major, trace, and rare earth elements.

For SEM observation, the cut samples were gold-coated and examined under a FEI Quanta 200 F scanning electron microscope, operated at 15 kV with an object distance of 10–12 mm.

The real hydrocarbon generation potential (HGPR) and the original hydrocarbon generation potential (HGPO), defined as  $\delta Q$ , were calculated using an established model specific

to the DD. A  $\delta Q$  value greater than zero indicates that HGPO exceeds HGPR, characterizing hydrocarbon extramigration (HEM), while a  $\delta Q$  value less than zero indicates that HGPO is less than HGPR, defining hydrocarbon intramigration (HIM).

Significant loss of light hydrocarbons can occur during core preservation and sample preparation, leading to errors in the assessment of oil content (Zhang et al., 2014). Therefore, light hydrocarbon calibration is necessary prior to evaluating shale oil content to ascertain the actual oil saturation (Ross and Bustin, 2007). Light hydrocarbon calibration involved thermal simulation experiments on low-maturity samples of different kerogen types, based on the assumption that the proportions of hydrocarbon components between generated hydrocarbons and residual hydrocarbons remain consistent (Jiang et al., 2016). The calibration coefficient for light hydrocarbons ( $K_{lh}$ ) was calculated using the ratio of  $C_{1-14}$  to  $C_{14+}$ . For detailed methodology, refer to Hu et al. (2024b) and Wu et al. (2024a).

## 4 Results

### 4.1 Shale lithofacies classification

Previous studies have classified the lithofacies of fine-grained rocks based on rock color, sedimentary textures, mineral composition, total organic carbon (TOC) content, and

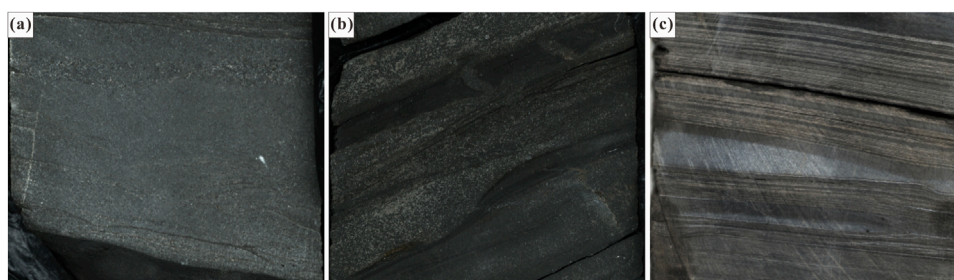


FIGURE 2

The sedimentary textures of shales in the Dongpu Depression. (A) Massive structure, well Wei 4457HF, 3,683.85 m; (B) Layered structure, well Wei 457HF 3861.57 m; (C) Laminae structure, well P161 3,840.11 m.

mechanical properties (Stow and Piper, 1984; Singh et al., 2009; Zhang et al., 2022; Lv et al., 2023). In this study, fine-grained sedimentary rocks are classified into three types, focusing on sedimentary textures, mineral composition, and TOC content.

Three sedimentary textures are identified in the continental shale: massive shale, bedded shale, and laminated shale (Figure 2). XRD results indicate that the primary mineral components include clay, quartz, feldspar, calcite, and dolomite, with trace amounts of gypsum, halite, and pyrite. Clay content varies from 3.45% to 74.7% (average: 34.4%), with 24% of the samples exceeding 50% clay. The felsic component (quartz + feldspar) ranges from 2.6% to 72.9% (average: 28.1%), with 17% of samples surpassing 50%. Carbonate content ranges from 1.2% to 84.8% (average: 27.3%), with 15% of samples exceeding 50%, primarily consisting of calcite, which ranges from 0.6% to 84.7% (average: 19.5%). In the 4th Member of the Shahejie Formation through to the 3rd Member in the DD, fine-grained rock types are predominantly gray massive-layered clay shales, dark-colored laminated lime-dolomite shales, and dark-colored lime-dolomite rocks. These are followed by dark-colored layered-massive clay shales and dark-colored laminated-massive clayey lime-dolomite shales.

For shales with TOC greater than 1 w. t. %, a ternary diagram of mineral composition for HSS was established. The fine-grained rock types identified in the DD include siliceous shale, argillaceous shale, calcareous shale, and mixed shale (Figure 3) (Wang et al., 2022c; Wang et al., 2025). These lithofacies types display specific correlations with sedimentary textures. Based on the mineral composition and microstructural characteristics, we identified three primary lithofacies (Figure 4). Lithofacies I: Massive argillaceous shale. This facies is characterized by a relatively uniform microstructure, indicating consistent sedimentation processes and minimal variation in composition (Figure 4A). Lithofacies II: Bedded argillaceous shale. This facies predominantly consists of clay minerals, with laminar fractures observed between the clay layers and clastic mineral layers. The presence of these fractures suggests a history of differential compaction or desiccation (Figure 4B). Lithofacies III: Laminated calcareous shale. This facies is primarily composed of alternating clay-rich and carbonate rock laminae, with laminae thickness ranging from 50 to 200  $\mu\text{m}$  (Figure 4C). The distinct layering indicates episodic deposition and variations

in sediment supply, likely influenced by environmental factors.

## 4.2 Organic matter abundance, type, and maturity of different lithofacies

The TOC contents of Lithofacies I (Figure 5A) range from 0.28–2.27 w. t. %, with an average of 0.78 w. t. % (Table 1). Most samples within this facies exhibit TOC values below 0.5 w. t. % (Figure 5D). The organic matter (OM) is primarily classified as Type III (Figure 5E), indicating a predominance of terrigenous organic matter that has reached a mature stage. Under fluorescence microscopy, the OM content is low, with only a few weakly fluorescent OM particles and some black higher plant debris observed (Figures 6A, B).  $T_{\text{max}}$  ranges from 384°C–493°C, with an average of 424°C. Moreover, the average vitrinite reflectance ( $R_o$ ) of Lithofacies I is 0.89, indicating that the Lithofacies I shale is in the mature stage.

The TOC contents of Lithofacies II range from 0.09–2.17 w. t. %, with an average of 0.91 w. t. % (Figure 5B). Most samples in this facies have TOC values around 1 w. t. % (Figure 5D). The OM types are primarily Type III and Type II<sub>2</sub> (Figure 5E), indicating a mixed contribution from terrigenous and aquatic sources. Laminar fractures are noted between the clay layers and clastic mineral layers, with oriented OM present within the clay layers. The OM appears relatively dispersed, displaying weak fluorescence intensity under microscopy (Figures 6C, D).  $T_{\text{max}}$  ranges from 396°C–513°C, with an average of 427°C. The average  $R_o$  of Lithofacies II is 0.83, indicating that the Lithofacies I shale is in the mature stage.

The TOC contents of Lithofacies III (Figure 5C) range from 0.12–3.61 w. t. %, with an average of 1.02 w. t. %. The kerogen type is predominantly Type II<sub>1</sub> and Type II<sub>2</sub>, indicating quatic OM (Figure 5E). The OM interacts with clay minerals through flocculation, resulting in the OM-clay layers formation. Under fluorescence microscopy, the clay-rich laminae demonstrate strong fluorescence, whereas the carbonate rock laminae show weak fluorescence or none at all (Figures 6E, F).  $T_{\text{max}}$  ranges from 390°C–460°C, with an average of 436°C. The average  $R_o$  of Lithofacies II is 0.91, indicating that the Lithofacies I shale is in the

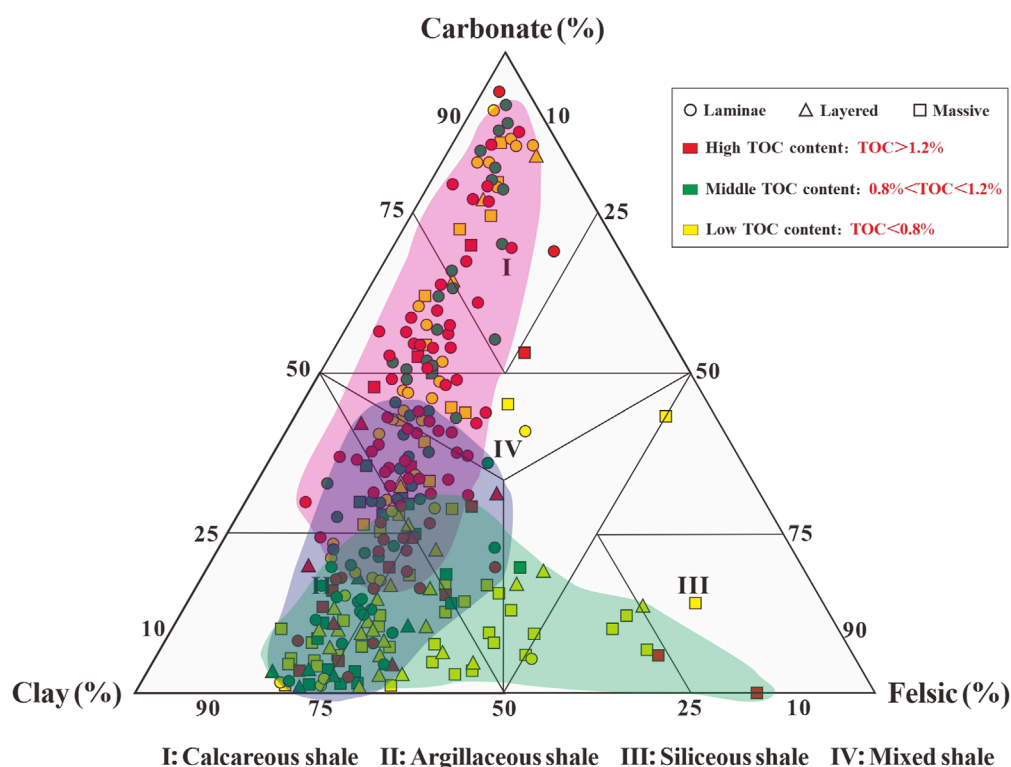


FIGURE 3

Mineral composition of Shahejie Formation, Dongpu Depression. Type I represents calcareous shale, type II represents argillaceous shale, type III represents siliceous shale, and type IV represents mixed shale. The red shadow part indicates the shale with high TOC content, the blue shadow indicates the shale with moderate TOC content, and the green shadow indicates the shale with low TOC content.

mature stage. Results show that Lithofacies III has the highest TOC content and the best organic matter quality, suggesting a greater hydrocarbon generation potential.

### 4.3 Oil content and mobility of different lithofacies

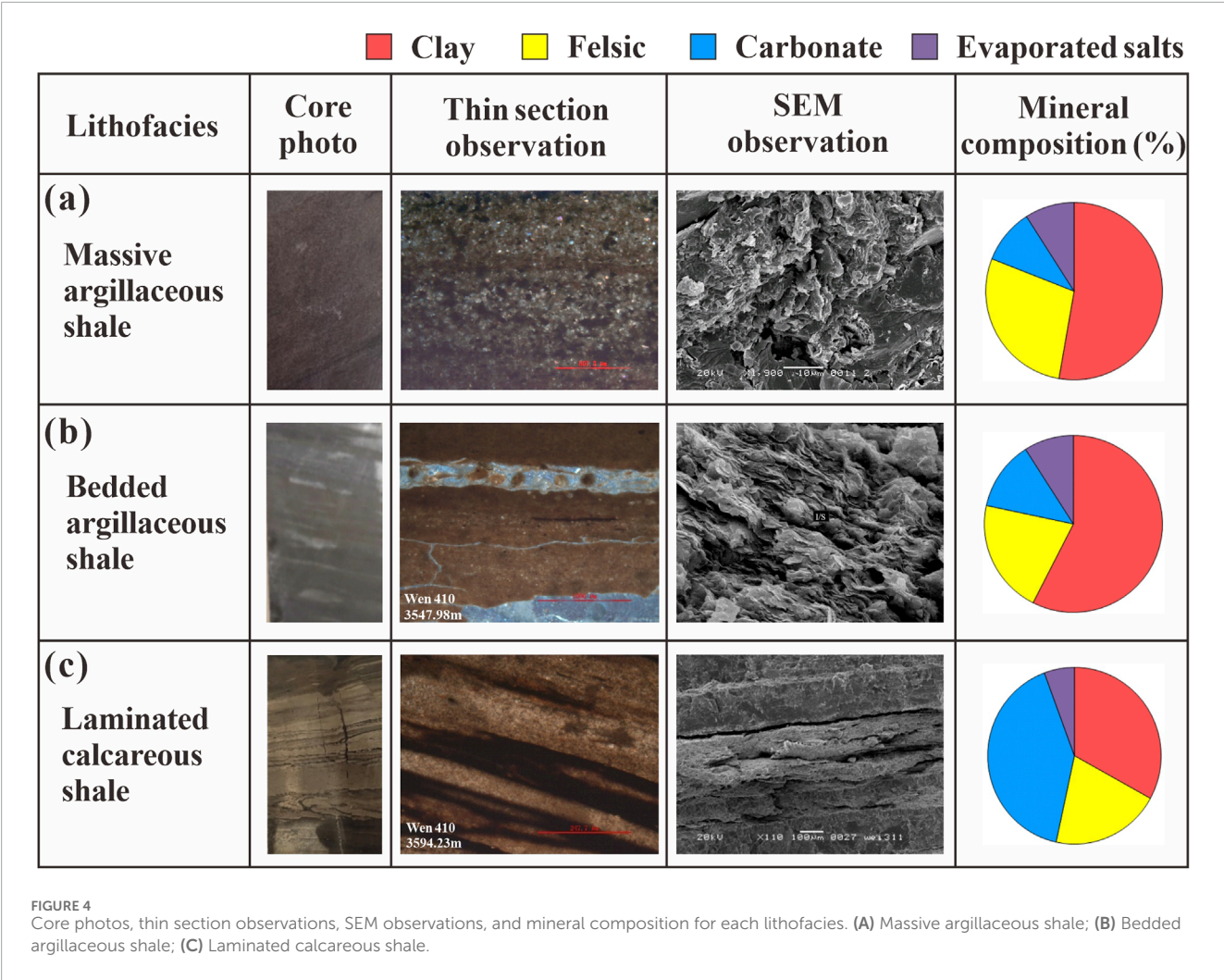
The  $S_1$  content has been widely used as an indicator of oil content in shale (Hu et al., 2021a; Guan et al., 2022). Jarvie et al. (2017) introduced the oil saturation index ( $OSI = 100 \cdot S_1 / TOC$ ) to characterize the mobility of shale oil, a metric that has been applied in various terrestrial shale formations in China (Jarvie et al., 2017; Wang et al., 2022a; Zhang et al., 2022). Therefore, this study employs the  $S_1$  value corrected for light hydrocarbons ( $S_{1C}$ ) and OSI to assess the oil content and mobility of different lithofacies. The results indicate that  $S_{1C}$  contents for Lithofacies I range from 0.01 to 6.03 mg/g, with an average of 1.22 mg/g, while OSI values range from 1 to 424 mg/g TOC, with an average of 135 mg/g TOC. For Lithofacies II,  $S_{1C}$  values range from 0.03 to 8.32 mg/g, averaging 1.80 mg/g, and OSI values range from 13 to 394 mg/g TOC, with an average of 181 mg/g TOC. Lithofacies III exhibits  $S_{1C}$  values ranging from 0.01 to 6.08 mg/g, with an average of 1.94 mg/g, and OSI values from 11 to 713 mg/g TOC, averaging 188 mg/g TOC. Comparative results show that Lithofacies III has the highest oil content and best mobility.

## 5 Discussion

### 5.1 Identification and evaluation of micro-migration

Anomalies in geochemical data are key indicators of micro-migration phenomena (Liu et al., 2023; Hu et al., 2024b; Hu et al., 2025). The Productivity Index (PI) shows a negative correlation with  $T_{max}$  (Figure 7A), suggesting that substantial amounts of hydrocarbons persist even at low  $T_{max}$  values. Additionally, the  $S_2 / (S_1 + S_2)$  ratio shows a positive correlation with  $T_{max}$ , indicating that the proportion of  $S_1$  is higher at lower maturity levels (Figure 7B).  $T_{max}$  negatively correlates with TOC (Figure 7C), suggesting that organic-rich shales have migrated towards areas with lower organic carbon content during hydrocarbon generation pressurization. This migration results in positive anomalies in the Oil Saturation Index (OSI) and PI, alongside a negative anomaly in  $T_{max}$ . Notably, these anomalies intensify with decreasing TOC. As organic-rich shales reach the adsorption capacity, hydrocarbons begin migrating into adjacent low-organic shales with more favorable reservoir properties. Overall, these data suggest that micro-migration has occurred across different shale lithofacies, highlighting the dynamic nature of hydrocarbon migration within geological formations.





Micro-migration hydrocarbon content across the three types of lithofacies was assessed using the  $\delta Q$  method, with results detailed in Table 1. For Lithofacies I, the original hydrocarbon index (HIO) ranged from 53 to 1,673 mg/g TOC, with an average of 249 mg/g TOC. The overall  $\delta Q$  values for this lithofacies ranged from -393–912 mg/g TOC, yielding an average of -123 mg/g TOC. Lithofacies II exhibited an HIO ranging from 18 to 1,565 mg/g TOC, with an average of 216 mg/g TOC. The overall  $\delta Q$  for Lithofacies II varied between -713 and 635 mg/g TOC, with an average of -106 mg/g TOC. Lithofacies III had an HIO range from 25 to 917 mg/g TOC, with an average of 216 mg/g TOC. The overall  $\delta Q$  for this lithofacies ranged from -493 to 347 mg/g TOC, averaging -138 mg/g TOC. Notably, the micro-migration in Lithofacies III was found to be more pronounced compared to the other lithofacies. In terms of OSI, Lithofacies III recorded the highest OSI at 188.09 mg/g TOC, followed closely by Lithofacies I with an OSI of 181.75 mg/g TOC. Lithofacies II had the lowest OSI, measuring 134.93 mg/g TOC. These findings indicate that Lithofacies III not only exhibited the most significant micro-migration but also had the highest  $S_1$  and OSI, suggesting a more favourable condition for hydrocarbon retention and migration.

## 5.2 Key factors controlling oil content and mobility

### 5.2.1 Hydrocarbon generation capacity

The hydrocarbon generation potential and the composition of hydrocarbon-forming organisms are crucial factors influencing shale oil enrichment (Mackenzie et al., 1983; Begum et al., 2019; Hu et al., 2021b). A strong positive correlation between TOC and  $S_{IC}$  (Figure 8A) indicates that higher organic matter abundance corresponds to increased oil content. However, when TOC exceeds 1 w. t. %, the adsorption capacity of organic matter increases, which restricts oil mobility (Yang et al., 2019; Awad et al., 2020; Xiao et al., 2024). The HIO provides a more accurate assessment of primary hydrocarbon generation potential than hydrogen index (HI) and can be used to determine whether variations in organic matter type affect shale oil content (Pepper, 1991; Wu, 2023). As shown in Figure 8B, higher HIO correlates with higher oil content, suggesting that shale with higher organic matter types contributes more to shale oil resources (Quan et al., 2022). Figure 8C shows that  $S_{IC}$  increases and then decreases with rising  $T_{max}$ . In the mature stage of shale, kerogen cracking generates significant hydrocarbons; However, excessive maturity leads to the



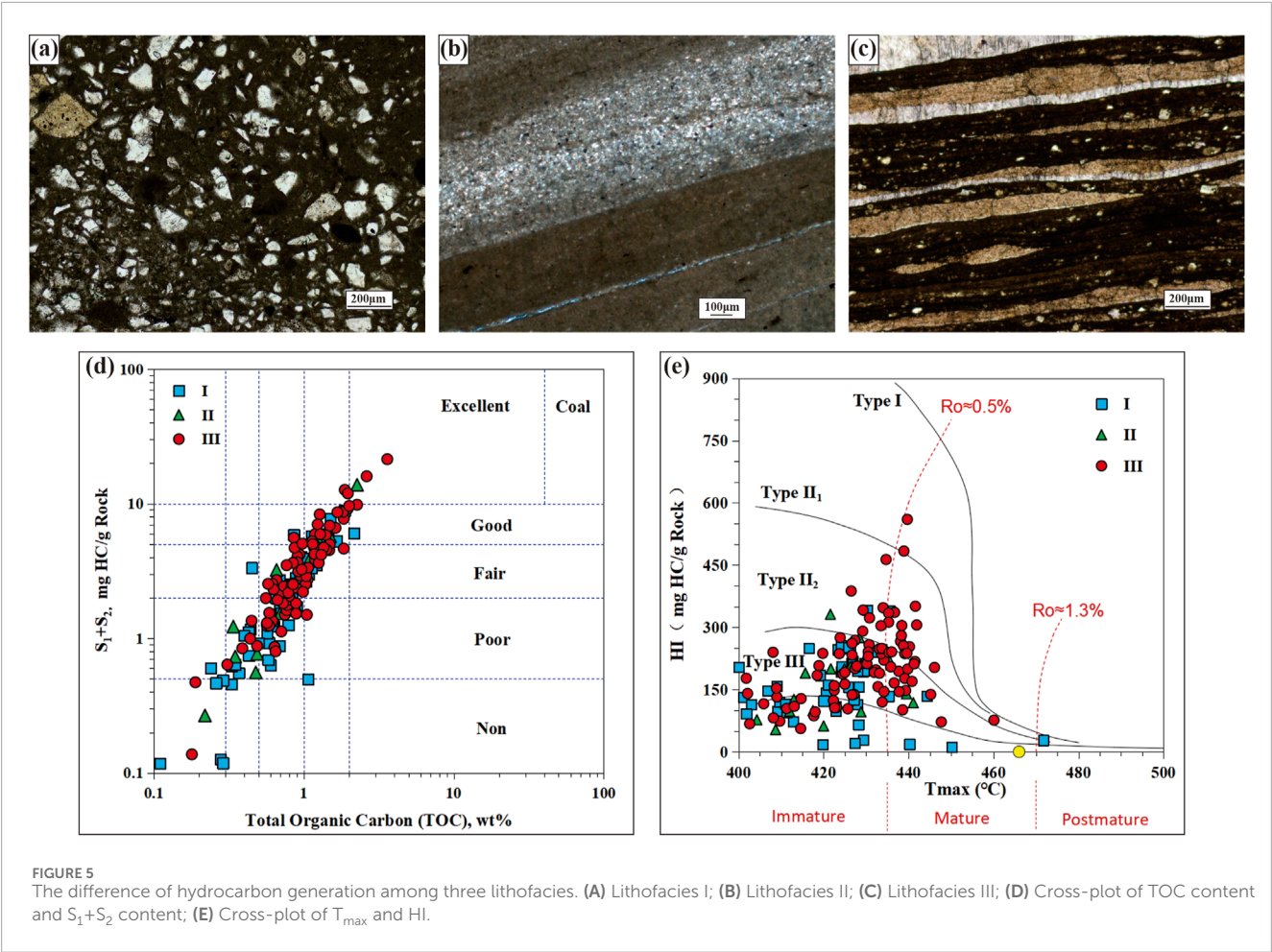


TABLE 1 Hydrocarbon generation characteristics of three lithofacies.

| Sample  |                 | TOC (%) | HI (mg/g) | S <sub>1C</sub> (mg/g) | S <sub>2</sub> (mg/g) | T <sub>max</sub> (°C) | Ro (%) | OSI (mg/g TOC) | δQ   |
|---------|-----------------|---------|-----------|------------------------|-----------------------|-----------------------|--------|----------------|------|
| Min     |                 | 0.09    | 11        | 0.01                   | 0.01                  | 384.0                 | 0.69   | 1              | −713 |
| Max     |                 | 3.61    | 561       | 6.30                   | 17.46                 | 513.0                 | 1.13   | 713            | 912  |
| Average | Lithofacies I   | 0.78    | 155       | 1.22                   | 1.47                  | 423.8                 | 0.89   | 181            | −123 |
|         | Lithofacies II  | 0.91    | 161       | 1.80                   | 1.78                  | 422.4                 | 0.83   | 135            | −106 |
|         | Lithofacies III | 1.02    | 264       | 1.94                   | 2.51                  | 428.2                 | 0.91   | 188            | −138 |

hydrocarbon degradation, reducing oil content (Shao et al., 2020). Therefore, hydrocarbon generation potential is a controlling factor for shale oil content. The correlation between OSI and TOC, HI, and  $T_{max}$  is relatively weak (Figures 8D–F), indicating that hydrocarbon generation capacity may not significantly influence shale oil mobility.

Lithofacies III stands out for containing more samples with high TOC and oil content compared to other lithofacies. We analyzed the differences in oil content among the three lithofacies from the perspectives of sedimentary environment and hydrocarbon-forming organisms. Lithofacies I primarily contains organic matter

(OM) dominated by vitrinite, with present in smaller quantities (Figure 9A). In Lithofacies II, sedimentary conditions transitioned to deeper waters, increasing the phytoplankton content while decreasing vitrinite (Figures 9C, D), reflecting a reduction in terrestrial input. Lithofacies III, indicative of deep to semi-deep lacustrine deposition, exhibits the highest phytoplankton content. Fluorescence microscopy observations have identified bundant cyanobacterial laminations in this lithofacies (Figures 9E–H). The type and quantity of organic matter during sedimentation were significantly influenced by the sedimentary environment and mineralogical factors. High productivity coupled with reducing

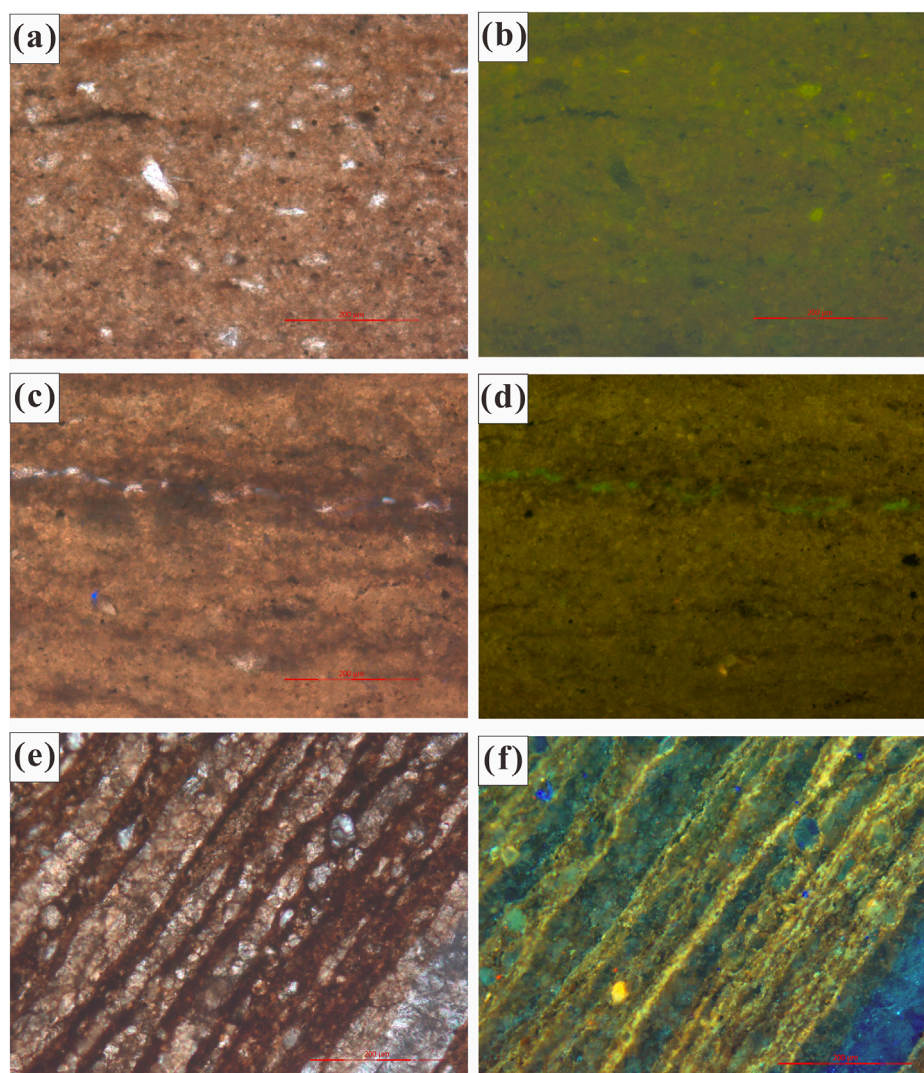


FIGURE 6

Microscope characteristics of different lithofacies. (A) Normal light, Wei 457HF, 3,667.17 m; (B) fluorescence, Wei 457HF, 3,667.17 m; (C) Normal light, Wei 457HF, 3,694.82 m; (D) fluorescence, Wei 457HF, 3,694.82 m; (E) Normal light, Wei 457HF, 3,697.59 m; (F) fluorescence, Wei 457HF, 3,697.59 m.

environments promoted the organic matter enrichment. Moreover, the origin, abundance, and preservation of organic matter played a crucial role in determining hydrocarbon source rock potential (Young and McIver, 1977). Research indicates that algae and plankton exhibit higher oil generation potential than higher plant-derived organic matter, which generally has a lower oil generation capacity (Bouchez et al., 2011; Lupker et al., 2011; Garzanti et al., 2010). Consequently, the interaction between sedimentary environments and the types of hydrocarbon-forming organisms explains the differences in shale oil content across the lithofacies.

### 5.2.2 Storage capacity

Table 1 shows that Lithofacies III possesses the highest oil content and mobility. We conducted an analysis of the shale oil occurrence characteristics in Lithofacies III. Intergranular pores and calcite dissolution pores associated with felsic minerals exhibit good connectivity and can store significant amounts of free oil

(Figures 10A, E, I) (Loucks et al., 2009; Mastalerz et al., 2013; Wang et al., 2019). Conversely, shale oil is less likely to accumulate in pyrite aggregates, where the pore structure is less conducive to hydrocarbon storage (Figures 10C, D, J). Clay minerals, while contributing to stronger adsorption capacity and confinement effects, can hinder the mobility and flowability of hydrocarbons, resulting in poorer oil recovery (Allawe et al., 2015; Mastalerz et al., 2018; Xu et al., 2021). However, when the pore space within clay minerals is sufficiently large and well-connected, it can still facilitate the deposition of free oil (Figure 10B). Adsorbed oil primarily resides in the pores of organic matter, with oil enrichment being more likely in organic matter pores that have larger pore sizes and good connectivity (Figures 10F–H). The width of fractures is another critical factor influencing shale oil occurrence (Aydin, 2000). Wider fractures are associated with a greater presence of free oil, while narrower fractures tend to retain more adsorbed oil (Figure 10C). Notably, Lithofacies III exhibits

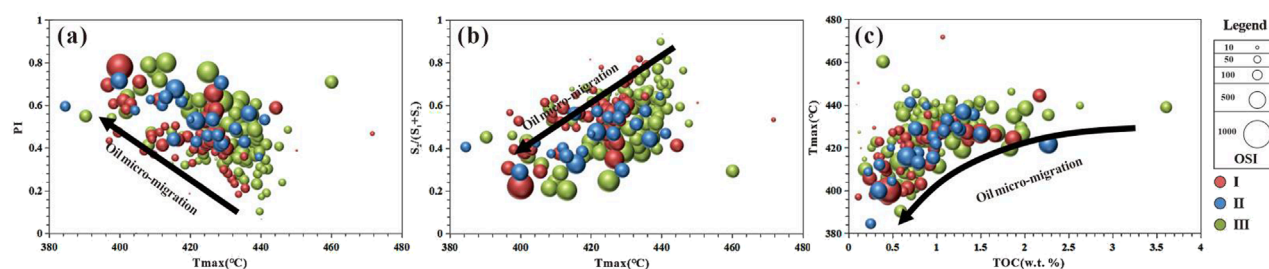


FIGURE 7  
(A) Cross-plot of  $T_{max}$  and PI; (B) Cross-plot of  $T_{max}$  and  $S_2/(S_1+S_2)$ ; (C) Cross-plot of TOC and  $T_{max}$ . Red, blue, and green points represent the lithofacies I, lithofacies II, and lithofacies III, respectively.

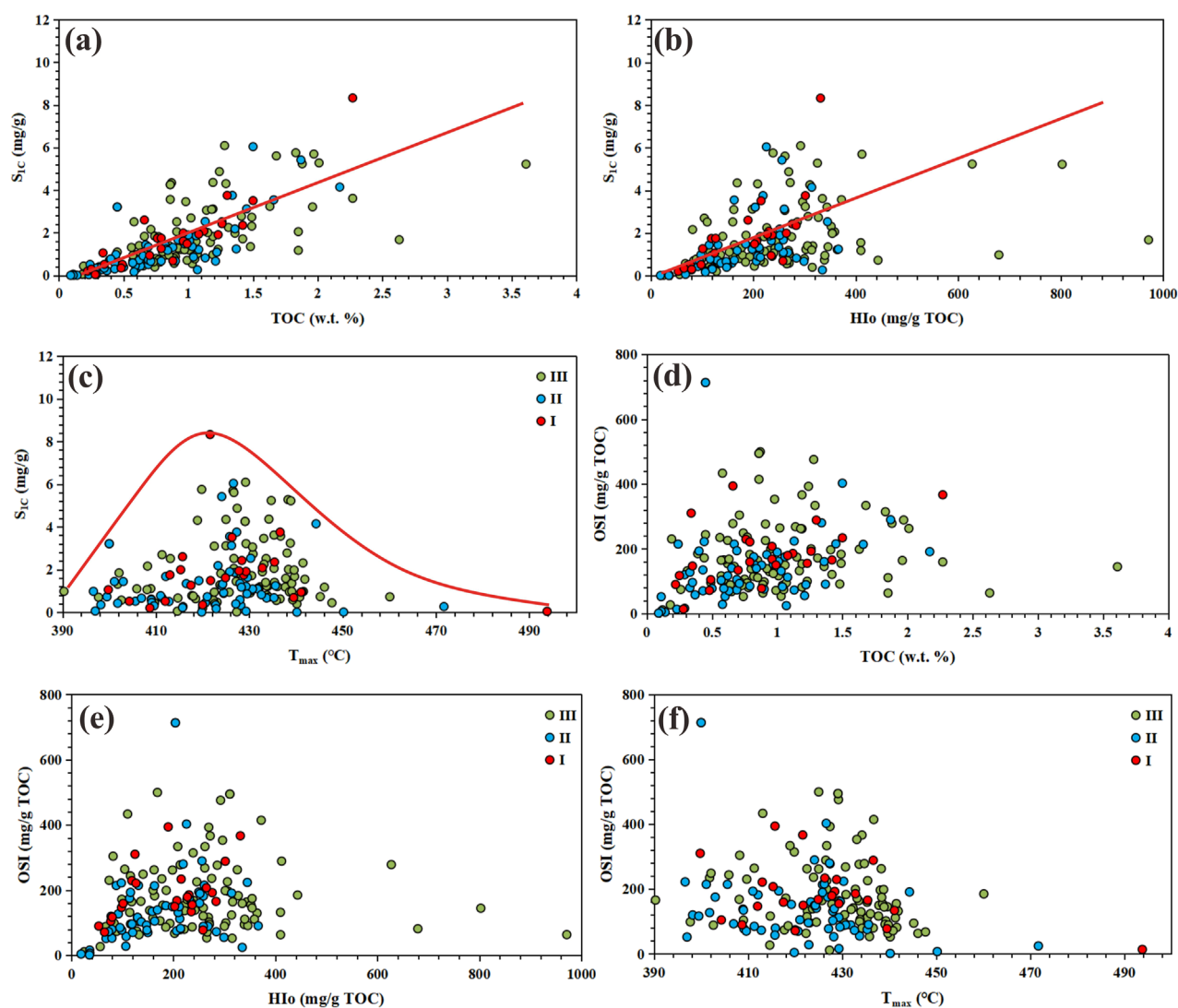
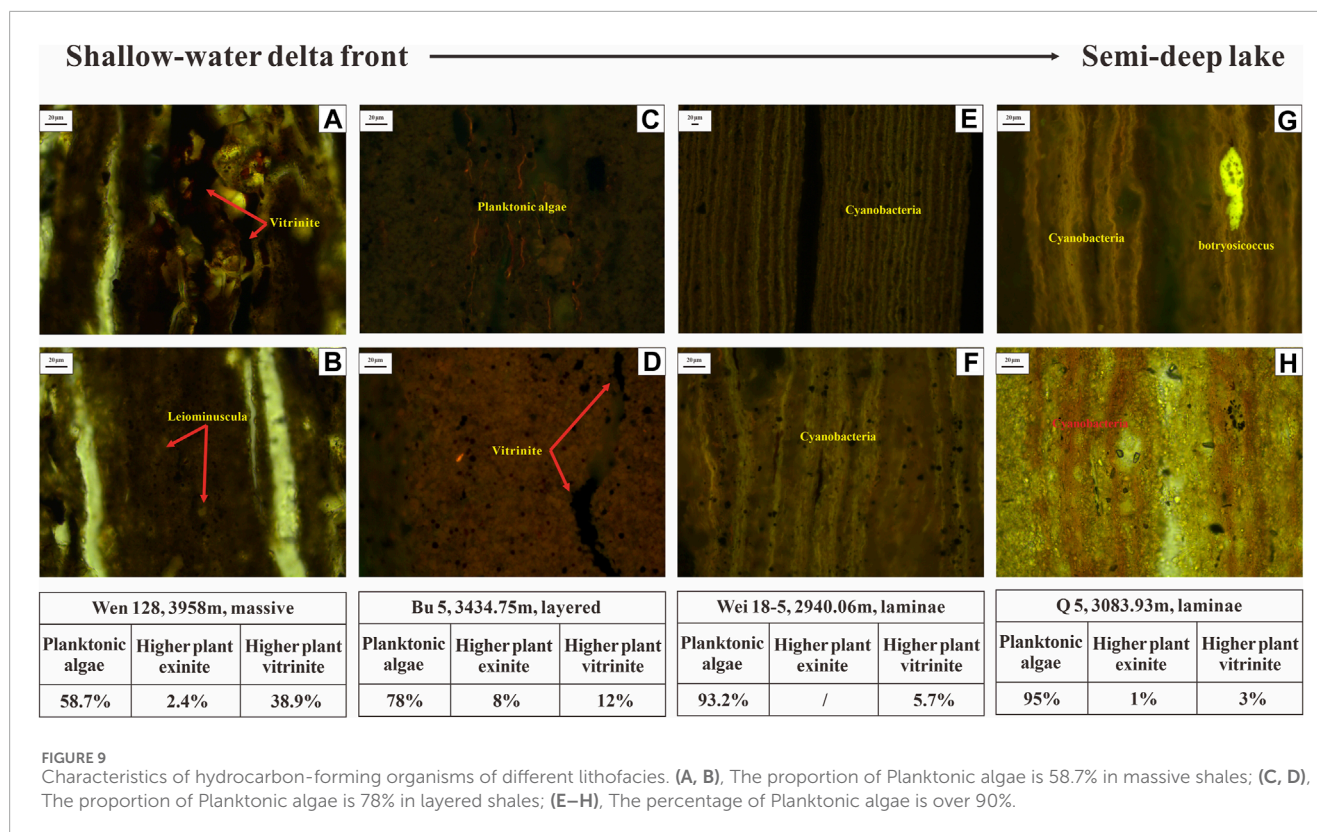


FIGURE 8  
The relationship between hydrocarbon generation capacity, oil content, and mobility. (A) TOC vs.  $S_{1C}$ ; (B) Hlo vs.  $S_{1C}$ ; (C)  $T_{max}$  vs.  $S_{1C}$ ; (D) TOC vs. OSI; (E) Hlo vs. OSI; (F)  $T_{max}$  vs. OSI.





wider fractures, which enhances the potential for oil mobility. The connection between vertical and bedding fractures creates pathways that facilitate micro-migration of shale oil, resulting in increased mobility and hydrocarbon recovery potential. This interplay of pore structure, mineral composition, and fracture characteristics underscores the complexity of shale oil enrichment and the factors that influence its distribution and mobility.

Pore structures play a crucial role in determining the enrichment space for oil and gas, and these structures are primarily influenced by mineral composition (Loucks et al., 2009; Liu et al., 2021; Wang et al., 2022b). The mineral composition of shale not only affects pore evolution but also influences adsorption capacity, which is essential for determining the characteristics of shale oil. In this study, we analyzed the impact of different minerals on the oil content and mobility of HSS oil.

The results indicate that as the clay mineral content increases,  $S_{IC}$  initially increases and then decreases (Figure 11A). The strong adsorption capacity of clay minerals for organic matter enhances the hydrocarbon generation potential of shale, leading to higher oil content (Sandvik et al., 1992; Ahmat et al., 2017; Zhao et al., 2022a). However, excessively high clay mineral content can occupy pore space, limiting the shale's ability to contain additional oil (Du et al., 2024). Similarly, feldspar minerals exhibit a corresponding trend with  $S_{IC}$ , likely due to their high brittleness (Figure 11B). A certain content of feldspar improves pore space and connectivity, which is conducive to the storage of shale oil, while excessive felsic contents promote the hydrocarbon expulsion, which is not conducive to the shale oil accumulation. The correlation between carbonate minerals and  $S_{IC}$  is relatively weak (Figure 11C), suggesting that

carbonate minerals have a limited effect on the oil content of shale. The positive correlation between clay mineral content and OSI can be attributed to two main reasons (Figure 11D). First, clay minerals have small particle sizes and large specific surface areas, leading to rapid adsorption kinetics and strong adsorption stability for organic matter. Consequently, the generated hydrocarbons are easily adsorbed by clay minerals and are less likely to be released. Second, the pores in clay minerals are primarily composed of nanopores, which impose stronger confinement effects on shale oil, significantly reducing the micro-migration of hydrocarbons (Lanson et al., 1998; Peltonen et al., 2009). As the content of feldspar minerals increases, OSI shows a trend of initially increasing and then decreasing (Figure 11E). This phenomenon may be due to the improved pore connectivity that facilitates the expulsion of shale oil from the reservoir, thereby reducing  $S_{IC}$  and resulting in a lower OSI. In contrast, carbonate minerals exhibit a positive correlation with OSI (Figure 11F), indicating that higher carbonate mineral content enhances mobility. The layered fractures and hydrocarbon pressurized fractures within carbonates serve as pathways for micro-migration, facilitating the movement of generated hydrocarbons into carbonate reservoirs (Aydin, 2000; Gale et al., 2004; Liu et al., 2020).

### 5.2.3 Preservation conditions

Preservation conditions play a significant role in determining the content and composition of shale oil (Zhao et al., 2023b; Usman et al., 2024). Organic-rich shales are important as they function both as traditional source rocks and as reservoirs for shale oil and gas (Bou Daher et al., 2014; Bou Daher et al., 2015). Results indicate differences in pore development among the various



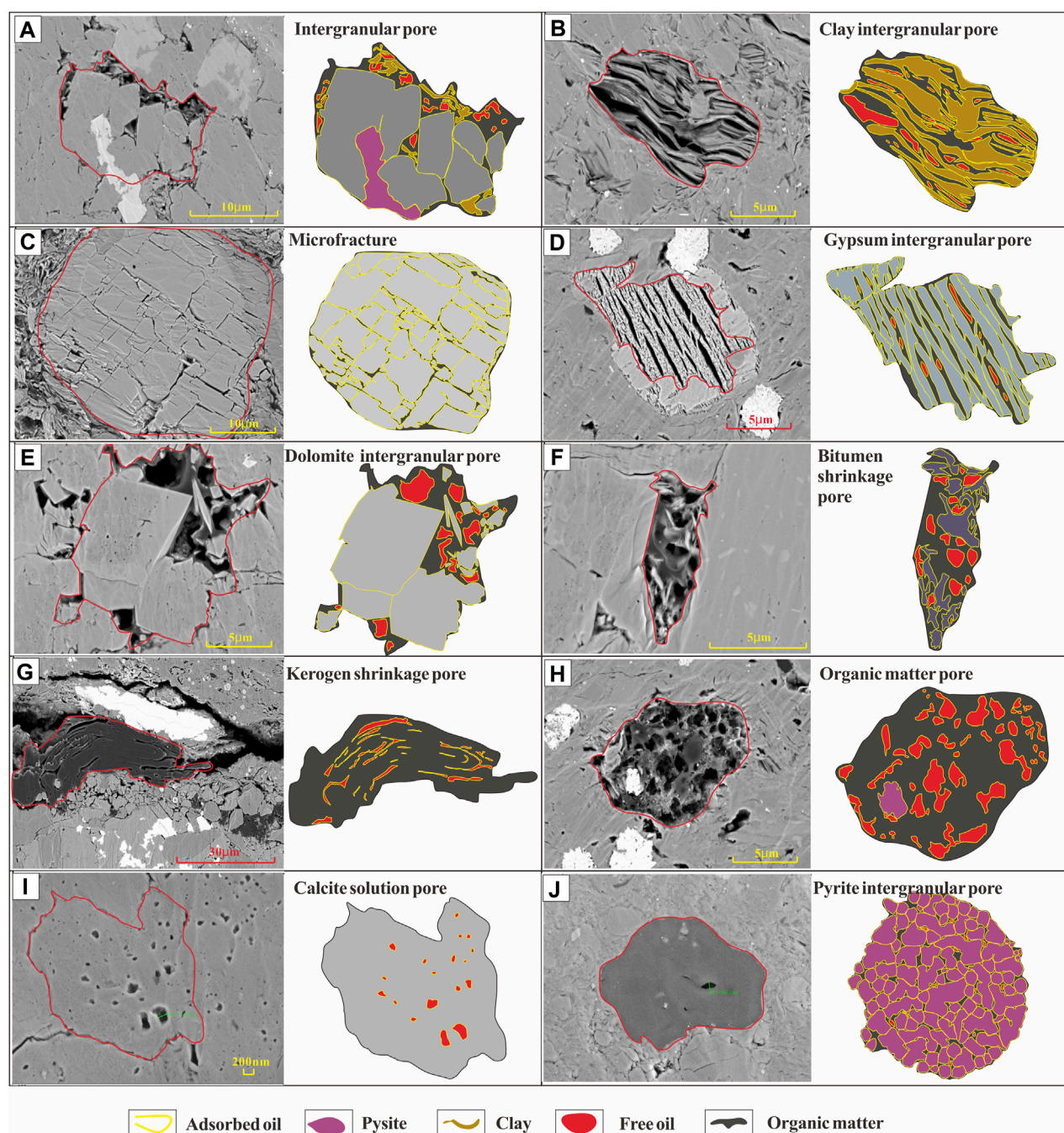
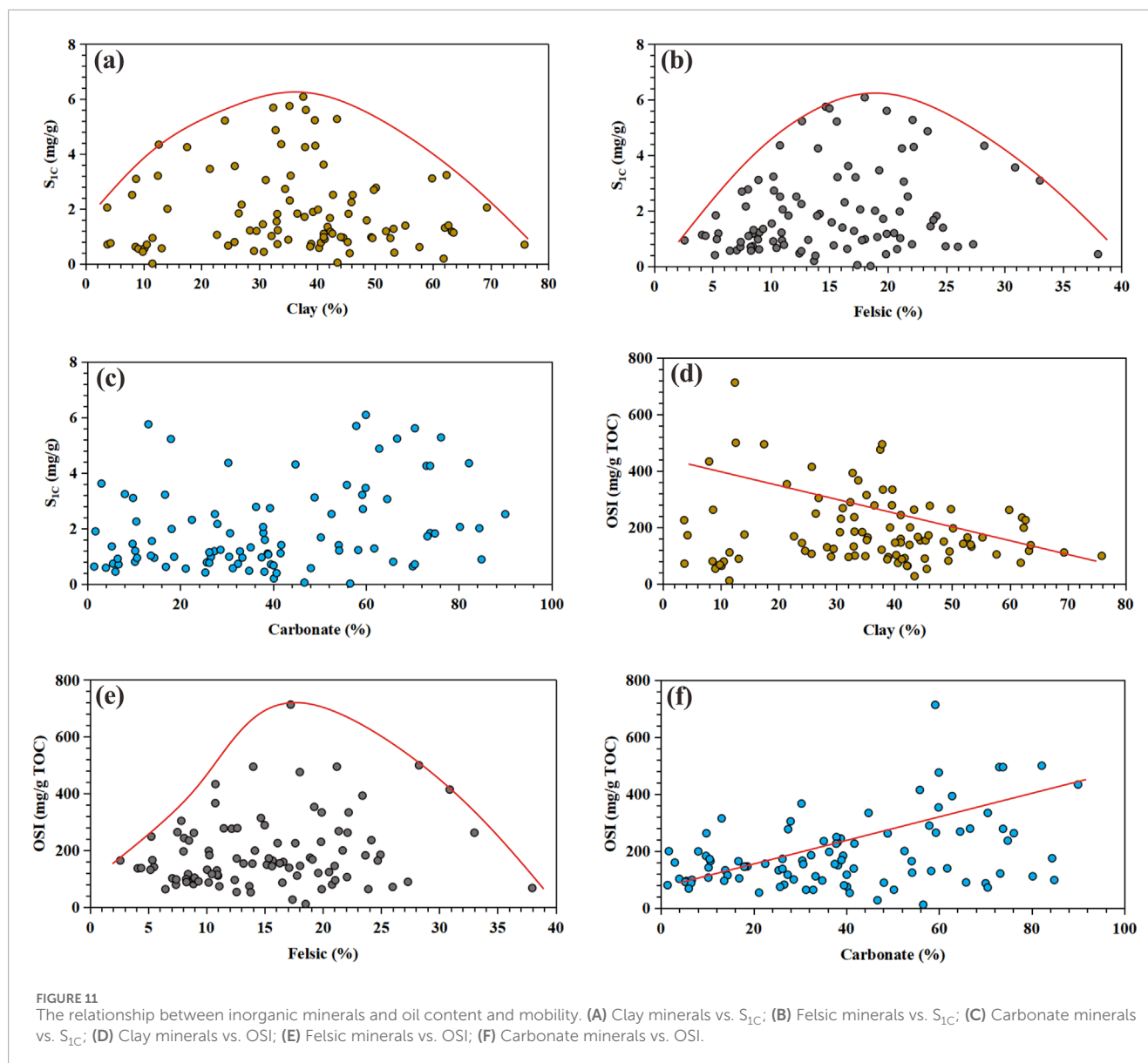


FIGURE 10

Shale oil occurrence characteristics of hybrid sedimentary shales in the Dongpu Depression. (A) Intergranular pore of feldspar; (B) Clay intergranular pore; (C) Microfractures formed by gypsum minerals; (D) Gypsum intergranular pore; (E) Dolomite intergranular pore; (F) Bitumen shrinkage pore; (G) Kerogen shrinkage pore; (H) Organic matter pore; (I) Calcite solution pore; (J) Pyrite intergranular pore.

lithofacies. Lithofacies I exhibits the micropores and mesopores, while Lithofacies II and III are characterized by the predominance of mesopores and macropores (Figures 12A–C). In the case of the Shahejie Formation, the porosity is relatively low, averaging less than 5% (specifically, 2.6%), and the permeability is quite limited, measuring less than  $0.1 \times 10^{-3} \mu\text{m}^2$  (with an average of  $0.037 \times 10^{-3} \mu\text{m}^2$ ). These poor physical properties pose challenges for the migration and enrichment of shale oil and gas. However,

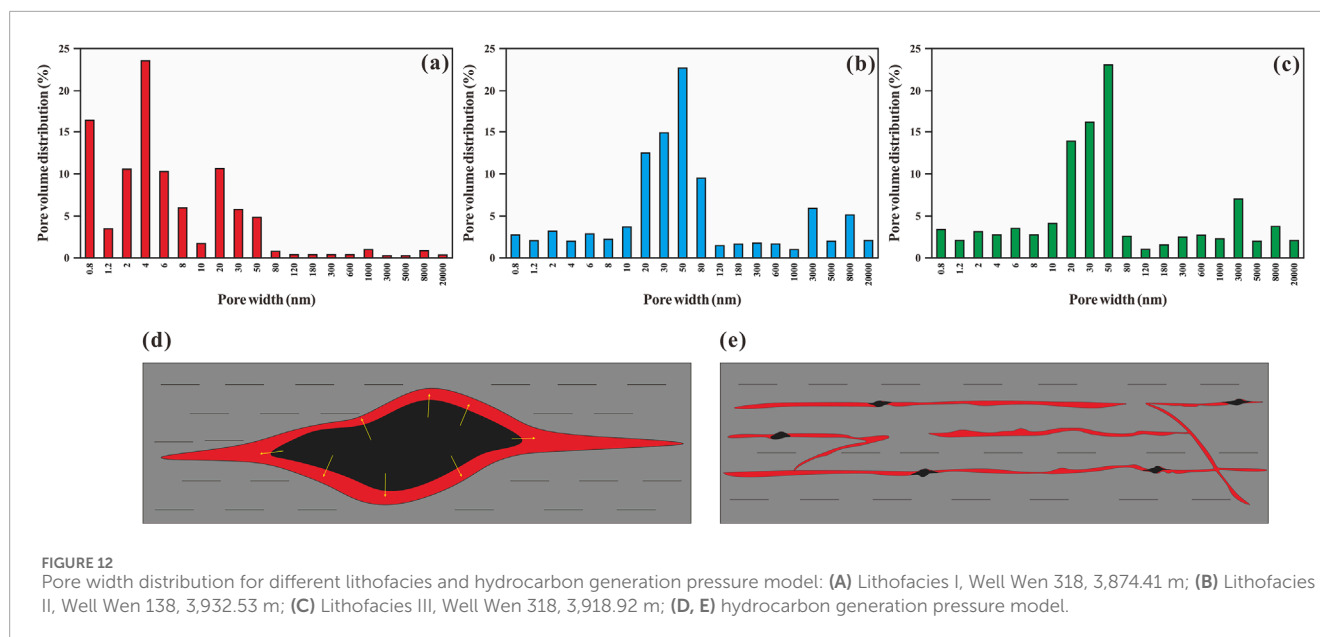
development of salt minerals such as halite, gypsum, and carbonate minerals in the DD create favourable conditions for the storage and migration of shale oil (Poetz et al., 2014; Wu et al., 2023). The presence of these minerals contributes to the formation of micro-migration pathways that enhance the movement of hydrocarbons (Lanson et al., 1998; Milliken et al., 2012; Eyoung et al., 2018). Using the Monte Carlo method, researchers calculated that the porosity of intersalt overpressure fractures in the Shahejie Formation ranges



from 0.02% to 0.99%, with an average of 0.58%. This indicates that these fractures contribute approximately 22.3% to the total porosity of the shale. Additionally, the permeability of these intersalt overpressure fractures ranges from  $0.001$  to  $0.860 \times 10^{-3} \mu\text{m}^2$ , averaging  $0.019 \times 10^{-3} \mu\text{m}^2$ , which accounts for about 51.4% of the shale's overall permeability. The findings highlight that intersalt overpressure fractures significantly enhance the porosity of shale reservoirs while also serving as the primary conduits for the seepage of shale oil and gas (Gale et al., 2004; Zanella et al., 2014; Liu et al., 2020). This dual role is crucial for understanding the dynamics of hydrocarbon migration and enrichment within these complex geological formations.

The pressure generated during kerogenic hydrocarbon generation is a key driving force behind hydrocarbon migration, with fractures induced by this pressure serving as essential pathways for micro-seepage (Figure 12D) (Tyson, 2001; Wu et al., 2018; Jia et al., 2021; Sharifi et al., 2021). As hydrocarbons generate,

the resulting pressure creates overpressure fractures that extend horizontally through the strata and interconnect at their endpoints (Zanella et al., 2014; Wu et al., 2016). Under the influence of fluid pressure, newly formed shale oil migrates along the path of least resistance within the shale matrix (Figure 12E). This process facilitates the gradual enrichment of oil into larger structural and diagenetic fractures, enabling short-distance migration of shale oil and gas (Chapman, 1972; Wu et al., 2021). Following this primary migration, a substantial quantity of organic matter, along with residual oil and gas, remains trapped within the intricate fracture network (Ko et al., 2016; Ko et al., 2018). This network ultimately evolves into an interconnected organic matter framework, leading to the development of an organic-rich zone characterized by high porosity, which acts as the primary reservoir space for shale oil and gas. Consequently, the interconnected fracture network within overpressured shales plays a dual role: it is both the principal pathway for the initial migration of hydrocarbons and a crucial reservoir



space within shale formations. This network significantly influences the aggregation and enrichment of shale oil and gas, highlighting its importance in the overall dynamics of hydrocarbon enrichment within these geological systems.

### 5.2.4 Micro-migration

The results showed that  $\delta Q$  has a significant negative correlation with  $S_{1C}$  and OSI (Figure 13), indicating that shales with obvious micro-migration have higher mobility and hydrocarbon expulsion potential. In addition, the micro-migration phenomenon is most pronounced in Lithofacies III, which corresponds to higher oil content and mobility (Figure 13). Shale oil enrichment is controlled by hydrocarbon generation capacity, reservoir capacity, and preservation conditions (Lu et al., 2012; Curtis and Zumberge, 2018). Micro-migration is the bridge connecting these factors (Hu et al., 2024a). Shale with strong hydrocarbon generation potential can lead to poor oil content due to hydrocarbon expulsion, while shale with weak hydrocarbon generation potential can have good oil content due to hydrocarbon charging (Bernard et al., 2012b; Hu et al., 2024b). The proportion of heavy components in shale where hydrocarbon expulsion occurs is high, while the proportion of light components in shale that receives hydrocarbons is high (Leythaeuser et al., 1988).

Petroleum micro-migration encompasses the entire process of oil generation, expulsion, and subsequent enrichment (Chapman, 1972; Todaro et al., 2022). The migration of hydrocarbons is influenced by a variety of factors, including geological, chemical, and physical conditions (Kat and Lin, 2014). Micro-migration plays a critical role in the enrichment of shale oil, as evidenced by variations in oil content and composition (Hu et al., 2024a; Hu et al., 2024b; Wu et al., 2024a). Identifying and evaluating the pathways and mechanisms of shale oil micro-migration can provide essential theoretical support for establishing differential shale oil enrichment models. Understanding these dynamics can help pinpoint areas with varying enrichment levels and hydrocarbon potential (Ross and Bustin, 2008a; Ross and Bustin, 2008b; Curtis

and Zumberge, 2018). Furthermore, the intervals of micro-migration should also be assessed in terms of shale oil content and the identification of “movable sweet spots,” where the shale oil is more easily extractable. This approach allows for a more nuanced understanding of shale reservoirs and can guide exploration and production strategies, maximizing the efficiency and effectiveness of hydrocarbon recovery efforts.

### 5.2.5 Pearson correlation analysis of key controlling factors for oil content and mobility

The controlling factors of shale oil content and mobility were determined by Pearson correlation analysis in this study (Figure 14). A positive coefficient indicates a positive correlation between the two parameters, and a negative coefficient indicates a negative correlation between the two parameters. The closer the coefficient is to  $\pm 1$ , the stronger the correlation between the two parameters. The results indicated that TOC (correlation coefficient with  $S_{1C}$ : 0.70),  $T_{max}$  (correlation coefficient with  $S_{1C}$ : 0.56), and  $\delta Q$  (correlation coefficient with  $S_{1C}$ : -0.54) are influential factors affecting the HSS oil content. Meanwhile,  $\delta Q$  (correlation coefficient with OSI: -0.81), clay minerals (correlation coefficient with OSI: 0.27), and carbonate minerals (correlation coefficient with OSI: 0.46) are the factors influencing oil mobility. Among these, TOC has the highest correlation coefficient with  $S_{1C}$ , while  $\delta Q$  has the highest correlation coefficient with OSI (Figure 14). Therefore, the key controlling factor for the oil content of HSS is TOC, while  $\delta Q$  serves as the main controlling factor for oil mobility.

## 5.3 Comparisons and perspectives

We compared the oil content and mobility of the DD with the Delaware and Midland Basins in the United States and the Mahu Sag in China to reveal the connections and differences in HSS oil across these regions.



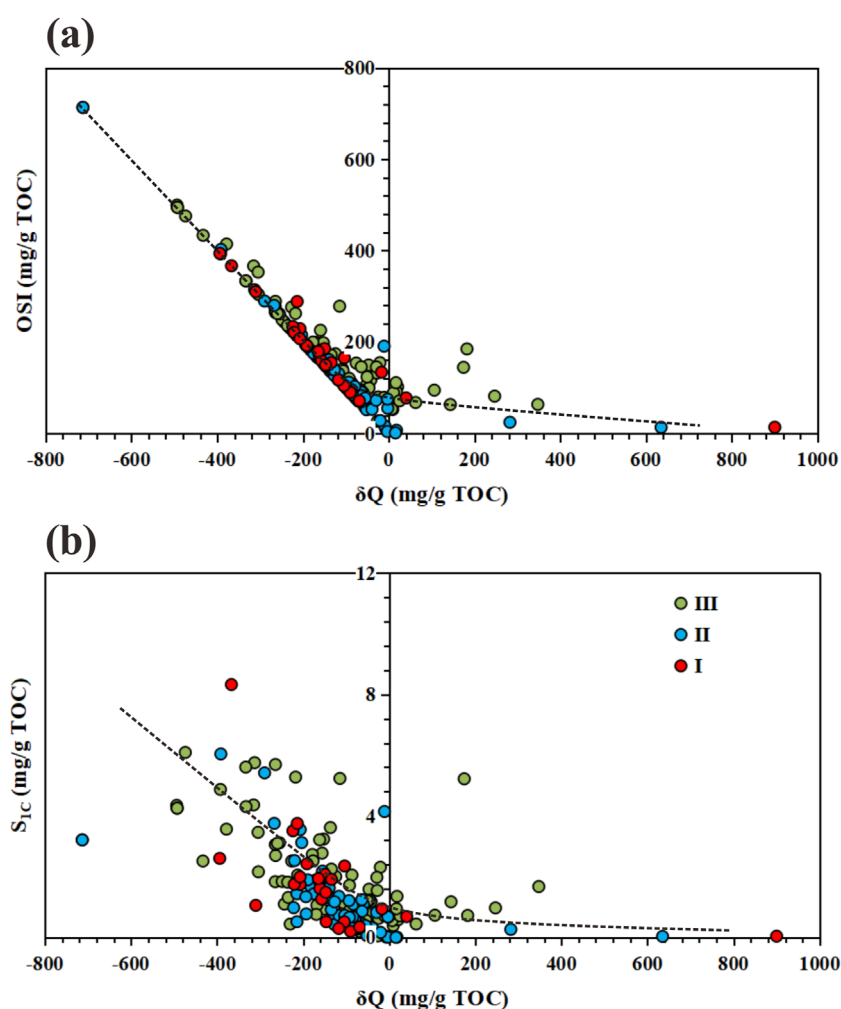


FIGURE 13  
The relationship between micro-migration and oil content and mobility. (A)  $\delta Q$  vs OSI; (B)  $\delta Q$  vs  $S_{1C}$ .

In the Wolfcamp A Formation of the Delaware and Midland Basins, the high-quality source rock primarily consists of basal carbonate facies, overlaid by calcareous or siliceous mudrocks (Gaswirth et al., 2016; Zhang et al., 2021). The average TOC content is 2.88 wt%, with an average  $S_1$  content of 3.68 mg/g and an average OSI of 128 mg/g TOC (Table 2). Siliceous mudrocks exhibit higher TOC content (average: 3 w. t.%), while thin carbonate laminae show the lowest TOC content (average: 1 w. t.%). A stable tectonic environment promotes the enrichment and preservation of organic matter, resulting in high-quality organic-rich source rocks (Breyer, 2012; Ko et al., 2018; Li et al., 2019). Meter-scale laminae cycles likely contribute to oil production from the Wolfcamp A. Micro-migration allows oil generated from organic matter-rich mudrocks to be charged into organic matter-poor carbonate laminae through vertical microfractures, leading to shale oil accumulation (Sandvik et al., 1992; Esemie et al., 2012). Additionally, the micro-migration of organic-rich siliceous mudstone and calcareous mudstone resulted in high oil saturation of the Wolfcamp A (Barker, 1990; Jarvie et al., 2017).

The Fengcheng Formation in the Mahu Sag has a relatively low TOC content (average: 0.92 wt%), but higher  $S_1$  content (average: 3.52 mg/g) and OSI values (average: 382 mg/g TOC) (Zhang et al., 2022). The unique alkaline minerals present in the Fengcheng Formation facilitate early hydrocarbon generation and an extended oil window, resulting in a sustained supply of oil and gas (Zhi et al., 2016; Jiang et al., 2023b). The shale in the Fengcheng Formation possesses more pore space and better connectivity, contributing to high oil mobility and considerable commercial development potential (Li et al., 2023). Hu et al. (2024a), Hu et al. (2024b) found that micro-migration in the Fengcheng shale is prominent, with both lateral and vertical micro-migration enhancing the shale oil accumulation.

TOC contents of the Shahejie Formation HSS in the DD averages 1.02 wt%, which is intermediate between the Fengcheng Formation and the Wolfcamp A Formation. Although the oil content is relatively low (average  $S_1$ : 1.94 mg/g), its mobility (average OSI: 188 mg/g TOC) is higher than the Wolfcamp A Formation. The DD is characterized by typical saline lake sedimentation, where salt minerals enhance organic matter hydrocarbon generation.

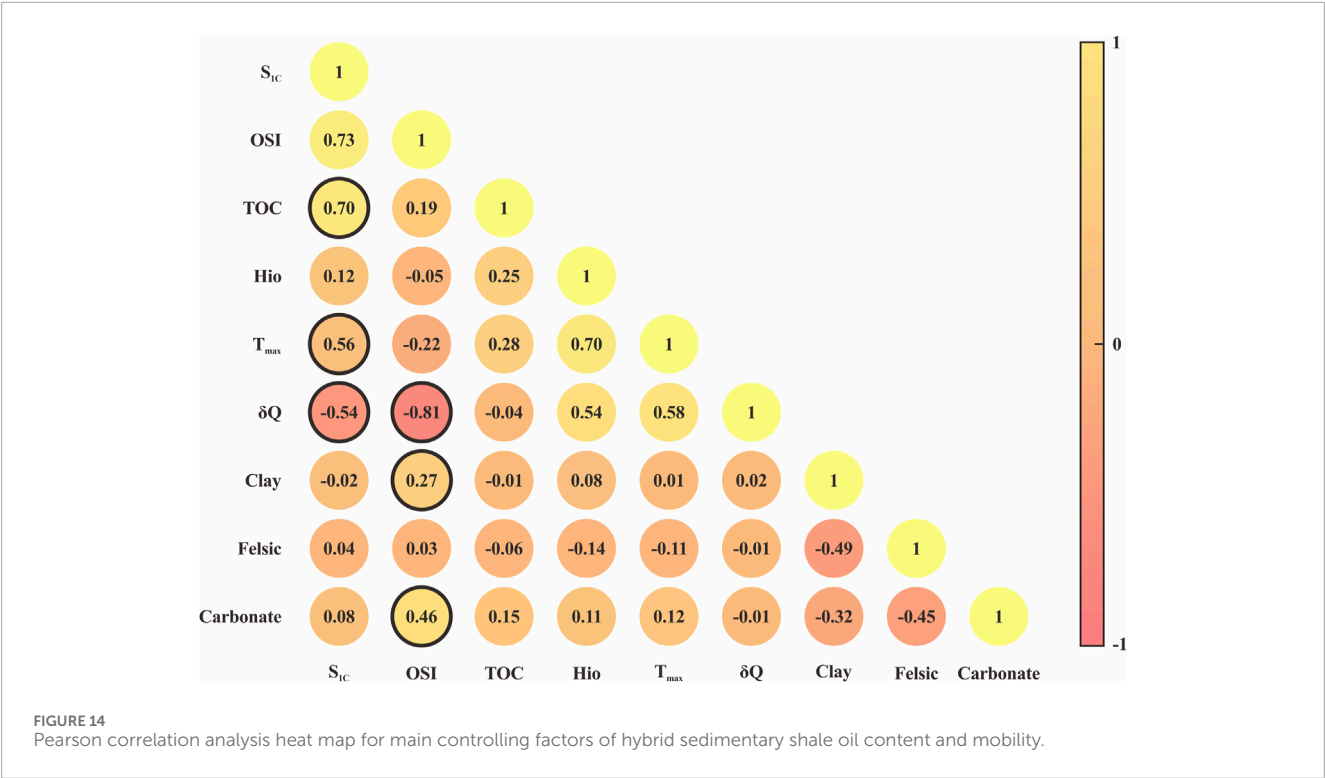


TABLE 2 Shale oil content and mobility characteristics in different basins.

| Basin/Depression/Sag               | Formation  | Dominant lithofacies                                                | TOC (w.t. %) | $S_1$ (mg/g) | OSI (mg/g TOC) |
|------------------------------------|------------|---------------------------------------------------------------------|--------------|--------------|----------------|
| Dongpu Depression, Bohai Bay Basin | Shahejie   | Laminated carbonate/carbonate-rich facies                           | 1.02         | 1.94         | 188            |
| Delaware and Midland Basins        | Wolfcamp A | Basal carbonate facies overlain by calcareous or siliceous mudrocks | 2.88         | 3.68         | 128            |
| Mahu Sag, Junggar Basin            | Fengcheng  | Siliceous shale                                                     | 0.92         | 3.52         | 382            |

However, frequent tectonic activities and a complex sadimentary environment increase the heterogeneity of the HSS (Wu et al., 2024b), leading to more complex micro-migration of oil and gas. Consequently, the distribution of shale oil resources in the DD exhibits a more fragmented characteristic.

Comparison results indicate that the HSS oil enrichment in three basins is controlled by micro-migration. Differences in oil content and mobility are primarily related to sedimentary environment and tectonic background. A stable sedimentary environment is conducive to the development of source rocks, providing the basis for shale oil formation. Good reservoir capacity and micro-migration pathways are key factors for HSS oil enrichment. Future research should focus on comparing the sedimentary environments, tectonic evolution, and organic matter characteristics of different basins to identify the key factors controlling the reservoir capacity of HSS oil. Our study provides a theoretical foundation for the exploration and development of global HSS, promoting the sustainable utilization of regional oil and gas resources.

## 6 Conclusion

Three lithofacies types of HSS have been identified in the lacustrine basin: massive argillaceous shale (lithofacies I), bedded argillaceous shale (lithofacies II), and laminated calcareous shale (lithofacies III). Lithofacies III features the highest average TOC (1.56 w. t. %), hydrogen index (HI) (264 mg/g TOC), oil content  $S_{1C}$  (1.81 mg/g), and oil mobility OSI (188 mg/g TOC). Micro-migration phenomena were identified based on anomalies in the geochemical data, and the quantity of hydrocarbons involved in micro-migration ( $\delta Q$ ) was assessed. Results show that Lithofacies III exhibits the most pronounced micro-migration with an average  $\delta Q$  of  $-138$  mg/g TOC.

Correlation analysis shows that TOC (correlation coefficient: 0.70),  $T_{max}$  (correlation coefficient: 0.56), and  $\delta Q$  (correlation coefficient: -0.54) influence the oil content of HSS. TOC emerges as the primary controlling factor, suggesting that shales with high organic matter abundance possess better hydrocarbon generation potential and can produce more shale oil. Conversely,  $\delta Q$

(correlation coefficient: -0.81), clay minerals (correlation coefficient: 0.27), and carbonate minerals (correlation coefficient: 0.46) affect mobility.  $\delta Q$  is the main controlling factor for mobility, indicating that micro-migration governs the connectivity, transport, and enrichment of shale oil within the drainage and receiving units.

Through comparisons across different basins, we find that the HSS oil enrichment is influenced by micro-migration, while variations in oil content and mobility are primarily associated with sedimentary environment and tectonic background. Future research should focus on detailed analyses of the relationships among sedimentary environments, tectonic evolution, and organic matter to identify key factors affecting HSS oil enrichment. Our study provides insights into the controlling factors of HSS oil enrichment and offers new perspectives for global HSS oil exploration and development.

## Data availability statement

The raw data supporting the conclusions of this article will be made available by the authors, without undue reservation.

## Author contributions

JD: Writing—original draft, Writing—review and editing. YX: Writing—original draft, Writing—review and editing. BY: Writing—review and editing. LL: Writing—review and editing. TX: Writing—review and editing. DW: Writing—review and editing. KC: Writing—review and editing. DY: Writing—review and editing. HL: Writing—review and editing.

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## Conflict of interest

Authors JD, YX, BY, LL, TX, DW, KC, DY, and HL were employed by SINOPEC.

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## Generative AI statement

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