Mass Balance-Based Method for Quantifying the Oil Moveable Threshold and Oil Content Evaluation of Lacustrine Shale in the Paleogene Shahejie Formation, Nanpu Sag, Bohai Bay Basin

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ABSTRACT: Substantial heterogeneity in lacustrine shale brings significant challenges to oil exploration. Therefore, a clear and effective resource evaluation standard can significantly reduce the exploration risk and cost, thus further guiding the prediction in productive areas. However, due to the lack of consideration of the thermal maturity and kerogen type, the present evaluation standards may result in the misjudgment of the resource quality of shale oil reservoirs. In this study, a method based on mass balance involving a hydrocarbon generation statistical model was proposed to calculate oil movable threshold (OMT) values. The OMT values for different types of kerogens are determined from simple and easily obtained pyrolysis parameters. Based on the OMT values, a three-dimensional resource quality evaluation model is constructed and applied to the source rocks in Member (Mbr) 1 of the Shahejie Formation (Fm) Nanpu Sag, Bohai Bay Basin, eastern China. The results show that the Mbr 1 of Shahejie Fm shale is a set of high-quality source rocks with high total organic matter (TOC) and S_{1c} (calibrated free hydrocarbons) content. Meanwhile, the hydrocarbon generation potential of the studied lacustrine shales are in the order of type I > type II_{1} > type II_{2} > type III, whereas the OMT values show a similar order. From type I to type III, the hydrocarbon expulsion threshold (HET) values for the four types of shales correspond to pyrolysis peak temperatures ($T_{\text{max}}$) at 438, 426, 428, and 432 °C with the maximum OMT values being 143, 128, 127, and 122 mg HC/g TOC, respectively. The movable and favorable shale oil accumulations are mainly associated with type II_{1} and II_{2} shales. Our work provides a novel method for distinguishing the resource quality and locating a favorable exploration target for lacustrine shale, improving efficiency and reducing exploration risks.

1. INTRODUCTION

In recent years, significant breakthroughs in exploration and exploitation of shale, or source rock, reservoirs have been achieved in China, such as in the Silurian Longmaxi Formation (Fm) in the Sichuan Basin, Cretaceous Qingshankou Fm in the Songliao Basin, Triassic Yanchang Fm in the Ordos Basin, Permian Lucaogou Fm in the Junggar Basin, and Paleogene Shahejie Fm in the Bohai Bay Basin.¹⁻⁸ Shales in China are generally deposited in lacustrine environments with strong heterogeneity and complexity, which are obviously different from marine shales in North America.¹⁻¹¹ These features bring challenges for predicting productive areas, both laterally and vertically, and hence affect petroleum exploration; therefore, an accurate estimation of the oil content and production potential of source rock reservoirs is of great importance to shale oil exploration.¹²,¹³

Shale oil exists mainly in two forms: free and adsorbed. The adsorbed oil is primarily stored on the surface of the shale matrix and inside of kerogen. When the generated hydrocarbons exceed the kerogen adsorption capacity, a large amount of oil can flow, and this corresponding geological condition (e.g., thermal maturity level) is defined as the oil movable threshold (OMT).

14 For evaluating the resource quality of the shale oil reservoirs, several methods were proposed. Jarvie¹⁵ proposed an index that combines the total organic carbon (TOC) and Rock-Eval pyrolysis results ($S_{1}$: free hydrocarbons) to judge the quality of shale oil accumulations: the oil saturation index ($\text{OSI} = S_{1}/\text{TOC} \times 100$) and the oil crossover effect ($\text{OSI} > 100 \text{ mg HC/g TOC}$); these indices eliminate the effects of organic matter adsorption; therefore, $\text{OSI} = 100 \text{ mg HC/g TOC}$ can be regarded as the OMT value of shale oil. However, some layers have high OSI values, but resource accumulations may be limited. For example, a tiny amount of hydrocarbon migration may cause high OSI values when the TOC values of nonsource rocks are relatively low. In fact, the resource potential of these accumulations is relatively limited. To overcome this defect,
previous studies have constructed alternative evaluation standards for assessing the quality of shale oil by two independent variables (S_i and TOC, Figure 1a). However, evaluation standards proposed by Lu et al. did not consider the mobility of oil, thus making it more difficult to exploit some oil enrichment accumulations. Hu et al. combined the OMT value proposed by Jarvie and the grading evaluation standard constructed by Lu et al. to establish an improved grading evaluation standard, and they applied this method to evaluate strongly heterogeneous lacustrine shale in the Junggar Basin (Figure 1b); but the boundary value proposed by Jarvie for marine sedimentary shales in North America may not be applicable to lacustrine shales and therefore cannot provide effective guidance for oil exploration. Meanwhile, previous research indicates that the adsorption capacity of organic matter to oil is strongly impacted by thermal maturity. Wang et al. proposed a novel three-dimensional resource evaluation method for shale oil reservoirs. They introduce the pyrolysis peak temperatures (T_max) as an independent parameter, and their method provides a new insight into the resource potential assessment of shale oil accumulations. However, due to the different oil and gas adsorption capacities of different kerogen types, it is inappropriate to judge shale oil accumulation quality by ignoring kerogen types. Therefore, it is important to specify the OMT value before the shale oil content is evaluated.

When source rocks enter the hydrocarbon generation threshold (HGT), hydrocarbons are formed. The point at which a large number of hydrocarbons begin to flow and expel from the source rock is often referred to as the hydrocarbon expulsion threshold (HET). After passing the HET, the oil can be flowed and expelled from shale, which means that the generated oil amount exceeds the adsorption amount of organic matter. Therefore, the OSI of the HET can be viewed as the OMT value of shale. There are several methods to quantify the HET, among which the hydrocarbon generation potential method is widely applied due to its high efficiency and simplicity.

In this study, an improved evaluation model based on mass balance involving a hydrocarbon generation statistical method was proposed to calculate OMT values of different kerogen types in shales. The present shale oil evaluation standard is further improved and applied to the member (Mbr) source rocks of the Shahejie Formation (Fm) in the Nanpu Sag. The objectives can be summarized as follows: (1) the geochemical features and sedimentary environments of the shales were systematically described; (2) a hydrocarbon generation statistical model was used to quantify the hydrocarbon generation potential and OMT values of different types of kerogen; and (3) a three-dimensional resource quality evaluation model was established to judge the production potential for shale oil reservoirs. Our work is a meaningful attempt at shale oil exploration and provides an effective workflow for studying lacustrine shale oil systems.

2. GEOLOGICAL BACKGROUND

The Nanpu Sag is located in the northeastern Huanghua Depression of the Bohai Bay Basin and lies in the NNE–SSW direction, with a total area of ~1932 km² (Figure 2a,b). From the bottom to top, the Nanpu Sag contains middle-upper Proterozoic, Paleozoic, Mesozoic, and Cenozoic sedimentary rocks. The Cenozoic strata host the main petroleum exploration target, with more than 5000 m of sedimentary rocks, including the Paleogene Shahejie and Dongying Formations and the Neogene Guantao and Minghuazhen Formations (Figure 2c). The Shahejie Fm was deposited in a lacustrine delta, shallow water to deep water lacustrine sedimentary environment, and is composed of mudstone, sandstone, and conglomerate at a depth of more than 2800 m.

Our study area is located in the southern Nanpu Sag, including Nanpu No. 1 to No. 4 structural belts, and covers an area of ~1000 km² (Figure 2b). The target formation is Mbr 1 of the Shahejie Fm. The sedimentary center of the Shahejie Fm is located in the Linque Subsag (Figure 2b), which adjoins the study zone, resulting in the thickness of Mbr 1 of the Shahejie Fm being ~400 to 500 m. The layer can obviously be divided into two sections, including the lower member of Mbr 1 of the Shahejie Fm (Lower Mbr) and the upper member of Mbr 1 of the Shahejie Fm (Upper Mbr). The lower part of Mbr is composed of shale interbedded with sandstone. The upper part of Mbr mainly consists of siltstone, sandstone, and conglomerate interbedded with thin mudstone layers. Mbr 1 of the Shahejie Fm is considered one of the main oil-supplying source rocks in the Nanpu Sag, and its favorable hydrocarbon generation conditions have significant shale oil potential; therefore, it can be considered a good research target for lacustrine shale.
3. DATA AND METHODS

3.1. Samples and Experiments. The database of our research is from 15 exploration wells, and 252 numbers of drilling core samples were collected, ranging in depth from 3337.8 to 5640.0 m, and these samples contain gray, dark gray, and black mudstones. The pyrolysis experiment was conducted on a Rock-Eval VI instrument, and the parameters obtained included $S_1$ (thermal peak at 300 °C), pyrolysis hydrocarbon ($S_2$, the quantity of hydrocarbons released between 300 and 650 °C), and $T_{\text{max}}$. A LECO CS-400 instrument was used to measure the TOC content of the samples after the samples were powdered to a size of 80 mesh and carbonate removal (dissolved by hydrochloric acid). Before the testing, the crucible with iron and tungsten fluxes and standard samples was used to correct the data accuracy of the instrument. To quantify the thermal maturity, 24 samples were tested for vitrinite reflectance ($R_o$); a Leica MPV Compact II reflected light microscope with a microphotometer and an oil immersion lens was used. The reflectance measurement system was linearly calibrated with standards of known reflectance (saphir, $R_o = 0.589\%$, gadolinium–gallium–garnet, $R_o = 1.725\%$), more than 20 points were counted on each sample to ensure accurate testing, and the standard deviation of each result was less than 0.05. All these experiments were conducted in the Wuxi Institute of Petroleum Geology of Sinopec.

3.2. Hydrocarbon Generation Statistical Model Establishment. 3.2.1. Organic Carbon Correction. Pepper et al.\textsuperscript{17} suggested that in some samples with poor TOC content, most measured TOC values are from generated oil. When calculating the OSI value, only organic carbon in kerogen ($C_{\text{org,k}}$) has an impact on oil sorption. Therefore, the carbon from generated petroleum should be removed from the total carbon ($C_{\text{org-som}}$ eq 1).

$$C_{\text{org-k}} = C_{\text{org-som}} - (S_1 \times W \times 100)/1000$$

Figure 2. Nanpu Sag geological map (reproduced with permission from ref 23. Copyright 2019 Marine and Petroleum Geology). (a) The locations of the Bohai Bay Basin. (b) The location and structural belt distribution of the Nanpu Sag. (c) Columnar section of the Nanpu Sag.
where \( W \) is the weight fraction of carbon in hydrocarbon, and the value is \( \sim 0.85 \).\(^{35}\)

3.2.2. Light Hydrocarbon Calibration. On the basis of the database, this paper selects the light hydrocarbon evaporation recovery model proposed by Chen et al.\(^{26}\) to obtain a more accurate result. The total light hydrocarbon evaporation \( (S_I) \) can be calculated by combining the light hydrocarbon evaporation during sample collection \( (S_{IC}) \) and sample preservation \( (S_{IP}) \), eq 2.

\[
S_I = S_{IC} + S_{IP} \tag{2}
\]

There is a relationship between \( S_{IC} \) and the formation volume factor \( (FVF) \), and FVF correlates with \( T_{max} \). Therefore, \( S_{IC} \) can be calculated by eq 3, while \( S_{IP} \) is related to many factors. In this paper, the average experimental calculated value of 38% is selected as the recovery coefficient (eq 4). Therefore, the recovered \( S_I \) value \( (S_{IC}) \) can be approximated by eq 5.

\[
S_{IC} = FVF \times S_1 \frac{R_{OB}}{R_{OC}} \tag{3}
\]

\[
S_{IP} = (S_{1c} - S_{IC}) \times 0.38 \tag{4}
\]

\[
S_{IC} = S_I (1 + 0.62FVF)/0.62 \tag{5}
\]

3.2.3. Hydrocarbon Generation Statistical Model. Based on the mass balance principle and the method of Chen and Jiang,\(^{19}\) Li et al.\(^{22}\) proposed a hydrocarbon generation statistical method to fit the evolution of the hydrogen index \( (HI = S_I/TOC \times 100 \) refers to the residual hydrocarbon generation potential per gram of organic carbon) and the hydrocarbon generation index \( (Ig = (S_1 + S_2)/TOC \times 100 \) refers to the sum of residual hydrocarbon generation potential and the generated hydrocarbon amount per gram of organic carbon) in the context of thermal maturity for a set of samples (the detailed formula derivation can be found in Appendix A of Li et al.;\(^{22}\) this method is used directly in this study). This method can quantify the hydrocarbon generation, expulsion, and retention capacity of a specific shale Fm with a certain number of samples (Figure 3). In this study, due to the similar geological significance, we use \( T_{max} \) to replace \( Ro \) in all equations. The theoretical basis of this method is the mass balance principle, where the Ig of the shale should remain nearly constant until the shale starts to expel oil. Using pyrolysis and TOC content, the Ig and HI of each sample can be calculated, and based on these parameters, the HI, and Ig of a set of samples can be expressed as eqs 6 and 7:

\[
HI(T_{max}) = \frac{HI_0}{1 + \exp(\theta_1 \times \ln(\frac{T_{max}}{\beta_1}))} \tag{6}
\]

\[
Ig(T_{max}) = \frac{Ig_0}{1 + \exp(\theta_2 \times \ln(\frac{T_{max}}{\beta_2}))} \tag{7}
\]

where HI \( (T_{max}) \) and Ig \( (T_{max}) \) represent the HI and Ig of a specific \( T_{max} \) value. HI_0 and Ig_0 are the initial hydrogen index \( (mg \text{ HC/g TOC}) \) and the hydrocarbon generation index \( (mg \text{ HC/g TOC}) \), respectively. Before hydrocarbon generation, the values of HI_0 and Ig_0 are equal. \( \theta_1 \) and \( \beta_1 \) are \( (\text{dimensionless}) \) variables related to kerogen type and have different values in eqs 6 and 7.

Based on the above parameters, the OSI can be obtained by eq 8:

\[
\text{OSI}(T_{max}) = Ig(T_{max}) - HI(T_{max}) \tag{8}
\]

where OSI \( (T_{max}) \) is the OSI of a specific \( T_{max} \) value.

The transformation rate \( (T_r, \%) \) is defined as the transformed effective carbon in kerogen. Several methods have been proposed to calculate this parameter,\(^{22,27,28}\) In this study, the calculation is from Li et al.\(^{22}\) (eq 9)

\[
T_r(T_{max}) = \frac{1000\alpha \times (HI_0 - HI(T_{max})) - HI_0 \times \text{OSI}(T_{max})}{HI_0 \times (1000\alpha - HI(T_{max}) - \text{OSI}(T_{max}))} \tag{9}
\]

where \( T_r(T_{max}) \) is the transformation rate of a specific \( T_{max} \) and \( \alpha \) represents the organic carbon consumption of \( \alpha \) grams of hydrocarbons.

The expulsion rate \( (E_r, \%) \) is equal to the specific value of expelled hydrocarbons with the maximum number of generated hydrocarbons, which is a parameter to quantify the degree of hydrocarbon expulsion. \( E_r \) can be expressed as eq 10

\[
E_r(T_{max}) = \frac{1200 \times (Ig_0 - Ig(T_{max}))}{Ig_0 \times (1200 - Ig(T_{max}))} \tag{10}
\]

where \( E_r(T_{max}) \) is the expulsion rate of a specific \( T_{max} \) and \( E_r \) is the ratio of expelled hydrocarbons to the total generated hydrocarbons.

As described before, our goal is to quantify the OMT value or the oil sorption ability of a specific shale. In the initial stage of hydrocarbon generation, most generated oil is absorbed and adsorbed by organic matter and minerals, respectively, rather than in a free state (Figure 4a,b). After kerogen sorption, oil begins to occupy the pores and fractures in shale with the free state (Figure 4c). They are finally expelled from the shale when the petroleum-generation-induced pore pressure becomes high enough to drive the generated fluids out of the shale (Figure 3).
4d), this geological condition is the HET. After reaching the HET, shale obviously contains a significant portion of free oil; in other words, parts of the oil are obviously movable after entering the HET. Therefore, the OSI value fitted by the hydrocarbon generation statistical model was taken at the HET and subsequent data were used as the shale OMT value to obtain the OMT values for shales with different thermal maturities (Figure 4a). Pang et al.\textsuperscript{18} argue that the HET is the geological condition corresponding to the large amount of hydrocarbons that begin expelling. In this work, we hold that the specific point with an Er greater than 5% can be considered as the HET.

3.3. Shale Oil Reservoir Quality Evaluation Model. As mentioned before, we select the method proposed by Wang et al.,\textsuperscript{14} and the parameters TOC, S\textsubscript{1c}, and T\textsubscript{max} are chosen for constructing the evaluation model. The OSI values can be regarded as OMT values after the shale enters the HET, and this method can quantify the oil adsorption characteristics of organic matter in different thermal maturities (Figure 5). First, similar to the classification method proposed by Lu et al.,\textsuperscript{16} TOC and S\textsubscript{1c} are used to divide the shale oil reservoirs into three zones: resource enrichment zone, potential resource zone, and resource unavailable zone. After taking the OMT value into consideration, the resource classification can be modified into four areas. Zone 1 is the area with the highest enrichment (high S\textsubscript{1c} values), and the OSI is greater than the OMT value, indicating the most favorable exploitation target. Zone 2 refers to the movable oil in a potential resource zone (moderate S\textsubscript{1c} values) and should be viewed as a secondary development target. Zone 3 indicates that even though the accumulations have certain resource potential (moderate S\textsubscript{1c} values), the OSI values are less than OMT values, leading to these accumulations being relatively hard to exploit, which are not favorable exploration targets in their current state. Zone 4 has limited resource potential (low S\textsubscript{1c} values), and as such, there is no need to consider further exploration in this area because its resources are identified as unavailable.

4. RESULTS

4.1. Bulk Geochemical Features. 4.1.1. Organic Carbon Calibration. According to the organic carbon and light hydrocarbon correction model mentioned above, the following
calibrations are completed. The corrected value of organic carbon is in good agreement with the measured TOC content, as shown in Figure 6, which means that the tested TOC values of our database are mainly from $C_{org-k}$. Therefore, in this study, we maintain the original value of TOC content. It should be noticed that this recovery cannot be ignored in the high oil-bearing shale with poor organic matter abundance.

4.1.2. Kerogen Type. Kerogen is the source material of the hydrocarbon formed in the source rocks, and different types of kerogen generally have various hydrocarbon generation and expulsion characteristics. The scatterplot of HI and $T_{max}$ can be applied to determine the kerogen type. Our results show that the HI ranges from 43.3 to 423.7 mg HC/g TOC, and the average value is 204.9 mg HC/g TOC. $T_{max}$ has a wide distribution range, varying from 410 to 466 °C, and the average value is 441 °C. Based on the previous classification, types II and III dominate the kerogen type. Only a tiny part of the samples fall into the type I and type II regions (Figure 7).

4.1.3. Organic Matter Abundance. In general, a high TOC content reflects a great base material and is favorable for hydrocarbon generation. The $S_1c$ value refers to the free hydrocarbon in the sample, which is one of the most important indices for shale oil exploration, and the $S_1c + S_2$ value represents the total hydrocarbon generation ability of source rocks. The quality of the source rock can be classified by a scatterplot of the TOC content and the $S_1c + S_2$ value (Figure 8). The TOC content ranges from 0.56 to 4.54%, with an average of 1.86%. The $S_1c$ value varies from 0.11 to 9.27 mg HC/g rock, and the average is 2.56 mg HC/g rock. The $S_1c + S_2$ value varies from 0.92 to 17.47 mg HC/g rock (the average is 6.42 mg HC/g rock). In general, nearly all samples can be classified as fair to good source rocks, indicating that the Mbr 1 of the Shahejie Fm is a set of high-quality source rocks.

For shale with different types of kerogen, the TOC contents and $S_1c + S_2$ values vary. The average TOC contents of the four kinds of source rocks are similar: from type I (shale with type I kerogen) to type III, they are 1.84, 1.84, 1.87, and 1.84%, respectively. However, there are obvious differences in the $S_1c$ and $S_1c + S_2$ values. In terms of $S_1c$, type II exhibits the highest value (mean value of 2.68 mg HC/g rock), which is significantly higher than that of type III (average value of 1.99 mg HC/g rock). The samples with type II kerogen have the largest $S_1c + S_2$ value (mean value of 8.75 mg HC/g rock), which is far beyond the value of type III samples (average value: 4.31 mg HC/g rock). In general, the $S_1c$ and $S_1c + S_2$ values of type I, II, and III kerogen samples are significantly higher than those of type III kerogen.

4.1.4. Thermal Maturity. The statistical results of Ro and $T_{max}$ are exhibited in Figure 9. All Ro values exceed 0.6%, and the highest value is more than 1.2%, which indicates that the source rocks are in the mature to high-mature stage. The $T_{max}$ values are concentrated in the range of 430–450 °C, indicating that the source rocks stay in the mature stage and the oil-generating window, which is consistent with the results obtained by Ro testing.

4.2. Hydrocarbon Generation Statistical Model. To restore hydrocarbon generation and expulsion processes, the evolution models are constructed based on pyrolysis results by...
obtaining the HI\textsubscript{0} and Ig\textsubscript{0} of shales with different types of kerogen using eqs 6 and 7 (Figure 10). In general, the trends of HI and Ig are similar; they remain constant, and the T\textsubscript{max} value first increases, then starts to decline, and eventually levels out. Our results show that the HI\textsubscript{0} values of different types of source rocks vary; from type I to type III, the HI\textsubscript{0} values are 725, 633, 537, and 223 mg HC/g TOC, respectively. For different types of kerogen, the evolution process varies; from type I to type III, the HET values are \(\sim 438, 426, 428,\) and 432 °C, respectively.

Compared with variations in Ig and HI, the OMT value evolutions can be identified, and the evolution processes of different types of shales are shown in Figure 11. The OMT values can be identified as the OSI values after the shale reaches the HET; according to the definition of HET, the OMT values of different types of kerogen can be obtained. The maximum OMT values of the four types of shales are 143, 128, 127, and 122 mg HC/g TOC, respectively. It should be noticed that in the research of Wang et al.,\textsuperscript{14} they considered the highest oil content (maximum OSI value) as the HET of the shale, and the OMT values decrease with increasing T\textsubscript{max} in their study. Because of the difference in the OMT definition, the OMT evolution trend in our study is not consistent with the result of Wang et al.\textsuperscript{14} According to our hydrocarbon generation statistical model, the point with the highest oil content does not coincide with the HET point. At the initial stage of hydrocarbon expulsion, the hydrocarbon expulsion rate is lower than the hydrocarbon generation rate, and the oil retention in the shale will continue to increase. Therefore, in our study, the OMT values increase at the initial stage, and after reaching the maximum point, they start to decline.

5. DISCUSSION

5.1. Variation in Geochemical Features and Parameters of the Hydrocarbon Generation Statistical Model.

There are obviously differences in geochemical features (hydrocarbon generation capacity, oil content) of different types of shales. In this section, we mainly discuss the variation of geochemical features of samples and the parameters of the hydrocarbon generation statistical model.

Pang et al.\textsuperscript{18} proposed the hydrocarbon generation potential method and argued that Ig is a parameter that can quantify the hydrocarbon generation ability of source rocks; a higher value represents a stronger hydrocarbon generation capacity. In terms of data measured directly from the sample, the differences in TOC content are not significant, but the S\textsubscript{1c} + S\textsubscript{2} values are widely various, which further contributed to the variation of Ig. The Ig of different types of shales is ranked as type II\textsubscript{1} (average value 468.0 mg HC/g TOC) > type II\textsubscript{2} (average value 355.3 mg HC/g TOC) > type I (average value 271.1 mg HC/g TOC) > type III (average value 222.7 mg HC/g TOC). The average values of the tested OSI of four types of shales are 129.6, 154.0, 140.1, and 100.4 mg HC/g TOC, respectively. By comparison, the OSI value varies much less than the Ig value.

Theoretically, the parameters of the constructed hydrocarbon generation statistical model should be consistent with the patterns obtained from the sample data. However, as mentioned before, the parameter Ig of the hydrocarbon generation statistical model of four types of shales is in the order of type I > type II\textsubscript{1} > type II\textsubscript{2} > type III, and the OMT values show a similar order. This phenomenon may be because the collected samples of type I shale are generally in the high-mature stage (average T\textsubscript{max} value is 462 °C, which is significantly higher than those of the other three types of shales), and the samples at this stage have already passed the peak of oil generation and expulsion; thus, the oil content and hydrocarbon generation capacity are lower than those of type II\textsubscript{1} shale. By constructing the hydrocarbon generation statistical model, we can recover the evolution curves of hydrocarbon generation, expulsion, and retention abilities of shales based on the available data. For different types of shales, the fitted evolution curves of HI and Ig show a decreasing trend with increasing thermal maturity, showing the hydrocarbon generation and expulsion processes, respectively. The OSI values of the four types of shales show a trend of increasing first and then decreasing with increasing thermal maturity, indicating that the generated oil first meets the adsorption condition of organic matter and minerals and then is expelled from the shale.

5.2. Resource Quality Evaluation Model Establishment and Application. According to the resource evaluation

![Figure 9](https://example.com/figure9.png)

**Figure 9.** Thermal maturity assessment of the source rocks in the Mbr 1 of the Shahejie Fm. (a) Kerogen maturity is assessed using a plot of Ro. (b) Kerogen maturity is assessed using a plot of T\textsubscript{max}.
Figure 10. continued
standard proposed by Wang et al.,¹⁴ the resource abundance is mainly controlled by $S_{1c}$, $T_{max}$, TOC, and OMT values. By this method, four resource zones are identified, including the enriched resource with excellent $S_{1c}$ and movable oil content.

Figure 10. HI and Ig models for different types of shales. (a) Type I, (b) type II$_1$, (c) type II$_2$, and (d) type III.

Figure 11. Hydrocarbon generation and expulsion models for different types of shales. (a) Type I, (b) type II$_1$, (c) type II$_2$, and (d) type III.
(zone 1 in Figure 5); potential resources with moderate $S_{1c}$ and movable oil content (zone 2 in Figure 5); less efficient resources with excellent or moderate $S_{1c}$ values but weak oil mobility (zone 3 in Figure 5); and invalid resources with low $S_{1c}$ values (zone 4 in Figure 5). This classification method avoids abnormally high OSI values (due to low TOC content) caused by oil migration into nonsource rock reservoirs; moreover, it does consider the oil mobility of shale and its dynamic changes. After considering the OMT values of the four types of shales, the resource evaluation results of shale with different organic matter types in the study area are shown in Figure 12. We use the method proposed by Lu et al. to determine the $S_{1}$ boundary values for judging the resource quality of shale oil reservoirs. Since light hydrocarbon evaporation is considered in this study, the mean value of the light hydrocarbon evaporation coefficients of each type of shale is applied to these two boundary values.

Due to low $S_{1c}$ values and oil movability, although OMT values of type III shale are relatively low, more than half of type III shales are in the less efficient and unavailable resource zone. The most favorable exploration reservoirs are dominated by type II1 and II2 shales, which both have a portion of reservoirs classified as enriched resources and also include a portion of potential resources. Although type I shales have the highest hydrocarbon generation ability, the quality of this type of source rock is relatively low in the current study area. Due to the limitation of data collection, the thermal maturities of type I shale samples in this study belong to the high-mature stage. Meanwhile, the OMT values of type I shale in the established model are higher than that of type II shale. Therefore, from the prospects of oil content ($S_{1c}$ value) and oil movability (OMT...
value), the type I shale in the study area is not the optimum target for shale oil exploration (only potential resource is detected).

Although our work provides a systematic evaluation of the resource quality of shale oil reservoirs, which can offer a more robust guide for shale oil exploration and reduce exploration risks, there are still some problems that need to be clarified. Such as in our work, the kerogen types determined by pyrolysis data may not be accurate enough, and more technologies like microscopic examination and the proxies of organic facies should be used in future studies to make a clearer kerogen type classification. Meanwhile, due to the defect of routine pyrolysis, some phenomena such as $T_{\text{max}}$ suppression should be considered. Therefore, advanced technologies (such as multistep pyrolysis) could be used to quantify the oil content in the resource quality evaluation for shale oil reservoirs in the future.

6. CONCLUSIONS

In this work, we describe the geological and geochemical features of the Mbr 1 shales of the Shahejie Fm. The results show that the Mbr 1 of Shahejie Fm shale is a set of high-quality source rocks with high TOC and $S_{\text{org}}$ content. Meanwhile, we used hydrocarbon generation statistical models to restore the evolutionary process of source rocks of the Mbr 1 of the Shahejie Fm, and various parameters, including the Ig, HET, and OMT values were quantified. The Ig values of the hydrocarbon generation statistical model of four types of shales are in the order of type I $>$ type IIa $>$ type IIb $>$ type III. From type I to type III, the HETs are located at $T_{\text{max}}$ 438, 426, 428, and 432 °C, and the maximum OMT values are 143, 128, 127, and 122 mg HC/g TOC, respectively.

An improved three-dimensional resource quality evaluation model of shale oil in the Mbr 1 of the Shahejie Fm in the Nanpu Sag was proposed. Our method is superior because it takes the influence of the kerogen type into consideration. Our results show that the type IIa and IIb shales are favorable exploration targets in the study area. Even though the type I shale has the strongest hydrocarbon generation capacity, the high thermal maturity and the OMT value caused the low resource quality of this type of shale. Type III shale is not suitable for exploration due to its weak hydrocarbon generation capacity and low hydrocarbon retention rate.

Author Contributions

E.W., C.L., and Y.F. contributed equally to this work.

Notes

The authors declare no competing financial interest.

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