Research Article

Oil Content Prediction Method Based on the TOC and Porosity of Organic-Rich Shales from Wireline Logs: A Case Study of Lacustrine Intersalt Shale Plays in Qianjiang Sag, Jianghan Basin, China

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Organic-rich shales in between salt rock layers distribute widely in Qianjiang Sag, Jianghan Basin, central China. Due to the complexity of matrix mineral components and their distribution and tight pore structure, Archie’s law cannot be used directly to calculate oil saturation in those shale oil reservoirs. A new oil content model for shale oil reservoirs was introduced. By analyzing the logging and core experimental data from Qianjiang Sag, Jianghan Oilfield, we built the relationship between kerogen and the different well logging porosities including nuclear magnetic resonance (NMR) porosity, neutron porosity, and density porosity. And we used the dual-Vsh method to calculate the total organic carbon (TOC). After calculating the volume fraction of the solid organic matters and separating it from the TOC, we acquired the hydrocarbon fluid content in the formations. The calculated oil content results are coherent with the core experimental data, which indicates the efficiency of this model. This model is simple and can be quickly applied. However, this method also shows its weakness in calculation precision when the TOC is not calculated precisely or the quality of the porosity logs is low.

1. Introduction

Shale oil resources develop vastly in China, which are mainly lacustrine, including the Paleogene shale oil plays in the Bohai Bay Basin, the Triassic shale oil plays in the Ordos Basin, the Eocene shale oil plays in the Pearl River Mouth Basin, the Middle Permian Lucaogou Formation, Jurassic Xishanyao formation shale oil plays in the Junggar Basin, Cretaceous Qingshankou Formation in the southern Songliao Basin, and the intersalt shale oil plays in Qianjiang Formation in the Jianghan Basin [1–15]. Those shale oil plays have variable total organic carbon content (TOC) and strong heterogeneity. The intersalt organic shale reservoirs in the Qianjiang Sag have very unique properties with more than 190 salt-bearing rhythms of the Qianjiang Formations and a total thickness of around 4200 meters. The roughly estimated petroleum reserve is up to 1.68 × 108 tons [6]. Many studies have been conducted in this area. However, how to accurately estimate the in-place oil content in oil-bearing shales is a remaining challenge.

For a common reservoir, with well logs, petrophysicists can distinguish the lithology and calculate the porosity, and with a suitable saturation model such as Archie’s law, the resistivity information can be converted into oil saturation to quantitatively evaluate the in-place oil content [16, 17]. The classic Archie law [18] reveals the relationship between

\[ S_o = \frac{1}{1 + \frac{1}{R_s} - \frac{1}{R_w}} \]

where \( S_o \) is the oil saturation, \( R_s \) is the true formation resistivity, and \( R_w \) is the formation water resistivity. However, Archie’s law cannot be used directly for shale oil reservoirs due to the complexity of matrix mineral components and their distribution and tight pore structure.
resistivity and saturation in pure sandstones. There are three basic assumptions to use Archie’s law, including (1) the saturation and the resistivity have a unique relationship which is not affected by the displacement order; (2) for one specific rock, the saturation index $n$ has a certain value; and (3) all the brine contained in the pore space contribute to the electric conductivity [19]. However, for a shale oil reservoir, the conventional petrophysical models are not suitable because of the strong heterogeneity and complex pore structure and mineral contents [20]. The common way to accurately evaluate the oil content is to obtain rock samples and examine them by pyrolysis in the laboratory [21], which is time-consuming and not continuous in depth. Building a new well logging interpretation model that is suitable for shale oil plays is urgently needed. Chen et al. found that the abundance and distribution of macro pores in lacustrine shales at peak oil generation are critical factors of a shale oil reservoir [22]. Based on the fluid distribution and conductive properties of the rock, lots of researches have been done, and saturation models for reservoirs with complicated pore structures have been developed [23–25]. By combining NMR logging and resistivity logging, Nie et al. developed a saturation model for the inter salt shale oil reservoirs [6]. The model can eliminate the effect of nonconductive pores and background conductivity; it was successfully applied in this area. However, the total process of the model is too complicated, and the process to calculate the nonconductive porosities has many uncertainties.

In this paper, we also introduce a bulk volume model for the inter salt shale reservoir rocks, and by analyzing the core pyrolysis data, we find a way to calculate the kerogen volume fraction with the NMR log, density log, and neutron log. After we calculate the TOC with the mature dual-$V_{sh}$ method, we can separate kerogen from TOC and, finally, obtain the oil content of the inter salt organic shales in the Qianjiang Sag which agrees with core data well. This method allows us to avoid calculating effective porosity and saturation and directly get the oil content parameter.

2. Geological Setting

Jianghan Basin is in Hubei province, central China. Qianjiang Sag is a secondary tectonic unit lying in the middle of the Jianghan Basin with an area of 2500 km$^2$, which is the most important oil-rich sag in the whole basin. It is bounded by the Qianbei Fault to the north, the Yuekou and Longzaihu low Uplift to the northeast, the Tongbai Fault to the southeast, the Yajiao-Xingou low Uplift to the southeast, and the Dongting Fault to the south (Figure 1) [6].

Qianjiang Sag is a double-faulted dustpan sag with obvious fault-sag characteristics. According to the characteristics of fault distribution and NW structural zonings, the northern part of Qianjiang Sag can be divided into five subunits: QianBei Steep Slope Zone, Western Slope Zone, Banghu Syncline Zone, Zhouji Syncline Zone, and Eastern Slope Zone. The strata are mainly Cenozoic sediments. From top to bottom, the strata are Quaternary, Guanhuasi Formation of Neogene, Jinghezhen Formation, Qianjiang Formation, Jingsha Formation, Xingouzu Formation, and Shashi Formation of Paleogene. The Qianjiang Formation of the upper Eocene and lower Oligocene is the oil-bearing formation with the best reserve conditions and the richest petroleum resources in the Qianjiang Sag. According to the lithology and other differences, the Qianjiang Formation can be divided into four sections from top to bottom: Qianjiang sections 1 to 4.

Over 190 salt rhythms develop through the whole Qianjiang Formation. A salt rhythm is composed of salt layers and shales in between. The inter salt layers of the Qianjiang Formation are medium or above source rocks. The carbonate and argillaceous rocks in those formations have good hydrocarbon generation ability. Because of the sealing effect of the salt layers, the generated oil and gas can hardly migrate in the vertical direction. And because the bedding seepage flow is slow, the oil and gas gathering in between the salt layers become the inter salt multilayer reservoirs. The formations in between the salt layers are mainly composed of clay minerals, carbonate minerals, and glauconite. This makes the calculation of oil saturation with resistivity logs extremely difficult. Dark argillaceous rocks and carbonates are potential hydrocarbon source rocks.

3. Methods

3.1. Shale Oil Bulk Volume Model and Porosity Calculation. According to the component analysis of the inter salt shale formations, the bulk volume can be simplified as pores, kerogen, and mineral matrix as shown in Figure 2. The bulk volume equation is shown as

$$V_{kero} + V_{ma} + V_{pore} = 1,$$

where $V_{kero}$, $V_{ma}$, and $V_{pore}$ are the volume fractions of kerogen, matrix, and porosity, respectively. The pores contain fluids, so they can be detected by the NMR logging. And the response for solid kerogen of NMR logging can be ignored. Meanwhile, because of the similarity between kerogen’s density and its hydrogen index and those of other fluids such as water and oil, the kerogen has similar responses for density and neutron loggings to fluids. Therefore, the response equation for density logging can be written as

$$DEN = V_{kero}\rho_{kero} + V_{ma}\rho_{ma} + V_{pore}\rho_{p},$$

where DEN is the density log value (g/cm$^3$) and $\rho_{kero}$, $\rho_{ma}$, and $\rho_{p}$ are the density of kerogen, mineral matrix, and fluid, respectively (g/cm$^3$). Thus, if there is a difference between the NMR porosity and the porosity deduced with the density or neutron logs, we can assume that there is solid kerogen. It should be noted that, in reality, NMR logging does detect the fluids, but not the ones in very small pores. It can also respond to kerogen, but the signal is poor and we can ignore it. Thus, we rely on the trend of difference between the porosities and calibrate the results using core data along with coefficients $k_1$ and $k_2$ to reflect the bulk volume of kerogen. Therefore, from Equation (1), by setting $V_{pore}$ as $\phi_{NMR}$, $V_{ma}$ can be written as

$$V_{ma} = 1 - V_{kero} - \phi_{NMR},$$
and then, the kerogen volume fraction can be calculated by using NMR and DEN logs as shown in Equation (4); the one calculated by using NMR and neutron logs can be written as shown in Equation (5).

\[
V_{\text{DEN\ kero}} = \frac{\text{DEN} - \rho_{\text{ma}} + \rho_{\text{ma}} \phi_{\text{NMR}} - \phi_{\text{NMR}}}{(\rho_{\text{kero}} - \rho_{\text{ma}}) k_1}, \tag{4}
\]

\[
V_{\text{CNL\ kero}} = \frac{\phi_{\text{N}} - \phi_{\text{NMR}}}{k_2}, \tag{5}
\]

where \(V_{\text{DEN\ kero}}\) and \(V_{\text{CNL\ kero}}\) are the volume fractions calculated with density log and neutron log, respectively; \(\phi_{\text{N}}\) is the neutron log value; \(k_1\) and \(k_2\) are correction coefficients that can be acquired with the help of core kerogen analysis results.

3.2. TOC Calculation Model. The TOC can be calculated by using well logging data with various methods, including the \(\Delta \log R\) method and dual-\(V_{\text{sh}}\) method [26–28]. In this paper, we choose the dual-\(V_{\text{sh}}\) model presented by Nie et al. [26] because it has been proved efficient in the research area. The workflow of this method is as follows.

The formation bulk model was simplified into two parts: brine-bearing shale and organic-bearing shale (Figure 3) [26]. Because clay minerals have a stronger ability to absorb radioactive substances than other minerals, mudrock formations always show high values of natural gamma radiation in well logs. Therefore, \(V_{\text{sh}}\) can be calculated using gamma-ray logs. The classic formulas used to calculate the total \(V_{\text{sh}}\) with gamma-ray logs are as follows:

\[
\text{SH} = \frac{\text{GR} - \text{GR}_{\text{min}}}{\text{GR}_{\text{max}} - \text{GR}_{\text{min}}}, \tag{6}
\]

\[
V_{\text{sh}} = \frac{2\text{gcur}\cdot\text{SH} - 1}{2\text{gcur} - 1}, \tag{7}
\]

where \(\text{SH}\) is the original shale content, \(\text{GR}_{\text{min}}\) and \(\text{GR}_{\text{max}}\) are the GR values of sandstone and pure mudstone formations.
respectively, and \( g_{cur} \) is the correction coefficient, which is 2 in old strata and 3.7 in new strata.

The \( V_{sh} \) values calculated from the GR logs contain the volume of shales bearing both brine and organic matters. The water-bearing shale content can be calculated with electrical conductivity measured through well logging. Under ideal conditions, the content of water-bearing shale (\( V_{shw} \)) and effective resistivity (\( R_t \)) can be written as follows [29].

\[
R_t = R_{sh} V_{shw}^{a}, \tag{8}
\]

where \( R_{sh} \) is the resistivity of pure shale formations, which is always set as the \( R_t \) value of the formation that has the highest shale content, and \( a \) is an index that is related to the conductivity of clay minerals, gas-bearing conditions, and porosity values, and its value varies between 1 and 2.

From Equation (8), we can deduce the \( V_{shw} \) calculation formula using \( R_t \) logs as

\[
V_{shw} = 10^{\frac{\log R_{sh} - \log R_t}{a}}. \tag{9}
\]

The organic-bearing shale content (\( V_{sho} \)) can be calculated as follows:

\[
V_{sho} = V_{sh} - V_{shw}. \tag{10}
\]

Then, the relative volume content of TOC (simplified as \( V_{TOC} \) in Equation (11)) in the oil shale formation can be calculated by multiplying \( V_{sho} \) by the apparent porosity of the formation (\( \phi_{sh} \)). \( \phi_{sh} \) can be selected as an empirical constant or calculated in the nearby organic-barren shale formation from porosity logs including density log, acoustic transit time log, and neutron log. Then, we have

\[
V_{TOC} = V_{sho} \cdot \phi_{sh}. \tag{11}
\]

The volume fraction can then be transformed into the mass fraction:

\[
TOC = \frac{V_{TOC} \cdot \rho_{TOC}}{DEN}, \tag{12}
\]

where \( \rho_{TOC} \) is the density of the organic matters (g/cm\(^3\)) and

\(DEN\) is the density logging value (g/cm\(^3\)). This is the final equation used to calculate the TOC content using the dual-\( V_{sh} \) method. In this research, what we need is the result of Equation (10), which is the volume fraction of total organic matters.

3.3. Oil Content Calculation. After obtaining the kerogen volume fraction total organic matter volume fraction, the oil volume fraction can be calculated as

\[
V_o = V_{TOC} - V_{kero}, \tag{13}
\]

where \( V_o \) is the oil volume fraction. If \( V_{TOC} \) is less than \( V_{kero} \), we assume there is no fluid oil in the formation and set \( V_o \) as 0. Then, we can convert the volume fraction into oil content which is the weight fraction of the oil as

\[
C_o = 1000 \frac{V_o \cdot \rho_o}{DEN}, \tag{14}
\]

where \( C_o \) is the oil content (g/kg\(^3\)) and \( \rho_o \) is the oil density (g/cm\(^3\)). This is the final equation used to calculate the oil content.

Therefore, the flowchart of this processing workflow is shown in Figure 4.

4. Results and Discussion

The method introduced in the above section was applied in well B and well W located in Qianjiang Sag. The application result of depth interval of between 3390 m and 3410 m of well B is shown in Figure 5. In Figure 5, the first track is the
lithology track, which contains natural gamma-ray (GR) and caliper of the borehole (CAL). The lower GR formations are salt rocks. The second track is the porosity track, which contains matrix density, acoustic interval transit time (AC), compensated neutron logging (CNL), density logging (DEN), and NMR porosity. Some of those porosity logs are used to calculate the volume fraction of kerogen. The third track is the resistivity track, which contains the shallow lateral resistivity log (LLS) and deep lateral resistivity log (LLD). The LLD is used as $R_t$ when calculating TOC with the dual-$V_{sh}$ method. The fourth track shows the calculation of $V_{shw}$ from $V_{shw}$ and $V_{sh}$. The fifth track shows the calculated TOC (TOC) and core TOC. The sixth track shows the calculated kerogen volume (KEROGEN) and the kerogen volume from core data (KEROS). From the result, we can see in the whole depth interval, the calculated TOC and kerogen volume agree well with core data, which reveals the TOC and kerogen calculation method is efficient. Tracks 7–9 show the calculated oil content results with the method presented in this paper (OILC), the method presented in Nie et al. [6] (OILC_BG), and Archie’s law (OILC_POR) in comparison with oil content from core data (S1). Both the oil content results in tracks 7 and 8 are higher or agree well with core data at most depth points. The reason for the higher results may be caused by the oil loss before the pyrolysis experiments because no hermetic sealing process was taken at the coring site. The results show the method introduced in this paper is efficient in this depth interval of well B. However, for the result calculated with Archie’s law in track 9, the oil content is much higher than the core data. This shows that Archie’s model is not suitable in those inter salts shale oil reservoirs.

Although at most depth range the calculated oil content with our method is higher or almost equal to the core data, at the depth of 3404.15 m, the calculated oil content is lower than S1 from the core. At this depth, the GR is relatively lower than the upper and lower shale formations. This causes the calculated TOC to be lower than the real condition. Therefore, the most uncertainty of this method is whether the TOC is precisely calculated. If there is an error in TOC content, there will not be a good oil content result.

In another case of well W, the application depth interval is 2595 m to 2615 m (Figure 6). In the depth range below 2605 m, the calculated oil content result with the method presented in our paper agrees well with core data. However, above 2605 m, the calculated result is much higher than the core results. This might be caused by two reasons. (1) Because the cores were not hermetic sealed when being collected at the well site in this well, the loss of S1 was severe.
The NMR logging quality in this depth interval is not very good. Therefore, the reliance on the porosity logs including the NMR log, neutron porosity log, and density log is also a weakness for this method.

5. Conclusions

Oil content is an essential parameter for evaluating shale oil plays. Conventional methods for calculating oil content are all based on conductive properties of the pores, which is difficult to realize in shale oil reservoirs. In this paper, we introduced a method that calculates oil content in the shale oil formations in Qianjiang Sag, Jianghan Basin, from TOC and kerogen content, avoiding calculating the porosity and saturation. The conclusions are as follows:

(1) The high TOC and pyrolysis S1 data reveal good hydrocarbon generation ability in the intersalt shale formations in Qianjiang Sag, Jianghan Basin. Those formations have special characteristics of complicated matrix minerals and low permeability which make it difficult to calculate the oil saturation

(2) By analyzing the porosity logs and pyrolysis data, we established the method to calculate kerogen content from well logs and core data. With this method, we can calculate kerogen volume fraction with porosities calculated or measured from NMR, density, and neutron logs

(3) The GR and porosity logs, especially the NMR log, are very important for this method. The oil content calculation strongly depends on the TOC result.
Based on the dual-$V_{an}$ method, the TOC can be calculated efficiently. However, the TOC result is very sensitive to the GR log. When an abnormality exists in the GR log, the TOC result can be strongly affected. And the kerogen calculation is sensitive to the porosity logs.

(4) All parameters in the method introduced in this paper can be obtained according to logging data and laboratory data. Compared with core data, this method is proved to be accurate and practical. This method provides a realization for quickly and accurately calculating the oil content of shale oil reservoirs with logging data and may have great practical potential in the exploration of shale oil. However, the applicability of this method in other regions still needs to be discovered in future studies.

Data Availability

The well log and core data used to support the findings of this study are not available for confidential reasons.

Conflicts of Interest

The authors declare that there is no conflict of interest regarding the publication of this paper.

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