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Evaluation of thermal maturity of source rock based on geochemical method, a case study of Late Oligocene source rock in Hoa Tra field, Cuu Long basin, Vietnam

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ABSTRACT

The Hoa Tra field is located in the southeast of the Cuu Long basin which has great potential for oil and gas. The source rocks in this area are mainly fine-grained sediments from the late Oligocene and early Miocene, which are located in a continuous deposition zone and under anaerobic conditions. This paper focuses on studying the maturity level of late Oligocene source rock through geochemical analysis methods. Specifically, the paper uses indicators such as T, R_o, MPI-1, $T_s/(T_s+T_m)$ and C_{29} steran 20S/(20S+20R) from Rock-Eval Pyrolysis, Vitrinite reflectance and Gas chromatography-Mass spectrometry methods, respectively, to evaluate the level of thermal maturity of the source rock. The source rocks in the Hoa Tra field mainly contain types I and II, which are poor in vitrinite particles, leading to low R_o measurement results. However, when R_o is calculated from T_{max} and (MPI-1), it indicates that the thermal maturity of source rock from the upper part of the late Oligocene is in the early mature stage ($R_{o\ avg}$= 0.56%), while those from the lower part of late Oligocene are mature and in the phase of oil generation ($R_{o\ avg}$= 0.65%). These results are similar to those obtained from assessing thermal maturity using $T_s/(T_s+T_m$ and C_{29} 20S/(20S+20R) indicator (the average values for the respective parameters are 0.32 and 0.31 for the upper part, while those are 0.39 and 0.42 for the lower part of late Oligocene). The article also shows that the contribution to the Hoa Tra field is not only from in-situ generated oil but also from migratory oil coming from nearby troughs.

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1. Introduction

Source rock is one of the main elements of a hydrocarbon system. Therefore, studying the source rock and its characteristics is important and necessary. Good source rocks must contain rich and high-quality organic matter to create hydrocarbons when subjected to heat and pressure over time. To be an effective source rock, a rock needs to reach a certain temperature that allows it to mature and convert organic matter into hydrocarbons. The level of thermal maturity is the primary factor that determines whether a source rock can produce oil, gas, or condensate.

Hoa Tra field is located in block A, Southeast of the CuuLong basin (Figure 1), which was discovered in 2012. This is considered to be a field with great potential for oil and gas. In the Hoa Tra field, there are five exploration wells during the exploration phase from 2012÷2018 (HT-2X, HT-3X. HT-4X, HT-5X, and HT-6X). The petroleum system in this field has been proven to be fully elements. The source rocks in the Hoa Tra field are shale in the Upper Oligocene and Lower Miocene periods. The reservoirs consist of fracture granitoid basements and sandstone from the Early Oligocene to Early Miocene age. The caprocks are composed of shale layers from the Con Son, Bach Ho, Tra Tan, Tra Cu formations, and Rotalia shale in the BachHo formation which is the most important caprock in the CuuLong basin. The traps in this field are primarily structural, stratigraphic and combination ones. They were mostly formed during syn-rift and early post-rift periods. The migration timing of Upper Oligocene source rock started in the Late Miocene. The timing of complete traps are earlier migration timing of Hydrocarbon from source rock. Therefore, makes it favourable for hydrocarbon to be trapped (Tran and Phung, 2007; Nguyen et al., 2019). According to published studies, the source rock in the Hoa Tra field is mainly shale of late Oligocene and early Miocene, but early Miocene source rock is considered immature. Therefore the objective of this article is to study and assess the thermal maturity of Oligocene source rock in the Hoa Tra field, Cuu Long basin. This will be achieved by using maturity indicators obtained from the analysis of geochemical data.

2. Geology setting

2.1. Basin evolution

Hoa Tra field belongs to block A, Cuu Long basin which is the Early tertiary rift basin located off the southeast coast of Vietnam. Three main tectonic phases were interpreted in Cuu Long Basin. The main basin extension occurred during the early Eocene-Oligocene, which was affected by the opening of the Vietnamese East Sea (Figure 2). The Con Son Swell and Central Ridge were

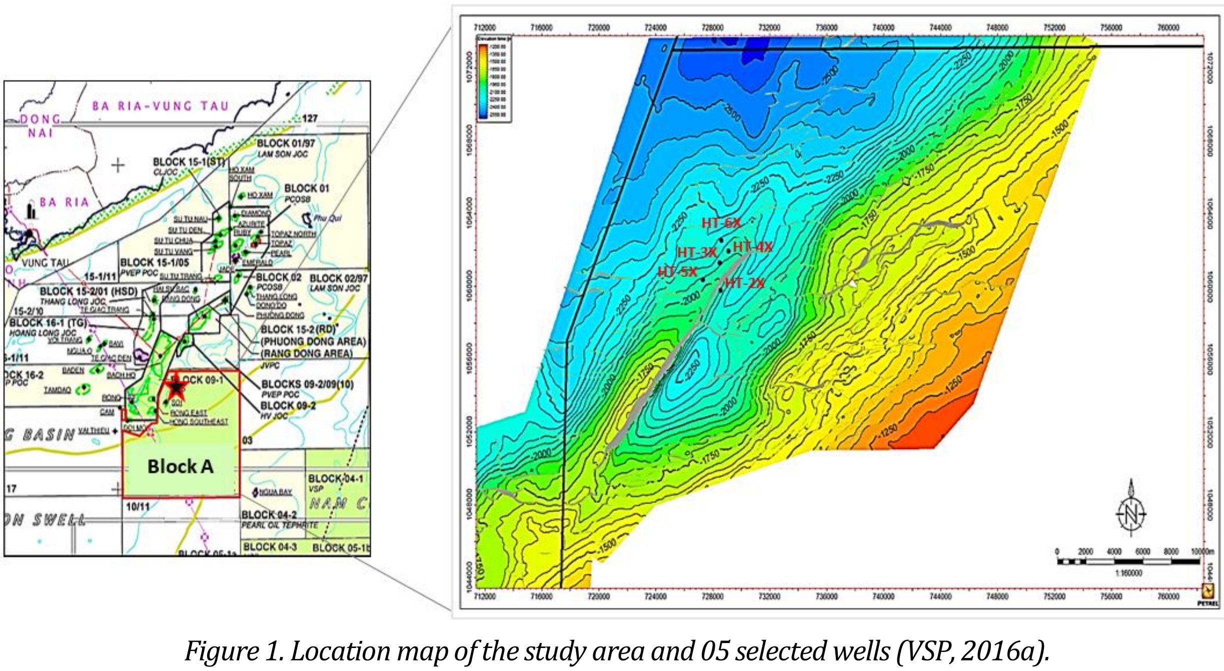

Figure 1. Location map of the study area and 05 selected wells (VSP, 2016a).

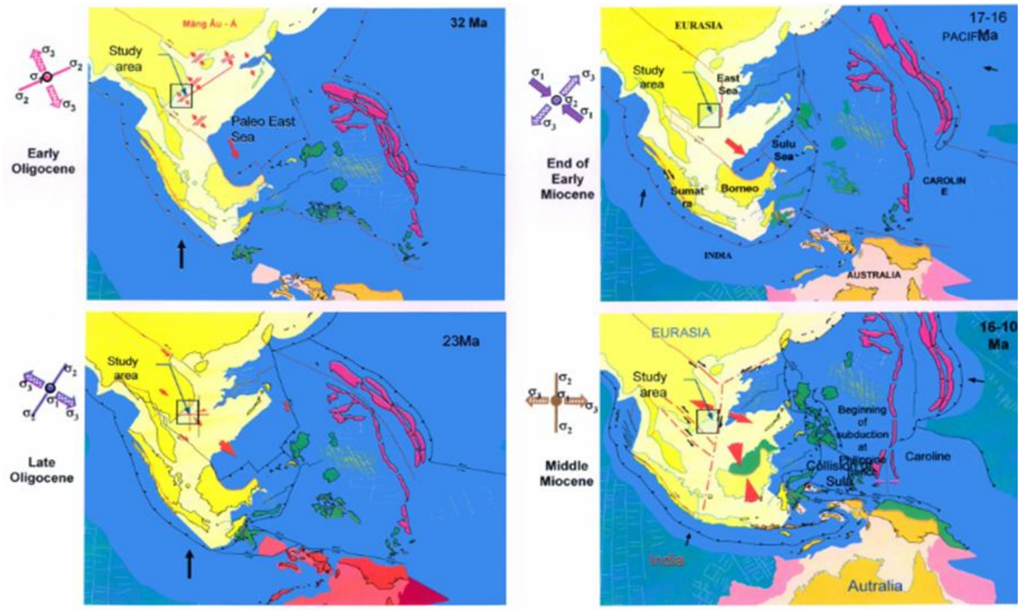

Figure 2. Tectonic movement of the Cenozoic age in Southeast Asia (VRJ, 2006).

formed during this extensional phase and are bounded by a series of normal faults mainly in a NE-SW direction with major displacements. The second tectonic phase occurred in the late Oligocene. During this period, the extension was accompanied by right-lateral shear movements along the NE-SW trending faults. These movements caused significant uplift of the pre-existing basement highs and resulted in the fracturing of the basement rocks. The major portion of the WNW-ESE trending faults and the Doi Moi Structure were formed during this stage. A thermal subsidence phase began in the early Miocene. The activity of faults during this phase was generally weak, and it is believed that the activity of the faults was caused by differential compaction of thick shale sections between the basement highs and surrounding areas (VRJ, 2006).

The geological cross-section of the region is divided into three tectonic phases related to three structural layers: The basement structural layer represents the topography of the region. The basement surface consists of separated sets of faults, half-grabens, and horsts. The Oligocene structural layer is related to inherited formation elements. All major structural elements are mostly inherited from the basement and appear in the Oligocene phase. The influence of the basement surface morphology on the Oligocene sedimentary basin decreases gradually from bottom to top along the cross-section. The Miocene-Pleistocene structural layer is characterized by relatively flat topography and a sudden decrease in the number of faults.

2.2. Stratigraphy

The stratigraphy column of the southeastern area as well as the whole CuuLong basin can be summarised as follows in Figure 3 (Tran and Phung, 2007; Nguyen et al., 2019).

Pre-Tertiary basement: In the Cuu Long basin, the pre-Tertiary basement consists mainly of magnetic intrusive rocks such as granite, granite-gneiss, granodiorite, diorite, monzodiorite, and gabbro. The metamorphic rocks are also encountered in some places.

Lower Oligocene (Oliogocen E): This section consists of shale, siltstone, and sandstone that were deposited unconformably on the Pre-Tertiary basement. It is widely distributed across the southeastern area and is divided into two parts. The lower part is dominated by medium- to coarse-grained sandstone composed mostly of granitic fragments and feldspars, with interbeds of hard, organic-rich black shale layers. The upper part is composed mainly of fine to medium-grained sandstone interbedded with grey shale layers. In addition, magma intrusions such as dykes, composed majorly of basalt were found occasionally.

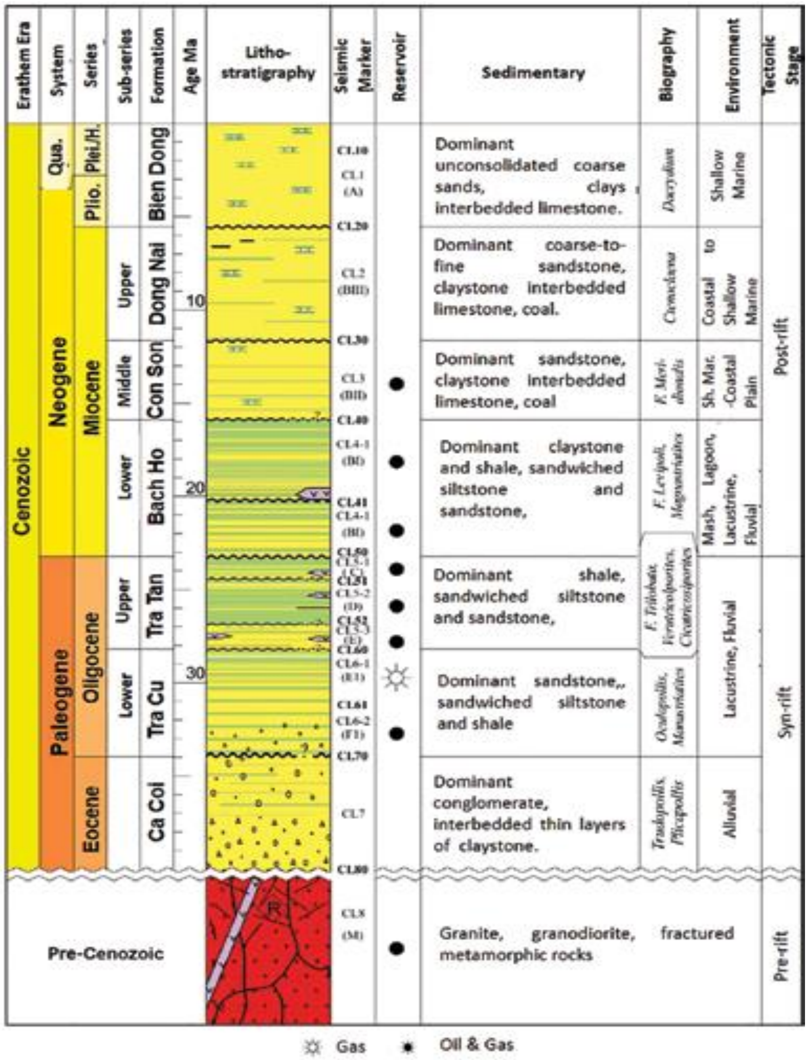

Figure 3. Generalised litho- stratigraphic column of Cuu Long basin (Nguyen et al, 2019).

Upper Oligocene (Oligocene D): The Tra Tan formation consists mainly of organic-rich brown shale that was deposited in a lacustrine environment, with occasional interbeds of coal or sandstone. However, near the eastern boundary of the sub-basin (close to the Con Son swell), thick layers of sandstone were deposited on top of the Oligocene D shale. In the upper section of the Tra Tan formation, there is a mixture of fine-grained sandstone and lacustrine brown shale.

Miocene: This stratigraphic sequence is divided into two sub-units: the lower part and the upper part. The lower part of the Miocene is primarily composed of sandstone with dominant fluvial-deltaic deposits and small intercalations of shale that were deposited in a floodplain environment. In contrast, the upper part is mainly composed of sandstone interbedded with shale/claystone, occasionally shallow marine siltstone, and limestone. The top section of the Miocene consists of Bach Ho shale, which is a thick and continuous layer acting as a regional seal for the entire Cuu Long basin.

3. Material and Methodology

This article uses data which are provided for scientific research purposes by The Science Research and Engineering Institute, VietsovPetro (VSP, 2014; 2016b; 2018; 2019). The dataset includes the results of geochemical analysis of five wells in the study area and related geological-geophysical materials. This article focuses solely on evaluating the maturity of late Oligocene source rocks and is divided into two parts: the upper and the lower of late Oligocene.

Information about the names of the wells and the number of samples analyzed for each of the five wells can be found in Table 1.

Various methods can be used to evaluate the thermal maturity of source rocks. However, Vitrinite reflectance, Rock-Eval pyrolysis and Gas Chromatography-Mass Spectrometry methods are still the most effective and popular as standard techniques in petroleum exploration. The workflow of using indicators to assess the maturity of the source rock is shown in Figure 4

Vitrinite reflectance (% R_o) is the main indicator used to evaluate the thermal maturity of source rock. %R_o is a key tool for assessing thermal maturity, which is based on measuring the vitrinite through a microscope equipped with an oil-immersion objective lens and photometer. Vitrinite is a maceral (plant and animal remains) found in many kerogens and is formed from the thermal alteration of lignin and cellulose in plant walls (Dembicki, 2017). The temperature increases with the depth of burial and reflectance measurements represent the presence of light reflected in oil. Generally, values less than 0.45% R_o are considered immature and the oil window is within a range from 0.72÷1.3% R_o.

Rock-Eval pyrolysis is used extensively for characterizing the quality, quantity and thermal maturity of organic matter in sedimentary rocks. This method is used in determining kerogen heat maturation. Behar et al., 2001 define heat parameters based on maximum temperature (T_{max}) which can be used to determine the dimensions of the oil window (Millayanti et al., 2019). T_{max} is the maximum peak temperature of thermal cracking involved in the S_2 curve that corresponds to a maximum thermal HC yield. According to that definition, the T_{max} value for the start of the oil window is usually 440÷460^{0}C, for the peak is 460÷500 ^{0}C and for the postmature is more than 500 ^{0}C.

However, the level of thermal maturity for different types of organic matter may be estimated from the T_{max} range (Dembicki, 2017). The thermal maturity of sample can be determined by plotting the value of T_{max} versus HI. In addition, the PI indicator was also used to evaluate the level of thermal maturity of the samples.

Table 1. Well data information and the number of samples analyzed in Hoa Tra field.

Well name	Depth of study for Upper part of late Oligocene (m)	Depth of study for Lower part of late Oligocene (m)	The number of samples analysis			
			Rock- Eval pyrolysis	Vitrinite reflectance	Gas chromatography-Mass spectrometry (GC-MS)	
					Extract sample	Oil sample
HT-2X	2300-2850	2850-3250	85	85	28	3
HT-3X	2980-3440	3440-4320	88	92	28	2
HT-4X	3710-4030	4030-4500	88	57	0	1
HT-5X	2890-3410	3410-3894	80	62	27	1
HT-6X	2930-3750	3760-4481	90	78	27	1

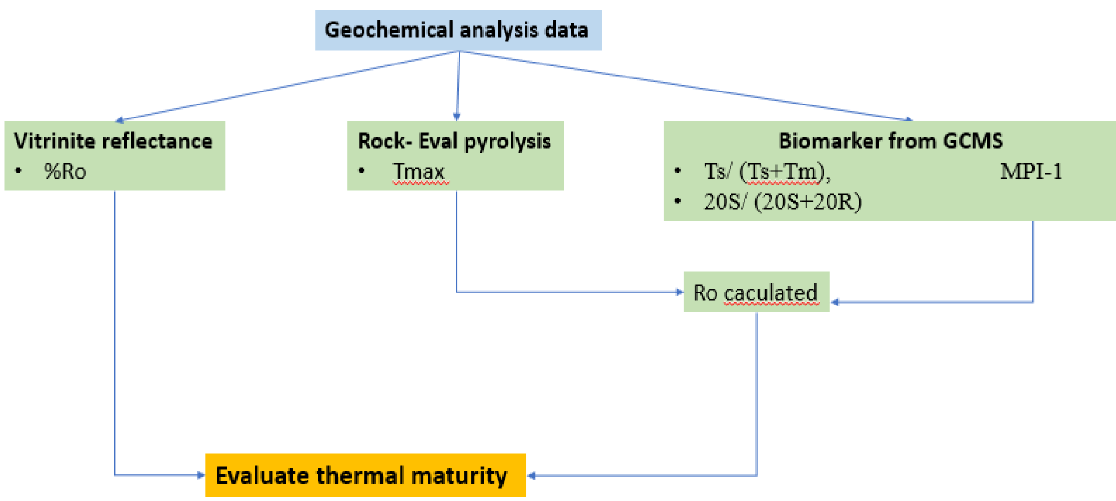

Figure 4. Workflow to evaluate the thermal maturity of source rock.

The increase of S_1 and decrease of S_2 as a source rock matures make PI ($S_1/(S_1+S_2)$) a thermal maturity indicator, which increases until the onset of expulsion (Pham & Vu, 2019). If PI> 0.1, the source rock is mature and vice versa (Table 2).

Biomarkers are molecular fossils in sediment, rock, and crude oil that consist of complex organic compounds having chemical structures readily linked to their source compounds in living organisms. To obtain biomarker data, analysis of the hydrocarbons is done on a gas chromatograph in tandem with a mass spectrometer, GC-MS. For the terpanes and steranes, the saturated hydrocarbon fractions from liquid chromatography of a crude oil or source rock extract are used. The saturated hydrocarbon fraction is first separated in the gas chromatograph. The column effluent is then sent to the sample inlet of a mass spectrometer. As the hydrocarbons enter the ion source, they are bombarded with electrons that cause the hydrocarbons to ionize and, if enough energy is applied, break apart into fragments. The biomarker compounds will break at specific places in their structure and form fragments with a characteristic mass. These mass fragments are described in units of m/z, which is mass divided by charge. The ions are then formed into a beam using electrical fields and sent through the mass filter. The mass filter is used to focus molecular fragments of a single mass onto the ion detector. In this way, several mass fragments can be detected and measured nearly simultaneously. By this method, the biomarker parameters such as $T_s/(T_s+T_m$, 20S/ (20S+20R) and MPI-1 from GC-MS analysis results of saturated and aromatic components of the extract sample were also used to evaluate the thermal maturity of source rock. Biomarker maturation parameters respond in different ranges of maturity, allowing estimates of the extent of maturity for crude oil and source rock extracts relative to the oil window (Peters et al., 2005) (Figure 5).

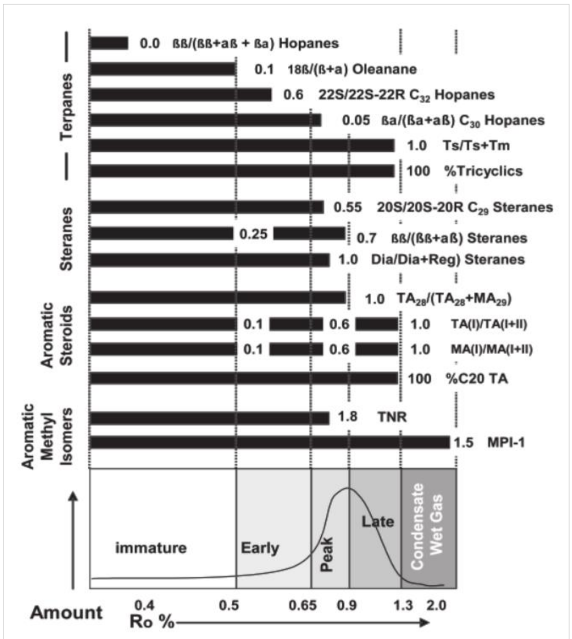

Figure 5. Biomarker maturation parameters respond in different ranges of maturity (Peters et al., 2005).

4. Results and Discussion

4.1. Evaluating thermal maturity of source rock from Rock-Eval Pyrolysis methods

The T_{max} and Production Index (PI) parameters from the Rock-Eval pyrolysis method could be used as a popular indicator for the maturity level of source rocks, however, depend on the types of organic matter. Tissot and Welte (1984) mentioned the value of T_{max} to be considered as a maturity indicator, between 440÷450^{0}C; 435÷460^{0}C and 440÷470^{0}C for kerogen type I, type II and type III kerogen, respectively (Table 2). The Rock-Eval Pyrolysis data reveal the type of kerogen is mostly type I and II and minor type III (Figure 6). The average T_{max} for source rock from the upper part of the late

Table 2. Guidelines for describing stages of thermal maturity (Peters & Cassa, 1994).

Stage of thermal maturity of Oil		T_{max} for type I	T_{max} for type II	T_{max} for type III	Production index (PI)
Immature		<440	<435	<445	<0.10
Mature	Early	440	435	445	0.10-0.25
	Peak	445	440	450	0.25-0.40
	Late	450	460	470	>0.40
Post mature		>450	>460	>470	-

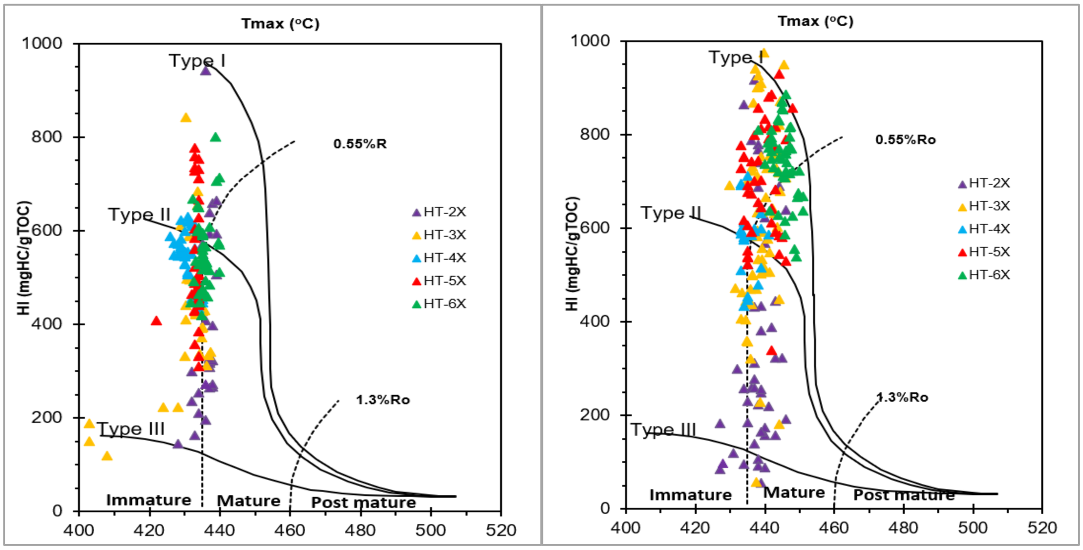

Figure 6. Cross plot of HI versus T_{max} shows the types and the maturity of the samples from Upper part of late Oligocene (left) and Lower part of late Oligocene (right), Hoa Tra field.

Oligocene is 432^{0}C, with a range of 401÷439^{0}C, reflecting the source rock is in the early mature stage. Meanwhile, samples obtained from the lower part of the late Oligocene have an average T_{max} of 442^{0}C, ranging from 427÷451^{0}C. It reflects that source rock has matured and oil generated phase. The T_{max} index also shows that the source rock at well HT-6X is more mature than the source rock at other wells. The average T_{max} value of source rock at well HT-6X is about 443^{0}C, while in other wells, the average T_{max} ranges from 420÷437^{0}C.

Based on their maturity level definition using T_{max} and PI (Table 2) reported that samples from the upper part of the late Oligocene have an average PI of 0.11, with most samples exceeding 0.1. The samples from the lower part of the late Oligocene source rock have a higher value compared to the upper part, with an average PI of around 0.18. However, there are some samples from five wells with PI values > 0.3, which indicates the presence of oil migrating from a trough nearby. The conversion can be mathematically expressed as R_0 (calculated) = (0.018) x (T_{max}) -7.16. To obtain reasonable Ro data, the above formula was not used for samples that have S_2 values smaller than 0.5 mg HC/g rock and samples with T_{max}<420^{0}C or >500^{0}C (Abdula, 2017). The vitrinite reflectance values calculated for samples in this study area show a progressive increase in R_o with depth. The average R_c is 0.56% for the upper part of the late Oligocene source rock, and 0.68% for the lower part of the late Oligocene source rock. Thus, according to the T_{max} and PI indicator from the Rock-Eval pyrolysis method, the source rock from the upper part of the late Oligocene is an early mature phase, while those from the lower part are mature and within the oil generating zone.

4.2. Evaluating thermal maturity of source rock from Vitrinite reflection methods.

The vitrinite reflectance R_o is an effective and widely used indicator when assessing the maturity of organic matter. However, when evaluating, it is important to note that some reasons may confuse the results (which may be higher or lower than the actual value). There are many possible interferences with the vitrinite trend that can complicate the interpretation of the data, which include lack of vitrinite, caved sediments, reworked organic material, and fault, (Dembicki, 2017).

Based on the Vitrinite reflectance measurement data, the upper part of the late Oligocene source rock has R_o values ranging from 0.33÷0.60%, with an average of 0.50%. In contrast, most samples from the lower part of the late Oligocene have R_0 values greater than 0.45%, with an average of 0.62%. Besides, most of the samples from wells HT-3X, HT-4X and HT-6X at depths greater than 3840 m have% R_o values ranging from 0.62÷0.73%. Therefore, the upper part of late Oligocene source rocks is in the stage of immaturity to early maturity, while the lower part of late Oligocene source rocks are in the mature to oil generation phase (Figure 7).

It can be seen that the R_0 values calculated from T_{max} are higher than the Ro values obtained from Vitrinite reflectance measurements in both the upper and lower parts of late Oligocene source rocks. As mentioned above, the source rocks in the study area mainly contain type I, II and minor type III kerogen (Figure 6) Therefore, most of the samples in the interval study for Vitrinite reflectance measurement were poor in vitrinite particles. Some small vitrinite particles but no good quality and give a low % R_0 value.

4.3. Evaluating thermal maturity of source rock from Gas Chromatography-Mass Spectrometry methods

The methylphenanthrene index (MPI-1) from the GCMS method is one of the most widely used maturity parameters. The 2-methylphenanthrene (2-MP) and 3-methylphenanthrene (3-MP) isomers are more thermally stable than the 1-methylphenanthrene (1-MP) and 9-methylphenanthrene (9-MP) isomers, and as a result, the MPI-1 value increases with increasing thermal maturity. However, the ratio reverses and decreases with increasing maturation as phenanthrene (P) is formed from the thermal cracking of the methyl groups. Published comparisons of % R_0 and MPI-1 for coals and shales generally show a good correlation (Walters et al., 2012). The estimated vitrinite reflectance values calculated from MPI-1 follow: R_c= 0.6 x (MPI-1) +0. 4 (Radke, 1983; Radke & Wetle, 1983). In the oil window, the reflectance R_c has a positive correlation with the (MPI-1) value, meanwhile, the R_c shows a negative correlation with the (MPI-1) value in the high mature stage (R_c > 1.3%) (Figure 8). As a result of the GC-MS analysis of C15+ aromatic hydrocarbons, MPI-1 values indicated that extract and oil samples were relatively high (MPI-1 = 0.55÷0.75 in the oils and 0.23÷0.59 in the extracts). The R_c average values for samples from the Upper part and Lower part of the late Oligocene are 0.61 and 0.65 respectively. It indicated that the level of thermal maturity of the source rock is moderate to high mature from the upper to lower part of the late Oligocene.

C_{29} 20S/(20S+20R) and C_{29} αββ/ (ααα+αββ) sterane isomerization parameters are widely used to assess oil maturity for R_0 values below 0.8%. When maturity exceeds 0.8%, both

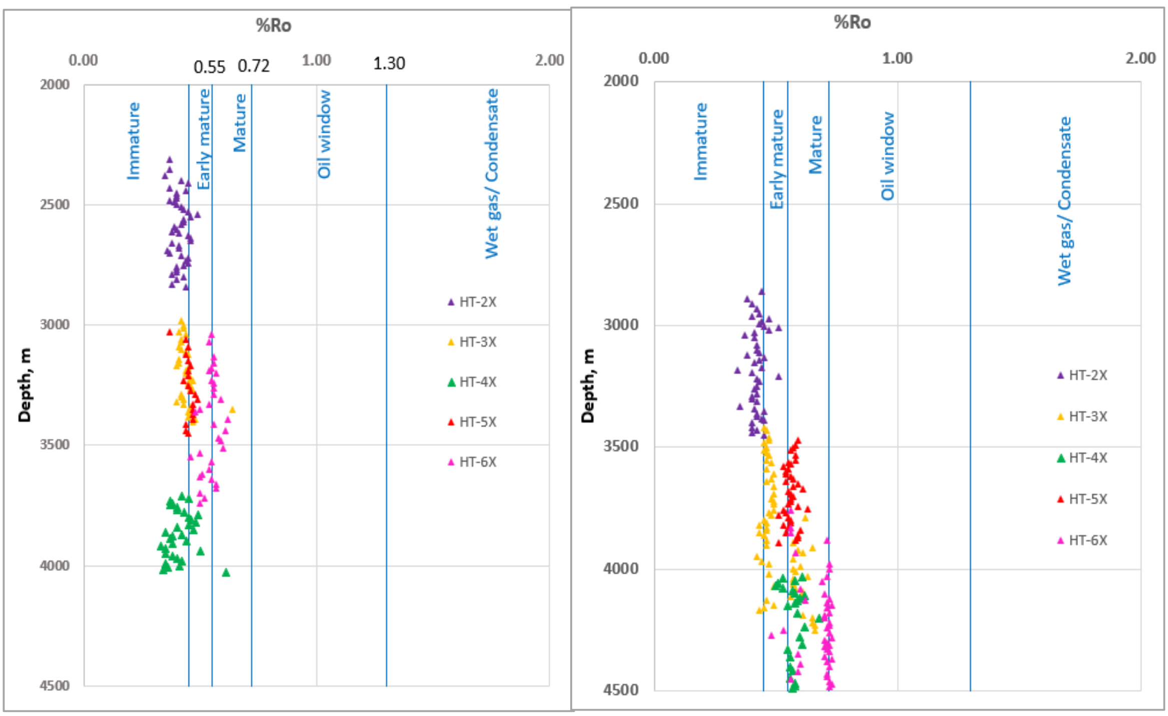

Figure 7. Plot of Ro data versus Depth of samples from Upper part of Late Oligocene (left) and Lower part of Late Oligocene(right).

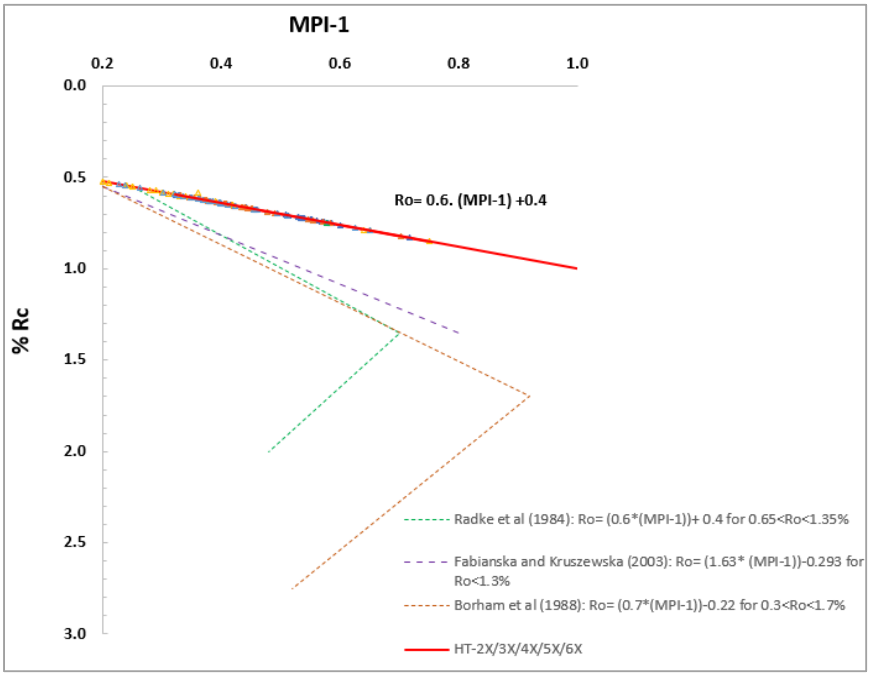

Figure 8. MPI-1 indicator based on the ratio of Methylphenanthrene isomers and Phenanthrene for samples from HT-2X/3X/4X/5X/6X.

isomerization values reach equilibrium and remain within the range of 0.55÷0.66 (Ma et al., 2017). As previously mentioned, the R_0 values of the extract samples from five wells in the study area ranged from 0.31÷0.73. Therefore, C_{29} sterane isomerization values are effective indicators to assess the thermal maturity of the source rock. Figure 9 shows the relationship between C_{29} 20S/(20S+20R) and C_{29} αββ/(ααα+αββ) sterane isomerization values. The C_{29} 20S/(20S+20R) and C_{29} αββ/(ααα+αββ) sterane isomerization values of the oil and extract samples from the upper part of late Oligocene mostly plotted in the early mature (0.22÷0.43). In contrast, the sterane isomerization values of those obtained from the lower part of the late Oligocene ranged from 0.25÷0.65, indicating that the source rock is low to moderate maturity. In addition, the extract samples have lower maturity than the oil samples found in five wells, showing the presence of oil migrating from nearby troughs to the Hoa Tra field. Especially, the value of C_{29} 20S/(20S+20R) and C_{29} αββ/(ααα+αββ) sterane isomerization for samples from well HT-6X is significantly higher than that of other wells because the HT-6X well was drilled into a deeper and more subsided area than the other wells, as a result, it has a greater influence on the degree of thermal maturation and has a higher degree of thermal maturity.

The $T_s/(T_s+T_m)$ ratio depends on both source and maturity. Ts and Tm are barely affected because they are resistant to biodegradation, even in the heavily biodegraded oils (Ma et al., 2017). This ratio is most reliable as a maturity indicator when evaluating oil from a common source with consistent organic facies (Peters et al., 2005). The result of the oil-to-source rock correlation of five wells indicated that they originated from similar source rock (VSP, 2016a). Therefore, the $T_s/(T_s+T_m)$ ratio can effectively be used to assess the thermal maturity of source rocks in the Hoa Tra field. This value approximates 1 in the high mature stage and vice versa. The $T_s/(T_s+T_m)$ ratios of samples from the upper part of the late Oligocene range from 0.24÷0.52, indicating that the source rocks are low mature threshold. Meanwhile, the source rock from the lower part of the late Oligocene is the low to medium maturity threshold, with $T_s/(T_s+T_m)$ ratio ranging from 0.3÷0.67 (Figure 10). Figure 10 also indicates that the oil and extract samples from well HT-6X have a higher $T_s/(T_s+T_m)$ ratio value when compared to the samples of other wells, suggesting that the source rocks in well HT-6X have higher maturity levels than other wells. This observation is consistent with the previous discussions.

5. Conclusions

Based on the results of the geochemical analysis, it is concluded that:

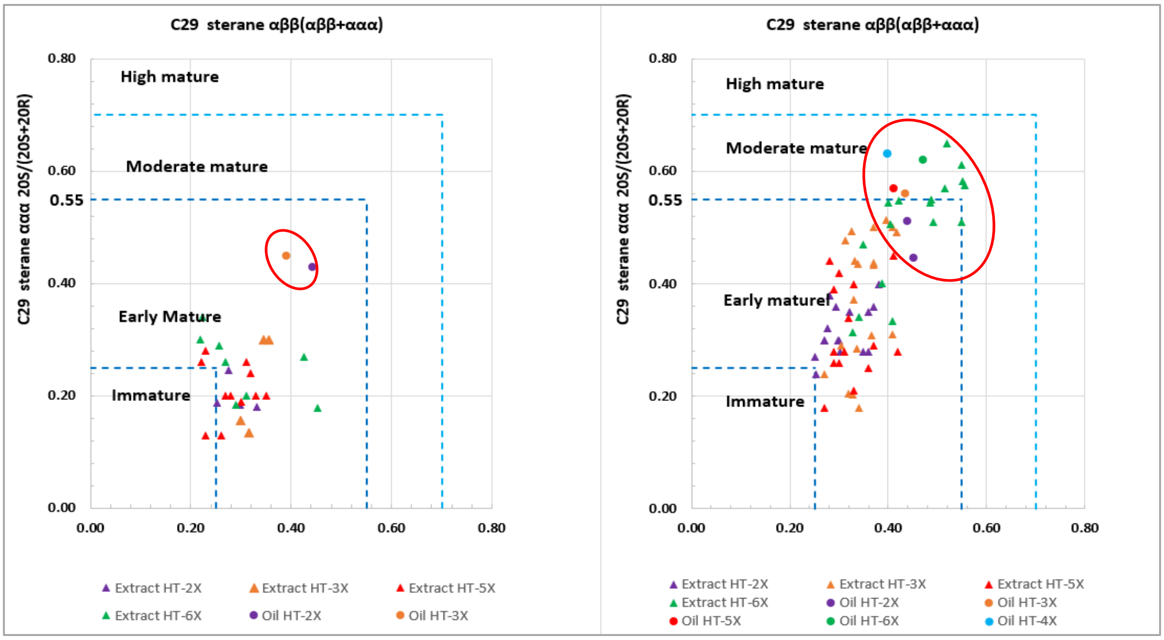

Figure 9. C_{29} sterane ααα 20S/(20S+20R) versus C_{29} sterane αββ/(ααα+αββ) of extract and oil samples from Upper part of late Oligocene (left) and Lower part of late Oligocene.

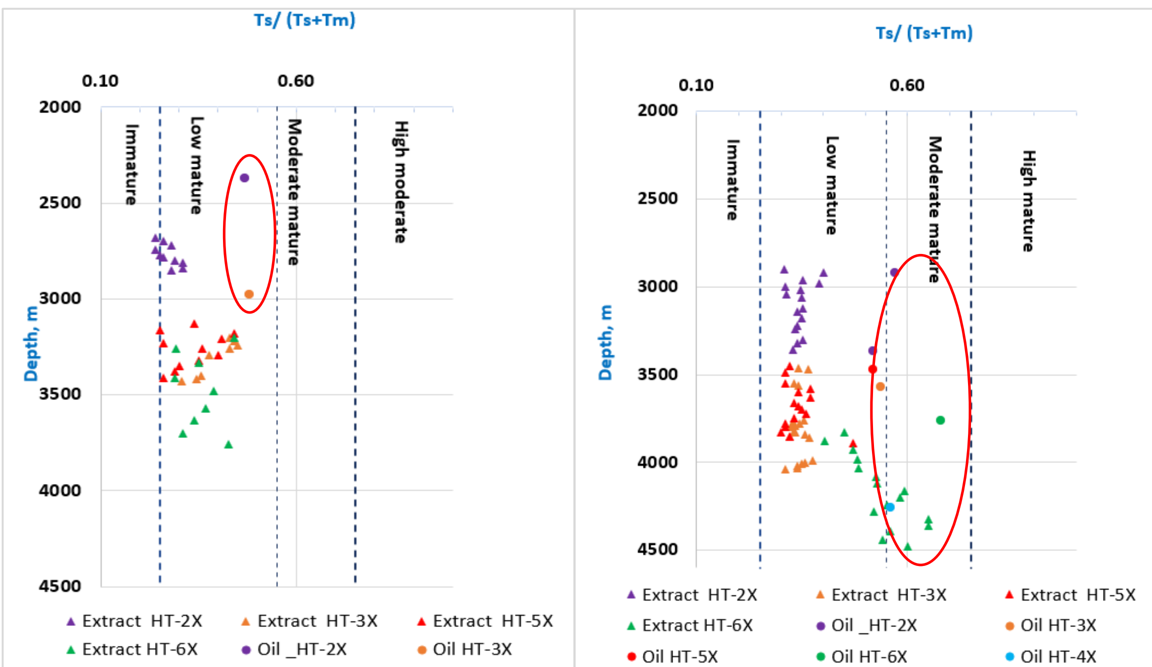

Figure 10. Plot of $T_s/(T_s+T_m)$ versus Depths of extract and oil samples from Upper part of Late Oligocene (left) and Lower part of Late Oligocene (right).

The thermal maturity indicators suggest that the source rock from the upper part of the late Oligocene is in the early mature stage, while those from the lower part of the late Oligocene have entered the phase of oil generation ($R_{c\ average}$ = 0.56% and 0.65%, respectively).

The oil in this field is the result of both in situ generation and the migration of oil from nearby troughs.

Shale source rock in HT-6X well has a higher maturity ($R_{0\ avg}$= 0.62%, T_{max} ave=440^{0}C) than the source rock in other wells ($R_{0\ avg}$ = 0.5%, $T_{max\ avg}$ = 420÷435^{0}C).

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Contributions of authors

Oanh Thi Tran - proposed ideas and contributed to the writing of the manuscript; Ngoc Bao Pham, Hong Minh Thi Nguyen, Linh Thuy Thi Do - reviewed and edited the manuscript; Muoi Duy Nguyen, Ngan Thi Bui - collected and analyzed the data.

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