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Organic Geochemical and Petrographic Characteristics of the Coal Measure Source Rocks of Pinghu Formation in the Xihu Sag of the East China Sea Shelf Basin：Implications for Coal Measure Gas Potential

WANG Yang[1, 2, 3, *], QIN Yong[1, 2], YANG Liu[4], LIU Shimin[3], Derek ELSWORTH[3] and ZHANG Rui[3, 5]

[1] *Key Laboratory of Coalbed Methane Resources and Reservoir Formation Process, Ministry of Education, China University of Mining and Technology, Xuzhou, Jiangsu 221008, China*

[2] *School of Resources and Earth Science, China University of Mining and Technology, Xuzhou, Jiangsu 221116, China*

[3] *Department of Energy and Mineral Engineering, G[3] Center and Energy Institute, The Pennsylvania State University, University Park, PA 16802, USA*

[4] *Jiangsu Design Institute of Geology for Mineral Resources, Xuzhou, Jiangsu 221006, China*

[5] *Neutron Scattering Division, Oak Ridge National Laboratory, Oak Ridge, TN 37830, USA*

Abstract: Coal measure source rocks, located in the Xihu Sag of the East China Sea Shelf Basin, were analyzed to define the hydrocarbon generation potential, organic geochemistry/petrology characteristics, and coal preservation conditions. The Pinghu source rocks in the Xihu Sag are mainly gas-prone accompany with condensate oil generation. The coals and shales of the Pinghu Formation are classified from “fair” to “excellent” source rocks with total organic carbon (TOC) contents ranging from 25.2% to 77.2% and 1.29% to 20.9%, respectively. The coals are richer in TOC and S_1+S_2 than the shales, indicating that the coals have more generation potential per unit mass. Moreover, the kerogen type of the organic matter consists of types Ⅱ-Ⅲ and Ⅲ, which the maturity Ro ranges from 0.59% to 0.83%. Petrographically, the coals and shales are dominated by vitrinite macerals (69.1%–96.8%) with minor proportions of liptinite (2.5%–17.55%) and inertinite (0.2% –6.2%). The correlation between maceral composition and S_1+S_2 indicates that the main contributor to the generation potential is vitrinite. Therefore, the coals and shales of the Pinghu Formation has good hydrocarbon generation potential, which provided a good foundation for coal measure gas accumulation. Furthermore, coal facies models indicates that the Pinghu coal was deposited in limno-telmatic environment under high water levels, with low tree density (mainly herbaceous) and with low-moderate nutrient supply. Fluctuating water levels and intermittent flooding during the deposition of peat resulted in the inter-layering of coal, shale and sandstone, which potentially providing favorable preservation conditions for coal measure gas.

Key words: hydrocarbon generation potential, coal facies, coal measure gas, Pinghu Formation, Xihu Sag

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1 Introduction

Coal measure gas, including coalbed methane, shale gas, and tight sandstone gas, are important components of unconventional gas resources characterized by their global distribution, rich resource, homology, and co-existence (Sun, 2015). The East China Sea shelf basin is one of the important hydrocarbon-bearing basins in the eastern coastal areas of China (Deng, 2009; Zhu et al., 2012). In recent years, with the development of oil and gas exploration, eight oil and gas fields with 30 million tons of oil and over 10^{11} m^3 of gas reserves have been found in the Xihu Sag (Huang and Ye, 2010; Shen et al., 2016). The middle-upper Eocene coal-bearing source rocks of the Pinghu Formation are believed to be the ideal precursor for the oil and gas fields and favorable characteristics of these source rocks are anticipated to be regionally extensive in the Xihu Sag (Li et al., 2014). The coal measure source rocks mainly include coal, carbonaceous shale and gray shale.

Coal measure source rocks have strong potential in hydrocarbon generation (Wilkins and George, 2002; Petersen, 2006; Moore, 2012; Jia et al., 2012; Li et al., 2012; Wang et al., 2016; Song et al., 2017; Bao et al., 2018), and have been implicated in contributing oil and gas fields, worldwide. Notable are the Tarim and Jungger Basins in China (Chen et al., 2003; Ding et al., 2003), the Gippsland and Bowen Basins in Australia, the Taranaki Basin in New Zealand and the Greater Green River Basin in the US (Shanmugam, 1985; García-González, 1997; Norgate et al., 1999). Therefore, characterization of accumulation environments and geochemical properties of

* Corresponding author. E-mail: wangycumt@163.com

the organic matter, as it contributes to hydrocarbon generation potential, is of the major interest in exploration and gas production (Davis et al., 2007; Gross et al., 2015; Zhang et al., 2018). Various techniques have been used to characterize the organic matter (Petersen and Nytoft, 2006; Alsaab et al., 2007; Longbottom et al., 2016). Rock Eval pyrolysis is one of the most basic organic geochemical methods for the characterization of total organic matter potential, organic type and thermal maturity (Bertrand, 1984; Dayal et al., 2014). Elemental analysis, palynology, and maceral micro-component analysis, together with the use of biomarkers and carbon isotope composition are widely used to identify deposition conditions and the potential of the field (Dai et al., 2014; Mardon et al., 2014; Reyhan, 2015; Li et al., 2017; Shan et al., 2018). Additionally, the petrography of low-rank coals provides useful information to reconstruct peat-forming environments from plant fragments preserved as macerals (Flores, 2002; Singh et al., 2010). The preservation and gelification of the vitrinite tissues, together with the type and content of liptinite, generally reflect the depositional environment and subsequent diagenesis. The source of the organic matter, contributing to the accumulation of the peat biomass, can be identified from the proportions of the macerals in the coals (Petersen and Andsbjerg, 1996; Suárez-Ruiz, 2012). Furthermore, the organic matter distribution, richness, type of kerogen and thermal maturity are attributed to the gas generation potential and hence essential properties for the delineation of coal measure gas potential. However, there are lack of sufficient data of drilled cores from offshore drilling. Thus, there is a need to integrate detailed organic geochemical and petrographic methods in evaluating the organic matter preservation, paleodepositional environment, paleoclimatic conditions and the origin of the organic matter in the Pinghu Formation.

In this study, coals, carbonaceous shales and gray shales, collected from the Pinghu Formation are analyzed by Rock-Eval pyrolysis, elemental analysis and microscopy. We present organic geochemical and petrologic analyses to evaluate the hydrocarbon potential of these source rocks and to discuss the impact of changes in the paleo-environment during their geological history. This study will have broad applications in defining the hydrocarbon generation potential in the East China Sea Shelf Basin with the focus on regional coal measure gas exploration and development.

2 Geological Settings

The Xihu Sag is located in western belt of the East China Sea Shelf Basin as shown in Fig. 1. It lies between the southeast margin of the Eurasian Plate and the middle segment of the active tectoniczone of the Western Pacific Continental Margin (Yu et al., 2001; Xu et al., 2015). Transiting from east to west, the Xihu Sag can be divided into the Baochu Slope Belts, the Santan Sub-depression, the Zhedong Central Anticline Belts, the Baidi Sub-depression and the Tianping Fault Belts，all striking NNE (Zhu et al., 2012a) (Fig. 1). Underlying the Xihu Sag is former Cretaceous metamorphic or sedimentary basement, draped with ~10,000m of Mesozoic and Cenozoic strata (Zhang et al., 2015; Guan et al., 2016).

The Xihu Sag experienced three principal stages of tectonic evolution (extensional fault depression, depression and regional subsidence), recorded in its nine Formations as shown in Fig. 2 (Zhang et al., 2013; Zhao et al., 2016). From Cretaceous to Eocene, The Xihu Sag is characterized by a fault stage and the well developed land-marine sediments of the Baishi and Pinghu Formations.

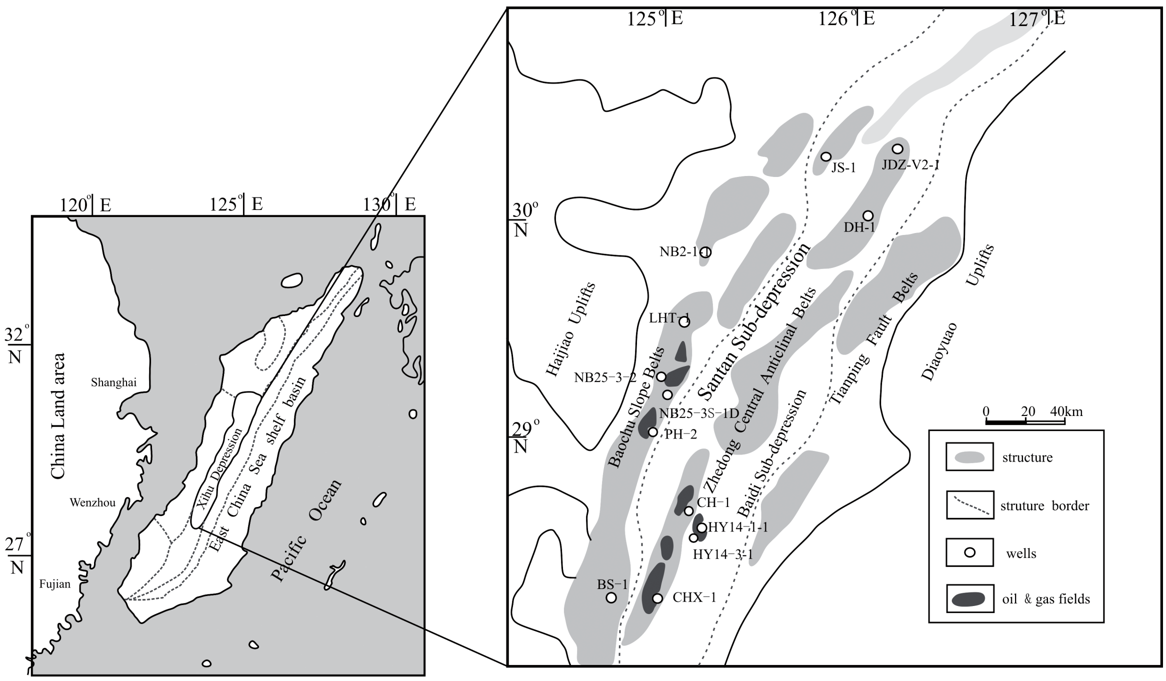

Fig. 1. Geographical map of the tectonic units in the Xihu Sag, East China Sea basin (modified from Zhu et al., 2012a).

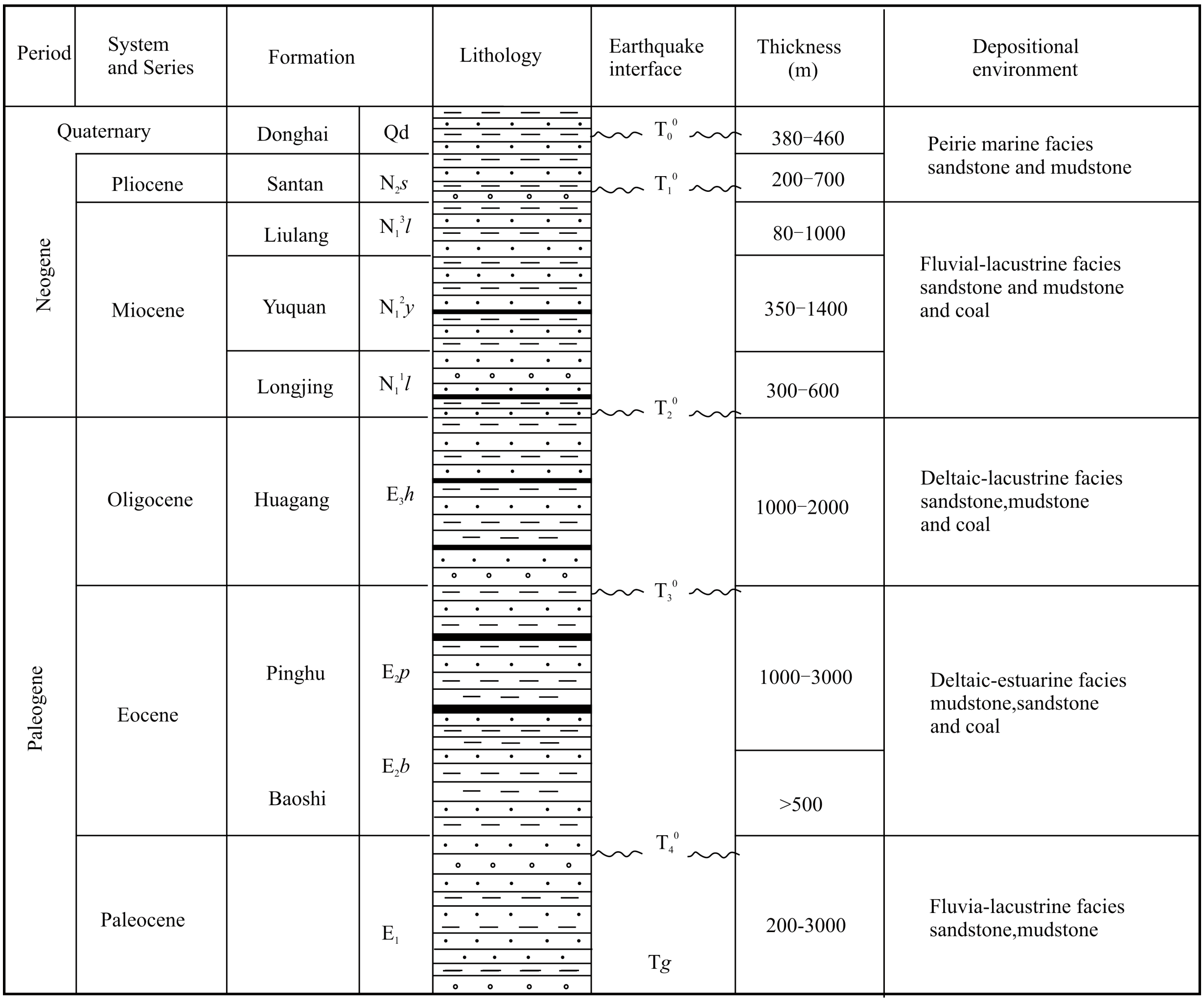

Fig. 2. Generalized stratigraphic column of the Xihu Sag (modified from Zhu et al., 2012b).

With the weakening of tectonic movement, the area turned into a Sag stage from Oligocene to Miocene with widely deposited Huagang, Longjiang, Yuquan, Liulang Formation lacustrine sediments. Regional subsidence occurred from Pliocene to present, depositing coastal-bay sediments and forming the Santan and Donghai Formations (Zhu et al., 2012).

According to the thickness, areal extent, thermal maturity and comparative analysis of the oil gas-source rocks, the Pinghu Formation contains the most important coal-bearing source rocks in this area. Their thickness decreases from south to north and from east to west (Dayal et al., 2014). Source rocks within the Formation are composed of coal, carbonaceous shale, grey shale and silty shale, incorporating foraminifera, calcareous, dinoflagellates and ostracoda fossils. According to the data from the sixteen drilled wells in the Xihu Sag, the average thickness of coal seams is 16.9 m with single minimum and composite layer thicknesses in the range 0.3–1.2 m, and 30–75.8 m, respectively. The shale beds commonly have an accumulative thickness of more than 200 m (Wei et al., 2013). The coal seams are characterized by thin single layer thickness, multiple layers, large accumulated thickness and the unstable lateral migration. The thickness and occurrence of coal seams and shales decrease towards the center of the depression.

3 Materials and Methods

A total of twenty-six samples were collected from drilled cuttings of the NB25-3s-1D, YH14-1-1, NB2-1-1, HY14-3-1 and HY25-3-2 wells in the Xihu Sag (Fig. 1). The samples comprise coals, shales and carbonaceous sandstones of the Eocene strata, Pinghu Formation (Table 1). The sampling was selected to broadly represent different lithologies but avoid weathered materials and those affected by drilling fluid. The collected samples were thoroughly cleaned prior to geochemical and petrographic analyses.

Rock-Eval pyrolysis was conducted on twenty-four samples that were all crushed to a particle size less than 200 mesh and pre-treated with dilute (1N) HCl. The total organic carbon (TOC) of the samples was determined by carbon-hydrogen analyzer, based on combustion of the samples. A Rock-Eval II instrument was used to identify the organic matter content, kerogen type and maturation of the preserved organic matter. Samples with 100mg were pyrolyzed in a helium atmosphere followed by a

Table 1 Organic components of samples in the Pinghu Formation

Well	No.	Lithology	Depth (m)	Pyrolysis data							Element data	
				TOC(%)	Tmax(°C)	S1(mg/g)	S2(mg/g)	HI(mg/g TOC)	PY(mg/g)	PI	H/C	O/C
NB25-3S-1D	1	Shale	3260	1.29	330	0.26	2.90	225	3.16	0.09	0.72	0.18
	2	Coal	3289	34.45	430	9.48	92.82	269.43	102.30	0.09	0.76	0.11
	3	Shale	3296	3.07	431	1.28	6.12	199	7.40	0.17		
	4	coal	3446	46.90	433	8.55	89.65	191	98.20	0.09	0.78	0.11
	5	Shale	3514	20.90	426	2.48	43.61	209	46.09	0.05	0.72	0.10
	6	Shale	3530	2.29	332	0.26	4.90	214	5.16	0.05	0.81	0.11
	7	Shale	3550	3.55	435	1.30	7.09	200	8.39	0.15		
	8	Coal	3676	25.20	436	4.61	65.92	262	70.53	0.07	0.78	0.12
	9	Shale	3680	17.40	432	3.71	43.79	252	47.50	0.08		
	10	Shale	3770	2.95	433	0.34	3.01	102	3.35	0.10		
	11	Shale	3844	1.37	434	0.66	3.58	261	4.24	0.16	0.73	0.11
	12	Shale	3896	18.20	443	4.50	37.95	209	42.45	0.11	0.71	0.19
	13	coal	3920	28.10	441	6.05	76.28	271	82.33	0.07		
	14	Shale	3934	15.50	445	4.49	34.75	224	39.24	0.11		
	15	Shale	3974	14.90	438	4.89	46.22	310	51.11	0.10		
	16	coal	4000	30.60	445	5.31	81.43	266	86.74	0.06	0.60	0.15
NB2-1-1	17	Shale	3813	1.90	439	0.19	2.26	119	2.45	0.08		
	18	Shale	4011	3.54	442	0.44	5.49	155	5.93	0.07	0.74	0.16
	19	Shale	4038	2.22	438	0.37	3.92	177	4.29	0.09		
	20	Shale	4140	4.31	438	0.69	8.39	195	9.08	0.08		
HY14-1-1	21	Shale	3561	5.64	447	0.58	5.77	102	6.35	0.09		
	22	Coal	3839	40.00	450	4.62	56.37	145	60.99	0.08	0.88	0.14
HY14-3-1	23	Coal	4351.9	77.20	448	12.81	174.56	226	187.37	0.07		
	24	Shale	4205.2	11.70	433	2.59	33.73	288	36.32	0.07		
	25	Shale	4205.8	4.47	432	0.68	10.62	238	11.30	0.06		
HY25-3-2	26	Coal	3237.6	50.20	418	11.68	152.11	303	163.79	0.07	0.78	0.20

Note: TOC: Total organic carbon, wt%. S_1: Volatile hydrocarbon (HC) content, mg HC/g rock. S_2: Remaining HC generative potential, mg HC/g rock. Tmax: The temperature at which the maximum amount of S_2 hydrocarbons.
HI: Hydrogen Index = S_2×100/TOC, mg HC/g TOC. PY: Potential yield = S_1+S_2(mg/g). PI: Production Index = S_1/(S_1+S_2).

programmed pyrolysis with a rate of 25 °C/min to 600 °C/min. Recovered parameters include volatile hydrocarbon content (S_1), remaining HC generative potential(S_2) and temperature of maximum hydrocarbon release (T_{max}). The hydrogen index (HI), production index(PI) and potential yield (S_1+S_2) were calculated as shown in Table 1. Following the results of Rock-Eval pyrolysis, microscopic examination and petrography were conducted to measure the selected samples.

Organic petrographic examinations were performed on the fifteen polished samples. The maceral analysis was performed on a Leica DM6000M microscope under monochromatic and ultraviolet illumination and oil immersion objective on 500 points. Mean vitrinite reflectance (*Ro* %) measurements were performed using the same instrument with a reflected white light source on an average of objective at least 25 points. The maceral description of the coals and shales follows the standard international terminology (ICCP, 1994; 2001).

4 Results

4.1 Organic matter generation potential

TOC and pyrolysis analyses characterize the organic content, hydrocarbon potential of the organic matter and its thermal maturity (Reyhan, 2015; Daher et al., 2015). Unsurprisingly, TOC contents of the coals are obviously higher than that of the shales in the Pinghu Formation (Table 1, Fig. 3). TOC contents of coals and shales range from 25.2% to 77.2% and 1.29% to 20.9%, respectively. These values are more than the minimum acceptable TOC value for the sedimentary type rocks indicating source potential is 1.0% (Mardon et al., 2014; Phiri et al., 2016; Baiyegunhi Christopher et al., 2018).

The hydrocarbon yield (S_1+S_2) generated during pyrolysis is a useful parameter to evaluate the hydrocarbon generation potential of source rocks (Peters and Cassa, 1994; Mukhopadhyay et al., 1995; Li Wenhao et al., 2013). Generally, the S_1+S_2 yields range from 3.16 to 183.37 mg HC/g of rock in the Pinghu sediments (Table 1) and vary with TOC content (Fig. 3). These TOC contents and (S_1+S_2) yields meet the accepted standards of a source as having "fair to excellent" source rock potential (Fig. 4) as classified by Peters and Cassa, 1994. The HI of the coal and shale samples exhibit wide ranges, from 145 to 303 and from 102 to 282 mg HC/g TOC (Table 1), respectively. The coals also have higher HI magnitudes than that of the shales, implying a slightly hydrogen-richer kerogen and a relatively greater hydrocarbon-generating potential (Zhu et al., 2012).

4.2 Organic matter type and thermal maturity

Based on the pyrolysis analysis, kerogen is classified relative to HI and T_{max} (Shalaby, 2011). The kerogen type of the samples in this study were defined as Type II–III grading to Type III, and dominated in the Type III zone in the mature stage (Fig. 5). The atomic ratios (H/C) of the kerogen are relatively low, varying between 0.60 and 0.88 while the O/C ratio ranges from 0.10 to 0.20. As shown in Fig. 6, most of the data points are located in the Type III zone according to the definition from Powell (1989). Therefore, the kerogen types determined from both

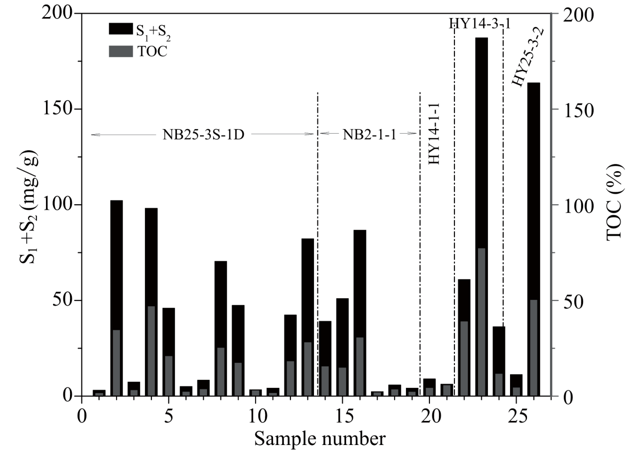

Fig. 3. TOC and S_1+S_2 of the Pinghu coal-measure source rocks.

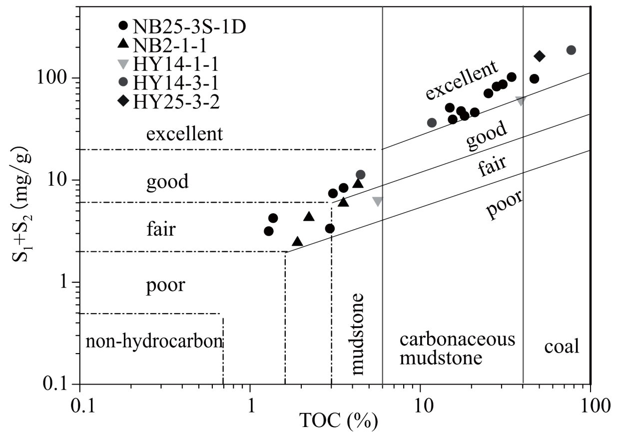

Fig. 4. Distribution of the samples on S_1+S_2 versus TOC, showing how well the potential of hydrocarbon generation.

pyrolysis and element analyses are in good agreement with each other.

Organic maturity is directly related to vitrinite reflectance (*R*o) determined by microscopy with white light and oil eyepiece (Christoph, et al., 2015; Hakimi et al., 2016). The distribution of R_o is generally in the range from 0.59% to 0.83%. This indicates that the coal measure source rocks are within the oil window for hydrocarbon generation, since the thermal maturity varies with the type of organic matter between 0.5% and 1.0% for the oil window and from 1.3% to 3.5% for the gas window (Farhaduzzaman et al., 2013; Hackley et al., 2016). T_{max} is also a reliable and useful indicator for thermal maturity since it is unaffected by weathering (Singh et al., 2010; Xie et al., 2016). The T_{max} values range from 425°C to 455°C indicating that the thermal maturity of tested samples was within the mature stage (Fig. 5), which is consistent with the result obtained from the *R*o values.

4.3 Organic petrology characteristics

The maceral composition and content of the selected samples (mineral matter free) are listed in Table 2 and illustrated in Fig. 7. The source rocks are dominated by vitrinite macerals ranging from 69.1%–96.8% with common appearance of liptinite (2.5%–17.55%) and only

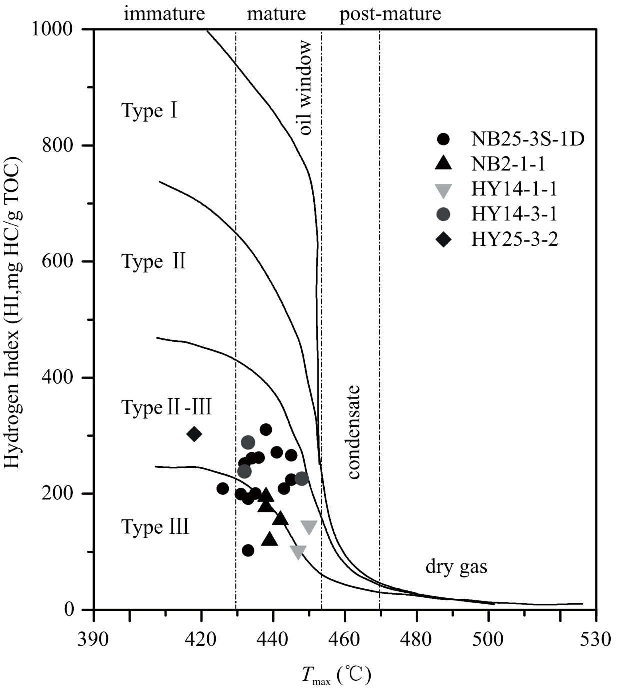

Fig. 5. Hydrogen Index (HI) versus pyrolysis T_{max}, showing the kerogen type and the thermal maturity stage.

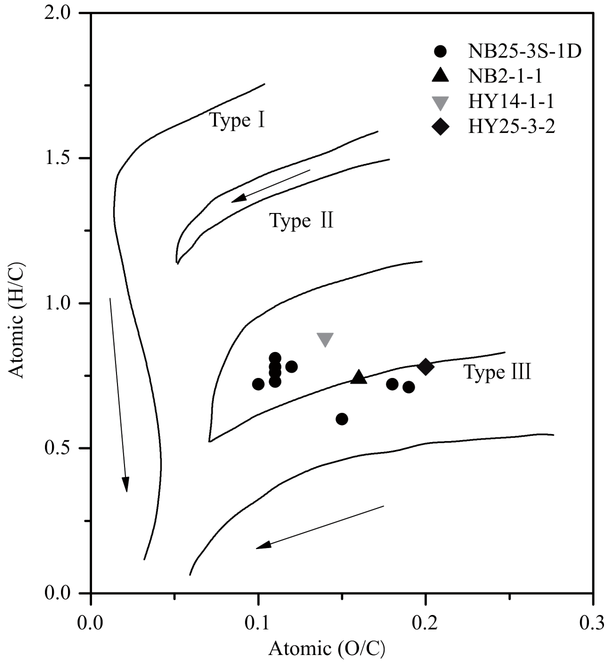

Fig. 6. O/C versus H/C of kerogens from the Pinghu Coal-measure source rocks.

minor content of inertinite (0.2%–6.2%). Sedimentary rocks with these characteristics are classified as humic and Type Ⅲ kerogen source rocks (Singh et al., 2010; Xie et al., 2016).

Vitrinite group components are characteristically identified by their typical intermediate reflectance and light-grey color in comparison to the darker liptinite and lighter inertinite groups (Sykes and Snowdon, 2002). Collotelinite is the most dominant sub-group of the vitrinite maceral group with rare collodetrinite and vitrodetrinite. The comparatively darker color in reflected white light, the yellow to brownish-yellow fluorescence together with the shape in ultraviolet light were used to identify the liptinite group components. Liptinite macerals observed in the source rocks were sporinite (most dominant), cutinite, resinite, suberinite, exsudatinite and liptodetrinite (Fig. 8a, b). Sporinite appeared as greenish-yellow slender strips of micro-sporinite (Fig. 8c, d and f). Cutinite was always associated with sporinite and characterized by a smooth edge on one side and a serrated edge on the other side (Fig. 8b and g). Resinite always appeared as isolated ellipsoidal inclusions, sometimes infilling the vitrinite cell cavity (Fig. 8e). Inertinite group components, identified by distinct higher reflectance in white light and the absence of fluorescence in ultraviolet light, are rare in the source rocks and are dominated by inertodetrinite. Mineral asphalt matrix is a complex of fluorescent organic secretions and does not belong to the organic maceral component, appearing in shale source rocks as shown in Fig. 8h.

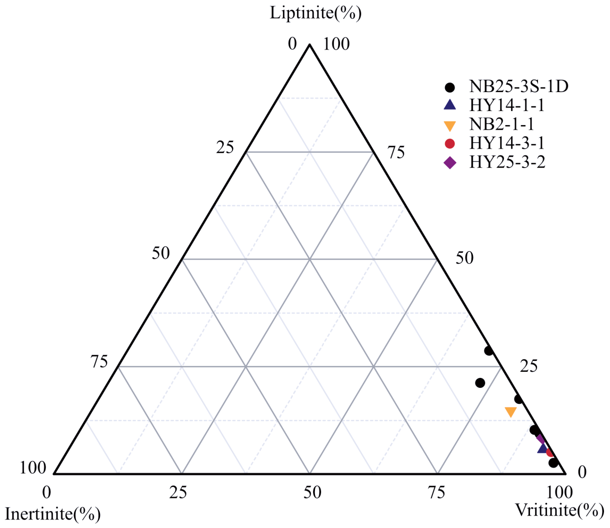

Fig. 7. Ternary diagram showing the maceral group composition.

5 Discussions

5.1 Hydrocarbon generation potential of the organic matter

The hydrocarbon generation potential of the Pinghu coal measure source rocks was evaluated based on the

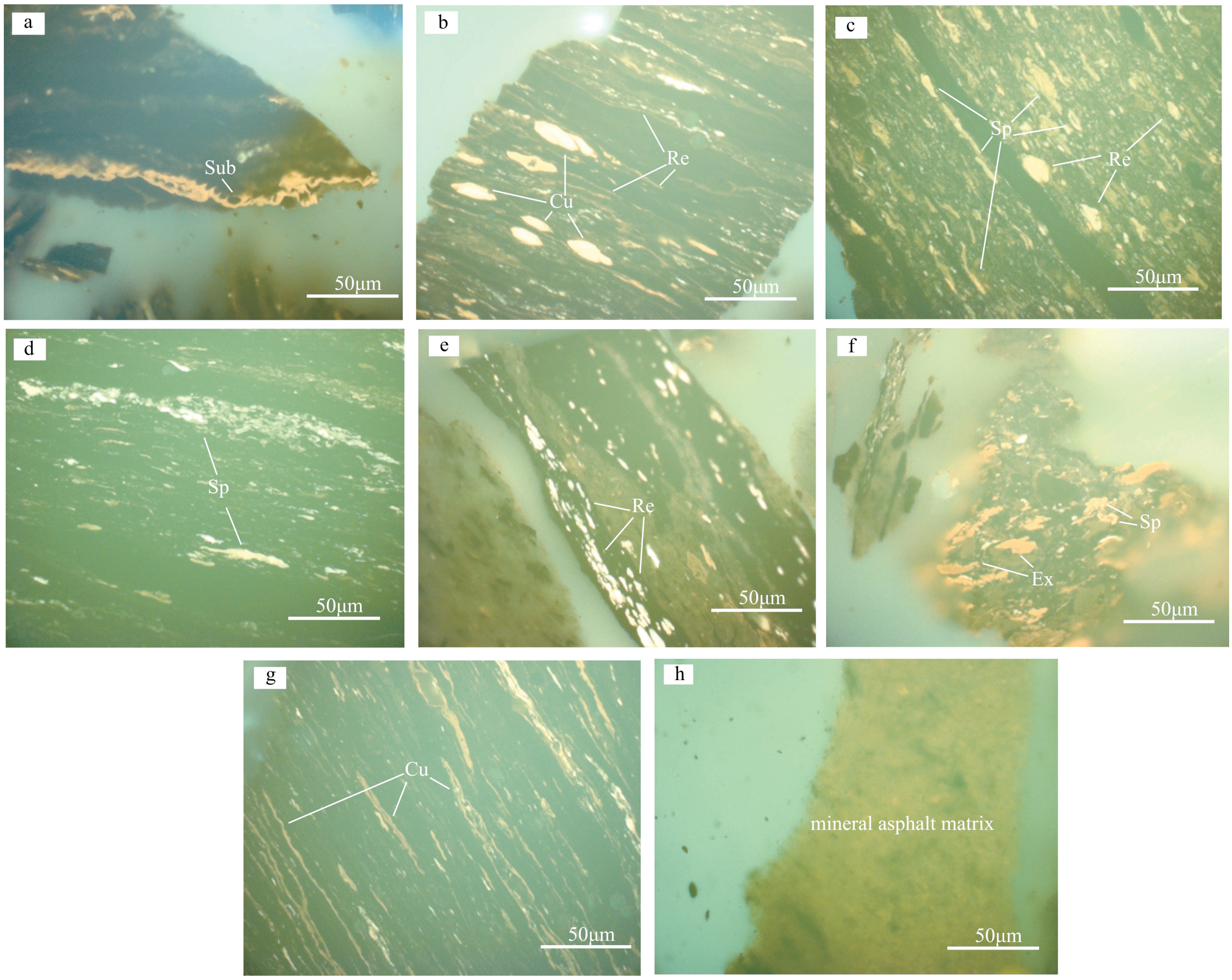

Fig. 8. Photomicrograph of liptinite under ultraviolet light.

quantitative pyrolysis analysis. As discussed in 4.1 section, the TOC content is sufficiently elevated to be a source rock for generating hydrocarbons. Meanwhile, HI can be interpreted as an indicator for oil and gas products (Carroll and Bohacs, 2001; Petersen and Nytoft, 2006; Phiri, et al., 2016). Kerogen with HI values >200mg HC/g TOC can generate oil, although the main products are typically both gas and condensate oil. HI values > 300 mg HC/g TOC are the generally accepted conditions for forming petroleum reservoirs (Hackley et al., 2016). Thus, it can be concluded that the samples are gas-prone source rocks based on the HI values (102–303 mg HC/g TOC). Moreover, the HI value is not the only criterion for kerogen type determination because the high content of TOC is also beneficial in determining kerogen type, using petrographic methods (Hunt, 1991). The potential oil richness of the samples is relatively dependent on the amounts of liptinite and hydrogen-rich vitrinite. A minimum of 15–20% liptinite content of total macerals in sediments is considered as an important criterion for a rock to be characterized as a potential oil source rock (Hunt, 1991; Calder, 1991). A low proportion of liptinite and high proportion of vitrinite in the samples (Fig. 7 and Table 2) imply the presence of Type Ⅱ-Ⅲ and Ⅲ kerogens confirmed by the pyrolysis data (Nowak, 2007; Song et al., 2014). Based on the pyrolytic and petrographic data, the source rocks are identified as gas-prone type, with the potential of minor condensate oil products. The *R*o values range from 0.58% to 0.85%, indicating the potential of the generation of thermogenic gas generated during burial.

In addition, the production index (PI) and T_{max} can be used to indicate the origin of hydrocarbons produced. As shown in Fig. 9, the hydrocarbons are expected to be indigenous rather than migrated hydrocarbon. As apparent in Fig. 10, the hydrocarbon generation potential (S_1+S_2) positively correlates with both vitrinite content (R^2=0.79) and the sum content of vitrinite and liptinite (R^2=0.72), but poorly correlates with liptinite (R^2=0.16) and TOC (R^2=0.21) contents. Thus, vitrinite is the main contributor to hydrocarbon generation potential in the source rocks. Vitrinite is mainly responsible for gas generation, with a minor impact from liptinite.

5.2 Depositional environment of organic matter

Coal facies models based on maceral concentrations were used to describe and reconstruct the depositional conditions (Singh et al., 2010). The Gelification Index (GI) and Tissue Preservation Index (TPI) were used to identify the degree of gelification, natural fragmentation and the proportion of woody plant matter (Diessel, 1986.; Singh et al., 2010). The Ground Water Index(GWI) and Vegetation Index (VI) were used to describe the water cover conditions for the deposition of coal (Petersen and Andsbjerg, 1996; Singh and Singh, 1996). The introduced four parameters are listed in Table 3.

Both the low TPI (0.002–0.028) and relatively high GI (16.37–77.89) indices for the Pinghu Formation coals indicate that the peat was accumulated in limno-telmatic environment under high water levels (Fig. 11). It suggests a low tree density in the origin of the terrestrial organic matter. Low TPI values indicate a laterally rapid increase

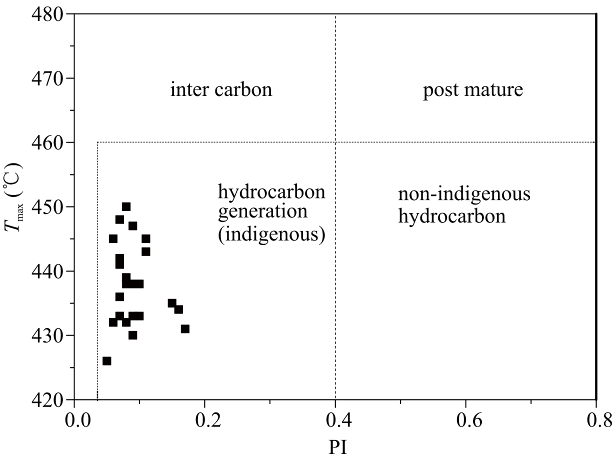

Fig. 9. T_{max} versus production index (PI), showing the maturity and nature of hydrocarbon products of the Pinghu source rocks.

Table 2 Vitrinite reflectance and maceral composition of coal-measure source rocks in the Xihu Sag

No.	R_o	Vritinite (%)				T_V	Liptinite(%)						T_L	Inertinite(%)			T_I	Im
	(%)	T	Cd	Ct	Vd	(%)	Sp	Re	Cu	Sub	Ld	Ex	(%)	Idt	F	Sf	(%)	(%)
3	0.59		4.8		0.59	4.8	0.3	0.3		0.2	0.6		1.4		0.2	0.2	0.4	93.1
4	0.63	0.5	76.7	0.3	0.64	78.14	1.7	0.5	2.5	0.4	2.8	0.1	8	0.8	0.2	0.2	1.2	12.66
5	0.64		39.8			39.8	1.5	0.2	0.8	0.6	3		6.1					54.1
7	0.66		5.2		0.66	5.2	0.3		0.1		0.6		1					93.8
8	0.66		37		0.66	37.66	4.2	0.7	5.6	0.3	3	1.2	15	1.2	0.3	0.8	2.3	45.04
10	0.69		9.2			9.2	0.1				0.2		0.3					90.5
12	0.72		18.9			18.9	0.3		0.1		0.1		0.5		0.2		0.2	80.6
13	0.75		29.2		0.75	29.95	2.3		0.6		3.3		6.2	0.3		0.1	0.4	63.45
16	0.76		19.8	0.3	0.76	20.86	1.1	0.1	0.1		1		2.3	0.3			0.3	76.54
19	0.71		6.1		0.71	6.1	0.4		0.9		0.1	0.2	1.4					92.5
20	0.73		7.2		0.73	7.2	0.5	0.2	0.3		0.3		1.5	0.2			0.2	91.3
22	0.84		19.4		0.84	20.24	0.2	0.1	0.3		0.6		1.2	0.3	0.1	0.2	0.6	77.96
23	0.82	0.8	82.2	0.8	0.82	84.62	0.7	0.4	0.3	0.5	2.6		4.5	0.5	0.2	0.3	1	11.7
24	0.79	1.5	10.6	1.8	0.79	12.4	0.5	0.2	0.7	0.2	0.1	0.2	1.9	0.2				84.2
26	0.50		69.6		0.5	70.1	1.4	1.6	1	0.9	1.5		6.4	0.7	0.2		0.9	22.6

Note: Ro%: Vitrinitereflectance. T_V, T_L,T_I=total maceral composition of vitrinite, liptinite, Inertinite respectively.
T:telinite;Cd:collodetrinite;Ct: collotelinite; Vd: vitrodetrinite.
Sp:sporinite; Re:Resinite;Cu:cutinite; Sub: Suberinite; Ld:Liptodetrinite; Ex: Exsudatinite.
Idt:Inertodetrinite; F: Fusinite; Sf: semifusinite.
Im: Inorganic minerals.

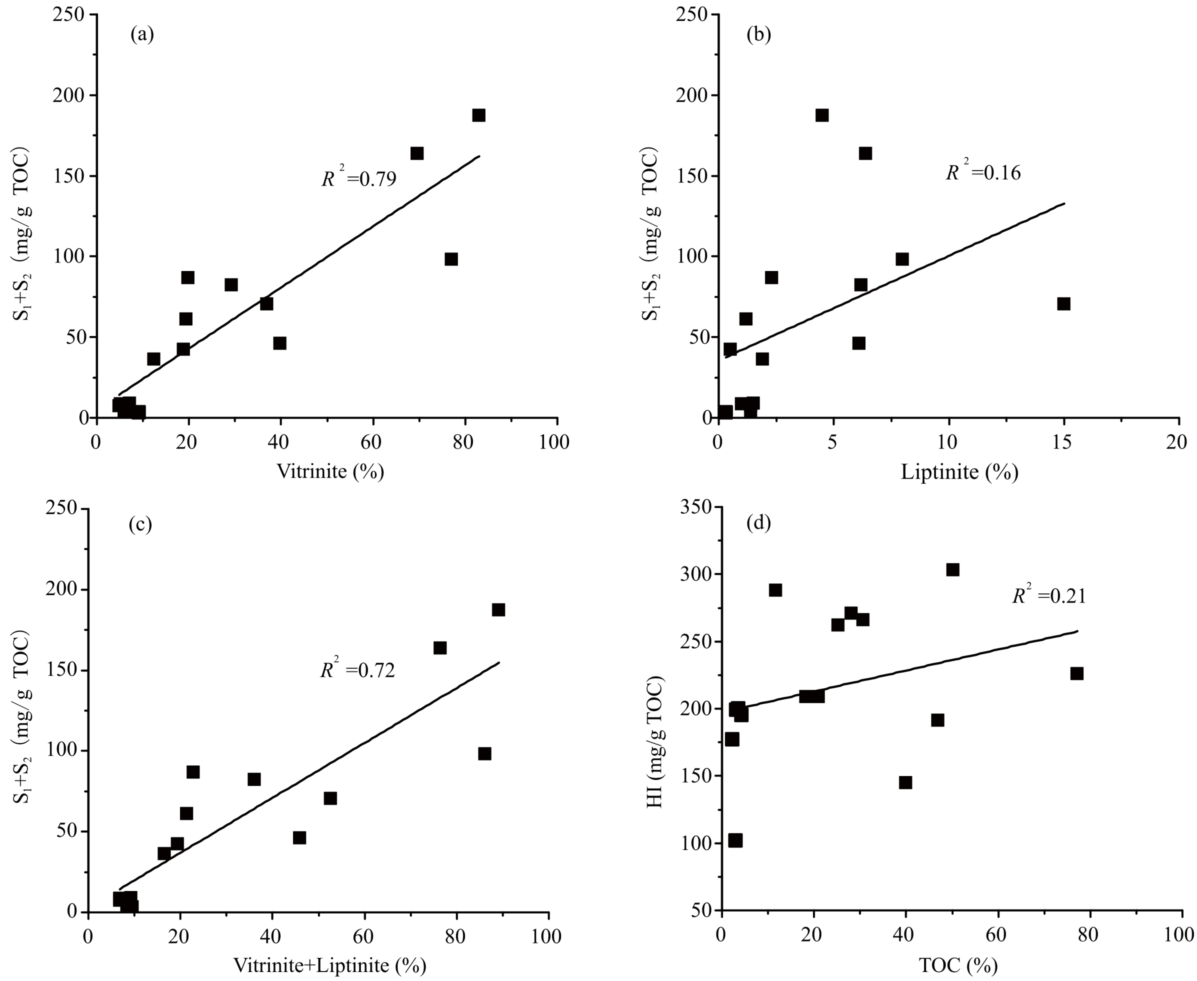

Fig. 10. Relationships between maceral composition and S_1+S_2 of the source rocks, indicating the main hydrocarbon generation ingredient.

Table 3 Petrographic parameters of coal samples in the PinghuFormation

No.	TPI	GI	GWI	VI
4	0.015	65.11	0.17	0.25
8	0.028	16.37	1.23	0.17
13	0.004	74.87	2.20	0.02
16	0.015	69.53	3.84	0.19
22	0.02	33.73	4.06	0.19
23	0.03	84.62	0.13	0.59
26	0.002	77.89	0.33	0.49

GI (Gelification Index) =(Vitrinite+Macrinite)/(Semifusinite+Fusinite+Inertodetrinite)
TPI (Tissue Preservation Index)=(Telinite+Collotelinite+Semifusinite+Fusinite)/(Collodetrinit+Macrinite+Inertodetrinite+Vitrodentrinite+Corpogelinite)
GWI (Groundwater influence index) = (Gelinite+Corpogelinite+Mineralmatter+Vitrodetrinite)/(Telinite+Collotelinite+Collodetrinite)
VI(Vegetationindex)=(Telinite+Collotelinite+Fusinite+Semifusinite+Funginite+Secretinite+Resinite)/(Collodetrinite+Inertodetrinite+Alginite+Liptodetrinite+Cutinite)

in the rate of subsidence and the depth of the Xihu Sag. Very low inertinite content and high vitrinite content (especially collodetrinite), as shown in Table 2, indicate that the peat underwent a high degree of gelification due to the underwater accumulation conditions. High GI values indicate an intense nonacidic microbial activity during the peat formation.

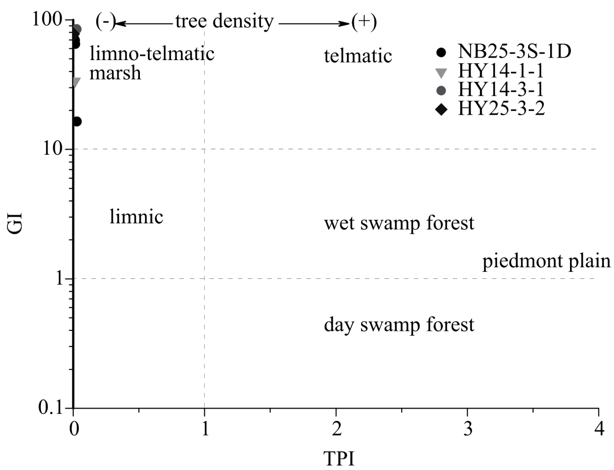

Fig. 11. Cross-plot of the Gelification Index (GI) and Tissue Preservation Index (TPI) showing the depositional settings of the peat mires (revised after Diessel, 1986).

The GWI values indicate that the coals were formed under high water levels (Dai et al., 2014). The low values of GWI (0.1–2.2) and VI (0.02–0.59) indicate that the coals evolved under ombotrophic (very low nutrient levels for plant development) to mesotrophic (moderate nutrient levels for plant development) conditions (Fig. 12), and contained herbaceous plants (given the evidence of low concentrations of textinite, semifusinite and fusinite in Table 2). The coal measure strata containing shale and limestone interlayers are indicative of a rise in the water level in the swamp, followed by the waters reaching lake level, resulting in the restarting of the peat development. This finding is further supported by the model proposed by Singh and Singh (1996). As shown in Fig. 13, samples located in the zone "F" indicate the frequent fluctuations of water level with intermittent flooding from moderate to high during the evolutionary history of the peats. During the frequently turbulent environment, terrigenous clastic was added into the peat, in which the concentration of the organic matter would be diluted. Also, the frequently turbulent environment would directly lead to the alternating sequences of coal, shale and sandstone during the process of the deposition of the coal measure strata.

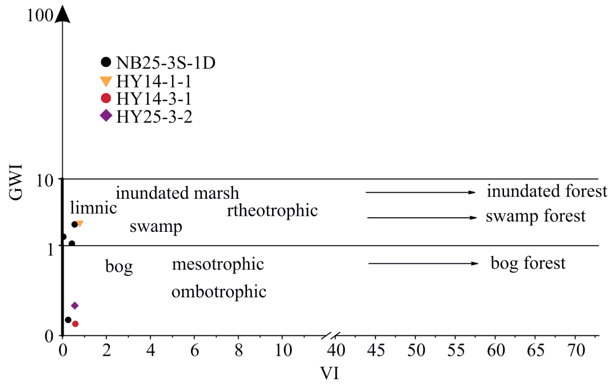

Fig. 12. Cross-plot of the Ground Water Index (GWI) and Vegetation Index (VI) identifying the palaeo-environments of the coal mires.

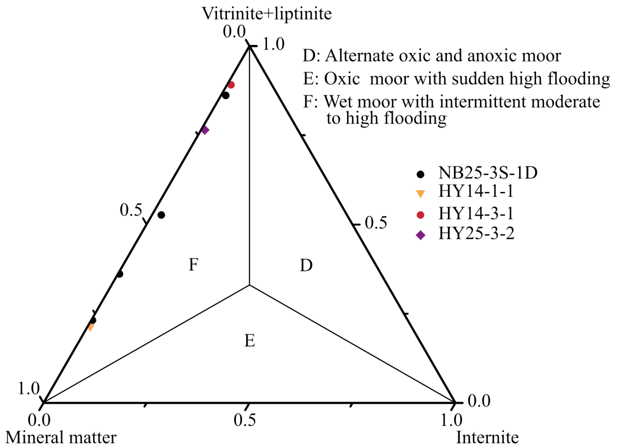

Fig. 13. Trinary diagram illustrating the peat-forming depositional environments based on the maceral compositions.

5.3 Depositional system of the Pinghu Formation

Based on the aforementioned results, the TPI value is generally increasing from the lower section to the middle section of the Pinghu Formation, whereas the GI value show the inverse trend (Fig. 14). All of these findings indicate that the peat swamp water level gradually becomes shallower from bottom to top. Furthermore, the depth of water cover have an effect on the coal-forming material and gelatification, thereby influencing the coal type of Pinghu Formation. Meanwhile, frequent changes in the content of organic matter, desmocollinite and exinite component indicate frequent changes in water condition during peat swamp development.

In addition, organic geochemical and petrographic characteristics of the coal measure source rocks was directly influenced by the depositional system of the Pinghu Formation. The development of Xihu Sag was mainly controlled by fault basin. The coal-bearing source rocks of Pinghu Formation in the Xihu Sag were formed in barrier island-lagoon and delta depositional system (Fig. 14). The thickness of coal seam was mainly controlled by the syndepositional fault activity during deposition of the Pinghu Formation. Moreover, long-term fault activity would influence the swamp water level fluctuations, and thus lead to the alternating sequences of coal, shale and sandstone. Such interlayers of sandstones and shales may provide favorable conditions for preservation of coal measure gas.

6 Conclusions

The organic geochemical and petrographic characteristics of the coal measure gas source rocks from the Xihu Sag of the East China Sea shelf basin were analyzed using variety of quantitative techniques. The following conclusions are drawn below:

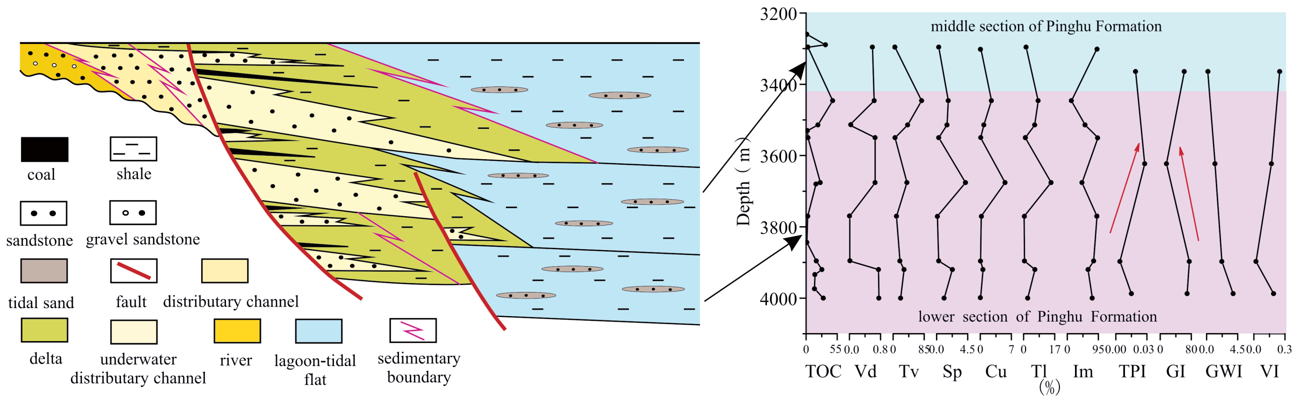

Fig. 14. Depositional system of the Pinghu Formation, Xihu sag (modified from Shen et al., 2016).

(1) The Pinghu coals and shales are organic-rich with TOC contents of 25.2% to 77.2% and 1.29% to 20.9%, respectively. The source rocks can be defined from “fair” to “excellent” based on the TOC content. Moreover, the correlation between HI and T_{max} and the atomic ratios of both the H/C and O/C indicate that the kerogen are Type II –III and III, with Ro varying between 0.59% and 0.83%. The Pinghu source rocks in the Xihu Sag are mainly disposed to be gas-prone, but also have the potential to generate condensate oil.

(2) Coals and shales of the Pinghu Formation have a humic composition dominated by vitrinite macerals (69.1%–96.8%). Vitrinite is the main contributor to the hydrocarbon generation potential, suggesting that the Pinghu Formation is the main hydrocarbon source for gases and oils in the Xihu Sag.

(3) The coal-bearing source rocks of Pinghu Formation in the Xihu Sag were formed in barrier island-lagoon and delta depositional system. The proportions of mineral matter, inertinite, vitrinite and liptinite suggest that water levels frequently fluctuated with intermittent flooding from moderate to high during the deposition of the peats, resulting in the alternate appearance of coal and shale during the process of the deposition of the coal measure strata.

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About the first and corresponding author

WANG Yang, male, male, born in 1989 in Zhenjiang City, Jiangsu Province; doctor; graduated from China University of Mining and Technology; lecturer of the School of Resources and Earth Science, China University of Mining and Technology. His current research interest focuses on nanopore characterization and methane adsorption of organic-rich shales. He has published some papers in “Fuel”, “Energy & Fuels” and “Geological Journal”. Email: wangycumt@163.com; Tel: 15896422124