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Abstract The process and mechanisms of secondary hydrocarbon migration in the Huixi half-graben, Pearl River Mouth Basin, were investigated on the basis of geological analysis of the strata and study of the porosity and permeability of the reservoir rocks, fluid potential, oil properties, and geochemistry of oil-source correlation. The results suggest that the hydrocarbons of the Zhujiang Formation in the Huixi half-graben were derived from source rocks of the Eocene Wenchang Formation and the Eocene–Oligocene Enping Formation in the Huizhou Sag. The hydrocarbons migrated laterally from northeast to southwest. The sandstone in the upper member of the Zhujiang Formation exhibited superior physical properties (porosity and permeability) and connectivity than the lower member. Thin sandstone beds with good physical properties and stable distribution in the upper member of the Zhujiang Formation were the main carrier beds for lateral hydrocarbon migration.

Key words: Secondary migration, Heterogeneous carrier beds, Oil-source correlation, Huixi half-graben, Zhujiang Formation

Introduction

Hydrocarbon migration, which connects the processes of hydrocarbon generation and final accumulation, has been a matter of interest in petroleum geology for many years (Maggon and Dow 1994). However, it is also a challenge for petroleum research because of the lack of direct geological evidence and the extreme conditions required for experimental physical simulation of hydrocarbon migration (Pang et al. 2013; Chen et al. 2013). Although the mechanism of secondary hydrocarbon migration has been studied, the preferred pathway and main controlling factors are still unclear.

Schowalter (1979) claimed that the driving forces for secondary petroleum migration are buoyancy and groundwater flow and that the restraining force is capillary pressure, which increases with decreasing pore-throat size and increasing interfacial tension and wettability. Hindle (1997) used three-dimensional computer modeling to verify that petroleum migration is mainly driven by structural morphology in sedimentary basins. This hypothesis has been corroborated by other studies (Gussow 1968; Momper and Williams 1984; Tissot and Welte 1984; Pratsch 1983, 1986, 1988, 1994; Welte et al. 2000; Hao et al. 2007, 2009). Miles (1990) studied secondary migration routes in the Brent sandstones in the North Sea and demonstrated that for a given unit of time during secondary migration, more oil will pass through a highly permeable, thin sandstone bed than through a less-permeable, thick sandstone bed. Rhea et al. (1994) and Bekele et al. (1999, 2002) confirmed this conclusion and stated that petroleum migration is largely controlled by the heterogeneity of the porosity and permeability of the carrier beds. Fustic et al. (2012) studied the oil-trapping mechanisms in the McMurray Formation, Alberta Basin, and concluded that internal reservoir heterogeneities can have major control on reservoir charging and

petroleum entrapment mechanisms. Chen et al. (2013) studied lateral migration routes in sandstones in the Fudong slope, Junggar Basin, China, and concluded that (i) petroleum migrates along structural nodes through sandstone beds with high porosity and permeability and (ii) both the structural morphology and heterogeneity of carrier beds control petroleum migration.

Hydrocarbon exploration in Chinese offshore basins began relatively late and some basic geological data are incomplete because of few wells have been drilled. Therefore, studies on secondary hydrocarbon migration in the Huixi half-graben and other areas of the Pearl River Mouth Basin are not as advanced as those in other areas. The mechanisms behind the secondary migration of hydrocarbons in the Zhujiang Formation in the Huixi half-graben are poorly understood. Zou et al. (1991) studied hydrocarbon migration in the Pearl River Mouth Basin based on hydrocarbon properties. The results showed that due to the generation of heavy hydrocarbons during the migration process, the density and sulfur content of the oil increase gradually from northwest to southeast. This demonstrates that hydrocarbons migrated from northwest to southeast. Zou et al. (1991) concluded that continuous sandstone, combined with structural ridges, acted as major pathways for long distance hydrocarbon migration because LH11, the largest oil field in the Zhu 1 Depression, was found in structural ridges 40 km away from source rocks. Long et al. (2006) claimed that the heterogeneity of the carrier beds was the primary control of petroleum migration pathways in the Huizhou Sag of the Pearl River Mouth Basin. Shi (2013) studied hydrocarbon migration in the Pearl River Mouth Basin based on three-dimensional computer modeling and reported that hydrocarbon migration is mainly controlled by structural morphology in this region.

New oil reservoirs have been discovered in the Zhujiang Formation in the Huixi half-graben, Pearl River Mouth Basin, making it an area of focus for hydrocarbon exploration. However, the

hydrocarbon source along with the direction and dominant pathway of secondary hydrocarbon migration are uncertain, hindering further petroleum exploration. This study integrates geological and geochemical methods to analyze the secondary migration of hydrocarbons in the Zhujiang Formation in the Huixi half-graben. The key factors analyzed include rock characteristics, porosity and permeability, fluid potential, oil properties, and oil-source correlation. The results will be useful for future hydrocarbon exploration in the area.

Geological setting

The Pearl River Mouth Basin is the largest depositional basin in the northern continental margin of the South China Sea and is located at 111°–118.5°E, 18°–23°N. With a length of about 800 km and a width of about 100–300 km, the basin has a northeastward trend and covers an area of approximately $1.7 \times 10^5 \text{ km}^2$. The Pearl River Mouth Basin is divided into five tectonic units: the northern uplift zone, the northern depression zone (containing the Zhu I and Zhu III Depressions), the central uplift zone, the southern depression zone, and the southern uplift zone (Fig. 1a) (Chen 2000). The Huixi half-graben is located in the western part of the Huizhou Sag, Zhu I Depression. It forms a part of the northern depression zone and has an exploration area of 3900 km^2 (Fig. 1b). This half-graben is located north of the Dongsha Uplift and east of the Xijiang Sag (Fig. 1c). The Huixi half-graben is a north-dipping slope, with structural positions relatively higher in elevation in the south than in the north (Fig. 2). The reservoirs discovered in the Huixi half-graben are mainly structural reservoirs. Recent exploration has indicated that the geological reserves of hydrocarbons in the Huixi half-graben amount to $22.09 \times 10^8 \text{ t}$, accounting for 34.3% of the Pearl River Mouth Basin reserves. More than 50% of the Huixi

reserves are in the Zhujiang Formation (Shi 2013; Shi et al. 2014). This finding further supports the Huixi half-graben being a major hydrocarbon-rich area in the Pearl River Mouth Basin.

The study area experienced three stages of structural evolution during the Cenozoic (Fig. 3). During the extensional rifting stage (early Eocene–middle Oligocene), episodic movements (the Zhuqiong I and Zhuqiong II movements) formed the structural configuration of the Huixi half-graben (Robinson et al. 1998; Zhang et al. 2004; Cui et al. 2009). In the subsidence stage (late Oligocene–middle Miocene), the Nanhai movement altered the Pearl River Mouth Basin from the rifting stage to the steady subsidence stage and sea water intruded widely into the study area from southeast to northwest, with little tectonic activity (Zhang et al. 2004; Cui et al. 2009). During the block faulting stage (middle Miocene), initiated by the Dongsha movement, old faults were reactivated and many new west–northwest trending faults developed (Zhang et al. 2004; Cui et al. 2009). The geological structures of the area have remained stable since the middle Miocene.

With the development of these complex tectonic events, the Cenozoic sedimentation of the Huixi half-graben evolved from continental to marine sedimentation (Fig. 3). The general stratigraphic characteristics, from oldest to youngest, are as follows. The Eocene Wenchang Formation is a source rock of the region and contains semi-deep to deep lacustrine facies dark mudstone and interbedded sandstone. The Eocene–Oligocene Enping Formation, which consists of shore-shallow lacustrine facies gray and dark gray mudstone, is also a source rock. The marine facies Zhuhai, Zhujiang, and Hanjiang Formations, which were deposited during the subsidence stage, are the main hydrocarbon reservoirs. In combination with marine shale, the high-porosity and permeability sandstone beds in these three formations form excellent reservoir-seal

assemblages (Chen 2000). Three sets of regional-flooding mudstone deposited at 18.5, 16, and 13.2 Ma constitute the major regional caprocks of the study area.

Lithological features of Zhujiang Formation

The Pearl River Mouth Basin has experienced a sea-level rise since the beginning of the Zhujiang Formation (Shi et al. 1999). Based on the features of lithology and sedimentary facies, the Zhujiang Formation can be divided into two members: the lower member and the upper member. The lower member of the Zhujiang Formation in the Huixi half-graben is mainly deltaic facies, which contains frequently interbedded thin medium- to coarse-grained sandstone and mudstone covered with thick mudstone formed during the transgression at 16 Ma (Chen et al. 2000; Chen 2003). The reservoir rocks mainly consist of distributary channel sand and mouth-bar sand of the delta facies (Chen et al. 2012). Affected by the transgression from southeast to northwest, the upper member of the Zhujiang Formation in the Huixi half-graben is primarily shoreface facies, which consists of interbedded thick, medium- to coarse-grained sandstone and thin mudstone covered with thick mudstone formed during the transgression at 18.5 Ma (Chen et al. 2000; Chen 2003). The reservoir rocks mainly consist of beach sand, coastal sand dam, and shoreface sand in the shoreland facies (Chen et al. 2012). The sand bodies have good reservoir physical properties with a stable and wide distribution and are overlain by mudstone deposited during a small transgression. This forms an ideal reservoir-cap assemblage (Chen et al. 2012).

The thick mudstones deposited during the transgressions at 16 and 18.5 Ma act as regional caprocks for the upper and lower members, respectively (Shi 1999). In general, the reservoir lithology of the Zhujiang Formation is chiefly medium- to coarse-grained sandstone with good

sorting and rounding. The cement is mainly argillaceous with some calcitic and dolomitic cement, although the cement content is low, generally less than 10% (Chen 2003; Fu et al. 2013). The reservoir pores are chiefly primary intergranular pores and secondary dissolution pores (such as intergranular dissolved pores, intragranular dissolved pores, and moldic pores) (Chen 2003; Fu et al. 2013). In addition, dissolution fractures and kaolinite intercrystal pores can still be observed and the pore to throat connectivity is excellent. The capillary pressure curve shows mainly large pore-throat. The maximum throat width is greater than 20.9 μm and the throat sorting is good (Chen 2003).

Data and methods

Samples

In this study, more than 300 samples from 14 wells (shown in Fig. 1) were collected and submitted for source-rock analysis. All of the sampled wells were relatively evenly distributed within the study area and included all of the current wells that were drilled into source rocks. Abundant core samples from each source rock layer were available for analysis. The seven oil samples (from six wells; Table 3) selected for the geochemical analysis were evenly distributed across the study area.

In addition, data on the formation thickness and percentage of sandstone in 10 wells (shown in Table 1) were obtained from the Shenzhen Company of China National Offshore Oil Corporation (Guangzhou, China). More than 1000 data points related to porosity and permeability from 14 wells (Fig. 1) and 10 oil sample physical property data points (Table 4) were obtained from the Shenzhen Company of China National Offshore Oil Corporation (Guangzhou, China).

Laboratory workflows

The geochemical analyses included determination of TOC content, Rock-Eval pyrolysis, bitumen extraction, chemical composition, and vitrinite reflectance (R_o). The TOC was measured using a LECO CS-400 analyzer. Rock-Eval pyrolysis was performed using a Rock-Eval II instrument. Measurements of mean random R_o were obtained using an oil immersion lens and a Leica MPV Compact II reflected light microscope fitted with a microphotometer. The reflectance for each sample was calculated by averaging the histograms of more than 50 data points.

Biological markers were identified by gas chromatography-mass spectrometry (GC-MS). The instrument used was an Agilent 7890–5975C Model GC-MS (developed by Agilent Technologies Inc., California, USA). The hydrocarbons were analyzed using a J&W VF-5MS quartz capillary column (60 m $\times$ 0.25 mm $\times$ 0.25 mm). The oven heating program was as follows: a constant temperature of 50°C for 1 min, heating to 100°C at a rate of 20°C/min, heating from 100°C to 315°C at a rate of 3°C/min, and a constant temperature of 315°C for 20 min. Helium was used as the carrier gas at a flow rate of 1 mL/min.

Methods for analysis of secondary hydrocarbon migration

Lateral petroleum migration in the Zhujiang Formation was investigated based on the geological analysis of the thickness and connectivity of the sandstone, porosity and permeability of the reservoir, geochemical study of the oil-source correlation and oil properties, and fluid potential.

Oil-source correlation is an important method for analyzing the origin and secondary migration of petroleum (Chen et al. 2014). However, not all biomarkers are reliable indices for

oil-source correlation. The markers used for oil-source correlation must satisfy the following conditions: (1) the compounds must be biologically derived, i.e., they should have a definite source significance; (2) the compounds must not be influenced by rock and hydrocarbon maturity; and (3) the compounds must not be influenced by secondary factors, such as gas deasphalting, biodegradation, water washing, and geochromatographic effects, during the migration process (Peters and Moldowan 1993). In this study, we did not attempt to find further parameters for oil-source correlation, but ensured that the parameters used met the above conditions. The parameters used were the ratios of carbon isotopes ($\delta^{13}\text{C}$), pristane/phytane (Pr/Ph), $\text{C}_{19}/\text{C}_{23}$ tricyclic terpanes ($\text{C}_{19}/\text{C}_{23}$ TT), bicadinane/ C_{30} and hopane ($\text{T}/\text{C}_{30}\text{H}$), and the distribution pattern of $\text{C}_{27}\text{-C}_{28}\text{-C}_{29}$ steranes. The significance of these parameters is well-known. Carbon isotopes ($\delta^{13}\text{C}$) reflect the origin of petroleum (Hayes et al. 1987). The ratio Pr/Ph can reflect the oxidizing or reducing state of an environment, and low Pr/Ph values can indicate an anoxic (usually hypersaline) sedimentary environment (Peters and Moldowan 1993). Tricyclic terpanes are the most common class of compounds in crude oil and are derived from the cell membranes of protozoans. In general, C_{23} homologues are the dominant components in tricyclic terpanes. Some $\text{C}_{19}\text{-C}_{20}$ tricyclic terpanes are derived from higher plants. The $\text{C}_{19}/\text{C}_{23}$ tricyclic terpanes can reflect the sedimentary environment and organic matter input (Peters and Moldowan 1993). Bicadinane is a characteristic indicator of a resin input from higher plants. The bicadinane/ C_{30} hopane ratio reflects the sources and properties of organic matter, with the ratio being proportional to the input of terrigenous higher plants (Fu et al. 2007). The content of 4-methyl sterane is closely related to the presence of algae rich in 4-methyl sterol and reflects the contribution of aquatic organisms. The distribution pattern of $\text{C}_{27}\text{-C}_{28}\text{-C}_{29}$ steranes has a close relationship with the input of parent

material into the source rock (Brassell et al. 1986; Summons et al. 1992).

In a petroliferous basin, fluid potential controls the migration direction and final distribution of hydrocarbons; the hydrocarbons always migrate from areas with high potential toward those with low potential (Hubbert 1953; England et al. 1987). In 1953, Hubbert put forth a formula to calculate the mechanical energy of a unit mass of fluid, the definition of fluid potential he proposed. The formula is

$$\Phi = gz + \int_0^p \frac{dp}{\rho} + \frac{q^2}{2},$$

where Φ = fluid potential (J/kg); g = acceleration caused by gravity (9.81 m/s^2 [32.19 ft/s^2]); z = altitude (m); p = reservoir pressure (Pa); ρ = fluid density (kg/m^3); and q = fluid velocity (m/s). Considering that the natural motion of fluid in the subsurface environment is extremely slow, the flow velocity can be assumed to be zero.

Results

Thickness and connectivity of sandstone

Data on the stratal thickness and sandstone content of the Zhujiang Formation (Table 1) show that the thickness of the upper member of the Zhujiang Formation is between 222 and 652 m and that of the lower member is between 87 and 545 m. However, the sandstone content of the upper member (15%–42%) is more variable than that of the lower member (42%–62%), suggesting strong reservoir heterogeneity (Fig. 4). The thickness of sandstone, which is essential for hydrocarbon migration, is 41–209 m in the upper member of the Zhujiang Formation and 37–299 m in the lower member (Fig. 5). The sandy beach bar subfacies developed in the upper member of

the Zhujiang Formation in area HZ25-8-1 lead to the anomalous sandstone thickness (Shi et al. 1999).

Another key factor for hydrocarbon migration and accumulation is sandstone connectivity (Fustic et al. 2012). Theoretically, the distributary channel sand and mouth-bar sand of the delta facies in the lower member should have large thicknesses (Table 1) but limited distribution (Fig. 2), whereas the beach sand, coastal sand dam, and shoreface sand in the shoreland facies may have relatively low thicknesses (Table 1) but stable and wide distribution (Fig. 2). Despite the sandstone content and thickness being larger in the lower member, more than 60% of the discovered hydrocarbons occur in the upper member, suggesting that the thin sandstone beds of the upper member are more favorable for secondary hydrocarbon migration and accumulation. Specifically, the XJ24-1-1, XJ24-3-1, and XJ30-2-1 wells revealed 1304 m³, 3529 m³, and 4966 m³ petroleum reserves (in-place reserve), respectively, in the upper member; however, no reserves have been found in the lower member, whose sandstone thickness and content are relatively large (Figs. 4 and 5). This result suggests that the distributary channel sand and mouth-bar sand of the delta facies are more likely to form isolated sandstone sealed by large-scale non-reservoir depositional elements, such as mud plug deposits, and are unfavorable for hydrocarbon migration and accumulation. On the contrary, despite their lesser thicknesses, the beach sand, coastal sand dam, and shoreface sand in the shoreland facies, which have stable and wide distributions (Fig. 2), are favorable for hydrocarbon migration and accumulation.

Porosity and permeability

Reservoir physical properties, especially porosity and permeability, can reflect the

characteristics of fluid flow and play an important role in secondary hydrocarbon migration (Miles 1990). Secondary hydrocarbon migration is controlled by the heterogeneity of the carrier beds, with hydrocarbon preferentially migrating through carrier-bed portions with relatively high porosity and permeability (Rhea et al. 1994; Bekele et al. 1999, 2002).

In the Huixi half-graben, the porosity and permeability of the Zhujiang Formation were measured in almost 1000 sandstone samples from 14 wells (Fig. 1) by Shenzhen Company of China National Offshore Oil Corporation (Guangzhou, China). The sandstones of the Zhujiang Formation show considerable variation in porosity and permeability, with the measured porosities ranging from less than 5% to over 30% (Fig. 6a) and the measured permeabilities ranging from less than 0.1 to over 1000 mD (Fig. 6b). Even a single sandstone body from a given well can display considerable variation in porosity and permeability within a very small distance (on the scale of centimeters). The maximum porosity and permeability of the upper member of the Zhujiang Formation are less than 32.9% and 9550 mD, with average values of 17.6% and 750 mD, respectively. The maximum porosity and permeability decrease as depth increases in the lower member of the Zhujiang Formation, with maximum values of 29.4% and 5940 mD and average values of 18.7% and 587 mD, respectively.

Overall, the Zhujiang Formation is strongly heterogeneous. The maximum porosity and permeability are higher in the upper member than in the lower member. Though the sand ratio and reservoir thickness in the upper member are smaller than those in the lower member, oil and gas are more likely to migrate laterally along the thin sand layers in the upper member, which have more favorable porosity and permeability. This finding is confirmed by the results of hydrocarbon exploration, in which more than 60% of the discovered oil and gas reserves have

been found in reservoirs in the upper member.

Oil-source correlation

Previous petroleum exploration has shown that there are two main source rocks in the Zhu I Depression: the Eocene Wenchang Formation and the Eocene–Oligocene Enping Formation (Shi 2013; Shi et al. 2014). These two source rocks and their geochemical characteristics are described below.

Source rock in the Wenchang Formation

The source rock in the Wenchang Formation was deposited during the extensional rifting stage, when the basin subsidence rate was rapid and the water depth was large. During this interval, deep–semi-deep lacustrine facies dark mudstone was formed. The maximum thickness of this mudstone is 1800 m. The kerogen is mainly of type II (humus-sapropelic-type kerogen with a relatively high hydrogen content, albeit slightly lower than that of the sapropelic type), with a small amount of type I (Shi 2013).

Geochemical analysis (Table 2) showed that the TOC of source rocks in the Wenchang Formation is between 0.5% and 7.55%, with an average value of 1.69%. The oil-generation potential is high: the mean value of the hydrocarbon index is 322.86 mg/g and that of hydrocarbon generation potential ($S_1 + S_2$) is 11.37 mg/g. The source rock had reached the mature stage (vitrinite reflectance 0.46%–0.93%), in which a large amount of liquid oil was generated. The $\delta^{13}\text{C}$ values of the hydrocarbon extracted from the source rocks in the Wenchang Formation range from -28.2‰ to -25.2‰ (Fu et al. 2001). The pristane (Pr) content is relatively low, while the phytane (Ph) content is relatively high, with Pr/Ph values less than 4. The value of $\text{C}_{19}/\text{C}_{23}$ tricyclic terpanes is less than 2.5; the bicadinane content is relatively low, with bicadinane/ C_{30}

hopane values less than 0.4; the 4-methyl sterane content is high; and the contents of C_{27} sterane and C_{29} sterane are greater than that of C_{28} sterane, generating a V-shaped distribution pattern of C_{27} - C_{28} - C_{29} sterane (Zhang et al. 2004; Fu et al. 2007).

Source rock in the Enping Formation

The source rock in the Enping Formation formed in the period of transition from extensional rifting to subsidence. During this time, the water depth was shallower, and the deposition of shallow lacustrine to limnetic facies and deltaic swamp plain to fluvial facies mudstone or carbonaceous mudstone with coal interbeds took place. The maximum thickness is more than 1000 m and the kerogen is mostly of types II and III (Shi 2013). Geochemical analysis (Table 2) showed that the abundance of organic matter in the Enping Formation source rocks is between 0.5% and 9.82%, with an average value of 2.03%. However, the oil-generation potential is finite and the rock was prone to gas generation (Shi 2013). The mean value of the hydrocarbon index is 179.31 mg/g and that of the hydrocarbon generation potential ($S_1 + S_2$) is 11.83 mg/g. This is due to the development of carbonaceous mudstone and coal layers in the Enping Formation, leading to higher measured TOC levels and hydrocarbon generation potential. The source rock had reached the mature stage, with vitrinite reflectance values of 0.45%–1.04%. The $\delta^{13}C$ values of hydrocarbon extracted from source rocks in the Enping Formation range from -29.5‰ to -26.2‰ (Fu et al. 2001). The pristane (Pr) content is relatively high, while the phytane (Ph) content is relatively low, with Pr/Ph values between 4 and 7. The value of C_{19}/C_{23} tricyclic terpanes is greater than 2.5; the bicadinane content is relatively high, with bicadinane/ C_{30} hopane values of greater than 0.5; the 4-methyl sterane content is low; and the levels of C_{27} sterane and C_{28} sterane are relatively low, while the content of C_{29} sterane is relatively high, generating an L-shaped distribution pattern of C_{27} - C_{28} - C_{29} sterane (Zhang et al. 2004; Fu et al. 2007).

Oil characterization

In this study, geochemical indicators of crude oil were detected in seven crude oil samples from the Zhujiang Formation obtained from six oil wells in the Huixi half-graben (Table 3). The results show that the previously discovered oil and gas in the Zhujiang Formation have relatively low Pr/Ph and C_{19}/C_{23} TT ratios (except for well HZ21-1-1): the Pr/Ph ratios are all less than 4 and the C_{19}/C_{23} TT ratios are less than 2.5 for the other six oil samples (Table 3). The 4-methyl sterol contents in the seven crude oil samples are all high, the values of $C_{30,4-MS}/C_{29S}$ range from 0.67 to 1.90, and the distribution pattern of C_{27} - C_{28} - C_{29} sterane is V-shaped. Using well XJ24-1-1X as an example, the levels of C_{27} sterane, C_{28} sterane, and C_{29} sterane are 27.07%, 20.35%, and 52.58%, respectively (Table 3). For these crude oil samples, the parent material input was mostly aquatic organisms in a lacustrine reducing environment, which is similar to the source rocks of deep lacustrine facies in the Wenchang Formation. However, the $\delta^{13}C$ values of the crude oil range from -25.15‰ to -28.4‰ and the T/ $C_{30}H$ ratio is between 0.25 and 1.02. This indicates an input from terrestrial higher plants and demonstrates that the source rocks in the Enping Formation contributed to the crude oil formation. The above evidence shows that the hydrocarbons in the Huixi half-graben originated from source rocks of both deep lacustrine facies in the Wenchang Formation and limnetic facies in the Enping Formation. Two classical biomarker parameters that reflect maturity indicate that the hydrocarbons are mature oil (Fig. 7), i.e., the values of the parameters $C_{29}20S/(20S+20R)$ and $C_{29}\alpha\beta/\sum C_{29}$ are 0.46–0.8 and 0.37–0.53, respectively.

Fluid potential

The fluid potential field in a basin is mostly determined by the morphology of carrier beds, and any identification of migration directions using the fluid potential gradient requires the

delineation of compartmental troughs in the potential fields within the area of interest (Liu et al. 2002; Pang et al. 2013). As the geographical divides or ridges separate regions of differing drainage, the compartmental troughs separate different hydrocarbon accumulation units. On opposite sides of a compartmental trough area, hydrocarbon units move in opposite directions. Each area divided by compartmental troughs is a relatively independent system for hydrocarbon accumulation. For example, if the fluid potential field is equivalent to the topography, the compartmental troughs would equate to the ridge, the principal migration direction would equate to the valley, and the drainage area surrounded by multiple ridges would equate to a relatively independent hydrocarbon accumulation unit (Hubbert 1953; Toth 1980; England et al. 1987). Figure 8a shows the location of the Huizhou Sag and study area (Huixi half-graben). Figure 8b shows the compartmental troughs of hydrocarbon migration and the associated hydrocarbon units of the Huizhou Sag, Zhu I Depression. The Huixi half-graben is located in hydrocarbon accumulation unit I. Controlled by the compartmental troughs and structural morphology of carrier beds, hydrocarbons migrate from northeast to southwest in the Huixi half-graben.

Using the equation proposed by Hubbert (1953), fluid potential characterization in the Huixi half-graben was obtained (Fig. 8c). Fluid potential values of wells HZ21-1-1 and HZ25-4-1 in the northeastern region were relatively high, i.e., 3205 and 3190 J/kg, respectively. Conversely, the fluid potential value was relatively low in wells HZ26-1-1 and HZ32-2-1 in the southwestern region, i.e., 2465 and 2353 J/kg, respectively. This distribution pattern indicates that hydrocarbon migration was initially from the northeast to the southwest, followed locally with migration from the northwest to the southeast (Fig. 8).

Oil properties

Fluid properties are the outcome of a series of geological processes that hydrocarbons have experienced since their generation. The processes of hydrocarbon generation, migration, accumulation, degradation, and dispersion can all change oil properties (Pang et al. 2013; Chen et al. 2013). Because most of the hydrocarbons in the reservoirs were injected on one side, along the principal direction of migration, it can be inferred that crude oil composition changes with the gradient (Hwang et al. 1994; Lin and Zhang 1996). Relatively high-maturity oil (usually with low density) resides in traps near source rocks, whereas maturity decreases in traps away from source rocks. This is because traps filled by petroleum of lower maturity can be displaced via fill and spill as petroleum migrates from higher-maturity source rocks (Fustic et al. 2012).

The crude oil in the Zhujiang reservoirs in the Huixi half-graben is primarily light crude, with density and viscosity values of 0.80–0.91 g/cm³ and 2.20–107.00 mPa·s, respectively (Table 4). Oil from wells HZ21-1-1 and HZ25-8-1 in the northeastern region had relatively low density, i.e. 0.80 and 0.82 g/cm³, respectively. Conversely, the density was relatively high in wells XJ30-2-1X and HZ32-2-1 in the southwestern region, with values of 0.90 and 0.89 g/cm³, respectively. The same pattern was also observed for oil viscosity. From northeast to southwest, the oil densities and viscosities increased gradually (Fig. 9). At the same time, crude oil in the northeast region had a relatively high gas/oil ratio, whereas in the southwestern region, the ratio was relatively low. As the maturity of source rocks increases, the composition of the migrating oil changes because relatively high-maturity oil with low density will migrate into traps near source rocks, where the early low-maturity oil will be displaced

via fill and spill. Mature oil and gas generated in the late stage continually push oil and gas generated in the early stage, causing it to migrate away. This results in the oil and gas in traps near the source rock having a higher maturity and lower density and viscosity. Along the migration direction, the maturity of petroleum decreases, while the density increases. This result is similar to the oil distribution pattern in the McMurray Formation, Alberta Basin (Fustic et al. 2012).

In addition, the abundant contents of n-alkanes and 4-methyl sterane in oil samples (Fig. 10) indicate that the oils in the Zhujiang Formation were not subject to biodegradation. This is evident because n-alkanes and steranes are the most vulnerable compounds during biodegradation (Peters and Moldowan 1993). For the Pearl River Mouth Basin, there was only one pool-forming stage. For the two main source rocks (Wenchang Formation and Enping Formation), the generation and migration period started in 16–10 Ma and the subsequent peak expulsion period was reached gradually (at 10–5 Ma). The structure of the study area tended to be stable after the Dongsha movement (about 10 Ma), which was favorable for petroleum accumulation and preservation (Shi et al. 2014). Therefore, the oil distribution pattern should not be affected by biodegradation or later tectonic movement. It is believed that petroleum fill and spill charging led to this pattern and that lateral petroleum migration occurred from northeast to southwest.

Discussion

The primary control on the dominant pathways of secondary petroleum migration is a matter of debate in petroleum geology. Many geologists hold the view that petroleum migration pathways are controlled largely by structural morphology (Gussow 1968; Momper and Williams 1984;

Tissot and Welte 1984; Pratsch 1983, 1986, 1988, 1994; Welte et al. 2000; Hao et al. 2007, 2009).

The reservoirs discovered in the Huixi half-graben are mainly structural reservoirs (Fig. 2). In the Huixi half-graben, all hydrocarbon reservoirs discovered so far in the Zhujiang Formation occur on structural ridges. By assessing the relationships between the relative distance from reservoirs to structural ridges and hydrocarbon reserves (relative distance = absolute distance/the distance between the boundary and vertices of structural ridges) (Fig. 11), we can see that hydrocarbon reserves decrease with increasing relative distance. Moreover, the reservoirs that have been found are all distributed within the area for which the relative distance is less than 1. These data indicate that lateral hydrocarbon migration is controlled by structural morphology. This is because under hydrostatic conditions, such as those in the Huixi half-graben, the driving force for secondary petroleum migration is buoyancy and the restraining force is capillary pressure, which is largely controlled by permeability (e.g., Schowalter 1979; England et al. 1987; England 1994; Hindle 1997; Bekele et al. 1999, 2002). As a result of the Dongsha movement during the middle Miocene, the Zhujiang Formation has relatively large dip angles, with a relative peak in the southwest (Fig. 8b). The variation in buoyancy components in different potential migration directions is much more significant than capillary pressure.

Despite the importance of structural ridges (low-fluid-potential areas) and buoyancy driving forces, the carrier bed (connected sandstone) is an essential factor for hydrocarbon migration because it provides specific pathways during the migration process. The stable and wide distribution of beach sand, coastal sand dam, and shoreface sand in the shoreland facies, in combination with marine shale, formed excellent reservoir sealing assemblages in the upper member of the Zhujiang Formation. These are favorable for lateral hydrocarbon migration and

accumulation (Fig. 12). The distributary channel sand and mouth-bar sand of the delta facies in the lower member are more likely to be sealed by large-scale non-reservoir depositional elements such as mud plug deposits. In addition, simulation experiments (Dembicki and Anderson 1989; Catalan et al. 1992; Thomas and Clouse 1995), migration modeling (Sylta 1991; Hindle 1997; Hantschel et al. 2000), and field observations in geological basins (Miles 1990; Terken and Frewin 2000; Terken et al. 2001) have all suggested that hydrocarbons move through only a small portion of the carrier rock during lateral migration (Hindle 1997). The hydrocarbons migrate through probably less than 10% of the cross-sectional area that contains high porosity and permeability (England et al. 1987). Hydrocarbons preferentially migrate in finite carrier beds with good porosity and permeability (Miles 1990; Chen et al. 2013). The Zhujiang Formation in the Huixi half-graben contains two sandstone-bearing units: the upper member and lower member. The porosity and permeability of the upper member are higher than those of the lower member. Despite the sandstone content and thickness being smaller than those of the lower member, the upper member contains in excess of 60% of the hydrocarbon reserves discovered so far, indicating that the secondary hydrocarbon migration in this area was determined by the sandstone connectivity and physical properties (porosity and permeability) of the carrier beds.

In general, the hydrocarbons of the Zhujiang Formation in the Huixi half-graben mainly migrated along the structural ridges through sandstone beds with good connectivity and physical properties (relatively high porosity and permeability). Structural ridges act as low fluid potential areas, buoyancy provides driving forces, and the good connectivity and physical properties of sandstone provide specific migration pathways. The findings in this paper suggest that the hydrocarbons of the Zhujiang Formation in the Huixi half-graben were derived from the Eocene

Wenchang Formation and Eocene–Oligocene Enping Formation source rocks in the Huizhou Sag and migrated laterally from northeast to southwest. However, the distance from the Wenchang and Enping Formations to the Zhujiang Formation is hundreds to thousands of meters, indicating that faults in this area have played a vital role in connecting source and reservoir rocks as the main channel for vertical hydrocarbon migration (Fig. 12). In addition, the thin sandstone beds in the upper member of the Zhujiang Formation, which have stable and wide distribution and superior physical properties (porosity and permeability), are favorable for lateral hydrocarbon migration and accumulation.

Conclusion

From analysis of the geological conditions and integration of geological, fluid potential, oil property, and geochemical parameters, the following conclusions on secondary hydrocarbon migration in the Zhujiang Formation, Huixi half-graben, Pearl River Mouth Basin, can be obtained.

1. The hydrocarbons of the Zhujiang Formation in the Huixi half-graben were derived from Eocene Wenchang Formation and Eocene–Oligocene Enping Formation source rocks in the Huizhou Sag. The hydrocarbons migrated laterally from northeast to southwest.
2. Thin sandstone beds with stable and wide distribution in the upper member of the Zhujiang Formation are more favorable for lateral hydrocarbon migration compared with large thicknesses, but there is limited sandstone distribution in the lower member of the Zhujiang Formation.
3. From analysis of the rocks, the porosity and permeability of the upper member of the Zhujiang Formation were observed to be better than those of the lower member. The high-porosity

and high-permeability thin sandstone beds in the upper member of the Zhujiang Formation were the main carrier beds for the lateral migration of hydrocarbons.

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Table 1 Thickness and sandstone content of the Zhujiang Formation

Well	Member	Thickness of strata (m)	Thickness of sandstone(m)	Thickness of mudstone(m)	Percentage of sandstone(%)
HZ21-1-1	upper	244	41	203	17
	lower	506	283	223	56
HZ26-1-1	upper	222	49	173	22
	lower	87	37	50	43
HZ25-4-1	upper	348	80	268	23
	lower	476	233	243	49
HZ25-8-1	upper	652	209	443	32
	lower	275	129	146	47
HZ32-2-1	upper	305	46	259	15
	lower	277	116	161	42
HZ32-3-1	upper	261	60	201	23
	lower	123	53	70	43
HZ33-1-1	upper	244	46	198	19
	lower	230	101	129	44
XJ24-1-1	upper	355	117	238	33
	lower	482	299	183	62
XJ24-3-1	upper	374	157	217	42
	lower	520	281	239	54
XJ30-2-1	upper	376	117	259	31
	lower	545	273	272	50

Table 2 Geochemical properties of the source rocks in the Huixi half-graben

Stratum	TOC (%)	HI (mg/g)	S ₁ +S ₂ (mg/g)	R _o (%)
Enping	0.5-9.82	44-729.7	0.2-208.24	0.45-1.04
Formation	2.03/(489)	179.31/(268)	11.83/(481)	(85)
Wenchang	0.5-7.55	71-704	0.04-87.35	0.46-0.93
Formation	1.69/(195)	322.86/(123)	11.37/(310)	(32)

*In the table, $\frac{0.5-9.82}{2.03/(489)}$ is $\frac{\text{minimum-maximum}}{\text{mean}/(\text{sample number})}$, and samples in which the TOC value is below the lower limit for hydrocarbon source rocks (0.5%) are not included. The value of R_o varies with depth, so the average values are not shown.

Table 3 Oil geochemical properties of the Zhujiang Formation in the Huixi half-graben

Well	Depth (m)	Oil-bearing interval thickness (m)	Stratig- raphic 1	$\delta^{13}\text{C}(\text{‰})^2$	Pr/Ph	%C ₂₇ $\alpha\alpha$ αS	%C ₂₈ $\alpha\alpha$ αS	%C ₂₉ $\alpha\alpha$ αS	T/C ₃₀ H	C ₁₉ /C ₂₃ TT	C _{30,4-M} S/C ₂₉ S
XJ24-1-1X	2674-2681.5	7.5	U	-28.4	2.84	27.07	20.35	52.58	1.02	1.02	1.07
HZ21-1-1	2850-2856	6	U	-27.96	4.11	25.28	23.07	51.65	0.96	2.88	1.09
HZ25-4-1	2228.5-2230	1.5	U	-25.15	1.96	27.24	36.5	36.26	0.4	0.45	0.67
HZ25-8-1	2528.3	< 1	L	—	2.57	29.14	16.63	54.23	0.32	0.19	0.34
HZ26-1-1	2307-2312	5	L	-26.92	2.56	30.85	18.28	50.86	0.79	0.64	1.85
HZ26-1-1	2025-2029.5	4.5	U	-26.7	2.69	34.66	14.66	50.68	0.25	0.39	1.90
HZ27-1-1	2230-2240	10	U	-27.42	2.59	33.42	25.2	41.38	0.63	0.62	1.62

¹U, upper member of Zhujiang Formation; L, lower member of Zhujiang Formation.

²—, no analytical data.

Table 4 Oil properties of the Zhujiang reservoirs in the Huixi half-graben

Well	Depth (m)	Density (g/cm ³)	Kinematic viscosity(50℃) (mPa/s)
XJ24-1-1X	2543-2558	0.83	5.90
XJ23-1-1X	1753.5-1760	0.91	103.05
XJ30-2-1X	2242	0.90	107.00
XJ24-3-1AX	1904-1912	0.89	32.16
HZ21-1-1	2850-2856	0.80	2.20
HZ26-1-1	2019-2029	0.87	2.50
HZ26-2-1A	2324-2331	0.83	12.5
HZ25-4-1	2234.9	0.82	4.80
HZ25-8-1	2181.5-2185.5	0.87	37.01
HZ32-2-1	2387-2401.8	0.89	40.15

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Fig. 1 (a) Location of the Zhu I Depression in the Pearl River Mouth Basin. (b) Location of the Huixi half-graben in the Zhu I Depression. (c) Geological structures and distribution of hydrocarbon reservoirs in the Zhujiang Formation in the Huixi half-graben.

Fig. 2 Cross-section of the Huixi half-graben (section position is shown in Fig. 1)

Fig. 3 Stratigraphic column of the Huixi half-graben.

Fig. 4 Histogram showing percentage of sandstone in the lower and upper members of the Zhujiang Formation.

Fig. 5 Histogram showing sandstone thickness of the lower and upper members of the Zhujiang Formation.

Fig. 6 Variation in measured porosity (a) and permeability (b) with depth for sandstones from the Zhujiang Formation in the Huixi half-graben.

Fig. 7 Plot showing the relation between $C_{29}\alpha\beta/\sum C_{29}$ and $C_{29}20S/(20S+20R)$

Fig. 8 Hydrocarbon migration analysis using fluid potential distribution features in the Zhujiang Formation in the Huixi half-graben, Pearl River Mouth Basin. (a) Location of the Huizhou Sag and study area. (b) Structural contour map for the top of the Zhujiang Formation, showing the accumulation unit division in the Zhu I Depression. Accumulation unit: I = Huixi area; II = Huizhong area; III = Huilu area; IV = Huinan area. (c) Fluid potential distribution features in the Zhujiang Formation in the Huixi half-graben.

Fig. 9 Oil density contour map in the Zhujiang Formation in the Huixi half-graben.

Fig. 10 Representative saturated gas chromatography and mass chromatograms (m/z 217).

Fig. 11 Relation between the distance from structural ridges and hydrocarbon reserves.

Fig. 12 Hydrocarbon migration and accumulation model of the Zhujiang Formation in the Huixi

half-graben, Pearl River Mouth Basin (section position is shown in Fig. 1).

Draft

Fig. 1 (a) Location of the Zhu I Depression in the Pearl River Mouth Basin. (b) Location of the Huixi half-graben in the Zhu I Depression. (c) Geological structures and distribution of hydrocarbon reservoirs in the Zhujiang Formation in the Huixi half-graben. Oil reservoirs in HZ26-2-1A, XJ24-1-1, XJ24-3-1, and XJ30-2-1 wells are from the upper member of Zhujiang Formation, and the remaining oil reservoirs are from both upper and lower members of Zhujiang Formation.

Fig. 2 Cross-section of the Huixi half-graben (The section position is shown in Fig. 1). E_2w , Wenchang Formation; E_{2-3e} , Enping Formation; E_3z , Zhuhai Formation; N_1Z^1 , the lower member of Zhujiang Formation; N_1Z^2 , the upper member of Zhujiang Formation; N_1h , Hanjiang Formation.

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Draft

Fig. 5 Histogram showing sandstone thickness of the lower and upper members of the Zhujiang Formation.

Fig. 6 Variation in measured porosity (a) and permeability (b) with depth for sandstones from the Zhujiang Formation in the Huixi half-graben. Sandstone samples from 14 wells in Fig. 1.

Fig. 7 Plot showing the relation between $C_{29}\alpha\beta/\Sigma C_{29}$ and $C_{29}20S/(20S + 20R)$.

Fig. 8. Hydrocarbon migration analysis using fluid potential distribution features in the Zhujiang

Formation in the Huixi half-graben, Pearl River Mouth Basin. (a) Location of the Huizhou Sag and study area. (b) Structural contour map for the top of the Zhujiang Formation, showing the accumulation unit division in the Zhu I Depression. Accumulation unit: I = Huixi area; II = Huizhong area; III = Huilu area; IV = Huinan area. (c) Fluid potential distribution features in the Zhujiang Formation in the Huixi half-graben.

Draft

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Draft

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175x206mm (300 x 300 DPI)

Fig. 2 Cross-section of the Huixi half-graben (The section position is shown in Fig. 1). E_{2w}, Wenchang Formation; E_{2-3e}, Enping Formation; E_{3z}, Zhuhai Formation; N_{1Z}¹, the lower member of Zhujiang Formation; N_{1Z}², the upper member of Zhujiang Formation; N_{1h}, Hanjiang Formation.
73x46mm (300 x 300 DPI)

Fig. 3 Stratigraphic column of the Huixi half-graben.
198x248mm (300 x 300 DPI)

Fig. 4 Histogram showing percentage of sandstone in the lower and upper members of the Zhujiang Formation.

Fig. 5 Histogram showing sandstone thickness of the lower and upper members of the Zhujiang Formation.

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Fig. 6 Variation in measured porosity (a) and permeability (b) with depth for sandstones from the Zhujiang Formation in the Huixi half-graben. Sandstone samples from 14 wells in Fig. 1.
69x42mm (300 x 300 DPI)

Fig. 7 Plot showing the relation between $C_{29}\alpha\beta/\Sigma C_{29}$ and $C_{29}20S/(20S + 20R)$.

Fig. 9 Oil density contour map in the Zhujiang Formation in the Huixi half-graben.
206x166mm (300 x 300 DPI)

Fig. 10 Representative saturated gas chromatography and mass chromatograms (m/z 217).
76x37mm (300 x 300 DPI)

Fig. 11 Relation between the distance from structural ridges and hydrocarbon reserves.

Fig. 12 Hydrocarbon migration and accumulation model of Zhujiang Formation in the Huixi half-graben, Pearl River Mouth Basin (The section position is shown in Fig. 1). E₂w, Wenchang Formation; E₂₋₃e, Enping Formation; E₃z, Zhuhai Formation; N₁Z¹, the lower member of Zhujiang Formation; N₁Z², the upper member of Zhujiang Formation; N₁h, Hanjiang Formation.