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Origin and Accumulation Mechanism of Gas Condensate in Kailashtila Gas Field, Sylhet Basin, Bangladesh

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Abstract: The Kailashtila gas field (KGF) is situated in the northeastern part of Sylhet basin, Bangladesh. This paper presents chemical characteristics of extractable natural gas in drilled well KTL-2, in order to examine their potential source and maturity of organic matter, and hydrocarbon accumulation mechanism in the basin. The gas condensate in the KTL-2 composed primarily of methane (85.81 wt.%), ethane (6.68 wt.%), propane (2.13 wt.%), and traces of higher hydrocarbons (i-butane, 0.69 wt.%; n-butane, 0.73 wt.%; i-pentane, 0.50 wt.%; n-pentane, 0.44 wt.%; hexane, 1.27 wt.%; heptane, 0.99 wt.%; octane, 0.24 wt.%). Nitrogen and CO_2 contents in the gas condensate are low (0.46 wt.% and 0.05 wt.%, respectively). Average dry coefficient ($C_1/C_{1–5}$) value in the gas condensate is 0.93 (0.91–0.95), which reflects relatively mature hydrocarbon migrating from nearby deeply buried source rocks. The $\delta^{13}C_1$ (–39 to –40‰) and $C_1/C_{(2+3)}$ (19.77) variation diagram show that gas condensate in the KGF is mainly controlled by type III kerogen, and the organic matter was thermally mature in nature. However, the relationships between stable isotope value of methane ($\delta^{13}C_1$), ethane ($\delta^{13}C_2$) and propane ($\delta^{13}C_3$) indicate mainly thermogenic origin of the studied gas condensate, and minor input from mixed thermogenic and bacteriogenic processes.

Keywords: Chemical composition; source and maturity; natural gas condensate; Kailashtila gas field; Sylhet basin; Bangladesh.

Introduction

The Bengal Basin of Bangladesh is geographically positioned towards the northeastern vicinity of Indian subcontinent (Fig. 1). It is bordered to the west, north and easternmost part by India (West Bengal, Assam and Tripura, respectively), and only a small portion by Myanmar to the southeast. This basin covers an onshore area of 144,000 km^2 and offshore area of 63,000 km^2 (Curiale et al., 2002). The Bengal Basin initiated among the continental collisions of India, Eurasia and Myanmar plates, developing the extensive Himalaya-Tibetan Plateau towards north and the Indo-Burman (Myanmar) Ranges to the east (Fig. 1). This basin extends from 20°34' to 26°38' N latitude and 88°01' to 92°41' E longitude (Hossain et al., 2013). The Bengal Basin comprises approximately 22 km thick clastic sediments (Alam et al., 2003; Hossain et al., 2009a, 2010), which contains enormous volume of terrestrial-derived organic matter. This organic matter is important for generation of hydrocarbons in the Bengal territory.

The Sylhet basin is situated in northeastern part of the Bengal Basin (Fig. 1), consisting of a thick pile of sedimentary rocks mostly sandstone, mudstone/shale, siltstone and small carbonate (Alam et al., 2003; Hossain et al., 2009a; Rahman et al., 2009). There are several gas fields (Kailashtila, Rashidpur, and Beanibazar) and one oil field (Haripur) present in this basin (Fig. 1). Kailashtila gas field (KGF) is a giant natural gas field in Bangladesh, and it has been discovered since 1962 by Shell Oil Company of Pakistan. The KGF is located in the northeastern edge of the Sylhet structure. Current production of gas condensate in this gas field is approximately 65.2 MMscfd (Annual Report, 2017). Three main hydrocarbon zones (e.g. upper gas sand, middle gas sand and lower gas sand) were identified in the Kailashtila succession within the depth between ~2280 and 3045 m. These gas-bearing zones were encountered within the Surma Group of Mio-Pliocene in age (Shah and Hossain, 2015).

The northeastern province of Bangladesh is important for petroleum geoscientists worldwide due to many hydrocarbon exploration wells (e.g., Rasidpur, Fenchuganj, Kailashtila, Atgram, Beani bazar, Patharia) are located there (Hossain et al., 2009a, b). Numerous authors have investigated Tertiary sedimentary rocks in northeastern part of Bangladesh from differing viewpoints (Alam, M., 1989; Ahmed et al., 1991; Johnson and Alam, 1991; Shamsuddin and Abdullah, 1997; Alam et al., 2003; Rahman and Faupl, 2003; Najman et al., 2008; Hossain et al., 2009a, b, 2010, 2013; Rahman et al., 2009; Shah and Hossain, 2015; Islam et al., 2017). However, there are no scientific works published in the KGF based on chemical composition of gas condensate to date. In the present study, we use geochemical records of gas

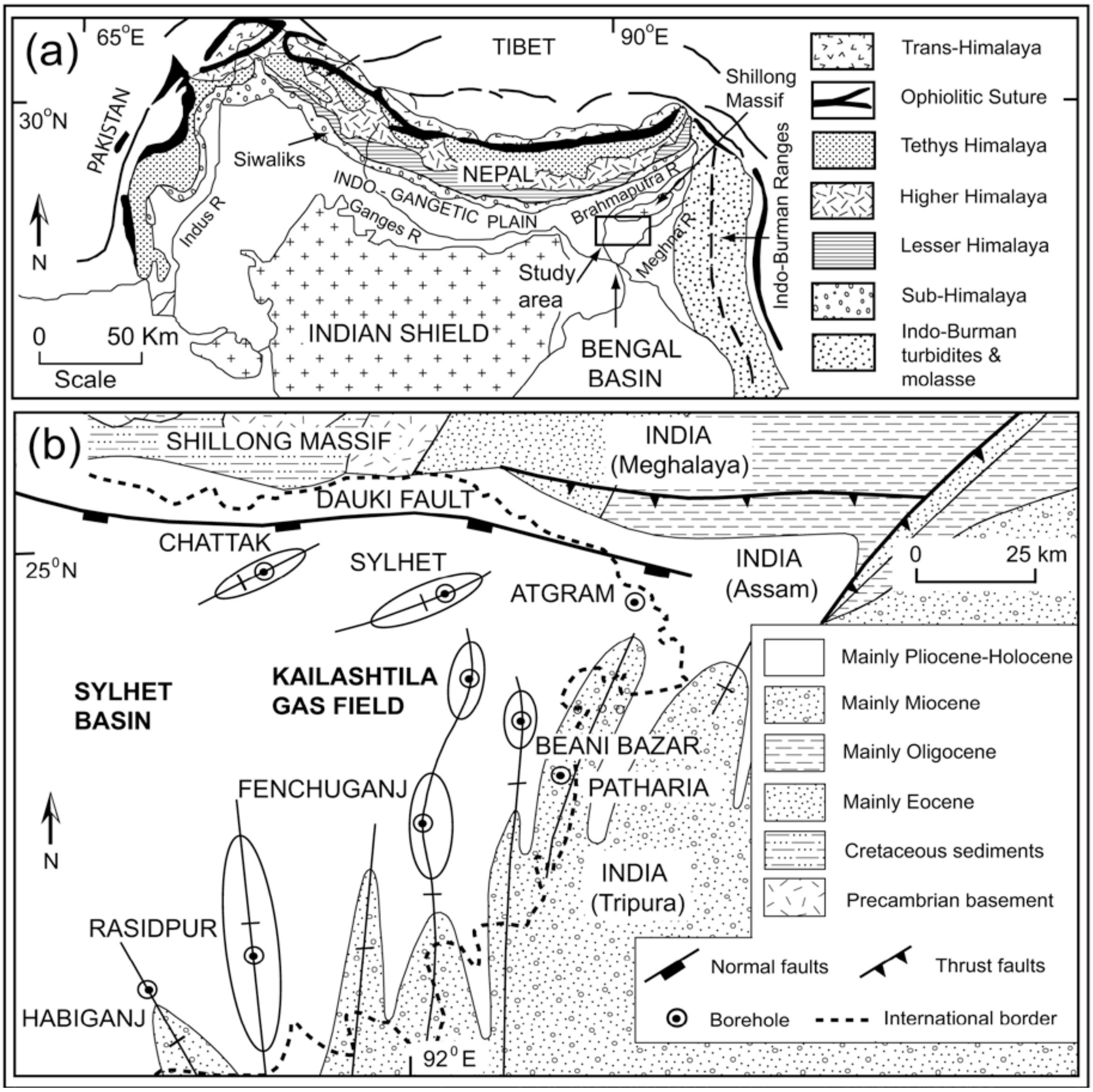

Fig. 1 (a) Map of the Bengal Basin and adjoining areas, showing major lithotectonic units of the Himalaya (after Uddin and Lundberg, 1998), (b) Map showing major geographic features (after Hiller and Elahi, 1984) in the Sylhet basin and locations of main hydrocarbon exploration wells drilled in the Sylhet basin together studied Kailashtila gas field (Hossain et al., 2009a).

condensate of KGF in order to infer source, kerogen type, thermal maturity of organic matter, and hydrocarbon accumulation mechanism in the Kailashtila basin, Bangladesh.

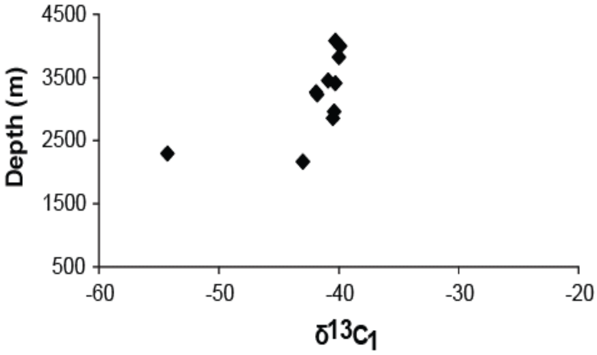

Fig. 2 Depth vs carbon isotope value of methane ($\delta^{13}C_1$) in total gas fields of Bangladesh (data taken from Curiale et al., 2002).

Geological Settings

The Bengal Basin forms the typical river-dominated delta in the globe, which is prominent for its huge volume of sedimentary deposit of Tertiary to Recent in age (Alam et al., 2003; Hossain et al., 2010; Shah and Hossain, 2015). It is trace ocean basin, which formed due to north-west contemporaneous drifting and diagonal collision of Indian plate with the Tibetan and Burmese plates (Ingersoll et al., 1995, Alam et al., 2003). This diagonal subduction dynamic was made due to the west-direction movement of accretionary blocks (Dasgupta and Nandy, 1995; Alam et al., 2003; Hossain et al., 2010). According to geological settings, the whole basin is divided into three different provinces namely the Stable Shelf (Province I), the Central Deep Basin (Province II), and the Chittagong-Tripura Fold Belt (Province III) (Alam et al., 2003). The Bengal Basin is bounded on the west and east by the Indian Shield and Indo-Burman Ranges, respectively, in the north by the Shillong Plateau and it extends southward into the Bay of Bengal (Hossain et al., 2010).

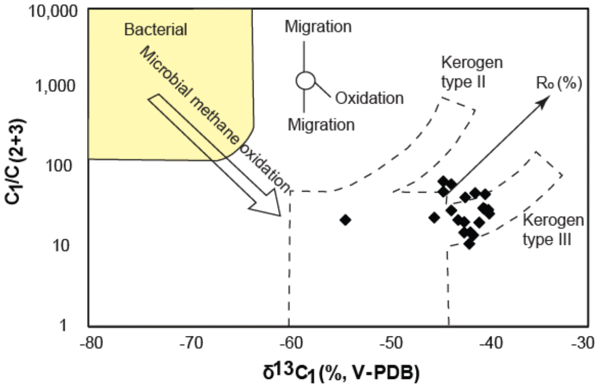

Fig. 3 Relationship between $\delta^{13}C_1$ and $C_1/(C_2+C_3)$ (modified after Bernard et al., 1978; Whiticar, 1999; Moritz et al., 2015; Faramawy et al., 2016) in total gas fields of Bangladesh (data taken from Curiale et al., 2002).

Stratigraphically, the sedimentary sequence in the Sylhet basin is subdivided into the Paleocene to late Eocene Jaintia Group, late Eocene to early Miocene Barail Group, middle to late Miocene Surma Group, late Miocene to Pliocene Tipam Group, Pliocene to Pleistocene Dupi Tila Group, and late Pleistocene Dihing Group, in ascending order (Table 1). The Jaintia Group is further subdivided into the basal Tura Sandstone, middle Sylhet Limestone and upper Kopili Shale Formations (Table 1). The basal Tura Sandstone Formation consists primarily of sandstones, minor mudstone/shale, and limestone. This Formation has been accumulated in marine environmental conditions (Khan, 1991; Najman et al., 2008; Hossain et al., 2009a, 2010). The conformably overlying Sylhet Limestone Formation comprises chiefly of fossiliferous limestone and thin bedded sandstone, subsequently deposited in shallow marine environment (Reimann, 1993; Shamsuddin and Abdullah, 1997). The upper Kopili Shale Formation contains typically of fossiliferous limestone, shale and sandstone. The upper and lower contact is unconformable. This formation was deposited in open marine condition (Reimann, 1993; Alam et al., 2003).

The Barail Group consists predominantly of sandstone, shale, and siltstone. This group is again subdivided into the lower Jenam and the upper Renji formations. The Jenam Formation consists typically of shale, whereas Renji Formation consists predominantly of sandstone, siltstone and shale (Hossain et al., 2009a). The upper contact is erosional. The Barail Group was accumulated in shallow marine to deltaic conditions (Johnson and Alam, 1991; Najman et al., 2008; Hossain et al., 2013).

The Surma Group overlies the Barail Group and it contains sandstone, siltstone and mudstone. This Group is further subdivided into the lower Bhuban (mostly arenaceous) and upper Boka Bil formations (mainly argillaceous). The Surma Group was deposited in deltaic to marine conditions (Shamsuddin and Abdullah, 1997; Hossain et al., 2009a; Rahman et al., 2009).

Table 1. Stratigraphy of the Sylhet basin, Bangladesh (modified after Johnson and Alam, 1991; Khan, 1991; Reimann, 1993; Najman et al., 2008; Hossain et al., 2009a, 2010).

Age	Group	Formation	Lithology	Depositional Environment
Recent	Alluvium	Alluvium	Sand, silt, clay	Fluvial
Late Pleistocene	Dihing	Dihing	Sandstone, shale	Fluvial
Pliocene–Pleistocene	Dupi Tila	Dupi Tila	Sandstone, shale	Fluvial
Late Miocene–Pliocene	Tipam	Girujan Clay	Clay, sandstone	Fluvial, lacustrine
		Tipam Sandstone	Sandstone, shale	Fluvial
Middle–Late Miocene	Surma	Boka Bil	Sandstone, shale	Marine, deltaic
		Bhuban	Sandstone, shale	
Late Eocene–Early Miocene	Barail	Renji	Sandstone, shale	Shallow marine, deltaic
		Jenam	Shale, sandstone	
Late Eocene	Jaintia	Kopili Shale	Shale, minor lst.	Shallow marine, deltaic
Early–Middle Eocene		Sylhet Limestone	Limestone	Shallow marine
Paleocene–Early Eocene		Tura Sandstone	Quartz arenites	Shallow marine

The Tipam Group is subdivided into the Tipam Sandstone and the Girujan Clay Formation, in ascending order (Khan, 1991; Reimann, 1993; Hossain et al., 2009a). The lower Tipam Sandstone Formation consists largely of medium to very fine grained sandstone with inter-bedded siltstone. The unconformably overlying Girujan Clay Formation composed entirely of claystone, subsequently developed in lacustrine, flood plain and overbank settings (Reimann, 1993; Hossain et al., 2010). Lower and upper contact of the Girujan Clay Formation is erosional.

Table 2. Molecular composition of gas condensate samples from the Kailashtila gas field, Sylhet basin, Bangladesh.

Well no	Component	S1 - 2010 (mole %)	S2 - 2007 (mole %)
KTL – 2	Nitrogen (N_2)	0.286	0.2025
KTL – 2	Carbon dioxide (CO_2)	0.021	0.0535
KTL – 2	Methane	93.808	90.6707
KTL – 2	Ethane	3.898	2.3447
KTL – 2	Propane	0.846	2.0909
KTL – 2	i-Butane	0.208	1.0963
KTL – 2	n-Butane	0.221	1.085
KTL – 2	i-Pentane	0.123	1.2271
KTL – 2	n-Pentane	0.108	1.0639
KTL – 2	Hexane	0.265	0.0774
KTL – 2	Heptane	0.179	0.0881
KTL – 2	Octane	0.037	0
KTL – 2	Nonane	0	0
KTL – 2	Decane	0	0
	Dry coefficient (C_1/C_{1-5})	0.946	0.911

The Dupi Tila Group conformably overlies the Tipam Group, which comprises typically of sandstone, minor siltstone and shale (Johnson and Alam, 1991, Hossain et al., 2009a). The upper contact of the Dupi Tila Group is erosional. The Dihing Group conformably overlies the Dupi Tila Group, which comprises predominantly of boulder and pebble beds, with interbedded sandstone and siltstone, subsequently accumulated in piedmont fluvial settings (Johnson and Alam, 1991; Khan, 1991; Najman et al., 2008; Hossain et al., 2010). The upper contact is erosional. The topmost part of the Sylhet stratigraphic sequence is covered by recent alluvium, which is composed primarily of sand, silt, and clay.

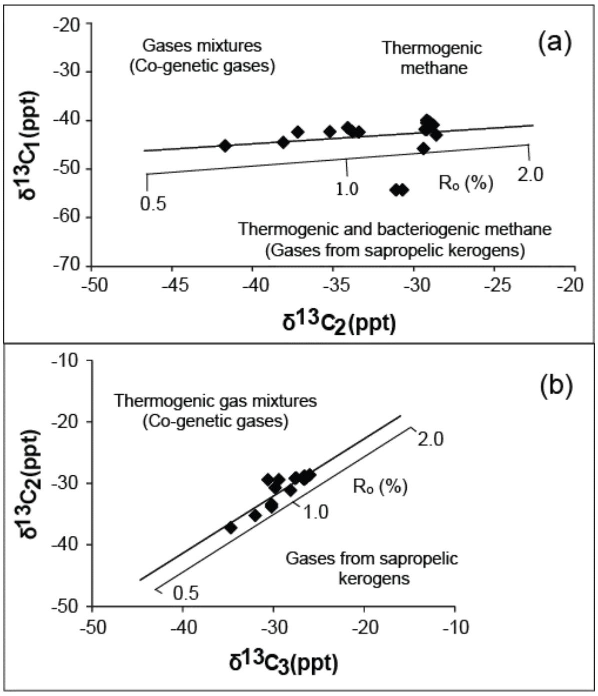

Fig. 4. Identification and differentiate gas mixture through carbon isotope ratios of methane ($\delta^{13}C_1$), ethane ($\delta^{13}C_2$) and propane ($\delta^{13}C_3$) in all gas fields of Bangladesh (modify after Faber, 1987; data taken from Curiale et al., 2002).

Materials and Methods

Sampling

Samples were collected from KTL-2 of KGF, Sylhet basin, Bangladesh (Fig. 1). These samples were taken from Well-Head Gas, Inlet Separator, and Inlet Separator (out let) of Molecular Sieve Turbo-expander (MSTE) Plant at 82 bar pressure.

Geochemical Analysis

Measurement of gas condensate molecular compositional data for the collected samples of KGF in Sylhet basin, Bangladesh are listed in Table 2. Analysis of gas condensate samples was conducted in geochemical laboratories at BAPEX (Bangladesh Petroleum Exploration and Production Company) and BUET (Bangladesh University of Engineering and Technology). Typical molecular compositions for the investigated gas condensate samples (in mol %) were taken from gas chromatography (GC) analysis. Isotope values of methane, ethane and propane in the present study were also taken from published literatures (Pairazian et al., 1985; Ahmed et al., 1991; Shamsuddin and Khan, 1991; Curiale et al., 2002).

Results

Extractable natural gas condensate in KGF composed primarily of methane, ethane, propane, i-butane, n-butane, i-pentane, n-pentane, hexane, heptane, and octane (Table 2). Here i-butane, n-butane, i-pentane, n-pentane, hexane, heptane, and octane are higher hydrocarbons, and less amount of non-hydrocarbon gases such as nitrogen and carbon-dioxide (CO_2) are also present in the investigated gas condensate (Table 2).

Discussion

Chemical Composition

The gas condensate zones in the KGF are typically Miocene sandstones at a burial depth of ~2280 to 3045 m. The natural gas condensate samples from KGF are mainly composed of CH_4 (91–94%) with comparatively high $C_{2\text{-}5}$ (~4–9%) and low $C_{6\text{–}8}$ (0.2–0.5%) components, and low non-hydrocarbon gas contents (N_2 = 0.20–0.29% and CO_2 = 0.02–0.05%). The studied gas condensate samples contained relatively high dry coefficient values ($C_1/C_{1\text{–}5}$ = 0.91–0.95). These values represent hydrocarbons in the KGF were initiated from extremely buried organic matter in the deeper part of the basin.

Maturity and Origin of Gas Condensate in the KGF

The origin of natural gas condensate belongs to different kerogen types such as thermal cracking of kerogen type I–II in highly maturation level (R_o = 1.3–2.0%), terrestrial derived type III kerogen in early mature level (R_o = 0.4–0.6%) or mature phase (R_o = 0.6–1.3%), and process involving evaporative fractionation of crude oil (Tissot and Welte, 1984; Heting et al., 2017; Ratnayake et al., 2018). The vitrinite reflectance (R_o) and T_{max} values in the late Eocene to early Miocene Sylhet succession varies between 0.51–0.66% and ~435–445 °C, respectively (Hossain et al., 2009a). Methylphenanthrene index (MPI 3 = (1-MP+2MP)/(1-MP+9-MP)) ratio for the Barail and Jaintia Groups mudstones varied from ~0.43–0.98 and 0.49–0.85, respectively, therefore it suggested early mature to mature stages of the deposited organic matter (Hossain et al., 2009b; Ratnayake and Sampei, 2015). The Jaintia and Barail Groups were developed during these times, and TOC values (~0.50–1.56) are also high relative to other formations developed in the Sylhet succession (Table 1), and organic matter derived from terrestrial higher plants and significant portion of planktons (Hossain et al., 2009a). The high TOC corresponding to R_o and

T_{max} values match with terrestrial derived organic matter in early mature level (R_o = 0.4–0.6%; Tissot and Welte, 1984) suggesting that the studied gas condensate in the KGF probably originated from terrigenous origin. There is relatively higher hydrocarbon generation potential in the Jaintia and Barail Groups organic matter as suggested by Hossain et al. (2009a). Ahmed et al. (1991) documented that oil and condensate in the Surma Group, Sylhet basin are mature in nature (R_o = ~0.9%), which suggests land plants origin for the oils and condensates experienced in mature condition. However, oil and condensate from southern part of the Sylhet basin were originated from terrestrial higher plants under relatively less mature condition (R_o = 1.0–1.3%; Shamsuddin and Khan, 1991). Hossain et al. (2014) reported that oils from the northern and central parts of the Sylhet basin are experienced in mature condition (R_o = ~0.7%), and hydrocarbons were derived from terrigenous organic matter rich source rocks. This result is also supported by the study of organic matter in Sylhet succession (Hossain et al., 2009a) and suggested that oil and condensate in the northeastern Bengal Basin of Bangladesh was originated from the lowermost two Groups (e.g. Jaintia and Barail) sedimentary rocks of late Eocene to early Miocene time. Terrestrial vascular plants derived organic matter is rich in these groups of mudstones as revealed by high relative abundance of sterane C_{29} rather than C_{28} or C_{27} steranes (Hossain et al., 2009a; Farhaduzzaman et al., 2012). Therefore, high sterane $C_{29}/(C_{27–29})$ ratios in organic matter of the Sylhet succession are ascribed to be input from terrigenous sources (Hossain et al., 2009a). The aromatic biomarker such as methyl anthracene, pimanthrene (1,7-dimethylphenanthrene) and 1-methylphenanthrenes are much abundant in mudstones from the Jaintia and Barail Groups, which represent mainly higher plant origin of organic matter in the basin (Hossain et al., 2009b).

The carbon isotopic excursions of natural gas condensate are widely used to identify their origin and maturity (Baojia et al., 2012; Heting et al., 2017). The carbon isotope excursions of methane ($\delta^{13}C_1$) in KGF varied from –41 to –39‰, and δ^2H values of –200 to –150‰, suggesting thermogenic origin (Ahmed et al., 1991). Low $\delta^{13}C_1$ isotopic value of gas condensate is considered as lighter hydrocarbon, whereas high $\delta^{13}C_1$ value is mostly associated to isotopically heavier methane. The $\delta^{13}C_1$ isotope value of oil and condensate in the Sylhet structure is low (Ahmed et al., 1991), whereas isotope value of $\delta^{13}C_2$ and $\delta^{13}C_3$ is relatively high, typically ranging from –30 to –29 ‰ and –27 to –26‰, respectively.

The $\delta^{13}C_1$ values for several gas producing wells (Curiale et al., 2002) in eastern Bengal Basin were compared with burial depth (Fig. 2). This variation diagram suggests that increasing depth of burial of organic matter with increasing heavy $\delta^{13}C_1$ excursions (–41 to –40‰), and shallow depth samples contains more negative $\delta^{13}C_1$ values of –45 to –43‰. The high $\delta^{13}C_1$ value in greater depth samples indicating thermogenic origin, and shifting to positive excursion towards shallow depth reflect mixing of both thermogenic and biogenic gases (Pernaton et al., 1996; Curiale et al., 2002). The $\delta^{13}C_1$ value is more negative than –60‰ for bacterial gas and $\delta^{13}C_1$ value is less negative than –60‰ denote as thermogenic gas (Moritz et al., 2015; Faramaway et al., 2016), whereas $\delta^{13}C_1$ value of –50 to –60‰ for mixing of both bacteriogenic and thermogenic gases (Faramaway et al., 2016). The $\delta^{13}C_1$ excursions in the studied KGF well vary from –41 to –39‰, which signifies that gas condensate in the Sylhet succession was derived from thermogenic processes.

The $\delta^{13}C_1$ and $C_1/C_{(2+3)}$ variation diagram (Fig. 3) is commonly used as a proxy to identify thermal maturity of buried organic matter and kerogen type for gas generation (Bernard et al., 1978; Whiticar, 1999; Feng et al., 2016). Thermogenic gas has $C_1/C_{(2+3)}$ ratios fall between 10 and 100, whereas biogenic gas has $C_1/C_{(2+3)}$ ratios greater than 1000 (Claypool and Kvenvolden, 1983; Schoell, 1983; Whiticar, 1996; Curiale et al., 2002; Moritz et al., 2015). The $C_1/C_{(2+3)}$ ratio values for Sylhet basin samples vary from 10 to 95% (Curiale et al., 2002), and $C_1/C_{(2+3)}$ ratios of gas condensate in the studied KGF samples vary from 19.8 to 20.4% (Fig. 3). This feature suggests that gas condensate in the KGF and associated fields are typically derived from thermogenic processes. However, $\delta^{13}C_{org}$ excursions for C3 plants are ranging from –32 to –21‰ (average –27‰), whereas –17 to –9‰ (average –13‰) for C4 plant (Meyers, 1994; Ratnayake et al., 2017; Hossain et al., 2019). The $\delta^{13}C_{al}$ in the Sylhet basin samples varies from –29 to –24‰ and $\delta^{13}C_{al}$ values in the KGF samples range from –29 to –28‰ (Curiale et al., 2002), inferring that hydrocarbon in the KGF and northeastern Bengal Basin were input primarily from C3 plants. In $\delta^{13}C_1$ and $C_1/C_{(2+3)}$ variation diagram (Fig. 3), majority of the Sylhet basin samples were clustering near the type III kerogen field and a small number of samples plot position on the type II field, indicating that they were derived from mixed sources with dominating control of terrestrial higher plants. The organic matter in shales from the Sylhet succession is characterized by typically kerogen type III and minor kerogen type II inferring mainly land plant origin (Hossain et al., 2009a; Farhaduzzaman et al., 2012).

The stable isotope excursion of $\delta^{13}C_1$, $\delta^{13}C_2$ and $\delta^{13}C_3$ is used to identify gas mixture conditions of source either thermogenic or bacteriogenic gases (Stahl and Carey, 1975; Faber, 1987). The carbon isotope values of $\delta^{13}C_1$ and $\delta^{13}C_2$ for the Sylhet basin are plotted on schematic diagram (Fig. 4a; Faber, 1987). This bivariate plot shows that most of the samples are clustering over the maturation line and some are just below the line and two samples apart from maturation line with low $\delta^{13}C_1$ values, suggesting a dominant control by thermogenic process and minor contribution of gas condensate from mixed process. The bivariate plot between $\delta^{13}C_2$ and $\delta^{13}C_3$ (Fig. 4b; Faber, 1987) shows a pattern similar to $\delta^{13}C_1$ and $\delta^{13}C_2$ pattern (Fig. 4a), and majority of the samples fall on the maturation line. From the above features, we conclude that gas or gas condensate in the Sylhet basin, Bangladesh were typically originated from thermogenic process and small amount of gas or gas condensate from mixed origin i.e., thermogenic and bacteriogenic processes.

Accumulation Mechanism of Gas Condensate in the KGF

The Jaintia and Barail Groups (late Eocene to early Miocene) source rock can provide sufficient supply of gas condensate in the KGF. The late Eocene Kopili Shale Formation (upper Jaintia Group) contains relatively high TOC (up to 1.20 wt.%), abundant pristane and phytane, high thermal maturity (~445 °C) and vitrinite reflectance (0.66%) at a burial depth of >5000 m (Hossain et al., 2009a). Shale of this formation comprises primarily of humic kerogen resulting in generation of methane rich hydrocarbon. However, the overlying Oligocene Barail Group mudstone also contains high TOC (1.56 wt. %), high pristane/phytane ratio (~3), T_{max} (~443 °C) and vitrinite reflectance (0.59%) (Hossain et al., 2009a). Mudstone in this Group also contains higher terrestrial derived organic matter, with a burial depth of approximately 4800 m. The high TOC bearing Jaintia and Barail Group mudstones experienced in certain maturity conditions that have generated thermal gasses due to larger depth of burial, and migrating upward to charging hydrocarbon pools in the Miocene Surma Group. All oils or gas condensates in Bangladesh have been found in Miocene sandstone rich Bhuban Formation within the Surma Group (Hossain et al., 2009a, 2014). The examined gas condensate samples contained relatively high dry coefficient values (C_1/C_{1-5} = 0.91–0.95). This elevated dry coefficient ratio indicating mature condition and the hydrocarbon was migrating from deeply buried source rocks in and around the Sylhet basin.

Conclusion

Geochemical composition and biomarker parameters were conducted on gas condensate samples taken from KGF, Sylhet basin, Bangladesh in order to examine origin, maturity and accumulation mechanism of hydrocarbons in the Sylhet structure. Our main conclusions are as follows:

1. Gas condensate in KGF is composed predominantly of methane (85.81 wt.%), ethane (6.68 wt.%), propane (2.13 wt.%), and minor amounts of higher hydrocarbons (i-butane, 0.69 wt.%; n-butane, 0.73 wt.%; i-pentane, 0.50 wt.%; n-pentane, 0.44 wt.%; hexane, 1.27 wt.%; heptane, 0.99 wt.%; octane, 0.24 wt.%), and low amount of non-hydrocarbon components (N_2 = 0.46 and CO_2 = 0.05 wt.%).

2. The studied gas condensate show relatively high dry coefficients (0.91–0.95), indicating relatively mature gas originating from deeply buried source rocks.

3. The $\delta^{13}C_1$ and $C_1/C_{(2+3)}$ bivariate plot reveals that gas condensate in KGF hydrocarbon pools is mainly derived from type III kerogen.

4. Biomarker and $\delta^{13}C$ isotope record indicates that gas condensate in the studied basin was experienced in early mature to mature stage, which commenced largely from thermogenic processes and a small contribution from mixed processes.

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