

PRELIMINARY ASSESSMENT OF THE PETROLEUM SOURCE-ROCK
POTENTIAL OF UPPER EOCENE KOPILI SHALE, BENGAL BASIN,
BANGLADESH

by

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Abstract

The upper Eocene Kopili Shale occurs throughout the northern end of the Bengal Basin, including on the northwestern Indian Platform and in deeper basin areas (e.g., Sylhet Trough) of northeastern Bangladesh. The Kopili-equivalent mudrocks in India, interpreted as shallow-marine to lagoonal deposits, are hydrocarbon source rocks for the Sylhet-Kopili/Barail-Tipam composite petroleum system of Assam, India. In the current study, thin section petrography, organic petrologic analysis, XRD and XRF techniques, as well as field observations of the Kopili Shale were used to characterize this mudrock in various parts of Bangladesh. In addition, geochemical analyses such as TOC analysis, Rock-Eval pyrolysis, and vitrinite reflectance studies were used to assess organic richness, type, and thermal maturity of the Kopili Shale.

Petrographic thin section analyses reveal localized skeletal grains (e.g., foraminifera), bioturbate fabrics, pyrite framboids, sand lenses and flame structures, suggesting deposition in shallow marine environments characterized by at least periodically oxygenated bottom waters and sulfidic pore waters. XRD and XRF results reveal high quartz content in silt-rich Kopili Shale.

Organic petrologic observations and limited reliable Rock-Eval pyrolysis data indicate that organic matter in the Kopili Shale is largely terrestrial, including an admixture of type II (liptodetrinite, cutinite, bituminite), type III (vitrodetrinite), and type IV (inertodetrinite) macerals. Mean vitrinite reflectance values ($R_o = 0.86-1.32\%$) and a single reliable T_{max} value (433°C) indicate that organic matter from all sampled sections

are thermally mature. However, mean total organic carbon (TOC) contents for samples from the northwestern core sections and two of three northeastern outcrop sections are generally low (<0.6%) and, thus, reflect relatively poor hydrocarbon-source potential. As an exception, TOC values (mean = 1.0%) and Rock-Eval parameters (S2) for samples from the remaining outcrop section (Sripur section) suggest a somewhat higher potential.

Taken together, results indicate that the Kopili Shale of the Bengal Basin is a silty mudrock, deposited in a shallow marine environment, and has limited hydrocarbon source potential compared to presumed equivalent shales of the Kopili Formation in the Assam basin of India. Further studies are required to understand the variable source potential and migration pathways of the hydrocarbons generated from Paleogene mudrocks in the region.

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CHAPTER 1: INTRODUCTION

1.1 Introduction

Clay-rich, fine-grained rocks are by far the most important sediment type on Earth (Potter et al., 2005) accounting for over 60% of sedimentary strata. These mudstones and shales were deposited in a wide range of environments from fluvial to deep marine (Rine et al., 1985). Fine-grained rocks deposited under certain circumstances may contain large amounts of organic matter, making them potential source rocks for hydrocarbons.

The Kopili Shale in the Bengal Basin, Bangladesh, is a dark gray to black fossiliferous shale with subordinate marlstone beds. It is exposed at various localities on the northern margin of the Sylhet Trough in the northeastern part of the Bengal Basin, and also is encountered in the subsurface in the northwestern Indian Platform part of the basin (Figure 1). The depositional environment of the Kopili Shale has been interpreted as paralic (brackish-marshy) based on lithological and fossil content (Uddin and Ahmed, 1989; Reimann, 1993). However, detailed lithologic and petrographic work on the Kopili Shale has not yet been done.

Petroleum source rocks are evaluated by assessing the abundance (total organic carbon, or TOC), quality/type, and maturation state of organic matter using various geochemical techniques (Merrill et al., 1991). The current study focuses on the evaluation of petroleum source-rock potential of the Kopili Shale from Bengal Basin, Bangladesh. Previous workers (e.g., Alam, 1990; Shamsuddin et al., 2001) have proposed that the

Kopili Shale of Bangladesh may be an effective hydrocarbon source rock that charges known and as-yet-undiscovered Cenozoic reservoirs in the extensive Bengal Basin. The Kopili-equivalent shale in Assam, northeastern India, is a proven source-rock for both oil and gas in the well-defined Sylhet-Kopili/Barail-Tipam composite petroleum system of Assam, India (Wandrey, 2004). However, owing to limited deep well control and lack of petrologic data, the source-rock potential of the Kopili Shale in Bangladesh remains poorly known. To address this problem, we initiated geochemical and petrologic studies of organic matter in core and outcrop samples of the Kopili Shale derived from different parts of the Bengal Basin.

The objectives of this thesis are to: (1) characterize the Kopili Shale based on thin-section petrography, organic petrologic analysis, x-ray fluorescence (XRF) and x-ray diffraction (XRD); (2) evaluate the Kopili Shale as a hydrocarbon source-rock based on amount, types, and maturity of organic matter contained therein; and (3) compare the character and source potential of the Kopili Shale in the Bengal Basin with that of the equivalent Kopili Formation in Assam, India.

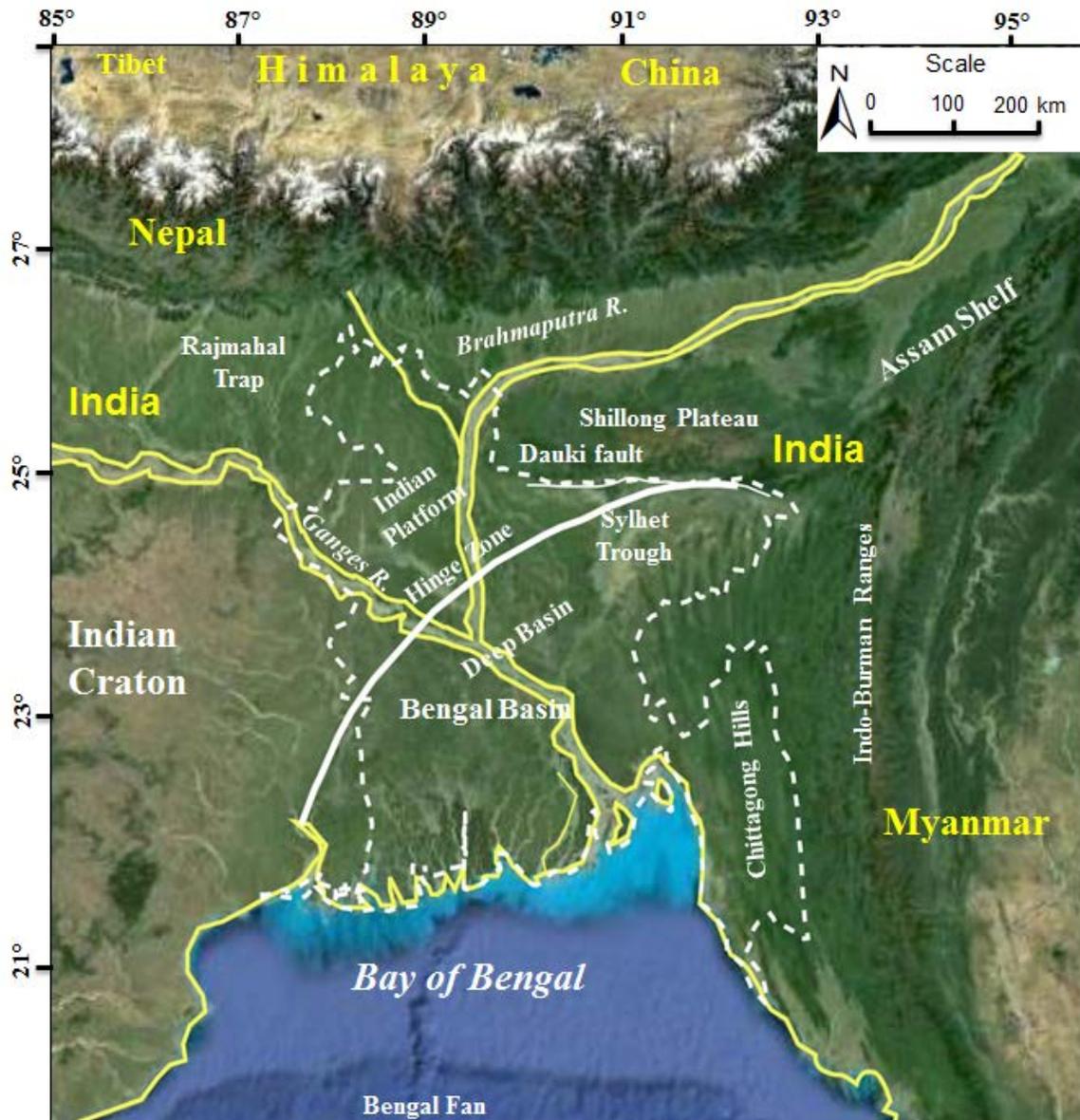


Figure 1: Location map of Bangladesh showing pertinent features of the Bengal Basin. The hinge zone that separates the stable shelf (Indian Platform) from the deep basin continues to the northeast as the Assam Shelf. Google Earth imagery © Google Inc., used with permission.

1.2 Geologic Setting and Depositional History of Bengal Basin

The location of the Bengal Basin is at the juncture of three interacting plates, viz., the Indian, Burma (Myanmar), and Tibetan (Eurasian) plates. The basin-fill history of these geotectonic provinces varied considerably. Precambrian crystalline basement rocks and Permian-Carboniferous sedimentary rocks (Figure 2A) have been encountered only in drill holes beneath the stable Indian Platform. After Precambrian peneplanation of the Indian Shield, Carboniferous sedimentation in the Bengal Basin began in isolated graben-controlled Gondwanan Basins on the basement. With the breakup of Gondwanaland during Jurassic and Cretaceous and northward movement of the Indian Plate, the basin started downwarping during Early Cretaceous, and sedimentation on the stable shelf and deep basin continued in most of the basin to the present day (Figures 2B & 3A). Subsidence of the basin can be attributed to differential adjustments of the crust, collision with the various elements of South Asia, and uplift of the eastern Himalayas and the Indo-Burman Ranges (Figure 1). Movements along several well-established faults were initiated following the breakup of Gondwanaland and during downwarping in the Cretaceous. Due to middle to upper Eocene major marine transgression, the stable shelf came under a carbonate regime (Figures 3B and 3C), while the deep basinal area was dominated by deep-water sedimentation (Alam et al., 2003). This was also the time when sudden deepening of the basin took place some distance (between 80 and 100 km) away from the western margin, triggering deposition of thick carbonates (Sylhet Limestone) and then the shallow marine Kopili Shale (Banerji, 1981; Roy and Chatterjee, 2015). A major switch in sedimentation pattern over the Bengal Basin occurred during Oligocene (Figure 3D) to early Miocene as a result of collision of India with the Burma and Tibetan

blocks. The influx of clastic sediment into the basin from the Himalayas to the north and the Indo-Burman Ranges to the east rapidly increased at this time, as did the rate of basin subsidence. At this stage, deep marine sedimentation dominated in the basinal areas, while deep to shallow marine conditions prevailed in the eastern part of the basin. By middle Miocene, with continuing collision events between the plates and uplift of the Himalayas and Indo-Burman Ranges, the influx of clastic sediments from the northeast and east increased dramatically (Banerji, 1984). Throughout Miocene, depositional settings continued to vary from deep marine in the basin to shallow and nearshore marine along the marginal parts of the basin (Alam et al., 2003). From the Pliocene onwards, large amounts of sediments were introduced into the Bengal basin from the west and northwest and major delta-building processes continued to develop the present-day delta morphology.

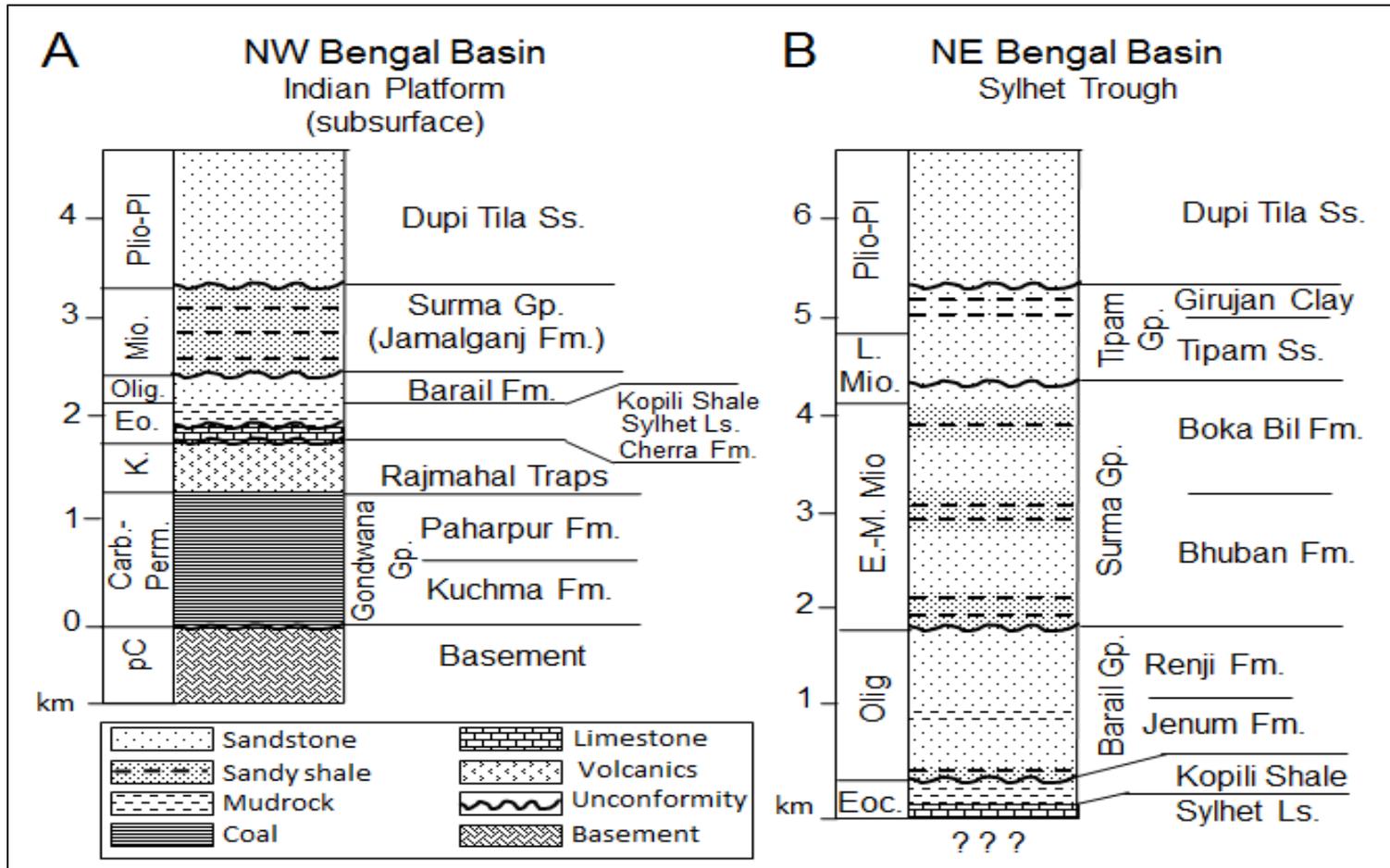
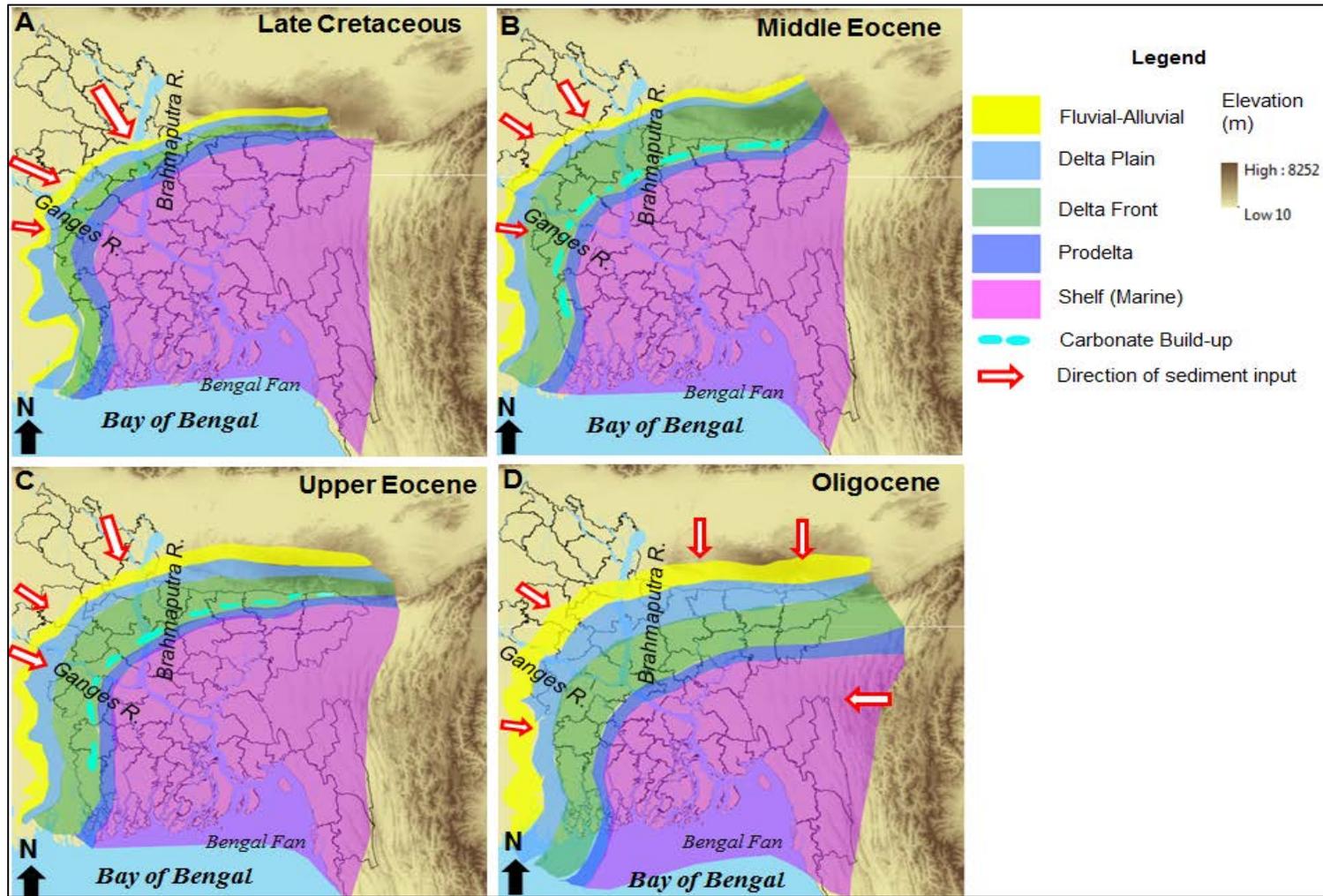


Figure 2: Stratigraphic framework of the Bengal Basin, Bangladesh. (A) Stratigraphic section of the Indian Platform, northwestern Bengal Basin. (B) Stratigraphic section of the Sylhet Trough, northeastern Bengal Basin. Note that Miocene sediment thickness is considerably lower in the northwestern part of the basin (Indian Platform), which is underlain by continental crust (basement has not been penetrated in remainder of the basin)



1.3 Bengal Basin and Kopili Shale

The Bengal Basin (Figure 1) is a large foreland basin in which a relatively thick succession (up to 16 km) of Cenozoic sediments has accumulated in response to the uplift and erosion of the Himalayas. The basin is bounded on the west by the Indian Craton, on the east by the Indo–Burman ranges, and to the north by the Shillong Plateau, a Precambrian massif adjacent to the Himalayas. The basin extends southward into the Bay of Bengal and is contiguous with the Bengal deep sea fan (Figure 1). Cenozoic sequences within the basin thicken from west to east and from north to south (Figure 4; Murphy, 1988; Uddin and Lundberg, 1999).

The Bengal Basin has two broad tectonic provinces separated by a northeast-trending hinge zone (Figure 1): (1) the northwestern Indian Platform, where a relatively thin sedimentary succession (<6 km) overlies basement rocks of the Indian Craton; and (2) the southeastern deep basin, which hosts a thicker Cenozoic sedimentary sequence that overlies deeply subsided basement of undetermined origin (Figure 2). In most areas of the basin, Tertiary strata are concealed by Quaternary sediments. However, Tertiary strata have been locally uplifted and exposed along the northern and eastern margins of the Sylhet Trough (aka Surma Basin) of the northeastern Bangladesh and in the Chittagong fold belt in the southeastern Bangladesh. Outcrop studies in these areas, along with limited drilling and geophysical data (Anwar and Husain, 1980), have led to an at least preliminary understanding of the Bengal Basin lithostratigraphy (Khan and Muminullah, 1980; Figure 2).

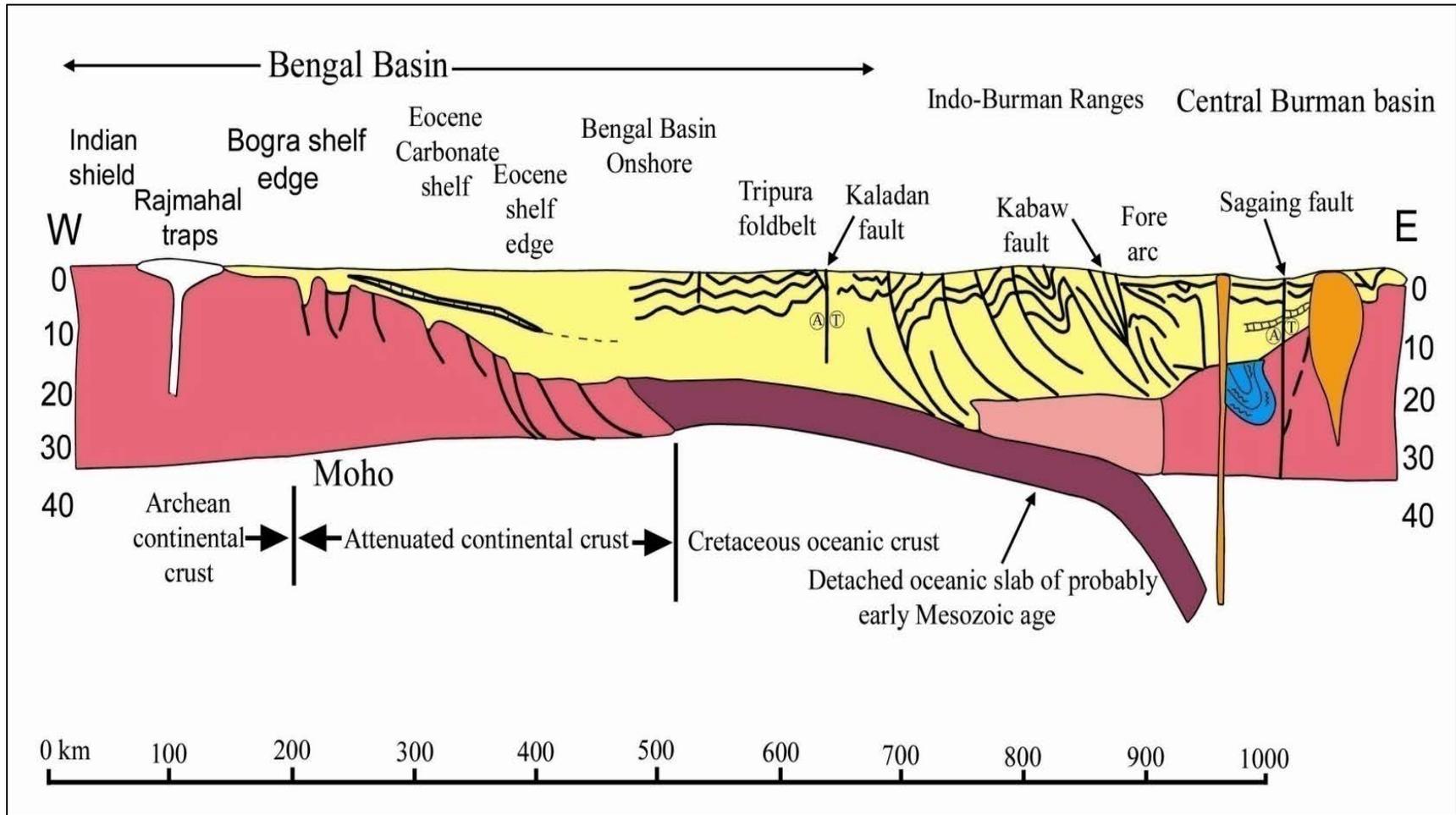


Figure 4: Schematic east-west cross-section of the Bengal Basin from the northeast to the Chittagong Hills in the southeast (after Murphy, 1988; Uddin and Lundberg, 2004). Note the sediment thickening towards the east.

In the Indian Platform area (Figure 2A), Cenozoic strata overlie Precambrian basement, a thick (up to 955 m) succession of Carboniferous to Upper Permian coal-bearing siliciclastic sediments of the Gondwana Group (Kuchma and Paharpur formations), and an ~500-m-thick sequence of Cretaceous flood basalts, the Rajmahal Traps (Figure 1). The latter are overlain by marine carbonaceous sandstones and subordinate shales and marls of the Paleocene-Eocene Cherra Formation, deep-water nummulitic carbonates of the middle Eocene Sylhet Limestone, and shallow-marine dark-gray to black (Figure 5), fossiliferous mudstone and subordinate marls of the upper Eocene Kopili Shale. The Kopili Shale, which is ~30 m thick in the platform area (Banerji, 1981), is in turn overlain by sandstones and/or mudrocks of the Oligocene Barail Formation, Miocene Surma Group, and Plio-Pleistocene Dupi Tila Sandstone.

In deep basinal areas, including the Sylhet Trough (Figure 2B), rocks older and deeper than the middle Eocene Sylhet Limestone have not been encountered in outcrops or by drilling. Here, nummulitic carbonates of the Sylhet Limestone are overlain by 40 to 90 m of the Kopili Shale, which consists of dark-gray to black (Figure 5), fossiliferous mudrocks and subordinate marl beds. The Kopili Shale, attributed to shallow marine deposition by Reimann (1993), is overlain by the Oligocene Barail Group, which in the northeastern Bengal Basin is divided into the argillaceous Jenum Formation and the arenaceous Renji Formation (Figure 2B). The Barail Group, in turn, is overlain by the lower to middle Miocene Surma Group, which includes the Bhuban and the Boka Bil formations, both of which comprise alternating mudrock and sandstone packages (Uddin and Lundberg, 1999). The Surma Group is unconformably overlain by the upper Miocene to Pliocene Tipam Group, which includes the Tipam Sandstone and the Girujan Clay.

The latter is unconformably overlain by the Plio–Pleistocene Dupi Tila Sandstone (Hiller and Elahi, 1984).

The upper Eocene Kopili Shale is exposed at various localities in northeastern Bangladesh; e.g., along the eastern bank of the Dauki River, and in two road-cut sections (Tamabil and Sripur) in the Sylhet Trough, Bengal Basin, Bangladesh. The type section of Kopili Shale is in the Garo Hills of Assam, India. The Kopili Shale varies in thickness across Bangladesh and India; thicknesses reach 500 m at the type area in the Shillong Plateau region, 700 m in the upper Assam region of India, 30 m in the northwest stable shelf area, and ~40 m in the northeast Sylhet Trough, Bangladesh (Banerji, 1981). In the Indian Platform area, the Kopili Shale was encountered in the two subsurface wells at a shallow depth of 88 m at Gaibandha and 40 m in Singra, Bogra (Farhaduzzaman et al., 2014).

The Kopili Shale exposed along the Dauki River includes several beds of oyster shell hash or coquina, with a high proportion of shell debris and sandy matrix and a low proportion of silt or clay (Brouwers et al., 1992). Several of the siltstone beds have symmetrical wave ripples, and some have grazing traces (Johnson and Nur Alam, 1991). The upper contact of the Kopili Shale is not exposed in the study area perhaps due to Pliocene tectonic activity related to the adjacent Dauki fault (Figure 1) (Johnson and Nur Alam, 1991; Uddin and Lundberg, 1998).



Figure 5: (A) Dark-gray Kopili Shale cropping out at the Sripur section, northeastern Bengal Basin. Coin is 2.5 cm in diameter. (B) Sample collection using hand auger (2 feet long) from the outcrop shown in A.

1.4 Previous Studies

Most previous studies of the Kopili Shale in the Bengal Basin, Bangladesh, focused on the microfossil assemblages (Brouwers et al., 1992) and sequence stratigraphy (Roy, 2008). Only a few published studies on the evolutionary history of the Bengal Basin (Roy and Chatterjee, 2015; Reimann, 1993) or palynological studies of the Kopili Shale (Uddin and Ahmed, 1989) address the depositional environment of the Kopili Shale. These studies suggest a paralic (brackish-marshy) setting. In contrast, the Kopili-equivalent rock in Assam, India, has been widely studied; depositional environments have been interpreted as shallow-marine to lagoonal (Moulik et al., 2009) or estuarine (Zaidi and Chakrabarti, 2006).

Very few studies have been carried out on the source-rock potential of the Kopili Shale from Bengal Basin, Bangladesh. Shamsuddin (1993) performed some geochemical analyses on core samples of the Kopili Shale from the northwestern Indian Platform area, which revealed TOC values ranging from 0.50-1.70%, T_{max} values of 429-432°C, and vitrinite reflectance (R_o) of 0.40-0.46%, thus indicating immature Type-III organic matter with fair to good source-rock potential. Applications of the modeling software GENEX indicate that considerable oil and gas may have been expelled from the Cherra Formation and Kopili Shale (Figure 2A) in the deeper part of the northwestern Indian Platform and the “Hinge Zone” area (Shamsuddin, 1993). In the northeastern and deep basin areas, lower Miocene source rocks are mainly gas prone and all other source rocks, including the upper Eocene Kopili Shale, have fair to good hydrocarbon potential as the oil window ($R_o = 0.65-1.30\%$) is presently located at a depth interval between 5000 and 8000 m (Shamsuddin, 1993). The Renji Formation (Barail Gp.; Figure 2B) has been encountered

at the greatest depth of drilling in the northeast Sylhet Trough area, which is about 5000 m. As the Kopili Shale lies below the Barail Group, it may have reached the oil window and could be mature enough to generate hydrocarbons (Ismail and Shamsuddin, 1991). Carbon-isotope ($^{13}\text{C}/^{12}\text{C}$) analyses on all the gas samples from Miocene reservoirs in the Sylhet Trough, Bengal Basin, indicate a marine origin and that the gases originated from a mature source rock (Anwar and Husain, 1980). Kerogen-type analyses of the Miocene Bhuban shales indicate that associated organic matter was derived primarily from terrestrial sources, and that these mudrocks are organically lean ($\text{TOC} \pm 1.0\%$) and thermally immature to early mature (Farhaduzzaman et al., 2014). Hence, the gases in the Miocene reservoirs of the Bengal Basin may not have come from the Miocene Bhuban shale units. Rather, gases may have been generated from more mature source rocks in the deep basin area (Sylhet Trough) and migrated a distance of about 5 km (Khan, 1980). For example, the gas may have been generated from the organic-rich ($\text{TOC}=1.40\text{-}2.70\%$) Oligocene Jenum Formation (Figure 2B), which is generally regarded as the principal source rock for the Miocene gas reserves. Alternatively, the gases also may have migrated from the marine Kopili Shale (Ismail and Shamsuddin, 1991; Curiale et al., 2002).

The Kopili equivalent shale in the upper Assam, northeastern India, which is about 700 m thick, is a proven source rock for both oil and gas in the well-defined Sylhet-Kopili/Barail-Tipam composite petroleum system of Assam, India (Wandrey, 2004). Naidu and Panda (1997), calculated source-rock richness ($\text{Thickness} \times \text{TOC}$) of the Kopili Formation in Assam, India, which has significant amounts of type II and type III organic matter ($\text{TOC}= 0.50$ to 1.50%), and has good source-rock potential. The type area of the

Kopili Formation is 500 m thick and is about 100 km away from the Bangladesh border (Mandal, 2009). As the Kopili Shale in Bengal Basin, Bangladesh is thought to be a continuation of the Kopili Formation in Assam, India (Uddin et al., 2007), the Kopili Shale is expected to be a potential source-rock in the northeastern Bengal Basin. The current research on organic geochemistry and thermal maturity of the Kopili Shale was designed to help assess the potential of this unit as the source for hydrocarbons in Miocene reservoirs in the petroliferous Bengal Basin.

1.5 Petroleum Systems of the Bengal Basin

1.5.1 Petroleum Systems in Deep Basin area and Northeastern Bengal Basin

The Bengal Basin is a prime target for hydrocarbon exploration in Bangladesh. Thus far, economic hydrocarbon accumulations have been discovered only southeast of the hinge zone in the Miocene Surma Group. Since commercial production began in 1962, 23 gas fields and 1 oil field have been established in the Sylhet Trough and, as of 2002, 69 wells in 22 gas fields had estimated proven reserves of 15.5 Tcf (Imam and Hussain, 2002; Alam et al., 2006). Reservoirs and seals in this petroleum system are sand-dominated units (with porosities of 10-20%; Uddin, 1987) and shale units, respectively, in the Boka Bil and Bhuban formations. Hydrocarbon traps are primarily structural (anticlinal) (Imam and Hussain, 2002; Alam et al., 2006), although some stratigraphic traps may exist, particularly in the southern part of the Bengal Basin (Imam, 2012). The Oligocene Jenum Shale (Barail Group), with TOC contents of 1.40-2.70%, is generally regarded as the principal source-rock for this hydrocarbon system (Ismail and Shamsuddin, 1991; Curiale et al., 2002). Based on thermal modeling, the Jenum

Formation reached the oil window ~28 Ma and the gas window ~5 Ma (Figure 6), and may still be producing hydrocarbons today (Shamsuddin and Yakovlev, 1987).

While the Jenum Formation is likely the major source-rock for the Surma Group oil and gas reservoirs, older shale units, including the Eocene Kopili Shale, also may have served as sources of hydrocarbons in these and other (Eocene-Oligocene) as yet unidentified reservoirs in the Bengal Basin (Shamsuddin et al., 2001). Thermal modeling (Curiale et al., 2002) indicates that, in the Surma Basin area, hydrocarbon generation from the Kopili Shale could have begun ~32 Ma (Figure 6). However, to date, the source-rock potential and thermal maturity of the Kopili Shale have not been directly assessed and, thus, remain controversial (Imam and Hussain, 2002).

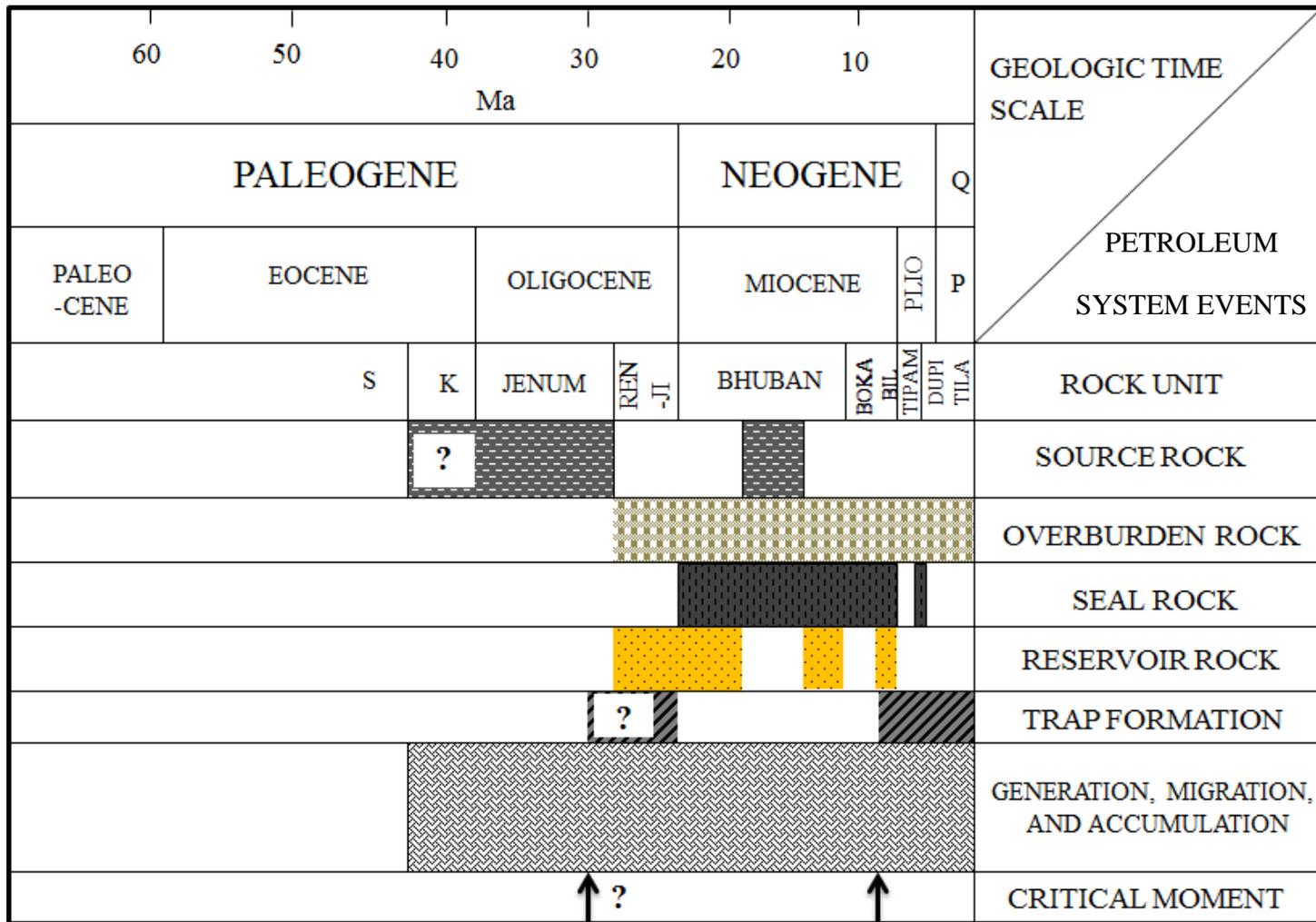


Figure 6: Petroleum systems event chart for the Sylhet Trough, northeastern Bangladesh, showing the primary Jenam–Bhuban Boka Bil petroleum system and older Eocene-Oligocene petroleum system (modified from Curiale et al., 2002). Abbreviation: S=Sylhet Limestone; K=Kopili Shale; P=Pleistocene; Q=Quaternary.

1.5.2 Petroleum System in the Shelf area, Northwest Bengal Basin

There are three different petroleum systems that have been identified in the Bogra Shelf area, northwestern Bengal Basin. They are 1) the Gondwana (Permian-Carboniferous) petroleum system, 2) the Cherra-Sylhet-Kopili (Paleocene-Eocene) petroleum system, and 3) the Barail-Surma (Oligocene-Miocene) petroleum system.

Gondwana (Permian-Carboniferous) Petroleum System:

The Kuchma Formation in the lower Gondwana Group is approximately 1,620 feet thick and contains five coal seams with thicknesses ranging from 13 to 72 feet. These coals act as gas-prone source rocks for the Permian-Carboniferous Gondwana petroleum system (Shamsuddin et al., 2001). The Paharpur Formation (Figure 2A) is approximately 1680 feet thick, which is composed of feldspathic sandstones acting as a reservoir rock. This unit also contains four coal seams (Uddin, 1987), which themselves may serve as a source rocks. Cretaceous Deccan Trap volcanics may contribute to reservoir sealing (Alam et al., 2006). As the generation and migration of gases from Gondwana coals continue today in the upper shelf, any trap within the Paleogene-Neogene sediments could be charged at least partially by the coal seams (Shamsuddin et al., 2001).

Cherra-Sylhet-Kopili (Paleocene-Eocene) Petroleum System:

The Cherra Formation (also known as Tura Sandstone) of early Paleocene to middle Eocene age is about 340 feet thick and consists of carbonaceous sandstone and subordinate shale (Jalangi Shale) and marl (Uddin, 1987). The Jalangi Shale acts as a potential source rock for Cherra-Sylhet-Kopili petroleum system. Any hydrocarbon generated from the Jalangi Shale may have moved updip into carrier beds beneath the Sylhet Limestone towards the basin margin where carbonate traps may be present. The

Kopili Shale forms a regional seal throughout the shelf area. The expulsion of oil and gas from both the Cherra Formation and the Kopili Shale are thought to be continuing today and may charge reservoirs in the lower and upper slope areas in the northwest (Alam et al., 2006).

Barail-Surma (Oligocene-Miocene) Petroleum System:

The Oligocene Jenum Shale is relatively organic carbon rich (TOC = 1.40-2.70%) and has sufficient thermal maturity to act as a source rock for the Barail-Surma (Oligocene-Miocene) petroleum system in the northwest Bengal Basin (Ismail and Shamsuddin, 1991; Curiale et al., 2002). The Miocene Bhuban Formation of the Surma Group also contains potential shale source rocks (Farhaduzzaman et al, 2015), and the sandstone units of the Surma Group may serve as reservoirs. The Boka Bil shale unit in the Surma Group acts as a seal for this petroleum system.

CHAPTER 2: STUDY LOCATIONS AND METHODS

2.1 Study Area

The present study is located in the northern Bengal Basin, Bangladesh. To determine the depositional environment, rock composition, and source-rock potential of the upper Eocene Kopili Shale, twenty-four samples were collected from three outcrops (Figures 7A-D and 9; Table 1) of the Kopili Shale exposed on the northern margin of the Sylhet Trough (Figures 8 and 9) in the northeastern part of the Bengal Basin, and one sample was collected from cuttings (Figures 7E and 7F) from each of three wells in the northwestern Indian Platform (Figure 8) part of the basin (samples GDH-31, GDH-51, and GDH-55; Figure 8). Of the 24 surface samples, eleven were collected at ~4-6 m intervals at the Dauki River section (Figure 9; samples D₁-D₁₁), five were collected at ~0.5-1.0 m intervals at the Tamabil section (Figure 9; samples T₁-T₅), and eight were collected at ~3-4 m intervals at the Sripur section (Figure 9; samples S₁-S₈). The stratigraphic positions of all samples, i.e., height above outcrop base or core depth, are provided in Table 1. Stratigraphic lithologs for the three outcrop sections (Figure 10) and drill cores (Figure 11) have been constructed to show the sample locations at each stratigraphic section in northeastern and northwestern parts of the Bengal Basin, respectively.

Table 1: Location, stratigraphic position, and types of analyses completed on Kopili Shale samples.

Section	Sample no.	Stratigraphic height	TOC	Rock-Eval Pyrolysis	Organic Petrology/VR	XRD and XRF	Thin section petrography
Dauki River	D ₅	4 m from base	*			*	*
	D ₆	8 m	*			*	
	D ₇	11 m	**	*	*	*	*
	D ₈	14 m	*			*	
	D ₉	18 m	*			*	
	D ₁₀	22 m	**	*	*	*	*
	D ₁₁	26 m	*			*	
	D ₄	30 m	*			*	
	D ₃	33 m	*			*	
	D ₂	36 m	**	*	*	*	*
	D ₁	39 m	*			*	
Tamabil	T ₁	0.5 m from base	*			*	
	T ₂	1.5 m	**	*	*	*	*
	T ₃	2.5 m	*			*	
	T ₄	3 m	*			*	
	T ₅	4 m	*			*	
Sripur	S ₁	3 m from base	*			*	
	S ₂	6 m	*			*	
	S ₃	10 m	*			*	
	S ₄	13 m	*			*	
	S ₅	16 m	*			*	
	S ₆	19 m	**	*	*	*	*
	S ₇	22 m	*			*	
	S ₈	25 m	*			*	
Core	GDH-31	796 m depth	*			*	
Core	GDH-51	431 m depth	**	*	*	*	*
Core	GDH-55	358 m depth	*			*	

**TOC data derived from Rock-Eval pyrolysis

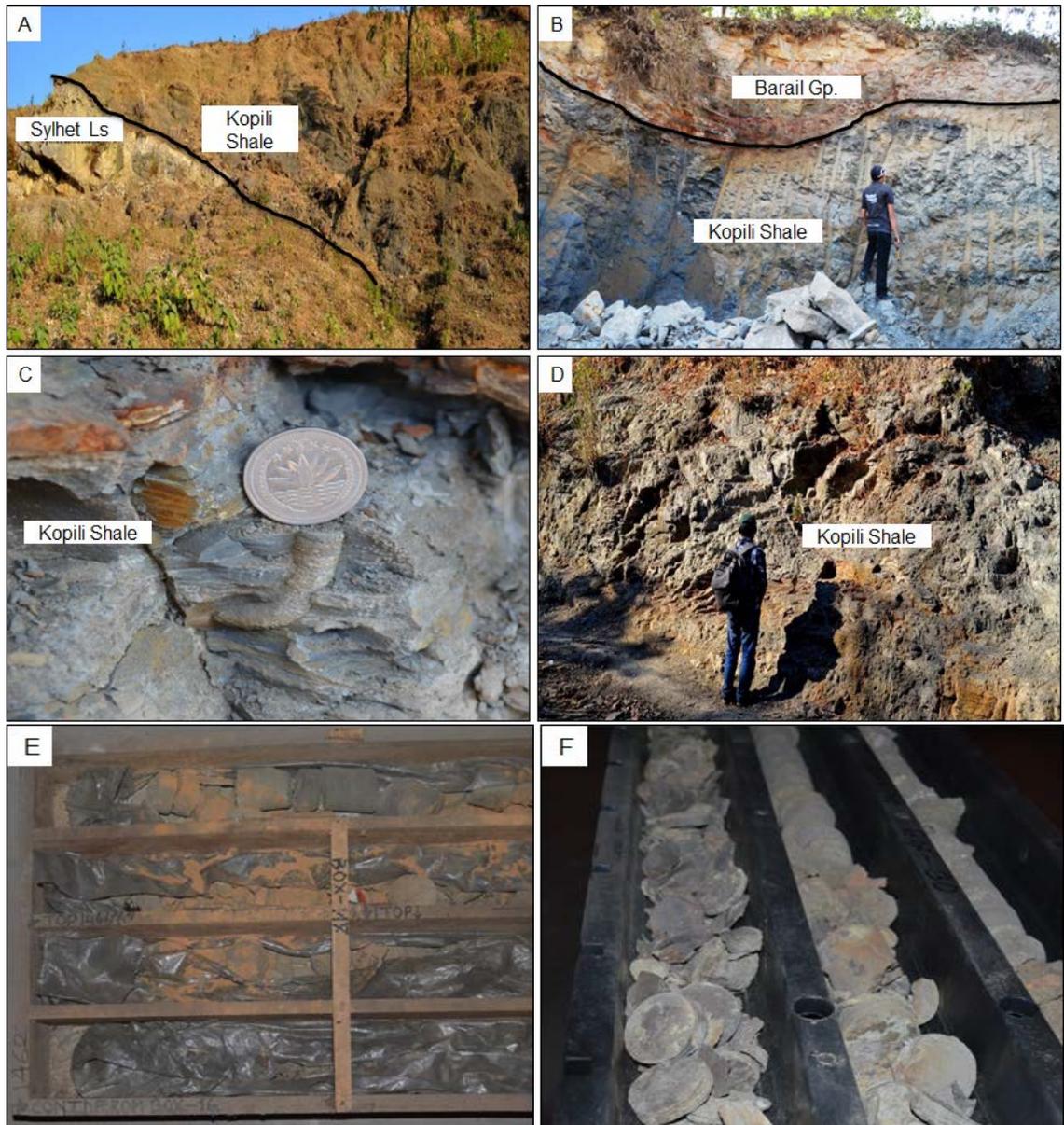


Figure 7: Outcrops and core photos of the Kopili Shale from the northeastern and northwestern Bengal Basin, respectively. (A) Dauki River section. (B) Tamabil section. (C) Vertical burrow observed in the Kopili Shale from Tamabil section (coin is 2.5 cm in diameter). (D) Sripur section. Black lines in (A) and (B) represent unconformity. (E, F) Core cuttings of the Kopili Shale from Geological Survey of Bangladesh at Bogra, northwestern Bengal Basin.

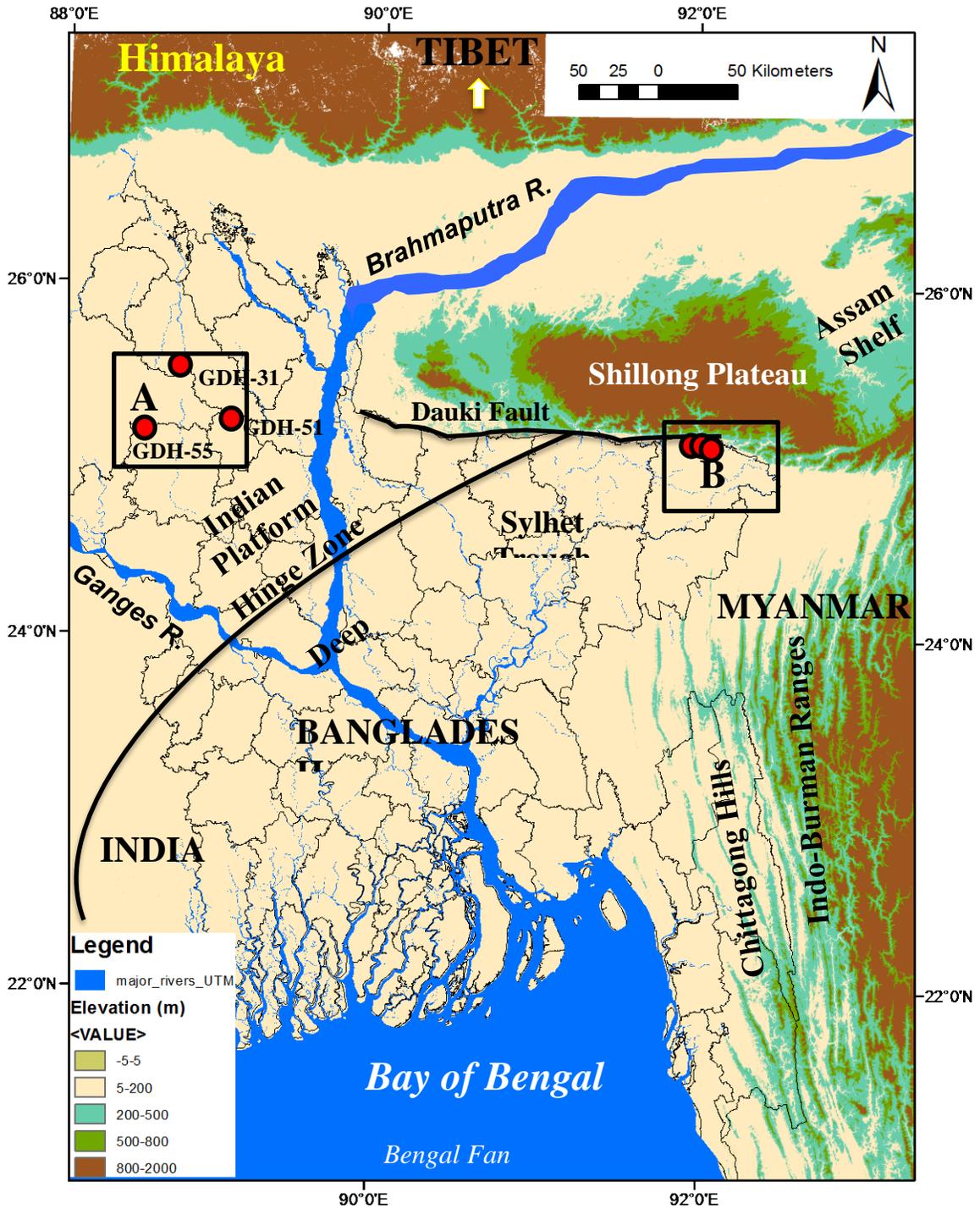


Figure 8: Map of Bangladesh showing pertinent features of the Bengal Basin and locations of cores (A) and outcrops (B) examined in this study. The area in box B is shown in detail in figure 9. The hinge zone that separates the stable shelf (Indian Plateform) from the deep basin continues to the northeast as the Assam Shelf.

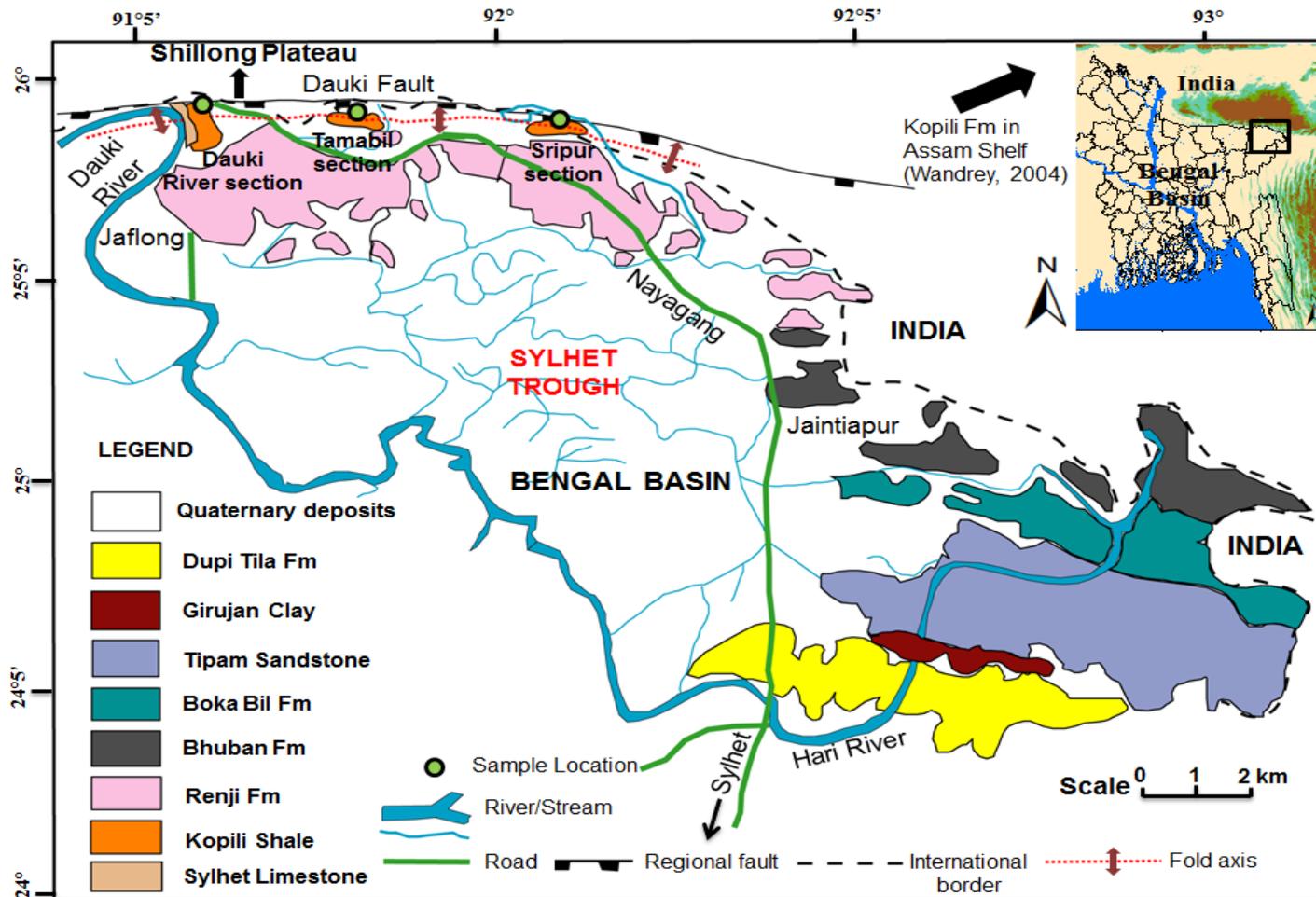


Figure 9: Geological map of Cenozoic sequences, including the Kopili Shale, exposed in the Sylhet Trough, northeastern Bengal Basin, Bangladesh. Sample location sites for the current study are shown by green dots (modified from Hossain et al., 2013 and Worm et al., 1998). The Kopili Formation in the upper Assam area is about 100-200 km away from Sripur section, northeastern Bengal Basin, Bangladesh.

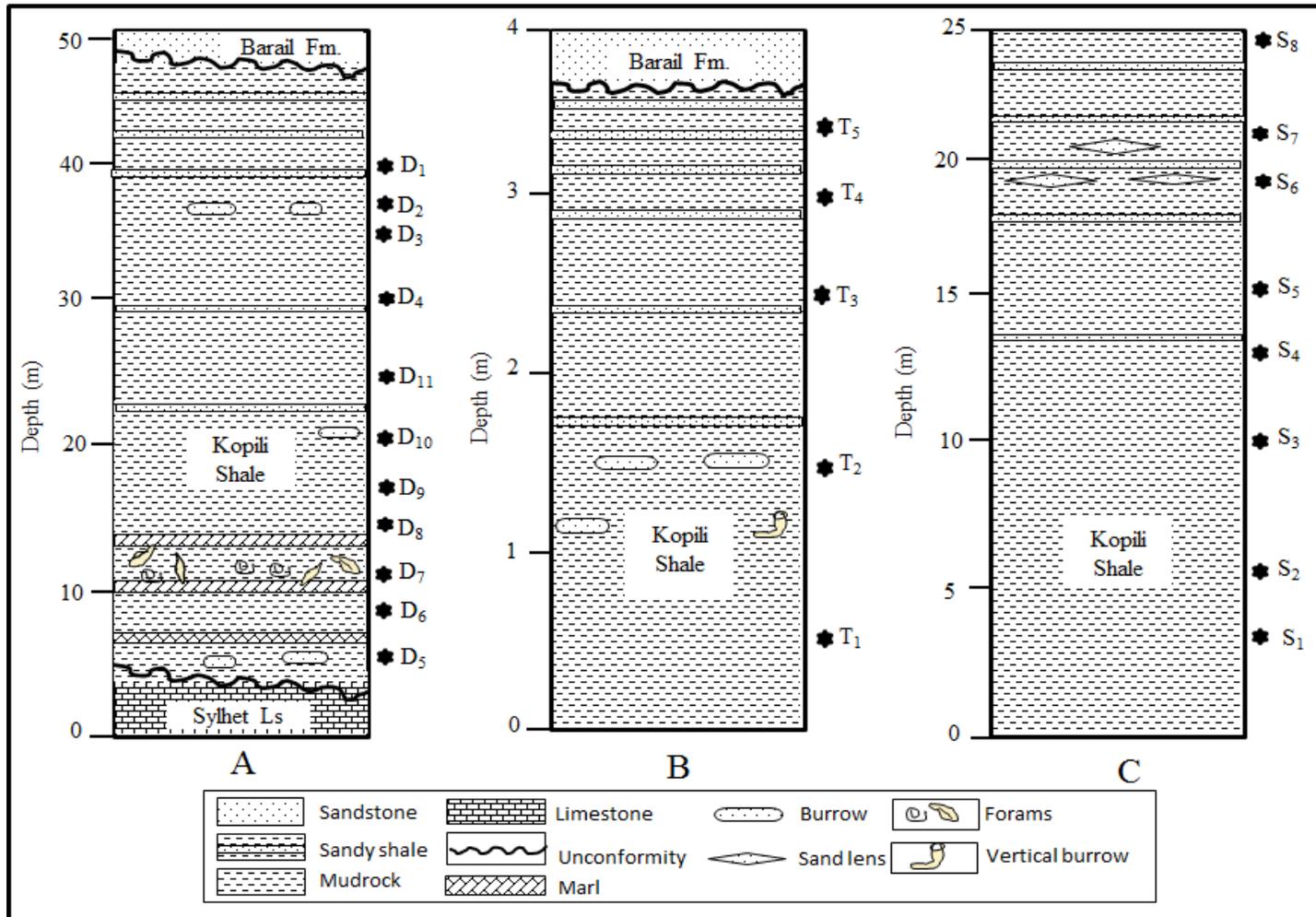


Figure 10: Generalized stratigraphic columns of outcrop sections of the Kopili Shale from the northeastern Bengal Basin. (A) Dauki River section. (B) Tamabil section. (C) Stripur section. Black asterisks show stratigraphic positions of samples (Data source: Khan, 1991).

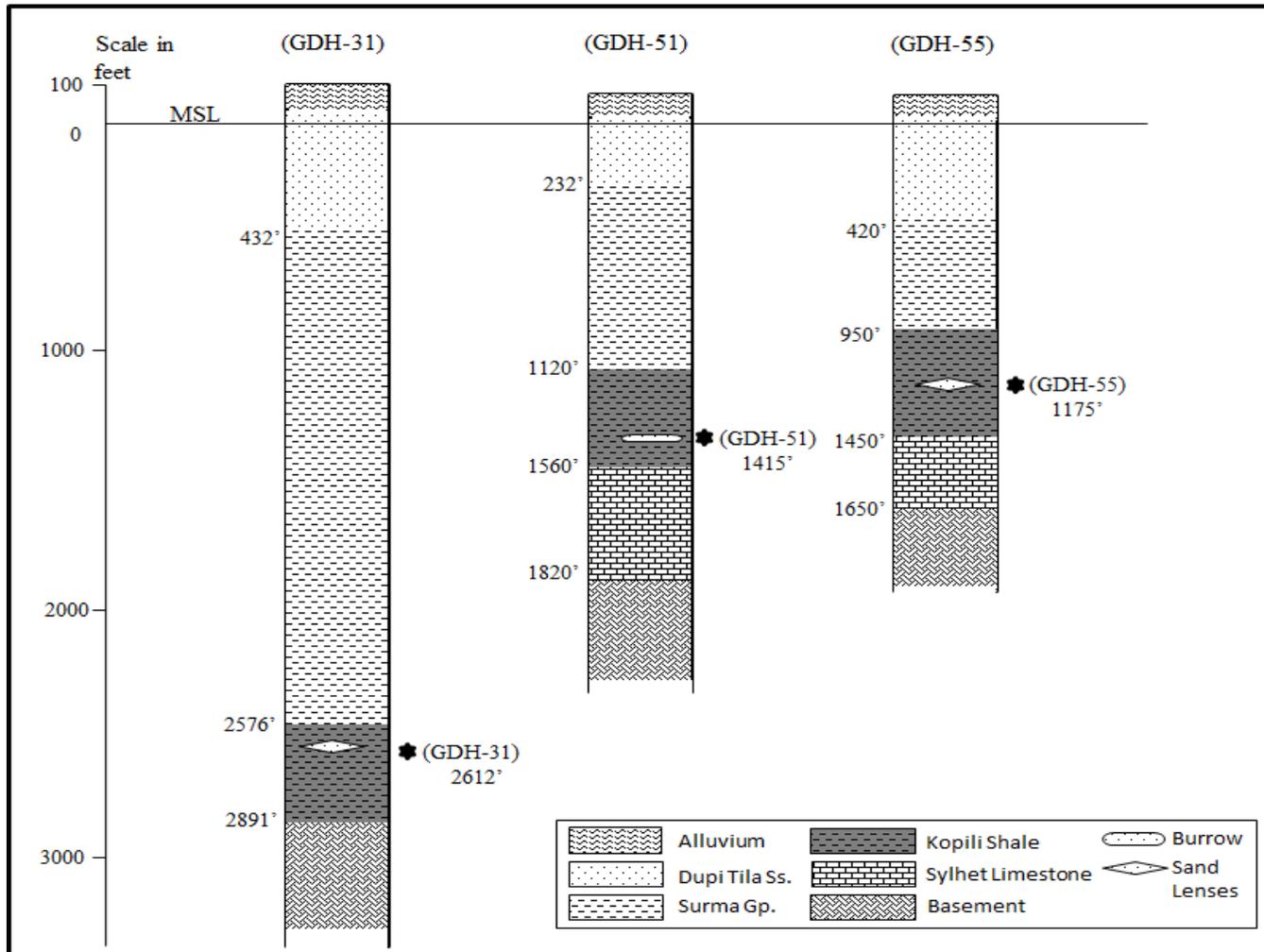


Figure 11: Vertical sections of drill holes GDH-31, GDH-51 and GDH-55 from the northwestern Bengal Basin. Black asterisks show the stratigraphic positions of samples collected from cores (Data source: Khan, 1991).

2.2 Methods

2.2.1 Thin Section Petrography

In order to infer the depositional processes and environments, petrographic and fabric analyses were carried out on thin sections of seven samples; six (D₂, D₅, D₇, D₁₀, T₂, S₆) from different outcrops and one core sample (GDH-51) (Table 1). Fresh outcrop samples were collected from all representative sections guided by regional geological experts. Seven rock samples were sent to Wagner Petrographic Llc. (Table 1) for making standard thin sections, which were impregnated with blue epoxy. Prepared thin sections were observed with a Nikon petrographic microscope using objectives with magnification of 4x, 10x, and 20x.

2.2.2 Organic Petrologic Analysis

Organic petrologic analysis of dispersed organic matter was performed on subsamples of the six samples (Table 1). Shale subsamples were crushed, and particles passing the 20-mesh screen (< 0.85 mm) were used to form ~3-cm-diameter polished pellets (Figure 12). Petrologic analyses of the pellets were performed in the Unconventional Reservoir/Basin Research Laboratory, Boone Pickens School of Geology at Oklahoma State University using a Nikon petrographic microscope and a Craic Technologies 308PV microphotospectrometer driven by CoalPro III software. Analyses were conducted using oil immersion objectives with magnification of 50x and 100x.

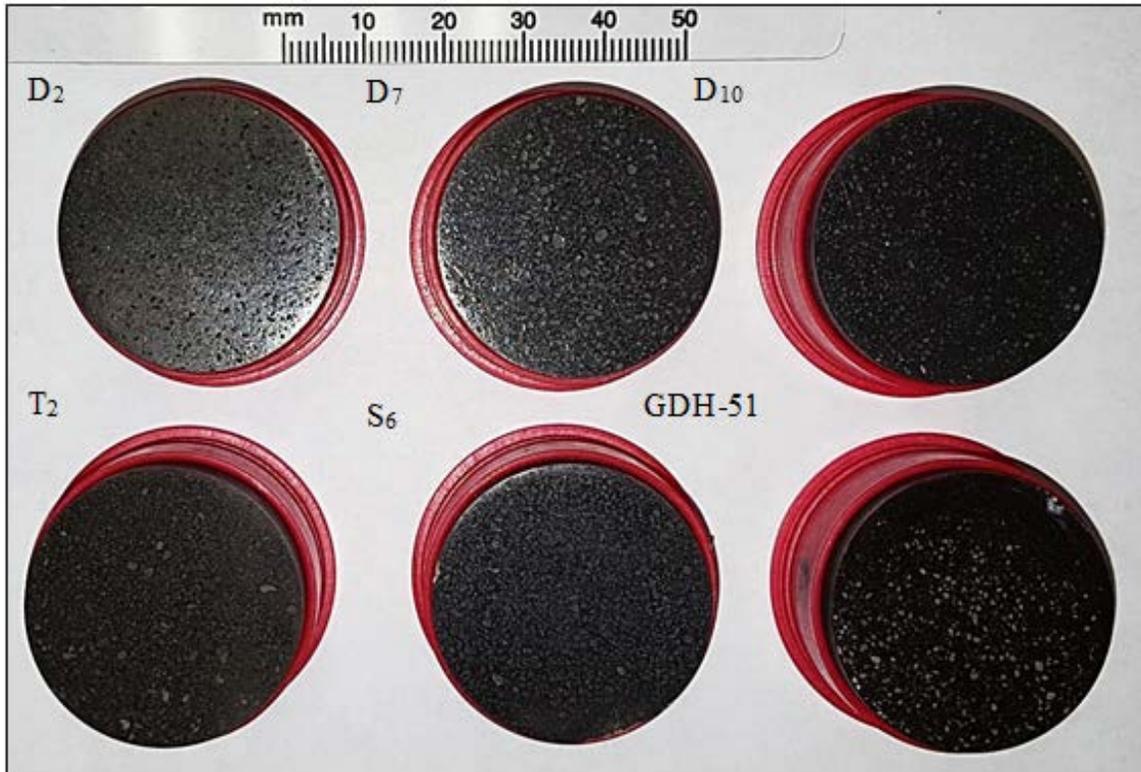


Figure 12: Organic pellets of the Kopili Shale from the northeastern (D₂, D₅, D₇, D₁₀, T₂, S₆) and northwestern (GDH-51) Bengal Basin, Bangladesh.

For each sample, organic particles were identified using reflected white light and blue light excitation; reflectance of organic macerals such as liptinite, bituminite, vitrinite, and inertinite were measured.

2.2.2.1 Vitrinite Reflectance Analysis

Vitrinite reflectance (VR) is the most widely used technique to estimate thermal maturity of organic matter in shale (Tissot and Welte, 1978). This technique is based on measurements of the reflective properties of terrestrial organic matter, and values are reported as mean percent reflectance. The most reliable VR measurements are obtained from the vitrinite maceral collotelinite (most abundant maceral in coal), but this maceral

may be difficult to identify in rocks such as shale that contain relatively low concentration of dispersed organic matter (Teichmuller and Durand, 1983).

Vitrinite reflectance analyses were performed on randomly-oriented organic macerals present in the same six organic pellets used for organic petrologic analyses. Samples were observed using the same Nikon petrographic microscope and Craic Technologies 308PV microphotospectrometer driven by CoalPro III software (Figure 13A). Oil immersion objectives with magnification of 50x and 100x were used. Spinel with $R_o = 0.421\%$, yttrium-aluminum-garnet with reflectance $R_o = 0.901\%$, and gadolinium-gallium-garnet with reflectance $R_o = 1.733\%$ were used as standards (Figure 13B). For each sample, twenty-five organic particles were identified under reflected white light, and fluorescence properties of liptinite, bituminite, and vitrinite macerals were measured under blue light excitation. The organic matter particles observed in the Kopili Shale were too small to rotate the stage to measure maximum reflectance values and anisotropy for each particle, so in this study the reflectance values are reported as mean random (Table 2), which are typical for dispersed organic matter. Mean reflectance of all dispersed organics were measured and plotted to assess thermal maturity.

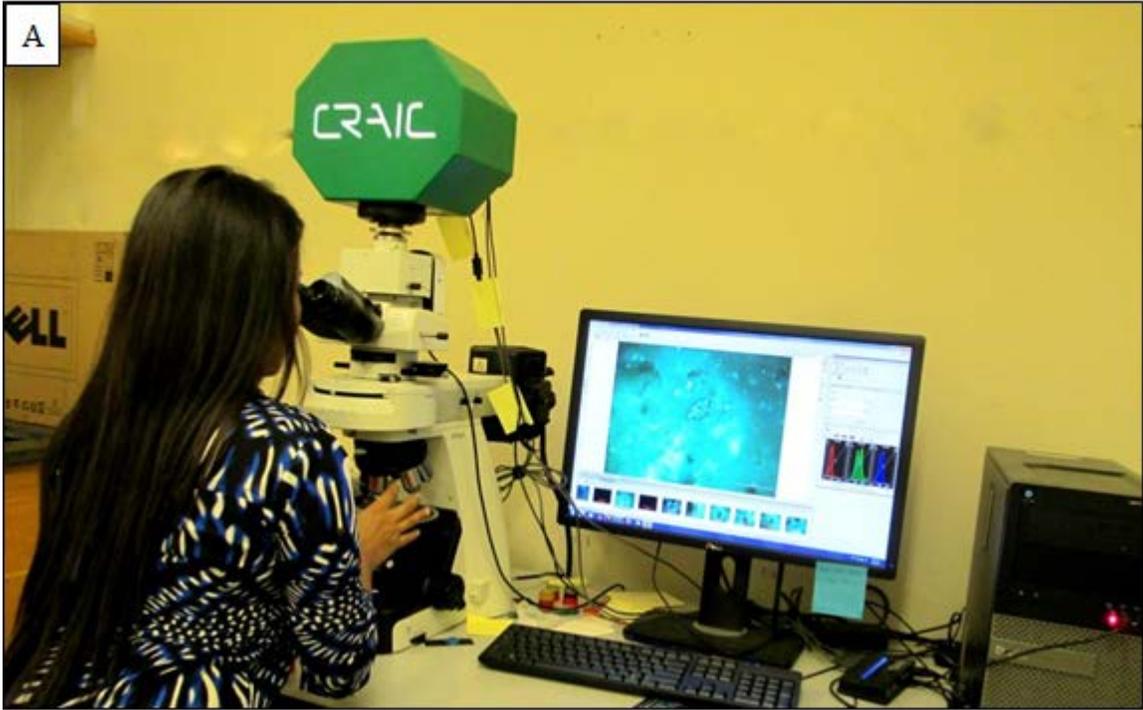


Figure 13:(A) Analysis of vitrinite maceral under a CRAIC microscope. (B) Standards used for vitrinite reflectance measurements.

Table 2: Sample site, stratigraphic position, and analytical, results for Kopili Shale samples.

Sample site	Sample no.	Stratigraphic height	TOC (Wt. %)	TOC avg. (Wt. %)	Rock-Eval pyrolysis						Mean R ₂ (%) (each sample)	Mean Ro (%) (each section)
					S ₁	S ₂	S ₃	HI	OI	T _{max} (°C)		
Dauki River	D ₃	4 m from base	0.45	0.60								1.15
	D ₆	8 m	0.53									
	D ₇	11 m	*0.64		0.01	0.04	0.41	6	64	**431	1.02	
	D ₈	14 m	0.46									
	D ₉	18 m	0.70									
	D ₁₀	22 m	*0.55		0.02	0.10	0.22	18	40	**436	1.12	
	D ₁₁	26 m	0.66									
	D ₄	30 m	0.61									
	D ₅	33 m	0.76									
	D ₂	36 m	*0.83		0.02	0.10	0.19	12	23	**443	1.32	
D ₁	39 m	0.40										
Tamabil	T ₁	0.5 m from base	0.45	0.40								1.15
	T ₂	1.5 m	*0.41		0.01	0.08	0.26	21	68	**443	1.15	
	T ₃	2.5 m	0.35									
	T ₄	3 m	0.36									
	T ₅	3.5 m	0.34									
Sripur	S ₁	3 m from base	1.43	1.0								0.86
	S ₂	6 m	1.07									
	S ₃	10 m	0.77									
	S ₄	13 m	1.03									
	S ₅	16 m	1.20									
	S ₆	19 m	*0.97		0.03	0.70	0.16	72	16	433	0.86	
	S ₇	22 m	1.20									
	S ₈	25 m	0.56									
Core	GDH-31	796 m depth	0.50	0.5								1.24
Core	GDH-51	431 m depth	*0.52		0.01	0.14	0.99	27	190	**506	1.24	
Core	GDH-55	358 m depth	0.45									

2.2.3 XRD and XRF Analysis

Twenty-seven samples (Table-1) were subjected to XRD and XRF analyses. Subsamples weighing ~5 grams were powdered with a mortar and pestle. To avoid cross contamination, the mortar and pestle were scrubbed using soap and water after each sample was prepared. The whole-rock powder was mounted on a sample holder and the surface was smoothed by pressing the powder with a glass slide. XRD patterns were recorded for powdered samples using a Bruker D2 Phaser with Ni-filtered Cu K α radiation at 30 kV and 10 mA in the laboratory facility of the Department of Geosciences at Auburn University. Samples were scanned from 2 Θ of 7° to 65° for 2853 steps at 0.02° seconds per step. Identification of clay minerals, which requires preparation of oriented sample, was not performed in this study.

XRF analyses were performed on the same samples subject to XRD study. The XRF technology analyzes the energy emission of characteristic fluorescent X-rays from a sample that has been excited by bombarding with high-energy (i.e., short-wavelength) X-rays. The XRF technology can quantify the elemental composition of a material because each element has unique electronic orbitals of characteristic energy. The intensity of each characteristic radiation is directly related to the amount of each element in the material. Major elements of shale samples, in the range of parts per million (ppm), were measured using an Elemental Tracer IV-ED handheld unit in the Geosciences Department at Auburn University. The mineral composition of the samples was determined by a peak search and match procedure using DIFFRAC.EVA, ARTAX and S1PXRF software.

2.2.4 Rock-Eval Pyrolysis

Six samples (D₂, D₇, D₁₀, T₂, S₆, and GDH-51) were subjected to Rock-Eval pyrolysis using a Rock-Eval 6 instrument at ActLabs. Subsamples weighing 25 grams were sent to the commercial lab. During Rock-Eval pyrolysis, samples were heated under an inert atmosphere of helium or nitrogen. A flame ionization detector (FID) response was recorded for each sample, which senses organic compounds emitted during each stage of heating. The first peak (S1) generated corresponds to free oil and gas that evolve from a rock sample without cracking the kerogen during the first stage of heating at 300°C. The second peak (S2) corresponds to the hydrocarbons that evolve from the sample from the cracking of heavy hydrocarbons and from the thermal breakdown of kerogen. The third peak (S3) generated corresponds to CO₂ derived from thermal cracking of the kerogen during pyrolysis (McCarthy et al., 2011). Pyrolysis temperatures were also recorded, which produce a T_{max} peak (S2) that corresponds to the pyrolysis oven temperature during maximum generation of hydrocarbons. Tmax is reached during the second stage of pyrolysis, when cracking of the kerogen and heavy hydrocarbons produces the S2 peak (McCarthy et al., 2011). Pyrolysis data—total organic carbon (TOC), hydrogen index (ratio of hydrogen to TOC; 100*S2/TOC), oxygen index (ratio of CO₂ to TOC; 100*S3/TOC), T_{max} (temperature of maximum pyrolysate yield), and pyrograms of FID response versus time and T_{max} were used to assess organic richness, thermal maturity, and petroleum-source potential.

2.2.5 TOC Analysis

Total organic carbon (TOC) measurements are the first screen for evaluating organic richness (McCarthy et al., 2011). The TOC content of the twenty-one Kopili

Shale samples (excluding six for Rock-Eval pyrolysis) were determined using a separate technique. This included nineteen samples from northeast (Table 1), and two core samples from the northwest. Samples were dried in an oven at 100°C for ~24 hours (Figure 14). Approximately 0.50 grams of dried sample were powdered with a mortar and pestle to a grain size of <0.63 mm. To avoid cross contamination, the mortar and pestle were scrubbed using soap and water after each sample was prepared. All the powdered samples were acid digested using 10% dilute hydrochloric acid to remove the inorganic carbon content (i.e., carbonate carbon) from the shale. The samples were then filtered through carbon-free borosilicate glass prefilters and then oven dried; weights of the samples in grams, weight percentages of carbonate and organic carbon are noted in Table 3. TOC analysis of insoluble residues was performed using an Elementar Vario Macro NCS Analyzer at the Soil Testing Laboratory in the Department of Agronomy and Soils at Auburn University. With this instrument, carbon contained in kerogen is converted to CO and CO₂ and the evolved carbon fractions are measured in an infrared cell, converted to TOC, and recorded as mass weight percent of rock. Table 3 summarizes the data obtained from TOC analysis.



Figure 14: Oven-dried, crushed samples of the Kopili Shale, showing various colors ranging from brown to different shades of gray.

Table 3: TOC data from the Kopili Shale from the northeastern and northwestern Bengal Basin, Bangladesh.

Sample No.	Wt. of sample in gm	Wt. of filter paper in gm	Wt. of residue+filter paper in gm	Wt. of residue in gm (Total C without CaCO ₃)	Wt. % CaCO ₃	% Organic C (Carbon by combustion)
D1	0.5068	0.1014	0.6019	0.5005	1.243	0.40
D3	0.4457	0.1003	0.5460	0.4569	10.591	0.76
D4	0.4986	0.1012	0.5416	0.4404	11.673	0.61
D5	0.5076	0.1020	0.4928	0.3908	23.010	0.45
D6	0.5068	0.1023	0.5654	0.4631	8.623	0.53
D8	0.5016	0.1016	0.5414	0.4398	12.321	0.46
D9	0.5004	0.1007	0.5319	0.4312	13.829	0.70
T1	0.5084	0.1006	0.5711	0.4705	7.455	0.45
T3	0.4972	0.1020	0.5654	0.4634	6.800	0.35
T4	0.4972	0.1020	0.5654	0.4540	5.850	0.36
T5	0.4972	0.1020	0.5654	0.4584	5.950	0.34
S1	0.5068	0.0794	0.5443	0.4649	8.268	1.43
S2	0.4970	0.1025	0.5890	0.4865	2.113	1.07
S3	0.4997	0.1014	0.5734	0.4720	5.543	0.77
S4	0.5020	0.1014	0.5647	0.4633	7.710	1.03
S5	0.5005	0.1024	0.5917	0.4893	2.238	1.20
S7	0.5042	0.1002	0.5842	0.4840	4.010	1.20
S8	0.5009	0.1005	0.5580	0.4575	8.664	0.56
GDH-31	0.5892	0.0925	0.5615	0.4690	7.100	0.50
GDH-55	0.4987	0.1017	0.5615	0.4598	7.800	0.45

CHAPTER 3: RESULTS

3.1 Thin Section Petrography

Thin sections of Kopili Shale reveal localized skeletal grains (e.g., foraminifera), bioturbate fabrics, pyrite framboids, sand lenses, flame structures, and silt-sized particles. The Kopili Shale from the northeastern Dauki River section (sample D₇) contains numerous fossil fragments (Figure 15). Bioturbate fabrics were observed in most samples (D₂, D₅, D₁₀, T₂, and S₆) of the Kopili Shale from the northeast (Figure 16), where burrows are mostly filled with silt or fine sand (Figures 16A and 16E) and are surrounded by a darker organic-rich, finer-grained matrix (Figures 16B-D). A few cubic pyrite grains (Figures 17A) and very fine grained dispersed pyrite grains (Figure 17B) are visible under reflected light, indicating presence of sulfidic pore waters. Sand lenses (Figure 17C), starved ripples (Figure 17D), and flame structures (Figure 18B), are also observed in the northeastern samples of Kopili Shale. Photomicrographs of Kopili Shale from the northeastern and northwestern samples show silt-sized particles and a darker, organic-rich, finer-grained matrix (Figure 18).

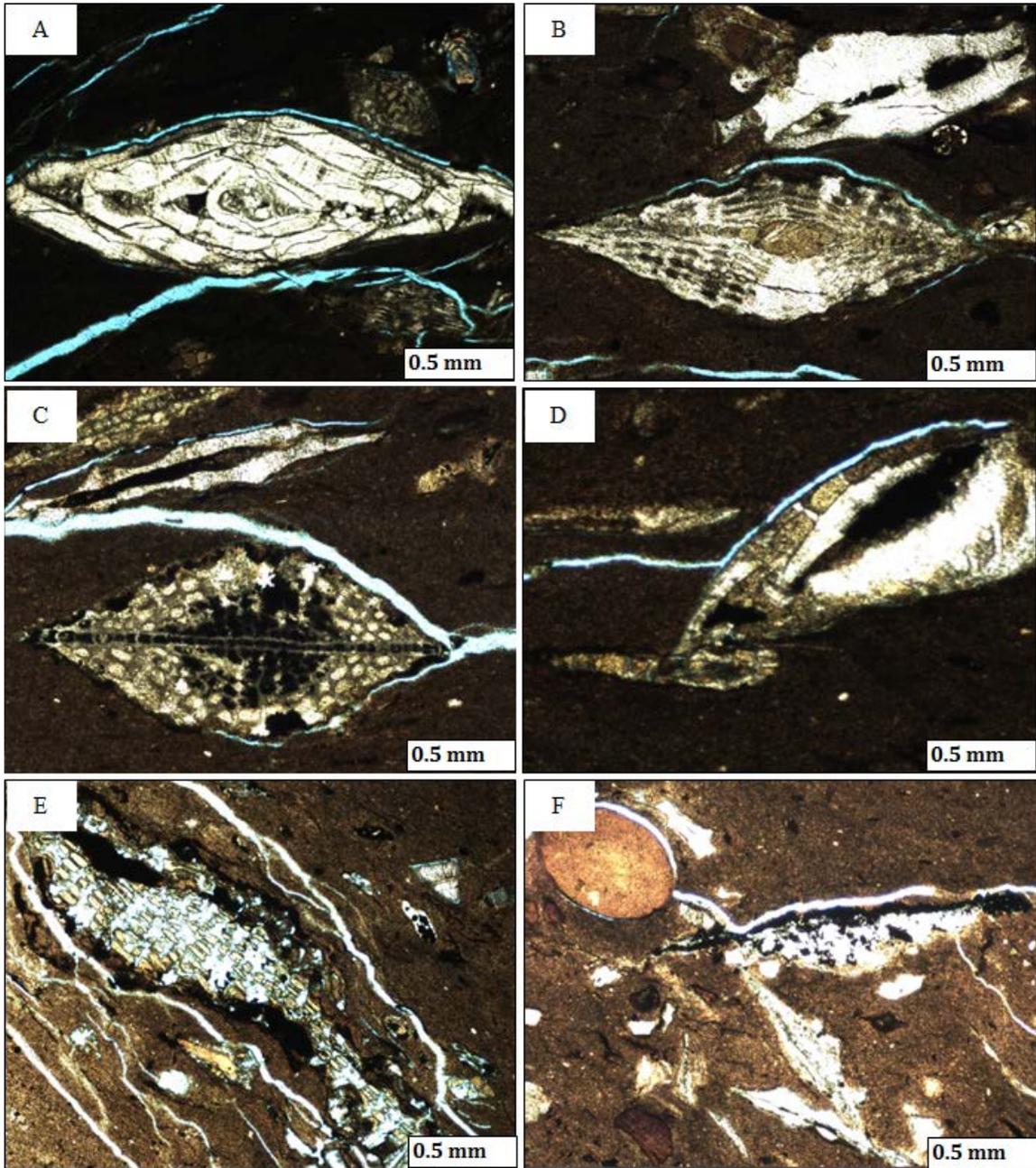


Figure 15: Representative photomicrographs of the Kopili Shale from Dauki River section (sample D₇), northeastern Bengal Basin. (A) Nummulite. (B-F) Forams surrounded by dark carbonaceous (?), fine-grained matrix.

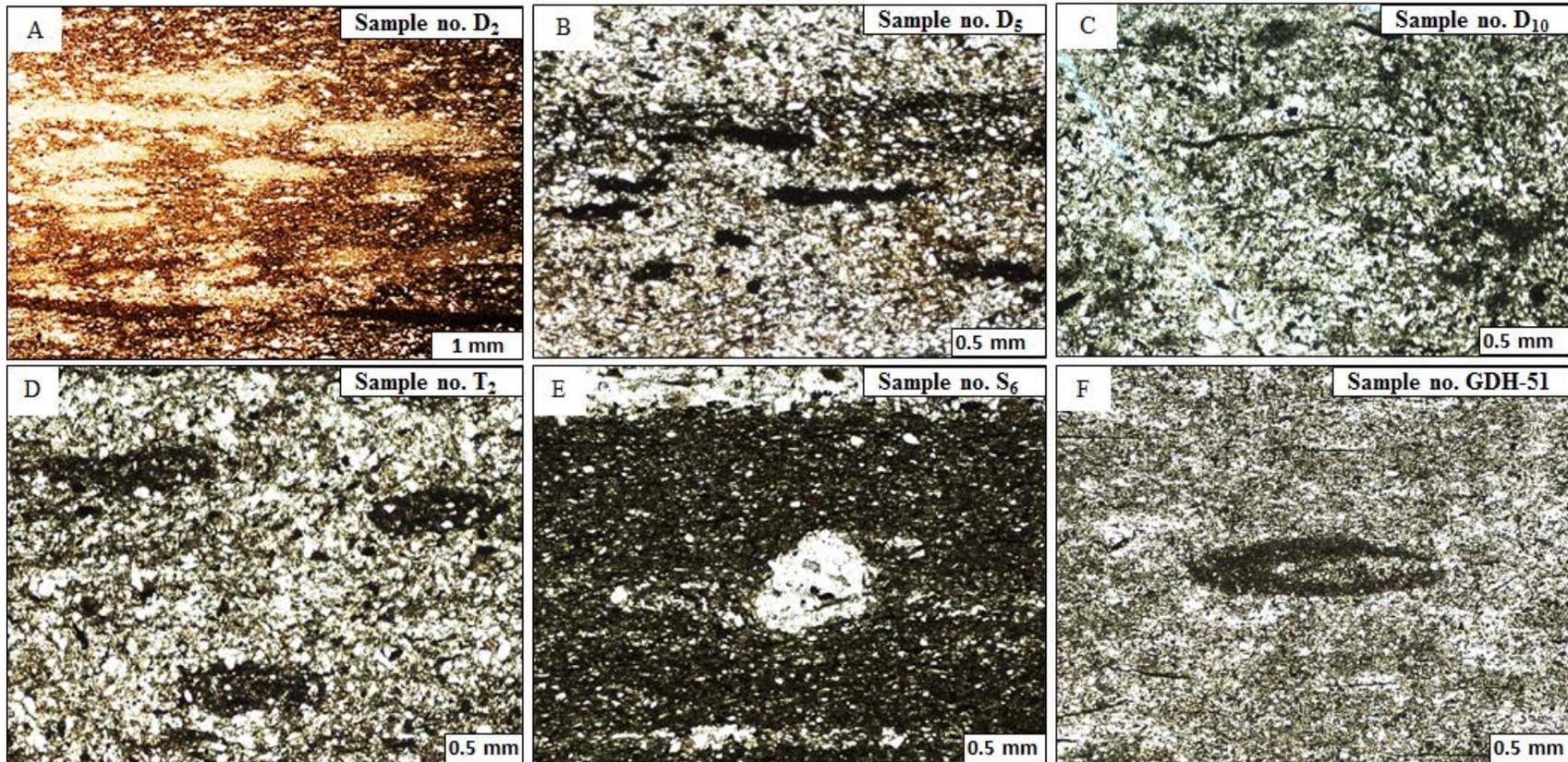


Figure 16: Representative photomicrographs of Kopili Shale from the northeastern (A-E) and northwestern (F) Bengal Basin showing bioturbate fabrics. (A and E) Burrows filled with silt and fine-sand. (B, C, D, and F) Burrows filled with darker more carbonaceous (?), fine-grained matrix.

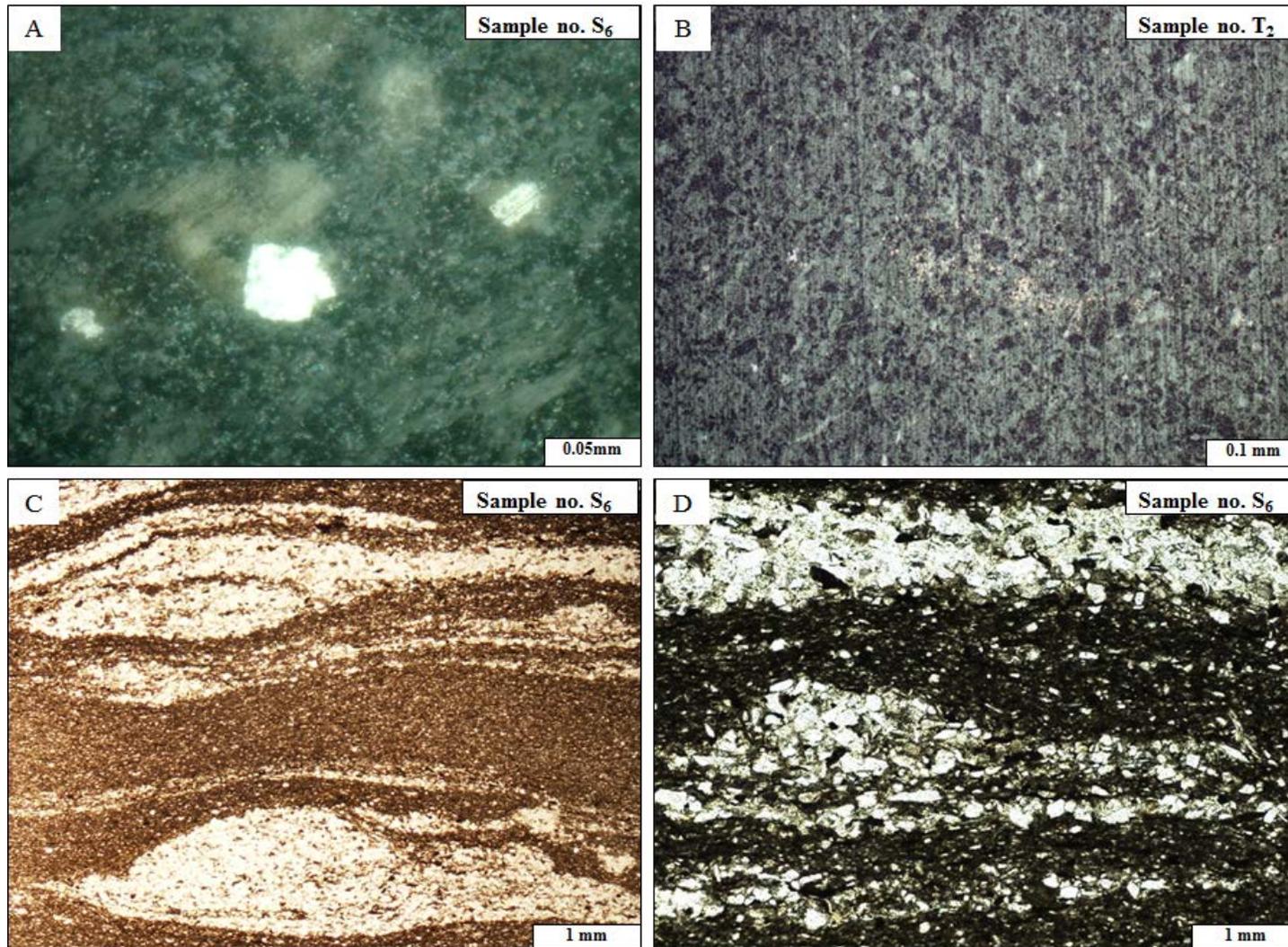


Figure 17: Representative photomicrographs of the Kopili Shale from the northeastern Bengal Basin. (A) Cubic pyrite grains. (B) Very fine dispersed pyrite grains. (C) Sand lenses. (D) Starved ripples.

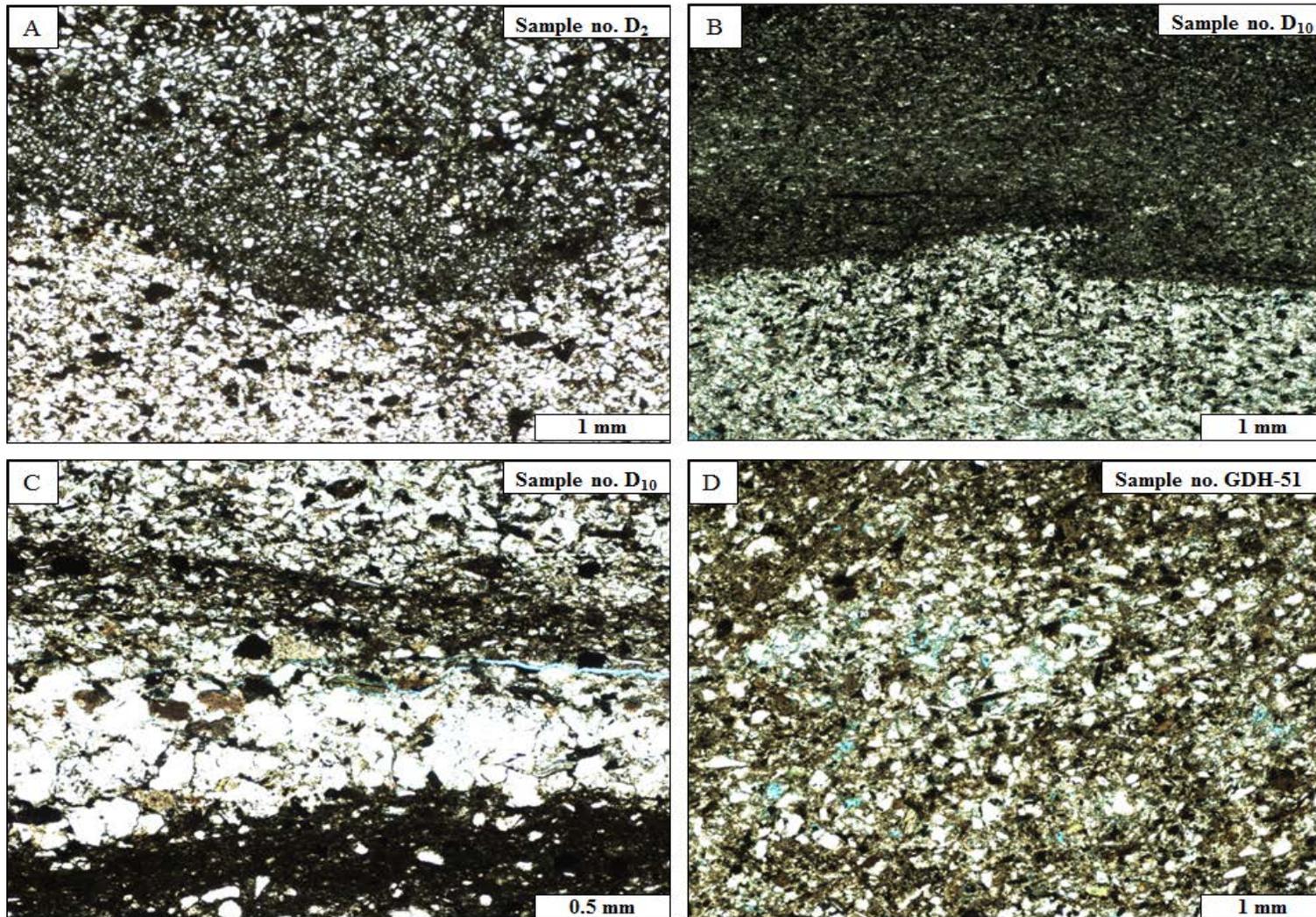


Figure 18: Representative photomicrographs of the Kopili Shale from both northeastern (A-C) and northwestern (D) Bengal Basin, showing concentrations of silt-sized particles and darker more organic-rich, finer-grained matrix (A-D).

3.2 Organic Petrologic Analysis

Organic petrologic analysis of a clastic sedimentary rock (e.g. shale) or organic rich coal source-rock may show several dispersed organic macerals. The compositions and types of each maceral are described in Table 4. The appearance of organic macerals in reflected white light for both thermally immature and thermally mature petroleum source-rocks is shown in Table 5. The maturity of a source rock is determined microscopically from vitrinite reflectance because the chemical and optical properties of vitrinites alter more uniformly during maturation than the other maceral groups (e.g. liptinite, bituminite, and inertinite). In addition, fluorescence intensity of the macerals decreases with increasing maturity (Littke, 1987; Taylor et al., 1998). The presence of alginite with admixtures of bituminite (micrinite) as well as minor inertinite and vitrinite suggest a marine to shallow marine source rock (Littke et al., 1988).

Table 4: Organic maceral types in petroleum source rocks (modified from Taylor et al., 1998).

Macerals	Composition	Types of kerogen	Change in composition during maturation
Liptinite	High hydrogen content (sporopollenin, resins, waxes and fats)	I	Macerals become richer in carbon and poorer in hydrogen and oxygen
Bituminite		II	
Vitrinite	High oxygen content (lignin and cellulose of plant cell walls)	III	
Inertinite	High carbon content (same plant substances as vitrinite and liptinite, but they have experienced different primary transformation)	IV	

Table 5 : Appearance of macerals in reflected white light for thermally immature and mature petroleum source-rocks. Maximum reflectance observed in the Kopili Shale is shown in parenthesis.

Macerals	Thermally immature	Thermally mature
Appearance of macerals in incident light		
Liptinite	Dark grey-black	Dark grey (<0.5%)
Bituminite		Medium grey (0.5 to 0.8%)
Vitrinite	Dark grey	Light grey to white (0.8 to 1.5%)
Inertinite	Pale grey-white	Greyish white to yellowish white (>1.5%)

Organic petrologic analysis of the Kopili Shale under reflected white and blue light excitation reveals several varieties of dispersed organic matter, including liptodetrinite, bituminite, vitrodetrinite, and inertodetrinite. The dispersed organic matters observed in the Kopili Shale are described below.

Liptinite (liptodetrinite) - Liptinite originates from relatively hydrogen-rich plant materials such as sporopollenin, cutin, resin, waxes, as well as from bacterial degradation of proteins, cellulose, and other carbohydrates (Table 4; Taylor et al., 1998). Liptinite macerals are equivalent to Type I kerogen (Table 4; Taylor et al., 1998). The Liptinite macerals commonly have a short interval of variations of the reflectance, which increase with the increasing maturity of the source rock (Sotirov et al., 2002). Liptinites change systematically during diagenesis, but their reflectivity and fluorescence show higher standard deviations than vitrinite (Littke, 1987). The liptinite group is divided into specific macerals such as sporinite, cutinite, resinite, and liptodetrinite. In the Kopili Shale, the two most common liptinite-group macerals observed are cutinite and liptodetrinite. Cutinite originates from cuticular layers and cuticles, which are formed within the outer walls of the epidermis of leaves, stems, and other aerial parts of plants (Taylor et al., 1998). In reflected white light, cutinites look darker in color (Figure 19A-C) and give lower reflectance values in the range of 0.0 to 0.5% R_o . Cutinite observed in the Kopili Shale is weakly fluorescent with a brown color (Figure 19D), which is an indicator of thermal maturity. Liptodetrinite macerals include liptinitic constituents that are small in size and finely detrital in nature. Many different substances contribute to the formation of liptodetrinite. These include fragments and finely degraded remains of sporinite, cutinite, resinite, alginite, and suberinite, but they also may derive from

unicellular algae (Taylor et al., 1998). Liptodetrinite also was observed in the Kopili Shale, which has low reflectance (Figure 20A-E) similar to cutinite and is weakly fluorescent to non-fluorescent (Figure 20F). The weakly to non-fluorescent liptinite macerals in the Kopili Shale also shows high standard deviation (Figure 5), indicating a thermally mature source-rock.

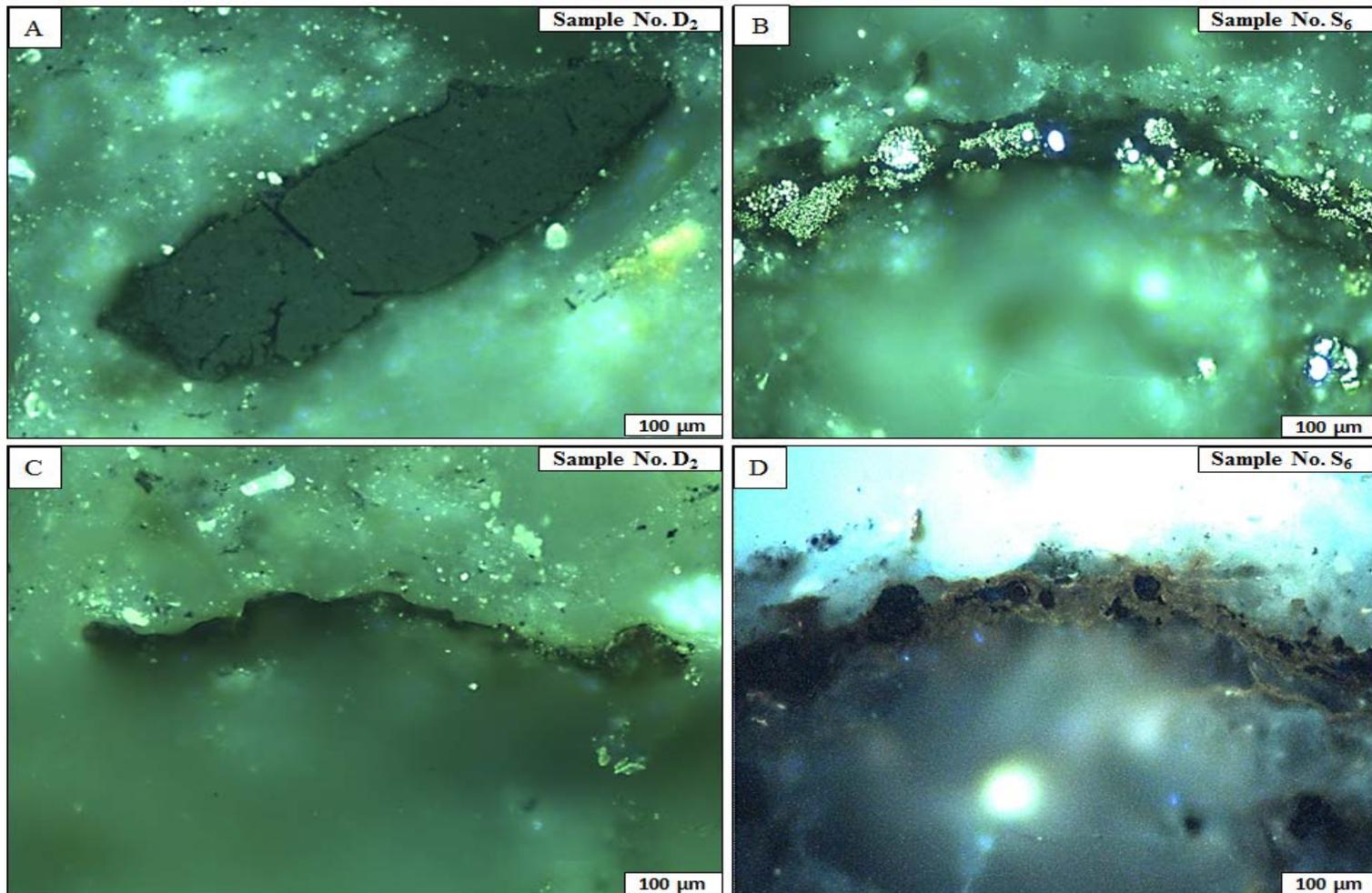


Figure 19: Representative photomicrographs of cutinites in the Kopili Shale from the northeastern Bengal Basin observed under white (A-C) and fluorescent light (D), respectively. (A-C) Cutinites representing leaf structure with dark appearance. (D) Weak fluorescence and brown color of the same cutinite particle shown in B.

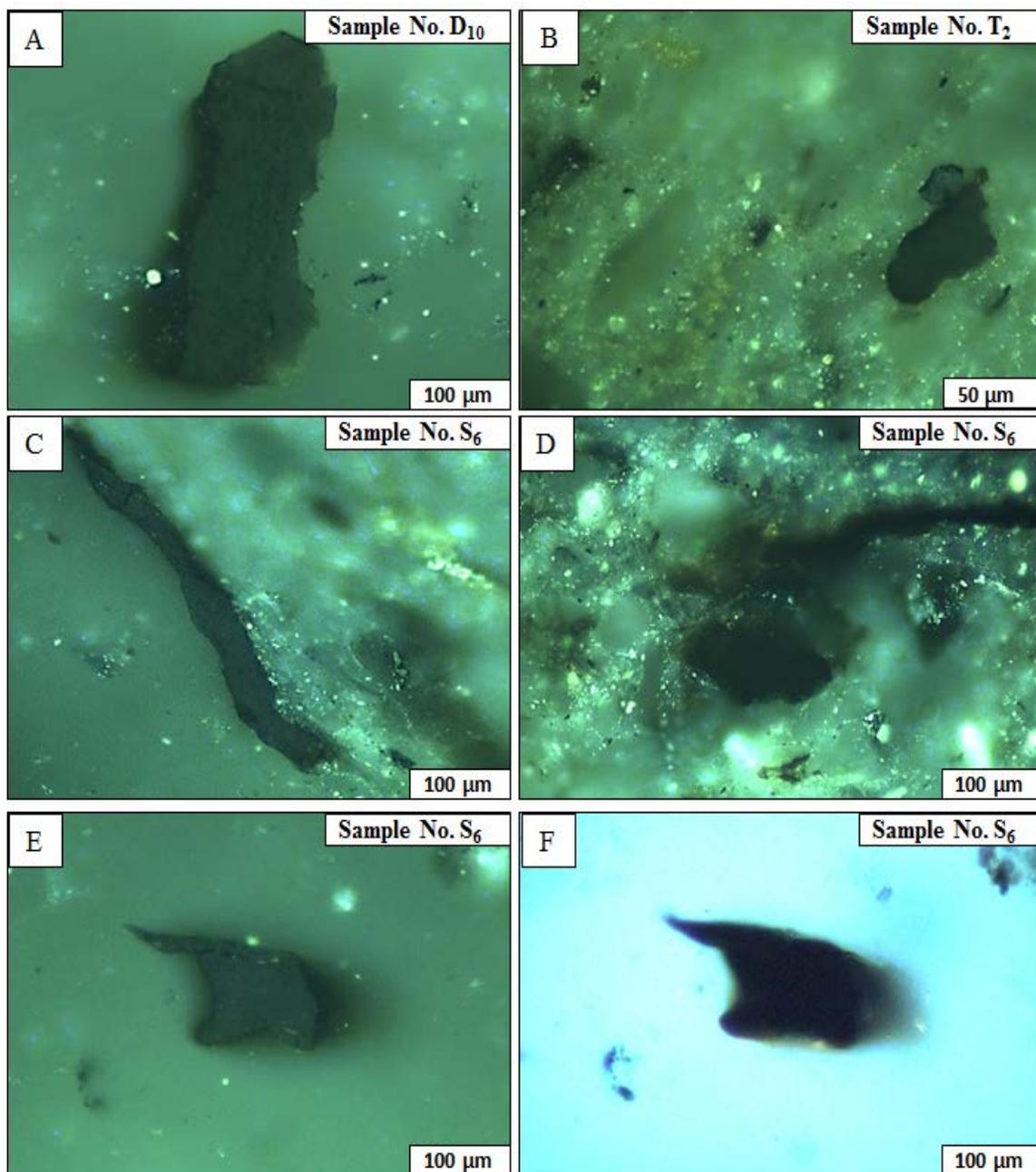


Figure 20: Representative photomicrographs of liptodetrinites in the Kopili Shale from the northeastern Bengal Basin observed under white (A-E) and fluorescent light (F), respectively. (A-F) Fragments of liptinite macerals. (F) Non-fluorescent liptodetrinite.

Bituminite – Bituminite particles fall in the liptinitic group of macerals that give low reflectance (weak brownish reflectance or none at all) in reflected white light (Figures 21A) and lack characteristic shapes and structure. Bituminite macerals are equivalent to Type II kerogen (Table 4). Bituminite is a major source material for oil in oil-prone source-rocks (Taylor et al., 1998). Micrinite is a maturation product of bituminite in oil shales, and is common in marine to shallow marine source rocks (Taylor et al., 1998). Micrinite is interpreted to be a product of diagenetic changes within the oil generation zone (vitrinite reflectance 0.5 to 1.2%), where oil-like substances like exsudatinite are produced and micrinite forms as a residue (Littke, 1987). Micrinites in Kopili Shale are very small rounded to subangular grains (2 μm in diameter; Figure 21B). The presence of weakly to non-fluorescent bituminite and micrinite in the Kopili Shale indicate a mature petroleum source-rock. Exsudatinite is a secondary maceral generated at the beginning of the bituminization process. A genetic relationship exists between exsudatinite and the brightly fluorescing fluid expulsions, which indicates the presence of oil in source rock (Taylor et al., 1998). Weakly fluorescing bituminite (Figures 21C and 21D) and brightly fluorescing exsudatinites (Figures 22A and 22B) were observed in both the northeastern and northwestern samples of the Kopili Shale. Bituminite in the Kopili Shale displays alteration from bituminite enclosing liptodetrinite/alginate at early mature stage (Figures 22C and 22D; sample S6) to micrinitised bituminite at mature stage (gas window; Figure 21B). This type of alteration is generally regarded as a result of liquid hydrocarbon generation from thermally cracked bituminite (Teichmüller, 1974).

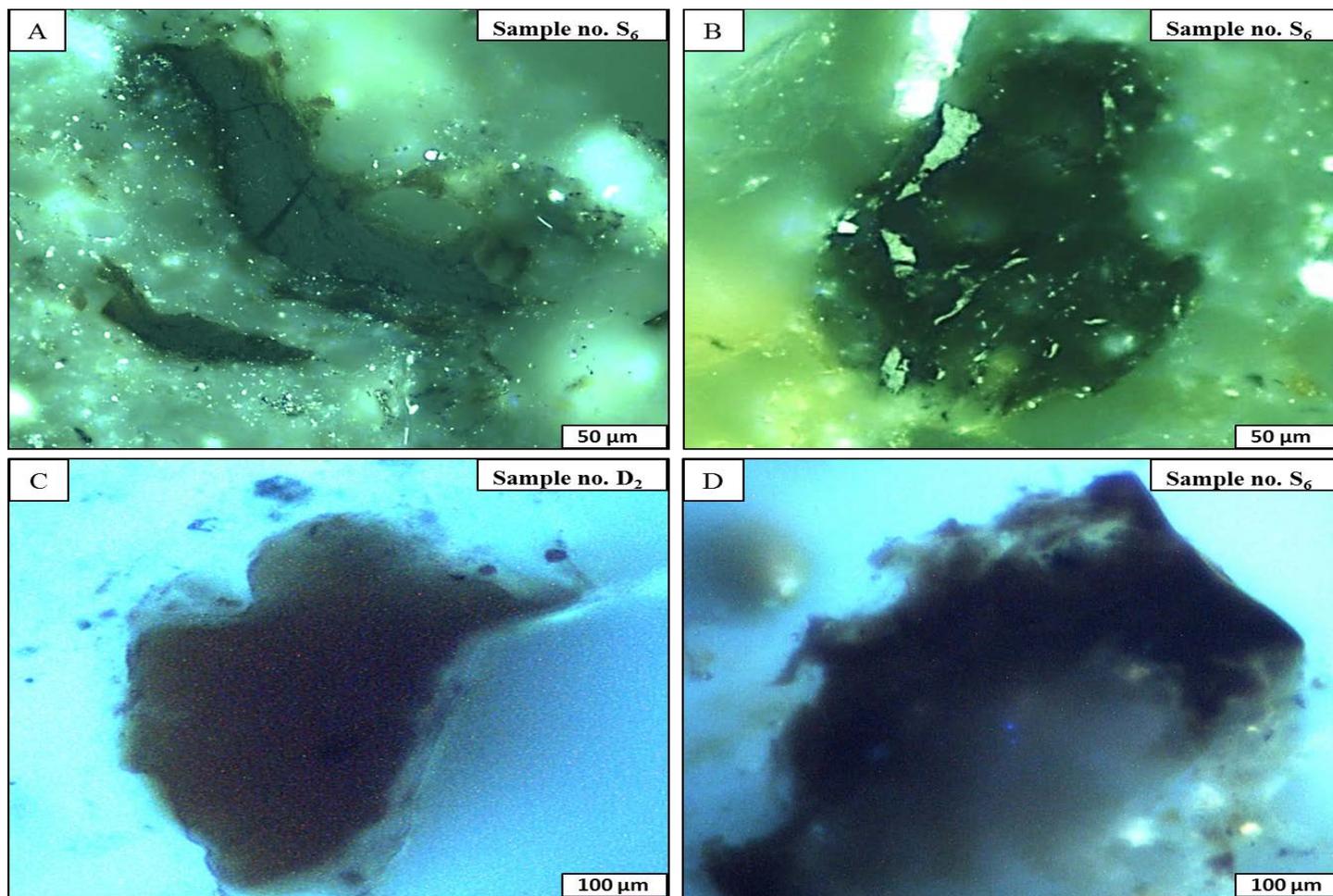


Figure 21: Representative photomicrographs of bituminites and micrinities, observed under reflected white light (A, B) and fluorescent light (C, D) in the Kopili Shale from the northeastern Bengal Basin. (A) Bituminite showing darker reflectance. (B) Dispersed micrinite over a dark bituminite maceral. (C, D) Weakly to non-fluorescent bituminites.

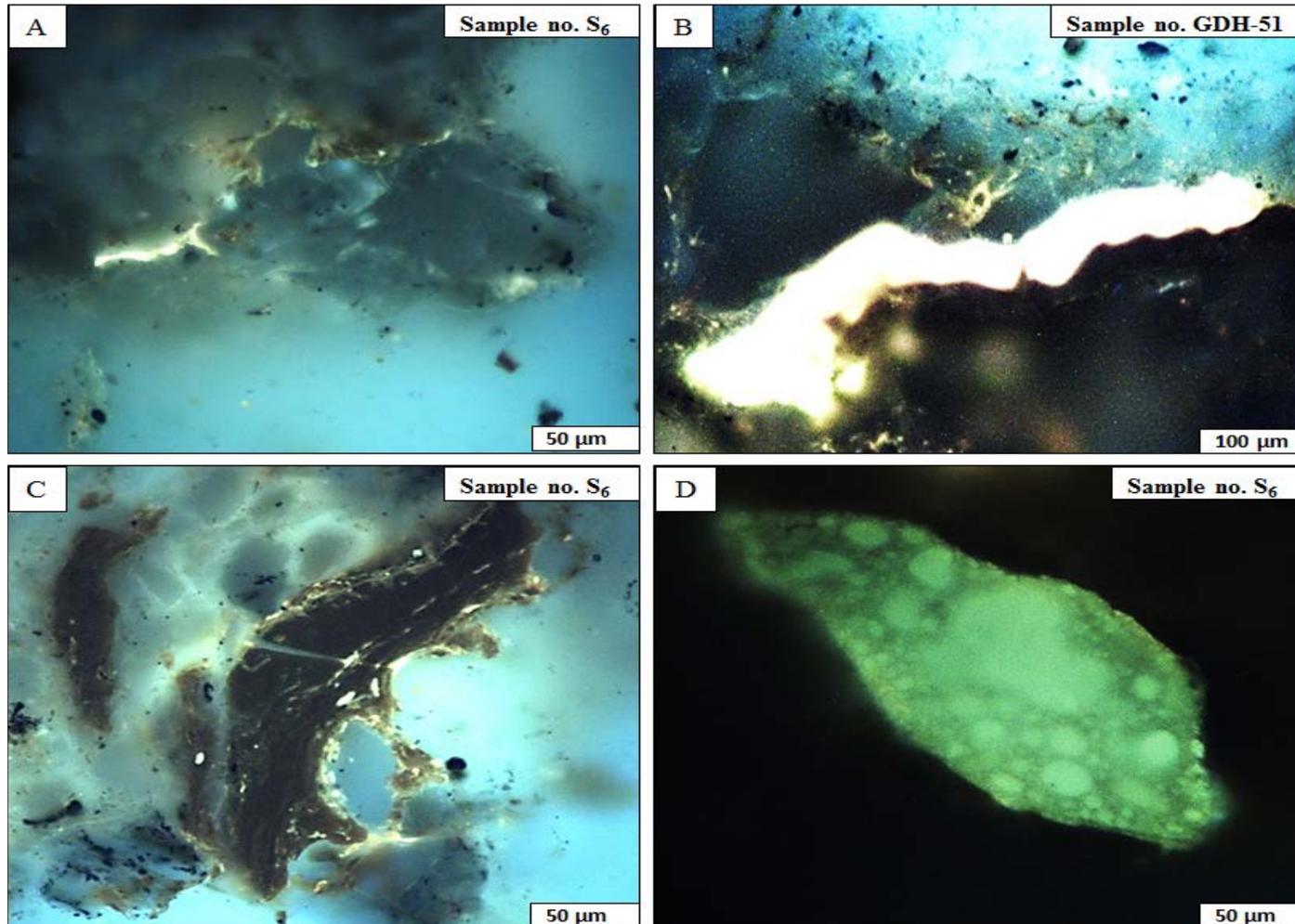


Figure 22: Representative photomicrographs of bituminites (exsudatinites) and alginites, observed under fluorescent light, in the Kopili Shale from the northeastern (A, C and D) and northwestern (B) Bengal Basin. (A, B) Brightly fluorescing exsudatinites. (C, D) Weakly to non-fluorescent bituminite with inclusions of brightly fluorescing alginite.

Vitrinite - Vitrinite originates from humic substances, which are dark-colored compounds of complex composition and are largely alteration products of lignin and cellulose, which are derived from woody tissues of roots, stems, bark and leaves (Taylor et al., 1998). Vitrinite macerals are equivalent to Type III kerogen (Table 4; ICCP, 1994a). Vitrinite designates a group of macerals whose color is gray and whose reflectance is generally between that of the associated darker liptinites and lighter inertinites (Table 5; ICCP, 1994a). Vitrinite is characterized by relatively high oxygen content compared with the macerals of the other groups. Carbon increases and oxygen decreases steadily during the maturation of the source-rock, whereas vitrinite has the highest hydrogen content of about 85% ^{14}C in the form methane, corresponding to a random reflectance of 1.0-1.1% (ICCP, 1994a). Vitrinite reflectivity also proved to be the best because of its low standard deviation and its constant change (Littke, 1987). Fluorescence intensity of the vitrinite decreases with increasing maturity (Teichmüller and Durand, 1983). Vitrinite is a major source of natural gas. The Kopili Shale from the Bengal Basin contains vitrinite macerals, which were identified by their light gray color; plant cell structures (Figure 23) under incident white light, and have reflectance in the range of 0.8-1.5% (Table 5), but are also non-fluorescent, indicating that the Kopili Shale is a thermally mature source-rock.

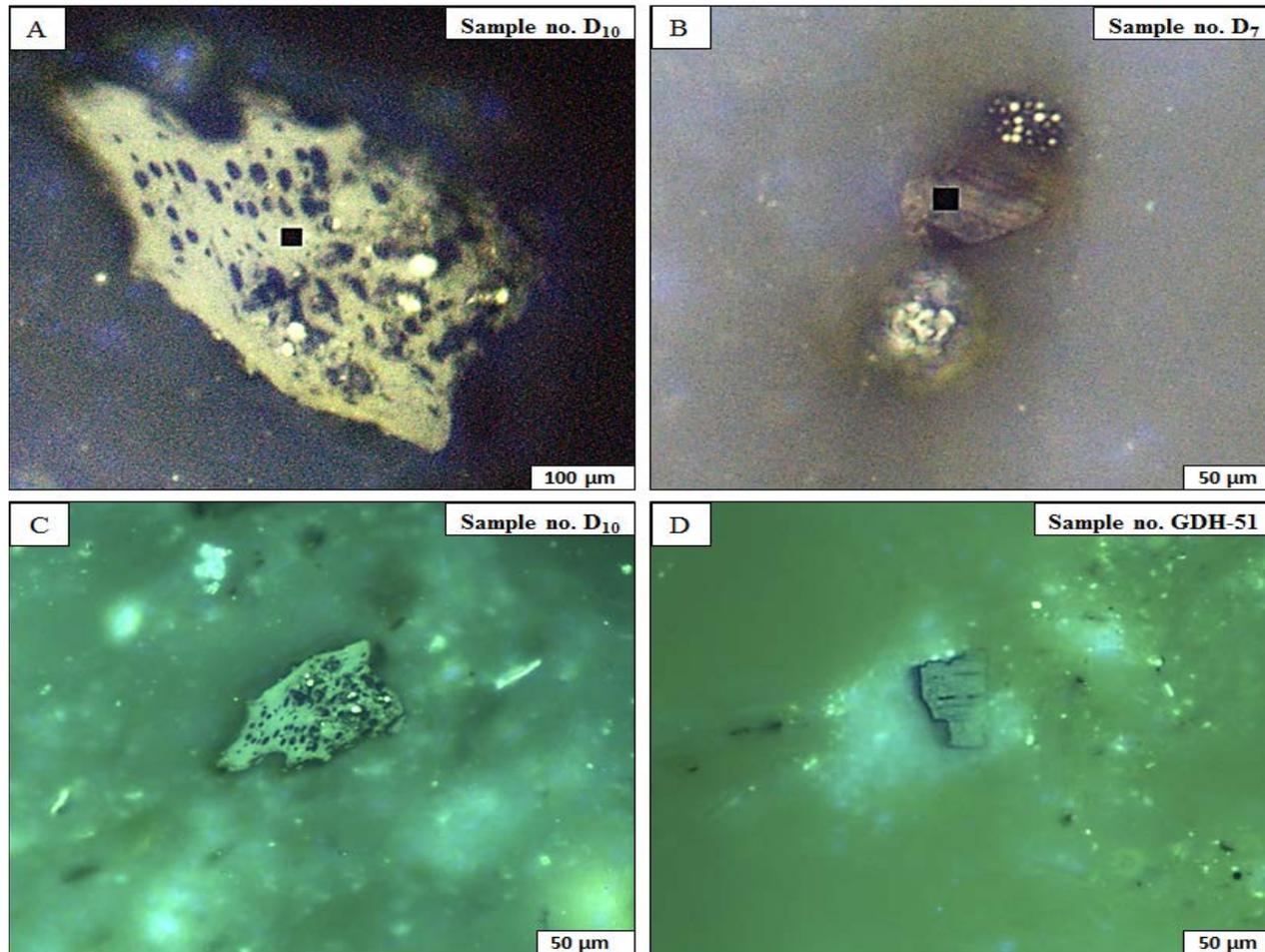


Figure 23: Representative photomicrographs of vitrinites, observed under reflected light, in the Kopili Shale from the northeastern (A-C) and northwestern (D) Bengal Basin. (A and C) Vitrinite macerals showing plant cell structure. (B and D) Vitrinite maceral showing plant fibers in core sample of the Kopili Shale. Black squares in A and B show the vitrinite reflectance measurement points in these vitrinite macerals.

Inertinite – Inertinite macerals originate from the same plant substances as vitrinite and liptinite, but have undergone different primary transformation and are marked by higher degrees of decomposition (Littke, 1987). Inertinite is a maceral group that comprises macerals whose reflectance in mature source rocks is higher than that of the macerals of the vitrinite and liptinite groups. The term inertinite implies that the constituents are more inert than the macerals of the vitrinite and liptinite groups. Inertinite is characterized by high carbon content and low oxygen and hydrogen content, reflecting the process of fusinitization. Inertinite macerals are equivalent to Type IV kerogen (Table 4; ICCP, 1994b). The sub-macerals of the inertinite group are fusinite, semifusinite, micrinite, and inertodetrinite (Taylor et al., 1998). The reflectance of both micrinite and inertodetrinite is higher than the vitrinite, resembling semifusinite/fusinite (Figure 24). Inertodetrinites was commonly observed in the Kopili Shale (Figure 24), which occurs as discrete small inertinite fragments of varying shape. The reflectance of inertinite in mature source rock is higher than that of the macerals of the vitrinite and liptinite groups. Inertinite macerals are also characterized by absence or lower fluorescence than displayed by vitrinite (ICCP, 1994b). Micrinite (Figure 21B) and inertodetrinite (Figures 24A and 24C) were commonly observed in the Kopili Shale, the reflectance of which is higher than vitrinite, resembling semifusinite/fusinite (Figures 24B and 24D). In the northwestern Kopili Shale, inertinite macerals with a maximum reflectance value ($R_o=4\%$; Figure 26A) is probably a shard of anthracite that was transported from elsewhere. This is an indication that some material from the source area was being cooked to anthracite rank, exhumed, and transported into the study area.

Among the described macerals present in the Kopili Shale, liptodetrinite, cutinite, and bituminite are the most common macerals of the liptinitic group. A few brightly fluorescing macerals were observed locally, which may be attributed to exsudates (Figures 22A and 22B) and alginite (Figures 22C and 22D) of the liptinitic group. Inertinite macerals include various forms of inertodetrinite (Figure 24) resembling semifusinite/fusinite with higher reflectance values. The presence of vitrinite and inertinite macerals in the Kopili Shale indicates a woody-plant origin, which suggests both Type-III and Type-IV kerogen, respectively; where Type-III kerogen is mostly gas prone and Type-IV kerogen is inert. On the other hand, the presence of brightly fluorescing alginite and exsudatinites (Figure 22) indicates Type-II oil/gas prone kerogen, and the presence of cutinites indicate Type-I oil prone kerogen.

Framboidal pyrite occurs in some liptinitic macerals (Figures 25A and 25B), including degraded cutinite. This indicates early diagenetic sulfate reduction at shallow burial depth. Leaf litter and other plant debris in the shale indicate significant input of terrestrial material into the system. Dominance of the terrestrial organic matter, along with pyrite, in the Kopili Shale suggests a relative shallow marine depositional setting with reducing pore waters (Taylor et al., 1998).

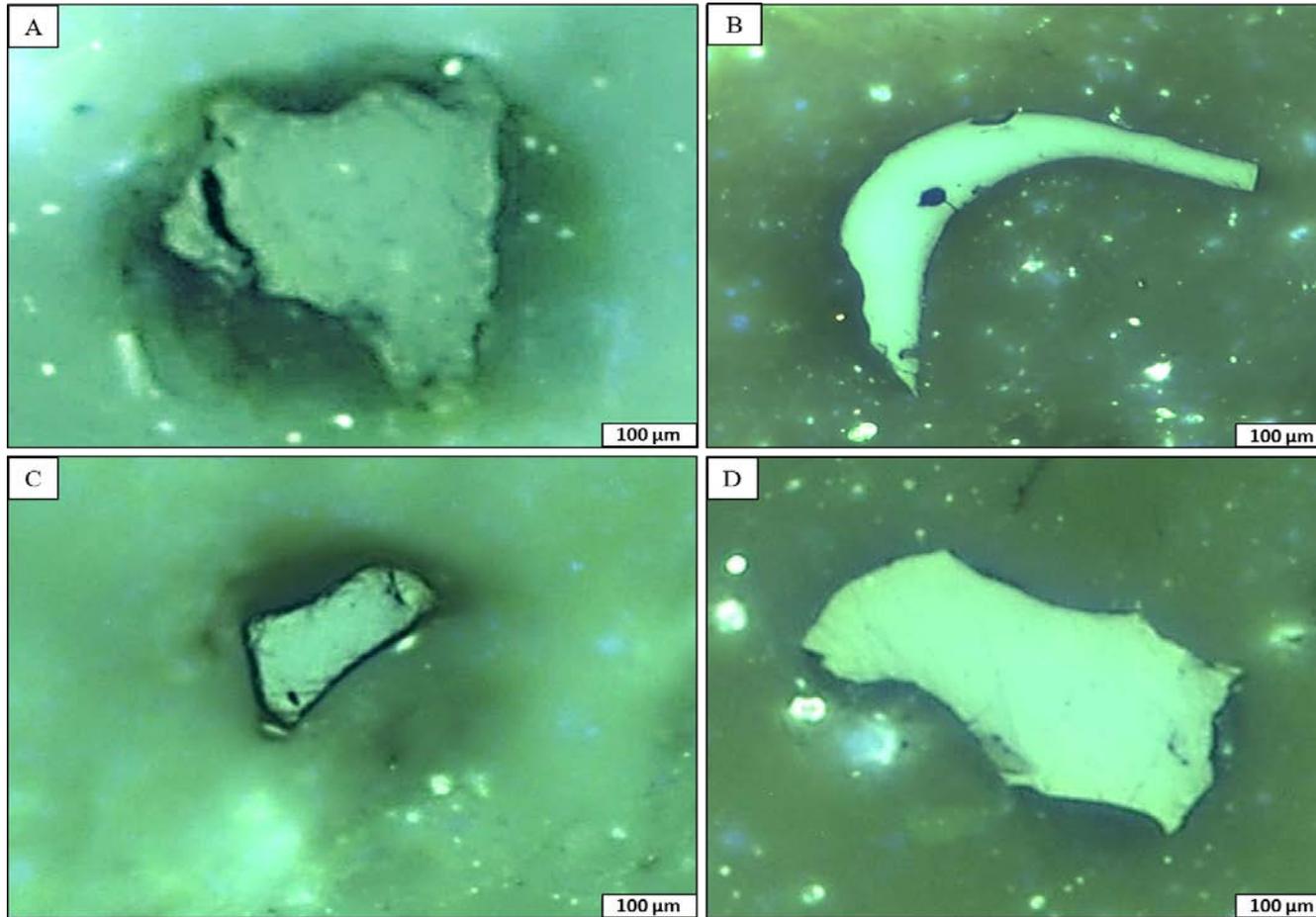


Figure 24: Representative photomicrographs of inertinites (A-D), observed inreflected white light, in the Kopili Shale, Bengal Basin. (A, C) Inertodetrinites. (B, D) Semi-fusinite/fusinite.

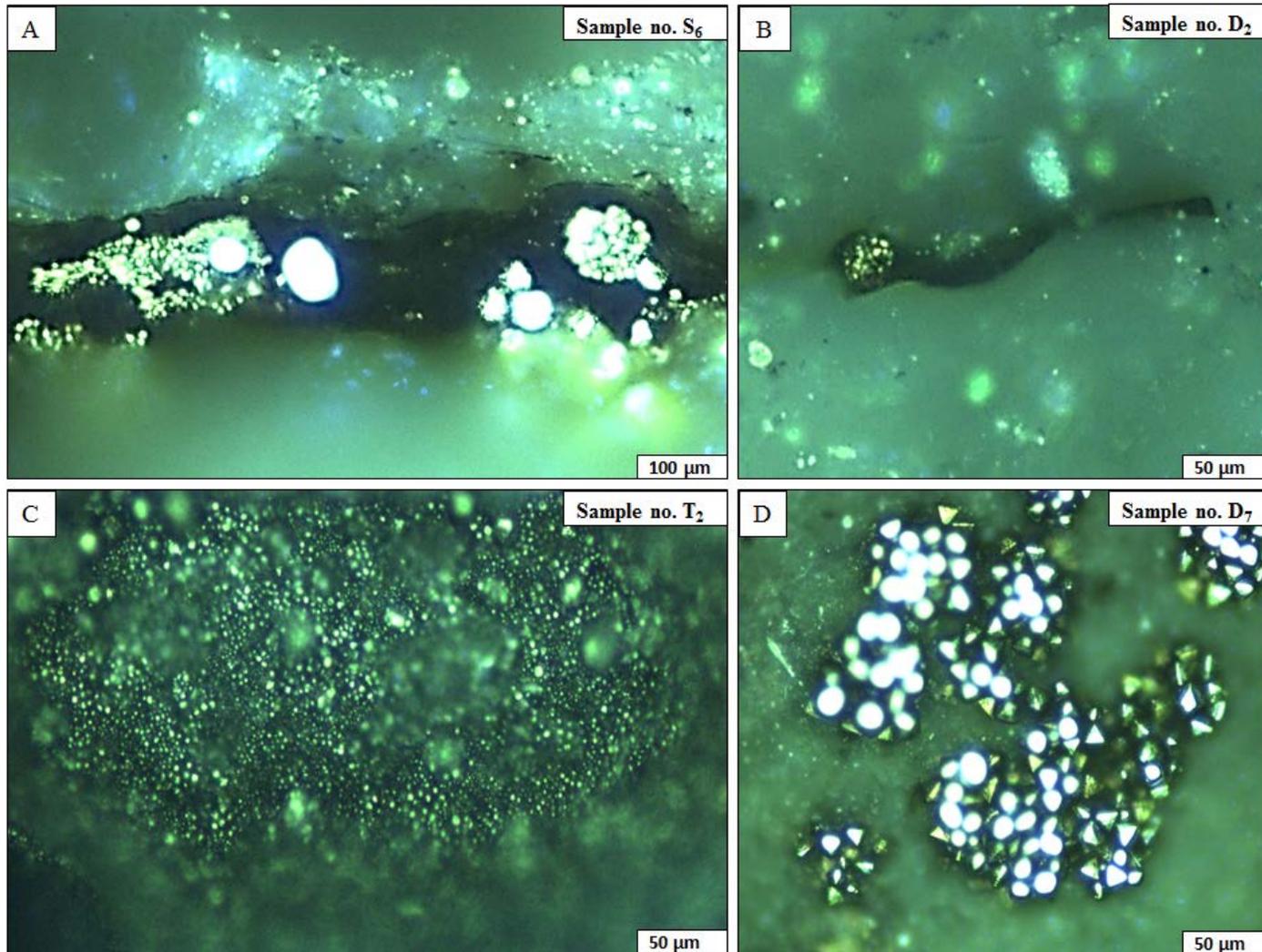


Figure 25: Representative photomicrographs of pyrite, observed under reflected light, in the Kopili Shale from the northeastern (A-D) Bengal Basin. (A-D) Pyrite framboids.

3.2.1 Vitrinite Reflectance Analysis

Vitrinite reflectance is a strong thermal maturity indicator of organic matter. The ranges of reflectance for each maceral group in the Kopili Shale samples are illustrated in histograms shown in figure 26. The reflectance of the macerals from all groups (liptinite, bituminite, vitrinite, and inertinite) increases with increasing maturity of the shale (Sotirov et al., 2002). The reflectance of liptinite, vitrinite, and inertinite macerals in the Kopili Shale ranges from 0.0 to 0.5%, 0.6 to 0.8%, 0.8 to 1.5%, and 1.8 to 4.0%, respectively (Figure 26). The average reflectances of the vitrinite and liptinite macerals are similar in both the northwestern samples (Figure 26A) and the northeastern (Figures 26B-F). The mean vitrinite reflectance values of the Kopili Shale in the northeast (Dauki River, Tamabil, and Sripur sections) and northwest core samples are 1.15%, 1.15%, 0.86%, and 1.24%, respectively (Table 2). From the Dauki River section, samples no. D₂ and D₇, are at a greater depth than sample no. D₁₀. The presence of inertinite macerals in sample no. D₂ and D₇ indicate that the Kopili Shale attains thermal maturity at greater depths. The presence of higher reflectance inertinite macerals suggest that the northwest Kopili Shale sample is also mature. Vitrinite reflectance values for all samples (except sample S₆ from Sripur section) range from 1.02 to 1.32%, indicating that the Kopili Shale in these areas is mature and falls within the oil to wet-gas windows (Table 6). In contrast, vitrinite reflectance ($R_o = 0.86\%$) for sample S₆ indicates that the Sripur section falls in an immature to early mature oil window prior to uplift. Together, the reliable T_{max} result from the northeast Sripur section and vitrinite reflectance results for all samples suggest that the upper Eocene Kopili Shale is thermally mature.

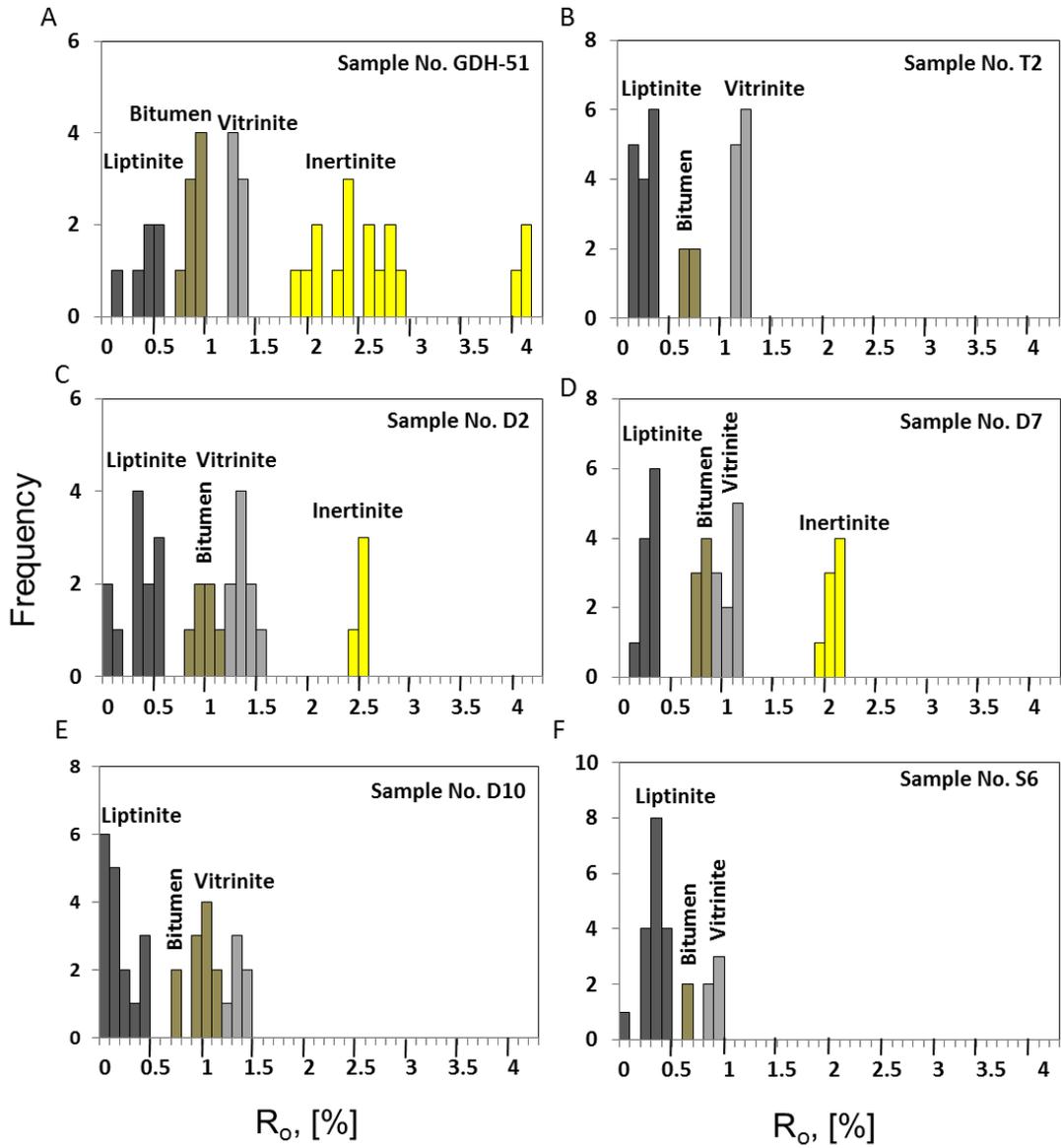


Figure 26: Histograms showing reflectance, R_o (%), of different maceral groups in the Kopili Shale from the northeastern (A-E) and northwestern (F), Bengal Basin, Bangladesh.

Table 6: Comparison of source-rock potential between the Kopili Shale in Bengal Basin and Assam Shelf.

Geochemical Parameters		Northwest (Stable Shelf) Bengal Basin	Northeast (Sylhet Trough) Bengal Basin	Assam Shelf Assam, India
Thickness (m)		30-60 (Drilled)	40-90 (outcrop)	300-700(outcrop)
Organic Richness	TOC (wt. %)	0.45-0.52 (Poor)	0.34-1.43 (Poor to Fair)	0.50-1.50 (Fair to Good)
Organic Matter Type	Hydrogen Index (HI) and maceral types	Type-I,II,III, and IV Oil and gas-prone	Type-I,II,III, and IV Oil and gas-prone	Type-II-III Oil and gas-prone
Maturity	T _{max} (°C)	506*	(431-443)*;(S ₆ = 433)	410-450
	Vitrinite Reflectance (% R _o)	1.24% Mature	0.86 – 1.15% Mature	0.5 – 0.7% Immature to early mature
Generalized HC Zone	T _{max} and R _o	Wet-Gas Window	Peak Oil Window	Peak Oil Window

*Unreliable Tmax; low S₂ peak

3.3 XRD and XRF Analysis

X-ray diffraction (XRD) and x-ray fluorescence (XRF) analyses of the Kopili Shale were performed on all the samples collected in the northeastern and northwestern Bengal Basin.

3.3.1 XRD analysis - XRD technique was used to characterize variations in shale mineralogy. X-ray diffractograms of the Kopili Shale from the northeast (Figure 27A-C) and northwest (Figure 27D) show various minerals such as quartz, pyrite, muscovite, montmorillonite, and illite. Mineralogy of the Kopili Shale from the northeast is dominated by quartz and illite. Iron-rich sulfide minerals (pyrites) and oxides are accessory minerals. Large amounts of quartz were observed in the Kopili Shale from Dauki River and Sripur sections (Figure 27A and 27C). Amounts of clay minerals such as illite and montmorillonite are higher in the northeastern samples compared to the northwestern sample. XRD analysis on limited number of samples suggests that the Kopili is quartz-rich shale.

3.3.2 XRF analysis - X-ray spectrums of the Kopili Shale are plotted as energy (KeV) vs. counts of each element. XRF analysis resulted in peaks for Fe, Ti, K, Cl, and Si, along with Mn, Cr, V, S, and Al. The presence of both the iron and sulfur content in the northeastern and northwestern Kopili Shale samples indicate the presence of pyrite (FeS_2). This result is supported by petrologic analyses of the samples, which shows pyrite framboids (Figure 25). Higher silicon concentrations are observed in few analyzed samples from the Dauki River section, which is backed by XRD results, revealing an abundance of quartz. One analyzed core sample from the northwest shows high calcium

content (Figure 28D), and other samples from the northeast (Figure 28A-C) show low calcium content. The presence of calcium can come from the carbonate cement and/or biogenic carbonate. Other elements such as Al, S, Cl, K, Ti, V, Cr, and Mn show very low peaks in all the samples.

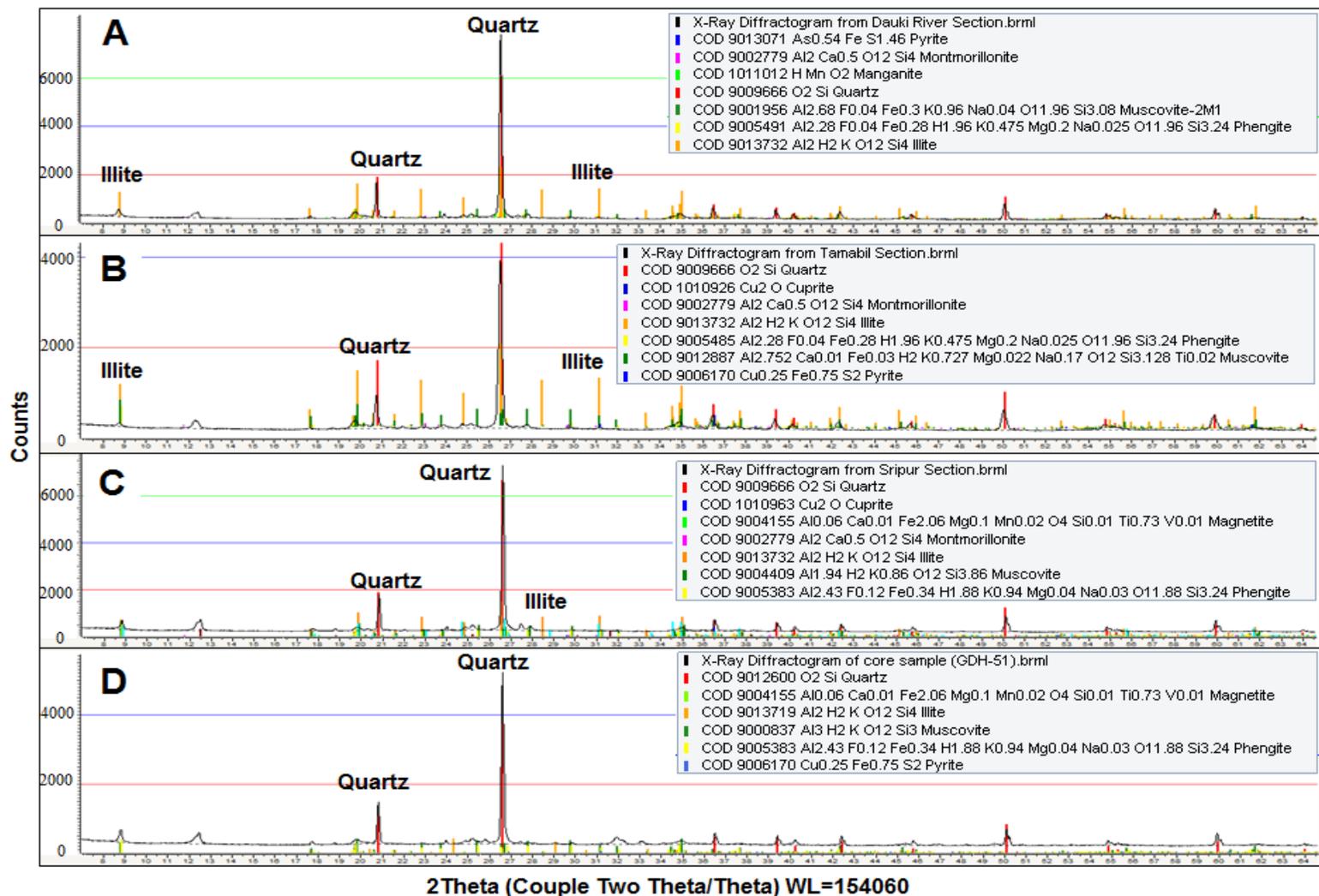


Figure 27: X-ray diffractograms (2 θ spectrums) of Kopili Shale samples from the northeastern (A-C) and northwestern (D) Bengal Basin, Bangladesh. Quartz and illite has the dominant patterns.

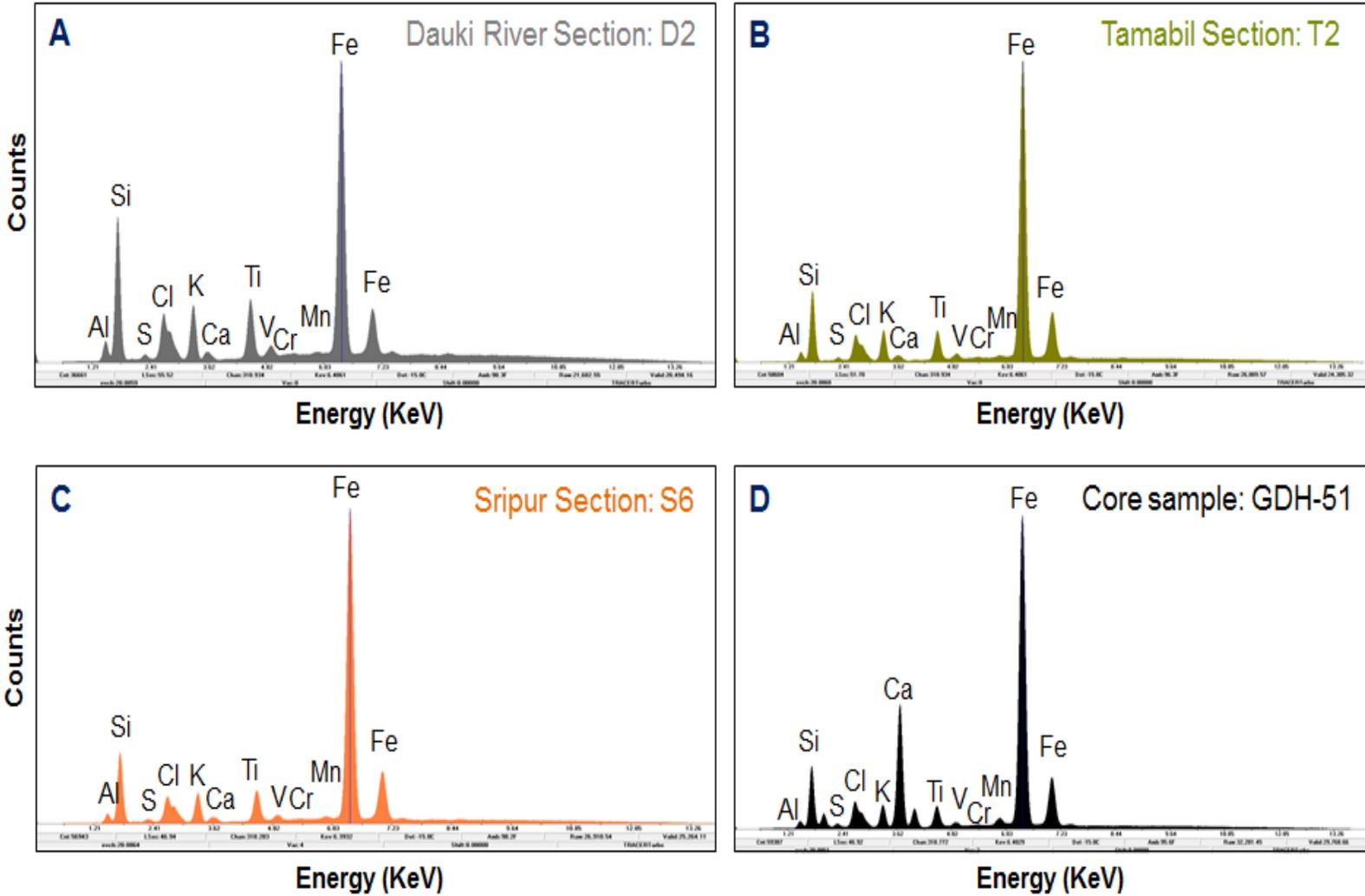


Figure 28: X-ray spectra of Kopili Shale samples from northeastern (A-C) and northwestern (D) Bengal Basin, Bangladesh.

3.4 TOC Analysis

The data obtained from total organic carbon (TOC) analyses are reported in Table 2. The average TOC values for samples from the northeast Dauki River, Tamabil, and Sripur sections are 0.6%, 0.4%, and 1.0% (average = ~0.67%), respectively. The Kopili Shale from the Sripur section is comparatively organic rich (TOC = 0.56 to 1.43%), suggesting fair hydrocarbon potential. The Kopili Shale samples from the Dauki River, Tamabil, and northeastern core samples have TOC contents ranging from 0.40 to 0.83%, 0.34 to 0.45%, and 0.45 to 0.52%, respectively. These values all indicate poor hydrocarbon potential.

3.5 Rock-Eval Pyrolysis

The data obtained from Rock-Eval pyrolysis are reported in Table 7 and Appendices A and B. The programmed pyrolysis illustrates a series of peaks on the pyrograms (Figure 29). Hydrocarbon generation potential of shale depends on the amount (organic richness), type, and maturity of the organic matter present in it (Tissot and Welte, 1978). On the basis of geochemical analyses such as TOC and Rock-Eval pyrolysis, the hydrocarbon generation potential is described into the following three sections:

3.5.1 Organic Richness

Rock-Eval pyrolysis and TOC analyses result shows an average TOC value of 0.50% and 0.67%, in the northwest and northeast, respectively. The northwest core sample is organically lean with TOC of 0.52% (obtained from Rock-Eval pyrolysis). Programmed pyrolysis on the Kopili Shale samples resulted in S2 peaks. These are

illustrated in pyrograms (Figure 29), wherein the amount of hydrocarbons emitted is plotted against T_{\max} and time required to complete the pyrolysis. All the samples show S2 peaks near 12 minutes (Figure 29), but at a slightly different T_{\max} . The pyrogram for the northeast sample from Sripur section shows a sharp S2 peak (Figure 29F), indicating higher expulsion of hydrocarbons during pyrolysis from this comparatively organic-rich (TOC=1.0%; Table 2) shale. Samples from the northwestern core sample (Figure 29A) and the other two outcrop sections (Figures 29B-E) show low and broad S2 peaks. Together with the low TOC contents (Table 2), these data indicate low hydrocarbon generation potential. The core sample (Figure 29A) also shows a high S3 peak compared to those of the northeast samples (Table 7), indicating the presence of carbonate in the shale. The overall hydrocarbon potential of the Kopili Shale based on Rock-Eval pyrolysis is poor to fair (Table 6).

Table 7: Rock-Eval analysis data of Kopili Shale showing total organic carbon, carbonate, and programmed pyrolysis data.

Sample No.	RE	RE			Tmax (°C)	**	HI	OI	S2/S3	S1/TOC *100	RE
	TOC	S1	S2	S3							CARB
S ₆	0.97	0.03	0.70	0.16	433		72	16	4.4	3	1.58
T ₂	0.38	0.01	0.08	0.26	443	**	21	68	0.3	3	1.17
D ₂	0.83	0.02	0.10	0.19	443	**	12	23	0.5	2	1.17
D ₇	0.64	0.01	0.04	0.41	431	**	6	64	0.1	2	2.92
D ₁₀	0.55	0.02	0.10	0.22	436	**	18	40	0.5	4	1.00
GDH-51	0.52	0.01	0.14	0.99	506	**	27	190	0.1	2	2.17

Notes:

LECO - TOC on Leco Instrument

TOC - Total Organic Carbon, wt. %

** - low S₂, T_{max} is unreliable

RE - Programmed pyrolysis on Rock-Eval instrument

S1 - volatile hydrocarbon (HC) content, mg HC/ g rock

S2 - remaining HC generative potential, mg HC/ g rock

S3 - carbon dioxide content, mg CO₂ / g rock

HI - Hydrogen index = S₂ x 100 / TOC, mg HC/ g TOC

OI - Oxygen Index = S₃ x 100 / TOC, mg CO₂/ g TOC

CARB – Carbonate = Mineral Carbon% x 100_(CaCO₃) / 12_(C)

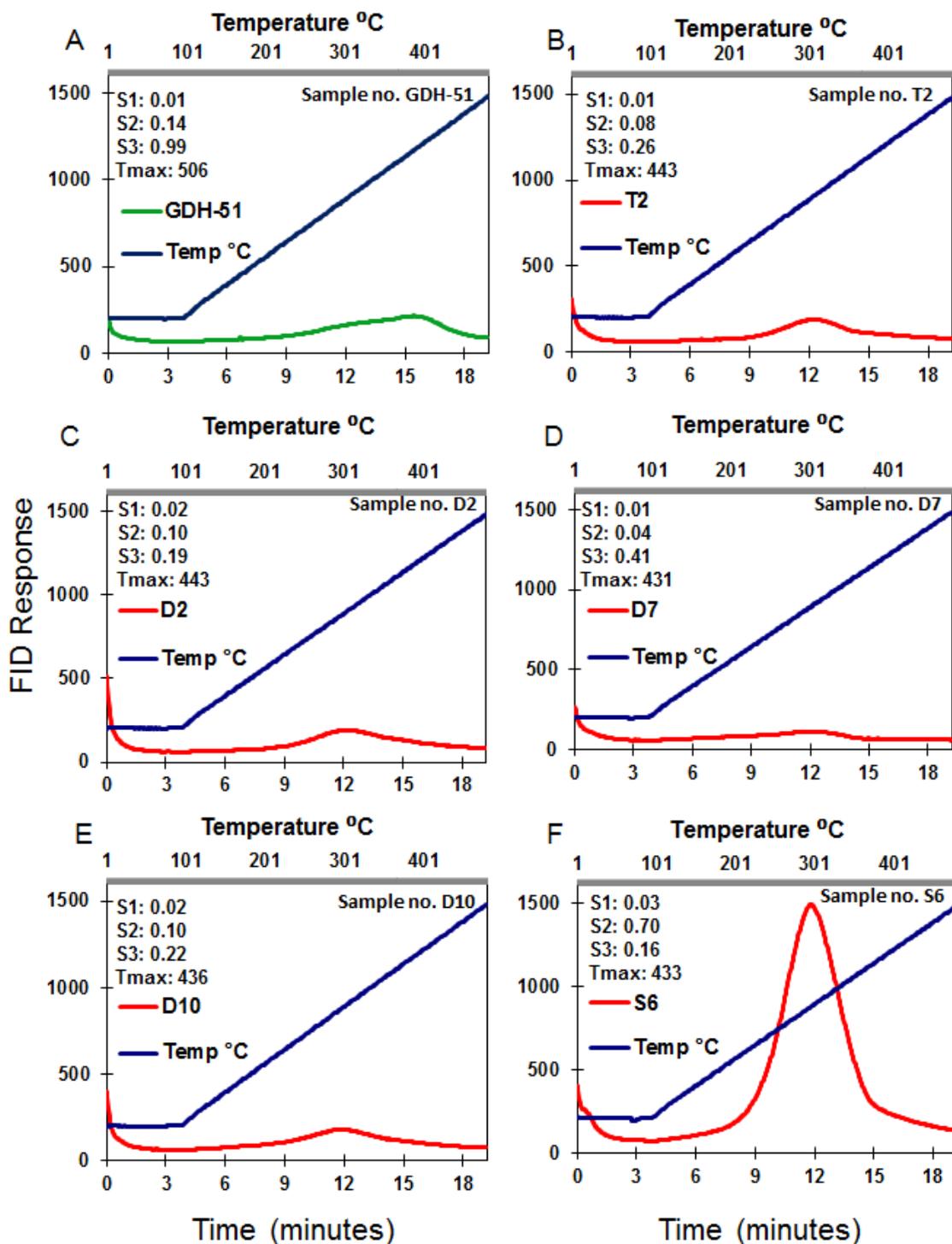


Figure 29: Pyrograms showing S2 peaks (green and red curves) of samples from the northwestern (A) and northeastern (B-F) Kopili Shale samples. Free hydrocarbons are measured by the S1 peak and residual hydrocarbons are measured by the S2 peak. CO, CO₂, and mineral carbon components are recorded as S3.

3.5.2 Type of Organic Matter

The type of kerogen present in a source rock can be determined by using parameters such as hydrogen index (HI) and oxygen index (OI) from Rock-Eval pyrolysis. The HI and OI data are reported in Table 2. A modified Van Krevelen diagram (Figure 30) shows the presence of both Type-III and Type-IV kerogen. The Kopili Shale from the northeast Sripur section has high hydrogen index and low oxygen index, and has a reliable T_{max} value (based on well-developed S2 peak; Figure 29F), indicating Type-III kerogen (Figure 30). The Kopili Shale samples from other sections in the northeast and northwest show very low hydrogen and high oxygen indices, but T_{max} values are unreliable due to low and broad S2 peaks.

The Rock-Eval pyrolysis results on the kerogen types in the Kopili Shale are backed by results from organic petrologic analysis, which show the prevalence vitrinite and inertinite macerals and thus, Type-III and Type-IV kerogen. Presence of less common brightly fluorescing alginite and exsudatinites also suggest Type-II kerogen. Hence, the bulk kerogen type in Kopili Shale samples, based on both Rock-Eval pyrolysis and organic petrologic analysis, is mixed Type-II, III and IV.

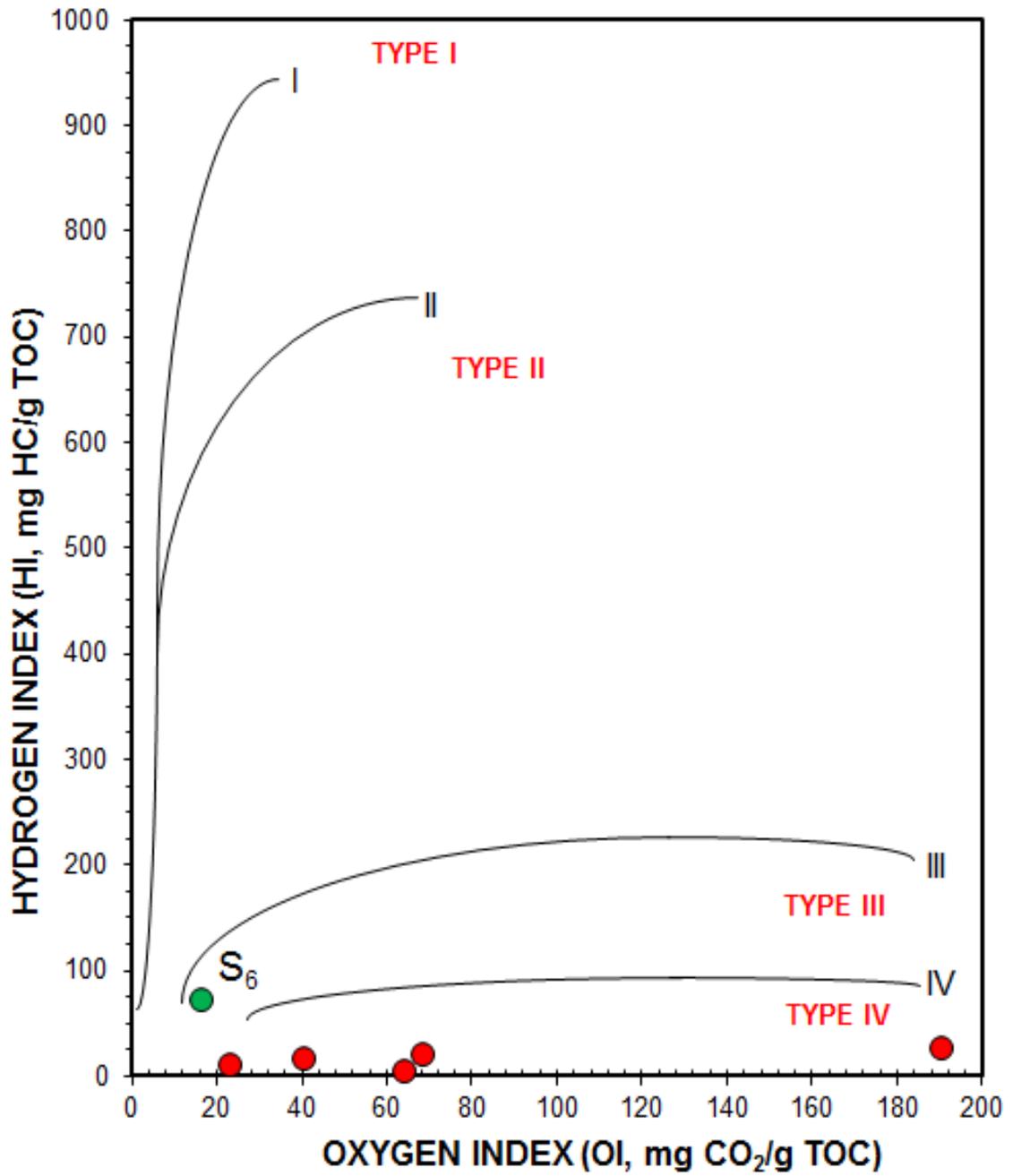


Figure 30: Modified Van Krevelan diagram showing the types of kerogen present in the Kopili Shale from the Bengal Basin. Green circle and red circles, respectively, represent reliable and unreliable HI and OI data for the Kopili Shale obtained from Rock-Eval pyrolysis.

3.5.3 Maturation state of organic matter

Thermal maturity of organic matter can be assessed based on T_{\max} data derived from Rock-Eval pyrolysis. Samples from the northeast and northwest samples have T_{\max} values ranging from 431 to 443°C and 506°C, respectively (Table 2). Given generally low S_2 values for all but the more carbonaceous sample S_6 , most of the T_{\max} values reported in Table 2 are unreliable. The T_{\max} value of 433°C for sample S_6 suggests that the Kopili Shale at the Sripur section is immature to early mature, and lies in the oil generation window (Table 6). This is supported by vitrinite reflectance data described above.

CHAPTER 4: DISCUSSION

The Kopili Shale in the Bengal Basin, Bangladesh, was deposited at a passive margin setting south of the Tibetan (Eurasian) plate (Figure 1). During late Eocene, regression of the sea deposited fine clastics of the Kopili Shale over the marine limestone in distal deltaic to shelf and/or slope environments (Banerji, 1981). The depositional environment of the Kopili Shale was also interpreted as paralic (brackish-marshy) based on lithological and fossil content (Uddin and Ahmed, 1989; Reimann, 1993). At the same time, the Kopili-equivalent shales were deposited in a shallow-marine to lagoonal environment in the Assam shelf area (Wandrey, 2004; Moulik, 2009). The depositional environments and lithologies of the Kopili Shale in the Bengal Basin are different from the Kopili Formation in Assam, India. The Kopili Formation in Assam consists of shale and fine-grained sandstone beds with marl beds (Moulik, 2009), while the Kopili Shale in the Bengal Basin consists of mostly dark gray shale, silty-shale, and subordinate marl beds (Khan, 1991; Uddin and Lundberg, 1998). The Kopili Formation is potential source rock for oil and gas in the Sylhet-Kopili/Barail-Tipam composite petroleum system in Assam, India (Wandrey, 2004), while the source-rock potential of the Kopili Shale in the Bengal Basin is still not known well.

Thin section petrographic analysis of the Kopili Shale samples from the Dauki River section shows a layer (sample D₇; Figure 15) with several kinds of foraminifera including larger *Nummulites* in the lower part of the formation, which is a biostratigraphic indicator of late Eocene (Brouwers, 1992). Thin sections from all three

outcrops (Dauki River, Tamabil and Sripur) of the Kopili Shale show bioturbation structures and pyrite framboids, which indicate deposition in an environment characterized by at least periodically oxygenated bottom waters and sulfidic pore-water conditions. Sand lenses and silt-sized particles were observed in the upper part of the Kopili Shale in all three outcrops in the northeast and core sample from the northwest, which indicate relative shallow setting wherein high-energy pulses carried coarser sediments.

Organic petrologic analysis of Kopili Shale samples from the northwestern Bengal Basin reveal smaller micrinite macerals, which usually are present in oil shales (Teichmuller and Wolf, 1977) and deposited in marine environments (Taylor, 1998). Brightly fluorescing alginites were observed in Kopili Shale samples from both the northeastern and northwestern Bengal Basin, which indicate the presence of some oil-prone kerogen in the shale.

XRD diffractograms (Figure 27A) show large amounts of quartz in the Kopili Shale, which is supported by the presence of high silicon peaks in XRF spectra (Figure 28A) from the northeastern Dauki River section. The dominant peaks for quartz in the diffractograms suggest most samples of the Kopili Shale are quartz-rich. The XRF spectrum for the northwest core sample shows a high calcium peak, indicating the presence of carbonate cement in the shale.

The average geothermal gradient in the northeastern Sylhet Trough region (Figure 1) of the Bengal Basin is low, ranging from 15.8 to 30°C/km (Hossain, 2009), which along with high sediment thickness may have resulted in thermal maturation of the shales

at depths > 5 km. The Kopili Shale in the Sylhet Trough occurs at a depth > 6 km and, is expected to be thermally mature (Shamsuddin et al., 2001; Curiale, 2002). In the Indian Platform area (Figure 1), the average geothermal gradient ranges from 21.1 to 31.6° C/km, where high temperatures at shallow depth provide adequate heat for thermal maturation of petroleum source rocks. The Kopili Shale was encountered at a shallow depth of 240 m (Banerji, 1984) in the Indian Platform area. Given its proximity to the Rajmahal hotspot trap (Figure 4), the shale was expected to be thermally mature. The work of Shamsuddin et al. (2001) on the Kopili Shale from the Indian Platform area suggests that the Kopili Shale is thermally immature ($T_{\max}=429-432^{\circ}\text{C}$ and $R_o=0.40-0.46\%$).

Geochemical analyses such as TOC analysis and Rock-Eval pyrolysis results suggest that the Kopili Shale in the northwest and two northeastern outcrop sections (Dauki River and Tamabil) in the Bengal Basin, have poor hydrocarbon generation potential (mean TOC <0.6%, low S2 peaks). As an exception, Kopili Shale samples from Sripur section have fair hydrocarbon generation potential (mean TOC= 1.0%; moderate S2 peak). The Kopili Formation in the upper Assam, northeast India, has TOC contents of 0.5 to 1.5%, indicating fair to good hydrocarbon generation potential (Wandrey, 2004). The differences in organic richness in coeval units indicate changes in facies, depositional environments, and, perhaps, tectonic activity in areas surrounding the basin. The Kopili Shale contains mixed kerogen types (Type II, Type III, and Type IV) as determined from Rock-Eval pyrolysis and organic petrologic analyses. The reliable HI and OI data from the northeast Sripur section indicate Type III gas-prone kerogen, which is supported by the presence of common vitrinite macerals in the samples from the

northeast Bengal Basin. The presence of inertinite macerals in the samples suggests Type-IV kerogen. Presence of a few brightly fluorescing bituminite macerals in the Kopili Shale from both the northeast and northwest indicates Type-II oil-prone kerogen. Similarly, the Kopili Formation in the upper Assam, India, contains mixed Type II and Type III kerogens (Naidu and Panda, 1997).

Maturity of the organic matter from the northwest core samples suggest that the Kopili Shale is mature ($R_o=1.24\%$; Table 2) and falls in the wet-gas generation window (Table 6). The Kopili Shale in the northeast is also mature ($R_o=0.86-1.15\%$; Table 2) and falls in the peak oil-generation window (Table 6). The Kopili Formation in Assam, India, is immature to early mature ($R_o=0.50$ to 0.70%) and falls in the peak oil-generation window (Table 6). Hence, in comparison, the Kopili Shale from the Bengal Basin is generally more mature (Tables 2 and 6) than the Kopili Formation in Assam, India. The organic carbon content in the Kopili Shale from the northeast Sripur section is similar to the Kopili Formation in upper Assam, which is about 100 to 200 km away from the Sripur section (Figure 9). The organic richness (Thickness * TOC) of the Kopili Formation makes it a potential source rock for petroleum systems in Assam, India (Naidu and Panda, 1997). A generally inadequate thickness (~30 m) of the Kopili Shale in the northwestern Indian Platform area makes it difficult to consider as a major source rock. Rather, it more likely serves as a seal for the Cherra-Sylhet-Kopili petroleum system in western Bangladesh (Shamsuddin et al., 2001). Based on the current research, hydrocarbons (gas and minor oil) may have been expelled from the Kopili Shale both in the northwest and in the Sylhet Trough. The hydrocarbons generated from the Kopili Shale could have been accumulated in Eocene-Oligocene stratigraphic traps (if any) in

the deeper part of the basin, or may have contributed hydrocarbons to the structural traps of the Miocene reservoirs. Future detailed analysis of subsurface core samples from the northwestern and northeastern (if available) Bengal Basin will help better assess the generation potential. Further work needs to be carried out on migration of gaseous hydrocarbons in the Sylhet Trough, Hinge Zone, and deep basin areas.

CHAPTER 5: CONCLUSIONS

Based on the results of analyses carried out for this research, the following conclusions can be drawn:

1. Petrographic and organic petrologic analyses suggest that the Kopili Shale was deposited in a shallow marine environment, characterized by at least periodically oxygenated bottom and sulfidic pore waters.
2. XRD and XRF results reveal high quartz content in the Kopili Shale.
3. TOC analysis of the Kopili Shale samples show TOC contents ranging from 0.34-1.43% (average = ~0.67%) and 0.45-0.52% (average = ~0.50%) in the northeast and northwest, respectively, indicating poor to fair hydrocarbon-generation potential.
4. Hydrogen and oxygen indices determined from Rock-Eval pyrolysis for the organic-rich Sripur sample (S_6) suggest Type-III gas-prone kerogen. Petrologic observations indicate that organic matter in the Kopili Shale is predominantly terrestrial in origin and represents an admixture of Type-I, II, Type III, and Type IV kerogens.
5. Based on Rock-Eval pyrolysis ($T_{max} = 433^{\circ}\text{C}$; Sample no. S_6) and vitrinite reflectance ($R_o = 0.86$ to 1.24%) analyses, the Kopili Shale in the Bengal Basin is thermally mature. Most samples fall in the oil to wet-gas generation windows

(Table 6). As an exception, the Sripur sample falls within the peak oil window prior.

6. The geochemical results from the current study suggest that, excepting the Sripur section, the Kopili Shale in the Bengal Basin is thermally mature but has poor hydrocarbon generation potential. In comparison, the Kopili Formation in Assam, India, is early mature to mature and has fair to good hydrocarbon generation potential. A more comprehensive study using additional samples of the Kopili Shale will help better assess the petroleum potential of this unit.

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