The Dhaka University Journal of Earth and Environmental Sciences, Vol. 13 (2): 2024

Petroleum Source Rock Evaluation in the Eastern Fold Belt, Bengal Basin, Bangladesh: An Integrated Study using Seismic, Well Log, Field Investigation and Laboratory Analysis Data

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Manuscript received: 24 September 2024; accepted for publication: 20 January 2025

ABSTRACT: This study focuses on the source rock, a critical component of the petroleum system, within the Eastern Fold Belt (EFB) of Bangladesh. It aims to assess the occurrence and quality of source rocks by employing a comprehensive approach that includes fieldwork, laboratory analysis, seismic interpretation, and well data. The research was conducted in the Sylhet and Khagrachari regions, where prior source rock evaluations were inadequate. Organic carbon content evaluation using TOC analysis reveals a substantial presence of source rock in the EFB, which can produce hydrocarbon upon maturation. Depositional environment analysis suggests the source rocks were deposited in geological settings, including the continental shelf, prodeltaic, shallow marine, and deltaic sub-environments. Laboratory studies indicate the total organic carbon (TOC) content varied, ranging from 0.24% to 1.812%, with an average TOC of 0.65% to 0.7% in Sylhet and an average TOC of 0.28% to 0.33% in Khagrachari where the Kopili Shale of Sylhet exhibiting the highest amount of organic content. The samples from the northern part of the Bengal Basin were observed to be richer in organic content than those from the southern regions. Well-log data from Fenchuganj show that the source rocks are located at depths ranging from 3500 to 4200 m, which is correlated by seismic data. This depth suggests that the source rocks have undergone sufficient thermal maturation (in the temperature window of 105 -140°C) to generate hydrocarbons. Seismic sections further demonstrate the regional distribution of source rock, reinforcing the potential for gas-prone hydrocarbon prospects in the EFB. The integrated approach provides valuable insights into the petroleum potential, emphasizing the crucial role of source rocks in the EFB for future hydrocarbon exploration efforts in the Bengal Basin, offering hope for future discoveries.

Keywords: Source Rock; Bengal Basin; Organic Carbon; Kopili Shale; Jenum Shale; Bhuban

INTRODUCTION

The potential for hydrocarbon occurrence in any region depends on several critical geological factors, including source rocks, reservoir rocks, seal rocks, traps, and migration pathways. Each of the three elements and two processes are essential in forming a petroleum system, and together, they determine the hydrocarbon potential of the basin in concern. Source rocks, in particular, play a vital role as they are responsible for generating hydrocarbons. In the Bengal Basin, a few key formations have been identified as primary source rocks, which hold significant importance for the petroleum system (Alam et al., 2006).

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DOI: https://doi.org/10.3329/dujees.v13i2.79462

The Jenum Shale of the Barail Group is recognized as the primary source rock in the Bengal Basin (Imam, 2013). Additionally, the Miocene shale of the Bhuban Formation, which belongs to the Surma Group, is considered the second significant source rock in the region (Curiale et al., 2002). Moreover, the Kopili Shale has been identified as a potential source rock (Jahan et al., 2017). Despite these findings, comprehensive studies evaluating source rock potential in the Bengal Basin have been somewhat limited, leaving gaps in our understanding of the full hydrocarbon potential of the area.

The Eastern Fold Belt (EFB), a region shaped by the tectonic upliftment of the Chittagong-Tripura Fold Belt, exposes Miocene and Oligocene rock units (Hossain et al., 2019). Previous research on source rock potential has focused mainly on microfossil assemblages and depositional environments (Alam et al., 2003). Findings from these studies suggest that the source rocks developed in a paralic climate, where the transition from marine to terrestrial settings occurred (Roy et al., 2010).

Geochemical analyses have provided further insights into the rock source characteristics. Core samples taken from the Kopili Shale in the northwest stable platform of the Bengal Basin reveal total organic carbon (TOC) values ranging from 0.5% to 1.7%, with T_{max} values between 429°C and 432°C and vitrinite reflectance (Ro) values of 0.4% to 0.46% (Islam et al., 2015). These values suggest the presence of immature Type III organic matter, which has fair to good source rock potential. In contrast, the source rocks in the northeastern and deeper parts of the basin, particularly those from the Lower Miocene, are primarily gas-prone. Upper Eocene Kopili Shale, on the other hand, exhibits fair to good hydrocarbon potential, with the oil window (Ro = 0.65% to 1.3%) occurring at depths of 5000 to 8000 meters (Shamsuddin et al., 2004).

Further evidence for the hydrocarbon potential of Kopili Shale comes from carbon isotope analysis (13C/12C) of gas samples from Miocene reservoirs in the Sylhet Trough. These analyses suggest that the Kopili Shale is mature enough to generate hydrocarbons, supporting its classification as a marine to shallow-marine source rock that has reached a sufficient maturity level for hydrocarbon generation (Khan et al., 1988).

In neighboring Assam, India, studies on the Kopili Shale have shown that the formation contains significant amounts of Type II and Type III organic matter, with TOC values between 0.5% and 1.5%, indicating good source rock potential (Naidu and Panda, 1997). The formation is approximately 500 m thick and about 100 km from the Bangladesh border (Mandal, 2009). Given the continuity of the Kopili Formation between Assam and Bangladesh, the Kopili Shale within the Bengal Basin is also expected to serve as an essential source rock. Thermal modeling suggests hydrocarbon generation from the Kopili Shale could have begun around 32 million years ago (Curiale et al., 2002).

Another significant source rock in the Bengal Basin is the Oligocene-aged Jenum Shale, which has TOC values ranging from 1.4% to 2.7% (Ismail and Shamsuddin, 1991; Curiale et al., 2002). Thermal models indicate that this formation entered the oil window approximately 28 million years ago and transitioned into the gas window around 5 million years ago (Shamsuddin and Yakovlev, 1987). Due to its significant depth and fine-grained, organic-rich material, the Bhuban Formation has also been identified as a potential source rock in the Bengal Basin (Curiale et al., 2010).

While earlier studies on source rock evaluation have focused primarily on organic fossil assemblages and geochemical characteristics, there is a growing need for an integrated approach that combines field investigation data, geophysical data, and other analytical methods, including TOC analysis, rock-eval pyrolysis, visual kerogen analysis, etc. This approach would help comprehensively understand regional distribution, occurrence, and burial history. Integrating seismic section analysis with well data can also provide a more detailed picture of subsurface conditions and the extent of source rock distribution across the basin.

The current study focuses on the rock units exposed in the Sylhet and Khagrachari areas. Sylhet, located in the northeastern part, and Khagrachari, further south in the southeast, were selected as the primary sites for field investigation and sample collection (Fig. 1). Stream-cut sections in these areas were examined to collect prime source rock samples from the Jaintia, Barail, and lower Surma groups. These samples have undergone laboratory analysis, including X-ray Diffraction (XRD), Scanning Electron Microscopy (SEM), and Total Organic Carbon (TOC) determination. Seismic section analysis is also integrated into the overall study to understand subsurface conditions better.

A comprehensive assessment of source rock occurrence and distribution is essential for understanding the petroleum plays in the Bengal Basin. This study's findings could pave the way for further integrated studies and contribute to identifying new hydrocarbon prospects in the region. Ultimately, this research could help guide future petroleum exploration efforts in the Bengal Basin by providing valuable insights into the region's source rock potential and hydrocarbon generation capabilities.

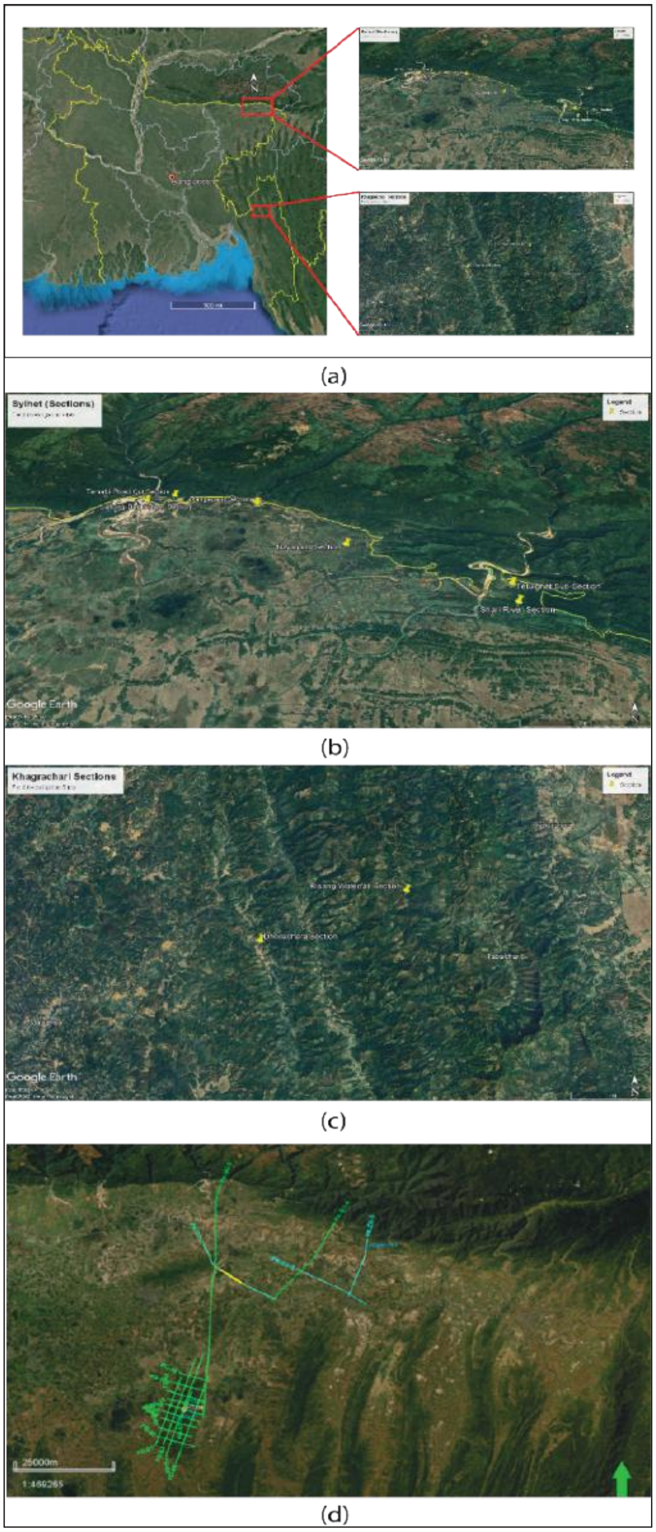


Figure 1: (a) Location Map of the Studied Sections- (b) Sylhet with Their Respective Positions in Bangladesh and Field Investigation Locations Indicated by Yellow Pin Drops; (c) Khagrachari with Their Respective Positions in Bangladesh and Field Investigation Locations Indicated by Yellow Pin Drops and (d) Seismic Lines on the Location Map. The Map is Taken from the Google Earth Image

GEOLOGICAL SETTINGS

The formation of the Bengal Basin began in the Late Jurassic to Early Cretaceous when the Indian Plate separated from Gondwana and drifted northward (Alam et al., 2003). This movement culminated in a collision with the Eurasian Plate, with a soft collision occurring between the Paleocene and Early Eocene, followed by a hard collision in the Oligocene (Curray and Moore, 1974; Reimann, 1993). This series of tectonic events uplifted both the Himalayas and the Indo-Burman Mountain belts, setting the stage for the development of the Bengal Basin.

The Indian Plate separation from Antarctica in the Early Cretaceous laid the foundation for the basin's evolution. As the Indian Plate collided with the Eurasian Plate during the Tertiary period (Armijo, 1986), the subduction zone along the collision belt caused a depression southeast of the Himalayan uplift, forming the Bengal Basin (Imam, 2013). Over time, sediment transported by major rivers, including the Ganges, Brahmaputra, and Meghna, accumulated in the basin due to erosion from the rising Himalayas. Meanwhile, the convergence of the oceanic Indian Plate and the continental Burmese Plate led to the formation of the Indo-Burman fold range, contributing to the sedimentary deposits.

The basin began to subside in the Early Cretaceous due to Gondwanaland's breakup and the Indian Plate's northward drift. This subsidence, along with tectonic collisions and the uplift of the eastern Himalayas and Indo-Burman ranges (Gani and Alam, 1999) (Fig. 2), continued to shape the basin's evolution (Salt et al., 1986). Marine transgressions during the middle to upper Eocene resulted in a carbonate regime on the stable shelf, with deep-water sedimentation (Figs. 3B and 4A) in the basin (Uddin and Lundberg, 1999). Thick carbonate sequences, such as the Sylhet limestone, were deposited, followed by the marine Kopili Shale (Banerji, 1981; Roy and Chatterjee, 2015).

By the early Miocene, sedimentation from the Himalayas and the Indo-Burman ranges accelerated, with the Bengal Basin becoming the main depocenter for sediment since the Cretaceous. Over time, the depocenter has shifted southeastward, starting in the Oligocene. The basin's fill history shows variation across different geotectonic provinces. For instance, in stable regions like the Indian Platform, boreholes have revealed crystalline basement rocks overlain by Permian-Carboniferous sedimentary units. After the

Indian Shield was peneplained in the Precambrian, sedimentation began in the Carboniferous, influenced by grabens within the Gondwana Basins (Alam et al., 2003) (Fig. 3).

From the Oligocene to the Early Miocene, sedimentation rates and subsidence increased due to continued tectonic collisions (Imam and Hussain, 2002). In contrast, deep marine sedimentation dominated the central basin, and the eastern parts of the basin transitioned from deep to shallow marine environments (Alam et al., 2003). The depositional environments ranged from deep marine in the basin to shallow and nearshore settings along the basin margins, influenced by ongoing uplift and sediment influx from the surrounding mountain ranges. Thus, the development reflects a complex interaction of tectonics, sedimentation, and marine processes.

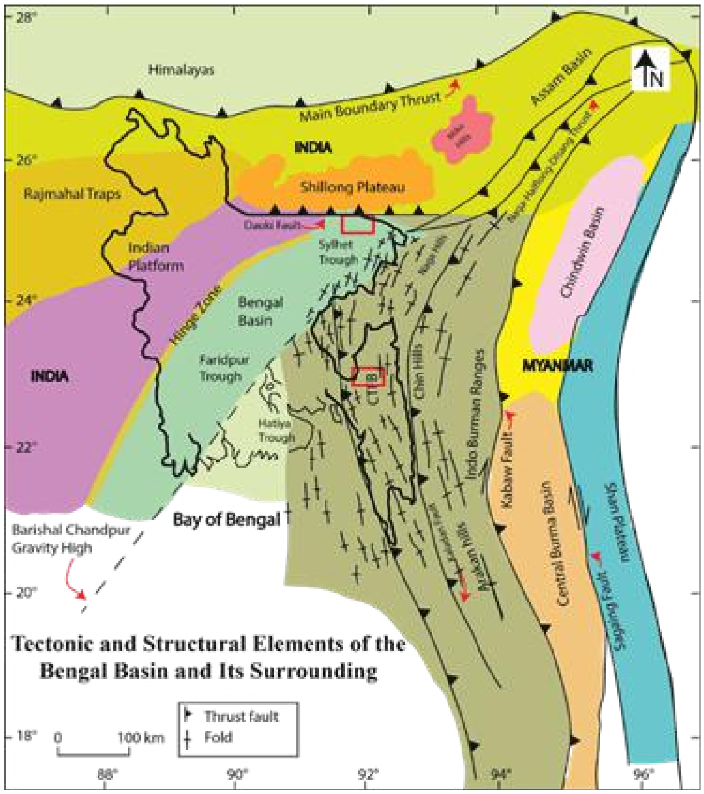


Figure 2: Regional Map Showing the Tectonic and Structural Elements of the Bengal Basin and its Surrounding Areas (Modified from Johnson & Alam (1991) and Uddin & Lundberg (1999)). The Two Red Boxes Indicate the Study Areas- Sylhet (Upper) and Khagrachari (Lower)

MATERIALS AND METHODS

The study focuses on identifying potential organic-rich source rocks in the EFB. Field investigations were conducted in two primary areas: the Jaflong-Tamabil-Jaintiapur structure in Sylhet and the Changotang Anticline in Khagrachari. The targeted source rocks include the Kopili Shale, Jenum Shale, and Lower Bhuban Shale, known for their hydrocarbon potential in the region (Farhaduzzaman et al., 2012).

Fieldwork involved outcrop data collection from eight different sections: six in Sylhet and two in Khagrachari. The purpose was to identify organic-rich, fine-grained facies based on lithological characteristics such as grain size, texture, sedimentary structures, and other vital features. Samples were collected systematically from these locations, with each sample assigned a unique identifier— “S” for Sylhet and “K” for Khagrachari, followed by a sequence number. A total of 20 samples were collected: 14 from Sylhet and 6 from Khagrachari.

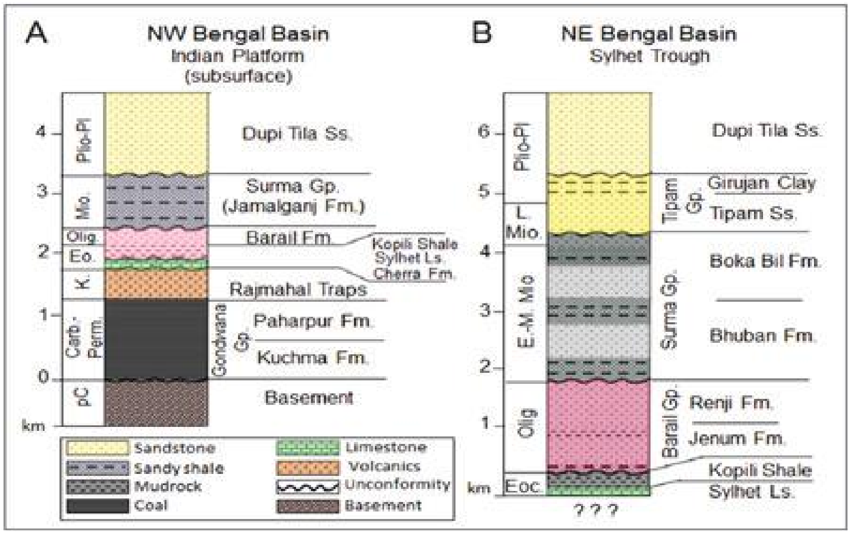


Figure 3: Stratigraphic Framework of the Bengal Basin, Bangladesh. (A) Stratigraphic Section of the Indian Platform, north-western Bengal Basin. (B) Stratigraphic Section of the Sylhet Trough, Northeastern Bengal Basin (Modified from Uddin and Lundberg, 1999)

Lithological columns were constructed for each outcrop to document the vertical succession of rock layers exposed at the sample collection sites. These columns were then analyzed for facies associations to interpret the depositional environments and infer the tectonic history. The facies analysis, combined with structural data from the field, helped identify the relationship between lithology, sea level changes, and sediment transport processes, which was essential for reconstructing the depositional sequences.

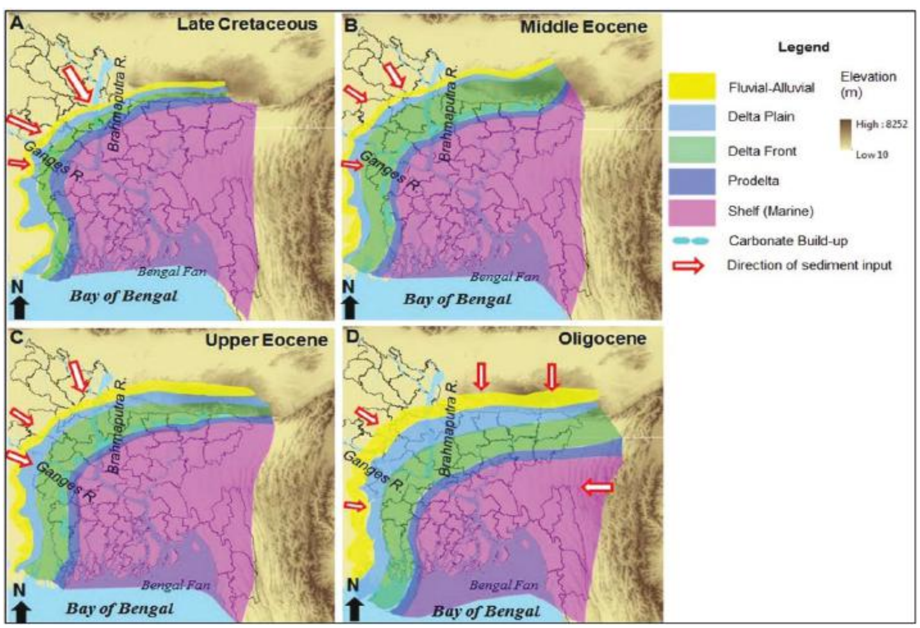


Figure 4: Paleogeographic maps of Bengal Basin, Showing the Depositional History from (A) Late Cretaceous to (D) Oligocene Time. Present-day Locations of Rivers and Coastline are Shown for Reference (Modified from Ismail, 1975; and Uddin and Lundberg, 1998)

Laboratory analyses were crucial to the study, focusing on the mineralogical and geochemical characterization of the collected shale samples. The analyses conducted include X-ray Diffraction (XRD), Scanning Electron Microscopy (SEM), and Total Organic Carbon (TOC) measurements.

The **X-ray Diffraction (XRD)** analysis was used to characterize the mineralogy of the fine-grained sediments. Each sample was prepared by cleaning, drying, and crushing it into a fine powder. The powdered samples were mounted on a Rigaku X-ray power diffractometer, with an analysis range of 5° to 60°. A separate glass slide method was used for clay mineralogy analysis, in which the sample was suspended in distilled water and allowed to settle before being spread on a glass slide and air-dried. XRD analysis was conducted under three conditions—air-dried, heated to 550°C, and treated with ethylene glycol. This allowed the identification of mixed-layered clays, such as the transformation of smectite to illite (Mosser-Ruck et al., 2005), along with other critical clay minerals like vermiculite and high-charge smectite.

Scanning Electron Microscopy (SEM) provided detailed images of the mineralogy and diagenetic processes affecting the shale samples. A ZEISS Gemini Sigma 300 scanning electron microscope with a backscattered electron detector was used. The samples were prepared by cutting them into small sections and coating them with gold-palladium to ensure conductivity. The SEM analysis revealed insights into the fine-grained mineral structures and helped clarify the diagenetic history of the sediments.

Total Organic Carbon (TOC) analysis was performed using a PerkinElmer PE 2400 Series II CHNS/O Analyzer. This analysis measured the organic carbon content of the samples, which is crucial for assessing their potential as hydrocarbon source rocks. The TOC was measured in two stages: before and after acid treatment. The acid treatment removed inorganic carbon, allowing the calculation of organic carbon content by subtracting the inorganic fraction from the total carbon content. In addition to laboratory work, seismic and well-log data were integrated to build a more comprehensive understanding of the regional geology. Seismic attributes were used to interpret depositional environments. Well-log data from Fenchuganj well-02 was correlated with seismic sections from the Fenchuganj and Atgram areas to establish a regional framework for understanding the distribution of source rocks (Fig. 5). The study also considered sediment transport processes, tectonic activity, and sea level changes to reconstruct the depositional sequences. The interaction between these factors and the identified facies provided insights into the depositional environments and the tectonic evolution of the Bengal Basin. A detailed flowchart (Fig. 6) shows the complete workflow for the study, including sample collection, laboratory analysis, and data integration.

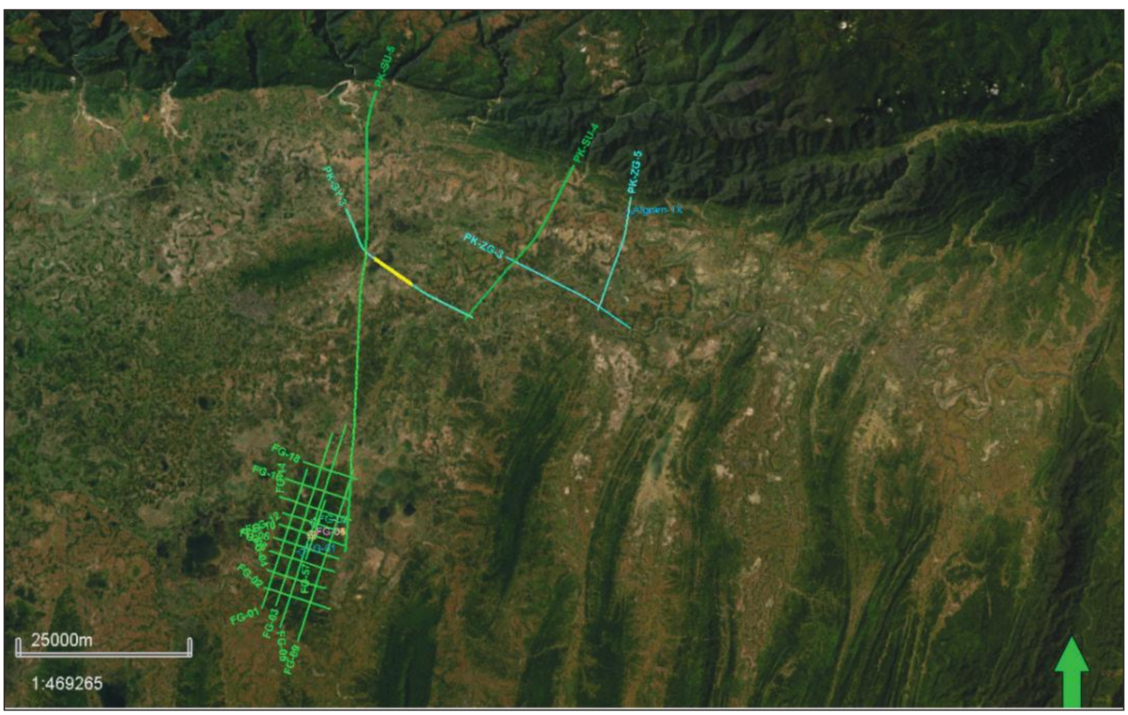


Figure 5: Base Map Showing Regional Correlation between Fenchuganj and Atgram Using Regional Seismic Lines. The Two-dimensional (2D) Seismic Lines PK-SU-5, PK-FG-5 to PK-FG-9 has been Laid Out to Make the Regional Connections. The Scale of the Map is 1: 469265

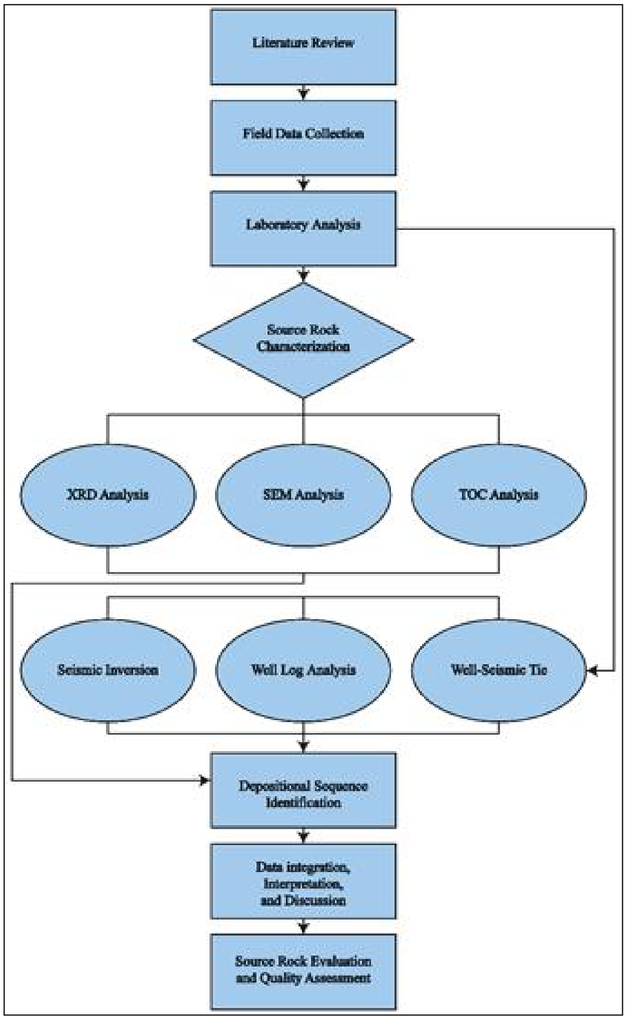


Figure 6: Complete Flowchart of the Study Workflow

Combining field data, laboratory analysis, and seismic interpretation, this multi-disciplinary approach provides a comprehensive understanding of the source rock potential and depositional history in the Bengal Basin. The results of this study contribute to the broader sense of the petroleum system, emphasizing the potential of the Kopili, Jenum, and Bhuban shales as essential hydrocarbon source rocks.

The TOC values will indicate the presence of organic carbon suitable for hydrocarbon generation. In contrast, XRD and SEM analysis will reveal the mineralogical composition of the rocks, suggesting the potential for thermal maturation based on mineralogy and diagenetic history. Seismic to well tie will show the overall distribution and qualitative evaluation of the source rock-bearing formations.

RESULTS

Field Investigation

Lateral field investigation was conducted in several sections in Sylhet and Khagrachari. The Kopili, Jenum, and Bhuban formations were identified. Field investigation in the exposure of approximately 40 m in the Jaflong-Dauki section revealed 10 - 15 m thick black to greyish blue, highly fissile, laminated, compacted, and organic-rich Kopili Shale over the Sylhet Limestone. The facies characteristics indicate the depositional environment to be a continental shelf environment. The lithological column in Figure 7 shows the studied outcrop of 17 meters in the Jaflong-Dauki River section. Interbedded gypsum, along with the influence of tectonic and overburden, indicated by heavy jointing and fracturing (Fig. 8), suggests the presence of a north-dipping Dauki fault. The slow sedimentation rate of the Kopili Shale over 22 million years (0.02 mm/year) suggests the unlikeliness of the presence of overpressure. (Banerji, 1981)

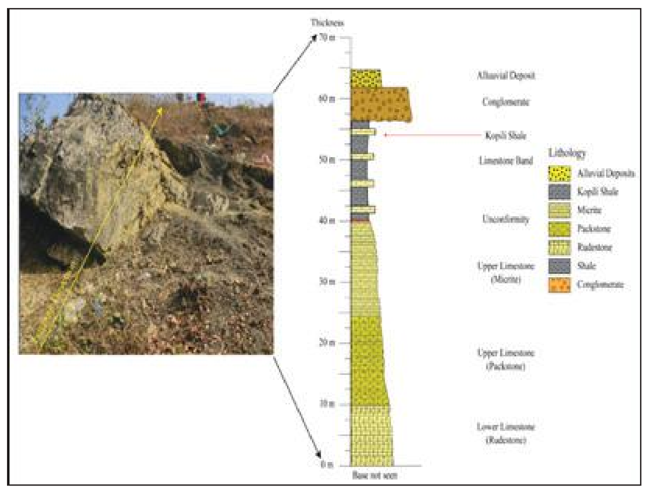


Figure 7: Lithologic Column of Jaflong-Dauki River Section. The Total Column Exhibits 70 Meters of Thickness with the Rudestone on the Bottom Part, Followed by Packstone, and Micrite. Then an Unconformity Boundary Takes Place Overlain by Kopili Shale

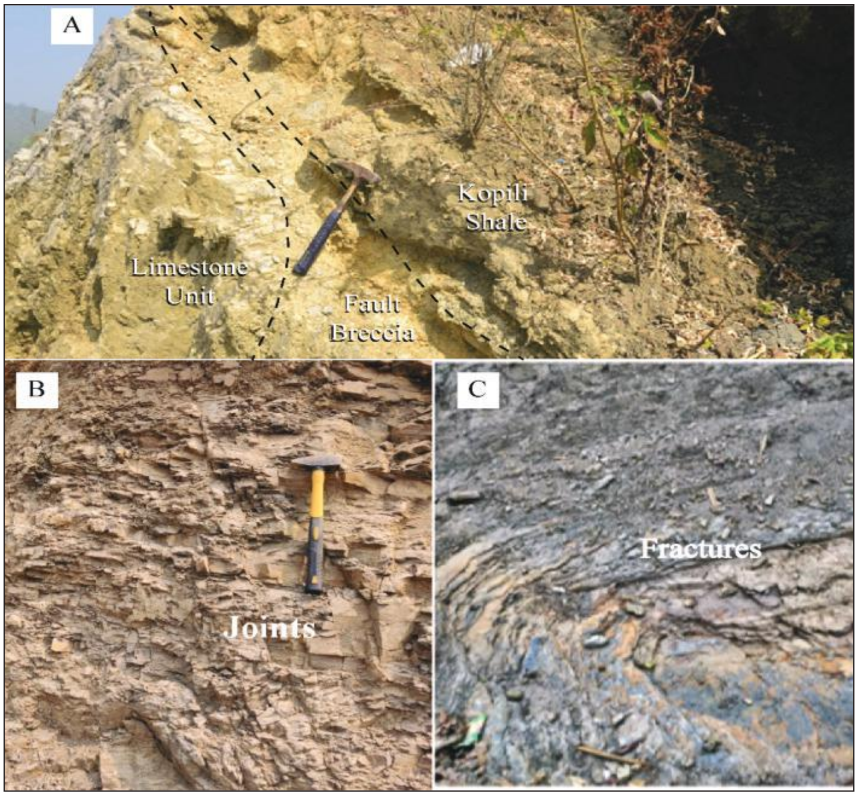


Figure 8: A) Close View of Fault Breccia. The Left Part of the Boundary Indicates the Limestone Unit and the Right Side Indicates the Kopili Shale Unit B) Numerous Joints in Shale C) Shale Fracture

Jenum Formation was encountered in two sections in Sylhet: The Rangapani section (Fig. 9) and the Tamabil Road-Cut section (Fig. 10). A 25-m succession in the Rangapani section was studied, showing thinly laminated silty shale with organic-rich carbonaceous layers. Numerous joints, micro-faults, and paleoseismic features like dragging indicate the influence of tectonic stress. The formation is over 2000 m thick in the Surma Basin (Holtrop and Keizer, 1970). A slow sedimentation rate during deposition indicates a lack of an overpressure zone in the formation.

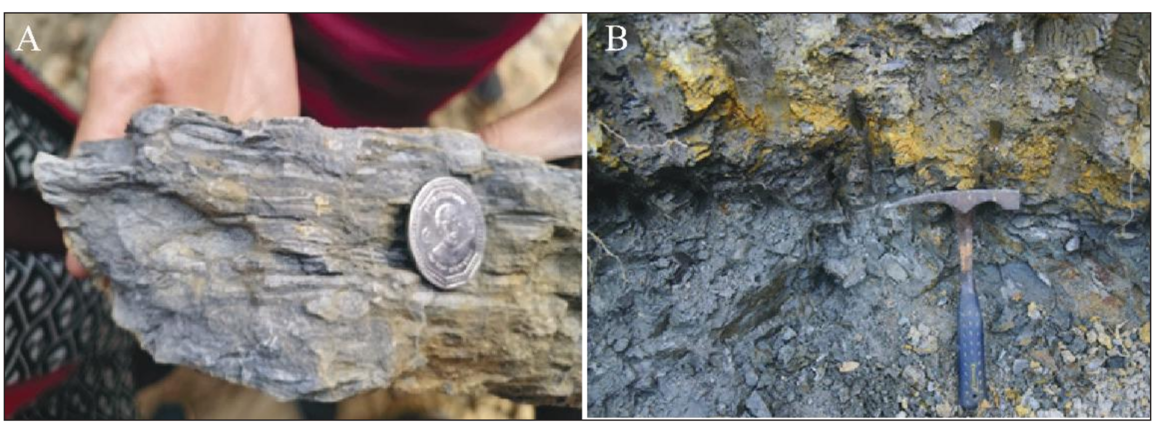


Figure 9: A) Laminated Silty Shale in Jenum Formation of Rangapani Section B) Jenum Shale Mottling due to Weathering in Rangapani Section

Tamabil Road-cut section provides detailed lithology of the exposed Barail Group. The lithologic column of the 15 m exposed section is constructed (Fig. 10).

In Nayagang, an investigation at an interval of 25 m within the lower units of the Bhuban formation revealed the formation consisting of lithology of nodular shale with varying sedimentary structures and mudstones with sand lenses. The nodular shale is dark to light grey and moderately to firmly compacted. The lithology suggests a depositional environment ranging from deltaic to shallow marine pro-deltaic environment.

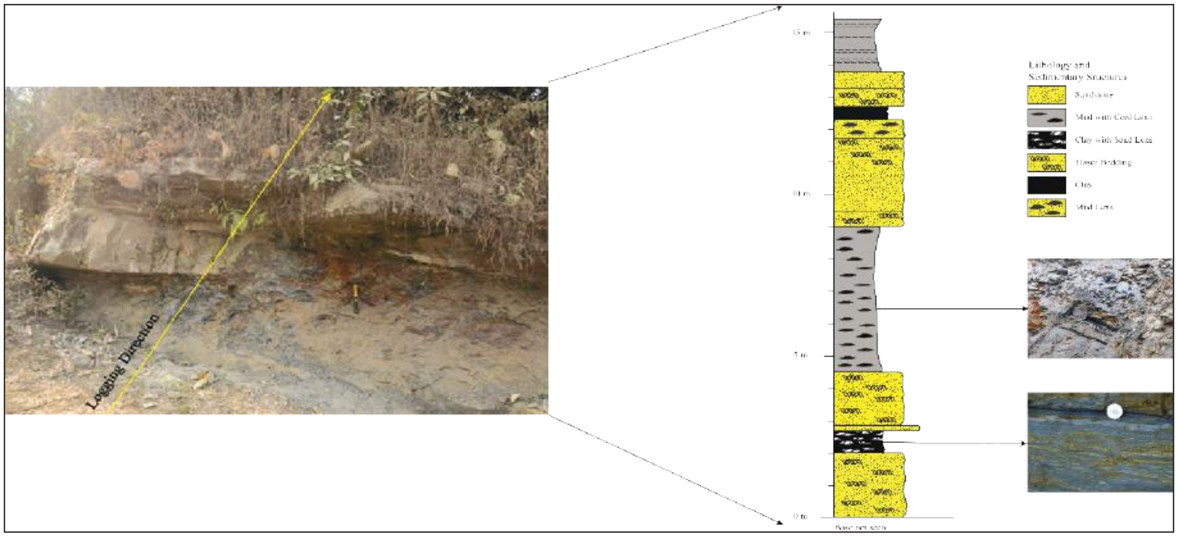


Figure 10: Lithologic Column of Tamabil Road Cut Section with Indication of Mud with Coal Lenses and Mud with Sand

The 50 m succession of the lower Bhuban formation in Tetulghat comprises dark to bluish-grey shale, moderately compacted nodular, and silty shale. Identified facies in succession included fissile shale, nodular shale, and parallel laminated silty shale (Fig. 11). The northern part of the Tetulghat section revealed a distinct 10-12 m unit of pure clay. Significant tectonic deformation within the unit was evident from joints, fractures, micro-faults, and paleo-seismic features like dragging and pseudo-bedding. This indicates extensive tectonic influence during the Miocene lower Bhuban Units deposition.

Bhuban exposed in the Khagrachari are encountered downstream of the Risang and Dhoilachara stream. Shale facies with lenticular bedding and abundant clay particles dominate the lithology. Lenticular beds consist of isolated, weakly connected lenses of coarse silt and fine sand within the shale matrix. The shale is dark grey to bluish-grey. Internal micro-cross laminations are present in the sand lenses. Downstream sections in the Dhoilachara stream section are rich in dark, bluish-grey, laminated fissile shale. Alternating dark and light-colored lithology indicates the seasonal variation during deposition (Fig. 12).

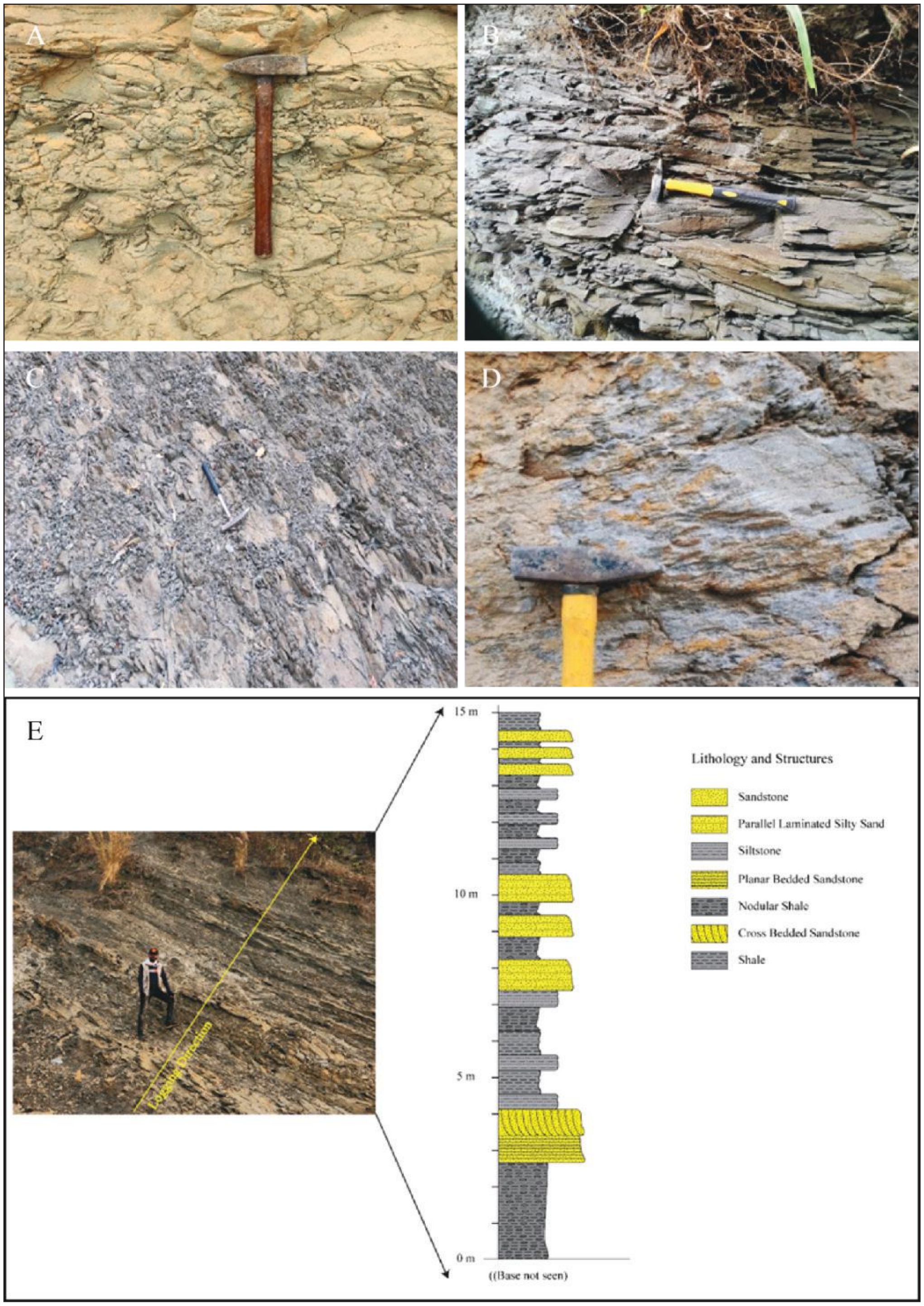


Figure 11: A) Nodular Shale in Nayagang Section B) Parallel Laminated Silty Shale in Tetulghat Section C) Fissile Shale in Tetulghat Section D) Mudstone with the Sand Lens in Nayagang Section E) Lithologic Column of Tetulghat Section Section of the Lower Shale Unit of Bhuban Formation

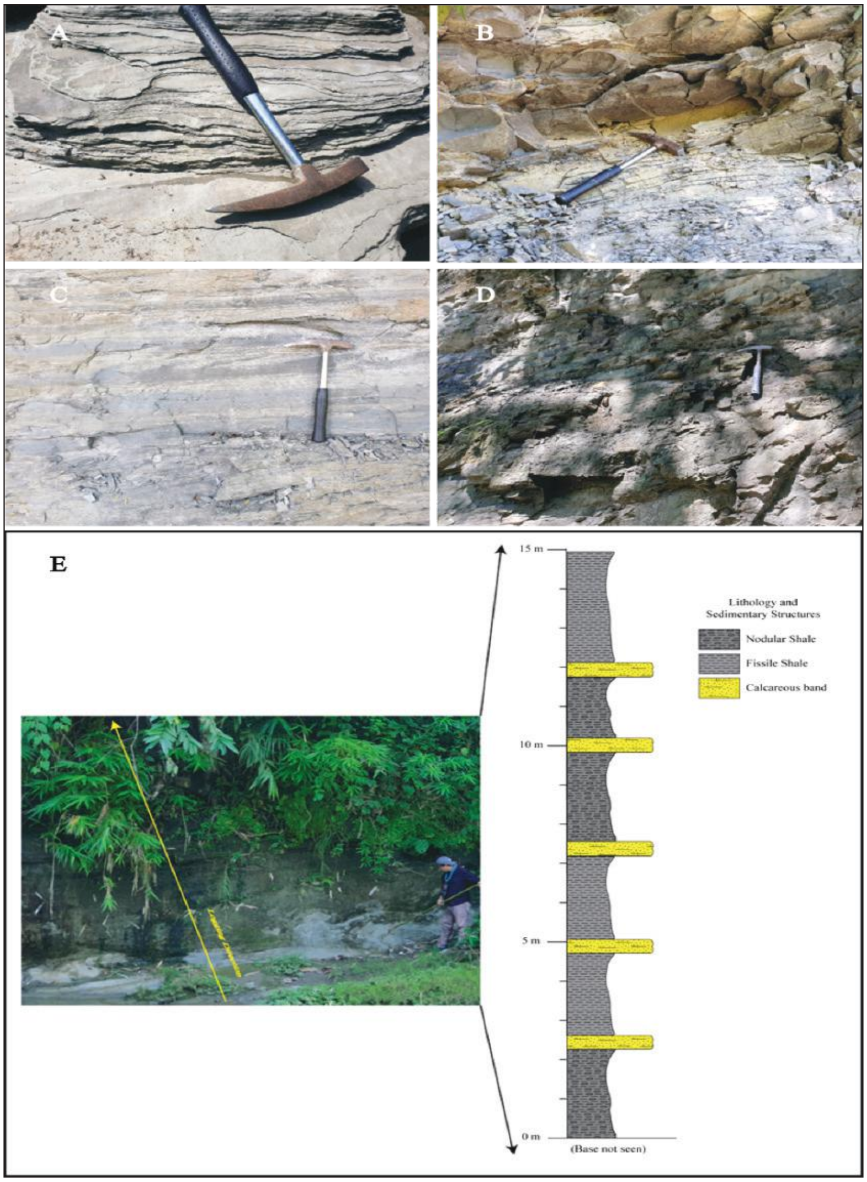


Figure 12: A) Sand-embedded Shale in Dhoilachara Section B) Nodular Shale in Dhoilachara Section C) Internal Micro Cross Lamination in Risang Section D) Shale with a Sand Lens in Risang Section E) Lithologic Column of Dhoilachara Section in Khagrachari of the Lower Shale Unit of Bhuban Formation

Table 1 shows the findings from the field investigation, including the lithologic description, sedimentary structures, and interpreted depositional environments.

Table 1: Lithologic Description of the Organic-rich Shale Units with Interpreted Depositional Environments

Section name	Fm. (Out. Thick. m)	Lithologic description	Depositional environment
Jaflong-Dauki River section	Kopili Shale (40)	Black to greyish blue, compacted and fissile shale with thick lamination to paper-thin lamination. Presence of organic matter and ferruginous cement	Continental shelf environment

Rangapani section	Jenum Shale (25)	Dark grey to bluish grey, clay-dominated, thinly laminated shale with silty streaks and organic-rich carbonaceous layers	Deltaic to the shallow marine environment
Tamabil Road-cut section	Jenum Shale (15)	Black to dark grey fissile shale, with occasional mottling due to weathering, Dark grey mudstone units with no dominant structure, Mud with coal lenses, Mudstones with sand lenses	Fluvio-deltaic to shallow-marine environment
Nayagang section	Bhuban Fm. (25)	Dark to light grey, moderate to firmly compacted nodular shale, Mudstone with sand lenses	Deltaic to shallow marine pro-deltaic environment
Tetulghat section	Bhuban Fm. (50)	Dark to bluish-grey fissile shale, Light to dark grey moderately compacted nodular shale, Light grey to bluish-grey Silty shale	Deltaic to shallow marine pro-deltaic environment
Risang-Dhoilachara Stream section	Bhuban Fm. (18)	Lenticular bedding with an abundance of clay particles, Dark grey to bluish grey shale with sand lenses, Dark grey to bluish grey nodular shale, Dark grey to bluish grey laminated fissile shale, Coarse silt to fine sand lenses with ripple lamination	Intertidal deltaic to shallow marine pro-deltaic and deep marine environment

X-RAY DIFFRACTION

Five samples from the study sections were analyzed using X-ray diffraction, revealing the organic mineralogical composition. The following samples, shown in Table 2, were collected from outcrops of Sylhet and Khagrachari for XRD analysis.

Table 2: List of Samples Used in XRD Analysis

Sample No	Geological Formation	Location	Lithology
S-1	Kopili	Jaflong	Shale
S-2	Jenum	Rangapani	Shale
S-4	Bhuban	Tetulghat	Pure Clay
K-3	Bhuban	Risang	Nodular Shale
K-4	Bhuban	Dhoilachara	Silty Shale

Figures 13 - 14 show the results of the XRD analysis of the selected representative samples. The identified clay minerals are illite, chlorite, kaolinite, montmorillonite, and illite/smectite in the mixed-layer phase. Non-clay minerals include quartz, feldspar, calcite, dolomite, and siderite.

The X-ray diffractograms of Kopili Shale samples S-1 indicate the absence of smectite and illite-smectite mixed layer clay. The presence of illite suggests the potential illitization of smectite in the Kopili Shale (Fig. 13(a)). The X-ray diffractograms of Jenum Shale samples S-2 indicate that smectite is absent, whereas illite is abundant by several prominent reflections (10.3 Å, 5.1 Å). Illite-smectite mixed layer clay may indicate incomplete conversion of smectite into illite (Fig. 13(b)). The X-ray diffractograms of Bhuban Clay samples S-4 reveal that smectite is still absent, whereas illite is abundant by several prominent reflections (10.3 Å, 4.7 Å). Illite-smectite mixed layer clay may indicate incomplete conversion of smectite into illite (Fig. 13(c)). Quartz is found to be the dominant non-clay mineral.

X-ray diffractograms of Bhuban Shale samples from Khagrachari (K-3) indicate that illite is abundant by several prominent reflections (10.3 Å, 5.1 Å). Illite-smectite mixed layer clay may indicate incomplete conversion of smectite into illite (Figure 14(a)). The X-ray diffractograms of Bhuban Shale samples of Khagrachari structure (K-4) show the absence of both smectite and (I/S) mixed layer clay, along with the presence of illite, which may suggest the potential illitization of smectite. Non-clay minerals (Quartz, Mica, Feldspars) are present in this sample. Both K-Feldspars & plagioclase feldspars are found in trace amounts.

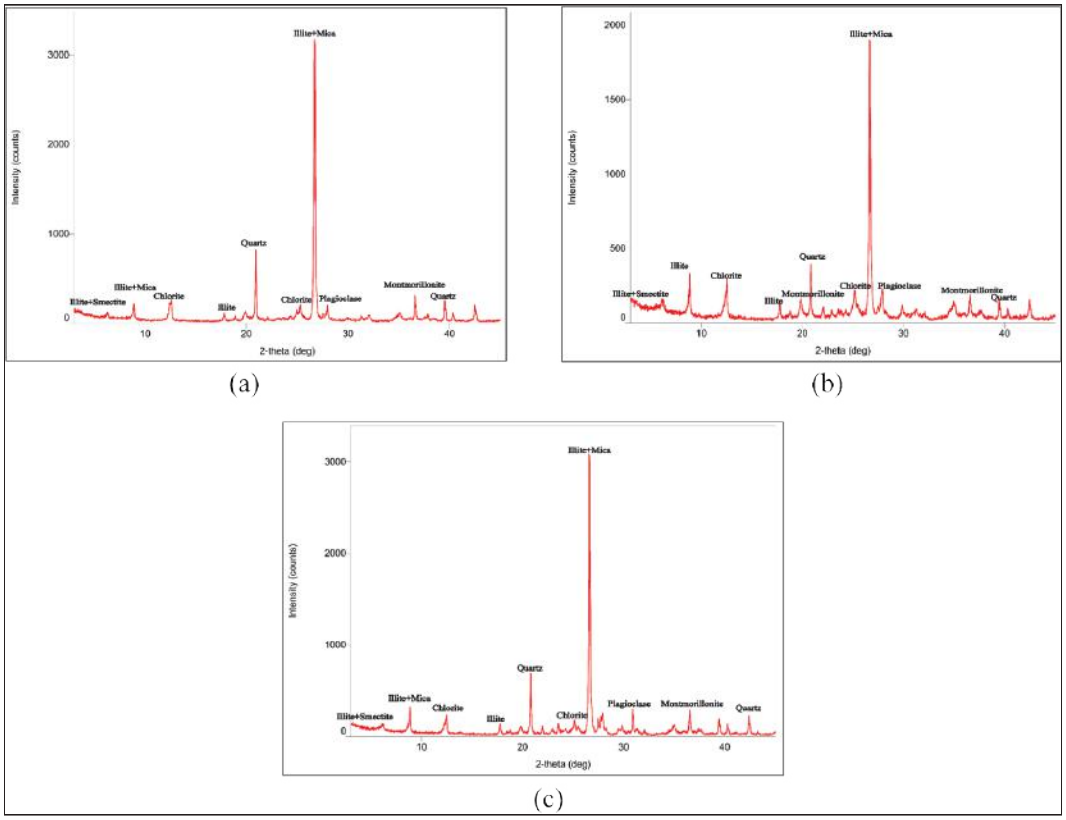


Figure 13: (a) X-ray Diffractograms of Kopili Shale Samples S-1. The Absence of Both Smectite and (I/S) Mixed Layer Clay and the Presence of Illite Suggests the Potential Illitization of Smectite. (b) X-ray Diffractograms of Jenum Shale Samples S-2. Smectite is Absent, Whereas Illite is Abundant by Several Prominent Reflections (10.3 Å, 5.1 Å). The Presence of (I/S) Mixed Layer Clay May Indicate Incomplete Conversion of Smectite into Illite. (c) X-ray Diffractograms of Bhuban Clay Samples S-4. Smectite is Absent, Whereas Illite is Abundant by Several Prominent Reflections (10.3 Å, 4.7 Å). The Presence of (I/S) Mixed Layer Clay May Indicate Incomplete Conversion of Smectite into Illite. Quartz is Found to be the Dominant Non-clay Mineral

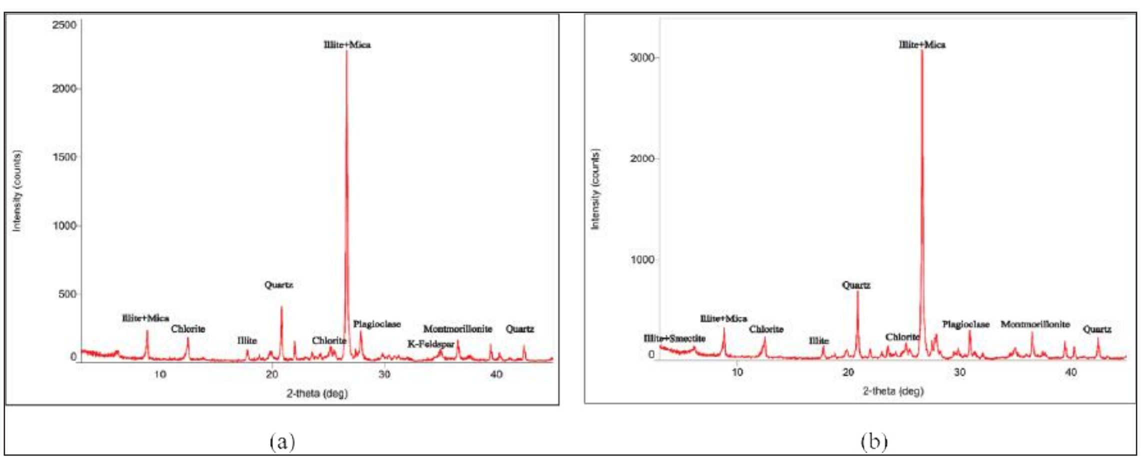


Figure 14: (a) X-ray Diffractograms of Bhuban Shale Samples K-3. Illite is Abundant by Several Prominent Reflections (10.3 Å, 5.1 Å). The Presence of (I/S) Mixed Layer Clay May Indicate Incomplete Conversion of Smectite Into illite. (b) X-ray Diffractograms of Bhuban Shale Samples K-4. The Absence of Both Smectite and (I/S) Mixed Layer Clay, Along with the Presence of Illite, May Suggest the Potential Illitization of Smectite. Non-clay Minerals (Quartz, Mica, Feldspars) are Present in this Sample. Both K-Feldspars & Plagioclase Feldspars are found in Trace Amounts

Table 3: Relative Percentages of Clay Minerals in the Studied Samples

	Percentages				
	Sylhet Samples				
Minerals	**S-1**	**S-2**	**S-4**	**K-3**	**K-4**
Illite/Smectite		3.79	14.75	8.23	9.15
Illite	45.28	37.55	58.32	57.80	56.15
Chlorite	12.43	10.34	5.48	13.64	10.82
Illite+Mica	40.00	48.32	18.45	20.323	23.88

The transformation from smectite to illite via an intermediate mixed-layer illite/smectite (I/S) clay is a well-documented diagenetic process in mudrocks during progressive burial. Clay diagenesis causes the ordered illite/smectite to convert into illite during deeper burial. Sylhet samples show a decreasing trend in expandability, but ordered illite-smectites are not found.

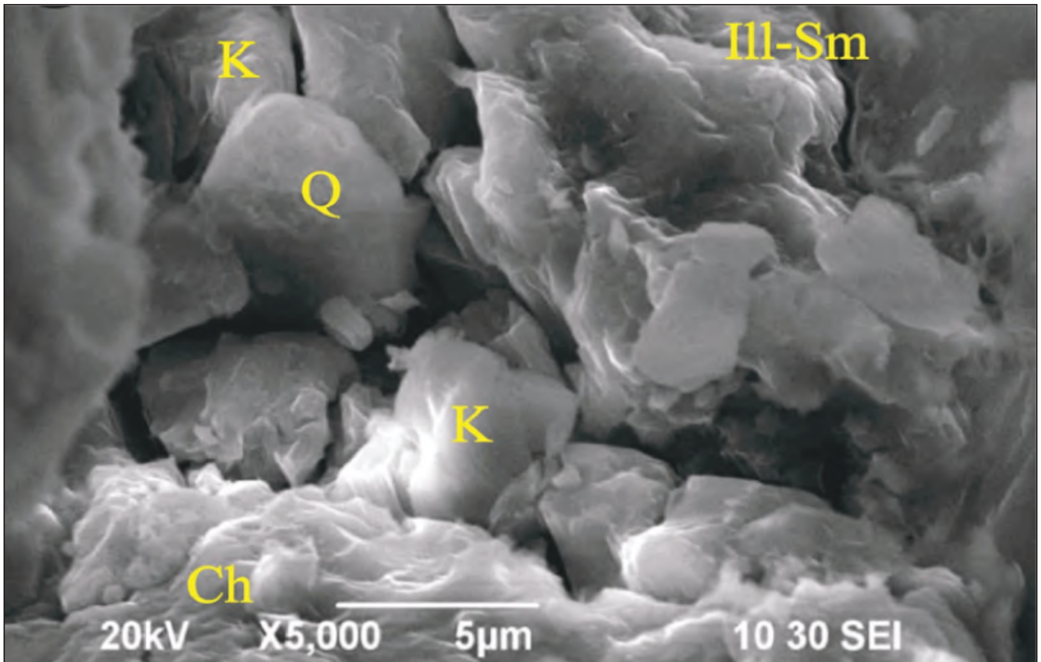
X-ray diffraction (XRD) analysis of samples from the Sylhet region indicates that the Kopili Shale experienced the greatest burial depth before uplift, as evidenced by its advanced degree of illitization. This is followed by the intermediate maturation of the Jenum Shale, suggesting that the Kopili Shale is more thermally mature as a source rock than the Jenum Shale. In contrast, the Bhuban Shale from Sylhet exhibits the lowest burial depth, as indicated by its lower degree of illitization, reflecting minimal thermal maturation in this region (Fig. 13C).

However, Bhuban Shale samples collected from Khagrachari exhibit higher illitization. The XRD-derived mineral composition indicates that these formations were initially deposited at greater burial depths, resulting in higher thermal maturity as a source rock. The illitization degree in Khagrachari samples surpasses that of Bhuban Shale from Sylhet, suggesting deeper burial and enhanced maturation. These findings highlight more significant thermal maturation of Bhuban Shale in the southern part of the Eastern Fold Belt of the Bengal Basin (Figs. 13C and 14).

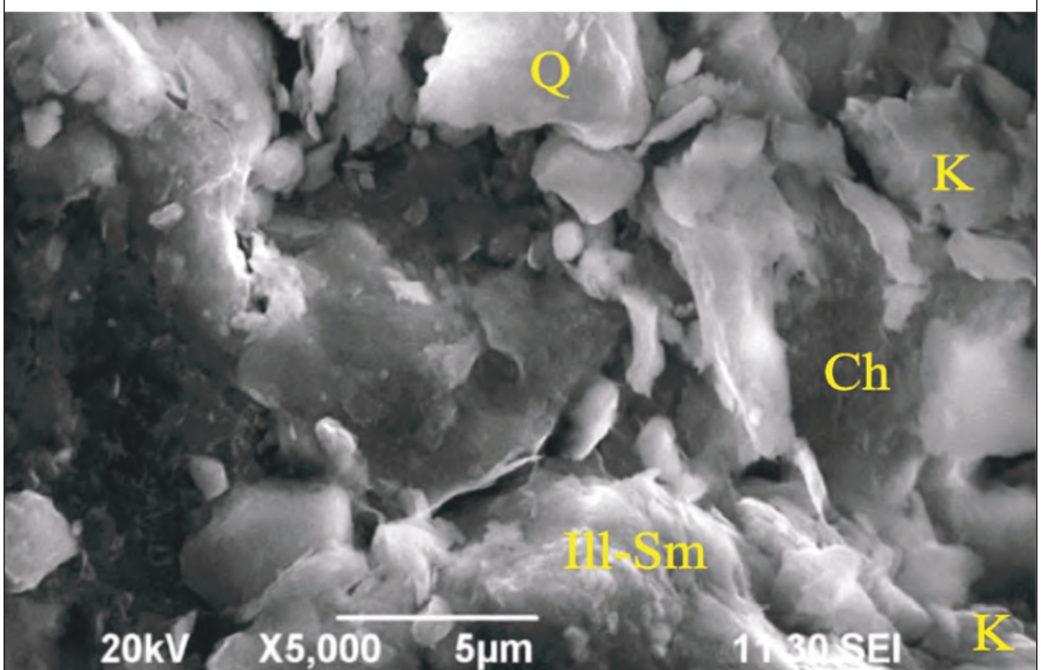
SCANNING ELECTRON MICROSCOPY (SEM)

Eight samples, labeled S-1, S-2, S-4, S-6, S-9, S-12, K-3, and K-4, were analyzed using scanning electron microscopy (Figs. 15-18). The images revealed the presence of quartz grains, kaolinite, chlorite, smectite, and illite and the absence of authigenic quartz. Some dissolved orthoclase grains surrounded by illite/muscovite platelets are observed.

Authigenic chlorite is present in three distinct forms, most commonly in the radial rim around detrital grains. Authigenic kaolinite is the final authigenic phase to form within the Surma Group sandstones, appearing as isolated pore-filling cements and as in situ alteration products of pre-existing feldspars. Stacks of kaolinite platelets often clog both primary pore spaces and secondary porosity created by the leaching of feldspars and Fe-calcite cement.



(A)



(B)

Figure 15: (A) Scanning Electron Micrographs of Shale Samples (S-1) from Shari River Section Showing Quartz (Q), Kaolinite (K), Chlorite (Ch), Illite (Ill), and Smectite (Sm). It has been Zoomed to 5000x Magnification. **(B)** Scanning Electron Micrographs of Shale Samples (S-2) from Tetulghat Sub Section Showing Quartz (Q), Kaolinite (K), Chlorite (Ch), Illite (Ill), and Smectite (Sm). It has been Zoomed to 5000x Magnification

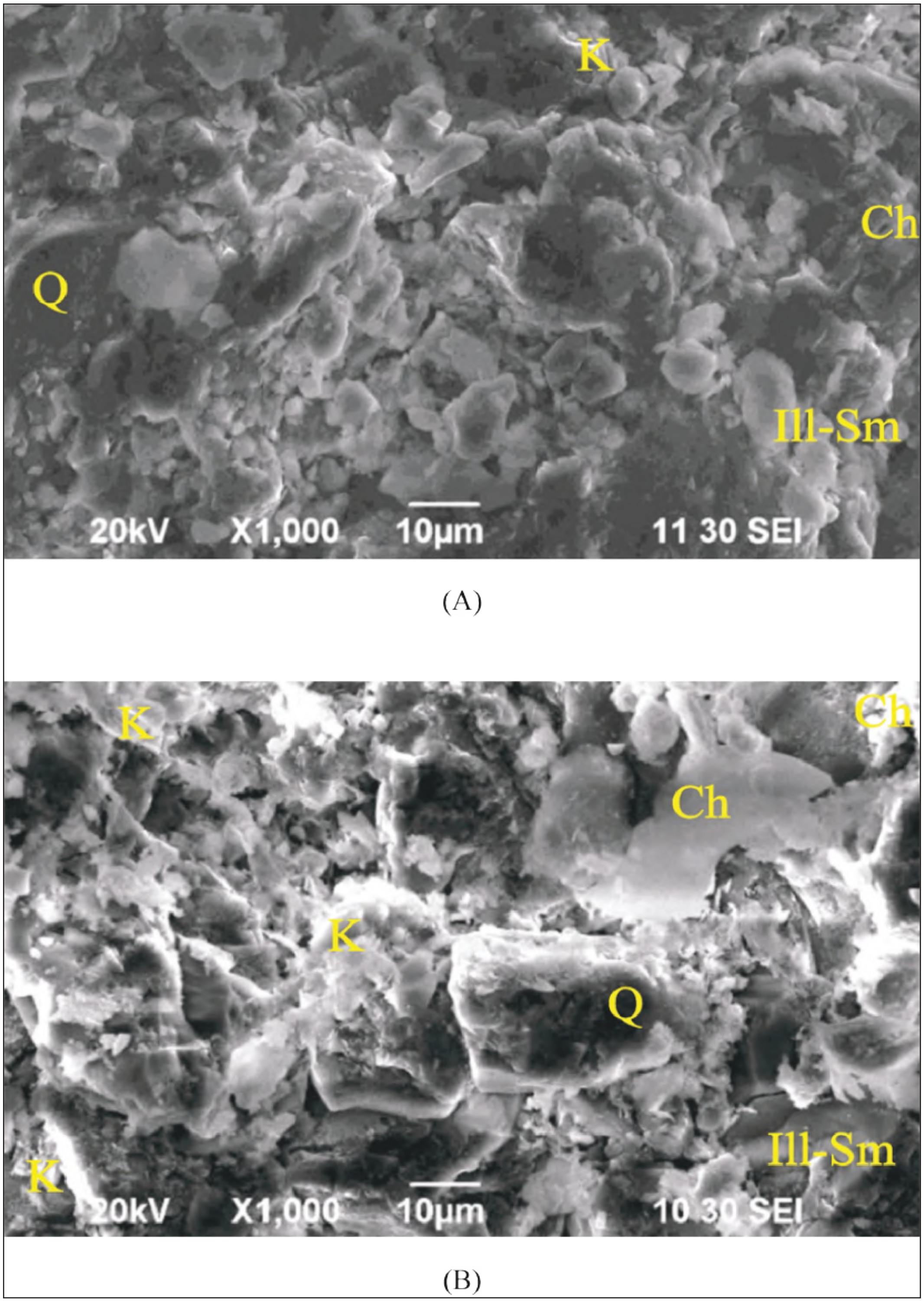
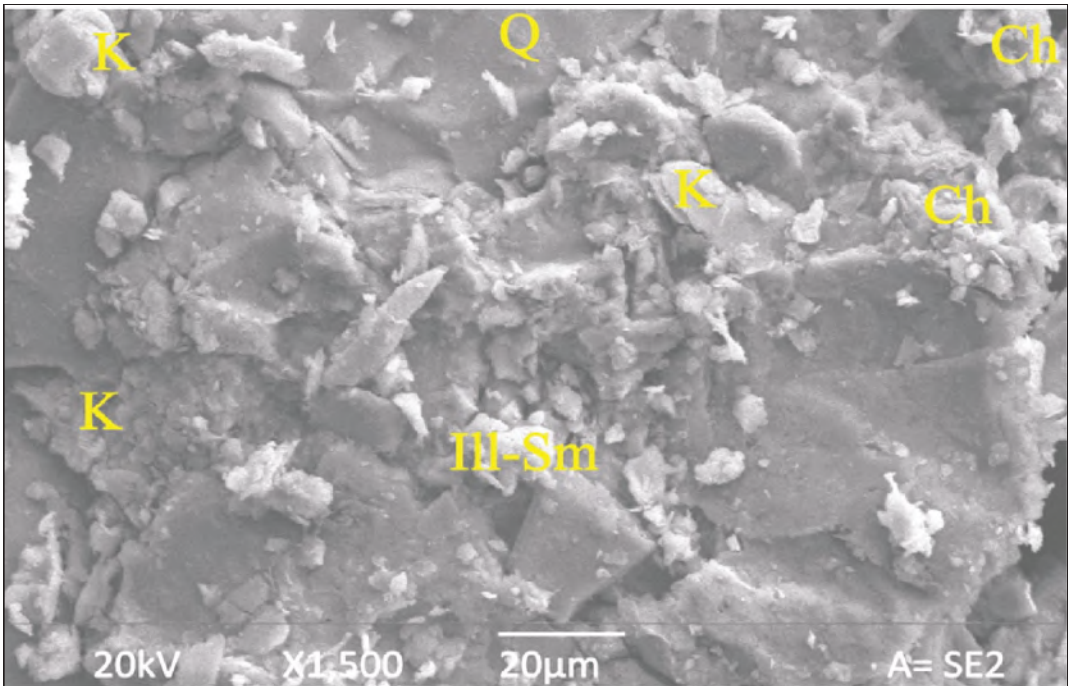
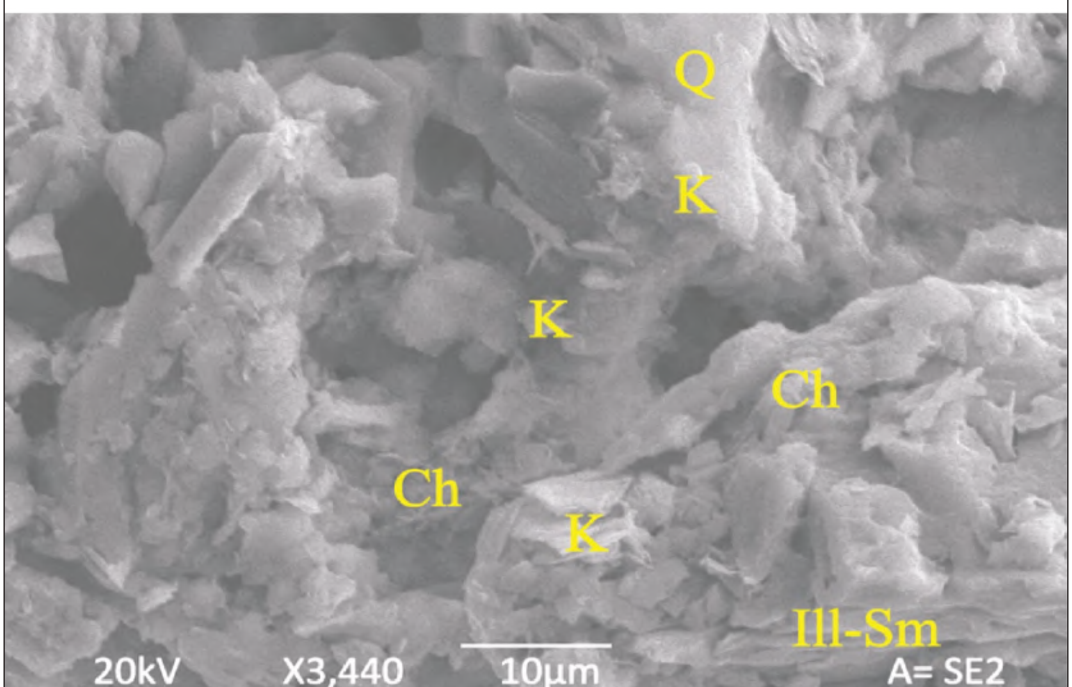


Figure 16: (A) Scanning Electron Micrographs of Shale Samples (S-4) from Nayagang Section Showing Quartz (Q), Kaolinite (K), Chlorite (Ch), Illite (Ill), and Smectite (Sm). It has been Zoomed to 1000x Magnification. **(B)** Scanning Electron Micrographs of Shale Samples (S-6) from Tamabil Road Cut Section Showing Quartz (Q), Kaolinite (K), Chlorite (Ch), Illite (Ill), and Smectite (Sm). It has been Zoomed to 1000x Magnification

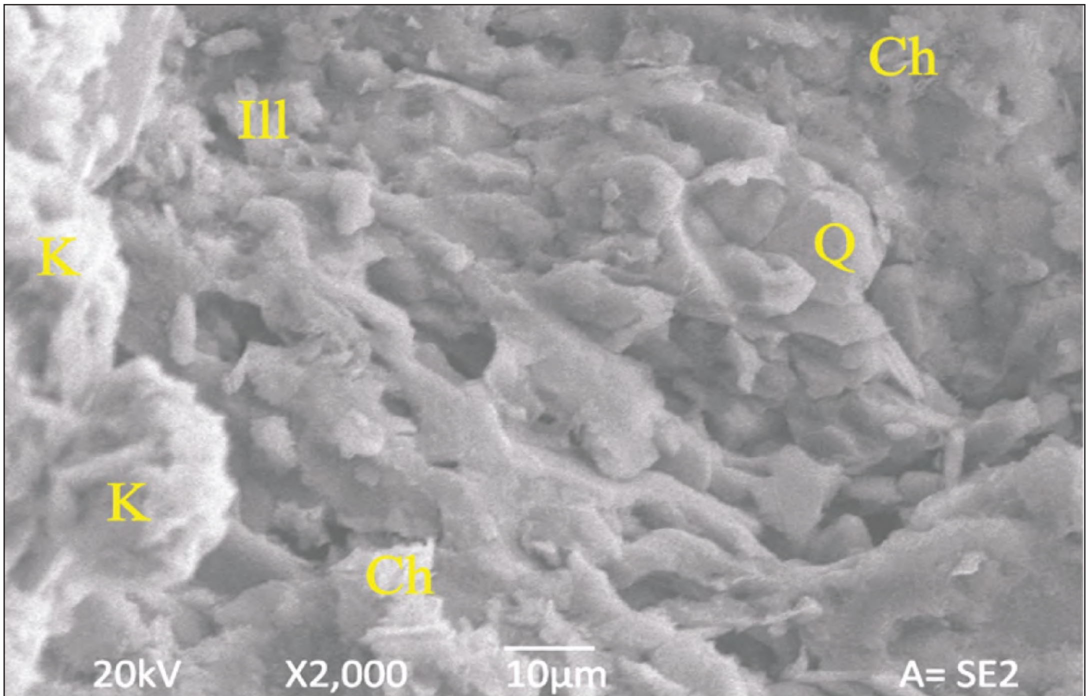


(A)

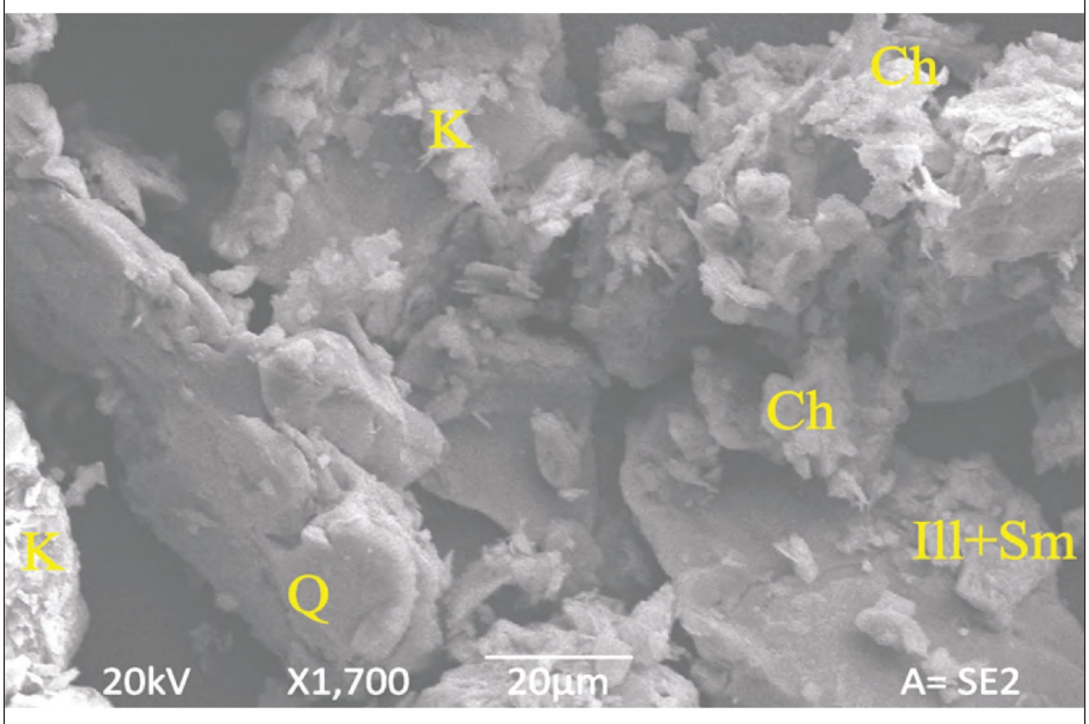


(B)

Figure 17: (A) Scanning Electron Micrographs of Shale Samples (S-9) from Rangapani Section Showing Quartz (Q), Kaolinite (K), Chlorite (Ch), Illite (Ill), and Smectite (Sm). It has been Zoomed to 1500x Magnification. (B) Scanning Electron Micrographs of Shale Samples (S-12) from Jaflong- Dauki River Section Showing Quartz (Q), Kaolinite (K), Chlorite (Ch), Illite (Ill), and Smectite (Sm). It has been Zoomed to 3440x Magnification



(A)



(B)

Figure 18: (A) Scanning Electron Micrographs of Shale Samples (K-3) from Risang Waterfall Section Showing Quartz (Q), Kaolinite (K), Chlorite (Ch), and Illite (Ill). It has been Zoomed to 2000x Magnification. **(B)** Scanning Electron Micrographs of Shale Samples (K-4) from Dhoilachara Section Showing Quartz (Q), Kaolinite (K), Chlorite (Ch), Illite (Ill), and Smectite (Sm). It has been Zoomed to 1700x Magnification

TOTAL ORGANIC CARBON (TOC) ANALYSIS

Twenty outcrop samples were collected from the Sylhet and Khagrachari field investigation areas for geochemical analysis. The Total Organic Carbon (TOC) content was measured to evaluate the source rock potential of these samples. The collected samples with lithologic descriptions are shown in Table 4.

Table 4: Lithological Description of the Samples Collected from Outcrops for TOC Analysis

Serial No	Sample No	Sample Area	Sample Type	Lithology
1.	S-1	Shari River	Shale	Grey colored, hard and compact highly weathered sample.
2.	S-2	Tetulghat	Shale	Dark grey colored fissile shale, iron inclusion, non-calcareous.
3.	S-3	Tetulghat	Nodular Shale	Dark grey colored silty shale with thin silt lamination, weathered, hard and compact, non-calcareous.
4.	S-4	Nayagang	Shale	Light grey colored, moderate hard to compact, sandy shale with no thick to thin sand lamination, non-calcareous, iron inclusion present.
5.	S-5	Nayagang	Shale	Grey colored, slightly hard and compact, laminated shale.
6.	S-6	Tamabil Road Cut	Shale	Brownish grey colored shale, moderate hard and compact, non-calcareous.
7.	S-7	Tamabil Road Cut	Shale	Grey colored, hard and compact, non-calcareous.
8.	S-8	Tamabil Road Cut	Shale	Yellowish grey colored, moderate hard and compact, non-calcareous.
9.	S-9	Rangapani	Shale	The dark grey colored shale is moderately complex and compact, with an iron band present and non-calcareous.
10.	S-10	Rangapani	Shale	Dark grey-colored shale is hard, compact, thinly to thickly laminated silty shale, and non-calcareous.
11.	S-11	Rangapani	Shale	Light grey colored shale, moderately hard and compact, weathered, laminated silty shale, non-calcareous
12.	S-12	Jaflong-Dauki River	Shale	Dark grey-colored shale is hard, compact, and non-calcareous.
13.	S-13	Jaflong-Dauki River	Nodular Shale	Dark grey colored shale, moderately complex and compact, non-calcareous nodules.
14.	S-14	Jaflong-Dauki River	Shale	Grey-colored shale is hard, compact, and calcareous.
15.	K-1	Risang Waterfall	Shale	Grey-colored, hard and compact, non-calcareous sandy shale.
16.	K-2	Risang Waterfall	Shale	Dark grey colored, moderately hard, non-calcareous shale.

17.	K-3	Risang Waterfall	Shale	Dark grey-colored shale is hard, compact, and calcareous.
18.	K-4	Dhoilachara	Nodular Shale	Grey colored, non-calcareous claystone.
19.	K-5	Dhoilachara	Shale	Dark grey colored, hard and compact, slightly calcareous shale.
20.	K-6	Dhoilachara	Shale	Dark grey colored laminated shale, hard and compact, noncalcareous. Silt lamination is present. Some weathered surfaces are present.

TOC analysis results of the outcrop samples are presented in Table 5 along with the results of total carbon (TC) and total inorganic carbon (TIC).

Table 5: TOC Analysis Results of Outcrop Samples from Sylhet and Khagrachari

Serial No	Sample No	Sample Area	Sample Type	Total Carbon (TC), %	Total Organic Carbon (TOC), %	Total Inorganic Carbon (TIC), %
1.	S-1	Shari River	Shale	0.374	0.275	0.072
2.	S-2	Tetulghat	Shale	0.185	0.024	0.161
3.	S-3	Tetulghat	Nodular Shale	0.247	0.170	0.077
4.	S-4	Nayagang	Shale	0.470	0.450	0.020
5.	S-5	Nayagang	Shale	0.345	0.283	0.062
6.	S-6	Tamabil Road Cut	Shale	0.650	0.410	0.241
7.	S-7	Tamabil Road Cut	Shale	0.409	0.335	0.074
8.	S-8	Tamabil Road Cut	Shale	0.526	0.517	0.010
9.	S-9	Rangapani	Shale	0.920	0.527	0.393
10.	S-10	Rangapani	Shale	0.960	0.407	0.553
11.	S-11	Rangapani	Shale	0.950	0.466	0.483
12.	S-12	Jaflong-Dauki River	Shale	0.965	0.816	0.149
13.	S-13	Jaflong-Dauki River	Nodular Shale	0.805	0.407	0.398
14.	S-14	Jaflong-Dauki River	Shale	1.812	1.662	0.152
15.	K-1	Risang Waterfall	Shale	0.345	0.283	0.062
16.	K-2	Risang Waterfall	Shale	0.191	0.100	0.091
17.	K-3	Risang Waterfall	Shale	0.224	0.110	0.114
18.	K-4	Dhoilachara	Nodular Shale	0.272	0.170	0.102
19.	K-5	Dhoilachara	Shale	0.360	0.349	0.011
20.	K-6	Dhoilachara	Shale	0.480	0.458	0.022

Source rock of terrestrial origin is considered pretty rich in organic matter when the TOC value is >0.5%. Most of the samples collected from the field show TOCvalues around or greater than 0.4%.

The bar diagram of the TOC analysis shows that samples collected from Kopili show the highest organic carbon content with comparatively lower inorganic carbon content. Jenum shows intermediate organic carbon content, while Bhuban has the lowest organic content among all samples.

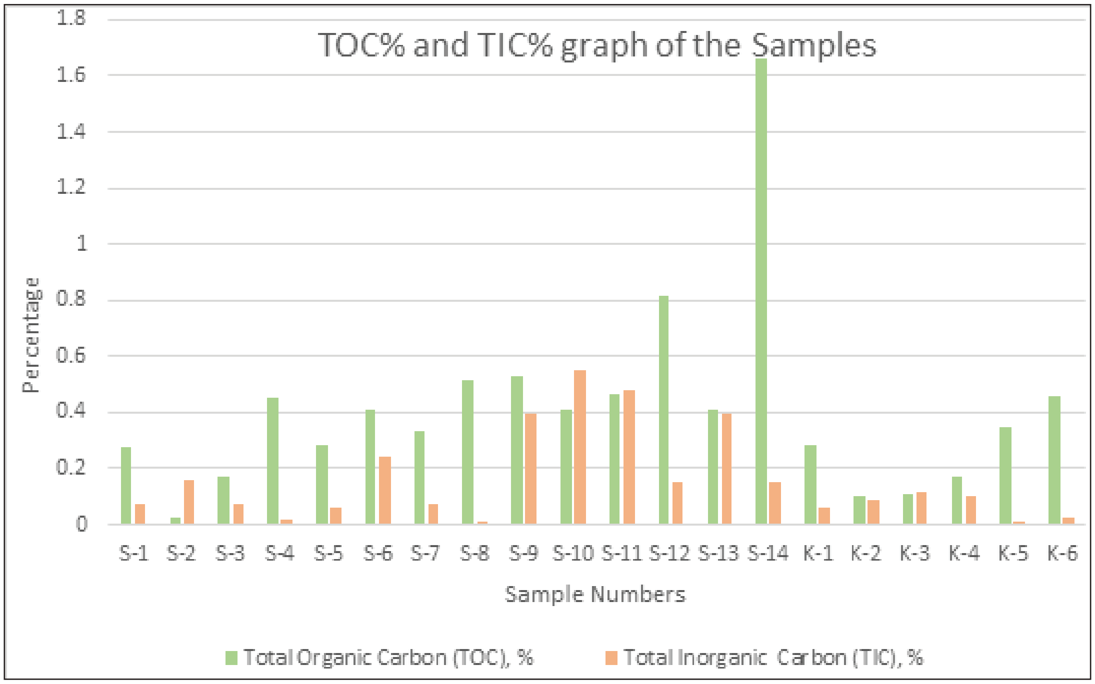


Figure 19: Bar Diagram Showing the Percentages of Total Organic Carbon (TOC) and Total Inorganic Carbon Content

The Kopili Shale was deposited within a passive margin setting (Alam et al., 2003) characterized by a relatively low sedimentation rate that facilitated the preservation of higher organic carbon content. In contrast, the Jenum Shale experienced a higher sedimentation rate, resulting in comparatively lower organic carbon content. The Bhuban Formation, deposited under the highest sedimentation rates, contains the lowest organic carbon content among the three.

SEISMIC SECTION INTERPRETATION

A 2D seismic section over the Fenchuganj structure was used to explain the subsurface structure and condition of the source rock-bearing formation. The section reveals anticlinal structure in the well site with tectonic features like faults and fractures (Fig. 20). The boundaries of the source-bearing formations are identified and marked based on the difference in acoustic impedance. Organic-rich formations possess less density, causing the acoustic impedance to be lower than the surrounding formation, facilitating the boundary identification with contrast in acoustic impedance.

The seismic interpretation shows that the thickness of different source rocks (Kopili to Bhuban formations) increases upwards. The thickness of Kopili Shale is ~40 m (Fig. 20 and Table 1), whereas the thickness of Jenum Shale is ~300 m (Figs. 20 and 21) and Bhuban Shale is ~550 m (Figs. 20 and 21). Therefore, the rate of sedimentation also increases. Considering the sedimentation time (Imam, 2013) of Kopili, Jenum, and Bhuban formations, the TOC is decreasing upwards, as is evident from the TOC analyses (Fig. 19) of the representative samples.

WELL-LOG INTERPRETATION

Well-log data from the Fenchuganj well–2 was used to interpret the subsurface lithology and correlate with the regional seismic section (Fig. 21). The Gamma log was used to identify the subsurface lithology at various depths. Shale and other fine-grained rocks have higher gamma values on the log, which marks their presence in the subsurface. The well-log data reveals the presence of organic matter bearing fine-grained rocks with spikes in gamma value. The source rock-bearing formations are delineated based on their facies change and contrast in gamma-ray value. The potential shale-bearing zones are seen at 4023 to 4310 m and below 4310 m, which are the Jenum and Kopili formations, respectively, distinguished by the higher gamma value than other formations in the log. The lower Bhuban has an alternating sand-shale bearing zone between 3100 m and 3350 m, another potential source rock for the hydrocarbon occurring in the region.

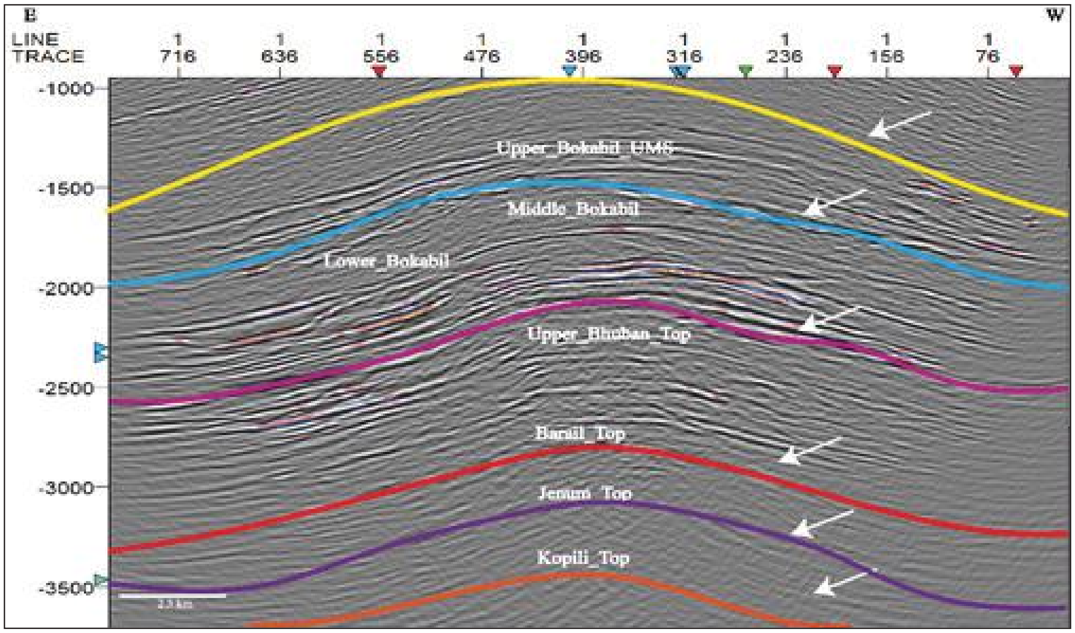


Figure 20: Interpreted Seismic Section of Fenchuganj Area Displaying Picked Horizons and Seismic Subsurface Features. The Section is Given in Time up to ~3600ms. The Colored Lines Indicate different Formation Layers in the Eastern Part of Bangladesh

The gamma-ray log response of the Kopili Shale reflects a high clay content, which progressively decreases upward through the Jenum Shale and Bhuban Shale strata. This clay abundance is consistent with depositional environments characterized by calm sedimentation for the Kopili Shale, intermediate sedimentation for the Jenum Shale, and rapid sedimentation for the Bhuban Shale. Additionally, gamma-ray readings provide insights into the thermal maturity of the formations, as the internal heat for source rock maturation is generated from the decay of Uranium, Thorium, and ^{40}K (Allen and Allen, 2013). The presence of these radioactive elements increases the gamma response of the thermally mature source rocks. The log responses indicate a strong gamma signal for the Kopili Shale, followed by the Jenum Shale and Bhuban Shale, suggesting a progressive decline in thermal maturity from the Kopili to the Bhuban Shale, which coincides with the results of the XRD analysis (Figs. 13 and 14).

REGIONAL CORRELATION

Regional well correlation has established connections between the Fenchuganj well and the Atgram structure. The seismic lines from Fenchuganj and Atgram have been connected through regional seg lines PK-SU-5, PK-SU-4, PK-SY-3, PK-ZG-3, and PK-ZG-5. Both structures are in the NE-SW direction relative to each other, so these lines are joined separately and serve as a medium to correlate between them. In the regional well correlation, we see the stratigraphic boundaries of the Jenum. Renji, Bhuban, and Bokabil formations. These formations are encountered at 3600 m, 3200 m, 2400m, and 1800m in the ground (Fig. 22). The correlative section indicates that the whole area was prone to compressional tectonic force, resulting in a series of anticlines with ample hydrocarbon generation, migration, accumulation, and entrapment opportunities in the petroleum system. The field investigation data indicates potential source rock occurrence of the deeper Kopili and Jenum formations and Lower Bhuban shales near the Zaflong-Jaintiapur area, close to the Fenchuganj and Atgram structures.

Regional seismic correlation with well-seismic ties reveals thickness variations in the Kopili, Jenum, and Bhuban formations (Fig. 22). Transparent seismic attributes with minimal internal reflections indicate shale-dominated source rocks. Seismic interpretation shows weak but laterally persistent acoustic impedances at the top of the Kopili-Bhuban source rocks (Figs. 20, 22). These weak reflectors correspond to high gamma-ray values in well-log data, confirming their shale lithology (Fig. 21). This relationship highlights the interplay of seismic and lithological characteristics in the formations.

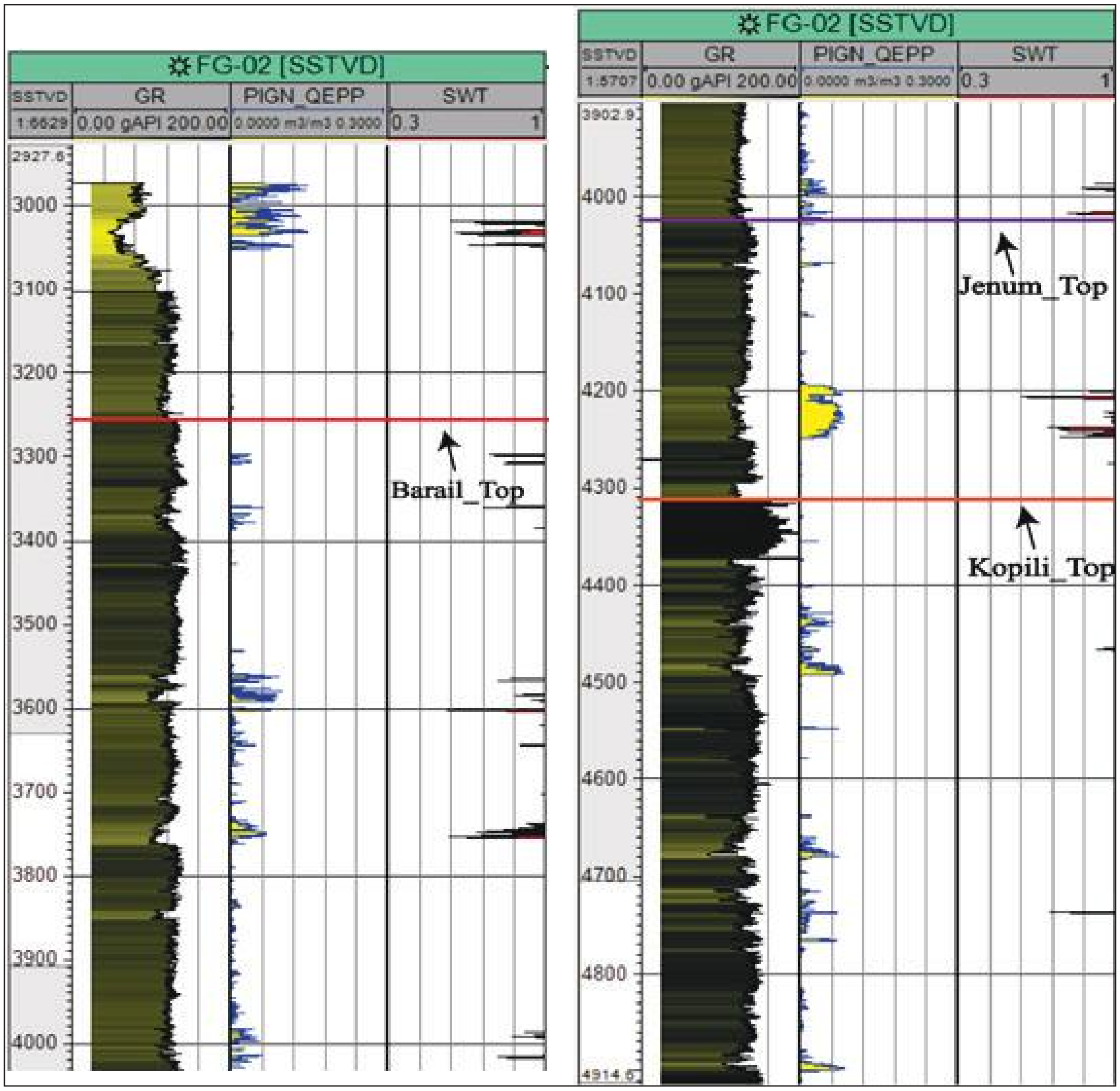


Figure 21: Well log Section of Fenchuganj Well – 02 with an Indication of Gamma-ray Values and Effective Porosity Values

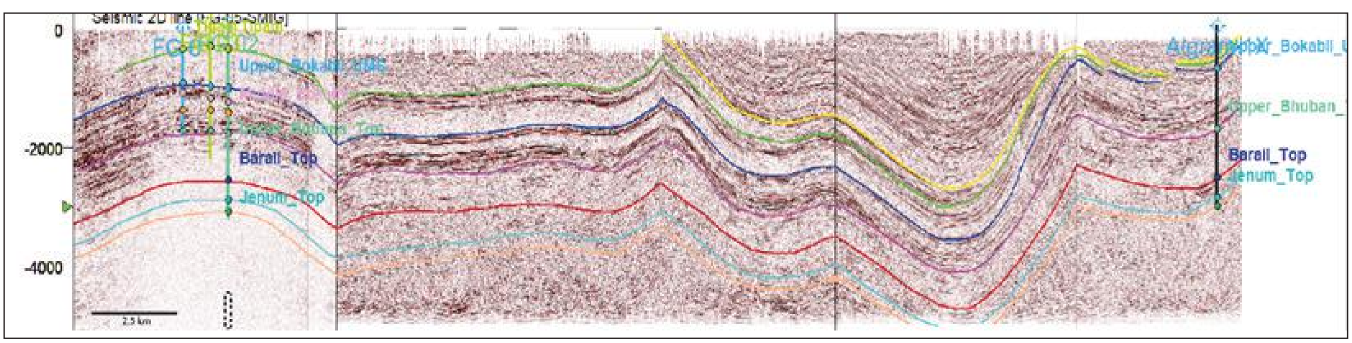


Figure 22: Regional Well Correlation from Fenchuganj to Atgram

DISCUSSION

This investigation provides a detailed analysis of the depositional environments, organic content, diagenetic processes, and hydrocarbon generation potential of the Eocene Kopili Shale, Oligocene Jenum Shale, and Miocene Lower Bhuban unit in the Sylhet and Khagrachari regions. The study integrates field observations, laboratory analysis, seismic data, and well logs to assess the geological history and the potential for hydrocarbon generation in these formations.

Depositional Environments

The depositional settings of the three formations are crucial in understanding their potential for hydrocarbon generation. Each shale was formed in distinct environments that influenced the preservation of organic matter and the conditions required for hydrocarbon maturation.

The Kopili Shale was deposited in a low-energy continental shelf environment. This setting is characterized by the relatively slow accumulation of sediments, which is ideal for preserving organic matter, as it reduces the oxidation and decomposition of organic material. The low-energy conditions in which Kopili Shale was formed contribute to its significant potential for hydrocarbon generation, as organic matter is more likely to be preserved in such environments. This formation shows the highest hydrocarbon-generating potential due to the combination of organic matter richness and favorable conditions during deposition.

In contrast, the Jenum Shale was formed in a pro-deltaic shallow marine setting. This environment represents a more dynamic depositional setting, transporting sediments from river systems into a shallow marine area. While this environment can still preserve organic matter, the constant influx of sediments and the energy of the depositional environment make preservation less favorable than in low-energy settings. The Jenum Shale's hydrocarbon potential is somewhat lower than that of the Kopili Shale but still notable due to the organic matter content and the conditions during burial.

The Lower Bhuban shale was deposited in a deltaic to pro-deltaic environment with strong tidal influences. In both Sylhet and Khagrachari, this tidal influence suggests more energy in the system, which could impact preserving organic material. While deltaic environments can be rich in organic material, the tidal influence may have caused periodic reworking of sediments, potentially reducing the preservation of organic matter. Therefore, this formation's hydrocarbon potential depends more on the burial depth and the diagenetic processes that have occurred since deposition.

Laboratory Analysis

Laboratory studies, including XRD and SEM, provide essential insights into the mineralogy and diagenesis of shale formations. These results are critical for understanding the burial history and the conditions that have influenced the source rock maturity and transformation of organic matter into hydrocarbons.

X-ray diffraction (XRD) analysis provides insights into the shale's mineral composition and diagenetic history. The identified clay minerals, including illite, chlorite, and dolomite, along with the absence of smectite, suggest deep burial diagenesis. The transformation of smectite into illite under high-pressure and high-temperature conditions indicates significant burial depths for these formations. Among the studied samples from the Sylhet region, the Kopili Shale exhibits the highest degree of illitization, marking it as the most thermally mature formation, consistent with its substantial burial depth before uplift. The Jenum Shale shows intermediate levels of illitization, suggesting moderate thermal maturation compared to the Kopili Shale. In contrast, the Bhuban Shale demonstrates the lowest degree of illitization, indicating minimal burial depth and limited thermal maturation in this region. These findings align with earlier studies (Imam 1983, 1993), documenting similar diagenetic processes and burial histories (Fig. 13C).

Bhuban Shale samples from Khagrachari exhibit higher illitization, indicating greater burial depths and increased thermal maturity as a source rock. The mineral composition suggests these formations experienced deeper burial than Bhuban Shale from Sylhet. The enhanced illitization in Khagrachari samples highlights their deep burial diagenesis and thermal maturation. These findings reveal more significant thermal maturation of Bhuban Shale in the southern part of the Eastern Fold Belt of the Bengal Basin (Figs. 13C and 14).

SEM analysis confirms the presence of quartz grains, kaolinite, chlorite, smectite, and illite, further supporting the XRD results. Importantly, no authigenic quartz was observed, but dissolved orthoclase grains surrounded by illite or muscovite suggest that feldspar diagenesis has occurred. The presence of chlorite, a mineral formed under high-pressure conditions, further supports the idea of deep burial for these formations. Additionally, tectonic activity has influenced the grain orientations in these rocks, with highly deformed grains indicating shifts in local and regional stress fields.

TOC and Hydrocarbon Potential

TOC analysis provides insights into the organic richness of the studied formations. TOC values above 0.5% indicate good hydrocarbon generation potential, yet most samples show slightly above 0.4%, reflecting moderate organic richness. The Kopili Shale exhibits the highest TOC values (1.812%), attributed to excellent organic matter preservation in a low-energy depositional environment. Samples from northern Sylhet display higher TOC values than those from Khagrachari, likely due to tidal influences in the Lower Bhuban Formation, which hindered organic matter preservation in Khagrachari.

While all formations have hydrocarbon potential, the Kopili Shale stands out for its organic richness and favorable depositional conditions. Deposited in a passive margin setting with low sedimentation rates (Alam et al., 2003), it preserved higher organic carbon content. Conversely, the Jenum Shale, with higher sedimentation rates, has lower organic carbon content, and the Bhuban Formation, deposited under the highest sedimentation rates, contains the lowest organic carbon content.

Seismic and Well-Log Data

Seismic sections and well-log data provide a subsurface image of the basin, revealing the depth and extent of the organic-rich formations. Seismic data indicates that these formations are low-density compared to surrounding stratigraphic units, consistent with their organic richness. The Fenchuganj well-02 data confirms that the source-bearing rocks are buried deep within the subsurface, with the Jenum Formation encountered between 4,023 and 4,310 meters and the Bhuban Shale identified at depths of 3,100 to 3,350 meters. The rapid subsidence of the basin during the Tertiary period contributed to the deep burial of these formations, providing the pressure and temperature conditions necessary for hydrocarbon generation. The investigation highlights the Kopili Shale as the most promising source rock for hydrocarbon generation due to its high TOC values, favorable depositional environment, and deep burial history. The Jenum and Lower Bhuban Shales also exhibit potential, though they are influenced by more dynamic depositional environments and tectonic activity. Seismic and well-log data support these findings by providing insights into the depth and distribution of these formations. Further geophysical surveys and a more extensive dataset could enhance understanding of the basin's hydrocarbon potential and guide future exploration efforts.

The thickness of the Kopili (~40m) , Jenum (~300m), and Bhuban (~550m) formations increases upwards. Considering the thicknesses and sedimentation time (Imam, 2013) of the Kopili, Jenum, and Bhuban formations, the TOC is decreasing upwards, as is evident from the TOC analyses (Fig. 19) of the representative samples.

The gamma-ray log response of the Kopili Shale reflects a high clay content that progressively decreases upward. The Kopili, Jenum, and Bhuban Shales are characterized by calm, intermediate, and rapid sedimentation. Additionally, varying gamma-ray readings indicate differential thermal maturity of source rocks (high in Kopili, intermediate in Jenum, and low in Bhuban). The log responses coincide with the results of the XRD analysis (Figs. 13 and 14).

The regional seismic correlation with well-seismic ties indicates varying thicknesses of the Kopili, Jenum, and Bhuban formations (Fig. 22). Transparent seismic attributes with minimal internal reflections suggest shale-dominated source rocks. The seismic interpretation reveals weak but laterally continuous acoustic impedances at the top of source rocks (Kopili-Bhuban) (Figs. 20, 22). Well-log data confirm these weak reflectors correspond to high gamma-ray values, consistent with shale lithology (Fig. 21).

CONCLUSIONS

This study focused on assessing the quality of source rocks in the EFB, utilizing field investigations, laboratory data analysis, and geophysical seismic and log data analysis. The field investigations and sampling were conducted in the Sylhet and Khagrachari areas of the EFB due to their structural upliftment, which provided distinct outcrops for fieldwork and sample collection. A total of 20 shale samples were collected from 7 road-cut and stream sections. Eight 2D seismic sections and logs from the Fenchuganj 2 well were used for geophysical data analyses.

The field investigations indicate significant potential for source rock occurrence in the EFB. The literature review suggests that the identified source rocks are primarily Type II and gas-prone. While the southern portion of the basin contains rocks with higher humic content, the northern formations are less humic. These rocks were deposited in diverse environments, including the continental shelf, fluvio-deltaic, shallow marine, and deep marine prodeltaic settings. Sequence stratigraphic investigations indicate that the Kopili and Jenum formations are predominantly marine and prone to less humic organic matter. At the same time, the Lower Bhuban shales in the Khagrachari area are shallow marine to prodeltaic deposits prone to terrestrial organic origin.

Mineralogical analysis, including X-ray diffraction and Scanning Electron Microscopy, suggests a deep burial history and clay diagenesis. The transformation of smectite into illite and K-feldspar into kaolinite reflects clay diagenesis, while chlorite indicates high pressure and temperature conditions. This suggests that the source rock underwent deep burial. Total Organic Carbon (TOC) values range from 0.024% to 1.812%, with most samples exceeding 0.4%, indicating fair organic richness. Lower energy deposition conditions make rocks with higher TOC content more prevalent in the northeastern basin. In contrast, higher energy conditions in the southeastern basin produced less organic-rich rocks. However, due to Kopili not being regionally distributed over the Bengal Basin, it is not the best option to consider this as a significant source rock bearing formation.

Log data from Fenchuganj confirms that source rock-bearing formations occur between 3500 and 4200 m at temperatures between 105 and 140°C. This depth and seismic data confirm that deep burial provided the necessary conditions for gaseous hydrocarbon generation with many condensates. Structural deformation in seismic sections also highlights the tectonic influences during source rock deposition, further supporting the potential for hydrocarbon exploration in the Bengal Basin.

ACKNOWLEDGMENT

The authors thank the University Grants Commission of Bangladesh for selecting and providing the UGC Research Grant (2022-2023), University of Dhaka, to conduct the research successfully. They are also sincerely thankful to the Department of Geology, University of Dhaka, for permitting this research project and using lab facilities in the Department of Geology, Dhaka University. Data analyses have been conducted in the GNG Simulation, Sedimentology, and GIS Labs. CARS-DU, BAPEX, and BUET have provided secondary geophysical/geological data and laboratory facilities.

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