Geochemical Evaluation of Early Cretaceous Massive Sand Member of Lower Goru Formation, Bitrism Block, Thar Platform, Pakistan

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GEOCHEMICAL EVALUATION OF EARLY CRETACEOUS MASSIVE SAND MEMBER OF LOWER GORU FORMATION, BITRISM BLOCK, THAR PLATFORM, PAKISTAN

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Abstract

The shale intervals of the Massive Sand Member of the Early Cretaceous Lower Goru Formation were selected for geochemical analysis in the southern Indus Basin, particularly the Thar Platform area of Pakistan. The formation was evaluated for organic matter quantity, quality, and maturity to determine the petroleum generation potential using TOC and Rock-Eval Pyrolysis measurements. The studied samples contain TOC ranging from 0.57- 3.35 wt.%, indicating fair to very good source rock potential. The analyzed samples have hydrogen index values ranging from 78 to 298 mg HC/g TOC, indicating mainly terrestrial organic matter input with kerogen type-III along with minor kerogen type-II/III. The *Tmax* values range from 426 to 439°C, along with calculated VRo values of 0.51-0.74% which exhibits an immature to early mature status for this formation. Based on the analysis, some shale intervals contain mature organic matter for mainly gas generation, but commercial amounts of gas have not yet been generated at the current maturity level. The present study investigates the petroleum generation potential and suggests the shale intervals of the Massive Sand Member of Lower Goru Formation as a secondary target (at more depth) after the Sembar Formation in the southern Indus Basin, Pakistan.

Keywords: Cretaceous, Massive Sand, Lower Goru, Shale Gas Resource, Southern Indus Basin, TOC and Rock-Eval Pyrolysis

Introduction

The southern Indus Basin of Pakistan is considered one of the most prolific basins for conventional and unconventional hydrocarbon resources. 206 TCF of technically recoverable gas reserves have been estimated by the US Energy Information Administration (Kuuskraa et al., 2011). A complete study carried out by the ministry of energy with the help of USAID depicts 95 TCF of risked recoverable shale gas reserves in the Lower Indus Basin (Ministry of Energy report, 2020). Many researchers (e.g., Ahmad and Zaigham, 1993; Khan et al., 1996; Zaigham et al. 2000, Ehsan et al., 2019) worked in the Thar Platform area, and their findings are mainly confined to structural configuration, conventional hydrocarbon potential, and coal mining in the area. For the first time in this study, the Goru Formation’s Massive Sand Member was evaluated on the Thar Platform region. Well-cutting samples of Bitrisim-1X located in the Bitrism Block, central Sindh Province (Fig. 1) were investigated for their petroleum generation potential using TOC and Rock-Eval pyrolysis measurements.

This study aims to determine the organic matter quantity, quality, and maturity of shale intervals in the Massive Sand of Lower Goru Formation. The results of the present study will help in defining the petroleum generation potential of the study area.

Geological settings

The study area is situated in the Thar Platform, southern Indus Basin, Pakistan. The southern Indus Basin is bounded to the north by the Sukkur Rift (a divide between the central and southern Indus basins). The Indian Shield borders the southern Indus Basin to the east, and the Indian Plate's marginal zone borders it to the west. The offshore Murray Ridge-Oven Fracture plate boundary limits the southward extension of this basin (Kadri, 1995). The main units of the southern Indus Basin are the Thar Platform, Karachi Trough, Kirthar Foredeep, Kirthar Fold Belt, and Offshore Indus (Kadri, 1995). Zaigham and Mallick (2000) presented a three-step evolutionary model in which initial rifting during the Paleozoic anticipates the first step. The second step reveals the breaking of the upper crust and subsidence, and Mesozoic and Tertiary sediment accumulation represent the evolutionary model's third step. Though analogous to the Punjab Platform, the Thar Platform depicts the buried structures formed due to the counter-clockwise movement of the Indian Plate (Siddiqui, 2016).

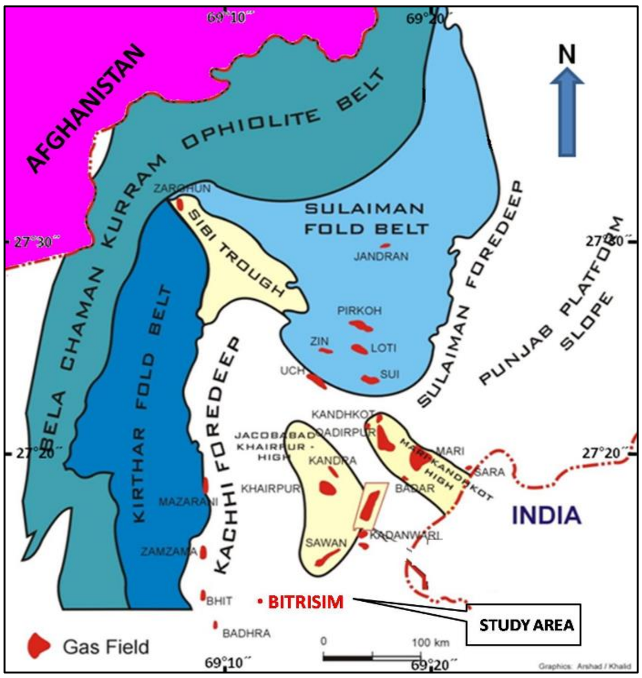

Figure 1. Location map of the study area (Modified after Ahmed et al., 2013).

The oldest drilled rock sequence is the Jurassic Chiltan Limestone, and the youngest is the Plio-Miocene Siwaliks followed by Recent alluvium (Baig et al., 2016; Fig. 2). The Goru Formation consists of interbedded sandstone, limestone, shale, and siltstone (Shah, 1977). Different companies use their own classification scheme for Lower Goru Formation. The Lower Goru Formation's Massive Sand Member is mainly sandstone with interbeds of shale (Siddiqui, 2016). The shale interbeds of the massive sandstone unit of the Goru Formation were selected for geochemical evaluation in this research. The Early Cretaceous Sembar Formation and interbedded shale units of the Lower Goru Formation are considered favorable source rocks in the region (Aziz et al., 2020; Ahmed et al., 2020; Awan et al., 2021). The Cretaceous Lower Goru Sandstone is the most prolific reservoir in the area, and the Upper Goru shales act as a seal rock in the area (Zaigham and Mallick, 2000; Solangi et al., 2016).

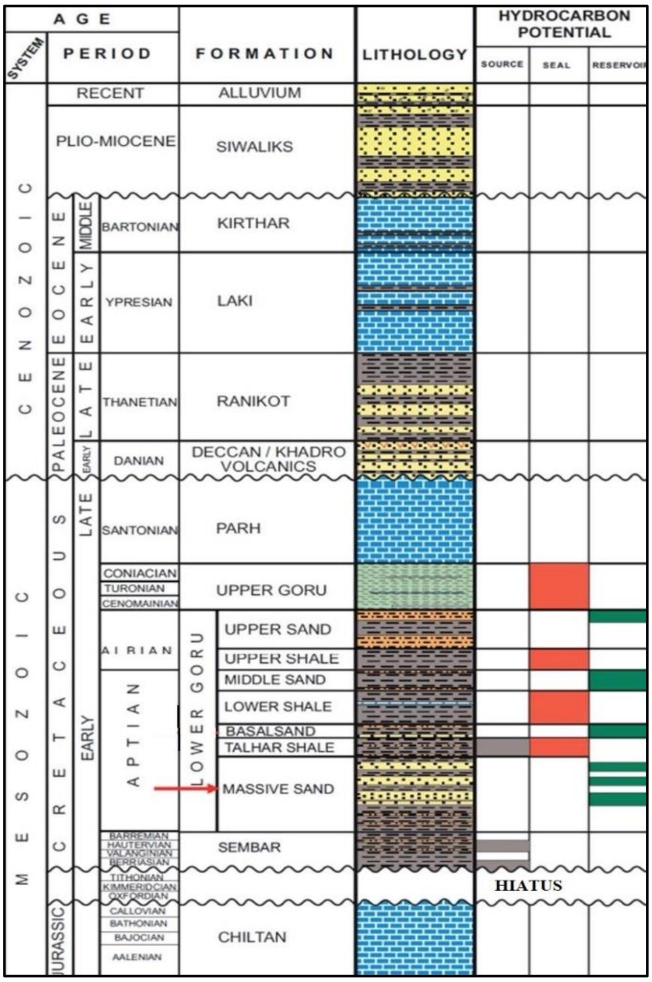

Figure 2. Stratigraphy of the southern Indus Basin (Baig et al., 2016).

Material and Methods

A total of nine well-cutting samples of the shale intervals in the Massive Sand Member of Early Cretaceous Lower Goru Formation were selected from a well (Bitrism-1X) located in the Bitrism Block, Thar Platform of Pakistan (Fig. 1; Table 1). Contaminants (such as drilling additives and drilling mud) were removed, and the samples were washed before the geochemical analysis. Following that, 100–150 mg samples were ground, and to remove inorganic content (carbonate minerals), samples were treated with 10% diluted HCl in ceramic crucibles. Then the carbon– sulphur determinator was used for TOC determination in the samples. Using Rock-Eval 6 instrument, 60–65 mg of each sample (with TOC > 0.5 wt.%) were placed in a Rock-Eval crucible and analyzed. The instrument detected the amount of hydrocarbons produced by heating the sample at a rate of 25°C per minute up to 650°C. Free and residual hydrocarbons were detected by the FID detector and formed the S_1 and S_2 pyrogram peaks, respectively. The S_3 peaks formed due to oxygen-containing molecules, which produced CO_2 (as detected by the IR detector). The temperature at which the most generated hydrocarbons are released in an S_2 peak is defined as *Tmax*, also measured by Rock-Eval 6. The hydrogen index (HI=S_2*100/TOC), oxygen index (OI = S_3*100/TOC), and genetic potential (GP=$S_1 + S_2$) were among the geochemical parameters calculated based on the values of S_1, S_2, and S_3 peaks and TOC values (El Nady and Mohamed 2016; Ahmed et al., 2020).

Results and Discussion

The amount of organic content (organic richness), the quality of the organic matter (kerogen type), and the thermal maturity of the organic matter present in the rock are all used to evaluate source rock potential for hydrocarbon generation (Hunt, 1964; Peters, 1986; Tissot et al., 1987; Waples, 1994; McCarthy, 2011). The current study depicts source rock evaluation data using a TOC analyzer and Rock-Eval pyrolysis (Table 1).

a) Organic matter quantity

The examination of source rocks is dependent on assessing the richness of organic matter (organic matter quantity), which is usually expressed as total organic carbon (TOC wt. %). The TOC values of shale intervals range from 0.57 to 3.35 wt.%, showing that the interbedded shales interval of Massive sand of Lower Goru Formation have fair to very good source rock potential (e.g., Peters and Cassa, 1994). Figure 3 shows TOC values plotted versus depth, and indicates that the general trend of organic content declines as depth increases. S_1 (hydrocarbons released before pyrolysis); S_2 (hydrocarbons released after pyrolysis); and GP (genetic potential, $S_1 + S_2$) are all measured Rock-Eval parameters used in this work. S_1 is less than 0.5 mg/g for all samples, indicating poor source rock potential. The range of S_2 values is 0.58 to 7.24 mg/g, indicating poor to good source rock potential (Peters and Cassa, 1994).

According to Hunt (1996), source rocks with a GP less than 2 have a poor generative potential, those with a GP between 2 and 5 have a fair generative potential, those with a GP between 5 and 10 have a good generative potential, and those with a GP greater than 10 have a very good generative potential. GP values range from 0.60 to 7.64 mg/g in the analyzed shale intervals, indicating poor to good source rock potential (Fig. 4). Considering TOC as the most reliable indicator of organic richness, the shale intervals of the Lower Goru Formation's Massive Sand Member have enough organic richness (quantity) to be regarded as potential source rock.

b) Organic matter quality (kerogen type)

Organic matter (OM) in petroleum source rocks is produced by a variety of species. These species differ in terms of their structure, which is made up of lignin, carbohydrates, protein, lipids, and other substances. These species are further modified by sedimentary processes such as diagenesis, catagenesis, and metagenesis during burial. Some source rocks produce oil, whereas others produce gas due to the diversity of species and sedimentary processes (Dow, 1977).

Table 1. Geochemical results of shale intervals of Massive Sand Member of Lower Goru Formation in Bitrism-1X.

Depth (m)	TOC (wt. %)	S_1 (mg/g)	S_2 (mg/g)	S_3 (mg/g)	*Tmax* (°C)	GP (mg/g)	HI (mg/g)	OI (mg/g)	Calculated VRo (%)
2510	3.35	0.26	3.85	0.31	430	4.11	115	9	0.58
2540	1.60	0.11	2.00	0.44	435	2.11	159	35	0.67
2550	1.39	0.1	2.26	0.16	432	2.36	163	12	0.62
2590	0.76	0.02	0.59	0.82	439	0.61	78	108	0.74
2610	0.57	0.02	0.58	0.26	437	0.60	102	46	0.71
2620	1.69	0.08	2.18	0.22	435	2.26	129	13	0.67
2630	1.29	0.07	1.89	0.2	436	1.96	147	16	0.69
2690	2.43	0.4	7.24	0.01	426	7.64	298	0	0.51
3010	0.60	0.1	0.84	0.86	437	0.94	140	143	0.71

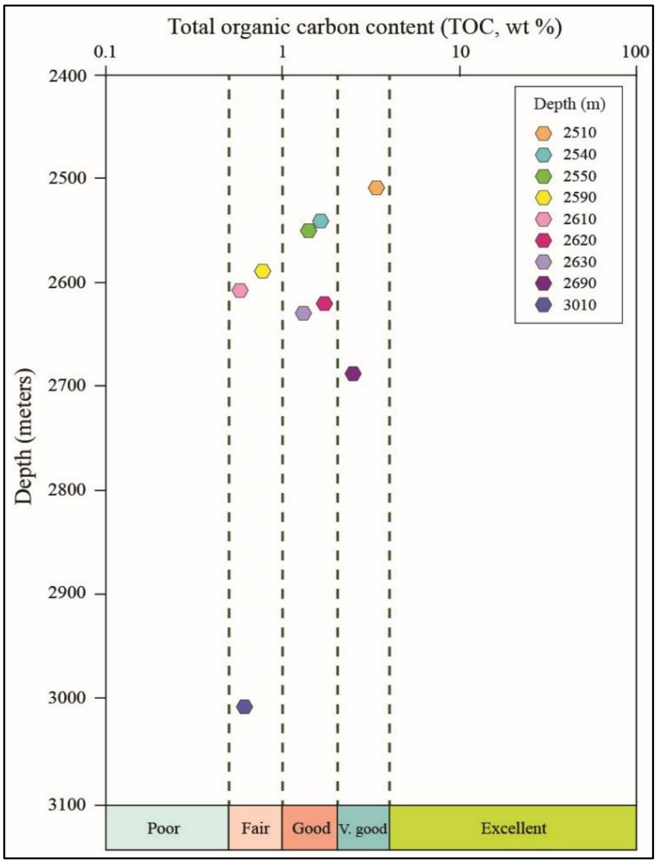

Figure 3. Organic richness trend of shales intervals from Massive Sand Member of Lower Goru Formation indicating fair to very good source rock potential (after Peters, 1986).

Kerogen types (quality) in the source rock help define the petroleum products in the source rock. In this study, the quality of organic matter was determined by plotting samples on the HI vs. *Tmax* diagram, HI vs. OI diagram and S_2 vs. TOC diagram. Type III kerogen (gas potential) of source rock is represented by HI values between 50 and 200 mg/g, while type II/III kerogen is represented by HI values between 200 and 300 mg/g (oil and gas potential; Magoon and Dow, 1994; El Nady et al., 2016; Mohamed and El Nady, 2016; Hakimi et Al., 2018 a, b). The hydrogen index values of the examined samples ranged from 78 to 298 mg/g, indicating type III and type II/III kerogen (Fig. 5 and Fig. 6).

The results indicated that just one sample had HI value of 298 mg/g, whereas the other samples all depicted kerogen type-III and lay within HI values of 50-200 mg/g, suggesting terrestrial organic input (e.g., Peters and Cassa, 1994). A cross plot of S_2 vs. TOC (Fig. 7) also shows the dominant occurrence of kerogen type-III (gas potential), and few samples fall into the organic lean category (e.g., Langford and Blanc-Valleron, 1990).

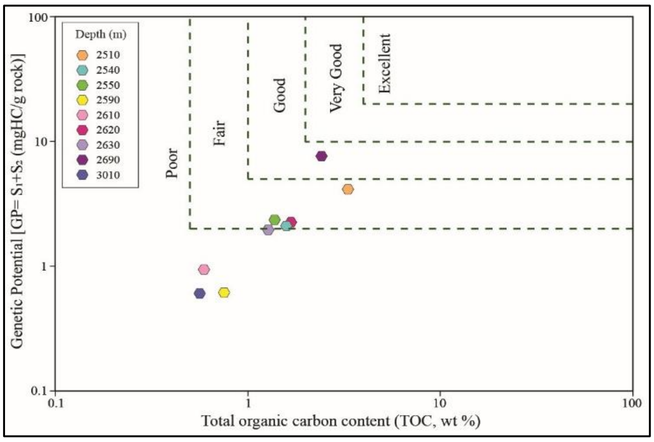

Figure 4. Genetic potential (GP) vs. TOC plot indicating poor to good source rock potential for shales intervals from Massive Sand Member of Lower Goru Formation (after El Nady and Mohamed 2016).

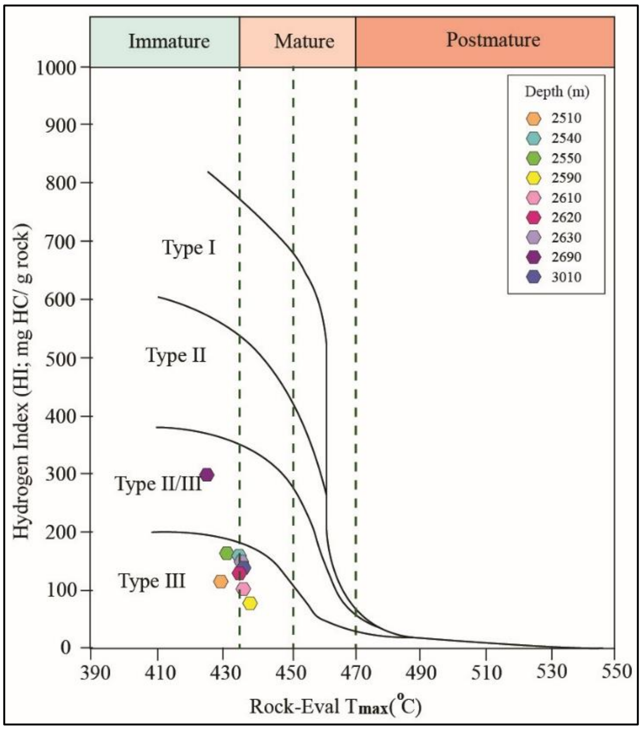

Figure 5. Modified van Krevelen diagram (HI vs. *Tmax* plot) indicating mainly kerogen type-III for shales intervals from the Massive Sand Member of Lower Goru Formation (Hunt, 1996; Ahmed et al., 2020).

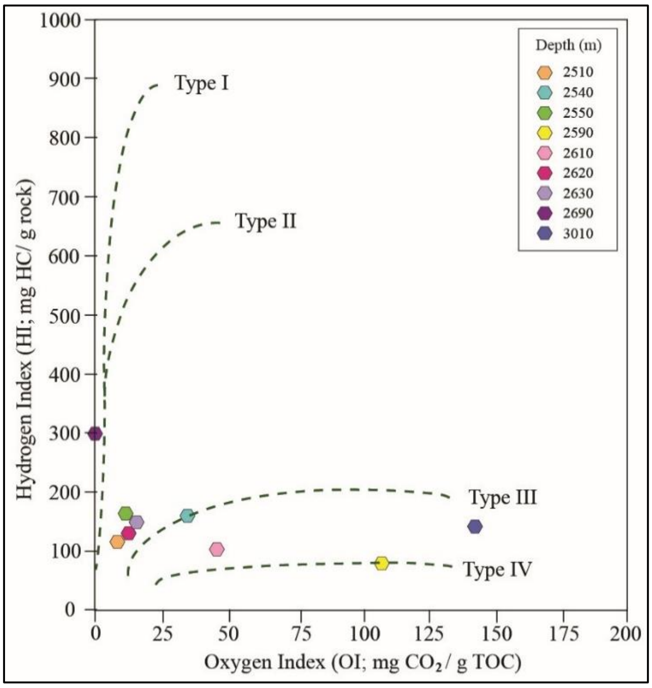

Figure 6. Modified van Krevelen diagram (HI vs. OI plot) indicating mainly kerogen type-III for shales intervals from the Massive Sand Member of Lower Goru Formation (after Peters, 1986).

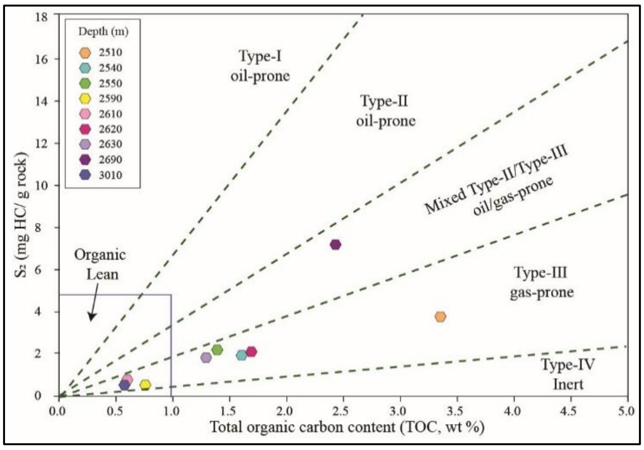

Figure 7. S_2 vs. TOC plot suggests predominantly kerogen type-III along with a few organic lean samples for shale intervals from the Massive Sand Member of Lower Goru Formation (modified from Langford and Blanc-Valleron, 1990).

c) Organic matter maturity

Maturation is the chemical alteration of sedimentary organic matter caused by burial, i.e., the effect of increasing temperature and pressure over geological time (Miles, 1989). *Tmax* is employed in this work to determine the maturity of organic matter. *Tmax* is the temperature in the S_2 peak of the pyrogram at which the most pyrolyzed hydrocarbons are released. The source rock is considered immature if its *Tmax* value is less than 435ºC. *Tmax* values for early mature source rock range from 435 to 445°C (Magoon and Dow, 1994).

The *Tmax* values in the analyzed shale intervals range from 426 to 439ºC, indicating an immature to the early mature stage for this formation. A plot of *Tmax* against depth is also established (Fig. 8) to assess the maturity pattern with depth, which shows maturity tends to increase as depth increases.
Because measured vitrinite reflectance data (optical VRo) was unavailable for this study, thus calculated VRo values (Table 1) were derived using Rock-Eval *Tmax* data employing Jarvie et al. (2001) equation: VRo = (0.018* *Tmax*) - 7.16. The best *Tmax* values were observed in samples with S_2 greater than 0.50 mg/g rock (Jarvie et al. 2001; Ahmed et al., 2020). Since all the samples had S_2 values of more than 0.50 mg/g rock in this study (Table 1); hence, *Tmax* values can be considered reliable for calculating VRo values using the Jarvie et al. equation (2001). The calculated VRo values range from 0.51 to 0.74 % and are plotted on the *Tmax* vs. Calculated VRo diagram which confirmed the immature to early mature status for shale intervals of Massive Sand Member of Lower Goru Formation (Fig. 9).

d) Petroleum-generation potential

A combination of geochemical and petrological data can be used to estimate the amount of petroleum that could be produced during thermal maturation (Makeen et al., 2015; Abdullah et al., 2017, Ahmed et al., 2020). To define petroleum generation potential, the HI vs. TOC plot is employed in this study. The shale interval of the Massive Sand Member of Lower Goru Formation indicated mainly gas-generation potential as indicated by the HI vs. TOC plot (Fig. 10). Gas generation potential (kerogen type-III) was also corroborated by HI vs. *Tmax*, HI vs. OI, and S_2 vs. TOC plots. The S_1 vs. S_2 plot was developed to discriminate between indigenous (generation hydrocarbons) and nonindigenous (non-generation hydrocarbons/migrated hydrocarbons).

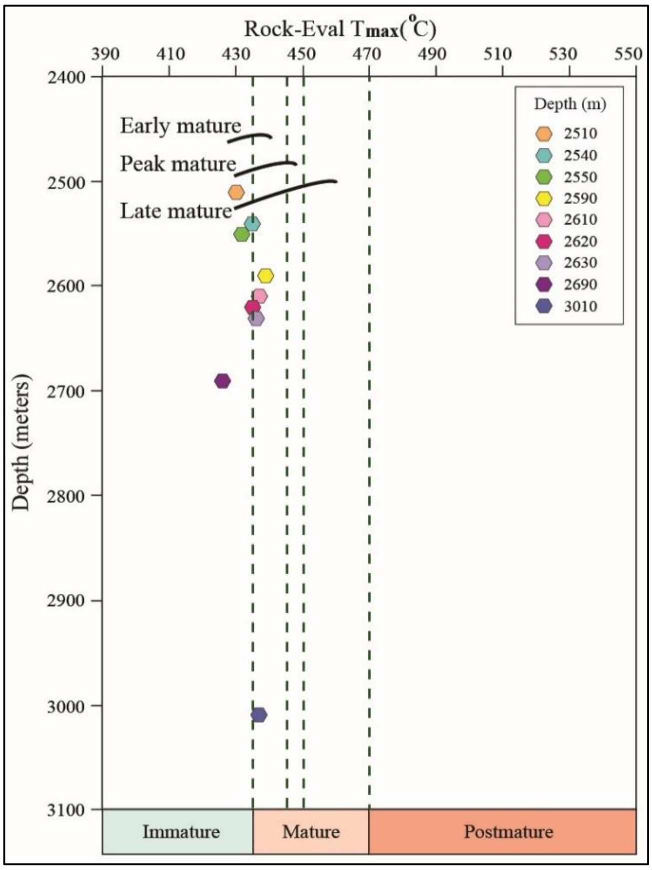

Figure 8. *Tmax*-maturity trend of shales intervals from Massive Sand Member of Lower Goru Formation with depth (m) indicating immature to early mature source rock (Peters, 1986; Hakimi et al., 2020).

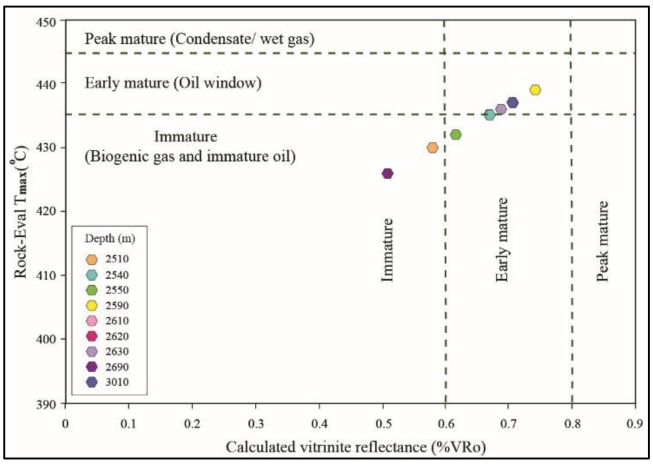

Figure 9. *Tmax* vs. Calculated VRo plot confirms immature to early mature status for shale intervals from the Massive Sand Member of Lower Goru Formation (modified from Atta-Peters and Garrey, 2014; Ahmed et al., 2020).

All the examined samples contained indigenous hydrocarbons and were not contaminated by drilling fluid or other contaminants (Fig. 11; Younes et al, 2017, Hakimi et al., 2020), indicating that these results are reliable. The petroleum generation potential of the shale interval of the Massive Sand of Goru Formation has been further examined by utilizing the maturity level of the organic matter. Considering the formation's early maturity as shown by *Tmax* and calculated VRo values, it may be inferred that this formation contains a sufficient quantity and quality of organic matter but lacks the high maturity level required to produce commercial amounts of gas.

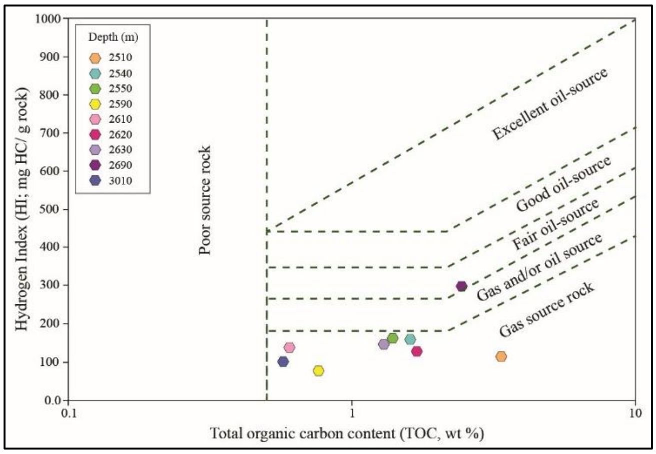

Figure 10. HI vs. TOC plot suggests predominantly gas generation potential for shale intervals from the Massive Sand Member of Lower Goru Formation (Hakimi et al., 2018b).

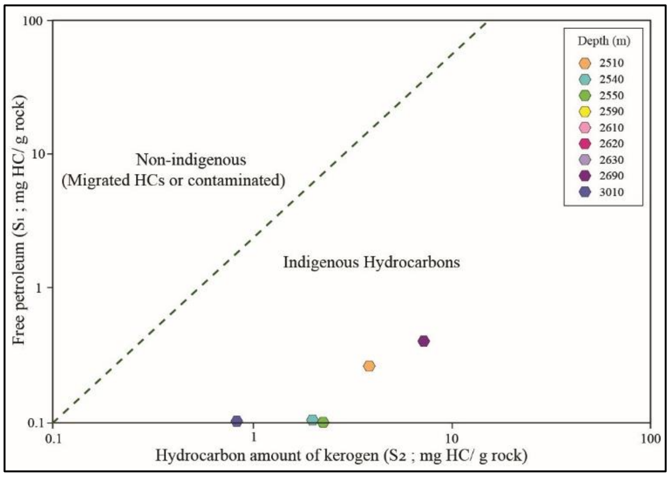

Figure 11. S_1 vs. S_2 plot suggests indigenous hydrocarbons for shale intervals from the Massive Sand Member of Lower Goru Formation (after Hunt, 1996).

Conclusions

Shale intervals from Massive Sand Member of the Early Cretaceous Goru Formation were selected for organic geochemical investigation. The main conclusions are outlined below, based on well cuttings of 09 different depth intervals from a single well in the Thar Platform, southern Indus Basin of Pakistan.

- The TOC values of the shale intervals ranged from 0.57 to 3.35 wt%, implying that these sedimentary horizons could be potential source rock.
- The shale samples exhibited high quantities of terrestrial organic matter input and mainly were kerogen type-III, with HI values ranging from 78 to 298 mg HC/g TOC. The presence of terrestrial kerogen type-III in the shale

intervals of Massive Sand Member of Lower Goru Formation shows that the shale interval is likely to generate gas.

- The geochemical maturity measurements, such as *Tmax* (426-439ºC) and calculated VRo (0.51-0.74%), indicated that the examined samples contained immature to early mature organic matter. However, no commercial amounts of gas have yet been generated at present maturity level.
- These findings have implications for exploration tactics for commercial gas generation and production in deep areas of Pakistan's southern Indus Basin, where the shale interval of Massive Sand of Lower Goru Formation may have reached a high maturity level of gas-window.

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