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An Integrated Approach to Assess and Map Organic Shale Reservoirs- A Case History from Central Part of Lower Indus Basin, Pakistan

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ABSTRACT

The focus of the present study is to evaluate and map the unconventional resources particularly, organic shale reservoirs in the central part of Lower Indus Basin Pakistan. Integration of geochemical and petrophysical data shows that shales of Middle and Lower Cretaceous horizons in the study area has retained enough hydrocarbon potential for exploration and are comparable to world known shale gas producing reservoirs. The estimated OHIP (gas equivalent) values shows that the Sembar Formation contains approximately 34 TSCF, Talhar Shale has 0.6 TSCF and 3.41 TSCF in shales of Massive Sand. Assessment shows that better OHIP values, reasonable resource density, fair to very good TOC values, moderate to good effective porosities, low water saturation, and appropriate stress barriers, favorable fracking characteristics high net pay of the Sembar Formation and lower shale of Massive Sand may be qualified for good and low risk targets for shale gas pilot well in the study area. The main objective of the study is to identify Prospective shale intervals in-terms of reasonably good reservoir properties and better completion quality i.e., favorable petro-elastic characterization of lower Cretaceous Shales. To quantify shale gas potential and map potential shale gas horizons within Talhar, Massive Sand of Lower Goru and in the Sembar Formation. Favorable Study results may provide guideline for the exploitation, to strategize shale gas development plan in the area.

INTRODUCTION

As the deficiency load of energy is increasing day-by-day and conventional fossil fuel supplement of energy being depleted rapidly. Therefore, it is primary requisite to assess and exploit unconventional potential resources i.e. shale and tight gas. In Pakistan, various E&P companies are utilizing their resources to delineate the spatial and stratigraphic extent of the unconventional reservoirs as per instructions of Ministry of Energy Petroleum Division Government of Pakistan. However, companies are reluctant to invest in this business, as it is not being considered economically viable due to myriads of reasons. Shale reservoir characterization is essential to understand the anatomy of shales before making any investment in this high-risk business. Shale is a fine-grained, clastic sedimentary rock formed from mud that is a mixture of flakes of clay minerals and tiny fragments (silt-sized particles) of other minerals. Organic shale reservoirs are dominantly composed of consolidated clay-sized particles with higher organic content that formerly known as source rocks and a primary element for conventional petroleum system. Sufficient subsurface pressures and temperatures convert frequently organic matter to oil and gas with time, which may migrate to conventional petroleum traps but quiet significant amount may remain within the shale (Harry et al., 2017). However, very small size of pore throats with extremely low permeabilities are in nano-darcy range (Hashmy et al., 2012), as typical organic shale reservoirs are tight and very heterogeneous in nature. Advancement in technology has made it possible to exploit low permeability reservoirs worldwide. However, in Pakistan, cost effective price of commodity, optimized drilling and hydraulic fracturing are required to exploit the unconventional resources commercially. Prior to optimized drilling and hydraulic fracturing, delineation of sweet spots for organic shale resources is pre-requisite. vertical and lateral heterogeneity due to variable clay content limits the gas and fluid flow within the shales. Therefore, it is essential to evaluate organic shales in detail in terms of reservoir properties (Ahmed et al., 2012) i.e. clay types, total clay content, nature of clay, and total content of other brittle minerals, organic matter, thermal maturity, existence of natural/micro fractures, paleo & in-situ-stresses, bulk volume water saturation, bound water, effective porosity, permeability and reasonable net thickness to determine its production potential. Optimized drilling and stimulation technologies (hydraulic fracturing etc.) are necessary for economical rates. Volumes of oil and gas also depend on these organic shale reservoir characteristics. Shale reservoirs are now being actively exploited worldwide i.e. USA, China, Russia, Argentina and other parts of the world. The shale-as-reservoir has its beginnings in 1820 but commercial shale-gas wells were drilled in 1990s in Mississippian Barnett Shale of USA by Mitchell Energy after persistent experimentations and new developments in drilling and stimulation techniques. In North America, shale-gas plays (e.g., Barnett Shale, Eagle Ford Shale, Haynesville Shale, Marcellus Shale etc.) are producing commercially (Harilal and Tendon, 2012).

In contrast with conventional plays, shale plays are giant – some time their outspreading up to several hundred miles. Shale gas is available in the organically rich shales reservoir as both free and adsorbed gas (Tian et al., 2013). Natural gas stored in organic shale reservoirs is believed to exist in three forms: (1) free gas in pores and natural fractures, (2) adsorbed gas in organic matter and inorganic minerals, and (3) dissolved gas in oil and water. Free gas fills in the matrix and organic porosity, while adsorbed gas is held on the surface of Kerogen and clayey minerals. Free gas can flow easily through the gas filled in matrix and organic porosity, while adsorbed gas may only release afterward the pressure drops in the reservoir rock (free gas inexistent). Dissolved gas in the form of liquid hydrocarbons present in the bitumen. Now advanced techniques (reservoir and completion quality) has made it possible to mark potential intervals, i.e. shale gas accumulations to define sweet spots which are favorable for horizontal drilling to exploit optimum gas quantity. The shale rock mineralogy is another vital factor because it directly controls the fracturing feasibility and the quantitative use of proppant during hydraulic fracturing operation (Xiaodong and Mark, 2017). Shale gas reservoirs are different from conventional gas reservoir, as it requires more detailed evaluation of reservoirs characterization and completion quality. In Pakistan, various organizations and exploration companies are utilizing their resources to delineate the spatial and stratigraphic extent of the prospective shales as per instructions of Ministry of Energy Petroleum Division Government of Pakistan. However, E&P companies are reluctant to invest in this business, as it is not economically viable at current gas pricing due to cost intensive frac technology, proppants, chemicals i.e. frac fluids are expensive but optimized fracking rheology may improve hydrocarbon flow from unconventional reservoir (Ramana and Chavali, 2020), based on geostatistical characterization of unconventional reservoirs. However, data integrated (geochemical, reservoir and elastic properties) approach is used to delineate the target horizons, which was lacking in previous assessments of potential organic shales reservoirs. The present work is an attempt to assess and map organic shale reservoirs in central part of Lower Indus Basin (Figure 1).

METHODOLOGY

Geochemical lab data (TOC and Rock-Eval pyrolysis), of four wells used to evaluate the organic richness, kerogen types, and thermal maturity and production index. The available triple combo logs of four well and image log of one well were used to calculate shale reservoirs properties i.e. log derived TOC values (calibrated with measured TOC from ditch cuttings), total clay and quartz content calibrated with available XRD data, Effective Porosity, Bulk Volume Water Saturation (BVSW), net pay thickness, Poisson’s ratio, Young’s Modulus, brittleness, estimation of original hydrocarbon in-place (OHIP) and determination of sweet spots for organic shales of Talhar, Massive Sand of Lower Goru and the Sembar Formation. The workflow has been adopted is given in Figure 2.

TECTONICS AND STRUCTURE

Tectonically, the study area is situated in the central part of the Lower Indus Basin, which covers an area of approximately 300 km^2. The Lower Indus Sub-basin is located south of Mari-Kandhkot High, bounded by Indian Shield to the east, marginal zone of Indian Plate to the west. The southern border of the Lower Indus Basin is taken along the offshore Indus Sub-basin. Structurally, it is divided into Lower Indus Platform in the east and Kirthar Fold Belt in the west. Tectonic inversion affected several parts of this area (Pakistan Hydrocarbon Habitat, 1988). However, different subsurface data sets show that inversion is not significant. The study area does not exhibit the impact of India-Eurasia collision during the Early Tertiary, being quite far from the collision zone. Extensional faulting events generate mostly NNW to SSE oriented horst and graben structures (Figure 3). In Late Cretaceous, the Lower Indus Basin also experienced another rifting event when Madagascar separated out from Indian Plate (Wandrey et al., 2004). The faults inherited from the first rifting episode were re-activated and continued sense of normal faulting. The study area lies in the tectonic zone of the “Indus Platform slope and foredeep (Figure 1).

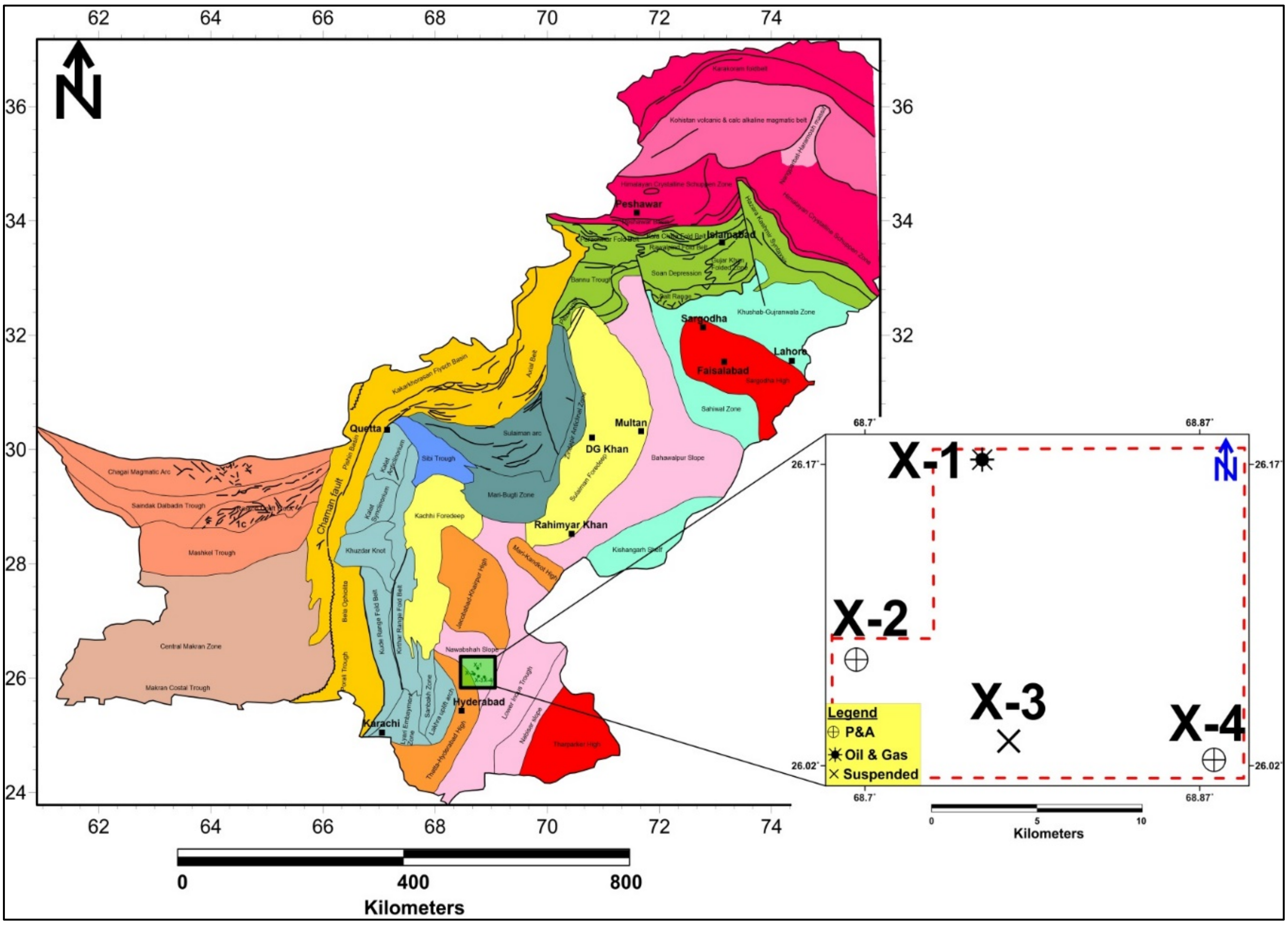

Figure 1 Tectonic zone map of Pakistan (Kadri 1995). The zoom part shows the location of the studied wells i.e. X-1, X-2, X-3, and X-4

STRATIGRAPHY AND DEPOSITIONAL SETTING

The commonly drilled stratigraphic succession ranges from Jurassic to recent in Lower Indus Basin. However, some wells have been drilled up to Precambrian strata. Stratigraphic succession changes from east to west across the Lower Indus Basin. Precambrian basement is exposed in the southeastern corner of the Lower Indus Basin. The thickness of the sediments increases westward (Kadri, 1995). Known unconformities are base Permian and base Tertiary. Malkani (2012) reported the revised stratigraphy of Lower Indus Basin that mostly show same lithological units like Sulaiman Basin. The stratigraphic intervals of interest primarily are Talhar Shale, shales of Massive Sand of the Lower Goru and the Sembar Formation of Cretaceous age. The Sembar Formation is comprised of basinal shale unit and the overlying wedges of sand and shale (Figure 4). Over all Massive Sand represents sand dominated delta systems during the lowstand depositional environment (Ahmad et al., 2004). Talhar shale is mostly shallow to deep marine shale and mudstone. The Sembar Formation was deposited on top of a carbonate platform of the Chiltan Limestone. The carbonate sedimentation was terminated during Late Jurassic time due to rifting between the African and Indian Plates followed by a subsequent marine transgression (Ahmad et al., 2004). The log data suggests that upper part of the Sembar Formation is sand prone in some areas evidenced by the presence of sand/silt lenses on the basin floor (Figure 4). The lower part of the Sembar Formation is characterized by deep-water marine shale. The main source of sediments supposed to be the Indian craton. However different data sets provide the evidence of secondary sediment source i.e. Jacobabad High. The average thickness of the Sembar Formation ranges from 660 meters in the study area extrapolated from the drilled thicknesses in nearby area (OGDCL, unpublished reports) However, the entire thickness of the Sembar Formation has not been yet drilled in the study area. In X–3 well about 341 m thickness has penetrated. The Massive Sand is composed of sandstone and alternate beds of shales. The deposition occurs in middle to lower shoreface setting (Baig et al., 2016), and it was observed that in the deeper part of the basin, the Massive Sand is mostly shale prone (Figure 4).

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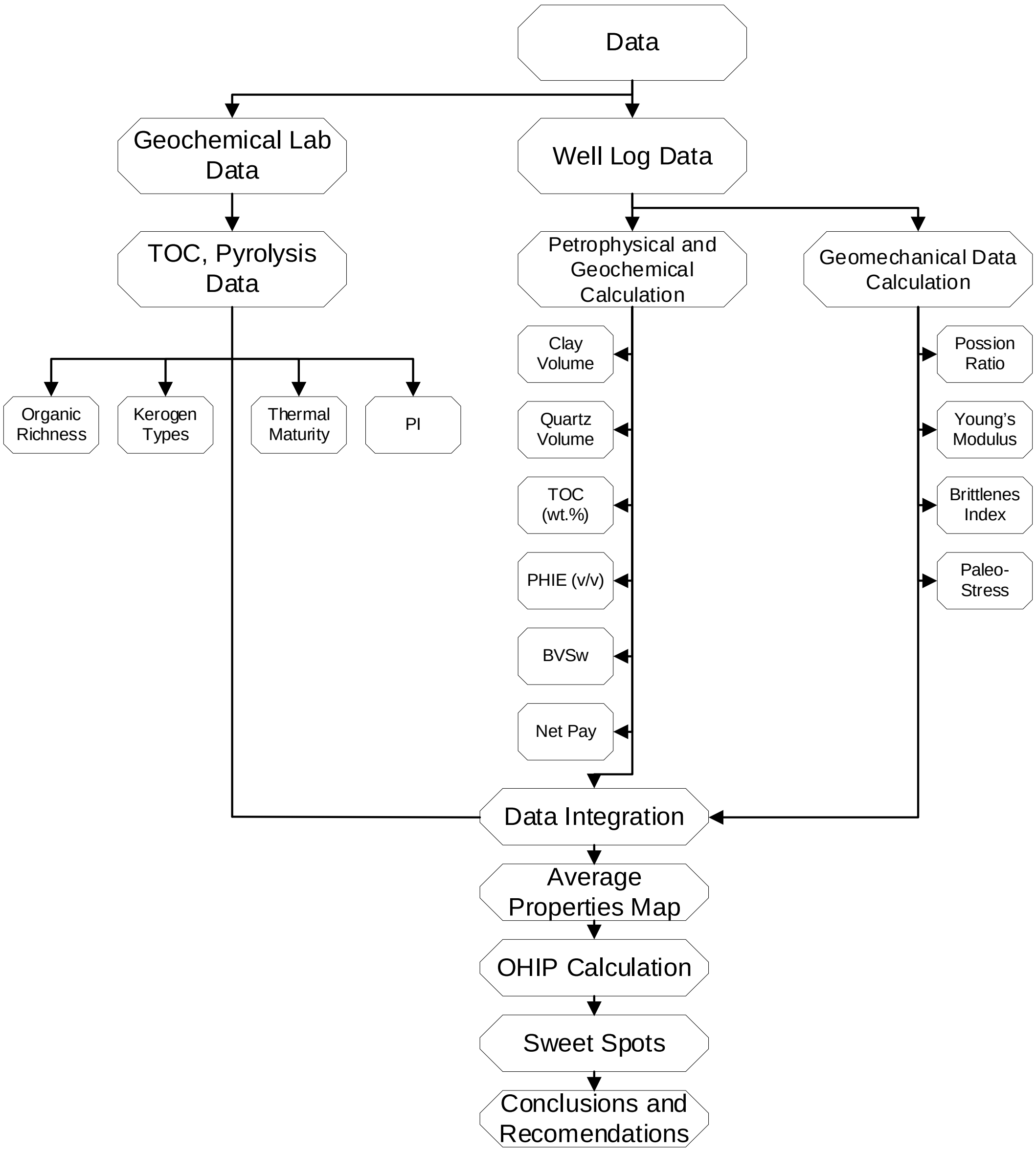

Figure 2 Workflow adopted for the assessment of organic shale reservoirs

In this study various shale units within Massive Sand were observed. Two prominent shale units were identified, one is in its lower part (lower shale) and other in its upper part (upper shale). Thickness of lower shale of Massive Sand varies from 50 m to 115 m. Talhar Shale, which was deposited at the top of Massive Sand during the relative sea level rise, is considered as a secondary source rock and seal facies in certain areas. The thickness of Talhar Shale ranges from 60 m to 70 m in the study area.

DISCUSSIONS

The Hazara Kashmir Syntaxis is a regional antiformal like structure which is formed by the folding of Panjal Thrust and Main Boundary Thrust. Hazara Kashmir Syntaxis is marked as a tight antiform in the north and is opens towards the south. The core of this Syntaxis highly deformed and the western limb of HKS (Hazara Kashmir Syntaxis) is displaced by Jhelum strike slip Fault (Bossart et al., 1988). Lithologically, research area comprises of the Miocene and post Miocene rocks which includes Kamlial Formation, Chinji Formation, and Nagri Formation, Dhok Pathan Formation, Soan Formation, Mirpur Formation and Recent alluvium. These rock units are also regarded as molasses of the Himalayan orogeny. This molasses sequence is highly deformed due to tectonic episodes of Hazara Kashmir Syntaxis which resulted complex geological structure in term of folds and faults. Geological structures in the form of folding are common in area because of the soft lithologies. The major folds observed in the field are Maliar anticline (A), Maliar syncline. Maliar

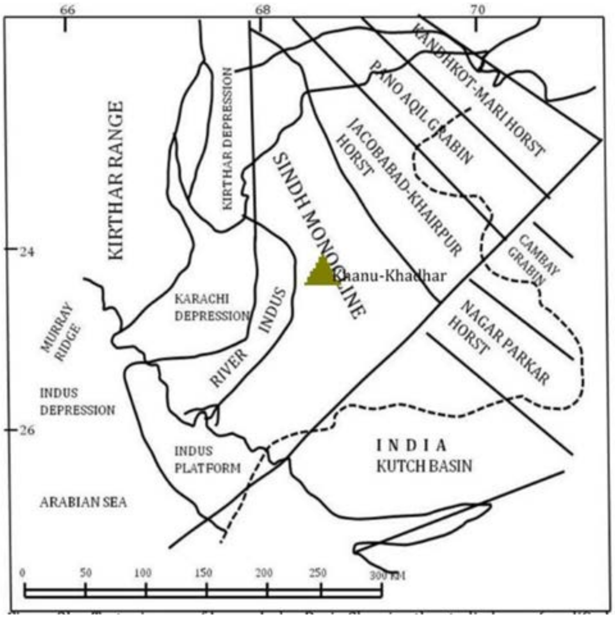

Figure 3 Tectonic map of Pakistan showing horst and graben structures in Lower Indus Basin (Brohi et al., 2013)

anticline (B), Chouk Borjan syncline, Chouk Borjan anticline, and Sadiqabad syncline. In the Maliar section, Maliar anticlines and synclines are formed due to the folding of Kamlial and Murree Formation. The Murree Formation occupies the core while the Kamlial Formation lies on the limbs of Maliar anticlines whereas Kamlial Formation is traced along the core of Maliar syncline. These folds are characterized by its asymmetric and close nature which exists in between the Malikpur-Diljaba and Maliar faults. Their fold axes are truncated by the Malikpur-Diljaba fault. The north-south trending and west vergent overturned Chouk Borjan syncline, Chouk Borjan anticline occurs in between the Jhelum Fault and Malikpur-Diljaba fault. The Malikpur-Diljaba fault is back thrust splay fault of Jhelum Fault. The folded and imbricated hanging wall block between these faults is interpreted and regarded as popup structure. The Sadiqabad syncline is resulted due to the bending of Dhok Pathan Formation. Dhok Pathan Formation is in the core of syncline whereas the Nagri Formation exists on the limbs of the Sadiqabad syncline. Based on interlimb angle, this synclinal structure is regarded as gentle fold. Besides from folds structures, the prominent existing faults in the research area include the Chillayar fault, Malikpur-Diljaba fault and Maliar fault and Jhelum Fault. Chillayar fault is a reverse nature fault where the Nagri Formation occupies the hanging wall whereas the Dhok Pathan Formation lies on the footwall of the fault. The Malikpur-Diljaba fault is also reverse nature fault. In the south of research area, lower Chinji Formation has been thrusted over the upper Chinji Formation whereas in north it runs between Chinji Formation and Soan Formation. In Khad area Chinji Formation lie on the hanging wall and the Soan Formation on the footwall. Maliar fault is a reverse splay of Malikpur-Diljaba fault. This fault passes in between Kamlial Formation and Soan Formation. Kamlial Formation lies on the hanging wall block and Soan Formation lies on the footwall. Jhelum fault is a regional strike slip fault running through the research area. It is northeast-southwest trending and northwest dipping high angle fault as well as a LLSS (left lateral strike slip) fault movement. In the research area, this fault runs in between Dhok Pathan Formation and Kamlial Formation. Jhelum Fault sharply truncates the fold and thrust belt in the western and eastern flanks of Jhelum River near Pajand area.

RESULTS AND DISCUSSION

Geochemical Evaluation

Lab measured TOC and pyrolysis data of about 90 samples/ditch cuttings of selected shales drilled in the study area were available. Geochemical evaluation in this study includes organic richness, kerogen types, thermal maturity, and production index.

Organic richness (TOC)

The fundamental screening for any source rock is organic richness, as measured by total organic carbon (Jarvie, 2012). It is important to classify quality of organic richness (poor to very good) of shales on the basis of TOC values as suggested by Maky and Ramadan (2008) (Figure 5).

Talhar Shale shows that TOC values are in the range of poor to very good (0.3-5.6 wt. %) in the study area. The average TOC map of Talhar Shale (Figure 6) shows that it has high organic richness in south western part of the study area. Well log data shows lower part of Talhar Shale has relatively high organic content as compared to its upper part. The average TOC values of Talhar Shale increasing south to north in the study area (Figure 7). Massive Sand unit is composed of organic rich shales as well as organic lean intervals (sandstone). 'Upper shales' of Massive Sand show fair to good organic richness (0.5-2 wt. %) followed by organic lean interval (Figure 8). Organic richness of 'lower shales' of Massive Sand is in the range of good to very good (1.5-2.6 wt. %) and average TOC distribution

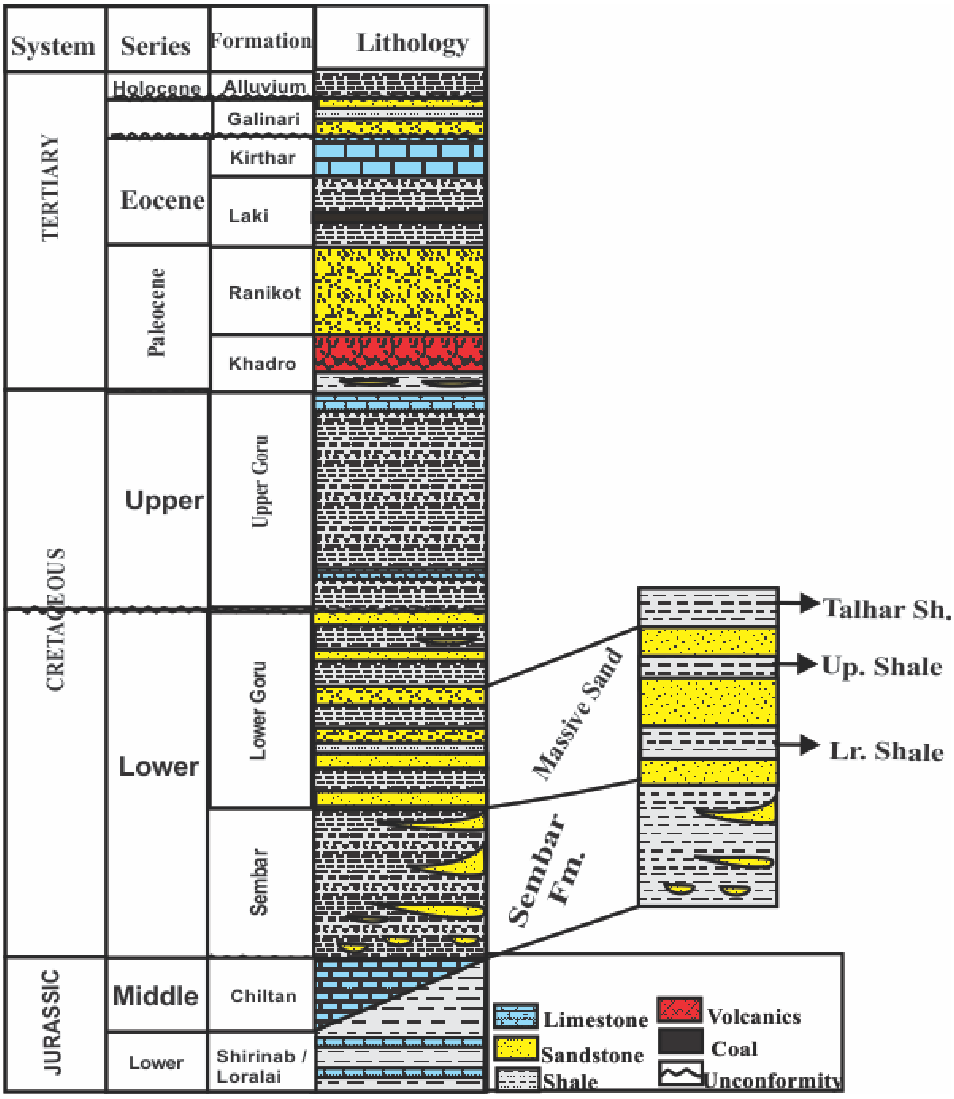

Figure 4 Generalized stratigraphic column for the study area (modified after Mahmoud, 2015)

map shows it has better potential in study area except in eastern side (Figure 9). The Sembar Formation has fair to very good organic richness (0.7- 4 wt. %) and TOC map shows that it has high TOC values in western side of the study area (Figure 10). Well log data shows that it has substantial organic richness potential over the study area. 'Lower shales' of Massive Sand and the Sembar Formation in the study area have significant potential in-terms of organic richness. But only higher organic richness in shale cannot be considered as prospective organic shale reservoir. Other geochemical parameters i.e. kerogen type, thermal maturity, along with better reservoir properties (clay content, brittleness, effective porosity, net pay thickness, water saturation, free as well as adsorbed gas and geomechanical characteristics i.e. stresses, paleo & present stresses) are also play important role for exploitation of shale gas from rich organic shale intervals.

Kerogen types and thermal maturity

Various types of organic matter found in the organic rich shale rocks. The type of kerogen present in the shale determines source rock quality (Espitalie et al., 1980). Four Basic types of organic matter (Figure 6) are found in shale rocks (Brooks, 1981; Peters and Cassa, 1994). Heat and pressure convert organic matter into a substance called humin and then into kerogen. Time and temperature convert kerogen into hydrocarbon.

Thermal maturity is another key element that determines whether a source rock can produce oil, gas, or condensate. Rock–Eval pyrolysis, Tmax data has been used to classify organic shales maturation as suggested by Nady et al. (2015). In the study area, shales are thermally immature to mature (428-456 ^{o}C Tmax; Figure 6), probably

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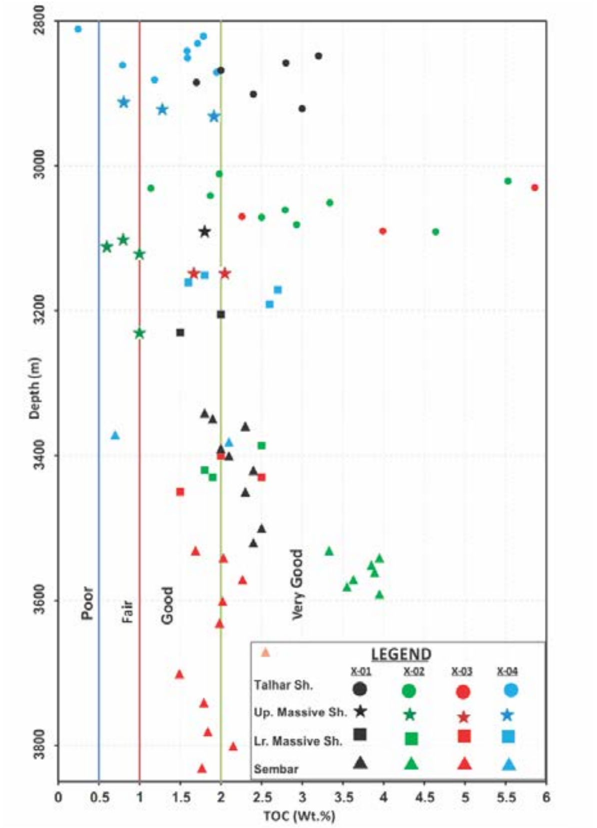

Figure 5 Organic Richness of selected shales in the study area (modified by Maky and Ramadan, 2008)`

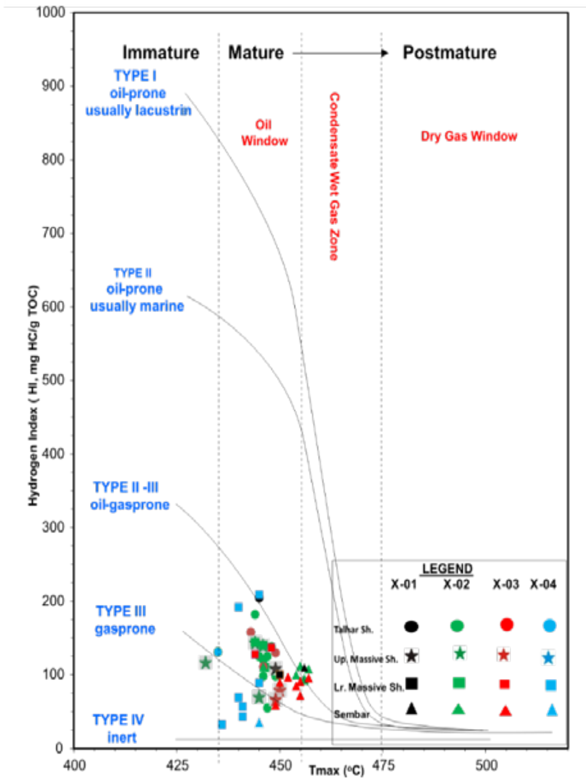

Figure 6 Kerogen Types and Thermal Maturity of selected shales in the study area (Modified after Akar et al., 2015)

in early oil window to wet gas window. Talhar Shale is immature in X–4 well and thermally mature (442-450 ºC Tmax) in other parts of the study area. 'Upper shales' of Massive Sand is thermally immature to mature, perhaps in early oil window (427-450 ºC Tmax). 'Lower shales' of Massive Sand and the Sembar Formation are thermogenically in peak oil to wet gas (condensate) window. Hydrogen index (HI) and S2/S3 data reflects that substantial Type-III kerogen input with minor amount of mix Type-II and Type-III kerogen is present particularly in the Sembar Formation (Figure 6).

Production index (PI)

Maturity of a homogeneous source (organic shale) section can be accessed from the production index (PI). PI is calculated from Rock-Eval data. The production index of Talhar shale ranges from 0.12 to 0.25 in the study area which suggests that Talhar Shale is in early oil window and endorses the thermal maturity data. The PI values of upper and lower shale's of Massive Sand ranges from 0.14 to 0.51, which also confirm that shales of Massive Sand are in oil to wet gas window. The PI data of the Sembar Formation is in the range of 0.24 to 0.81 showing peak oil to wet gas window. Production Index data verifies the thermal maturity of the selected shales in the study area.

Petrophysical Evaluation

It is important to understand and determine appropriate mineralogy (volume of clay, volume of brittle minerals), TOC, porosity, bulk volume water saturation, Poisson's ratio, Young's Modulus, paleo and in-situ stresses for organic shale reservoir characterization and placement of lateral boreholes in prospective intervals with in organic shale reservoirs. These properties were derived from the available well log data. Available XRD, TOC lab data is used for calibration of petrophysically driven parameters.

Volume of clay

Clay in organic shale reservoirs are the cause of decrease in porosity and the estimated clay volume is used in water saturation calculation. The difference between neutron and density porosities is a recognized model of clay volume that works well in clastic depositional system. In shale, the porosity range may diverge because of a lower matrix density, causes a reduction in density, porosity and higher neutron porosity as a result the effect of hydrogen

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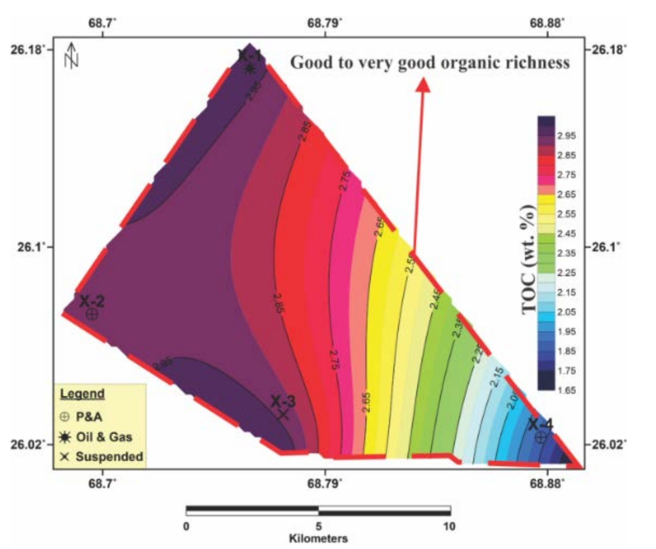

Figure 7 Average TOC distribution map of Talhar Shale

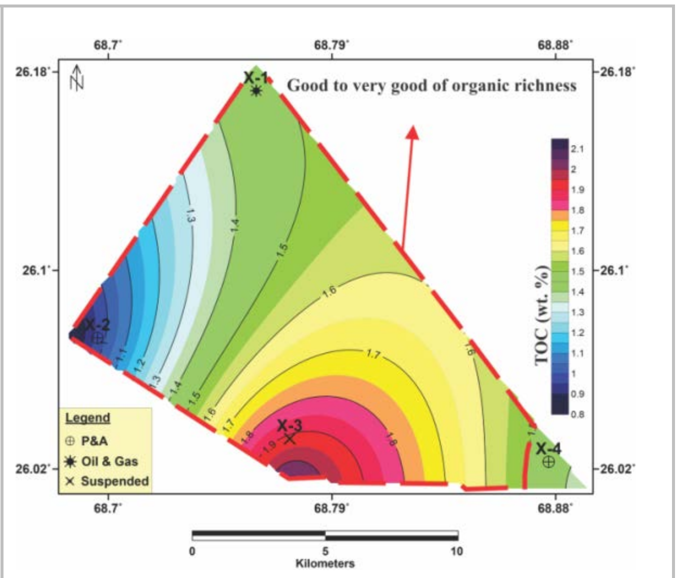

Figure 8 Average TOC distribution map of upper shale of Massive Sand

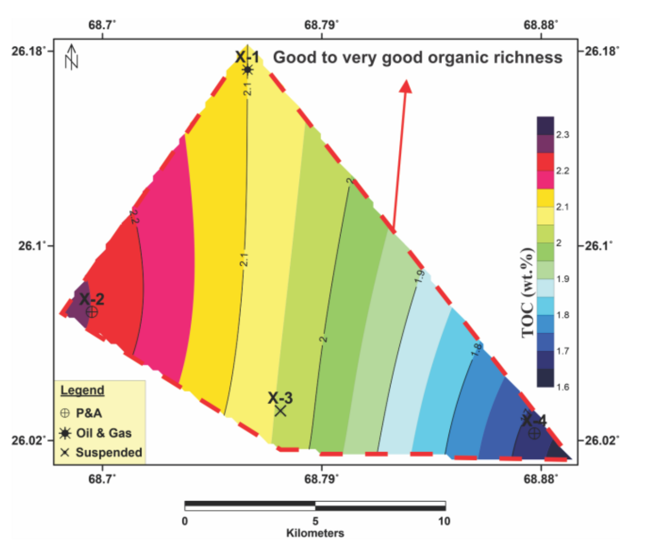

Figure 9 Average TOC distribution map of lower shale of Massive Sand

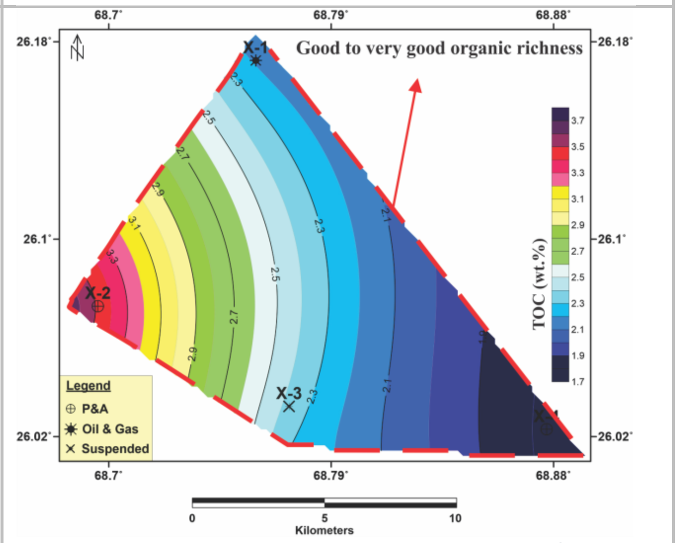

Figure 10 Average TOC distribution map of Sembar Formation

index in clay volume (Kim et al., 2016). Therefore, Kim uses Bhuyan and Passey (1994) equation, for determination of volume of clay.

$$\frac{NPHI_{matrix} - NPHI}{NPHI_{matrix} - NPHI_{fluid}} - \frac{RHOB_{matrix} - RHOB}{RHOB_{matrix} - RHOB_{fluid}}$$

(Equation 01)

Where NPHI, RHOB is the neutron porosity and density log values.

Shales may be ductile or brittle, subject to the type of clay present in the shale. Illite tends to be brittle, whereas smectite and smectite/illite (mixed clay is more likely to be elastic (Rickman et al., 2008). XRD in X–2 well and ECS data of X–3 well were available for clay volume calibration. The average percentage of clay content in Sembar Formation is 35.2 %, 30 %, 31.2 % and 34 % in X–1, X–2, X–3 and X–4 wells, respectively (Table 1, 2, and 3). The average clay content (%) in ‘lower shale’ of Massive Sand is 29.2 %, 34 %, 27 % and 30.8 % in X–1, X–2. X–3 and X–4 wells respectively (Table 2).

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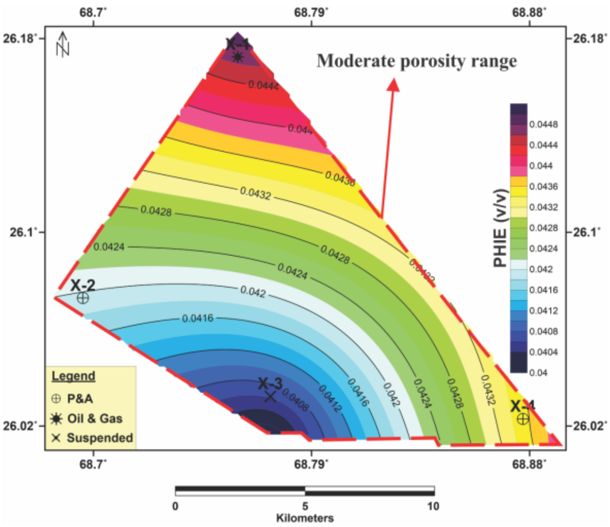

Figure 11 Average porosity distribution map of Talhar shale

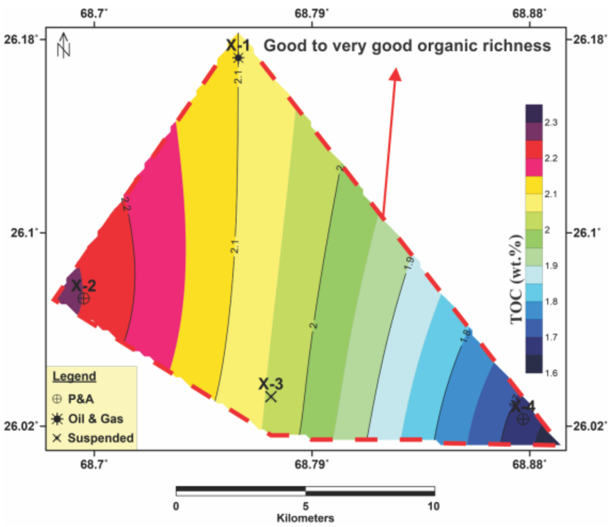

Figure 12 Average porosity distribution map of lower Shale of Massive Sand

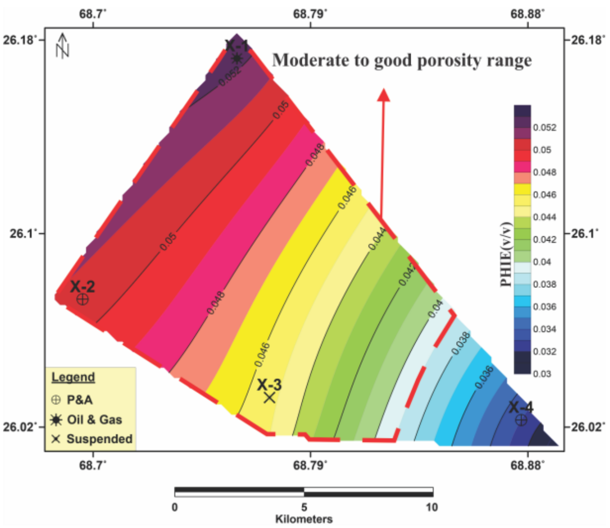

Figure 13 Average porosity distribution map of the Sembar Formation

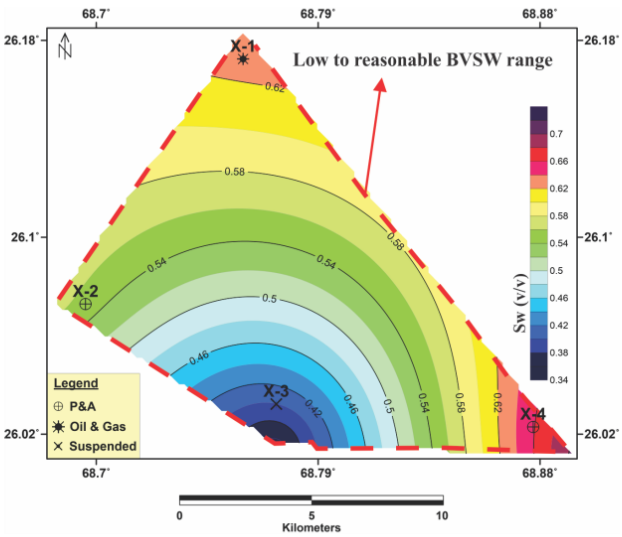

Figure 14 Average BVSW distribution map of lower shale of Massive Sand

The average clay content in the Talhar Shale is higher as compare to other shales which ranges from 29.4 to 41.2 % in the study area. PEF log available for the calculation of quartz/carbonate content and XRD data for its calibration of logs in shales (Figure 18).

Porosity

Matrix porosity is one of the important input variable for estimation of gas/oil and water saturation, it must be accurately determined. Usually when shale has high clay content, the neutron log overestimates the porosity due to the hydrogen effect of clay (Kim et al., 2016). Therefore, the density log is used to calculate the porosity of an organic rich shale reservoir; the equation is as follows;

$$\Phi = \rho m - \rho b/\rho m - \rho f \qquad \textit{(Equation-02)}$$

Where Φ is porosity (dimensionless)
ρb is bulk density (g/cm^3)
ρm is matrix density (g/cm^3)
ρf is fluid density (g/cm^3)

In gas reservoirs, the bulk density results in lower value than the actual because of gas effects,

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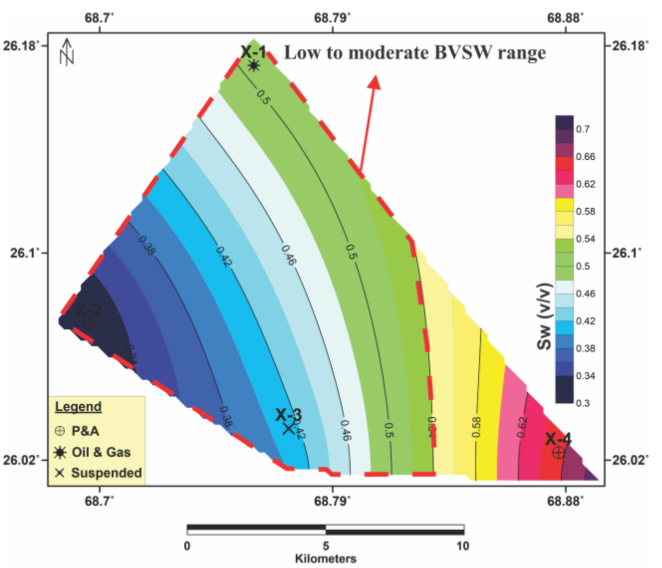

Figure 15 Average BVSW distribution map of the Sembar Formation

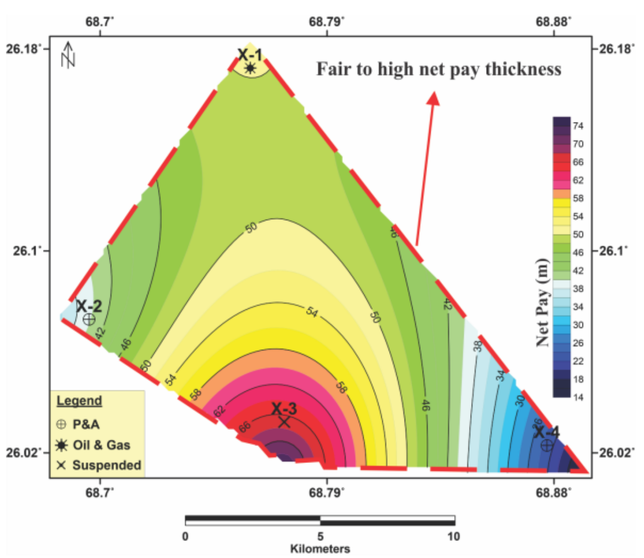

Figure 16 Average net pay distribution map of lower shale of Massive Sand

therefore porosity calculated by using the density log is greater than the actual value. Therefore, Sondergeld et al. (2010) suggested for TOC in the porosity calculation as follows:

$$\emptyset = \frac{\rho_m - \rho_b \left(\rho_m \frac{w_{TOC}}{\rho_{TOC}} - w_{TOC} + 1\right)}{\rho_m - \rho_f + w_{TOC} \text{ x } \rho_f \text{ x } \left(1 - \frac{\rho_m}{\rho_{TOC}}\right)}$$

(Equation 03)

Where ρ_{TOC} is the kerogen density (g/cm^3), and WTOC is the weight fraction of lab calibrated TOC.

The calculated average effective porosity after correction in Talhar Shale is in the range of 4 to 4.5 % (Table 1) and its porosities varies from south to north in the study area (Figure 11). The average effective porosity 4.4 to 5.5 % was calculated in 'lower shale' of Massive Sand (Table 2) and varies from east to west (Figure 12), and 2.6 to 5.3 % in the Sembar Formation (Table 3) and highest porosities lies in the north of the study area (Figure 13).

Water saturation

Water saturation is another key variable for calculating gas and oil saturation, as it has direct relation with hydrocarbon saturation. Archie (1942) suggested an equation constructed on research data using clay free sand. Archie's equation was found to be inappropriate for shale, because clay ions affect layer resistivity (Waxman and Smits, 1968). Water saturation is high with increased clay bound water. Waxman and Smits (1968) proposed a saturation equation for water estimation that permits free as well as clay-bound water (Kim et al, 2016).

$$\frac{a}{R_t X\, \emptyset^m} = \frac{1}{R_w} \mathbf{x}\, Sw^n + \frac{\emptyset_{sh}\, X\, V_{sh}}{\emptyset}\; X \left[\frac{1}{{\emptyset_{sh}}^m \;\; X \;\; R_{sh}} - \frac{1}{R_w}\right] Sw^{(n-1)}$$

(Equation 04)

Where Φ_{sh} is the porosity of shale (dimensionless),
R_{sh} is the resistivity of shale (ohm.m),
Use V_{CLAY} (instead of Vsh).

The value of n varies with the salinity of the pore water and the water saturation of the clay. Here in this study, value of 2 was taken for 'n' and 1.7 to 2 for 'm' in organic shale reservoirs generally. The average water saturation in Talhar shale ranges from 65 to 85.5 % in the study area. The average water saturation in 'lower shale' of Massive Sand is found to be 35 to 71 % (Figure 14). Whereas 'upper shale' of Massive Sand has high water saturation (85 %). The average water saturation in the Sembar Formation is 30 to 70 % in the study area (Figure 15). The Sembar Formation and 'lower shale' of Massive Sand has lower water saturation as compare to Talhar shale and 'upper shale' of Massive Sand in the study area.

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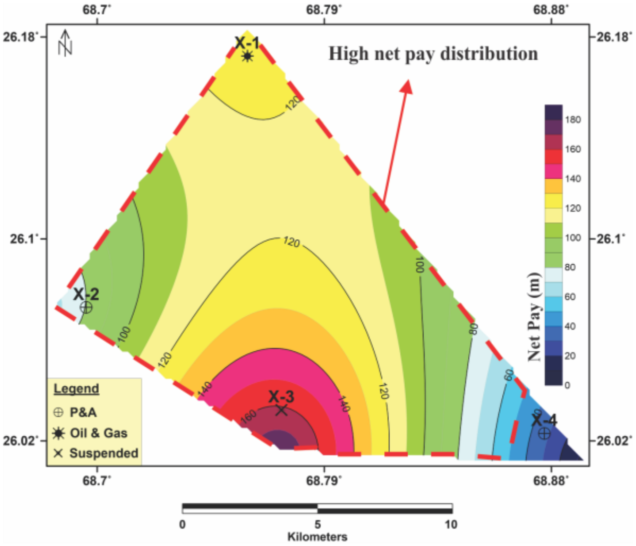

Figure 17 Average net pay distribution map of the Sembar Formation

Net pay

Cut-offs values given in Table 4 were used in petrophysical interpretation to establish the net pay thickness of Talhar, shales with in Massive Sand and the Sembar Formation in the study area as shown in the Table 1, 2, and 3. Average net pay maps were generated for only those shales where 10 m continuous net pay was found in the study area. 'Lower shale' of Massive Sand has 15 m to 65 m net pay thickness in the study area (Figure 16). Talhar Shale has the least 7 m to 23 m net pay thickness (disseminated) in the study area. In X–4 well the Sembar Formation was drilled only 22 m and has 2.5 m net pay thickness. X–1, X–2 and X–3 wells have net pay thickness of 130 m, 65.5 m and 181 m respectively in drilled section of the Sembar Formation (Figure 17).

Geomechanical Properties and Stresses

Geomechanical properties (brittleness, Poisson's ratio and static Young's Modulus) are essential requirement for development of well placement strategies in unconventional reservoirs. These properties determine fracbility, delineation of sweet spots, and placement of lateral wells in organic shale reservoirs estimated from petrophysical data. In literature, static Poisson's ratio values less than 0.25 and static Young's Modulus values greater than 3.0 MMpsia and brittleness value greater than 50 % indicate that rock is ideal for successful hydraulic fracture stimulation. These properties may be calibrated with core-tested results but core data was not available for this study. Estimated average Poisson's ratio of 'lower shale' of Massive sand is in the range of 0.22 to 0.35 (Figure 19) and 0.23 to 0.3 in the Sembar Formation (Figure 20). Whereas static Young's Modulus is in the range of 3.7 to 4.8 MMpsia in 'lower shale' of Massive Sand (Figure 21). Moreover, 3 to 4.5 MMpsia in the Sembar Formation (Figure 22). Brittleness of 'lower shale' of Massive Sand ranges from 50 to 60 % and 55 to 60 % in the

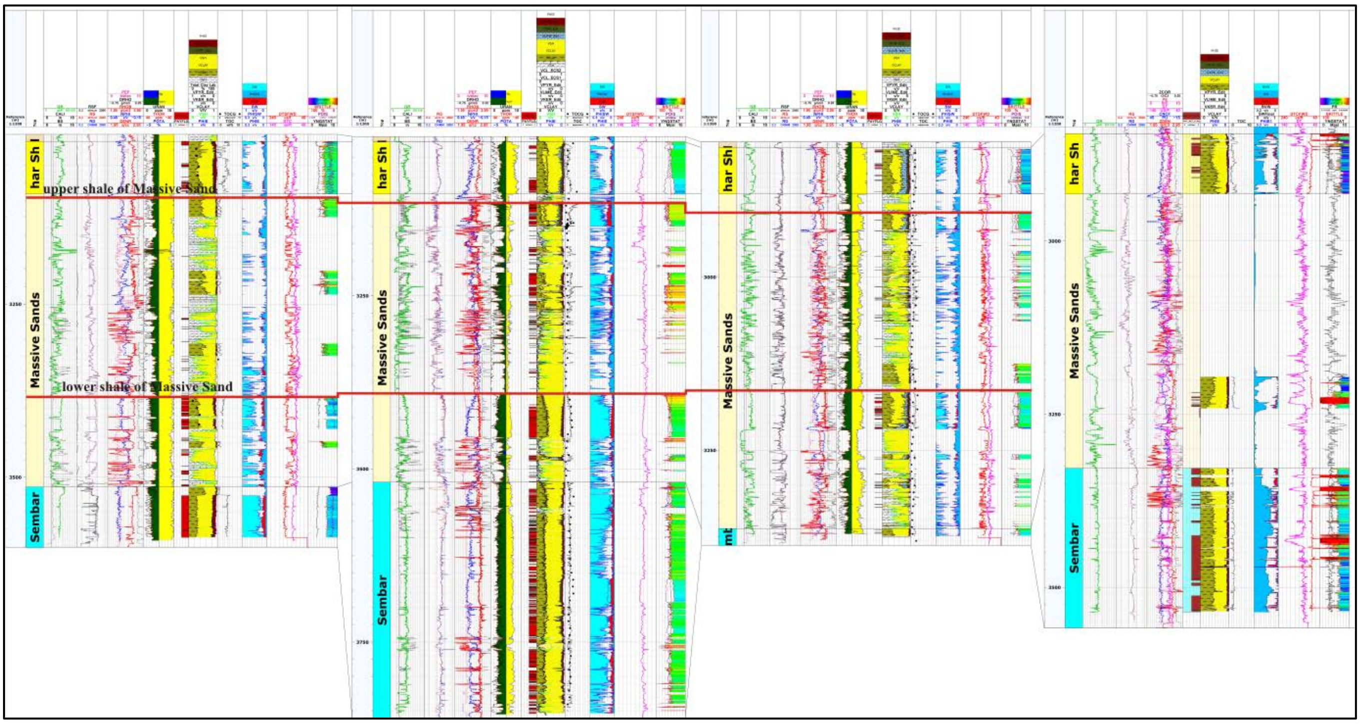

Figure 18 Correlation of X–2. X–3, X–4 & X–1 Well showing organic shale potential in each well

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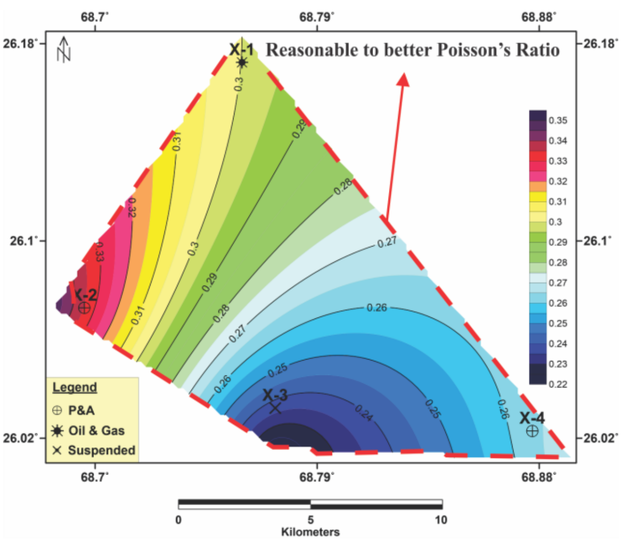

Figure 19 Avg. Poisson Ratio distribution map of lower shale of Massive Sand

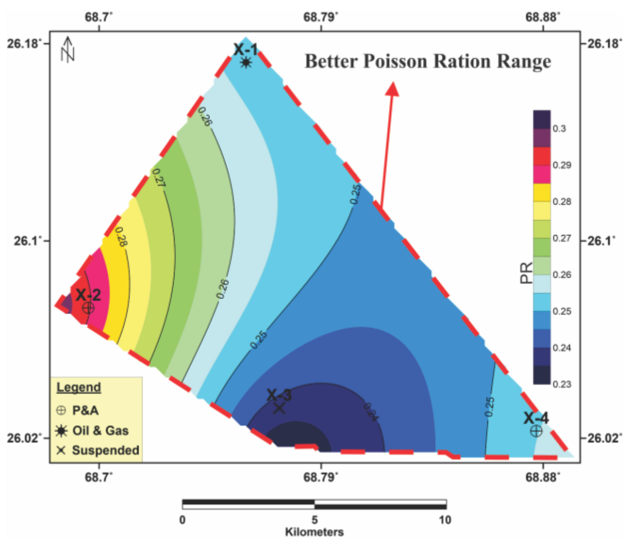

Figure 20 Avg. Poisson Ratio distribution map of the Sembar Formation

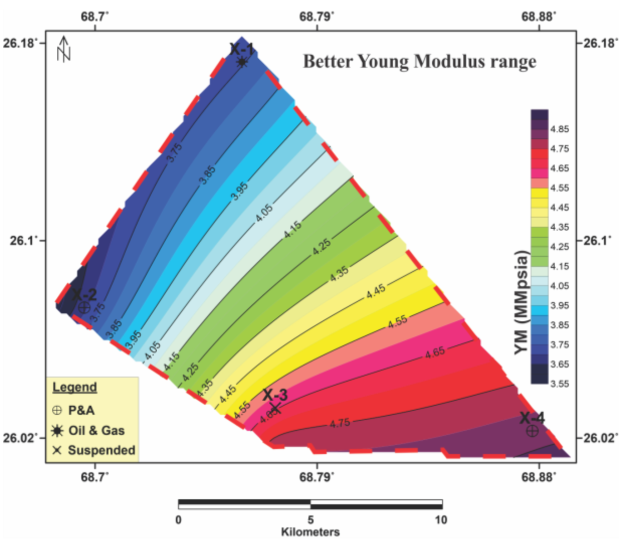

Figure 21 Avg. Young Modulus distribution map of lower shale of Massive Sand

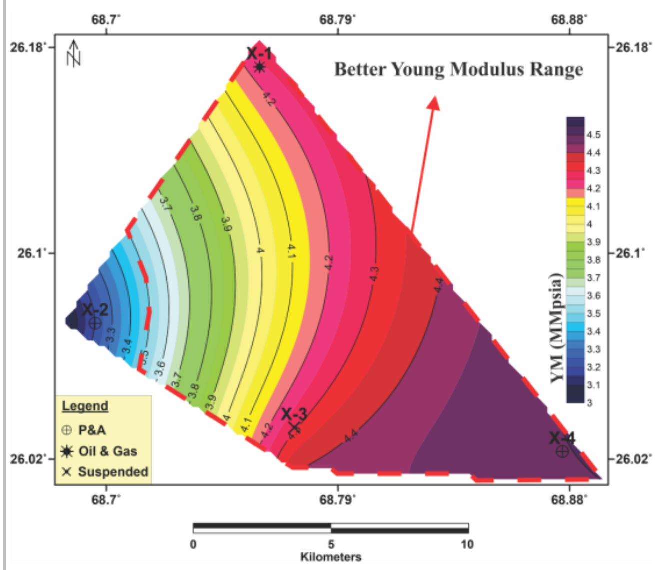

Figure 22 Avg. Young Modulus distribution map of the Sembar Formation

Sembar Formation (Figures 23, 24). Sembar and 'lower shale' of Massive Sand have reasonably good properties for fracking. Breakout data (Figure 25) in drilled wells shows NW-SE minimum stresses direction at lower cretaceous level. Maximum stress direction is NW-SE as indicated by NW-SE oriented faults in the study area (Figure 26).

OHIP Calculations (Free Gas)

Talhar shale and 'upper shale' of Massive Sand have no considerable hydrocarbon potential in-place as they do not show sufficient net pay thickness in the study area. 'Lower shale' of Massive Sand and the Sembar Formation have taken into account for OHIP calculation because of sufficient net pay thicknesses. Assuming 362 m net pay thickness for the Sembar Formation as it is not completely drilled in

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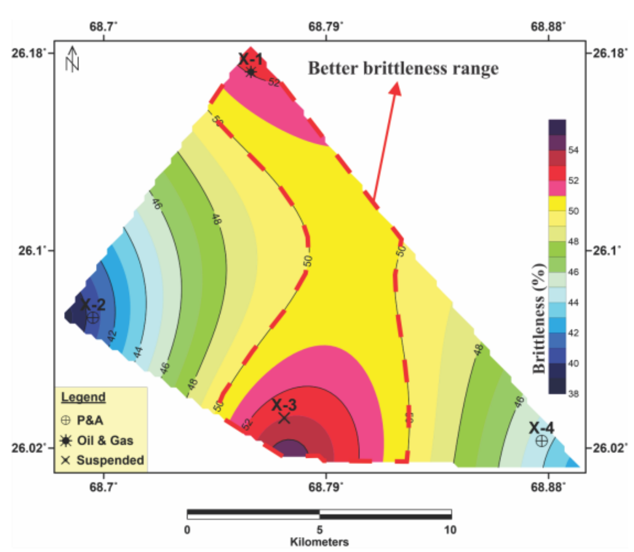

Figure 23 Avg. brittleness distribution map of lower shale of Massive Sand

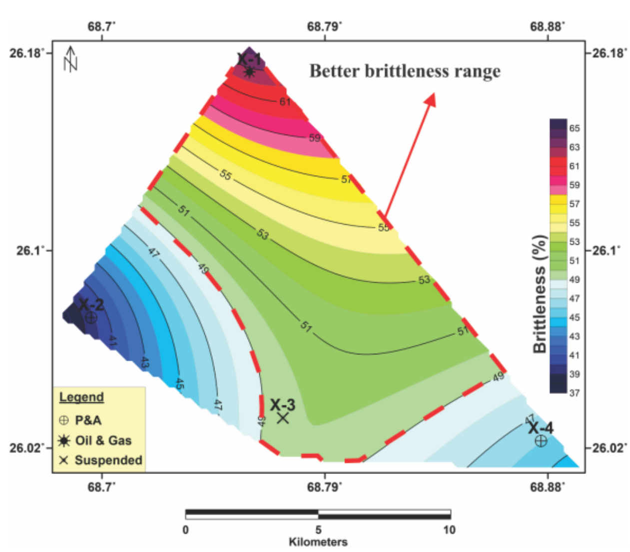

Figure 24 Avg. brittleness distribution map of the Sembar Formation

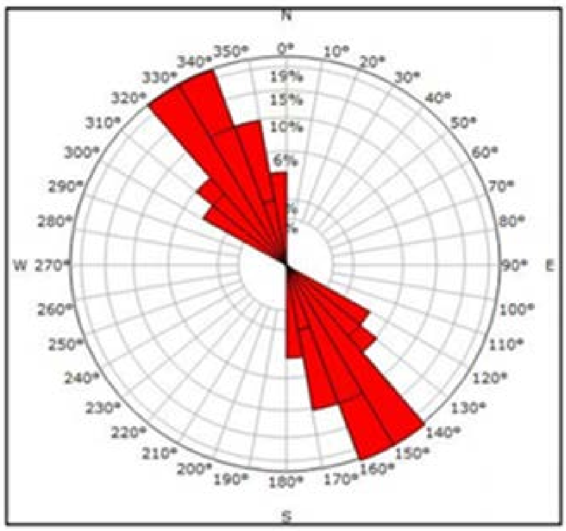

Figure 25 Break out direction (min. stresses) at Lower Cretaceous level in X–3 well

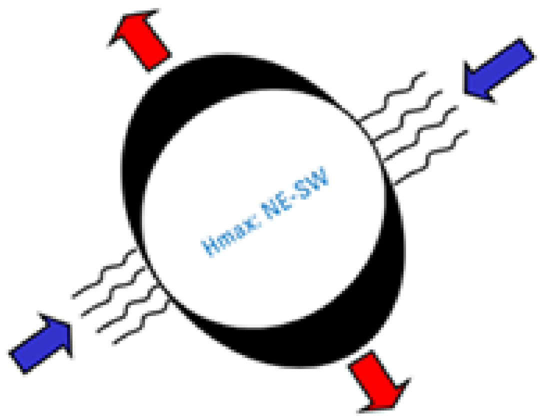

Figure 26 Maximum stress direction (present stress) at Lower Cretaceous level in X–3 well

the study area. The Sembar Formation has approximately 34 TSCF with average resource density of 113 BSCF/km^2 while ‘lower shale’ of Massive sand has 3.4 TSCF with average resource density of 11.3 BSCF/km^2 over an area of 300 km^2. No adsorbed gas was calculated as the adsorption isotherm or gas content data was not available in any of the well. Free gas was calculated by using equation-06. Bg factor 0.0029 rcf/scf was calculated from equation-05. Equation-06 used for OHIP$_{\text{free gas}}$ calculation.

$$Bg = (Ps * (Tf + KT2)) / (Pf * (Ts + KT2)) * ZF$$

(Equation-05)

$$OHIP_{free\ gas} = AREA * THICK * PHIe * (1 - Sw) / Bg$$

(Equation-06)

OHIP$_{\text{free gas}}$ = 33.9 TSCF (Sembar Formation)

OHIP$_{\text{free gas}}$ = 3.4 TSCF (Lower Massive Shale)

Table 1 Petrophysical results of Talhar Shale

Avg. Prosperities	**Unit**	**Well Name**			
		X–1	**X–2**	**X–3**	**X–4**
Gross Thickness	m	64	74	75	77
Net Pay	m	7	20.1	23	11
Net-to-Gross	%	10.9	27	30.6	14.2
Porosity	%	4.4	4.2	4	4.5
Water Saturation (Sw)	%	75.5	70	65	85.5
TOC	WT. %	1.63	2.9	2.1	3
Clay	%	28.4	41.2	31	29.5
Quartz (Sand)	%	35.4	39.4	49	50.4
Calcite	%	20.8	0.1	6	3.1
Ratio (PR)		0.28	0.3	0.24	0.28
Young’s Modulus (YM)	MMpsia	3.4	3.5	3.8	3.7
Free Gas	(bscf/section)	2.25	7.7	9.82	2.2

Table 2: Petrophysical results of lower shale of Massive Sand

Avg. Prosperities	**Unit**	**Well Name**			
		X–1	**X–2**	**X–3**	**X–4**
Gross Thickness	m	116	87	90	80
Net Pay	m	15	30	65	51
Net-to-Gross	%	13	34.5	72.2	63.7
Porosity	%	4.5	5	4.4	5.5
Water Saturation (Sw)	%	71	57	35	60
TOC	WT. %	1.65	2.3	2.05	2.1
Clay	%	30.8	34	27	29.2
Quartz (Sand)	%	40	52.5	57.3	56.4
Calcite	%	15.1	2.3	3.8	1.6
Ratio (PR)		0.27	0.35	0.22	0.25
Young’s Modulus (YM)	MMpsia	4.7	3.7	4.8	4.3
Free Gas	(bscf/section)	6	19.6	56.7	34.2

Table 3: Petrophysical results of Sembar Formation

Avg. Prosperities	**Unit**	**Well Name**			
		X–1	**X–2**	**X–3**	**X–4**
Gross Thickness	m	+ 22	+ 87	+ 341	+ 230
Net Pay	m	2.5	65.5	181	130
Net-to-Gross	%	11.3	75.3	55	57
Porosity	%	2.6	5.1	4.5	5.3
Water Saturation (Sw)	%	70	30	40	50
TOC	WT. %	1.7	3.7	2.3	2.1
Clay	%	34	32	31.2	35.3
Quartz (Sand)	%	53.4	52.8	55.8	56.3
Calcite	%	0.1	0.3	0.8	2
Ratio (PR)		0.26	0.3	0.23	0.25
Young’s Modulus (YM)	MMpsia	4.5	3	4.4	4.3
Free Gas	(bscf/section)	0.1	71	156.4	105

CONCLUSIONS

Through integration and evaluation of available laboratory geochemical data, petrophysical logs, estimated geomechanical parameters and average petro-elastic property mapping, the most prospective area was identified around X–1 well and X–3 well. Favorable fracking characteristics for lower shale of Massive Sand and the Sembar Formation. X–2 well has also showed substantial potential in-terms of reservoir quality but geo-mechanical (completion) properties are not favorable for fracking. The total estimated OHIP/GIIP in the study area shows that Sembar Formation and 'lower shale' of Massive Sand have significant hydrocarbon potential to test and further planning and placement of lateral wells, to intersect maximum surface area with concentrated hydraulic fracs for the production of gas from prospective shales. Talhar and 'upper shales' of Massive Sand did not show substantial potential and have very low resource density in the study area.

Table 4 Net pay cut-offs

Variables	Unit	Organic Shale
Minimum Porosity	%	2
Maximum Sw	%	70
Minimum TOC	wt. %	1.5
Maximum Clay Volume	%	50

RECOMMENDATIONS

Core tested results are desired for proper calibrations and adjustment of all the parameters derived from the petrophysical and geo-mechanical data (stresses) as the authentication of estimated values for the better assessment and development of thermally mature and rich organic shale reservoirs. As organic shale, reservoirs have ultra-low permeabilities, variable stress regimes, and presence of enormous degree of vertical and lateral heterogeneity in shales therefore, it is recommended to drill pilot vertical wells and then lateral wells with maximum possible frac stages in the study area to cover that maximum surface area of potential shales. As adequate hydrocarbon, volumes drained after optimized stimulation. It is also recommended that paleo, in-situ stresses and their magnitude will be taken into account while planning lateral wells in prospective zones, sweet spots. It is highly recommended that regulatory authorities drag E&P companies to collect conventional cores and specialized logs for precise quantification of shale gas potential in all over Indus Basin.

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