EVALUATION AND RESOURCE ESTIMATION OF SEMBAR FORMATION AS A GAS SHALE RESERVOIR OF CRETACEOUS AGE, LOWER INDUS BASIN, PAKISTAN

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Abstract: *Hydrocarbons are considered as the primary sources of energy in the world from several decades extracted by conventional means. Successful production of natural gas from the fine grained organic rich, silty shales is the latest advancement in the developed countries like USA, Canada, China, Argentina and Middle East. Usually, shales do not support unassisted flow due to the ultra low permeability (nano-Darcy). In order to meet the need of energy in Pakistan, the Government is fully devoted to test and exploit the gas shale resources of Pakistan. The primary objective of the study is to evaluate Shales of Sembar Formation by geochemical (quality and quantity of organic richness, thermal maturity), reservoir properties (porosity, water saturation) derived from petrophysical logs, estimated geomechanical properties (Youngs modulus, Poisson's ratio and brittleness) and gas initial in place (GIIP) status in the study area. Based on examined parameters, potential zones were identified in wells (X3 & X4), X2 well only for geochemical evaluation Organic shale reservoirs are dominantly composed of consolidated clay to silt sized particles with sufficient organic content and thermal maturity. Isopach maps shows that the average thickness of the Sembar Formation in the study area is approximately 600m with an average > 2 wt. % TOC with type II to III kerogen, 4 % gas filled porosity, <70% water saturation and is in condensate or wet gas window in the study area. Average Young Modulus 4 Mpsi and <0.3 Poisson's ratio. Cumulative GIIP of potential gas bearing* zones is more than 100 SCF/TON *or 45 BSCF/ Section (Free and adsorbed gas) over an area of 1359 acres.*

INTRODUCTION

Historically, shale is considered as a source rock and a primary element for conventional petroleum system and plays. Sufficient subsurface pressures and temperature convert organic matter to oil and gas with time, which may partly migrate to adjacent conventional reservoirs leaving behind a significant amount of hydrocarbons within organic shales (Javaid et al., 2017). Gas shale reservoirs are dominantly composed of consolidated clay-sized particles with higher organic content that is formerly known as source rocks and a primary element for conventional traps. 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 (MOE) Petroleum Division Government of Pakistan. However, E&P companies are reluctant to invest in this business as it is not considered economically viable due to multiple reasons. Conventional gas reserves are rapidly depleting, it is required to assess and exploit unconventional resources for future utilization.

Objectives of the study is to evaluate gas shale reservoirs in terms of reservoir properties such as porosity, water saturation, permeability, free and adsorbed gas derived from well log parameters and integrated with core analyses, geochemical (TOC and Thermal Maturity), geomechanical properties (Young's modulus, Poisson's ratio and brittleness) and Gas Initial Inplace (GIIP) and to compare with international producing shales of USA.

Stratigraphy of the study area ranges from Pre-Cambrian to Recent (Fig. 1). The thickness of the Sembar Formation increases northward in the study area (Fig. 2). The known stratigraphy of the Sembar Formation shows that it is composed of shales interbedded with thin bands of sandstone and siltstone. XRD data shows that shales of Sembar Formation is composed of chlorite, illite, and kaolinite, pyrite, quartz, K-feldspar, dolomite, plagioclase, siderite and little amount of calcite in the study area. Geochemical evaluation of Sembar Formation has been carried out by using TOC (Total Organic Carbon) data of 3 wells in the study area.

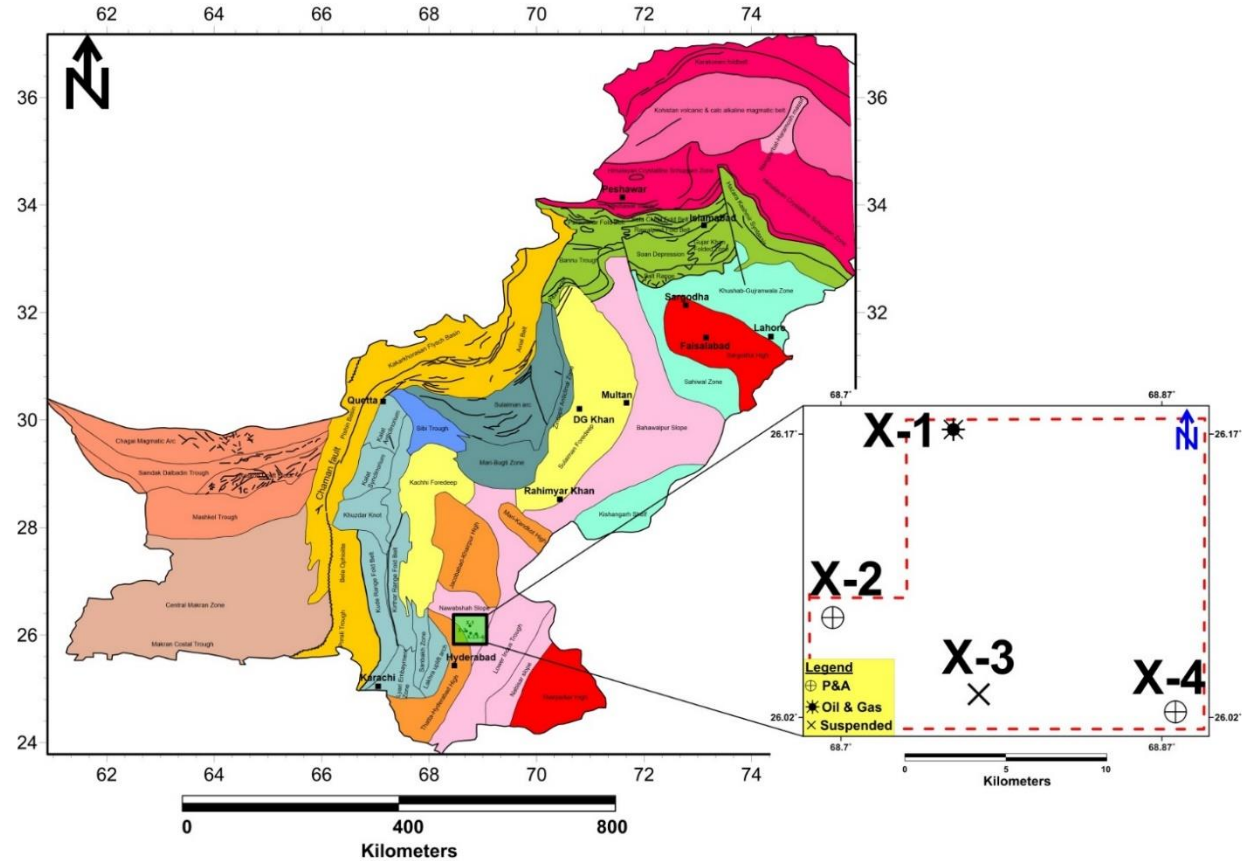

Fig. 1 Tectonic zone map of Pakistan showing study area (Javaid et.al. 2017).

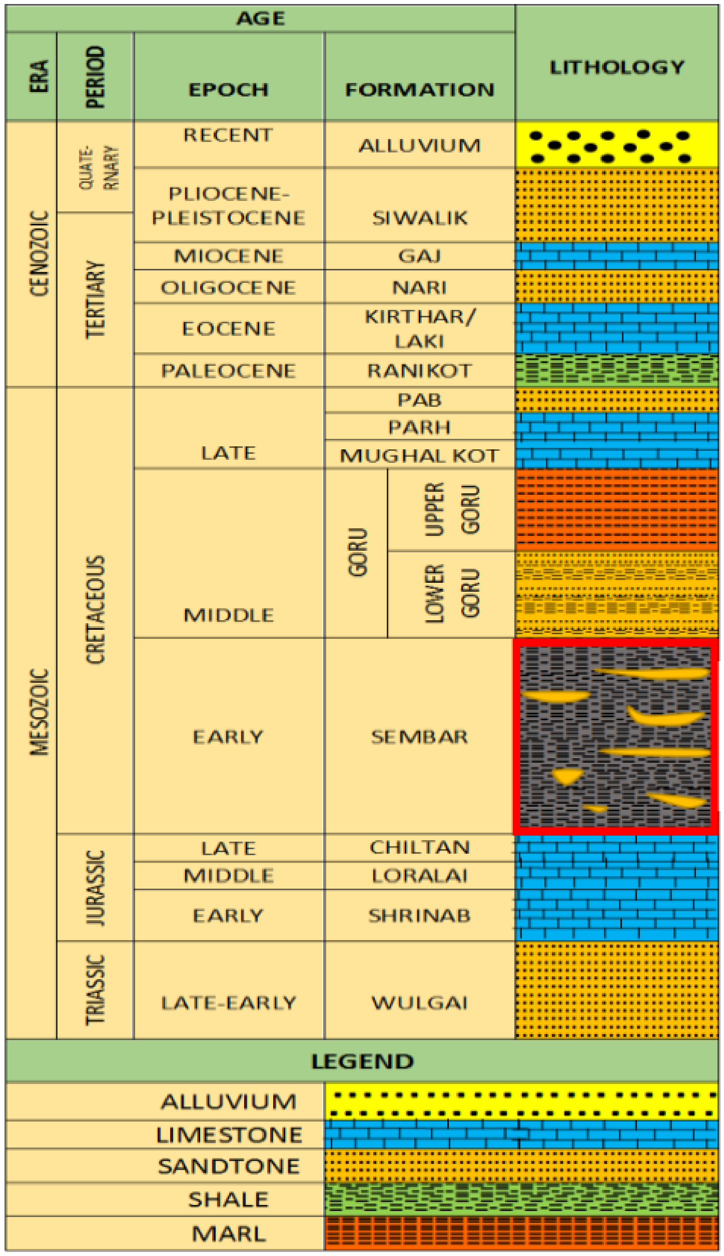

Fig. 2 Generalized stratigraphy of the study area

RESULTS AND DISUCSSION

Geochemical Evaluation

Gas shale potential of the Sembar Formation has been evaluated by using the geochemical (pyrolysis) data of 3 wells in the study area. The data comprises Total Organic Carbon (TOC) and rock-eval data. The Total Organic Carbon (TOC) to delineate its organic richness (Fig. 3), T_{max} (pyrolysis) and VR_0 (Vitrinite Reflectance) data for thermal maturity was used. The pyrolysis data includes over 50 TOC & T_{max} data points and 08 VR_0 data were used. In the study area to assess the quality of organic richness. cut-offs were established for the organic richness and their thermal maturity (Fig. 4 & 5).

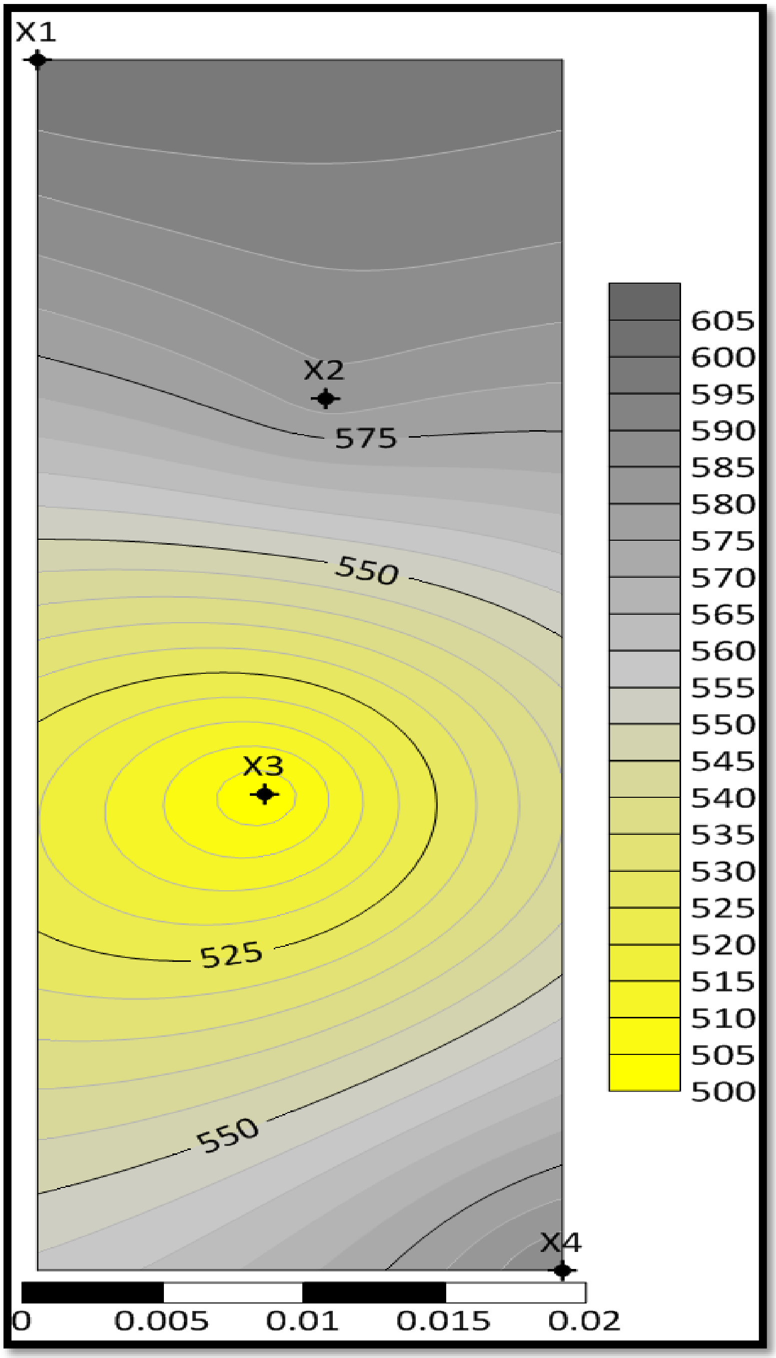

Fig. 3 Isopach map of the Sembar Formation

Organic Richness

The fundamental screening for any source rock is organic richness, as measured by total organic content (Jarvie, 2012). The basic evaluation criteria to classify quality of organic richness (poor, good, very good) in gas shale reservoirs on the basis of TOC (Total Organic Carbon) (Fig. 4). On the basis of geo-chemical, thermal maturity and log data three zones were established.

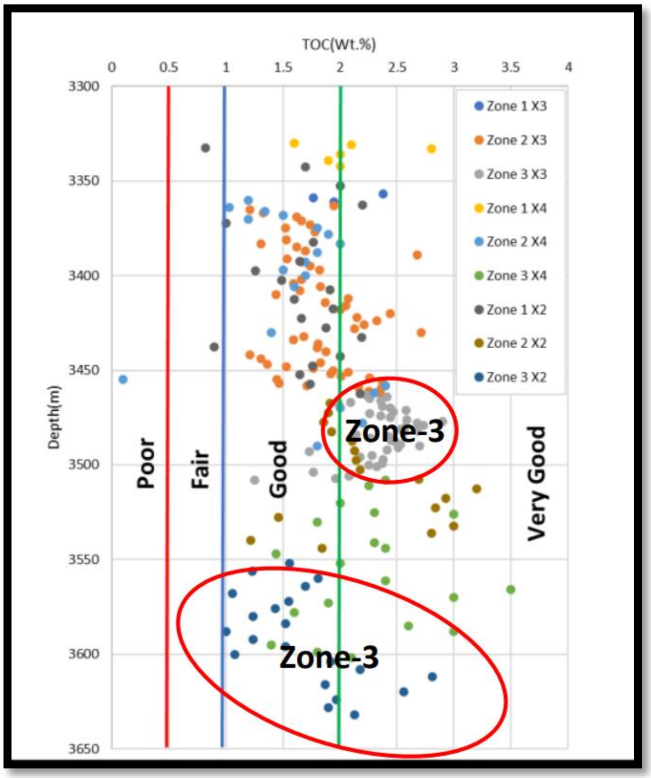

Fig. 4 Organic Richness of X2, X3 & X4 Well (Modified by Maky and Ramadan, 2008).

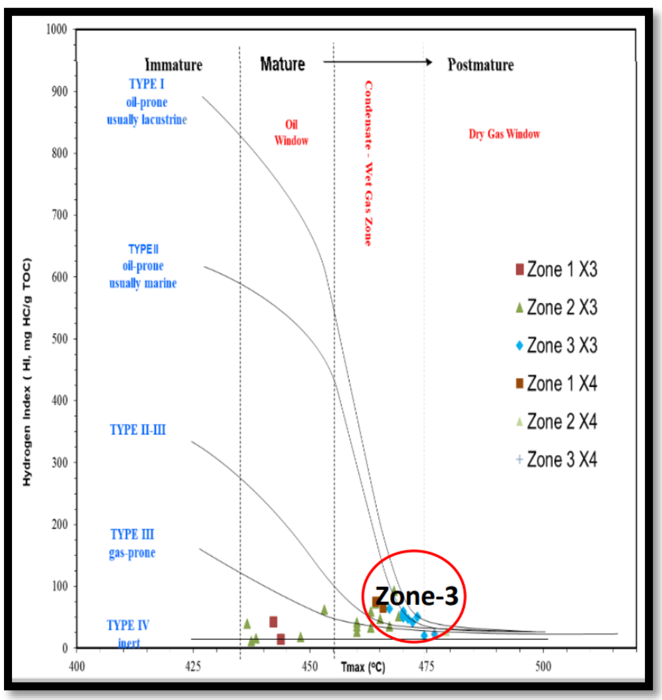

Fig. 5 Thermal Maturity of X2, X3 & X4 Well (Modified Van Krevelen Diagram, Demaison et. al., 1983).

The average TOC values in the study area (X2, X3 and X4 well), Zone-1 has 1.5 wt. %. 1.7 & 2.2 wt. % in Zone-2 and Zone-3, respectively. Majority of Shales of Sembar Formation has good to very good organic richness, that indicate its proven source rock potential. On the other hand, shale gas potential is yet to be proved. Organic richness is not a single parameter to define the potential of gas shale reservoirs. Other parameters such as thermal maturity, reservoir characteristics, geomechanical properties and certain amount of gas in-place are equally important.

Thermal Maturity

Thermal maturity is the key factor that determines whether the shale indigenous organic matter can produce oil, gas or condensate. Prospective shale needs to be in thermal maturity window for gas production through hydraulic fracturing. As shales act as semi permeable membrane and allow only tiny molecules of hydrocarbons which can pass through the nano size sieves and larger molecules choke pore throat of shales and can't pass through it. So, it is the primary factor to locate the transition phase from gas and oil window as wells in the oil window are subjected to poor performance even after fracure. Rock–Eval pyrolysis data, T_{max} has been used to classify organic shales maturation as suggested by Nady et al., (2015). T_{max} and VR_0 (Vitrinite Reflectance) data were used to classify the thermal maturity range in the Sembar Formation. Core and ditch cutting data were used to classify the thermal maturity windows in this study. Thermal maturity of shale has more importance than thickness of shale to be considered as a shale gas reservoir. The thermal maturity in the study area ranges from mature to post mature. Majority of T_{max} (℃) is in the range of 460-480 ℃ (Fig. 5). The VR_0 data ranges from 0.9-1.8 in the study area.

Reservoir Properties

Packing and consolidation control reservoir properties and therefore higher porosities in conventional reservoirs. Unconventional reservoir systems exhibit unique behavior due to low to ultra-low permeability caused by depositional and digenetic issues, and reservoir heterogeneity governed by deposition and digenetic events (Blasingame, 2008). Shale rock is composed of micro-and nano-sized space pores with varying amount of water saturation (adsorbed and free) and residual quantity of organic matter and shale have effective porosity where the retained hydrocarbons are accommodated. Pore system is defined by the volume, shape and size distribution of connected and non-connected space occupied by fluids in a reservoir rock. In conventional reservoirs, the pore size ranges from the micrometer to millimeter scale and fluids mainly occur as free phases (as opposed to adsorbed phase). In shale however, the pore size ranges dominantly in the tens to hundreds of nanometers, where capillary bounded as well as adsorbed fluids become a significant portion of the total pore fluid volume. Therefore, understanding the pore system in a shale is necessary to quantify storage and flow capacity (Euzen, 2011).

In summary, results of the comprehensive quantitative logging identification show that the Sembar Formation have the potential as shale gas reservoir. Identification of porosity and water saturation plays a key role in gas shale reservoirs for the determination of hydrocarbon accommodation. Though amount of free, adsorbed and dissolved gases i.e., solution gas dependent on many variables but in the study estimation of free gas in potential shale layers of Sembar Formation, Well X3 &X4 were analyzed and has 3.5%-4%estimated porosity. The Sw ranges from 50%-75% in X3 well and 60%-75% in X4 well (Fig.6 & 7). Measured core analyses (porosity and water saturation) of two conventional cores were integrate with petrophysical logs of X4 well for reliable results. The computed net thickness 150-200 m in each well of the study area. Cut-off for estimated shale properties were established. The Zone 3 is a favorable zone that encountered at the middle part of the Sembar Formation where the calculated high net thickness (70 m), porosity (4%), water saturation (50%), Poisson's ratio (0.24) and Young's modulus (10^{65} Psi). The mapping of these reservoir properties (Fig.11, 12 &13) in study area also suggests that zone 3 may act as sweet spot. A summary result of average properties of each zone is shown in Table 1.

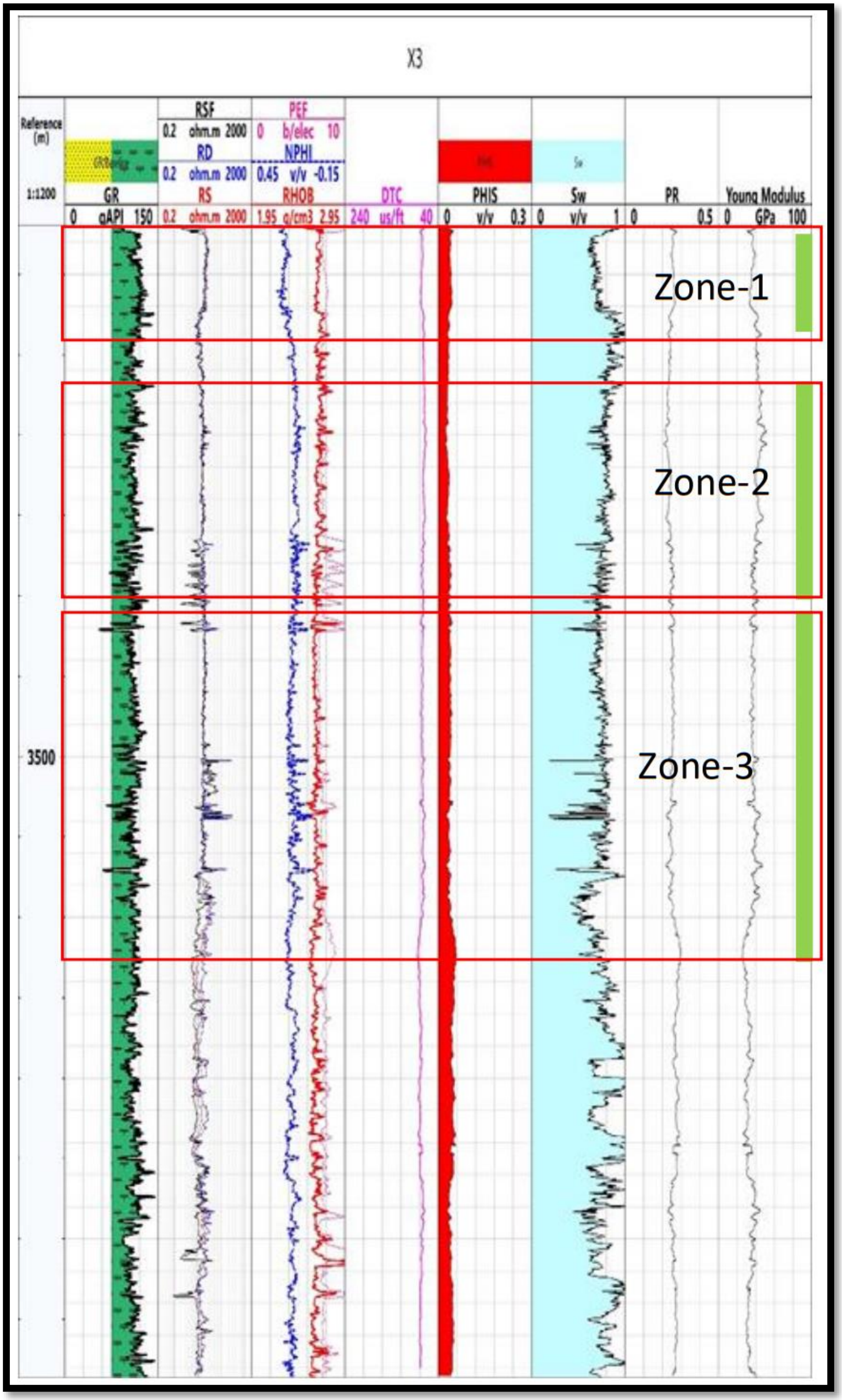

Fig. 6 Petrophysical properties of Sembar Formation in Well X3.

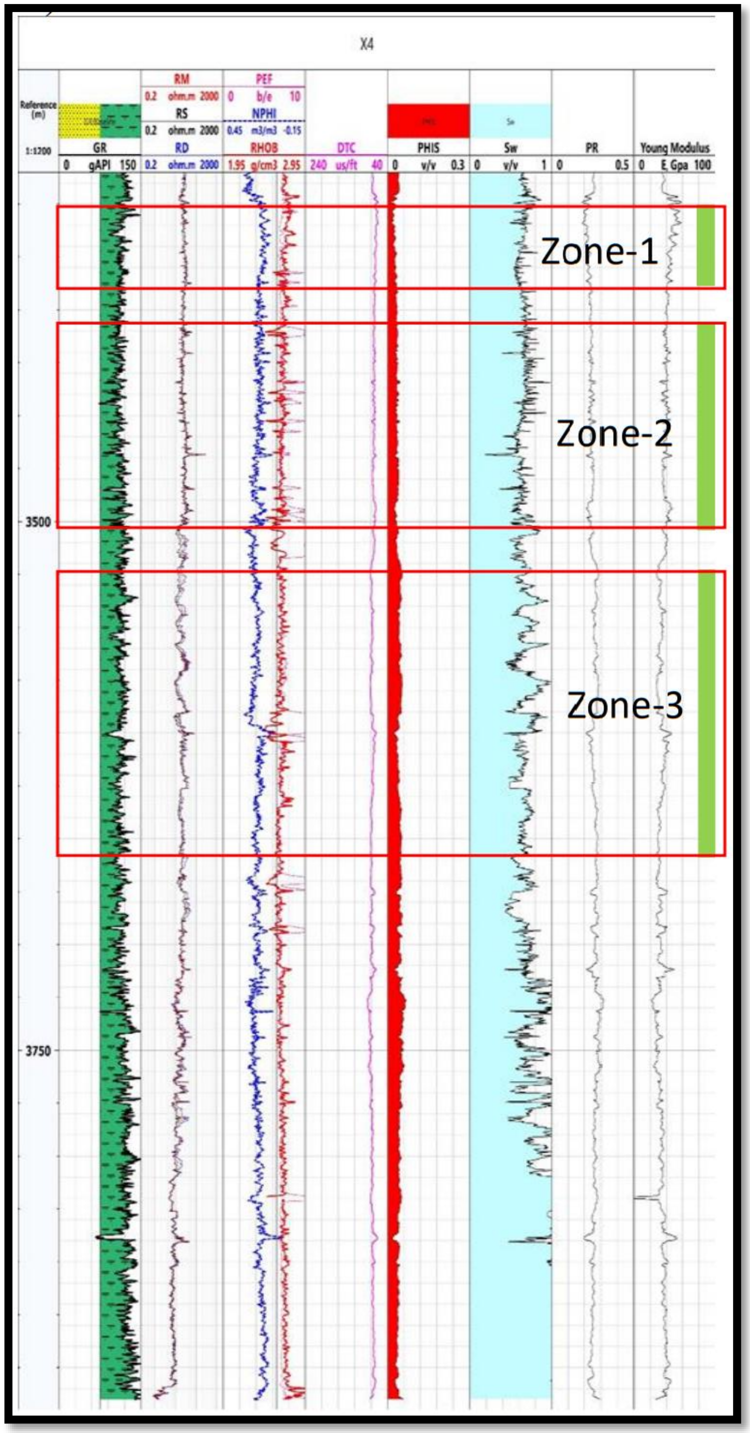

Fig. 7 Petrophysical properties of Sembar Formation in Well X4

Table 1. Results of petrophysical interpretation of Sembar Formation (reservoir properties)

Well Names	Zones	Depth (m)	Avg. Porosity (v/v)	Water Saturation (v/v)	Net Thickness (m)
Well X3	Zone 1	3335-3361	0.032	0.75	25
	Zone 2	3362-3462	0.035	0.65	55
	Zone 3	3464-3600	0.04	0.5	70
Well X4	Zone 1	3328-3347	0.032	0.75	10
	Zone 2	3347-3502	0.033	0.6	50
	Zone 3	3510-3603	0.037	0.6	55

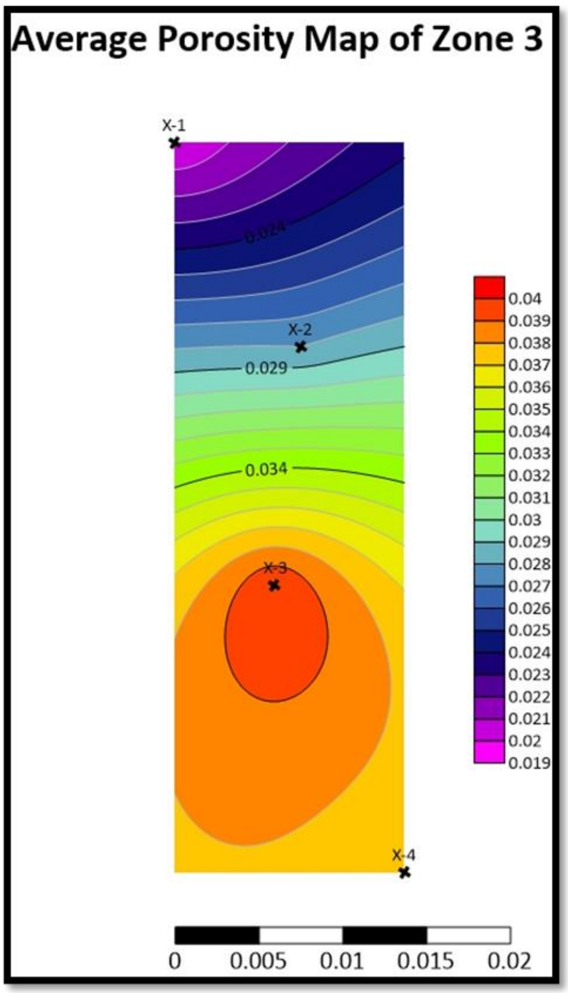

Fig. 8 Average porosity map Zone 3

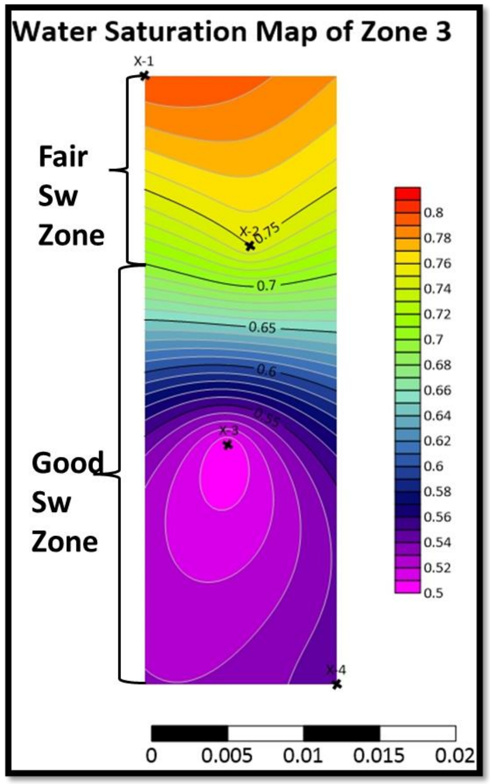

Fig. 9 Average Sw map Zone 3

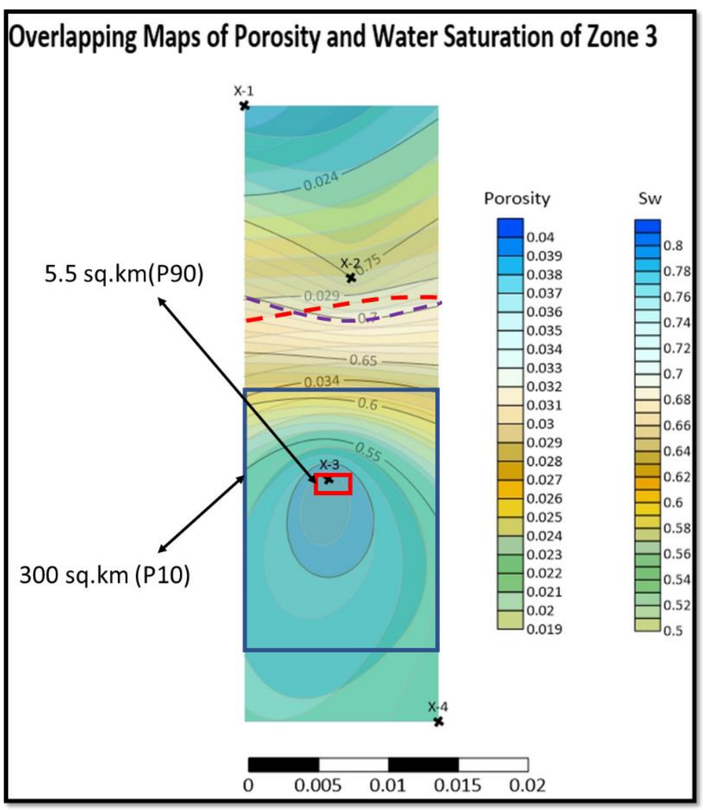

Fig. 10 Overlapping map of porosity and water saturation

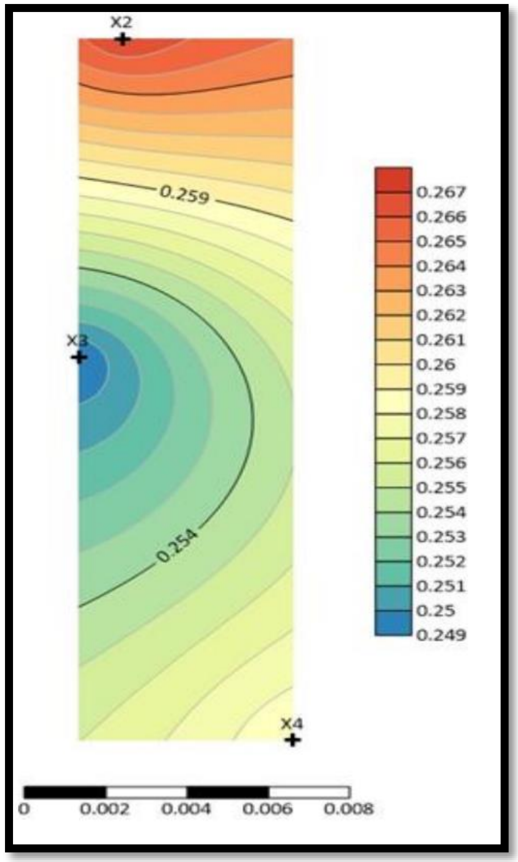

Fig. 11 Avg. Poisson's ratio map of zone 3

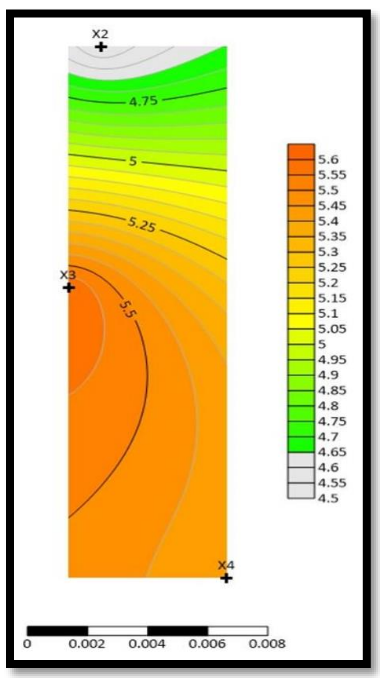

Fig. 12 Average Young's modulus map of zone 3

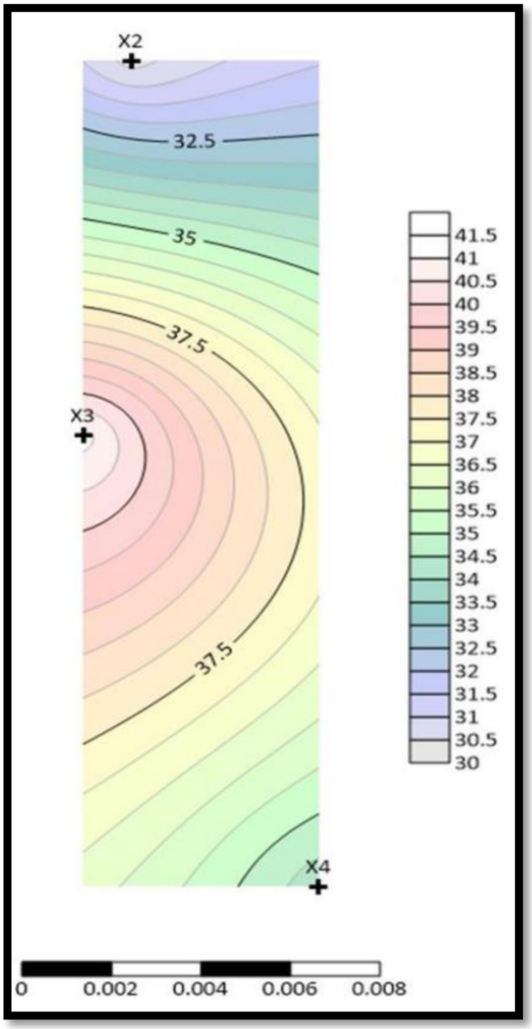

Fig. 13 Average brittleness map of zone 3

Mineralogy

Mineralogy is a primary control on the pore network structure of both conventional and unconventional reservoirs. Furthermore, the initial mineralogical composition of sediments has a strong impact on the nature and magnitude of diagenetic transformations occurring during their burial history (Euzen, 2011). Mineralogy plays a vital role as it impacts the geomechanical properties of the shale rocks and their response to hydraulic fracturing. Clay minerals dominate the inherent anisotropy (vertical and lateral) widely distributed in shale gas plays. Understanding these variations is essential to build reliable petrophysical and geomechanical models and to optimize the placement of fracturing stages (Euzen, 2011). In terms of mineralogy, Sembar Formation resembles with Barnett Shale of USA (Fig. 14, 15 & 16). XRD data shows the presence of kaolinite, illite, montmorillonite, smectite in the Sembar Formation and total amount of clays range from 30-45% (Fig. 17). Quartz or brittle minerals range from 35-50%.

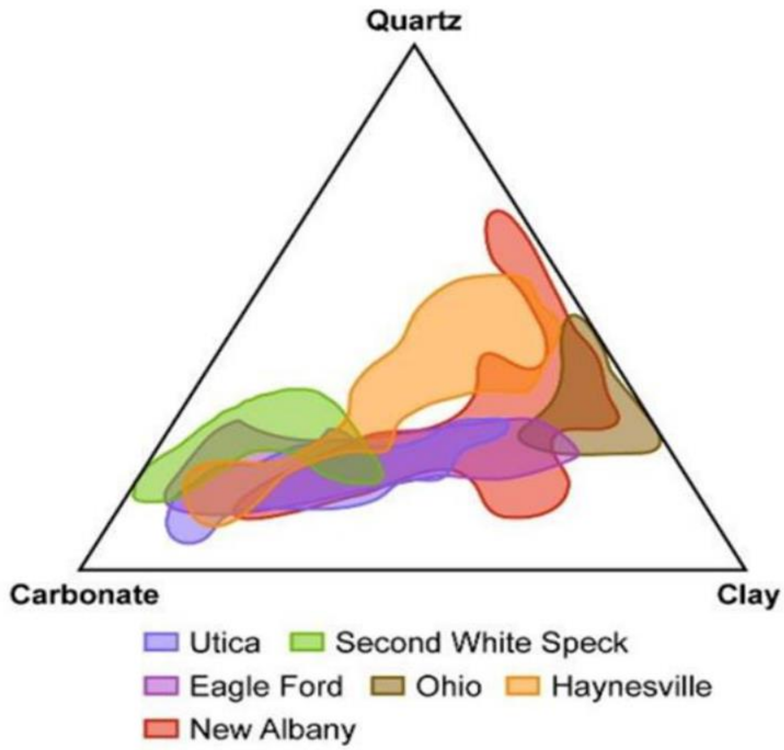

Fig. 14 Mineralogy of US Shales (Euzen, 2011).

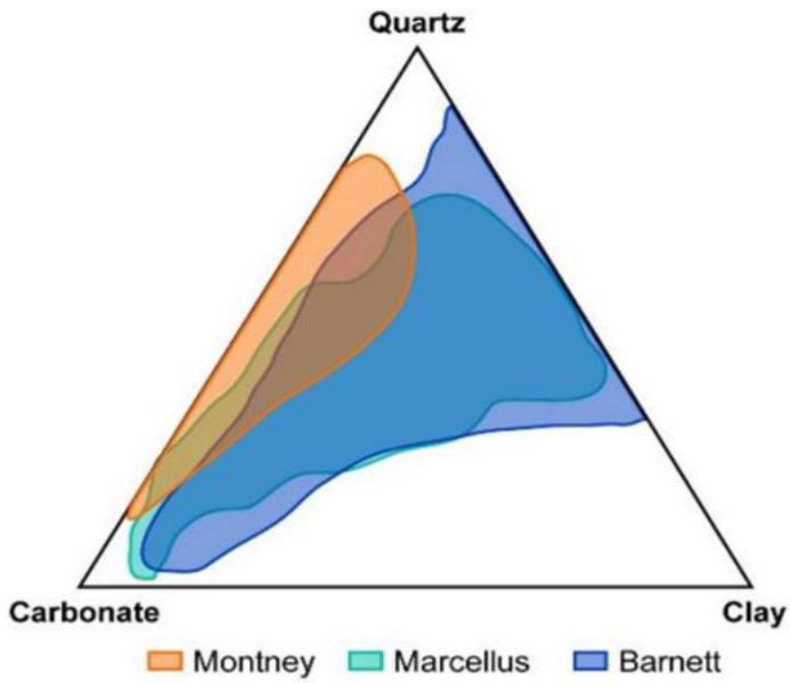

Fig. 15 Mineralogy of US Shales (Euzen, 2011).

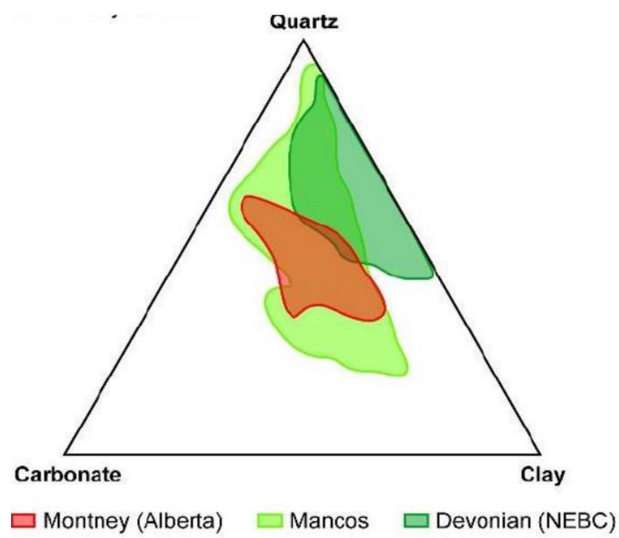

Fig.16 Mineralogy of US Shales (Euzen, 2011).

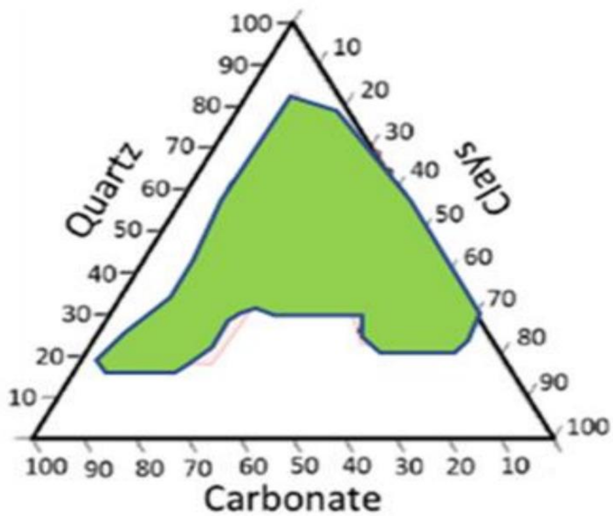

Fig. 17 Mineralogy of Sembar Formation based on X3 & X4 core and cutting data

Geomechanics

Geo-mechanical characterization of shale gas reservoirs designed to understand the fundamental controls on the outcome of hydraulic fracturing operation. Natural gas production from gas shale reservoirs is now proven to be feasible from numerous operations in various shale gas reservoirs in USA (Sone, 2012). In full scale exploitation of gas shales reservoirs are still facing multiple challenges in the development stage. Geo-mechanical properties (brittleness, Poisson's ratio and static Young's modulus), stresses and type and quantity of clays are the main functions for fracbility of the shale rock, fracture growth, fracture geometry and drainage area. In brittle shales placement of hydraulic fracture is ideal where fracture can penetrate with maximum length and enough

Stimulated reservoir volume (SRV) of hydrocarbon for effective gas shale reservoirs. In producing gas shale reservoirs, static Poisson's ratio values are less than 0.25 and static Young's Modulus values are greater than 3.0 MMpsia and brittleness values are greater than 50 % indicate that rock is reasonably good for successful hydraulic fracture stimulation.

These properties may be helpful when they are calibrated with core testing results but core data was not available for this study. Estimated average Poisson's ratio from log data is 0.24 (Fig. 11) in Zone 3 of the Sembar Formation. Whereas static Young's modulus is in the range of 4 to 5 MMpsia (10^6) in Zone 3 of the Sembar Formation (Fig. 12). Brittleness of 45 to 60 % in the Sembar Formation (Fig. 13). Sembar Formation has reasonably good properties for fracking. Major Stress's direction (Faults) and breakout data in drilled wells show NW-SE. So hydraulic fracking half-length and fracking design can be modeled accordingly to achieve maximum SRV. Vertical well is not enough to produce gas from shales with economic viability. Therefore, lateral wells are need of the day with maximum half-length and enough frac stages. Zone 3 can be a better target horizon for lateral well placement with engineered frac stages stimulation for optimum results. As study area is located in the central part of the Lower Indus Basin where relatively calm tectonic environment can provide easy frac testing in lateral wells.

Sembar Formation & US Shales

Mostly US shale plays are geologically and chronologically, Middle-Upper Devonian, Late Devonian-Mississippian and Upper Cretaceous age (Figure 22). Sembar Formation was deposited during Early Cretaceous time. Chronologically (geological age) Haynesville and Eagle Ford may be two closest analogues of Sembar Formation from US Shales.

To establish analogy of shale reservoirs geological, geochemical, petrophysical and geomechanical parameters of the Sembar Formation in study area were evaluated and to compare the US producing shales. The parameters like organic matter content (TOC), thermal maturity, net thickness, mineralogy, and porosity were evaluated. Spider plot, comparing average values for some of those parameters. In-terms of organic richness (TOC) Sembar shale resembles with Lewis, Haynesville, Muskwa, and Utica (Fig. 18). Thermal maturity correlation shows that Sembar Formation has good concurrence with all US Shales except with few which are immature (Fig. 19). Porosity correlation shows that it has good correlation with Lewis Shale and fairly concurrence with Haynesville (Fig. 20). Spider plot (Fig. 21) shows that Sembar Formation exhibit lowest permeability. On the other hand, it has unique characteristic i.e., net pay thickness which is the higher from all US shales. This property of Sembar Formation may indicate encouraging shale reservoir potential. It can be observed that the Sembar Shale exhibits a mixture of characteristics compared to US Shale plays, except for the net thickness (Fig. 22).

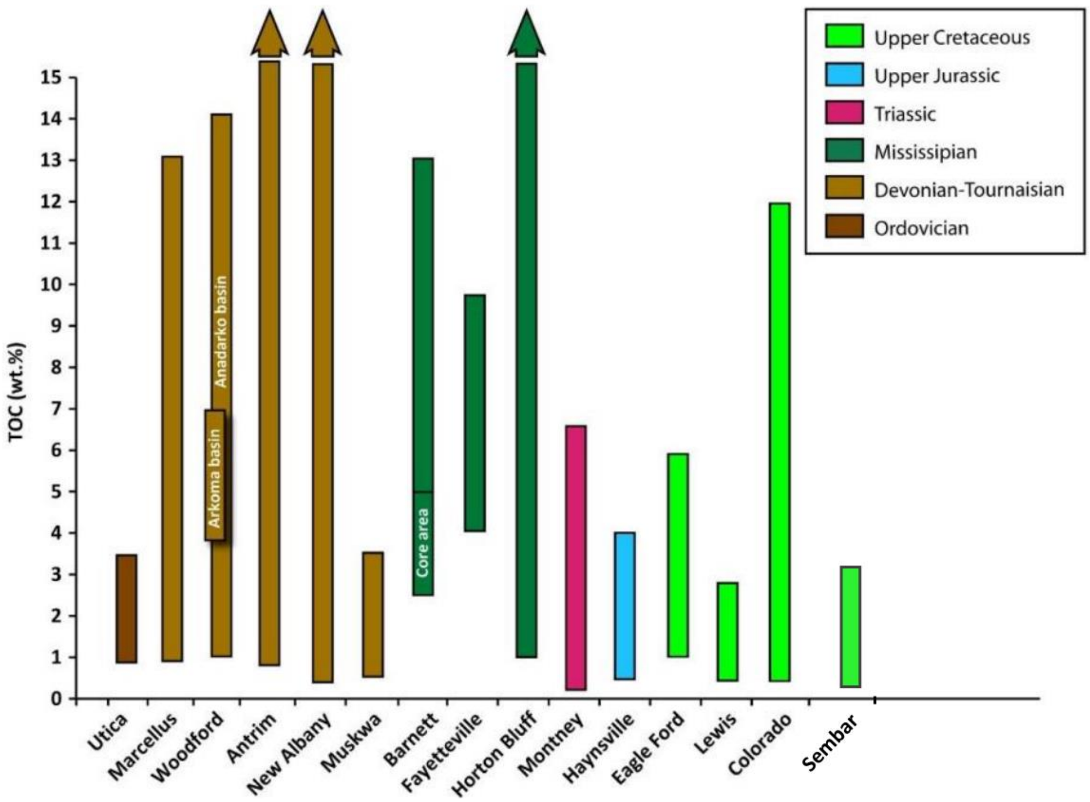

Fig. 18 TOC range of Sembar and US Shale plays (modified after Euzen, 2011)

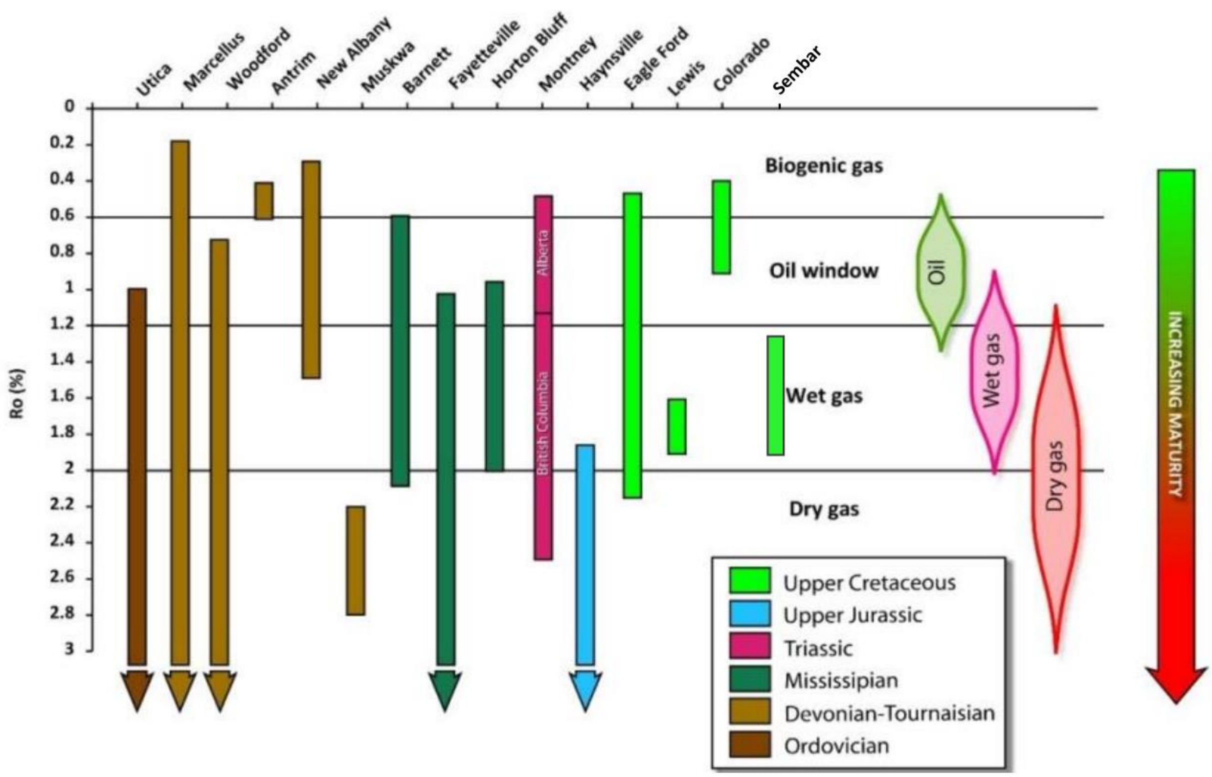

Fig. 19 Thermal maturity range of Sembar and US Shale plays (modified after Euzen, 2011)

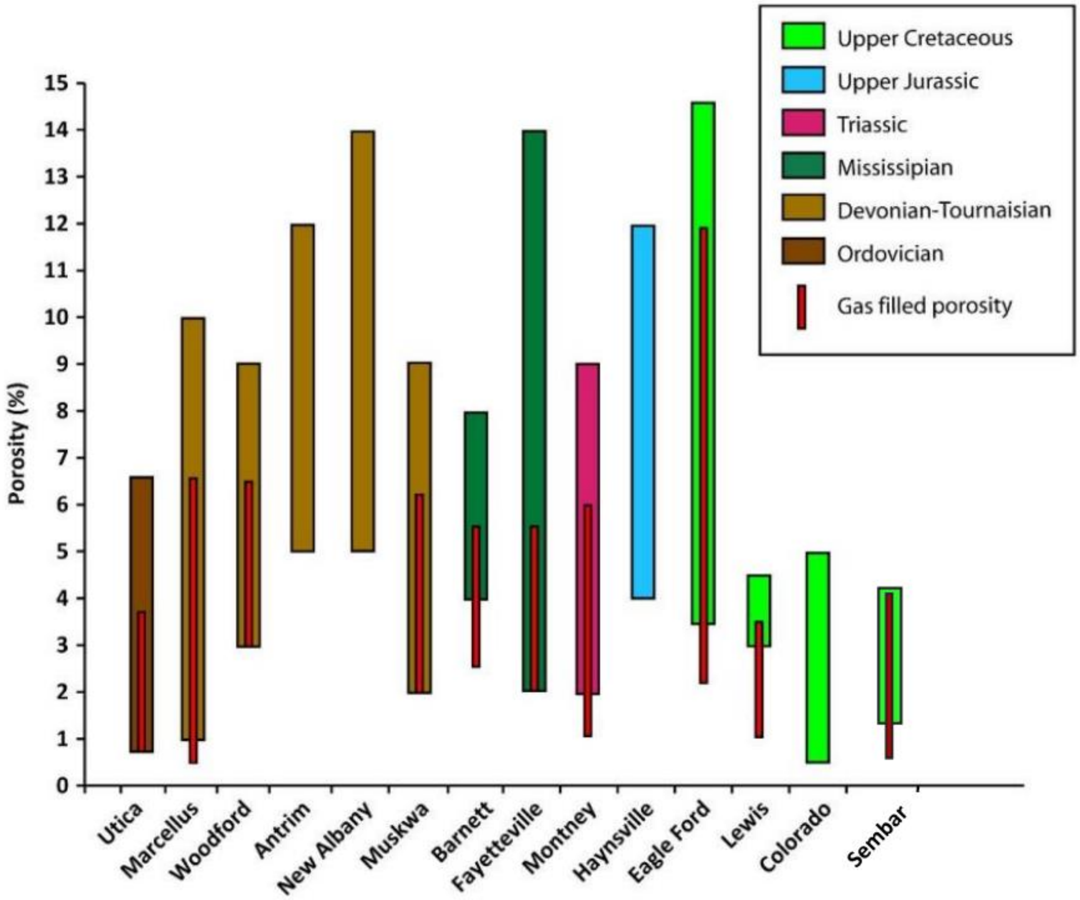

Fig. 20 Porosity range of Sembar and US Shale Plays (modified after Euzen, 2011)

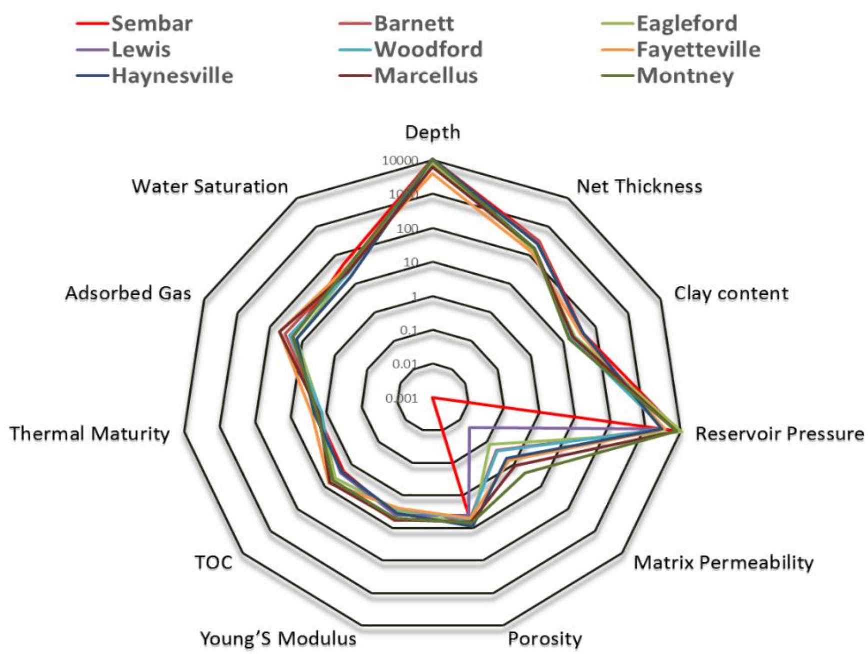

Fig. 21 Spider Plot of Sembar Formation and US shale plays

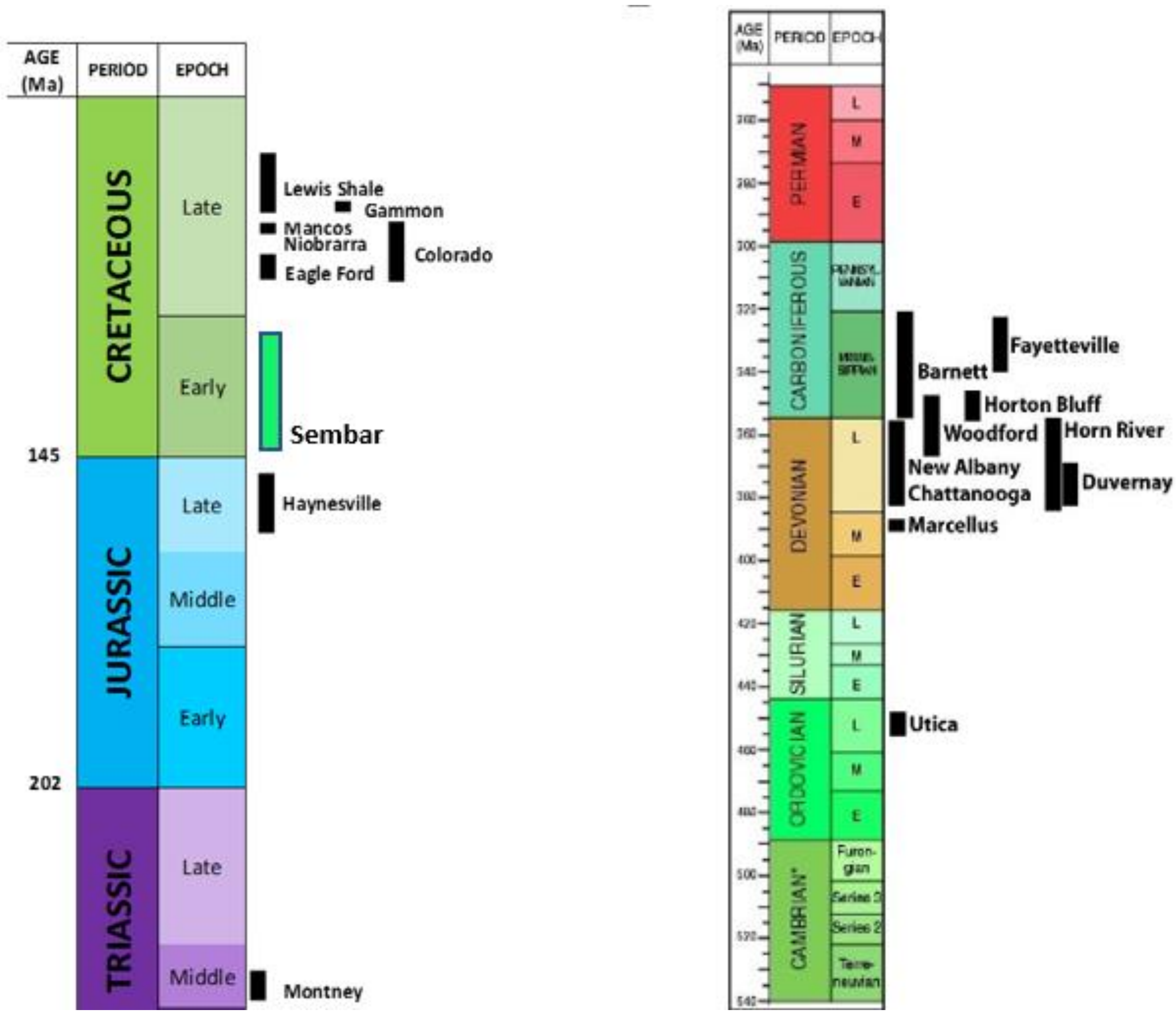

Fig. 22 Geological time chart of US Shale Plays & Sembar Formation (modified after Euzen,2011)

GIIP Estimation

Based on estimated log properties and maps of porosity and water saturation, free and adsorbed Gas In-place (GIIP) was calculated. GIIP indicates that X3 well and its vicinity have the promising shale Gas potential in the study area. GIIP is calculated in BSCF/Section (1 square mile). Zone 3 of X3 well has the highest free GIIP i.e., 60 BSCF (Table 2). Therefore Zone 3 is favorable for lateral well placement. As vertical well it is difficult to set no of stages to expose maximum surface area of the sweet spot.

$GIP_{total} = OGIP_{free} + OGIP_{adsorb}$

$OGIP_{free}=K1*PHIE*(1-Sw)*H*A/Bg$

A = Area in acres

Bg = Gas formation volumetric factor, cf/scf

GIP_{total} = Total gas in-place in MCF

H = Thickness in ft

K1 = Units conversion factor; 0.000043560

$OGIP_{free}$ = Original free gas in place in BSCF

PHIE = porosity, fraction

Sw = water saturation, fraction

OGIP adsorb = $KG6*GC*D*H*A/Bg$

Where: A = Area, acres

D = Layer density from log or lab measurement ρb (g/cm3)

GC = Gas content in scf/ton

H = Thickness in ft

KG6 = units conversion factor; 1.3597×10^{-3}

$OGIP_{adsorb}$ = adsorbed gas in place, Mcf

(Amparo et al., 2019)

Table 2. Estimated free and adsorbed GIIP by incorporating above parameters

Area (Acres)	Well Names	Zones	Intervals (m)	Porosity (v/v)	Net Thickness (m)	Net Thickness (feet)	Water Saturation (v/v)	Bg	TOC %	GIIP(free Gas) BCF/Sec	Resource Density/sq.km	Adsorbed Content (SCF/Ton)
1359	X3	Zone 1	3335-3361	0.032	25	82	0.7	0.0045	2.033	9.709	0.602363636	2.35099
		Zone 2	3362-3462	0.035	55	180.4	0.65		1.8324	29.07	5.285454545	14.568
		Zone 3	3462-3537	0.04	70	229.6	0.5		2.335	60.4	10.98181818	23.627
	X4	Zone 1	3328-3347	0.032	10	32.8	0.7		2.066	4.142	0.753090909	2.9864
		Zone 2	3347-3502	0.033	50	164	0.6		1.6235	28.478	5.177818182	11.734
		Zone 3	3502-3603	0.037	55	180.4	0.6		2.2595	35.123	6.386	17.96

CONCLUSIONS

Evaluation of geochemical (organic richness thermal maturity), petrophysical properties and geo-mechanical mapping of gas shale reservoir suggested that most favorable area lies in the vicinity of well X3. Comparison with analogue formations a Sembar Formation is the reasonably favorable prospect of gas shale reservoir. Reservoir properties and computation of GIIP (free gas and adsorbed gas) indicate that Sembar Formation has enough i.e., reasonably good resource potential.

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