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Total organic carbon content and total porosity estimation in unconventional resource play using integrated approach through seismic inversion and well logs analysis within the Talhar Shale, Pakistan

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ABSTRACT

Around the globe, the organic rich shale has become an increasingly important hydrocarbon resource due to the rapid depletion of conventional hydrocarbon reservoirs. The successful exploration and production schemes for organic rich shale are based on reliable identification of major organic components and total porosity. Therefore it is mandatory to identify the organic content in terms of total organic carbon (TOC) content and total porosity in promising shale formations through indirect seismic data, which is usually the only available source of information in most exploration phases. This research paper is focused on quantifying the Talhar Shale (member of Lower Goru Formation) as an unconventional reservoir using model based inversion in Badin concession area located near Karachi, Pakistan. Model based inversion is applied for computation of total porosity and total organic carbon (TOC) content because it provide a greater bandwidth and detail of variation of the acoustic impedance over the study area. The empirical relation for Total Organic Carbon (TOC) content has been derived through Passey et al. (1990) technique using data from Zaur-Deep 01, while for porosity a simple relation between impedance and porosity is used. The TOC and porosity models indicate that the unconventional reservoir potential is significantly greater over the northern region while it tends to decrease towards the south-eastern area.

1. Introduction

Hydrocarbon production from organic-rich shale formations has significantly increased since the advent of sophisticated recovery techniques which allow for economical productions from such formations. Organic rich rocks that contain sufficient amounts of organic carbon to generate hydrocarbons are called source rocks. Some of the properties that help operators to determine whether a formation can be economically produced include total organic carbon (TOC) content, thermal maturity, hydrocarbon saturation, porosity, mineralogy and brittleness. With the development of unconventional organic-rich shale formations, greater effort to characterize the formations has been put forth through the collection of seismic data. However, the information of source rock quality derived only from well data does not give regional views of source rock potential in the sedimentary basin.

The Lower Indus Basin of Pakistan is enriched with thick sequence of shale formations as a source and has a proven petroleum system. A significant amount of gas has been trapped within the unconventional reservoirs a part from oil and gas resources within the conventional reservoirs. The conventional reservoirs have been explored and developed in Pakistan; however very little work has been done so far in developing these unconventional reservoirs. Pakistan has approximately 200 trillion cubic feet (TCF) of unconventional gas resources within the shale formations. Studies have identified that approximately 70% area of Pakistan is covered by shale gas. It is estimated that most of the shale resources are in mature stage for hydrocarbon generation and are estimated to be thicker than the shale plays in North America. Therefore these shale resources in Pakistan have potential to become good resource play (Abbasi et al., 2014a,b). In their study on Talhar Shale identifies that Pakistan on average has shale gas ranging from 70 to 80 TCF.

An integrated approach using mineralogy, lithology, and Total Organic Carbon (TOC) content data combined with petrophysical logs are used for accurate prediction of the unconventional reservoir characteristics (Chopra et al., 2012; Brindle et al., 2015). The porosity prediction from post stack seismic inversion technique provides insight

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into porosity variations away in case of limited well data control. Seismic inversion can enhance characterization of shale-gas reservoirs (Ouadfeul and Aliouane, 2016a,b; Das et al., 2017). Quantitative interpretation of the seismic data has enabled us to extract more information about the reservoir properties as compared to conventional interpretation. In seismic inversion, the amplitude data is translated into quantitative properties of the reservoir particularly like porosity, fluid content, TOC, etc. Quantitative properties of reservoir become more important as they are shifted from the conventional reservoir to the unconventional reservoir (Tight sands/shales). Therefore quantitative properties due to their significance in seismic inversion are considered to be more reliable as compared to the spatial properties (Gonzalez, 2006).

This study including estimation of total organic carbon (TOC) content and total porosity using seismic and well logs data in terms of prospective shale gas potential within the Talhar Shale, Pakistan, is based on seismic inversion and well logs analysis. This present research is able to overcome the problem of evaluation of hydrocarbon potential. In this case study, the source rock properties has been established by model based inversion. Seismic acoustic properties are determined by inverting the seismic amplitude data. A correlation between the results deduced equations to transform seismic inversion-derived acoustic properties to source rock properties through regression analysis. It is the accurate and cheap way to check the hydrocarbon potential of unconventional reservoir formation in the absence of geochemical and core data. The reliability of the results are verified by calibrating the seismic and well log data. This quantitative interpretation of the reservoir properties helped in understanding the potential of the source rock (Talhar Shale) in the Badin field, Lower Indus Basin, Pakistan.

2. Geological setting of the study area

Badin is the most prolific with respect to oil and gas exploration located in the Sindh Monocline. The Sindh Monocline is a part of the Lower Indus Basin situated in the south eastern corner of Pakistan (Kadri, 1995). The slope of the sedimentary succession covering the Sindh Monocline generally dips westward bonded on the east by the Indian Shield (Nagar Parker granite area). Towards its western limits include the Kirthar Fold and Thrust Belt and Karachi Trough where it merges with a tectonically different entity (Bender and Raza, 1995; Abbasi et al., 2014a,b). The area lies between the latitude 25° N and 24° N and longitude 68° E and 69° E as illustrated in Fig. 1(a). The data set included the 3D seismic data and well logs of Zaur-Deep 01, Chakri −01 and Babu-01 as illustrated in Fig. 1(b).

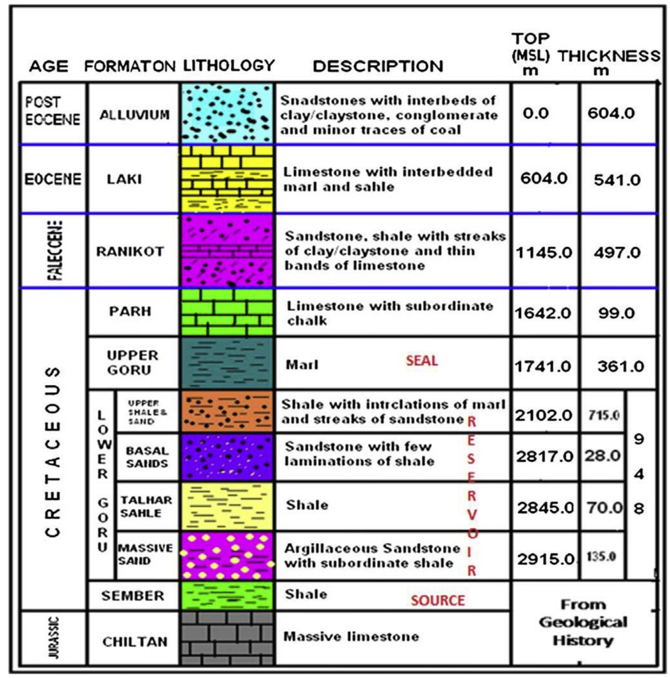
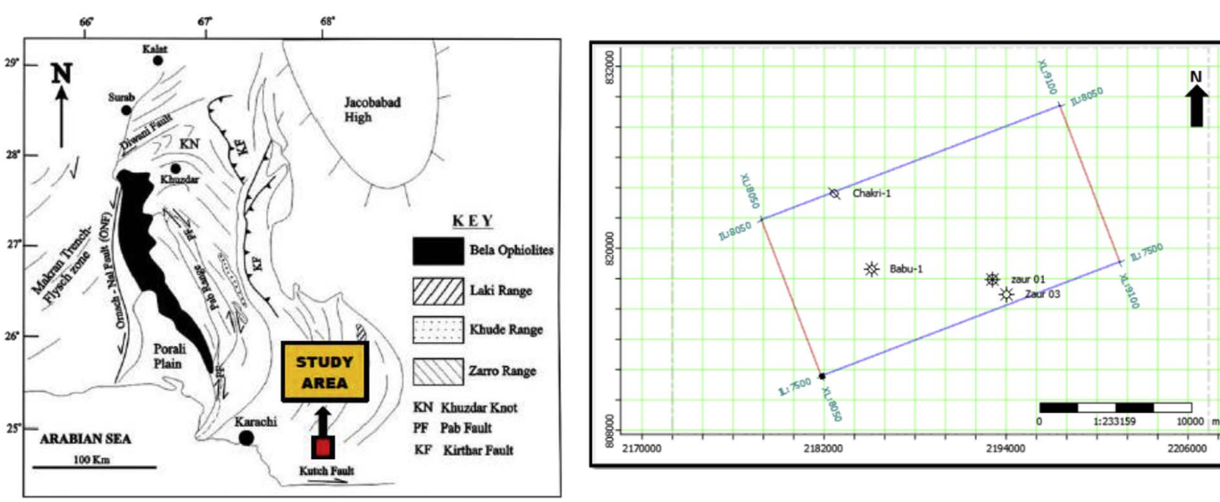


Fig. 2. Lithostratigraphic column for the study area, Lower Indus Basin (Akhter et al., 2015).

3. Geological characteristics of the Talhar Shale

The Lower Goru Formation with medium to coarse-grained sediments of Cretaceous age, which acts as a primary source of hydrocarbon in the Indus Basin Pakistan. These sediments have alternate bedding of shale and sand which are favorable for the hydrocarbon exploration (Sheikh and Naseem, 1999). The shales sediments of the Lower Goru Formation have fault/fracture system with high TOC values zones which are favorable for the future unconventional resource exploration (Naseer and Asim, 2017). Talhar Shale is a member of the Lower Goru



(a) (b)

Fig. 1. (a) Location map of the study area (Badin Block), Lower Indus Basin along with geologic setting of Lower Indus basin. The red color square show the location of the study area (after Bannert et al., 1992) (b) Base map of the study area with marked well locations. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

Formation (Solangi et al., 2016) as illustrated in Fig. 2, which is deposited in the deltaic settings over the westward dipping passive margin. The shale units comprise of Type II and Type III Kerogen with a TOC in the range of 0.5–3.5%. The Talhar Shale sequence can generate up to 21 million bbl/sq km. Its thickness varies from 24 m in the southeast to 80 m in southwest of Badin Block, where it is mature (Haider et al., 2012). It is present at a depth of 2700–3500 m. Talhar Shale is in the wet gas to dry gas window based on the maturity data of surrounding wells. Talhar Shale possesses the required brittleness for hydraulic fracturing (Nazir and Fazeelat, 2016).

4. Methodology

The seismic data with a high lateral resolution can help map the potential shale zones laterally for hydrocarbon exploration (Haris et al., 2017). The goal of post-stack inversion is to quantitatively describe geological formation from porosity, TOC, impedance, and lithology (Das et al., 2017). The seismic inversion technique has been widely used to characterize the conventional and unconventional hydrocarbon reservoirs (Ouadfeul and Aliouane, 2016a,b). The seismic inversion method is basically a process of transforming seismic amplitude value to impedance value. Inversion is the subsurface modeling technique and used to produce a geologic structure using seismic data as input and well data as control. Model based seismic inversion was run on 3D seismic data of Badin area to produce images of the acoustic impedance in time. The seismic properties (P-Impedance, S-Impedance, Bulk Modulus, etc) were translated into reservoir properties (porosity, water saturation, shale volume) with the help of algorithms derived on various assumptions (Hampson et al., 2005). The seismic inversion technique was applied to transform seismic data into organic geochemical data by producing the acoustic impedance (AI) cube (Haris et al., 2017).

The model based Inversion was used in an attempt to characterize the source rock i. e Talhar Shale which is the primary objective of the study. The inversion technique was applied based on the log values from Zaur-Deep-01 and a 3D post stack seismic volume of the Badin area. Before inversion of seismic data, the low frequency model was generated to avoid the thin bed tuning effect. The Model based inversion was conducted by dividing the Talhar Shale into three time slices 1823, 1900, and 2100 ms to show the impedance variation with increment in time. The inverted volume then converted for porosity, which is the ratio of the total pore space to the total volume of the rock. The empirical relation between P-impedance and porosity was used to convert the impedance values into porosity using model based inversion. While TOC was calculated from inverted volume using Passey et al., 1990 method by applying site specific constants.

4.1. Seismic data interpretation

4.1.1. Generation of synthetic seismogram

Synthetic seismogram has been generated to correlate the well log data with seismic data. The synthetic seismogram is constructed by first multiplying the density log with the sonic log values and then convolving the resulting impedance log with a suitable wavelet, usually extracted from the seismic data to match the character. The concept behind the synthetic seismogram is that the seismic waveform recorded at the geophone is a convolution of the reflectivity from the subsurface and the source wavelet sent into the earth and hence it can be reproduced from the log data (Box and Lowrey, 2003).

For the sake of seismic interpretation, the sonic and density logs from Zaur-Deep-01 were multiplied and convolved with a wavelet extracted from the seismic data as illustrated in Fig. 3.

4.1.2. Horizon interpretation

The study is focused mainly on Talhar Shale, the Lower Goru and Chiltan formations that were interpreted to constraint the low frequency model in inversion and have an understanding about the overall change in thickness of the stratigraphic sequence over the study area.

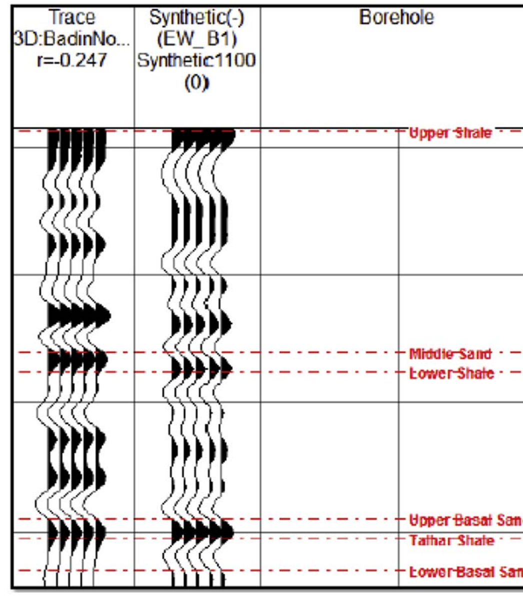


Fig. 3. Comparison of the synthetic trace and the seismic trace against the formation tops at well Zaur Deep-01 and seismic inline 7535. The red colored dotted lines are representing the formation tops, with their names mentioned in red color. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

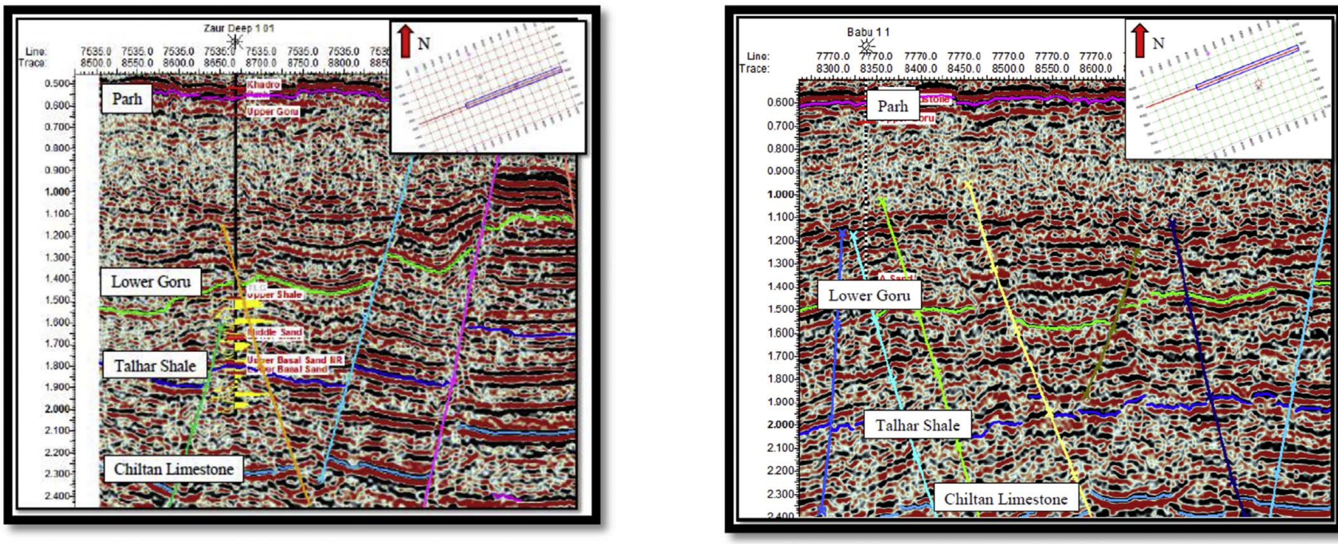
Badin area was distal to main deformation, and it exhibits a provisional degree of deformation. As a result the degree of deformation is relatively low, and progressively increases from East to West. The extensional tectonics during Cretaceous time created tilted fault blocks over a wide area as illustrated in Fig. 4a and b. Seismic reflectors (Lower Goru Formation, Talhar Shale, and Chiltan Formation), are broken by a system of faults with normal dip separation. Commonly, faults are arranged in en-echelon sets, aligned in zones that trend almost north-south. The tilted fault block traps were in existence at time of hydrocarbon generation. Fault associated structural closures are responsible for trapping oil and gas in Lower Goru Formation in Badin block. The under filling of structures can be attributed to upward leakage across extensive structures and redistributed hydrocarbon (Kemal et al., 1991; Munir et al., 2014).

4.1.3. Model based inversion

The model based inversion is usually taken as the most reliable inversion model because it uses a generalized linear inversion (GLI) algorithm that is run iteratively until the derived results match with those of the seismic data within some acceptable bounds (Das et al., 2017). The perturbation of the model continues until the error, as set by the user, is minimized. However, it is necessary to have good geological knowledge of the study area that will help in building the initial model.

4.1.3.1. Wavelet extraction. To convert the seismic amplitude volume to impedance volume, the wavelet is extracted from the data that is convolved with the reflectivity results of the seismic volume. Extraction of this wavelet from the seismic data, helped to correctly estimate the amplitude of the wavelet. This helps the seismic prediction from the inversion scale properly in comparison to the actual seismic. The algorithm behind the process works by autocorrelation of the amplitude spectrum of the traces over a specified time window as shown in Fig. 5.

4.1.3.2. Low frequency model. The low frequency spectrum is assumed



(a) (b)

Fig. 4. (a) Display of interpreted seismic inline 7535 highlighting the interpreted reservoir zone. The seismic to well tie (yellow wiggle trace) is also shown, generated using the data of well Zaur Deep-01 (b) Interpreted seismic inline 7770 highlighting the interpreted reservoir zone. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

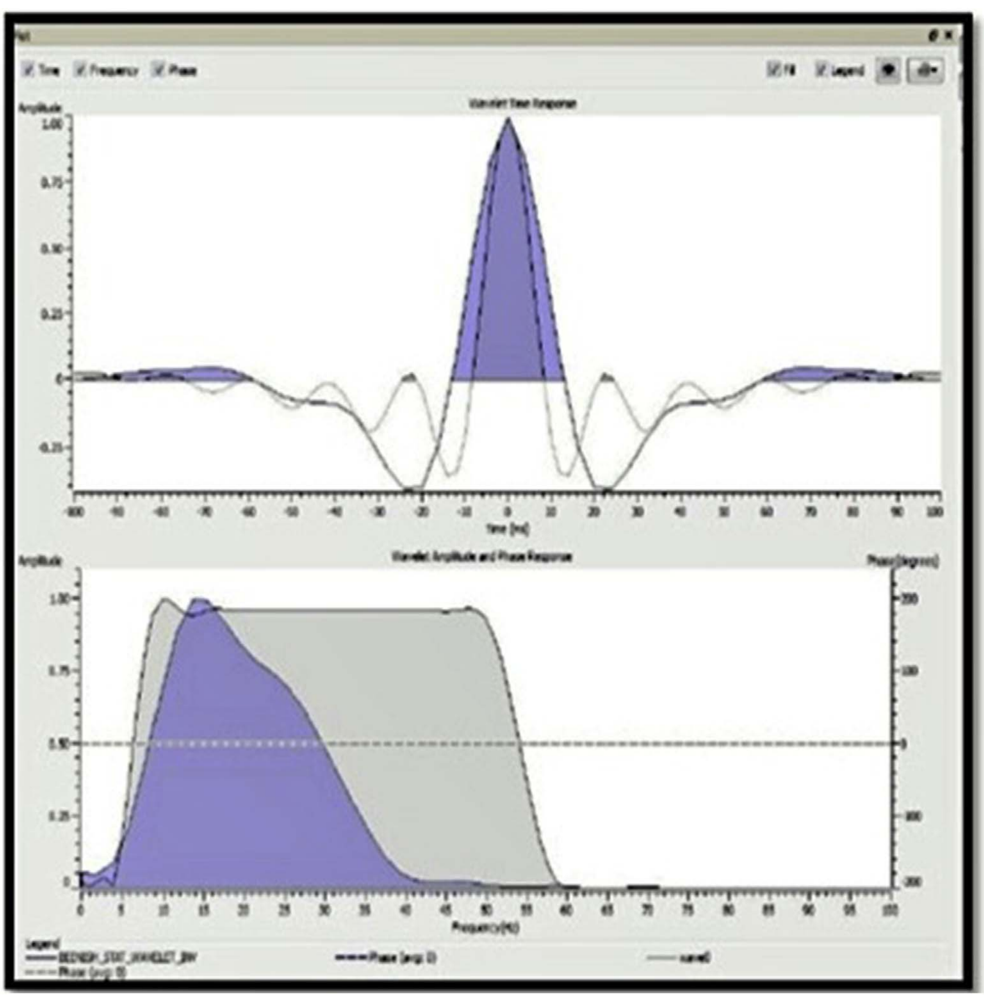


Fig. 5. The comparison of the wavelet from the seismic data (grey) and the statistically computed wavelet (purple). It can be seen that the statistically computed wavelet has a broader frequency there by providing a more detailed analysis of the subsurface. The dotted line is displaying the average phase of the wavelet. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

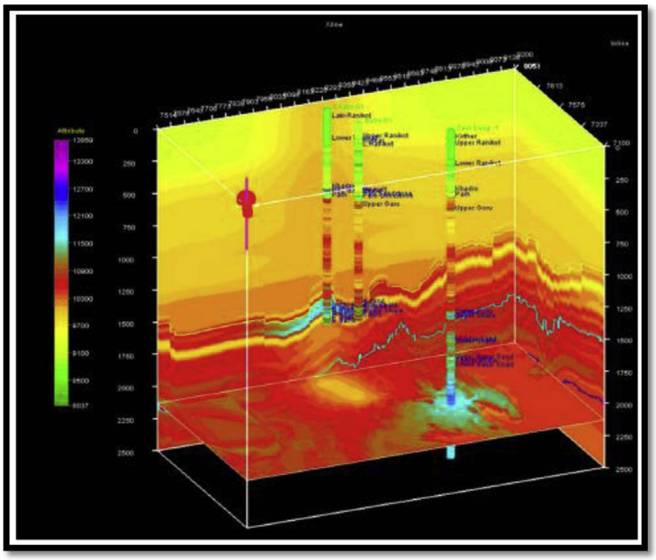


Fig. 6. The initial Low Frequency Model (LFM) used for the application of model-based inversion along with the well locations. The blue and cyan color represents high values, red and yellow color intermediate values, while green color represent low values. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

to have been completely removed from the seismic data. The absolute acoustic impedance is an absolute layer property, which is used in both qualitative and quantitative interpretations. To obtain absolute acoustic impedance a proper low-frequency component (approximately 0–12 Hz) is incorporated in inversion algorithms (Cooke and Cant, 2010). In model-based inversions, low frequencies are added as part of the inversion algorithm. A low frequency model generated for the application of a model-based inversion is shown in Fig. 6. For model-based inversion techniques, low frequencies are added from the well data to assure more realistic results, because it filled the region of the frequency spectrum that lies below the region contained in the seismic data.

The low frequency model is built after inclusion of the correct low frequencies for seismic inversion as illustrated in Fig. 6. The wells Chakri-01, Babu-01 and Zaur Deep-01, are displayed along with the formation tops. This low frequency model is providing the information on slowly varying vertical trends within the Lower Goru Formation. The low frequency model is illustrating the mix frequencies at Lower Goru level because of the continuous changes in lithologies. This low frequency model is useful as it is providing valuable information about gradual changes at Talhar Shale level and correct conversion of reflectivity to impedance contrast.

4.1.3.3. Model based inversion results. The impedance model resulted by performing model-based inversion is shown in Fig. 7. It is evident from the figure that the impedance values are very meticulous. The model based inversion shows more detail within the high or low impedance areas. This minute detail of the model based inversion helps to identify structures such as sand lobes, etc.

The 3D impedance model determined from the inversion reflects the changes due to the seismic reflection data are illustrated in Fig. 7. The wells (Chakri-01, Babu-01 and Zaur Deep-01) are displayed along with the formation tops. The impedance model is generated by interpolating the impedance at the well locations. The horizons are picked accordingly to guide the interpolation. The extrapolation at the top and bottom of the wells is based on compaction trends in the well. The model is displaying the lower values of impedance at shallower depths and more values at deeper depths. The inversion result (Fig. 7) shows zones of low impedance (green-yellow) at Top Lower Goru Formation level. Higher impedance values correspond to more shaly units that is Talhar Shale.

4.1.3.4. Time slices of model based inversion of Talhar Shale. Talhar Shale is divided into three time slices 1823, 1900, and 2100 ms (ms) to show the impedance variation with increment in time. Fig. 8(a) displays time slice at 1823 ms with low values of impedance encountered at two places as shown in Area A and B. Likewise, Fig. 8(b) displays time slice at 1900 ms with low impedance values in the north as Area A. The same "Area A" is highlighted at 1823 ms as well. Lastly Fig. 8(c) displays the time slice at 2100 ms along with potential hydrocarbon prospects in the northwest (Area A) and extreme northeast of the study area (Area C). The impedance values within these potential hydrocarbon areas lie within 9800–10,200 Pa s/m.

Based on the comparison of the results, the model based inversion is used for the computation of porosity and total organic carbon content since it showed the most detailed model of impedance.

4.1.3.5. Estimation of porosity from impedance volumes. Porosity is the volume of space that is available for the occupation of fluids (Nimmo, 2004). The fluids most commonly found in the rocks are water, gas and oil. The derivation of porosity from acoustic impedance is based on the relation that acoustic impedance itself is a product of density and velocity. It has been found that at greater depths velocity becomes more sensitive to changes in porosity as compared to fluid type (Cemen et al., 2014; Dolberg et al., 2000). Hence an empirical relation established between porosity and impedance at the well location has been used to extrapolate porosity over the complete acoustic impedance volume as illustrated in Fig. 9.

The empirical relation between P-impedance and total porosity which is color coded with volume of shale is shown in Fig. 9. The x-axis represents the impedance values and the y-axis the total porosity values. The relation between the porosity and permeability is based on the linear equation whose general form is given below:

$$y = Ax + B$$

Wherey = Total porosity, A = slope of equation, x = P- Impedance, B = y-intercept

The co-efficient of determination R^2 shows that the equation is a good fit for the plotted data and hence it is reliably used for the conversion of impedance model into porosity. The equation derived in Fig. 9 has been used for calculation of porosity volume over the impedance data of Model-based Inversion.

Time slice of porosity at 1823 ms is displayed in Fig. 10(a). High range of porosity values (7.5–13%) and (7–12.5%) are shown in areas of interest as Area A and Area B. Areas of higher porosity are of great significance because they indicate where the reservoir may have enough space to hold hydrocarbons as well as where induced permeability would be most effective. Fig. 10(b) shows the time slice of porosity at 1900 ms. High porosity ranging from 7.5 to 13% are shown only in Area A. Time Slice of porosity at 2100 ms is shown in Fig. 10(c). High porosity values ranging between (7.5–13%) and (7–11%) are shown in Area A and Area C for this time slice.

These porosity values show that within Talhar Shale, Area A has significant porosities even as in the deeper part of Talhar Shale. However, the Area B and Area C are more discontinuous in terms of favorable porosity continuation with increasing depth as shown in Fig. 11. Since the Area A within Talhar Shale is showing more porosity, there are chances of good production. As a matter of fact the higher the porosity would be of Talhar Shale, brighter be the chances of presence of fluids.

The porosity volume computed from impedance values using the empirical relation between porosity and impedance is illustrated in Fig. 11. The wells are displayed on the porosity volume along with the formation tops. The porosity is interpolated over the whole cube to get

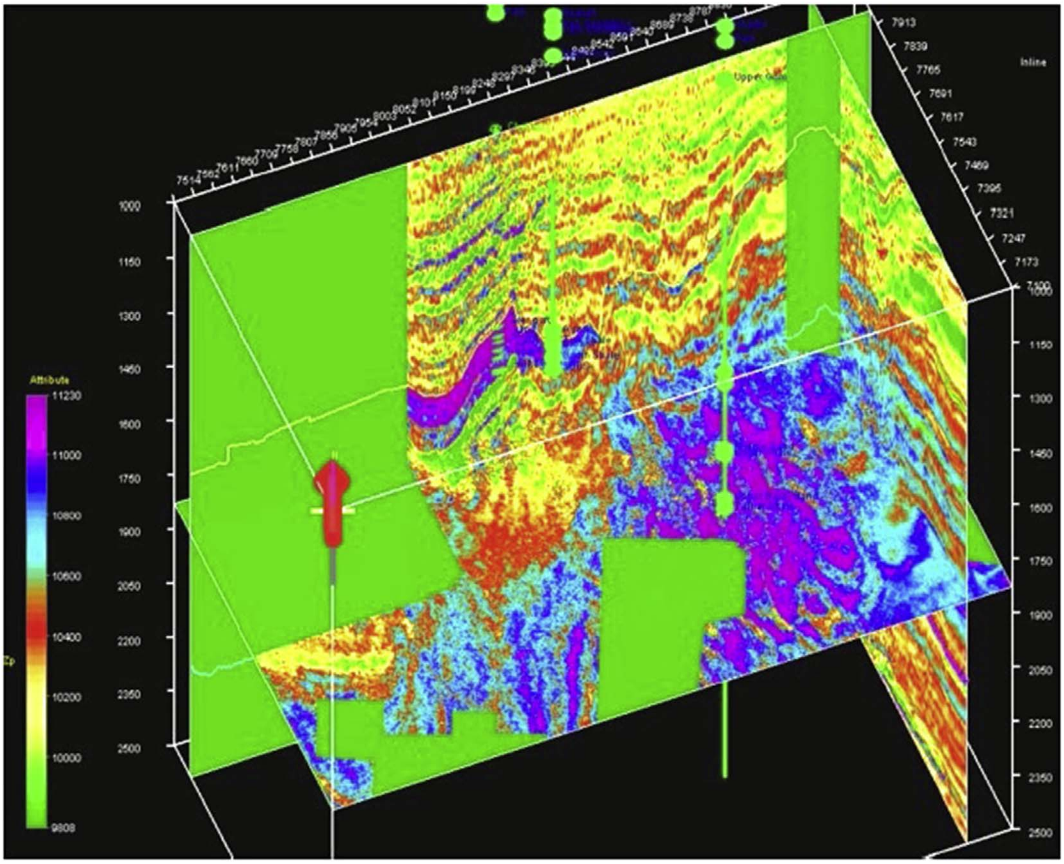


Fig. 7. A 3D acoustic impedance model of Model-based Inversion along with the marked horizons and well locations. The well locations are shown with green lines. A red arrow is representing the north direction. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

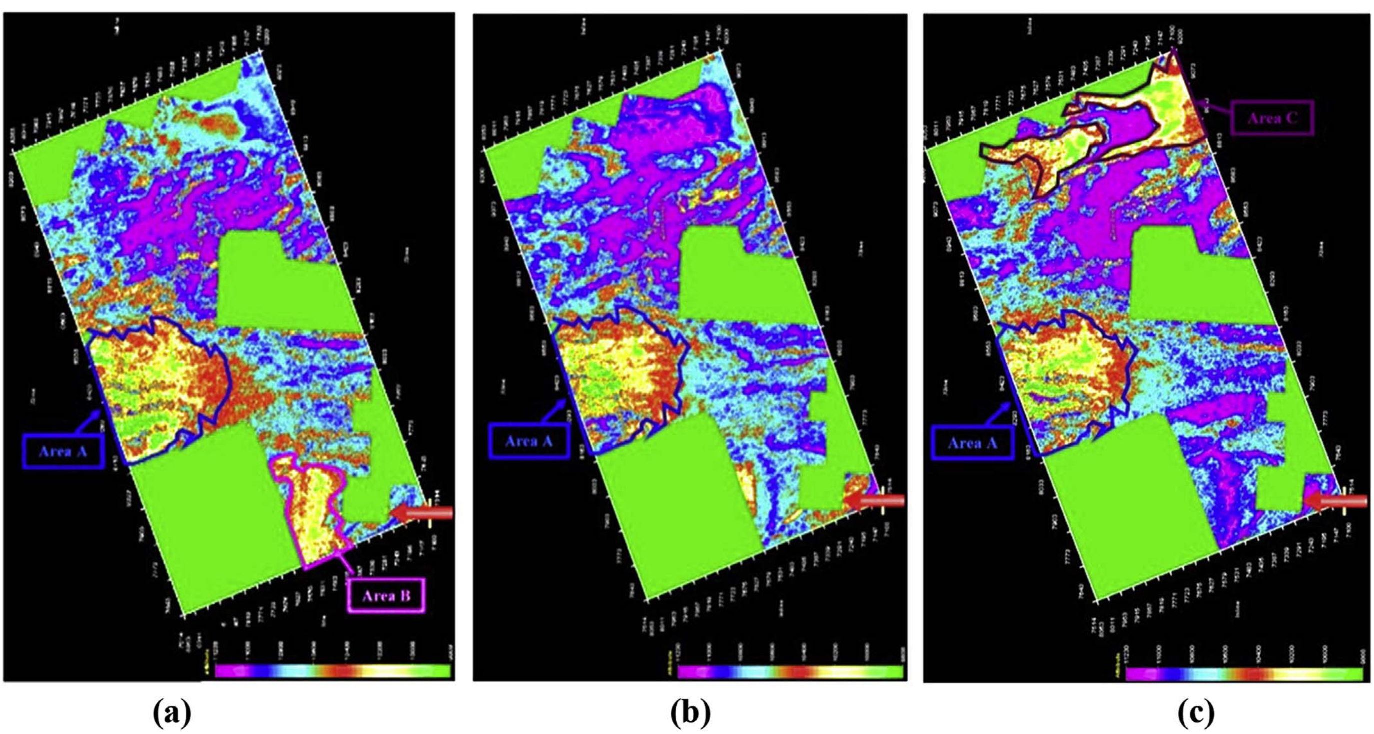


Fig. 8. (a) Time slice of Model-Based Inversion at 1823 ms. Area A in blue color and Area B in pink color are highlighting the zones of interest, with low values of impedance **(b)** Time slice of Model-Based Inversion at 1900 ms. Area A in blue color is highlighting the zone of interest **(c)** Time slice of Model-based inversion at 2100 ms. Area A in blue color and Area C in purple color are highlighting the zones of interest. A red arrow is indicating the north direction. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

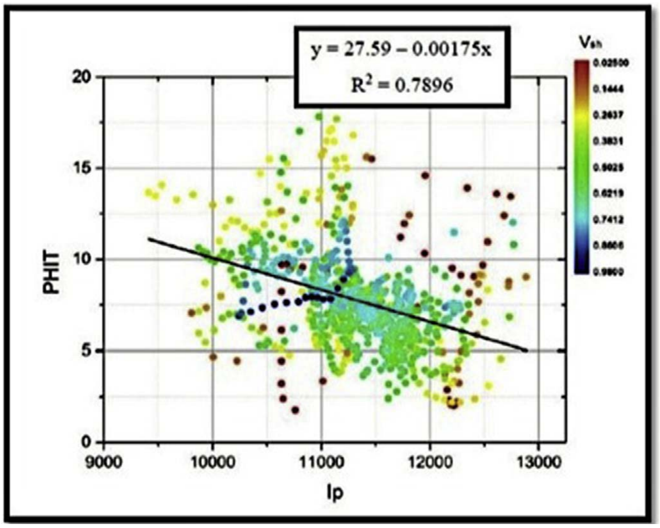


Fig. 9. A graph showing the empirical relation between P-impedance plotted on x-axis and total porosity plotted on y-axis, color coded with volume of shale. As the values of P-impedance increase the values of total porosity decrease. The computed equation is mentioned at top of figure. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

the information of the lateral distribution of porosities. The average value of computed porosity at Talhar Shale level is 10.25%.

4.1.3.6. Estimation of total organic carbon content from impedance. The organic content left in the pores of the shales, after degradation of the biological content is called as Total Organic Carbon content. Source rocks are typically rich in TOC and exhibit various degrees of maturation of this TOC based on time, temperature and pressure they have endured. Based on this TOC the quality of source rock is determined.

Among the various methods developed for economically viable TOC calculation include those by (Schmoker, 1979) (Schmoker and Hester, 1983), and (Passey et al., 1990). All of these methods proved that wireline logs can also be used for TOC estimation after reasonable calibration for the constants used. For the purpose of this study Passey method is used for TOC calculation in view of the available log data. The Passey Method relies on the resistivity and sonic logs for calculation of TOC. Apart from these wireline log values, a reliable estimate of Level of Maturity (LOM) of the rocks is used (Baig et al., 2014). This is important because a sound base of LOM provided TOC values that are almost similar to those derived from the core values.

The Passey Method also known as ΔLog R technique, has been used for the quantitative estimation of TOC of source rock intervals or unconventional reservoirs to determine their maturity and organic richness from the wireline log data. The technique relies on the fact that the sonic log values will completely overlay resistivity values in intervals with no TOC content (on a properly scaled tracked) and show separation in intervals with significant TOC values. The separation between the sonic log and resistivity has enabled to calculate the ΔLog R factor and it is found to be directly proportional to the TOC content. This ΔLog R factor is further used to calculate TOC values after multiplying with a maturity factor (LOM).

The basic equations (Passey et al., 1990) used for this technique as defined are below:

$$\Delta LogR = Log_{10}\left(\frac{R}{R_{baseline}}\right) + 0.02*(\Delta T - \Delta T_{baseline})$$

TOC = (Δlog R) * 10(2.297–0.1688*LOM)

$$TOC = (\Delta LogR)*10^{(2.297-0.1688*\mathrm{LOM})}$$

$$LOM = 13.6078 - 5.924*Log_{10}\left(\frac{TOC}{\Delta LogR}\right)$$

Where,

R is the resistivity value (LLD),

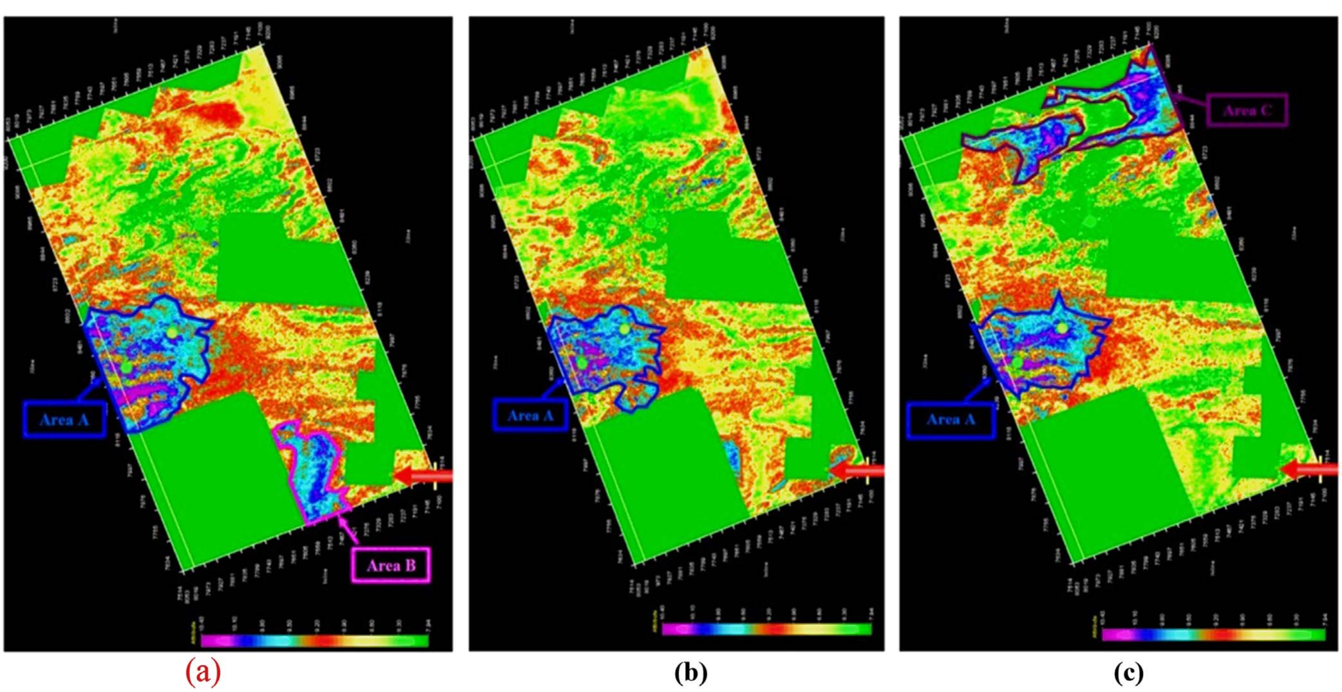


Fig. 10. **(a)** Time slice of Porosity at 1823 ms. Areas A and B in blue and pink colors respectively are highlighting the zones of interest, with high values of porosity **(b)** Time slice of Porosity at 1900 ms. Area A in blue color is highlighting the zone of interest **(c)** Time slice of Porosity at 2100 ms. Areas A and C in blue and purple colors respectively are highlighting the zones interest. The well locations are shown in green color. A red arrow is indicating the north direction. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

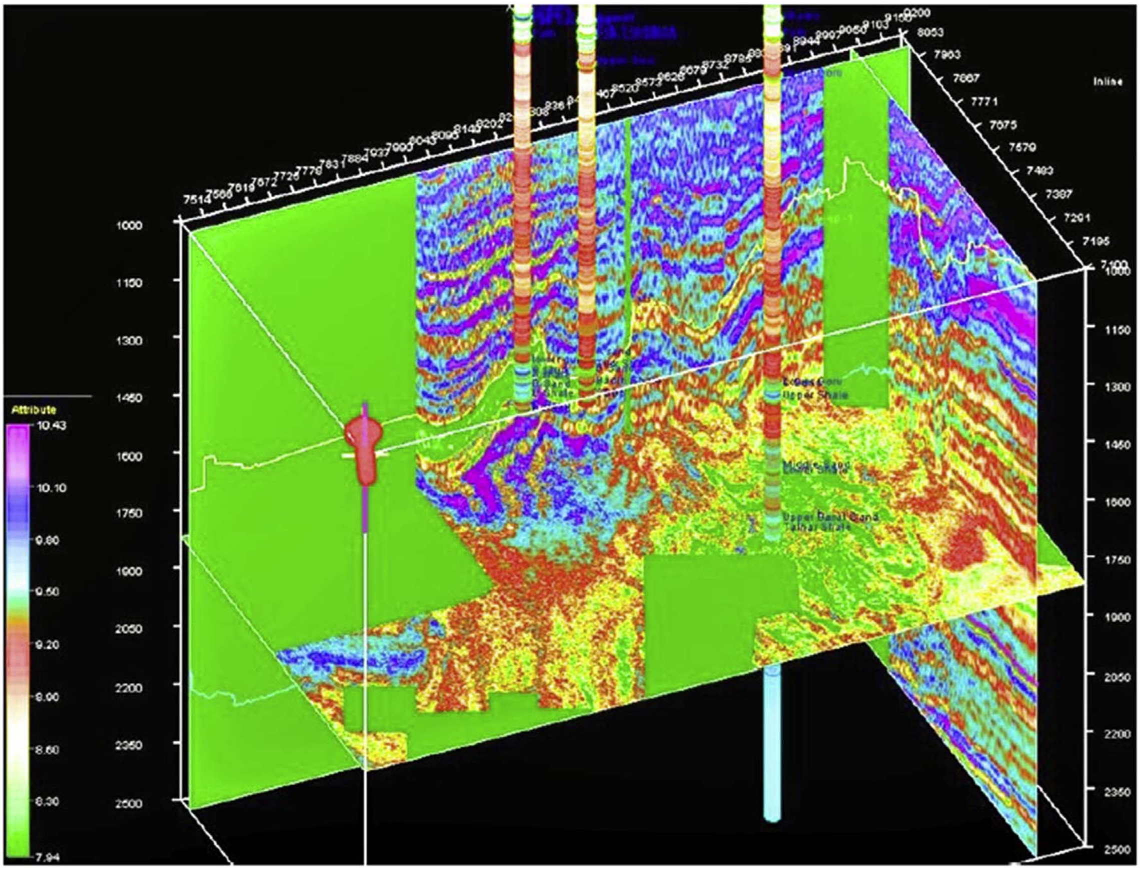


Fig. 11. A 3D view of the porosity volume estimated from P-Impedance at 1823 ms, along with marked horizons and well locations (Chakri-01, Babu-01 and Zaur Deep-01). A red arrow is indicating the north direction. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

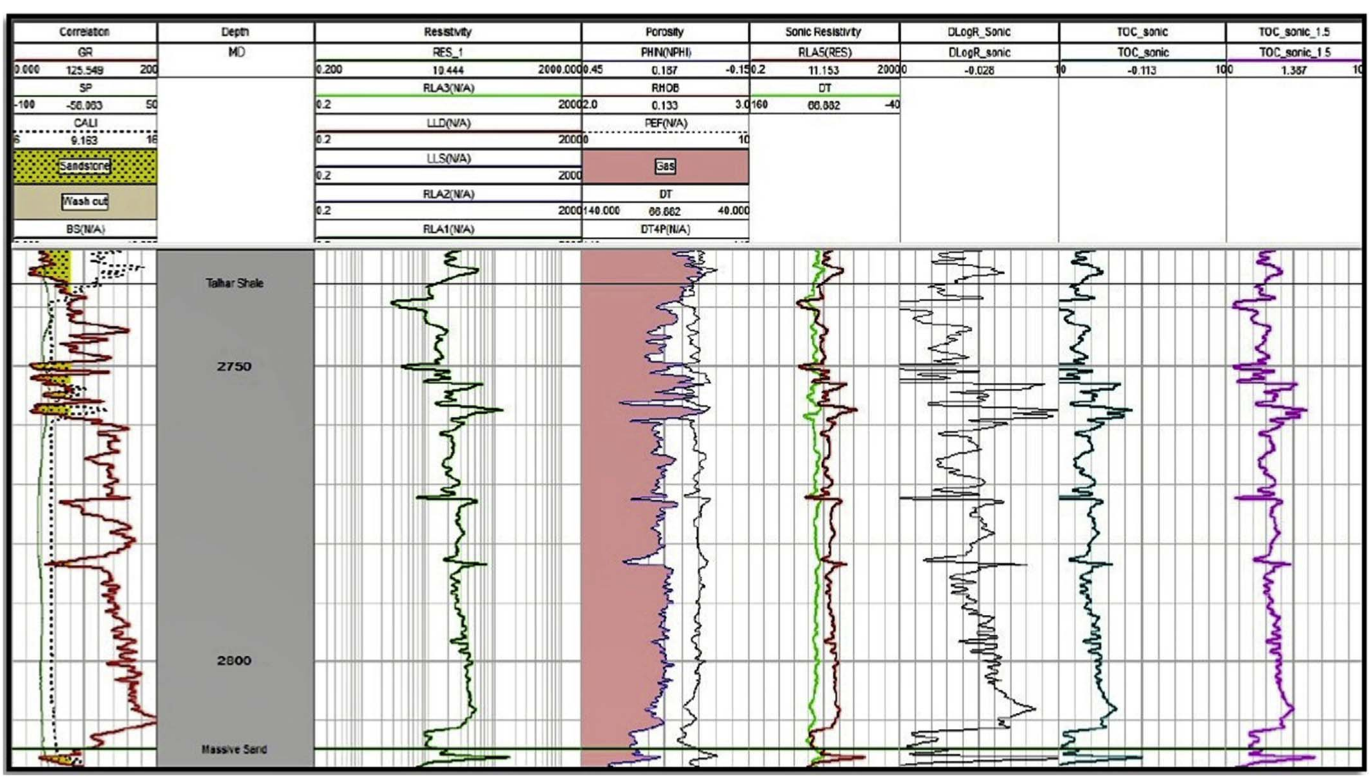


Fig. 12. The application of Passey Method for the quantitative estimation of TOC of Talhar Shale to determine the maturity and organic richness. Log trends of Sonic and Resistivity logs are shown in Track 4.

R baseline is the value of resistivity in the overlain zone
ΔT is the sonic log value
ΔT baseline is the sonic log value in the overlain zone
LOM is the level of maturity usually derived from core values.

The most important consideration before using this technique is perhaps the identification of the zone where the resistivity and the sonic log values overlay. This zone is assumed to be one with clean shales (no TOC content). The overlay in the Zaur Deep-01 values has been identified to be within the Talhar Shale. Within this interval, the resistivity and sonic log values become completely overlain providing a baseline as shown in Fig. 12.

The level of organic maturity (LOM) defines the source rock thermal metamorphism that occurred during the process of its burial. LOM plays key role to develop source rock properties like porosity and water saturation at the time of source rock evolution. The LOM value for the Southern Lower Indus Basin established by Ehsan et al., 2016 using the TOC values obtained from density log and ΔLog R values. The value of LOM is 6.6. Since this value is derived for Talhar Shale, therefore the values have assumed to be reliable and applied to the log values.

For an unconventional reservoir, such as Talhar Shale, TOC is critical because the unconventional reservoir is in fact a source rock that is capable of expelling hydrocarbons when heated (Frantz and Jochen, 2005). Studies have shown that this TOC is related to the amplitude of the seismic data. It is possible to extract information about the TOC from the reflectivity data extracted during inversion (Broadhead et al., 2016). It is found that the TOC generally has a linear relation with the impedance values (Ouadfeul and Aliouane, 2016a,b) as shown in Fig. 13.

The linear relationship between the Impedance data and TOC data (color coded with volume of shale) derived from Zaur Deep-01 well logs (Zone – 2650–2850 m) as shown in Fig. 13. These values give a true representation of the dependence of TOC on impedance values within the study area. Hence this equation has been used to extrapolate the values of impedance into TOC through inversion.

The equation used for the above relation is given below:

$$y = A + Bx + Cx^2 + Dx^3$$

Where

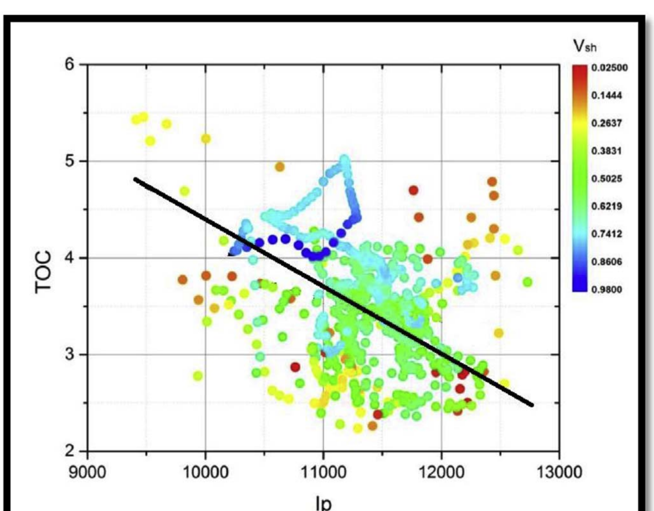


Fig. 13. Relationship between Total Organic Carbon (TOC) content plotted on y-axis and P-Impedance (Ip) values plotted on x-axis, color coded with volume of shale. As the value of P-Impedance increases, the value of TOC decreases. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

y = Total Organic Carbon content
x = P-Impedance

While the values of the constants can be defined as follows:

A = 52.998
B = −0.01025
C = 6.74 E−7
D = −1.387E-11

The value of determination co-efficient for the above equation has been calculated to be 0.896, which depicts the reliability of the equation. Hence the equation is used in the conversion of impedance model into TOC content.

Fig. 14(a) is displaying the time slice for 1823 ms. The areas highlighted as Area A and Area B showing the range of TOC values between 2.1 to 3.3% and 2.3–3.5% respectively in the time slice. Fig. 14(b) displays 1900 ms time slice. High TOC values are only observed in Area A lying between 2.1 and 3.3% for this time slice. The time slice of 2100 ms is displayed in Fig. 14(c), that is showing high TOC values in areas highlighted as Area A and Area C. The range of values lie between 2.3 and 3.5% for this time slice.

The 3D model of TOC at 1823 ms is illustrated in Fig. 15. The wells are displayed along with the formation tops. The equation is used to extrapolate the values of impedance into TOC. The magenta color represents the high values of TOC while green color the low values. The computed value of TOC at Talhar Shale is 2.35%.

4.1.4. Relationship between porosity and TOC of Talhar Shale

The Talhar Shale is analyzed in terms of the relationship of porosity to the organic matter maturity and TOC. Organic enrichment is one of the most important parameters for shale play. It is because after the generation of hydrocarbons, some of them is not able to overcome the retention capacity of the organic matter and therefore is sucked inside the pores of organic matter. So organic-enriched Talhar Shale is acting as special reservoir.

The total porosity and gas content (gas-filled porosity or bulk-volume gas BVG) are directly associated with the TOC content of the Talhar Shale as shown in Fig. 16. That means high local TOC is a critical factor to assess when evaluating potential shale-gas reservoirs (Passey et al., 2010). The porosity of organic matter is high, therefore the shale beds of Talhar Shale with a TOC value less than 5% display a positive correlation between TOC and porosity which is indicating the early stage of maturity. Beds with a TOC greater than 5% display a limited increase in porosity with increasing TOC. The porosity of Talhar Shale is decreasing with increasing maturity. The free gas in porosity is the key factor for successful development of shale gas potential of Talhar Shale. The free gas volumes are controlled by porosity and gas saturation. Within Talhar Shale, higher TOC shale beds has higher porosity and gas saturation. The average TOC value of Talhar shale range from 2.1% to 3.3%, with good porosity values. It indicates more gas saturation within Talhar Shale and high free gas volume can result in high production.

4.2. Discussions and results

Developing a technique for the evaluation of shale gas potential using the seismic inversion technique is a big challenge for researchers. Seismic inversion always play a key role for the exploration and exploitation of hydrocarbon. In this study, model based inversion technique has proved to be very beneficial to check the hydrocarbon potential of the Talhar Shale.

The average thickness of Talhar shale (member of Lower Goru Formation) in study area is 75 m (Haider et al., 2012). Previous studies carried out by (Ehsan et al., 2016), (Ahmad, 1997), (Robison et al., 1999) and (Smith et al., 1992) reported that Talhar Shale has type II

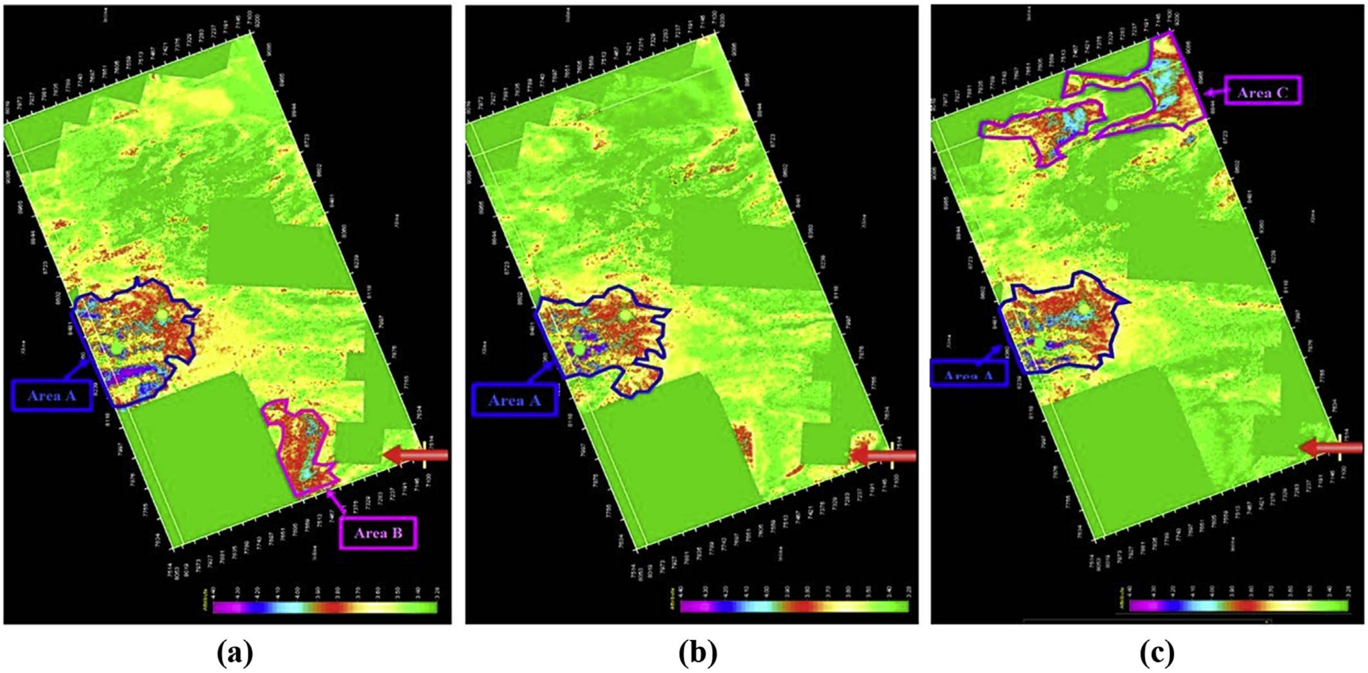


Fig. 14. **(a)** Time slice of TOC at 1823 ms. Areas A and B in blue and pink colors respectively are highlighting the zones of interest, with high values of TOC **(b)** Time slice of TOC at 1900 ms. Area A is highlighting the zone of interest **(c)** Time slice of TOC at 2100 ms. Areas A and C in blue and purple colors respectively are highlighting the zones of interest. The well locations are shown in green color. A red arrow is indicating the north direction. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

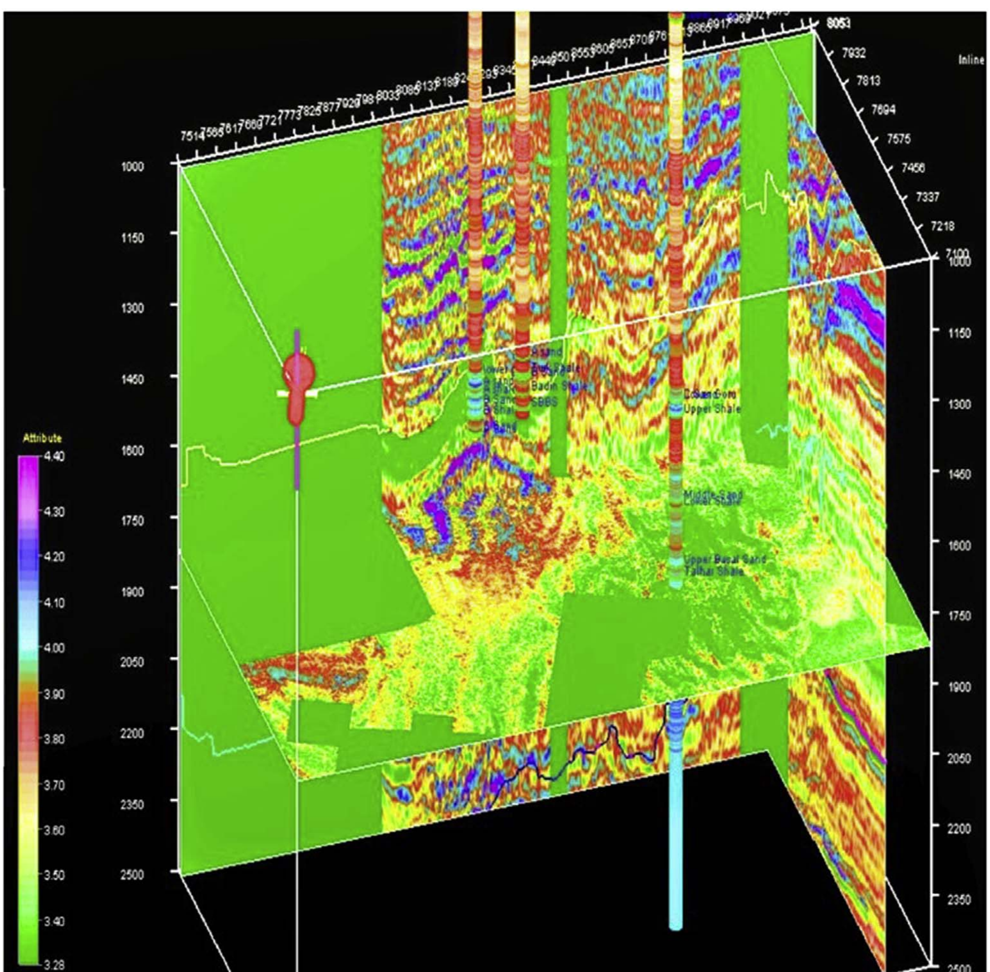


Fig. 15. A 3D view of the Total Organic Carbon content at 1823 ms, along with marked horizons and well locations (Chakri-01, Babu-01 and Zaur Deep-01). A red arrow is indicating the north direction. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

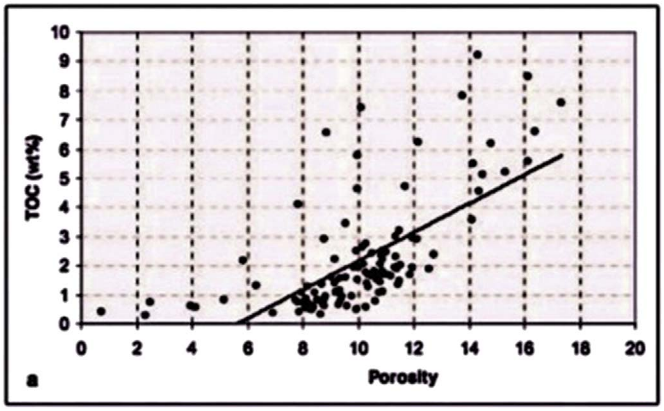


Fig. 16. Relationship between Total porosity and TOC content of the Talhar Shale. The TOC values are plotted on y-axis while porosity values on x-axis. As the value of porosity increases, TOC increases.

and type III kerogen (Machel et al., 1995). reported the effect of temperature and vitrinite reflectance on oil and gas, which indicates that Talhar Shale bears capability to produce oil and gas.

Seismic inversion is proved to be the best interpretation techniques for subsurface especially when the unconventional reservoir demands a quantification of the reservoir characteristics in terms of porosity and Total Organic Carbon content (Heidari and Torres-Verdín, 2014). For post-stack inversion the changes in amplitude and acoustic impedance are mainly derived by the changes in the reservoir properties such as porosity, mineralogy, Total Organic Carbon content and diagenesis, which are related to the impedance. During hydrocarbon exploration, these impedance driven variations are of significance as they help to identify reservoirs in areas that were previously overlooked. It is, in fact, on the basis of these advanced interpretation techniques that the exploration industry has moved from structure based reservoirs to more unconventional reservoirs such as tight sands and shale gas. Within the unconventional reservoir, seismic inversion facilitates to delineate areas where the reservoir has the greatest potential as well as how best to exploit it based on its petrophysical properties (Hu et al., 2015).

In this study, the primary focus was to estimate porosity and Total Organic Carbon content through seismic inversion. Porosity and TOC content are the most important properties that help to quantify the reservoir, in terms of its hydrocarbon potential. Porosity dictates the amount of space that may be available for the hydrocarbons to take up, and TOC determines how much organic material is available in the reservoir to be produced by advanced techniques. Hence, these two factors form the basis for the analysis of a formation to consider it for unconventional exploitation.

The total porosity maps derived from the impedance values of model-based inversion for this study showed favorable results of total porosity. For the porosity, it was found that a linear (negative) relation existed with the impedance values. The relationship derived for calculating total porosity value (Fig. 9) dictated that for lower values of impedance i.e. between 9800 and 10,200 Pa s/m^3, the porosity values lie between 7.5 and 13%. As described by (Smith et al., 1992) and (Ehsan et al., 2016), Talhar Shale has high potential to produce gas, which is verified by our study. The average porosity value of Talhar Shale in the study area is 11% (Ehsan et al., 2016). The average porosity value computed from impedance by authors come out to be 10.25%. In general if any formation has porosity value greater than 6% it is considered to be a reservoir. Therefore Talhar Shale has high potential to produce gas. These results could also be verified with the well logs of Zaur Deep-01, which is currently producing gas in Badin area. This region is demarcated as Area A on total porosity maps.

The TOC content maps derived from the impedance values of model-based inversion for this study showed excellent results. Fig. 13 displays a relation between TOC and impedance values with a significant non-linear decrease in the amplitude that is the direct result of increase in TOC. The relationship derived for calculating TOC from impedance value in Figs. 13 and 14 indicated that for lower values of impedance i.e. between 9800 and 10,200 Pa s/m, the value of TOC lie between 2.1 and 3.3%. This was confirmed from observations of the different time slices of total organic content models. Robison et al., 1999 and Ahmad, 1997 calculated the value of TOC of Lower Goru Formation as 2.35% by using core samples data. Ehsan et al., 2016 calculated the value of TOC by using well logs data of Talhar Shale as 2.83%. The average value of TOC calculated by authors using model based inversion is 2.7%, which indicate the validity of our study. The TOC values indicate that this formation has good to excellent hydrocarbon source potential.

The total porosity and TOC maps helped to identify areas where the porosity as well as total organic content values were sufficiently in the range for exploitation. On these basis, three areas have been identified. The first area identified as Area A with potential hydrocarbons having impedance values between 9800 and 10,200 Pa s/m, values of porosity between 7.5 and 13% and TOC values between 2.1 and 3.3%. However, for Area B the impedance values are 9800–10,500 Pa s/m, porosity values between 7 and 12.5% with total organic content ranging from 2.3 to 3.5%. Area C has porosity range from 7 to 11%, TOC content between 2.3 and 3.5%, and impedance values vary between 9800 and 10,500 Pa s/m.

4.3. Conclusions

Integrated analysis through seismic inversion and well logs data has successfully applied to estimate total organic carbon (TOC) content and total porosity in unconventional resource play within the Talhar Shale, Pakistan. It is evaluated that Talhar Shale has TOC range from 2.1 to 3.5 wt %. The average value of TOC evaluated using the model based inversion is 2.7%. The three potential zones are identified on the basis of low impedance values. The impedance values lie in the range of 9800–10,500 Pa s/m. The empirical relation between porosity and impedance at the well location has been used to extrapolate porosity over the complete acoustic impedance volume. The average porosity values computed from the impedance for these potential areas is 10.25%. These values indicates that Talhar Shale has ability of oil and gas production. The current findings and their correlation with parameters (porosity and TOC content) derived by various authors represent good to excellent conditions, which therefore also validates the authenticity of our study.

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