An integrated approach for fracture characterization of tight carbonates formation using conventional logs to determine the fracture porosity: A case study in Vindhyan Basin

Pradeep Singh Tomar[1], S. S. Khanna
[1]Email: tomar_pradeep@ongc.co.in, Oil and Natural Gas Corporation Limited

Abstract

Fracture characterization is quite challenging for geoscientists. Fractures play a major role in production from low primary porosity and permeability reservoirs which generally occurs in tight sandstone, carbonates and basement. Fractures improve the local connectivity of the reservoir and provide the pore space to increase the hydrocarbon production whereas; deep rooted fractures sometimes enhance the risk of early water breakthrough (Jian Yang, et al., 2011). In this study, an integrated approach was applied for fracture characterization and determination of fracture porosity using conventional log suite comprising gamma ray, caliper, resistivity, neutron, density and sonic logs. The total porosity, effective porosity, water saturation, volume of clay were estimated through multi-mineral log processing. These processed outputs were used to estimate the fracture attributes viz. secondary porosity index and fracture porosity.

Introduction

Identification of fractured zone is a key parameter for production from tight carbonate reservoirs. Fractures attribute i.e. secondary porosity index and fracture porosity were estimated from conventional logs and validated with the fractures attributes viz. fracture dip, aperture, density and porosity from micro resistivity borehole image log. The presence of fractures is characterized as open and partially open fractures which provide the path for hydrocarbon flow from the reservoir. Fractures can be either open or closed (filled with secondary mineralization) which acts as a barrier to fluid flow.

Formation micro imager log provides high contrast resistivity image which is quite capable of detecting a variety of geological features like bedding dip, fracture, fault and carbonate secondary porosity. The fractures (like open, partial and closed) were identified and classified from processed static and dynamic formation micro imager images and used to estimate the fracture dip, orientation, aperture, density and porosity. The presence of open and partially open fractures is able to contribute and increase hydrocarbon flow through connected network of fractures reservoir. The cross dipole acoustic log data was used to identify fractures interval through anisotropy and dispersion analysis which usually gives different response in factures reservoir. An integrated approach has been attempted to identify and characterize fractures reservoir from conventional logs and high-tech logs. The processed parameters from conventional log processing such as secondary porosity index and fracture porosity were depicting reasonable validation with the fracture attributes of processed results of borehole image. This case study was applied in tight carbonate reservoir of Rohtas Formation in Vindhyan Basin.

The present study is an attempt to identify fractures from conventional logs and micro resistivity image log. This technique is an attempt to identify fractures from conventional logs and validated with image logs. In addition, acoustic cross dipole tool is able to measure the dynamic elastic properties of the formation. This technique is applied in tight carbonate reservoir of Rohtas Formation of Son-Valley in Vindhyan Basin.The study area falls in Nohta-Damoh-Jabera (Fig.1) area situated in Son-Valley of Vindhyan Basin.

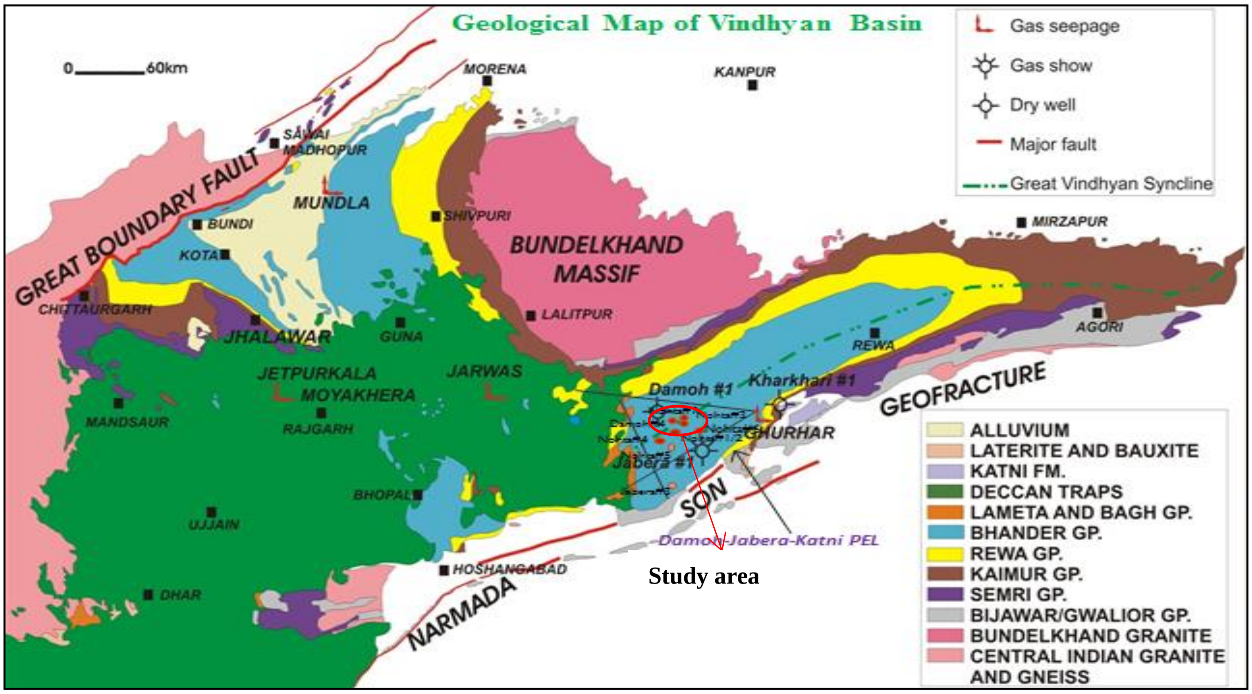

Fig.1: Study area; Nohta, Son-Valley, Vindhyan Basin

Discussion:

In Rohtas Formation, the majority of natural fractures identified from image log are partial in nature and few of them are open or closed fractures. Partial and closed fractures are recrystallized or filled by secondary mineralization. Partial fractures are extended up to two or three pads. These picked fractures are used for determination of fracture aperture, fracture density and fracture porosity.

Rohtas Formation is characterized by tight carbonate reservoir whereas, flow potential of the reservoir is mainly due to the fractures. The matrix primary porosity and permeability are very low in the whole reservoir. So, the orientation of fractures with respect to present day stress regime plays an important role in hydro-fracturing the reservoir.

A) Conventional Log Analysis:

The main objective of conventional log analysis is to determine the realistic water saturation and porosity through multimineral processing. However, in case of a fractured reservoir, it is difficult to estimate realistic porosity. In this study, the secondary porosity index and fracture porosity were determined using conventional logs (L. A. Lander, et al., 2015). Fig.2 shows the conventional log analysis with estimated fracture parameters. Elkewedy and Tiab developed a technique to estimate the important petrophysical parameters of naturally fractured reservoir. This technique is simple and based on derivation used in processed results of open hole logs such as total porosity, effective porosity, water saturation, volume of clay. Hence, we can apply this simple technique to evaluate the fractured reservoir where image log are not available.

- **Estimation of secondary porosity index (SPI)**

A secondary porosity index (SPI) is difference between the density neutron porosity (ϕ_{dn}) and sonic porosity (ϕ_s). This gives the porosity contributed by the fractures as (equation-1).

SPI= (ϕ_{dn} - ϕ_s) -(1)

- **Estimation of fracture porosity**

The estimation of fracture porosity (ϕ_f) is necessary to access the producibility of the formation.

$\phi_f = (\phi_t^{m+1} - \phi_t^{m}) / (\phi_t^{m}-1)$ -(2)

Where, (ϕ_t) is total porosity, cementation exponent m=2 has been used to estimate the fracture porosity.

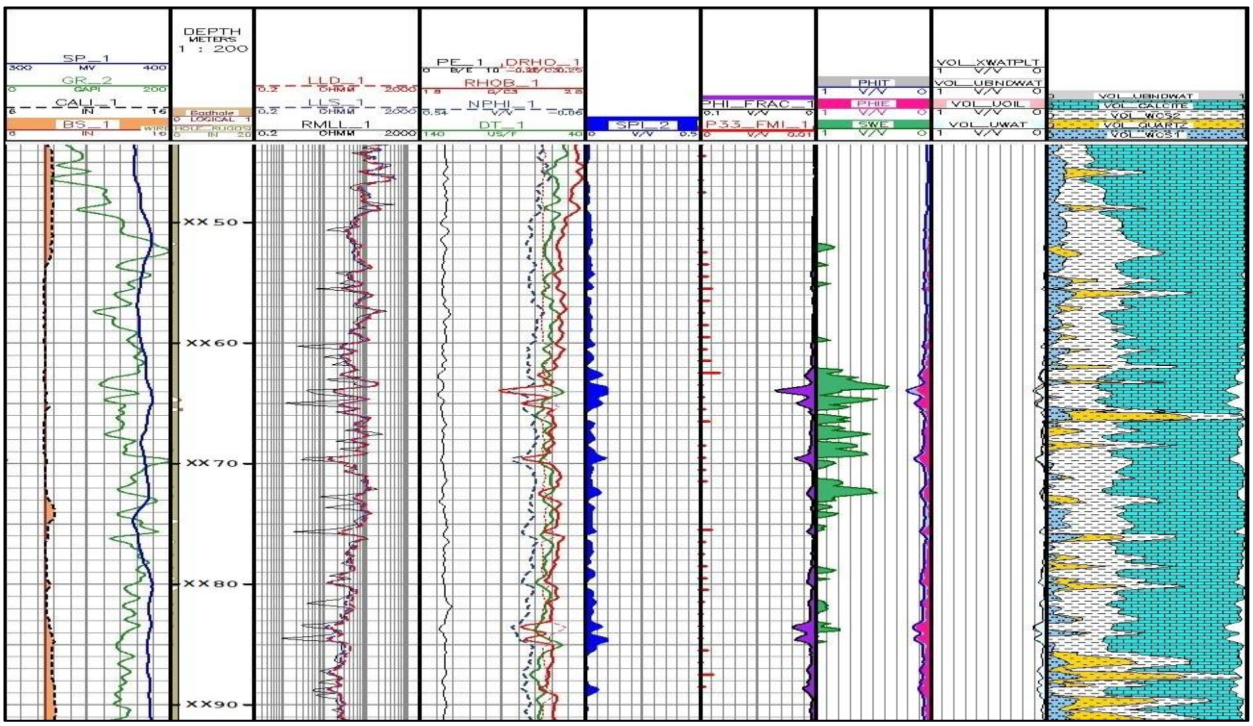

Fig.2: Well-X; Secondary porosity index and fracture porosity determination from conventional well logs

B) Fracture Analysis from Borehole Images:

Borehole imaging is an important logging technique to characterize the small geological features like fractures, formation bedding and structural features. The resistivity imaging tool gives the high resolution borehole images in 360º orientation. Through the resistivity contrast, the structural features like bedding planes, fractures planes and faults with their orientation can be identified.

In a carbonate reservoir, resistivity image log provides the final output in the form of fracture types, orientation, fracture aperture, fracture density and fracture porosity. Natural fractures can be classified as conductive (open fracture), resistive (closed fracture) and partially open fracture. Drilling induced fractures are developed on two sides in the borehole wall with 180º direction to each other which do not extend in to the formation while natural fractures extend beyond the borehole as a part of reservoir fractures network.

- **Estimation of fracture aperture**

A fracture aperture is the opening size of a fracture. It controls the permeability of the reservoir. Rohtas Formation is tight carbonate and low permeability reservoir where, permeability is controlled by fractures only. Luthi and Souhaite (1990) have developed an equation for estimation of fracture aperture from micro resistivity imager tool response. This equation has been used for estimation of fracture aperture in the present study.The relationship between fracture width and excess conductance due to the presence of the fracture is as follows.

$$W = cAR_m^b R_{xo}^{1-b}$$

Where,

W	fracture width /mm,	A	excess conductance
R_m	mud resistivity,	R_{xo}	formation resistivity
c,b	tool-specific constants derived from forward modelling		

$$A = \frac{1}{V_e}\int_{z_0}^{z_n}\{I_b(z) - I_{bm}\}dz$$

Where,

V_e	voltage difference across tool,	I_b	button current, fracture
I_{bm}	button current matrix,	z	vertical position
$0,n$	base, top		

It is observed that the calculated value of fracture aperture is found to be good in the Rohtas formation (Fig. 3).

- **Estimation of fracture density and porosity**

A fracture intensity classification has been developed by Dershowitz and Herda (1992) (Table-1). This defines fracture intensity based on dimensions of the sample (1D, 2D, 3D) and the dimension of measurement (feature counts per 1D, 2D area, 3D volume).

Dimension of sample	Dimension of measurement			
	0	1	2	3
1D	P10			
2D		P21		
3D			P32	P33
	Density	Intensity	Intensity	Porosity

Table-1: Fracture density, intensity and porosity classification

The commonly used dip feature counting based on classification for fracture modelling are P10, P21, P32 and P33 which are defined as:
P10- Fracture density (no. of fracture per unit length)
P21- Fracture length per unit borehole wall area
P32- Fracture area per unit borehole volume
P33- Fracture porosity (Fracture volume per unit borehole volume)

The fracture density and porosity determined from this method are near to realistic as the formation is tight and has low fracture porosity which has been confirmed from conventional log secondary porosity index and fracture porosity estimation (Fig. 3).

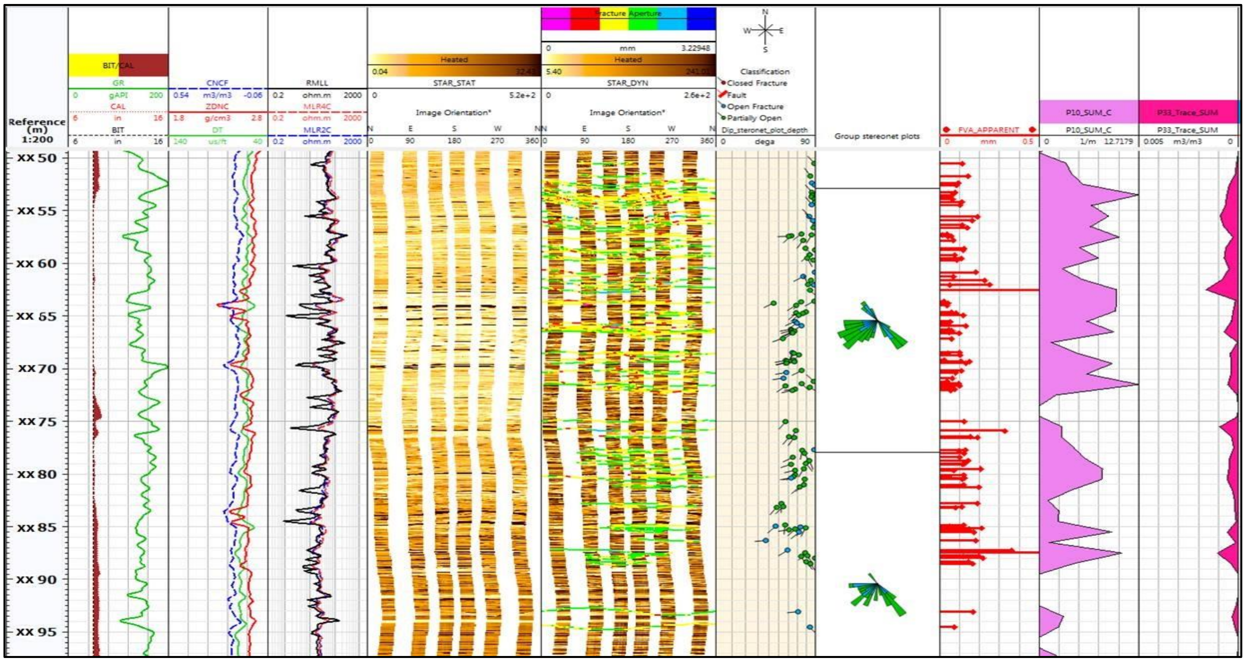

Fig.3: Well-X; Determination of fracture attributes; fracture aperture, fracture density and fracture porosity from borehole image log

The identified fractures were plotted in stereonet plot (Fig.4) to know their orientation. Plot shows two trends of fractures orientation whereas, majority fractures are aligned toward SW and few of them towards NW-SE. The polar plots are in stereographic projection and lying in upper hemisphere.

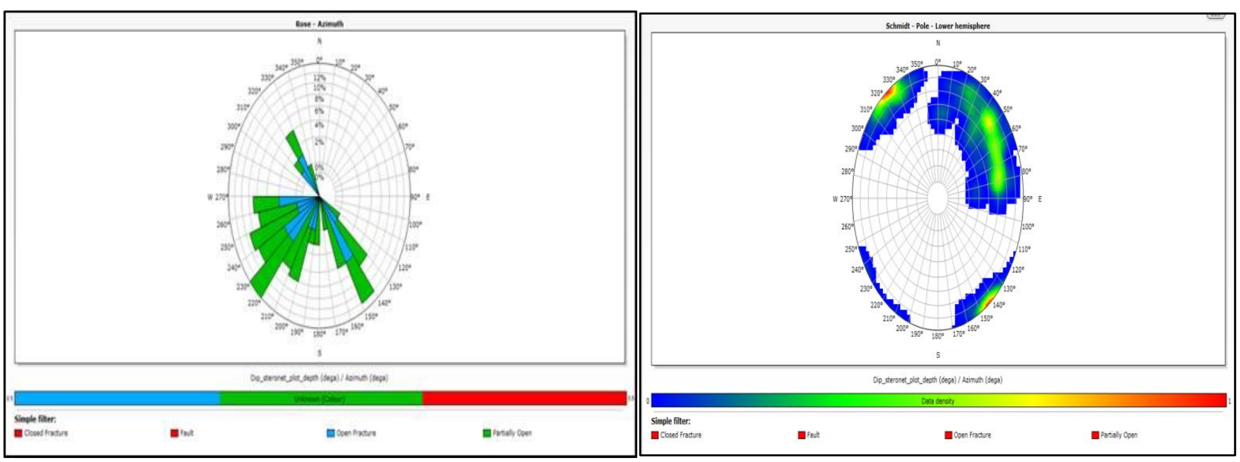

Fig.4: Well-X; Stereonet and Polar plots of fractures orientation

- **Acoustic analysis**

Acoustic cross dipole tool is able to measure the dynamic elastic properties compressional, shear and stonely around borehole wall. This has deeper depth of investigation as compared to image log. It measures the shear wave by transmitting and receiving flexural dispersive waves along the borehole. The tool has two set of cross dipole arranged in 90º facing to each other and it measures the formation shear slowness. This shear slowness is useful in recognizing fractures from the shear anisotropy and dispersion analysis. Sedimentary Formation has anisotropy due to the presence of fractures/shale bedding, near wellbore alteration and stress imbalance. Shmax direction can be measured from the fast shear azimuth.

- **Shear anisotropy and dispersion**

Formation anisotropy occurs in two orthogonal directions. Shear anisotropy is useful in characterizing the fractures through fast and slow shear wave characteristics. Magnitude of the anisotropy is the measured difference of fast and slow shear slowness in terms of time anisotropy (TIMANI), slowness anisotropy (SLOANI) and energy anisotropy in the forms of minimum energy (MINE) and maximum energy (MAXE).

A major anisotropy was observed in the processed log from TIMANI, SLOANI, and MINE, MAXE at a depth 1683m. The maximum horizontal stress (Shmax) direction estimated from fast shear azimuth is in the direction of NW-SE with an angle N100-130º (Fig.5).

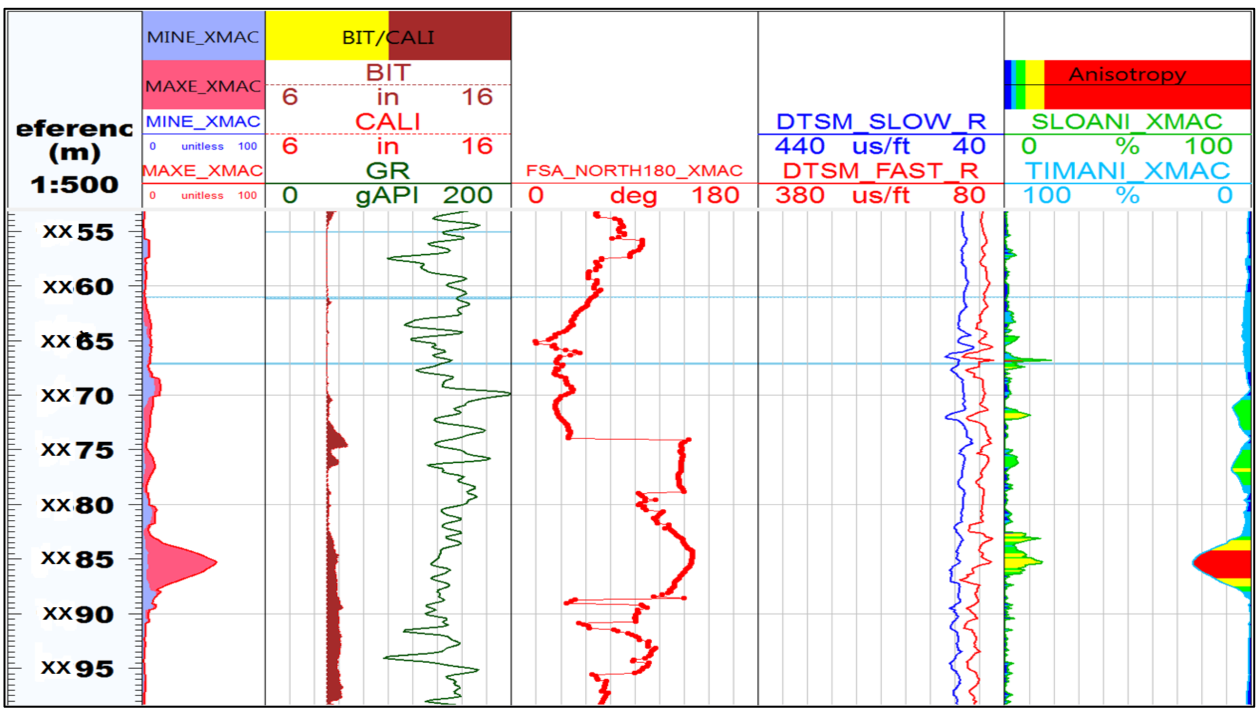

Fig.-5: Well-X; Anisotropy analysis of Time Anisotropy (TIMANI), Slowness Anisotropy (SLOANI) and Energy Anisotropy Min. Energy (MINE) and Max. Energy (MAXE)

The dispersion profile between the frequency and slowness of fast and shear waves give the information about anisotropy in the formation. Fast and slow shear slowness dispersion profile at depth XX57.05 m indicate the parallel nature of curves (inhomogeneous isotropic) Fig.6. On other hand, fast and slow shear slowness dispersion profile at depth XX82.95 m indicate split or cross over nature of curves (inhomogeneous anisotropic) Fig.7.

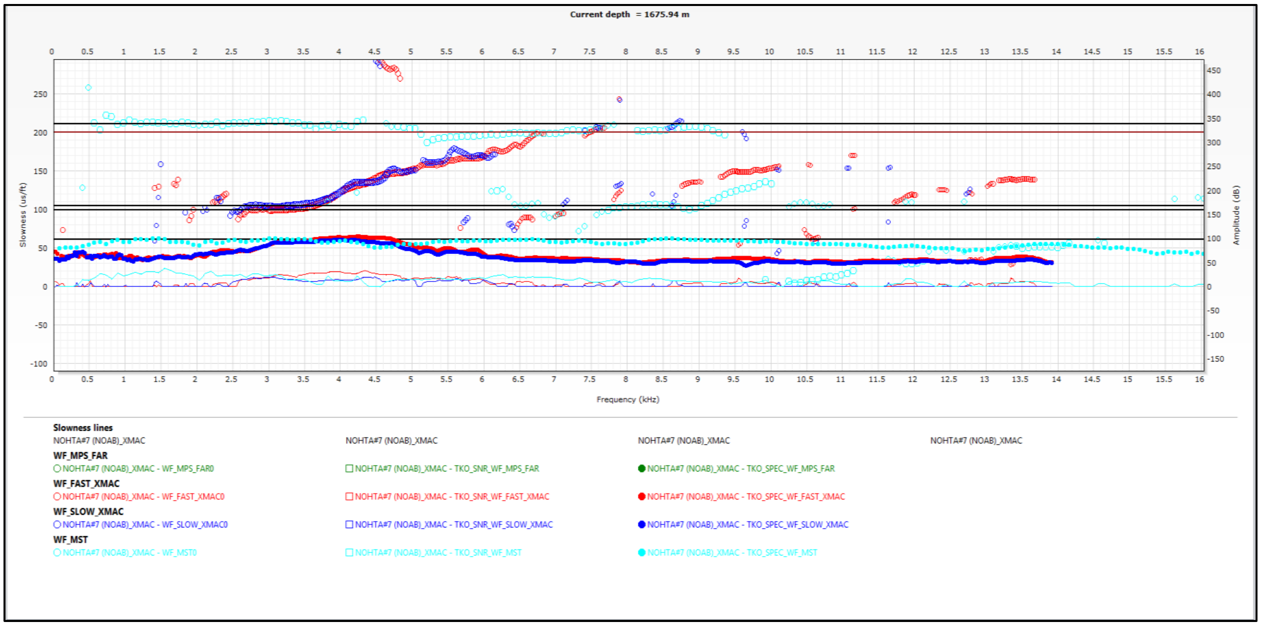

Fig.6: Well-X; Dispersion analysis at depth XX75.94 (Inhomogeneous isotropic)

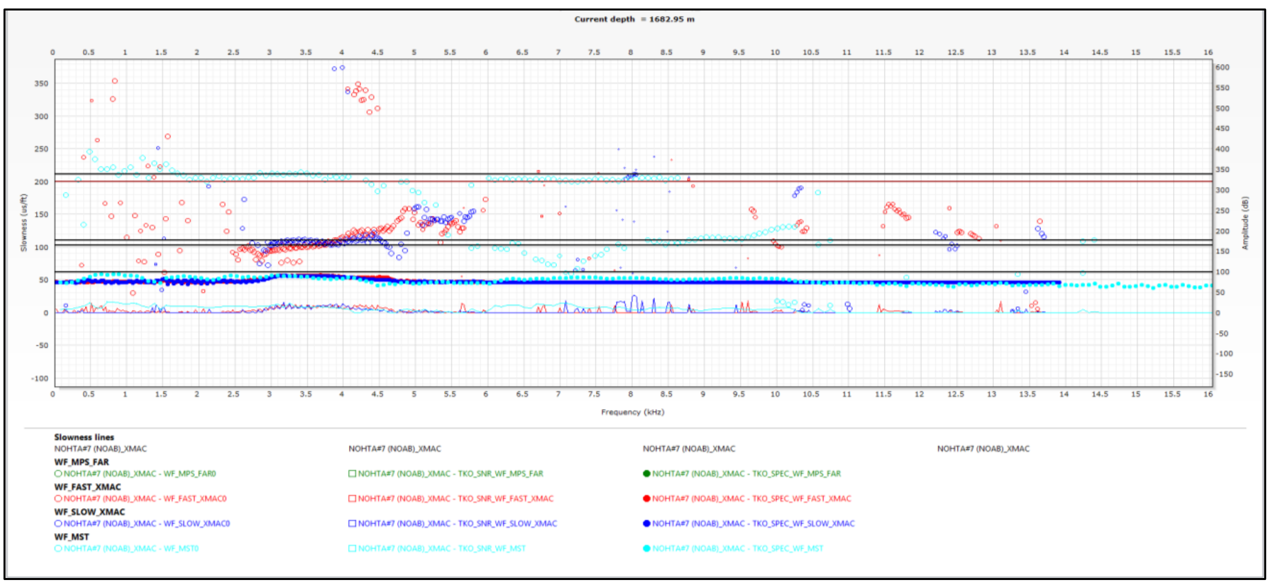

Fig.7: Well-X; Dispersion analysis at depth XX82.95 m (Inhomogeneous anisotropic)

Conclusions:

The study has successfully estimated the fracture porosity and secondary porosity index using conventional logs. The derived parameters have been validated with image logs and found to be in good agreement. This has helped in characterizing the tight carbonate reservoir of Rohtas Limestone of Vindhyan Basin. The study shows that fracture porosity and secondary porosity index estimated from conventional logs are in the range 0.01-0.03% and 0.05-0.1% respectively. The study further shows that the development of porosity in Rohtas Limestone is mainly the fractures. This methodology will be very useful in determining fracture porosity and secondary porosity index where image logs are not available.

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