PaperID **AU435**
Author **Aakanksha Bansal , ONGC , India**
Co-Authors **JP Dobhal**

Porosity Partitioning Using Image Log for Improved Carbonate Rock Physics Modelling & Seismic Reservoir Characterization - A Case Study of Western Offshore Basin, India

Abstract

Carbonate reservoirs are one of the biggest sources of hydrocarbon. Clearly, the evaluation of these reservoirs is important and critical. For rigorous reservoir characterization and performance prediction from geophysical measurements, the exact interpretation of geophysical response of different carbonate pore types is crucial. In this paper, Pore types partitioning which is the biggest challenge in carbonates has been done using Electrical Borehole images. Electrical borehole images provide both high resolution and azimuthal coverage to quantify the heterogeneous nature of the carbonate porosity. The technique involves the processing of image logs for generating porosity map around the borehole and subsequently used for evaluation of secondary porosity in carbonates. The outputs are further integrated with conventional log evaluated porosity and a very fair match between the two was observed. Hence wherever the image log is not available, conventional log computed porosity has been used. The pore geometry revealed by a FMI log fits well with the core information. The estimation of secondary porosity has reduced the uncertainty in rock physics model for predicting shear wave velocity. This technique has been applied for the Bassein formation in B-22 and SB-12 fields successfully. Using this approach, a very good match has been observed between the recorded and modelled logs. The lithology and fluids are clearly identifiable in VpVs and p-impedance cross plots. There is very good discrimination in type of fluid which has lead to improved seismic reservoir characterization. Quantification with type of porosities in carbonates enable us to give precise inputs to rock physics model and hence helps in achieving good results.

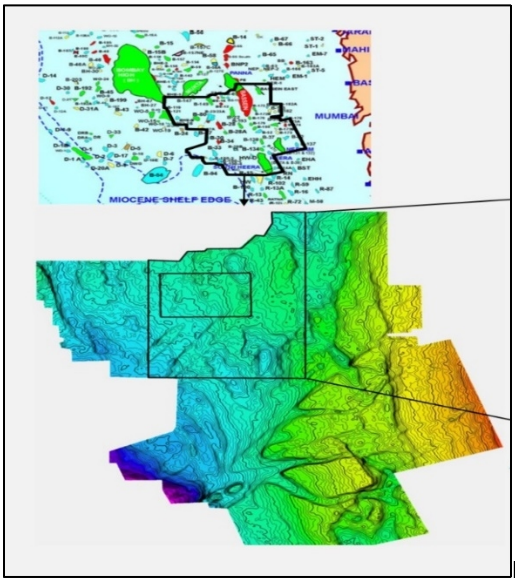
Introduction

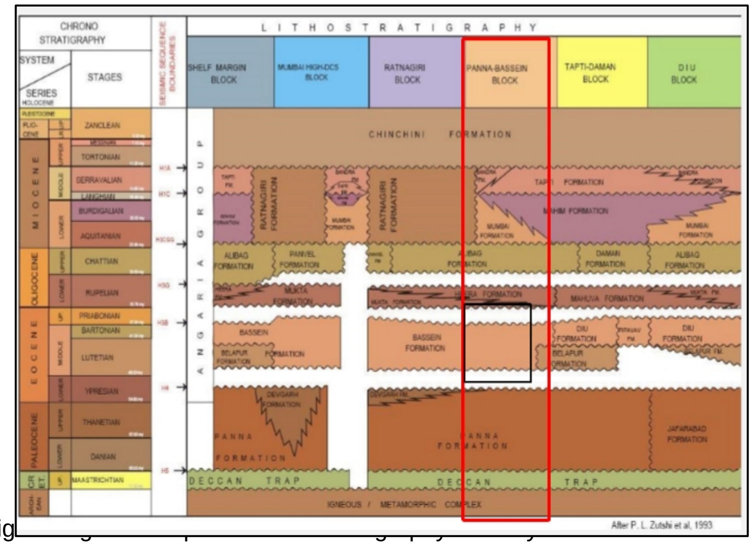
The characterization of carbonate reservoir rocks is extremely difficult due to their complex pore systems. The significant diagenesis process and complex depositional environment makes pore systems in carbonates far more complicated than in clastics. Therefore, it is difficult to establish rock physics model for carbonate rock type. Further, carbonates rock physics modeling has been done using Xu-Payne model, which is extension of the Xu-White model that is originally designed for clastic rocks, by accounting for a variety of pore types.

The study area falls in the Heera-Panna-Bassein sector bounded in the northernmost part by the BS structure, in South by B-193 field while in the west by BHE fault and to the east by Bassein field. The Heera- Panna-Bassein (HPB) sector is part of shelfal Horst Graben complex located to the East of Mumbai High. HPB sector is host to all the major oil and gas fields of the Mumbai Offshore Basin, other than Mumbai High Field.
The Bassein field is situated in the central part of the sector and was discovered in 1976. This giant gas bearing structure is N-S trending asymmetrical anticline with an areal extent of about 235 Km2 and has a 120 m closure at Bassein Pay level. The eastern side of the structure is bounded by Bassein East Fault whereas the western limb of the anticline has a gentle slope. The present study is focused only on the Bassein reservoirs. The Bassein formation of Middle to Late Eocene carbonates overlies the Panna formation unconformably. The Bassein formation are further divided into Upper, Middle and Lower Bassein based on the shale markers within the Bassein formation.
The Bassein Formation top is a major unconformity which has exposed the carbonates resulting in the generation of secondary porosity. In the entire study area the top 50m of Upper Bassein Formation is highly porous and it forms the main gas reservoir. The Middle Bassein is mostly tight with little porosity. Lower Bassein is porous. The porosity generation in the Lower Bassein is mostly because of the fractures observed on the crest of the structure as envisaged from the present study.

Carbonate rocks are well cemented, hence grain contact elasticity is not as important as compared to other parameters like mineralogical compositions and pore geometry (Brie et al., 1985).
Therefore, an effective medium model which takes into account pore-shape factor is required to estimate the elastic properties of the rock. In this study, RPM has been done in six wells in Bassein

formation out of which 2 wells have image data available in which pore types are characterized using POROSPECT analysis and traditional SPI (Secondary Porosity Index) method has been used in the remaining two wells.





Fig

Porosity Spectrum Analysis (POROSPECT)

Porosity Spectrum Analysis (PoroSpect) is a textural analysis technique that gives porosity distribution and vug fraction quantification from high-resolution electrical borehole images such as the Formation Micro-Imager (FMI).

The primary assumption for this technique is that the conductivity measurement from the electrical images is measured in the flushed zone of the borehole. After calibration with a shallow resistivity log, the conductivity images are transformed into a porosity map of the borehole using log porosity. The following equation is used to get such transformation (Akbar et al., 2000).

$$\varphi_i = \varphi_{log} [R_{LLS} * C_i]^{1/m}$$

Where Ci is conductivity of each image button, RLLS is external shallow flushed zone resistivity curve, φlog is external porosity curve, m is Archie cementation exponent and φi is derived porosity for each image button.

A histogram of porosities over a short depth window (typically 1.2") is computed. Different methods are then used to compute a threshold between the primary and secondary porosity.

(1) In the Newberry method (Newberry et al., 1996), the standard deviation of the porosity distribution is computed and a threshold is obtained by adding a multiple of this standard deviation to the median porosity.

(2) The SDR or Fixed-Percentage method locates the threshold at a fixed percentage above the mean porosity.

(3) The TSR Discriminant method (Ramakrishna et al., 2001) does not require any user input to define the threshold. It involves decomposing a distribution using linear discriminant analysis (LDA). This method works by grouping the data into classes by minimizing within-class scatter and maximizing between-class scatter so that within a group data are "similar" while between groups they are "different". Simply stated, if the porosity data consists of two populations, then the best threshold should maximally separate the two means.

(4) The Gaussian Extraction Optimization-based method (Goswami et al., 2006) involves multimodal decomposition of a composite distribution, in this case applied to the porosity distribution. The porosity distribution can considered as a superposition of several distributions, each corresponding to some type of pore configuration. The method selects one of the identified Gaussian distributions, classifies it as secondary porosity and computes secondary porosity by integrating the distribution.

(5) The manual method which allows user to manually set a fixed threshold per zone.

The best threshold should separate the primary and secondary porosity.

In this paper, the TSR method is used to locate cut-off separating primary and secondary porosity.
Hence Wells with FMI data available,
Vuggy porosity is estimated from PoroSpect.
Crack porosity: 1 % of PHIE (As FMI data supports & was helpful in finding good match with recorded logs).
Therefore IP(Interparticle) =PHIE- (Vug + crack)
Hence all types of porosities are determined.

In wells where FMI log is not recorded, traditional SPI (Secondary Porosity Index) method applied after calibration with PoroSpect.

Well A (Bassein Formation)

Secondary porosity from POROSPECT

Secondary porosity from Conventional Log (SPI)

Fig.2: Match of secondary porosity computed from PoroSpect vs secondary porosity from SPI method with FMI processed output on the left side

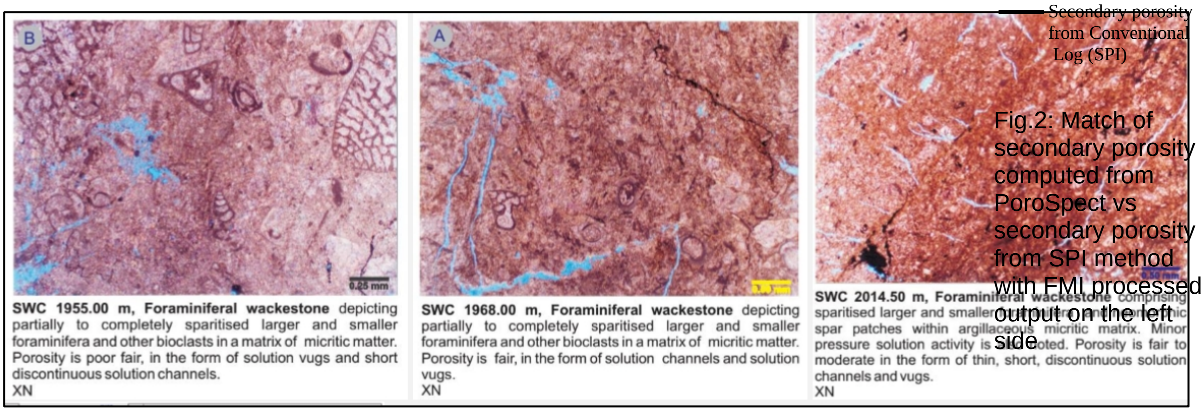


Fig.3: Secondary Porosity observed in Well A validating porosity evaluated from POROSPECT

Petrophysical Analysis

The most important part of establishing the consistent rock physics model is evaluating the correct and consistent petrophysical properties. The petrophysical properties, Volume of clay, total and effective porosities, saturation are estimated using STATMIN module of Jason Powerlog software. Ƶ - plot of Neutron-Density with GR on Ƶ - axis is generated to identify the constituting minerals within Bassein formation (Fig.4). The Ƶ – plot indicates dominant lithology as Limestone alongwith Dolomite and minor Clay. Pyrite and Dolomite have also been reported in core data (Ref.2). Therefore based on these z-plots along with the reported core, side wall core and cutting data: Calcite, Dolomite, Pyrite and clay has been incorporated into petrophysical model and used for the processing of log data. Oil, Gas and Water have been taken into the model as fluid volumes.

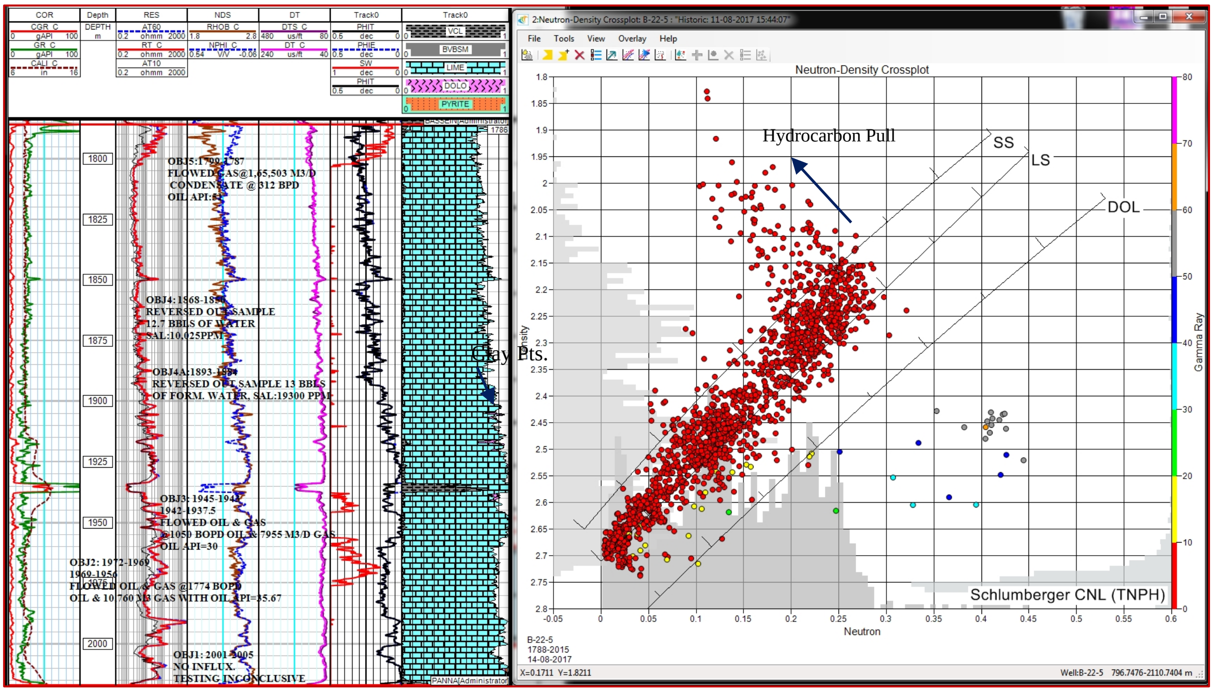


Fig:-4: RHOB-NPHI Z-plot for Bassein Formation with Petrophysical output on the left side(Well A)

The petrophysical parameters for Bassein processing were taken as a = 1, m = 2 and n= 2. The processed results were integrated with core/cutting, production testing and other geological inputs. Indonesian equation is used for estimation of water saturation (Sw). Fig-4 shows the petrophysical output of a well-A.

Rock Physics

Rock Physics describes a reservoir rock by physical properties such as porosity, rigidity, compressibility; properties that will affect how seismic waves physically travel through the rocks. Rock Physics use information provided by the Petrophysicist, such as shale volume, saturation levels, and porosity in establishing relations between rock properties or in performing fluid substitution analyses. The work flow diagram of RPM integrating petrophysics with rock physics is given in Fig 5.

For Carbonate rock physics model, Volume fraction of different pore types are estimated using POROSPCT Analysis.

After integrating petrophysics and rock physics Xu-Payne model indulging pore types evaluated from POROSPECT, the effect of lithology, porosity and fluids are improved (Fig. 8). The estimation of different pore types has reduced the uncertainty in rock physics model for predicting shear wave velocity. The crossplot of P-impedance modeled and Vp/Vs modeled with litho fluid colour on Z-Axis is able to differentiate reservoir with fluids and the non-reservoir. Also, very good quality 1D correlation have been found between model and raw data for density, compressional velocity and shear velocity(Fig. 8).The correlation coefficient is more than 75% in general for shear velocity whereas it is very high for density (more than 90%) and for compressional velocity(more than 85%) as in Fig.9. Typical crossplot of 4 wells discriminating Gas, Oil, Water, Shale is shown in Fig.7.

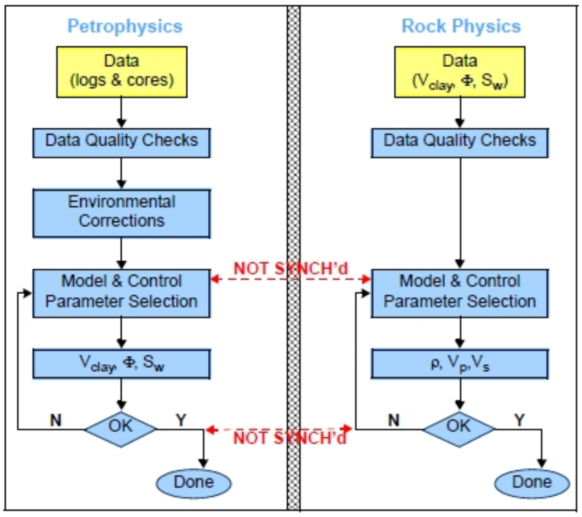


Fig.5: Integrated workflow of petrophysics and rockphysics

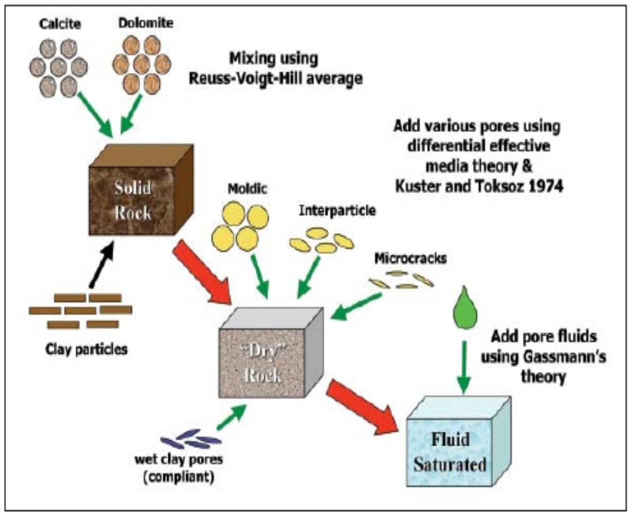
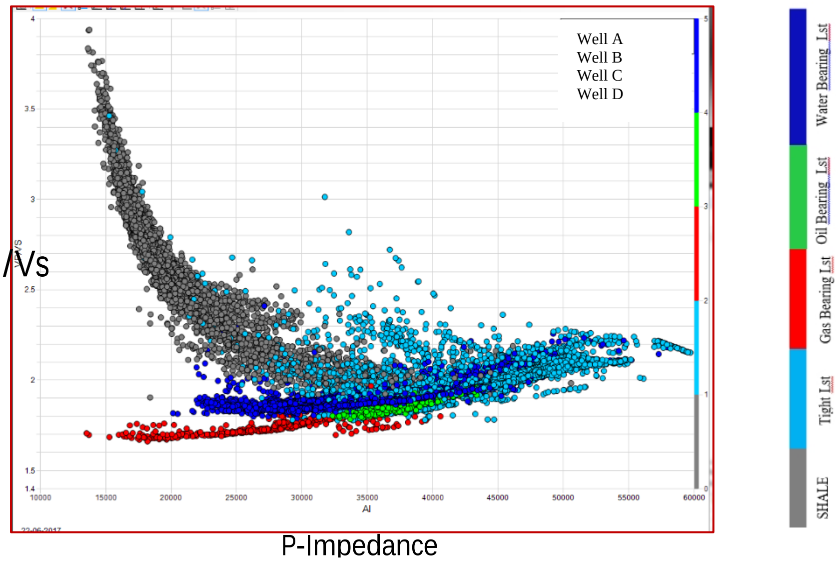


Fig.6: Development of Carbonate rock physics model

Fig.7: Modelled Vp/Vs versus AI Xplot of 4 wells discriminating fluids & lithology.



Conclusions

We have demonstrated that rock physics modelling based on pore characterization from porosity spectrum analysis integrated with traditional porosity method and core data is efficient for elastic properties prediction on carbonate rock. We use the rock physics modelling approach that takes into account different pore types reducing uncertainty in the prediction of compressional and shear velocities leads to improved seismic reservoir characterization. Building of a Robust Petrophysical model gives more realistic and consistent elastic logs. The lithology and fluids are identifiable in VpVs and p-impedance cross plots. With the help of integrated Petrophysics –Rockphysics approach, the generated modelled elastic logs have helped in finding out sweet spots from hydrocarbon point of view by using prestack seismic inversion study.

Acknowledgement

The authors are indebted to Shri A. Bhardwaj, ED-HOI-GEOPIC, Dehradun, India for providing the technical input and guidance for writing this paper. Thanks are due to Shri Dhruvendra Singh, Head-INTEG, GEOPIC, Dehradun, India for providing all kind of support for this work. We thank ONGC management for allowing us to submit this paper in GEOINDIA 2018.
The views expressed in this paper are solely of the authors and do not necessarily reflect the view of ONGC.

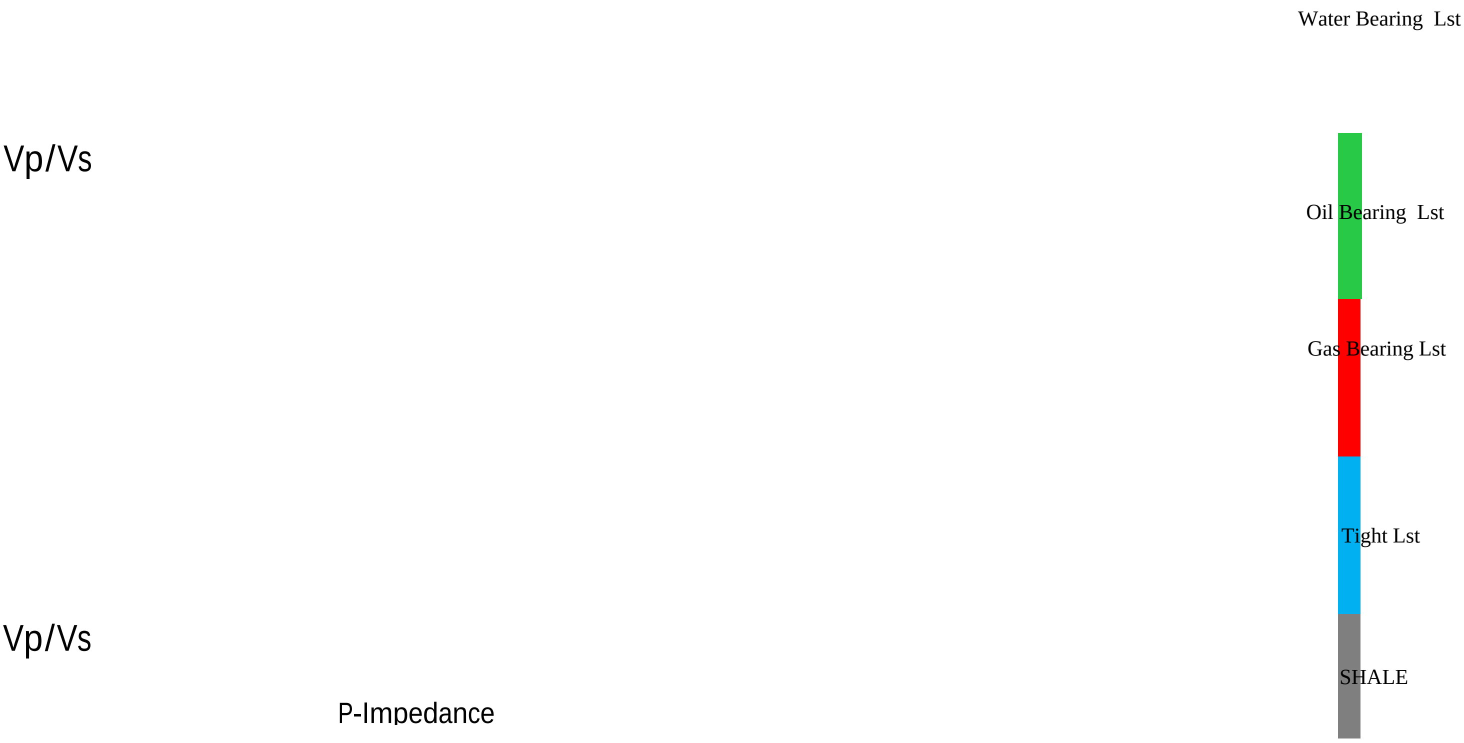


Fig.8: Vp/Vs versus AI Xplot of raw and model data with processed output & 1D match of Vp, Vs, Rhob in the right

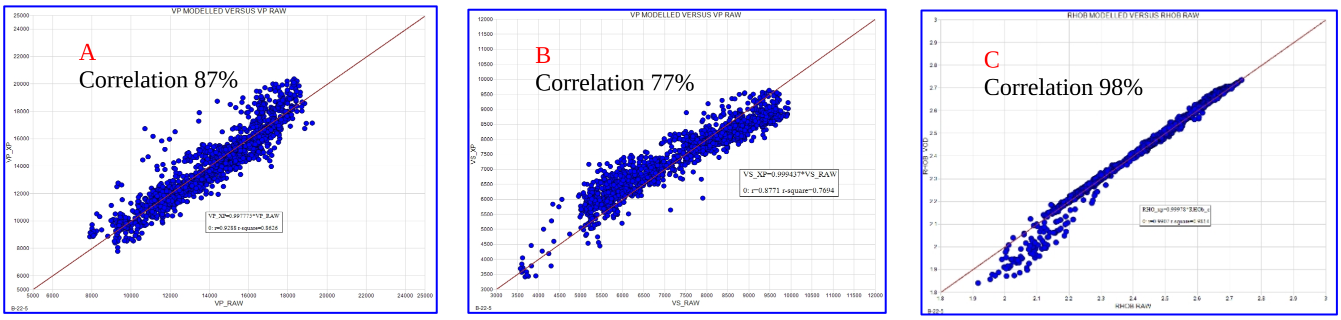


Fig.9: A. Vp recorded vs Vp Modelled, B. Vs recorded vs Vs Modelled C. RHOB recorded vs RHOB

References

1. Xu, S., and Payne, M.A.,Modelling Elastic Properties in Carbonate rocks: The Leading Edge, 66-74, 2009
2. Micro facies Analysis, Diagenetic History, Reservoir Characterization and relationship with Fluid Transmissibility of Bassein Formation Bassein and adjoining areas. Unpublished report by RGL, Mumbai, March 2004
3. Mavko, G., Mukerji ,T. and Dvorkin, J., The rock physics handbook: tools for seismic analysis in porous
4. Newberry, B.M., L.M. Grace, and D.D. Stief, 1996, Analysis of carbonate dual porosity systems from borehole electrical images: SPE 35158 presented at the Permian Basin Oil and Gas Recovery conference, March 27-29, 1996.
5. Ramakrishnan, T.S., R. Ramamoorthy, E. Fordham, L. Schwartz, M. Herron, N. Saito, and A. Rabaute, 2001, A Model-Based Interpretation Methodology for Evaluating Carbonate Reservoirs: SPE Annual Technical Conference and Exhibition, 30 September-3 October, New Orleans, Louisiana, SPE-71704-MS. doi.org/10.2118/71704-MS