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The role of seismic modeling in Reservoir characterization: A case study from Crestal part of South Mumbai High field

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Summary

The objective of the modeling was to determine if water /oil bearing carbonate could be distinguished from gas filled carbonate rock and what critical oil/ water/ gas saturation was able to change the seismic response before making plan for 4D seismic. Pore space and thickness replacement modeling was carried out to understand the necessity of high resolution survey for better and refined reservoir modeling.

The methodology for the seismic modeling includes a fluid replacement modeling using Biot- Gassmann equation, AVO modeling using Zoeppritz equation, porosity modeling using Gassmann equation and thickness effect modeling using wedge out model. Seismic models can be generated either from synthetic gathers using well data or seismic survey acquired CDP gathers or using both side by side. But in the present case, well data has been taken for generation of synthetic offset gathers, fluid replacement analysis, porosity modeling and thickness (tuning effect) modeling with variation of offset from 0 to 2500m, saturation from 0% to 100% porosity from 0 to 50% and thickness from 0 to 125 meters.

Many more models could be made with various wavelets at varying frequencies to narrow down the uncertainty. In the present case the wavelet has been extracted from current 3-D seismic data for modeling purpose so that the analysis based on well data could be closure to real seismic.

Introduction

The seismic horizons were tracked in normal interpretation after data conditioning and well to seismic tie up process of the area around crestal part of South Mumbai High Field (Figure 1). Well to seismic correlation was found above 80% for the fulfillment of the criteria for seismic modeling. Fluid Replacement modeling (FRM) requires P and S wave and density for modeling using Biot-Gassmann equation. In the present case, S wave, VP/VS and Poisson's ratio are not available. It was calculated from empirical formulas using Castagna's equation before model building. During the modeling the modulus and density of matrix and fluid can be changed based on prior knowledge. But in present case default value based on well data were taken.

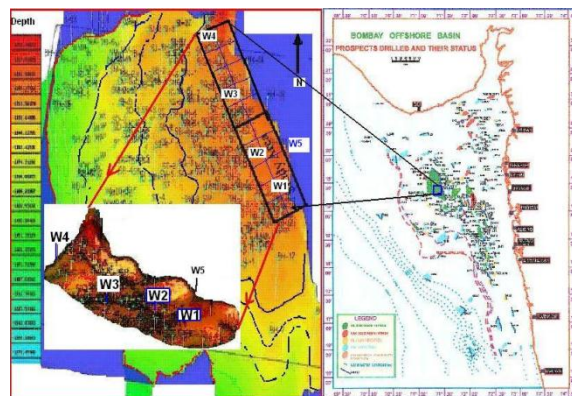


Figure 1: Location map of Study area with reference to Western Offshore Basin

The geometric parameters used in synthetic modeling were taken from the 3-D seismic data to model the synthetics gathers for the cases of gas, oil and brine fluid filling the rock pore space. The modeling was focused in the depth interval from 1270 to 1350 meters containing the LIII



layers. For the reservoir rock matrix, carbonate rock was taken as default.

Substitution of sandstone in place of carbonate rock is able to show a distinguished change in seismic. But in the present case carbonate rock has been taken for the reservoir matrix.

Evaluation of Well logs

In this process of modeling we started with evaluation of well logs for petrophysical properties, combining the

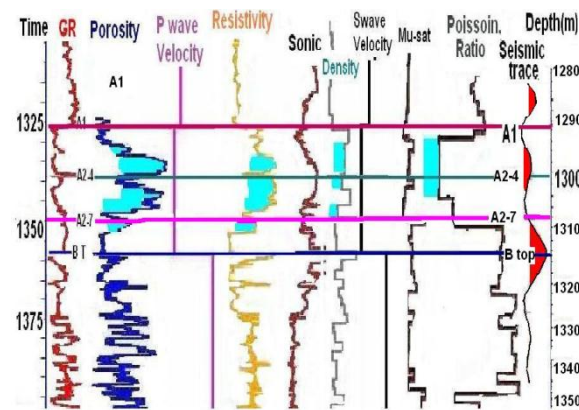


Figure 2: Well curves model of Well W2 shown with well picks, used for seismic modeling

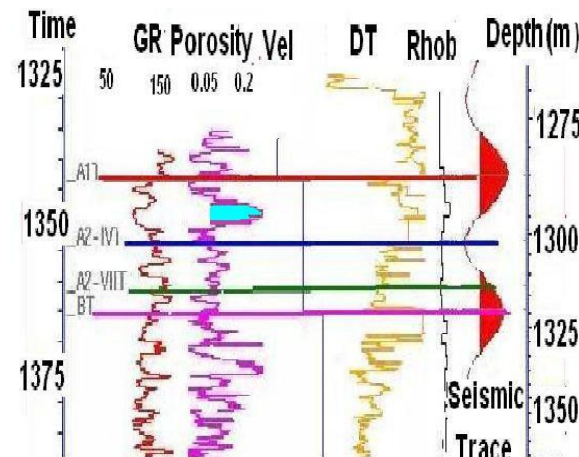


Figure 3: Well curves model of Well W1 shown with well pick used for seismic modeling. Note that velocity contrast at A1 and B top matches with seismic peak

Gamma Ray, resistivity logs and density logs with computed porosity log, S wave velocity, Poisson's ratio etc.

to determine reservoir zone with considerable hydrocarbon saturation as shown in figure 2 for well W2 and figure 3 for well W1. Three zones are very clearly observed in the logs. With the limited resolution of seismic, the study was confined for A1 to A2-4, A2-4 to A2-7 and A2-7 to B top only. Well W2 has good porous zone from 1295 to 13220 m (A2-2 to A2-7) and resolved with seismic whereas well W1 has thin porous layer from 1290 to 1295m (only in A2-2) and not resolved with seismic

Frequency modeling

In the first attempt of modeling, frequency modeling was carried out to evaluate the requirement of high resolution seismic survey. Figure 4 indicate the test performed for the

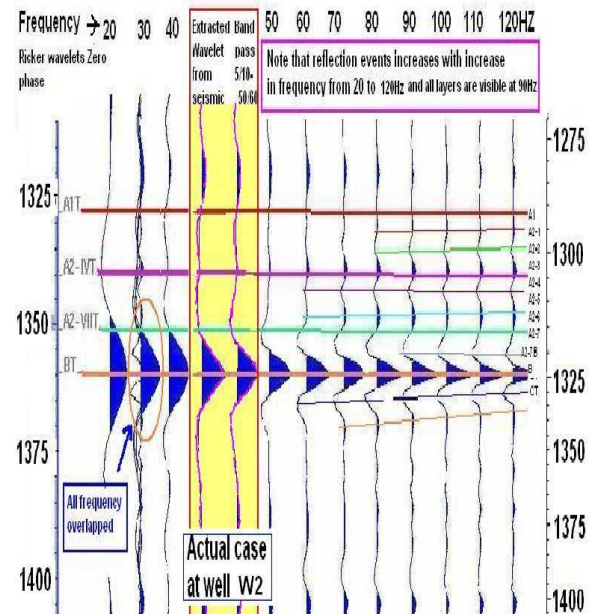


Figure 4: Frequency model to analyze the effect of frequency on seismic response and to decide the wavelet for Seismic modeling. Notice that a single peak is resolved in two trough and peak with higher frequency as shown by circle

selection of suitable frequency for modeling. A band of Ricker wavelets of zero phases from 20 Hz to 120Hz was tested on L3 layers to test the efficiency of frequency to seismic resolution at well W2. It was observed that extracted wavelet is equivalent to 40/50Hz frequency and band pass filter of 5/10-50/60 Hz with operator length of 200 milli seconds as shown in yellow color box. The frequency range of 40-50Hz is able to generate the seismic



signature closed to A1, A2-4, A2-7 and B layer top. For identifying the other layer within L3, frequency band of 90 Hz and above is required for high resolution survey and plan can be made accordingly.

AVO Analysis for offset model

AVO analysis was carried out at LIII reservoir using Zoeppritz equation to examine the response of offset on seismic amplitude and identification of AVO class near gas well W2 and well W1. The equation uses the layer rock properties (P wave, S wave and density) to model transmitted and reflected wave at a surface. In the present case only reflected wave from A1 top (L3 top) has been taken for analysis considering the geometrical spreading and transmission loss for modeling.

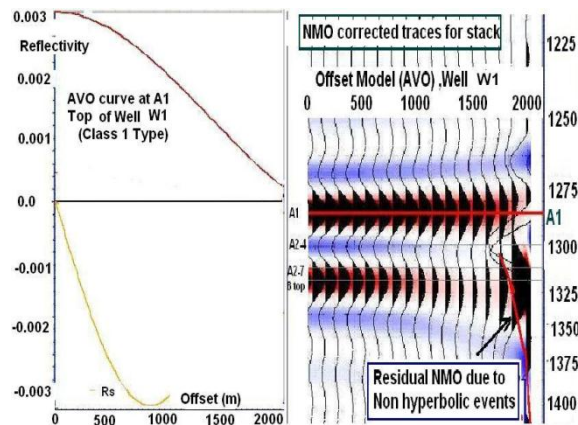


Figure 5: AVO curve and offset response for well W1 showing the response of seismic reflectivity based on offset variations. Curve is response of A1 top (L3 top)

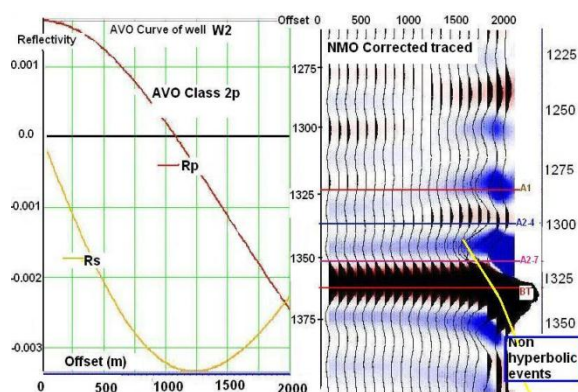


Figure 6: AVO curve and offset response for well W2 showing the response of seismic reflectivity based on offset variations. Curve is response of A1 top (L3 top)

The cross plot of offset versus reflectivity (figure 5) shows the character of AVO response at well W1 is of Class 1. In the first segment of offset from 0 to 2000mts reflectivity is +ive and decreases from 0.003 to 0.0. The seismic response after the offset of 2000m becomes non hyperbolic as observed in figure and it may spoil the data during stacking of seismic traces. But the response of S wave reflectivity is -ive. AVO anomaly of class 1 is rare case and occurs due to high impedance carbonate / sandstones surrounded by shale.

For the case of A2-4 top in W1, the amplitude at nearest offset is -ive and changes to +ive with offset increase (AVO class 4). Lithology plays an important role in AVO response in addition to pore fluid. If we replace the carbonate rock with sandstone, the AVO response will be changed.

AVO response at well W2 is of class 2P. Its range from 0.002 to 0 in first segment of offset from 0 to 1000m and then changes in -ive from 1000mt to 2000mts as shown in figure 6. The NMO corrected synthetic gather are also shown side by side. Non hyperbolic events at far offset may spoil the summed or stacked traces. The AVO class vary from one well to other depending on porosity and fluid contents.

Even in same well different layer may have different class of AVO anomaly. In the present case we have taken only the top of A1 (top of L3 reservoir). The summation of full offset stacking makes the response as very weak. Even the stacking of first segment also makes the signal poorer. Class 2 and 2P anomaly occurs due to very low impedance between carbonate/sandstone and shale. This situation happens only when high porous carbonate is filled with gas as in the case of well W2. Ross and Kinman (1995) suggest for using far trace range stack as final stack for suspected class 2 anomaly. Also, they suggested creating different stack between far and near offset for class 2P.

AVO Analysis of reservoir rock of Mumbai high indicates the full stack of traces have spoiled seismic events and the resultant trace or stacked trace became very poor in processed seismic data which may not distinguish oil and water as in the case of class III AVO anomaly in gas sands. But in contrast, the S wave response is -ive and increases with offset from 0 to 1000 mts and remains -ive throughout the offset. AVO analysis with 4-C 3D seismic data may be more useful in future.



Fluid Replacement modeling (FRM)

Shallow reservoirs with good porous zone and light oil or gas contribute for easy fluid discrimination. In the present case, carbonate rock is shallow and filled with gas. Therefore an attempt was done to carryout the fluid replacement modeling to evaluate the effect of gas and oil saturations on seismic. This process allow us to create a zero offset synthetic for a selected well modeling with the effect of change in either fluid (oil, gas and water) type and its saturation or log response. In the present case, three synthetic gathers corresponding to gas, oil and brine saturated cases are modeled for well W 1 and W 2. The variation in amplitude with fluid type and its saturation is difficult to distinguish from visual inspection. Therefore gradational color of blue for trough and red/black color for peak is used. Color increases the visual dynamic range of seismic data. We cannot interpret the subsurface details that do not show color distinction.

FRM model AT Well W 2

Seismic response changes with change of gas saturation from 100 to 20 % and oil saturation from 100% to 50% due to significant thickness of porous layer within reservoir layer from A1 to B top.. There is significant change in seismic amplitude response for saturation for all the cases with existing frequency of 40/50 Hz as shown in figure 7 .The time delay is observed with increase in saturation of gas and oil .A time shift of 8 ms (8-10mt) is observed in case of oil for change of saturation from 100 to 0% with change in amplitude or reflection strength. But there is negligible time shift in case of gas at L3 top with significant change in amplitude. A sharp time shift of the order of 5 ms (6-8mt) is observed after a saturation change from 30% to 0% at A2-4 and A2-7 level in the case of gas. It indicates that it is very difficult to distinguish the commercial and non commercial gas pool having gas saturation less than 30% from gas saturated economical reservoir with the existing seismic data.

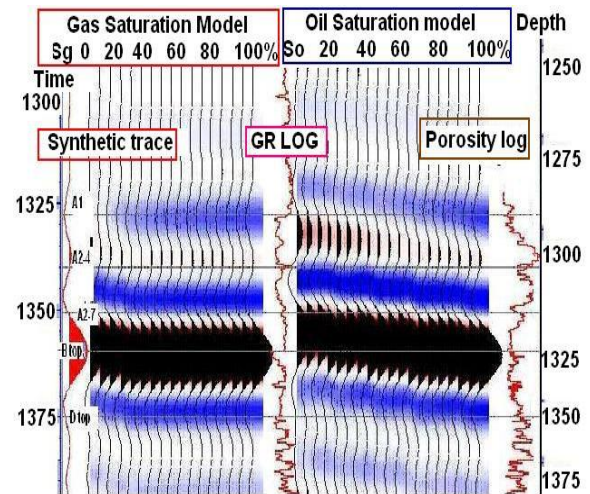


Figure 7 : Fluid substitution for well W2 showing the effect of fluid type and its saturation effects on seismic response

FRM model at well W 1

There is no visual change in seismic response from 100 % to 5% in case of gas, oil and water due to low porosity and poor reservoir rock as shown in figure 8 in comparison to Well W

1 . But the lower layers as B top to A2-7 shows variations in case of oil saturation model. Due to limited thickness of porous layer, the oil saturation model does not show any difference from gas saturation model. Only with high resolution seismic survey we can expect some improvement in the result and observe the effect of fluid saturation on seismic.

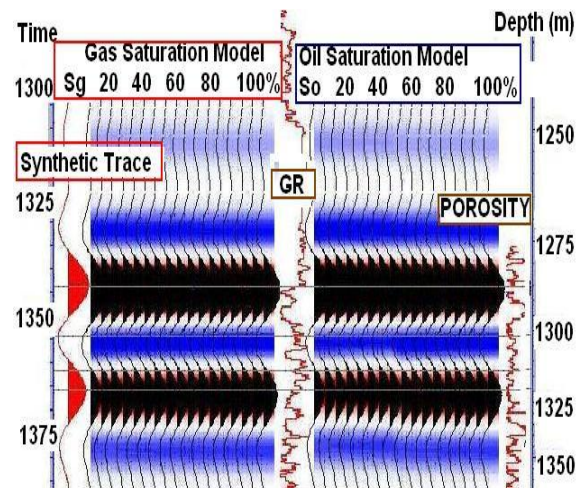


Figure 8: Fluid substitution for well W1 showing the effect of fluid type and its saturation effects on seismic response



All the two case of fluid do not show either time shift in seismic event or in reflection strength visually.

Gassmann Porosity modeling

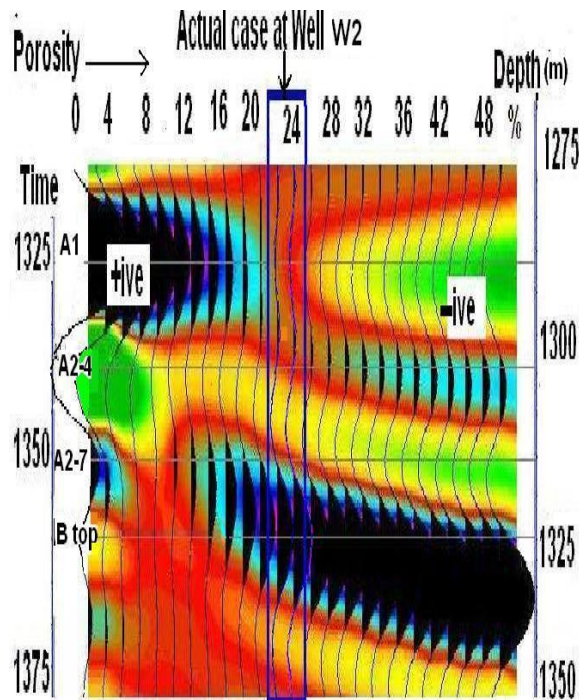


Figure 9: Porosity replacement model for well W2 showing effect of porosity variation on seismic

Porosity modeling was carried out for the analysis of porosity variations from 0% to 50 % on seismic amplitude. Taking the base case of porosity as 22-24% for well W2 for layer A1 to B top, the variation of porosity to the higher side from 24% to 50% and lower side from 22% to 0% can be felt on seismic amplitude. The porosity change affects the velocity and density factors of bulk rock (carbonate). In the present case lithology is kept constant as carbonate reservoir rock. Therefore Acoustic impedance (velocity*density) is primarily affected by change in porosity.

From this porosity modeling, it can be inferred that porosity variations play major role in creating strong peak or trough and hence play important role in the data quality rather than data acquisition and processing.

It can be clearly observed that seismic response at A1 top is +ive at the imaginary porosity of 0% within L3 layer

and decreases with increase in porosity upto around 26% then polarity change starts and get total reversal at 50% porosity as shown in figure 9. Pore pressure and overburden pressure is negligible in the present case. Therefore it has not been taken into account. Due to decrease in velocity with increase in porosity, a time thickness will also be observed in time domain seismic data.

Thickness replacement modeling (Wedge out model)

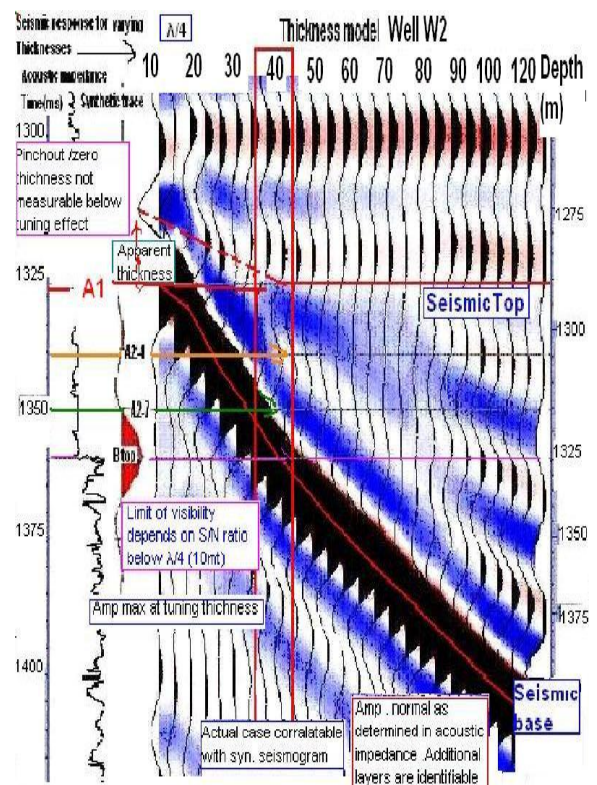


Figure 10: Reflections from top (A1 top) and bottom (B top) of wedge model showing pinch out effect and thickness variations effect on seismic events at well W2

The forward modeling technique called incremental pay thickness (IPT) modeling is used to establish the relationship between pay thickness versus seismic amplitude and seismic time thickness. As detailed by Neff (1990), this modeling approach allow analysis of gross interval thickness Figure 10 illustrate the key detail of modeling. The original input model values are shale volume (GR log), porosity, sonic and density log as shown in figure 2.



The thickness between A1 top and B top is taken as 35-40 meter as base case marked with red color rectangle. Now we have to analyze the effect of thickness variations on seismic response with the existing dominant frequency as 40-50Hz for L3 layer. With this frequency well picks A 1 top (L3 top) is correlated with trough and B top is correlated with peak with intermediate layers A2-4 and A2-7. Seismic events measure the apparent thickness and A top and B top are separated from each other even if the thickness decreases to zero. It is difficult to measure true thickness as it is beyond tuning thickness. But both of the events are separated at 10 mts which is called limit of tuning thickness or separability of layers and at this limit, amplitudes are maximum. All the 8 layers from A1 to B top could have been separated in term of peak and trough with thickness of A1 to B top as 125 mts with the existing frequency of 40-50Hz at reservoir level. Otherwise high resolution seismic with dominant frequency above 90 Hz is required to resolve all the layers of L3 as analyzed in frequency modeling in figure 4.

Physical modeling (density and velocity modeling)

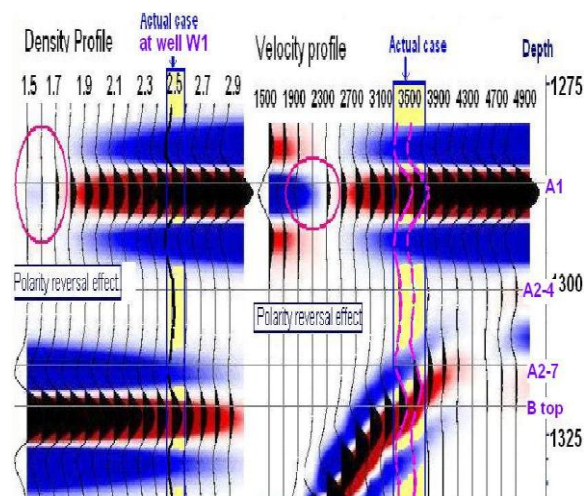


Figure11: Synthetic seismic profile corresponding to a density variations from 1.5 to 2.9 gm/cc and velocity variations from 1500 to 4900mt/sec using the actual log curve of the well W 1.

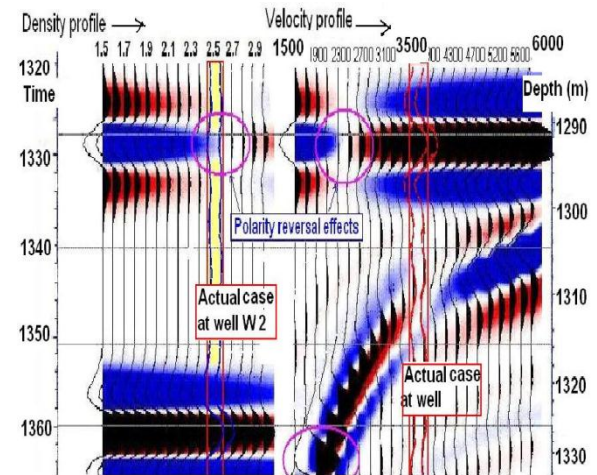


Figure 12: Synthetic seismic profile at well W2 with a density variations from 1.5 to 3.0 gm/cc and velocity variations from 1500 to 6000mt/sec

From the figure 11 and 12 of density and velocity modeling done for well W1 and W2 separately, it looks that density as physical property plays major role in amplitude variations. Synthetic seismic profile corresponding to a density variations from 1.5 to 3.0 gm/cc and velocity variations from 1500 to 6000mt/sec is shown in the figures using the actual log curves of the wells. Note the seismic amplitude and phase change with density and velocity variation and a time shift of bottom of reservoir (B top) with velocity variation while top L3 top is fixed.

We have taken density of carbonate layers as 2.5gm/c and analyzed the effects of density on seismic amplitude. For the range of density from 1.7gm/cc to 3.0gm/cc the amplitude is +ive (peak) in case of well W1 polarity reversal starts below 1.5gm/cc. But in the case of well W2, the amplitude is -ive at actual density of 2.5 gm/cc and decreases with decrease in density. The trough changes into + ive (peak) by increase in density from 2.5gm/cc onwards.

Similarly, the effect of velocity change on seismic amplitude can be generated. Amplitude of seismic events depends on increase and decrease of velocity as acoustic impedance is product of velocity and density. But the same time, the time shift in B top can be observed with velocity variations. From the figure it is clear that velocity plays greater role in affecting the time domain seismic data if proper velocity was not applied during data processing.



Cross plot techniques used in seismic modeling for sensitivity analysis

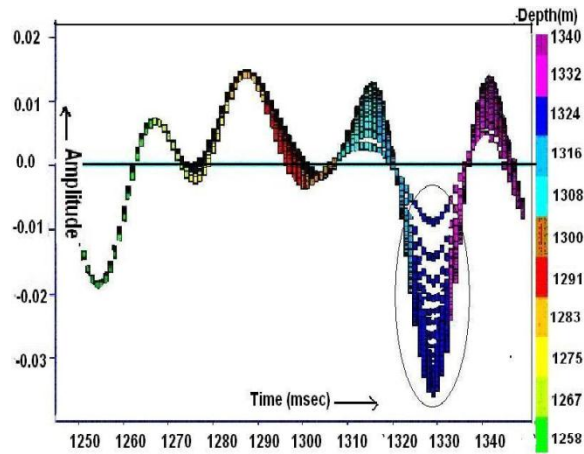


Figure 13: Cross plot showing amplitude variation with change in gas saturation, Maximum variation observed at time interval 1320-1340 ms (-ive amplitude: trough) due to gas

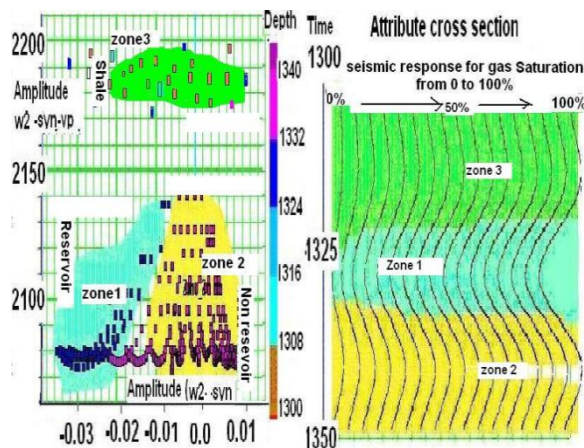


Figure 14: Cross plot of seismic amplitude versus P wave velocity showing maximum variation of amplitude in two cluster, identified as zone of reservoir and non reservoir in depth domain and corresponding cross section in time domain showing reservoir zone.

Cross plot as shown in figure 13 shows the amplitude variation with gas saturation change at well W2. Maximum variation in amplitude observed between 1324-1330 ms (blue dots) due to high porosity filled with gas. Amplitude values in -ive from 1324 to 1330ms (blue dots) indicate carbonate reservoir/gas cap. Green dots around 1250ms may be due to S1 sand with low porosity and not resolvable with seismic as being very thin layer.

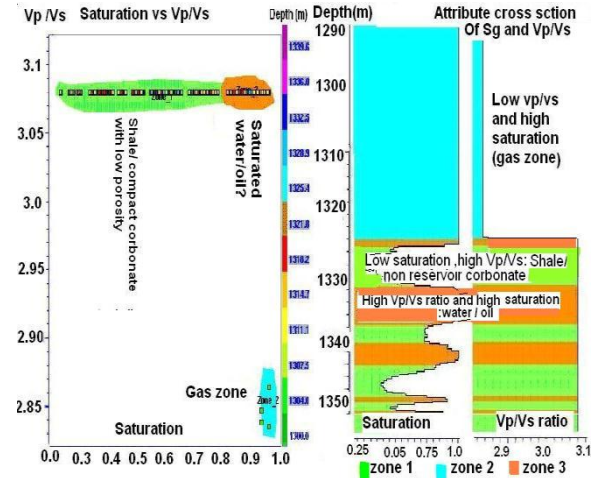


Figure 15: Sensitivity analysis of pore fluid saturation on seismic property Vp/Vs showing 3 Zones in vertical section on the basis of cross plot of saturation vs Vp/Vs Ratio

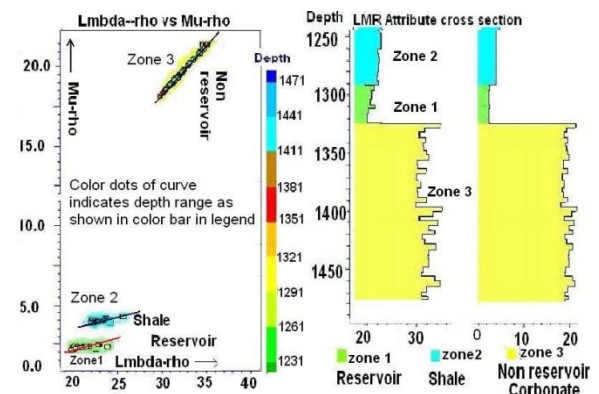


Figure 16: Sensitivity analysis of reservoir rock type on seismic property Lambda- Rho and Mu-Rho, discriminating non reservoir carbonate and shale from reservoir zone

Cross plot of amplitude versus P wave velocity (Figure 14) indicates three clusters identified as zone 1 of reservoir, zone 2 of non reservoir carbonate rock and zone 3 of shale. Corresponding synthetic section showing the change in amplitude with fluid saturation is shown in the right side of figure. Blue dots (zone1 with blue shade) from 1290 -1333mt represent reservoir and zone 2 (Pink/ violet dots with yellow shade) from 1333-1350mt represents non reservoir. Zone 3 has different color dots with green shade correspond to mainly shale. Sensitivity analysis of saturation, porosity and reservoir rock quality on seismic suggest that seismic is sensitive to pore fluid saturation as observed in cross plot of Vp/ Vs versus saturation as shown in figure 15 and sensitive to reservoir quality as observed in



cross plot of Lambda-Rho versus Mu-Rho and corresponding seismic attributes sections shown in figure 16. Three trends of curve shown with different zones identified as shale, reservoir rock and non reservoir rock is shown with color dots for the depth range shown with legend.

Conclusion

Seismic modeling was carried out to understand the effect of petrophysical properties as porosity and fluid saturations on elastic property, offset effect on seismic amplitude, source frequency on resolution of seismic data and layer thickness effect on analysis of seismic tuning effect.

Models indicate the relation of elastic properties is more sensitive to change in porosity and lithology in hydrocarbon leg especially in the gas zone in comparison to brine leg.

High resolution seismic is more useful in resolving the intra layers as indicated by frequency model. The importance of high resolution seismic has increased in view of ongoing horizontal infill well drilling and redevelopment of field.

A significant time/depth shift with change in amplitude was observed in seismic events for the saturation change of oil from 100% to 10%. However, in gas case, the time shift and seismic amplitude change is visible from 30% to 0% only.

Porosity and fluid saturation have a significant impact on the seismic elastic properties and the impact is significantly detectable at good reservoir facies having thick layer and porous zone than thin and poor reservoir facies.

Sensitivity test performed through cross plot technique between elastic constants and rock physics suggest the ability of seismic to differentiate the reservoir rock from non reservoir rock and its fluid saturation subject to availability of high resolution seismic data.

From this porosity modeling, it can be inferred that porosity variations play major role in creating strong peak or trough and hence play important role in the data quality. Physical modeling validates the result of porosity modeling.

Synthetic seismic modeling is more valuable in characterizing hydrocarbon reservoir early in the phase of data acquisition, and processing for the optimization of parameters as it is integral part of seismic data interpretation.

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