Value of Seismic in Developing Greater Understanding of an Onshore Brown Field with Abundant Well Information

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Summary

The Mangala field is located in the northern part of the onshore Barmer Basin in Rajasthan and is the largest discovery till date in Cairn’s Rajasthan block. The field is in production since 2009. The primary reservoir in the field is the Fatehgarh Formation. The Mangala field has more than 300 wells penetrating this formation and is currently undergoing polymer EOR flooding. Moreover, there is a plan of drilling some more infill wells in future in the structural crest of the field to drain the attic oil. Although, the drilling locations will be primarily identified based on the static and dynamic reservoir models, however, it will be quite useful to have a seismic derived attribute which can help in developing a greater geological understanding of the field, in general, as well as in identifying more “sandier” areas, especially, in a meandering fluvial depositional setting like that of Upper Fatehgarh which holds majority of the reservoir oil. Hence, the primary objective of this study was to do a seismic inversion and multi-attribute reservoir property prediction study for Fatehgarh formation. The results of this study were integrated with the abundant well information in order to identify the areas with higher and lower reliability. The output volume was then used for interpreting horizons as well as for identifying “sandier” areas in Fatehgarh in order to reduce subsurface uncertainty in a brown field. The results will ultimately be used as 3D trends for facies population during static model building.

Introduction

The Mangala field is located in the northern part of the onshore Barmer Basin in Rajasthan (Figure 1) which is a Tertiary rift basin containing predominantly Palaeocene-Eocene sediments. The field is in a SSE-tilted three-way structural trap, formed by two main bounding faults: a NE-SW oriented Northern main fault and NW-SE oriented Southern main fault (Figure 2). The primary reservoir i.e. the Fatehgarh group consists of inter-bedded sands and shales. The reservoir has been sub-divided into an Upper Fatehgarh Formation (dominated by sinuous, meandering, fluvial channel sands) and a Lower Fatehgarh Formation (dominated by well-connected sheet flood and braided channel sands).
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Correlation of flood plain shales and fluvial sands based on well data alone in a highly heterogeneous fluvial system of Upper Fatehgarh poses a major challenge in reservoir characterization. The reservoir characteristics of the Fatehgarh sands, in general, are excellent.

The field is covered with 3D seismic data from two vintages of acquisition. The first survey, the NR3D was acquired and processed in 2005. Data from this was used to support early appraisal well drilling in the field and the initial field development plan. Subsequently, this data was reprocessed in 2010. A second high density 3D seismic survey, the HD3D, was acquired with a different orientation and processed during 2007, to support field development. Subsequently, in 2012, a high resolution sparse layer inversion was also done on HD3D PSTM dataset.

Methodology

Rock-Physics Analysis

A detailed rock physics analysis was done and various cross plots were generated to identify the best lithology discriminator for Mangala field. In general, Acoustic Impedance (AI) attribute is a good discriminator of shales and sands in the Fatehgarh formation. Although, this discrimination is less pronounced for one particular shale unit of Upper Fatehgarh (as marked by arrow in Figure 3) which may be discriminated with Lambda-Rho, but, overall, for Fatehgarh AI is a better discriminator of lithology as compared to Lambda-Rho. Moreover, AI acts as a direct proxy for NtG of the target unit (Figure 4).

Hence, an AI attribute volume can help in predicting the composite NtG for the desired unit further helping in optimization of the future well locations by identifying areas of higher NtG.

Choice of Appropriate Seismic Dataset

The field is covered with 3D seismic data from different vintages of acquisition as well as processing. Based on the previous interpretation experience and seismic to well tie analysis, focusing mainly on the crestal part of the field, the NR3D PSTM dataset was chosen to carry out this study. NR3D dataset was the best available dataset in terms of event continuity, S/N ratio, seismic bandwidth and preservation of amplitudes, especially in the structural crest, which was the prime area of interest.
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Wavelet Extraction, Seismic-to-Well ties and LFM building

Extensive seismic-to-well ties were done using a deterministically derived wavelet for 30 wells spread across the field. This wavelet along-with the VSP corridor stack data, was also used to rotate the seismic to near zero phase. The synthetic seismograms obtained for different wells, showed excellent correlation with actual seismic in all parts of the field (Figure 5) including in the crestal part where seismic data quality was not as good as the flanks. This deterministic wavelet (Figure 5) was used for seismic inversion as well.

A robust low frequency model of AI attribute was then generated using 25 wells and key horizons. This apriori model was QC’ed and subsequently used as an input to the model-based seismic inversion workflow for generating the inverted AI volume.

Detailed QC of Inversion Results

In order to assess the quality of output AI volume, 1D composite traces were extracted along the well paths at different well locations (mostly blind wells) from the inverted AI cube and were compared with the actual AI filtered to the seismic bandwidth. All across the field, good match between actual and inverted AI was observed (Figure 6).

As good 1D matches were obtained for most of the wells in Mangala field, a detailed scanning of AI volume was done all across the Mangala field. The inverted AI volume was now QC’ed at blind well locations by matching the inverted AI values to the Vshale values derived from well logs filtered to the seismic bandwidth. It should also be noted that as seen from the cross-plots (Figure 3), all the Fatehgarh shales, except the anomalous shale unit, will have higher AI values (~9000-10000g/cc*m/s), whereas, the thick clean sands will have lower AI values (~7500g/cc*m/s). However, as the target Upper Fatehgarh unit does not have thick clean sands at all locations, therefore, the inverted absolute AI value in these units (at seismic resolution) will act as a proxy for NtG or relative “sandiness” of the target units instead of resolving individual sands units.

The comparison of inversion results with well data within the seismic bandwidth confirmed good correlation between AI and geological facies (Figure 7). Inversion results also showed clear variation in the composite sandiness and shaliness of key Upper Fatehgarh units which have complex meandering depositional system. The lateral continuity and thickness variation of some shale units as seen from the inverted AI volume (Figure 7) offered critical insights on relative NtG as well as sand connectivity which in turn will play a key role in future well placement activities (Figure 7).

Detailed 2D QC’s of inverted volume provided evidences of AI attribute capturing the geological trends which were further validated by drilled wells. It also helped in demarcating areas having poorer matches. This prompted us to use this volume further for Vshale prediction using multi-attribute analysis.

Vshale prediction using Multi-Attribute Analysis

A statistical approach that allows multi-attribute and Probabilistic Neural Network (PNN) analysis was used to predict Vshale property from seismic derived attributes including the inverted AI cube (Figure 8 Middle). This predicted Vshale was then subjected to a detailed 1D & 2D QC at blind well locations similar to the AI volume (Figure 8 top and Figure 9). The predicted Vshale volume had slightly higher frequency content than the AI volume. Also, the zone of poor well match in Vshale volume reduced drastically. Moreover, the Vshale volume, being a reservoir property volume, gives a more intuitive idea
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Figure 6: 1D QC of inversion results: Inverted AI log (in Red) and Measured AI log filtered to seismic bandwidth (in blue) for 5 wells spread across the Mangala field; shaded area is the Fatehgarh formation

Figure 7: 2D QC of inversion results: Sections passing through many blind wells showing good match of inverted AI and filtered Vshale log; The sections show the lateral variability of shales and sands, especially, in Upper Fatehgarh being captured by inverted AI attribute

Figure 8: (Top) Validation of predicted Vshale at different well locations showing good match between actual Vshale log (black) and predicted Vshale log (red); Workflow followed for Vshale prediction from AI volume (Middle left); Choice of optimum number of parameters and operator length was done on the basis of validation error plot (Middle right)
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of the “sandiness” of the target reservoir than the AI volume. As a result, the predicted Vshale volume is more convenient to use for interpretation purposes as well as for optimization of future well locations. Moreover, as this Vshale volume has transformed an elastic property into a reservoir property, hence, it can be directly used as a trend for facies population during static modelling.

Using seismic derived attributes to develop greater geological understanding of the field

The output Vshale volume helped in interpreting an additional horizon in seismic which corresponded to a 2-5m thick regional shale sandwiched between 2 thick sand units (Figure 10). This shale was not evident in the original seismic data but was detectable in the derived Vshale volume and in the inverted AI volume as well. Additionally, the predicted Vshale volume was combined with the abundant well information as well as previous interpretation experience to come up with polygons of high and low reliability (shown as a map in Figure 12). It was also observed that there were very small zones of low reliability and these zones were primarily due to sub-optimal input seismic data quality in those areas. By shifting this newly picked horizon, an average Vshale map for the layer marked with a bracket in Figure 10, was generated. It was then compared with a net sand map generated for this layer using wells (Figure 11). Although, this comparison was not exact as the shifted horizons did not exactly match with the top and base of the target layer, however, it demonstrated that the average Vshale map (Figure 11) captured the gross trends of “sandiness” for this layer. This encourages us to further incorporate this Vshale volume as a 3D trend during facies population in static model, especially in the areas of higher reliability.

Additionally, the reliability map (Figure 12) also helps in identification of those areas where future well locations can be optimized using the seismic derived Vshale volume as an additional constraint to the results of dynamic simulation of the reservoir model in order to reduce subsurface uncertainty. For example, in a heterogeneous meandering fluvial system of Upper Fatehgarh, there is a high possibility that the seismic derived reservoir properties will capture the sand channel geometries better than the existing static model, especially, at locations away

Figure 9: 2D QC of Predicted Vshale volume: Sections passing through many blind wells showing good match of predicted AI and filtered Vshale log

Figure 10 (2D section on left) shows the new shale horizon picked using Vshale volume;

Figure 11 (2 maps on the right) compares the average Vshale values (left) for a layer (marked with bracket) with a net sand map (right) for the same layer using wells. The Vshale map captures the gross trends of low relative net sands (southern part of the field) and high relative net sands (middle part of the field). It additionally gets rid of the non-geological bull’s eyes which can be seen in the net sand map (right) generated using wells only especially around the red dashed line where there are very few well penetrations.
from the drilled wells which were incorporated in the static model. Although, this seismic derived attribute will have lower resolution than the static model.

**Figure 12:** A map demarcating areas of lower reliability, where the predicted Vshale matches poorly with the actual Vshale due to poor seismic data quality

**Figure 13:** A 2D section (left) and an average Vshale map (right) over FM3 to FM3-25ms interval showing that a well location proposed on the basis of dynamic simulation can be optimized further by using seismic derived Vshale attribute as an additional data point. (Red arrows show stacked channels responses in the map)

however, the derived attribute will capture the spatial relative NiG trends better. Therefore, a well optimized solely on the basis of dynamic simulation may be placed right at the edge of a channel (as shown in Figure 13). In such case, if the area around the proposed well location is screened with the seismic derived Vshale volume as an additional data point, then the well location can be better optimized by moving it towards the center of the channel channels instead (Figure 13). In other cases where the well location proposed by dynamic simulation lies in a higher net sand zone, the predicted attribute will validate those locations.

**Conclusions**

A Rock physics analysis, seismic inversion and multi-attribute reservoir prediction study was conducted for Mangala field, having abundant well information. The output of this study was a predicted Vshale volume which was extensively integrated with the abundant well information to demarcate zones of high and low reliability. The predicted Vshale volume helped in interpretation of additional horizons which were not evident in the original seismic data. Moreover, this attribute helped in identifying “sandier” zones, especially, in Upper Fatehgarh Formation which is dominated by sinuous, meandering, fluvial channel sands and hence can be used as a 3D trend to populate facies model. This attribute is also being used in addition to the results of dynamic simulation to optimize the future infill well locations in the structural crest of the field. This study, thus, demonstrated the value of seismic information in reducing the subsurface uncertainty even in a field with more than 300 wells. In fact, the sands encountered in a few recently drilled wells were consistent with the predictions made using this Vshale volume.

**References**


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