A fit for purpose seismic-to-simulation in a low permeability gas reservoir: a case history from Barmer Basin

Sreedurga Somasundaram, Ritesh Kumar, Ruchika Sharda, Bineet Mund, Abhudai Beohar and Tanzeem Patankar, Cairn Oil and Gas, Vedanta Limited*
Sreedurga.somasundaram@cairnindia.com

Keywords

Natural fractures, Volcanics, Hydraulic fracturing, Seismic characterization, Porosity, Permeability, Microseismic, Static and Dynamic model and History match

Summary

Improved seismic imaging, interpretation along with full integration of subsurface well data and modeling applications are keys to cost-effective and fast paced field development. In this study a fit for purpose ‘seismic-to-simulation’ model was created for the low permeability gas reservoirs of Raageshwari Deep Gas (RDG) field that suitably include seismic characterization, modeling techniques and relevant validations through history match of production data. This model is used for reserves estimation; production forecast and optimal placement of development wells thereby maximize field Estimated Ultimate Recovery (EUR).

Introduction

The current study area, Raageshwari Deep Gas (RDG) field is situated in the southern part of onshore Barmer Basin in Rajasthan, India. The field contains a gas condensate reservoir with excellent gas quality. Stratigraphically, the reservoir is composed of clastic Fatehgarh Formation, overlying a volcanic complex comprising basic lava flows (basalts) and stacked silicic pyroclastic flows (felsics), which are interbedded with another older generation of basalts. Figure-1 shows the location of RDG field in Barmer Basin with type log of the RDG reservoirs. These are low permeability reservoirs and optimal field development necessitates reasonable characterization of reservoirs and natural fractures thereby aiding well placement by targeting areas of enhanced permeability for better well performance.

This field is currently in the early development phase with 30 wells drilled and hydraulically-fractured before being put to production. In this study the ‘seismic-to-simulation’ model is aimed to incorporate newly acquired and interpreted seismic data, integrated with well data using reservoir modeling techniques to effectively capture reservoir heterogeneities. The integrated reservoir model was then successfully used to match the well performance with the available seven years of production history of the field.

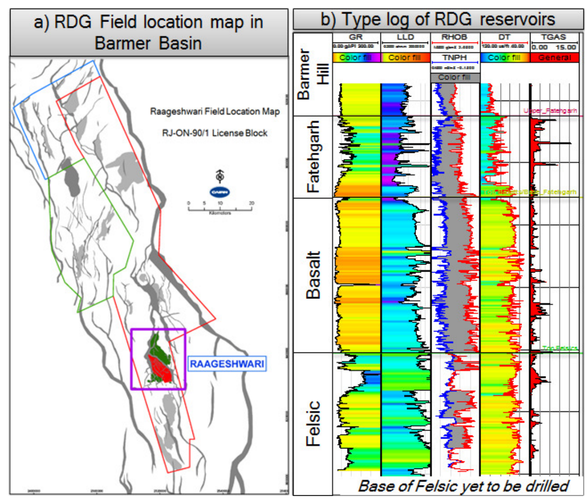

Figure-1: a) RDG Field location map in Barmer Basin and b) Type log of RDG reservoirs

In order to effectively simulate the flow properties in a low permeability reservoir like RDG, a detailed understanding of dynamic properties is imperative which in this case includes matrix permeabilities and fractures. However, with lack of sufficient dynamic data, reliably processed microseismic data, detailed high resolution fracture and matrix characterization, and considering limitations on seismic resolution, we created a fit for purpose ‘seismic-to-simulation’ model with suitable use of matrix and fracture distribution obtained from seismic reservoir characterization. Calibration of the seismic derived information with independent well data and production behavior helped to build confidence in the results. Figure-2 shows the workflow adopted in this study.

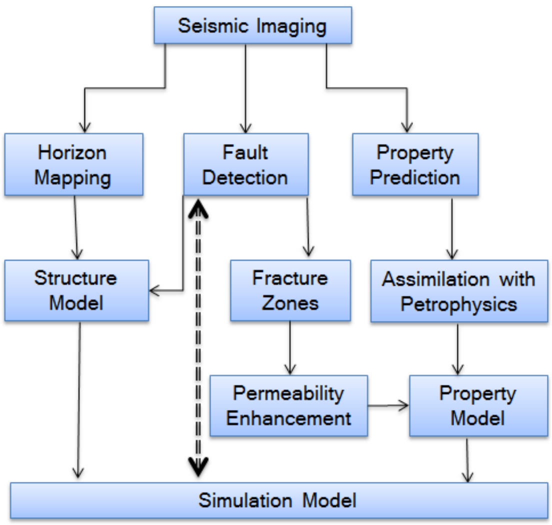

Figure-2: Workflow for seismic-to-simulation adopted in RDG Field

Methodology

Seismic Interpretation and Characterization

A 3D wide azimuth seismic survey was acquired over the study area in 2014. Subsequently azimuthal Pre-Stack Depth migration (PSDM) processing was performed in 2016. This yielded adequate image quality in the target reservoirs and helped better seismic interpretation that was carried out as a part of this study. Detailed structural studies in the reservoir area are largely in agreement with the regional tectonic evolution. From 3D seismic, the major key interpreted surface representing the Top Fatehgarh, Top Basalt, Top Felsic and Base Felsic (Base Volcanic) were used to generate the structural framework.

Natural fractures and faults in the low permeability reservoirs have an important role in fluid flow and production. Mapping of faults and fracture zones was carried out using the conventional geometric attributes such as variance. The variance attribute, which is an edge detection method (computed as opposite of semblance) responds to trace-to-trace variability over a particular interval making any discontinuities in the seismic data detectable and is widely used to delineate faults and stratigraphic edges. Figure-3 shows the Variance extracted from Top Basalt and Base Felsic (Base Volcanics). Two generations of fault trends can be identified in the vicinity of the reservoir. Younger generation of faults in the upper volcanic interval shows a shattered, broken network of faults with varied throws. Consistent with the geological model and tectonic settings of the basin, these faults have a major orientation in the NW-SE direction. Second generation of faults is observed in the basal part of Felsic interval where major fault orientation in EW direction clearly indicates that faulting is of different age.

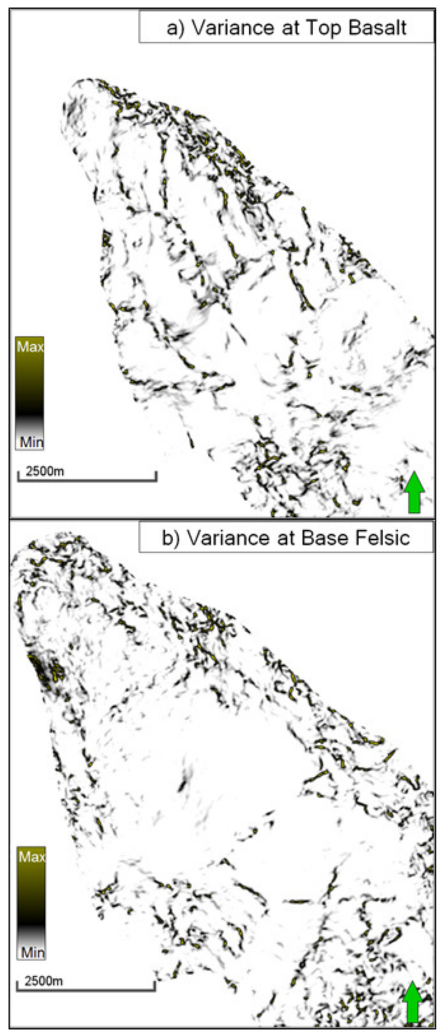

Figure-3: Variance attribute extracted at (a) Top Basalt and (b) Base Felsic

Quite often the hydrocarbon volume stored within the natural fractures is much lower than is stored in the matrix. But the natural fractures have much higher permeability than the matrix, as calibrated with well performance data. In order to account for this effect in permeability modeling, three times permeability enhancement on the estimated matrix permeability is applied along fault/fractured zones mapped using seismic and Variance data. The sensitivity of applying this modifier is discussed later in the history match section. Presence of natural fractures enhances connectivity for large volume of hydrocarbons residing in the matrix.

Besides detection of natural fractures, predicting the subsurface properties for low permeability reservoirs is very important for assessment and development of the field. In this study, multi attribute analysis was performed for porosity prediction using seismic attributes such as variance, reflection curvature, acoustic impedance, instantaneous frequency, phase and amplitudes and iso-frequency volumes- 10Hz, 25Hz and 35Hz that have shown significant value in detecting porous zones in the RDG reservoirs, especially in regions of poor well control.

Total porosity from NMR logs, filtered to seismic bandwidth was used as the target log for prediction. Sufficient training wells with a good areal spread were provided for the analysis, to establish a statistical multi-variate linear regression between porosity logs and the seismic attribute volumes at well locations using cross-validation plots (Hampson et al., 2000). This established relationship is used to predict the target (porosity) log property throughout the 3D seismic volume and provides best prediction with correlation of 78% with RMS prediction error of 1.5% porosity units. The reliability of the final predicted porosity volume is further validated by 'blind' wells. The blind well validation showed a reasonable correlation of 63% with error of 2.2%.

Figure-4 shows a map of predicted averaged porosity over upper 100ms within the Felsic unit with a cross-section of the predicted porosity along selected training wells (T1, T2, T3, T4, T5, T6 and T7) and blind wells (B1, B2 and B3). The predicted 3D porosity volume showed a heterogeneous distribution within the volcanic reservoirs with porosities ranging from 2 to 11%. This Predicted porosity in the low permeability reservoirs aids in property modeling for gas in place (GIIP) estimation, development well planning and in understanding the varied production behavior within the volcanic reservoir interval.

Static reservoir modeling

A geo-cellular model was created using Petrel™ software in order to tie the seismic interpretations with the well data. The framework of the static model was built using Corner Point Gridding incorporating key seismic horizons and seismically interpreted faults that were tied to well markers wherever available. Further granularity in the model was based on well-based zonation and optimized vertical layering to capture the reservoir property heterogeneity. Subsequent to construction of the structural model, petrophysical interpretation and core integration was carried out to estimate reservoir porosity, saturation and matrix permeability for different facies identified for each formation. Reservoir properties derived from well logs were propagated across the 3D grid using geostatistical algorithms. Typically, facies modeling in a reservoir is constrained by well-level interpretations. However, lack of well data poses an uncertainty, which in this case has been mitigated by use of seismic multi-attribute analysis to generate predicted average porosity distribution maps within Fatehgarh and volcanic formations. These have been utilized to generate probability trend maps for guiding areal variability of the Facies and thereby Porosity model away from well data. In order to account for the effect of presence of natural fractures in permeability modeling, a permeability modifier of 3 is applied along the mapped 3D objects as fault/fractured zones using variance data. The final 3-D static model incorporated available data from seismic horizon mapping, attribute analysis, honored well elevations and well level petrophysical properties.

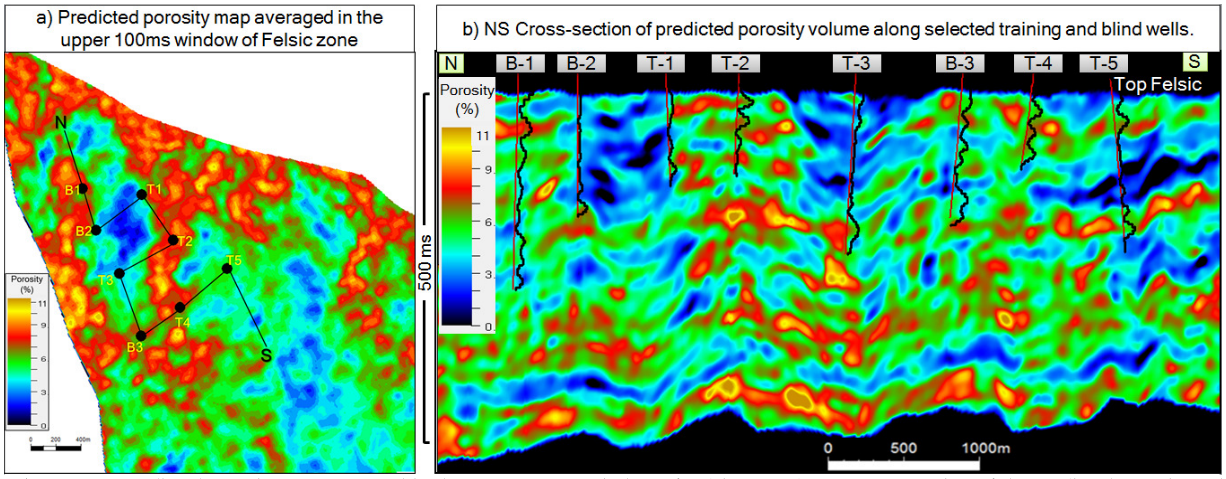

Figure-4: a) Predicted porosity map averaged in the upper 100ms window of Felsic zone. b) NS Cross-section of the predicted porosity volume along selected training and blind wells. Cross-section is flattened at Top Felsic marker and shows validation between actual NMR porosity logs (filtered to seismic bandwidth) plotted along well tracks (in the scale 0-12% porosity)

Dynamic reservoir modeling

The grid dimensions, porosity, permeability, Net to Gross and water saturation properties are carried forward from geo-cellular model upscaled to perform simulation in CMG-IMEX software. PVT properties of fluid were used based on robust fluid characterization of bottomhole samples collected which were distributed spatially throughout the field. . In absence of lab data for the relative permeability, Corey exponent has been used to define relative permeability for gas, condensate and water based on technical literature (Hinchman and Barree, 1985) of analogue reservoirs. For hydraulic fracture modeling, a new cell/well modifier method as described in Burgoyne et.al, 2012 has been utilized to avoid runtime and convergence issue in the routinely applied LGR method.

In low permeability reservoirs, a typical production profile starts with a peak initial rate followed by rapid decline and stabilizing to a pseudo-steady state rate for long term. The RDG Field has more than seven years of production history. The simulation model was used to do history matching to honor the production data and well performance of the existing 30 wells in the field.

Validating through history match

A sensitivity test was performed to calibrate how much permeability enhancement applied along fault/fracture zones was necessary. Keeping the rest of the model parameters unmodified and changing only the permeability enhancement along fault zones, history match was compared with the actual well performance. It was determined that, three times permeability enhancement for wells near fault zones facilitated a reasonable match with well performance data.

Microseismic data acquired during hydraulic fracturing of a stage in well W-A1 (Figure-5a) showed the majority of microseismic events (blue circles) to be positioned along a fault mapped near the well. The hydraulic fracture interpretations through diagnostic fracture injection test (DFIT) also suggest the possibility of presence of natural fractures around the well and fracture growth along a pre-existing plane of weakness. This cross-validates the presence of the fault and the associated microseismic data. The history match was performed with and without application of permeability enhancement along the fault shown as blue and red solid line (Figure-5b) respectively. It is observed that to obtain the necessary well pressure and performance match, it is necessary to apply permeability enhancement along the fault zone which validates our understanding on higher permeability associated with natural fractures.

As additional validation, and to investigate if the presence of faults and associated natural fractures improves permeability, production data for well W-

A2 was analyzed along with the seismic data. It is observed that the well intersects a fault mapped in seismic in the basalt interval that also show relatively better zonal production compared to the other zones of the well, as highlighted by the red dotted rectangle in the Figure-6a. History match also supported the necessity of permeability enhancement along the fault plane to match the actual well performance (Figure-6b). Further, the 950 hours pressure build up (pressure transient analysis) performed in the Basalt unit suggested presence of a sealing boundary with two or more faults around the well. The variance map at Top Basalt suggests presence of four faults around the well at distances of 30m, 50m, 290m and 190m respectively shown as F1, F2, F3 and F4 in Figure-6c.

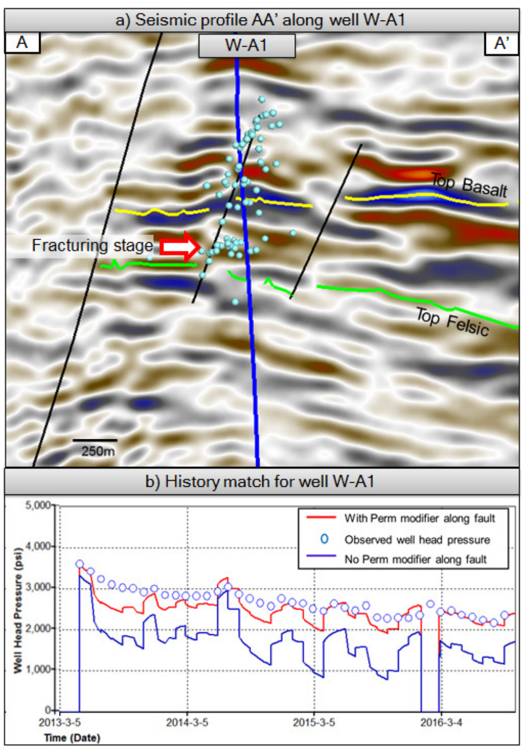

Figure-5: a) Seismic profile AA' along well W-A1 and b) History match for well W-A1

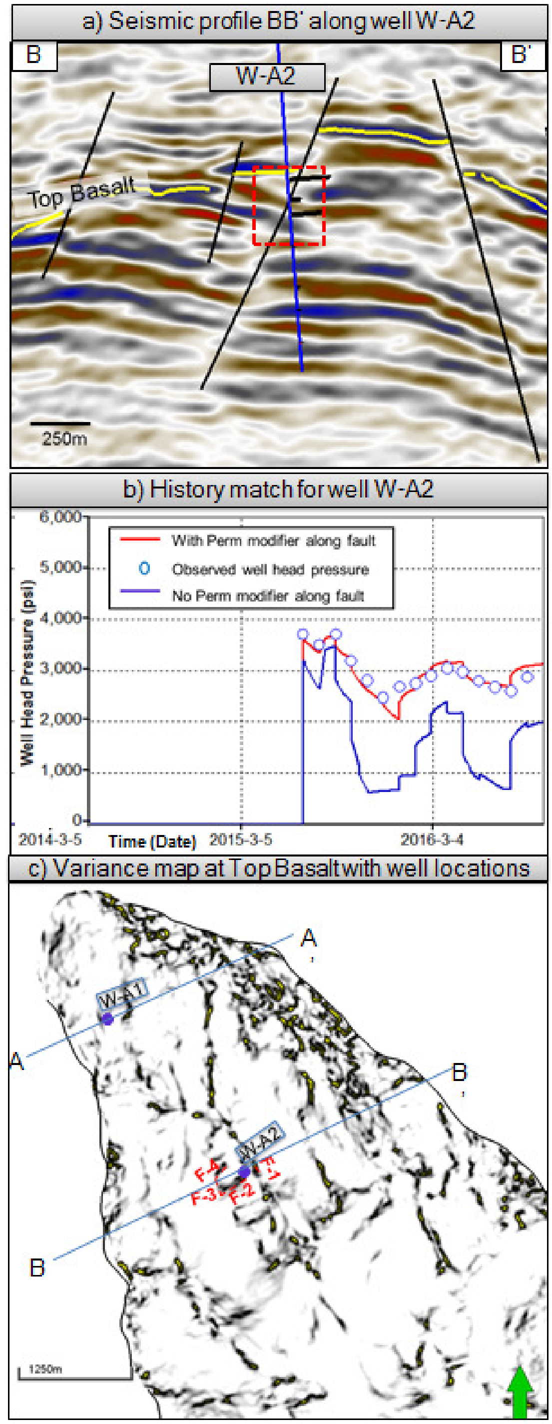

Figure-6: a) Seismic profile BB' along well W-A2, b) History match for well W-A2 and c)Variance map at Top Basalt

Conclusions

Reservoir models are constructed to gain better understanding of the subsurface that leads to optimal well placement, reserves estimation, production forecast and production optimization. An effective 'seismic-to-simulation' model is one that reasonably depicts the subsurface and provides a successful history match.

In RDG reservoirs, a fit for purpose 'seismic-to-simulation' model with suitable use of matrix and fracture distribution obtained from seismic reservoir characterization, calibrated to well data with appropriate geostatistical modeling techniques achieved a successful history match validating the subsurface understanding. Furthermore, the study results are being used for reserves estimation; production forecast and optimal placement of development wells thereby maximize field Estimated Ultimate Recovery (EUR).

References

Hampson, D., Todorov, T. and Russell, B. [2000] Using multi-attribute transforms to predict log properties from seismic data. Exploration Geophysics, 31(3), 481-487.

Burgoyne, M. W., & Little, A. J. H. (2012, January). From high perm oil to tight gas-A practical approach to model hydraulically fractured well performance in coarse grid reservoir simulators. In SPE Asia Pacific Oil and Gas Conference and Exhibition.

Hinchman, S. B., & Barree, R. D. (1985, January). Productivity loss in gas condensate reservoirs. In *SPE Annual Technical Conference and Exhibition*.

Acknowledgements

We thank Cairn Oil and Gas, Vedanta Limited and our JV partner, ONGC Ltd, for allowing us to publish this paper.