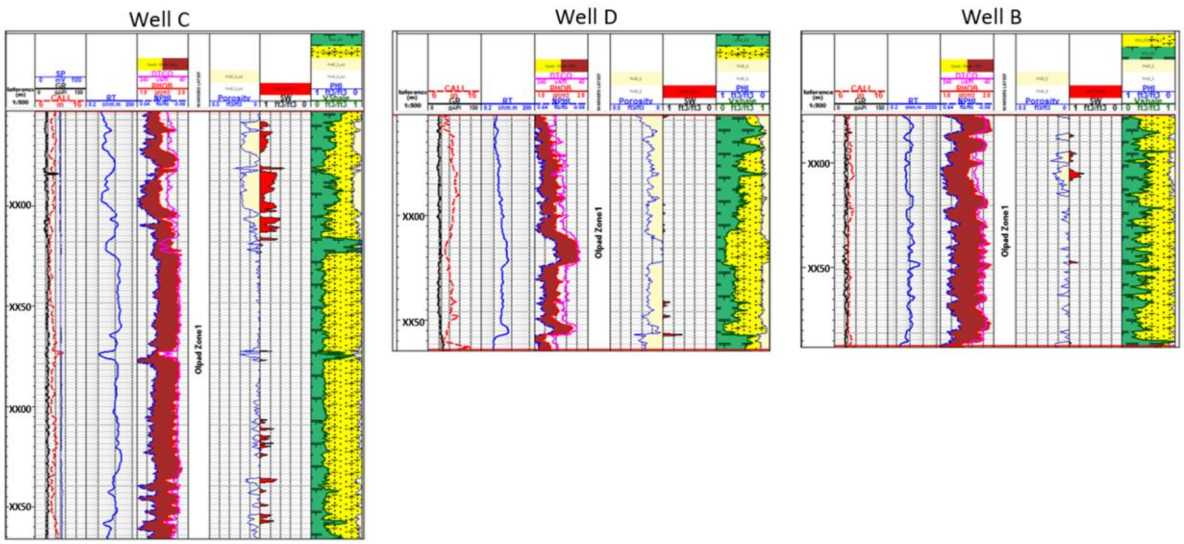

Figure 5. Log evaluation in study area.

Zone-1 of Well-C which flowed oil and gas to the surface, the primary phase being oil. The well self-flowed with stable oil flow rates ranging from 25 to 36 sm^3/day. However, in Well-B and Well-D, Olpad Zone-1 was more shalier and had no hydrocarbon indications and was not considered for testing. Well-A was tested through different objects in the Olpad Formation which flowed water or didn't show any influx. These observations further point to the possibility of a fault between the wells in the area.

The Well-C was put on regular production and water cut increased gradually to 60% within four months of production. Several workovers were attempted to isolate the water but failed to produce the desired results and the well was shutoff. The cement bond logs and variable density logs were studied to understand the possible reasons of high water cut, and they showed poor cementing throughout the well.

In order to understand the inflow performance for the reservoir, the available well test data was used. The bottomhole pressure data was not available and hence Hagedorn and Brown multiphase flow correlations were used to convert the tubing-head pressure to the bottomhole. A single well reservoir model was setup with average reservoir thickness, porosity, water saturation and net to gross taken from petrophysical analysis to understand the production behavior of the Olpad Formation and estimate the production profiles of the well under different production scenarios. Very limited PVT data of collected fluid samples was available and hence a correlation-based black oil fluid modeling was done to estimate reservoir fluid properties. A special core analysis (SCAL) experiment was not available for the field so the Brooks and Corey model was used to construct the relative permeability curves.

The single well model was run on oil rate control and parameters like gas production rate, water production rate, well productivity index and pressures were matched (Fig. 6).

In the absence of the core data, several sensitivities were run on the uncertain parameters, and the permeability estimated from the match of the available well test data is ~12 mD.

The model calculated well productivity index was also in the same range as estimated from the inflow performance relationship, thus further increasing the confidence in the history-matched parameters.

Following the conclusion of history match exercise, performance prediction of the well under various production constraints was run to understand the range of estimated ultimate recovery (EUR). Several sensitivities were run to estimate the range of EUR like flowing bottom hole pressure, drainage acreages, and peak production rates.

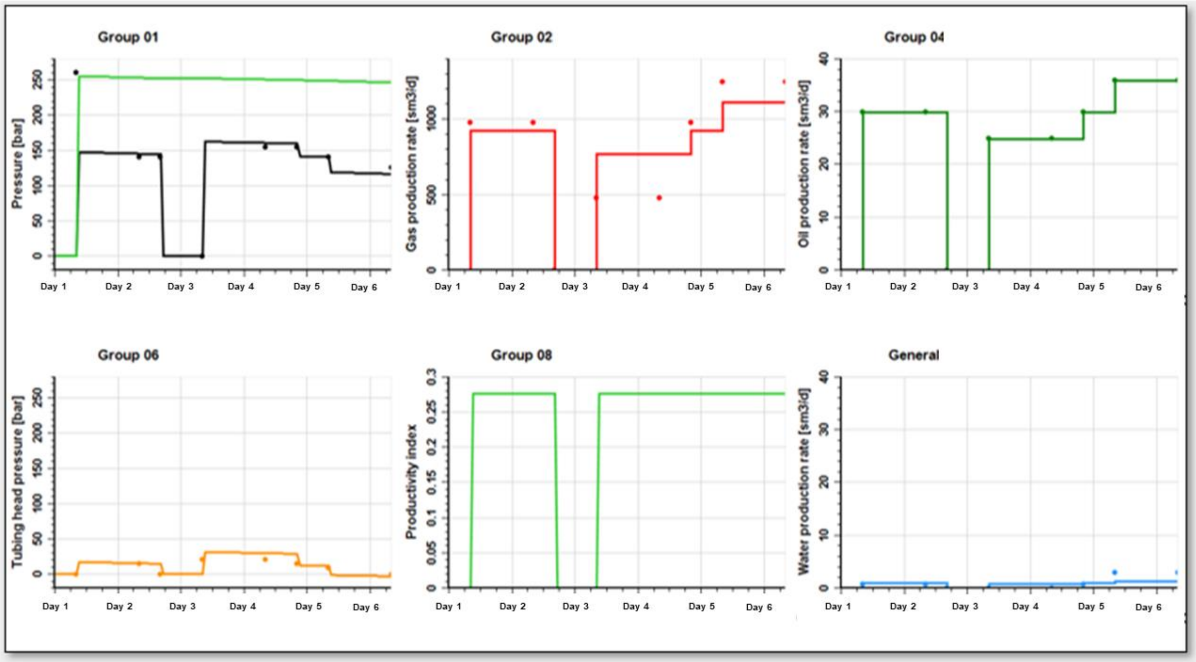

Figure 6. Well-C reservoir model history match**.**

From the analysis, it was concluded that in low permeability reservoirs like the Olpad Formation, the low flowing bottomhole pressure would help to recover more per well. Moreover, increasing the number of the wells will help in increasing the overall recoverable resources from the field. This could be an important consideration for the future business decisions.

Prospect Evaluation: The seismic data was analyzed and linked with well level information from geological and petrophysical studies.

Well-C, which is a discovery well, was in the area of interest, but outside the range of 3D seismic. As a vertical seismic profile (VSP) was not present for the entire well section, a sonic log was used to carry out seismic to well tie. With the seismic data quality being extremely poor, the basic aim was to tie the prominent regional reflector which was further used for key seismic horizon mapping.

Faults were interpreted manually using the seismic sections and time slices. Variance attribute was used to guide the fault interpretation in 3D. Outside the 3D seismic coverage, fault interpretation was conceptual based on available data analysis and regional understanding.

During velocity modeling, due to absence of seismic velocity, the lateral velocity variation was not captured. This could lead to uncertainty of actual configuration of structure. Due to this constraint, constant interval velocity from Well-C time-depth relation was used.

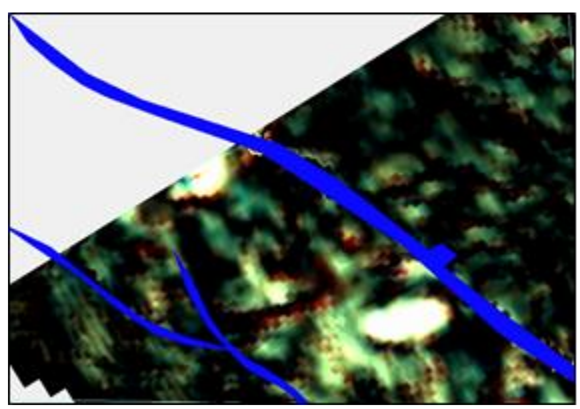

Figure 7. Spectral decomposition using 25-28-30 Hz at 75 msec below the top of the Olpad Formation showing the NW-SE reservoir fairway.

Post-stack attribute analysis was carried out to understand and highlight better reservoir facies in the Olpad Formation (Fig. 7). However, due to absence of wells falling in the 3D seismic area, it was not possible to calibrate the seismic attribute with petrophysical or fluid properties. Therefore, the attribute analysis carried out in this block is qualitative and was used to understand gross depositional pattern. This attribute analysis also demarcates faults perpendicular and parallel to fault influx.

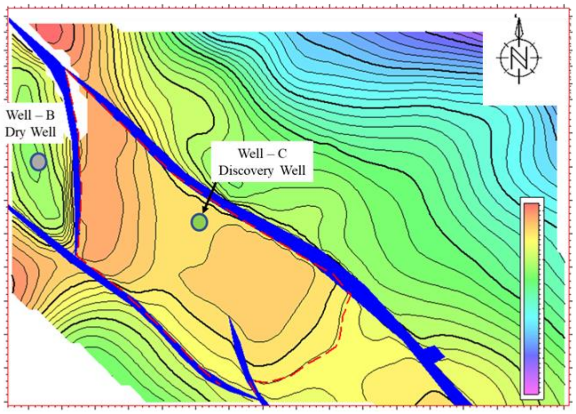

Figure 8. Depth structure map at the top of the Olpad Formation.

Based on structural interpretation, fault bound structural closures were identified at the top of the Olpad Formation (Fig. 8).

Conclusion

Based on the analysis carried out, well locations were identified within the structural closures, that could help in increasing the overall recoverable resources from the field.

The main challenge in the evaluation was data quality, data availability and data coverage. This could be mitigated by the acquisition of addition seismic data or by drilling of additional wells.

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Acknowledgement

We would like to thank Megha Engineering & Infrastructure Ltd. and Schlumberger for allowing us to publish this work. Also special thanks to Hassan Kolivand for his advice and valuable inputs during the work.