Reservoir characterization as a guide to inversion—a case study from a deep sandstone reservoir in Block B, Saudi Arabia

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Summary

Deeply buried tight sandstones present at least two challenges to the seismic interpreter—p-waves are not sensitive to differences between sand and shale, increasing the non-uniqueness of inversions; and it is difficult to interpret pore fluids in low porosity reservoirs. This study demonstrates how detailed reservoir characterization can be used to determine the most effective method for inversion as well as for calibrating and interpreting the inversion results. This approach was used to map reservoir potential in the Sarah Formation, Block B, Rub al-Khali Basin, Saudi Arabia.

Introduction

Block "B" is located in the Mukassir uplift of the Rub al-Khali basin. The Sarah reservoir, developed at the top of the Ordovician, is one of the major exploration targets in the area. The Sarah was deposited in a deltaic environment that was subsequently eroded by glacial plucking. The formation comprises very thick units of brown grey, fine–medium, lithic quartz sandstone, quartz sandstone and a few layers of detrital conglomerate.

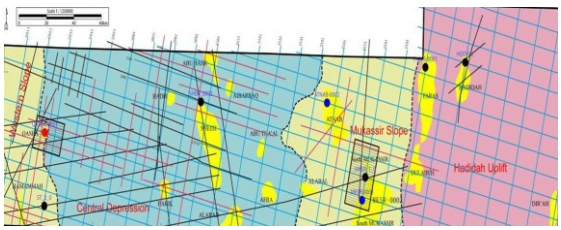

Figure 1. Location of the study area.

So far, two wells, the MKSR-1 and MSKR-2, have been drilled and 3D seismic data has been acquired over an area of 946.238 km^2. Well MKSR-1 penetrated the entire Sarah Formation and was drilled to 18110 ft; MKSR-2 was drilled to 17117 ft. Although both wells have oil and gas shows, well test results indicate the reservoirs penetrated are not commercial.

Methods and Analyses

Analysis of logs from MKSR-1 and analyses of core from both MKSR-1 and MKSR-2 indicates that porosity in the Sarah Formation occurs primarily as dissolved grains, dissolution-enhanced grain boundaries and enlarged inter-granular pores. The porosity range is 1.1~18% with an average of 6%; the permeability range is 0.1~0.7×10^{-3}μm^2 with an average of 0.18×10^{-3}μm^2 (Figure 2). Interpretation of logs from well MKSR-1 shows that porosity in the Sarah reservoir is 6.73~8.69% with an average of 7.8%; permeability is 0.066–3.09×10^{-3} μm^2 with an average of 2.6×10^{-3}μm^2. The Sarah reservoir has considerable heterogeneity.

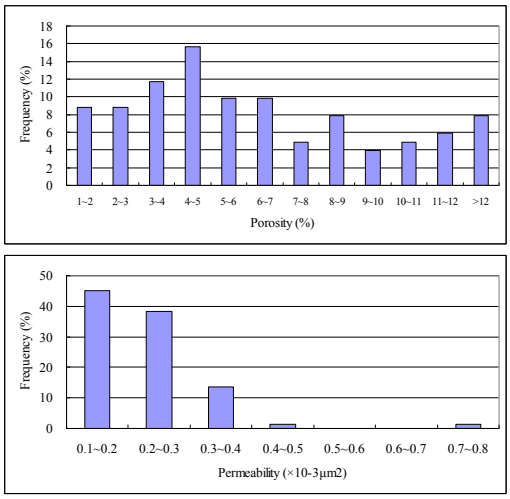

Figure 2. Porosity and permeability histograms for Sarah Formation.

Based on the porosity curves and measured core porosity, high porosity intervals occur as interbeds between tight sand. Taking the DT/RHOB curve for well MKSR-1 as an example (Figure 3), some sandstones show low DT and high RHOB, others show high DT and low RHOB.

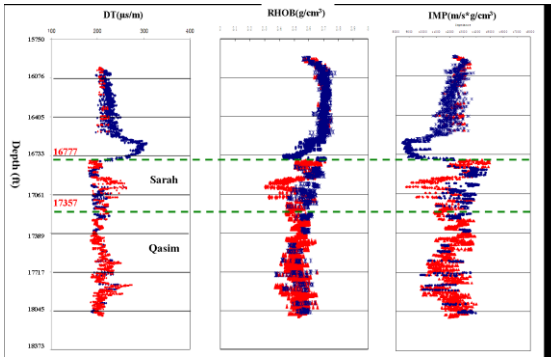

Figure 3. DT, RHOB and IMP characteristics of well MKSR-1.

Sandstones with low DT and high RHOB are high porosity and constitute the reservoir in the Sarah.

The crossplot of calculated acoustic impedance and porosity (Figure 4) shows that (reservoir) sandstones with high porosity shows low acoustic impedance.

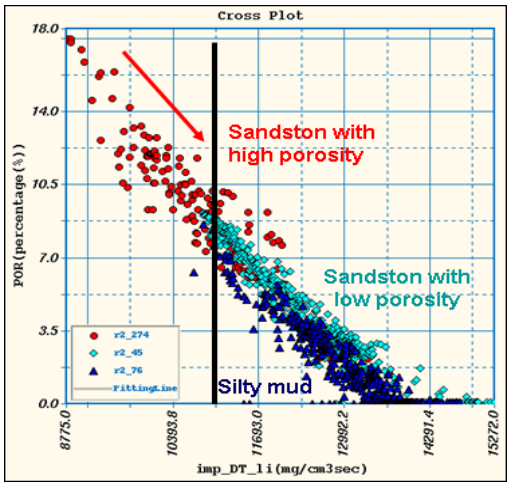

Figure 4. Crossplot of DT and POR.

Exploration experience in the study area indicates that gas and gas-water bearing sandstones with relatively high porosity always show a logging anomaly and, therefore, logs cannot be used to discriminate between gas and gas-water in the pores. There are two suspicious gas layers (36 ft of net pay) at 16770~16840 ft and three gas-water layers (85 ft of net pay) between 16915~17055 ft in well MKSR-1.

Based on the well logging and lithology data, p-wave and s-wave velocity data, and density, the different lithologies, and types of pore fluids (argillaceous siltstone, sandstone, oil-bearing sandstone, gas-bearing sandstone and water-bearing sandstone) were determined (Table 1) and used to build the geological model (Figure 5). Using the geological model as input to forward model the seismic data (Figure 6) and spectrally decomposing that result allows us to analyze the variation of amplitude with frequency (Figure 7). Hydrocarbon detection parameters can be determined by applying wave equation theory and forward modeling techniques.

The forward modeling results show that both high and low frequency attenuation gradients reliably match the well log interpretation—the attenuation gradient can be used as an indicator of the type of pore fluid in the reservoir.

Table 1. Parameters defined from forward modeling.

Lithology definition		P-wave velocity	S-wave velocity	Density
Lithology 1	argillaceous siltstone	5052	3236	2600
Lithology 2	sandstone	4901	3048	2538
Lithology 3	oil-bearing sandstone	4683	2755	2561
Lithology 4	gas-bearing sandstone	4675	2770	2540
Lithology 5	water-bearing sandstone	4690	2750	2570

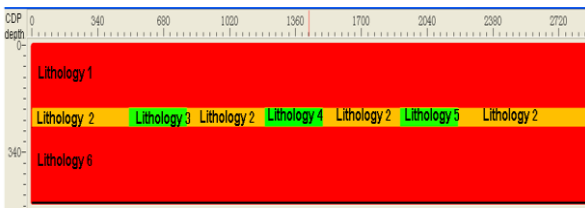

Figure 5. Forward modeling parameters.

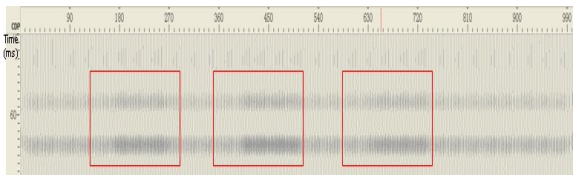

Figure 6. Stacked migration section from forward modeling.

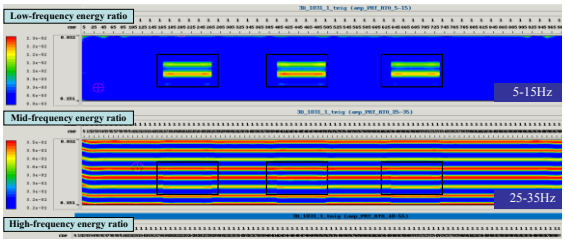

Figure 7. Forward modeling results for the time-frequency analysis.

The primary geophysical techniques for characterizing and mapping the oil- and gas-bearing potential of the low impedance Sarah Formation are well-constrained impedance inversion and spectral imaging. The methodology used in this study shows significant potential for exploration and reservoir characterization of the Sarah in Block B.

The accuracy of a well-constrained impedance inversion model depends on the geological model used as the forward modeling input. The method of least squares is used to minimize the residual (difference) of the modeled and real data. This method combined with available logging, seismic and geological data generates a high resolution result. The spectral imaging technique adopted for this study uses the wavelet transform to generate energy and phase data for single frequencies. This technique can image fine detail within a sedimentary sequence by analyzing the variation of amplitude with frequency.

The combined application of impendence inversion and spectral imaging improves the vertical and lateral resolution of the interpretation and the accuracy of the reservoir model used for simulation. Figure 8 shows the flow diagram of the processes and analyses used in this study.

Results

With fine horizon calibration, accurate wavelet extraction and parameter optimization, a good initial geological model was developed and used for the well-constrained impedance inversion. The impedance volume with values below 11,000 mg/cm^{3}sec was obtained (Figure 4) and mapped (Figure 9) to show the distribution of porous (low impedance) sands—they occur mainly in a north-south zone to the west of well MKSR-1. Neither well is located in a prospective zone, consistent with the well tests that determined the reservoirs are not commercial. Nevertheless, the data indicate potentially good reservoir to the west of MKSR-1.

The wave equation forward modeling indicates that both the high frequency attenuation attribute and the low-frequency energy ratio are very sensitive to the presence of oil-gas in the reservoir.

The calculated attenuation gradients for the intervals for which the well logs indicate gas are mainly below -0.5 in both the MKSR-1 and MKSR-2 wells. Given that fluid-filled sands should have an attenuation gradient even lower, we chose -0.5 as the threshold below which fluid-filled sands are indicated. The distribution of fluid-filled sands was mapped by calculating time-thickness for the Sarah reservoir with attenuation gradients below -0.5.

The low-frequency energy ratio can be chosen as the attribute indicating pore fluid. In figure 11, the areas with high ratios indicate fluid-filled sand.

oth the attenuation attribute and the low-frequency energy ratio indicate that zones of increased hydrocarbon potential are found in a north-south band west of the MKSR-1 well. These results show that the distribution of sand with low-impedance is consistent with the distribution of fluid-filled sand. Results also indicate that porous fluid-filled sand has low-impedance, distinct attenuation gradients and high (low-frequency) energy ratios. The results indicate areas of good potential west of well MKSR-1.

Conclusions

Good reservoir characterization used to develop a good geologic model along with determining the seismic attribute that best corresponds to reservoir potential is very important for determining the appropriate inversion method and for calibrating the interpretation of the inversion results. Forward modeling is an effective method for determining the seismic parameters sensitive to pore fluid. Forward modeling can be considered as a bridge connecting seismic attributes and well geological

attributes. And it can be used to determine the parameters most sensitive to characterizing the pore fluid.

Acknowledgments

The authors would like to thank manager Fan Shengli, Lu Zhanggen, and Zhang Shenggen for their considerable help in this project, and the Sinopec International Petroleum Exploration & Production and Oversea Central Institute, SIPC for permission to publish this work

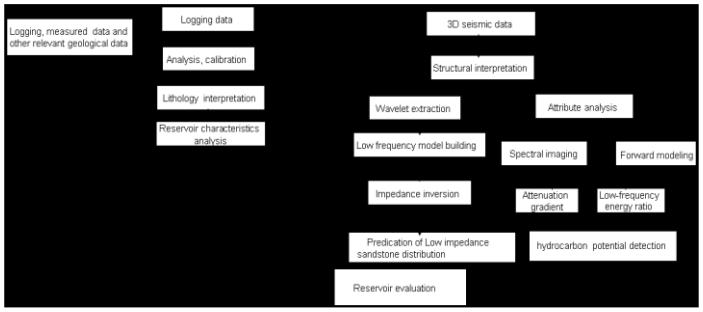

Figure 8. Technical flow of log analyses and seismic techniques for developing the reservoir model for Sarah.

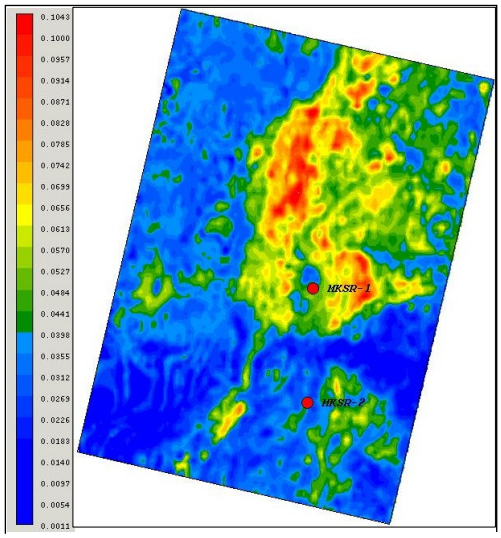

Figure 9. Time thickness map of sand with high porosity in Sarah reservoir

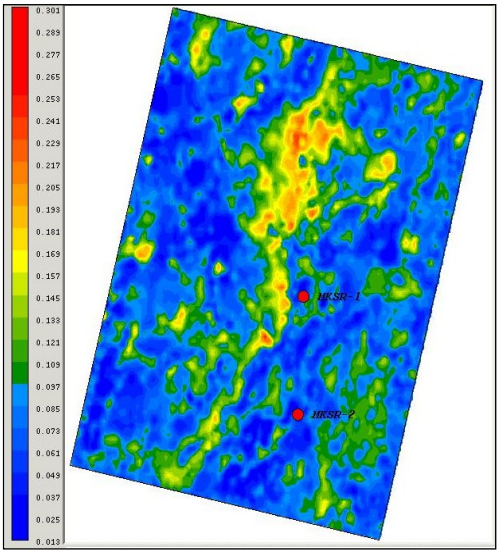

Figure 10. Time-thickness map of high potential sands with attenuation gradients below -0.5.

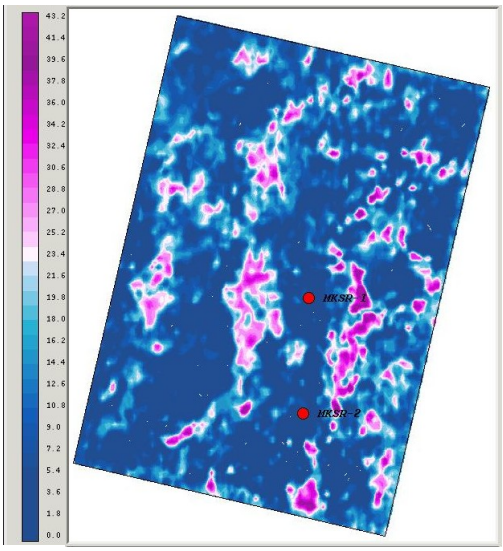

Figure 11. Distribution of low-frequency energy ratios.