Introduction

The ability to predict good quality reservoirs away from well control is vital in field development, particularly in deep reservoir settings where well costs can be high. The Semyrenky field of the Poltava Basin, onshore Ukraine, lies within the NW-SE trending Dneiper-Donets rift basin. The basin is of Late Devonian age, overlain with Carboniferous and Early Permian post-rift clastic marine and alluvial deltaic sediments. The targets for field development are clastic reservoir sandstones of the post-rift sequence, which are buried to depths beyond 5000 m where high levels of compaction limit reservoir porosities to less than 13 %. The high expense of drilling to these depths means that wells must yield good production rates for a sustained period of time to make them economical. Optimal production is typically associated with higher-porosity interconnected sands. Seismic reflectivity data alone cannot reliably identify these productive, high porosity sands. A quantitative interpretation (QI) project comprising statistical rock physics, combined with simultaneous inversion of re-processed seismic data, was successfully undertaken to help identify target areas of superior reservoir quality to assist well planning.

Seismic Re-processing

The seismic data used for this study comprised 260 km^2 of multi-azimuth vibroseis acquired and (first) processed in 2015. An important objective of the project, prior to the QI work, was to improve the quality of the pre-stack imaging by re-processing from field tapes. 5D regularization was an important ingredient in the pre-processing to increase signal-to-noise ratio and infill missing data. Multi-azimuth data was combined pre-stack to further improve signal-to-noise ratio (Hung and Yin, 2012). Post-stack processing improved bandwidth via Q compensation, as well as targeted spectral balancing to further boost the higher frequencies over the zone of interest. An additional 20 Hz of usable high-frequency signal was recovered compared to the legacy PreSTM data as can be seen in Figure 1.

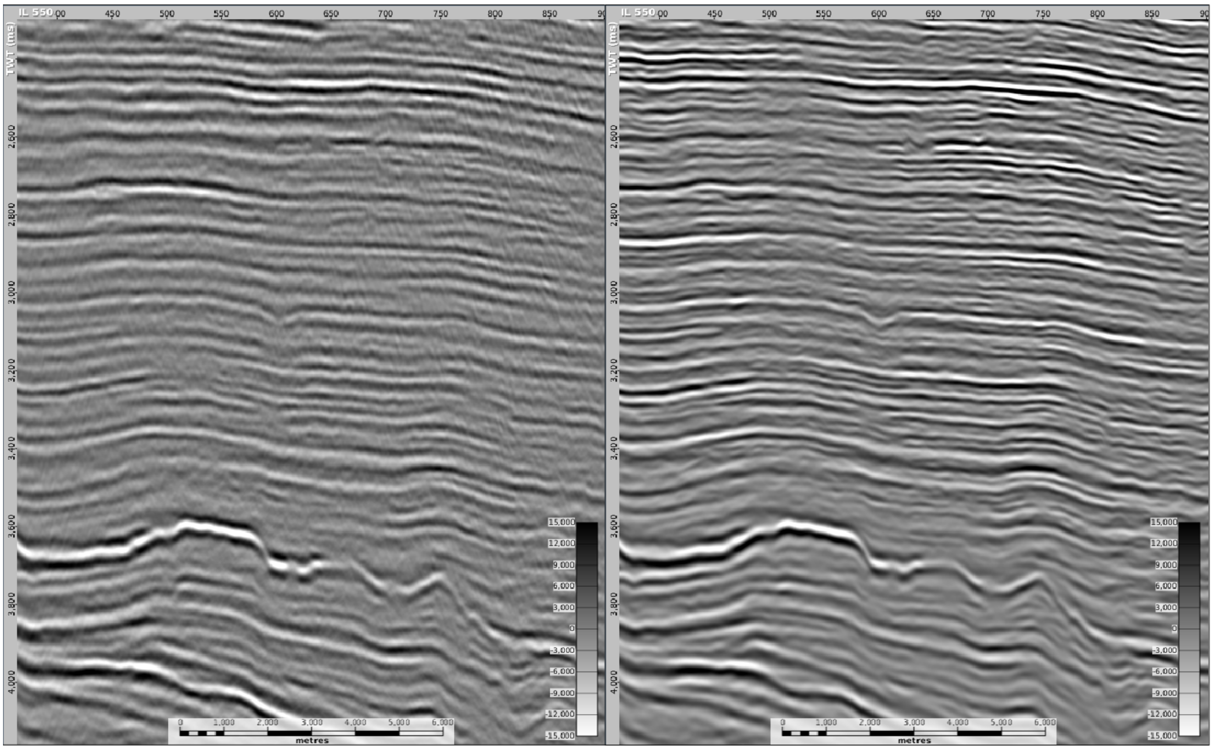

Figure 1: *Full-stack section in TWT from the legacy preSTM processing (left) and the re-processed preSDM (right). The preSDM volume has improved event continuity and has an additional 20 Hz of usable high-frequency signal compared to the legacy volume.*

Statistical Rock Physics

A QI workflow (Lamont et.al., 2008; Thompson et.al., 2011) was implemented to predict lithology in a probabilistic manner in 3D and to quantify variability in reservoir porosity. A statistical, depth-dependent, rock physics analysis was performed using 14 wells. End-member lithology types were identified for both reservoirs and non-reservoirs based on unique trends in their elastic properties (Vp, Vs, density and porosity as a function of TVDBGL). The interpretation revealed three types of sands with distinct porosity trends, as shown in Figure 2. The statistical rock physics model captures the most-likely behaviour and the uncertainty (inherent scatter) in the end-member rock properties. This uncertainty can be sampled stochastically to create probability density functions (PDFs), which define the population behaviour of expected lithology and fluid combinations at every depth level. An example is shown in Figure 3. They form the interpretation template against which the results of simultaneous inversion can be appraised, both qualitatively and quantitatively.

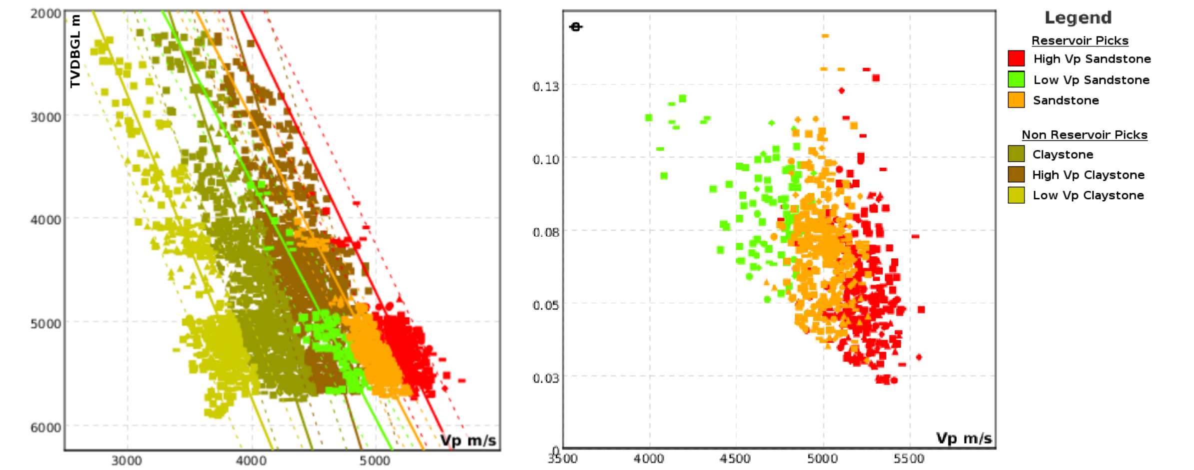

Figure 2: *Statistical rock physics analysis. Samples of the same colour represent end-member picks of a particular lithology. Solid lines are end-member trends and dashed lines are two standard deviations of distribution for each end-member lithology. Reservoir end-members comprise three types of sands ranging in porosity from 2-13%. Non-reservoir lithologies comprise three types of shale.*

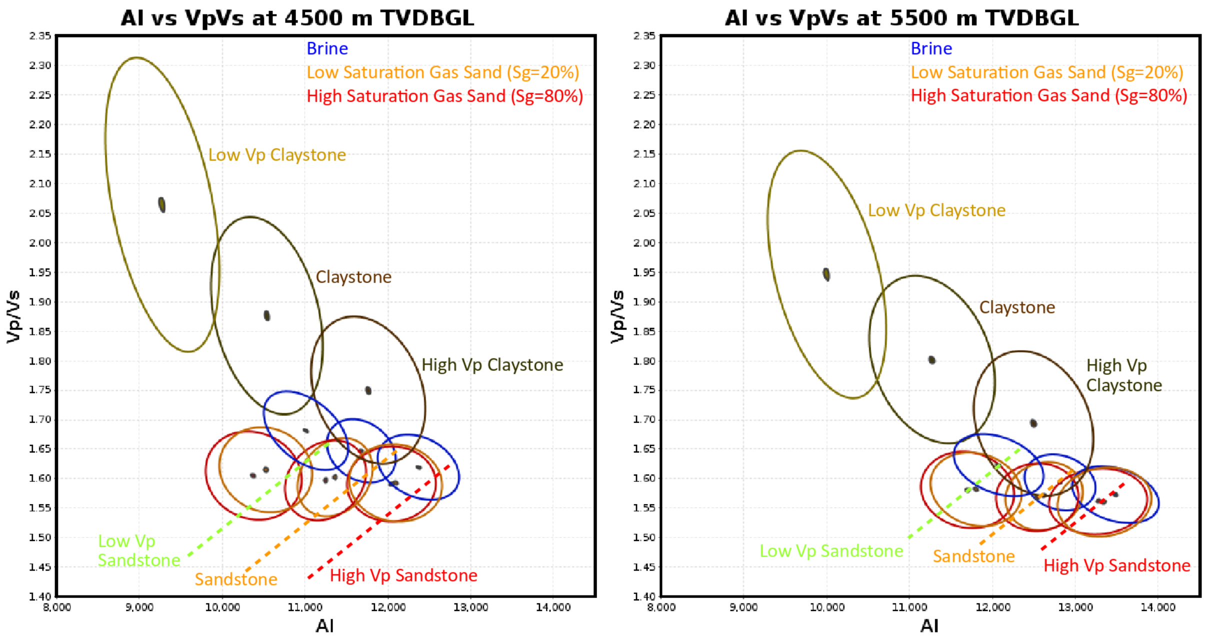

Figure 3: *Stochastic forward modelling results showing the depth dependency of the PDFs at 4500 m and 5500 m TVDBGL. Even at 5500 m there is good separation between the reservoir and non-reservoir distributions.*

Absolute Simultaneous Inversion

Five angle stacks spanning 5 to 30 degrees were used as input into the inversion. Low frequency models were built using a geostatistical approach which incorporated available well logs and regional horizons for structural control. A constrained absolute simultaneous inversion was run to generate elastic rock property volumes of acoustic impedance (AI) and Vp/Vs ratio. These absolute properties were quantitively compared to the corresponding PDFs using a Bayesian approach to produce a range of reservoir probability volumes for the different sand quality types (Figure 4). Porosity as a function of AI relationships for each sand were also developed. The probability volumes were considered as part of the porosity estimation process (Figure 5).

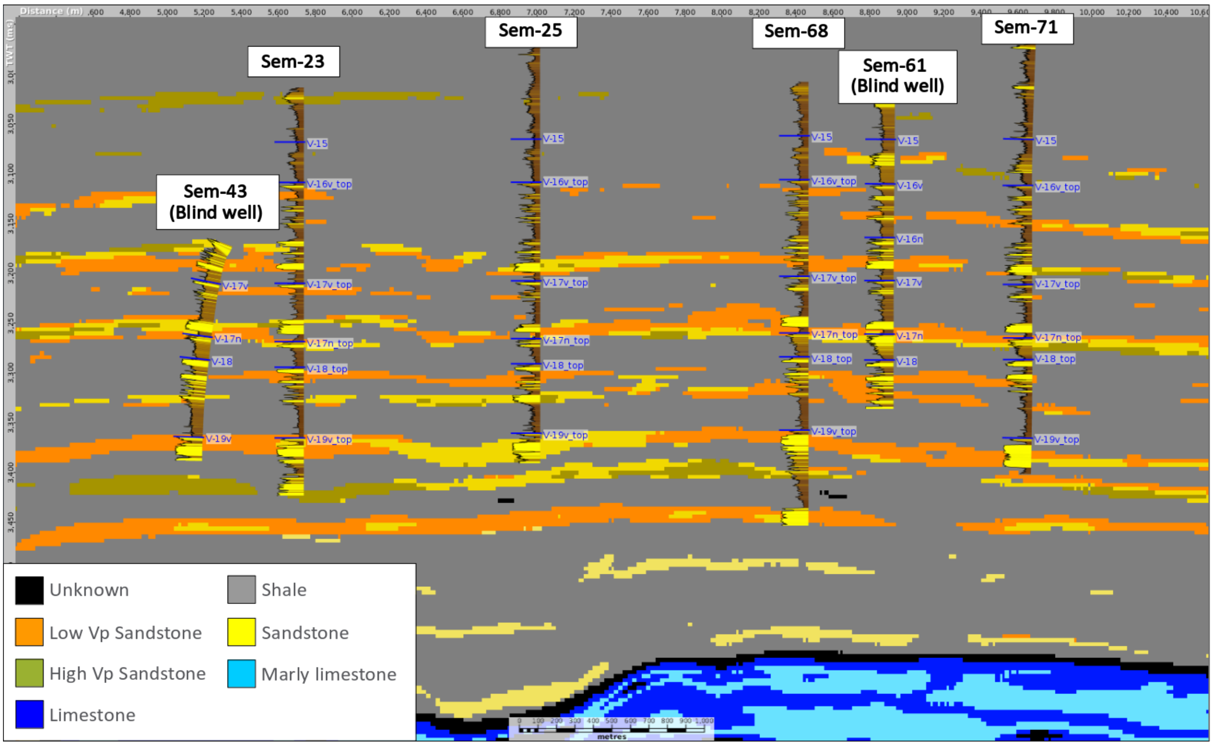

Figure 4: *Arbitrary line showing lithology prediction from absolute simultaneous inversion overlain by Vclay logs. There are good agreements between inversion-predicted and log-defined reservoir sands at multiple intervals across the wells. Two wells (Sem-43 and Sem-61) were drilled after the completion of this study and display a good match between predicted sands and well logs.*

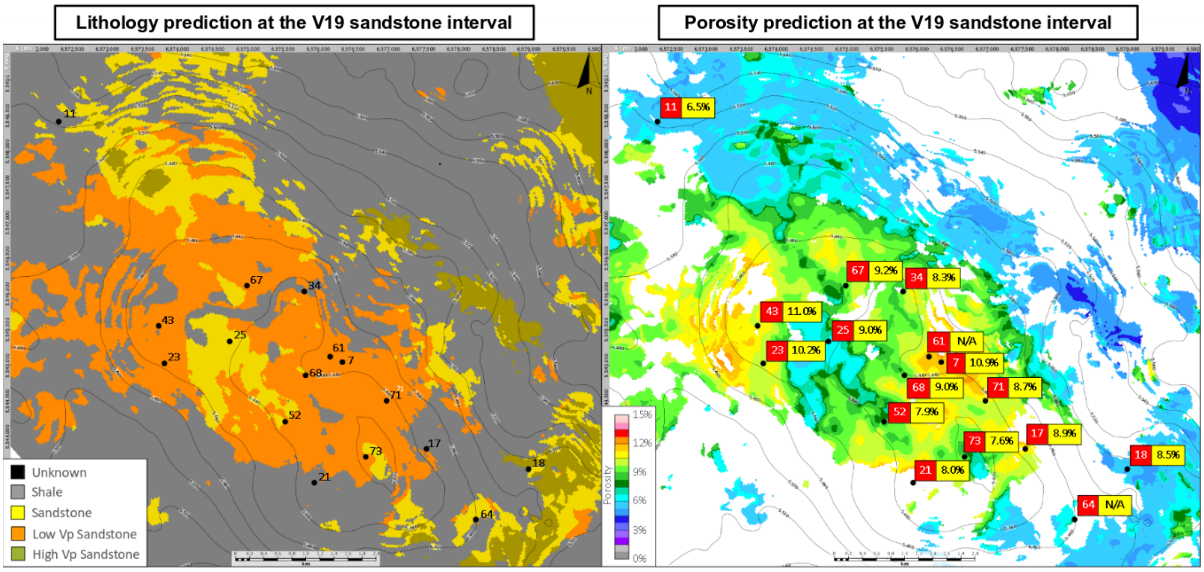

Figure 5: *Map views of the most-likely lithology (left) and predicted porosity (right) across the V19 interval of the Semerenky field. The porosity map is overlain by well-based porosity information. Lithology type and distribution is a major control on porosity variability across the field and has led to poor flow performance for a number of wells. This QI study has allowed the mapping of different lithologies and the prediction of associated porosity, verified by well control. Porosities tend to be highest around the centre of the field and reduce towards the periphery. This fits with the geological setting of a fluvial system where highest porosities are expected in the main channel system.*

Conclusions

Deciding where to place production wells within the Semyrenky onshore gas field can be challenging and uncertain when using only reflectivity data. The best gas flow rates come from large interconnected sand bodies with high porosity. The ability to correctly predict sand distribution and porosity over the field is therefore of great value. The QI workflow applied to achieve this goal used a combination of statistical rock physics (to capture variability and uncertainty in rock properties) and high-quality seismic data, obtained through a bespoke re-processing solution. Seismic inversion was used to generate rock property volumes, which were quantitatively compared to the rock physics model to produce probabilistic estimates of lithology. Existing wells within the field validate the reservoir and porosity predictions produced by this study. Well production data was compared to predicted reservoir quality and showed good correlation. Results at two wells drilled post-study also show a good match between predicted results and well logs for both reservoir presence and quality. The results of this study will be of value in further field development and have helped give possible reasons for historic poor performance in some wells.

References

Hung, B. and Yin, Y. [2012] Optimal stacking for multi-azimuth pre-stack seismic data. *22nd International Geophysical Conference and Exhibition,* Brisbane.

Lamont, M.G., Thompson, T.A., and Bevilaqua, C. [2008] Drilling success as a result of probabilistic lithology and fluid prediction: a case study in the Carnarvon Basin. W.A. *APPEA Journal*, **48**(1).

Thompson, T., Lamont, M., Bevilacqua, C., and Hendrick, N. [2011] Fit for Purpose Seismic Reservoir Characterisation. *Petroleum Geology Conference and Exhibition,* Kuala Lumpur, Extended Abstracts.