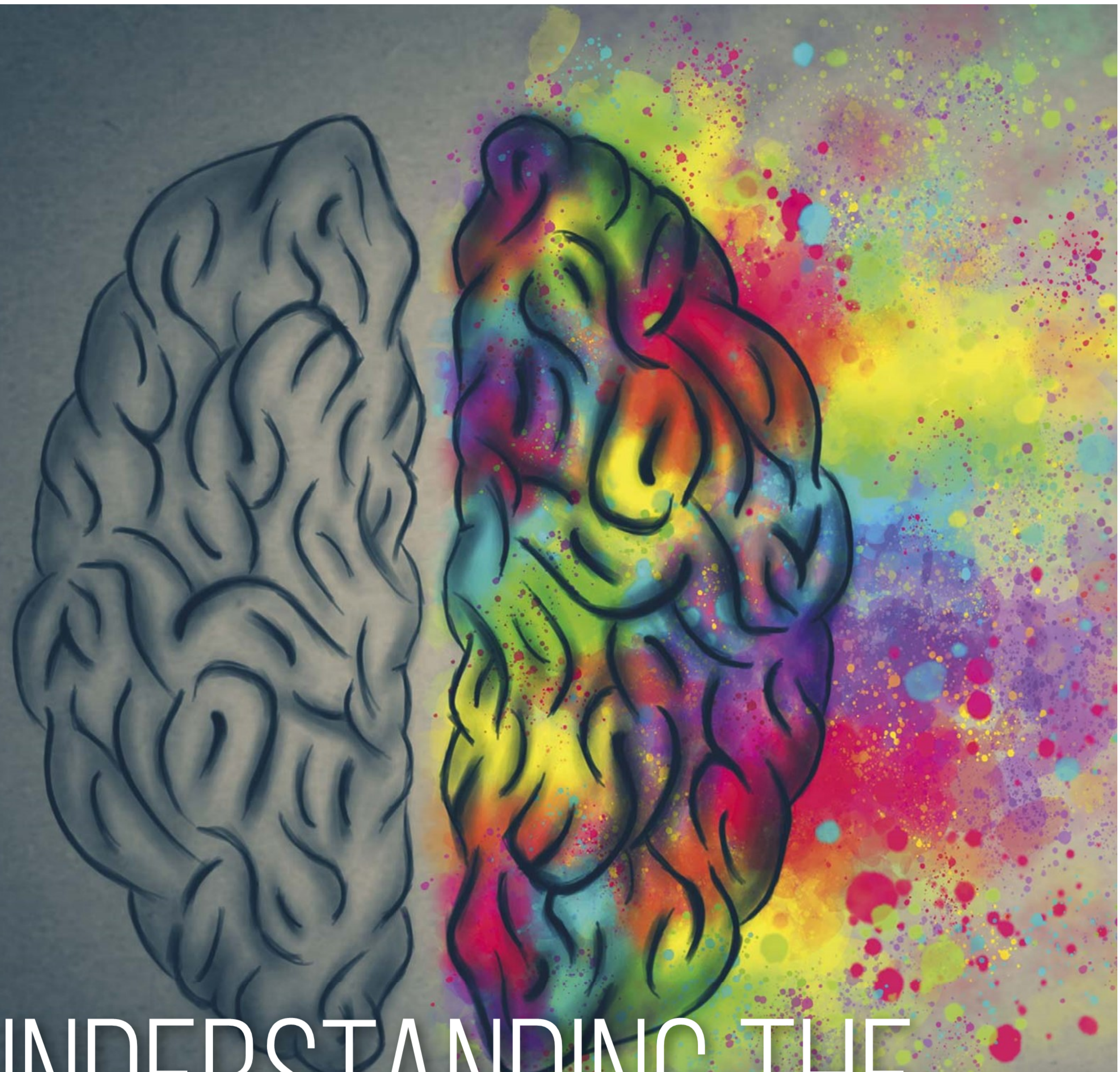

UNDERSTANDING THE UNCONVENTIONAL

Carrie Glaser and Ellen Scott, Fracture ID, Tim Foltz and Kit Clemons, Lario Oil & Gas Company, USA, highlight the driving force of horizontal well production in the Wolfcamp D, Midland Basin.

To develop unconventional reservoirs economically, operators must identify both good reservoir quality and the properties conducive to effective stimulation. By combining conventional petrophysical analyses with geomechanics data, one can attempt to answer the question, 'what drives horizontal well production?' Lario Oil & Gas Company, a Midland Basin operator, drilled and completed seven horizontal wells in the Wolfcamp D. The wells that are less than 12 miles from one another share the same target landing zone, and were completed in a similar manner. However, despite comparable drilling and completion designs, the seven wells' 30 day initial productions, normalised by stimulated lateral length, differed by almost 40%. Moreover, six of the seven wells had more than 90 days of production and varied by nearly 60%.

The Wolfcamp in the Midland Basin is a very heterogeneous formation both texturally and mineralogically. Specifically, the formation consists of highly interbedded carbonates and sandstones with variable amounts of clay and kerogen. This heterogeneity impacts not only the reservoir storage capacity (porosity), but also the producibility. Furthermore, it also influences the effectiveness of hydraulic fracture treatments. This analysis used drill bit geomechanics data, combined with petrophysical analyses, to identify fundamental reservoir properties impacting initial production in the Wolfcamp. This shows that measuring the formation's lateral heterogeneity is important to explain production variability among a set of wells.

Drill bit geomechanics

Drill bit geomechanics provides mechanical rock property data by recording drilling-induced vibrations. Triaxial accelerometers record continuous, high-frequency (i.e. at least 1 kHz) data while positioned behind or in the drill bit. These sensors measure forces on the bit and the resulting displacement from the bit-rock interaction. Earthquake seismology models transform the high-frequency, triaxial,

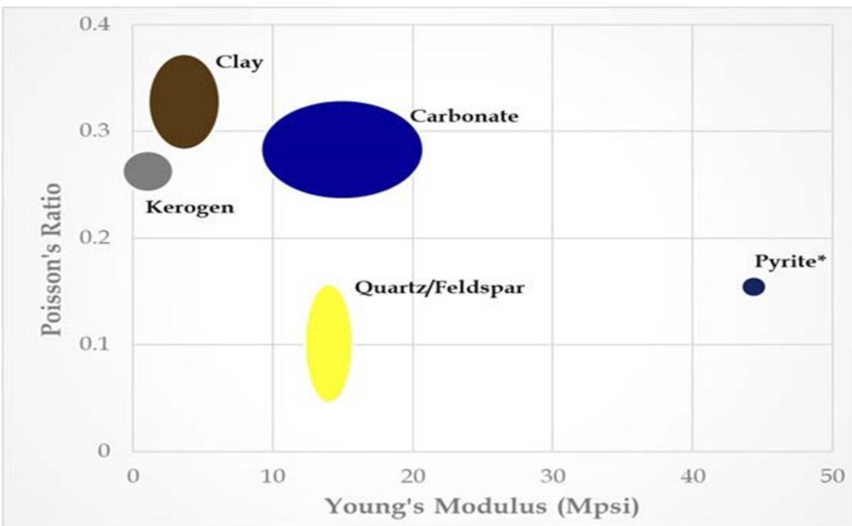

Figure 1. *Graph of approximate Young's modulus and Poisson's ratio ranges for mineral groups. Mineral end-member values are used to derive the four-group mineralogic model in the lateral wells. This figure uses mineral values from the Rock Physics Handbook and other sources.[4,5,6] *Accessory minerals are accounted for using positive correlations to one or more mineral groups.*

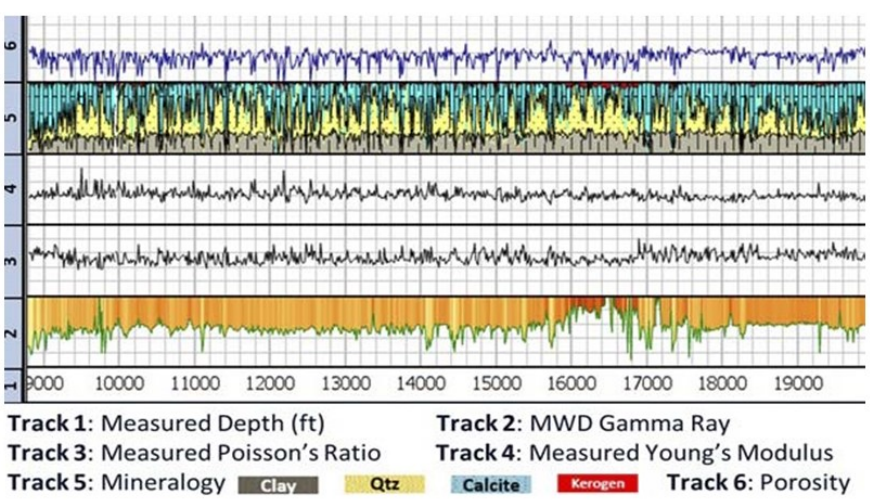

Figure 2. *Example of a petromechanical log along one lateral well. Drill bit geomechanics data are displayed in Tracks 3 and 4. Mineralogy and porosity data from the petromechanical workflow are displayed in Tracks 5 and 6.*

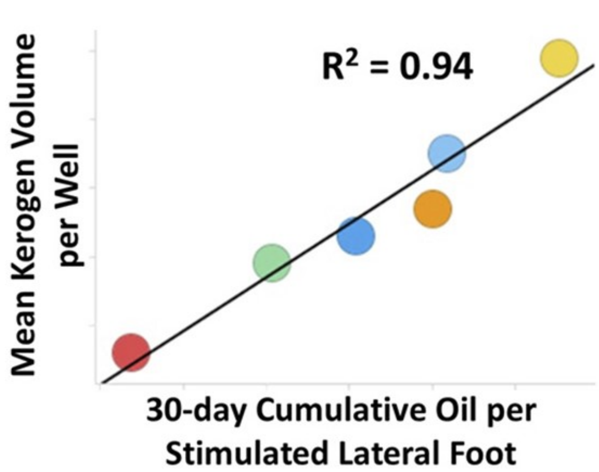

Figure 3. *Comparison of mean kerogen volume and 30-day cumulative oil production for 6 wells. There is a strong correlation coefficient between these variables (R^2 = 0.94).*

drilling-induced vibrations into mechanical rock properties along the drilled wellbore.[1] Young's modulus and Poisson's ratio are determined by resolving the stress-strain matrix with isotropic stiffness coefficients. Anisotropy is estimated by solving for transversely isotropic (TI) derivations of the stress-strain matrix. Generally, a vertically transverse isotropic (VTI) matrix contains laminar bedding, layering, and higher clay content. A horizontally transverse isotropic (HTI) matrix contains fractures or vertical bedding.[1] This article defines VTI anisotropy as layering and HTI anisotropy as fracture intensity.

The primary advantage of this technology is the high-resolution characterisation of geomechanical variability along horizontally drilled wells. This is especially important in highly heterogeneous formations like the Wolfcamp. Overall, to understand the production variability of multiple horizontal wells in a single target formation, one must understand the lateral geomechanical and petrophysical variability that each well encounters.

Petromechanical workflow

Wireline data in a pilot well facilitated a four-group mineralogic model and porosity across the target zone. The mineralogic groups include clay, kerogen, carbonate, and quartz/feldspar/mica (QFM). The relative contribution of different minerals within these groups is built into the pilot well calibration and helps define the effective mechanical properties of each group (Figure 1). From the calibrated mineralogy and porosity, Poisson's ratio and Young's modulus are estimated in the pilot well by leveraging the close association between porosity and Young's modulus.[2] Comparing the resulting mechanical properties to core or sonic ensures the validity of the petromechanical model. The calibration parameters establish a mathematical relationship between the petrophysical properties and the mechanical properties in the pilot well. Then, the relationship is applied in reverse to the lateral wellbore. Here Young's modulus and Poisson's ratio, which are measured during drilling, compute porosity and mineralogy.

Data acquisition in the lateral wellbore consists of measurements while drilling (MWD) gamma ray and three properties from drill bit geomechanics: Young's modulus, Poisson's ratio, and layering (VTI anisotropy).

Layering is used to estimate clay volume directly along the lateral using an empirical understanding of the relationship between mechanical anisotropy and clay.[3] The mechanical derivation of clay volume is then combined with the MWD gamma ray to estimate kerogen volume. This technique assumes that the clay content estimated from gamma ray radioactivity is linearly correlated to mechanical anisotropy and that 'excess' radioactivity relative to anisotropy is a function of non-laminarly distributed kerogen volume. Although these approximations may not be appropriate in all reservoirs, they are suitable for the Wolfcamp.

With the clay and kerogen groups complete, Poisson's ratio determines the relative contributions of the carbonate and quartz groups. This process uses end-member values based on the calibrated mineral contribution and mineral property data (Figure 1).[4] Finally, Young's modulus is combined with the mineralogic solution to estimate porosity. This is accomplished by reversing the porosity-to-Young's-modulus relationship built in the pilot well.

Figure 2 shows an example of this workflow applied to a lateral well. Tracks 2 through 4 contain the input data measured while drilling. Track 5 shows the four-group mineralogic model. In this track, clay is grey, quartz is tan, calcite is blue, and the trace amounts of kerogen are red. The model assumes the volumes of all four mineral groups sum to one. Track 6 shows porosity derived from Young's modulus and calibrated to the pilot well wireline data. For the Lario project, the authors created the four-group mineralogic model and porosity curves for all seven Wolfcamp D wells.

Results

Of the seven Wolfcamp D wells, one well had significant operational issues. As a result, nearly half of its treatment stages failed to place the designed amount of proppant. While there was an attempt to correct production for the under-stimulated portions of the lateral, due to the uncertainty involved in an accurate production correction it was removed from the analysis. Mean mechanical, and reservoir properties for the remaining wells were compared to the normalised initial production. Properties with the highest coefficient of determination (R^2) suggest the strongest impact on initial production.

Of the four inputs to the petromechanical workflow (layering, Young's modulus, Poisson's ratio, and gamma ray), layering had the strongest negative relationship (R^2 of 0.77) to initial production. This negative trend between layering and production was attributed to both the adverse impact of clay minerals on reservoir quality (permeability) and the effect of highly laminar rock types on effective fracture development during stimulation. The analysis confirmed previous expectations that wells with generally higher layering have lower initial oil production. Young's modulus also showed a relatively strong impact on production (R^2 of 0.60); however, the trend was opposite to what might be expected based on the assumptions of a negative correlation between Young's modulus and porosity and a positive correlation between porosity and production. Instead, Young's modulus had a positive relationship to initial production, which implies that wells with higher average porosity have lower initial oil production. As Young's modulus is inversely related to clay volume, this result suggests the mineralogic impact on initial production outweighs that of porosity. Building an effective porosity model may be required to accurately identify the relationship between porosity and production. Neither Poisson's ratio nor gamma ray had a meaningful correlation with production (R^2 of 0.02 and 0.07, respectively).

Mean values for the five outputs from the petromechanical workflow (clay volume, kerogen volume, carbonate volume, QFM volume, and porosity) were then compared to cumulative oil production. As expected from the comparison to Young's modulus, total porosity showed a strong negative relationship to production both in the 30 day and 90 day production periods. Mean porosity values range from 5 to 9%. Lithology with very low porosity (e.g. tight limestone stringers) are poorly represented in this data set and would not be expected to fall on the same linear trend. The QFM and carbonate volumes were more predictive of production than Poisson's ratio alone, (R^2 of 0.18 and 0.31, respectively) but the overwhelming impact of clay volume may also explain these trends.

As shown in Figure 3, the property with the strongest correlation to initial 30 day production is kerogen volume (R^2 of 0.94). The strong correlation between production and kerogen continued for the 90 day production period (R^2 of 0.92).

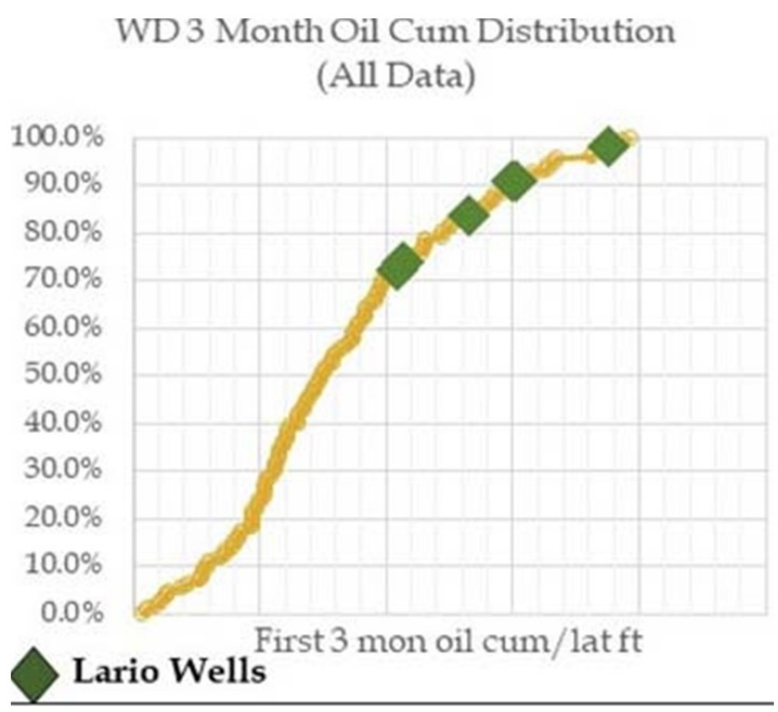

Figure 4. *Probability distribution of 3 month cumulative oil in the Wolfcamp D wells for all operators in Midland and Martin Counties. The green diamonds show Lario's wells.*

Discussion

In this study area, horizontal well production in the Wolfcamp D strongly correlates with kerogen volume. Lario uses kerogen as a critical component in its horizontal well target selection. Thus, the analysis' findings validate this approach. Lario's Wolfcamp D wells consistently produce in the top 30th percentile among wells in the two surrounding counties (Figure 4). Based on this study, the success was likely driven by its attention to reservoir characterisation, specifically kerogen targeting.

The petromechanical workflow primarily uses drill bit geomechanics data. As drill bit geomechanics data are derived from the drill bit-rock interaction, they inherently measure near-wellbore properties. After these wells are stimulated, the multi-stage fracture networks connect the wells to the far field. Despite this caveat, the analysis' positive correlations suggest near-wellbore measurements are essential to initial production. The authors hypothesise near-well petromechanical properties impact stimulation effectiveness during fracturing and near-well connectivity during production.

In Midland and Martin Counties, Wolfcamp D and adjacent targets remain the focus for improving return on investments. To refine the understanding of the near-well properties' role in long-term oil recovery, the team must examine longer production windows. While there is more still to learn, the petromechanical workflow presented here has the potential to offer a cost-effective way to approach field development. Gathering data along horizontal wells reduces the uncertainty in geologic drivers of production variability. Extrapolation of mechanical and petrophysical reservoir properties from vertical pilot wells to lateral targets may fail to capture the meaningful differences between laterals which impact production. Because the workflow's input data are acquired during horizontal drilling, without requiring additional logging runs or drilling rig time, the technique offers a cost-effective and operationally undemanding way to measure the heterogeneity along lateral wells.

Using MWD gamma ray and drill bit geomechanics data in lateral wells allows operators to measure the heterogeneity in key rock properties, including kerogen, to understand early oil production variability. This understanding creates an actionable framework for field development and landing zone optimisation. The petromechanical workflow can apply to other Midland Basin formations as well as formations in other basins.

References

1. HAECKER, A., LAKINGS, J., MARSHALL, E., and ULLA, J., *A Novel Technique for Measuring (Not Calculating) Young's Modulus, Poisson's Ratio and Fractures Downhole: A Bakken Case Study.* Presented at the SPWLA 58th Annual Logging Symposium held in Oklahoma City, Oklahoma, USA, 17-21 June 2017.
2. SHUKLA, P., KUMAR, V., CURTIS, M., SONDERGELD, C.H., and RAI, C.S., *Nanoindentation studies on shales.* Presented at the US Rock Mechanics/ Geomechanics Symposium held in San Francisco, California, USA, June 2013.
3. SONE, H., ZOBACK, M. 'Mechanical properties of shale-gas reservoir rocks – Part 1: Static and dynamic elastic properties and anisotropy.' *Geophysics*, Vol. 78, No. 5 (September – October 2013), pp. 381-392.
4. MAVKO, G., MUKERJI, T., and DVORKIN, J., *The Rock Physics Handbook 2nd Edition* (2009), pp 21-40.
5. ROBERTSON, E.C, ROBIE, R.A, BOOKS, R.A, and KENNETH, G., *Physical Properties of Salt, Anhydrite and Gypsum – Preliminary Report. United States Department of the Interior Geological Survey. Trace Elements Memorandum Report 1048* (1958).
6. PABST, W., GREGOROVA, E., RAMBALDI, E., and CHIARRA BIGNOZZI, M., 'Effective Elastic Constants of Plagioclase Feldspar Aggregates in Dependence of the Anorthite Content - A Concise Review', *Ceramics-Silikáty*, Vol. 59, No. 4 (2015), pp. 326 - 330.