Optimizing CSG development: Quantitative estimation of lithological and geomechanical reservoir quality parameters from seismic data

E. Bathellier
CGGVeritas
27, avenue Carnot
91341 Massy cedex, France
eric.bathellier@cggveritas.com

J. Downton
Hampson-Russell
2200-715 5 Ave SW
Calgary, T2P 5A2, Canada
jon.downton@cggveritas.com

A. Sena
Hampson-Russell
10300 Town Park Dr
Houston, TX 77072, USA
arcangelo.sena@cggveritas.com

SUMMARY

Work over the last decade on seismic azimuthal anisotropy has identified a link between fracture density and orientation observed by well logs and the intensity and orientation of the observed anisotropy. Recent work has correlated these measurements to provide quantitative estimates of fracture density from 3D wide-azimuth seismic data for tight gas sands. The work highlights the impact of advanced seismic processing in successfully recovering reliable fracture estimates which correlate well with borehole observations. These kind of areal, quantitative estimates of fracture density provide a valuable tool to guide drilling and completion programs in tight reservoirs.

Building upon this work and considering Coal Seam Gas plays in particular we need to consider some additional reservoir quality parameters whilst trying to impose the same quantitative approach on the interpretation of seismic data and correlation with borehole logging observations. The characterization of CSG plays involves the understanding of the reservoir matrix properties as well as the in-situ stresses and fracturing that will determine optimal producing zones.

Pre-stack seismic data and azimuthal WAZ (wide azimuth) seismic processing can help in the identification of sweet spots in CSG resource plays through detailed reservoir-oriented gather conditioning followed by pre-stack seismic inversion and multi-attribute analysis. This analysis provides rock property estimates such Poisson's ratio, and Young's modulus, amongst others. These properties are in turn related to quantitative reservoir properties such as porosity and brittleness. In this presentation we show an integrated approach based on pre-stack azimuthal seismic data analysis and well log information to identify sweet spots, estimate geomechanical properties and in situ principal stresses.

Key words: azimuthal anisotropy, 3D seismic, fracture, stress estimation, unconventional gas.

INTRODUCTION

All unconventional gas plays rely on the presence of fractures (either natural or induced) to enhance or create permeability in the reservoir. Fractures cause significant, measureable changes in 3D seismic data. These changes appear as variations in seismic amplitudes and velocities with shot-receiver azimuth and are known as seismic azimuthal anisotropy. Recent publications have correlated these measurements to provide quantitative estimates of fracture density from 3D wide-azimuth seismic data for tight sands (Hunt et al., 2010), coal seams (Gray, 2008) and shales (Gray et al., 2003).

The first part of the work presented here demonstrates the benefits of using advanced seismic processing to improve AVO and AVAZ analysis of a 3D dataset from Western Canada and their economical impact on improving the drilling success (Downton et al., 2011).

More recent advances in pre-stack azimuthal seismic data analysis yield attributes that are correlated to formation lithology, rock strength and stress fields (Sena et al., 2011). In the last part of the work, we show an integrated seismic approach based on the above analysis applied to some shale plays in northwest Louisiana (USA) and well log information. Lithological and geomechanical attributes, Poisson's ratio, Young's modulus, and Differential Horizontal Stress Ratio (DHSR) were estimated from pre-stack seismic data and were found to be highly correlated to observed production data.

METHOD AND RESULTS

CASE HISTORY, WEST CENTRAL ALBERTA

The 3D seismic data in the studied area is an orthogonal survey of roughly 600 square kilometres. The nominal source and receiver line spacing of this 3D survey is 660m and 600m respectively. The source and receiver lines are irregular due to surface conditions, and can be as wide as 100m in some areas. The shot interval was 120m, and the receiver interval was 60m. Full fold was 27, and the nominal fold at the zone of interest was 27. The data are band-limited to about 55Hz.

Implementing pre-stack migration for subsequent AVO and AVAZ analysis in this dataset can be problematic because of the relatively large source and receiver line spacing. Minimum weighted norm interpolation was implemented in five dimensions prior to migration to address this problem. Figure 1 shows a comparison of the pre-stack time migrated (PSTM) gathers without and with interpolation. PSTM gathers after interpolation have fewer migration artefacts and better signal-to-noise.

Viking AVO analysis

The Viking formation in our study area is composed of shoreface sandstone assemblages that often retain 12-14 percent porosity over 0 to 7m thickness and occur at depths greater than 2800m. The sandstones have low permeability (<

1mD) but are commonly overpressured and gas bearing with typical recoverable hydrocarbons of 8 Bcf and 80,000 bbls condensate per section. These variables contribute to a poor correlation between seismic amplitude and measures of porosity thickness (Phi-h), which is what we are trying to predict with the seismic.

There exists a wide variety of AVO attributes that could have been used for mapping and validation. We chose a very simple parameter, the R_p (compressional reflectivity) to R_s (shear reflectivity) ratio (Gidlow et al., 1992). Figure 2 shows the impact of a new processing technique (5D interpolation) on hte estimation of this attribute. The interpolated PSTM AVO flow behaves in the most geologically reasonable fashion and correlates best to the available well control. Table 1 summarizes the correlation coefficients of the linear fit linking the R_p/ R_s ratio attribute to the Phi-h at each well point. It is clear that the new interpolated PSTM method yield the best results. Since this original work was done, nineteen new wells targeting the Viking have been drilled testing these predictions (Table 2). The new wells based on the AVO analysis performed on the 5D interpolated PSTM gathers have on average 32% greater Phi-values than those drilled previous to the study.

Nordegg AVAZ analysis

The Nordegg formation is composed of a carbonate overlain by a sandstone reservoir which is overlain by shales. It averages 12m of net pay with a7% porosity and 0.01 to 0.1mD permeability. To perform the azimuthal AVO analysis the seismic data needed to be migrated with an algorithm which preserved both the azimuthal information and the offset information. Two different azimuthal migration strategies were tried: azimuthally sectored migration and Common Offset Vector (COV) migration. In practice, there are a number of issues and limitations with this approach. This can be addressed by using 5D interpolation to fully populate azimuthal gathers. The AVAZ analysis used here is based on the near offset Rueger (1996) equation. Assuming the crack theory of Hudson (1981), the anisotropic gradient, (one of the parameters of Rueger equation) is proportional to the fracture density and can be quantitatively related to the image log data from the well control. We may thus objectively compare different processing flows in similar fashion as we did in the Viking part of this paper.

Figure 3 shows the anisotropic gradient at the Nordegg horizon with two horizontal well logs superimposed. Once again the interpolated results appear to be less noisy than the results without interpolation and appear to have better correlations to the well control. Examining Figure 3 to determine the quality and accuracy of the three interpolated results is subjective. In order to objectively and quantitatively compare these results, linear regressions were computed between the anisotropic gradient for each of the processing flows and fracture density of the image logs. Table 3 shows that the COV migrated results are slightly superior to the azimuthally sectored migrated results.

CASE HISTORY, NW LOUISIANA

Reservoir characterization workflow

Isotropic pre-stack seismic data analysis provides only after calibration with well data quantitative understanding of rock geomechanical properties such as acoustic impedance, Poisson's ratio and Young's modulus (Goodway et al., 2010). These properties are in turn related to quantitative reservoir properties such as porosity, mineral composition and water saturation.

Understanding fracture behaviour in shales requires azimuthal anisotropic analysis and interpretation. The preservation of azimuths from the processed seismic gathers through azimuthal velocity and AVO analysis, in combination with geomechanical properties derived from isotropic methods, can be used to predict in-situ stresses acting on shale reservoirs. Such stresses, when oriented, would yield oriented fracture patterns during well completion and can be used in a predictive mode to design optimal well completions.

An important parameter for prediction of hydraulic fracture behaviours, the Differential Horizontal Stress Ratio (DHSR), can be estimated solely from the seismic parameters, without independent knowledge of the stress state of the reservoir. Estimated stresses should be calibrated to the stress state of the reservoir derived from drilling and completion data, microseismic analysis and regional information. In some cases, optimal targets exhibit relatively high values of isotropic Young's modulus (more brittle) and low differential horizontal stress ratio (no preferential orientation). Such zones are more prone to fracturing and tend to fracture randomly; producing radial fracture swarms when completed which can access a larger reservoir volume and thus potentially have increased production.

Using this workflow, we present the results from a Haynesville study in northwest Lousiana, USA.

Seismic rock properties

Petrophysical methods used for conventional reservoir analysis appear to work well in the Haynesville and Mid-Bossier shales, despite the fact that these reservoirs are unconventional. Elastic properties associated with free gas in gas-bearing rocks in conventional reservoirs also appear to be associated with gas-bearing rocks in the Haynesville and Mid-Bossier.

Azimuthal Analysis

Anisotropy plays a key role in the sweet spot discrimination and optimization of horizontal well placement on the Haynesville shale. In order to estimate the stress field distribution, the azimuthal data were adequately recorded and processed: S/N values were maximised, reflector events flattened and amplitude variations preserved.

Seismic Analysis and Stress Estimation

Analysis of the data suggests preferential development locations in areas that have a combination of certain key rock properties. A detailed rock property analysis shows that Poisson's ratio bring valuable information in identifying these areas. Well calibrated Young's modulus estimates from pre-stack seismic inversion can then identify brittle areas within the shale. However, interpretation of Young's modulus alone is insufficient to identify optimum targets for hydraulic fracturing (Gray et al., 2010). It is also necessary to understand the relative stress regime characterized by DHSR. Areas that display both low DHSR and high Young's modulus values characterize ideal areas for hydraulic fracturing, as indicated in Figure 4. Hooke's law provides the relationship between stress and strain which is controlled by the elastic properties of the rock. By combining this information through linear slip theory (Gray et al., 2010), the three principal components of the stress tensor can be obtained.

Multi-Attribute Analysis / Integration

Fractures will propagate without a preferential horizontal orientation in brittle areas with low DHSR. Figure 5A displays a cross plot of these properties in the Haynesville within the study area. Figure 5B shows a map of the most probable optimal hydraulic fracturing zones in the lower Haynesville.

A key objective of this work was to use isotropic and anisotropic attributes derived from 3D seismic data to predict rock property behaviour away from well control. Multi-attribute analysis determines the best fit to known logs (control) at well locations and then applies the corresponding multi-attribute transform to the 3D volume. Input data included the results of the simultaneous inversion, pore pressure prediction, stress analysis, curvature and other seismic attributes. In general, we found that no single attribute provides enough information to correlate seismic data to production. By correlating multiple elastic and stress-related attributes to initial 6 months production (compensated for horizontal well length) at well locations, a predicted production map can be generated (Figure 6) with 95% correlation to existing wells. The map shows several undrilled areas with potentially high predicted productivity. The main drivers in this correlation are the Young's modulus, the DHSR, Poisson's ratio and density.

Validation

A seismically derived prediction of the stress regime must be calibrated to core and well test measurements. In order to validate the use of multi-azimuth seismic data to predict local stress regimes, we compared the predicted local stress fields to triaxial measurements from core samples at two locations. The full strain tensor and the principal stress directions were measured from these core samples, which then served as baseline values to which seismic predictions were correlated. We found that the direction of maximum horizontal stress, predicted from seismic observations, matched the corresponding cores stress measurements to within 5%.

CONCLUSIONS

The case studies show that seismic attributes can be correlated to observed fracture intensity and production results. Including 5D interpolation in the seismic data processing sequence in the presented Canadian examples improves the AVO and AVAZ results as compared quantitatively to the well control. But the use of 5D interpolation should not be viewed as a justification to acquire sparser land seismic data.

We also presented an integrated seismic approach for shale production development based on pre-stack azimuthal seismic data analysis and well log information to estimate geomechanical properties, predict in-situ principal stresses, and identify preferential drilling locations. Young's modulus and Poisson's ratio prove to be valuable for target discrimination. DHSR, a critical parameter in the fracture stimulation was estimated and calibrated by triaxial test measurements. Production estimates were also derived from combining geomechanical and stress properties. With similar input data sets, this methodology can easily be extended to CSG development with minimal modifications.

ACKNOWLEDGMENTS

The authors would like to thank CGGVeritas for permission to show its results.

REFERENCES

Downton, J., Hunt, L., Trad, D., Reynolds, S., and Hadley, S., 2011. 5D interpolation to improve AVO and AVAZ: a quantitative case history; VII INGEPET conference.

Gidlow, P., Smith, G., and Vail, P., 1992. Hydrocarbon detection using fluid factor traces, a case study: How useful is AVO analysis? Joint SEG/EAEG summer research workshop, Technical program and Abstracts, 78-79

Goodway, B., Perez, M., Varsek, J., and Abaco, C., 2010. Seismic petrophysics and isotropic-anisotropic AVO methods for unconventional gas exploration.; TLE, vol. 9, 12, p. 1500-1508

Gray, D., 2008. Fracture Detection in Unconventional Gas Plays Using 3D-Seismic Data; SPE-114902-PP.

Gray, D., Boerner, S., Todorovic-Marinic, D., and Zheng, Y., 2003. Analyzing fractures from seismic for improved drilling success, World Oil, Vol. 224, No. 10.

Gray, D., Anderson, P., Logel, J., Delbecq, F., and Schmidt, D., 2010. Estimating in-situ, anisotropic principle stresses from 3D seismic; 72nd EAGE Annual Meeting.

Hudson, J.A,., 1981. Wave speeds and attenuation of elastic waves in material containing cracks. Geophysical Journal of the Royal Astronomical Society, 64, 133-150.

Hunt, L., Reynolds, S., Brown, T., Hadley, S., Downton, J., and Chopra, S., 2010. Quatitative estimate of fracture density variations in the Nordegg with azimuthal AVO and curvature: A case study; TLE, vol. 29, 9, p. 1122-1137.

Rueger, A, 1996. Reflection Coefficients and Azimuthal AVO Analysis in Anisotropic Media. Doctoral Thesis, Centre for Wave Phenomena, Colorado School of Mines.

Sena, A., Castillo, G., Chesser, K., Voisey, S., Estrada, J., Carcuz, J., Carmona, E., Hodgkins, P., and Schneider, R., 2011. Sesimic reservoir characterization in resource shale plays: stress analysis and sweet spot discrimination; TLE

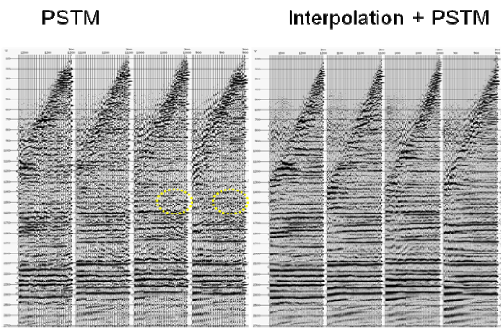

Figure 1. PSTM migrated gathers without (left) and with interpolation (right).

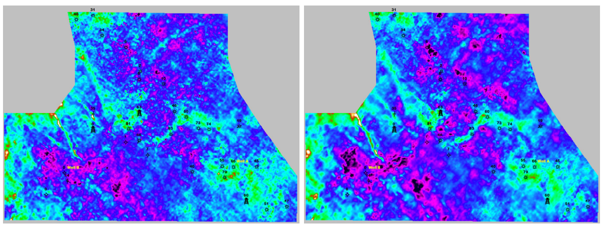

Figure 2. Maps comparing the R_p/R_s ratio attributes. The PSTM based on the interpolated gathers (right) has a better S/N ratio and less footprint than that without (left).

Correlation Coefficients	No migration	Poststack migration	Prestack migration
Raw gathers	0.14	0.12	0.39
Super gathers	0.29	0.15	0.28
Interpolated gathers	0.18	0.18	**0.57**

Table 1. The correlation coefficients of the different data processing versions that the AVO attribute was extracted from and regressed with Phi-h.

Economic models	Count	Average PHI-H	% Diff	3 Month IP Prediction (mcf/d)	EUR Prediction (mmcf)	NPV 10 high price deck ($M)	IRR high price deck (%)	Pay Out (yrs) high price deck	NPV 10 low price deck ($M)	IRR low price deck (%)	Pay Out (yrs) low price deck
All Wells	69	39.8	-20%	859	1535	$ 3,125	25	2.6	$ 1,525	17.2	3.6
Wells not targetting Viking	18	6.0	-88%	665	1176	$ 1,575	18	3.4	$ 335	10.7	4.6
Old Wells, targetting Viking	32	49.5	0%	948	1707	$ 3,800	29	2.3	$ 2,095	20.1	3.2
New Wells, targetting Viking	19	65.3	32%	1144	2092	$ 5,000	35	1.9	$ 3,100	24.5	2.7

Table 2. New drilling results and their economic impact.

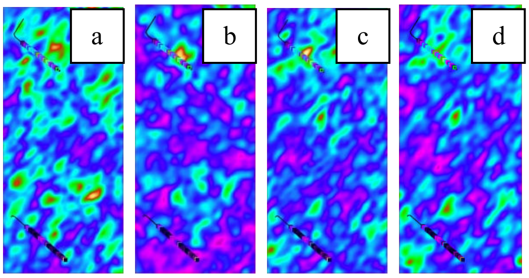

Figure 3. Horizon attribute maps of the anisotropic gradient at the Nordegg level.

AVAZ sensitivity to sampling		
Correlation coefficient with image log	1x1 average	5x3 average
No interpolation, azimuthal sectored migration	0.417	0.485
Interpolation, azimuthal sectored migration	0.621	0.684
COV, surface consistent regularization		0.705
COV, sub-surface consistent regularization		0.693

Table 3. The correlation coefficients for the interpolated and non-interpolated flows. The supergather size is indicated in the column label (e.g. 5x3).

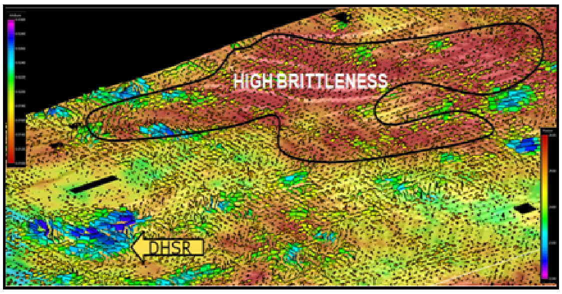

Figure 4. DHSR plates (indicating magnitude and orientation) overlaying Young's modulus values estimated from the seismic data.

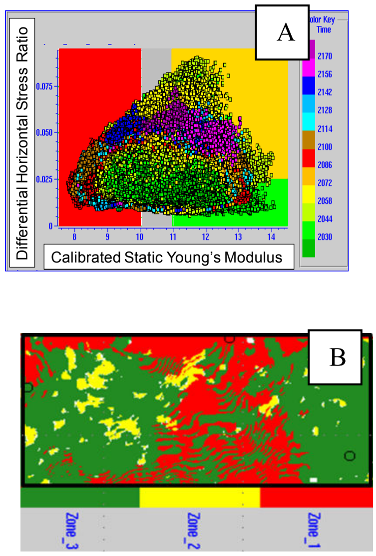

Figure 5. A. Cross plot of calibrated static Young's modulus against DHSR. B. Map showing the color overlay from the zones in A, where green is indicative of optimal fracturing based on these attributes.

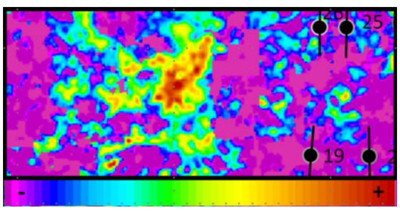

Figure 6. Potentially high-productivity area that have yet to be drilled.