ILLUMINATING 3D FRACTURED RESERVOIRS BY INTEGRATING 2D VSP AND VERTICAL INCIDENCE DATA

N. ENESCU[1], C. COSMA[1], S. J. EMSLEY[2] AND P. SHINER[3]
[1]*Vibrometric, #204, 372 Richmond St. West, Toronto, ON, M5V1X6, Canada*
[2]*Golder Associates, Clyde House, Reform Road, Maidenhead, UK*
[3]*Shell Italia Roma, Italy*

ABSTRACT

Over the studied area of a fractured carbonate reservoir few faults or fracture zones were interpretable with confidence from the surface seismic data due to the variable quality of these data. From earlier experience, [4], it was considered that VSP data may produce information on faulting and/or fracturing that may otherwise be difficult to determine with certainty. It is shown here that VSP, including vertical incidence, data can contribute to the understanding of the investigated reservoir and enables well-derived information to be extrapolated away from the wells. This case history also shows that by integrating the processing of two different data sets from two different wells acquired at different times a more complete image of the sub-surface can be interpreted thereby enhancing the value of 2D data sets.

INTRODUCTION

VSP and vertical incidence data acquired in two wells were reprocessed, in order to image fracture systems and other geological features, displaying contrasts in reflectivity and map these in 3D space. Geometric information on the structures identified through this investigation was integrated with the interpretation of image log information and the seismic interpretation. The geometry of the two wells and position of the shots is shown in *Figure 1a*. Data were recorded from one zero offset and one far offset for Well 1; whilst the data were recorded in Well 2 as a vertical incidence survey and utilised five offsets, located on surface above the well track.

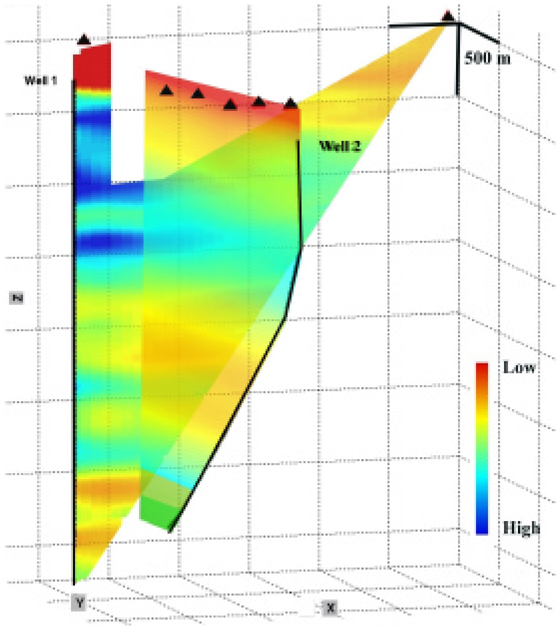
It should be noted that the ability to image fracture systems and other geological features is dependent on the limitations imposed by the frequency content of the data, the number of components recorded (i.e. single or three component data) and the available geometries between source points, well and receiver string. The ability to locate reflectors, once imaged, is dependent on a sufficient number of offsets having been recorded to define the azimuths of the reflectors.

VSP DATA FILTERING AND REFLECTOR IMAGING

The reflecting interfaces in the rock mass are generally from lithological contacts but can also be from faults, fracture zones and dissolution features. Reflections from faults and fracture zones usually display relatively weak seismic characters and extensive processing of the VSP sections is needed to obtain information on the position of these reflectors. The processing of the data described in this case study was accomplished in two stages.

In the first stage, termed Pre-Processing, data pre-conditioning, time picking, frequency analysis and filtering (5 – 60 Hz), rotation, velocity estimation, wavefield separation and amplitude compensation and equalisation were undertaken. The P-wave frequencies of the data are quite low for the fracture imaging methodology and this has an effect on the detection and resolution of features in the VSP data.

An appropriate velocity model is of outmost importance for all subsequent processing, as the velocity variation in the area is significant and assuming a constant or quasi-linear velocity model cannot be justified. A velocity model was derived by tomographic inversion of the P-wave arrival times obtained from the VSPs acquired in the two wells [2]. The reconstruction was constrained with the use of the resampled sonic log data. *Figure 1a* depicts the 3D velocity distributions around the wells and the reconstruction errors along the wells are shown as relative percentage errors in *Figure 1b*. The match between the velocity models and the sonic logs are generally good, although departures are seen in the near surface. The fact that the relative errors have mainly zero mean values implies that the variations in the major trends along each well were determined correctly.



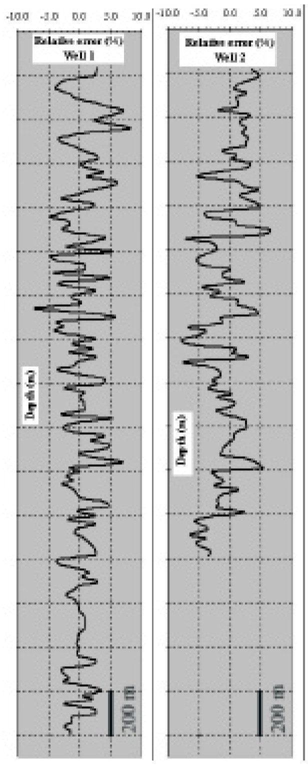


Figure 1. 3D geometry and P-wave reconstructed velocity fields (left: a). Relative estimation errors of the velocities along the wells from tomographic inversion (right: b).

On completion of the Pre-Processing stage, it can be seen, for example in the zero offset section of Well 1, that some reflection patterns are visible in the VSP section (*Figure 2a*), although these are generally weak. Whilst a large amount of reflected energy is visible at this stage, it is masked by non-coherent back scattered energy and the principal reflectors cannot be seen clearly.

The second stage of processing, termed Reflector Imaging, generally involves 3 component Image Space filtering, polarisation analysis and dip filtering [3]. During this stage, due to the anticipated weak seismic character and strength, the first step in the processing sequence is to improve the signal-to-noise ratio, so that weak coherent events, e.g. reflections, become visible. As the reflection coefficients are expected to be low, the reflectors cannot be identified by amplitude contrast. Phase consistency is a much more sensitive indicator of reflectors but this must be used with caution as there is always a degree of coincidental coherency in the data, which may create artefacts, in the absence of true events [1]. If the data quality is poor this can result in over processed profiles. An example of the results obtained after the Image Space and dip filtering is shown in (*Figure 2b*). It can be seen that after the removal of noise the weak coherent events become clearer.

Once all seismic profiles have been filtered, information on the position of a reflecting interface can be obtained using an interactive 3D fitting procedure, illustrated in *Figure 3,* applied to clustered coherent events that most probably originate from the same region in space. In this formulation it is assumed that the fracture zones develop more or less along planes. 3D imaging is an interactive interpretative exercise that utilises expert judgment and an interactive decision making process is undertaken. This procedure consists of fitting a time-depth function to an observed coherent pattern in the processed seismic profiles. Each curve is paired with a point in the Image Point (IP) space, which in turn determines the geometry of the corresponding reflection plane up to its relative azimuth. To determine the dip and true interpreted azimuth Crux Point analysis is undertaken.

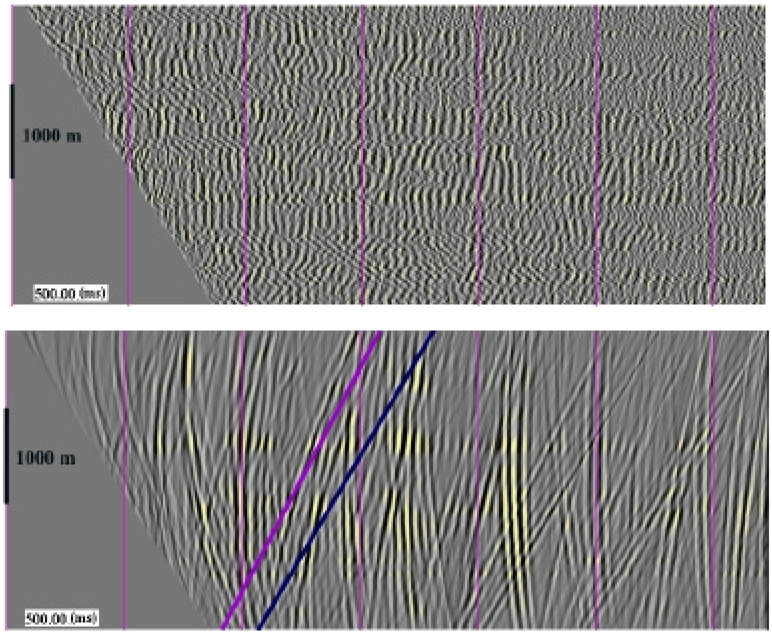


Figure 2. Axial zero offset VSP profile acquired from Well 1, after the Pre-Processing stage (above: a) and after the Reflector Imaging stage (image space & dip filtering) (below: b). The time curves generated by two gently dipping reflectors are marked.

A Crux Point, defined as the foot of the perpendicular projected on to a given reflection plane from a common origin for all profiles, can be used to describe a reflection plane. When the azimuth is not determined, the Crux Point defines a locus in 3D space, as shown in *Figure 3*. If the coherent pattern originated from the same reflector, assumed to be quasi planar, was determined from several seismic profiles, the corresponding Crux curves will intersect/cluster, in the same region of space.

The unknown dip-azimuth corresponding to a reflector plane can therefore be determined as the intersection point of several Crux curves. Where the information is available from only two source locations e.g. Well 1 a unique solution cannot be determined, unless reliable amplitude data for all components is available. However, by combining data sets from both wells and using a 3D fitting procedure, [3], it is possible to constrain the solution and uniquely determine the orientation of the mapped structures.

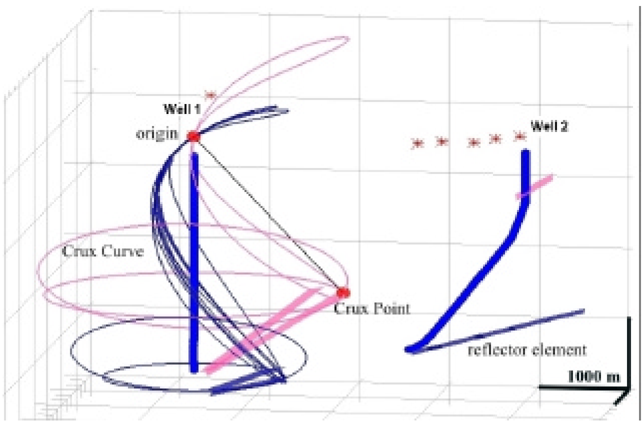


Figure 3. Crux Point diagram for both wells. The Crux Point curves and the interpreted reflecting elements of the two gently dipping reflectors marked in *Figure 2* are represented in 3D.

INTEGRATION

The imaging process has resulted in a number of reflectors being identified in the data, with certain reflector segments being identified from the data from different source points. Where these have approximately the same parameters, in terms of dip and dip direction, these are interpreted to be sections of the same reflector or reflector group and are designated as such.

The results of the specialist VSP processing (*Figure 4*) were validated by comparing identified reflectors against the results of image log analysis [4]. Initially, only part of the structures could be identified, utilising only the existing archive data from Well 1. As data from only two source locations were available from this well, two equally probable solutions for the interpreted structure in the region could be proposed. Once the vertical incidence data from Well 2 were available and the two data sets were interpreted in an integrated system, the azimuthal ambiguity could be removed and more features could be interpreted with confidence around the two wells.

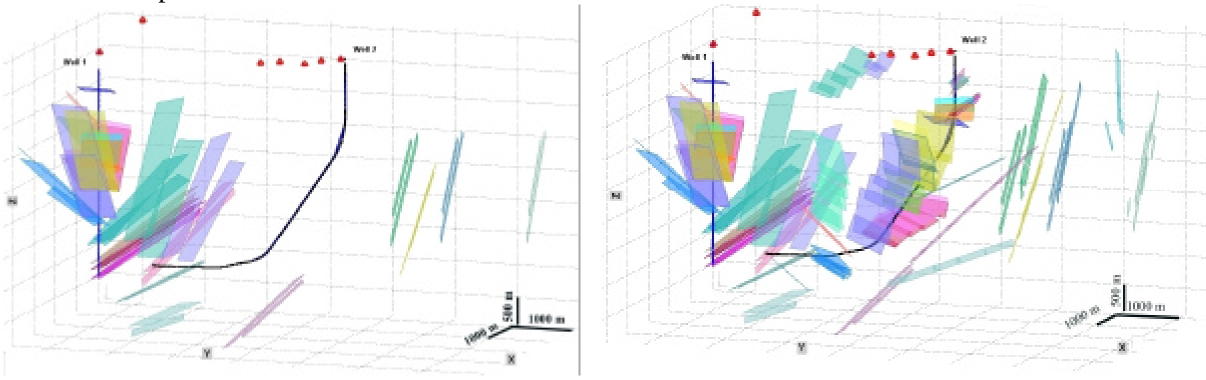


Figure 4. 3D view of interpreted reflectors. (a) Left: one option for elements identified from Well 1 only; (b) Right: elements identified from both Well 1 and Well 2.

The combined interpretation of data sets from the two wells resulted in reflector elements with a range of dips and dip directions as can be seen in *Figure 4*. Those gently dipping reflectors may be interpreted to represent or be related to bedding, whilst those with steeper dips are likely to represent faults and fractures.

CONCLUSIONS

Specialised VSP processing and integrated interpretation results in a high resolution 3D structural data/model that can be used in areas away from well control. If 2D data sets, which may not be regarded as appropriate for processing, exist and at a later date further data becomes available from the same region, these may be successfully used for a combined interpretation that can illuminate the space around the wells. This case study demonstrates that VSP data contain significant information that can be extracted, either from a single well or by integrating the processing of a number of wells, thus enhancing the value of 2D data sets. Based on the large number of surveys and direct and indirect verifications, multi-azimuth multi-offset VSP data are considered to be a powerful tool for determining the positions and orientations of fracture zones when characterising structurally complex reservoirs.

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