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Diffraction imaging applied to pre-existing 3D seismic data to map fracture corridors in an unconventional play

Marianne Rauch-Davies^{1*}, Kostya Deev¹, Danil Pelman¹ and Maria Kachkachev-Shuifer¹ demonstrate how naturally occurring fractures in tight rocks can be detected using conventionally acquired seismic data.

‘Unconventional reservoir’ is a commonly used term that refers to rocks containing hydrocarbons which cannot be exploited with conventional technologies. However, this terminology is in flux as unconventional reservoirs are becoming more and more the conventional approach to hydrocarbon exploration. Generally, these rocks are tight and most of the time they are the source rock for the conventional reservoirs. Exploration and production from this reservoir type is relatively recent and through success and failure we learnt that it is essential to map the sweet spots. These consist of areas with high total organic content (TOC), high brittleness of the rock, knowledge about the maturity of the hydrocarbons and presence or absence of naturally occurring fracture swarms and corridors.

The concept that naturally occurring fractures in tight rocks can be detected using conventionally acquired seismic data is taking hold in our industry. Various methods are currently being developed and applied but generally these are indirect measurements like attributes such as coherence or curvatures and structural interpretation. The only direct measurement is diffractivity and we will discuss the MultiFocusing diffraction imaging technology and show the application on a 3D case example from Siberia.

The amplitudes of diffracted waves are much weaker than those of specular reflections. Diffractions are essentially lost during the conventional processing/migration sequence, or they are masked in conventional seismic stacked sections. Local structural and lithological elements in the subsurface of a size comparable to the wavelength are usually ignored during processing and indirectly identified only during interpretation and not through direct measurements.

The imaging method is based on the MultiFocusing move-out time correction (Berkovitch et al., 2009), which adequately describes not only reflection but also diffraction events. Optimal summation of the diffracted events and attenuation of the specular reflections enables the creation of an image that contains mostly diffraction energy. We will

briefly describe the theory of the MultiFocusing method and demonstrate the efficiency of the proposed diffraction imaging technique on a data case study. This technology does not require seismic data that was specifically acquired for this task and data with any shooting design can be utilized.

Technology

The MultiFocusing method (Berkovitch et al., 1994, Landa et al., 2009) consists of constructing a zero-offset image wherein each trace of this image is computed from pre-stack traces arbitrarily located around an imaging position. This modified move-out correction does not require knowledge about the subsurface and, unlike in the CMP method is valid for arbitrary observation geometry.

Let us consider the ray diagram in Figure 1. A normal ray starts at the central point X_0 at an angle β with the vertical, hits the reflector Σ at the normal-incidence point O (NIP) and turns back to X_0 . Its reflection travel time is denoted by T_0 . We also consider a paraxial ray from the source point S , reflecting on Σ at the point D and emerging at the receiver R . MultiFocusing expresses the travel time in terms of two corrections at S and R . This is done by considering fictitious waves, which initiated at the intersection point P of the normal and paraxial ray and emerges at X_0 as the wavefront Σ_S and Σ_R . Assuming that the near-surface velocity V_0 is known and constant and that the wavefronts Σ_S and Σ_R can be locally approximated by spherical surfaces results in the following expression:

$$\Delta\tau = \frac{\sqrt{(R^+)^2 - 2R^+\Delta X^+ \sin\beta + (\Delta X^+)^2} - R^+}{V_0} + \frac{\sqrt{(R^-)^2 + 2R^-\Delta X^- \sin\beta + (\Delta X^-)^2} - R^-}{V_0} \tag{1}$$

where

$$R^+ = \frac{1 + \sigma}{\frac{1}{R_{cee}} + \frac{\sigma}{R_{cre}}} ; R^- = \frac{1 - \sigma}{\frac{1}{R_{cee}} - \frac{\sigma}{R_{cre}}} \tag{2}$$

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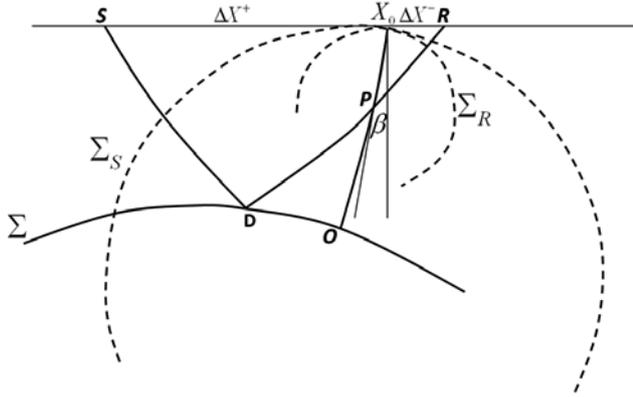


Figure 1 Geometrical scheme of MultiFocusing for a reflector Σ and imaging point X_0 . S and R are the source and receiver positions; ΔX^+ and ΔX^- are the offsets of source and receiver from the central point; Σ_s and Σ_r are the wavefronts of two fictitious waves with the centre at point P and the radii of curvatures R^+ and ΔX^- ; β is the emergent angle for the normal-incidence ray; and O is the reflection point for the normal incident ray (NIP).

$$\sigma = \frac{\Delta X^+ - \Delta X^-}{\Delta X^+ + \Delta X^- + 2 \frac{\Delta X^+ \Delta X^-}{R_{cre}} \sin \beta} \quad (3)$$

In these equations, β is the normal ray; R_{cre} and R_{cee} are the radii of curvatures of two paraxial wavefront: normal incident point wave and normal wave respectively; ΔX^+ and ΔX^- are the source and receiver offsets for a given ray with respect to the central point X_0 ; R^+ and ΔX^- are the radii of curvature of the fictitious waves defined by equations (2) and (3); V_0 is the near-surface velocity; and σ is a focusing parameter.

Let us consider now a situation when the reflection interface in Figure 1 shrinks to a diffraction point O . Then, point P coincides with point O , and $R_{cre} = R_{cee}$. Hence, from equation (2) for the radii of curvature, we have $R^+ = R^- = R_{cee} = R_{diff}$. Here R_{diff} is the radius of curvature of the diffracted wave. Substituting these values into expression (1) for move-out correction, we obtain the formula for diffraction MultiFocusing move-out:

$$\Delta \tau = \frac{\sqrt{R_{diff}^2 - 2R_{diff}\Delta X^+ \sin \beta + (\Delta X^+)^2} - R_{diff}}{V_0} + \frac{\sqrt{R_{diff}^2 + 2R_{diff}\Delta X^- \sin \beta + (\Delta X^-)^2} - R_{diff}}{V_0} \quad (4)$$

DMF can be considered as a special case of MultiFocusing. For diffraction stacking, however, only two parameters should be searched, namely R_{diff} and β . In the 3D case there are five parameters to be estimated from the data: three radii of curvatures and two emergence angles. The parameters are estimated by maximizing the semblance function calculated for all seismic traces in the super-gather in a vicinity of the imaging point. Result of the diffraction imaging is a 3D zero-

offset cube in time domain that includes mostly optimally stacked diffraction energy and residual specular reflections. Such an image contains important information regarding local subsurface heterogeneities and discontinuities.

Geology

The Bazhinov-Neocomian Formation is located in the West Siberian Basin and is outlined in green on Figure 2. Geographically, the basin resides in a swampy plain between the Ural Mountains and the Yenisey River. The basin sediments are composed of clastic rocks ranging from the Middle Triassic through to the Tertiary period.

During Tithonian and early Berriasian times, sediments were deposited in a deep water sea that covered more than one million square kilometres. During this period anoxic conditions prevailed and resulted in highly organic-rich siliceous shale layers at the bottom of the sea. Rocks of the Bazhenov Formation are thinly laminated to massive, siliceous, carbonaceous shales with layers of argillaceous silicilith. The content of silica varies from 20% to 30%, and it is as high as 50–60% in the silicilith (Nesterov et al., 1987).

The first hydrocarbon discovery was made in 1953, when a well-tested gas from Upper Jurassic sandstones and organic limestones in the Berezov field on the western margin of the basin (Ulmishek, 2003) with most of the large oil and gas field that contains a bulk of the basin’s reserves being developed between 1960 and 1980.



Figure 2 Base map of Siberian Basin in red with Bazhenov Formation outlined in green.

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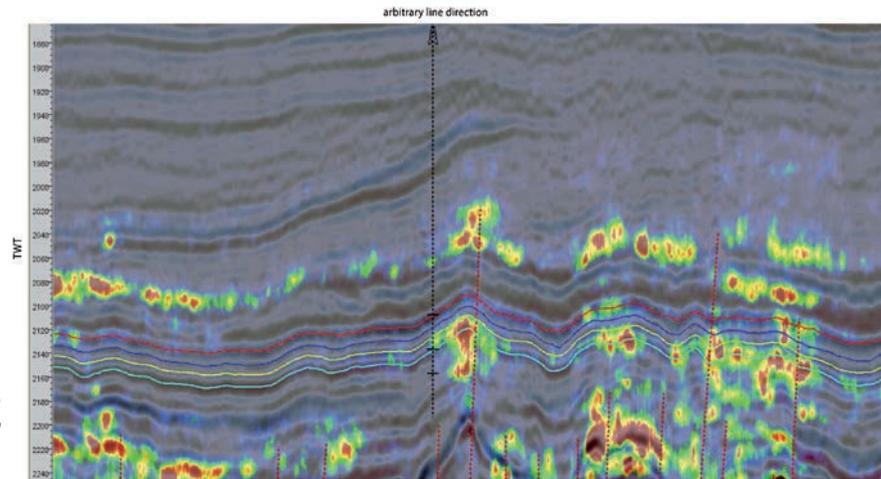


Figure 3 Arbitrary line showing the PSTM data in the background with migrated diffractivity in colour. The interpreted horizons show the top, inter-formation and base of the Bazhenov.

The Bazhenov Shale is the world's largest known deep-water source rock and is estimated to contain two trillion barrels of oil in place. This in-place oil resource is very large but productivity varies greatly and is poorly understood. The formation is between 20 m and 50 m thick and contains 5-20% TOC. The self-sourced reservoir rocks are fractured siliceous shales with the fracturing strongly dominating along the bedding planes. The most likely cause for these fracture zones is hydrocarbon generation, which resulted in overpressure that is larger than the lithostatic pressure. Understanding and mapping highly fractured areas is the key to successfully extracting oil from this source rock.

Study outline

MultiFocusing diffraction imaging was performed on a narrow azimuthal 3D dataset of approximately 200 km². These data were not acquired with wide azimuths and as a result no azimuthal velocity analysis could be done. A conventional PSTM dataset was obtained and key horizons over and around the reservoir interval were picked. Incomplete log information from six wells that are located within the survey area was available and a detailed petrophysical analysis was performed. The result of this workflow was a calculated fracture porosity estimation using a modified Archie equation. Corrected production data are available and a calibration of the calculated fracture porosity, with average diffractivity and production data with average diffractivity over the reservoir interval, was made.

Study results

The diffractivity resulting from the MultiFocusing methodology is largely free of specular events that generally overwhelm the weak diffraction events. The diffraction stack was migrated using dip corrected velocities and the resulting seismic cube was inputted into an interpretation platform for the interpretation and calibration part of the project.

Figure 3 shows an arbitrary line that was extracted from the migrated diffraction data. The background represents the PSTM data and the diffractivity is shown in colour. Previous synthetic and field studies are indicating that there is a good relationship between diffraction strength and fracture density (Berkovich et al., 2009). As such, stronger colours are indicative for more fractured areas. The figure also displays the horizons that were picked at the top, inter-formation and base of the Bazhenov, together with some faults that were interpreted on the diffraction results. The annotated well was a good oil producer from the Bazhenov and the diffractivity values are high at this location. This is in agreement with the theory that highly fractured rocks are producing large diffraction events. Additional anomalies are observed in areas of uplift and compression.

The available log data were edited and a petrophysical interpretation was performed in order to define fracture interval and fracture parameters. The diffractivity values were averaged over the reservoir interval and cross-plotted versus these calculated fracture porosity values. Normalized production data from within the Bazhenov Formation was made available and as an additional calibration point, these data points were calibrated to the averaged diffractivity over the interval. Figure 4 displays on the left site the cross-plot between the production data and the average diffractivity values. On the left hand site, the calculated fracture porosity was multiplied by the column height and cross-plotted versus the average diffractivity.

Both cross-plots exhibit a very high correlation to the diffractivity. The correlation coefficients of both, the production rate and diffractivity and the fracture porosity and diffractivity are close to 0.8.

When a wide azimuth 3D survey is available, the velocity anisotropy will be added to this workflow. A wave field penetrating an isotropic medium will be spherical whereas the wave will exhibit an elliptical shape if it encounters an anisotropic rock type. This ellipse is defined by a slow

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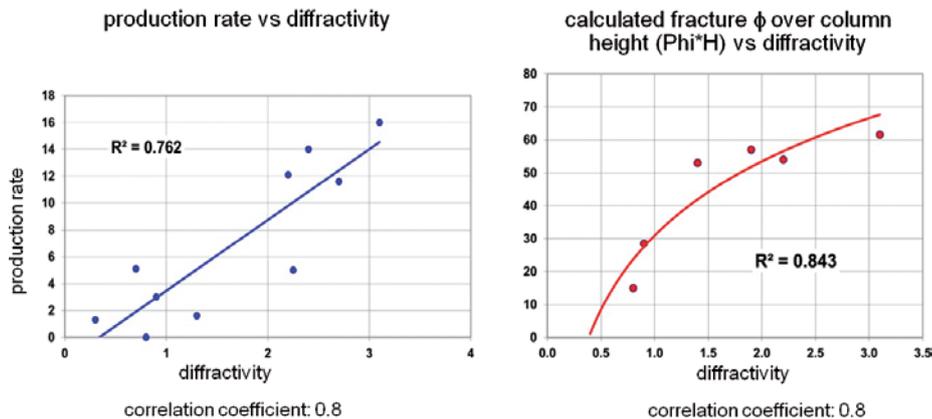


Figure 4 Left site: normalized production rate versus average diffractivity. Right site: calculated fracture porosity multiplied by the column height versus average diffractivity.

velocity and a fast velocity component. The output of a velocity anisotropy analysis is two velocity cubes, V_f (fast velocity) and V_s (slow velocity). These two variables can be combined in various ways to generate anisotropy attributes such as direction of anisotropy and by dividing V_s by V_p , the percentage of anisotropy in the rock layer. The MultiFocusing technology produces very detailed velocities at each trace and sample interval and as they are dip corrected, the resulting velocity attributes are more accurate than in conventional processing and add valid information to mapping fractured intervals.

Conclusion

The MultiFocusing imaging technology is able to describe not only reflection but also diffraction events from conventionally acquired seismic data and is performed in the pre-stack domain. By optimally summing diffracted events and attenuating specular reflections, an image that contains mostly diffraction energy is being generated. Synthetic and seismic studies are indicating a direct relationship between fracture density and intensity of the diffractivity. This phenomenon is being exploited to use seismic to directly map zones within unconventional/tight reservoirs that are naturally fractured.

A diffraction imaging study that was performed on a vintage 3D dataset from Siberia over the Bazhenov Formation is discussed. The Bazhenov Shale is the world's largest known deep-water source rock and the latest estimation puts its oil in place at two trillion barrels. The current assumption is that fractures developed in conjunction with hydrocarbon generation as the resulting overpressure exceeded the lithostatic pressure within the source rock. A study of a number of wells that have production data from within the shale shows that a higher fracture density ensures a better oil recovery rate.

The seismic data was not acquired with wide azimuth and no azimuthal velocity analysis was executed. Such an analysis is very useful and the velocity attributes, which for example are indicating the direction and percentage of anisotropy, can be added to an integrated fracture detection approach.

The migrated diffractivity cube was loaded into an interpretation workstation, key horizons were picked and wells calibrated. Available log data were edited and a petrophysical interpretation was performed. Finally, the fracture interval and parameters were defined. Furthermore, normalized production data were made available for the calibration process.

A clear association between diffractivity and well results is present: wells that had higher production rates and higher fracture porosities intersected with areas of higher diffraction values. Although the Bazhenov Shale does not exhibit large structural elements, small uplifts and compressions are observed and there is a good agreement between these elements and stronger diffraction anomalies, which is to be expected as these zones are under higher pressure.

The MultiFocusing diffraction imaging methodology makes it possible to extract the weak diffractive element from the overall wave field and suppresses the strong specular events. This technology has been tested on synthetic and field data and good-to-excellent correlations between diffraction values and well information are being seen. In addition, this technique doesn't require seismic with specific acquisition design and is a useful tool to map naturally occurring fracture swarms/corridors in unconventional oil and gas saturated rocks. This advantage shortens the time between exploration/mapping and production and enhances the profitability of the unconventional play.

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